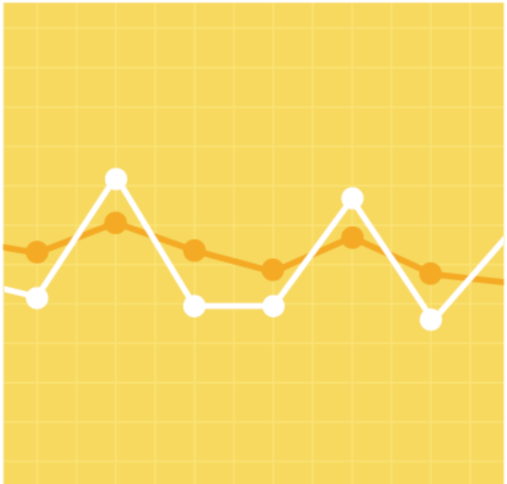
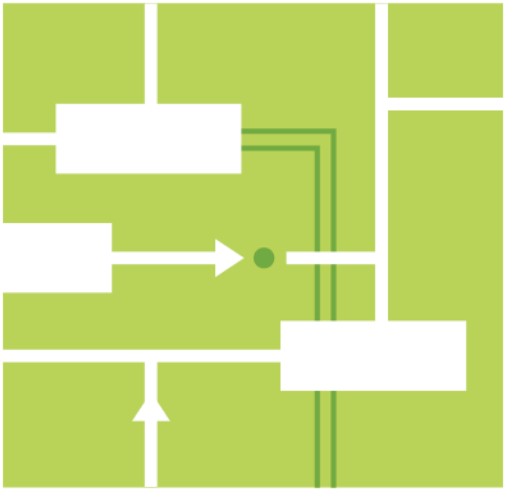
Spring 2019
Quarterly Markets Report

By ISO New England's Internal Market Monitor

SEPTEMBER 5, 2019





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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 Spring 2019 (March 1, 2019 through May 31, 2019).[3]

Wholesale Costs: The total estimated wholesale market cost of electricity was $1.91 billion, up 2% from $1.87 billion in Spring 2018.

- Higher capacity market costs were offset somewhat by lower energy costs.

Capacity costs totaled nearly $1 billion, up 30% (by $226 million) over last Spring. Beginning in Summer 2018, higher capacity clearing prices from the ninth Forward Capacity Auction (FCA 9) contributed significantly to the higher wholesale costs relative to previous quarters.[4] Last year, the capacity payment rate was $7.03/kW-month. This year, the payment rate for new and existing resources increased to $9.55/kW-month in all capacity zones with the exception of SEMA/Rhode Island. As a result of inadequate supply, the payment rate in SEMA/Rhode Island was higher than in other zones, at $17.73 and $11.08/kW-month for new and existing resources, respectively.

Energy costs totaled $892 million; down 16% (or $170 million) from Spring 2018 costs. Lower energy costs were a result of lower natural gas prices, which decreased by 21% relative to Spring 2018 prices.

Energy Prices: Day-ahead and real-time energy prices at the Hub averaged $29.78 and $28.89 per megawatt hour (MWh), respectively. Day-ahead and real-time prices were 13-14% lower than Spring 2018 prices, on average.

- Day-ahead and real-time energy prices continued to track with natural gas prices.
- Gas prices averaged $3.04/MMBtu in Spring 2019, a decrease of 21% compared to $3.86/MMBtu in the prior spring.
- Hourly load averaged 12,301 MW, down by 3% (≈ 430 MW) on the previous spring. The decrease was driven by milder weather, with warmer temperatures in April and cooler temperatures in May compared to 2018.
- Increased baseload generator outages in Spring 2019 counteracted some of the downward pressure on LMPs that resulted from lower gas prices and loads.
- Energy market prices did not differ significantly among the load zones.

Net Commitment Period Compensation: NCPC payments totaled $6.3 million, a decrease of $14.3 million compared to Spring 2018. NCPC payments represented less than 1.0% of total wholesale energy costs in Spring 2019, down from 1.9% in Spring 2018. The majority of NCPC (83%) was for first contingency protection (also known as "economic" NCPC). The ISO paid out most of the first contingency payments in the real-time market. Compared to Spring 2018,

[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] FCA 9 was run in February 2015, approximately 3.5 years prior to the annual delivery period commencing on June 1, 2018.

economic out-of-merit payments[5] fell by 54% (from $7.8 million to $3.6 million), while external transaction payments fell by 78% (from $1.7 million to $0.4 million).

At $0.5 million, local second-contingency protection (LSCPR) payments accounted for 8% of total NCPC payments. These payments decreased significantly by $6.9 million relative to Spring 2018, and were primarily paid to generators in Maine. Nearly all of the LSCPR NCPC paid out in Spring 2018 went to generators located in NEMA/Boston that were needed to support planned transmission outages.

Real-time Reserves: Real-time reserve payments totaled $2.4 million, a $4.7 million decrease from $7.1 million in Spring 2018. All reserve payments were for ten-minute spinning reserve (TMSR).

The decline resulted from 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 also decreased relative to Spring 2018, from $12.85 to $10.97/MWh. The frequency of non-zero spinning reserve prices fell from 451 hours to 371 hours.

Regulation**n:** Total regulation market payments were $4.3 million, down 11% from $4.9 million in Spring 2018. The decrease in payments reflects a reduction in real-time energy market LMPs that reduced energy market opportunity costs for regulation units.

Summer 2019 Forward Reserve Market Auction: In April 2019, ISO New England held the forward reserve auction for the Summer 2019 delivery period (i.e., June 1 to September 30, 2019). System-wide supply offers in the Summer 2019 auction exceeded the requirements for both ten-minute non-spinning reserve (TMNSR) and thirty-minute operating reserve (TMOR). There was one pivotal supplier at the system level for the TMNSR product, as the Residual Supply Index (RSI) for TMNSR declined to 90, slightly below the structurally competitive level. The decreased competitiveness resulted from an increased TMNSR requirement and a medium-sized supplier not participating in the Summer 2019 auction. At the zonal level, NEMA/Boston has been structurally uncompetitive for all recent auctions in which it had a requirement. In these auctions, every participant that offered forward reserves in NEMA/Boston was needed to meet the local requirement.

The net clearing prices for offline thirty- and ten-minute system reserves were both $1,899/MW-month, a small increase from the Summer 2018 price ($1,780/MW-month).

[5] Out-of-merit NCPC ensures recovery of as-offered commitment and dispatch production costs that are not recovered through the LMP.

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	Spring 2019	Winter 2019	Spring 2019 vs Winter 2019 (% Change)	Spring 2018	Spring 2019 vs Spring 2018 (% Change)
Real-Time Load (GWh)	27,149	31,276	-13%	28,101	-3%
Peak Real-Time Load (MW)	17,837	20,773	-14%	7,518	2%
Average Day-Ahead Hub LMP ($/MWh)	$29.78	$46.93	-37%	$34.69	-14%
Average Real-Time Hub LMP ($/MWh)	$28.89	$43.65	-34%	$33.27	-13%
Average Natural Gas Price ($/MMBtu)	$3.04	$5.76	-47%	$3.86	-21%
Average Oil Price ($/MMBtu)	$12.86	$11.61	11%	$11.60	11%

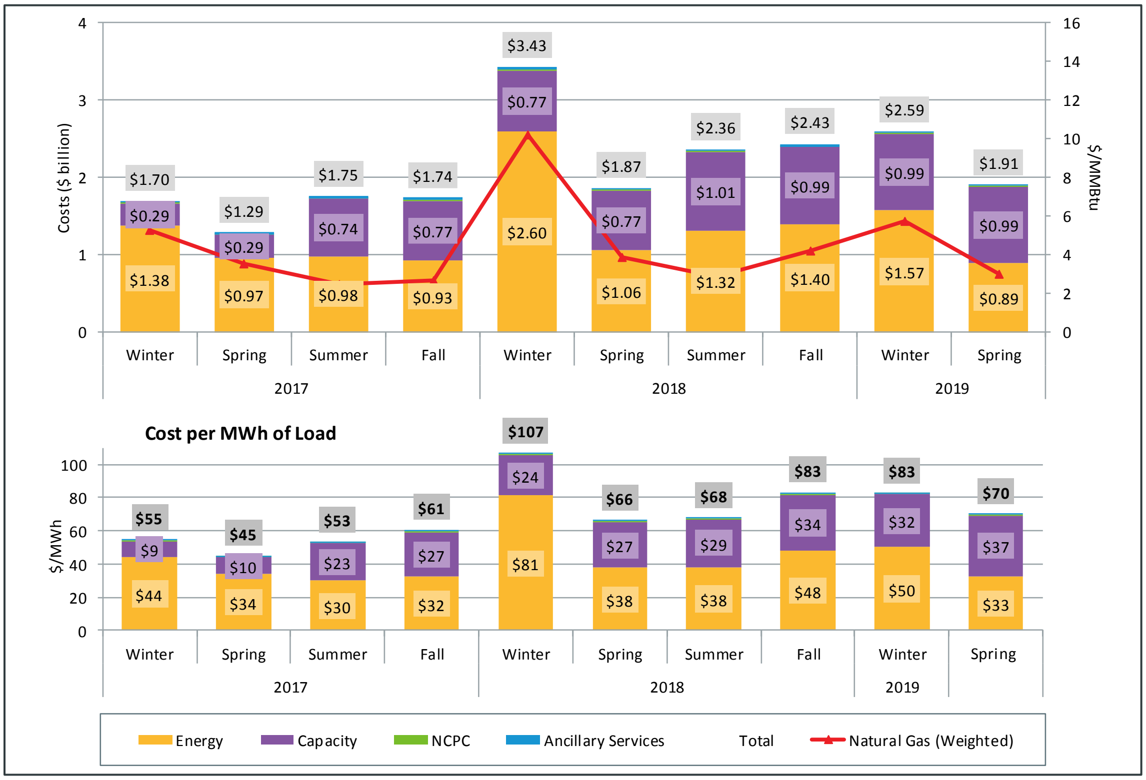
To summarize the table above:

- Average day-ahead LMPs in Spring 2019 were $29.78/MWh, 14% lower than in Spring 2018. Lower gas prices in Spring 2019 ($3.04/MMBtu) compared to Spring 2018 ($3.86/MMBtu) put downward pressure on LMPs. Nuclear generation outages averaged about 300 MW higher in Spring 2019 compared to the previous spring, partially offsetting the effect of declining gas prices on LMPs.
- Total load in Spring 2019 (27,149 GWh) was 3% lower than in Spring 2018 (28,101 GWh). This was driven by a decline in cold days in April and warm days in May compared to Spring 2018.

