2019 Annual Markets Report

Internal Market Monitor

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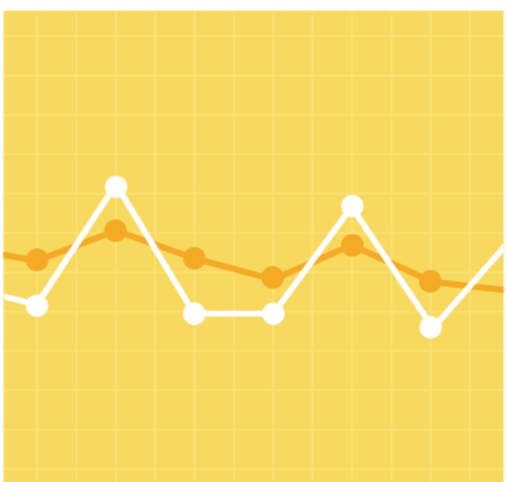

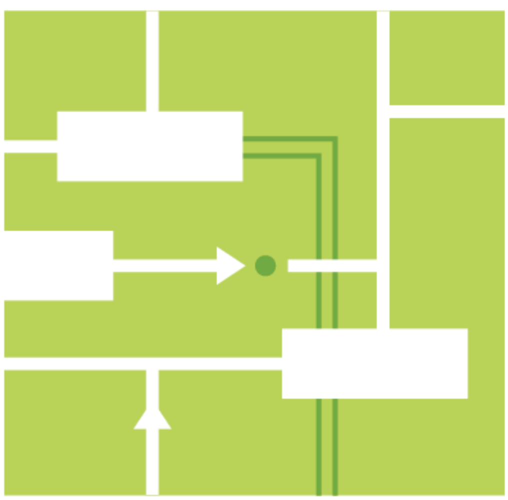

Document Revision History		
Date	**Version**	**Remarks**
5/26/2020	Original	Initial Posting
6/9/2020	Revision 1	Correction to the driver of reduced regional network loads costs in 2019. This is largely attributable to lower peak demand and lower recovered infrastructure costs, and not to reduced administration costs as cited in the original report [correction on pages 5 and 26].

Preface/Disclaimer

The Internal Market Monitor (IMM) of ISO New England (ISO) publishes an Annual Markets Report (AMR) that assesses the state of competition in the wholesale electricity markets operated by the ISO. The *2019 Annual Markets Report* covers the ISO's most recent operating year, January 1 to December 31, 2019. The report addresses the development, operation, and performance of the wholesale electricity markets administered by the ISO 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.17.2.4, *Market Monitoring, Reporting, and Market Power Mitigation*:

> *The Internal Market Monitor will prepare an annual state of the market report on market trends and the performance of the New England Markets and will present an annual review of the operations of the New England Markets. The annual report and review will include an evaluation of the procedures for the determination of energy, reserve and regulation clearing prices, Net Commitment-Period Compensation costs and the performance of the Forward Capacity Market and Financial Transmission Rights Auctions. The review will include a public forum to discuss the performance of the New England Markets, the state of competition, and the ISO's priorities for the coming year. In addition, the Internal Market Monitor will arrange a non-public meeting open to appropriate state or federal government agencies, including the Commission and state regulatory bodies, attorneys general, and others with jurisdiction over the competitive operation of electric power markets, subject to the confidentiality protections of the ISO New England Information Policy, to the greatest extent permitted by law.*[1]

This report is being submitted simultaneously to the ISO and the Federal Energy Regulatory Commission (FERC) per FERC order:

> *The Commission has the statutory responsibility to ensure that public utilities selling in competitive bulk power markets do not engage in market power abuse and also to ensure that markets within the Commission's jurisdiction are free of design flaws and market power abuse. To that end, the Commission will expect to receive the reports and analyses of a Regional Transmission Organization's market monitor at the same time they are submitted to the RTO.*[2]

This report presents the most important findings, market outcomes, and market design changes of New England's wholesale electricity markets for 2019. Section 1 summarizes the region's wholesale electricity market outcomes, the important market issues and our recommendations for addressing these issues. It also addresses the overall competitiveness of the markets, and market mitigation and market reform activities. Section 1 through Section 8 includes more detailed discussions of each of the markets, market results, analysis and recommendations. A list of acronyms and abbreviations is included at the back of the report. Key terms are italicized and defined within the text and footnotes.

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[1] *ISO New England Inc. Transmission, Markets, and Services Tariff* (ISO tariff), Section III.A.17.2.4, *Market Rule 1*, Appendix A, "Market Monitoring, Reporting, and Market Power Mitigation", http://www.iso-ne.com/static-assets/documents/regulatory/tariff/sect_3/mr1_append_a.pdf.

[2] FERC, PJM Interconnection, L.L.C. et al., *Order Provisionally Granting RTO Status*, Docket No. RT01-2-000, 96 FERC ¶ 61, 061 (July 12, 2001).

A number of external and internal audits are also conducted each year to ensure that the ISO followed the approved market rules and procedures and to provide transparency to New England stakeholders. Further details of these audits can be found on the ISO website.[3]

All information and data presented are the most recent as of the time of writing. The data presented in this report are not intended to be of settlement quality and some of the underlying data used are subject to resettlement.

In case of a discrepancy between this report and the ISO New England Tariff or Procedures, the meaning of the Tariff and Procedures shall govern.

Underlying natural gas data are furnished by the Intercontinental Exchange (ICE):

ICE Global markets in clear view

Underlying oil and coal pricing data are furnished by Argus Media.

[3] See https://www.iso-ne.com/about/corporate-governance/financial-performance

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Section 1
Executive Summary

The *2019 Annual Markets Report* by the Internal Market Monitor (IMM) at ISO New England (ISO) addresses the development, operation, and performance of the wholesale electricity markets administered by the ISO. The report presents an assessment of each market based on market data and performance criteria. In addition to buying and selling wholesale electricity day-ahead and in real-time, the participants in the forward and real-time markets buy and sell operating reserve products, regulation service, Financial Transmission Rights, and capacity. These markets are designed to ensure the competitive and efficient supply of electricity to meet the energy needs of the New England region and secure adequate resources required for the reliable operation of the power system.

Overall, the ISO New England capacity, energy, and ancillary service markets performed well and exhibited competitive outcomes in 2019. The day-ahead and real-time energy markets performed well, with electricity prices reflecting changes in underlying primary fuel prices and electricity demand. In 2019, there were no periods in the real-time energy market when a relative shortage of energy and reserves resulted in scarcity pricing. This was due to the combination of surplus supply capacity, mild summer weather and the lack of sustained cold temperatures during the winter. This was in contrast to last year, when summer and winter system events resulted in extremely high energy or reserve scarcity pricing. The contrast between this year and last, when there was also a high level of surplus supply on average, highlights that the market in New England, like in other jurisdictions, can experience scarcity events due to unanticipated supply and demand shocks. The New England system, in particular, can also be susceptible to higher energy prices and reliability issues during cold weather events when the natural gas system is constrained.

The overall price-cost markups in the day-ahead energy market were within a reasonable range for a competitive market.[4] The structural competitiveness of the real-time energy market also improved further in 2019. This was evident by the fact that there were much fewer hours with pivotal suppliers in real-time compared with the prior four years.[5] This was due to the increase in the supply margin and a relatively unconcentrated portfolio ownership. Further, the number of energy market supply offers mitigated for market power remained very low, totaling 1,104 unit-hours, or just 0.02% of all supply offers.

For the sixth consecutive year, the forward capacity auction (FCA) procured surplus capacity, as the capacity clearing price continued a downward trend. The most recent auction, FCA 14, cleared at an all-time low price of $2/kW-month. The surplus capacity in FCA 14 was almost 1,500 MW, or 5%, above the installed capacity requirement, despite a significant amount of capacity (over 2,500 MW) exiting the capacity market, mostly for a one-year period, in response to low prices.

The total wholesale cost of electricity in 2019, at $9.8 billion, was considerably lower than in 2018, decreasing by 19%, or by $2.3 billion. Lower energy costs accounted for about 85% of the overall decrease.

[4] Price-cost markup is an estimate of the premium in consumer prices as a result of supply resources bidding above their short-run marginal costs in the energy market.

[5] In other words, there was a lower frequency with which the capacity of the largest supplier was needed to meet demand.

Energy costs totaled $4.1 billion, down 32%, or $1.9 billion, on 2018. The decrease was driven by lower natural gas prices, particularly due to milder weather during the high electricity demand seasons of summer and winter. This was in contrast to a 2018 winter with an extended cold snap, and a hot and humid summer in 2018, which led to high natural gas prices in winter and much higher electricity prices in both seasons. Natural gas prices averaged $3.26/MMBtu in 2019, down by $1.69/MMBtu, or by 34% on 2018 prices.[6] In January 2019, natural gas prices averaged $6.99/MMBtu, significantly lower than the January 2018 average price of $15.97/MMBtu. Year-over-year, January energy costs were down by $671 million. Electricity demand in the third quarter of the year decreased by 6%, or by 1,011 MW per hour, on average, and drove a 4% decrease in annual demand. On a weather-normalized basis, demand was down slightly, continuing a longer-term downward trend due to the increase in utility-backed energy efficiency programs and behind-the-meter photovoltaic generation.

Capacity costs totaled $3.4 billion, down by 6%, or $0.2 billion, driven by clearing prices in the ninth and tenth Forward Capacity Auctions (FCA 9 and 10).[7] In FCA 8, high system-wide prices of $7.03/kW-month were triggered by capacity deficiency and administrative pricing. The market reacted in FCA 9 by attracting new supply investment, with clearing prices peaking at $9.55/kW-month, bringing the region back to surplus capacity. The clearing price and resulting payments in FCA 10 were comparable to FCA 8.

Capacity costs will continue to decline after June 2019 and through June 2024, as new resources enter the market and a higher capacity surplus applies downward pressure to capacity prices. In the past two auctions (FCA 13 and 14), the market has responded to lower clearing prices by removing a significant amount of existing capacity, either permanently or temporarily.

Capacity prices have fluctuated in response to changes in the region's capacity margin as one would expect, with prices increasing in response to low or negative margins, and vice versa. However, achieving sound economic price formation in the Forward Capacity Market (FCM) continues to be a challenge. Two challenging factors negatively impacting price formation have been the participation of state-sponsored resources with out-of-market revenues in the capacity market, and the reliability retention of resources for their energy security attributes. Both of these factors have reduced the auction clearing price (for at least a portion of supply) as a result of out-of-market payments.

The first challenge has been to accommodate new resources that secure revenue through state-sponsored programs designed primarily to meet state environmental goals. These out-of-market revenues economically advantage a subset of resources, which can lead to market distortions and price suppression in the capacity market. Starting with FCA 13, the ISO introduced Competitive Auctions with Sponsored Policy Resources (CASPR), which, along with the Minimum Offer Price Rule (MOPR), helps address this issue. MOPR helps ensure proper price formation in the primary auction by removing the impact of subsidies from offer prices of new entrants. CASPR provides a market-based mechanism for state-sponsored resources to enter the FCM through a secondary market, known as a substitution auction. However, while the price-suppressing impact is mitigated in the first year, the sponsored resources will likely be price-takers in subsequent auctions, thereby

[6] 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 to hour ending 11 on D+2.

[7] FCA 9 corresponds to the delivery period June 1, 2018 to May 31, 2019, and FCA 9 to June 1, 2019 to May 31, 2020.

applying downward pressure to FCA clearing prices in the long-term. This underlying compromise behind the CASPR design is unavoidable as long as (a) the resource is counted toward meeting capacity requirements and (b) the resources continue to receive out-of-market revenues. Also, while CASPR and the associated market power mitigation rules help mitigate price suppression concerns for new resources, they do not address the impact of out-of-market revenues paid to retain existing resources, when they might otherwise retire.

The first two CASPR substitution auctions have had limited participation. In the substitution auction following FCA 13, a 54-MW wind resource cleared in the auction against an existing dual-fuel oil/gas-fired resource, which will retire in the corresponding capacity commitment period.[8] In FCA 14, the substitution auction was not run, as there were no eligible existing resources to clear against the almost 300 MW of new supply resources seeking to acquire a capacity supply obligation.

The second challenge is the reliability retention of resources in the FCM based on their underlying energy-security attributes; attributes that are not explicitly valued in the current FCM or energy market designs. The ISO retained the Mystic 8 and 9 resources (approx. 1,400 MW in total) in FCAs 13 and 14 to satisfy a reliability need for energy security. This was done prior to the auction, and the retained capacity from the two resources was represented as price-taking capacity ($0 bid price) in the auction. While this administrative pricing action likely impacted price formation in both auctions, the price formation issue more directly derives from a missing product (energy security) that is not being appropriately valued in the energy markets, or reflected in the capacity market.

Out-of-market actions often have the potential to interfere with price formation. It is not clear to what extent FCA prices would have been different had energy security been explicitly valued and those that could provide it appropriately compensated. In order to accurately simulate the resulting valuation and to estimate the impact, a completely different market model (including FCM, energy, and reserves) would need to be developed as the appropriate counter-factual.

However, the issue of not valuing energy security is transient. Going forward, the ISO has proposed an interim measure to compensate for energy security for Winter 2023/24, and has recently proposed a long-term market-oriented approach.[9, 10] This measure will seek to explicitly value the energy security service and put all resources that can provide the service on equal footing to compete for the resulting market opportunity.

Overall, the FCM and the energy market exhibited competitive outcomes despite the continued presence of structural market power. Measures are in place in both markets to identify and mitigate market power. The identification of seller-side market power in the energy and capacity markets relies on a pivotal supplier test that measures the ability of a supplier to increase price by withholding supply. Buyer-side market power mitigation (MOPR as mentioned above), which is applicable in the capacity market, prevents the use of subsidies to allow a participant to enter via

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[8] The clearing price in the substitution auction was $0/kW-month, meaning the retiring resource sells its capacity supply obligation to the new resource for $0/kW-month and receives a net amount of $3.80/kW-month – the difference between the primary and substitution auction prices - similar to a severance payment.

[9] See ISO New England Inc., Compliance Filing of Energy Security Improvements Addressing New England's Energy Security Problems; Docket Nos. EL18-182-000 and ER20-1567-000, at https://www.iso-ne.com/static-assets/documents/2020/04/energy_security_improvements_filing.pdf

[10] See also, Comments of the IMM on Energy Security Improvements, at https://www.iso-ne.com/static-assets/documents/2020/05/imm_esi_comments.pdf

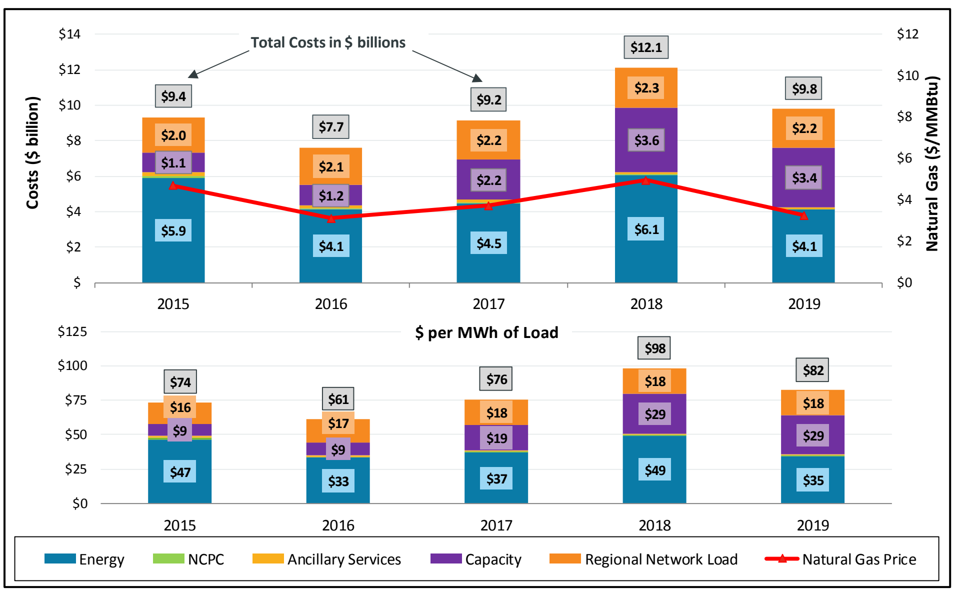
the primary auction at prices below competitive levels and to artificially lower the market-clearing price. Both mitigation processes for the energy and capacity markets have functioned reasonably well and have resulted in competitive outcomes. However, the mitigation measures for system-level market power in the real-time energy market provide suppliers a considerable degree of deviation from competitive marginal-cost offers before the mitigation rules would trigger and mitigate a supply offer. The potential impact of structural market power in the real-time market and the effectiveness of existing mitigation thresholds will be further evaluated.

An important function of the IMM is to assess and make recommendations on potential enhancements to current market design and rules. Table 1-2 at the end of this section contains a list of our recommended changes and areas to be further evaluated by the ISO that could improve market performance.

1.1 Wholesale Cost of Electricity

In 2019, the total estimated wholesale market cost of electricity was $9.8 billion, a decrease of $2.3 billion (19%) compared to 2018 costs.[11] Together, energy and capacity costs accounted for 93% of the overall decrease. The total cost equates to $82 per megawatt hour (MWh) of wholesale electricity demand served. The components of the wholesale cost over the past five years, along with the average annual natural gas price (on the right axis), are shown in Figure 1-1 below.

Figure 1-1: Wholesale Costs and Average Natural Gas Prices



A description of each component, along with an overview of the trends and drivers of market outcomes, is provided below. The amount of each category in dollars, dollars per MWh of load served, along with the percentage contribution of each category to the overall wholesale cost in 2019 is shown in parenthesis.

[11] 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.

Energy ($6.0 billion, $35/MWh, 42%): Energy costs are a function of energy prices (LMPs) and wholesale electricity demand:

- Day-ahead and real-time LMPs averaged $31.22 and $30.67/MWh, respectively (simple average). Compared with 2018, prices were down by about 30%, or by almost $13/MWh, in both markets.
- Supply and demand-side participants continued to exhibit a strong preference towards the day-ahead market, with 98% of the cost of energy settled on day-ahead prices.
- Total energy costs track closely with average natural gas prices, with gas continuing to be the primary driver of LMPs. Gas prices averaged $3.26/MMBtu, a decrease of 34%, or $1.69/MMBtu, compared with 2018. The 32% fall in energy costs tracked closely with the reduction in natural gas prices.
- Demand (or real-time load) averaged 13,598 MW per hour, down 4% (or almost 500 MW per hour) on 2018. A material factor was the milder 2019 summer compared to hot and humid conditions in 2018. While demand was down across all quarters during 2019, the decrease in summer demand accounted for about half of the annual reduction. While weather largely explains year-over-year changes, wholesale load has been trending down in recent years due to energy efficiency gains and increased behind-the-meter generation, particularly photovoltaic generation. Controlling for changes in weather, load (weather-normalized) continued to decline, by about 1% in 2019 compared with 2018.

Regional Network Load Costs ($2.2 billion, $18/MWh, 22%): Regional Network Load (RNL) costs cover the use of transmission facilities, reliability, and certain administrative services. Transmission costs in 2019 were 5% lower than 2018 costs, primarily driven by reduced peak demand and lower recovered infrastructure costs.

Capacity ($3.4 billion, $29/MWh, 35%): Capacity costs were relatively stable, decreasing by 6%, or by $0.2 billion. Capacity clearing prices peaked in FCA 9 (2018/19) at $9.55/kW-month, before declining in FCA 10 (2019/20) to $7.03, as new resources entered the market. New entry has added to a system surplus and applied downward pressure on prices. Capacity costs will continue to decline, based on lower trending prices through May 2024.

NCPC ($0.03 billion, $0.3/MWh, 0.3%): Uplift, the portion of production costs in the energy market not recovered through the LMP, totaled $30 million, a decrease of about $40 million (down by 57%) on 2018. NCPC remained relatively low when expressed as a percentage of total energy payments, at just 0.7%, continuing a downward trend in the share of NCPC from prior years, due to lower energy prices, fewer reliability commitments and market design improvements.

The decrease in total 2019 NCPC costs was driven by two factors: the significant decrease in fuel and energy costs as discussed above, and also, the absence of manual operator actions, in the form of posturing oil-fired generators for fuel security, which occurred during the cold snap of January 2018.

Ancillary Services ($0.1 billion, $0.6/MWh, 1%): Ancillary services include costs of additional services procured to ensure system reliability, including operating reserve (real-time and forward markets), regulation, and the winter reliability program.[12] In 2019, the costs of ancillary services decreased by 29%, driven by the reduction in energy prices and the end of the winter reliability

[12] The winter reliability program ended after Winter 2018, coinciding with the start of the pay for performance rules in the capacity market in June 2018.

program after Winter 2018. The end of the five-year winter program coincided with the start of pay for performance rules in June 2018.

1.2 Overview of Supply and Demand Conditions

Key statistics on some of the fundamental market trends over the past five years are presented in Table 1-1 below. The table comprises five sections: electricity demand, estimated generation costs, electricity prices, wholesale costs and the New England real-time supply mix.

Table 1-1: High-level Market Statistics

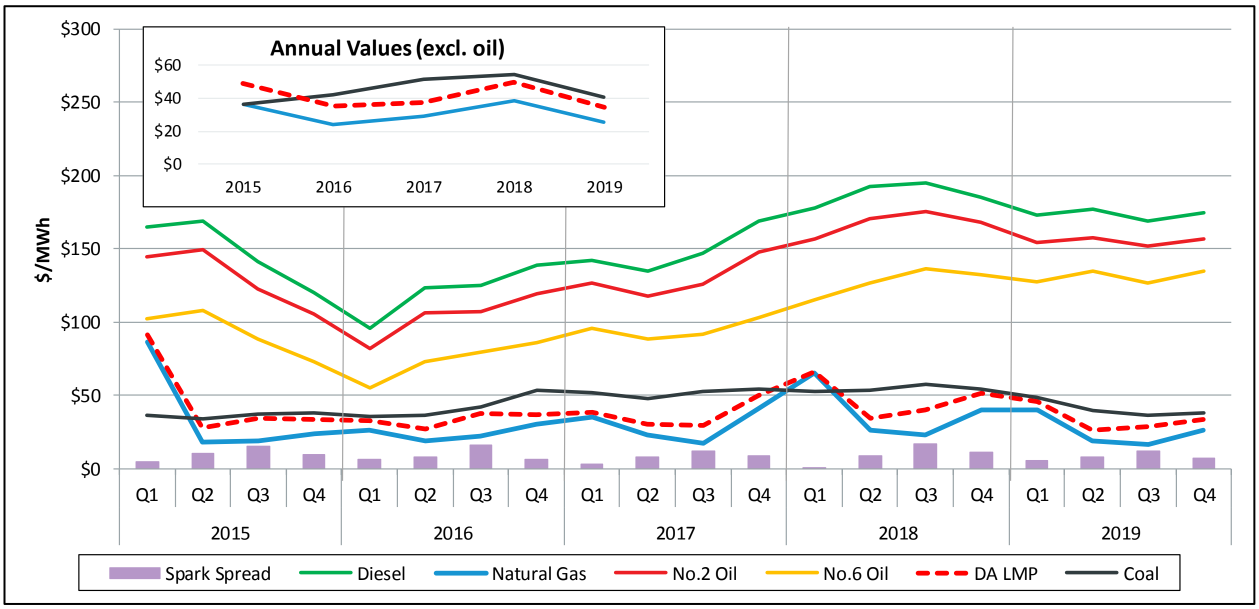
Statistic	2015	2016	2017	2018	2019	% Change 2019 to 2018
Demand (MW)						
Real-time Load (average hourly)	14,493	14,165	13,837	14,095	13,598	↓ -4%
Weather-normalized real-time load (average hourly)[a]	14,358	14,111	13,737	13,725	13,546	↓ -1%
Peak real-time load (MW)	24,437	25,596	23,968	26,024	24,361	↓ -6%
Generation Fuel Costs ($/MWh) [b]						
Natural Gas	36.62	24.29	29.02	38.61	25.41	↓ -34%
Coal	36.34	41.97	51.57	54.54	40.54	↓ -26%
No.6 Oil	92.63	73.34	94.76	127.80	130.90	↑ 2%
Diesel	148.68	120.78	148.36	187.60	173.54	↓ -7%
Hub Electricity Prices - LMPs ($/MWh)						
Day-ahead (simple average)	41.90	29.78	33.35	44.13	31.22	↓ -29%
Real-time (simple average)	41.00	28.94	33.93	43.54	30.67	↓ -30%
Day-ahead (load-weighted average)	44.64	31.56	36.15	46.85	32.32	↓ -31%
Real-time (load-weighted average)	45.03	31.74	35.23	46.88	32.82	↓ -30%
Estimated Wholesale Costs ($ billions)						
Energy	5.9	4.1	4.5	6.1	4.1	↓ -32%
Capacity	1.1	1.2	2.2	3.6	3.4	↓ -6%
Net Commitment Period Compensation	0.1	0.1	0.1	0.1	0.03	↓ -57%
Ancillary Services	0.1	0.1	0.1	0.1	0.1	↓ -29%
Regional Network Load Costs	2.0	2.1	2.2	2.3	2.2	↓ -5%
Total Wholesale Costs	**9.3**	**7.6**	**9.1**	**12.1**	**9.8**	↓ **-19%**
Supply Mix [c]						
Natural Gas	41%	41%	40%	40%	39%	↓ -1%
Nuclear	25%	26%	26%	25%	25%	⇨ 0%
Imports	16%	16%	17%	17%	19%	↑ 2%
Hydro	6%	6%	7%	7%	7%	⇨ 0%
Other[d]	6%	6%	6%	6%	6%	⇨ 0%
Wind	2%	2%	3%	3%	3%	⇨ 0%
Coal	3%	2%	1%	1%	0%	⇨ -1%
Oil	2%	0%	1%	1%	0%	⇨ -1%

[a] Weather-normalized results are those that would have been observed if the weather were the same as the long-term average.
[b] Generation costs are calculated by multiplying the daily fuel price ($/MMBtu) by the average standard efficiency of generators for each fuel (MMBtu/MWh)
[c] Provides a breakdown of total supply, which includes net imports. Note that section 2 provides a breakdown of native supply only.
[d] The "Other" fuel category includes landfill gas, methane, refuse, solar, and steam
⇨ denotes change is within a band of +/- 1%

As can be seen from Table 1-1, costs for the major fuels decreased significantly in 2019, with gas prices being the key driver of the decrease in electricity prices. The system continues to be highly dependent on natural gas, accounting for almost 40% of the total supply mix. The fuel mix did not change substantially year-over-year. Renewable generation types (which are included in the wind, solar, and hydro categories) have also not experienced significant changes over the five-year period.

Energy Market Supply Costs: The trend in quarterly estimated generation costs for each major fuel, along with the day-ahead on-peak LMP over the past five years, is shown in Figure 1-2 below.[13, 14] The inset graph shows annual values and excludes oil prices to better illustrate the long-term trend.

Figure 1-2: Quarterly and Annual (Inset) Generation Costs and Day-Ahead LMP (On-Peak Periods)



The cost of natural gas and coal decreased in 2019, with No.6 oil being the only major fuel with a slight increase of 2%. The strong positive correlation between natural gas prices (blue line) and the LMP (dashed red line) is evident. Coal prices in 2019 decreased by 26% over the previous year. Falling coal demand throughout the country outweighed production cuts, leading to oversupply in the market and lower prices.[15] Both Brent (10%) and WTI (12%) crude oil prices decreased as United States oil production increases put downward pressure on prices, leading to lower prices in New England.[16]

The average cost of a combined-cycle natural gas-fired generator was about $25/MWh in 2019, down 34% compared with $39/MWh in 2018. On-peak LMPs saw a corresponding decrease of

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[13] On-peak periods are weekday hours ending 8 to 23 (i.e., Monday through Friday, excluding North American Electric Reliability Corporation [NERC] holidays.

[14] Generation costs for each fuel are calculated by multiplying the fuel costs (in $/MMBtu) by a representative standard heat rate for generators burning each fuel (in MMBtu/MWh). For example, the heat rate assumed for a natural gas-fired generator is 7.8 MMBtu/MWh. The cost estimates exclude variable operation and maintenance and emissions costs.

[15] https://www.eia.gov/outlooks/steo/report/coal.php

[16] https://www.eia.gov/todayinenergy/detail.php?id=42415

30%. The average natural gas cost ranged from $17/MWh in Q3 to $40/MWh in Q1 2019, significantly lower than the $23-$65/MWh range in 2018, the high end of which was driven by cold weather in January 2018.

Spark spreads (the difference between the LMP and the estimated energy production cost of a gas-fired generator) were highest again during Q3 in 2019, when more expensive, or less efficient, generators were dispatched to meet higher system demand. In contrast, Q1 spreads were again the lowest of the year, at $6/MWh, as higher gas prices tend to push more expensive gas-fired generators out-of-merit. Spark spreads were down slightly in 2019, at $9.02/MWh for the average gas-fired generator, driven by lower electricity demand in Q3 and higher nuclear generator availability in Q4.

The difference between average generation costs for natural gas-fired generators and generators of competing fuel types (coal and oil) remained large in 2019. On average, coal and No.6 oil generation costs were higher than natural gas costs by $15 and $105/MWh, respectively. Oil and coal generation accounted for only a half a percent of total supply in 2019.

Emissions costs are not included in the generation cost estimates in Figure 1-2 above, and have a relatively small, albeit increasing, impact on operating costs. The key driver of emission costs for all New England generators is the Regional Greenhouse Gas Initiative (RGGI), the marketplace for carbon dioxide (CO_2) credits. In addition, a new CO_2 cap-and-trade program that places an annual cap on aggregate CO_2 production from fossil fuel generators began in Massachusetts in 2018.[17] Both cap-and-trade programs attempt to make the environmental cost of CO_2 explicit in dollar terms so that producers of energy consider it in their production decisions.

In 2019, RGGI prices increased 22% year-over-year, (from $4.50/short ton to $5.51/short ton). This equates to an average 2019 RGGI CO_2 cost for a natural-gas fired generator of $2.51/MWh, or about 10% on top of the fuel-related cost. Massachusetts CO_2 prices were estimated to remain in the $7-8/short ton range in 2019, adding about $3.20 to $3.65/MWh to the average variable generation cost of a natural-gas fired generation located in that state.[18]

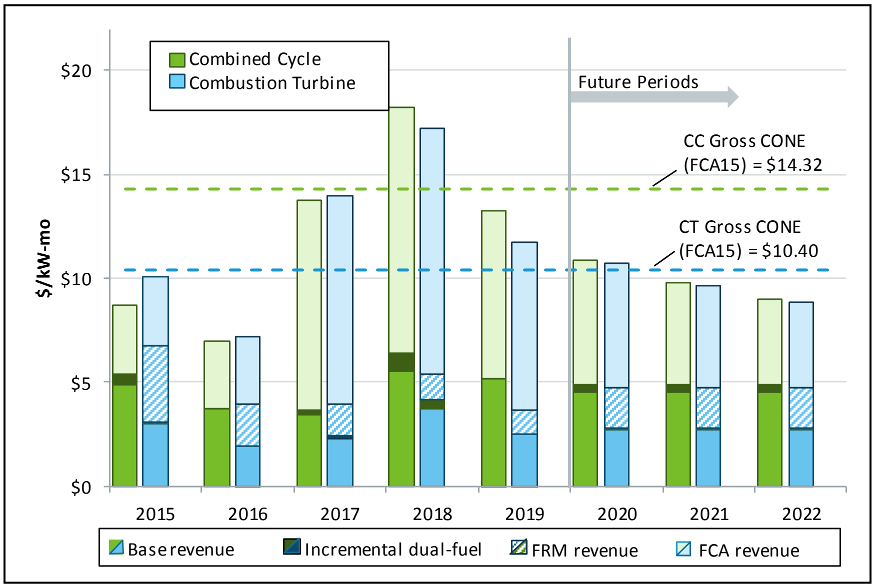
Generator Profitability: New generator owners rely on a combination of net revenue from energy and ancillary service (E&AS) markets and forward capacity payments to cover their fixed costs. The total revenue requirement for new capacity, before revenues from the energy and ancillary services markets are accounted for, is known as the Cost of New Entry, or CONE.

A simulation analysis was conducted to assess whether historical energy and capacity prices were sufficient to cover CONE. The results are presented in Figure 1-3 below. Each stacked bar represents revenue components by generator type and year. The analysis enables a comparison of total expected net revenue to the estimated CONE for combined cycle (CC) and combustion turbine (CT) resources. If the height of a stacked bar chart rises above the relevant CONE estimate, overall market revenues are sufficient to recover total costs.

[17] 310 CMR 7.74: Reducing CO2 Emissions from Electricity Generating Facilities (https://www.mass.gov/guides/electricity-generator-emissions-limits-310-cmr-774)

[18] The conversion of CO_2 costs in $/ton to $/MWh assumes an average heat rate of 7.8 MMBtu/MWh and a natural gas emissions rate of 117 lbs/MWh.

Figure 1-3: Estimated Revenue and Profitability for New Gas-fired Generators



Notes: Base revenue is the net revenue from E&AS markets. Additional revenue to CTs in the forward reserve market and to CC and CT with dual-fuel capability is also modelled.

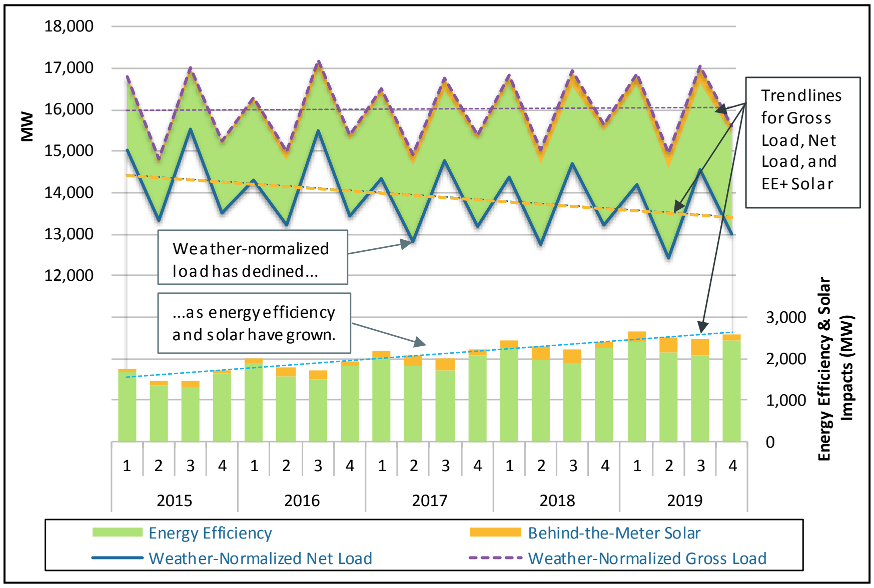
Compared to 2018, the simulation results show energy net revenues for 2019 decreasing by approximately 20% for dual-fuel combined cycle generators and approximately 34% for dual-fuel combustion turbines. Revenue for gas-only generators dropped by approximately 7% and 26% for combined cycle and combustion turbines generators, respectively. The year-over-year decreases are a reflection of the lower energy prices that resulted from generally milder weather and system conditions in 2019. Dual-fuel generators are especially impacted under these conditions because oil capability offers no advantage when natural gas remains relatively inexpensive.

In recent years, capacity prices were generally high enough to support the entry of new gas-fired generation. However, capacity prices have been trending downwards reflecting a system that is increasingly long on capacity. Total revenues from the energy and capacity markets appear insufficient to support new entry from combined cycle generators and would likely only incent the most efficient of combustion turbines to enter the region's energy market. While two recent forward capacity auctions (FCA12, FCA13) have each had the entry of one new gas-fired generator, no new gas-fired generation cleared in the most recent auction (FCA14).[19]

Energy Market Demand: The demand for electricity is weather-sensitive and this contributes to the seasonal variation in energy prices. New England's net native electricity demand, referred to as net energy for load (NEL) averaged 13,598 MW per hour in 2019, down 4% on 2018. Energy efficiency, and to a lesser but growing extent, behind–the-meter photovoltaic (PV) generation continue to have a significant downward impact on NEL as shown in Figure 1-4 below.

[19] It should be noted that CONE benchmarks are produced from financial and engineering studies that estimate the cost of adding green-field generators. In practice, the cost of new entry for a generator may be lower, or higher, than the current CONE benchmarks for a number of reasons. In particular, when new generators are built on existing generation sites or when there are material additions to the capacity of an existing operational plant, the presence of existing infrastructure tends to lower fixed costs. Conversely, the cost of permitting and litigation in New England can add significantly to project costs, including time delays, of new projects.

Figure 1-4: Average Quarterly Weather-Normalized Load with Energy Efficiency and Solar Impacts



From the figure above, we can see that energy efficiency has the largest impact on NEL. The average hourly impact on wholesale demand has grown from about 1,510 MW in 2015 to 2,280 MW in 2019, a 50%, or 770 MW, increase. Behind-the-meter PV is also having an impact, decreasing average load by an estimated 290 MW in 2019, but has increased by almost 200% from just over 100 MW in 2015.

Operating Reserves: The bulk power system needs reserve capacity in order to respond to contingencies, such as those caused by unexpected outages. The system reserve requirement has been relatively constant over the past five years, with an average total ten-minute reserve requirement of 1,700 MW and total thirty-minute reserve requirement of about 2,500 MW.

In 2019, the average thirty-minute operating reserve margin was over 3,000 MW, about 270 MW higher than the average margin in 2018. This was due to additional capacity from new generators and demand response assets. The 10-minute spinning reserve margin averaged over 2,200 MW, similar to the 2018 margin.

Imports and Exports: New England has transmission connections with Canada and New York. Under normal circumstances, the Canadian interfaces reflect net imports of power into New England whereas the interfaces with New York can reflect net imports or net exports, depending on market conditions. Net imports have been consistent over the past four years, meeting between 17% to 19% of native demand. In 2019, net imports averaged 2,633 MW per hour, an increase of about 200 MW on 2018.

About 75% of net imports were from the Canadian provinces, with the remaining imports coming from the New York North interface. Real-time net interchange with Canada averaged 1,977 MW per hour in 2019, a decrease of 4% (80 MW) on 2018. The average hourly real-time net interchange with New York increased significantly for a second year in row, by 63% in 2019 relative to 2018 (from 403 MW to 656 MW per hour), driven by higher imports at the New York North interface.

Most external transactions continue to be price insensitive. That is, participants submitting import and export bids tend to submit fixed-priced bids or bid at extreme prices such that the bid will always flow. Over 70% of day-ahead transactions across the Canadian interfaces were fixed-priced in 2019.

Real-time external transactions across the New York North interface are subject to the Coordinated Transaction Scheduling (CTS) rules. Overall, the bids submitted at New York North in 2019 allowed power to flow in the correct economic direction (from low- to high-priced region) 58% of the time – similar to 2018. We have observed an increase in negative import spread bids into New England, which contributes to the uneconomic flow. Negative import spread bids will be scheduled even when the power is being imported from the higher-cost region to a lower-cost region. This is likely due to contractual positions entered into prior to the operating day, and the availability of renewable energy credits in New England when backed by eligible power. This import behavior, on average, provided the CTS process with an aggregate transaction curve that allows the direction of flows to be less consistent with price differences.[20]

Economic scheduling is based on forecast price differences between the New England and New York markets, and therefore poor forecasting by the ISOs can reduce the efficiency of CTS. When looking at the potential effects of price forecasting, we observed that both ISOs have improved their forecasts when measuring error on an absolute basis (i.e. each jurisdiction's forecast is closer to the actual real-time price). However, on an average forecast error basis (rather than absolute error), ISO-NE consistently under-forecasts, while the NYISO consistently over-forecasts prices, therefore compounding the average forecast error. We have recommended that the ISO assess the causes of these price forecast biases[21] and how the accuracy of the forecast can be improved.

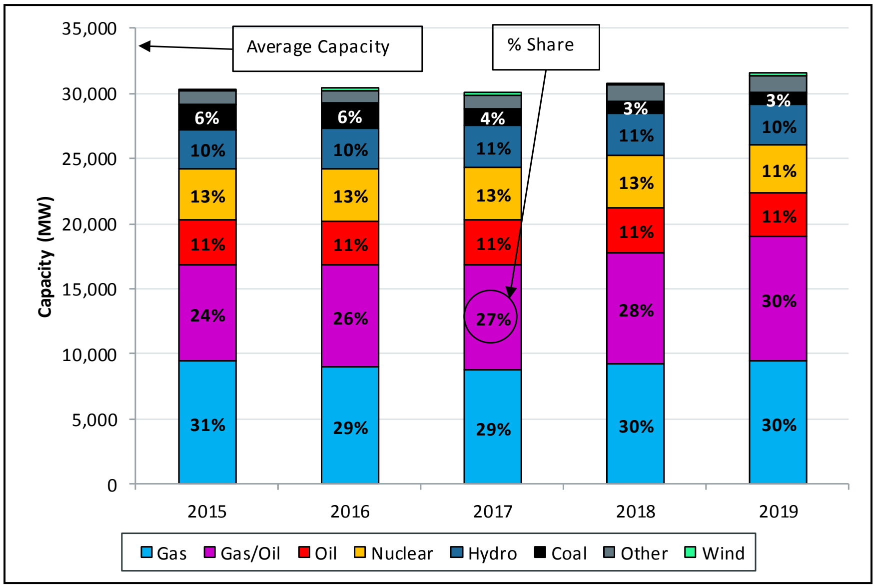
Capacity Market Supply and Demand: As with energy prices, there is also a strong link between capacity prices and natural gas-fired generators. Gas-fired generators have comprised the vast majority of new generation additions since the inception of the FCM. Newer, cleaner and more efficient technology, combined with low natural gas prices, increasing emissions costs, and environmental regulations contributed to more investment in new natural gas-fired generators compared to other fossil fuel generation. Further, the benchmark price in the capacity market, the net cost of new entry, is linked to the recovery of the long-run average costs of a new-entrant combustion turbine.

Supply: Three categories of capacity resources participate in the FCM. Generators make up 88% of total capacity (about 31,370 MW in CCP 2019/20), with the remainder comprised of imports (4% or 1,235 MW) and demand response (8% or about 2,746MW). Overall demand response capacity has fluctuated in recent years, with retirements of active demand resources being offset by the new entry of passive (energy efficiency) demand resources. A breakdown of generator capacity by fuel type is shown in Figure 1-5 below.

[20] In 2019, participants were willing to import power to New England when New York prices were higher by $9/MWh, similar to the $8 spread in 2018; in other words, they were willing to begin moving power at a loss of $9/MWh.

[21] The term "bias" here relates to attributes of the modelling and mechanics of CTS that result in measureable differences between forecast and actual outcomes. It is not intended to refer to human-driven bias.

Figure 1-5: Average Generator Capacity by Fuel Type



Notes: Coal category includes generators capable of burning coal and dual-fuel generators capable of burning coal and oil. "Other" category includes active capacity demand response, landfill gas, methane, refuse, solar, steam, and wood.

Natural gas continues to be the dominant fuel source of capacity in New England. The share of capacity from gas-fired and gas/oil-fired dual-fuel generators has increased over the past few years with the retirement of generators of other fuel types. In 2019, we saw the largest increase in capacity from dual-fuel generators; from 28% (8,600 MW) in 2018 to 31% (9,600 MW). This was due, in most part, to the commissioning of Bridgeport Harbor 5 and Canal 3, which added a combined 800 MW of dual-fuel capability to the system. Combined, gas-fired and gas/oil-fired dual-fuel generators accounted for 60% of total average generation capacity, up from 58% in 2018.

Capacity from nuclear generators declined in 2019, now making up 11% of generation capacity, following the retirement of the 680 MW Pilgrim nuclear facility in May 2019. In 2020, the capacity of nuclear generation will be about 3,350 MW, which is less than 10% of the installed capacity requirement.

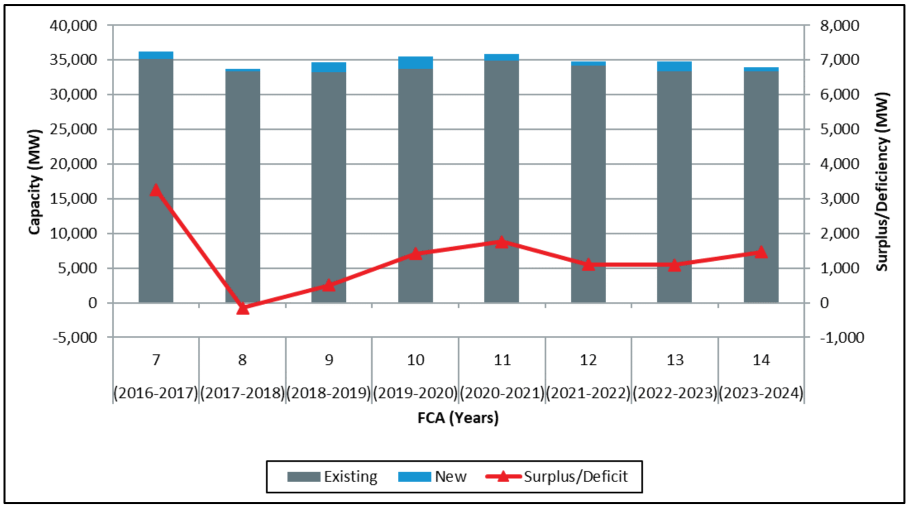
Demand: The system Net Installed Capacity Requirement (NICR) had been relatively flat over five of the past six FCAs, averaging about 34,000 MW, and with annual changes of between +/- 1%.[22] The flat demand for capacity is driven by slow demand growth coupled with increased energy efficiency and behind-the-meter photovoltaic (PV) generation. NICR decreased significantly in FCA 14 to 32,490 MW, down by 1,260 MW or 4%, compared to FCA 13 due to a number of methodological changes to the forecast calculation.

Supply/Demand Balance: The supply and demand balance in the FCM has gone through a number of shifts in recent years. The volume of capacity procured in each auction relative to the NICR is shown in Figure 1-6 below. The stacked bar chart shows the total cleared volume in each auction, broken

[22] The Net Installed Capacity Requirement (NICR) is the amount of capacity (MW) needed to meet the region's reliability requirements (after accounting for tie benefits with Hydro-Quebec). The value is grossed up to account for the amount of energy efficiency reductions participating in the FCM. Due to transmission limitations there are also local sourcing requirements (LSR) for import-constrained areas and maximum capacity limits (MCL) for export-constrained areas.

down between existing and new capacity resources. The red line (corresponding to the right axis) shows the level of capacity surplus or deficit relative to NICR.

Figure 1-6: Cleared and Surplus Capacity in FCA 7 through FCA 14



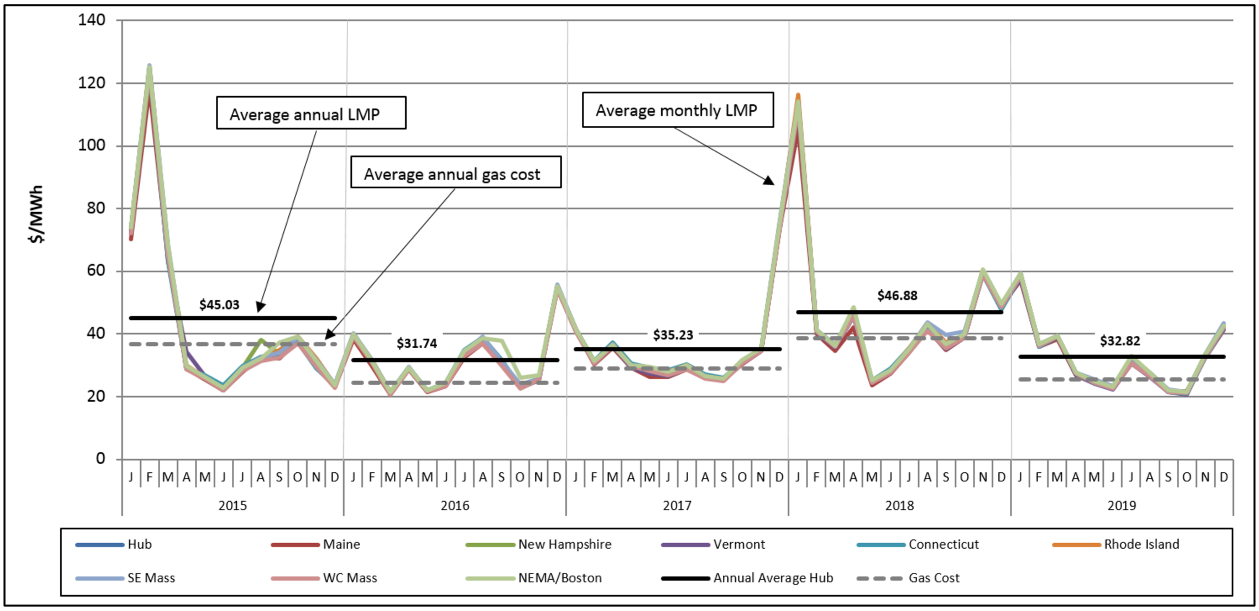
Following resource retirements of 2,700 MW in FCA 8 (and an increase in NICR), the surplus capacity in FCA 7 of over 3,000 MW was quickly eroded. However, higher clearing prices brought new capacity to the market in the three subsequent auctions; in the subsequent three auctions (FCAs 9, 10, 11) new generation and demand response resources cleared 1,400, 1,800, and 900 MW, respectively. The new generation, along with fewer retirements, turned a 140 MW deficit into a 1,800 MW surplus in the span of three auctions. With lower capacity clearing prices, the surplus declined in FCA 12 and 13, primarily due to one-year de-lists of existing resources. The surplus rose once again in FCA 14 to 1,500 MW, driven primarily by a decrease in the NICR of almost 1,300 MW.

1.3 Day-Ahead and Real-Time Energy Markets

Prices: Price differences among the load zones were relatively small in 2019, reflecting a continued trend of modest levels in both marginal losses and congestion. The average absolute difference between the Hub and average load zone prices was $0.27/MWh in the day-ahead energy market and $0.26/MWh in the real-time energy market – a difference of approximately 1%.

The monthly load-weighted prices across load zones over the past five years are shown in Figure 1-7 below. The black line shows the average annual load-weighted Hub price. The dashed gray lines show the estimated annual average gas generation cost.

Figure 1-7: Day-Ahead Energy Market Load-Weighted Prices



The graph illustrates a pattern in prices that varies considerably by year and by month, but not by load zone. For winter months in 2015 and 2018 constraints on the natural gas system resulted in large price spikes in natural gas and electricity prices. Extreme pricing did not occur in Q1 during 2016, 2017 and 2019. The highest prices in 2019 were in January, with (load-weighted) prices of $59/MWh in the day-ahead market.

Price-setting transactions: A significant proportion of the aggregate supply and demand curves in the energy markets are not price-sensitive. On the supply side, this is due to importers submitting fixed-priced bids, generators self-scheduling, or generators operating at their economic minimum. The first two categories are price-takers in the market. Price-takers are even willing to pay to supply power when LMPs are negative. On the demand side, load serving entities (LSEs) submit a large amount of fixed bids. Overall, only 28% to 35% of aggregate supply and demand can set price in the day-ahead energy market. However, this amount effectively falls to about 5% on the demand side, considering that very high-priced bids (whereby the bids always clear) can be considered to be effectively fixed-priced.

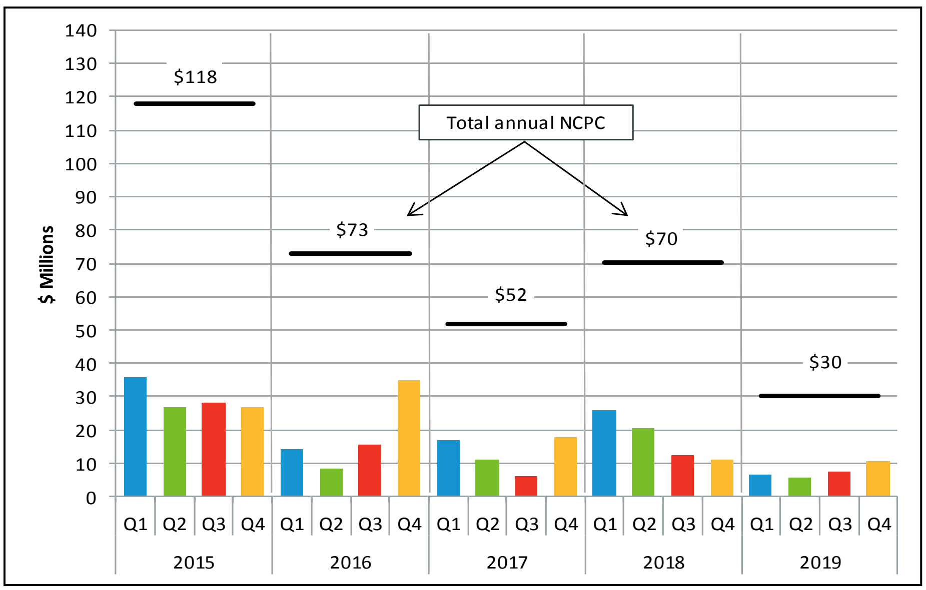
Large volumes of unpriced supply in the market can result in low or negative pricing, particularly when energy provided by renewable generators is at the margin. However, the overall frequency of negative real-time prices at the Hub remains relatively low, and is mostly consigned to small export-constrained pockets. Negative prices at the Hub occurred in 1.1% and 0.6% of hours in 2018 and 2019, respectively.

In this context of limited price-setting ability, virtual demand and supply tend to serve an important price-discovery role in the day-ahead market. Cleared virtual transactions have increased steadily over the last five years, rising from 461 MW per hour in 2015 to 976 MW per hour in 2019. The growth in cleared virtual transactions has been particularly pronounced for virtual supply, which has increased by 157% (from 260 MW per hour to 666 MW per hour) in this five-year period. Virtual transactions (virtual demand bids and virtual supply offers) set price for about 27% of day-ahead load in 2019, comparable to prior years' statistics.

Natural gas-fired generators continued to be the dominant price-setting resources in 2019, with a load- weighted share of 48% in the day-ahead market and 75% in the real-time market. Pumped-storage units (both generators and pumps) continued to be the second largest marginal entity, being marginal for about 20% of load in 2019. Although wind generators are frequently marginal, they are usually marginal for only a small share of total system load (~1% in 2019). Wind generators are often located in export-constrained areas and can only deliver the next increment of load in a small number of locations because the transmission network that moves energy out of their constrained area is at maximum capacity.

Net Commitment Period Compensation (NCPC): In 2019, NCPC payments totaled $30 million, a decrease of $40 million (down by 57%) compared with 2018, and the lowest amount over the five-year reporting period. Like last year, NCPC remained relatively low when expressed as a percentage of total energy payments, at just 0.7%. This continued a downward trend in the share of NCPC from prior years, driven by a number of market rule changes.[23] Quarterly (colored bars) and annual total NCPC payments (black lines) are shown in Figure 1-8 below.

Figure 1-8: Total NCPC Payments by Quarter and Year



The decrease in 2019 NCPC payments was driven by a couple of factors. First, total uplift for 2018 was high due to the manual posturing of oil-fired generators for fuel security during the cold snap in early January. In 2018, uplift payments in January alone accounted for about 30%, or $20.3 million, of total annual payments, with 80% of January payments made during a 4-day period of very cold weather and high natural gas prices (January 4 through 7, 2018). Second, natural gas prices were 34% lower in 2019 compared to 2018, which led to a 30% decrease in LMPs, and in turn put downward pressure on NCPC costs.

Virtual Transactions: As discussed above, the volume of cleared virtual transactions has increased over the last five years. Two factors behind this increase, which have created profitable opportunities for virtual transactions, include market rule changes and a reduction in NCPC

[23] The elimination of day-ahead commitment eligibility for real-time NCPC (in February 2016) and the introduction of fast-start pricing (in March 2017) both applied downward pressure on NCPC costs.

charges.[24] However, virtual transactions yielded lower profits in 2019 than in prior years, despite 2019 having the lowest NCPC charge rate of the last five years, as a result of diminishing price spreads between the day-ahead and real-time energy markets.

While less pronounced than in previous years, NCPC charges continue to limit the extent to which virtual transactions can help with day-ahead and real-time price convergence. During the last four years, this rate averaged about $0.82/MWh, and was particularly low in 2019, averaging around $0.40/MWh. We have previously recommended that the ISO develop and implement processes and mechanisms to reduce NCPC charges to virtual transactions (to better reflect the NCPC cost causation principle). A reduction in NCPC charges to virtual transactions will likely improve day-ahead scheduling by adjusting expectations of real-time conditions.

Congestion Costs and Financial Transmission Rights: Congestion revenue totaled $32.9 million in 2019. This represents a 50% decrease from $64.5 million in 2018. Congestion revenue represents less than 1% of total energy costs, similar to the prior four years. Almost half (45%) of the congestion revenue in 2019 occurred in two months: January and December. During these months, two constraints in particular limited the flow of relatively cheaper power to the system; the Keene Road Export interface constraint in Maine, and the New York – New England (NYNE) interface constraint.

In general, the New England transmission system has been more export constrained in recent years. This trend has led to a shift between generation and load in terms of who is paying congestion costs, with load paying a declining share of these costs every year over the reporting period.

Over the last five years, there has been a steady decrease in the average MW-amount of FTRs held by participants; this value in 2019 (31,981 MW) was 16% less than the amount in 2015 (37,958 MW). This may be due to lower levels of congestion in New England, resulting in a decreased demand for FTRs as a hedging instrument, or reducing profitable arbitrage opportunities.

FTRs were fully funded in 2019, as they were in each of the other years covered in this report. However, 2019 was the first year in the last five years that FTR holders as a group were not profitable; they lost $10.9 million in 2019. This indicates that less congestion materialized in the day-ahead market than was expected by FTR market participants and was reflected through FTR auction clearing prices. This comes after FTR holders made a profit of $26.7 million in 2018. The change in profitability for FTRs sourcing from the Roseton node (at the New York - New England tie) between 2018 and 2019 contributed significantly to this overall loss.[25]

In term of market concentration, the ownership of FTRs continued to be relatively concentrated in 2019, with around 60% of FTR MWs in both the on-peak and off-peak periods held by the top four participants. The total number of FTR holders has been relatively steady over the reporting period, ranging between 38 to 45 different companies

[24] The higher percentages of virtual transactions clearing may be the result of three notable market rule changes: (i) modifications to the real-time commitment NCPC credit calculation, (ii) the implementation of Do-Not-Exceed (DNE) dispatch rules, and (iii) the implementation of Fast-Start Pricing (FSP).

[25] Several of the largest MW holders of FTRs that sourced from .I.ROSETON 345 1 were also the largest MW importers of physical power across the New York – New England interface in 2019. These companies may be using these FTRs as a hedging tool to help manage basis risk between the two control areas.

Energy Market Competitiveness: We apply a broad range of industry-standard economic metrics to assess the general structure and competitiveness of the energy market. The metrics presented in this report include a measure of market concentration known as the C4, the Residual Supply Index, Pivotal Supplier Test, and the Lerner Index. Each metric assesses market concentration or competitiveness with varying degrees of usefulness, but combined, can complement one another. Market power mitigation rules are also in place in the energy market (as well as the capacity market) that allow the IMM to closely review underlying costs of offers and to protect the market from the potential exercise of market power.

The following metrics were calculated for the real-time energy market:[26]

- *Residual Supply Index (RSI) and Pivotal Supplier Test (PST)*[27]
  Results from the RSI and pivotal supplier analysis for 2019 indicate that there have been supply portfolios with market power in 12% of hours. This represents a further improvement in structural competitiveness compared to prior years, down from 30% in 2018, and from 56% in 2017.

  The reduction in the number of intervals with pivotal suppliers appears to be driven by two factors: 1) the increase in the 2019 reserve margin, and 2) there being no significant changes in participant portfolios that increased supply-side market concentration.

- *C4 for supply-side participants*
  The C4 value expresses the percentage of supply controlled by the four largest companies. In 2019, the C4 in the real-time energy market was 43%, a slight decrease compared to 44% in 2018. This value indicates low levels of system-wide market concentration in New England, particularly when the market shares are not highly concentrated in any one company. The four same suppliers made up roughly 44% of the total supply of generation in the day-ahead market.

- *C4 for demand-side participants*
  The demand share of the four largest firms in the real-time energy market in 2019 was 55%, a slight increase from 53% in 2018. The observed C4 values indicate relatively low levels of system-wide concentration. Further, most real-time load clears in the day-ahead market and is bid at price-insensitive levels; two behavioral traits that do not indicate an attempt to exercise buyer-side market power. In the day-ahead market, the same firms made up the top four, and together accounted for 56% of total day-ahead load.

The competiveness of pricing outcomes in the day-ahead energy market was assessed using the Lerner Index:

- *Lerner Index*

[26] In each metric we account for our best estimate of affiliate relationships among market participants.

[27] The RSI provides a measure of structural competitiveness by evaluating the extent to which supply, without the single largest supplier, can meet demand. This provides an indication of the extent to which the largest supplier has market power and can economically or physically withhold generation and influence the market price. A related concept is that of a pivotal supplier. If some portion of supply from a portfolio (not necessarily the largest supplier) is needed to meet demand then that supplier has market power and can withhold one or more of its resources to increase the market price.

The Lerner Index is a measure of market power that estimates the component of the price that is a consequence of offers above marginal cost.[28] In a perfectly competitive market, all participants' offers would equal their marginal costs. Since this is unlikely to always be the case, the Lerner Index is used to estimate the divergence of the observed market outcomes from this ideal scenario.

The Lerner Index remained relatively low in 2019, indicating that competition among suppliers limited their ability to increase price by submitting offers above estimates of their marginal cost. The 2019 Lerner Index for the day-ahead energy market remained relatively low at 6.6%. This indicates that offers above marginal cost increased the day-ahead energy market price by approximately 6.6%. These results are consistent with previous years and within an acceptable range given modeling and estimation error.

The number of energy market supply offers mitigated for market power remained very low in 2019, totaling 1,104 unit-hours, or just 0.02% of all supply offers. Most mitigations continue to be of resources committed to meet local reliability needs. In the absence of effective mitigation measures, participants may have the ability to unilaterally take action that would increase prices above competitive levels. While the energy market mitigation rules are in place to protect the market from such action, the rules permit a high tolerance level, whereby a participant must submit supply offers in excess of $100/MWh or 300% above a competitive benchmark price, and impact price, before mitigation takes place. Further analysis is currently underway to assess the appropriateness of the mitigation thresholds.

1.4 Forward Capacity Market (FCM)

Capacity prices resulting from the Forward Capacity Auctions (FCAs) have fluctuated as the number of resources competing and clearing in the auctions and the region's capacity surplus have changed. Overall, the FCM has largely achieved its design objectives of attracting new efficient resources, maintaining existing resources and encouraging the retirement of less efficient resources. However, the capacity market continues to face challenges due to the impact of out-of-market revenues resulting in market distortions and price suppression. Out-of-market revenues relate, in particular, to state-backed programs to incent resources consistent with meeting environmental policy goals, and to recent ISO actions to retain resources for fuel-security needs.

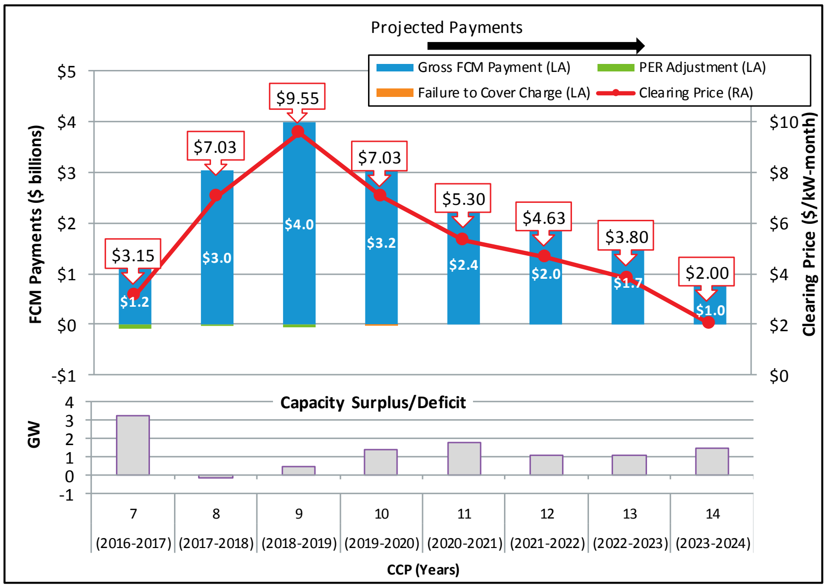
FCM Prices and Payments: Rest-of-Pool clearing prices, payments and the capacity surplus from the seventh capacity commitment period (CCP 7) through CCP 14 are shown in Figure 1-9 below.[29]

[28] The Lerner Index is calculated as the percentage difference between the annual generation-weighted LMPs between two scenarios. The first scenario calculates prices using actual supply offers, while the second scenario uses marginal cost estimates in place of supply offers. The IMM uses the PROBE, or "Portfolio Ownership and Bid Evaluation," simulation model for this analysis. The software simulates the day-ahead LMP-based market clearing. See http://www.power-gem.com/PROBE.html. This is a more dynamic approach than calculating the difference between a static offer price and marginal cost. Rather, this approach re-runs the market optimization process with both as-offered and competitive supply curves, and calculates the difference in the resulting LMPs.

[29] Payments for future periods, CCP 10 through CCP 14, have been estimated as: $FCA\ Clearing\ Price\ \times Cleared\ MW\ \times 12$ for each resource. Note that the 2019 capacity market costs presented earlier in this section includes half of CCP 9 and half of CCP 10.

The figure captures the inverse relationship between capacity surplus above the Net Installed Capacity Requirement (NICR) and capacity clearing prices[30].

Figure 1-9: FCM Payments and Capacity Surplus by Commitment Period



Beginning with FCA 9, the adoption of a system sloped demand curve has improved price formation; specifically, it reduced price volatility and delivered efficient price signals to maintain the region's long-run reliability criteria.

The system was relatively long on capacity until *FCA 7*, with prices clearing at an administrative floor price averaging $3.26/kW-month over the first seven auctions. Capacity payments more than doubled from *CCP 7* to *CCP 8* due to higher primary auction clearing prices (from $1.2 billion to $3.0 billion). *FCA 8* cleared with a capacity deficiency, primarily due to a large amount of retirements. The capacity deficiency triggered administrative pricing rules, which set the clearing price for existing resources at $7.03/kW-month and new resources at $15/kW-month. In *FCA 9,* the clearing price was $9.55/kW-month for all capacity resources, except for higher prices in the import-constrained zone of Southeastern Massachusetts/Rhode Island (SEMA/RI).[31]

High clearing prices in *FCA 8* and *FCA 9* provided price signals to the market that new generation was needed. As more capacity cleared in those auctions, clearing prices declined from FCA 10 through to the most recent auction, FCA 14. Since FCA 11, clearing prices have fallen below the dynamic de-list bid threshold price. De-list bids below this threshold are not subject to IMM review, since it is less likely for participants to successfully exercise market power given the surplus capacity conditions associated with prices in this range.

The FCA 13 auction cleared 34,839 MW, a surplus of 1,089 MW above NICR, at a price of $3.80/kW-month for rest-of-system. While a significant amount of capacity exited the market (about 2,100 MW), either permanently or for one year, there was also a significant amount of new entry (almost

[30] The Net Installed Capacity Requirement (NICR) is the amount of capacity needed to meet the region's reliability requirements after accounting for tie benefits with Hydro-Quebec.

[31] Clearing prices in SEMA/RI were $17.73/kW-month for new resources and $11.08/kW-month for existing resources.

1,500 MW). New entrants comprised mostly of combined cycle generation, energy efficiency, active demand response and solar capacity. In FCA 13, Mystic 8 and 9, two combined cycle generators in SENE that submitted retirement bids, were retained for reliability due to fuel security concerns. The retention also carried over the most recent auction, FCA 14.

The clearing price in FCA 14 of $2/kW-month was the lowest price since the inception of the FCM. Capacity totaling 2,085 MW dynamically de-listed, including 900 MW of oil-fired generation, and 1,000 MW of gas-fired generation. New cleared capacity totaled 637 MW, and primarily consisted of either resources with a renewable technology resource (RTR) exemption, or passive demand response resources.

Market Competitiveness: Two metrics were calculated to evaluate the competitiveness of the capacity market with respect to existing resources: the residual supply index (RSI) and the pivotal supplier test (PST). The results of these two complementary measures indicate that the New England capacity market can be structurally uncompetitive at both the zonal and system levels. The extent of structural competitiveness has fluctuated widely across capacity zones over the last five auctions as the capacity margin has changed. FCA 14 was the only auction of the past five, in which there were no pivotal suppliers at the system-wide level. However, there continued to be pivotal suppliers at the zonal level, in Southeast New England (SENE).

The market has both buyer- and supplier-side mitigation rules to prevent the potential exercise of market power. Specific to the RSI and pivotal supplier metrics, existing resources are subject to a cost-review process and supplier-side mitigation. This process ensures that suppliers do not withdraw capacity from the auction at uncompetitive prices to raise the FCA clearing price in a way that may benefit the remainder of their portfolio. In the most recent auction (FCA 14), no pivotal suppliers in SENE submitted a de-list bid, which is the mechanism a supplier may use when it wants to attempt to withdraw capacity from an auction.

For buyer-side mitigation, offers from about 460 resources were reviewed over the past five auctions (FCA 10-14). The IMM mitigated approximately 56% of the new supply offers that it reviewed, or approximately 64% of the new supply by capacity. This means that these resources had to exit the auction at a higher price than their submitted offer price, and thus protected the market from possible price suppression. Over the past five auctions, the mitigation process resulted in an average increase in offer prices of $3.23/kW-month (from a submitted price of $2.90/kW-month to an IMM-determined price of $6.13/kW-month).

The test price mitigation rule was introduced in FCA 14, and applies to resources (above 3 MW) seeking to retire through the substitution auction. The rule is designed to address the incentive for resources to reduce their primary auction bid below a competitive level in the hopes of retaining its CSO, and subsequently trading out of it for a larger severance payment in the substitution auction. Without an IMM review, this behavior would have a price-suppressing impact on the primary auction.

In FCA 14, fourteen existing resources with a combined capacity of 445 MW elected to participate in the substitution auction. The weighted-average submitted test price was $4.83/kW-month. The IMM reviewed and denied 10 resources (above the 3 MW threshold), with a combined capacity of 443 MW. The weighted-average IMM-determined test price was $12.54/kW-month. Since the auction cleared at $2/kW-month, none of these resources were eligible to participate in the substitution auction.

1.5 Ancillary Services Markets

The ancillary services markets includes a number of programs designed to ensure the reliability of the bulk power system, including operating reserves (forward and real-time), blackstart, voltage, and regulation. In 2019, ancillary services costs totaled about $114 million, down by about $39 million, or by 25%, on 2018 costs.[32]

Real-time Reserves: Total gross real-time reserve payments for 2019 were $10.1 million, a significant decrease of $23.3 million (or 70%) from 2018. The decline in payments is directly due to the reduction in both the frequency and magnitude of non-zero reserve prices. The lower prices reflected lower opportunity costs of providing reserves due to lower energy prices. About 98% of payments were for spinning reserve (ten-minute spinning reserve). There was an extremely low frequency of non-zero offline (or non-spinning) reserve prices, which was consistent with a generally large non-spinning reserve surplus and a lack of strained system conditions throughout the year. This was in contrast to 2018, when scarcity conditions on September 3 alone, resulted in reserve payments of $9.1 million, accounting for 27%, of total annual gross payments.

Forward Reserves: Costs associated with the Forward Reserve Market (FRM) totaled $37.5 million in 2019, down by 6% on 2018 costs. Final costs are largely determined by clearing prices in the twice-yearly auctions, as penalties for non-performance have historically been low compared to base payments.

FRM prices have generally declined, except for the NEMA Boston local reserve zone and the Summer auctions in 2018 and 2019. The elevated NEMA Boston prices have reflected inadequate supply to satisfy local requirements during auctions for several procurement periods; the elevated prices for recent summer periods have reflected elevated offer prices (relative to other periods) and differences in ten-minute non-spinning reserve (TMNSR) offer prices relative to thirty-minute operating reserve (TMOR) offer prices.[33]

With only a few exceptions, the FRM auctions have been structurally competitive. One exception in particular is that the NEMA Boston reserve zone has had inadequate supply to satisfy the local requirement and every supplier within that zone has had structural market power. At the system level, only one recent auction – Summer 2019 – has indicated structural market power; in that instance, the residual supply index of 90 indicated that the single largest FRM supplier in that auction would need to provide at least 10% of cleared supply to satisfy the TMNSR requirement.

Regulation: The regulation market has an abundance of regulation resources and relatively unconcentrated control of supply, which implies that market participants have little opportunity to engage in economic or physical withholding. Regulation payments declined significantly in 2019, due to the decline in the larger capacity component of regulation prices; 2019 payments were $25.4 million compared to payments of $32.5 million in 2018. Regulation clearing prices for capacity declined significantly from $28.30/MWh in 2018 to $21.96/MWh in 2019, reflecting reductions in energy market opportunity costs for regulation resources.

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[32] This total includes voltage services and blackstart services, which are included in the RNL cost total in the preceding wholesale cost section of the Executive Summary (rather than the ancillary services total), since they are recovered via the Open Access Transmission Tariff.

[33] TMNSR can be substituted for TMOR in an auction, when TMNSR offers exceed the TMNSR requirement and the relevant portion of the TMNSR supply curve is below (i.e., has lower offer pricing) than the TMOR offer curve.)

1.6 IMM Market Enhancement Recommendations

The following table summarizes the IMM's recommended market enhancements, along with the status and IMM's priority ranking of each recommendation. The priority ranking (High, Medium or Low) considers the potential market efficiency gains, as well the potential complexity and cost of implementing each recommendation. High priority recommendations may deliver significant market efficiency gains, with the benefit outweighing the cost of implementing them. At the other end of the scale, Low priority recommendations are not intended to indicate low importance, but rather issues which may not have as significant long-term efficiency gains (compared to high priority recommendations) and/or may be very costly to implement.

One new recommendation has been added to the table below since last year's report. This relates to providing multi-stage generators with the ability to dynamically change their configuration for reference level and energy market mitigation purposes. This topic is covered in detail in our Winer 2019/2020 quarterly markets report.[34]

Table 1-2: Market Enhancement Recommendations

Recommendations	Status as of the AMR '20 Publication Date	Priority Ranking
Improving price forecasting for Coordinated Transaction Scheduling: There is a consistent bias in the ISO's internal price forecast at the New York North interface, which may reduce the effectiveness of CTS. To date, biases in ISO-NE and NYISO forecasts have been in *opposite* directions, which increase the price spread between the markets relative to actual spreads, and may produce inefficient tie schedules. ISO-NE should assess the causes of biases in the price forecast and assess how the accuracy of the forecast can be improved. ISO-NE should periodically report on the accuracy of its price forecast at the NYISO interface, as well as the differences between the ISO-NE and NYISO price forecasts.	The External Market Monitor is actively assessing the price forecast and the ISO is periodically reporting on the forecast accuracy. Future improvements are not in the scope of the ISO's current work plan.	High
Corporate relationships among market participants: The ISO develop and maintain a database of corporate relationships and asset control that allows for accurate portfolio construction for the purpose of identifying uncompetitive participation, including the potential exercise of market power and market manipulation.	IMM and ISO are currently implementing a new IMM market analysis system that will seek to address this recommendation.	Medium
Pivotal supplier test calculations: The ISO, working in conjunction with the IMM, enhance the real-time energy market mitigation pivotal supplier test to include (1) ramp-based accounting of supply recognizing the differences between energy and reserve products and (2) participant affiliations.	IMM and ISO to assess the implementation requirements for this project.	Medium
NCPC charges to virtual transactions: The ISO develop and implement processes and mechanisms to reduce NCPC charges to virtual transactions (to better reflect the NCPC cost causation principle) in response to the historical decline in virtual trading activity. A reduction in NCPC	The ISO plans to review this issue as part of the conforming changes related to the Energy	Medium

[34] See ISO New England's Internal Market Monitor Winter 2020 Quarterly Markets Report, at https://www.iso-ne.com/static-assets/documents/2020/05/2020-winter-quarterly-markets-report.pdf

Recommendations	Status as of the AMR '20 Publication Date	Priority Ranking
charges to virtual transactions will likely improve day-ahead scheduling by adjusting expectations of real-time conditions.	Security Improvements Project.	
***Analyzing the effectiveness of Coordinated Transaction Scheduling*:** ISO-NE should implement a process to routinely access the NYISO internal supply curve data that is used in the CTS scheduling process. This data is an important input into the assessment of the cost of under-utilization and counterintuitive flows across the CTS interface.	Related to the item above (Improving price forecasting for CTS). Not in the scope of the ISO's current work plan.	Medium
Treatment of multi-stage generation Due to the ISO's current modeling limitations, multi-stage generator commitments can result in additional NCPC payments and suppressed energy prices. This issue was first raised by the external market monitor, Potomac Economics.[35]The IMM recommends that the ISO consider improvements to its current approach to multi-stage generator modeling. Two possible options are: a. *Expanding the current pseudo-combined cycle (PCC) rules* − Consider whether to make PCC rules a mandatory requirement for multi-stage generators through proposed rule changes *or* *b. Adopt multi-configuration resource modeling capability* − More dynamic approach to modeling operational constraints and costs of multiple configurations	Not in the scope of the ISO's current work plan.	Medium
Reference level flexibility for multi-stage generation Given that the preceding recommendation is not part of the ISO's workplan, and is unlikely to be developed for some time, we recommend related changes that could be made to the market power mitigation function in the meantime. We believe these changes will be less resource-intensive and complex to adopt, compared to incorporating multi-stage generation modeling into the day-ahead and real-time market and systems software. However, it is not a replacement of the above recommendation. The recommendation is to provide generators with the ability to dynamically select their active or planned configuration and to adjust reference levels to be consistent with their operating costs and their supply offers. This will address the current risk of false positive and negative errors in mitigation, given the potentially high costs differences between configurations. It may also eliminate a potential deterrent to generators from offering configurations to avoid the risk of mitigation, which may ultimately be more cost effective to consumers.	New recommendation in the Winter 2019/220 QMR.	Medium
Unoffered Winter Capacity in the FCM The IMM is concerned that generators may be contracting at, or close to, their maximum capacity (i.e. their winter qualified capacity), as determined by the ISO,	Not in the scope of the ISO's current work plan.	Medium

[35] Similar to our findings detailed in the *Fall 2017 Quarterly Markets Report,* Potomac Economics raised issues of inefficient commitments for local reliability, depressed clearing prices, and increased NCPC charges. Potomac has recommended that the ISO expand its authority to commit combined-cycle generators in a single turbine configuration when that configuration will satisfy the underlying reliability need. See page 36 in Section III of the EMM's 2016 *Assessment of the ISO New England Electricity Markets*: https://www.iso-ne.com/static-assets/documents/2017/08/iso-ne-2016-som-report-full-report-final.pdf.

Recommendations	Status as of the AMR '20 Publication Date	Priority Ranking
even though that capacity is not deliverable in certain months given expected ambient temperatures. The IMM recommends that the ISO review its existing qualification rules to address the disconnect between the determination of qualified capacity for two broad time horizons (summer and winter), the ability of the generators to transact on a monthly basis, and the fluctuations in output capability based on ambient conditions. A possible solution would be for the ISO to develop more granular (e.g. monthly) ambient temperature-adjusted qualified capacity values, based on forecasted temperatures and the existing output/temperature curves that the ISO currently has for each generator.		
Forward reserve market and energy market mitigation: The ISO develop and implement processes and mechanisms to resolve the market power concerns associated with exempting all or a portion of a forward reserve resource's energy supply offer from energy market mitigation.	The IMM will evaluate revising or eliminating mitigation exemptions for FRM resources to resolve the market power issues.	Low
Limited energy generator rules: The ISO modify the market rules as necessary to ensure that the use of the limited-energy generator (LEG) provisions in both the day-ahead and real-time markets are restricted to instances when the availability of fuel is physically limited.	Further analysis required by the ISO to assess whether specific rule or procedure improvements are appropriate. The IMM will continue to monitor the use of the limited-energy generation provision and address any inappropriate use on a case-by-case basis.	Low

Section 2
Overall Market Conditions

This section provides an overview of the key trends in wholesale market outcomes over the past five years (2015 through 2019). It covers the underlying supply and demand conditions behind those trends, and provides important context to the market outcomes discussed in more detail in the subsequent sections of this report.

2.1 Wholesale Cost of Electricity

In 2019, the total estimated wholesale market cost of electricity was $9.8 billion, a decrease of $2.3 billion (or 19%) compared to 2018 costs.[36] The primary factor driving the change was a decrease of almost $2 billion (down 32%) in energy payments, which was driven by a 34% drop in natural gas prices.[37]

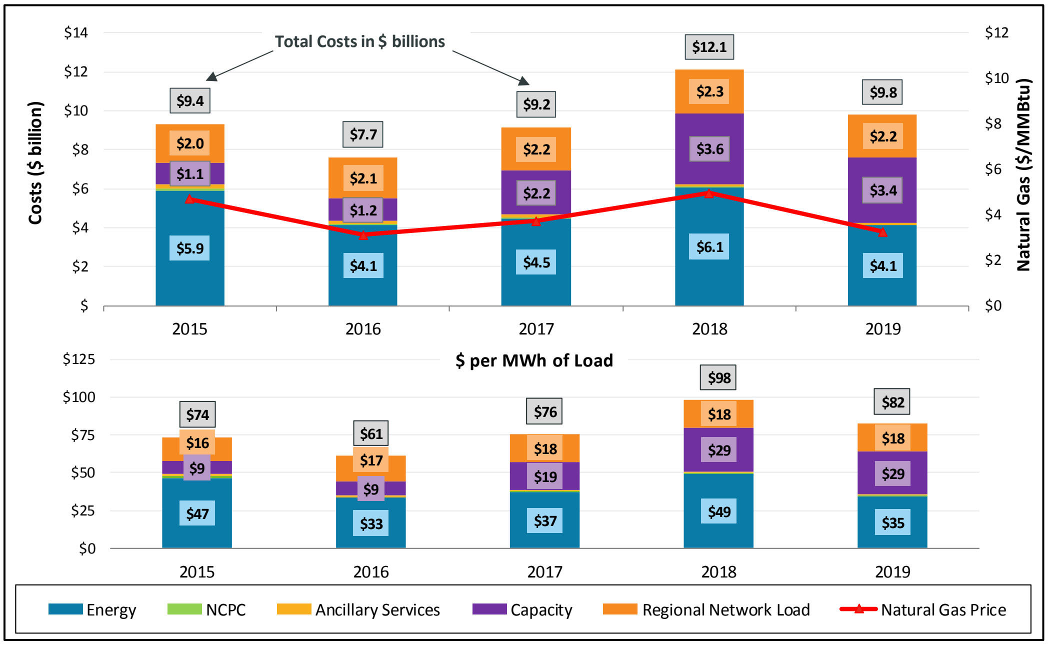
A breakdown of the wholesale electricity cost for each year, along with average natural gas prices, is shown in Figure 2-1 below. The wholesale cost estimate is made up of several categories:

- the energy component includes costs to load from the day-ahead and real-time energy market.
- the net commitment period compensation (NCPC) category shows total uplift costs.
- ancillary services includes the costs of operating reserves, regulation, and the Winter Reliability Program (which ended in February 2018).
- the capacity category reflects the cost to attract and retain sufficient capacity to meet energy and ancillary service requirements.
- the regional network load (RNL) or transmission costs category includes transmission owners' recovery of infrastructure investments, maintenance, operating, and reliability costs.

