2015 ASSESSMENT OF THE ISO NEW ENGLAND ELECTRICITY MARKETS

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POTOMAC ECONOMICS

EXTERNAL MARKET MONITOR FOR ISO-NE

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Guide to Abbreviations

ASM	Ancillary Services Market
AMP	Automated Mitigation Procedures
CONE	Cost of New Entry
CT DPUC	Connecticut Department of Public Utility Control
EMM	External Market Monitor
FCA	Forward Capacity Auction
FCM	Forward Capacity Market
FTR	Financial Transmission Rights
GW	Gigawatt (1 GW = 1,000 MW)
HHI	Herfindahl-Hirschman Index, a measure of market concentration
ISO	Independent System Operator
ISO-NE	ISO New England Inc.
LFRM	Locational Forward Reserve Market
LMP	Locational Marginal Price
LOC	Lost Opportunity Cost, a component of the regulation price
LSR	Local Sourcing Requirement
MMbtu	Million British Thermal Units, a measure of energy content
IMM	Internal Market Monitor
MW	Megawatt
MWh	Energy associated with producing 1 MW for one hour
NCPC	Net Commitment Period Compensation
NEMA	North East Massachusetts
NERC	North American Electric Reliability Corporation
NPCC	Northeast Power Coordinating Council, Inc.
NYISO	New York ISO
PER	Peak Energy Rent
PPR	Performance Payment Rate
RA	Reconfiguration Auction
RAA	Reserve Adequacy Assessment
RCP	Regulation Clearing Price
RCPF	Reserve Constraint Penalty Factors
RMR	Reliability Must-Run
RTO	Regional Transmission Organization
SEMA	South East Massachusetts
SCR	Special Constraint Resources
SMD	Standard Market Design
TMNSR	Ten-minute non-spinning reserves
TMOR	Thirty-minute operating reserves
TMSR	Ten-minute spinning reserves
UDS	Real-time dispatch software

Preface

Potomac Economics serves as the External Market Monitor for ISO-NE. In this role, we are responsible for evaluating the competitive performance, design, and operation of the wholesale electricity markets operated by ISO-NE.[1] In this assessment, we provide our annual evaluation of the ISO's markets for 2015 and our recommendations for future improvements. This report complements the Annual Markets Report, which provides the Internal Market Monitor's evaluation of the market outcomes in 2015.

We wish to express our appreciation to the Internal Market Monitor and other staff of the ISO for providing the data and information necessary to produce this report.

1 The functions of the External Market Monitor are listed in Appendix III.A.2.2 of "Market Rule 1."

Executive Summary

ISO-NE operates competitive wholesale markets for energy, operating reserves, regulation, financial transmission rights ("FTRs"), and forward capacity to satisfy the electricity needs of New England. These markets provide substantial benefits to the region by coordinating the commitment and dispatch of the region's resources to ensure that the lowest-cost supplies are used to reliably satisfy demand in the short-term. At the same time, the markets establish transparent, efficient price signals that govern long-term investment and retirement decisions.

Based on our evaluation of the ISO-NE's wholesale electricity markets contained in this report, we find that the markets performed competitively in 2015. Although structural analyses indicate that one or more suppliers were pivotal in the real-time market in a large number of hours in 2015, our assessment did not raise significant competitive concerns associated with suppliers' market conduct (see Section II.F for more details). In addition, the ISO's automated market power mitigation process was effective in preventing the exercise of market power under conditions when a supplier may face limited competition. The report does recommend some improvements to increase the competitiveness of ISO-NE's forward capacity market. However, the ISO has taken a number of steps over the last year to address some prior recommendations that mitigate competitive concerns in the forward capacity market. This executive summary discusses our evaluation of market outcomes and our recommended market enhancements.

A. Key Developments and Market Outcomes in 2015

1. Energy Market Outcomes

Trends in the energy market have been dominated by reductions in fuel prices over the last two years. From 2014 to 2015:

- Natural gas prices declined more than 40 percent, falling to multi-year lows in mid-2015 largely because of higher shale production from the Marcellus and Utica regions; and
- Fuel oil prices fell by more than 35 percent because of increased global supply, and world liquefied natural gas (LNG) prices have fallen similarly. These reductions helped limit the increase in natural gas prices during tight gas supply conditions in the winter.

As a result, average energy prices fell roughly 35 percent from 2014 to 2015. The strong relationship between energy and natural gas prices indicated by these results is expected in a well-functioning, competitive market. Natural gas-fired resources were the marginal source of supply in most intervals in 2015 and competition compels suppliers submit offers consistent with their marginal costs, most of which are resources' fuel costs.

In addition to natural gas price fluctuations, other variations in supply and demand also affected energy prices in 2015:

- On the demand side, average load levels fell slightly and peak load fell by 4 percent in the winter because of milder winter weather in 2015 (the Polar Vortex produced much colder temperatures than normal in 2014). Summer load levels were relatively low in both years.
- On the supply side, the share of production from nuclear units fell from 35 percent in 2014 to 30 percent in 2015 because of the Vermont Yankee retirement at the end of 2014. The loss of nuclear output was offset by additional generation from gas-fired resources.

Transmission congestion has been limited in New England for many years. In 2015, only $30 million of congestion revenues were collected in the day-ahead market, which was 3 to 7 percent of the congestion revenues collected in other RTO/ISO markets. Low levels of congestion contributed to low real-time price volatility in New England.

A major market design change, Energy Market Offer Flexibility, was implemented in December 2014. This has allowed market participants to vary their supply offers by hour and to update their supply offers during the operating day to reflect actual costs. Previously, suppliers submitted one offer on the day prior to the operating day that was applicable to all hours of the day. This change is a significant improvement because supply offers are now more reflective of actual fuel costs, especially in the winter months when natural gas prices are more volatile. This has improved the market's real-time price signals and fast start deployments.

2. Reserve and Regulation Markets

ISO-NE procures operating reserves in the real-time market to maintain reliability when system contingencies occur. It also procures regulation, which allows it to adjust the output of selected resources every 4 to 6 seconds to keep supply and demand in balance.

Real-Time Reserves

The average real-time reserve prices fell 28 to 33 percent from 2014 to 2015, consistent with the decrease in real-time energy prices. Less frequent reserve shortages in 2015 also contributed to the price reduction. The reduction in shortages was most pronounced during the winter in 2015, which exhibited less extreme weather conditions than the Polar Vortex conditions in 2014. The price effects of this reduction in shortage frequency was partially offset by changes the ISO implemented to enhance its shortage pricing. The ISO increased the Reserve Constraint Penalty Factors (RCPFs) for the 10-minute total reserves and 30-minute operating reserves from $850 and $500 per MWh to $1,500 and $1,000 per MWh in December 2014. The RCPFs set prices during shortages and these increased values better reflect the value of the electricity consumption (i.e., the "value of lost load"), and improve generators' performance incentives.[2]

Forward Reserves

After deducting the forward capacity prices, the effective forward 30-minute reserve clearing prices fell from roughly $8.10/MWh in 2014 to $5.00/MWh in 2015.[3] The decreases are expected given that a large component of the cost of providing forward reserves for a fast start generator is the expected forgone revenue from selling real-time reserves. However, the forward reserve prices are still very high relative to the real-time operating reserve prices or day-ahead operating reserve prices in other RTO markets.[4]

Regulation Service

On average, more than 600 MW of available supply competed to provide less than 60 MW of regulation service in 2015. The significant excess supply generally limits competitive concerns in the regulation market.

Although total regulation expenses fell 24 percent to $21.9 million in 2015, average regulation capacity clearing price actually increased 23 percent from 2014. The increase in prices was due to a market design change implemented on March 31, 2015 to comply with FERC Order 755. This change allowed two-part bidding (for availability and movement), and decoupled the

2 Section II.B provides additional detail and compares reserve prices to the MISO and NYISO markets.

3 Until 2016, forward reserve suppliers were paid based on the difference between the forward reserve clearing price and the forward capacity price. However, effective for the summer 2016 forward reserve auction, the ISO eliminated this provision.

4 Section II.B compares forward reserve prices to day-ahead prices in the MISO and NYISO markets.

compensation rate for availability and actual regulation movement. Although other RTOs implemented similar changes to comply with Order 755, the regulation prices in New England were significantly higher than in the MISO and NYISO markets. This is primarily because ISO-NE's regulation market is not co-optimized with energy and operating reserves as in MISO and NYISO. ISO-NE's separate hourly clearing process tends to increase the estimated opportunity costs of providing regulation, thereby raising the regulation costs.[5] Co-optimizing this market would improve its performance.

3. Uplift Costs

While NCPC charges make up a share of the overall cost of operating the wholesale market, NCPC charges are difficult for participants to hedge and are important because they generally indicate that there are significant system needs that are not fully reflected in market clearing prices. Thus, we identify causes of NCPC that may distort incentives or that may be reduced by more efficient prices and/or market operations. NCPC charges to internal resources fell from $164 million in 2014 to $115 million in 2015, primarily because of the sharp decline in fuel prices. These changes varied over the year:

- In the first quarter, NCPC payments fell from $101 million in 2014 to $37 million in 2015 because of: a) much lower natural gas prices, b) better resource performance, and c) procedural changes to make more reliability commitments in the day-ahead market when it is easier for units to procure fuel.
- In the remaining quarters, NCPC payments rose from $63 million in 2014 to $78 million in 2015 despite lower natural gas prices and reduced commitments for reliability. The increase was driven primarily by NCPC rule changes that over-compensate non-fast start units committed in the day-ahead market.

We estimate total over-compensation of $47 million to non-fast start units in 2015, which accounted for 41 percent of all internal NCPC uplift. We identified this concern shortly after the payments began in December 2014 and recommended that ISO-NE eliminate excess NCPC payments. After working through stakeholder and regulatory processes, the ISO implemented this change in February 2016.[6]

5 Section II.B provides additional detail and compares regulation prices to the MISO and NYISO markets.

6 This issue is discussed further in Section II.C.

Finally, it is instructive to compare uplift costs across various RTOs. This comparison shows that ISO-NE's uplift costs, averaging $0.84 per MWh of load in 2015, was substantially higher than both the NYISO ($0.39) and MISO ($0.22).[7] The higher costs incurred in New England can be attributable to the fact that:

- Both the NYISO and MISO markets have provisions to allow peaking resources to more reliably set prices, while peaking units in ISO-NE recover more of their as-bid costs through uplift. ISO-NE is developing a similar pricing approach that is expected to lower NCPC uplift costs by approximately $10 million per year.[8]
- ISO-NE's fuel costs tend to be higher than the other RTO's, leading to higher required make-whole payments.
- ISO-NE over-compensated non-fast start units in 2015 because of the NCPC rule described above. This rule accounted for $0.34 per MWh of load in 2015, but was corrected in February 2016.

4. Long Run Price Signals

Markets provide economic signals that guide participants' long-run investment decisions, including new entry, retirement, and major maintenance decisions. We measure these signals by estimating the net revenues that a generator would receive in excess of its production costs. Net revenues for all generators fell significantly from 2014 to 2015 primarily, because of lower energy revenues resulting from lower natural gas prices.

We examine a number of hypothetical new generators an found them uneconomic to build based on 2015 prices. In other words, the estimated net revenues were lower than their annualized cost of new entry ("CONE"). This was expected given the substantial surplus capacity (which lowers both energy and capacity prices) anticipated until the summer of 2017. We also found that:

- Dual fuel capability made a substantial contribution to the net revenues of a combined cycle unit (~$8/kW plus Winter Reliability Program revenue), suggesting that the market provides incentives to install and maintain dual fuel capability if New England continues to experience tight gas market conditions during the winter;
- Net revenues are biased towards fast-start units because of high revenues from the Forward Reserve Market ("FRM"). The FRM produces higher revenues for fast-start units than day-ahead reserve markets that are co-optimized with energy because day-ahead markets facilitate full competition and efficient reserve procurement.

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7 This comparison of uplift charges is discussed in Section II.C.

8 The uplift charges resulting from this issue and the ISO's project to allow fast start units to set price are discussed in Section II.C.

We also analyzed the incentives for the entry of new renewables and the retention of nuclear resources. This analysis indicated:

- *Nuclear Plant Viability* – Smaller, single-unit nuclear plants are likely to be unprofitable for the remainder of the decade. Larger nuclear units may become economic when capacity prices increase in 2017, but considerable uncertainty remains regarding future energy prices and associated net revenues.
- *Incentives for Renewable Development* – Net revenues for renewable generation depend primarily on federal and state incentive programs. Given these subsidies, estimated net revenues exceed entry costs for onshore wind units, which is consistent with the high levels of wind turbine installation in New England. Alternatively, utility-scale solar PV units were not economic in 2015 and will only become marginally economic in the future if the cost of new installations falls significantly and subsidies continue.

Finally, we estimate and compare the cost per ton of CO_2 to reduce emissions by: developing new renewable projects, retaining existing nuclear generation, importing power from large-scale hydro resources, and developing new efficient gas-fired generation. This analysis revealed a range of costs associated with these options for achieving carbon emissions reductions. The wide variation in the cost per ton of emission reductions through investments in different technologies underscores the importance of promoting technology-neutral, market-based solutions for emission reductions.

B. Key Market Design Improvements: Energy Markets and Uplift

1. Hourly Offer Functionality

The ISO implemented this project in December 2014, which allows generators to vary their offer curves hourly and much closer to real-time. Previously, generators had to submit one offer curve for the entire day by 6 pm on the previous day. The new functionality allows generators to respond to unforeseen changes in electric market conditions and to conserve scarce fuel during tight gas market conditions. We have observed that hydro generators have begun to offer their capacity in a more price-sensitive manner and rely less on self-scheduling.[9] The hourly offer functionality helps the ISO maintain reliability (particularly during the winter) by ensuring that energy limited generators expend their output in periods when it will be most valuable.

[9] This pattern is discussed further in Section IV.A.

2. Real-Time Scheduling and Pricing of Fast-Start Units

Efficient real-time prices are important because they encourage competitive scheduling by suppliers, participation by demand response, and investment in new resources when and where needed. Additionally, efficient price signals during shortages and tight operating conditions can reduce the reliance on revenue from the capacity market to maintain resource adequacy.

Our evaluation finds that fast-start generators are routinely deployed economically, but the resulting costs are often not fully reflected in real-time prices. In 2015, 36 percent of the fast-start units that were started in the real-time market did not recoup their as-offered costs. This leads fast-start resources with flexible characteristics to be substantially under-valued in the real-time market, despite the fact that they provide significant economic and reliability benefits.

If the average total offers of these units were fully reflected in the energy price, the average real-time LMP would increase $3 to $4/MWh in each year of 2013 to 2015 (although market responses by external suppliers and changes in commitment patterns would partially offset this increase). We estimate that these price increases would have reduced NCPC costs by $9 to $10 million in each year of 2013 to 2015.[10]

Based on these substantial benefits, we have been recommending that the ISO develop a pricing model that would allow fast-start peaking units to set real-time prices when they are economic to run. The ISO is addressing this recommendation and plans to implement pricing rule changes in the first quarter of 2017, which we strongly support. (Recommendation 1).

3. Day-Ahead Market Liquidity and NCPC Allocations

When prices in the day-ahead market converge well with the real-time market, it leads to an efficient commitment of resources (and the most economic procurement of fuel). We found that price convergence between the day-ahead and real-time markets has not been optimal in recent years. Average real-time prices were higher than average day-ahead prices in most months. This relationship is not efficient because, ideally, day-ahead prices would need to clear higher than real-time prices to produce an efficient commitment of the system's resources. This is true

10 These findings are discussed further in Section IV.A.

because ISO-NE's real-time prices tend to be under-stated because fast start resources frequently do not set prices when they are on the margin.

The primary means to achieve an efficient relationship between day-ahead and real-time prices is to foster liquidity in the day-ahead market and allocate uplift costs efficiently. Much of the true liquidity in the day-ahead market is provided by virtual transactions whose purchases and sales are sensitive to changes in day-ahead prices. Unfortunately, virtual load and supply schedules averaged just 1 to 2 percent of actual load in the ISO-NE market in recent years, far lower than in the NYISO and the MISO markets where scheduled virtual load and supply both averaged 5 to 7 percent of the actual load.

One factor that helps explain the prevailing relationship between day-ahead and real-time prices and the relatively low level of virtual transactions in New England is ISO-NE's current method for allocating economic NCPC charges, which suffers from the following issues:

- Virtual transactions are deviations between the day-ahead and real-time market (because they do to buy or sell in real time) and most of the NCPC is allocated to deviations. This is inefficient because NCPC costs are caused by many factors other than deviations.
- ISO-NE's allocation does not distinguish between "helping" and "harming" deviations and is, therefore, not consistent with cost causation.[11] The current allocation of NCPC costs to "helping" deviations (those that reduce NCPC by reducing the need to commit peaking resources in real time) likely have the largest adverse effect on the performance of the day-ahead market.

This issues result in charges to virtual transactions that have averaged \$2 to \$4 per scheduled MWh in the past several years, which is significantly higher than the charges that virtual traders face in the NYISO (\$0.10) and MISO (\$0.41) markets. Further, these RTOs generally allocate no costs to helping virtual transactions or other helping deviations. Therefore, we find that the current NCPC allocation reduces the day-ahead market liquidity and hinders its natural response to sustained price differences. Therefore, we continue to recommend that the ISO modify its rules to allocate Economic NCPC allocation to participants that cause it. (Recommendation 2).

11 "Helping" deviations, such as over-scheduling load (including virtual load), generally result in higher levels of resource commitments in the day-ahead market and, therefore, usually decrease the ISO's need to make additional commitments to reduce associated NCPC. "Harming" deviations, such as under-scheduling physical load in the day-ahead market, can cause the ISO to have to commit additional units in real-time to satisfy the system's requirements, which are likely to increase NCPC.

4. Efficiency of Interface Scheduling with New York

Efficient scheduling of the interfaces between New England and its neighbors can have a significant effect on the ISO-NE market outcomes. It is particularly important with New York because both regions have real-time spot markets and market participants can schedule market-to-market transactions based on transparent price signals in each region.

Our evaluation of the primary interface between New England and New York finds that, in 2015:

- The price difference between the two markets exceeded \$10/MWh in 31 percent of the unconstrained hours and exceeded \$30/MWh in 9 percent of the unconstrained hours; and
- Transactions were adjusted in response to real-time prices in the inefficient direction (i.e., from the high-priced region to the low-priced region) in 44 percent of all intervals.

These results indicate that the current process does not fully utilize the interface. Uncertainty and long scheduling lead times have prevented participants from fully arbitraging the interface. This has resulted in inefficiencies and higher costs in both areas. It also degrades reliability because the interchange does not adjust predictably to changes in supply or demand.

To address this issue, ISO-NE and NYISO implemented a Coordinated Transaction Scheduling (“CTS”) process on December 15, 2015, which allows intra-hour changes in the interchange between the two control areas. We evaluate the performance of CTS in the first three-and-a-half months following its implementation and find that:

- The average amount of price-sensitive CTS bids that were offered and cleared were substantial, and exceed the CTS transactions scheduled between New York and PJM by an order of magnitude. This can be attributed to the fact that:
  - NYISO and PJM impose large costs on CTS transactions while ISO-NE and NYISO have agreed to impose no costs; and
  - The price forecast errors used to schedule CTS transactions have been much smaller between NYISO and ISO-NE, which reduces risk for the participants.
- The CTS scheduling process has resulted in substantial efficiency savings, but these savings are roughly half of the projected savings primarily because of forecast errors. We have identified certain simplifications that may be contributing to the forecast errors.

Although it is too early to draw strong conclusions, these initial results indicate a successful implementation of CTS, although additional benefits may be realized by improving the accuracy of the ISO’s price forecasts.

5. Commitment of Multi-Turbine Units for Local Reliability

Reliability commitments of these multi-turbine units accounted for 69 percent of NCPC uplift in 2014 and 58 percent in 2015.[12] In many cases, the reliability need could have been satisfied with only one of the units, so committing multiple units led to excess NCPC costs. We believe compelling the ISO to commit multiple units at a plant when only one unit is need is analogous to a dual-fueled unit requiring ISO-NE to compensate it for burning oil rather than burning natural gas at a much lower cost. This latter conduct is not acceptable, and requiring the ISO to commit resources in a multi-turbine configuration should also be deemed unacceptable. Additionally, over-committing these resources for local reliability also impairs efficient pricing by depressing LMPs and reducing real-time performance incentives. Hence, we recommend that the ISO modify its tariff to allow it to commit a single unit at a multi-unit generator location when this is a more efficient means of satisfying the local reliability need (Recommendation 3).

6. Improving the Operating Reserve Markets

As in prior years, we found nearly all of the resources assigned to satisfy forward reserve obligations in 2015 were fast-start resources capable of providing offline reserves. The forward reserve prices are still very high relative to real-time reserve prices or the day-ahead operating reserve prices in other RTO markets.[13] This occurs because all suppliers can compete to provide reserves in a reserve market that is co-optimized with energy (rather than in the forward reserve market that is dominated by peaking resources). The value of the forward reserve market is questionable because:

- It has not achieved its objective to lower NCPC by purchasing forward reserves from high-cost units frequently committed for reliability.
- The forward procurements do not ensure that sufficient reserves will be available during the operating day. In 2015, the day-ahead market did not schedule sufficient energy and operating reserves to satisfy the system's forecasted needs on 60 days.
- The obligation of forward reserve suppliers to offer at prices higher than the Forward Reserve Threshold Price can distort the economic dispatch of the system and inefficiently raise costs. These distortionary effects will have larger price effects in the future when the ISO begins to allow peaking units to more consistently set real-time energy prices.

[12] These percentages exclude the excess NCPC payments that the ISO corrected in February 2016.

[13] Section II.B compares forward reserve prices to day-ahead prices in the MISO and NYISO markets.

For these reasons and because it biases the economic signals in favor of fast-start units, we recommend the ISO eliminate the forward reserve market. (See recommendations 5)

Additionally, we recommend the ISO introduce day-ahead reserve markets that are co-optimized with energy (see Recommendation 4). Such markets would allow the ISO to procure sufficient resources to satisfy its combined energy and reserve needs for the following day and to set clearing prices that reflect the costs of satisfying the operating reserve obligations. Day-ahead reserve markets would also help address the ISO's concerns regarding unit availability. The day-ahead reserve schedules would be established in a timeframe in which suppliers can make arrangements for fuel and staffing to allow them to respond reliably to reserve deployments.

C. Key Market Design Improvements: Capacity Market

Forward Capacity Markets are designed to allow participation by prospective new investors, which increases competition and disciplines existing suppliers. In each of the last four forward capacity auctions, new resources were needed in at least one capacity zone so participation by new developers is needed to ensure the auction results are efficient and competitive. The ISO has recently taken significant steps that will enhance competition in the forward capacity market, which are expected to be implemented in FCA 11, including:

- Sloped demand curves in the local capacity zones, which greatly reduce the effectiveness of anticompetitive conduct and improve incentives to offer competitively.
- New rules to mitigate market power exercised by retiring an economic existing generator.

However, based on our review of the conduct and incentives of suppliers in FCA 9 and FCA 10, we have identified issues that hinder competition. Notwithstanding the two enhancements that will be implemented for FCA 11, we recommend the ISO consider the following market changes that could enhance competition in the FCA (Recommendations 6 to 8):

- Evaluate changes in the availability or timing of information about qualified supply before the auction. The specific information sources are discussed in Section II.B.
- Replace the descending clock auction format with a sealed bid auction format.
- Modify its queue rules to allow the FCA to select between projects that are interdependent, rather than designating one project as Primary and the other as conditionally-qualified. This will allow the FCA to clear the most economic unit and set more efficient prices.
- Consider changes to the minimum offer price rules to ensure they will be effective under the ISO's pay-for-performance framework.

D. Table of Recommendations

We make the following recommendations based on our assessment of the ISO-NE's market performance in 2015. A number of these recommendations have been made previously and are now reflected in the ISO's *Wholesale Market Plan*.

Recommendation	Wholesale Mkt Plan	High Benefit[14]	Feasible in ST[15]
Energy Markets			
1. Allow the costs of fast-start resources, operator actions, and demand response deployments to be reflected in real-time prices.	✓	✓	
Reliability Commitments and NCPC Allocation			
2. Modify allocation of "Economic" NCPC charges to make it consistent with a "cost causation" principle.	✓	✓	✓
3. Utilize the lowest-cost configuration for multi-unit generators when committed for local reliability.			✓
Reserve Markets			
4. Introduce day-ahead operating reserve markets that are co-optimized with the day-ahead energy market.	✓	✓	
5. Eliminate the forward reserve market.			✓
Capacity Markets			
6. Evaluate changes in the availability or timing of information about qualified supply before the auction to improve competition in the FCA.			✓
7. Replace the descending clock auction with a sealed bid auction.		✓	✓
8. Allow the FCA to select between projects that are interdependent, rather designating a priority.			✓
9. Assess changes in the MOPR provisions to ensure it will be effective under the pay-for-performance framework.			✓

14 Recommendation will likely produce considerable efficiency benefits.

15 Complexity and required software modifications are likely limited.

I. Overview of Market Outcomes and Trends

The ISO-NE operates a multi-settlement wholesale market system consisting of a financially-binding day-ahead market for energy and a real-time market for energy, operating reserves, and regulation. Through these markets, the ISO-NE commits generating resources, dispatches generation, procures ancillary services, schedules external transactions, and sets market-clearing prices on a locational basis. In this section, we review wholesale market outcomes in New England during 2015 and highlight market results and performance in the following areas:

- Wholesale energy and reserve markets;
- Out-of-market actions and uplift costs;
- Forward capacity market;
- Long run price signals; and
- Competitive performance of the energy market.

A. Energy Market Outcomes

ISO-NE manages flows over the network to avoid overloading transmission constraints by altering the dispatch of its resources and establishing Locational Marginal Prices ("LMPs") to establish efficient, location-specific prices that reflect the marginal value of transmission congestion and losses in order to serve load at that location.

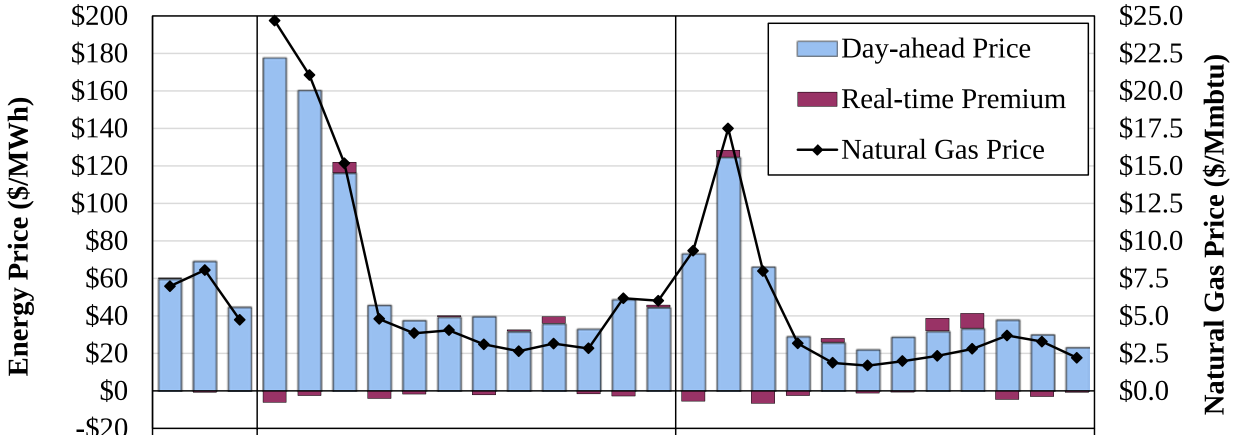
Transmission congestion has been relatively limited in New England in the past several years. In 2015, total day-ahead congestion revenues were only $30 million in New England, which is 15 to 30 times less than in other RTO/ISO markets. The low congestion levels in New England are attributable to the extensive transmission investment made over the last ten years. Given the limited congestion, we generally focus on the New England Hub in this section as a representative location for our evaluation of price trends and price convergence in the ISO-NE energy market.[16]

[16] The New England Hub is in the geographic center of New England. The Hub price is an average of prices at 32 individual pricing nodes, which has been published by the ISO to disseminate price information that facilitates bilateral contracting. Futures contracts are currently listed on the New York Mercantile Exchange and Intercontinental Exchange that settle against day-ahead and real-time LMPs at the Hub.

1. Energy Prices and Price Convergence

Figure 1 summarizes monthly day-ahead prices and the convergence between day-ahead and real-time prices at the New England Hub over the past two years.[17] The figure also shows the average natural gas price, a key driver of energy prices when the market is operating competitively, which is discussed in more detail in subsection 2.[18] The table below the figure provides additional metrics that we will discuss in this section.