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 below. The bottom graph shows the wholesale cost per megawatt hour of real-time load served. [6,7]

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



In Spring 2019, the total estimated wholesale cost of electricity was $1.91 billion (or $70/MWh of load), a 2% increase compared to $1.87 billion in Spring 2018, and a decrease of 27% over the previous quarter (Winter 2019). Natural gas prices continued to be a key driver of energy prices.

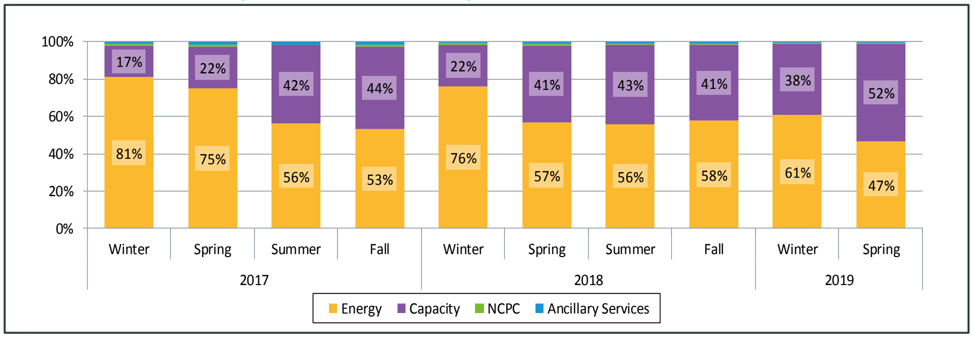
Energy costs were $892 million ($33/MWh) in Spring 2019, 16% lower than Spring 2018 costs, driven by a 21% decrease in natural gas prices. Energy costs made up 47% of the total wholesale cost. The share of each wholesale cost component is shown in Figure 2-2 below.

[6] 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.

[7] 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 9), and totaled $993 million ($37/MWh), representing 52% of total costs. Beginning in Summer 2018, rising capacity market costs contributed to higher wholesale costs relative to previous quarters. In the prior capacity commitment period (CCP 8, June 2017-May 2018), the capacity payment rate was $7.03/kW-month.[8] In the current CCP (CCP 9, June 2018 – May 2019), the payment rate for new and existing resources increased to $9.55/kW-month in all capacity zones but SEMA/Rhode Island. As a result of inadequate supply, the payment rate in SEMA/Rhode Island was higher than in other zones, at $17.73 and $11.08/kW-month for new and existing resources, respectively. The higher clearing prices caused capacity costs to increase.

Figure 2-2: Percentage Share of Wholesale Cost



At $6.3 million ($0.23/MWh), Spring 2019 Net Commitment Period Compensation (NCPC) costs represented less than 1% of total energy costs, a similar share compared to other quarters in the reporting horizon. In dollar terms, NCPC costs were $14.3 million lower than Spring 2018 NCPC costs, with decreases across several uplift categories. Local second-contingency protection uplift payments and economic out-of-merit payments were $6.9 and $4.2 million lower in Spring 2019 compared to Spring 2018, respectively.

Ancillary services, which include operating reserves and regulation, totaled $15.2 million ($0.56/MWh) in Spring 2019, representing 1% of total wholesale costs. Ancillary service costs decreased by 22% compared to Spring 2018, and decreased by 28% compared to Winter 2019.

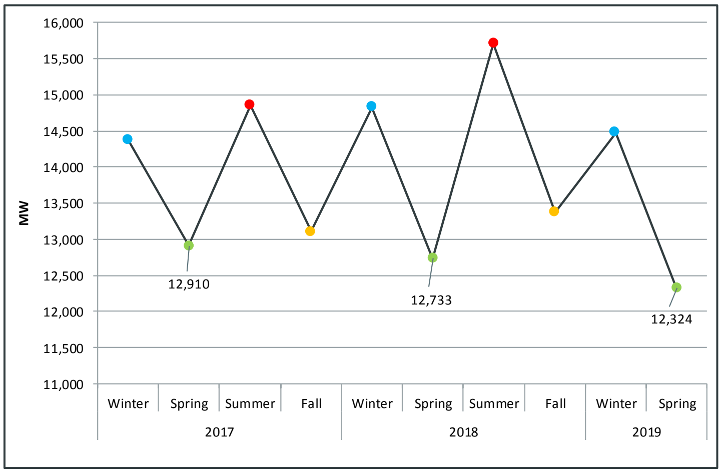
2.2 Load

Lower loads in Spring 2019 were driven by increased energy efficiency and behind-the-meter solar generation along with more temperate weather.[9] 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.

[8] In FCA 8, administrative pricing rules set the capacity payment rate for new and existing resources at $7.03/kW-month.

[9] 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).

Figure 2-3: Average Hourly Load

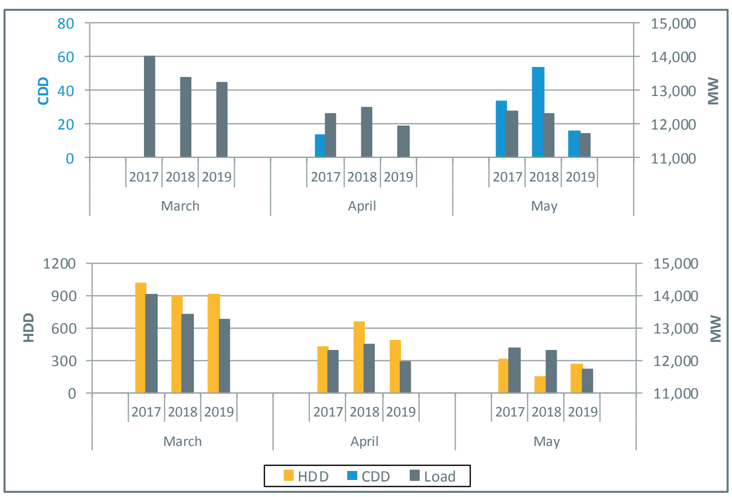


Average hourly load in Spring 2019 was 12,301 MW, a 3% and 5% decrease from Spring 2018 and Spring 2017, respectively. Despite steady seasonal temperatures during the past 3 years (averaging 47°F each spring), the lower loads were driven by more temperate weather during April 2019 (49°F vs. 43°F) and May 2019 (57°F vs 62°F), along with continued increase in behind-the-meter solar generation and energy efficiency.

Load and Temperature

The stacked graphs in Figure 2-4 below show monthly average loads compared to monthly cooling-degree days (CDD) and heating-degree days (HDD). [10]

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



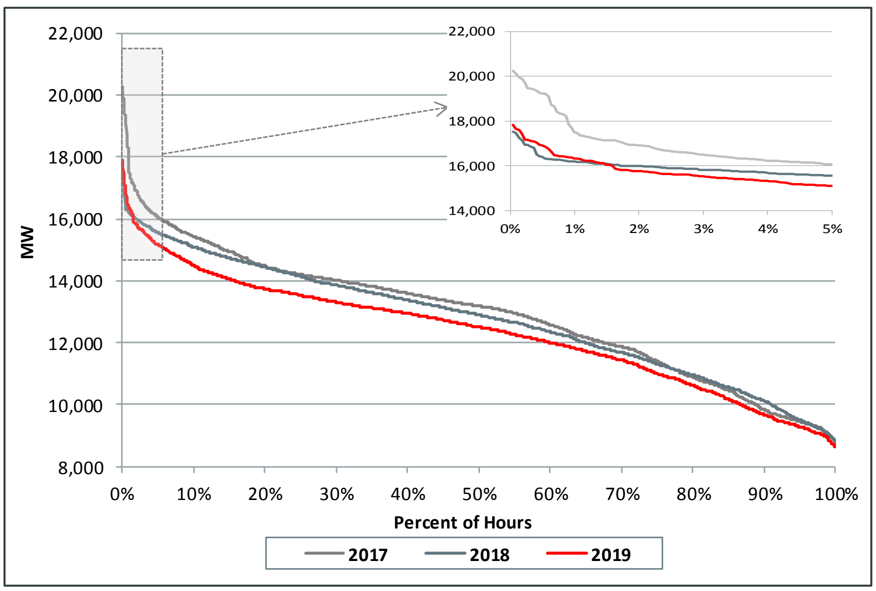
[10] Heating degree day (HDD) measures how cold an average daily temperature is relative to 65°F and is an indicator of electricity demand for heating. It is calculated as the number of degrees (°F) that each day's average temperature is below 65°F. For example, if a day's average temperature is 60°F,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

Figure 2-4 shows that loads were lower every month in Spring 2019 when compared to both Spring 2018 and 2017, on average. While quarterly temperatures were flat year-over-year, temperatures drove differences in monthly loads. In April 2019, temperatures were 6^0F warmer than April 2018 (49^0 vs. 43^0F), on average, leading to less HDD and lower loads (11,946 MW vs. 12,494 MW). Cooler weather in May 2019 led to more HDDs but less CDDs than in 2018, resulting in lower average monthly loads (11,709 MW vs 12,298 MW).

Peak Load and Load Duration Curves

The system load for New England over the last three spring seasons is shown as load duration curves in Figure 2-5 below with the inset graph showing the 5% of hours with the highest loads. A load duration curve depicts the relationship between load levels and the frequency that load levels occur. Plotting several seasonal load duration curves can help illustrate differences between periods.