[36] 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 Hub 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, known as regional network load (RNL) costs, are also included in the estimate of annual wholesale costs.

[37] 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 2-1: Wholesale Costs ($ billions and $/MWh) and Average Natural Gas Prices



Natural gas-fired generators, which provided approximately 48% of total native demand, are the single largest resource type in New England. As such, natural gas prices are a primary driver of energy, ancillary services and NCPC costs. This relationship is apparent in Figure 2-1, with annual energy costs and gas prices moving in the same direction.

In addition to energy and capacity payments, regional network load (RNL) costs also account for a large share of total costs each year. Transmission and reliability costs in 2019 were similar to 2018 costs. A decrease in peak loads and recovered infrastructure costs led to a year over year decline in total RNL costs from 2018 to 2019.

NCPC costs, at $30 million in 2019, decreased by 57% relative to 2018 and were the lowest of the five-year reporting period. There were reductions in both economic and local second contingency protection uplift costs. Ancillary service costs totaled $72 million in 2019, $45 million under 2018 costs.[38] This decrease was due to the expiration of the winter reliability program (WRP) in 2018, and lower natural gas prices.

2.2 Supply Conditions

This section of the report provides a macro-level view of supply conditions across the wholesale electricity markets in 2019, and describes how conditions have changed over the past five years. Topics covered include the New England generation mix (Section 2.2.1), fuel and emission market prices (Section 2.2.2), and estimates of generator profitability (Section 2.2.3).

[38] The ancillary services total presented here does not include blackstart and voltage costs, since these costs are represented in the RNL category.

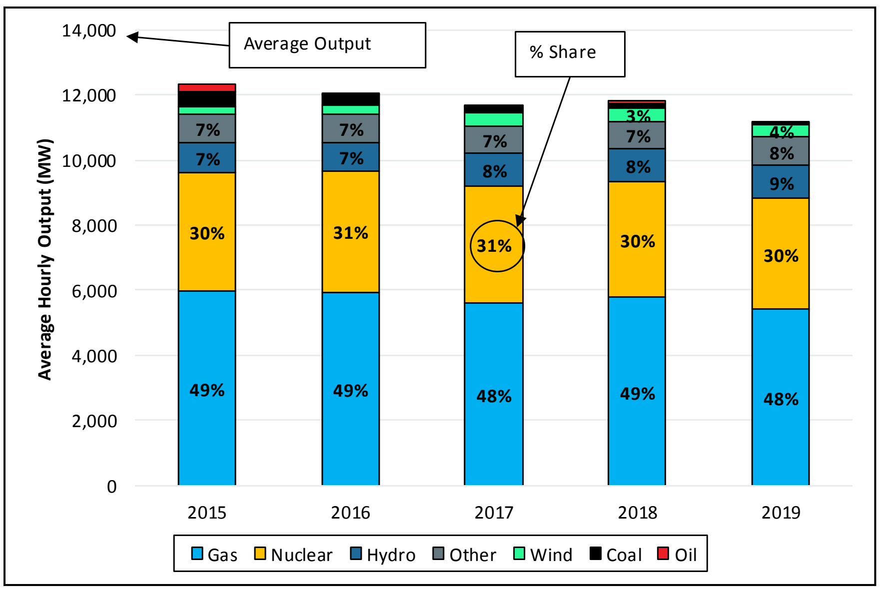
2.2.1 Generation and Capacity Mix

This subsection provides a summary of the New England generation mix over the past five years. The composition of New England's native generation provides important context to overall supply conditions and market outcomes. Information about generation is provided across a series of different dimensions, including fuel type, location, and age. The focus here is on generators located within New England and excludes power imported from generators located outside New England (which are covered separately in Section 2.4).

Average Generator Output by Fuel Type: Analyzing actual energy production (generation output in megawatt hours) provides additional insight into the technologies and fuels used to meet New England's electricity demand. Knowing what fuel is burned and where generators are located in the context of actual energy production helps us better understand pricing outcomes.

Actual energy production by generator fuel type is illustrated in Figure 2-2 below. Each bar represents a fuel type's percent share of native generation.

Figure 2-2: Average Output and Share of Native Electricity Generation by Fuel Type



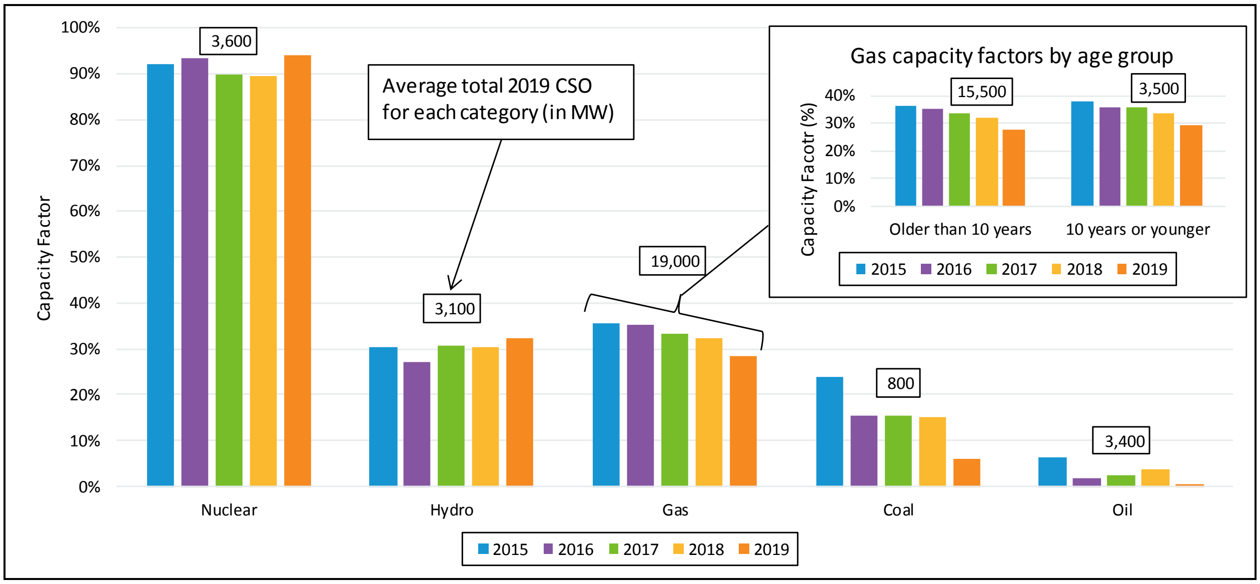
Notes: "Other" category includes battery storage, demand response, landfill gas, methane, refuse, solar, steam, and wood.

Nuclear and gas shares of native generation remained consistent compared to prior years. Nuclear generation accounted for 30% (approx. 3,400 MW per hour) of annual generation despite the retirement of Pilgrim, a 680 MW nuclear generator in Southeastern Massachusetts, in June 2019. Nuclear shares remained consistent due to fewer nuclear outages in 2019, and an overall decrease in demand. Oil generation was down 86%, from 132 MW per hour in 2018, to just 18 MW per hour in 2019. The sharp decline was due to lower gas prices in the winter, which consequently decreased the amount of time oil-fired generators were in economic merit. Based on average heat rates, residual fuel oil-fired generators were in-merit less than 1% of the year in 2019, compared to roughly 5% in 2018.

Figure 2-2 also illustrates that native generation fell by roughly 670 MW (6%) per hour, on average, from 11,840 MW in 2018 to 11,170 MW in 2019. Lower generation in 2019 was driven by decreased native consumption and increased imports at the New York North interface. These topics are discussed in Sections 2.3 and 2.4.

Capacity Factors: In general, capacity factors fell year-over-year due to lower demand.[39] The reduction in capacity factors across the system was due to a 670 MW per hour, on average, decline in the amount of actual generation (the numerator), and an increase in the amount of capacity on the system (the denominator), which was up by 580 MW, on average. The change in capacity factors varied by fuel type. Capacity factors between 2015 and 2019 by fuel type are shown in Figure 2-3 below.

Figure 2-3: Capacity Factor by Fuel Type[40]



Nuclear generators, which provide baseload generation, had slightly higher capacity factors in 2019. As mentioned above, nuclear generators experienced fewer outages in 2019, and therefore provided more generation relative to their CSO than in previous years. Natural gas-fired generator capacity factors continued to decline from 36% in 2015 to 29% in 2019. Capacity factors for gas-fired generators categorized by age are shown in the in-set graph. The decline in demand and increase in installed capacity have impacted both categories similarly. Further, new natural gas-fired generators are replacing retired coal- and oil- fired generators, not older gas- fired generators. This helps explain the decline in coal and oil capacity factors since 2015. Coal- and oil-fired generators had lower capacity factors, of about 6% and 1%, respectively. Their low capacity factors were driven by high operating costs compared to more efficient natural gas-fired generators with lower average fuel prices.[41]

Generation by State: A breakdown of energy production and consumption by state and aggregated across the ISO-NE market is shown in Figure 2-4 below. The figure is shown for 2015 and 2019.

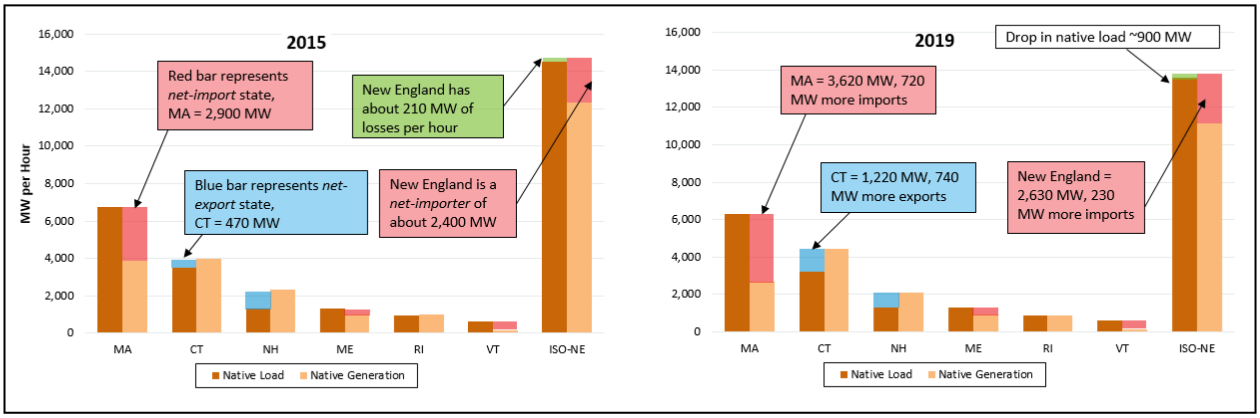
[39] A capacity factor indicates how much of the full capability of a generator is being utilized in the energy market. For example, a capacity factor of 60% for a 100 MW generator means that the generator is producing 60 MW, on average, each hour.

[40] Wind and solar capacity factors are excluded as their average capacity is lower than actual average output due to the FCM qualification rules.

[41] A detailed discussion about the effects of input fuels and supply-side participation on electricity prices can be found in Section 2.2.2 of this report.

The state breakdown shows where energy is being produced and consumed. Darker shaded bars represent native load while lighter shaded bars represent native generation. The red bars represent net imports into each state and the blue bars show net exports out of the state.[42] The green bar for ISO-NE represents losses as energy flows through the system.

Figure 2-4: Average Native Electricity Generation and Load by State, 2015 and 2019



Notes: Megawatt values are rounded to the nearest 10 MW.

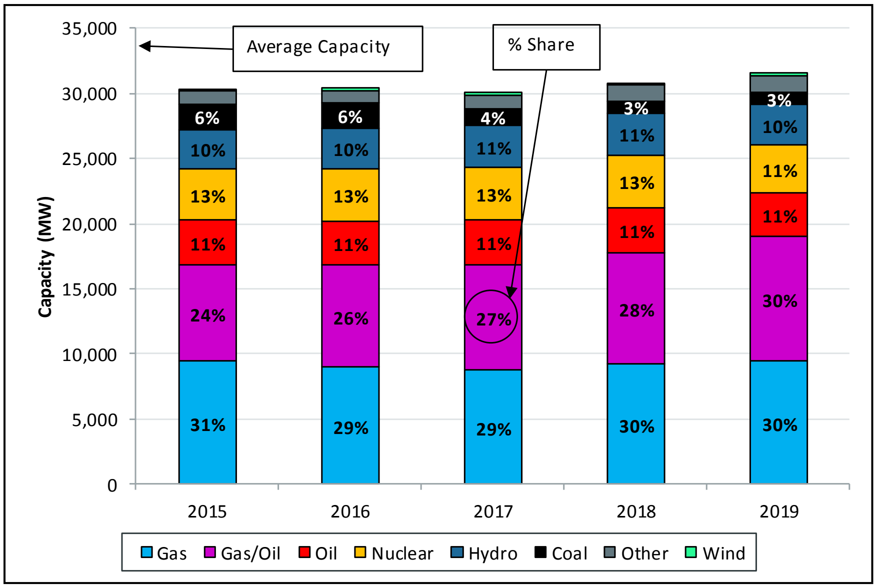
Massachusetts consumed an average of 3,620 MW more than it generated in 2019, up 720 MW from 2015. The gap between load and generation was driven by two factors. First, the 680 MW Pilgrim nuclear facility located in Southeastern Massachusetts retired in June 2019. Second, two existing combined cycle generators operated less frequently due to relatively expensive fuel input costs, which was only partially offset by output from a new gas-fired generators in the state. Connecticut generated an average 1,220 MW more than it consumed in 2019, up 740 MW from 2015. Several new gas-fired generators were built in Connecticut over the past five years, including Bridgeport Harbor 5 (510 MW) and CPV Towantic (800 MW).

The final bar summarizes two key trends in this graph. First, average native load in New England fell by 900 MW compared to 2015. The impact of energy efficiency and behind-the-meter solar generation on native load is discussed in Section 2.3 below. Second, New England continues to be a net importer of power. In 2019, New England imported 19% of its load consumption, or 2,630 MW per hour, on average. This was 230 MW higher than in 2015. Imports flow from Canada into Vermont, Massachusetts and Maine, and from New York into Vermont, Massachusetts and Connecticut. This is discussed further in Section 2.4.

[42] Net imports in this context are not necessarily from neighboring jurisdictions outside of New England (New York or Canada), but refer to any imports from outside the State.

Capacity by Fuel Type: Capacity by fuel type provides context about the capabilities of New England's fleet, rather than actual generation. Average generator capacity by fuel type for the past five years is shown in Figure 2-5 below.[43,44]

Figure 2-5: Average Generator Capacity by Fuel Type



Notes: Coal category includes generators capable of burning coal and dual-fuel generators capable of burning coal and oil. "Other" category includes active capacity demand response, landfill gas, methane, refuse, solar, steam, and wood.

Natural gas continues to be the dominant fuel source in New England. Combined, gas- and gas/oil-fired dual-fuel generators accounted for 61% (19,000 MW) of total average generator capacity in 2019. This year, the largest increase in capacity came from generators that burn both gas and oil; from 28% (8,600 MW) in 2018 to 31% (9,600 MW) in 2019. Two new dual-fuel generators, Bridgeport Harbor 5 and Canal 3, added a combined 800 MW of capacity in 2019. Many new generators have implemented dual fuel capability to improve fuel availability. This provides additional market protection and opportunities when the gas and power systems are tight on capacity and there is a risk of a scarcity event.

Capacity from nuclear generators declined in 2019, now making up 11% of generation capacity, following the retirement of the 680 MW Pilgrim nuclear facility.

Average Age of Generators by Fuel Type: As generators age, they require increased maintenance and upgrades to remain operational. This is true for all generators, but older coal- and oil-fired

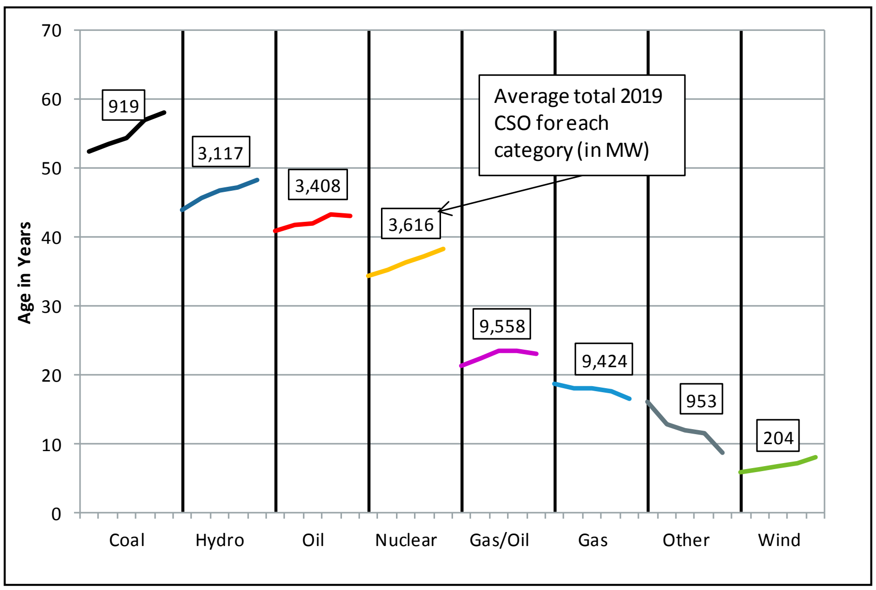
[43] For the purpose of this section, capacity is reported as the capacity supply obligations (CSO) of generators in the Forward Capacity Market, which may be less than a generator's rated capacity. A CSO is a forward contract in which the generator agrees to make the contracted capacity available to serve load or provide reserves by offering that capacity into the energy market. The capacity shown here is the simple average of all monthly generator CSOs in a given year. Analyzing the aggregated CSOs of generators shows how much contracted capacity is available to the ISO operators, barring any generator outages or reductions. Rated generator capacity is generally defined as continuous load-carrying ability of a generator, expressed in megawatts (MW).

[44] The underlying data to determine resource fuel type changed in the 2019 AMR. The change was reflected across all five years. Due to the change, more resources were identified as dual-fuel. This shifted resources out of the gas category into the gas/oil category.

generators in New England face other market dynamics, including higher emissions costs and costs associated with other public policy initiatives to reduce greenhouse gas emissions. Compared with coal- and oil-fired generators, new natural gas-fired generators are cleaner, more efficient and generally have lower fuel costs. As a result, most recent investments have been in new natural gas-fired, wind, and solar generators. Most retirements include older nuclear, coal- and oil-fired generators.

The average age, in years, of New England's generation fleet is illustrated in Figure 2-6 below. Age is determined based on the generator's first day of commercial operation. Each line represents average generator age by fuel type, from 2015 to 2019. The values are weighted by CSO for each generator within the fuel type. If there were no retirements or new generation, we'd expect the line to increase by one year as generators age. An influx of new generators can cause a decline in average age, as was the case with solar resources in the "other" category. Data labels above the bars show total capacity in 2019 by fuel type.

Figure 2-6: Average Age of New England Generator Capacity by Fuel Type (2015-2019)



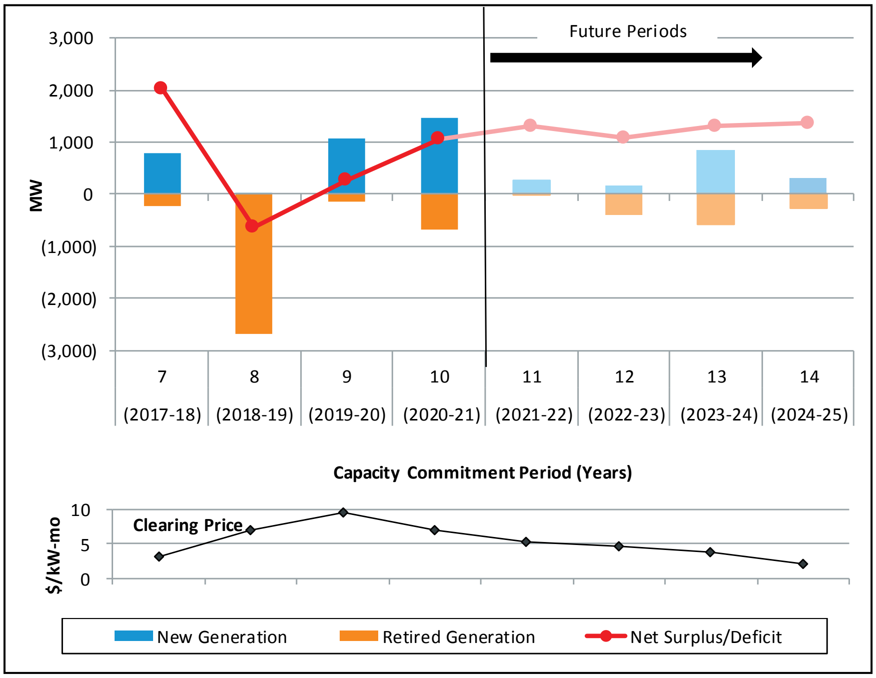
Note: "Other" category includes landfill gas, methane, refuse, solar, steam, and wood.

The average age of New England's generators in 2019 ranged from 8 years (wind) to 58 years (coal), with weighted-average total system age of 28 years. The "other" category continues to decline as new solar resources in the Forward Capacity Market reach commercial operation.

Generation Additions and Retirements: Generator additions and retirements beginning with Capacity Commitment Period 7 (CCP 7, 2016/17) are shown in Figure 2-7 below.[45] Blue bars represent new generation added through the capacity market. Orange bars represent generation that permanently retired. Future periods are years for which the Forward Capacity Auction (FCA) has taken place, but the capacity has yet to be delivered or retired. The FCA clearing prices (for existing rest-of-system resources) are also shown for further context.

[45] Capacity Commitment Periods start on June 1st and end on May 31st of the following year. For example, CCP 7 started June 1 2016 and ended May 31 2017. The CCP numbers correspond to the FCA numbers (e.g., FCA 7 procures capacity for delivery during CCP 7).

Figure 2-7: Generation Additions, Retirements and FCM Outcomes



There have been large swings in generation additions and retirements over the past eight commitment periods. Many of the large retiring generators cite long-run economic issues as the reason for exit, including emissions, capital and maintenance costs for coal- and oil-fired generators. It also includes persistently low wholesale energy prices, mostly cited by baseload nuclear generators. After FCA 8, higher system clearing prices in response to a capacity deficit signaled a need for more capacity. Subsequently, a large number of generators, including five combined cycle natural gas-fired generators totaling 2,659 MW, entered the market as new capacity between FCAs 9 and 13.

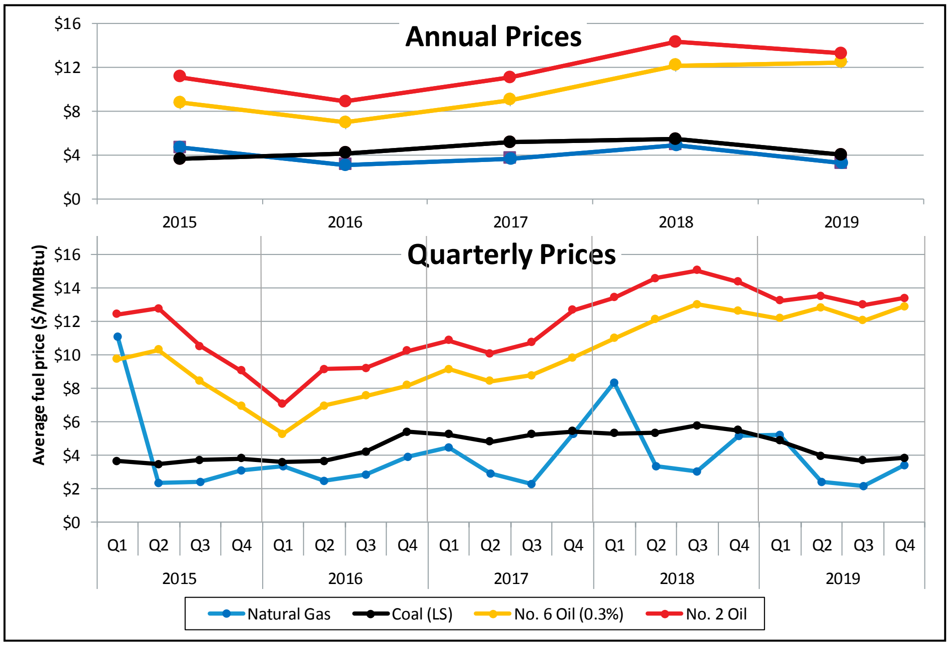
Lower prices, combined with mitigation of new supply resources, led to very little new gas generation in FCA 14. In fact, a majority of the new capacity in FCA 14 came from generators that elected a renewable technology exemption, which allows them to clear when they would have otherwise been removed due to higher offer floor prices. See Section 6 for more information on renewable exemptions in the FCM.

2.2.2 Generation Fuel and Emissions Costs

Input fuel costs and combustion engines' operating efficiencies are the major drivers of New England's electricity prices. In 2019, average prices for most fuels decreased year over year; natural gas (34%), No. 2 oil (8%) and coal (26%). Only No. 6 oil increased (2%) year over year.

Natural gas-fired generators produced 48% of New England's electricity, while oil- and coal-fired generators combined produced less than 1%. The quarterly average costs of natural gas, low-sulfur (LS) coal, No. 6 (0.3% sulfur) oil and No. 2 fuel oil for the past five years are shown in Figure 2-8 below. Average annual costs are shown in the inset graph.

Figure 2-8: Average Fuel Prices by Quarter and Year

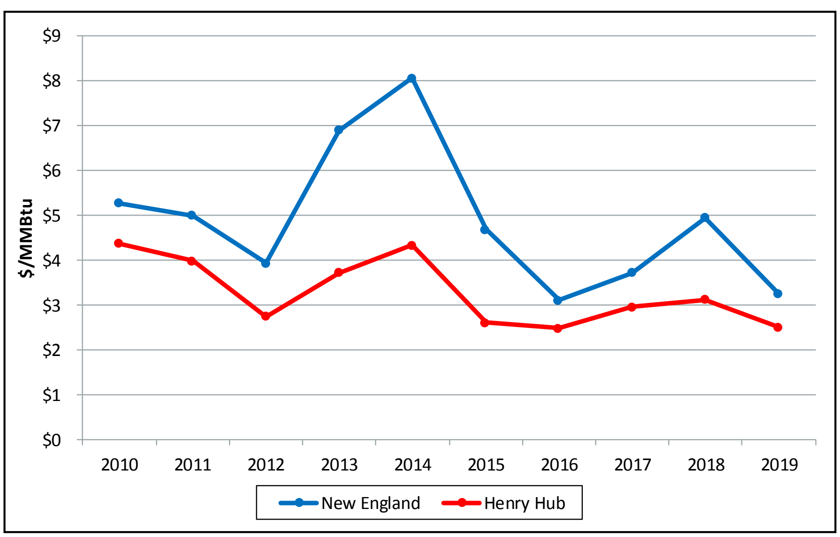


Natural Gas

In 2019, natural gas prices averaged $3.26/MMBtu, a 34% (or $1.69/MMBtu) decrease compared to 2018. In New England, 2019 average monthly natural gas prices were lower in every month compared to 2018. This was due to lower natural gas prices at different supply basins nationwide, and lower natural gas prices in January 2019 in New England due to milder weather.

Since New England has no native natural gas production, New England's natural gas prices are influenced by prices across the country. Figure 2-9 below compares annual average prices in New England (blue) to Henry Hub (red) over the past 10 years.

Figure 2-9: New England vs. Henry Hub Natural Gas Prices



In 2019, natural gas prices were low at major hubs across the country, especially during the second half of the year. In 2019, prices at Henry Hub averaged $2.51/MMBtu, a 3-year low, and the second lowest price since at least 2005. Natural gas production outpaced demand growth across the country, leading to higher levels of natural gas storage and lower prices than in 2018.[46] The lower prices at supply basins are reflected in the New England price, which also had the lowest price since 2016, and the second lowest price in at least 10 years. The New England natural gas price spread tends to increase when winter temperatures are colder due to natural gas infrastructure constraints.

Lower prices in January 2019 ($6.99/MMBtu) compared to January 2018 ($15.97/MMBtu) also contributed to lower average natural gas prices for 2019.[47] Average temperatures in January 2019 were slightly warmer than average temperatures in January 2018 (27ºF vs. 26ºF). However, January 2018 had higher natural gas prices due to an extended cold snap, whereas January 2019 had no extreme weather events. New England's natural gas infrastructure can get constrained during cold spells, leading to extremely high natural gas prices. The 2018 cold snap saw average temperatures below 20ºF for 11 days during a 12-day period from December 2017 into January 2018. During the first week of January 2018, natural gas prices averaged $33.78/MMBtu, including a daily average high of $61.54/MMBtu. January 2019 never had more than two consecutive days below 20ºF, and the daily average natural gas price never exceeded $14.00/MMBtu.

Oil

In 2019, No. 2 Oil prices decreased by 8% ($1.08/MMBtu) while No. 6 oil prices increased by 2% ($0.30/MMBtu), on average. Both Brent (10%) and WTI (12%) crude oil prices decreased, as increases in United States oil production put downward pressure on prices, leading to lower prices in New England.[48]

Coal

In 2019, coal prices decreased by 26% ($5.45/MMBtu to $4.05/MMBtu) year over year. Falling coal demand throughout the country outweighed production cuts, leading to oversupply in the market and lower prices.[49]

Emission Prices

While fuel prices and generator operating efficiencies are the main drivers of electricity prices, emission allowances, as required by federal and state regulations, are a secondary driver of electricity production costs for fossil fuel-fired generators. New England has two carbon reducing cap-and-trade programs that influence electricity prices: the Regional Greenhouse Gas Initiative (RGGI), covering all New England states, and 310 CMR 7.74, which covers only Massachusetts.

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[46] https://www.spglobal.com/platts/en/market-insights/latest-news/natural-gas/120219-analysis-henry-hub-winter-natural-gas-prices-hit-record-low

[47] When January is excluded, 2019 natural gas prices were $1.02/MMBtu lower than in 2018 ($2.91/MMBtu vs. $3.93/MMBtu).

[48] https://www.eia.gov/todayinenergy/detail.php?id=42415

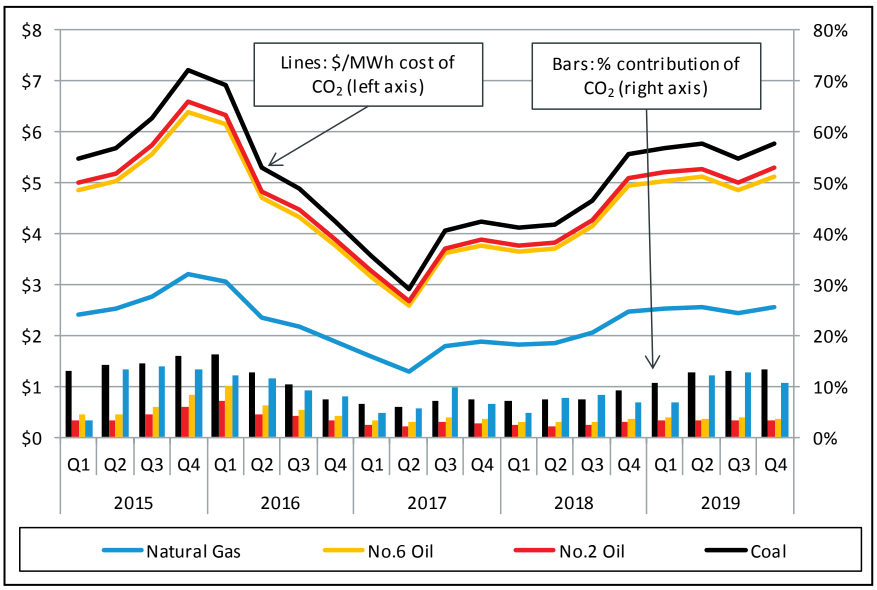
[49] https://www.eia.gov/outlooks/steo/report/coal.php

Regional Greenhouse Gas Initiative Prices:

The key driver of emission costs for New England generators is the Regional Greenhouse Gas Initiative (RGGI), a marketplace for CO_2 credits in the Northeast and Mid-Atlantic. It covers all six New England states. RGGI operates as a cap-and-trade system, where fossil fuel-fired generators must hold allowances equal to their emissions over a certain period.[50] Market prices for CO_2 credits affect total energy costs of fossil fuel-fired generators which must purchase allowances to meet RGGI requirements. This creates a market incentive for lower emitting generators to operate, and pushes new generators to use less carbon-intensive resources.

The estimated average dollar per MWh costs of CO_2 emissions and their average contribution as a percentage of total variable costs is shown in Figure 2-10 below.[51] The line series illustrate the average estimated cost of emission allowances for fossil fuels for the past five years. The bar series on the figure shows the proportion of the average energy production costs attributable to emissions costs for each year.

Figure 2-10: Average Cost of RGGI CO_2 Allowances and Contribution to Energy Production Costs



Note: this figure shows the CO_2 costs associated with the RGGI program only. Generators in Massachusetts are subject to an addition CO_2 costs from the Massachusetts GHG, which is covered further below.

RGGI prices have continued to increase since the second half of 2017. In Q2 2017, RGGI prices reached a daily low of $2.55/short ton, or an additional cost of $1.29/MWh for natural gas-fired generators. However, emissions prices increased 40% from $3.30/short ton to $4.60/short ton on August 23, 2017 after a RGGI review placed a 30% reduction on the cap by 2030, relative to 2020

[50] For more information, see the RGGI website: https://www.rggi.org/program-overview-and-design/elements

[51] CO_2 prices in $ per ton are converted to estimated $/MWh using average generator heat rates for each fuel type and an emissions rate for each fuel.

levels (from 78.2 million short tons to 54.7 million short tons).[52,53] In 2019, emissions prices increased 22% year-over-year, (from $4.50/short ton to $5.51/short ton). The average 2019 CO_2 cost for a natural-gas fired generator was $2.52/MWh.

The bars in Figure 2-10 show the relative contribution of CO_2 emissions allowance costs to generation costs. The relative cost increased this year for coal and gas, but decreased for No.2 and No. 6 Oil. For natural gas-fired generators, the CO_2 share of variable generation costs ranged from 4.7% in Q1 when gas prices were highest, to 8.2% in Q3, due to lower gas prices and higher emissions costs.

A wider view of the impact of CO_2 allowances on generation input costs is presented in Figure 2-11 below. The line series in the figure illustrate the quarterly average estimated production costs using the average heat rate for generators of a representative technology type in each fuel category. The height of the shaded band above each line series represents the average additional energy production costs attributable to CO_2 emissions costs in each quarter.

Figure 2-11: Average Contributions of CO2 Allowance Cost to Energy Production Costs

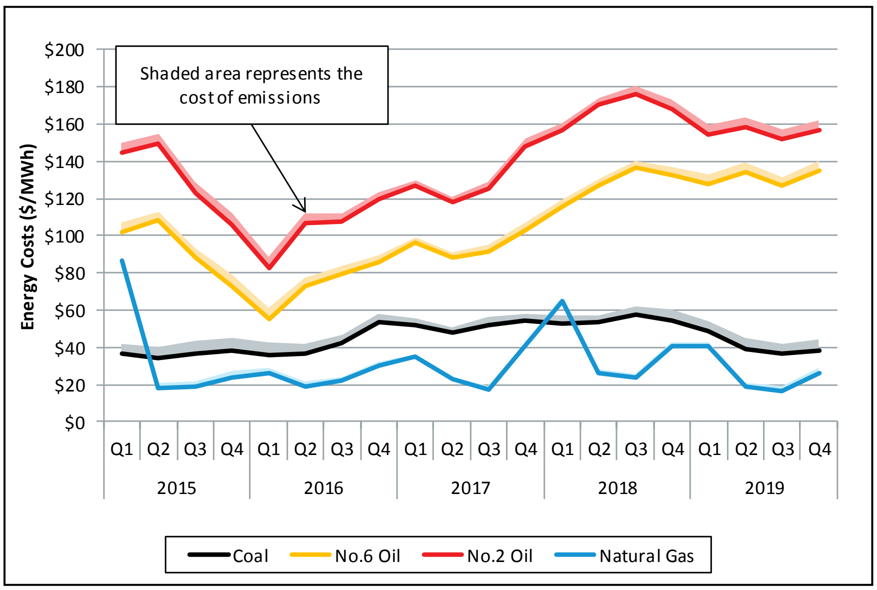


Figure 2-11 highlights that CO_2 allowance costs have a relatively small impact on generation production costs and consequently do not have a noticeable impact on the economic merit order of generators.

Massachusetts GHG (310 CMR 7.74):

In January 2018, a new CO_2 cap-and-trade program began in Massachusetts.[54] The program is in addition to the RGGI discussed above. Administered by the Massachusetts Department of

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[52] RGGI Inc. RGGI States Announce Proposed Program Changes: Additional 30% Emissions Cap Decline by 2030 August, 2017. https://www.rggi.org/sites/default/files/Uploads/PressReleases/2017_08_23_Announcement_Proposed_Program_Changes.pdf

[53] https://www.rggi.org/sites/default/files/Uploads/Program-Review/12-19-2017/Principles_Accompanying_Model_Rule.pdf

[54] 310 CMR 7.74: Reducing CO2 Emissions from Electricity Generating Facilities (https://www.mass.gov/guides/electricity-generator-emissions-limits-310-cmr-774)

Environmental Protection (MassDEP), the program places an annual cap on aggregate CO_2 production for the majority of fossil fuel-fired generators within the state. The cap will be lowered every year until the target annual CO_2 emission rate is reached in 2050. To ensure compliance, the regulation requires electricity generators to hold a permit, called an allowance, for each metric ton of CO_2 they produce during a year. For the first two years, these allowances were primarily allocated based on historical emissions levels, but from 2021 allowances will be allocated by auction only.[55] The program allows generators to trade emissions allowances to meet their quotas.

The cap-and-trade program attempts to make the environmental cost of CO_2 explicit in dollar terms so that producers of energy consider it in their production decisions. Consequently, carbon emission costs must be incorporated when developing the reference levels used to assess energy offer competitiveness. By neglecting to consider the cost of carbon, market power mitigation could result in mitigated energy offers that are below actual variable and opportunity costs leaving generators unable to recover their cost of production.

To begin the program, the MassDEP allocated allowances based on historical emissions levels. Consequently, the market value of an allowance was unknown and the IMM calculated an opportunity cost-based adder for each facility using historical data to estimate the potential net revenue associated with each metric ton of CO_2 output, i.e., the profit associated with each allowance held by a facility of generating assets. However, as 2018 progressed, trading activity became sufficient to allow calculation of the reference level adder by valuing the allowances based on a weighted average of recent trades. This approach continued in 2019 with the IMM now also considering allowance auction results in the calculation allowance values.

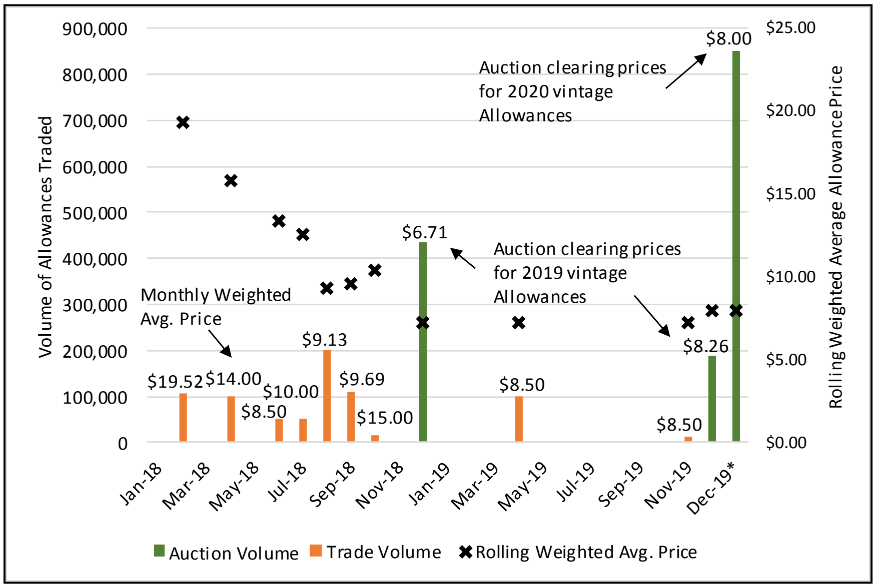
Allowance trading activity was noticeable lower in 2019 when compared with the prior year. At least five of the 15 participants traded a total of 260,000 allowances over the course of the year. This represents only 3% of the total allowance allocation for 2019, a drop of 4% from 2018. The reduction in trading is likely a result of participants having sufficient allowance allocations to meet their needs as well as lower load levels over the course of the year. In general, generators continued to incorporate the allowance adder into their offers.[56]

Reported allowance trading volumes and weighted average prices (in $/ton)for each month since the start of the program in 2018 are shown in Figure 2-12 below. The graph also shows a rolling average weighted allowance price that illustrates the general price movement over this time.

[55] A portion of the 2020 allowances will also be allocated to facilities.

[56] For the set of generators impacted by the cap-and-trade program, the average energy offer markup above reference level remained consistent with the average value for the prior five years.

Figure 2-12: Allowance Trading Activity, 2018 and 2019



Note: * Two bars are shown for December 2019 to represent both the 2019 vintage and 2020 vintage auctions.

Higher allowance prices at the beginning of the program were the result of uncertainty surrounding allowance usage and valuation, potential program changes and regulatory risk, and very low market liquidity. With a relatively mild winter in 2018, participants were aware that the chance of the aggregate constraint on CO_2 emissions binding was decreasing which implied that a surplus of allowances would be available for those that might need them. Consequently, allowance prices tended to trend downwards towards the end of the year. For 2019, prices remained in the range of $7-$8/ton largely as a result of continued mild weather.

2.2.3 Generator Profitability

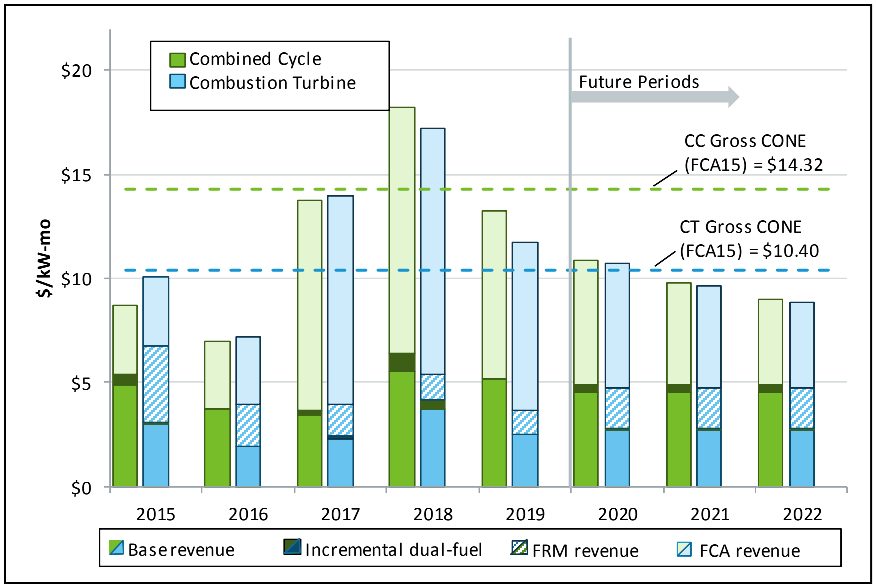
New generator owners rely on a combination of net revenue from energy and ancillary service markets and forward capacity payments to cover their fixed costs. Revenue from the Forward Capacity Market (FCM), which is conducted three-plus years in advance of the delivery period, is a critical component of moving forward with developing a new project. Given the cost of a new project (CONE, or cost of new entry), developer expectations for minimum capacity revenues will be based on this cost and their expectation for net revenue from the energy and ancillary services markets. In New England, the majority of revenue to support new entry comes from the capacity market. There is an inverse relationship between expected net revenue from energy and ancillary service sales and the amount of revenue required from the capacity market in order to support new entry.

This section presents estimates of the net revenues that hypothetical new gas-fired generators (combined cycle (CC) and combustion turbine (CT)) could have earned in the energy and ancillary services markets in each of the previous five years. In addition to providing a basis for the amount of revenue required from the capacity market to build a new generation project, this section also highlights the incremental revenue that could be earned from dual-fuel capability and evaluates participation in the Forward Reserve Market (FRM) for a combustion turbine generator.

The analysis is based on simulations of generator scheduling under an objective that maximizes net revenue while enforcing operational constraints, i.e., ramp rates, minimum run and down times, and economic limits.[57]

The result of the simulations is shown in Figure 2-13 below.[58] Each stacked bar represents revenue components for a generator type and year. A combined cycle generator is shown in green and a combustion turbine generator that participates in the FRM market is shown in blue. The simulation produces base revenue (energy and ancillary services (AS)) and incremental dual-fuel revenue numbers for years 2015-2019.[59] Estimates of future years' base and dual-fuel revenue are simple averages of these numbers. For all years, the FCA and FRM revenue numbers shown are calculated using the actual payment rates applied to calendar years.

Figure 2-13: Estimated Revenue for New Gas-fired Generators



In recent years, capacity prices were generally high enough to support the entry of new gas-fired generation. However, capacity prices have trended downwards reflecting a system that is increasingly long on capacity. Total revenues from the energy and capacity markets appear insufficient to support new entry from combined cycle generators and would likely only incent the most efficient of combustion turbines to enter the region's energy market. And, while two recent forward capacity auctions (FCA12, FCA13) have each had entry by one new gas–fired generator, no new gas-fired generation cleared in the most recent auction (FCA14).

Compared to 2018, the simulation results show energy net revenues for 2019 decreasing by approximately 20% for dual-fuel combined cycle generators and approximately 34% for dual-fuel combustion turbines. Revenue for gas-only generators dropped approximately 7% and 26% for combined cycle and combustion turbines generators, respectively. The year-over-year decreases

[57] The simulation uses historical market prices, which implies that the generator's dispatch decisions do not have an impact on day-ahead or real-time energy prices. Results should be considered in the high range for potential revenue estimates because this analysis does not account for forced outages (which should be infrequent for a new resource).

[58] The Gross CONE figures for the CC and CT gas-fired generators reflect Net CONE values of $9.00/kW-month and $7.23/kW-month with the difference between gross and net figures attributed to net revenue from energy and ancillary service sales.

[59] Incremental dual-fuel energy revenue is earned by the generator when running on its second fuel type.

are a reflection of lower energy prices that resulted from generally milder weather and system conditions in 2019. Dual-fuel units are especially impacted under these conditions because oil capability offers no advantage when natural gas remains relatively inexpensive.

Overall, the results show that if future market conditions remain similar to the previous five years, owners of new gas-fired combined cycle generators could expect net revenues (not including capacity payments) to average $4.56/kW-month, which increases to $4.88/kW-month for generators with dual-fuel capability. Under the same conditions, new combustion turbines could expect net revenue earnings from $3.18/kW-month for single fuel generators to $3.33/kW-month for generators with dual-fuel flexibility. With higher capacity factors, combined cycle generators can benefit more often from dual-fuel capability than peaking generators, but both technologies can expect significant revenue gains when gas prices rise above oil prices as occurred in winters 2014 and 2018.

A combustion turbine generator can also participate in the Forward Reserve Market (FRM) where offline reserves are procured prior to the reserve season. A forward reserve generator receives revenue from the forward reserve auction, but it foregoes real-time reserve payments and, in most hours where the energy price is within a normal range, also foregoes energy revenue since it will be held in reserve. When the energy price is abnormally high, as in the case of a scarcity event, the forward reserve resource may be dispatched for energy and would then receive net revenue (above variable cost) for those high-priced periods. While FRM auction payments appear to be trending lower, this analysis shows that a new combustion turbine which is designated as an FRM resource could earn $1.44/kW-month more net revenue than the same resource could have accumulated in the real-time market alone.

In addition, participation in the FRM market results in greater net revenue than non-participation in all five years where these revenues have been observed (not future periods). Note, however, that the profitability of FRM participation is particularly sensitive to the frequency of scarcity pricing events via the Reserve-Constraint Penalty Factor (RCPF). This is because an FRM designated generator will have fewer opportunities to earn energy revenue than it would otherwise as a non-FRM generator. Consequently, RCPF revenue will form a greater share of the FRM resources total revenue than if it had not participated in the Forward Reserve Market. The simulations show that average revenues for new gas-fired generators appear to be in-line with benchmark estimates used to establish CONE numbers for the FCM auctions. The most recent CONE revisions filed with FERC establish net revenue components of $5.32/kW-month and $3.17/kW-month for combined cycle and combustion turbine generators respectively.[60] However, revenue numbers in this range are clearly insufficient to support new entry without the addition of capacity payments to cover the fixed costs of a new gas-fired generator.

Note that CONE benchmarks are produced from financial and engineering studies that estimate the cost of adding green-field generators. In practice, the cost of new entry for a generator may be lower than the current CONE benchmarks for a number of reasons. In particular, when new generators are built on existing generation sites or when there are material additions to the capacity of an existing operational plant, the presence of existing infrastructure tends to lower fixed costs.

[60] These revenue components include “Pay for Performance” (PFP) revenue which this study does not.

2.3 Demand (Load) Conditions

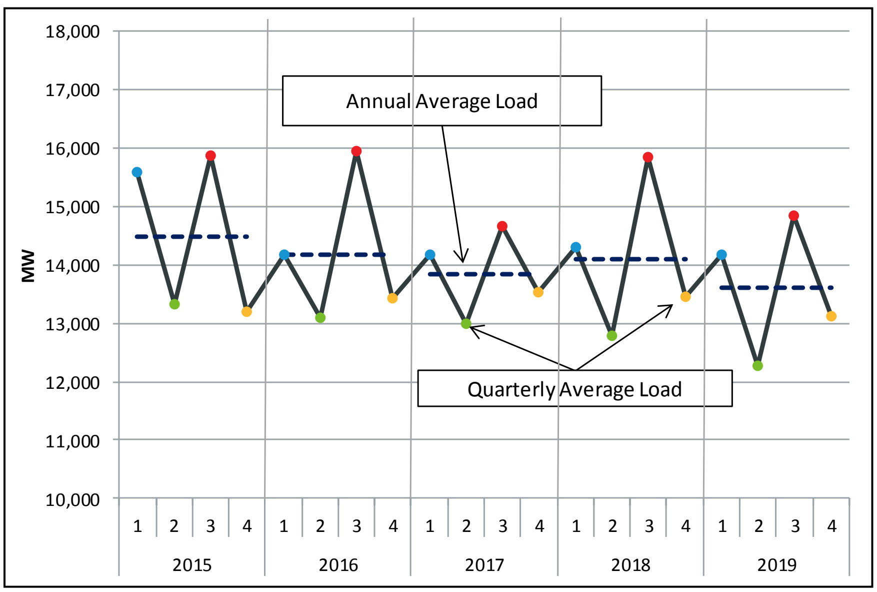
Consumer demand for electricity is a key determinant of wholesale electricity prices in New England.[61] The section focuses on wholesale demand, otherwise known as Net Energy Load (NEL).[62] Weather, economic forces, energy efficiency, and behind-the-meter solar are the primary factors influencing wholesale electricity demand over time. The following sections describe these drivers, as well as system reserve requirements and the amount of capacity needed to meet the region's reliability needs.

2.3.1 Energy Demand

In 2019, New England wholesale electricity load decreased by 3.5% mainly due to a cooler summer and more temperate weather during the spring. Typically, temperature fluctuations drive yearly differences in wholesale load, but wholesale load has decreased most years due to increased energy efficiency and behind-the-meter solar generation. On a weather-normalized basis, wholesale load decreased by 1.3% compared to 2018.

Average quarterly load from 2015 to 2019 is shown in Figure 2-14 below. The solid black lines show average quarterly load and the dashed black lines represent annual average load. The different colored dots identify each calendar quarter (Q1 – blue, Q2 – green, Q3 – red, Q4 – yellow).

Figure 2-14: Average Hourly Load by Quarter and Year



In 2019, average loads in Q1 decreased by less than 1% (114 MW) year over year despite colder weather. Average load decreased in every quarter relative to 2018, most significantly in Q2 and Q3. In Q2, quarterly average load decreased by 4% (507 MW) due to more temperate weather. While

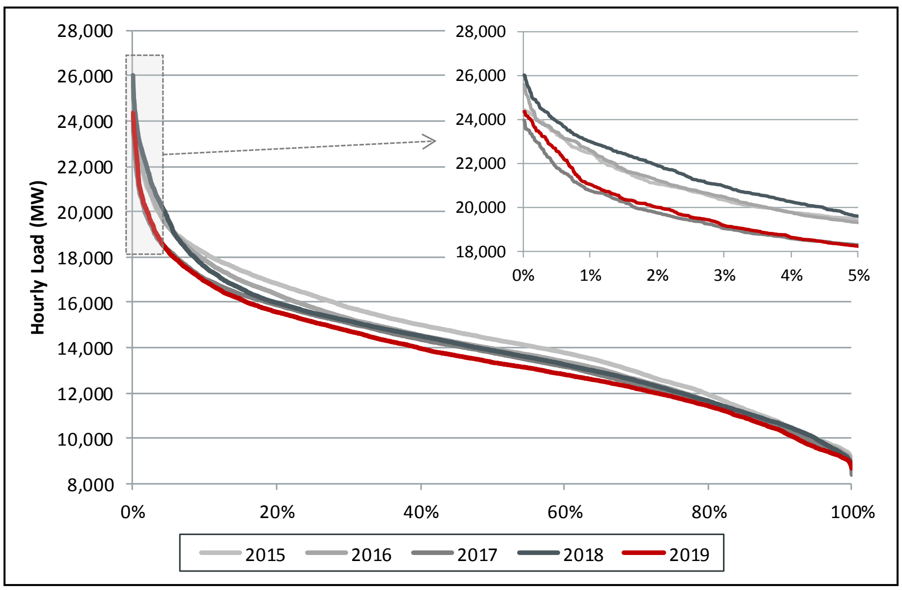
[61] The terms "load" and "demand" are used throughout this report. The term "load" typically refers to actual real-time wholesale electricity consumption. The term "demand" can have a more general meaning, but typically refers to demand that clears in the day-ahead energy market when used in that context.

[62] NEL is net of (excludes) electricity demand that it met by "behind-the-meter" generation, including photovoltaic generation, not participating in the wholesale market. It also excludes pumped-storage demand since pumped-storage facilities are energy neutral.

Q2 2019 average temperatures increased by only 0.2°F year over year, the number of heating degree days (HDD) and cooling degree days (CDD) both decreased.[63] In Q3, quarterly average load decreased by 6% (1,011 MW), the largest decrease of the year, due to cooler and less humid weather in August and September. In August 2019, the Temperature-Humidity Index (THI) was 68.8, a 3.5 decrease compared to August 2018. In September 2019, the THI fell by 2.6 (63.3 vs. 65.9) compared to September 2018. The cooler weather caused CDDs to decrease by 98 and 66 year over year in August 2019 and September 2019, respectively. Quarterly average Q4 load decreased by 2% (310 MW) year over year. This was caused by more temperate weather in October 2019. HDDs and CDDs both decreased compared to October 2018, leading to less electricity demand.

New England's system load over the last five years is shown as load duration curves in Figure 2-15 below. A load duration curve depicts the relationship between load levels and the frequency that load levels occur. The red line shows 2019 and the range of gray lines (from lightest to darkest) show 2015-2018. The inset graph highlights the 5% of hours with the highest load levels for each year.

Figure 2-15: Load Duration Curves



The 2019 load duration curve shows that load levels were generally lower in 2019 than in all other years shown. This highlights the long-term trend of decreasing wholesale load due to increases in energy efficiency and behind-the-meter solar generation. The 2019 load duration curve was lower across all hours compared to 2015, 2016 and 2018. Only the 2017 load curve fell below the 2019 load duration curve for only 4% of hours, most of which occurred due to a relatively warmer summer in 2019 compared to 2017.

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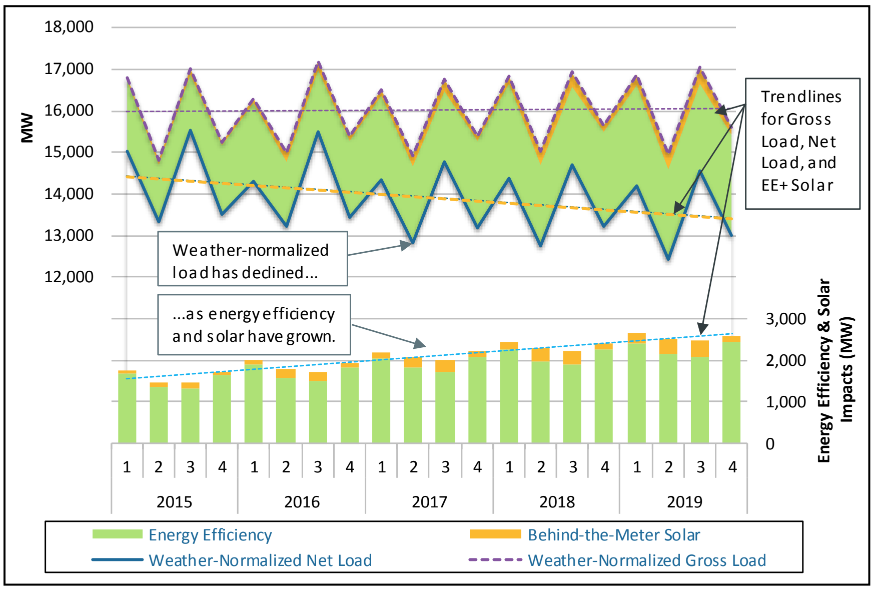
[63] Heating degree day (HDD) measures how cold an average daily temperature is relative to 65°F and is an indicator of electricity demand for heating. It is calculated as the number of degrees (°F) that each day's average temperature is below 65°F. For example, if a day's average temperature is 60°F,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

The inset graph highlights the load duration curves during the top 5% load levels during the year. These hours tend to occur during the summer when increased air-conditioning demand drives higher wholesale electricity demand. In 2019, the top 5% of load levels were significantly lower than 2018 load levels due to a cooler summer in 2019. Q3 2018 had nearly twice as many hours (37 hours vs. 19 hours) where temperatures were above 90°F.

While actual average load decreased by 3.5%, weather-normalized load only declined by 1.3% relative to 2018.[64] Average annual weather-normalized load has fallen every year since 2011 due to growth in energy efficiency and, to a lesser extent, behind-the-meter solar generation. Figure 2-16 displays the average quarterly weather-normalized load and the estimated impact of energy efficiency and behind-the-meter solar over the past five years.[65]

Figure 2-16: Average Quarterly Weather-Normalized Load with Energy Efficiency and Solar Impacts



Weather-normalized load (solid blue line in Figure 2-16) fluctuates from quarter to quarter but has trended downward over the past five years. Weather normalized gross load (dashed purple line), which shows load without the effects of energy efficiency and behind-the-meter solar, has grown slightly since 2014. The gap between weather-normalized gross load and actual load is the combined impact of energy efficiency (green area) and behind-the-meter solar generation (gold area). Greater energy efficiency and behind-the-meter solar generation have helped offset the increase in gross load, causing weather-normalized load to fall.

In 2019, energy efficiency reduced average load by an estimated 2,276 MW, an 8% increase (176 MW) compared to 2018, and a 51% increase (769 MW) compared to 2015. Behind-the-meter solar generation reduced average load by 286 MW, a 19% increase (45 MW) compared to 2015. While

[64] Weather-normalized load adjusts observed load for the effects of weather, leap year and non-holiday weekdays.

[65] Energy Efficiency is based on aggregated performance of installed measures on end-use customer facilities that reduce the total amount of electrical energy needed, while delivering a comparable or improved level of end-use service. Such measures include, but are not limited to, the installation of more energy efficient lighting, motors, refrigeration, HVAC equipment and control systems, envelope measures, operations and maintenance procedures, and industrial process equipment. Energy Efficiency and Demand Response Distributed Generation (DG) measures are aggregated to On-Peak and Seasonal-Peak resources. Performance of DG accounts for only 5% of energy efficiency performance.

the effect of behind-the-meter solar generation is less than that of energy efficiency, behind-the-meter solar generation has grown more rapidly, increasing 177% compared to 2015. Energy efficiency and behind-the-meter solar generation impact wholesale load differently during the year. Figure 2-16 shows that energy efficiency has a greater effect during Q1 and Q4, while behind-the-meter solar generation has a greater impact during Q2 and Q3.

2.3.2 Reserve Requirements

All bulk power systems need reserve capacity to respond to contingencies. ISO New England's reserve requirements are designed to allow the bulk power system to serve load uninterrupted if there is a loss of a major generator or transmission line.[66] The first level requirement is for the ISO to maintain a sufficient amount of reserves to be able to recover from the loss of the largest single system contingency (N-1) within 10 minutes. This requirement is referred to as the total 10-minute reserve requirement. At least 25% of the total 10-minute reserve requirement must be synchronized to the power system. The exact amount is determined by the system operators, and this amount is referred to as the 10-minute spinning reserve (TMSR) requirement. The rest of the total 10-minute reserve requirement can be met by 10-minute non-spinning reserve (TMNSR).

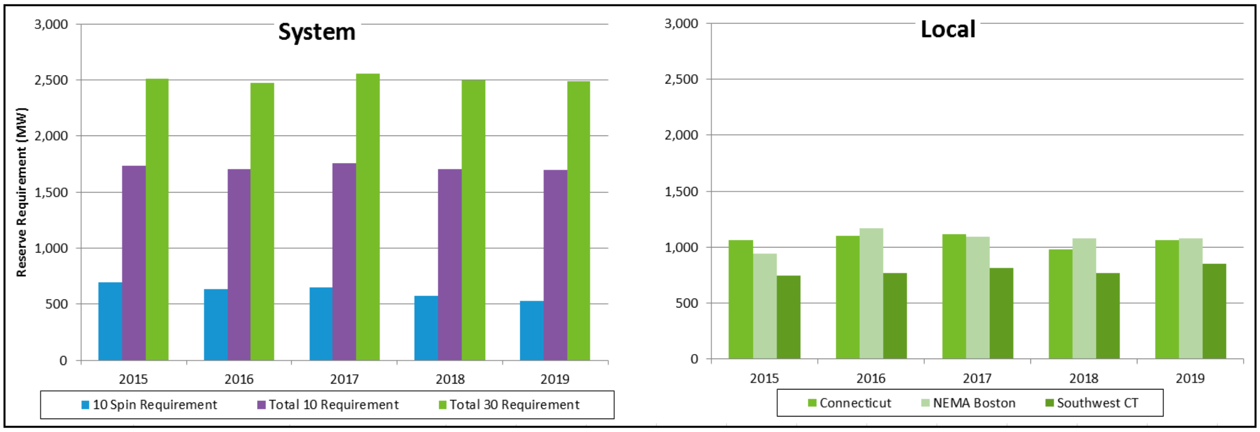
Additionally, adequate operating reserves must be available to meet 50% of the second-largest system contingency (N-1-1) within 30 minutes. This requirement can be satisfied by 30-minute operating reserves (TMOR). Starting in October 2013, the ISO added a 30-minute replacement reserve requirement of 160 MW for the summer and 180 MW for the winter months.[67] Adding these additional requirements to the total 10-minute reserve requirement comprises the system total reserve requirement.

In addition to the system-wide requirements, 30-minute reserves must be available to meet the local second contingency in import-constrained areas. Local TMOR requirements exist for the region's three local reserve zones – Connecticut (CT), Southwest Connecticut (SWCT), and NEMA/Boston (NEMABSTN). Local reserve requirements reflect the need for 30-minute contingency response to provide second contingency protection for each import constrained reserve zone. Local reserve requirements can be satisfied by resources located within a local reserve zone or through external reserve support. Average annual local reserve requirements are shown in the right panel of Figure 2-17 below.

[66] Operating Procedure No. 8, *Operating Reserves and Regulation* (August 2, 2019), https://www.iso-ne.com/static-assets/documents/rules_proceds/operating/isone/op8/op8_rto_final.pdf

[67] OP 8 states that in addition to the operating reserve requirements, ISO will maintain a quantity of Replacement Reserves in the form of additional TMOR for the purposes of meeting the NERC requirement to restore its Ten-Minute Reserve. ISO will not activate emergency procedures, such as OP-4 or ISO New England Operating Procedures No. 7 - Action in an Emergency (OP-7), in order to maintain the Replacement Reserve Requirement. To the extent that, in the judgment of the ISO New England Chief Operating Officer or an authorized designee, the New England RCA/BAA can be operated within NERC, NPCC, and ISO established criteria, the Replacement Reserve Requirement may be decreased to zero based upon ISO capability to restore Ten-Minute Reserve within NERC requirements.

Figure 2-17: Average System Reserve and Local 30-Minute Reserve Requirements



The reserve requirements are primarily determined by the size of the first and second largest contingencies on the system, so the average annual requirements tend not to fluctuate substantially from year to year. The average 10-minute spinning requirement was 527 MW in 2019, an 8% decline from 2018. This decline was due in-part to the milder weather in 2019 leading to a decrease in the need for TMSR versus TMNSR as part of the total 10-minute reserve requirement. In addition, with the milder weather, a large generation facility operated less frequently, which led to a smaller average largest contingency on the system compared to 2018. Over the past five years, the 10-minute spinning and total 10-minute reserve requirements have averaged around 600 MW and 1,700 MW, respectively. The total reserve requirement (including replacement reserves) has averaged about 2,500MW.

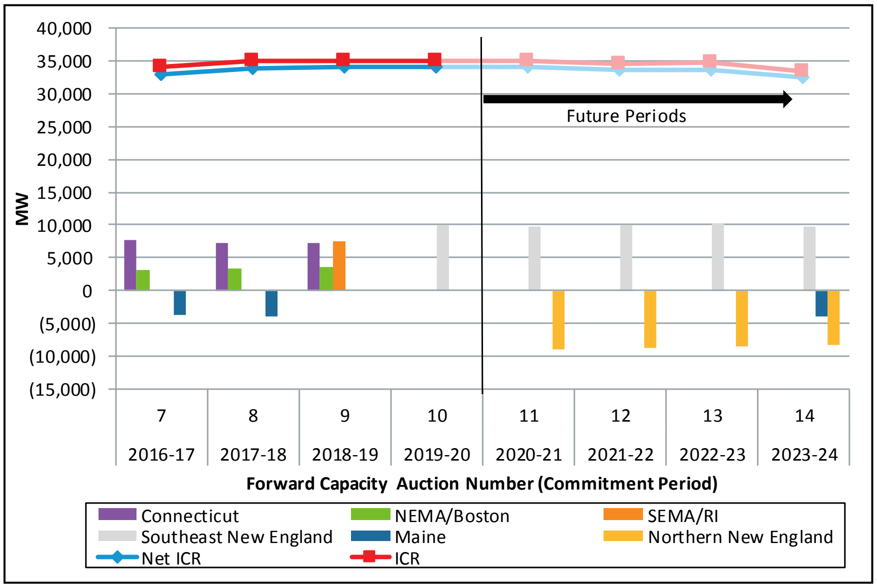
2.3.3 Capacity Market Requirements

The Installed Capacity Requirement (ICR) is the amount of capacity (expressed in megawatts) needed to meet the region's reliability requirements (including energy and reserves). The ICR requirements are designed such that non-interruptible customers can expect to have their load curtailed not more than once every ten years. The ISO develops the ICR through a stakeholder and regulatory process with review and action by various NEPOOL committees, state regulators, and the New England States Committee on Electricity.

When developing the target capacity to be procured in the Forward Capacity Auction (FCA), the ISO utilizes a Net ICR. The Net Installed Capacity Requirement (NICR) is the amount of capacity needed to meet the region's reliability requirements after accounting for tie benefits with Hydro-Quebec. Due to transmission limitations there are also local sourcing requirements (LSR) for import-constrained areas and maximum capacity limits (MCL) for export-constrained areas.

Trends in system capacity requirements, ICR and Net ICR, between 2016 and 2024 are shown in Figure 2-18 below. The system ICR and Net ICR are represented as line series. LSRs (positive bars) and MCLs (negative bars) are also shown.

Figure 2-18: ICR, NICR, Local Sourcing Requirements, and Maximum Capacity Limits



The Net Installed Capacity Requirement for FCA 14 was 32,490 MW. The Net ICR decreased by 1,260 MW, or by 4%, from FCA 13, primarily due to updates to the 2019 long-term forecast which resulted in lower peak load forecasts for FCA 14. Some of the updates include[68]:

- Incorporation of a second weather variable (i.e., cooling degree days)
- Separation of the July and August monthly peak demand models
- Shortening the historical weather period from 40 years to 25 years

LSRs are placed on import-constrained zones due to limited import capability and generation-load imbalances. As zonal capacity approaches and falls below the LSR, additional capacity within the zone becomes increasingly valuable due to declining reliability in the local area. Starting in FCA 10, Southeast New England (SENE) was the only import-constrained zone.[69] The SENE capacity zone was modeled again in FCA 14, with an LSR of 9,757 MW. This value was about a 400 MW decrease from FCA 13 (10,141 MW) due to greater capacity from existing SENE resources and a reduction in assumed unavailable capacity.[70]

Maximum capacity limits (MCLs) are placed on export-constrained zones due to limited export capability. These zones may procure more generation capability than can be exported to the rest of the system. Surplus capacity within the export-constrained zone becomes decreasingly valuable due to its declining contribution to system reliability. The Maine and Northern New England (NNE) capacity zones were modeled as separate export constrained capacity zones for FCA 14, after applying the updated nested capacity methodology that is detailed in Section III.12.2.2 of the Tariff.

[68] For more information see https://www.iso-ne.com/static-assets/documents/2019/09/a9_icr_and_tie_benefits_for_fca_14.zip

[69] Southeast New England consists of the NEMA/Boston, Southeastern Massachusetts, and Rhode Island load zones.

[70] For more information, see the following presentation to the NEPOOL Reliability Committee. https://www.iso-ne.com/static-assets/documents/2019/09/a3_icr_and_tie_benefits_for_fca14_presentation.pptx

The MCLs were 4,020 MW in Maine, and 8,445 MW in Northern New England; which includes Maine, Vermont, and New Hampshire.

2.4 Imports and Exports (External Transactions)

New England engages in the buying and selling of power with its neighboring control areas of New York, Hydro Québec, and New Brunswick over the transmission lines that interconnect the regions. These external transactions allow competitive wholesale markets to deliver load at a lower cost by displacing more-expensive native generation when imported power is available at a lower cost. In other words, importing ISOs are able to serve demand at an overall lower production cost than could be achieved using only native supply. Generators in exporting ISOs also benefit when there is no willing buyer of their power in their region, but there are customers willing to purchase their energy in another region.

External transactions allow power to be purchased in one region, and sold in another, in the day-ahead and real-time markets, with the goal of profiting from the spot price difference (or spread). Market participants can also use external transactions to fulfill other contractual obligations to buy or sell power (e.g., a power purchase agreement) or to import and collect a premium for renewable power. Participants submit external transactions to specific locations known as external nodes, which are affiliated with specific external interfaces. The nodes represent trading and pricing points for a specific neighboring area. A pricing node may correspond to one or more transmission line(s) that connect the control areas.

The ISO schedules these transactions and coordinates the interface power flow with the neighboring area based on the transactions that have been cleared and confirmed. The energy price produced by ISO-NE for an external node represents the value of energy at the location in the New England market, *not in the neighboring area.* The ISO-NE market settles the part of the transaction that occurs in the New England market; the neighboring control area settles the corresponding transaction on the other side of the interface.

New England's six external nodes are listed in Table 2-1 below, along with the commonly used external interface name. These names will be used throughout this section. There are three interfaces with New York, two with Hydro Québec and one with New Brunswick. The table also lists each interface's import and export total transfer capability (TTC) ratings. The operational ratings can be different due to the impact of power transfers in each direction on reliability criteria.

Table 2-1: External Interfaces and Transfer Capabilities

Neighboring area	Interface name	External node name	Import capability (MW)	Export capability (MW)
New York	New York North	.I.ROSETON 345 1	1,400 - 1,600	1,200
New York	Northport-Norwalk Cable	.I.NRTHPORT138 5	200	200
New York	Cross Sound Cable	.I.SHOREHAM138 99	346	330
Hydro Québec (Canada)	Phase II	.I.HQ_P1_P2345 5	2,000	1,200
Hydro Québec (Canada)	Highgate	.I.HQHIGATE 120 2	225	0-75
New Brunswick (Canada)	New Brunswick	.I.SALBRYNB345 1	1,000	550
Total			**5,171 – 5,371**	**3,480-3,555**

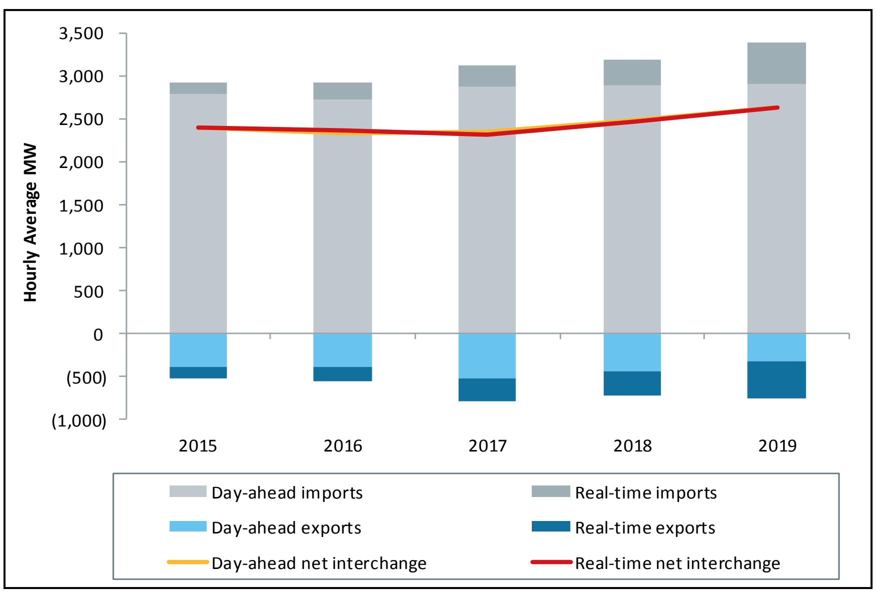
Net Interchange

New England continued to be a net importer of power. In 2019 real-time net imports averaged 2,633 MW each hour, meeting 19% of New England's wholesale electricity demand. Total net interchange was 7% higher than in 2018. In 2019 there was a 208 MW increase in average import transactions and a 35 MW increase in average export transactions relative to 2018, netting to a 174 MW positive increase in net interchange, on average. The overall increase was driven by more imports from New York.

New England imports significantly more power from the Canadian provinces than it does from New York. Across all three Canadian interfaces (i.e., Phase II, New Brunswick, and Highgate) the real-time net interchange averaged 1,977 MW per hour in 2019, which was 80 MW less than the average interchange in 2018. The real-time net interchange across the three interfaces with New York (i.e., New York North, Cross Sound Cable and Northport-Norwalk) averaged 656 MW per hour in 2019, 254 MW more than the average 2018 net interchange. Section 5 of this report provides further detail on the breakdown of total external transactions among the various interfaces with the New York and Canada.

The hourly average net interchange in the day-ahead and real-time markets for 2015 through 2019 are shown in the line series of Figure 2-19 below. The figure also charts the hourly average imported volume (positive values) and exported volume (negative values) in the bar series. The real-time import and export volumes are shown as the incremental additions to the amounts cleared in the day-ahead market.

Figure 2-19: Hourly Average Day-Ahead and Real-Time Pool Net Interchange



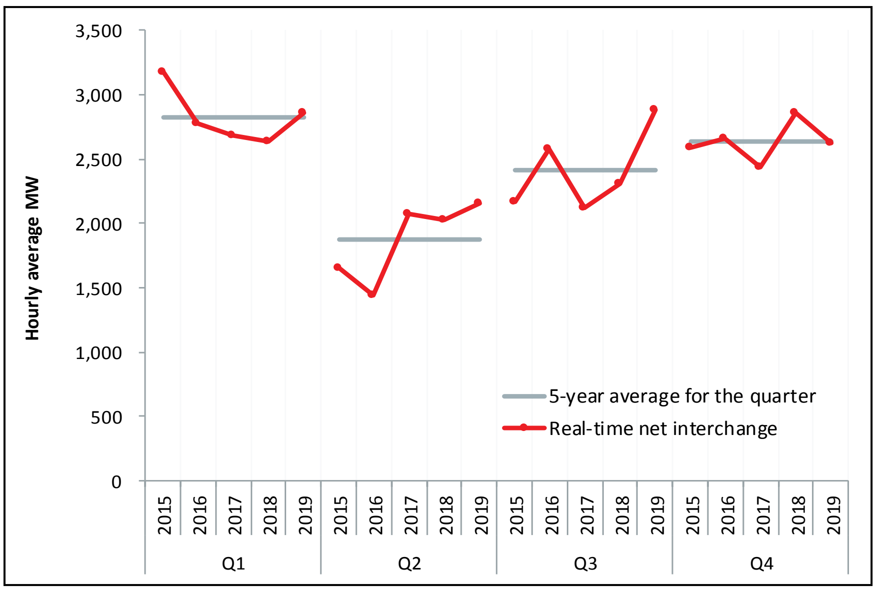
The average real-time net interchange has slowly increased since 2017, as shown by the red line series. One notable change in 2019 is an increase in real-time imports and exports. Real-time imports have increased by 474 MW per hour (16%) from 2015 to 2019, on average. Similarly, real-time exports have increased by 236 MW per hour (45%), on average, over the reporting period. The increases occurred primarily at the New York North interface, where Coordinated Transaction Scheduling (CTS) went into effect on December 15, 2015. CTS was designed to improve the efficiency of energy transactions between New England and New York.

The close proximity of the day-ahead net interchange (orange) and real-time net interchange (red) line series highlights that day-ahead market outcomes across the external nodes do, on average, closely predict the real-time scheduled flows.[71] Although additional import and export transactions are scheduled in real-time relative to day-ahead (shown by the darker colored bar series), the volumes of incremental real-time import and export schedules almost offset each other. In aggregate, real-time net interchange was greater than day-ahead net interchange by just 1.8% during 2019 (*i.e.*, slightly more power was imported in real-time than planned for day-ahead). For the remainder of this section, only the real-time values are presented since they align so closely with day-ahead values.

Net Interchange by Quarter

The hourly average real-time pool net interchange value is plotted by quarter for 2015 through 2019 in Figure 2-20 below. Note that the observations are grouped by calendar quarter in the chart. Each quarter's net interchange value is plotted with the red line series and, for comparison purposes, the five-year averages for each quarter are shown with the gray line series.

Figure 2-20: Hourly Average Real-Time Pool Net Interchange by Quarter



As the quarterly-segmented plots in Figure 2-20 show, there is seasonal fluctuation in the system net interchange. The fluctuation is demonstrated by the movement in the five-year average lines (gray) from a high during late winter (*i.e.*, Q1) when heating demand and natural gas-fired generators compete for constrained gas supplies, down to a low during the spring (*i.e.*, Q2) when temperatures are moderate, and loads and natural gas prices are typically at their lowest levels. The average net interchange climbs during the summer (*i.e.*, Q3) when New England loads are typically highest, and moves to a second peak at the start of winter (*i.e.,* Q4) when heating demand once again begins to put upward pressure on natural gas and electricity prices. Fuel prices are discussed more in Section 2.2.2.

[71] Virtual transactions cleared at external interfaces in the day-ahead market are included in the day-ahead net interchange value. In the day-ahead energy market, virtual supply and demand are treated equivalent to physical imports or exports.

Relative to 2018, the 2019 quarterly average net interchange increased in the first three quarters of the year. New England imported less power in Q4 2019 than in the same quarter in 2018. Most notably, in Q3 2019, the average net interchange into New England was over 550 MW per hour more than in Q3 2018. Increases in net imports over the New York North and Phase II interfaces between Q3 2018 and Q3 2019 were partially offset by a decrease in net imports over the New Brunswick interface. The increase in imports over the New York North interface year-round seems to be driven by an increase in fixed and low-priced import offers.   These fixed and low-priced offers may be due to contractual positions that participants enter into prior to the delivery day. The increase in imports over the Phase II interface is more straightforward. The average real-time total transfer capability of the Phase II lines was higher during Q3 2019 than in Q3 2018, which allowed New England to import more less-expensive hydro energy.

Section 3
Day-Ahead and Real-Time Energy Market

This section covers energy market outcomes, including the drivers of prices, market performance, competitiveness and market power mitigation.

The day-ahead and real-time energy markets are designed to ensure wholesale electricity is supplied at competitive prices, while maintaining the reliability of the power grid. Competitive energy market prices that reflect the underlying cost of electricity production are key to achieving both design goals. If suppliers can inflate prices above competitive levels, buyers will be forced to pay uncompetitive prices that exceed the cost of supplying power. On the other hand, if market prices are deflated (priced below production cost), suppliers lose the incentive to deliver power when it is needed. Further, investment in new, economically viable is hindered by deflated prices, hurting the short-term and long-term reliability of the New England power grid. Competitive energy market prices send the correct market signals, resulting in efficient buying and selling decisions that benefit consumers and suppliers alike.

In 2019, total day-ahead and real-time energy payments reflected changes in underlying primary fuel prices, most notably natural gas. The average Hub price was $32.22/MWh in the day-ahead market, down by 29% on 2018, and consistent with the 34% decrease in natural gas prices.

Under certain system conditions, suppliers can have local or system-wide market power. If suppliers exploit market power opportunities by inflating energy offers, uncompetitive market prices can result. To diminish the impacts of market power, energy market mitigation measures are applied when market power is detected; an uncompetitive generator offer is replaced with an IMM calculated competitive offer (i.e. reference level) consistent with the generator's cost of energy production.

Overall, day-ahead price-cost markups (i.e. the premium in market prices resulting from differences in generator offers and marginal costs) were within reason and market concentration levels, on average, remained reasonably low. Energy supply portfolios with structural market power in the real-time market declined markedly for the second consecutive year, from over half of all hours in 2017, to a third of hours in 2018, to only 12% of all hours in 2019. The reduction in the number of intervals with pivotal suppliers is consistent with a number of market trends, including a higher reserve surplus, and lack of scarcity conditions in 2019, and the commissioning of new entrant generators in 2018.

The energy market has a fairly extensive set of rules to identify and mitigate the impact of uncompetitive offers at times when structural market power exists. However, the mitigation measures for system-level market power in the real-time energy market provide suppliers a considerable degree of deviation from competitive marginal-cost offers before the mitigation rules trigger and mitigate a supply offer. We are currently evaluating the potential impact of structural market power and the effectiveness of existing mitigation thresholds in the real-time market. The analysis will be presented in a future quarterly markets report.

3.1 Overview of the Day-Ahead and Real-Time Energy Market

This section provides an overview of the day-ahead and real-time energy markets.

ISO-NE administers its wholesale energy market using a two-settlement system. The first settlement takes place in the day-ahead energy market. This is a *forward* market where market participants buy and sell power for the following operating day. The day-ahead market is often considered a *financial* market because there is no physical requirement that the energy bought and sold in this market be consumed or delivered in real-time.[72] The second settlement occurs in the real-time energy market. This is a *spot* market that coordinates the dispatch of resources in real-time based on actual conditions in the power system. The real-time market is a *physical* market because the transactions that occur in this market correspond to actual power flows.