Figure 1: Monthly Average Energy Prices and Natural Gas Prices
New England Hub, 2014 – 2015



	13	14	15	J	F	M	A	M	J	J	A	S	O	N	D	J	F	M	A	M	J	J	A	S	O	N	D
	Annual Avg.			2014												2015											
Implied Heat Rate (MMbtu/MWh)	8.2	8.5	8.8	7.7	7.4	7.6	8.5	8.5	8.6	10.7	9.7	9.4	9.9	7.3	6.8	7.2	7.0	7.8	7.5	10.6	9.7	10.8	10.7	9.6	9.1	7.6	7.9
RT Premium (%)	0.3	-1.1	-0.6	-3.4	-1.6	4.8	-8.6	-4.2	1.5	-5.0	1.7	9.5	-4.4	-5.5	2.2	-7.5	2.9	-9.9	-8.4	7.4	-5.1	-2.2	20.7	23.3	-11.8	-9.8	-3.3
Avg. Abs. Diff (%)	26	27	29	24	29	27	18	19	24	27	28	36	27	20	48	26	17	27	25	41	36	37	42	54	25	32	32

Summary of Energy Prices in 2015

Overall, the load-weighted average New England Hub price in the day-ahead market fell 35 percent from 2014 to 2015 primarily because natural gas prices decreased 41 percent over the same period. Differences in the first quarter accounted for roughly 65 percent of the annual reduction. Variations in natural gas prices are discussed in more detail in Section II.A.2. The

[17] These are load-weighted average prices.

[18] The figure shows the simple average of gas price indices reported by Platts for Algonquin City Gates.

effects of lower fuel prices were partly offset by the retirement of Vermont Yankee Nuclear Plant at the end of 2014 and by increased CO_2 allowance costs in 2015.

Implied Marginal Heat Rate

The table in Figure 1 also shows an average implied marginal heat rate.[19] This metric is helpful in identifying changes in energy prices that are not driven by changes in fuel prices (e.g., energy demand, supply availability, etc.). The implied marginal heat rate shows a seasonal variation in energy prices because of factors other than natural gas prices that are not readily apparent in the average monthly prices. For example, the implied marginal heat rates were highest in the peak summer months when high load levels led to tight market conditions on hot days.

In the summer months (June to September), implied marginal heat rates rose from 9.6 MMbtu per MWh in 2014 to 10.2 MMbtu per MWh in 2015 primarily because of reduced production from nuclear generation and increased load levels in 2015. The variations in load levels are discussed in more detail in the Section II.A.3.

In the winter months of January to March, implied marginal heat rates fell from 7.6 in 2014 to 7.3 MMbtu per MWh in 2015 despite the reduced nuclear generation. This reduction is attributable to slightly milder winter conditions overall and improved generator availability because of fewer claimed outages and deratings.

Correlation of Energy Prices and Fuel Prices

The figure shows that natural gas price fluctuations were a significant driver of variations in monthly average energy prices in 2014 and 2015. This correlation is expected in a well-functioning, competitive market because fuel costs represent the majority of most suppliers' marginal production costs. Since suppliers in a competitive market have an incentive to offer supply at marginal cost, changes in fuel prices should translate to comparable changes in offer prices. In 2015, over 50 percent of the installed generating capacity in New England was

[19] The Implied Marginal Heat Rate equals the day-ahead electricity price minus a generic unit Variable Operations and Maintenance ("VOM") cost (assumed to be $3/MWh in this calculation), then divided by the fuel cost that includes the natural gas cost and greenhouse gas emission cost (i.e., RGGI Allowance Cost).

capable of burning natural gas (including gas-only and dual-fuel units).[20] However, natural gas-fired units were on the margin and set the market clearing price in most hours because low-cost nuclear resources and other baseload resources typically produce at full output and are not marginal. Therefore, energy prices should be strongly correlated with natural gas prices in a well-functioning competitive market.

Day-Ahead and Real-Time Price Convergence

The first measure of convergence reported in Figure 1 is the average real-time premium (the average real-time price minus the average day-ahead price). The table below the chart shows this measure of convergence as a percentage of average day-ahead price. The second measure of convergence is the average absolute difference. This indicates the average hourly price difference, regardless of whether the day-ahead price is higher or the real-time price is higher.

The figure shows that the market exhibited a small day-ahead premium in 2015 on an annual basis. New England's day-ahead market produces the most efficient outcomes when it is priced higher than the real-time market on a sustained basis. This leads to a more efficient commitment of the system's resources. This is the case because real-time energy prices frequently do not reflect the full costs of the marginal source of supply. In particular, when high-cost peaking resources are committed to satisfy the real-time demand, real-time prices generally do not reflect the full costs of such resources. Because the real-time prices are understated in these cases, day-ahead prices would have to be slightly higher than the actual real-time prices in order to efficiently facilitate a day-ahead commitment of resources to fully satisfy the real-time system needs.

One reason that the New England energy markets do not achieve fully efficient price convergence is its allocation of NCPC charges. If these costs are allocated to those participants that contribute to the need to commit resources after the day-ahead market (e.g., virtual supply, under-scheduled load, etc.) and not to those participants that reduce the need to commit additional resources (e.g., virtual load), the convergence of New England's day-ahead and real-

20 ISO-NE, "2015-2024 Forecast Report of Capacity, Energy, Loads, and Transmission (CELT) Report," May 2015.

time energy prices would be more efficient. We have recommended a change in ISO New England's allocation of NCPC and these issues are discussed in detail in Section III.A.

We have also recommended real-time pricing improvements to address this price setting issue described above. The ISO plans to address this recommendation when it implements the "Fast-Start Pricing Improvements" project in March 2017. This will lead real-time prices to reflect more accurately the cost of maintaining reliability using peaking resources (which is discussed further in Section IV.A). Once implemented, it will be most efficient for day-ahead prices to converge more completely with real-time prices.

2. Fuel Prices

In recent years, fossil fuel price fluctuations have been the primary driver of changes in wholesale energy prices because most of the marginal costs of thermal generators are fuel costs. Natural gas units are usually the marginal source of generation in New England, therefore natural gas prices more directly affect wholesale energy prices.

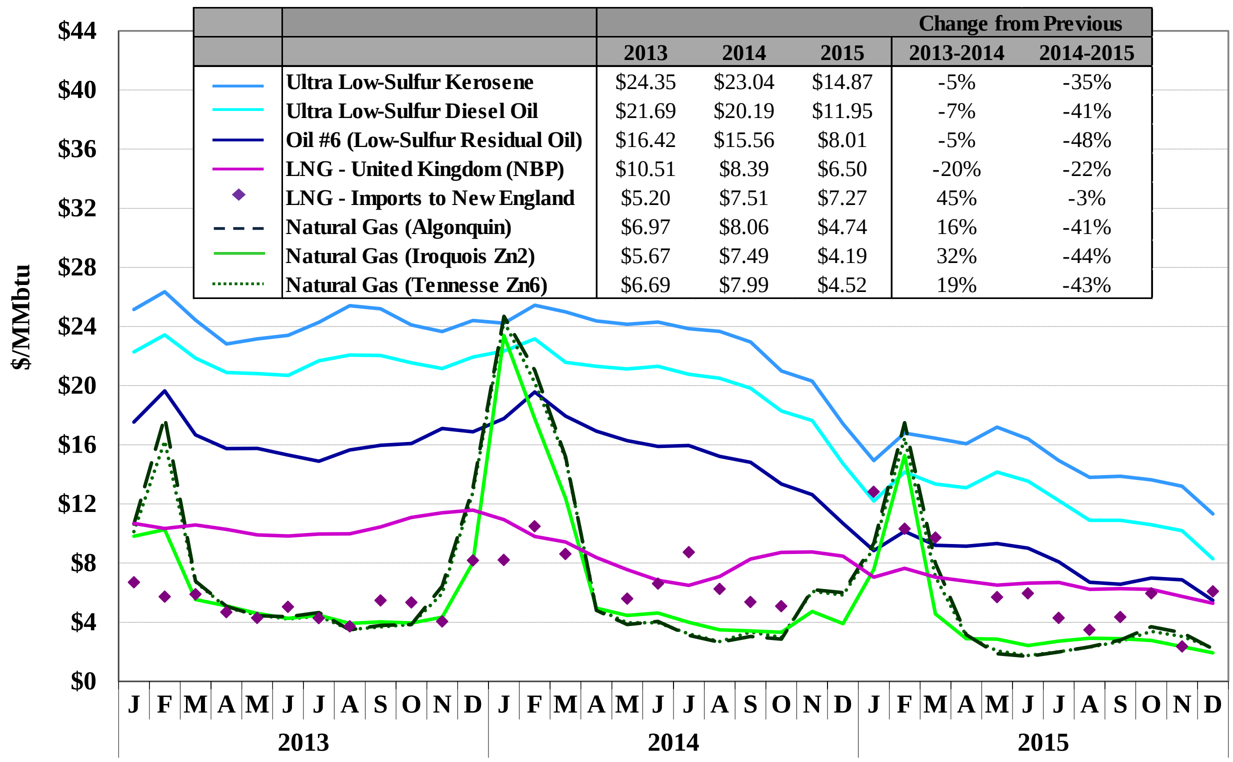
Nearly 10 GW of generating capacity in New England is capable of burning oil (including oil-only and dual-fuel capability).[21] On very cold winter days when the supply of natural gas is constrained, the effects of natural gas price spikes on energy prices can be partly mitigated by generators burning fuel oil.

Figure 2 shows natural gas price indices for three pipelines, Algonquin, Iroquois Zone 2, and Tennessee Zone 6, which serve most of generators in Connecticut and Massachusetts, and three oil price indices, ultra low-sulfur kerosene, ultra low-sulfur diesel, and low-sulfur residual oil (#6 oil), which are commonly used fuel oils in New England. Liquefied natural gas ("LNG") has become increasingly important as a supplementary source of fuel during periods when bottlenecks on the gas pipeline system limit imports to New England, particularly during winter months. LNG prices are shown for the NBP trading hub in the UK, which is an indicator of the demand for LNG shipments to competing markets in the Atlantic, and for deliveries to the Everett terminal in Boston in months when such deliveries occurred. The figure shows these

[21] ISO-NE, "2015-2024 Forecast Report of Capacity, Energy, Loads, and Transmission (CELT) Report," May 2015.

average fuel prices by month from 2013 to 2015 and the table shows the annual average fuel prices for three years.

Figure 2: Monthly Average Fuel Prices
2013 – 2015



	2013	2014	2015	Change from Previous 2013-2014	2014-2015
Ultra Low-Sulfur Kerosene	$24.35	$23.04	$14.87	-5%	-35%
Ultra Low-Sulfur Diesel Oil	$21.69	$20.19	$11.95	-7%	-41%
Oil #6 (Low-Sulfur Residual Oil)	$16.42	$15.56	$8.01	-5%	-48%
LNG - United Kingdom (NBP)	$10.51	$8.39	$6.50	-20%	-22%
LNG - Imports to New England	$5.20	$7.51	$7.27	45%	-3%
Natural Gas (Algonquin)	$6.97	$8.06	$4.74	16%	-41%
Natural Gas (Iroquois Zn2)	$5.67	$7.49	$4.19	32%	-44%
Natural Gas (Tennesse Zn6)	$6.69	$7.99	$4.52	19%	-43%

Natural gas prices exhibited a typical seasonal pattern, rising in the winter when demand for natural gas was highest and bottlenecks on the natural gas system occurred most frequently. In 2015, natural gas prices rose to an average of $9 to $12 per MMBtu in the first quarter, up significantly from an average of less than $3 per MMBtu during the rest of the year.

Natural gas prices also showed a notable year-over-year variation. From 2014 to 2015, natural gas prices declined substantially by 41 to 44 percent. These reductions were particularly large in the winter because of the combined effects of milder winter weather, more LNG imports to the region, and higher production from Marcellus and Utica shales in 2015. By mid-2015, natural gas prices fell to multi-year lows across the system largely because of higher shale production.

Natural gas prices rose above fuel oil prices on many days in the winter of 2015, leading oil-fired generation to be economic more frequently. This helped reduce the severity of natural gas price spikes during tight winter operations. In addition, fuel oil prices started to fall in the middle of 2014, after several years of stability, because of increased global supply. Reported fuel oil prices fell 35 to 49 percent on an annual basis from 2014 to 2015.

LNG prices for deliveries to New England were generally less than or equal to pipeline gas prices before 2014 and then rose to levels more consistent with the NBP trading hub in 2014 and 2015. The volume of LNG deliveries to New England in the first three months of each year fell from an average of 39 BCF from 2010 to 2012 to 18 BCF in 2013, 12 BCF in 2014, and 21 BCF in 2015. These patterns indicate that in recent years, New England has had to compete more with other markets around the world for LNG imports, leading to higher prices and reduced imports. New England received additional imports of LNG in the first quarter of 2015, reflecting very tight LNG supplies during the Polar Vortex in 2014 and lower LNG prices in 2015.

Overall, natural gas prices are more volatile in New England than in most other regions. This may reflect for higher degree of gas pipeline constraints. Some of this volatility, however, may indicate a) that the scheduling process are not resulting in full utilization of the available pipeline capability, or b) potential competitive concerns in the natural gas markets. These issues warrant monitoring and evaluation if data can be gathered that would allow such monitoring.

3. Energy Demand

In addition to fuel prices, energy demand is another key driver of wholesale market outcomes in New England. Fluctuations in energy demand normally explain much of the short-term variations in energy prices.

Table 1 summarizes the average load level, the summer peak load level (which is also the annual peak load level in New England), and the winter peak load level for each year from 2013 to 2015. The table also shows the number of hours when the system was in high load conditions separately for the summer and winter seasons.[22] The hours with the highest loads are important because a disproportionately large share of the market costs to consumers and revenues to generators occur in these hours.

[22] In this table, the summer season includes the months of June, July, August, and September, and the winter season includes the months of December, January, February, and March.

Table 1: Summary of Energy Demand
2013-2015

Year	Average Load (GW)	Summer Peak Load (GW)	Winter Peak Load (MW)	Number of Hours: Summer >22GW	Number of Hours: Summer >25GW	Number of Hours: Winter >18GW	Number of Hours: Winter >20GW
2013	14.9	27.4	21.5	181	44	239	18
2014	14.7	24.4	21.4	71	0	327	25
2015	14.6	24.3	20.5	102	0	270	8

In general, energy demand grows slowly over time, tracking population growth and economic activity. However, weather patterns can cause year-to-year fluctuations in load levels. In 2015, load averaged 14.6 GW and never exceeded 25 GW. Both the annual peak level and the average level fell slightly from 2014 and were the lowest levels in the past six years.

The average load rose modestly in the summer of 2015 (although the peak was slightly lower), which is attributable to warmer overall weather conditions from late July through August. As a result, the number of hours when load exceeded 22 GW rose 44 percent from the prior summer.

Winter peak load fell 4 percent from the prior winter because of milder weather conditions in January, March, and December. Nonetheless, February 2015 experienced much colder temperatures, leading average load in this month to exceed that of last winter's peak month (January 2014).

4. Summary of Imports and Exports

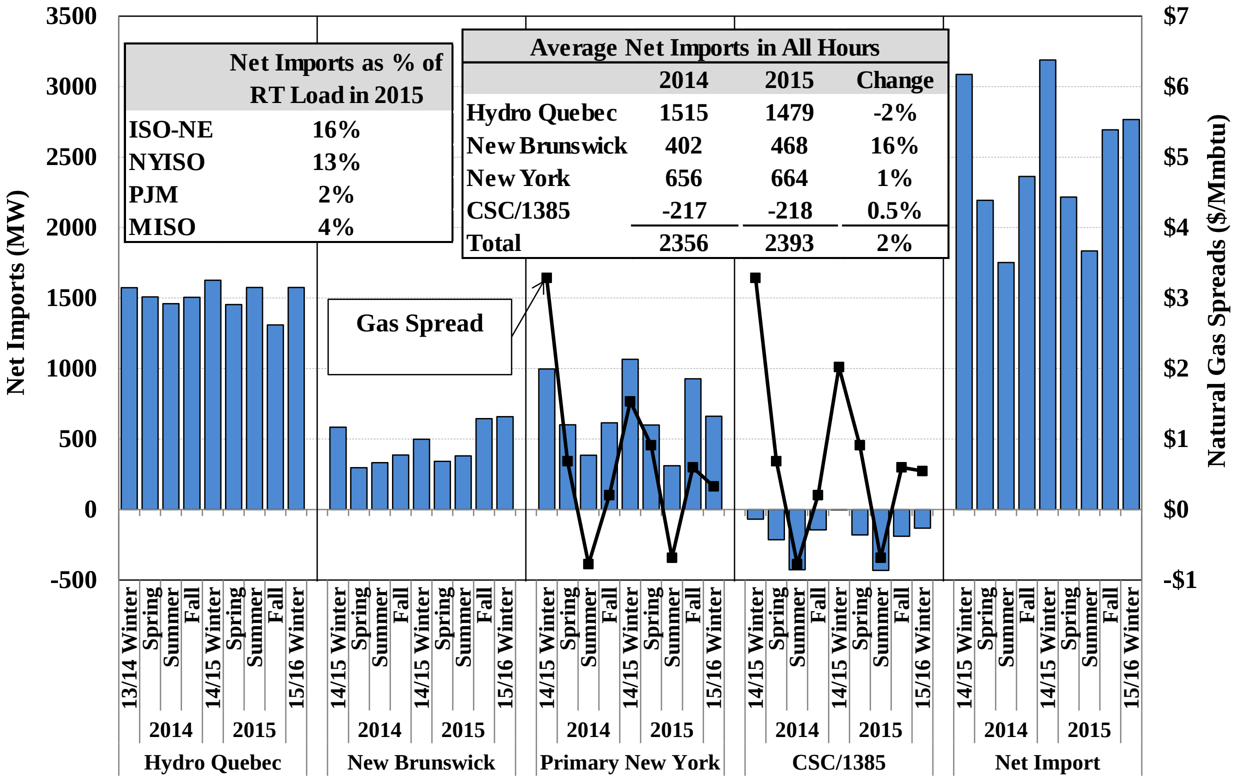
Consumers benefit from the efficient use of external transmission interfaces. The external interfaces allow low-cost external resources to compete to serve demand in New England. The ability to draw on neighboring systems for emergency power, reserves, and capacity also lowers the costs of meeting reliability needs in the interconnected system. Wholesale markets should facilitate the efficient use of both internal resources and transmission interfaces between markets.

ISO-NE receives imports from Quebec and New Brunswick in most hours. Between New England and New York, power can flow in either direction depending on market conditions, although ISO-NE imported more power from NYISO than it exported in the past several years. The transfer capability between New England and adjacent control areas is large (relative to the

New England's load), making it particularly important to schedule interfaces efficiently. This subsection summarizes the patterns of ISO-NE's imports and exports.

Figure 3 provides an overview of imports and exports for 2014 and 2015, which shows the hourly average net imports by season across the external interfaces with Quebec, New Brunswick, and New York.[23] The net imports across the two interfaces linking Quebec to New England (i.e., Phase I/II and Highgate) are combined. The net imports across the two interfaces between Connecticut and Long Island (i.e., Cross Sound Cable and the 1385 Line) are combined as well. The figure shows the average spreads in natural gas prices (in black lines) between New England and New York across their three interfaces. [24]

Figure 3: Average Net Imports from Neighboring Areas
By Season, 2014 – 2015



23 The figure shows a nine-season period from December 2013 to February 2016.

24 Gas indices reported by Platts are used to calculate the spread between New England and New York. On the New York side, gas indices for Iroquois Zone 2 are used for the CSC/1385 interfaces and the higher of gas indices for Iroquois Zone 2 and for Transco Zone 6 NY (plus a 7% NYC tax) are used for the primary interface. On the New England side, gas indices for Algonquin City Gates are used for all three interfaces.

Net imports to New England averaged 2.4 GW in 2015, consistent with 2014. Net imports satisfied 16 percent of real-time load in New England, modestly higher than the 13 percent in New York and significantly higher than the 2 to 4 percent in PJM and MISO markets. During periods of high imports from New York, New England has relied on imports to serve more than 20 percent of its load in some months.

The reason that New England (and New York) rely more on imports than most other US markets is because of their close proximity to low-price Canadian markets. Additionally, Natural gas pipeline limitations lead to higher production costs from gas-fired generation in New England, which attracts higher levels of electricity imports. This highlights the importance of efficient interchange scheduling with neighboring areas.

Net imports from Canada averaged around 1.9 GW in 2014 and 2015. Although the interfaces with Quebec were often fully utilized to import to New England, average net imports from Quebec were generally higher during peak hours and in the winter months during periods of high natural gas prices. This reflected the tendency for hydro resources in Quebec to store water during low demand (low profit) periods in order to make more power available during high demand (high profit) periods. This pattern is beneficial to New England because it tends to smooth the residual demand on New England internal resources.

New England's net imports from New York averaged roughly 450 MW in 2014 and 2015. Flows across the primary interface with upstate New York and the two controllable interfaces with Long Island exhibited a seasonal pattern, which was strongly correlated with the spreads in natural gas prices between the two markets. New England imported significantly more power across the primary interface from upstate New York (and exported less power across the two controllable interfaces to Long Island) in the winter months for several reasons:

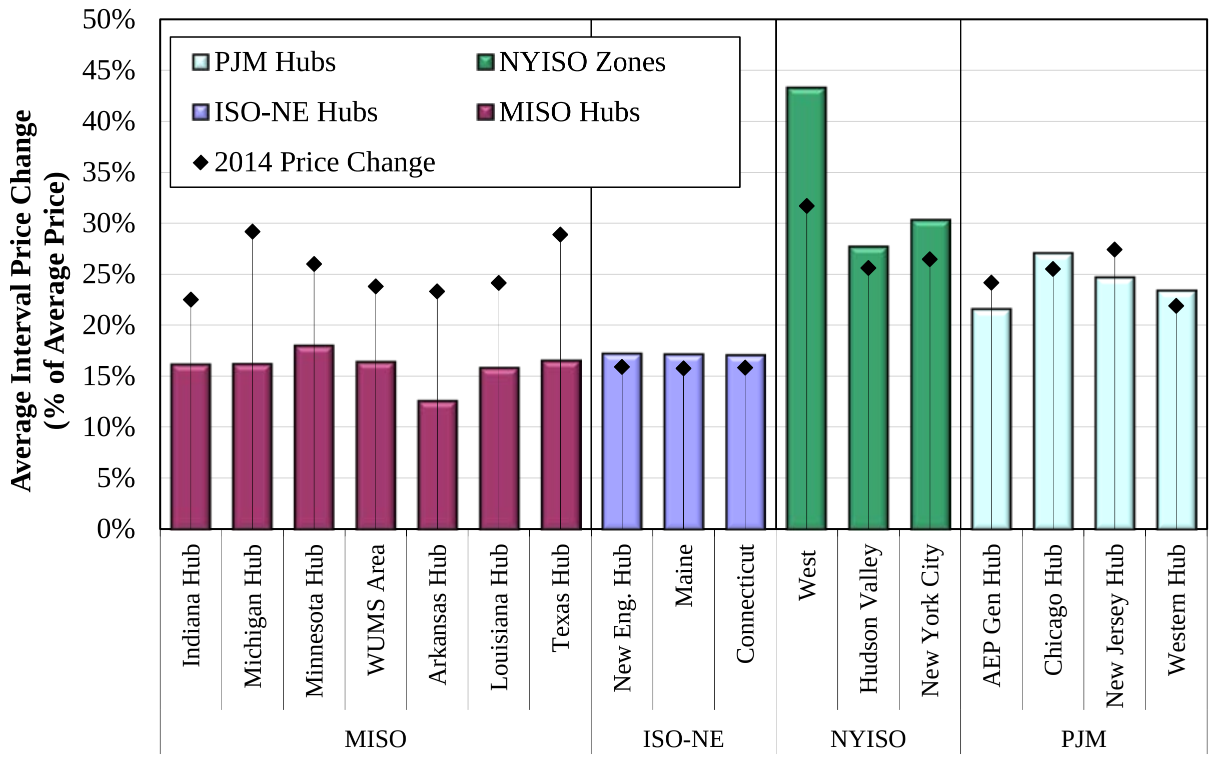
- First, New England is more reliant on natural gas generation, which is typically most expensive in the winter months.
- Second, the spread in natural gas prices between New England and eastern New York tends to increase in the winter months when demand for heating rises. The gas spreads between New England and New York averaged roughly $1.50 to $2.00 per MMBtu in the winter but only $0.30 per MMBtu in the remaining three seasons of 2015.

5. Real-Time Price Volatility

Volatility in real-time energy markets is expected because the demand of the system can change rapidly, and supply flexibility is restricted by the physical limitations of resources and the transmission network. In contrast, the day-ahead market operates on a longer time horizon with more commitment options and liquidity provided by virtual transactions.

Real-time markets solve over a limited time horizon – 15 minutes in New England.[25] The real-time market only has access to the dispatch flexibility that its units can provide in this horizon. Since the real-time market software is limited in its ability to anticipate near-term needs, the system is frequently "ramp-constrained" (i.e., generators are moving as quickly as they can). This limitation can result in transitory price spikes (upward or downward). Figure 4 compares fifteen-minute price volatility (the percentage change in prices, up or down, each quarter hour) at representative points in ISO-NE and in three other RTOs in the eastern interconnect.

Figure 4: Fifteen-Minute Real-Time Price Volatility
2014 - 2015



[25] MISO and NYISO dispatch over a 5 minute horizon while PJM is consistent with ISO-NE.

This figure shows that volatility in New England did not change significantly from 2014 to 2015. Reduced price volatility during the winter months offset the effects of two market changes implemented in December 2014 that tended to increase volatility:

- The increases of the RCPFs for system-wide total 10-minute and 30-minute reserve requirements to $1,500 and $1,000/MWh, respectively; and
- The decrease of energy offer floor to -$150/MWh.

These changes have improved real-time price formation during shortage conditions and during over-supply conditions. These improvements are beneficial in part because real-time price volatility rewards flexible resources and improves the incentives for all suppliers to be available and perform well in following the ISO's dispatch instructions.

The figure shows that New England was the least volatile of the RTO/ISO markets in the eastern interconnect. However, price volatility in the MISO market fell notably in 2015 after it implemented its Extended Locational Marginal Pricing model in March. This model allows offline peaking resources to set prices during shortages and, based on our evaluation, has inefficiently muted volatility. When MISO addresses this concern, the volatility in MISO should rise to historical levels. We do not expect ISO New England's fast-start pricing project to raise this concern because of key differences in the designs.

Several factors have contributed to typically low price volatility in New England, including:

- ISO New England (and PJM) dispatches their systems every 10 to 15 minutes. Their longer time horizon results in lower volatility by allowing the model more ramp capability from interval to interval.
- ISO New England experiences much smaller fluctuations in imports and exports than some of the RTO's, particularly MISO and PJM.
- ISO New England experiences much less congestion, and much of the price volatility observed in other markets is related to variations in congestion patterns.
- Some RTOs have larger amounts of unpredictable supply and demand than ISO-NE, including wind output on the supply side and "non-conforming" load on the demand side.

B. Reserves and Regulation Markets

This subsection evaluates the operation of the markets for operating reserves and regulation. These markets only operate in real time and include system-level and locational reserve requirements. The real-time markets co-optimize the scheduling of reserves and energy, which enables real-time prices to reflect economic trade-offs between scheduling resources as reserves or energy. When available reserves are not sufficient to meet the requirement, the market will be short of reserves. The applicable Reserve Constraint Penalty Factor (RCPF), which represents the costs of the reserve shortage, will contribute to setting the price for reserves and energy in this case. ISO-NE also procures regulation to balance generation with load on a moment-to-moment basis. Unlike its reserve markets and other RTOs' regulation markets, ISO-NE's regulation market is not co-optimized with its reserves and energy markets.

The forward reserve market allows suppliers to sell reserves into a forward auction on a seasonal basis. The forward reserve market has both system-level and locational requirements. Suppliers that sell in the forward auction satisfy their forward reserve obligations by providing the specified class of reserves or offering above a designated price threshold.

Figure 5 summarizes market outcomes in the real-time reserves market, the forward reserves market, and the regulation market by quarter and by year in 2014 and 2015.[26] Although there are four geographic areas with reserve requirements: Boston, Southwest Connecticut, Connecticut, and the entire system (i.e., "All of New England"), our evaluation focuses on the system level because the reserve requirements in local areas were rarely binding in the past two years.

The figure shows average clearing prices over all hours for 10-minute spinning reserves, 10-minute total or "non-spinning" reserves, and 30-minute operating reserves.[27] Each price is broken into components for each underlying requirement. For example, the system-level 10-minute spinning reserve price is based on the costs of meeting three requirements: the 10-minute spinning and 10-minute total reserve requirements and the total 30-minute reserve requirement.