Figure 2-5: Seasonal Load Duration Curves



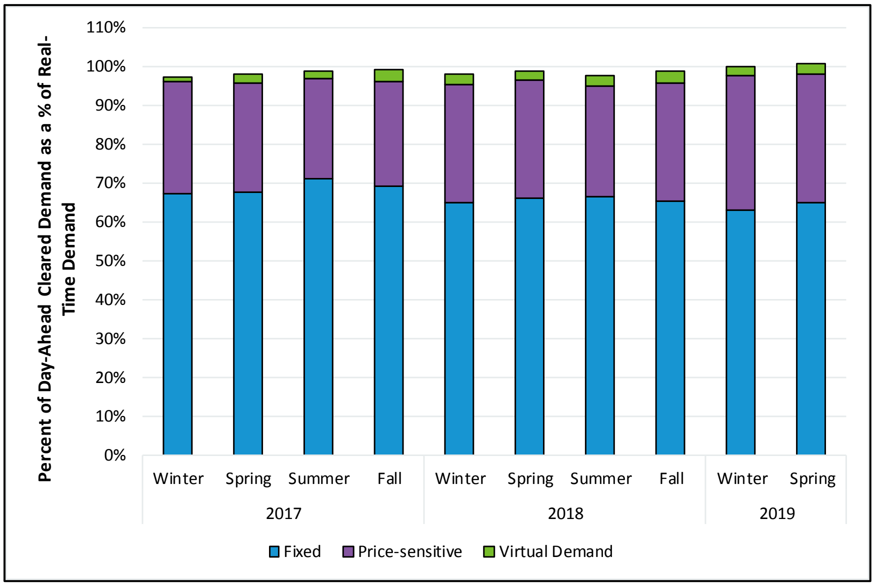
The red line shows Spring 2019 had lower loads than Spring 2018 in nearly all hours, and lower loads than Spring 2017 in every hour. In Spring 2019, loads were higher than 14,000 MW in 15.3% of hours, compared to about 27.0% and 30.5% in Spring 2018 and 2017, respectively.

The inset graph, containing the top 5% of all hours, illustrates that 2019 had lower loads than 2018 for all but the highest 1.5% of hours, while the highest loads of 2017 were significantly higher. The top 5% of hours in Spring 2019 were an average of 160 MW and 1,238 MW lower than Spring 2018 and Spring 2017, respectively.

Load Clearing in the Day-Ahead Market

In Spring 2019, higher levels of demand cleared in the day-ahead market than in previous seasons. The day-ahead cleared demand as a percentage of net energy load (NEL) is shown in Figure 2-6 below. Day-ahead demand is broken down into the three bid types for day-ahead demand: fixed (blue), price-sensitive (purple) and virtual (green) demand.[11]

Figure 2-6: Day-Ahead Cleared Demand by Bid Type



Day-ahead cleared demand as a percent of real-time demand was higher in Spring 2019 than in any other period over the past two years. On average, 100.7% of real-time demand cleared in the day-ahead market compared to 98.8% and 98.2% during Spring 2018 and 2017, respectively. The year-over-year increase was driven by increased price-sensitive demand, which cleared 33.2% of real-time demand in Spring 2019, an increase from 30.4% and 28.4% in Spring 2018 and 2017, respectively.[12]

2.3 Supply

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

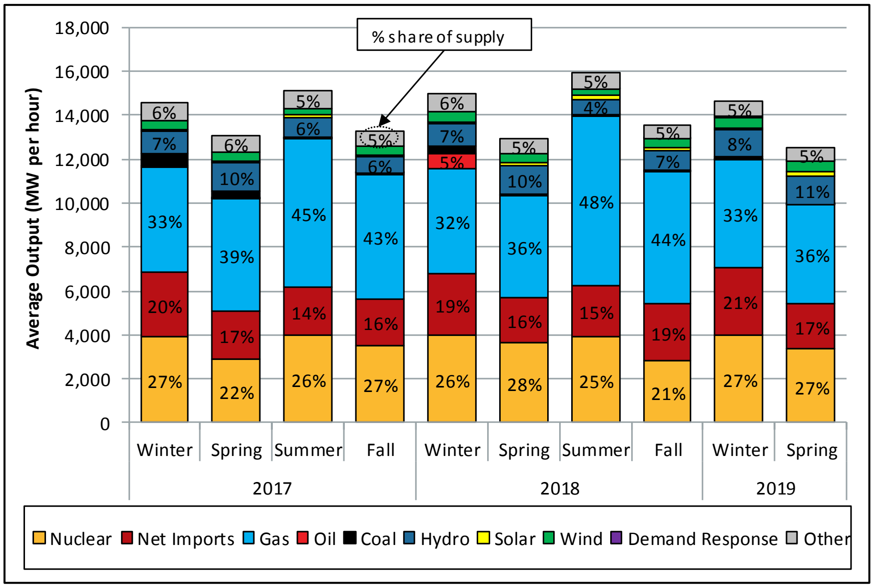
[11] Day-ahead cleared demand is calculated as fixed demand + price-sensitive demand + virtual demand, while real-time metered load is calculated as generation + settlement-only generation – asset-related demand + price-responsive demand + net imports – losses. This is different from the ISO Express 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 net energy for load can provide better insight into day-ahead and real-time price differences.

[12] While price-sensitive demand only clears if it is above the day-ahead LMP, the term can be misleading since 99.2% of cleared price-sensitive demand bids were priced above the highest day-ahead LMP ($99.02/MWh) of the season.

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 Winter 2019 is illustrated in Figure 2-7 below. Each bar's height represents average electricity generation, while the percentages represent the percent share of generation from each fuel type.[13]

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 (netted for exports). Together, these categories accounted for 79% of total energy production in Spring 2019. Similar to 2018, natural gas production increased and net imports decreased from Winter to Spring. The increase in natural gas was driven by lower gas prices, which caused gas generators to move down the supply stack. The decrease in net imports was driven by more exports and fewer imports across interfaces with New York. For more information, see Section 2.3.2 below.

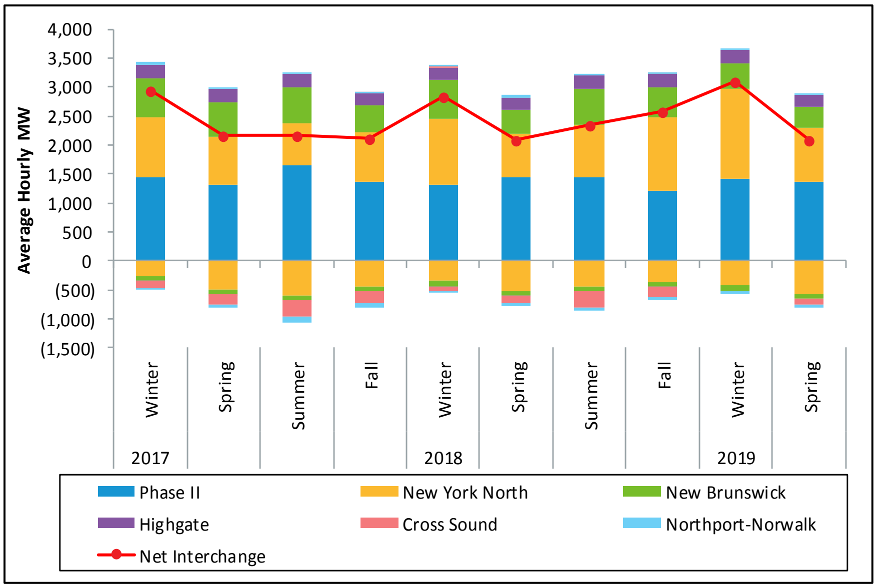
Average hourly nuclear production fell roughly 300 MW in Spring 2019 compared to Spring 2018. This was driven by increased nuclear outages, which are discussed in Section 3.1. Nuclear production is expected to fall in Summer 2019 due to the retirement of Pilgrim, a 680 MW generator in Southeastern Massachusetts. Based on its capacity factor over the past 5 years, the retirement of the facility equates to a loss of 569 MW in Summer 2019 and beyond, on average. That equates to a 14% drop in nuclear generation in Summer 2019 based on average nuclear generation over the past two summers.

[13] 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.

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 Spring 2019.[14] On average, the net flow of energy into New England was about 2,097 MW per hour. Figure 2-8 shows the average hourly import, export and net interchange power volumes by external interface for the last ten quarters.

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



In Spring 2019, New England met about 17% of its average load (NEL) from power imported from New York and Canada. This is slightly lower than the average of the prior nine seasons (18%). The average hourly net interchange value of 2,097 MW was down by 33% from Winter 2019, when average hourly net interchange was 3,110 MW per hour. The Spring 2019 net interchange value was consistent with Spring 2018, when average hourly net interchange was 2,085 MW per hour.

Figure 2-8 illustrates that net interchange and imports generally fall from winter to spring, when New England energy prices and demand tend to be lower. Most of the decrease in net interchange is driven by a simultaneous decrease in imports and increase in exports over the New York North (NYN) interface. Over the reporting period, imports have consistently fallen at the NYN interface from winter to spring by an average of 410 MW per hour. Meanwhile, exports at the NYN interface have increased by an average of 184 MW per hour from winter to spring over the same period.

A large transmission line outage resulted in reduced total transfer capability (TTC) over the New York North and Northport-Norwalk (NN) interfaces during the reporting period. In March 2019 the NYN and NN import TTCs were reduced to 500 MW (from 1,600 MW) and 100 MW (from 200 MW), respectively. The export TTCs were also limited to 400 MW over the NYN

[14] 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.

interface and 100 MW over the NN tie line. This was due to substation replacement work connecting the two control areas.

The largest share of imports into New England in Spring 2019 (47%) came from the Phase II interface, with imports averaging 1,369 MW. This represents a 3% decrease from Winter 2019 (1,415 MW) and a 6% decrease from Spring 2018 (1,458 MW). The New York North interface contributed an average of 945 MW or 33% of total imports. This represents a 40% decrease from Winter 2019 (1,563 MW) and a 26% increase from Spring 2018 (750 MW).

