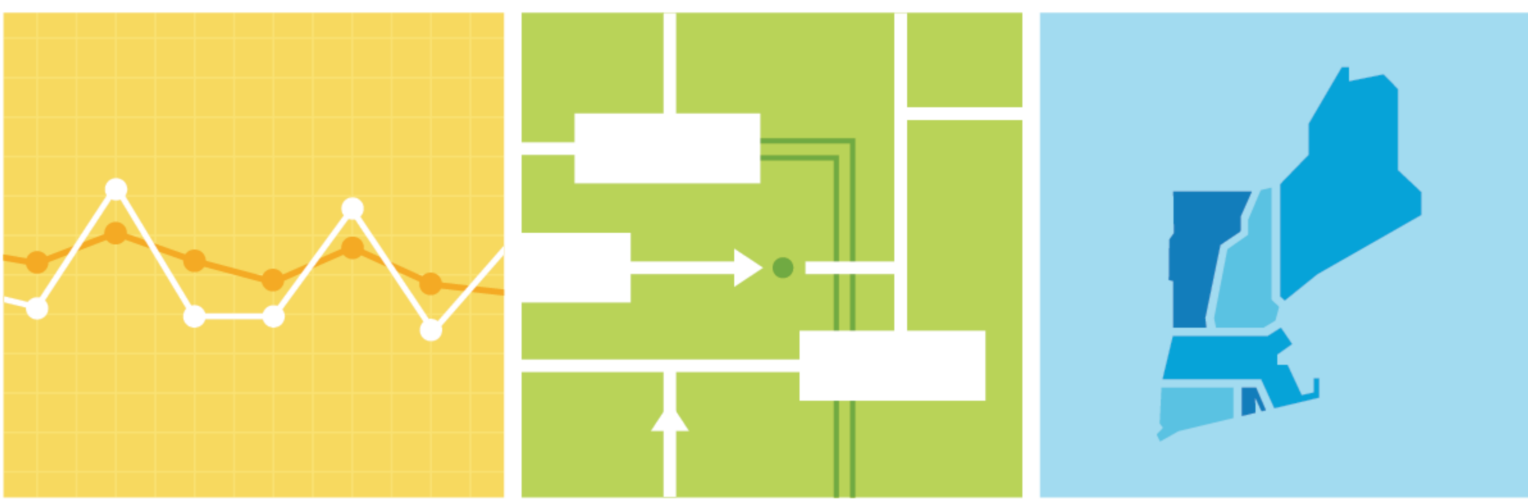
Fall 2019
Quarterly Markets Report

By ISO New England's Internal Market Monitor

FEBRUARY 12, 2020



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Preface

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

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

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

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

Underlying natural gas data furnished by:

ice Global markets in clear view[2]

Oil prices are provided by Argus Media.

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

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

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Section 1
Executive Summary

This report covers key market outcomes and the performance of the ISO New England wholesale electricity and related markets for Fall 2019 (September 1, 2019 through November 30, 2019).[3]

Wholesale Costs: The total estimated wholesale market cost of electricity was $1.52 billion, down 38% from $2.43 billion in Fall 2018. Energy and capacity market costs both decreased, as well as NCPC and ancillary services costs.

Energy costs totaled $746 million; down 47% ($655 million) from Fall 2018 costs. Lower energy costs were a result of lower natural gas prices (down 42% or $1.77/MMBtu) and lower loads (down 6% or about 800 MW on average). The decrease in load was a result of milder weather compared to Fall 2018.

Capacity costs totaled $749 million, down 24% ($239 million) from last fall. Beginning in Summer 2019, lower capacity clearing prices from the tenth Forward Capacity Auction (FCA 10) contributed to lower wholesale costs relative to the previous FCA. Last year, the capacity payment rate was $9.55/kW-month in all capacity zones except SEMA/Rhode Island.[4] This year, the payment rate for new and existing resources was lower, at $7.03/kW-month. The lower clearing prices caused capacity costs to decrease.

Energy Prices: Day-ahead and real-time energy prices at the Hub averaged $24.69 and $24.98 per megawatt hour (MWh), respectively. Day-ahead and real-time prices were 43-45% lower than Fall 2018 prices, on average.

- Day-ahead and real-time energy prices continued to track with natural gas prices.
- Gas prices averaged $2.44/MMBtu in Fall 2019, a decrease of 42% compared to $4.21/MMBtu in the prior fall.
- Hourly load averaged 12,551 MW, down by 6% (≈ 820 MW) on the previous fall. The decrease was driven by milder weather.
- The spread between energy prices and natural gas generation costs was lower compared to the previous fall. In Fall 2018, higher loads and significant nuclear generator outages contributed to a higher spread between LMPs and gas costs. There were no notable nuclear generator outages in Fall 2019.
- Energy market prices did not differ significantly among the load zones.

Net Commitment Period Compensation (NCPC): NCPC payments totaled $8.5 million, a decrease of 26% ($2.9 million) compared to Fall 2018. NCPC remained relatively low when expressed as a percentage of total energy payments, at around 1%. The majority of NCPC (57%) was for first contingency protection (also known as "economic" NCPC). Fall 2019 economic payments fell by about 46% compared to Fall 2018 payments. Most of these payments occurred in the real-time market.

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

[4] As a result of inadequate supply, the payment rate in SEMA/Rhode Island was higher than in other zones.

At $1.8 million, local second-contingency protection reliability (LSCPR) payments accounted for 21% of total NCPC payments. These payments increased by $0.3 million relative to Fall 2018 payments. The majority (65%) of Fall 2019 LSCPR payments went to generators located in Maine. These generators were needed to support planned transmission work during September and October 2019 which affected the Maine/New Hampshire interface.

Real-time Reserves: Real-time reserve payments totaled $2.1 million, a $12.0 million decrease from $14.1 million in Fall 2018. All reserve payments were for ten-minute spinning reserve (TMSR).

The primary driver behind lower reserve payments compared to the previous fall was the lack of shortage conditions in Fall 2019. During the previous fall, a system event on September 3, 2018 resulted in negative reserve margins and high reserve prices. Of the $14.1 million in reserve payments in Fall 2018, about $9 million were paid on September 3. No comparable system event occurred in Fall 2019.

Additionally Fall 2019 saw lower energy prices (and consequently lower opportunity costs), and a decrease in the frequency and magnitude of non-zero reserve pricing. The average non-zero hourly spinning reserve price decreased relative to Fall 2018, from $27.58 to $9.60/MWh. The frequency of non-zero spinning reserve prices fell from 442 hours to 364 hours.

Regulation: Total regulation market payments were $6.2 million, down 31% ($2.7 million) from $8.9 million in Fall 2018. This significant decrease reflects the shortage event in September 2018, which resulted in very high energy prices and energy market opportunity costs for regulation generators last fall. An overall decrease in energy prices also contributed to lower regulation payments in Fall 2019. Even when the prices that resulted from the shortage event are excluded, energy prices were significantly lower in Fall 2019 compared to the previous fall.

Financial Transmission Rights and the Balance of Planning Period (BoPP) Project: On September 17, 2019, the ISO implemented the Balance of Planning Period (BoPP) project. This project increased opportunities for market participants to reconfigure their monthly Financial Transmission Rights (FTR) positions following the two annual auctions.

- Prior to BoPP, participants could only buy or sell FTRs for a given month during the prior month ("prompt-month").
- Under the new rules, participants can buy and sell monthly FTRs positions over the remainder of the year before the "prompt-month" auctions take place. The new auctions are called "out-month" auctions.
- The out-month auctions don't make additional network capacity available. However, participants can still purchase FTRs in out-month auctions for paths that weren't completely sold in the second annual auction, as the result of counterflow FTR purchases, or as the result of FTR sales.
- 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.

Section 2
Overall Market Conditions

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

Table 2-1: High-level Market Statistics

Market Statistics	Fall 2019	Summer 2019	Fall 2019 vs Summer 2019 (% Change)	Fall 2018	Fall 2019 vs Fall 2018 (% Change)
Real-Time Load (GWh)	27,412	33,000	-17%	29,209	-6%
Peak Real-Time Load (MW)	19,105	24,361	-22%	24,475	-22%
Average Day-Ahead Hub LMP ($/MWh)	$24.69	$25.89	-5%	$43.22	-43%
Average Real-Time Hub LMP ($/MWh)	$24.98	$25.09	0%	$45.37	-45%
Average Natural Gas Price ($/MMBtu)	$2.44	$2.17	12%	$4.21	-42%
Average Oil Price ($/MMBtu)	$12.48	$12.08	3%	$13.26	-6%

