2015 State of the Market Report for the New York ISO Markets

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I. Executive Summary

As the NYISO's Market Monitor Unit ("MMU"), our Core Functions include reporting on market outcomes, evaluating the competitiveness of the wholesale electricity markets, identifying market flaws, and recommending improvements to the market design. The *2015 State of the Market Report* presents our assessment of the operation and performance of the wholesale electricity markets administered by the NYISO in 2015. This executive summary provides an overview of market outcomes and highlights, a list of recommended market enhancements, and a discussion of the highest priority recommendations.

The NYISO operates competitive wholesale markets to satisfy the electricity needs of New York. These markets establish short-term and long-term prices that reflect the value of energy at each location on the network. They deliver significant benefits by coordinating the commitment and dispatch of generation to ensure that resources are started and dispatched each day to meet the system's demands at the lowest cost. These markets also provide competitive incentives for resources to perform efficiently and reliably.

The energy and ancillary services markets are supplemented by the installed capacity market, which provides incentives to satisfy NYISO's planning reliability criteria over the long-term by facilitating efficient investment in new resources and retirement of older uneconomic resources.

As the MMU, we evaluate the competitive performance of each of these markets. Additionally, market power mitigation rules effectively limit anticompetitive conduct that would undermine the benefits of the competitive markets.

A. Key Developments and Market Highlights in 2015

The NYISO markets performed competitively in 2015. Substantial reductions in fuel prices and lower load levels in 2015 led to lower energy prices, uplift costs, and the net revenues received by suppliers that motivate them to invest in new resources and maintain existing resources. These changes also affected generation dispatch, congestion patterns, and import levels. These results for 2015 are summarized below.

Natural Gas Prices and Load Levels

Natural gas prices decreased considerably from 2014 to 2015, falling 58 percent in Western New York, 38 percent in New York City, and 43 to 50 percent in other areas of Eastern New York. These reductions were particularly large in the winter because of lower oil prices, increased LNG imports to the region, and higher natural gas production from Marcellus and Utica shales in 2015. Natural gas prices also fell to multi-year lows in mid-2015 across the system because of the growing natural gas shale production.

Load averaged 18.4 GW and peaked at 31.1 GW in the summer of 2015. Although the summer peak load level was up 5 percent from 2014, the summer of 2015 was still mild relative to conditions from 2010 to 2013. The winter of 2015 was not as cold as in 2014 overall, but February 2015 was the coldest month in the last decade.

Energy Prices and Transmission Congestion

Day-ahead and real-time energy prices fell approximately 30 to 50 percent across the system from 2014 to 2015 with the largest reduction occurring in the first quarter of 2015. A strong relationship between energy and natural gas prices is expected in a well-functioning, competitive market because natural gas-fired resources are the marginal source of supply in most intervals.

Transmission congestion and losses led real-time prices to vary from an average of $27 per MWh in the North Zone to $50 per MWh in Long Island in 2015. Congestion revenues collected in the day-ahead market fell 6 percent from 2014 to $539 million in 2015. Congestion patterns in the NYISO were driven primarily by congestion on the natural gas pipeline system, which exhibited significant gas price spreads between eastern and western New York throughout the year. The most significant congestion appeared on the Central-East Interface, which flows power from Western New York to Eastern New York and accounted for nearly 45 percent of total day-ahead congestion revenues in 2015. Transmission bottlenecks became increasingly common in the West Zone because of rising imports from Ontario and because reduced operation of coal-fired units in western New York and Pennsylvania have changed the pattern of flows across the network. Congestion in the West Zone could not be resolved using available physical resources in roughly 2 percent of all intervals in 2015, leading to more frequent peaking conditions.

The electricity market performed well in the coldest month (February 2015) over the last decade despite challenging gas market conditions as many suppliers switched to burning fuel oil. The NYISO markets provide price signals and scheduling information that enables suppliers to make better fuel purchasing and consumption decisions during extreme winter weather. This underscores the importance of the NYISO markets in helping coordinate the efficient use of scarce fuel supplies during cold weather conditions. (See Recommendations #19 & #20.).

Installed Capacity Market

Capacity costs fell notably from 2014 to 2015, down by 17 percent in Long Island, 19 percent in New York City, 24 percent in Lower Hudson Valley (i.e., Zones GHI), and 40 percent in the Rest of State. A key driver of the reductions was the return-to-service of multiple generating units, which added over 1 GW of capacity in the new G-J capacity locality, including 170 MW in New York City and 855 MW in the Hudson Valley.

In addition, the Local Capacity Requirements ("LCR") in New York City and Long Island fell from 85 to 83.5 percent and from 107 to 103.5 percent from the prior Capability Year, contributing to lower capacity costs. However, the LCR in the G-J Locality rose from 88 to 90.5 percent, partly offsetting the overall decrease of capacity costs in Lower Hudson Valley.

The primary factor leading to changes in the LCRs was the increased capacity in Hudson Valley. The current rules for determining the LCRs and IRM are not optimal and are likely to produce variations that are difficult to predict, leading to significant market uncertainty. We recommend changes in the rules that will lower the costs of satisfying NYISO's planning requirements and lead to more stability and predictability in the requirements. (See Recommendation #1.)

Long Run Investment Signals

The economic signals the markets provide that govern participants' long-run decisions (including investment, retirement, and maintenance decisions) can be measured by the net revenues generators receive in excess of their production costs. Net revenues for new and existing generators fell notably in all areas in 2015 because of lower energy and capacity net revenues.

Although our net revenue analysis indicates that the additional revenues from dual-fuel capability were significantly lower in 2015 than the extraordinarily high levels witnessed in

2014, the potential returns from dual-fuel capability are adequate for many units to maintain dual-fuel capability and modest oil inventories.

Our evaluation indicates that the estimated net revenues for a new Frame 7 gas turbine were lower than the annual levelized cost of new entry ("CONE") at all locations with the exception of the West Zone. However, this may not be sufficient to attract new investment in the West Zone if developers believe that the elevated net revenue levels will be short-lived given that large transmission upgrades are being considered to relieve these bottlenecks in Western New York.

We also analyze the investment incentives for existing nuclear units and potential new renewable projects, which have become more important as New York seeks to comply with the Clean Power Plan. Low natural gas prices present significant challenges for the financial viability of these zero-emission technologies. Based on current electricity futures prices, single-unit nuclear installations in upstate New York are not expected to recoup their going-forward costs over the next five years. We also compare the cost per ton of reducing CO_2 emissions by developing new renewable projects, by retaining existing nuclear generation, and by developing new fuel-efficient gas-fired generation. This evaluation indicates that building new gas-fired generation in certain areas to displace inefficient generation is among the lowest-cost measures available. This underscores the importance of relying on technology-neutral mechanisms to encourage emission reductions such as a tradable rate-based emission credit program, a cap-and-trade carbon market, or a carbon tax.

B. Day-Ahead Market Performance

Convergence between day-ahead and real-time prices is important because the day-ahead market determines which resources are committed each day, affecting fuel procurement and other scheduling decisions.

Day-ahead prices were higher on average than real-time prices in most areas in 2015. In general, a small day-ahead premium is expected in a competitive market because of the increased financial risk of purchasing at the real-time price.

Virtual trading helped align day-ahead prices with real-time prices, particularly when supply offer changes and modeling differences between the day-ahead and real-time markets would otherwise have led to inconsistent prices. Although effective arbitrage led to low average profits for virtual trades, virtual traders earned a gross aggregate profit of $10 million at the eleven load zones in 2015. This indicates that they generally improved convergence between day-ahead and real-time prices at the zonal level.

Convergence on an hourly basis is limited by real-time price volatility, which increased modestly in most regions from 2014 to 2015. Volatility increased in the summer because of higher load levels and more frequent peaking conditions. The West Zone exhibited significantly more price volatility than other areas in 2015 because of transient real-time congestion on the 230 kV constraints downstream of the Niagara plant. To a lesser extent, these constraints also contributed to statewide price volatility, since these constraints limit the deliverability of Niagara generation and Ontario imports to other areas of the state.

At the nodal level, convergence was poor at several locations because of inconsistent congestion patterns between the day-ahead and real-time markets. The most significant examples were:

- The Niagara bus in the West Zone, which exhibited average day-ahead prices that were 12 percent higher than average real-time prices in 2015. Frequent real-time congestion limited Ontario imports and Niagara generation but was not well-reflected in the day-ahead market. This pattern was driven by several factors, including volatile loop flows around Lake Erie and operating practices that do not fully utilize parallel 115kV transmission lines to reduce congestion on the 230kV lines. (See Recommendation #15.)

- The Valley Stream load pocket in Western Long Island, which experienced frequent real-time congestion that was not well-reflected in the day-ahead market. This was largely attributable to inconsistencies between day-ahead schedules and real-time flows across the 901 Line. (See Recommendation #11.)

C. Competitive Performance of the Markets

As the Market Monitoring Unit, we evaluate the competitive performance of the markets for energy, capacity, and other products on an on-going basis. The energy market performed competitively in 2015 because the conduct of suppliers was generally consistent with expectations in a competitive market. The mitigation measures were generally effective in limiting conduct that would raise prices above competitive levels.

In the capacity market, the supply-side mitigation measures were enhanced as part of the implementation of new rules dealing with generators: (a) that stop selling capacity because of a forced outage and (b) that propose to leave the market but which may be needed for reliability. The new measures lay out a robust process for the NYISO to conduct a physical withholding evaluation in such cases.

There were also several significant developments related to the buyer-side mitigation measures in the capacity market, including the Competitive Entry Exemption, which will help ensure that the buyer-side mitigation do not prevent competitive new entry. The report discusses assumptions that undermine the accuracy of the price forecast that is used in the buyer-side mitigation test and recommends improvements to address them. (See Recommendation #4b.)

D. Real-Time Market Operations and Market Performance

We evaluate several aspects of market operations, focusing on scheduling efficiency and real-time price signals, particularly during tight operating conditions. Efficient prices reward resources for performing reliably during tight real-time conditions.

Market Operations under Tight Gas Supply Conditions

Cold weather in early January and February led to high and volatile gas prices on a number of days. During these periods, uncertainty about natural gas prices and the availability of other fuels makes it challenging for suppliers to offer their resources efficiently and for the NYISO to maintain reliability while minimizing out-of-market actions. Our evaluation found that the market performed well under the tight gas supply conditions by increasing the use of oil and conserving the available supply of natural gas. Operations and market performance have improved over the past three winters as many dual-fueled generators have become increasingly prepared to burn oil.

However, we found that on days when the gas system was constrained and the NYISO had to rely on some gas-only capacity to satisfy the Eastern 10-minute reserve requirement, reserve clearing prices did not always reflect the limited availability of operating reserves or the costs of the supplemental commitments made to maintain reserves. (See Recommendation #20.)

Drivers of Transient Real-Time Price Volatility

Volatile prices can be an efficient signal for compensating resource flexibility, although unnecessary volatility imposes excessive costs on market participants. Price volatility is an efficient signal when it results from sudden changes in system conditions that cannot be predicted by the NYISO (e.g., a generator or line trips offline). However, unnecessary price volatility can occur when the NYISO's market models do not incorporate an observable factor that affects market conditions significantly. Hence, it is important to identify the causes of volatility. Real-time prices became more volatile in 2015. We performed an evaluation of the drivers of price volatility and found the following two categories were most significant:

- Resources scheduled by RTC – The RTC model schedules external transactions and gas turbines on a 15-minute basis without considering how large changes in output will affect the market on a 5-minute basis; and

- Flow changes resulting from non-modeled factors – Includes volatile loop flows and unforeseen variations in flows across PAR-controlled lines because of the inconsistency between actual PAR operations and assumed PAR operations in NYISO's models.

These changes can create brief shortages and over-generation conditions when flexible generators cannot ramp quickly enough to compensate for the change, leading to sharp changes in energy prices and congestion. In this report, we discuss potential solutions and recommend improvements that better align RTC and RTD. (See Recommendations #12 & #13.)

Efficiency of Coordinated Transaction Scheduling ("CTS") with PJM

CTS is a novel market process whereby two wholesale 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.

We found that the amount of CTS bids submitted at the primary PJM interface was very small relative to its size, and most of these CTS bids were submitted with substantial margins above $0. On average, less than 50 MW of price-sensitive CTS bids were offered at less than $10/MWh at the PJM border, which were significantly lower than the nearly 500 MW of CTS bids in the same price range at the New England border (since CTS-NE was implemented in December 2015). The large difference in performance of the two CTS processes is likely the result of large fees imposed on and uplift costs allocated to transactions at the PJM interface (while fees are not significant at the ISO-NE interface). Imposing large transaction fees on a low-margin trading activity dramatically reduces liquidity and the overall efficiency of the CTS process. Therefore, we recommend working with PJM to eliminate these charges at the border. (See Recommendation #9.)

In addition, we estimated $13.5 million of production cost savings at the PJM border based on information at the time that RTC determined final interchange schedules. However, only a small portion (slightly more than 10 percent) was realized, partly because of inaccurate regional price forecasts. Our evaluation of RTC forecast error found that RTC price forecasts were much less accurate when the level of net imports changed by a large amount in response to market conditions, which reduced the efficiency benefits from CTS. We recommend improvements to better align RTC and RTD (that were discussed above as a remedy for unnecessary price volatility) to address this issue. (See Recommendation #12.)

Market Performance under Shortage Conditions

The impact of shortage conditions was substantial in 2015. Most shortages were brief and relatively small as flexible generation ramped in response to changes in load, external interchange schedules, and other system conditions. Brief shortages provide strong incentives for resources to provide flexibility and perform reliably. Shortage pricing accounted for a large share of the net revenues that a generator could use to recoup capital investment costs, contributing up to $45 per kW-year, depending on the zone and availability of the resource.

Operating reserve and regulation shortages occurred in less than two percent of intervals in 2015 and increased the annual average real-time price in Eastern New York by 3 to 4 percent. However, after implementation of the Comprehensive Shortage Pricing project in November 2015, statewide 30-minute reserve prices increased significantly because: (a) the statewide requirement increased by 655 MW, and (b) Long Island is now limited to a maximum of 540 MW to ensure reserves are fully deliverable in the event of a contingency. We find that the requirement for Long Island may be too restrictive, so we recommend a market change to address this concern. (See Recommendation #16.)

Transmission shortages occurred in nine percent of intervals in 2015, accounting for the majority of shortage pricing incentives. Although average constraint shadow prices were relatively high during shortages, they generally did not reflect the severity of the shortage because of the manner in which such constraints are "relaxed" when managing congestion. Even after the implementation of Graduated Transmission Demand Curve in February 2016, it is unclear that prices appropriately reflect the severity of the shortage. Hence, we recommend the NYISO replace the current process of relaxing transmission shortages with a process that uses graduated transmission demand curves that vary according to the severity and duration of the constraint. (See Recommendation #17.)

Operations of Non-Optimized PAR-Controlled Lines

Phase angle regulators ("PARs") are used to control power flows over the network, generally to reduce overall production costs. However, some PAR-controlled lines are not operated for this purpose and, thus, sometimes move power in the inefficient direction (i.e., from a high-priced area to a low-priced area). The most significant inefficiencies we identified were associated with: (a) two lines that normally flow up to 290 MW of power from Long Island to New York City in accordance with a wheeling agreement between Consolidated Edison ("ConEd") and Long Island Power Authority ("LIPA"); and (b) some lines between New York and New Jersey that are used to wheel up to 1,000 MW in accordance with a wheeling agreement between ConEd and PSEG.

The operation of these lines (in accordance with the wheeling agreements) increased day-ahead production costs by an estimated of $44 million in 2015 and contributed to price volatility and balancing congestion uplift. Hence, the report recommends that NYISO work with these parties to explore potential changes that would allow the lines to be used more efficiently. (See Recommendations #10 & #11.)

E. Out-of-Market Actions and Guarantee Payment Uplift

Guarantee payments to generators, which account for a large share of Schedule 1 uplift charges, fell by 52 percent to $71 million in 2015 primarily because lower natural gas prices (particularly in the first quarter) reduced the commitment costs of gas-fired units needed for reliability.

In addition, supplemental commitments for reliability fell 19 percent from 2014 to 2015, contributing to the reduction in guarantee payment uplift as well. On Long Island, the reduction was partly due to the transmission upgrades that have reduced local needs to run oil-fired peaking units on the East End during the summer. In New York City, the reduction reflected: (a) fewer generation and transmission outages that require steam turbines to run for reliability; and (b) updates to the modeling of NOx bubble constraints that require less steam turbine capacity to satisfy the NOx bubble requirements.

Despite the reduction in other regions, reliability commitment and OOM dispatch in Western New York rose in 2015, offsetting the overall decrease in guarantee payment uplift. Several units that were often needed to manage post-contingency flows on 115kV facilities in the West Zone and the Central Zone became less economic because of lower natural gas prices and resulting lower LBMPs in 2015. These units accounted for $24 million of guarantee payment uplift. In addition, the NYISO frequently took OOM actions to manage congestion on the 115 kV system, including: (a) manually instructing the Niagara generator to shift output between the generators at the 115kV station and the generators at the 230kV station; and (b) taking certain lines out of service on the primary PJM-NYISO interface. (See Recommendation #15.)

F. Capacity Market

The capacity market continues to be an essential element of the NYISO electricity markets, providing vital economic signals needed to facilitate market-based investment to satisfy the state's planning requirements. The overall market design and rules governing the capacity market are sound, although this report identifies several areas of improvement.

Capacity clearing prices are now set at four distinct locations: New York City, Long Island, the G-J Locality and NYCA. While the creation of the new G-J Locality was a positive market development, it was overdue and there are potential market enhancements that would further improve locational signals in the capacity market. In this report, we discuss several deficiencies with the current rules for creating new capacity zones and recommend an alternative framework where zones or deliverability interfaces are pre-defined rather than added incrementally over time. (See Recommendation #3.)

Furthermore, the capacity demand curves could be determined considering where capacity is most valuable for reliability, resulting in lower overall investment costs. In particular, the IRM & LCR setting processes and the treatment of export-constrained zones should be reformed to consider the marginal reliability benefit of capacity in each area. This would lead capacity to be distributed in a manner that is most cost-effective for maintaining reliability. (See Recommendation #1.)

Finally, substantial amounts of capacity in the Lower Hudson Valley has contracted to sell into the ISO-NE starting in 2018. However, the NYISO does not have a comprehensive set of rules to account for such transactions in a manner that will lead to efficient capacity prices and competitive outcomes. If such rules are not devised soon, clearing prices will be set above competitive levels in the Lower Hudson Valley. Therefore, we recommend rules to account for these transaction that would ensure efficient pricing in NYISO's capacity zones. (See Recommendation #8.)

G. Overview of Recommendations

The NYISO markets generally performed well in 2015. Our evaluation identifies a number of areas of improvement, so we make recommendations that are summarized in the following table. The table identifies the highest priority recommendations and those that the NYISO is addressing in the 2016 Project Plan or in some other effort. In general, the recommendations that are designated as the highest priority are those that produce the largest economic efficiencies by lower the production costs of satisfying the system's needs or improving the incentives of participants to make efficient long-term decisions.

The table also identifies recommendations as scoping/future if there is significant work is necessary to determine the appropriate solution or establish the priority level, or if the anticipated benefits would be smaller in the short-term than in the long-term. A detailed discussion of each recommendation is provided in Section XI.

RECOMMENDATION	Discussed in	Current Effort	High Priority	Scoping/Future
Capacity Market Enhancements				
(1) Implement location-based marginal cost pricing of capacity that minimizes the cost of satisfying planning reliability criteria.	VIII.C	X	X	
(2) Grant financial capacity transfer rights between zones when investors upgrade the transmission system and help satisfy planning reliability needs without a cost-of-service rate.	VIII.D			X
(3) Establish a dynamic locational capacity framework that addresses future potential deliverability constraints to allow prices to reflect the locational value of capacity and quickly adjust to changes in market conditions.	VIII.F			X
(4) Enhance Buyer-Side Mitigation measures to deter uneconomic entry while ensuring that economic entrants are not mitigated.				
(a) Reform the Offer Floor for mitigated projects.	IV.C.2			
(b) Modify assumptions used to forecast ICAP prices and net revenues, especially relating to the treatment of existing generation and potential new entrants.	IV.C.2	X		
(5) Expand buyer-side mitigation measures to address other actions that can suppress capacity prices.	IV.C.2	X		X
(6) Modify the pivotal supplier test to prevent a large NYC supplier from circumventing the mitigation rules by selling capacity in the forward capacity auctions (i.e., the strip and monthly auctions) to avoid being designated as a pivotal supplier for NYC.	IV.C.4			
Economic Transmission Planning Process				
(7) Reform the CARIS process to better identify and fund economically efficient transmission investments.	VIII.E			X
Broader Regional Markets				
(8) Modify the capacity market and planning process to better account for capacity that is exported to neighboring control areas from import-constrained capacity zones.	VIII.B		X	
(9) Eliminate transaction fees for CTS transactions at the PJM-NYISO border.	VII.D			
(10) After the ConEd-PSEG wheeling agreement expires, work with PJM to coordinate scheduling of the associated controllable lines (i.e., the A, B, C, J, and K lines) to minimize production costs across the two regions.	IX.D			
Energy Market Enhancements - RT Market Operations				
(11) Operate certain PAR-controlled lines to minimize production costs and create financial rights that compensate affected transmission owners.	IX.D		X	
(12) Adjust look ahead evaluations of RTD and RTC to be more consistent with the timing of external transaction ramp and gas turbine commitment.	VII.D IX.E	X	X	X
(13) Consider enhancing modeling of loop flows and PAR-controlled lines to reflect the effects of expected generation, load, and PAR-controls on line flows more accurately.	IX.E	X		X

RECOMMENDATION	Discussed in	Current Effort	High Priority	Scoping/Future
Energy Market Enhancements - RT Pricing				
(14) Modify criteria for GTs to set prices in the real-time market by allowing GTs to be eligible to set price in the final pricing pass and incorporating start-up costs.	IX.C	X		
(15) Model 100+ kV transmission constraints in the DA and RT markets using economic commitment and dispatch software and develop associated mitigation measures.	IX.F.3			
(16) Dynamically adjust operating reserve requirements to account for factors that increase or decrease the amount of reserves that must be held on internal resources.	IX.A.1			X
(17) When a transmission constraint cannot be satisfied, utilize graduated transmission demand curves to set constraint shadow prices.	IX.A.2			X
Energy Market Enhancements - BPCG Eligibility Criteria				
(18) Work with generators in NOx bubbles to ensure their RACT compliance plans use the most economic compliance option available.	IX.F.2			
Energy Market Enhancements - Fuel Assurance				
(19) Consider allowing generators to submit offers that reflect certain energy storage and fuel supply constraints in the day-ahead market.	IX.B.2	X		X
(20) Enhance recognition of gas system limitations when scheduling resources to provide operating reserves.	IX.B.2			X
Energy Market Enhancements - DAM Scheduling				
(21) Improve assumptions in the commitment logic of the DAM to avoid scheduling uneconomic gas turbines.	V.A			

II. Introduction

This report assesses the efficiency and competitiveness of New York's wholesale electricity markets in 2015.[1] The NYISO operates competitive wholesale markets to satisfy the electricity needs of New York. These markets include:

- Day-ahead and real-time markets that simultaneously optimize energy, operating reserves and regulation;
- A capacity market that ensures the NYISO markets produce efficient long-term economic signals that guide decisions to invest in new generation, transmission, and demand response resources (and to maintain existing resources); and
- A market for transmission rights that allows participants to hedge the congestion costs associated with using the transmission network.

The energy and ancillary services markets establish prices that reflect the value of energy at each location on the network. They deliver significant benefits by coordinating the commitment and dispatch of generation to ensure that resources are started and dispatched each day to meet the system's demands at the lowest cost.

The coordination provided by the markets is essential due to the physical characteristics of electricity and the transmission network used to deliver it to customers. This coordination affects not only the prices and production costs of electricity, but also the reliability with which it is delivered. In addition, the markets provide transparent price signals that facilitate efficient forward contracting and are a primary component of the long-term incentives that guide generation and transmission investment and retirement decisions. Relying on private investment shifts the risks and costs of poor decisions and project management from New York's consumers to the investors. Indeed, moving away from costly regulated investment was the primary impetus for the move to competitive electricity markets.

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1 NYISO MST 30.10.1 states: "The Market Monitoring Unit shall prepare and submit to the Board an annual report on the competitive structure of, market trends in, and performance of, other competitive conditions in or affecting, and the economic efficiency of, the New York Electric Markets. Such report shall include recommendations for the improvement of the New York Electric Markets or of the monitoring, reporting and other functions undertaken pursuant to Attachment O and the Market Mitigation Measures."

The NYISO markets are at the forefront of market design and have been a model for market development in a number of areas. The NYISO was the first RTO market to:

- Simultaneously optimize energy and operating reserves, which efficiently allocates resources to provide these products;
- Impose locational requirements in its operating reserve and capacity markets, which play a crucial role in signaling the need for resources in transmission-constrained areas;
- Introduce capacity demand curves that reflect the value of incremental capacity to the system and provide for increased stability in market signals;
- Implement operating reserve demand curves, which contribute to efficient prices during shortages when resources are insufficient to satisfy all of the needs of the system;
- Use a real-time commitment system (i.e., RTC) that commits quick-start units (that can start within 10 or 30 minutes) and schedules external transactions. RTC runs every 15 minutes, optimizing over a two-and-a-half hour period. Most other RTOs rely on their operators to determine when to start gas turbines and other quick-start units; and
- Introduce a market scheduling system to coordinate an economic evaluation of interchange transactions between markets.

In addition to its leadership in these areas, the NYISO is one of a few markets to implement:

- A mechanism that allows inflexible gas turbines and demand-response resources to set energy prices when they are needed. This is essential for ensuring that price signals are efficient during peak demand conditions. Demand response in other RTOs has distorted real-time signals by undermining the shortage pricing; and
- A real-time dispatch system (i.e., RTD) that runs every five minutes and optimizes over a one-hour period. This allows the market to anticipate the upcoming needs and move resources to efficiently satisfy the needs. RTD can also commit quick-start units (that can start within 10 minutes) based on economic criteria.

These markets provide substantial benefits to the region by ensuring that the lowest-cost supplies are used to meet demand in the short-term and by establishing transparent, efficient price signals that govern investment and retirement decisions in the long-term. However, it is important for the markets to continue to evolve to improve alignment between the market design and the reliability needs of the system, to provide efficient incentives to the market participants, and to adequately mitigate market power. Hence, Section XI of the report provides a number of recommendations that are intended to achieve these objectives.

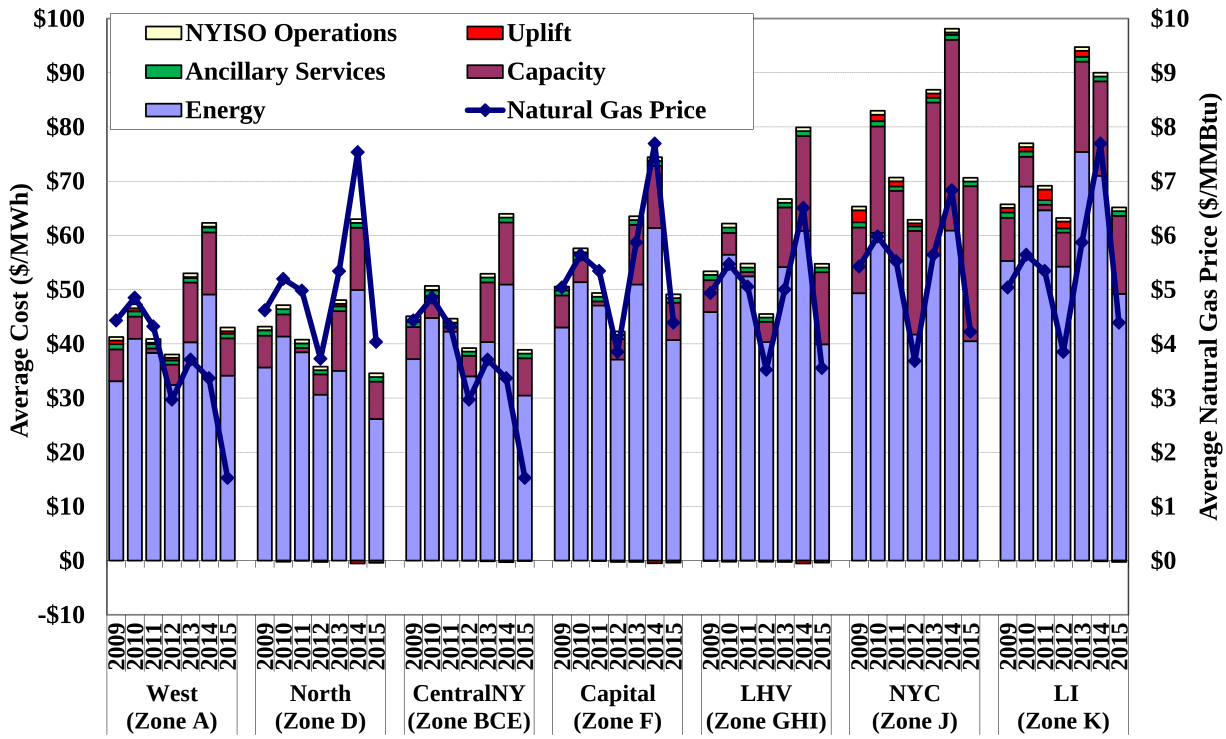
III. Overview of Market Trends and Highlights

This section discusses significant market trends and highlights in 2015. It includes evaluations of energy and ancillary service prices, fuel prices, generation and demand patterns, congestion patterns, and investment signals.

A. Total Wholesale Market Costs

Figure 1 summarizes wholesale market costs during the past seven years by showing the all-in price for electricity, which reflects the average cost of serving load from the NYISO markets. The energy component of this metric is the load-weighted average real-time energy price, while all other components are the costs in the areas divided by the real-time load in the area.[2]

Figure 1: Average All-In Price by Region
2009-2015



2 Section I.A of the Appendix provides a detailed description of the all-in price calculation.

Average all-in prices of electricity fell sharply in 2015, ranging from $35 per MWh in the North Zone to $71 per MWh in New York City, as falling natural gas prices led to energy prices reductions of 31 to 48 percent across the system.[3] Energy prices continue to account for the vast majority of the all-in prices, accounting for 57 percent of the all-in price in New York City and 72 to 82 percent of the all-in price in the other regions. Capacity costs were the second largest component in each region, accounting for nearly all of the remaining wholesale market costs.

The largest year-over-year reductions in energy and natural gas prices occurred in the first quarter of 2015, which was attributable to lower oil prices, increased LNG imports to the region, and higher natural gas production from the Marcellus and Utica shales. Imports increased because of higher resource margins in Ontario and Quebec.

Unlike previous years, the West Zone exhibited the highest average energy prices in Western New York (i.e., including Zones A to E) in 2015. Transmission bottlenecks have become increasingly common in this area because of rising imports from Ontario and because the low natural gas prices have made coal-fired generation in this area relatively uneconomic. Congestion in the West Zone could not be resolved using available physical resources in roughly 2 percent of all intervals in 2015, resulting in more hours with real-time prices above $500 per MWh than any other zone.[4]

Average capacity costs also fell by 19 to 24 percent in the downstate zones from 2014 to 2015, and by 40 percent Rest of State ("ROS"). Capacity prices fell partly because the supply of capacity increased by 1.1 GW after the multiple units returned to service and new wind capacity entered. Increased SCR sales and lower capacity requirements in most capacity localities also contributed to the lower capacity prices. However, the reduction in capacity prices in the G-J Locality was partly offset by a significant increase in the ICAP requirement.[5]

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3 Section I.A in the Appendix shows seasonal variations in energy and natural gas prices.

4 Section I.A in the Appendix shows real-time price duration curves for various locations, while Sections IX.A.2 and IX.E provide additional details about congestion that could not be resolved.

5 See VIII.A for additional details.

B. Fuel Prices

In recent years, 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. Table 1 summarizes fossil fuel prices in 2014 and 2015 on an annual basis and separately for the first quarter and the rest of the year as well.[6] The table also shows average real-time energy prices in seven regions of New York State over the same time periods. Representative gas price indices are associated with each of the seven regions.

Table 1: Average Fuel Prices and Real-Time Energy Prices
2014-2015

	Annual Average			Q1 Average			Q2 - Q4 Average		
	2014	2015	% Change	2014	2015	% Change	2014	2015	% Change
Fuel Prices ($/MMBtu)									
Ultra Low-Sulfur Kerosene	$23.05	$14.87	-35%	$24.89	$16.06	-35%	$22.44	$14.47	-35%
Ultra Low-Sulfur Diesel Oil	$20.21	$11.95	-41%	$22.36	$13.23	-41%	$19.50	$11.53	-41%
Low-Sulfur Residual Oil	$15.59	$8.03	-49%	$18.43	$9.40	-49%	$14.64	$7.57	-48%
NG - Dominion North	$3.18	$1.33	-58%	$4.59	$1.49	-68%	$2.71	$1.27	-53%
NG - Tx Eastern M3	$5.13	$2.57	-50%	$11.78	$6.10	-48%	$2.91	$1.39	-52%
NG - Transco Z6 (NY)	$6.21	$3.84	-38%	$15.72	$8.97	-43%	$3.05	$2.13	-30%
NG - Iroquois Z2	$7.54	$4.26	-44%	$17.85	$9.14	-49%	$4.11	$2.64	-36%
NG - Tennessee Z6	$8.04	$4.59	-43%	$19.87	$10.85	-45%	$4.10	$2.51	-39%
Energy Prices ($/MWh)									
West (Dominion)	$49.23	$32.21	-35%	$91.38	$47.00	-49%	$34.37	$26.93	-22%
North (Waddington)	$51.89	$26.61	-49%	$95.48	$45.91	-52%	$29.71	$18.75	-37%
Centrl NY (Dominion)	$52.34	$30.88	-41%	$102.21	$51.60	-50%	$33.80	$23.07	-32%
Capital Zone (Iroquois)	$65.97	$41.07	-38%	$147.43	$81.37	-45%	$36.88	$26.51	-28%
Lw. Hudson(TxEastern/Iroq.)	$64.73	$40.70	-37%	$139.02	$75.19	-46%	$38.83	$28.92	-26%
New York City (Transco)	$63.82	$40.58	-36%	$141.44	$75.53	-47%	$39.13	$29.61	-24%
Long Island (Iroquois)	$72.77	$49.83	-32%	$155.62	$91.30	-41%	$46.32	$36.56	-21%

Although much of the energy used by New York consumers is generated by hydro and nuclear units, natural gas units are usually the marginal source of generation that set market clearing prices, especially in Eastern New York. Consequently, energy prices in New York have followed a pattern similar to natural gas prices over the past several years.

