ISO New England's Internal Market Monitor

Summer 2017

Quarterly Markets Report

Internal Market Monitor

December 20, 2017

Table of Contents

Tables

Figures

Preface

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

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

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

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

Underlying natural gas data furnished by:

ICE Global markets in clear view[2]

Oil prices are provided by Argus Media

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

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

Section 1
Executive Summary

This report covers key market outcomes and the performance of ISO New England wholesale electricity and related markets for **Summer 2017 (June 1, 2017 through August 31, 2017)**.[3] This section presents the highlights across the various markets and also provides a summary of our analysis of the fast-start pricing rules that were implemented in March 2017.

1.1 Market Outcomes and Performance for Summer 2017

Wholesale Costs: The total estimated wholesale market cost of electricity was $1.75 billion, an increase of about 12% (a $187 million difference) compared to costs of $1.56 billion in Summer 2016. Compared to the prior season (Spring 2017), costs were up by 36% ($461 million).

- Rising Forward Capacity Market prices were the biggest contributor to the increase in wholesale market costs. Capacity costs totaled $740 million, up 144% ($436 million) compared to last summer. Since the start of the FCM in 2010, the region had excess capacity, resulting in relatively low and stable capacity prices. June 2017 marked the beginning of the FCA 8 capacity commitment period, which had tighter system conditions due to a number of generator retirements.
    - FCA 8 was the first auction that did not clear at an administratively-set floor price.
    - Capacity payments to existing resource outside of NEMA/Boston increased 123%, from $3.15/kW-month to $7.03/kW-month
    - Capacity payments to new and existing resources in NEMA/Boston increased to $15.00/kW-month.
- A reduction in energy costs offset some of the increase due to increased capacity costs. Summer 2017 energy costs totaled $979 million, down 19% ($230 million) on the prior summer. The reduction in energy prices was due primarily to lower natural gas prices and electricity demand (load):
    - Natural gas prices averaged $2.44/MMBtu, a decrease of 10% ($0.27/MMBtu) compared to the prior summer, and a decrease of 31% ($1.11/MMBtu) compared to Spring 2017.
    - Average hourly load and peak hourly load were both down by 7%, primarily due to milder weather. Average hourly and peak hour load were 14,796 MW and 23,889 MW, respectively, compared to 15,944 MW (down 148 MW) and 25,596 MW (down 1,707 MW) in Summer 2016.

Energy Prices: Day-ahead and real-time energy market prices at the Hub averaged $26.00/MWh and $24.78/MWh, respectively. Day-ahead prices were 13% lower ($3.83/MWh) and real-time prices were 18% lower ($5.57/MWh) than Summer 2016 prices.

- Day-ahead and real-time energy prices continue to trend with natural gas prices. One of the reasons for the relatively large reduction in 2017 real-time prices, relative to last summer, was the tight systems conditions in 2016 that raised energy and reserve prices substantially for two days (on August 11 and 12, 2016). The two-day period alone increased last summer's average quarterly price by over $3.50/MWh (or by over 13%).

[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).

- Energy market prices did not differ significantly among the load zones. Maine, an export-constrained region, had the highest deviation with consistently lower prices relative to the other zones. In the day-ahead market, the Maine average price was $0.54/MWh (2%) lower than the Hub. Day-ahead price separation in Maine was generally consistent with the price separation observed in real-time, with prices $0.73/MWh (3%) lower than Hub prices.

Net Commitment Period Compensation: NCPC payments totaled $5.5 million, down by 57% ($7.3 million) compared to Summer 2016. Payments were at their lowest level during the 2½ -year reporting horizon and represented about 0.6% of the total wholesale energy costs, down from Summer 2016 (1.1%). The majority of NCPC (92%) was for first contingency (economic) and nearly three quarters (72%) of total NCPC was paid in the real-time market. The fast-start pricing rule changes had an expected downward impact on NCPC during Summer 2017. It is estimated that the new rules reduced real-time economic NCPC by as much as $3 million.

Real-Time Reserves: Real-time reserve payments totaled $6.9 million, which was a large decrease relative to the Summer 2016 total of $14.2 million. Though the frequency of reserve pricing was much higher (due to lower operating reserve margins), the average reserve price was significantly down. This trend in price reflects the lower opportunity cost of dispatching generators down to provide reserves rather than energy. As mentioned above, the two-day period of tight system conditions last summer has a significant impact on reserves prices, and accounted for almost 70% of total reserve payments in Summer 2016. The fast-start pricing rules also led to an increase in reserve payments.

***Regulation*:** Total regulation market payments were $5.4 million, down 39% from $8.9 million in Summer 2016. Lower natural gas and real-time energy market prices led to a reduction in regulation offers prices (primarily the opportunity cost adder) and clearing prices. Additionally, reduced manual regulation commitments by the ISO combined with lower regulation clearing prices during manual commitment periods resulted in a $1.5 million decrease in Summer 2017 payments compared to Summer 2016 payments.

Forward Reserve Market: In August 2017, ISO New England held the forward reserve auction for the Winter 2017-18 delivery period (i.e., October 1, 2017 to May 31, 2018). Control area supply offers exceeded the requirements for both thirty- and ten-minute reserves. The clearing prices for offline thirty- and ten-minute reserves for the control area were $949/MW-month and $990/MW-month, respectively. These clearing prices were lower than Winter 2016-17 prices, when both thirty and ten-minute reserves cleared at a price of $1,420/MW-month. Of the three local reserve zones, only NEMA/Boston had a different price than the control area. Because of inadequate supply (meaning all suppliers were pivotal suppliers), the thirty-minute reserve price for NEMA/Boston was set to the auction's offer price cap of $9,000/MW-month.

1.2 Analysis of Fast-Start Pricing Rules

In March 2017, ISO New England implemented fast-start pricing rules in the real-time energy market. The change introduced new mechanics to the market clearing software intended to improve price formation and performance incentives when fast-start resources are deployed.

Results of the analysis presented in Section 5 of this report indicate that fast-start pricing has worked as intended; real-time LMPs have better reflected the costs of committing fast-start resources. Key observations from March 1st through October 31st include:

- The average system LMP in all intervals increased by $2.72/MWh (11%) due to the fast-start pricing rules. Higher LMPs resulted in increased real-time energy charges by load of $5.9 million (11%). Prices increased during intervals when fast-start generators produced energy, and decreased when fast-start pump-storage demand has consumed energy. Both real-time generation and demand have stronger incentives to follow commitment instructions.
- The total number of fast-start commitments requiring NCPC decreased from 27% to 18%. NCPC also decreased by $8.8 million as a result of fast-start pricing. NCPC for committed or dispatched out-of-merit costs decreased by $10.6 million, a reduction of more than half. This decrease has been slightly offset by $1.9 million in rapid response pricing NCPC, a new category of NCPC necessitated by fast-start pricing mechanics.
- Reserve pricing has been more frequent and higher in magnitude due to fast-start pricing. The estimated increase in the average reserve price in all intervals is $2.23/MWh (192%). Additional reserve payments totaled $19.8 million, an increase of 181%. This is an expected outcome of fast-start pricing due to the tradeoffs produced when relaxing physical constraints to determine a price more reflective of total production costs. A reserve accounting approach was taken that avoids the appearance of more reserve capacity than is physically available, and ensures reserves are priced when the reserve requirement is physically binding. It has also resulted in reserve pricing in cases when a physical re-dispatch is not needed to maintain reserves.

Section 2
Overall Market Conditions

This section provides a summary of key trends and drivers of wholesale electricity market outcomes from Winter 2015 through Summer 2017.

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

	Summer 2017	Spring 2017	Summer 2017 Vs. Spring 2017 (% Change)	Summer 2016	Summer 2017 Vs. Summer 2016 (% Change)
Real-Time Load (GWh)	32,671	28,493	15%	35,204	-7%
Weather Normalized Real-Time Load (GWh)	33,143	28,005	18%	34,898	-5%
Peak Real-Time Load (MW)	23,889	20,250	18%	25,596	-7%
Average Day-Ahead Hub LMP ($/MWh)	$26.00	$30.78	-16%	$29.83	-13%
Average Real-Time Hub LMP ($/MWh)	$24.78	31.92	-22%	$30.35	-18%
Average Natural Gas Price ($/MMBtu)	$2.44	$3.55	-31%	$2.72	-10%
Average Oil Price ($/MMBtu)	$8.38	$8.56	-2%	$7.60	10%

The combination of lower loads and natural gas prices contributed to differences between Summer 2017 and Summer 2016 market outcomes. To summarize the highlights table above:

- Lower natural gas prices in Summer 2017 led to lower day-ahead and real-time LMPs, compared to Spring 2017 and Summer 2016. Natural gas prices decreased by 31% compared to Spring 2017 and by 10% compared to the prior summer.[4] The impact of natural gas prices on LMPs is further examined in Section 3.1 below.
- Total real-time load and peak-load in Summer 2017 were 7% lower than last summer. The decline is primarily due to milder weather in Summer 2017. Changes in load are further discussed in Section2.2.

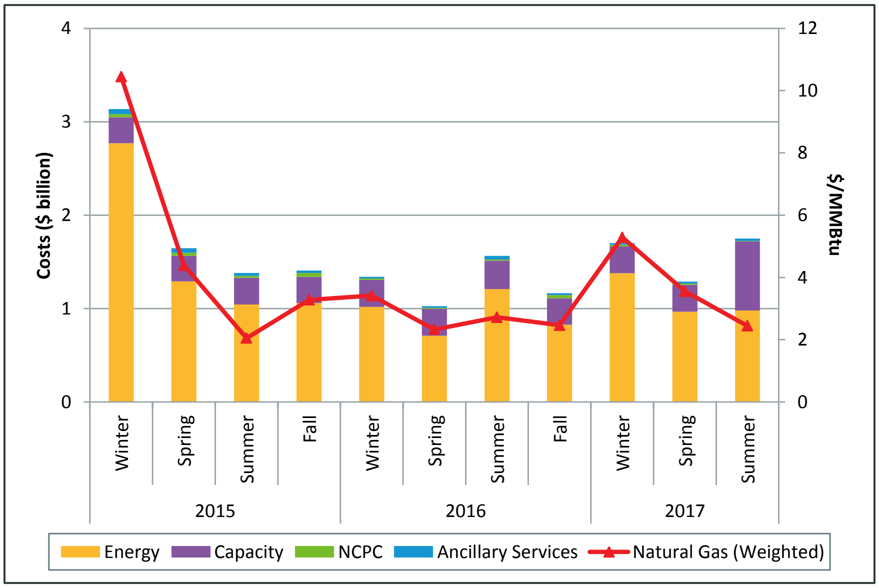
2.1 Wholesale Cost of Electricity

The estimated wholesale electricity cost for each season (in billions of dollars) by market, along with average natural gas prices (in $/MMBtu) is shown in Figure 2-1 below.[5, 6]

[4] Prices of $4.46/MMBtu in March 2017 were 127% greater than the previous March, which explains the relatively high Spring 2017 gas prices.

[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

Figure 2-1: Wholesale Market Costs and Average Natural Gas Prices by Season ($ billions and $/MMBtu)



In Summer 2017, the total estimated wholesale market cost of electricity was $1.75 billion, an increase of about 12% compared to $1.6 billion in Summer 2016, and an increase of 36% over the previous quarter (Spring 2017). Natural gas prices continued to be the key driver behind energy prices. However, despite lower natural gas prices, overall energy payments were similar in Summer 2017 compared to the Spring 2017; this was due to the opposing effect of higher load levels.

Rising capacity market costs were the biggest contributor to the higher wholesale costs in Summer 2017. Up to June 2017, capacity prices were relatively low as the region was long on capacity (i.e. had an excess of supply compared to the region's requirements). Capacity prices from the eighth forward capacity auction (FCA 8), which went into effect beginning in June 2017, reflect tighter system conditions due to a number of generator retirements. Due to a shortfall in capacity in FCA 8, prices were set administratively at $7.03/kW-month for existing (non-NEMA/Boston) resources and at a price of $15.00/kW-month for new and existing resources in NEMA/Boston. This compares to a rest-of-pool clearing price of $3.15/kW-month in the prior auction, FCA 7.

At $6 million, Summer 2017 Net Commitment Period Compensation (NCPC) costs represented approximately 0.6% of energy costs, a lower share than all other quarters in the reporting period. In dollar terms, NCPC costs were 57% lower than Summer 2016 NCPC costs, and 59% lower than Spring 2017 NCPC costs. NCPC costs are discussed further in Section 3.4.

Ancillary services, which include operating reserves and regulation, totaled $26 million in Spring 2017. Ancillary services costs decreased by 33% compared to Summer 2016, and increased by 23% compared to Spring 2017.

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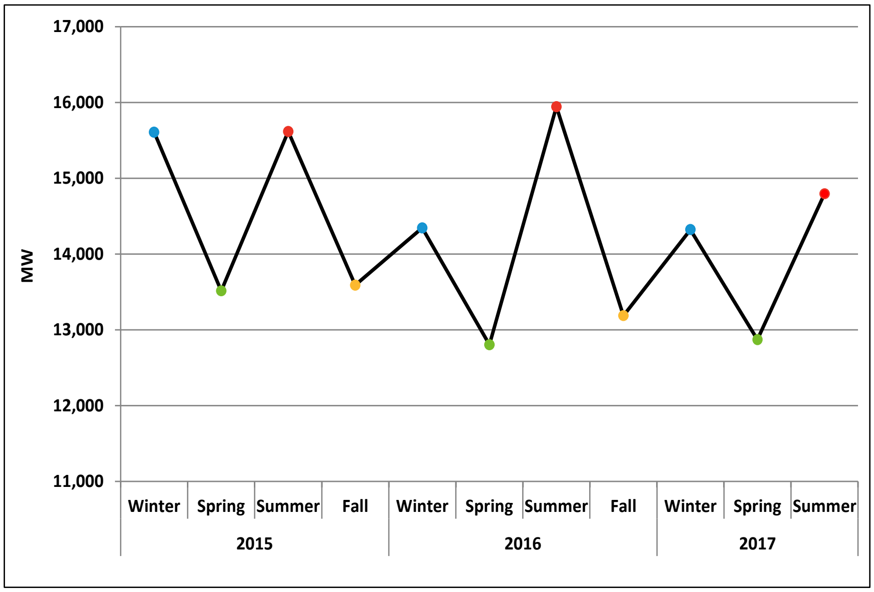
average real-time LMP. Transmission network costs as specified in the Open Access Transmission Tariff (OATT) are not included in the estimate of quarterly wholesale costs.

[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.

2.2 Load

Average hourly load during Summer 2017 was 14,796 MW, lower than the previous two summer seasons; by 5.3% on 2015 levels and 7.2% on 2016 levels. Average hourly load by season is illustrated in Figure 2-4 below. The blue dots represent winter, the green dots represent spring, the red dots represent summer, and the yellow dots represent fall.

Figure 2-2: Average Hourly Demand



Contributing factors of lower loads during Summer 2017 include milder temperatures, and the growth of energy-efficiency programs and behind-the-meter generation.

Table 2-2 below compares the weather conditions of the summer months over the past three years. The table compares the average monthly temperature and the number of hours per month when the average Temperature Humidity Index (THI)[7] was greater than 73°F. Air conditioning use (and the associated electric load) increases when the THI exceeds 73°F.