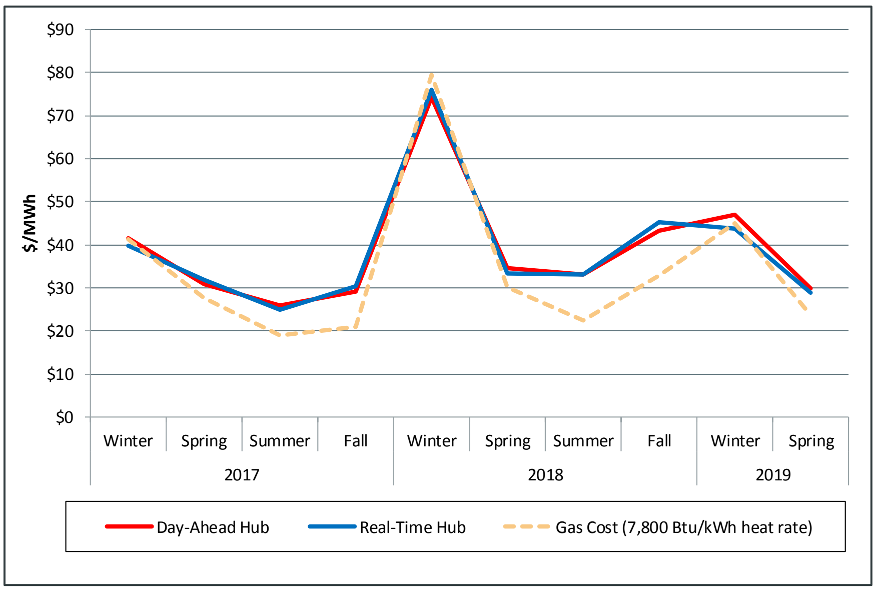
Section 3
Day-Ahead and Real-Time Markets

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

3.1 Energy Prices

The average real-time Hub price for Spring 2019 was $28.89/MWh. This was 3% or $0.89/MWh lower than the average day-ahead price of $29.78/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.[15]

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 $24/MWh in Spring 2019. Average day-ahead electricity prices were $6/MWh above average estimated gas costs in Spring 2019, slightly higher than the $5/MWh spread in Spring 2018.

In Spring 2019, average day-ahead and real-time prices were lower than Spring 2018 prices, by about $5 and $4/MWh, respectively. This is consistent with the change in natural gas prices, which decreased by 21%. The impact of lower gas prices on LMPs was partially offset by greater baseload generation outages in Spring 2019. This spring, out-of-service nuclear

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

generation capacity averaged about 300 MW higher than in Spring 2018 due to a planned refueling outage, as well as forced outages and reductions caused by mechanical issues.

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

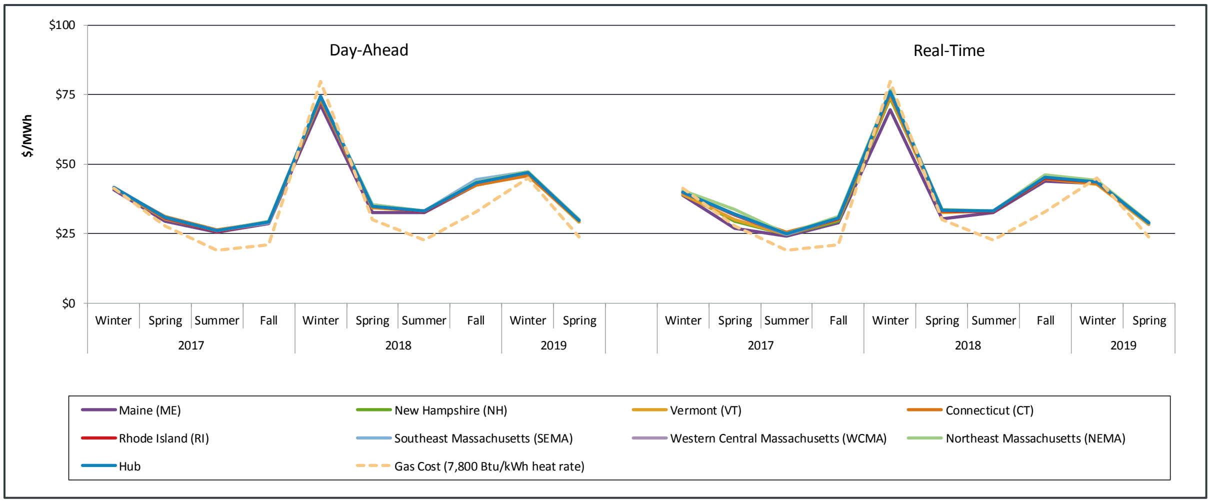


Figure 3-2 illustrates that prices did not differ significantly among the load zones in either market, indicating that there was relatively little congestion on the system at the zonal level.[16]

3.2 Marginal Resources and Transactions

The LMP at a pricing location is set by the cost of the next megawatt (MW) the ISO would dispatch to meet an incremental change in load at that location. The resource that sets price is "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.

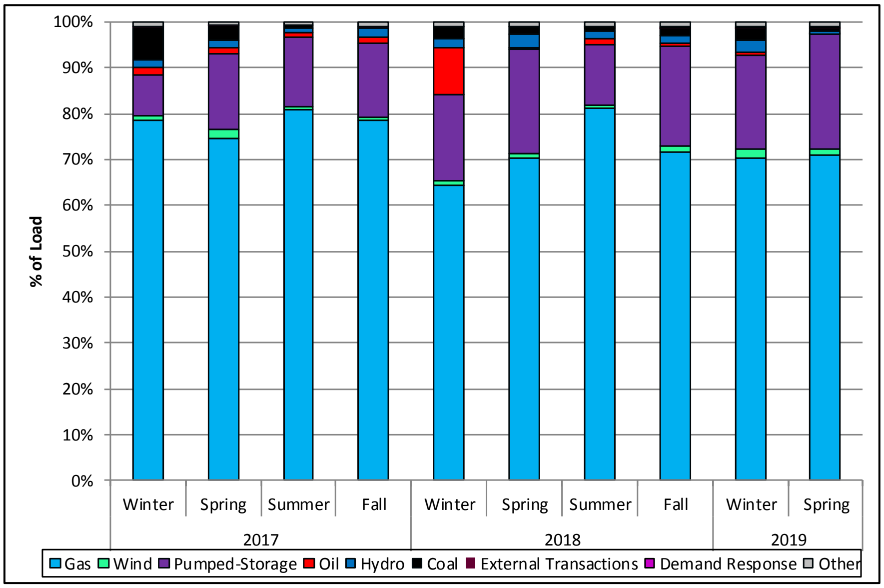
In the day-ahead market, a greater number of transaction types can be marginal; these include virtual bids and offers, fixed and priced-demand, generator supply offers and external transactions. By contrast, only physical supply, pumped-storage demand, and external transactions can set price in the real-time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

[16] 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.

time market are typically generators (predominantly natural gas-fired generators) and pumped-storage demand.

The percentage of load for which each fuel type set price in the *real-time market* by season is shown in Figure 3-3 below.[17] Note that with the implementation of the price-responsive demand (PRD) project on June 1, 2018, demand response resources are now eligible to be marginal and set price; in Spring 2019, they were rarely marginal in real-time or day-ahead (< 1% of the time).

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



Natural gas-fired generators set price for about 71% of total load in Spring 2019, which is roughly the same as Winter 2019 and Spring 2018. 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 meet system demand, and therefore set price less frequently.

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

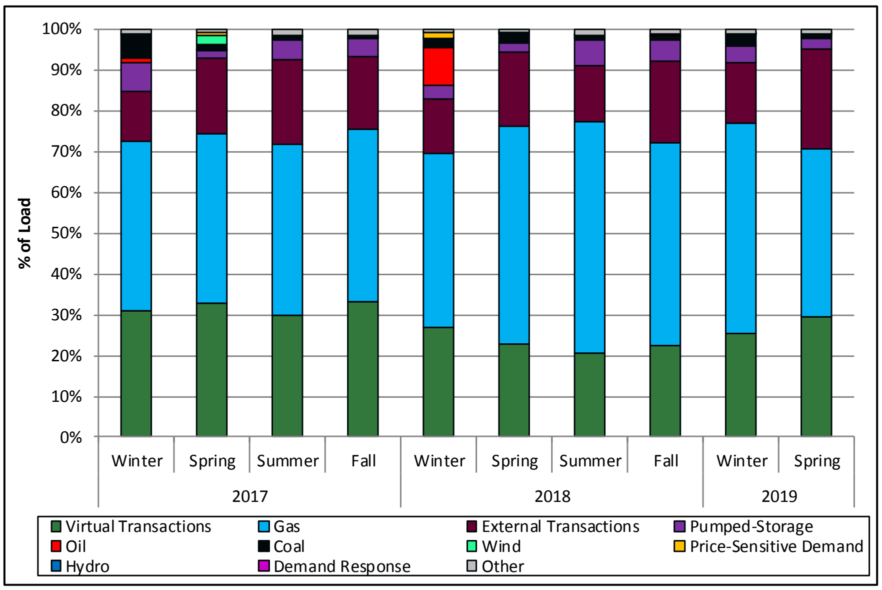
Pumped-storage units (generators and demand) set price for about 25% of total load in Spring 2019, which is a slight increase from Spring 2018 (23%), and Winter 2019 (21%). Pumped-storage units generally offer energy at a price that is close to the margin. They are often called upon when conditions are 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.

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

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

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

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



In Spring 2019, external transactions across the Canadian interfaces and virtual transactions primarily at the Hub displaced some of the price-setting transactions of gas generators in the day-ahead market. Natural gas set price for 41% of load in Spring 2019, a 10% decline from Winter 2019, and a 12% decline from Spring 2018.

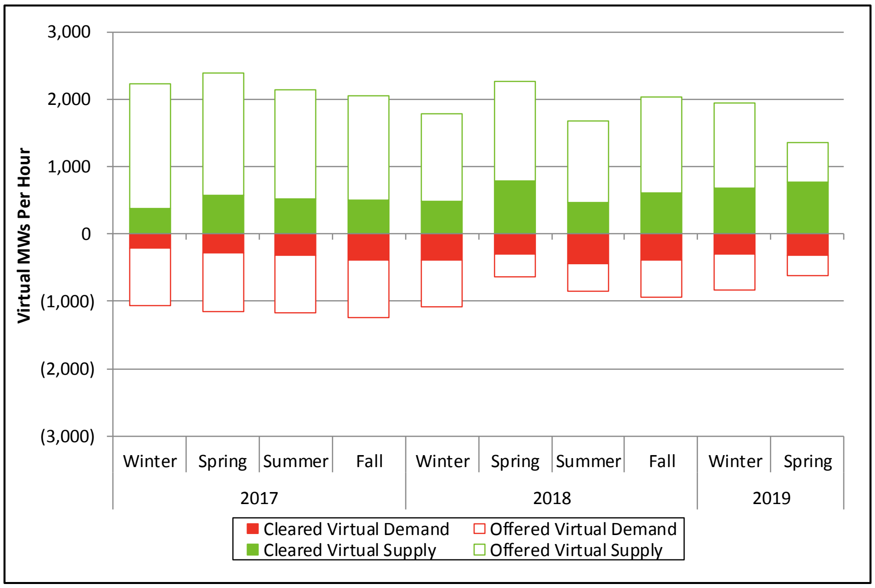
Over the same period, the amount of load externals set price for increased to 25% in Spring 2019, up from 15% in Winter 2019 and 18% in Spring 2018. External transactions at the New Brunswick interface set price for more load due to fewer day-ahead constraints in Maine. As you can see in Figure 2-8, net imports across New Brunswick tie lines are relatively consistent between Spring 2018, Winter 2019, and Spring 2019. The difference in Spring 2019 is that fewer constraints in Maine allowed marginal externals to set price for more load across the system.