As mentioned above, the day-ahead energy market allows participants to buy and sell electricity the day before the operating day. Participants that are interested in purchasing electricity can submit *demand bids* into the day-ahead energy market. These bids indicate the maximum price a buyer is willing to pay in order to purchase a certain quantity of electricity. Demand bids with bid prices greater than the locational marginal price (LMP) clear in the day-ahead market. Participants that are interested in selling electricity can submit *supply offers* into the day-ahead energy market.[73] These offers indicate the minimum price the seller is willing to accept in order to sell a certain quantity of electricity. Supply offers with offer prices less than the LMP clear in the day-ahead market.

Clearing a demand bid or a supply offer in the day-ahead market results in an initial settlement (i.e., the day-ahead settlement) and creates a financial obligation for the buyer or seller. For example, a generator that clears a 100 MW supply offer in the day-ahead market at a price of $50/MWh would be *credited* $5,000 in the day-ahead settlement. This generator receives a payment because it has financially obligated itself to provide power in real-time on the following day. This obligation requires the generator to deliver in real-time every megawatt it sold forward or else purchase power at a replacement price; i.e. at the real-time price. Physical delivery in real-time results in the second settlement for the generator (i.e., the real-time settlement). For example, if the generator provides no energy in real-time and the real-time price of energy is $75/MWh, then the generator would be *charged* $7,500 in the real-time settlement. The net outcome from the two settlements would be a charge of $2,500 to the generator for not delivering on its obligation.

One of the primary reasons for this two-settlement design is that it affords participants a way to reduce their exposure to real-time energy price volatility. Unexpected events like transmission or generator outages can lead to very high real-time energy prices. However, buyers and sellers who bought or sold energy in the day-ahead market are not exposed to these extreme real-time prices so long as they do not deviate from their day-ahead market obligations. This is because real-time energy prices apply only to deviations from day-ahead market obligations.

For example, consider a load-serving entity (LSE) that purchases 100 MW of electricity in the day-ahead market at a price of $50/MWh. This purchase creates a charge to the LSE of $5,000 in the day-ahead settlement. If the real-time price is $75/MWh and the real-time load for the LSE is 110 MWs, then the real-time settlement would result in an additional charge of $750. This is because the real-time price only applies to the 10 MW deviation. The net outcome from the two settlements would be a charge of $5,750 to the LSE. If the LSE had not participated in the day-ahead market,

[72] However, the day-ahead market is not completely separated from the physical world as the commitments made in the day-ahead energy market form the basis of the operating plan that is used in real-time.

[73] Resources with a capacity supply obligation (CSO) are required to submit supply offers into the day-ahead energy market of a magnitude at least equal to the megawatt amount of CSO they hold. The obligations associated with assuming a CSO create a linkage that ties the energy market to the capacity market, which is discussed in more detail in Section 6.

then it would have been charged $75/MWh for all 110 MWs of its real-time load. This would have resulted in a charge of $8,250 to the LSE. Effectively, the LSE has partially insulated itself from the higher real-time prices by participating in the day-ahead market.

Because the day-ahead energy market is a financial market, participants may submit *virtual* demand bids (decrement bids) or *virtual* supply offers (incremental offers) into this market. As the name implies, virtual demand bids and supply offers do not require a market participant to have physical load or supply. Collectively known as virtual transactions, these instruments allow participants to take financial positions in the day-ahead market with the expectation that the associated power will not be delivered or consumed in real-time. There are a number of arguments on how two-settlement markets, like ISO-NE's wholesale energy market, benefit from virtual transactions. These include the ability of virtual transactions to reduce market power, the increased liquidity they provide to the day-ahead market, and their ability to improve price convergence. Virtual transactions are discussed in more detail in Section 4.

The day-ahead market purchases enough physical and virtual supply to meet physical and virtual demand.[74] In order to determine which bids and offers clear, the day-ahead market uses a clearing algorithm with the objective of maximizing social surplus, while respecting transmission constraints. The day-ahead market results form the basis of the ISO Control Room's operating plan for the following day. In the day-ahead market, virtual bids and offers can be submitted at a nodal level, zonal level or at the Hub.[75] However, supply offers from generators must be submitted at the nodal location where that generator is electrically interconnected, and non-virtual demand bids are submitted at a zonal level. All results are hourly in the day-ahead market. The results are usually posted no later than 1:30 p.m. the day before the operating day.

The real-time energy market can be thought of as a "balancing market," settling the differences between positions (production or consumption) cleared in the day-ahead energy market and actual production or consumption in the real-time energy market. The ISO coordinates the production of electricity to ensure that the amount produced moment to moment equals the amount consumed, while respecting transmission constraints. While resources continue to make supply offers in real-time, the demand is the actual physical load. In real-time, the ISO calculates LMPs every five minutes for each location on the transmission system at which power is either withdrawn or injected.

[74] Operating reserves, described in Section 7.1, are not explicitly purchased through the day-ahead market. Operating reserves are procured in the Forward Reserve Market (see Section 7.2), and additional procurement occurs in the real-time energy market where reserve procurement is co-optimized with energy procurement.

[75] The Hub, load zones, and internal network nodes are points on the New England transmission system at which locational marginal prices (LMPs) are calculated. *Internal nodes* are individual pricing points (*pnodes*) on the system. *Load zones* are aggregations of internal nodes within specific geographic areas. The *Hub* is a collection of internal nodes intended to represent an uncongested price for electric energy that is used to facilitate energy trading. The Hub LMP is calculated as a simple average of LMPs at 32 nodes, while zonal LMPs are calculated as a load-weighted average price of all the nodes within a load zone. An *external interface* node is a proxy location used for establishing an LMP for electric energy received by market participants from, or delivered by market participants to, a neighboring balancing authority area.

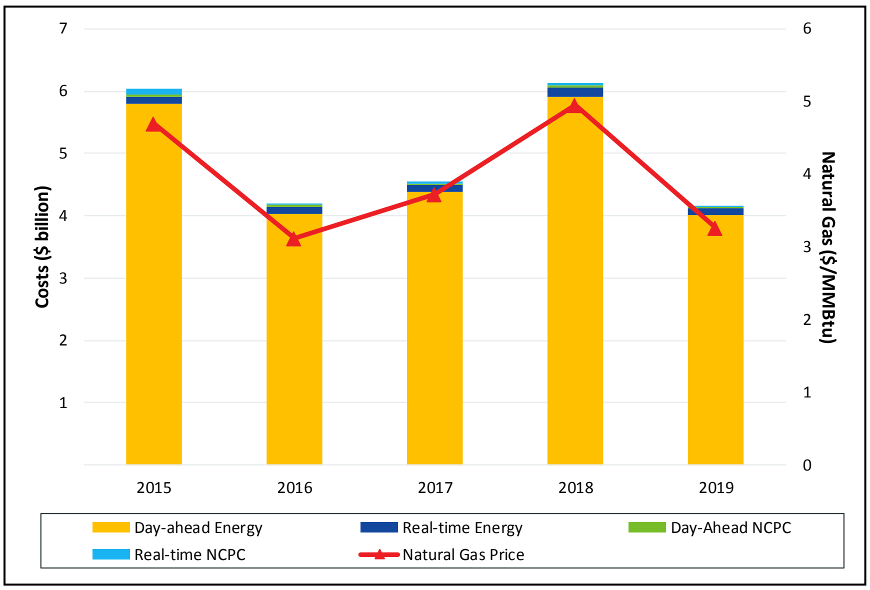
3.2 Energy and NCPC (Uplift) Payments

In 2019, total estimated energy and NCPC[76] payments decreased by 32% compared to 2018 ($4.2 billion in 2019 compared to $6.1 billion in 2018) largely due to a 34% decrease in natural gas prices.

In 2019, NCPC payments totaled $30.3 million, a decrease of $39.8 million (down by 57%) compared to 2018. Most NCPC payments in 2019 occurred in the real-time market. NCPC payments remained relatively low, at 0.7%, when expressed as a percentage of total energy payments. Section 3.5 discusses NCPC in detail.

Energy and NCPC payments for each year (billions of dollars), by market, along with the annual average natural gas price ($/MMBtu), are shown in Figure 3-1 below.

Figure 3-1: Energy, NCPC Payments and Natural Gas Prices



The relationship between natural gas prices and energy market payments is illustrated in Figure 3-1; specifically how natural gas prices are the primary driver behind changes in energy and NCPC payments. Lower average natural gas prices resulted in decreased energy payments in 2019. Natural gas prices averaged $3.26/MMBtu, down 34% from 2018 prices.

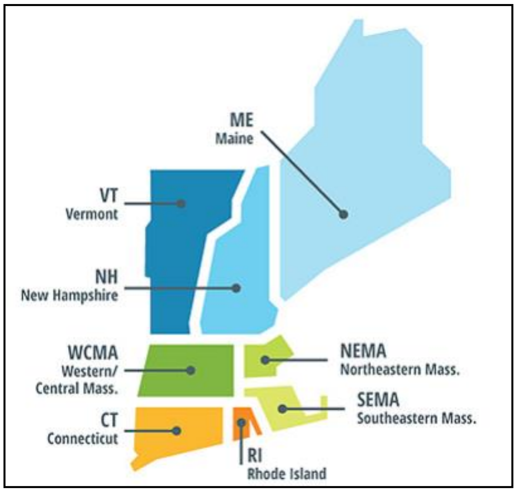
3.3 Energy Prices

Day-ahead and real-time LMPs are presented in this section. Both simple-average and load-weighted prices are summarized by time period and location. All prices are summarized as either annual average or monthly average values. On-peak periods are weekday hours ending 8 to 23 (i.e., Monday through Friday, excluding North American Electric Reliability Corporation (NERC)

[76] NCPC, or Net Commitment Period Compensation, payments cover the potion of as-offered production costs of ISO- or market-scheduled resources that are not recovered through the LMP.

holidays); the off-peak period encompasses all other hours. Prices are differentiated geographically by "load zone" (as shown in Figure 3-2 below) and the "Hub".

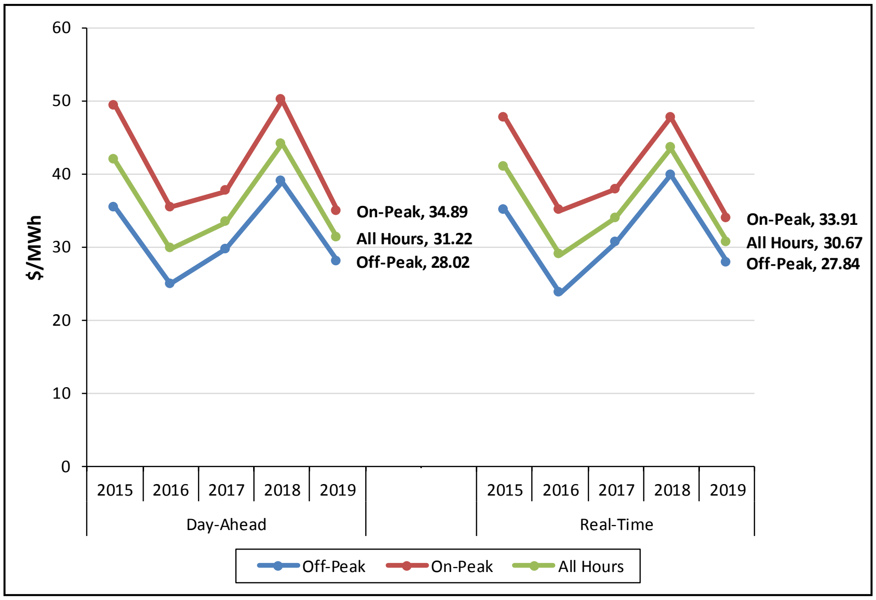
Figure 3-2: ISO New England Pricing Zones



3.3.1 Hub Prices

An illustration of energy market prices in the day-ahead and real-time markets, from 2015 to 2019, is provided in Figure 3-3 below.

Figure 3-3: Annual Simple Average Hub Price



In 2019, the simple annual average Hub price (in all hours) was $31.22/MWh in the day-ahead market and $30.67/MWh in the real-time market. Hub prices declined by 29% in the day-ahead market and by 30% in the real-time market compared to 2018 prices, on average.[77]

[77] These prices represent a simple average of the hourly-integrated Hub LMPs for each year and time-period, respectively.

Pricing by time-of-day (i.e., on-peak and off-peak) in 2019 exhibited the same trend when compared with 2018; average on-peak prices decreased by 30% in the day-ahead market and 29% in the real-time market, while average off-peak prices decreased by 28% in the day-ahead market and 30% in the real-time market, respectively.

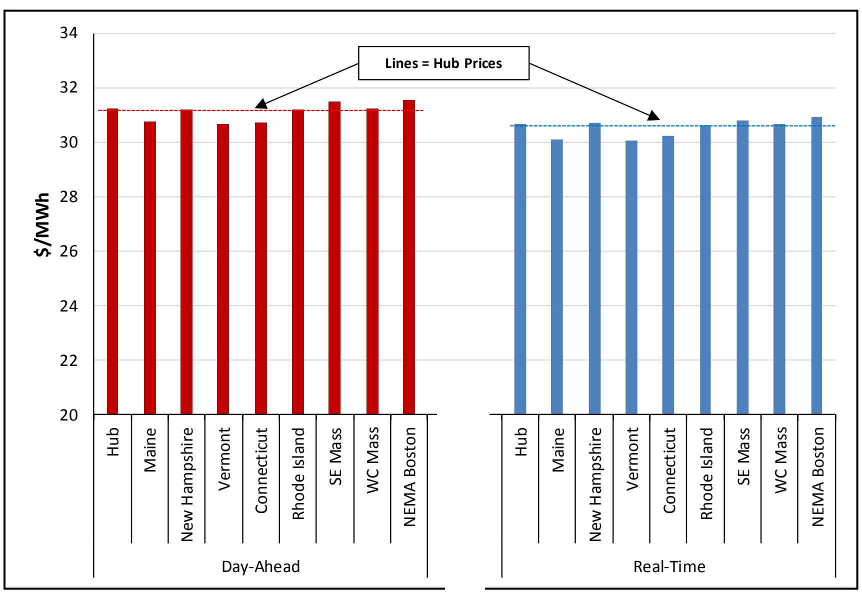
These price changes are consistent with observed market conditions, including input fuel costs, load levels, and generator operations. Compared to 2018, average natural gas prices decreased significantly in 2019, falling by approximately 34%. The reduction in fuel prices, a milder winter, and the lack of system scarcity events largely explain the decline in LMPs between 2018 and 2019. A small decrease in average 2019 loads (approximately 4%), driven primarily by lower summer demand, also contributed to the decline in LMPs.

Average real-time prices were slightly lower than day-ahead prices in 2019 overall (-1.8% in all hours) and during on-peak (-2.8%) and off-peak (-0.6%) periods. The lower average overall real-time prices continue a longer-run trend of average day-ahead prices slightly exceeding real-time prices, except in 2017 when average real-time prices were higher than day-ahead prices resulting primarily from relatively high real-time prices in the latter part of December 2017.

3.3.2 Zonal Prices

This section describes differences among zonal prices. Within the day-ahead and real-time energy markets, price differences among load zones will result from energy "losses" and transmission congestion that vary by location.[78] In 2019, price differences among the load zones were relatively small, as shown in Figure 3-4 below.

Figure 3-4: Simple Average Hub and Load Zone Prices, 2019



[78] The loss component of the LMP is the marginal cost of additional losses resulting from supplying an increment of load at the location. New England is divided into the following eight load zones used for wholesale market billing: Maine (ME), New Hampshire (NH), Vermont (VT), Rhode Island (RI), Connecticut (CT), Western/Central Massachusetts (WCMA), Northeast Massachusetts and Boston (NEMA), and Southeast Massachusetts (SEMA).

The relatively small price differences between the load zones were the result of modest levels of both marginal losses and congestion. The average absolute difference between the Hub annual average price and average load zone prices was $0.27/MWh in the day-ahead energy market and $0.26/MWh in the real-time energy market – a difference of approximately 1.0%.

The Vermont load zone had the lowest average prices in the region in 2019. Vermont's prices averaged $0.55/MWh (1.7%) and $0.62/MWh (2.0%) lower than the Hub's prices for the day-ahead and real-time markets, respectively. Most of the difference in average prices between Vermont and the Hub resulted from the imputed cost for transmission losses that is included in the LMP; losses represented about 74% of the price difference in both the day-ahead and real-time energy markets.

Conversely, NEMA had the highest average prices in the day-ahead and real-time markets. NEMA's average day-ahead and real-time prices were slightly higher than the Hub's, by $0.32/MWh and $0.25/MWh, respectively. NEMA is import-constrained at times, with the transmission network limiting the ability to import relatively inexpensive power into the load zone.

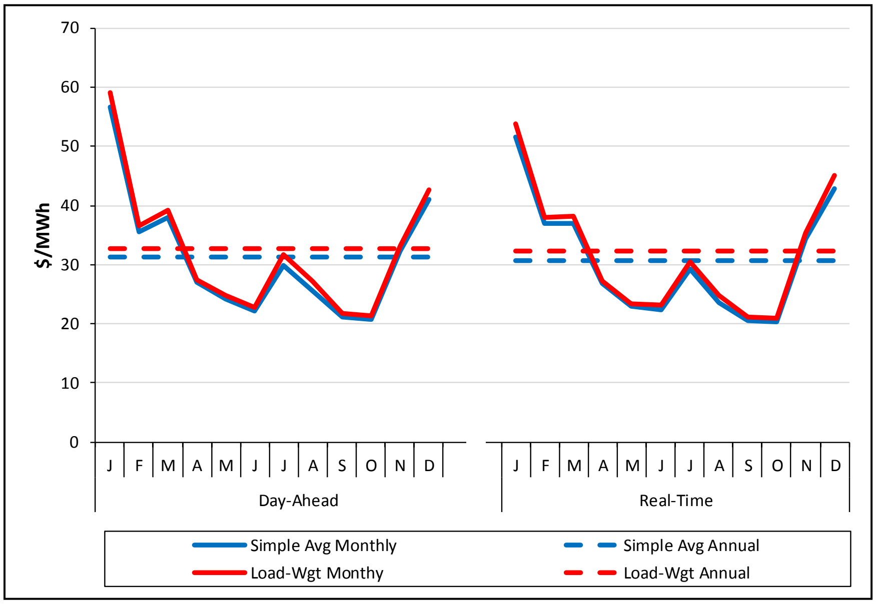
3.3.3 Load-Weighted Prices

While simple average prices are an indicator of actual observed energy prices within the ISO's markets, load-weighted prices are a better indicator of the average price that load serving entities (LSEs) pay for energy.[79] The amount of energy consumed in the markets can vary significantly by hour and energy price. Load-weighted prices reflect the increasing cost of satisfying demand during peak consumption periods when load is greater; during high load periods more expensive supply resources must be committed and dispatched. Load-weighted prices tend to be higher than simple average prices.

The average load-weighted prices were $32.82 and $32.32/MWh in the day-ahead and real-time markets, respectively. Monthly load-weighted and simple average prices for 2019 are provided in Figure 3-5.

[79] While a simple average price weights each energy market price equally across the day, load weighting reflects the proportion of energy consumed in each hour: load-weighted prices give higher weighting to high-load consumption hours than to low load consumption hours, with each hour being weighted in proportion to total consumption for the entire day.

Figure 3-5: Load-Weighted and Simple Average Hub Prices, 2019

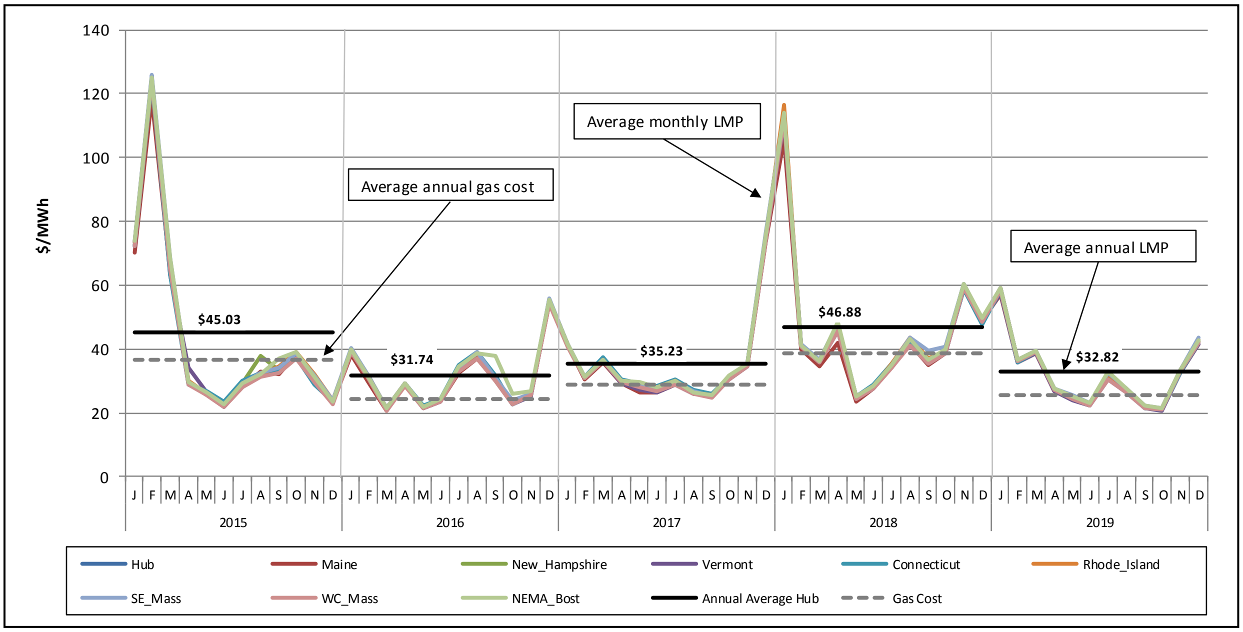


As expected, load-weighted average prices were higher than simple average prices in 2019. The differences range from approximately 2% to 6%, depending on the month and energy market (day-ahead and real-time). These price differences reflect the variability in load over the course of a day, which is typically a function of temperature and business/residential consumption patterns. For example, hours with low electricity consumption tend to occur overnight, when business and residential activity is low and summer cooling needs are minimal.

In 2019, load variability during the day had the least impact on the average prices paid by wholesale consumers in April, when simple and load-weighted average prices differed by just 2% in both the day-ahead and real-time markets. Summer and winter months exhibited the greatest impact of load variability on the average prices paid by wholesale consumers. In the day-ahead market, January experienced the largest difference, at $2.25/MWh, with July having the largest percentage difference at 6%. In the real-time market, January also had the highest difference between load-weighted prices and simple average prices at $2.41/MWh, while August and December had the largest percentage differences, each at 5%.

Day-ahead load-weighted prices across load zones over the past five years are shown in Figure 3-6 below. The black lines show the average annual load-weighted Hub prices and highlight the degree of variability in prices throughout the year. The dashed grey lines show the annual average cost of natural gas.

Figure 3-6: Day-Ahead Load-Weighted Prices



Load-weighted energy prices by load zone from 2015 to 2019 indicate a pattern that varies considerably by year and month, but typically not by load zone. As described above, a primary driver of material price differences between load zones is congestion; with a few notable exceptions (for example, September 2016), monthly average prices did not exhibit significant price differences across load zones over the review period.[80]

Extreme pricing in the months February 2015 and January 2018 occurred due to high natural gas prices. This is consistent with varying weather patterns and natural gas prices over the period, and reasonably uniform load shapes across load zones. Winter periods with high fuel prices and summer months with elevated load variability have the highest load-weighted prices; a similar trend applies to the real-time market. Notably, extreme winter gas and energy prices did not occur during 2019.

3.3.4 Energy Price Convergence Between Day-Ahead and Real-Time Market

This section focuses on three aspects of price convergence. First, we describe the importance of price convergence as a signal of market efficiency. Second, we review the degree of day-ahead and real-time energy price convergence in recent years. In 2019, the average day-ahead Hub price was $0.55/MWh (or 1.8%) higher than the average real-time Hub price, and the level of price convergence was similar to previous years. Lastly, we examine the drivers that influence energy price convergence, including the factors that cause real-time and day-ahead prices to differ.

Importance of Price Convergence

The objective of the real-time energy market is to provide least-cost dispatch while meeting load and reliability requirements. The day-ahead energy market serves an important role in achieving

[80] In May 2017, transmission line outages and warm temperatures, with elevated load levels, resulted in noticeable differences in average monthly prices across load zones.

this ultimate goal because it can help produce a least-cost schedule that reliably meets expected load in advance of real-time.

Scheduling generators in the day-ahead market is advantageous because it allows for more flexibility in generator selection. After the day-ahead market closes and the real-time market approaches, the number of generators the ISO can commit and dispatch shrinks. This is because longer-lead time generators, which can require several hours to start up, are no longer available to dispatch in the real-time market. Thus, in real-time, there is a greater reliance on more-expensive, fast-start generators.[81]

Price convergence is an important metric because it can be indicative of how well the day-ahead market has anticipated real-time conditions. For example, consider a day where real-time load is much higher than the amount of demand that had cleared in the day-ahead market. To meet this additional load, the ISO would need to commit additional (and often more expensive) fast-start generators in real-time. The result would be a real-time price that is greater than (sometimes much greater than) the day-ahead price.

If the day-ahead market had better anticipated real-time conditions, the day-ahead and real-time prices would have been better aligned. Participants forecasting high real-time load would have cleared more demand in the day-ahead market, which would have led to less-expensive, longer-lead time generators being committed day-ahead. The result would be a lower overall dispatch cost as these less-expensive generators would remove the need to commit a more-expensive, fast-start generators in real-time. Day-ahead and real-time prices would move closer; more demand in the day-ahead market would increase the day-ahead price, while no longer needing to dispatch an expensive fast-start generator would decrease the real-time price. Thus, strong price convergence serves as a signal that the day-ahead market is accurately anticipating real-time conditions and helping ensure reliable, least-cost dispatch.

Price Convergence 2015-2019

The overall convergence between day-ahead and real-time prices has remained relatively stable over the past five years. Figure 3-7 below shows the distribution of the day-ahead price premium at the Hub (i.e., the day-ahead Hub price minus the real-time Hub price) along with annual average day-ahead Hub LMP (orange line) for 2015–2019.[82]

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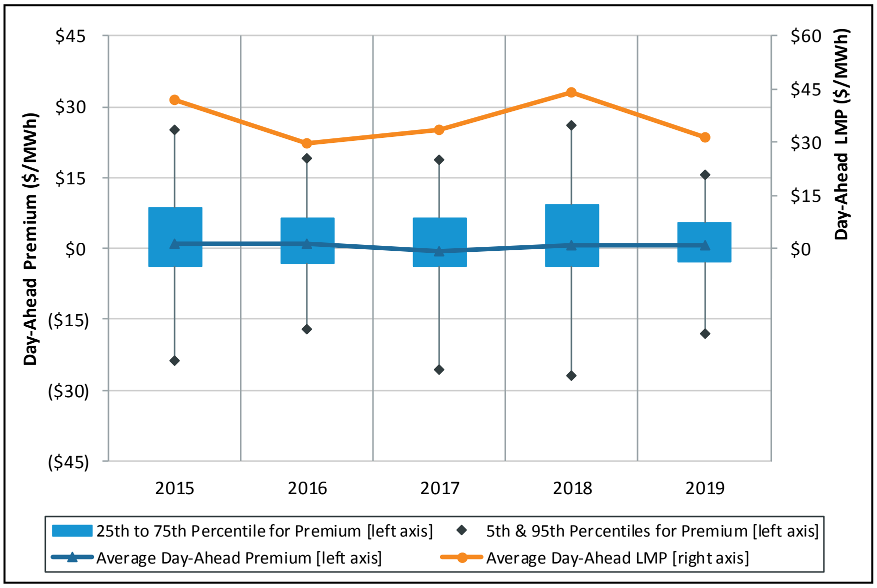
[81] Scheduling in the day-ahead market is also beneficial for generators that have operational and fuel procurement constraints, which can be better managed when they are committed prior to the operating day.

[82] Some other metrics for assessing price convergence are presented in Section 4.1.4.

Figure 3-7: Day-Ahead Hub LMP Premium and Average Day-Ahead Hub LMP



The day-ahead premium at the Hub averaged $0.55/MWh in 2019 (i.e., the day-ahead Hub price averaged $0.55/MWh more than the real-time Hub price). However, there was considerable variation around this average over the year. The blue boxes in Figure 3-7, which denote the range of 25th and 75th percentiles of the day-ahead premium for each year, show that for half of all hours in 2019, the day-ahead Hub premium was between -$2.92/MWh and $5.39/MWh.

The whiskers in the figure show the 5th and 95th percentiles for the day-ahead Hub premium, which were -$18.14/MWh and $15.53/MWh, respectively, in 2019. Over time, the 5th/95th percentiles generally track the average day-ahead LMP (orange series, right axis). Since average LMPs are primarily driven by natural gas prices in New England, differences between day-ahead and real-time prices tend to be larger when gas prices are higher. This is because the difference in cost between two gas-fired generators with different heat rates is greater when gas prices are higher.[83]

Drivers of Price Divergence

Real-time conditions will usually differ from day-ahead expectations. Market efficiency does not require that real-time and day-ahead prices be equal all the time. Rather, it means that prices reflect all available information, and in turn, day-ahead prices represent an unbiased expectation of real-time prices.

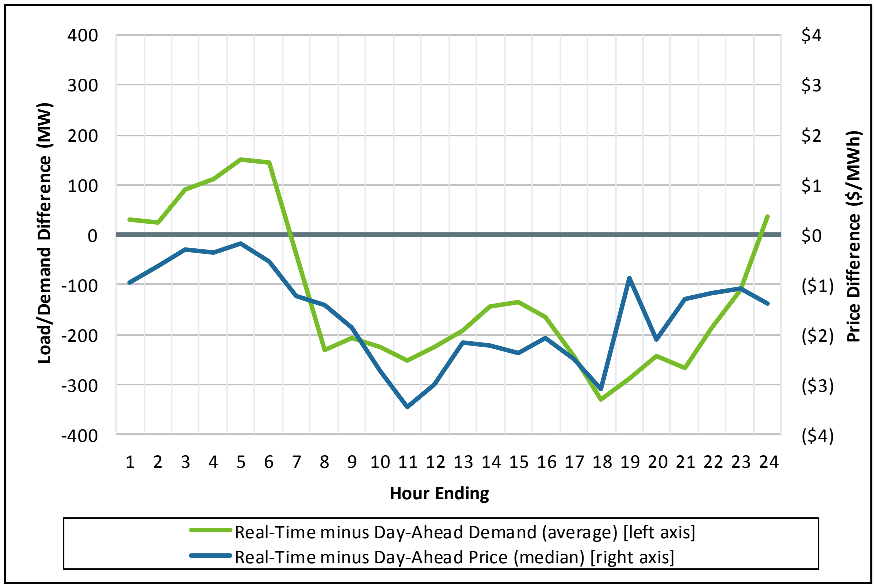
Ultimately, supply and demand forces, as well as actions taken by the ISO to ensure reliability, determine day-ahead and real-time prices. Thus, when day-ahead and real-time prices do vary, it is often driven by shifts in supply and demand conditions. On the supply-side, for example, if a generator clears in the day-ahead market and then has a forced (unplanned) outage in real-time, the available system capacity falls and real-time prices will likely rise. On the demand-side, for

[83] For example, consider two gas-fired generators: Gen A has a heat rate of 7 MMBtu/MWh and Gen B has a heat rate of 10 MMBtu/MWh. If the gas price is $5/MMBtu, the generation cost for Gen A is $35/MWh (7 MMBtu/MWh x $5/MMBtu) and the cost for Gen B is $50/MWh (10 MMBtu/MWh x $5/MMBtu). The difference in generation cost between Gen A and Gen B is $15/MWh. If the gas price increases to $10/MMBtu, the generation costs for Gen A and Gen B are now $70/MWh and $100/MWh, respectively, for a difference of $30/MWh.

example, warmer-than expected temperatures on a summer day can translate to greater real-time loads and higher real-time prices.

The close connection between deviations in real-time load and day-ahead demand and the differences in real-time and day-ahead Hub prices are shown in Figure 3-8 below. The green line depicts the average difference between real-time metered native load and day-ahead native demand (i.e., real-time load minus day-ahead demand) during 2019 by hour of the day (hours ending 1–24). The blue line shows the median difference between real-time and day-ahead Hub prices (i.e., real-time Hub price minus day-ahead Hub price) during 2019 by hour of the day.

Figure 3-8: Deviations in Real-Time and Day-Ahead Native Demand and Hub Price by Hour in 2019



The difference in real-time and day-ahead Hub prices correlates well with the deviations in real-time and day-ahead demand. Hours with lower real-time load compared to day-ahead demand (e.g., HE 7-23) tend to be the hours with the lowest real-time prices relative to day-ahead prices.[84] When real-time load falls below day-ahead demand (e.g., if temperatures on a summer day end up cooler than expected), the ISO will often back down the most-expensive generators; this results in moving down the supply stack to less-costly generators, which translates to a lower real-time price relative to the day-ahead price. The fact that real-time demand tends to be lower than day-ahead demand during the daylight hours indicates that participants in the day-ahead market may be struggling to accurately assess the impact of behind-the-meter-solar generation on real-time load. The difficulty of quantifying this impact is discussed in more detail in Section 3.4.5.

In addition to unforeseen changes between day-ahead and real-time conditions, market participants may prefer one market to another. For example, a supplier with a gas-fired generator may prefer to sell power in the day-ahead market. Receiving an operating schedule the day before expected physical delivery allows the supplier to better manage buying and scheduling natural gas for the following day. Similarly, an LSE may want to limit their exposure to more volatile real-time prices and prefer to purchase load in the day-ahead market.

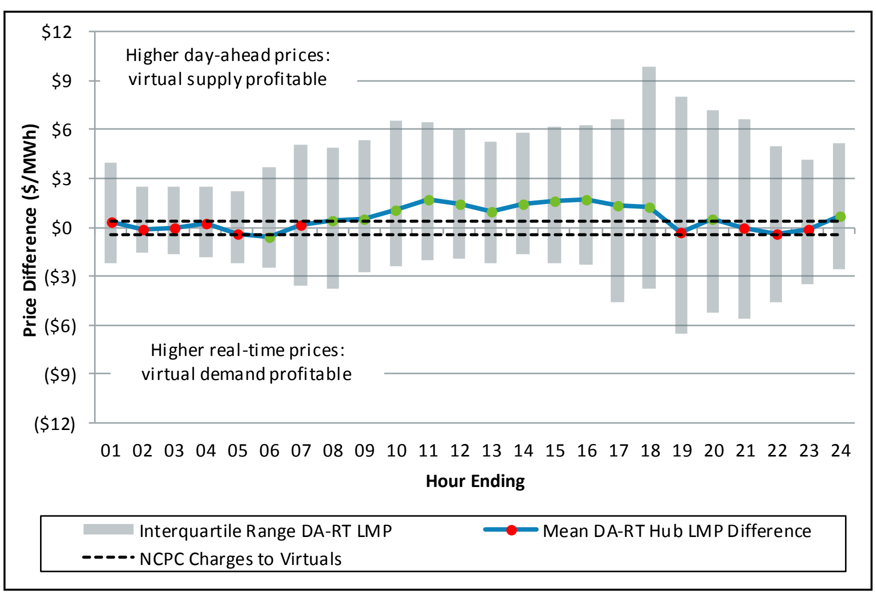
[84] In 2019 the median difference between real-time and day-ahead Hub prices was negative in every hour.

Role of Virtual Transactions in Price Convergence

As discussed in more detail in Section 4.1, virtual transactions play a critical role in improving market efficiency and price convergence. Virtual traders profit from differences between the real-time and day-ahead price. Generally, profit earned by a virtual trader is a reflection of the value that the trader adds in helping prices to converge. For example, consider a virtual trader who anticipates that higher-than forecasted temperatures will cause real-time load and price to be much higher than others expect. The trader submits a virtual demand bid, and it clears in the day-ahead market. If the real-time price is higher than the day-ahead price, the trader profits (ignoring charges and other costs). Although the trader's motivation was profit, the virtual transaction helped improve price convergence; by clearing the demand bid, the trader increased the day-ahead price, thereby bringing day-ahead prices closer to real-time prices. Importantly, by increasing day-ahead demand, the virtual demand may have worked to commit additional physical generators that could serve the higher load and preclude the need to call upon higher-cost, fast-start generators in real-time.

Although hourly price differences continue to offer profitable opportunities for virtual transactions, Net Commitment Period Compensation (NCPC) charges allocated to virtual transactions diminish the profitability and frequency of these opportunities. This is demonstrated Figure 3-9 below, which shows average hourly trends in the day-ahead to real-time price difference at the Hub in 2019, together with average NCPC charges. The blue line shows the mean price difference. When price differences are above zero it is profitable for virtual supply to clear, and when they are below zero it is profitable for virtual demand to clear, before considering NCPC. The dashed black lines show the average NCPC charge to virtual supply and virtual demand. Where the blue line falls between the two dashed black lines (red circles), on average, neither virtual supply nor virtual demand is profitable as the NCPC charges are greater than the day-ahead to real-time price difference. Conversely, where the blue line falls outside the dashed lines, on average, virtual supply or demand is profitable (green circles). The gray bars show the interquartile range (i.e., the middle 50 percent) of the day-ahead to real-time price difference at the Hub.

Figure 3-9: Hourly Day-Ahead to Real-Time Price Differences and NCPC Charges, 2019



In some hours, it was not profitable, on average, for a virtual participant to help converge prices. For example, in hours ending one through five, the average gross profit to be made from a virtual transaction at the Hub is less than the NCPC costs it would be charged. Although a participant will not know in advance what the NCPC charge will be, this expectation of a loss (or a higher possibility of a loss) diminishes the incentive for a virtual participant to capture these price differences.

In other hours, it was profitable, on average, for virtual traders to help converge prices, yet this did not occur. This is most apparent for hours ending 8 through 18, when day-ahead prices were, on average, above real-time prices and this difference exceeded the average NCPC charge. It would have been profitable, on average, for a participant to clear a virtual supply offer in the day-ahead market in these hours — effectively selling at the higher day-ahead price and buying back at the lower real-time price. The lack of price convergence may have been hindered by uncertainty over NCPC charges or uncertain load conditions in these hours, with the latter being increasingly impacted by the growth in behind-the-meter solar generation.

3.4 Drivers of Energy Market Outcomes

Many factors can provide important insights into long-term market trends. For example, underlying natural gas prices can explain, to a large degree, movements in energy prices. Other factors, such as load forecast error or notable system events can provide additional insight into specific short-term pricing outcomes. This section covers some of the important factors that provide context to energy market outcomes. The section is structured as follows:

- Generation costs (Section 3.4.1)
- Supply-side participation (Section 3.4.2)
- Load and weather conditions (Section 3.4.3)
- Demand bidding (Section 3.4.4)
- Load forecast error (Section 3.4.5)
- Supply margin (Section 3.4.6)
- System events (Section 3.4.7)
- Reliability commitments (Section 3.4.8)
- Congestion (Section 3.4.9)
- Marginal resources (Section 3.4.10)

3.4.1 Generation Costs

Day-ahead and real-time electricity prices continue to be closely correlated with the estimated cost of operating a natural gas-fired generator. As discussed later in Section 3.4.10, one or more marginal resources set the price of electricity in any given time interval. In a competitive, uniform clearing price auction, a resource's offer price should reflect its variable production costs. For fossil fuel-fired generators, their variable costs are largely determined by their fuel costs and operating efficiencies (heat rates). Since natural gas-fired generators set price more frequently than generators of any other fuel type in New England, electricity prices are positively correlated with the estimated marginal cost of a typical natural gas-fired generator.

One way to understand the relationship between electricity prices and fuel costs is to compare the variable costs of different fuel types to the wholesale price (LMP). Quarterly average day-ahead

LMPs and estimated generation costs of various fuel types (assuming standard heat rates), and spark spreads are shown below in Figure 3-10.[85]

Figure 3-10: Estimated Generation Costs and LMPs during Peak Hours

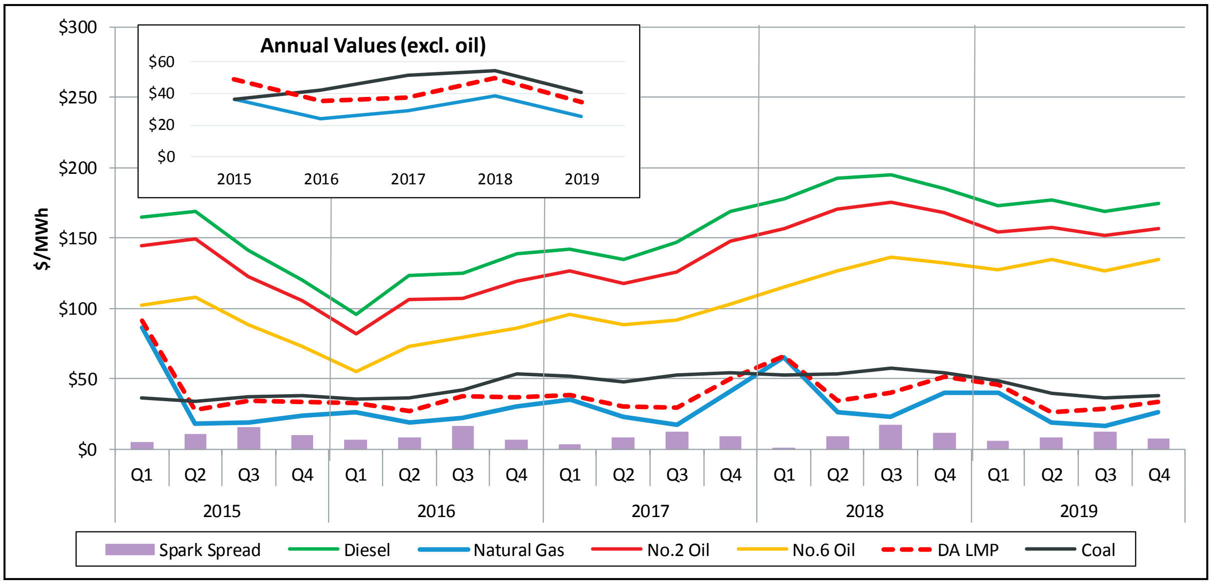


Figure 3-10 shows that prices are closely correlated with the estimated costs of operating a natural gas-fired generator. The correlation varies within each year, especially during the summer when electricity demand is typically higher. Higher loads typically require the operation of less efficient natural gas-fired generators and/or generators that burn more expensive fuels. During the summer months, efficient natural gas-fired generators earn higher margins (commonly referred to as spark spreads) compared to other months.[86]

In New England, natural gas-fired generators are the dominant price setters and supply nearly 50% of native generation. Therefore, it is worth reviewing trends in profitability metrics for gas-fired generators. Such metrics include implied heat rates and spark spreads across a range of efficiencies applicable to the New England fleet of natural gas-fired generators.

Table 3-1 shows the average day-ahead on-peak LMP and the annual average natural gas price; these are the key inputs into the calculation of the implied heat rate (or breakeven point) for natural gas-fired generators. A heat rate of 7,800 Btu/kWh represents the average standard efficiency of the New England fleet of combined cycle natural-gas fired generators, and a heat rate of 6,381 Btu/kWh reflects a new entrant combined cycle gas-fired generator.[87]

[85] 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.

[86] During the winter months, coal- and oil-fired generators, as well as imports, can displace natural gas-fired generators in economic merit order more frequently than in other seasons, as natural gas prices increase due to gas network demand and constraints. This tends to lessen the impact of higher gas prices on LMPs as more costly gas-fired generators are pushed out of merit and leads to reduced spark spreads.

[87] The heat rate of 6,381 Btu/kWh represents the estimated baseload net heat rate of a new combined cycle, gas turbine from the 2017 net cost of new entry study (CONE).

Table 3-1: Annual Average On-Peak Implied Heat Rates and Spark Spreads

Year	Day-Ahead On-Peak LMP ($/MWh)	Gas Price ($/MMBtu)	Implied Heat Rate (Btu/kWh)	Spread ($/MWh) corresponding to Heat Rate (Btu/kWh)					
				6,381	7,000	7,800	8,000	9,000	10,000
2015	49.32	4.81	10,262	18.65	15.68	11.83	10.87	6.06	1.26
2016	35.39	3.17	11,149	15.13	13.17	10.63	9.99	6.82	3.65
2017	37.64	3.69	10,188	14.06	11.78	8.82	8.08	4.39	0.69
2018	50.11	5.05	9,918	17.87	14.74	10.70	9.69	4.64	(0.41)
2019	34.89	3.32	10,520	13.73	11.67	9.02	8.36	5.04	1.72

The table shows that the spark spreads for a typical New England gas-fired generator (7,800 Btu/kWh) decreased by 16% ($9.02/MWh vs. $10.70/MWh) year over year while the implied heat rate increased by 6% (10,520 Btu/kWh vs. 9,918 Btu/kWh). This suggests that less efficient gas generators had slightly higher gross margins compared to 2018.

New England's reliance on natural gas

A number of market forces influence the relationship between New England's natural gas and electricity markets, including the following:

- An influx of natural gas-fired generating capacity over the past 25 years.[88]
- An aging and declining fleet of nuclear, oil- and coal-fired generators, many of which were constructed during the 1960s and 1970s.
- Lower natural gas prices resulting from increased production of domestic shale gas from the Marcellus Shale region of the country.
- The natural gas system becoming increasingly constrained due to high heating demand during winter months and greater demand from natural gas-fired generators. Also, limited additional gas pipeline capacity to alleviate those constraints due to regulatory, political and market challenges.

The first three factors listed above have resulted in gas-fired generators supplying a much higher proportion of electricity in New England. However, during winter months, gas-fired generators must compete with heating demand, which can push gas pipeline capacity to its limit over periods with peak gas demand. Consequently, the reliability of New England's wholesale electricity grid is partially dependent on the owners and operators of natural gas-fired generators effectively managing natural gas deliveries during contemporaneous periods of high gas and electric power demand. Reliability is also increasingly dependent on the region's oil fleet having sufficient oil on hand to operate when the gas network is highly constrained. During these periods, oil-fired

[88] During the 1990s, the region's electricity was produced primarily by oil-fired, coal-fired, and nuclear generators, with very little gas-fired generation. In 1990, oil-fired and nuclear generators each produced approximately 35% of the electricity consumed in New England, whereas gas-fired generators accounted for approximately 5%. Coal-fired generators produced about 18% of New England's electricity. In contrast, by 2019, oil- and coal-fired generators combined produced less than 1% of electricity generated in New England. Natural gas-fired generators produced 48%.

ISO New England, *Addressing Gas Dependence* (July 2012), http://www.iso-ne.com/static-assets/documents/committees/comm_wkgrps/strategic_planning_discussion/materials/natural_gas_white_paper_draft_july_2012.pdf.

generation can be cheaper than gas-fired generation, leading to oil-fired generators being dispatched more frequently.

One of the challenges identified in the ISO's Strategic Planning Initiative is the region's reliance on natural gas-fired generators.[89] Over the past few years the ISO has undertaken a number of related initiatives, including the following:

- Redesigning Forward Capacity Market performance penalties with the pay-for-performance (PFP) capacity market design, which began June 1, 2018. [90]
- Introducing the Winter Reliability Program, which was in place until PFP was implemented in 2018.
- Allowing the ISO to share information concerning the scheduled output of natural gas-fired generators with the operating personnel of the interstate natural gas pipeline companies serving New England.
- Introducing changes to the energy market design, including improving price signals for fast-start resources, accelerating the closing time of the day-ahead energy market (May 2013) and the introduction of energy market offer flexibility in December 2014.
- Increasing the procurement of ten-minute non-spinning reserves in the Forward Reserve Market to account for generator non-performance.
- A one-year program, known as the Interim Compensation Treatment, to compensate generators for making fuel arrangements for Winter 2023/4.
- A longer term effort, known as the Energy Security Improvement (ESI) project, to put in place a market-based approach to valuing and pricing energy security.[91]

Relationship between natural gas and electricity prices

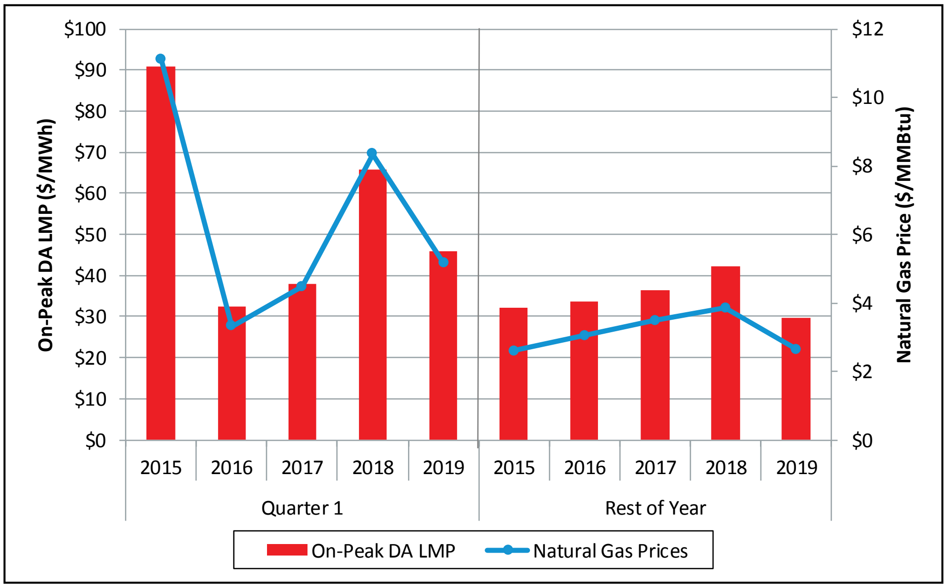
Average annual day-ahead on-peak LMPs and natural gas prices from 2015 to 2019 are shown in Figure 3-11 below. Since cold weather in the first quarter (Q1) can cause higher natural gas prices and electricity prices, Q1 is shown separately from the rest of the year.

[89] See the ISO's "Strategic Planning Initiative Key Project" webpage at http://www.iso-ne.com/committees/key-projects/implemented/strategic-planning-initiative.

[90] See Section 6.2.2 for information on pay-for-performance

[91] ESI is more generally being driven by changes in the energy mix to more just-in-time fuels, including natural gas, and thus making the system energy-constrained at times, while can happen even when the system has ample capacity (i.e. is not capacity constrained).

Figure 3-11: Average Electricity and Gas Prices for Q1 Compared with Rest of Year



Colder temperatures in Q1 tend to cause higher natural gas prices and LMPs than the rest of the year. In Q1 2019, day-ahead on-peak electricity prices were significantly lower than Q1 2018 and Q1 2015, but were higher than 2016 and 2017. Typically, colder temperatures cause higher natural gas prices. However, Q1 2019 had lower average natural gas prices and LMPs despite colder average temperatures (33°F vs. 34°F) compared to Q1 2018. While average temperatures often explain natural gas price differences, other factors influence the gas market. In Q1 2019, there were increased LNG deliveries into New England and no extreme weather events, resulting in lower natural gas prices. In 2018, a cold snap (i.e. prolonged period of sustained cold weather) was a major driver of high gas prices during Q1. From January 1 to January 9, 2018, temperatures averaged 14°F driving natural gas demand higher causing increased natural gas prices ($31.22/MMBtu). No sustained cold snap occurred in Q1 2019. Over the same period of 2019, temperatures averaged 34°F and natural gas prices averaged $3.30/MMBtu.[92]

When the primary natural gas pipelines flowing from west and south to New England become constrained, LNG deliveries can provide counter flow. This helps alleviate natural gas constraints and puts downward pressure on natural gas prices. LNG deliveries into New England more than doubled in Q1 2019, increasing from 10.8 million Dth to 21.9 million Dth. The year over year increase in LNG equated to nearly enough natural gas to run a 650 MW standard heat rate natural gas-fired generator for the entire quarter.

Energy Market Opportunity Costs

Beginning in December 2018, energy market reference levels included an energy market opportunity cost (EMOC) adder for generators that maintain an oil inventory.[93] 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

[92] When the 9-day period is removed from both Q1 2018 and Q1 2019, natural gas prices both averaged around $5.40/MMBtu.

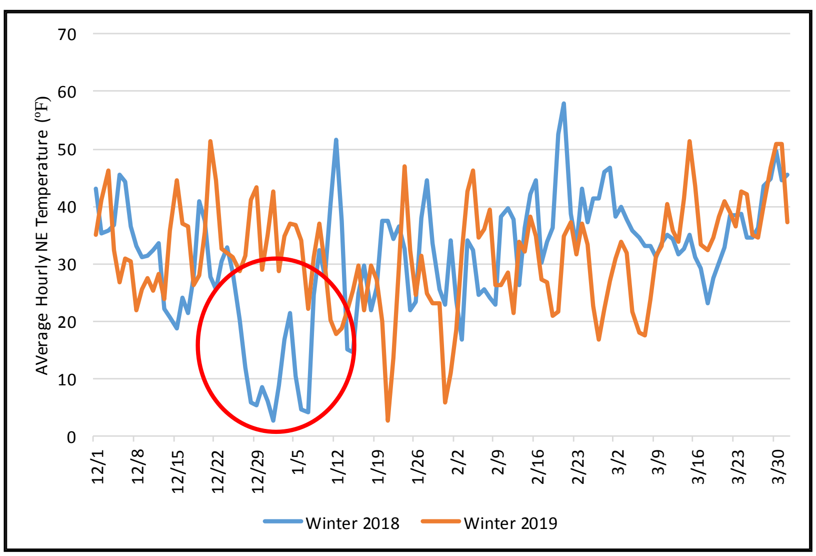
[93] https://www.iso-ne.com/static-assets/documents/2018/10/a7_memo_re_energy_market_opp_costs_for_oil_and_dual_fuel_revised_edition.pdf

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.

The IMM calculates 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 LMP 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 the generator's 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 before to the start of the real-time market. The real-time update of the opportunity cost calculation is based on data that becomes available after the day-ahead market closes but prior to the start of the real-time market. This calculation incorporates updated fuel price forecasts which produces more accurate opportunity costs for the real-time market.

Since the implementation of the EMOC adder, both winters (2019 and 2020) have been mild and the EMOC adder has never increased above zero for any generator that was part of the program. As a result, EMOC adders had no impact on the supply curve over the winter periods.[94] During these winters, episodes of very cold weather did not sustain for long enough to put sufficient strain on the natural gas system and, consequently, oil inventories. A cold snap of the type that initiated the posturing of oil-fired generators in January 2018 did not occur and no oil-fired generators were postured in either Winter 2019 or the most recent winter. Figure 3-12 below compares New England average hourly temperatures from Winter 2019 to the cold snap in Winter 2018.

Figure 3-12: Average Hourly NE Temperatures Winter 2018 and Winter 2019

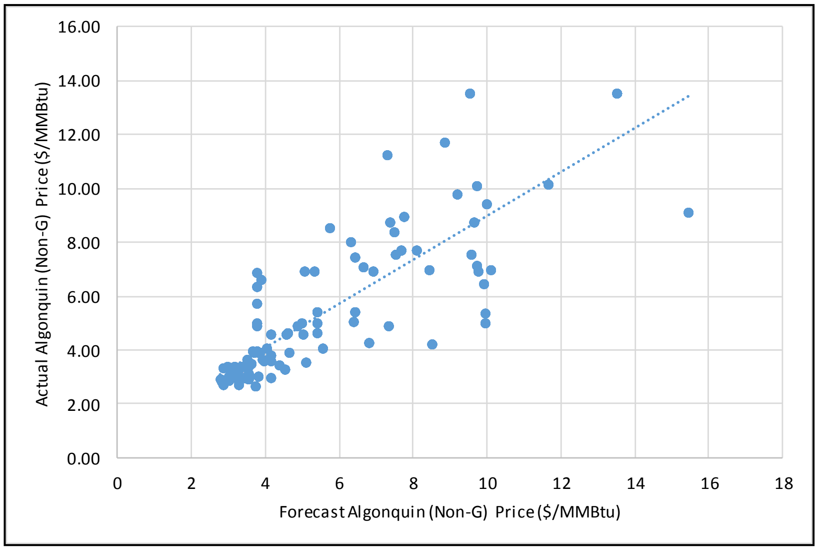


While there were very cold periods during Winter 2019, they were short-lived when compared with the persistent extreme cold of Winter 2018, which is highlighted by the red circle in the figure. Similarly, Winter 2020 had no prolonged periods of extreme cold.

[94] Only generators with specific calculation EMOC methodologies had hours with non-zero opportunity costs.

One of the primary drivers of the EMOC adder is the fuel price forecast, and particularly the natural gas price forecast due to the high volatility of New England natural gas prices in the winter. For Winter 2019, the EMOC calculation model relied on a gas price forecast developed by the ISO using a neural network forecasting model.[95] A scatter plot of the forecasted values against the actual values for next day gas is shown in Figure 3-13 below.

Figure 3-13: Daily Average Algonquin Gas (Non-G) Actual vs. Forecast Price, Winter 2019

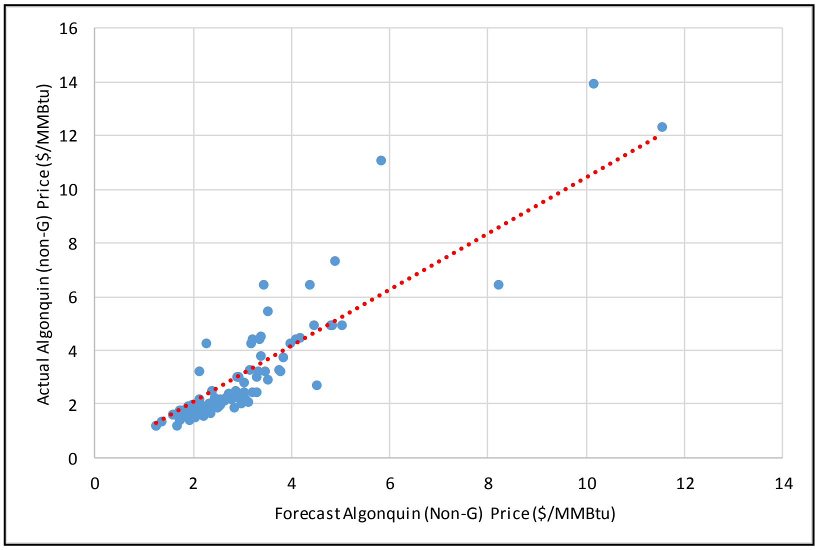


It is clear that the model performs better when gas prices and volatility are low. Across all winter hours, the ISO-calculated daily average gas price forecast had a mean absolute forecast error (MAE) of $0.85/MMBtu when compared to the actual daily average Algonquin (non-G) price. However, it should be noted that this number includes weekend strips for which the price for Sunday and Monday gas is already known when forecasting on Saturday.

In December 2019, the ISO began calculating EMOC adders using gas price forecasts developed by a third-party vendor. A scatter plot of the forecasted vs actual next-day gas prices for Winter 2020 is shown in Figure 3-14 below.

[95] https://www.iso-ne.com/static-assets/documents/2018/10/a7_memo_re_natural_gas_forecast_method_energy_market_opportunity_costs.pdf

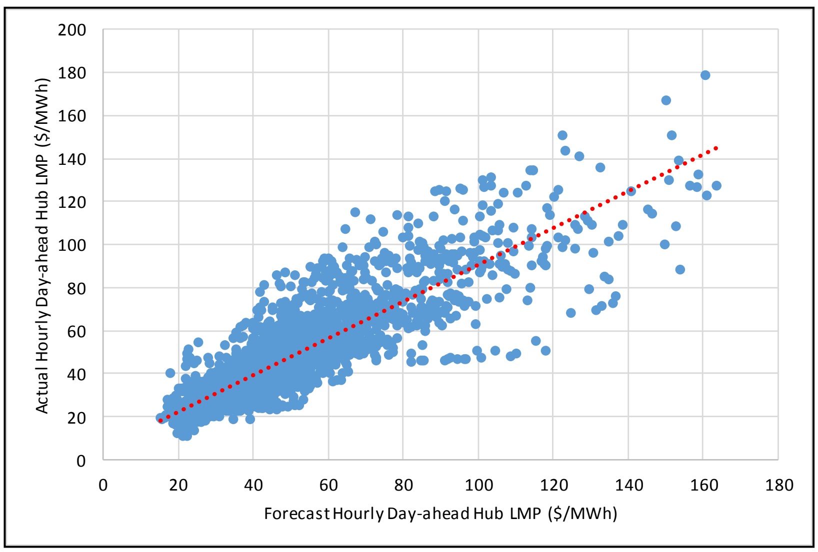
Figure 3-14: Daily Average Algonquin Gas (Non-G) Actual vs. Forecast Price, Winter 2020



With a MAE of $0.57/MMBtu, the third-party forecast appears to be an improvement over the previous model.

The third-party vendor also supplies the day-ahead and real-time LMP price forecasts that serve as primary inputs for the EMOC model. A scatter plot of forecasted versus actual day-ahead LMPs is shown in Figure 3-15 below.

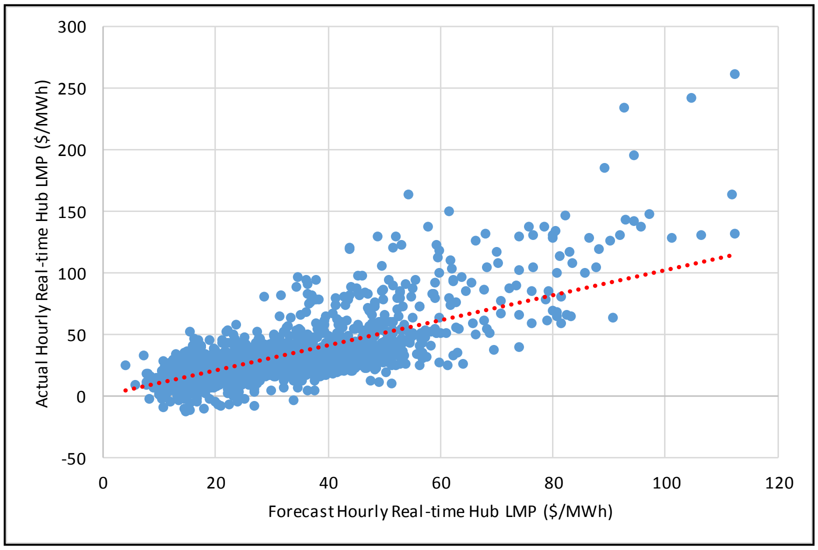
Figure 3-15: Actual Hourly Day-Ahead Hub LMP vs. Forecast Hourly Day-Ahead Hub LMP, Winter 2019



Again, the forecast is seen to have greater accuracy when overall prices are lower. For Winter 2019, the day-ahead LMP forecast had a MAE of $8.04/MWh.

For Winter 2020, which is shown below, the MAE was $5.48/MWh reflecting even milder weather conditions. The real-time LMP forecast for Winter 2020 had a MAE of $8.31/MWh.

Figure 3-16 Actual Real-Time Hub LMP vs. Forecast Real-Time Hub LMP (Winter 2020)



While the accuracy of various forecasting methodologies can be debated, it is clear that the primary driver of energy market opportunity cost is the weather. Without a period of sustained extreme cold weather to put strain on the gas system it is unlikely that non-zero energy market opportunity costs will materialize.

3.4.2 Supply-Side Participation

In 2019, unpriced supply made up around 70% of total supply, a level similar to previous years. Unpriced supply consists of offers from suppliers that are willing to sell (i.e., clear) at any price, or offers that cannot set price. These suppliers may be insensitive to price for a number of reasons, including fuel and power contracts, hedging arrangements, unwillingness to cycle (on and off) a generator, or operational constraints. The remaining 30% of supply is considered priced supply—it is either eligible to set energy prices, or only willing to sell at specified price or higher.

There are three categories of unpriced supply: fixed imports, self-scheduled generation, and generation-up-to economic minimum.

- **Fixed imports** are power that is scheduled to flow into New England on the external interfaces regardless of price.
- **Self-scheduled generation** is offered into the energy market as must-run generation. Generators self-schedule at their economic minimum (EcoMin).[96]
- **Generation-up-to economic minimum** from economically-committed generators is the portion of output that is equal to or below Ecomin. For example, if a generator producing 150 MW has an EcoMin of 100 MW, then its generation-up-to EcoMin is 100 MW. Generation-up-to economic minimum is ineligible to set price, as the market software is unable to dispatch it down without turning off the generator.

There are two categories of priced supply: priced native supply and priced imports.

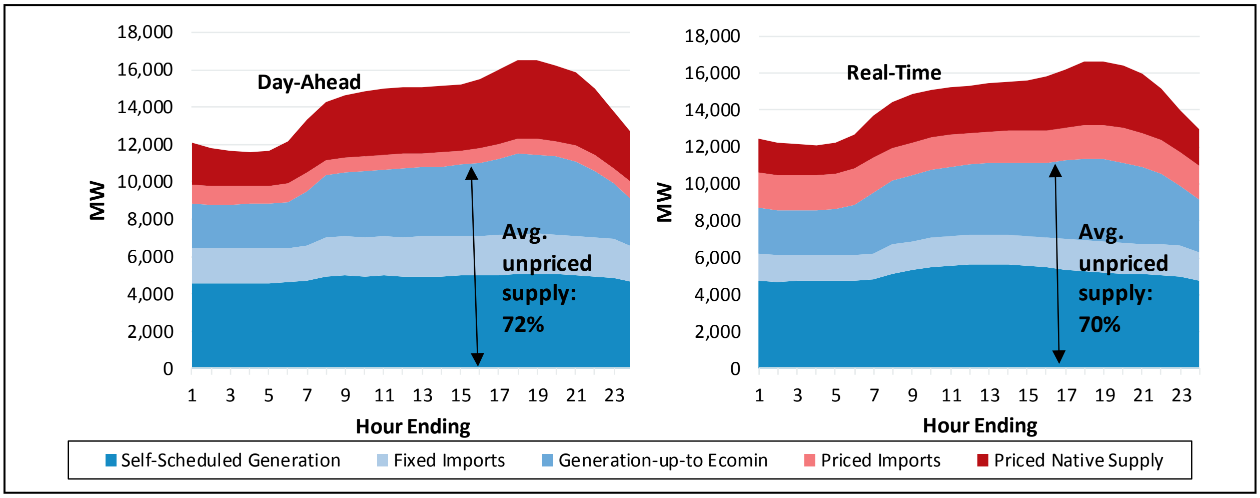
[96] The Economic Minimum (EcoMin) is the minimum MW output that a generator must be allowed to produce while under economic dispatch.

- **Priced native supply** is energy from generators, active demand resources, and virtuals (day-ahead market only) that is dispatched economically (i.e., is scheduled based on its price).
- **Priced imports** include cleared up-to-congestion and price-sensitive imports.

There are some nuances to the priced imports category in terms of price-setting ability. Unlike unpriced supply, priced imports are not price-taking (i.e., suppliers are not willing to sell at any price), and priced imports regularly set price in the day-ahead market. However, priced imports rarely set price in real-time because the tie-lines are scheduled in advance of the delivery interval and are given a small dispatchable range in the real-time dispatch and pricing algorithm. This prevents the market software from dispatching the tie-lines far away from the schedule amount determined by the transaction scheduling process.

An hourly average breakdown of unpriced and priced supply by category for the day-ahead and real-time markets in 2019 are provided in Figure 3-17 below.

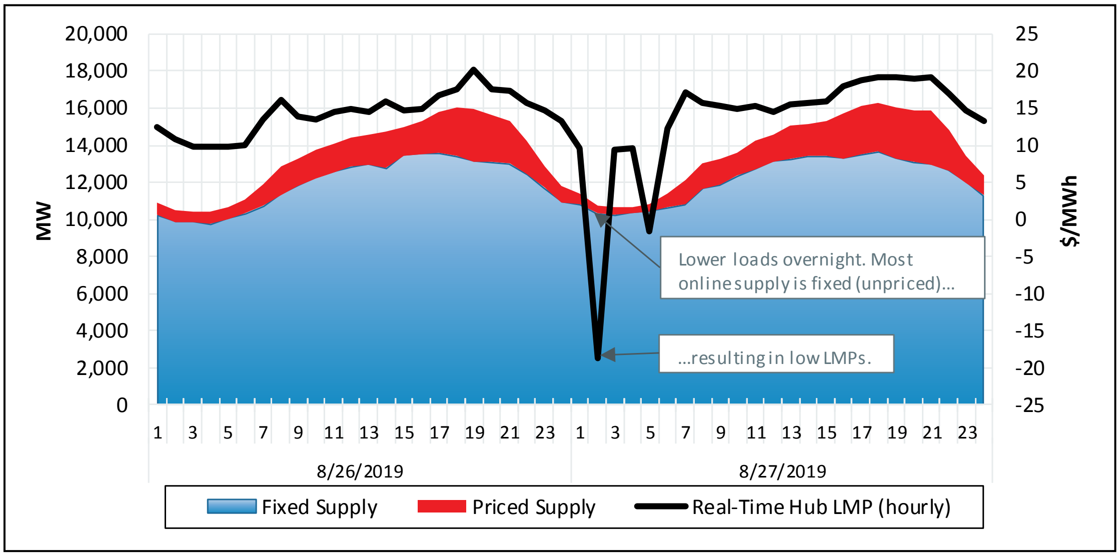
Figure 3-17: Day-ahead and Real-time Hourly Average Supply Breakdown, 2019



Over the course of a day, the share of supply from self-scheduled generation (the largest component of unpriced supply) and fixed imports tends to be fairly stable. In real-time, average hourly self-scheduled generation was slightly higher during midday, due to output from settlement-only solar generators. In both markets, the daily ramp-ups in load are typically met by additional supply from generation-up-to EcoMin and priced supply. Priced supply averaged 30% of total supply over all hours in real-time in 2019, with its share peaking in hours ending (HE) 18-20 at 32%. On average, unpriced supply made up 72% and 70% of total supply in the day-ahead and real-time markets, respectively.

The large amount of unpriced supply has important implications for real-time pricing outcomes because it increases the likelihood of low or negative prices. An example of this is illustrated in Figure 3-18 below, which shows unpriced and priced supply along with the Hub LMP for August 26-27, 2019. Unlike the figure above, this figure includes all imports in the fixed supply category for convenient illustrative purposes.

Figure 3-18: Price and Unpriced Supply vs. Real-Time LMP, August 26-27, 2019



In the early morning hours of August 27, real-time loads were lower than expected. System load fell very close to the level of unpriced supply, and as a result the ISO only had to dispatch a small amount of priced generation. The small amount of generation dispatched economically had offered into the market with negative offers, resulting in negative prices. The 5-minute Hub LMP fell to about -$25/MWh and averaged -$19/MWh during HE 2.

In situations like this, there is very little generation with price-setting capability on the system. The combination of low loads with large amounts of unpriced generation can thus bring about a sudden drop in prices, to low or even negative levels. However, the overall frequency of negative real-time prices at the Hub remains relatively low. Negative prices occurred in 1.1% and 0.6% of hours in 2018 and 2019, respectively.

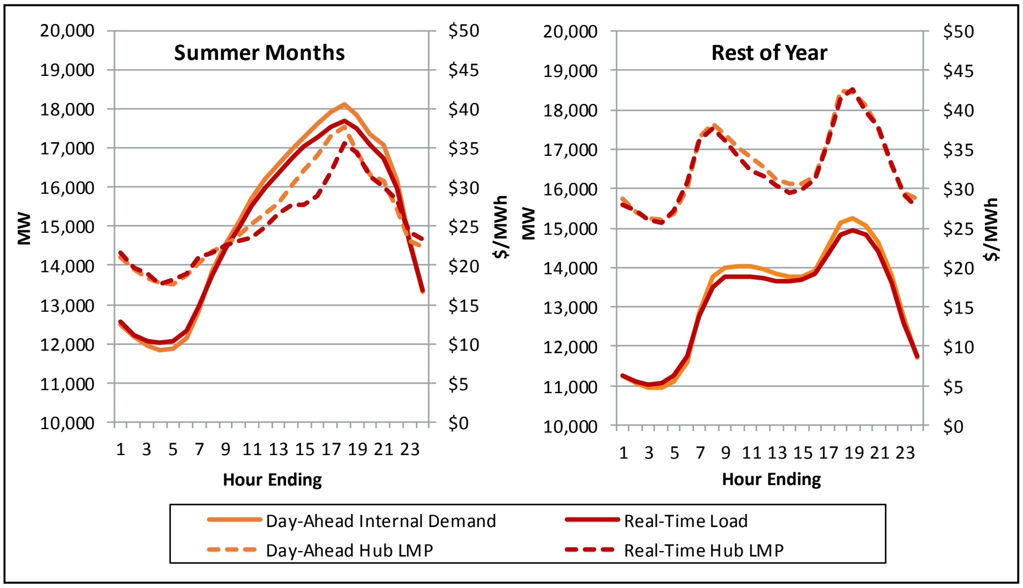
3.4.3 Load and Weather Conditions

Load is a key determinant of day-ahead and real-time energy prices. Higher loads generally lead to higher prices, as costlier generation is dispatched to meet the higher load levels. Weather, economic factors and energy efficiency tend to drive changes in wholesale electricity load. Behind-the-meter photovoltaic generation has also played a small, but increasing, role in declining wholesale load.

Demand/Load Statistics

The strong connection between energy prices and load is particularly evident over the course of the operating day. Hours with the lowest loads typically have lower prices, and hours with the highest loads usually have higher prices. Figure 3-19 below depicts the average time-of-day profile for both day-ahead demand and real-time load compared to day-ahead and real-time LMPs for 2019. Since load curves have different shapes during different seasons, the left panel shows the average load curve for the summer (June-August). During the summer, load often climbs throughout the day as air conditioning demand rises. The right panel shows the average load curve for the rest of the year, when load usually has morning and evening peaks, with a midday dip.

Figure 3-19: Average Demand and LMP by Hour in 2019



Note: Day-ahead Internal Demand is equal to fixed demand + price-sensitive demand + virtual demand. This includes pumped storage demand and excludes virtual demand at external nodes. Real-time load is the total end-use wholesale electricity load within the ISO New England footprint.

Figure 3-19 shows a clear, positive correlation between demand levels and prices in both the day-ahead and real-time markets. The figure also shows that the day-ahead market tends cleared more internal demand than actually materializes in real-time, which is discussed further in Section 3.4.4.

Net Energy for Load (NEL) averaged 13,605 MW per hour in 2019, a 3.5% decrease (490 MW decrease) compared to 2018. This was the largest year-over-year decrease in average load over the reporting period. New England's native electricity load is shown in Table 3-2 below.[97]

Table 3-2: Load Statistics

Year	Load (GWh)	Hourly Load (MW)	Peak Load (MW)	Weather Normalized Load (GWh)	Hourly Weather Normalized Load (MW)
2015	126,955	14,493	24,437	125,779	14,358
2016	124,416	14,164	25,596	123,953	14,111
2017	121,217	13,838	23,968	120,668	13,737
2018	123,471	14,095	26,024	120,560	13,725
2019	119,200	13,607	24,361	118,663	13,546

Note: *Weather-normalized* results are an estimate of load if the weather were the same as the long-term average.

In 2019, load decreased due to a combination of milder weather and increases in energy efficiency and photovoltaic generation. The peak load in 2019 was 24,361 MW and occurred on July 30 in HE 18, the only weekday where the temperature was above 90°F. This was 3.5% lower than the average peak load during 2015-2018. The longer-term trend of declining load is best reflected in the weather-normalized load measure. On a weather-normalized basis, average load was 13,546

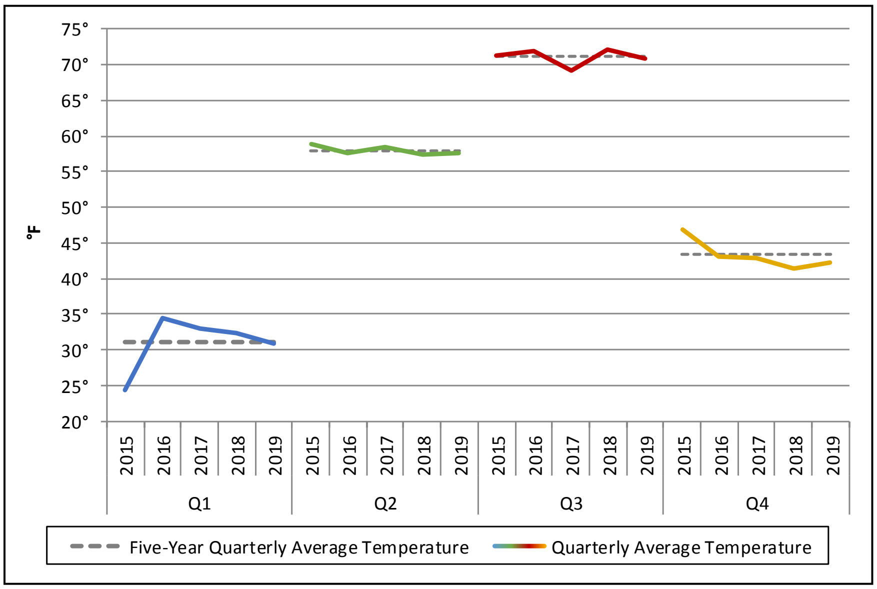
[97] In this analysis, load refers to *net energy for load* (NEL). NEL is calculated by summing the metered output of native generation, price-responsive demand and net interchange (imports – exports). It excludes pumped storage demand.

MW in 2019, a 1.3% decline from 2018. Annual weather-normalized load has declined every year since 2010 due to increases in energy efficiency and behind-the-meter solar generation.

Impact of Weather

Weather is the primary driver of load in New England. Temperatures in 2019 were generally milder than in 2018, causing average loads to decrease. Quarterly average and five-year average temperatures for 2015 through 2019 are illustrated in Figure 3-20, below.[98] The first quarter, Q1 (January-March), is shown in blue, Q2 (April-June) is green, Q3 (July-September) is red and Q4 (October-December) is yellow.

Figure 3-20: Seasonal vs. Five-Year Average Temperatures

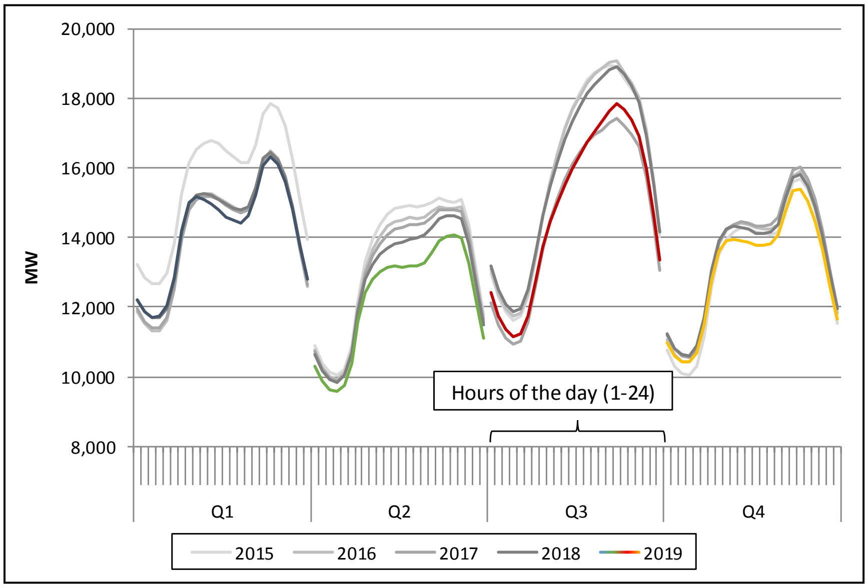


Quarterly average temperatures in 2019 were close to their historical five–year averages. While Q1 2019 was slightly colder, on average, than in 2018 (31°F vs. 32°F), the weather was generally milder in 2019 than in 2018. In Q2 and Q4 2019, temperatures were less than 1°F degree warmer, on average, than in 2018, but each quarter had fewer cooling degree days (CDDs) and heating degree days (HDDs) than in 2018. While the temperature in Q3 2019 was around the five-year average, it was cooler and less humid than in Q3 2018. The average temperature in Q3 decreased from 72°F to 71°F, while the average quarterly temperature-humidity index decreased from 70 to 68.

Average quarterly load by time of day (hour endings 1-24) is shown in Figure 3-21 below. Temperature changes affect load differently throughout the year. Lower temperatures in the winter (Q1) typically result in higher loads while lower temperatures in the summer (Q3) typically result in less air conditioning demand and therefore lower loads. The shape of the load curve differs by quarter. In the summer, load typically rises throughout the day to a single peak in the late afternoon/early evening, then declines as temperatures decline. When the weather gets colder, there are typically two load peaks: one after the morning ramp, and the second during the evening.

[98] Actual New England temperatures are based on weighted hourly temperatures measured in eight New England cities: Windsor CT, Boston MA, Bridgeport CT, Worcester MA, Providence RI, Concord NH, Burlington VT, and Portland ME.

Figure 3-21: Average Quarterly Load Curves by Time of Day



Quarterly average load in 2019 was lower than the five-year average in nearly all hours. This tracks accordingly with generally milder weather and the trend of falling wholesale load due to increased energy efficiency and behind-the-meter solar generation. Quarterly average load was lower in 93% of hours compared to 2018. The 7% of hours with higher average loads occurred during Q1, the only quarter with more total HDDs than 2018

3.4.4 Demand Bidding

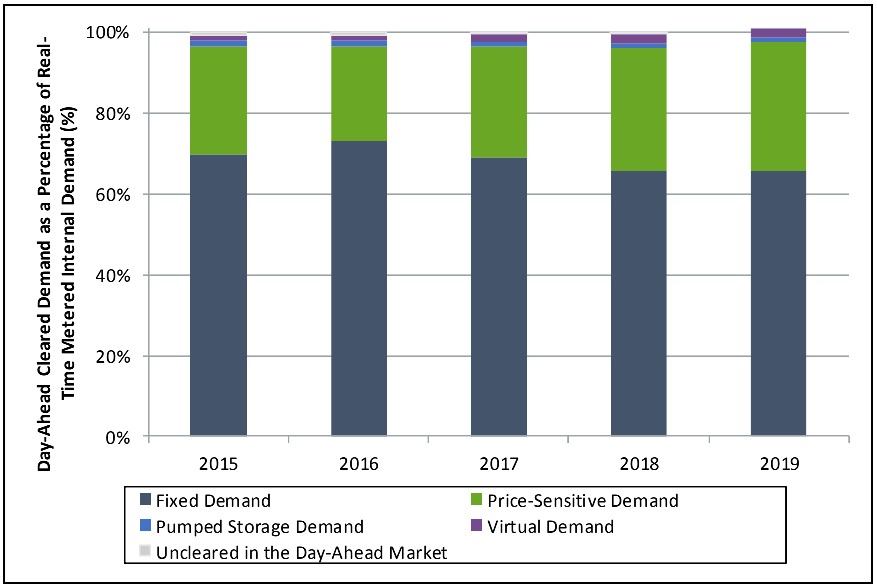
The amount of day-ahead cleared demand is significant, because along with the ISO's Reserve Adequacy Assessment, it influences generator commitment decisions for the operating day.[99] In this section, we examine native day-ahead demand cleared (i.e. delivery within the New England jurisdiction, which excludes exports).[100] Native demand consists of fixed, price-sensitive, virtual and pumped-storage demand. Day-ahead cleared demand by bid type as a percentage of real-time load is shown below in Figure 3-22. [101]

[99] 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.

[100] Exports are not included as this section focuses on demand participation within New England. Exports are discussed in Section 2.4 and Section 5.

[101] Real-time load is the total end-use wholesale electricity load within the ISO New England footprint. Real-time load is equal to Net Energy for Load – Losses.