Table 2-2: Monthly Temperature Humidity Index Statistics for Summer Periods

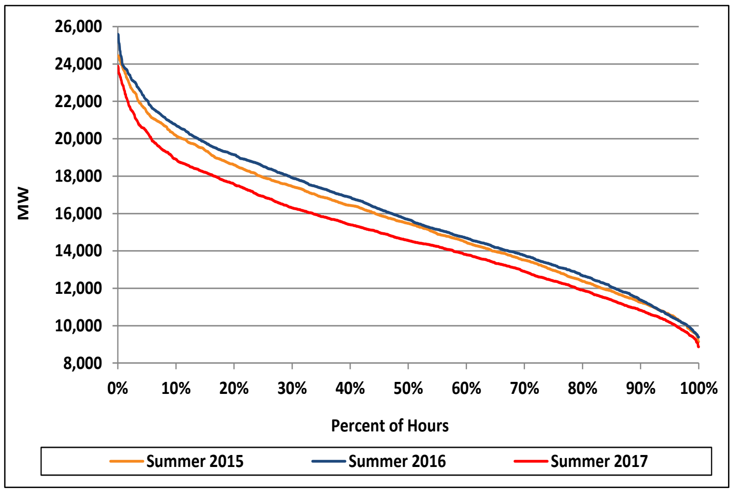
	Summer 2015		Summer 2016		Summer 2017	
	Average (in °F)	Number of Hours with THI > 73°F	Average (in °F)	Number of Hours with THI > 73°F	Average (in °F)	Number of Hours with THI > 73°F
June	64	20	64	9	65	77
July	70	153	70	199	69	118
August	70	120	71	212	67	73

[7] The Temperature Humidity Index accounts for the combined effects of environmental temperature and relative humidity. It is a useful explanatory factor of electricity demand levels during summer months, when humidity levels have the greatest impact.

There were fewer hours when the THI exceeded 73°F in Summer 2017 (268 hours) compared to Summer 2016 (420 hours) and Summer 2015 (293 hours). In particular, August 2017 was significantly milder than the prior two Augusts.

The system load for New England over the last three summer seasons is shown as load duration curves in Figure 2-3 below. 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 reveal differences between periods.

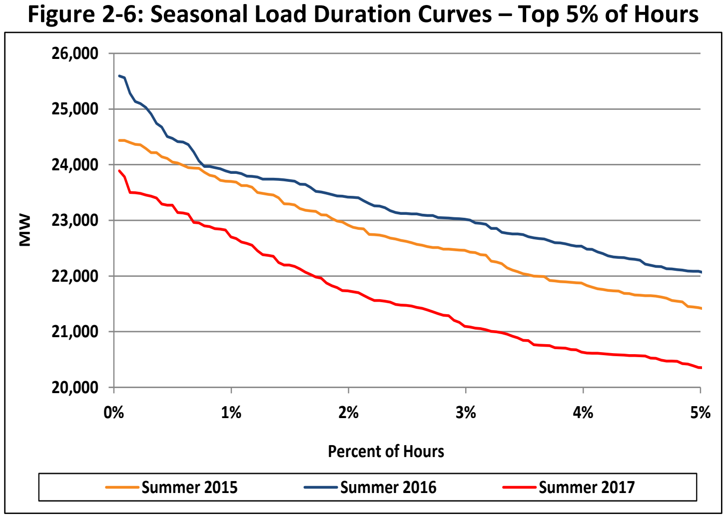
Figure 2-3: Seasonal Load Duration Curves



The load duration curve for Summer 2017 is lower than the curves for Summer 2015 and 2016 for 100% of the hours, indicating there may have been systematic factors affecting load across all the hours in Summer 2017.

The load duration curves for the top 5% of hourly observations for the last three summer seasons are shown in Figure 2-6 in order to reveal how the peak loads have changed. The top 5% of the loads in Summer 2017 were less than the top 5% of loads in Summer 2016 by an average of 1,600 MW. The largest contributing factor of lower peak loads during Summer 2017 was milder weather during Summer 2017;

Figure 2-6: Seasonal Load Duration Curves – Top 5% of Hours



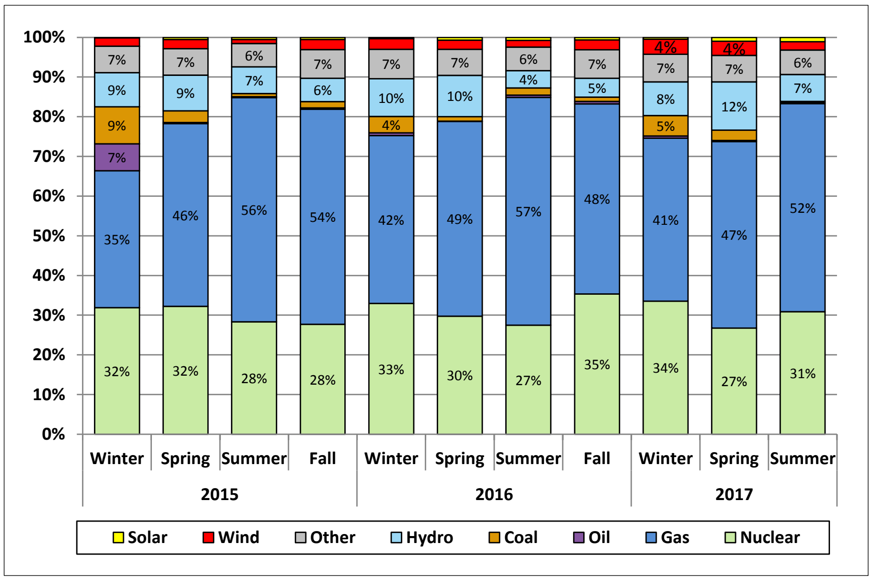
2.3 Supply

This subsection summarizes actual energy production (generation output in megawatt-hours) by fuel type and flows of power between New England and its neighboring control areas.

2.3.1 Native Generation by Fuel Type

The breakdown of actual energy production by fuel provides useful context for the drivers of market outcomes. Actual energy production by generator fuel type for Winter 2015 through Summer 2017 is illustrated in Figure 2-4 below.

Figure 2-4: Share of Native Electricity Generation by Fuel Type



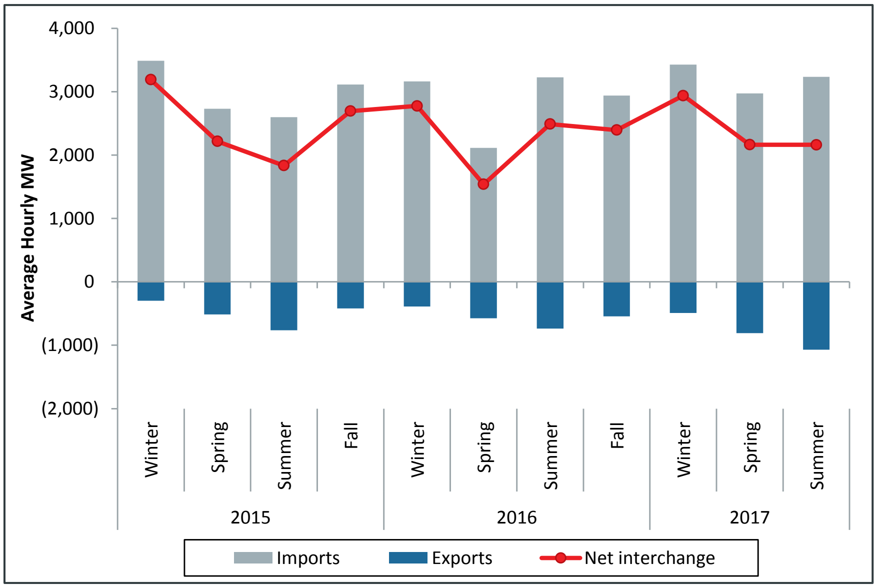
The majority of New England's generation comes from nuclear and gas-fired generation, which together accounted for 83% of total native energy production in Summer 2017. The percentage of generation from natural gas dropped slightly (52% in Summer 2017 from 57% in Summer 2016) mainly due to lower loads in Summer 2017.

Coal-fired generation accounted for 0.3% of native energy production during Summer 2017, significantly less energy compared to the Summer 2016 value of 1.9%. This reduction was driven by the retirement of the Brayton Point generation station in May. Hydro generation accounted for 6.8% of native energy production in Summer 2017, which is higher compared with 4.3% in Summer 2016, and at the same level as Summer 2015. Wind and Solar generation made up 3.2% of native energy production during Summer 2017, an increase from 2.4% in Summer 2016.

2.3.2 Imports and Exports

New England was a net importer of 2,162 MW per hour, on average, during Summer 2017, which was 326 MW, or 13%, less than the average net interchange of 2,488 MW per hour in Summer 2016. The average hourly gross import and export power volumes and the net interchange amount are shown in Figure 2-5 below.

Figure 2-5: Average Hourly Real-Time Imports, Exports, and Net Interchange



Although there is seasonal variation in the overall interchange volumes, the New England area is typically a net importer of power from the neighboring control areas in Canada and New York (red line).[8] Figure 2-5 illustrates that Summer 2017 net interchange volume was slightly lower compared to Summer 2016 and about equal to Spring 2017. A 319 MW average hourly increase in exports over the New York North interface was the primary contributor to the year-over-year decrease in net interchange. Since Summer 2016, participants have increased price-sensitive export bid volumes at the New York North interface, where Coordinated Transaction Scheduling was implemented in December 2015. The increase in price-sensitive bidding has resulted in a higher volume of exports clearing as New York and New England market conditions change during the operating day.

[8] 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, which both 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.

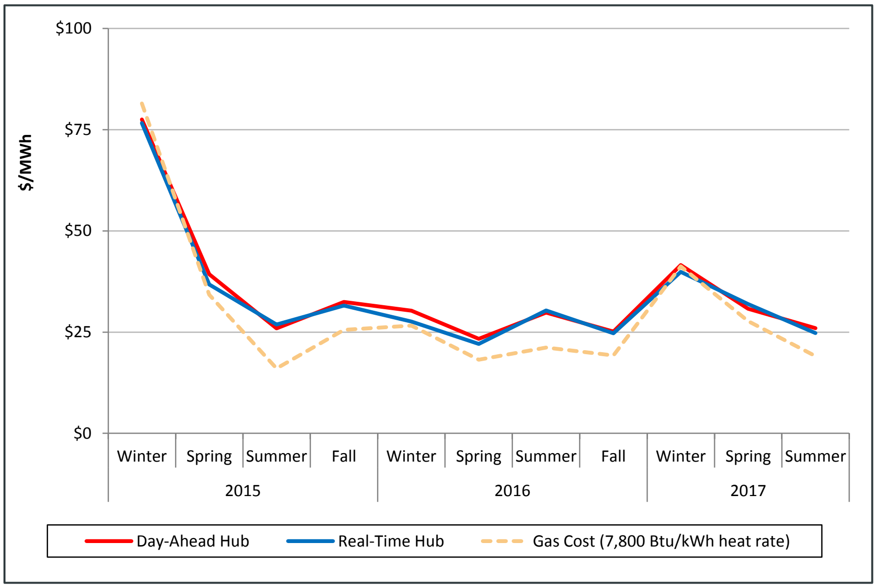
Section 3
Day-Ahead and Real-Time Markets

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

3.1 Energy Prices

The average day-ahead Hub price for Summer 2017 was $26.00/MWh. This was 5%, or $1.22/MWh, higher than the real-time price of $24.78/MWh. Day-ahead and real-time prices, along with the cost of generating electricity using natural gas, 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.

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



Average prices continue to track closely with the cost of natural gas generation. As Figure 3-1 illustrates, the seasonal movements of energy prices (solid lines) are consistent with changes in natural gas generation costs (dashed line). The spread between natural gas and electricity prices tends to be highest during summer months as less efficient generators, or generators burning more expensive fuels than gas, are required to meet the region's higher demand.

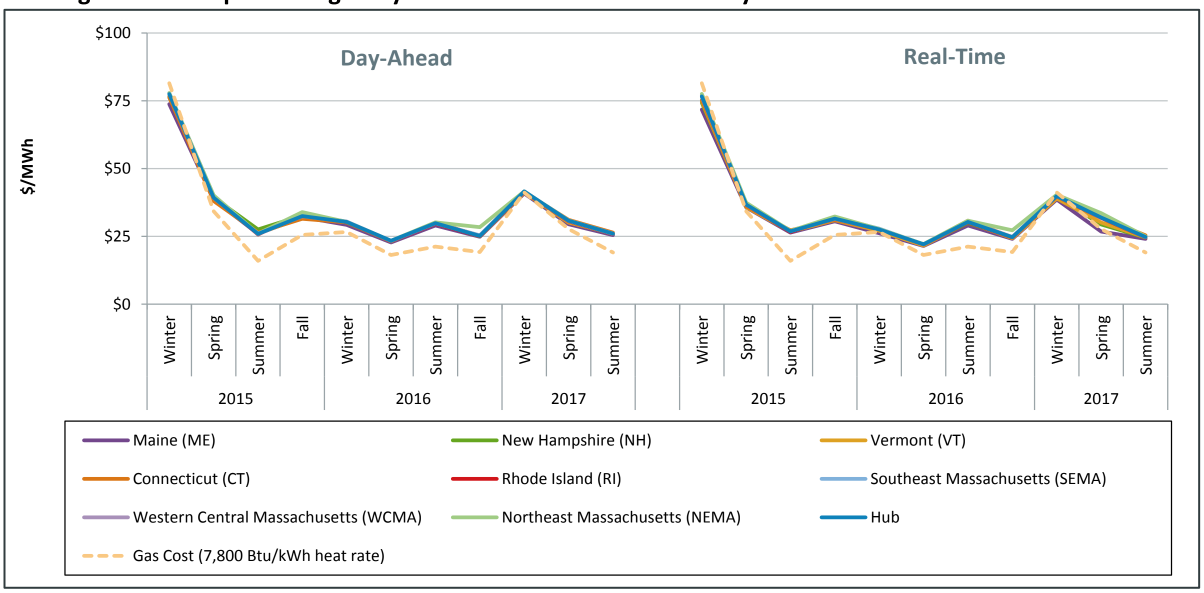
In Summer 2017, the month of June saw the greatest price divergence, with average real-time prices $1.55/MWh less than average day-ahead prices. Lower real-time prices in June were primarily driven by significant negative price spikes that took place over three non-consecutive days. During these periods, additional renewable generation and fixed supply on the system led to depressed real-time prices. Renewable (such as wind and solar) generators do not always offer into the day-ahead market due to their intermittent nature, but they frequently offer low-priced generation into the real-time market. Therefore, large quantities of real-time renewable generation can lead to depressed real-time prices.

The Summer 2017 day-ahead price of $26.00/MWh was lower than the Summer 2016 average of $29.83/MWh (down 13%), and similar to the average Summer 2015 price of $25.94/MWh (up 0.2%). In real-time, the average price of $24.78/MWh represented a decrease of 18% compared to the prior summer average of $30.35/MWh, and by 8% compared to the Summer 2015 price of $26.86/MWh.

In Summer 2017, milder temperatures relative to Summer 2016 resulted in lower natural gas and energy prices. Additionally, there was a period of tight conditions during Summer 2016 that raised energy and reserve prices substantially for two days (on August 11 and 12, 2016). This two-day period impacted overall quarterly real-time prices significantly, increasing the quarterly average price by over $3.50/MWh (or by over 13%). The absence of such an event in Summer 2017 also contributed to lower real-time energy prices relative to Summer 2016. The decrease in energy prices was consistent with the combination of a 10% decrease in natural gas prices and a 7% decrease in load between these periods.

The seasonal average day-ahead energy prices for the Hub and each load zone are shown below in Figure 3-2 along with the estimated cost of gas generation.

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



Day-ahead prices did not differ significantly among the load zones in either market.[9] In the day-ahead market, the Maine average price was $0.54/MWh (2%) lower than the Hub. Price separation in Maine was generally consistent with the price separation observed in real-time, with prices $0.73/MWh (3%) lower than Hub prices.