Virtual transactions set price for 29% of load; up 4% from Winter 2019 and 6% from Spring 2018. The increase was driven by virtual participation at the Hub. Virtuals at the Hub set price for 11% of load in Spring 2019, compared to 6% in Winter 2019, and 3% in Spring 2018.

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 Spring 2019 are shown in Figure 3-5 below.

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



In Spring 2019, total offered virtual transactions averaged approximately 1,992 MW per hour, which was 28% lower than the average amount offered in Winter 2019 (2,778 MW per hour) and 32% lower than the average amount offered in Spring 2018 (2,911 MW per hour). This is the lowest amount of offered virtual transactions of any quarter in the reporting period. Prior to Spring 2019, the average amount of offered virtual transactions had stayed fairly constant, rising as high as 3,560 MW per hour in Spring 2017 and falling as low as 2,527 MW per hour in Summer 2018. The primary reason for the decrease in virtual transaction offers in Spring 2019 is that one participant significantly reduced their virtual activity. This participant submitted close to 800 MW per hour of virtual transactions, on average, in Winter 2019, and submitted less than 10 MW per hour, on average, in Spring 2019.

On average, 1,086 MW per hour of virtual transactions cleared in Spring 2019, which represents an increase of 10% compared to Winter 2019 (987 MW per hour) and a decrease of 1% compared to Spring 2018 (1,094 MW per hour). Cleared virtual supply amounted to 778 MW per hour, on average, in Spring 2019, up 14% from Winter 2019 (685 MW per hour) and down 3% from Spring 2018 (800 MW per hour). Meanwhile, cleared virtual demand amounted to 308 MW per hour, on average, in Spring 2019, up 2% from Winter 2019 (303 MW per hour) and up 5% from Spring 2018 (294 MW per hour). In general, the percent of submitted virtual transactions that have cleared has increased over the 10-quarter period covered in this report, rising from 18% in Winter 2017 to 55% in Winter 2019. The growth is likely linked to a reduction in transaction costs, in the form of reduced NCPC charges, to virtual transactions.[18]

Additionally, beginning in May 2016, certain wind and hydro generators became dispatchable under the Do Not Exceed (DNE) dispatch market rule. Under this change, DNE resources can set price in the real-time energy market. Prior to the change, DNE resources could only set price in the day-ahead energy market. DNE resources tend to offer higher-priced energy in the day-ahead market due to uncertainty surrounding environmental and production conditions. Because there is more certainty in real-time, DNE resources often reduce their offers and frequently set price. This creates an opportunity for virtual supply to take advantage of the difference in day-ahead and real-time offer behavior. Beginning on June 1, 2019, all DNE resources with capacity supply obligations will be required to offer the full amount of the resource's expected physical capability into the day-ahead energy market.

3.4 Net Commitment Period Compensation

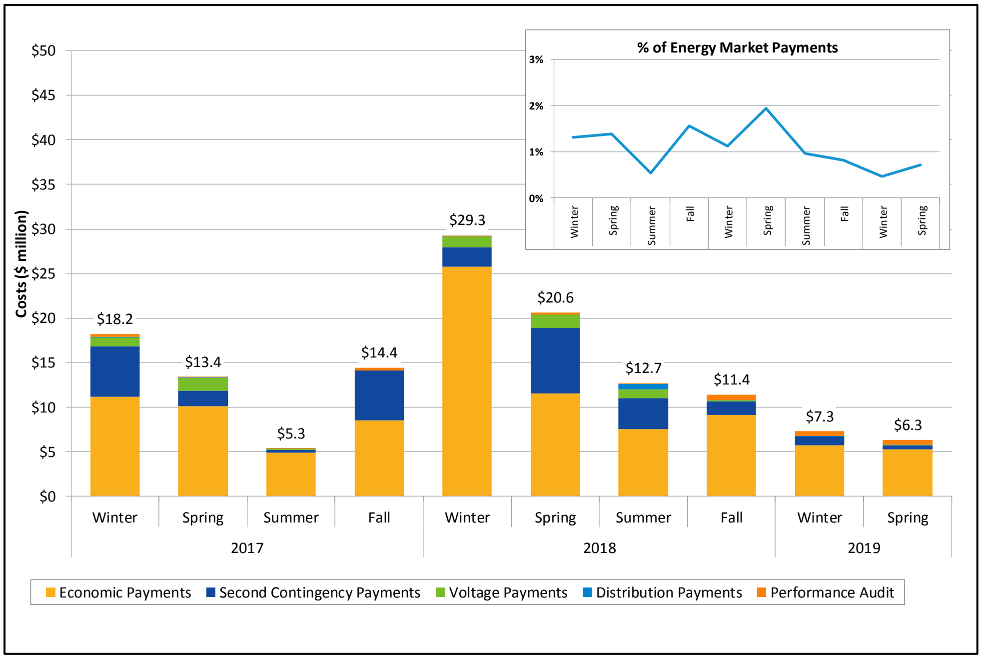
Net Commitment Period Compensation (NCPC), commonly known as uplift, are make-whole payments provided to resources when energy prices are insufficient to cover production costs or to account for any foregone profits the resources lost by following ISO dispatch instructions. Uplift may be required for resources committed and dispatched economically, dispatched out of economic-merit order for reliability purposes, or dispatched away from their economic dispatch point. 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.[19]

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.

[18] 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

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

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

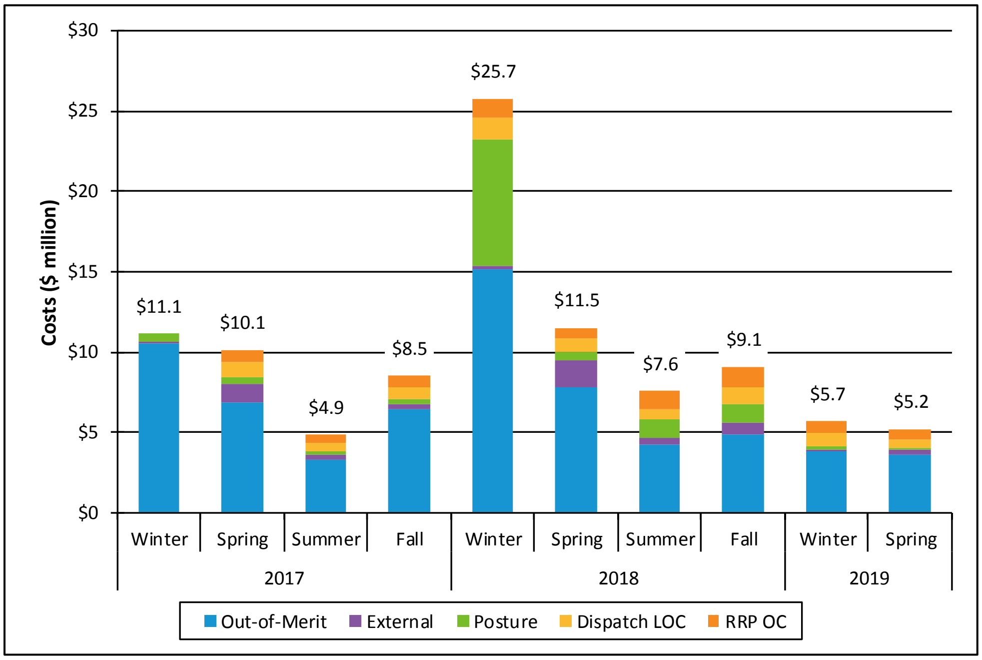


Total NCPC payments in Spring 2019 amounted to $6.3 million, a decrease of $1.0 million or 13% compared to Winter 2019. With a decrease in total energy payments of about $681 million from Winter 2019, total NCPC payments as a percentage of energy payments rose in Spring 2019 to 0.7% from 0.5%. Similarly, compared to Spring 2018, NCPC payments fell by 69%, or by $14.3 million.

Economic payments made up the majority of uplift (83% or $5.2 million) during the reporting period. Like Spring 2018, this quarter saw the majority of total economic payments paid in the real-time market. Compared to Spring 2018, economic NCPC fell by $6.3 million. The main drivers behind this decrease were reductions in economic out-of-merit and external transaction uplift payments, which are discussed below.

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 category.

Figure 3-7: Economic Uplift by Season by Sub-Category



As illustrated by Figure 3-7, out-of-merit payments continue to make up the majority of economic NCPC. Spring 2019 economic payments were consistent with Winter 2019 payments, varying by less than $0.5 million. Out-of-merit payments fell by 54% from $7.8 million to $3.6 million between Spring 2018 and Spring 2019. External transactions payments fell by 78%, from $1.7 million to $0.4 million. Import and export transactions are scheduled in the real-time market based on ISO forecasted prices but the transactions are settled based on actual prices. This NCPC credit is intended to make external transactions that end up being out-of-rate (based on actual prices) whole to their bid or offer.[20] In Spring 2019, 63% of real-time external transaction NCPC was paid to imports at the New Brunswick interface. This is a decrease from Spring 2018 when 93% or $1.6 million were paid out at the New Brunswick interface.

Total second contingency or LSCPR payments of $0.5 million were 50% lower than in Winter 2019 and 93% lower than in Spring 2018. Nearly all of the LSCPR NCPC paid out in Spring 2018 was paid in April to generators located in NEMA/Boston that were needed to support planned outages on the 345-kV transmission system. Transmission improvements in this area were the primary driver behind the lower LSCPR payments made in Spring 2019. In Spring 2019, over 90% of LSCPR payments were paid to generators that were needed for reliability in Maine.