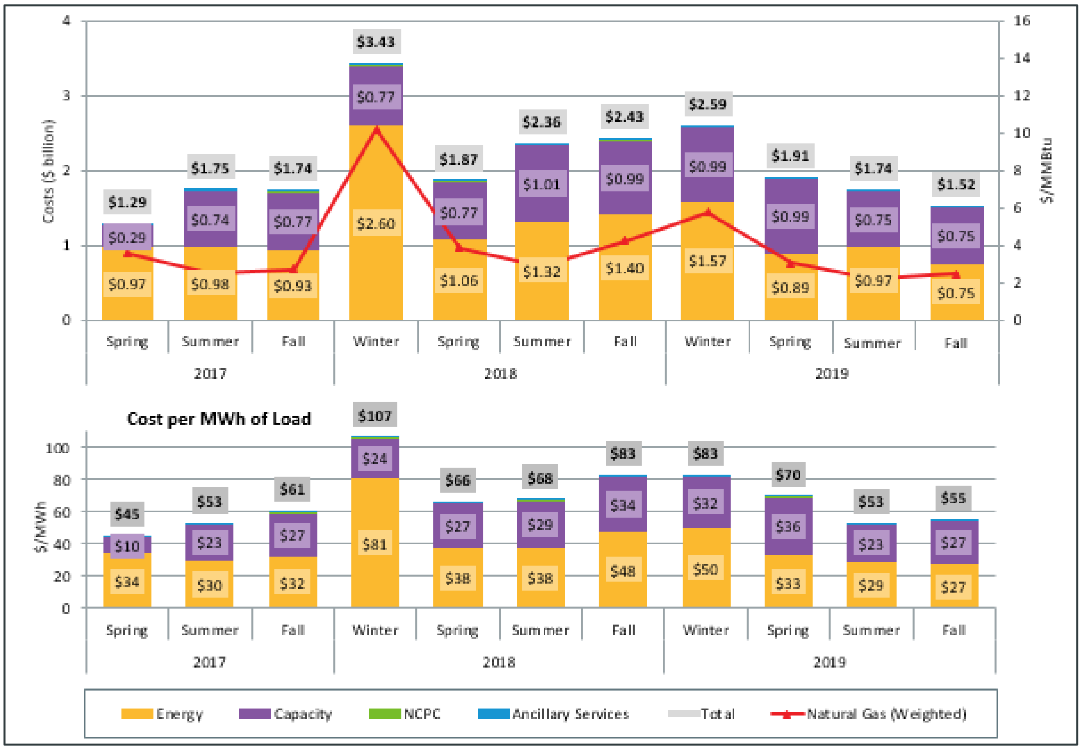
To summarize the table above:

- Average day-ahead LMPs in Fall 2019 were $24.69/MWh, 43% lower than in Fall 2018. Lower gas prices in Fall 2019 ($2.44/MMBtu) compared to Fall 2018 ($4.21/MMBtu) and lower load put downward pressure on LMPs.
- Total load in Fall 2019 (27,412 GWh, or an average of 12,551 MW per hour) was 6% lower than in Fall 2018 (29,206 GWh). This was driven by cooler temperatures in September, and warmer temperatures in late November. This is described in more detail in Section 2.2 below.

2.1 Wholesale Cost of Electricity

The estimated wholesale electricity cost (in billions of dollars) for each season by market, along with average natural gas prices (in $/MMBtu) is shown in Figure 2-1. The bottom graph shows the wholesale cost per megawatt hour of real-time load served. [5,6]

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



In Fall 2019, the total estimated wholesale cost of electricity was $1.52 billion (or $55/MWh of load), a 38% decrease compared to $2.43 billion in Fall 2018, and a decrease of 13% over the previous quarter (Summer 2019). Natural gas prices continued to be a key driver of energy prices.

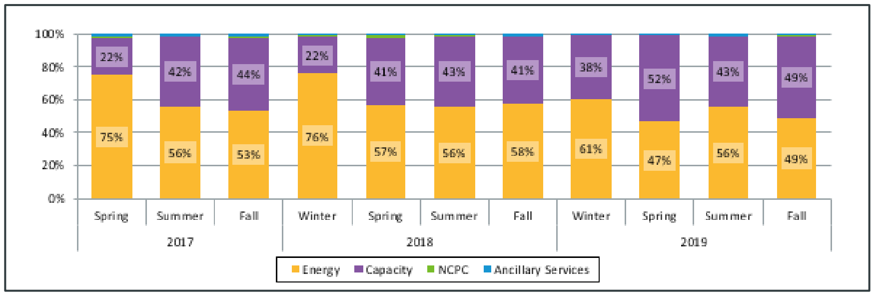
Energy costs were $746 million ($27/MWh) in Fall 2019, 47% lower than Fall 2018 costs, driven by a 42% decrease in natural gas prices. Energy costs made up 49% of the total wholesale cost. The share of each wholesale cost component is shown in Figure 2-2 below.

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

[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 through hour ending 11 on D+2.

Capacity costs are driven by clearing prices in the primary capacity auctions (in this reporting period, FCA 10), and totaled $749 million ($27/MWh), representing 49% of total costs. Beginning in Summer 2019, capacity market costs decreased relative to previous quarters. In the prior capacity commitment period (CCP 9, June 2018 – May 2019), the clearing price for new and existing resources was $9.55/kW-month in all capacity zones but SEMA/Rhode Island.[7] In the current capacity commitment period (CCP 10, June 2019 – May 2020), the clearing price for all new and existing resources was $7.03/kW-month. The lower clearing prices caused capacity costs to decrease.

Figure 2-2: Percentage Share of Wholesale Cost



At $8.5 million ($0.31/MWh), Fall 2019 Net Commitment Period Compensation (NCPC) costs represented 1% of total energy costs, a similar share compared to other quarters in the reporting horizon. In dollar terms, NCPC costs were $2.9 million (or 26%) lower than in Fall 2018, with the largest reduction coming from economic payments (down $4.2 million), which was somewhat offset by slight increases across other reliability related NCPC categories.

Ancillary service costs, which include payments for operating reserves and regulation, totaled $15.8 million ($0.58/MWh) in Fall 2019, representing 1% of total wholesale costs. Ancillary service costs decreased by 52% compared to Fall 2018, and decreased by 27% compared to Summer 2019.

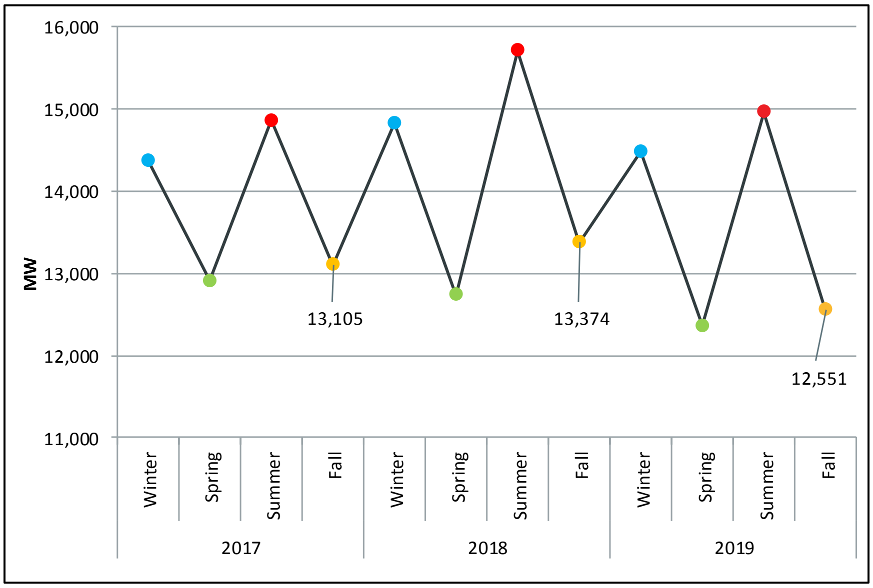
2.2 Load

Lower average loads in Fall 2019 were due to more temperate weather along with increased energy efficiency and behind-the-meter solar generation.[8] Average hourly load by season is illustrated in Figure 2-3 below. The blue dots represent winter, the green dots represent spring, the red dots represent summer and the yellow dots represent fall.

[7] As a result of inadequate supply, the clearing price in SEMA/Rhode Island was higher than in other zones, at $17.73 and $11.08/kW-month for new and existing resources, respectively.

[8] In this section, the term "load" typically refers to net energy for load (NEL), while "demand" typically refers to metered load. NEL is generation needed to meet end-use demand (NEL – Losses = Metered Load). NEL is calculated as Generation + Settlement-only Generation – Asset-Related Demand + Price-Responsive Demand + Net Interchange (Imports – Exports).

Figure 2-3: Average Hourly Load



In Fall 2019, average hourly load was 12,551 MW, a 6% decrease compared to Fall 2018 and a 4% decrease compared to Fall 2017. Lower loads in Fall 2019 were driven more temperate weather. While average seasonal temperatures increased by only 1^{0}F (53^{0}F vs. 52^{0}F) year over year, Fall 2019 had fewer Heating Degree Days (1,162 HDD vs. 1,280 HDD) and Cooling Degree Days (55 CDD vs. 135 CDD) year over year.[9]

Load and Temperature

The stacked graph in Figure 2-4 below compares average monthly load (right axis) to the monthly total of degree days (left axis). The top panel compares average monthly load to CDDs. The bottom panel compares average monthly load to HDDs.

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[9] A heating degree day (HDD) measures how cold an average daily temperature is relative to 65°F and is an indicator of electricity demand for heating. It is calculated as the number of degrees (°F) that each day's average temperature is below 65°F. For example, if a day's average temperature is 60°F, the HDD for that day is 5. A cooling degree day (HDD) measures how warm an average daily temperature is relative to 65°F and is an indicator of electricity demand for air conditioning. It is calculated as the number of degrees (°F) that each day's average temperature is above 65°F. For example, if a day's average temperature is 70°F, the CDD for that day is 5.