New Hampshire and Vermont load zone prices were also, on average, lower than the Hub price in real-time by 1%. Renewable-type generation resources with lower marginal costs are located in export-constrained areas of northern New England and frequently set real-time prices in these areas. The discount in energy prices in Maine, Vermont, and New Hampshire was less pronounced than in the previous quarter (Spring 2017). This is because there were fewer instances in which

[9] A *load zone* is an aggregation of pricing nodes within a specific area; there are currently eight load zones in the New England region that correspond to the reliability regions.

line reductions and outages reduced the transmission capability available to export power to the rest of the system.

Real-time energy prices in the Northeast Massachusetts and Boston (NEMA) zone averaged $25.02/MWh during Summer 2017, which was $0.24/MWh (1%) higher than the Hub. This premium in NEMA energy prices for the quarter was almost entirely the result of price separation that occurred on June 13, when high temperatures led to high loads in the area combined with limited transmission import capability. System conditions on this day required using more-expensive NEMA resources to meet the Boston area's load and reserve requirements.

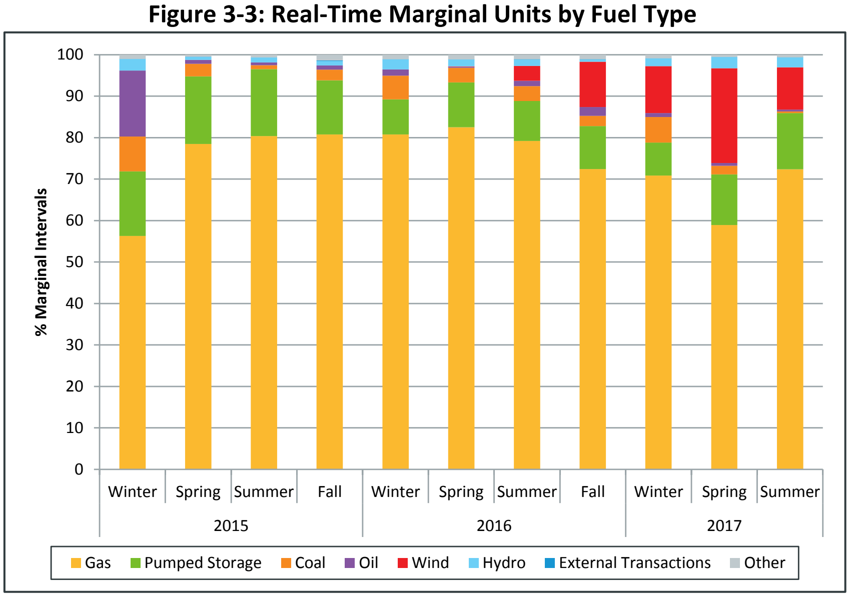
3.2 Marginal Resources and Transactions

The LMP at a pricing location is set by the cost of the next megawatt 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 type of transaction can provide additional insight into day-ahead and real-time pricing outcomes.

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

The percentage of time resources of different fuel types were marginal in the real-time market by season is shown in Figure 3-3 below.[10]

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



Combined, both gas and pumped-storage units set price during about 86% of intervals in Summer 2017. Units burning natural gas were marginal most often, in 72% of the pricing intervals. Over the past year we have observed an increase in the frequency of wind generators being marginal. In

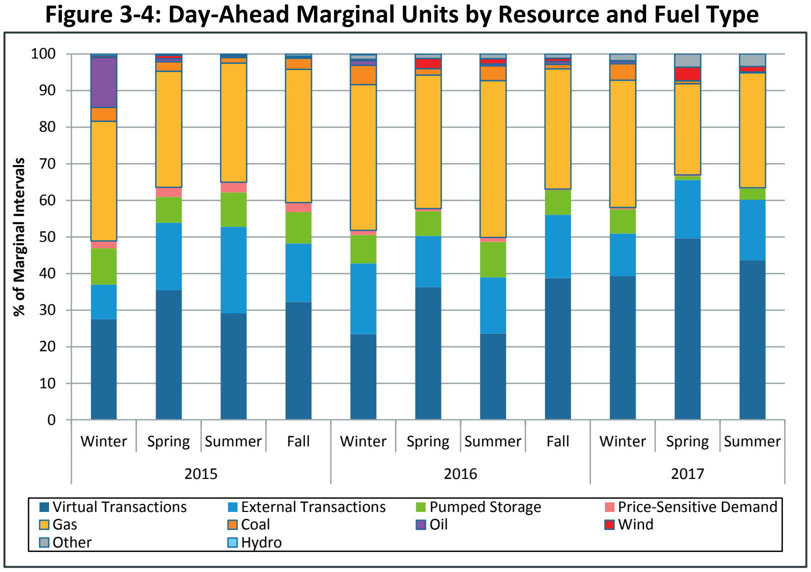
[10] "Other" category contains wood, biomass, black liquor, fuel cells, landfill gas, nuclear, propane, refuse, and solar.

Summer 2017, wind set price in 10% of intervals, down from 23% in Spring 2017, but consistent with Fall 2016 and Winter 2017. The decrease from Spring 2017 was consistent with the reduction in output of wind generators during the summer months and the increase in transmission export capability (resulting in fewer binding constraints) following the completion of the spring outage season. In Spring 2017, wind generation produced an average hourly output of 390 MW, compared with 270 MW in Summer 2017.

The higher frequency of marginal wind units that began in Summer 2016 is driven by the Do Not Exceed (DNE) dispatch rules, which went into effect on May 25, 2016 (at the end of the Spring 2016 reporting period).[11] DNE incorporates wind and hydro intermittent units into unit dispatch, making the units eligible to set price. Previously, these units had to self-schedule their output in the real-time market and, therefore, could not set price. Most of the wind units are located where the transmission system is regularly export-constrained. This means that the wind units frequently set price within their constrained region while another unit(s) set price for the rest of the system. Wind was the single marginal fuel type on the system in roughly 1% of all five-minute intervals.[12] By contrast, gas was the single marginal fuel type in about 62% of intervals.

The percentage of time that each resource, or transaction, type set price in the day-ahead market since Winter 2015 is illustrated in Figure 3-4 below. Marginal units are shown by category, and generators are outlined in blue and broken up by fuel type further within the generator category.

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



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[11] *ISO New England Inc. and New England Power Pool*, Do Not Exceed ("DNE") Dispatch Changes, ER15-1509-000 (filed April 15, 2015); Order Conditionally Accepting, In Part and Rejecting, In Part, Tariff Revisions and Directing Compliance Filing, 152 FERC ¶ 61,065 (2015). In a subsequent filing, the Filing Parties modified the DNE Dispatch changes to remove the exclusion of DNE Dispatchable Generators from the regulation and reserves markets, to comply with the Commission's order on the original rule changes. The Commission accepted the ISO's compliance filing in a subsequent order. *ISO New England Inc. and New England Power Pool*, Compliance Filing Concerning DNE Dispatch Changes, ER15-1509-002 (filed August 21, 2015); Letter Order Accepting DNE Dispatch Compliance Filing, ER15-1509-002 (issued October 1, 2015.

[12] When the transmission system is unconstrained there will be at least one marginal unit. When it is constrained, there will be more than one. As a suitable example in this case, if a transmission line is at capacity in a local area of the system and limits the ability to export wind generation from that area, price could be set for a small number of pricing nodes behind that constraint by a wind generator. The price at all other nodes on the system would be set by another generator, which is frequently a thermal generator.

The frequency of marginal units by resource (or transaction) type during the reporting period was within a normal range based on historical observations and relatively recent trends. A large increase in marginal virtual supply offers appeared in Fall 2016, and persisted into Summer 2017. Virtual transactions (virtual supply and demand) set price approximately 44% of the time, which represents an increase from 24% in Summer 2016. This increase is due to a higher frequency of virtual supply offers being marginal in export-constrained areas.

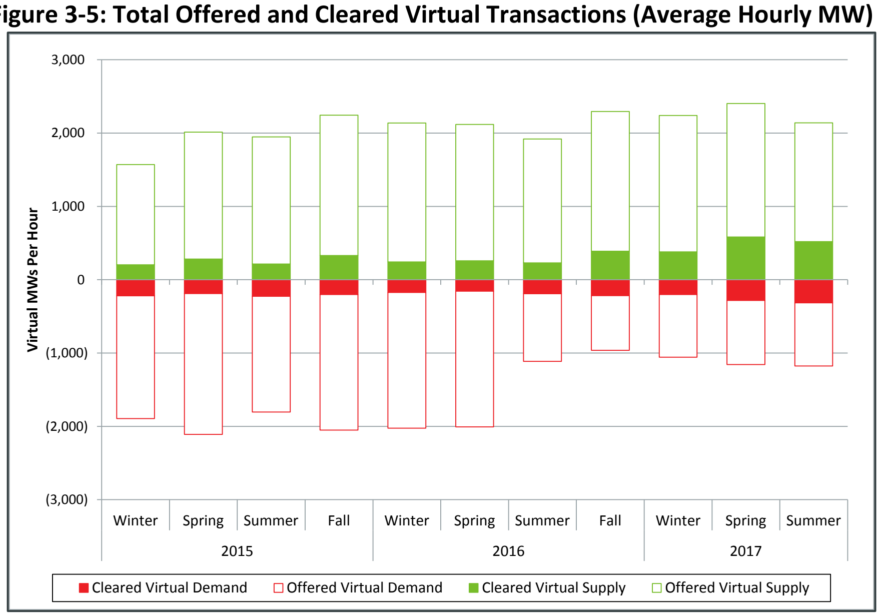
Wind generators tend to clear lower volumes in the day-ahead compared to real-time, thereby putting downward pressure on real-time prices. In the absence of virtual supply, day-ahead prices would be higher in these export-constrained areas. Virtual supply tends to take the place of wind generation in the day-ahead market and helps converge prices with the real-time market. In most of these intervals, virtual supply offers were not the only marginal transaction on the system. They only set price for the whole system in 9% of hours in Summer 2017.

Aside from virtual transactions, generators set price approximately 40% of the time, and external transactions set price approximately 17% of the time.

3.3 Virtual Transactions

Virtual transaction volumes from Winter 2015 through Summer 2017 are shown in Figure 3-5 below.

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



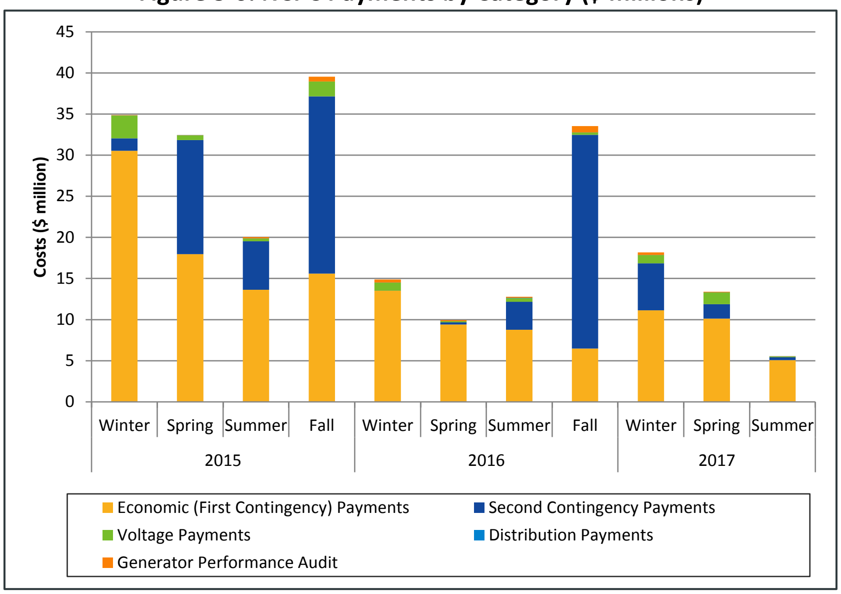
In Summer 2017, submitted virtual demand bids and virtual supply offers averaged 3,316 MW per hour, a 7% decrease from Spring 2017, and a 9% increase from Summer 2016. Total volumes of cleared virtual transactions decreased by 3% from Spring 2017 to Summer 2017, but nearly doubled compared to Summer 2016.

Beginning in Summer 2016, the average offer prices of virtual transactions have converged towards actual LMPs, resulting in higher percentages of virtual transactions clearing. A reduction in transaction costs, in the form of reduced NCPC costs that are charged in part to virtual transactions, has likely contributed to this offer behavior. In February 2016, real-time economic NCPC payments made to generators receiving a day-ahead commitment were eliminated, reducing the total pool of real-time economic NCPC paid.[13] In Winter 2016, the average RT NCPC charge was $2.81/MW. This value declined substantially, reaching an average charge of $0.44/MW in Summer 2017.

3.4 Net Commitment Period Compensation

Net Commitment Period Compensation (NCPC) is a method of providing a make-whole payment to resources when energy market payments are insufficient to cover production costs. Resources committed and dispatched economically (in-merit), as well as resources dispatched out of economic-merit order for reliability purposes, may require uplift payments. NCPC is paid to resources for providing a number of services, including first- and second-contingency protection, voltage support, distribution system protection, and for generator performance auditing.[14] NCPC payments by season and category are illustrated in **Error! Reference source not found.**.

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



As illustrated in Figure 3-6, NCPC payments in Summer 2017 were at the lowest level since 2015. Payments totaled $5.5 million, representing about 0.6% of total wholesale energy costs for the season, down from Summer 2016 (1.1%). In dollar terms, this is a 57% decrease (or $7.3 million) compared to the same season last year, and 59% less (or $7.9 million) than last quarter. As discussed in Section 5, the fast-start pricing rule changes had an expected downward impact on NCPC during Summer 2017. It is estimated that the rule changes reduced real-time economic NCPC by as much as $3 million.

[13] Real-time economic NCPC is charged to deviations from the day-ahead schedule, including virtual transactions. More about NCPC can be found in Section 3.3.

[14] 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*.

Nearly three quarters (72%) of the total NCPC paid in Summer 2017 was in the real-time market, while the other 28% originated from the day-ahead market. The majority of NCPC (92%) was for first contingency protection (or economic NCPC).[15] First contingency payments of $5.1 million were 42% lower than payments made last summer and 50% lower than payments made in Spring 2017.

Of the total first contingency payments in the reporting period, $0.89 million (18%) was paid during a four-day period between June 11 and June 14, when the highest peak loads observed to date in 2017 led to tight system conditions. On each day in this period, fast-start resources were required to help meet the heightened demand, resulting in close to $90 thousand of Rapid-Response-Pricing Opportunity Cost (RRPOC) NCPC over this time. RRPOC NCPC is paid to resources that are postured down when a rapid-response resource is setting price. Additionally, many of the fast-start units that were called upon during this four-day period didn't recover their full costs through the LMP and were subsequently paid NCPC. On June 14, several pumped-storage hydro units were also postured to conserve their limited fuel supply in order to help maintain system reliability.

Payments for second contingency protection totaled about $0.3 million between June 11 and June 14, when system conditions necessitated reliability commitments in local areas. The second contingency payments made in these four days accounted for 89% of total second contingency payments made in the reporting period. LSCPR NCPC payments in Summer 2017 reflect a 90% decrease from their Summer 2016 level ($3.4 million) and a 94% decrease from their Summer 2015 level ($5.9 million). In Summer 2015, resources were required for second contingency protection in New Hampshire and Southeast Massachusetts that weren't required in Summer 2016 and Summer 2017. Additionally, LSCPR payments to resources in NEMA Boston have fallen from $5.4 million in Summer 2015 to $3.4 million in Summer 2016 to $0.3 million in Summer 2017.

