ISO New England's Internal Market Monitor

2015 Annual Markets Report

Internal Market Monitor
May 25, 2016

Preface

The Internal Market Monitor (IMM) of ISO New England (ISO) publishes an Annual Markets Report (AMR) that assesses the state of competition in the wholesale electricity markets operated by the ISO. The *2015 Annual Markets Report* covers the ISO's most recent operating year, January 1 to December 31, 2015. The report addresses the development, operation, and performance of the wholesale electricity markets administered by the ISO and presents an assessment of each market based on market data, performance criteria, and independent studies.

This report fulfills the requirement of *Market Rule 1*, Section III.A.17.2.4, Appendix A, *Market Monitoring, Reporting, and Market Power Mitigation*:

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

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

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

The External Market Monitor (EMM) also publishes an annual assessment of the ISO New England wholesale electricity markets. The EMM is external to the ISO and reports directly to ISO New England's board of directors. Like the IMM's report, the External Market Monitor's report assesses the design and operation of the markets and the competitive conduct of the market participants.

This report presents the most important findings, market outcomes, and market design changes of New England's wholesale electricity markets for 2015. Section 1 summarizes the region's wholesale electricity market outcomes for 2015, the important market issues and our recommendations for addressing these issues, the overall competitiveness of the markets, and market mitigation and market reform activities. Section 2 through Section 8

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[1] *ISO New England Inc. Transmission, Markets, and Services Tariff* (ISO tariff), Section III.A.17.2.4, *Market Rule 1*, Appendix A, "Market Monitoring, Reporting, and Market Power Mitigation" (December 3, 2014), http://www.iso-ne.com/static-assets/documents/regulatory/tariff/sect_3/mr1_append_a.pdf.

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

includes more detailed discussions of each of the markets, market results, analysis and recommendations. Section 9 provides information on audits conducted to ensure that the ISO followed the approved market rules and procedures and to provide transparency to New England stakeholders. A list of acronyms and abbreviations is included at the back of the report. Key terms are italicized and defined within the text and footnotes.

All information and data presented are the most recent as of the time of publication. The data presented in this report are not intended to be of settlement quality and some of the underlying data used are subject to resettlement. Underlying natural gas data is furnished by the Intercontinental Exchange (ICE):

ICE Global markets in clear view

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

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Section 1
Executive Summary

The *2015 Annual Markets Report* addresses the development, operation, and performance of the wholesale electricity markets administered by ISO New England (ISO) and presents an assessment of each market based on market data and performance criteria. In addition to buying and selling wholesale electricity day ahead and in real time, the participants in the ISO-administered forward and real-time markets buy and sell operating reserve products, regulation service, Financial Transmission Rights (FTRs), and capacity. These markets ensure the competitive and efficient supply of electricity to meet the energy needs of the New England region and secure adequate resources required for the reliable operation of the power system.

This section summarizes the region's wholesale electricity market outcomes for 2015 and the key market trends over the past five years. It presents the important market issues and recommendations for addressing these issues. It covers the overall competitiveness of the markets, market mitigation and market reform activities.

Overall, the ISO New England capacity, energy, and ancillary service markets performed well in 2015. The capacity market procured additional new capacity in the ninth forward capacity auction at a competitive price. The day-ahead and real-time energy markets have performed well, with electricity prices closely reflecting changes in underlying primary fuel prices. There were few periods in the real-time energy market when relative shortage impacted price, and overall price-cost markups in the day-ahead energy market were within reason.

The total wholesale cost in 2015, at $9.3 billion, was considerably lower than 2014, representing a 25% decrease. The primary drivers were lower natural gas prices and less frequent need for reliability commitments. The price of two key input fuels, natural gas and oil, decreased by 41% and 46%, respectively, which drove lower electricity prices and consequently lower total wholesale electricity costs.

Total wholesale costs to date have been influenced by low capacity market prices that have ranged from $2.95/kW-month to $4.50/kW-month. This influence will continue until the 2017-18 capacity commitment period (associated with FCA 8) when capacity market prices increased, reflecting the end of the period where the New England system was structurally long on capacity. The capacity price in FCA 8 increased to a system-wide price of $7.03/kW-month and in FCA 9 to $9.55/kW-month. The higher capacity market prices needed to attract new investment to replace retired capacity will increase the capacity component of the total wholesale cost of electricity from June 2017.

The ISO implemented three market changes that were intended to improve the dispatch and pricing of electricity. The first two; the ability to submit hourly energy offers and a lower offer price floor of -$150/MWh, were implemented in December of 2014. Market participants have leveraged the hourly offer flexibility, especially to reflect the change in natural gas price that can happen when the gas market day changes at 10 a.m. The ability to offer at a negative price has also been utilized by participants and the market has, at times, leveraged this flexibility during over-supply conditions, clearing at prices between -$150/MWh and the former offer price floor of $0/MWh. The third market change allowed for additional real-time economic clearing of import and export transactions between ISO New England and the New York ISO and was implemented in December 2015. While each of these changes has resulted in targeted additional dispatch and pricing flexibility, there is still a persistence of price-insensitive scheduling of energy which limits the extent to which these specific market rule changes can result in more liquid market clearing and better price formation.

The forward capacity market and the energy market have exhibited competitive outcomes despite the presence of structural market power. Measures are in place in both of these markets to identify and mitigate market power. The identification of seller-side market power relies on a pivotal supplier test that measures the ability of a supplier to increase price through withholding their supply. There also exists buyer-side market power mitigation that prevents a participant that is positioned to pay the capacity price from artificially lowering the price. Both mitigation processes for the capacity market have functioned well and resulted in competitive outcomes.

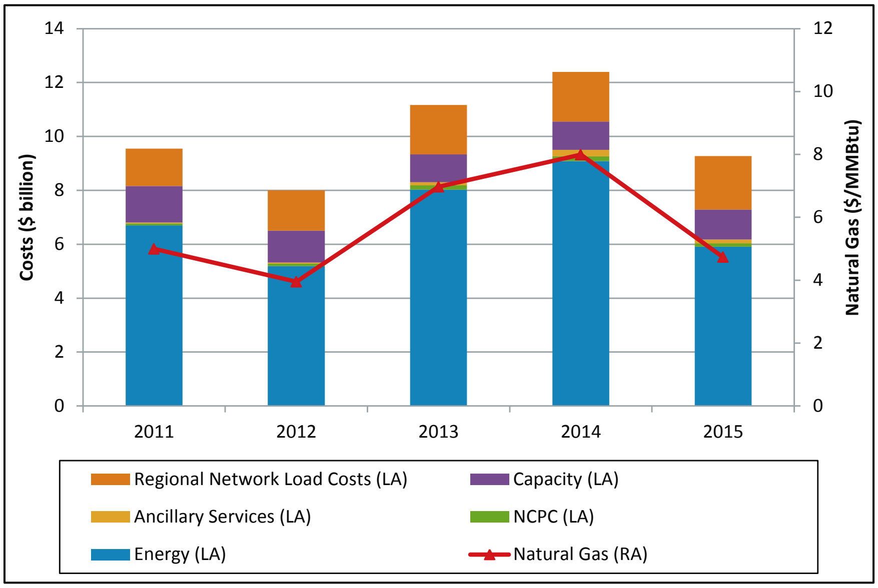
The forward reserve market does not currently have any active market power mitigation provisions and, as highlighted in this report, has structural market power issues that are currently being evaluated. The energy market has a fairly rich set of rules to identify and mitigate seller-side market power. There are energy supply portfolios that have structural market power in the real-time market in over half of the hours. In general, the real-time market has produced competitive outcomes. However, the mitigation measures for system-level market power in the real-time energy market provide suppliers a considerable degree of deviation from competitive marginal-cost offers before the mitigation rules would trigger and mitigate a supply offer. The potential impact of structural market power in the real-time market and the effectiveness of existing mitigation thresholds will be evaluated this year.

1.1 Wholesale Cost of Electricity

Lower prices in the natural gas market resulted in a significant decrease in the overall wholesale cost of electricity in 2015. The estimated cost of wholesale electricity of $9.3 billion represented a decrease of $3.1 billion, or 25%, compared with 2014 costs. Figure 1-1 below shows the components of the wholesale cost over the past five years (on the left axis, “LA”) along with the average annual natural gas price (on the right axis, “RA”).[3]

[3] Unless otherwise stated, the natural gas prices shown in this report are based on the Intercontinental Exchange next-day index for the Algonquin Citygates trading hub. Next-day implies trading today (D) for delivery during tomorrow’s gas day (D+1). The gas day runs from hour ending 11 on D+1 through hour ending 11 on D+2.

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



A description of each cost category along with an overview of the trends and drivers of market outcomes is provided below. The dollar amount and percentage contribution of each category to the overall wholesale cost in 2015 is shown in parenthesis.

Energy ($5.9 billion, 63.8%): Energy costs are a function of cleared demand (megawatt hours, or MWh) in both the day-ahead or real-time energy markets and the market clearing prices (the Locational Marginal Price, or LMP):[4]

- Annual demand was relatively flat in 2015 compared with 2014, and down by between 1% to 2% on prior years (2011 through 2013).
- Day-ahead and real-time LMPs averaged $41.90/MWh and $41.00/MWh, respectively (simple average). Prices were at their lowest since 2012 and were down by 35%, or by more than $22/MWh, compared with 2014. Supply and demand-side participants continued to exhibit a strong preference towards the day-ahead market, with approximately 98% of the total cost of energy settled on day-ahead LMPs.
- Natural gas next-day prices continued to be the primary driver of LMPs. Prices averaged $4.73/MMBtu, representing the lowest annual average since 2012, and a reduction of 41%, or $3.26/MMBtu, compared with 2014.

[4] MWh stands for megawatt-hours; MW stands for megawatts; and MMBtu stands for million British thermal units. The LMP presented here is the Hub LMP, a collection of energy pricing locations that has a price intended to represent an uncongested price for electric energy, facilitate energy trading, and enhance transparency and liquidity in the marketplace.

Regional Network Load Costs ($2.0 billion, 21.4%): RNL costs cover the use of transmission facilities, reliability, and certain administrative services. Of the three cost categories included in RNL (Infrastructure, Reliability and Administrative), infrastructure costs make up over 90%. RNL costs rose by 8% in 2015 as a result of investment in new transmission infrastructure, upgrades to existing infrastructure, operating and maintenance costs and other components impacting the overall revenue requirement.

Capacity ($1.1 billion, 12.0%): Capacity costs were up about 5% compared with 2014 in line with auction clearing prices. The costs of procuring capacity in the Forward Capacity Market (FCM) in 2015 are the product of the clearing prices associated with the fifth and sixth Forward Capacity Auctions (FCAs) and the capacity requirement.[5] The FCA clearing prices of $3.21 and $3.43/kW-month for the two auctions were set at the administrative price floor due to a surplus of capacity in the market. The capacity requirements for the fifth and sixth auctions were 33,200 MW and 33,456 MW, respectively.

NCPC ($0.1 billion, 1.3%): Net Commitment Period Compensation costs, also known generically as make-whole payments, are the portion of production costs in the energy market not recovered through the LMP. NCPC costs decreased by 32% in 2015 in line with the reduction in underlying fuel prices. The majority of NCPC (70%) was paid in the real-time market in 2015.

Ancillary Services ($0.1 billion, 1.6%): These are costs of additional services procured to ensure system reliability, including operating reserve (real-time and forward markets) and regulation. These costs have decreased by 39% in line with lower fuel input costs.

[5] The capacity commitment period associated with an auction is an annual period beginning on June 1st each year and therefore spans two years calendar years. The fifth and sixth forward capacity auctions were for commitment periods 2014/15 and 2015/16, respectively. The capacity required is known as the Installed Capacity Requirement.

1.2 Overview of Supply and Demand Conditions

Table 1-1 below shows the key statistics regarding demand, generation costs, electricity prices, and the New England fuel mix over the past five years.

Table 1-1: Highlights

Statistic	2011	2012	2013	2014	2015	% Change 2015 to 2014
Demand (MW)						
Real-time Load (average hourly)	14,745	14,581	14,769	14,518	14,479	0%
Weather-normalized real-time load (average hourly)[a]	14,726	14,600	14,584	14,511	14,358	-1%
Peak real-time load (MW)	27,707	25,880	27,379	24,443	24,437	0%
Generation Fuel Costs ($/MWh)						
Natural Gas	39.02	30.87	54.39	62.16	36.90	-41%
Coal	45.17	40.69	40.77	40.44	36.34	-10%
No.6 Oil	192.35	194.53	181.45	172.14	92.60	-46%
Diesel	269.79	278.91	269.92	251.19	148.64	-41%
Hub Electricity Prices ($/MWh)[b]						
Day-ahead LMP (simple average)	46.38	36.08	56.42	64.56	41.90	-35%
Real-time LMP (simple average)	46.68	36.09	56.06	63.32	41.00	-35%
Day-ahead LMP (load-weighted average)	47.98	37.66	59.37	67.81	44.13	-35%
Real-time LMP (load-weighted average)	48.50	37.93	59.45	67.00	43.71	-35%
Fuel Mix (% of native New England Generation for Top 5 Fuels)						
Natural Gas	51%	52%	45%	43%	49%	13%
Nuclear	28%	31%	33%	34%	30%	-13%
Hydro	8%	7%	7%	8%	7%	-7%
Coal	6%	3%	6%	5%	4%	-23%
Other[c]	3%	4%	4%	4%	4%	-4%

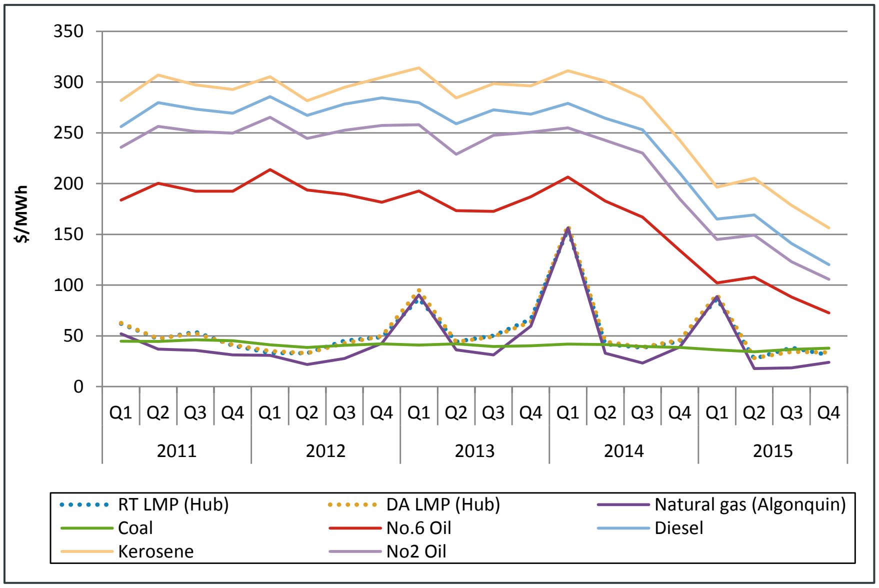
[a] Weather-normalized results are those that would have been observed if the weather were the same as the long-term average.
[b] Generation costs are calculated by multiplying the daily fuel price ($/MMBtu) by the average standard efficiency of generators for each fuel (MMBtu/MWh)
[c] The "Other" fuel category includes landfill gas, methane, refuse, solar, and steam

As can be seen from Table 1-1, costs for the major fuels have declined significantly in 2015 and have been the key driver of the decrease in electricity prices. Natural gas has increased its share of overall generation due to lower gas prices.

The supply side continues to be highly dependent on natural gas. Gas-fired generators have the largest share of the market in terms of both energy (see Table 1-1 above) and capacity.

Energy Market Supply: LMPs track spot natural gas prices very closely on average, as can be seen in Figure 1-2 below.

Figure 1-2: Estimated Generation Costs and LMPs



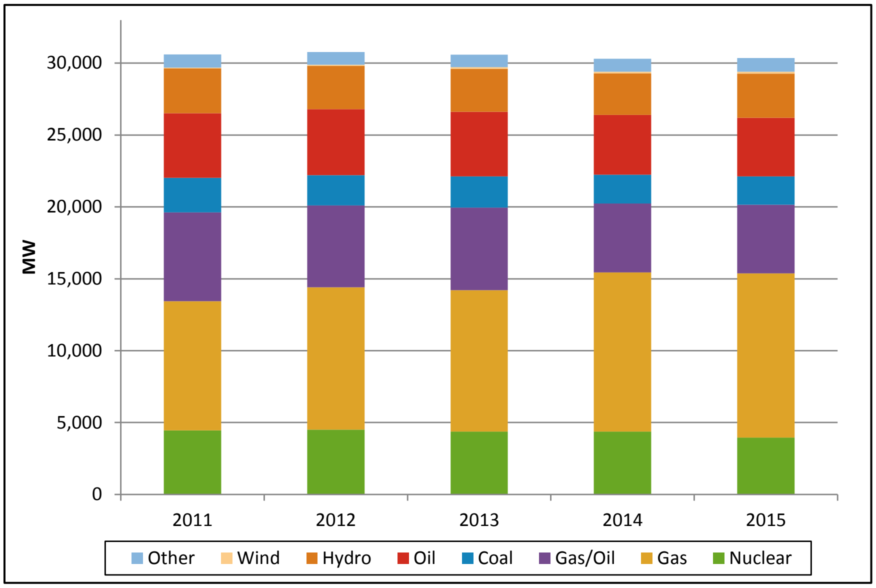
Natural gas prices during 2015 were highest during the first quarter, which is consistent with observations in prior years when total regional gas demand has stressed New England's gas network.

However, the average natural gas price of $11.36/MMBtu during Q1 2015 was 43% lower than the Q1 2014 average of $20.04/MMBtu. Annually, natural gas prices were lower in each quarter of 2015 relative to 2014. According to the U.S. Energy Information Administration (EIA), increases in domestic natural gas production, above-average storage inventories, and lower heating demand at the start of the 2015-16 winter season contributed to low prices in the latter part of 2015. Oil prices were also significantly lower in 2015 relative to the prior four years as global excess production increased inventories and reduced prices. Coal prices were, in contrast, relatively stable during 2015, but were also as much as 17% lower than 2014 prices in a quarter-over-quarter comparison. By EIA estimates, domestic coal production and consumption fell by 11% during 2015 largely due to falling demand in the electric power sector.

Emissions costs are not included in the generation cost estimates in Figure 1-2. During 2015, emissions allowance costs continued to rise, primarily driven by carbon dioxide (CO_2) allowance prices. It is estimated that a natural gas generator had emissions costs of roughly $2.40-3.20/MWh, on average, in 2015. Coal unit emissions costs were about $5.50-7.20/MWh, and oil units had emissions costs ranging from $4.80-6.60/MWh, on average, during 2015.

Capacity Market Supply: There is also a strong link between capacity prices and natural gas-fired generators which accounted for 78% of new additions to capacity in the past eight auctions. The benchmark price in the capacity market, or the net cost of new entry, is calculated based on the recovery of the long-run average costs of a new-entrant combined cycle gas turbine. Figure 1-3 provides a breakdown of capacity supply obligations in the capacity market by fuel type.

Figure 1-3: Average Generator Capacity by Fuel Type

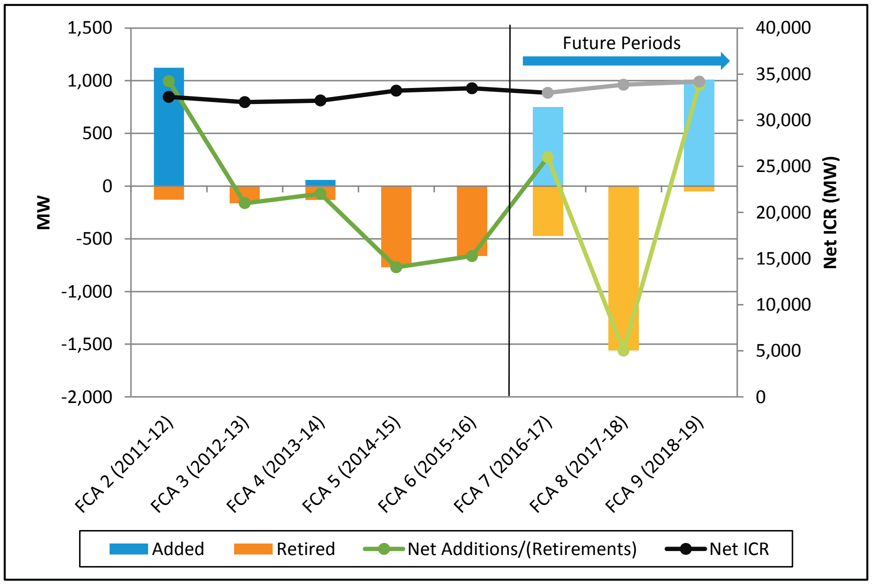


In 2015 gas- and gas/oil-fired generators (generators capable of firing on gas or oil) comprised 53% of overall generation capacity. Nuclear and oil-fired generators were the next largest by capacity share, with 13% each (26% in total) of generation capacity.

The capacity mix is characterized by an aging and declining fleet of oil- and coal-fired generators, many of which were constructed during the 1960s and 1970s. Also, with the retirement of the Vermont Yankee nuclear station, older generators are increasingly being displaced by new technologies. Most new investments have been in new natural gas generators rather than in new or upgrades in coal or oil generators. In parallel, there has also been new investment in renewable generation such as wind and solar.

Figure 1-4 below shows capacity additions and retirements (resources over 50 MW), alongside the demand for capacity (the Net Installed Capacity Requirement, or NICR) over the past eight forward capacity auctions (FCAs).

Figure 1-4: Generator Additions, Retirements, and NICR



Capacity retirements have exceeded new capacity additions by about 1,000 MW over the past five years and the surplus of capacity supply in the first seven auctions was significantly eroded in FCA 8 and FCA 9 (with associated capacity commitment periods of 2017/18 and 2018/19). Newer, cleaner and more efficient technology, combined with low natural gas prices, increasing emissions costs, and environmental regulations have contributed to more investment in new natural gas generators.

Prices in the capacity market have increased significantly in FCA 8 and FCA 9 as the supply conditions tightened, with system-wide prices of $7.03 and $9.55/kW-month, respectively. Prices in the previous seven auctions ranged from a low of $2.95/kW-month in FCA 4 to a high of $4.50/kW-month in FCA 1.

Generator Profitability: New generator owners rely on a combination of net revenue from energy and ancillary service markets and forward capacity payments to cover their fixed costs. Revenue from the FCM is a critical component of moving forward with developing a new project. The total revenue requirement for new capacity, before revenues from the energy and ancillary services markets are accounted for is known as the cost of new entry, or CONE. The revenue required from the capacity market is often referred to as the net cost of new entry, or Net CONE.

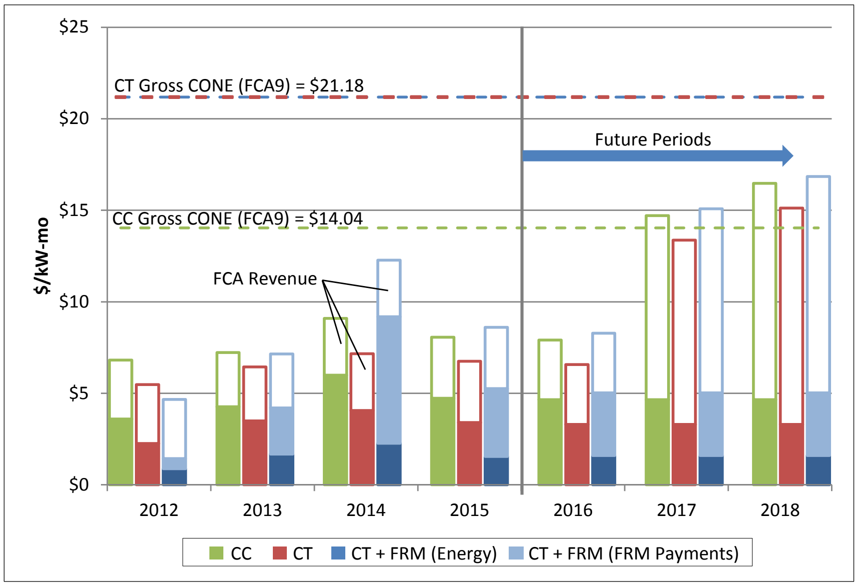
Results of simulations of market participation for characteristic new combined cycle and combustion turbine resources indicate that capacity market prices (at a system level) coupled with net revenue from energy and ancillary service sales were not sufficient to incent new generation prior to FCA 8 as the system was relatively long on capacity.[6,7] However, beginning

[6] This analysis looks at system-level pricing. In FCA 7 the NEMA/Boston capacity zone was short and cleared a new combined cycle resource at just under $15/kW-month. The price impact was limited to new entry in that capacity zone, so the remainder of the system did not exhibit a price signal that would be sufficient for new generation.

[7] The FCM prices represent (blended) prices over a calendar year (January to December) as opposed to a capacity period (June to May).

with FCA 8 the system was no longer long on capacity. New resources were procured in FCA 8 and FCA 9, resulting in auction prices sufficiently high to support new entry after expected net revenue from energy and ancillary service sales.[8] Results of the simulation analysis are presented in Figure 1-5. Net revenue (solid bar segments) and capacity market revenue (outlined bar segments) are stacked to compare total expected net revenue to the characteristic cost of new entry.

Figure 1-5: Estimated Net Revenue from Energy and Ancillary Services for New Gas-fired Generators



When compared with CONE benchmarks, revenues for new generation and FCA clearing prices in the earlier periods appear to be too low to incent the addition of new gas-fired generation units. Recent FCAs have cleared at significantly higher prices and have cleared a number of new combined cycle and combustion turbine units.

Energy Market Demand: The demand for electricity is weather-sensitive and contributes to the seasonal variation in energy prices. In 2015, New England's native electricity demand, referred to as net energy for load, or "NEL", averaged 14,479 MW per hour. While demand is highest during the summer months, electricity prices over the past several years have been highest during the winter months because of high natural gas prices.

Operating Reserves: The bulk power system needs reserve capacity to be able to respond to contingencies, such as those caused by unexpected outages. Operating reserves are provided by the unloaded capacity of generating resources, either online or offline, which can deliver energy within 10 or 30 minutes. The ISO procures both system-wide reserve, and local reserve for import-constrained areas. The system reserve requirement has been relatively constant over the past three years, with a total ten-minute reserve requirement of about 1,700MW and total thirty-minute reserve requirement of about 2,500MW in 2015.

[8] Capacity prices during the earlier periods ranged from $2.95 to $3.34/kW-month during the period, which were administratively-set floor prices based on over-supply conditions.

Capacity Market Requirements: The Installed Capacity Requirement (ICR) is the amount of capacity (MW) needed to meet the region's reliability requirements. The reliability requirements are designed to ensure that non-interruptible customers are not disconnected from the wholesale grid more than once every ten years.

Due to transmission limitations there are also local sourcing requirements for import-constrained areas and maximum capacity limits for export-constrained areas. The system installed capacity requirement for the forward capacity auction held in 2015 (FCA 9) for delivering in the capacity commitment period 2019/20 was 35,142 MW. Some of this requirement is satisfied through tie benefits with Hydro-Quebec.[9] With the Hydro-Quebec tie benefits included, the net installed capacity requirement (or NICR) for FCA 9 was 34,189 MW. For FCA 9, there were local capacity requirements in Connecticut (7,331 MW), NEMA Boston (3,572 MW), and Southern Massachusetts/Rhode Island (7,479 MW). No more than approximately 3,800 MWs can be located in Maine because of transmission limitations of moving power out of that region.

Imports and Exports: New England has transmission connections with Canada and New York. Under normal circumstances, the Canadian interfaces reflect net imports of power into New England whereas the interfaces with New York can reflect net imports or net exports depending on market conditions.

External transactions (imports and exports) can represent a significant share of either the supply stack (when importing) or additional demand on the system (when exporting). New England was a net importer of power in 2015, with net imports meeting almost 17% of total native electricity demand on average. The net interchange with neighboring balancing authority areas in the real-time market increased roughly 1.5% compared with the previous year.

Most external transactions continue to be insensitive to price. Across the Canadian interfaces the percentage of fixed-priced transactions has averaged over 75% over the past five years in the day-ahead energy market, whereas across New York interfaces the fixed-priced transactions have averaged about 60%. New rules came into effect in December 2015, known as Coordinated Transaction Scheduling, to allow for additional economic clearing of import and export transactions based on expected real-time prices. This will improve market efficiency by further facilitating scheduling of power from the lower-cost region to the higher-cost region.

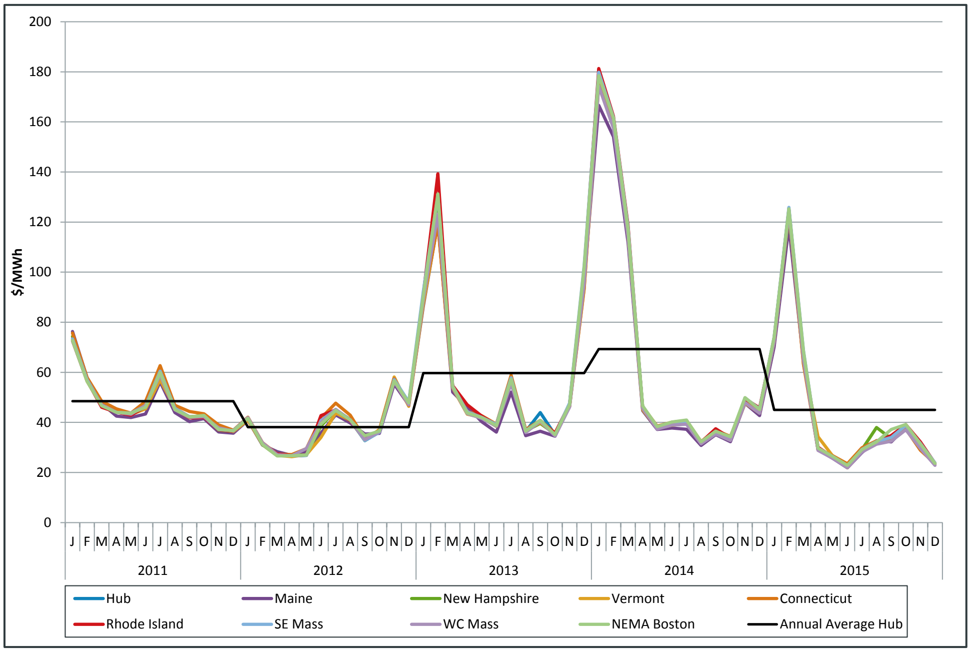
1.3 Day-Ahead and Real-Time Energy Markets

Price differences among the load zones were again relatively small in 2015. Price differences resulted from modest levels for both marginal losses and congestion, as there was little congestion between zones during the year.

The average absolute difference between the Hub annual average price and average load zone prices was $0.45/MWh in the day-ahead energy market and $0.58/MWh in the real-time energy market – a difference of approximately 1.0-1.5%. This indicates congestion had very little effect on electricity price. Figure 1-6 shows the monthly load-weighted prices across load zones over the past five years. The black line shows the average annual load-weighted hub price and highlights the degree of variability in prices throughout the year.

[9] Tie benefits reflect the amount of emergency assistance that is assumed will be available to New England from its neighboring Control Areas in the event of a capacity shortage in New England.

Figure 1-6: Day-Ahead Energy Market Load-Weighted Prices



Constraints in the natural gas system have resulted in higher natural gas prices and higher electricity prices in the months of January and February over the past three years. Recent winter periods with high fuel prices, and summer months with elevated load levels, have the highest load-weighted electricity prices.

The day-ahead market's ability to reflect real-time conditions is important for efficient scheduling of generation to reliably serve real-time load in the least-cost way. There are many factors that can cause divergence in price between the two markets; however price convergence between the two markets can be viewed as a rough indicator of the day-ahead market's ability to predict real-time conditions. On average, electricity price in the day-ahead and real-time markets were fairly convergent with an average difference of $0.90/MWh in 2015, down from $1.25/MWh in 2014.

A significant proportion of the aggregate supply and demand curves in the energy markets do not have the ability to set price. On the supply side, this is due to importers offering fixed bids, generators self-scheduling, or generators operating at their economic minimum levels. The first two categories are price-takers in the market, even expressing a willingness to pay when LMPs are negative. On the demand side, participants with load submit a large amount of fixed bids. Approximately one quarter of both aggregate supply and demand can set price in the day-ahead energy market. Virtual demand and supply tend to serve an important price-discovery role in the day-ahead market.

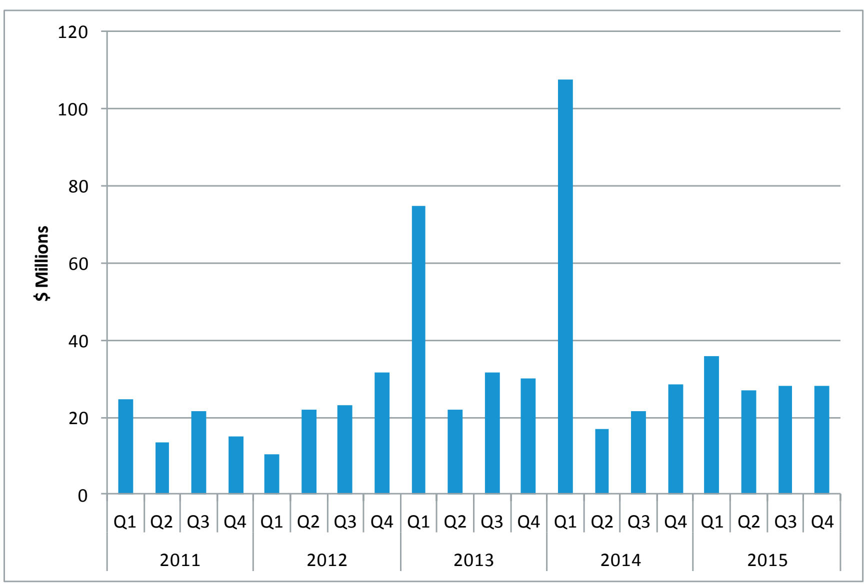
On average, only a small portion of the total supply clearing each day was economically dispatched based on price. Despite the increased flexibility provided by the introduction of negative offers in December 2014, many participants have continued to self-schedule generation in both the day-ahead and real-time market. On average, during each hour over 76% of the supply being offered into the day-ahead market cannot set price. This increases to over 82% on average in the real-time energy market. Since the introduction of the energy market offer flexibility rules in December 2014 and a lower offer floor price of -$150/MWh, the frequency of negative LMPs has increased significantly, particularly in the real-time market.

Although volumes have declined in recent years, in 2015 virtual transactions (demand and supply) set the LMP in the day-ahead market during 31% of intervals. This is comparable to previous years, ranging from 27% to 33% between 2011 and 2014. The low volume of cleared virtual transactions, coupled with the high percentage of time these transactions set the market clearing price in the day-ahead market, is an indicator of the low volume of price-sensitive offers from other (non-virtual) supply sources. Generators set price only 44% of the time in the day-ahead market in 2015.

In the real-time energy market there are no virtual transactions and the majority of price-sensitive offers are from natural gas-fired (or dual-fuel) resources. Consequently, the price-setting intervals for natural gas resources are significantly higher in the real-time at roughly 75%. The percentage of price setting intervals for coal fell from 8% to 3% in 2015. This displacement was, in part, due to lower gas prices in 2015 as gas generators were in-merit more often compared with coal. Other fuel types' price-setting percentages were comparable to last year.

Uplift payments, or Net Commitment Period Compensation (NCPC) payments, decreased significantly in 2015 to $119 million compared with $175 million in 2014 (a reduction of 32%). NCPC payments to generators represented less than 2% of their total energy payments in 2015. Figure 1-7 below shows total NCPC payments by quarter.

Figure 1-7: Total NCPC Payments by Quarter



The increases in NCPC compensation observed in 2013 and 2014, and the reduction in 2015, are generally consistent with changes in fuel costs (especially natural gas) over this time period.[10]

[10] Other factors also influence NCPC payments. These include varying system conditions (i.e., instances of load forecast and generator commitment error, instances of local transmission issues and resulting local reliability needs,

However, NCPC payments in Q2 through Q4 of 2015 were relatively high compared with 2014, despite lower fuel prices during these quarters in 2015. A number of key changes to the NCPC rules implemented in December 2014 contributed to the increase. First, NCPC payments are now calculated over a generator's duration of commitment, rather than over the 24-hour operating day. This means that a profitable commitment is not being offset by an unprofitable commitment, thereby improving performance incentives. Second, the NCPC compensation structure was improved to account for the lost opportunity costs of generators postured to meet system reliability needs. When the ISO postures a generator it is moved away from its economically optimal output by the ISO. In practice this applies frequently to limited energy generators. Third, up until February 2016, a generator scheduled in the day-ahead market was eligible for both day-ahead and real-time NCPC. When combined with lower real-time prices compared with prices in the day-ahead energy market, this results in higher real-time NCPC when the underlying supply offer does not change between the two markets.[11] It is estimated that this third factor resulted in NCPC payments of approximately $68 million from December 2014 through January 2016. In 2015, the payments are estimated to total almost $58 million, or almost half of total NCPC payments. This aspect of the NCPC redesign, where a generation resource could receive two uplift payments for the same day-ahead commitment, was reconsidered and ultimately eliminated in February 2016 as it was not consistent with the make-whole and performance incentives intended in the redesign.

1.4 Virtual Transactions

Virtual transactions have declined significantly since 2008. Corresponding to this decline, cleared virtual transactions incur a greater share of real-time economic NCPC as the total amount of real-time deviations has fallen. Cleared incremental offer and decremental bids are allocated real-time economic NCPC based on their share of real-time deviation MWs.[12] As participants reduce their virtual activity, the few remaining virtual transactions incur higher NCPC charges which hinder participants' ability to arbitrage smaller price differences.

In 2015, approximately 462 MW/hour of virtual transactions cleared which is consistent with recent years, but represents a material reduction in cleared virtual transaction from years prior to 2011. For example, in 2008 there were about 3,633 MW/hour of cleared virtual transactions. While there are opportunities for virtual transactions to profit from hourly differences in day-ahead and real-time price (gross profit), the allocation of uplift to cleared virtual transactions reduces this opportunity (net profit). In 2015 the average per-MW real-time NCPC charge rate was $2.93; in 2008 the rate was $0.67.

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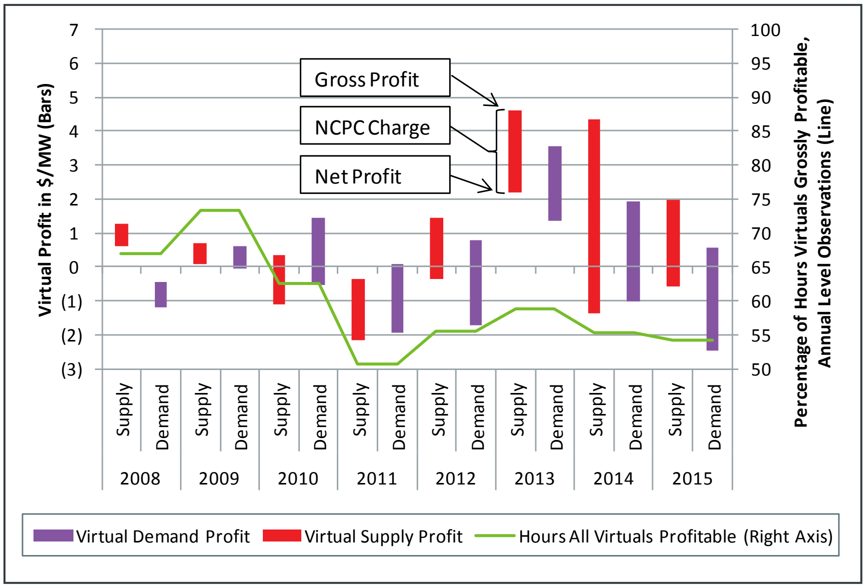
etc.) and changes in NCPC payment rules. For example, the total NCPC payments for 2015 reflect changes in payment rules that allowed generators to collect more NCPC than under prior NCPC rules.

[11] ISO New England Inc., joined by the NEPOOL Participants Committee, filed tariff revisions to modify two provisions of the NCPC credit rules. The main change was to eliminate payment of NCPC to cover commitment costs in the Real-Time energy market when a non-fast start resource is operating pursuant to a schedule it received in the Day-Ahead energy market. See ISO New England Inc. and the NEPOOL Participants Committee, Market Rule 1 Revisions Related to the NCPC Credit Rules, Docket No. ER16-250-000 (filed November 3, 2015).The revised rules went into effect in February 2016.

[12] Real-time deviation MWs are real-time deviations from the day-ahead schedule. By definition, virtual transactions are deviations because they are not physically delivered in the real-time market. Real-time DEC deviations may be offset by positive load deviations within a portfolio. However, these balancing load deviations are not considered in this analysis.

Figure 1-8 displays the annual average net and gross profit (before NCPC charges) of virtual transactions since the beginning of 2008. The bars are categorized by year and type (i.e. virtual supply or virtual demand). The top of each bar represents gross profit, the bottom represents the net profit, and the height of the bar represents the per-MW NCPC charge. In addition, there is a line on the graph that shows the percentage of hours during the year that virtual transactions were profitable on a gross basis.

Figure 1-8: Virtual Net and Gross Profits and Percentage of Hours Profitable (Gross)



Although virtual transactions have been profitable on a gross basis, virtual trades have had negative net profits after accounting for NCPC charges, with the exception of 2013. Other than virtual demand in 2008 and virtual supply in 2011, virtual transactions have, on average, had positive gross annual profits. The per-MW gross profits between 2013 and 2015 were substantially greater than 2008 and 2009. Despite the increase in per-MW gross profit, the percentage of hours that virtual transactions are profitable on a gross basis and helped converge prices has decreased. In 67% of hours in 2008, virtual transactions were profitable on a gross basis. This number increased to 73% in 2009; in 2015, virtual transactions only helped converge price in 54% of hours

1.5 Forward Capacity Market

The FCM is a long-term market designed to procure the resources needed to meet the region's local and system-wide resource adequacy requirements. The FCM is needed because, in general, revenue from the energy and ancillary services markets alone are not sufficient to encourage investment in new resources or upgrades to existing resources. Resources are procured forty months in advance of when the capacity will be delivered. After the primary auction, participants are allowed to trade their capacity supply obligation (CSO) positions. The secondary trading of CSOs takes place through a series of reconfiguration auctions and bilateral trading administered by the ISO. Like the real-time energy market, reconfiguration auctions and bilateral trading are essentially imbalance markets.

The first eight FCAs used a vertical demand curve that had a fixed capacity requirement. A vertical demand curve, by definition, lacks price-sensitivity and can result in large changes in capacity prices from year to year. Starting with FCA 9 (conducted in February 2015 for the 2018/19 delivery period) a sloped demand curve replaced the vertical demand curve. The system sloped demand curve is intended to improve price formation – specifically, to reduce price volatility and establish efficient price signals to maintain the region's long run reliability criteria.

The system was relatively long for the first seven auctions, clearing at prices ranging from $2.95/kW-month to $4.50/kW-month. However, retirements and changes in zonal definition created opportunity for new entry to meet demand. In FCA 7, the NEMA/Boston zone was short, resulting in a new combined cycle plant clearing and the zonal capacity price being administratively set to $14.999/kW-month (for new resources in that zone only). In FCA 8, a capacity deficit of 153 MW occurred which triggered administrative pricing rules. As a result, existing (non-NEMA/Boston) resources will be paid $7.025/kW-month and new and existing resources in NEMA/Boston will be paid $15/kW-month.

In FCA 9 four capacity zones were modelled: Southeastern Massachusetts/Rhode Island (SEMA-RI), Connecticut, Northeastern Massachusetts/Boston (NEMA-Boston) and Rest-of-Pool. A system-wide sloped demand curve was applied for the first time. At prices below the FCA Starting Price of $17.728/kW-month, the system-wide quantity increased linearly as the price decreases.

System-wide, existing capacity (32,101 MW) was approximately 2,100 MW less than the NICR of 34,189 MW. As a result, the IMM determined that all participants with existing resources were pivotal suppliers and therefore resources with mitigated de-list bids were entered into the auction at those mitigated bid prices. The IMM reviewed the cost basis of all submitted de-list bids and imposed mitigation, where necessary, on submitted de-list bids. Over 5,400 MW of new resources qualified to participate in the auction.

Local requirements and restrictions, coupled with different levels of supply offered in these locations, resulted in the capacity zones and external interfaces clearing at different prices.

- *SEMA-RI:* There was insufficient existing and new capacity to meet the requirement in the SEMA-RI capacity zone. As a result of the shortage and applicable administrative pricing rules, the payment rate for existing resources located in SEMA-RI was set to the Net CONE of $11.080/kW- month, and the payment rate for new resources was set to the FCA 9 starting price ($17.728/kW-month).[13]
- *System-wide:* The system demand curve, including the 238 MW of shortage from the SEMA-RI capacity zone, cleared at a price of $9.551/kW-month. This price applied to resources in NEMA-Boston, Connecticut and Rest-of-Pool capacity zones.
- *Interfaces:* Generally, there was surplus supply offered at the interfaces. The New York AC ties cleared at a price of $7.967/kW-month and the New Brunswick tie cleared at a price of $3.940/kW-month.

Almost 2,800 MW of new capacity cleared in the auction. A total of 118 delist bids were entered in the auction from existing capacity resources. The ISO accepted 12 of these bids for a total of

[13] See Market Rule 1, III.13.2.8.

194 MW. All of the delist bids were for a single year (static delist bids), meaning that these resources participate in FCA 10.

The outcome of the ninth FCA system-wide was the result of a competitive auction with the exception of the SEMA-RI capacity zone where there was insufficient competition to the point that there was insufficient capacity to meet the zonal requirement. The combination of offer mitigation and administrative pricing rules served to protect the auction from uncompetitive outcomes in this zone through the potential exercise of market power.

1.6 Market Competitiveness and Mitigation

A number of metrics have been applied to the various markets to assess their general structure and competitiveness. A broad range of industry-standard economic metrics are presented in this report, such as market concentration and the C4, the Residual Supply Index and Pivotal Supplier Test, and the Lerner Index. Each metric assesses market concentration or competitiveness with varying degrees of usefulness, but combined, can complement each other. Market power mitigation rules are also in place in both the energy and capacity markets that allow the IMM to closely review underling costs of offers and bids. The rules are designed to protect the market from the potential exercise of market power and to thereby ensure a level playing field.

Energy Market

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

- *C4 for supply-side participants*
  The C4 is the simple sum of the percentage of system-wide market supply provided by the four largest firms in all on-peak hours in the year and reflects the affiliate relationships among suppliers. In 2015, the C4 value was 41%, which was the same value as observed for 2014 and somewhat lower than previous years.
- *C4 for demand-side participants*
  The demand share of the four largest firms in 2015 was almost 50%, representing an increase over previous years. This was the result of two load participants adding demand obligations.
- *Residual Supply Index (RSI) and Pivotal Supplier Test (PST)*
  The RSI provides a measure of structural competitiveness by evaluating the extent to which supply, without the single largest supplier, can meet demand. This provides an indication of the extent to which the largest supplier has market power and can economically or physically withhold generation and influence the market price. A related concept is that of a pivotal supplier. If some portion of supply from a portfolio (not necessarily the largest supplier) is needed to meet demand then that supplier has market power and can withhold one or more of its resources to increase the market price. Results from the RSI and pivotal supplier analysis indicate that there have been supply portfolios with market power in the majority of hours.[14] In the absence of

[14] Note that previous reports indicated a much lower percent of hours were the RSI was less than 100. While the general methodology for calculating the RSI has remained the same, the new calculation of RSI reported here is more accurate in accounting for available capacity as well as reserve requirements. The current calculation uses the same inputs as are used by the mitigation software that is run in real-time and produces much more accurate results.

effective mitigation measures participants may have the ability to unilaterally take action that would increase prices above competitive levels.

While mitigation rules are in place to protect the market from such action, the rules permit a high tolerance level, whereby a participant must submit supply offers in excess of $100/MWh or 300% above a competitive benchmark price, and impact price, before mitigation takes place. The conduct test, which looks at whether the offer price is greater than the competitive benchmark price for a resource by the specified tolerance level, was violated by pivotal suppliers in roughly 30 percent to 55 percent of hours. This triggers further evaluation in the automated mitigation process. The impact of these high offer prices on market price is evaluated and if the price impact exceeds the threshold then mitigation is applied. The impact threshold was violated on only 5 to 25 hours (roughly zero percent of hours). Further analysis is required to assess the appropriateness of the mitigation thresholds, particularly for pivotal supplier mitigation.

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

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

  The Lerner Index is calculated as the percentage difference between the annual generation-weighted LMPs between two scenarios. The first scenario calculates prices using actual supply offers, while the second scenario uses marginal cost estimates in place of supply offers. The results are shown in Table 1-2 below.

Table 1-2: Lerner Index for Day-Ahead Energy

Year	Lerner Index
2011	9.3
2012	9.9
2013	4.3
2014	9.0
2015	9.8

  The results show that competition among suppliers limited their ability to increase price by submitting offers above estimates of their marginal cost. Pricing outcomes in the day-ahead energy market were competitive on average over the past five years.

Capacity Market

Two metrics were calculated to evaluate the competitiveness of the capacity market; the RSI and PST.

- *Residual Supply Index*
  The RSI is measured on a continuous scale with a lowest possible value of 0 and an uncapped upper limit. When the RSI is less than 100 percent, the largest supplier is needed to meet demand and could, in principle, impact the market clearing price. At the system level, the RSI exceeded 100% in FCA 6 only. The system-wide RSI has dipped in recent FCAs, falling by over 10% between FCA 7 and 8. The RSI in the Connecticut capacity zone fluctuated between 89% and 98% during FCAs 7 and 9. While improving from an RSI of approximately 28% in FCA 7, the Northeast Massachusetts / Boston capacity zone had an RSI of approximately 48% in FCA 9, indicating that the capacity from the largest supplier in that zone accounted for more than half of the Local Sourcing Requirement (LSR). The RSI was approximately 76% in the Southeast Massachusetts / Rhode Island (SEMA-RI) capacity zone in FCA 9.
- *Pivotal Supplier Test*
  The PST is measured on a binary scale and provides an indication of the number of suppliers who may be able to influence prices. The PST is a portfolio-level test that is conducted at the system and import-constrained zone levels for each supplier. The PST compares 1) the total existing capacity in a zone without that supplier's portfolio of existing capacity to 2) the relevant capacity requirement for that zone.[15] If the former quantity is less than the latter quantity, the supplier is deemed a pivotal supplier and any delist bids it has submitted at prices above the Dynamic Delist Bid Threshold may be subject to mitigation.[16] With the exception of the NEMA-Boston capacity zone, capacity levels exceeded requirements in FCAs 6 and 7; consequently, there were few, if any, pivotal suppliers outside of the NEMA-Boston zone during these auctions. At the system level, the capacity margin fell by over 90% between FCAs 7 and 8. It was negative leading into FCA 9, indicating that the supply of existing capacity could not meet the ICR, causing every supplier to be deemed pivotal. Conversely, the capacity margin increased to over 250 MWs in the NEMA-Boston capacity zone between FCAs 7 and 9. Meanwhile, the Connecticut capacity zone maintained a comfortable capacity margin of over 1,400 MWs during the same time period. Lastly, all suppliers in the SEMA-RI capacity zone were pivotal in FCA 9 given the area's shortfall against the LSR.

Ancillary Services Markets

The Residual Supply Index was calculated for the Forward Reserve Market (FRM) and the regulation market.

The FRM was structurally uncompetitive (RSI < 100) in 3 out of the 7 auctions for Ten-Minute Non-Spinning Reserve (TMNSR) and in 5 out of the 7 auctions in at least one zone. Pivotal suppliers exist when the RSI is less than 100 and means that the supplier may able to strategically offer reserves into the FRM at uncompetitive prices. There is currently no market power mitigation in the FRM beyond simple offer caps. Further analysis indicates that there is eligible capacity that is not offered into the FRM. If all the available reserve capability was offered in the FRM, there would not have been a pivotal supplier in any of the auctions for TMNSR and the auctions would have been structurally competitive. The same would have been

[15] The relevant requirements are the Installed Capacity Requirement (net of HQICCS) (ICR) at the system level and the Local Sourcing Requirement (LSR) at the import-constrained zonal level.

[16] Note that there are certain conditions under which capacity is treated as non-pivotal. These conditions are described in Section III.A.23.2 of the Tariff.

true in the case of Thirty-Minute Operating Reserve (TMOR) for the SWCT zone only. Additional analysis is required to determine if the presence of pivotal suppliers has resulted in uncompetitive prices.

In the regulation market, the lowest hourly average RSI in 2015 did not fall below 1,000%, implying that, on average, the system has the capability to serve 10 times the regulation requirement without the largest regulation supplier, even in the hours with the greatest regulation requirement. The average available regulation supply per hour, in terms of the number of participants in the market, provides additional evidence to suggest that the regulation market is structurally competitive.

Market Power Mitigation

There are times when market power exists in the energy and capacity markets and rules are in place to prevent the potential exercise of market power from impacting market outcomes.

In the energy market in 2015 there were 2,838 unit-hours of mitigation. For context, during 2015 supply offers were submitted for 337 generators over 8,760 hours during the year; this amounted to approximately 2.9 million unit-hours tested for mitigation. The 2,838 unit-hours of mitigation amount to roughly 0.1% of tested unit-hours (i.e., 2,838 mitigated unit-hours / 2.9 million tested unit-hours). Mitigation events in the energy market (in unit-hours) continued to decline during 2015.

There are two types of resource mitigation that can take place in the forward capacity market: seller-side mitigation and buyer-side mitigation.

For FCAs 8, 9 and 10, the IMM reviewed over 200 static de-list bids from a variety of participants where seller-side market power mitigation may be applied. For generation resources, the static de-list bids for the past three auctions totaled nearly 16,000 MW.[17] The IMM applied mitigation to approximately 63% of the static de-list bids it reviewed, which represents approximately 69% of the de-listed capacity (MW). For demand resources, which consist of many smaller resources, the static de-list bids for the past three auctions totaled slightly less than 1,200 MW. The IMM applied mitigation to approximately 54% of the reviewed demand resource static de-list bids, which represented approximately 48% of the de-listed capacity (MW).

After the IMM's review, participants with generation resources subsequently withdrew 54% of the static delist-bids that were mitigated, as compared with a 38% withdrawal rate of static de-list bids that were not mitigated. There were very few withdrawals of demand resources prior to the auction. Participants with generation resources further reduced the price of mitigated static de-list bids by a weighted average of $0.59/kW-month. The resulting final weighted-average price for these mitigated resources was $2.12/kW-month less than the participant's originally submitted price. By comparison, participants whose static de-list bids were not mitigated reduced their final prices, relative to their originally submitted price, by a weighted average of $1.14/kW-month. There were very few price reductions for demand resources.

For FCAs 8, 9 and 10, the IMM reviewed over 200 new supply offers from a variety of participants with generation, demand resources and imports where buyer-side market power

[17] A resource with a static de-list bid in each of the three auctions would be counted three times in the MW total.

mitigation may be applied. Offers from import resources were reviewed starting with FCA 9. For generation resources, new supply offers for the past three auctions totaled over 9,000 MW.[18] The IMM applied mitigation to approximately 40% of new supply offers it reviewed, which also represented approximately 40% of the new generation capacity (MW). For demand resources, the new supply offers for the past three auctions totaled less than 400 MW. The IMM applied mitigation to approximately 16% of the new supply offers from demand resources it reviewed, which represented approximately 22% of the new demand resource capacity.

Participants can withdraw a new supply offer prior to the auction. Participants with generation resources withdrew 25% of the new supply offers that were mitigated, as compared with a 50% withdrawal rate of new supply offers that were not mitigated. The weighted-average increase to the mitigated new supply offers that withdrew prior to the auction was $2.09/kW-month, about 35% higher than the $1.54/kW-month weighted-average increase to mitigated new supply offers that participated in the auction. There were very few withdrawals of new supply offers from demand resources.

1.7 Market Design Changes

The following is a summary of the major revisions to the market design implemented in 2015 and planned for in future years:

Major Design Changes Implemented in 2015

Coordinated Transaction Scheduling for External Transactions: The CTS project identified three root causes of the economic inefficiencies on the tie lines between New York and New England: *Latency Delay*, *Non-economic Clearing* and *Transaction Costs*. The CTS project was designed to remedy the root causes by employing higher-frequency scheduling and eliminating most transaction charges on external transactions. FERC approved CTS on April 19, 2012. CTS was implemented at the New York-North interface in the real-time energy market on December 15, 2015.[19]

Market Monitoring-Related Capacity Market Changes: Changes were made to the FCM Dynamic De-List Bid Threshold, the method for calculating the Pivotal Supplier Test, and to the mitigation rules pertaining to import capacity resources.

- The dynamic delist bid threshold used for FCA 9 did not explicitly account for capacity performance charges under the pay-for-performance rules, yet all the submitted static delist bids for FCA 9 included capacity performance charges. The dynamic delist bid threshold was increased from $3.94 /kW-month to $5.50/kW-month starting with FCA 10 to account for capacity performance charges. This change is intended to avoid the review of de-list bid information at prices below a competitive offer price.
- Changes were made to improve the pivotal supplier test for FCA 10 that apply a consistent treatment of interface constraints for purposes of determining whether a supplier is pivotal; move the calculation of the test closer to the time of the auction; and

[18] A resource with a new supply offer in each of the three auctions would be counted three times in the MW total.

[19] FERC, *Order Accepting Tariff Revisions, Subject to a Compliance Filing*, Docket No. ER12-1155-000 (April 19, 2012), http://www.iso-ne.com/regulatory/ferc/orders/2012/apr/er12-1155-000_4-19-12_order_accept_cts.pdf.

add a new definition of "control" that more accurately accounts for resources that should be included in the assessment of a supplier's overall capacity portfolio.

- The ISO improved the rules governing the treatment of import capacity resources in the FCA. The changes will ensure that capacity imports that are similar to existing resources receive the same mitigation treatment in the Forward Capacity Auction as existing resources. The changes also will ensure that capacity imports that are similar to new resources receive the same treatment as other new resources during the auction.

Major Design Changes Proposed for Future Years

Uneconomic Retirements Changes Proposed for FCA 11: On December 17, 2015, market rule changes were filed that will provide a process for reviewing options for capacity market participation or retirement, and market power mitigation measures in the capacity auction.[20] The proposed rule changes address three issues:

- The primary means of fully retiring a resource under the current rules is the use of non-price retirement requests. This means that a supplier with a resource that may be nearing retirement but which also may continue to be economic at a particular price does not have an effective way to submit the resource's retirement price under the existing structure. The proposed rule changes address this issue by providing for the use of priced retirement bids in place of non-price retirement requests.
- The current FCM rules do not address the potential for a capacity supplier to exercise market power by retiring a resource prematurely in order to decrease supply, artificially increase prices, and benefit the remainder of the supplier's portfolio. The proposed rule changes address this issue by providing for review of priced retirement bids by the IMM and the FERC and, if appropriate, the use of the FERC-approved prices to mitigate the impact of an uneconomic retirement.
- The current FCM auction schedule does a poor job of signaling to the market in a timely manner that additional capacity may be needed due to the retirement of existing resources. The proposed rule changes address this issue by changing the FCM auction timeline to provide for the submission of retirement bids prior to the "show of interest" deadline for new resources.

FCM Zonal Demand Curves (planned effective date, FCA 11): On April 15, 2016, rule changes were filed to address the shortcomings of the existing set of demand curves to improve the performance of the Forward Capacity Market.[21] The new set of curves (at both the system and zonal level) are based on design principles that reflect the marginal improvement in reliability associated with adding capacity in constrained capacity zones versus the remainder of the system. The new set of demand curves will set prices that more accurately reflect the locational marginal reliability impact of capacity. At the zonal level, replacing the existing vertical demand curves with sloped demand curves addresses the price volatility and market power concerns by specifying a more gradual change in prices corresponding to shifts in supply and accounting for the partial substitutability of capacity across zones.

[20] *Forward Capacity Market Reforms* (ER16-551-000), December 17, 2015, http://www.iso-ne.com/static-assets/documents/2015/12/er16-551-000_retire_reforms.pdf.

[21] *Demand Curve Design Improvements* (ER16-1434-000), April 15, 2016, http://www.iso-ne.com/static-assets/documents/2016/04/er16-1434-000.pdf.

Fast Start Pricing (Quarter 1, 2017): On September 24, 2015, rule changes were filed to improve real-time price formation when fast-start resources are deployed.[22] Four changes to dispatch, pricing, and compensation when fast-start resources are committed and dispatched are being made:

- Adjusting the real-time dispatch process to satisfy the offered minimum output level of each committed fast-start resource during its initial commitment interval;
- "Relaxing" a pool-committed fast-start resource's minimum output to zero in the pricing process that calculates real-time LMPs and Reserve Market Clearing Prices ("RMCPs");
- Revising the current treatment of a fast-start resource's Start-Up Fee and No-Load Fee in the pricing process; and
- Providing compensation to resources that, in certain circumstances, may incur a lost-opportunity cost for following the ISO's dispatch instructions when a fast-start resource sets the LMP under the new pricing method.

Sub-Hourly Settlement (Quarter 1, 2017): The rule changes will improve the incentive to follow price signals in the real-time energy market. Sub-hourly settlement will settle all assets and transactions in the real-time energy and reserve market on a 5-minute basis, rather than on the hourly average prices and quantities.

Do-Not-Exceed Dispatch (Quarter 2, 2016): On April 15, 2015, rule changes were filed to improve the dispatch of certain wind and hydro resources in order to achieve more efficient economic outcomes and improve system reliability.[23] The do-not exceed dispatch changes will improve price formation in local areas that have a high penetration of renewable resources and limited transmission capacity.

Market Enhancements for Asset-Related Demand (Quarter 1, 2017): On February 17, 2016, rule changes were filed to improve the way that pump storage hydro-generating resources are modeled and dispatched.[24] The changes establish new modeling practices and bidding parameters that allow participants with pump storage hydro-generating resources to better reflect the operating characteristics of this type of resource in the resource's supply offer data and to better reflect those operating characteristics in the economic dispatch. The rule changes also include several modifications of the NCPC rules related to pump storage hydro-generating resources and other resources with similar characteristics.

Price Responsive Demand (Quarter 2, 2018): On March 15, 2011, FERC issued *Order 745: Demand Response Compensation in Organized Wholesale Energy Markets*, which requires organized wholesale energy markets to pay demand-response providers the market price for electric energy for reducing consumption below expected levels.[25] Various sets of changes to the market

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[22] *Revisions to Fast-Start Resource Pricing and Dispatch* (ER15-2716-000), September 24, 2015, http://www.iso-ne.com/static-assets/documents/2015/09/er15-2716-000_fast_start.pdf

[23] *Do-Not-Exceed Dispatch Changes* (ER15-1509-000), April 15, 2015, http://www.iso-ne.com/static-assets/documents/2015/04/er15-1509-000_-_do_not_exceed_dispatch_changes.pdf.

[24] *DARD Pump Parameter Changes* (ER16-954-000_, February 17, 2016, http://www.iso-ne.com/static-assets/documents/2016/02/er16-954-000.pdf

[25] http://www.ferc.gov/EventCalendar/Files/20110315105757-RM10-17-000.pdf.

rules are being implemented to meet the obligations of Order 745: The ISO modified its existing demand-response programs to immediately comply with the requirements of Order 745, is also working toward full integration of demand response into the energy markets to further improve overall market efficiency, and has proposed modifications to market rules to allow demand response resources that participate in the energy market to also provide reserves, similar to other supply resources.

1.8 Recommendations

The following table summarizes the IMM's recommended market enhancements from this report and from previous reports, along with the status of each recommendation.

Table 1-3: Market Enhancement Recommendations

Recommendations	Status as of the AMR '15 Publication Date
The ISO develop and maintain a database of corporate relationships and asset control that allows for accurate portfolio construction for the purpose of identifying uncompetitive participation, including the potential exercise of market power and market manipulation	New recommendation included in the Q2 2015 Quarterly Markets Report
The ISO, working in conjunction with the IMM, enhance the real-time energy market mitigation pivotal supplier test to include (1) ramp-based accounting of supply recognizing the differences between energy and reserve products and (2) participant affiliations.	New Recommendation
The ISO develop and implement the following processes and mechanisms regarding uneconomic resource retirements in the Forward Capacity Market: • A process for identifying resource retirements that appear to be pre-mature with respect to their expected economic life and can be used to exercise market power, • A mitigation measure that ensures auction clearing prices are not distorted by the exercise of market power through pre-mature retirement of capacity resources, • A more robust mechanism for existing resources to retire through competitive price discovery in the Forward Capacity Market rather than through administrative means, and • A timeline for the retirement process that will facilitate signaling to prospective new entry the extent of potential retirement capacity prior to the show of interest deadline for new capacity resources.	The IMM has worked with the ISO and stakeholders to address this recommendation. Proposed rule changes were filed on December 17, 2015. They were accepted by FERC in April 2016.
The ISO develop and implement processes and mechanisms to resolve the market power concerns associated with exempting all or a portion of a Forward Reserve resource's energy supply offer from energy market mitigation.	New recommendation included in the Q2 2015 Quarterly Markets Report
The ISO modify the market rules as necessary when EMOF is introduced to ensure that the use of the limited-energy generator (LEG) provisions in both the day-ahead and real-time markets are restricted to instances when the availability of fuel is physically limited.	The ISO is currently assessing this issue
The ISO discontinue or replace the locational marginal price calculator for calculating real-time prices.	Completed late May, 2015
The ISO develop and implement processes and mechanisms to reduce NCPC charges to virtual transactions (to better reflect the NCPC cost causation principle) in response to the decline in virtual trading activity. A reduction in NCPC charges to virtual transactions will likely improve day-ahead scheduling by adjusting expectations of real-time conditions.	Stakeholder process not expected to start until after Q2 2017.
The ISO make available to the market the metrics that describe the accuracy of the new baseline methodology for demand resources. The planned implementation date for a new methodology for determining demand-resource baselines is June 1, 2018, at which time new market rules will become effective that will fully integrate dispatchable demand resources into the day-ahead and real-time markets. The new methodology's predictive ability in estimating a resource's actual load should be made transparent to the market.	The ISO is currently assessing this issue

Section 2
Overall Market Conditions

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

2.1 Wholesale Cost of Electricity

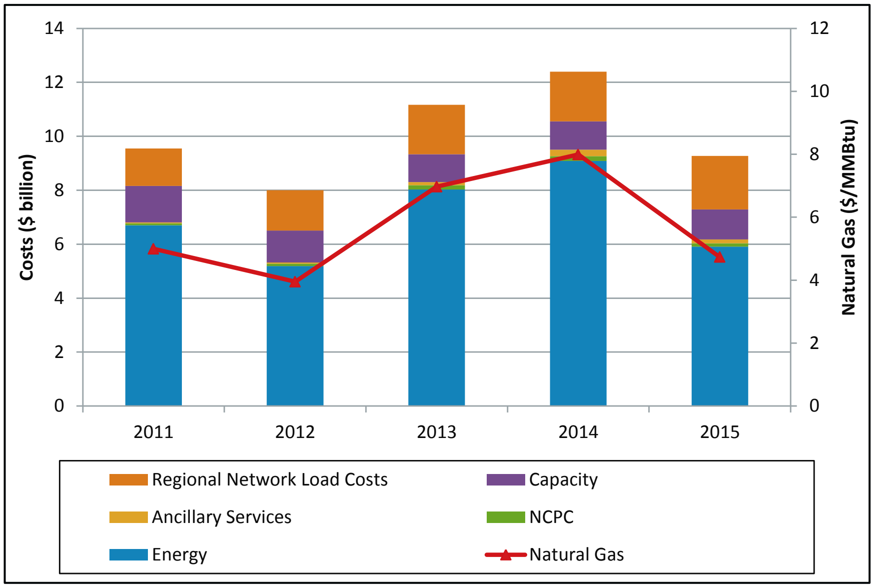
In 2015, the total estimated wholesale market cost of electricity was $9.3 billion, a decrease of about 25% compared with $12.4 billion in 2014.[26] The wholesale cost estimate is made up of three general categories; energy, capacity and transmission. The first category, energy, includes costs to load from the energy and reserves markets, which in turn can be broken down to energy, Net Commitment Period Compensation (NCPC, or out-of-market uplift) and Ancillary Services (operating reserve for contingencies plus regulating reserve) costs. This category comprised almost 67% of total wholesale costs in 2015. The second category, capacity, reflects the cost to retain sufficient generation capacity to meet energy and ancillary service requirements. This cost represented roughly 12% of total wholesale cost. The third category, transmission, includes transmission owner's recovery of infrastructure investments, maintenance, operating and reliability costs. These costs are also referred to as Regional Network Load (RNL) costs and represented approximately 21% of total wholesale costs.[27]

Figure 2-1 shows the estimated wholesale electricity cost for each year by market along with average natural gas prices.