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

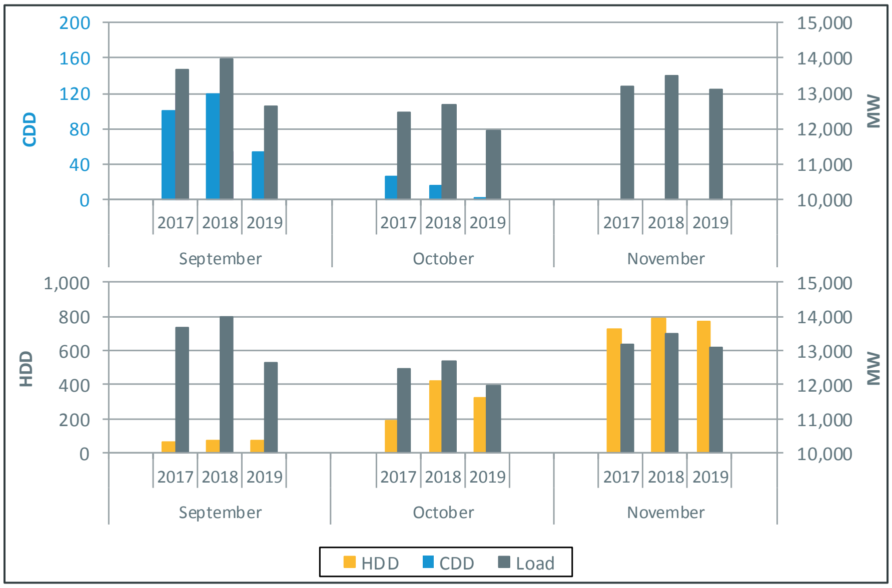


Figure 2-4 shows that average loads were lower every month in Fall 2019 compared to both Fall 2018 and 2017. While quarterly temperatures were less than 1^{0}F warmer year over year, temperatures drove differences in monthly loads. Average load in September 2019 decreased significantly compared to September 2018 (12,618 MW vs. 13,971 MW) due to cooler temperatures (64^{0}F vs. 66^{0}F). The first week of September 2018 had unseasonably warm weather driving monthly loads higher. The average temperature for the week was 75^{0}F, leading to higher average loads (16,614 MW). Comparatively, the average temperature during the first week of September 2019 was 66^{0}F, while average loads were 12,869 MW.

Peak Load and Load Duration Curves

New England's system load over the past three fall seasons is shown as load duration curves in Figure 2-5 below. A load duration curve depicts the relationship between load levels and the frequency in which loads occur at that level or higher. Fall 2019 is shown in red, Fall 2018 is shown in dark gray and Fall 2017 is shown in light gray. The inset graph displays the top 5% of all hours.

Figure 2-5: Load Duration Curve

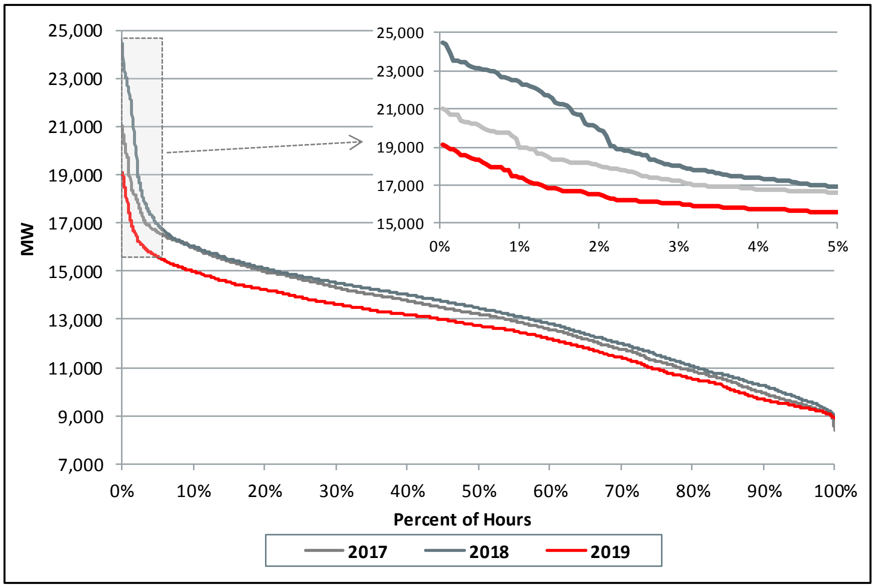


Figure 2-5 highlights that loads in Fall 2019 were lower across more than 99% of observations when compared to Fall 2018 and 2017. In Fall 2019 loads were higher than 15,000 MW in 10.0% of all hours compared to 21.5% and 19.7% in Summer 2018 and 2017, respectively.

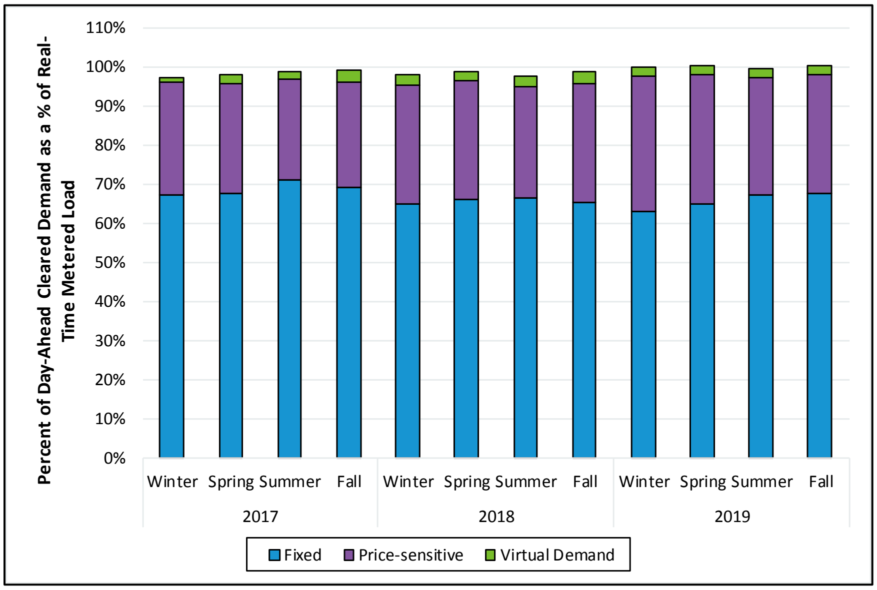
The inset graph shows that in the highest 5% of all hours, loads in Fall 2019 were lower than observations in both Fall 2018 and Fall 2017. In Fall 2019, the top 5% of all hours averaged 16,567 MW, which was 3,005 MW lower than Fall 2018 (19,572 MW) and 1,393 MW lower than Fall 2017 (17,960 MW). Peak loads in Fall 2018 were largely affected by extreme temperatures (78.8^{0}F) between September 3 and September 6. Over half of all observations in the top 5% of Fall 2018 hours occurred during this period.

Load Clearing in the Day-Ahead Market

In recent periods, there have been higher levels of demand as a percent of real-time demand clearing in the day-ahead market. The day-ahead cleared demand as a percentage of real-time demand is shown in Figure 2-6 below. Day-ahead demand is broken down by bid type: fixed (blue), price-sensitive (purple) and virtual (green) demand.[10]

[10] Day-ahead cleared demand is calculated as fixed demand + price-sensitive demand + virtual demand. Real-time metered load is calculated as generation + settlement-only generation – asset-related demand + price-responsive demand + net imports – losses. This is different from the ISO Express report, which defines day-ahead cleared demand as fixed demand + price-sensitive demand + virtual demand - virtual supply + asset-related demand. Real-time load is calculated as generation – asset-related demand + price-responsive demand + net imports – losses. The IMM has found that comparing the modified definition of day-ahead cleared demand and real-time metered load can provide better insight into day-ahead and real-time price differences.

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



Day-ahead cleared demand as a percent of real-time demand was higher in Fall 2019 (100.4%) than in Fall 2018 (98.7%) and in Fall 2017 (99.3%). The primary driver of higher cleared demand was fixed demand, which accounted for 67.7% of day-ahead cleared demand in Fall 2019, compared to 65.2% in Fall 2018. However, the percent of fixed demand in Fall 2019 was still below the level in Fall 2017 (69.2%).

2.3 Supply

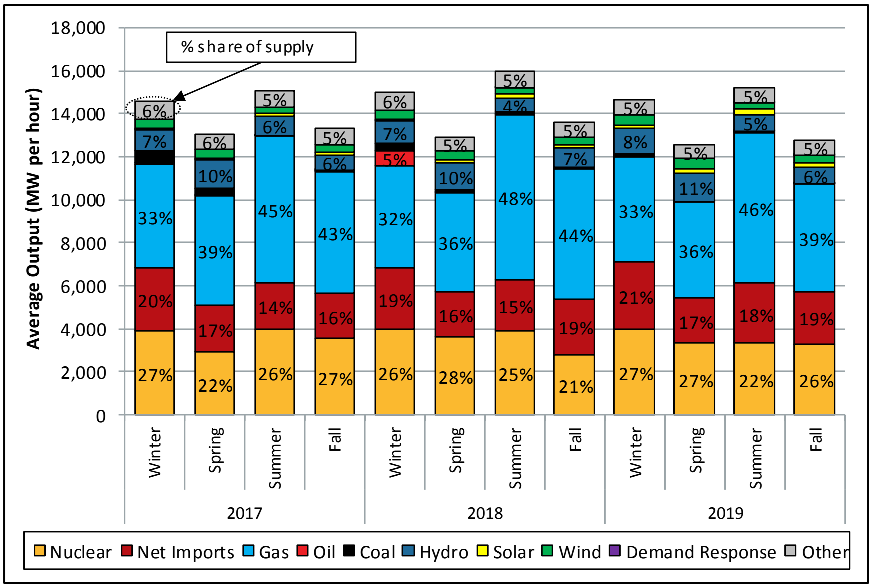
This subsection summarizes actual energy production by fuel type, and flows of power between New England and its neighboring control areas.