Figure 3-22: Day-Ahead Cleared Demand as a Percentage of Real-Time Load by Bid Type

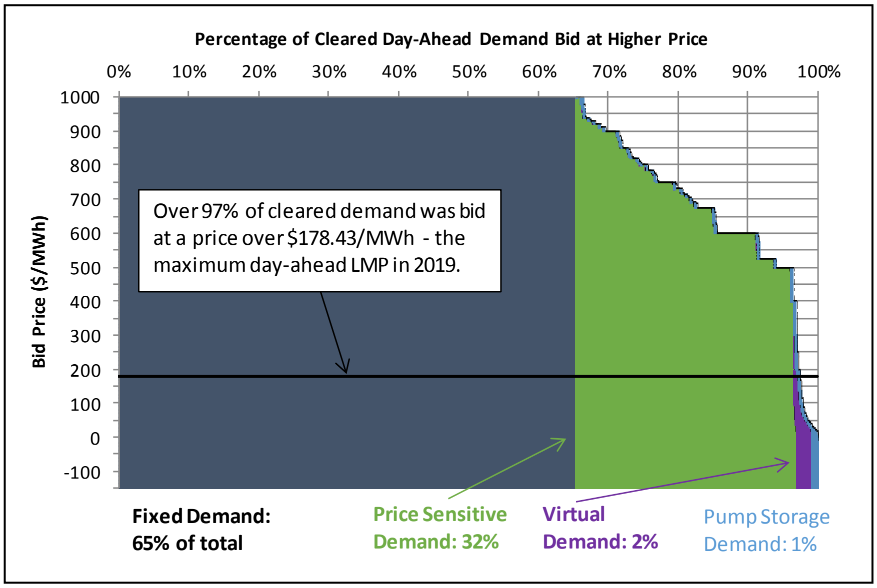


Fixed demand bids indicate that participants are willing to pay the market-clearing price, regardless of the cost. Fixed day-ahead cleared demand averaged 65.8% of real-time load in 2019, a slight increase from 65.5% in 2018. Participants that submit price-sensitive demand bids are only willing to clear if the market-clearing price is below their bid price. In 2019, price-sensitive demand bids accounted for 31.9% of real-time load, an increase from 30.5%. Lastly, virtual demand as a percentage of real-time load, decreased from 2.6% to 2.2% year over year. Virtual demand trends are discussed in detail in Section 4. Overall, the increase in fixed demand and price-sensitive demand resulted in the day-ahead market over-clearing on average in 2019, when day-ahead demand cleared nearly 101% of real-time load.

Although price-sensitive demand bids are submitted with a MW quantity and corresponding price, the majority of bids are priced significantly above the LMP. In addition, pumped-storage demand can self-schedule demand in the day-ahead market. Such transactions are, in practical terms, fixed demand bids. High bid prices are not limited to internal demand bids; Section 5 of the report examines the breakdown of exports between priced and fixed transactions.

Cleared internal demand bids by price are shown in Figure 3-23 below. The bid prices are shown on the vertical axis, and the percentage of cleared bids that were willing to pay at each bid price are shown on the horizontal axis. For example, over 97% of cleared day-ahead demand was willing to pay more than $178.43/MWh, the maximum day-ahead hub LMP in 2019.

Figure 3-23: Components of Day-Ahead Cleared Demand as a Percentage of Total Day-Ahead Cleared Demand



Generally, demand in New England is price insensitive. Nearly two-thirds (65%) of total day-ahead cleared demand was bid as fixed demand, so it clears in the market at any price. While price-sensitive demand bids have an attached price, the price is usually above the day-ahead LMP. Therefore price-sensitive demand bids typically clear, accounting for 32% of all day-ahead cleared demand. Virtual demand and price-sensitive pumped-storage demand bids often have lower prices attached to the bid, so they do not clear as often. However, virtual and pumped-storage demand only account for approximately 3% of cleared demand bids. Overall, over 97% of cleared day-ahead demand was willing to pay a higher price than the maximum day-ahead LMP in 2019, $178.43/MWh. This continues a similar trend to prior years.

3.4.5 Load Forecast Error

The ISO produces several different load forecasts, ranging from long-term projections that look out 10 years to short-term forecasts made within the operating day. This section focuses on the *day-ahead load forecast*: the forecast made around 9:30 am each day that projects hourly load for the next operating day.[102] This forecast is the ISO's last load projection that is made prior to the close of the day-ahead market. It is published on the ISO's website and available to the market. Although the ISO's forecast is not a direct input into the day-ahead market, it serves as an informational tool for participants bidding in the day-ahead market, and generally aligns well with total day-ahead cleared demand.

Additionally, the ISO's load forecasts are used in the reserve adequacy assessment (RAA) process to make supplemental generator commitment decisions. During the RAA process, the ISO may determine that, based in part on their load forecast, the day-ahead market has scheduled insufficient capacity. In these situations, the ISO will commit additional capacity over what cleared in the day-ahead market to satisfy real-time load and reserve requirements. These commitments do not happen often, but when they occur, they affect *real-time* market outcomes.

[102] Twice a day, the ISO produces a three-day system load forecast that projects load for the current day and the following two days. The first forecast is typically released after 6:00 am and the second and final forecast is the published near 10:00 am.

Just as the day-ahead market cannot perfectly predict real-time conditions, the ISO load forecast will inevitably differ from real-time load. Since weather is both a key driver of load and difficult to predict, real-time load is challenging to forecast. Other factors, such as behind-the-meter solar generation and industrial demand processes, compound the difficulty of accurately estimating load even in short time horizons.

The mean absolute percent error (MAPE) of the ISO's day-ahead load forecast (over the past five years) by the time of year is shown in Figure 3-24 below. Months of the year are partitioned into four groups based on the ISO's monthly load forecast goal (shown as dashed lines). Prior to 2018, the ISO had a MAPE goal of 2.6% for the summer months (June-August) and 1.5% MAPE for the other months.[103] In 2018, the ISO revised its goals to 1.5% MAPE in January–April and October–December; 1.8% in May and September; 2.6% remained the goal for months June–August.

Figure 3-24: ISO Day-Ahead Load Forecast Error by Time of Year

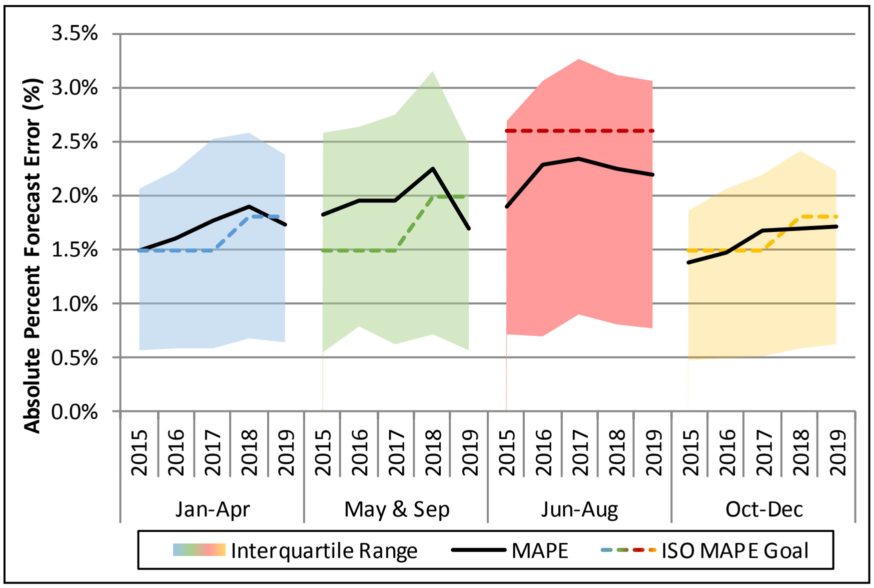


Figure 3-24 shows forecast error tends to be highest during the summer months when cooling demand causes the load forecast to be more sensitive to temperature forecast error. June – August had the highest MAPE (2.2%) and interquartile range (2.3%) in 2019. After trending upward in recent years, the MAPE fell in three of the four groups in Figure 3-24. The MAPE was below the goal in each group, with only December having a monthly MAPE higher than the ISO's goal (1.9% MAPE vs. 1.8% goal). Overall, the MAPE decreased from 2.0% in 2018 to 1.8% in 2019, the first yearly decrease during the reporting period. The decrease may be attributable to improvements in the ISO's ability to forecast behind-the-meter solar generation.

[103] Mean absolute percent error (MAPE) is the average of the hourly absolute percent errors across all hours (on-peak and off-peak). The absolute percent error is calculated as | ([forecast load] – [actual load]) / [actual load] |.

The growth of behind-the-meter solar generation in recent years makes accurate forecasting particularly challenging.[104] For one, it is hard to estimate the location and installed capacity of thousands of small-scale solar installations around New England. Second, forecasting cloud cover at a granular level is notoriously difficult.[105] The ISO has made significant investments to better forecast behind-the-meter solar generation, which should help improve the ISO's load forecasts as behind-the-meter solar generation continues to grow in the region.[106]

The Interaction between Forecast Error and Pricing Outcomes in 2019

When the ISO's load forecast differs from real-time load, the forecast error can provide insight into energy market outcomes, including divergence between day-ahead and real-time cleared demand and prices. ISO load forecast error tends to be consistent with the market's forecast error. That is, when the ISO over-forecasts, the day-ahead market tends to over-clear demand compared to real-time load. Further, when the ISO's load forecast is greater than actual load, the day-ahead market tends to commit more generation than is required to satisfy actual real-time load. This can result in depressed real-time prices as more expensive generators are backed down from their day-ahead schedules.

Alternatively, when actual loads are greater than the ISO's forecast, fewer generators are committed in the day-ahead market than what is needed in real-time. This can result in real-time prices that are higher than day-ahead prices because more expensive generators (than what cleared in the day-ahead) are required, and there is a smaller selection of generators to choose from due to start-up time constraints. In such cases, expensive fast-start generators can be required to serve actual load.

The statistical relationship between average daily load forecast error and price divergence is shown in Figure 3-25 below.

[104] By the end of 2019, New England had estimated 3,380 MW of solar generation that does not have real-time telemetry with the ISO, up 535 MW from 2,845 MW at the end of 2018. This includes both behind-the-meter solar generation and settlement-only solar generation, neither of which are visible to the ISO operators. Settlement-only differs from behind-the-meter because it participates in the settlement process of the energy market, while behind-the-meter does not participation in the energy market.

[105] See, for example, https://www.bnl.gov/isd/documents/94838.pdf.

[106] For more information on ISO New England's investment in forecasting with behind-the-meter photovoltaic generation, see https://www.esig.energy/building-data-intelligence-for-short-term-load-forecasting-with-behind-the-meter-pv/

Figure 3-25: Price Separation and Forecast Error Relationship

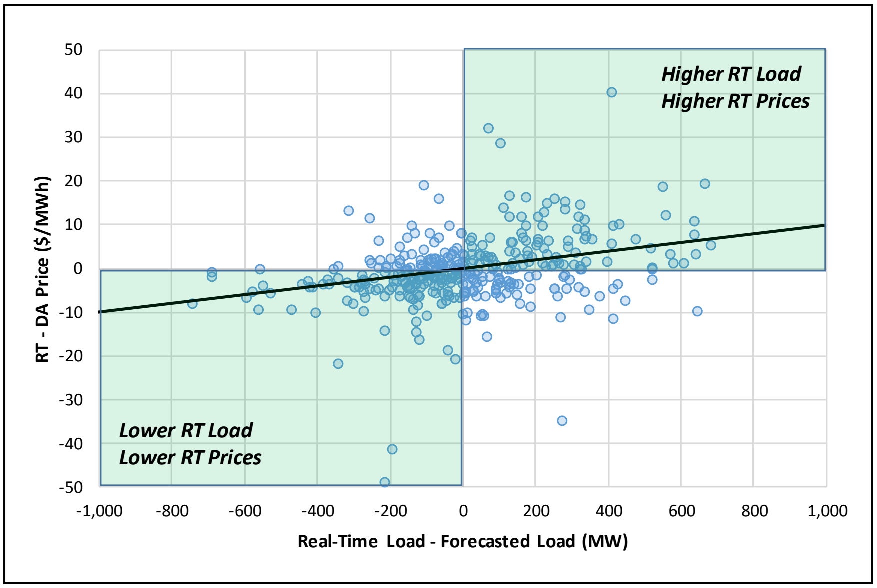


Figure 3-25 illustrates that there is a positive correlation between forecast error and price separation between real-time and day-ahead prices. In other words, when real-time loads are higher than day-ahead forecasted demand, real-time prices tend to be higher than day-ahead prices, and vice versa.

3.4.6 Reserve Margin

The reserve margin measures the additional available capacity over the load and reserve requirements. If the margin is low, the ISO may have to commit more generation to meet load and reserves, resulting in elevated LMPs. Additionally, the energy market is more susceptible to market power when system conditions are tight.

The reserve margin is the difference between available capacity and demand. The equations below illustrate this relationship:

i. $Gen_{Energy} + Gen_{Reserves} + [Imports - Exports] = Demand + [Reserve\ Requirement]$

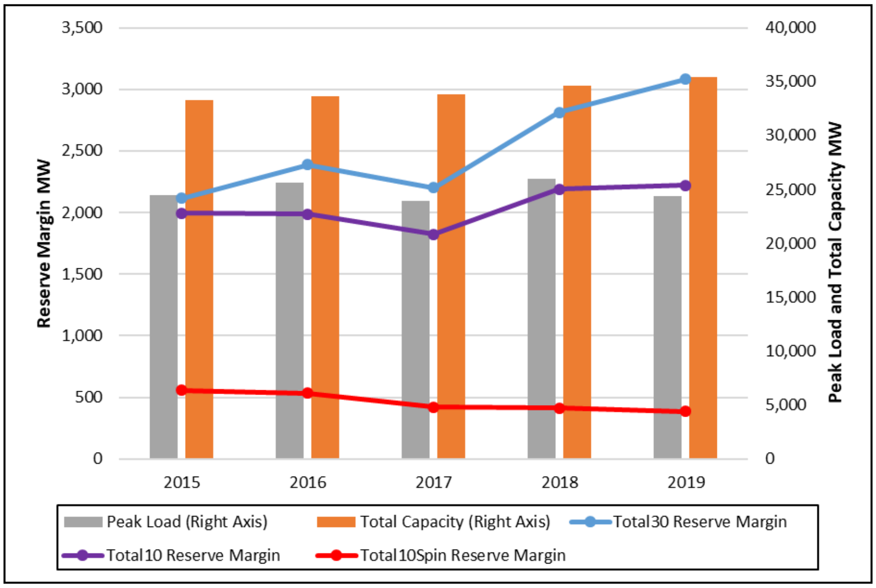
Equation i. is equivalent to:

$$Supply + Gen_{Reserves} - [Reserve\ Requirement] = Demand$$

$$Supply + Reserve\ Margin = Demand$$

The annual average margins for each type of reserve requirement and product (10-minute spinning reserve, total 10-minute reserve, and total 30-minute reserve) are shown in Figure 3-26 below. The margins are equal to the actual amount of reserves provided in excess of the corresponding reserve requirement. The total 30 reserve margin surplus is the overall reserve surplus above the total reserve requirement. The total 30 reserve requirement is equal to the total 10-minute reserve requirement, plus 50% of the second largest system contingency.

Figure 3-26: Reserve Margin, Peak Load, and Total Capacity



In 2019, total capacity was about 860 MW higher than in 2018, on average, as shown by the orange bar. This corresponds to an increase in reserve margins.

The total 10-minute reserve margin was very similar in 2019 to the previous year, increasing by 28 MW, on average. The average 30-minute reserve surplus was 270 MW higher than the average 2018 surplus. The increase was driven by additional capacity from generators (130 MW) and demand response resources (140 MW). A generator that changed to a more flexible operating mode in March 2019 provided 40 MW more offline reserves in 2019 than it did in 2018. Two newly commissioned fast-start generators combined to add another 80 MW of offline reserves. The rest of the net increase in reserves was due to small changes, both increases and decreases, in many different generators. About 52% of generators provided more reserves, on average, in 2019 than in 2018, while 20% provided the same amount and 28% provided less.

The increase in both total capacity and offline reserves over the past two years has led to lower reserve prices and increased competitiveness in the reserve market (discussed further in Section 3.7.3).

3.4.7 System Events during 2019

System conditions were relatively benign in 2019, with no shortage events or instances of prolonged cold or hot temperatures. The following metrics illustrate the frequency of abnormal system conditions and extreme market outcomes over the past five years.

OP 4 and M/LCC 2 Events

The ISO uses the following established procedures to alert participants and relieve issues during times of tight or abnormal system conditions:

- **Master Local Control Center Procedure No. 2** (M/LCC 2, Abnormal Conditions Alert)[107] notifies market participants and power system operations personnel when an abnormal condition is affecting the reliability of the power system, or when such conditions are anticipated. The ISO expects these entities to take certain precautions during M/LCC 2 events, such as rescheduling routine generator maintenance to a time when it would be less likely to jeopardize system reliability.
- **Operating Procedure No. 4** (OP-4, Action during a Capacity Deficiency)[108] establishes criteria and guidelines for actions during capacity deficiencies. There are eleven actions described in the procedure which the ISO can invoke as system conditions worsen.

The number of instances for each type of event during the reporting period is detailed in Table 3-3 below.

Table 3-3: OP-4 and M/LCC 2 Event Frequency

	2015	2016	2017	2018	2019
# of OP-4 Events	1	1	0	1	0
# of M/LCC 2 Events	7	4	7	7	0

There were no OP-4 or M/LCC 2 events in 2019. During 2018, there was one OP-4 event due to shortage conditions on September 3, which were caused by generator outages and higher than expected load. There were also multiple M/LCC 2 events in 2018, primarily due to sustained cold temperatures in January, severe snowstorms in March, and the September 3 capacity deficiency. In 2019, there were no comparable events.

Negative Reserve Margins

Negative reserve margins are an indicator of stressed system conditions. In these instances, the system does not have enough available supply to meet the reserve requirements necessary to maintain system reliability. In particular, negative *non-spinning* reserve margins result in very high real-time energy prices, because reserve prices reach the Reserve Constraint Penalty Factor prices of $1,000 for thirty minute operating reserve (TMOR) and/or $1,500 for ten-minute non-spinning reserve (TMNSR).[109] The number of hours of negative non-spinning and spinning reserve margins are presented in Table 3-4 below.

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[107] Information on individual M/LCC 2 events is available at:

https://www.iso-ne.com/static-assets/documents/2016/02/mlcc_2_20111219_to_20160105.xlsx

[108] See ISO New England Operating Procedure No. 4 – Action During A Capacity Deficiency, available at

https://www.iso-ne.com/static-assets/documents/rules_proceds/operating/isone/op4/op4_rto_final.pdf

[109] Section 7.1.1 provides additional information on Reserve Constraint Penalty Factors.

Table 3-4: Frequency of Negative Spinning and Non-Spinning Reserve Margins

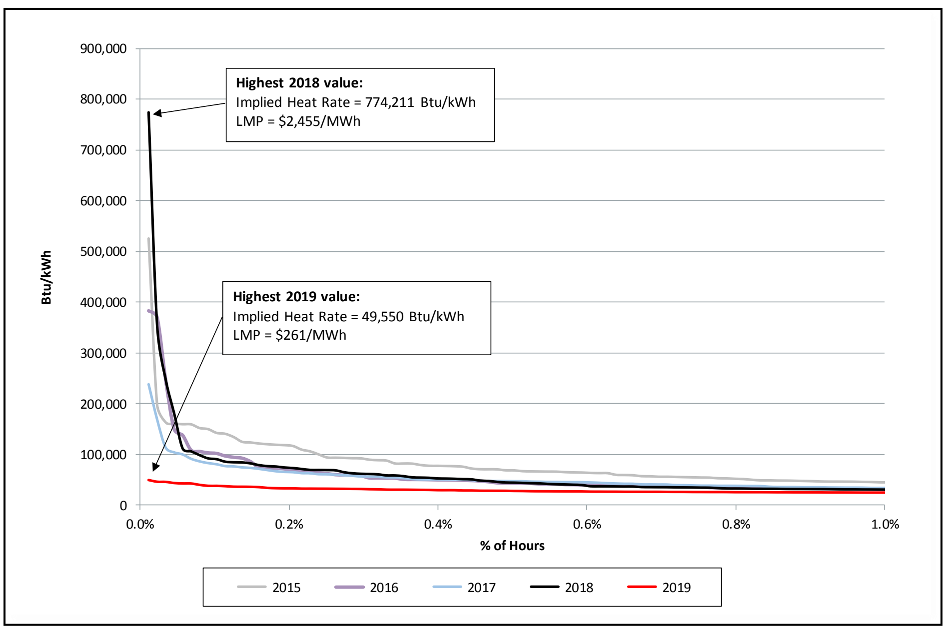
Year	Hours of Negative Non-Spinning Reserve Margins	Hours of Negative Spinning Reserve Margins
2015	1.6	25.8
2016	3.3	40.2
2017	0.6	57.0
2018	2.8	68.1
2019	0	25.9

Unlike every other year in the reporting period, there was always a surplus of TMNSR and TMOR in 2019. Additionally, spinning reserve shortages occurred less frequently compared to every year in the reporting period except 2015. Lower loads, higher reserve margins, and milder weather contributed to the benign conditions in 2019.

Frequency of Extreme Energy Prices at the Hub

High real-time LMPs can also indicate times of stressed system conditions, as higher-cost generation is required to meet load and reserve requirements. LMPs will also include the cost of dispatching the system to satisfy the reserve requirement. To control for different fuel prices, the duration curves in Figure 3-27 below show the top 1% of hourly implied heat rates ranked from high to low over the past five years. The implied heat rate provides an estimate of the breakeven heat rate for a gas-fired generator, suggesting that high-cost gas-fired generation would be in merit at a given LMP.[110]

Figure 3-27: Implied Heat Rate Duration Curves for Top 1% of Real-Time Hours



[110] The real-time implied heat rate is computed by dividing the hourly real-time Hub LMP by the respective gas price. The resulting number is expressed in Btu/kWh. High implied heat rate events occur when higher-cost generators (such as oil-fired generators) – compared to natural gas-fired generators - set price, and/or prices reflect reserve scarcity prices.

The figure shows that 2019 implied heat rates were lower and fell within a more narrow range compared to most years of the reporting period. The same is true for LMPs. In 2019, 90% of hourly day-ahead and real-time LMPs fell within a range of $15-$66/MWh and $13-$68/MWh respectively. These were the smallest ranges of the reporting period for each respective market. Additionally, 2019 saw the lowest maximum real-time Hub LMP of the past 5 years.

3.4.8 Reliability Commitments and Posturing

The ISO is required to operate New England's wholesale power system to the reliability standards developed by the North American Electric Reliability Corporation (NERC), the Northeast Power Coordinating Council (NPCC), and in accordance with its own reliability criteria.[111] To meet these requirements, the ISO may commit additional resources for several reasons, including to ensure that adequate capacity is available in constrained areas, for voltage protection, and to support local distribution networks. Such reliability commitments can be made in both the day-ahead and real-time markets. The ISO may also take manual actions to constrain (posture) resources from operating at a higher level as determined by the economic dispatch software, in order to improve system reliability. This typically occurs in order to maintain adequate reserves from fast-start pumped-storage resources generators and to reserve limited fuel oil inventory.

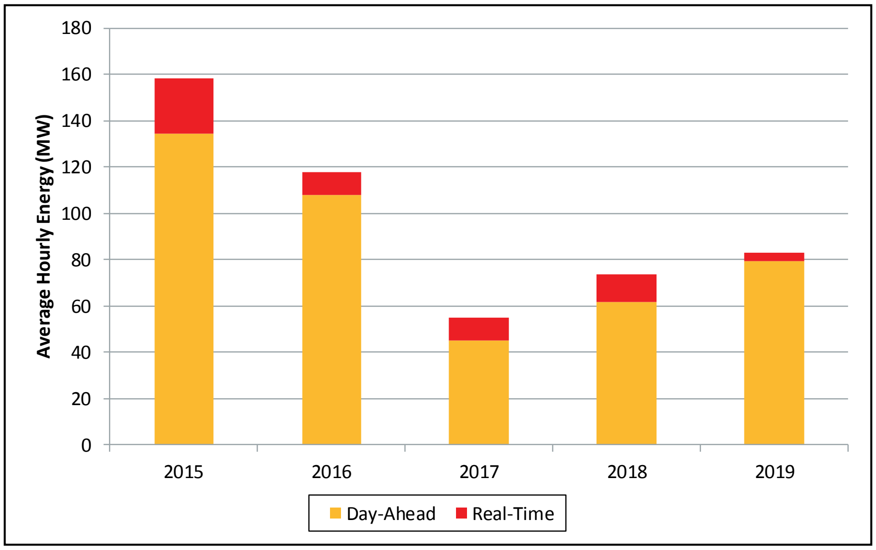
Reliability Commitments

Reliability commitment decisions are often "out-of-merit", meaning they are not based on the economics of a generator's offer. When this happens, lower-cost generators that would otherwise have been economically committed (if the reliability need had not existed) are displaced. Consequently, overall production costs increase in the market. If LMP payments are insufficient to cover the out-of-merit generator's costs, NCPC payments will be made to the out-of-merit generator. The impact on consumer costs (i.e. the LMP) is less straightforward. Often, the more-expensive generator needed for reliability will operate at its economic minimum and price will be set by a less expensive generator. In some cases, generators needed for reliability can make themselves appear less flexible and potentially increase their uplift compensation.

In 2019, the amount (MW) of ISO reliability commitments increased but remained relatively low. The real-time average hourly energy output (MW) from reliability commitments during the peak load hours (hours ending 8-23) for 2015 through 2019 is shown in Figure 3-28 below. The figure also shows whether the commitment decision was made in the day-ahead or real-time market.

[111] These requirements are codified in the NERC standards, NPCC criteria, and the ISO's operating procedures. For more information on the NERC standards, see http://www.nerc.com/pa/stand/Pages/default.aspx. For more information on the NPCC standards, see https://www.npcc.org/Standards/default.aspx. For more information on the ISO's operating procedures, see http://www.iso-ne.com/rules_proceds/operating/isone/index.html.

Figure 3-28: Average Hourly Energy Output from Reliability Commitments, Peak Load Hours



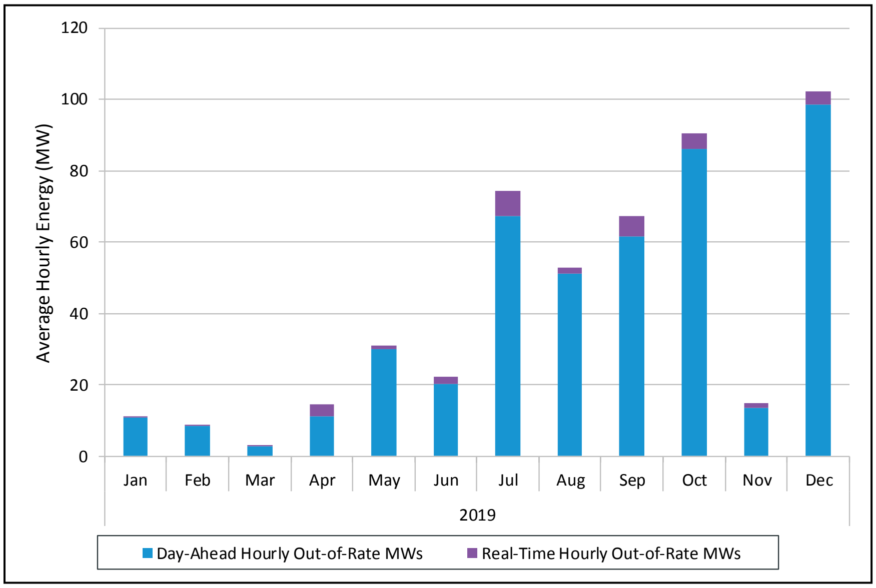
Reliability commitments remain a relatively small component of total system generation, at less than 0.4%, on average. The average hourly energy from reliability commitments during the peak load hours has decreased significantly starting in 2016. Commitments in the day-ahead market have become more common as a percentage of total reliability commitments.

The increase in overall reliability commitments in 2019 resulted from local reliability commitments in Maine and SEMA between May and December, to support planned transmission work. In 2019 overall, 94% (79.2 MW/hr) of the output from reliability commitments was for Local Second Contingency Reliability Protection (LSCPR), with 56% (45 MW/hr) of LSCPR commitments in Maine and 27% in SEMA (22 MW/hr). Voltage support commitments tend to represent a relatively small percentage of overall reliability commitments and, in 2019, accounted for just 2.8% of reliability commitments (2.4 MW/hr).

The 2018 increase in reliability commitments resulted from outages during transmission upgrade work in the NEMA/Boston, Rhode Island and SEMA zones. Prior to 2018, reliability commitments decreased significantly in 2016 and 2017, compared to earlier years. The completion of planned transmission work that required must-run generation in the Boston area led to these overall reductions.

A monthly breakdown of reliability commitments made during 2019 is shown in Figure 3-29 below. The figure shows the out-of-merit energy for reliability commitments during the peak load hours in 2019, by market and month. Out-of-rate energy includes reliability commitment output that is offered at a higher price than the LMP, and, therefore, would not likely have been committed or dispatched in economics.

Figure 3-29: Day-Ahead and Real-Time Average Out-of-Rate Energy from Reliability Commitments, Peak Load Hours, 2019



Of the roughly 79 MW of average hourly output from generators committed for reliability, about 41 MW (on average) was out-of-rate. This is a relatively small amount of out-of-rate energy (in the context of average hourly load of 13,598 MW in 2019) that was served by more expensive generation to meet a reliability need. Figure 3-29 shows that the greatest amount of out-of-rate energy from reliability commitments occurred in December. The LSCPR reliability commitments explain the pattern and magnitude of the out-of-rate commitments. As noted earlier, approximately 94% of all reliability commitments were for LSCPR in 2019.[112] In terms of the uplift payments required to support out-of-rate commitments, total LSCPR NCPC payments in 2019 were approximately $7 million; while this represented 24% of total uplift payments for the year, it represented just 0.2% of total energy payments.

As shown in the two figures above, a large majority of the 2019 reliability commitments were made in the day-ahead market. This helps minimize surplus capacity and the amount of economic generation that is displaced in the real-time operating day. If a reliability requirement is known prior to the clearing of the day-ahead market, commitments can be made in the day-ahead market to meet the requirement.

Committing generators in the day-ahead market is more desirable than commitments later in the Resource Adequacy Assessment (RAA) process or in real-time as day-ahead commitments tend to reduce the risk of suppressed real-time prices and NCPC. If reliability commitments are known in the day-ahead market, the commitment schedules of other generators can be adjusted to accommodate the reliability commitment. This provides more flexibility than if the commitment is made later, reducing the risk of having excess inflexible supply online. Excessive generator commitments can distort prices by removing other generators from the supply stack and adding

[112] Local second contingency protection reliability (LSCPR) commitments are made for import-constrained subareas, if necessary, to ensure that the ISO can re-dispatch the system to withstand a second contingency within 30 minutes after the first contingency loss without exceeding transmission element operating limits.

fixed energy to the supply stack. The excess fixed supply could potentially suppress real-time prices and increase NCPC.

Posturing Actions

In addition to committing off-line, out-of-merit generators to ensure local reliability, the ISO may limit the output of potentially in-merit generators to ensure either system-wide or local reliability. Limiting the output of generators is called "posturing." Posturing generators results in the preservation of fuel for "limited energy" generators, to allow fuel to be used later in the event of system contingencies. Generators may be postured either on-line or off-line. When generators are postured on-line, it is often at the generator's economic minimum; the generator provides operating reserves while postured, but is only available for manual dispatch above the posturing level in the event of a system contingency. Generators postured off-line also provide either 10- or 30-minute operating reserves, if fast-start capable.

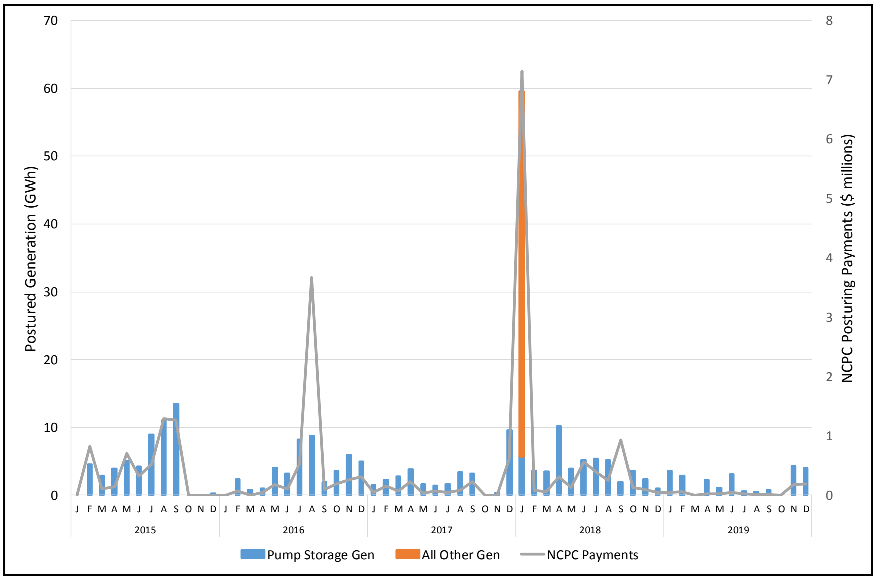
Because posturing removes potentially in-merit generation from economic dispatch, postured generators may be worse-off as a result of the ISO's actions, unless the ISO provides uplift payments to compensate for foregone profitable dispatch. Postured generators may receive NCPC for any foregone profits that occurred during the posturing period. Generally, the remaining energy at the postured generator is compared to its economic dispatch opportunities during the posturing period; NCPC is provided for the net profits of optimal economic dispatch that would have occurred absent posturing, compared to the profitability of the actual dispatch that occurred during the posturing period.[113]

Postured energy (GWh) and NCPC payments by month are shown in Figure 3-30 below. The bars indicate the postured energy obtained (the amount of energy constrained down) from pumped-storage generators and all other types of generators.[114]

[113] See Market Rule 1, Appendix F, Sections 2.3.8 and 2.3.9.

[114] Very infrequently, pumped-storage demand (or asset-related demand) is postured. These resources are postured on-line (in consumption mode) to increase operating reserves. The energy associated with these posturing activities is not depicted in the figure.

Figure 3-30 Monthly Postured Energy and NCPC Payments



As indicated in the figure above, pumped-storage generators are frequently postured throughout the year. In 2019, only pumped-storage generators were postured, and posturing levels were relatively low, at 23 GWh in total, compared other years in the review period.[115] Only in January 2018 have non-pumped-storage generators been postured. The posturing in January 2018 involved a number of oil-fired generators, with limited fuel, being postured during a prolonged "-cold snap period that resulted in significant concerns about the day-to-day availability of natural gas for electric generation. The postured oil-fired generators were effectively providing back-up electricity supply, in the event of a natural gas shortage during the cold snap.

As indicated in the figure, NCPC payments to postured generators were quite low throughout 2019. NCPC payments were highest during January 2018, when the cold snap period resulted in significant posturing of oil-fired generators. While the magnitude of NCPC payments is generally consistent with the quantity of energy being postured, posturing during very high energy price periods also can result in high NCPC payments, even when the postured energy quantity is not extremely large. This is noticeable in August 2016, when pumped-storage generators were postured on August 11, during a capacity deficiency period (Operating Procedure 4) with operating reserve deficiencies and very high energy prices.

3.4.9 Congestion

This section provides an overview of how congestion occurs in an electrical transmission system and how it affects the locational marginal prices (LMPs) that are used to settle generation and load. This section explores where congestion occurred in the New England transmission system in 2019. It then looks at the amount of congestion that the New England power system experienced in 2019 and compares it against historical levels of congestion over the last five years. In general, the New England transmission system has become more export constrained in recent years. This trend has led to a shift between generation and load in terms of who is paying congestion costs, with load paying a smaller share of these costs every year over the reporting period. This section concludes

[115] For context, the total supply/load in 2019 was over 123,000 GWh.

by looking at some of the most frequently binding transmission constraints in New England in 2019.

Overview of Congestion

At every node in the New England power system, LMPs reflect the cost of delivering the next megawatt (MW) of energy at the lowest cost to the system. The LMP is comprised of three components: the energy component, the congestion component, and the loss component. The energy component is the same for all locations in the power system. The congestion component reflects the additional system costs when transmission constraints prevent the use of the least-cost generation to meet the next increment of load. The loss component reflects the dispatch of additional generation because some electric energy is lost during transmission. Breaking down the LMP into these components enables the ISO to determine how much of the difference in LMPs at two locations is due to transmission congestion versus losses. Locational differences in the congestion component serve as the basis for determining the value of financial transmission rights (FTRs), a financial instrument that market participants can use to hedge transmission congestion cost risk. FTRs are covered in more detail in Section 4.2.

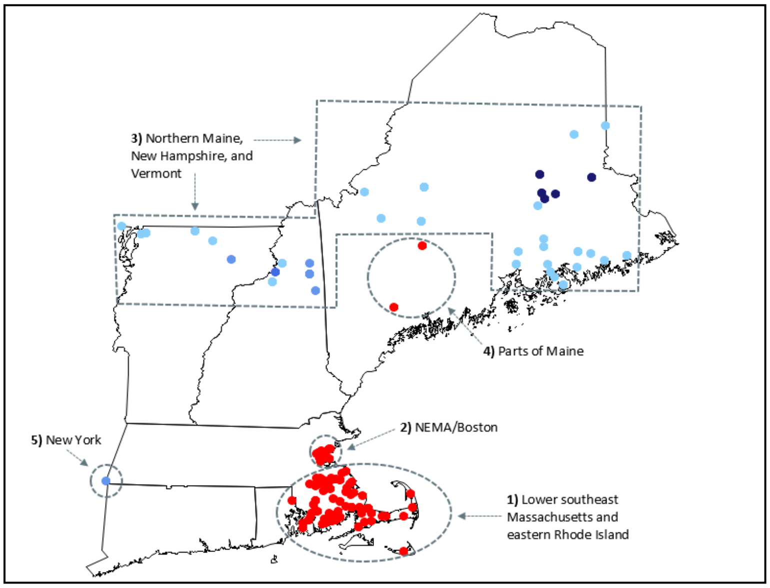
When transmission lines connecting a part of the power system to the rest of the system reach the maximum amount of power allowed to flow, the transmission line is said to "bind." When this happens, each of these areas has at least one marginal resource that is setting the price in that area (marginal resources are discussed in more detail in Section 3.4.10). For example, when a transmission line connecting an area with low-cost generation to the rest of the system binds, the two areas will have different prices. A low-cost resource will set the price in the lower-cost area and a different resource will set the price for the rest of the system. Locational difference in prices caused by a binding transmission constraint like the one just discussed are reflected in the LMP through the congestion component. The congestion component can be positive or negative. A negative congestion component indicates an export-constrained area, and a positive congestion component indicates an import-constrained area.

Congestion patterns in New England

The New England nodes most affected by transmission congestion in 2019 are shown in Figure 3-31 below.[116] The colors of the nodes are indicative of the average day-ahead congestion component in 2019. Blue dots represent locations that had an average day-ahead congestion component that was negative in 2019. The darker the blue, the lower the average day-ahead congestion component. These nodes are in export-constrained areas (i.e., areas where there is an imbalance of generation relative to load and there is insufficient transmission capability to *export* the excess generation). Red dots represent locations that had an average day-ahead congestion component that was positive in 2019. These nodes are in import-constrained areas (i.e., areas where there is an imbalance of load relative to generation and there is insufficient transmission capability to *import* the additional needed generation). Day-ahead data was used to produce the map because the majority of congestion revenue comes from the day-ahead market.

[116] This figure only includes nodes that had an average day-ahead congestion component of greater than or equal to \$0.15/MWh or less than or equal to -\$0.15/MWh in 2019.

Figure 3-31: New England Pricing Nodes Most Affected by Congestion, 2019



Several patterns of congestion stand out in Figure 3-31:

1) Lower southeast Massachusetts (SEMA) and eastern Rhode Island (RI) had higher congestion prices, on average, in 2019 than in other areas in the region. On June 1 2019, Pilgrim Nuclear Power Station, located in Plymouth Massachusetts, retired from New England's markets. This retirement, in combination with transmission work during the year, led the lower SEMA/Eastern RI Import (LS-ERI) interface to bind at times in the day-ahead energy market. Congestion would have been worse in this area had the ISO not intervened to ensure reliability. In 2019, the ISO frequently made local reliability commitments within this constrained area. Reliability commitments like these are discussed in Section 3.4.8.

2) Some locations inside northeast Massachusetts (NEMA/Boston) had positive congestion prices, on average, in 2019. With the highest concentration of load in New England, the Boston area has traditionally seen higher-than-average congestion prices. However, transmission improvements in recent years related to the Greater Boston Reliability Project have increased the ability of this area to import power. While the Boston Import (BSTN) interface, which is used to manage flows into the Boston area, did not bind often in the day-ahead market in 2019, certain 115 kV transmission lines within this area did bind with some frequency to create pockets with positive congestion pricing.

3) Several areas on the system with a high concentration of intermittent generators had lower congestion prices, on average, than the rest of the system. In 2019, areas in northern Maine, New Hampshire, and Vermont were frequently export-constrained. Renewable generators (predominantly wind) are frequently marginal in these areas in real-time when they commonly offer their energy at very low, even negative, prices. Virtual supply is often marginal in these areas in the day-ahead market, attempting to profit from the low real-time prices. Many of the interface constraints that are used to manage these areas are some of the most frequently binding constraints in the day-ahead market (see Table 3-5 below).

4) Despite being thought of as an export-constrained area, Maine was actually import-constrained at times in 2019. Evidence of this can be seen by the red dots in the southwestern part of Maine in Figure 3-31, indicating positive congestion pricing, on average, in 2019. The New Hampshire – Maine Import (NHME) interface, which is used to manage flows from New Hampshire into Maine, bound periodically in 2019, creating positive congestion pricing in Maine. This congestion was particularly pronounced in the fall during the planned outage of a 345 kV line. Maine also experienced a large number of reliability commitments in 2019. More information about these commitments is contained in Section 3.4.8.

5) The New York – New England (NYNE) interface was one of the most frequently binding transmission constraints in ISO-NE's day-ahead market in 2019. This interface is a collection of seven lines that control the flow of power between the New York and New England control areas. As discussed in Section 5, New England typically imports power over this interface. This constraint frequently binds during periods when there are large spreads between power prices in New England and New York (e.g., some winter months, when New England's gas infrastructure can become constrained) or when there are reductions in the interface limit. When this constraint binds, it is reflected in the congestion component of the .I.ROSETON 345 1 pricing node, which is ISO-NE's external node for trading across the New York – New England interface. This constraint is discussed in more detail toward the end of this section.

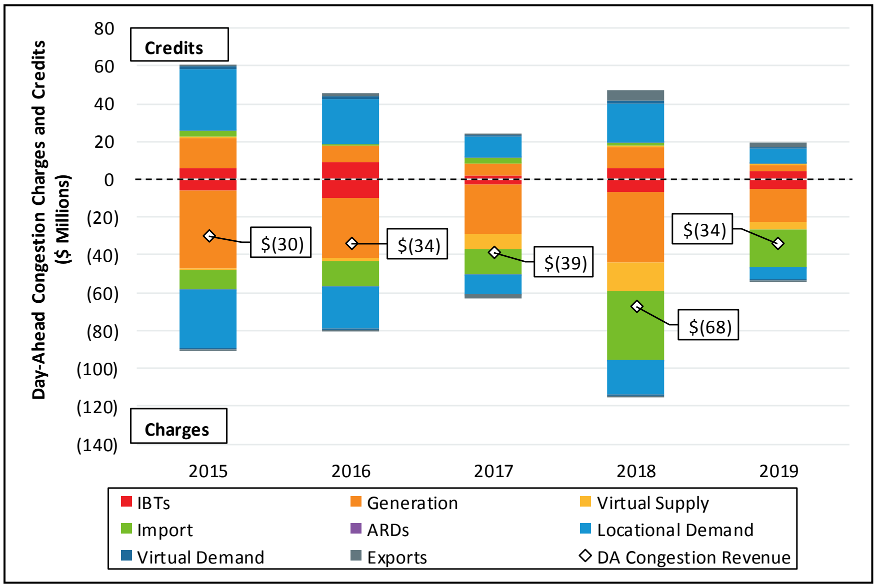
Cost of Congestion

One way to explore the financial impact of transmission congestion is to look at congestion charges and credits. The ISO settles the day-ahead and real-time energy markets by calculating charges and credits for all market activity that occurs at each pricing location (node) in the system. Energy market settlement is performed on each part of the three components of the LMP separately. By design, the credits and charges based on the congestion component of the LMP do not balance; the charges are expected to exceed the credits. The surplus revenue is called congestion revenue. Congestion revenue is collected in both the day-ahead and real-time energy markets and it forms the basis of the congestion revenue fund, which is used to pay the holders of FTRs.

The congestion charges and credits for the day-ahead energy market for the last five years are shown in Figure 3-32 below. In this figure, charges are shown as negative values, while credits are shown as positive values. This chart also shows the sum of the congestion charges and credits (i.e., the day-ahead congestion revenue) each year with white diamond shapes. Further, this chart depicts the congestion credits and charges associated with the different categories that constitute day-ahead generation obligation (DAGO) and day-ahead load obligation (DALO) and shows the impact of day-ahead energy internal bilateral transactions (IBTs).[117]

[117] Day-ahead energy internal bilateral transactions are contracts between two market participants in which the "buyer" receives a reduction in its day-ahead and real-time adjusted load obligation of the MW amount listed in the contract and the "seller" receives an increase in its day-ahead and real-time adjusted load obligation for the same MW amount.

Figure 3-32: Day-ahead Energy Market Congestion Charges and Credits

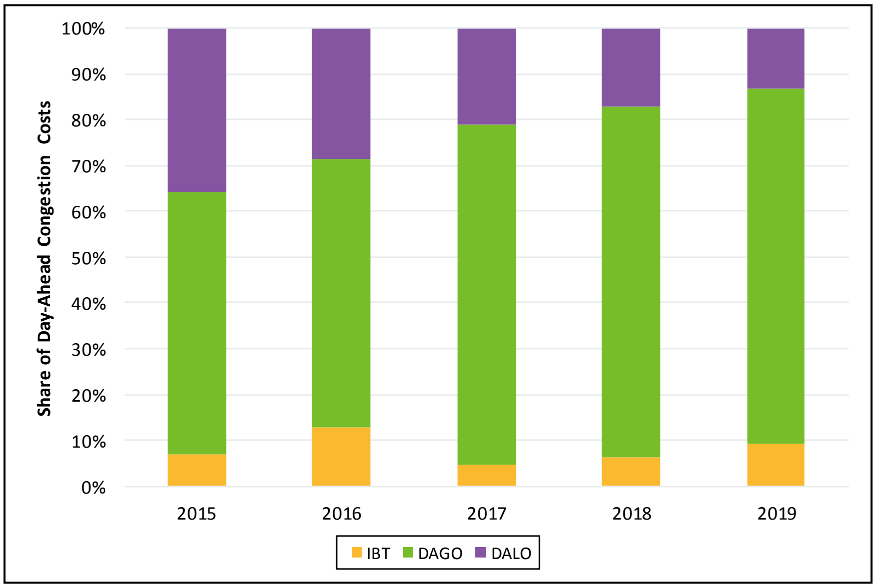


Day-ahead congestion charges totaled $53.4 million in 2019, their lowest level of the last five years. This represents a 54% decrease from the $115.0 million that participants paid in day-ahead congestion charges in 2018. Day-ahead congestion credits were also at their lowest level of the last five years, totaling $19.0 million in 2019. This represents a 60% decrease from the $47.2 million that participants received in day-ahead congestion credits in 2018. In total, the day-ahead congestion revenue in 2019 (white diamond) amounted to $34.4 million, which was a 49% decrease from the day-ahead congestion revenue in 2018 ($67.8 million).

This decrease in congestion charges between 2018 and 2019 was particularly notable for several categories of day-ahead generation obligation: generation paid $19.6 million less, imports paid $16.3 million less, and virtual supply paid $10.9 million less. However, these groups still comprise a large percentage of all the day-ahead congestion charges. In 2019, imports paid 37% of day-ahead congestion charges ($19.6 million), generation paid 33% ($17.4 million), and virtual supply paid 8% ($4.5 million). Generation obligation incurs congestion charges when it receives a reduced price for its energy as a result of a negative congestion component at the location where it is supplying energy. Meanwhile, locational demand (i.e., demand that is not virtual, an export, or associated with asset-related demand) paid only 13% of day-ahead congestion charges in 2019 ($6.8 million). Load obligation incurs congestion charges when it has to pay more for its energy as a result of a positive congestion component at the location where it is assuming the load obligation.

In fact, load has paid an increasingly smaller share of congestion costs in the day-ahead market relative to generation over the last five years. This can be seen in Figure 3-33 below which shows the share of day-ahead congestion costs that are paid by day-ahead generation obligation (green) and day-ahead load obligation (purple). This figure also shows the congestion costs associated with internal bilateral transactions (yellow).

Figure 3-33: Percent of Day-ahead Energy Market Congestion Costs Paid by Category

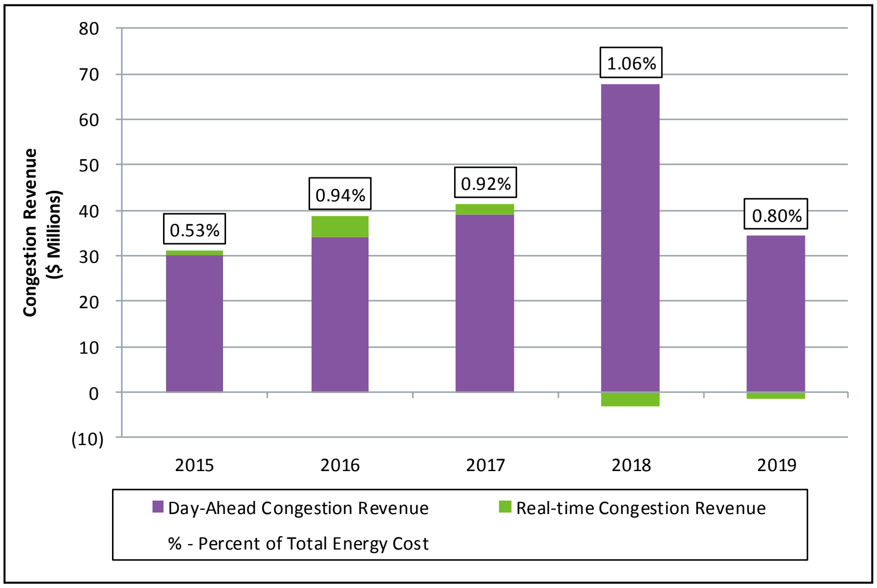


In 2019, load paid only 13% of day-ahead congestion costs; this is the smallest share paid over the reporting period. In contrast, load paid 36% of day-ahead congestion costs in 2015. The share of day-ahead congestion costs paid by load has decreased every year, while the share of these costs paid by generation has increased every year. In 2015, generation paid 57% of day-ahead congestion costs, while in 2019 that share grew to 78%. This shift of congestion costs between load and generation is reflective of a transmission system in New England that has evolved from one that was more import-constrained to one that is now more export-constrained. This change is also evident in Table 3-5, which appears toward the end of this section. This table shows that almost all of the most frequently binding interface constraints in the day-ahead market in 2019 were export constraints.

Congestion relative to Energy Market Payments

The congestion revenue in New England by market and year is shown in Figure 3-34 below. The purple bars represent the day-ahead congestion revenue, and the green bars represent the real-time congestion revenue. The percentages in the figure are the total congestion revenue each year expressed as a percent of total energy market costs.

Figure 3-34: Congestion Revenue Totals and as Percent of Total Energy Cost



Total day-ahead and real-time congestion revenue was $32.9 million in 2019. This represents a 49% decrease from $64.5 million dollars in 2018. The congestion revenue in 2019 represents less than 1% of total energy costs (labels). Day-ahead congestion revenue is much higher than real-time congestion revenue because the real-time market is a balancing market.

Almost half (45%) of the congestion revenue in 2019 occurred in two months: January and December. The amount of congestion revenue in a month depends on the transmission constraints that bind in that month. Identifying the contribution of each binding constraint to the amount of congestion revenue in a month is complex.[118] However, two factors that can be examined to explore this relationship are the frequency with which a constraint bound in a given month and the marginal value of the constraint when it bound.[119] For example, a constraint that bound very frequently but did not have a large marginal value could have the same impact on congestion revenue as a constraint that bound infrequently but had an extreme marginal value when it did.

The Most Frequently Binding Interface Constraints

The 10 interface constraints that bound the most frequently in the day-ahead market in 2019 are listed in Table 3-5 below. Interfaces are sets of transmission elements whose power flows are jointly monitored for voltage, stability, or thermal reasons. Interface constraints can often have a larger impact on congestion revenue when they bind than individual transmission elements because more load and generation are likely to be affected. Also included in the table is the average marginal value ($/MWh) of each constraint when it bound in 2019.

[118] Determining the amount of congestion revenue associated with a particular constraint is dependent upon many factors including: 1) the sensitivity of each node within the constrained and unconstrained areas to the binding constraint, 2) the amount of load and generation obligation at each node that has a nonzero sensitivity to the constraint, and 3) the marginal value of the binding constraint.

[119] The marginal value of the constraint indicates how much the production cost of the system would change if the limit of the interface increased by one megawatt. All the marginal values are negative because allowing an additional megawatt to flow over the binding constraint would *reduce* total system production costs.

Table 3-5: Most Frequently Binding Interface Constraints in the Day-Ahead Market in 2019

Constraint Name	Constraint Short Name	% of Hours Binding	Average Marginal Value of Constraint ($/MWh)
Keene Road Export	KR-EXP	29.5%	-$14.37
New York - New England	NYNE	19.8%	-$7.69
Sheffield + Highgate Export	SHFHGE	8.1%	-$4.27
Burgess Generation	BURG	3.4%	-$26.78
Wyman Hydro Export	WYM-EX	2.9%	-$21.33
Whitefield South + GRPW	WTS+GR	2.2%	-$12.58
Orrington - South	ORR-SO	2.1%	-$5.60
Sheffield Generation	SHEF	1.9%	-$32.75
Lower SEMA/Eastern RI Import	LS-ERI	1.7%	-$10.76
Kingdom Wind Generation	KCW	1.4%	-$23.72

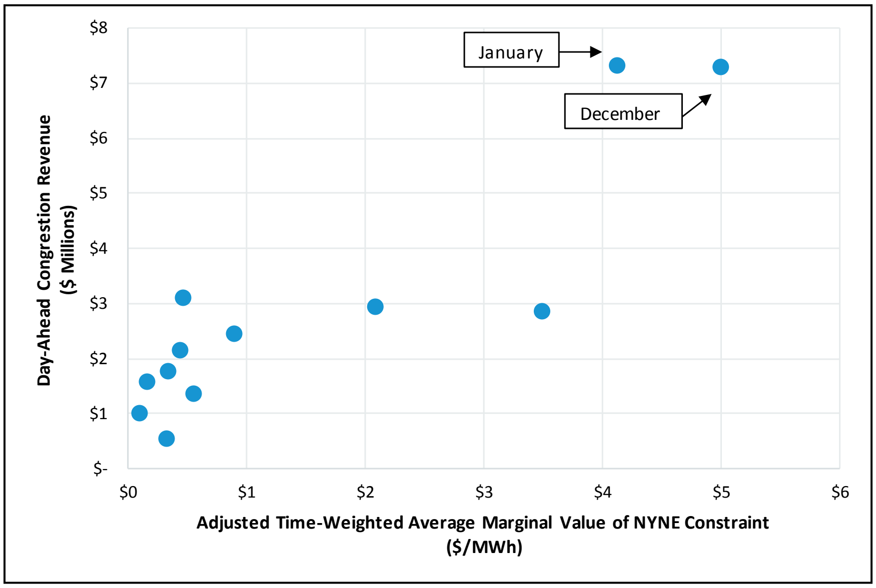
The most frequently binding interface constraint in the day-ahead market in 2019 was the Keene Road Export interface constraint. This interface consists of a line and a transformer that control flows through the Keene Road substation. The Keene Road substation is where one of the two 345-kV lines that electrically connects the New England and New Brunswick control areas terminates. There are numerous wind generators located at nearby substations whose power flows through the Keene Road substation. The Keene Road Export interface helps manage the flow of this intermittent energy. The average day-ahead congestion revenue was $5,571 per hour in the 2,582 hours the Keene Road Export interface was binding compared to the average revenue of $3,236 per hour in the hours in which it was not binding. Although it was only binding in 29.5% of hours, the congestion revenue within these hours comprised 41.8% of the total day-ahead congestion revenue.

The second most frequently binding interface constraint in the day-ahead market in 2019 was the New York – New England (NYNE) interface constraint. As mentioned above, this interface is a collection of seven lines that controls the flow of power between the New York and New England control areas. The average day-ahead congestion revenue (system-wide) was $10,719 per hour in the 1,732 hours that the New York – New England interface was binding compared to the average revenue of $2,250 per hour in the hours in which it was not binding. Although the interface was only binding in 19.8% of hours, the congestion revenue within these hours comprised 54.0% of the total day-ahead congestion revenue.

The New York – New England interface tends to have a significant impact on congestion revenue when it does bind. This can be seen in Figure 3-35 below, which shows the monthly day-ahead congestion revenue totals from 2019 plotted against a measure that captures both the frequency and the magnitude of the NYNE constraint when it bound in the day-ahead market.[120]

[120] The x-axis in Figure 3-35, which is labeled Adjusted Time-Weighted Average Marginal Value of the NYNE Constraint, is equal to the average marginal value of the NYNE constraint when it bound in the day-ahead market multiplied by the percent of hourly intervals in the day-ahead market that the constraint bound. It is considered *adjusted* because it is further multiplied by -1 in order to make the values positive.

Figure 3-35: Monthly Day-Ahead Congestion Revenue Values in 2019 by Average Marginal Value of the NYNE Constraint in the Day-Ahead Market



There is a clear and positive relationship between this metric and the amount of day-ahead congestion revenue in 2019. The two months with the highest value for this metric – January and December – are also the two months with the highest monthly totals of day-ahead congestion revenue. The relationship between the NYNE interface constraint and day-ahead congestion is discussed in more detail in Section 4.2. This section looks specifically at how market participants have viewed congestion at this interface by scrutinizing their use of FTRs that source from .I.ROSETON 345 1, ISO-NE's external node for trading across the New York – New England interface, over recent years.

3.4.10 Marginal Resources

The LMP at each pricing location is set by the cost of the next megawatt of supply the ISO would dispatch (or the next MW of demand the ISO would back down) to meet an incremental change in load at that location. The supply offer or demand bid that sets price is considered "marginal."

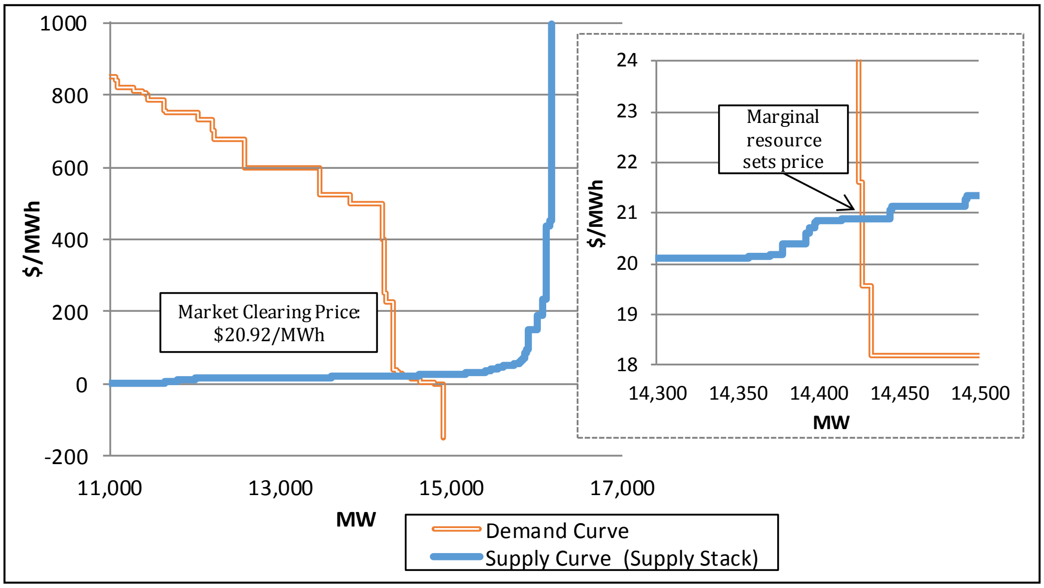
Ranking supply offers from lowest to highest offered price creates a supply curve or "supply stack" with the relative position of each generator in the stack largely determined by the relative cost of different fuels (gas, oil, coal, etc.). On the demand-side, for the day-ahead market, ranking demand bids from highest to lowest produces the demand curve. The intersection of the supply and demand curves determines the market-clearing price and the quantity of MWs that clear.[121] The individual offer or bid located at the intersection of the supply and demand curves sets the market price and that offer/bid is said to be marginal.

An example of a supply offer setting the price for a particular hour in the day-ahead market (hour ending 14 on June 14, 2019) is shown in Figure 3-36 below. The blue curve shows the supply stack, where supply offers are ranked from lowest to highest. The large section of supply at -

[121] This is a crude simplification of the optimization that occurs to clear the day-ahead market, but it accurately describes the essence of optimization's goal to maximize social welfare by bringing supply and demand in balance.

$150/MWh[122] consists of self-scheduled generation, fixed imports, and generation up-to economic minimum, all of which are not eligible to set price and are treated as fixed supply in this example. The demand curve consists of day-ahead demand bids, with a large section of fixed demand bids at the offer cap of $1,000/MWh.

Figure 3-36: Day-Ahead Supply and Demand Curves – June 14, 2019, HE 14



At the intersection of the supply and demand curves, which is highlighted in the inset graph of Figure 3-36, a supply offer of $20.92/MWh intersects with the demand curve at about 14,430 MW. The resource that submitted this supply offer is therefore marginal, as an incremental MW of demand would be served by an increase in supply from this resource. As a result, this marginal resource sets the market-clearing price at $20.92/MWh.

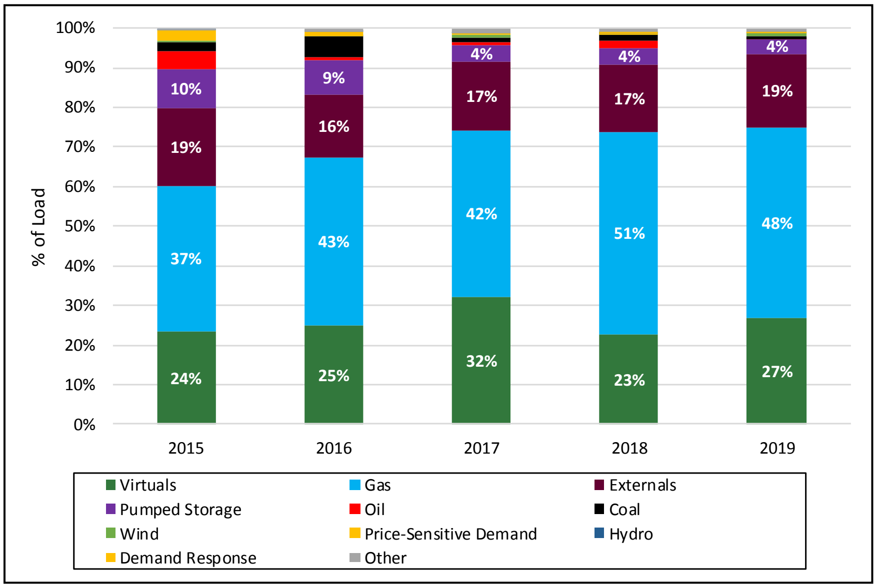
In cases where transmission constraints are binding and energy cannot flow freely, there will be more than one marginal resource. For example, if transmission lines are limiting the amount of generation exported from a given area, that area is *export-constrained*. Transmission limitations do not allow for resources within this area to serve the next MW of load outside of the export-constrained area. In this case, there will be a marginal resource that could serve the next increment of load inside the export-constrained area, and at least one other marginal resource that serves incremental load outside the export-constrained area.

Marginal Resources in the Day-ahead Market

Many different types of transactions can be marginal in the day-ahead market, including: virtual transactions, price-sensitive demand bids, price-responsive demand, asset-related demand, generator supply offers, and external transactions. The percentage of load for which each transaction type was marginal over the past five years is illustrated in Figure 3-37 below.

[122] Negative $150/MWh is chosen for illustrative purposes only.

Figure 3-37: Day-Ahead Marginal Resources by Transaction and Fuel Type

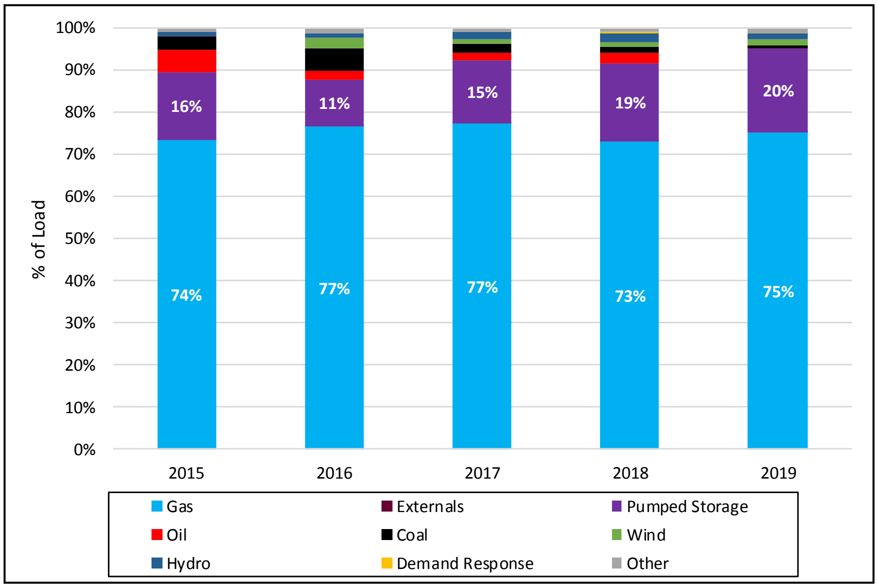


Natural gas (48%), virtual transactions (27%), and external transactions (19%) continue to set price for a majority of load (94%) in the day-ahead market. External transactions from Canada and virtual transactions bid in at the New York North interface set price more frequently in 2019 than in 2018. Though external transactions from all interfaces only set price for 2% more load in 2019, there was a large increase in imports setting price for load across the New Brunswick interface (4.4% in 2019 from 1.6% in 2018). The increase was primarily due to fewer transmission constraints in Maine that allowed imports to set price for more load across the system. Virtual supply offers at the New York North interface set price for 2.6% of load in 2019, up from 0.9% in 2018. Along with changes in bidding strategies year-over-year, the New York North interface bound less frequently in 2019, from 23% of hours in 2018 down to 20% of hours in 2019.

Marginal Resources in the Real-time Market

In the real-time market, only physical supply, pumped-storage demand, price-responsive demand, and external transactions can set price. In reality, real-time marginal resources are typically generators (predominantly natural gas-fired generators) and pumped-storage demand. The marginal fuel mix in the real-time market over the past five years is shown in Figure 3-38 below.

Figure 3-38: Real-Time Marginal Resource by Fuel Type



Natural gas was the marginal fuel for 75% of load in the real-time market in 2019. Gas-fired generators are typically the lowest-cost fossil fuel type generator and thus typically operate much more often than coal- or oil-fired generators. Pumped-storage units (both generators and demand) are the second largest marginal resource, setting price for 20% of load in 2019.[123] Because they are online relatively often and priced close to the margin, they can set price frequently. They are also 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.

The remaining transaction types were marginal for less than 5% of load in 2019. Although wind generators are frequently marginal, they are usually marginal for only a small share of total system load (1% in 2019). Wind generators are often located in export-constrained (excess generation) areas and can only deliver the next increment of load in a small number of locations because the transmission network that moves energy out of their constrained area is at maximum capacity. Oil-fired generators set price for 0.2% of load in 2019, down from 2.4% in 2018. Oil-fired generators had fewer opportunities to set price because they operated much less frequently in 2019 compared to 2018. The decline in generation was due to fewer extreme pricing events and high operating costs compared to other generators.[124]

3.5 Net Commitment Period Compensation

This section provides an overview of Net Commitment Period Compensation (NCPC) payments. It covers payment types, reasons, and trends over the past five years.

Generators are eligible for NCPC or *uplift* payments when they are unable to recover their operating costs in the day-ahead or real-time energy markets. The uplift rules are designed to make

[123] Pumped-storage generation and demand are broken into different categories as they have different operational and financial incentives. Pumped-storage generators (supply) tend to operate and set price in on-peak hours when electricity prices are generally higher. Pumped-storage demand have lower offers and typically consume energy and set price in off-peak hours, when it is generally cheaper to pump water.

[124] For more information on system conditions over reporting period, see Section 3.4.7.

generators that follow the ISO's operating instructions no worse off financially than the generator's next best alternative.[125] Uplift is also paid to generators for "lost opportunities", i.e. situations in which a generator foregoes opportunities for additional energy market revenue by following ISO instruction. This typically occurs when the market clearing software, or the ISO operators, restrict a generator's output below its economically optimal level.

In 2019, uplift payments totaled $30.3 million, a decrease of $39.8 million (down by 57%) compared to 2018. Uplift payments remained relatively low, at 0.7%, when expressed as a percentage of total energy payments. Table 3-6 below details the continuing downward trend over the reporting horizon.

Table 3-6: Uplift Payments as a Percent of Energy Costs

	2015	2016	2017	2018	2019
Day-Ahead NCPC	0.6%	1.1%	0.6%	0.4%	0.3%
Real-Time NCPC	1.4%	0.7%	0.5%	0.7%	0.4%
Total NCPC as % Energy Costs	**2.0%**	**1.8%**	**1.2%**	**1.2%**	**0.7%**

Total uplift payments as a percent of energy costs were lower in 2019 than in any other year of the reporting period. This decrease was driven by a few factors. First, total uplift for 2018 was high due to the manual posturing of oil-fired generators for fuel security during the cold snap in early January. In January 2018, uplift payments accounted for about 30%, or $20.3 million, of total annual payments, with 80% of January payments made during a 4-day period of very cold weather and high natural gas prices (January 4 through 7, 2018). Second, average natural gas prices were 34% lower in 2019 compared to 2018, which led to a 29% and 30% decrease in average day-ahead and real-time Hub LMPs, respectively. This, in turn, put downward pressure on NCPC.

3.5.1 Uplift Payment Categories

Generators that operate at the ISO's instruction may be eligible for one of the following types of uplift depending on the reason for ISO commitment:

- **Economic/first-contingency NCPC**[126]:
    - *Out-of-merit NCPC:* Payments provided to a generator committed in economic merit order to satisfy system-wide load and reserves to cover the portion of as-offered costs not recovered through the LMP.
    - *External NCPC:* Payments made to external and virtual transactions that relieve congestion at the external interfaces, and for external transactions that are unable to recover as-offered costs due to price forecast error.[127]
    - *Dispatch lost opportunity cost NCPC (DLOC):* Payments provided to a resource that is instructed by the ISO to run at levels below its economic dispatch point.

[125] The terms "generators" or "generation" are used in this section in a broad sense; in practice, external transactions and pumped-storage demand also receive certain types of NCPC payments, but the vast majority of payments are made to generators.

[126] A system's *first contingency* (N-1) is the loss of the power system element (facility) with the largest impact on system reliability. A *second contingency* (N-1-1) takes place after a first contingency has occurred and is the loss of the facility that at that time has the largest impact on the system.

[127] See Section 5.3 for further detail on external transaction uplift payments.

- *Posturing NCPC:* Payments provided to a resource that follows an ISO manual action that alters the resource's output from its economically-optimal dispatch level in order to create additional reserves.
- *Rapid-response pricing opportunity costs (RRP OC):* Payments provided to a resource that is instructed by the ISO not to operate at its economic dispatch point when fast-start generators are setting the LMP.

- **Local second-contingency protection NCPC:** Payments made to a generator committed to provide local operating reserve support in a transmission-constrained area to ensure local reliability needs.
- **Voltage reliability NCPC**: Payments made to a generator that is dispatched to provide reactive power for voltage control or support.
- **Distribution reliability NCPC**: Payments made to a generator committed to support local distribution networks.
- **Generator performance auditing NCPC**: Payments made to a generator that is operating to satisfy the ISO's performance auditing requirements.[128]

3.5.2 Uplift Payments for 2015 to 2019

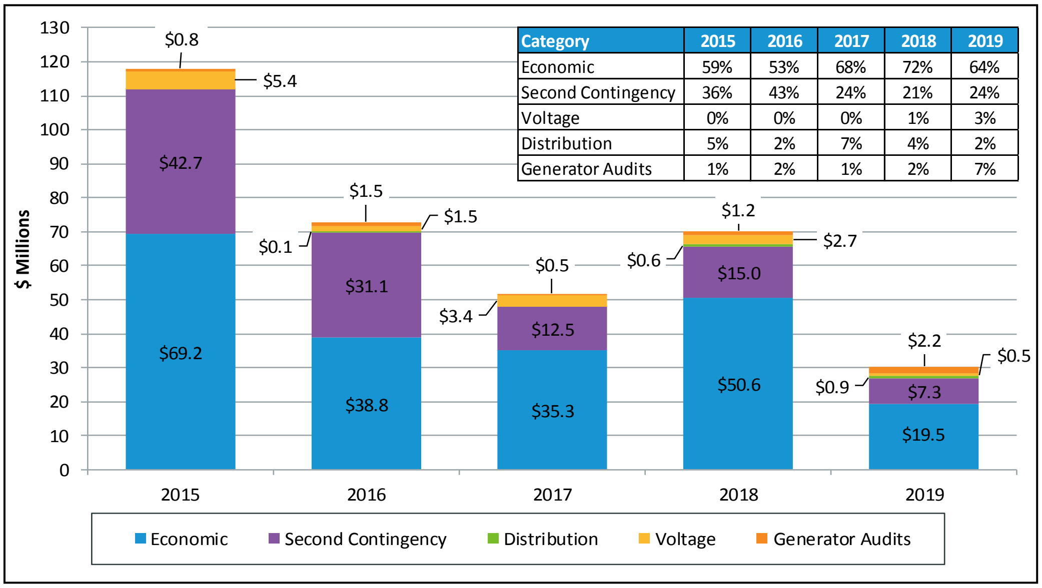
Uplift payments decreased by $39.8 million (or by 57%) in 2019, from $70.1 million in 2018 to $30.3 million in 2019. This decrease follows the general downward trend of total uplift from 2015 through 2017. Higher uplift costs in 2018 were largely due to a cold snap at the beginning of January. No similar events occurred in 2019. Economic uplift payments make up most of the 2019 decrease, down by $31.1 million. Local second-contingency reliability payments totaled $7.3 million in 2019, and were about half of 2018 payments, or down by $7.7 million.

Uplift Payments by Category

Over the past five years, most uplift payments have been for economic (or first contingency) needs, as shown in Figure 3-39, which depicts total uplift payments by year and payment category. The inset table shows the percentage share of total uplift for each category by year.

[128] Uplift payments for generator performance audits became effective on June 1, 2013. Eligibility for payment under this uplift category includes: Performance audits of on-line and off-line reserves and for seasonal claimed capability audits initiated by the ISO rather than the participant, and dual-fuel testing.

Figure 3-39: Total Uplift Payments by Year and Category



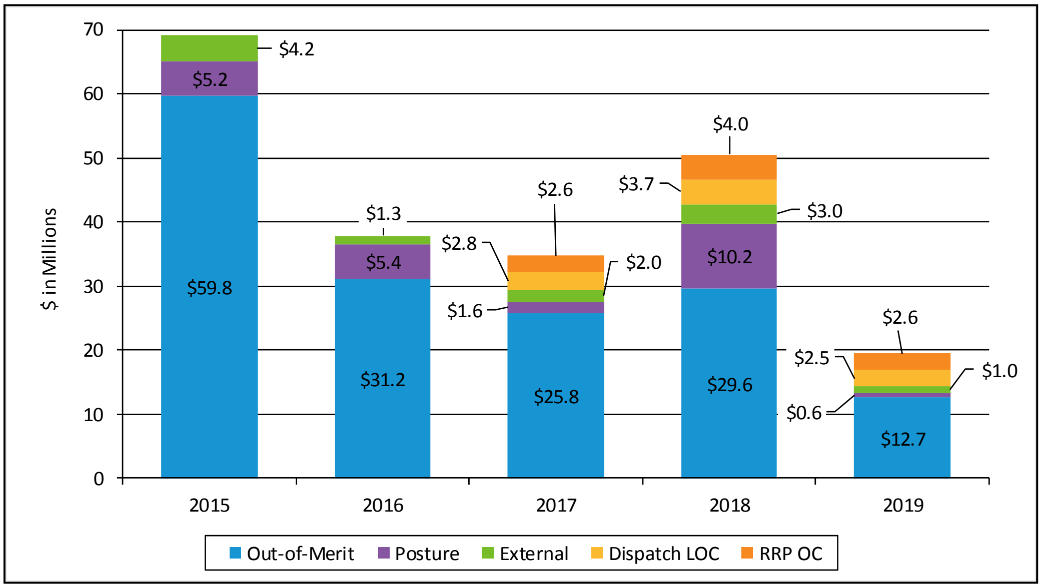
Category	2015	2016	2017	2018	2019
Economic	59%	53%	68%	72%	64%
Second Contingency	36%	43%	24%	21%	24%
Voltage	0%	0%	0%	1%	3%
Distribution	5%	2%	7%	4%	2%
Generator Audits	1%	2%	1%	2%	7%

Economic, second contingency, and voltage payments decreased in 2019, while distribution and generator audit payments, which only made up 9% of total NCPC, increased by $0.27 and $0.94 million, respectively. At $19.5 million, economic uplift accounted for most of the payments, representing 64% of total uplift payments in 2019. This is a $31.1 million (61.5%) decrease from 2018 and a $49.7 million (or 71.9%) decrease from the high in 2015. This decrease was driven by two factors: the absence of significant posturing of oil-fired generators, which had occurred in January 2018, and lower natural gas and energy prices. Second contingency payments also decreased significantly, by $7.7 million or 51% compared to 2018 payments. Although there was a slight increase in reliability commitments in 2019, most reliability commitments were for gas-fired generators. Lower gas prices were a significant driver of lower second contingency payments.

Economic Uplift Sub-Categories

Every sub-category of economic uplift decreased in 2019. Most notably, posturing payments decreased by 94% or $9.6 million and out-of-merit payments decreased by 57% or $16.9 million. A breakdown of economic uplift by year and by sub-category is shown in Figure 3-40 below.

Figure 3-40: Economic Uplift by Sub-Category



Posturing uplift payments were much higher in 2018 than in 2019. The driving force behind the 2018 posturing payments was a 4-day period of very cold weather and high natural gas prices from January 4 through 7, 2018. Consequently, uplift payments were made to oil-fired generators whose energy was postured (i.e. held back) to maintain fuel supply while system conditions were stressed. The generators were paid uplift to recover lost revenues because they did not operate during this high-priced period, even when it was economic for them to do so. . The average temperature during this period was 10.2°F, with an average low of 3.4°F. In comparison, during the same 4-day period in 2019 the average temperate was 32.5°F, with an average low of 26.5°F.

Reliability Uplift Payments

Figure 3-39 above shows that Local Second Contingency Protection (LSCPR) payments decreased by $7.7 million, or 51.4%, from 2018 payments. Approximately 77%, or $11.5 million, of 2018 LSCPR payments were made during the 2018 January cold snap, and during planned transmission work and local reliability protections in NEMA Boston in April and July. In contrast, even with an increase in reliability commitments, total LSCPR payments were only $7.2 million in 2019. The main driver behind these lower payments was lower fuel costs for reliability-committed gas-fired generators. The most LSCPR uplift was paid in July and December 2019 to support planned transmission work in Maine and eastern Rhode Island. The percentage of real-time LSCPR payments has remained low at 9% in 2019 compared to 17% in 2018.

Distribution reliability protection payments increased by $0.27 million (by 43%) in 2019 from 2018 payments. The vast majority, 94%, of these payments are paid in real-time. During July and August two oil-fired generators on Cape Cod were committed to support distribution reliability in the SEMA load zone. During spring and early fall two oil-fired generators in lower Maine were committed to support local reliability needs. There was an increase in payments in the fall of 2019 (September and October) due to work on the low voltage network.

Uplift Payments by Quarter

Uplift payments can vary significantly by season for a number of reasons, including: fluctuating fuel prices, diverse load conditions, the timing of major transmission outages, and other factors. Quarterly total uplift payments for 2015 through 2019 are shown in Figure 3-41 below. The colored bars illustrate the quarterly uplift totals (Q1 is blue, Q2 is green, Q3 is red, and Q4 is yellow) and the black lines above the bars correspond to total annual uplift payments for that year.

Figure 3-41: Total Uplift Payments by Quarter

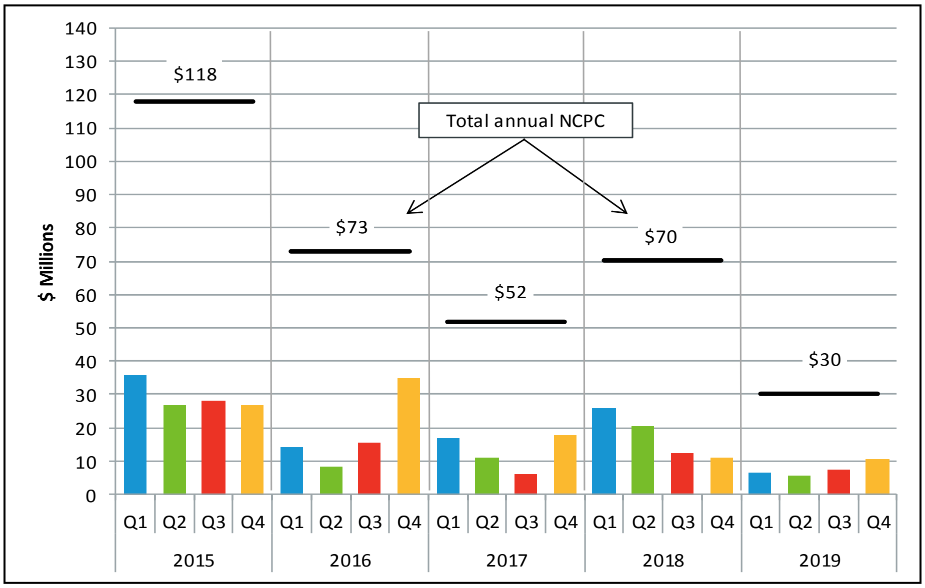
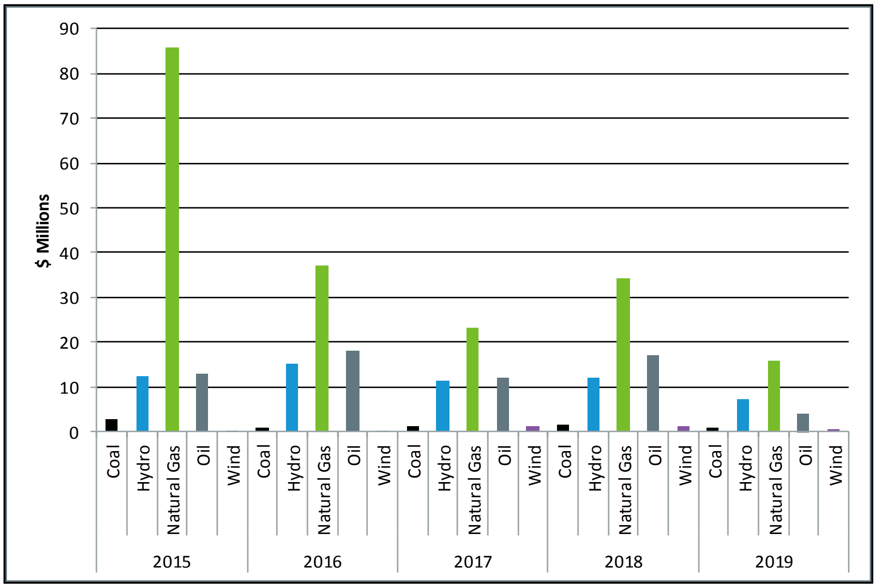


Figure 3-41 illustrates that uplift payments by quarter were the lower than every other corresponding quarter in the reporting period (with the exception of Q3, which was the lowest in 2017). The highest 2019 quarterly total uplift payments occurred in Q3 and Q4. This largely reflects increased economic and LSCPR uplift payments during the second half of the year. Between July and December, there were planned transmission outages in Maine and SEMA/Eastern Rhode Island that caused numerous day-ahead reliability commitments. During this period 89%, or $5.9 million, of total day-ahead LSCPR payments were made.