[26] The total cost of electric energy is approximated as the product of the day-ahead load obligation for the region and the average day-ahead Locational Marginal Price (LMP) plus the product of the real-time load deviation for the region and the average real-time LMP. Transmission network costs, known as Regional Network Load (RNL) costs, are also included in the estimate of annual wholesale costs. RNL costs were not included in prior year reports. The methodology used in this report for the calculation of energy market costs represents an enhancement to that used in previous annual reports. In previous reports, the energy market was valued using the real-time LMP, whereas the new methodology more accurately reflects the amount of energy settled in both the day-ahead and real-time energy markets.

[27] RNL, or Open Access Transmission Tariff (OATT), costs are associated with providing regional network service (RNS) and other services to transmission customers that collectively provide for the use of transmission facilities, reliability, and certain administrative services. Of the 3 costs categories included in RNL (infrastructure, reliability and administrative), infrastructure costs make up the over 90%. The OATT governs the allocation of these costs, which are billed according to a transmission customer's hourly load at the time of the peak load of its local transmission network.

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



Note: MMBtu stands for million British thermal units.

Prices in the natural gas spot market are a key driver of energy, ancillary services and NCPC costs and this correlation can be seen clearly in the annual changes in those costs in Figure 2-1. Energy costs were $5.9 billion in 2015, 35% lower than 2014. NCPC costs in 2015, at $119 million, declined by 32% compared with 2014. Ancillary service costs, which include reserve and regulation payments, totaled $144 million in 2015, a decrease of 39% when compared with 2014. Natural gas prices were 41% lower in 2015 compared with the previous year. The decrease in average natural gas prices in 2015 compared with 2014 resulted in the significant decrease in energy costs.

Capacity market costs increased by 5% in 2015, which was expected given the increased capacity clearing price (from the auction held three years prior). Transmission costs increased by approximately 8% in 2015 as a result of investment in new transmission infrastructure, upgrades to existing infrastructure, operating and maintenance costs and other components impacting the overall revenue requirement.

2.2 Supply Conditions

This subsection of the report provides a macro-level view of supply conditions across the wholesale electricity market in 2015, and describes how those conditions have changed over the past several years. Topics covered include the generation mix within New England, fuel and emission market prices and estimates of generator profitability.

2.2.1 Generation and Capacity Mix

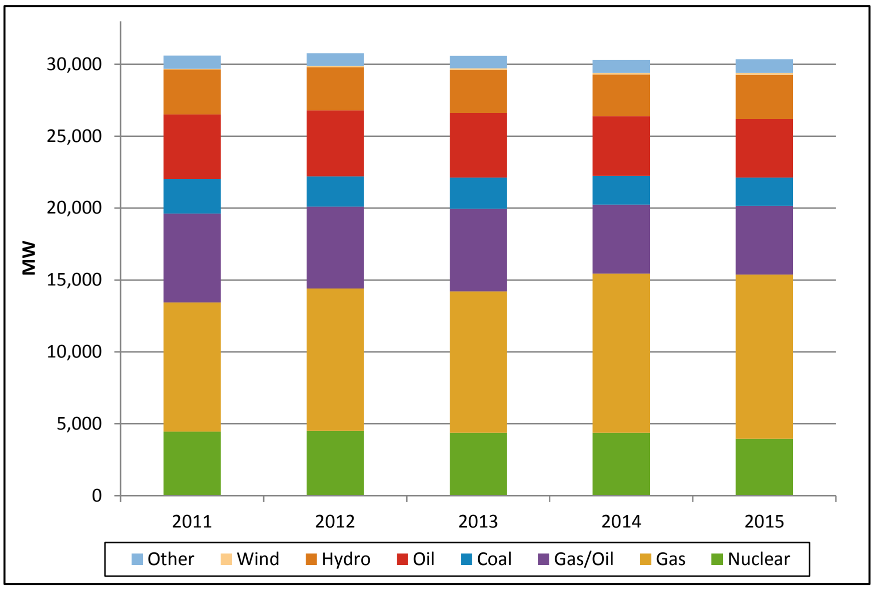
This section provides a summary of the generation mix in New England over the past five years. Information about generation is provided across a series of different dimensions, including fuel type, location, and age. The focus here is on generators native to New England and excludes external transactions (which are covered separately in Section 2.3.4 and Section 5). Understanding the composition of the native generation adds important context to overall supply conditions and market outcomes in New England.

2.2.1.1 Capacity by Fuel

Capacity is generally defined as the rated and continuous load-carrying ability of a generator, expressed in megawatts (MW). For the purpose of this section capacity is reported as the capacity supply obligations (CSO) of generators, which may be less than the rated capacity. A CSO is a forward contract in which the generator agrees to make the contracted capacity available to serve load or provide reserves by offering that capacity into the energy market.[28] Analyzing the aggregated CSOs of generators shows how much contracted capacity is available to the ISO operators, barring any generator outages or reductions.

Figure 2-2 below shows average generator capacity by fuel type for the past five years. Capacity in this case is the simple average of all monthly generator CSOs in a given year.

Figure 2-2: Average Generator Capacity by Fuel Type



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

In 2015 nuclear generation accounted for 13% of generation capacity physically located within the New England footprint. The impact of the retirement of the Vermont Yankee nuclear facility in 2014 can be seen in the reduced green bar in 2015. The retirement of the similarly-sized Pilgrim nuclear facility (about 690 MW) in 2019 will further reduce the capacity and energy share of nuclear fuel in future years. Natural gas-fired generators accounted for 38% of capacity and generators capable of burning either oil or natural gas (i.e., a type of dual-fuel generator) accounted for 16% of capacity. Combined, these gas and gas/oil dual fuel generators accounted for 53% of total average generation capacity. The percentage of capacity from gas and gas/oil dual fuel generators has been increasing slowly over the past few years as generators using other fuels have retired and new replacement capacity has largely been gas or gas/oil-fired. The share of coal-fired generation, which at about 2,000 MW makes up 6% of

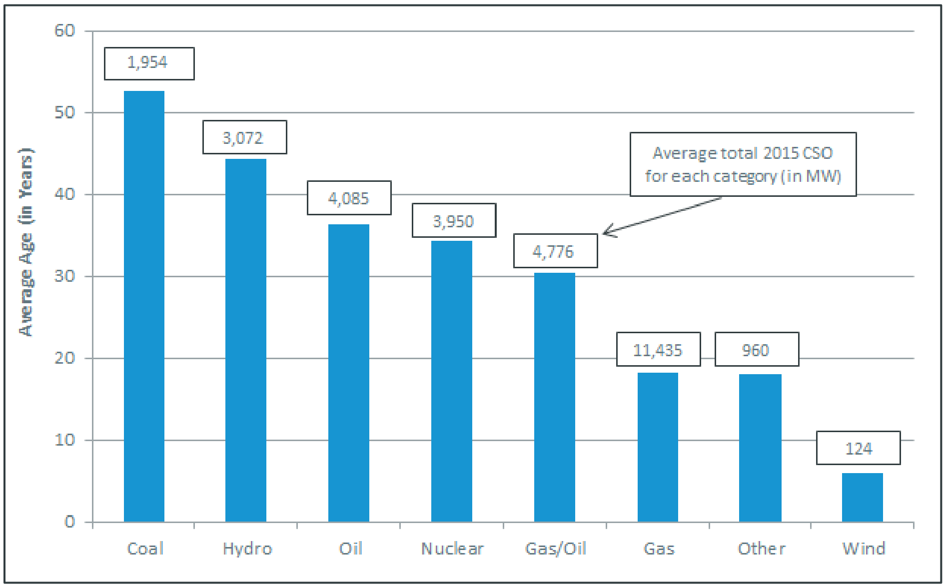
[28] More specifically, a CSO is "an obligation to provide capacity from a resource, or a portion thereof, to satisfy a portion of the Installed Capacity Requirement that is acquired through a Forward Capacity Auction in accordance with Section III.13.2, a reconfiguration auction in accordance with Section III.13.4, or a Capacity Supply Obligation Bilateral in accordance with Section III.13.5.1 of Market Rule 1." Section I- General Terms and Conditions, http://www.iso-ne.com/static-assets/documents/regulatory/tariff/sect_1/sect_i.pdf

overall native generation capacity, is likely to be halved in 2017 with the retirement of the Brayton Point facility.

2.2.1.2 *Average Age of Generators by Fuel*

Figure 2-3 below illustrates the average age, in years, of generators in New England, based on the generator's first day of commercial operation.

Figure 2-3: Average Age of New England Generator Capacity by Fuel Type[29]



As illustrated in Figure 2-3, the average age of generators by category ranged from 6 years to 53 years, with an average total system age of 30 years. Coal generators, which comprise 6% of total generation capacity, have the highest average age of 53 years. Oil generators, which make up 13% of total capacity, are 36 years old on average. Gas and gas/oil generators, which total over half of total capacity are relatively newer.

As generators age, they require increased maintenance and upgrades to remain operational. This is true for all generators, but older coal and oil generators in New England face other market dynamics, including increased emissions costs and public policy initiatives to reduce greenhouse gas emissions. Compared with coal and oil generators, new natural gas generators are cleaner, more efficient and generally have lower fuel costs. As a result, most new investments have been in new natural gas generators rather than in new or upgrades to coal or oil generators. In parallel, there has also been new investment in renewable generation, such as wind and solar. The old age of coal and oil generators coupled with the aforementioned economic drivers have contributed to generator retirements. More about generator retirements and new entry can be found in the next Section 2.2.2.

2.2.1.3 *Average Generator Output by Fuel Type*

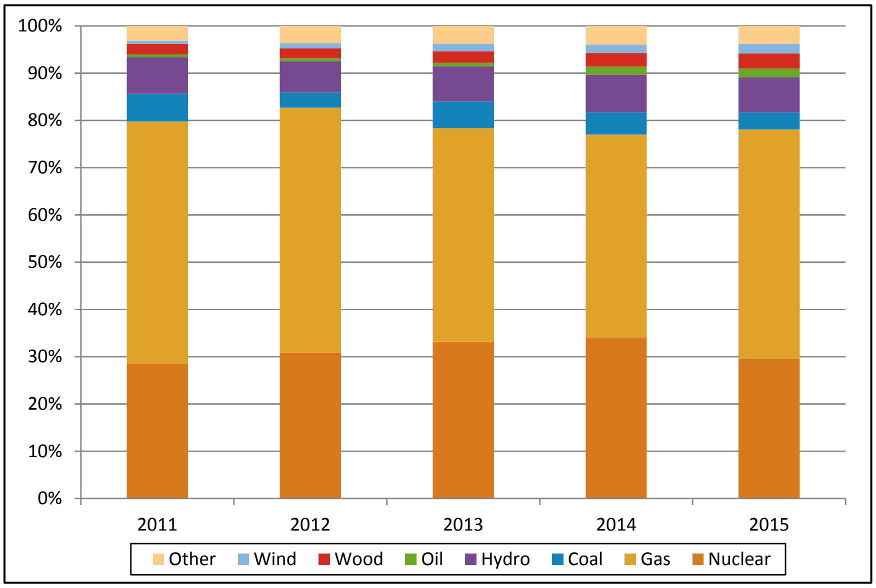
Up to this point, this section has focused on capacity. Though capacity is a useful measure to understand the generation fleet's capability and characteristics, analyzing actual energy

[29] Coal category includes units capable of burning coal and dual fuel units capable of burning coal and oil.

production (generation output in megawatt-hours, MWh) provides additional insight into the technologies and fuels used to meet New England's electricity consumption. Knowing what fuel is burned and where generators are located in the context of actual energy production helps us to understand and frame market outcomes.

Figure 2-4 below illustrates actual energy production by generator fuel type for the past five years. Unlike the capacity section above, oil/gas as a combined category is not shown. This is because the fuel that generators burned can be estimated based on the fuel included in the energy market offers of generators.

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



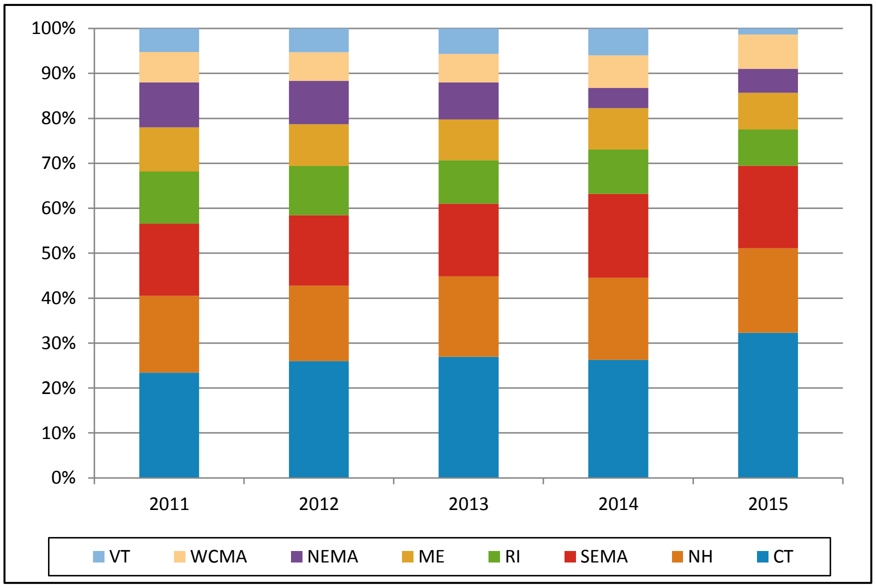
Note: The ISO New England load zones are as follows: Vermont (VT), Western-Central Massachusetts (WCMA), Northeast Massachusetts (NEMA), Maine (ME), Rhode Island (RI), Southeast Massachusetts (SEMA), New Hampshire (NH), and Connecticut (CT).

Annual energy production by fuel type has been relatively consistent over the past 5 years. In 2015, nuclear generation accounted for 30% of annual real-time energy production while natural gas generation accounted for 49%. Coal and oil generation together accounted for 6% of total energy production. Oil-fired generators typically run when they are needed for local reliability or when system conditions are stressed, and on average have very low capacity factors. Increased natural gas prices can cause coal or oil-fired generators to be less expensive to run than gas-fired generators. Coal-fired generators tend to be in-merit more often than oil and, as a result, have higher capacity factors. In winter months restrictive conditions on natural gas pipelines can greatly increase gas prices, making coal economic to run. For example, coal-fired generation had a capacity factor of about 80% during the first two months of 2015, and produced more energy than oil-fired generation, despite the capacity supply obligations of oil and gas/oil generators being far greater.[30] A detailed discussion about the effects of input fuels and supply-side participation on electricity prices can be found in Section 3.4 of this report.

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

Figure 2-5 below breaks down energy production by load zone. A load zone is a geographic area in New England in which pricing nodes are aggregated. Looking at this breakdown gives us a general idea of where energy is being produced.

Figure 2-5: Share of Native Electric Generation by Load Zone



Most of the region's electricity production comes from Connecticut (32%) and Massachusetts (31%). Massachusetts is broken into three different load zones: Western-Central Massachusetts (WCMA, 8%), Southeastern Massachusetts (SEMA, 18%), and Northeastern Massachusetts (NEMA, 5%). In the past few years, the NEMA load zone and the state of Vermont (VT) have seen reductions in energy production. The reduction in Vermont is mainly due to the retirement of Vermont Yankee Nuclear Power Station (604 MW) which will be covered in more detail in the Section 2.2.2. The reason for the reduction in NEMA is due to economics, where generators located in this load zone tend to be more expensive to run than generators located elsewhere. Major factors affecting energy prices and generator energy production will be covered in Section 3.4 of this report.

2.2.2 New Entry and Retirements

New supply-side and demand-side resources undergo a qualification process in order to participate in the Forward Capacity Market (FCM). For new power plant proposals, the ISO conducts several studies to ensure that the proposed generator can connect to the power grid without having a negative impact on reliability or violating safety standards. When a resource retires, the participant submits a retirement request to the ISO, which is an irrevocable request to retire all or a portion of a resource.

Figure 2-6 shows generator additions, retirements, (over 50 MW) and the net installed capacity requirement (NICR) from FCA 2 through FCA 10. Future periods indicate where the auction has already taken place but the delivery period, otherwise known as the capacity commitment period, is in the future.

Figure 2-6: Generator Additions, Retirements, and NICR

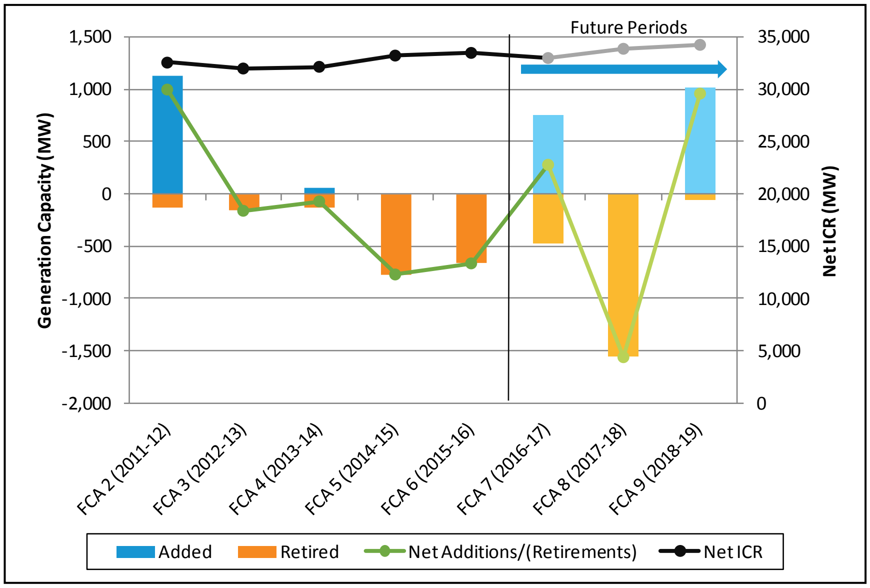


Figure 2-6 shows that capacity retirements have exceeded new capacity additions by about 1,000 MW. Most of the retirements (78%) have been coal and oil resources. In FCA 5, Salem Harbor 3 (coal), Salem Harbor 4 (fuel oil), and AES Thames (coal) retired. In FCA 6, Vermont Yankee (nuclear), retired, and in FCA 8, Brayton Point 1-4 (coal and fuel oil) retired.

Figure 2-6 also shows new capacity additions. In FCA 2, over 1,100 MW of natural gas and peaking unit capacity were added in Connecticut. In FCA 7, Footprint (natural gas) located in NEMA was added, and in FCA 9, over 1,000 MW of capacity, including 920 MW of dual fuel capacity, was added in Connecticut and Southeastern Massachusetts.

Natural gas generating resources accounted for 78% of new additions to capacity. Newer, cleaner and more efficient technology, combined with low natural gas prices, increasing emissions costs, and environmental regulations has contributed to more investment in new natural gas generators.

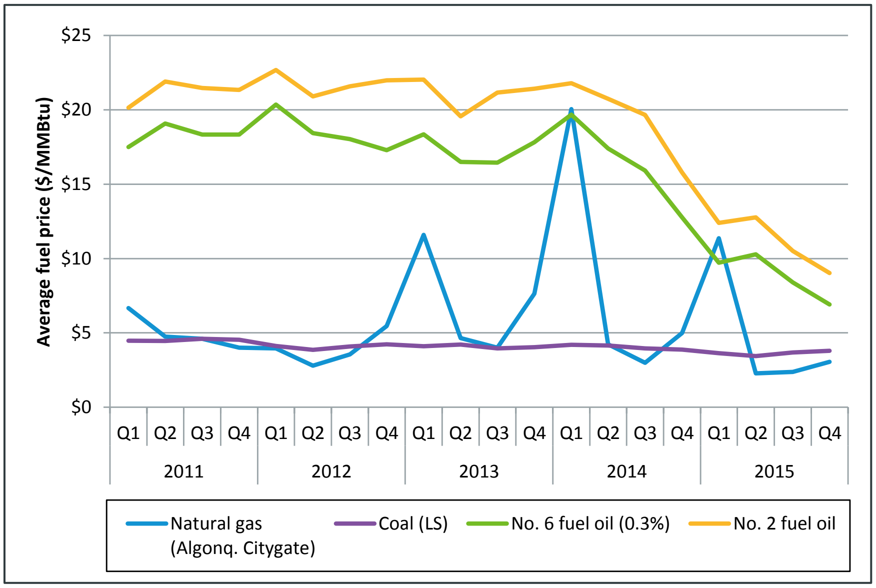
2.2.3 Generation Input Costs

This section provides a review of trends in both fuel prices and emissions prices over the past number of years. While fuel makes up the majority of variable production costs of thermal generators, the contribution of emissions to the variable cost of production has been increasing in recent years.

2.2.3.1 Fuel Prices

The primary drivers of New England's electricity prices are fuel costs and the operating efficiency of combustion generators. Generators fueled by natural gas, coal, and oil produce roughly 55% of the electricity to meet New England load. Overall for 2015, the cost of these fuels was lower than during 2014. Figure 2-7 below graphs the quarterly, simple-average cost of natural gas (at the Algonquin Citygate hub), low-sulfur (LS) coal, No. 6 (0.3% sulfur) and No. 2 fuel oils for the past five years.

Figure 2-7: Average Fuel Prices by Quarter



As shown in Figure 2-7, natural gas prices during 2015 were highest during the first quarter (Q1), which is consistent with observations in prior years when total regional gas demand has stressed New England's gas network. However, the average natural gas price of $11.36/MMBtu during Q1 2015 was 43% lower than the Q1 2014 average of $20.04/MMBtu. Injections of Liquefied Natural Gas (LNG) into the interstate pipeline system in New England more than doubled in Q1 2015 compared with Q1 2014. This increase in supply coincided with lower natural gas prices as well as lower variability in daily prices. Natural gas prices were lower in each quarter of 2015 compared with 2014. According to the U.S. Energy Information Administration (EIA), increases in domestic natural gas production, above-average storage inventories, and lower heating demand at the start of the 2015-16 winter season contributed to low prices in the latter part of 2015.[31]

Fuel oil prices were significantly lower in 2015 relative to the prior four years as global excess production increased inventories and reduced prices.[32] In Q1 2015, the average cost of No. 6 oil was 51% lower than in Q1 2014. Oil prices then dropped further, by roughly 30%, between Q1 and Q4 of 2015. Coal prices were, in contrast, relatively stable during 2015, but were also as much as 17% lower than 2014 prices when comparing quarterly prices for each year. By EIA estimates, domestic coal production and consumption fell by 11% during 2015 largely due to falling demand in the electric power sector.[33]

2.2.3.2 Emission Prices

The cost of obtaining emissions allowances (i.e., permits to produce emissions), as required by federal and state regulations, is a secondary driver of electricity production costs for

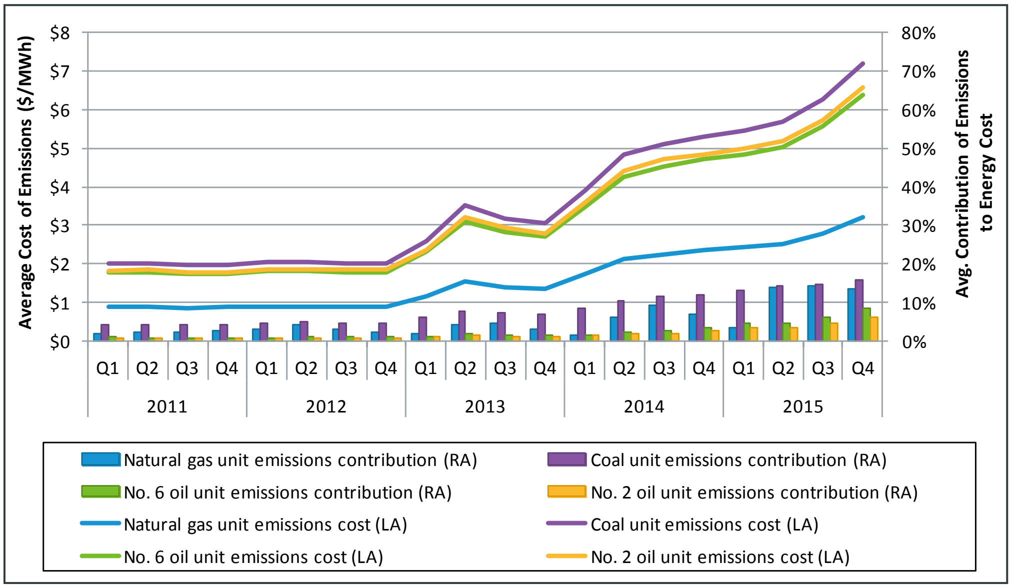
[31] US Energy Information Administration. *Short Term Energy Outlook January 2016*. Washington, DC: US Department of Energy, January 2016. https://www.eia.gov/forecasts/steo/archives/Jan16.pdf. Pages 9 – 10.

[32] *Id.* at page 5.

[33] *Id.* at page 11.

combustion generators. During 2015, emissions allowance costs continued to rise, primarily driven by carbon dioxide (CO_2) allowance prices. The cost of CO_2 allowances is the largest contributor to emissions costs because the rate of CO_2 production (pounds per unit of fuel burned) is higher than other pollutants. Accordingly, the cost of sulfur dioxide (SO_2) and nitrous oxide (NOx) emissions are a smaller proportion of total emissions costs. The line series on Figure 2-8 illustrate the average estimated cost of emissions allowance for fossil fuel generators (the left vertical axis [LA]; the average cost of emissions in $/MWh) for the past five years. The bar series on the figure shows the proportion of the average energy production costs attributable to emissions costs (right axis [RA]; the average contribution of emissions to energy costs) for the same years.

Figure 2-8: Contribution of Emissions Allowance Cost to Energy Production Cost



The quarterly average cost of emissions for natural gas, coal, and oil fuel units are represented by the line series in Figure 2-8. Note that these line series correspond with the left vertical axis (Average Cost of Emissions in $/MWh). These estimated costs were calculated using the emissions allowance prices utilized to set marginal cost reference levels and a benchmark full-load, average heat rate for generators of a representative technology type in each fuel category.[34] The line series for each of the fuel types show that, since 2013, the cost of emissions has risen and continued to rise through 2015. A natural gas generator had emissions costs of roughly $2.40-3.20/MWh, on average, in 2015. Coal unit emissions costs were about $5.50-7.20/MWh, and oil units had emissions costs ranging from $4.80-6.60/MWh, on average, during 2015.

The bar chart series in Figure 2-8 represent the quarterly average contribution of emissions allowance costs to the incremental cost of producing electricity. Note that the bar chart series correspond with the right vertical axis (Average Contribution of Emissions to Energy Costs). The proportions were calculated by estimating the fuel cost of each generator type (using the

[34] The full-load, average heat rate reflects incremental energy production and no load costs. Start-up fuel and emissions costs were excluded from this analysis.

same benchmark heat rates) and calculating the emissions cost component as a proportion of the estimated total fuel and emissions costs. As shown in Figure 2-8 the relative contribution of emissions allowance costs to generation costs rose in 2015. For coal- and oil-fired generators, the increase was primarily driven by a rise in CO_2 allowance prices. For natural gas generators, the rise in CO_2 allowance prices was a factor, but the low cost of natural gas during Q2-Q4 2015 also caused an increase in the cost of emissions relative to fuel costs. During the same period, the contribution of emissions costs to the estimated energy offer of a representative natural gas unit was above 10% on average.

2.2.4 Generator Profitability

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

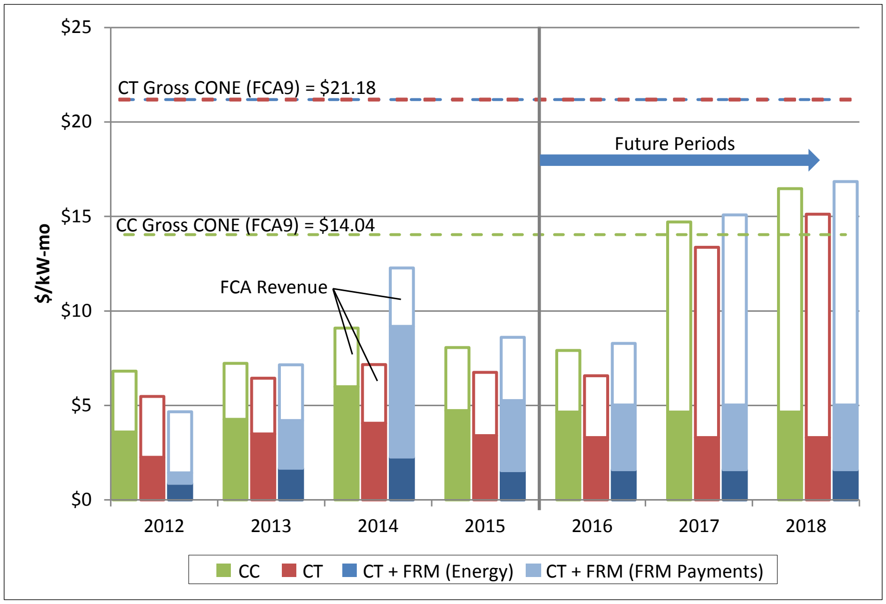
This section presents estimates of the net revenues that hypothetical new gas-fired generation units (combined cycle (CC) and combustion turbine (CT)) could have earned in the energy and ancillary services markets in each of the previous four years. This provides a basis for the amount of revenue required from the capacity market to move forward with a new generation project. The section also compares net revenue earnings for a combustion turbine unit that participates in the Forward Reserve Market (FRM) with one that does not.

The analysis simulates generator scheduling under an objective that maximizes net revenue while enforcing operational constraints, i.e., ramp rates, minimum run and down times, and economic limits. The simulation uses historical market prices, which implies that the generator's dispatch decisions do not have an impact on day-ahead or real-time energy prices. In addition, this analysis does not account for forced outages (which should be infrequent for a new resource) or dual-fuel capability[35]. Consequently, these results should be considered in the high range for potential revenue estimates. Figure 2-9 below shows the result of the simulations.[36]

[35] Planned modeling improvements include generator fuel-switching capability

[36] The Gross CONE figures for the CC and CT gas fired resources reflect Net CONE values of $11.08/kW-month and $19.88/kW-month with the difference between gross and net figures attributed to net revenue from energy and ancillary service sales.

Figure 2-9: Estimated Net Revenue from Energy and Ancillary Services for New Gas-fired Generators



Simulation results show that if market conditions remain similar to the previous four years, owners of new gas-fired generation units could expect net revenues to average $3.30-$5.02/kW-month. In addition, a new combustion turbine that is designated as an FRM resource could earn $1.72/kW-month more net revenue than the same resource could have accumulated in the real-time market alone. However, this result appears to be particularly sensitive to the frequency of scarcity pricing events via the Reserve-Constraint Penalty Factor (RCPF). While this study indicates that potential net revenue numbers exceed the benchmarks used to establish CONE numbers, total revenues - that include capacity payments - appear inadequate to incent green-field generation to enter the market in earlier years. During this period, the system was long on capacity. It is expected that the capacity price will be lower, and insufficient to incent new generation, when the system is long. In contrast, generation retirements moved the system into a state where it was not long on installed capacity during the period 2017 – 2018. Using average net revenue from prior years as a proxy, the combination of capacity market revenue and net revenue from energy and ancillary service sales are sufficient to support new entry from combined cycle resources, as was observed in these auctions.

A combustion turbine asset can also participate in the Forward Reserve Market where off-line reserves are procured prior to the reserve season. A forward reserve resource receives revenue from the forward reserve auction. However, it foregoes real-time reserve payments and, in most hours where the energy price is within a normal range, also foregoes energy revenue since it will be held in reserve. When the energy price is abnormally high, as in the case of a scarcity event, the forward reserve resource may be dispatched for energy and would then receive net revenue (above variable cost) for those high-priced periods. For the combustion turbine scenarios, participation in the FRM market results in greater net revenue than non-participation for three of the four years where these revenues have been observed (not future periods).

When compared with CONE benchmarks, revenues for new generation and FCA clearing prices appear to be sufficient to meet the cost of entry for gas-fired combined cycle units but remain too low to incent the addition of new combustion turbine generation units. However, recent FCA auctions have cleared a number of combined cycle and combustion turbine units. CONE benchmarks were produced from financial and engineering studies to estimate the cost of adding green-field generation units. In practice, the cost of new entry for a generator unit may be lower than the established CONE benchmarks for a number of reasons. In particular, when new generating units are built on existing generation sites or when there are material additions to the capacity of an existing operational plant, the presence of existing infrastructure tends to lower fixed costs.

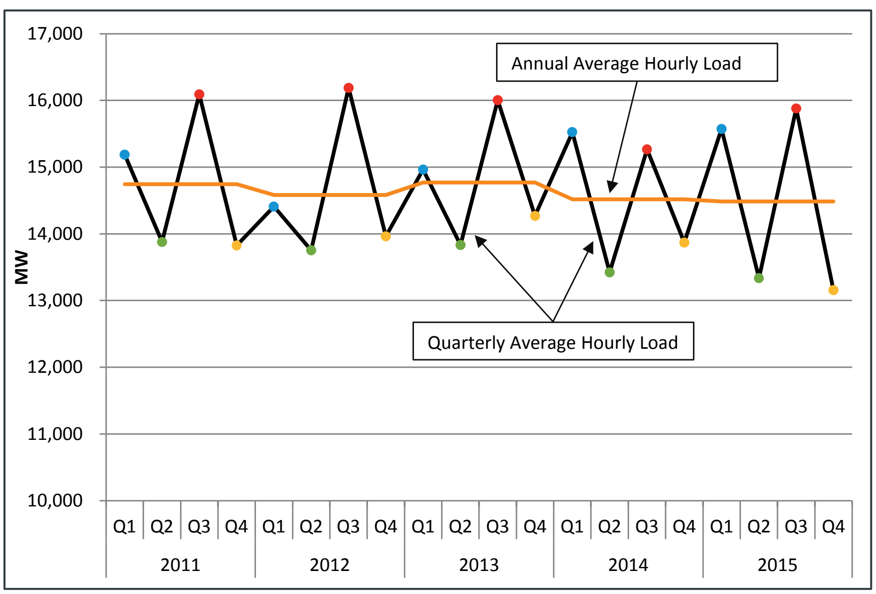
2.3 Demand Conditions

The real-time energy market coordinates the dispatch of generation and demand resources to meet the demand for electricity and to meet reserve requirements. Consumer demand is one of the key drivers of wholesale electricity prices in New England. Electricity demand is driven primarily by weather and economic factors.

2.3.1 Energy Demand

Figure 2-10 below shows the average hourly demand, or load, by year and quarter from 2011 through 2015. The orange line represents average hourly loads and calendar quarters are identified by different colored dots on that line.

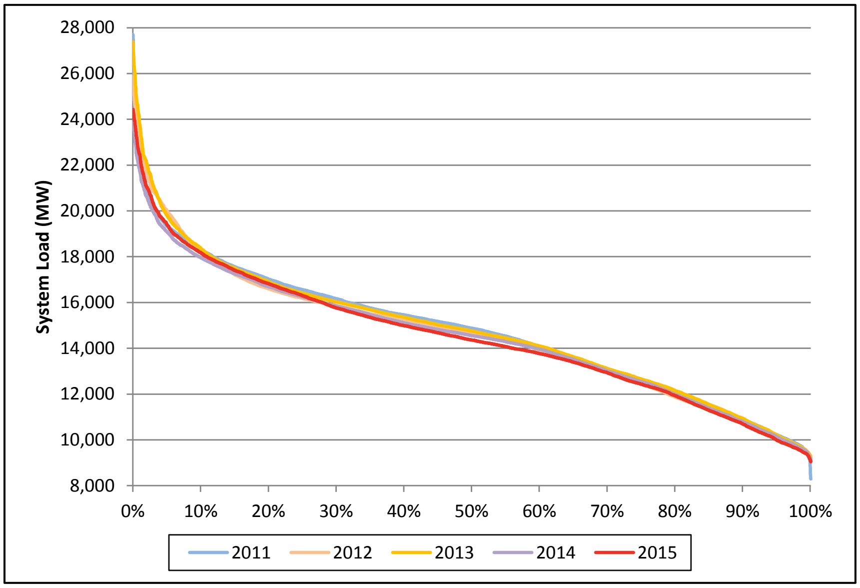
Figure 2-10: Average Hourly Load by Quarter and Year



Annual average hourly loads have fallen from a high of about 14,770 MW in 2013 to a low of about 14,480 MW in 2015. Loads in the summer months, or Quarter 3 (red dots), have been the highest load quarters except for 2014. In 2014 and 2015, loads in the first quarter (blue dots) were higher than 2011 through 2013 as a result of lower temperatures. Second quarter (green dots) and fourth quarter (yellow dots) had lower loads in 2014 to 2015 than in 2011 to 2013. Quarter 4 of 2015 had low quarterly loads, the result of mild temperatures in December. The peak load in 2014 (24,483 MW) was almost the same as that for 2015 (24,437 MW). Earlier years had warmer summers and more hours with loads over 25,000 MW. In 2011, the peak load was 27,707 MW, in 2012 it was 25,880 MW, and in 2013 the peak load was 27,379 MW.

Figure 2-11 shows the actual system electrical load for New England over the last five years as load-duration curves, with load levels ordered from highest to lowest. By plotting several annual load duration curves, one can observe differences between years.

Figure 2-11: Load Duration Curves



The duration curve for each year shows the percentage of time the hourly load was at or above the load levels shown on the vertical axis. Hourly loads in 2015 were below the levels for 2014 in 73% of hours; however, only marginally so. Overall loads were a modest 0.2% lower in 2015 when compared with 2014.

Figure 2-12 below shows the load duration curves for the highest 5% of hours.

Figure 2-12: Load Duration Curves - Top 5% of Hours

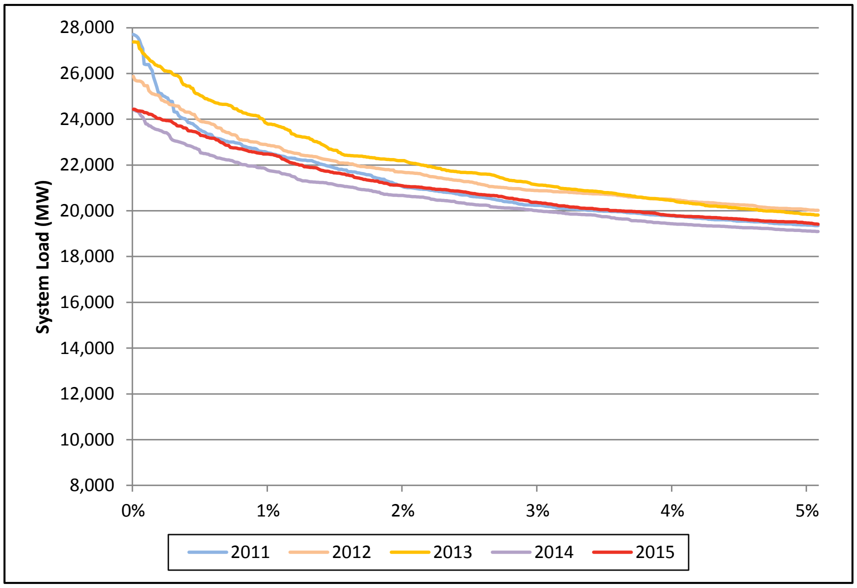


Figure 2-12 shows that earlier years (2011-2013) had much higher peak loads. In 2014 and 2015, there were no hours with loads over 25,000 MW. The peak load in 2014 (24,483 MW) was almost the same as that for 2015 (24,437 MW). Earlier years had warmer summers and more hours with loads over 25,000 MW. In 2011, the peak load was 27,707 MW, in 2012, 25,880 MW, and in 2013, 27,379 MW. The peak load in 2015 of 24,437 MW is 13% lower than the all-time system load of 28,130 MW, which was set on August 2, 2006.

2.3.2 Reserve Requirements

All bulk power systems, including the system in New England, need reserve capacity in order to respond to contingencies. ISO New England's operating-reserve requirements are designed to protect the system from the impacts associated with the loss of generation or transmission equipment.[37] The ISO maintains a sufficient amount of reserves to be able to recover from the loss of the largest single system contingency (N-1) within 10 minutes. This requirement is referred to as the total 10-minute reserve requirement. Additionally, reserves must be available within 30 minutes to meet 50% of the second-largest system contingency (N-1-1). Adding this additional requirement to the total 10-minute reserve requirement comprises the system total reserve requirement.

Operating reserves are provided by the unloaded capacity of generating resources, either online or offline, which can deliver energy within 10 or 30 minutes. Between 25% and 50% of the total 10-minute reserve requirement must be synchronized to the power system. The exact amount is determined by the system operators, and this amount is referred to as the 10-minute spinning reserve requirement. The rest of the total 10-minute reserve requirement can be met by 10-minute nonspinning reserve (TMNSR). The remainder of the total reserve requirement can be served by 30-minute operating reserves (TMOR). Starting in October 2013, in addition to

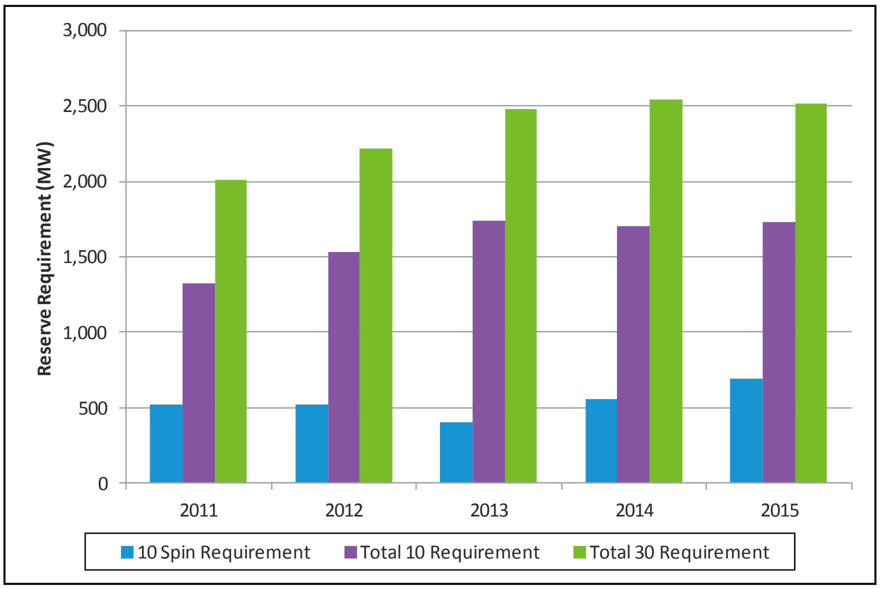
[37] Operating Procedure No. 8, *Operating Reserves and Regulation* (May 2, 2014), http://www.iso-ne.com/static-assets/documents/rules_proceds/operating/isone/op8/op8_rto_final.pdf.

the total reserve requirement, a replacement reserve requirement was added.[38] The replacement reserve requirement adds 160 MW to the total reserve requirement in the summer and 180 MW to the requirement in the winter.

In addition to the system-wide requirements, 30-minute reserves must be available to meet the local second contingency in import-constrained areas. Currently, local TMOR requirements exist for the region's three local reserve zones – Connecticut (CT), Southwest Connecticut (SWCT), and NEMA/Boston (NEMABSTN).

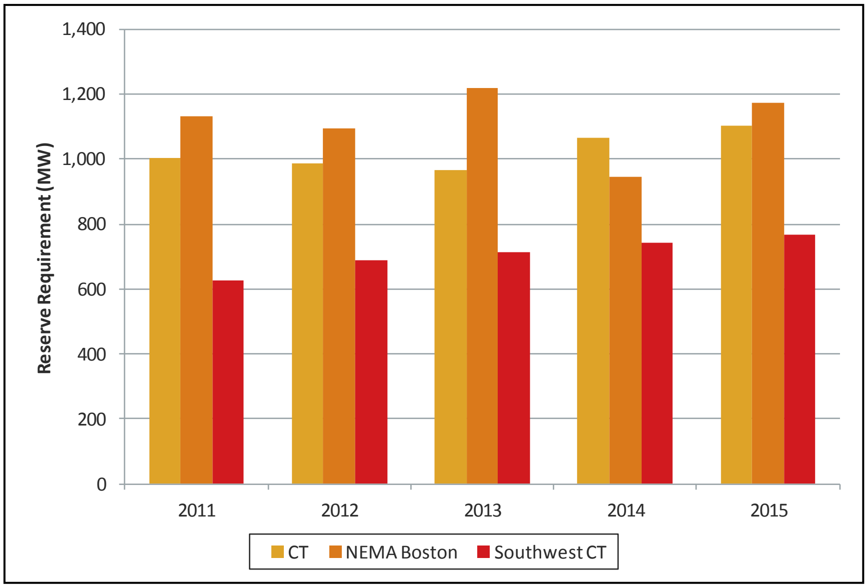
Average annual system reserve requirements are shown in Figure 2-13 and average annual local reserve requirements for each local reserve zone are shown in Figure 2-14.

Figure 2-13: Average System Reserve Requirements



[38] OP 8 states that in addition to the operating reserve requirements, the ISO must maintain sufficient replacement reserves in the form of additional TMOR for meeting the NPCC requirement to restore its 10-minute reserve within 105 minutes if it becomes deficient as a result of a reportable contingency, and within 90 minutes if it becomes deficient for reasons other than a reportable contingency, as described in NPCC Directory #5, *Reserve* (October 11, 2013), https://www.npcc.org/Standards/Directories/Forms/Public%20List.aspx.

Figure 2-14: Average Local 30-Minute Reserve Requirements



In July 2012, ISO New England increased the total 10-minute reserve requirement by 25% to account for generator non-performance that had been observed in prior years. In October 2015, this amount was reduced to a 20% increase. In 2013, the total reserve requirement increased due to the addition of the replacement reserve requirement. The local reserve requirements vary from year to year as the import capability into each local reserve zone varies with changing system conditions.

2.3.3 Capacity Market Requirements

The Installed Capacity Requirement (ICR) is the amount of capacity (MW) needed to meet the region's reliability requirements. The reliability requirements are designed to ensure that non-interruptible customers are not disconnected from the wholesale grid more than once every ten years.

The system installed capacity requirement for the forward capacity auction held in 2015 (FCA 9) for delivery in the capacity commitment period 2019-20 was 35,142 MW. Some of these requirements are satisfied through tie benefits with Hydro-Quebec.[39] With the Hydro-Quebec tie benefits included, the net installed capacity requirement (or NICR) was for FCA 9 was 34,189 MW.

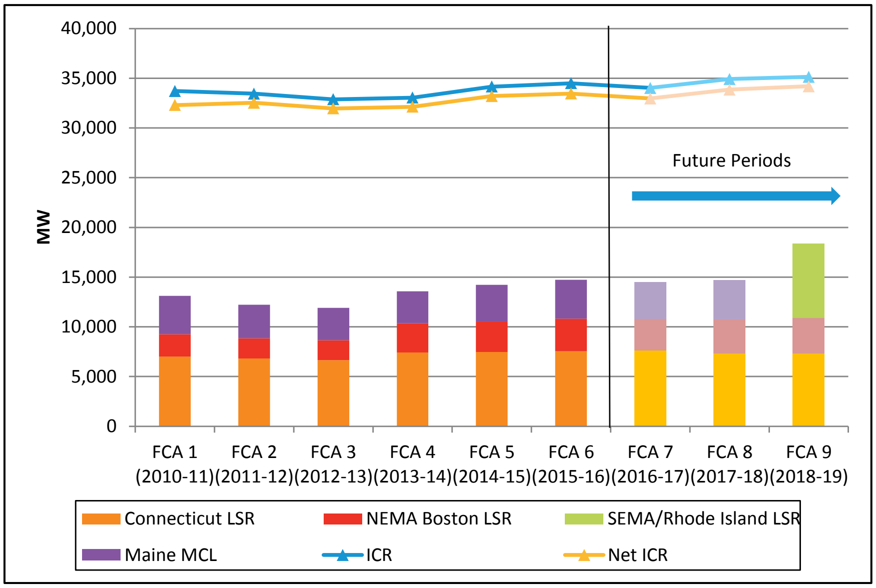
For FCA 9, there were local capacity requirements in Connecticut (7,331 MW), NEMA Boston (3,572 MW), and Southern Massachusetts/Rhode Island (7,479 MW). Because of transmission constraints capacity must be located within those regions. Sufficient power cannot always be moved into those regions and therefore the zones are deemed import constrained. In past FCAs, there have been maximum capacity limits to reflect the limited amount of power that can be moved from a zone into the rest of the system, in particular for the Maine region through FCA 8.

[39] Tie benefits reflect the amount of emergency assistance that is assumed will be available to New England from its neighboring Control Areas in the event of a capacity shortage in New England.

No more than approximately 3,800 MWs can be located in Maine because of transmission limitations that constrain the deliverability of that capacity to the rest of New England.

Figure 2-15 shows the ICR, NICR, the local sourcing requirement (LSR) by region, and the maximum capacity limits for Maine for FCA 1 through FCA 9.

Figure 2-15: ICR, NICR, Local Sourcing Requirements, and Maximum Capacity Limits



The Southeast Massachusetts and Rhode Island load zones were modeled as a single capacity zone for the first time in FCA 9. The ISO performed an assessment to identify persistent transmission constraints at or near the boundary of Southeast Massachusetts and Rhode Island, and determined that the SEMA/RI capacity zone should be modeled as a separate zone for FCA 9.

Also for FCA 9, the Maine zone was modeled as rest-of pool for the first time. In FCA 9, the maximum capacity limit for Maine was greater than the sum of existing capacity and new capacity that would qualify for the FCA, and so it was not possible for that limit to affect procurement.[40] As a result, Maine was not modeled as an export constrained zone for FCA 9.

2.3.4 Imports and Exports of Energy

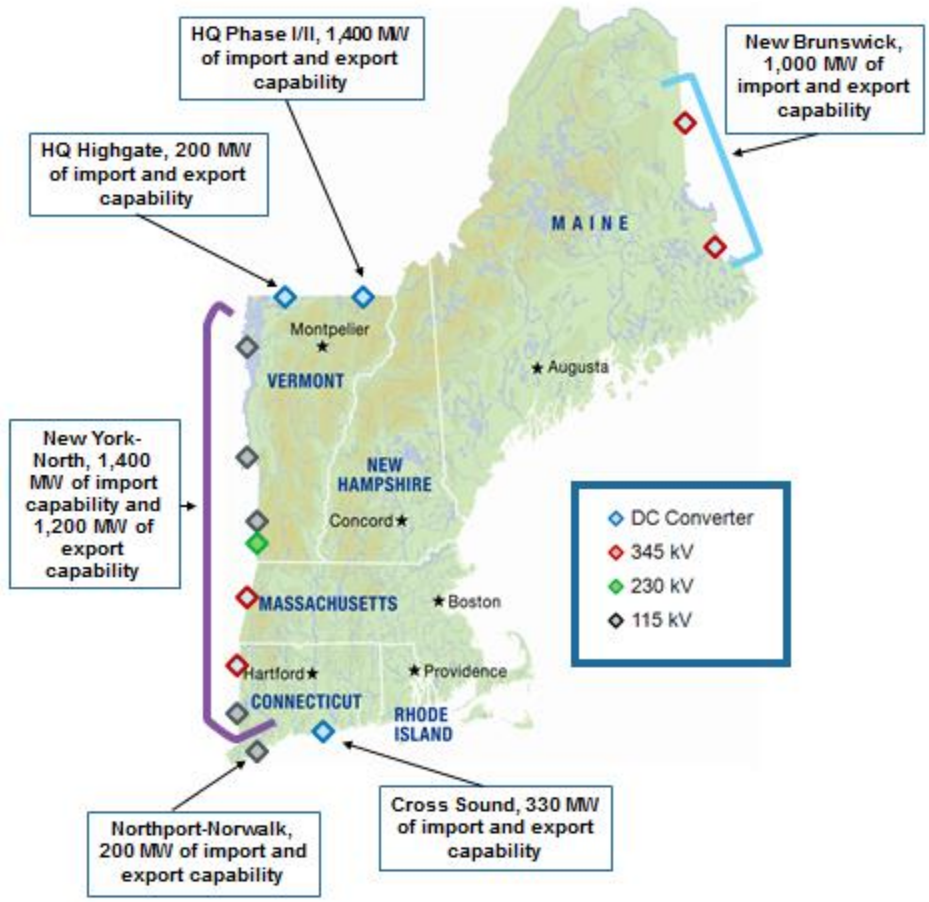
New England has transmission connections with Canada and New York:

- Canada: With Quebec via the HQ Phase I/II and HQ Highgate interfaces, and with New Brunswick; and
- New York: via the New York-North, Northport-Norwalk and the Cross Sound Cable interfaces.

Figure 2-16 shows the New England interconnection ties.

[40] See *Zonal Modeling for FCA 9*, PSPC Meeting August 28, 2014, http://www.iso-ne.com/static-assets/documents/2014/08/fca9_zone_formation_pspc.pdf

Figure 2-16: New England Interconnection Ties

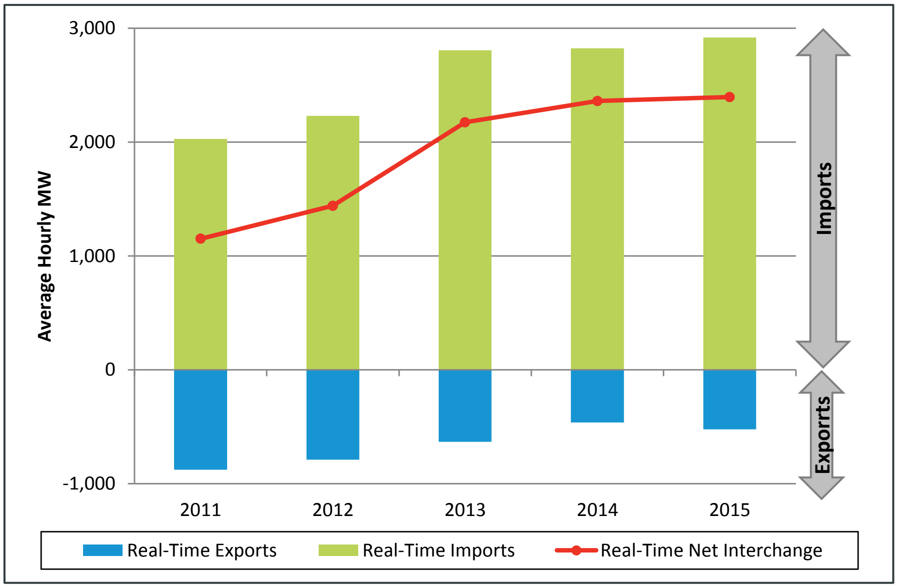


The Canadian interfaces total approximately 2,600 MW (New England/New Brunswick: 1,000 MW, Highgate HVDC: 200 MW, and Phase II HVDC: 1,400 MW) in import capability. Under normal circumstances, the Canadian interfaces import energy into New England.

There are three interfaces connecting New York and New England. The New York-North interface has a net import capability of 1,400 MW and a net export capability of approximately 1,200 MW. This interface can import power to, or export power from New England. Northport-Norwalk has a capability of approximately 200 MW and is generally a net exporter of power to New York. The Cross Sound Cable is a DC Converter with a capability of approximately 330 MW and power is generally exported to New York over this interface.

Figure 2-17 shows scheduled imports, exports, and net energy flow by year from 2011 through 2015.

Figure 2-17: Scheduled Imports, Exports, and Net Energy Flow



In 2015, New England was a net importer of power and net imports met almost 17% of total native electricity demand. Net imports from Canada (the Quebec interfaces and New Brunswick) exceeded net imports and exports from New York. The net interchange with neighboring balancing authority areas totaled about 21,000 GWh for 2015 (almost 2,400 MW per hour on average) in the real-time market, a 1.5% increase compared with the previous year. The increase in the net interchange is the result of slightly greater imports in 2015 compared with 2014. The reduction in exports in 2014 was partially due to the unplanned outage of the Cross Sound Cable, which was the result of a transformer fire in New Haven. The Cross Sound Cable is predominantly a net exporter of power to New York.

Figure 2-18 shows imports and exports by interface.

Figure 2-18: Scheduled Imports and Exports by Interface

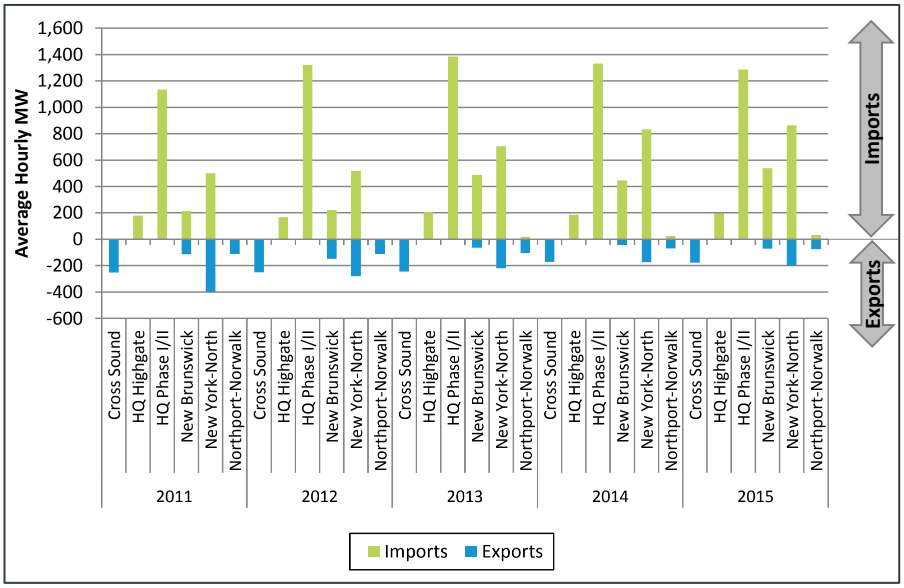


Figure 2-18 further shows that New England was a net importer of power. It shows that imports along the HQ Phase I/II interface were the highest of all interfaces in all five years. Imports along the New York-North interface have been increasing, while exports along the New York-North interface have been decreasing. Imports from the New Brunswick interface increased from 2014-2015, while imports along the HQ Highgate interface have been relatively steady.

Section 3
Day-Ahead and Real-Time Energy Market

This section describes the outcomes, structure, and competitiveness of the day-ahead and real-time energy markets. First, an overview of the main features of each market is provided.

Day-Ahead Energy Market:

The day-ahead market allows participants to buy and sell electricity the day before the operating day. Electricity buyers, also known as load-serving entities (LSEs), acting on behalf of end-users may submit energy demand "bids" and schedules, which express their willingness to buy a quantity of electricity at prescribed prices. Electricity sellers (suppliers) have the option to submit day-ahead supply offers, which express their willingness to sell a quantity of electricity at prescribed prices. Suppliers, or generators, with a capacity supply obligation (CSO) (see Section 6) are required to sell electricity into the day-ahead market at a quantity at least equal to the CSO MW value. In addition, as described in Section 4, any market participant may submit *virtual* demand bids (i.e., decrement bids) or *virtual* supply offers (incremental offers) into the day-ahead market. As the name implies, virtual demand bids and supply offers do not require a market participant to have physical load or supply.

Supply offers from generators are submitted at a nodal level, while demand bids from LSEs are submitted at a zonal level. Virtual bids and offers can be submitted at a nodal level, zonal level or at the Hub.[41] The bids and offers indicate the willingness to buy or sell a quantity of electric energy in the day-ahead market at that location. The ISO uses a clearing algorithm that selects bids and offers to maximize benefit to both supply and demand, subject to transmission constraints. The day-ahead market purchases enough physical and virtual supply to meet the physical and virtual demand. Operating reserves, described in Section 7, are not explicitly purchased through the day-ahead market. Operating reserves are procured in the forward market for reserves (see Section 7.2), and additional procurement occurs in the real-time energy market where reserve procurement is co-optimized with energy procurement.

The day-ahead market results are usually posted no later than 1:30 p.m. the day before the operating day. Resources that clear in the day-ahead energy market, but do not recover their as-offered costs through the hourly locational marginal price, receive additional payment in the form of day-ahead Net Commitment-Period Compensation (NCPC).

Real-Time Energy Market:

The real-time energy market is the physical market in which generators sell, and load-serving entities (LSEs) purchase, electricity during the operating day. The ISO coordinates the

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

production of electricity to ensure that the amount produced moment to moment equals the amount consumed, while respecting transmission constraints. The ISO calculates LMPs every five minutes for each location on the transmission system at which power is either withdrawn or injected. The prices for each location reflect the cost of the resource needed to meet the next increment of load at that location.

The real-time energy market LMP includes both energy and operating reserve pricing. Energy and reserves are co-optimized and resulting LMPs reflect the relationship between energy price and reserve procurement. Reserve prices reflect the opportunity cost of dispatching generators down from their otherwise optimal energy output to ensure adequate ten- or thirty-minute reserves and are capped at values known as reserve constraint penalty factors (RCPFs). The real-time energy market can also be thought of as a "balancing market", settling the difference between positions (production or consumption) cleared in the day-ahead energy market and actual production or consumption in the real-time energy market. Participants that consume more or provide less than their day-ahead schedule pay the real-time LMP, and participants that consume less or provide more than their day-ahead schedule are paid the real-time LMP.

Similar to the day-ahead energy market, generators are entitled to NCPC payments if they do not recover their bid-on costs through the LMP.

3.1 Energy and NCPC (Uplift) Payments

In 2015, total estimated energy and NCPC payments declined by about 35% compared with 2014 ($6.0 billion in 2015 compared with $9.3 billion in 2014).[42] The vast majority of energy market payments made in 2015 were made in the day-ahead energy market (DAM), while most of the NCPC payments were made in the real-time energy market (RTM). Energy payments in the DAM accounted for approximately 98% of total energy market payments, while NCPC payments in the DAM accounted for only 30% of total NCPC payments. (Section 3.5 discusses NCPC in detail.)

Figure 3-1 shows the estimated energy and NCPC payments for each year (in billions of dollars), by market, along with the average natural gas price (in $/MMBtu).

[42] The total cost of electric energy is approximated as the product of the Day-Ahead load obligation for the region and the average Day-Ahead locational marginal price (LMP) plus the product of the Real-Time load deviation for the region and the average Real-Time LMP.

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

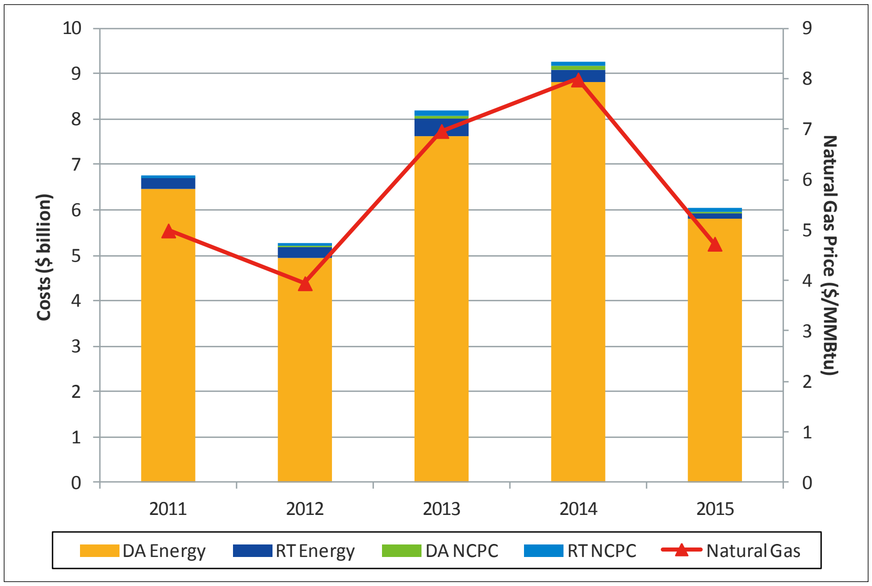
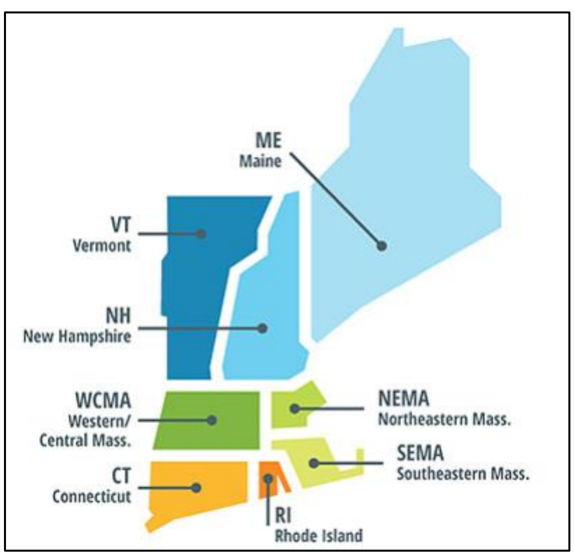


Figure 3-1 illustrates how fuel input prices, specifically natural gas prices, were a key driver behind the year-to-year changes in energy and NCPC payments. The significant drop in the average natural gas price in 2015 compared with 2014 resulted in the decrease in total energy and NCPC payments in 2015.