3.5 Real-Time Operating Reserves

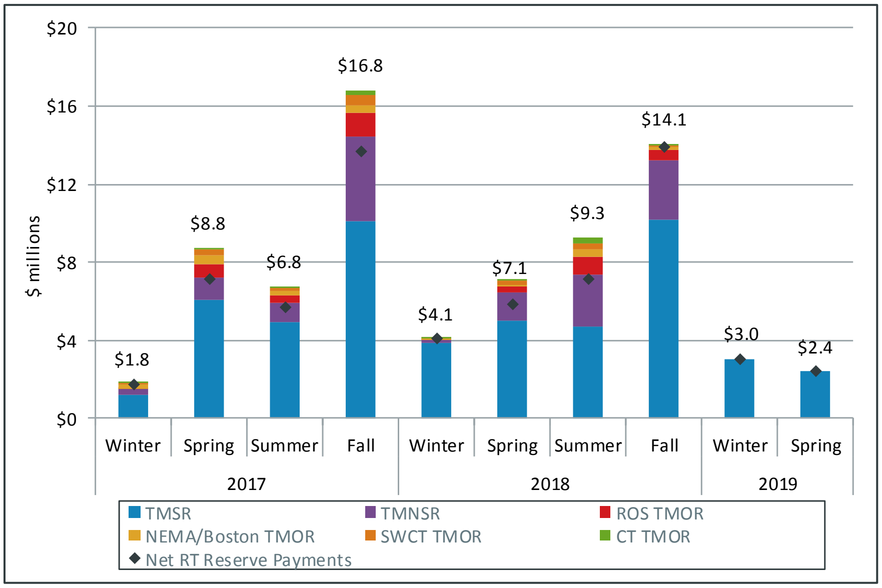
Bulk power systems must be able to quickly respond to contingencies, such as the unexpected loss of a large generator. To ensure that adequate backup capacity is available, the ISO procures reserve products through the locational Forward Reserve Market and the real-time energy market. The ISO's market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

[20] External transactions at the CTS interface are not eligible for this from of NCPC .

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 $2.4 million in Spring 2019, are shown as black diamonds in Figure 3-8. During Spring 2019, there were no reductions to real-time reserve payments for forward reserve obligations because there were no instances of non-zero, non-spinning reserve pricing.

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



Spring 2019 reserve payments were down $4.7 million from Spring 2018. The decline resulted from lower energy prices and a decrease in the frequency and magnitude of non-zero reserve pricing. All Spring 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. [21]

[21] 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.

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

Product	Zone	Spring 2017		Spring 2018		Spring 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	399.7	$15.85	451.0	$12.85	371.4	$10.97
TMNSR	System	0.7	$4.20	1.7	$2.94	0.0	$0.00
TMOR	System	13.5	$4.13	8.5	$2.11	0.0	$0.00
	NEMA/Boston	30.6	$11.08	0.0	$2.11	0.0	$0.00
	CT	0.0	$4.13	0.0	$2.11	0.0	$0.00
	SWCT	0.0	$4.13	0.0	$2.11	0.0	$0.00

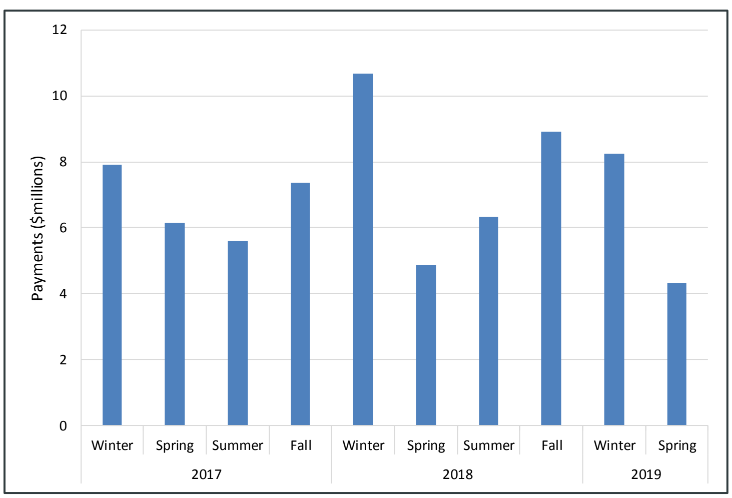
The TMSR clearing price was positive (i.e., there was non-zero reserve pricing) in 371 hours (17% of total hours) during Spring 2019, lower than the number of hours of non-zero reserve pricing in Spring 2018. In the hours when the TMSR price was above zero, the price averaged $10.97/MWh, a decrease from the prior spring 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 Spring.

There were no instances of non-zero ten-minute non-spinning reserve (TMNSR) or thirty-minute operating reserve (TMOR) pricing in Spring 2019. As Table 3-1 shows, the frequency and magnitude of TMNSR and TMOR pricing were also small in previous spring seasons. Average total 30-minute reserve margins were 24% higher in Spring 2019 than in Spring 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.[22]

Figure 3-9: Regulation Payments ($ millions)



[22] 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.

Total regulation market payments were $4.3 million during the reporting period, down approximately 11% from $4.9 million in Spring 2018, and down by 47% from $8.2 million in Winter 2019. The modest decline in payments comparing Spring 2018 and 2019 reflects a reduction in real-time energy market LMPs that reduced energy market opportunity costs for regulation generators. The substantial decline in regulation payments for Spring 2019 compared to Winter 2019 reflects several factors: a significant reduction in real-time energy market LMPs and opportunity costs for regulation generators, a reduction in regulation service price offers, and a relatively modest decline in 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 Summer 2019 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.[23] The region developed the FCM in recognition of the fact that the energy market alone does not provide sufficient revenue to facilitate new investment or, in many cases, cover the cost of maintaining and operating existing resources. A central objective of the FCM is to create a revenue stream that replaces the "missing" revenue and thereby induces suppliers to undertake the investments necessary for reliable electric power service.

The ISO introduced Pay-for-Performance (PFP) rules beginning on June 1, 2018 to incent reliable operation during scarcity conditions.[24] Prior to June 1, 2018, resource owners faced de minimis financial penalties when unable to perform during periods of scarcity. The PFP rules improve the underlying market incentives by replicating performance incentives that exist in a fully functioning and uncapped energy market. Pay-for-performance rules provide a two-settlement construct that links payments to performance during scarcity conditions. Without this linkage, participants lack the incentive to make investments that ensure their resources perform when needed most. Also, absent these incentives, participants that have not made investments to ensure their resources' reliability are more likely to clear in future FCAs because they can offer at lower prices. This can create a structural bias in the FCM to clear less reliable resources, which, over time, erodes system reliability. Paying for actual performance during scarcity conditions incents resource owners to make investments and perform routine maintenance to ensure resource readiness to provide energy or operating reserves during scarcity conditions.

Pay-for-performance works as follows: a resource owner is compensated for that resource's Capacity Supply Obligation (CSO) held in a given month, but is subject to adjustments based on its performance during scarcity 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 expectations, it must buy the difference back at a performance payment rate. Under-performers compensate over-performers, with few exceptions.[25] Additionally, energy market only assets (known as PFP-only resources) are compensated for their contribution to load and reserve requirements. Since they hold no CSO, PFP-only resources cannot under-perform and can only receive compensation for over-performance during scarcity conditions.

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

[24] A scarcity condition occurs for the system or for certain capacity zones in five-minute increments. For more information, see Section III.13.7.2.1 of the tariff.

[25] Energy efficiency resources are provided an exemption during off-peak periods. See III.13.7.2.2 of the tariff for actual capacity provided calculations.

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.[26] Between the initial auction and the commitment period, there are six discrete opportunities to adjust annual CSOs. 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 Spring 2019 reporting period falls within the Capacity Commitment Period (CCP) that started on June 1, 2018 and ended on May 31, 2019. In the corresponding Forward Capacity Auction (FCA 9), the ISO introduced a sloped zonal demand curve. This means that cleared demand could exceed the Net Installed Capacity Requirement (NICR).[27]

In FCA 9, conditions existed which caused the capacity zones and external interfaces to close at different rounds and prices:

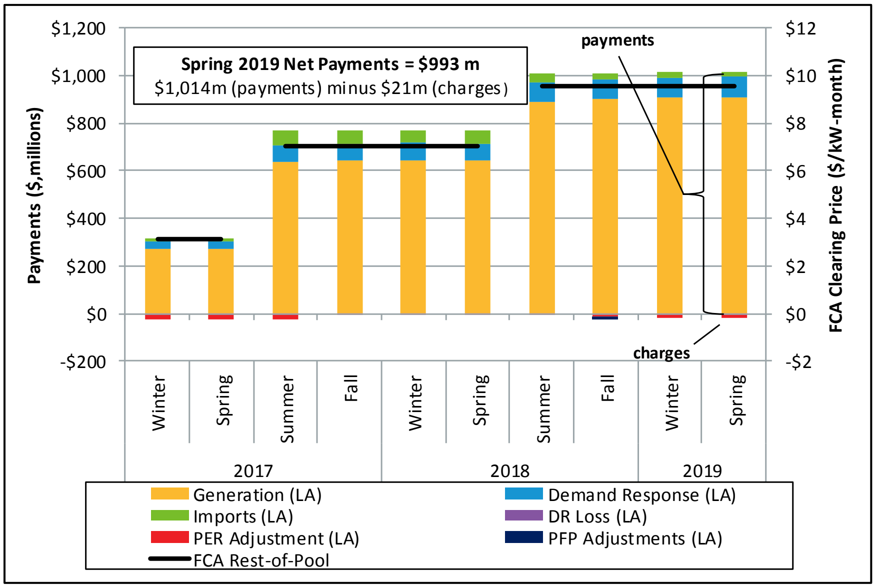
- The auction did not run in the SEMA/Rhode Island capacity zone, as conditions were met to trigger inadequate supply. As a result, the payment rate for existing resources located in SEMA/Rhode Island was set to the Net Cost of New Entry (or net CONE) of $11.08/kW- month, and the payment rate for new resources was set to the FCA 9 starting price ($17.73/kW-month).
- The rest of the system (with the exception of New York AC Ties and New Brunswick Interfaces) closed in round three with a payment rate of $9.55/kW-month.
- New York AC Ties closed in round four with a payment rate of $7.97/kW-month.
- New Brunswick closed in round five with a payment rate of $3.94/kW-month, which concluded the auction.

Total FCM payments, as well as the clearing prices for Winter 2017 through Spring 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) adjustments. The dark blue bar represents Pay-for-Performance adjustments.

[26] 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.