Uplift by Fuel Type

Total uplift payments by generator fuel type are shown in Figure 3-42 below.

Figure 3-42: Total Uplift Payments by Generator Fuel Type



Natural gas-fired and hydro generators received the majority (81%) of uplift payments because of their locational importance, both in the supply stack and geographically. These generators are often neither the least- nor most-costly generators, but are needed to ensure the reliable operation of the power system and are more economic to commit than very costly generators. Given some operational inflexibility (such as minimum run times), these generators may need to operate during hours when energy market prices do not allow them to fully recover their production costs.

Pumped-storage generation was the only fuel type that received posturing uplift payments in 2019. This is different from 2018 when oil-fired generators received uplift credits during the cold snap. Coal-fired generators continued to receive small amounts of uplift, between 1%-3% ($0.8 to $2.8 million), annually. Oil-fired generators received lower share of uplift this year, 14% ($3.9 million) compared to 26% ($17.1 million) in 2018. Lastly, wind generators first started receiving relatively small amounts of uplift in 2017 and have received a steady 2% (between $0.2 million and $1.1 million) a year since, mainly comprising dispatch lost opportunity cost payments, which are paid when resources are instructed to run at levels below their economic dispatch point.

3.6 Demand Resource Participation in the Energy and Capacity Markets

On June 1, 2018, the ISO implemented the Price-Responsive Demand (PRD) program to integrate demand response resources into the day-ahead and real-time energy markets in order to comply with FERC Order 745 (Demand-Response Compensation in Organized Wholesale Energy Markets).[129] This program allows demand response resources to submit demand reduction offers into the day-ahead and real-time energy markets. With the program change, demand resources now are committed and dispatched in the energy market based on economics and are eligible to set price. Demand resources also provide operating reserves, in a manner similar to traditional generators. Along with energy market integration, active demand resources are now treated

[129] Prior to June 1, 2018, demand response resources participated in the ISO's energy markets (1) as emergency resources activated during OP4 system conditions (i.e., a capacity deficiency) in the real-time market and (2) through the Transitional Price-Responsive Demand (TPRD) Program in the day-ahead market.

similarly to other resources in the capacity market, having a must-offer obligation in the energy market for capacity with a CSO.

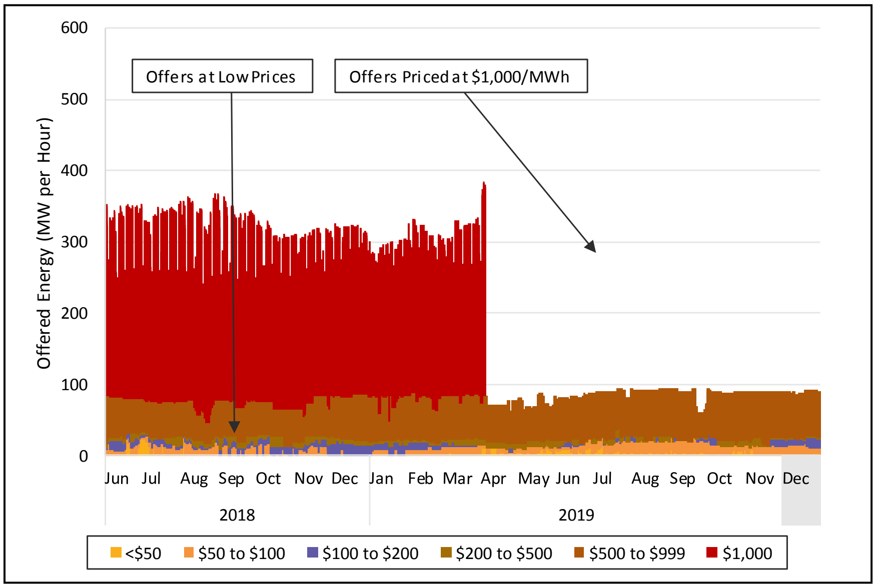
In 2019, participation in the PRD program followed trends observed during the initial implementation period in 2018:

- Most PRD resources primarily served as capacity and operating reserve resources available for dispatch at very high offer prices:
    - 75% of PRD capacity was offered at the energy market offer cap of $1,000/MWh in 2019; on average, 94% of offers have been priced above $200/MWh since the program's implementation;
    - Given offer prices, dispatch of these resources averaged just 5.5 MW in the day-ahead energy market in 2019; and,
    - With low dispatch levels, energy market revenues totaled just $1.6 million for 2019.
- PRD resources represented a modest amount of overall capacity procured in the ISO's forward capacity market:
    - PRD resources provided approximately 435 MW of total capacity in the capacity commitment period beginning June 1, 2019 (CCP 10) – an increase of 85 MW over the prior period;
    - The PRD resources accounted for 1.2% of the capacity supply obligations acquired in FCA 10; and,
    - Capacity payments provided to these resources totaled approximately $38 million in 2019.

3.6.1 Energy Market Offers and Dispatch under PRD

Under the Price-Responsive Demand (PRD) program implemented in June 2018, over 400 MWs of demand response resources participate in the day-ahead and real-time energy markets, more than 100 MWs higher than pre-PRD active demand response participation levels. However, consistent with pre-PRD participation, demand resources continue to predominately function as capacity deficiency resources, providing a source of high-priced energy and 30-minute operating reserves in the real-time energy market. Figure 3-43 below indicates hourly demand reduction offers in the day-ahead energy market, by offer price category for segment energy offers.

Figure 3-43: Demand Response Resource Offers in the Day-Ahead Energy Market

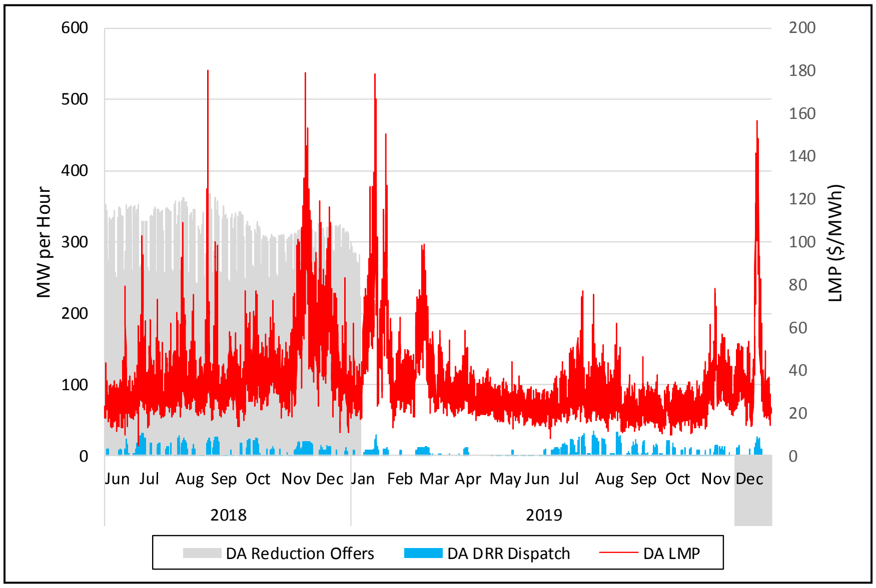


As indicated in the figure, most offers continue to be priced at the energy market offer cap of $1,000/MWh; 75% of offered capacity, on average, in 2019 and 72% in 2018. Only the lower tiers of offered capacity ($200/MWh or less) have a reasonable likelihood of being dispatched in the day-ahead energy market; these offers did not exceed 19% of offered demand reduction capacity in any hour of 2018 or 2019, and averaged just 6% of offered capacity.[130]

Given the pattern of offer prices for PRD, relatively small quantities are dispatched in the ISO's energy markets. Figure 3-44 below illustrates the hourly dispatch of Demand Response Resources (DRRs) in the day-ahead energy market, relative to resources' offered reductions and hourly energy prices.

[130] Energy prices in the day-ahead market did not exceed $200/MWh in any hour during the period of June 2018 to December 2019, and in the vast majority hours were below $100/MWh.

Figure 3-44: Demand Response Resource Dispatch in the Day-Ahead Energy Market



The maximum hourly quantity of demand response capacity dispatched in the day-ahead energy market was 31.2 MW in 2018 and 35.3 MW in 2019, representing about than 10% of offered demand reduction for those time periods. While demand resources were dispatched frequently in the day-ahead market - in 46% of hours in 2018 and 43% of hours in 2019– the dispatch level was very small, averaging just 7.7 MW in 2018 and 5.5 MW in 2019.[131]

As noted earlier, DRRs also provide a source of operating reserves in the real-time energy market. DRRs are considered fast-start capable, if those capabilities have previously been demonstrated. To be designated during the operating day as providing thirty-minute fast-start reserves, a DRR must offer certain operating constraints consistent with fast-start operation.[132] While DRRs can provide ten-minute reserves, that service requires interval metering with granularity of one minute or less, to be able to provide either non-synchronized (TMNSR) or synchronized reserves (TMSR). From June to December 2018, DRRs provided only 1.3 MW, on average, of ten-minute operating reserves, but provided substantially more in thirty-minute operating reserves (TMOR), averaging 147 MW per hour. In 2019, ten-minute reserve designations did not increase substantially, rising to only 1.7 MW on average, but total thirty-minute operating reserves (TMOR) increased to 224.4 MW per hour, partially reflecting new capacity added in 2019. This has had an upward impact on the total operating reserve margin, as discussed in Section 3.4.6.

3.6.2 NCPC and Energy Market Compensation under PRD

Demand Response Resources (DRRs) have received relatively modest energy market compensation. This results from low dispatch rates in the energy market and infrequent thirty-minute operating reserve pricing in the real-time energy market. When dispatched, DRRs are eligible to receive uplift payments (Net Commitment Period Compensation, NCPC). NCPC provides additional compensation

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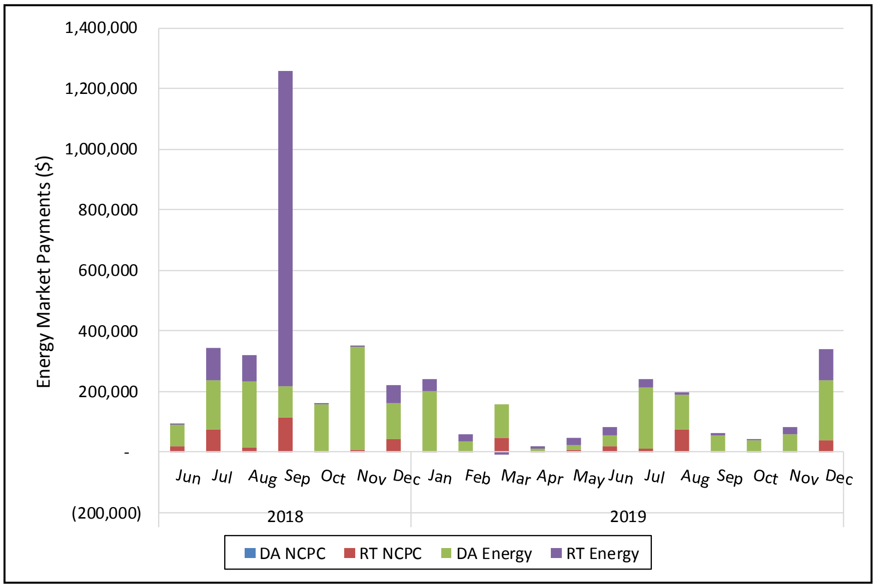
[131] Because real-time energy market dispatch is similar to day-ahead dispatch (with the exception of the capacity scarcity period on September 3), real-time dispatch is not displayed.

[132] These operating constraints are: total start-up time (including notification time) of less than or equal to 30 minutes, minimum time between reductions and a minimum reduction time of less than or equal to 1 hour, and a "claim 30" (30-minute reserve capability) greater than 0.

to resources when energy market revenues are insufficient to cover as-offered operating costs in the day-ahead and real-time energy markets. Figure 3-45 indicates energy and NCPC payments by month.

Figure 3-45: Energy Market Payments to Demand Response Resources



As indicated in the figure, both NCPC payments and energy market payments have been relatively small, since the implementation of PRD in June 2018. Payments for NCPC represent just 11% of total energy market compensation for DRRs, and total energy payments for 2019 were only $1.6 million. (This compares to energy market payments of $4.1 billion for all resources during the full year.) Except for the capacity scarcity event in September of 2018 (when many DRRs were providing either demand reductions or operating reserves), day-ahead energy market payments were the largest source of revenue.

3.6.3 Capacity Market Participation under PRD

For the Forward Capacity Market, DRRs have capacity supply obligations (CSOs) totaling approximately 435 MW, up by 85 MW (24%) on 2018.[133] These resources are called "Active Demand Capacity Resources" (ADCR) for capacity market purposes. All active demand resources with capacity market obligations are required to offer "physically available" capacity into the day-ahead and real-time energy markets.[134] Figure 3-46 indicates the CSO by participant for ADCRs.

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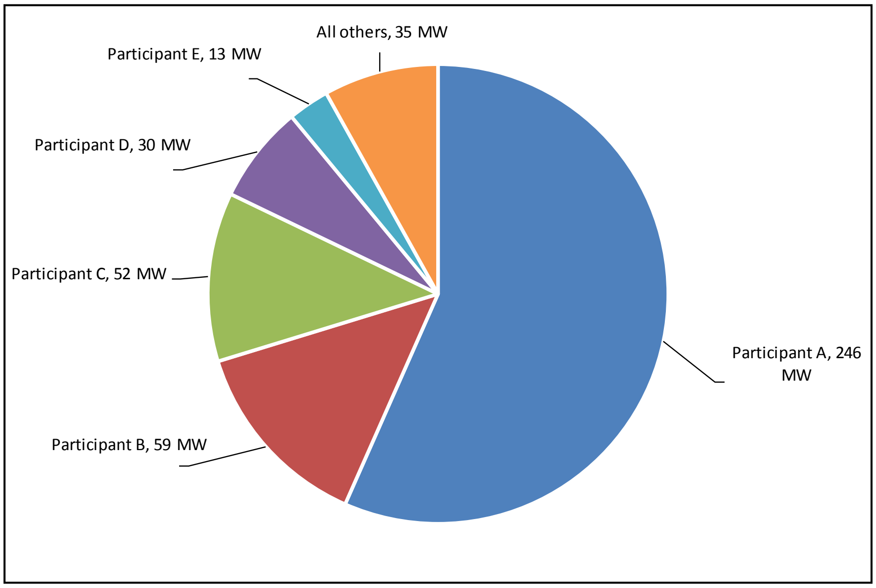
[133] The CSO estimate indicates the average capacity supply obligation for the first seven months of the 2019-2020 capacity commitment period (i.e., June – December 2019).

[134] The relationship between demand response resources (DRRs) and active demand capacity resources (ADCRs) is somewhat complicated. DRRs are mapped to ADCRs. More than one DRR can be mapped to an ADCR, which holds the capacity supply obligation. To satisfy the ADCR's capacity supply obligation, DRRs mapped to an ADCR need to offer demand reductions into the energy market at an aggregate level consistent with the parent ADCR's capacity supply obligation.

Figure 3-46: CSO by Lead Participant for Active Demand Capacity Resources



Just nine participants have CSOs; the two largest participants account for approximately 70% of ADCR capacity supply obligations. Capacity market compensation for the delivered obligations has totaled about $38 million, or about 23.8 times the amount of energy market compensation received by these resources.[135]

3.7 Market Structure and Competitiveness

Administering competitive wholesale energy markets is one of ISO New England's three critical roles. A competitive energy market is crucial to ensuring that consumers are paying fair prices that incent short-run and long-run investment that preserves system reliability. This section presents an evaluation of energy market competitiveness in New England. It covers (1) opportunities to exercise market power, (2) the market impact of uncompetitive (i.e. above cost) offers, and (3) measures to prevent the exercise market power.

Opportunities for market participants to exercise market power are examined using several metrics: the C4, the pivotal supplier test (PST), and the residual supply index (RSI). The C4, the combined market share of the four largest participants, is a measure of market concentration. In this section it is applied to both supply and demand to assess the level of structural competition in New England. Both the PST and RSI are widely used metrics to identify potential opportunities for the largest supplier to exercise market power at any given time. The RSI represents the percentage of demand that can be met without energy from the largest supplier's portfolio of generators. If the value is less than 100%, the largest supplier is necessary 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.

The Lerner Index is presented to estimate the *impact* of uncompetitive offer behavior in the day-ahead energy market. To produce the Lerner index, generator offers are replaced with estimates of

[135] The FCM compensation estimate focuses just on the payments for the actual obligation that these resources needed to deliver in 2019. It does not take into account any payment gains or losses that might have occurred from altering obligations through FCM bilateral and reconfiguration activities.

each generator's marginal cost and LMPs are re-simulated. The resulting value is an estimate of the LMP premium that is attributable to generators marking up their offers above marginal cost.

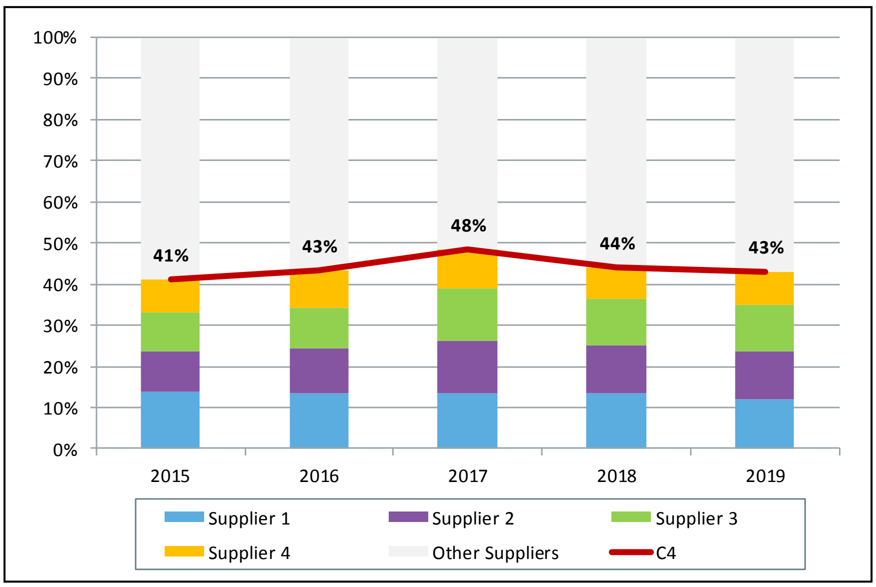
The IMM administers market power mitigation rules in the energy market to prevent potentially harmful effects of the exercise of market power. Mitigation is discussed at the end of this section.

3.7.1 C4 Concentration Ratio for Generation

This subsection analyzes supplier market concentration among the four largest firms controlling generation and scheduled import transactions in the real-time energy market. This measure, termed the "C4," is useful in understanding the general trend in supply concentration as companies enter, exit, or consolidate control of supply serving the New England region over time.

The C4 is the simple sum of the percentages of system-wide market supply provided by the four largest firms in all on-peak hours in the year and accounts for affiliate relationships among suppliers.[136] The C4 value expresses the percentage of real-time supply controlled by the four largest companies. As shown in Figure 3-47 below, the C4 value of 43% for 2019, a small decline from 44% in 2018 and from the average for 2015–2018.

Figure 3-47: Real-time System-wide Supply Shares of the Four Largest Firms



Note: The firms labeled "Supplier 1," "Supplier 2" and so on are not necessarily the same companies across all years; these are generic labels for the top four firms during a given year.

The C4 values of the last five years range between 41-48%, indicating low levels of system-wide market concentration in New England, particularly because the market shares are not highly concentrated in any one company. In 2019, the total supply of generation and imports during on-peak hours was about 65,000 GWh, of which about 28,000 (43%) came from the four largest suppliers. The same four suppliers made up roughly 44% of the total supply of generation in the day-ahead market. The red C4 trend line in Figure 3-47 shows no clear trend in the concentration

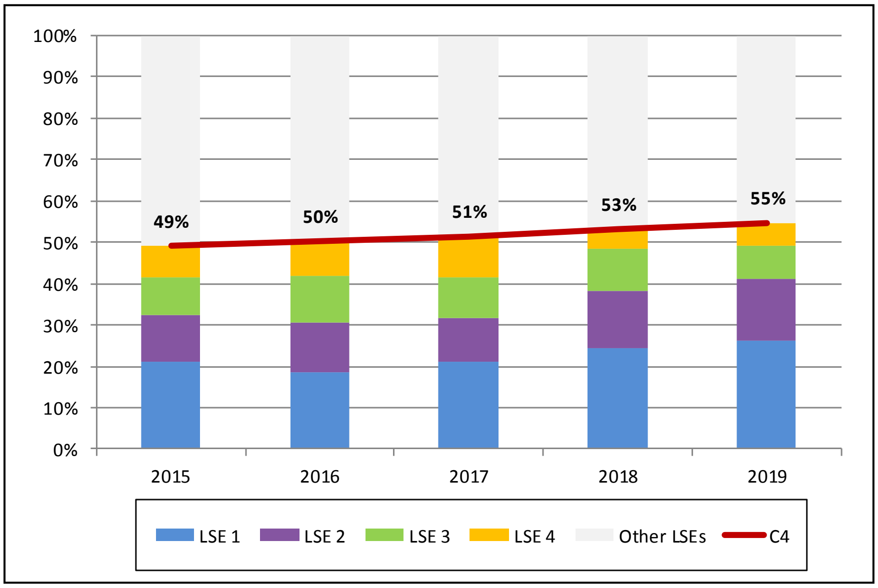
[136] On-peak hours are the 16 hours of each weekday between hour ending 8 and hour ending 23, except for North American Electric Reliability Corporation (NERC) off-peak days (typically, holidays). Affiliate relationships are based on IMM's research of controlling entities of power generators in New England using a combination of non-public ISO and public information.

ratio over the past five years. No one company maintains a dominant share of supply, and the split among the top four suppliers has remained stable.

3.7.2 Concentration Ratio for Load

This section takes the same C4 metric discussed in the previous section and applies it to real-time load. The C4 for load measures the market concentration among the four largest load-serving entities (LSE) in the real-time energy market. It also accounts for any affiliations among different LSEs. Figure 3-48 presents the results of the market share of the four largest LSEs along with the rest of market share during on-peak hours.

Figure 3-48: Real-time System-wide Demand Shares of the Four Largest Firms



Note: The firms labeled "LSE 1", "LSE 2" and so on are not necessarily the same LSE across all years; these are generic labels for the top four firms during a given year.

In 2019, the real-time load obligation (RTLO), or the amount of electricity purchased, was 64,078 GWh.[137] Overall, the four largest LSEs served 55% (35,048 GWh) of total load, 2% higher than their share in 2018. The red C4 trend line in Figure 3-48 shows that the total load share of the four largest LSEs has steadily increased over the past 5 years. In the day-ahead market, the same LSEs make up the top four firms, and together accounted for 56% (35,323 GWh) of total day-ahead load.

The C4 analyses presented here and in the previous section do not account for market participants with both load and generation position. These firms generally have less incentive to exercise market power. Any spot market actions that would tend to raise prices for their generation would come at a cost to their load position. Any actions that would suppress prices for load would come at a cost to their generation position.

The observed C4 values presented above indicate relatively low levels of system-wide market concentration, especially given the size of the New England market. The above figure shows that individual shares are not highly concentrated in any one company. Additionally, there is no

[137] Real-time load obligation is measured as all end-use wholesale load in the ISO New England region, along with all exports. The difference between this number and the real-time generation obligation should equate to energy losses.

evidence to suggest that LSEs exhibit any energy market bidding behavior that would suppress prices. Over 100% of demand clears in the day-ahead market and the aggregate demand curve is relatively price-insensitive around expected LMPs (see Section 3.4.4 on Demand Bidding).

3.7.3 Residual Supply Index and the Pivotal Supplier Test

The Residual Supply Index (RSI) identifies instances when the largest energy supplier has market power.[138] Specifically, the RSI measures the percentage of real-time demand (load and operating reserve requirements) that can be met without energy from the largest supplier's portfolio of generators. When the RSI is below 100, at least a portion of the largest supplier's generation is required to meet real-time energy demand. In such instances, the largest supplier is considered a "pivotal supplier" and has market power to unilaterally raise the real-time LMP. The pivotal supplier can set an uncompetitive market price by offering a portion of its supply above marginal cost (economic withholding), or by physically withholding capacity, and forcing the market to clear at a higher-than-competitive price. When the RSI exceeds 100, there is enough supply available to meet demand without any generation from the largest supplier. In this case, no individual supplier is pivotal and sufficient competition exists in the market.

This RSI analysis uses the same data that is used in the real-time pivotal supplier tests conducted by the ISO's real-time market software (the Unit Dispatch System, or UDS). A pivotal supplier test is performed before issuing generator dispatch instructions.[139] The test results are used in conjunction with the energy market mitigation process. The data used to calculate the RSI come from the real-time pivotal supplier test inputs. Based on these data the RSI for an interval t is calculated as follows:

$$RSI_t = \frac{Total\ Available\ Supply_t - Largest\ Supplier's\ Supply_t}{Load_t + Reserve\ Requirements_t}$$

In this analysis the average RSI for all the dispatch intervals in an hour are reported. Table 3-7 shows the hourly average RSI values and the resulting percentage of hours with at least one pivotal supplier for years 2015 to 2019.

Table 3-7: Residual Supply Index and Intervals with Pivotal Suppliers

Year	% of Hours with a Pivotal Supplier	RSI
2015	54%	96.8
2016	46%	100.8
2017	56%	99.3
2018	30%	103.4
2019	12%	107.1

[138] The RSI and pivotal supplier test presented here measure system-wide market power. There may also be presence of other forms of market power such as local market power in the real-time energy market.

[139] There are typically six to seven pivotal supplier tests conducted each hour coinciding with each run of the Unit Dispatch System.

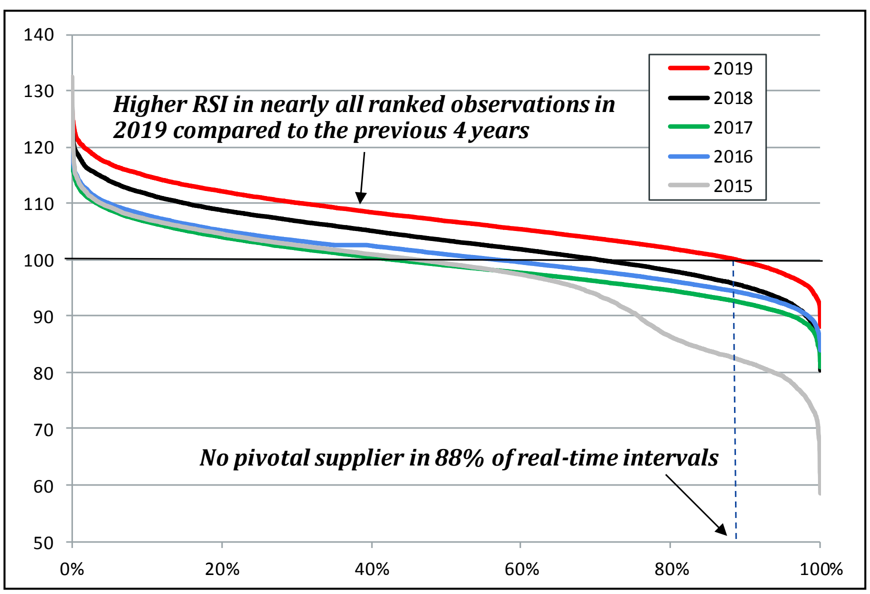
There were significantly fewer hours with a pivotal supplier in 2019 than in 2015-2018. This indicates that during 2019 suppliers faced relatively more competition compared to the past four years. The reduction in the number of intervals with at least one pivotal supplier appears to be driven by two factors: 1) the increase in the 2019 reserve margin, and 2) the absence of significant changes in participant portfolios that would increase supply-side market concentration.

The higher supply margin is evident in the higher level of 30-minute operating reserves in 2019 compared to 2018. The average total 30-minute reserve surplus was about 270 MW or 10% higher in 2019 compared to 2018. The capacity/reserve margin section (Section 3.4.6) discusses the 2019 increase, citing additional off-line reserves from new generators and demand response resources as drivers of increased off-line reserve margins. When reserve margins are higher, it is less likely that the available capacity of any one supplier is needed to satisfy load and reserve requirements. In 2018, nearly all (98%) suppliers were pivotal in fewer hours compared to 2017.

Additionally, 2019 did not see any significant changes in participant portfolios. Market concentration and opportunities to exercise market power can increase if participants with large volumes of capacity merge, but no notable activity occurred in 2019. The C4 concentration ratio for generation, discussed in Section 3.7.1, was 43% in 2019, similar to the 2018 value.

A duration curve shows the hourly RSI level over the year arranged in a descending order. Figure 3-49 shows the percent of hours, on an annual basis, when the hourly RSI was above or below 100 for the period between years 2015 and 2019. An RSI below 100 indicates the presence of at least one pivotal supplier.

Figure 3-49: System- wide Residual Supply Index Duration Curves



Like the pivotal supplier statistics, Figure 3-49 shows that there was greater availability of competitive supply in 2019 than in any other year in the reporting period, with the RSI above 100 in almost 90% of all hours.

3.7.4 Lerner Index

In a perfectly competitive market, all energy market supply offers would equal marginal cost. In reality, participants can raise their supply offers above marginal costs by a certain threshold before mitigation is applied. The Lerner Index estimates the extent to which marked-up supply offers influence LMPs by analyzing the divergence of the observed market outcomes from this ideal scenario. Since market competition incentivizes participants to offer at marginal cost, the Lerner Index provides insight into market power and competitiveness. Uncompetitive offers priced above marginal cost can distort prices and impact resource allocation decisions, leading to inefficient market outcomes.

To calculate the Lerner Index, the day-ahead market clearing was simulated using two scenarios:[140]

- Scenario 1 was an *offer case* that used the actual offers market participants submitted for the day-ahead energy market.
- Scenario 2 was a *marginal cost case* that assumed all market participants offered at an estimate of their short-run marginal cost.[141]

The Lerner Index (L) was then calculated as the percentage difference between the annual generation-weighted LMPs for the offer case and the marginal cost case simulations:

$$L = \frac{LMP_O - LMP_{MC}}{LMP_O} \times 100$$

where:

LMP_O is the annual generation-weighted LMP for the offer case

LMP_{MC} is the annual generation-weighted LMP for the marginal cost case

A larger L means that a larger component of the price is the result of marginal offers above estimates of their marginal cost.

The annual Lerner Index values from the simulation are shown in Table 3-8 below.

[140] The IMM uses the PROBE, or "Portfolio Ownership and Bid Evaluation," simulation model for this analysis. The software simulates the day-ahead LMP-based market clearing. See http://www.power-gem.com/PROBE.html. This is a more dynamic approach than calculating the difference between a static offer price and marginal cost. Rather, this approach re-runs the market optimization process with both as-offered and marginal cost supply curves, and calculates the difference in the resulting LMPs.

[141] The marginal costs estimates are based on underlying variable cost data and generator heat rate parameters used reference level calculations. Reference levels are calculated pursuant to Appendix A to Market Rule 1 of the ISO tariff and are used in market power mitigation analyses to represent a competitive offer. Where a good estimate of marginal cost does not exist (for virtual transactions for example) the marginal cost is set equal to the supply offer. Some differences between estimated and actual marginal costs are to be expected.

Table 3-8: Lerner Index for Day-Ahead Energy

Year	Lerner Index
2015	8.3
2016	8.2
2017	4.9
2018	4.9
2019	6.6

The 2019 Lerner Index for the day-ahead energy market remained relatively low at 6.6%. This indicates that offers above marginal cost increased the day-ahead energy market price by approximately 6.6%. This result is the similar to the 2018, and is consistent with normal year-to-year variation given modeling and estimation error.[142] This indicates that competition among suppliers in the day-ahead market limited their ability to inflate the LMP by submitting offers above marginal cost.

This analysis also calculated Lerner Index values at an hourly level, and compared the peak load hour Lerner Index with the forecasted supply margin at the peak. Comparing these attributes provides insight into whether participants are taking advantage of tight system condition by exercising increased market power during those times. There was no meaningful correlation between the Lerner Index and the supply margin in 2019, indicating that the day-ahead market remained competitive even when the ISO expected supply margins to be low and market power was present.

3.8 Energy Market Mitigation

Mitigation rules, systems, and procedures are applied in the day-ahead and real-time energy markets to attenuate the impact of uncompetitive generator offers. The mitigation rules are intended to prevent market prices from being set above competitive levels and avoid the potentially harmful effects of market power. When a participant's supply offer fails specific mitigation tests the offer is replaced with a competitive benchmark price known as the reference level. Generator reference levels are determined in consultation with the participant and are intended to reflect a competitive supply offer.[143]

This section provides an overview of the energy market mitigation tests and presents statistics on the occurrences of offer mitigation.

3.8.1 Types of Mitigation

There are eight types of energy market mitigation, each corresponding to a scenario where market power could be exercised. The two primary categories of mitigation are *commitment* scenarios and *energy* dispatch scenarios. Commitment mitigation pertains to generators that are started or kept

[142] Note that the IMM's estimates of marginal cost are an approximation of actual marginal costs, and the simulations used to calculate the Learner Index are subject to modeling differences when compared to the market model the ISO runs for the day-ahead market.

[143] There are three methodologies prescribed in Appendix A to Market Rule 1 for setting the reference level: (i) calculating the marginal cost of production, (ii) considering historical accepted supply offers, and (iii) using historical prices at the generator node. The IMM consults with the participant to determine the appropriate inputs to the marginal cost estimate. The highest value determined by these three methodologies is used to set the reference level except in certain circumstances.

on at the ISO's request. Energy mitigation evaluates online generators that are dispatched by the market software or manual instructions.

Determining whether a participant's supply offer must be mitigated involves up-to three tests depending on the applicable scenario: the structure, conduct, and impact tests.

Structure test. The market structure test evaluates the level of competition faced by a participant to determine whether they possess market power. A participant is deemed to have market power in any of three conditions. The first is when they are a *pivotal supplier* controlling resources needed to meet system-wide load and reserve requirements. The second condition is when their resource is in a *constrained area* of the system and has the ability to affect local area prices. And the third is when their resource is required to meet a specific *reliability need* such as voltage support; in this scenario the resource may be the only generator, or one of very few, capable of serving the need.

Conduct test. The conduct test checks whether the participant's offer is above its competitive reference level by more than the allowed thresholds. The allowed threshold, expressed as a percentage or dollar amount, depends on the type of market structure test that applies in the scenario. The threshold values are tightest for scenarios where opportunities to exercise of market power are most prevalent.

Impact test. The market impact test gauges the degree to which the participant's offer affects the energy LMP relative to an offer at its competitive reference level. The impact test applies to energy dispatch scenarios that require testing the incremental energy offers of online generators.

The participant's offer must fail all the applicable tests in order for mitigation to occur. When a generator has been mitigated, all three components of the offer (*i.e.*, start-up, no-load, and incremental energy) are replaced by the reference level values and mitigation remains in effect until the market power condition is no longer present.

An overview of energy market mitigation types and each of the tests applied for the scenario is provided in Table 3-9 below.[144] Where a certain test is not applicable it is noted in the table with the text "n/a." Note that the dollar and percentage thresholds specified for the conduct and impact tests are the values at which the participant's offer is determined to fail the test.

[144] Dual-fuel mitigation is excluded from the summary.

Table 3-9: 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	Reliability	10%	n/a
Start-Up and No-Load Fee	n/a	200%	n/a
Manual Dispatch Energy		10%	n/a

Most mitigation types are applied in both the day-ahead and real-time markets, but the few that are only applied in real-time are indicated by the "(real-time only)" note below the mitigation type name in Table 3-9. Except for manual dispatch energy, the energy mitigation types involve all three tests. For commitment mitigation, only the structure and conduct tests apply since the impact on LMPs is not relevant to commitment events. Energy and commitment mitigation types also differ in terms of the supply offer components evaluated. For energy mitigation, only the incremental energy segments of the supply offer are relevant. In commitment tests, the aggregate cost of start-up, no-load, and incremental energy at minimum output (*i.e.*, the commitment or "low load" cost) are evaluated over the commitment duration.

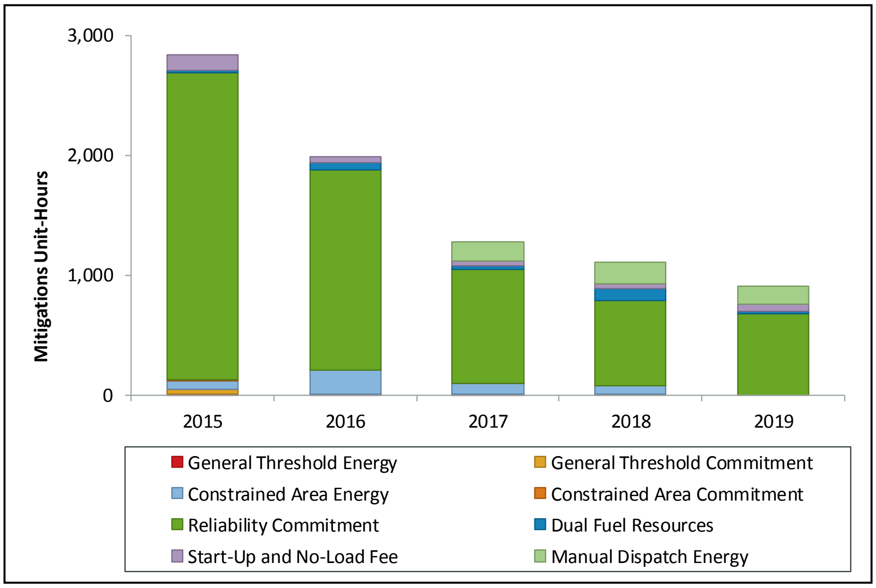
There is one additional mitigation type specific to dual-fuel generators not listed in Table 3-9 above. Dual-fuel mitigation occurs after-the-fact in cases where the supply offer indicated a generator would operate on a higher-cost fuel than it actually used (*e.g.*, if offered as using oil, but the generator actually ran using natural gas). This mitigation will affect the amount of NCPC payments the generator is eligible to receive in the market settlements.

3.8.2 Mitigation Event Hours

This section summarizes energy market mitigation occurrences for 2015 - 2019. For these summaries, each hour that the submitted offer for an individual generator was mitigated in either the day-ahead or real-time energy market is counted as one observation (i.e., the tallies represent unit-hours of mitigation). For example, if a single generator offer was mitigated for five hours when committed in the day-ahead market, the mitigation count for this day will be five unit-hours. If a second generator offer was mitigated on the same day for three hours during real-time, the total would then be eight unit-hours.

In 2019, the total amount of mitigations declined relative to earlier periods. There were 908 unit-hours when some form of mitigation was applied. This is 18% lower than the 1,104 total unit-hours that occurred in 2018. For context, if every available generator were mitigated in every hour in the day-ahead and real-time markets, there would be 5.4 million unit-hours of mitigation. The amount of 2019 mitigations is 0.02% of this total. Figure 3-50 below presents the annual tallies of mitigations by type for each year between 2015 and 2019.

Figure 3-50: Mitigation Events by Annual Period



The number of energy (i.e., non-commitment) mitigations decreased year-over-year in 2019 and also decreased relative to earlier years. Energy mitigations declined from 254 to 156 unit mitigation hours in 2019 compared to 2018. This decrease was the result of a significant decline in constrained area energy mitigations and a small decrease in "manual dispatch energy" mitigations.[145] The reduction in constrained area energy mitigations resulted in part from a large decline in instances when generators were located in import-constrained areas in the real-time energy market. Dual-fuel mitigations also decreased in 2019; these mitigations occurred more frequently in 2018 due to the cold snap and generally colder weather in Winter 2018.

Reliability commitment mitigations remained the predominant mitigation type, accounting for 74% (672 unit hours) of mitigation occurrences in 2019. The frequency of reliability commitment mitigation is consistent with the Energy Market Offer Flexibility rule changes that expanded the application of this mitigation test to scenarios where a generator remains online beyond the end its scheduled commitment.[146] During 2019, reliability commitment mitigations declined slightly to 672 unit-hours (a 5% reduction). Most commitment mitigations occurred in Maine and SEMA-Rhode Island (93% of reliability commitment mitigation hours), reflecting increased reliability commitments in those areas to support transmission work that required local supply to replace reduced local import capabilities.

[145] Manual Dispatch Energy (MDE) Mitigation is applied to generators dispatched manually, out-of-merit by the ISO. When the system operator manually dispatches a generator out of merit for any reason, and the energy offer segment prices exceed the 110% mitigation threshold (relative to LMP), a generator will be mitigated for a period of time equal to (1) the duration of the dispatch period, (2) its return to its economic minimum, or (3) the generator's offer price is equal to or less than the LMP.

[146] In 2018, the logic for mitigating generators that were held online beyond a scheduled commitment was slightly refined. Commitment mitigation no longer applies to the period when a generator is held online; only energy mitigation applies during this period.

Section 4
Virtual Transactions and Financial Transmission Rights

This section discusses trends in the use of two important financial instruments in the wholesale electricity markets: virtual transactions and financial transmission rights (FTRs).

The first type of financial instrument is a virtual transaction. Virtual transactions are financial bids and offers that allow participants to take a position on differences between day-ahead and real-time prices. Virtual transactions can improve market performance by helping converge day-ahead and real-time market prices. That is, virtual transactions can help ensure that the forward day-ahead market reflects expected spot prices in the real-time market, especially where systematic or predictable price differences may otherwise exist between them. However, virtual transactions are not costless – they are subject to NCPC charges that can often vary widely by day – and this cost can limit the ability of virtual transactions to perform this important market function.

In general, the volume of cleared virtual transactions has increased over the last five years as market rule changes have created opportunities for virtual transactions to profitably participate in New England's day-ahead energy market and NCPC charges have fallen. Virtual transactions yielded lower profits in 2019 than prior years, despite 2019 having the lowest NCPC charge rate in the last five years, as a result of diminishing price spreads between the day-ahead and real-time energy markets. Section 4.1 below provides more details about virtual transactions.

The second type of financial instrument is a financial transmission right or "FTR". These rights provide participants with physical generation or load in New England's energy markets a way to manage the risks associated with transmission congestion. They also provide market participants a way to speculate on locational congestion differences in the day-ahead market. FTRs are purchased through ISO-administered auctions. In 2019, ISO-NE increased the number of opportunities it provides market participants to procure FTRs via auction when it implemented the Balance of Planning Period (BoPP) project on September 17, 2019.

As a whole, FTRs were unprofitable in 2019 for the first time in the last five years. This indicates that less congestion materialized in the day-ahead market than was expected by FTR market participants and reflected through FTR auction clearing prices. The total profitability for FTRs fell from $26.7 million in 2018 to negative 10.5 million in 2019. A good portion of this change in profitability between 2018 and 2019 was driven by the participants' expectations for congestion over the New York – New England interface. Section 4.2 below discusses trends in FTRs.

4.1 Virtual Transactions

The first subsection (4.1.1) provides an overview of virtual transactions and describes how they can benefit the wholesale energy market. However, the ability of virtual transactions to provide these benefits can be hindered by the transaction costs placed on them. One of these costs comes in the form of Net Commitment Period Compensation (NCPC) charges. This is the topic of subsection 4.1.2. The third subsection (4.1.3) examines virtual transaction profitability and how NCPC charges affected that profitability.

One of the primary benefits virtual transactions can provide energy markets is to improve market efficiency, which, in this case, means achieving the commitments that are needed in the real-time market at the lowest possible cost. Market participants can, by following arbitrage opportunities, use virtual transactions to drive commitments made in the day-ahead market closer to the commitments that are needed in real-time. Improved commitment convergence is reflected through improved price convergence. The relationship between price convergence and virtual transaction volumes is examined in subsection 4.1.4. Lastly, subsection 4.1.5 summarizes some of the market rule changes implemented in New England's energy markets over the last five years that likely had an impact on the use of virtual transactions.

Key Takeaways

In general, the volume of cleared virtual transactions increased over the last five years; cleared transactions rose from 461 MW per hour in 2015 to 976 MW per hour in 2019, on average. Partly as a result of certain market rule changes, the increase in cleared virtual transactions has been particularly pronounced for virtual supply, which increased by 157% between 2015 and 2019. The increase in cleared virtual transactions is also related to the relatively low real-time economic NCPC charge rates over most of the reporting period. During the last four years, this rate averaged about \$0.82/MWh, and was particularly low in 2019, averaging around \$0.40/MWh. While lower NCPC charges helped virtual supply remain profitable in 2019 (average net profit of \$0.86/MWh), virtual demand made a net loss of \$1.59/MWh, on average.

4.1.1 Virtual Transaction Overview

In the New England day-ahead energy market, participants submit virtual demand bids and virtual supply offers to profit from differences between day-ahead and real-time LMPs. One of the primary benefits of virtual transactions is to improve the day-ahead dispatch model to better reflect real-time conditions.[147] Virtual demand bids and supply offers that clear in the day-ahead market (based on participants' expectations of future real-time system conditions) can improve the generator commitments made in the day-ahead market. This is because the commitments that result from the day-ahead market clearing with virtual transactions will better reflect market participants' *combined* expectations of real-time market conditions.

Virtual transactions that are profitable based on the price difference between the day-ahead and real-time markets generally improve price convergence. To see this, we can consider two examples. In the first example, day-ahead prices are systematically higher due to over-commitment in the day-ahead market. In this case, virtual suppliers (who are profitable when day-ahead prices are higher than real-time prices) can take advantage of the price difference by offering at lower prices than the physical generation, displacing some of it, while driving the day-ahead price downward toward the real-time price. In the second example, real-time prices are systematically higher due to under-commitment in the day-ahead market. In this case, virtual demand (which is profitable when real-time prices are higher than day-ahead prices) can take advantage of the price difference by bidding at higher prices than physical demand, resulting in more generation being committed in the day-ahead market, while driving the day-ahead price upward toward the real-time price.

Virtual bids and offers can be submitted into the day-ahead market at any pricing location on the system during any hour. Virtual transactions clear in the day-ahead market like other demand bids

[147] Virtual transactions provide other market benefits than those discussed here. One of the most significant is their ability to mitigate both buyer-side and seller-side market power through enhanced levels of competition. Additionally, virtual transactions increase the liquidity of the day-ahead market, which allows more participants to take forward positions in the energy market. Lastly, they can be used by participants as a way to manage/hedge the price risks associated with delivering or purchasing energy in the real-time energy market.

and supply offers (see Section 3.1 for more information). The ISO settles virtual transactions based on the quantity of cleared virtual energy and the difference between the hourly day-ahead and real-time LMPs at the location. Cleared virtual supply offers make a "gross" profit if the day-ahead price is greater than the real-time price (sell high, buy back low), and cleared virtual demand bids make a gross profit if the day-ahead price is less than the real-time price (buy low, sell back high).

The ISO allocates the following NCPC charges to cleared virtual transactions:[148]

1. **Real-time Economic NCPC**: all cleared virtual transactions (supply and demand) are obligated to pay a per-MW charge to contribute towards the payment of real-time economic NCPC because they are considered real-time deviations.
2. **Day-ahead Economic NCPC**: virtual demand bids are also charged day-ahead economic NCPC based on their share of day-ahead load obligation. This charge is typically much smaller because the total day-ahead economic NCPC is divided among a much larger quantity of energy.

In general, the total profit after these two NCPC charges are levied will be referred to as "net" profit in this section. These NCPC charges effectively serve as "transaction costs" for virtual transactions, reducing a virtual transaction's profit. Transaction costs can undermine price convergence when the expected magnitude in day-ahead to real-time price difference does not provide an adequate risk-adjusted return to offset the transaction costs. For example, if the expected spread (or gross profit) is $1/MW and the magnitude of NCPC charges (transaction cost) is uncertain, but may be greater than $1/MW, resulting in a net loss, then NCPC charges can discourage virtual participation, thus inhibiting price convergence. The IMM has recommended reviewing the allocation of NCPC charges to virtual transactions to ensure the charges are consistent with principles of cost causation and do not present a barrier to price convergence.

4.1.2 The Impact of Real-Time Economic NCPC Charges

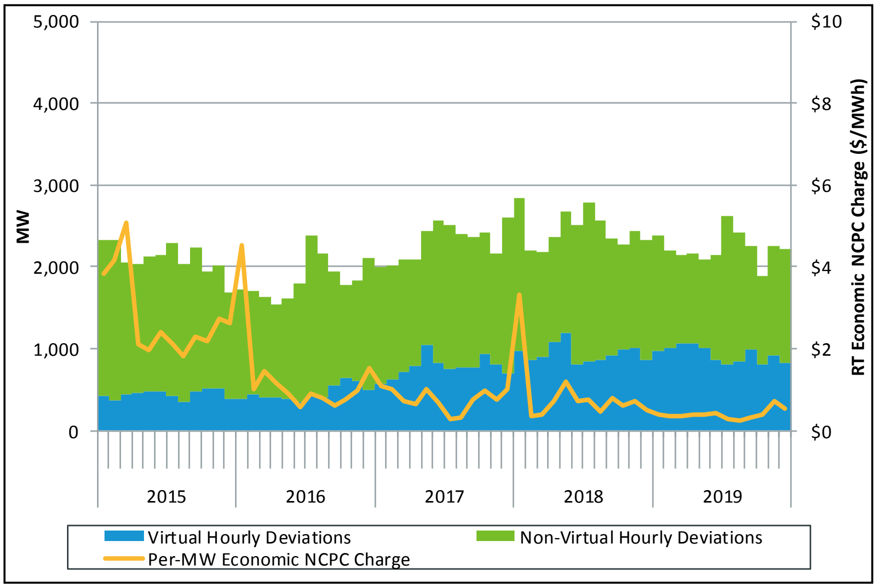
As mentioned above, real-time economic NCPC charges can impact participants' virtual transaction activity. The real-time economic NCPC charge rate is a function of the total amount of real-time economic NCPC credits and the total volume of deviations over which to allocate the credits. The total amount of real-time economic NCPC credits has trended downward over the last few years as new NCPC rules have taken effect. Some of these new NCPC rules are discussed in subsection 4.1.5. The total volume of deviations will depend partly on the volume of virtual transactions. As participants clear more virtual transactions, real-time economic NCPC charges are spread across more deviations and so the transactions that clear the market incur lower NCPC charges. This increases the ability of virtual transactions to profit from smaller price differences, which, in turn, may increase the volume of virtual transactions trying to arbitrage those price differences.

In general, virtual transactions have accounted for a larger share of real-time system deviations over the last five years as the level and variability of the real-time economic NCPC charge rate has diminished over the same period. The average hourly real-time system deviation (MW) by month is

[148] Virtual transactions can also receive NCPC charges associated with causing congestion at the external interfaces. These payments are transfers between the participants causing the congestion and those relieving the congestion and are only applied to transactions that clear at the external interfaces. Because these NCPC charges do not have a broad market impact or apply to virtual transactions at most locations, they are not considered in much detail in this report. However, they are accounted for in the determination of net profitability for virtual transactions in Table 4-1 and Table 4-2. The NCPC credits (i.e., revenue) associated with relieving congestion at the external interfaces are also accounted for in the determination of net profitability in these two tables.

shown over the last five years in Figure 4-1 below. This figure divides the system deviation by type (virtual or non-virtual), and also depicts the average hourly real-time economic NCPC charge rate ($/MWh).[149]

Figure 4-1: Average Hourly Real-Time Deviation MWs and Real-Time Economic NCPC Charge Rate



There are several key observations to be made from Figure 4-1:

- Virtual deviations (blue bars) have generally trended up over the five-year period to account for a larger share of average hourly deviations. However, virtual deviations have stayed relatively flat over the last two years of that period.
- The average real-time economic NCPC charge rate has been relatively low over the last four years, averaging about $0.82/MWh. The average charge rate was particularly low in 2019, averaging around $0.40/MWh.
- Real-time economic NCPC and associated deviation charges can still be somewhat volatile (e.g. in January 2018 the rate was $3.33/MWh).

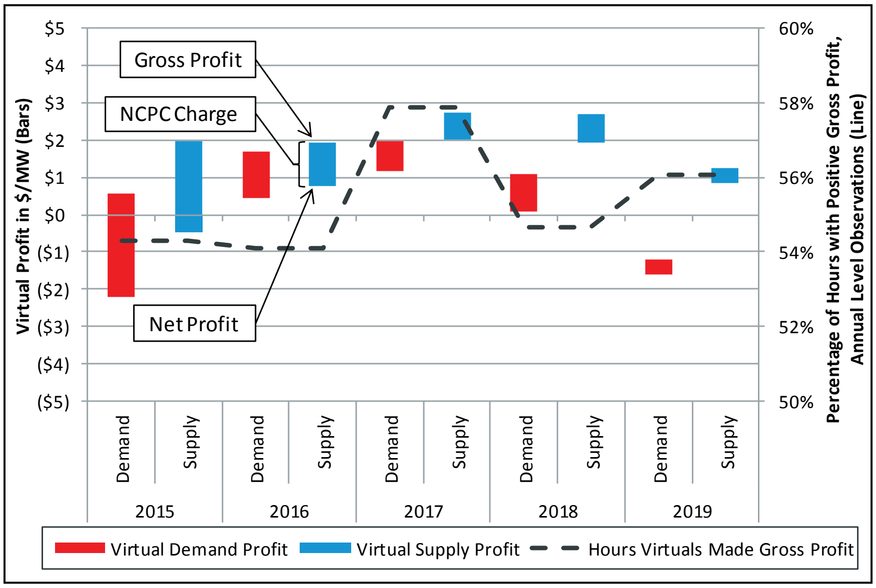
4.1.3 Virtual Transaction Profitability

NCPC charges can make profitable virtual transactions on a gross basis into unprofitable transactions on a net basis, limiting the ability of virtual transactions to close the spread between

[149] The series labeled virtual hourly deviations (blue) is not simply the sum of average hourly cleared virtual supply and average hourly cleared virtual demand. This is because, while virtual supply is always treated as its own real-time deviation, virtual demand is not. Virtual demand is included as a part of a participant's total real-time load obligation deviation and can therefore increase or decrease a participant's total deviations. Consequently, classifying the full amount of cleared virtual demand as a deviation would result in overstating the percent of the total system deviations that are attributable to virtuals and understating the percent of total system deviations that are not attributable to virtuals. The methodology for attributing real-time deviations to virtuals and non-virtuals that was used to develop **Error! Reference source not found.** accounts for this r elationship that virtual demand has on total system deviations.

day-ahead and real-time prices.[150] Figure 4-2 provides additional detail on the impact of NCPC charges on the profitability of virtual transactions. The figure displays the average annual gross and net profit of virtual transactions since 2015. The bars are categorized by year and type with virtual demand shown in red and virtual supply shown in blue. The top of each bar represents gross profit, the bottom represents net profit, and the length of the bar represents the per-MW NCPC charge. The net profits consider real-time economic NCPC charges for both virtual demand and virtual supply as well as day-ahead economic NCPC charges for virtual demand. In addition, the dashed black line shows the percentage of hours during the year that virtual transactions were profitable on a gross basis, computed annually.[151]

Figure 4-2: Gross and Net Profits for Virtual Transactions



In 2019, virtual supply had positive annual gross profits, on average, while virtual demand did not. This marked the first year in the last five years where only one of the virtual transaction types had a positive gross profit on average. However, even during years when both virtual transaction types have been profitable on a gross basis, they have often been net losses after accounting for NCPC charges. For example, both types of virtual transactions had positive annual gross profits in 2015, on average, but high NCPC charges that year resulted in negative net profits for both transaction types. The average annual NCPC charge has generally decreased year over year during the five-year reporting period. This reduction in NCPC charges is reflected in the diminishing length of the bars over the study period.

In 2019, virtual supply remained profitable after NCPC charges were levied, making a net profit of $0.86/MWh, on average, while virtual demand made a net loss of $1.59/MWh. Part of the reason that virtual demand was profitable in 2018 had to do with the very high real-time prices that were

[150] The NCPC charges to cleared virtual transactions are calculated after the market has cleared. Participants must have a sense of what their expected exposure to NCPC charges is before those charges are calculated and, of course, before submitting their virtual bids. Relationships drawn in the analysis here presume participants are able to fairly accurately predict exposure to NCPC charges, which may not always be the case given the variability of such charges and lack of information available to the participant in advance.

[151] The line is flat for observations in the same year because the value is computed as the number of hours that all virtual transactions together were profitable on a gross basis, as a percentage of total hours in the year.

observed on September 3, when the system experienced a capacity scarcity condition.[152] No such shortage conditions occurred in 2019, as discussed in Section 3.4.7. Virtual transactions were profitable on a gross basis in 56% of hours in 2019, up slightly from the prior year.

Most Profitable Locations for Virtual Demand

The top 10 most profitable locations for virtual demand in 2019, after accounting for ISO-NE transaction charges and all relevant NCPC charges/credits, are shown in Table 4-1 below.[153] These locations are ranked by total net profit over the course of the year. The table also includes information about the volume of submitted and cleared MWs of virtual demand bids at each location, the profitability per MW, and the number of participants submitting virtual demand bids at each location.

Table 4-1: Top 10 Most Profitable Locations for Virtual Demand

Location	Location Type	Submitted MW	Cleared MW	Gross Profit ($k)	Net Profit ($k)	Gross Profit Per MW	Net Profit Per MW	# of Participants
LD.HALVARSN345 SMDINTLD	Load Node	61,987	57,664	$126	$102	$2.19	$1.77	5
.I.SHOREHAM138 99	External Interface	29,639	28,824	$82	$72	$2.86	$2.49	4
UN.BERLN_NH13.8BURG	Generator Node	37,562	3,916	$34	$32	$8.77	$8.20	8
LD.W_AMESBY13.2	Load Node	11,915	10,984	$20	$15	$1.81	$1.35	7
LD.HIGH_ST 14.4511 LD	Load Node	15,094	11,361	$19	$13	$1.70	$1.18	2
LD.KING_ST 23	Load Node	1,815	1,790	$10	$9	$5.60	$5.13	4
UN.MYSTIC 18.1MYS8	Generator Node	16,156	9,225	$9	$5	$1.01	$0.58	2
.I.HQHIGATE120 2	External Interface	2,033	227	$(1)	$5	$(2.41)	$22.32	2
UN.POWERSVL115 GNRT	Generator Node	1,400	214	$5	$4	$21.49	$20.14	5
LD.W_AMESBY23	Load Node	1,171	1,143	$5	$4	$4.06	$3.61	5

The two most profitable locations for virtual demand in 2019 were at nodes located near the Cross Sound Cable (CSC), which is a high-voltage direct current cable that runs between Long Island and Connecticut. The node .I.SHOREHAM138 99 is ISO-NE's external proxy node, which is used for settling transactions between New England and New York over the CSC, while the LD.HALVARSN345 SMDINTLD node is the "first inward" node associated with the CSC in the New England control area. Participants at these nodes benefitted from a systematic difference in the loss components at these locations between the day-ahead and real-time markets. However, this modeling difference was remedied by ISO-NE in the middle of May 2019. In total, market

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[152] A capacity scarcity condition (CSC) is any five-minute interval in which the system is not meeting certain reserve requirements. See Forward Capacity MarketSection 6 for more information about these conditions and how they fit into the Pay for Performance (PFP) construct that exists in New England's Forward Capacity Market (FCM).

[153] The relevant NCPC charges/credits that are used in the calculation of net profitability for virtual transactions in Table 4-1 and Table 4-2 include not only the day-ahead and real-time economic NCPC charges discussed in detail in this section, but also the NCPC charges associated with causing congestion at external interfaces, as well as the NCPC credits (i.e., revenue) associated with relieving congestion at these same interfaces.

participants made a gross profit of $209 thousand and a net profit of $174 thousand by placing virtual demand bids at these two locations.

Many of the other most profitable locations for virtual demand in 2019 were at nodes located inside the Boston Import interface, an area that tends to experience positive congestion pricing. These nodes include: LD.W_AMESBY13.2, LD.HIGH_ST 14.4511 LD, LD.KING_ST 23, UN.MYSTIC 18.1MYS8, and LD.W_AMESBY23. Meanwhile, the net profit for virtual demand bids at .I.HQHIGHGATE120 2 was positive, despite negative gross profit, as a result of these virtual transactions receiving NCPC credits for relieving congestion at the Highgate Interface that connects the New England transmission system with Quebec.

In comparison to the most profitable locations for virtual supply (see below), the top 10 most profitable locations for virtual demand in 2019 were fairly lightly traded – both in terms of MW volumes and number of participants. Between two to eight different participants submitted virtual demand bids at these locations over the course of the year. While not shown in Table 4-1, some of the most active locations for virtual demand in 2019 (e.g., .H.INTERNAL_HUB, .Z.CONNECTICUT, .Z.NEMASSBOST) were some of the least profitable locations. In total, virtual demand transactions made a gross loss of $3.3 million in 2019 and a net loss of $4.4 million.

Most Profitable Locations for Virtual Supply

The top 10 most profitable locations for virtual supply in 2019, after accounting for transaction costs and NCPC charges/credits, are shown in Table 4-2 below. Again, these locations are ranked by net profit.

Table 4-2: Top 10 Most Profitable Locations for Virtual Supply

Location	Location Type	Submitted MW	Cleared MW	Gross Profit ($k)	Net Profit ($k)	Gross Profit Per MW	Net Profit Per MW	# of Participants
UN.OAKFIELD34.5OAKW	Generator Node	472,117	331,634	$940	$801	$2.83	$2.42	15
UN.BINGHAM 34.5BNGW	Generator Node	197,596	141,088	$479	$418	$3.39	$2.97	19
.I.SALBRYNB345 1	External Interface	363,628	280,779	$480	$369	$1.71	$1.31	12
.Z.MAINE	Load Zone	1,147,360	663,013	$596	$324	$0.90	$0.49	22
UN.ROLLINS 34.5ROLL	Generator Node	109,857	76,084	$279	$245	$3.67	$3.22	12
.H.INTERNAL_HUB	Hub	1,433,084	766,266	$546	$239	$0.71	$0.31	27
.Z.SEMASS	Load Zone	829,952	268,575	$351	$237	$1.31	$0.88	16
UN.STETSON 34.5STE2	Generator Node	119,671	68,841	$251	$219	$3.65	$3.17	11
UN.STETSON 34.5STET	Generator Node	79,865	54,413	$233	$207	$4.28	$3.81	11
.Z.RHODEISLAND	Load Zone	471,068	193,318	$271	$190	$1.40	$0.98	12

Many of the most profitable locations for virtual supply in 2019 were locations where wind power generators are interconnected. These locations include UN.OAKFIELD34.5OAKW, UN.BINGHAM 34.5BNGW, UN.ROLLINS 34.5ROLL, UN.STETSON 34.5STE2, and UN.STETSON 34.5STET. All wind generators are part of the set of resources known as DDGs, who operate under the DNE rules discussed below. These locations tend to be the most profitable given the opportunity virtual participants have to take advantage of the difference between day-ahead and real-time supply offers by DDGs. These locations tended to be competitive in 2019 with between 11 to 19 different participants offering virtual supply over the course of the year.

Table 4-2 also shows the magnitude of the transaction costs and NCPC charges. For example, based on the difference in day-ahead and real-time prices alone, virtual supply at the Hub made a gross profit of $546 thousand in 2019. The additional cost of allocated NCPC reduced the profitability of virtual supply at the Hub by more than 50% to $239 thousand. In total, virtual supply transactions made a gross profit of $7.4 million in 2019 and a net profit of $4.9 million.

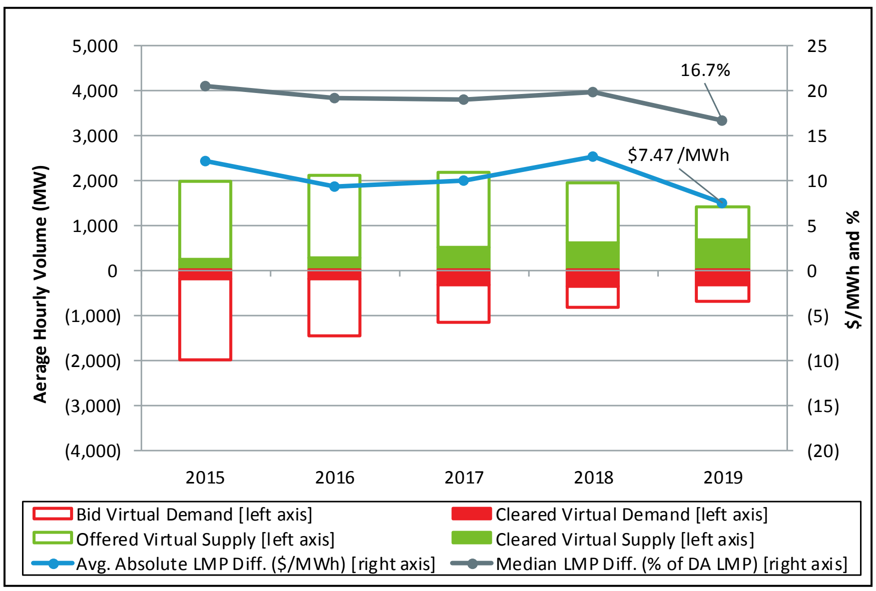
The Hub was the most active location for virtual supply in 2019 in terms of both the number of unique participants and the MW-volume of offers. Twenty-seven different participants submitted more than 1.4 million megawatts of virtual supply offers at the Hub in 2019.

4.1.4 Price Convergence and Virtual Transaction Volumes

The ability of virtual transactions to help converge prices between the day-ahead and real-time markets is considered to be one of the primary benefits of virtual transactions in a two-settlement system. The relationship between the volume of virtual transactions and the level of price convergence is shown in Figure 4-3 below. This figure presents two measures of price convergence:[154]

1) The mean absolute difference in $/MWh between the real-time and day-ahead Hub prices (blue line series).
2) The median absolute difference between real-time and day-ahead Hub prices as a percentage of the day-ahead Hub LMP (gray line series).

Figure 4-3: Virtual Transaction Volumes and Price Convergence



In 2019, the two measures of price convergence provide some evidence that the gap between day-ahead and real-time prices is narrowing, possibly helped by the increase in cleared virtual transactions. The average absolute price difference between the day-ahead and real-time Hub

[154] For both of these metrics, the price difference is the absolute value of the day-ahead and real-time price difference. The absolute value is used because we are interested in virtual transactions' potential impact on price convergence, including both positive and negative price differences. For the second metric, the price difference is divided by the day-ahead LMP to help normalize for systematic differences between prices in different years and the median is used to reduce the influence of outliers.

prices (blue line) was $7.47/MWh in 2019, the lowest level of the last five years. In the four prior years, this measure had fluctuated between $9.27/MWh (in 2016) and $12.58/MWh (in 2018). Price convergence also fell to its lowest level of the last five years as measured by the median absolute price difference between day-ahead and real-time Hub prices as a percent of the day-ahead Hub price (gray line). The median difference (as a percentage of the day-ahead Hub price) fell to 16.7% in 2019, down from the 19.8% observed in 2018. Section 3.3.4 discusses price convergence in more depth.

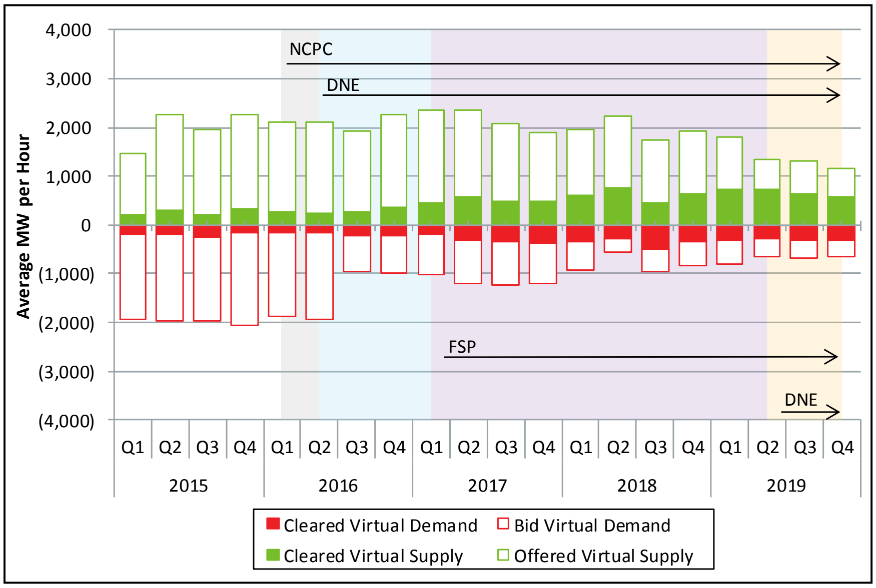
Virtual Transaction Volumes

In general, the level of submitted virtual transactions has fallen over the last five years, while the level of cleared virtual transactions has increased. In 2019, participants submitted an average of 2,095 MWs of virtual transactions per hour. This represents a 25% decrease from the 2,790 MWs of virtual transactions that were submitted, on average, per hour in 2018 and a 47% decrease from the 3,968 MWs that were submitted, on average, per hour in 2015. However, cleared virtual transactions have increased steadily over the last five years, rising from 461 MW per hour in 2015 to 976 MW per hour in 2019. In fact, in 2019 47% of submitted virtual transaction MWs cleared, which was the highest level of the last five years. The increase in cleared virtual transactions has been particularly pronounced for virtual supply, which has increased by 157% (from 260 MW per hour to 666 MW per hour) in this five-year period.

4.1.5 The Impact of Market Rule Changes

Over the last five years, numerous market rule changes have been implemented in New England's energy markets that have likely had an impact on, and created opportunities for, the use of virtual transactions. Among the relevant changes are: (i) modifications to the real-time commitment NCPC credit calculation, (ii) the implementation of Do-Not-Exceed (DNE) dispatch rules, and (iii) the implementation of Fast-Start Pricing (FSP). The period when each of these market rule changes took effect is depicted in Figure 4-4 below. This figure also shows the average hourly virtual transaction volumes by quarter over the period from 2015 through 2019, with virtual supply as positive values (in green) and virtual demand as negative values (in red). Each of these market rule changes is discussed in more detail below this figure.

Figure 4-4: Total Offered and Cleared Virtual Transactions by Quarter (Average Hourly MW)



Changes to NCPC rules

In February 2016 (gray shaded area), real-time economic NCPC payments made to generators with day-ahead commitments were eliminated, reducing the total pool of real-time economic NCPC paid. The average per-MW real-time NCPC charge was approximately $0.40 in 2019 versus $2.79 in 2015; the decrease in this average charge rates was driven by the February 2016 rule change, other market rules changes, and lower energy costs. The lower real-time economic NCPC equates to reduced transaction costs for virtual transactions. This may partly explain the increase in cleared virtual transaction volumes that can be seen in Figure 4-4 after this rule change went into effect.

Do-Not Exceed Dispatch Rules

Beginning in May 2016 (blue shaded area), certain wind and hydro resources became dispatchable under the Do Not Exceed (DNE) Dispatch rules. Under this change, DNE dispatchable generators (DDGs) can set price in the real-time energy market. DDGs tend to offer higher-priced energy in the day-ahead market due to a combination of factors, such as uncertainty about environmental and production conditions and terms under their power purchase agreements. Consequently, these generators often clear less day-ahead energy compared to their real-time production. In real-time, when there is more production certainty, these generators often reduce their offers and frequently set price.

This creates the opportunity for virtual supply to take advantage of the difference in day-ahead and real-time offer behavior. Since the implementation of DNE, virtual supply is frequently marginal in the day-ahead energy market in geographic areas with DDGs. In the real-time energy market, DDGs are frequently marginal in these same areas. The increase in cleared virtual supply after this rule change went in to effect is readily apparent in Figure 4-4.

Beginning in June 2019 (peach shaded area), ISO-NE implemented a requirement that all DDGs with Capacity Supply Obligations (CSOs) must offer the full amount of their expected hourly capability into the day-ahead energy market. This new requirement may reduce the opportunity for virtual transactions to participate in the day-ahead energy market in geographic areas with DDGs to the same extent as they did before this requirement went into effect. This is because this rule has triggered more participation of wind generators in the day-ahead market.

Fast-Start Pricing

In March 2017 (purple shaded area), new Fast-Start Pricing (FSP) rules went into effect. These changes more accurately reflect the cost of operating higher cost fast-start generators in the real-time market. The day-ahead market does not apply the FSP mechanics. Consequently, this change has the ability to increase real-time energy market prices relative to day-ahead prices, which may create more opportunities for virtual demand to converge prices.

In the case of DNE and FSP, virtual transactions provide an important service to the market as they help converge day-ahead and real-time prices by reflecting expectations for real-time operating conditions in the day-ahead market. Virtual supply prevents higher-cost generators from being committed in the day-ahead market that would not actually be needed in real-time because of the lower-cost DDG generation that shows up in real-time. Virtual demand prevents under-commitment in the day-ahead market thereby preventing the need to commit fast-start generators in real-time.

4.2 Financial Transmission Rights

The first subsection (4.2.1) provides an overview of Financial Transmission Rights (FTRs) and gives details about how participants can purchase and sell FTRs in the various auctions that ISO-NE conducts. It also discusses how FTRs can be used both as a financial tool to hedge the risk of transmission congestion for physical supply or demand or as a speculative instrument. At the end of this subsection is an overview of the Balance of Planning Period (BoPP) project that ISO-NE implemented in September 2019. The next subsection (4.2.2) delves into the volume of FTRs purchased and considers the supply and demand forces that impact these totals. This is followed by a subsection (4.2.3) that explores the funding of FTRs. The subsequent subsection (4.2.4) assesses the concentration of FTR ownership. The final subsection (4.2.5) examines the profitability of FTR holders in recent years, giving special attention to FTR paths that source from ISO-NE's external node for trading across the New York – New England interface.

Key Takeaways

Over the last five years, there has been a steady decrease in the average MW-amount of FTRs held by participants; this value in 2019 (31,981 MW) is 16% less than the amount in 2015 (37,958 MW). In 2019, FTRs were fully funded, as they were in each of the other years covered in this report. Meanwhile, the ownership of FTRs continued to be fairly highly concentrated in 2019 with around 60% of FTR MWs in both the on-peak and off-peak periods held by the top four participants. Additionally, 2019 was the first year in the last five years that FTR holders as a group were not profitable; together they lost $10.9 million in 2019. This comes after FTR holders made a profit of $26.7 million in 2018.

4.2.1 FTR Overview

FTRs provide participants with a way to hedge or speculate on transmission congestion in New England's day-ahead energy market. Congestion occurs when the power flowing across a transmission element reaches the limit of what that element can reliably carry. When this happens, the power system must be re-dispatched away from the least-cost solution that existed in the absence of that limiting element. Re-dispatching resources incurs additional production costs on the power system because the most economic generation isn't able to provide all the needed energy. The energy market reflects these additional costs through the congestion component of the LMP. FTRs provide participants with a mechanism to reduce their exposure to these additional costs.

Eligible bidders can obtain FTRs by participating in ISO-administered auctions for annual and monthly products. There are separate auctions for on-peak and off-peak hours.[155] The FTRs awarded in the two annual auctions have a term of one year, while the FTRs awarded in one of the monthly auctions have a term of one month. FTRs can be purchased in all auctions, but can only be sold in the second annual auction or the monthly auctions as only FTRs that are owned (i.e., have been purchased) can be sold by participants (i.e., there is no short selling). Five important elements in a bid to purchase an FTR are summarized in Table 4-3 below.

Table 4-3: Elements of an FTR Bid

Element	Description
Path	FTRs are defined between two points (locations) on the electrical system: 1) the point of withdrawal or the "sink" and 2) the point of injection or the "source"
Price	The $/MW value the participant is willing to pay to acquire the FTR
MW-amount	The size of the FTR (in MWs) the participant is willing to buy
Term	The monthly or annual period to which the FTR applies (e.g., November 2019)
Period	The hours in which the FTR applies (i.e., on-peak or off-peak)

Once awarded, 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 occur when the congestion component of the sink location is greater than the congestion component of the source location in the day-ahead energy market. Positive target allocations amount to a credit to FTR holders. Negative target allocations occur in the opposite situation and equate to a financial liability to FTR holders. FTR settlement occurs on a monthly basis. Payments to FTR holders with positive target allocations come from day-ahead and real-time congestion revenue and from FTR holders with negative target allocations.

Hedging vs. Speculating

To see how an FTR could be used to hedge congestion risk, we can consider a simple example of a load-serving entity (LSE) located in an import-constrained area (i.e., an area prone to positive congestion) that has entered into an annual contract to buy energy at the day-ahead Hub price. This contract locks-in the energy component of the price that the LSE must pay, but not the congestion component. Absent ownership of an FTR, the LSE still bears the congestion cost risk associated with serving load in an area prone to positive congestion. The LSE can lock-in the congestion component as well by participating in the annual on- and off-peak FTR auctions. Purchasing an FTR from the Hub to the zone where it serves energy in both these auctions entitles the LSE to the difference in the congestion components at these locations over the course of the year. The positive target allocations that accrue to the FTRs that the LSE holds offset the day-ahead congestion costs that the

[155] On-peak hours are defined by the ISO as weekday, non-holiday hours ending 8-23. The remaining hours are off-peak hours.

LSE incurs in the zone where it serves load. The cost required to hedge this congestion risk is the price the LSE paid to purchase these FTRs.

FTRs can also be purchased as a completely speculative instrument. For example, a market participant that has no load or generation position may want to purchase an FTR solely because it expects a certain amount of positive target allocations to accrue along a specific path.[156] This transaction would be profitable if the participant is able to purchase the FTR at a cost that is less than the revenue realized from holding the FTR. Such activity is not without risk, as expected patterns of congestion may not actually appear in the day-ahead market. In such cases, FTRs can quickly change from being a financial benefit to a financial obligation requiring payment. This sort of trading is considered speculative because it is an attempt to profit by engaging in a risky financial transaction that isn't tied to any physical position in the ISO-NE marketplace. Speculative trading is permitted in FTR auctions because of the liquidity and competition it provides.

Balance of Planning Period Project (BoPP)

On September 17, 2019, ISO-NE implemented the Balance of Planning Period (BoPP) project for FTRs. This project increased the number of opportunities that market participants have to reconfigure their monthly FTR positions following the two annual auctions. Prior to the implementation of this project, market participants could only purchase or sell FTRs for a specific month in an auction that occurred during the month prior to that effective month. For example, if a market participant wanted to buy FTRs that would be effective for December 2019, it would have to wait until the monthly auction that took place in November 2019. Under the BoPP design, ISO-NE now administers monthly FTR auctions for not just the next month (now called the prompt-month auction), but also for all the other months remaining in the calendar year (called the out-month auctions). This means that a participant who wants to buy December 2020 FTRs no longer has to wait until November 2020; it can purchase these FTRs in any of the out-month auctions that take place earlier in the year. However, the out-month auctions don't make available any additional network capacity than was made available in the second annual auction (in contrast to the prompt-month auctions, which do make additional capacity available).[157] The volume of FTR transactions in the out-month auctions in 2019 was fairly low, as can be seen in some of the later figures.

4.2.2 FTR Market Volume and Supply and Demand

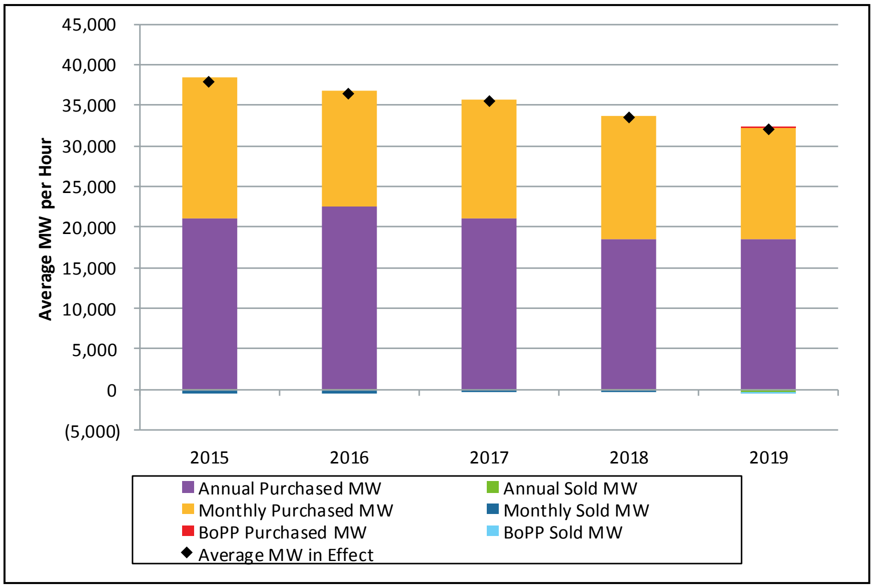
Fewer FTRs (by MWs) were in effect per hour, on average, in 2019 than in 2018, continuing a trend of steady decreases in FTR MWs that has occurred over the last five years. This trend can be seen in Figure 4-5, which shows the average MW volume of FTRs that were in effect each hour by year

[156] This example is for a *prevailing flow* FTR, which is an FTR whose path is defined in the direction that congestion is expected to occur based on FTR auction clearing prices. The holder of a prevailing flow FTR pays to acquire that FTR and then expects to receive positive target allocations as congestion occurs in the day-ahead energy market. Alternatively, a speculator could acquire a *counterflow* FTR. An FTR purchased at a negative price in an auction is called a counterflow FTR because its path is defined in the opposite direction that congestion is expected to occur based on the FTR auction clearing prices. The auction pays the counterflow FTR holder to take on this counterflow position, and this position will be profitable to the counterflow FTR holder if the total negative target allocations for this FTR are less than this payment from the auction.

[157] The first round of the annual auction makes available 25% of the transmission system capability. The second round of the annual auction makes available an additional 25%, meaning that a total of 50% of the network capability is sold in the two annual auctions. The prompt-month auctions make available an additional 45% of the network capability, meaning that 95% of the network capability is sold by the time the effective month arrives. The out-month auctions do not make available any additional network capability beyond that which was made available in the second round of the annual auction. However, FTRs can still be purchased in the out-month auctions on paths that weren't completely subscribed in the second annual auction, as the result of counterflow FTR purchases, or as the result of FTR sales.

between 2015 and 2019 as black diamonds.[158] This figure also shows the average hourly MW volume of FTRs purchased and sold by auction type during each year.