6 Section I.B in the Appendix shows the monthly variation of fuel prices.

Natural gas prices declined substantially from 2014 to 2015, falling 58 percent in much of Western New York, 38 percent in New York City, and 43 to 50 percent in other areas of Eastern New York. 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 and gas price spreads between regions (e.g., between Western and Eastern New York) exhibited a typical seasonal pattern. Both tended to rise in the winter when the demand for natural gas was highest and bottlenecks on the natural gas system occurred most frequently. During 2015:

- Natural gas prices in Eastern New York averaged \$6 to \$11 per MMBtu in the first quarter, compared to an average of less than \$3 per MMBtu during the rest of the year.
- Similarly, gas spreads between Western and Eastern New York averaged 310 to 630 percent in the first quarter compared to 67 to 107 percent during the rest of the year.

The natural gas price spreads varied significantly from 2014 and 2015, leading to comparable variations in congestion patterns and associated energy price spreads between Western and Eastern New York. These variations also affected import levels and uplift costs. These effects are discussed throughout the report.

C. Generation by Fuel Type

Variations in fossil fuel prices, retirements and mothballing of old generators, and the additions of new gas-fired generation in recent years have led to concomitant changes in the mix of fuels used to generate electricity in New York. Table 2 summarizes the annual usage of generation by fuel type from 2013 to 2015, including: (a) the average quantities of generation by each fuel type; (b) the share of generation by each fuel type relative to the total generation; and (c) how frequently each fuel type was on the margin and setting real-time energy prices.[7] The marginal

7 Section I.B in the Appendix describes the methodology that was used to determine how frequently each type of resource was on the margin (i.e., setting the real-time price).

generation percentages sum to more than 100 percent because more than one type of unit is often marginal, particularly when the system is congested.

Table 2: Fuel Type of Real-Time Generation and Marginal Units in New York
2013-2015

Fuel Type	Average Internal Generation						% of Intervals being Marginal		
	GW			% of Total					
	2013	2014	2015	2013	2014	2015	2013	2014	2015
Nuclear	5.1	4.9	5.1	33%	31%	32%	0%	0%	0%
Hydro	2.7	2.8	2.8	17%	18%	18%	44%	45%	49%
Coal	0.5	0.5	0.3	3%	3%	2%	11%	7%	2%
Natural Gas CC	4.9	5.0	5.2	32%	31%	33%	67%	60%	67%
Natural Gas Other	1.5	1.6	1.7	10%	10%	10%	42%	29%	28%
Fuel Oil	0.1	0.2	0.2	1%	1%	1%	5%	6%	5%
Wind	0.4	0.5	0.5	3%	3%	3%	7%	4%	5%
Other	0.3	0.3	0.3	2%	2%	2%	0%	0%	0%

Gas-fired generation accounted for the largest share of electricity production (41 to 43 percent) from all internal generating resources in each year of 2013 to 2015. Gas-fired generation rose modestly from 2014, reflecting lower natural gas prices in 2015, as well as congestion and local reliability needs in New York City and Long Island during the summer.[8]

Combined generation from nuclear and hydro resources accounted for nearly 50 percent of all internal generation in each year. Small year-over-year variations in total production were driven primarily by variations in the amount of generation deratings and outages.

Average coal-fired generation fell sharply in 2015 from prior years. Natural gas prices in Western New York were low throughout the year (even during much of the winter), making coal production much less economic. More than 90 percent of oil-fired generation occurred in the first quarter in both 2014 and 2015 during periods of high natural gas prices.[9] However, lower natural gas prices and higher gas supply in the first quarter of 2015 led to a 20 percent reduction in oil-fired generation from 2014.

8 Section I.B in the Appendix shows generation mix by region by quarter in 2014 and 2015.

9 Section I.C in the Appendix summarizes generation patterns by fuel type in the Eastern New York on a daily basis in the winter.

Gas-fired and hydro resources were most frequently on the margin in recent years. Most marginal hydro units have storage capacity, leading their offers to include the opportunity cost of foregone sales in other hours (when gas units are marginal). Thus, the prices set by hydro units are also affected by gas prices. Hydro units set prices more frequently in 2015 as a result of increased congestion in the West Zone that was often relieved by backing-down hydro resources.

Other fuel types set prices less frequently. Oil units set the price occasionally during very high-load periods or on days when natural gas prices were substantially higher than oil prices. Coal units were on the margin much less frequently in 2015 because aggregate coal-fired generation fell and most of it was dispatched out-of-merit for congestion on the 115 kV system.[10]

D. Demand Levels

Demand is another key driver of wholesale market outcomes. Table 3 shows the following load statistics for NYCA over the past seven years: a) annual summer peak; b) annual winter peak; c) annual average load; and d) number of hours when load exceeded certain levels.

Table 3: Peak and Average Load Levels for NYCA
2009 – 2015

Year	Load (GW)			Number of Hours >		
	Summer Peak	Winter Peak	Annual Average	32GW	30GW	28GW
2009	30.8	24.3	18.1	0	13	54
2010	33.5	23.9	18.7	13	69	205
2011	33.9	24.3	18.6	17	68	139
2012	32.4	23.9	18.5	6	54	162
2013	34.0	24.7	18.7	33	66	145
2014	29.8	25.7	18.3	0	0	40
2015	31.1	24.6	18.4	0	23	105

In 2015, load averaged 18.4 GW and peaked at 31.1 GW. The average level rose roughly one percent from 2014 and the summer peak level rose nearly five percent, reflecting warmer weather and more frequent peaking conditions in the summer of 2015. Nonetheless, average load levels were still noticeably lower than those from 2010 to 2013.

10 See Section IX.F.3 for additional information about out-of-merit dispatch.

Winter peak load fell four percent from the all-time high winter peak set in January 2014. Although weather was milder in January and March than in 2014, February was the coldest month in recent history. The average load in February 2015 to exceed average load in January 2014. Variations in load levels, along with variations in natural gas prices (discussed earlier), resulted in concomitant changes in congestion patterns that are discussed in the next subsection.

E. Transmission Congestion Patterns

Figure 2 shows the value and frequency of congestion along major transmission lines in the day-ahead and real-time markets in 2014 and 2015.[11] The vast majority of congestion revenues are collected by the NYISO in the day-ahead market, where most generation is scheduled. It is also important to evaluate the value of congestion in the real-time market because it indicates where physical constraints occur on the network during the operating day.[12] In a well-functioning market, the value of congestion in the day-ahead and real-time markets should be consistent.

Although the frequency of congestion rose from 2014 to 2015 in the day-ahead market, the value of day-ahead congestion fell 6 percent to $539 million.[13] This reduction was largely due to the decrease in natural gas prices in 2015, which reduced the marginal costs of managing congestion.

Congestion across the Central-East interface accounted for the largest share of total congestion value in both 2014 and 2015. In 2015, the Central-East interface accounted for 44 percent of congestion value in the day-ahead market and 37 percent in the real-time market. The majority of this congestion occurred in the first quarter of 2015 when larger spreads in natural gas prices between Western and Eastern New York increased flows across the interface and resulted in more frequent and costly congestion. Congestion rose in November and December as lengthy transmission outages reduced the interface's voltage stability limit by as much as 900 MW.

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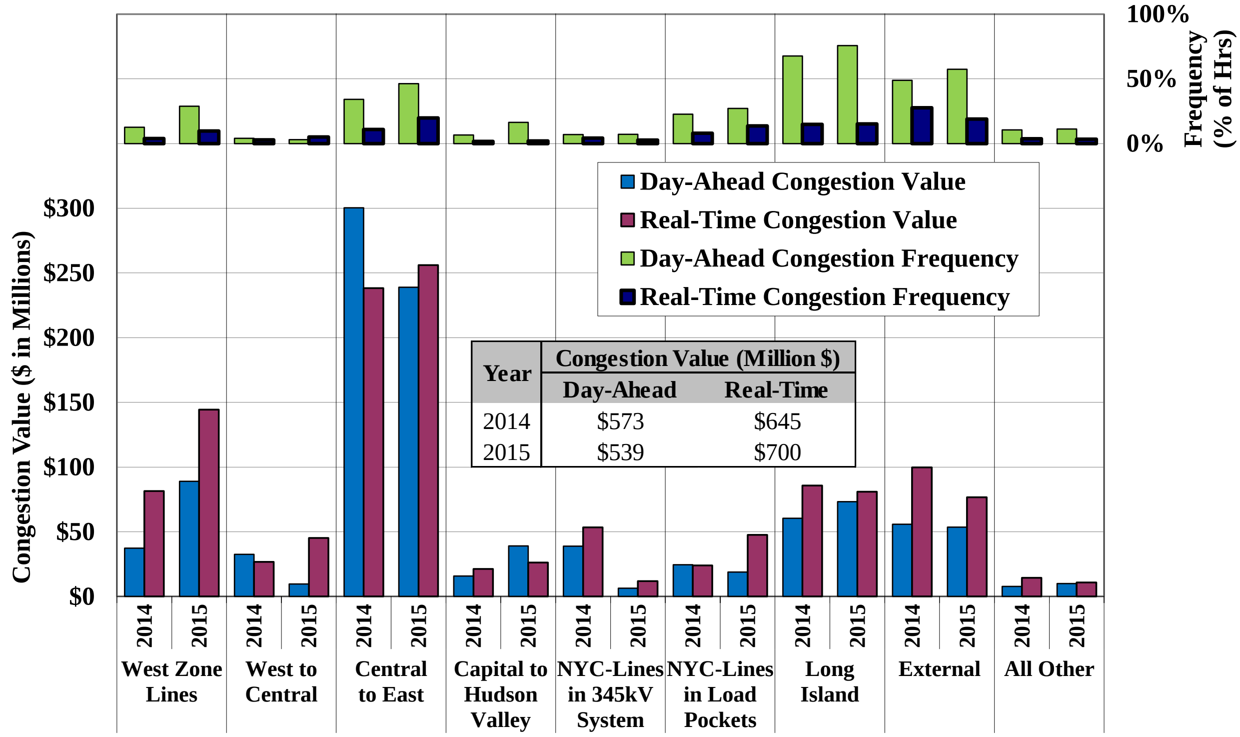
11 Section III.B in the Appendix shows the congestion patterns in greater detail.

12 Most congestion settlements occur in the day-ahead market. Real-time settlements are based on deviations in the quantities scheduled relative to the day-ahead market. For example, if 90 MW is scheduled to flow over an interface in the day-ahead market and 100 MW is scheduled in the real-time market, the first 90 MW settle at day-ahead prices, while the last 10 MW settle at real-time prices.

13 The value of day-ahead congestion shown in Figure 2 and the day-ahead congestion collected are slightly different because of the settlement for several grandfathered transmission agreements that pre-date NYISO.

Figure 2: Day-Ahead and Real-Time Congestion by Transmission Path
2014-2015



Congestion into Southeast New York rose modestly in 2015 because of higher load levels and more transmission outages in the summer season. Nonetheless, this congestion has been mild over the past two years because of low natural gas prices, low summer load levels, and increased utilization of the Ramapo line to relieve this congestion under the M2M process.

Congestion on 230kV lines in the West Zone rose notably from 2014 to 2015, accounting for the second largest share of congestion value in both day-ahead (17 percent) and real-time (21 percent) markets in 2015. This rise has been driven by increased Ontario imports, lower PJM imports, and reduced production from downstream coal units in western New York and western Pennsylvania. Congestion was generally more severe in the real-time market than in the day-ahead market on these constraints. This was driven primarily by:

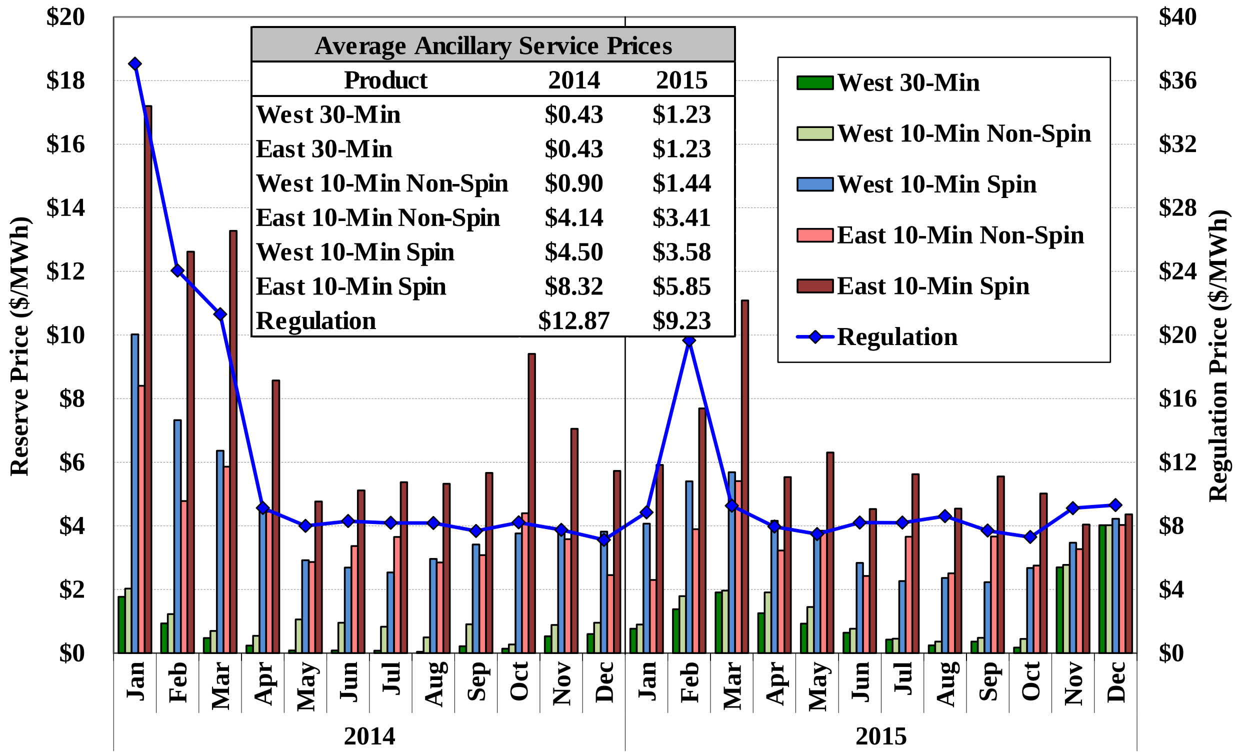
- Volatile Lake Erie loop flows;
- Changes in offers between the day-ahead to real-time markets from generation and imports that are upstream of the constraints; and

- Operation of the ABC, JK, and Ramapo PARs. These PARs relieve Central-to-East and Capital-to-Hudson Valley congestion, but increase flows across West Zone constraints.[14]

F. Ancillary Services Markets

Figure 3 shows the average prices of six key ancillary services products in the day-ahead market in each month of 2014 and 2015.[15]

Figure 3: Average Day-Ahead Ancillary Services Prices
2014-2015



Ancillary services and energy scheduling is co-optimized, so a major cost of providing ancillary services for most generators is the opportunity cost of not providing energy when it otherwise would be economic to do so. Co-optimized scheduling is beneficial because it ensures that the foregone profits from backing down generation to provide reserves is properly reflected in LBMPs and reserve clearing prices. Hence, the ancillary services markets provide additional

14 In November 2015, operating procedures were modified to reduce the effects of these PAR control actions on congestion in Western New York. See NYISO Management Committee meeting minutes for the December 17, 2015 meeting.

15 See Sections I.E and I.I in the Appendix for additional information regarding the ancillary services markets.

revenues to resources that are available during periods when operating reserves are most valuable. This additional revenue affects long-term investment in favor of resources that have high rates of availability in the day-ahead and real-time markets.

The average prices for most classes of operating reserves decreased modestly from 2014 to 2015. The decrease was generally in line with variations in energy prices across the two years. In addition, the number of shortages for most ancillary service products fell notably from 2014 to 2015, particularly in the first quarter as a result of less frequent winter peaking conditions and higher availability of generation.

However, 30-minute operating reserve prices rose significantly in the last two months of 2015 because of two key changes made in the procurement of NYCA 30-minute reserves starting November 4, 2015: [16]

- The NYCA 30-minute reserve requirement rose from 1,965 MW to 2,620 MW; and
- The quantity of 30-minute reserves on Long Island that can be used to satisfy the reserve requirements for outside of Long Island is now limited to its 30-minute reserve requirement (normally 270 to 540 MW).

The limitation is intended to ensure that reserves scheduled there would be fully deliverable following a large contingency outside Long Island, but may be overly restrictive. Long Island frequently imports more than 1 GW from upstate, so it may be possible for a comparable amount of reserves to be held on Long Island to satisfy the reserve requirements for SENY, Eastern New York, and NYCA. This is because converting Long Island reserves to energy will simply reduce imports to Long Island, thereby reducing the amount of power that must be generated outside Long Island. Hence, we recommend that the NYISO modify the market software to optimize the upper limit on the amount of reserves that can be held on Long Island.[17]

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16 There were other changes made in the ancillary service market on November 4, 2015. See Section V.H in the Appendix for additional information regarding these changes.

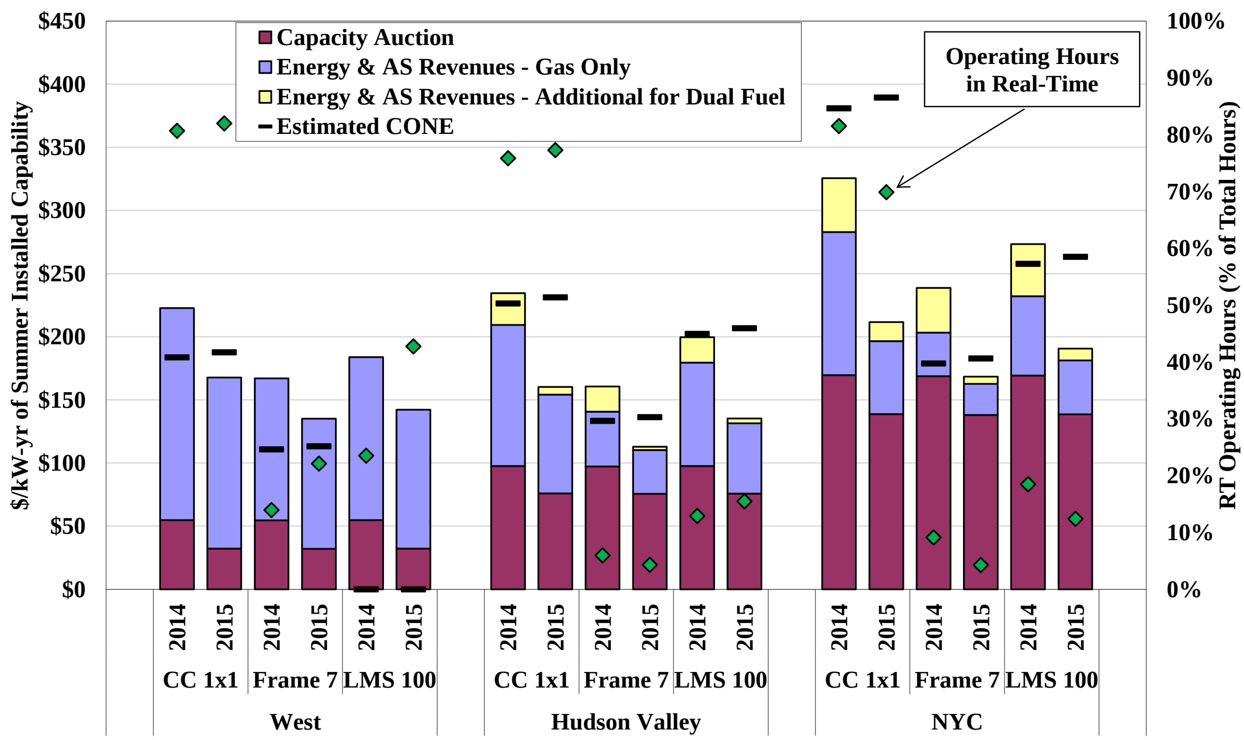
17 See Recommendation #16.

G. Long-Term Investment Signals

A well-functioning wholesale market establishes transparent price signals that provide efficient incentives to guide generation and transmission investment and retirement decisions. We evaluate the long-term price signals by calculating the net revenue that a new unit would have received from the NYISO markets by comparing it to the levelized Cost of New Entry ("CONE"). We also examine the investment signals for several zero-emissions technologies. Net revenue is the total revenue that a generator would earn in the New York markets less its variable production costs.

Figure 4 shows the estimated net revenues compared to the CONE for new unit types in 2014 and 2015. The figure shows the incremental net revenues that would result from dual-fuel capability and the estimated number of running hours as a percent of all hours in the year.[18]

Figure 4: Net Revenue and CONE by Location for Gas-Fired and Dual Fuel Units
2014-2015



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18 See Section I.G of the Appendix for a description of the methodology, as well as detailed results for more locations for new and existing technologies under various gas price assumptions.

Net revenues for new gas-fired and dual fuel unit types decreased from 2014 to 2015 in all locations because of lower energy and capacity revenues. Energy net revenues fell in 2015 because LBMPs fell more than the fuel costs of all new gas-fired generators. Capacity net revenues fell as several generators the returned to service and capacity requirements decreased in most areas.[19]

The estimated net revenues for a new Frame 7 unit were lower than the annual levelized cost of new entry ("CONE") at almost all locations. The lone exception was in the West Zone, where high levels of congestion occurred in 2015. However, these market conditions will not likely induce new investment in the West Zone if developers believe that the elevated net revenue levels will be short-lived. The estimated net revenues for Frame 7 units were less than CONE for many years before 2014 and proposed transmission upgrades in Western New York are likely to reduce the energy prices there.[20]

Among older technologies, the estimated net revenues were highest for a 10-minute gas turbine unit. The older technologies are online for fewer hours during the year (given the high heat rates), but can provide operating reserves when they are offline. Since 10-minute reserve prices tend to be highest in the reserve markets, units capable of providing 10-minute reserves earn the highest revenue. The 30-minute gas turbines were the only units that had higher net energy revenues in 2015 than in 2014. This was due to the notable increase in the average 30-minute reserve prices from $0.43 per MWh in 2014 to $1.23 per MWh in 2015.

Our net revenue analysis indicates that the additional revenues from dual-fuel capability were significantly lower in 2015 than the extraordinarily high levels witnessed in 2014. This is primarily due to lower gas price volatility and lower electric load during the winter months. The estimated net revenues from dual-fuel capability in the downstate zones ranged from $3 to $6.50 per kW-year for new Frame 7 units and from $6 to $15 per kW-year for new combined cycles

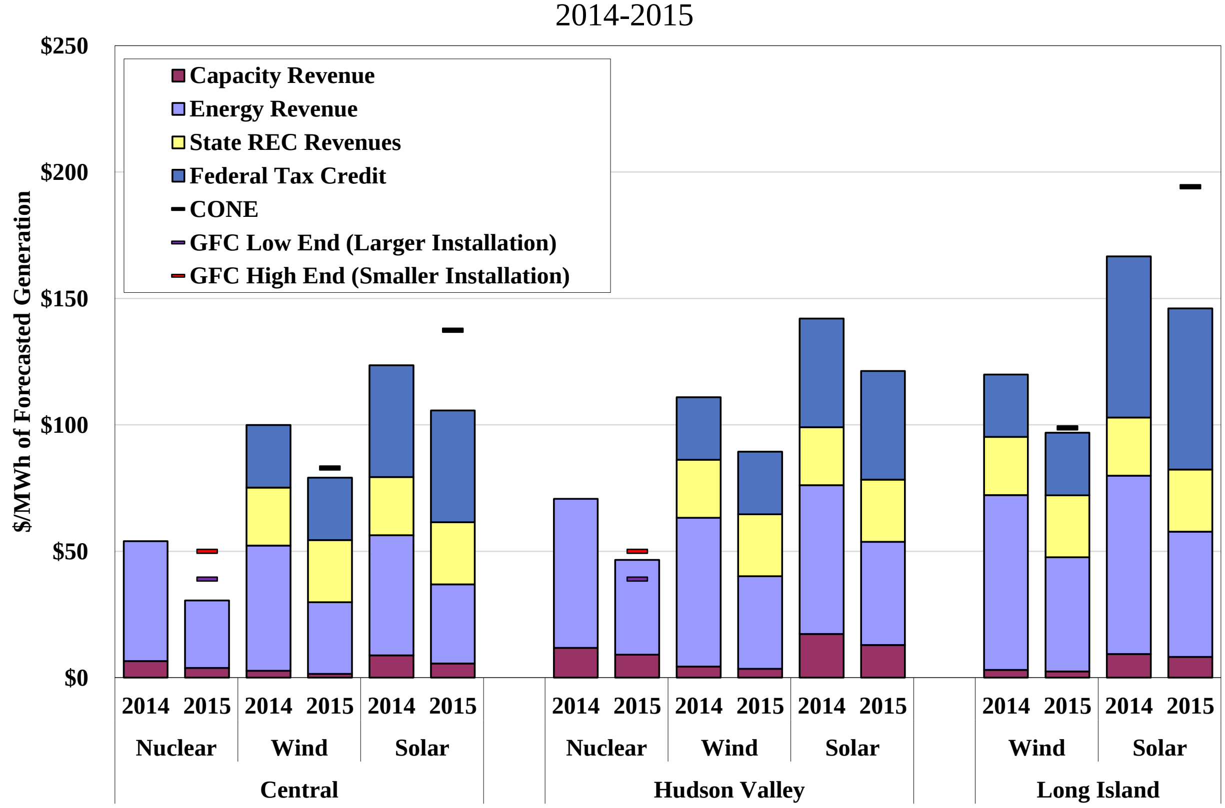
19 Capacity prices and requirements are discussed further in Section VIII.A.

20 Significant transmission upgrades have recently occurred or are planned. In May 2013, upgrades were completed to allow Dunkirk 1 to mothball. In December 2015, the Five Mile Road project was completed to allow Dunkirk 2 to retire. In May 2016, upgrades will be completed to allow Huntley Units 67 and 68 to retire. The NYISO is currently evaluating proposals for the Western New York Public Policy Transmission Need in response to a New York PSC order.

and older steam turbines. The potential returns from dual-fuel capability are likely sufficient for many units to retain the capability and maintain modest inventories of oil.[21]

Figure 5 compares the estimated net revenues for existing nuclear units, new onshore wind and utility scale solar PV plants in various locations in 2014 and 2015. For comparison, the figure shows the estimated Going Forward Costs ("GFCs") for the nuclear units and the CONE estimates for the renewables. [22]

Figure 5: Net Revenues of Nuclear and Renewable Units
2014-2015



Energy revenues constitute account for 86 percent of the estimated net revenue received by the nuclear units over the last three years. Consequently, the retirement decisions for nuclear units are largely driven by expected energy prices rather than capacity prices. Our analyses indicate

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21 Dual fuel cost and inventory estimates were derived from analysis presented in the Eastern Interconnection Planning Collaborative's "Gas-Electric System Interface Study – Target 3 Report – Natural Gas and Electric Contingency Analysis" report published March 27, 2015.

22 See Section I.G of the Appendix for a detailed description of the methodology.

that the estimated net revenues were lower than the GFCs for large and small nuclear plants in the Central Zone in 2015. In addition, the average Central Zone and West Zone net revenues for 2009 through 2015 were lower than the all-in costs for smaller (i.e., single-unit) plants in five of the last seven years.[23] Based on recent electricity forward contract prices, single-unit nuclear plants outside Southeast New York are unlikely to recoup their operating costs from the wholesale market over the next five years.[24]

Renewable units rely on multiple revenue streams from the NYISO markets and incentive programs from the state and federal governments. Wind and solar resources are both intermittent resources and, as a result, the capacity value of these units is low. Over half of the estimated net revenues for both wind and solar units in 2015 were from federal and state programs, such as the purchase of Renewable Portfolio Standard Attributes and the Investment or Production Tax Credits. Even with these subsidies, however, the estimated net revenues for onshore wind and utility-scale solar PV units were lower than their CONE levels in 2015.

Although new renewable units and existing smaller nuclear units do not appear to be economic at 2015 prices, these resources 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 mechanisms being proposed for supplementing the revenues these resources receive from the NYISO markets. However, the design of such mechanisms have a significant effect on the long term economic signals for all generators operating in the NYISO market. For instance, both renewable and nuclear units have very low operating costs, so they tend to lower both energy and capacity prices.

In addition, to the extent that these mechanisms are proposed to satisfy legitimate public policy objectives, it is generally most economic to structure a mechanism in a technology neutral manner that is designed to minimize the costs of satisfying the objective. Exhibiting an undue preference for certain technologies could ultimately increase the cost of meeting the public

23 See Section I.A of the Appendix.

24 Around-the-Clock electricity forward prices (annual strip as reported by SNL on March 31, 2016) for Central Zone over the 2017-2021 timeframe were between $29 and $36 per MWh.

policy objectives. To illustrate this, we estimated the cost per-ton of reducing CO_2 emissions using several generic investments (recognizing that the costs of individual projects vary based particular circumstances). Based on net revenues in 2015, we find that the costs of reducing carbon emission varies substantially by technology and location:

- Building a new 1x1 combined cycle unit on Long Island would cost $20 per ton.[25]
- Retaining existing nuclear capacity in Upstate New York would cost $20 to $43 per ton.[26]
- Using onshore wind and utility-scale solar PV resources on Long Island would cost $41 and $115 per ton, respectively.[27]

The results indicate the value of utilizing a technology-neutral approach in pursing carbon reductions in New York, such as a carbon tax or cap-and-trade market. In fact, the Regional Greenhouse Gas Initiative is a successful cap-and-trade market that has been implemented in the region and could potentially be modified to address New York's Clean Power Plan goals. This would likely reduce the costs of achieving these goals and minimize adverse effects on the NYISO capacity and energy markets.

25 This assumes that the new combined cycle on Long Island would displace generation with an average carbon intensity of 0.65 tons per MWh. Cost varies based on revenues at different locations of the new generator.

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

27 This assumes that the new renewable units on Long Island would displace generation with an average carbon intensity of 0.65 tons per MWh.

IV. Competitive Performance of the Market

We evaluate the competitive performance of the markets for energy, capacity, and other products on an on-going basis. This section discusses the findings of our evaluation of 2015 market outcomes in three areas. First, we evaluate patterns of potential economic and physical withholding by load level in Eastern New York. Second, we analyze the use of market power mitigation measures in New York City and in other local areas when generation is committed for reliability. Third, we discuss developments in the capacity market and the use of the market power mitigation measures in New York City and the G-J Locality in 2015.

A. Potential Withholding in the Energy Market

In a competitive market, suppliers have strong incentives to offer their supply at prices close to their short-run marginal costs of production. Fuel costs account for the majority of short-run marginal costs for most generators, so the close correspondence of electricity prices and fuel prices is a positive indicator for the competitiveness of the NYISO's markets.

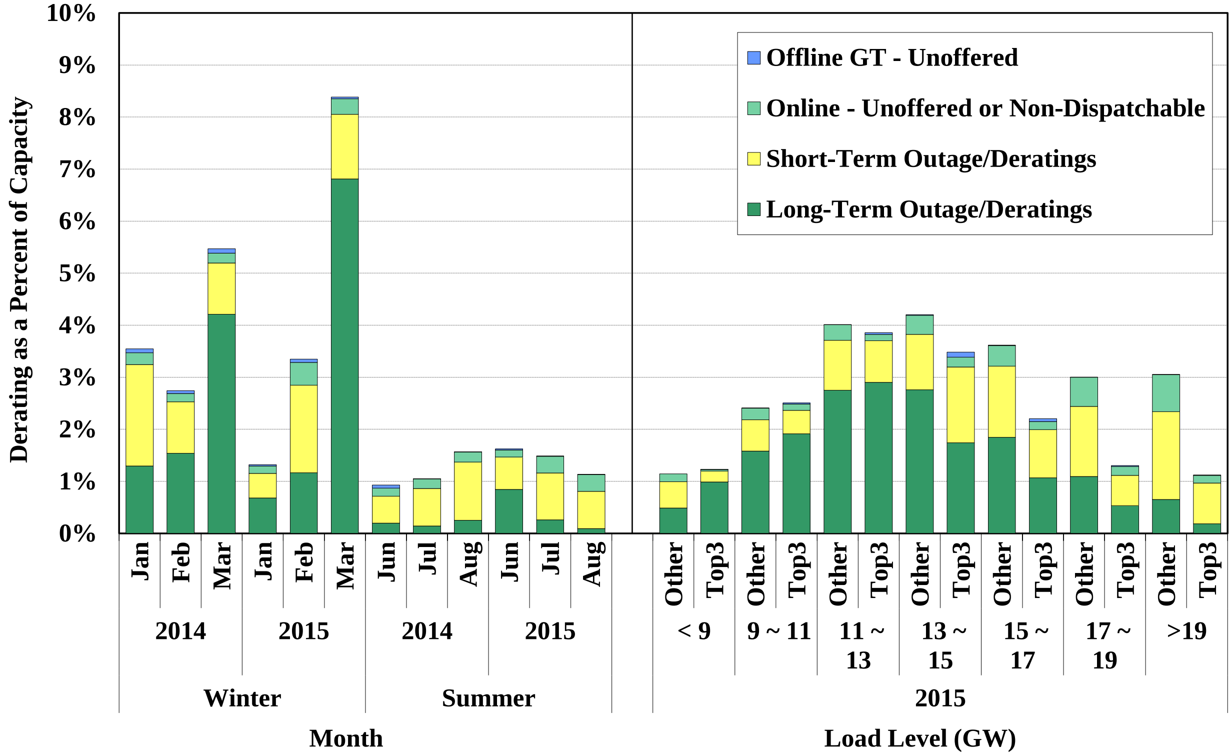
The "supply curve" for energy is relatively flat at low and moderate load levels and relatively steep at high load levels. Hence, as demand rises, prices rise gradually until demand approaches peak levels at which point prices can increase quickly, since more costly supply is required to meet load. Thus, prices are generally more sensitive to withholding and other anticompetitive conduct under high load conditions.

Prices are also more sensitive to withholding in transmission-constrained areas. When transmission constraints are binding, each supplier within the constrained area faces competition from fewer suppliers, which tends to increase the effects of withholding. Hence, our assessment focuses on potential withholding in Eastern New York because it contains the most transmission-constrained areas.

In this competitive assessment, we evaluate potential physical withholding by analyzing economic capacity that is not offered in real-time, either with or without a logged derating or outage. We evaluate potential economic withholding by estimating an "output gap". The output gap is the amount of generation that is economic at the market clearing price, but is not producing output because of the owner's offer parameters (including start-up cost, minimum generation cost, incremental energy cost, and/or time-based parameters) that exceed the reference level by a given threshold.[28]

Figure 6 and Figure 7 show the two potential withholding measures relative to season, load level, and the supplier's portfolio size.[29,30] Generator deratings and outages are shown according to whether they are short-term (i.e., seven days or fewer) or long-term.

Figure 6: Unoffered Economic Capacity in Eastern New York
2014-2015



The left portion of Figure 6 shows that in both 2014 and 2015, unoffered economic capacity was higher in the winter than in the summer, primarily because of capacity that was on long-term

28 The output gap calculation excludes capacity that is more economic to provide reserves. In this report, the Mitigation Threshold refers to the threshold used for statewide mitigation, which is the lower of $100 per MWh or 300 percent of the reference level. Lower Threshold 1 is the 25 percent of the reference level, and Lower Threshold 2 is 100 percent of the reference level.