3.2 Energy Prices

Day-ahead and real-time LMPs are presented below. Both simple-average and load-weighted prices have been summarized by time period and location. All pricing data are summarized as either annual average or monthly average values. On-peak periods refer to weekday hours 8 to 23 (i.e., Monday to Friday, North American Electric Reliability Corporation [NERC] holidays); the off-peak period encompasses all other hours. Pricing data are differentiated geographically by “load zone” (as indicated in the Figure 3-2 below) and the “Hub”.

Figure 3-2: ISO New England Pricing Zones



3.2.1 Hub Prices

As shown in Table 3-1 below, in 2015 the average Hub price (in all hours) was $ 41.90/MWh in the day-ahead energy market and $41.00/MWh in the real-time energy market, down approximately 35% from 2014 prices in both markets.[43] Pricing by time-of-day (i.e., on-peak and off-peak) exhibits the same trend of significantly declining prices in ISO-New England in 2015: on-peak prices declined by 36%, when compared with 2014, and off-peak prices declined by 34%.

Table 3-1: Annual Simple Average Hub Price

	Day-Ahead			Real-Time		
Year	**Off-Peak**	**On-Peak**	**All Hours**	**Off-Peak**	**On-Peak**	**All Hours**
2011	40.75	52.84	46.38	41.74	52.34	46.68
2012	31.29	41.59	36.08	31.61	41.26	36.09
2013	48.74	65.24	56.42	48.97	64.19	56.06
2014	54.07	76.60	64.56	53.22	74.90	63.32
2015	35.39	49.32	41.90	35.11	47.70	41.00

These price changes are consistent with observed market conditions, including those for input fuel costs, loads, and generating resource operations. Fuel prices, in particular, declined significantly in 2015 compared with 2014, explaining much of the change in electricity prices.

Comparing day-ahead to real-time energy market prices for 2015, average real-time prices were slightly less than day-ahead prices: 0.8% off-peak, 3.3% on-peak, and 2.2% overall. This continues a recent trend (2013-2015) of the real-time energy market experiencing slightly decreased prices overall compared with the day-ahead market. A number of factors can influence the relationship between day-ahead to real-time prices: the difference between forecasted load and actual load, unforeseen system contingencies experienced in the real-time market, participants' willingness to pay a premium in the day-ahead market to hedge real-time price risks, etc. The combination of these factors, on a day-to-day basis over the course of the year, results in the observed average differences between the day-ahead and real-time prices. Section 3.3 of this report discusses "price convergence" (i.e., differences between day-ahead and real-time prices) in more detail.

3.2.2 Zonal Prices

This section describes differences among zonal prices. Within a market (i.e., day-ahead and real-time), price differences among load zones will result from energy "losses" and transmission congestion that vary by location.[44] Price differences among the load zones were relatively small in 2015, as shown in Table 3-2.

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

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

Table 3-2: Simple Average Hub and Load Zone Prices for 2015 ($/MWh)

	2015	
Zone	**Day-Ahead**	**Real-Time**
Hub	41.90	41.00
Maine	40.81	39.23
New Hampshire	42.11	40.20
Vermont	41.58	40.22
Connecticut	41.23	40.58
Rhode Island	42.20	41.03
SE Mass	42.23	41.21
WC Mass	41.93	40.96
NEMA Boston	42.56	41.58

The average absolute difference between the Hub annual average price and average load zone prices was $0.45/MWh in the day-ahead energy market and $0.58/MWh in the real-time energy market – a difference of approximately 1.0-1.5%. The Maine load zone had the lowest average prices in the region, while the NEMA-Boston load zone had the highest. This occurred in both the day-ahead and real-time energy markets. Maine's prices averaged $1.09/MWh and $1.77/MWh lower than the Hub's prices during the year for the day-ahead and real-time energy markets, respectively. NEMA-Boston's average prices were slightly higher than the Hub's prices, by $0.66/MWh and $0.59/MWh, respectively.

Price differences between the load zones primarily resulted from modest levels for both marginal losses and congestion, as there was little congestion between zones during the year.

3.2.3 Load-Weighted Prices

While simple average prices are an indicator of the actual observed energy pricing within the ISO's markets, load-weighted prices represent a better indicator of the average price that wholesale load pays to consume energy.[45] This is because the amount of energy consumed in the ISO's markets can vary significantly by hour and energy prices are not uniform throughout the day. Moreover, load-weighted prices will tend to exceed simple average prices. This is because load weighted prices reflect the increasing cost of satisfying demand in peak consumption periods when load is greater; during high load periods more expensive supply resources must be committed and dispatched to meet the higher loads.

Table 3-3 shows both monthly simple and load-weighted average prices for 2015.

Table 3-3: Simple Average and Load-Weighted Hub Prices, 2015 ($/MWh)

	Simple Average		Load-Weighted Average	
Month	**Day-Ahead**	**Real-Time**	**Day-Ahead**	**Real-Time**
Jan 2015	71.14	65.59	73.43	67.90
Feb 2015	122.77	126.70	125.04	128.39
Mar 2015	64.25	57.93	66.36	59.77

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

Apr 2015	28.43	25.88	29.34	26.83
May 2015	24.92	26.12	26.14	28.05
Jun 2015	21.16	19.61	22.39	21.21
Jul 2015	26.44	25.40	29.07	28.40
Aug 2015	30.06	35.35	32.12	38.78
Sep 2015	30.82	35.83	33.43	41.34
Oct 2015	37.01	32.62	38.29	33.72
Nov 2015	29.42	26.12	30.40	27.35
Dec 2015	22.42	21.35	23.56	22.72
Annual Average	**41.90**	**41.00**	**44.13**	**43.71**

The simple average electricity prices in 2015 were less than the load-weighted average prices. The difference ranges from approximately 2% to 15%, depending on the month and energy market (day-ahead and real-time). These price differences reflect the variability of load over the course of a day, which is a function of temperature and business/household consumption patterns. For example, hours with low electricity consumption tend to occur overnight, when business and household activity is low and summer cooling needs are minimal. For 2015, load variability during the day had the least impact on the average prices paid by wholesale consumers in February, when simple and load-weighted prices differed by just 2%. Warm weather months exhibited the greatest impact of load variability on the average prices paid by wholesale consumers, with load-weighted prices exceeding simple average prices by 10% (July for the day-ahead market) and 15% (September for the real-time market).

Figure 3-3 and Figure 3-4show monthly load-weighted prices across load zones over the past five years. The black line shows the average annual load-weighted Hub price and highlights the degree of variability in prices throughout the year.

Figure 3-3: Day-Ahead Energy Market Load-Weighted Prices

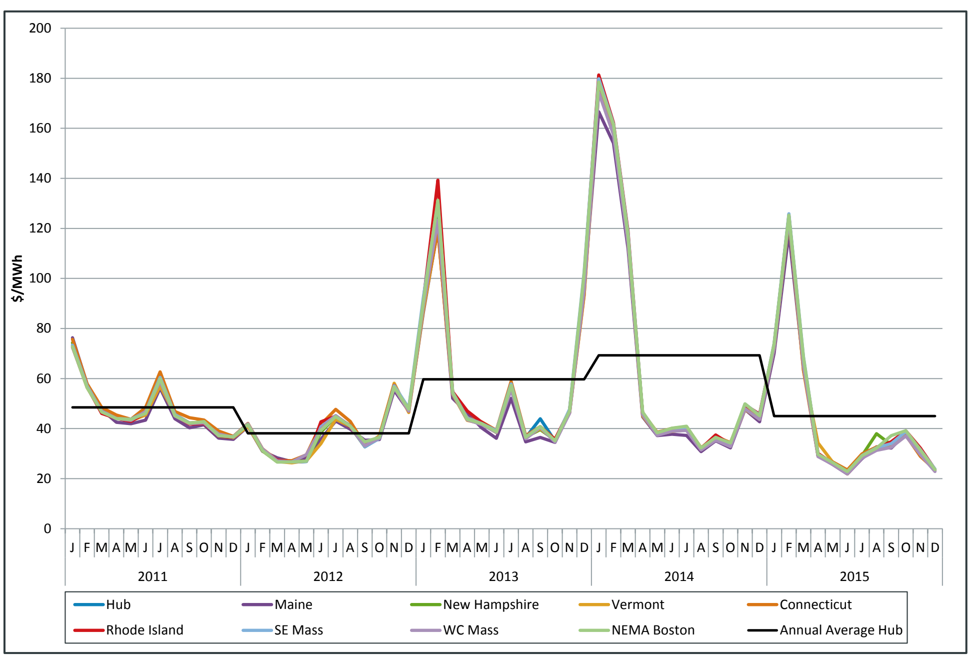
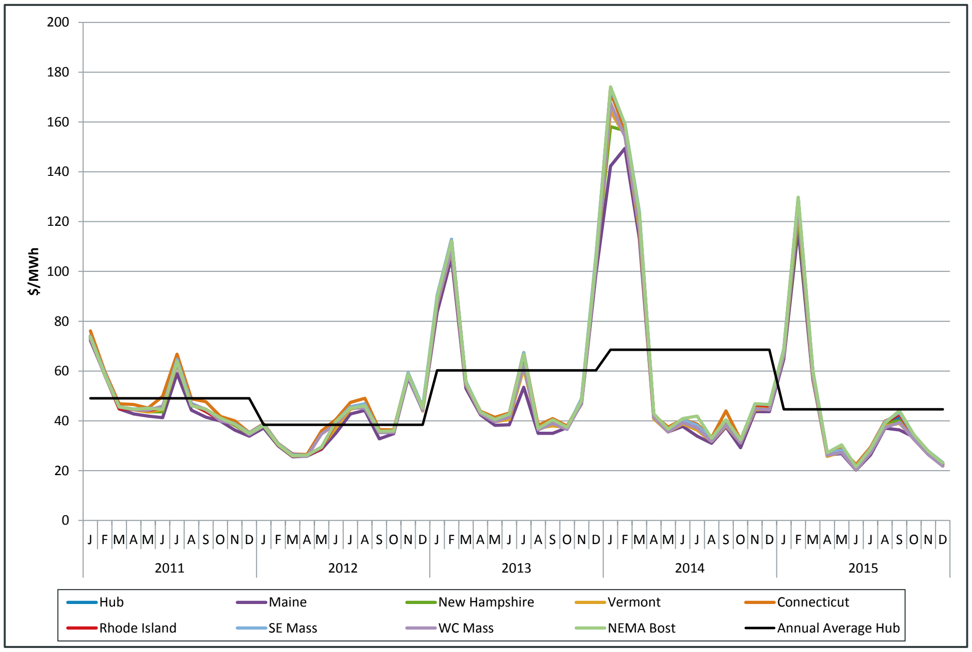


Figure 3-4: Real-Time Energy Market Load-Weighted Prices



Load-weighted energy prices by load zone from 2011 to 2015 indicate a pattern that varies considerably by year and month, but not by load zone. As described above, a primary driver of material price differences between load zones is congestion and the ISO New England control area has not experienced significant congestion on internal interfaces in recent years. Extreme pricing in the months of January and February has occurred over the past three years (2013-2015) due high natural gas prices. This is consistent with varying weather patterns and fuel prices over the period, and reasonably uniform load shapes across load zones. Recent winter periods with high fuel prices and summer months with elevated load variability have the highest load-weighted prices.

3.3 Energy Price Convergence

This section discusses the importance of price convergence in New England and the performance of the day-ahead market in reflecting real-time prices in 2015. The day-ahead market's ability to reflect real-time conditions is important for efficient scheduling of generation to reliably serve real-time load in the least-cost way. The degree of price convergence between day-ahead and real-time prices is used as one measure of the extent to which the day-ahead market (structure and participation) adequately reflects expected real-time conditions and market outcomes.

In New England, participants can buy and sell energy for delivery on the following day in the day-ahead energy market. This allows participants to hedge against price volatility in the real-time energy market by securing a schedule to buy or sell electricity for the next day at day-ahead prices. The ISO also provides two virtual energy products, virtual supply and virtual demand, that are settled based on day-ahead and real-time locational marginal price differences and add liquidity to the day-ahead market. Virtual products are used by participants to hedge physical positions or to arbitrage price differences between the day-ahead and real-time energy markets.

If a supplier selling energy in the day-ahead market is not able to physically provide the contracted energy in the real-time market, or if it is not economic for them to do so, they are able to buy out their position at real-time prices. Similarly, if a load serving entity buys energy in the day-ahead market and does not consume the contracted amount they can sell the additional megawatts that were purchased in the day-ahead market but not consumed in the real-time. There is risk associated with both of these situations if a day-ahead seller must buy out their position at a high real-time price, or if a buyer must sell their surplus at a low real-time price. Virtual transactions can be used to hedge this risk.

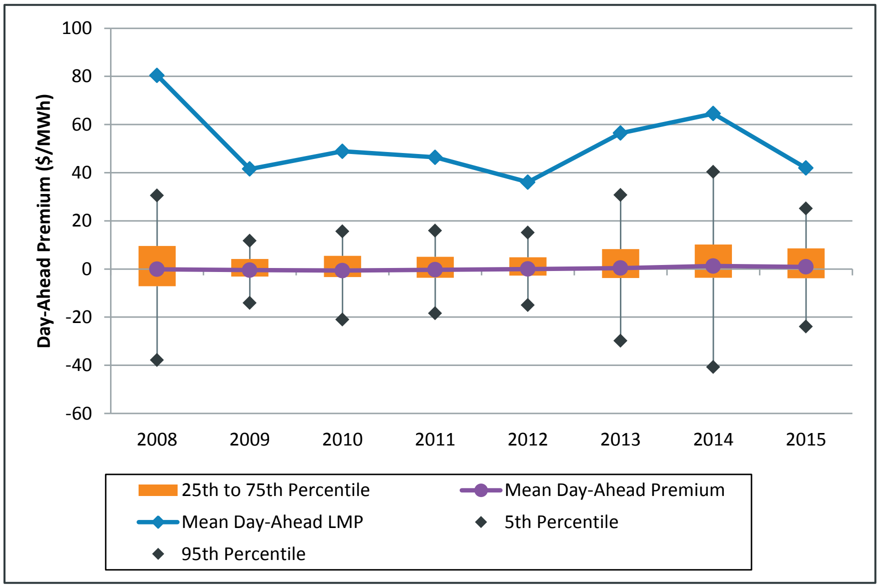
The day-ahead market's ability to reflect real-time conditions is important for efficient scheduling of generation to reliably serve real-time load in the least-cost way. To assess the day-ahead market's ability to predict real-time conditions, we examine the degree of price convergence between day-ahead and real-time prices. If the day-ahead market reflects real-time conditions, the day-ahead schedule will need less adjustment in real-time, a similarly-priced unit will be marginal, and day-ahead prices will be more consistent with real-time prices. The ISO can schedule additional units after the day-ahead market through reliability assessments (called the Reserve Adequacy Assessment (RAA) process) to ensure there is enough generation to meet the forecasted load in the following day. However, when day-ahead schedules do not match real-time needs, adjustments in real-time can lead to inefficient real-time pricing, higher system-wide energy costs, and NCPC payments.

Although we use price convergence to examine the ability of the day-ahead market to predict real-time conditions, it is not a perfect proxy. Real-time pricing is dependent on many variables, only one of which is the day-ahead schedule's reflection of real-time conditions. Real-time prices could be affected by the dispatch of higher cost units for reliability, reserve pricing, or unforeseen or emergency conditions. Price convergence is just one way to measure the day-ahead market's accuracy in predicting real-time conditions.

A systematically higher price in either market incentivizes participants to adjust when they sell or purchase energy, which leads to consistent pricing. For example, if day-ahead prices were systematically higher, load would substitute away from buying in the day-ahead market to buy in the real-time market. Generation would seek the higher day-ahead prices and increase supply in the day-ahead market. The increase in supply, and decrease in demand in the day-ahead market would lower the day-ahead price until it was similar to the real-time price. This is the mechanism that allows prices to converge. The liquidity that virtual transactions add to the markets can improve price convergence through the same mechanism. Virtual transactions are discussed in Section 4.1.

Figure 3-5 shows the distribution of the day-ahead price premium and the mean day-ahead LMP from 2008 through 2015.

Figure 3-5: Day-Ahead Hub LMP Premium and Mean Day-Ahead LMP



In 2015, the mean day-ahead price premium was $0.90/MWh. This is down from $1.25/MWh in 2014. In half of the hours in 2015, the price difference was between -$3.83 and $8.60/MWh. This is consistent with load paying a premium in the day-ahead market. Since 2009, the interquartile range (the box in the Figure 3-5 representing values in the 25th percentile to 75th percentile range) has become larger, increasing from $7.35 in 2009 to $12.43 in 2015. However, energy prices in New England are highly correlated with gas prices. Differences in prices could be larger when gas prices are higher. This is because the difference in cost between two gas generators with different heat rates is higher when gas prices are higher. An example is shown in Table 3-4 below.

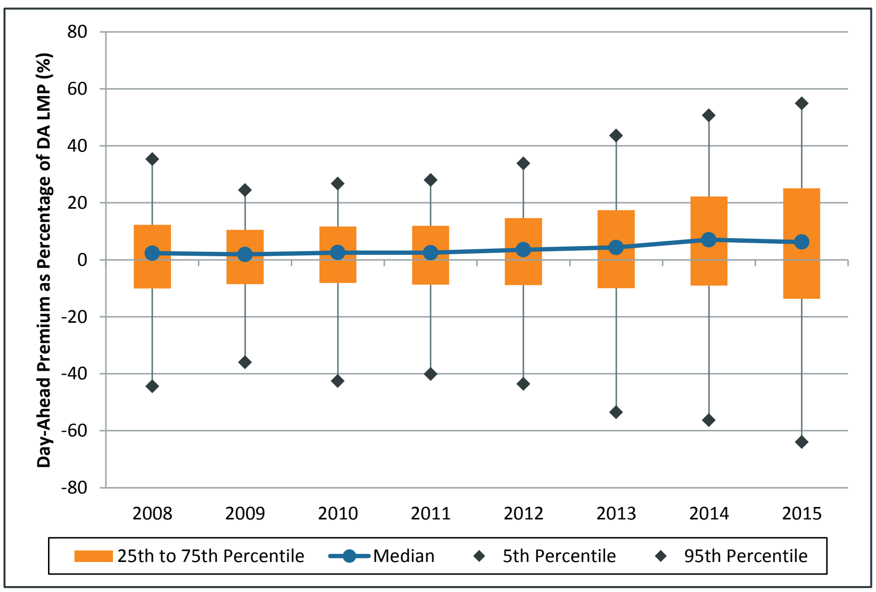
Table 3-4: Example of Price Difference Due to Change in Marginal Generator

Gas Price	Day-Ahead Marginal Generator Heat Rate	Day-Ahead Marginal Generator Cost (Day-Ahead LMP)	Real-Time Marginal Generator Heat Rate	Real-Time Marginal Generator Cost (Real-Time LMP)	Day-Ahead Premium
$5/MMBtu	7 MMBtu/MWh	$35/MWh	10 MMBtu/MWh	$50/MWh	-$15/MWh
$10/MMBtu	7 MMBtu/MWh	$70/MWh	10 MMBtu/MWh	$100/MWh	-$30/MWh

Two days are shown in Table 3-4 where gas prices are $5 and $10. For this simple example, in both days a generator with a heat rate of 7 MMBtu/MWh is marginal in the day-ahead market and a generator with a heat rate of 10 MMBtu/MWh is marginal in the real-time market. This could be the case if generation is under-committed in the day-ahead market, and more expensive generation is needed in real-time. The example shows how, even with the same generators being marginal on both days, the price difference increases due to the different fuel prices. When gas prices are $5/MMBtu, the 7 MMBtu/MWh heat rate generator costs $35/MWh, and the 10 MMBtu/MWh heat rate generator costs $50/MWh to run. The difference between day-ahead and real-time prices is $15/MWh. When the gas price increases to $10/MMBtu, the costs to run each generator double, as does the price difference to $30/MWh. So, when using the price difference to evaluate the performance of the day-ahead market in anticipating real-time conditions, normalizing by LMP can help put the differences into perspective.

Figure 3-6 shows the day-ahead price premium as a percentage of the day-ahead LMP. The median is used here, as opposed to the mean, to get a better idea of a typical hour. This is because very low day-ahead prices distort the mean price difference as a percent of day-ahead LMP. In Figure 3-5 above, the mean is used to see how a generator or load serving entity would be affected if they offered or bid into the same market every hour. On average, in 2015, a generator would have made $0.90/MWh more if they sold into the day-ahead market in every hour (not accounting for differences in price due to adding generation to the supply stack). In Figure 3-6 below, the day-ahead premium is shown as a percentage of the day-ahead LMP. There are many hours where the day-ahead LMP is very low, which yields a high percentage unless the real-time price is also very low. In this context, using the median value provides a more accurate representation of the day-ahead price premium in relation to the price of energy.

Figure 3-6: Day-Ahead Hub LMP Premium as Percent of Hub LMP



The median day-ahead price premium, as a percentage of the day-ahead LMP, has increased significantly since 2008. In 2015, the median day-ahead price premium as a percentage of the day-ahead LMP was 6%, in 2008 this number was 2%. The spreads of day-ahead price premiums as a percent of day-ahead LMPs have also increased. The divergence in prices may reflect day-ahead scheduling that does not reflect real-time conditions.

Although the mean day-ahead price premium is under $1/MWh, as a percentage of the day-ahead LMP, the price premium in a typical hour has increased since 2008. This may indicate that the day-ahead market is not reflecting real-time conditions as well as it has in the past. While a wide range of factors can drive the differences between day-ahead and real-time prices we believe that improvements can be made to increase the liquidity of virtual transactions and potentially improve price convergence between the day-ahead and real-time markets.[46]

Since 2008 virtual transaction volumes have decreased significantly. Transaction costs, in the form of NCPC charged to cleared virtual transactions, have seen a corresponding increase. These transaction costs make arbitraging differences in day-ahead and real-time prices more difficult, as the transaction costs are often larger than the price difference between day-ahead and real-time LMPs. Although price formation is complex, and is dependent on many variables, a portion of the divergence may be attributed to a decrease in these virtual transactions. Virtual transactions add liquidity to the market and, if they are profitable during an hour (before transactions costs are levied), help converge day-ahead and real-time prices in that hour. In response to the increase in price divergence occurring between 2008 and 2015, we recommend a change to NCPC charge allocation rules. A closer look at the influence of virtual transactions on price convergence is presented in Section 4.1.

3.4 Major Factors Affecting Energy Prices

In this section the following key inputs or events that influence day-ahead and real-time energy market prices are discussed:

- Generation costs
- Supply-side participation
- Marginal resources
- Load and weather conditions
- Demand bidding
- Load forecast error
- System events
- Reliability commitments
- Congestion and losses

3.4.1 Generation Costs

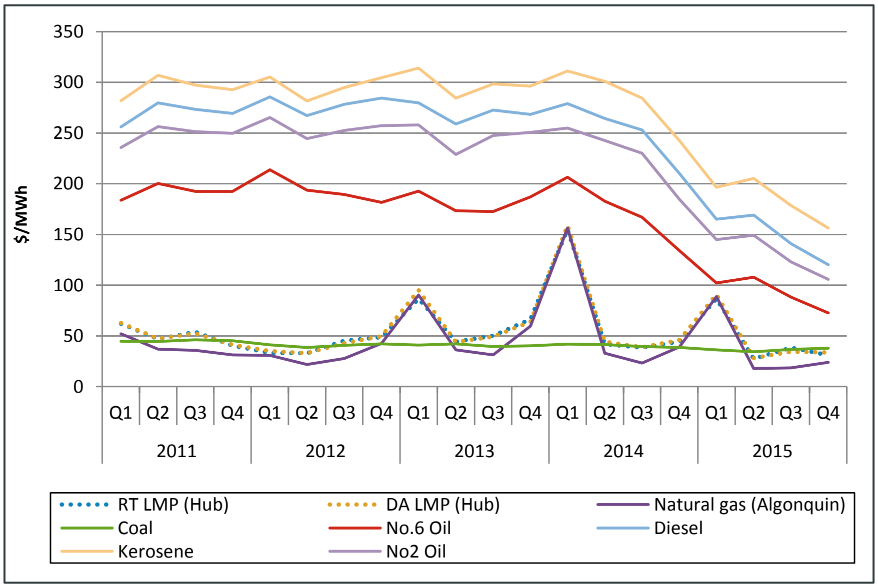
This section addresses the relationship between generation costs and electricity prices in New England.

As discussed later in Section 3.4.3 (Marginal Resources), the price of electricity is set by one or more marginal resources in any given interval and the price of the marginal resource is largely determined by its fuel type. This is because fuel costs are a primary component of variable production costs for typical combustion-type resources. Since gas-fired generators set price more frequently than generators of any other fuel type in New England, we would expect New England electricity prices to be well correlated with the estimated operating costs of a typical natural gas-fired generator. Figure 3-7 below illustrates the quarterly average day-ahead and

[46] Such factors that can differ between the day-ahead and real-time markets include, among other things, network and reserve modelling differences, optimization differences, changes in participants' offering behavior and levels of participation in the either market, as well as stochastic operational events like forced outages and load forecast error.

real-time LMPs alongside the estimated generation costs of various fuel types. The generation costs are calculated by multiplying the daily fuel price ($/MMBtu) by the average standard efficiency of generators of a given technology and fuel type (MMBtu/MWh). The differences between the power prices series (dotted lines) and the fuel price series is the hypothetical quarterly average energy market spread for each generation type.

Figure 3-7: Estimated Generation Costs and LMPs



As expected, Figure 3-7 above illustrates that both day-ahead and real-time electricity prices in New England are, on average, closely correlated with the estimated costs of operating a natural-gas fired generator. During the summer months, gas generators typically earn higher margins (also known as spark spreads) compared with the winter months (see Q1 2015 compared with Q3 2015 for example). This is because higher demand levels during the summer months require the running of less efficient gas generators, or generators burning more expensive fuels, which leads to a higher price being set than the generation cost of the proxy combined-cycle gas turbine (CCGT) with a heat rate of 7,800 Btu/kWh (or 7.8 MMBtu/MWh).

3.4.1.1 Electricity Prices and Natural Gas Prices

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

- An influx of natural gas-fired generating capacity over the past 15 years.[47]
- An aging and declining fleet of oil- and coal-fired generators, many of which were constructed during the 1960s and 1970s, and the retirement of the Vermont Yankee

[47] During the 1990s, the region's electricity was produced primarily by oil, coal, and nuclear generating plants, with very little gas-fired generation. In 1990, oil and nuclear generating plants each produced approximately 35% of the electricity consumed in New England, whereas gas-fired plants accounted for approximately 5%. Coal plants produced about 18% of New England's electricity. In contrast, by 2011, oil-fired plants produced 0.6% of electricity consumed in New England, and approximately 51% was produced by gas-fired generation. Coal production also fell by about two-thirds. ISO New England, *Addressing Gas Dependence* (July 2012), http://www.iso-ne.com/static-assets/documents/committees/comm_wkgrps/strategic_planning_discussion/materials/natural_gas_white_paper_draft_july_2012.pdf.

nuclear station. These generators would have been displaced by more efficient gas-fired generators in recent years.

- Lower natural gas prices resulting from the increased production of domestic shale gas from the Marcellus Shale region of the country.
- Relatively static gas pipeline capacity in New England[48] that has had to accommodate a 37% increase in overall natural gas consumption in New England since 1999; 95% of which was for power generation by natural gas facilities.[49]

The confluence of these factors has resulted in a much higher proportion of electricity being generated by gas-fired generators in New England, while pushing gas pipeline capacity to its limits during periods of peak gas demand. As a consequence, the reliability of New England's wholesale electricity grid is dependent, in part, on the owners and operators of natural gas-fired generators effectively managing natural gas deliveries during contemporaneous periods of high gas and electric power demand. Reliability is also increasingly dependent on the region's oil fleet having sufficient oil on hand to operate when the gas network is highly constrained and gas prices rise to levels that exceed the price of oil. When this occurs, oil units are dispatched more frequently.

One of the most pressing challenges identified in the ISO's Strategic Planning Initiative was the region's reliance on generators fueled by natural gas.[50] The ISO has undertaken a number of projects aimed at improving reliability through better generator performance and fuel assurance and has been, or is addressing the problem through the following initiatives:

- Increasing ten-minute non-spinning reserve to be procured in the Forward Reserve Market.
- Modifying generation resource auditing requirements and procedures.
- Allowing the ISO to share information concerning the scheduled output of natural gas-fired generation resources with the operating personnel of the interstate natural gas pipeline companies serving New England.
- Accelerating the closing time of the day-ahead energy market.
- Considering procurement of additional intra-day operating reserve capability.
- Allowing intra-day reoffers.
- Redesigning Forward Capacity Market performance penalties with the pay-for-performance (PFP) capacity market design.

[48] There has been no capacity change since the Maritimes and Northeast Pipeline went commercial in 1999.

[49] Approximately 12,000 of 14,000 MW of new capacity have come from gas-fired, combined-cycle generators. *ISO New England 2013 Regional Electricity Outlook*, p. 15 (2014), http://www.iso-ne.com/aboutiso/fin/annl_reports/2000/2014_reo.pdf. US Energy Information Administration (EIA), "Natural Gas Consumption by End Use," webpage (data for state-level and end-user natural gas consumption, 1999–2012) (March 31, 2014), http://www.eia.gov/dnav/ng/ng_cons_sum_dcu_SCT_a.htm. Total consumption in New England increased by 37%; total deliveries to electric power consumers increased by 99%; and total consumption by residential, industrial, and vehicle fuels increased by 1,394%. Note that these data have not been weather normalized.

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

- Introduction of Winter Reliability Programs, which will be needed until PFP become fully effective in 2018 (see Section 7.4).

3.4.1.2 *Natural Gas Prices and LMPs*

Figure 3-8 shows, by quarter, average day-ahead and real-time LMPs and the Algonquin gas price from 2011 to 2015. Gas and electricity prices during the first quarter of each of the past five years are shown separately from the remainder of the year.

Figure 3-8: Electricity and Natural Gas Price for Q1 Compared With Rest of the Year

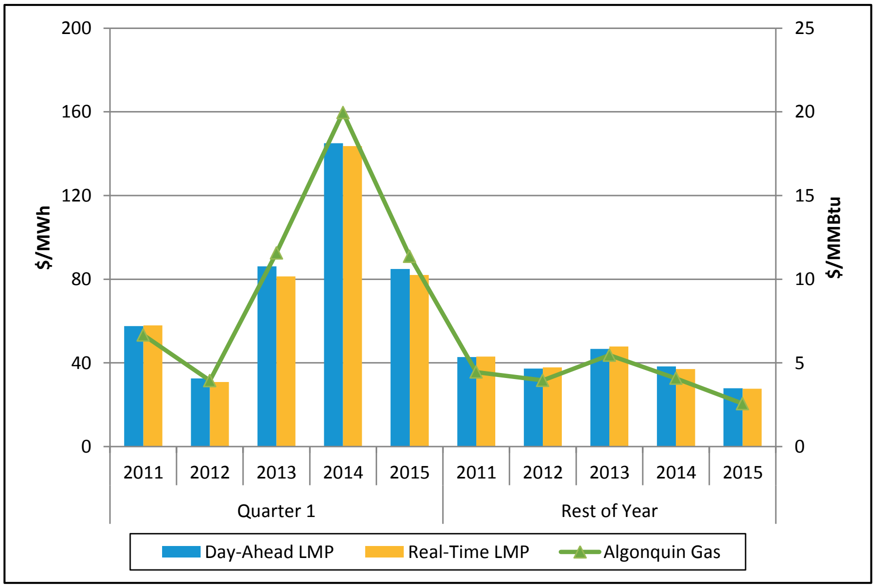


Figure 3-8 illustrates how extreme seasonality in gas prices impacts power prices. The Algonquin gas price in Q1 2014 averaged $19.96/MMBtu, 72% higher than the Q1 2013 price. In 2015, gas prices averaged $11.37/Mmbtu in Q1; for the rest of the year gas prices averaged $2.56/MMBtu.

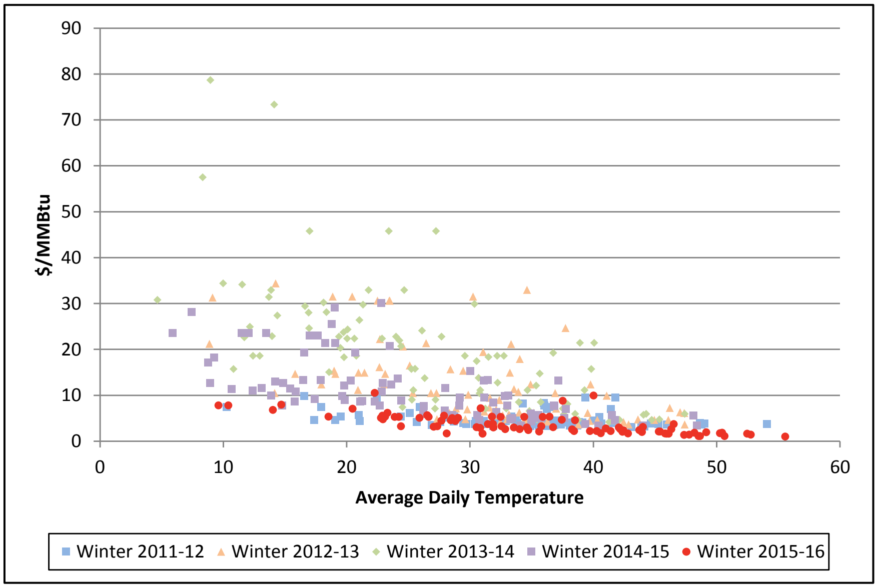
Figure 3-8 also shows a decrease in natural gas prices and subsequent LMPs in the second to fourth quarters of 2013, 2014, and 2015 compared with the same quarters in each respective year. If Q1 prices are excluded, 2015 day-ahead and real-time prices fell by 27% and 25% compared with 2014 prices. This was a similar trend observed in 2014.

A number of factors contributed to lower LMPs from April to December 2015. Relatively mild weather contributed to lower loads during the remainder of the year. Oil prices continued to decrease in 2015, the result of high inventories of crude oil, uncertainty of economic growth, volatility in energy and non-energy commodity markets, and the potential for additional crude supply to enter the market.[51] These factors tend to put downward pressure on natural gas prices, given that oil is a substitute for natural gas.

[51] EIA, Today in Energy, (February 4, 2016), http://www.eia.gov/todayinenergy/detail.cfm?id=24832 http://www.eia.gov/todayinenergy/detail.cfm?id=24832.

Gas prices have been less volatile in winter 2015-16 and winter 2014-15 compared with winter 2013-14 and winter 2012-13. Figure 3-9 displays the median daily trade prices for Algonquin next-day trades compared with the average daily temperature for the past five winters. Winter includes the months of December, January, and February. For example, if on a given day, there were 25 trades for the Algonquin next-day product, the price displayed for that day would be the median trade value of the 25 trades.

Figure 3-9: Algonquin Next-Day Trades (median daily price) and Temperatures



Average temperatures were generally higher, and gas prices lower in winter 2015-16 (red dots) than in prior years. The median daily trade prices for winter 2014-15 (purple dots), given similar temperatures, were less than winter 2013-14 and winter 2012-13. Winter 2013-14, in particular, experienced high and volatile fuel prices.

3.4.2 Supply-Side Participation

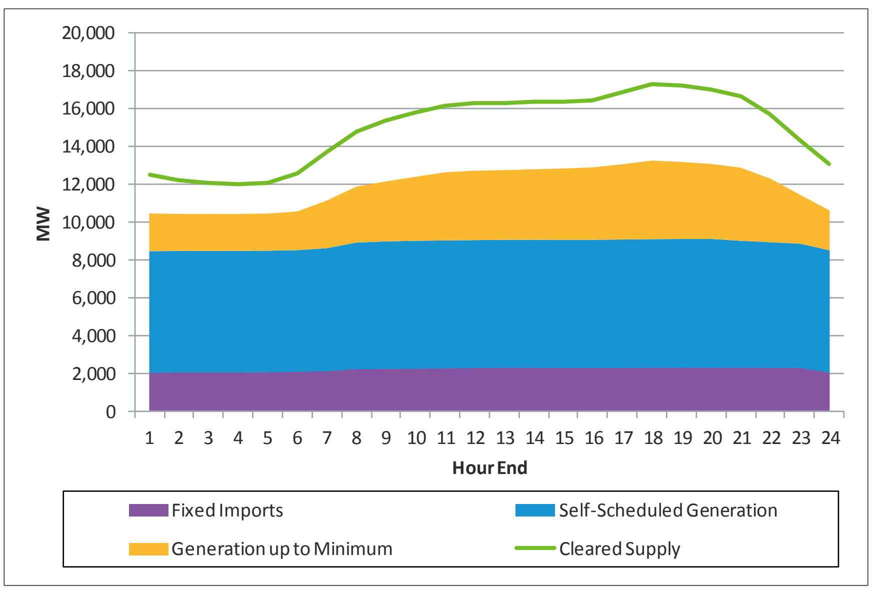
Throughout 2015, a large percentage of the supply-side participants (importers, generators) offering into the day-ahead market and real-time market was unpriced. Unpriced supply is willing to clear in the market at any price (i.e., they are *price-takers* and not eligible to set clearing prices). Supply may be willing to be insensitive to price for a number of reasons, including fuel and power contractual or hedging arrangements, or the unwillingness of a participant to cycle its generator. As a result, on average, only a small portion of the total supply clearing each day was economically dispatched based on price. Despite the increased flexibility provided by the introduction of negative offers in December 2014, many participants have continued to self-schedule generation in both the day-ahead and real-time markets. *Self-scheduling* means that participants commit and schedule their resources at their economic minimum limit to provide generation within an hour, regardless of price or whether the ISO would have scheduled or dispatched the resource to provide the service in any event. These participants are willing to let their generators be price-takers in the market, despite their cost to generate, and even pay to remain on line when prices go negative.

The unpriced portion of the supply curve is made up of three components including fixed imports, self-scheduled generation, and generation at a resource's economic minimum limit.

- **Fixed imports** refer to generation scheduled to flow into New England on the external interfaces regardless of price.
- **Self-scheduled generation** is offered into the energy market as must-run generation. Currently, in the day-ahead market generators can self-schedule up to their economic minimum limit. In the real-time market, generators can self-schedule up to their economic minimum limit for each hour up to 30 minutes before to the start of that hour. After this 30 minute deadline has passed, generators can then call the control room directly and request to be self-dispatched for that hour to any desired output level, as long as it does not cause or worsen a reliability constraint.
- **Generation up to economic minimum** is fixed and cannot be dispatched down by the dispatch software without shutting down a unit. Generators committed economically and operating at economic minimum are included as they are non-price setting in the energy market but they are, unlike the other two categories, entitled to NCPC, should LMPs be insufficient to cover production costs.

Figure 3-10 shows a breakdown of the hourly average day-ahead generation by price-setting ability along with average hourly cleared supply.

Figure 3-10: Hourly Average Day-Ahead Generation by Price Setting Ability, 2015



Note: Hour ending (HE) denotes the preceding hourly time period. For example, 12:01 a.m. to 1:00 a.m. is hour ending 1. Hour ending 6:00 p.m. is the time period from 5:01 p.m. to 6:00 p.m.

Figure 3-10 shows that, on average, during each hour over 76% of the supply offered into the day-ahead market is from unpriced generation. The space between the cleared supply curve and the total unpriced generation represents generation economically dispatched with the ability to set price.

Frequently, fixed imports and self-scheduled generation that clear the real-time market increase compared with the day-ahead market. This increase in unpriced generation further decreases the amount of generation economically dispatched and able to set price during real-time. Figure 3-11 shows a breakdown of the hourly average real-time generation by price setting ability along with average hourly cleared supply.

Figure 3-11: Hourly Average Real-Time Generation by Price Setting Ability, 2015

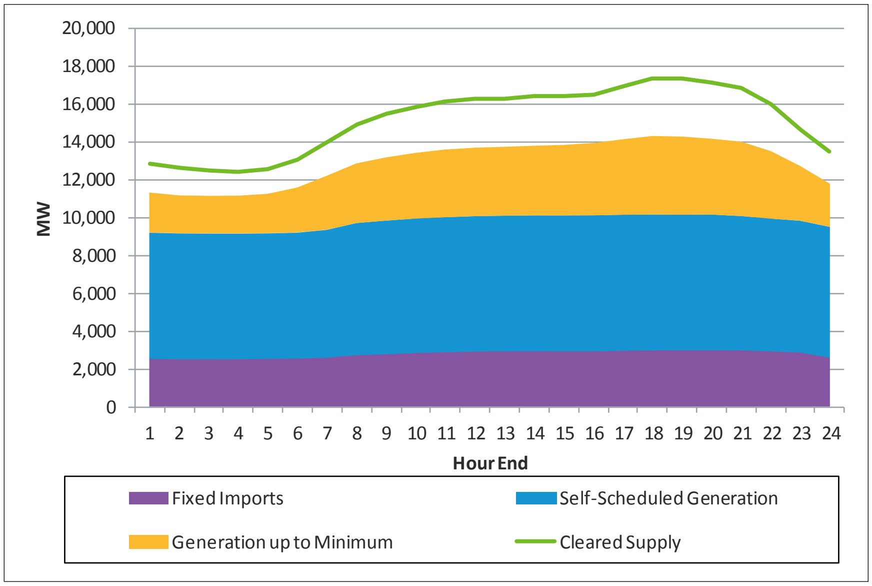
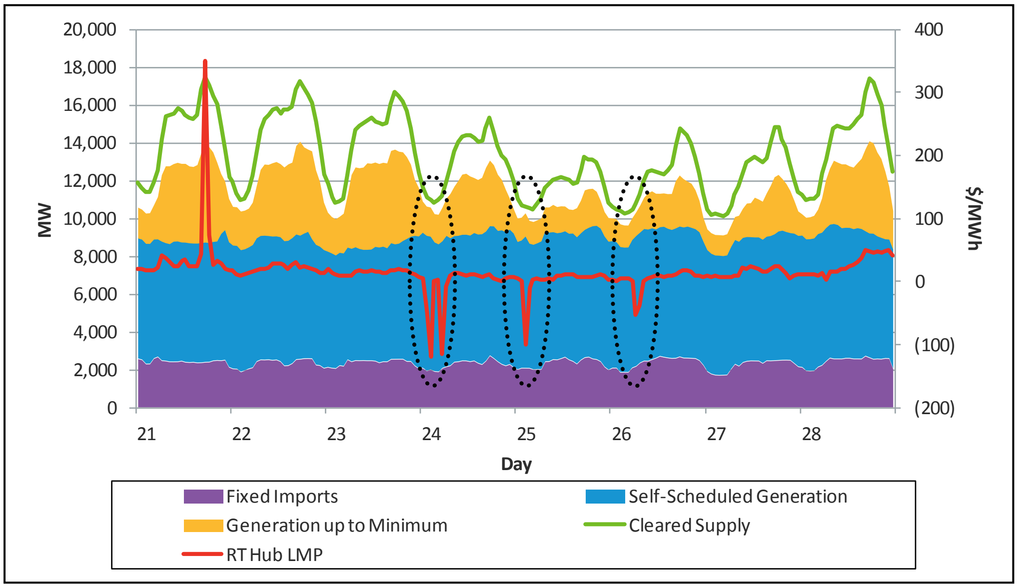


Figure 3-11 shows that, on average, over 82% of the supply offered into the real-time market is from unpriced generation. Comparing Figure 3-10 and Figure 3-11, on average, the amount of generation economically dispatched in real time decreases compared with day ahead. A decrease in the supply of economically dispatched generation increases the likelihood of low or negative prices.

An example of a large amount of unpriced generation contributing to negative pricing occurred during the early morning hours on December 24–26, 2015. Figure 3-12 shows a breakdown of the supply curve by price-setting ability along with cleared supply and the real-time Hub LMP during this period.

Figure 3-12: Real-Time Generation by Price Setting Ability and Hub Real-Time LMP, Dec. 21-28, 2015



In Figure 3-12, negative pricing occurred when the amount of total unpriced generation came very close to the cleared supply curve. During these times, very little generation with price-setting capability was economically dispatched—these times are highlighted by the oval shapes. The small amount of generation economically dispatched had offered into the market with negative offers, resulting in negative prices. Such negative-pricing situations tend to only occur when the system is approaching a point of over-supply due to the limited downward dispatchability and price-setting capability of the on-line resources. Unpriced generation typically does not impair upward dispatch flexibility.

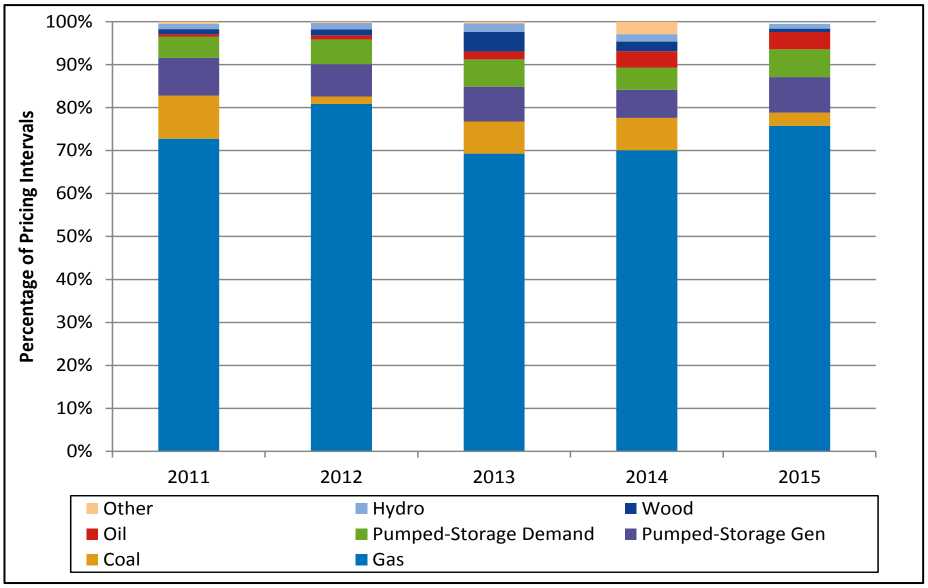
3.4.3 Marginal Resources

This section addresses the relationship between marginal (price-setting) resources and LMPs in both the real-time and day-ahead markets. The influence of differing costs of input fuels on electricity prices are evaluated by examining the percentage of time that resources of a certain fuel type are marginal in the real-time market. This section also examines the relationship between marginal resources and LMPs in the day-ahead market. More resource types, such as demand and virtual transactions, compete in the day-ahead market, compared with the real-time market, and can therefore set.

In both markets, the LMP is set by the cost of the next megawatt that the ISO would have to dispatch to meet an incremental change in load at a pricing location. The resource that sets price is called the marginal unit. The price of electricity changes as the price of the marginal unit changes and the price of the marginal generating unit is largely determined by its fuel type. Because of this, examining marginal units by fuel type helps us understand changes in electricity prices. At least one marginal unit will meet the energy requirements on the system during each pricing interval. If transmission is not constrained, we classify the marginal unit as the unconstrained marginal unit. In intervals with binding transmission constraints, an additional marginal unit exists for each binding constraint.

Natural gas was the marginal fuel for 75% of all pricing intervals in the real-time market in 2015. This is an increase compared with 2014. One reason for this increase is that gas displaced coal as the price-setting fuel in a noticeable percentage of intervals which can be seen in Figure 3-13 below.

Figure 3-13: Real-time Marginal Fuel-Mix Percentages



As the price-setting intervals for natural gas increased from 70% to 75% between 2014 and 2015, the percentage of price setting intervals for coal fell from 8% to 3%. This displacement was, in part, due to lower gas prices in 2015. These lower prices made gas-fired generators more economically viable than coal-fired generators, particularly in non-winter months. Other fuel types' price-setting percentages were comparable to last year.

Unlike the real-time market, generators of all fuel types set price only 44 % of the time in the day-ahead market in 2015. This is because generators in the day-ahead market compete with other physical and financial price-setting entities. Many of these entities either do not exist or are not eligible to set price in the real-time market. Virtual supply and demand, for example, are financial products which only exist in the day-ahead market.[52] Similarly, price-sensitive demand only exists in the financial construct of the day-ahead market. In real-time, only pumped-storage demand is price-sensitive. All other demand that is physically consumed needs to be served by real generation. Lastly, even though external transactions exist in the real-time market, they set price more frequently in the day-ahead market. This is because there are more priced external transactions in the day-ahead market than in the real-time market; most real-time external transactions are fixed, or price takers, meaning they are ineligible to set price.[53]

[52] See Section 4.1 on virtual transactions.

[53] See Section 5 on External transactions.

Figure 3-14 and Figure 3-15 below illustrates the percentage of time that each entity set price in the day-ahead market over the past five years. The pie chart provides a further breakdown for 2015, showing the generator fuel types that set price in the day-ahead market.[54]

Figure 3-14: Day-ahead Marginal Fuel-Mix Percentages

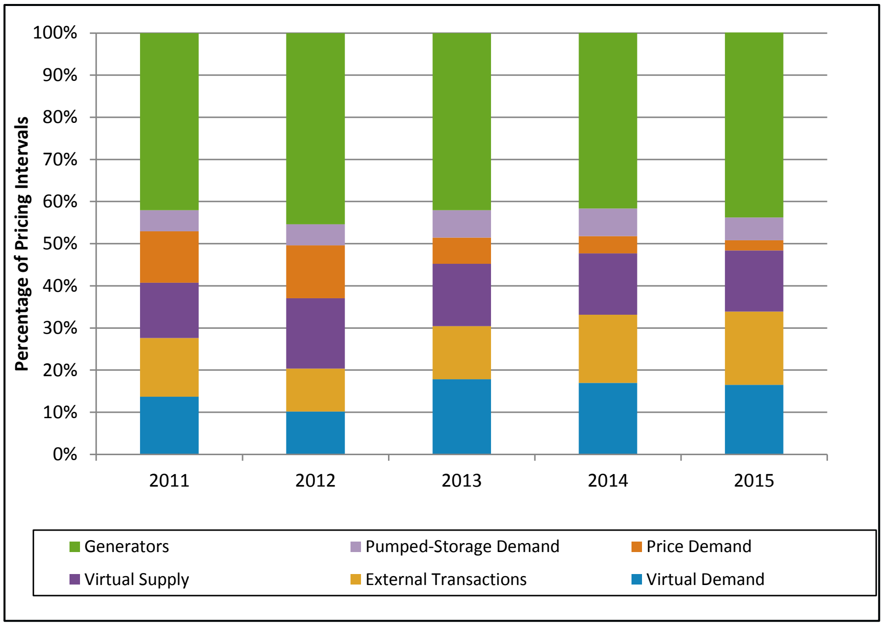
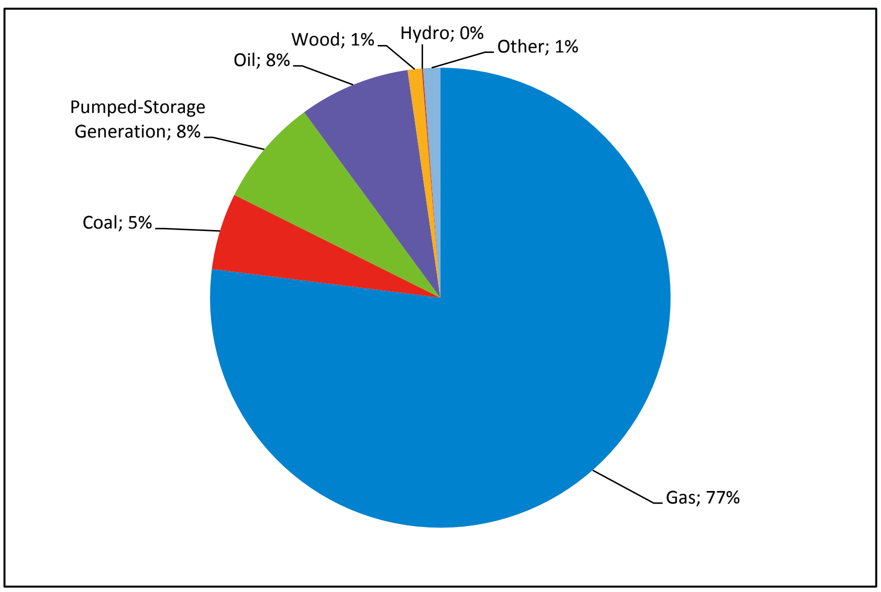


Figure 3-15: Marginal Generation Fuel-Mix Percentages, 2015



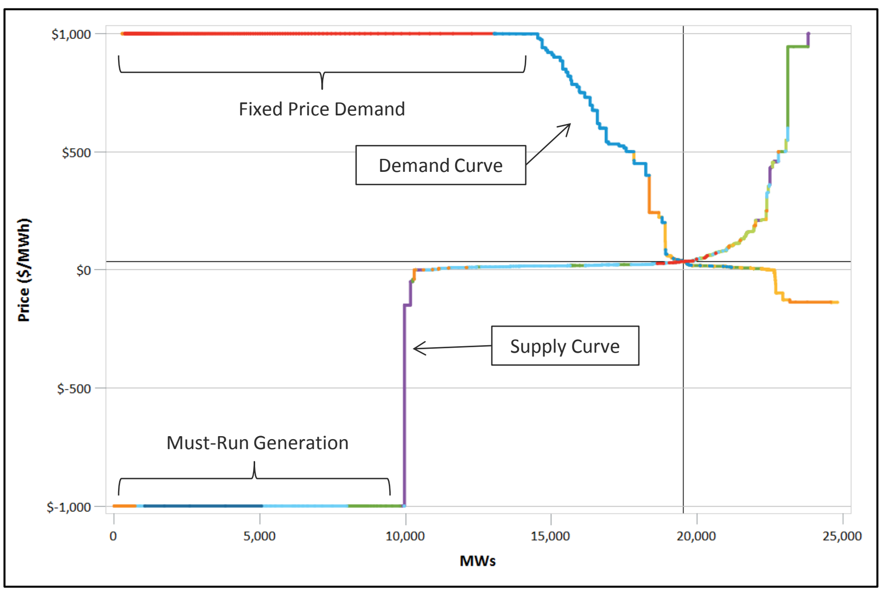
[54] With the introduction of Energy Market Offer Flexibility (EMOF) in December 2014 generators submit information regarding fuel represented in their supply offer. This provides better information on the fuel underlying the marginal unit than existed prior to EMOF. The metric has been adjusted accordingly from 2015.

Similar to the real-time market, gas-fired generators set price more than generators of all other fuel types combined in 2015. This shows that even though other entities affect the supply curve, natural gas is typically needed more than any other generator fuel type to serve the next incremental increase in load in New England. Additionally, Figure 3-14 above suggests that many different types of entities other than generators can also be marginal.

To illustrate the clearing of the day-ahead market, the aggregate supply and demand curves during the peak load hour of a sample market day (August 1, 2015) are shown below. The illustration provides insight into the clearing of the day-ahead market and price-setting ability of the various resource types.[55] The aggregate supply and demand curves in Figure 3-16 approximate the clearing of the day-ahead market when no constraints are binding on the system.[56] The aggregate supply curve stacks the offer blocks of each available supply resource offering into the day-ahead market and accounts for generator economic minimum and maximum operating parameters, as well as resources that offer as must-run. The supply curve consists of offers from generators, imports, and virtual supply (Incs). The aggregate demand curve stacks the bid blocks of each demand resource bidding into the day-ahead market. The demand curve consist of bids from fixed demand, price sensitive demand, dispatchable asset-related demand (ARD), exports and virtual demand (Decs). For the purpose of this illustration we assume that units offering as must-run or fixed transactions offer in at $-1,000/MWh for supply offers and $1,000/MWh for demand bids. In practice, entities bidding in this way will produce or consume electricity regardless of the market price.

Figure 3-16: Day-Ahead Market Aggregate Supply and Demand Curves

August 1, 2015, Hour Ending [17]



[55] Hour Ending 17 was the peak load hour for August 1.

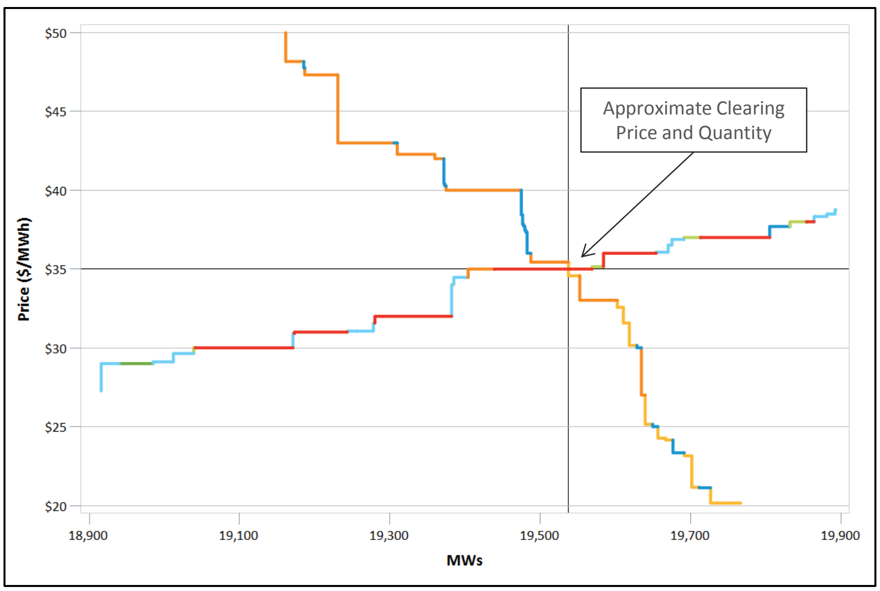
[56] The actual clearing of the day-ahead market is much more complex than the use of aggregate supply and demand curves described here.

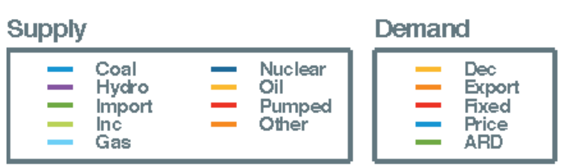
The intersection of the aggregate supply and demand curves represents the approximate market clearing price and quantity.

Many unit types can be marginal within a narrow market clearing price range. A close-up of the intersection of the two curves for August 1, 2015, hour ending 17, is shown in Figure 3-17. The approximate clearing price is $35/MWh and the amount of cleared supply is 19,537 MW. The marginal unit type was pumped storage as shown where the day-ahead Hub LMP of $35/MWh intersects the aggregate supply curve.

Figure 3-17: Intersection of the day-ahead market aggregate supply and demand curves

August 1, 2015, hour ending 17





Each segment of the supply and demand curves is colored to represent the type of resource offering to sell or bidding to buy electricity. In the aggregate supply curve, the offers shown are provided by resources burning natural gas, wood (other category), and coal, along with pumped storage, imports and virtual supply. The aggregate demand curve is composed of bids from virtual demand, exports, and price sensitive demand. Pumped storage is the marginal unit type because the price would continue to be set by a pumped storage unit offer block for a small increase or decrease in load. However, the curves highlight the fact that small changes in offers or bids can impact which product is marginal. Within the $10/MWh range around the clearing price, there are virtual demand and supply bids, external transactions, gas, coal, pumped-storage gen, and price-sensitive demand.

3.4.4 Load and Weather Conditions

The demand for electricity in New England is weather-sensitive and contributes to the seasonal variation in energy prices.[57] New England's native electricity demand is referred to as *net energy for load* or "NEL". As shown in Table 3-5, the NEL was highest in the third quarter of 2015, at 35,022 gigawatt-hours (GWh), equivalent to an average hourly value of 15,691 MW.

Table 3-5: Energy Statistics, 2011-2015

	NEL (GWh)	NEL (average hourly MW)	Recorded Peak Demand (MW)	Normalized NEL (GWh) [a]	Normalized NEL (average hourly MW)
2011 Annual	129,162	14,745	27,707	128,998	14,726
2012 Annual	128,082	14,581	25,880	128,249	14,600
2013 Annual	129,377	14,769	27,379	127,754	14,584
2014 Annual	127,175	14,518	24,443	127,114	14,511
2015 Annual	126,833	14,479	24,437	125,779	14,358
Q1 2015	33,633	15,571	20,583	32,440	15,019
Q2 2015	29,129	13,337	20,923	29,145	13,345
Q3 2015	35,022	15,861	24,437	34,316	15,542
Q4 2015	29,049	13,156	18,157	29,878	13,532

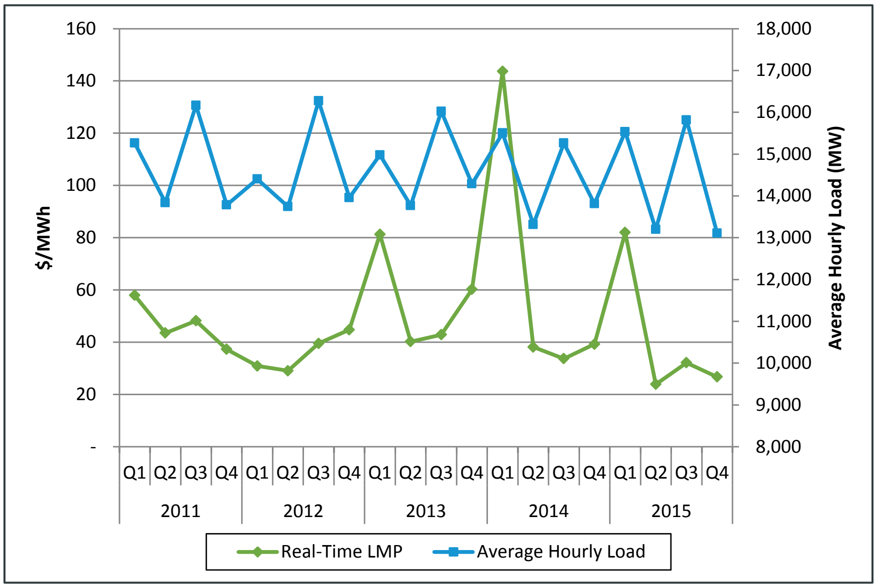
(a) *Weather-normalized* results are those that would have been observed if the weather were the same as the long-term average.

The annual peak demand of 24,437 MW also occurred in the third quarter, on July 20. The first quarter had the second-highest demand for electricity in 2015, at 33,633 GWh of electricity consumption, which is consistent with historical observations and is driven by the higher electrical heating demand on the system during the peak winter months. The second and fourth quarters of 2015, with more mild temperatures, had the lowest demand for electricity. The major factor behind the reduced level of demand year-over-year was weather-related. Summer weather in 2015 was warmer than in 2014, but fall and spring of 2015 were also milder than those seasons in 2014, contributing to overall lower demand in 2015.

Figure 3-18 shows real-time LMPs and average hourly load.

[57] *Net energy for load* is calculated as total generation (not including the generation used to support pumping at pumped-storage hydro generators) plus net imports.

Figure 3-18: Quarterly Average Real-Time Hub Prices and Average Hourly Load



Of particular note is the fact that winter electricity prices, driven by high natural gas prices, exceeded electricity prices during the summer months even though the summer electrical demand exceeds the winter electrical demand (see Table 3-5). This can be seen to a large extent in Quarter 1 2015, when average prices exceeded $81/MWh, while the average prices in July 2015, the month with the annual peak load, were around $25/MWh. This highlights the impact weather can have on both load and electricity prices.

Figure 3-19 shows the average hourly load and implied heat rates for the past five years by quarter. An implied heat rate is the calculation of the electric price divided by the day-ahead natural gas price. An implied heat rate is also known as the break-even natural gas market heat rate, because only a natural gas generator with an operating heat rate (measure of unit efficiency) below the implied heat rate value can be profitable by burning natural gas to generate power. Natural gas plants with a higher operating heat rate cannot be profitable at the prevailing electricity and natural gas prices.

Figure 3-19: Average Hourly Load and Gas Implied Heat Rates

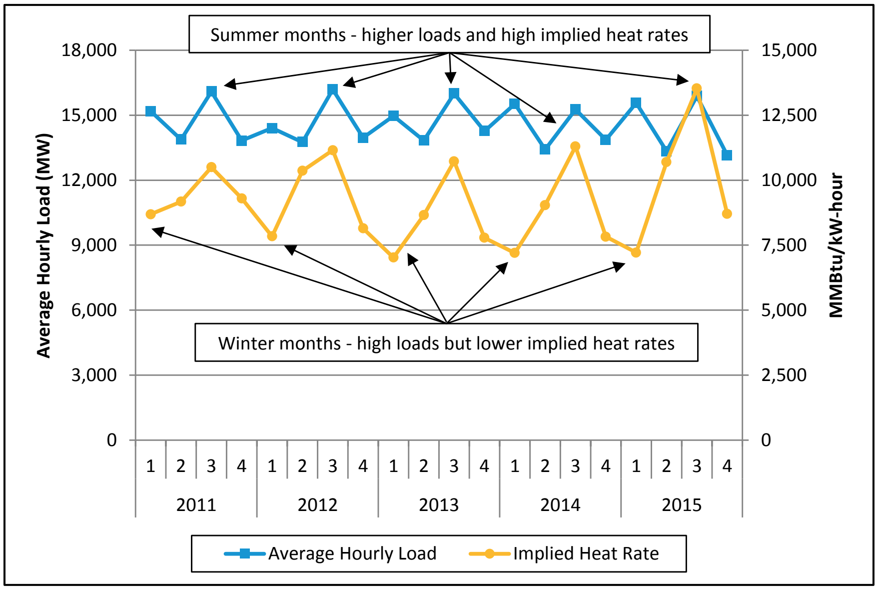
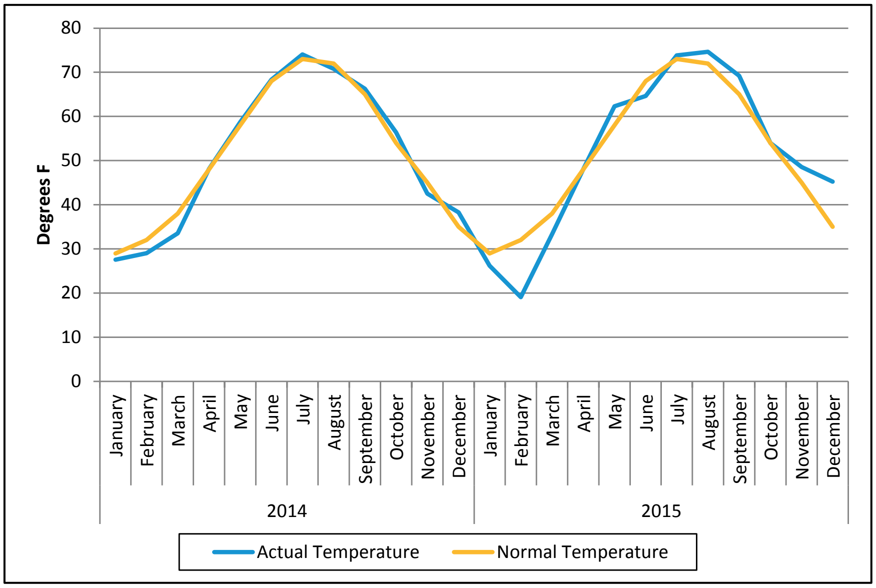


Figure 3-19 shows that in the summer months (July, August, September, Quarter 3) heat rates are generally higher, and loads are generally higher. Less efficient gas units are more profitable during these periods. In contrast, even though loads are relatively high in the winter months (January, February, and March, Quarter 1), heat rates for gas-fired units are low – especially for Quarter 1 for 2013, 2014, and 2015. These were years and quarters where gas prices were high and volatile and some gas generation was displaced with oil-fired generation.