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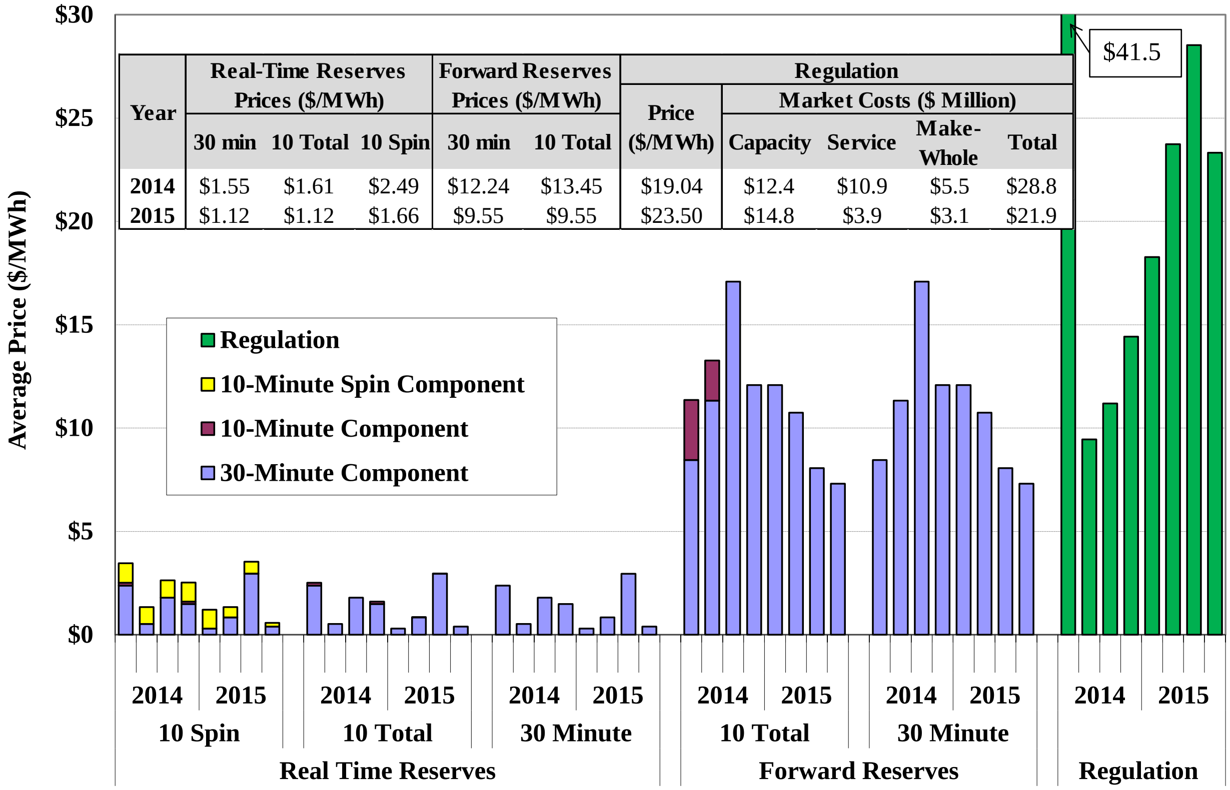
[26] ISO-NE holds two forward reserve auctions -- for the summer procurement period (June through September) and the winter procurement period (October through May). The reported quarterly average prices are time-weighted average clearing prices in the relevant procurement-period auctions.

[27] ISO-NE does not purchase 10-minute spinning reserves in the forward reserve auctions.

Unlike resources providing forward reserves and real-time operating reserves, resources providing regulation service receive other market payments in addition to the payment for availability. The inset table reports these payments to resources providing regulation service in the following categories:

- Capacity Payment = the Regulation Capacity Clearing Price times the amount of regulation capability provided by the resource.
- Service Payment = the Regulation Service Clearing Price times the amount of actual regulation movement (i.e., the up and down movement in MW) provided by the resource.
- Make-Whole Payment = Paid when the revenues from the regulation clearing price are less than the as-offered costs of providing regulation.

Figure 5: System-Level Reserves Clearing Prices and Regulation Costs
By Quarter, 2014 – 2015



Year	Real-Time Reserves Prices ($/MWh)			Forward Reserves Prices ($/MWh)		Regulation				
						Price	Market Costs ($ Million)			
	30 min	10 Total	10 Spin	30 min	10 Total	($/MWh)	Capacity	Service	Make-Whole	Total
2014	$1.55	$1.61	$2.49	$12.24	$13.45	$19.04	$12.4	$10.9	$5.5	$28.8
2015	$1.12	$1.12	$1.66	$9.55	$9.55	$23.50	$14.8	$3.9	$3.1	$21.9

To provide context on the ancillary service prices in New England, Table 2 compares the annual average prices for each class of reserves between the ISO-NE, NYISO, and MISO markets. All prices shown as dashes are not applicable because that reserve class does not exist for that RTO.

Table 2: Summary of Reserve Prices by RTO
2014 – 2015

	ISO-NE		NYISO		MISO	
	2014	2015	2014	2015	2014	2015
Real-Time Reserves						
10-Minute Spin	$2.49	$1.66	$6.57	$3.30	$2.48	$1.51
10-Minute Total	$1.61	$1.12	$1.79	$0.87	$1.50	$0.88
30-Minute Total	$1.55	$1.12	$0.11	$0.00	-	-
Regulation	$19.04	$23.50	$13.79	$8.95	$12.04	$6.89
Day-Ahead Reserves						
10-Minute Spin	-	-	$8.32	$5.85	$2.58	$1.95
10-Minute Total	-	-	$4.14	$3.41	$1.35	$0.98
30-Minute Total	-	-	$0.43	$1.23	-	-
Regulation			$12.87	$9.23	$11.23	$7.18
Forward Reserves						
10-Minute	$13.45	$9.55	-	-	-	-
30-Minute	$12.24	$9.55	-	-	-	-

Real-Time Operating Reserves

Average real-time reserve prices fell 28 to 33 percent from 2014 to 2015, consistent with a similar decrease in real-time LMPs. In both years, the reserve requirements that accounted for most real-time reserve costs were the system 30-minute reserve requirement and the 10-minute spinning reserve requirement. System 10-minute spinning reserves prices fell in 2015 as energy prices fell because the main cost of providing spinning reserves is the foregone profits from selling energy.

The 30-minute reserve prices fell in 2015 because of less frequent shortages (of both the replacement reserve and 30-minute reserve requirements). Despite the overall reduction, 30-minute reserve prices were relatively high in the third quarter of 2015 partly because:

- Higher load levels and more frequent peaking conditions resulted in more frequent tight system conditions, and
- The ISO increased the RCPF for the 30-minute operating reserves from $500/MWh to $1,000/MWh in December 2014.[28] The higher RCPF has led to higher prices during 30-minute reserve shortages.

28 Likewise, the ISO increased the RCPF for the 10-minute total reserves from $800 to $1,500/MWh in December 2014. These changes improve the efficiency of real-time prices by allowing the ISO's true reliability needs to be more fully priced.

In general, Table 2 shows that ISO-NE's prices were comparable to the other RTO's shown. The differences can be explained by differences in the requirements in each market, and the differences in the available supply to satisfy the requirements:

- ISO-NE's 30-minute reserve requirement was 64 percent larger (as a share of average demand) than the NYISO's, which resulted in much higher reserve prices in ISO-NE (while the MISO does not have a requirement for 30-minute reserves).
- ISO-NE had lower spinning reserve prices than the NYISO primarily because ISO-NE has a larger proportion of fast-ramping combined cycle generation online in most hours.
- Although ISO-NE also has a larger proportion of fast-ramping combined cycle generation than MISO, MISO's spinning reserve prices were similar because the MISO's spinning reserve requirement is roughly 50 percent lower (as a share of demand) than ISO-NE's.

Forward Reserves

Similar to real-time operating reserves prices, the average clearing prices for forward reserves fell 22 to 29 percent from 2014 to 2015. Forward reserve suppliers are paid based on the difference between the forward reserve clearing price and the forward capacity price. For example, after deducting the forward capacity prices, the effective forward 30-minute reserve clearing prices fell from roughly $8.10/MWh in 2014 to $5.00/MWh in 2015.[29] Similar to prior years, we also found that nearly all of the resources assigned to satisfy forward reserve obligations in 2015 were fast-start resources capable of providing offline reserves.

The value of the forward reserve market is questionable because:

- It has not achieved one of its primary objectives, which was to lower NCPC by purchasing forward reserves from high-cost units frequently committed for reliability.
- The forward procurements do not ensure that sufficient reserves will be available during the operating day. Forward reserve sellers are simply obligated to offer at prices higher than the Forward Reserve Threshold Price, but may still be dispatched for energy. In 2015, the day-ahead market did not schedule sufficient energy and operating reserves to satisfy the system's forecasted needs in some hours on 60 days (even though forward reserve providers met their obligations).
- The obligation of forward reserve suppliers to offer at prices higher than the Forward Reserve Threshold Price can distort the economic dispatch of the system and inefficiently raise costs. These distortionary effects will have larger price effects in the future when the ISO begins to allow peaking units to set the LMP.

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29 Effective for the summer 2016 forward reserve auction, the ISO eliminated the provision that would deduct the value of forward capacity from the forward reserve payment rate. See docket ER16-921-000.

Accordingly, we recommend ISO-NE eliminate the forward reserve market. (See Recommendation 5).

We also recommend the ISO introduce day-ahead reserve markets that are co-optimized with energy (See Recommendation 4). Such markets would allow the ISO to procure sufficient resources to satisfy its combined energy and operating reserves needs for the following day and to set clearing prices that reflect the costs of satisfying the operating reserve obligations. Such markets would also likely help address the ISO's concerns regarding unit availability. The day-ahead reserve schedules would be established in a timeframe in which suppliers can make arrangements for fuel and staffing to allow them to respond to reserve deployments. This is particularly true for spinning reserve providers, since it is prohibitively costly for them to accept forward reserve obligations for an entire procurement period.

Regulation Service

In 2015, an average of over 600 MW of available supply competed to provide less than 60 MW of regulation service. The significant excess supply generally limited competitive concerns in the regulation market.

Total regulation expenses fell 24 percent to $21.9 million in 2015. The decrease was largely attributable to lower natural gas prices in 2015, which generally led to lower opportunity costs to provide regulation service and lower movement costs even though the clearing prices was higher.

Table 2 above shows that the average regulation capacity clearing price rose 23 percent from 2014 to 2015, which resulted from a market design change implemented by the ISO on March 31, 2015 in compliance with FERC Order 755. This change allowed two-part bidding for availability and movement, and decoupled the compensation rate for actual regulation movement from the rate for availability.

Table 2 shows that regulation prices were notably higher than in the MISO and NYISO markets. This is partly attributable to the fact that the regulation market was separately cleared in real-time (once every hour at the top of the hour) and was not co-optimized with energy and operating reserves as they are in MISO and NYISO. This hourly clearing process tends to increase the foregone energy profit for units providing regulation service, thereby raising the overall cost of procuring regulation. Co-optimizing this market in New England would improve its performance.

C. Out-of-Market Actions and Uplift Costs

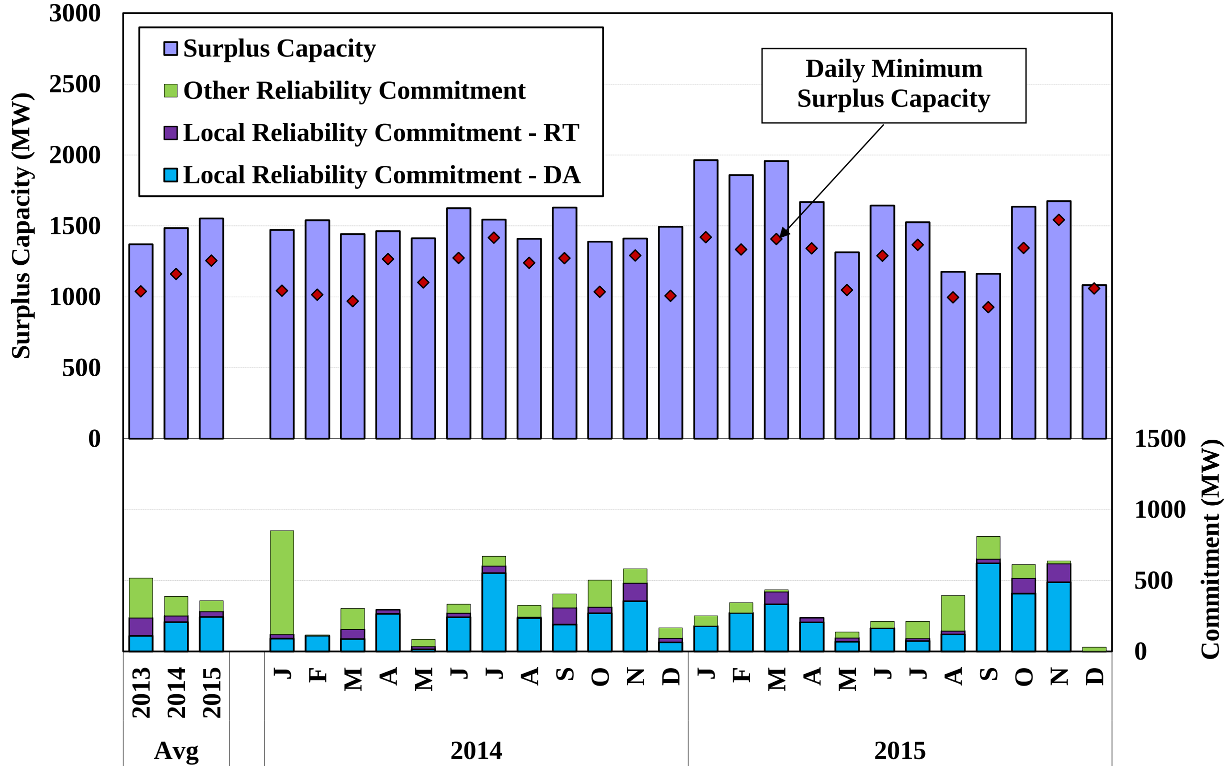
ISO-NE's markets generally procure sufficient resources to satisfy local and system reliability requirements. However, the ISO must sometimes commit additional generators to meet these requirements. Once committed, these generators may lower market prices and generally require NCPC payments to recover their as-bid costs. Hence, it is important to evaluate the supplemental commitments made by the ISO.

1. Supplemental Commitment and Surplus Capacity

Given the effects of supplemental commitment on market signals, it is important to minimize these commitments while still maintaining reliability. Figure 6 shows the average amount of capacity committed to satisfy local and system-level requirements in the daily peak load hour in each month of 2014 and 2015. Local Reliability Commitment shows capacity committed both in the day-ahead market and after the day-ahead market to: (a) ensure that reserves are sufficient in local constrained areas to respond to the two largest contingencies; (b) support voltage in specific locations of the transmission system; and (c) manage constraints on the distribution system that are not modeled in the market software (known as Special Constraint Resources ("SCRs")). Other Reliability Commitment shows capacity committed after the day-ahead market for local first contingency protection and for system-level reserve requirements together.

The figure shows the entire capacity of these units, although their impact on prices depends on the amounts of energy and reserves they provide to the market. In the upper panel of the figure, the blue bars show average surplus capacity in the daily peak load hour and the red diamonds indicate average daily minimum surplus capacity.

Figure 6: Supplemental Commitments and Surplus Capacity
During Daily Peak Load Hours, 2014-2015



Supplemental commitment by the ISO has decreased steadily over the past three years, falling by 30 percent from 2013 to an average of 360 MW during daily peak load hours in 2015. The overall reduction was largely due to the decrease of non-local reliability commitments from 2013 to 2015, which may associated with the higher levels of day-ahead scheduling.

Local Reliability Commitments

Local reliability commitments accounted for nearly 80 percent of all supplemental commitments in 2015. Nearly half of local reliability commitments were made for the second contingency protection in Boston. Most Boston generating capacity is located at the Mystic plant, where combined cycle units are supplied with fuel through an LNG terminal, rather than the gas pipeline system. Consequently, the pattern of local reliability commitment in Figure 6 and the resulting NCPC charges shown in Figure 7 was affected by the pricing of LNG deliveries to New England (summarized in Figure 2). For example, during periods when Figure 2 shows that LNG prices were high relative to pipeline gas prices (June to October 2014, May to June 2015, and

September to October 2015), the amount of capacity committed for local reliability and the Boston-area second contingency protection NCPC uplift generally increased.

Transmission outages that reduce transfer capability into import-constrained areas were another important driver of higher local reliability commitment in some periods. Local reliability commitment rose in Boston in September partly because planned transmission outages reduced the import capability to Boston by more than 500 MW on average. Likewise, local reliability commitment rose in October and November when planned transmission outages greatly reduced its transfer capability across the New England West-East interface as on many days.

Most of local reliability commitment has shifted to the day-ahead market since May 2013 (from 46 percent in 2013 to 87 percent in 2015) because of enhancements in ISO procedures. Making these commitments in the day-ahead market has reduced over-commitment (because fewer units outside the local area are likely to be committed) and lowered costs.

Other Reliability Commitments

Other reliability commitments accounted for 21 percent of all supplemental commitments in 2015 and were mostly made for system-wide reserves. These commitments decreased more than 70 percent from an average of 280 MW in 2013 to 77 MW in 2015. The reduction coincided with increased net day-ahead load scheduling, which rose from 94.8 percent in 2013 to 97.6 percent in 2015.

Several changes in market operations since 2013 have contributed to the increase in net day-ahead scheduling and reduced commitment for system-wide reserves, including: a) earlier timelines for the day-ahead market and the RAA process starting in May 2013; b) revisions to the generator audit process in June 2013 to improve the reliability of reserve schedules; c) enhanced analytical tools to track supply and usage of natural gas on New England generators,[30]

2. NCPC Uplift Costs

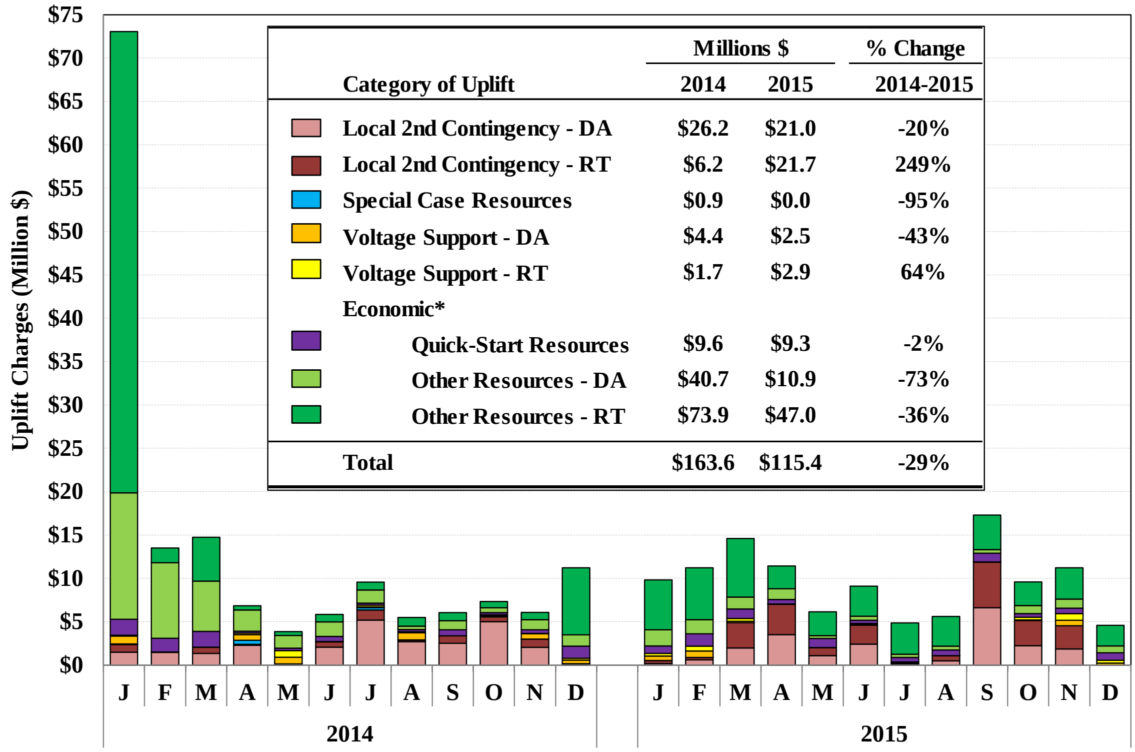
When ISO-NE makes supplemental commitments of resources that were not economic in the day-ahead market to satisfy the reliability needs of the system, such generators receive NCPC

[30] See our 2013 State of Market report Section VIII.C for more discussion of effects of these changes.

payments to recover their full as-bid costs. These costs are recovered from market participants through uplift charges. This subsection describes the main sources of NCPC uplift charges and how they are allocated to market participants. The following figure summarizes the monthly NCPC uplift in 2014 and 2015 incurred to meet local reliability requirements (second contingency protection, SCRs called by transmission owners, and voltage support), and to meet system-wide capacity and congestion management needs (economic and first contingency).

Uplift charges incurred to address local reliability are appropriate to allocate to the local customers who benefit directly from the commitments. For this reason, all local reliability commitments are allocated locally, with the exception of voltage support costs that are allocated system-wide. "Economic" NCPC is allocated throughout New England to real-time deviations (up or down) from participants' day-ahead schedules. This allocation to deviations is not consistent with the causes of this NCPC, which is discussed in Section III.A.

Figure 7: Uplift Costs by Category by Month[31]
2014 – 2015



31 Reported NCPC uplift payments are for internal resources only, which do not include the NCPC payments to external locations that totaled $10.6 million in 2014 and $2.7 million in 2015.

Total NCPC payments to internal resources fell from $164 million in 2014 to $115 million in 2015. The month-to-month variations in each category of NCPC uplift were generally consistent with the level of supplemental commitments and the level of natural gas prices, which affects the commitment costs of gas-fired units.[32]

- In the first quarter, NCPC payments fell from $101 million in 2014 to $37 million in 2015 because of: a) much lower natural gas prices, b) better resource performance, and c) procedural changes to make more reliability commitments in the day-ahead market when it is easier for units to procure fuel.
- In the remaining quarters, NCPC payments rose from $63 million in 2014 to $78 million in 2015, despite lower natural gas prices and reduced commitment for reliability. The increase was driven by NCPC rule changes discussed in the following paragraph.

NCPC uplift charges rose substantially beginning in December 2014 because of rule changes that over-compensate non-fast start units committed in the day-ahead market. The new rule would make NCPC payments to units whose offer costs were fully covered by day-ahead prices or units that were paid day-ahead NCPC to cover their offer costs. This resulted in double-payments to reliability-committed units and would tend to discourage suppliers from efficiently decommitting resources under low-priced conditions when excess resources are online. We estimated a total over-compensation of $57 million for the period from December 2014 to January 2016. In 2015, this over-compensation accounted for 41 percent of all internal NCPC uplift. We identified this concern in early 2015 and recommended the excess NCPC payments be eliminated. The ISO implemented this change in February 2016. We discuss this issue in more detail in Section III.B.

Supplemental commitment for second contingency protection in local areas occurs mostly in the day-ahead market and accounted for 23 percent of the NCPC uplift charges in 2015 (not including NCPC uplift resulting from the over-payment issue). Units in Boston accounted for the majority of NCPC uplift in this category. We discuss a recommended improvement in Section III.C that would reduce the amount of capacity committed for local reliability and the resulting NCPC charges significantly. Reducing the amount of capacity committed for reliability is also beneficial for price formation, since it allows the need for local resources to be reflected more in the prices of local energy and operating reserves.

32 These factors converged during the Polar Vortex, causing 45 percent of total NCPC uplift in 2014 to occur in January.

The "Economic" NCPC payments associated with fast-start resources were down slightly to $9.3 million in 2015. As discussed in Section II.C, fast-start resources committed economically by the real-time market can require NCPC payments to cover their as-offered costs because they often do not set the LMP at the level of their total offer cost. This underscores the importance of the ISO's project to modify the real-time pricing and dispatch software to allow fast start resources to set the clearing price when they are the marginal source of supply (i.e., when their deployment enables the real-time model to avoid scheduling more expensive resources).[33]

Finally, to place these costs in context, Table 3 shows the total day-ahead and real-time uplift costs over the past two years incurred by ISO-NE, NYISO, and MISO. Because the size of the ISOs varies substantially, the table also shows these costs per MWh of load. Recognizing that some RTOs differ in the extent to which they make reliability commitments in the day-ahead horizon versus real-time, the table includes a sum of all day-ahead and real-time uplift at the bottom to facilitate cross-market comparisons.

Table 3: Summary of Uplift by RTO
2014 - 2015

		ISO-NE		NYISO		MISO	
		2014	**2015**	**2014**	**2015**	**2014**	**2015**
Real-Time Uplift							
Total	**Local Reliability ($M)**	$7.95	$23.02	$8.65	$10.54	$8.23	$6.67
	Market-Wide ($M)	$77.55	$51.87	$45.90	$13.70	$114.04	$57.36
Per MWh of Load	**Local Reliability ($/MWh)**	$0.06	$0.18	$0.05	$0.07	$0.01	$0.01
	Market-Wide ($/MWh)	$0.60	$0.40	$0.29	$0.08	$0.17	$0.09
Day-Ahead Uplift							
Total	**Local Reliability ($M)**	$30.60	$23.11	$64.32	$34.81	$90.59	$54.23
	Market-Wide ($M)	$40.65	$9.13	$12.01	$3.53	$47.94	$26.57
Per MWh of Load	**Local Reliability ($/MWh)**	$0.24	$0.18	$0.40	$0.22	$0.13	$0.08
	Market-Wide ($/MWh)	$0.32	$0.07	$0.08	$0.02	$0.07	$0.04
Total Uplift							
Total	**Local Reliability ($M)**	$38.56	$46.13	$72.97	$45.35	$98.82	$60.90
	Market-Wide ($M)	$118.20	$61.00	$57.91	$17.23	$161.98	$83.93
Per MWh of Load	**Local Reliability ($/MWh)**	**$0.30**	**$0.36**	**$0.46**	**$0.28**	**$0.15**	**$0.09**
	Market-Wide ($/MWh)	**$0.92**	**$0.48**	**$0.36**	**$0.11**	**$0.24**	**$0.13**
	All Uplift ($/MWh)	**$1.22**	**$0.84**	**$0.82**	**$0.39**	**$0.38**	**$0.22**

33 See Section IV.A for a discussion of this recommendation.

This table shows that on a per MWh basis, ISO-NE incurred more than twice as much uplift costs as NYISO or MISO. This difference can be attributable to a number of factors:

- ISO-NE's fuel costs tend to be higher than the other RTO's, leading to higher required make-whole payments.
- NYISO and MISO allocate uplift costs more consistently with cost causation, particularly MISO. MISO's allocation promotes full net load scheduling in the day-ahead market (i.e., close to 100 percent) and reduces the need to rely on high-cost peaking units to satisfy the incremental load in real time (generally contributes to market-wide uplift).
- ISO-NE's NCPC payment rules led to significant over-compensation for non-fast start units in 2015, although this issue was corrected in the first quarter of 2016.
- Both NYISO and MISO's software includes functionality that allows high-cost peaking resources to set prices that may otherwise require higher uplift payments to cover their as-bid costs. ISO-NE is working on a similar approach that is expected to lower NCPC uplift costs significantly.
- Gas pipeline operating issues tend to lead to higher gas availability concerns in New England than in other areas, which tended to increase the amount of supplemental commitments made by ISO-NE and associated uplift payments.

D. Forward Capacity Market

The Forward Capacity Market (FCM) is designed to attract and maintain sufficient resources to satisfy ISO-NE's long-term resource planning requirements efficiently. FCM provides economic signals that supplement the signals provided by the energy and ancillary services markets. In combination, these three sources of revenue provide economic signals for new investment, retirement decisions, and participation by demand response.

Forward Capacity Auctions are held roughly 3 years before the beginning of each year-long Capacity Procurement Period to provide sufficient lead time for a new generator to be built if its offer is accepted in an FCA. Ten FCAs have been held so far, which have facilitated the procurement of installed capacity through May 2020.

This section summarizes the outcomes of FCAs 9 and 10, which were held in February 2015 and February 2016 to procure capacity for the two years from June 1, 2018 to May 31, 2020. Table 4 shows the outcomes from these two FCAs for local capacity zones, the internal interfaces, and the overall system.[34] Cleared resources are divided by type of resource and location.[35] The amounts of un-cleared resources are divided into new unsold generation, de-listing generation, demand response resources, and imports. The table also shows the clearing prices from each FCA, separately for new and existing resources at each location.