2.3.1 Generation by Fuel Type

The breakdown of actual energy production by fuel type provides useful context for the drivers of market outcomes. The share of energy production by generator fuel type for Winter 2017 through Fall 2019 is illustrated in Figure 2-7 below. Each bar's height represents average electricity generation, while the percentages represent the share of generation from each fuel type.[11]

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

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



The majority of New England's energy comes from nuclear generation, gas-fired generation, and net imports (imports netted for exports). Together, these categories accounted for 84% of total energy production in Fall 2019. Average nuclear generation was 500 MW higher in Fall 2019 (3,300 MW), compared to Fall 2018 (2,800 MW) despite the retirement of the Pilgrim Power plant. The increase was driven by reduced nuclear outages in Fall 2019. As expected, natural gas made up a smaller percent of generation than in the summer. This occurs in shoulder seasons when additional gas in not needed to meet higher loads.

2.3.2 Imports and Exports

New England was a net importer of power from its neighboring control areas of Canada and New York in Fall 2019.[12] On average, the net flow of energy into New England was about 2,441 MW per hour. Figure 2-8 shows the average hourly import, export and net interchange power volumes by external interface for the last 12 quarters.

[12] There are six external interfaces that interconnect the New England system with these neighboring areas. The interconnections with New York are the New York North interface, which comprises several AC lines between the regions, the Cross Sound cable, and the Northport-Norwalk cable. These last two run between Connecticut and Long Island. The interconnections with Canada are the Phase II and Highgate interfaces, which both connect with the Hydro-Québec control area, and the New Brunswick interface.

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

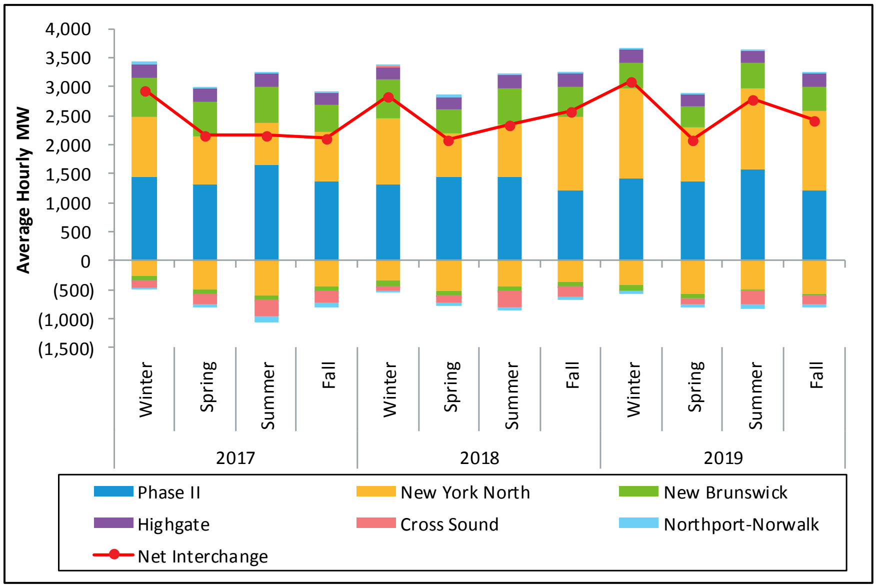


Figure 2-8 illustrates that net interchange was lower in Fall 2019 than in both Summer 2019 and Fall 2018. Compared to Fall 2018, New England imported a consistent amount from Canada but less from New York, primarily as the result of increased exports over the New York North interface. Exports over the New York North interface increased by an average of 196 MW an hour (53%) between Fall 2018 and Fall 2019.

In Fall 2019, ISO-NE met about 19% of its average load (also known as Net Energy for Load) with power imported from New York and Canada. This is slightly higher than the average of the prior 11 seasons (18%). The average hourly net interchange of 2,441 MW per hour was 6% lower than in Fall 2018, when average hourly net interchange was 2,587 MW per hour.

The largest share of imports into New England in Fall 2019 were from the New York North interface, making up 42%, or an hourly average of 1,358 MW. This is slightly higher than the hourly average of 1,278 MW in Fall 2018. The Phase II interface contributed an average of 1,219 MW, or 37%, of total imports in Fall 2019, which is consistent with Fall 2018.

For the third time during the 12-quarter reporting horizon (previously Fall 2018 and Winter 2019), New England imported more over the New York North interface than the Phase II interface. The driving factor behind this occurrence was annual maintenance on the Phase II lines, which took both lines completely out of service for two weeks from late September to mid October 2019.

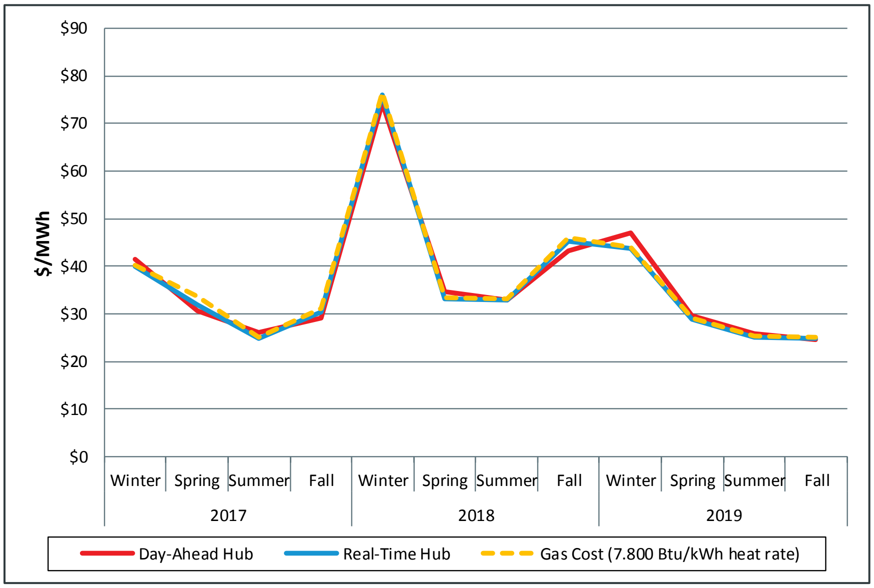
Section 3
Day-Ahead and Real-Time Markets

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

3.1 Energy Prices

The average real-time Hub price for Fall 2019 was $24.98/MWh. This was just 1% or $0.29/MWh higher than the average day-ahead Hub price of $24.69/MWh. Day-ahead and real-time prices, along with the estimated cost of generating electricity using natural gas in New England, are shown in Figure 3-1 below. The natural gas cost is based on the average natural gas price each season and a generator heat rate of 7,800 Btu/kWh.[13]

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



As Figure 3-1 illustrates, the seasonal movements of energy prices (solid lines) are generally consistent with changes in natural gas generation costs (dashed line). The spread between the estimated cost of a typical natural gas-fired generator and electricity prices tends to be highest during the summer months as less efficient generators, or generators burning more expensive fuels, are required to meet the region's higher demand. Gas costs averaged $19/MWh in Fall 2019. The spread between the average day-ahead electricity prices and average estimated gas costs were $6/MWh in Fall 2019, lower than the $10/MWh spread in the previous fall. In Fall 2018, higher loads and an increase in nuclear generator outages contributed to the higher spread between LMPs and gas costs. In Fall 2019, there were no notable outages for nuclear generators.

Average day-ahead and real-time prices in Fall 2019 were lower than Fall 2018 prices by about $19 and $20/MWh, respectively. This is consistent with lower natural gas prices and loads in

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

Fall 2019. Gas prices decreased by 42% in Fall 2019 compared to Fall 2018, while average and peak loads decreased by about 820 MW and 5,370 MW, respectively.

The seasonal average day-ahead and real-time energy prices for each of the eight New England load zones and for the Hub are shown below in Figure 3-2.

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

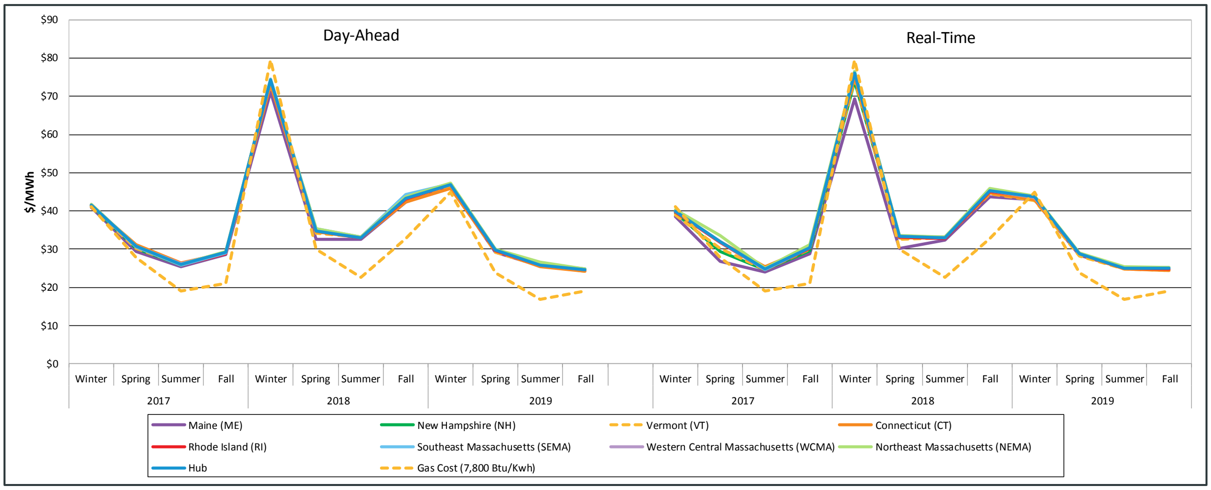


Figure 3-2 illustrates that prices did not differ significantly among the load zones in either market, indicating that there was relatively little congestion on the system at the zonal level.[14]