[27] For a detailed IMM review of FCA 9, see the Q1 2015 report: https://www.iso-ne.com/static-assets/documents/2015/06/q1_2015_qmr_for_publication_0609.pdf

Figure 4-1: Capacity Payments ($ millions)



Total net FCM payments increased significantly from Spring 2018. In Spring 2019, capacity payments totaled $993 million, which accounts for adjustments to primary auction CSOs.[28] New and existing resource payment rates outside of SEMA/Rhode Island increased 36%, from $7.03/kW-month in Spring 2018 to $9.55/kW-month in Spring 2019 due to the higher clearing price in FCA 9. Payments to import resources declined due to lower prices at the external interfaces. Payments to generation resources increased due to higher clearing prices across all capacity zones. The only adjustment to credits in Spring 2019 was for Peak Energy Rent (PER), which totaled $21.3 million. The PER adjustments can be attributed to the September 3 event in 2018.

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

[28] 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 9 (2018-19)	Primary	12-month	9.55	34,695	17.73/11.08*	3.94	7.97
	Monthly Reconfiguration	Apr-19	1.00	780			
	Monthly Bilateral	Apr-19	1.91	441			
	Monthly Reconfiguration	May-19	1.05	860			
	Monthly Bilateral	May-19	1.01	393			
FCA 10 (2019-20)	Primary	12-month	7.03	35,567		4.00	6.26
	Monthly Reconfiguration	Jun-19	2.02	299			
	Monthly Bilateral	Jun-19	2.05	235			

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

***bilateral prices represent volume weighted average prices*

Prices and volumes in April 2019 and May 2019 were consistent with previous winter monthly auctions in CCP 9. Prices in June 2019 nearly doubled from $1.05/kW-month in May 2019 to $2.02/kW-month in June 2019. Meanwhile, cleared volumes fell 65% to 299 MW in June 2019, down from 860 MW in May 2019. These changes were driven by fewer low-priced offers from generation resources. Generation resources are unable to offer as much capacity in summer months due to the summer and winter qualification rules. The absence of low-priced offers shifts the supply curve inward, which normally leads to higher prices and lower volumes in summer months.

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.[29] FTRs are sold in annual and monthly auctions, both of which conduct separate auctions for on-peak and off-peak hours. The amount of FTRs awarded in each auction is based on a market feasibility test that ensures that the transmission system can support the awarded set of FTRs during the period. FTRs awarded in one of the two annual auctions have a term of one year. The remaining feasible FTRs are made available in monthly auctions, each having 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 through the congestion revenue fund, which is the collection of congestion costs in the day-ahead and real-time energy markets for that month. Because congestion costs are based on actual system conditions, the congestion

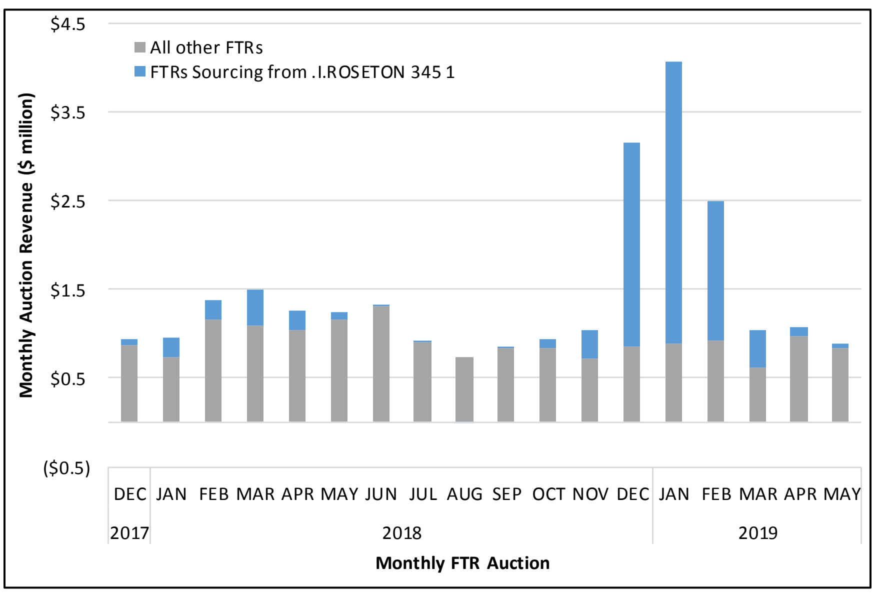
[29] FTRs are valued based on the FTR MW quantity and the difference between congestion components of the day-ahead LMP at the point of delivery (where power is withdrawn from the New England grid) and the point of receipt (where power is injected onto the New England grid) designated in the FTR. FTRs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

revenue fund can be larger or smaller than the positive target allocations to FTR holders.[30] If the congestion revenue fund for a month is less than the total positive FTR target allocation for that month, the payments to FTR holders are prorated. If there is excess revenue in the congestion revenue fund at the end of the year, any monthly deficiency is made up to the extent possible.

The monthly auctions for March 2019, April 2019, and May 2019 resulted in a combined total of 78,483 MW of FTR transactions. Thirty-one bidders participated in the March 2019 auction, 39 bidders participated in the April 2019 auction, and 38 bidders participated in the May 2019 auction. The level of participation was slightly higher than in recent auctions.

The total auction revenue for Spring 2019 was $3.0 million, which represents a 69% decrease compared to Winter 2019 ($9.7 million) and a 26% decrease compared to Spring 2018 ($4.0 million). The decrease in auction revenue relative to the Winter 2019 can largely be explained by the amount of auction revenue associated with FTRs that source from .I.ROSETON 345 1, ISO-NE's external proxy node for the New York North interface. This interface is often constrained in the day-ahead market, as less expensive supply from New York is frequently imported into New England. Figure 4-2 below shows that the magnitude of FTR auction revenue associated with FTRs that source from .I.ROSETON 345 1 rose dramatically in Winter 2019, reflecting participants' expectations of increased congestion at the New York North interface during this period. Meanwhile, the magnitude of the auction revenue associated with FTRs other than those that source from .I.ROSETON 345 1, shown in gray below, has been fairly constant over the last year and a half.

Figure 4-2: Monthly FTR Auction Revenue



FTRs in March 2019 and May 2019 were fully funded, meaning that enough congestion revenue and revenue from negative target allocations was collected to pay the positive target allocations

[30] 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 sinking and sourcing locations. Positive target allocations (credits) occur when the congestion component of the sinking location is greater than the congestion component of the sourcing location. Negative target allocations (charges) occur in the opposite situation.

in those months. However, FTRs in April 2019 were not fully funded. In April 2019, FTR holders with positive target allocations received only 88.6% of the revenue that they were entitled to. However, there were surpluses in March 2019 ($0.8 million) and May 2019 ($0.1 million). 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.

4.3 Forward Reserve Market

Twice each year, ISO New England holds forward reserve auctions. The ISO uses forward reserve auctions to enter into forward obligations with participants to provide operating reserves in the real-time energy market. These forward obligations are intended to ensure the delivery of adequate operating reserves for both the ISO New England system-wide and local reserve zones. During April 2019, the ISO held the forward reserve auction for the Summer 2019 delivery period (i.e., June 1, 2019 to September 30, 2019).[31]

4.3.1 Auction Reserve Requirements

Prior to each auction, the ISO establishes the amount of forward reserves, or requirements, for which it will enter into forward obligations. These requirements are set at levels intended to ensure adequate reserve availability in real-time, based on possible system and local reserve zone contingencies (unexpected events such as the forced outage of a large generator or loss of a large transmission line).

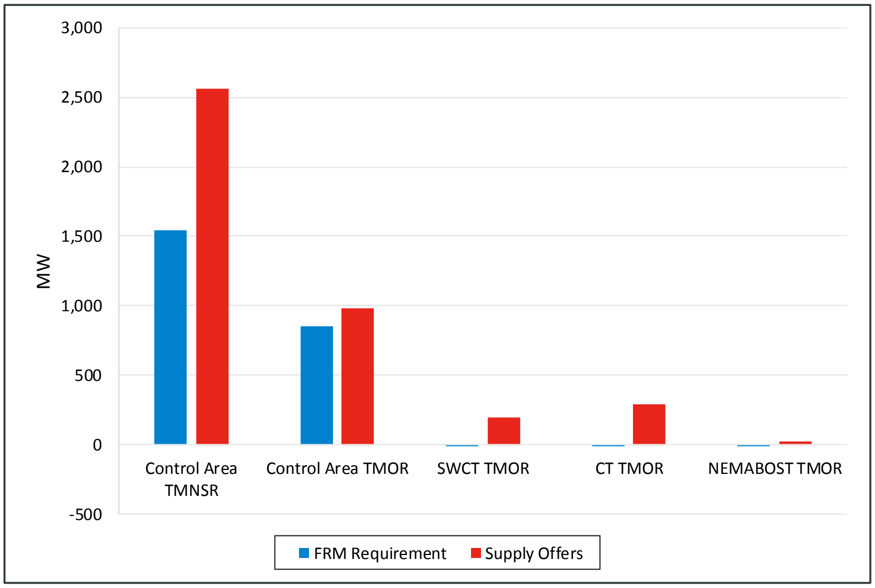
The requirements for the Summer 2019 auction are illustrated in Figure 4-3 below. These requirements were specified for the ISO New England system and three local reserve zones.[32] The figure also illustrates the total quantity of supply offers available in the auction to satisfy the reserve needs.[33]

[31] The Forward Reserve Market has two delivery ("procurement") periods per year: Summer (June 1 to September 30) and Winter (October 1 to May 31).

[32] The local reserve zones are Connecticut (CT), Southwest Connecticut (SWCT), and NEMA/Boston (NEMABOST).

[33] Because TMOR supply offers within local reserve zones also provide TMOR to the system, the system-wide TMOR offers shown in the figure include the local reserve zone supply offers. Hence, the system-wide TMOR offers represent the total offers throughout the system. A similar adjustment has been made to the Connecticut TMOR supply offers; the SWCT zone is nested within the Connecticut zone, and SWCT offers can contribute to the Connecticut TMOR supply. Given this, SWCT TMOR supply offers are shown in the CT TMOR total.