29 Both evaluations exclude capacity from hydro, solar, wind, landfill-gas, and biomass generators.

30 Sections II.A and II.B in the Appendix show more detailed analyses of potential physical and economic withholding.

outage. Economic capacity that was short-term derated or on outage was also higher in the coldest winter months than in the summer in both 2014 and 2015, reflecting that cold temperatures tend to increase outage risks, particularly for oil-fired units. The amount of economic capacity on long-term outages increased in late March as suppliers scheduled more maintenance expecting milder conditions. In retrospect, it would have been efficient to postpone the outages for a portion of this capacity because it would have been economic to operate given actual market conditions. However, some generators will be economic whenever they take an outage because they have very low operating costs (e.g., nuclear units).

The right portion of Figure 6 shows that the three largest suppliers and other suppliers increased the availability of their capacity during periods of high load when capacity was most valuable to the market, which is generally consistent with expectations in a competitive market.

Economic capacity in Eastern New York that was not offered because of long-term outages rose from 1.3 percent in 2014 to 2.0 percent in 2015. In some cases, these outages could have been scheduled at a time when the capacity would have been less valuable. Although the NYISO can require a supplier to re-schedule a planned outage for reliability reasons, the outage scheduling rules do not allow the NYISO to require a supplier to re-schedule for economic reasons. In addition, there are no mitigation measures that would prevent outage scheduling that is not consistent with competitive behavior. We will continue to monitor outage scheduling patterns going forward and consider whether the NYISO's role could be expanded to enable more efficient outage scheduling.

One useful metric for identifying potential economic withholding is the "output gap". The output gap is the amount of generation that is economic at the market clearing price, but is not producing output due to the owner's offer.[31] We assume that the unit's competitive offer price is equal to its reference level. To determine whether a unit is economic, we evaluate whether it would have been economic to commit based on day-ahead prices and whether its incremental energy would have been economic to produce based on real-time prices. Figure 7 shows the patterns of output gap in Eastern New York by load level and participant size.

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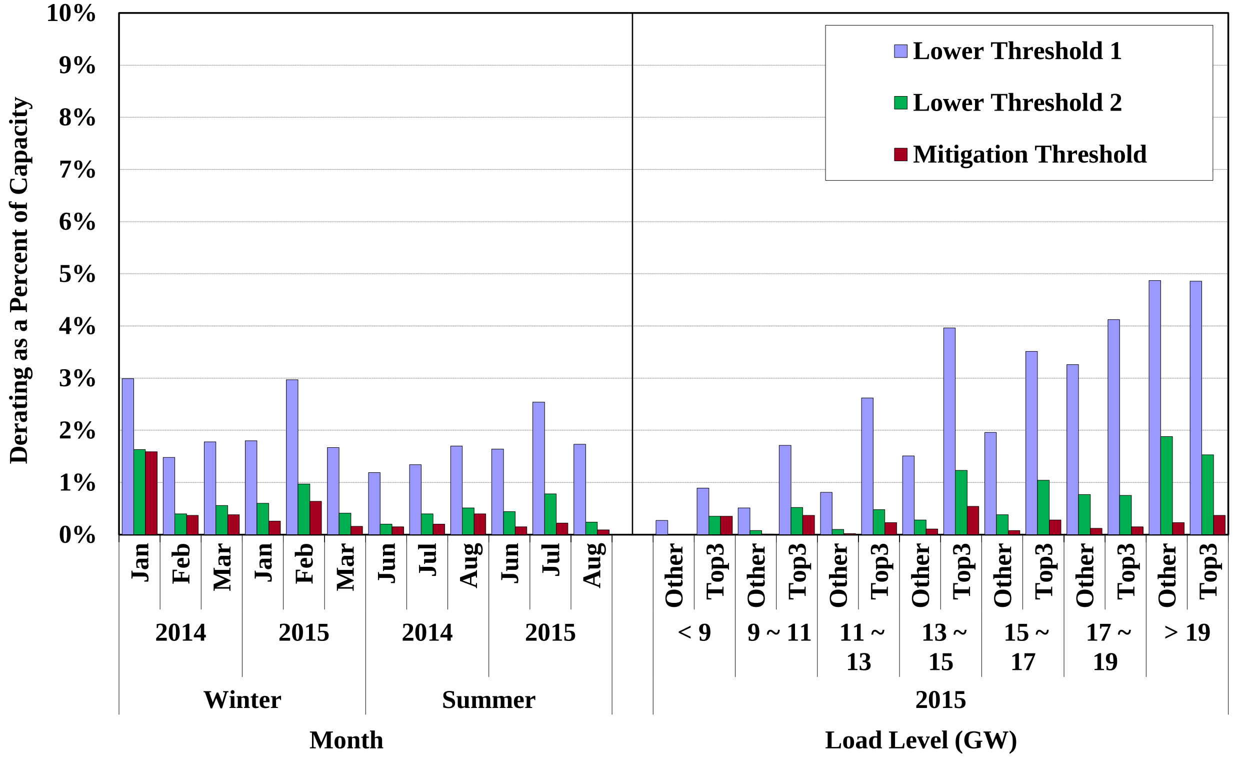
31 The output gap calculation excludes capacity that is more economic to provide ancillary services.

Figure 7: Output Gap in Eastern New York
2014-2015



The amount of output gap averaged less than 0.25 percent of total capacity in Eastern New York at the mitigation threshold and roughly 1.75 percent at the lowest threshold evaluated (i.e., 25 percent) in 2015. The output gap averaged less than 0.5 percent as a share of total capacity for both large and small suppliers in Eastern New York at the statewide mitigation threshold during 2015. At the lowest threshold evaluated (i.e., 25 percent above the reference level), the output gap averaged less than 3 percent. Output gap at lower thresholds was higher during higher-load hours, which is partially due to the fact that a much larger share of New York's resources tend to be economic at high-load levels. However, much of this increase occurred on units that are: (a) co-generation resources; and/or (b) generators with gas supply limitations that are triggered when other units nearby are also committed (either because of low gas pressure or loss-of-gas reliability rules).

Most co-generation resources operate in a relatively inflexible manner because of the need to divert energy production to non-electric uses. For generators with gas limitations that are dependent on the commitment status of nearby units, these escalating costs are difficult to reflect dynamically in reference levels. In addition, it is generally a positive indicator that the output gap was comparable for top suppliers and other suppliers during high load conditions when the market is most vulnerable to the exercise of market power.

Overall, the patterns of output gap were generally consistent with expectations in a competitive market and did not raise significant concerns regarding potential economic withholding under most conditions.

B. Automated Mitigation in the Energy Market

In New York City and other transmission-constrained areas, individual suppliers are sometimes needed to relieve congestion and may benefit from withholding supply (i.e., may have local market power). Likewise, when an individual supplier's units must be committed to maintain reliability, the supplier may benefit from raising its offer prices above competitive levels. In these cases, the market power mitigation measures effectively limit the ability of such suppliers to exercise market power. This section evaluates the use of three key mitigation measures.

- Automated Mitigation Procedure ("AMP") in New York City – This is used in the day-ahead and real-time markets to mitigate offer prices of generators that are substantially above their reference levels (i.e., estimated marginal costs) when their offers would significantly raise the energy prices in transmission-constrained areas.[32]

- Reliability Mitigation in New York City – When a generator is committed for local reliability, the start-up cost and minimum generation cost offers of the generator may be mitigated to its reference levels. A $0 conduct threshold is used in the day-ahead market and the AMP conduct threshold is used in the real-time market.

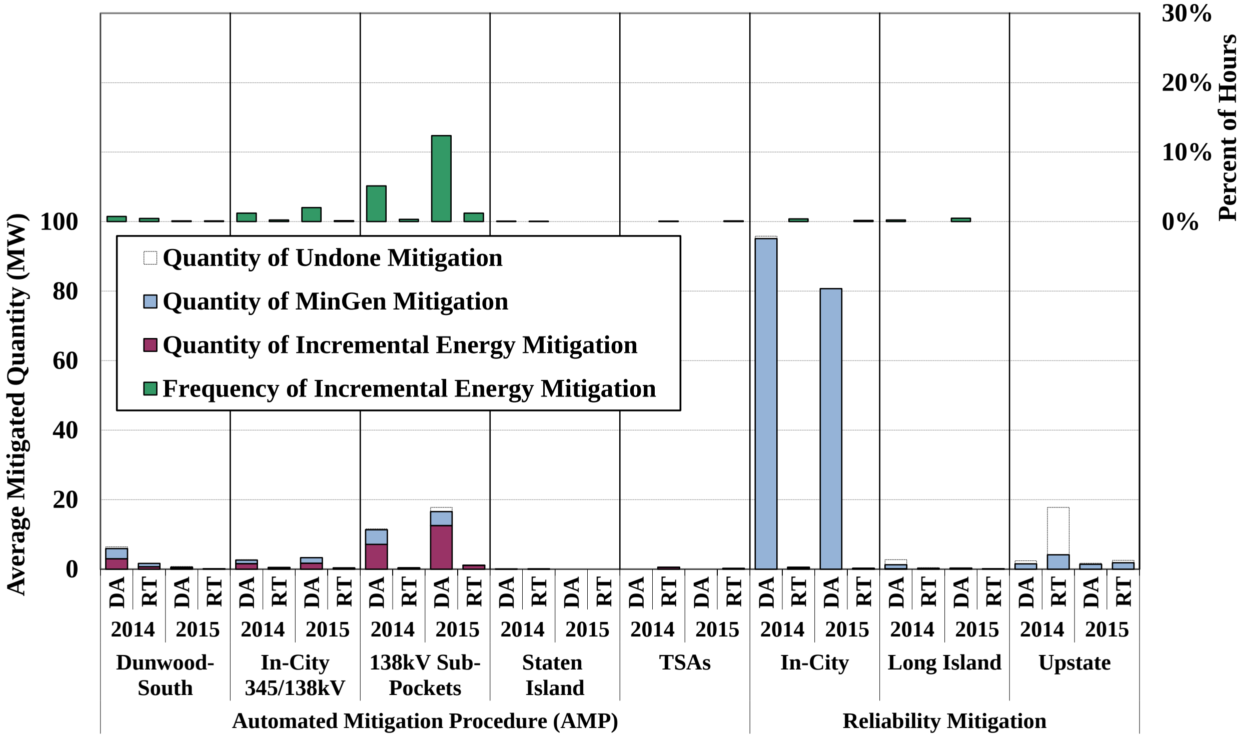
- Reliability Mitigation in Other Areas – When a generator is committed for reliability and the generator is pivotal, the start-up cost and minimum generation cost offers of the generator may be mitigated to its reference levels. A conduct threshold of the higher of $10 per MWh or 10 percent of the reference level is used.

Figure 8 summarizes the amount of mitigation that occurred in the day-ahead and the real-time markets in 2014 and 2015. Most mitigation occurs in the day-ahead market, since that is where most supply is scheduled. The figure also shows the amount of capacity that was unmitigated

32 The conduct and impact thresholds used by AMP are determined by the formula provided in the NYISO Market Services Tariff, Section 23.3.1.2.2.1.

after consultation with NYISO.[33] Approximately 90 percent of AMP mitigation occurred in the day-ahead market in 2015, similar to 2014. Likewise, 97 percent of reliability mitigation occurred in the day-ahead market in 2015, primarily for DARU and LRR commitments in New York City. Reliability mitigation accounted for 79 percent of all mitigation in 2015. Unlike AMP mitigation, this mitigation generally affected guarantee payments but not energy prices.

Figure 8: Summary of Day-Ahead and Real-Time Mitigation
2014-2015



The frequency of AMP mitigation in New York City has decreased substantially in the past four years, falling from an average of over 250 MW in 2011 to just 25 MW in 2014 and 24 MW in 2015. These reductions were mostly attributable to less frequent transmission congestion in New York City, particularly in the 138kV load pockets. Congestion has fallen primarily because of generation additions and transmission upgrades in recent years. In addition, lower natural gas prices in New York City relative to other regions of the state and lower summer load levels in 2015 contributed to the reduction congestion in New York City and lower AMP mitigation.

33 Generators were sometimes mitigated in the day-ahead or real-time market and then subsequently unmitigated after consultation with the NYISO for several reasons. Section II.C in the Appendix has more details on these reasons and also provides additional description of the figures.

C. Competition in the Capacity Market

The capacity market is designed to ensure that sufficient capacity is available to meet planning reserve margins by providing long-term signals for efficient investment in new and existing generation, transmission, and demand response. Buyer-side mitigation measures are used in New York City and the G-J Locality to prevent entities from artificially depressing prices below competitive levels by subsidizing the entry of uneconomic capacity.[34] Supply-side mitigation measures prevent a large supplier from inflating prices above competitive levels by withholding economic capacity in these areas.[35] Given the sensitivity of prices in these areas to both of these actions, we believe that these mitigation measures are essential for ensuring that capacity prices in the mitigated capacity zones are efficient. This section discusses issues related to the use and design of capacity market mitigation measures in 2015.

1. Application of the Buyer-Side Mitigation Measures

The NYISO performed a Mitigated Exemption Test for the Berrians GT III Project and provided a BSM determination at the end of the Final Decision Round for Class Year 2012 ("CY12") in January 2015. The Berrians GT III Project was determined not to be exempt and would have been subject to Offer Floor mitigation if the developer had moved forward with the project.[36] The Berrians GT III Project (which was a proposed 250 MW combined cycle project in Zone J) accepted its Project Cost Allocation but subsequently withdrew its interconnection request.

In 2015, the NYISO commenced BSM evaluations for five "additional CRIS" projects that are part of the CY15. The five Examined Facilities are Bowline 2 in Zone J (requested additional summer CRIS of 10 MW), East River 1 in Zone J (requested additional summer CRIS of 10

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34 The buyer-side mitigation measures work by imposing an offer floor on mitigated capacity, thereby preventing such capacity from depressing the clearing price. These are described in NYISO Market Services Tariff, Section 23.4.5.7.

35 The supply-side mitigation measures work by imposing an offer cap on pivotal suppliers in the spot auction and by imposing penalties on capacity otherwise withheld. These are described in NYISO Market Services Tariff, Sections 23.4.5.2 to 23.4.5.6.

36 The Mitigation Exemption Tests for the CY12 projects are discussed in detail in *Assessment of the Buyer-Side Mitigation Exemption Tests for the Class Year 2012 Projects*, January 13, 2015 ("BSM Report for CY12 Projects").

MW), East River 2 in Zone J (requested additional summer CRIS of 10 MW), Linden Cogeneration Plant in Zone J (requested additional summer CRIS of 35.5 MW) and Astoria Energy CC1 and CC2 in Zone J (requested additional summer CRIS of 27.8 MW).[37]

The NYISO is also considering the request for a Competitive Entry Exemption from the developers of the Champlain Hudson Power Express Project (which is a proposed 1000 MW merchant transmission project running from the US-Canada border to Zone J).[38]

2. Improvements to the Buyer-Side Mitigation Measures

It is important to continue refining the BSM evaluation methodology, since an incorrect assessment of whether a project is economic could cause buyer-side mitigation to inefficiently restrict investment or allow uneconomic entry that substantially depresses capacity prices.

Offer Floors for Mitigated Projects

A new project receives an exemption from Buyer-Side Mitigation when capacity prices are forecasted to be higher than:

- 75 percent of the Mitigation Net CONE ("MNC") in the first year of the project's operation, where MNC is equal the annual capacity revenues that the demand curve unit would need to be economic (i.e., the Part A test); or
- Unit Net CONE ("UNC") in the first three years of operation, where UNC is the estimated net CONE of the project (i.e., the Part B test).

If a project fails both the Part A and Part B tests, then an offer floor is imposed on the project that is set equal to the lower of UNC and 75 percent of MNC. The use of 75 percent of MNC is reasonable for purposes of the Part A exemption test because it recognizes that the entry of the new unit will tend to lower the project's net revenues in the initial year. However, its use as an

37 See *Overview of Class Year 2015*, Presented by Steve Corey to Class Year 2015 Working Group, May 11, 2015, Slide 4.

38 The NYISO confidentially provided a BSM determination for the Champlain Hudson Power Express ("CHPE") Project as part of its CY12 evaluation. However, the CHPE Project rejected its Project Cost Allocation and dropped out of the CY12. The CHPE project subsequently entered the next Class Year (i.e. CY15) requested a Competitive Entry Exemption. For additional details on Competitive Entry Exemption, see the NYISO's April 13, 2015 compliance filing: Consolidated Edison Company of New York, Inc., et al v. New York Independent System Operator, Inc., 150 FERC ¶ 61,139.

offer floor for projects that have failed both tests significantly weakens the buyer-side mitigation measures because it allows the uneconomic project to lower capacity prices as much as 25 percent below the cost of new entry. To address these issues, we recommend setting the offer floor of mitigated units at the lower of UNC and 100 percent of the MNC.[39]

Assumptions Used in the Mitigation Exemption Test

Our past reports evaluating the Mitigation Exemption Tests ("METs") have identified concerns with several assumptions that are used in the exemption test and that are described below.[40] We recommend that the NYISO modify the MET to address each of the issues discussed below.[41]

First, the MET assumes that an Examined Facility will become operational in the Starting Capability Period, which is defined to be three years after a class year starts. The Starting Capability Period is important because the timing of entry affects the load forecast and other key assumptions. If the Starting Capability Period is significantly earlier than an Examined Facility would likely begin operating, it can depress the ICAP price forecasts, thereby increasing the likelihood of mitigating an economic resource. In the METs conducted so far, we found that the Starting Capability Period was not well-aligned with when the Examined Facility would likely be operational, making the facility appear less economic than it actually would be at the time of its entry. We recommend the NYISO consider modifying the tariff so that the Starting Capability Period is better aligned with when the Examined Facilities could actually begin operating.[42] Specifically, an Examined Facility should be assumed to enter in the earliest feasible capability period (based on potential construction timelines) when it would anticipate being economic.

Second, the set of generators that is assumed to be in service for the purposes of the MET is important because the quantity of available supply can substantially affect the forecasted prices. Over-estimating the amount of in-service capacity increases the likelihood of mitigating an

39 See Recommendation #4a in Section XI.

40 For example, see BSM Report for CY12 Projects.

41 See Recommendation #4b in Section XI.

42 See BSM Report for CY12 Projects, Section VII.A.

economic project, while under-estimating the amount of in-service capacity may lead to under-mitigation. The Tariff requires the NYISO to include all existing resources other than Expected Retirements, which leads to the inclusion of some mothballed resources that are unlikely to re-enter the market.[43] The Tariff also compels the NYISO to exclude resources that have submitted a retirement notice but retain the ability to re-enter the market.[44] We recommend the NYISO modify the definition of Expected Retirements to allow the forecasted prices to reflect capacity that would likely be available under the circumstances modeled in the exemption test.

Third, the capacity price forecast used for the METs is very sensitive to the assumed Locational Minimum Installed Capacity Requirements ("LCR") levels. The NYISO, when conducting the MET, uses the actual LCRs that are in place at the time of analysis for the duration of the Mitigation Study Period ("MSP"). However, LCR levels over the MSP are likely to be impacted by changes in capacity sales from UDRs because these sales could alter the amount of available emergency assistance.[45] The entry of Examined Facilities from current or prior CYs and the retirements or mothballing of existing capacity is another factor that could have a significant impact on the LCRs for the MSP. Therefore, we recommend the NYISO consider adjusting the LCR levels for changes in UDR sales and installed capacity in its future BSM evaluations.

Fourth, in the Part B test, the NYISO compares the forecasted capacity price over the MSP with the Unit Net CONE ("UNC") of the Examined Facility. If the average forecasted price is greater than the UNC, the facility is exempt under the Part B test. The NYISO assumes that the Examined Facilities offer at the lower of their UNC and Default Net CONE in its price forecast. So it is possible for an uneconomic Examined Facility to clear partially and set the forecasted price in some of the capability periods, and to fully clear during the rest of the MSP. In such a case, the NYISO's current methodology could have unintended consequences by allowing the

43 The definition of Expected Retirements for the purposes of the mitigation exemption test is specified in MST Section 23.4.5.7.2.3.1.

44 See BSM Report for CY12 Projects, Section VII.B.

45 A decrease in the capacity sales from a UDR will tend to increase the available emergency assistance. Consequently, the existence of the UDR will tend to reduce the LCRs for New York City and the G-J Locality.

uneconomic unit to secure a Part B exemption. Therefore, we recommend the NYISO modify the Part B test procedure to recognize that if a project receives an exemption, it would be expected to offer as a price taker and sell its full capacity. Such an approach would ensure that the forecast for the Part B test accurately captures the reduction in capacity prices that would result from new entry.

In addition to addressing the above issues, we further recommend that the NYISO develop reasonable assumptions regarding the treatment of current-CY and prior-CY projects in the capacity price forecast, including projects that are seeking or have received a Competitive Entry Exemption, a Self-Supply Exemption, or a Renewable Exemption. Likewise, the NYISO should develop reasonable assumptions regarding current-CY and prior-CYs projects in areas that are not subject to the MET.[46] Therefore, it is important for the NYISO to develop objective criteria for treatment of these units in future METs, since the number of projects seeking Competitive Entry, Self-Supply, and Renewable Exemptions is likely to increase.

Potential Expansion of Buyer-Side Mitigation Measures

In response to a complaint by the Independent Power Producers of New York, the Commission recognized that the current buyer-side mitigation measures do not address all potential conduct that may suppress capacity prices.[47] To determine whether the buyer-side mitigation measures should be expanded to address additional classes of conduct and additional capacity zones, the NYISO performed an analysis evaluating the incentives to suppress capacity prices. The NYISO concluded that there are incentives to retain existing capacity resources in operation after they are economic to retire or mothball and submitted a compliance filing proposing a process for monitoring for such activity.[48, 49]

46 This issue could also impact the capacity price forecast used for the MET in situations where the prices in G-J and/ or NYC Localities are set based on the NYCA demand curve.

47 See the Commission's Order on March 19, 2015: *Independent Power Producers of New York, Inc. v. New York Independent System Operator, Inc.*, 150 FERC ¶ 61,139.

48 See NYISO filing dated December 16, 2015: *Response to Information Request*, Attachment II – pages 13 to 20, Docket No. EL13-62-002.

49 The NYISO also concluded that there are limited or no incentives for LSEs to subsidize new entry in the "Rest of State" ("ROS") capacity market and concluded that there is no compelling evidence to support

We agree with the NYISO's determination regarding the incentives to suppress capacity prices below competitive levels through out-of-market payments to existing units. However, we did not support NYISO's proposed remedy and proposed that the Commission require rules that would impose an offer floor on a generator (at its going-forward cost level) if the NYISO determines that the generator would have retired but for an above-market contract.[50]

We are concerned that some of the mechanisms that have been proposed to promote the public policy goal of reducing CO_2 emissions may be in conflict with the buyer-side mitigation rules. If a generator receives compensation for providing a non-electricity product or service, the mitigation rules would treat such compensation as a reduction in the generator's net CONE or going-forward cost. However, if such a mechanism unduly discriminates between resources, the associated compensation may be treated as out-of-market subsidy that would not reduce the generator's net CONE or going-forward cost, thereby increasing the likelihood that the generator would be mitigated. The most efficient policies for reducing emissions are those that establish a value for emissions that compensates participants in a non-discriminatory manner for achieving reductions. In the case of CO_2 emissions, this could include a carbon tax, a tradeable rate-based emission credit program, or a cap-and-trade program. Such programs would increase expected energy revenues for low-emitting and zero-emitting technologies, thereby reducing their net CONE or going-forward cost.

Lastly, we are concerned that the buyer-side mitigation rules focus only on investment in uneconomic generation and controllable transmission facilities. The current rules do not address other types of uneconomic transmission investment, including projects that increase transmission capability on internal NYISO interfaces and projects that increase the amount of emergency assistance that is available from external areas. The NYISO should also consider how to effectively address these issues.[51]

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application of BSM rules to new entry in ROS. (See NYISO's June 17, 2015 filing in Docket No. EL13-62.) However, we identified several issues with assumptions underlying the NYISO's analysis and recommended revisions before drawing conclusions about whether to apply mitigation to new units in ROS. (See MMU's comments filed on July 17, 2015 in Docket No. EL13-62.)

50 See MMU's comments filed on January 11, 2016 in Docket No. EL13-62.

51 See Recommendation #5 in Section XI.

3. Application of the Supply-Side Mitigation Measures

In 2015, a number of units in Zone J have initiated steps to deactivate their capacity by filing notices to mothball or by beginning to transition into an ICAP Ineligible Forced Outage ("IIFO"). The NYISO's tariff requires that it evaluate whether a proposal to remove capacity from a Mitigated Capacity Zone has a legitimate economic justification.[52] NRG and TC Ravenswood proposed to remove a total of ten older gas turbines from the capacity market. NRG noticed its intent to mothball Astoria GTs 8, 10, and 11, and it moved Astoria GTs 5, 7, 12, and 13 into an IIFO on January 1, 2016. TC Ravenswood noticed its intent to mothball Ravenswood GTs 4, 5, and 6 by May 1, 2016. [53]

The NYISO filed new tariff provision for administering Reliability-Must-Run contracts on October 19, 2015. The proposed rules require the NYISO to determine if the proposed deactivation is consistent with competitive behavior.[54] Two generators in ROS, Huntley (which is a 336 MW coal facility in Zone A) and Fitzpatrick (which is an 882 MW nuclear facility in Zone C), filed their notices of intent to retire on August 25 and November 2, respectively.[55] The NYISO analyzes whether proposals to retire are consistent with competitive behavior in accordance with the proposed rules. Huntley was subsequently retired on March 1, 2016. The NYISO is currently evaluating the reliability impact of the proposal to retire Fitzpatrick in the last quarter of 2016 or the first quarter of 2017.

4. Improvements to the Supply-Side Mitigation Measures

The supply-side mitigation measures for New York City limit the offers of a pivotal supplier in the spot capacity auction based on the Going Forward Costs of its generators. In previous State

52 See MST §23.4.5.6.1

53 See NRG's Notice of Intent to Mothball Astoria GTs 8, 10 and 11. See TC Ravenswood's Notice of Intent to Mothball GTs 4, 5 and 6. See 2016 Goldbook.

54 See *New York Independent System Operator, Inc.*, Docket No. ER16-120-000, Compliance Filing, October 19, 2015

55 See Entergy's Notice of Intent to Retire Fitzpatrick. See NRG's Notice of Intent to Retire Huntley.

of the Market Reports, we have identified circumstances when a large supplier with an incentive to withhold capacity would not be subject to the supply-side mitigation measures.[56]

To address this concern, we recommended modifying the pivotal supplier test to prevent a large supplier from circumventing the mitigation rules by selling capacity in the forward capacity auctions (i.e., the strip and monthly auctions), thereby avoiding designation as a pivotal supplier. The current definition of a pivotal supplier effectively assumes that selling capacity in the forward auctions eliminates the incentive for a large supplier to withhold in the spot auction. However, increased spot capacity prices affect the expectations of other market participants, increasing the clearing prices in subsequent forward auctions. This allows a large supplier to benefit from withholding in the spot capacity auction even if it does not meet the definition of a pivotal supplier in the supply-side mitigation measures because it has sold most of its capacity in the forward auctions. Hence, we recommend modifying the pivotal supplier criteria to include in the evaluation for a particular supplier any capacity that it sold prior to the spot auction. Although this issue has already been addressed for the G-J Locality, the issue has not been rectified for the purposes of determining whether a supplier is pivotal in New York City.[57]

[56] See 2012 NYISO State of the Market Report, Section III.C.3.

[57] See Recommendation #6 in Section XI.

V. Day-Ahead Market Performance

The day-ahead market enables firms to make forward purchases and sales of power for delivery in real-time, allowing participants to hedge their portfolios and manage real-time price volatility. In a well-functioning market, we expect that day-ahead and real-time prices will not diverge systematically because participants will adjust their purchases and sales to arbitrage such differences. Price convergence is desirable also because it promotes the efficient commitment of generation, procurement of natural gas, and scheduling of external transactions. Subsection A evaluates the convergence of the day-ahead and real-time energy and ancillary services prices, while Subsection B analyzes virtual trading and other day-ahead scheduling patterns.

A. Day-Ahead to Real-Time Price Convergence

1. Convergence of Zonal Energy Prices

The following table evaluates price convergence at the zonal level by reporting the percentage difference between the average day-ahead price and the average real-time price in select zones, as well as the average absolute value of the difference between hourly day-ahead and real-time prices in 2014 and 2015.[58] These statistics are shown on an annual basis and also separately for the first quarter and the rest of the year.

Table 4: Price Convergence between Day-Ahead and Real-Time Markets
Select Zones, 2014-2015

	Annual Average (DA - RT)				Q1 Average		Q2-Q4 Average	
	Avg. Diff		Avg. Abs. Diff		Avg. Abs. Diff		Avg. Abs. Diff	
Zone	2014	2015	2014	2015	2014	2015	2014	2015
West	0.4%	-5.6%	39.9%	52.8%	41.7%	41.5%	38.3%	59.9%
Central	3.6%	1.3%	33.4%	37.3%	38.4%	34.5%	27.8%	39.6%
Capital	7.2%	0.9%	32.9%	33.0%	36.8%	30.6%	27.4%	35.8%
Hudson Valley	6.4%	2.3%	31.8%	32.8%	35.3%	28.7%	27.3%	36.6%
New York City	5.1%	1.0%	31.2%	34.0%	34.4%	29.4%	27.5%	37.7%
Long Island	3.5%	2.4%	38.1%	41.8%	35.1%	31.0%	41.4%	50.5%

58 Section I.H in the Appendix shows monthly variations of average day-ahead and real-time energy prices.

Day-ahead prices were higher on average than real-time prices by a modest margin in most areas in 2015. In general, a small day-ahead premium is expected in a competitive market, since load serving entities and other market participants avoid buying at volatile real-time prices by shifting more of their purchases into the day-ahead market.

The average day-ahead premiums fell from 2014 to 2015. Convergence was notably better in most regions in the first quarter of 2015 primarily because of less frequent winter peaking conditions and significantly lower and less volatile natural gas prices (relative to the first quarter of 2014).

The average absolute difference between day-ahead and real-time prices increased modestly in most regions. This was most evident in the period from the second quarter to the fourth quarter of 2015 when real-time prices were more volatile because of more frequent summer peak conditions and transmission outages in Southeast New York in 2015. Since price volatility is measured as a percent of the average LBMP, the lower natural gas and energy prices contributed to the higher volatility. However, the average absolute difference also continues to indicate higher volatility in Western New York, which is attributable to relatively low production costs of resources there and the variable effects of congestion on 230kV lines downstream of the Niagara plant as discussed below.

2. Convergence of Nodal Energy Prices

Certain generator nodes exhibited less consistency between average day-ahead and real-time prices than zonal prices did in 2015.[59] This part of the section discusses three locations where price convergence was particularly poor in 2015.

First, the Niagara 230kV generator bus in the West Zone exhibited average day-ahead prices that were 12 percent higher than average real-time prices in 2015. This pattern reflects frequent real-time congestion on the 230kV transmission system that limited Ontario imports and Niagara generation from flowing east and that was not well-reflected in the day-ahead market. This pattern was driven by several factors, including increases in the amount of supply (offered at a

59 See Section I.H in the Appendix for detailed results.

given price level) from Ontario and Niagara after the day-ahead market, volatile loop flows around Lake Erie, and operating practices that do not fully utilize parallel 115kV transmission lines in order to reduce congestion on the 230kV lines.[60]

Second, the Valley Stream load pocket in Western Long Island was affected by frequent real-time congestion on the East Garden City-to-Valley Stream line that was not well-reflected in the day-ahead market. The primary cause was the large differentials between day-ahead scheduled flows and actual real-time flows across the Jamaica-to-Valley Stream PAR-controlled line (i.e., the "901 Line"), which contributed to real-time price spikes in the load pocket.[61] The agreement under which the 901 Line is used to flow power from the Valley Stream Load Pocket to New York City results in inefficient market outcomes, since the Valley Stream Load Pocket usually has much higher LBMPs. Furthermore, inconsistencies between day-ahead schedules and real-time flows across the 901 Line contribute to real-time price volatility and poor convergence between day-ahead and real-time prices. For these reasons, we recommend the NYISO optimize the scheduling of the 901 Line in the day-ahead and real-time markets as discussed in Section IX.D.

Third, the Greenwood load pocket in New York City exhibited much less congestion in the day-ahead market than in real-time.[62] Although several reasons were identified for this pattern, we found that day-ahead congestion was understated because of the scheduling of uneconomic gas turbines in the day-ahead market. These schedules are the result of software changes that were made in conjunction with the introduction of the MIP ("Mixed Integer Program") software in December 2014. These changes included a module that runs after the initial MIP solution to:

- Evaluate whether to schedule gas turbines assuming they are capable of operating to a minimum of less than 1 MW (even though that is not physically possible), and

60 External transaction bids and offers and generators offers are posted on the NYISO website on a 3-month lagged basis. These factors are discussed in more detail in Sections III.C, III.D, and V.E of the Appendix.

61 The volatility of flows across the 901 Line has been found to be a leading cause of transient price volatility in Long Island as shown in Section IX.E and balancing congestion residual uplift as shown in Section VI.A.3.

62 See Subsection III.B in the Appendix for a discussion of day-ahead and real-time congestion patterns.

- Lock-in the preliminary decision to schedule a gas turbine that occurs in the initial MIP solution even if it is no longer economic because another resource is subsequently scheduled.

We recommend modifying the software to address both of these issues so that the day-ahead market no longer tends to over-schedule gas turbines.

At times, the pattern of intra-zonal congestion may differ significantly between the day-ahead market and the real-time market, leading to poor convergence at individual nodes even though convergence is good at the zone level. Allowing virtual trading at a disaggregated level would enable market participants to better arbitrage day-ahead and real-time prices at nodes that exhibit poor convergence. This would help improve consistency between day-ahead and real-time prices and ensure adequate resources are committed in the day-ahead market in areas such as the Valley Stream Load Pocket.

3. Convergence of Ancillary Service Prices

Average reserve prices fell from 2014 to 2015, while the reserve prices did not converge as well in 2015.[63] The average absolute differences between day-ahead and real-time reserve prices increased, driven by factors affecting energy price convergence that were discussed in Part 1 of this subsection. In addition, reserve price volatility (which is measured as percentage of average reserve prices) increased partly because some drivers of volatility are not correlated with average prices. For example, the shortage price for the eastern New York spinning reserve requirement is always $25/MWh, so the price effect (in percentage terms) of a shortage of this product increases when average reserve prices fall.

B. Day-Ahead Load Scheduling and Virtual Trading

Convergence between day-ahead and real-time energy prices continues to be better at the zone level than at the node level partly because physical loads and virtual traders are able to bid at the zonal level in the day-ahead market. Under-scheduling load generally leads to lower day-ahead

63 Appendix Section V.A.3 evaluates the convergence between day-ahead and real-time prices for: 10-minute spinning reserves in Western New York and in Eastern New York and 10-minute non-spin reserves in Eastern New York.

prices, while over-scheduling can raise day-ahead prices above real-time prices. Virtual trading helps align day-ahead prices with real-time prices, which is particularly beneficial when systematic inconsistencies between day-ahead and real-time markets would otherwise cause the prices to diverge. Such price divergence ultimately raises costs by undermining the efficiency of the resource commitments in the day-ahead market.