Lastly, voltage payments in the quarter totaled only $0.09 million. This was a significant decrease compared to $0.4 million last summer and $1.4 million last quarter. The decrease in payments was mainly associated with fewer outages that required specific generator commitments for voltage support.

3.5 Real-Time Operating Reserves

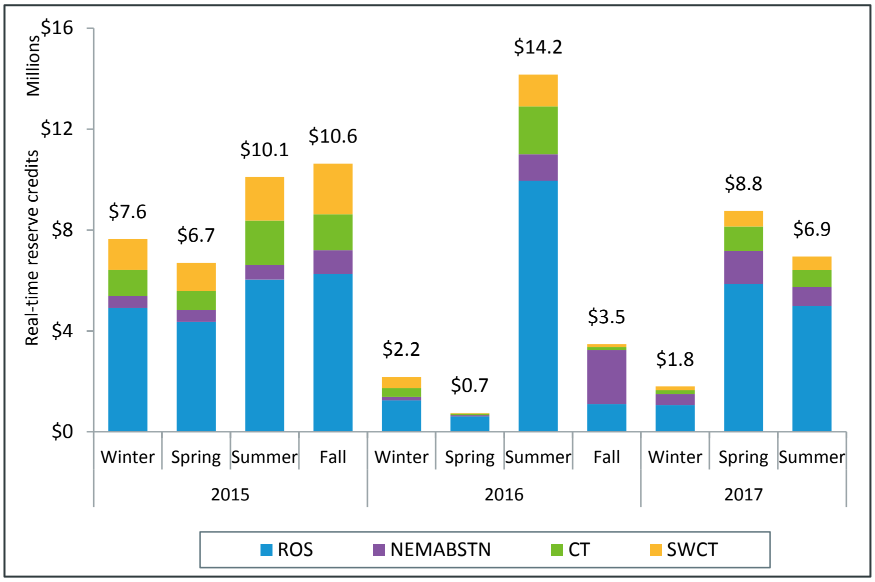
Real-time reserve payments for Summer 2017 totaled $6.9 million, which was a large decrease relative to the Summer 2016 total of $14.2 million and the Summer 2015 total of $10.1 million.

Total real-time reserve payments, by reserve zone, from Winter 2015 through Summer 2017 are plotted in Figure 3-7 below. Note that these figures are intended to show the value of real-time reserves and therefore are the gross real-time credits for providing reserve products at the

[15] First Contingency payments include real-time dispatch lost opportunity cost NCPC and rapid response pricing NCPC beginning in Spring 2017. Dispatch Lost-Opportunity Cost (DLOC) is an NCPC credit calculated for a resource instructed by the ISO to run at a level less than its economic dispatch point. DLOC compensates the resource for the difference between the maximum net revenue it could have earned at its economic dispatch point and the actual net revenue earned at the dispatch instruction point. Rapid-Response-Pricing Opportunity Cost (RRPOC) is an NCPC credit calculated for a resource that is postured down when a rapid-response resource is setting price. RRPOC compensates the resource for the difference between the amount it would have earned for energy and reserves absent being postured down and the amount that it actually earned for energy and reserves in the interval. Both of these credits were implemented on March 1, 2017 with fast-start pricing rule changes. (https://www.iso-ne.com/participate/support/faq/ncpc-rmr).

respective real-time clearing price. The netting of real-time payments for a participant's forward reserve market obligations is not accounted for in the chart totals. For reference, the total reductions for forward reserve obligations amounted to $1.1 million during Summer 2017, which resulted in total net real-time payments of $5.9 million.

Figure 3-7: Real-Time Reserve Payments by Zone ($ million)



As shown in Figure 3-7, total real-time reserve payments were lower in Summer 2017 than in the preceding two Summer periods. The distribution of payments among the reserve zones reflects that the majority of reserve pricing occurred for system requirements over this quarter.

The frequency of non-zero reserve pricing by zone along with the average price during these intervals over the past three summer periods are shown in Table 3-1 below.[16]

Table 3-1: Hours and Level of Non-Zero Reserve Pricing[17]

Product	Zone	Summer 2015		Summer 2016		Summer 2017	
		Avg. Price $/MWh	*Hours of Pricing*	*Avg. Price $/MWh*	*Hours of Pricing*	*Avg. Price $/MWh*	*Hours of Pricing*
TMSR	System	$43.33	92.2	$68.75	89.0	$13.70	375.8
TMNSR	System	$31.62	0.7	$54.74	1.5	$2.35	2.2
TMOR	System	$31.59	20.1	$50.46	18.8	$2.19	8.5
	NEMA/Boston	$31.97	0.2	$53.61	6.3	$3.88	11.7
	CT	$31.59	0.0	$50.46	0.0	$2.19	0.0
	SWCT	$31.59	0.0	$50.46	0.0	$2.19	0.0

During the Summer 2017 period, the overall ten-minute operating reserve margin (reserves in excess of the requirement) was down compared to the two previous summers, which is consistent with the increased frequency of ten-minute reserve pricing. Though the frequency of ten-minute

[16] Non-zero reserve pricing means that there was 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.

[17] The CT and SWCT load zones have positive average TMOR prices but 0 hours of pricing. This is because the TMOR price for CT and SWCT is equal to the System TMOR price even when reserve zone pricing is not in effect.

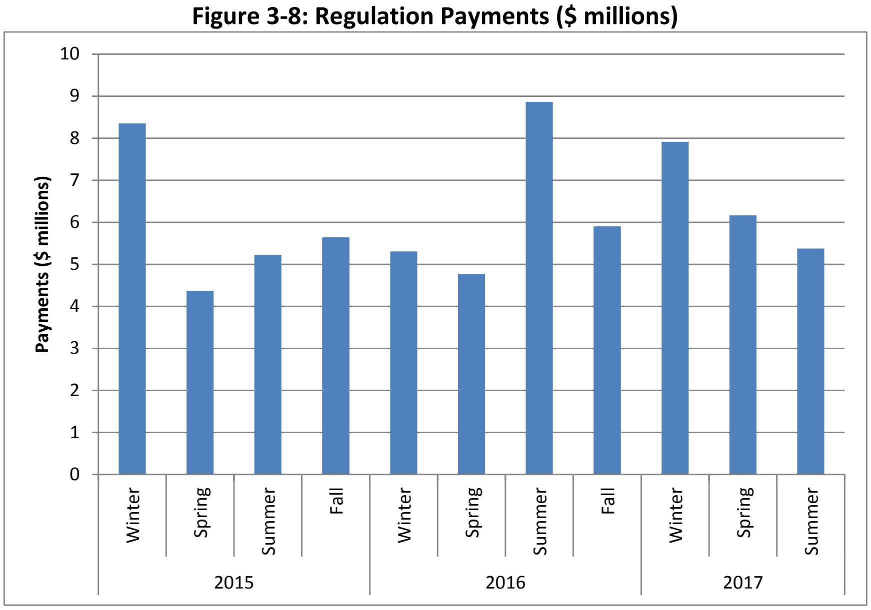
spinning reserve pricing was much higher, the average reserve price was significantly down. This trend reflects a lower opportunity cost of holding back generators to provide reserves rather than energy. As shown in Table 3-1, there were about 376 hours of system ten-minute spinning reserve pricing during Summer 2017. During these hours, there were 11.3 hours of reserve deficiency, whereby reserve prices were capped at the corresponding reserve constrained penalty factor (RCPF) of $50/MWh.[18]

The thirty-minute operating reserve margin was also lower in Summer 2017 compared to the previous summer. Despite this decrease, thirty-minute reserve frequency and pricing were both lower. In Summer 2017, system thirty-minute operating reserve pricing occurred for a total of 8.5 hours, and the replacement thirty-minute operating reserve RCPF was triggered for only 10 minutes. Thirty-minute reserve frequency and pricing were much higher in Summer 2016 due to a system event that took place over two days. There were 8.9 hours of thirty-minute reserve pricing during this two-day period. No comparable event occurred in Summer 2017.

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 capacity to match supply and demand (and to regulate frequency) over short time intervals. Quarterly regulation payments are shown in Figure 3-8 below.[19]

Figure 3-8: Regulation Payments ($ millions)



Total regulation market payments were $5.4 million during the reporting period, down 13% from $6.2 million in Spring 2017, and down 39% from $8.9 million in Summer 2016. Summer regulation

[18] The reserve constraint penalty factors are limits on the re-dispatch costs the system will incur to satisfy reserve constraints and will function as the reserve clearing price during a reserve deficiency. The penalty factors for the respective reserve products and their application are defined in Market Rule 1 Section III.2.7.A.

[19] 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.

payments declined relative to the earlier periods for several reasons. Reduced natural gas and real-time energy market prices led to lower regulation offer prices (primarily to the opportunity cost adder) and regulation market clearing prices, compared to the earlier periods. Additionally, for the summer periods, reduced manual regulation commitments by the ISO combined with lower regulation clearing prices during manual commitment periods resulted in a $1.5 million decrease in Summer 2017 payments compared to Summer 2016 payments.

Section 4
Forward Markets

This section of the report covers activity in markets in which transactions occur well in advance of the actual operating day, or delivery period. It also covers activity during the reporting period in the forward capacity market (FCM), the forward reserve market (FCM) and financial transmissions rights (FTRs).

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.[20] 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.[21] Between the initial auction and the commitment period, there are six discrete opportunities to adjust annual capacity supply obligations (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 capacity obligations. Trading in monthly auctions adjusts the CSO position for a particular month, not the whole commitment period. The following sections summarize FCM activities during the reporting period, including total payments and trading of CSOs specific to each commitment period.

The current capacity commitment period (CCP) started on June 1, 2017 and ends on May 31, 2018. In the corresponding forward capacity auction (FCA 8), generator retirements resulted in a system-wide capacity deficiency of 143 MW. Administrative pricing rules were triggered due to the shortfall, resulting in a price of $7.03/kW-month for existing (non-NEMA/Boston) resources and a price of $15.00/kW-month for all new resources. Existing resources in NEMA/Boston were also paid $15.00/kW-month due to administrative rules.[22]

Total FCM payments as well as the existing clearing price for Winter 2015 through Summer 2017 are shown in Figure 4.1 below. The black lines (corresponding to the right axis, "RA") represent the

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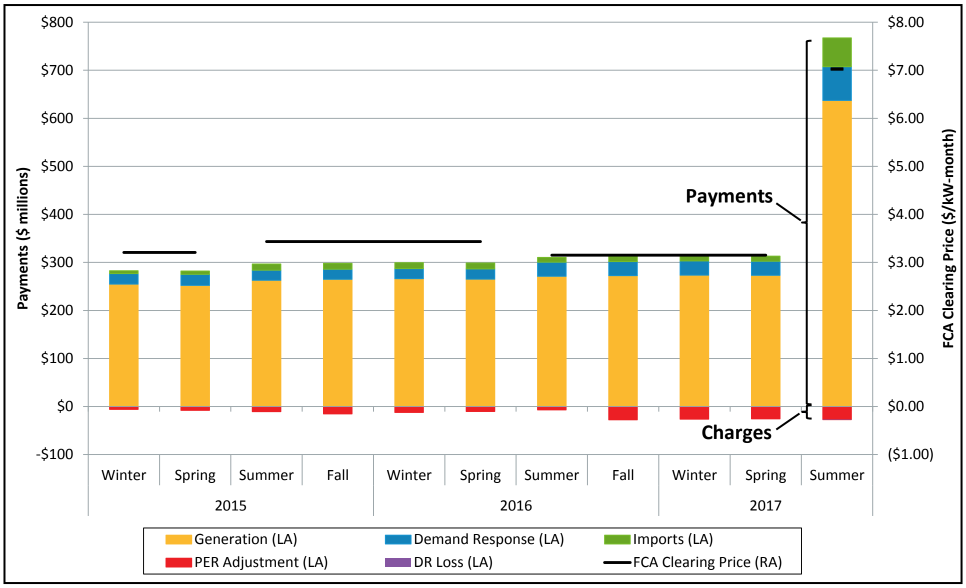
[20] In the capacity market, resource categories include generation, demand response and imports.

[21] 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.

[22] The specific rule is the "capacity carry forward" rule. See pages 11-15 of the FCA 8 filing with FERC: https://www.iso-ne.com/static-assets/documents/regulatory/ferc/filings/2014/feb/er14_1409_000_fca8_results_filing_2_28_2014.pdf

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.

Figure 4-1: Capacity Payments ($ millions)



Total net FCM payments increased significantly from prior quarters. In Summer 2017, capacity payments totaled $740 million, which accounts for adjustments to primary auction CSOs.[23] This was the first auction where no new or existing capacity cleared at the floor price. Existing resource payment rates outside of NEMA/Boston increased 123%, from $3.15/kW-month payments to $7.03/kW-month. The proportion of payments shifted away from generation resources towards import resources. The shift is primarily due to the large amount of generator retirements.[24]

The negative red bar represents the reduction in payments due to Peak Energy Rent (PER) adjustments. Peak energy rent adjustments remained higher than in previous seasons because of high real-time energy prices that occurred in August 2016.[25] PER adjustments totaled $27 million in Summer 2017.

Secondary auctions allow participants the opportunity to buy or sell capacity after the initial auction.

Table 4-1 provides a summary of prices and volumes associated with reconfiguration auction and bilateral trading activity during Summer 2017, alongside the results of the relevant primary Forward Capacity Auction (FCA).

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[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.

[24] See the 2016 Annual Markets Report, Section 2.2.2 for more information. https://www.iso-ne.com/static-assets/documents/2017/05/annual_markets_report_2016.pdf

[25] To read more about the effect of Peak Energy Rent Adjustments on capacity payments, see the IMM's Summer 2016 Quarterly Markets Report: https://www.iso-ne.com/static-assets/documents/2016/11/qmr_2016_q3_summer_11_15_2016.pdf .

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

					Capacity Zone/Interface Prices (if different from systemwide price)			
FCA # (Commitment Period)	**Auction Type**	**Period**	**Systemwide Price ($/kW-mo)****	**Cleared MW**	**NEMA/Bos**	**SEMA/RI**	**New Brunswick**	**New York AC Ties**
FCA 8 (2017-18)	Primary	12-mo	15/7.03*	33,712	15/15*			
	Monthly Reconfiguration	Aug-17	4.4	618				
	Monthly Bilateral	Aug-17	5.50	118				
	Monthly Reconfiguration	Sep-17	3.52	644			3.15	3.21
	Monthly Bilateral	Sep-17	5.73	111				
	Monthly Reconfiguration	Oct-17	3.53	641				
	Monthly Bilateral	Oct-17	4.20	272				
FCA 9 (2018-2019)	Primary	12-mo	9.55	34,695		17.73/11.08	3.94	7.97
	Annual Bilateral (2)	12-mo	5.59	28				
	Annual Reconfiguration (2)	12-mo	5.32	416/169***				4.75
FCA 10 (2019-2020)	Primary	12-mo	7.03	35,567			4.00	6.26
	Annual Reconfiguration (1)	12-mo	5.87	338/646***				4.13

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

***prices represent volume weighted average prices for bilaterals*

***cleared supply/cleared demand

The following two sub-sections provide further detail on the outcomes of the secondary auctions during the reporting period.

Monthly Periods

Monthly reconfiguration prices for monthly CCP 8 (2017-2018) periods decreased from June through September, while cleared demand increased. Total offered supply increased from 544 MW in June to 820 MW in October. Cheaper supply offers lowered clearing prices, while increasing total cleared volumes.