Table 4: Summary of FCM Auction Results
FCA 9 – FCA 10

Modeled Capacity Zone/Interface	FCA	Cleared in the Auction (MW)					De-List/ Retire (MW)	Unsold (MW)			Reqmt/ Limit (MW)	Rate ($/kW-Mo)	
		Exist. Gen	New Gen	DR	Import	Total		New Gen	DR	Import		Existing	New
System Wide													
ISO-NE	FCA 9	29,382	1,060	2,803	1,449	34,694	656	1,032	253	1,362	34,189	$9.55	$9.55
	FCA 10	29,912	1,459	2,746	1,450	35,567	844	1,671	253	1,570	34,151	$7.03	$7.03
Import Zone													
NEMA/Boston	FCA 9	3,301	1	625	0	3,927	8	195	73	0	3,572	$9.55	$9.55
	FCA 10												
Connecticut	FCA 9	8,415	837	550	0	9,802	227	495	49	0	7,331	$9.55	$9.55
	FCA 10												
SEMA-RI	FCA 9	6,413	214	614	0	7,241	33	0	0	0	7,479	$11.08	$17.73
	FCA 10												
SouthEast NE	FCA 9												
	FCA 10	9,266	853	1,230	0	11,349	698	1,194	100	0	10,028	$7.03	$7.03
Interface													
Quebec	FCA 9				218	218				0	499	$9.55	$9.55
	FCA 10				224	224				59	483	$7.03	$7.03
New Brunswick	FCA 9				177	177				213	177	$3.94	$3.94
	FCA 10				181	181				473	181	$4.00	$4.00
New York	FCA 9				1,054	1,054				1,149	1,054	$7.97	$7.97
	FCA 10				1,045	1,045				1,212	1,046	$6.26	$6.26

FCA 9

The system-level sloped demand curve was used for the first time in FCA 9, which set the price at $9.55 per kW-month for all new and existing resources located outside the SEMA-RI zone (excluding external resources). There was no price separation between all of New England, NEMA/Boston, and Connecticut because excess capacity cleared in both local capacity zones.

34 Auction results were not shown for Southeast New England in FCA 9 because it was not modeled in this auction. Likewise, results for NEMA/Boston, Connecticut, and SEMA-RI are not shown in FCA 10.

35 These limits and requirements include: a) the Local Sourcing Requirement ("LSR") for NEMA/Boston, Connecticut, SEMA-RI, and Southeast New England, b) the import limit for each external interface; and c) the Net Installed Capacity Requirement ("NICR") for the overall system.

The SEMA-RI Capacity Zone was modeled for the first time in FCA 9. However, there were inadequate resources to meet the zone's LSR. Therefore, the Inadequate Supply Rule was invoked, setting price in SEMA-RI for new and existing resources at $17.73 and $11.08 per kW-month respectively. New York AC Ties imports and New Brunswick imports cleared at a lower price of $7.97/kW-month and $3.94/kW-month respectively. This occurs to ration the available transfer capability when more external capacity is offered than can be delivered over interface.

FCA 10

Southeast New England ("SENE") was the only Local Capacity Zone modeled in FCA 10, which includes three load zones: NEMA/Boston, SEMA, and Rhode Island. However, there were adequate resources to meet the zone's LSR and, thus, no price separation between the SENE Capacity Zone and the rest of New England. The supply margin increased because:

- The requirement for the combined SENE zone was 1 GW lower in FCA 10 than the sum of requirements for NEMA/Boston and SEMA/RI in FCA 9; and
- More than 2 GW of new generation participated in the auction, more than offsetting the 677 MW delisted before auction due to the announced retirement of the Pilgrim unit. This new generation was a sizable increase from the 410 MW offered in FCA 9.

At the system level, the auction was closed by the withdrawal of a non-rationable offer from new capacity at $7.03/kW-month, which set the clearing price for all new and existing resources in all of New England (except imports over the New York AC Ties and New Brunswick interface). This price is substantially less than Net CONE, which may indicate that the new capacity had cost advantages over a typical green-field project, or that the new developers had incurred substantial costs and were largely committed to entering prior to the auction. The interfaces cleared at lower prices for the same reasons discussed above for FCA 9.

Although the auction results in FCA 9 and FCA 10 were generally competitive, they revealed issues that may undermine the competitive performance of the capacity market in the future:

- First, the descending clock auction format likely diminished competitive discipline on suppliers at the New York AC Ties interface in FCA 9 and in FCA 10. This issue is discussed further in Section IV.
- Second, one of the administrative pricing rules, the Inadequate Supply Rule, was invoked in FCA 9. The administrative pricing rules produce less efficient price signals that lead

to less efficient decisions by market participants because they discriminate in favor of new resources against existing resources.

The ISO has proposed to eliminate the administrative pricing rules when sloped demand curves are introduced in the local zones for FCA 11. Together, these changes will foster more robust competition from new and existing resources.[36]

E. Long-Run Price Signals

The ISO-NE markets play a critical role in governing investment, retirement, and other long-term decisions made by market participants. The expected net revenues from ISO New England's energy, ancillary services, and capacity markets are the primary economic signal governing these decisions. Therefore, it is important to evaluate the net revenues earned by generators, which are defined as the total revenues that a generator would earn (from all market and non-market sources) less its variable production costs. These net revenues serve to cover a supplier's fixed costs and the return on its investment.

Net revenues may not be sufficient in the short-run to justify entry of a new generator when: new capacity is not needed, load conditions are below expectations due to mild weather, or market rules or conduct are causing revenues to be reduced inefficiently.

Alternatively, if prices provide excessive revenues in the short-run, this would indicate a shortage of capacity, unusually high load conditions, or market rules or conduct resulting in inflated prices. Evaluating the net revenues allows us to assess the design and performance of the market in providing efficient long-run economic signals.

In addition to evaluating net revenues for conventional new resources, the recent decline in natural gas prices coupled with state and federal initiatives to reduce CO_2 emissions has increased the interest in the net revenues of existing nuclear units and new renewable generation. By comparing net revenue to the CONE or GFC of a particular technology, we can approximate the cost of reducing emissions by increasing the amount of that technology type. In addition, the entry or retention of low-emission generation can have significant impacts on the resource mix,

36 See ISO-NE filing in Docket No. ER16-1434, dated April 15, 2016. Also see supporting intervention of Potomac Economics, dated May 13, 2016.

market operation, and market design, especially at high renewable penetration levels. Thus, it is important to monitor the incentives for the entry and continued operation of such resources.

In this report, we estimate the net revenues received by the following types of representative plants located at the New England Hub: (a) new and existing gas-fired units, (b) new utility-scale solar PV units, (c) new onshore wind units, and (d) existing nuclear plants.

1. Net Revenues for Gas-Fired Units

We estimate the net revenues the ISO-NE markets would have provided to three types of older existing gas-fired units and to the three types of new gas-fired units, which include most of the new generation built in ISO-NE in recent years. The technologies we evaluate are:

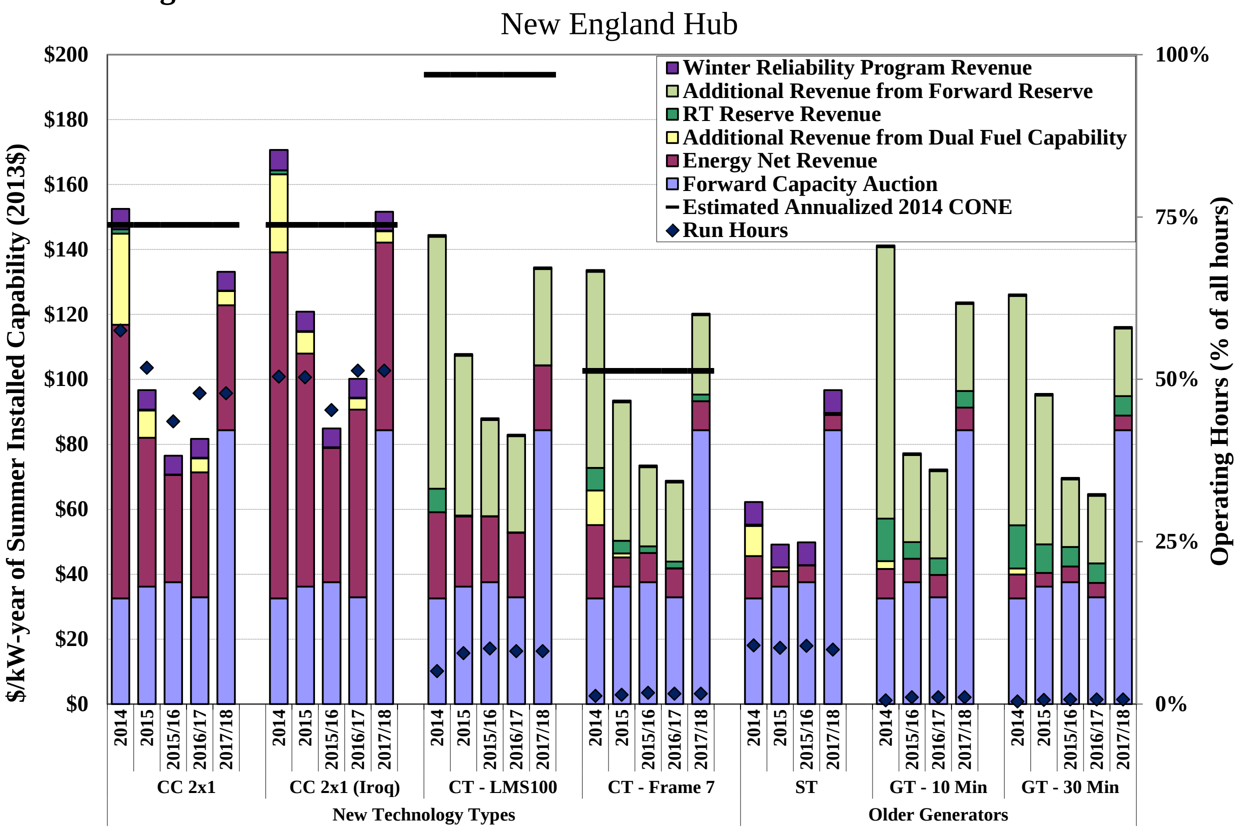
- *Hypothetical new units*: (a) a 2x1 Combined Cycle ("CC") unit, (b) a LMS 100 aeroderivative combustion turbine ("LMS") unit, and (c) a frame-type F-Class simple-cycle combustion turbine ("Frame 7") unit; and
- *Hypothetical existing units*: (a) a Steam Turbine ("ST") unit, (b) a 10-minute Gas Turbine ("GT-10") unit, and (c) a 30-minute Gas Turbine ("GT-30") unit.[37]

Estimated net revenues are shown separately by revenue category (e.g. capacity versus energy and ancillary services). We simulate the two-settlement system by calculating net revenues based on day-ahead prices and schedules, but allow gas turbines to be committed and dispatched based on the real-time prices (deviations from day-ahead schedules are settled at real-time prices). A detailed list of assumptions is provided in Appendix A.

Figure 8 summarizes the net revenue estimates and the levelized Cost of New Entry ("CONE") for three new gas-fired technologies. The figure shows net revenues from each of the ISO's markets in which a resource is capable of participating. The revenues shown for the Forward Reserve market are only those that exceed the revenue that would be earned from selling energy, real-time operating reserves, and capacity. The figure also shows the additional revenues that units possessing dual-fuel capability would have earned from the ISO-NE markets. The Winter Reliability Program Revenue is based on the average revenue earned by the participating resources. The CONE value is from the analysis supporting ISO-NE's 2014 demand curve reset.

[37] Fuel costs are based on the Algonquin City Gates gas price index. We performed additional simulations to analyze the profitability of a CC unit ("CC (Iroq)") with access to gas priced at the Iroquois Zone 2 index.

Figure 8: Annual Net Revenue for Gas-Fired and Dual Fuel Generators



Net revenues fell significantly from 2014 to 2015 for most technologies because falling natural gas prices led to lower energy prices, and because the unusually high energy revenues during the Polar Vortex in early 2014 were not repeated in 2015. Even though New England experienced colder-than-usual weather in early 2015, lower prices for fuel oil and LNG and improved generator performance that led to lower winter net revenues. In the first quarter, the average net energy and ancillary services revenue received by the new combined cycle unit fell by 65 percent from the prior year. The relatively mild winter weather in early 2016 has further reduced the net revenues for most types of units. However, the increase in capacity prices beginning in the 2017/2018 planning year will significantly increase the net revenues for all of the units shown.

Profitability of New and Existing Units

Among new resources, the net revenues for a new combined cycle unit would normally be much higher than those for a new gas turbine because it is much more efficient and would be dispatched more often. However, the additional forward reserve revenues provided to gas turbines lead their net revenues to be comparable to those of the combined cycle unit in 2015.[38]

Since the CONE for a Frame 7 gas turbine is much lower, the analysis indicates gas turbines would have been closer to recovering their annualized new entry costs in 2015 than a combined cycle unit. In reality, however, these units are less economic investments than the combined cycle units. We do not expect these net revenues for gas turbines to induce new investment if developers believe the inflated forward reserves net revenues will be short-lived. Nonetheless, we are concerned about the excessive revenues provided by forward reserve market to a specific subset of generators, which can lead to inefficient investment decisions.

Accordingly, we recommend eliminating the Forward Reserve Market and incorporating operating reserve products into the existing day-ahead market. Co-optimizing reserves with energy in the day-ahead market results in prices that are more competitive and efficient than the Forward Reserve Market because all resources can compete to provide operating reserves.

For older existing units, the estimated net revenues were generally higher than the annualized Going Forward Costs ("GFC"), which is expected since older units would retire if net revenues fell below their GFCs for a significant period. Among these units, net revenues were highest for gas turbines, primarily because of the high forward reserve prices. Although energy net revenues and winter reliability program revenue were significant for dual-fueled steam turbines, steam turbines earned the vast majority of their net revenue from selling capacity. Given the moderate capacity prices up to 2017, it is not surprising that 30 percent of the steam turbine capacity in service before 2010 has retired or plans to retire by 2017. With the retirement of the 1.5 GW Brayton Point steam turbine plant in 2017, the capacity surplus will dissipate and the capacity prices after 2017 are substantially higher. This should allow the remaining steam turbines to be more profitable. Notwithstanding this trend, steam turbine units will face additional challenges once the Pay-For-Performance ("PFP") capacity market rules phase-in from 2018 to 2024, since PFP will shift an increasing portion of the capacity revenue towards generators that are frequently online or available to start within 30 minutes.

38 The reserve revenues for Frame 7 units in the ISO-NE exceeded the reserve revenues for comparable units in NYISO, MISO and ERCOT by 36 to 45 per kW-year in 2014 and 2015.

Impacts of Natural Gas Pipeline Congestion

Our analysis also shows that the source of natural gas can be important. A unit with access to gas priced at the Iroquois Zone 2 index (which is the case for many generators in Connecticut) would have earned up to $27 per kW-year more in 2015 than a similar unit that procures gas at the Algonquin City Gates index (which is more representative of other areas in New England). However, the average spread between Algonquin City Gates index and Iroquois Zone 2 index was reduced by the mild weather in early 2016. Consequently, units with access to Iroquois Zone 2 gas prices received only modest additional revenues in the winter of 2015/16. In addition, the current gas forwards indicate that the spread between these two indices is likely to diminish in the future because of new planned investments in areas served by the Iroquois pipeline. Nonetheless, this example illustrates that congestion on the natural gas pipeline system will lead to opportunities for well-situated suppliers and will likely influence investment decisions.

Incentives for Dual Fuel Capable Units

The ability to switch fuels away from natural gas can substantially affect a unit's net revenues. Although additional revenues from the dual fuel capability dropped significantly for all technologies from 2014 levels because of less extreme winter market conditions in 2015, the incremental net revenues a supplier earned in 2015 from having dual fuel capability were substantial for combined-cycle units (~$8 per kW-year not including Winter Reliability Program revenue).[39] This analysis shows the role that efficient real-time energy pricing can play in providing incentives for suppliers to incur costs to increase their availability and performance, such as maintaining dual fuel capability. These increased net revenues reflect the increased reliability value these units provide to the system.

The effect of dual fuel capability was minimal for gas turbines because many can provide reserves during tight gas supply conditions without having to run on the alternative fuel. While high operating reserve revenues for these units are justified under tight gas conditions if the units

[39] This analysis does not include all of the additional costs necessary to maintain an inventory of fuel oil, and that the use 0of fuel oil may be limited by low inventories or air permit restrictions.

can reliably by deployed, they are not justified if the units' ability to acquire gas is questionable. This indicates the importance of programs that ensure that off-line peaking units selling operating reserves are capable of responding if deployed, particularly during winter operating conditions when some reserve providers may be less reliable than at other times of year.

Incentives for Flexible Units

The energy and reserve markets provide critical incentives for generators to be flexible and available in real-time when clearing prices are likely to be high. This is illustrated by the fact that an older gas turbine that can start quickly and provide off-line reserves would earn $33 to $79 per kW-year more net revenue than an older steam turbine (that has slower start times and longer operating times). Although this additional net revenue is inflated by the Forward Reserve Market, day-ahead operating reserve markets would also provide net revenues that would reward flexible units. Finally, as capacity margins fall and shortages are priced more efficiently, flexible units that can respond more effectively under these conditions will earn more net revenue.

The additional returns to being flexible and available highlight the benefits of the real-time pricing improvements during tight conditions that are discussed in Section IV.A. This additional revenue to flexible generation will increase as the PFP capacity market rules are phased-in from 2018 to 2024.

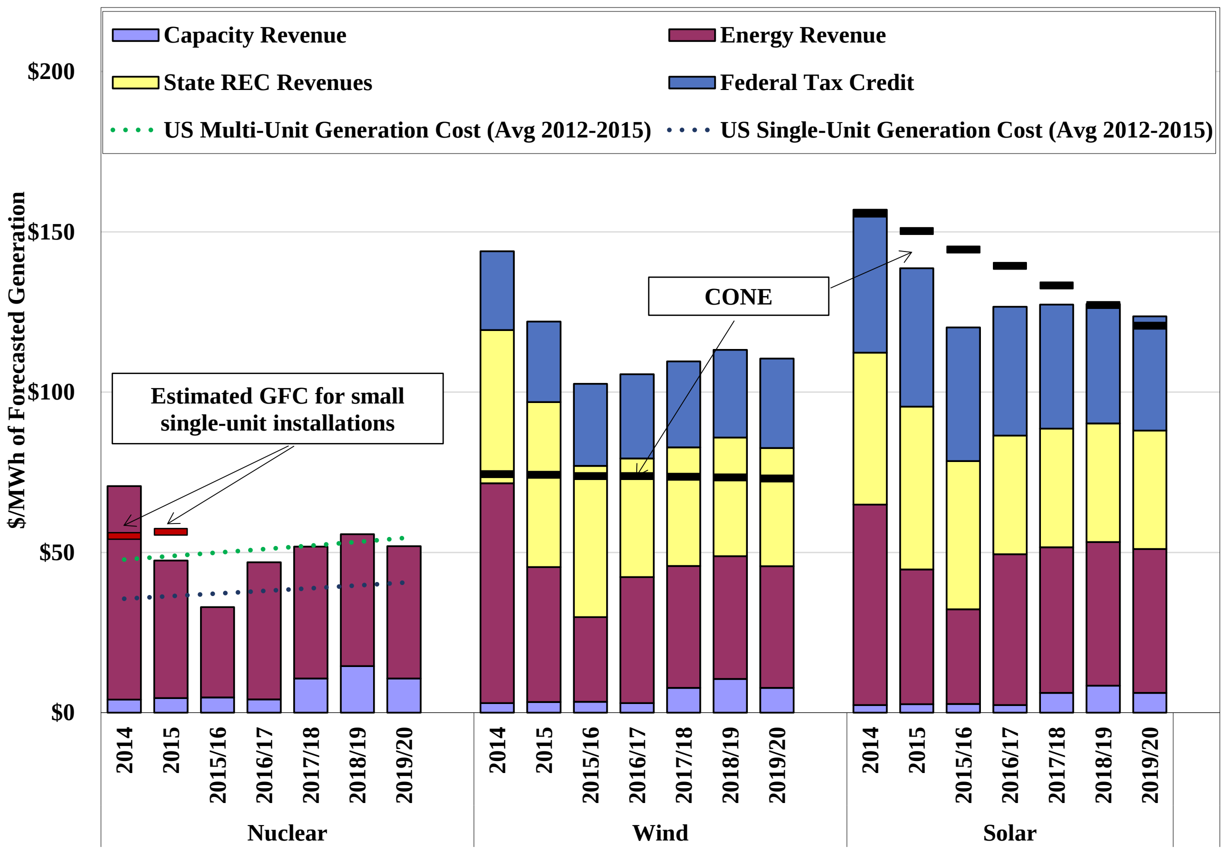
2. Net Revenues for Existing Nuclear and New Renewable Plants

We estimate the net revenues for representative existing nuclear plants as well as onshore wind and utility-scale solar PV plants based on wholesale prices at New England Hub. For each of these technologies, we estimated the revenues from the ISO-NE markets and the state and federal incentive programs. These assumptions are detailed in Appendix A.

Figure 9 summarizes the estimated net revenues for three types of zero-emission technologies for the years 2014, 2015, and Capacity Commitment Periods from 2015/16 through 2019/2020. Hourly energy prices for future periods are derived from OTC peak and off-peak futures. For comparison, the figure also shows the CONE estimates for renewable resources and average cost of generation (including O&M, fuel, and capex) for existing nuclear plants in the US.

The operating costs and the GFC for nuclear plants can vary significantly based on several factors, including the number of units at the plant, technology and age. Hence, Figure 9 also shows the estimated GFC for smaller (< 1000 MW) single-unit nuclear plants in ISO-NE.[40] Net revenues are shown for each of the revenue streams that the generator is able to receive from the wholesale electricity markets. In addition, new renewable generators are usually eligible for certain state and federal incentives in addition to revenues from the ISO-NE's markets.

Figure 9: Annual Net Revenue for Existing Nuclear and New Renewable Plants
New England Hub, 2014 through 2019/20



The estimated net revenues for nuclear and renewable plants decreased markedly from 2014 to 2015 in line with the overall decrease in energy prices discussed in the prior sub-section.

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40 The GFC values for small, single-unit nuclear plants are based on the all-in cost estimates for the Pilgrim unit by UBS analysts. See "US Electric Utilities & IPPs De-Nuclearizing the Northeast", October 13th 2015. The average cost of operation of nuclear plants in the US are based on NEI/ EUCG reports and presentations. See http://www.nei.org/Issues-Policy/Economics/Financial-Analyst-Briefings and http://www.nei.org/CorporateSite/media/filefolder/Policy/Papers/statusandoutlook.pdf?ext=.pdf

Net Revenues for Nuclear Plants

Energy revenues constitute the majority of the revenue received by nuclear plants and accounted for 85 percent of the estimated net revenue in 2015/16, much higher than the share of energy revenues for all other types of units. Hence, expected energy prices play a much more dominant role in the decision to retire or continue operating a nuclear unit than expected capacity prices. Consequently, the sharp decline in natural gas prices and associated reduction in energy prices have placed substantial economic pressure on nuclear resources throughout the country.

The results indicate that estimated net revenues were lower than the GFCs for small, high-cost nuclear plants in 2015/16. Based on electricity forward prices and the forward capacity auctions, these units would be unlikely to recoup its GFCs from the wholesale markets through 2019/20.[41] The economics of larger (> 1000 MW) nuclear plants are expected to improve after 2017 as capacity revenues increase, however net revenues beyond 2017 are uncertain and quite sensitive to certain policy and regulatory outcomes. For instance, the forecasted energy net revenues for the 2016/17 increased by $4/MWh from early March (before the Constitution pipeline permit application was rejected) to early May.[42] Hence, a larger single-unit nuclear plant may not be able to recover its operating costs over the remainder of the decade if energy prices remain low.

Net Revenues for Renewable Plants

Renewable units rely on revenues from the ISO-NE markets, as well as from state and federal incentive programs. Over 70 percent of the estimated net revenues for both wind and solar units in the 2015/16 period were from federal and state programs, such as the purchase of Renewable Energy Credits ("RECs") and the Investment or Production Tax Credits ("ITC" or "PTC"). Given the relatively low capacity value of solar PV and onshore wind units, energy market revenues constitute a large majority of the wholesale market revenues these units receive.

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41 The additional revenues from the PFP market rules are unlikely to generate sufficient revenues for the small nuclear installations to recover their GFCs. The additional PFP revenues will be less than $0.5 per MWh assuming the following parameters: H = 14.7, A = 0.975, Br = 0.85.

42 The Constitution pipeline was proposed to bring up to 650,000 Dth/day from Pennsylvania to an interconnection with the Iroquois and Tennessee pipelines near the New York/Massachusetts border. This would have helped increase the supply of natural gas to New England.

Onshore wind plants appear to be economic in 2014 and 2015, primarily due to REC revenues and the PTC. However, the future profitability of these units is likely to be lower than implied by our results for several reasons.

- REC prices in the New England states have been on a downward trend as the quantity of renewable resources increase and their entry costs fall.
- The PTC is set to gradually decrease for units commencing construction in 2017 and later.[43]
- Almost 1 GW of new onshore wind units have signed interconnection agreements (with an additional 4 GW of wind capacity in the interconnection queue). As these projects are developed, the availability of low-cost sites for wind power will decline.
- Lastly, our analysis is based on a representative wind project that is able to secure energy revenues at the hub prices. The energy prices received by projects at other locations are likely to be negatively affected by transmission congestion and losses.

The estimated net revenues for a utility-scale solar PV unit, though higher than those for the wind unit, were lower than its annualized CONE in 2015/16. The investment costs for utility-scale solar PV are projected to decrease by 18 percent from 2015 to 2020. However, future solar PV projects will (like onshore wind units) be limited by the availability of suitable locations and the tendency of net revenues to decrease as the penetration of solar increases.

Cost-Effectiveness of Measures to Reduce CO_2 Emissions

New renewable units, existing smaller nuclear units and hydropower-backed imports provide carbon-free electricity that may be needed to achieve public policy goals, such as complying with the Clean Power Plan. As a result, there are several initiatives being considered for soliciting energy or other related attributes from these resources. Some of the recent initiatives undertaken by states in ISO-NE include:

- The Massachusetts legislators are considering a bill to procure large-scale hydropower.[44]
- Massachusetts, Connecticut and Rhode Island issued a joint RFP to procure clean energy from a number of sources. (See https://cleanenergyrfp.com)

43 See http://energy.gov/savings/renewable-electricity-production-tax-credit-ptc

44 See http://www.mass.gov/governor/press-office/press-releases/fy2016/administration-files-hydropower-legislation.html.

- The Connecticut Senate passed a bill to allow study of procuring 8.4 TWh of energy from renewables, large-scale hydro and nuclear units.[45]

These initiatives would supplement the revenues these resources receive from the ISO-NE markets. However, the design of such mechanisms can have a significant effect on the long-term economic signals for all generators operating in the ISO's markets. Public policy initiatives are generally most economic when structured in a technology-neutral manner designed to minimize the costs of satisfying the objective. Undue preference for certain technologies is likely to increase the cost of satisfying the policy objectives. To illustrate this point, we estimate the cost per-ton of reducing CO_2 emissions using several generic investments (recognizing that the costs of individual projects vary based on their particular circumstances). Based on net revenues in 2015, we find that the costs of reducing CO_2 emissions varies substantially by technology:

- Building a new 2x1 combined cycle unit with access to gas priced at Iroquois Zone 2 index would cost $30 to $32 per ton, depending on the efficiency of the unit.[46]
- Building a new onshore wind unit would cost $8 to $12 per ton with subsidies, or $64 to $68 excluding state and federal subsidies.[47]
- Retaining a small, single-unit nuclear plant would cost $20 per ton.[48]
- Using utility-scale solar PV resources would cost $139 per ton.

In addition, hydro imports from Canada via multiple proposed HVDC transmission lines are being considered as a strategy to reduce CO_2 emissions. Given the costs of reducing emissions

45 See https://www.cga.ct.gov/2016/lcoamd/2016LCO05586-R00-AMD.htm

46 This assumes that the new combined cycle would displace generation with an average carbon intensity of 0.65 tons per MWh. The cost of reducing carbon emission using a combined cycle varies based on revenues at different locations and the efficiency of the unit, some of which are more efficient than the combined cycle unit we studied. For instance, one of the proposed combined cycle units that cleared in FCA-10 is significantly more efficient (heat rate of 6254 BTU/kWh HHV at 52F) than the unit we studied, which would cause it to run for more hours and receive more net revenues. Consequently, the actual cost of reducing carbon emissions by building new gas-fired generation may lower than our estimated value.