New England weather in 2015 was marked by temperatures that were well below normal through April and periods of warm weather from May through December. Figure 3-20 shows monthly normal and actual temperatures for 2014 and 2015.[58]

[58] The "normal" average temperature is defined as the 30-year average of temperatures from 1981 to 2010. See *1981-2010 U.S. Climate Normals,* https://www.ncdc.noaa.gov/data-access/land-based-station-data/land-based-datasets/climate-normals/1981-2010-normals-data

Figure 3-20: Actual and Normal Temperatures



The ISO reported that during a number of periods from December 2013 through February 2014, daily average temperatures were well below the 20-year historical average.[59] In March 2014, the average temperature in Boston was 6.3 degrees F (°F) below average.[60] January 2014 started with a three-day cold spell, from January 2 to January 4, with very cold temperatures (6.8°F at the peak hour). On Tuesday, January 7, a polar vortex that brought subzero temperatures throughout the Midwest pushed into New England, with temperatures falling into the low teens. The rest of the year was moderate and had temperatures close to average.

The first four months of 2015 were cold in the Northeast. On January 24-27, a Nor'easter brought blizzard conditions and coastal flooding to New England. The cold weather in the first four months of 2015 resulted in a high demand for natural gas, which led to high natural gas prices. The ISO reported from January through April 2015, daily average temperatures were below the historical average. Natural gas was sufficiently scarce and its price was sufficiently high during this period that, at times, other fuel types were more economic. This resulted in fuel switching among resources and high LMPs.

In May, the northeast was warm and dry. Connecticut, Massachusetts, Rhode Island, and New Hampshire were record warm for May. June daytime temperatures were below average, associated with above average precipitation. In August, Connecticut, Massachusetts, New Hampshire, Maine, and Rhode Island had August temperatures that were near record warm. December was an extremely mild month as the Northeast was record warm. Mild temperatures in December led to below-normal snowfall for the entire region.[61]

[59] The periods are December 10–17, 2013; January 1–10, 2014; January 21–30, 2014; February 6–12, 2014; February 16–19, 2014; and February 25–28, 2014. See *NEPOOL Participants Report, March 2014*.

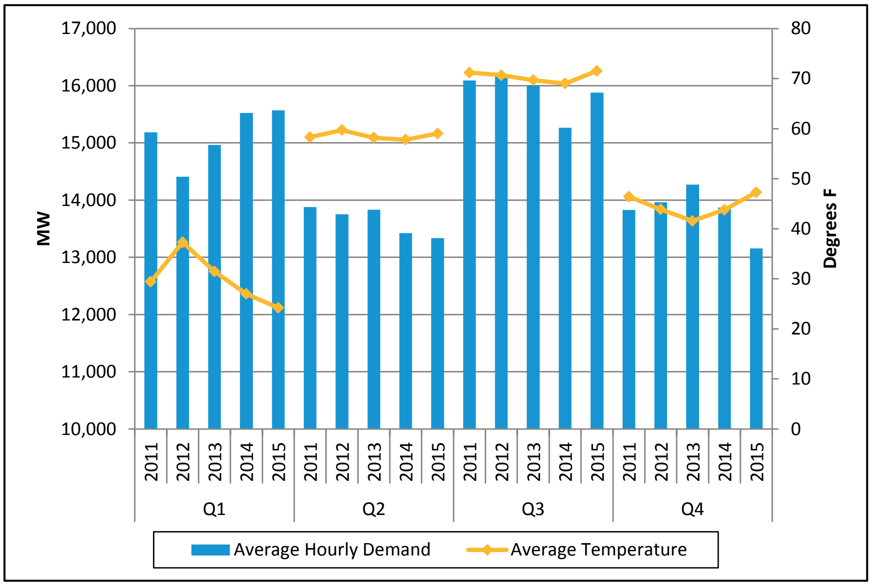
[60] See *NEPOOL Participants Report, April 2014* (April 4, 2014), http://www.iso-ne.com/static-assets/documents/committees/comm_wkgrps/prtcpnts_comm/prtcpnts/mtrls/2014/apr42014/coo_report_apr_2014.pdf.

[61] See *State of the Climate*, National Centers for Environmental Information, http://www.ncdc.noaa.gov/sotc/

The 2015 system-peak hourly load of 24,437 MW occurred on July 20. The temperature at the time of the peak was 89°F, with a dew point of 66°F.[62] Loads did not exceed 25,000 MW at any time in 2015 or 2014, but exceeded this level for 45 hours in 2013, 17 hours in 2012, and 21 hours in 2011.

Figure 3-21 shows average hourly demand and temperature ordered by quarter for the last five years.

Figure 3-21: Average Demand and Temperature by Quarter



Cold temperatures in quarter 1 of 2015 resulted in the highest hourly quarterly demand in the five-year period. Quarter 3 of 2015 was warmer than 2014, resulting in higher air conditioning loads. Even with the highest average temperature in 2015, the average hourly demand in 2015 was lower than 2011-2013. The second and fourth quarters 2015 had the lowest loads in the five year period.

3.4.5 Demand Bidding

Load Serving Entities (LSEs) express their willingness to purchase electricity in the day-ahead and real-time energy markets through demand bids. Demand bids can take two forms; fixed and price-sensitive.

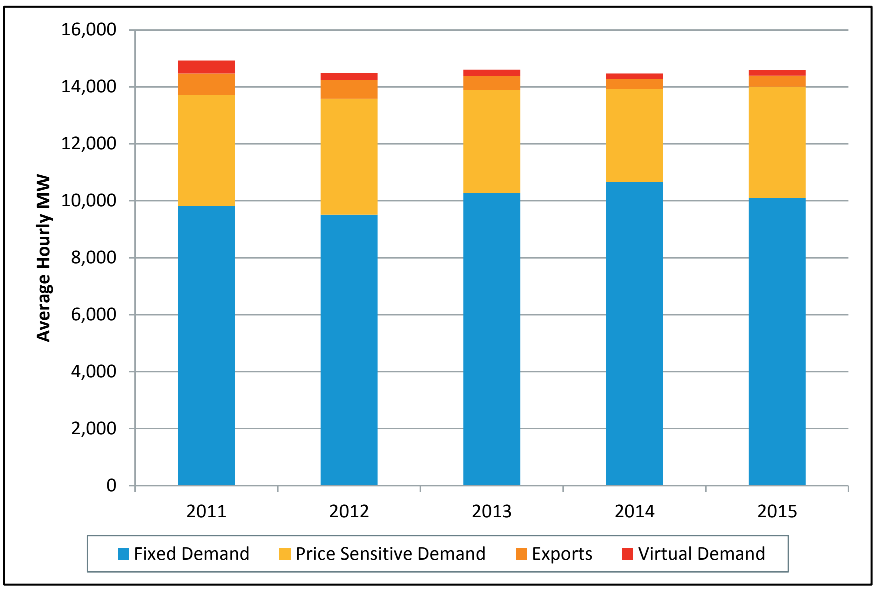
As the name implies, an LSE submitting a fixed demand bid is willing to purchase a fixed quantity of electricity regardless of the price. In 2015, fixed demand bids decreased by 4,833 GWh (by an hourly average of 551 MW), or by 5%, in 2015 when compared with 2014. This occurred despite relatively flat year-on-year demand and decreased fixed demand as a percentage of total demand cleared in the day-ahead market from 74% in 2014 to 69% in 2015.

[62] *Dew point* is a measure of humidity. Dew point is the temperature at which dew forms and is a measure of atmospheric moisture. A higher dew point indicates more moisture in the air. A dew point greater than 68 °F is considered uncomfortable and greater than 72 °F is considered to be extremely humid.

When an LSE submits a price-sensitive demand bid they are expressing their willingness to purchase more or less electricity depending on the price. When the price of electricity is low, the LSE is willing to purchase more electricity than when the price is high. The quantity from cleared price-sensitive demand bids increased by 630MW, on an average hourly basis, in 2015 compared with 2014, making up for the reduction in fixed demand. The share of price-sensitive demand of total day-ahead cleared demand increased from 23% in 2014 to 27% in 2015. Almost all price-sensitive demand (about 95%) cleared in the day-ahead market in 2015. This is because most price-sensitive demand is bids in significantly above the LMP.

Figure 3-22 presents hourly average demand that cleared in the day-ahead market.

Figure 3-22: Hourly Average Day-Ahead Demand Cleared



Compared with 2014, exports increased slightly in 2015 in both volume and as a percentage of total cleared demand, while virtual demand stayed relatively flat. The decrease in export transactions in quarter 4 of 2014 and quarter 1 of 2015 is attributable to the unplanned loss of the Cross Sound cable, which was the result of a transformer fire in New Haven, Connecticut. The total amount of physical load (fixed, price-sensitive and exports) that cleared in the day-ahead market in 2015 was 126,125 GWh (hourly average of about 14,400MW), which accounted for 99% of the total demand cleared in the day-ahead market.[63] Overall, 127,889 GWh cleared in the day-ahead market overall (hourly average of about 14,600 MW) in 2015.

3.4.6 Load Forecast Error

Each day, the ISO develops load forecasts, which are used to make commitment and dispatch decisions. Therefore, load forecasts have an impact on real-time prices. Load forecast error can result in real-time prices that are too low due to too much online capacity with a large volume of minimum load energy that cannot set price. It can also result in real-time prices that are too high due to insufficient online capacity to meet real-time demand. The load forecast is updated periodically throughout the day as conditions change and the ISO receives new information.

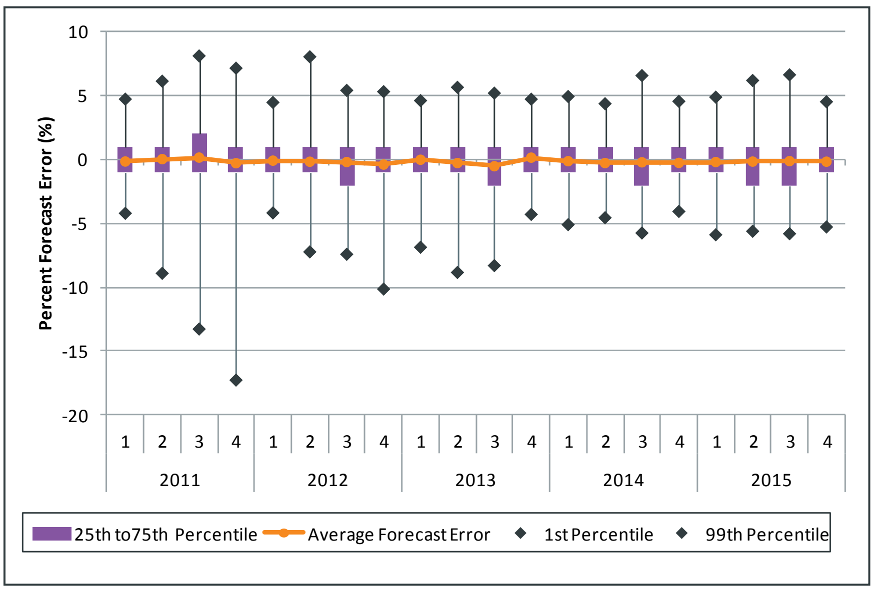
[63] Physical load is defined as fixed demand, price-sensitive demand and exports.

While there are instances where load forecast error appears to contribute to price deviations, the variation in load forecast error has declined over time, which helps the integrity of real-time price formation.

The forecast can be different from the actual loads due to unexpected weather variation or other changes to typical load patterns. If sufficient capacity is scheduled in the day-ahead market and all system and local area requirements are satisfied, no additional capacity will be scheduled by the ISO. If insufficient capacity is scheduled in the day-ahead market, the ISO will commit internal generators to meet ISO system and/or local area requirements. When this happens, the objective is to minimize the cost of bringing additional capacity to the market (minimize the combined start-up, no-load, and energy cost to operate at economic minimum).

Figure 3-23 below shows the average load forecast error by quarter for the last five years along with the 1st, 25th, 75th and 99th percentile of load forecast error.[64] Values greater than zero indicate that actual loads were greater than the forecast; values less than zero indicate the opposite.

Figure 3-23: Forecast Error by Quarter



Minimum and maximum forecast errors have been declining over time. Overall, the average forecast error is close to zero, but there are hours where the error can be high in some hours due to unexpected weather variation or other changes to typical load patterns. Seventy percent of all the hourly intervals in 2015 had forecast errors between -2% and 2%.

An illustration is provided below showing the importance of accurate load forecasting and the potential impact on price of large forecast errors. Two days in 2015 with large forecast errors and the LMPs during those hours are shown; one when actual load were less than the forecast and one when actual loads were greater than the forecast.

[64] Load Forecast Error = (ISO real-time telemetered load – Forecast)/Forecast. The forecast used in these analyses is the forecast generated between 7AM and 11AM on the day before the Operating Day.

The first example, September 10, 2015, is shown in Figure 3-24 below. LMPs, loads, and the forecast are shown by hour. This was a day where there were a number of hours throughout the day when loads were under the forecast. Overall, loads were 4% under the forecast on September 10, 2015. In this analysis, we focus on HE 14 through HE 20, a time when the loads were 8% or more under the forecast.

Figure 3-24: LMPs, Loads, and Forecast, September 10, 2015

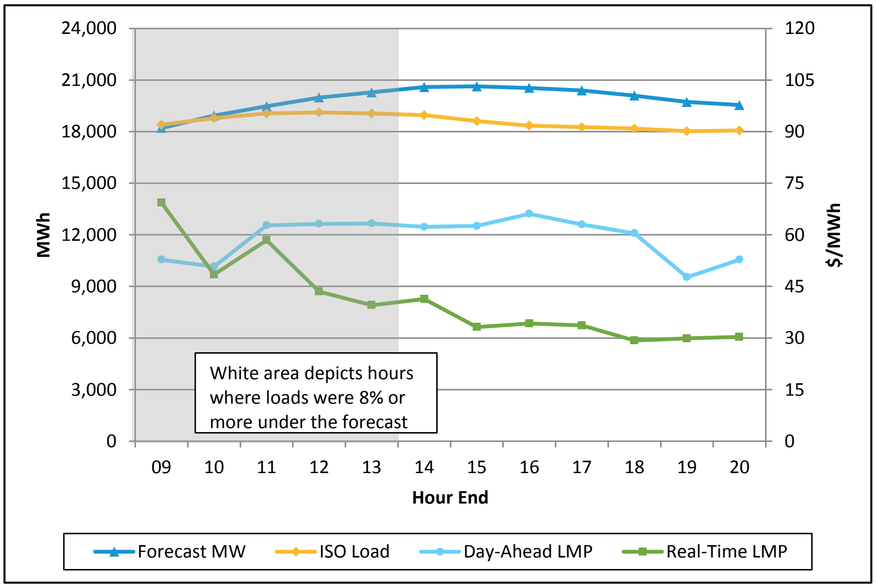


Figure 3-24 shows that there were lower LMPs in the seven hour period. From HE 14-20, loads averaged 18,347 MW, while the forecast MW averaged 20,241 MW, a 9% forecast error over these hourly intervals. Day-ahead prices averaged $59.26/MWh in this timeframe. Alternatively, real-time prices averaged $33.11/MWh, a -44% difference from the day-ahead.

The second date that we show is January 4, 2015, in Figure 3-25. This is a day when there were a number of hours where the loads were over the forecast. In this analysis, we are focusing on HE 12 through HE 17, a time where loads were 8% or more over the forecast. Overall, loads were 6%.

Figure 3-25: LMPs, Loads, and Forecast, January 4, 2015

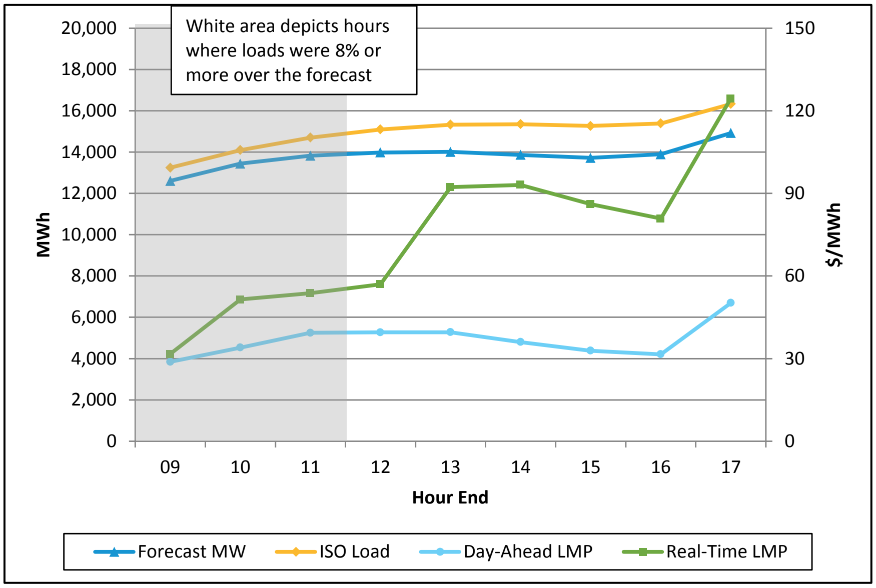


Figure 3-25 shows that there were higher LMPs in the six-hour period. From HE 12-17, loads averaged 15,458 MW, while the forecast MW averaged 14,063 MW, a 10% forecast error over these hourly intervals. Day-ahead prices averaged $38.28/MWh in this timeframe. Real-time prices averaged $88.94/MWh, a 132% difference from the day-ahead.

We note that overall, the price impact depends on how much time in advance the error was detected (more notice means less reliance on the commitment of expensive flexible units) and the generation available to meet the unexpected load.

3.4.7 System Events

Two notable system events occurred during 2015, one Minimum Generation Emergency event when the ISO anticipated that generation and external transactions would exceed system demand, and one Operating Procedure #4 (OP4) event when supply margins were tight.[65] During the OP4 event, low operating reserve surplus relative to energy and reserve requirements, occurred due to a number of unforeseen events, resulting in operating reserve prices and elevated real-time energy prices.

Sunday, July 5, 2015: ISO New England implemented Control Room Operating Procedure 25005, *Minimum Generation*. During the early morning hours, load on the system was very low due to below average temperatures and it being the July 4th holiday weekend. At 6:00, the ISO declared a Minimum Generation Emergency in anticipation of generation and external transactions exceeding system demand. The ISO declares a Minimum Generation Emergency when the sum of fixed external transactions that cleared the Day-Ahead Energy Market plus the economic

[65] For more information on Minimum Generation Emergencies, see *Minimum* Generation, Control Room Operating Procedure 25005 (March 7, 2016), http://www.iso-ne.com/static-assets/documents/rules_proceds/operating/sysop/cr_ops/crop_25005.pdf. For more information on OP events, see, Operating Procedure No. 4, *Action during a Capacity Deficiency* (June 24, 2015), http://www.iso-ne.com/static-assets/documents/rules_proceds/operating/isone/op4/op4_rto_final.pdf.

minimum limits of all on-line generators is within 100 MW or greater than the projected demand.[66]

Once declared, all LMPs in the system were administratively set to the floor price of -150/MWh, external transactions entering the region were reduced on multiple interfaces, and generating resources were subject to being reduced to their emergency minimum limits. At 8:15 as loads began to increase with the morning ramp and the threat of generation exceeding demand had passed, the event was canceled.

It is notable that there has been a significant decline in the number of minimum generation emergency events since the introduction of the Energy Market Offer Flexibility (EMOF) rules in December 2014. Under the EMOF rules the supply offer price floor was changed to negative $150/MWh from $0/MWh, allowing for greater downward dispatchability based on price as the system approaches over-supply conditions. For example, in 2013 and 2014 (prior to EMOF) there were 27 and 36 minimum generation emergency events, respectively, whereby the price was administratively set to $0/MWh. This compares to a total of 2 events since EMOF was implemented, the first of which occurred in December 2014, and the second in July 2015 as described above.

Wednesday, September 9, 2015: ISO New England implemented Master/Local Control Center Procedure #2 (M/LCC 2), *Abnormal Conditions Alert*, and Operating Procedure #4 (OP#4), *Action during a Capacity Deficiency*. Going into the day, an operating reserve surplus of 204 MW was projected based on the forecasted load of 23,810 MW. The actual peak load was 24,230 MW for hour ending 17, which was 420 MW above the forecasted value. The climb in load was attributable to higher temperatures and dew points than forecasted during the afternoon hours. The forecasted temperatures in Boston and Hartford during the peak hour were 86 and 88 degrees Fahrenheit, respectively, with actual temperatures of 90 and 91 degrees Fahrenheit.

At 16:36, a transmission contingency occurred that reduced transfers into New England over the Hydro-Quebec Phase 2 interface by approximately 500 MW creating a deficiency in operating reserves. At 16:45, M/LCC 2 and OP #4 Action 1 were declared, which allowed the ISO system operators to begin depleting thirty minute operating reserves (TMOR). Action 1 of OP#4 was then cancelled at 18:15 and M/LCC 2 was cancelled at 22:00. System operating reserves and operating reserve requirements during the OP #4 event are shown in Figure 3-26.

[66] For more information on Minimum Generation Emergencies, see http://www.iso-ne.com/static-assets/documents/rules_proceds/operating/sysop/cr_ops/crop_25005.pdf.

Figure 3-26: Operating Reserves and Reserve Requirements, September 9, 2015

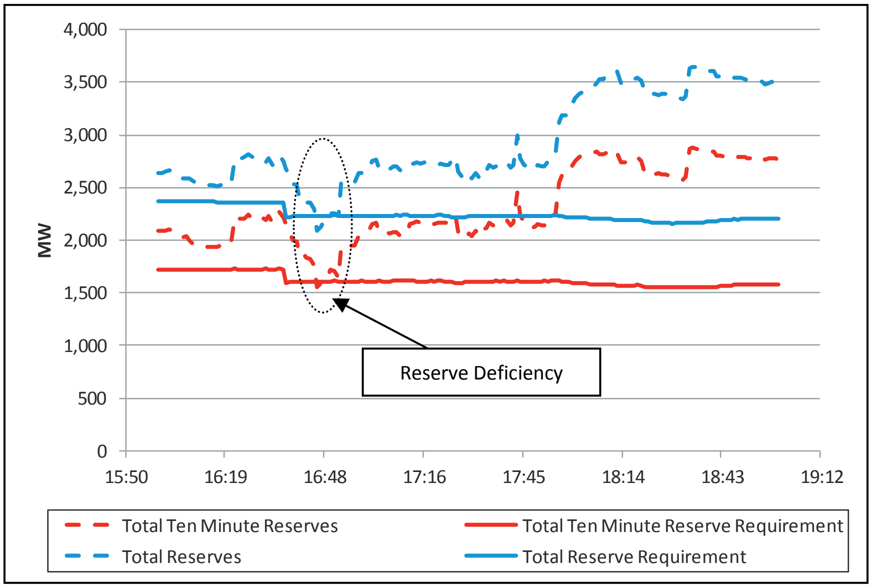


Figure 3-26 shows that following the transmission contingency at 16:36 both ten-minute and total reserves dropped below their requirements for a short period (highlighted by the oval shape). The average hourly Hub real-time LMP and rest-of-system ten-minute spinning reserve (TMSR) prices are shown in Figure 3-27.

Figure 3-27: Real-Time Hub LMP and TMSR Prices, September 9, 2015

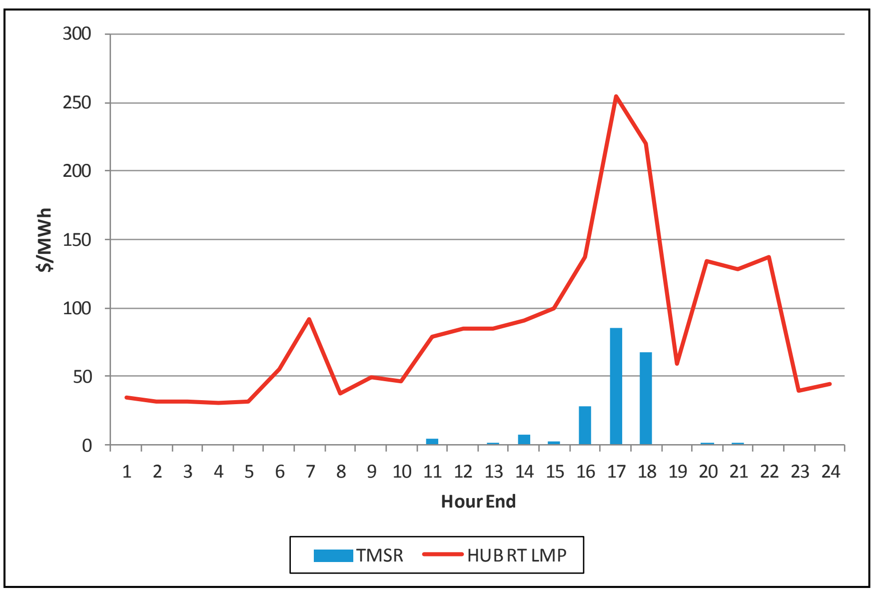


Figure 3-27 shows that the drop in operating reserves resulted in positive reserve pricing in hours ending 16-18, and as a result increased LMPs. In hour ending 18, reserve margins began to fully recover. Once reserve margins recovered, reserve prices decreased.

3.4.8 Reliability Commitments

In 2015, the amount of commitments ISO New England made for reliability reasons slightly increased. ISO New England is required to operate New England's wholesale power system to the reliability standards developed by the North American Electric Reliability Corporation (NERC), the Northeast Power Coordinating Council (NPCC), and in accordance with its own reliability criteria.[67] To meet these requirements, the ISO may commit additional resources for several reasons, including to ensure that adequate capacity is available in constrained areas, for voltage protection, and to support local distribution networks. Such reliability commitments can be made in both the day-ahead and real-time markets. The real-time average hourly energy output from reliability commitments during the peak load hours (hours ending 8-23) for 2011 through 2015 is shown in Figure 3-28. The figure also shows whether the commitment decision was made in the day-ahead or real-time market.

Figure 3-28: Average Hourly Energy Output from Reliability Commitments during Peak Load Hours (HE 8-23)

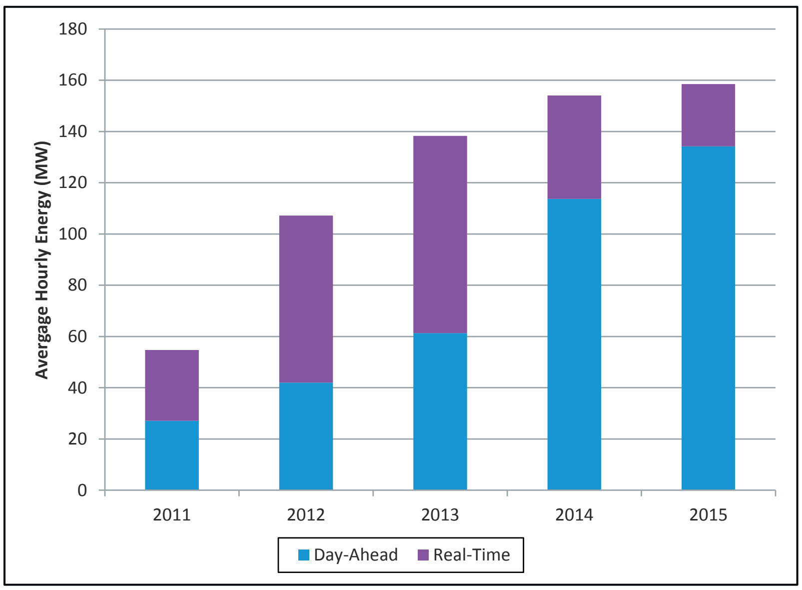


Figure 3-28 shows that the average hourly energy from reliability commitments during the peak load hours has been increasing over time, and that commitments in the day-ahead market have become more common. Nevertheless, energy from reliability commitments still remains a relatively small component of total system generation, at about 1% on average. One driver for the increase in reliability commitments is the need for additional generation in the NEMA Boston area for local second contingency protection.[68] Prior to 2013, there was ample supply of economic generation available in the Boston area. Beginning in 2013, however, due to changing fuel prices, these generators have become out-of-rate for significant periods of time. The shift to reliability commitments being made in the day-ahead market is partly due to the addition of

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

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

capacity constraints in the day-ahead market beginning in May 2013. The reasons for including reliability commitments in the day-ahead market are discussed below.

Often, generators committed and dispatched by the ISO for reliability are out-of-rate, meaning that these unit's energy prices are greater than the LMPs at their locations. During these times, these generators are eligible for NCPC payments to recover their as-offered costs if they are not recovered through energy market revenues. The real-time average hourly energy for reliability commitments during the peak load hours in 2015, by month, is shown in Figure 3-29. In addition, the figure shows a breakdown by when the generation was committed, and the amount of total average hourly generation that was out-of-rate.

Figure 3-29: Real-Time Average Hourly Energy from Reliability Commitments during Peak Load Hours (HE 8-23), 2015

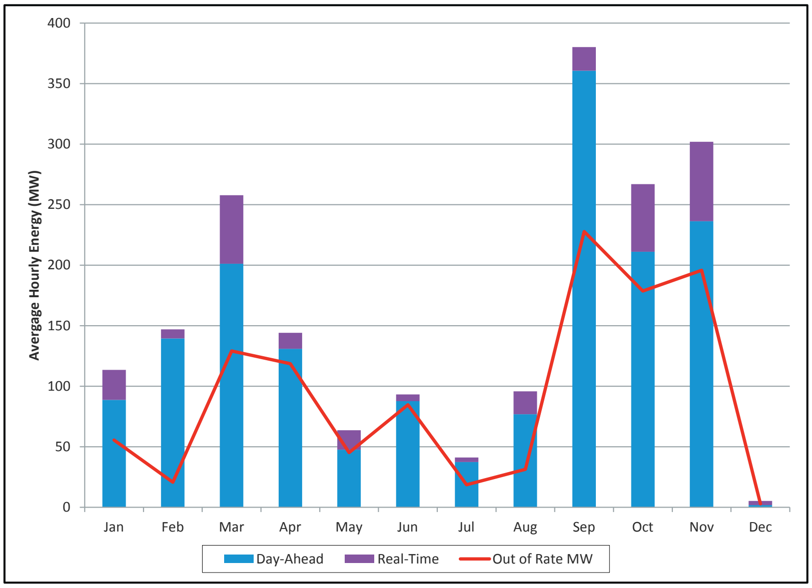


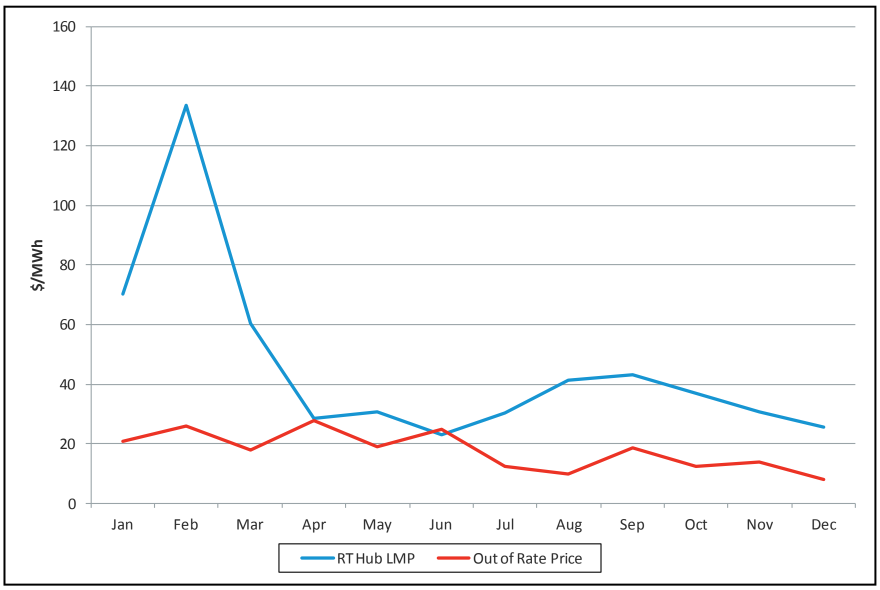
Figure 3-29 shows that March, September, October, and November had the greatest amounts of energy output from reliability commitments. Reliability commitments in these months were predominantly made for local second contingency protection.

A large majority of the reliability commitments were made in the day-ahead market, which helps minimize excess surplus capacity and the amount of economic generation that is displaced on the system from these units in the real-time operating day.

If a reliability requirement is known prior to the clearing of the day-ahead market it can be reflected in the network model. This will enforce the reliability constraint and result in the necessary units committed in the day-ahead market. However, it is possible if not likely that the some resources needed to meet the reliability constraint "out-of-merit" and would not have been committed were it not for the requirements of the reliability constraint. Because they are "out-of-merit", the market price is not likely to cover their costs and these resources will be provided uplift, or NCPC, to make them whole for their commitment period. Committing these units in the day-ahead market to meet real-time reliability requirements may displace other, less expensive, units in the day-ahead market from being economically committed and dispatched. Absent these reliability commitments were not made in the day-ahead market the ISO may need to commit additional resources subsequent to the day-ahead market in the reliability assessments (the Reserve Adequacy Assessment (RAA) process) or in the real-time market. In this case, these reliability commitments would be in addition to those other units that would have been economically committed and dispatched in the day-ahead market. In other words, making the reliability commitments in the day-ahead market limits the amount of surplus, and often out-of-rate, capacity online in real-time, and the amount of economic generation that is displaced, which can suppress real-time prices and increase NCPC.

Figure 3-30 shows the average energy offer price that out-of-rate reliability commitments were above the LMP during the peak load hours. For context, a plot of the average real-time Hub LMP is also included.

Figure 3-30: Average Offer Price Reliability Commitments were above the LMP during Peak Load Hours (HE 8-23), 2015



In Figure 3-30, the average price that out-of-rate reliability commitments were above the LMP during the peak load hours was relatively constant throughout the year despite the high LMPs in early 2015. One reason for this trend is that the same units tend to be committed for reliability throughout the year, and their offers tend to closely track fuel costs, which are a major driver of the LMP.

3.4.9 Congestion and Losses

This section addresses the components of the LMP, the calculation of these components, and discusses changes in the total congestion and losses in the system over the past five years.

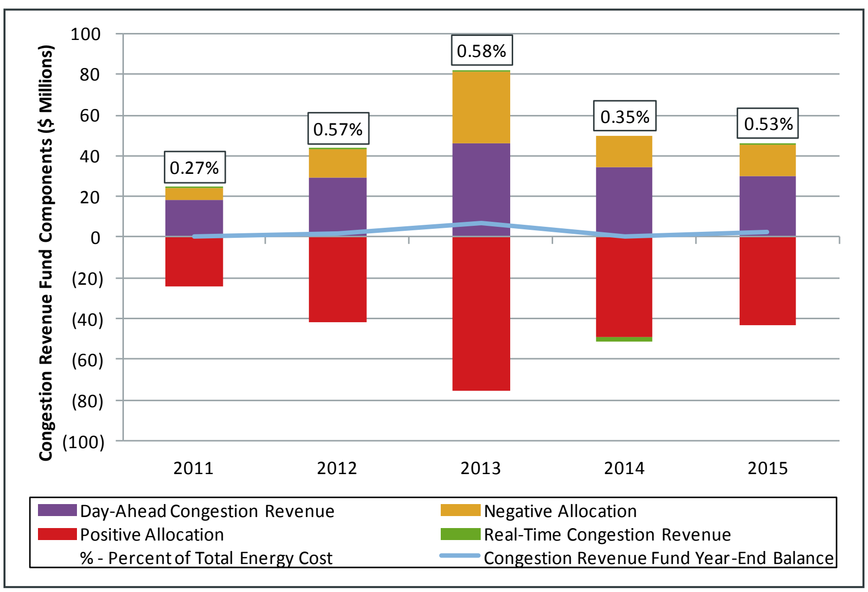
At every node in New England, LMPs reflect the cost of delivering the next megawatt (MW) of energy at the lowest cost to the system. The LMP is then divided into three components for the purpose of settling financial transmission rights: the energy component, congestion component, and loss component.

The energy component of the LMP is the same for all of the nodes on the system and is equivalent to the price at the reference bus, which is a load-weighted average of all LMPs on the system. The loss component is the marginal cost of additional losses caused by supplying an increment of load at a location as supplied by the reference bus. The loss component can be positive or negative. The congestion component of the LMP is the marginal cost of congestion caused by supplying an increment of load at a location as supplied by the reference bus. Like the loss component, the congestion component can be positive or negative. Congestion and loss components of LMPs are only important relative to each other, and only differences between locational values are used in settlements.

Due to significant investments in the transmission system, congestion in New England is relatively infrequent and small in magnitude. The total amounts of congestion and losses in New England are reflected in the congestion revenue fund and the marginal loss revenue fund, respectively. The congestion revenue fund is composed of congestion revenue and FTR allocations. Congestion revenue is collected in both the day-ahead and real-time markets. Congestion revenue for each line is calculated by multiplying the price difference between the LMP congestion components at the two ends of any line times the MW flow on that line. Total system congestion revenue is then calculated by summing the congestion revenue for each line. FTR allocations can be positive or negative. “Positive allocations” are payments made to FTR holders when the paths that they own generate revenue when the sink congestion component is greater than the source congestion component. In addition, “negative allocations” to financial transmission right holders are collected when the holders own paths that are congested in the opposite direction of their FTRs. The sum of the congestion revenue and negative allocations are then used to fund the positive FTR allocations. FTRs are discussed in detail in Section 4.2.

Congestion revenue fund components, balances, and the percent of the total energy cost in New England are shown in Figure 3-31 below.

Figure 3-31: Congestion Revenue Fund Components, Balances, and Percent of Total Energy Cost



Total day-ahead and real-time congestion revenue in 2015 was $31.2 million. Day-ahead congestion revenue is much higher than real-time congestion revenue because approximately 98% of the energy transacted in New England is settled in the day-ahead market. In addition to congestion revenue, FTR holders contributed approximately $15.0 million in negative allocations, and were paid approximately $43.6 million in positive allocations. FTRs were fully funded in 2015, with a total congestion revenue fund surplus of $2.6 million at the end of the year. This was an improvement from 2014, when only 96.5% of positive FTR allocations were paid because of a shortfall in the congestion revenue fund. As mentioned previously, congestion is relatively infrequent in New England. Day-ahead and real-time congestion revenue was only approximately 0.53% of the total cost of energy during 2015. This was only slightly higher than the average over the previous five years, 0.46%.

The marginal loss revenue fund is made up of six components:

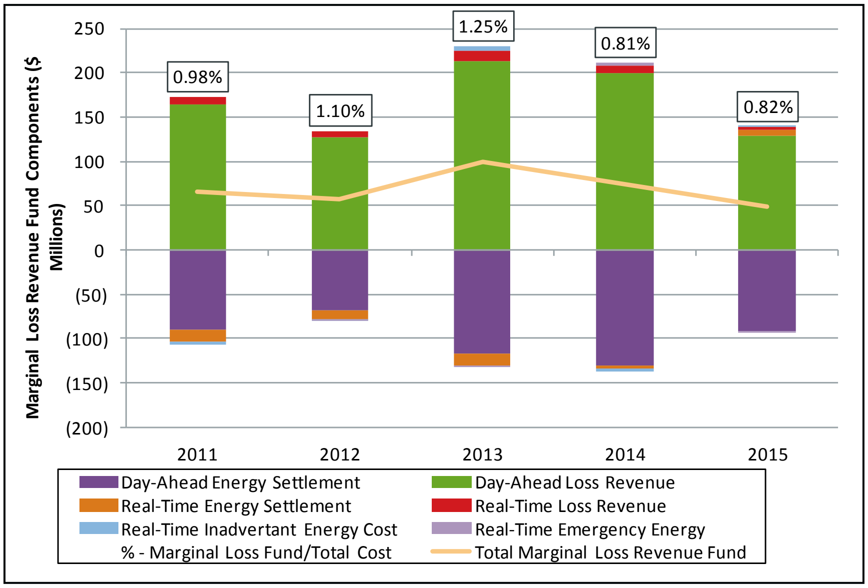
- Day ahead
- Real time
- Energy settlement
- Loss revenue
- Emergency energy
- Inadvertent energy

As previously mentioned, day-ahead values of energy settlement and loss revenue are much larger in magnitude compared with the real-time values, because nearly all of the energy transacted in New England is settled in the day-ahead market. Loss revenue is calculated for each line by multiplying the price difference between the LMP loss components at the two ends of any line times the MW flow on that line. Total system loss revenue is then calculated by summing the loss revenue for each line.

Energy settlement is the additional cost arising from imbalances in load and generation and is calculated using the energy component of the LMP. Inadvertent energy can be positive or negative, and occurs because external transactions are settled at scheduled values and the scheduled values may differ, positively or negatively, from actual flows during each hour.

Emergency energy costs arise when the ISO purchases, or sells, energy to a neighboring control area during an emergency. Marginal loss revenue fund components, balances, and percent of the total energy cost in New England are shown in Figure 3-32 below.

Figure 3-32: Marginal Loss Revenue Fund Components, Balances, and Percent of Total Energy Cost



In 2015, the year-end marginal loss revenue fund balance was approximately $48 million. This is the smallest year-end balance in the last five years. One reason for the difference from previous years is a decrease in the total value of the energy purchased during the year. Low fuel prices and mild weather contributed to the decrease in total energy costs. The year-end marginal loss revenue fund balance was 0.8% of the total cost of energy in 2015. This is consistent with 2014, and slightly lower than the prior years.

3.5 Net Commitment Period Compensation

Generators that are unable to recover their cost of operation in the day-ahead and real-time energy markets are eligible for “make-whole payments” (sometimes also referred to as “uplift”). In these cases, a generator’s revenue from providing energy and ancillary services is insufficient to recover some portion of its start-up and other short-run production costs. The make-whole payments, called “Net Commitment Period Compensation” or NCPC, are based on a comparison of a generator’s revenue and its as-offered costs. The ISO provides the payments to ensure the reliable operation of the power grid, as generators would be reluctant to operate when costs are expected to exceed revenues.

3.5.1 Reliability NCPC Payments

The ISO provides NCPC under a number of circumstances. These have been classified into standard categories. Generators that operate at the ISO’s instruction but do not recover their as-offered costs through energy market revenues are paid one of the following types of compensation, depending on the reason for the commitment:[69]

- **Economic/first-contingency NCPC**: Generators are sometimes committed to satisfy system-wide load and reserves but fail to recover costs. Situations that can lead to “economic” NCPC include the following:

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

  - Generation committed and dispatched to provide energy on short notice or to create reserves, allowing the system to recover from the loss of the first contingency within a specified period
  - Generation providing system-wide stability or thermal support or to meet system-wide electric energy needs during the daily peak hours
  - Generation committed for peak hours that must remain on line after the peak hours to satisfy minimum run-time requirements
- Local second-contingency NCPC: Generation is committed to provide local operating reserve support in transmission-constrained areas, to ensure local reliability needs.
- Voltage reliability NCPC: Generation is dispatched by the ISO to provide reactive power for voltage control or support.
- Distribution reliability NCPC: Generation is operating to support local distribution networks.
- Generator Performance Auditing NCPC: Generation operating to satisfy the ISO's performance auditing requirements.[70]

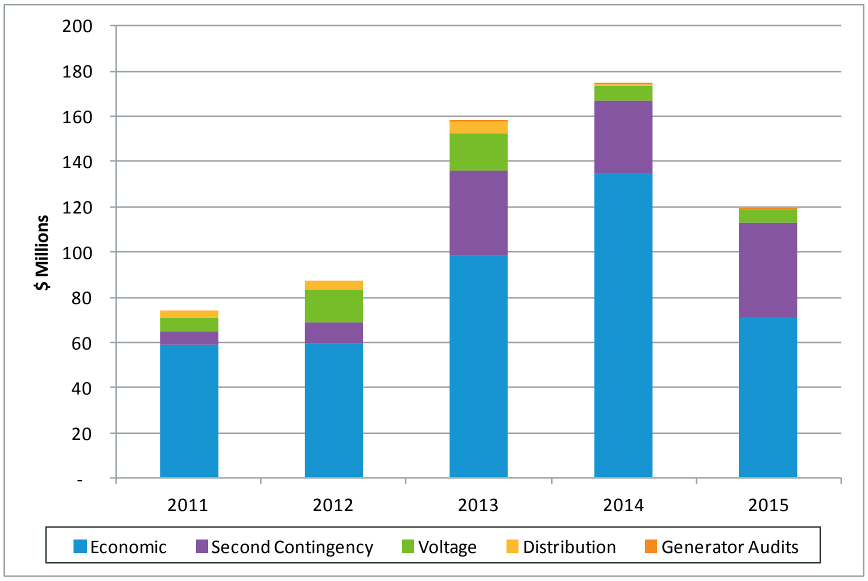
3.5.2 Reliability Payments for 2011 to 2015

Figure 3-33 indicates total reliability payments by year and payment category; as can be noted from the graph, NCPC payments decreased significantly in 2015 compared with 2014, going to $119 million from $175 million (a reduction of 32%). In part, NCPC payments over time mirror changes in generator fuel costs (an important component of generator short-run costs). The increases in NCPC compensation observed in 2013 and 2014, and the reduction in 2015, are consistent with changes in fuel costs (especially natural gas) over this time period.[71] It is also noteworthy that total NCPC payments represent a small fraction of compensation provided to generators. For example, generators' direct energy market revenues alone totaled $5.9 billion in 2015 and $9.1 billion in 2014. Therefore, NCPC payments to generators represented less than 2% of their total energy payments.

[70] NCPC payments for generator performance audits became effective on June 1, 2013. NCPC payments to participants for this category are incurred for the following: Performance audits of on-line and off-line reserves and for seasonal claimed capability audits initiated by the ISO rather than the participant, and dual-fuel testing services as part of the ISO's Winter Reliability Program.

[71] Other factors also influence NCPC payments. These include varying system conditions (i.e., instances of load forecast and generator commitment error, instances of local transmission issues and resulting local reliability needs, etc.) and changes in NCPC payment rules. For example, the total NCPC payments for 2015 reflect changes in payment rules that allowed generators to collect more NCPC than under prior NCPC rules.

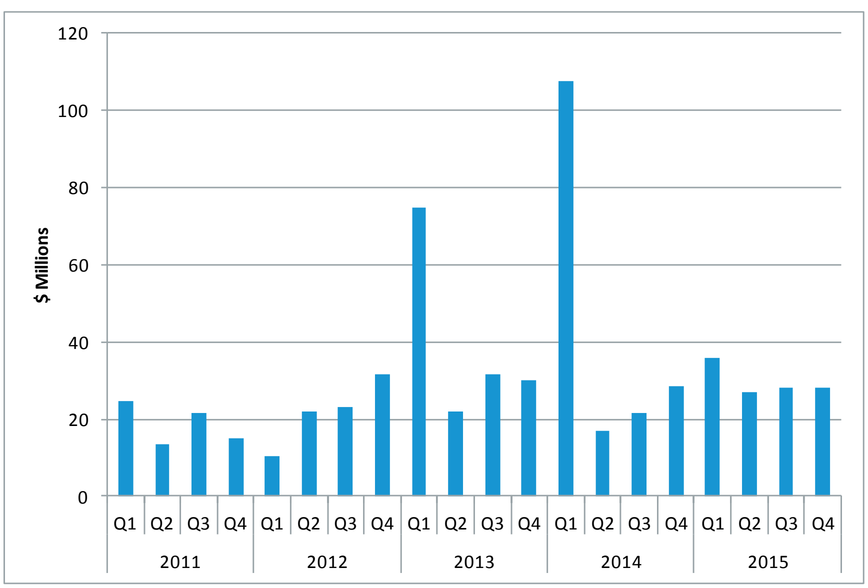
Figure 3-33: Total NCPC Payments by Year and Category



As indicated in the Figure 3-33, most NCPC payments are for economic (or first contingency) needs. These payments have ranged from a high of 79% of total NCPC payments in 2011 to a low of 59% of total NCPC payments in 2015. In recent years, second contingency payments (incurred to meet local load and reserve requirements) have increased as a proportion of total payments. This is in line with the increase in energy output from generators committed for reliability and their corresponding out-of-market rates as discussed in Section 3.4.8 (Reliability Commitments) above. In 2011-2012, these payments averaged just 10-12% of total NCPC payments; beginning in 2013, the payments have averaged 19-36% of total payments. Other types of NCPC payments have been relatively small in each year.

Considering NCPC Payments by Quarter (Figure 3-34), the highest NCPC payments have tended to occur in winter months (the first quarter of each year).

Figure 3-34: Total NCPC Payments by Quarter

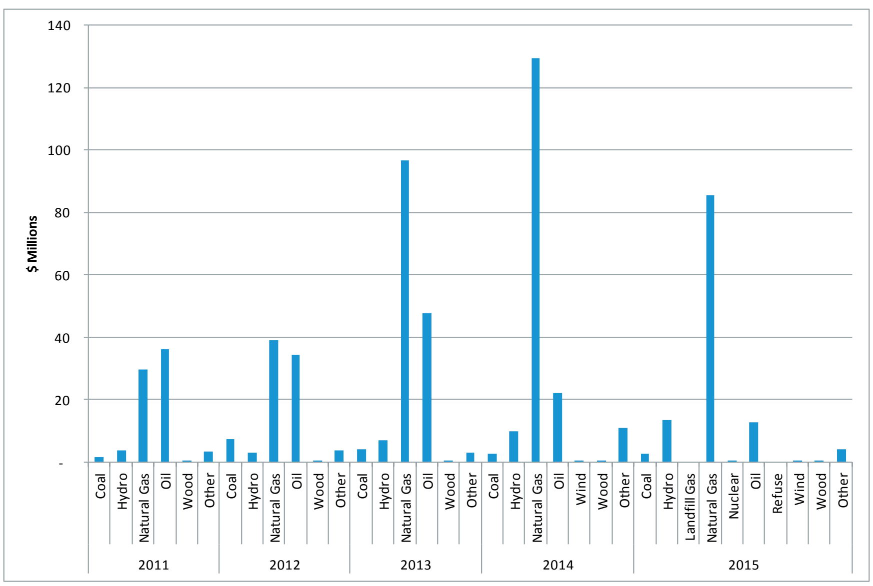


This largely reflects higher natural gas costs during the winter months (i.e., higher operating costs for generators) and concerns about natural gas scarcity and system reliability impacts in the Day-Ahead and Real-Time energy markets. The higher Q1 NCPC payments in 2013 and 2014 explain a significant portion of the overall increase in NCPC payments in those years.

In addition to fuel costs, revisions to NCPC rules, implemented in December 2014, have influenced recent NCPC payments. Firstly, NCPC payments are now calculated over a generator's duration of commitment, rather than over the 24-hour operating day. This means that a profitable commitment is not being offset by an unprofitable commitment, thereby improving performance incentives. Second, the NCPC compensation structure was improved to account for the lost opportunity costs of generators postured to meet system reliability needs and that are moved away from their economically optimal output by the ISO. In practice this applies frequently to limited energy generators. Third, up until February 2016, a generator scheduled in the day-ahead market was eligible for both day-ahead and real-time NCPC. When combined with lower real-time prices compared with prices in the day-ahead energy market, this results in higher real-time NCPC when the underlying supply offer does not change between the two markets. It is estimated that this third factor resulted in NCPC payments of approximately $68 million from December 2014 through January 2016. In 2015, the payments are estimated to total almost $58 million, or almost half of total NCPC payments. This aspect of the NCPC redesign, where a generation resource could receive two uplift payments for the same day-ahead commitment, was reconsidered and ultimately eliminated in February 2016 as it was not consistent with the make-whole and performance incentives intended in the redesign.

Figure 3-35 shows total NCPC payments by generator fuel type.

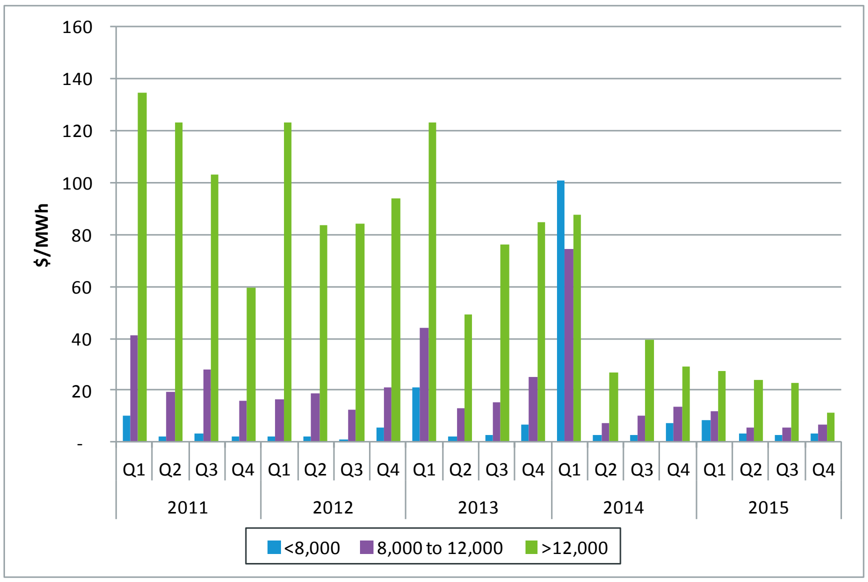
Figure 3-35: Total NCPC Payments by Generator Fuel Type



In most years, natural gas and fuel oil generators receive the majority of NCPC payments. Occasionally, hydro generators also receive noticeable NCPC payments. These fuel types receive the majority of NCPC payments because of their locational importance, both in the supply stack and geographically. These generators typically are neither the least- or most-costly generators, but are needed to ensure the reliable operation of the power system and are more economic to commit than very costly generators. Given some operational inflexibility, these generators may need to operate during hours when energy market pricing does not allow the generators to fully recover production costs. The large payments to natural gas generators in 2013-2015 represent the high fuel cost for operating these generators during winter months.

To examine NCPC payments further, we have classified average payments for "real-time" "economic" NCPC by generator heat rate level.[72] It is expected that generators with higher heat rates (i.e., require more fuel to create a unit, MWh, of electricity) will also require higher average make-whole payments when revenues are insufficient to cover costs.[73] Figure 3-36 below indicates the average real-time NCPC payments ($/MWh) to generators according to generator heat rate categories.

Figure 3-36: Average Economic Real-Time NCPC Payments by Generator Heat Rate



As expected, higher average real-time NCPC payments go to generators with higher heat rates. However, this relationship may sometimes not hold. For example, in Q1 2014, New England experienced very high natural gas costs; as a consequence, even fuel-efficient natural gas generators (with heat rates below 8,000 Btu/kWh) had higher operating costs than, for instance, fuel oil-fired generators with heat rates greater than 8,000 Btu/kWh.

Although generators with high heat rates receive relatively high average NCPC payments, these generators received only approximately 26% of economic NCPC payments from 2011 to 2015. These generators were committed less frequently than lower heat rate generators. Average payments to these generators have been declining over time, and represented just 10% of economic NCPC payments in 2015. To provide additional perspective for these payments, Table 3-6 below indicates the magnitude of total real-time economic NCPC payments as a percentage of total energy costs in ISO New England.

[72] Heat rates indicate the rate at which fuel (e.g., natural gas) is converted into electricity. These rates are typically stated in Btu/kWh. "Real-time" refers to the real-time energy market.

[73] Heat rates are one component of production costs; fuel prices are another important element and have a significant impact on production costs and make-whole payment magnitude. We have not tried to control for fuel price variation in our review.

Table 3-6: Real-Time Economic NCPC Payments as a Percent of Total Wholesale Costs

2011	2012	2013	2014	2015
0.6%	0.6%	0.6%	0.7%	0.6%

As the table indicates, real-time economic NCPC payments represent less than 1% of total costs (ranging from 0.6% to 0.7%) within the ISO's markets.

3.6 Demand Resources in the Energy Market

Demand resources participate in the energy market through the Transitional Price-Responsive Demand (TPRD) Program. The TPRD program was designed to transition New England to full integration of price-responsive demand in the energy markets in order to comply with FERC Order 745 (Demand-Response Compensation in Organized Wholesale Energy Markets). The TPRD program replaced both the Real-Time Price Response and Day-Ahead Load Response programs in June 1, 2012. The TPRD program allows market participants with assets registered as RTDR resources to offer load reductions in response to day-ahead LMPs. Market participants are paid the day-ahead LMP for their cleared offers and are obligated to reduce load by the amount cleared day-ahead. The participant is then charged or credited at the real-time LMP for any deviations in curtailment in real-time compared with the amount cleared day-ahead.

The TPRD program will remain in effect until June 1, 2018, at which time new market rules will become effective that will fully integrate dispatchable demand resources into the Day-Ahead and Real-Time Energy Markets.[74]

Participation in this program, overall, has been very limited. About 300 MW are enrolled in the program. In 2015, three to five market participants participated in the program on a regular basis. Payments to TPRD participants in 2015 amounted to just over $2 million.

Integration of Dispatchable Demand Resources: FERC Order 745 Legal Status

FERC Order 745 was challenged in 2012 in the D.C. Circuit of the US Court of Appeals. Order 745 requires Regional Transmission Organizations (RTOs) to pay the full LMP for load reductions produced by demand-response resources participating in organized wholesale energy markets subject to certain conditions. The case was argued in front of three judges in September 2013. In May 2014, the D.C Circuit issued an opinion (by a 2 to 1 vote) vacating the order, stating that, among other things, FERC lacked jurisdiction to promulgate the rules established by Order

[74] In April 2012, the ISO requested that the transitional rules remain in effect until June 1, 2017, when FCM rules address how capacity resources will be integrated into the energy markets. *ISO New England Inc., Market Rule 1 Price-Responsive Demand FCM Conforming Changes for Full Integration*, Docket No. ER12-1627-000 (filed April 26, 2012), http://www.iso-ne.com/regulatory/ferc/filings/2012/apr/er12-1627-000_4-26-2012_prd.pdf.

On October 29, 2015, the ISO requested that full integration of demand response resources into the energy market by delayed by one year. This request stemmed from the uncertainty created by the decision of the U.S. Court of Appeals for the District of Columbia Circuit vacating Order No. 745, which was being reviewed by the U.S. Supreme Court. ISO New England Inc., and New England Power Pool, Part 1 of Two-Part Filing of Demand Response Changes, Docket No. ER16-167-000 (filed October 29, 2015), http://www.iso-ne.com/static-assets/documents/2015/10/er16-167-000_part_1.pdf.

745.[75] However, the D.C. Circuit also stayed the mandate to vacate Order 745 pending the outcome of any further appeal to the United States Supreme Court.

In July 2014, FERC asked the D.C. Circuit to rehear the case *en banc*—a request for rehearing before the full 11-member court. In September 2014, the D.C. Circuit denied FERC's request for this rehearing. In January 2015, the US Department of Justice, on behalf of FERC, petitioned the US Supreme Court to review the D.C. Circuit's decision and overturn its ruling.

The Supreme Court issued a ruling on January 25, 2016 upholding FERC's authority to regulate demand response programs in wholesale markets.[76] In a 6-2 decision, the justices ruled the agency was within its authority under the Federal Power Act when it issued Order 745. The Supreme Court majority disagreed with the Court of Appeals, ruling that demand response is primarily a wholesale market function and FERC Order 745 only addresses wholesale market transactions.

[75] United States Court of Appeals, *Electric Public Supply Association v. FERC* (May 23, 2014), http://www.cadc.uscourts.gov/internet/opinions.nsf/DE531DBFA7DE1ABE85257CE1004F4C53/%24file/11-1486-1494281.pdf.

[76] Supreme Court of the United States*, Federal Energy Regulatory Commission v. Electric Public Supply Association et. al.* (January 25, 2016), http://www.supremecourt.gov/opinions/15pdf/14-840_k537.pdf

Section 4
Virtual Transactions and Financial Transmission Rights

This section discusses trends in the use of two key financial instruments in the wholesale electricity markets; virtual transactions and financial transmission rights (FTRs). These instruments provide a means for taking a position on differences between day-ahead and real-time prices (virtuals), and on day-ahead congestion between two pricing nodes (FTRs).

4.1 Virtual Transactions

This section addresses participation in the virtual energy market and the potential impact of virtual transactions on the day-ahead market. Since 2008, "transaction" costs imposed on virtual transaction volumes have increased significantly. Transaction costs for virtual supply and demand are the allocation of NCPC charges to the real-time deviations inherent with virtual transactions. Coinciding with the increase in transaction costs, virtual transaction volumes have decreased. The IMM made a recommendation to eliminate the allocation of NCPC charges to virtual transactions, and thereby remove a likely barrier to participants submitting virtual supply and demand.

4.1.1 Virtual Transaction Mechanics

In the New England day-ahead energy market, participants submit purely financial virtual bids (demand) and offers (supply) to capture differences between day-ahead and real-time LMPs. Virtual bids and offers can be submitted at any pricing location on the system during any hour. Virtual transactions are settled based on the quantity of cleared virtual energy and the difference between the hourly day-ahead and real-time LMP at the location. Cleared virtual transactions are also obligated to pay a per-MW charge to contribute towards the payment of NCPC to generators.

Virtual supply clears in the day-ahead market if the offered price is lower than, or equal to, the day-ahead LMP. The energy sold is strictly financial and is not physically provided in the real-time market. A participant that clears virtual supply receives the day-ahead price for the virtual energy sold. That virtual supply position is liquidated after the day-ahead market, creating a deviation. The participant pays the hourly real-time price on the liquidated virtual supply position. So, a participant that clears virtual supply profits from the transaction when the day-ahead price is greater than the real-time price ("sell high, buy low").

Because participants must price their offers below the day-ahead price for the offers to clear, they contribute to the supply stack below the clearing price. This tends to lower the day-ahead price closer to the virtual trader's expectation of the real-time LMP by displacing otherwise more expensive generation.[77] If the trader's expectation of price is correct, the trade will be profitable (at least on a gross basis before considering transaction costs), and the day-ahead price will have been moved by the virtual transaction closer to the real-time price. For this reason, profitable virtual transactions improve price convergence during any given hour.

Virtual demand bids use the same mechanism as virtual supply offers, but in the opposite direction. Virtual demand bids will clear if the willingness to buy virtual energy, the bid price, is

[77] A virtual supply offer or demand bid may also have no effect on price if the supply and demand curves are crossing at a perfectly elastic portion of either curve.

greater than the day-ahead LMP. The bid will be profitable if the real-time price is greater than the day-ahead price ("buy low, sell high"), and will contribute to the demand curve above the clearing price. This will likely increase the day-ahead LMP.

4.1.2 Market Impact and Participant Use

The primary function of virtual transactions is to improve the day-ahead dispatch model to better reflect real-time conditions. Virtual demand bids and supply offers that clear in the day-ahead market (based on participant's expectations of *future* real-time system conditions) can improve the generator commitments made in the day-ahead market. The resulting day-ahead commitments will better reflect market participants' *combined* expectations of real-time market conditions.

Virtual transactions that are profitable based on the price difference between the day-ahead and real-time markets generally will tend to improve price convergence. However, this does not necessarily mean that they improve the optimization of the day-ahead market. We expect that price convergence demonstrates better day-ahead scheduling in terms of reflecting real-time conditions. If the day-ahead schedule is optimized similarly to the real-time commitments, similar marginal units at approximately the same part of the supply curve should be scheduled in both the day-ahead and real-time markets. However, this is not always the case. Price formation is complex and is determined by many more variables than just the accuracy of the day-ahead schedule, such as unplanned outages, and real-time dispatch of higher-cost generation for reliability.

In addition, the degree to which virtual transactions improve price convergence is dependent on how successful virtual traders are at submitting profitable trades. Traders will not always accurately anticipate the real-time price, and virtual transactions can also be submitted as hedging mechanisms to physical positions, rather than to simply arbitrage day-ahead and real-time price differences. Participants use virtual transactions to hedge against the possibility of unplanned generation outages or exposure to real-time prices if they are serving load. Thus, the underlying motive behind the trade, whether it is intended as a hedge or speculative trade, may impact offer behavior.

4.1.3 Analysis of Virtual Transactions and Price Convergence

The volume of virtual transactions has declined significantly since 2008. Corresponding to this decline, nontrivial increases in transaction costs have been imposed on cleared virtual transactions. Both virtual supply and virtual demand are charged a portion of real-time economic NCPC based on their share of total real-time deviation megawatts.[78] Virtual demand bids are also charged day-ahead economic NCPC based on their share of day-ahead load obligation, but this charge is typically much smaller because the total day-ahead economic NCPC is divided among a much larger quantity of energy. Figure 4-1 shows the per-MW NCPC charge rate, hourly average economic NCPC payments and hourly average deviation (MW) by month for 2008-2015.

[78] Real-time deviation MWs are real-time deviations from the day-ahead schedule. By definition, virtual transactions are deviations because they are not physically delivered in the real-time market. Real-time DEC deviations may be offset by positive load deviations within a portfolio. However, these balancing load deviations are not considered in this analysis.