There were also three bilateral periods for August, September, and October during the quarter. The bilateral periods for August and September had similar results to the first two months of the summer period in CCP 8. On average, during the summer capacity commitment period, demand response and import resources netted 8 MW and 52 MW of capacity, respectively; generation resources averaged a net negative position of 60 MW.[26] There was a shift in the first winter month of the commitment period. Demand response and import resources had net negative positions of 22 MW and 92 MW. Meanwhile, generation resources acquired 113 MW of capacity. Additionally the total amount of capacity transferred increased from an average of 115 since the June bilateral to 272 MW in October.

[26] The summer capacity commitment period consists of June through September. This differs from the summer reporting period definition of June through August typically used in this report.

Annual Periods

The second annual bilateral period and annual reconfiguration auction for CCP 9 (2018-2019) took place during Summer 2017. Like other recent annual bilateral periods, there was a small amount of CSO transferred. The second annual reconfiguration auction (ARA) for 2018-2019 utilized the sloped system demand curve in addition to participant demand bids and supply offers. The sloped demand curve allows cleared supply to differ from cleared demand. If there is an abundance of inexpensive supply, the auction can clear more supply than demand. Conversely, if participants offer high demand bids, more demand can clear than supply.

The second ARA for 2018-2019 cleared 420 MW of supply offers and 170 MW of demand bids at a price of at $5.32/kW-month. This was well below the rest-of-pool price of $9.55/kW-month in FCA 9.[27] The first driver of lower prices was the inward shift in the demand curve from the FCA and ARA 1.[28] Second, there was an influx of low-priced supply offers. Load will pay for the additional 250 MW of supply obligations, which were purchased based off cleared portions of the sloped demand curve.

The first annual reconfiguration auction for CCP 10 (2019-2020) also took place during the summer. As was the case in CCP 9, the ISO revised the sloped system demand curve downward due to changes in system conditions. The auction cleared 338 MW of supply and 646 MW of demand at $5.87/kW-month.[29] This was the first reconfiguration auction where cleared demand exceeded cleared supply. The primary driver was increased volumes of demand bids above $7.00/kW-month. In ARA 1 for CCP 10, there were 570 MW of demand bids above $7.00/kW-month. For comparison, ARA 1 in CCP 9 had 90 MW of similar bids, while ARA 2 only had 60 MW.

4.2 Forward Reserve Market Auction for Winter 2017-18

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 control area and local reserve zones within the control area. During August 2017, ISO New England held the forward reserve auction for the Winter 2017-18 delivery period (i.e., October 1st, 2017 to May 31st, 2018).[30]

4.2.1 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, based on possible control area and local reserve zone contingencies (unexpected events such as the forced outage of a large generator or loss of a large transmission line).

[27] In ARA 2, the New York AC ties cleared at $4.75/kW-month. In the FCA, the Southeast Massachusetts/Rhode Island capacity zone cleared at $17.73/kW-month for new resources and $11.08/kW-month for existing resources.

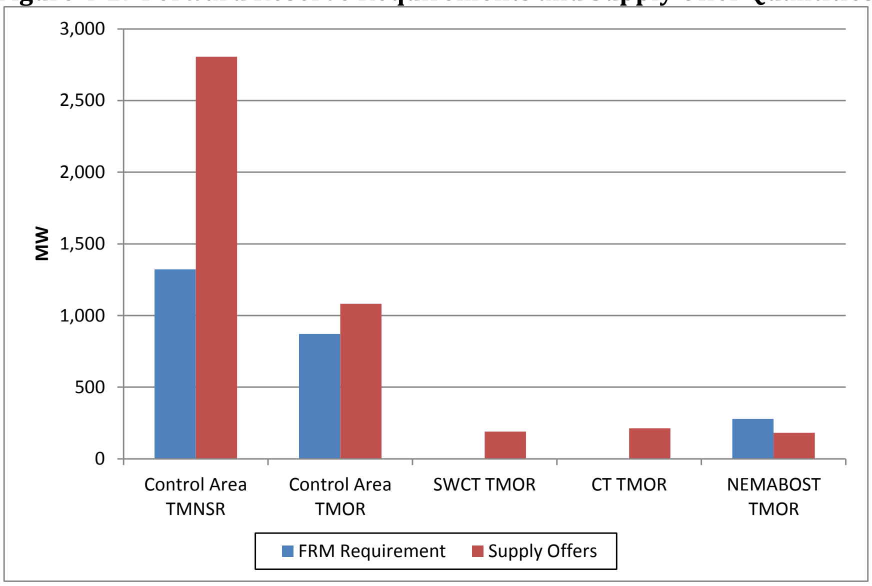
[28] The demand curve is designed to procure sufficient capacity to maintain resource adequacy and reduce price volatility over time. The demand curve used in ARA 2 was revised downward from the curves used in the FCA and ARA 1 to reflect changes in system conditions.

[29] There was price separation at the New York AC ties due to interface limits.

[30] The Forward Reserve Market has 2 delivery ("procurement") periods per year: Summer (June 1 to September 30) and Winter (October 1 to May 31).

Figure 4-2 below indicates the requirements for the Winter 2017-18 auction. These requirements were specified for the ISO New England control area and three local reserve zones.[31] The figure also indicates the total quantity of supply offers available in the auction to satisfy the reserve needs.[32]

Figure 4-2: Forward Reserve Requirements and Supply Offer Quantities



For the control area, 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 1,323 MW TMNSR reserve need. The control area TMOR requirement was based on the expected single contingency of the Mystic 8 and 9 generators, and was estimated as an 872 MW TMOR need.[33]

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 also can effectively supply reserves to the local area).[34] After adjustments, the Connecticut and Southwest Connecticut reserve zones were found to need no local reserve requirement, as "external reserve support" (available transmission capacity) exceeded the local second contingency requirements; the NEMA/Boston reserve zone, however, needed 279 MW of local reserves, after adjustments.

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

[32] Because TMOR supply offers within local reserve zones also provide TMOR to the Control Area, the Control Area TMOR offers shown in the figure include the local reserve zone supply offers. Hence, the Control Area TMOR offers represent the total offers throughout the Control Area.

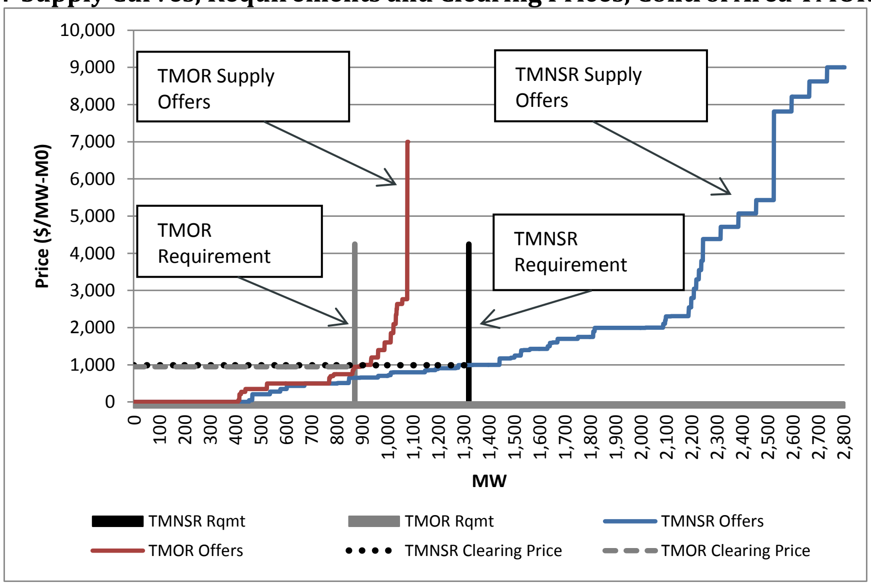
[33] ISO New England Memorandum to Market Participants (Subject: Assumptions and Other Information for the Winter 2017-2018 Forward Reserve Auction), published July 21, 2017, indicates the control area and local reserve zone requirements.

[34] 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."

4.2.2 Supply and Auction Pricing

As noted previously, control area supply offers in the Winter 2017-18 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 4-3 provides the control area supply curves for both TMNSR and TMOR, and indicates the auction clearing prices for each, given the reserve requirements.

Figure 4-3: Supply Curves, Requirements and Clearing Prices, Control Area TMOR & TMNSR

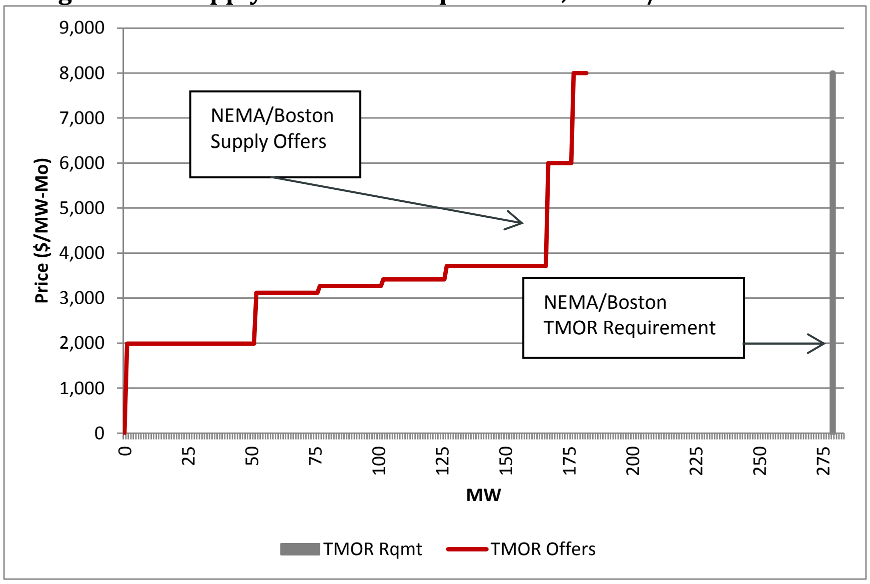


With a control area requirement of 872 MW, TMOR control area supply offers resulted in a clearing price of $949/MW-month (gray dashed line in the figure).[35] TMNSR supply offers led to pricing of $990/MW-month (black dashed line in the figure), given the reserve requirement of 1,323 MW. These clearing prices are lower than the Winter 2016-17 auction clearing prices for the control area TMOR and TMNSR reserve products, which were $1,420/MW-month for each product.

For the local areas, only NEMA/Boston required the procurement of additional reserves. The supply curve for the NEMA/Boston reserve zone in the Winter 2017-18 auction, relative to the local reserve requirement is shown in Figure 4-4 below. As indicated in the figure, the offered TMOR supply was inadequate to satisfy the local reserve requirement.

[35] Because local reserve zone TMOR supply can be used to satisfy the control area requirement, local TMOR supply that was cleared to satisfy local TMOR requirements is shown as unpriced (at $0/MW-month) supply on the control area supply curve. This results from local TMOR supply being needed irrespective of the control area's reserve requirement and clearing price. The same result could be produced by using an adjusted "rest of system" requirement and supply curve that excluded the procurement of supply in local reserve zones.

Figure 4-4: Supply Curve and Requirement, NEMA/Boston TMOR



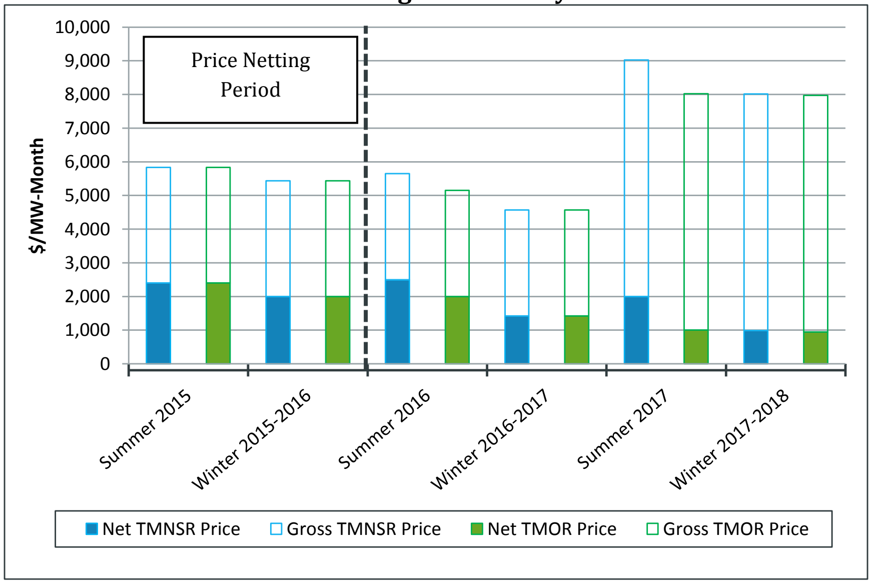
Because of inadequate supply, the TMOR price for NEMA/Boston was set to the auction's offer price cap of $9,000/MW-month.[36] Since the NEMA/Boston area did not require local reserves for the year-earlier Winter 2016-17 period, the reserve zone had a TMOR price last winter equal to the control area price of $1,420/MW-month.

4.2.3 Price Summary

The gross and net forward reserve prices for system-wide TMNSR and TMOR are shown in Figure 4-5 below; for periods prior to Summer 2016, FRM auction prices were netted against Forward Capacity Market clearing prices, and the net price represents the FRM auction income for participants. Beginning with Summer 2016, FRM auction prices are no longer netted. In the figure, the gross price indicates the FRM auction income plus the FCA price (both stated as $/MW-month values), while the net price shows the FRM-only income. The net price provides the effective TMNSR and TMOR compensation rates for FRM system-wide resources for all periods in the graph. The gross price represents the FRM auction clearing price for 2015 and earlier periods. The net price represents the auction clearing price for later auctions.

[36] ISO New England's Market Rule 1 specifies: "If there is insufficient supply to meet the Forward Reserve requirements for a Reserve Zone, the Forward Reserve Clearing Price for that Reserve Zone will be set to the Forward Reserve Offer Cap."

Figure 4-5: Gross and Net FRM Clearing Prices for System-Wide TMNSR and TMOR



Over the review period, TMOR auction income has consistently declined at the system-wide level. TMNSR auction income has maintained more consistent pricing, except for a reduction in the Winter 2017-18 period.

4.2.4 Structural Competitiveness

The competitiveness of the FRM can be measured by the Residual Supply Index (RSI). RSI measures the extent to which an individual participant has market power and controls enough supply to be able to increase price above a competitive level. In other words, the RSI measures the percentage of the forward reserve requirement that can be met without the largest 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 control area (or 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 the TMNSR quantity also satisfies the TMOR requirement, the TMNSR offer quantity in a zone is included in the total TMOR offer quantity within that zone.

The heat map table – Figure 4-6 below - shows the offer RSI for TMNSR for the control area 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 4-6: Offer RSI in the FRM for TMNSR (system-wide) and TMOR (zones)

Procurement Period	Offer RSI TMNSR (System-wide)	Offer RSI TMOR (ROS)	Offer RSI TMOR (SWCT)	Offer RSI TMOR (CT)	Offer RSI TMOR (NEMA)
Summer 2015	117	158	69	122	12
Winter 2015-16	109	154	283	382	N/A
Summer 2016	203	222	76	N/A	23
Winter 2016-17	313	308	302	N/A	N/ A
Summer 2017	240	278	183	N/A	21
Winter 2017-18	285	292	N/A	N/A	24

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 the significant variation in the reserve requirement. For instance, for the SWCT zone the TMOR RSI value jumped from 76 (structurally uncompetitive levels) in Summer 2016 auction to 302 (structurally competitive level) in Winter 2016-17 period. For the same zone and time period, the TMOR local requirement went down from 250 MW to 32 MW. More suppliers were competing to fill a lower requirement.