Table 5 shows the day-ahead schedules of physical load, virtual trades, and virtual imports and exports as a percent of real-time load on an annual basis in 2014 and 2015 for various regions in New York State.[64]

Table 5: Day-Ahead Load Scheduling versus Actual Load
By Region, 2014-2015

Region	Year	Bilateral + Fixed Load	Price-Capped Load	Virtual Supply	Virtual Load	Virtual Import	Virtual Export	Net Scheduled Load
West	2014	98.7%	0.0%	-4.3%	21.4%			115.8%
	2015	99.5%	0.0%	-4.6%	24.2%			119.1%
Central NY	2014	124.4%	0.0%	-36.9%	2.9%			90.4%
	2015	119.6%	0.0%	-33.0%	3.1%			89.7%
North	2014	98.1%	0.0%	-45.9%	1.6%			53.8%
	2015	97.7%	0.0%	-51.7%	3.3%			49.3%
Capital	2014	102.2%	0.0%	-19.3%	4.7%			87.6%
	2015	97.8%	0.0%	-21.1%	5.6%			82.2%
Lower Hudson	2014	79.1%	18.0%	-8.9%	9.0%			97.1%
	2015	76.2%	20.8%	-12.1%	6.9%			91.7%
New York City	2014	90.9%	6.3%	-0.3%	3.2%			100.1%
	2015	89.0%	8.1%	-0.5%	4.2%			100.9%
Long Island	2014	98.6%	0.0%	-0.4%	11.8%			110.0%
	2015	100.7%	0.0%	-1.2%	9.3%			108.9%
NYCA	2014	99.2%	4.3%	-11.8%	6.9%	-3.1%	0.4%	95.8%
	2015	97.1%	5.3%	-11.8%	7.0%	-2.9%	0.4%	95.2%

Overall, net scheduled load in the day-ahead market was nearly 96 percent of actual NYCA load during daily peak load hours in 2015, comparable to 2014. Day-ahead net load scheduling patterns in each of the sub-regions were generally consistent between 2014 and 2015 as well.

64 Figure A-40 to Figure A-47 in the Appendix also show these quantities on a monthly basis at these locations in New York.

Average net load scheduling tends to be higher in locations where volatile real-time congestion is more common. Net load scheduling was generally higher in New York City and Long Island because they were downstream of most congested interfaces. Net load scheduling was the highest in the West Zone in the past two years partly because of higher and more volatile real-time congestion on the West Zone 230kV system.

Load was typically under-scheduled in the North Zone by a large margin primarily in response to the scheduling patterns of wind resources in this area. Wind generators typically operate in real-time above their day-ahead schedules. Likewise, other renewable generators exhibit a tendency to operate above their day-ahead schedule in real-time. In 2015, renewable generators added an average of 525 MW of additional energy supply in real-time, satisfying nearly 7 percent of the average real-time load outside Southeast New York. These increases in physical supply after the day-ahead market provide opportunities to profit from scheduling of virtual supply and virtual imports in most of upstate regions.

In general, the patterns of day-ahead scheduling have helped improve convergence between day-ahead and real-time prices and were generally consistent with the price premiums exhibited in each of the zones. The patterns of day-ahead scheduling also improved the commitment of resources. For example, if congestion in the West Zone is not adequately reflected in the day-ahead market, areas east of the West Zone will rely too heavily on Niagara generation and Ontario imports and insufficient internal resources will be committed. Consequently, day-ahead scheduling patterns that increase west-to-east congestion through the West Zone help increase resource commitments east of the West Zone in the day-ahead market.

The following figure summarizes virtual trading by geographic region in 2015, which includes virtual trading at the eleven load zones and virtual imports and exports at the proxy buses.[65] The figure shows that a large number of market participants regularly participated in virtual trading. In 2015, an average of 33 participants submitted virtual trades at the load zones and 10 participants submitted virtual imports and exports at the proxy buses. Both numbers rose modestly from 2014.

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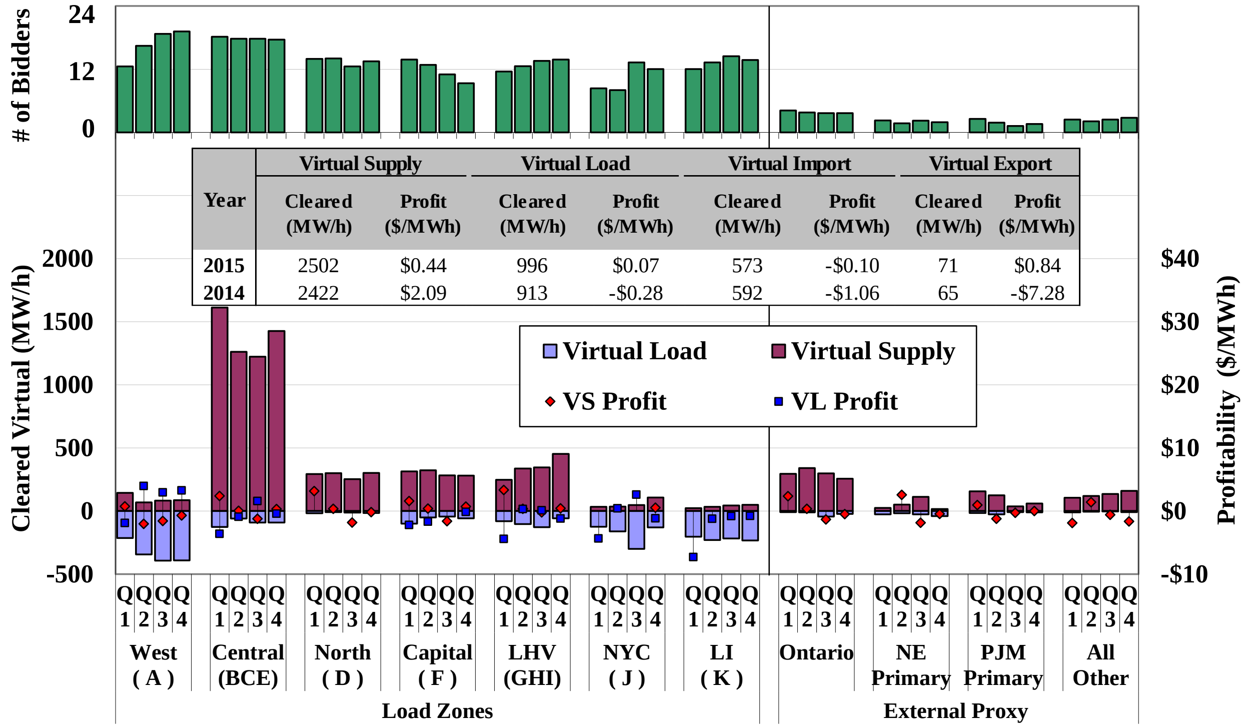
65 See Figure A-49 in the Appendix for a detailed description of the chart.

Figure 9: Virtual Trading Activity
by Region by Quarter, 2015



Year	Virtual Supply Cleared (MW/h)	Virtual Supply Profit ($/MWh)	Virtual Load Cleared (MW/h)	Virtual Load Profit ($/MWh)	Virtual Import Cleared (MW/h)	Virtual Import Profit ($/MWh)	Virtual Export Cleared (MW/h)	Virtual Export Profit ($/MWh)
2015	2502	$0.44	996	$0.07	573	-$0.10	71	$0.84
2014	2422	$2.09	913	-$0.28	592	-$1.06	65	-$7.28

At the load zones, virtual traders generally scheduled more virtual load in the West Zone and downstate areas (i.e., New York City and Long Island) and more virtual supply in other regions in 2015. This pattern was consistent with the day-ahead load scheduling patterns discussed earlier for similar reasons. At the proxy buses, nearly 90 percent of scheduled virtual transactions were virtual imports. Over half of virtual imports were scheduled at the Ontario interface, which exhibited an average day-ahead premium of 4 percent during 2015 because of higher real-time congestion on the West Zone 230 kV facilities.

The profits and losses of virtual load and supply have varied widely by time and location, reflecting the difficulty of predicting volatile real-time prices. However, in aggregate, virtual traders netted approximately $10 million of gross profits in 2015, indicating that they have generally improved convergence between day-ahead and real-time prices. Additionally, the average profit per MWh was relatively low in 2015, indicating that the markets were relatively well-arbitraged and consistent with the good convergence achieved in 2015. Good price convergence, in turn, facilitates an efficient commitment of generating resources.

VI. Transmission Congestion and TCC Auctions

A. Day-ahead and Real-time Transmission Congestion

Congestion arises when the transmission network does not have sufficient capacity to dispatch the least expensive generators to satisfy demand. When congestion occurs, the market software establishes clearing prices that vary by location to reflect the cost of meeting load at each location. These Location-Based Marginal Prices ("LBMPs") reflect that higher-cost generation is required at locations where transmission constraints prevent the free flow of power from the lowest-cost resources.

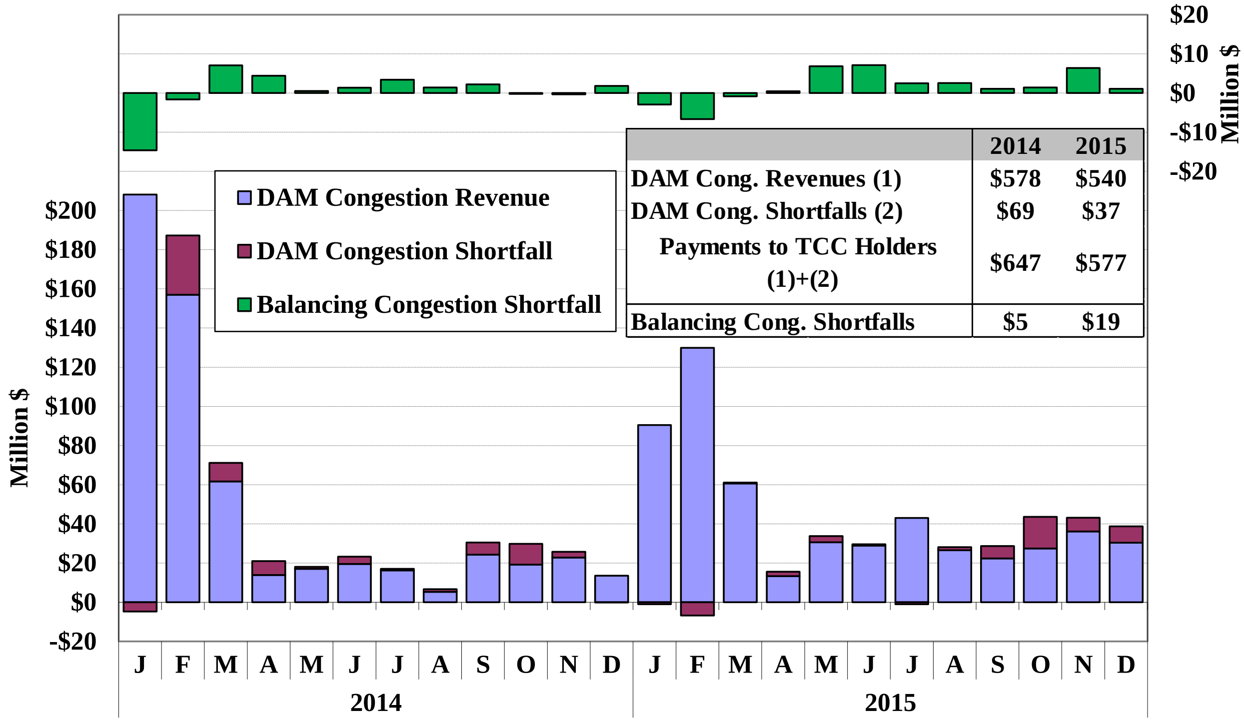
Congestion charges are applied to purchases and sales (including bilateral transactions) in the day-ahead and real-time markets based on the congestion components of day-ahead LBMPs and real-time LBMPs, respectively.[66] Market participants can hedge congestion charges in the day-ahead market by owning Transmission Congestion Contracts ("TCCs"), which entitle the holder to payments corresponding to the congestion charges between two locations. However, there are no TCCs for real-time congestion since most power is scheduled through the day-ahead market.

The next figure evaluates overall congestion by summarizing:

- Day-ahead Congestion Revenues – These are collected by the NYISO when power is scheduled to flow across congested transmission lines in the day-ahead market.
- Day-ahead Congestion Shortfalls – This uplift occurs when the day-ahead congestion revenues collected by the NYISO are less than the payments to TCC holders. This is caused when the amount of TCC sold by the NYISO exceeds the transmission capability of the power system as modeled in the day-ahead market.
- Balancing Congestion Shortfalls – This uplift arises when day-ahead scheduled flows over a constraint exceed what can flow over the same constraint in the real-time market.

66 Congestion charges to bilateral transactions scheduled through the NYISO are based on the difference in congestion component of the LBMP between the two locations (i.e., congestion component at the sink minus congestion component at the source). Congestion charges to other purchases and sales are based on the congestion component of the LBMP at the purchasing or selling location.

Figure 10: Congestion Revenues and Shortfalls
2014 – 2015



The figure shows that the overall congestion revenues and shortfalls fell from 2014 to 2015. Congestion revenues collected in the day-ahead market fell by 7 percent from 2014 to $540 million in 2015. Similarly, day-ahead and balancing congestion revenue shortfalls fell by 24 percent to a total of $56 million in 2015.

1. Day-Ahead Congestion Revenues

Variations in day-ahead congestion revenues from 2014 to 2015 were primarily driven by variations in natural gas prices and load levels. Congestion typically rose during periods of:

- Higher natural gas prices and larger gas price spreads between regions, which increased the costs of gas-fired units that were dispatched to manage congestion; and
- Higher load levels, which increased flows across the network and resulted in more frequent transmission bottlenecks.

Day-ahead congestion revenues fell 34 percent year-over-year in the first quarter of 2015 primarily because of the 45 to 70 percent reduction in average natural gas prices across the state over the same period. However, day-ahead congestion revenues rose 139 percent year-over-year in the third quarter of 2015 largely because of a 6 percent increase in average load and a 5 percent increase in peak load from 2014.

Higher gas price spreads between Western and Eastern New York generally result in higher levels of west-to-east congestion. Accordingly:

- $239 million (or 44 percent) of day-ahead congestion revenues accrued on the Central-East interface in 2015, down from $300 million in 2014 when gas price spreads were larger.[67]
- $279 million (or 52 percent) of day-ahead congestion revenues accrued in the first quarter of 2015, when gas price spreads were largest.

Congestion on 230kV lines in the West Zone rose notably from 2014 to 2015, accounting for the second largest share (17 percent) of day-ahead congestion revenues in 2015. Most of this congestion occurred along the Niagara-Packard, Packard-Sawyer, and the Huntley-Sawyer transmission lines, which have become more congested following the mothballing of capacity at the Dunkirk plant and retirement of several PJM units that had previously helped relieve congestion on this corridor. In addition, increased congestion in 2015 was also attributable to higher load levels, higher Ontario imports and reduced PJM imports (both of which increase flows over these lines), and more transmission outages. In 2016, this congestion has been further exacerbated by retirements at the Dunkirk plant in January and at the Huntley plant in March, although transmission upgrades are expected in the second quarter of 2016 that will help reduce this congestion by diverting more flows on to parallel facilities. [68]

2. Day-Ahead Congestion Shortfalls

Day-ahead shortfalls occur when the network capability in the day-ahead market is less than the capability embedded in the TCCs sold by the NYISO. On the other hand, day-ahead surpluses (i.e., negative shortfalls) occur when the amount of transactions scheduled across a congested

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67 Figure A-51 in the Appendix shows the day-ahead and real-time congestion by interface in 2014 and 2015. Figure A-6 shows monthly natural gas prices for several regions in New York.

68 Planned upgrades include the installation of two 100 MVAr shunt capacitor banks at Huntley 230 kV station and two bypassable series reactors on the Packard-Huntley 230 kV #77 and #78 lines. See *Western NY Public Policy Transmission Need: Updated Baseline Results*, Presented by Zach Smith at ESPWG/TPAS meeting, October 29, 2015.

facility exceed what was sold in the TCC auctions. Table 6 shows total day-ahead congestion shortfalls in 2015 for selected transmission facility groups.[69]

Table 6: Day-Ahead Congestion Shortfalls
By Facility Group, 2015

Facility Group	Annual Shortfalls ($ Million)
West Zone Lines	
Niagara Modeling Assumption	**$7**
Other Factors (e.g., Outages, Loopflows)	**$10**
Central to East	**$7**
North Zone Lines	**$14**
Long Island Lines	
901/903 PARs	**-$11**
Excess GFTCC Allocations	**$4**
Other Factors	**$9**
External	**-$10**
All Other Facilities	**$7**

Day-ahead congestion shortfalls fell notably from $69 million in 2014 to $37 million in 2015 primarily because of fewer costly transmission outages. Nonetheless, transmission outages were still the primary driver of day-ahead congestion shortfalls in 2015. Notable examples include: [70]

- $14 million of shortfalls accrued on the North Zone lines, primarily from outages in October;
- $9 million of shortfalls accrued on Long Island lines, primarily from outages in January, June to August, and October; and
- $10 million of shortfalls accrued on West Zone lines, although this does not distinguish between shortfalls from transmission outages versus loop flows.

The NYISO has a process for allocating the day-ahead congestion shortfalls that result from transmission outages to specific transmission owners.[71] In 2015, the NYISO allocated 103

69 Figure A-57 in the Appendix summarizes the day-ahead congestion shortfalls on major transmission facilities for 2014 and 2015 on a monthly basis. Section III.B in the Appendix also provides detailed description of each transmission facility group.

70 Section III.E in the Appendix discusses the transmission outages that are responsible for these shortfalls.

71 The allocation method is described in NYISO Open Access Transmission Tariff, Section 20.

percent of the net total day-ahead congestion shortfalls in this manner.[72] Transmission owners can schedule outages in ways that reduce labor and other maintenance costs, however, these savings should be weighed against the additional uplift costs from congestion shortfalls. Allocating congestion shortfalls to the responsible transmission owners provides incentives for minimizing the overall costs of transmission outages.[73]

Modeling inconsistencies between the TCC auction and the day-ahead market contributed to congestion shortfalls (or surpluses) in the day-ahead market. These are generally allocated across all transmission owners. Notable examples in 2015 include:

- Grandfathered TCCs that exceed the actual transfer capability from Dunwoodie (Zone I) to Long Island.[74] This resulted in a shortfall of $4 million in 2015, down from $6 million in 2014.
- The difference in the assumed schedule on the two PAR-controlled lines between New York City and Long Island (i.e., the 901 and 903 lines). The TCC auctions typically assumed a total of 286 MW flow from Long Island to New York City across the two lines, while the day-ahead market assumed an average of 193 MW in 2015. Since these flows are generally uneconomic and raise production costs, reducing the assumed flow from the TCC auction to the day-ahead market led to surplus congestion revenue. This difference contributed a surplus of $11 million in 2015 and $9 million in 2014.
- The difference between the TCC auction and the day-ahead market in the assumed amount of 115 kV Niagara generation.[75] The 115 kV Niagara generation generally helps relieve congestion on the 230 kV constraints in the West Zone, but is priced in the day-ahead market as if it were located at the 230 kV bus. This difference led to a shortfall of $6 million in 2014 and $7 million in 2015. This category of day-ahead congestion shortfalls will be eliminated in May 2016 when the NYISO implements a project to recognize the distribution of Niagara across the 230 kV and 115 kV buses in the DAM LBMP.[76]

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72 In 2015, the NYISO allocated more than 100 percent of day-ahead congestion shortfalls to transmission owners because some transmission facilities generated congestion surpluses during the year.

73 Transmission outages can also result in uplift from balancing congestion shortfalls and from BPCG payments to generators that must run out-of-merit for reliability due to the outage. The majority of these BPCG payments (which are discussed in Section IX.G) are assigned to the transmission owner.

74 This is categorized as “Excess LI GFTCC Allocations” in the table.

75 This is categorized as “Niagara Modeling Assumption” under “West Zone Lines”. This modeling issue is discussed further in Subsection A.2.

76 See *Niagara Generation Modeling Update* by David Edelson at MIWG, April 5, 2016.

In addition, external interfaces accounted for nearly $10 million of surpluses in 2015, offsetting the total shortfalls. Most of these surpluses accrued in the first quarter when imports (from Ontario and Quebec) and exports (to New England) scheduled in the day-ahead market exceeded the amount of TCCs that had been sold over the interface.

3. Balancing Congestion Shortfalls

Balancing congestion shortfalls result from reductions in the transmission capability from the day-ahead market to the real-time market. Balancing congestion surpluses (i.e., negative shortfalls) occur when real-time transactions utilize congested transmission facilities that were not fully scheduled in the day-ahead market. Unlike day-ahead congestion shortfalls, balancing congestion shortfalls are socialized through Rate Schedule 1 charges. Balancing shortfalls rose from $5 million in 2014 to $19 million in 2015. Table 7 shows total balancing congestion shortfalls accrued in the real-time market in 2015 for selected transmission facility groups.[77]

Table 7: Balancing Congestion Shortfalls[78]
By Facility Group, 2015

Facility Group	Annual Shortfalls ($ Million)
West Zone Lines	
Niagara Modeling Assumption	**$1**
Ramapo, ABC & JK PARs	**$8**
Other Factors (e.g., Outages, Loopflows)	**$18**
Central to East	
Ramapo, ABC & JK PARs	**-$7**
Other Factors	**-$3**
Capital to HVL (TSAs)	**$4**
Long Island Lines	
901/903 PARs	**$4**
Other Factors	**$1**
All Other Facilities	**-$1**

77 Figure A-58 in the Appendix summarizes the balancing congestion shortfalls on major transmission facilities for 2014 and 2015 on a monthly basis. Section III.E in the Appendix also provides detailed description for these transmission facility groups and a variety of reasons why their actual flows deviated from their day-ahead flows.

78 The balancing congestion shortfalls estimated in this table differ from actual balancing congestion shortfalls because the estimate: (a) is partly based on real-time schedules rather than metered injections and withdrawals; and (b) uses the original constraint shadow costs from the dispatch model therefore does not reflect the effect of price corrections and Scarcity Pricing Adjustments.

Balancing congestion shortfalls rose from 2014 to 2015 primarily because higher shortfalls accrued on the West Zone lines. The primary drivers were transmission outages and un-modeled factors (such as loop flows), which collectively accounted for nearly $18 million of shortfalls. Clockwise loop flows around Lake Erie reduce the transmission capacity available for scheduling internal generation to satisfy internal load and increase congestion on transmission paths in Western New York, particularly in the West Zone. Large congestion shortfalls typically arose in congested intervals when the amount of actual unscheduled clockwise loop flows was significantly higher than the amount assumed in the day-ahead market. A correlation was apparent between the severity of West Zone congestion and the magnitude of unscheduled clockwise loop flows and sudden changes in loop flow from the previous interval.[79]

Operation of the Ramapo PARs under the M2M JOA with PJM has provided significant benefits to the NYISO in managing congestion on coordinated transmission flow gates since January 2013. Additional flows (into New York) across the Ramapo, ABC, & JK PAR-controlled lines contributed an estimated $8 million of surpluses on the Central-East interface ($7 million) and the Leeds-to-Pleasant Valley line during TSA events ($1 million, which is not shown separately in the table). However, these additional flows contributed nearly $8 million of shortfalls on the West Zone lines that are currently not under M2M JOA. The NYISO has recognized this issue and modified its operating procedures in November 2015 to limit use of the Ramapo PARs when the NYISO expects constraints in Western New York to be active.[80]

The two PAR-controlled lines between New York City and Long Island (i.e., the 901 and 903 lines) consistently contributed to congestion shortfalls (rather than surpluses) in the real-time market. This was also due to the differences between the schedule assumptions on the two lines in the day-ahead markets and their actual flows in real-time. Although average real-time flows from Long Island to New York City on the two lines were similar to their average day-ahead assumptions, real-time flows across these lines were volatile. Therefore, when flows rose above

79 See Sections III.D and V.E in the Appendix for more discussion of loop flows and their effect on congestion.

80 See NYISO Management Committee meeting minutes for the December 17, 2015 meeting.

the day-ahead assumption, they often contributed to high prices in Long Island.[81] For example, real-time flows from Long Island to New York City on the 901 line exceeded the day-ahead assumption by an average of 20 percent during intervals with real-time congestion even though they were consistent on average. The operations of the two lines contributed to the balancing congestion shortfall by $4 million in 2015 (and $5 million in 2014).

B. Transmission Congestion Contracts

We evaluate the performance of the TCC market by examining the consistency of TCC auction prices and congestion prices in the day-ahead market for the Winter 2014/15 and Summer 2015 Capability Periods (i.e., November 2014 to October 2015).

Table 8 summarizes TCC cost and profit for the evaluation period separately for inter-zonal and intra-zonal TCCs.[82] The *TCC Cost* measures what market participants paid to obtain TCC rights from the TCC auctions. For a particular path, the *TCC Cost* is equal to the purchased TCC MW multiplied by the TCC price for that path. The *TCC Profit* measures the difference between the *TCC Payment*, which is equal to the TCC MW between two points multiplied by the congestion cost difference in the day-ahead market between the two points, and the *TCC Cost*. The table also shows the profitability for each category, where the total TCC profit is measured as a percentage of total TCC cost.

Market participants purchasing TCCs in the auctions covering the 12-month period from November 2014 to October 2015 netted a total net loss of $78 million. Overall, the net profitability for TCC holders in this period was *negative* 24 percent (as a weighted percentage of the original TCC prices).

81 The analysis discussed in Section V.E in the Appendix indicates that these lines were the primary cause of price volatility in the Valley Stream load pocket on Long Island.

82 Section III.F in the Appendix describes the methodology to break each TCC into inter-zonal and intra-zonal components.

Table 8: TCC Cost and Profit
Winter 2014/15 and Summer 2015 Capability Periods

	TCC Cost ($ Million)	TCC Profit ($ Million)	Profit as a Percent of Cost
Intra-Zonal TCC			
West Zone	$15	$4	29%
New York City	$20	-$10	-49%
Long Island	$6	$4	63%
All Other	$4	-$2	-51%
Total	**$46**	**-$4**	**-8%**
Inter-Zonal TCC			
Other to West Zone	$12	$20	165%
Other to New York City	$24	-$13	-56%
PJM to Hud VL	$55	-$25	-45%
PJM to New England	$49	-$33	-67%
Hud VL to New England	$77	-$48	-62%
All Other	$63	$25	39%
Total	**$280**	**-$74**	**-26%**

More than 55 percent (or $181 million) of TCC purchase costs were spent on paths along the transmission corridor from PJM to Hudson Valley Zone to New England. TCC buyers netted a 58 percent (or $105 million) loss on these transmission paths because of much lower-than-expected congestion along this corridor.

- The day-ahead congestion between areas across the Central-East interface was well below the TCC prices in the TCC auctions, particular during the Winter 2014/15 Capability Period. As explained above, natural gas prices and price spreads between areas were much lower than expected, particularly at the time of the one-year and six-month TCC auctions, contributing to lower-than-anticipated west-to-east congestion. This resulted in much lower-than-anticipated congestion prices at the New England proxy bus.

- Day-ahead congestion in the West Zone rose notably from the previous year for reasons discussed in Subsection A.1, leading to higher-than-anticipated congestion prices at the PJM proxy bus (since PJM imports to Western New York help relieve these constraints).

Day-ahead congestion into and within the 345 kV system in New York City fell significantly in 2015. Consequently, much lower-than-anticipated congestion in this area led to a net 53 percent (or $23 million) loss on inter-zonal and intra-zonal transmission paths sinking at New York City. However, TCC buyers netted a sizable profit of $24 million (or 89 percent) on all inter-zonal and intra-zonal transmission paths sinking at the West Zone, consistent with higher-than-anticipated congestion in this area.

In general, the TCC prices reflected the anticipated level of congestion at the time of auctions, most likely based on information from prior periods. The results of the TCC auctions show that the level of congestion was increasingly recognized by the markets from the annual auction to the six-month auction and from the six-month auction to the reconfiguration auction.[83] This is expected since more accurate information is available about the state of the transmission system and likely market conditions in the auctions that occur closer to the actual operating period. Since 100 percent of the capability of the transmission system is available for sale in the form of TCCs of six-months or longer, very little revenue is collected from the monthly Reconfiguration Auctions. Hence, selling more of the capability of the transmission system in the monthly Reconfiguration Auctions would likely raise the overall amount of revenue collected from the sale of TCCs.

83 See Figure A-59 in the Appendix for TCC costs and profits by auction round.

VII. External Transactions

New York imports and exports substantial amounts of power from four adjacent control areas: New England, PJM, Ontario, and Quebec. In addition to the four primary interfaces with adjacent regions, Long Island and New York City connect directly to PJM and New England across eight controllable lines: the Cross Sound Cable, the 1385 Line, the Linden VFT Line, the HTP Line, the Neptune Cable, and three lines known as the A, B, and C lines. The controllable lines are collectively able to import nearly 3.5 GW directly to downstate areas.[84] The total transfer capability between New York and the adjacent regions is substantial relative to the total power consumption in New York, making it important to schedule the interfaces efficiently.

Efficient use of transmission interfaces between regions is beneficial in at least two ways. First, the external interfaces allow low-cost external resources to compete to serve consumers who would otherwise be limited to available higher-cost internal resources. Likewise, low-cost internal resources gain the ability to compete to serve consumers in adjacent regions. Second, the ability to draw on neighboring systems for emergency power, reserves, and capacity helps lower the costs of meeting reliability standards in each control area. Wholesale markets facilitate the efficient use of both internal resources and transmission interfaces between control areas.

A. Summary of Scheduling Pattern between New York and Adjacent Areas

Table 9 summarizes the net scheduled imports between New York and neighboring control areas in 2014 and 2015 during peak (i.e., 6 am to 10 pm, Monday through Friday) hours.[85] Total net imports from neighboring areas averaged slightly over 2.5 GW during peak hours in 2015, up modestly from 2014. Although net imports across most interfaces did not change much from 2014 to 2015 on an annual average basis, some interfaces varied significantly by season.

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84 The A, B, and C lines (which interconnect New York City to New Jersey from Hudson-to-Farragut and Linden-to-Goethals) are used to flow 1,000 MW from upstate New York through New Jersey into New York City under the ConEd-PSEG wheeling agreement, which pre-dates the NYISO. These lines are scheduled as part of the primary PJM to NYISO interface rather than by participant-submitted transaction, so they are evaluated in Section VII.A.2.

85 Figure A-60 to Figure A-63 in the Appendix show more detailed on net scheduled interchange between New York and neighboring areas by month by interface.

Table 9: Average Net Imports from Neighboring Areas
Peak Hours, 2014 – 2015

Year	Hydro Quebec	Ontario	PJM	New England	CSC	Neptune	1385	VFT	HTP	Total
2014	1,152	768	352	-702	173	528	56	43	68	2,438
2015	1,149	934	256	-664	186	510	46	61	69	2,548

1. Controllable Interfaces

Imports from neighboring control areas satisfied a large share (roughly 30 percent) of the demand on Long Island in 2015, comparable to 2014. The Neptune line was typically fully scheduled during daily peak hours absent outages/deratings, while net imports over the Cross Sound Cable and the 1385 line were normally much lower in the winter months when natural gas prices in New England were much higher than natural gas prices on Long Island.

Net imports to New York City over the Linden VFT and the HTP interfaces were modest, averaging 130 MW during peak hours in 2015.[86] Net imports across these two controllable interfaces typically rose in the winter months when natural gas prices in New York City were frequently higher than in New Jersey and fell from May to October when natural gas prices in New York City fell relative to most areas in PJM.

2. Primary Interfaces

Average net imports from neighboring areas across the four primary interfaces increased marginally from 1,570 MW in 2014 to 1,675 MW in 2015 during the peak hours.

Net imports from Hydro Quebec to New York accounted for 69 percent of net imports across all primary interfaces in 2015. Average net imports rose over 20 percent in the first quarter of 2015 from a year ago, reflecting less frequent winter peaking conditions in Quebec this year. However, the increases were largely offset by lower imports in May and October when this interface was out of service for several weeks.

86 The HTP interface has a capability of 660 MW and Linden VFT has a capability of 315 MW.

Average net imports from Ontario increased more than 20 percent from 2014 to 2015, which had significant effects on operations and LBMPs in the West Zone. Most of the increase occurred in the first quarter of 2015 (when imports were up by an average of 740 MW), reflecting less frequent peaking conditions and lower natural gas prices than in the prior winter in Ontario. Net imports fell notably in September partly because of nuclear unit outages (~4 GW) in Ontario, helping to offset the annual increase.

Net imports from PJM and New England across their primary interfaces varied considerably, tracking variations in gas price spreads between these regions. For example, New York normally had higher net imports from PJM and higher net exports to New England in the winter season, consistent with the spreads in natural gas prices between these markets in the winter (i.e., NE > NY > PJM). Net exports to New England fell sharply in May and June of 2015 and New York imported power from New England on many days when gas prices were lower on the New England side.

B. Unscheduled Power Flows

The pattern of unscheduled power flows (i.e., loop flows) around Lake Erie has a significant effect on power flows in the surrounding control areas. Loop flows that move in a clockwise direction generally exacerbate west-to-east congestion in New York, leading to increased congestion costs.

Although clockwise circulation has fallen notably since the IESO-Michigan PARs went in service in April 2012, rapid and large fluctuations in loop flows were still common in 2015.[87,88] For example, clockwise loop flows rose from one 5-minute interval to the next by more than 50 MW in approximately 20 percent of the intervals in each month from 2012 to 2015.[89]

[87] These PARs are generally operated to better conform actual power flows to scheduled power flows across the Ontario-Michigan interface. MISO and IESO have indicated the PARs are capable of controlling up to 600 MW of loop flows around Lake Erie, although the PARs are generally not adjusted until loop flows exceed 200 MW.

[88] Use of these PARs since April 2012 is discussed extensively in Commission Docket No. ER11-1844-002.

[89] See Figure A-55 in the Appendix for more details.

Unscheduled clockwise loop flows have had significant impact on congestion in Western New York in the recent years, particularly in the West Zone. A correlation was apparent between the severity of West Zone congestion and the magnitude of loop flows as well as sudden changes in loop flow from the previous interval.[90] In 2015, when congestion was not present in the West Zone, the average amount of clockwise loop flows was close to 0 MW. However, West Zone congestion became more prevalent when loop flows were clockwise or happened to swing rapidly in the clockwise direction. Our analysis found that:

- Congestion value on the West Zone 230 kV constraints exceeded $200,000 in only 0.1 percent of all intervals in 2015. However, these intervals accounted for over 25 percent of the total congestion value in the West Zone in 2015.[91]
- During these intervals, unscheduled clockwise loop flows averaged over 160 MW and changes of unscheduled loop flows in the clockwise direction averaged nearly 60 MW.

Subsection IX.E discusses additional analysis of transient congestion that is caused by unscheduled loop flows and other factors that are not explicitly modeled in the dispatch software.