Figure 4-1: Monthly Average Economic NCPC Payments, Deviation MWs, and per-MW NCPC Charge Rate

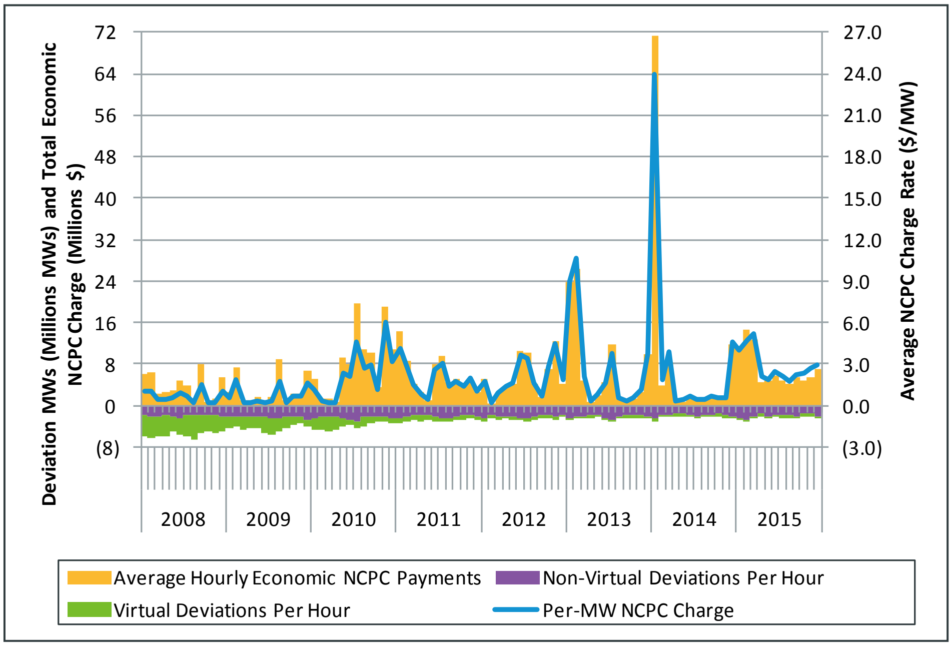


Figure 4-1 shows how NCPC charges to virtual transactions, the volume of virtual transactions and the average NCPC charge rate ($/MW) have changed in the past seven years. There are several key observations:

- The volume of virtual deviations (green bar) has declined since 2008, while the volume of non-virtual deviations (purple bar) has remained relatively constant.
- The total NCPC charges allocated to all deviations has changed over the years with a relatively large increase occurring in 2010.
- The increase in NCPC charges resulted in an increase in the average NCPC (transaction) charge rate since 2008.
- The NCPC charge rate is a function of the NCPC charges ($) and the total volume of deviations over which to allocate the charges. Decreasing virtual transaction volumes have contributed to the decrease in total deviations, which has led to higher per-MW transaction charges. As the volume of deviations decreased, the economic NCPC charges were divided among a smaller volume and the NCPC charge rate tended to increase.

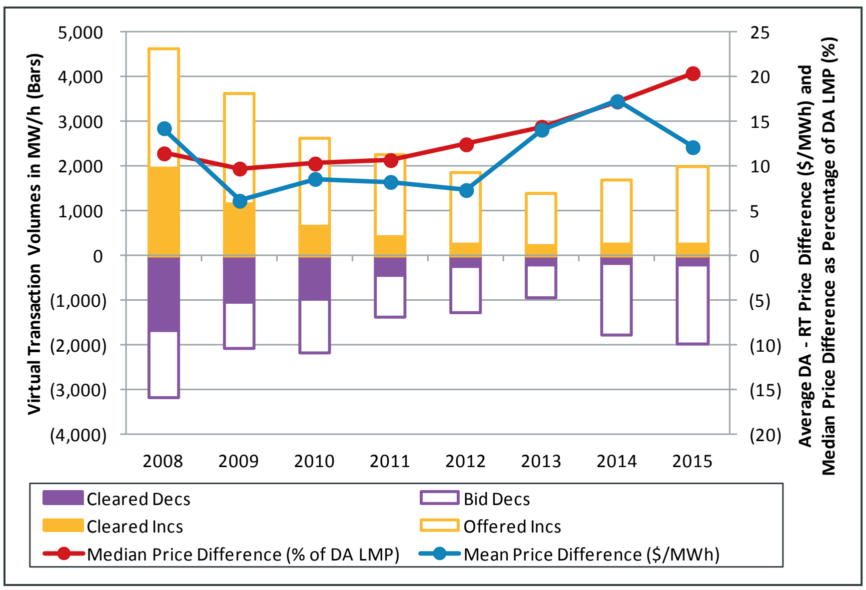
For example, in 2015, approximately 462 MW/hour of virtual transactions cleared, compared with about 3,633 MW/hour in 2008. The average per-MW real-time NCPC charge rates during these years were $2.93 and $0.67, respectively.

Participants reduce their virtual activity in response to higher NCPC (transaction) costs, which contributes to the increasing transaction cost. As more and more participants elect not to submit virtual transactions, the few remaining virtual transactions that clear the market incur higher NCPC charges which hinder participants' ability to arbitrage smaller price differences. For example, if there is a $5 per-MW NCPC charge, a virtual transaction will only be profitable if the price difference is greater than $5. In 19% of hours in 2015, there was no trade at the ISO hub that could have been profitable because the per-MW NCPC charge was greater than the price difference.[79] This may lead to traders structuring their virtual demand bids and supply offers to clear only if the day-ahead price is extreme relative to the expected real-time price. In the presence of high and volatile NCPC charges, we expect that virtual volumes would decrease and the number of hours that virtual transactions are profitable would decrease.

Figure 4-2 shows the decline in submitted and cleared volumes occurring between 2008 and 2015, and two measures of price convergence. The first measure of price convergence shown is the average absolute difference between day-ahead and real-time prices. This is the average absolute value of the difference, in dollars at the ISO Hub, between day-ahead and real-time prices. The absolute value is in order to examine the magnitude of the difference between prices in all hours.

The second measure of price convergence shown is the median absolute difference between real-time and day-ahead prices, as a percentage of the LMP. In this metric, the price difference is normalized by the day-ahead Hub LMP. Although there are many variables that determine how well prices converge, by normalizing by day-ahead LMP, the price difference better represents the accuracy of day-ahead scheduling. The median is used to reduce the influence of outliers on the analysis. Other measures of price convergence, and a more in depth look at price convergence, are presented in Section 3.3.

Figure 4-2: Virtual Transaction Volumes and Median Day-Ahead and Real-Time Absolute Price Difference as a Percentage of the LMP



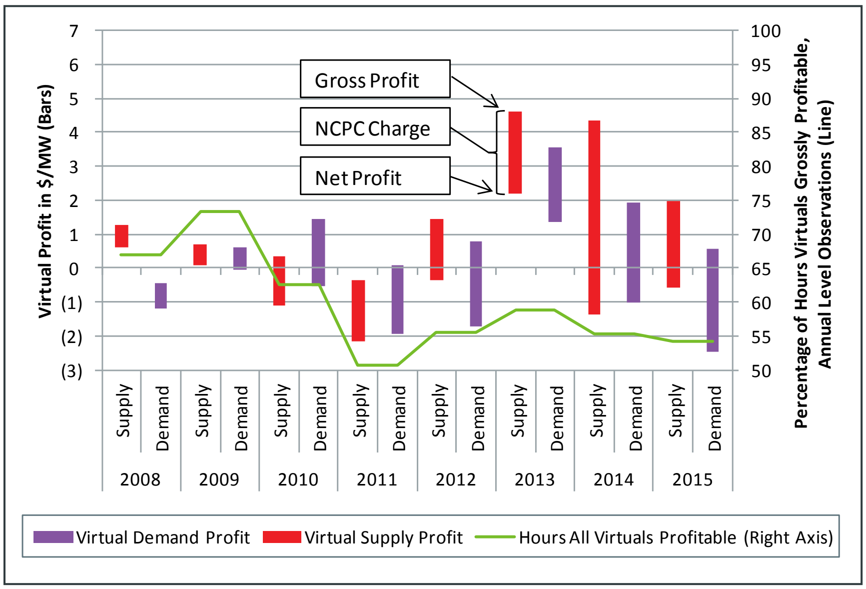
Cleared virtual transactions declined from over 2,000 MW per hour in 2008 and 2009 to less than 500 MW per hour in 2013 through 2015. During this time, the mean price difference has fluctuated between $6.14 in 2009 and $17.29 in 2014. The median difference between the day-ahead and real-time price as a percentage of the day-ahead LMP is also presented. Overall price convergence has declined since 2008 as illustrated by the increasing median price difference

[79] This number is in hindsight, and does not account for changes in per-MW NCPC or the DA LMP due to additional virtual transactions.

between day-ahead and real-time prices. The median difference (as a percentage of day-ahead prices) increased to over 20% in 2015 from about 11% in 2008, and less than 10% in 2009.[80]

Figure 4-3 provides additional detail on the impact of uplift charges on the profitability of virtual transactions, and by implication, on the opportunity to profitably trade virtual electricity and the decline in volumes transacted. The figure displays the annual average net and gross profit of virtual transactions since the beginning of 2008. The bars are categorized by year and type (i.e. virtual supply or virtual demand). The top of each bar represents gross profit, the bottom represents the net profit, and the height of the bar represents the per-MW NCPC charge. In addition, the green line shows the percentage of hours during the year that virtual transactions were profitable on a gross basis, computed annually. The line is flat for observations in the same year because the value is computed as the number of hours that all virtual transactions together were profitable on a gross basis, as a percentage of total hours in the year.

Figure 4-3: Virtual Net and Gross Profits and Percentage of Hours Profitable (Gross)



Other than virtual demand in 2008 and virtual supply in 2011, virtual transactions have, on average, had positive gross annual profits. The per-MW gross profits between 2013 and 2015 were substantially greater than in 2008 and 2009. In 2008 and 2009, virtual transactions made $0.53/MW before NCPC. In 2013 to 2015, virtual transactions made $2.86/MW.

Despite the increase in per-MW gross profit, the percentage of hours that virtual transactions are profitable on a gross basis (and helped converge prices) has decreased. In 67% of hours in 2008, virtual transactions were profitable on gross basis. This number increased to 73% in 2009; in 2015, virtual transactions only helped converge price in 54% of hours, despite having gross profits of $1.36 per-MW during the year. The increase in gross profit per-MW and decrease in the percentage of hours that virtual transactions were profitable may indicate that

[80] The price difference that is shown is the absolute value of the day-ahead and real-time price difference. The absolute value is used because we are interested in virtual transactions' potential impact on price convergence, including both positive and negative price differences.

traders are structuring bids and offers to take advantage of larger price differences in fewer hours, rather than consistently capturing small differences.

Although virtual transactions have been profitable on a gross basis, virtual trades have incurred net losses after accounting for NCPC charges, with the exception of 2013. Net profit per-MW is shown by the bottom of the bars in Figure 4-3. The reduction in profitability due to the increase in the magnitude of per-MW NCPC charges can be seen as the bars increase in length over the study period.

4.2 Financial Transmission Rights

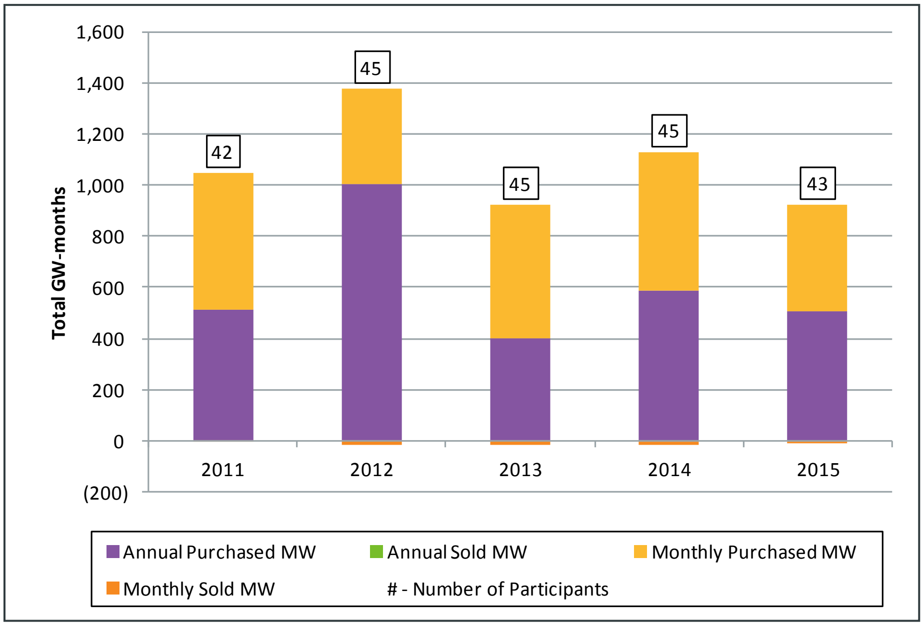
In this section, we discuss the purpose of financial transmission rights (FTRs) and the performance of the FTR market. FTRs allow participants in the New England energy market to hedge the cost of transmission congestion and arbitrage differences between expected and actual day-ahead congestion costs.

FTRs can be purchased between any two nodes on the system. For each pair of nodes there are two paths, one sourced at Location A and sunk at Location B, and one sourced at Location B and sunk at Location A. An FTR holder receives revenue when the sink congestion component is greater than the source congestion component; alternatively, the path obligates the holder to pay when the source congestion component is greater than the sink congestion component. Payments to FTR holders are provided from the congestion revenue fund. Participants purchase and sell FTR MWs in annual and monthly auctions.

Similar to virtual transactions, there can be various motives driving activity in the FTR market. FTRs can be purchased strictly to arbitrage the difference between the expected and actual day-ahead congestion (for example, by pure financial players that can also provide liquidity to the auction) or to hedge physical positions.

Participants purchase and sell FTRs in annual and monthly auctions. There are two annual and twelve monthly FTR auctions each year. FTRs are bought and sold in the second annual auction and each monthly auction. Figure 4-4 shows the number of GW-months purchased during each year between 2011 and 2015.

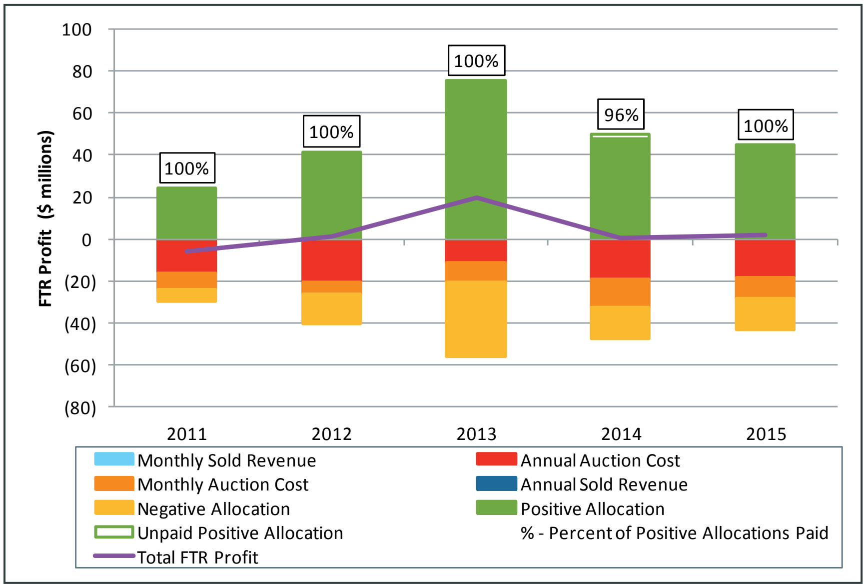
Figure 4-4: Financial Transmission Rights Purchased and Sold



In 2015, 43 participants purchased approximately 923 GW-months of FTRs. About half were purchased in annual auctions, which is consistent with previous years. Very few FTRs are sold by FTR holders each year, as can be seen below the horizontal axis in Figure 4-4. In the 2015 annual auction, 20% of the MW volumes bid into the auction cleared, while 42% of bids by W cleared in the monthly auctions.

Paths can be purchased at a negative price if congestion is expected in the "counter-flow" direction which results in the expected congestion component of the LMP at the source exceeds the congestion component of the LMP at the sink. When the source congestion component is greater than the sink congestion component, the FTR holder is obligated to pay the difference in the congestion components for each MW held. When congestion moves in the direction of a path held by a participant, the payment is referred to a "positive allocation." Conversely, a participant must pay when congestion moves opposite of the path they own, it is referred to as a "negative allocation." Total system profit in the FTR market is the sum of the positive allocations and the revenue from sales, minus negative allocations and the cost of purchases. While total profit is provided, in practice the surplus (or shortfall) is allocated back to FTR holders through a monthly and annual true-up process. These components, as well as total profit can be seen in Figure 4-5.

Figure 4-5: Financial Transmission Profits and Costs



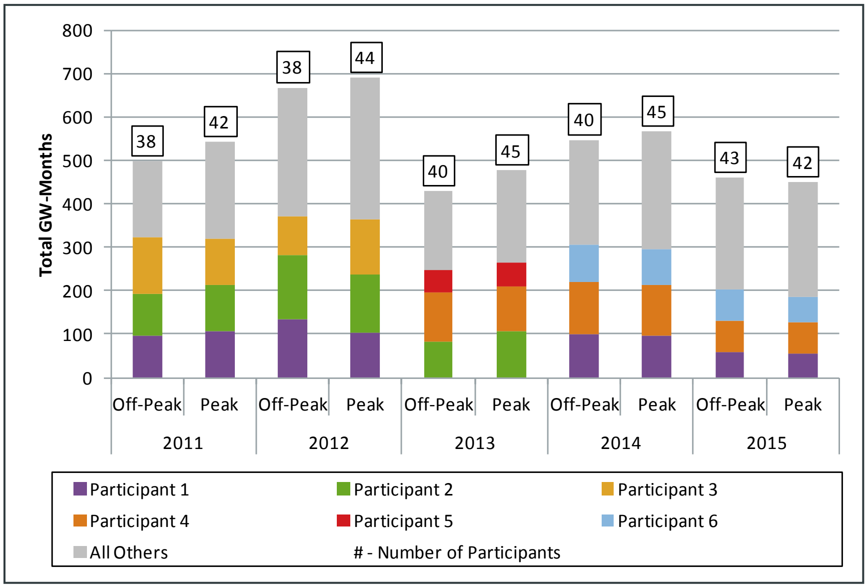
In 2015, total profit was $1.6 million. During 2015, there were approximately 910 GW-months of FTRs owned, profiting $1.76/MW-month on average. The relatively higher profits in 2013 were the result of several unplanned transmission outages that resulted in higher than expected congestion pricing. The overall modest profits indicate that FTR holders appropriately valued congestion as a whole. Significant investment in transmission over the past ten years has reduced congestion in the New England footprint which has contributed to lowering the value of the FTR market.

FTRs are paid from the congestion revenue fund, which was discussed in Section 3.4.9. If there are shortfalls in the congestion revenue fund, only the portion that can be funded is paid. In 2014, 3.6% of positive allocations were unpaid due to a shortfall in the congestion revenue fund. The unpaid portion of positive allocations in 2014 can be seen in Figure 4-5. FTRs were fully funded in 2015.

Figure 4-6 shows the amount of FTRs held by the top three participants with the most MW each year in on-peak and off-peak hours.[81]

[81] On-peak hours are defined by the ISO as weekday, non-holiday hours ending 8-23. The remaining hours are off-peak hours.

Figure 4-6: Top Six Holders of Financial Transmission Rights



In 2015, approximately the same number of on-peak and off-peak megawatts were purchased. Fewer total megawatts were purchased than in previous years. The reduction in megawatts may have been influenced by lower loads due to mild weather that participants anticipated would lessen congestion on the system. Three participants owned slightly less than half the megawatts owned during the year, which was slightly less than in past years. To ensure that participants with FTR portfolios are not manipulating congestion with virtual transactions, the ISO tariff stipulates FTR capping rules, which are applied by IMM mitigation software.[82]

[82] See Market Rule 1, Appendix A, Section III.A.12.

Section 5
External Transactions

This section discusses the trends in transactions to import power into, or export power from, New England with New York and Canada. The section also covers trends in the commercial bids of participants across the various external interfaces.

5.1 Day-Ahead and Real-Time Transactions

Participants use external transactions to move energy between New England and its neighboring control areas. External transactions can be submitted in the day-ahead and real-time energy markets and are subject to the same deadlines and many of the same offer constraints as other resources.

Like all transactions in the day-ahead market, external transactions submitted in the day-ahead energy market are a financial instrument and do not create physical energy flow. External transactions submitted in the day-ahead energy market can be priced or fixed. If an external transaction is fixed then it will receive an obligation regardless of the day-ahead LMP. External transactions that clear in the day-ahead market assume an obligation in the real-time market.

External transactions in the real-time market can be priced or fixed. The same principle applies as in the day-ahead market. Fixed external transactions move power from one region to another regardless of the price. For energy to flow in real-time there must be a corresponding energy transaction in the neighboring control area (to either purchase power from the neighboring area or supply power from one or more generating units located in the neighboring control area) and the participant must have reserved adequate transmission to move the power between the control areas. Real-time transactions may be used to satisfy financial positions created in the day-ahead market, or they may be submitted to the real-time market even if no day-ahead market transactions were submitted.

5.1.1 Transmission Connections

ISO-NE is interconnected with three neighboring control areas: the New York ISO, TransEnergie (Quebec), and the New Brunswick System Operator.

- The Hydro Quebec (HQ) Phase I/II and HQ Highgate interfaces connect New England to the TransEnergie (Quebec) control area. These direct current (DC) lines are located between Vermont and Quebec.
- The New Brunswick interface connects New England to the New Brunswick System Operator. This interface consists of two alternating current (AC) lines between Maine and New Brunswick.
- New England is connected to the New York ISO via the New York-North, Northport-Norwalk and the Cross Sound Cable interfaces.
    - The New York North Interface (also known as the Roseton Interface), includes several AC tie lines connecting upstate New York to Connecticut, Massachusetts, and Vermont.
    - The Norwalk-Northport interface is an AC interconnection between Norwalk and Long Island.

- The Cross Sound Cable interface is a DC interconnection between Connecticut and Long Island.

Table 5-1 below provides an overview of the transmission connections and interconnection capability between New England and Canada and New York.

Table 5-1: Overview of Transmission Interconnection Capacity with Canada and New York

Canada	**Import Capacity (MW)**	**Export Capacity (MW)**
New Brunswick	1,000	1,000
HQ Highgate	200	200
HQ Phase I/II	1,400	1,400
Total Canada	***2,600***	***2,600***
New York		
New York-North	1,400	1,200
Northport-Norwalk	200	200
Cross Sound	330	330
Total New York	***1,930***	***1,730***
Total System Interchange	***4,530***	***4,330***

Even though the total system interchange in Table 5-1 is over 4 GW for both imports and exports at any given time, actual flows can be less due to transmission margins, limits, and other contingencies.[83]

Under *normal* circumstances:

- All of the Canadian interfaces import power into New England.
- The New York-North interfaces import power into or export power from New England.
- The Northport-Norwalk interface is a net exporter of power to New York.
- The Cross Sound Cable is a net exporter of power to New York.

5.1.2 Imports and Exports with Canada

Figure 5-1 shows real-time scheduled imports and exports with Canada. Day-ahead imports and exports are very similar to real-time. In general, the major difference between day-ahead and real time are a small amount of additional priced transactions that are submitted in the real-time market. Priced transactions in the real-time market must be submitted before 10:00

[83] The New York interface has the ability to import power up to its full capability, but is highly dependent on the transmission margin on interfaces in New York (*i.e.* Central East). It competes with power flows to Eastern New York, which includes New York City and Long Island. As a result, the limit for Central East is reduced by the ISO by approximately 600 MW 86% of the time. New Brunswick's full import capability of the interface is also limited at times. The limitations prevent transfers up to its full import capability by about 350 MW.

a.m. on the day prior to the operating day (at the same time that the day-ahead market closes). We also observe that the percentage of priced transactions to total transactions in the real-time market was very small. These percentages ranged from 2% to 3% from 2011 to 2015.

Figure 5-1: Imports and Exports with Canada

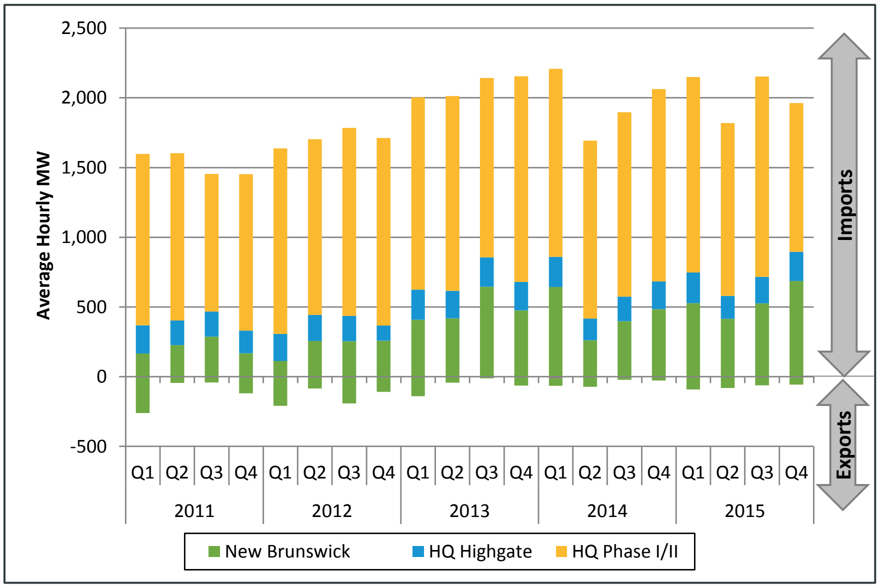


Figure 5-1 shows that Canada net exports to New England. HQ Phase I/II and HQ Highgate use a large percentage of tie-line capability. Imports over the HQ Phase I/II averaged 1,300 MW per hour (92% of the interfaces capability) over the past five years. Quarterly variations can be explained by seasonality (in Q1 and Q2 of 2014 and 2015), and routine maintenance. Imports over the HQ Highgate interface averaged 190 MW per hour or 94% of the interfaces capability.

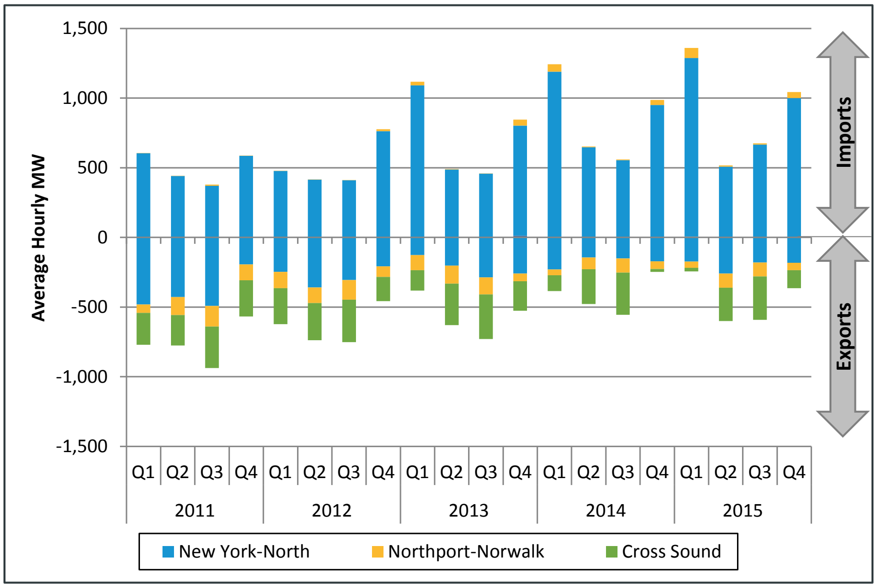
Imports over the New Brunswick interface averaged 380 MW per hour, while exports over the same interface averaged 88 MW per hour. Most of the exports from New England to New Brunswick occurred prior to 2014. If one compares New Brunswick's imports of about 380 MW per hour to its total capacity of about 1,000 MW, the total amount of the tie that is utilized is about 38%. However, New Brunswick's full import capability is limited at times to approximately 650 MW.

5.1.3 Imports and Exports with New York

The *New York-North* interface has a net import capability of 1,400 MW and a net export capability of approximately 1,200 MW. Northport-Norwalk has a capability of approximately 200 MW and is generally a net exporter of power to New York. The Cross Sound Cable is a DC line with a capability of approximately 330 MW and power is generally exported to New York over this interface. In 2015, New England was a net importer of power from New York.

Figure 5-2 shows real-time scheduled imports and exports with New York. As with Canada, day-ahead imports and exports are very similar to real-time. In general, the major difference between day-ahead and real-time are a small amount of additional priced and fixed transactions submitted in the real-time market. The percentage of priced transactions to total transactions in the real-time market was very small. These percentages ranged from a minimum of 0% to a maximum of 5% from 2011 to 2015.

Figure 5-2: Imports and Exports with New York



The *Cross Sound cable* is predominantly a net exporter of power to New York. Over the past five years, exports over the Cross Sound cable averaged 220 MW per hour, utilizing approximately 66% of the interfaces 330 MW capability. As with the Canadian interfaces, the utilization of the line can vary somewhat due to maintenance and other factors. In particular, the Figure 5-2 also shows a reduction in exports from New England to New York in Quarter 4 of 2014 and Quarter 1 of 2015. This was the result of the unplanned outage of the Cross Sound cable in Quarter 4 2014 and Quarter 1 2015, which was the result of a transformer fire in New Haven, Connecticut.

Northport-Norwalk is also predominantly a net exporter of power to New York, but over the past few winters (Quarter 1 for 2013-2015) more imports have been coming into New England. Northport-Norwalk has imported approximately 17 MW per hour (a utilization using the ties capability of 200 MW of about 8%). It has exported approximately 95 MW per hour (a utilization of approximately 47%).

The *New York-North interface* comprises the majority of the transmission capacity between the two regions. The figure shows that the New York-North interface has both exported power from, and imported power to New England. Figure 5-2 also shows that exports have decreased over time. We note that imports have been seasonal in nature, with more imports to New England occurring in the winter months. New York-North has imported approximately 685 MW per hour (a utilization of approximately 49%) and has exported approximately 255 MW per hour (a utilization of approximately 21%).

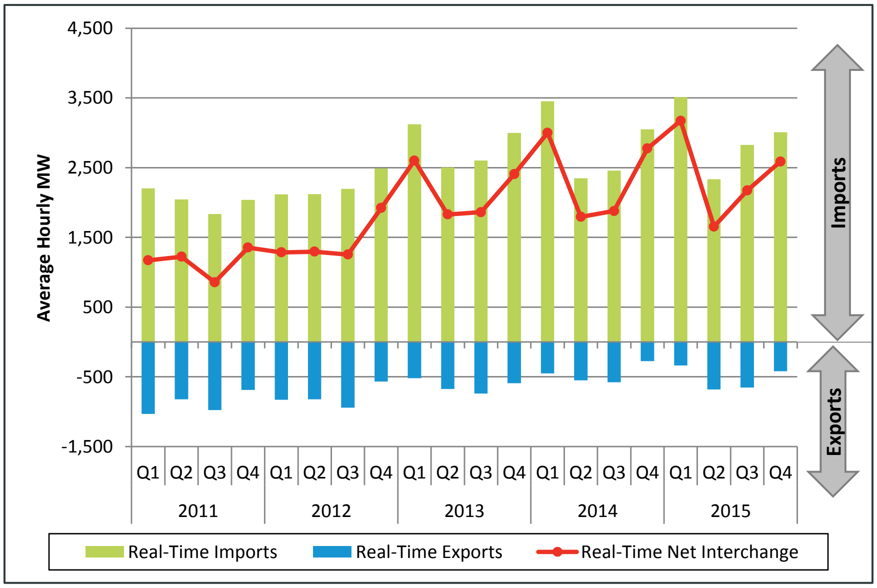
The utilization of the New York-North line can vary somewhat due to maintenance and other factors; however, imports and exports between New England and New York have not been directly attributable to observed price differentials between the regions. Rather, in many instances, imports have been scheduled from New York into New England even though prices are higher in New York than in New England. There are a number of factors that may contribute to this result including price indifference due to contracting outside of the ISO market, difficulty in accurately anticipating price spreads between the two regions, and market incentives that do not align scheduling with price spreads. See Section 5.2 for additional discussion of this issue and the ISOs' solution, called Coordinated Transaction Scheduling (CTS).

5.1.4 Total External Transactions (Canada and New York)

As discussed above, New England imports more power than it exports. In 2015, a total of about 2,400 MW per hour (or about 21,000 GWh) of energy was net imported from Canada and New York, a 1.5% increase compared with last year.

Figure 5-3 shows net interchange by quarter for the real-time market (which is similar to day-ahead scheduled transactions).

Figure 5-3: Real-Time Imports, Exports, and Net Interchange by Quarter



Net imports to New England have been increasing over time. New York-North imports have been seasonal in nature, with more imports to New England occurring in the winter months. New York-North interface has both exported power from, and imported power to New England, but exports over this interface have decreased over time. New Brunswick has also trended away from exporting power from New England. The figure also shows a slight reduction in exports in Quarter 4 2014 and Quarter 1 2015, due to the unplanned outage of the Cross Sound cable.

5.1.5 Supply Offers of External Transactions

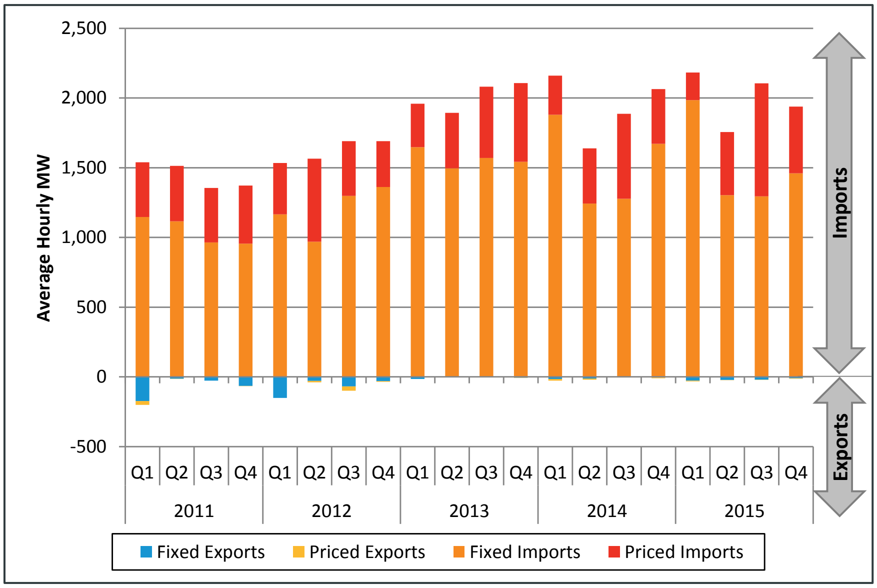
Participants can submit three types of external transactions:

- Fixed
- Priced
- Up-to congestion

Most external transactions are composed of fixed and priced external transactions. A fixed transaction will be scheduled in the day-ahead market or will flow in the real-time market at any price (similar to a generator self-scheduling), whereas a priced transaction is price-sensitive (similar to a generator submitting a priced based offer).

Figure 5-4 shows cleared priced and fixed transactions in the day-ahead market by year and quarter at the Canada interfaces.

Figure 5-4: Cleared Fixed and Priced External Transactions in the Day-Ahead Market for the Canadian Interfaces

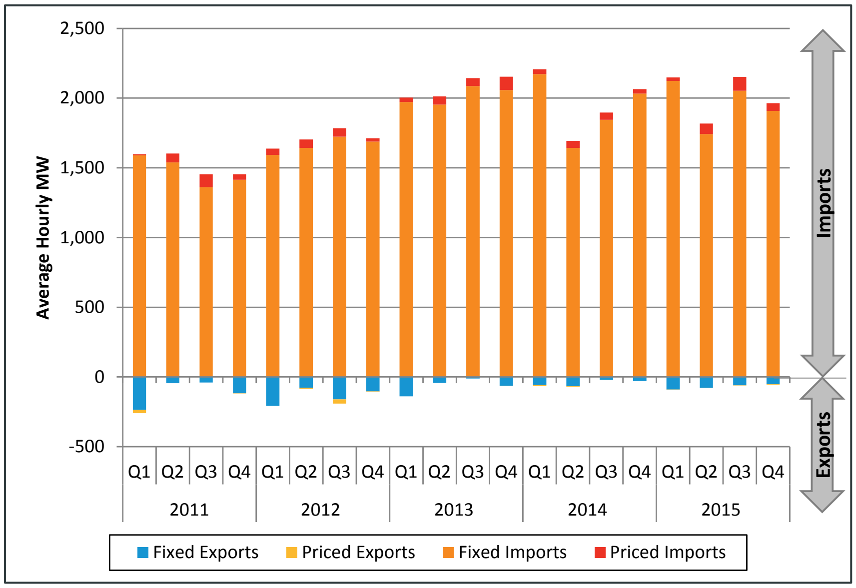


There are few fixed and priced export transactions that cleared over the Canada interfaces in the day-ahead market. Under normal circumstances, all of the Canadian interfaces import power into New England. Net transactions over the Canada interfaces totaled about 1,972 MW per hour on average, a 3% increase over 2014. There was also an increase in fixed import transactions from Canada over time in MW terms. The percentage of fixed to total transactions ranged from about 73% to 78%.

Figure 5-5 shows scheduled priced and fixed transactions in the real-time market by year and quarter at the Canada interfaces.[84]

[84] Transactions "clear" in day day-ahead market and are "scheduled" in the real-time market. Cleared and scheduled MWs are what is used for settlement. Actual flow MWs are very close to, if not the same as Scheduled MW in the real-time market.

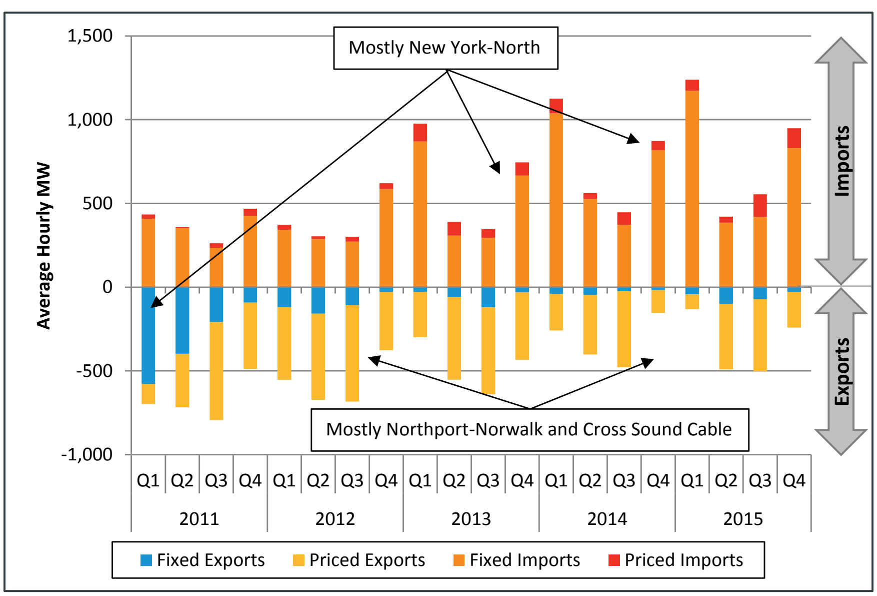
Figure 5-5: Scheduled Fixed and Priced External Transactions in the Real-Time Market for the Canadian Interfaces



The volume of priced transactions in the real-time market is considerably lower than in the day-ahead market. This decrease is attributable to how day-ahead priced transactions are scheduled in the real-time market. Priced transactions submitted to both the day-ahead and real-time market that cleared in day-ahead are scheduled as a fixed transaction during real-time unless the price is adjusted by the market participant during the reoffer period. The percentage of fixed to total transactions in Canada was about 97%.

Figure 5-6 shows cleared priced and fixed transactions in the day-ahead market by year and quarter for the New York interfaces.

Figure 5-6: Cleared Priced and Fixed External Transactions in the Day-Ahead Market at the New York Interfaces

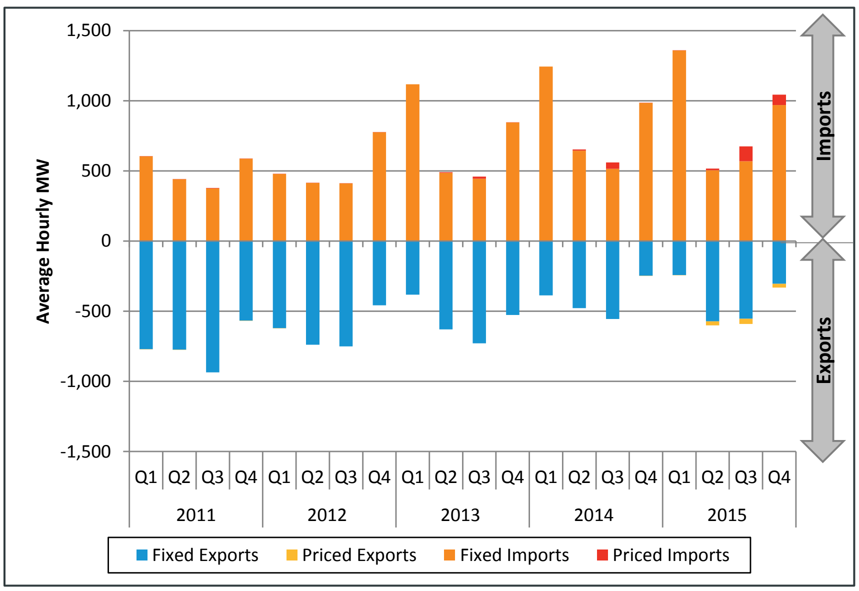


The figure shows that, over time, fewer fixed exports have occurred over the New York interfaces. The New York-North interface, while capable of exporting approximately 1,200 MW, primarily imports power into New England. This interface has exported fewer fixed exports from 2012 through 2015. The figure also shows that there has been an increase in fixed imports over the New York-North interface, with more fixed imports clearing in the winter months.

The Northport-Norwalk and Cross Sound Cable interfaces are generally net exporters of power to New York. The participants place priced export transactions at these interfaces. The decrease in priced export transactions in quarter 4 of 2014 and quarter 1 of 2015 is attributable to the unplanned outage of the Cross Sound cable, which was the result of a transformer fire in New Haven as noted above. Net transactions over all of the New York interfaces totaled about 1,797 MW per hour on average, a 5% decrease over 2014.

Figure 5-7 shows scheduled priced and fixed transactions in the real-time market by year and quarter at the New York interfaces.

Figure 5-7: Scheduled Fixed and Priced External Transactions in the Real-Time Market for the New York Interfaces



The figure shows that there is a decrease in priced transactions in the real-time market when compared with the day-ahead market in New York. This decrease is attributable to how day-ahead priced transactions are scheduled in the real-time market. All MWs of a priced day-ahead market transaction that clear are considered self-scheduled in real-time unless the price is adjusted during the reoffer period.[85] The percentage of fixed to total transactions in New York was around 96%.

Up-to congestion transactions are a third type of offer and represent a purchase of congestion and losses in the day-ahead market. These transactions are a way to profit by correctly predicting whether, how much, and in what direction the price difference (or "spread") between two nodes will change between the day-ahead market and real-time market.

[85] The price can only be adjusted downward or changed to a self-schedule.

Up-to congestion transactions will clear in the day-ahead market if the difference between LMPs at two locations (one of which must be an external node) is below the offered price. Up-to congestion transactions are supported in the day-ahead market only. They may not be submitted at less than \$0.01/MWh, or more than \$25/MWh.

Historically, there have not been a significant volume of up-to congestion transactions. In 2015, only one participant entered up-to congestion transactions. Cleared up-to congestion volumes have averaged 9 MW per hour in exports to the Canada interfaces and 14 MW per hour in exports to the New York interfaces.

5.2 Coordinated Transaction Scheduling

There are nine major transmission tie lines between New York and New England. In total, these tie lines are capable of transferring approximately 1,800 MW of power between the regions under normal operating conditions. Although the New York and New England wholesale electricity markets are administered separately, the tie-lines make the markets interdependent and provide opportunity for economic trade of power between the two regions. Power can flow from one region to the other based on the buying and selling activities of market participants in both markets.

The New York-North Interface (NYN) includes seven AC tie lines connecting upstate New York to Connecticut, Massachusetts, and Vermont. This interface has the capability to import power to or export power from New England. The NYN interface comprises the majority of the transmission capacity between the two regions and was the focus of the Coordinated Transaction Scheduling or "CTS" project that was implemented in December 2015.[86]

When an interface like NYN is used efficiently, power should flow from the lower priced region into the higher priced region to the extent possible. With sufficient transmission capacity, this trade would tend to reduce the price spread between the two regions.

Historically imports and exports between New England and New York have *not* been directly attributable to a price differential between the regions. Rather, in many instances, imports were scheduled from New York into New England even though prices were *higher* in New York than in New England. In the past, power was scheduled in the "right" direction (low price to high price) on the NYN interface only about half the time.[87]

Table 5-2 shows the percentage of time that external transactions were scheduled in the direction of the higher price on the New York-North interface, from 2011 through December 14, 2015.

[86] The two remaining ties operate differently than the NYN interface. The Cross Sound Cable (CSC) and the Northport-Norwalk (NNC) link run between Connecticut and New York underneath the Long Island Sound. The former is a direct current line, and the latter is a controllable AC line (via phase angle regulators). These lines are used nearly all hours they are in service to deliver power to Long Island.

Unlike the eight AC transmission links (NYN and NNC), the CSC is not a pool transmission facility but has merchant transmission status under FERC regulations. Parties that seek to trade electricity across it must use a different reservation system than the ISOs' process for pool transmission facilities.

[87] *Roseton* and *Sandy Pond* are the "border," or proxy bus, pricing nodes for real-time, hourly integrated LMPs for NYISO and ISO New England.

Table 5-2: Percentage of Time Transactions are Scheduled in the Direction of the Higher Price on the New York-North Interface

Year	Real-Time (%)	Day-Ahead (%)
2011	52	57
2012	52	57
2013	52	55
2014	50	47
2015	48	54

The CTS project identified three root causes of the economic inefficiencies on the tie lines between New York and New England:

- *Latency delay*. The time delay between when the import or export transaction is scheduled and when power actually flows, during which time system conditions and prices in New York and New England may change.[88]

- *Non-economic clearing*. The New York and New England ISOs made decisions about which import or export transactions to accept without economic coordination, producing inefficient schedules.[89]

- *Transaction costs*. The fees and charges levied by each ISO on external transactions served as a disincentive to engage in trade, impeding price convergence and raising total system costs.[90]

The CTS project was designed to remedy many of the root causes by employing higher-frequency scheduling and eliminating most transaction charges on external transactions. FERC approved CTS on April 19, 2012. CTS was implemented at the NYN interface in the real-time energy market on December 15, 2015.[91]

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[88] Under the inter-regional trading system, the latency delay is nearly two hours for both NYISO and ISO-NE. Each ISO determines whether or not a "real - time" external transaction offer clears about an hour before the corresponding delivery hour, and this quantity remains fixed for the full delivery hour. This combination of hourly lead-time and the hourly duration-time are referred to an "hourly scheduling" system, although the latency delay is double that.

[89] Under the current system, market participants submit separate external transaction requests to each ISO. There is no economic coordination between the ISOs when they set the aggregate net tie schedule. This absence of economic coordination when external transaction requests are accepted produces inefficient tie schedules, and raises total system costs.

[90] These include:

- An allocation to external transactions of general 'uplift' costs incurred by the ISO on a per-MW basis;
- Financial Impact Charges imposed by NYISO on import/export requests that fail the "check-out" process for reasons within the market participant's control; and
- ISO scheduling fees paid by market participants on a per MWh basis, which for external transactions are levied by both ISOs.

[91] FERC, *Order Accepting Tariff Revisions, Subject to a Compliance Filing*, Docket No. ER12-1155-000 (April 19, 2012), http://www.iso-ne.com/regulatory/ferc/orders/2012/apr/er12-1155-000_4-19-12_order_accept_cts.pdf.

What is unchanged from CTS implementation is that day-ahead external transactions between New York and New England still clear hourly.

An important feature of CTS is a simplified bid format, called an *interface bid.* An *interface bid* is a unified transaction to buy and sell power simultaneously on each side of the border. This bid structure is designed to resolve one of the root causes of the prior system's inefficiencies, ensuring that transactions determining real-time flows result in a net interface schedule that moves power in the right direction: from the lower-cost region to the higher-cost region. The ISOs use two sets of market-based offers under CTS to set real-time external interface schedules. The following is a summary of the key features of CTS:

- There is a single platform for participants to use to enter interface bids between New York and New England.
- At the NYN interface (Roseton-Sandy Pond location), there is real-time bidding, scheduling, and settling at 15-minute intervals.
- Most transaction charges have been eliminated.

The IMM's analysis of the outcomes of CTS will be presented in a future *Quarterly Markets Report*.

Section 6
Capacity Market

This section provides information on the outcomes of the Forward Capacity Auctions (FCAs), trends in Capacity Supply Obligations (CSO), and Forward Capacity Market (FCM) payments.

6.1 Forward Capacity Market Overview

The FCM is a long-term market designed to procure the resources needed to meet the region's local and system-wide resource adequacy requirements. Resources are procured 40 months in advance of when the capacity will be delivered. The delivery period is known as the capacity commitment period.

A goal of the FCM is to attract new capacity resources, maintain more efficient existing resources, and retire less efficient resources through a coordinated market while meeting the region's resource adequacy standard. The FCM is needed because, in general, revenues from the energy and ancillary services markets alone are sufficient to maintain operation of existing resources but are not sufficient to encourage investment in new resources or expensive upgrades to existing resources.[92] This revenue gap is often referred to as "missing money". A central objective of the FCM is to create a revenue stream that can replace the missing revenue, and thereby induce market participants to make investments, when and where they are needed to ensure reliable electric power service. The ISO has also implemented a price lock, up to seven years, for new capacity that is cleared in the FCM to reduce the risk that capacity price variation may reduce the changes a new project can adequately recover (amortized) costs attributed to the first years of the new project.

The capacity market is designed to provide a revenue source for market participants building new resources where they may recover their long-run average investment and operating costs through the various ISO markets. The FCM also ensures market participants with existing resources have sufficient revenue to adequately maintain their resources to operate reliably and, where appropriate, send a signal to the market that a resource is too costly to operate and should be retired.

6.1.1 Capacity Resource Qualification and Review

Market participants seeking to enter the capacity market with a new resource go through a lengthy qualification review process. The ISO determines the maximum capacity the resource can safely and reliably deliver to the system and sets the resource's "qualified capacity". As described in Section 7, market participants that want to offer a new resource in the auction at prices below pre-determined minimum competitive offer prices are required to go through a cost review with the IMM. The IMM determines the market participant's minimum offer floor price. The cost review process is designed to mitigate a market participant's ability to exercise buyer-side market power and suppress the capacity clearing price below a competitive level.

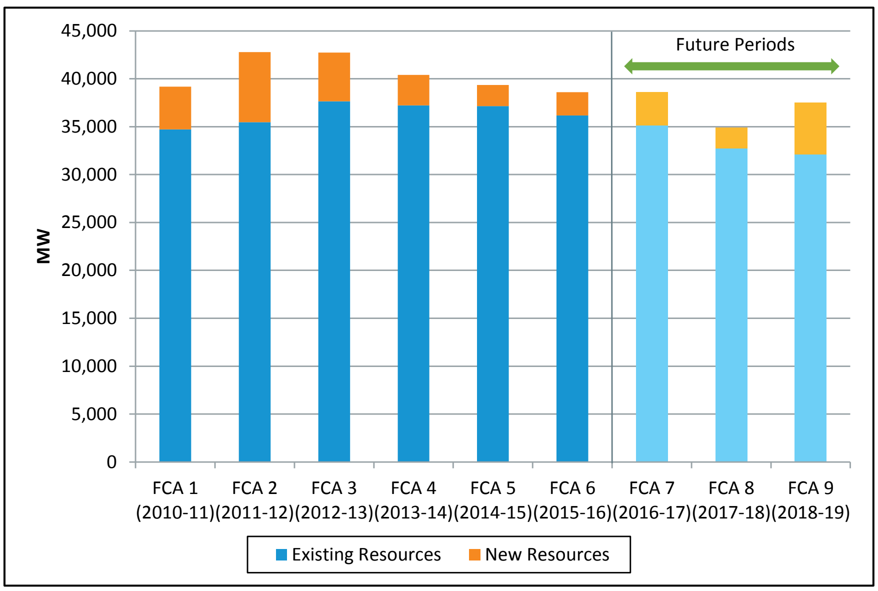
[92] Pricing of energy and ancillary services is designed to reflect the marginal cost of providing those services. There are scarcity pricing mechanisms in place in the real-time market to produce the correct price signals and incent performance during those periods. Scarcity pricing does provide valuation well in excess of the marginal cost to provide the services. However, these mechanisms are not calibrated to provide sufficient revenue to cover the cost to build new generation.

Once a market participant's new resource clears in a primary auction it becomes an existing resource. In subsequent auctions, existing resource are "price takers". In other words, the market participant does not offer its existing capacity resource at a price; rather the Market Participant accepts the auction clearing price.

Market participants with existing resources seeking to exit the capacity market – permanently or temporarily - must submit a de-list bid in a FCA. There are a variety of de-list bid types (i.e., static, dynamic, permanent, retirement). The choice of de-list bid type depends on the type of resource, the time period market participant wants to exit the capacity market and the price at which it wants to exit. Market participants that submit de-list bids must go through a cost review with the IMM. The IMM determines the market participant's competitive de-list bid price. The cost review process, described in more detail in Section 7, is designed to mitigate a market participant's ability to exercise supplier-side market power and increase the capacity clearing price above a competitive level.

Figure 6-1 below shows the qualified MW for new and existing resources for each FCA.

Figure 6-1: Qualified Capacity



There was a decrease of 3,679 MW in qualified capacity between FCA 7 and FCA 8. The amount of qualified capacity rebounded in FCA 9, with 3,047 MW of new generating and import capacity qualified for the auction. As described below, the clearing price increased to $15.00/kW-month for new capacity resources in FCA 8, which likely provided the incentive for market participants' to offer new capacity in FCA 9.

6.1.2 Primary Forward Capacity Auction

After the ISO qualifies capacity resources' MW values and the IMM reviews new supply offers and de-list bids, the information – representing the inputs to the primary FCA - are filed with the FERC. The ISO then conducts the primary FCA to select resources to receive a capacity supply obligation for the forward capacity commitment period.

The first eight FCAs used a vertical demand curve that had a fixed capacity requirement, referred to as the Installed Capacity Requirement or "ICR".[93] A vertical demand curve, by definition, lacks price sensitivity and can result in large changes in capacity prices. For the first seven FCAs, capacity commitment period prices ranged from $2.95 per kilowatt-month (kW-month) to $4.50/kW-month, while FCA 8 yielded a clearing price of $15.00/kW-month for new resources.[94] Extreme prices (low and high) that can result from a vertical demand curve were addressed through administrative pricing rules prior to implementing a sloped system demand curve in FCA 9. Rules existed to moderate high price when there was insufficient competition or inadequate supply. There was also an administrative price floor to prevent extremely low auction prices as a result of excess supply and the vertical demand curve. The price floor ranged from $2.95/kW-month to $4.50/kW-month and set the price in seven auctions, the last of which was in FCA 7. Since that time, the system has not been sufficiently long that the price floor would bind and the institution of a sloped system demand curve has also helped moderate price volatility.

Starting with FCA 9 a sloped demand curve replaced the vertical demand curve. The system sloped demand curve is intended to improve price formation – specifically, to reduce price volatility and establish efficient price signals to maintain the region's long run reliability criteria. The shape of the sloped curve is based on both financial and reliability parameters. These parameters include the estimated cost of a new resource (Cost of New Entry or "CONE") and well-established system planning design criteria. The system planning criteria are based on the probability of disconnecting load no more than once in ten years due to a resource deficiency (also referred to as Loss of Load Expectation or "LOLE"). The curve's prices are indexed to an estimated Net CONE value (the estimated CONE net of revenues from energy, reserve and other markets).

The Forward Capacity Auction is conducted in two stages: a descending-clock auction followed by an auction-clearing process. The descending-clock auction consists of multiple rounds. During one of the rounds, the amount of capacity willing to remain in the auction at a given price level will equal or fall below the capacity requirement as determined by the demand curve. FCM resources that remain in the auction are paid the FCA clearing price, as determined in the auction-clearing stage.

6.1.3 Secondary Forward Capacity Auctions

After the primary auction, market participants are allowed to trade their CSO positions. The secondary trading of CSOs takes place through a series of reconfiguration auctions and bilateral trading administered by the ISO.

Reconfiguration auctions take place before and during the capacity commitment period to allow market participants with CSOs to trade their positions with other market participants that do not have CSOs or wish to assume additional CSOs. Annual reconfiguration auctions (ARAs) to acquire one-year commitments are held approximately two years, one year, and just before the capacity commitment period begins. Monthly reconfiguration auctions, held beginning the first

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[93] The ICR is the minimum amount of resources (level of capacity) a balancing authority area needs in a particular year to meet its resource adequacy planning criterion, according to *NPCC Regional Reliability Reference Directory #1 Design and Operation of the Bulk Power System*. This criterion states that the probability of disconnecting any firm load because of resource deficiencies shall be, on average, not more than 0.1 day per year.

[94] Insufficient competition in FCA8 resulted in the application of administrative pricing rules setting the capacity prices for most existing resources at $7.025/kW-month.

month of a capacity commitment period, adjust the annual commitments during the commitment period.

Bilateral trading allow for a transfer of CSOs between two market participants or between the same market participant's resources. There are three annual CSO bilateral periods, which are held in the same time periods as the annual reconfiguration auctions. Monthly CSO bilateral periods, held beginning the first month of a capacity commitment period, adjust the annual commitments during the commitment period.

6.1.4 Capacity Payments, Performance and Charges

Market participants are paid for the capacity delivered during the commitment period, subject to penalties for non-performance and adjustments.

There are a number of key features of the FCM that are designed to incent good resource performance:

- Penalties for failing to make capacity available during periods of reserve deficiencies, referred to as "shortage events". Shortage event penalties are in effect until May 31, 2018).
- The opportunity to earn additional payments or incur charges based on a resource's performance during periods of reserve deficiencies. The "pay for performance" rules become effective on June 1, 2018.
- Adjustments for Peak Energy Rent (in effect until May 31, 2019).

Paying for actual performance during shortage events provides an incentive to resource owners to make investments and perform routine maintenance to ensure that their resources will be ready and able to provide energy or operating reserves during these periods. To be effective, the capacity market must replicate the performance incentives that would exist in a fully functioning and uncapped energy market by linking payments to performance during scarcity conditions. Without this linkage, individual market participants would lack the incentive to make investments that ensure the performance of their resources when needed most. Also, absent these incentives, market participants that have not made investments to ensure their resources' reliability would be more likely to clear in future FCAs because they can offer at lower prices. This can create a structural bias in the FCM to clear less reliable resources which, over time, will erode system reliability.

Under the current FCM design in place until May 31, 2018, the consequences of poor performance are practically nonexistent. Even with recent revisions to the shortage-event definition, shortage events are extremely rare. Through the end of 2015, only *one* shortage event has occurred. Furthermore, the current rules include numerous exemptions. Resources can be considered "available" during a shortage event – exempt from penalties - even when they do not provide any energy or operating reserves. Finally, even when a capacity resource is exposed to penalties under the current design, these penalties are capped such that market participants cannot lose money.

The Pay-for-Performance (PFP) design will replace the current shortage event rules starting in the 2018/2019 capacity commitment period. PFP is a two-settlement forward market. PFP is built around a well-defined product—the delivery of energy and operating reserves when they are needed most. Its rules apply in the same manner to all resource types, without exceptions.

PFP is expected to create strong incentives for resource performance, consistent with the FCM's original design objectives.

The *peak energy rent* adjustment is primarily a protection for load against energy prices in real-time that are above a threshold or "strike" price. The threshold price is an estimate of the cost of the most expensive resource on the system. Under the PER concept, load has paid in advance for sufficient capacity to maintain reliability through the FCM. The PER adjustment limits the gains to generators and import capacity resources, even those not producing energy, who sold capacity forward in the FCM in hours with high real-time prices resulting from shortage conditions.[95] This helps ensure that load does not pay through the FCM to maintain a fleet of resources that meets reliability conditions and then later pay when those reliability conditions are not met and result in high real-time prices. The PER value is based on revenues that would be earned in the energy market by a hypothetical peaking unit with heat rate of 22,000 British thermal units/kilowatt-hour (Btu/kWh) that uses the more expensive of either natural gas and No. 2 fuel oil.

The PER adjustment also discourages physical and more extreme economic withholding. The revenue adjustment resulting from the PER adjustment is based on the entire quantity sold in the capacity market, not just the portion of that capacity subject to the high real-time price. As a result, a withholding strategy that increases real-time price above the PER strike price can cause a significant revenue adjustment for the portfolio that outweighs the potential benefits of withholding.[96]

On March 6, 2015, the ISO filed market rule changes to eliminate PER on a prospective basis starting with the capacity commitment period that begins on June 1, 2019. As described in more detail in Section 6.2.4 below, the PER mechanism is no longer needed to serve its intended purposes, and retaining the mechanism could result in higher capacity market costs without producing substantial benefits.

6.2 Forward Capacity Market Auction Outcomes

6.2.1 Installed Capacity Requirements

The New England Installed Capacity Requirement (ICR) is the amount of capacity (MW) needed to meet the region's reliability requirements. The reliability requirements are designed to ensure that non-interruptible wholesale customers are not disconnected from the grid more than once every 10 years.

The net ICR (*i.e.*, the Installed Capacity Requirement minus HQICCs) is the amount of installed capacity that is procured in the FCAs.[97] These values are based on the load forecast, resource

[95] Demand resources are excluded from the PER adjustment through FCA 8. The PER Adjustment will be applied to Demand Response Resources on June 1, 2018 (FCA 9) once these resources can participate in the Energy Markets.

[96] The lower volatility of total payments might not affect the entire amount that load market participants pay in the long run because the resources' capacity bids reflect the lower PER-adjustment amounts.

[97] HQICCs are capacity credits that are allocated to the Interconnection Rights Holders, which are entities that pay for and, consequently, hold certain rights over the Hydro Quebec Phase I/II HVDC Transmission Facilities ("HQ Interconnection"). The tie benefit value for the HQ Interconnection was established using the results of a probabilistic calculation of tie benefits with Quebec. The ISO calculates HQICCs, which are allocated to Interconnection Rights Holders in proportion to their individual rights over the HQ Interconnection, and must file the HQICC values established for each Capacity Commitment Period's FCA. The HQICC value for the 2018/2019 Capacity Commitment Period was 953 MW per month.

availability, and tie benefits. Starting with the ninth FCA, a sloped demand curve was used in the FCA.

In addition, there are local sourcing requirements (LSR) that establish minimum capacity requirements for different regions. For example, if a region has import constraints then a certain amount of that region's capacity much come from within the region. Similarly, if a region has export constraints then maximum capacity limits (MCL) put restrictions on how much capacity can be located within that region. The local sourcing requirements and maximum capacity limits are set to satisfy NPCC's and the ISO's bulk power system reliability planning criteria.

Table 6-1 shows the ICR, the net ICR, the local sourcing requirements (LSR), and the maximum capacity limits (MCL) for FCA 1 to FCA 9.

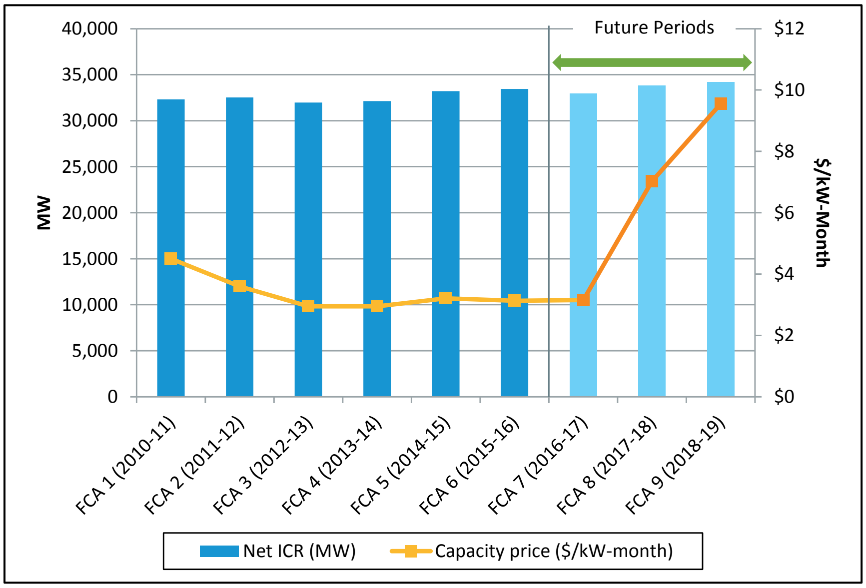
Table 6-1: Capacity Requirements (MW)

			LSR			MCL
Capacity Commitment Period	ICR	Net ICR	CT	NEMA/ Boston	SEMA/RI	ME
FCA 1 (2010-11)	33,705	32,305	7,017	2,246		3,855
FCA 2 (2011-12)	33,439	32,528	6,817	2,016		3,395
FCA 3 (2012-13)	32,879	31,965	6,640	2,019		3,257
FCA 4 (2013-14)	33,043	32,127	7,419	2,957		3,187
FCA 5 (2014-15)	34,154	33,200	7,478	3,046		3,702
FCA 6 (2015-16)	34,498	33,456	7,542	3,289		3,888
FCA 7 (2016-17)	34,023	32,968	7,603	3,209		3,709
FCA 8 (2017-18)	34,923	33,855	7,319	3,428		3,960
FCA 9 (2018-19)	35,142	34,189	7,331	3,572	7,479	

The table shows that ICRs, net ICRs, LSRs, and MCLs have all slightly increased over most FCAs.

Figure 6-2 below shows the net installed capacity requirement and the rest-of system capacity price for the FCA commitment periods from 2010/2011 through 2018/2019.

Figure 6-2: Net Installed Capacity Requirement and System Capacity Price



The figure differentiates between past and future commitment periods. In many of the earlier FCAs there was excess supply and capacity prices cleared at the administratively set auction floor price. In the last two auctions (FCA 8 and 9), the capacity price has reflected a tightening of supply and the auction clearing price was set by a marginal supply resource. The increase in price corresponds with lower supply margins (see Figure 6-3) that are the result of a significant amount of capacity that has retired. New capacity was procured in these auctions as a result of the reduction in existing supply margin and system and zonal requirements.