From the Summer 2016 through the Winter 2017-18 procurement periods, the TMNSR RSI values were significantly greater than 100; earlier period values were competitive, but closer to the competitiveness threshold. These higher values suggest that the TMNSR offer quantities in these auctions were consistent with a structurally competitive level.

Similarly, the TMOR RSI values for the Rest-of-System (ROS) zone were consistent with a structurally competitive level.[37] The Southwest Connecticut (SWCT) zone was structurally competitive for the Winter 2015-16, Winter 2016-17 and Summer 2017 periods, but the offer RSI value was below a structurally competitive level for the Summer 2015 and Summer 2016 periods. Connecticut did not have any auctions that were below the structurally competitive level. The RSI value for NEMA/Boston was significantly below a competitive level for each of the three Summer periods and the Winter 2017-18 period. Every participant who offered forward reserves in NEMA/Boston was pivotal in those auctions because the total offered quantity was significantly below the local requirement.

4.3 Financial Transmission Rights

Three Financial Transmission Rights (FTR) auctions were conducted during the reporting period for a combined total of 89,289 MW of FTR transactions. The total amount distributed as Auction Revenue Rights (ARRs) was $2.3 million, which was a similar amount to the previous reporting period. Thirty bidders in June, twenty-nine bidders in July and twenty-seven bidders in August participated in the monthly auctions for the quarter. The level of participation was consistent with recent auctions.

[37] The "rest-of-system" zone is simply the portion of the control area that excludes the local reserve zones (CT, SWCT, and NEMABOST).

Section 5
Fast Start Pricing

Fast-start pricing is intended to improve price formation and performance incentives in the real-time energy market.[38] The rules use two broad methods to accomplish this. First, the rules redefine the concept of marginal cost for fast-start generators by combining both energy and commitment offers into an effective final offer. Second, the rules increase the ability of fast-start generators to set price by relaxing certain operational constraints. The intended impact is to produce a price more reflective of the short-run production costs of fast-start resources, to improve market transparency and signals, and to reduce the reliance on uplift payments to ensure cost recovery.

Approved by the Federal Energy Regulatory Commission (FERC) in October 2015, the market rules changes went into effect on March 1, 2017.[39, 40] This section of the report covers our assessment of how the new rules are performing since their implementation, and includes an estimate of the energy market impacts.

This analysis assesses market results since implementation through to the end of October 2017. The results indicate that fast-start pricing is working as intended: the real-time price (LMP) has better reflected the costs of committing fast-start resources.[41] The key observations of fast-start pricing are as follows:

- *Real-time energy prices have more effectively reflected fast-start resource commitment costs*

  Prices have been higher during intervals when fast-start generators have been committed, allowing them to recover their production costs through the LMP in more instances. Overall, fast-start pricing has led to an estimated increase of $2.72/MWh in the average system LMP, an increase of 11%. Conversely, for pumped-storage demand, which can reduce LMPs by consuming energy as a dispatchable fast-start resource, there were fewer intervals in which prices exceeded the resources' willingness to pay. As a result, both real-time generation and demand have stronger incentives to follow commitment instructions.

- *Uplift payments have decreased*

  The number of fast-start commitments requiring uplift payments declined for both generation and pumped-storage demand, decreasing from 27% to 18% of commitments. The amount of NCPC paid over the study period also decreased by $10.6 million, or by 58%. The decrease more than outweighed the $1.9 million in Rapid Response NCPC, which is a new category of NCPC necessitated by fast-start pricing mechanics.

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[38] Fast-start pricing was implemented in the real-time energy market only, and not in the day-ahead energy market.

[39] Letter order accepting Tariff Revisions to Fast-Start Resource Pricing and Dispatch, Docket No. ER15-2716-000 (issued October 19, 2015).

[40] ISO New England Real-Time Fast-Start Pricing Project web page: https://www.iso-ne.com/participate/support/customer-readiness-outlook/real-time-fast-start-pricing-project

[41] ISO New England undertook a similar impact assessment of the fast-start pricing rules. The results presented in this section are not materially different from the ISO's assessment and can largely be explained by methodological differences. See https://www.iso-ne.com/static-assets/documents/2017/11/a4_presentation_review_of_march_1_2017_implementations.pdf.

- *Reserve pricing is higher and more frequent due to fast-start pricing mechanics*

  It is estimated that the average reserve price in all intervals increased from $1.16 to $3.39/MWh. This is an expected outcome due to the tradeoffs produced when relaxing (or violating) certain fast-start resource operational constraints in order to determine a price more reflective of total production costs. The EcoMin and downward ramp constraints of fast-start resources are relaxed in order to price energy, but are not relaxed for reserves. This approach avoids the appearance of more capacity available for reserves than actually available, and ensures reserves are priced when the reserve requirement is physically binding. However, in doing this, it can produce reserve pricing when, from an operational perspective, a re-dispatch of resources is not required to satisfy the reserve requirement.

The key highlights of the impact assessment are presented in Table 5-1 below. Outcomes under the fast-start pricing rules are compared to an estimate of what the outcomes would have been in the absence of fast-start pricing.

Table 5-1: Fast-Start Pricing Analysis Highlights (March through October 2017)

	Non-Fast-Start Pricing	Fast-Start Pricing	Difference
System LMP ($/MWh)	$25.75	$28.46	$2.72 (11%)
Real-Time Energy Charges ($ - Millions)[42]	$55.8	$61.7	$5.9 (11%)
NCPC Payments ($ - Millions)[43]	$18.3	$9.6	-$8.8 (-48%)
Reserve Prices ($/MWh)	$ 1.16	$3.39	$2.23 (192%)
Reserve Payments ($ - Millions)[44]	$10.9	$30.7	$19.8 (181%)
Intervals Fast-Start Resource Marginal[45]	3.2%	22.7%	19.6%

The remaining sub-sections are structured as follows (hyperlinks included):

5.1 The Goals and Mechanics of Fast-Start Pricing

To understand the goals of fast-start pricing, it is helpful to understand the characteristics of fast-start resources and the price formation challenges caused by how they typically operate.

[42] The estimation of energy payments is calculated using generation weighted zonal LMPs, as opposed to load weighted, due to data limitations. The actual value of real-time payments is $62.7 million.

[43] NCPC payments included in this analysis are Commitment-Out-Of-Merit (COOM), Dispatch-Out-Of-Merit (DOOM), and Rapid Response Pricing Opportunity Cost (RRPOC) payments.

[44] The netting of real-time payments for a participant's forward reserve market obligations is not accounted for in the reported reserve payments.

[45] Excludes DDG resources. DDG stands for Dispatchable Do-Not-Exceed Dispatch resources and includes intermittent hydro and wind resources that can be dispatched down.

Fast-start resources[46] must be capable of receiving and responding to ISO commitment and dispatch instructions. Their supply offers must also have the following characteristics:

- Minimum run time and minimum down time ≤ 1 hour (each)
- Total start time (cold notification time + cold start-up time) ≤ 30 minutes

Despite being able to start-up and shut down quickly, fast-start resources typically have a limited dispatchable range, meaning they are either offline, or online and operating at maximum output. As a result of the nature of their operation, under the old rules they were generally ineligible to set price after the first few intervals following their initial commitment. Therefore, the LMP understated the production cost of deploying fast-start resources.

The ISO described the resulting price-formation problem in its September 2015 FERC filing on fast-start pricing:

> *"From a price formation standpoint, in these conditions the energy market's price signal fails to convey the costs of operating the fast-start resource – costs that the ISO must incur to operate the power system reliably and economically."*[47]

The fast-start pricing design is intended to remedy the shortcomings of the previous real-time energy market clearing algorithm and improve price formation by better reflecting the commitment costs of fast-start deployments in real-time LMPs. It also strengthens performance incentives for all resources, not just fast-start resources. Higher prices that better reflect the cost of fast-start commitments increase the deviation payment (cost) for being unable to deliver on a day-ahead schedule, and are more likely to sufficiently compensate generators for following commitment instructions. When LMPs are insufficient to recover costs for fast-start resources, uplift payments are required to make the resources whole for following their start-up and dispatch instructions.

Mechanics

Fast-start pricing is achieved through a mechanism that, at a high-level, separates the dispatch and pricing optimization processes. The dispatch process is similar to the prior process in that it respects operational constraints when determining output levels. However, the prices produced by the dispatch process are not used for settlement. The pricing process creates the prices used in settlement, however the relaxation of some operational constraints may create output levels that are infeasible, and are discarded as a result. In addition, a new lost opportunity cost is paid (through uplift) to any resource that receives a dispatch instruction below its optimal economic level when prices increase due to fast-start resources. A comparison of the two processes is provided in Table 5-2 below.

[46] When fast-start pricing was implemented, a new tariff definition, "Rapid-Response Pricing Asset" was created to encompass fast-start generators, flexible DDG, and dispatchable asset related demand resources that meet the fast-start resource definition. For readability, in this report "fast-start resource", "fast-start generator" and "Rapid-Response Pricing Asset" are used synonymously.

[47] *ISO New England Inc. and New England Power Pool*, Revisions to Fast-Start Resource Pricing and Dispatch, Docket No. ER15-2716-000 (filed September 24, 2015).

Table 5-2: Comparison of Dispatch and Pricing Market Processes

Dispatch Process	Pricing Process
Determines least-cost dispatch points and reserve designations for all resources that are committed: • respects all physical parameters • uses the incremental energy offers to determine post-commitment DDPs • DDPs are communicated to generators	Determines least-cost energy and reserve prices to be paid to all on-line and reserve-designated resources: • relaxes EcoMin of fast-start resources to 0 MW and ignores the ramp rate for downward movements • includes start-up and no-load costs in fast-start resources' incremental offers[48] • LMPs are communicated to market

The relaxation of EcoMin in the pricing process has an important impact on the market supply curve. Under the old rules, energy produced by fast-start resources up to (and including) EcoMin was considered fixed-priced, meaning it was treated as must-take energy in the pricing logic. Under the fast-start pricing rules, this energy can now set price; it moves up the supply curve and impacts the generation merit order. In addition, fast-start resources now have a larger dispatchable range, allowing more opportunity to set LMPs.

The mechanics of fast-start pricing and the impact on market outcomes are illustrated in a simplified example below. In this example we assume:

- Demand = 1,300 MW
- Available Supply = 1,400 MW, comprised of two generators; a 200 MW fast-start resource and a 1,200 MW non-fast-start resource

The offers and operational parameters for each generator are shown in the table below.

Table 5-3: Simplified Example of Fast-Start Pricing Mechanics - Inputs

Generator	EcoMin (MW)	EcoMax (MW)	Incremental Offer Price ($/MWh)	Start-Up Cost ($)	No-Load Cost ($/hour)	Min. Run Time (Hours)
Fast-Start	200	200	100	2,000	2,000	1
Non-Fast Start	1,000	1,200	50	1,000	1,000	6

The next table illustrates how the resources would operate and how the market would clear in the dispatch and pricing processes. The inputs that are **adjusted by fast-start pricing logic** are highlighted in **gold**. The **effective outputs** are highlighted in **green**, and the **outputs that are unused** are highlighted in **red.**

Table 5-4: Simplified Example of Fast-Start Pricing Mechanics - Market Clearing

Algorithm	Generators	EcoMin (MW)	EcoMax (MW)	Offer Price ($/MWh)	DDP (MW)	LMP ($/MWh)
Dispatch	**Fast-Start**	200	200	100	200	50
	Non-Fast Start	1,000	1,200	50	1,100	50
Pricing	**Fast-Start**	0	200	120	100	120
	Non-Fast Start	1,000	1,200	50	1,200	120

[48] The no-load cost (amortized over economic maximum) and startup cost (amortized over EcoMax for the duration of the unit's minimum run time) are added to the incremental energy offers.

The first notable differences are the changes that are made to inputs into the pricing process, highlighted in **gold** cells;

- the EcoMin of the fast-start resource is reduced, from 200 MW to 0 MW and
- the offer price of the fast-start resource is increased, from $100/MWh to $120/MWh. The increased offer includes the incremental offer price and the amortized start-up and no-load costs.[49]

The **green** cells highlight the final effective outputs; the DDPs from the dispatch process and the LMPs from the pricing process. The values in the **red** cells are not used. However, there are two useful observations when comparing the unused values to the effective values:

1. The DDP produced by the pricing process is less than the fast-start unit's EcoMin and, therefore, violates an operational constraint (the unit cannot operate at the 100 MW output level).
2. Prices produced by the dispatch software are not sufficient to compensate the fast-start unit for following its start-up instruction, whereas the prices produced by the pricing solution are.

Therefore, the goals of improving price formation and respecting operational constraints in fast-start dispatch instructions can only be satisfied by retaining the valid outputs from the respective processes.

5.2 The Impact of Fast-Start Pricing on the Market Supply Curve

This section illustrates how fast-start pricing can impact the real-time energy market supply curve. Here, and in sections to follow, the impact of fast-start pricing on various aspects of the real-time market are quantified. Fast-start pricing outcomes are based on actual market results over the eight-month study period. Outcomes from the dispatch process are used to approximate the counterfactual outcomes of no fast-start pricing. The dispatch solution is a reasonable counterfactual but has a number of caveats.[50, 51]

A comparison of the supply curves from the dispatch and pricing processes is shown in Figure 5-1 below using a representative market case from August 4, 2017. The supply curve from the dispatch process is on the left ("Non-Fast-Start Pricing Supply Curve") and the curve from the pricing

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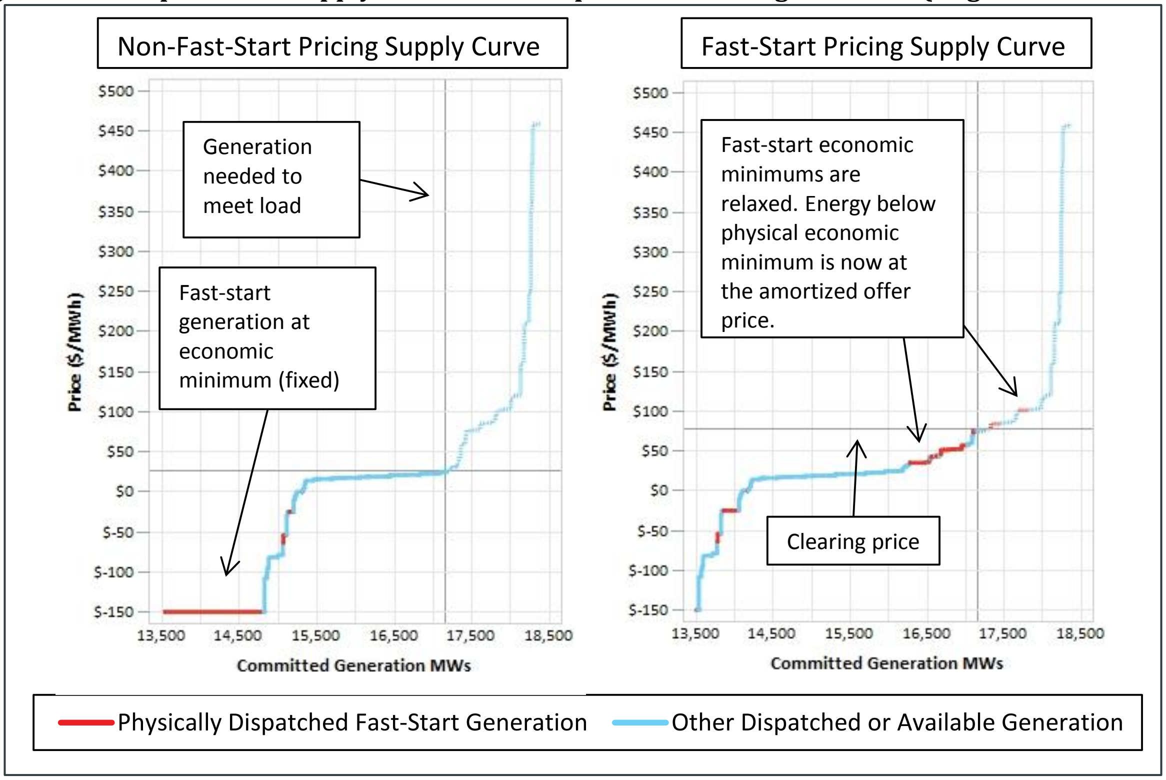
[49] Start-up and no-load costs are amortized over the economic maximum and converted into an hourly value ($100/MWh + ($2,000/200MW) + ($2,000/200MW) = $120/MWh). Start-up costs are applied during the minimum run time, and no-load costs are applied the entire time the fast-start unit is running.