3.2 Marginal Resources and Transactions

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

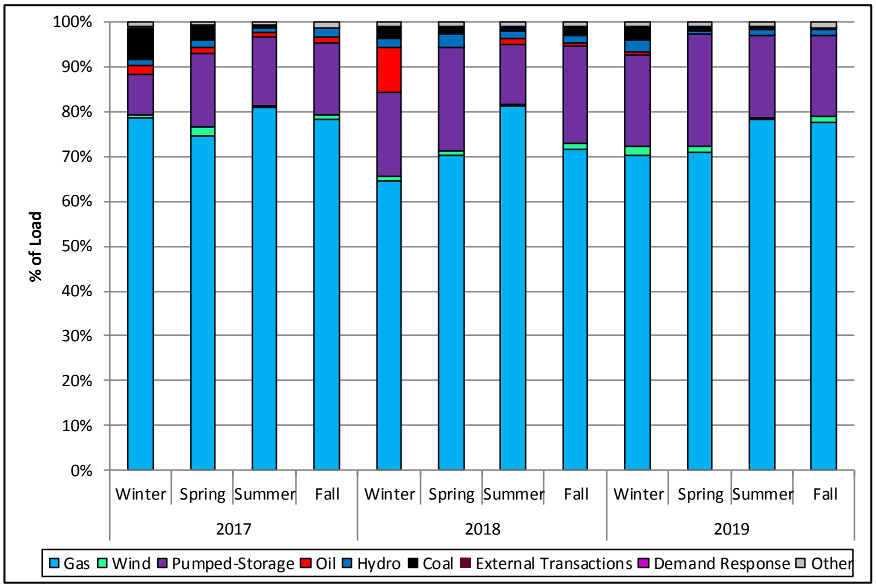
This section reports marginal units by transaction and fuel type on a load-weighted basis. The methodology accounts for the contribution that a marginal resource makes to the overall price paid by load. When more than one resource is marginal, the system is typically constrained and marginal resources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

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

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

The percentage of load for which each fuel type set price in the *real-time market* by season is shown in Figure 3-3 below.[15]

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



Natural gas-fired generators set price for about 78% of total load in Fall 2019. Gas-fired generators are often the most expensive units operating, and therefore set price frequently. More expensive coal- and oil-fired generators are not typically required to operate to meet system demand, and therefore set price less frequently. Coal set price for less load in Fall 2019 than in Fall 2018. Gas prices in Fall 2019 were lower than in Fall 2018, leading to fewer opportunities for coal to be in-merit and set price.

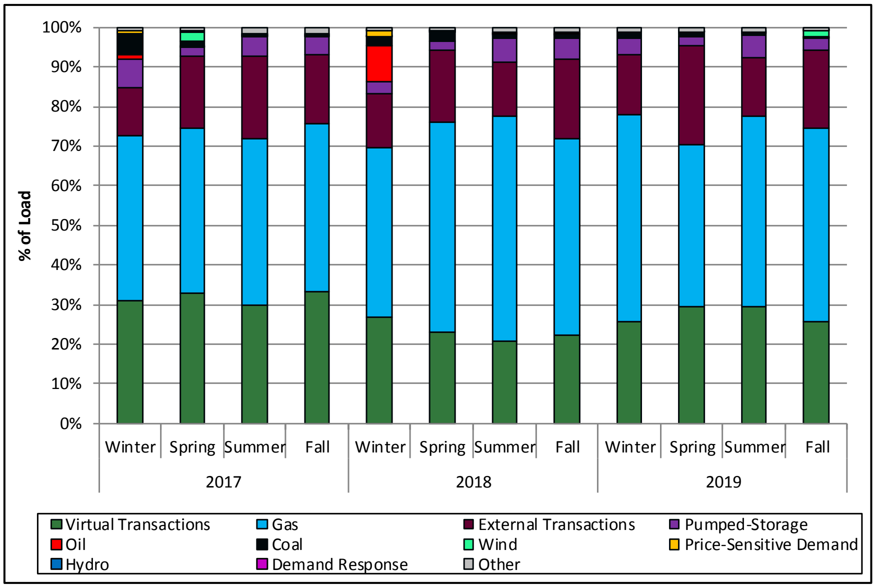
In addition to their relative cost, many gas-fired generators are eligible to set price due to their dispatchability. By contrast, nuclear generation accounts for about one fourth of native generation in New England, but does not set price. Nuclear generators in New England offer at a fixed output, meaning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

Pumped-storage units (generators and demand) set price for about 18% of total load in Fall 2019. Pumped-storage units generally offer energy at a price that is close to the margin. They are 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. Because they are online relatively often and priced close to the margin, they can set price frequently.

The percentage of load for which each transaction type set price in the *day-ahead market* since Winter 2017 is illustrated in Figure 3-4 below.

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

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

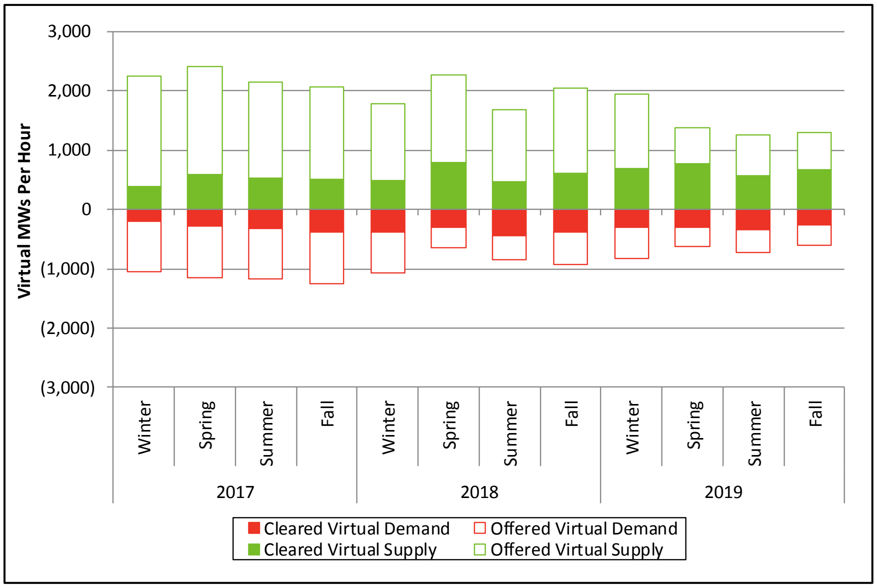


In Fall 2019, gas-fired generators, virtual transactions, and external transactions set price for 94% of load. That is within 1% of the 93% averages for the previous two Fall seasons and 2019. In Fall 2019, wind set price for just over 1% of load. The increase over previous quarters was driven by higher wind offers in Fall 2019. The offers above zero shifted a small amount of wind up the supply curve, which led to wind setting price in place of other fuel types.

3.3 Virtual Transactions

In the day-ahead energy market, participants submit virtual demand bids and virtual supply offers to capture differences between day-ahead and real-time LMPs. The primary function of virtual transactions is to improve the day-ahead dispatch model to better reflect real-time conditions. Virtual transactions that are profitable based on the price difference between the day-ahead and real-time markets generally improve price convergence. Offered and cleared virtual transaction volumes from Winter 2017 through Fall 2019 are shown in Figure 3-5 below.

Figure 3-5: Total Offered and Cleared Virtual Transactions (Average Hourly MW)



In Fall 2019, total offered virtual transactions averaged 1,909 MW per hour, which was 4% lower than the average amount offered in Summer 2019 (1,996 MW per hour) and 36% lower than the average amount offered in Fall 2018 (2,973 MW per hour). Over the period from Winter 2017 to Winter 2019, the average amount of offered virtual transactions was 3,060 MW per hour. However, the average amount of offered virtual transactions over the last three quarters (i.e., Spring 2019 to Fall 2019) has been only 1,966 MW per hour. Offered virtual transactions decreased during this period primarily because one participant significantly reduced their virtual activity. Between Winter 2017 and Winter 2019, this participant submitted over 1,000 MW per hour of virtual transactions, on average. In the last three quarters, the participant has submitted less than five MW per hour, on average.

On average, 942 MW per hour of virtual transactions cleared in Fall 2019, which represents an increase of 4% compared to Summer 2019 (908 MW per hour) and a decrease of 6% compared to Fall 2018 (1,007 MW per hour). Cleared virtual supply amounted to 672 MW per hour, on average, in Fall 2019, up 18% from Summer 2019 (571 MW per hour) and up 9% from Fall 2018 (615 MW per hour). Meanwhile, cleared virtual demand amounted to 270 MW per hour, on average, in Fall 2019, down 20% from Summer 2019 (337 MW per hour) and down 31% from Fall 2018 (391 MW per hour). In general, the percent of submitted virtual transactions that have cleared has increased over the 12-quarter period covered in this report, rising from 18% in Winter 2017 to 49% in Fall 2019 (reaching a high of 55% in Spring 2019). The trend is partly linked to a reduction in transaction costs, in the form of reduced NCPC charges, to virtual transactions.[16] Lower transaction costs allow market participants to submit virtual transactions closer to their expectation of real-time prices, increasing the likelihood that the virtual transactions will clear while still remaining profitable.