Figure 4-5: Average FTR MWs in Effect per Hour by Year



Market participants had an average of 31,981 MWs of FTRs in effect per hour in 2019. This represents a 4% decrease from the average amount of FTRs in effect in 2018 (33,444 MW) and a 16% decrease from the average amount in effect in 2015 (37,958 MW). FTR MW purchases fell by 16% over the five-year reporting period; participants purchased an average of 38,472 MWs of FTRs per hour in 2015 but only 32,235 MWs per hour in 2019. The decrease in FTR purchases is particularly pronounced in the monthly auctions, where the average purchase volume dropped by 21% over the reporting period (from 17,367 MWs per hour in 2015 to 13,746 MWs per hour in 2019). FTR holders sell very few FTRs each year, as can be seen below the horizontal axis in Figure 4-5.

Supply and Demand

The demand for FTRs is primarily driven by participants' expectations of congestion in the day-ahead market. If participants expect less day-ahead congestion than prior years, their need to purchase FTRs to hedge against this congestion may decrease. The volume of FTR purchases is also particularly dependent on the variability of participants' expectations of congestion. For example, if participants have similar expectations for congestion in a certain year, the set of FTR paths that they bid on is likely to be fairly limited, which would result in fewer FTRs being purchased. Additionally, participants may be unwilling to take counterflow FTR positions if they hold comparable outlooks.[159] On the other hand, if participants have a diverse range of expectations for

[158] The averages here are hourly-weighted MW volumes. This weighting accounts for the fact that there are more off-peak hours than on-peak hours in a year. The hourly-weighted average MW volume of FTRs in effect each year represents the hourly-weighted average MW volume of FTRs purchased less the hourly-weighted average MW volume of FTRs sold.

[159] The purchase of counterflow FTRs is important because it impacts the supply of FTR MWs. This is because every MW purchased on a counterflow path (say from B to A) allows participants to buy an additional MW of the prevailing flow path (in this case, A to B).

congestion, the set of FTR paths that they bid on is likely to be larger, and more participants may be willing to take counterflow positions.

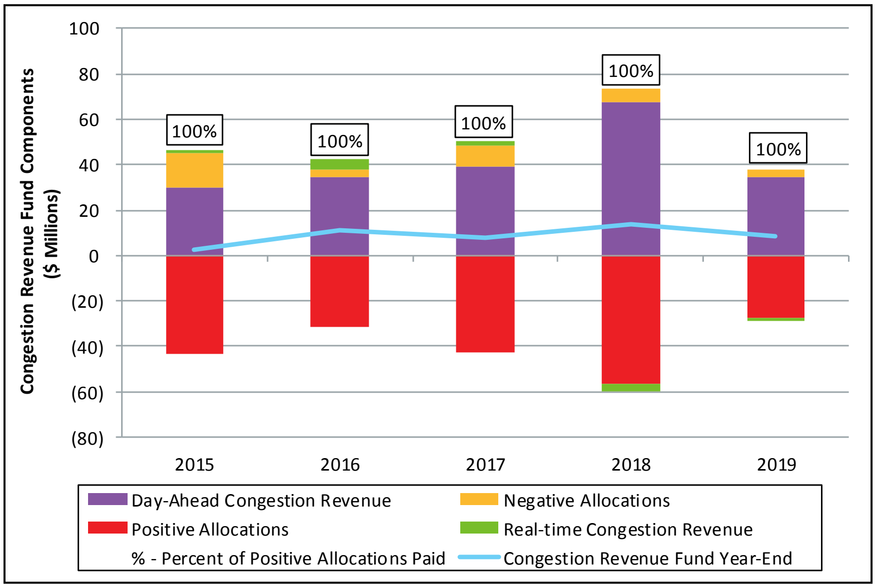
The supply side of the FTR market is predominantly dependent on the physical capability of the transmission system. The amount of FTRs awarded by the ISO in each auction depends on a market feasibility test that ensures that the awarded set of FTRs respects the transmission system's limits under normal and post-contingent states. This test is performed in order to increase the likelihood of revenue adequacy, which means that the FTRs are fully funded; in other words, that there is sufficient congestion revenue collected in 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.

4.2.3 FTR Funding

Theoretically, the values of the transmission constraints that are modeled in the FTR auctions should closely match the values used in the day-ahead market. To see why this is significant, we can consider two cases: 1) the FTR auction values are high relative to the day-ahead market values and 2) the FTR auction values are low relative to the day-ahead market values. In the first case, there may not be enough revenue collected in the day-ahead market to pay FTR holders (i.e., more congestion materialized than the market anticipated and FTR holder revenues are reduced pro rata). This would mean that FTRs were not fully funded. In the second case, there may be an excess of congestion revenue collected relative to the payments owed to FTR holders (i.e., the transmission system was undersold). This might mean that energy market participants were not fully able to hedge their day-ahead market positions because the FTRs they wanted to purchase were limited. The result in this case would be the congestion revenue fund ending the year with a positive balance.

One indication that the limits used in the FTR auctions may be low relative to their day-ahead values can be seen in Figure 4-6 below, which shows the year-end balance of the congestion revenue fund for the last five years (the blue line). This figure also shows the different components that make up the congestion revenue fund, and provides the percent of positive target allocations that were paid each year (indicated by number above each stacked column). A value of 100 percent indicates that the FTRs were fully funded that year.

Figure 4-6: Congestion Revenue Fund Components and Year-End Balance by Year



For each of the last five years the congestion revenue fund has ended up with excess revenue at the end of the year (i.e. they have been fully funded). In 2019, the fund had a year-end balance of $8.7 million. This means that 25% of the day-ahead congestion revenue from 2019 ($34.4 million) remained in the fund at end of the year.[160] After being used to pay any FTRs that may have been underfunded during the year, this surplus is then allocated to entities that paid congestion costs during the year in a proportion to the amount of congestion costs they paid.[161]

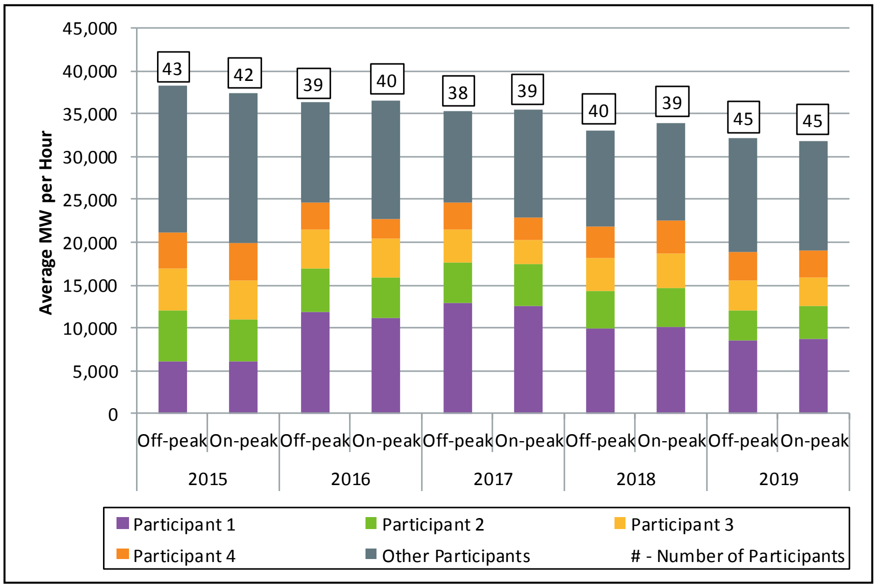
4.2.4 FTR Market Concentration

The concentration of ownership of FTRs among market participants in 2019 was similar to prior years. The average amount of FTRs held per hour by the top four participants with the most MW each year is shown in Figure 4-7 below. Also included in this figure is the number of participants that held FTRs each year (indicated by the number above each stacked column).This figure provides information for both the on-peak and off-peak periods.

[160] The congestion revenue fund is discussed in more detail in Section 3.4.9.

[161] See Section III.5.2.6 of Market Rule 1 for more information.

Figure 4-7: Average FTR MWs Held by Top Four FTR Holders per Hour by Year and Period



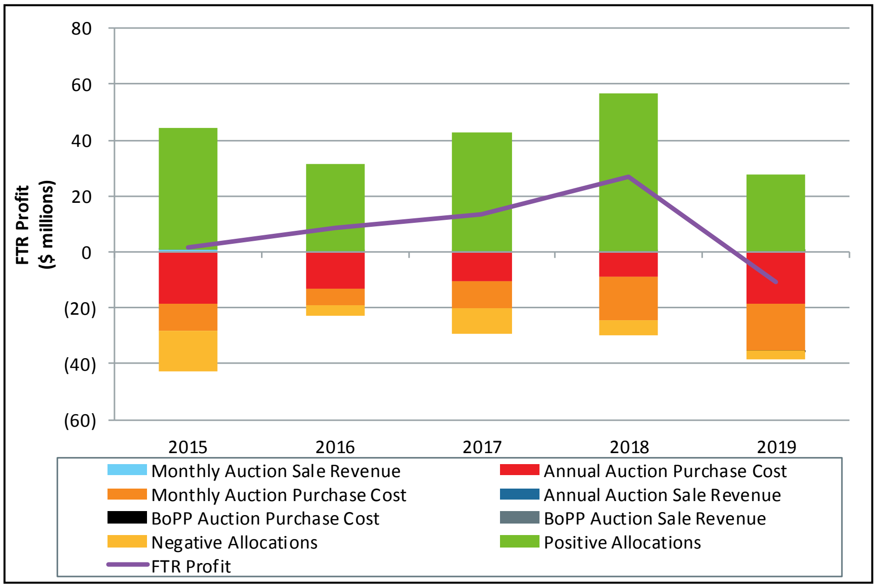
Note: The firms labeled "Participant 1," "Participant 2" and so on are not necessarily the same companies across all years; these are generic labels for the top four firms during a given year.

In 2019, the percentage of on-peak FTR MWs held by the top four participants was 60%. This ratio is often referred to as the C4. The off-peak concentration ratio of the top four FTR holders in 2019 was similar to the on-peak; the top four participants held 59% of the off-peak FTR MWs. The concentration ratio of the top four FTR holders has held relatively steady over the five-year report horizon, ranging between 53% and 70% depending on the period (i.e., on-peak or off-peak) and year. The total number of unique FTR holders has also stayed relatively steady over the reporting period, ranging between 38 to 45 different companies.

4.2.5 FTR Profitability

For the first time in the last five years, FTRs were not profitable in 2019, even after the disbursement of excess congestion funds. Profit in the FTR market is measured as the sum of the positive target allocations and the revenue from FTR sales, minus negative target allocations and the cost of FTR purchases. Each of these components, as well as total profit (purple line), can be seen in Figure 4-8 below.

Figure 4-8: FTR Profits and Costs



In 2019, the total loss from FTRs was $10.5 million (purple line), which is a decrease of $37.2 million from 2018, when total FTR profit was $26.7 million. Two primary factors led to the decrease in FTR profitability in 2019:

1. Positive target allocations *decreased*. Payments to FTR holders with positive target allocations decreased by $28.7 million in 2019 ($27.5 million) relative to 2018 ($56.2 million). Positive target allocations in 2019 were at their lowest level of the last five years.
2. FTR purchase costs *increased*. Participants spent $10.9 million more to procure FTRs in 2019 than they did in 2018. The increase in purchase costs was particularly notable in the annual auctions, where participants increased their FTR expenditures by 117% between 2018 ($8.7 million) and 2019 ($18.8 million).

Most Profitable FTR Paths

Significant investment in transmission infrastructure over the past ten years, targeted primarily at import-constrained areas, has reduced the amount of positive congestion in the New England footprint. However, the growth in wind power, the implementation of Coordinated Transaction Scheduling (CTS) at the New York North interface (see Section 5), and other factors have led to more export-constrained areas, which, in turn, has led to more negative congestion. This is reflected in Table 4-4 below, which provides information about the most profitable FTR paths in 2019.

Table 4-4: Top 10 Most Profitable FTR Paths in 2019

Source Location	Sink Location	Purchase Amount ($k)	Sale Amount ($k)	Positive Target Allocations ($k)	Negative Target Allocations ($k)	Profit ($k)
UN.PONTOOK 34.5PONT	LD.LOSTNATN34.5	$(212)	$27	$674	$-	$489
UN.PONTOOK 34.5PONT	LD.WHITEFLD34.5	$(172)	$-	$523	$-	$351
UN.KIBBY 34.5KIBY	LD.WINSLOW 34.5	$(4)	$-	$251	$-	$247

Source Location	Sink Location	Purchase Amount ($k)	Sale Amount ($k)	Positive Target Allocations ($k)	Negative Target Allocations ($k)	Profit ($k)
UN.BERLN_NH34.5GORH	LD.LOSTNATN34.5	$(118)	$7	$348	$-	$237
UN.POWERSVL115 GNRT	.H.INTERNAL_HUB	$(1,003)	$-	$1,261	$(23)	$235
UN.STETSON 34.5STE2	UN.ENFLD_ME115 IND5	$(224)	$125	$249	$-	$151
UN.WYMAN_HY13.8WYM2	LD.WINSLOW 34.5	$(20)	$-	$146	$(0)	$126
.Z.SEMASS	.H.INTERNAL_HUB	$126	$-	$0	$(23)	$104
UN.WYMAN_HY13.8WYM2	LD.DETROIT 34.5	$(19)	$-	$120	$(0)	$101
UN.OAKFIELD34.5OAKW	LD.BUCKSPRT34.5	$(59)	$-	$159	$(0)	$100

Many of the profitable FTR paths in 2019 were prevailing flow FTR paths that sourced from locations that tend to be export-constrained, making them more prone to negative congestion pricing. In fact, this was true for nine of the top 10 most profitable FTR paths in 2019. The two most profitable FTR paths in 2019 were paths that sourced from UN.PONTOOK 34.5PONT. This is a location in the northern part of New Hampshire that often experiences negative congestion pricing as a result of a number of intermittent resources competing to use limited transmission capability.

In some cases, counterflow FTRs were also profitable in 2019. As can be seen in Table 4-4, the counterflow FTR path from .Z.SEMASS, the node for the Southeast Massachusetts load zone, to .H.INTERNAL_HUB was one of the most profitable FTR paths in 2019. For the year, FTR holders were paid $126 thousand to hold FTRs on this path. These FTRs only incurred $23 thousand of negative target allocations, rewarding the holders of this path with a profit of $104 thousand. The prevailing flow version of this FTR (i.e., sourcing at the .H.INTERNAL_HUB and sinking at .Z.SEMASS) was actually the second least profitable FTR path in 2019. Collectively, participants spent $2.8 million to buy FTRs on this path but earned relatively little in positive target allocations ($765 thousand). The net result was that participants made a financial profit of -$2.1 million on this path in 2019.

Congestion across the New York – New England Interface

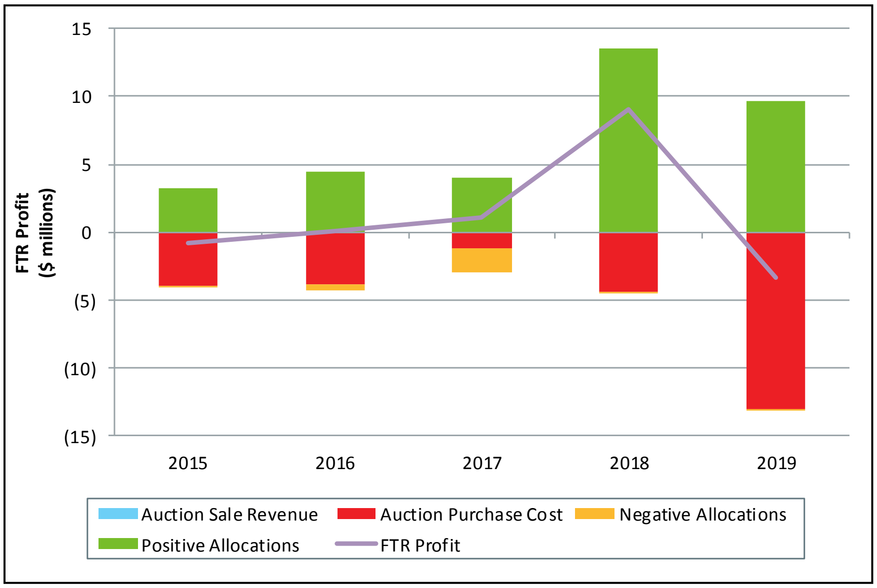
The least profitable path in 2019 was the path that sourced from .I.ROSETON 345 1, ISO-NE's external node for trading across the New York – New England interface, and sank at the .H.INTERNAL_HUB.[162] Participants acquired FTRs along this path for $12.7 million but they only yielded positive target allocations of $9.5 million, earning holders of these FTRs a loss of $3.2 million.[163] This is in stark contrast to 2018, when this path was the most profitable path. In 2018, participants were able to acquire FTRs along this path for $4.2 million, and they yielded positive target allocations of $12.0 million, earning holders of these FTRs $7.9 million in profit.

[162] The New York – New England interface is sometimes referred to as the New York North interface, the New York Northern AC interface, or the Roseton interface.

[163] Several of the largest MW holders of FTRs that sourced from .I.ROSETON 345 1 were also the largest MW importers of physical power across the New York – New England interface in 2019. These companies may be using these FTRs as a hedging tool to help manage basis risk between the two control areas.

The change in profitability for FTRs sourcing from .I.ROSETON 345 1 between 2018 and 2019 contributed significantly to the overall market outcomes. Figure 4-9 shows the purchase costs, sale revenue, and positive and negative target allocations for all FTRs that sourced from .I.ROSETON 345 1 by year over the last five years. Also shown in this figure is total profit for this set of FTRs, which is shown by the purple line.

Figure 4-9: FTR Profits and Costs for FTRs Sourcing from .I.ROSETON 345 1



The profitability of FTRs sourcing from .I.ROSETON 345 1 decreased by 137% between 2018 ($9.1 million) and 2019 (-$3.4 million). Perhaps in response to the profitability of these FTRs in 2018, participants paid considerably more (193%) more to acquire FTRs sourcing from .I.ROSETON 345 1 in 2019 ($13.0 million) than they did in 2018 ($4.5 million). This increase in expenditure was a significant reason for the decrease in profitability, as the positive target allocations that accrued to these FTRs only decreased by 29% between 2018 ($13.6 million) and 2019 ($9.6 million). To provide some perspective, the purchase costs for FTRs sourcing from .I.ROSETON 345 1 represented 37% of all the FTR auction purchase costs in 2019, which was a significantly higher share than any of the previous four years. As discussed in more detail in Section 3.4.9, the New York – New England interface is one of the most frequently binding interface constraints in New England's power system.

Section 5
External Transactions

This section examines trends in external transactions in the day-ahead and real-time energy markets. In 2019, New England remained a net importer of power with net real-time imports averaging 2,633 MW each hour, meeting about 19% of New England native demand. This section provides a detailed breakdown of the total flows across the external interfaces with New York and Canada, along with a review of bidding behavior and the performance of the Coordinated Transaction Scheduling (CTS) mechanism with New York.

Key Takeaways

In general, we continue to see import bids being price insensitive, particularly over the Canadian interfaces. Over the primary New York interface, New York North, CTS performance has been consistent with prior years. CTS Import bids continue to be price sensitive, however, an increase in low-priced bids means participants are willing to flow power in the direction of the lower price market. This is likely due to contractual positions entered into prior to the operating day, and the availability of renewable energy credits in New England when backed by eligible power. In 2019, real-time flows over this interface moved in the economically correct direction during 58% of intervals.

In addition to participant bidding behavior, the ability of ISO New England and the New York ISO to accurately forecast prices is important to the effectiveness of CTS. When looking at the potential effects of price forecasting, we observed that both ISOs have improved their forecasts when measuring error on an absolute basis; each jurisdiction's forecast is closer to the actual real-time price. However, on an average forecast error basis, New England consistently under-forecasts, while New York consistently over-forecasts prices, therefore compounding the average forecast error. Given that CTS transactions are scheduled using spread bids between the control areas, the average forecast error is worse this year than prior years, and may be inhibiting economic flows.

5.1 External Transactions with New York and Canada

There are six external interfaces that interconnect the New England system with its neighboring control 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.

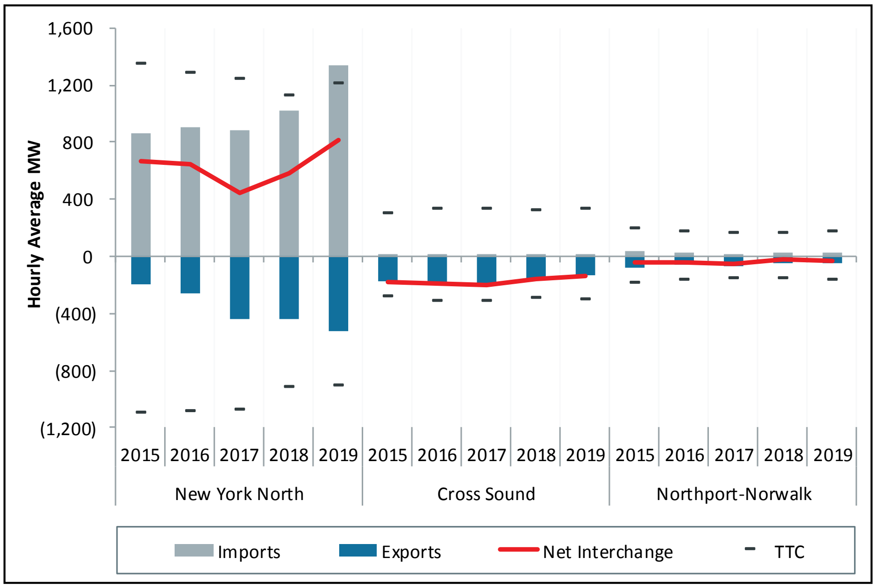
New York Interfaces

The New York North interface is comprised of seven AC lines between New York and New England. It has the largest import and export transfer capacities among the New York interfaces and facilitates the majority of power transactions between the two markets.[164] The Cross Sound Cable and Northport-Norwalk Cable ties run between Connecticut and Long Island and are typically

[164] New York North has a 1,400 MW import capacity in the summer, 1,600 MW import capacity in the winter, and 1,200 MW export capacity year round.

utilized to deliver power to New York. [165, 166] While New England continues to be a net importer of power overall, there are also substantial volumes of power exported from New England, particularly at the New York interfaces. The annual hourly average real-time net interchange as well as the gross import and export volumes at each New York interconnection for 2015 through 2019 are shown in Figure 5-1 below. The average hourly real-time total transfer capability (TTC) ratings for each interface in the import and export directions are also plotted in Figure 5-1 using the black dash lines.[167] Note that the annual observations are grouped by interface.

Figure 5-1: Real-Time Net Interchange at New York Interfaces



New England predominately imports power over the New York North interface and exports power over both the Cross Sound and Northport-Norwalk interfaces. Combining flows at all three interfaces, the real-time net interchange with New York averaged 656 MW per hour in 2019, making New England a net importer of power from New York.

The average hourly real-time imports at the New York North interface increased by 31% in 2019 relative to 2018 (from 1,023 MW to 1,341 MW per hour). Average hourly real-time exports at the New York North interface also increased, by 19%, between 2018 and 2019 (from 442 MW to 525 MW per hour). The combined effect was that average hourly net interchange increased by 40% (from 581 MW to 816 MW per hour).

A primary driver of this increase in imports was an increase in the amount of offered supply at low, and even negative, price spreads. One other notable trend is that the amount of average hourly real-time exports at the New York North interface has increased by 164% over this five-year period (from 199 MW per hour in 2015 to 816 MW per hour in 2019). This increase in exports is the result of Coordinated Transaction Scheduling (CTS), which was implemented at the New York North

[165] Cross Sound Cable has a 346 MW import capacity and a 330 MW export capacity year round.

[166] Northport-Norwalk Cable has a 200 MW import and export capacity year round.

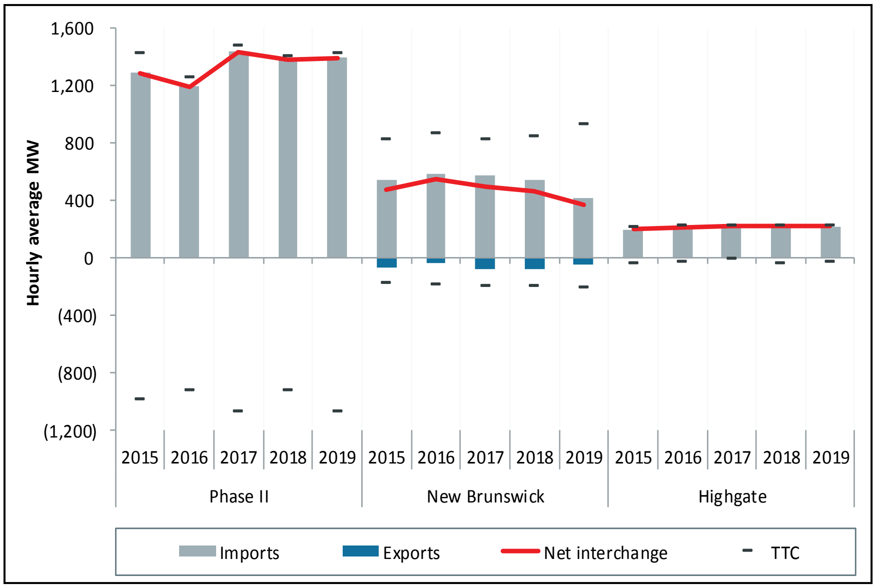
[167] The total transfer capability (TTC) rating is the MW amount that can be reliably transferred from one system to the other over the transmission line.

interface in mid-December 2015 to improve the efficiency of real-time power flows between the two control areas.

Canadian Interfaces

The annual hourly average real-time net interchange volumes and the gross import and export volumes at each interconnection with Canada are graphed for each year between 2015 and 2019 in Figure 5-2 below. The average hourly real-time total transfer capability (TTC) ratings for each interface in the import and export directions are also plotted using the black dash lines. Note that the annual observations are grouped by interface.

Figure 5-2: Real-Time Net Interchange at Canadian Interfaces



New England continues to import significantly more power from Canada than it does from New York. Across all three interfaces, the real-time net interchange with Canada averaged 1,997 MW per hour in 2019, which was a slight decrease of 4% (80 MW) relative to the average real-time net interchange in 2018. New England predominately imports power from Canada with limited quantities of exports to the New Brunswick system. Exports averaged only 49 MW per hour in 2019, a 36% decrease from 2018. One of the major factors that contributed to the slight decrease in average real-time net interchange in 2019 was planned transmission work that lowered the real-time imports over the New Brunswick interface. Between the end of March and the middle of May, there was planned circuit breaker and substation maintenance. During these outages, the import TTC was lowered to around 600 MW (from the normal capacity of 1,000 MW).

5.2 Bidding and Scheduling

The primary categories of external transactions include imports or exports at a single external node.[168] These transactions may be submitted as either priced or fixed and are allowed in both the day-ahead and real-time markets. A priced transaction is evaluated for clearing based on its offer price relative to the nodal LMP. A fixed transaction is akin to a self-scheduled generator offer, that

[168] Virtual transactions, including up-to-congestion, can also be bids at external nodes. However, the volumes are relatively small compared to the exports and imports.

is, there is no price evaluation and the transaction will be accepted unless there is a transfer constraint.

Day-Ahead Market

In the day-ahead market, external transactions establish financial obligations to buy or sell energy at external nodes. There is no coordination with other control areas when clearing day-ahead transactions. There is also an up-to congestion (UTC) transaction type, which allows a participant to create sell and buy obligations at an external and internal node based on differences in LMPs between the nodes; however UTC volumes have historically been very low. All external transactions are cleared for whole-hour periods based on economics while respecting interface transfer limits.

Real-Time Market

Contrary to the day-ahead market, the scheduled real-time transactions define the physical flow of energy that will occur between control areas. In real-time, in addition to import and export transactions, participants may also use wheel-type transactions to ship power across New England between two external nodes. Wheel transactions are evaluated as fixed transactions. CTS introduced an additional real-time transaction type called an interface bid. Interface bids indicate the direction of trade and the minimum price spread between the New York and New England prices the participant is willing to accept to clear.

The ISO-NE operators coordinate real-time tie flows with the neighboring balancing authorities based on joint acknowledgement that the transactions have been scheduled in each area and can be accommodated under operational criteria. At locations other than New York North, where CTS is enabled, transactions are scheduled at 45 minutes ahead for a one-hour schedule duration and must be confirmed by the neighboring area. At the CTS location, interface bids are cleared 20 minutes ahead for 15-minute schedules.[169]

External transaction clearing in the day-ahead and real-time markets occurs independently, although a single transaction can have day-ahead and real-time offers. A cleared day-ahead transaction does not automatically carry over to real-time; the participant must elect to also submit the transaction in real-time or may choose to offer the transaction only in real-time. When a participant does submit a transaction with both day-ahead and real-time offers, there is some scheduling priority afforded during real-time. In particular, the day-ahead MW-amount cleared is scheduled as if it were offered as a fixed transaction in real-time unless the participant alters the offer price or withdraws the transaction in real-time.[170]

New York Interfaces

The composition of day-ahead and real-time cleared transactions (both imports and exports) at the New York interfaces is charted in Figure 5-3 below for each year between 2015 and 2019.[171] The lighter yellow series illustrates the total volume of cleared fixed transactions; the percentage is the share of overall cleared transactions that were fixed. The darker yellow series illustrates the

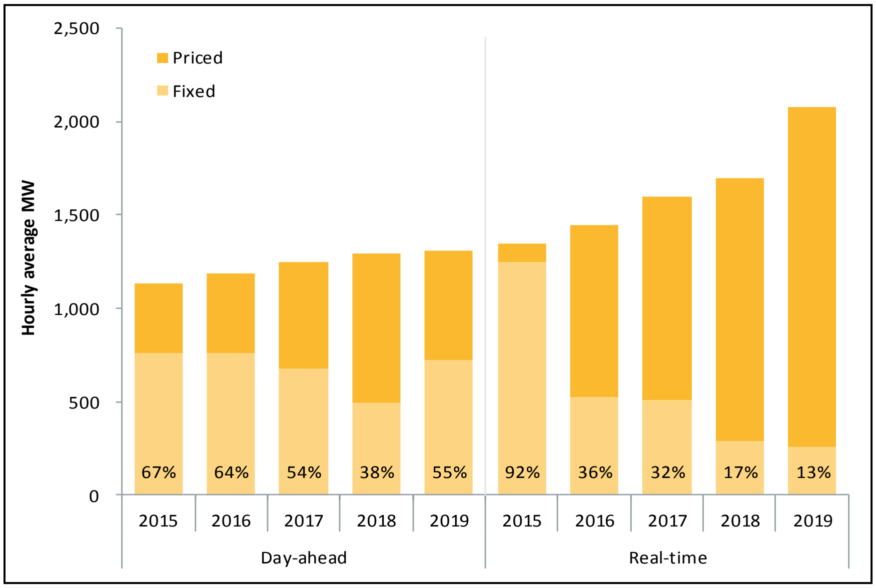
[169] The clearing process *begins* 45 minutes before the 15-minute interval and ends 20 minutes before.

[170] This scheduling priority is not applicable to real-time interface bids at CTS locations.

[171] Refer to Section 2.4 for details of the external nodes associated with the New York, Québec, and New Brunswick areas.

volume of cleared priced transactions. The volumes presented represent the annual average MW volumes per hour for each year.

Figure 5-3: Cleared Transactions by Market and Type at New York Interfaces



Due to the implementation of CTS at the New York North interface in December 2015, a large percentage of New York real-time transactions shifted from fixed to priced in 2016. This trend continued in 2019 as the percentage of New York real-time fixed transactions fell to only 13%, the lowest percentage of the last five years. Due to CTS, all real-time transactions at New York North are now evaluated based on price, although participants may offer prices as low as -$1,000/ MWh to effectively schedule the transaction as fixed. The percentage of day-ahead priced transactions at the New York interfaces fell in 2019 from 62% to 45%, consistent with 2015-2017 outcomes.

The breakout of fixed and priced transactions at the New York interfaces is separated by import and export transactions in Table 5-1 below. The values presented in this table are for cleared transactions and the volumes are the average MW per hour.

Table 5-1: Transaction Types by Market and Direction at New York Interfaces (Average Cleared MW per hour)

Market	Direction	Type	2015	2016	2017	2018	2019
Day-ahead	**Import**	Priced	89	133	195	447	323
		Fixed	700	709	577	441	699
		Percent Priced	11%	16%	25%	50%	32%
	Export	Priced	281	298	375	354	268
		Fixed	61	48	101	54	21
		Percent Priced	82%	86%	79%	87%	93%
Real-time	**Import**	Priced	70	651	657	967	1,281
		Fixed	827	281	234	82	86
		Percent Priced	8%	70%	74%	92%	94%
	Export	Priced	32	272	436	442	536
		Fixed	418	242	272	205	175
		Percent Priced	7%	53%	62%	68%	75%

In 2019, 32% of the average hourly cleared day-ahead import transactions at the New York interfaces were priced transactions (323 MW per hour). This represents a 28% decrease from the average hourly day-ahead volume of priced import transactions at the New York interfaces in 2018. Conversely, the majority of day-ahead export transactions at the New Yok interfaces continue to be priced. The percentage of priced export transactions rose to 93% in 2019 from 87% in 2018.

Comparing transaction direction in the day-ahead market, 78% of cleared MW per hour were imports. This is slightly higher than 2018, which was 69%.], When breaking out day-ahead cleared volume further by type, Table 5-1 highlights the continuing trend of imports comprising the majority of fixed cleared volumes. Imports into New England are generally less price-sensitive than those that export power. This may be due to contractual positions that participants have entered into prior to the delivery day, or eligibility for renewable energy credits in the New England states.

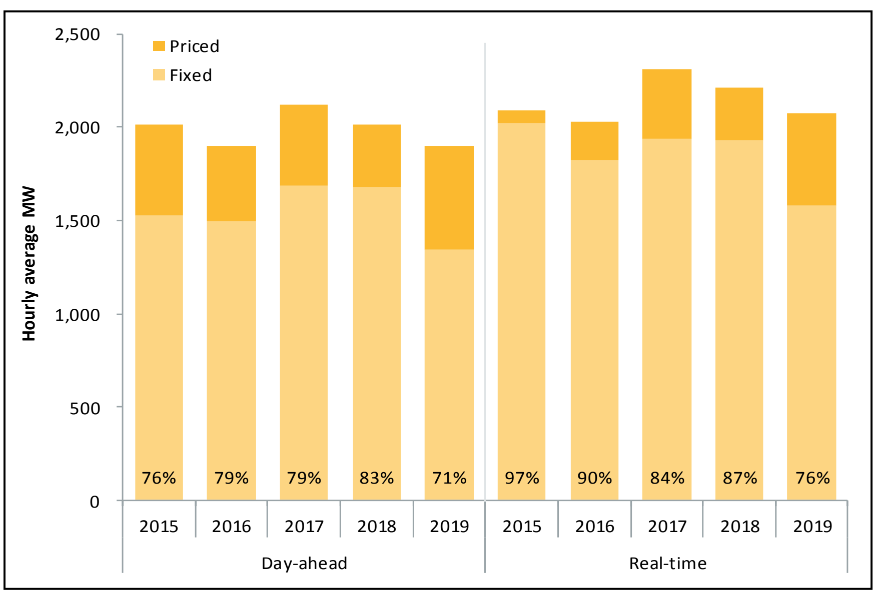
Table 5-1 also shows that those participants usually clear greater volumes of transactions. This contributes to New England predominately importing power from New York despite variations in price differences between the control areas.

In the real-time market, we continue to see the majority of cleared MW per hour being priced. Table 5-1 shows a large increase in priced imports and exports starting in 2016 with the implementation of CTS. Since then, we have continued to see more real-time imports and exports clear as priced transactions.

Canadian Interfaces

The composition of transactions cleared in the day-ahead and real-time markets at interfaces with the Canadian provinces is charted for each year between 2015 and 2019 in Figure 5-4 below. The lighter yellow series is the total volume of cleared fixed transactions and the percentage value is the share of overall cleared transactions that were fixed. The darker yellow series is the volume of cleared priced transactions. The volumes presented are the average MW per hour values each year.

Figure 5-4: Cleared Transactions by Market and Type at Canadian Interfaces



Accounting for both the day-ahead and the real-time markets, there are higher volumes of power transacted over the Canadian interfaces compared with the New York interfaces, on average. Comparing Figure 5-4 to Figure 5-3 highlights that, for the first time in this reporting period, there was more power transacted in the real-time market over the New York interfaces (2,077 MW per hour) than the Canadian interfaces (2,075 MW per hour), on average.

The breakout of fixed and priced transactions at the Canadian interfaces by import and export transactions is shown in Table 5-2 below. Here again, the values presented are for cleared transactions and the volumes are the average MW per hour.

Table 5-2: Transaction Types by Market and Direction at Canadian Interfaces (Average MW per hour)

Market	Direction	Type	2015	2016	2017	2018	2019
Day-ahead	Import	Priced	486	399	418	327	544
		Fixed	1,509	1,491	1,677	1,667	1,336
		Percent Priced	24%	21%	20%	16%	29%
	Export	Priced	3	2	18	12	10
		Fixed	20	6	11	12	8
		Percent Priced	12%	22%	61%	50%	56%
Real-time	Import	Priced	64	203	354	275	487
		Fixed	1,955	1,788	1,871	1,859	1,539
		Percent Priced	3%	10%	16%	13%	24%
	Export	Priced	2	4	13	10	8
		Fixed	70	35	69	69	41
		Percent Priced	3%	10%	16%	12%	16%

Both imports and exports at the Canadian interfaces continue to be submitted as fixed transactions as shown in Table 5-2. Fixed imports into New England remain the majority of transactions occurring at the Canadian interfaces.

5.3 External Transaction Uplift (Net Commitment Period Compensation) Credits

The ISO lacks sufficient information to calculate day-ahead or real-time congestion prices at non-CTS external nodes (*i.e.*, the marginal cost of power on the other side of the interface).[172] Instead, the cost of relieving congestion is reflected in a transfer of uplift payments between those causing the congestion and those relieving the congestion.

Uplift payments accrue in the day-ahead market when fixed import or export transactions exceed the TTC of the interface and offsetting interchange transactions (withdrawals or injections over the interface) are cleared to create counter-flow for the fixed transactions to clear. The participant with the offsetting transaction that provided the counter-flow *receives* the uplift and the participant with the fixed transaction that was allowed to clear is *charged* the uplift.

Absent congestion pricing, the day-ahead market applies a nodal constraint that limits the net injections to the transfer capability of the external interface. Offsetting injections (import transactions and virtual supply) and withdrawals (export transactions and virtual demand) will be cleared so long as the interface limit is not exceeded. This means, for example, that a total volume of import transactions or virtual supply offers that exceeds the import transfer capability can be

[172] Prior to CTS, this was the case at all external nodes. However, congestion pricing has been implemented for the New York North external node in both the day-ahead and real-time markets since December 2015, coincident with CTS implementation.

cleared so long as offsetting export transactions or virtual demand bids are available. The clearing of these offsetting transactions does not affect the nodal LMP.

Similar to generator out-of-merit credits, real-time uplift credits at external nodes are paid to priced transactions that prove to be out-of-merit for the hour. In the real-time energy market, external transactions are scheduled based on a comparison of the transaction price to the ISO-NE forecasted price for the external node.[173] If the actual real-time LMP for an external node is *less* than the offer price of a cleared *import* transaction at that node, the participant will receive uplift payments to be made whole to its offered price. Conversely, if the actual real-time LMP for an external node is *more* than the offer price of a cleared *export* transaction at that node, the participant will receive uplift payments to be made whole to its offered price. Real-time uplift payments to external transactions are only paid to priced transactions – fixed transactions are willing to clear at any price, and therefore cannot clear out-of-merit.

The annual uplift credit totals (millions of $) at all external nodes in both the day-ahead and real-time markets for each year from 2015 through 2019 are presented in Table 5-3 below.

Table 5-3: NCPC Credits at External Nodes

Year	Day-ahead credits ($ million)	Real-time credits ($ million)
2015	$3.05	$1.15
2016	$0.90	$1.28
2017	$0.56	$1.92
2018	$0.30	$2.73
2019	$0.02	$1.02

The total amount of uplift credits paid at external nodes is very small compared with other types of uplift (see Section 3.5). In the day-ahead market, we typically see these payments occur when there is an unexpected or large decrease in an interface TTC until participants adjust their fixed bidding behavior.

Day-ahead uplift credits at external nodes decreased 92% in 2019 compared to 2018. The majority (69%) was paid at the Phase II interface. Total day-ahead credits at this interface in 2019 ($17k) decreased by 94% from their total in 2018 ($285k). There is no longer any uplift paid at the New York North interface since congestion pricing was implemented at this interface on December 15, 2015, under the CTS design. The very small amount of the day-ahead uplift that was paid out at the external nodes in 2019 went to virtual transactions ($6k).

As Table 5-3 shows, total real-time external transaction uplift credits during 2019 were 63% lower than in 2018. The decrease in payments was seen primarily at the New Brunswick interface, where payments fell by 68% from $2.2 million in 2018 to $0.7 million in 2019. This decrease in payments is likely due to improved price forecasting.

[173] This is for non-CTS interfaces. For New York North (the only CTS interface) real-time interface bids are cleared based on forecasted price *differences* between NYISO and ISO-NE.

5.4 Coordinated Transaction Scheduling

The Coordinated Transaction Scheduling (CTS) mechanism is intended to improve the efficiency of real-time energy trades between New England and New York. CTS was implemented by ISO-NE and the New York Independent System Operator (NYISO) in December 2015, for the New York North interface. The design modified the bidding and scheduling mechanics for real-time transactions. The design changes unified the bid submission and clearing process, decreased the schedule duration from one hour to 15-minute intervals, moved bid submittal and clearing timelines closer to the interval when power flows, and eliminated transaction fees.[174] The CTS design was intended to improve the extent to which power moves from the lower- to higher-cost region and increase the utilization of interface transfer capability to better converge prices between the regions.

CTS Scheduled Flow in the Correct Direction 58% of time in 2019

As discussed in Section 5.1 above, New England was a net importer of power across the New York North interface, importing an average of 816 MW each hour in 2019. Average annual data on CTS scheduled flows are presented in Table 5-4 below. The table shows the percentage of intervals when the net CTS flows were in either the New England or New York direction, and the percentage of intervals when the flows were in the economically correct direction (i.e. from lower-cost to higher-cost market). The latter statistic is shown based on the forecast of price difference (relevant to the actual clearing of CTS bids), as well as on actual settled prices.

Table 5-4: Summary of CTS Outcomes

	Net Flow (% of intervals), to:		Correct Flow (% of intervals), based on:	
Year	**ISO-NE**	**NYISO**	**Forecast Spread**	**Actual Spread**
2016	94%	6%	63%	56%
2017	79%	20%	68%	61%
2018	88%	12%	59%	63%
2019	94%	6%	47%	58%

In 2019, New England was a net importer during 94% of real-time intervals. Overall, CTS bids in 2019 allowed power to flow consistent with *forecast* price differences only 47% of the time, which was down from 59% observed in 2018. This trend continues to be consistent with the increase in negative import spread bids into New England. Negative import spread bids will be scheduled even when the power is being imported from the higher-cost region to a lower-cost region.

Based on *actual* price differences, power flowed in the correct direction 58% of the time, which was slightly worse than the 63% observed in 2018. The percentage of correct flows based on forecast and on actual price spreads was farther apart than prior years (an 11% difference in 2019 compared to 4% in 2018).

CTS Transactions Continue to Flow in the Uneconomic Direction due to Bidding Behavior

The bid types submitted by participants over the CTS interface heavily affect the ability for the CTS design to schedule real-time power efficiently. The process can only schedule volumes up to the

[174] The design basis documents, FERC filing materials, and implementation documentation describing the CTS design in detail can be found on the ISO-NE key project webpage: http://www.iso-ne.com/committees/key-projects/implemented/coordinated-transaction-scheduling/

amount of the bid volumes submitted and at the price up to the forecasted price spread. Bid prices can be positive, negative, or zero. A positive bid price indicates the participant is willing to move power when, as forecasted, the price in the destination market exceeds the price in the source market by at least the bid price (i.e., buy low and sell high). A negative bid price indicates a willingness to trade power when the energy price is higher at the source than at the destination, by as much as the negative bid price (i.e., to counterintuitively buy high and sell low).

Average CTS transaction curves, by year, are shown in Figure 5-5 below. Import offers are shown in the first graph (gold curves) followed by export bids (red curves). Lastly imports and exports are aggregated to produce a new net supply curve (orange curves). The import and export curves show the average volume of energy willing to clear at each New England - New York price spread. The aggregate supply curve shows the net flow that would be produced if all of the economic import and export transactions were to clear. The darker-colored lines show the 2019 curves and lighter colored lines show the 2018 curves. The x-axis shows the spread of New England and New York prices – positive numbers indicate that New England prices are higher. When New England prices are higher (i.e. the price spread is positive), the expectation is that more imports and less exports would be willing to clear. The y-axis shows the volume of energy that would clear, on average, at each price spread.

For example, in 2019, at a price spread of $0/MWh, 1,199 MW of imports would have cleared, 310 MW of exports would have cleared, and the net flow of CTS transactions would have been 889 MW, on average.

Figure 5-5: Price Sensitivity of Offered CTS Transactions

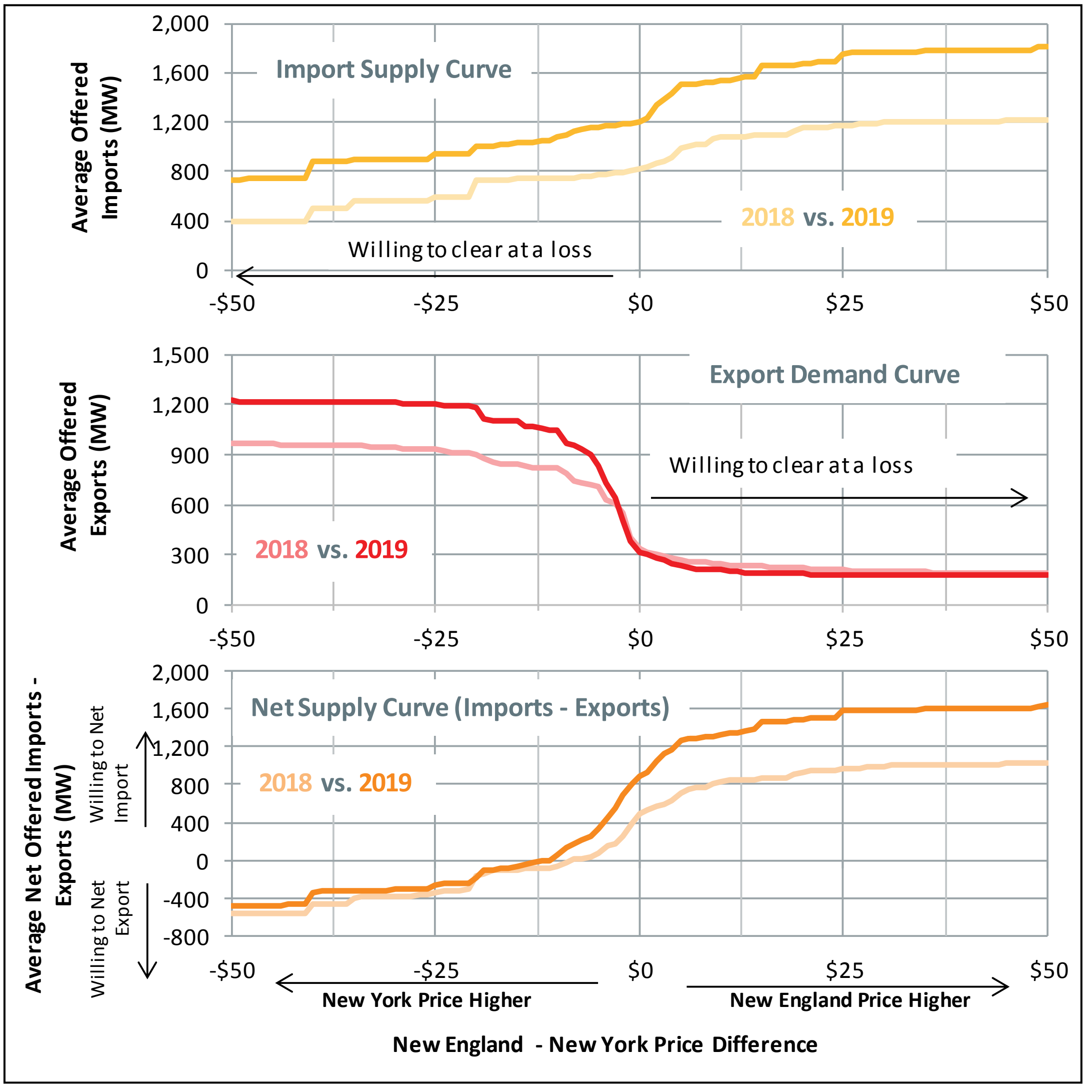


Figure 5-5 shows a large increase in import offers at a very low price spreads (-$50/MWh) in 2019 compared with 2018. Between 2018 and 2019 there was an approximate increase of 350 MW offered at this lowest offer price spread. The addition of these imports shifts the entire 2019 curve above the 2018 curve. Import offers between $0 and $15/MWh also increased between 2018 and 2019. This additional increase is carries through to the largest price spread of $50/MWh. Additionally, a large increase in export bids in 2019 compared to 2018 was mostly at prices below $0/MWh (the price spread at which exports are willing to clear at a gain). While the shift in the export demand curve allowed for more flows in the correct direction, this was more than offset by opposite impact of the supply curve shift. In other words, the aggregate supply curve allowed the direction of flows to be less consistent with price differences than in the prior year, on average. Therefore, in 2019 more net imports were scheduled to flow into New England at a loss than in 2018.

In 2018, market participants were willing to export energy to New York only when New York prices were at least $9/MWh higher (see the intersection of the 2018 net supply curve at 0 MW), on average. This trend in uneconomic power flow worsened in 2019, when participants were only willing to export power to New York when New York prices were at least $11/MWh higher, on average. One possible explanation for this bidding behavior (willing to flow energy at a loss) may be due to contractual positions that some participants entered into prior to the delivery day, or eligibility for renewable energy credits in the New England states.

Price Convergence Improved in 2019

To examine the degree of real-time price convergence achieved under the CTS design relative to prior years, we examine two main factors: (1) the percent difference of the average hourly real-time price between the two control areas' respective pricing locations for the New York North interface and (2) the level of volatility in each area. These two metrics are provided in Figure 5-6 below.[175] Percentage differences are to adjust for absolute price levels.[176] The line series in Figure 5-6 plot the cumulative distribution function for observations of the absolute percentage difference between the ISO-NE and NYISO real-time hourly energy prices at the New York North interface.

In the chart below, the vertical axis represents the absolute percentage difference in price at each side of the interface. The horizontal axis represents the probability of a price difference at that percentage or less. For example, at a 10% absolute price difference (on the vertical axis), scanning horizontally to the right, the 2019 line corresponds to a horizontal axis value of 37%. This means that 37% of hours in 2019 had an absolute price difference between the control areas of 10% or less. To help compare across years, the table embedded in the chart provides the probabilities of a few price difference values (i.e., 10%, 25%, 50%) for each year.

To describe the relative market price volatility in each of these years, the table in Figure 5-6 also includes the coefficient of variation for real-time energy prices. The coefficient of variation measures how much each ISO's real-time price varied relative to its average price for the year.[177] The lower the price volatility the more we would expect to observe New England and New York prices remaining close to one another. When price volatility is higher, a greater degree of price divergence between the regions is expected, unless a scheduling system like CTS is frequently adjusting the interface flow.

[175] The NYISO pricing node is called "N.E._GEN_SANDY PD" and the ISO-NE node is "I.ROSETON 345 1."

[176] Higher absolute prices often result in larger price differences. Percentage differences are shown so that larger magnitude price divergences due to higher absolute prices are not attributed to CTS.

[177] The coefficient of variation is the ratio of the standard deviation to the mean.

Figure 5-6: New York North Real-Time Price Difference between ISO-NE and NYISO

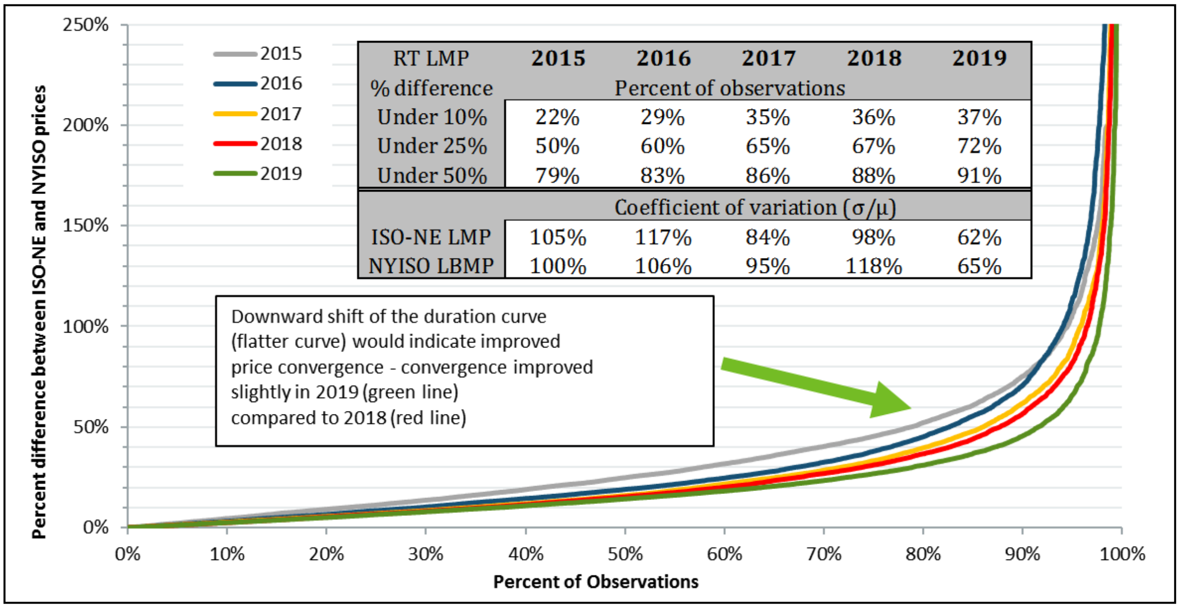


Figure 5-6 indicates that there was a slight improvement in price convergence in 2019. Price differences between New York and New England continue to decrease, indicating that CTS may be improving price convergence between the two control areas. At all three values of price difference shown in the embedded table in Figure 5-6, 2019 contains the highest percentage of observations. Unlike the last four years, the current reporting year saw much more stable prices. In 2019, the coefficient of variation in real-time prices was 62% for ISO-NE, the lowest value since before the implementation of CTS. Similarly, on the NYISO side the coefficient of variation in real-time prices was 65%. This is consistent with the New York North interface binding with smaller marginal values (less congestion) as well as the New England system experiencing no extreme events or scarcity conditions which would drive prices up. The lack of extreme system events is further explained in Section 3.4.7.

Price Forecast Error may be Continuing to Inhibit CTS Effectiveness

The efficiency of CTS schedules can be impacted by the accuracy of the ISOs' internal price forecasts at the external node. Price forecasts are calculated for each 15-minute interval and used to determine the direction of price differences between the regions, which participant bids clear, and the interface net flow. Interface bids clear if the offer price is below the forecasted price difference. ISO-NE creates its CTS price forecast using current offers and system conditions at about 45 minutes ahead of the scheduling interval. The NYISO forecasts its internal price at about 30 minutes ahead of the scheduling interval. A summary of forecast versus actual prices, as well as the average and absolute forecasting errors, is provided in Table 5-5 below.

Table 5-5: Forecast Error in CTS Solution

	Forecast LMP			Actual LMP			Average Forecast Error			Average Absolute Forecast Error		
	ISO-NE	NYISO	Spread	ISO-NE	NYISO	Spread	ISO-NE	NYISO	Spread	ISO-NE	NYISO	Spread
2016	$28.82	$27.66	$1.16	$28.02	$29.23	($1.22)	$0.80	($1.58)	$2.38	$0.80	$1.58	$0.77
2017	$33.37	$31.29	$2.08	$32.02	$32.37	($0.34)	$1.34	($1.08)	$2.42	$1.34	$1.08	$0.27
2018	$38.21	$38.99	($0.77)	$39.29	$40.80	($1.51)	($1.07)	($1.81)	$0.74	$1.07	$1.81	$0.74
2019	$26.69	$28.79	($2.09)	$27.71	$28.43	($0.72)	($1.02)	$0.36	($1.37)	$1.02	$0.36	$0.66

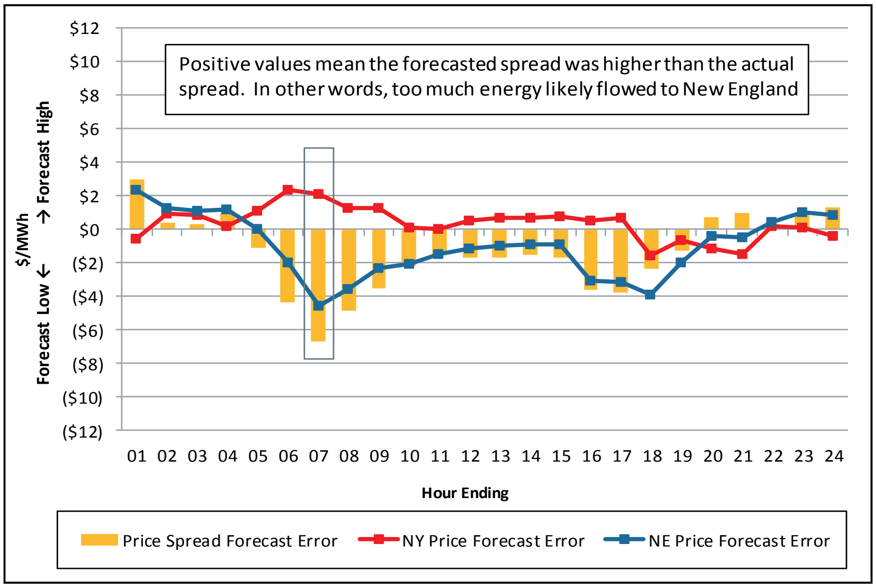
Both ISOs have improved the accuracy of their price forecasts when measured on an absolute average basis. However, the simple average forecast error was worse in 2019 relative to 2018. Absolute forecast error ignores the directionality of the error and focuses on the magnitude. Both control areas were, in absolute terms, closer to actual LMP in 2019 than in 2018.

CTS transactions are scheduled on a spread basis and average forecast error, which considers directionality, captures the offsetting or compounding effect of each control areas forecast error. The average difference between the forecast NE-NY spread and the actual NE-NY spread was -$1.37/MWh, up from $0.74/MWh in 2018.[178] The average ISO-NE forecast error fell slightly from -$1.07/MWh in 2018 to -$1.02/MWh in 2019. In other words, the forecasted price of power in New England was, on average, $1.02/MWh less than the actual price. The forecast for the price of power in New York in 2019 was, on average, $0.36/MWh more than the actual price. The forecast errors in 2019 were compounding (rather than offsetting like in 2018) resulting in a larger average difference between the forecast NE-NY spread and the actual NE-NY spread than last year.

Forecast performance remains inconsistent for both ISO-NE and NYISO across many hours of the day. On average, errors in the New England price forecast are largest during system ramp periods. New York forecast errors are most apparent during the morning peak hours. Compared to 2018 both ISOs have reduced the volatility of their error. Forecast error in 2019 ranged from -$6.67 (HE 07) to $2.96/MWh (HE 01), compared to 2018 where the forecast error ranged from -$8.90 (HE 08) to $9.83/MWh (HE 20). Figure 5-7 below shows the simple average of forecast errors for 2019 calculated by hour of the day.

[178] Price difference forecast error is: (Forecast $_{\text{New England}}$ – Forecast $_{\text{New York}}$) – (Actual $_{\text{New England}}$ – Actual $_{\text{New York}}$).

Figure 5-7: Average Real-Time ISO Price Forecast Errors, by hour



A positive observation in Figure 5-7 indicates the forecast is higher than the actual price and a negative observation indicates the forecast is lower than actual price. The red line series represents the average error in the NYISO price forecast for each hour and the blue line series represents the average error in the ISO-NE price forecast each hour. The tendency for New England to forecast too low are evident in most hours. On average, errors for both ISO's price forecast are largest during the morning hours (i.e., HE 05-10).

When there is a negative price spread error, indicated by a negative value of the yellow bar series in Figure 5-7, this means that the forecast NE-NY spread was *less* than the actual NE-NY spread. For example, in HE 07 (the hour with the highest error) the New England forecast price was less than the actual price by $4.46/MWh, on average, and the New York forecast price was more than the actual price by $2.14/MWh, on average. Thus, the forecast NE-NY spread was less than the actual NE-NY spread by $6.67/MWh, on average. In these hours, it is likely that too little energy was scheduled to flow into New England.

Compared to 2018 the price forecast error over the evening peak has greatly improved. In 2018 the price forecast error was consistently over $4/MWh, averaging $6.87/MWh, from HE 17 – HE 21. In 2019, for those same hours, the average forecast error was -$1.14/MWh, with a max value in HE 17 of -$3.78/MWh. The ISOs' forecast biases may consistently produce inefficient tie schedules. When the forecasted price difference is over-estimated, more higher-priced interface bids can clear than will actually be in rate and the tie schedule can exceed the economically efficient level. Conversely, when forecasted price differences are under-estimated, too few interface bids may clear and the interface may be underutilized.

Section 6
Forward Capacity Market

This section reviews the performance of the forward capacity market (FCM), including key trends in resource participation, auction prices and auction competiveness.

Overall, the FCM has achieved its design objectives of attracting new efficient resources, maintaining existing resources and sending price signals for the retirement of less efficient resources. Capacity prices resulting from the forward capacity auctions (FCAs) have increased and decreased as the number of resources competing and clearing in the auctions and the region's surplus capacity has changed. However, ensuring competitive pricing outcomes in the FCM is becoming increasingly challenging and the ISO and stakeholders have been working on exploring innovative solutions to these challenges.

The first challenge has been to accommodate new resources which secure revenue through state-backed programs designed primarily to meet state environmental goals – these so-called "out-of-market" revenues can lead to market distortions and price suppression. For FCA 13, the ISO introduced Competitive Auctions with Sponsored Policy Resources (CASPR) to help address this issue. CASPR provides a market-based mechanism for state-sponsored resources to enter the FCM while maintaining competitive prices in the primary auction. However, while the price-suppressing impact is mitigated in the first year, the sponsored resources will likely be price-takers in subsequent auctions thereby applying downward pressure to future FCA clearing prices in the long-term. This underlying compromise behind the CASPR design is unavoidable so long as resources receive out-of-market revenues. Also, while CASPR and the current market power mitigation rules help mitigate the impacts on new resources, they do not address the impact of out-of-market revenues paid to retain existing resources, when they might otherwise retire.

The second challenge is the reliability retention of FCM resources based on their underlying energy-security attributes; attributes that are not reflected in the current FCM or energy market designs. Once such an attribute becomes scarce and impacts market outcomes, it is important from a market efficiency perspective to value it appropriately in the wholesale market. To that end, the ISO has worked with stakeholders on designing new reserve products to be procured in the day-ahead market, with the objective of valuing and compensating resources for providing energy security. This new rules are proposed to be implemented in June 2024.[179] In the interim, for the Winter 2023/24, the ISO will administer a compensation mechanism to pay energy-secure resources an administrative rate for unused inventory during cold winter days. One objective of this interim program is to create a revenue stream which may help avoid the otherwise uneconomic retirement of energy-secure resources.

Summary of FCA Trends Covered in this Section

The first seven FCAs, for the commitment periods between June of 2010 through May of 2017, experienced relatively stable capacity prices resulting from surplus capacity and administrative price-setting rules. In contrast, in FCA 8 the retirement of over 2,700 MW of older nuclear, coal- and oil-fired generators reduced the region's capacity surplus and produced higher capacity prices.

[179] See ER20-1567-000; Energy Security Improvements Compliance Filing, April 15, 2020 at https://www.iso-ne.com/static-assets/documents/2020/04/energy_security_improvements_filing.pdf

Payments for capacity commitment period (CCP) 8 reached $3 billion, a 162% increase in payments from prior commitment period ($1.2 billion).

The trend of minimal surplus and increased capacity payments will continue into 2018-19. As capacity prices increased, new suppliers entered the market in FCAs 9 and 10. However, as new suppliers entered the market, the amount of system capacity increased, resulting in declining prices. This pattern of increasing prices followed by decreasing prices is what one would expect in a market that is gaining new and losing older generators as it oscillates around an equilibrium. Further, planned transmission improvements, coupled with an increase in the number of resources competing in the auctions, increased the capacity market's overall competitiveness.

The clearing price in the most recent auction, FCA 14, was $2/kW-month (with expected payments of $1 billion); the lowest price since the inception of the FCM. Capacity totaling 2,085 MW dynamically de-listed, including 900 MW of oil-fired generation, and 1,000 MW of gas-fired generation. New cleared capacity totaled 637 MW, and primarily consisted of either resources with a renewable technology resource (RTR) exemption, or passive demand response resources.

This section is structured as follows:

- Section 6.1 provides a high-level overview of the market design, summarizing resource qualification, auctions mechanics and performance incentives.
- Section 6.2 summarizes overall payments made to capacity resources, including adjustments such as peak energy rent, shortage event penalties, and pay-for-performance.
- Section 6.3 summarizes the inputs and outcomes of the most recent forward capacity auction, FCA 14.[180]
- Section 6.4 reviews key trends in primary (FCA) and secondary capacity trading.
- Section 6.5 focuses on trends in the resource mix and the major new entry and exit of resources that have shaped those trends.
- Sections 6.6 and 6.7 present metrics on the structural competiveness of the FCAs. They also describe mitigation measures in place to address the potential exercise of market power, and provide statistics on the extent to which uncompetitive offers were mitigated.

6.1 Forward Capacity Market Overview

The FCM is designed to achieve several market and resource adequacy objectives. First, the FCM provides developers of new resources and owners of existing resources an additional revenue source. The FCM or "capacity" revenue is intended to offset the revenue shortfall or "missing money" that arises as a result of marginal-cost bidding and administrative offer caps in the energy market. Second, the FCM can provide new resource owners with reasonable certainty about future capacity revenues, particularly when they choose to lock in the payment rate for up to seven years. A developer or owner will know their capacity payment rate ($/kW-month) in advance of starting construction of a new resource or making a significant capital investment in an existing resource. Third, the FCM provides all owners (of a new or existing resource) with financial incentives to operate and maintain their resource so it is available during system shortage conditions. Finally, the FCM's descending clock auction is designed to produce a market-based price for capacity by

[180] A more detailed review of FCA 14 is covered in the IMM Winter 2019/2020 Quarterly Markets Report, at https://www.iso-ne.com/static-assets/documents/2020/05/2020-winter-quarterly-markets-report.pdf

selecting the least-cost set of qualified supply resources that will satisfy the region's price-sensitive demand needs.

The FCM provides Additional Revenue to Capacity Developers and Owners

If New England's energy markets included sufficiently high scarcity pricing, resource owners would have the opportunity to earn infra-marginal rents (the difference between energy market prices and their resource's variable costs) to cover fixed costs, earn reasonable profits, and gain return on capital investments in the long run. Marginal-cost bidding and energy market offer caps intrinsically limit energy market prices, creating "missing money" or a gap between the revenue developers and owners need to justify capital investments and the revenue available to fund those investments. This "missing money" is synonymous with several specific terms used throughout this report, including Net Cost of New Entry (Net CONE), Offer Review Trigger Prices (ORTPs), offer floor prices, net going-forward costs, and de-list bids.

The FCM's capacity prices and revenues facilitate efficient entry and exit decisions. That is, the market *should* attract new resources, maintain competitively-priced resources, and retire uncompetitive resources while meeting the region's resource adequacy standard in the most cost-effective manner. In FCA 13, this was not the case. 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.[181] The agreement suggests that the FCA could not facilitate an efficient *and* reliable solution. The ISO is working on an interim compensation method and multi-day-ahead market to address fuel security through other means.[182]

The FCM provides Resource Owners with Reasonable Certainty about the Future

The FCM procures capacity through an auction mechanism 40 months in advance of when it must be delivered in the energy markets. The delivery period is known as the capacity commitment period (CCP). A resource that successfully sells its capacity in the auction assumes a capacity supply obligation (CSO) and is expected to deliver capacity at the start of the CCP. The long lead time between the auction and the CCP was chosen to provide developers and owners with sufficient time to design, finance, permit, and build new capacity resources. The FCM also provides opportunities for secondary CSO trading through reconfiguration auctions and bilateral trading between the primary auction and the CCP. The volumes transacted in the secondary auctions are typically a small fraction of those in the primary auction.

The FCM provides Financial Incentives to Operate and Maintain Resources

The FCM provides financial incentives to owners to offer their resources competitively in the energy markets and to ensure the resource's availability during times of system shortage conditions. First, the tariff requires the owner of a capacity resource to offer its CSO into the day-ahead and real-time energy markets every day, provided the resource is physically available.[183] Second, changes were made to the FCM rules starting with FCA 9 to improve resource performance.

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

[182] For more information on the interim compensation treatment see: https://www.iso-ne.com/static-assets/documents/2019/01/a2_iso_presentation_interim_compensation_treatment.pptx

[183] See Section III.13.6.1. of the tariff for more information.

The changes are known as the "pay-for-performance" (PFP) rules.[184] Up to that auction, a resource owner faced *de minimis* financial penalties if it was unable to perform during shortage conditions. The rule changes improve underlying market incentives by replicating performance incentives that would exist in a fully functioning and uncapped energy market.

Pay-for-performance rules achieve this goal by linking payments to performance during scarcity conditions. Without this linkage, participants would lack incentive to make investments that ensure the performance of their resource when needed most. Also, absent these incentives, participants that have not made investments to ensure their resource's reliability would be more likely to clear in future FCAs because they could offer at lower prices. This can create a structural bias in the FCM to clear less reliable resources, which, over time, will erode system reliability. Paying for actual performance during scarcity conditions incents resource owners to make investments and perform routine maintenance to ensure that their resources will be ready and able to provide energy or operating reserves during these periods.

PFP works as follows: a resource owner is compensated at the auction clearing price and is subject to adjustments based on its performance during shortage conditions. The PFP design replaced the shortage event rules in place through May 31, 2018. PFP is based on a two-settlement market built around the delivery of energy and operating reserves when they are needed most. If a resource fails to perform relative to expectation, it must buy the difference back at a performance payment rate. Under-performers will compensate over-performers, with no exceptions. Prior to PFP the consequences of poor performance were limited. Shortage events were rare, with only two occurring and each limiting penalties to a maximum of 5% of annual capacity revenues. Furthermore, the prior rules included numerous exemptions, which diluted performance incentives.

Another adjustment to FCM payments is peak energy rent ("PER"). The PER adjustment is primarily a protection for load against real-time energy prices that exceed a threshold or "strike" price.[185] Under the PER concept, load has paid in advance for sufficient capacity to maintain reliability through the FCM. The PER adjustment limits payments to generator and import capacity resources in hours with high real-time prices.[186] This helps ensure that load does not pay through the FCM to maintain a fleet of resources that meets reliability conditions and then later pay when those reliability conditions are not met and result in high real-time prices.

The PER adjustment is also intended to discourage physical and more extreme economic withholding. The PER adjustment is based on the entire quantity of capacity sold in the FCM, not just the portion of capacity subject to a high real-time price. Consequently, a withholding strategy that increases the real-time price above the PER strike price can cause a significant revenue adjustment for the portfolio that outweighs the potential benefits of withholding.[187]

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[184] The PFP rules have been in effect since FCA9, meaning that the settlement rules will be effective from the CCP beginning on June 1, 2018.

[185] The PER threshold is based on revenues that would be earned in the energy market by a hypothetical peaking generator with heat rate of 22,000 British thermal units/kilowatt-hour (Btu/kWh) that uses the more expensive of either natural gas or No. 2 fuel oil.

[186] Demand resources are excluded from the PER adjustment through FCA 8. The PER Adjustment will be applied to Demand Response Resources on June 1, 2018 (FCA 9) once these resources can participate in the Energy Markets.

[187] Lower total payment volatility may not affect the entire amount that load-serving participants pay in the long run because the resources' capacity bids reflect the lower PER-adjustment amounts.

The stronger performance incentives of the PFP rules largely make the PER mechanism redundant, and retaining the mechanism could result in higher capacity market costs without producing substantial benefits. Starting with CCP 10 that began on June 1, 2019, the PER mechanism was eliminated.

The FCM produces Market-Based Capacity Prices:

The ISO conducts a primary FCA once per year. The FCA is conducted in two stages: a descending clock auction followed by an auction clearing process. The FCA results in the selection of resources that will receive a CSO for the future CCP, and capacity clearing prices ($/kW-month) for the period. The descending clock auction consists of multiple rounds. During the rounds, resource owners and developers submit offers expressing their willingness to keep specific MW quantities in the auction at different price levels. During one of the rounds, the capacity willing to remain in the auction at some price level will intersect the demand curve. At that point, the auction will stop and move on to the auction-clearing stage, which produces the capacity clearing prices with the objective of maximizing social welfare.

Inputs into the Forward Capacity Auction

The demand curve used in the auction is based on resource adequacy planning criteria that establish the installed capacity requirement (ICR).[188] Load-serving entities do not actively participate in the FCA. Instead, the willingness of demand to pay for capacity at certain levels of reliability (relative to ICR) is determined by an administrative demand curve. Over the 14 FCAs to date, the market has transitioned from vertical to sloped demand curves. A vertical demand curve, by definition, lacks price sensitivity and can therefore result in large changes in capacity prices at different quantity levels. Accounting for price elasticity through sloped curves reduces market price volatility; it allows the market to procure more or less than the ICR, and reduces the likelihood of activating any market protection mechanisms, such as price floors and caps.

The auction supply curve is based on offers from market participants seeking to enter new capacity into the FCM, and bids from market participants seeking to remove their existing capacity from the FCM. All other existing resources are price takers.

Market participants seeking to enter a new resource into the FCM must first go through a qualification process. At a high level, the process comprises two parts. First, the ISO determines the maximum capacity the resource can safely and reliably deliver to the system; this establishes the resource's "qualified capacity". Second, the new resource is subject to buyer-side market power mitigation rules, which are administered by the IMM. This is done through a cost-review process, which mitigates the potential for a new resource that receives out-of-market revenues to suppress capacity prices below competitive levels. A developer with a new resource wishing to remain in the auction below a benchmark minimum competitive offer price (known as an Offer Review Trigger Price) is required to provide cost justification for review and approval by the IMM.

Once a new resource clears in a primary auction it becomes an existing resource and goes through a different qualification process. Similar to new resources, the high-level qualification process for existing resources, comprises two parts. First, a resource's qualified capacity for an auction is based on actual measured performance. Second, existing resources are subject to seller-side market

[188] 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"

power mitigation rules, which are also administered by the IMM. The cost-review process mitigates the potential for existing resources that have market power (as a pivotal supplier) to inflate capacity prices above competitive levels by withdrawing capacity from the market at an artificially high price. A participant submitting a request to remove an existing resource from the auction at a price above a competitive benchmark price (known as the dynamic de-list bid threshold) is required to provide cost justification for review and approval by the IMM.

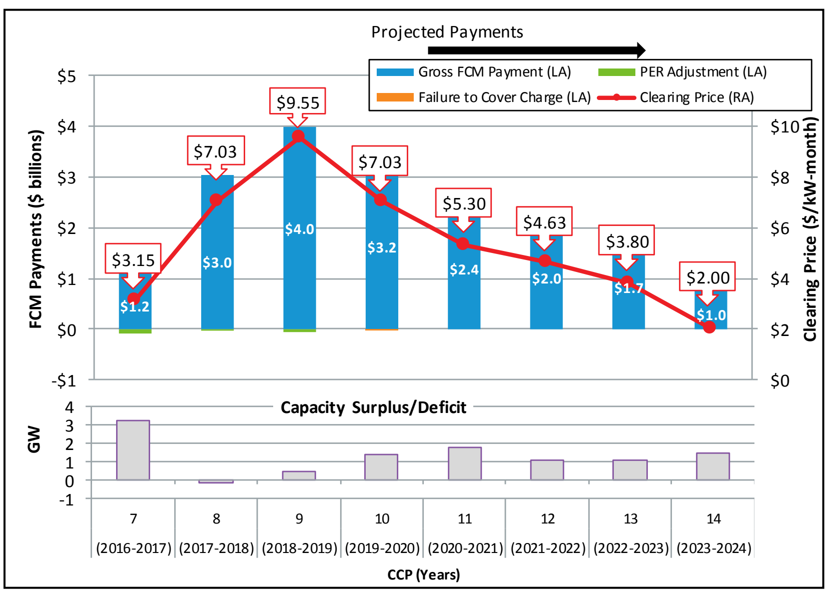
6.2 Capacity Market Payments

This section provides an FCM payment overview, including trends in overall payments and pay-for-performance (PFP) outcomes in 2019. Total payments more than doubled in *CCP 8* (2017/18) due to higher system-wide clearing prices in FCA 8, the corresponding capacity auction. Payments in *CCP* 9 (2018/19) reached a record $4 billion. After the payment peak of *CCP 9*, projected payments declined by an average of $600 million each year through *CCP 14*. This was due to an increasing capacity surplus and lower clearing prices as new capacity entered the market.

6.2.1 Payments by Commitment Period

Trends in FCM payments are driven by underlying FCA clearing prices and volumes. Payments for CCPs 7 -14 are shown in Figure 6-1 below, alongside the Rest-of-Pool clearing price for existing resources. The blue bars represent gross FCM payments by commitment period. Payments for CCPs 10-14 are projected payments based on FCA outcomes, as those periods have not yet been settled.[189] The green bar represents PER adjustments made in past commitment periods. The red line series represents the existing resource clearing price in the Rest-of-Pool capacity zone.[190] Payments correspond to the left axis, while prices correspond to the right axis.

Figure 6-1: FCM Payments by Commitment Period



[189] Payments for incomplete periods, CCP 10 through CCP 14, have been estimated as: $FCA\ Clearing\ Price \times Cleared\ MW \times 12$ for each resource.

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

In *CCP 7*, payments remained relatively low due to system-wide surplus capacity and clearing prices set at the administrative floor price.[191] Capacity payments more than doubled from *CCP 7* to *CCP 8* due to higher primary auction clearing prices. FCA 8 cleared with a capacity deficiency, primarily due to a large amount of retirements. The capacity deficiency triggered administrative pricing rules, which set the clearing price for existing resources at $7.03/kW-month and new resources at $15/kW-month. This resulted in a 162% increase in capacity payments, from the *CCP 7* payment of $1.2 billion to $3.0 billion in *CCP 8*. Peak energy rents declined year-over-year from $87 million in *CCP 7* to $33 million in *CCP 8* due to a system event in August 2016. The event led to PER adjustment settlements in nine months of *CCP 7*, but did not impact *CCP 8* PER adjustments.[192]

High clearing prices in *FCA 8* and *FCA 9* provided price signals to the market that new generation is needed. As more capacity cleared and Net ICR fell, clearing prices declined. System-wide clearing prices fell from $7.03/kW-month in *FCA 10* to $3.80/kW-month in *FCA 13*. In the most recent auction, 637 MWs of new generation and demand response capacity cleared, even as the clearing price fell to $2.00/kW-month. Lower clearing prices are expected to cause a 75% decrease in projected payments, from $4 billion in *CCP 9* down to $1.0 billion in *CCP 14*. FCA 14 prices and payments are the lowest of all 14 primary auctions to date.

6.2.2 Pay-for-Performance Outcomes

There were no Pay-for-Performance (PFP) events in 2019, and therefore no performance charges and credits. The absence of system events and scarcity pricing is discussed in more detail in Section 3.4.7. On September 3, 2018, three months after the implementation of the PFP rules, scarcity conditions were triggered over the course of about 2½ hours due to a combination of higher than anticipated loads and unplanned generator outages. Based on the performance scores of supply resources during the event, credits totaled $44.2 million and charges totaled $36.3 million, representing a small fraction of $4 billion in annual base payments for the corresponding CCP.

6.2.3 Delayed Commercial Operation Rules

On June 1, 2019, the ISO implemented rules to address resources holding capacity supply obligations (CSOs) with a delayed commercial operation date. The rules incent resources to cover their CSOs when they have not physically demonstrated the ability to offer capacity into the energy market. Over the first six months of CCP 10, 28 resources were charged roughly $0.7 million for undemonstrated capacity.

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[191] In FCA 7, Northeastern Massachusetts/Boston capacity zone (NEMA/Boston) supply fell short of the local sourcing requirement. The price in this import-constrained zone was administratively set at $14.99/kW-month for new resources, and $6.66/kW-month for existing resources. This caused the payments for CCP 7 to be slightly higher than CCP 6, despite the decline in the Rest-of-Pool clearing price.

[192] For more information on the August 2016 event, see our Summer 2016 Quarterly Markets Report: https://www.iso-ne.com/static-assets/documents/2016/11/qmr_2016_q3_summer_11_15_2016.pdf

The failure-to-cover charges reallocate money from resources unable to demonstrate their CSOs to load customers who originally paid for the capacity. To determine how much a resource must pay, the ISO calculates a maximum demonstrated output and a charge-rate. The maximum demonstrated output calculation varies by resource type, but is generally the highest output level reached after a resource achieves commercial operation. The value is taken from the past six commitment periods, in addition to the current commitment period through the most recently completed calendar month.[193] The charge rate (prior to June 1, 2022) is the maximum clearing price of the FCA and three annual reconfiguration auctions (ARAs) for the given commitment period. This calculation is used as a transition to the charge-rate run for ARA 3, which will occur for settlements after June 1, 2022. The charge-rate run will incorporate undemonstrated capacity into the original ARA 3 demand curve for the commitment period, and will produce charge-rates for each capacity zone.[194] Once the charge rate is determined, a resource's failure-to-cover charge is the product of its maximum demonstrated output subtracted from its CSO for the settlement month, multiplied by the charge rate.

Before the implementation of the June 2019 failure-to-cover rules, the ISO entered mandatory demand bids for resources that did not take action to cover their CSOs, and were expected to under-perform during the commitment period. The Delayed Commercial Operation rules replace, and improve upon, prior rules by shifting the responsibility of covering undemonstrated capacity to the participant. Now, the participant can either choose to cover the CSO through the secondary markets (annual *or* monthly auctions) until the resource reaches commercial operation, or if the participant does not cover all of the resource's undemonstrated capacity, then they will incur a failure-to-cover charge.

6.3 Review of the Fourteenth Forward Capacity Auction (FCA 14)

This section provides a closer review of FCA 14, the most recent primary auction held in February 2020. Further detail on the auction is contained in the IMM's Winter 2020 quarterly markets report.[195] This section is organized into two subsections. First, an overview of qualified and cleared capacity across a number of different dimensions is provided. Then the focus shifts to auction results, with emphasis on the shift in the demand curve, auction competitiveness and the results of the second substitution auction.

At the beginning of the auction, qualified capacity (41,915 MW) significantly exceeded the Net Installed Capacity Requirement (32,490 MW) by 9,425 MW. The surplus grew from FCA 13 (8,781 MW) as a result of updated forecast models that that led to a 1,260 MW decrease in the Net Installed Capacity Requirement (NICR) from the prior year. The auction closed in the fifth round with a surplus capacity of just under 1,500 MW relative to NICR. As capacity exited the auction, prices fell below the dynamic de-list bid threshold (DDBT) price of $4.30/kW-month in the fourth round. The auction continued into the fifth round (starting price $3.00/kW-month), and cleared at $2.00/kW-month across the entire system. Payments for FCA 14 ($1 billion) are projected to be the lowest since the inception of the forward capacity market.