C. Efficiency of External Scheduling by Market Participants

We evaluate external transaction scheduling between New York and the three adjacent control areas with real-time spot markets (i.e., New England, Ontario, and PJM) in 2015. As in previous reports, we find that while external transaction scheduling by market participants provided significant benefits in a large number of hours, the scheduling did not fully utilize the external interfaces or achieve all of the potential benefits available from inter-regional trading. Table 10 summarizes our analysis showing that the external transaction scheduling process generally functioned properly and improved convergence between markets during 2015.[92]

The table shows that transactions scheduled by market participants flowed in the efficient direction (i.e., from lower-priced area to higher-priced area) in more than half of the hours on

90 See Figure A-56 in the Appendix for more details.

91 Congestion value is a measure of real-time flow over a constraint times the shadow price of the constraint. The quantity is used to quantify congestion in Section III.E.

92 See Section IV.B in the Appendix for a detailed description of this table.

most interfaces between New York and neighboring markets during 2015. Information is provided separately for transactions scheduled in the day-ahead market versus the real-time market except for Ontario, since it does not operate a day-ahead market.

Table 10: Efficiency of Inter-Market Scheduling
Over Primary Interfaces and Scheduled Lines – 2015

	Day-Ahead Market				Adjustment in Real-Time			
	Average Net Imports (MW/h)	Avg Internal Minus External Price ($/MWh)	Percent of Hours in Efficient Direction	Estimated Production Cost Savings (Million $)	Average Net Imports (MW/h)	Avg Internal Minus External Price ($/MWh)	Percent of Hours in Efficient Direction	Estimated Production Cost Savings (Million $)
Free-flowing Ties								
New England	-660	-$0.20	54%	$9	-4	$1.74	56%	$8
Ontario					947	$8.01	79%	$72
PJM	339	-$1.55	62%	-$1	-91	-$1.48	64%	$21
Controllable Ties								
1385 Line	74	$0.93	69%	$4	-32	$1.12	53%	$1
Cross Sound Cable	181	$3.70	76%	$9	-5	$1.67	66%	$0
Neptune	488	$7.22	83%	$34	-1	$7.35	56%	$1
HTP	43	-$1.29	59%	-$2	12	-$5.52	59%	-$1
Linden VFT	69	$2.44	71%	$7	-3	$2.88	58%	$1

In the day-ahead market, the share of hours with scheduling from the low-price region to the high-price region ranged from 59 to 83 percent across the five controllable ties, higher than over the free-flowing ties. A total of $52 million in day-ahead production cost savings was achieved in 2015 across the five controllable ties. The Neptune Cable accounted for 65 percent of these savings because the interface was fully scheduled most of time and the price on the New York side was higher by an average of more than $7/MWh in 2015. The share of hours with scheduling from the low-price region to the high-price region ranged from 54 to 62 percent on the New England and PJM primary interfaces.

In the real-time market, transactions scheduled between Ontario and New York flowed in the efficient direction in nearly 80 percent of hours, which was partly due to the fact that the price on the New York side was higher by an average of $8/MWh in 2015. As a result, a total of $72 million in production cost savings was achieved across the Ontario interface. Nonetheless, additional Ontario imports were limited in many hours by the transfer capability of the Ontario-to-New York interface, the congestion on the 230 kV system in the West Zone, and/or the substantial charges assessed to export transactions ($3 to $4 per MWh in 2015). Market participants also frequently responded to real-time price variations by increasing net flows into the high-price region in 56 to 64 percent of hours across the PJM and New England primary interfaces, resulting in a total of $29 million savings in real-time production costs. Real-time adjustments across the controllable ties were generally infrequent. Many of the adjustments resulted from curtailments or checkout failures of a day-ahead transaction rather than a firm's desire to schedule, so many of the real-time adjustments resulted in small increases in production costs.

Although significant benefits have been achieved in the majority of hours, there was still a large share of hours when power flowed in the inefficient direction on all of the interfaces. Furthermore, there were many hours when power flowed in the efficient direction, but additional flows would have been necessary to fully arbitrage between markets. These scheduling results illustrate the difficulty of predicting changes in real-time market conditions, the lack of coordination between markets, and the other costs and risks that interfere with efficient interchange scheduling.

D. Evaluation of Coordinated Transaction Scheduling

Although scheduling by market participants tends to improve convergence, significant opportunities remain to improve the interchange between regions. Coordination Transaction Scheduling ("CTS") is a novel market design concept whereby two wholesale 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 hourly LBMP-based scheduling system.

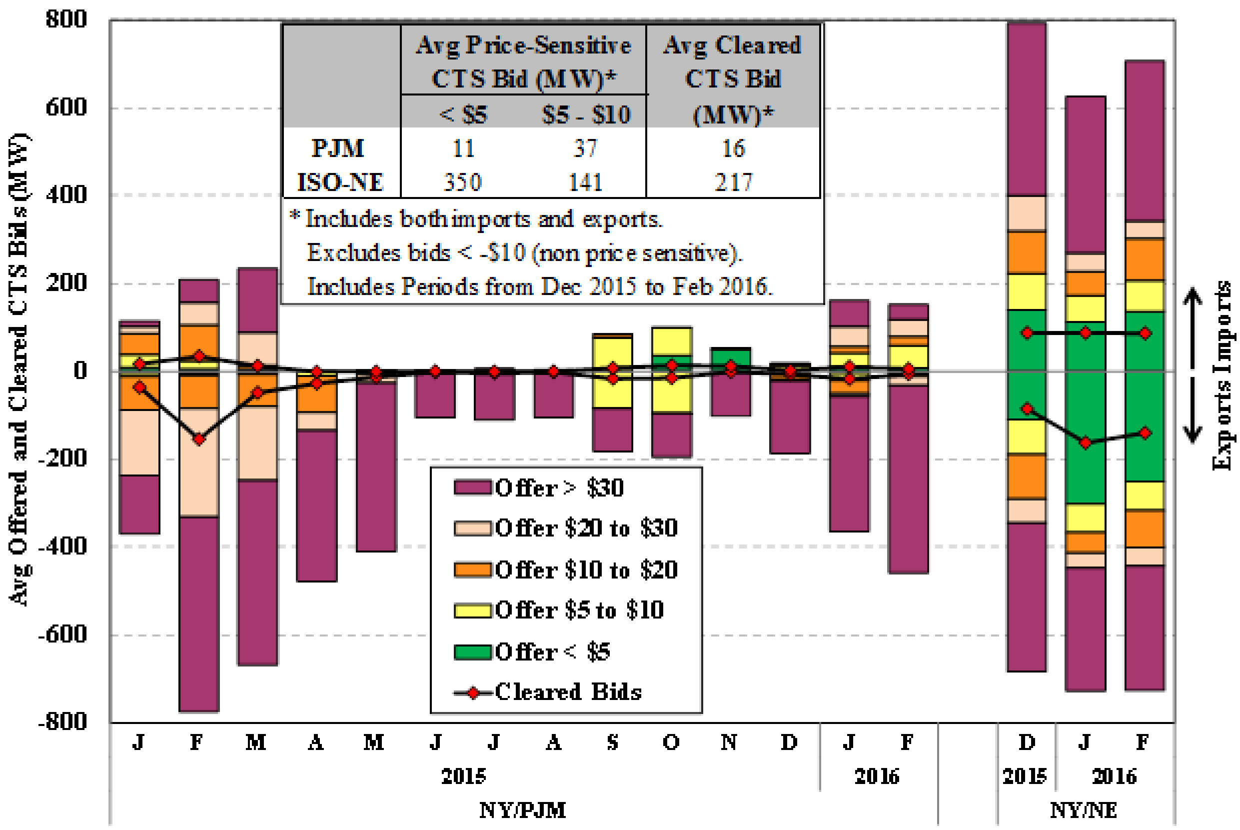
- First, CTS bids have greater potential to be scheduled accounting for changes in system conditions in the adjacent market compared with LBMP-based bids. Market participants must forecast market prices in the adjacent market (more than 75 minutes in advance) in order to formulate LBMP-based bids, while CTS bids are evaluated relative to the neighboring ISO's forecast of prices.
- Second, RTC is now able to schedule transactions much closer to operating time. Previously, schedules were established up to 105 minutes in advance, while schedules are now determined 15 minutes ahead when more accurate system information is available.

- Third, interface flows can be adjusted every 15 minutes instead of every 60 minutes, which allows for much quicker response to real-time events.

The CTS was first implemented with PJM on November 4, 2014 and then with ISO-NE on December 15, 2015. This subsection focuses on the performance of CTS with PJM, since it has been in operation much longer than CTS with ISO-NE.

Figure 11 shows the average amount of CTS transactions at the primary PJM interface during peak hours (i.e., HB 7 to 22) by month from January 1, 2015 through the end of February 2016. For a comparison, the figure also shows these quantities for the primary New England interface during the first two and a half months following its CTS activation.[93]

Figure 11: Average CTS Transaction Bids and Offers by Month
PJM and NE Primary Interfaces



The amount of CTS bids submitted at the primary PJM interface was small relative to its size (with total transfer capability of up to 2.5 GW), and most of these CTS bids were submitted with

93 Section IV.D in the Appendix describes this figure in greater detail.

substantial margins above $0. During the examined period, an average of just 11 MW of CTS bids (including both imports and exports) were offered at less than $5/MWh and an average of 37 MW were offered between $5 and $10/MWh. These were substantially lower than 350 MW and 141 MW offered in the same two price ranges at the primary New England interface.

One factor that discourages external transactions and provides incentives for CTS bidders to increase their bid prices is that transactions that flow across the PJM interface must pay substantial transmission service charges and uplift charges. Firms that flow physical exports from New York to PJM are charged $3 to $7 per MWh,[94] while PJM charges physical imports, physical exports, and "real-time deviations," which include imports and exports with a real-time schedule that is higher or lower than the day-ahead schedule. The combination of PJM charges often range from $3 to $10 per MWh. The PJM charges are generally harder to predict because they vary based on hourly real-time market results (while NYISO charges adjust monthly and are set in advance). These charges are a barrier to achieving the potential benefits from the CTS process, since large and uncertain charges deter participants submitting price-sensitive CTS offers at the PJM border.

On the other hand, there are no substantial transmission charges and or uplift charges in either direction on transactions between New York and New England. Even though CTS with ISO-NE is relatively new (and liquidity tends to increase as participants gain experience), the quantity of price-sensitive CTS spread bids has been much higher than at the PJM border. Most transactions that cleared at the ISO-NE border were bid at less than $5/MWh. Given that PJM charges are uncertain and often exceed $5/MWh, it is not surprising that almost no CTS transactions were bid at prices in this range.

Imposing large transaction fees on low-margin trading dramatically reduces trading and liquidity. Much of the difference in performance of the two CTS processes can be explained by the large fees that are imposed on CTS transactions at the PJM interface. These fees are far in excess of

94 Charges are updated on a monthly basis and may be calculated from information posted at: http://mis.nyiso.com/public/P-62list.htm.

any costs that can be attributed to price-sensitive scheduling between markets. Hence, recommend eliminating these charges.[95]

Table 11 examines the performance of the intra-hour scheduling process under CTS during 2015, focusing on the primary PJM interface.[96]

Table 11: Efficiency of Intra-Hour Scheduling Under CTS
Primary PJM Interface, 2015

			Adjustments in the Export Direction (NY to PJM)	Adustments in the Import Direction (PJM to NY)	Average/ Total
% of All Intervals			34%	40%	**73%**
Average Flow Adjustment (MW)			-81	82	**7 (Net) / 82 (Gross)**
Production Cost Savings ($ Million)	Projected at Scheduling Time		$8.1	$5.4	**$13.5**
Production Cost Savings ($ Million)	Unrealized Savings Due to:	NY Fcst. Err.	-$1.6	-$2.7	**-$4.3**
Production Cost Savings ($ Million)	Unrealized Savings Due to:	PJM Fcst. Err.	-$4.6	-$2.4	**-$7.0**
Production Cost Savings ($ Million)	Unrealized Savings Due to:	Other	-$0.4	-$0.3	**-$0.7**
Production Cost Savings ($ Million)	Actual		$1.5	$0.0	**$1.5**
Interface Prices ($/MWh)	NY	Actual	$35.51	$36.20	**$36.23**
Interface Prices ($/MWh)	NY	Forecast	$32.11	$39.16	**$36.07**
Interface Prices ($/MWh)	PJM	Actual	$38.09	$38.12	**$38.41**
Interface Prices ($/MWh)	PJM	Forecast	$45.26	$34.58	**$39.72**
Price Forecast Errors ($/MWh)	NY	Fcst. - Act.	-$3.53	$2.80	**-$0.16**
Price Forecast Errors ($/MWh)	NY	Abs. Val.	$10.08	$14.25	**$12.27**
Price Forecast Errors ($/MWh)	PJM	Fcst. - Act.	$7.17	-$3.54	**$1.31**
Price Forecast Errors ($/MWh)	PJM	Abs. Val.	$19.46	$13.57	**$16.36**

Our analyses estimate that $13.5 million in production cost savings was anticipated based on information available when RTC determined final interchange schedules. However, a relatively small portion was realized partly because of inaccurate price forecasts in both markets. Price forecast errors on the New York side accounted for $4.3 million of unrealized projected savings, and price forecast errors on the PJM side accounted for $7 million of additional unrealized

95 See Recommendation #9.

96 Section IV.D in the Appendix describes this table in greater detail.

projected savings.[97] Overall, average forecast errors were smaller on the New York side than on the PJM side in 2015. Nonetheless, forecast errors on the PJM side became smaller after the first several months of CTS implementation. On the New York side, forecast errors generally increased during periods of real-time congestion, particularly in the West Zone where congestion prices were highly volatile.

We also evaluate the RTC price forecast error and find that inconsistencies in the ramp assumptions used in RTC and RTD contribute to forecasting errors on the NYISO side of the interface. RTD assumes that external transactions start to ramp five minutes before the target interval and reach their schedule five minutes after the target interval, while RTC assumes transactions reach their schedule at the target interval—five minutes earlier than RTD.[98]

Our evaluation of RTC forecast error finds that price differences between RTC and RTD were much larger when the difference between RTD net imports and RTC-assumed net imports was larger than 200 MW in 2015. During the examined period:[99]

- RTC-assumed net imports exceeded RTD net imports by 200 MW or more in 3 percent of the quarter-hours, during which the RTD price exceeded the RTC price by an average of $16.80/MWh and the mean absolute difference was $27.40/MWh.
- Similarly, RTD net imports exceeded RTC-assumed net imports by 200 MW or more in 2 percent of the quarter-hours, during which the RTD price was less than the RTC price by an average of $6.30/MWh and the mean absolute difference was $10.40/MWh.
- When RTC-assumed net imports were within 200 MW of RTD net imports, the mean absolute difference between RTC and RTD prices was just $6.80/MWh.

Hence, RTC price forecasts are less accurate when the level of net imports changes by a large amount in response to market conditions, thereby reducing the efficiency benefits from CTS.

97 Although not shown in this report, our analyses observed similar patterns at the other three smaller interfaces between PJM and New York (i.e., Neptune, Linden VFT, and HTP).

98 Figure A-72 in Section IV.D in the Appendix illustrates the ramp profiles that are assumed by RTC and RTD for external transaction.

99 See Section IV.D in the Appendix for our evaluation in more detail.

Although CTS-enabled intra-hour scheduling has been a significant market innovation, additional benefits may be realized if enhancements are made to the process. First, reducing or eliminating the fees charged to transactions between PJM and the NYISO would encourage more efficient utilization of the interfaces between the two regions. Second, improving the accuracy of the forecast assumptions by NYISO and PJM would lead to more efficient interchange scheduling.[100] We will continue to monitor the performance of CTS between the NYISO and neighboring markets.

[100] See Recommendation #9 to eliminate transaction fees and Recommendation #12 to bring consistency between the ramp assumptions used in RTC versus RTD.

VIII. Capacity Market Results and Design

The capacity market is designed to ensure that sufficient capacity is available to reliably meet New York's planning reserve margins. This market provides economic signals that supplement the signals provided by the NYISO's 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. The capacity auctions have set clearing prices since their inception for three distinct locations: New York City, Long Island, and NYCA. Beginning with the Summer 2014 Capability Period, the capacity auctions incorporated an additional capacity Locality in Southeast New York, known as the G-J Locality. By setting a distinct clearing price in each Locality, the capacity market can facilitate investment in areas where it is needed. This section summarizes the capacity market results in 2015, discusses the treatment of exports from import-constrained areas, and proposes new rules to better reflect the value of resources in different locations.

A. Capacity Market Results in 2015

The Capacity Demand Curves determine how variations in the supply of capacity or in the capacity requirements (i.e., demand for capacity) affect capacity clearing prices. Based on the Capacity Demand Curves for the 2015/16 Capability Year (i.e., the 2015 Summer Capability Period and the 2015/16 Winter Capability Period), a 100 MW change in capacity supply or demand would change the clearing price by: \$0.21/kW-month in NYCA, \$0.59/kW-month in the G-J Locality, \$1.14/kW-month in New York City, and \$0.44/kW-month in Long Island.

Table 12 displays the average spot auction capacity prices for each of the four capacity localities for the 2015/16 Capability Year. The table also shows year-over-year changes in key factors that drove the change in capacity prices from the 2014/15 Capability Year.[101]

101 See Sections VI.D and VI.E in the Appendix for more information on spot prices and key drivers on a monthly basis.

Table 12: Capacity Spot Prices and Key Drivers by Capacity Zone [102]
2015/16 Capability Year

	NYCA	NYC	LI	G-J Locality
Avg. Spot Price				
2015/16 Yr ($/kW-Month)	$2.39	$10.68	$3.68	$6.17
% Change Yr-Yr	-40%	-21%	-24%	-24%
Change in Demand				
Load Forecast (MW)	-98	147	43	49
IRM/LCR	0.0%	-1.5%	-3.5%	2.5%
ICAP Requirement (MW)	-115	-54	-148	451
Change in ICAP Supply*				
Generation (MW)	1157	168	1	1029
SCR (MW)	224	65	11	84

Capacity spot prices fell 21 to 40 percent from the 2014/15 Capability Year to the 2015/16 Capability Year because of changes in both demand and supply.

On the supply side, internal generation rose in several areas, adding over 1.1 GW, including:

- A total of 855 MW in Hudson Valley as the four Danskammer units returned to service between October 2014 and January 2015, and Bowline Unit 2 returned to full capability (after several years of partial availability) in July 2015;
- Over 100 MW in Western New York as a result of the return-to-service of the Binghamton co-gen unit in the first quarter of 2015 and additions of new wind capacity;
- 170 MW in New York City as the Astoria Unit 2 returned to service in March 2015; and
- However, these increases were partly offset by 450 MW of retirements in the West Zone, including the Dunkirk 2 unit in January 2016 and two Huntley units in March 2016.

In addition, SCR sales also increased, especially in the Summer Capability Period, during which SCR sales rose by an average of roughly 10 to 225 MW in each capacity zone. These increases in both generation and SCR supply resulted in the decreases in capacity prices across the system.

On the demand side, the ICAP requirement fell in every capacity zone except the G-J Locality. The ICAP requirements fell by:

102 In this table, the MW quantities under "Change in ICAP Supply" are based on ICAP differences between the 2014 Summer Capability Period and the 2015 Summer Capability Period.

- 115 MW (or 0.3 percent) in NYCA because of a modest decrease in the peak load forecast;
- 54 MW (or 0.5 percent) in New York City primarily because of a decrease in the LCR from 85 to 83.5 percent, partly offset by a modest increase in the peak load forecast; and
- 148 MW (or 3 percent) in Long Island primarily because of a decrease in the LCR from 107 percent to 103.5 percent, partly offset by a modest increase in the peak load forecast.

In contrast, the ICAP requirement rose 451 MW (or 3 percent) in the G-J Locality because of an increase in the LCR from 88 percent to 90.5 percent and a modest increase in peak load forecast. This partly offset the overall decrease of capacity prices in the G-J Locality.

Increased capacity in the Hudson Valley Zone was the primary factor that led to: (a) lower LCRs for New York City and Long Island; and (b) a higher LCR for the G-J Locality for the 2015/16 Capability Year. Under the current method for determining LCRs, the G-J Locality LCR tends to rise and fall with the amount of capacity resources in the region. Conversely, the Zone J and Zone K requirements rise when capacity leaves the Lower Hudson Valley and fall when capacity is added to the Lower Hudson Valley. These variations are inefficient and create significant market uncertainty. Subsection C discusses our recommendation improving the method for calculating locational capacity requirements.

B. Treatment of Export Transactions from Import-Constrained Localities

A generator in the G-J Locality sold 500+ MW of capacity into the ISO-NE Forward Capacity Auction for the 2018/19 and 2019/20 commitment periods, raising questions about how the NYISO should treat capacity export transactions from an import-constrained zone.[103] When a generator in Rest of State ("ROS") exports capacity, the generator is simply ignored for purposes of clearing the NYCA capacity demand curve. However, it would be inappropriate to simply ignore a generator in an import-constrained locality because it is exporting, since the generator still helps satisfy the need for capacity within the constrained locality. Currently, the NYISO

103 The Roseton 1 generator sold 511 MW in FCA 9 and 532 MW in FCA 10. Information pertaining to capacity obligations in the FCA 9 and 10 auctions can be found by selecting "Forward Capacity Auction 2018-2019 Obligations" and "2019-2020 Forward Capacity Auction Obligation" from the Documents section at http://www.iso-ne.com/markets-operations/markets/forward-capacity-market/?load.more=1.

does not have a comprehensive set of rules to account for such transactions, but they should be treated such that capacity prices remain efficient and the potential for the exercise of market power is limited. The rest of this subsection discusses a recommended approach for ensuring that prices are efficient and competitive when capacity is exported from an import-constrained Locality.

It is important to consider how NYISO reliability is affected by two types of capacity exports. First, when a generator in Zone F exports ICAP to ISO-NE, NYISO Operations is obliged to treat the export as firm as long as the generator is on-line. Thus, the impact is modeled as an injection in Zone F and a withdrawal at Sandy Pond (i.e., ISO-NE). Second, when a generator in an import-constrained zone such as Zone G exports ICAP to ISO-NE, the impact is modeled as an injection in Zone G and a withdrawal at Sandy Pond. This is equivalent to: (a) an injection in Zone G and a withdrawal in Zone F plus (b) an injection in Zone F and a withdrawal at Sandy Pond.

Hence, these two types of capacity exports have the same effect on the NYISO, except that the Zone G export has an additional leg from Zone G to Zone F, which helps reduce net flows across the UPNY-SENY interface (which separates Zone F from Zone G). This counterflow explains why additional resources would not need to be procured in Zone G to replace the export as long as the resource remains under the operational control of the NYISO. Therefore, all exports (regardless of the location of the resource) should have the same reliability impacts on the NYISO and, thus, should produce the same clearing prices under an efficient market design.

This equivalence can be achieved if the NYISO divides a capacity export from an import-constrained zone to a neighboring ISO into two components:

- A transaction from the import-constrained zone to the ROS region, which is paid the clearing price in the import-constrained zone minus the clearing price in NYCA. The associated MWs would count towards meeting the local capacity requirement in the import-constrained zone.
- A transaction from the ROS region to the neighboring ISO. This would not receive payment from the NYISO, and the associated capacity would not count towards meeting the requirement in NYCA.

Hence, we recommend that the NYISO develop rules to price capacity exports from import-constrained localities that would affect only the ROS capacity prices.

C. Efficient Locational Requirements Under the Current Zone Configuration

Capacity markets should be designed to facilitate investment in new and existing capacity by providing efficient price signals that reflect the value of additional capacity in each locality. Additional capacity improves reliability by an amount that depends on where it is located, so the capacity prices should be proportional to the reliability improvements from additional capacity in each location. This will direct investment to localities where it is most valuable and reduce the overall cost of achieving a certain degree of reliability.

The creation of the new G-J Locality was a positive development because it enabled the market to provide a targeted price signal for new investment in Southeast New York. However, to provide an efficient price signal, it is necessary to set locational capacity requirements that minimize the cost of satisfying the resource adequacy criteria. This section discusses market enhancements that would lead to more efficient price signals and lower capacity costs. Part 1 identifies concerns with the current rules for setting capacity requirements in each area. Part 2 discusses two approaches for implementing a location-based marginal cost pricing mechanism in the capacity market.

1. Capacity Prices and Requirements Under the Current Rules

The one-day-in-ten-year resource adequacy standard can be met with various combinations of capacity in different areas of New York. The current annual process for determining the IRM and LCRs is known as the "Unified Methodology."[104] The Unified Methodology was instituted to define the minimum LCRs for the localities in a manner that provides some balance in the distribution of capacity between upstate and downstate regions. However, the Unified Methodology does not consider economic or efficiency criteria, so the LCRs are not based on where capacity would provide the greatest reliability benefit for the lowest cost. The demand

[104] See Locational Minimum Installed Capacity Requirements Study Covering the New York Balancing Authority Area for the 2016 – 2017 Capability Year.

curve reset process sets the capacity demand curve for each locality relative to the IRM/LCR without considering whether this results in a consistent relationship between the clearing prices of capacity and the marginal reliability benefits from additional capacity in each Locality. Setting IRM/LCRs such that the capacity demand curves reflect the marginal reliability value of additional capacity in each locality would provide incentives for more efficient investment, which would lower overall capacity costs.

The following table illustrates the inefficiency that results from the IRM/LCRs for the 2015/16 Capability Year by comparing the marginal reliability value of capacity in each region.[105] It shows that reliability is valued much more highly in some areas than in other areas. The table is based on the system at the long-term equilibrium that is modeled in the demand curve reset process, which assumes each locality has a modest excess (known as its "Excess Level") so that the system is more reliable than the 0.1 LOLE minimum criteria. An Excess Level is assumed so that the demand curve in each area is set sufficiently high to ensure the system never exceeds the 0.1 LOLE criteria. This modest excess results in an LOLE of 0.064.[106]

The table illustrates two scenarios: (a) the base scenario illustrating the equilibrium in the demand curve reset where each area contains an amount of capacity equal to the Excess Level, and (b) an alternative scenario where small amounts of capacity are shifted in order to reduce costs without increasing the LOLE. For the base scenario, the table shows the following for each area:

105 Table 13 shows data for the 2015/16 Capability Year because comparable information is not available for the 2016/17 Capability Year.

106 The demand curve reset process is required by tariff to assume that the average level of excess in each capacity region is equal to the size of the demand curve unit in that region. The 2014/17 demand curve reset assumed proxy units of approximately 210 MW in each area. To model the system at Excess Level, the system was initially set such that each locality was at the applicable LCR/IRM. To bring the system to Excess Level, Zone J supply should be increased by 210 MW, Zone K should be increased by 210 MW, supply in zones G to I should not be modified because the addition to Zone J is sufficient for the G-J Locality to reach its Excess Level, and supply in Zones A, C, and D should be reduced by 210 MW because the amounts added to Zones J and K would be more than sufficient for NYCA to reach the Excess Level. For the MARS results discussed in this section, the basecase was set close to the Excess Level in each area, although the amounts were slightly different. The amount of capacity in Zone K was actually 25 MW lower than the Excess Level and the amount of capacity in Zones A, C, and D was 125 MW higher than the Excess Level. These differences should not affect the overall conclusions from the analysis.

- *Net CONE of Demand Curve Unit* – Based on the four demand curves for the 2015/16 Capability Year.

- *NYCA LOLE at Excess Level in Demand Curve Reset* – This was found by setting the capacity margin in each area to the Excess Level from the last demand curve reset. This is a single value for all of NYCA. This value is lower than 0.1 since it assumes more capacity than necessary to satisfy the requirement in each locality.

- *Change in LOLE from 100 MW Addition* – The estimated reliability benefit from placing 100 MW of additional capacity in the area for the Base scenario. The reliability benefit is measured by the change in LOLE (i.e., annual probability of load shedding) from 100 MW of additional capacity. For example, the table indicates that adding 100 MW in Zones G-I would lower the annual LOLE by 0.006 from 0.064 to 0.058 in this scenario.[107]

- *Annual Cost of 0.001 LOLE Improvement* – This is calculated based on the ratio of the *Net CONE of Demand Curve Unit* to the *Change in LOLE from 100 MW Addition*. This is the annual levelized investment cost necessary for a 0.001 improvement in the LOLE from placing capacity in the area when the excess capacity margin is equal to the Excess Level in all Localities.[108, 109]

The table illustrates how capacity investment costs could be reduced by purchasing more capacity in areas where it is cost-effective (Zone K) and less capacity in areas where capacity is expensive (Zones A-F and Zone J). The alternative scenario shows an example of how capacity costs would vary with the following quantities:

- *Adjustment to Installed Capacity* – This shows an example set of additions and subtractions in each area for illustrative purposes.

- *Estimated Change in LOLE* – This is calculated by multiplying the *Change in LOLE from 100 MW Addition* and the *Adjustment to Installed Capacity*. This shows the LOLE changes that would result from the additions and subtractions by multiplying each by the Change in LOLE from a 100 MW Addition. These add up to 0.00 for the NYCA LOLE.

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107 These values were obtained by starting with the system at Excess Level with an LOLE of 0.064 and calculating the change in LOLE from a 200 MW addition in each area. For each area, the *Change in LOLE from 100 MW Addition* was approximated to be equal to 50 percent of the change in LOLE from a 200 MW addition.

108 For example, for Zones A-F: $83/kW-year × 1000kW/MW ÷ (0.003LOLEchange/100MW) × 0.001LOLEchange = $3.0 million.

109 Note, this value expresses the marginal rate at which LOLE changes from adding capacity when at the Excess Level. However, the actual cost of improving the LOLE by 0.001 might be somewhat lower since the impact of additional capacity tends to fall as more capacity is added at a particular location.

- *Change in Cost of Capacity* – Shows the resulting annual change in capacity investment cost, which is an efficiency gain rather than a wealth transfer between market parties.

Table 13: Cost of Improving Reliability from Additional Capacity
By Locality, 2015/16 Capability Year

Base Scenario - Equilibrium in Demand Curve Reset		**Capacity Area**				
		A-F	**G-I**	**J**	**K**	**NYCA**
Net CONE of Demand Curve Unit ($/kW-yr)	(1)	$83	$101	$145	$59	
NYCA LOLE at Excess Level in Demand Curve		0.064				
Change in LOLE from 100 MW Addition	(2)	-0.003	-0.006	-0.006	-0.006	
Annual Cost of 0.001 LOLE Improvement	(1)/(2)	$3.0M	$1.8M	$2.5M	$1.0M	
Alternate Scenario - Reduced Capacity Cost						
Adjustments to Installed Capacity (MW)	(3)	-120	0	-50	100	-70
Estimated Change in LOLE	(2)x(3)	0.003	0.000	0.003	-0.006	0.000
Change in Cost of Capacity	(1)x(2)	-$10.0M	0.0	-$7.3M	+$5.9M	-$11.3M

The table shows large disparities between different areas in the annual levelized cost of improving reliability when the system is at the equilibrium level of excess (see *Annual Cost of 0.001 LOLE Improvement*). To improve the overall NYCA annual LOLE from 0.064 to 0.061 when the system is at equilibrium, the annual levelized cost of new investment would be $9 million in Zones A-F and $7.5 million in Zone J (New York City), while comparable benefits could be achieved at a cost of just $5.4 million in the Zones G-I (Hudson Valley) and just $3 million in Long Island.[110]

The large disparities between areas in the costs of additional reliability (i.e., *Annual Cost of 0.001 LOLE Improvement*) illustrate that the current IRM and LCRs are not optimal when considered in light of the capacity demand curves. In this example, at the points where additional capacity in Zone J and Zone K provide the same reliability benefit, the price in Zone J is much higher than in Zone K. This example suggests:

- The statewide IRM and the LCR for Zone J (New York City) likely exceed the levels that would be necessary to minimize the overall cost of capacity investment; and
- Recognizing the benefits of exports from Zone K (Long Island) to the G-J Locality would likely be necessary to minimize the overall cost of capacity investment.

110 Note, these values were calculated by multiplying the values in the row *Annual Cost of 0.001 LOLE Improvement* times three for a 0.003 reduction in NYCA LOLE.

The alternate scenario illustrates the potential cost savings by removing 120 MW of capacity from Zones A-F, removing 50 MW of capacity from Zone J, and adding 100 MW of capacity to Zone K for export to the G-J Locality. By shifting capacity from high-cost areas to low-cost areas, $11.3 million is saved annually in this example with no change in LOLE. This example is provided for illustration purposes, but it is likely that larger amounts of capacity could be shifted in this manner to reduce annual capacity investment costs by well in excess of $11.3 million.

If these cost-benefit considerations were taken into account in determining the IRM/LCRs for each Locality and in devising rules for the treatment of exports from export-constrained capacity zones (e.g., Zone K), it would reduce the overall costs of satisfying reliability criteria over the planning horizon. Hence, we recommend the NYISO investigate implementing location-based marginal cost pricing of capacity using one of two approaches that are described in Part 2 of this subsection.[111]

2. Location-Based Marginal Cost Pricing for Capacity

One approach would adjust the LCRs and IRM considering the capacity demand curves in each area with the objective of minimizing overall cost of satisfying the resource adequacy criteria, and it would recognize the reliability benefits to the G-J Locality from allowing capacity exports from Zone K. A second approach would determine spot capacity prices as a function of the LOLE results for the as-found system in each auction. Both approaches are described briefly below.

Approach 1

Table 13 illustrates how capacity could be shifted to reduce cost while maintaining a target LOLE. By iterating between the LOLE model ("MARS") and the demand curve model, it is possible to add and subtract capacity from different locations until reaching an equilibrium point where the *Annual Cost of a 0.001 LOLE Improvement* (see fourth row of Table 13) is the same in all four areas, indicating no further capacity cost reduction is possible. Call this the optimal capacity allocation scenario. The optimal capacity allocation scenario should also satisfy

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111 See Recommendation #1 in Section XI.

interzonal transmission security criteria, so transmission security constraints should be satisfied by this allocation. The NYISO is currently working with GE to develop software to shift capacity in the iterative fashion described above, which will be used to identify the optimal capacity allocation.[112]

The LCRs could be determined taking this optimal capacity allocation scenario and proportionately increasing load until the system reaches 0.1 LOLE. However, this would result in a particularly high "requirement" for Zone K just because the net cost of new entry is relatively low there. Thus, it may be more appropriate to limit the LCR of Zone K such that the Zone K LOLE can be no lower than some minimum value (e.g., 0.01 or 0.02) when the NYCA LOLE is 0.1. This would prevent the LCR of Zone K from rising simply because it exports capacity to the G-J Locality. However, limiting the Zone K LCR in this manner would necessitate raising the G-J Locality LCR in order to satisfy the criteria that the LCRs must put the system at 0.1, but it would be important to recognize that exports from Zone K could be credited towards satisfying the G-J Locality LCR.[113]

Approach 2

An alternative approach to determining efficient capacity prices at each location would involve calculating the incremental reliability benefit (as measured by the MARS model) of adding capacity to the as-found system in each spot capacity auction. This would require developing a single capacity demand curve or value for the system quantifying the cost of improving LOLE (expressed as $s per unit change in LOLE). The capacity price at each location would be equal to the product of: (a) the demand value in $s per unit change in LOLE and (b) the marginal effect

[112] For a description of this effort, see *Alternative Methods for Determining LCRs Update*, Presented by Bob Logan at the March 24, 2016 Installed Capacity Working Group meeting.