47 This assumes that the new renewable units would displace generation with an average carbon intensity of 0.45 tons per MWh. The range stated is based on assuming a capacity factor during peak hours ranging from 10 percent to 30 percent. The low end of this range is based on experience in New York and MISO, while the high end of the range is based on estimates in New England. Note that our analysis does not include interconnection costs, integration costs at high penetration levels of renewables could increase the cost of reducing carbon emissions by with wind generation.

48 This assumes that a retiring nuclear unit would lead to increased generation with an average carbon intensity 0.45 tons per MWh.

estimated above, the cost of procuring electricity from hydropower would need to range from $50 per MWh to $70 per MWh for this strategy to be as cost-effective.[49] Although the levelized costs of new Canadian hydro resources is likely higher than this range, the cost to New England would depend on the portion of the costs ultimately incurred by parties in New England.[50] For example, operational resources whose costs are sunk may contract at prices less than the full original investment cost given current conditions.

The uncertainty regarding the costs of different carbon-reduction options underscores the value of technology-neutral approaches to reducing emissions, such as the cap-and-trade carbon market that currently operates in New England. The Regional Greenhouse Gas Initiative ("RGGI") is a successful cap-and-trade market operating in this region that could potentially be modified to address New England's Clean Power Plan goals. This would likely reduce the costs of achieving the goals and minimize adverse effects on the ISO-NE capacity and energy markets.

3. Conclusions

The net revenues received from the ISO-NE markets for all types of units fell significantly in 2015 and in early 2016 because of the continued decline in natural gas prices. The net revenues were insufficient to cover the CONE for any of the hypothetical new gas-fired units that we analyzed. This result is expected given that current capacity surpluses that are expected until the summer of 2017. We draw several conclusions from this analysis for gas-fired units:

- *Reserve market revenues* – Net revenues are currently skewed in favor of fast-start units (and away from new CCs and older steam turbines) because of the forward reserve market. A day-ahead co-optimized energy and operating reserve market would better enable all resources to compete and lower costs overall.
- *Retirement trends* – Steam turbines are much more dependent on capacity revenues than other technologies. Accordingly, during the period of relatively low capacity prices from 2010 to the spring of 2017, 30 percent of steam turbine capacity in New England has retired or plans to retire. Capacity revenues are increasing beginning in the summer of 2017, thereby reducing financial pressure on steam turbines. However, the PFP rules will

49 This assumes that the imported hydropower via HVDC lines would displace generation with an average carbon intensity of 0.45 tons per MWh.

50 In addition to the cost of transmission, Hydro Quebec estimates the cost of electricity from the Romaine project to be $48 per MWh. See Page 55 of Hydro Quebec's 2015 Sustainability Report, available at http://www.hydroquebec.com/publications/en/docs/sustainability-report/rdd_2015_en.pdf.

reduce capacity revenues for steam turbines and other units with low-availability factors as it is phased-in from 2018 to 2024.

- *Revenues for Dual-Fuel Units* – Our analysis indicated that the additional revenue from dual fuel operation was substantial for combined cycle generation in 2015 (~$8/kW-month in addition to Winter Reliability Program revenue), indicating that there are incentives for many suppliers to install and maintain dual-fuel capability.

We also make several key observations regarding the net revenues for zero-emissions resources:

- *Nuclear Plant Viability* – Smaller, single-unit nuclear plants are likely to be unprofitable for the remainder of the decade. Larger nuclear units may become economic when capacity prices increase in 2017, but considerable uncertainty remains regarding future energy prices and associated net revenues.
- *Incentives for Renewable Development* – Net revenues for renewable generation depend primarily on federal and state incentive programs. Given these subsidies, estimated net revenues exceed entry costs for onshore wind units, which is consistent with the high levels of wind turbine installation in New England. Alternatively, utility-scale solar PV units were not economic in 2015, but may become marginally economic in the future if the cost of new installations falls as expected.
- Emission Reductions – The wide variation in the cost per ton of emission reductions through investments in different technologies underscores the importance of promoting technology-neutral, market-based solutions for emission reductions.

F. Competitive Performance of the Energy Market

This section evaluates the competitive performance of the ISO-NE wholesale markets in 2015. This type of assessment is particularly important for LMP markets. While LMP markets increase overall system efficiency, they can provide incentives for the localized exercise of market power in areas with limited generation resources or transmission capability. Most market power in wholesale electricity markets is dynamic, existing only in certain areas and under particular conditions. The ISO employs mitigation measures to prevent suppliers from exercising market power under these conditions. Although these measures have generally been effective, it is still important to evaluate the competitive structure and conduct in the ISO-NE markets because participants with market power may still have the incentive to exercise market power at levels that would not warrant mitigation.

Based on the analysis presented in this section, we identify the geographic areas and market conditions that present the greatest potential for market power abuse. We use a methodology for measuring and analyzing potential withholding that was developed in prior assessments of the competitive performance in the ISO-NE markets.[51] We address four main areas in this section:

- Mechanisms by which sellers exercise market power in LMP markets;
- Structural market power indicators to assess competitive market conditions;
- Potential economic and physical withholding; and
- Market power mitigation.

1. Market Power and Withholding

Supplier market power can be defined as the ability to profitably raise prices above competitive levels. In electricity markets, this is generally done by economically or physically withholding generating resources. Economic withholding occurs when a resource is offered at prices above competitive levels to reduce its output or otherwise raise the market price. Physical withholding occurs when all or part of the output of a resource is not offered into the market when it is available and economic to operate. Physical withholding can be accomplished by "derating" a generating unit (i.e., reducing the unit's high operating limit).

While many suppliers can cause prices to increase by withholding, not every supplier can profit from doing so. The benefit from withholding is that the supplier will be able to sell into the market at a clearing price above the competitive level. However, the cost of this strategy is that the supplier will lose profits from the withheld output. Thus, a withholding strategy is only profitable when the price impact exceeds the opportunity cost of lost sales for the supplier. The larger a supplier is relative to the market, the more likely it will have the ability and incentive to withhold resources to raise prices.

There are several additional factors (other than size) that affect whether a market participant has market power:

- The sensitivity of real-time prices to withholding, which can be very high during high-load conditions or high in a local area when the system is congested.
- Forward power sales that reduce a large supplier's incentive to raise prices in the spot market.[52]

[51] See, e.g., Section VIII, "2013 Assessment of Electricity Markets in New England", Potomac Economics.

- The availability of information that would allow a large supplier to predict when the market may be vulnerable to withholding.

2. Structural Market Power Indicators

This subsection examines structural aspects of supply and demand affecting market power. Market power is of greatest concern in areas where capacity margins are small, particularly in import-constrained areas. Hence, this subsection analyzes the three main import-constrained regions and all of New England using the following structural market power indicators:

- Supplier Market Share - The market shares of the largest suppliers determine the possible extent of market power in each region.
- Herfindahl-Hirschman Index ("HHI") - This is a standard measure of market concentration calculated by summing the square of each participant's market share.
- Pivotal Supplier Test - A supplier is pivotal when some of its capacity is needed to meet demand and reserve requirements. A pivotal supplier has the ability to unilaterally raise the spot market prices raising its offer prices or by physically withholding.

The first two structural indicators focus on the supply-side, providing some useful competitive inferences. However, their usefulness is limited because they ignore the demand-side factors (e.g., load relative to available supply) that substantially affect the competitiveness of the market.

The Pivotal Supplier Test is a more reliable means to evaluate the competitiveness of spot energy markets. When one or more suppliers are pivotal and have the incentive to take advantage of their position to raise prices, the market may be subject to substantial market power abuse. However, this does not mean that all pivotal suppliers should be deemed to have market power.[53] Suppliers must have both the *ability* and *incentive* to raise prices in order to have market power. For a supplier to have the ability to substantially raise real-time energy prices, it must be able to foresee that it will likely be pivotal. In general, the more frequently a supplier is pivotal, the easier it will be for it to foresee circumstances when it can raise the clearing price.

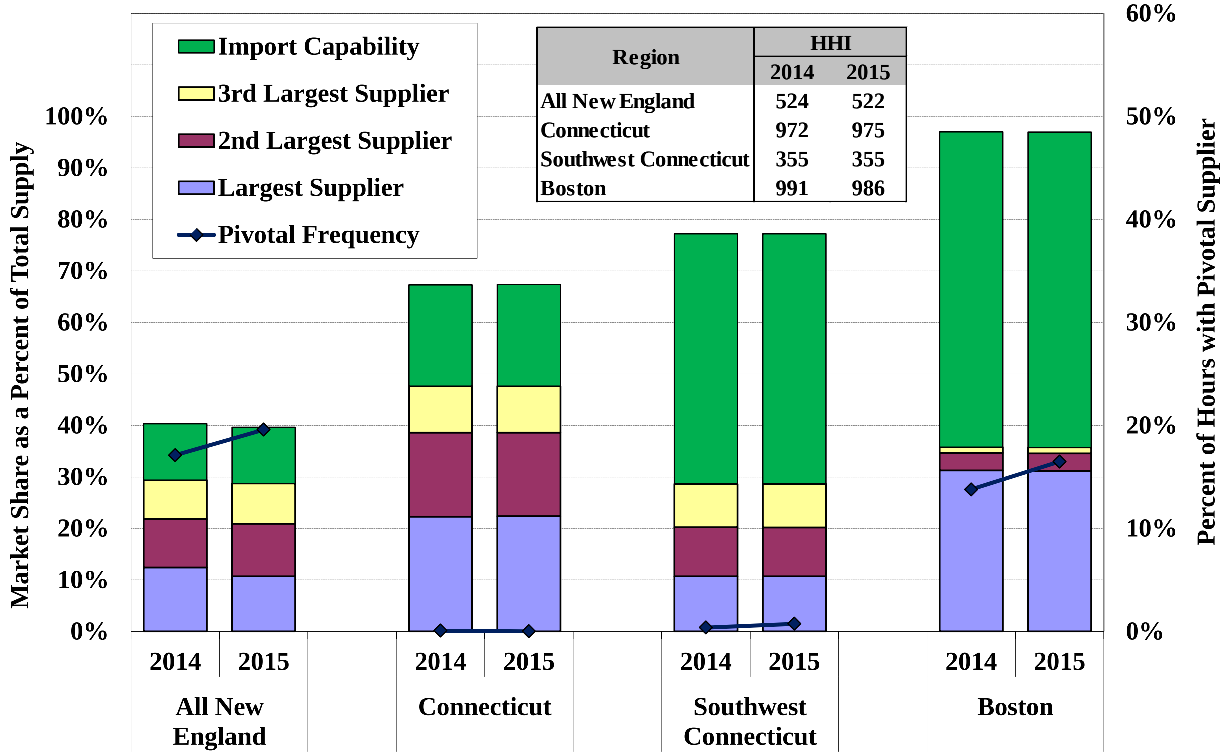
[52] When a supplier's forward power sales exceed the supplier's real-time production level, the supplier is a net buyer in the real-time spot market, and thus, benefits from low rather than high prices. However, some incentive still exists because spot prices will eventually affect prices in the forward market.

[53] Even small suppliers can be pivotal for brief periods. For example, all suppliers are pivotal during periods of shortage. But this does not mean they all have market power.

Figure 10 shows the three structural market power indicators for each of the four regions in 2014 and 2015. First, the figure shows the market shares of the largest three suppliers and the import capability in each region in color-coded stacked bars.[54,55] The remainder of supply to each region comes from smaller suppliers. The inset table shows the Herfindahl-Hirschman Index (HHI) for each region. In our analysis, we assume imports are highly competitive so we treat the market share of imports as zero in our HHI calculation. Finally, the diamonds in the figure indicate the portion of hours where one or more suppliers were pivotal in each region. In this analysis, we exclude potential withholding from nuclear units because they typically cannot ramp down substantially and would be costly to withhold due to their low marginal costs.

Figure 10: Structural Market Power Indicators

2014 – 2015



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54 The market shares of individual firms are based on information in the monthly reports of Seasonal Claimed Capability("SCC"), available at: http://iso-ne.com/isoexpress/web/reports/operations/-/tree/seson-claim-cap. In this report, we use the generator summer capability in the July SCC reports from each year.

55 The import capability shown for each region is the transmission interface limit used in each year's Regional System Plan, available at: http://iso-ne.com/system-planning/system-plans-studies/rsp. The Base Interface Limit (or Capacity Import Capability) is used for external interfaces, and the N-1-1 Import Limits are used for each reserve zone.

Figure 10 indicates that market concentration changed slightly from 2014 to 2015 in all New England. The market share of the largest supplier fell from over 12 percent in 2014 to slightly less than 11 percent in 2015 because of the following two ownership changes:

- Exelon sold two Fore River units to Calpine Energy in late 2014, reducing its portfolio by roughly 800 MW.
- Dynegy acquired EquiPower and Brayton Point from Energy Capital Partner in early 2015 and became the largest supplier in New England following the acquisition.

Nonetheless, market concentration has not changed significantly in the three reserve zones, despite the change in asset ownership. Consistent with 2014, the largest suppliers had market shares ranging from 11 percent in Southwest Connecticut to 31 percent in Boston in 2015.

There is variation in the number of suppliers that have large market shares. For instance, Boston had one supplier with a large market share, while Southwest Connecticut and all New England had three internal suppliers with comparable market shares. Because the import capability accounted for a significant share of total supply in each region (ranging from 11 percent in all New England to 61 percent in Boston), the market concentration in all of the areas was relatively low (i.e., less than 1000) in 2015.[56]

However, these results do not establish that there are no significant market power concerns. These concerns are most accurately assessed under the pivotal supplier analysis, which indicates:

- In, Southwest Connecticut and Connecticut, there were very few hours (< 0.5 percent) when a supplier was pivotal in 2015.
- In Boston, one supplier owned roughly 80 percent of the internal capacity, but was pivotal in only 17 percent of hours in 2015. This underscores the importance of import capability into constrained areas in providing competitive discipline; and
- In all New England, a supplier was pivotal in 20 percent of hours in 2015.[57]

The pivotal frequency rose modestly in Boston and all New England from 2014 to 2015. The increase occurred primarily in the summer because of higher average load levels due to warmer weather conditions from late July to early September. Average load was higher by 1,400 MW in

56 Antitrust agencies and the FERC consider markets with HHI levels above 1800 as highly concentrated for purposes of evaluating the competitive effects of mergers.

57 The pivotal supplier results are conservative for “All New England” because we assume the actual imports are fixed and would not change in response to withholding.

August than from the prior year. More frequent peaking conditions contributed to the modest increase in the pivotal supplier frequency during 2015. In addition, the combined cycle units of the largest supplier in Boston were committed economically more frequently in the summer of 2015 because of lower LNG procurement costs (relative to natural gas prices). The amount of generation from these combined cycle units averaged more than 1 GW in July and August, compared to an average of less than 150 MW in the rest of the year. This increased its real-time market share and the frequency in which it was pivotal in both Boston and all New England.

The results in these regions warrant further review to identify potential withholding by suppliers in these regions. This review is provided in the following section, which examines the behavior of pivotal suppliers under various market conditions to assess whether the behavior has been consistent with competitive expectations.

3. Economic and Physical Withholding

Suppliers that have market power can exercise it in electricity markets by economically or physically withholding resources as described above. We measure potential economic withholding by estimating an output gap for units that fail a conduct test for their start-up, no-load, and incremental energy offer parameters indicating that they are submitting offers in excess of competitive levels. The output gap is the difference between the unit's capacity that is economic at the prevailing clearing price and the amount that is actually produced by the unit.[58] In essence, the output gap shows the quantity of generation that is withheld from the market as a result of having submitted offers above competitive levels. Nonetheless, it is important to recognize that the output gap tends to overstate the amount of potential economic withholding because some of the offers that are included in the output gap reflect legitimate responses by the unit's owner to operating conditions, risks, or uncertainties.

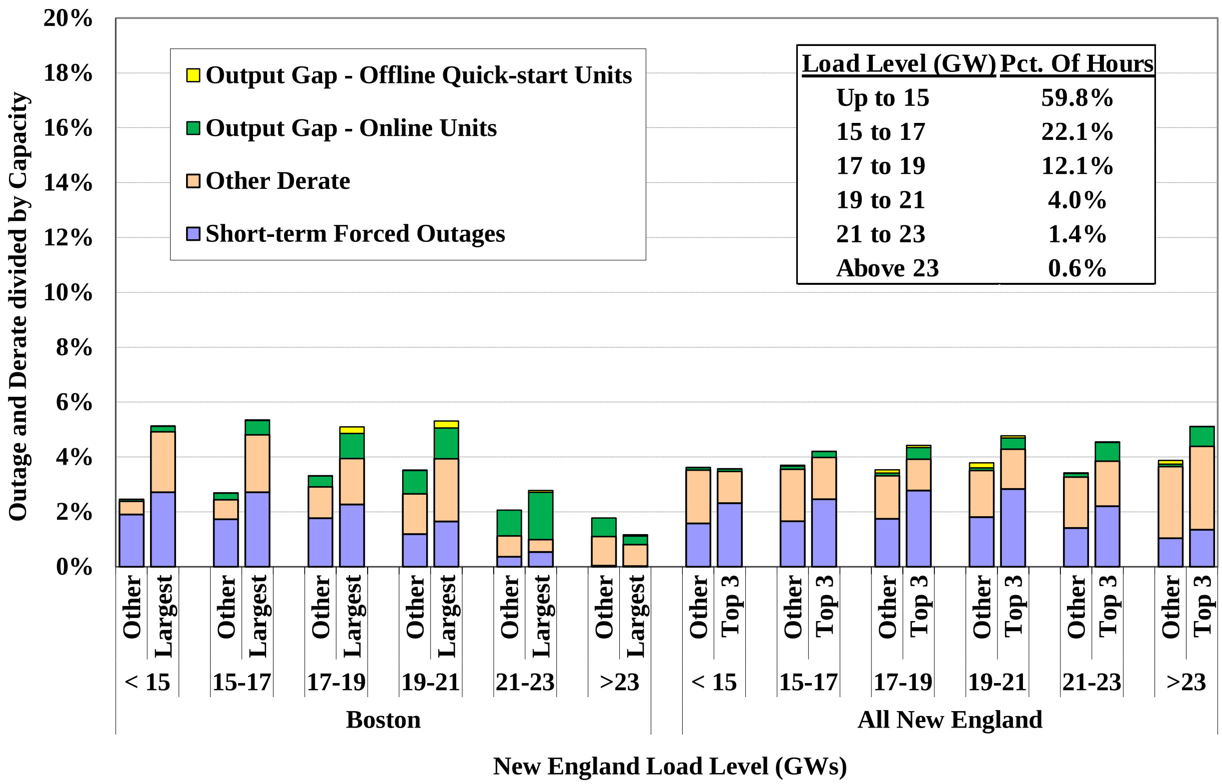
We evaluate potential physical withholding by focusing on short-term deratings and outages because they are more likely to reflect attempts to physically withhold than long-term deratings. In general, it is less costly to withhold a resource for a short period of time. Long-term outages generally result in larger lost profits in hours when the supplier does not have market power.

[58] To identify clearly economic output, the supply's competitive cost must be less than the clearing price by more than a threshold amount -- $25 per MWh for energy and 25 percent for start-up and no load costs.

The following analysis shows the output gap results and physical deratings relative to load and participant characteristics. The objective is to determine whether the output gap and/or physical deratings increase when factors prevail that increase suppliers' ability and incentive to exercise market power. This allows us to test whether the output gap and physical deratings vary in a manner consistent with attempts to exercise market power.

Because the pivotal supplier analysis raises competitive concerns in Boston and all New England, Figure 11 shows the output gap and physical deratings by load level in these two regions. The output gap is calculated separately for: a) offline quick-start units that would have been economic to commit in the real-time market (considering their commitment costs); and b) online units that can economically produce additional output. Our physical withholding analyses focus on: a) "Short-term Forced Outages" that typically last less than one week; and b) "Other Derate" that includes reductions in the hourly capability of a unit that is not logged as a forced or planned outage. The Other Derates can be the result of ambient temperature changes or other legitimate factors.

Figure 11: Average Output Gap and Deratings by Load Level and Type of Supplier
Boston and All New England, 2015



The figure above shows the supplier's output gap and physical deratings as a percentage of its portfolio size in each region by load level. In Boston, we compare these statistics for the largest supplier to all other suppliers in the area. In all New England, we compare the top three suppliers, who collectively own one-third of internal resources, to all other suppliers.

Figure 11 shows that the overall output gap and deratings for the largest suppliers were relatively small as a share of their total capacity (around 4 percent on average) in both Boston and all New England. In addition, the largest suppliers in each region generally exhibited output gap levels and deratings that were consistent with other smaller suppliers in the region.

In Boston, the total amount of output gap and deratings generally fell as load levels increased to the highest levels, which is a good indication that suppliers tried to make more capacity available when the capacity needs were the highest.

In all of New England, the total amount of output gap and deratings rose slightly as load levels increased to the highest levels. The modest increase in the "Other Derate" category reflected out-of-merit actions by operators to manage local reliability on the hottest summer days.

Overall, these results indicate that the market performed competitively and was not subject to substantial withholding in 2015.

4. Market Power Mitigation

Mitigation measures are intended to mitigate abuses of market power while minimizing interference with the market when it is workably competitive. The ISO-NE applies a conduct-impact test that can result in mitigation of a participant's supply offers (i.e., incremental energy offers, start-up and no-load offers). The mitigation measures are only imposed when suppliers' conduct exceeds well-defined conduct thresholds above a unit's reference levels and when the effect of that conduct on market outcomes exceeds well-defined market impact thresholds. This framework prevents mitigation when it is not necessary to address market power, while allowing high prices during legitimate periods of shortage.

The market can be substantially more concentrated in import-constrained areas, so more restrictive conduct and impact thresholds are employed in these areas than market-wide. The

ISO has two structural tests (i.e., Pivotal Supplier and Constrained Area Tests) to determine which of the following mitigation rules are applied:[59,60]

- Market-Wide Energy Mitigation ("ME") – ME mitigation is applied to any resource that is in the portfolio of a pivotal Market Participant.
- Market-Wide Commitment Mitigation ("MC") – MC mitigation is applied to any resource whose Market Participant is determined to be a pivotal supplier.
- Constrained Area Energy Mitigation ("CAE") – CAE mitigation is applied to resources in a constrained area.
- Constrained Area Commitment Mitigation ("CAC") – CAC mitigation is applied to a resource that is committed to manage congestion into a constrained area.
- Local Reliability Commitment Mitigation ("RC") – RC mitigation is applied to a resource that is committed or kept online for local reliability.
- Start-up and No-load Mitigation ("SUNL") – SUNL mitigation is applied to any resource that is committed in the market.

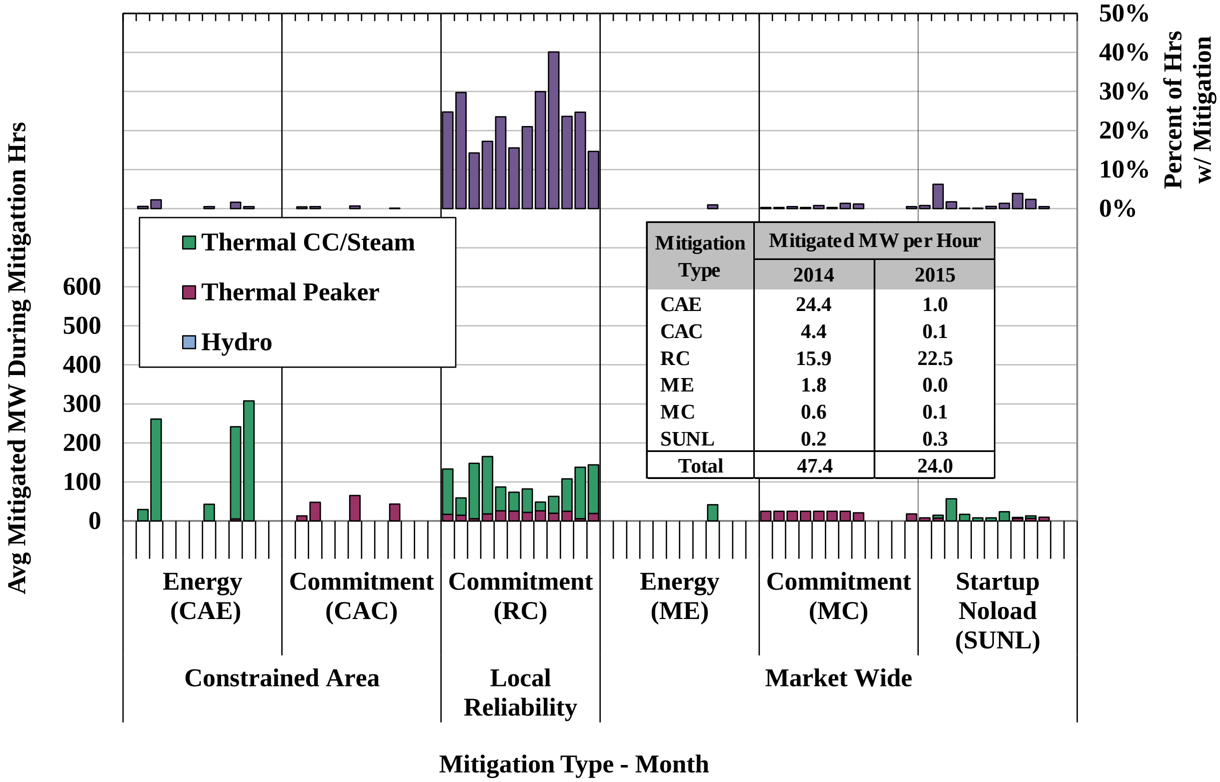
There are no impact tests for the SUNL mitigation and the three types of commitment mitigation (i.e., MC, CAC, and RC), so suppliers are mitigated if they fail the conduct test in these three categories. This is reasonable because this mitigation is only applied to uplift payments, which will tend to rise substantially as offer prices rise so, in essence, the conduct test is serving as an impact test as well. When a generator is mitigated, all the economic offer parameters are set to their reference levels for the entire mitigated hour.

Figure 12 examines the frequency and quantity of mitigation in the real-time energy market. Any mitigation changes made after the automated mitigation process were not included in this analysis. The upper portion of the figure shows the portion of hours affected by each type of mitigation. If multiple resources were mitigated during the same hour, only one hour was counted in the figure. The lower portion of the figure shows the average mitigated capacity in each month (i.e., total mitigated MWh divided by the number of mitigated hours) for each type of mitigation and for three categories of resources: hydroelectric units, thermal peaking units, and thermal combined cycle and steam units. The inset table shows the annual average amount of mitigation for each mitigation type in 2015.

59 See Market Rule 1, Appendix A, Section III.A.5 for details on these tests and thresholds.

60 In addition, manual dispatch mitigation is applied to units dispatched OOM above their Mingen level.

Figure 12: Frequency of Real-Time Mitigation by Mitigation Type and Unit Type
By Month, 2015



Mitigation Type	Mitigated MW per Hour	
	2014	2015
CAE	24.4	1.0
CAC	4.4	0.1
RC	15.9	22.5
ME	1.8	0.0
MC	0.6	0.1
SUNL	0.2	0.3
Total	47.4	24.0

The vast majority of mitigation in 2015 was local reliability commitment mitigation, which occurred in approximately 23 percent of hours and accounted for 94 percent of all mitigation. This is consistent with the fact that local sub-areas raise the most significant potential market power concerns and are mitigated under the tightest thresholds. In general, this mitigation only affects NCPC payments and has little impact on LMPs.

Nonetheless, not all local reliability mitigation was on units that were committed for reliability reasons. Some local reliability mitigation was on units that were committed economically, but started earlier or shut down later than their schedules.[61] Most local reliability mitigation of thermal peaking units was of those that shut down later than scheduled. This mitigation typically occurred during start-up and shut-down periods and did not have substantial impact on LMPs or NCPC payments.

61 This was implemented by the ISO in December 2014 to address a potential gaming concern.

Hydro resources were rarely mitigated in 2015 and mitigation of resources during periods of tight gas supply fell in 2015. Both of these results are positive and are partly due to a market enhancement introduced in December 2014 that allows suppliers to offer on an hourly basis and update their offers and fuel costs in real time. In addition to improving the competitiveness of the offers themselves, this change as improved the accuracy of the mitigation, particularly for:

- Energy limited hydro resources, whose costs are almost entirely opportunity costs (the trade-off of producing more now and less later). This costs were difficult to accurately reflect when only one single offer was allowed for the entire day.
- Oil-fired resources, which become economic when gas prices rise above oil prices, but have limited on-site oil inventory. The suppliers may raise their offer prices to conserve the available oil in order to produce during the hours with the highest LMP.
- Gas-fired resources during periods of tight gas supply. Volatile natural gas prices create uncertainty regarding fuel costs that can be difficult to reflect accurately in offers and reference levels. The uncertainty is increased by the fact that offers and reference levels must be determined by 2 pm on the prior day.

To supplement this improvement in offer flexibility, reference level adjustments should be made as necessary to account for the opportunity costs associated with these types of energy limitations, which will reduce the potential for inappropriate mitigation of competitive offers.