A total of 2,085 MW of capacity dynamically de-listed (i.e. did not take on a CSO for one year) in rounds four and five; including 900 MW of oil-fired generation, and 1,000 MW of gas-fired

[193] For more information see Section III.13.3.4(b).

[194] For more information see Section III.13.3.4(b).

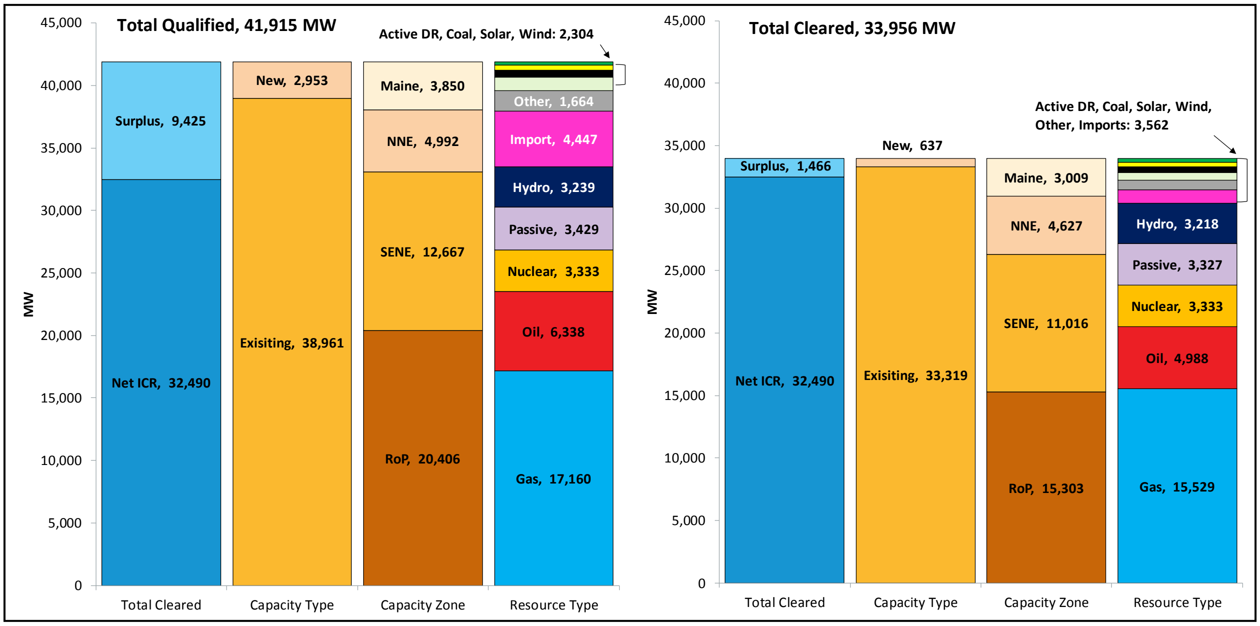
[195] See https://www.iso-ne.com/markets-operations/market-monitoring-mitigation/internal-monitor.

generation. New cleared capacity totaled 637 MW, and primarily consisted of either resources with a renewable technology resource (RTR) exemption, or passive demand response resources. The substitution auction following FCA 14 did not take place since all active demand bids failed to either clear capacity in the FCA or had high Test prices.

6.3.1 Qualified and Cleared Capacity

The amount of qualified and cleared capacity from new and existing resources compared to the capacity requirement provides an important indication of the level of potential competition in the auction. The qualified and cleared capacity in FCA 14 compared to Net ICR (blue bars) is illustrated in Figure 6-2 below. Qualified capacity is shown in the graph on the left and cleared capacity on the right. The height of the stacked bars equals total capacity. The bars on the right show the breakdown of total capacity across three dimensions: capacity type, capacity zone and resource type.

Figure 6-2: Qualified and Cleared Capacity in FCA 14



Overall in FCA 14, qualified capacity exceeded Net ICR of 9,425 MW, by almost 29%. New qualified capacity totaled 2,953 MW, decreasing almost 900 MW from the FCA 13 value (3,840 MW). While each of the prior five FCAs qualified at least 500 MW of new gas-fired generation projects, no new gas-fired generation projects qualified in FCA 14. The decline in clearing prices and increase in capacity surplus over the past several FCAs has made the economic case for new build less attractive. Due to minimum offer floor price rules, new supply can only stay in the auction to a pre-determined price.[196] Many of these prices are above the FCA 14 clearing price of $2.00/kW-month.

As excess supply declined during the auction, total surplus fell from 9,425 MW of qualified capacity to 1,466 MW of cleared capacity. The 7,959 MW difference stems from existing resources de-listing, and new supply resources exiting the market at prices greater than the $2.00/kW-month clearing price. The first orange bar (capacity type) illustrates that existing capacity accounted for over 98% of cleared capacity. Out of the 637 MW that cleared, 635 MW were either resources with a

[196] For more information on the IMM's role in new supply mitigation, see section 6.1.

renewable technology resource (RTR) exemption (described in more detail below), or passive demand response resources.

Resources with an RTR exemption accounted for 50% of total new cleared capacity in FCA 14. The RTR designation allows 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 revenues sources and qualify as a renewable or alternative energy resource under a New England state's renewable portfolio standards located within that state.[197] Entering the auction, there were only 336 RTR MWs available to the entire pool of RTR qualified resources, which totaled 775 MW. Consequently, each resource had their final qualified capacity prorated by 45%. By the end of the auction, 325 of the resources partially cleared 317 MW, leaving 19 MW of RTR-exempt capacity for FCA 15.

Three capacity zones were modelled in addition to Rest-of-Pool: the import-constrained zone of Southeastern New England (SENE), the export-constrained zone of Northern New England (NNE), and the nested export-constrained zone of Maine. The qualified and cleared values are illustrated in the second orange bars (by Capacity Zone). If the import-constraints and export-constraints were binding in the auction, one would expect higher prices in SENE and lower prices in NNE or Maine. None of the constraints bound, which is reflected in an equal clearing price across zones.

6.3.2 Results and Competitiveness

In addition to the amount of qualified capacity eligible to participate in the auction, several other factors contribute to auction outcomes. These factors, including the auction parameters provided by the ISO as well as participant behavior, are summarized in Figure 6-3 below.

On the *demand* side, the demand curve, Net CONE, and Net ICR are shown in black. FCA 14 was the first 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 impacts system reliability at various capacity levels.[198] Net ICR and Net CONE are used as the scaling point for the MRI curve. Net CONE changed due to updated reference technologies in FCA 12.[199] The reference technology for FCAs 12 - 14 reflects costs of a combustion turbine ($8.19/kW-month in FCA 14), which was selected as the most economically efficient resource. The Net ICR value for FCA 14 was 32,490 MW, or 1,260 MW lower than in FCA 13.

On the *supply* side, the qualified and cleared capacities are shown (solid and dashed red lines, respectively). The clearing price of $2.00/kW-month is shown at the intersection of the cleared MW (dotted red line) and the demand curve, 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.[200]

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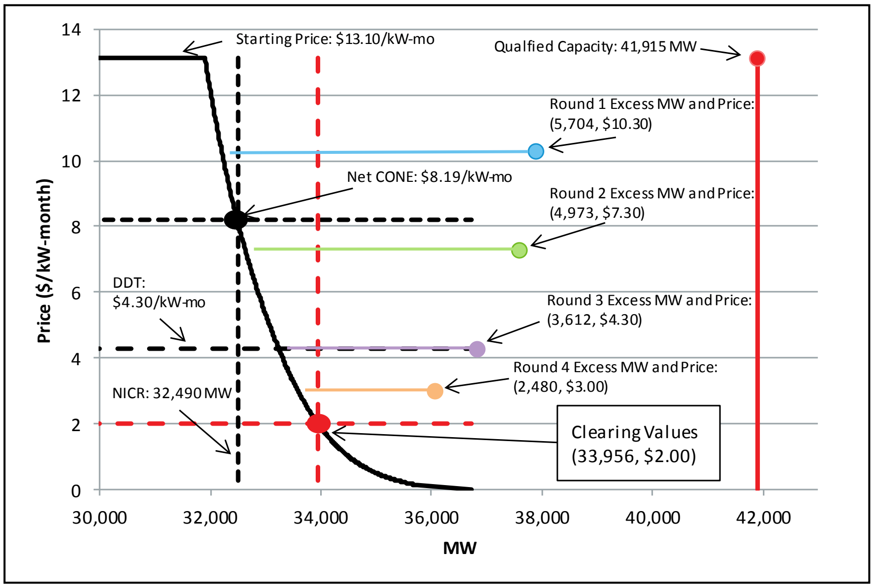
[197] For more information see https://www.iso-ne.com/markets-operations/markets/forward-capacity-market/fcm-participation-guide/qualification-process-for-new-generators

[198] Prior to FCA 14, a transitional approach was taken, with the demand curve reflecting a hybrid of the previous linear demand curve and the new convex-shaped MRI curve. The transition period began 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.

[199] 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).

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

Figure 6-3: System-wide FCA 14 Demand Curve, Prices, and Quantities



The auction closed in the fifth round for the whole system. The fourth round opened with 3,612 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.[201] 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. Despite the fact that the fourth round closed at $3.00/kW-month, existing resources submitted just 424 MW of de-list bids. Therefore, the auction continued into the fifth round with excess supply of 2,480 MW.

In the fifth round, existing resources submitted 3,684 MW of de-list bids, and new resources submitted 600 MW of offers to exit the auction. Nine resources, including six existing resources and three new active demand response resources, set price at $2.00/kW-month. The market-clearing engine, which selects capacity to maximize social surplus while setting supply equal to demand, partially cleared capacity from the six existing resources and did not clear new resource capacity (as they had not elected to be rationable).[202]

Competitiveness

The IMM reviews bids and offers flagged by buyer-side (ORTPs) and seller-side (DDBT prices) market power thresholds for competitiveness. The detail and results of this review process are covered further in Section 6.7. This review process is done before the auction. After the auction, the IMM reviews participant behavior, the presence of market power, and whether market power potentially impacted auction outcomes. Dynamic de-list bids, which ultimately set the clearing price

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[201] Excess system capacity only includes import capacity up to the capacity transfer limit.

[202] 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.

as described above, are not subject to an IMM cost review.[203] The supply curve in the fourth and fifth rounds was relatively flat, which would make it difficult for a market participant to profit from economic withholding given the small impact on clearing prices of doing so.

The pivotal supplier test, covered in detail in Section 6.6, does not measure a portfolio's ability to exercise market power beyond the beginning of the auction. Because capacity conditions change in the auction (new resources leave, existing capacity de-lists, the quantity demanded changes), a supplier that was not pivotal at the start of the auction (when the IMM made the pivotal status determination) may become pivotal in the auction.[204] This is increasingly likely as the auction proceeds into later rounds and the capacity margin decreases. Heading into the fifth round, capacity exceeded demand by 2,480 MW, meaning that a supplier would need a portfolio of at least this size to unilaterally exercise market power. Only one supplier had a portfolio this large, and did not attempt to remove that level of capacity during this round. The fact that there was only one system-level pivotal supplier entering the final round (none at the zonal level), and that the supplier did not attempt to remove the necessary quantity of capacity to exercise market power, further suggests there was sufficient competition across the system to support competitive price levels.

Based on the pre-auction mitigations, excess capacity during the auction, and liquidity of dynamic de-list bids, it is our opinion that the results of the auction came out of a competitive process.

6.3.3 Results of the Substitution Auction (CASPR)

In FCA 13, the ISO introduced Competitive Auctions with Sponsored Policy Resources (CASPR). CASPR provides a market-based mechanism for state-sponsored resources to enter the FCM while maintaining competitive prices in the primary auction. The substitution auction is intended to accommodate new resources that secure out-of-market revenue through state-sponsored programs designed primarily to meet state environmental goals.

FCA 14 marked the second year with the substitution auction construct. In order to participate, resources submit demand bids and supply offers prior to the FCA; however, this does not guarantee inclusion in the substitution auction. For example, any new supply capacity that clears in the FCA, but was offered into the substitution auction, is removed. Like all other auctions in the FCM, prices can separate at external interfaces and capacity zones if certain constraints bind. Cleared supply offers obtain capacity from the FCA, while cleared demand bids shed capacity obtained in the FCA. Depending on whether the substitution auction-clearing price is positive, cleared supply offers are compensated, and cleared demand bids are charged, and *vice versa*.

In FCA 14, the substitution auction did not proceed. While there were 292 MW of supply seeking to acquire capacity obligations, there was no demand because the existing capacity resources either exited the FCA without a CSO or were deemed ineligible because their Test price was higher than the FCA clearing price (allowing for a certain tolerance). A test price is an IMM-calculated value that represents the competitive cost of obtaining a CSO, exclusive of any potential severance payment expectation (Section 6.7.2 covers test prices in more detail).

[203] Under the Tariff, as the DDBT is a proxy price intended to represent the net going forward costs of the likely marginal resource. See Docket No. ER18-620-000, Order Accepting Tariff Revisions, to update the DDBT price at https://www.ferc.gov/CalendarFiles/20180309160822-ER18-620-000.pdf

[204] In fact, suppliers that have been deemed pivotal prior to the auction may not be pivotal at the start of the auction (if the quantity demanded along the sloped demand curve is greater than NICR or LSR, respectively).

6.4 Forward Capacity Market Outcomes

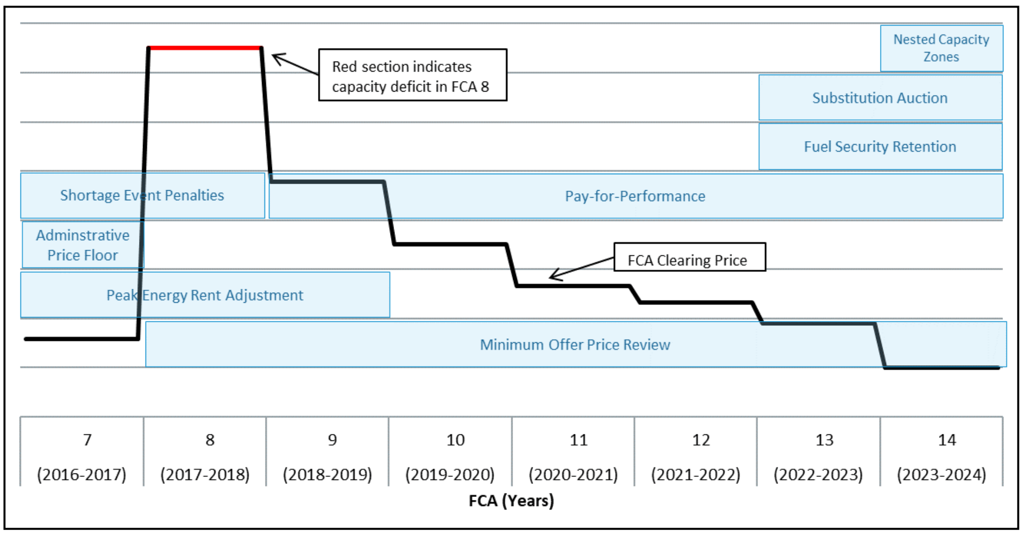
This section reviews the overall trends in prices and volumes in the FCM. It covers both the primary auction (FCA), as well as secondary trading of capacity in the substitution auction, reconfiguration auctions, and bilateral transactions.

6.4.1 Forward Capacity Auction Outcomes

FCM prices are determined by the interaction of capacity supply and demand. When capacity is in relatively short supply, like in FCA 8, we expect prices to be higher. When supply is more abundant, we expect the opposite.

It is also important to interpret pricing outcomes in the context of the market rules that were in effect at the time of an auction. This is particularly important, since the FCM has undergone a number of significant market rule changes in recent years. This is illustrated in Figure 6-4 below, which shows the trend in Rest-of-Pool FCA clearing prices against the backdrop of some of the major parts of the FCM rules that were in effect for some, but not for all, auctions.

Figure 6-4: FCA Clearing Prices in the Context of Market Rule Changes



The first seven auctions cleared at the administrative market price floor. The price floor protected supply from low prices in a market environment with excess supply and a vertical (fixed) demand curve. Capacity prices under the vertical demand curve construct were subject to large year-to-year changes as the result of under- and over-supply. Administrative pricing was the mechanism to price capacity when supply did not equal demand. Such a large swing in price occurred in FCA 8, when a number of large resources retired and cleared capacity fell short of Net ICR. By contrast, in FCA9 the sloped demand curve improved price formation and reduced price volatility.[205] When there is a surplus of supply relative to Net ICR, as happened since FCA 9, a sloped demand curve results in a price below Net CONE.

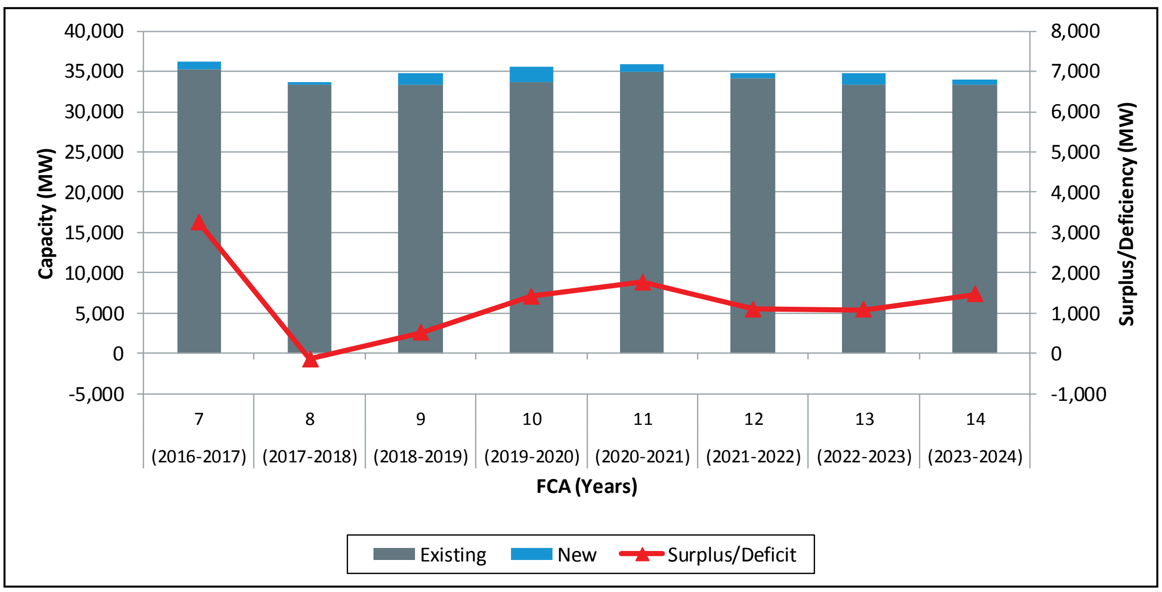
[205] A linear sloped system demand curve was implemented for FCA 9, but the zonal demand curves remained vertical. In FCA 10 linear sloped demand curves were used at both the system and zonal level. More recently, for FCA 11 both sloped and non-linear demand curves (except for a portion of the system curve) were implemented based on the MRI methodology.

Starting with FCA 8, there were a number of significant changes to the capacity market design. The minimum offer floor price rules were implemented, which are intended to protect the market from the exercise of buyer-side market power (i.e. the ability to decrease prices below competitive levels). From FCA 9, the new Pay-for-Performance (PFP) market rules replaced the shortage event penalty rules. Combined, these rules delivered a greater degree of active participation in the auctions, with more new and existing resources submitting offers in the auction.

In the most recent auction, two rules were implemented with opposing expected impacts on FCA clearing prices. First, the ISO agreed to a cost-of-service agreement with Mystic 8 and 9, citing system-wide fuel security needs. The Mystic resources account for 1,413 MW of capacity (by CSO), and were treated as price-takers in the FCA. This has a downward impact on prices in FCA 13 and FCA 14. The second rule, CASPR, addresses the price-suppressing impact of state-sponsored resources in the FCA, along with the Minimum Offer Price Rules (MOPR). These resources are often priced too high (after the application of buyer-side mitigation) to clear in the FCA, but with CASPR are able to take on capacity obligations through participation in the secondary auction.

The procured capacity relative to the Net ICR by auction is shown in Figure 6-5 below. The stacked bar chart shows the total cleared MWs in each auction, broken down between existing and new capacity resources. The red line (corresponding to the right axis) shows the surplus or deficit relative to Net ICR.

Figure 6-5: Cleared and Surplus Capacity in FCAs 7 through 14



Prior to FCA 8, the auction was largely dominated by price-insensitive supply and an administrative price floor. The auction clearing price was limited by a floor price, which led to some price certainty for existing resources. With these auction conditions, there was at least 2,000 MW of excess cleared capacity in the early FCAs.[206] In FCA 8, cleared capacity fell below Net ICR for the first time due to a higher Net ICR (up 900 MW from FCA 7) and 2,700 MW of retirements.

[206] Cleared capacity in this figure represents the cleared MW value from the FCA. It does not account for any proration or specific resource caps.

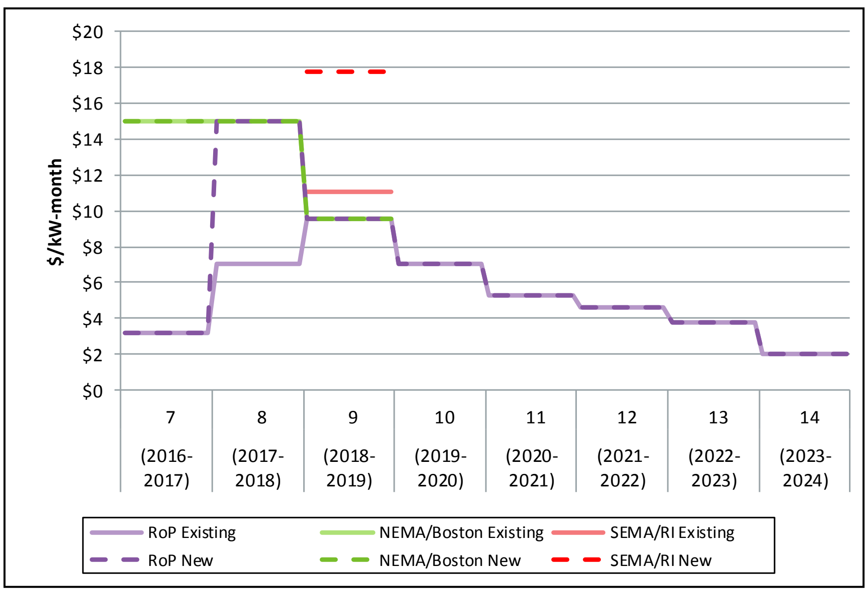
In the subsequent three auctions (FCAs 9, 10, 11) new generation and demand response resources cleared 1,400, 1,800, and 900 MW, respectively. The new generation, along with fewer retirements, turned a 140 MW deficit into a 1,800 MW surplus in the span of three auctions.

The surplus declined in FCAs 12 and 13, primarily due to one-year dynamic de-lists. Once the auction price went below the dynamic de-list bid threshold ($5.50/kW-month in FCA 12 and $4.30/kW-month in FCA 13), resources entered de-list bids to remove their capacity for the commitment period. In FCA 13, the dynamic de-lists were comprised of 742 MW of oil-fired resources, 95 MW of coal-fired resources, and 29 MW of other resources. The surplus fell 700 MW from roughly 1,800 MW in FCA 11 to 1,100 MW in FCAs 12 and 13.

The surplus rose once again in FCA 14 to 1,500 MW, driven primarily by a decrease in the Net ICR of almost 1,300 MW. New resources accounted for over 600 MW of cleared capacity, primarily passive demand resources, solar, and wind. Dynamic de-list bids, totaling almost 2,100 MW, were comprised of mostly oil- (900 MW) and gas-fired (1,000 MW) resources.

The changes in new and existing capacity clearing prices for each FCA are illustrated in Figure 6-6 below. The solid lines represent the price paid to existing resources. Dashed lines represent the price paid to new resources.

Figure 6-6: Forward Capacity Auction Clearing Prices



In FCA 7, the NEMA/Boston zone cleared at $15.00/kW-month for new capacity when a new qualified resource submitted a bid in the first round. Existing capacity in NEMA/Boston was paid an administrative price of $6.66/kW-month. That price was set by administrative pricing rules.[207] New and existing capacity across the rest of the system cleared at the floor price of $3.15/kW-month.

FCA 8 concluded in the first round when a new resource submitted a bid to withdraw capacity at $14.99/kW-month. In this case, the auction closed during the first round and various

[207] See Attachment B of the FCA 7 results filing to FERC: https://www.iso-ne.com/static-assets/documents/regulatory/ferc/filings/2013/feb/er13_992_000_2_26_13_7th_fca_results_filing.pdf

administrative prices were triggered.[208] New capacity resources in Rest-of-Pool (RoP) and all resources in NEMA/Boston received $15.00/kW-month. Existing resources in RoP were paid an administrative price of $7.03/kW-month.

The higher capacity prices in FCA 8 sent a signal to market participants that load is willing to pay for more capacity that will improve system reliability. Clearing prices fell steadily from FCA 9 through FCA 11. The system-wide clearing price in FCA 9 was $9.55/kW-month.[209] Clearing prices continued to fall in FCAs 10 and 11.

In FCAs 12 through 14, the clearing prices dropped below the dynamic de-list bid threshold (DDBT) price. In each auction, the closing round started at the DDBT price. A dynamic de-list bid set the system-wide clearing price at $4.63/kW-month in FCA 12, at $3.80/kW-month in FCA 13 and at $2.00/kW-month in FCA 14.

6.4.2 Secondary Forward Capacity Market Results

Reconfiguration auctions and bilateral transactions facilitate the secondary trading of CSOs. That is, they provide an avenue for participants to adjust their CSO positions after the primary FCA takes place.[210] Differences between the FCA and reconfiguration auction clearing prices can also present an opportunity for participants that obtained an obligation in the FCA to shed it at a lower price (i.e. they receive the FCA clearing price minus the ARA clearing price).

Prices in the secondary markets are set through ISO administered reconfiguration auctions or through bilateral agreements between parties. Unlike the primary auctions in FCA 1 through 7, there are no floor prices in Annual Reconfiguration Auctions (ARAs), which led to low clearing prices during periods when the system was long. The absence of a floor price means that the clearing price could be set below the FCA floor price in those reconfiguration auctions.

Recently, the IMM reported on a number of combined cycle (CC) and gas turbine (GT) resources taking on additional capacity supply obligations (CSOs) in the secondary markets during CCP 9, and not offering the acquired capacity in the day-ahead and real-time energy markets.[211] The unoffered capacity was particularly pronounced in October, as the FCM transitioned from the summer period (June through September) to the winter period (October through May). As the FCM transitions to winter, resources receive higher qualified capacity values. The IMM published its position that participants should not take on additional obligations if they do not expect to be capable of delivering the capacity, and that the market rules around qualified capacity be reviewed.[212]

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[208] See page 2 for more information: https://www.iso-ne.com/static-assets/documents/regulatory/ferc/filings/2014/feb/er14_1409_000_fca8_results_filing_2_28_2014.pdf

[209] Within SEMA/RI, the price separated due to inadequate supply. The administratively-set prices were $17.73/kW-month for new resources and $11.08/kW-month for existing resources.

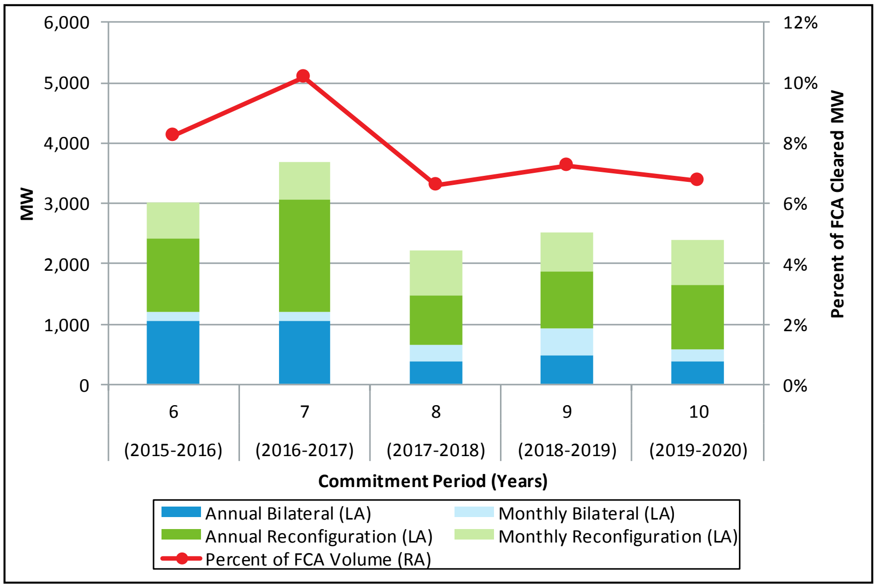
[210] There are many opportunities for participants to adjust their obligations. Immediately after the FCA occurs, the ISO holds a substitution auction. Before the commitment period, there are three annual reconfiguration auctions (ARAs) to acquire one-year commitments. There are twelve monthly reconfiguration auctions (MRAs) held starting two months before a capacity commitment period. Windows for submitting bilateral transactions are open around the reconfiguration auctions.

[211] Combined cycle (CC) and gas turbine (GT) generators are the focus of this section as their maximum capacities are heavily impacted by ambient air conditions.

[212] See Section 5, Unoffered Winter Capacity in the FCM, of the IMM's Fall 2018 Quarterly Markets Report, at https://www.iso-ne.com/static-assets/documents/2019/03/2018-fall-quarterly-markets-report.pdf

Figure 6-7 below shows the average annual volume by secondary market product (stacked bars corresponding to the left axis) and volume as a percentage of cleared volume in the corresponding FCA (red line corresponding to the right axis).[213] Monthly and annual *reconfiguration auction* volumes are shown in green colors and monthly and annual *bilateral transaction* volumes in blue colors.

Figure 6-7: Traded Volumes in FCA and Reconfigurations



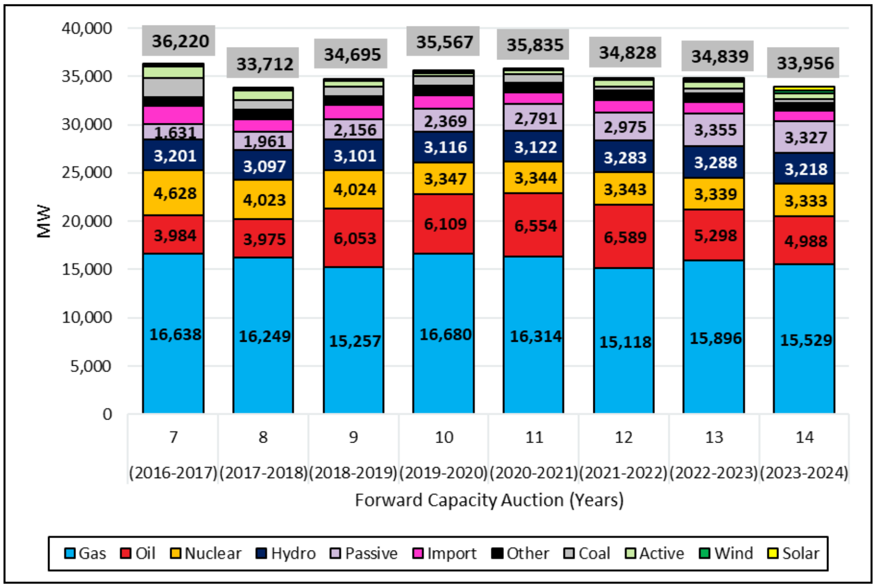
Historically, the traded volume in the secondary markets has been much lower than in the primary auctions. From CCP 6 through CCP 10, secondary traded volumes averaged about 8% of the primary auction volumes, with a high of 10% occurring in CCP 7 (roughly 3,700 MW). The majority of secondary trading occurs during annual bilateral periods and reconfiguration auctions. The monthly reconfiguration auction volumes are affected by seasonal temperatures. During the winter periods many thermal generators have additional capability that can be traded in the monthly auctions.

6.5 Trends in Capacity Supply Obligations

This section discusses trends and major changes in capacity since FCA 7. Retirements and new additions drive major changes in capacity supply. There are three categories of capacity resources that can participate in the FCM: generation, demand response and import resources. Figure 6-8 below illustrates the relative share of these categories in the context of total capacity (gray box), with generation broken down by fuel type and demand response categorized as passive or active..

[213] Volumes are shown as average annual weighted values. For example, a monthly product gets a weight of 1/12th, an annual product a weight of 1 etc.

Figure 6-8: Capacity Mix by Fuel Type from FCA 7 through FCA 14



The most substantial movements over the past eight FCAs were made by passive and active demand response resources. Between FCAs 7 and 14, active demand response fell from 1,117 MW to 592 MW. Meanwhile, passive demand response more than doubled from 1,631 MW to 3,327 MW. This is in line with state policy goals to increase energy efficiency, and federal regulations that impact the ability of certain emergency generators to participate as active demand response resources. More recently, capacity from oil- and gas-fired generation decreased by over 300 MW each, while solar and wind generation were the fuel only types with capacity increases; they increased by over 180 MW and 90 MW respectively.

6.5.1 Retirement of Capacity Resources

A participant can choose to retire its resource by submitting a retirement request to the ISO.[214] This is an irrevocable request to retire all or a portion of a resource.[215] Up to FCA 11, this request was not contingent on market clearing prices; it was known as a non-price retirement. Starting in FCA 11, non-price retirements were replaced by priced-retirements which go through a cost-review process to establish if the bid may be an attempt to inflate clearing prices above competitive levels. A resource can also choose an unconditional retirement, choosing to retire regardless of the ISO's reliability determination.

Retired generating resources with capacity exceeding 50 MW from the FCA 7 are shown in Table 6-1 below.

[214] The FCA retirement permanently sheds a CSO; however, a resource may effectively retire before the FCA retirement, if it sheds its obligation through secondary markets and the retirement does not trigger reliability concerns.

[215] Non-price retirement requests are subject to a review for reliability impacts. If the ISO notifies a resource owner of a reliability need for the resource, the resource owner has the option to retire the resource as requested or continue its operation until the reliability need has been met. Once the reliability need has been met, the resource must retire.

Table 6-1: Generating Resource Retirements over 50 MW from FCA 7 to FCA 14

FCA # (Commitment Period)	Resource Name	Fuel Type	Capacity Zone	FCA MW
FCA 7 Total (2016/17)	**AES Thames**	**Coal**	**Connecticut**	**184 MW**
FCA 8 (2017/18)	Brayton Point 1	Coal	SEMA	228
FCA 8 (2017/18)	Brayton Point 2	Coal	SEMA	226
FCA 8 (2017/18)	Brayton Point 3	Coal	SEMA	610
FCA 8 (2017/18)	Brayton Point 4	Coal	SEMA	422
FCA 8 (2017/18)	Bridgeport Harbor 2	Oil	Connecticut	130
FCA 8 (2017/18)	Norwalk Harbor 1	Oil	Connecticut	162
FCA 8 (2017/18)	Norwalk Harbor 2	Oil	Connecticut	168
FCA 8 (2017/18)	Vermont Yankee Nuclear	Nuclear	Vermont	604
FCA 8 Total (resources > 50 MW)				**2,550 MW**
FCA 9 (2018/19)	Mt. Tom.	Coal	WCMA	144
FCA 10 (2019/20)	Pilgrim Nuclear	Nuclear	SEMA	677
FCA 12 (2021/22)	Bridgeport Harbor 3	Oil	Connecticut	383
FCA 13 (2022/23)	Mystic 7	Oil	NEMA/Boston	575
FCA 14 (2023/24)	Yarmouth 1	Oil	Maine	50
FCA 14 (2023/24)	Yarmouth 2	Oil	Maine	51
FCA 14 Total (resources > 50 MW)				**101 MW**

Note: The capacity defined here is the most recent non-zero FCA cleared capacity for each resource.

Energy policy and market dynamics have been cited as reasons leading to increased retirement pressure on nuclear, coal- and oil-fired generators. Increasing emissions prices and other energy polices have led to increased production costs. Many of the retiring resources are older resources that may require environmental upgrades or major overhauls. Finally, the decreasing price of renewables and natural gas has led to lower energy prices and additional natural gas-fired capacity.

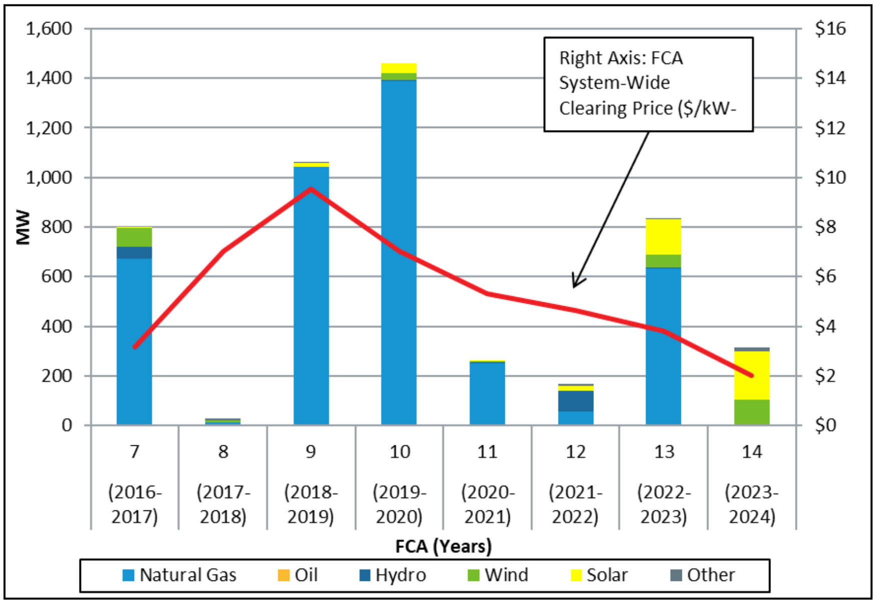
6.5.2 New Entry of Capacity Resources

This section provides an overview of major new resources entering the FCM. New entry typically implies a resource entering the market for the first time. However, existing resources that require significant investment to repower or provide incremental capacity, and meet the relevant dollar per kilowatt thresholds in the tariff, can also qualify as new capacity resources.[216] Project sponsors of new capacity resources can elect to lock in the FCA clearing price for up to seven years.

Newer, cleaner and more efficient technology, combined with low natural gas prices, increasing emissions costs, and environmental regulations have contributed to more investment in new natural gas-fired generators. Figure 6-9 represents new generation capacity by fuel type since FCA 7.

[216] See Market Rule 1, Section III.13.1

Figure 6-9: New Generation Capacity by Fuel Type from FCA 7 to FCA 14



Note: "Other" category includes landfill gas, methane, refuse, solar, steam, and wood.

The majority of new additions between FCA 7 and FCA 13 were natural gas-fired resources. In *FCA 7*, Footprint (gas) added 674 MW of capacity. In *FCA 9*, over 1,000 MW of capacity was added; the largest addition was CPV Towantic, a 725 MW combined cycle resource in Connecticut. *FCA 10* saw the largest amount of new generation entry, with an additional 1,400 MW of new natural gas-fired capacity. Three natural gas-fired resources accounted for 94% of this supply: Bridgeport Harbor 6(484 MW), Canal 3 (333 MW), and Burrillville Energy Center (485 MW).[217]

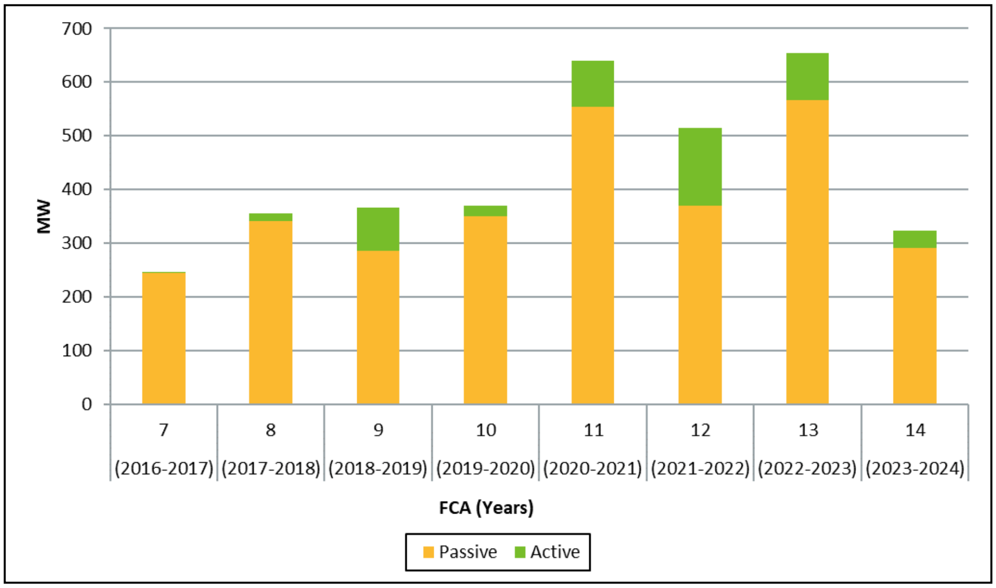
For *FCA 14*, no new, large gas-fired resources cleared in the auction. This led to a reduction in cleared new generation compared to FCA 13. An increase in state-sponsored solar resources and new wind resources were the primary sources of new cleared generation. Total new cleared solar capacity increased by 36%, from 141 MW in FCA 13, to 192 MW in FCA 14. State policies continue to be a key driver in the development of new renewable and energy efficiency resources, as discussed below.

Significant increases in new passive demand response resources have more than offset active demand response retirements as with the previous FCA. Passive demand response is defined as on-peak and seasonal-peak resources. Active demand response is broken into real-time demand response and emergency generation.[218] Figure 6-10 below shows cleared new active and passive resources since FCA 7.

[217] In September 2018, ISO-NE filed to terminate the 485 MW CSO of the Burrillville Energy Center, which was accepted by the Commission. Per the filing, the project sponsor had not made sufficient progress to achieve Clear River Unit 1's critical path schedule milestones, and the commercial operation date for Clear River Unit 1 was more than two years beyond June 1, 2019, which is the start of the Capacity Commitment Period in which the resource first obtained a CSO.

[218] On-peak resources are energy efficiency and load-reducing distributed generation projects that provide long term peak capacity reduction. Seasonal-peak resources are comprised of energy efficiency projects that also provide long term peak reductions. The difference is that seasonal-peak resources provide reductions at or near the system peak, meaning they have a broader definition of peak hours. Lastly, real-time demand response resources are dispatchable resources that provide reliability during demand response events.

Figure 6-10: New Demand (Reduction) Resources with a CSO



The annual additions of new demand resources in the FCM is primarily driven by state-sponsored energy efficiency programs that participate in the FCM as passive (on-peak or seasonal-peak) supply resources. In FCA 14 alone, over 320 MW of new demand resources cleared. This was split between 31 MW of active demand response resources and 292 MW of passive demand resources.

6.6 Market Competitiveness

This section discusses the competitiveness of the Forward Capacity Market (FCM) using two key metrics:

- Residual Supply Index (RSI)
- Pivotal Supplier Test (PST)

The RSI measures the percent of capacity remaining in the market after removing the capacity of the largest supplier. The PST determines whether the ISO needs a supplier's capacity to meet system and import-constrained zone requirements.[219] Both metrics respect system constraints and account for affiliations between suppliers to reflect all capacity under a supplier's control. These metrics consider only existing resources prior to the auction to avoid predicting intra-auction new supply behavior.[220]

The RSI measures the percentage of capacity requirements (system or zonal) that can be met without capacity from the largest supplier's portfolio of qualified capacity resources. It is measured on a continuous scale from zero to an uncapped upper limit. When the RSI is greater than 100%, relevant capacity requirements can be met without capacity from the largest supplier. This

[219] Section III.A.23 of the Tariff.

[220] 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)."

indicates that the largest supplier should have little opportunity to profitably increase the market-clearing price. Alternatively, if the RSI is less than 100%, the largest supplier is needed to meet demand. Consequently, the largest supplier could increase its offer prices above competitive levels to increase the market clearing price. Therefore, the lowest possible value of zero represents a pure monopoly scenario.

While the RSI uses a continuous measure and provides a sense of the largest supplier's ability to influence clearing prices, the PST is binary and asks whether each individual supplier is needed to meet the system and import-constrained zone requirements. The PST therefore provides the total number of suppliers who may be able to influence prices. The PST compares (1) the total existing capacity in a zone without a given supplier's portfolio of existing capacity to (2) the relevant capacity requirement for the zone.[221] If the former quantity is less than the latter quantity, the supplier is pivotal. As a result, any de-list bids submitted by pivotal supplier at prices above the dynamic de-list bid threshold may be subject to mitigation.[222] This process ensures that suppliers do not withdraw capacity from the auction at uncompetitive prices to raise the FCA clearing price in a way that may benefit the remainder of their portfolio.

Both metrics use the following inputs:

- *Capacity requirements* – both at the system level (Net Installed Capacity requirement, or Net ICR) and the import-constrained area level (Local Sourcing Requirement, or LSR). The Net ICR and LSR change from year to year.
- *Capacity zone modelling* – different capacity zones are modelled for different FCAs depending on the quantity of capacity in the zone and on transmission constraints.
- *The total quantity of existing capacity* – a value driven by retirements from existing resources and additions from new resources (which become existing resources in subsequent years). Recently, there have been steady gains in large new and incremental generation (described in Section 6.5.2).
- *Supplier-specific portfolios of existing capacity* – values that can change year-over-year as a result of mergers, acquisitions, divestitures, affiliations, resource performance, etc. To avoid providing supplier-specific data, these are not described in any detail in this document, but should be taken into account when considering the analysis.

6.6.1 Residual Supply Index Results

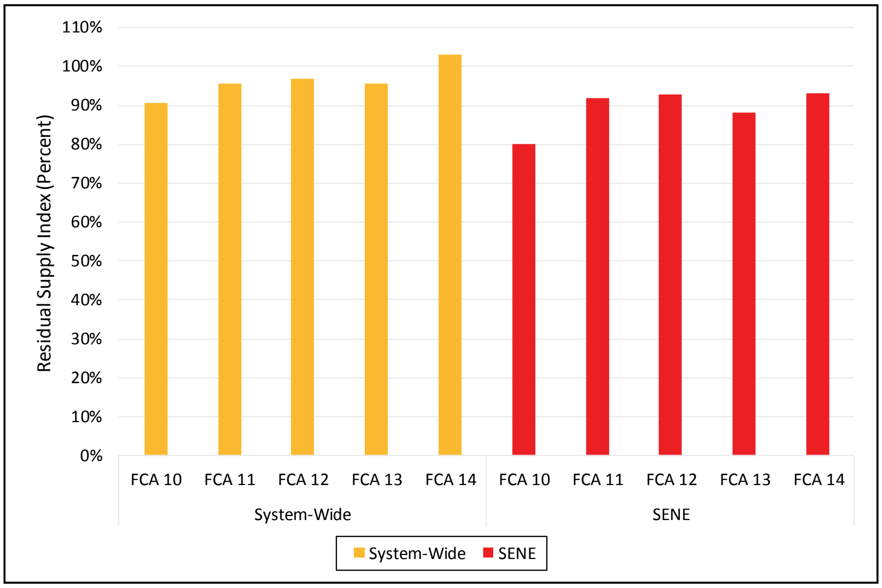
The RSIs for the system and for each import-constrained zone over the past five FCAs are illustrated in Figure 6-11 below.[223]

[221] The relevant 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.

[222] Note that there are certain conditions under which capacity is treated as non-pivotal. These conditions are described in Section III.A.23.2 of the Tariff.

[223]The RSI measure in this section leverages the capacity counting rules outlined in the Tariff for the Pivotal Supplier Test. These are the most recent capacity counting rules for this purpose and were in effect beginning with FCA 10. They are used for prior auction periods for consistency.

Figure 6-11: Capacity Market Residual Supply Index, by FCA and Zone



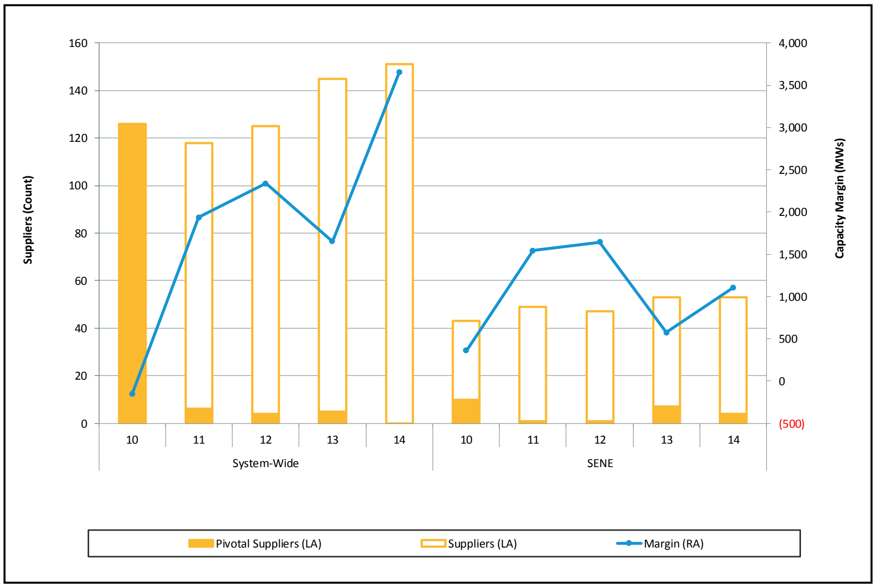
With the exception of the most recent auction (FCA 14), the RSI was below 100% in every auction since FCA 10, at both the system and zonal levels. An RSI below 100% indicates the presence of at least one pivotal supplier. The system-wide RSI (yellow) increased from 91% in FCA 10 to a high of 103% in FCA 14. The changes can be attributed to a variety of factors including: changes to the largest supplier (there were three over the study period) resulting from resource retirements, acquisitions, and sales; the steady procurement of new generation in recent FCAs; and reductions in Net ICR.

The zonal RSI (red) increased from 80% in FCA 10 to a high of 93% in FCAs 12 and 14. The decrease in FCA 13 is due to a higher LSR value and retirements within the capacity zone.

6.6.2 Pivotal Supplier Test Results

The number of suppliers (both pivotal and non-pivotal) within each zone over the past five FCAs are presented in Figure 6-12 below. To provide additional insight into the approximate portfolio size needed to be pivotal, the figure also presents the margin by which the capacity exceeded or fell below the relevant capacity requirement. For example, consider the SENE capacity zone in FCA 14. The amount of capacity exceeded the LSR, resulting in a capacity margin of approximately 1,105 MWs (right axis – blue marker). Consequently, only suppliers with a portfolio of greater than 1,105 MWs in this zone were pivotal in FCA 14. Of the 53 suppliers in SENE in FCA 14 (left axis – yellow bar), only 4 (highlighted in yellow) were pivotal.

Figure 6-12: Overview of Suppliers, Pivotal Suppliers, and Capacity Margin, by Zone



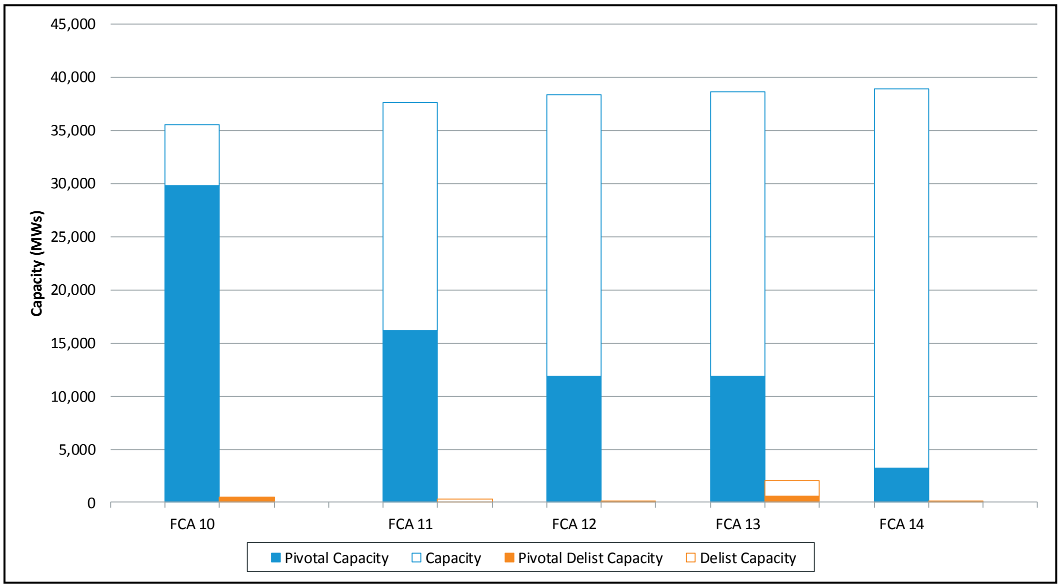
At the system level, the negative capacity margin in FCA 10 turned positive in FCA 11, which explains why all suppliers were pivotal in FCA 10 and only a small handful were pivotal in FCA 11. The capacity margin increased significantly and remained high over the next four FCAs. In FCA 14, a supplier needed a portfolio of over 3,650 MWs to be pivotal, resulting in no pivotal suppliers. The dramatic increase in the system capacity margin from 1,650 MWs in FCA 13 was driven largely by a significant decrease in net ICR, down 1,260 MWs from FCA 13 to FCA 14 (as opposed to no significant change in net ICR from FCA 12 to FCA 13). Consequently, there have been few pivotal suppliers at the system level since FCA 11.

The SENE capacity zone margin fell in FCA 13 due to a higher LSR value and retirements within the capacity zone, but rose again in FCA 14 primarily due to a significant drop in the LSR. The margin rose 530 MWs, from 570 MWs in FCA 13 to 1,100 MWs in FCA 14. The higher capacity margin led to four pivotal suppliers in FCA 14, down from seven pivotal suppliers in FCA 13.

Pivotal Suppliers submitting De-list Bids

While a pivotal designation may indicate a supplier's ability to influence clearing prices, a de-list bid is necessary to exercise it. An overview of total capacity, pivotal capacity (i.e., capacity associated with a pivotal supplier), de-list capacity, and pivotal capacity with de-list bids, for the last five FCAs, across all capacity zones is presented in Figure 6-13 below.

Figure 6-13: Overview of Resources, Pivotal Resources, De-lists, and Pivotal De-lists



There have been significant swings in de-list bids and their pivotal status. In FCA 10 when system conditions were tight, all of the de-list capacity was deemed pivotal. As the capacity margin turned positive in FCAs 11 and 12, not only did the number of pivotal resources decrease, but there were no active de-lists from pivotal suppliers during either auction. As a result, no mitigation was applied to existing resources in these auctions. In FCA 13, several pivotal resources submitted 628 MW of de-lists bids; these accounted for 30% of total de-list capacity. Ultimately, mitigation did not apply to any de-list capacity in FCA 13, since resources either withdrew their bid or lowered their price below the IMM mitigated price. In FCA 14, there were a handful of pivotal suppliers at the zonal level, though none submitted de-list bids.

The results of these two complementary measures (the residual supply index and the pivotal supplier test) indicate that, historically, with the exception of FCA 14, the New England capacity market has been structurally uncompetitive at both the zonal and system levels. However, even when suppliers do have market power, buyer- and supplier-side mitigation rules are in place to prevent the potential exercise of market power. This is discussed in the next section.

6.7 Capacity Market Mitigation

In this section, we provide an overview of the mitigation measures employed in the FCM, as well as summary statistics on the number and impact of these measures. To address market changes, this section presents summary information for FCA 10 through FCA 14.

The FCM is monitored for two forms of market power: supplier-side and buyer-side.

6.7.1 Supplier-Side Market Power

A market participant attempting to exercise supplier-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.

De-list bids are the mechanism that allow capacity resources to remove some or all of their capacity from the market for one or more commitment periods. De-list bids specify the lowest price that a resource would be willing to accept in order to take on a capacity supply obligation (CSO). To restrict resources from leaving the market at a price greater than their costs, the IMM reviews de-list bids above a proxy competitive offer threshold called the dynamic de-list threshold (DDBT) price.[224] A competitive de-list bid is consistent with the market participant's net going forward costs, expected capacity performance payments, risk premium, and opportunity costs. All existing capacity resources, as well as certain types of new import capacity resources (described below), are subject to the pivotal supplier test, which is described in more detail in the last section. If the IMM determines that a de-list bid is uncompetitive and the supplier fails the pivotal supplier test, the IMM mitigates the de-list bid to a competitive price.

While there are a variety of de-list bid types, only a few require review by the IMM. Prior to FCA 11, reviewable de-list bid types included general static de-list bids, import and export bids, and permanent de-list bids.[225,226]

In FCA 11, permanent de-list bids were replaced by "retirement and permanent de-list bids" for resources greater than 20 MW. Between FCAs 8 and 11, there were no permanent de-list bids or retirement de-list bids for resources greater than 20 MW, and there was only one export de-list bid. In *FCA 12*, the lead participant for Bridgeport Harbor 3 submitted a 383 MW retirement de-list bid, and Enerwise Global Technologies, Inc. submitted retirement de-list bids for over 100 MWs. In *FCA 13,* over 1,400 MW of retirement de-list bids came from Mystic 8 and 9. While their bids were mitigated down, they were denied for reliability and treated as existing capacity in FCAs 13 and 14.

For *FCA 10* through *FCA 14*, the IMM reviewed 130 general static de-list bids from 12 different lead participants, totaling roughly 9,100 MW of capacity (an average of 1,800 MW per auction).[227] Generation resources accounted for 8,500 MW of the total capacity, even though they only accounted for 45 of the 130 general static de-list bid submissions. Demand response resources made up 83 resources, but only 600 MW of the total capacity. This is consistent with the smaller size of demand response resources compared to generation resources. Separate from the above statistics, the IMM reviewed over 11 supply offers from new import capacity resources without transmission investments, totaling approximately 3,500 MW.[228]

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[224] De-list bids priced below the DDBT are presumed to be competitive and are not subject to the IMM's cost review or mitigation; consequently, they are not discussed in this section. Market participants can dynamically de-list resources if the auction price falls below the DDBT price. The DDBT has undergone a number of revisions since the start of the FCM. The DDBT price was $5.50/kW-month in FCAs 10, 11, and 12, and $4.30/kW-month in FCAs 13 and FCA14.

[225] In FCA 10, various changes were made, including limiting this review to new import capacity resources without transmission investments.

[226] The term "general" is used to differentiate between other types of static de-list bids, including ambient air static de-list bids and ISO low winter static de-list bids, which are not subject to IMM review.

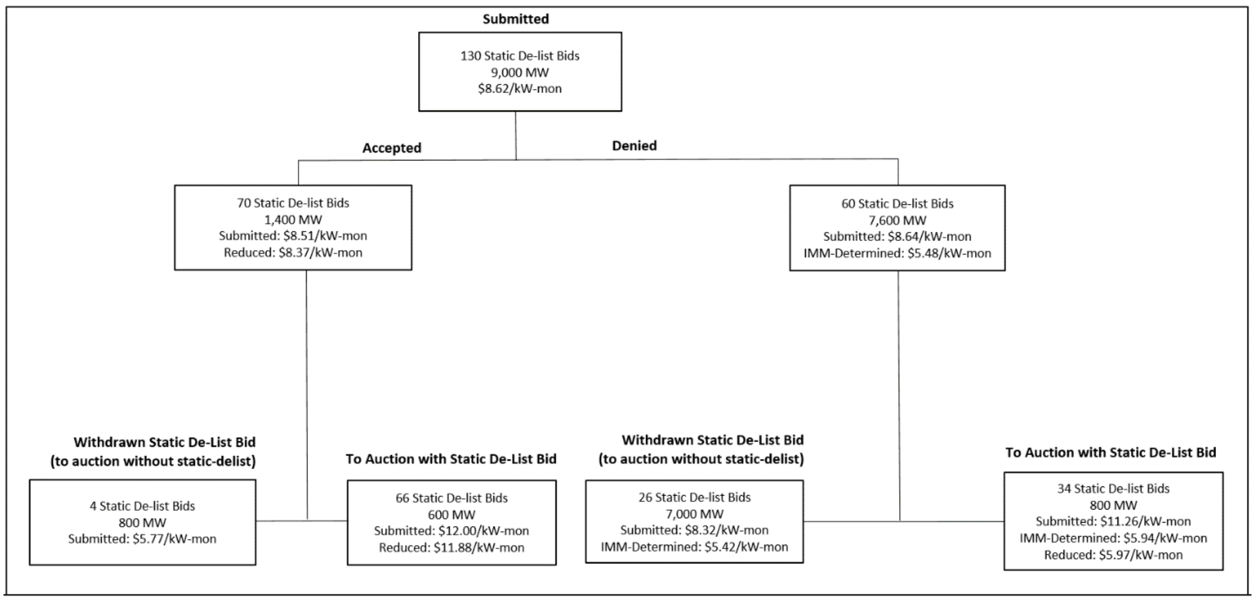
[227] A resource with a static de-list bid in each of the three auctions would be counted three times in the MW total; however, the associated lead participant is only counted once.

[228] For market power mitigation purposes, import resources without transmission investment are evaluated for seller-side market power. New imports resources with associated transmission investment are evaluated for buyer-side market power.

As previously stated, the IMM reviews de-list bid submissions to determine if they are consistent with the participant's net going forward costs, expected capacity performance payments, risk premium, and opportunity costs. This process resulted in mitigations for approximately 46% of the general static de-list bids (84% of de-list MW capacity).[229]

Summary statistics for static de-list bids from *FCA 10* through *FCA 14* as well as the path the bids took from the time of initial submittal to the auction are provided in Figure 6-14 below. Note that all de-list bid prices are megawatt-weighted averages.[230]

Figure 6-14: General Static De-list Bid Summary Statistics, by Key Milestone Action (FCAs 10 – 14)



Roughly 54% of bids were accepted by the IMM without any changes (left box, second level). Of the static de-list bids that were denied, many were voluntarily withdrawn or the bid price further reduced prior to the auction. For resources that were denied and went to the auction (box furthest to the right, third level), the weighted-average price of denied static de-list bids was $5.29/kW-month less than the market participant's originally submitted price.

As discussed in Section 6.6, only de-list bids belonging to pivotal suppliers are mitigated. There were active de-list bids from pivotal suppliers in FCAs 10 and 13 only. In the three other auction denied bids were therefore not used. In FCA 10 and 13, the denied de-list bids for 64 resources (1,098 MW) had mitigated bids in the auction.

6.7.2 Test Price Review

The test price mitigation rule was introduced in FCA 14, and applies to resources (above 3 MW) seeking to retire through the substitution auction. The rule is designed to protect the primary FCA from price suppression, by mitigating behavior commonly referred to as "bid shading".

[229] If a supplier is pivotal, the IMM-determined value is entered into the auction; if not, the participant-submitted bid is entered.

[230] Price calculations are not presented for new import capacity resources because, depending on the circumstances, the direction of the price difference can vary for price-quantity pairs within the same supply offer. Consequently, the resulting price difference summary statistics are less meaningful.

In other words, an existing resource may have an incentive to reduce its primary auction bid below a competitive level in the hopes of retaining its CSO, and subsequently trading out of it for a larger severance payment in the substitution auction. The test price is an IMM-calculated value, based on a cost submission from the resource owner, which represents the competitive cost of obtaining a CSO, excluding any expected severance payment from the substitution auction.

The test price serves as a screen to determine whether a resource's demand bid will be entered into the substitution auction based on the clearing price of the primary auction. If the resource's test price is below the primary auction clearing price, the resource is allowed to enter the substitution auction. If the test price is greater than the primary auction clearing price, the resource is not permitted to enter a demand bid into the substitution auction.

In FCA 14, fourteen existing resources with a combined capacity of 445 MW elected to participate in the substitution auction. The weighted-average submitted test price was $4.83/kW-month. The IMM reviewed and denied 10 resources (above the 3 MW threshold), with a combined capacity of 443 MW. The weighted-average IMM-determined test price was $12.54/kW-month. Since the auction cleared at $2/kW-month, none of these resources were eligible to participate in the substitution auction.

6.7.3 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, not necessarily capacity suppliers. In practice, the risk of price suppression in the ISO-NE market is largely due to out-of-market revenue streams to incent new build to help meet the states' environmental goals. To guard against price suppression, the IMM evaluates requests to offer capacity below pre-determined competitive threshold prices, or Offer Review Trigger Prices (ORTPs). Market participants that want to offer below the relevant ORTP must submit detailed financial information to the IMM about their proposed project. The financial information is reviewed for out-of-market revenues or other payments that would allow the market participant to offer capacity below cost.[231] The out-of-market revenues are either replaced with market-based revenues or removed entirely and the offer is recalculated to a higher, competitive price, i.e. the offer is mitigated.

For FCAs 10 through 14, the IMM reviewed nearly 460 new supply offers from participants requesting to offer below the ORTP.[232] These offers came from 76 different lead participants and totaled 16,400 MWs of qualified capacity, of which about 11,200 MW (~68%) entered the auction.[233] Generation resources accounted for the majority of new capacity reviewed, with 91% of the total (14,900 MW). Demand response resources accounted for the remaining 9% (1,500 MW). No new import capacity resources with transmission investments completed the review process.

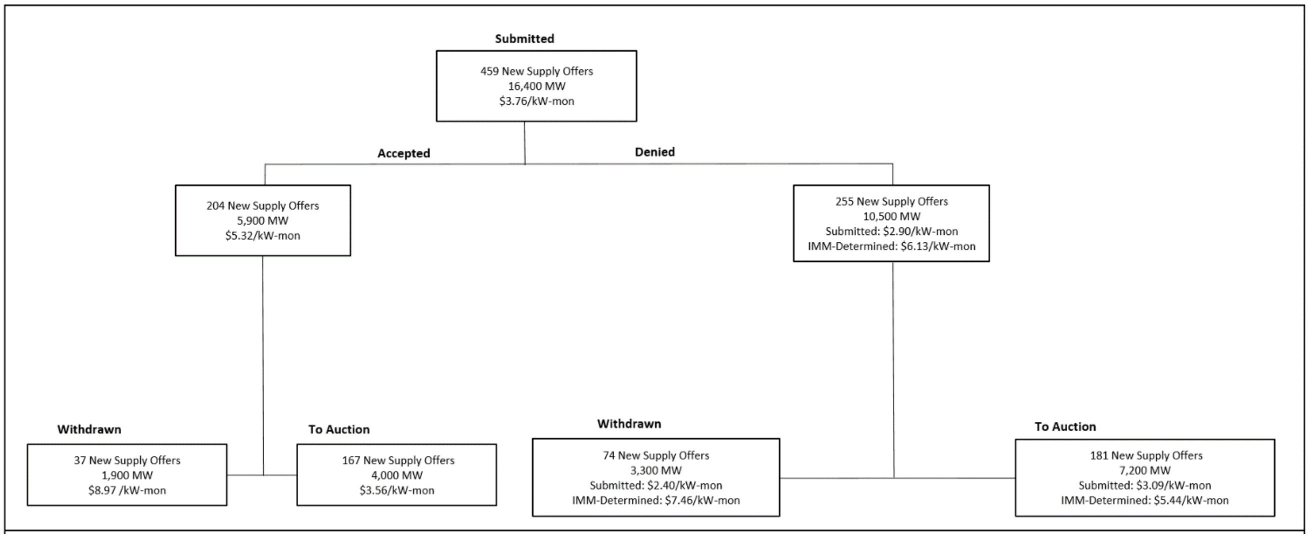
[231] Out-of-market revenues are defined in Section III.A.21.2 of the tariff.

[232] Note that this total does not include supply offers from new import capacity resources without transmission investments, which are discussed in the supplier-side market power section.

[233] A resource with a new supply offer in each of the three auctions would be counted three times in the MW total. In addition, where FCA qualified capacity does not exist for a resource (e.g., the proposal was withdrawn or denied), the summer capacity from the resource's show of interest is used instead. Consequently, the presented total overstates the actual capacity.

Summary statistics for resources requesting to offer below their respective ORTP in FCAs 10 through 14 are provided in Figure 6-15 below. Note that all offer prices are megawatt-weighted averages.

Figure 6-15: Reviewable Offer Request Summary Statistics, by Key Milestone Action (FCAs 10 – 14)



The IMM mitigated approximately 56% of new supply offers it reviewed, or approximately 64% of new supply capacity.[234] Similar to supplier-side mitigation, the degree of buyer-side mitigation can be measured by the relative increase in the offer floor price imposed by the IMM. The mitigation process (box furthest to the right, second level) resulted in an average increase in offer price of $3.23/kW-month (from a submitted price of $2.90/kW-month to an IMM-determined price of $6.13/kW-month).

[234] Note that the number of mitigated new supply offers also includes 92 projects that went on to elect the Renewable Technology Resource (RTR) exemption, which exempts the associated capacity from the ORTP process. The IMM-Determined price for these resources reflects the mitigated price and not the resulting auction treatment value, so as not to distort the summary statistics.

Section 7
Ancillary Services

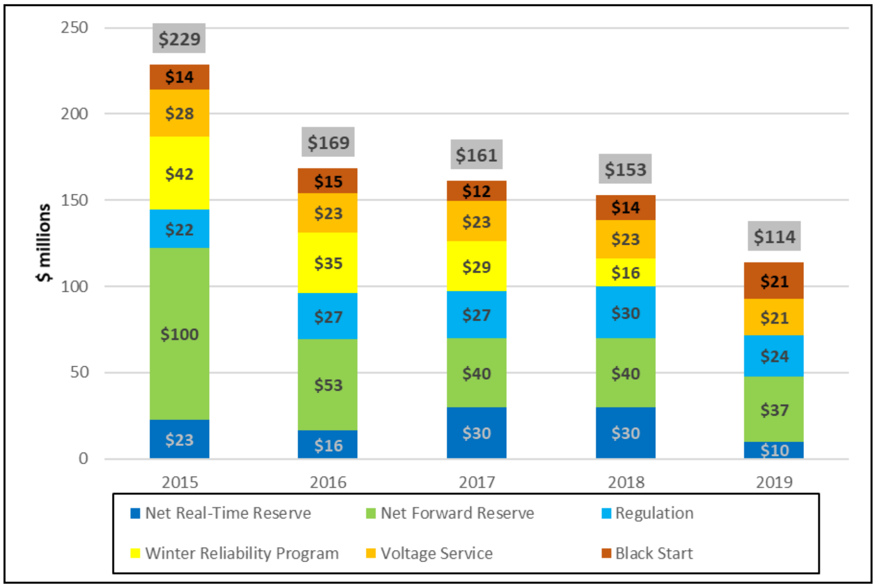
This section reviews the performance of ancillary services in ISO New England's forward and real-time markets. In 2019, the costs of most ancillary service products and their associated make-whole payments were significantly lower than 2018 costs. Further, there were no Winter Reliability Program payments in 2019 since the program expired in March 2018.

There are six types of ancillary service products discussed in this section:

- *Real-time operating reserves* represent additional generating capacity that is available to respond to unexpected contingencies (such as the unexpected loss of a generator or transmission line) during real-time market operation.
- *Forward reserves* represent fast-response reserve capability procured from generators in advance of the delivery period; that is, generators that have the ability to start and ramp quickly in the event of a system contingency.
- *Regulation* service is provided by generators that alter their energy output over very short time intervals (minute-to-minute) to balance supply and demand in the real-time energy market.
- The ISO implemented the *Winter Reliability Program* from 2013 to 2018 to remedy fuel supply issues that threatened reliability. The program paid market participants to purchase sufficient fuel inventories (oil or LNG) or provide additional demand response during the winter months, when it is more challenging to procure natural gas. The program ended after the winter in 2018, coinciding with the start of the pay for performance rules in the capacity market in June 2018.
- *Voltage support* helps the ISO maintain an acceptable range of transmission system voltage, and is necessary for the reliable flow of electricity. The ISO regulates voltage through reactive power dispatch; the generators that provide this service receive voltage support payments.
- The ISO selects and compensates strategically located generators for providing *blackstart service*. Blackstart generators must be able to restart quickly without an outside electrical supply. This service is necessary to facilitate power system restoration in the event of a partial or complete system shutdown.

Ancillary service costs over the past five years, by category, are displayed in Table 7-1 below.

Table 7-1: Ancillary Service Costs, 2018 and 2019 (in $ millions)



7.1 Real-Time Operating Reserves

Bulk power systems need reserve capacity to be able to respond to contingencies, such as the unexpected loss of a large generator or transmission line. To ensure that adequate reserves are available, the ISO procures several different reserve products through the locational Forward Reserve Market (FRM) and the real-time energy market. The following section reviews real-time operating reserve products and analyzes real-time reserve outcomes in 2019.

7.1.1 Real-Time Operating Reserve and Pricing Mechanics

There are four types of reserve products that can be provided by generators, dispatchable asset related demand, and demand response resources:

- **Ten-minute spinning reserve (TMSR):** TMSR is the highest-quality reserve product. It is provided by online resources that can convert reserves to energy within 10 minutes. For example, a synchronized generator that can increase its output within 10 minutes can provide TMSR. This gives the system a high degree of certainty that it can recover from a significant system contingency quickly.
- **Ten-minute non-spinning reserve (TMNSR):** TMNSR is the second-highest quality reserve product. It is provided by offline units that require a successful startup (e.g., a generator that can electrically synchronize to the grid and increase output within 10 minutes).
- **Thirty-minute operating reserve (TMOR):** TMOR is a lower quality reserve product provided by less-flexible resources (e.g., an on-line resource that can increase output within 30 minutes or off-line resource that can electrically synchronize to the system and increase output within 30 minutes).
- **Local Thirty-minute operating reserve (Local TMOR)**: Local TMOR is thirty-minute operating reserve provided for a local reserve zone in order to meet the local second contingency in import-constrained areas. Local TMOR requirements are set for each of the local reserve zones: Connecticut (CT), Southwest Connecticut (SWCT), and NEMA/Boston.

Real-time prices for each of the above reserve products are determined by the ISO dispatch and pricing software. The software co-optimizes energy and reserves together. That is, it solves for the least-cost dispatch, while meeting energy demand and satisfying the reserve requirements (see Section 2.3.2 for information on reserve requirements), and generates energy and reserve prices. A reserve price above zero occurs when the software must re-dispatch resources to satisfy the reserve requirement and by doing so, imposes additional costs to the system. When this happens, the reserve price is set by the resource with the highest re-dispatch cost (or opportunity cost) to provide the reserves, but is capped by the Reserve Constraint Penalty Factor (RCPF).

The software will not re-dispatch resources to meet reserves at any price. When the re-dispatch costs exceed the RCPF, the price will be set equal to the RCPF and the market software will not continue re-dispatching resources to meet reserves. RCPFs limit the re-dispatch cost the system will incur to satisfy reserve requirements.[235] These RCPFs are then reflected in the energy price due to the interdependence in procurement. The RCPFs also serve as a pricing mechanism that signals scarcity in real-time through high reserve prices. Each reserve product has a corresponding RCPF, as shown in Table 7-2 below.

Table 7-2: Reserve Constraint Penalty Factors

Requirement	Requirement Sub-Category	RCPF ($/MWh)
System TMSR (10-min spinning)		50
System TMNSR (10-min non-spinning)		1,500
System TMOR (30-min)	Minimum TMOR	1,000
System TMOR (30-min)	Replacement Reserves	250
Local TMOR		250

Although the TMSR is the highest-quality reserve product, it has the lowest RCPF ($50). On average, the cost incurred to re-dispatch assets providing TMSR is lower than the cost incurred to re-dispatch less flexible resources to provide 30-minute operating reserves. This is because there are additional costs associated with offline resources that are not already online and operating in merit like those providing TMSR. This is why the RCPFs associated with TMSR are less than the TMNSR and TMOR RCPFs; RCPFs are designed to reflect the upper range of the re-dispatch costs rather than the quality or value of the product.

To ensure that the incentives for providing the individual reserve products are correct, the market's reserve prices maintain an ordinal ranking. This ranking is consistent with the quality of the reserve provided as follows:

10-Minute Spinning (TMSR) ≥ 10-Minute Non-Spinning (TMNSR) ≥ 30-Minute (TMOR)

The price of higher-quality reserve products must be at least as high as the price of lower-quality reserve products. For example, if the ISO alters the dispatch to provide TMOR at a cost of $40/MWh,

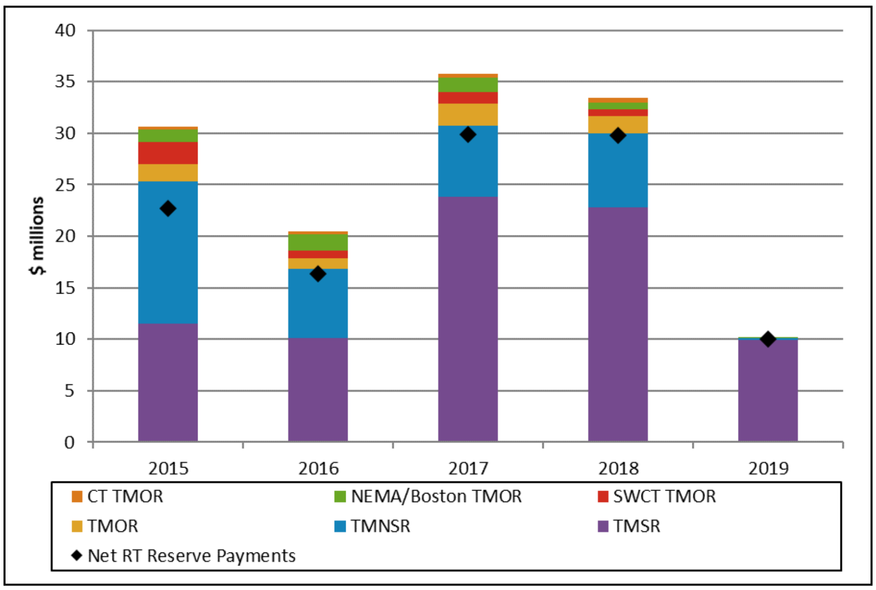
[235] When an RCPF is reached and the real-time energy market's optimization software stops re-dispatching resources to satisfy the reserve requirement, the ISO will manually re-dispatch resources to obtain the needed reserves, if possible.

the prices for TMSR and TMNSR both must be equal to or greater than $40/MWh. The ordinal ranking of reserve prices is also maintained when the ISO needs to re-dispatch the system to create multiple reserve products. For example, if the ISO re-dispatches the system to create TMSR, the reserve price is capped at $50/MWh, the TMSR RCPF. However, if the ISO re-dispatches the system to create TMSR *and* TMNSR, the reserve price is capped at $1,500/MWh for TMNSR resources and the higher-valued TMSR resources are paid $1,550/MWh – the sum of the two reserve products' RCPFs – thereby preserving the ordinal ranking of the reserve product prices.

7.1.2 Real-Time Operating Reserve Payments

Total gross real-time reserve payments in 2019 were $10.1 million, a decrease of $23.3 million (or 70%) from 2018. This decline reflects a decrease in all reserve product payment categories and large decrease in reserve-pricing events in 2019. This represents the lowest annual total of real-time reserve payments since 2011 ($9.5 million). Reserve payments for all reserve products is shown for 2015- 2019 in Figure 7-1 below.

Figure 7-1: Real-Time Reserve Payments 2015 - 2019



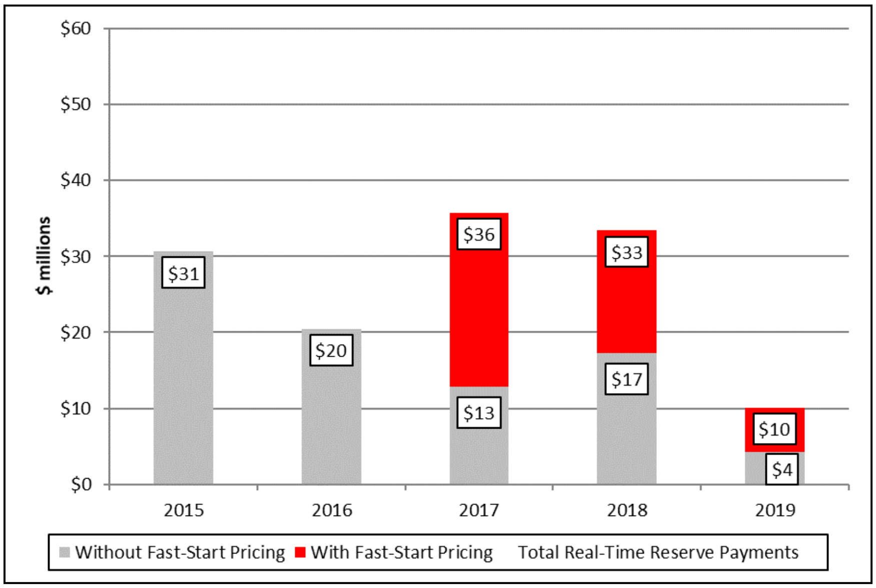
Although real-time operating reserve payment totals may change significantly on a percentage basis from year to year as a result of changes in operating reserve requirements, fuel prices, and system conditions, total payments are relatively small compared to overall energy market and capacity market payments. Total gross real-time reserve payments were approximately 0.1% of total wholesale market costs in New England in 2019.

The gross payments presented above are a measure of the value of real-time reserves. They are based on each resource's real-time reserve designation and the reserve market clearing prices. However, to ensure participants are not paid twice for the same service, there is a settlements mechanism to adjust the real-time reserve payment for resources that are paid for reserves in the forward reserve market.

Impact of Fast-Start Pricing on Operating Reserve Payments

The uptick in reserve payments in 2017 and 2018 relative to prior years was due to the implementation of fast-starting pricing. Fast-start pricing, which was discussed in detail in the Summer 2017 Quarterly Markets Report, was implemented in March 2017 to improve price formation and performance incentives in the real-time energy market.[236] Figure 7-2 below shows the impact of fast-start pricing on real-time reserve payments over the past three years.

Figure 7-2: Impact of Fast-Start Pricing on Reserve Payments



Without fast-start pricing, real-time reserve payments would have been approximately $4 million in 2019, compared to the actual amount about $10 million. As intended, fast-start pricing more accurately reflects the cost of operating higher-cost fast-start generators and, on average, has increased the price of energy. Because the price of energy has increased, so too has the opportunity cost of holding back resources to provide reserves rather than energy, which has resulted in higher and more frequent reserve pricing.

7.1.3 Real-Time Operating Reserve Prices: Frequency and Magnitude

Average TMSR and TMNSR prices during all intervals (i.e. zero- and non-zero pricing intervals) decreased by 43% and 99%, respectively, in 2019 relative to 2018, which are illustrated in Figure 7-3 below. This was due in-part to the milder weather in 2019 leading to lower overall market prices and a decrease in the need for TMSR versus TMNSR as part of the total 10-minute reserve requirement. In addition, with the milder weather, changes to the operation of the largest contingency led to a smaller average largest contingency on the system compared to 2018.