[16] In February 2016, real-time economic NCPC payments made to generators that received a day-ahead commitment were eliminated, reducing the total pool of real-time economic NCPC paid. The fast-start pricing rules implemented in March 2017 also had a downward effect on real-time economic NCPC. For more information about fast-start pricing, see Section 5 of the IMM's Summer 2017 Quarterly Markets Report: https://www.iso-ne.com/static-assets/documents/2017/12/2017-Summer-quarterly-markets-report.pdf

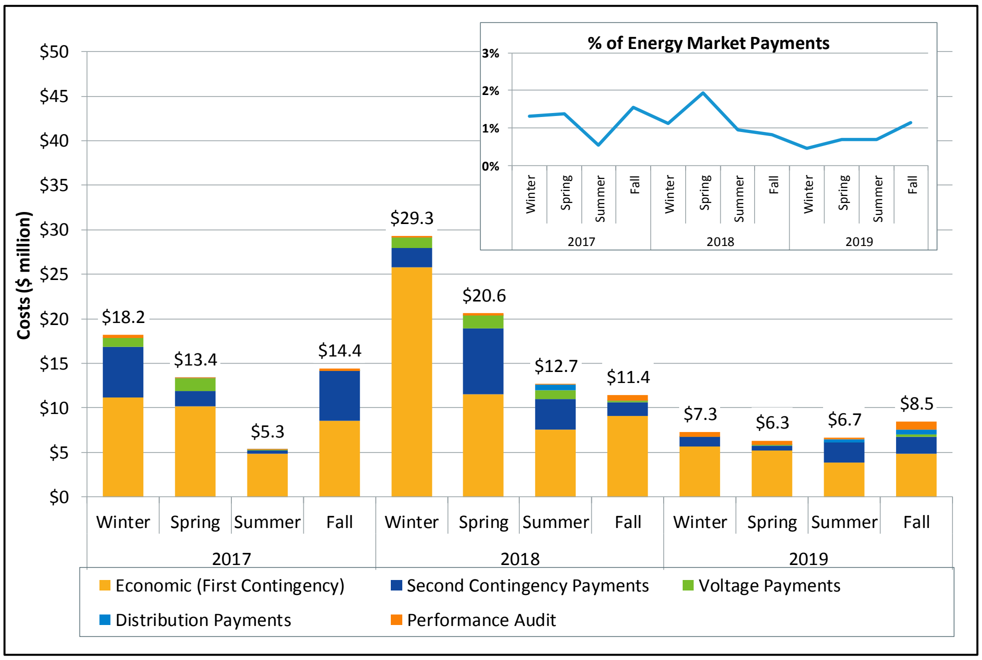
3.4 Net Commitment Period Compensation

Net Commitment Period Compensation (NCPC), commonly known as uplift, are a particular kind of make-whole payments provided to resources in two circumstances: (1) when energy prices are insufficient to cover production costs or (2) to account for any foregone profits the resource may have lost by following ISO dispatch instructions. This section reports on quarterly uplift payments and the overall trend in uplift payments over the last three years. The data show that total uplift payments continue to decrease year over year.

Uplift is paid to resources that provide a number of services, including first- and second-contingency protection, voltage support, distribution system protection, and generator performance auditing.[17]

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

Figure 3-6: NCPC Payments by Category ($ millions)



Total uplift payments in Fall 2019 amounted to $8.5 million, a decrease of $2.9 million from Fall 2018. This decrease was mostly driven by lower economic payments. This is consistant with lower natural gas prices and lower loads. A further breakdown and analysis of economic uplift payments is provided below. Uplift represented 1.1% of total energy payments in Fall 2019, in line with the historical average over the reporting horizon.

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

Second contingency payments made up slightly less than a quarter of total uplift payments (21% or $1.8 million) in Fall 2019. , with almost all second contingency payments was made in the day-ahead market. Compared to Fall 2018, second contingency payments increased by $0.3 million (16%). Most of these commitments (65%) were made in to support planned transmission work during September and October 2019 which affected the Maine/New Hampshire interface.

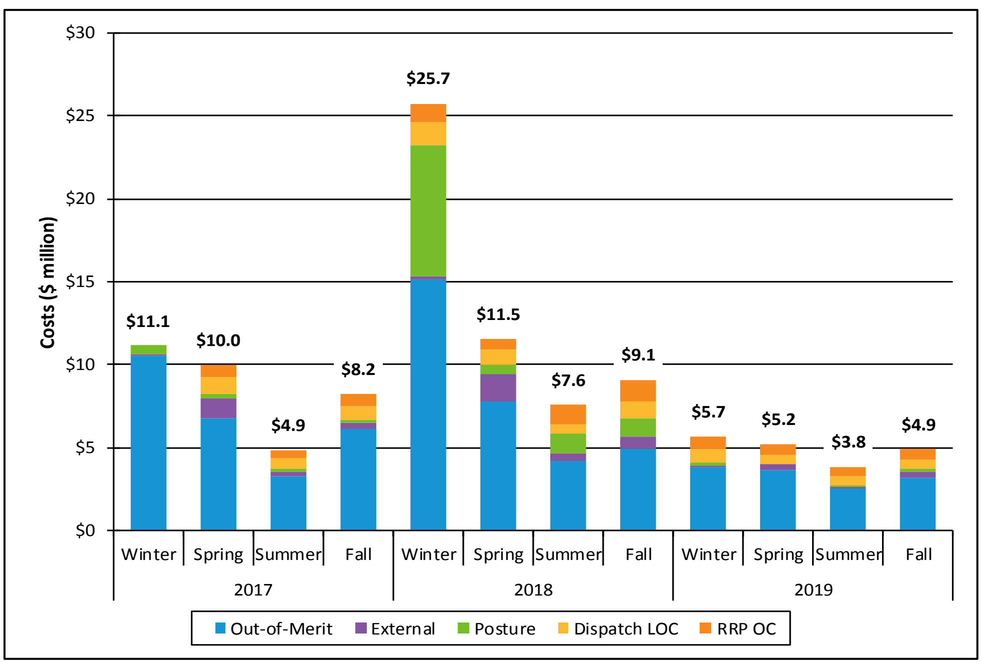
Distribution uplift payments in Fall 2019 totaled only $0.5 million but represent the second largest (Summer 2018 was the largest) quarterly total in the reporting period. All of the distribution payments were made in the real-time market to two oil-fired generators in Maine for reliability purposes.

Economic Uplift

Economic uplift payments made up the majority of total uplift (57% or $4.9 million) paid during the reporting period, with 75% of total economic payments made in the real-time market. Economic uplift fell by $4.2 million (46%) compared to Fall 2018.

Economic uplift includes payments made to resources providing first-contingency protection as well as resources that operate at an ISO-instructed dispatch point below their economic dispatch point (EDP). This deviation from their EDP creates an opportunity cost for that resource. Figure 3-7 below shows economic payments by subcategory.

Figure 3-7: Economic Uplift by Season by Subcategory



All subcategories of economic uplift decreased in Fall 2019 compared to Fall 2018. Out-of-merit payments, which ensure recovery of as-offered commitment and dispatch production costs that are not recovered through the LMP, make up the majority of economic uplift (65%). These payments fell by $1.7 million (35%). Posturing payments fell by $0.97 million (84%) from $1.15 million in Fall 2018 to $0.18 million in Fall 2019.

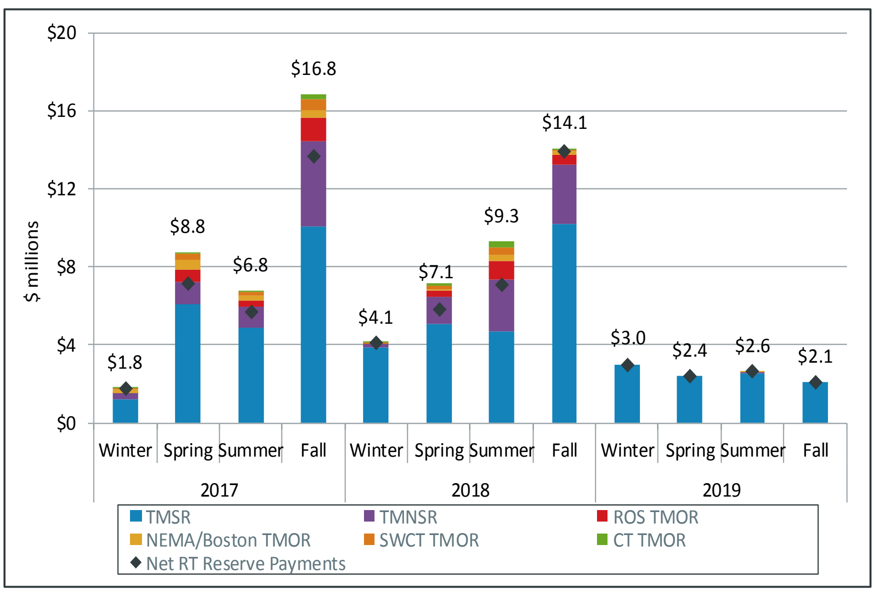
The majority of posturing payments made in Fall 2018 (69% or $0.8 million) were paid during the September 3 shortage event. When payments during the shortage event are removed, posturing payments still fell by 49% or about $0.2 million. These payments are consistently made to fast-start pumped-storage facilities.

3.5 Real-Time Operating Reserves

Bulk power systems must be able to quickly respond to contingencies, such as the unexpected loss of a large generator. To ensure that adequate backup capacity is available, the ISO procures reserve products through the locational Forward Reserve Market (FRM) and the real-time energy market. The ISO's market software determines real-time prices for each reserve product. Non-zero real-time reserve pricing occurs when the software must re-dispatch resources to satisfy the reserve requirement.