[113] This would entail setting: (a) an export limit when additional exports would no longer be fungible with capacity from other zones in Southeast New York, (b) one or more benefit ratios to discount additional exports when the export limit is exceeded and (c) clearing Zone K exports on the G-J Locality demand curve. This concept is discussed further in Section VII.C.3 of *2013 State of The Market Report for the New York ISO Markets* and on slides 15-22 in *2013 State of the Market Report Recommendation to Enhance Locational Pricing in the Capacity Market*, Presented by Market Monitoring Unit to Installed Capacity Working Group, August 20, 2014.

on LOLE from additional MW in the zone for the as-cleared system.[114] This approach would require fewer approximations and simplifying assumptions and, thus, would be less resource-intensive prior to the spot capacity auction.

D. Financial Capacity Transfer Rights for Transmission Upgrades

The current market rules do not provide capacity payments to internal transmission facilities. However, investment in transmission can significantly reduce the cost of maintaining adequate installed reserve margins. Transmission also enhances the deliverability of existing resources and reduces the effects of contingencies. Therefore, when developers make transmission upgrades, they should receive financial capacity transfer rights ("FCTRs") so that transmission developers have efficient incentives to build transmission that has a value comparable to installed capacity for meeting resource adequacy criteria.

Compensation should be based on the amount by which installed capacity requirements are reduced by the facility. Thus, efficient compensation equals the product of the following three inputs:[115]

- The effect on the TTC of one or more interfaces from adding the new facility to the As-found system,
- The marginal effect of a change in TTC on the LOLE of the As-found system, and
- The value of reliability in dollars per unit of LOLE. This demand value is described under Approach 2 in the previous subsection.

To illustrate this concept, suppose a project were to increase TTC for the as-found system on interface A by 200 MW and interface B by 50 MW. Further suppose that the marginal LOLE effect of increasing TTC of interface A by 100 MW is -0.002, and the marginal LOLE effect of increasing TTC of interface B by 100 MW is -0.001. Suppose the value of reliability determined in the demand curve reset was $1.2 million per -0.001 per year. In this case, the project would

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114 See *2013 State of the Market Report Recommendation to Enhance Locational Pricing in the Capacity Market*, Presented by Market Monitoring Unit to Installed Capacity Working Group, August 20, 2014, Slides 26 & 27.

115 *Ibid.*, Slides 23-25.

receive a FCTR in the first year with a value of \$6.0 million = {(200MW x -0.002 per 100MW) + (100MW x -0.001 per 100MW)} x \$1.2 million per -0.001. To ensure revenue adequacy, the effect of the new facility on interface TTC should be recalculated as often as the locational capacity requirements, which currently happens on an annual basis.

A developer would not have an incentive to build a new generator in New York without being able to earn revenue from the sale of capacity, so developers will also not have efficient incentives to build new transmission without capacity revenues. To address the lack of incentives for developers to build transmission when it would help satisfy resource adequacy criteria, we recommend granting financial capacity transfer rights between zones when investors upgrade the transmission system and help satisfy planning reliability needs.[116]

Similarly, it would also be appropriate to compensate (or charge) new generation projects for their impact on deliverability constraints through capacity transfer obligations (i.e., negative-value FCTRs). In some cases, it would be more efficient (i.e., cost-effective) for a project developer to accept negative FCTRs than make transmission upgrades (if the value of upgrading the transmission system was lower than the cost of the upgrades). Such compensation would provide incentives to interconnect at points that increase the deliverability of other generators. Such charges would be more efficient than assigning SDU costs, since these can be a barrier to efficient investment if the SDU costs are higher than the value of the upgrade.

E. Incorporating Capacity Market Benefits and Other Reforms to CARIS

The NYISO has an economic transmission planning process known as the Congestion Assessment and Resource Integration Study ("CARIS"). The process was intended to provide cost-of-service compensation through the NYISO tariff when a project is expected to be economic based on a tariff-defined benefit-cost analysis. However, since being established in 2008, no transmission has ever been built and received cost recovery through CARIS. Recently, the NYISO has commenced two transmission needs assessments under the new Public Policy Transmission Need ("PPTN") assessment process in response to NYPSC orders defining a

116 See Recommendation #2 in Section XI.

Western New York PPTN and an AC Transmission PPTN.[117] However, the competitive wholesale markets price congestion and should provide incentive to make investments to relieve congestion when it is cost-effective. The use of the PPTN assessment process to reduce congestion in New York highlights deficiencies in the CARIS process, which we discuss below.

We identify several deficiencies in the CARIS process, including: (i) assumptions that systematically undervalue projects, (ii) deficiencies in forecasting models, and (iii) elements that may make an economic project ineligible for funding. We recommend the following changes to address these deficiencies. First, we recommend changing the following assumptions that systematically undervalue projects:

- *Capacity Market Benefits* – The benefit-cost ratio that is used to identify economic projects ignores capacity market benefits. This omission leads CARIS to undervalue transmission projects that make significant contributions to satisfying the NYISO's planning requirements. These benefits should be quantified using the metric discussed in Subsection D,

- *Retirements and New Entry Assumptions* – CARIS starts with a base case from the Comprehensive Reliability Plan ("CRP"), but the CRP is developed for a different purpose that is not suited to evaluating the economics of new investment. CARIS should recognize that if a new transmission project goes forward, it will likely affect the retirement and/or entry decisions of other resources. [118]

Second, quality forecasting is essential before making large capital investments, so we recommend the following enhancements to the models that are used to evaluate projects:

- *Gas System Modeling* – Unprecedented levels of congestion have arisen on the natural gas pipeline system since 2012, and this congestion has been the principal driver of congestion in the wholesale electricity market. Thus, efficient electricity transmission investments cannot be identified without improvements to the forecasts of future congestion on the gas pipeline system.

- *Electric System Modeling* – The NYISO uses GE MAPS to model the electrical system, which is a sound platform. However, enhancements are need to better represent

117 Each order is attached to the corresponding project solicitation letter that is posted on the NYISO website at http://www.nyiso.com/public/markets_operations/services/planning/planning_studies/index.jsp.

118 In addition, this would require CARIS to measure the benefit of a project based on the market value of energy and capacity in the scenario with the project rather by comparing the base case scenario to the scenario with the project.

contingencies, other real-time events, and transmission facility outages that contribute to congestion.

Third, there are elements of the CARIS process that could prevent an economic project from moving forward. In particular:

- *80 Percent Voting Requirement* – Before an economic project is funded, the project must garner approval from 80 percent of the beneficiaries. While it may be beneficial to hold a vote as a check against the possibility that a project would receive a good benefit-cost evaluation but evidently be uneconomic, the 80 percent requirement is too high and may enable a small group of participants to block an economic investment.
- *$25 Million Threshold* – To be evaluated in CARIS, a project must cost in excess of $25 million, but this requirement may screen out economic projects or prevent a project from being sized optimally.

These recommendations address many of the issues that we believe are impediments to the CARIS process supporting investment in economic transmission projects. The NYISO should review the CARIS process and the methods used to measure benefits to identify any additional changes that would be valuable. Once identified, we recommend the NYISO make the changes necessary to ensure that the CARIS process will identify and fund economically efficient transmission investments (and not fund uneconomic projects).[119]

F. Pre-defining Capacity Market Interfaces and Zones

1. Deficiencies in the Current Process for New Zone Creation

The new capacity zone for the G-J Locality in Southeast New York ("SENY") has greatly enhanced the efficiency of the capacity market signals, but it was overdue. This delay has had several adverse consequences that illustrate the importance of promptly creating new capacity zones when they are needed.

- The total amount of unforced internal capacity sold in Zones G, H, and I fell by 1 GW (or 21 percent) from the summer of 2006 to the summer of 2013, even as the need for resources to address the UPNY-SENY interface became more apparent in the NYISO's Comprehensive Reliability Planning Process. Some of this capacity may have been

119 See Recommendation #7 in Section XI.

economic to remain in service or would have been maintained more reliably if the G-J Locality had been implemented sooner.

- Because the binding UPNY-SENY interface limited supply resources from reaching Zones G-K, capacity retirement in Zones G and H has resulted in higher Local Capacity Requirements ("LCRs") for Zones J and K. From the 2010/11 Capability Period to the 2013/14 Capability Period, the LCR for Zone J rose from 80 percent to 86 percent. A one percent increase in the LCR equated to a $1.30/kW-month increase in capacity prices given the 2013/14 capacity demand curve for New York City. Consequently, the delay in modeling a SENY capacity zone resulted in much higher capacity prices in Zone J.
- Although the capacity market did not recognize the higher reliability benefits of capacity in Zones G, H, and I relative to capacity in Zones A to F until 2014, the Highway Deliverability Test has recognized this for several years. Consequently, some capacity suppliers outside SENY were prevented from selling at the prevailing price levels, which increased the capacity prices in Zones A to F.

In summary, the creation of the G-J Locality before 2014 would have facilitated more efficient investment in both new and existing resources.

The NYISO's current NCZ Study process will not lead to the timely creation of other new capacity zones in the future for three reasons. First, the NCZ Study methodology is based on the Highway Deliverability Test criterion and does not consider whether additional capacity is needed to satisfy resource adequacy requirements in a particular area. Hence, if the NYISO's RNA identifies areas where additional capacity is needed to meet resource adequacy criteria, there is no guarantee that the NCZ Study criteria will trigger the creation of a new capacity Locality.

Second, the NCZ criteria are only triggered if existing CRIS rights result in a binding highway deliverability constraint. Hence, if new resources are entering or imports are being offered that are not deemed deliverable because of a highway constraint, the NCZ Study criteria may not be triggered. This is a case where a new zone is needed to allow the price to fall in the zone with the excess capacity, which will help facilitate more efficient capacity trading with external areas and investment decisions.

Third, the NCZ study process is lengthy and uncertain, occurring just once every three years, and leading to the creation of a capacity zone in no less than 13 months from the filing date. This process would be particularly inadequate if the unexpected retirement of large generation resources led to significant unmet reliability needs that were not properly reflected in the capacity market for several years. Consequently, it would be difficult to address the reliability need without regulated investment.

Because of the issues with the current process for defining additional capacity zones, we recommend the NYISO move to a framework where potential deliverability and resource adequacy constraints are used to pre-define a set of capacity constraints and/or zones.[120] This framework is discussed in the next part of this sub-section.

2. Pre-Defining Capacity Market Interfaces and Zones

In order to create new capacity zones promptly, we recommend pre-defining potential deliverability constraints or zones that would be modeled in the NYISO capacity markets. Once defined, the NYISO would cease allocating transmission upgrade charges to resources that affect these constraints. Instead, the capacity market would efficiently limit sales from these resources by binding in the capacity auction. Upgrade of these deliverability constraints could be governed economically by the resulting locational price differences in the capacity, energy, and ancillary services markets. Finally, unexpected retirements that have significant reliability implications in an area would cause locational capacity prices to move immediately and provide efficient price signals to the market. In some cases, retirements may be avoided altogether by the improved price signals in an area.

The NYISO has a set of inter-zonal transmission interfaces that are used in the planning process to identify potential future Highway Deliverability issues and deficiencies in the RNA. Ultimately, the capacity market is the primary market mechanism for satisfying the resource adequacy needs (i.e., the 1 day in 10 year standard). Hence, it may be appropriate for the capacity market to include the same eleven inter-zonal interfaces that are modeled in the RNA.[121]

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120 See Recommendation #3 in Section XI.

121 The 2014 RNA will model the limitations of the following 11 interfaces: Dysinger East (ZoneA->ZoneB), West Central (ZoneB->ZoneC), Volney East (ZoneC->ZoneE), Moses South (ZoneD->ZoneE), Central East + Fraser-Gilboa (ZoneE->ZoneF), UPNY-SENY (ZoneE+F->ZoneG), UPNY-CE (ZoneG->ZoneH), Millwood South (ZoneH->ZoneI), Dunwoodie South (ZoneI->ZoneJ), Y49/Y50 (ZoneI->ZoneK), CE-LIPA (ZoneJ->ZoneK).

Although four of these interfaces are already reflected in the capacity market as of the Summer 2014 Capability Period, the interfaces among Zones A through F and among Zones G through I are not currently reflected. These could suddenly bind in future RNAs if certain generation retirements occur, leaving the market without a mechanism for signaling the value of capacity for years.

IX. Market Operations

The objective of the wholesale market is to coordinate resources efficiently to satisfy demand while maintaining reliability. The day-ahead market should commit the lowest-cost resources to meet expected conditions on the following day, and the real-time market should dispatch the available resources efficiently. Clearing prices should be consistent with the costs of dispatching resources to satisfy demand while maintaining reliability. Under shortage conditions, the real-time market should provide incentives for resources to help the NYISO maintain reliability and set clearing prices that reflect the shortage of resources.

The operation of the real-time market plays a critical role in the efficiency of market outcomes because changes in operations can have large effects on wholesale market outcomes and costs. Efficient real-time price signals are beneficial because they encourage competitive conduct by suppliers, participation by demand response, and investment in new resources and transmission where they are most valuable.

This section evaluates the following six aspects of market operations, focusing on the efficiency of scheduling and whether real-time prices provide appropriate incentives, particularly during tight operating conditions:

- Market Performance under Shortage Conditions
- Market Performance under Tight Gas Supply Conditions
- Efficiency of Gas Turbine Commitments
- Operations of Non-Optimized PAR-Controlled Lines
- Drivers of Transient Real-Time Price Volatility
- Supplemental Commitment & Out of Merit Dispatch for Reliability

The final subsection shows the uplift from Bid Production Cost Guarantee (“BPCG”) payments, which are driven primarily by supplemental commitment and out-of-merit dispatch.

A. Market Performance under Shortage Conditions

Prices that occur under shortage conditions are an important contributor to efficient long-term price signals. Shortages occur when resources are insufficient to meet the energy and operating reserves needs of the system while satisfying transmission constraints. Efficient prices also reward suppliers and demand response resources for responding during real-time shortages. Rewarding for good performance during shortage conditions has a beneficial effect on the resource mix in the long run because it shifts a portion of net revenues from the capacity market to the energy market, which tends to lower overall costs to consumers.

In this subsection, we evaluate the operation of the market and resulting prices in the real-time market when the system is under the following two types of shortage conditions:

- Operating reserve and regulation shortages – These occur when the real-time model is unable to schedule the required amount of an ancillary service at a marginal cost less than the "demand curve" for the requirement. Due to the co-optimization of energy and ancillary services, the value of the ancillary service is reflected in LBMPs.
- Transmission shortages – These occur when modeled power flows exceed the limit of a transmission constraint. Clearing prices for energy in the constrained area are set according to several methods during transmission shortages.[122]

1. Operating Reserve and Regulation Shortages

In our evaluation, we found that the frequency of physical shortage conditions fell from 2014 to 2015 for all ancillary services products. The frequency of shortage conditions fell roughly 44 to 87 percent in the first quarter of 2015 from a year ago primarily because of lower and less volatile natural gas prices, less frequent peak load conditions, and higher net imports from Ontario and Quebec. Overall, shortages of regulation and eastern 10-minute reserves had the largest effects on real-time energy prices, collectively increasing annual average LBMPs in Eastern New York by 3 to 4 percent in 2015.

[122] Section V.H in the Appendix describes these methods in greater detail.

[123] See *NYSRC Reliability Rules & Compliance Manual*, Version 35, See Section E.1 Operating Reserves: Establishing the Minimum Level of Operating Reserve, Requirement R6.

Several changes were made to shortage pricing of ancillary services products on November 4, 2015 as part of the Comprehensive Shortage Pricing project, including:

- NYCA 30-minute reserve requirement was increased from 1,965 MW to 2,620 MW, reflecting the requirement to restore 10-minute reserves to 1,310 MW within 30 minutes following the system's largest supply contingency of 1,310 MW. [123]
- Demand curves for some ancillary services products were restructured to better align with the cost of operator actions to maintain reserves. [124]
- A 30-minute reserve requirement was created for Southeast New York, reflecting the requirement to restore flows below the normal rating within 30 minutes following a contingency. [125]

These changes better enable the market to reflect different kinds of shortages at different locations and more accurately reflect the severity of the shortage conditions. We will continue to monitor the effects of these changes in 2016, particularly after the implementation of the Comprehensive Scarcity Pricing project, which is expected to occur in the second quarter of 2016. This project will better enable the market to satisfy reliability needs during tight conditions by raising the demand curve levels that are below $500/MW to $500/MW for the NYCA 30-minute reserve requirement during any EDRP/SCR activation and from $25/MW to $500/MW for the SENY 30-minute reserves requirement. This is a significant improvement because the higher demand curve levels will be sufficiently high that the NYISO will rarely go short of these reserves when additional reserves could be scheduled. These higher demand curves should enhance reliability and reduce the need for out-of-market actions to maintain reliability. On the other hand, this Comprehensive Scarcity Pricing project will also reduce the incidence of excessively high prices during deployments of emergency demand response. [126]

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[123] See *NYSRC Reliability Rules & Compliance Manual*, Version 35, See Section E.1 Operating Reserves: Establishing the Minimum Level of Operating Reserve, Requirement R6.

[124] See Appendix Section V.F for a list of changes.

[125] See *NYSRC Reliability Rules & Compliance Manual*, Version 35, See Section C.2 Transmission Operation: Post-Contingency Operation, Requirement R1.

[126] See Section X for additional details.

Notwithstanding these market enhancements that will better recognize and price reserve shortages, we have identified circumstances when the NYISO tends to schedule more operating reserves than necessary. This is because the NYISO relies only on internal resources to satisfy operating reserve requirements, which, in some cases, ignores the capability and the economic value of imports for maintaining security in the reserve region. For example, 10-minute operating reserves are held in Eastern NY to ensure that if a large contingency in Eastern New York results in a sudden overload of the Central-East Interface, sufficient reserves can be deployed to reduce flows in order to maintain security. This need could also be met partly by reducing flows across the Central-East interface before the contingency occurs. In some cases, it is more costly to schedule reserves on resources in Eastern New York than it would be to simply reduce flows across the Central-East Interface (thereby "holding reserves on the interface"). [127]

Accordingly, we recommend the NYISO modify the market models to dynamically determine the optimal amount of reserves that should be held in Eastern New York considering that the need can also be met by reducing pre-contingent flows over the Central-East Interface. Likewise, we recommend the NYISO dynamically determine the optimal amount of 30-minute reserves that should be held in SENY considering that the need can also be met by reducing pre-contingent flows over the UPNY-SENY interface. [128]

2. Transmission Shortages

Table 14 summarizes transmission shortage events for select transmission facilities during 2015, by showing the number of shortage intervals and associated average constraint shadow prices under three types of shortages. [129]

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127 The category "Unused Central East" in Figure 13 illustrates that the amount of reserves held on the interface can be substantial when available resources are limited in eastern New York.

128 See Recommendation #16.

129 See Section V.H in the Appendix for more facility groups and a detailed description of this analysis.

Table 14: Real-Time Prices During Transmission Shortages
2015

Transmission Facilities	Shortage Type	Transmission Shortage MW: < 5 MW # Intervals	< 5 MW Avg Shadow Price ($/MWh)	5 - 20 MW # Intervals	5 - 20 MW Avg Shadow Price ($/MWh)	> 20 MW # Intervals	> 20 MW Avg Shadow Price ($/MWh)	Total # Intervals	Total Avg Shadow Price ($/MWh)
West Zone 230 kV Lines	Relaxation	95	$548	1232	$438	950	$547	2277	$488
	Offline GT								
	Demand Curve	30	$4,000	32	$4,000	98	$4,000	160	$4,000
	Total	**125**	**$1,376**	**1264**	**$528**	**1048**	**$870**	**2437**	**$719**
ConEd - LIPA 345 kV Lines	Relaxation			1	$323	10	$599	11	$574
	Offline GT	365	$233	748	$232	535	$303	1648	$255
	Demand Curve			3	$4,000			3	$4,000
	Total	**365**	**$233**	**752**	**$247**	**545**	**$309**	**1662**	**$264**
E. Garden City - Valley Stream	Relaxation	48	$993	326	$767	184	$824	558	$805
	Offline GT	449	$463	473	$379	39	$378	961	$418
	Demand Curve	59	$4,000	49	$4,000	9	$4,000	117	$4,000
	Total	**556**	**$884**	**848**	**$738**	**232**	**$872**	**1636**	**$807**
Lines into Greenwood Load Pocket	Relaxation	106	$198	862	$74	246	$62	1214	$82
	Offline GT								
	Demand Curve	108	$4,000	10	$4,000			118	$4,000
	Total	**214**	**$2,117**	**872**	**$119**	**246**	**$62**	**1332**	**$429**
All NYCA Facilities	Relaxation	315	$423	3141	$288	1756	$427	5212	$343
	Offline GT	1205	$311	1810	$254	929	$308	3944	$284
	Demand Curve	263	$4,000	121	$4,000	121	$4,000	505	$4,000
	Grand Total	**1783**	**$875**	**5072**	**$364**	**2806**	**$542**	**9661**	**$510**

Transmission shortages occurred in roughly 9 percent of all intervals in 2015. The Transmission Shortage Cost was used to set constraint shadow price at $4,000/MWh in only 5 percent of these shortage intervals. Of the remaining 95 percent of shortage intervals:

- Constraint relaxation occurred in 57 percent of intervals;
- Offline gas turbines were treated as scheduled for LBMP-calculation purposes but not started in the remaining 43 percent of intervals.

The two 345 kV lines from upstate New York to Long Island and the East Garden City-to-Valley Stream line on Long Island accounted for 34 percent of all transmission shortages in 2015. Severe congestion across these lines frequently occurred because of ramping limitations on Long Island. These ramp limitations generally occurred because of large changes in external interface schedules between Long Island and other regions, large changes in PAR-controlled line flows between Long Island and New York City, and/or when gas turbines were shutdown.[130] For more

130 These contributors to transient price spikes are evaluated in Section IX.E.

than 80 percent of transmission shortages in Long Island, offline gas turbines were counted towards resolving congestion but not started because of the transient nature of the congestion.

The 230 kV transmission lines in the West Zone along the Niagara-Packard-Sawyer-Huntley transmission paths accounted for 25 percent of all transmission shortages in 2015. Acute congestion has occurred more frequently on these lines in recent years. The constraint limit was relaxed in almost every shortage interval because of the small number of flexible resources in the West Zone that can be dispatched to manage congestion.

Transmission lines into Greenwood load pocket in New York City accounted for 14 percent of all transmission shortages in 2015. The constraint limit was relaxed in almost every shortage interval because of a lack of flexible resources (i.e. 10-minute GTs) in the Greenwood load pocket for managing congestion.

Although average constraint shadow prices were relatively high during shortages, shadow prices often did not properly reflect the severity of the shortage. For example, the shadow price averaged over $2,000/MWh when transmission shortages occurred in the Greenwood load pocket of New York City when the constraint was violated by 5 MW or less, but the shadow price averaged less than $200/MWh when the constraint was violated by more than 5 MW. Shadow prices were generally uncorrelated with the shortage amount, the duration of the constraint, or any other measure of the severity of the shortage.

The new graduated transmission demand curve that was implemented on February 11, 2016 was designed to provide price signals that are more consistent with the severity of shortages. The new Graduated Transmission Demand Curve ("GTDC") is set at $350/MWh for shortages of less than 5 MW, $2,350/MWh for shortages of 5 to 20 MW, and $4,000/MWh for shortages of more than 20 MW. However, it is unclear whether price signals have improved since the GTDC was implemented. The NYISO still uses a process whereby some transmission constraints that cannot be resolved or could only be solved at an extraordinarily high cost are "relaxed." This process, which is not described in the tariffs or manuals, still does not always result in efficient prices that reflect the severity of the constraint as intended. We recommend that the NYISO document the current process and replace it with a process where transmission constraint violations are resolved with graduated transmission demand curves that vary according to the severity and importance of the constraint.[131]

B. Market Performance Under Tight Gas Supply Conditions

When transmission bottlenecks on the natural gas pipeline system limit the availability of gas, the wholesale electricity market has the important role of helping determine which generators burn the available gas, how much electricity to import, and how to conserve the available fuel inventories of internal oil-fired generation and other non-gas resources. Uncertainty about natural gas prices and the availability of other fuels contribute to electricity price volatility. These factors make it more challenging for suppliers to offer their resources efficiently and for the NYISO to maintain reliability while minimizing out-of-market actions. This section of the report evaluates market efficiency during periods of tight natural gas supply.

1. Fuel Usage Under Tight Gas Supply Conditions

The availability of natural gas to electric generators is often limited by high demand from other gas customers on cold winter days. However, a large share of generators in Eastern New York have dual-fuel capability, allowing them to switch to an alternative fuel on these days when natural gas becomes expensive or unavailable. Figure 12 summarizes the average hourly generation by actual fuel consumed in Eastern New York on a daily basis in the first quarter of 2015.[132] It also shows the day-ahead natural gas price index for Iroquois Zone 2 and Transco Zone 6 (NY) on these days.

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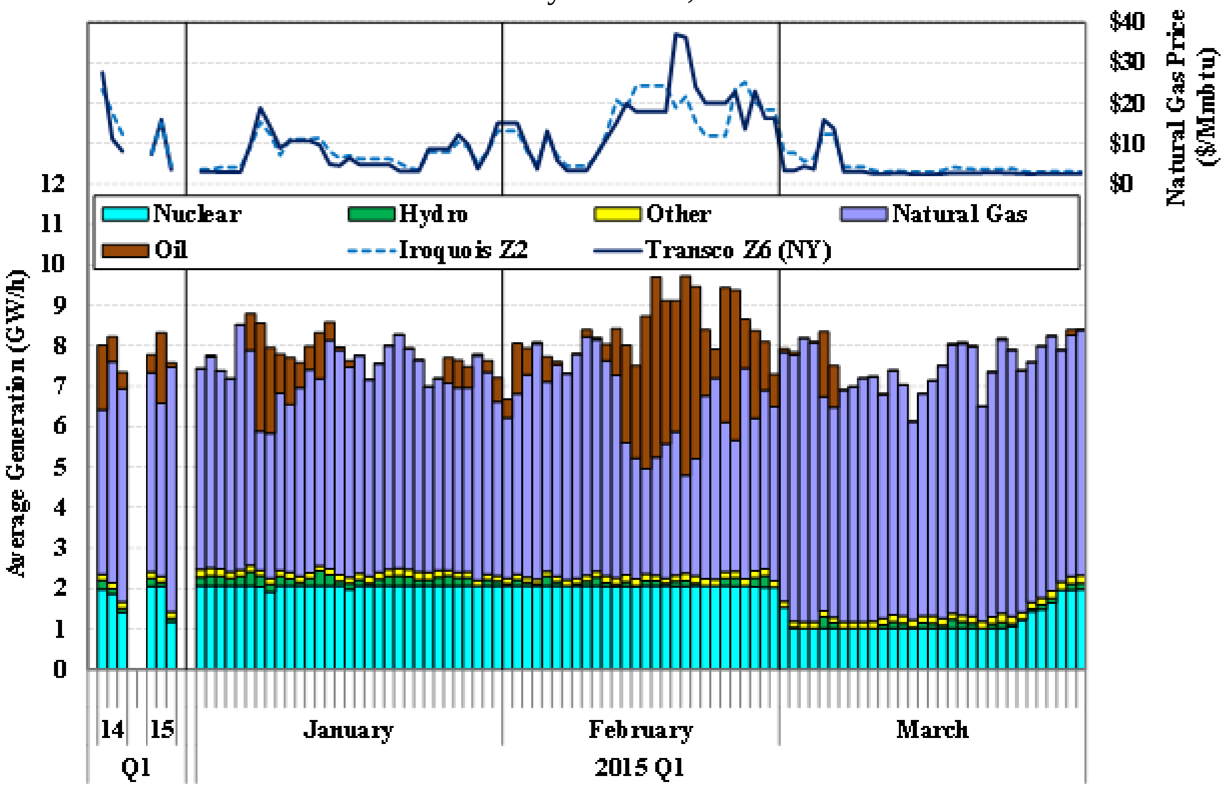
[131] See Recommendation #17.

[132] See Section I.C in the Appendix for a more detailed description. Each day in the figure represents a 24-hour gas day, which starts from 10 am each calendar day and ends at 10 am on the next calendar day.

Figure 12: Actual Fuel Use and Natural Gas Prices in Eastern New York
January to March, 2015



Oil-fired generation in Eastern New York totaled roughly 1.5 million MWh in the first quarter of 2015, down from 1.9 million MWh in the first quarter of 2014. Cold weather led natural gas prices to rise above $15 per MMbtu on 22 days in Eastern New York in the first quarter of 2015. Oil-fired generation in Eastern New York (which normally averages less than 100 MW) rose sharply on these days, averaging over 2.2 GW. In particular, gas prices exceeded $15 per MMbtu on 17 consecutive days from mid to late February because of extreme cold weather conditions. The total amount of oil-fired generation during this 17-day period accounted for 68 percent of total oil-fired generation during the entire first quarter. The large amount of oil use in a single period illustrates the difficulty in predicting (before the winter) how much oil will be needed over the entire winter season.

The NYISO market provides pricing and scheduling information that helps coordinate decisions by generators about whether to operate on natural gas, oil, or a blend. However, several factors reduced the use of oil by generators in the first quarter of 2015, including: increased forced outage risk for some units running on oil, non-maintenance of permits and/or equipment for burning oil, low oil inventories, and air permit restrictions that limit the run hours. Nonetheless, operations and market performance improved over the past three winters as many dual-fueled generators have become increasingly prepared to burn oil.

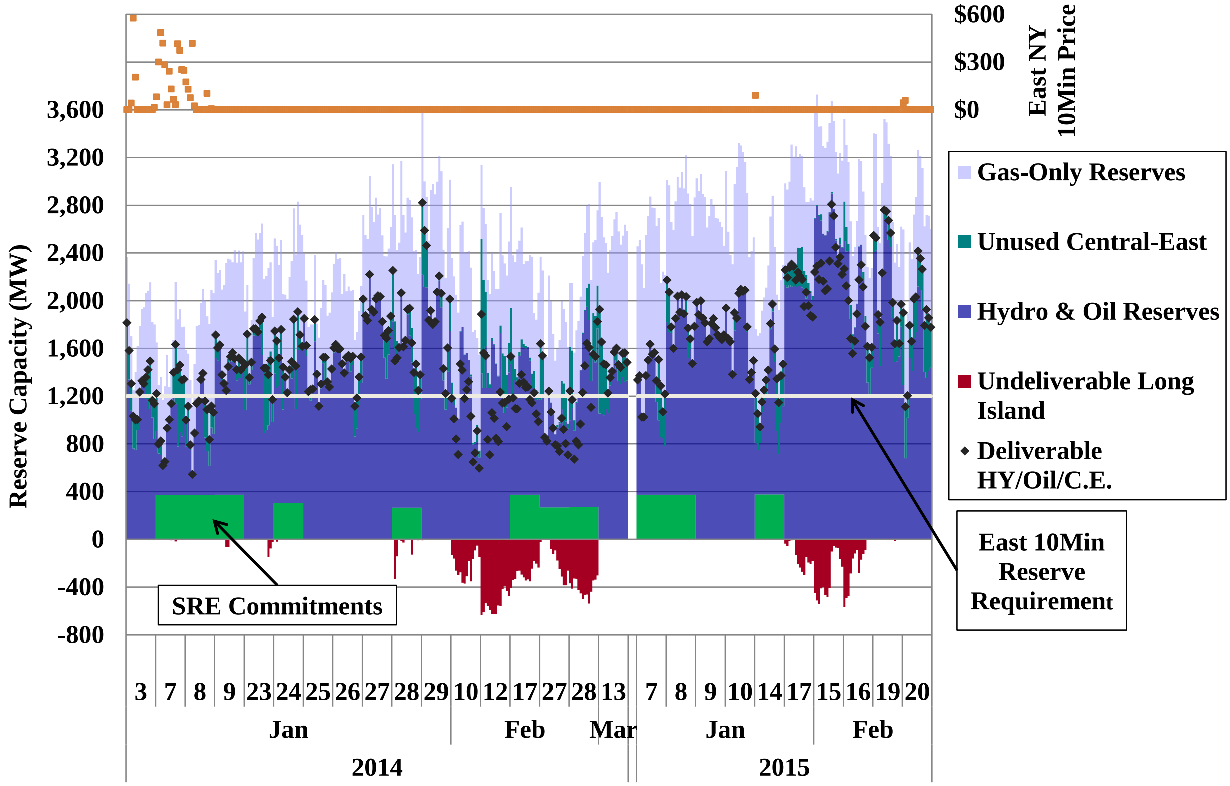
2. Availability of Reliable Eastern 10-Minute Reserves on Hourly OFO Days

Hourly Operational Flow Orders ("OFOs") are often declared on the days when gas supply is very tight. During hourly OFOs, many generators that are reliant on natural gas may be unable to start-up or ramp-up if deployed in response to a sudden large contingency. Even if generators are authorized to take additional gas on such days, pipeline operators may have difficulty maintaining sufficient pressure to allow a large amount of generation to suddenly respond to a reserve pick-up. The following analysis evaluates the extent to which the NYISO satisfied the Eastern 10-minute reserve requirement by scheduling generators that would have needed to consume gas if deployed on days when hourly OFOs were declared by one or more Local Distribution Companies ("LDCs") in New York City and Long Island. If operators perceive that some reserve capability is scheduled but not reliably available, the operators may take out-of-market actions to maintain adequate reserve levels. Such actions often result in uplift charges and depressed real-time clearing prices for energy and ancillary services. This may undermine efforts to ensure that generators have efficient incentives to perform reliably during tight winter operating conditions and at other times of tight gas system conditions.

Figure 13 shows the amount of 10-minute reserve capability and average 10-minute reserve prices in Eastern New York on select hourly-OFO days in 2014 and 2015 and examines: (a) whether the Eastern 10-minute reserve requirement was satisfied by dependable reserve capability that was not affected by gas supply constraints; and (b) if not, whether the reserve prices reasonably reflected tight gas supply conditions.[133]

[133] See Section V.G in the Appendix for more detailed description of this analysis.

Figure 13: 10-minute Reserve Capacity in Eastern New York
On Cold Days with Hourly OFOs, 2014-2015



The figure shows that there were 8 hours (on hourly-OFO days) in the first quarter of 2015 and 72 hours in the first quarter of 2014 when the NYISO relied on some gas-only capacity to satisfy the Eastern 10-minute reserve requirement. However, Eastern 10-minute reserve prices: (a) averaged just $8 per MWh in these hours during 2015; and (b) cleared at $0 per MWh in 53 of these hours and averaged just $190 per MWh in another 19 hours in 2014. In addition, roughly 300 to 400 MW of capacity was SRE-committed on eight of these days in 2014 and three of these days in 2015 for Eastern New York reserve needs, but Eastern 10-minute reserve prices cleared at $0 per MWh during most hours on these 11 days. These results suggest that, on the days when the natural gas system was constrained, reserve clearing prices did not always reflect the limited availability of operating reserves, nor did they reflect the costs of supplemental commitments to maintain reserves.