[50] The prices produced by the dispatch process are not identical to the prices that would have been produced prior to fast-start pricing. In the prior market clearing solution, there was a subtle difference in how fast-start resources were treated during their initial start-up. Methodology similar to the current fast-start pricing logic was applied, but only directly after a fast-start resource was committed. For example, if a block loaded fast-start resource with a minimum run time of 1 hour was committed in a market case with a duration of ten minutes and began ramping upon receiving the signal, it could set price for only the first ten minutes of its commitment. Under fast-start pricing today, it is eligible to set price for every subsequent case. The *non-fast-start pricing* case used as a counterfactual in this analysis assumes fast-start pricing logic is never applied, even directly after the initial start-up. Therefore, a simple comparison of dispatch and pricing LMPs will tend to over-state the impact of fast-start pricing. However, we do not believe the approach will materially impact the findings, and is appropriate in the absence of a more accurate means of simulating the counterfactual.

[51] This analysis does not consider the effects of changes in participant behavior resulting from the rule change.

process is on the right ("Fast-Start Pricing Supply Curve"). Both curves are composed of offers from the same online generators.

Figure 5-1: Comparison of Supply Curves from Dispatch and Pricing Processes (Aug 4, 2017, 6:15PM)



The solid red lines represent the volume of fast-start generation, the solid blue the volume of non-fast start generation. The corresponding dotted lines represent generation that did not clear. Fixed-priced generation is shown at -$150 (for convenience).[52] In the dispatch process, energy at or below EcoMin is "fixed" because after the commitment decision the energy is must-take, and therefore cannot not set price.

The movement of the flat red line segment in the left graph up the supply curve in the right graph shows how the fast-start pricing logic shifts lumpy fast-start energy from "fixed" to dispatchable at the amortized offer price. The clearing price (the point of intersection of the supply curve with the vertical demand curve) increased from about $25 in the dispatch process to about $75/MWh in the pricing process. The pricing solution produced infeasible dispatch instructions for some of the fast-start generation that was cleared at EcoMin in the dispatch process – as shown by the red dotted lines that are above $75/MWh in the pricing process.

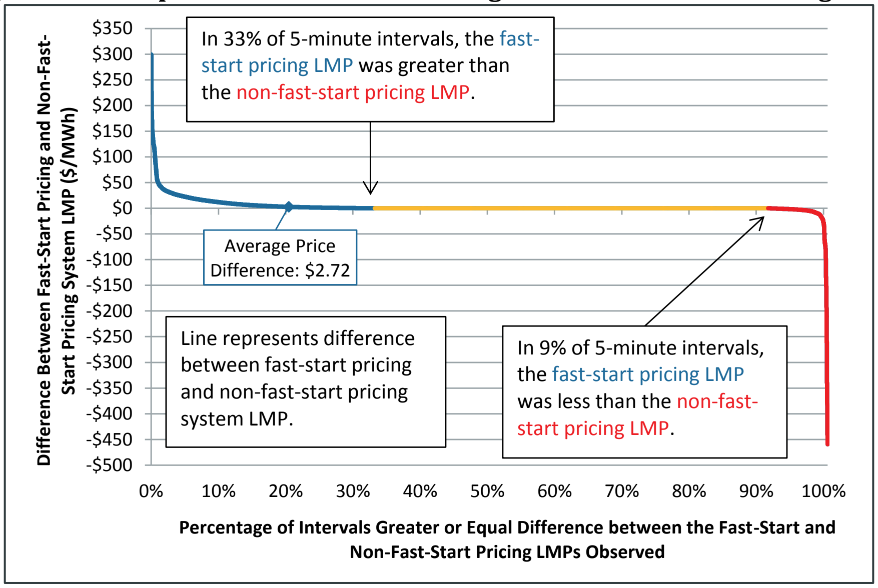
5.3 The Impact of Fast-Start Pricing on LMPs

During the eight-month period, from March 1 through October 31, 2017, the average system LMP was $28.46/MWh. Without fast-start pricing, it is estimated that the average LMP would have been

[52] Generation up to where the supply curves appear to start (about 13,500MW) is composed of fixed non-fast start generation and is not important for understanding the fast-start pricing design. These supply curves only represent generation; imports have already been netted out from demand.

$25.75/MWh; a difference of $2.72/MWh or 11%.[53] The frequency, magnitude, and direction of the price differences between the pricing and dispatch solutions are shown in Figure 5-2 below.

Figure 5-2: Comparison of Fast-Start Pricing and Non-Fast-Start Pricing LMPs



In 58% of the 5-minute intervals there was no impact on price.[54] In the other 42% of 5-minute intervals prices were different; higher 33% of the time and lower 9% of the time. During intervals with higher prices, the fast-start logic applied to generation resulted in an upward shift in the supply curve. Conversely, in lower-priced intervals the logic applied to pumped-storage demand caused a downward shift in the demand curve. [55]

The impact exceeded $50/MWh in 1% of intervals, and $100/MWh in just 0.6% of intervals. This low frequency of large price differences is largely due to expensive fast-start oil units that have only been deployed in less than 1% of 5-minute intervals. Although there have been far fewer intervals with lower LMPs, the price differences have been larger in magnitude. The average negative price difference was $14/MWh, compared to the average positive price difference of $12/MWh. This is due to relatively large movements along the supply curve in the pricing process resulting from large block-loaded pumped-storage demand units receiving the fast-start treatment. As opposed to pumped-storage generation, which is also large but typically offered with a dispatchable range, pumped-storage demand is often fixed and therefore ineligible to set price in the dispatch process.

5.4 The Impact of Fast-Start Pricing on NCPC Payments (Uplift)

This analysis measures the improvement in LMPs reflecting short-run generator production costs, and assesses the frequency of fast-start commitments requiring Net Commitment Period Compensation (NCPC) payments. In addition, fast-start pricing introduced a new type of NCPC payment called rapid-response pricing (RRP) opportunity cost.

[53] Eight outlier prices during the period were excluded from the analysis.

[54] This finding is consistent with the ISO's estimates in its September 2015 filing that in approximately 70 percent of the hours in its simulation, there were no changes in the LMPs. See *ISO New England Inc. and New England Power Pool*, Revisions to Fast-Start Resource Pricing and Dispatch, Docket No. ER15-2716-000 (filed September 24, 2015).

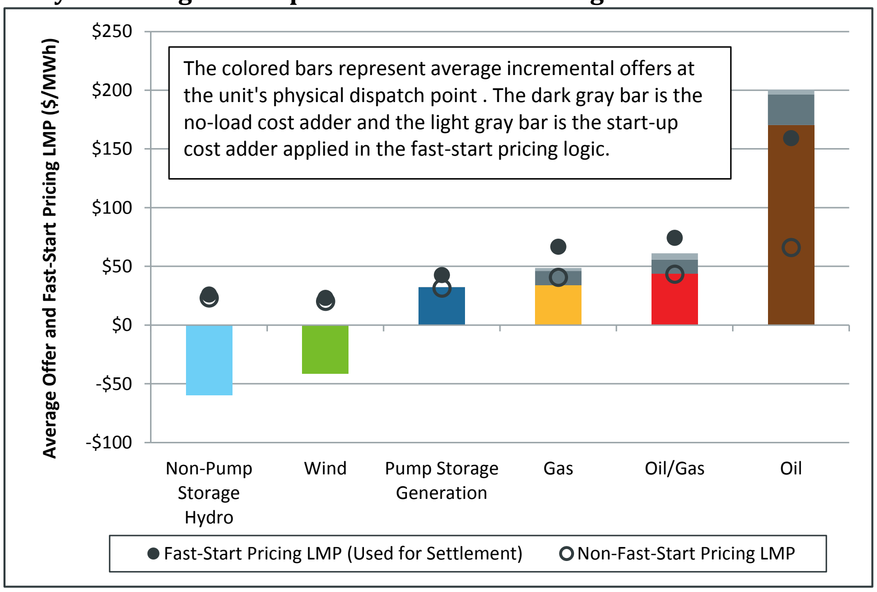
[55] The impact of fast-start pricing on pumped-storage demand is described in more detail in Section 0.

As expected, the increase in real-time energy prices resulted in a decrease in NCPC payments. Although fast-start pricing has not entirely eliminated the need for NCPC, prices better reflect the commitment costs of fast-start resources, improving market transparency and price signals.

Prices Versus Production Costs

Over the eight-month study period, prices better reflected the production costs of online fast-start generators. Figure 5-3 shows, by fuel type, the average incremental offers at the fast-start generators' physical dispatch points, the amortized start-up and no-load adders, the average actual LMPs from the pricing process (solid-fill circles) and the average non-fast-start pricing LMPs from the dispatch process (no-fill circles).

Figure 5-3: Ability of Pricing and Dispatch LMPs in Recovering Fast-Start Generator Costs



The positions of the circles relative to the tops of the stacked bars illustrate the ability of actual LMPs to compensate fast-start units compared to non-fast-start pricing LMPs. When the circles appear below the tops of the bars, the assets in the fuel type category required NCPC.[56]

The offers from 51 hydro and seven wind resources that have qualified as fast-start resources are negative on average. With or without fast-start pricing, LMPs were more than sufficient to recover costs. Therefore, fast-start pricing did not improve incentives, on average, for these resources. There have been seven gas and eight dual fuel units deployed as fast-start units. On average, they have recovered their costs from actual LMPs, but would not have if fast-start pricing was not applied. Relatively more expensive oil units, 71 in total, have not recovered their costs, on average, under either the non-fast-start or fast-start pricing methods.

Fast-start pricing alleviates, but does not completely eliminate a problem resulting from commitment "lumpiness." This is because the system does not always require the entire EcoMin of a fast-start resource or may not require the resource for its full minimum run time. Consider a

[56] However, the difference between the dots below the tops of the bars and the tops of the bars cannot be interpreted as average NCPC. For example, a generator can make $20 during one commitment, and lose $10 during another. In this figure, the dot would appear $5 above the top of the bar (because they were profitable on average), but their actual NCPC would be $10 because NCPC is calculated by commitment.

situation in which a fast-start resource is needed to deliver 10 MW, but it has an EcoMin of 20 MW. When the EcoMin of the resource is relaxed for pricing, it will be marginal and priced on a 10 MW dispatch point (although it will receive a physical DDP at its EcoMin of 20 MW). Because it has increasing marginal costs, it could still require uplift to make it whole for the remaining 10 MW of its physical output.

Fast-start oil resources have been physically dispatched close to their EcoMin, on average, but have typically been priced based on dispatch points well below their EcoMin. In these cases, they have not been fully compensated through the fast-start LMPs and have required NCPC. Fast-start pricing has not eliminated the need for NCPC but LMPs have better reflected the costs of online fast-start resources and have compensated them for a greater portion of their costs.

Impact on NCPC Payments

The impact of fast-start pricing on NCPC was assessed for three key categories that capture the majority of overall payments:[57]

- Commitment and Dispatch NCPC: ensures recovery of start-up, no-load and energy costs for following ISO commitment and dispatch instructions during, and after, a resource's minimum run time.
- Rapid Response Pricing Opportunity Cost (RRP): Introduced with fast-start pricing to address an inconsistency created by the different outputs of the dispatch and pricing processes. In some cases, when the prices from the pricing process exceed the price produced in the dispatch process, generators that are sent DDPs from the dispatch solution are incentivized to increase their output; i.e. not follow dispatch instructions. In other words, a portion of available energy that was uneconomic in the dispatch solution may be economic in the pricing solution. In these cases, when the generator adheres to the lower dispatch the generator is essentially compensated for the opportunity cost of being "postured down".[58]

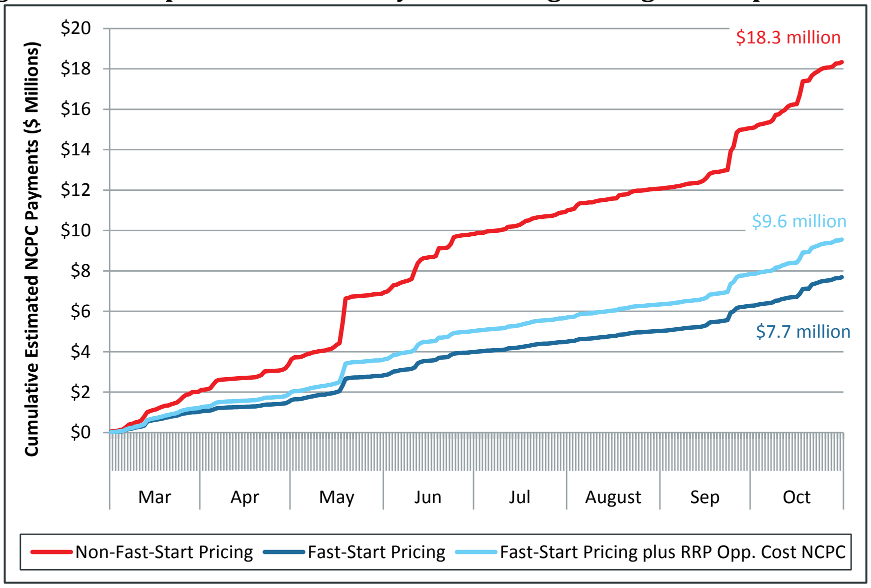
The estimated impact of fast-start pricing on commitment and dispatch NCPC payments is shown in Figure 5-4 below. The red line represents NCPC that would have been paid without fast-start pricing. The dark blue line shows actual commitment and dispatch payments based on LMPs from the pricing solution.[59] A light blue line is also shown that represents actual rapid response pricing NCPC in addition to commitment and dispatch payments. The difference between the light blue and red lines represents the impact of fast-start pricing on NCPC.

[57] Since fast-start pricing increases prices on average, all categories of real-time NCPC are impacted, including posturing credits, external transaction credits, hourly shortfall credits etc. These credits are relatively small compared to commitment and dispatch and are not considered in this analysis.

[58] Conversely, if the pricing run LMP is lower than the dispatch run LMP, units that are incentivized to generate less than their DDP are eligible to receive RRP Opportunity Cost NCPC.

[59] The NCPC values shown are estimates that were calculated using slightly simplified NCPC logic and pricing solution and dispatch solution LMPs. The estimated pricing solution NCPC differed from the actual NCPC by only 0.21%.

Figure 5-4: Comparison of NCPC Payments Using Pricing and Dispatch LMPs



A significant reduction in NCPC payments is apparent. Overall, it is estimated that NCPC was reduced by $8.8 million ($18.3m minus $9.6m). The estimated reduction in commitment and dispatch uplift payments is $10.6 million ($18.3m minus $7.7m), a reduction of more than half.