5. Competitive Performance Conclusions

The pivotal supplier analysis suggests that market power concerns remain in Boston and in all of New England under high-load conditions. However, based on the analyses of potential economic and physical withholding, we find that the markets performed competitively with little evidence of market power abuses or manipulation in 2015.

In addition, we find that the market power mitigations have generally been effective in preventing the exercise of market power in the New England markets. The automated mitigation process helps ensure the competitiveness of market outcomes by mitigating attempts to exercise market power in the real-time market software before it can affect the market outcomes. To ensure competitive offers are not mitigated, it is important for generators to proactively request reference level adjustments when they experience input cost changes due to fuel price volatility and/or fuel quantity limitations. The implementation of the hourly offers in December 2014 has better enabled generators to submit offers that reflect their marginal costs and for the ISO to set reference levels that properly reflect these costs.

II. Improving the Payment and Allocation of Uplift Costs

This section of the report discusses Net Commitment-Period Compensation (“NCPC”) costs, which are ISO-NE’s primary form of uplift costs. In general, NCPC costs are incurred because the market requirements do not include all of the reliability requirements that ISO-NE must satisfy or, for other reasons, the prices do not fully reflect these requirements. When this occurs, resources are sometimes utilized when the prevailing market prices do not fully cover the resource’s as-bid costs, which results in a guarantee payment in the form of NCPC. This section identifies three issues and associated recommendations regarding how NCPC payments are made and how they are allocated back to ISO-NE’s customers.

A. Allocation of NCPC Costs

The allocation of NCPC costs plays an important role in facilitating efficient actions by participants and the performance of ISO-NE’s day-ahead market. Most economic NCPC costs are currently allocated to deviations from the day-ahead market, including virtual transactions. Unfortunately, virtual transactions and other deviations provide liquidity to the day-ahead market and facilitate its convergence with the real-time market. This is important because the day-ahead market coordinates the overall commitment of resources that are used to satisfy the next day’s needs at the lowest cost.

In well-functioning day-ahead and real-time markets, we expect that day-ahead and real-time prices will not systematically diverge by a substantial amount. However, day-ahead prices tend to be slightly higher than real-time prices in a well-functioning energy market because many buyers are willing to pay a small premium for day-ahead purchases to avoid the more volatile real-time prices.

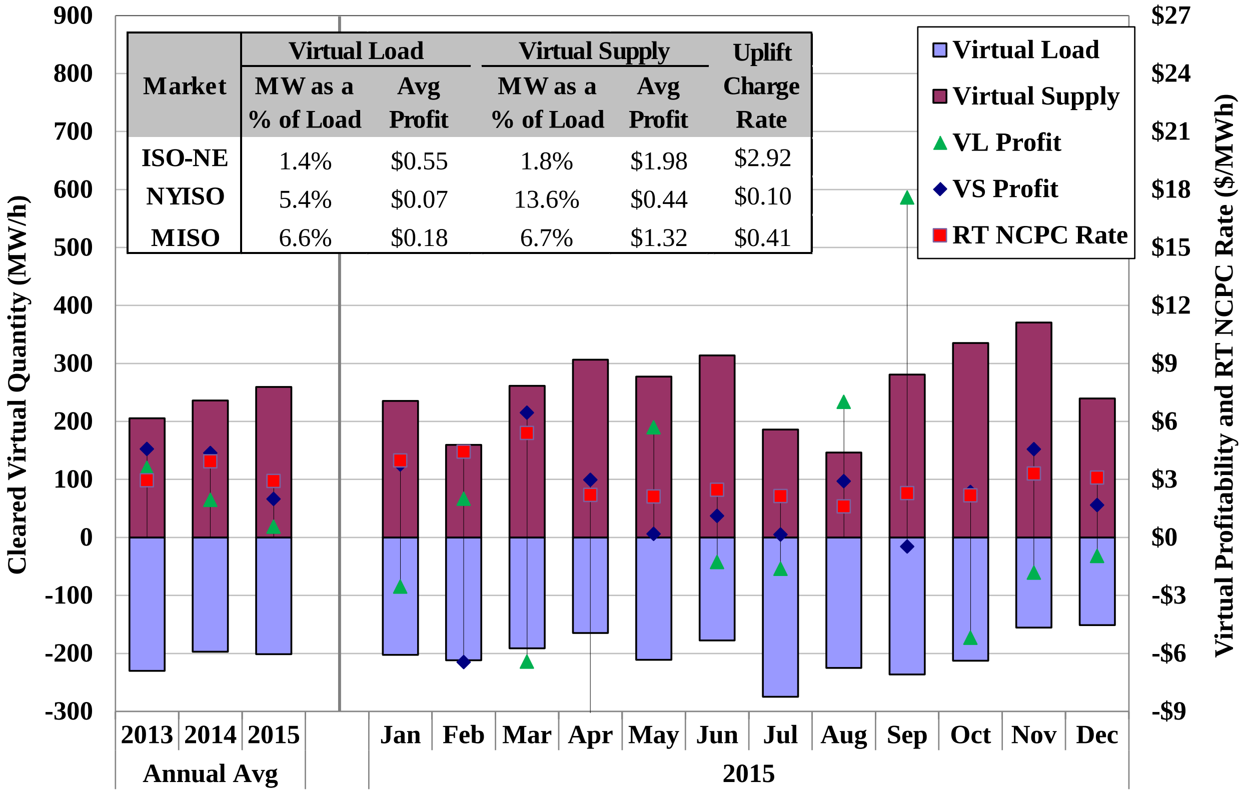
Additionally, a larger day-ahead premium is efficient in New England because the real-time prices are understated, as discussed in Section III.A. To achieve this larger and more efficient day-ahead premium, it is important to allocate the market’s NCPC uplift efficiently to the actions that cause NCPC. Such actions include under-scheduling load and virtual supply, among others. The current allocation, which tends to over-allocate NCPC costs to all virtual transactions contributes to reduced liquidity in the day-ahead market as shown below.

1. Virtual Trading and Profitability in New England

Virtual trading plays a key role in the day-ahead market by providing liquidity and improving price convergence between day-ahead and real-time markets. However, we have observed a relatively small amount of virtual trades in the past several years although the market exhibited a real-time price premium during most of the months. The increased allocation of NCPC charges (per MWh) to virtual load in particular has likely inhibited the natural market response to the frequent real-time price premiums.

Figure 13 shows the average volume of virtual supply and demand that cleared the market in each month of 2015, as well as the monthly average gross profitability of virtual purchases and sales. Gross profitability is the difference between the price at which virtual traders bought and sold energy between the day-ahead and real-time market. The gross profitability does not account for NCPC costs allocated to virtual transactions, which are shown separately in the figure.

Figure 13: Virtual Transaction Volumes and Profitability
2015



Market	Virtual Load MW as a % of Load	Virtual Load Avg Profit	Virtual Supply MW as a % of Load	Virtual Supply Avg Profit	Uplift Charge Rate
ISO-NE	1.4%	$0.55	1.8%	$1.98	$2.92
NYISO	5.4%	$0.07	13.6%	$0.44	$0.10
MISO	6.6%	$0.18	6.7%	$1.32	$0.41

The inset table compares the average volume (i.e., average cleared quantity as a percentage of average actual load) and gross profitability of virtual transactions during 2015 in ISO-NE, NYISO, and MISO. The table also lists the average major category of market costs that are charged to virtual traders in each market. The major category of market costs to virtual transactions are the real-time economic NCPC cost allocations in the ISO-NE, the Rate Schedule 1 charge in the NYISO, and the Day-ahead Deviation and Headroom Charge in the MISO. Almost all of these charges are designed to recover similar uplift costs in the various markets.

Virtual transactions have decreased substantially in the past several years. In 2015, scheduled virtual load averaged roughly 200 MW and scheduled virtual supply averaged roughly 260 MW. On average, virtual load and virtual supply accounted for 1.4 and 1.8 percent of the actual load in the ISO-NE market, notably lower than in the NYISO and the MISO markets (where virtual load and virtual supply both generally account for more than 5 percent). The low levels of virtual trading are likely the result of the high NCPC charges to scheduled virtual transactions (which we recommend changing) and increased regulatory risk associated with enforcement activities.

Figure 13 shows that virtual trading was generally profitable in 2015 (before including NCPC charges) with an overall net gross profit of $5 million, indicating that virtual trading improved convergence between day-ahead and real-time prices.[62] This is because virtual trades that are profitable generally contribute to better convergence between day-ahead and real-time prices. However, including NCPC charges, virtual transactions netted a *loss* of $6 million in 2015.

In ISO-NE, real-time economic NCPC charges are allocated across virtual transactions and other Real-Time Deviations. The rate of economic NCPC charges allocated to virtual transactions has been relatively high for several years, averaging roughly $2 to $4 per MWh each year from 2012 to 2015. These charges are significantly higher than the charges that virtual transactions face in the NYISO and the MISO markets, which were only $0.10 and $0.41/MWh in 2015, respectively. High NCPC rates provide a significant disincentive for firms to schedule virtual transactions because virtual profits tend to be small relative to day-ahead and real-time prices.

62 Not including NCPC charges, profits can be tabulated for each category of virtual transactions in the figure by multiplying “Avg MW” and “Avg Profit” by the number of hours in each year.

Hence, high NCPC rates contribute to the low level of virtual trading activity and the inconsistency between day-ahead and real-time prices in New England.

2. Economic NCPC Allocation

ISO-NE currently allocates nearly all real-time "Economic" NCPC charges to deviations between the day-ahead and real-time schedules.[63] In reality, some deviations are "harming" and tend to increase NCPC, while others are "helping" and reduce NCPC. For example, under-scheduling physical load in the day-ahead market can cause the ISO to commit additional units in real-time, which are likely to increase NCPC—this is a "harming" deviation. Conversely, "helping" deviations, such as over-scheduling load (including virtual load), generally result in higher levels of resource commitments in the day-ahead market and, therefore, usually decrease the ISO's need to make additional commitments, thereby avoiding NCPC charges. The current allocation does not distinguish between helping and harming deviations and is, therefore, not consistent with the principle of allocating costs to actions that cause those costs. Hence, this allocation assigns NCPC charges to transactions that actually tend to *reduce* the need for supplemental commitments, including virtual load.

The ISO is working to address some of the factors that cause NCPC, including peaking resources not setting real-time prices when they are effectively the marginal source of supply. However, it will still be the case that NCPC charges are caused by many factors other than real-time deviations, including: operator actions to satisfy system reliability needs, and unforeseen events such as outages. Hence, we find that the current allocation scheme over-allocates costs to deviations relative to the portion of the NCPC they likely cause. This is particularly true of virtual load, which tend to increase day-ahead commitments and, therefore, decrease the need for supplemental commitments and for dispatching peaking resources.

Hence, we recommend that the ISO modify the allocation of Economic NCPC charges to be more consistent with a "cost causation" principle, which would involve:

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63 Real-Time Deviations include Real-Time Load Obligation Deviations, which are positive or negative differences between day-ahead scheduled load and actual real-time load, uninstructed generation deviations from day-ahead schedules, virtual load schedules, and virtual supply schedules.

- Not allocating NCPC costs to virtual load and other real-time deviations that cannot reasonably be argued to cause real-time economic NCPC, and
- Increasing the allocation to real-time firm load customers because most supplemental commitments are made to maintain reliability for such customers.

B. Real-Time NCPC Payments for Day-Ahead Scheduled Units

The ISO implemented a package of significant market reforms in December 2014, which included the hourly offers project and the Net Commitment-Period Compensation Key Project. The new NCPC rules were based on the "best alternative" principle that a generator should be "no worse-off" as a result of obeying an instruction from the ISO.[64] Although the best alternative framework is generally sound, the new NCPC rules included a provision that resulted in unnecessary payments to some generators. Specifically, the rules assumed that the best alternative for a non-fast start generator that is scheduled in the day-ahead market could be for the generator to stay offline in real-time. The resulting NCPC payments were much higher than necessary for generators to have an incentive to follow the ISO's commitment instruction. Ultimately, the ISO filed to modify the NCPC rules to address this issue, and the new rules became effective in February 2016, leading to a dramatic reduction in NCPC uplift.

From December 2014 through January 2016, this category accounted for approximately $57 million (or 62 percent) of the real-time NCPC payments over the period. These NCPC payments exceed the profits that these generators would have earned from not starting-up because:

- The NCPC formula assumes that the generator's costs and the real-time LMPs would not have been affected if the generator receiving the payment chose not to start-up, but this is unrealistic because such generators usually sell back unused fuel at a discount and LMPs are increased by the de-commitment of a generator.
- When ISO-NE schedules resources out-of-merit to satisfy reliability requirements through the day-ahead market (e.g., local reliability requirements), it makes a day-ahead NCPC payment to the supplier, so there is no need to make an additional make whole payment in real-time.

After this issue was identified, the ISO worked quickly to modify the NCPC rules to eliminate these payments.

64 For example, if a $50 generator is instructed to ramp-up when the LMP is $40, the generator should receive a $10 NCPC payment in addition to the LMP so that the generator is no worse-off for performing reliably.

C. Commitment of Multi-Turbine Units for Local Reliability

The ISO provides generators with significant flexibility in determining how to register multiple units at a particular plant. This is reasonable, since plants often contain individual units with costs that are interdependent. Individual units may share limited fuel supplies, have heat rates that are affected if other units are operating at the site, or have multiple configurations. Under competitive market conditions, generators have an incentive to offer efficiently while taking into account all of these interdependencies. However, this is not the case when a generator does not face competition. This section discusses whether generators that have local market power have registered their assets in a manner that enables them to earn more by being inflexible.

Our primary concern is that generators committed for local reliability may increase their profits by registering multiple units as a single generator, even though each unit is capable of operating separately. For example, a 2x1 combined cycle generator is normally capable of operating one gas turbine, typically resulting in a modest increase in the heat rate. When a generator is committed for local reliability, it receives total compensation equal to energy revenues plus NCPC payments equal to its operating costs plus a margin under the applicable mitigation thresholds. Hence, doubling the number of units committed for local reliability generally doubles the resulting profits. We believe this conduct is analogous to a dual-fueled unit requiring ISO-NE to compensate it for burning oil when it can burn natural gas at a much lower cost. This latter conduct is not permissible, but the former currently is permissible.

Excluding the excess NCPC payments discussed in Section III.B, $38.4 million in 2014 and $27.3 million in 2015 were received by non-fast start generators that were needed for local reliability.[65] Of this, $26.5 million (69 percent) in 2014 and $15.8 million (58 percent) in 2015 was paid to generators that registered multiple turbines as a single asset for bidding purposes. In many cases, it is likely that the local reliability need could have been satisfied with only one of the units, so committing multiple units led to increased NCPC costs and depressed LMPs. Hence, we recommend that the ISO modify its tariff to allow it to commit a single unit at a multi-unit generator location when this is a more efficient means to satisfy the local reliability need.

65 This includes units flagged for voltage support or for local second contingency protection.

III. Real-Time Scheduling Enhancements

The goal of the electricity market is to coordinate the use of resources to efficiently satisfy the needs of the system. It is critically important to coordinate real-time production and provide efficient real-time price signals. In this section, we evaluate real-time scheduling processes and key market design enhancements in the areas of real-time price formation and interchange scheduling with New York. These enhancements should foster more efficient market outcomes and price signals.

A. Real-Time Scheduling and Pricing of Fast Start Generators

Efficient real-time price signals are essential because they encourage reliable performance and increased availability by generators and demand response, and investment in new resources or transmission where it is needed most. The ISO's on-going efforts to enhance performance incentives recognize that efficient price signals during shortages motivate resources to be available when needed. Furthermore, to the extent that efficient price signals during shortages or tight operating conditions exceed generators' costs, the revenues needed from the forward capacity auctions to maintain adequate installed capacity margins will fall.[66] Hence, it is beneficial to regularly evaluate whether the market produces efficient real-time price signals and scheduling outcomes.

1. Commitment of and Price-Setting by Fast-Start Resources

Fast-start generators are highly beneficial for the operation of the system because they are a low-cost provider of operating reserves that would otherwise have to be held on online resources, which can be very expensive. They tend to be dispatched when the load is highest and are generally the highest-cost resources. During these high-load conditions, it is particularly important that these resources set prices accurately in order to reflect the cost of satisfying demand and reliability requirements. The analyses in this section, however, show that this is frequently not the case because they are inflexible.

66 Section II.E evaluates the amount of net revenue that new and existing generators earn from the capacity and energy markets.

Table 5 summarizes our evaluation of: (a) the efficiency of real-time scheduling and pricing during periods when fast-start units were deployed in merit order by UDS;[67] and (b) how LMPs would be affected if the average total offers were fully reflected in real-time prices from 2013 to 2015.[68,69]

Table 5: Scheduling and Pricing Efficiency of Fast-Start Generators
First Hour Following Start-Up by UDS

	2013	2014	2015
UDS Starts of Thermal Peaking and Hydro Units			
Average MW-Start per Day	1180	1250	1810
% of Starts being Economic	40%	42%	64%
% of All Intervals Offer > LMP	9%	11%	11%
Estimated Market Impact if Offer Sets LMP			
Average Increase in LMP ($/MWh)	$3.30	$4.20	$3.20
Max. Increase in Net Revenues ($/kW-year)	$29	$37	$28
NCPC Reduction ($ Million)	$9	$10	$9

The amount of in-merit starts by UDS rose notably from 2014 to 2015, primarily because hydro resources were started more frequently by UDS in 2015. This is partly because the new hourly offer functionality implemented in December 2014 that has allowed hydro resources to rely on the market scheduling system rather than on self-scheduling. This is more efficient because it helps ensure that the limited output of these units can be used during hours when the need for them is greatest. Consequently, the share of UDS starts that were economic relative to the LMP (i.e., the total offer cost < the LMP) rose from roughly 40 percent in 2013 and 2014 to nearly 65 percent in 2015.

67 The average total offer includes no-load and start-up costs amortized over one hour. The comparison is made between the average total offer and LMP over the first hour following the start by UDS for each quick-start unit. When the average real-time LMP is less than the average total offer, LMPs do not fully reflect the cost to the system of deploying the fast-start generator.

68 If a gas turbine was started with a total offer of $115/MWh when the LMP was $75/MWh, this analysis would assume the unit would increase the LMP by $40 per MWh. Other lower-cost gas turbines or hydro resources started in the same hour would not affect prices because they are inframarginal.

69 The analysis excludes fast-start units that were started in import-constrained areas because we are focused on market-wide price effects. The area is treated as import-constrained if the congestion component of the LMP at the fast-start unit's node is greater than the congestion component at New England Hub by $1 per MWh or more.

Nonetheless, fast-start units were still frequently deployed in-merit by UDS when their average total offer was greater than the real-time LMP. This occurred in 9 to 11 percent of all intervals each year from 2013 to 2015. These results indicate that real-time prices often do not fully reflect the marginal cost of serving real-time demand, which adversely affects the economic signals provided to the day-ahead and forward markets in New England.

If the total offers of these units were fully reflected in the energy price in these intervals, the average real-time LMP would have increased by $3 to $4 per MWh in each year from 2013 to 2015.[70] This would increase the net revenue of a generator with high availability by up to $28 to $37 per kW-year (net revenue is evaluated further in Section II.E).[71]

If the estimated price increases were reflected in the calculation of NCPC uplift charges, we estimate that NCPC charges would be reduced by $9 to $10 million each year in 2013 to 2015. Shifting these costs from uplift (which is difficult to hedge), to energy prices where the improved price signals will facilitate more efficient resource commitments and net imports is consistent with FERC's price formation objectives.

The ISO plans to implement market design changes in the first quarter of 2017 that will allow fast-start resources to set LMP when they are economic.[72] Likewise, the ISO will integrate fast-start demand response resources into this pricing model when it implements market changes in response to Order 745. The proposed changes are similar to MISO's "Extended LMP" or "ELMP" model implemented by MISO in early 2015, which in turn was patterned after NYISO's gas turbine pricing methodology that it has used for years. These two approaches have functioned well in practice. Hence, we support ISO-NE's improvements in this area.

70 The ISO performed a simulation study for most of 2014 and found that real-time prices would rise by $3.18 per MWh, which is generally consistent with our estimates. See "Fast Start Pricing – Impact Analysis: Price Formation When Fast Start Resources Are Committed and Dispatched" by Ben Ewing & Jon Lowell, April 16, 2015, NEPOOL market committee meeting, for more details of the ISO's simulation.

71 We note that higher expected real-time LMPs would provide incentives for the day-ahead market to commit additional resources, which would reduce the magnitude of the resulting price increases in the day-ahead and real-time markets and the frequency of fast start deployments.

72 See ISO-NE and NEPOOL filing to FERC, "Revisions to Fast-Start Resource Pricing and Dispatch", Docket No. ER15-2617-000.

2. Price Setting During Demand Response Deployments and Operator Actions

Participation in the market by price-responsive demand has great potential to enhance wholesale market efficiency. Modest reductions in consumption by end-users in high-price periods can significantly reduce the costs of committing and dispatching generation. Furthermore, price-responsive demand reduces the need for new investment in generating capacity. Indeed, a significant share of new capacity procured in the Forward Capacity Auctions has been composed of demand response capability. Although demand response has not been activated since 2013, substantial amounts of generation are scheduled to retire before the summer of 2017, which will increase the likelihood that ISO-NE will have to rely on demand response resources to maintain reliability.

Demand response participation also presents significant challenges for real-time pricing efficiency. Most demand resources that are procured in the forward capacity market will not be dispatchable within 30 minutes by UDS and, therefore, will not be able to set real-time energy prices (as a Fast Start Demand Response resource). Instead, most demand resources are dispatched as part of the OP-4 procedures under Actions 2 and 6 before the ISO goes short of operating reserves.

Our evaluation of demand response activations in previous reports found that demand response activations can depress real-time prices, particularly when the activation averts a shortage of operating reserves (i.e., when the response is larger than the magnitude of the shortage that would have occurred). In such cases, the demand response resources were effectively the marginal resources, so it would be efficient for real-time prices to reflect the value of their foregone consumption. This is not currently possible because demand response resources do not submit bids and are not activated based on economic criteria. Higher and more efficient prices in such cases would provide incentives to purchase more energy in the day-ahead market, which, in turn, would reduce the likelihood of the reserve shortages and the need to activate emergency demand response.

Hence, it is important to consider ways to appropriately reflect the value of foregone consumption in real-time prices when demand response or other emergency actions by the ISO are taken to avoid an operating reserve shortage. The ISO will integrate dispatchable demand

and Fast Start Demand Response in the real-time market as generation, but many demand response resources will still be relatively inflexible. Hence, after its initial implementation, it would be beneficial to consider expanding the set of resources that are able to set prices in the Fast Start Pricing model to include some demand response resources that do not qualify as Fast Start Demand Resources. Likewise, it would be beneficial for the ISO to consider similar pricing rules for emergency purchases and any other actions that allow the ISO to maintain adequate operating reserves.

B. Interchange Scheduling with New York

The performance of ISO-NE's wholesale energy markets depends not only on the efficient use of internal resources, but also the efficient use of transmission interfaces with adjacent areas. This subsection examines the scheduling of imports and exports between New England and New York. Since both regions have real-time spot markets, market participants can schedule market-to-market transactions based on transparent price signals in each region. In this subsection, we evaluate the extent to which the interface is scheduled efficiently.

When an interface is used efficiently, prices in adjacent areas should be consistent unless the interface is constrained. For example, when prices are higher in New England than in New York, imports from New York should continue until prices have converged or until the interface is fully scheduled. A lack of price convergence indicates that resources are being used inefficiently. In other words, higher-cost resources are operating in the high-priced region that could have been supplanted by increased output from lower-cost resources in the low-priced region. It is especially important to schedule flows efficiently between control areas during peak demand conditions or shortages when flows between regions have the largest economic and reliability consequences.

However, one cannot expect that trading by market participants alone will optimize the use of the interfaces. Several factors prevent real-time price differences between New England and New York from being fully arbitraged.

- Market participants do not operate with perfect foresight of future market conditions (e.g., may not be able to predict which side of the interface will have a higher real-time price) at the time when transaction bids and offers must be submitted.

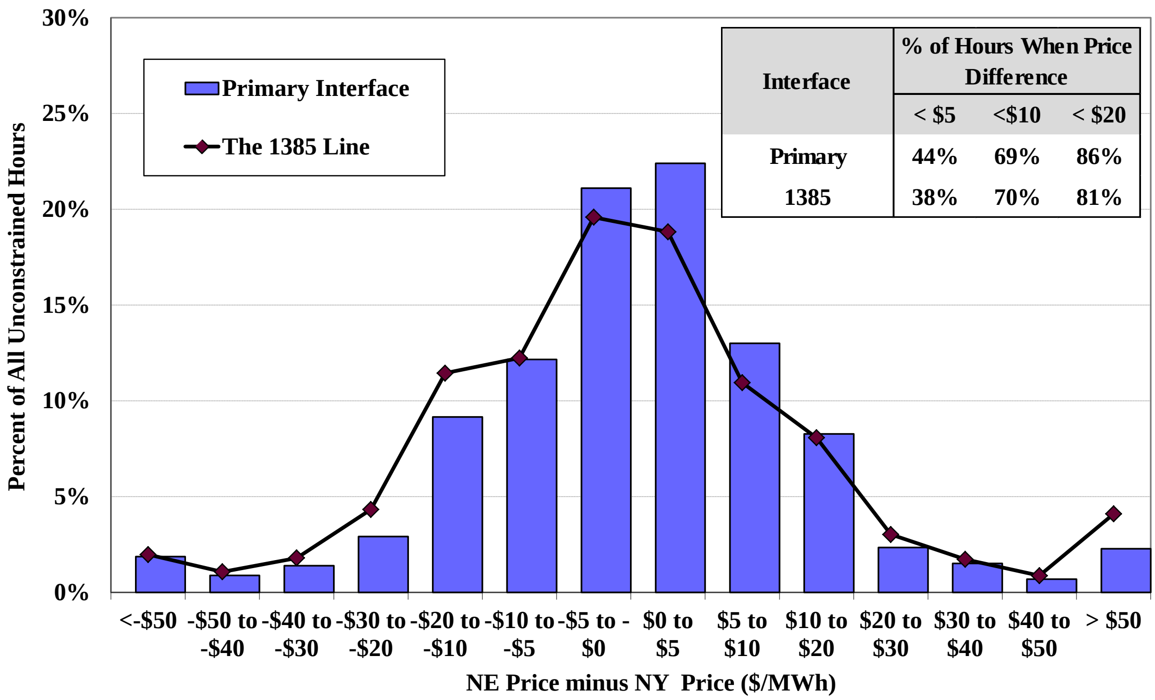
- Differences in the procedures and timing of scheduling in each market serve as barriers to full arbitrage.
- The risks associated with curtailment and congestion reduce participants' incentives to schedule external transactions when the expected price difference is small.

Given these considerations, one cannot reasonably expect that trading by market participants alone will fully optimize the use of the interface. Nevertheless, we expect trading to improve the efficiency of power flows between regions.

1. Price Convergence Between New England and New York

The following figure evaluates scheduling between New England and New York across the primary interface and the Northport-Norwalk Scheduled Line (i.e., the 1385 Line). The Cross-Sound Cable is omitted because it is scheduled under separate rules.[73] Figure 14 shows the distribution of real-time price differences across the primary interface between New England and New York and the 1385 Line in hours when the interfaces were not constrained.

Figure 14: Real-Time Price Difference Between New England and New York
Unconstrained Hours, 2015



73 Service over the Cross-Sound Cable is provided under the Merchant Transmission Facilities provisions in Schedule 18 of ISO-NE's Tariff, which is separate from the transmission service provisions governing use of the Pool Transmission Facilities.

While the factors described above prevent complete arbitrage of price differences between regions, trading should help keep prices in the neighboring regions from diverging excessively. Nonetheless, Figure 14 shows that although the price differences were relatively evenly distributed around $0 per MWh, a substantial number of hours had price differences more than $10 per MWh for each interface. In 2015, the price difference between New England and New York exceeded $10 per MWh in 31 percent and 30 percent of the unconstrained hours for the primary interface and the 1385 Line, respectively. Additionally, the price difference was greater than $30 per MWh in 9 percent of the unconstrained hours for the primary interface and in 12 percent of the unconstrained hours for the 1385 Line. These results indicate that the current process does not fully utilize the interface.