Overall, although the NYISO and market participants have been able to cope with challenging fuel supply conditions reasonably well, we have identified areas that may warrant changes in the market design and rules. First, the analysis shown in Figure 13 suggests that real-time reserve clearing prices (and LBMPs) may have been significantly understated during periods with hourly OFOs. Consequently, the energy market may not provide adequate incentives for generators to make reserve capacity available when gas is limited by maintaining oil inventories and equipment necessary to operate on oil. To address these concerns, we recommend that the NYISO implement procedures that would allow it to identify unloaded capacity that is not capable of responding reliably in the event of a reserve pick-up. This may require generators to provide necessary information in real-time and/or for pipeline operators to indicate when the pipeline has limited capability to support a large pick-up in gas-fired generation over a ten - minute period.[134]

Second, generators face significant fuel supply constraints that can be difficult or impossible to reflect efficiently in the day-ahead offer. For example, hourly OFOs may require a generator to schedule a specific quantity of gas in each hour of a 24-hour period even though this does not match its day-ahead schedule. Not only does this subject the generator to significant financial risks when it is scheduled in the day-ahead market, but it also raises costs for consumers, since the generator is likely to respond by reflecting these costs in other offer parameters or by reducing its availability. Hence, allowing generators to submit offers that are scheduled subject to an inter-temporal constraint would reduce the OFO-based risks of being available.[135]

Third, when gas prices are very high, oil-fired and dual-fueled generators can be limited by air permit restrictions and/or by low oil inventories. Likewise, gas-fired generators are sometimes limited to a daily nomination amount. It would be beneficial for the generator to be able to conserve its limited fuel for periods when it is most valuable. Currently, generators reflect these quantity limitations by raising offer prices, but this is an imprecise method that requires generators to guess what offer price levels are needed to achieve the targeted level of fuel consumption over the day. This leads to both foregone opportunities and unnecessary depletion of limited oil inventories. Hence, allowing generators to submit offers in the day-ahead market that reflect quantity limitations over the day would allow such generators to be scheduled more

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[134] Section XI, Recommendation #20 is related to this issue.

[135] Section XI, Recommendation #19 is related to this issue. The NYISO project to address this issue is discussed in *Fuel Constrained Bidding Project Timelines*, Presented by Cristy Sanada, April 5, 2016 Market Issues Working Group meeting.

efficiently when they are subject to fuel or other production limitations.[136] This capability would also be beneficial at other times of year for hydro-electric and other generators that also have significant energy limitations.

C. Efficiency of Gas Turbine Commitments

We evaluate the efficiency of gas turbine ("GT") commitment in the real-time market, which is important because excess commitment results in depressed real-time prices and higher uplift costs, while under-commitment leads to unnecessary price spikes.

We found that 43 percent of capacity committed by the real-time market model in 2015 was clearly economic over the initial commitment period and this was consistent with recent years.[137] This evaluation deemed a gas turbine clearly economic if the as-offered cost was less than the LBMP revenue earned over the initial commitment period (usually one hour). However, this criterion likely understates the share of gas turbine commitments that are efficient for two reasons. First, the efficient commitment of a gas turbine reduces LBMPs in some cases such that the LBMP revenue it receives is less than its offer. Second, in some cases, a gas turbine that is committed efficiently may still not set the LBMP due to the manner in which the real-time pricing methodology determines whether a gas turbine is eligible to set the LBMP.[138]

Table 15 evaluates the extent to which gas turbines were economic but appeared to be uneconomic because they did not set the LBMP in a portion of the initial commitment period.[139]

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136 See Footnote 135.

137 See Figure A-75 in the Appendix for details of this analysis.

138 See NYISO Market Services Tariff, Section 17.1.2.1.2 for description of real-time dispatch process.

139 See Section V.A in the Appendix for details of this analysis.

Table 15: Hybrid Pricing and Efficiency of Gas Turbine Commitment
2015

	New York City Load Pockets			Long Island
	Greenwood	Other 138 kV	345 kV	
# of Unit Starts	817	619	120	1692
% of Unit-Intervals that are:				
Uneconomic	34%	42%	39%	47%
Economic - Not Setting Price	11%	9%	10%	11%
Economic - Other	55%	49%	51%	42%
Est. Avg. Annual LBMP Impact If Economic Units Set Price ($/MWh)	**$0.66**	**$0.35**	**$0.08**	**$1.38**

We found that gas turbines that were committed in merit order in 2015 were clearly economic in roughly 53 to 66 percent of the five-minute intervals during their initial one-hour commitment period. However, the units did not set the LBMP in 16 to 21 percent of the intervals when they were economic. We estimated that allowing these economic gas turbines to set prices would have increased the real-time LBMPs by an average of $5 to $7 per MWh for each start in New York City and Long Island in 2015. Averaged over the year, this would increase LBMPs by an average of $0.35 to $1.40 per MWh in 2015 with the largest effect in Long Island.

These results suggest that the hybrid pricing logic should be evaluated to identify changes that would more effectively allow economic gas turbines to set prices in the real-time markets. Gas turbines are usually started during tight operating conditions when it is particularly important to set efficient real-time price signals that reward available generators that have flexible operating characteristics. Rewards for good performance also have a beneficial effect on the resource mix in the long run because it shifts a portion of net revenues from the capacity market to the energy market.

Currently, we are working with the NYISO to evaluate ways to: a) improve the hybrid pricing logic to better allow economic gas turbines to set the energy prices; and b) appropriately amortize the start-up costs of the gas turbines within the initial phase of commitment and reflect the cost in the price-setting logic. [140]

140 See Recommendation #14 in Section XI. See *Hybrid GT Pricing Improvements*, Presented by Ethan Avallone at March 23, 2016 Market Issues Working Group meeting,

D. Operations of Non-Optimized PAR-Controlled Lines

The majority of transmission lines that make up the bulk power system are not controllable, and thus, must be secured by redispatching generation in order to maintain flows within appropriate levels. However, there are still a significant number of controllable transmission lines that source and/or sink in the New York Control Area ("NYCA"). This includes High Voltage Direct Current ("HVDC") transmission lines, Variable Frequency Transformer ("VFT")–controlled lines, and Phase-Angle Regulator ("PAR")–controlled lines. Controllable transmission lines allow power flows to be channeled along pathways that lower the overall cost of generation necessary to satisfy demand. Hence, they have the potential to provide greater benefits than conventional AC transmission lines.

Controllable transmission lines that source and/or sink in NYCA are scheduled in three ways. First, some controllable transmission lines are scheduled as external interfaces using external transaction scheduling procedures.[141] Such lines are evaluated in Section VII.C, which evaluates external transaction scheduling. Second, "optimized" PAR-controlled lines are optimized in the sense that they are normally adjusted in order to reduce generation redispatch costs (i.e., to minimize production costs) in the day-ahead and real-time markets. Third, "non-optimized" PAR-controlled lines are scheduled according to various operating procedures that are not necessarily based on reducing production costs. This part of the section evaluates the use of non-optimized PAR-controlled lines.

The following table evaluates the consistency of the direction of power flows on non-optimized PAR-controlled lines and LBMP differences across these lines during 2015. The evaluation is done for nine PAR-controlled lines between New York and neighboring areas and two between New York City and Long Island. This analysis is shown separately for the portion of flows

141 This includes the Cross Sound Cable (an HVDC line), the Neptune Cable (an HVDC line), the HVDC line connecting NYCA to Quebec, the Dennison Scheduled Line (partly VFT-controlled), the 1385 Scheduled Line (PAR-controlled), the HTP Scheduled Line (an HVDC line), and the Linden VFT Scheduled Line.

scheduled in the day-ahead market versus the portion that is from balancing adjustments in the real-time market.[142]

Table 16: Efficiency of Scheduling on Non-Optimized PAR Controlled Lines[143, 144]
2015

	Day-Ahead Market Schedule				Adjustment in Real-Time			
	Avg Flow (MW/h)	Avg NYCA Price minus Avg Outside Price ($/MWh)	Percent of Hours in Efficient Direction	Estimated Production Cost Savings (Million $)	Avg Flow (MW/h)	Avg NYCA Price minus Avg Outside Price ($/MWh)	Percent of Hours in Efficient Direction	Estimated Production Cost Savings (Million $)
Ontario to NYCA								
St. Lawerence					2	$7.16	56%	$4
New England to NYCA								
Sand Bar	-77	-$15.75	91%	$11	-1	-$14.89	53%	$1
PJM to NYCA								
Waldwick	-862	$2.47	39%	-$19	152	$1.98	52%	$1
Ramapo	196	$3.78	68%	$30	157	$4.35	50%	$6
Farragut	645	-$2.60	45%	-$15	-66	-$6.47	50%	$0
Goethals	224	$2.60	62%	$5	67	$3.08	50%	$1
Long Island to NYC								
Lake Success	145	-$8.20	1%	-$9	-9	-$8.47	70%	$1
Valley Stream	48	-$13.19	1%	-$6	4	-$16.71	34%	-$2

In the day-ahead market, PAR-controlled lines that were used to support contractual wheeling agreements were scheduled less efficiently than other PAR-controlled lines. The Waldwick and Goethals/Farragut lines are operated under the ConEd-PSEG wheeling agreement to wheel up to 1000 MW from Hudson Valley in New York to New Jersey and then on to New York City. In 2015, power flowed in the inefficient direction in 61 percent of hours across the Waldwick lines and in 55 percent of hours across the Farragut lines. These led to an estimated net *increase* of $29 million in day-ahead production costs.

142 For example, if 100 MW is scheduled from the low-priced region to the high-priced region in the DAM, the DAM schedule would be considered *efficient direction*, and if the relative prices of the two regions was switched in the RTM and the flow was reduced to 80 MW, the adjustment would be shown as -20 MW and the RTM schedule adjustment would be considered *efficient direction* as well. For the St. Lawrence PARs between Ontario and NYCA, the analysis assumes a day-ahead schedule of 0 MW since Ontario does not operate a day-ahead market.

143 This table reports the estimated production cost savings from the actual use of these transmission lines. They are *not* the production cost savings that could have been realized by scheduling the lines efficiently.

144 As discussed further in Section V.C of the Appendix, this metric tends to under-estimate the production cost savings from lines that flow from low-priced to high-priced regions. However, it tends to over-estimate the production cost increases from lines that flow from high-priced to low-priced regions. Nonetheless, it is a useful indicator of the relative scheduling efficiency of individual lines.

The Lake Success and Valley Stream PARs operated the 901 & 903 lines under the ConEd-LIPA wheeling agreement to wheel up to 290 MW from upstate to Long Island and then on to New York City. In 2015, power flowed in the inefficient direction in 99 percent of hours, much more inefficient than any of the other PAR-controlled lines. The use of these lines *increased* DAM production costs by an estimated $15 million in 2015 because prices on Long Island were typically higher than those in New York City where the 901 and 903 lines connect.[145] In addition to increasing production costs, these transfers can restrict output from generators in the Astoria East/Corona/Jamaica pocket where the lines connect and the nearby Astoria Annex. Restrictions on the output of these New York City generators sometimes increases price in a much wider area (e.g., when there is an eastern reserve shortage or during a TSA event with severe congestion into Southeast New York). Furthermore, these transfers from Long Island to New York City also tend to increase the consumption of gas from the Iroquois pipeline, which normally trades at a significant premium over gas consumed from the Transco pipeline. These transfers also drive-up generation from older less-fuel efficient gas turbines and steam units without Selective Catalytic Reduction capability, leading to increased emissions of CO_2 and NOx pollution in a non-attainment area.

Real-time adjustments in flows were generally small relative to day-ahead scheduled flows, since most of these PAR-controlled lines are operated to the same schedule in the day-ahead and real-time markets. Likewise, real-time production cost savings were low because the operating protocols for most of these lines do not consider market conditions. However, the Ramapo line and St. Lawrence line show significant production cost savings in real-time because these lines are operated to flow a share of the external transactions between control areas that are submitted by traders and to manage real-time congestion.

Although the Ramapo line is scheduled under the M2M process to minimize congestion across PJM and New York, the process only considers congestion on certain pre-defined interfaces. Table 16 reports the production cost savings for balancing adjustments considering congestion on all flowgates. In 2015, the production cost savings were reduced by an estimated $7.6 million

145 These lines connect to the Jamaica bus, which is located within the Astoria East/Corona/Jamaica "load pocket," an area that is frequently export-constrained.

when additional Ramapo flows into New York increased production costs on non-M2M constraints in Western New York (e.g., the Niagara-Packard line). Hence, excluding the effects of balancing adjustments of the Ramapo line on constraints in Western New York, the production cost savings reported in Table 16 would likely have exceeded $13 million.

These results indicate that significant opportunities remain to improve the operation of these lines, particularly the Waldwick and Farragut/Goethals lines and the lines between New York City and Long Island. We recognize that the ability to achieve these improvements and the associated savings may be limited by the long-standing contracts between scheduling parties that pre-date open access transmission tariffs and the NYISO's markets.[146] However, it would be highly beneficial to modify these contracts or find other ways under the current contracts to operate the lines efficiently. Since more efficient operation would benefit one party financially at the expense of the other, it would be reasonable to create a financial settlement mechanism to compensate the party that would be losing some of the benefits from the current operation.

- Under the ConEd-LIPA wheeling agreement, ConEd possesses a physical right to receive power across the 901 and 903 lines. To compensate ConEd during periods when it does not receive power across these lines, ConEd should be granted a financial right that would compensate it based on LBMPs when the lines are redispatched to minimize production costs (comparable to a generator).[147] We recommend the NYISO work with the parties to this contract to explore potential changes that would allow the lines to be used more efficiently.[148]

- Under the ConEd-PSEG wheeling agreement, ConEd has the right to wheel power from the Hudson Valley through PJM into New York City. However, this agreement will expire after April 2017, so the associated lines will have to be scheduled differently in the future. We recommend the NYISO work with PJM to incorporate these lines into the M2M process so that these lines can be scheduled efficiently starting in May 2017. [149]

146 See NYISO OATT Section 18, Table 1 A - Long Term Transmission Wheeling Agreements, Contract #9 governs the operation of the lines between New York City and Long Island.

147 The proposed financial right is described in Section III.G of the Appendix.

148 See Recommendation #11 in Section XI.

149 See Recommendation #10 in Section XI.

E. Transient Real-Time Price Volatility

Volatile prices can be an efficient signal of the value of flexible resources, although unnecessary volatility imposes excessive costs on market participants, so it is important to identify the causes of volatility. In this subsection, we evaluate scheduling patterns that led to transient spikes in real-time prices for individual transmission constraints and the power-balance constraint (i.e., the requirement that supply equal demand) in 2015. The effects of transient transmission constraints are more localized, while transient spikes in the power-balance constraint affect prices throughout NYCA.

Although transient price spikes occurred in roughly 4 percent of all intervals in 2015, these intervals were important because they accounted for a disproportionately large share of the overall market costs. Furthermore, analyzing factors that lead to the most severe real-time price spikes provides insight about factors that contribute to less severe price volatility under a wider range of market conditions. In general, price volatility makes it more difficult for market participants, the NYISO, and neighboring system operators to commit quick-start resources and schedule external transactions efficiently. Hence, reducing unnecessary price volatility will lead to more efficient interchange between markets, lower production costs across markets, and less uplift from BPCG and DAMAP payments.

1. Drivers of Transient Real-Time Price Volatility

Table 17 summarizes the most significant factors that contributed to real-time price volatility in 2015 and shows their contributions as a percent of the total contributions to the price spike for the power-balance constraint and transmission facilities exhibiting the most volatility. Contributions are also shown for two key categories: (a) resources that are scheduled by RTC such as external interchange and (b) flow changes from un-modeled factors such as loop flows.[150] For each constraint category, the most significant contribution category is highlighted.

150 See Section V.E in the Appendix for more details about the evaluation and additional factors that contribute to transient real-time price spikes.

Table 17: Drivers of Transient Real-Time Price Volatility
2015

	Power Balance		West Zone 230kV Lines		Central East		Dunwoodie - Shore Rd 345kV		Intra-Long Island Constraints	
Average Transfer Limit	**n/a**		**637**		**2564**		**719**		**273**	
Number of Price Spikes	**557**		**1279**		**351**		**591**		**1311**	
Average Constraint Shadow Price	**$219**		**$810**		**$319**		**$521**		**$872**	
Source of Increased Constraint Cost:	**(MW)**	**(%)**	**(MW)**	**(%)**	**(MW)**	**(%)**	**(MW)**	**(%)**	**(MW)**	**(%)**
Scheduled By RTC	**174**	**65%**	**2**	**7%**	**66**	**45%**	**43**	**60%**	**5**	**25%**
External Interchange	113	42%	2	7%	36	25%	26	36%	1	7%
RTC Shutdown Resource	37	14%	0	0%	18	13%	13	19%	3	13%
Self Scheduled Shutdown/Dispatch	24	9%	0	0%	12	8%	4	6%	1	5%
Flow Change from Non-Modeled Factors	**9**	**4%**	**18**	**81%**	**59**	**40%**	**20**	**28%**	**14**	**72%**
Loop Flows & Other Non-Market	0	0%	14	63%	11	7%	7	9%	3	14%
Fixed Schedule PARs (excl. Ramapo)	0	0%	3	12%	29	20%	13	18%	11	56%
Ramapo PARs	0	0%	1	7%	16	11%	0	0%	0	0%
Redispatch for Other Constraint (OOM)	9	4%	0	0%	3	2%	1	1%	0	1%
Other Factors	**86**	**32%**	**3**	**11%**	**21**	**14%**	**9**	**12%**	**1**	**3%**
Total	**270**	**100%**	**22**	**100%**	**146**	**100%**	**72**	**100%**	**20**	**100%**
Redispatch for Other Constraint (RTD)	**106**		**1**		**34**		**9**		**1**	

Resources scheduled by RTC (e.g., external interchange and gas turbine shut-downs) were a key driver of transient price spikes for the Central-East Interface, the Dunwoodie-to-Shore Road 345kV line, and the power-balance constraint. RTC evaluates resources at 15-minute intervals and may shut-down large amounts of capacity or reduce imports by a large amount without considering whether sufficient resources will have sufficient ramp in each 5-minute period to satisfy the energy, reserve, and other operating requirements.

Flow changes resulting from non-modeled factors were a key driver of price spikes for Intra-Long Island constraints. In particular, flow variations on lines making-up the ConEd-LIPA wheel were a key driver of East Garden City-to-Valley Stream lines. These PARs contribute to volatility because they are modeled as if they fully control pre-contingent flow across the PAR-controlled line, so RTD and RTC assume the flow across these lines will remain fixed at the most recent telemetered value. However, this assumption only holds true if the PAR is adjusted in response to variations in generation, load, interchange, and other PAR adjustments. However, the telemetered value can change significantly before a PAR adjustment is triggered, resulting in transitory price spikes. In many cases, severe congestion occurred when low-cost resources that were available to relieve the constraint were under-utilized because they were not scheduled to ramp-up in advance.

Loop flows and other non-market factors were the primary driver of constraints across the West Zone 230kV Lines. For example, clockwise circulation around Lake Erie puts a large amount of non-market flows on these lines. Circulation can be highly volatile and difficult to predict, since it depends partly on facilities that are scheduled outside the NYISO market.

2. Discussion of Potential Solutions

When gas turbines and other units are in the process of shutting-down, they may reduce output quickly. When decommitments are not staggered, it sometimes results in a transitory statewide or local price spike. RTC evaluates system conditions at each quarter-hour (i.e., at :00, :15, :30, and :45) and determines when it is economic to shut-down gas turbines. Since RTC assumes a 15-minute ramp capability from one evaluation period to another, RTC may not anticipate that shutting-down several gas turbines simultaneously will result in a transient shortage within the 15-minute period. However, when RTD solves each five-minute market interval, it is unable to delay the shut-down of a gas turbine even if it would be economic to do so.

Real-time interchange typically adjusts in a direction that reduces generators' ramp requirements over the day. However, large adjustments from one hour to the next may lead to sudden price spikes. The "look ahead" evaluations in RTD and RTC evaluate system conditions at each quarter-hour (i.e., at :00, :15, :30, and :45), while external interchange schedules ramp over 10-minute periods from five minutes before the quarter-hour to five minutes after (i.e., from :55 to :05, from :10 to :20, etc.). Hence, RTC may schedule resources that require a large amount of ramp in one 5-minute portion of the 10-minute external interchange ramp period, and RTD may not anticipate transient shortages that occur in the second five minutes of each 10-minute external interchange ramp period (i.e., at intervals-ending :05, :20, :35, and :50).

Potential Solutions to Address RTC/RTD Inconsistencies

To reduce unnecessary price volatility that results from ramping external interchange and shutting-down generation, we recommend the NYISO consider one or more of the following enhancements to improve the modeling of ramp in RTC and RTD:[151]

[151] See Recommendation #12 in Section XI .

- Add two near-term look-ahead evaluations to RTC and RTD besides the quarter-hour, so that it could anticipate when a de-commitment or interchange adjustment would lead to a five-minute shortage of ramp. For example, for the RTC that evaluates CTS transactions for interval-ending :15, evaluations could be added at :10 and :20.

- Adjust the timing of the look-ahead evaluations of RTD and RTC to be more consistent with the ramp cycle of external interchange. This could be done by evaluating intervals-ending :05, :20, :35, and :50 rather than :00, :15, :30, and :45.

- Enable RTD to delay the shut-down of a gas turbine for five minutes when it is economic to remain on-line.

- Discount the ramp rate assumed in the look-ahead evaluations of RTC and RTD for steam turbines generators, which often ramp at a rate that is lower than their claimed ramp rate capability.

Potential Solutions to Address Non-Modeled Factors

To reduce unnecessary price volatility from variations in loop flows and other factors not explicitly modeled in the dispatch software such as fixed schedule PAR flow changes, we recommend the NYISO consider the following:[152]

- Adjust the last telemetered flow on a fixed-schedule PAR in RTD and RTC to account for variations in generation, load, interchange, and other PARs that are located in the NYISO footprint. (In each RTD and RTC run, this adjustment could be made before each iteration of the pricing and scheduling component of the model based on the results of the network security analysis component. This is already done to some extent for the estimate of loop flows around Lake Erie).

- Develop mechanism for forecasting additional adjustments from the telemetered value for loop flows and fixed-schedule PAR flows that result from factors not scheduled by the NYISO. This forecast should be "biased" to account for the fact that the cost resulting from forecast errors is asymmetric (i.e., the cost of an over-forecast may be much greater than the cost of an under-forecast of the same magnitude). The NYISO plans to begin using a forecast for the lines making-up the ConEd-LIPA wheel based on the operating plan of the transmission owner that operates the facilities. We expect this to reduce the occurrence of transient price volatility on Long Island. [153]

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152 See Recommendation #13 in Section XI.

153 See *Initialization of Lake Success and Valley Stream PARs*, Presented by David Edelson at the April 5, 2016 Market Issues Working Group.

F. Supplemental Commitment & Out of Merit Dispatch for Reliability

Supplemental commitment occurs when a generator is not committed economically in the day-ahead market, but is needed for reliability. It primarily occurs in three ways: (a) Day-Ahead Reliability Units ("DARU") commitment that typically occurs at the request of transmission owners for local reliability prior to the economic commitment in the SCUC; (b) Day-Ahead Local Reliability Rule ("LRR") commitment that takes place during the economic commitment within the day-ahead market process; and (c) Supplemental Resource Evaluation ("SRE") commitment, which occurs after the day-ahead market closes.

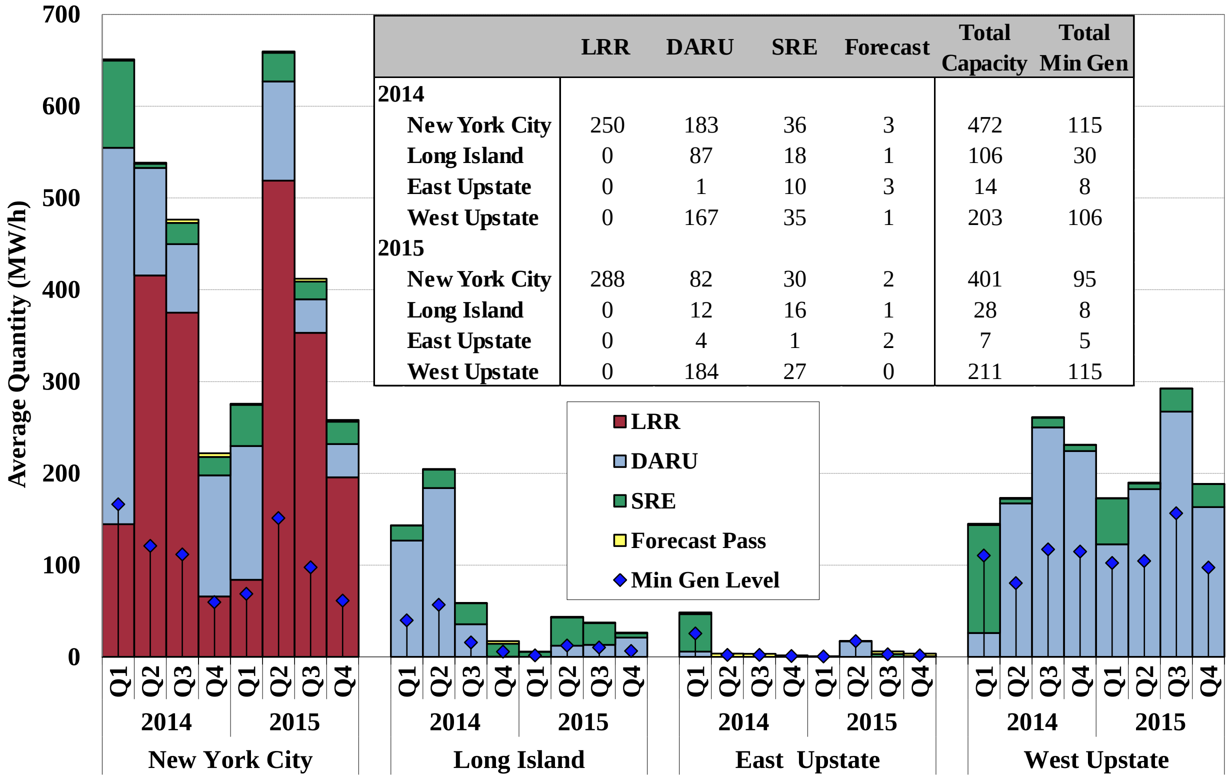
Similarly, the NYISO and local transmission owners sometimes dispatch generators out-of-merit order ("OOM") in order to: (a) manage constraints of high voltage transmission facilities that are not fully represented in the market model; or (b) maintain reliability of the lower voltage transmission system and the distribution system.

Supplemental commitments increase the amount of supply available in real-time, while OOM dispatch causes increased production from capacity that is normally uneconomic, which displaces production from economic capacity. The costs of both types of out-of-market actions are generally not reflected in real-time market prices and tend to depress real-time prices. This undermines the market incentives for meeting reliability requirements and generates expenses that are uplifted to the market. Hence, it is important to limit supplemental commitment and OOM dispatch as much as possible.

1. Supplemental Commitment in New York State

The following figure summarizes the quarterly quantities of four types of reliability commitment (i.e., DARU, LRR, SRE, and Forecast Pass) in New York City, Long Island, West, and East Upstate areas during 2014 and 2015. The first three types of commitment are primarily for local reliability needs. The forecast pass ensures that sufficient physical resources are committed in the day-ahead market to meet forecasted load. In addition to showing the total capacity committed in each category, it also shows the minimum generation level of the resources committed for these reasons. We show the minimum generation level because this energy must be accommodated by reducing the dispatch of other units, which is one of the ways that these commitments can affect real-time energy prices.

Figure 14: Supplemental Commitment for Reliability in New York
By Category and Region, 2014 – 2015



	LRR	DARU	SRE	Forecast	Total Capacity	Total Min Gen
2014						
New York City	250	183	36	3	472	115
Long Island	0	87	18	1	106	30
East Upstate	0	1	10	3	14	8
West Upstate	0	167	35	1	203	106
2015						
New York City	288	82	30	2	401	95
Long Island	0	12	16	1	28	8
East Upstate	0	4	1	2	7	5
West Upstate	0	184	27	0	211	115

The figure shows that roughly 650 MW of capacity was committed on average for reliability in 2015, down roughly 150 MW (or 19 percent) from 2014. Of this total, 62 percent of reliability commitment was in New York City, 33 percent was in Western New York, and only 4 percent was in Long Island.

Despite the reduction in other regions, reliability commitment in Western New York increased slightly from 2014, averaging 211 MW in 2015. DARU commitments increased when several units that were often needed to manage post-contingency flows on 115 kV facilities in Zones A and C became less economic because of lower natural gas prices and resulting low LBMPs. Nonetheless, SRE commitments fell in Western New York after March 2014 (when transmission upgrades in the North Zone were completed). The transmission upgrades reduced the size of key transmission contingencies and associated needs for supplemental commitments.

In Long Island, DARU commitments rarely occurred after the second quarter of 2014 because of transmission upgrades (including installation of the West Bus Distributed Reactive Sources ("DRSS") and Wildwood DRSS) in early 2014. These have reduced the need to: (a) commit generation for voltage (see ARR 28); and (b) burn oil to protect Long Island from a loss of gas contingency. A small amount of SRE commitments still occurred mainly keeping steam turbine units online during overnight hours so that they would be available the following day.

In New York City, reliability commitment fell 15 percent to an average of 400 MW in 2015. The reduction was driven partly by fewer costly generation and transmission outages. Most reliability commitments in 2015 were made for the sub-regions in the 138 kV system, primarily the Freshkills, Astoria West/Queensbridge, and the Astoria West/Queensbridge/Vernon load pocket. These commitments were usually made to ensure facilities into these load pockets would not be overloaded if the largest two generation or transmission contingencies were to occur, which typically rose when significant generation and/or transmission outages occurred in these load pockets. For example, reliability commitments rose in the second quarter of 2015 when transmission line outages increased needs in the Greenwood/Staten Island load pocket and generation outages increased needs in the Astoria West/Queensbridge load pocket.

2. LRR Commitment in New York City for NOx Bubble Constraints

The NOx bubble constraints were established by the NYISO in the LRR pass of SCUC for three generator portfolios in New York City based on the compliance plans they filed with the Department of Environmental Conservation ("DEC"), which rely on "System Averaging" to meet certain emissions limits.[154] These NOx bubble constraints require the operation of a steam turbine or a combined-cycle unit in order to reduce the overall NOx emission rate from a portfolio containing higher-emitting gas turbine units.[155] Such supplemental commitments occur

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154 See Section V.I in the Appendix for more background information on the NOx Bubble constraints.

155 In May 2014, the NYISO updated one of three NOx LRR constraints to reflect that one portfolio could use a combined cycle unit instead of a steam unit to balance the simple-cycle turbines. See "Ravenswood generating Station Nitrogen Oxide Emission Control Strategy for Compliance with 6 NYCRR Subpart 227-2."

only during the five-month ozone season (May to September) of each year. They are categorized as for local reliability, so the resulting out-of-market costs are uplifted to the local customers.

NOx bubble commitments accounted for 6 percent of all reliability commitment in New York City in 2015. This was down significantly from prior years because:

- One generation portfolio made changes in its NOx compliance plan, so that some cleaner combined cycle capacity can be committed instead of steam turbine capacity to satisfy the NOx requirement; and
- Units that were required to satisfy the NOx requirements were often needed at the same time for other local reliability needs and were flagged less frequently for NOx-only commitment.

Despite the reduction in NOx bubble commitments in 2015, they still had the effect of increasing rather than decreasing overall NOx emissions across electric generating units in New York City. This is because the commitment of steam turbine units typically crowds-out generation from new fuel efficient generation with selective catalytic reduction capability, and it is rare that these commitments would reduce production from older gas turbines (as intended). The following table summarizes our analysis of the effects of the NOx bubble constraints. Table 18 shows energy production (as a percent of total production in their category) from gas turbines in the NOx bubbles and steam units committed for the NOx bubble constraints in 2015 by load level.[156]

Table 18: Energy Production from NOx Bubble Generators
2015

Daily Load Levels	Generation Output from GTs in NOx Bubble	Generation Output from STs Committed for NOx
Low	**10%**	**92%**
Medium	**25%**	**8%**
High	**65%**	**0%**
Total	**100%**	**100%**

Our analysis finds that in 2015, 90 percent of energy production from the gas turbines in the NOx Bubbles occurred on days with medium to high load levels, while 92 percent of the energy production from steam units committed for the NOx constraints occurred on low-load days. This

156 See Section V.I in the Appendix for our evaluation of NOx emissions in more detail.

indicates that most of the NOx bubble commitments were made on low-load days when older gas turbines rarely operated. Hence, the commitment of steam turbines for NOx bubble constraints rarely coincided with the operation of gas turbines. In virtually all cases where a steam turbine was running at the same time as a gas turbine, the steam turbine was already committed for economic or some other reliability need.

When steam turbine units were committed for the NOx bubble constraints, their output usually displaced output from newer cleaner generation in New York City and/or displaced imports to the city. Our analysis shows that:

- An average of over 1.1 GW of offline capacity from newer and cleaner generators (equipped with SCRs) in New York City was available and unutilized on days when steam units were committed only for the NOx bubble constraint; and
- The steam units emit approximately 13 times more NOx per MWh than the newer generators with emission-reduction equipment.

Our analyses indicate that in 2015 the NOx bubble constraints did not lead to reductions in NOx emissions and may have actually led to higher overall NOx emissions. These commitments also result in uplift that is socialized to other parties and distorted clearing prices from the commitment of out-of-market resources. Owners of generation in NOx bubbles likely have additional RACT compliance options, which may result in lower emissions at lower cost. Hence, we recommend that the NYISO work with generators in NOx bubbles to ensure their RACT compliance plans use the most economic compliance option available.[157]

3. Out of Merit Dispatch

Table 19 summarizes the frequency (i.e., the total station-hours) of Out-of-Merit ("OOM") actions in 2014 and 2015 for the following four regions in New York: (a) West Upstate, which includes Zones A through E; (b) East Upstate, which includes Zones F through I; (c) New York City, which is Zone J; and (d) Long Island, which is Zone K. [158]

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157 See Recommendation #18 in Section XI.

158 Figure A-86 in the Appendix shows our analysis on a quarterly basis and shows top two stations that had most frequent OOM dispatches in 2015 for each region.