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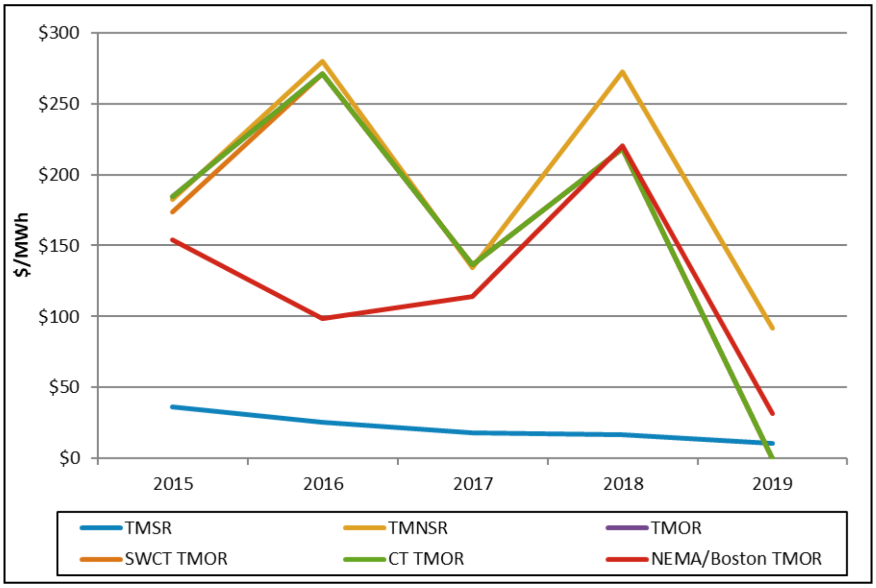
[236] See Section 5.5 of the Summer 2017 Quarterly Markets report for detail on fast-start pricing: https://www.iso-ne.com/static-assets/documents/2017/12/2017-summer-quarterly-markets-report.pdf

Figure 7-3: Average Real-Time Reserve Prices for all Pricing Intervals



The average reserve prices shown in Figure 7-3 are a function of two factors. The first is *frequency*, which represents how often (i.e., percentage of the time) a reserve product has a positive price (a price above $0/MWh). The second factor is *magnitude*. Magnitude is the average real-time reserve price for only the intervals where reserve prices were above zero. Figure 7-4 below illustrates both the frequency (left panel) and magnitude (right panel) of non-zero reserve prices by reserve product over time.

Figure 7-4: Frequency and Average of Non-Zero Reserve Prices

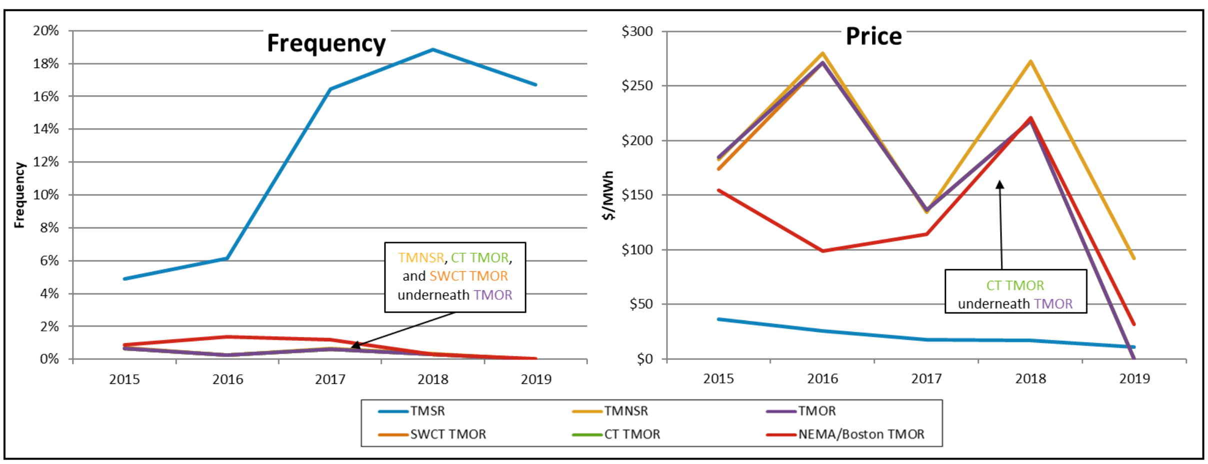


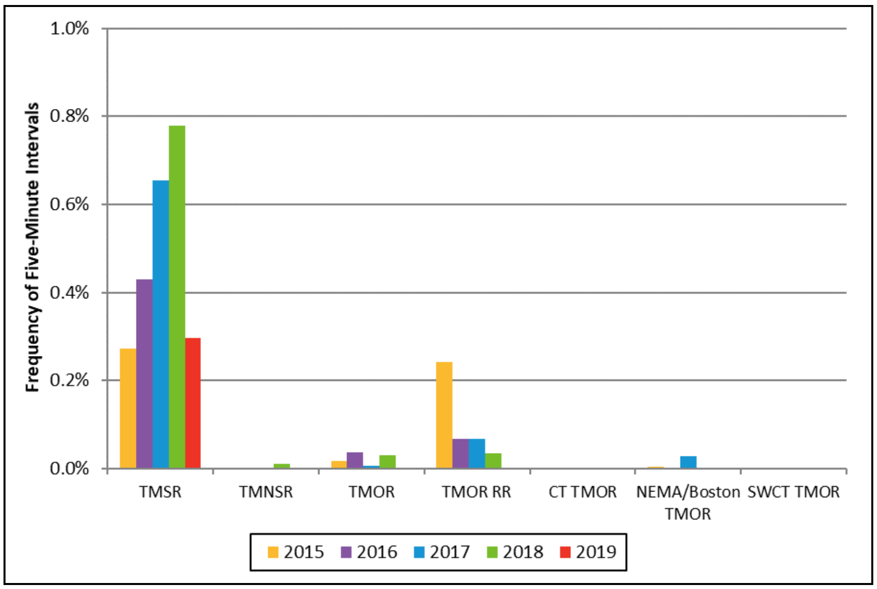
Figure 7-4 shows that TMSR price was non-zero (i.e., above $0/MWh) for about 17% of all hours in 2019, a slight decrease from 19% in 2018. For those hours in which the TMSR price was above zero, it averaged nearly $11/MWh, a decrease from an average of about $17/MWh in 2018 (right panel of Figure 7-4.) The decrease in the frequency of non-zero TMSR pricing coupled with the decline in average non-zero TMSR price resulted in a decrease of the average TMSR price across all hours (Figure 7-3) in 2019.

The frequency of non-zero TMNSR prices fell to almost zero in 2019 relative to 2018, with the average non-zero TMNSR price dropping from $272/MWh in 2018 to $92/MWh in 2019. This led to a 99% decrease in the average TMNSR price (across all hours).The low non-zero TMNSR price was driven by the mild weather, low energy prices and lack of system events in 2019. Similarly, the frequency of non-zero pricing for system-wide, SWCT, CT, and NEMA/Boston TMOR products decreased from 2018. This led to a fall in the average TMOR prices (across all hours).

Reserve Constraint Penalty Factors

RCPFs for reserve products are triggered due to either a shortage of available capacity to meet the reserve requirements or re-dispatch costs that exceeded the RCPF values. The number of five-minute intervals during which the RCPFs were triggered for each reserve constraint are shown in Figure 7-5 below.

Figure 7-5: Reserve Constraint Penalty Factor Activation Frequency



In 2019, only the RCPF for the TMSR product bound, with a frequency of 311 five-minute intervals (0.3% of total intervals), or about 26 hours over the year; this was the lowest frequency since 2015.

The TMSR RCPF had the highest frequency of activations due to the higher frequency of TMSR non-zero pricing intervals and its relatively low RCPF value ($50/MWh) compared to the other products. This means the dispatch software will stop trying to re-dispatch the system for TMSR much sooner than for the other reserve products with significantly higher RCPF values.

When RCPFs are triggered due to a reserve shortage, the reserve price will directly impact the energy price. During these times, the RCPF value is added to the energy price since satisfying any additional increment of load will decrease the amount of available system reserves by the same amount. The RCPF value determines the price of reserves during scarcity events. Thus, the LMP will reflect the total cost of serving an additional increment of load including the value of the loss of reserves.

7.2 Forward Reserves

The Forward Reserve Market (FRM) was designed to attract investments in, and provide compensation for, the type of resources capable of satisfying off-line (non-spinning) reserve requirements. However, any resource that can provide 10- or 30-minute reserves, from an on-line or off-line status, can participate in the FRM.

The ISO conducts two FRM auctions each year, one each for the summer and winter reserve periods (June through September and October through May, respectively). The auctions award obligations for participants to provide pre-specified quantities of each reserve product. Forward reserve obligations are not resource specific. In order to fulfill these obligations, participants must assign the obligation to one or more resources every day during the reserve delivery period. This is discussed in more detail below.

Forward- reserve auction clearing prices are calculated for each reserve product in each reserve zone. When enough supply is offered to meet the requirement for a product in a particular zone, the auction clearing price for that product is set equal to the price of the marginal supply offer. When supply offers are inadequate to meet a reserve requirement, the clearing price is set to the $9,000/MW-month price cap.[237]

Until the Summer 2016 FRM auction, the FRM payment rate (or price) was reduced by the contemporaneous delivery period's FCA clearing price. This "netting" was done to avoid compensating the same resource megawatt as both general capacity and forward-reserve capacity. Netting was eliminated starting with the Summer 2016 delivery period. This eliminated the unintended consequences of netting which, under certain circumstances, resulted in uneconomic resource selection and zero (or nearly zero) FRM compensation for auction participants.[238]

The FRM requires participants to convert their participant-level obligations to resource-level obligations by assigning forward reserve to their forward-reserve resources. Participants are not expected to assign forward reserve to resources that are normally in-merit because they would forego the infra-marginal revenue from selling energy. Conversely, assigning forward reserve to high-incremental-cost peaking resources creates a lower opportunity cost because such resources are in-merit less frequently.

To maintain resources that are normally expected to provide reserves instead of energy, the FRM requires resources to offer energy at or above the FRM threshold price. Participants must submit energy offers for the weekday, on-peak delivery period equal to or greater than the threshold price for these resources to satisfy their FRM obligations. The intent of the market design is to set threshold prices to approximate the marginal cost of a peaking resource with an expected capacity factor of 2% to 3%. Therefore, if the threshold price is set appropriately, LMPs should exceed the threshold price only 2% to 3% of the time. A resource offered at exactly the threshold will be dispatched only when the LMP exceeds the threshold price.

[237] As indicated below, the auction price cap was reduced to $9,000/MW-month beginning with the Summer 2016 auction, when "price netting" (i.e., subtraction of the FCA compensation from the FRM compensation) was terminated. Prior to the Summer 2016 auction, the auction price cap was $14,000/MW-month.

[238] ISO New England and New England Power Pool, Docket No. ER16-921-000; *Revisions to Forward Reserve Market Offer Cap and Elimination of Price Netting*. https://www.iso-ne.com/static-assets/documents/2016/02/er16-921-000.pdf See Section IV of the ISO's filing for a description of the unintended consequences and undesirable effects of the netting mechanism.

Bilateral transactions, as well as any reserve-capable resource in a participant's portfolio, can meet the reserve obligations obtained in an auction. Bilateral trading of forward reserve obligations allows suppliers facing unexpected generator outages to substitute alternative resources. This feature is useful to suppliers if the cost of expected penalties for non-delivery exceeds the cost of acquiring substitute resources through bilateral transactions. A failure-to-reserve penalty will result when a participant fails either to assign the obligation to a generator they control or to transfer of the obligation to another participant.

Allocation of the costs for paying resources to provide reserves is based on real-time load obligations in load zones. These obligations are allocated both at the system level and to specific reserve zones that have local forward reserve requirements.

Over the review period, the most significant FRM trends have been:

- Market requirements for the quantity of procured forward reserve capacity at the system level have relied on a stable set of second contingencies -- leading to reasonably stable requirements over the review period.
- Local reserve zone requirements have fluctuated to a more significant degree; these fluctuations have reflected the availability of transmission capacity to provide external reserve support to the local reserve zones.
- FRM prices have generally declined, except for the NEMA Boston local reserve zone and the Summer auctions in 2018 and 2019. The elevated NEMA Boston prices have reflected inadequate supply to satisfy local requirements during auctions for several procurement periods; the elevated prices for recent summer periods have reflected elevated offer prices (relative to other periods) and differences in TMNSR offer prices relative to TMOR offer prices.[239]
- FRM payments have declined during the review period overall, with relatively stable payments for 2017-2019.
- The FRM auctions have been structurally competitive, with only a few exceptions. In particular, the NEMA Boston reserve zone has had inadequate supply to satisfy the local requirement and every supplier within that zone has had structural market power. At the system level, only one recent auction – Summer 2019 –indicated structural market power; in that instance, the residual supply index of 90 indicated that the single largest FRM supplier in that auction would need to provide at least 10% of cleared supply to satisfy the TMNSR requirement.

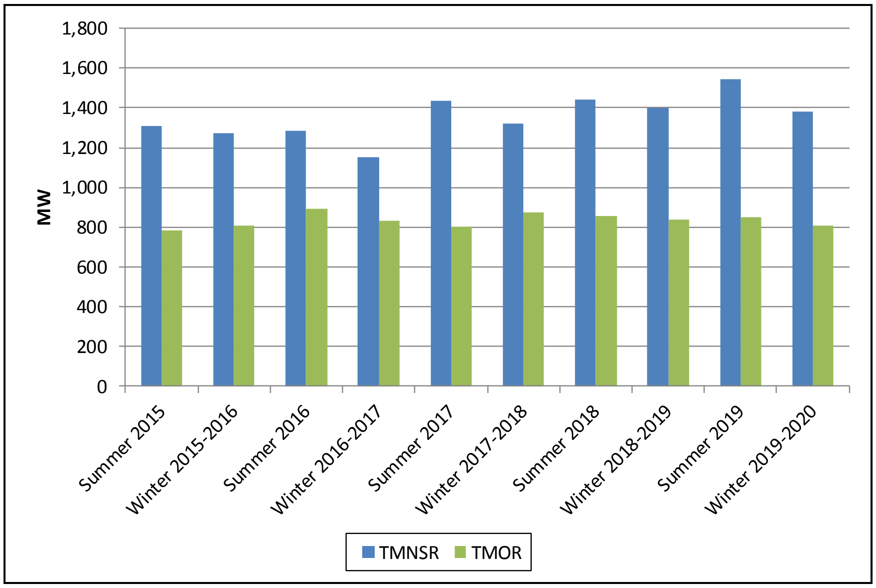
7.2.1 Market Requirements

The FRM auction is intended to ensure adequate reserves to meet 10- and 30-minute reserve requirements. The FRM requirements for the New England control area are based on the forecast of the first and second largest contingency supply losses for the next forward reserve procurement period. The ten-minute non-spinning reserve (TMNSR) requirement for the control area is based on the forecasted first contingency, while the thirty-minute operating reserve (TMOR) requirement for the control area is based on the forecasted second contingency.

[239] TMNSR can be substituted for TMOR in an auction, when TMNSR offers exceed the TMNSR requirement and the relevant portion of the TMNSR supply curve is below (i.e., has lower offer pricing) than the TMOR offer curve.

The system-wide forward reserve requirements from Summer 2015 through Winter 2019-20 are shown in Figure 7-6 below.

Figure 7-6: Forward Reserve Market System-wide Requirements



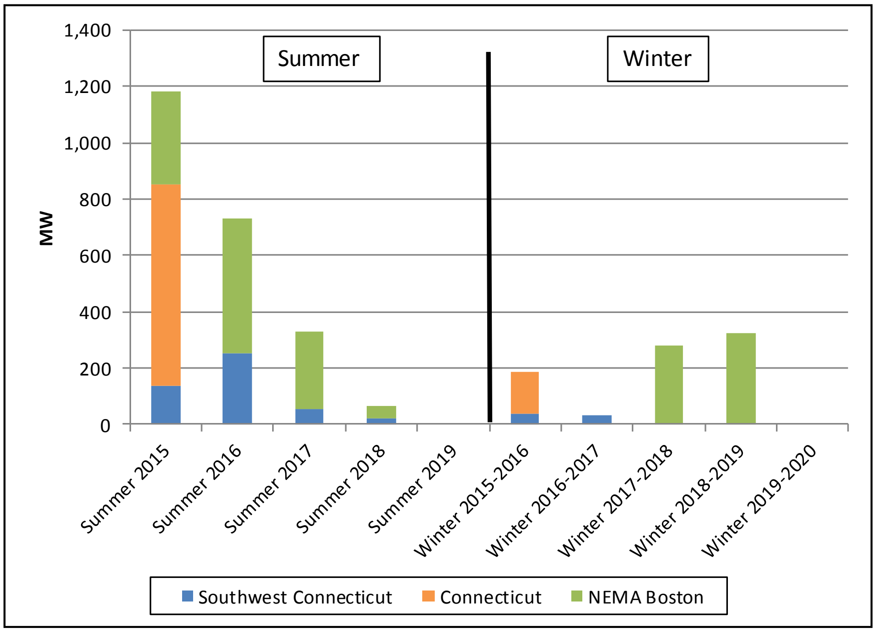
Over the past ten auctions, the TMNSR purchase amount has represented the expected single contingency of the HQ Phase II Interconnection. The TMOR purchase amount has represented the expected single second contingency of either Mystic 8/9 or Seabrook.[240] Therefore, the requirements have been relatively consistent at 1,200-1,500 MW for TMNSR and around 800 MW for TMOR. The reasonably small fluctuations in seasonal requirements reflect seasonal variation in expected capabilities for Phase II and Mystic 8/9 (or Seabrook), and relatively stable expectations for non-spinning reserve needs (affecting TMNSR), replacement reserve needs (affecting TMOR), and generator performance when called upon for system contingencies.

Some zones are constrained in terms of how much power they can import from other zones and can therefore have different clearing prices. As a result, instead of having a single reserve requirement for each reserve product for all of New England, the ISO identifies requirements at a zonal level and at the system level.

The aggregate reserve requirements for the past 10 auctions for the import-constrained reserve zones of Connecticut, NEMA/Boston, and Southwest Connecticut are shown in Figure 7-7 below. The local requirement is a thirty-minute operating reserve (TMOR) requirement, which can be met through 10- or 30-minute reserve supply offers in each local reserve zone.

[240]As noted in the ISO's assumptions memoranda for the individual FRM auctions, the FRM system requirements also may be biased up or down and, in the case of TMOR, include a replacement reserve adjustment.

Figure 7-7: Aggregate Local Forward Reserve (TMOR) Requirements



Local forward reserve requirements (which account for both local second contingency and external reserve support (ERS) MWs) for the reserve zones reflect the need for a 30-minute contingency response to provide support in import-constrained areas.[241] Resources within a local region as well as operating reserves available in other locations, through external reserve support, can satisfy second contingency capacity requirements.

At the local level, the summer procurement period has experienced a significant reduction in aggregate local FRM requirements, as illustrated in Figure 7-7. This results from a considerable increase in ERS for Connecticut due mainly to transmission upgrades; Connecticut's local requirement has declined to zero in the past four summer and winter periods as a result of increased ERS. Meanwhile, NEMA/Boston has had positive local requirements for four summer and two winter periods as a result of decreased ERS. However, for the two most recent auctions (Summer 2019 and Winter 2019-2020), an excess of external reserve support in all three reserve zones has led to no need for local requirements.

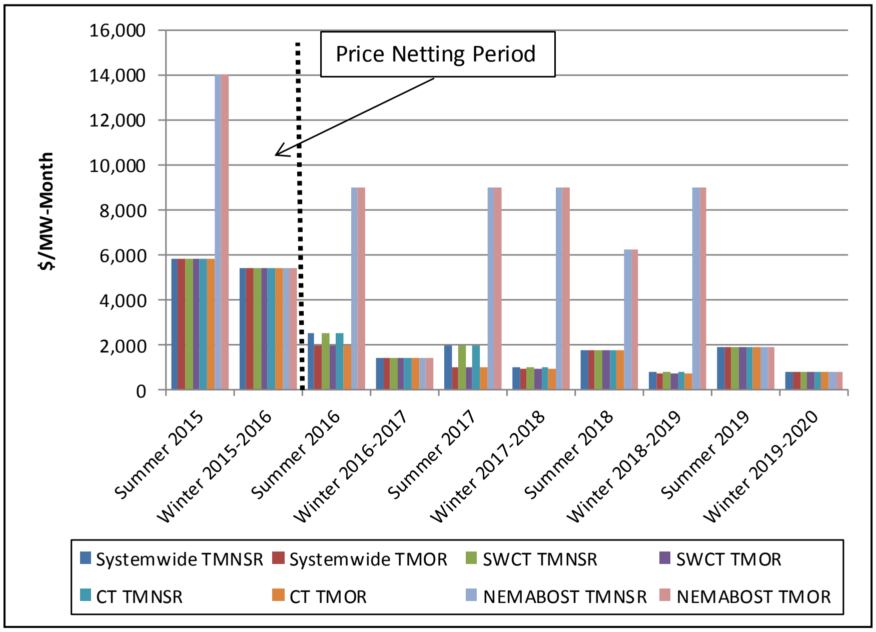
7.2.2 Auction Results

This section covers FRM auction pricing outcomes from the Summer 2015 auction through the Winter 2019-20 auction. The TMNSR and TMOR clearing prices by reserve zone for each auction are shown in Figure 7-8 below.[242]

[241] The ISO establishes the locational reserve requirements based on a rolling, two-year historical analysis of the daily peak hour operational requirements for each reserve zone for like forward reserve procurement periods (winter to winter and summer to summer). The daily peak hour requirements are aggregated into daily peak hour frequency distribution curves and the MW value at the 95th percentile of the frequency distribution curve for each reserve zone establishes the locational requirement.

[242] Forward reserve auction clearing prices are calculated for each reserve product in each reserve zone, and the requirements for the Connecticut reserve zone can be partially fulfilled by the requirements for Southwest Connecticut. When supply offers for forward reserve are not adequate to meet a requirement, the clearing price for that product is set to the offer price cap. When enough supply is offered under the price cap to meet the requirement in a particular zone, the auction clearing price for that product is set equal to the price of the marginal supply offer.

Figure 7-8: Forward Reserve Prices by FRM Procurement Period



With the exception of Summers 2018 and 2019 and local reserve prices for NEMA/Boston, auction prices for reserve products have generally declined by product and delivery season over the review period. A number of factors affect TMOR clearing prices, including: TMOR offer prices (i.e., the shape of TMOR supply curve), the ability to substitute lower-priced TMNSR supply for TMOR supply (when there is low-priced TMNSR supply in excess of the TMNSR requirement), and cleared high-priced TMOR supply needed for local requirements that reduces the amount of TMOR supply needed to meet the rest-of-system requirement.

In NEMA/Boston, forward reserve supply shortfalls frequently resulted in very high auction clearing prices, including clearing prices at the offer cap (discussed below). However, a local reserve requirement for NEMA/Boston was not needed for two most recent auctions (Summer 2019 and the Winter 2019-2020), as external reserve support supplanted that need.

Prices for the Summer2016 and later auctions are not readily comparable to earlier periods, since the FRM prices are no longer adjusted for FCA prices (i.e., price-netting was eliminated beginning with the Summer 2016 auction). The decline in prices in 2016, relative to earlier periods, is consistent with the elimination of price-netting.

The relatively uniform historic clearing prices for TMOR and TMNSR indicate that, in many auctions, some TMNSR was cleared to meet the system-wide TMOR requirement. The auction clearing software treats the system-wide TMOR requirement as an upper limit on the amount of TMOR that can clear the auction and will select the higher-quality TMNSR reserve product to meet the TMOR requirement when it is economical to do so.[243] When the auction has sufficient reserves to meet the total system-wide reserve requirement (TMNSR plus TMOR), but clears less TMOR than the system-wide TMOR requirement, the prices for TMNSR and TMOR will be identical. It is only when the auction reaches the upper limit for TMOR, represented by the system-wide TMOR

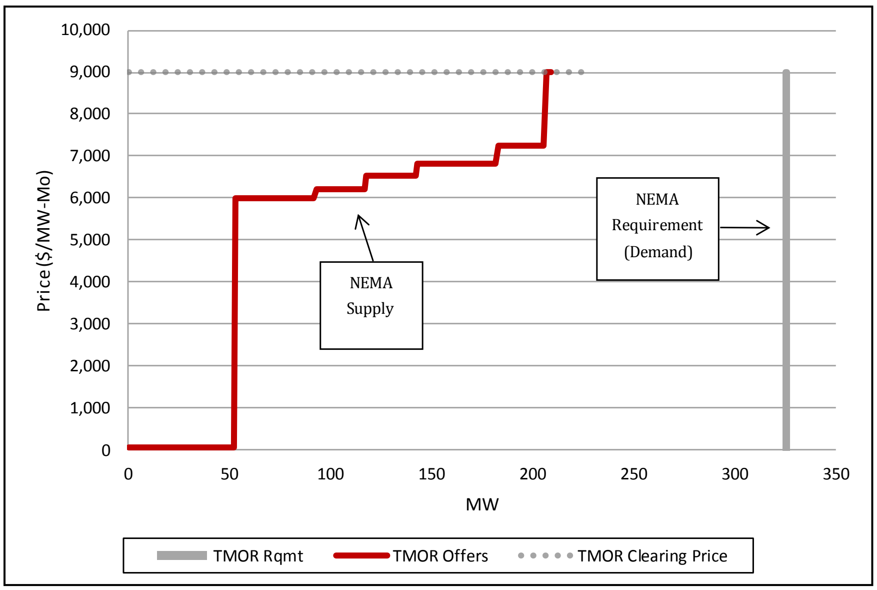
[243] See Market Rule 1, Section III.9.4, Forward Reserve Auction Clearing and Forward Reserve Clearing Prices; and, Manual M-36, Forward Reserve and Real-Time Reserve, Section 2.6, Forward Reserve Auction Clearing.

requirement, that there will be price separation between the TMOR and TMNSR reserve products. The result is that TMNSR cannot have a price that is less than TMOR. In four instances during the review period, TMNSR cleared the auction at higher prices than TMOR.

There have been six instances of significant price separation at the zonal level during the five-year period, as illustrated in Figure 7-8 above. In the summer periods for 2015 through 2018 and the winter periods for 2017-18 and 2018-19, there was price separation between NEMA/Boston and all other zones. In these instances (with the exception of Summer 2018), supply was inadequate to satisfy the local TMOR requirement, and pricing reached the auction offer cap. The 2015 NEMA/Boston summer period price exceeded the 2016 and 2017 summer prices, because the cap was reduced in 2016 (from $14,000/MW-month to $9,000/MW-month), when FCA price-netting was eliminated.[244] In Summer 2018, there was adequate supply to meet the local requirement at a price of $6,225/MW-month.

Figure 7-9 below shows NEMA/Boston's supply and demand curves for the 2018-19 Winter FRM auction.

Figure 7-9: Supply and Demand for NEMA/Boston TMOR, Winter 2018-19 Auction



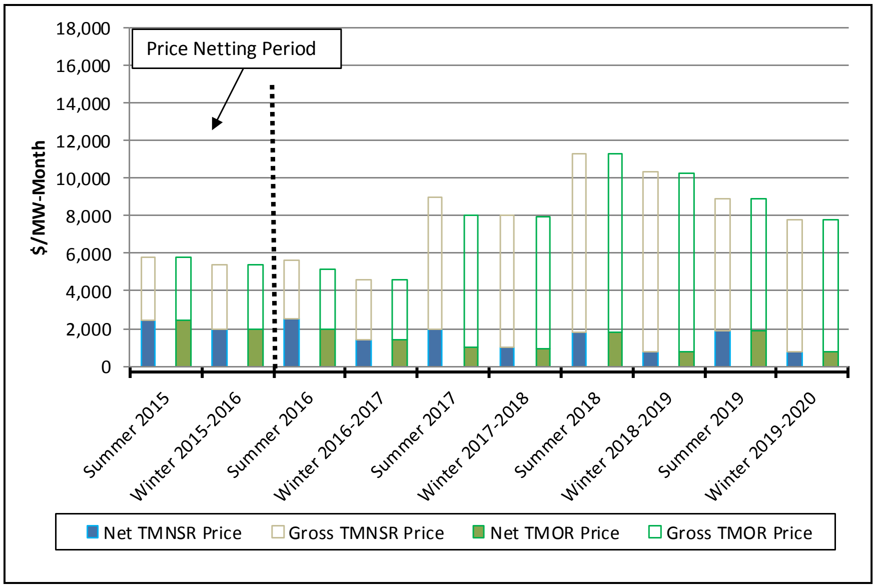
With zonal supply approximately 115 MW less than zonal demand, the zonal clearing price was set to the auction price cap, resulting in a $9,000/MW-month price for local TMNSR and TMOR. Higher FRM prices in NEMA/Boston over the past number of years have not been effective in delivering new fast-start capability to the region.

Finally, the gross and net forward reserve clearing prices for TMNSR and TMOR are shown in Figure 7-10 below and illustrate the price-netting concept as if it had applied to all periods (not just prior to Summer 2016). The gross price indicates the FRM auction price inclusive of the FCA price, while the net price shows the FRM-only price. The net price provides the effective TMNSR and TMOR compensation rates for FRM rest-of-system resources for all periods in the graph. The gross

[244] ISO New England and New England Power Pool, Docket No. ER16-921-000; *Revisions to Forward Reserve Market Offer Cap and Elimination of Price Netting*. https://www.iso-ne.com/static-assets/documents/2016/02/er16-921-000.pdf .

price represents the actual FRM auction clearing price for 2015 and earlier periods. The net price represents the actual auction clearing price for the Summer 2016 auction and beyond.

Figure 7-10: Gross and Net FRM Clearing Prices for Rest-of-System TMNSR and TMOR



For comparison, the graph includes the Summer 2016 and later auctions and provides an estimated gross price for these auctions; the contemporaneous FCA period clearing price has been added to the FRM auction clearing prices for rest-of-system TMNSR and TMOR to create "gross" FRM clearing prices. For prior periods, when the FRM price includes the FCA payment rate (or price) the net price represents the FRM price minus the FCA price. Net prices for TMNSR and TMOR have ranged from approximately $1,000 to $2000/MW-month throughout the review period, while gross prices have shown considerably more variation (reflecting variation in FCA prices).

7.2.3 FRM Payments

Participants obtain FRM payments by participating in Forward Reserve Auctions or by obtaining an obligation from another participant that has an auction-based obligation.[245] Auction obligations are specific to participants and are not specific to resources. Participants must convert their obligations into the physical delivery of operating reserve capacity by assigning obligations to generators in the real-time energy market. Assignments must be equal to or greater than the auction-based obligations controlled by the participant (whether obtained directly from an auction or through an internal bilateral transaction). FRM payments are provided during the FRM delivery period based on auction obligations, auction clearing prices, and the actual delivery of the obligation in the real-time energy market.

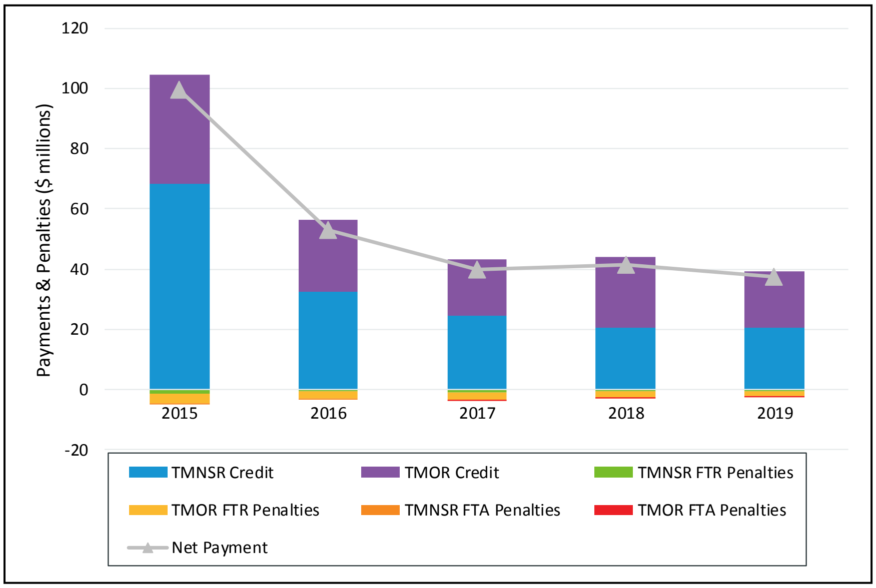
In the real-time energy market, participants are subject to two types of FRM delivery penalties: failure-to-reserve and failure-to-activate penalties. Failure-to-reserve penalties occur when a participant's assignments to generators are less than the participant's obligation. In this case, the

[245] Hourly FRM obligations may be transferred by participants on a daily basis up to two days after the delivery period. These transfers take place through "internal bilateral transactions" that allow the ISO to determine whether the holder of the obligation delivered the physical capacity needed to back the obligation in the real-time energy market. See ISO Manual M-36, Forward Reserve and Real-Time Reserve, Section 3.1.2.

participant forfeits auction revenue for any unassigned megawatts and is assessed additional penalties. The failure-to-activate penalties occur when a participant fails to provide energy (when called upon by the ISO) from a generator that has been assigned an FRM obligation. The failure-to-activate penalties are separate from the failure-to-reserve penalties assessed to a participant.

Annual FRM payment data by year are provided in Figure 7-11 below. The chart indicates the annual auction-based payments as positive stacked bar values and penalties as negative stacked bar values; the line graph indicates annual payments net of total penalties.[246]

Figure 7-11: FRM Payments and Penalties by Year



As indicated above, total reserve requirements have been relatively stable over the past three years. However, auction prices have declined significantly from the highs of 2015 and 2016. Penalties have been low relative to gross payments and have been fairly stable in the 5% to 8% range of total payments over the period. These penalties have been predominately for failing to reserve (99.4%). Since failure-to-reserve penalties result in forfeiture of auction-based payments for unassigned obligations, total penalties have declined as auction prices have declined over time,

7.2.4 Structural Competitiveness

The competitiveness of the FRM can be measured by the Residual Supply Index (RSI). RSI measures the extent to which an individual participant has market power and controls enough supply to be able to increase price above a competitive level. In other words, the RSI measures the percentage of the forward reserve requirement that can be met without the largest supplier's FRM portfolio offer. If the requirement cannot be met without the largest supplier, then that supplier is pivotal. The RSI is calculated based on the FRM offer quantities.

The RSI for TMNSR is computed at a system-level based on the total quantity of TMNSR offers across all reserve zones, excluding the largest TMNSR offer quantity by a single market participant. The RSI for TMOR is computed similarly for each reserve zone with a non-zero TMOR local reserve

[246] "FTR" refers to failure to reserve and "FTA" refers to failure to activate.

requirement. Given that the TMNSR quantity also satisfies the TMOR requirement, the TMNSR offer quantity in a zone is included in the total TMOR offer quantity within that zone.

The heat map provided in Table 7-3 below shows the offer RSI for TMNSR at a system level and for TMOR at a zonal level. The colors indicate the degree to which structural market power was present; red is associated with low RSIs, white with moderate RSIs, and green with high RSIs. Dark red indicates that structural market power was present, while dark green indicates that there was ample offered supply without the largest supplier. An RSI value less than 100 (shown in red) indicates the presence of at least one pivotal supplier, which means the auction was not structurally competitive. Pivotal suppliers may be able to strategically offer reserves at uncompetitive prices.

Table 7-3: Offer RSI in the FRM for TMNSR (system-wide) and TMOR (zones)

Procurement Period	Offer RSI TMNSR (System-wide)	Offer RSI TMOR (ROS)	Offer RSI TMOR (SWCT)	Offer RSI TMOR (CT)	Offer RSI TMOR (NEMA)
Summer 2015	117	158	69	79	12
Winter 2015-16	109	154	228	382	N/A
Summer 2016	112	139	76	N/A	23
Winter 2016-17	148	222	302	N/A	N/A
Summer 2017	110	197	183	N/A	21
Winter 2017-18	127	209	N/A	N/A	24
Summer 2018	112	214	438	N/A	34
Winter 2018-19	127	244	N/A	N/A	21
Summer 2019	90	204	N/A	N/A	N/A
Winter 2019-20	120	254	N/A	N/A	N/A

Table 7-3 shows that there were pivotal suppliers in one out of the ten FRM auctions for TMNSR. There were also pivotal suppliers in six out of ten auctions for TMOR in at least one of the reserve zones.

Generally, the RSI values for local zones fluctuate significantly from auction to auction. These fluctuations can be partly explained by the significant variation in the local reserve requirements. For instance, the TMOR RSI value for the SWCT zone jumped from 76 (structurally uncompetitive levels) in the Summer 2016 auction to 302 (structurally competitive level) in the Winter 2016-17 period. For the same zone and time period, the TMOR local requirement decreased from 250 MW to 32 MW.

For the recent 2018 and 2019 procurement periods, the TMNSR RSI values were greater than 100 (structurally competitive) for all auctions except Summer 2019. The decline in RSI for Summer 2019 resulted from a slightly increased TMNSR requirement (by approximately 7% compared to Summer 2018) and a medium-sized supplier not participating in the Summer 2019 auction. The TMOR RSI values for the Rest-of-System (ROS) zone were consistent with a structurally competitive level over the same period. The RSI values for the NEMA zone, however, have been significantly below a competitive level for every auction prior to 2019. In these auctions, every participant who offered forward reserves in NEMA was pivotal in that auction because the total offered quantity was significantly below the local requirement.[247]

7.3 Regulation

This section presents data about the participation, outcomes, and competitiveness of the regulation market in 2019. Overall, the available supply of regulation service in 2019 far exceeded the regulation requirements, resulting in a competitive market.

The regulation market is the mechanism for selecting and paying generators needed to balance supply levels with the second-to-second variations in electric power demand and to assist in maintaining the frequency of the entire Eastern Interconnection.[248] The objective of the regulation market is to acquire adequate resources such that the ISO meets NERC's *Real Power Balancing Control Performance Standard* (BAL-001-2).[249] NERC establishes technical standards for evaluating Area Control Error (ACE, unscheduled power flows) between balancing authority areas (e.g., between New England and New York). A new performance standard was implemented in 2016 for measuring the control of ACE; this metric, referred to as Balancing Area ACE Limits (BAAL), measures performance relative to violations (exceedances) of ACE.[250]

Regulation market performance in 2019 may be summarized as:

- Regulation clearing prices for capacity declined significantly from $28.30/MWh in 2018 to $21.96/MWh in 2019, reflecting reductions in energy market opportunity costs for regulation resources.
- Regulation service prices increased slightly ($0.03/mile), with 2019 service prices of $0.28/mile compared to 2018 pricing of $0.25/mile.
- Regulation payments declined significantly in 2019 reflecting the decline in capacity prices; 2019 payments were $25.4 million compared to payments of $32.5 million in 2018.
- Regulation requirements in 2019 were steady compared to 2018 requirements, needing 89.6 MW per hour, on average, in 2019 and 88.8 MW per hour, on average, in 2018 (a 1% increase).
- The regulation market was structurally competitive in 2019. The residual supplier index indicates that, on average, residual available supply always exceeded regulation needs by at least a factor of 10.

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[247] Note that some of the historical values reported in the table have changed since being reported in the 2017 Annual Markets Report (re RSIs for TMNSR, TMOR ROS, and TMOR SWCT). An error in the algorithm used to calculate the RSI was discovered, resulting in the changed values. The change in values, however, did not result in a change to earlier conclusions about the structural competitiveness of each auction. The correction resulted in reduced levels of competitiveness for some auctions, but the revised data continue to indicate that the auctions were structurally competitive.

[248] The *Eastern Interconnection* consists of the interconnected transmission and distribution infrastructure that synchronously operates east of the Rocky Mountains, excluding the portion of the system located in the Electric Reliability Council of Texas, Newfoundland, Labrador, and Québec.

[249] This NERC standard can be accessed at http://www.nerc.com/pa/Stand/Reliability%20Standards/BAL-001-2.pdf.

[250] The primary measure for evaluating control performance is as follows:

"Each Balancing Authority shall operate such that its clock-minute average of Reporting ACE does not exceed its clock-minute Balancing Authority ACE Limit (BAAL) for more than 30 consecutive clock-minutes, calculated in accordance with Attachment 2, for the applicable Interconnection in which the Balancing Authority operates." This measure replaces CPS2. See NERC BAL-001-2.

7.3.1 Regulation Prices

Regulation Clearing Prices (RCP) are calculated in real-time and are based on the regulation offer of the highest-priced generator providing the service. During 2015, FERC required the ISO to change how regulation pricing is determined.[251] Under the prior rule, generators offered regulation at a single price. Under the new rules, generators use two-part pricing: a service price and a capacity price.[252] The pricing change was implemented effective March 31, 2015.[253]

The service price represents the direct cost of providing the regulation service (also known as regulation "mileage"). Mileage represents the up and down movement of generators providing regulation and is measured as the absolute MW variation in output per hour. These direct costs may include increased operating and maintenance costs, as well as incremental fuel costs resulting from the generator operating less efficiently when providing regulation service.

The capacity price may represent several types of costs, including: (1) the expected value of lost energy market opportunities when providing regulation service,[254] (2) elements of fixed costs such as incremental maintenance to ensure a generator's continuing performance when providing regulation, and (3) fuel market or other risks associated with providing regulation.

Regulation clearing prices for the past five years are shown in Table 7-4 below. Note that the two-part pricing (implemented in 2015) is not comparable to the single-part prices for early 2015 shown on the left side of the table, because two-part pricing altered regulation compensation (and bidding incentives) for resources.

Table 7-4: Regulation Prices

	Regulation Clearing Price ($/MW per Hour)			Regulation Service Clearing Price ($/Mile)			Regulation Capacity Clearing Price ($/MW per Hour)		
Year	**Min**	**Ave**	**Max**	**Min**	**Ave**	**Max**	**Min**	**Ave**	**Max**
2015[(a)]	2.86	18.27	381.13	0.00	0.30	10.00	2.44	25.26	1,172.47
2016	n/a	n/a	n/a	0.00	0.43	10.00	1.33	27.33	1,384.57
2017	n/a	n/a	n/a	0.00	0.34	10.00	0.00	29.23	1,010.16
2018	n/a	n/a	n/a	0.00	0.25	10.00	0.00	28.30	2,331.55
2019	n/a	n/a	n/a	0.00	0.28	10.00	0.75	21.96	258.67

(a) Pricing rules changed on 3/31/15.

[251] The changes were instituted under FERC's Order No. 755, which required two-part bidding and for compensation of frequency regulation resources to be based on the actual service provided, including a capacity payment that includes the marginal resource's opportunity costs and a service payment for performance that reflects the quantity of frequency regulation provided.

[252] For convenience, the offers are described as two-part. Technically, participants have the ability to specify an intertemporal opportunity cost in their offers, in addition to service and capacity prices; intertemporal opportunity costs, however, are combined with capacity prices, when offers are evaluated for regulation commitment.

[253] Market Participants providing regulation service may also qualify for make-whole or NCPC payments.

[254] Opportunity costs represent the expected value to the regulation resource of foregone energy market opportunities, when providing regulation. The ISO adjusts capacity offer prices for these estimated opportunity costs. Additionally, the ISO also adjusts capacity offer prices to include "incremental cost savings." Incremental cost savings represent the reduction in total system cost provided by a specific regulation offer, when compared to the next most expensive offer.

In 2019, the average service price was $0.28/mile, a $0.03 (12%) increase compared to the average of $0.25/mile in 2018. Mileage payments represent a small share of overall regulation payments (15% or $3.8 million in 2019).

Regulation capacity prices decreased markedly (by 22%) in 2019 compared with 2018, reflecting a large decline in the "opportunity cost" component of regulation capacity pricing. The opportunity cost component of the regulation price indicates the expected value of foregone energy market opportunities, when providing regulation service to the ISO. The reduction in opportunity costs is consistent with reduced energy market LMPs in 2019, compared to 2018.

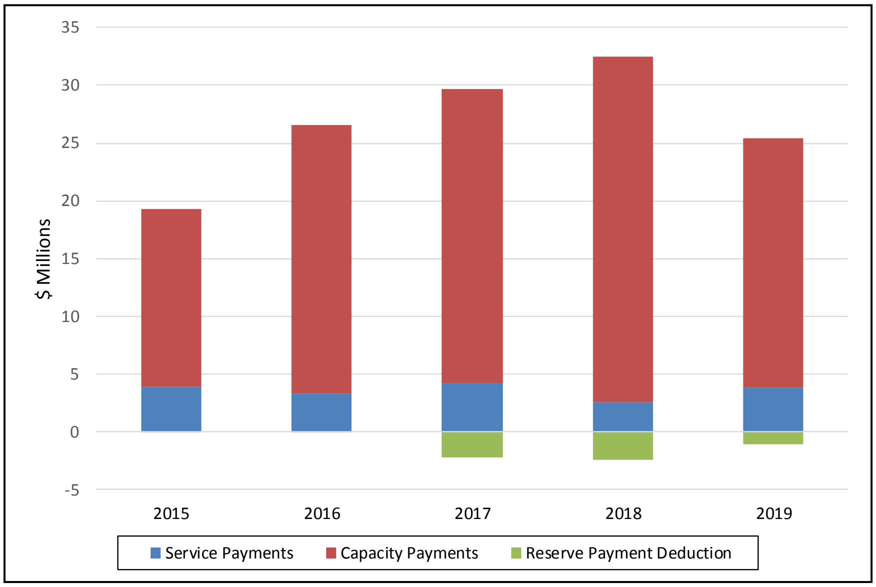
7.3.2 Regulation Payments

Compensation to generators providing regulation includes a regulation capacity payment, a service payment, and a make-whole payment. Starting in March 2017 with the sub-hourly settlement of several market activities (including real-time operating reserves), a deduction was added to regulation payments. This deduction represents the over-compensation of regulation resources for providing operating reserves. Under certain circumstances, part of a regulation resource's regulating range may overlap with the resource's operating reserve range. Since operating reserves are not actually provided within the regulating range, reserve compensation needs to be deducted from the resource's market compensation. The settlement of regulation resources includes the deduction for the over-compensation of providing operating reserves.[255]

Annual regulation payments over the past five years are shown in Figure 7-12 below. The reserve payment deduction is shown as a negative value in the exhibit; the positive values represent total payments (prior to reserve payment deductions) for the regulation capacity and service (mileage) provided by regulation resources during the period.

[255] The reserve payment deduction represents the MW quantity overlap of the regulating range and operating reserve range, multiplied by the operating reserve price.

Figure 7-12: Regulation Payments[256]



Payments to regulation resources totaled $25.4 million in 2019, a 22% decrease from the $32.5 million in 2018. (These totals exclude the reserve payment adjustment.) The 2019 reduction in payments is consistent with the significant decline in capacity prices noted above. The capacity component of regulation payments accounted for 77% of total regulation compensation in 2019.

Earlier years in the review period experienced increases in regulation payments. Regulation payments totaled $32.5 million in 2018, a 9% increase from the $29.7 million in 2017. In 2018, the average regulation requirement increased by 12%, which also led to a commensurate increase in regulation capacity utilization. A 3% decrease in average regulation capacity prices helped to moderate the increase in overall regulation payments.

In 2017, the increase in payments reflected several factors: an increase in regulation requirements, an increase in energy market opportunity costs, and an increase in regulation service volumes.[257] The increase in 2016 payments, compared to 2015, resulted primarily from two factors. The implementation of BAL-003 in April 2016 resulted in an approximately 25% increase in the average regulation requirement for 2016. Also, the manual selection of large regulation resources by the ISO during the summer months increased regulation payments by approximately $2 million compared to 2015.[258]

[256] In the chart, capacity payments include regulation uplift payments. Regulation uplift is provided when opportunity cost estimates included in regulation capacity prices are insufficient to cover actual energy market opportunity costs incurred by regulation resources.

[257] Regulation requirements increased in 2017 relative to 2016, as the implementation of NERC standard BAL-003 (Frequency Response and Frequency Bias Setting) affected all 12 months of 2017 compared to 9 months of 2016; for example, this change resulted in an additional 7% increase in the average regulation capacity requirement for 2017.

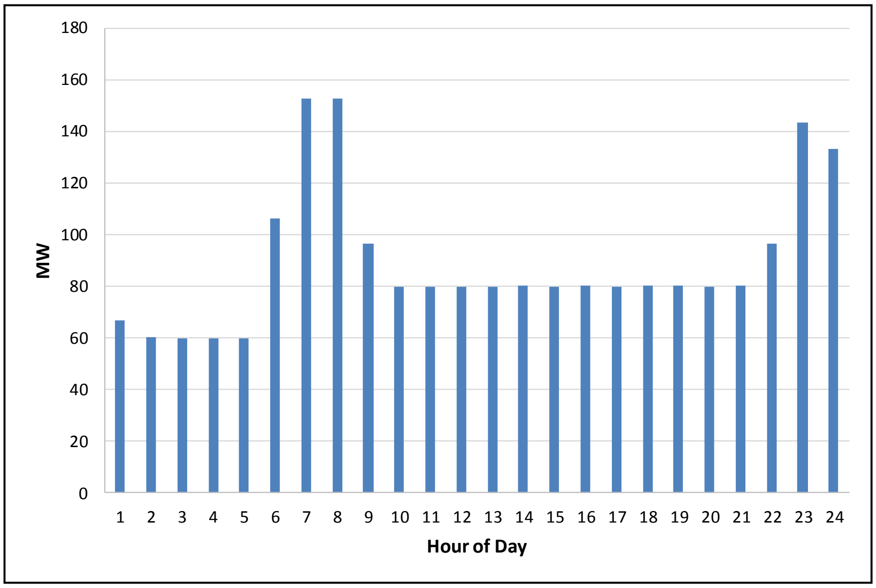
[258] See the Spring 2016 Quarterly Markets Report, available at https://www.iso-ne.com/static-assets/documents/2016/08/q2_spring_2016_qmr_final.pdf, for a detailed discussion of regulation payments in 2015 and earlier years. Note that the data presented in Quarterly reports uses a "seasonal" quarter, which differs from calendar quarters. As such, annual and quarter totals will not match when comparing a Quarterly Markets Report to the Annual Markets Report.

7.3.3 Requirements and Performance

The average hourly regulation requirement of 89.6 MW in 2019 was higher than the 88.8 MW requirement in 2018. This 1% increase in the average regulation requirement reflects operational needs in 2019.

The regulation requirement in New England varies throughout the day and is typically highest in the morning and the late evening. The higher regulation requirement during these hours is the result of greater load variability (load ramping up in the morning and down in the evening). The average hourly regulation requirement by hour of day for 2019 is shown in Figure 7-13 below.

Figure 7-13: Average Hourly Regulation Requirement, 2019

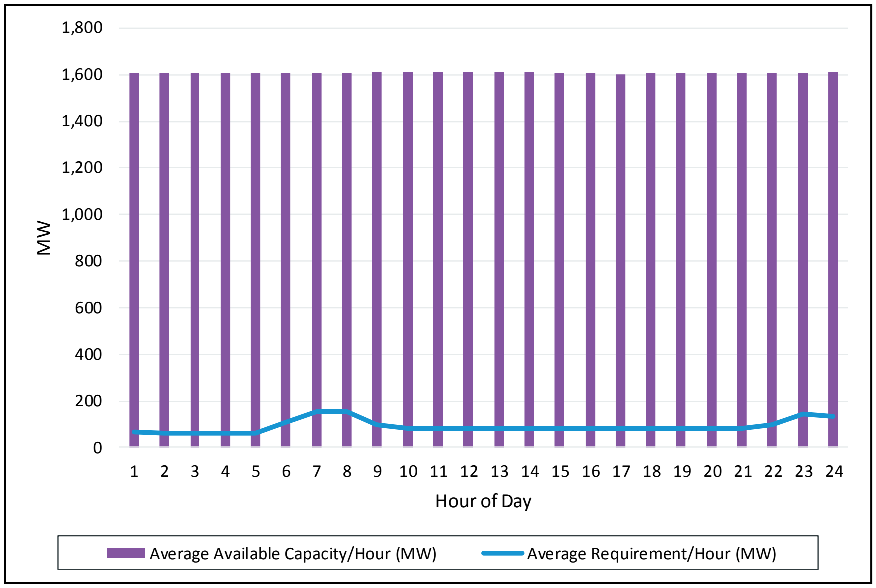


With the ISO's implementation of NERC BAL-001-2 standards in 2016, the ISO now uses violations of Balancing Authority ACE Limits (BAAL) to measure performance. Violations result from exceeding ACE limits for more than 30 consecutive minutes; in 2019, there were no BAAL violations.

7.3.4 Regulation Market Structural Competitiveness

The competitiveness of the regulation market was reviewed by examining market structure and resource abundance. The abundance of regulation resources, and relatively unconcentrated control of that supply, implies that market participants have little opportunity to engage in economic or physical withholding. For these reasons, we believe that the regulation market was competitive in 2019. Figure 7-14 below simply plots the regulation requirement relative to available supply.

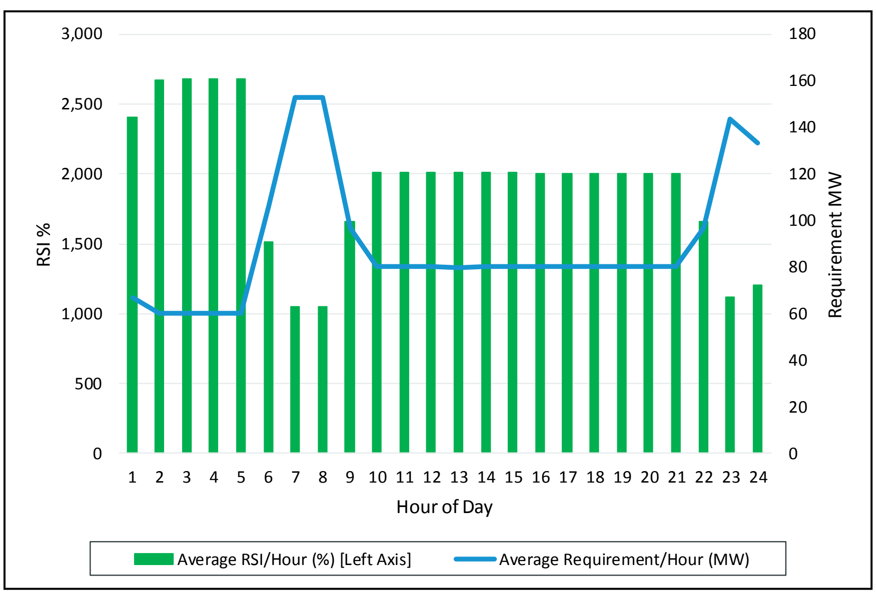
Figure 7-14: Average Regulation Market Requirement and Available Capacity, 2019



On average, during every hour of the day, available supply far exceeds the regulation requirements. However, an available abundance of supply alone is not a dispositive indicator of market competitiveness, as one - or a small number of suppliers - could control the available supply and seek to exercise market power.

The RSI provides a better indicator of the structural competitiveness of the regulation market. It measures how much of the regulation requirement can be met without any regulation supply from the largest supplier. An RSI below 100 indicates the presence of a pivotal suppler (i.e. supply from the largest regulation supplier is needed to fulfill the regulation requirement). As shown in Figure 7-15, the regulation requirement and RSI are inversely correlated (the lower the requirement the higher the RSI).

Figure 7-15: Average Regulation Requirement and Residual Supply Index



In 2019, the lowest hourly average RSI did not fall below 1,000%, implying that, on average, the system had the capability to serve ten times the regulation requirement without the largest regulation supplier, even in the hours with the greatest regulation requirements.

Section 8
Market Design Changes

This section provides an overview of the major market design changes that were recently implemented and those that are planned, or are being assessed, for future years. Table 8-1 below lists the design changes summarized in this section.[259]

Table 8-1: Market Design Changes

Major Design Changes Recently Implemented	Major Design Changes in Development or Implementation for Future Years
Competitive Auctions with Sponsored Policy Resources (CASPR)	Interim Compensation Treatment
FCM Delayed Commercial Resource Treatment	Energy Security Improvements: a long-term market-based approach
Annual Reconfiguration Transactions (ARTs) for Annual FCM Auctions	
Must Offer Requirement for DNE Generators	
FTR Balance of Planning Period (BoPP)	
Energy Market Opportunity Cost: Phase II	
Enhanced Storage Participation	
Energy Market Offer Caps	

8.1 Major Design Changes Recently Implemented

The following provides an overview of market rules changes that were implemented during 2019, and early 2020.

8.1.1 Competitive Auctions with Sponsored Policy Resources (CASPR)

First substitution auction was conducted on February 4, 2019 (for FCA 13)

In the Forward Capacity Market (FCM), new capacity resources are subject to a Minimum Offer Price Rule (MOPR) which sets their floor price based on an IMM-calculated competitive offer benchmark for a given resource's technology type. The MOPR mechanism is intended to prevent subsidies from depressing prices in the primary Forward Capacity Auction (FCA). However, many state-subsidized resources will be built regardless of obtaining a Capacity Supply Obligation (CSO). As a result, the region will purchase more capacity than it requires to meet its demand. Throughout 2017, the ISO worked with stakeholders to address this problem by developing a mechanism that would accommodate the entry of state-sponsored renewable resources into the FCM over time, and limit the extent to which those resources will artificially suppress capacity market prices. The

[259] An overview of Key ISO Projects is also available on the ISO website, at https://www.iso-ne.com/committees/key-projects

result of this effort, Competitive Auctions with Sponsored Policy Resources (CASPR), is intended to achieve these objectives by adding a secondary auction stage to the FCA process.

Under the CASPR Project, ISO New England coordinated the entry of new sponsored policy resources (SPRs) with the retirement of existing resources in an effort to balance federal and state energy policies with the competitive wholesale electricity market. This was accomplished by establishing a substitution auction (SA) to be run after the primary FCA to minimize the impact that SPRs may have on competitively-based capacity prices, maintain resource adequacy, and reduce over-supply concerns.

Eligible resources may participate in the SA as either supply or demand. The supply side of the auction consists of new FCM-qualified SPRs and the demand side is comprised of eligible retiring resources. SPRs participate in the SA in order to obtain a CSO for qualified capacity that was not awarded a CSO in the primary auction. Eligible retiring resources that acquire a CSO in the primary auction participate in the SA to shed the portion of their CSO that was designated in their demand bid, not to exceed their CSO available, after the primary auction. The auction clearing price and MW quantity are determined by the intersection of the supply and demand curves which are developed using the bids and offers submitted during the SA Offer/Bid price window.

When the delivery period (capacity commitment period, CCP) for the auction is reached, the SPRs that acquired a CSO in the SA will receive capacity payments based on the SA's lower clearing price. Retiring resources that were able to shed their CSO in the SA will receive payments equal to the primary auction price, but will pay the SA's lower clearing price to the SPRs that acquired a CSO. With the full primary auction clearing price paid for the CSOs transferred in the SA and the SPRs' MWs equal to the retiring resources' MWs, there is a net zero effect on the primary auction results.

The IMM had expressed concern about how effective CASPR would be in protecting competitive capacity market prices over time. Two potential effects, in particular, could exert downward pressure on capacity prices.

The first was recently addressed through an additional form of bid mitigation beginning with FCA 14, referred to as the test price mitigation rule. The rule addresses concerns about the incentive for retiring resources to submit FCA offers below their true competitive cost in order to improve their chances of receiving a CSO in the primary auction, which they then can shed for a severance payment in a secondary auction. The IMM determines a test price that serves as a screen to determine whether a resource's demand bid will be entered into the substitution auction based on the clearing price of the primary auction. If the resource's test price is below the primary auction clearing price, the resource is allowed to enter the substitution auction. If the test price is greater than the primary auction clearing price, the resource is not permitted to enter a demand bid into the substitution auction.

The second effect concerns the impact of state-sponsored resources on clearing prices in capacity auctions after they have initially cleared in a substitution auction. When resources first clear as "new" resources in a capacity auction they become "existing" resources in subsequent auctions. Existing resources do not have MOPR mitigation applied to limit the minimum price they can offer into the primary auction. Consequently, because an existing state-sponsored resource is no longer subject to the MOPR, it can offer into subsequent FCAs at a price that reflects its subsidies and is below a competitive market level. Further, state-sponsored resources are often renewable resources with low variable cost of producing energy (e.g., wind and solar). The low variable cost of production results in higher net revenue from the electricity market and thus reduces the "missing money" payment that these resources would need from the capacity market to operate profitably from year to year. This positions state-sponsored resources to offer a lower bid price in the FCA in years subsequent to their first clearing via the CASPR mechanism, which can have the effect of reducing auction clearing prices over time. Those state-sponsored resources would not otherwise have had the opportunity to suppress the FCA clearing price because, with sufficiently high construction costs, they would not have cleared as new resources and they would not have subsequently become existing resources (where MOPR does not apply) in the FCM.

This "subsequent year" effect does have the potential to suppress capacity market prices, however, it is a byproduct of the decision to create a mechanism that allows such resources to enter the capacity market and become existing capacity resources. Applying a MOPR-type rule to existing state-sponsored resources could result in either removing the resources once they have cleared through CASPR, which undermines the purpose of CASPR, or could be inconsequential due to the low "missing money" requirement for state-sponsored resources once they are built.

In FCA 13, the substitution auctioned cleared 54 MW at a price of $0/kW-month. This means that a state-sponsored resource will receive $0/kW-month in FCA 13, and clear subsequent auctions as an existing capacity resource. The resource that shed 54 MW was a dual-fuel oil/gas-fired generator and will receive their full FCA 13 payment for that capacity. The resource will also retire, partially or fully, from all New England markets starting June 1, 2022.

In FCA 14, the substitution auction did not proceed. While there was 292 MW of supply seeking to acquire capacity obligations, there was no demand because the existing capacity resources either exited the FCA without a CSO or were deemed ineligible because their test-price was higher than the FCA clearing price (see Section 6.3.3).

8.1.2 Forward Capacity Market Delayed Commercial Resource Treatment

Implemented on June 1, 2019[260]

On June 1, 2019, the ISO implemented rules to address resources holding capacity supply obligation (CSOs) with a delayed commercial operation date in the Forward Capacity Market (FCM). The rules incent resources to cover their CSOs when they have not physically demonstrated the ability to offer capacity into the energy market.

Prior to the changes, the ISO entered mandatory demand bids for resources that did not take action to cover their CSOs, and were expected to under-perform during the commitment period. The Delayed Commercial Operation rules replace, and improve upon, prior rules by shifting the responsibility of covering undemonstrated capacity to the participant. Now, the participant can either choose to cover the CSO through the secondary markets (annual *or* monthly auctions) until the resource reaches commercial operation, or if the participant does not cover all of the resource's undemonstrated capacity, then they will incur a failure-to-cover charge.

[260] https://www.iso-ne.com/static-assets/documents/2019/10/2019-summer-quarterly-markets-report.pdf

Over the first six months of capacity commitment period (CCP) 10, 28 resources were charged roughly $0.7 million for undemonstrated capacity. Charges were primarily incurred by passive and active demand response resources.[261]

8.1.3 Annual Reconfiguration Transactions (ARTs) for Annual FCM Auctions

Applied from the 2nd Annual Reconfiguration Auction for CCP 11, which was conducted in August 2019

Under the Annual Reconfiguration Transactions (ARTs) project, ISO New England replaced the annual capacity supply obligation (CSO) bilaterals with the new ARTs model to allow participants and their counterparties to acquire or shed CSO with price certainty. The previous annual CSO bilateral method, which transferred CSOs from one resource to another on a kilowatt-for-kilowatt basis, became obsolete when the marginal reliability impact (MRI) zonal demand curves were implemented with Forward Capacity Auction (FCA) 11 for capacity commitment period (CCP) 2020-2021. Under the MRI-based zonal curves, capacity is no longer considered fully substitutable on a kW-for-kW basis across zonal boundaries.

The new ARTs model, when used in conjunction with a demand bid or supply offer in an ARA, facilitates the equivalent of a private transaction. The demand bid or supply offer in the ARA accounts for each resource's change in CSO quantity and any effect from partial substitutability; the ART also provides price certainty for the CSO transfer or acquisition.

In ARA 2 for CCP 11, four resources totaling 34 MW participated. This represents just 6% of the total capacity cleared in ARA 2.

8.1.4 Must Offer Requirement for Do Not Exceed (DNE) Dispatchable Generators

Effective from June 1, 2019

In June 2019, the ISO implemented day-ahead energy market (DAM) offer requirements for do not exceed (DNE) dispatchable generators with capacity supply obligations (CSOs). DNE dispatchable generators are intermittent wind and hydro generators that were required by the ISO in 2016 to implement the capability to respond to electronic DNE dispatch instructions.[262] The June 2019 change required DNE generators with CSOs to offer the full hourly amount of expected real-time generation into the DAM; the change aligns the must-offer obligations for DNE generators with CSOs, with the must-offer requirements for other types of dispatchable generators. The change affected 37 hydro generators and 18 wind generators.

The IMM undertook and published an analysis on the impact of the rules changes based on experience from the first few months of operation.[263] This analysis concluded that DNE wind

[261] These rules are also covered in Section 5, Observations on New Market Rule Changes, in the 2019 Summer Quarterly Markets Report, at https://www.iso-ne.com/static-assets/documents/2019/10/2019-summer-quarterly-markets-report.pdf

[262] The DNE dispatch instruction specifies a maximum generation level for the DNE generator, and the ISO expects that the generator's output will not exceed that level. The 2016 DNE changes incorporated intermittent wind and hydro resources into the economic dispatch and pricing software. Rather than manually curtailing wind generators to manage congestion, the changes provided a market solution to this reliability issue and allowed congestion to be reflected in real-time prices. See ISO New England's Tariff change request, RE: ISO New England Inc. and New England Power Pool, Docket No. ER15- -000, Do Not Exceed ("DNE") Dispatch Changes (filed with FERC on April 15, 2015).

[263] Ibid.

generators have increased the hourly quantity of energy offered in the DAM, and overall, those offers reasonably reflect the expected level of real-time production during peak production hours. The analysis indicated an uptick in the amount of wind generation clearing in the DAM during the first month of the new rules, but a decline, to pre-rule change levels subsequently. Virtual supply, which historically has filled the gap for wind not clearing in the DAM, has shown slight reductions in cleared volumes at wind nodes.

8.1.5 Financial Transmission Rights (FTR), Balance of Planning Period (BoPP) Rules

Implemented on September 17, 2019

On September 17, 2019, ISO-NE implemented the Balance of Planning Period (BoPP) project for FTRs. This project increased the number of opportunities that market participants have to reconfigure their monthly FTR positions following the two annual auctions. Prior to the implementation of this project, market participants could only purchase or sell FTRs for a specific month in the auction that occurred during the month prior to that effective month. For example, if a market participant wanted to buy FTRs that would be effective for December 2019, it would have to wait until the monthly auction that took place in November 2019. Under the BoPP design, ISO-NE now administers monthly FTR auctions for not just the next month (now called the prompt-month auction), but also for all the other months remaining in the calendar year (called the out-month auctions). This means that a participant that wants to buy December 2019 FTRs no longer has to wait until November 2019; it can purchase these FTRs in any of the out-month auctions that take place earlier in the year. However, the out-month auctions do not make any additional network capacity available than was made available in the second annual auction (in contrast to the prompt-month auctions, which do make additional capacity available).[264]

The implementation of BoPP was coordinated with the October 2019 prompt-month auction, whose bidding window was open from September 17-19, 2019. During this bidding window, participants could also submit bids and offers for the November 2019 and December 2019 out-month auctions. FTRs purchased or sold in these out-month auctions are sometimes referred to as the "October 2019" *vintage* of the November 2019 or December 2019 FTR contracts.

The first out-month auctions that occurred were for November and December 2019. Cleared out-month transaction volumes were relatively low, representing 1.7% and 3.6% of all transaction volume for November and December, respectively.[265]

8.1.6 Energy Market Opportunity Cost: Phase II

Implemented on December 3, 2019

[264] The first round of the annual auction makes available 25% of the transmission system capability. The second round of the annual auction makes available an additional 25%, meaning that a total of 50% of the network capability is sold in the two annual auctions. The prompt-month auctions make available an additional 45% of the network capability, meaning that 95% of the network capability is sold by the time the effective month arrives. The out-month auctions do not make available any additional network capability beyond that which was made available in the second round of the annual auction. However, FTRs can still be purchased in the out-month auctions on paths that weren't completely subscribed in the second annual auction, as the result of counterflow FTR purchases, or as the result of FTR sales.

[265] See Section 4.2, Financial Transmission Rights, of the IMM's 2019 Fall Quarterly Markets Report, at https://www.iso-ne.com/static-assets/documents/2020/02/2019-fall-quarterly-markets-report.pdf

On 1 December 2018, energy market reference levels began including an opportunity cost (EMOC) adder for generators that maintain an oil inventory.[266] The update was motivated by concerns that during sustained cold weather events generators were unable to make energy supply offers that incorporated the opportunity costs associated with the depletion of their limited fuel stock. Such an event arose during the winter of 2017/2018 - 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.

The IMM calculates asset-specific EMOC numbers with a mixed-integer programming model that was developed by the ISO and runs automatically each morning. For a given forecast of LMP 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 asset operational characteristics. Opportunity costs produced by the model are available to participants an hour before the day-ahead market closes and, since December 2019 (i.e. EMOC Phase II), a real-time opportunity cost update is available at 6:30 pm, before to the start of the real-time market. 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.

This past winter was mild and the EMOC adder never increased above zero for any generator that was part of the program. As a result, energy market opportunity costs had no impact on the supply curve over the winter period.

8.1.7 Enhanced Storage Participation

Phase 1 was implemented on April 1, 2019, and Phase 2 in December 1, 2019 and March 1, 2020

In October 2018, the ISO filed proposed rule changes to enable emerging storage technologies to more fully participate in the New England markets and to comply with FERC Order 841.[267,268] The revisions are intended to allow emerging storage technologies to be dispatched in the real-time market in a manner that more fully recognizes their ability to transition continuously and rapidly between a charging state and a discharging state, and that provides a means for their simultaneous participation in the energy, reserves, and regulation markets.

The majority of the rules implementing ISO-NE's storage participation model were operational on April 1, 2019, eight months prior to the Order No. 841 effective date, and the rest went into effect in early December 2019.

The rules in effect provide a technology-neutral platform for electric storage resources to participate fully in the New England markets, as follows:

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[266] See memo entitled, Energy Market Opportunity Costs for Oil and Dual-Fuel Resources with Inter-temporal Production Limitations – Revised Edition, at 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

[267] *ISO New England Inc. and New England Power Pool;* Docket No. ER19-84-000; Enhanced Storage Participation Revisions (filed October 10, 2018). https://www.iso-ne.com/static-assets/documents/2018/10/er19-84-000_enhanced_storage_revisions.pdf

[268] See Electric Storage Participation in Markets Operated by Regional Transmission Organizations and Independent System Operators, Final Rule, 162 FERC ¶ 61,127 (February 15, 2018) ("Order No. 841").

- To allow participation in all New England wholesale markets with a capability down to 100 kW; and take on capacity supply obligations and participate fully in the Forward Capacity Market.
- To be dispatched to charge and discharge based on economics in both the day-ahead and real-time markets without risk of conflicting dispatch instructions.
- To set the LMP when charging or discharging in both the day-ahead and real-time markets
- To be designated for reserves when charging and discharging, even when providing regulation.
- In the case of batteries and similar technologies, to provide regulation while maintaining their state of charge and therefore participate simultaneously in the regulation and energy markets.
- In the case of pumped-storage hydroelectric facilities and similar technologies, to simultaneously provide regulation and inject energy; save energy for a future interval.
- To receive a day-ahead schedule that optimizes a full charge-discharge cycle.
- To receive Net Commitment Period Compensation (uplift) credits if they are dispatched out-of-rate.

8.1.8 Energy Market Offer Caps

Implemented on March 1, 2020

In May 2017, the ISO filed proposed market rule changes to comply with FERC Order No. 831.[269] The Order addresses the potential issue, primarily when fuel is scarce, for energy market offers to reach and exceed the current $1,000/MWh energy market offer cap that is in place in the majority of organized energy markets. The Order is intended to improve energy market price formation by reducing the likelihood that offer caps will suppress LMPs below the marginal cost of production, while compensating resources for the costs they incur to serve load. This will enable RTOs/ISOs to dispatch the most efficient set of resources when short-run marginal costs exceed $1,000/MWh, by encouraging resources to offer supply to the market when it is most needed, and by reducing the potential for seams issues between RTO/ISO regions.

The Order requires RTOs/ISOs to cap each resource's incremental energy offer at the higher of $1,000/MWh or that resource's verified cost-based incremental energy offer, and further imposes a hard cap of $2,000/MWh on incremental energy offers used in pricing calculations. In addition, there is a provision that allows a participant to request after-the-fact recovery of costs that it did not recover through the market either because it was precluded from doing so by the existing $1,000/MWh offer cap or because its offer was mitigated.

The ISO's bidding software, *emarket*, was updated to apply the following FERC Order 831 rules:[270]

- Capping incremental energy offers at the higher of the $1,000 per MWh soft-cap or that resource's verified cost-based incremental energy offer.
- Verifying incremental energy offers above the $1,000 per MWh soft-cap against the internal market monitor's (IMM's) reference schedules to test for reasonability.

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[269] *ISO New England Inc. and New England Power Pool,* Market Rule 1 Revisions to Modify Energy Market Offer Caps in Compliance With Order No. 831; Docket No. ER17-1565-000 (filed on May 8, 2017)

[270] See the project page on the ISO's website for further detail, at https://www.iso-ne.com/participate/support/customer-readiness-outlook/offer-caps-ferc-order-831-project

- Storing last-submitted offers when incremental energy offers are capped for subsequent analysis to determine make-whole payment eligibility. This applies to offers above the $1,000 per MWh soft-cap or the $2,000 per MWh "hard-cap".

8.2 Major Design Changes in Development or Implementation for Future Years

The following market rule changes are either currently in the design phase or have been completely designed. The planned implementation date is in in future years.

8.2.1 Interim Compensation Treatment

Planned implementation for Winter 2023/2024

In February 2019, the ISO filed proposed market rule changes to implement an interim solution to compensate and incent inventoried energy during winter months. The program is known as Interim Compensation Treatment (ICT).[271] The ICT is also intended to reduce the likelihood that an otherwise economic resource might seek to retire from the wholesale energy and capacity markets because of inadequate compensation for its winter energy security attributes.

Using a standard two-settlement structure, ICT allow resources to sell up to 72 hours (3-days) of inventoried energy to be held during trigger conditions[272] either at a forward settlement rate of $82.49 per MWh for the winter season or a spot settlement rate of $8.25 per MWh for inventoried energy maintained during each trigger condition. If a resource sells inventoried energy forward, it must either (i) maintain this amount of inventoried energy during each trigger condition or (ii) buy out of any shortfall at the spot rate, during the relevant winter month. The spot settlement rate represents the rate that resources are paid (or charged) for deviations between the quantity of inventoried energy sold forward and the quantity of inventoried energy maintained during trigger conditions.

By administratively setting these forward and spot settlement rates several years in advance, the ISO's intention is to provide greater revenue certainty to generators with inventoried energy, which in turn allowed generators to reflect such revenue stream in their bidding strategies for FCA 14. Initially, intended to also apply to FCA 15, the ISO recently proposed to sunset the program after one year, given the proposed effective date for the long-term market based solution of June 1, 2024.[273]

8.2.2 Energy Security Improvements: a long-term market-based approach

Proposed effective date of June 1, 2024

On April 15, 2020, the ISO submitted proposed rule changes in compliance with FERC's July 2018 Order directing the ISO, pursuant to Schedule 206 of the Federal Power Act, to submit "permanent Tariff revisions reflecting improvements to its market design to better address regional fuel security concerns". The ISO's proposed design seeks to address a misaligned incentive issue with

[271] ISO New England Inc., Docket No. ER19-1428-000; Inventoried Energy Program (filed March 25, 2019)

[272] A trigger condition occurs when the average of the daily high and low temperature is 17°F or lower.

[273] See ISO New England Inc., Compliance Filing of Energy Security Improvements Addressing New England's Energy Security Problems; Docket Nos. EL18-182-000 and ER20-1567-000, at https://www.iso-ne.com/static-assets/documents/2020/04/energy_security_improvements_filing.pdf

the current market construct. The economic value to a generator of making upfront fuel arrangements can be significantly less (or loss-making) than the value society receives through lower energy prices, as a result of avoiding energy scarcity conditions because of those fuel arrangements. Therefore, the design in essence seeks to provide participants with market products that will value and pay for the cost of making arrangements to deliver secure energy.

The proposed rules will incorporate real-time ancillary service requirements into the day-ahead market, and clear pre-determined ancillary service quantities. Energy and reserve offers will be co-optimized. Under the proposal, participants will submit ancillary services option offers for eligible physical resources, along with their energy offers. The ancillary services option represents an option on real-time energy, whereby an option closeout cost will be charged to the resource when real-time prices exceed the published “at-the-money” strike price.

The construct provides strong incentives for participants to cover options as real-time prices exceed the strike price and a generator’s marginal cost. If its resource does not perform, the participant is exposed to potentially high closeout costs that reflect the replacement cost of the undelivered energy.

The IMM recently submitted comments to FERC on the ISO’s Energy Security Improvement’s proposal to assist the Commission in its review and determinations regarding the proposed rule changes. [274]

[274] Comments of the IMM on Energy Security Improvements, at https://www.iso-ne.com/static-assets/documents/2020/05/imm_esi_comments.pdf

Acronyms and Abbreviations

Acronyms and Abbreviations	Description
°F	degrees Fahrenheit
AC	alternating current
ACE	area control error
ADCR	Active Demand Capacity Resources
AMR	Annual Markets Report
ARA	annual reconfiguration auction
ARD	asset-related demand
ART	Annual Reconfiguration Transaction
AS	ancillary service
BAA	balancing authority area
BAAL	Balancing Area ACE Limits
BAL-001-2	NERC's *Real Power Balancing Control Performance Standard*
BAL-003	NERC's *Frequency Response and Frequency Bias Setting Standard*
bbl	barrel (unit of oil)
Bcf	billion cubic feet
Btu	British thermal unit
C4	market concentration of the four largest competitors
CASPR	Competitive Auctions with Sponsored Policy Resources
CC	combined cycle (generator)
CCP	capacity commitment period
CDD	cooling degree day
CMR	Code of Massachusetts Regulations
CO_2	carbon dioxide
CONE	cost of new entry
CPS 2	NERC *Control Performance Standard 2*
CSC	Cross Sound Cable
CSO	capacity supply obligation
CT	State of Connecticut, Connecticut load zone, Connecticut reserve zone
CT	combustion turbine
CTL	capacity transfer limit
CTS	Coordinated Transaction Scheduling
DAGO	day-ahead generation obligation
DALO	day-ahead load obligation
DARD	dispatchable asset related demand
DDBT	dynamic de-list bid threshold
DDG	do-not-exceed dispatchable generators

Acronyms and Abbreviations	Description
DDT	dynamic de-list threshold
Dec	decrement (virtual demand)
DFC	dual fuel commissioning
DG	distributed generation
DLOC	dispatch lost opportunity costs NCPC
DNE	do not exceed
DOE	US Department of Energy
DR	demand response
EIA	US Energy Information Administration (of DOE)
EMM	External Market Monitor
EMOC	Energy Market Opportunity Cost
EMOF	Energy Market Offer Flexibility
EPA	Environmental Protection Agency
ERS	external reserve support
ETU	Elective Transmission Upgrade
FCA	Forward Capacity Auction
FCM	Forward Capacity Market
FERC	Federal Energy Regulatory Commission
FRM	Forward Reserve Market
FSP	Fast-Start Pricing
FTR	Financial Transmission Right
GT	gas turbine
GHG	greenhouse gas
GWh	gigawatt-hour
GW-month	gigawatt-month
HDD	heating degree day
HE	hour ending
HQ	Hydro-Québec
HQICCS	Hydro-Québec Installed Capacity Credit
IBT	internal bilateral transaction
ICE	Intercontinental Exchange, Inc.
ICR	Installed Capacity Requirement
ICT	Interim Compensation Treatment
IMAPP	Integrating Markets and Public Policy
IMM	Internal Market Monitor
Inc	increment (virtual supply)
ISO	Independent System Operator, ISO New England
ISO tariff	*ISO New England Transmission, Markets, and Services Tariff*

Acronyms and Abbreviations	Description
kW	kilowatt
kWh	kilowatt-hour
kW-month	kilowatt-month
kW/yr	kilowatt per year
L	symbol for the competitiveness level of the LMP
LA	left axis
LCC	Local Control Center
LEG	limited-energy generator
LMP	locational marginal price
LNG	liquefied natural gas
LOLE	loss- of-load expectation
LS/ERI	Lower SEMA/Eastern RI Import interface
LSE	load-serving entity
LSCPR	local second-contingency-protection resource
LSR	local sourcing requirement
M-36	*ISO New England Manual for Forward Reserve*
MA	State of Massachusetts
MAPE	mean absolute percent error
MassDEP	Massachusetts Department of Environmental Protection
MCL	maximum capacity limit
MDE	manual dispatch energy
ME	State of Maine and Maine load zone
M/LCC 2	Master/Local Control Center Procedure No. 2, *Abnormal Conditions Alert*
MMBtu	million British thermal units
MOPR	Minimum Offer Price Rule
MRA	monthly reconfiguration auction
MRI	marginal reliability impact
MW	megawatt
MWh	megawatt-hour
N-1	first contingency
N-1-1	second contingency
NCPC	Net Commitment-Period Compensation
NEL	net energy for load
NEMA	Northeast Massachusetts, Boston load zone
NEMA/Boston	Northeast Massachusetts/Boston local reserve zone
NEPOOL	New England Power Pool
NERC	North American Electric Reliability Corporation

Acronyms and Abbreviations	Description
NH	State of New Hampshire, New Hampshire load zone
NHME	New Hampshire-Maine Import interface
NICR	net Installed Capacity Requirement
NNE	northern New England
No.	Number
NPCC	Northeast Power Coordinating Council
NY	State of New York
NYNE	New York-New England interface
NYISO	New York Independent System Operator
OATT	*Open Access Transmission Tariff*
OP 4	ISO Operating Procedure No. 4
OP 7	ISO Operating Procedure No. 7
OP 8	ISO Operating Procedure No. 8
ORTP	offer-review trigger price
PER	peak energy rent
PFP	pay-for-performance
PJM	PJM Interconnection, L.L.C.
pnode	pricing node
PRD	price-responsive demand
PROBE	Portfolio Ownership and Bid Evaluation
PST	pivotal supplier test
PURA	Public Utilities Regulatory Authority
PV	photovoltaic
Q	quarter
RA	right axis
RAA	reserve adequacy assessment
RCA	Reliability Coordinator Area
RCP	regulation clearing price
RCPF	Reserve Constraint Penalty Factor
RGGI	Regional Greenhouse Gas Initiative
RI	State of Rhode Island, Rhode Island load zone
RMCP	reserve market clearing price
RNL	regional network load
RNS	regional network service
RoP	rest of pool
RoS	rest of system
RRP OC	rapid-response pricing opportunity costs NCPC
RSI	Residual Supply Index

Acronyms and Abbreviations	Description
RTDR	real-time demand response
RTLO	real-time load obligation
RTO	Regional Transmission Organization
RTR	renewable technology resource
SEMA	Southeast Massachusetts load zone
SENE	southeastern New England
SMD	Standard Market Design
SWCT	Southwest Connecticut
THI	Temperature-Humidity Index
TMNSR	10-minute non-spinning reserve
TMOR	30-minute operating reserve
TMSR	10-minute spinning reserve
TPRD	transitional price-responsive demand
TTC	total transfer capability
UDS	unit dispatch system
US	United States
VT	State of Vermont and Vermont load zone
WCMA	Western/Central Massachusetts
WRP	Winter Reliability Program
WTI	West Texas Intermediate