6.2.2 Primary Forward Capacity Auction Results

Table 6-2 shows, for each primary auction:

- the overall capacity requirement (“net ICR”)
- the total capacity purchased in the auction (“Cleared capacity resources”)
- whether there was more or less capacity purchased than required
- the amount of capacity from new supply resources (“Net capacity additions”)
- the clearing price (“Capacity price”)

Table 6-2: FCM Capacity Commitment Period Results

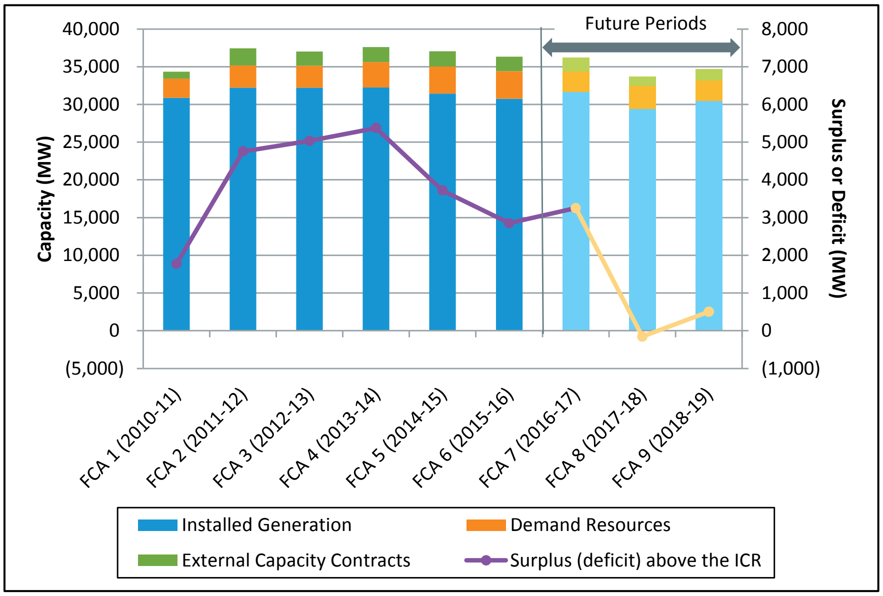
FCA# (Commitment Period)	Net ICR (MW)	Cleared capacity resources (MW)	*Surplus (Deficit) (MW)*	Net capacity additions (MW)	Capacity price ($/kW-month)
FCA 1 (2010/11)	32,305	34,077	1,772	900	4.50
FCA 2 (2011/12)	32,528	37,283	4,755	2,760	3.60
FCA 3 (2012/13)	31,965	36,996	5,031	1,329	2.95
FCA 4 (2013/14)	32,127	37,500	5,374	1,490	2.95
FCA 5 (2014/15)	33,200	36,918	3,718	1,176	3.21
FCA 6 (2015/16)	33,456	36,309	2,853	2,041	3.43
FCA 7 (2016/17)	32,968	36,220	3,252	2,763	3.15
FCA 8 (2017/18)	33,855	33,702	-153	1,536	7.03
FCA 9 (2018/19)	34,189	34,695	506	2,787	9.55

In the table above, net capacity additions reflect cleared new capacity, excluding repowering projects and including imports. Net ICR and cleared capacity resources had been steadily increasing through FCA 7.

- In FCA 7, the NEMA/Boston capacity price was administratively set to $14.999/kW-month for new resources. All other resources will be paid $3.15/kW-month.
- In FCA 8, a capacity deficit of 153 MW occurred, triggering insufficient competition and the Capacity Carry Forward rules. As a result, existing (non-NEMA/Boston) resources will be paid $7.025/kW-month and new and existing resources in NEMA/Boston will be paid $15/kW-month.
- In FCA 9, inadequate supply was triggered in the SEMA-RI capacity zone, so the payment rate for existing resources in SEMA-RI was set to the net CONE of $11.08/kW-month, and the payment rate for new resources was set to the FCA 9 starting price of $17.728/kW-month. The New York AC Ties will be paid $7.967/kW-month, and New Brunswick will be paid $3.940/kW-month.

Figure 6-3 presents a breakdown of capacity cleared in the FCA by the three resource types, generation, demand resources, and imports, in each capacity commitment period. It also shows the system surplus or deficit.

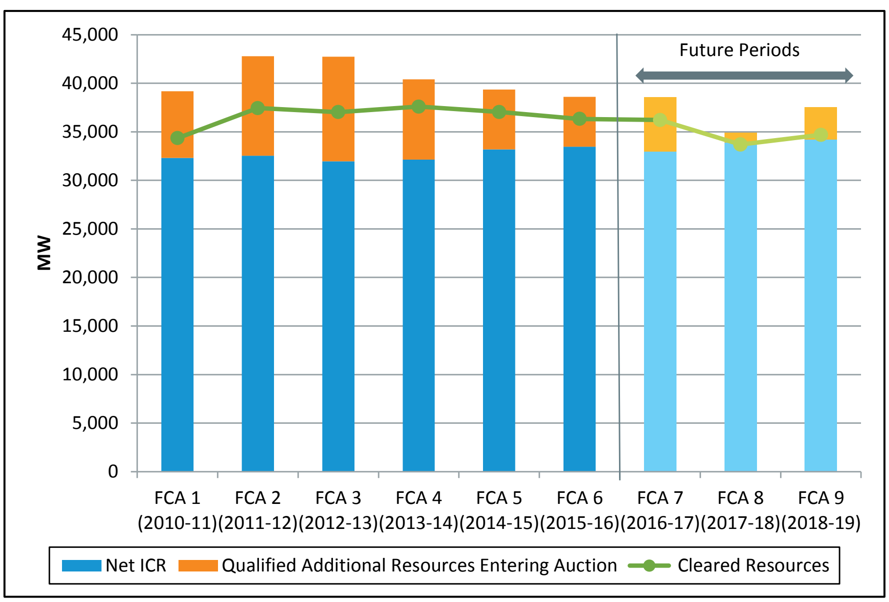
Figure 6-3: FCA Cleared Capacity Resources for Each FCM Capacity Commitment Period



The figure shows that the amount of installed generation declined in FCA 8, primarily the result of the Brayton Point units retiring. This resulted in a deficit of 153 MW below the ICR. The figure also shows a tightening of supply for FCA 8 and FCA 9. Net capacity additions increased for FCA 9, but the surplus was low compared with FCA 1 to FCA 7. In many of the earlier FCAs, capacity prices cleared at the auction floor due to an excess of supply. In the last two auctions, the capacity price has reflected a tightening of supply and the auction clearing price being set by a marginal supply resource, rather than by the administrative floor price.

Figure 6-4 below shows the Net ICR, the qualified MW that entered each FCA, and the MW that cleared in each FCA.

Figure 6-4: Net Installed Capacity Requirement, Qualified MW, and Cleared MW

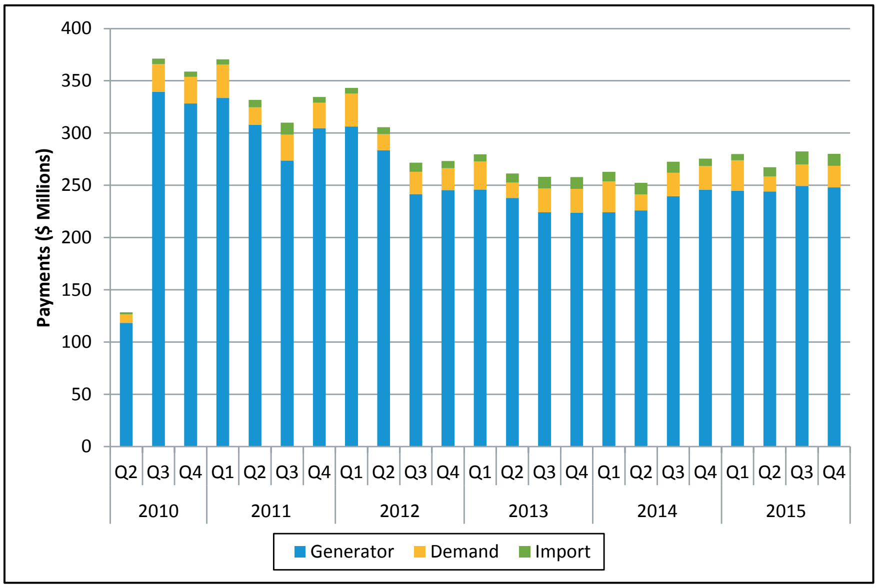


The figure shows that there has been a decrease in qualified resources entering the auction from FCA 3 to FCA 8, and shows the tightening of cleared supply compared with the capacity requirements (Net ICR) in the past two auction (FCA 8 and 9).

6.2.3 Forward Capacity Market Payments

Figure 6-5 shows the total FCM payments by quarter and year. For context, the commitment period for FCA 1 was June 2010 through May 2011 and for FCA 6 it is June 2015 through May 2016.

Figure 6-5: Capacity Market Payments by Resource Type



Capacity payments totaled $1.1 billion in 2015. The forward capacity auction payments were based on clearing prices of $3.21/kW-month and $3.43/kW-month in 2015.[98] The initial payments paid for CSOs can be adjusted based upon bilateral and reconfiguration auction activity, computed values for Peak Energy Rent, the participation of the ISO in reconfiguration auctions, and actual resource performance.

6.2.4 Peak Energy Rent Adjustments

Table 6-3 presents monthly PER adjustments during 2011 to 2015.

[98] The clearing prices for the 2014/2015 and 2015/16 capacity commitment periods (FCA 5 and FCA 6) were set by an administrative floor price.

Table 6-3: Monthly PER Adjustments ($ Millions)

Month	2011	2012	2013	2014	2015
January	17.6	–	–	3.2	2.4
February	17.2	–	0.4	2.9	2.5
March	16.8	–	0.4	2.8	2.7
April	16.3	–	0.4	2.8	2.7
May	16.3	–	0.4	2.8	2.7
June	14.0	–	0.4	2.9	3.6
July	12.1	–	0.5	2.8	3.6
August	7.9	–	1.9	1.3	3.6
September	2.9	–	1.9	1.3	4.7
October	0.3	–	2.0	1.3	5.4
November	0.2	–	2.0	1.3	5.4
December	–	–	2.3	1.1	5.4
Total	**121.7**	**–**	**12.6**	**26.6**	**44.6**
Total 2011 to 2015					**205.4**

When real-time energy prices exceed the PER threshold, the PER adjustment I triggered. On December 1, 2010, the fuel used to calculate the PER threshold was changed from the lower price of natural gas and No. 2 fuel oil to the higher price of the two.[99] As a result, the threshold increased from approximately $116/MWh on November 30, 2010, to $425/MWh on December 1, 2010. Because the amount of the PER adjustment is calculated from a moving 12-month average, the change in threshold affected the PER adjustment through November 2011. More specifically, PER adjustments decreased through 2011 because of an increase in the threshold.

Through the end of 2012, no hours had a positive hourly PER.[100] As a result, the PER adjustment fell to zero in December 2011 when all effects from a gas-based calculated strike price ended.[101] PER adjustments have increased from mid-2013 to the present as a result of elevated fuel costs and load levels leading to higher real-time prices, especially during cold and hot weather periods.

On March 6, 2015, the ISO filed market rule changes to eliminate PER on a prospective basis starting with the capacity commitment period that begins on June 1, 2019.[102] As described in

[99] FERC, *Order Accepting Tariff Provisions in Part, and Rejecting Tariff Provisions in Part*, Docket No. ER11-2427-000, (February 17, 2011), http://www.iso-ne.com/regulatory/ferc/orders/2011/feb/er11-2427-000_2-17-11_partial_accept-reject_tariff_rev.pdf. At the beginning of the FCM transition period (December 2006), and during most of the transition period, the prices of natural gas and oil were close to each other. Thus, the difference between adopting one or the other fuel as the standard was not substantial. This changed, however, when gas and oil prices diverged in January 2009.

[100] *Id.*

[101] *2011 Annual Markets Report*, Section 3.5.3.2, http://www.iso-ne.com/static-assets/documents/markets/mkt_anlys_rpts/annl_mkt_rpts/2011/2011_amr_final_051512.pdf.

[102] *ISO New England Inc. and New England Power Pool, Docket No. ER15- -000, PER Mechanism Changes*, FERC Filing (March 6, 2015), http://www.iso-ne.com/static-assets/documents/2015/03/er15-1184-000_3_6_15_fcm_per.pdf. The region's private and municipal utilities formed NEPOOL to foster cooperation and coordination among the utilities in the six-state region and ensure a dependable supply of electricity. Today, NEPOOL members serve as ISO stakeholders and market participants; the NEPOOL stakeholder process provides advisory

more detail below, the PER mechanism is no longer needed to serve its intended purposes, and retaining the mechanism could result in higher capacity market costs without producing substantial benefits.

First, a number of rule changes have improved real-time price formation, resulting in a high percentage of expected real-time load clearing in the day-ahead market. This means that most Market participants who have taken on a day-ahead obligation do not have a strong incentive to seek increased prices in real-time because they have locked into the day-ahead price.

Second, the PFP changes that will become effective in 2018 replicate some of the intended incentives of the PER mechanism that restricts withholding. The potential additional protection provided by peak energy rent while PFP is in place has been evaluated. PFP provides adequate disincentives to exercise market power through physical withholding. Also, the IMM has a range of tools to detect and address physical withholding.

Third, improved, automated Real-Time Energy Market mitigation measures have been put in place. These rule changes, combined with the IMM and FERC's authority to investigate and sanction economic withholding, should sufficiently remove any incentive for market participants to seek to exercise market power.

Given these considerations, the IMM did not oppose the proposal eliminating the PER.

6.2.5 Secondary Forward Capacity Auction Results

Reconfiguration auctions enable the exchange of capacity supply obligations. Each clearing price and quantity in the reconfiguration auctions depends on the amount of CSO MW market participants are willing to acquire and transfer. Market participants may submit an offer to increase or a bid to decrease a resource's total obligation. Reconfiguration auctions are also used to adjust the total capacity supply obligation amount based on updated requirements (ICR, LSR). The ISO can purchase to make up shortfalls in any annual reconfiguration auction, or buy back excess in the last annual reconfiguration auction. Three annual auctions are conducted between the FCA and the commitment period, for the entire commitment period. There are also monthly reconfigurations auctions for each month of the commitment period. [103]

Monthly auction clearing prices increased in the auctions for the 2014-15 commitment period compared with the 2013-14 commitment period, the result of capacity exiting during the capacity period.

Figure 6-6 below shows the FCA and reconfiguration prices from June 2010 through March 2019.

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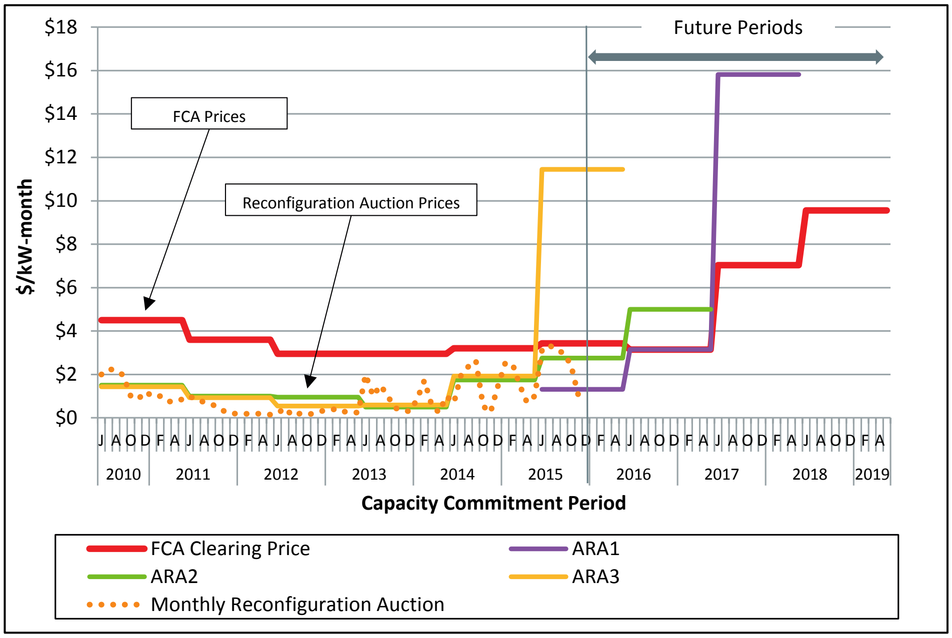
input on market, reliability, and *Open Access Transmission Tariff* (OATT) matters. More information is available at http://www.iso-ne.com/committees/nepool_part/index.html.

[103] All the monthly reconfiguration auctions have not been completed for all months in the 2015-16 capacity commitment period.

Figure 6-6: FCA and Reconfiguration Auction Prices



The clearing prices in the ARAs increased steadily in FCA 5 through FCA 7 but for most auctions the reconfiguration prices were lower than the FCA price. The reconfiguration auction clearing price, while still less than the corresponding primary FCA, has been increasing to reflect the lower capacity margins expected for future capacity delivery periods. In FCA 1 through FCA 7, there was an abundance of capacity and many FCA prices cleared at the floor. There is no floor in reconfiguration auctions and in some cases the monthly price cleared close to $0/kW-month. The floor price for FCAs was eliminated in FCA 8.

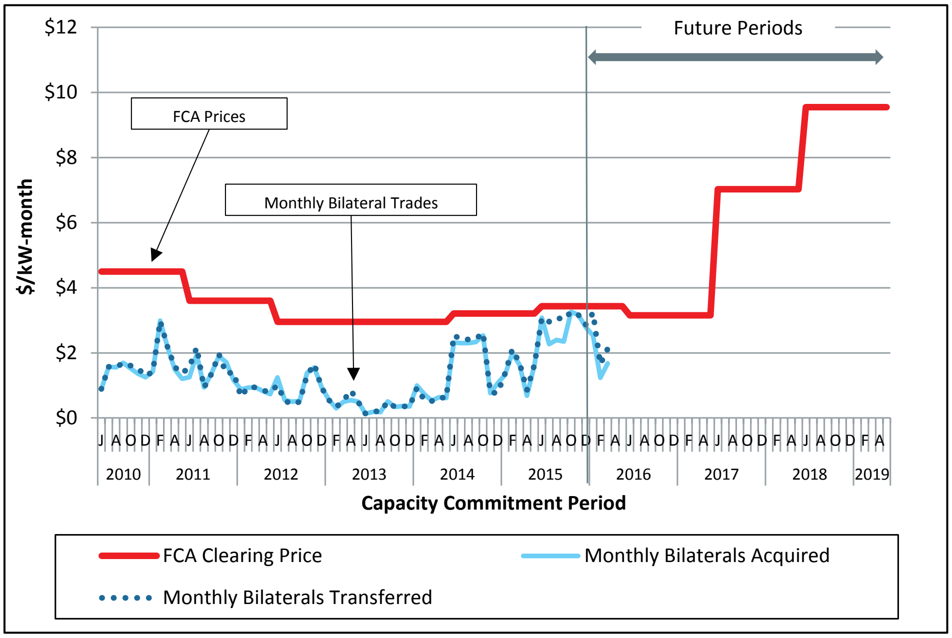
The graph also shows a higher price for the first ARA than the FCA price for the 2017-18 commitment period (FCA 8). The reconfiguration auction cleared 316 MW in capacity with a price of $15.82/kW-month, the result of demand bids placed in the auction at the cap by the ISO.

Capacity supply obligations can also be exchanged using a bilateral trade. The ISO facilitates these trades; windows for submitting trades are open before and after annual reconfiguration auctions. Prices may be submitted with these transactions to facilitate basic financial arrangements. The trades allows resources with CSOs to shed (or transfer) their obligations, and allows resources to acquire additional obligations. There are three annual CSO bilateral periods, which are held approximately two years, one year, and just before the capacity commitment period begins. Monthly CSO bilateral periods, held beginning the first month of a capacity commitment period, adjust the annual commitments during the commitment period.

Figure 6-7 shows the results of the monthly bilateral trades along with the FCA clearing price.[104]

[104] The bilateral prices shown in this exhibit are the MW weighted average of the accepted bilateral trades for each month or capacity commitment period.

Figure 6-7: FCA and Monthly Bilateral Trade Prices



The figure shows that for all bilateral trade periods the bilateral prices were lower than the FCA price. In FCA 1 through FCA 7, there was an abundance of capacity and many FCA prices cleared at the floor. The prices in the annual trade periods increased steadily but were still lower than the prices in the corresponding primary FCAs. The trade prices are also increasing in future periods to reflect lower capacity margins. This is a similar observation to what was observed with reconfiguration auction prices.

6.3 Trends in Capacity Supply Obligations

6.3.1 New Entry

New supply-side and demand-side resources undergo a qualification process to be able to participate in the FCM. Additionally, some resources may opt to be treated as new capacity resources in the FCA that were previously counted as existing capacity (including deactivated or retired resources) and incremental capacity from existing resources, subject to certain requirements.

For new power plant proposals, the ISO conducts several studies to ensure that a generator can connect to the power grid electrically without having a negative impact on reliability or violating safety standards. The qualification review assesses the project's feasibility (i.e., whether it realistically can be built and commercialized before the beginning of the relevant capability year). The ISO evaluates each new supply-side resource to ensure that it will be able to provide effective incremental capacity to the system. An overlapping impact analysis assesses whether the resource can provide useful capacity and electric energy without negatively affecting the ability of other capacity resources to provide these services also. See Table 6-4, which shows the new and incremental power plant projects over 50 MW added to the FCAs from FCA 2 through FCA 9.

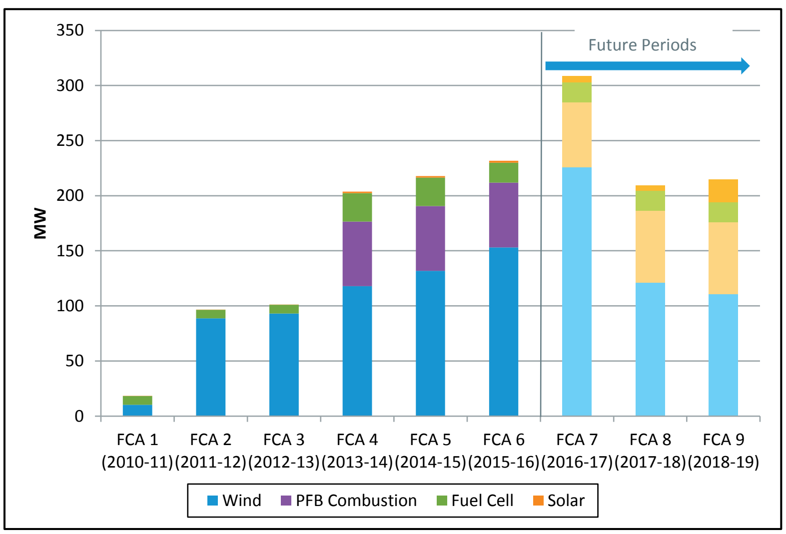
Table 6-4: New and Incremental Generator over 50 MW added to the FCAs

Resource Name	Primary Fuel Type	Load Zone	Effective Capacity Period	CSO MW
Devon 15-18	Kerosene	Connecticut	FCA 2 (2011/12)	188
Middletown 12-15	Kerosene	Connecticut	FCA 2 (2011/12)	186
Kleen Energy	Gas	Connecticut	FCA 2 (2011/12)	620
New Haven Harbor Incremental	Kerosene	Connecticut	FCA 2 (2011/12)	130
Berlin Biopower	Fuel Oil	New Hampshire	FCA 4 (2013/14)	59
Footprint Combined Cycle	Gas	NEMA Boston	FCA 7 (2016/17)	674
Cape Wind Offshore	Wind	Southeastern Mass	FCA 7 (2016/17)	74
Wallingford Unit 6 and Unit 7	Gas	Connecticut	FCA 9 (2018/19)	90
Medway Peaker - SEMARI	Gas	Southeastern Mass	FCA 9 (2018/19)	195
CPV Towantic	Gas	Connecticut	FCA 9 (2018/19)	725

Natural gas generating resources accounted for 78% of new additions to capacity. Newer, cleaner and more efficient technology, combined with low natural gas prices, increasing emissions costs, and environmental regulations has contributed to more investment in new natural gas generators. In FCA 2, over 1,100 MW of gas and peaking unit capacity were added in Connecticut. In FCA 7, Footprint (gas) was added, and in FCA 9, over 1,000 MW of capacity was added in Connecticut and Southeastern Massachusetts.

Figure 6-8 shows CSOs for power plant projects for newer technologies - wind, pressurized fluidized-bed (PFB) combustion, fuel cells, and solar.[105]

Figure 6-8: CSOs for Wind, PFB Combustion, Fuel Cells, and Solar

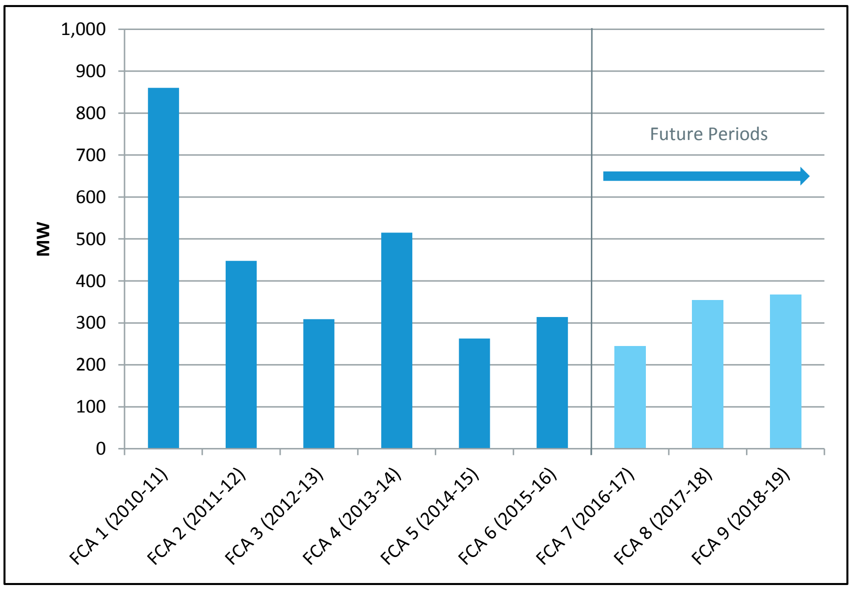


[105] *Pressurized Fluidized Bed (PFB) Combustion* is a new technology where fluidized beds suspend solid fuels on upward-blowing jets of air during the combustion process. The result is a turbulent mixing of gas and solids. The tumbling action, much like a bubbling fluid, provides more effective chemical reactions and heat transfer. Fluidized-bed combustion evolved from efforts to find a combustion process able to control pollutant emissions without external emission controls (such as scrubbers). The technology burns fuel at temperatures of 1,400 to 1,700 degrees F, well below the threshold where nitrogen oxides form (at approximately 2,500 degrees F, the nitrogen and oxygen atoms in the combustion air combine to form nitrogen oxide pollutants).

The figure shows that there has been new investment in renewable generation like wind and solar. The reduction in wind from the 2016-2017 capacity period to the 2017-2018 capacity period is due to Cape Wind Offshore, a project that was planned for implementation (and received a CSO for 2016-17) but ultimately withdrew from the market when the project was terminated. Solar projects increased from 0.1 MW in FCA 2 to 20.6 MW in FCA 9.

Figure 6-9 shows new demand resources by FCA. Demand resource proposals undergo a feasibility review, during which the ISO ensures that the plans and methods for reducing electricity use meet industry standards. This is the primary mechanism for assessing demand-resource project criteria because these projects have no interconnection impact. Demand resources submit a measurement and verification plan for this review, which outlines the project and its development and how the resource will achieve the demand reduction. The ISO subsequently reviews this plan to determine how much capacity the resource can provide.

Figure 6-9: New Demand (Reduction) Resources with a CSO



The figure shows varying activity in the participation of demand resources over time, with higher new entry in FCA 1 and FCA 4, and lower new entry from FCA 5 forward. Some of the lower new entry may be the result of the uncertainty about the future of demand resource programs in the ISO, the result of the legal challenge to FERC order 745, which is further discussed in Section 3.6.

6.3.2 Retirements

The qualification process for existing capacity resources begins with the ISO's determination of each resource's summer and winter qualified capacity. For generating capacity resources, the qualified capacity value relies on a resource's demonstrated performance over the previous five years. The summer and winter qualified capacity values are calculated for demand resources based on the sum of the previous qualified existing capacity and any incremental capacity that clears in the prior FCA.

Nonprice retirement requests, which are irrevocable requests to retire all or a portion of a resource, supersede any other delist bids submitted. Nonprice retirement requests are subject to a review for reliability impacts. If the ISO notifies a resource owner of a reliability need for the resource, the resource owner has the option to retire the resource as requested or continue to operate it until the reliability need has been met. Once the reliability need has been met, the resource must retire. Table 6-5 shows generating resources over 50 MW that have retired by capacity period.

Table 6-5: Generating Resource Retirements over 50 MW by FCA, FCA 1 to FCA 9

Resource Name	Primary Fuel Type	Load Zone	Effective Capacity Period[a]	CSO MW
Androscoggin Energy Center	Maine	ME	FCA #2 (2011/2012)	128
Salem Harbor 1	Coal	NEMA/Boston	FCA #3 (2012/2013)	82
Salem Harbor 2	Coal	NEMA/Boston	FCA #3 (2012/2013)	80
Bridgeport Harbor 2	Fuel oil	CT	FCA #4 (2013/2014)	130
Salem Harbor 3	Coal	NEMA/Boston	FCA #5 (2014/2015)	150
Salem Harbor 4	Fuel oil	NEMA/Boston	FCA #5 (2014/2015)	437
AES Thames	Coal	CT	FCA #5 (2014/2015)	184
Vermont Yankee Nuclear Power Station	Nuclear	VT	FCA #6 (2015/2016)	604
Ansonia Generating Facility	Gas	CT	FCA #6 (2015/2016)	60
Mt. Tom	Coal	WCMA	FCA #7 (2016/2017)	144
Norwalk Harbor 1	Fuel oil	CT	FCA #7 (2016/2017)	162
Norwalk Harbor 2	Fuel oil	CT	FCA #7 (2016/2017)	168
Brayton Point 1	Coal	SEMA	FCA #8 (2017/2018)	228
Brayton Point 2	Coal	SEMA	FCA #8 (2017/2018)	226
Brayton Point 3	Coal	SEMA	FCA #8 (2017/2018)	610
Brayton Point 4	Fuel oil	SEMA	FCA #8 (2017/2018)	422
Cape Wind Offshore	Wind	SEMA	FCA #8 (2017/2018)	74
Yarmouth 1	Fuel oil	ME	FCA #9 (2018/2019)	51

(a) The capacity period defined here is the FCA where the CSO capacity was zero. The resource may or may not have retired or shed all obligations at this time.

The table shows that most of the retirements (78%) have been coal and oil resources.

6.4 Detailed Results for the Ninth FCA

This section presents a review of the ninth Forward Capacity Auction (FCA), which covers the commitment period from June 1, 2018 to May 31, 2019 and was held in February 2015.

The FCA modeled four capacity zones: Southeastern Massachusetts/Rhode Island (SEMA-RI), Connecticut, Northeastern Massachusetts/Boston (NEMA-Boston) and Rest-of-Pool. For the first time, SEMA-RI was modeled as a single capacity zone and was determined to be import constrained.

Also for the first time, the system-wide sloped demand curve was applied to determine the clearing price. At prices below the FCA Starting Price of $17.728/kW-month, the system-wide quantity demanded increased linearly as the price decreased. The sloped demand curve is based, in part, on an administrative Net CONE value of $11.08/kW-month

Conditions existed which caused the capacity zones and external interfaces to close at different rounds and prices:

- Beginning of Auction: For the SEMA-RI capacity zone conditions were met to trigger the inadequate supply market rules.[106] As a result, the payment rate for existing resources located in SEMA-RI was set to the Net Cost of New Entry (or net CONE) of $11.080/kW-month, and the payment rate for new resources was set to the FCA 9 starting price ($17.728/kW-month).[107]
- Round 3: The rest of the system (with the exception of New York AC ties and New Brunswick interfaces) closed in round three with a payment rate of $9.551/kW-month.
- Round 4: New York AC ties closed in round four with a payment rate of $7.967/kW-month.
- Round 5: New Brunswick closed in round five with a payment rate of $3.940/kW-month, which concluded the auction.

6.4.1 Requirements and Resource Qualification

Table 6-6 shows the system and local capacity requirements for FCA 9. About 34,000 MW of capacity was needed to ensure system-wide resource adequacy. The Connecticut (CT), SEMA-RI, and NEMA-Boston zones are import-constrained zones. Local sourcing requirements, approximately 7,300 MW, 7,500 MW, and 3,600 MW respectively, were included for each region in the auction.

Table 6-6: Capacity Requirements or Limits for FCA 9 (MW)

Auction	Net Installed Capacity Requirement (NICR)	Local Sourcing Requirement (LSR)		
	System-wide	CT	SEMA-RI	NEMA-Boston
FCA 9	34,189	7,331	7,479	3,572

Table 6-7 summarizes the existing and new qualified capacity for FCA 9 by zone and compares that capacity to the relevant capacity requirement (i.e., NICR and LSR).

[106] See Market Rule 1, III.13.2.8.

[107] The net CONE value is the estimated capacity market value that a combined cycle unit would need in its first year of operation, with discounted cash flows over a 20-year economic life. Starting price is based on 1.6 * Net CONE.

Table 6-7: Qualified Capacity Compared with Requirement or Limit, FCA 9 (MW)

Zone	Existing	New	Total	Capacity Requirement or Limit
Connecticut	8,918	1,445	10,364	7,331
NEMA-Boston	3,833	362	4,195	3,572
SEMA-RI	6,888	353	7,241	7,479
Rest-of-Pool	12,461	3,271	15,733	n/a
Total	**32,101**	**5,432**	**37,533**	**34,189**

System-wide, existing capacity and imports (32,101 MW) was approximately 2,100 MW less than the NICR of 34,189 MW. There was a deficit because there were insufficient existing resources and imports available to meet the capacity requirement. Over the past few FCAs, there have been a number of generator retirements. In FCA 7, there were 474 MW of generator retirements and in FCA 8, 1,560 MW of generator retirements. New entry MW has not yet replaced the losses from these generator retirements (See 2.2.2 for a discussion for generation entry and exit). As a result, all market participants with existing resources were pivotal suppliers for the purpose of the application of de-list bid mitigation. In the import-constrained areas, Connecticut and NEMA-Boston were able to satisfy their respective local capacity sourcing requirements with existing capacity. SEMA-RI lacked sufficient capacity to satisfy the local capacity sourcing requirement.

Table 6-8 shows the breakdown of qualified capacity by resource type for each zone. Consistent with the ISO-NE Tariff rules, import capacity qualifies as new capacity in each auction, with the exception of certain grandfathered imports. Therefore, import capacity receives an annual, rather than long-term, obligation to supply capacity to the New England market if it clears.[108]

Table 6-8: Qualified Capacity by Resource Type and Qualification Status, FCA 9 (MW)

Zone	Existing			Existing Total	New			New Total	Total
	Demand	Generator	Import		Demand	Generator	Import		
Connecticut	486	8,432	0	**8,918**	113	1,332	0	**1,445**	**10,364**
NEMA-Boston	532	3,301	0	**3,833**	166	196	0	**362**	**4,195**
SEMA-RI	475	6,413	0	**6,888**	139	214	0	**353**	**7,241**
Rest-of-Pool	945	11,428	89	**12,461**	199	350	2,722	**3,271**	**15,733**
Total	**2,438**	**29,574**	**89**	**32,101**	**618**	**2,092**	**2,722**	**5,432**	**37,533**

6.4.2 Auction Results

System-wide. The auction started with a price of $17.728/kW-month. The auction ended in the third round when it bound system-wide when a new capacity offer was withdrawn. This

[108] Imports are new in every auction except if an import capacity resource that has cleared in a prior FCA with a multi-year capacity contract selling/importing capacity into New England. This is limited to grandfathered import capacity resources listed in the Market Rule (Section III.13.1.3.3(c)).

resulted in aggregate supply falling short of demand, after accounting for the 238 MW capacity shortfall in the SEMA-RI capacity zone. As a result, resources in NEMA-Boston, Connecticut and Rest-of-Pool capacity zones will be paid the capacity clearing price set to the system-wide sloped demand curve, which was $9.551/kW-month.

SEMA-RI. In the SEMA-RI capacity zone, there were inadequate resources to meet the zone's Local Sourcing Requirement (LSR). More specifically, the LSR in SEMA-RI was 7,479 MW. There were 6,888 MW of existing capacity offers in the SEMA/RI capacity zone thereby requiring 591 MW of new capacity. Since the 353 MW of qualified new capacity in SEMA-RI was less than the new capacity required, the administrative pricing provisions of Inadequate Supply were triggered.
As a result, the Inadequate Supply administrative pricing rules were triggered. Under these rules, the 353 MW of new capacity in the zone will receive the auction starting price of $17.728/kW-month, while 6,632 MW of existing resources in the zone will receive the Net Cone price of $11.08/kW-month. 256 MW of existing self-supply resources will not receive payments through the Forward Capacity Market.[109]

The amount of capacity procured in the SEMA-RI capacity zone was 238 MWs less than the capacity zone's LSR. The ISO will seek to procure additional resources to make up for this shortfall in the upcoming reconfiguration auctions for the 2018-2019 capacity commitment period.

New Brunswick and AC Ties. The auction continued for one additional round for New York AC ties imports, closing at $7.967/kW-month and two additional rounds for New Brunswick imports, closing at $3.94/kW-month. The capacity clearing price for the remaining external interfaces was $9.551/kW-month.

The New Brunswick and New York AC external interfaces had greater amounts of capacity offered than the capacity transfer limits for the interfaces at the Rest-of-Pool capacity clearing price of $9.551/kW-month. Accordingly, the New Brunswick and New York external interfaces were treated in the auction as if they comprised separately modeled export-constrained capacity zones. Therefore, additional bidding was required to determine the capacity clearing price for each of those external interfaces.

Table 6-9 shows the delisted capacity by zone and resource type for FCA 9. For more information on IMM mitigation in the capacity market, see Section 8.6.

[109] *Self-supply* in the FCM is when a market participant chooses to cover their forward capacity market obligations by using resources it has contracted with. The contract or agreement usually takes place outside of the ISO. By designating capacity from a resource it owns or has under contract as self-supplied, a load serving entity can satisfy its capacity load obligations. By self-supplying, it will not be subject to capacity charges. By designating self-supplied resources, the load serving entity is not eligible to receive capacity payments for its self-supplied MW capacity payments for its self-supplied MW.

Table 6-9: Delisted Capacity by Zone and Resource Type, FCA 9 (MW)

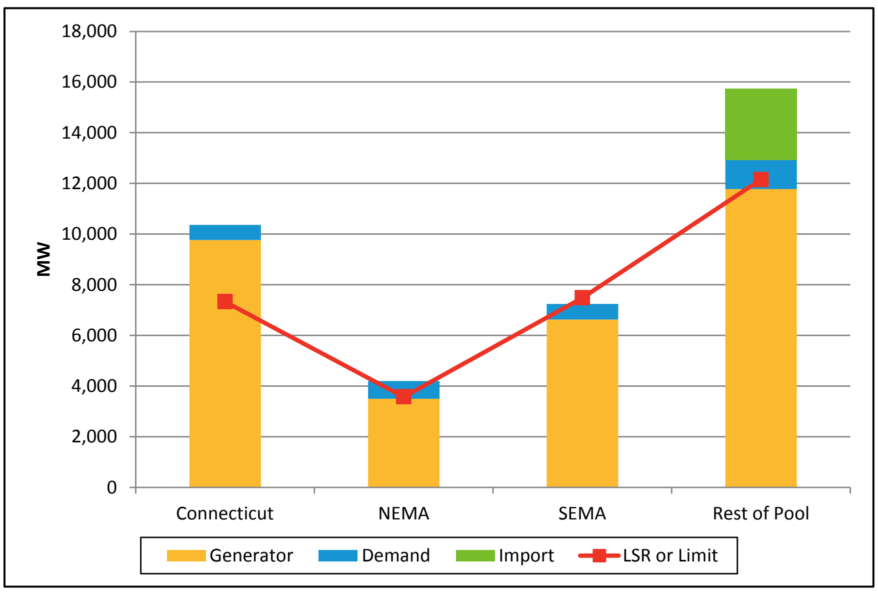
Zone	Demand	Generator	Total
Connecticut	0	17	17
NEMA-Boston	2	0	2
SEMA-RI	0	0	0
Rest-of-Pool	0	175	175
Total	**2**	**192**	**194**

For FCA 9, 118 delist bids were entered in the auction from existing capacity resources. The ISO accepted 12 of these bids for a total of 194 MW. All delist bids were for a single year (static delist bids), meaning that these resources will participate in FCA 10.

6.4.3 Cleared Capacity and Competitiveness of the Auction

Figure 6-10 below summarizes the cleared capacity (MW) from the auction, by capacity zone and resource type.

Figure 6-10: Cleared Capacity compared with Local Requirement or Limit, FCA 9



Generators represented approximately 84% of cleared capacity, while demand and import resources represented 8% and 7%, respectively.[110] These results by resource type are comparable to prior auctions.

We conclude that the outcome of the ninth FCA system-wide was the result of a competitive auction. However, there was insufficient capacity to meet the zonal requirement in the SEMA-RI zone. As a result of the capacity shortage, there could not be sufficient competition in this zone. The combination of offer mitigation and administrative pricing rules served to protect the

[110] The capacity requirement and excess capacity values are implied values for Rest-of-Pool, as those values are not explicitly modeled for the auction. The requirement for Rest-of-Pool is implied by the NICR less the zonal requirements and the excess capacity in NEMA-Boston and Connecticut.

auction from uncompetitive outcomes in this zone through the potential exercise of market power.

System-wide, there were insufficient existing resources to meet the Installed Capacity Requirement. Over the past few FCAs, there have been a number of generator retirements. In FCA 7, there were 474 MW of generator retirements and in FCA 8, 1,560 MW of generator retirements. New entry has not yet replaced the losses from these generator retirements (See Section 2.2.2 for a discussion for generation entry and exit). As a result, the IMM determined that all market participants with existing resources were pivotal suppliers and therefore resources with mitigated de-list bids were entered into the auction at those bid prices. The IMM reviewed the cost basis of all submitted de-list bids and imposed mitigation, where necessary, on submitted de-list bids.

Under the ISO tariff in effect for FCA 9, new supply resources, with the exception of New Import capacity resources associated with pivotal suppliers, can leave the auction at any price at or above their New Resource Offer Floor Price. However, sufficient new resources remained in the auction long enough such that, with the IMM mitigation of existing resources and New Import capacity resources associated with pivotal suppliers, the outcome of the auction system-wide was competitive, and no anti-competitive behavior was evident.

6.5 Demand Resources in the Capacity Market

The two main categories of demand resources in the FCM are active and passive demand resources. *Active demand resources* are dispatchable and reduce load in response to ISO dispatch instructions. *Passive demand resources* are not dispatchable and provide load reductions during only during certain time periods.

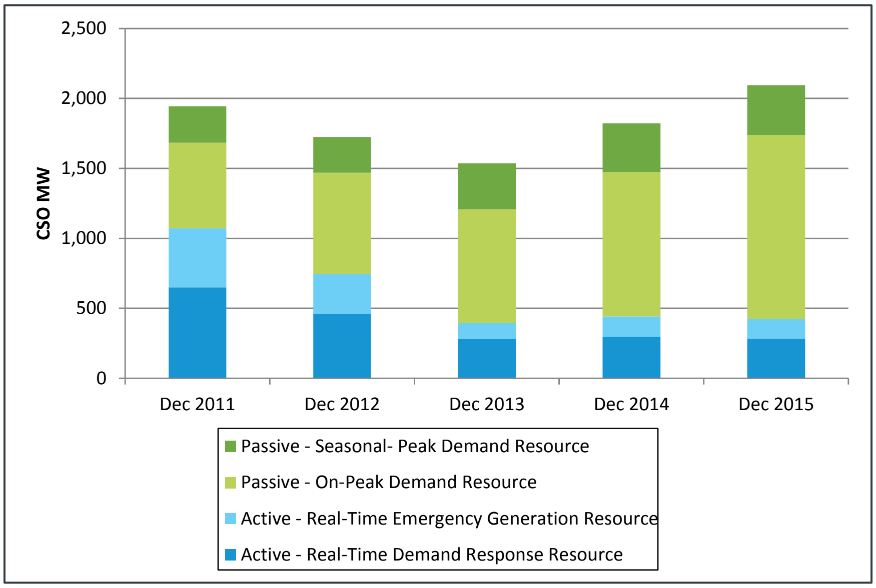
Active demand resources include *real-time demand response* (RTDR) and *real-time emergency generation* (RTEG). RTDR resources reduce load within 30 minutes of receiving an ISO dispatch instruction. RTEG resources reduce load by transferring load that otherwise would be served from the electricity grid to emergency generators. Passive demand resources include *on-peak resources*, such as energy-efficiency projects and distributed generation (DG). DG resources reduce load during predefined periods, and *seasonal-peak resources*, such as energy-efficiency projects where the project's load reduction is weather sensitive.[111]

6.5.1 Demand Resource Participation in the FCM

Figure 6-11 shows the total CSOs for all demand resources participating in the FCM. The CSO data is based on a snapshot of obligations held in December of each year.

[111] Distributed generators are a subset of demand-side resources and consist of relatively small-scale sources of power (i.e., several kilowatts to tens of megawatts in capacity) connected to the grid at the distribution or substation level, not the regional power system. DG technologies include both renewable resources (e.g., solar photovoltaics, wind turbines, fuel cells, biomass, and small hydro) and conventional resources (e.g., diesel reciprocating engines and gas turbines). RTEG is distributed generation the ISO calls on to operate during a 5% voltage reduction that requires more than 10 minutes to implement (i.e., OP 4 Action 6 or more severe actions) but must limit its operation to 600 MW to comply with the generation's federal, state, or local air quality permit(s) and the ISO's market rules.

Figure 6-11: Capacity Supply Obligations by Demand-Resource Type



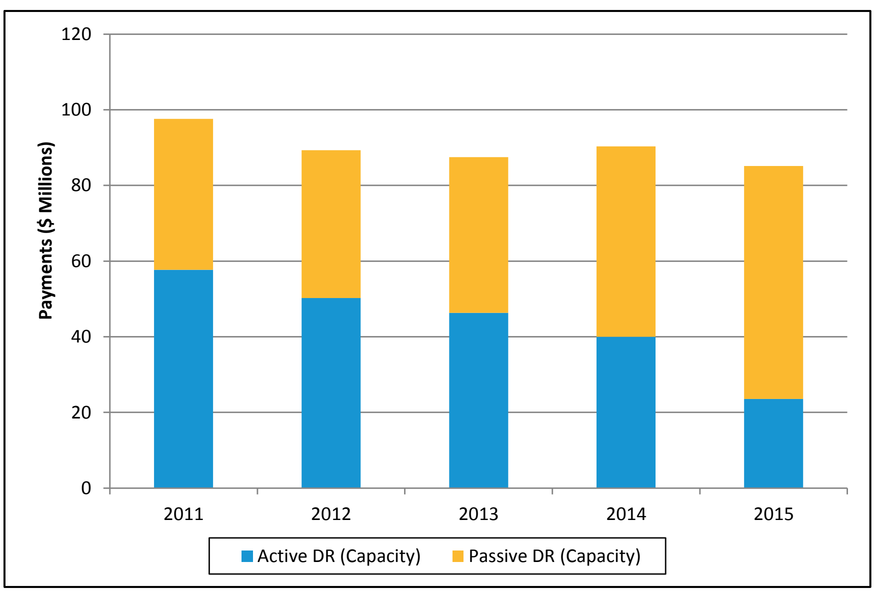
Demand resource increased by 15% in 2015 compared with 2014, a gain of 274 MW.

The CSOs of passive demand resources accounted for the vast majority of the increase. The increase in the CSOs over the year is mainly attributable to energy-efficiency programs administered by local utilities.

6.5.2 Demand Resource Payments

Figure 6-12 shows demand resource payments in the capacity market for the past five years. Active and passive demand payments are paid through the capacity market. Transitional PRD payments are paid through the energy market.

Figure 6-12: Total Payments to Demand-Response Resources



Total demand resource capacity payments were slightly lower in 2015 compared with 2014. Demand-resource payments in the capacity market totaled $85.2 million in 2015 compared with $90.3 million in 2014, a decrease of 5.7%. In 2015, demand resources accounted for about 8% of total capacity market payments. The increase in passive demand resource capacity payments over the year, like the increase in CSOs noted above, is mainly attributable to energy-efficiency programs administered by local utilities.

Section 7

Ancillary Services

This section reviews the performance of ancillary services in the ISO New England's forward and real-time markets. Ancillary services are procured to ensure the reliable operation of the ISO's real-time energy market. The ancillary services discussed in this section are: real-time operating reserves, forward reserves, regulation, and a special winter reliability program.

Real-time operating reserves represent excess generating capacity that is available to respond to unexpected contingencies (such as the unexpected loss of a generator or transmission line) during the operation of the real-time energy market;

- Forward reserves represent the procurement of fast-response reserve capability from generators in advance of the delivery period; that is, the ability to start and ramp quickly in the event of system contingencies.
- Regulation service refers to generators that alter their energy output over very short time intervals (minute-to-minute) to balance supply and demand and to maintain frequency in the real-time energy market.
- The Winter Reliability Program provides economic inducements for certain generating resources to maintain adequate fuel supplies during winter months, intended to remedy fuel supply issues that can threaten reliability.

Ancillary services (excluding costs associated with the winter reliability program) represent a small portion (1.6%) of the total wholesale energy costs within New England.

7.1 Real-Time Operating Reserves

All bulk power systems, including ISO New England, need reserve capacity to be able to respond to contingencies, such as the unexpected loss of a large generator or transmission line. As described in Section 2.3.2, in 2015, ISO New England maintained adequate levels of reserves to maintain system reliability. To ensure that adequate levels of reserves are available to respond to such contingencies, the ISO procures several different reserve products through the real-time market.

7.1.1 Real-Time Operating Reserve and Pricing Mechanics

The ISO maintains real-time reserve requirements for the following reserve products:

- **Ten-minute spinning reserve (TMSR):** TMSR is the highest-quality reserve product. It is provided by on-line resources able to increase their output within 10 minutes, allowing the system a high degree of certainty to be able to quickly recover from a significant system contingency.
- **Ten-minute non-spinning reserve (TMNSR):** TMNSR is the second-highest quality reserve product. It is provided by off-line units that require a successful startup (i.e., can electrically synchronize to the grid and increase output within 10 minutes) to ensure that needed reserves will be available in response to a contingency.
- **Thirty-minute operating reserve (TMOR):** TMOR is a lower quality reserve product provided by less-flexible resources on the system (i.e., on-line resources that can

increase output within 30 minutes or off-line resource that can electrically synchronize to the system and increase output within 30 minutes in response to a contingency).

- **Local Thirty-minute operating reserve (Local TMOR)**: Local TMOR is a product that requires additional TMOR for each local reserve zone to meet the local second contingency in import-constrained areas.

Participants with resources that provide reserves are compensated through both the locational Forward Reserve Market (FRM), which offers a product similar to a capacity product (see Section 7.2), and real-time reserve pricing. When the ISO dispatches resources in real-time, the process co-optimizes the use of resources for providing electric energy and real-time reserves. Reserve pricing occurs when the system must re-dispatch resources away from the lowest-cost solution for satisfying energy requirements and incur additional costs to meet the reserve requirements. When this happens, the reserve price is set by the resource with the highest re-dispatch cost or opportunity cost to provide the reserves, capped by the Reserve Constraint Penalty Factor (RCPF). RCPFs are limits on re-dispatch costs the system will incur to satisfy reserve constraints. The RCPFs also serve as a scarcity pricing mechanism that signals scarcity in real-time through high reserve prices which are also reflected in the energy price do to the interdependence in procurement. Each reserve constraint has a corresponding RCPF as shown in Table 7-1.

Table 7-1: Reserve Constraint Penalty Factors

Requirement	Requirement Sub-Category	RCPF ($/MWh)
System TMSR (10-min spinning)		50
System TMNSR (10-min non-spinning)		1,500
System TMOR (30-min)	Minimum TMOR	1,000
	Replacement Reserve	250
Local TMOR		250

Reserve prices are determined using each resource's real-time energy offer. Other features of the co-optimization process include the following:

- In the presence of a binding reserve constraint, the system dispatch may reduce the output of an otherwise economic unit in the energy market to create reserves on the system. When this occurs, the opportunity cost of altering the dispatch determines the market-clearing price for the reserve product.
- The market-clearing software will not re-dispatch resources to meet reserves at any price. When the re-dispatch costs exceed the RCPF, the price will be set equal to the RCPF and the market software will not continue re-dispatching resources to meet reserves.[112]

[112] When an RCPF is reached and the Real-Time Energy Market's optimization software stops re-dispatching resources to satisfy the reserve requirement, the ISO will manually re-dispatch resources to obtain the needed reserves, if possible.

- The market software optimizes the use of local transmission interfaces to minimize the cost of satisfying all energy and reserve requirements in each region.

- On average, the cost incurred to re-dispatch on-line 10-minute operating reserve assets is lower than the cost incurred to re-dispatch less flexible resources to provide 30-minute operating reserves.

To ensure that the incentives for providing the individual reserve products are correct, the market's reserve prices maintain an ordinal ranking consistent with the quality of the reserve provided as follows:

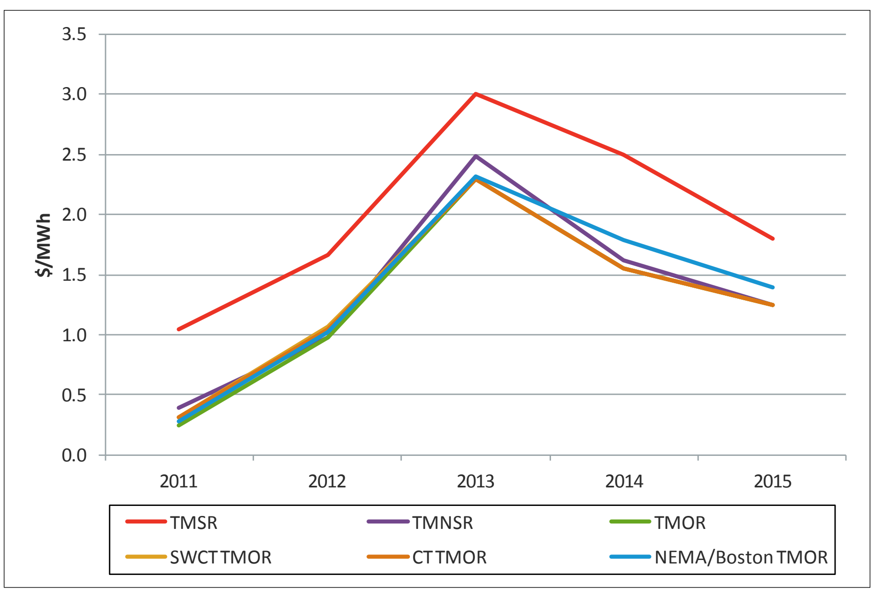
10-Minute Spinning (TMSR) ≥ 10-Minute Non-Spinning (TMNSR) ≥ 30-Minute (TMOR)

The price of higher-quality reserve products must be at least as high as the price of lower-quality reserve products. For example, if the ISO alters the dispatch to provide TMOR at a cost of $40/MWh, the prices for TMSR and TMNSR both must be equal to or greater than $40/MWh.

7.1.2 Real-Time Operating Reserve Outcomes

In 2015, average annual operating reserve prices decreased for all reserve products compared with 2014. The average annual TMSR price in 2015 was $1.80/MWh, a 28% decline from $2.50/MWh in 2014. One reason for the drop in average prices was due to fewer dispatch intervals with positive reserve prices for all reserve products in 2015. Average annual reserve prices and the frequencies of intervals with positive reserve prices for all reserve products are shown in Figure 7-1 and Figure 7-2, respectively. In addition, the average annual reserve price for each reserve product for all *positive* pricing intervals is shown in Figure 7-3.

Figure 7-1: Average Real-Time Reserve Prices



Note: Average operating reserve prices are based on preliminary prices and do not include any ex-post pricing adjustments. Ex-post adjustments to 5-minute reserve prices are not available.

Figure 7-2: Frequency of Intervals with Positive Real-Time Reserve Pricing

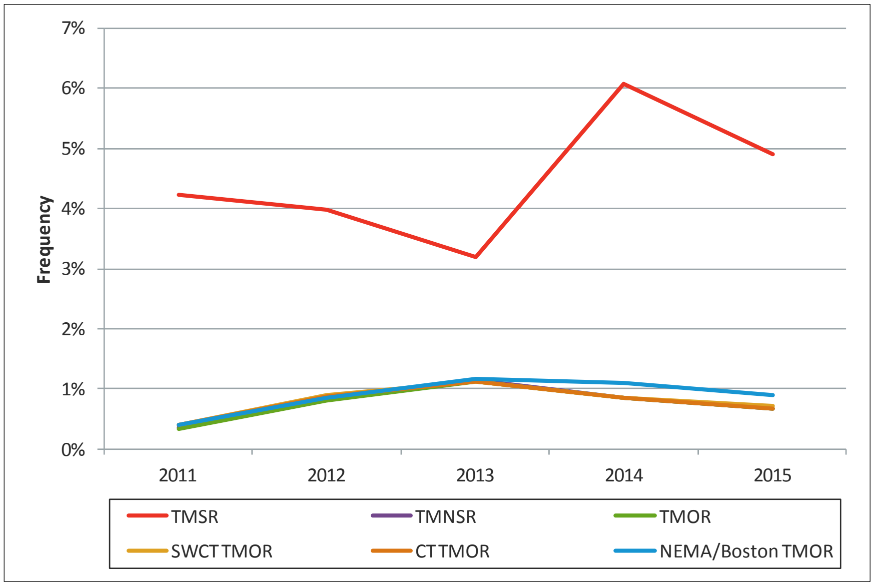
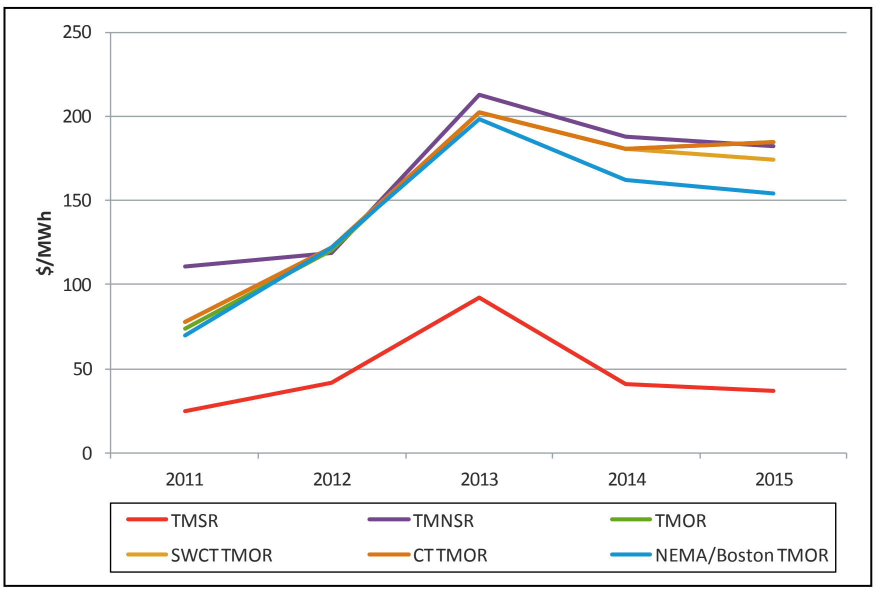


Figure 7-3: Average Real-Time Reserve Price for Positive Pricing Intervals

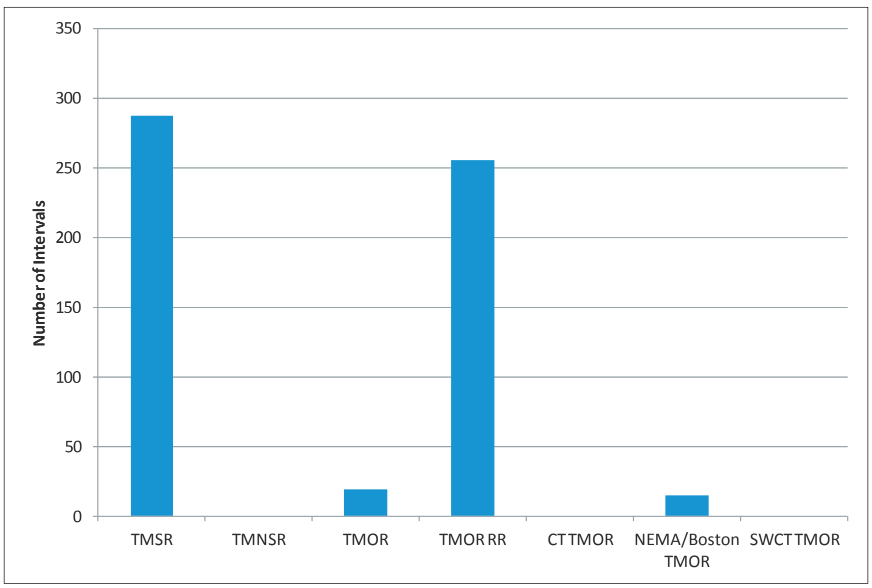


Average real-time reserve prices remained low in 2015 due to the low frequency of intervals with positive reserve prices for all reserve products. An interval without a positive reserve price signifies that there was adequate reserve capacity available on the system, and that the system did not have to be re-dispatched in order to meet reserve requirements. In 2015, on average, reserve prices for all positive pricing intervals remained relatively unchanged from 2014. Many factors influence the year-to-year variability of operating reserve prices and frequency including fuel-price variation, load forecast error, and unexpected changes in system conditions.

On average, the TMSR price and frequency were higher than the other reserve products. The higher TMSR price was due to the higher frequency of TMSR pricing intervals compared with the other reserve products. The frequency of TMSR pricing occurs more often because the TMSR reserve constraint tends to bind during times when the system is ramp constrained, which can quickly deplete 10-minute spinning reserves. These periods tend to occur during the morning and evening hours when load naturally increases. As load increases, many units are scheduled to increase their output. Each unit has a limited amount of ramping capacity (the amount of additional output it can provide over a period of time). As a unit ramps up to provide more energy, its ramp capacity is consumed in providing more energy and therefore does not retain that ramp capacity in reserve. During periods of heavy load ramp, a unit's ability to provide 10 minute spinning reserve can be limited. Once the unit reaches its desire dispatch point, however, it is no longer ramp constrained and is again able to provide spinning reserve.

During 2015, the RCPFs for several reserve constraints were triggered due to either a shortage of available capacity to meet the reserve requirements or re-dispatch costs that exceeded the RCPF values. RCPFs are the maximum re-dispatch costs the system will incur to meet each reserve constraint. The TMSR RCPF had the highest frequency of triggering with 287 five-minute intervals, or about 24 hours over the year. The TMOR replacement reserve RCPF was triggered in 255 intervals, or about 21 hours. The only local TMOR RCPF that was triggered in 2015 was for the NEMA/Boston local reserve zone with 15 five-minute intervals (a little over an hour). The number of five-minute intervals during which the RCPFs were triggered for each reserve constraint, in 2015, is shown in Figure 7-4.

Figure 7-4: Reserve Constraint Penalty Factor Activation Intervals, 2015



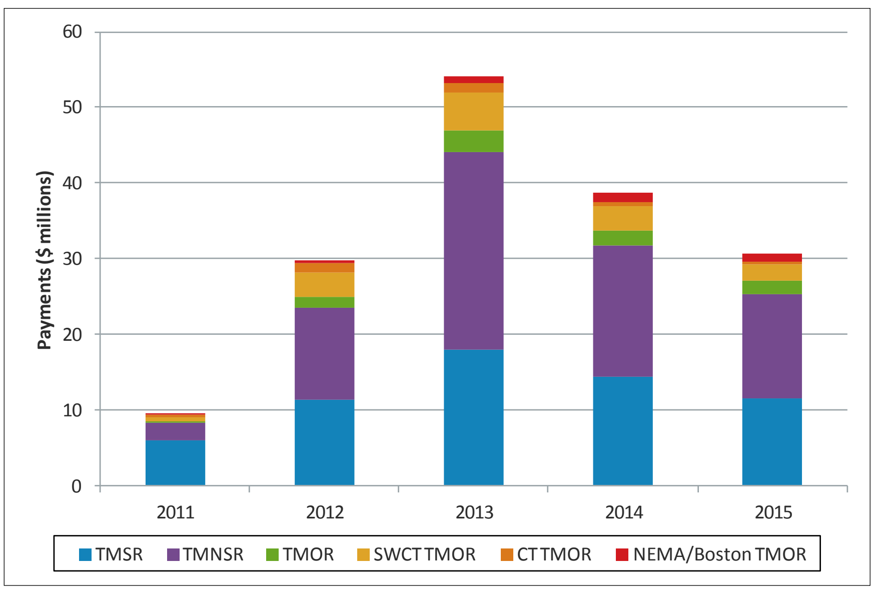
The TMSR RCPF had the highest frequency of activations in part due to the higher frequency of TMSR pricing intervals compared with the other reserve products. It also has a relatively low RCPF value of $50/MWh, which means the dispatch software will stop trying to re-dispatch the system much sooner than for the other reserve products, which have significantly higher RCPF values. The TMOR replacement reserve RCPF had the next highest frequency of activations because the system will not commit additional units to meet this requirement. Unlike for the other reserve requirements, replacement reserves are not a North American Electric Reliability Corporation (NERC) requirement.

When the RCPFs are triggered because of a shortage of available capacity to meet the reserve requirements, the reserve price will impact the energy price. During these times, the RCPF value will be added into the energy price since satisfying any additional increment of load will decrease the amount of reserves available on the system by the same amount. The RCPF value is the price that reserves are being valued at. Thus, the LMP will reflect the total cost of serving an additional increment of load including the value of the loss of reserves.

In 2015, on average, the impact of reserve pricing on the energy price was small. As shown in Figure 8-1, the average TMSR price in 2015 was $1.80/MWh, which is the maximum amount that the reserve price could impact the average energy price, assuming that each instance of reserve pricing was due to a shortage of available capacity. As a result, the average impact of reserve pricing on the real-time Hub LMP in 2015 was less than 5%.

Total real-time operating reserve payments decreased by 21% from $38.6 million in 2014 to $30.7 million in 2015. The exception was the NEMA/Boston TMOR payments, which increased by $47,000 or 4%. Reserve payments for all reserve products are shown in Figure 7-5.