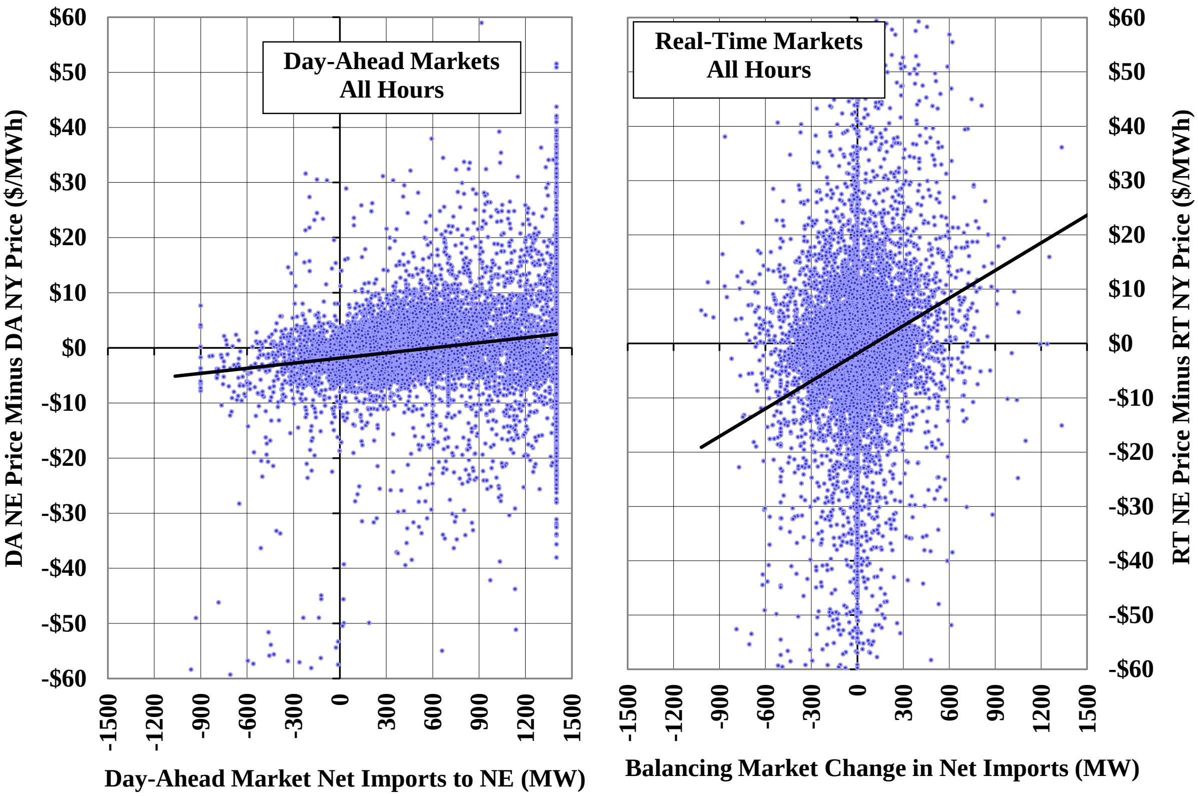
These results also indicate that sizable savings may be achieved by adjusting interchange. Given the pattern of price differences shown, there are many hours when increasing flows from the lower priced region to the higher priced region would have significantly improved the efficiency of prices and production in both regions. This failure to fully arbitrage the interfaces leads to market inefficiencies that can be remedied if the ISOs coordinate interchange effectively.

2. Efficiency of Scheduling Between New England and New York

Although market participants have not fully arbitraged the interface between New York and New England, these analyses evaluate whether transactions have been consistent with the relative prices in the two regions and have, therefore, improved price convergence and efficiency.

The following analysis focuses on whether the incremental changes in participants' schedules (i.e., real-time adjustments from day-ahead schedules) have been consistent with the relative prices in the two regions. Figure 15 shows a scatter plot of net scheduled flows across the primary interface versus the hourly difference in prices between New England and upstate New York in 2015. The left panel shows price differences in the day-ahead market on the vertical axis versus net imports scheduled in the day-ahead market on the horizontal axis. The right panel shows hourly price differences in the real-time market on the vertical axis versus the *change* in the net scheduled imports after the day-ahead market on the horizontal axis. For example, if day-ahead net imports hour are 300 MW and real-time net scheduled imports are 500 MW, the change in net scheduled imports after the day ahead would be 200 MW (= 500 – 300).

Figure 15: Efficiency of Scheduling in the Day-Ahead and Real-Time
Primary Interface Between New England and New York, 2015



The trend lines in the left and right panels show statistically significant positive correlations between the price difference and the direction of scheduled flows in the day-ahead and real-time markets. However, the correlation in the day-ahead market is relatively weak, which indicates the difficulty participants have in scheduling transactions efficiently. The correlation is stronger in the real-time market, which is consistent with market participants generally responding to price differences by increasing net flows scheduled into the higher-priced region. Additionally, total net revenues from cross-border scheduling in 2015 were $17 million in the day-ahead and real-time markets (not accounting for transaction costs).[74] The fact that significant profits were earned from the external transactions indicates that market participants generally help improve market efficiency overall by facilitating the convergence of prices between regions.

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74 This likely underestimates the actual profits from scheduling because it assumes that day-ahead exports from one market are matched with day-ahead imports in the other market. However, market participants have other options such as matching a day-ahead export in one market with a real-time import in the other market. This flexibility actually allows participants to earn greater profits from more efficient trading strategies than those represented in the figure.

However, the figure also shows that the response of market participants to inter-area price differences is incomplete and unpredictable. In 44 percent of the intervals, the real-time response to the price difference is ultimately in the wrong direction (*from* the high-priced areas *to* the low-priced area). Sometimes this occurs because the response is too large and it causes the prices to prices to reverse. This highlights both the difficulty of predicting changes in market conditions in real-time, as well as the effects of uncoordinated scheduling where each participant is submitting transactions independently. Although market participant scheduling has helped converge prices between adjacent markets, Figure 15 highlights that the external transmission interfaces remain poorly utilized. This can only be addressed by improved coordination of interchange by ISO-NE and NYISO, which is discussed in the next section.

3. Coordination of Interchange with New York

Coordinated Transaction Scheduling ("CTS") is a novel market design concept whereby two market operators exchange information about their internal prices shortly before real-time and this information is used to assist market participants in scheduling external transactions more efficiently. The CTS intra-hour scheduling system has at least three advantages over the previous hourly scheduling system.

- CTS bids are evaluated relative to the adjacent ISO's short-term forecast of prices, while the previous system required bidders to forecast prices in the adjacent market.
- The CTS process schedules transactions much closer to the operating time. Previously, schedules were established up to 105 minutes in advance, while schedules are now determined 20 minutes ahead when more accurate system information is available.
- Interface flows can be adjusted every 15 minutes instead of every 60 minutes, which allows for much quicker response to real-time events.

CTS was implemented with the NYISO on December 15, 2015. In this process, ISO-NE provides a forecasted supply curve to NYISO every 15 minutes, which the NYISO uses to schedule CTS transactions. The NYISO's scheduling model ("RTC") evaluates whether to schedule a CTS bid to import assuming it has a cost equal to the sum of: (a) the CTS bid and (b) ISO-NE's forecasted marginal price. Likewise, RTC evaluates whether to schedule a CTS bid to export assuming it is willing to export at a price up to the sum of: (a) the bid and (b) ISO-NE's forecasted marginal price.

It is important to evaluate the performance of CTS on an on-going basis so that the process can be made to work as efficiently as possible. This subsection evaluates the performance of CTS with New York during the first three-and-a-half months of its implementation by assessing CTS bidding patterns, the efficiency of scheduling patterns, differences between the forecasted pricing outcomes and the actual outcomes, and several factors that contribute to forecast errors in the CTS process. In these analyses, the performance of CTS between ISO-NE and the NYISO is benchmarked against the performance of CTS between PJM and the NYISO.

Evaluation of CTS Bidding Patterns

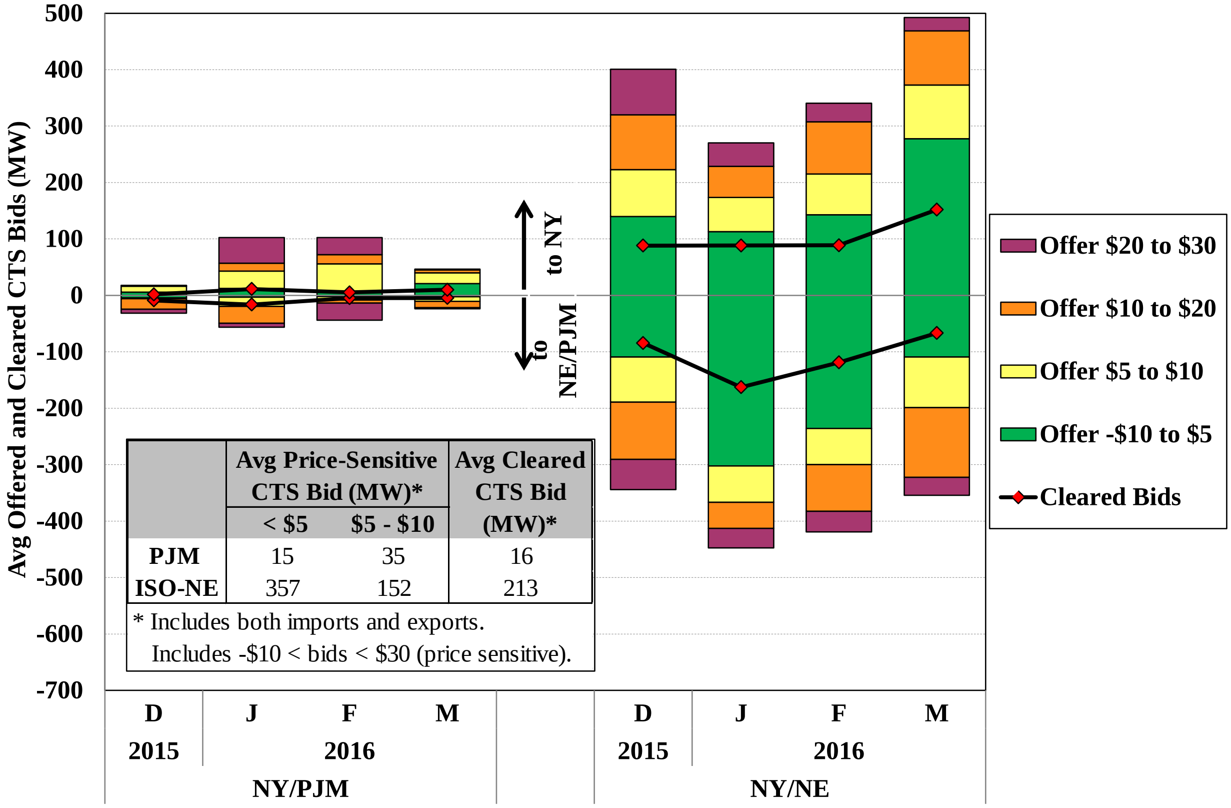
Figure 16 examines the bid volumes for CTS transactions, which shows the average amount of CTS transactions at the primary interface during peak hours (i.e., HE 8 to 23) by month from December 15, 2015 through the end of March 2016. [75] Positive numbers indicate export bids to New York and negative numbers represent import offers to New England. Stacked bars show the average quantities of price-sensitive CTS bids (bids that are offered below -$10/MWh or above $30/MWh are considered price insensitive for this analysis) for the following four price ranges: (a) less than $5/MWh; (b) between $5 and $10/MWh; (c) between $10 and $20/MWh; and (d) between $20 and $30/MWh. The two black lines in the figure indicate the average scheduled price-sensitive CTS imports and exports in each month during the examined period.

For comparison, the figure also shows these quantities for the primary PJM interface over the same period. [76] The table in the figure summarizes for the two CTS-enabled interfaces: a) the average amount of CTS bids with offer prices between -$10 and $5/MWh or between $5 and $10/MWh; and b) the average MW of cleared CTS bids during the examined period that were priced between -$10 and $30/MWh. Both imports and exports are included in these numbers.

75 The quantities reported in the chart for December 2015 are based on data from December 15 to December 31 and are averaged over these 17 days.

76 CTS was implemented between NYISO and PJM on November 4, 2014.

Figure 16: Average CTS Transaction Bids and Offers by Month
NE/NY and PJM/NY Primary Interfaces



The figure shows that the average amount of price-sensitive CTS bids submitted at the primary New England interface was much higher than at the PJM border, even though CTS with ISO-NE is relatively new. During the examined period, an average of 357 MW of CTS bids (including both imports and exports) were offered between -$10 and $5/MWh and an average of 152 MW were offered between $5 and $10/MWh at the NE/NY interface. Just 15 MW and 35 MW were offered in the same two price ranges at the primary PJM/NY interface. Likewise, the amount of cleared price-sensitive CTS bids was 10 times higher at the NE/NY interface. These results indicate much more active participation at the NE/NY interface.

These differences between the two CTS processes are largely attributable to the large fees that are imposed on CTS transactions at the PJM/NY interface, while there are no substantial transmission service charges or uplift charges in either direction on transactions between NYISO and ISO-NE. The NYISO charges physical exports to PJM at a rate normally ranging from $3 to $7/MWh, while PJM charges physical imports and exports less than $2/MWh, but PJM charges "real-time deviations" (which include imports and exports with a real-time schedule that is higher or lower than the day-ahead schedule) a combined rate that averages up to $10/MWh in some months. These charges are a significant barrier to efficient scheduling in the CTS process, since large and uncertain charges deter participants from submitting price-sensitive CTS bids at the PJM/NY border. The figure shows that most CTS transactions that cleared at the New England border were bid at prices between -$10/MWh and $5/MWh. Given that charges are uncertain and often exceed $5/MWh at the PJM/NY interface, it is not surprising that almost no CTS bids were submitted in this range at that interface.

These results suggest that imposing substantial charges on low-margin trading activity has a dramatic effect on liquidity at the interface and that the policy of not assessing uplift charges to transactions at the ISO-NE/NYISO interface will lead to more efficient scheduling outcomes.

Evaluation of Scheduling Efficiency of CTS Process

We evaluated the performance of CTS relative (in the initial 4 months of operation) to our estimates of the scheduling outcomes that would have occurred under the previous hourly scheduling process. This evaluation provides an indication of the degree to which the CTS process has improved scheduling outcomes at the NY/NE interface.

We estimated the hourly schedules that would likely have occurred under the previous hourly process (if it were used from December 2015 to March 2016) using advisory schedules that are produced by the NYISO's RTC model. Specifically, we calculated the average of the four advisory quarter-hour schedules that RTC produced for each hour during the study period at the time that RTC used to determine hourly schedules for the NY/NE interface.[77]

Table 6 examines the performance of CTS at the primary interface between New York and New England and at the primary interface between New York and PJM. For the examined period, the table shows the following quantities:

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[77] RTC is the real-time commitment engine in the NYISO market that is used to schedule CTS transactions between NE and NY and other external transactions. RTC determines the schedules for hourly interfaces at 15 minutes past previous hour. At the same time, RTC determines advisory schedules for CTS interfaces. Our evaluation uses these advisory schedules to estimate the hourly schedules that would have occurred.

- % of All Intervals – This shows the percent of quarter-hour intervals during which the interface flows were adjusted by CTS (relative to the estimated hourly schedule).
- Average Flow Adjustment – This measures the difference between the estimated hourly schedule and the final schedule. Positive numbers indicate flow adjustments in the direction from PJM or New England to New York and negative numbers indicate flow adjustments in the direction from New York to PJM or New England.
- Production Cost Savings – This estimates the market efficiency gains (and losses) that resulted from the CTS processes.
  - Projected Savings at Scheduling Time – The expected production cost savings at the time when RTC determines the interchange schedule across the primary interfaces.
  - Net Over-Projected Savings – This estimates production cost savings that are over-projected. CTS bids are scheduled based partly on forecast prices. If forecast prices deviate from actual prices, transactions may be over-scheduled, under-scheduled, and/or scheduled in the inefficient direction. This estimates the portion of savings that inaccurately projected because of PJM, NYISO, and ISO-NE forecast errors.
- Unrealized Production Cost Savings – This estimates production cost savings that are not realized when the following factors are taken into account:
  - Real-time Curtailment - Some of RTC scheduled transactions may not actually flow in real-time for various reasons (e.g., check-out failures, real-time cuts for security and reliability concerns, etc.). The reduction of flows in the efficient direction reduces market efficiency gains.
  - Interface Ramping – The price forecasting engine and real-time dispatch model in each market (e.g., CTSPE and UDS in ISO-NE) have different assumptions regarding interface schedule ramping. In UDS, interface flows start to ramp 5 minutes before each quarter-hour interval and reach the target level 5 minutes after, while CTSPE assumes that the target flow level is reached at the top of the quarter-hour interval (as illustrated in Figure 19). Therefore, an inherent difference exists between UDS flows and CTSPE flows at the top of each quarter-hour interval, which will lead a portion of projected savings to be unrealized in real-time.
- Price Curve Approximation – This applies only to the CTS process between New York and New England. CTSPE forecasts a 7-point piecewise linear supply curve and NYISO transfers it into a step-function curve for use in the CTS process (as shown in Figure 18). This leads to differences between the marginal cost of interchange estimated by ISO-NE and the assumptions used by the NYISO for scheduling.
- Interface Prices – These show forecasted prices at the time of RTC scheduling and actual real-time prices.
- Price Forecast Errors – These measure the performance of price forecasting by showing the average difference and the average absolute difference between the actual and forecasted prices on both sides of the interfaces.

To examine how price forecast errors affected efficiency gains, these numbers are shown separately for the intervals during which forecast errors are less than $20/MWh and the intervals during which forecast errors exceed $20/MWh.

Table 6: Efficiency of Intra-Hour Scheduling Under CTS
Primary NE and PJM Interfaces, December 15, 2015 to March 31, 2016

			Average/Total During Intervals w/ Adjustment					
			CTS - NY/NE			CTS - NY/PJM		
			Both Forecast Errors <= $20	Any Forecast Error > $20	Total	Both Forecast Errors <= $20	Any Forecast Error > $20	Total
% of All Intervals w/ Adjustment			76%	14%	**91%**	62%	8%	**70%**
Average Flow Adjustment (MW)			-16 (Net) / 81 (Gross)	-18 (Net) / 104 (Gross)	**-17 (Net) / 85 (Gross)**	20 (Net) / 64 (Gross)	6 (Net) / 104 (Gross)	**18 (Net) / 69 (Gross)**
Production Cost Savings ($ Million)	Projected at Scheduling Time		$0.9	$0.7	**$1.6**	$0.4	$0.9	**$1.3**
	Net Over-Projection by:	NY Market	-$0.02	-$0.2	**-$0.2**	-$0.1	-$0.6	**-$0.7**
		Neighbor Market	-$0.01	-$0.3	**-$0.3**	$0.001	-$0.3	**-$0.3**
	Unrealized Savings Due to:	Ramping	-$0.05	-$0.1	**-$0.1**	-$0.02	-$0.02	**-$0.04**
		Curtailment	-$0.01	-$0.01	**-$0.02**	-$0.002	-$0.5	**-$0.5**
		Price Curve	-$0.1	-$0.3	**-$0.4**	N/A	N/A	**N/A**
	Actual Savings		$0.7	-$0.1	**$0.6**	$0.3	-$0.6	**-$0.3**
Interface Prices ($/MWh)	NY Market	Actual	$21.64	$49.94	**$26.09**	$18.25	$54.06	**$22.41**
		Forecast	$22.40	$35.49	**$24.46**	$18.45	$35.63	**$20.45**
	Neighbor Market	Actual	$22.60	$34.63	**$24.49**	$20.84	$35.64	**$22.56**
		Forecast	$23.05	$29.47	**$24.06**	$21.21	$36.56	**$23.00**
Price Forecast Errors ($/MWh)	NY Market	Fcst. - Act.	$0.76	-$14.45	**-$1.63**	$0.20	-$18.43	**-$1.97**
		Abs. Val.	$4.67	$43.72	**$10.81**	$3.80	$48.59	**$9.01**
	Neighbor Market	Fcst. - Act.	$0.46	-$5.16	**-$0.43**	$0.38	$0.92	**$0.44**
		Abs. Val.	$4.26	$35.90	**$9.23**	$2.88	$38.94	**$7.07**

The table shows that interchange schedules were adjusted during 91 percent of all quarter-hour intervals (from our estimate of the hour schedule that would have occurred without CTS) at the primary NE/NY interface. This was much higher than the 70 percent observed at the primary PJM/NY interface. This was partly attributable to the fact that the amount of low-price CTS bids was substantially higher at the NE/NY interface than at the PJM/NY interface (as shown in Figure 16).

Our analyses show that $1.6 million and $1.3 million of production cost savings were projected at the time of scheduling at the primary NE/NY and PJM/NY interfaces during the examined period. However, an estimated $0.6 million of savings were realized at the NE/NY interface and savings were estimated to be negative $0.3 million at the PJM/NY interface. The reduced actual savings seem to be driven largely by price forecast errors.

However, it is important to consider that our evaluation may tend to under-estimate both projected and actual savings. This is because the hourly schedules (that we estimate would have occurred without CTS) may actually include some of the efficiencies that result from the CTS process. Our estimated hourly schedules are derived from earlier run of the RTC model, which still makes use of CTS bids and forecasting results, so the estimated hourly schedules may actually be more efficient than those that would have actually occurred without CTS. Nonetheless, the results of our analysis are still useful for identifying some of the sources of inefficiency in the CTS process.

The table also shows that when forecast errors were moderate (e.g., less than $20/MWh), projected savings were relatively consistent with actual savings. However, when forecast errors were larger, the CTS scheduling process produced much more inefficient results. Consequently, improvements in the CTS process should focus on identifying sources of forecast errors, and so we examine the price forecasting further in the next subsection.

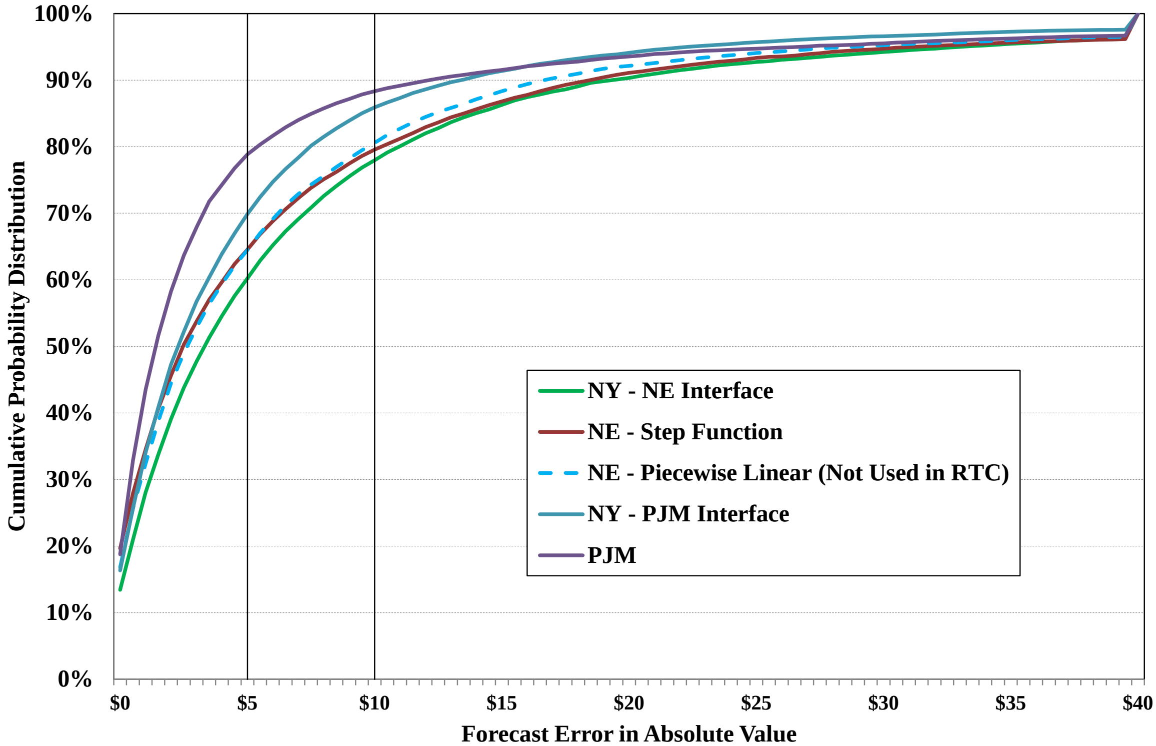
Evaluation of Price Forecasting

The next analysis compares the performance of price forecasting by the three ISOs in the CTS process. Figure 17 shows the cumulative distribution of forecasting errors during the period from December 15, 2015 to March 31, 2016. The price forecast error in each 15-minute period is measured as the absolute value of the difference between the forecast price and actual price. The figure shows the ISO-NE forecast error in two ways: (a) based on the piece-wise linear curve that is produced by its forecasting model, and (b) based on the step-function curve that the NYISO model uses to approximate the piece-wise linear curve.

The figure shows that the performance of the price forecast was generally better at the PJM/NY interface than at the NE/NY interface during the examined period. In particular:

- Price forecast errors were less than $5/MWh in 70 to 80 percent of intervals at the PJM/NY interface compared to 60 to 65 percent at the NE/NY interface; and
- Price forecast errors were less than $10/MWh in 86 to 88 percent of intervals at the PJM/NY interface compared to around 80 percent at the NE/NY interface.

Figure 17: Distribution of Price Forecast Errors Under CTS
NE and PJM Primary Interfaces, December 15, 2015 to March 31, 2016



These resulted partly from the fact that the price-elasticity of supply is normally greater at the PJM/NY interface than at the NE/NY interface because the larger size of the PJM market. Furthermore, at the PJM/NY interface, price forecasting was generally better in PJM than New York, which may be due to the larger size and lower price volatility in the PJM market. Similarly, price forecasting (at the NE/NY interface) was generally better in New England than New York, consistent with the lower price volatility observed in New England (in Section II.A).

Price forecasting was generally better at the PJM/NY interface than at the NE/NY interface, which is not surprising given the process was implemented 13 months earlier between PJM and the NYISO. However, we estimated higher production cost savings at the NE/NY interface because intra-hour interchange adjustments were more frequent and larger, in part because more low-priced CTS bids were available to respond to moderate price differentials between markets.

In addition, Figure 17 shows that the price forecasting based on NYISO's approximation of ISO-NE's supply curve was similar in accuracy to its' piecewise linear curve in the 80 percent of intervals when the forecast error was less than $10/MWh. However, the divergence of the two distribution curves becomes noticeable as the size of forecast errors increase, indicating that the step-function approximation leads to additional significant forecast errors in some cases.

Figure 18 illustrates this by showing example curves from January 5, 2016. The blue squares in the figure show the seven price/quantity pairs that the ISO-NE price forecast engine (CTSPE) provided to the NYISO. The blue line connecting these seven squares represents a piecewise linear supply curve at the New England border. The red step-function curve is generated by the NYISO and is actually used in RTC for scheduling CTS transactions at the New England border.