A further breakdown of payments indicates that generators received $7.4 million in commitment and dispatch NCPC since fast-start pricing, compared with $16.2 million they would have received in the absence of fast-start pricing. Pumped-storage demand experienced a relatively larger proportional decrease, from $2.2 million to $200,000.[60]

Frequency of Fast-Start Commitments Requiring NCPC

A reduction in NCPC payments does not necessarily equate to improved start-up performance incentives. For example, if a generator commitment costs $1,000, it is indifferent if it receives $900 through the energy market and $100 through NCPC or $100 through the energy market and $900 through NCPC. Either way, it only breaks even because NCPC is needed to make it whole. The potential to earn infra-marginal revenues through higher LMPs strengthens performance incentives when units are given commitment instructions. The frequency of commitments that require NCPC is an indication of how often a fast-start resource is incentivized to follow its commitment decision, as opposed to being indifferent (i.e. breaking even).

The frequency of commitments, by fuel type, that required uplift during their minimum run times is shown in Figure 5-5 below. The lines plot the difference between non-fast-start pricing and fast-start pricing and are colored by fuel type.[61] The labels express the quantity as a percentage of the total number of commitments. For example, 25% of pump-storage generation commitments would have required NCPC during their minimum run times in the absence of fast-start pricing.

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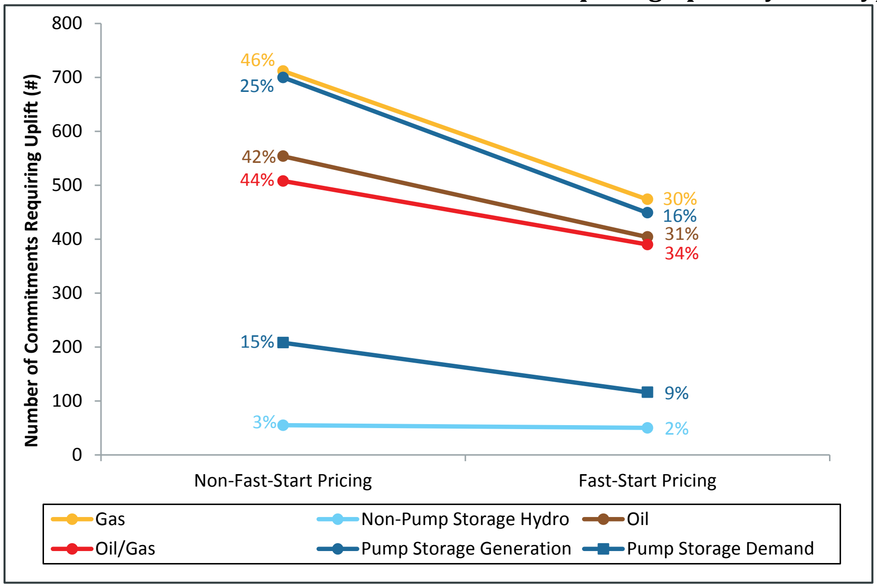
[60] Before the fast-start pricing implementation pumped-storage demand was not eligible for commitment or dispatch out-of-merit payments. Another rule change, the Market Enhancements for DARD Pumps project, was released concurrently with fast-start pricing and made DARD Pumps eligible to receive these payments. The effect of fast-start pricing on the new payments is considered in this analysis based on what DARDs would have otherwise received. *ISO New England Inc. and New England Power Pool,* DARD Pump Parameter Changes, ER16-954-000, (filed February 17, 2016).

[61] Fast-start wind generators are excluded because commitments requiring uplift are exceptionally rare.

Figure 5-5: Number of Fast-Start Commitments Requiring Uplift, by Fuel Type



Fast-start pricing has reduced the number of fast-start resource commitments requiring NCPC for all fuel types. This reduction indicates an improvement in start-up incentives. About 2,700 fast-start commitments (27% of all fast-start commitments) would have required NCPC without fast-start pricing, and only 1,900 of these (or 18% of the total) required uplift under the fast-start pricing rules.[62]

Natural gas and pumped-storage generation experienced the largest reduction in the number of commitments requiring NCPC. Gas generators required uplift for 30% of total fast-start commitments, a reduction from 46%. Pump storage generators required uplift in only 16% of commitments, as opposed to 25% that would have required uplift without fast-start pricing. Oil generators also experienced a reduction although, on average, prices were not sufficient to recover their costs; they recovered their costs 69% of the time through the LMP, compared with 58% of the time if fast-start pricing was not implemented. Pumped-storage demand units saw a 6% decrease in the percentage of commitments requiring NCPC. Pumped-storage demand will be discussed further in Section 5.6.

5.5 The Impact of Fast-Start Pricing on Operating Reserves

The impact on operating reserve was measured by comparing the frequency and magnitude of reserve prices in the dispatch and pricing processes since fast-start pricing was implemented. The difference is a reasonable estimate of the impact of the fast-start pricing rules on reserve pricing. Reserve pricing has been more frequent under fast-start pricing, occurring in 18% of five-minute intervals, an increase from 9%.[63] The average magnitude of reserve pricing when it is non-zero is also greater, increasing from $13 to $19/MWh.

[62] Post-minimum run time commitments that required uplift also decreased, from 35% of commitments to 29% of commitments. Post-minimum run time credits are received when a generator was kept on after the profit maximizing interval.

[63] Non-zero reserve pricing.

The principles underlying reserve pricing have not changed as a result of implementing fast-start pricing. If a resource is required to operate below its optimal economic output level to produce reserves, an opportunity cost equal to the difference between its offer price and the LMP is incurred.[64] Reserve prices are based on the opportunity cost of the marginal resource, such that the resource will be indifferent between providing energy or reserves.

Relaxing a fast-start resource's EcoMin in the fast-start pricing process creates a larger dispatchable range than what the resource can actually deliver. The larger dispatchable range allows the commitment costs of fast-start generators to be reflected in LMPs and reflects that a fast-start resource can make a short-run shut down decision if prices are not sufficient for them to recover their amortized offer costs.

However, the logic (relaxing EcoMin to zero) is only applied to energy and not to reserves. If it were applied to reserves a fast-start resource's entire capacity could be counted as reserves, although it cannot actually provide reserves from 0MW to its EcoMin (because that range must be producing energy). To avoid this situation, when online fast-start resources are priced at a MW level below EcoMin, only reserves above their true EcoMin are considered when reserve prices are produced. This methodology ensures that when there is a reserve requirement binding, the constraint will be priced, but it can also result in higher reserve prices or reserve prices when there is a physical surplus of reserves.

The two generator examples in Table 5-3 above are expanded on below to illustrate the reserve pricing mechanics. This example presents a situation in which there is a positive reserve price present under fast-start pricing, but physically there is no re-dispatch needed to maintain reserves. Table 5-5 includes one key modification; a 50MW reserve requirement in addition to the demand requirement. To reiterate the assumptions:[65]

- Demand = 1,300 MW
- Reserve = 50 MW
- Available supply = 1,400 MW, comprised of two generators; a 200 MW fast-start resource and a 1,200 MW non-fast-start resource

The color-coding is the same as the prior example; **differences between the inputs to the dispatch and pricing cases** are highlighted in **gold**. **The effective (used) outputs** are highlighted in **green**, and **unused outputs** are highlighted in **red**.

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[64] In most cases the opportunity cost is the difference between the offer and LMP. In some situations the system can be ramp-constrained and the opportunity cost of reserve prices are not reflected in LMPs.

[65] For simplicity, generator ramp rates are ignored. In this example, the reserve product being provided has a reserve constraint penalty factor (RCPF) exceeding $70. If this assumption was not made and the RCPF was assumed to be $50, the reserve price would be $50 (the RCPF), the LMP would be $120, the non-fast-start unit would get a pricing run DDP of 1,200MW, the fast-start would get a pricing run DDP of 100MW, and there would be a 50MW reserve deficiency.

Table 5-5: Simplified Example of Fast-Start Pricing Mechanics with Reserve Pricing - Inputs

Generators	Economic Minimum (MW)	Economic Maximum (MW)	Incremental Offer Price ($/MWh)	Start-Up Cost ($)	No-Load Cost ($)	Minimum Run Time (hours)
Fast-Start	200	200	100	2,000	2,000	1
Non-Fast-Start	1,000	1,200	50	1,000	1,000	6

Table 5-6: Simplified Example of Fast-Start Pricing Mechanics with Reserve Pricing - Market Clearing

Algorithm	Generator Type	Effective EcoMin (MW)	EcoMax (MW)	Effective Offer ($/MWh)	DDP (MW)	Reserve Design. (MW)	LMP ($/MWh)	Reserve Price ($/MWh)
Dispatch	**FS**	200	200	100	200	0	50	0
	Non-FS	1,000	1,200	50	1,100	100	50	0
Pricing	**FS**	0	200	120	150	0	120	70
	Non-FS	1,000	1,200	50	1,150	50	120	70

First, in the dispatch process (non-fast-start pricing scenario), the fast-start generator's EcoMin is respected, so it must provide 200 MW. The combined EcoMin value of both resources equals 1,200 MW. The additional 100 MW of generation needed to meet demand of 1,300 MW is provided by the lowest priced resource, the non-fast-start. At that output, the non-fast-start generator is indifferent to increasing its output as the LMP is equal to its energy cost of $50. Therefore, it will provide 100 MW of reserves without any additional incentive (i.e. the reserve price is $0/MWh).

In the pricing solution, the combined EcoMin value of both resources equals 1,000 MW. If the least expensive generator is used to deliver the remaining 300 MW needed to meet demand, the non-fast-start resource would supply 1,200 MW (its full output), and the fast-start resource would deliver 100 MW. However, in the pricing algorithm the fast-start resource is not permitted to deliver reserves below its EcoMin because it cannot actually provide these reserves.66 Therefore, the reserve requirement cannot be met without re-dispatching the system.

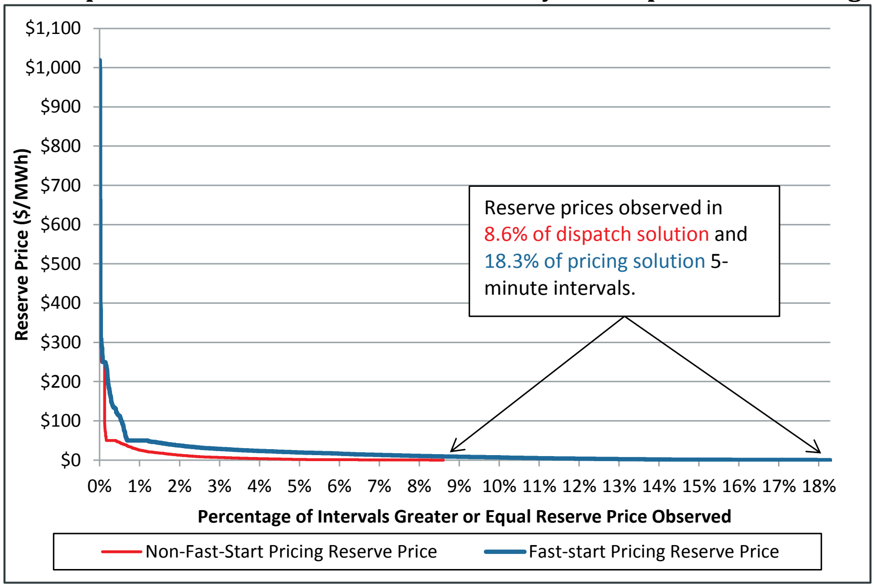
To meet the reserve requirement, the non-fast-start resource must be backed down by 50 MW. In turn, the lost energy must come from the fast-start resource, which will be given a DDP of 150 MW. The next increment of energy would come from the fast-start resource, so the energy price is set at $120/MWh. At this price, the non-fast-start resource wants to be dispatched to its full capacity; it has an opportunity cost. To compensate for the opportunity cost, the reserve price is equal to the difference between its offer and energy price, $70/MWh ($120 - $50/MWh); i.e. the price at which the non-fast-start resource is indifferent to providing reserves or energy.

Although this example is simplistic, it illustrates how the mechanics of fast-start pricing produce non-zero reserve pricing when otherwise it would be $0/MWh.

[66] The fast-start resource cannot actually provide any reserves because it is block loaded.

A comparison of reserve pricing with fast-start pricing (blue line) and without fast-start pricing (red line) is shown in Figure 5-6 below.

Figure 5-6: Comparison of Reserve Prices Produced by the Dispatch and Pricing Solutions



Reserve pricing has been more frequent under fast-start pricing, occurring in 18% of five-minute intervals, an increase from 9%.[67] The average magnitude of reserve pricing is also greater, increasing from $13 to $18/MWh. When prices increase, generators that were willing to provide reserves without any additional compensation before (i.e. the non-fast-start resource in the example) are faced with an opportunity cost and must be compensated for providing reserves, even when the reserve constraint is non-binding. In intervals where there would not have been reserve pricing in the absence of fast-start pricing, $14.3m in total reserve payments were made. In intervals where there was reserve pricing in both scenarios, $16.4m in total reserve payments were made, an increase from $10.9m.

This outcome is a consequence of the tradeoff between relaxing resources' operational constraints in order to determine a price more reflective of production costs over a fast-start resource's commitment. Essentially, it can — and does — lead to reserve prices when there was no physical re-dispatch required to maintain reserves. However, if the output was considered for reserves, reserve prices could be zero when the system needs to be re-dispatched (at a cost) to ensure adequate reserves are available.

5.6 Pumped-Storage Demand Treatment under Fast-Start Pricing

Six pumped-storage demand resources have qualified for fast-start treatment. There are both similarities, and differences, to the application of the fast-start pricing rules to these resources verses more traditional fast-start generators.

Similar to the relaxation of EcoMin for fast-start generators, the minimum consumption level is relaxed to zero for pumped-storage demand resources. In contrast to generation, the movement of the bid price from fixed to variable (through relaxing the minimum consumption level) shifts the

[67] Non-zero reserve pricing

demand curve downward (as opposed to the supply curve upwards).[68] In other words, the treatment of pumped-storage demand as fast-start resources has a price-suppressing effect.

From a pricing perspective, the application of fast-start pricing to pumped-storage demand is logical. Pumped-storage demand makes short-run decisions to follow commitment instructions, just as generators do, and allowing them to be treated as a fast-start resource improves their incentives to follow their commitment instruction.

The greater ability to set price has resulted in lower NCPC. Under fast-start pricing, pumped-storage demand has been paid $200k in commitment and dispatch NCPC, compared with the estimated $2.2 million they would have been paid in the absence of fast-start pricing.

An important difference between pumped-storage demand and fast-start generation is the treatment of reserves. Physically, online generation can deliver reserves when it has a dispatchable range above its dispatch point. Fast-start demand can deliver reserves by reducing energy consumption. In other words, the option to curtail a pump's consumption provides reserves.

In the pricing process, if a pumped-storage demand resource is dispatched at a point below its minimum consumption level, it is treated as delivering fewer reserves than it actually must be due to its minimum consumption constraint. The interaction between pumped-storage demand and the treatment of reserves can lead to a false perception that the pumps are delivering fewer reserves than they physically are in the price formation process. From a practical perspective, reserve prices are infrequent during the early morning hours when these resources are typically pumping. However, the approach that has been taken when pricing reserves has led to an increase in reserve pricing in hours in which pump-storage units are pumping, from 1.5% to 3.6% of intervals.

[68] For example, assume a 100 MW pumped-storage demand resource bids to consume at $20/MWh with a minimum consumption equal to its maximum consumption level. Without fast-start pricing it could not set price and NCPC would cover its costs if prices were higher than $20/MWh. With fast-start pricing, it can set price across its range up to 100 MW at $20/MWh. In practice this ensures that prices will be closer to $20/MWh and there will be less reliance on NCPC to ensure cost recovery.