Real-time reserve payments by product and by zone are illustrated in Figure 3-8 below. Real-time reserve payments to generators designated to satisfy forward reserve obligations are reduced by a forward reserve obligation charge so that a generator is not paid twice for the same service. Net real-time reserve payments, which were $2.1 million in Fall 2019, are shown as black diamonds in Figure 3-8. During Fall 2019, there were no reductions to real-time reserve payments for forward reserve obligations because there were no instances of nonzero, non-spinning reserve pricing.

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



Fall 2019 reserve payments were down $12.0 million from Fall 2018. The primary drivers of this decline were a lack of shortage conditions in 2019, as well as lower energy prices and an overall decrease in the frequency and magnitude of non-zero reserve pricing. Of the $14.1 million in reserve payments made in Fall 2018, about $9 million (about two-thirds) occurred on September 3, when a shortage event resulted in very high reserve prices. No comparable event occurred in Fall 2019. All of the Fall 2019 reserve payments were ten-minute spinning reserve (TMSR) payments.

The frequency of non-zero reserve pricing by product and zone along with the average price during these intervals for the past three spring seasons is provided in Table 3-1 below.[18]

Table 3-1: Hours and Level of Non-Zero Reserve Pricing[19]

Product	Zone	Fall 2017		Fall 2018		Fall 2019	
		Hours of Non-zero Pricing	*Avg. Price $/MWh*	*Hours of Non-zero Pricing*	*Avg. Price $/MWh*	*Hours of Non-zero Pricing*	*Avg. Price $/MWh*
TMSR	System	401.8	$23.62	442.2	$27.58	363.8	$9.60
TMNSR	System	31.6	$150.16	7.5	$688.66	0.0	$0.00
TMOR	System	28.7	$148.25	6.8	$505.50	0.0	$0.00
	NEMA/Boston	33.3	$136.06	6.8	$505.50	0.0	$0.00
	CT	28.7	$148.25	6.8	$505.50	0.0	$0.00
	SWCT	28.7	$148.25	6.8	$505.50	0.0	$0.00

The system TMSR clearing price was positive (i.e., there was non-zero reserve pricing) in 364 hours (17% of total hours) during Fall 2019, 18% lower than the number of hours of non-zero reserve pricing in Fall 2018. In the hours when the system TMSR price was above zero, the price averaged $9.60/MWh, a decrease from the prior fall season and consistent with the decrease in real-time energy prices. Fewer hours of non-zero reserve pricing, combined with a lower average TMSR price, helps explain the decrease in TMSR payments compared to the prior Fall. Average non-zero reserve prices in Fall 2018 were high due to the shortage event on September 3.

There were no instances of non-zero thirty-minute operating reserve (TMOR) or ten-minute non-spinning reserve (TMNSR) pricing in Fall 2019, reflecting more mild system conditions overall compared to Fall 2018.

3.6 Regulation

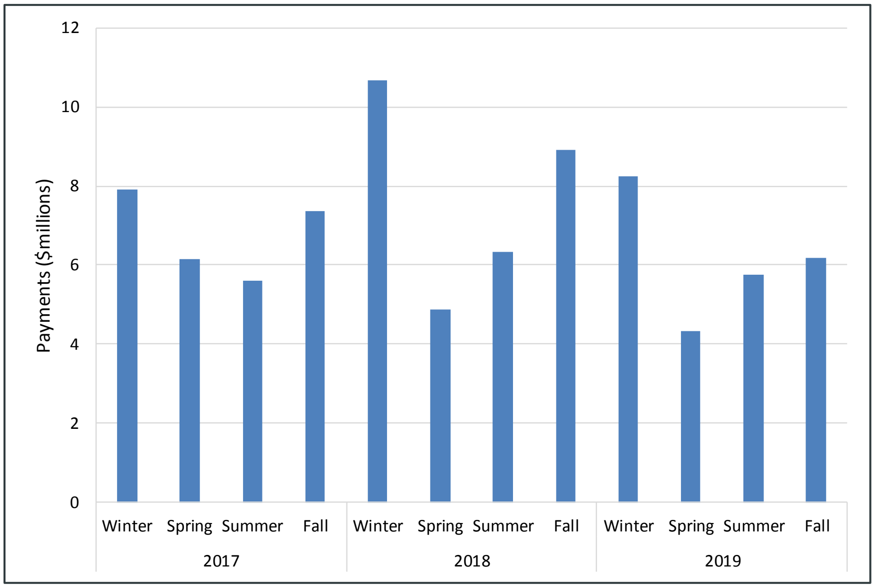
Regulation is an essential reliability service provided by generators and other resources in the real-time energy market. Generators providing regulation allow the ISO to use a portion of their available capacity to match supply and demand (and to regulate frequency) over short-time intervals. Quarterly regulation payments are shown in Figure 3-9 below.[20]

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

[19] The methodology for this metric has changed. In reports prior to Summer 2019, the sum of payments for each reserve product was averaged over the number of intervals for which *any* reserve price was non-zero, which resulted in low calculations for average non-spinning reserve prices. Now, the table shows the average non-zero price for each respective product and zone. For example, the system TMNSR price was non-zero for 35 minutes in Summer 2019. Therefore, the table shows the average system TMNSR price ($109.26) during these 35 minutes.

[20] As noted in the Spring 2016 Quarterly Markets Report, both regulation capacity and service requirements were increased due to the modification of calculations performed in accordance with NERC standard BAL-003, Frequency Response and Frequency Bias Setting. These changes were implemented in April 2016.

Figure 3-9: Regulation Payments ($ millions)



Total regulation market payments were $6.2 million during the reporting period, down approximately 31% from $8.9 million in Fall 2018, and up by 7% from $5.8 million in Summer 2019. The significant reduction in payments comparing Fall 2018 and 2019 reflects two factors:

- the shortage event in September 2018 (which resulted in very high energy market prices and energy market opportunity costs for regulation generators) and
- significantly reduced energy market LMPs in Fall 2019 (excluding the shortage event) compared to the earlier period.

The increase in regulation payments for Fall 2019 compared to Summer 2019 is consistent with a modest increase in regulation requirements and scheduled regulation capacity.

Section 4
Forward Markets

This section covers activity in the Forward Capacity Market (FCM), in Financial Transmission Rights (FTRs), and in the Winter 2019/20 Forward Reserve Auction.

4.1 Forward Capacity Market

The Forward Capacity Market (FCM) is a long-term market designed to procure the resources needed to meet the region's local and system-wide resource adequacy requirements.[21] The region developed the FCM in recognition of the fact that the energy market alone does not provide sufficient revenue to facilitate new investment or, in many cases, cover the cost of maintaining and operating existing resources. A central objective of the FCM is to create a revenue stream that replaces the "missing" revenue and thereby induces suppliers to undertake the investments necessary for reliable electric power service.

During any three-month period there can be FCM activity for up to four commitment periods. The initial capacity auction occurs three years and three months before the commitment period begins.[22] Between the initial auction and the commitment period, there are further opportunities to adjust annual Capacity Supply Obligations (CSOs) through annual and monthly reconfiguration auctions. Three of those are bilateral auctions where obligations are traded between resources at an agreed upon price and approved by the ISO. The other three are reconfiguration auctions run by the ISO, where participants can submit supply offers to take on obligations, or submit demand bids to shed obligations.

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

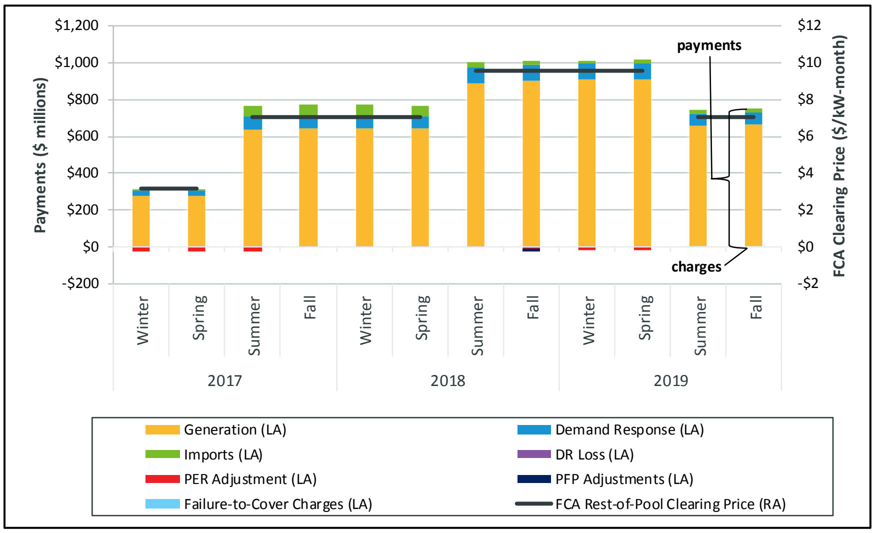
The current capacity commitment period (CCP) started on June 1, 2019 and ends on May 31, 2020. The conclusion of the corresponding Forward Capacity Auction (FCA 10) resulted in a lower clearing price than the previous auction while obtaining sufficient resources needed to meet forecasted demand. The auction procured 35,567 megawatts (MW) of capacity which exceeded the 34,151 MW Installed Capacity Requirement (ICR), at a clearing price $7.03/kW-month. The clearing price of $7.03/kW-month was 26% lower than the previous year's $9.55/kW-month. This clearing price was applied to all resources within New England as well as the imports from Québec. However, the clearing price was $6.26/kW-month for New York imports and $4.00/kW-month for New Brunswick imports. The results of FCA 10 led to an estimated total annual cost of $2.99 billion in capacity payments.