Figure 18: Example of Supply Curve Produced by CTSPE and Used by RTC

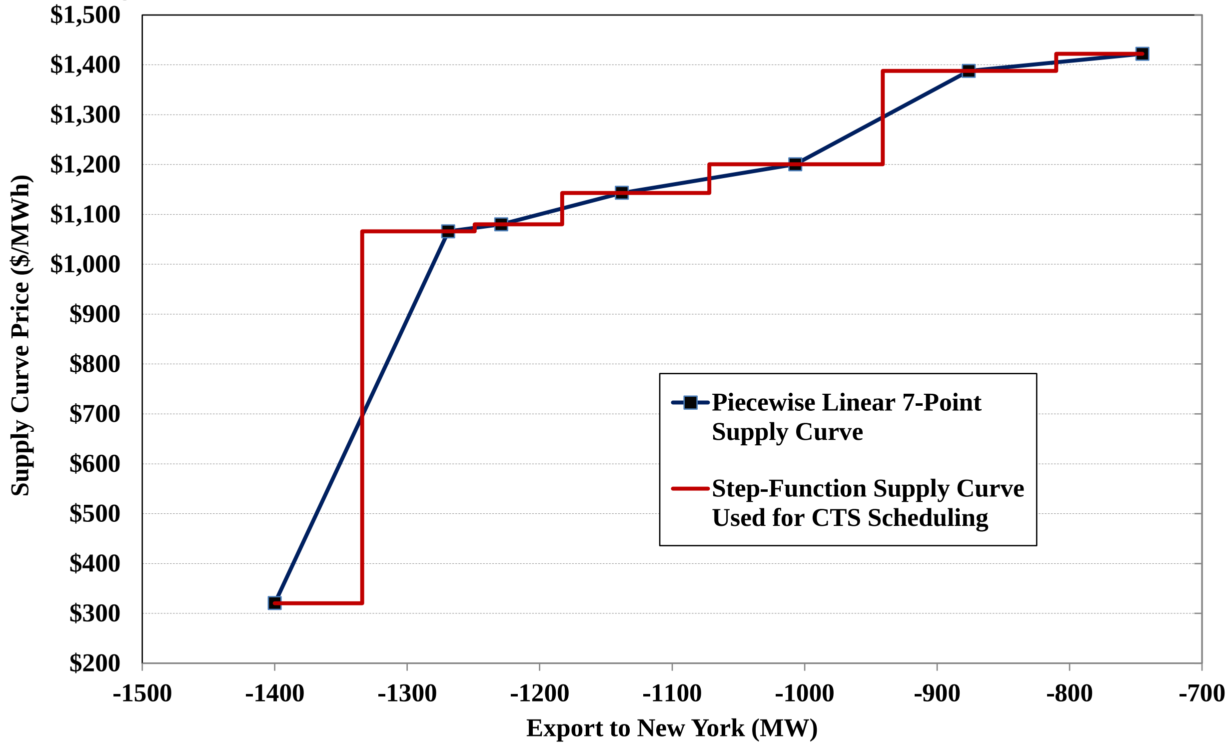
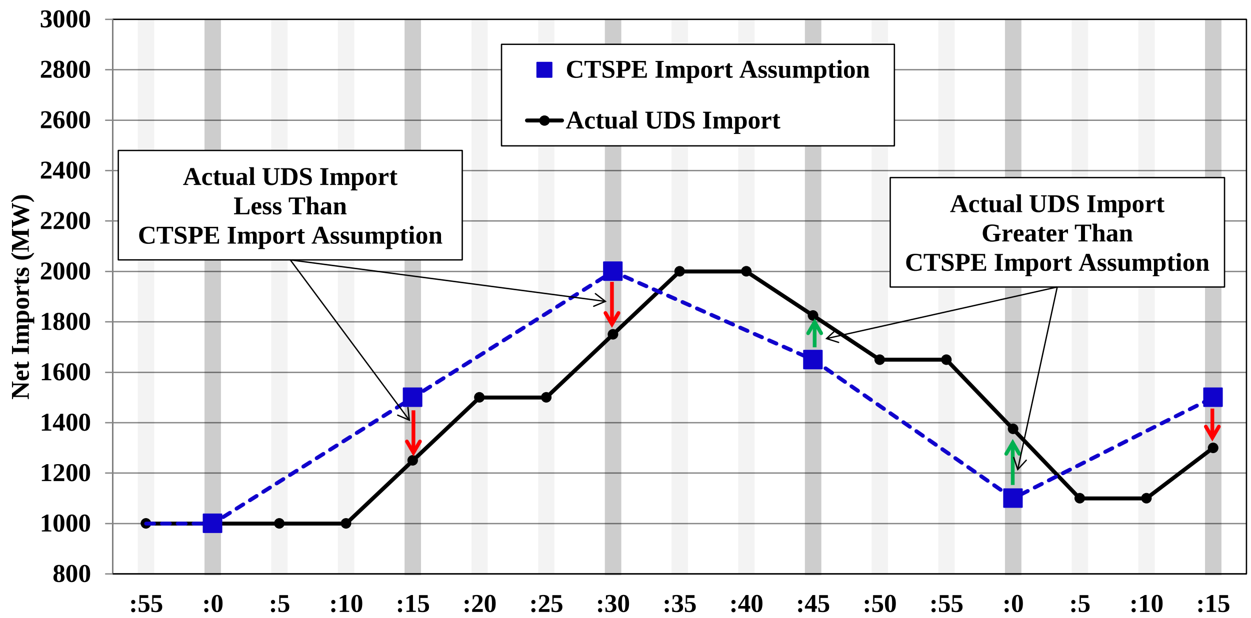


Figure 19 shows that the difference in price forecasting based on these two curves can be very large (nearly $400/MWh in this example when both markets experienced reserves shortages). In addition, CTSPE provides a forecasted supply curve to the NYISO every 15 minutes into the future, so its assumptions regarding the load profile and the ramp profile of individual resources can affect scheduling decisions with longer lead times than the CTS process. Figure 19 examines how the particular assumptions regarding the ramp profile of external transactions affect the accuracy of CTSPE's price forecasting. The figure provides an illustration of the ramp profiles that are assumed by CTSPE and UDS.

Figure 19: Illustration of External Transaction Ramping Profiles in CTSPE and UDS



In UDS, transactions are assumed to move over a 10-minute period from one scheduling period to the next. The 10-minute period goes from five minutes before the top-of-the-hour or quarter-hour to five minutes after. On the other hand, CTSPE assumes that transactions reach their schedule at the top-of-the-hour or quarter-hour, which is five minutes earlier than UDS. In the figure, green arrows are used to show intervals when UDS imports exceed the assumption used in CTSPE, while red arrows are used to shown intervals when imports assumed in CTSPE exceed the UDS imports.

The different ramp profiles lead to inconsistencies between CTSPE and UDS in the level of net imports, which contribute to differences between the CTSPE price forecast and actual UDS clearing prices. Hence, CTSPE price forecasts are less accurate when the level of net imports changes by a large amount in response to market conditions, which reduces the efficiency gains from CTS when it is likely to be most valuable. The NYISO scheduling model that forecasts conditions for scheduling CTS transactions and the NYISO real-time dispatch model exhibit a similar inconsistency in timing as is observed in Figure 19.

Preliminary Conclusions Regarding CTS Performance

We evaluate the performance of CTS scheduling between New York and New England across its primary interface in the first three-and-a-half months following its implementation and find that:

- The average amount of price-sensitive CTS bids that were offered and cleared at the NY/NE interface was higher by more than 10 times than those submitted and cleared at the NY/PJM interface. Much of the difference can be explained by the large fees that are imposed on CTS transactions at the NY/PJM interface while there are no substantial transmission service charges or uplift charges on transactions between New York and New England. (See Figure 16)
- The CTS scheduling process has resulted in substantial efficiency gains (as measured in production cost savings). However, less than half of the savings projected when CTS transactions were determined were actually realized. This was primarily because of price forecast errors. (See Table 6)
- Price forecast errors may be increased by certain simplifications that are used in the forecast models. In particular, both the NYISO and ISO-NE forecast models use timing assumptions for interchange that are inconsistent with their respective dispatch models. (See Figure 19) Also, the NYISO uses a simplified representation of the ISO-NE forecast that may contribute to its forecasting errors. (See Figure 18)

Although it is too early to draw strong conclusions, these initial results indicate a generally successful implementation of CTS scheduling between New York and New England. However, additional benefits will likely be realized from improving the accuracy of the forecast assumptions by both ISOs.

IV. Competition in the Forward Capacity Market

Forward Capacity Markets are designed to allow participation by prospective new investors, which increases competition by providing competitive discipline for existing suppliers. In each of the last four forward capacity auctions, new resources were needed in at least one capacity zone.[78] However, participation by new generation was relatively limited up until the last auction (FCA 10), causing some new suppliers to be pivotal in particular locations.[79] Although participation increased considerably in FCA 10, it is still important to evaluate the forward capacity market on an on-going basis and to identify factors that may inhibit participation by new resources or otherwise reduce competition.

The ISO has recently taken significant steps that will enhance competition in the forward capacity market, and these are expected to become effective in FCA 11. First, the ISO filed to implement sloped demand curves in the local capacity zones, which greatly reduces the effectiveness of anticompetitive conduct, thereby enhancing incentives to offer competitively. Second, the ISO is implementing new rules to protect the market if a supplier attempts to exercise of market power by retiring an existing generator.

This section evaluates participation by suppliers in FCA 9 and discusses factors that may have reduced competition. Although competitive conditions improved in FCA 10, these factors might facilitate strategic conduct in a future FCA if circumstances happen to be less favorable to competition. The end of this section summarizes our conclusions and recommendations to promote competition in the forward capacity market.

A. Participation by Suppliers in FCA 9

The FCM qualification process requires a developer to commit significant resources before participating in an FCA, so the number of new resources actually competing may be small. Consequently, participation by new resources may not always provide adequate competitive discipline for new and existing resources in the auction. Additionally, access to key information

78 New resources were needed to satisfy the NEMA/Boston LSR in FCA 7, the System-wide NICR in FCA 8, the SEMA/RI LSR in FCA 9, and the System-wide NICR and the SENE LSR in FCA 10.

79 A Market Participant is pivotal if some of its capacity is required to satisfy the LSR or System-Wide NICR.

can facilitate strategic conduct by suppliers in the auction. This section summarizes participation and identifies factors that may have reduced competition in FCA 9.

The first row of the following table shows the amount of non-intermittent generating capacity in the Interconnection Queue at sites located in one of the three import-constrained capacity zones before FCA 9. This represents the potential set of resources that could have submitted a Show of Interest and participated in the auction. Rows 2, 3, and 4 show the amounts of capacity that did not qualify for reasons that would have been evident to other auction participants from public information. The amounts of qualified generation (Row 5) and qualified generation excluding the largest new entrant (Row 6) are compared to the existing capacity surplus over the local capacity requirement (Row 7), where a negative value indicates a capacity shortfall.

Table 7: Potential Participation by New Generating Capacity in FCA 9

		Connecticut	SEMA/ RI	NEMA/ Boston	Total
New Generation Capacity in Interconnection Queue (non-intermittent)	[1]	1265	880	1048	3193
Large Units without SIS Study and/ or a Siting Permit Application	[2]		340		340
Capacity from Suspended MPs	[3]		332		332
Rejected New Capacity	[4]			841	841
FCA-9 Qualified Capacity from New Generation (non-intermittent)	[5] = [1]-[2]-[3]-[4]	1265	208	208	1680
Qualified Generation Excluding the Largest New Entrant	[6]	29	11		40
Excess Existing Capacity Relative to LSR	[7]	1790	-557	265	1498

Notes:

[1] Summer capacity (as per publicly available data) of all new non-intermittent generation with a valid Interconnection Request. Excludes resources that will not be operational by the Capacity Commitment Period

[3] ISO-NE issued a public notice suspending Advanced Power on 10/31/2014

[4] Units rejected due to overlapping interconnection impacts analysis were identified in a FERC filing on 11/04/2014

[5] This data differs from the actual qualified capacity to the extent the resource MW data reported in the Interconnection Queue (or other public data) are different from the actual summer capacity. Total actual FCA-9 qualified capacity from non-intermittent new generation (excluding ROP capacity) was 1693 MW

[6] Excludes qualified capacity from intermittent generation and demand resources

[7] Existing capacity and LSR data can be found in ISO-NE's informational FERC filing

Southeast Massachusetts

A relatively large amount (557 MW) of new capacity was needed to satisfy the local requirement in FCA 9. Although 880 MW of new generation was proposed to be operational by the Capacity Commitment Period in this area, it was apparent from public information on siting permit applications that 340 MW was not likely to participate. Several months before FCA 9, it became apparent that another 332 MW of capacity was not going to participate when ISO-NE published a Notice of Market Participant Suspension for the developer. Other auction participants might have speculated the project would not participate before this, but the notice made this a certainty.

Of the remaining 208 MW that did qualify, 95 percent was a single project, so the developer of the project should have known that its capacity would be pivotal in the auction. In this case, the developer would know that its offer would be accepted at any price below the FCA starting price of $17.73 per kW-month.

Connecticut

There was a relatively large amount of participation by several market participants on top of a substantial excess of existing capacity, so competition to satisfy the local Connecticut requirement was robust.

NEMA/Boston

There was a local excess of 265 MW prior to the auction, so additional resources would not have been needed unless existing capacity de-listed during the auction. While 1,048 MW of proposed new generation was in the interconnection queue, it was apparent from information filed by the ISO that 841 MW did not qualify for the auction (leaving just a single 208 MW new generator). Thus, if a non-price retirement request or other supply reduction had occurred, this developer would have perceived it was pivotal and could set the capacity price at the FCA starting price.

New York AC Ties

Although resources at this import interface have limited impact on the system-wide clearing price since the implementation of the system-wide sloped demand curve after FCA 8, individual suppliers may be able to influence the clearing price at the interface itself. In FCA 9, the descending clock auction format would have provided information of strategic value to any bidder that was interested in setting a higher clearing price at the interface. Specifically, at the end of Round 3, participants were informed that the System-wide region had cleared at a price of $9.55/kW-month and that 1,154 MW was still competing at the New York AC Ties interface (equal to 1,054 MW). In this situation, any supplier would know that withdrawing 100 MW would stop the clearing price from falling further. Not surprisingly, 100 MW was withdrawn moments after Round 4 started at a price of $8.00/kW-month, setting a clearing price of $7.97/kW-month.

Four observations can be drawn from the results of FCA 9:[80]

- Limited competition can enable a single supplier to unilaterally raise the capacity clearing price by a substantial amount.
- Publishing information on qualified capacity (new and existing) ensures that suppliers will recognize when they can benefit by raising capacity prices.
- To the extent that the qualification process limits the number of new resources participating in the auction, the competiveness of the auction will be reduced.

These observations point to market changes that could enhance competition in the FCA:

- Reducing any unnecessary barriers to participation helps provide additional competitive discipline that reduces the incentive for a supplier to raise its offer substantially above its net CONE.
- Reducing the amount of information available before the auction to make it more difficult for a pivotal supplier to determine its profit-maximizing offer and encourage new suppliers to offer competitively at prices closer to their net CONE.
- Transitioning from the descending clock auction process to a sealed-bid auction to eliminate the information provided during the auction that reduces the competitiveness of the auction.

The next subsection provides a discussion these potential changes greater detail.

80 It was also apparent that the vertical shape of the demand curve accentuates the price impact that a new resource can have when it is pivotal. However, the ISO has already proposed to address this.

B. Availability of Information to Participants in the Auction

This section discusses information that FCA participants can use to narrow down the list of potential new competitors in the FCA and to estimate the impact of their conduct on clearing prices. In general, it would be beneficial for the ISO to publish as little information possible regarding participation until after the auction. The list of potential competitors starts with the Interconnection Queue.[81]

Information from State Proceedings Related to Permit Applications

New generators and changes to existing generators require permits from various state and local agencies *before* the start of construction. The amount of lead time required can be substantial depending on the nature of the permit, type of facility, and location. In Connecticut and Massachusetts, it generally takes at least a year to obtain such permits. Although the FCM rules do not require a developer to obtain permits before the FCA, most new projects will not sell in the FCA before reaching an advanced stage in the permitting process so that the developer can be reasonably certain of being able to satisfy its obligations by the time the commitment period begins.

Permit applications in all New England states require the developer to disclose project information (including the project schedule) and engage the public very early in the process. Therefore, the open nature of the permitting process provides all FCA participants with important data that would allow them to evaluate the progress and feasibility of a new project participating in a given FCA.

Information Published by ISO New England

New and existing FCA participants can refine their offer strategies based on information the ISO publishes about new and existing resources at various stages of the FCA qualification process. In general, publishing such information tends to reduce competitive pressure on auction participants by helping them determine when withholding or raising the offers above net CONE

[81] All proposed new generators with active Interconnection Requests are listed in the public Interconnection Queue, which provides: the resource type, date of request, location, size, and progress towards interconnection.

would be profitable. The following four categories of information allow FCA participants to determine how much competition to expect from new resources.

- Rejected Projects – The ISO files with the Commission a description of new resources whose FCM qualification packages were rejected because of the overlapping interconnection impact analysis. These projects are unable to participate because they would require transmission upgrades that might not be feasible before the commitment period. 841 MW in NEMA/Boston was rejected for this reason (see Row 4 of Table 7).
- Conditionally-Qualified Projects – The ISO notifies the Primary (higher-queued) resource and Conditional (lower-queued) resource developers of how their resources will be treated in the FCA. Capacity from a Conditional resource cannot clear unless the Primary resource drops out of the FCA. Hence, providing this information to the Primary resource owner indicates that it cannot be under-cut by the Conditional resource.
- Status of System Impact Study – The Interconnection Queue shows the status of projects' System Impact Studies ("SIS") and approval under section I.3.9. The full scope of the SIS is broader than the scope of the initial interconnection analysis needed for the FCM qualification process and may identify substantial additional costs that must be incurred to interconnect. Therefore, large resources are likely to proceed only after completing a full SIS. Hence, publishing information about this process may indicate a new unit's likelihood of participating in the FCA.
- Suspension Notice – When a market participant stops meeting the requirements for participation in the market, it may lose its status as an ISO-NE market participant. When this occurs, the ISO must make a public filing notifying the Commission. In some cases, such as in Southeast Massachusetts in FCA 9, this involves a proposed project in an import-constrained zone (see Row 3 of Table 7).

The following sources of information indicate the amount of supply from existing resources.

1. Existing Resource Qualified Capacity – The ISO makes a filing to the Commission before the auction with a list of qualified existing generation, demand response, and import resources. Since this list includes the precise number of megawatts for each resource and its location, this information allows auction participants to calculate the exact amount of excess (or shortfall) capacity before the auction, excluding new resources.
2. Descending Clock Auction – The descending clock auction format is sometimes touted over sealed bid formats because it provides auction participants with information about the value of a good.[82] However, in the FCA, sellers do not receive any information that may be useful in establishing a competitive offer. Instead, the information learned through the auction process is primarily useful in determining when to leave the auction in order to set the highest price and receive the highest capacity revenue possible. In particular, the ISO-NE clock auction provides the amount of excess supply at the system-level and at each

[82] In most cases, is employed on the demand side with buyers determining when to stop the clock and set the price. It is generally referred to as a Dutch Auction because it is famously used in the Dutch flower market.

interface at the end of each auction round. Hence, suppliers will know when they are pivotal market-wide and, if the new resources are concentrated at a particular zone or interface, this information will allow suppliers to infer how supply conditions may be changing at that location.

Above is a list of six categories of information that are published by the ISO that reduce the competitiveness of the auction. We recommend the ISO review this list and identify reasonable changes in its information policies.

C. New Resource Offer Floor Rules

ISO-NE has New Resource Offer Floor rules that are a form of minimum offer price rule (MOPR). These rules are designed to deter uneconomic entry that is intended to lower capacity prices. We have evaluated these rules in light of ISO-NE's changing capacity market framework, including their "pay for performance" provisions. We have identified some important potential shortcomings of ISO-NE's MOPR that should be addressed to ensure its effectiveness.

First, the current MOPR does not prevent resources that are subject to an offer floor from selling its capacity after the forward auction. It may sell such capacity into an ISO reconfiguration auction or bilaterally to be used to satisfy an LSE's capacity obligations. This allows the supplier to circumvent the mitigation and receive credit for its uneconomic resource. Anticipating lower prices in the reconfiguration auctions, other capacity suppliers would tend to reduce their offer prices accordingly in the FCA, thereby leading FCA prices to be suppressed as well. Hence, we recommend that mitigated units not be allowed to sell capacity in subsequent auction or be used to satisfy any LSE's capacity requirements.

Second, under the pay for performance rules, most of the value of capacity will be embedded in the PPR payments. Participants that sell capacity are essential engaging in a forward sale of the expected PPR payments (they receive the capacity payment up front in exchange for not receiving the PPR later when they are running during a shortage). However, resources that do not sell capacity can earn comparable revenues by simply running during shortages and receiving the PPR payments. Therefore, simply preventing the uneconomic supplier from selling capacity will not be an adequate deterrent and we recommend the ISO consider barring the mitigated unit from receiving PPR revenues.

Finally, an uneconomic unit that is subsidized to enter may lower effective capacity payments even though it is not selling capacity. This occurs because the additional supply:

- Lowers the expected number of shortage hours, which:
- Reduces most suppliers offers (which are primarily determined by the expected PPR revenues during shortages they will be foregoing), which:
- Lowers the clearing price for capacity.

Therefore, we would recommend the ISO consider additional rules to close loop holes that would allow capacity prices to be artificially depressed by the entry of uneconomic supply.

D. Conclusions and Recommendations

The forward capacity auction is designed to enhance market efficiency by allowing new proposed resources to compete against existing resources. However, there will be circumstances when new proposed resources and/or imports find themselves in an auction where they face little competition and have the ability to raise the clearing price significantly at a particular location. ISO-NE has already taken significant steps to enhance competition by proposing sloped demand curves at the system and zone levels and by addressing the potential for a supplier to exercise market power by retiring a generator. However, we recommend additional changes to further enhance competition:

- Evaluate changes in the availability or timing of information about qualified supply before the auction. In particular, the ISO should consider providing less information regarding:
  - Proposed new resources that are rejected, conditionally-qualified, suspended, or have not undergone System Impact Studies; and
  - The quantity of qualified capacity from existing resources.
- Replace the descending clock auction format with a sealed bid auction format.
- Modify its queue rules to allow the FCA to select between projects that are interdependent, rather than providing a preference for one project by designating it Primary and designating the other project as conditionally-qualified. This will allow the FCA to clear the most economic unit and set more efficient prices.
- Assess a number of identified changes in the MOPR provisions to ensure that it will be effective under the pay-for-performance framework.

Appendix A: Net Revenue Assumptions

A. Assumptions for Gas-fired Units Net Revenue Estimation

The method we use to estimate net revenues for new gas units and older, existing fossil technologies uses the following assumptions:

- Fuel costs for all units are based on the Algonquin City Gates gas price index. We also analyzed the profitability of a CC unit ("CC (Iroq)") with access to gas priced at the Iroquois Zone 2 index.
- All units are scheduled before each day based on day-ahead prices, considering commitment costs, minimum run times, minimum generation levels, and other physical limitations.
- CC and ST units may sell energy, 10-minute spinning reserves, and 30-minute reserves; while combustion turbines may sell energy and 10-minute or 30-minute non-spinning reserves. Each gas-only and dual-fueled unit is assumed to offer reserves, limited only by its ramp rate and commitment status.
- Combustion turbines (including older gas turbines) are committed in real-time based on hourly real-time prices. Combustion turbines settle with the ISO according to real-time market prices and the deviation from their day-ahead schedule.
- Online units are dispatched in real-time consistent with the hourly integrated real-time LBMP and settle with the ISO on the deviation from their day-ahead schedule. However, to account for the effect of the slower ramp rate of the ST unit in this hourly analysis, the unit is assumed to operate within a certain margin of the day-ahead energy schedule. The margin is assumed to be 25 percent of the maximum capability.
- All technology types are evaluated under gas-only and dual-fuel scenarios to assess the incremental profitability of dual-fuel capability. ST units are assumed to use low sulfur residual oil. All other units are assumed to use ultra-low sulfur diesel oil.
- Combustion turbines (including older gas turbines) are also evaluated for their profitability based on the generator's decision to participate in the Forward Reserve Auctions for each of the capability periods. It is assumed that generators anticipate when selling forward reserves will be more profitable than selling real-time reserves before each capability period.
- All the dual-fuel units are assumed to offer into the Winter Reliability Program (WRP). The revenues from WRP were estimated based on the weighted average of accepted bids from each type of unit in the most recent auction.
- Fuel costs assume transportation and other charges of 27 cents/MMbtu for gas and $2/MMbtu for oil on top of the day-ahead index price. Intraday gas purchases are assumed to be at a 20% premium due to gas market illiquidity and balancing charges, while intraday gas sales are assumed to be at a 20% discount for these reasons.

- The minimum generation level is 440 MW for CCs and 90 MW for ST units. The heat rate is 7,639 btu/kWh at the minimum output level for CCs, and 13,000 btu/kWh for ST units. The heat rate and capacity for a unit on a given day are assumed to vary linearly between the summer values on August 1 and the winter values on February 1. The summer and winter values are shown in the following two tables.
- Regional Greenhouse Gas Initiative (RGGI) compliance costs are included.
- We also use the modified operating and cost assumptions listed in the following tables:

Table 8: New Unit Parameters for Net Revenue Estimates [83]

Characteristics	CC	LMS 100	Frame 7
Summer Capacity (MW)	715	188	417
Winter Capacity (MW)	754	202	450
Summer Heat Rate (Btu/kWh)	7469	9260	10806
Winter Heat Rate (Btu/kWh)	7405	9041	10383
Min Run Time (hrs)	4	1	1
Variable O&M ($/MWh)	2.4	5.4	3.7
Startup Cost ($)	18402	0	18328
Startup Cost (MMBTU)	3376	430	900
EFORd	2.5%	2.0%	2.0%

Table 9: Existing Unit Parameters for Net Revenue Estimates

Characteristics	ST	GT-10	GT-30
Summer Capacity (MW)	360	32	16
Winter Capacity (MW)	360	40	20
Heat Rate (Btu/kWh)	10000	15000	17000
Min Run Time (hrs)	16	1	1
Variable O&M ($/MWh)	8.0	4.0	4.5
Startup Cost ($)	6000	1200	519
Startup Cost (MMBTU)	2000	50	60
EFORd	5%	10%	20%

83 These parameters are based on technologies studied as part of the ISO's sloped demand curve filing.

B. Assumptions for Nuclear Units Net Revenue Estimation

Our estimates for the net revenues the market would have provided to existing nuclear units are based on the following assumptions:

- Nuclear plants are dispatched day ahead and may only sell energy and capacity.
- Nuclear units earn energy revenues throughout the year except during periods of forced outages and outages related to refueling. We assumed an EFORd of two-and-a-half percent, and a capacity factor of 75 percent during March, April, October, and November to account for reduced output during refueling.[84]

C. Assumptions for Renewable Units Net Revenue Estimation

We estimated the net revenues the markets would have provided to utility-scale solar PV and onshore wind plants in ISO-NE using the following assumptions:

- Net E&AS revenues are calculated using real time energy prices.
- The energy produced by these units is calculated using technology and location-specific hourly capacity factors for each month. The capacity factors are based on location-specific resource availability and technology performance data from the Energy Information Administration.
- The capacity revenues for solar PV and onshore wind units in every year are calculated using prices from the corresponding FCAs. The capacity values of solar PV and wind resources are based on the average ratio of qualified capacity to the nameplate rating (39 and 0 percent for the winter months and 14 and 43 percent for summer months for wind and solar, respectively).[85]
- We estimated the value of RECs produced by utility-scale solar PV and onshore wind units using the REC Index values from SNL Financial. Future REC prices were assumed to remain constant at the posted index level as of May 13, 2016.
- Solar PV and onshore wind plants, as renewable projects, are eligible for Investment Tax Credit ("ITC") and Production Tax Credit ("PTC") respectively as part of federal

84 The refueling cycle for nuclear plants in New England is typically 18 months. We assume reduced capacity factors in the Spring (April and May) and in the Fall (October and November) every year in order to enable a year over year comparison of net revenues.

85 The solar factors are from the ISO-NE presentation titled "Intermittent Resource Review in FCM Qualification, Update On The FCM Qualified Capacity Estimating Tool" (December 7, 2015). See http://www.iso-ne.com/static-assets/documents/2015/12/vrwg_intermittent_resource_qual_tool_status_update_12072015.pdf

Wind unit factors are from the ISO-NE presentation titled "Intermittent Resource Review, Update on the FCM Qualified Capacity Estimating Tool for Wind Resources" (March 7, 2016). See http://www.iso-ne.com/static-assets/documents/2016/03/vrwg_intermittent_resource_qual_tool_status_update_030716.pdf programs to encourage renewable generation. The ITC reduces the federal income tax of the investors by an amount equal to 30 percent of a solar PV unit's eligible investment costs and is realized in the first year of the project's commercial operation. The PTC is a per-kWh tax credit for the electricity produced by a wind facility over a period of 10 years.[86] We incorporate the value of these federal incentives as an additional revenue stream for solar PV and wind units.[87]

The cost of developing new renewable units, especially solar PV plants, has dropped rapidly over the last few years. As such, the estimated investment cost for solar PV technologies varies significantly based on the study methodology and study period. Table 10 shows our assumed costs and other operating for solar PV and onshore wind units. The data shown are based on cost estimates from NREL and regional cost multipliers from EIA.[88] The table also presents the operating and cost assumptions we used for calculating net revenues for utility-scale solar PV and onshore wind plants.

Table 10: Utility-Scale Solar and Onshore Wind Parameters for Net Revenue Estimates

Parameter	Utility-Scale Solar PV	Onshore Wind
Investment Cost (2015$/kW AC basis)	$2,787	$2,022
Fixed O&M ($/kW-yr)	$22	$51
Project Life	20 years	
Property Tax	0.50%	
Depreciation Schedule	5-years MACRS	
Average Annual Capacity Factor	22.2%	38.0%
Unforced Capacity Percentage	Summer: 43% Winter: 0%	Summer: 14% Winter: 39%

86 The PTC is available only for the first 10 years of the project life. The value of PTC shown is levelized on a 20-year basis using the after-tax WACC used in the latest demand curve reset.

87 In addition to these federal programs, renewable power projects may qualify for several other state or local-level incentives (for instance, property tax exemptions) in New England. However, our analysis does not consider any other renewables-specific revenue streams or cost offsets beyond the revenues from sale of RPS attributes and the PTC or the ITC.

88 NREL, 2015, *Annual Technology Baseline and Standard Scenarios*, See: http://www.nrel.gov/analysis/data_tech_baseline.html