Figure 4-3: Forward Reserve Requirements and Supply Offer Quantities



For the system, requirements were set for two reserve products: ten-minute non-spinning reserve (TMNSR) and thirty-minute operating reserve (TMOR). The ISO bases the requirements for each product on possible system contingencies. For TMNSR, the requirement was based on the expected single contingency of the Hydro Quebec Phase II Interconnection, and was estimated as a 1,544 MW TMNSR reserve need. The system-wide TMOR requirement was based on the expected single contingency of the Mystic 8 and 9 generators, and was estimated as an 853 MW TMOR need.[34]

For the local reserve zones, only a TMOR requirement is specified. The ISO bases the local requirements on local second contingencies, adjusted for the availability of transmission capacity (which can also effectively supply reserves to the local area).[35] After adjustments, all local reserve zones – Connecticut, Southwest Connecticut and NEMA/Boston – were found to need no local reserve requirement, as "external reserve support" (available transmission capacity) exceeded the local second contingency requirements. In NEMA/Boston, a significant increase in external reserve support (transmission capability) resulted in no need for local thirty-minute operating reserves.

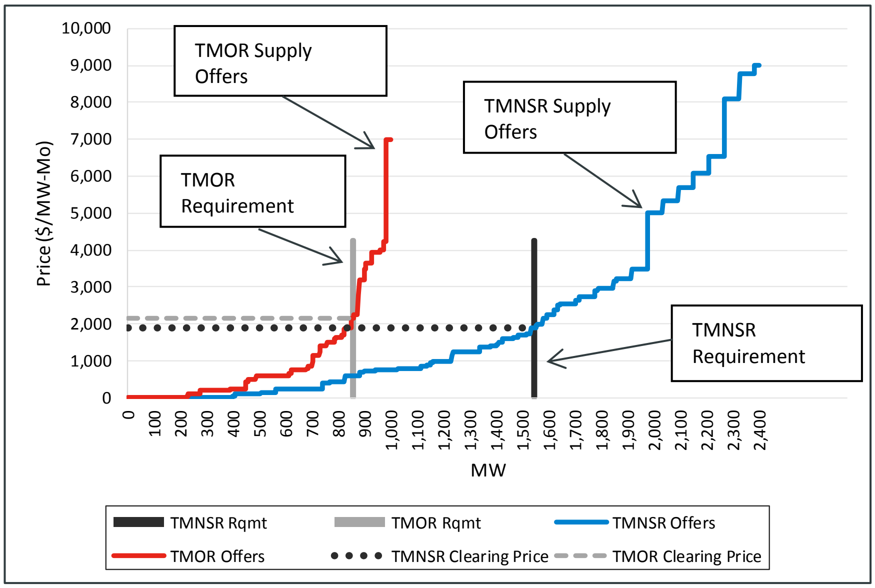
[34] ISO New England Memorandum to Market Participants (Subject: Assumptions and Other Information for the Summer 2019 Forward Reserve Auction), published March 18, 2019, indicates the system-wide and local reserve zone requirements. For the system-wide requirements, the final requirement may reflect ISO adjustments, such as biasing the requirement, increasing a requirement to reflect historical resource non-performance, and adjusting the TMOR requirement to reflect the replacement reserve requirement.

[35] See the ISO New England Manual for Forward Reserve and Real-Time Reserve for a more detailed indication of the determination of local reserve requirements (Manual M-36, Sections 2.2.3 – 2.2.5). The transmission capacity used to adjust the local requirement is referred to as "external reserve support."

4.3.2 System Supply and Auction Pricing

As noted previously, system-wide supply offers in the Summer 2019 auction exceeded the requirements for both TMNSR and TMOR. Adequate supply ensures that the ISO can successfully obtain forward obligations to meet expected reserve needs in the auction. Figure 4-4 provides the requirements and initial system-wide supply curves for both TMNSR and TMOR.

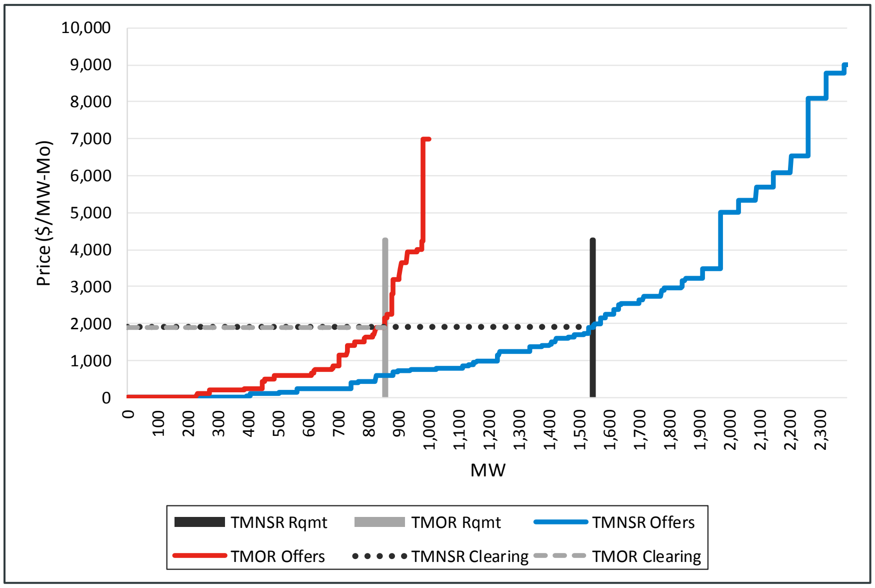
Figure 4-4: Requirements and Initial Supply Curves, System-Wide TMOR & TMNSR



The figure indicates the prices that would have been obtained if TMNSR could not be substituted for TMOR. The supply curve for TMOR is above (i.e., more expensive than) the supply curve for TMNSR. However, ten-minute reserves are a higher-quality product and so the auction clearing software substitutes the lower-quality 30-minute reserve product with it when it is economical to do so. Without substitution, the clearing prices for TMNSR and TMOR would be $2,149/MW-month since the higher-quality TMNSR product cannot have a lower price than the lower-quality TMOR product by auction design.

The clearing prices for TMNSR and TMOR with substitution are shown in Figure 4-5 below. In this instance, TMNSR is substituted for TMOR until the prices for the two products become equal, while ensuring that the requirement for each product is fully satisfied. Only a small quantity of TMNSR needs to be substituted for TMOR for each product's price to become equal.

Figure 4-5: Supply Curves, Requirements and Clearing Prices, System-Wide TMOR & TMNSR

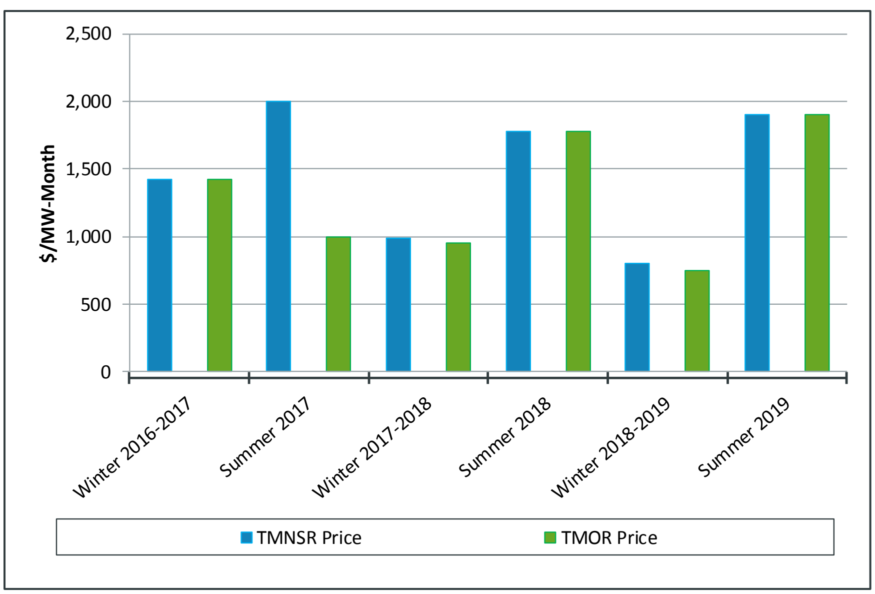


With system-wide requirements of 853 MW for TMOR and 1,544 for TMNSR, system-wide supply offers for the two products, with substitution, resulted in a clearing price for each product of $1,899/MW-month (gray and black dashed/dotted lines in the figure).

4.3.3 Price Summary

Forward reserve prices for the system-wide TMNSR and TMOR products are shown in Figure 4-6 below.

Figure 4-6: FRM Clearing Prices for System-Wide TMNSR and TMOR



In the Summer 2019 auction, TMOR and TMNSR cleared at the same price and at somewhat higher prices than in the Summer 2018 auction. The clearing prices rose in the Summer 2019 auction compared to the Winter 2018-2019 auction primarily as a result of TMNSR and TMOR offer prices having increased significantly.

4.3.4 Structural Competitiveness

The structural competitiveness of the Forward Reserve Market 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 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 requirement. Given that TMNSR can also satisfy the TMOR requirement, the TMNSR offer quantity in a zone is included in the total TMOR offer quantity within that zone.

The heat map table – Figure 4-7 below – shows the offer RSI for system TMNSR and TMOR for zones with a non-zero TMOR requirement. The colors indicate the degree to which structural market power was present, starting with low RSIs shown in red, followed by white and green colors, with the latter indicating that there was still ample offered supply without the largest supplier.

Figure 4-7: 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)
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

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. Generally, the RSI values can fluctuate significantly from auction to auction. These fluctuations can be partly explained by variation in the reserve requirement. For instance, the TMOR RSI value for the SWCT zone declined from 302 in Winter 2016-17 auction to 183 in Summer 2017 period. This resulted from the local TMOR requirement increasing from 32 MW to 52 MW, with a small quantity of local supply available to meet a requirement that increased by 63%.

From the Winter 2016-17 through Winter 2018-2019 procurement periods, the TMNSR RSI values were greater than 100. These values suggest that the TMNSR offer quantities in these auctions were consistent with a structurally competitive level. However, the TMNSR RSI declined slightly to 90 (below the structurally competitive level) for the Summer 2019 auction. The decline in RSI 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 throughout the review period.[36] Likewise, the Southwest Connecticut (SWCT) zone was structurally competitive, when it had a reserve requirement. NEMA/Boston, however, has been structurally uncompetitive for all recent auctions for which it had a requirement. In these auctions, every participant that offered forward reserves in NEMA/Boston was needed to meet the local requirement.

[36] The "Rest-of-System" zone is simply the portion of the system that excludes the local reserve zones (CT, SWCT, and NEMABOST).