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

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

Total FCM payments, as well as the clearing prices for Winter 2017 through Fall 2019, are shown in Figure 4-1 below. The black lines (corresponding to the right axis, "RA") represent the FCA clearing prices for existing resources in the Rest-of-Pool capacity zone. The orange, blue, and green bars (corresponding to the left axis, "LA") represent payments made to generation, demand response, and import resources, respectively. The red bar represents reductions in payments due to Peak Energy Rent (PER) adjustment. The dark blue bar represents Pay-for-Performance (PFP) adjustments, while the light blue bar represents Failure-to-Cover charges.

Figure 4-1: Capacity Payments ($ millions)



Total net FCM payments decreased significantly from Fall 2018. In Fall 2019 capacity payments totaled $749 million, which accounts for adjustments to primary auction CSOs.[23] The $7.03/kW-month clearing price in FCA 10 was a 26% decrease from the previous FCA clearing price of $9.55/kW-month.

In Fall 2019, there were approximately $0.2 million in Failure-to-Cover (FTC) charges. The FTC charge is a negative adjustment to the FCM credit which is applied when a resource has not demonstrated the ability to cover their CSO. The intent of this charge is to incent resources with CSOs to meet their obligations and is based on the capability of resources compared to their CSOs.

Secondary auctions allow participants the opportunity to buy or sell capacity after the initial auction. A summary of prices and volumes associated with the reconfiguration auction and bilateral trading activity during Fall 2019, alongside the results of the relevant primary FCA are detailed in Table 4-1 below.

[23] Adjustments include annual reconfiguration auctions, annual bilateral periods, monthly reconfiguration auctions, monthly bilateral periods, peak energy rent adjustments, performance and availability activities, and reliability payments.

Table 4-1: Primary and Secondary Forward Capacity Market Prices for the Reporting Period

FCA # (Commitment Period)	Auction Type	Period	Systemwide Price ($/kW-mo)**	Cleared MW	Capacity Zone/Interface Prices ($/kW-mo) SEMA/RI	New Brunswick	New York AC Ties
FCA 10 (2019-20)	Primary	12-month	7.03	35,567		4.00	6.26
	Monthly Reconfiguration	Nov-19	0.95	1,139			
	Monthly Bilateral	Nov-19	0.60	201			
	Monthly Reconfiguration	Dec-19	0.58	630			
	Monthly Bilateral	Dec-19	0.78	204			
	Monthly Reconfiguration	Jan-20	0.88	1,419			
	Monthly Bilateral	Jan-20	1.47	225			

**price paid to new resources/price paid to existing resources*

***bilateral prices represent volume weighted average prices*

Three monthly reconfiguration auctions took place in Fall 2019. Cleared volume decreased from 1,139 MW in November 2019 to 630 MW in December 2019. This corresponded with a clearing price that had a 39% decrease from November to December. Cleared volume and price rebounded in January 2020 with a volume of 1,419 MW at a clearing price of $0.88/kW-month.

4.2 Financial Transmission Rights

Financial Transmission Rights (FTRs) are financial instruments that entitle the holders to receive compensation for congestion costs that occur in the day-ahead energy market.[24] FTRs are sold in annual and monthly auctions, both of which conduct separate auctions for on-peak and off-peak hours. The amount of FTRs awarded in each auction is based on a market feasibility test that ensures the transmission system can support the awarded set of FTRs during the period. FTRs awarded in one of the two annual auctions have a term of one year, while FTRs awarded in a monthly auction have a term of one month. FTR auction revenue is distributed to Auction Revenue Rights (ARRs) holders, who are primarily congestion-paying Load Serving Entities (LSEs) and transmission customers.

All FTR holders are compensated on a monthly basis. Payments to the holders of FTRs with positive target allocations in a month come from the holders of FTRs with negative target allocations in that month and from the revenue associated with transmission congestion in the day-ahead and real-time energy markets in that month.[25] If the revenue collected from these three sources in a month is greater than the payments to the holders of FTRs with positive target allocations in that month, the excess revenue is carried over to the end of the calendar year. However, there is not always sufficient revenue collected to pay the holders of FTRs with positive target allocations in a month. In this case, the payments to holders of FTRs with

[24] FTRs are valued based on the FTR MW quantity and the difference between congestion components of the day-ahead LMP at the sink location (where power is withdrawn from the New England grid) and the source location (where power is injected onto the New England grid) designated in the FTR. FTRs can provide financial benefit, but can also be a financial liability resulting in additional charges to the holder.

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

positive target allocations are prorated. Any excess revenue collected during the year is allocated to these unpaid monthly positive target allocations at the end of the year, to the extent possible.

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 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).[26]

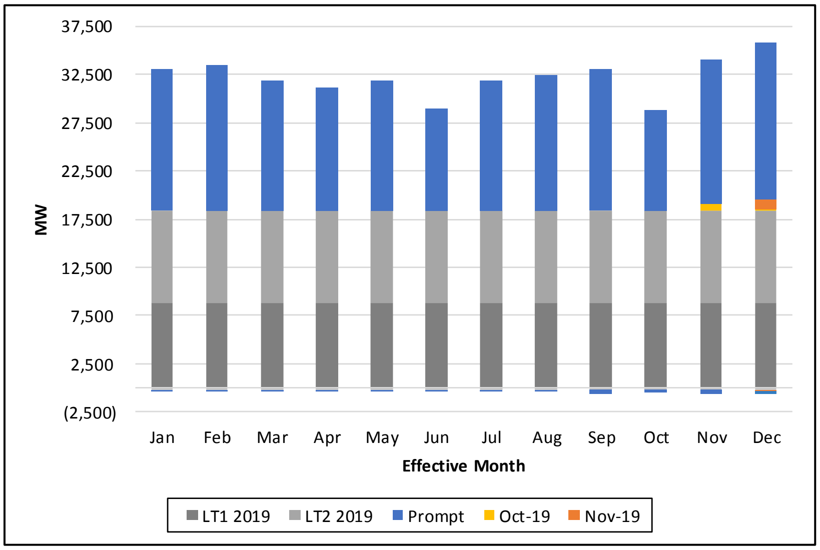
The implementation of BoPP was coordinated with the October 2019 prompt-month auction, whose bidding window was open from September 17-19, 2019. During this bidding window, participants could also submit bids and offers for the November 2019 and December 2019 out-month auctions. FTRs purchased or sold in these out-month auctions are sometimes referred to as the "October 2019" *vintage* of the November 2019 or December 2019 FTR contracts.

Auction Activity

The MW amount of cleared on-peak FTRs for each month in 2019 is broken down by the FTR auction in which the transaction occurred in Figure 4-2 below. Cleared FTR purchases are shown as positive values, while cleared FTR sales are shown as negative values. The gray bars indicate FTR transactions that cleared in either the first or second annual auctions (LT 1 and LT 2), the blue bars indicate FTR transactions that cleared in a prompt-month auction, and the yellow and orange bars indicate FTR transactions that cleared in an out-month auction. For example, the yellow bars reflect purchases and sales of November 2019 and December 2019 FTRs that were made in the out-month auctions that occurred at the same time as the October 2019 prompt-month auction.

[26] 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.

Figure 4-2: Monthly On-peak FTR MWs by Auction



The prompt-month auctions for October 2019, November 2019, and December 2019 were all conducted in Fall 2019. The volume of FTR transactions that cleared in these three prompt-month auctions – 22,043 MWs, 31,816 MWs, and 33,751 MWs, respectively – was consistent with the other prompt-month auctions this year. The relatively low volume of cleared FTR transactions in the October 2019 prompt-month auctions was mainly the result of two traditionally-large FTR holders participating in these auctions at significantly reduced levels. Thirty-two bidders participated in the October 2019 prompt-month auctions, while 33 participated in the November 2019 prompt-month auctions. The prompt-month auction for the December 2019 on-peak period had 31 participants but only 30 participants for the off-peak period. This level of participation was consistent with recent auctions.

At the same time as the October 2019 prompt-month auctions, the ISO administered out-month auctions for November 2019 and December 2019. These were the first out-month auctions under the BoPP design, and the volume of FTR transactions that cleared was quite low – 1,197 and 456 MWs, respectively. The volume of transactions clearing in the out-months auctions increased the following month as 2,182 MWs of FTR transactions cleared in the December 2019 out-month auctions that took place concurrently with the November 2019 prompt-month auctions. In total, transactions occurring in out-month auctions represented 1.7% of total transactions for November 2019 and 3.6% of total transactions for December 2019. Between eight and eleven participants participated in the out-month auctions that occurred in Fall 2019.

The total auction revenue for the prompt-month auctions that were conducted in Fall 2019 (i.e., the prompt-month auctions for October 2019, November 2019, and December 2019) was $3.2 million, which represents a 27% increase compared to the prompt-month auctions that were conducted in Summer 2019 ($2.5 million), and a 38% decrease compared to the prompt-month auctions that took place in Fall 2018 ($5.1 million). The total auction revenue of the out-month auctions that were conducted in Fall 2019 was only $18 thousand.

FTR Funding

FTRs in September 2019 and October 2019 were fully funded, meaning that enough congestion revenue and revenue from negative target allocations was collected to pay the positive target allocations in those months. However, FTRs in November 2019 were not fully funded. In November 2019, FTR holders with positive target allocations received only 88.1% of the revenue to which they were entitled. This was primarily the result of significant real-time congestion over the period from November 21 - 23, which led the congestion revenue fund balance to decrease by almost $1 million over these three days. However, there were surpluses in September 2019 ($0.3 million) and October 2019 ($0.4 million). As mentioned above, surpluses like these are carried over until the end of the year, when they are used to pay any unpaid monthly positive target allocations. Any remaining excess at the end of the year is then allocated to those entities that paid the congestion costs.