Figure 7-5: Real-Time Reserve Payments



The decrease in reserve payments in 2015 was due to lower average reserve prices and frequency of positive pricing for all reserve products compared with 2014 as shown in Figure 7-2 and Figure 7-3. Although operating reserve payment totals may change significantly on a percentage basis from year to year as a result of changes in operating reserve programs, fuel prices, and system conditions, total payments are relatively small compared with overall energy market and capacity market payments.

7.2 Forward Reserves

The Forward Reserve Market (FRM) was designed to attract investments in, and compensate for, the type of resources that provide the long-run, least-cost solution to satisfying off-line (non-spinning) reserve requirements. Any unit that can provide 10- or 30-minute reserves, from an on-line or off-line status, can participate in the FRM.

The ISO conducts two FRM auctions each year, one each for the summer and winter reserve periods (June through September and October through May, respectively). The auctions award obligations for participants to provide pre-specified quantities of each reserve product. Forward-reserve auction clearing prices are calculated for each reserve product in each reserve zone. When enough supply is offered under the price cap to meet the requirement for a product in a particular zone, the auction clearing price for that product is set equal to the price of the marginal supply offer. When supply offers for forward reserve are not adequate to meet a requirement, the clearing price for that product is set to the $14,000/MW-month price cap. To avoid compensating the same resource megawatt as both general capacity and forward-reserve capacity, actual FRM payments to participants are reduced by the FCA clearing price.

To attract and maintain resources that normally are expected to provide reserves instead of electricity, the FRM requires participants to designate resources as forward-reserve resources and to offer a megawatt quantity of energy equal to the participant's FRM obligation at or above the FRM threshold price. Participants are not expected to designate resources that are normally in merit below this level because they would forego the infra-marginal revenue from selling energy. Conversely, designating high-incremental-cost peaking resources creates a lower opportunity cost because such resources are in-merit less frequently.

The forward-reserve auction clears megawatt obligations that are not resource specific. Before the end of the re-offer period for the Real-Time Energy Market, participants must submit energy offers equal to or greater than the threshold price for resources they control to satisfy their obligation. Before midnight of the day before the operating day, participants with FRM obligation must assign physical resources to satisfy their FRM obligations.

The intent of the market design is to set threshold prices to approximate the marginal cost of a peaking resource with an expected capacity factor of 2% to 3%. If the threshold price is set accurately, LMPs should exceed the threshold price only 2% to 3% of the time. A resource offered at exactly the threshold will be dispatched only when the LMP exceeds the threshold price. If the threshold price is set too low, a forward-reserve-designated unit offered at the threshold price will be dispatched to provide electric energy more frequently and therefore will be unavailable to provide reserve. If participants expect LMPs to be higher than the threshold price regularly, the reserve market could inadvertently attract resources better suited to provide electric energy than reserve. This is because the lower threshold price lowers the opportunity cost of assuming an obligation and therefore non-peaking units might find the market more attractive.

Bilateral transactions, as well as any reserve-capable resource in a participant's portfolio, can meet the reserve obligations incurred in an auction. Bilateral trading of forward-reserve obligations allows suppliers facing unexpected unit outages to substitute alternative resources. This feature is useful to suppliers if the cost of expected penalties for non-delivery exceeds the cost of acquiring substitute resources through bilateral transactions. Failure to designate a unit they control or the transfer of the obligation to another participant results in the assessment of a "failure-to-reserve" penalty.

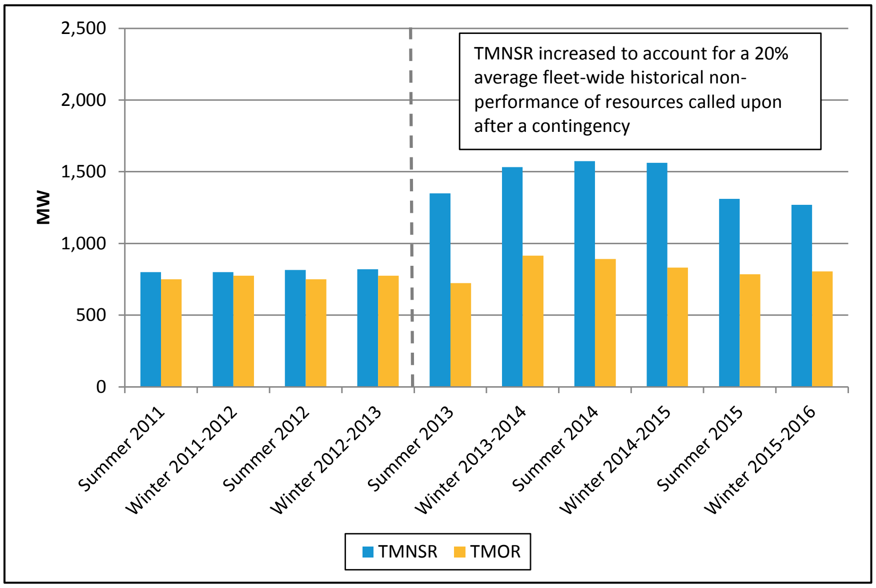
The allocation of the costs for paying resources to provide reserves is based on real-time load obligations in load zones. These obligations are price-weighted by the relative forward-reserve clearing prices of the reserve zones that correspond to each load zone.

7.2.1 Market Requirements

The FRM auction is designed to provide reserves to meet the reserve requirements of the reserve zones. Some zones are constrained in terms of how much power they can import from other zones and can have different clearing prices. As a result, instead of having a single reserve requirement for all of New England, the ISO identifies requirements at a regional level, as well as a system-wide requirement, for each reserve product procured in the auction.

Figure 7-6 shows the forward reserve requirements from Summer 2011 through Winter 2015-16.

Figure 7-6: Forward Reserve Market System-wide Requirements

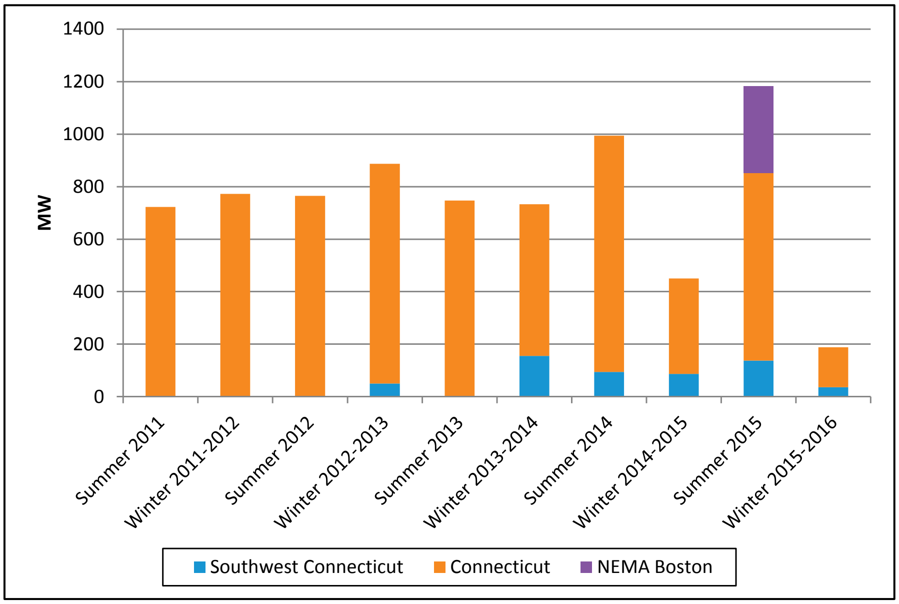


The FRM requirements for the New England control area are based on the forecast of the first and second largest contingency supply losses for the next forward reserve procurement period. Over the past ten auctions, the TMNSR purchase amount has represented the expected single contingency of the HQ Phase II Interconnection. The TMNSR purchase amount was increased for the Summer 2013 auction to reflect a 20% average fleet-wide historical non-performance of resources called upon after a contingency.[113] The TMOR purchase amount has represented the expected single second contingency of either Mystic 8/9 or Seabrook.

Figure 7-7 shows the net reserve requirement MW for the past 10 auctions for the Connecticut, NEMA/Boston, and Southwest Connecticut load zones.

[113] ISO New England Inc. and New England Power Pool, Docket No. ER 13-465-000, *Market Rule Revision Relating to the Procurement of Ten-Minute Non-Spinning Reserve in the Forward Reserve Market,* http://www.iso-ne.com/static-assets/documents/regulatory/ferc/filings/2012/nov/er13_465_000_11_27_2012_proc_ten_min_rule.pdf. This filing also allowed for an additional procurement of reserve to be procured in the Forward Reserve Market to help support the availability of reserves to meet the increased real-time reserve requirements.

Figure 7-7: Net Local Forward Reserve Requirements



The local forward reserve requirements for each applicable reserve zone are based on the 95th percentile value from historical requirements data for the previous two like forward reserve procurement periods for each reserve zone. Local forward reserve requirements (which account for both local second contingency and external reserve support (ERS) megawatts) for the reserve zones reflect the need for a 30-minute contingency response to provide support in import-constrained areas.[114] Resources within a local region as well as operating reserves available in other locations, through external reserve support (ERS), if needed, can satisfy second contingency capacity requirements.

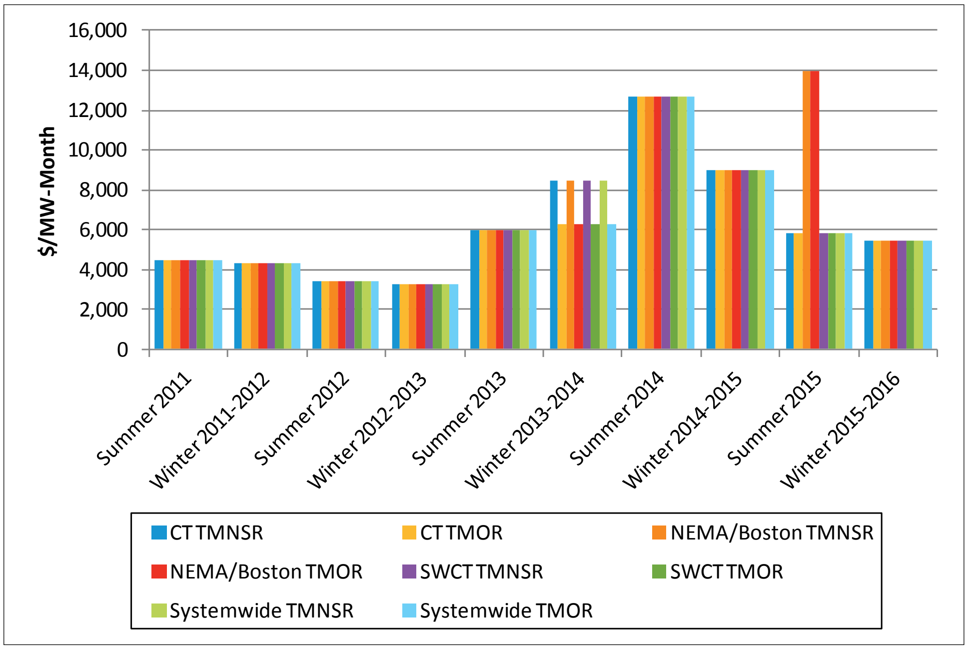
Except for the Summer 2015 auction, net reserve requirements have declined over time. This has been driven primarily by transmission upgrades which allow additional ERS capacity to support import-constrained regions. The historical requirements for Connecticut and NEMA Boston were higher for the Summer 2015 auction than for prior periods as a result of an increase in historical requirements calculated at the 95th percentile.

7.2.2 Auction Results

This section provides the market outcomes for the FRM auctions from Summer 2011 through Winter 2015-16. The TMNSR and TMOR clearing prices by reserve zone for each auction are shown in Figure 7-8.

[114] The ISO establishes the locational reserve requirements based on a rolling, two-year historical analysis of the daily peak hour operational requirements for each reserve zone for like forward reserve procurement periods (winter to winter and summer to summer). The daily peak hour requirements are aggregated into daily peak hour frequency distribution curves and the MW value at the 95th percentile of the frequency distribution curve for each Reserve Zone establishes the locational requirement.

Figure 7-8: Forward Reserve Prices by FRM Procurement Period



FRM prices for the system-wide products decreased in both the summer and the winter auctions in 2015. The summer system-wide TMNSR price decreased 54% relative to summer 2014. Similarly, the 2015-16 winter system-wide TMNSR price decreased by 40%. This is partially the result of a decrease in the TMNSR requirements when compared with 2014.

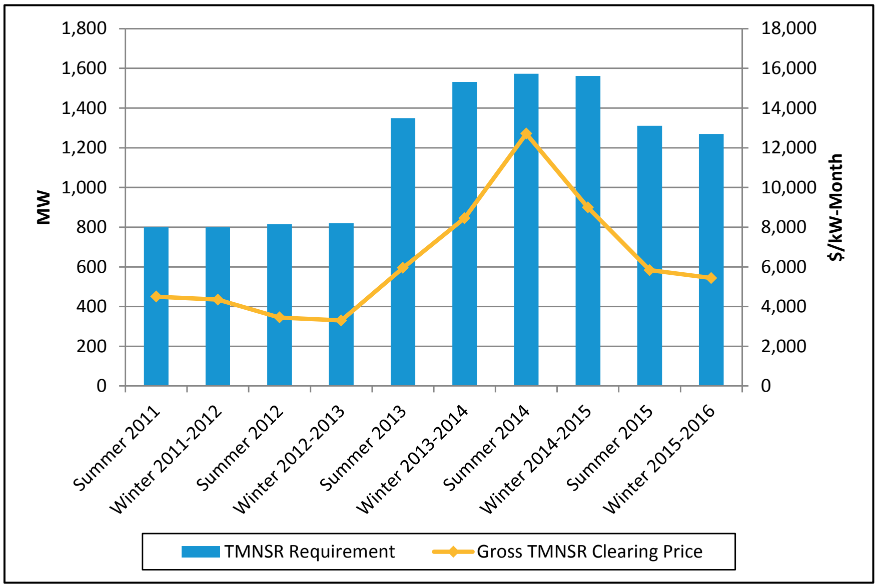
Forward-reserve auction clearing prices are calculated for each reserve product in each reserve zone, and the requirements for the Connecticut reserve zone can be partially fulfilled by the requirements for Southwest Connecticut. When supply offers for forward reserve are not adequate to meet a requirement, the clearing price for that product is set to the price cap, which is $14,000/MW-month.[115] When enough supply is offered under the price cap to meet the requirement in a particular zone, the auction clearing price for that product is set equal to the price of the marginal supply offer.

Figure 7-8 shows that there have been two instances of price separation in the five-year period. In the winter 2013-14 procurement period, there was price separation between the TMNSR and TMOR products. In that period, the TMNSR clearing price was nearly 34% higher than the TMOR clearing price.

The TMNSR purchase amount was increased for the summer 2013 auction to reflect a 20% average fleet-wide historical non-performance of resources called upon after a contingency. The increase in the TMNSR requirement to 1,532 MW from 820 MW in the winter 2012-13 auction contributed to the higher TMNSR clearing price. Figure 7-9 shows the TMNSR requirement and the gross TMNSR clearing price for the summer 2011 through winter 2015-16.

[115] *Market Rule 1*, Section III.9.4, "Forward Reserve Auction Clearing and Forward Reserve Clearing Prices" (March 1, 2014), http://www.iso-ne.com/participate/rules-procedures/tariff/market-rule-1.

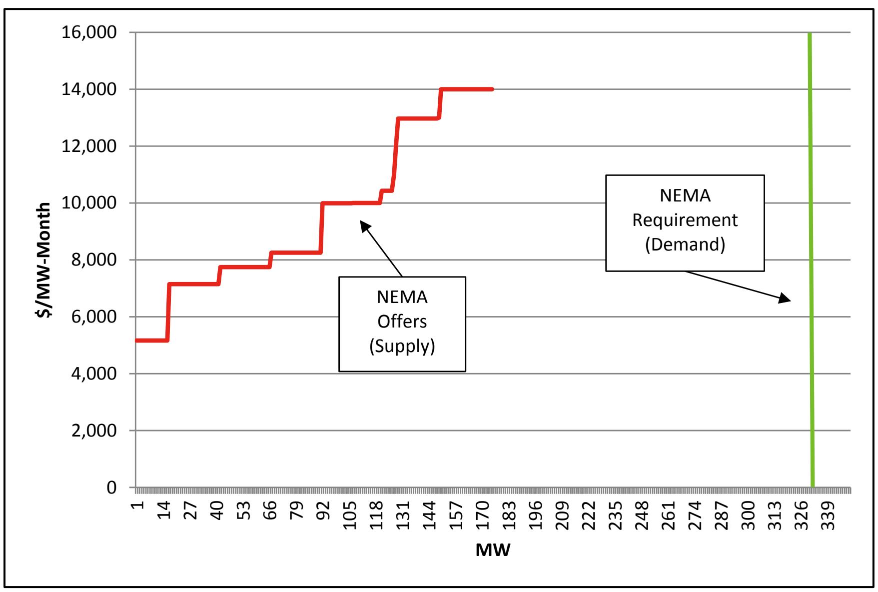
Figure 7-9: System TMNSR Requirements and TMNSR Clearing Price



The figure shows that along with the increased TMNSR requirements, the TMNSR price increased beginning in Summer 2013. The TMNSR price has fallen somewhat in 2016, partially the result of lower requirements.

The second incident of price separation occurred in the summer 2015 auction. Figure 7-10 shows the auction's supply and demand curves for the TMOR product for NEMA/Boston.

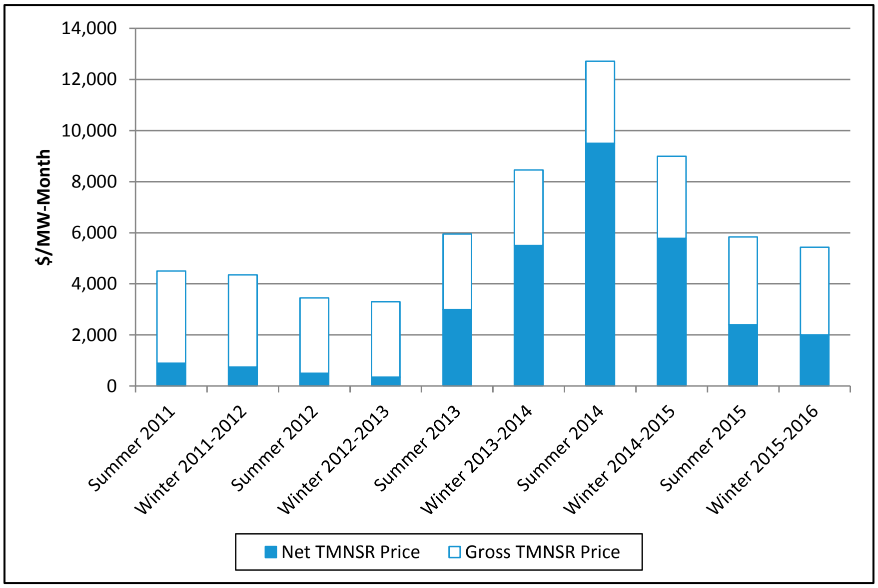
Figure 7-10: Supply and Demand for the TMOR Product in NEMA/Boston for the Summer 2015 Auction



The figure shows that the zonal price separation in NEMA/Boston was the result of inadequate total supply offered to meet the zonal requirements. The forward reserve auction clearing prices in NEMA/Boston hit the auction price cap, resulting in the $14,000/MW-month price for TMNSR and TMOR.

FRM offer and auction prices include the capacity market component. Therefore, FRM payments to participants are reduced by the FCA clearing price to avoid compensating the same resource megawatt as both general capacity and forward-reserve capacity. Figure 7-11 above shows the gross and net forward reserve prices for TMNSR.

Figure 7-11: Gross and Net Forward Reserve Market Clearing Prices for System-Wide TMNSR



Overall, both gross and net prices have increased since the TMNSR purchase amount was increased in the summer 2013 auction. The TMOR prices were the same as the TMNSR prices for all auctions except for the winter 2013-2014 auction. As noted above, in the winter 2013-14 procurement period, there was price separation between the TMNSR and TMOR products. The gross TMOR price for the winter 2013-2014 auction was $6,290/MW-month, and the net TMOR price was $3,339/MW-month. The gross TMNSR price for the winter 2013-2014 auction was $8,451/MW-month, and the net TMNSR price was $5,500/MW-month.

The FCM clearing price for the 2015-16 capacity commitment period was $3,434/MW-month. The net price by reserve providers is $2,400/MW-month ($5,834/MW-month less $3,434/MW-month) for the summer 2015 auction for the TMNSR product. Since there was price separation in NEMA/Boston, the net price for the TMOR reserve product is $10,556/MW-month. The net price to be received by reserve providers is $2,000/MW-month for the Winter 2015-16 auction for all reserve zones and products.

7.3 Regulation

This section presents data about the participation, outcomes, and competitiveness of the Regulation Market in 2015. The Regulation Market was competitive in 2015.

The Regulation Market is the mechanism for selecting and paying resources needed to balance supply levels with the second-to-second variations in electric power demand and to assist in maintaining the frequency of the entire Eastern Interconnection.[116] The objective of the Regulation Market is to acquire adequate resources such that the ISO meets NERC's *Real Power Balancing Control Performance Standard* (BAL-001-0).[117] NERC establishes technical standards, known as Control Performance Standards, for evaluating area control error (unscheduled power flows) between balancing authority areas (e.g., between New England and New York). For New England, NERC has set the Control Performance Standard 2 (CPS 2) at 90%.[118]

7.3.1 Regulation Pricing and Payments

The regulation clearing prices (RCP) are calculated in real time and are based on the regulation offer of the highest-priced generator providing the service. During 2015, FERC required the ISO to change how regulation pricing is determined. Under the prior rule, generators offered regulation at a single price. Under the new rules, generators use two-part pricing: a service price and a capacity price. The service price represents the direct cost of providing the regulation service. These direct costs may include increased operating and maintenance costs, as well as incremental fuel costs resulting from the generator operating less efficiently to provide regulation service. The capacity price represents the expected value of lost energy market opportunities, when the capacity is used to provide regulation service. The pricing change was implemented effective March 31, 2015.

In 2015, the average regulation price, prior to the implementation of 2-part pricing, was \$18.27/MWh, a 4% decline from the 2014 average price. Under 2-part pricing, which is not strictly comparable to the earlier pricing method, we do observe a difference in average pricing, compared with 2014. The average service clearing price was \$0.30/MWh and the average capacity clearing price was \$25.26/MWh. See Table 7-2.

Table 7-2: Regulation Prices (\$/MWh), 2011 to 2015

	Regulation Clearing Price			Regulation Service Clearing Price			Regulation Capacity Clearing Price		
Year	**Min**	**Ave**	**Max**	**Min**	**Ave**	**Max**	**Min**	**Ave**	**Max**
2011	0.00	7.16	95.00	n/a	n/a	n/a	n/a	n/a	n/a
2012	0.00	6.75	70.33	n/a	n/a	n/a	n/a	n/a	n/a
2013	0.00	11.68	692.08	n/a	n/a	n/a	n/a	n/a	n/a
2014	0.00	19.04	1,407.43	n/a	n/a	n/a	n/a	n/a	n/a
2015[a]	2.86	18.27	381.13	0.00	0.30	10.00	2.44	25.26	1,172.47

(a) Pricing rules changed on 3/31/15.

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[116] The *Eastern Interconnection* consists of the interconnected transmission and distribution infrastructure that synchronously operates east of the Rocky Mountains, excluding the portion of the system located in the Electric Reliability Council of Texas, Newfoundland, Labrador, and Québec.

[117] This NERC standard (effective April 1, 2014) can be accessed at http://www.nerc.com/pa/Stand/Pages/AllReliabilityStandards.aspx?jurisdiction=United States. Additional information on NERC requirements is available at http://www.nerc.com.

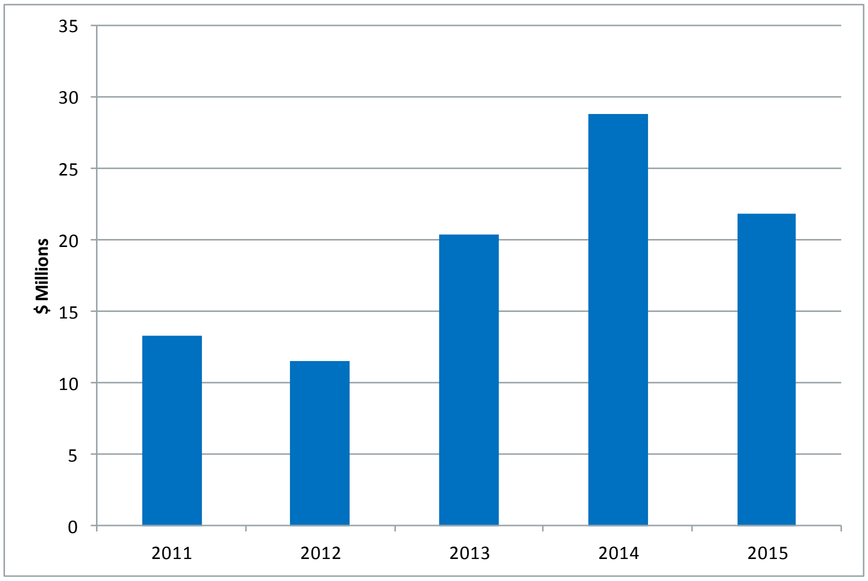
[118] The primary measure for evaluating control performance, (CPS 2), is as follows:

> *Each balancing authority shall operate such that its average area control error (ACE) for at least 90% of clock-10-minute periods (six non-overlapping periods per hour) during a calendar month is within a specified limit, referred to as L_{10}.*

More information on NERC's Control Performance Standard 2 is available at http://www.nerc.com/files/Reliability_Standards_Complete_Set.pdf (Resource and Demand Balancing; BAL).

Compensation to generators providing regulation includes a regulation capacity payment, a service payment, and a make-whole payment. Figure 7-12 shows annual regulation payments over the past five years.

Figure 7-12: Regulation Payments

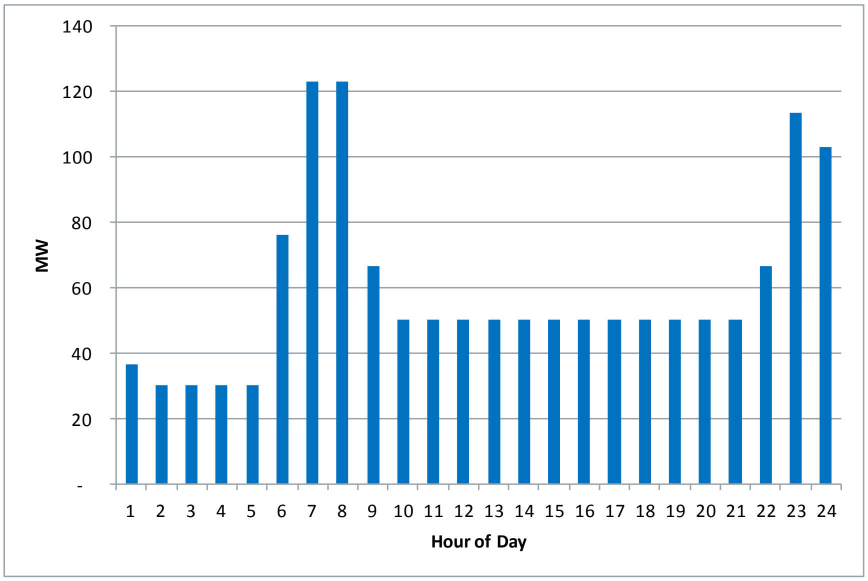


Payments to resources providing regulation service totaled $21.9 million in 2015, a 24% reduction from the $28.8 million in 2014. The reduction in payments primarily reflects reductions in fuel costs for generators in 2015, while the increased payments in prior years reflect both increases in fuel costs in those years and the impact of a series of regulation market rule changes that started in 2013.

7.3.2 Requirements and Performance

The average hourly regulation requirement of 59.56 MW in 2015 was virtually unchanged from the averages for the entire 2011 to 2015 periods. The regulation requirement in New England varies throughout the day and typically is highest in the early morning and the late evening (when load ramps up and down, respectively). The higher regulation requirement during these hours is the result of greater load variability. See Figure 7-13 below.

Figure 7-13: Average Hourly Regulation Requirement, 2015



The ISO seeks to maintain NERC *Control Performance Standard 2* within the range of 90% to 100%. The ISO has continually met its more stringent, self-imposed CPS 2 targets. For 2015, the ISO achieved a minimum monthly value of 93.7% and a maximum monthly value of 97.0%.

7.4 Winter Reliability Program

This section provides an overview of the 2015-16 Winter Reliability program. It includes a summary of procured volumes, level of participation, types of participation, pricing and payments.

The 2015-16 winter season marks the third year in which the ISO has implemented a winter reliability program for the region. The program was first implemented in the 2013-14 winter season and was prompted by electricity system reliability concerns during periods when the gas supply network is constrained. The program incentivizes market participants to purchase sufficient fuel inventories, or provide additional demand response, to alleviate reliability issues during the winter months when it is often challenging for participants to procure natural gas. The program will be in place until the winter preceding the Pay for Performance (PFP) rules going into effect (Winter 2017-18). The PFP rules should provide stronger market incentives for participants to have sufficient fuel available to satisfy their energy supply offers and capacity supply obligations.

The program is designed to procure increased fuel oil inventory service, LNG service, demonstrated-ability by dual fuel generators to operate on a secondary fuel, and additional reductions in demand and/or provision of net supply by demand response assets for the ISO New England control area. The rules governing the program are described in Appendix K of Market Rule 1.[119]

[119] *See* Market Rule 1, Appendix K, http://www.iso-ne.com/regulatory/tariff/sect_3/mr1_append-k.pdf.

7.4.1 Requirements, Participation, Pricing, and Payments

Oil Fuel Service Program:

To participate in the oil program, participants must have generators capable of operating on fuel oil[120]. Seventy-seven units participated in the program with a total of 4.489 million barrels (bbls) of oil. Almost three million barrels of the total inventory were eligible for compensation per the winter program rules at the base set rate of $12.90/bbl.[121] Given the initial inventory and payment rate, the maximum oil program cost exposure was $38.11 million.

Participants in the oil program are paid based on their final oil inventory at the end of the winter. Because of mild temperatures and low natural gas prices, little of the contracted oil was burned and some of the burned inventory was replenished resulting in a high remaining inventory. At the end of the program, 94% (2.785 million bbls) of the beginning inventory remained.

Liquefied Natural Gas (LNG) Service Program:

To participate in the LNG program, participants with natural gas-fired generators, including dual fuel generators, must be capable of receiving pipeline gas or supplies of liquefied natural gas.[122] Eight units, representing 1.278 million MMBtu of LNG, participated in the program at a rate of $2.15/MMBtu. With this quantity and rate, the maximum LNG program cost exposure was $2.75 million. Like the oil program, participants are paid based on the remaining inventory at the end of the winter. With mild temperatures and available natural gas, no LNG was used during the winter program months.

Demand Response (DR) Service Program:

To participate in the demand response program, participants must adhere to a list of criteria prescribed in Appendix K. Six demand response assets participated in the program with an aggregate interrupting capability of 26.5 MW of demand. During the winter months there was one event where the DR assets were called. On the morning of January 5, 2016 all six winter program assets were dispatched to provide demand response during tight system conditions. The total cost associated with the demand response service in the 2015-16 program was $210,316.[123]

Dual Fuel Commissioning Service Program:

The Dual Fuel Commissioning (DFC) program includes gas-fired generators that plan to commission oil-fired dual fuel capability. Eligibility for this program includes gas-fired generator assets that have not demonstrated the ability to operate on oil on or after December 1, 2011.124 Between the 2014-15 and 2015-16 winter seasons, six units submitted an intent to

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[120] Ibid.

[121] See 2015/2016 Winter Program Rate Memo, *http://www.iso-ne.com/markets-operations/markets/winter-program-payment-rate*

[122] *See* Market Rule 1, Appendix K, http://www.iso-ne.com/regulatory/tariff/sect_3/mr1_append-k.pdf.

[123] Winter 2015-2016 numbers are preliminary and subject to change.

[124] *See* Market Rule 1, Appendix K, http://www.iso-ne.com/regulatory/tariff/sect_3/mr1_append-k.pdf.

commission dual fuel capability; four units submitted intent in the 2014-15 season, totaling 1,039 MW of capability, and two additional units submitted an intent for the 2015-16 winter season totaling 735 MW of capability. Participation in this program has resulted in 1,774 MW of winter seasonal claimed capability from gas-fired generators that planned to add oil-burning capability. As of December 31, 2015 five of the six units had successfully commissioned the use of the secondary fuel. The total cost associated with the dual fuel service in the 2015-16 program was nearly $300,000.[125]

Table 7-3 below provides a summary of the volume procured, the payment rates and the costs of the three winter programs to date.[126]

Table 7-3: Winter Reliability Program Cost Summary

	2013-14	2014-15	2015-16
Contracted Volume			
Oil (bbl)	3,057,554	3,817,754	2,953,967
LNG (MMBtu)	n/a	500,000	1,277,976
Fuel Rate			
Oil ($/bbl)	n/a	18.00	12.90
LNG ($/MMBtu)	n/a	3.00	2.15
Remaining Inventory			
Oil (bbl) [127]	2,579,320	2,544,668	2,785,408
LNG (MMBtu)	n/a	500,000	1,277,976
Additional Costs			
Dual Fuel Service (includes commissioning and auditing costs)	n/a	1,081,114	299,414
Demand Response Service	198,489	160,857	210,316
Maximum Cost Exposure ($ millions)	**75.0**	**70.2**	**40.4**
Total Program Costs ($ millions)	**66.0**	**45.1**	**37.3**

As seen in the table above, even though the 2015-16 season had the highest remaining inventory levels for oil and LNG, the actual total program costs were the lowest of the past three winters. This is mainly the result of lower program payment rates for oil and LNG. Over the past three winter programs, the total cost of the program as a percentage of total energy for the winter months has been 1.3%, 1.6% and 3.7% respectively.

[125] Winter 2015-2016 numbers are preliminary and subject to change.

[126] Ibid.

[127] In first year of the program, units were paid up front for contracted fuel so the remaining inventory does not contribute to the total costs.

Section 8
Competitiveness and Market Power Mitigation

One of the core functions of the IMM is assessing the competitiveness of the electricity markets. This section presents an evaluation of the competitiveness of the energy, capacity and ancillary services markets. This section also provides a broad view of market concentration, competitive offers and market structure that can affect competition. In addition, this section includes an overview of the market power mitigation rules in the energy and capacity markets.

Market Concentration:

The ability of market participants to act uncompetitively and manipulate market outcomes is dependent on the relative number and size of individual market participants compared with the overall market. The industry standard "C4" metric presented in this section indicates that, on average, the New England energy market has low levels of concentration.

Competitive Offers:

In a perfectly competitive market, all market participants would offer to sell electricity at marginal cost. Market participants know that if they offer based on marginal cost and their supply offer does not clear (because there were lower priced offers to satisfy the demand) they will be better off, because they will not sell electricity below their marginal cost. More important, market participants know that if they offer based on marginal cost and their offer does clear, they can receive a payment based on a higher LMP. The uniform LMP approach allows market participants to earn the difference between their marginal cost and the LMP, which contributes towards the recovery of fixed costs.

The Lerner Index is a metric to evaluate market participants' ability to mark-up prices (i.e., offer above marginal cost). The Lerner Index is used to determine how well LMPs in the day-ahead energy market reflect the cost of generating the next available MW. The Lerner Index indicates that electricity prices, on average over the past five years, do not appear to have been consistently adversely impacted by uncompetitive bidding behavior.

Market Structure:

Markets are not always perfectly competitive. System or market conditions can change creating misaligned incentives. When this happens, the opportunity exists for some market participants to exert market power and unduly influence prices. The pivotal supplier test and the residual supply index are two metrics that examine the frequency of such opportunities.

A *pivotal* supplier has the ability to exercise market power because its portfolio of supply resources is needed to meet demand. Therefore, a pivotal supplier can unilaterally increase their supply offer and inflate market prices above competitive levels. To prevent such an uneconomic outcome, supply offers are subject to offer caps and pivotal suppliers are subject to mitigation. The pivotal supplier test and residual supply index are calculated for both the energy and capacity markets. The results of these measures indicate the presence of pivotal suppliers, suppliers having market power, in both the energy and capacity markets. Mitigation rules and procedures are in place for both markets, which limit the degree to which pivotal suppliers can uncompetitively influence market price.

Enhancements were made to the portfolio-based competitiveness measures presented in this report, including the capacity market's pivotal supplier test, to account for market participant affiliations. If a market participant owns many different affiliated companies, each of which is offering different resources on behalf of the market participant, then all the resources are included in the market participant's portfolio for purposes of conducting the competitiveness tests. This approach allows a more accurate determination of a market participant's ability to affect the market outcomes in a way that benefits their portfolio. Accounting for a market participant's affiliations in the pivotal supplier test is not in the current energy market mitigation rules. The IMM's *Q2 2015 Quarterly Markets Report* included a recommendation that the energy market pivotal supplier test be modified to include market participant affiliations. Such a change will improve the test's accuracy and the IMM's ability to detect market power and energy market manipulation.[128]

This section also presents an analysis of the degree of competition in the forward reserve and regulation markets, as well as a summary of mitigation activities in 2015.

8.1 Energy Market Metrics

The subsections below present analyses of supplier- and buyer-side energy market concentration.

8.1.1 C4 Concentration Ratio - Generation

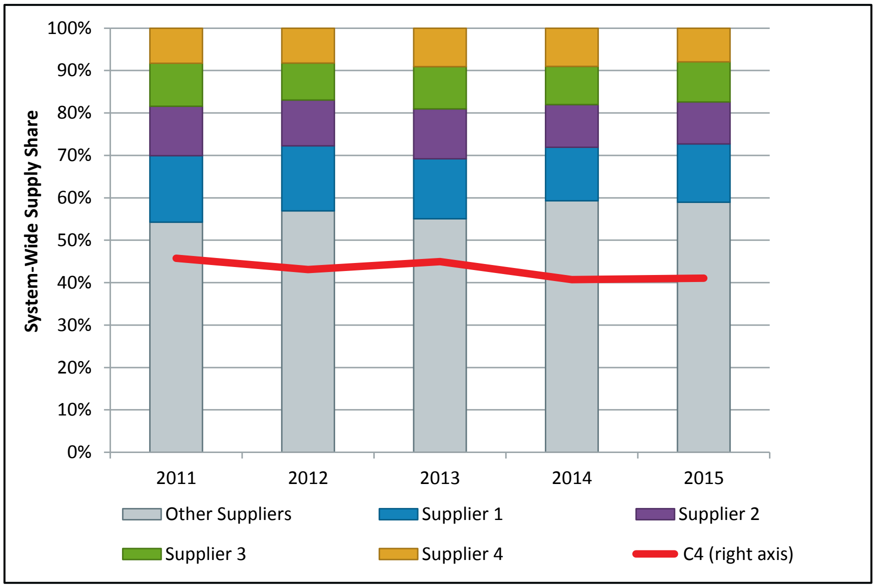
This section analyzes supplier market concentration among the four largest firms controlling generation and scheduled import transactions in the real-time energy market. This measure, termed the "C4," is useful to understand the general trend in supply concentration over time as companies enter, exit,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

The C4 is the simple sum of the percentage of system-wide market supply provided by the four largest firms in all on-peak hours in the year and reflects the affiliate relationships among suppliers.[129] As shown in Figure 8-1 below, the C4 value of 41% for 2015 is the same as observed for 2014 and somewhat lower than earlier years.

[128] See http://www.iso-ne.com/static-assets/documents/2015/10/qmr_q2_2015_10_1_2015_for_filing.pdf

[129] On-peak hours are the 16 hours of each weekday between hour ending 8 and hour ending 23, except for North American Electric Reliability Corporation (NERC) off-peak days (or "holidays").

Figure 8-1: System-wide supply shares of the four largest firms



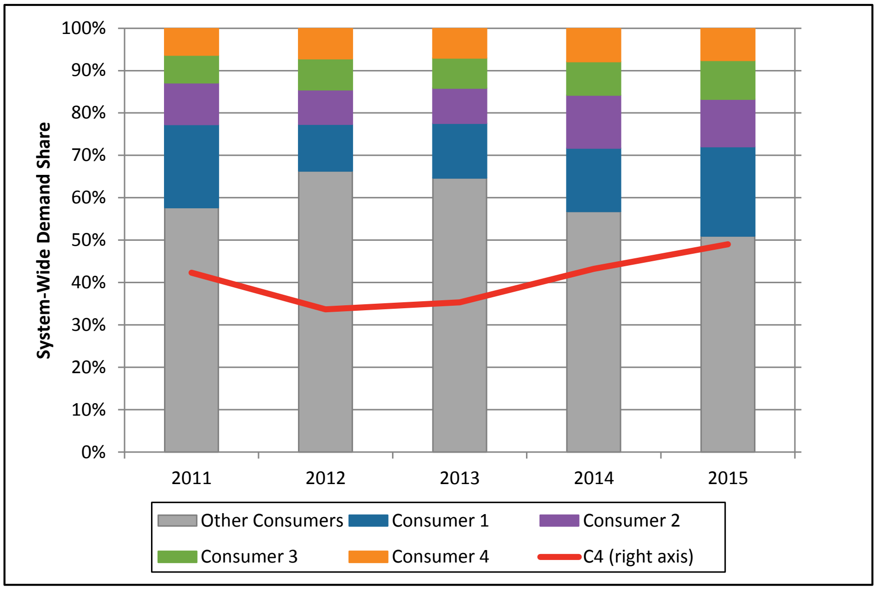
Note: The firms labeled "Supplier 1," "Supplier 2" and so on are not necessarily the same companies across all years; these are generic labels for the top four firms during a given year.

In 2015, the total supply of generation and import transactions in all on-peak hours was 69,344 GWh. The four largest suppliers provided 28,481 GWh, or roughly 41% of the total energy during these hours. As illustrated by the red C4 trend line in Figure 8-1, the aggregate amount of supply from the four largest suppliers in 2015 is comparable to, even slightly lower than, observations in prior years. C4 values in the range of 40% to 45% indicate low levels of system-wide market concentration, particularly with nearly even distributions of shares among the top four firms.

8.1.2 C4 Concentration Ratio - Load

This section presents demand-side market concentration among the four largest firms controlling load in the real-time energy market. Figure 8-2 below shows that the demand shares of the four largest firms have increased somewhat from 2015, from a 35% share in 2013 to almost 50% in 2015.

Figure 8-2: System-wide Demand Shares of the Four Largest Firms



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

In the on-peak load hours in 2015, the total amount of electricity purchased, or *real-time load obligation* (RTLO), was 71,350 GW.[130] Overall, as shown in Figure 8-2, the four largest load-serving market participants served 49% of the total system load for the 2015 on-peak load hours, while all other market participants served 51% of the total system load. As shown by the red C4 trend line in Figure 8-2, the aggregate amount of supply from the four largest suppliers in 2015 is slightly higher than observations in prior years. This is the result of two load participants adding obligations.

The C4 analysis presented here does not account for market participants with both load and generation positions, which generally have less incentive to exercise market power. Actions that would tend to raise prices for generation would come at a cost to load, and any actions that would suppress prices would come at a cost to generation. Consequently, a market participant's net position and the conditions under which unilateral action might become profitable are of highest concern.

8.1.3 Residual Supply Index and Pivotal Suppliers

The real-time demand for electricity is highly inelastic in the short-run – consumers of electricity have limited ability to respond to real-time price fluctuations. A supplier has market power if the real-time demand cannot be met without the available generation from that supplier. Such a supplier can unilaterally increase the real-time LMPs by raising the offer prices for its generation.

[130] This number differs by the generation number by losses and exports.

Background:

The Residual Supply Index (RSI) identifies when the largest supplier has market power.[131] Specifically, the RSI measures the percentage of real-time demand that can be met *without* the largest supplier's portfolio of generation resources. The RSI focuses only on the largest supplier.[132] When the RSI exceeds 100, there is enough supply available from other participants to meet demand without any supply from the largest supplier. When the RSI is below 100, a portion of the largest supplier's generation is required to meet demand. In this case, the largest supplier is considered a "pivotal supplier" and has market power because it can set an uncompetitive market price by increasing the price of their supply above marginal cost and force the market to clear at a higher price. If the largest supplier is not a pivotal supplier, then no other supplier can have system-wide market power and sufficient competition exists.

The pivotal supplier test is similar to the RSI, however the pivotal supplier test determines if *any individual* supplier (not only the largest supplier) has market power. The pivotal supplier test computes the total available generation without the generation of the supplier being tested. If demand can be met without the supplier's generation, then the supplier is not pivotal. On the other hand, a supplier is pivotal if demand cannot be met without the supplier's generation portfolio.

The current energy market mitigation rules and processes use the pivotal supplier test as one of the market structure screens conducted prior to applying mitigation. The pivotal supplier test compares the supply margin, which is the surplus available generation from all suppliers after meeting the real-time load and reserve requirements – to a supplier's generation portfolio. If the supplier's available generation is greater than the supply margin then some portion of the supplier's generation is needed to meet the load and reserve requirement and, therefore, the supplier is pivotal. If a supplier is pivotal, tests are applied to determine if the supplier's energy offers are materially higher than marginal cost (reference level) and can likely impact market prices. If so, the pivotal supplier's offers are mitigated.

RSI Analysis:

An RSI analysis was conducted using data from the real-time pivotal supplier tests conducted by the ISO's real-time market software (the Unit Dispatch System, or UDS). A pivotal supplier test is performed before issuing generator dispatch instructions.[133] The test results are used in conjunction with the energy market mitigation system and processes. The analysis used the total supply margin, energy supply offers, load, reserve requirements and Net Scheduled Interchange (NSI) from the real-time pivotal supplier test inputs. Based on these data the RSI for an interval *t* was calculated as follows:

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

[131] There may be presence of other forms of market power such as local market power in the real-time energy market. These instances are not captured in the system-wide RSI which is computed for this analysis.

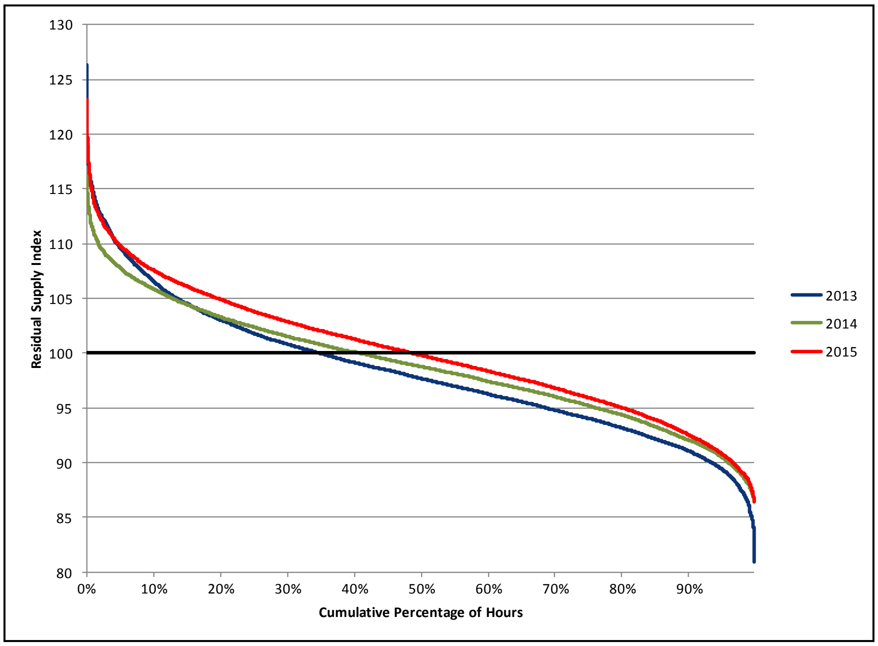
[132] The RSI can also be calculated to measure the extent to which multiple suppliers jointly have market power. Both PJM and the California ISO use a three-pivotal-supplier measure in assessing market power and applying mitigation.

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

In addition to more aggregated results, a detailed analysis was conducted for two individual hours with high and low RSI values to illustrate how the relative changes in load and supply affect the competitive conditions in real time. The analysis summarizes several factors that may have influenced the RSI. Finally, the analysis examines the relationship between the results of the pivotal supplier test and instances of energy offer mitigation.

Figure 8-4 shows the percent of hours, on an annual basis, when the hourly RSI was above or below 100. There is at least one pivotal supplier when the RSI is below 100.

Figure 8-3: System-wide Residual Supply Index Duration Curves by Year

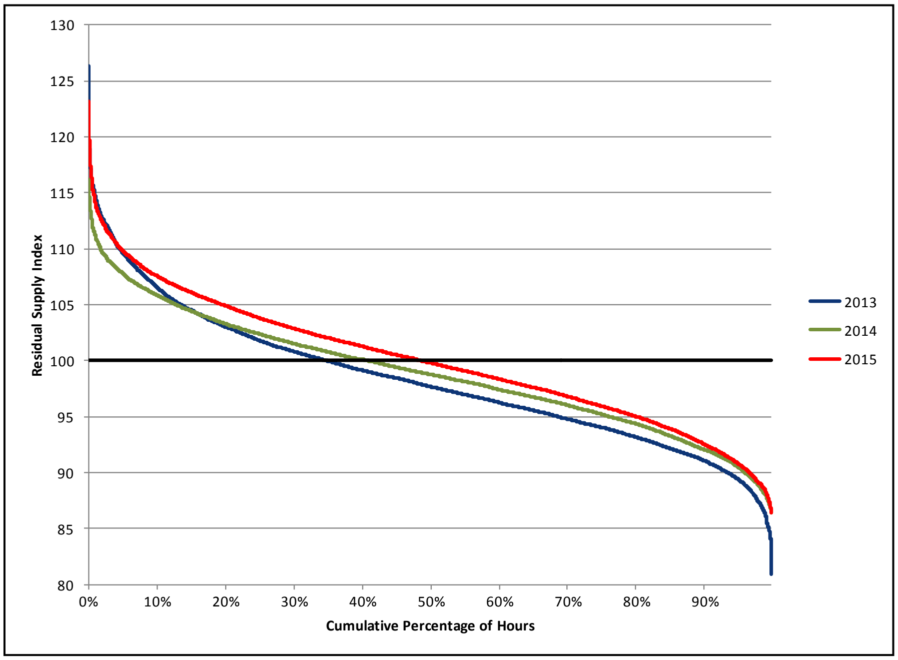


During the past three years, the RSI was less than 100 in more than 50% of the hours. The highest percentage of hours with an RSI less than 100 - nearly 65% of hours - occurred in 2013. And the lowest percentage - roughly 52% - was observed in 2015.

Note that previous reports indicated a much lower percent of hours where the RSI was less than 100. While the general methodology for calculating the RSI has remained the same, the new calculation of RSI reported here is more accurate in accounting for available capacity as well as energy and reserve requirements. This report uses the same inputs as are used by the mitigation software that is run in real-time and produces much more accurate results. The prior calculation accounted for more available capacity than was appropriate and also under-counted the requirement for reserves. As a result, the prior calculations significantly under-identified hours with a pivotal supplier.

As indicated by the RSI and pivotal supplier figures, there are a significant number of hours where one or more suppliers in the real-time market have market power. While these figures do not themselves indicate that real-time market price has been influenced by market power, it does bear further analysis along with the appropriateness of the existing market power mitigation measures for system market power – specifically the pivotal supplier, offer conduct and market impact tests. This analysis will be performed by the IMM in 2016.

Figure 8-4: System-wide Residual Supply Index Duration Curves by Year



The distribution of RSI values across quarters is represented in Figure 8-5, where the lower and upper endpoints show the 1st and 99th percentile values of hourly RSI and the bottom and top of the box show the 25th and 75th percentile values. The horizontal line which separates the box in two parts shows the median value for the period.

Figure 8-5: Distribution of RSI by quarter

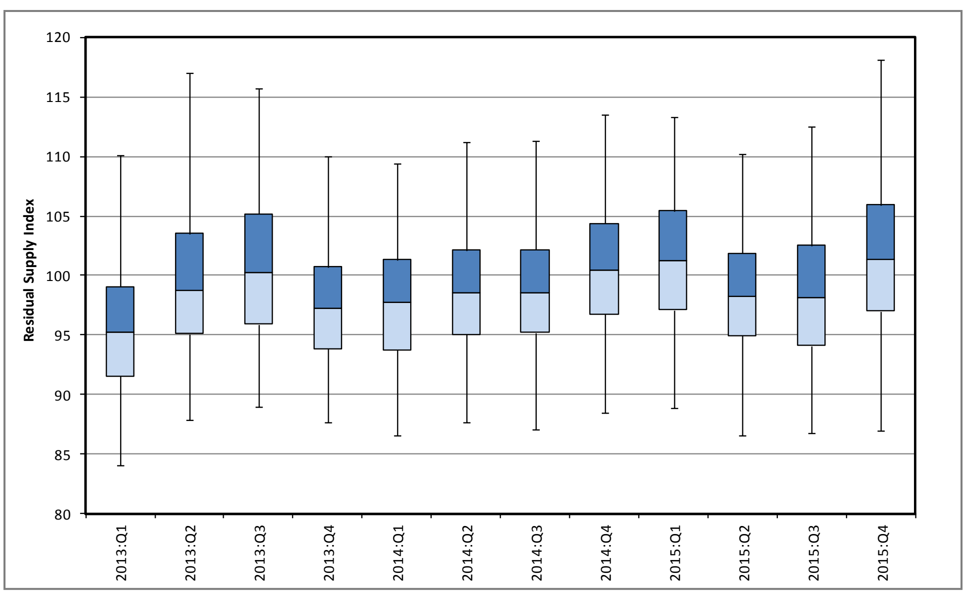


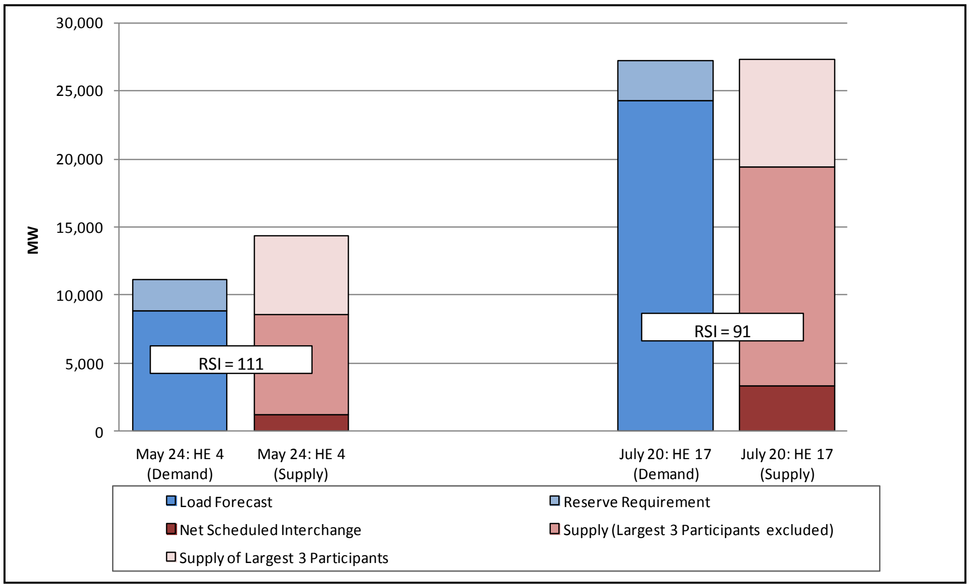
Figure 8-5 shows that there is no discernible pattern across quarters. The first quarter of 2013 and 2014 coincided with severe winter conditions and natural gas availability issues. For the first quarter of 2013 the median and percentile values are lower than any other quarter. Even though no pattern seems to emerge across quarters, there are some seasonal trends. For all years, lower RSI values are typically observed during summer months (July-August) where there is high availability from supply but also significantly higher load and reserve requirements. Higher load and reserve requirements generally reduce the amount of supply margin (available supply beyond what is needed to meet these requirements) which increases the likelihood that the single largest supply portfolio is needed to meet these requirements. This reduces the RSI measure and increases the likelihood that the measure indicates insufficient competition. Also, periods where constraints on the natural gas pipeline system are binding (December-January) can reduce available supply from generation which reduces the amount of residual supply and also increased the frequency of measured insufficient supply.

The distribution of RSI values during peak periods was lower (lower mean and variance) than in the off-peak periods across all years. The lowest hourly RSI value (80.54) was observed on May 11 during hour 1 and the highest RSI value (123.15) was observed on October 22 in hour 4. RSI values were lowest during early morning ramp period in hours 7 and 8 (not shown). During these hours load and reserve requirements increase quickly, which decreases the amount of supply margin and increases the likelihood that the largest supplier controls enough available supply to impact price. The highest RSI values are observed between late-night hours to early morning hours. On average, there were multiple pivotal suppliers in more than 90% of the hours where the RSI was below 100. This is consistent with the relatively higher market concentration in the real-time energy market.

The lowest hourly RSI value of 80 was observed on May 11 during hour 1 and the highest RSI value of 123 was observed on October 22 in hour 4. On May 11, the load forecast in hour ending 1 was significantly lower than the actual load which resulted in lower unit commitment that may have been warranted. This reduced the available supply margin and increased the opportunity of the largest supplier to influence price which resulted in a low RSI. On October 22, load declined sharply during the first few hours of the day which resulted in a higher supply margin and a higher RSI value.

In Figure 8-6, two individual hours are shown to illustrate how the relative changes in load and supply affect the competitive conditions in real time. We chose two hours - one each for a low and a high RSI value - to examine how each driver of RSI (load, reserve requirement, NSI , total available and largest supplier's generation) stack up to determine the supply margin and RSI. For this analysis, we have chosen the hours with the highest and lowest load levels in year 2015: July 20, 2015 hour ending 17 and May 24, 2015 hour ending 4, respectively.

Figure 8-6: Demand and Supply Components of the RSI (May 24 HE 4 and July 20 HE 17)



Although the RSI is calculated using the single largest supplier's generation, we have shown the supply of the largest three participants instead of one largest supplier to highlight the dominance of large participants. Figure 8-6 shows that the load and reserve requirement could not have been met without the largest three participants in both hours. On May 24 the single largest participant contributed 19% and the three largest participants contributed 44% of the total generation in hour 4.[134] Similarly, on July 20 the single largest and the first three largest suppliers contributed 12% and 33%, respectively, to available generation. Net Imports more than doubled on July 20 compared with May 24 but that increase in available supply was not sufficient to increase the supply margin enough to eliminate the impact the largest supplier could have on price. The supply margin for the lowest and highest load hours totaled 3,181 MW and 92 MW, respectively. Most generation portfolios in ISO New England are larger than 92 MW; therefore most generation portfolios will be pivotal when the supply margin is this low. The supply margin as a percentage of load was 36% on May 24 during hour 4 while the margin was less than 1% on July 20 during the peak load hour.

Influencing Factors:

There are two primary factors that have contributed to the RSI results; reduced real-time supply flexibility and supply concentration.

Reduced flexibility of generation resources in the real-time energy market, compared with the day-ahead market, is one driver of the large number of intervals with RSI below 100. Online resources and resources that can start within 30-minutes are included in the real-time RSI analysis. For comparison, the day-ahead market optimizes unit commitment and dispatch over 24 hours simultaneously and can choose to start a resource with a multi-hour start-up time early enough in the day so that it can contribute to meeting demand. The real-time market only looks ahead 15 minutes and therefore cannot commit resources with longer start times well enough in advance to meet the perceived need.

[134] The total available generation excludes net imports or NSI.

Another driver of the frequency of uncompetitive periods is the concentration of supply. With the single-supplier RSI, the amount of available supply that is controlled by the largest supplier will have a significant impact on the number of uncompetitive hours as measured by the RSI. The duration curves shown in Figure 8-4 use the Lead Participant (LP) for each resource as the basis for constructing portfolios. This is an ISO distinction and, in fact, one company can register multiple LPs to schedule their generation. It is important to reflect the common control or common profit interest of affiliated entities when constructing portfolios to test for market power. Therefore, the RSI is more accurately calculated using a portfolio that reflects assets associated with the Energy Market Controlling Entity (EMCE), which captures the affiliation among LPs. The average RSI values and the percent of hours with RSI values of less than 100 by year are reported in the Table 8-1 below. The results show that using EMCE instead of LP reduces average RSI and increases the number of hours with insufficient competition.

Table 8-1: Impact of Portfolio Construct on RSI

Year	RSI (EMCE)	RSI (LP)	% of Hours with a Pivotal Supplier (EMCE)	% of Hours with a Pivotal Supplier (LP)
2013	95.7	98.4	66.0%	64.3%
2014	95.5	98.9	61.6%	59.1%
2015	96.8	99.9	53.9%	51.7%

The LP-based portfolio is used in the rest of this analysis, however in future reports the EMCE-based portfolio will be the default.

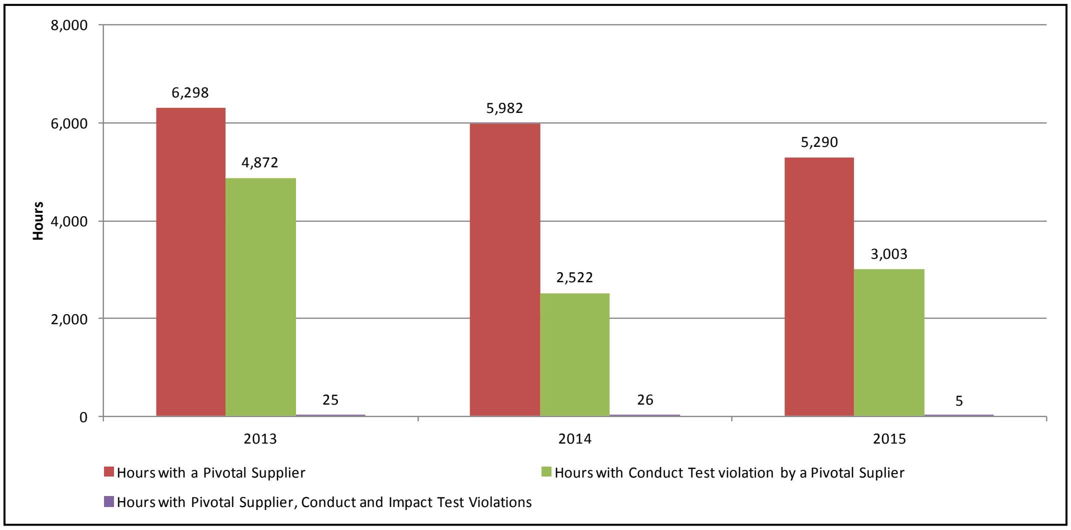
Pivotal Supplier Test in Energy Market Mitigation:

The real-time energy market mitigation process uses a pivotal supplier test to determine which supply portfolios, if any, have market power. The analysis below examines the link between the results of the pivotal supplier test and energy offer mitigation to better understand why, despite the presence of pivotal suppliers (at the system level) in a large number of hours, there were relatively few instances of energy market mitigation.

A conduct test is performed to determine whether the pivotal suppliers offered energy at prices high enough above competitive levels to violate the conduct thresholds. The conduct threshold for a pivotal supplier (at the system-level) is the lower of 300% or $100/MWh above the generator's reference level (see Section 8.5.1.) If the supply offers from pivotal suppliers violate the conduct test threshold, an additional test is performed to determine the extent these high-priced offers may impact the LMP. If the impact from the high-priced offers (compared with competitive offers) on the LMP is greater than the minimum of 200% or $100/MWh then the pivotal supplier's uncompetitive offers are mitigated.

Figure 8-7 shows, for the period 2013 through 2015, the number of hours with at least one pivotal supplier (the market structure test), the number of hours with at least one pivotal supplier's offer failing the conduct test and the number of hours with at least one pivotal supplier's offer failing both the conduct *and* impact tests. The latter condition resulted in the application of general threshold energy mitigation.

Figure 8-7: Hours with Pivotal Supplier, Conduct and Impact Test Violations



A pivotal supplier was identified in at least half of all the hours of the year. This result is consistent with those described RSI analysis above. There were less frequent instances when pivotal suppliers' offers failed the conduct test and relatively few hours when pivotal suppliers' offers failed both the conduct *and* impact tests, which when combined, resulted in very little mitigation.

As described above, the energy market mitigation pivotal supplier test relies on the supply margin to determine if a supplier is pivotal. The supply margin is calculated as the difference between the total of the maximum energy supply offers (economic maximum) from all available generating resources and net demand.[135] If the supply margin is less than the amount of total supply offers from a participant, then that participant is determined to be a pivotal supplier. Generating resources are considered available if they are in an on-line state or if they can come online in a 30-minute period. These resources are referred to as "fast start" resources.

In addition to the concerns identified above regarding the failure of the current pivotal supplier test to take account of participant affiliations and controlling interests, the energy market mitigation pivotal supplier test has several limitations:

- **Indifference to ramp constraints**: The current test ignores the speed at which available generating resources can increase their output when calculating the total available supply. A generating resource's speed is referred to as "ramping" ability, expressed in MW per minute. In order to meet rising load, the system needs sufficient generation to meet the *instantaneous* load as well as sufficient ramping capability to satisfy the *increasing* load. The ramping need is determined by the rate of change in system load. For instance, consider a situation in which 600 MWs of additional load is expected within a 30-minute period. The ramping need is 600 MW divided by 30 minutes or 20 MWs per minute. Also assume that the system has more than 1,000 MWs of generation available based on the total economic maximum of the online and fast start resources. However, if the available resources can ramp up no faster than 15 MWs per minute, then the system can only serve an additional 400 MWs of load within the

[135] Net demand is the system load plus reserve requirements (both 10-minutes and 30-minutes) minus net scheduled interchange.

30-minute period. Clearly, the available supply is only 400 MWs; not 1,000 MWs. By ignoring the ramp constraint, the pivotal supplier test *overestimates* the total available supply and potentially *underestimates* the number of pivotal suppliers. Further, ignoring ramping capability also results in an inaccurate accounting of the supply controlled by individual participants as it leads to over-counting of slow ramping units' generation - these generating units may not be able to reach their economic maximum in a 30-minute period.

- **Treatment of postured units**: From time to time, the ISO postures generating resources to create reserves.[136] The current pivotal supplier test ignores the reserves provided by postured resources. This *underestimates* the overall supply and the supply of individual participant whose units are being postured. This may result in *underestimating* the number of pivotal suppliers.

- **Identical treatment of load, 10-minute and 30-minute reserve requirement**: The current pivotal supplier test does not distinguish between the load, 10-minute and 30-minute reserve requirement. The test should account for the specific ramp requirements needed to satisfy load and reserves simultaneously. By simply summing across reserves and load, reserves are erroneously treated like load which has to be met instantaneously. Reserve requirements are over a predefined period of time. The demand for each product and characteristics of units (start-up time, ramp rates etc) which can meet that demand necessitates a more sophisticated accounting of load and reserves. Additionally, the pivotal supplier test completely ignores the regulation requirement.

Recommendation:

The pivotal supplier test used in mitigation should incorporate a ramp-based accounting of supply which mimics the co-optimized dispatch of energy and reserves. The ramp constraint for load can be derived by calculating change in load (based on the load forecast) between the time when pivotal supplier test is performed and the start of dispatch interval to which the results of the test apply. Once the change in load is calculated, it can be divided by the time difference in minutes to determine the ramp needed to meet system load. For instance, suppose the time of performing the test at 10:00 for the dispatch at 10:30 and the load increase in 30-minutes is 600 MW. Then the ramp needed to meet load is 20 MW/minute. Similarly, the ramp need imposed by 10 and 30-minute reserve requirements can be derived by dividing the requirement by the length of time associated with a reserve product. Also, the regulation requirement can be included with load. Finally, the pivotal supplier test should account for participant affiliations and reflect the actual controlling entity.

8.1.4 Lerner Index

The Lerner Index is a measure of the competitiveness of market outcomes, and conversely, the extent to which market power may have influenced price. The index estimates the level to which a supply offer is priced above marginal cost. Price is the principle means of coordinating short-run production and consumption decisions. When prices are distorted (as a result of

[136] Posturing a generating resource results in a portion of the resource's output being withheld from the energy market and therefore available towards satisfying the reserve requirement.

uncompetitive offers priced above marginal cost) short- and long-term resource-allocation decisions can also be impacted resulting in less efficient market outcomes.

In a perfectly competitive market, all market participants' offers would equal their marginal costs. The Lerner Index is used to estimate the divergence of the observed market outcomes from this ideal scenario.

To calculate the Lerner Index, the day-ahead market clearing was simulated using two scenarios:[137]

- Scenario 1 was an *offer case* that used the actual offers market participants submitted for the day-ahead energy market.
- Scenario 2 was a *marginal cost case* that assumed all market participants offered at an estimate of their short-run marginal cost.[138]

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

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

where:

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

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

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

For 2015, offers above marginal cost impacted the simulated day-ahead energy market price by approximately 9.8%. Therefore, the generation-weighted LMP in scenario 1 of the simulation (using actual offers) was 9.8% higher than the LMP from scenario 2 (using marginal cost). These results are consistent with previous years and within normal year-to-year system and modeling variability.[139] Table 8-2 shows the yearly results of the Lerner Index.

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[137] The IMM uses the PROBE, or "Portfolio Ownership and Bid Evaluation," simulation model for this analysis. The software simulates the day-ahead LMP-based market clearing. See http://www.power-gem.com/PROBE.htm.

[138] The marginal costs estimates are based on underlying variable cost data and generator heat rate parameters used in the calculation of reference levels. Where a good estimate of marginal cost does not exist (for virtual transactions for example) the marginal cost is set equal to the supply offer. Some differences between estimated and actual marginal costs are to be expected.

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

Table 8-2: Lerner Index for Day-Ahead Energy

Year	Lerner Index
2011	9.3
2012	9.9
2013	4.3
2014	9.0
2015	9.8

The results show that competition among suppliers in the day-ahead market limited their ability to inflate the LMP by submitting offers above their marginal cost.

8.2 Capacity Market Metrics

Two metrics are presented to evaluate the competitiveness of the Forward Capacity Market:

- Residual Supply Index (RSI)
- Pivotal Supplier Test (PST)

The former measures the percent of capacity remaining in the market after removing the largest supplier of capacity. The latter is a tariff-defined metric that attempts to incorporate demand conditions by examining whether a supplier's capacity is needed to meet the zonal capacity requirements.[140] Both metrics:

- respect system constraints such as capacity transfer limits
- take into account the affiliations between suppliers to accurately reflect all the capacity resources under the supplier's control
- consider only existing resources due to an inability to predict intra-auction new supply behavior.[141]

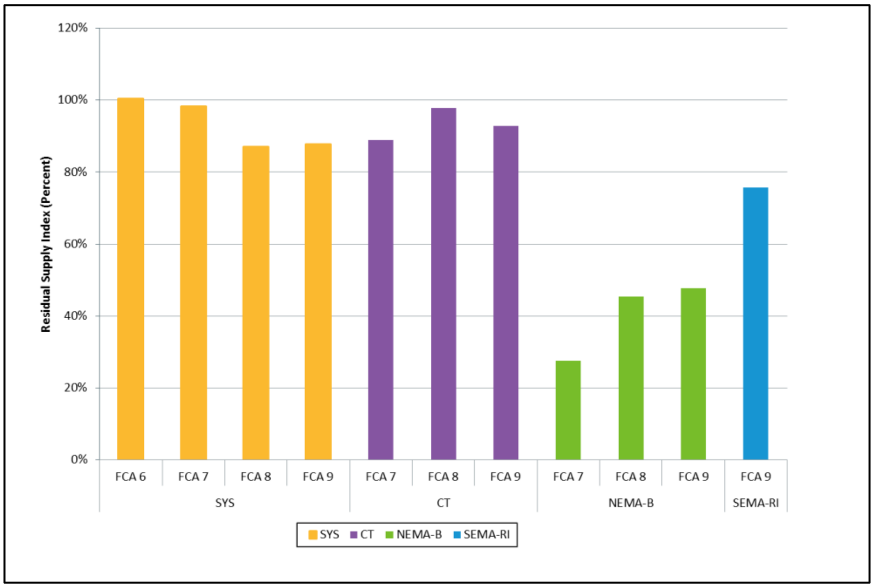
The RSI is measured on a continuous scale with a lowest possible value of 0 and an uncapped upper limit. When the RSI is greater than 100 percent, suppliers other than the largest supplier have enough existing capacity to meet the relevant capacity requirement, indicating that largest supplier should have little opportunity to profitably increase the market clearing price. Alternatively, if the RSI is less than 100 percent, the largest supplier is needed to meet demand and could, in principle, increase its offer prices above competitive levels to increase the market

[140] Section III.A.23 of the Tariff.

[141] As defined in Section III.A.23.4 of the Tariff, for the purposes of this test, "the FCA Qualified Capacity of a supplier includes the capacity of Existing Generating Capacity Resources, Existing Demand Resources, Existing Import Capacity Resources, and New Import Capacity Resources (other than (i) a New Import Capacity Resource that is backed by a single new External Resource and that is associated with an investment in transmission that increases New England's import capability; and (ii) a New Import Capacity Resource associated with an Elective Transmission Upgrade)."

clearing price. Figure 8-8 presents the RSI for the system and for each import-constrained zone over the past four FCAs.[142]

Figure 8-8: Capacity Market Residual Supply Index, by FCA and Zone



At the system level, only in FCA 6 at the system level did the RSI exceed 100%. The system-wide RSI has dipped in recent FCAs, falling over 10% between FCA 7 and 8 (the largest supplier also changed during this time interval). The RSI in the Connecticut capacity zone fluctuated between 89% and 98% during FCAs 7 and 9. While improving from an RSI of approximately 28% in FCA 7, the Northeast Massachusetts / Boston (NEMA-B) capacity zone had an RSI of approximately 48% in FCA 9, indicating that the capacity from the largest supplier in that zone accounted for more than half of the Local Sourcing Requirement (LSR). The RSI was approximately 76% in the Southeast Massachusetts / Rhode Island (SEMA-RI) capacity zone in FCA 9.

While the RSI uses a continuous measure and provides a sense of the largest supplier's ability to influence clearing prices, the PST is measured on a binary scale and provides an indication of the number of suppliers who may be able to influence prices. The PST is a portfolio-level test that is conducted at the system and import-constrained zone levels for each supplier. The PST compares 1) the total existing capacity in a zone without that supplier's portfolio of existing capacity with 2) the relevant capacity requirement for that zone.[143] If the former quantity is less than the latter quantity, the supplier is deemed a pivotal supplier and any delist bids it has submitted at prices above the dynamic delist bid threshold may be subject to mitigation.[144] This process ensures that suppliers do not withdraw capacity from the auction at uncompetitive

[142] The RSI measure in this section leverages the capacity counting rules outlined in the Tariff for the Pivotal Supplier Test. These are the most recent capacity counting rules for this purpose and were in effect beginning with FCA 10. They are used for prior auction periods for consistency.

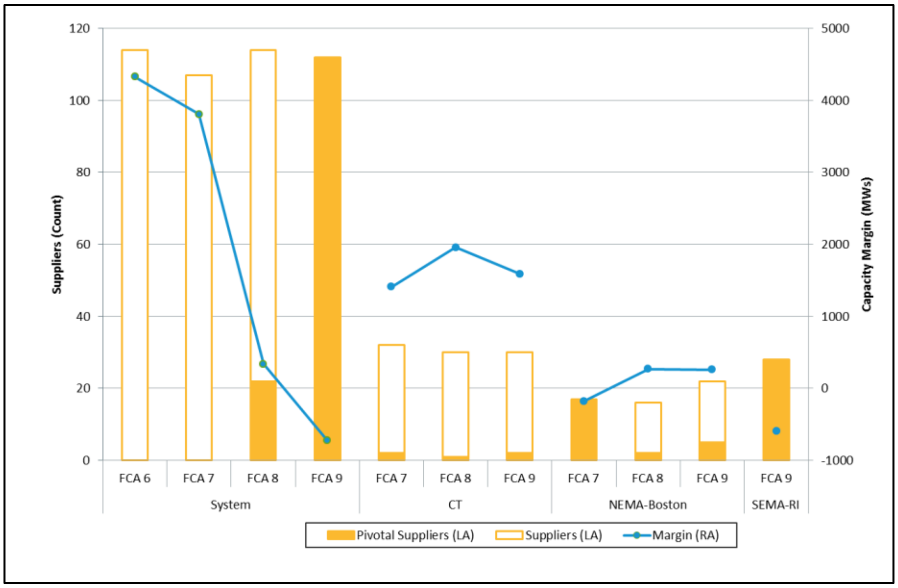
[143] The relevant requirements are the Installed Capacity Requirement (net of HQICCS) (ICR) at the system level and the Local Sourcing Requirement (LSR) at the import-constrained zonal level.

[144] Note that there are certain conditions under which capacity is treated as non-pivotal. These conditions are described in Section III.A.23.2 of the Tariff.

prices to raise the FCA clearing price in a way that may benefit the remainder of the supplier's portfolio.

Figure 8-9 presents the number of suppliers and pivotal suppliers within each zone over the past four FCAs. To provide additional insight into the approximate portfolio size needed to be pivotal, the figure also presents the margin by which the capacity exceeded or fell below the relevant capacity requirement.

Figure 8-9: Overview of Suppliers, Pivotal Supplier, and Capacity Margin, by Zone

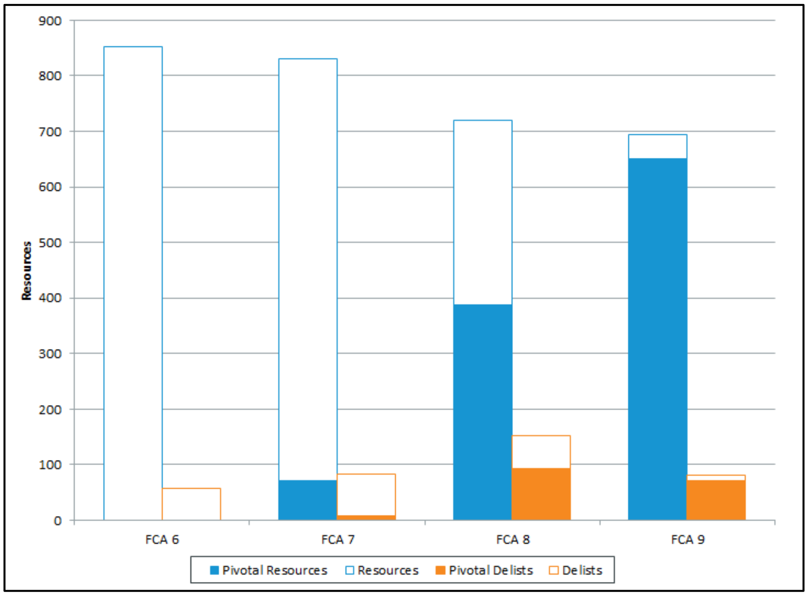


With the exception of the NEMA-Boston capacity zone, capacity levels exceeded requirements in FCAs 6 and 7; consequently, there were few, if any, pivotal suppliers outside of the NEMA-Boston zone in these auctions. At the system level, the capacity margin fell by over 90% between FCAs 7 and 8. There was insufficient new procurement in FCA 8 to counter this drop, which resulted in a negative capacity margin leading into FCA 9. The supply of existing capacity in FCA 9 could not meet the ICR, causing every supplier to be deemed pivotal. Conversely, the capacity margin increased to over 250 MWs in the NEMA-Boston capacity zone between FCAs 7 and 9. Meanwhile, the Connecticut capacity zone maintained a comfortable capacity margin of over 1400 MWs during the same time period. Lastly, all suppliers in the SEMA-RI capacity zone were pivotal in FCA 9 given the area's shortfall compared with the LSR.

While the PST is a portfolio-level test that results in supplier-specific pivotal status determinations, resources within a pivotal supplier's portfolio may still be non-pivotal. For instance, if the removal of a supplier's capacity at an external interface does not decrease the capacity over that interface because there is capacity in excess of that interface's capacity transfer limit, then those import resources will be deemed non-pivotal, as the supplier does not have the ability to exercise market power at that interface by removing those MWs.

While a pivotal designation may provide an indication of the ability to influence clearing prices, a delist bid is necessary to exercise it. Figure 8-10 presents an overview of the number of resources, pivotal resources, de-list bids, and pivotal resources with delist bids, for the last four FCAs.

Figure 8-10: Overview of Resources, Pivotal Resources, Delists, and Pivotal Delists



Consistent with the excess capacity shown in Figure 8-9, there were no pivotal resources in FCA 6 and very few pivotal resources in FCA 7. In addition, the proportion of pivotal resources with delist bids entering the FCA 7 auction (~8%) was consistent with the proportion of non-pivotal resources with delists entering the auction (~9%). While it is important to note that this analysis considers only delists that went to the auction, and not those that were withdrawn beforehand, this observation provides one indication that pivotal resources did not use delists to exercise market power for FCA 7. As system conditions tightened entering FCA 8, there was an increase of over 80% in the number of delist bids entering the auction over the prior auction. It is important to note that there were a number of market changes made at this time, including the removal of a price floor, which likely played a key role in this outcome. Lastly, as a function of the tightening capacity margin, both the number and proportion of pivotal resources increased between FCAs 8 and 9.

8.3 Forward Reserve Market

The RSI was calculated for the Forward Reserve Market (FRM) to determine whether a competitive level of supply was offered into this market. As background, the FRM procures operating reserve capacity from market participants with resources that can provide reserves, including 10-minute non-spinning reserve (TMNSR) and 30-minute operating reserve (TMOR). Reserves are procured through auctions held twice a year for both system-wide and local needs.

RSI on a System-wide Basis:

The RSI is calculated based on both FRM offers and observed real-time reserve capability. The offer-based RSI measures the percentage of the forward reserve requirement that can be met without the largest FRM portfolio offer. The offer RSI for TMNSR is computed at a system-level based on the total quantity of TMNSR offers across all reserve zones, excluding the largest TMNSR offer quantity by a single market participant. The offer-based RSI for TMOR is computed similarly for each reserve zone with a non-zero TMOR Local Reserve Requirement.[145] 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. Table 8-3 shows the offer RSI for TMNSR at a system level and TMOR for zones with a non-zero TMOR requirement.

Table 8-3: FRM Offer RSI for TMNSR (system-wide) and TMOR (zones)

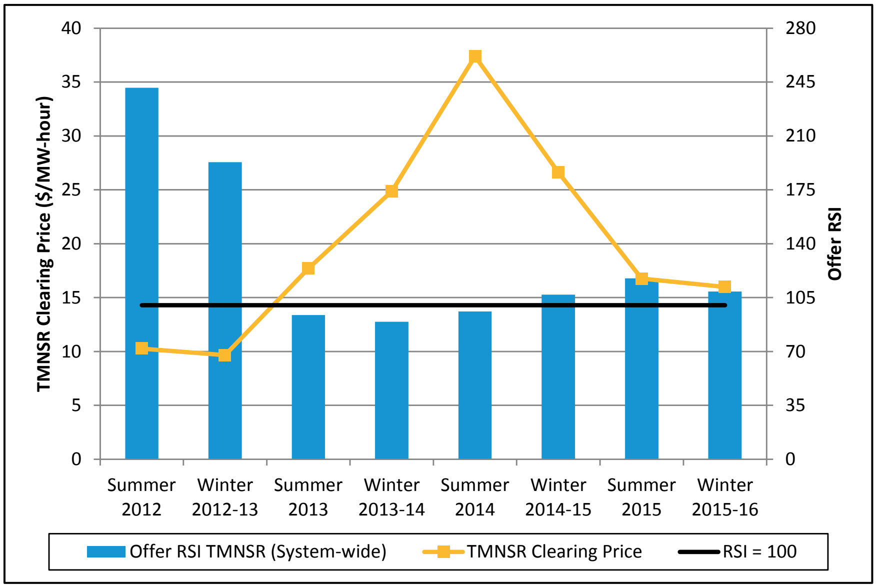
Procurement Period	Offer RSI TMNSR (System-wide)	Offer RSI TMOR (ROS)	Offer RSI TMOR (SWCT)	Offer RSI TMOR (CT)	Offer RSI TMOR (NEMA)
Summer 2012	241	189	N/A	114	N/A
Winter 2012-13	193	132	244	134	N/A
Summer 2013	**94**	138	N/A	**99**	N/A
Winter 2013-14	**89**	136	**58**	123	N/A
Summer 2014	**96**	124	**85**	**87**	N/A
Winter 2014-15	107	186	**84**	215	N/A
Summer 2015	117	158	**69**	122	**12**
Winter 2014-16	109	154	283	382	N/A

A RSI value less than 100 (shown in red) implies there was at least one pivotal supplier and the auction was not structurally competitive. Pivotal suppliers may be able to strategically offer reserves at uncompetitive prices. Table 8-3 shows that there were pivotal suppliers in 3 out of the 7 FRM auctions for TMNSR. There were also pivotal suppliers in 5 out of the 7 auctions in at least one zone. The Southwest Connecticut (SWCT) zone had an RSI less than 100 for four consecutive auctions. The lowest RSI value of 12 was observed in NEMA/Boston in the Summer 2015 auction.

Figure 8-11 shows the relationship between offer RSI and TMNSR clearing prices.

[145] The TMOR requirement for a zone is the maximum of the difference between the Local 2nd Contingency MW minus the External Reserve Support MW and zero.

Figure 8-11: TMNSR Offer RSI and the TMNSR Clearing Price



Notably, the auctions with pivotal suppliers (Summer 2013, Winter 2013-14, and Summer 2014) had the highest clearing prices. The high clearing price in the Summer 2014 FRM auction corresponds with the change in the penalty calculation for the FRM that went into effect at this time. However, the clearing price was high in the two auctions before the change in penalty rate during periods of low RSI, which indicates low or uncompetitive supply.

The RSI values for TMOR and TMNSR are also computed based on the observed TMNSR and TMOR reserve capability available in Real-Time. The availability-based RSI measures the degree of structural competitiveness if all the reserve capable generation quantity is offered in the FRM. Table 8-4 shows the RSI results for reserve capability, systemwide and zonal, for the summer and winter periods, 2012 to 2015.

Table 8-4: RSI based on the Observed Real-Time Available TMNSR (system-wide) and TMOR (zones)

Procurement Period	RSI: Observed Real-Time Available TMNSR (System-wide)	RSI: Observed Real-Time Available TMOR (ROS)	RSI: Observed Real-Time Available TMOR (SWCT)	RSI: Real-Time Available TMOR (CT)	RSI: Real-Time Available TMOR (NEMA)
Summer 2012	242	646	N/A	107	N/A
Winter 2012-13	158	484	1,988	100	N/A
Summer 2013	155	684	N/A	**92**	N/A
Winter 2013-14	138	397	733	134	N/A
Summer 2014	173	351	1,149	**83**	N/A
Winter 2014-15	254	522	1,366	229	N/A
Summer 2015	151	481	764	106	32

If all the available reserve capability was offered in the FRM, there would not have been a pivotal supplier in any of the auctions for TMNSR and the auctions would have been structurally competitive. The same would have been true in the case of TMOR for the SWCT zone. Generally, comparisons between RSI values based on FRM offers and the estimated amount of available reserves suggests that the FRM auction would have had been structurally competitive if all the available reserve capability was offered into the FRM auction.

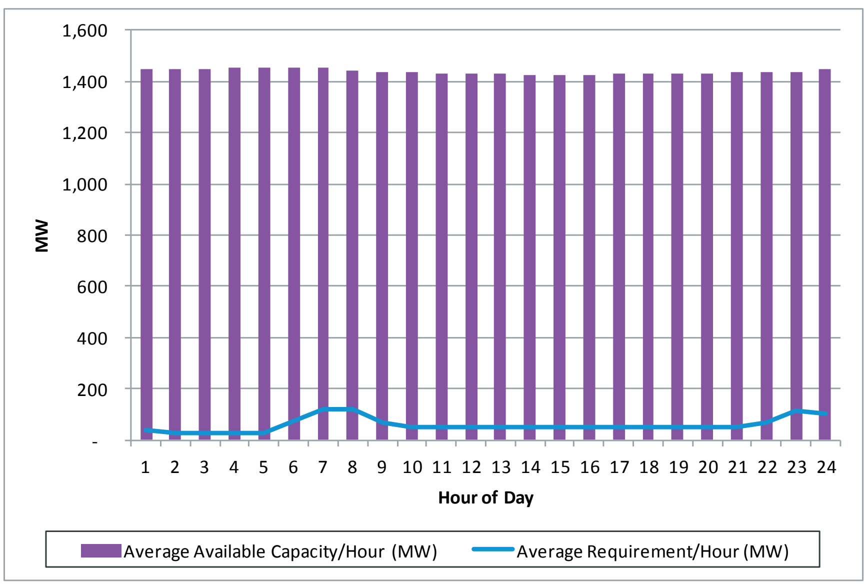
Additional analysis of the competitiveness of offer prices and resulting auction clearing prices is required to determine if the presence of pivotal suppliers has resulted in uncompetitive prices. As a result, no recommendation regarding additional market power mitigation measures is offered at this time.

8.4 Regulation

The competitiveness of the regulation market was reviewed by examining market structure and resource abundance. The abundance of regulation resources, and relatively unconcentrated control of that supply, implies that market participants have little opportunity to engage in economic or physical withholding. The regulation market was competitive in 2015.

Figure 8-12 below simply plots the regulation requirement relative to available supply.

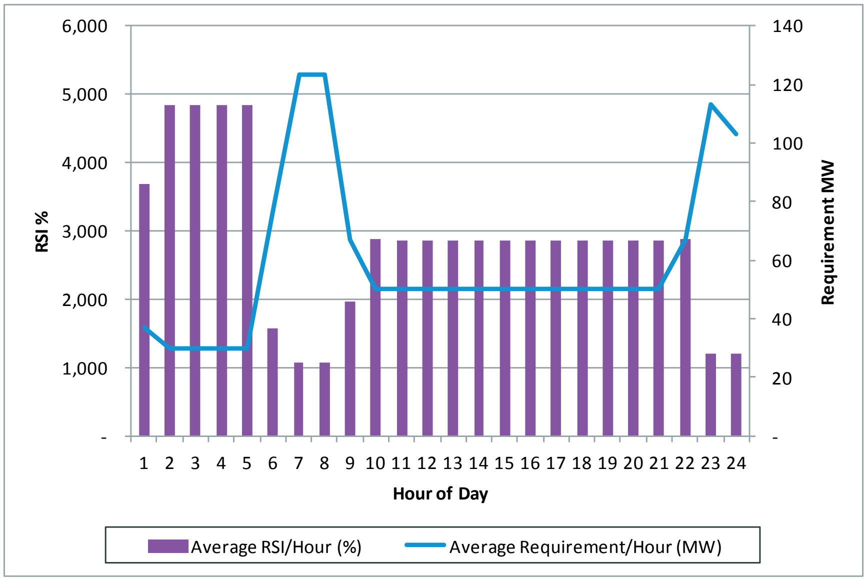
Figure 8-12: Regulation Market Average Requirement and Available Capacity, 2015



On average, during every hour of the day, available supply far exceeds the regulation requirements. However, an available abundance of supply alone is not a dispositive indicator of market competitiveness, as one -- or a small number of suppliers -- could control the available supply and seek to exercise market power.

The RSI provides a better indicator of the structural competitiveness of the regulation market. It measures available supply relative to need, after removing the largest regulation supplier in the market. As shown in Figure 8-13, the regulation requirement and RSI are inversely correlated (the lower the requirement the higher the RSI).

Figure 8-13: Average Regulation Requirement and Residual Supplier Index



In 2015, the lowest hourly average RSI did not fall below 1,000%, implying that, on average, the system has the capability to serve 10 times the regulation requirement without the largest regulation supplier, even in the hours with the greatest regulation requirement.

The average available regulation supply per hour, in terms of the number of market participants in the market, provides additional evidence to suggest that the regulation market is structurally competitive.[146] Table 8-5 below indicates several measures of participation in the regulation market.

Table 8-5: market participants Active in Regulation Market, 2015

Hour of Day	Number of market participants with Supply > Requirement	Number of market participants with Supply < Requirement (i.e., Small Participants)	Small Participant Supply (MW)	Average Requirement (MW)
1	13	9	181	37
2	15	7	110	30
3	15	7	110	30
4	15	7	110	30
5	15	7	110	30
6	6	16	572	76
7	4	18	787	123
8	4	18	775	123
9	7	15	492	67
10	9	13	370	50
11	9	13	369	50
12	9	13	368	50

[146] For this summary, "participant" refers to "lead participant."

Hour of Day	Number of market participants with Supply > Requirement	Number of market participants with Supply < Requirement (i.e., Small Participants)	Small Participant Supply (MW)	Average Requirement (MW)
13	9	13	368	50
14	9	13	367	50
15	9	13	367	50
16	9	13	367	50
17	9	13	368	50
18	9	13	368	50
19	9	13	369	50
20	9	13	369	50
21	9	13	370	50
22	7	15	492	67
23	4	18	775	113
24	6	16	568	103

The table shows that on average in hour one of the day, 13 market participants could supply more than the total requirement and the remaining nine market participants combined could supply 4.9 times the average requirement (181 MW/37 MW). While competitive conditions, along with changes in the regulation requirement, can vary from day-to-day throughout the year because of load variability and supply uncertainty, capacity available for regulation far exceeded the requirement, and participation levels in the market suggest limited structural opportunities for the exercise of market power.

8.5 Energy Market Mitigation

Mitigation rules, systems and procedures are in place to mitigate the impact of uncompetitive generator behavior in the day-ahead and real-time energy markets. Specifically, the mitigation rules are designed to prevent prices from being set above competitive levels. Mitigation serves an important purpose of ensuring economic price formation, free from the potentially harmful effects of the exercise of market power.[147] Mitigation is accomplished by replacing a market participant's uncompetitive supply offer with a competitive benchmark price, known as a reference level, when a market participant's supply offer fails certain mitigation tests.

This section provides an overview of the various mitigation tests and presents statistics on the number and types of mitigations that have occurred since the implementation of automated mitigation during the second quarter of 2012.

8.5.1 Mitigation Types

Mitigation is implemented through an automated process in the ISO market systems and involves the application of up to three tests, depending on the type of mitigation. Those tests are generally categorized as structure, conduct, and impact:

[147] The ability of a firm (or group of firms) to raise and maintain price above the level that would prevail under competition is referred to as market or monopoly power. The exercise of market power leads to reduced output and loss of economic welfare. Source: Organization for Economic Co-operation and Development (OECD).

- *Market Structure Test* evaluates the *structure* of the competition the market participant faces and whether it has market power.

- *Conduct Test* evaluates if the market participant's offer is above competitive levels.

- *Market Impact Test* assesses the *impact* the market participant's supply offer has on market outcomes.

A market participant's generator fails the *market structure test* and is deemed to have market power if under one of the following conditions:

- it is part of a *pivotal supplier's* portfolio. A generator belongs to a pivotal supplier if, at a system-wide level, the market participant's total available generation capacity is required to meet load and reserve requirements.

- it is in an *import-constrained area* of the system and is required to meet local demand. In this scenario there is the presence of local, rather than system-wide, market power.

- it is required to meet a specific *reliability* need such as local first or second contingency support or voltage support. In this scenario it is the "only store in town" that can meet a need.

A market participant's generator fails the *conduct test* if the supply offer exceeds the reference level by a given threshold. This is done by comparing the market participant's supply offer to its reference level. Its reference level is calculated by the IMM in consultation with the market participant and is designed to reflect a competitive offer.[148] The size of the conduct test threshold is different for each of the market structure tests discussed above. The thresholds become progressively larger as the frequency of the market structural test's triggering decreases, beginning with reliability, followed by the constrained area test and then the pivotal supplier test.

A market participant's generator fails the *impact test* if its uncompetitive offer increases the LMP by defined thresholds. The impact test applies to two energy mitigation types as explained below.

A market participant must fail all applicable tests in order for its supply offer to be mitigated. Mitigation results in all components of the three-part supply offer (start-up, no-load and energy) being replaced by the corresponding components of the reference level. Mitigation is imposed until market power no longer exists.

Table 8-6 below provides a general overview of the types of mitigation and the various tests applied. It shows the eight different mitigation types and, for each type, the corresponding structure test, the conduct test and impact test. Where a test does not apply to a particular mitigation type it is shown as "n/a".

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[148] There are a number of methodologies prescribed in the rules for calculating a generator's reference level, with the highest value of the methodologies generally been used. The reference level can be based on a calculation of the marginal cost of generating electricity, on the basis of historical competitive supply offers or using historical LMPs at the generator node.

Table 8-6: Overview of Energy Market Mitigation Tests

Mitigation Type	Market Structure Test	Conduct Test Thresholds *fails if Supply Offer exceeds Reference Level (RL) by:*	Market Impact Test *fails if LMP is increased by more than:*
General Threshold Energy (RTM only)	**Pivotal Supplier**	minimum of \$100/MWh and 300%	minimum of \$100/MWh and 200%
General Threshold Commitment (RTM only)		200%	n/a
Constrained Area Energy	**Constrained Area**	minimum of \$25/MWh and 50%	minimum of \$25/MWh and 50%
Constrained Area Commitment (RTM only)		25%	n/a
Reliability Commitment	**Reliability**	10%	n/a
Start-Up and No-Load Fee	**n/a**	200%	n/a
Manual Dispatch Energy		10%	n/a

Dual-fuel generators are also subject to an additional form of mitigation (referred to as "dual fuel resource" mitigation below). The market participant's offer can be mitigated when its reference level is calculated on the basis of the price of the higher cost fuel (e.g. oil), when in fact the generator burns the lower-cost fuel (e.g. gas). Mitigation is applied after the operating day and impacts the NCPC payments of the generator.

Most mitigation types apply to both the day-ahead and real-time energy markets, but several apply to the real-time market only (indicated as "RTM only" in the table above). Generally, energy market mitigations include the application of the three tests (structure, conduct and impact) while only two tests apply to commitment mitigation (structure and conduct).

The conduct tests for energy and commitment mitigations differ in terms of the elements of the three-part supply offer being tested. Energy mitigation conduct tests compare the energy price segments of the supply offer with the corresponding components of the reference level. Commitment mitigation conduct tests compare the commitment costs of the supply offer with the commitment costs of the reference level. The commitment costs, also known as the low load cost, include generator start-up and no-load costs, and the cost of operating at an economic minimum level over the duration of a commitment.

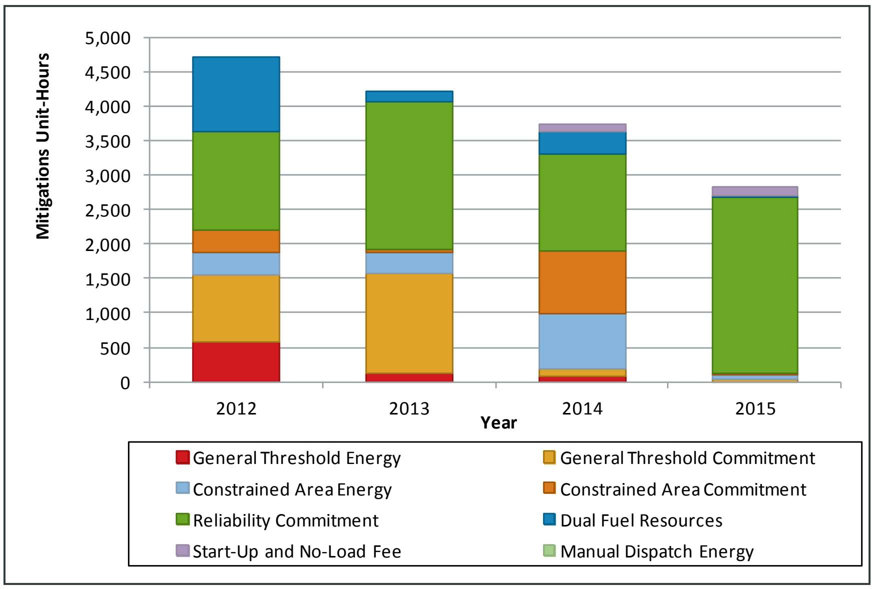
Further details on the energy market mitigation rules can be found in Appendix A of Market Rule 1 of the Tariff.

8.5.2 Mitigation Event Hours

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

Over the 2015 period, the total amount of mitigations declined relative to prior years. There were 2,838 unit-hours when one of the mitigation types presented in Table 8-6 above was applied. This is 24% lower than the 3,752 total unit-hours of mitigation during 2014. For context, during 2015 supply offers were submitted for 337 generators over 8,760 hours during the year; this amounted to approximately 2.9 million unit-hours tested for mitigation. The 2,838 unit-hours of mitigation amount to roughly 0.1% of tested unit-hours (*i.e.*, 2,838 mitigated unit-hours / 2.9 million tested unit-hours). A similar, alternate perspective: on average during 2015, less than one generator supply offer was mitigated each hour (*i.e.*, 2,838 mitigated unit-hours / 8,760 hours = 0.3 mitigated units per hour). Figure 8-14 below presents the annual mitigation tallies by mitigation type for each calendar year 2012 – 2015.

Figure 8-14: Mitigation events by annual period[149]



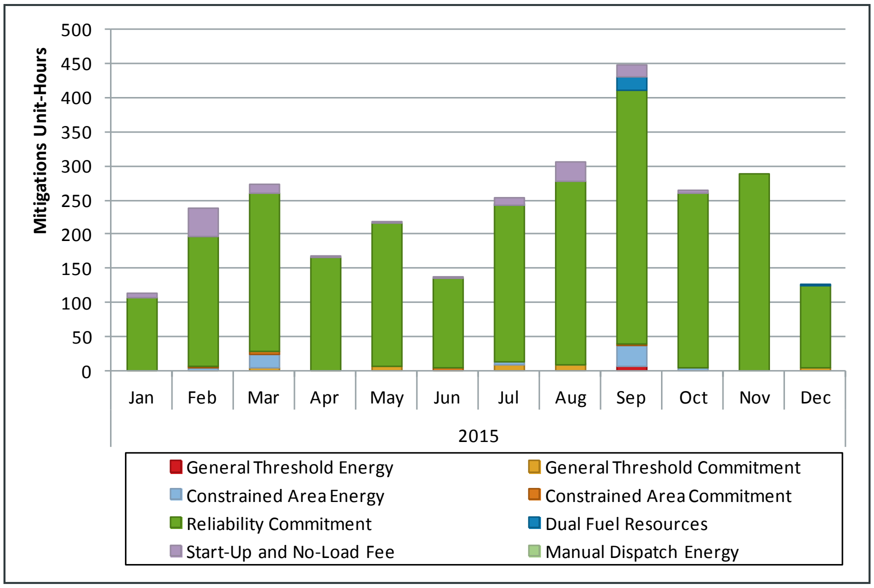
As shown in Figure 8-14, the frequency of mitigation continued to decline during 2015. Constrained area and dual fuel resource mitigation types all decreased in 2015. As a category, reliability commitment mitigations increased and were the predominant mitigation type applied during 2015, contributing 90% of the observations (2,567 of 2,838 total unit-hours) during the year. The larger number of constrained area mitigations during 2014 was largely attributable to high natural gas costs during the first quarter of 2014, which made the applicable mitigation thresholds relatively tight. Average gas prices during the first quarter of 2015 were roughly half the 2014 average price (see Section 2.2.3).

The decline in dual fuel resource mitigations is consistent with expectations for the Energy Market Offer Flexibility (EMOF) changes implemented in December 2014. Under the EMOF rules, supply offers can be modified hourly to reflect a generator's use of alternate fuels within a single operating day. The increase in reliability commitment mitigations is also consistent with the EMOF-related changes which expanded the application of reliability commitment mitigation to additional commitment events. Reliability commitment mitigation can also occur when a generator remains online beyond the end time of its scheduled commitment.

[149] Data for 2012 is for the period beginning April 19, 2012 when automated mitigation was implemented.

Figure 8-15 below shows the monthly totals of mitigation events (unit-hours) during 2015. Variation over the course of the year is expected as market and system conditions change.

Figure 8-15: Mitigation events by month



As Figure 8-15 shows, the number of mitigation events per month was fairly consistent throughout 2015. The slightly higher frequencies of reliability commitment mitigation in March and September-November are consistent with the higher levels of supplemental reliability commitments during these periods (see Section 3.4.8).

8.5.3 Mitigation Breakdown

This section is intended to provide some additional context regarding the energy market offer mitigations that occurred during 2015. To do this, the mitigation occurrences are classified by dimensions which illustrate certain operational attributes of the generators which had their submitted offers mitigated and their location within New England.

First, as a measure of dispersion we observe that five lead market participant companies were associated with 52% of energy market mitigations (unit-hours) during 2015. There were a total of 40 lead market participant companies which had a mitigated generator offer during 2015. The five most-frequently mitigated generators accounted for 22% of mitigations (unit-hours) among a total of 123 generating units with one or more hours of offer mitigation during the year.

Next, the occurrences of mitigations are classified by operational characteristics of the generators to which mitigation was applied during 2015. Figure 8-16 below classifies the mitigations by prime mover (or technology type). Figure 8-17 classifies mitigation events by registered primary fuel type, which may differ from the fuel type the market participant submitted on its supply offer at the time when mitigation was applied.

Figure 8-16
Mitigation events by prime mover (2015)

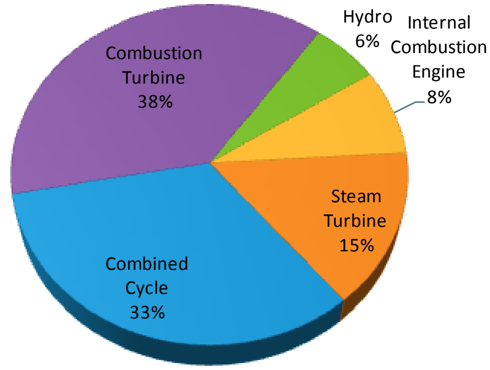
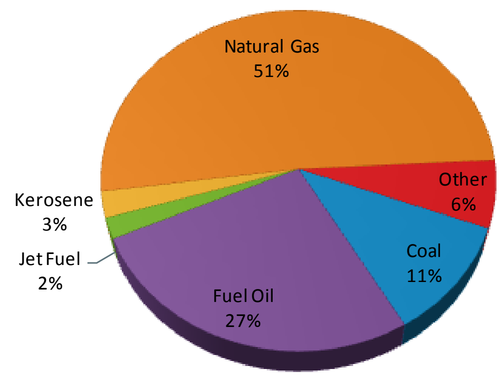


Figure 8-17
Mitigation events by primary fuel (2015)

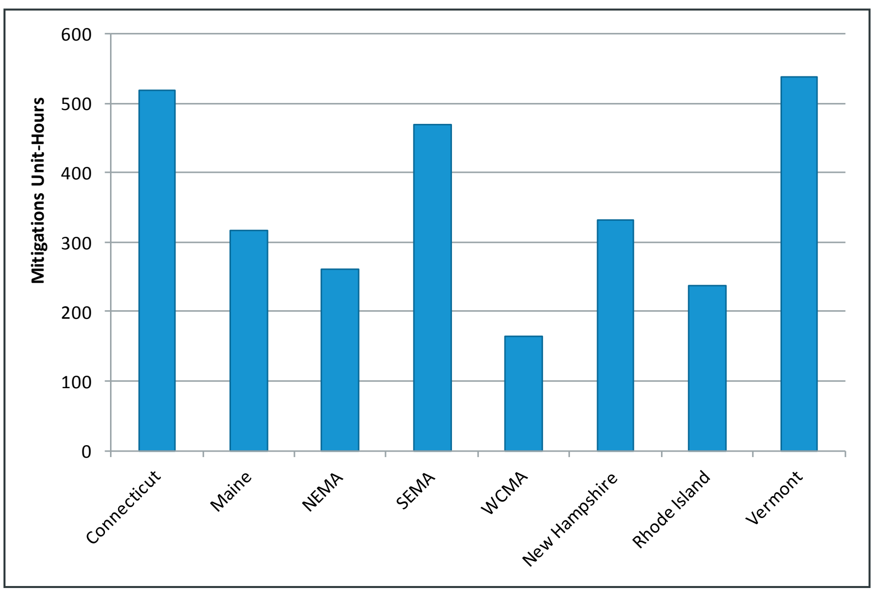


Note: The category "other" consists of resources with a primary fuel type of municipal waste, water, and wood.

As shown in Figure 8-16 above, the region's combustion turbine and combined cycle generating units account for over two-thirds of mitigation events. Figure 8-17 illustrates that generators that primarily use natural gas account for about one half (51%) of offer mitigations, while fuel oil units account for about one quarter (27%) of mitigations.

Finally, to illustrate the geographical concentration of mitigation events across the New England system the unit-hour counts are presented by the load zone corresponding the generator's location. As illustrated in Figure 8-18 below, there is no significant concentration observed in any load zone.

Figure 8-18: Mitigation events by load zone (2015)



The distribution by load zones shown in Figure 8-18 does not show significant concentration in a particular area of the system. When all Massachusetts load zones (NEMA, SEMA, and WCMA) are combined, generators located within Massachusetts account for 32% of mitigations, Connecticut accounts for 18%, Vermont about 19%, and the remaining 31% are distributed among Maine, New Hampshire, and Rhode Island.

8.5.4 Mitigation and LFRM Resources

In 2015, the IMM changed its practice for granting exemptions from energy market mitigations to resources meeting forward reserve obligations. A memo was issued in July 2015 describing concerns that granting exemptions to forward reserve resources created the potential for certain market participants to exercise market power.[150]

The concern was based on the criteria used to exempt forward reserve resources from energy market mitigation. Market participants can assign multiple resources to support their forward reserve obligation. In addition, market participants can assign additional resources in excess of their obligation. If the assigned resources are exempted in their entirety from energy market mitigation, the market participant can have a significant portion of their portfolio exempted from energy market mitigation, even though only a portion of the portfolio is effectively meeting the market participant's forward reserve obligation. This potential raises significant market power concerns.

Mitigation practices were updated in August 2015 to implement more stringent criteria for mitigation exemptions.[151] This limited exemption from mitigation was for the Winter 2015-16 Forward Reserve Procurement Period.

Alternative approaches will be evaluate to address the market power concerns raised in the July 28, 2015 memorandum, including the feasibility of modifying the existing automated mitigation systems to accommodate exempting, when appropriate, all or a portion of a forward reserve resource's energy supply offer.

8.6 Capacity Market Mitigation

The Forward Capacity Market (FCM) is monitored for two forms of market power; supplier-side and buyer-side.

Supplier-Side Market Power:

A market participant attempting to exercise supplier-side market power will try to economically withhold capacity (de-list) during the forward capacity auction – for a single year or permanently - in an effort to *increase* the clearing price above a competitive level. An inflated clearing price can benefit the remaining resources in the market participant's portfolio, as well as the portfolios of other suppliers. A market participant would only attempt this if they believed (1) their actions would inflate the clearing price and (2) the revenue gain from their remaining portfolio would more than offset the revenue loss from their de-listed resource. For this reason, de-list bids from market participants are evaluated to ensure the market participants' de-list bid are competitively priced. A competitive de-list bid is consistent with the market participant's net going forward costs, expected capacity performance payments, risk premium and opportunity cost. If it is determined that a de-list bid is uncompetitive and the

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[150] See *Monitoring of Forward Reserve Resources*, IMM Memo to the NEPOOL Markets Committee, July 28, 2015, http://www.iso-ne.com/static-assets/documents/2015/07/20150728_mitigation_frm_resources_final.pdf.

[151] See *Monitoring of Forward Reserve Resources – Update*, IMM Memo to the NEPOOL Markets Committee, August 27, 2015, http://www.iso-ne.com/static-assets/documents/2015/08/mitigation_frm_resources_08_27_2015.pdf .

supplier is pivotal, the de-list bid is mitigated (reduced) to a price that is competitive; consistent with the market participants' net going forward costs, expected capacity performance payments, risk premium and opportunity cost

For FCAs 8, 9 and 10, the IMM reviewed over 200 static de-list bids from a variety of market participants with generation and demand resources. Static delist bids are submitted for a resource at the existing capacity qualification deadline, which occurs approximately eight months before the FCA. Static de-list bids are a tool for resources opting to remove all or part of their total capacity from the market for a single commitment period at a price greater than or equal to the Dynamic De-List Threshold (DDT) price. The DDT is described in more detail below.

For generation resources, the static de-list bids for the past three auctions totaled nearly 16,000 MWs.[152] The IMM applied mitigation to approximately 63% of the static de-list bids it reviewed, which represents approximately 69% of the de-listed capacity (MW). For demand resources, which consist of many smaller resources, the static de-list bids for the past three auctions totaled slightly less than 1,200 MWs. The IMM applied mitigation to approximately 54% of the reviewed demand resource static de-list bids, which represented approximately 48% of the de-listed capacity (MW).

The degree of mitigation can be measured by the relative reduction in the static de-list bid price imposed by the IMM. For generation resources, the weighted-average reduction to the mitigated static de-list bids was $1.73/kW-month. For demand resources, the weighted-average reduction was slightly higher; $1.95/kW-month. The combined effect of the supplier-side mitigations is a shifting of a portion of the auction's supply curve down. Consequently, the mitigations prevent an uncompetitive static de-list bid from setting the auction clearing price.

After the IMM reviews the market participants' static de-list bid and makes its determination to apply mitigation or accept the market participants' submitted price, market participants can choose several options prior to the auction.

- Market participants can withdraw the static de-list bid, in which case their resource remains in the auction as an existing resource and accepts the clearing price. Market participants with generation resources withdrew 54% of the static delist-bids that were mitigated, as compared with a 38% withdrawal rate of static de-list bids that were not mitigated. There were very few withdrawals of demand resources prior to the auction.
- Market participants can reduce the static de-list bid price below the IMM's mitigated price or their originally submitted price. Market participants with generation resources further reduced the price of mitigated static de-list bids by a weighted average of $0.59/kW-month. The resulting final weighted-average price for these mitigated resources was $2.12/kW-month less than the market participant's originally submitted price. By comparison, market participants whose static de-list bids were *not* mitigated reduced their final prices, relative to their originally submitted price, by a weighted average of $1.14/kW-month. There were very few price reductions for demand resources.

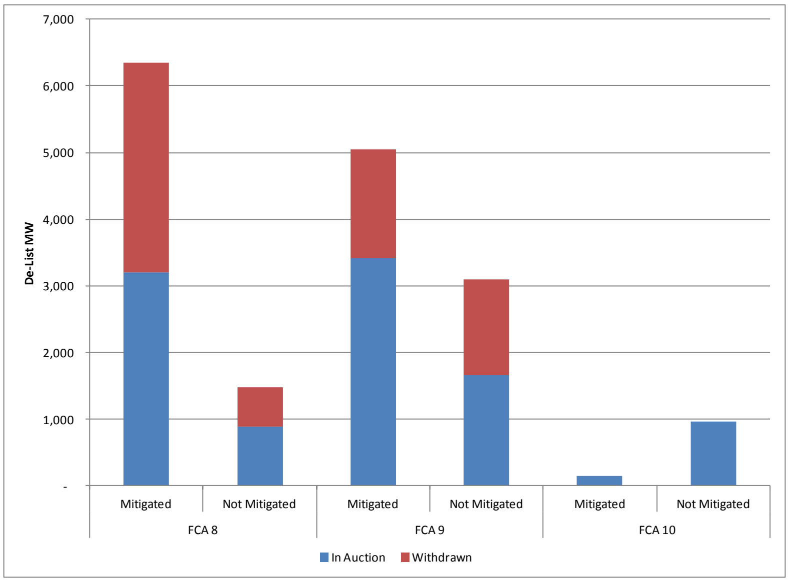
Static delist bids, export delist bids, and permanent delist bids priced below the DDT are presumed to be competitive and are not subject to the IMM's cost review or mitigation. Market

[152] A resource with a static de-list bid in each of the three auctions would be counted three times in the MW total.

participants can dynamically de-list resources if the auction price falls below the DDT price. The DDT has undergone a number of revisions since the start of the FCM. The DDT price was $1.00, $3.94 and $5.50/kW-month for FCAs 8, 9 and 10, respectively.

See Figure 8-19 shows a breakdown of static-delist bids from FCA 8 to FCA 10 based on mitigation status and auction status (i.e., participated in the auction vs. withdrawn prior to auction).

Figure 8-19: Static Delist Bids In Auction and Withdrawn



Permanent delist bids represent a binding request to remove the resource's capacity from the capacity market permanently at a certain price. Capacity associated with a permanent delist bid may only reenter the capacity market if they qualify for, and clear, as a new resource in a subsequent FCA. Permanent delist bids are submitted for a resource before the existing capacity qualification deadline. There were no permanent delist bids submitted for FCA 8, 9 or 10.

Export delist bids are bids to exit the New England capacity market and sell capacity to a neighboring area. The cost of an export delist bid may include an opportunity-cost component of selling capacity to a neighboring market.

Administrative export delist bids are submitted for capacity exports associated with multiyear contracts and are initiated using the same requirements as export delist bids. There were 100 MW of accepted administrative export delist bids in FCA 8 through FCA 10.

Non-price retirement requests, which are irrevocable requests to retire all or a portion of a resource, supersede any other delist bids submitted. Non-price retirement requests are subject to a review for reliability impacts. If the ISO notifies a resource owner of a reliability need for the resource, the resource owner has the option to retire the resource as requested or continue to operate until the reliability need has been met. Once the reliability need has been met, the resource must retire.

Table 8-7 shows generating resources over 50 MW that have retired for FCA 8 through FCA 10.

Table 8-7: Generating Resource Retirements over 50 MW by FCA

Resource Name	Effective Capacity Period[153]	CSO MW
Mt. Tom	FCA 8	144
Norwalk Harbor 1	FCA 8	162
Norwalk Harbor 2	FCA 8	168
Brayton Point 1	FCA 8	228
Brayton Point 2	FCA 8	226
Brayton Point 3	FCA 8	610
Brayton Point 4	FCA 8	422
Cape Wind Offshore	FCA 8	74
Pilgrim Nuclear Station	FCA 10	677

Buyer-Side Market Power:

A market participant attempting to exercise buyer-side market power will try to uneconomically offer capacity below cost in an effort to *decrease* the clearing price. A depressed clearing price benefits capacity buyers, not necessarily capacity suppliers. A supplier would only attempt to depress clearing prices if it received another source of revenue to reimburse the supplier for the reduced capacity revenues. For this reason, new supply offers are evaluated from market participants that want to enter the capacity market at prices below pre-determined competitive threshold prices or Offer Review Trigger Prices (ORTP). Market participants that want to offer below the relevant ORTP must submit detailed financial information to the IMM about their proposed project. The financial information is reviewed for out-of-market revenues or other payments that would allow the market participant to offer capacity below cost.[154] If any are present, the market participant's uncompetitive offer is mitigated. The out-of-market revenues are either replaced with market based revenues or removed entirely and the offer is recalculated to a higher competitive price.

For FCAs 8, 9 and 10, the IMM reviewed over 200 new supply offers from a variety of market participants with generation, demand resources and imports. Offers from import resources were reviewed starting with FCA 9. For generation resources, new supply offers for the past three auctions totaled over 9,000 MWs.[155] The IMM applied mitigation to approximately 40% of new supply offers it reviewed, which also represented approximately 40% of the new generation capacity (MW). For demand resources, the new supply offers for the past three auctions totaled less than 400 MWs. The IMM applied mitigation to approximately 16% of the new supply offers from demand resource it reviewed, which represented approximately 22% of the new demand resource capacity.

[153] The Capacity period defined here is the FCA where the CSO MW was zero. The resource may or may not have retired or shed all obligations at this time.

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

[155] A resource with a new supply offer in each of the three auctions would be counted three times in the MW total.

Similar to supplier-side mitigation, the degree of buyer-side mitigation can be measured by the relative increase in the new supply offer imposed by the IMM. For generation resources, the weighted-average increase to the mitigated new supply offers was $1.62/kW-month. For demand resources, the weighted-average increase to the mitigated new supply offer was almost identical; $1.61/kW-month. The combined effect of the buyer-side mitigations is a shifting of a portion of the auction's supply curve up. Consequently, the mitigations prevent an uncompetitive new supply offer from setting the auction clearing price.

Market participants can withdraw a new supply offer prior to the auction. Market participants with generation resources withdrew 25% of the new supply offers that were mitigated, as compared with a 50% withdrawal rate of new supply offers that were not mitigated. The weighted-average increase to the mitigated new supply offers that withdrew prior to the auction was $2.09/kW-month, about 35% higher than the $1.54/kW-month weighted-average increase to mitigated new supply offers that participated in the auction. There were very few withdrawals of new supply offers from demand resources.

8.7 Capacity Market Mitigation Changes

Market Monitoring-Related Capacity Market Changes. In its June 30, 2015 order, FERC accepted changes to the dynamic delist bid threshold, pivotal supplier tests, and new import capacity resources rules, all of which relate to the potential for the exercise of market power in the FCM.[156] These changes were in effect for FCA 10, which was conducted in February 2016.

Dynamic delist bid threshold. In the FCM, two types of delist bids enable a resource to leave the capacity market for a single capacity commitment period. Resources that wish to leave the market at prices equal to or above the dynamic delist bid threshold must submit static delist bids in advance of the FCA for review. If resources wish to leave the market at prices below the dynamic delist bid threshold price, they may submit a dynamic delist bid during the FCA without an IMM review of their cost information.

The Dynamic De-List Bid Threshold is intended to establish a price threshold below which mitigation for market power is likely to be redundant. The approach taken for FCA 9 established this threshold by estimating the competitive bid price for a characteristic oil-fired steam generator. The dynamic delist bid threshold used for FCA 9 did not explicitly account for capacity performance charges under the pay-for-performance rules, yet all the submitted static delist bids for FCA 9 included capacity performance charges. The dynamic delist bid threshold was increased from $3.94 /kW-month to $5.50/kW-month to account for capacity performance charges. This change is intended to avoid the review of de-list bid information at prices below a competitive offer price.

Pivotal Supplier Tests. The pivotal supplier test is administered prior to the auction to determine if a capacity supplier has the potential to exercise market power. The market rule establishes a single pivotal supplier test that applies to both capacity imports and existing resources. Changes were made to improve the pivotal supplier test for FCA 10. The improvements include:

[156] *Order on Tariff Revisions,* 151 FERC ¶ 61,270 (2015), *available at* http://www.iso-ne.com/static-assets/documents/2015/07/er15-1650-000_6-30-15_order_partially_accepting_mrkt_monitor_cap_related_rev.pdf

- a consistent treatment of interface constraints for purposes of determining whether a supplier is pivotal.
- moving the performance of the test closer to the time of the auction.
- a new definition of "control" that will accurately account for resources that should be included in the assessment of a supplier's overall capacity portfolio.

Import capacity resources. Along with the changes to the pivotal supplier test and the dynamic de-list threshold, the ISO improved the rules governing the treatment of import capacity resources in the FCA. The changes will ensure that capacity imports that are akin to existing resources receive the same mitigation treatment in the Forward Capacity Auction as existing resources. The changes also will ensure that capacity imports that are akin to new resources receive the same treatment as other new resources during the auction.

Uneconomic Retirements. On December 17, 2015, market rule changes were filed that will provide a process for reviewing options for capacity market participation or retirement, and market power mitigation measures in the capacity auction. [157] On April 12, 2016, FERC issued an order accepting the large majority of the proposed changes and requiring the IMM to include in its evaluation of certain retirement bids a materiality threshold.[158] The rule changes went into effect for use in FCA 11.

The changes recognize the need to develop market rules to explicitly address the potential for the uneconomic retirement of an existing capacity resource in order to ensure that the FCM remains competitive.[159] The proposed rule changes provide a means for capacity suppliers to price the retirement of existing resources. The proposed rule changes also address market power issues that can be associated with the retirement of existing resources in certain circumstances.

Currently, if a capacity supplier wants to permanently retire an existing resource without regard to price at all, it may submit a non-price retirement request as late as 120 days prior to the auction (October). The ISO conducts a review to determine whether a resource subject to a non-price retirement request is required for reliability, but that review does not consider the cost of the resource and the ISO cannot require the continued operation of the resource. Under the current rules, a resource subject to a non-price retirement request is removed from the supply stack for the upcoming auction regardless of whether the retirement is uneconomic and may benefit the resource owner's remaining resource portfolio.

The proposed rule changes address three issues:

- First, the primary means of fully retiring a resource under the current rules is the use of non-priced retirement requests as discussed above. This means that a supplier that has

[157] *Forward Capacity Market Reforms* (ER16-551,000), December 17, 2015, http://www.iso-ne.com/static-assets/documents/2015/12/er16-551-000_retire_reforms.pdf.

[158] *Order Accepting Tariff Filing, Subject to Condition*, 155 FERC ¶ 61,029 (2016), *available at* http://www.iso-ne.com/static-assets/documents/2016/04/er16-551-001_4-12-16_order_fcm_retirements.pdf.

[159] The External Market Monitor's recommendation was set forth at page 36 of its 2013 Assessment of the ISO New England Electricity Markets, which is available at: http://www.iso-ne.com/staticassets/documents/markets/mktmonmit/rpts/ind_mkt_advsr/isone_2013_emm_report_final_6_25_2014.pdf. The External Market Monitor repeated its recommendation in its 2014 market assessment, which is available at: http://www.iso-ne.com/staticassets/documents/2015/06/isone_2014_emm_report_6_16_2015_final.pdf.

a resource that may be nearing retirement but that also may continue to be economic at a particular price does not have an effective way to submit the resource's retirement price under the existing structure. The proposed rule changes address this issue by providing for the use of priced retirement bids in place of non-price retirement requests.

- Second, the current FCM rules do not address the potential for a capacity supplier to exercise market power by retiring a resource prematurely in order to decrease supply, artificially increase prices, and benefit the remainder of the supplier's portfolio. The proposed rule changes address this issue by providing for review of priced retirement bids by the IMM and the FERC and, if appropriate, the use of the FERC-approved prices to mitigate the impact of an uneconomic retirement.
- Third, the current FCM auction schedule does a poor job of signaling to the market in a timely manner that additional capacity may be needed due to the retirement of existing resources. The proposed rule changes address this issue by changing the FCM auction timeline to provide for the submission of retirement bids prior to the "show of interest" deadline for new resources.

Section 9
Other Market Information

In 2015, the following audits were conducted to ensure that the ISO followed the approved market rules and procedures and to provide transparency to New England stakeholders.

9.1 SOC 1 Type 2 Examination

In November 2015, the ISO successfully completed a SOC 1 Type 2 examination, which resulted in an "unqualified opinion" about the description of the market administration and settlements system. Developed by the American Institute of Certified Public Accountants, the SOC 1 examination covers aspects of a service organization's systems for processing transactions that may be relevant to a user entity's internal controls for financial reporting. Entities such as Regional Transmission Organizations complete SOC 1 examinations to assist user entities and the independent auditors of user entities in evaluating the internal controls over financial reporting.

The ISO's SOC 1 Type 2 engagement is a rigorous examination that entails detailed testing of the business processes and information technology for bidding, accounting, settlement, and billing the market products of electric energy, regulation, transmission, capacity, demand response, reserves, and related market transactions. The SOC 1 Type 2 examination covered the 12-month period from October 1, 2014, through September 30, 2015. The SOC 1 Type 2 examination reviews the following:

- Whether the market administration and settlements system is fairly presented as designed and implemented throughout the period
- Whether the controls were suitability designed to provide reasonable assurance that the control objectives would be achieved if the controls operated effectively throughout the period and user entities applied the complementary user entity controls contemplated in the design
- The controls tested, which together with the complementary user entity controls, were those necessary to provide reasonable assurance that the control objectives were achieved throughout the period

The ISO conducts a SOC 1 Type 2 examination annually. The 2015 SOC 1 Type 2 report is available to participants upon request through the ISO external website.[160]

[160] KPMG. *Report on Management's Description of its System and the Suitability of the Design and Operating Effectiveness of Controls Pertaining to the Market Administration and Settlements System for the Period October 1, 2014, to September 30, 2015*. This report is available to participants by request through the ISO external website, http://www.iso-ne.com/isoexpress/soc-1-type-2-report-request.

9.2 Market-System Software Recertification

The ISO has committed to engaging an independent third party, PA Consulting, to review and certify that the market-system software complies with the *Market Rule 1*, the Manuals, and standard Operating Procedures.[161] This recertification takes place every two years or sooner, in the case of a major market-system enhancement or new market features. After conducting detailed tests and analyses of the applicable mathematical formulations, PA Consulting issues a compliance certificate for each market-system module it audits. The certificates provide assurance that the software is operating as intended and is consistent with the *Market Rule 1* and associated Manuals and procedures.

In 2015, PA Consulting issued the following certifications:

- Auction Revenue Rights Market Software, October 27, 2015
- Financial Transmission Rights Market Software, October 27, 2015
- Locational Marginal Price Calculator Market Software, May 21, 2015
- Real-Time Scheduling, Pricing, and Dispatch, and Locational Marginal Price Calculator Market Software, December 22, 2015

9.3 Internal Audits

The ISO New England Internal Audit Department conducted a number of internal controls and compliance audits in the Forward Capacity Market, demand-resource, and information technology areas.

[161] *Market Rule 1,* http://www.iso-ne.com/participate/rules-procedures/tariff/market-rule-1.

Acronyms and Abbreviations

Acronyms and Abbreviations	Description
°F	degrees Fahrenheit
AC	alternating current
ACE	area control error
AMR	Annual Markets Report
ARA	annual reconfiguration auction
ARR	Auction Revenue Rights
BAL-001-0	NERC's *Real Power Balancing Control Performance Standard*
Btu	British thermal unit
C4	four largest competitors
Carry Forward Rule	*Capacity Carry Forward Rule*
CCGT	combined-cycle gas turbine
CCP	capacity commitment period
CPS 2	NERC *Control Performance Standard 2*
CSO	capacity supply obligation
CT	State of Connecticut, Connecticut load zone, Connecticut reserve zone
CTS	Coordinated Transaction Scheduling
DALRP	Day-Ahead Load Response Program
DFO	dual-fuel override
DG	distributed generation
DOE	US Department of Energy
DOJ	US Department of Justice
ecomax	economic minimum limit
ecomin	economic maximum limit
EIA	US Energy Information Administration (of DOE)
EMM	External Market Monitor
EMOF	Energy Market Offer Flexibility
ERS	external reserve support
F	Fahrenheit
FCA	Forward Capacity Auction
FCM	Forward Capacity Market
FERC	Federal Energy Regulatory Commission
FPA	fuel-price adjustment
FRM	Forward Reserve Market
FTR	Financial Transmission Right
GPA	generator performance audit
GWh	gigawatt-hour

Acronyms and Abbreviations	Description
HE	hour ending
HHI (also H)	Herfindahl-Hirschman Index
HQ	Hydro-Québec
IC Rule	*Insufficient Competition Rule*
ICE	Intercontinental Exchange, Inc.
ICR	Installed Capacity Requirement
IMM	Internal Market Monitor
ISO	Independent System Operator, ISO New England
ISO tariff	*ISO New England Transmission, Markets, and Services Tariff*
kW	kilowatt
kWh	kilowatt-hour
kW-mo	kilowatt-month
L	symbol for the competitiveness level of the LMP
LEG	limited-energy generator
LMP	locational marginal price
LNG	liquefied natural gas
LSE	load-serving entity
LSR	local sourcing requirement
M-36	*ISO New England Manual for Forward Reserve*
MCL	maximum capacity limit
ME	State of Maine and Maine load zone
Min Gen	Minimum Generation (Min Gen Emergency)
M/LCC2	Master/Local Control Center Procedure No. 2, *Abnormal Conditions Alert*
MMBtu	million British thermal units
MW	megawatt
MWh	megawatt-hour
N-1	first contingency
N-1-1	second contingency
NCPC	Net Commitment-Period Compensation
NEL	net energy for load
NEMA	Northeast Massachusetts, Boston load zone
NEMA/Boston	Northeast Massachusetts/Boston local reserve zone
NEPOOL	New England Power Pool
NERC	North American Electric Reliability Corporation
NH	State of New Hampshire, New Hampshire load zone
NICR	net Installed Capacity Requirement
NPCC	Northeast Power Coordinating Council

Acronyms and Abbreviations	Description
NPR	nonprice retirement request
NY	State of New York
NYISO	New York Independent System Operator
OATT	*Open Access Transmission Tariff*
OP 4	ISO Operating Procedure No. 4
OP 8	ISO Operating Procedure No. 8
ORP	offer-review price
ORTP	offer-review trigger price
PER	peak energy rent
PFP	pay for performance
PJM	PJM Interconnection, L.L.C.
pnode	pricing node
PRD	price-responsive demand
Q	quarter
QDN	Qualification Determination Notification
RAA	reserve adequacy analysis
RCP	regulation clearing price
RCPF	Reserve Constraint Penalty Factor
RI	State of Rhode Island, Rhode Island load zone
RSI	Residual Supply Index
RTDR	real-time demand response
RTEG	real-time emergency generation
RTLO	real-time load obligation
RTO	Regional Transmission Organization
RTPR	real-time price response
SEMA	Southeast Massachusetts load zone
SOC 1	present audit of market operations and settlement systems
SWCT	Southwest Connecticut
TMNSR	10-minute non-spinning reserve
TMOR	30-minute operating reserve
TMSR	10-minute spinning reserve
TPRD	transitional price-responsive demand
TTC	total transfer capability
US	United States
VT	Vermont and Vermont load zone
WCMA	Western/Central Massachusetts