Table 19: Frequency of Out-of-Merit Dispatch
By Region, 2014-2015

Region	OOM Station-Hours		
	2014	**2015**	**% Change**
West Upstate	2031	5050	149%
East Upstate	189	222	17%
New York City	241	613	154%
Long Island	701	1621	131%
Total	**3162**	**7506**	**137%**

OOM actions rose from 2014 to 2015 in all areas. In New York City and Long Island, this increase reflected higher summer load levels and more frequent peaking conditions in 2015. This was particularly evident on Long Island in the third quarter of 2015, during which higher load levels led to increased needs to OOM-dispatch peaking generators to manage voltage constraints on the East End of Long Island. [159]

OOM actions rose by more than 3,000 station-hours from 2014 to 2015 in Western New York, which accounted for the largest share of OOM station-hours in both years. The increase occurred primarily because the Dunkirk, Olean, and Milliken units were OOMed more frequently (because of lower LBMPs) to prevent post-contingency overloading on several 115 kV transmission facilities. These actions incurred a significant amount of guarantee payment uplift in 2015 (which are discussed in the next subsection).

The Niagara generator was often manually instructed to shift output between the generators at the 115kV station and the generators at the 230kV station in order to secure certain 115kV and/or 230kV transmission facilities. However, these were not classified as OOM in hours when the NYISO did not adjust the UOL or LOL of the Resource. In 2015, manual instructions were required in 950 hours to manage 115 kV constraints and in 2,330 hours to manage 230 or 345 kV constraints. Including unlogged manual dispatches, Niagara was OOM dispatched more frequently than any other generator in 2015.

159 Nonetheless, such needs have been greatly reduced since early 2014 because of transmission improvements (particularly the installation of West Bus and Wildwood DRSS).

In addition, the NYISO also frequently secured the 115 kV Gardenville-to-Dunkirk lines by taking certain lines out of service on the primary PJM-NYISO interface. This is because shifting the distribution of flows across the PJM-NYISO interface can reduce the loadings on the 115 kV Gardenville-to-Dunkirk lines. In 2015, the Dunkirk-to-South Ripley line was taken out for 690 hours and the Warren-to-Falconer line was taken out for 1,780 hours for this purpose. Although exports across the PJM-NYISO interface increase congestion on these 115 kV lines, exporters are not charged for the associated congestion costs because these 115 kV constraints are not modeled in the day-ahead and real-time scheduling and pricing software.

Given that frequent DARU commitments and OOM dispatches were taken to manage congestion on the 115 kV network in the Western New York and they incurred sizable uplift. We recommend the NYISO model certain up-state 115kV transmission constraints in the day-ahead and real-time markets scheduling and pricing software.[160]

G. Guarantee Payment Uplift Charges

The NYISO recovers the payments it makes to certain market participants that are not recouped from LBMP and other market revenues through uplift charges. It is important to minimize uplift charges because they are difficult to hedge and do not provide transparent economic signals to market participants and potential investors. When markets reflect reliability requirements and system conditions, uplift charges should be relatively low.

The following figure shows guarantee payment uplift for four local reliability categories and three non-local reliability categories in 2014 and 2015 on a quarterly basis.[161]

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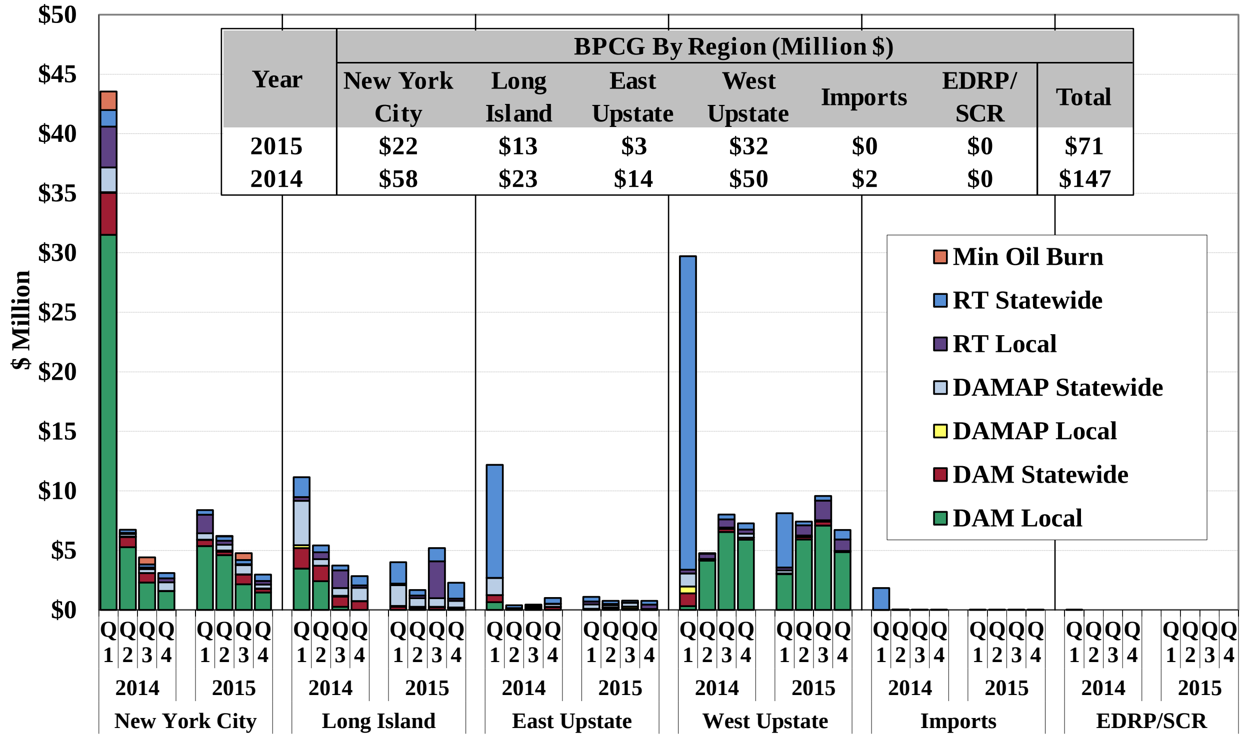
160 See Recommendation #15 in Section XI. The NYISO already models the 115kV system in its network security analysis software, but we recommend also modeling constraints for pricing and scheduling purposes that are currently managed with OOM actions that are costly or affect LBMPs.

161 See Figure A-87 and Figure A-88 in the Appendix for a more detailed description of this analysis.

Figure 15: Uplift Costs from Guarantee Payments in New York
By Category and Region, 2014 – 2015



The figure shows that the guarantee payment uplift totaled $71 million in 2015, down 52 percent from 2014.[162] The vast majority of the reduction occurred in the first quarter of 2015 because of decreased supplemental commitment in New York City and Long Island and much lower natural gas prices, which greatly decreased the commitment costs of gas-fired units that were needed for reliability. For example, the Polar Vortex from January 22-28, 2014 accounted for $30 million in guarantee payment when gas prices averaged over $50 per MMbtu in Eastern New York, while there were no such periods in 2015.

However, in the rest three quarters, guarantee payment uplift was generally comparable between 2014 and 2015 as lower natural gas prices that reduced commitment costs of gas-fired units were offset by increased OOM dispatches during 2015.

Western New York accounted for 45 percent of the total guarantee payment uplift in 2015, which was higher than New York City (32 percent) for the first time. Nearly 80 percent (or $25

162 The 2015 number was based on billing data available at the time of reporting, which may be different from final settlement.

million) of total guarantee payment uplift in Western New York totaled was local uplift. In particular, 95 percent of this local uplift was paid to several units that were committed for reliability and/or OOMed to manage congestion on the 115 kV transmission facilities (which are discussed earlier).

X. Demand Response Programs

Participation by demand response in the market is beneficial for many reasons. Demand response contributes to reliable system operations, long-term resource adequacy, lower costs, decreased price volatility, and reduced supplier market power. Even modest reductions in consumption by end-users during high-price periods can significantly reduce the costs of committing and dispatching generation to satisfy the needs of the system. These benefits underscore the value of designing wholesale markets that provide transparent economic signals and market processes that facilitate demand response. In this report, we evaluate the existing demand response programs and discuss the on-going efforts of the NYISO to facilitate more participation.

Demand response programs provide incentives for retail loads to participate in the wholesale market. Two of the programs, Day-Ahead Demand Response Program ("DADRP") and Demand-Side Ancillary Services Program ("DSASP"), provide a means for economic demand response resources to participate in the day-ahead market and ancillary services markets, respectively. The other three programs, Emergency Demand Response Program ("EDRP"), Special Case Resources ("SCR"), and Targeted Demand Response Program ("TDRP"), are reliability demand response resources that are called when the NYISO or the local Transmission Owner forecasts a shortage. Currently, more than 94 percent of the 1.3 GW of demand response resources registered in New York are reliability demand response resources.

Special Case Resources Program

The SCR program is the most significant demand response program operated by the NYISO with roughly 1,250 MW of resources participating in 2015. The primary incentive to participate in this program is that SCRs can sell capacity in the NYISO's capacity market. In the Summer 2015 Capability Period, SCRs made contributions to resource adequacy by satisfying:

- 4.1 percent of the UCAP requirement for New York City;
- 3.3 percent of the UCAP requirement for the G-J Locality;
- 2.4 percent of the UCAP requirement for Long Island; and

- 3.7 percent of the UCAP requirement for NYCA.

However, the registered quantity of reliability program resources has fallen considerably since 2010, down nearly 50 percent from 2010 to 2015. These reductions have occurred for several reasons.

First, in order to ensure that SCRs can perform when called, the NYISO made improvements in 2011 to the SCR baseline calculation methodology, which is used to estimate the capability of a resource to respond if deployed. The NYISO currently uses the Average Coincident Load ("ACL") methodology, which is based on the resource's load during the 40 highest load hours in the previous like capability period (i.e., Summer 2015 is based on 40 hours from Summer 2014). Since it is now coincident with NYCA peak loads, the new baseline calculation has reduced the amount of capacity that some SCRs qualify to sell.

Second, the NYISO audits the baselines of resources after each Capability Period to identify resources that might have had an unreported Change of Status that would reduce its ability to curtail if deployed. This has resulted in more accurate baselines for some resources, reducing the amount of capacity they are qualified to sell. Although both changes contributed to reductions in SCR enrollment in recent years, these changes will ensure that reliability demand response resources perform reliably when needed.

Third, business decisions by market participants contributed to the reduction in participating SCRs as well. This was partly driven by relatively low capacity prices in some areas in recent years and reduced revenues as a result of the enhanced auditing and baseline methodology.

Demand-Side Ancillary Services Program

The NYISO established the Demand-Side Ancillary Services Program ("DSASP") in 2008 to allow demand-side resources to offer operating reserves and regulation service in the wholesale market. DSASP resources have experienced difficulty setting up communications with the NYISO through the local Transmission Owner since the inception of the DSASP program. Consequently, no DSASP resources were fully qualified until 2012 when the NYISO introduced the capability for resources to communicate directly with the NYISO. Since the capability was introduced, approximately 130 MWs of DSASP resources are participating in the market, providing considerable value by reducing the cost of ancillary services in the New York market. These resources were capable of providing up to 19 percent of the NYCA 10-minute spinning reserve requirement in 2015.

Day-Ahead Demand Response Program

No resources participated in the DADRP program in the last four years. Given that the scheduled quantities are normally extremely small and that loads may hedge with virtual transactions that are very similar to DADRP schedules, the value of this program is questionable.

Demand Response and Scarcity Pricing

In an efficient market, clearing prices should reflect the cost of deploying resources to satisfy demand and maintain reliability, particularly under shortage conditions. NYISO has special scarcity pricing rules for periods when demand response resources are deployed.

In 2015, the NYISO did not deploy EDRP and SCR resources, therefore related operations and pricing are not evaluated in this report. Nonetheless, current scarcity pricing methodology has deficiencies. First, it adopts an *ex-post* logic, which tends to cause inconsistencies between resource schedules and pricing outcomes, resulting in potential uplift costs. Second, it does not apply to the Proxy Buses, which may result in inefficient scheduling of imports and exports during EDRP/SCR activations. The NYISO proposed Comprehensive Scarcity Pricing to address these two issues, and the proposal was approved by the Commission for implementation before July 2016.[163]

[163] See NYISO filing in Commission Docket No. ER16-425-000, *Proposed Revisions to Services Tariff and OATT to Implement Improved Scarcity Pricing*, November 30, 2015.

XI. Recommendations

Our analysis in this report indicates that the NYISO electricity markets performed well in 2015, although the report finds additional improvements that we recommend to improve market performance. The recommendations are presented in the following eight categories:

- Capacity Market Enhancements (#1 – #6)
- Economic Transmission Planning Process (#7)
- Broader Regional Markets (#8 – #10)
- Energy Market Enhancements - RT Market Operations (#11 – #13)
- Energy Market Enhancements - RT Pricing (#14 – #17)
- Energy Market Enhancements - Reliability Commitment (#18)
- Energy Market Enhancements - Fuel Assurance (#19 & #20)
- Energy Market Enhancements - DAM Scheduling (#21)

The majority of these recommendations were made in the 2014 SOM Report, but Recommendations 6 –10, 16, 17, and 21 are new in this report.

This section of the report describes each recommendation, discusses the benefits that are expected to result from implementation, and identifies the section of the report where the recommendation is evaluated in more detail. For each recommendation, this section indicates whether there is a current NYISO project or stakeholder initiative that might address the recommendation. The criteria for designating a recommendation as "High Priority" are discussed in the next subsection. The last subsection discusses several recommendations that we considered but ultimately chose not to include on the list this year.

A recommendation is typically categorized as "scoping/future" for one or more of the following reasons. First, there is significant uncertainty regarding the scope of the solution that would be necessary to address the underlying issue that motivated the recommendation. Second, some additional work may be necessary to investigate the costs and benefits of potential solutions before deciding on the priority level. Third, the anticipated benefits would be smaller in the short-term than in the long-term, so it is appropriate to take additional time to consider.

A. Criteria for High Priority Designation

As the NYISO MMU, we are responsible for recommending market rule changes to improve market efficiency. In each of our annual state of the market reports, we identify a set of market rule changes that we recommend the NYISO implement or consider. In most cases, a particular recommendation provides high-level specifics, assuming that the NYISO will shape a more detailed proposal that will be vetted by stakeholders, culminating in a 205 filing to the FERC or a procedural change. In some cases, we may not recommend a particular solution but we may recommend the NYISO invest some resources in evaluating the costs and benefits of addressing a market issue with a rule change or software change. We select the recommendations that appear to have the greatest potential to enhance market efficiency given our sense of the effort level that would be required. In each report, a few recommendations are identified as "High Priority" for reasons discussed below.

When evaluating whether to designate a recommendation as High Priority, we assess how much the recommended change would be likely to enhance market efficiency. To the extent we are able to quantify the benefits that would result from the enhancement, we do so by estimating the production cost savings and/or investment cost savings that would result because these represent the accurate measures of economic efficiency. As the MMU, we focus on economic efficiency because maximizing efficiency will minimize the costs of satisfying the system's needs over the long-term. Other potential measures of benefits that largely capture economic transfers associated with changing prices (e.g., short-term generator revenues or consumer savings) do not measure economic efficiency. Therefore, we do not use such measures when suggesting priorities for our recommendations.

It is challenging to perform quantitative estimates of the efficiency gains for every recommendation because this usually requires analyses that are highly resource intensive. Accordingly, we often rely on simplified or stylized analyses of the efficiency gains when they are sufficient to justify a particular recommendation or to justify it as "High Priority." In many cases, we provide quantitative analyses of the market issues that would be addressed by a particular recommendation to give the reader a sense of the significance of the issue, but we may not perform a quantitative analysis of the benefits of the specific recommended solution.

The NYISO operates a $5+ billion per year wholesale market for electricity. With the majority of wholesale market costs attributable to fuel and other inputs, it can be difficult to substantially lower the overall cost of production. Initiatives that reduce production costs often require significant upfront capital costs (e.g., replacement of a less fuel-efficient generator with a new generator). Consequently, market rule changes that reduce costs without requiring an investment in new infrastructure provide opportunities for large savings relative to the market development costs. In general, market developments that are anticipated to save $10 million of investment and/or production costs per year for at least five years warrant a high priority designation.

In addition to these considerations, we often consider the feasibility and cost of implementation. Quick, low-cost, non-contentious recommendations generally warrant a higher priority because they consume a smaller portion of the NYISO's market development resources. On the other hand, recommendations that would be difficult to implement or involve benefits that are relatively uncertain receive a lower priority.

B. Discussion of Recommendations

Capacity Market Enhancements

1. Implement location-based marginal cost pricing of capacity that minimizes the cost of satisfying planning reliability criteria. (High Priority, Current Effort)

The one-day-in-ten-year resource adequacy standard can be met with various combinations of capacity in different areas of New York. The demand curve reset process sets the capacity demand curve for each locality relative to the IRM/LCR without considering whether this results in a consistent relationship between the clearing prices of capacity and the marginal reliability value of capacity in each Locality. The resulting capacity prices do not provide efficient signals for investment, which raises the overall cost of satisfying the capacity needs. Setting capacity prices that reflect the marginal reliability value of additional capacity (and any transmission security or other planning criteria that might require a minimum amount of capacity) in each locality would provide more efficient incentives for investment and lower overall capacity costs. We describe two possible approaches in this report for implementing this recommendation, and the NYISO is currently evaluating one approach.[164]

This recommendation is designated as a high priority because more accurate price signals would lead to large investment cost savings, more price stability, and more predictable requirements. Although comprehensive estimates of the potential savings are not yet complete, Section VIII.B summarizes an analysis showing that even very limited adjustments in the 2015/16 IRM/LCRs would produce annual cost savings in excess of $10 million per year, supporting the notion that optimizing these requirements would lead to annual savings of many tens of millions of dollars per year under the current zone configuration. Accordingly, we place a high priority on this recommendation.

2. Grant financial capacity transfer rights between zones when investors upgrade the transmission system and help satisfy planning reliability needs without a cost-of-service rate. (Scoping/Future)

This is similar to the NYISO's current provision to provide Transmission Congestion Contracts ("TCCs"). New transmission projects can increase transfer capability over interfaces that bind in the NYISO's resource adequacy models. Hence, transmission projects can provide resource adequacy benefits that are comparable to capacity from generation and demand response resources. Accordingly, transmission should be compensated for the resource adequacy benefits through the capacity market. Creating financial capacity transfer rights will help: (a) provide efficient incentives for economic transmission investment when it is less costly than generation and DR alternatives, and (b) reduce barriers to entry that sometimes occur under the existing rules when a new generation project is required to make uneconomic transmission upgrades. Additional scoping is necessary to evaluate the extent to which this rule would affect the viability of market-based transmission investments.[165]

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164 Section VIII.C discusses the basis for this recommendation and the current NYISO initiative to address it.

165 The basis for this recommendation is discussed in Section VIII.D. This recommendation would provide more efficient signals for transmission investment regardless of whether Recommendation #1 is adopted. However, capacity prices that overvalue generation (before Recommendation #1 is implemented) could cause generation to preempt efficient transmission investment.

3. Establish a dynamic locational capacity framework that addresses future potential deliverability constraints to allow prices to reflect the locational value of capacity and quickly adjust to changes in market conditions. (Scoping/Future)

The existing rules for creating New Capacity Zones will not lead to the timely creation of a new capacity zones in the future when: (a) additional capacity is needed to meet resource adequacy criteria in areas that are not currently zones, and (b) when the NYISO's Class Year Deliverability Test is inefficiently restricting new entry and capacity imports. Establishing a dynamic locational framework by pre-defining interfaces and corresponding zones would ensure that locational capacity prices would immediately adjust to reflect changes in market conditions, including the unexpected retirement of key units in the state's aging fleet. This will, in turn, allow investors to be more confident that the reliability needs will be fully priced and facilitate timely market-based investment. This recommendation is identified as a future priority because there are no imminent reliability needs that would necessitate creation of a new capacity zone to motivate new investment and because a process to pre-define capacity zones will be more efficient after the implementation of Recommendation #1 (which would ensure that the resulting LCRs would be set appropriately). However, it is inevitable that future retirements and load growth will lead to circumstances when new interfaces and zones will be needed to encourage prompt and efficient new investment, so we recommend the NYISO begin considering potential solutions for this recommendation.[166]

4. Enhance Buyer-Side Mitigation measures to deter uneconomic entry while ensuring that economic entrants are not mitigated.

a. Reform the Offer Floor for mitigated projects.

A new project is exempted from mitigation if capacity prices are forecasted to be higher than: (i) 75 percent of Mitigation Net CONE ("MNC") where MNC equals the annual capacity revenues that the demand curve unit would need to be economic; or (ii) Unit Net CONE ("UNC"), a level set at the estimated net CONE of the new project. If a project fails both of these criteria, an Offer Floor is imposed at a level equal to the lower of 75 percent of MNC and UNC. The 75 percent of MNC is reasonable for purposes of the exemption test because

166 The basis for this recommendation is discussed in Section VIII.F.

it recognizes that the entry of the new unit will tend to lower the project's net revenues in the initial year. However, its use as an offer floor for projects that have failed both tests significantly weakens the buyer-side mitigation measures because it allows the uneconomic project to lower capacity prices 25 percent below the likely cost of entry. To address these issues, we recommend setting the offer floor of mitigated units at the lower of UNC or the 100 percent of the MNC.

b. Modify assumptions used to forecast ICAP prices and net revenues, especially relating to the treatment of existing generation and potential new entrants. (Current Effort)

The set of generators that is assumed to be in service for the purposes of the exemption test is important because the more capacity that is assumed to be in service, the lower the forecasted capacity revenues of the Examined Facility, thereby increasing the likelihood of mitigating the Facility even if it is economic. The Tariff requires the NYISO to include all existing resources other than Expected Retirements, which leads to the inclusion of mothballed resources that are unlikely to re-enter. This also results in the exclusion of resources that have submitted a retirement notice, but that retain the ability to re-enter the market. Furthermore, these inclusion rules should be reevaluated considering recent changes in other BSM rules, including newly created exemptions for competitive entry, renewables, and self-supply resources. We recommend the NYISO modify the BSM assumptions to allow the forecasted prices to be reasonably consistent with expectations.[167]

5. Expand buyer-side mitigation measures to address other actions that can suppress capacity prices. (Current Effort, Scoping/Future)

FERC is considering new buyer-side mitigation measures that would address uneconomic retention of existing resources to suppress capacity prices and apply the rules to areas outside Southeast New York. We have recommended that the Commission adopt an offer floor mitigation measure to address uneconomic retention outside Southeast New York. [168]

[167] Section IV.C.2 discusses the basis for this recommendation.

[168] The comments are discussed in Section IV.C.2.

Additionally, we are concerned that the buyer-side mitigation rules focus only on investment in uneconomic generation and controllable transmission facilities. The rules do not address other types of uneconomic transmission investment, including projects that increase transmission capability on internal NYISO interfaces and projects that increase the amount of emergency assistance that is available from external areas. The NYISO should evaluate how to effectively address these issues.[169]

6. Modify the pivotal supplier test to prevent suppliers from circumventing the mitigation rules by selling capacity in forward capacity auctions (i.e., the strip and monthly auctions) to avoid being designated a pivotal supplier for NYC.

The current definition of a pivotal supplier for NYC effectively assumes that selling capacity in the forward auctions eliminates the incentive for a large supplier to withhold in the spot auction. However, increased spot capacity prices affect the expectations of other market participants, increasing the clearing prices in subsequent forward auctions. This allows a large supplier to benefit from withholding in the spot capacity auction even if it does not meet the definition of a pivotal supplier in the supply-side mitigation measures because it has sold most of its capacity in the forward auctions. Hence, we recommend modifying the pivotal supplier criteria to include in the evaluation for a particular supplier any capacity that it sold prior to the spot auction. Although this issue has already been addressed for the G-J Locality, the issue has not been rectified for the purposes of determining whether a supply is pivotal in NYC.[170]

Economic Transmission Planning Process

7. Reform the CARIS process to better identify and fund economically efficient transmission investments. (Scoping/Future)

The current economic transmission planning process does not accurately estimate the economic benefits of proposed projects. Several key assumptions lead transmission projects to be systematically under-valued. Furthermore, the current requirement for 80 percent of

169 Section IV.C.2 discusses the basis for this recommendation.

170 Section IV.C.4 discusses the basis for this recommendation. Both the flawed pivotal supplier test and the pivotal supplier test used for the G-J Locality are found in MST 23.4.5.5.

the beneficiaries to vote in favor of a proposed project is too high and may prevent economic projects from being funded.[171] Hence, we recommend that the NYISO review the CARIS process and the methods used to measure benefits, and we recommend the NYISO identify changes that may be necessary to ensure that the CARIS process will identify and fund economically efficient transmission investments (and not fund uneconomic projects).

Broader Regional Markets

8. Modify the capacity market and planning process to better account for capacity that is exported to neighboring control areas from import-constrained capacity zones. (High Priority)

More than 500 MW of capacity was sold from the G-J Locality in each of the last two ISO-NE Forward Capacity Auctions, which will give the associated generator Capacity Supply Obligations to New England beginning in June 2018. Currently, NYISO's tariffs and procedures do not specify how it would treat such a generator in its planning process or in its capacity market. However, an efficient market and planning process should recognize that a generator that exports from an import-constrained capacity zone provides more reliability benefit to the NYCA than a generator of the same size that exports to the same market from the Rest of State ("ROS") region.[172] Hence, we recommend that the NYISO's capacity market rules be amended to recognize this value in the spot capacity auctions and other related processes.

This recommendation is a High Priority for several reasons. First, if this issue is not addressed promptly, we anticipate that capacity clearing prices in the Lower Hudson Valley could rise far (approximately $40/kW-year) above competitive levels at least during the two years for which capacity has already been sold into ISO-NE (May 2018 to April 2020). Second, we anticipate it is possible for the NYISO to implement the necessary changes in time to avoid a detrimental effect on the NYISO capacity market from this export.

171 Section VIII.E discusses the basis for this recommendation and specific elements that should be evaluated.

172 Section VIII.B discusses the basis for this recommendation and specific elements that should be amended.

9. Eliminate transaction fees for CTS transactions at the PJM-NYISO border.

The efficiency benefits of the CTS process with PJM have generally fallen well short of expectations since it was implemented in the fourth quarter of 2014. We have observed far greater utilization of CTS bidding at the ISO-NE interface since it was implemented in the fourth quarter of 2015. The lower utilization of the CTS with PJM can be attributed to the relatively large fees that are charged to transactions between NYISO and PJM, while fees were eliminated years ago between ISO-NE and NYISO.[173] It is unlikely that CTS with PJM will function effectively as long as transaction fees and uplift charges are large relative to the expected value of spreads between markets. Hence, we recommend eliminating transaction fees and uplift charges between the PJM and NYISO.

10. After the ConEd-PSEG wheeling agreement expires, work with PJM to coordinate scheduling of the associated controllable lines (i.e., the A, B, C, J, and K lines) to minimize production costs across the two regions.

In preparation for the Con Ed-PJM wheeling agreement expiration, the NYISO will need to work with ConEd and PJM to review interregional scheduling and dispatch rules so that economic transactions may be scheduled between the regions while considering the physical and operating limitations of the lines. We recommend the NYISO evaluate incorporating the ABC and JK lines into the M2M process with PJM as is done currently for the Hopatong-Ramapo tie line.[174]

Energy Market Enhancements – Real-Time Market Operations

11. Operate certain PAR-controlled lines to minimize production costs and create financial rights that compensate affected transmission owners. (High Priority)

Significant efficiency gains may be achieved by improving the operation of the PAR-controlled lines between New York City and Long Island (i.e., the 901 and 903 lines). These lines are all scheduled according to the terms of long-standing contracts that pre-date open access transmission tariffs and the NYISO's markets. It would be highly beneficial to

[173] Section VII.D evaluates the performance of CTS-PJM and CTS-NE.

[174] Section IX.D discusses the basis for this recommendation.

modify these contracts or find other ways under the current contracts to operate the lines efficiently.

In 2015, these lines were scheduled in the day-ahead market in the inefficient direction (i.e., from the high-priced area to the low-priced area) 99 percent of the time, and their operation increased production costs by an estimated $15 million. When these lines flow in the inefficient direction, it leads to inefficient prices between regions and can restrict production by economic generation in New York City.

This recommendation remains a high priority because these lines are operated in a way that is very inefficient, causing the dispatch of high-cost generation in place of lower-cost alternatives. In this report, we also find other significant effects. First, these lines were among the most significant factors causing transient price volatility in Long Island in 2015. Second, the resulting price volatility has led the western portion of Long Island to exhibit particularly poor consistency between day-ahead and real-time prices, making it difficult to commit resources economically in the day-ahead market. Third, the operation of the 901 and 903 lines contributed a net of $4 million to balancing congestion shortfall uplift which is socialized through Rate Schedule 1 charges.[175] The problems that arise from the operation of these lines will be difficult to address without operating the lines more efficiently.

Hence, we are recommending that the NYISO work with the parties to the underlying wheeling agreements to explore potential changes to agreements or to identify how the agreements can be accommodated within the markets more efficiently. Since more efficient operation would benefit one party financially at the expense of the other, it is reasonable to create a financial settlement mechanism to compensate the party that would be giving up some of the benefits from the current operation. We discuss a potential concept for providing compensation to ConEd in Section III.G of the Appendix.

175 Section IX.D discusses the estimates of production cost increases. Section IX.E discusses their effects on transient price volatility. Section V.A.2 discusses poor price convergence in Western Long Island. Section VI.A.3 discusses the effect of these lines on balancing congestion shortfall uplift.

12. Adjust look ahead evaluations of RTD and RTC to be more consistent with the timing of external transaction ramp and gas turbine commitment. (Current Effort, High Priority, Scoping/Future)

The look ahead evaluations of RTD and RTC evaluate the system at each quarter-hour (i.e., :00, :15, :30, and :45), while external transactions reach their scheduled levels at five minutes past each quarter-hour (i.e., :05, :20, :35, and :50). Gas turbines shutdown over one 15-minute period in the look ahead evaluations, but they actually shut-down over a 5-minute period, sometimes resulting in unforeseen ramp constraints. These timing inconsistencies contribute to transient shortage conditions and unnecessary price volatility, and they undermine the accuracy of the RTC prices that are used as the basis for scheduling CTS transactions with PJM and ISO-NE. Given the importance of gas turbines and external transactions to overall real-time market efficiency, it is essential to bring better consistency between the assumptions used in RTC and RTD.

To address these issues, we recommend the NYISO consider one or more of the following enhancements to improve the modeling of ramp in RTC and RTD:

- Add two near-term look-ahead evaluations to RTC and RTD besides the quarter-hour, so that it could anticipate when a de-commitment or interchange adjustment would lead to a five-minute shortage of ramp. For example, for the RTC that evaluates CTS transactions for interval-ending :15, evaluations could be added at :10 and :20.
- Adjust the timing of the look-ahead evaluations of RTD and RTC to be more consistent with the ramp cycle of external interchange. This could be done by evaluating intervals-ending :05, :20, :35, and :50 rather than :00, :15, :30, and :45.
- Enable RTD to delay the shut-down of a gas turbine for five minutes when it is economic to remain on-line.
- Discount the ramp rate assumed in the look-ahead evaluations of RTC and RTD for steam turbine generators, which often ramp at a rate that is lower than their claimed ramp rate capability.

Additional scoping is necessary to evaluate the relative complexity, costs, and benefits of these and other potential solutions to this recommendation.[176]

[176] This recommendation is discussed in the subsection on transient price spikes (IX.E) and the subsection on the performance of CTS (VII.D).

13. Consider enhancing modeling of loop flows and PAR-controlled lines to reflect the effects of expected generation, load, and PAR-controls on line flows more accurately. (Current Effort, Scoping/Future)

Variations in loop flows and in flows across certain PAR-controlled lines were among the leading causes of real-time transient price spikes in 2015. To reduce unnecessary price volatility and inefficient scheduling outcomes from these variations, we recommend the NYISO consider the following:

- Adjust the last telemetered flow on a fixed-schedule PAR in RTD and RTC to account for variations in generation, load, interchange, and other PARs that are located in the NYISO footprint. (This is already done to some extent for the estimate of loop flows around Lake Erie).
- Develop mechanism for forecasting additional adjustments from the telemetered value for loop flows and fixed-schedule PAR flows that result from factors not scheduled by the NYISO. (The NYISO will begin to do this for two PAR-controlled lines starting in April 2016).
- Forecasts of loop flows should be "biased" to account for the fact that the cost resulting from forecast errors is asymmetric (i.e., the cost of an over-forecast may be much greater than the cost of an under-forecast of the same magnitude).

Additional scoping is necessary to evaluate the relative complexity, costs, and benefits of these and other potential solutions to this recommendation.[177]

<u>Energy Market Enhancements – Real-Time Pricing</u>

14. Modify criteria for GTs to set prices in the real-time market by allowing GTs to be eligible to set price in the final pricing pass and incorporating start-up costs. (Current Effort)

The real-time pricing methodology (i.e., hybrid pricing) employs a step that causes some GTs to be deemed ineligible to set the LBMP. This causes LBMPs to not fully reflect the cost of the marginal resources scheduled to satisfy load and manage congestion. Hence, we recommend the NYISO modify the hybrid pricing logic to better allow economic gas turbines to set the energy prices. It would also be appropriate to amortize the start-up costs of the gas turbines over the initial phase of commitment and reflect the cost in the price-

[177] The basis for this recommendation is discussed in Section IX.E.

setting logic. Otherwise, a gas turbine that is economic in every interval of its minimum run time may not recoup its costs through LBMP revenues.[178]

15. Model 100+ kV transmission constraints in the DA and RT markets using economic commitment and dispatch software and develop associated mitigation measures.

Market incentives for investment in resources on the 115kV system in up-state New York are inadequate partly because these facilities are not reflected in the NYISO's energy and ancillary services markets. Currently, these constraints are managed through out-of-market actions, which has contributed to the need for cost-of-service contracts to keep older capacity in service. Since these 115kV constraints are not reflected in the market scheduling process, real-time dispatch and day-ahead commitment decisions are sometimes inefficient. Hence, for 115kV transmission facilities that require out-of-market actions to be resolved, we recommend the NYISO instead manage up-state 115kV transmission constraints in the day-ahead and real-time markets.[179] We recognize that implementing the processes to manage these constraints in the day-ahead and real-time markets would be a significant effort, since these constraints are currently managed by the local Transmission Owner.

Some 115kV transmission constraints give rise to local market power, which is currently addressed by market power mitigation measures that limit the ability of a supplier with market power to extract inflated guarantee payments when its resource is committed for reliability or dispatched out-of-merit order to manage the constraint. These mitigation measures should be expanded to address circumstances when resources are committed or dispatched in the day-ahead or real-time market to manage these constraints.

[178] The basis for this recommendation is discussed in Section IX.C. While this recommendation will reduce how frequently LBMPs are set lower than the offer price of committed gas turbines, we acknowledge that it will increase how frequently the LBMP will be set higher than the offer price of headroom on other units (creating lost opportunity costs). The new methodology should seek to minimize the incidence of both pricing inconsistencies.

[179] The basis for this recommendation is discussed in Section IX.F.3.

16. Dynamically adjust operating reserve requirements to account for factors that increase or decrease the amount of reserves that must be held on internal resources. (Scoping/Future)

In some cases, the reserve requirement for a local area can be met more efficiently by importing reserves (i.e., reducing flows into the area and treating the unused capability as reserves) rather than scheduling reserves on internal generation. The report identifies two examples where this functionality would provide significant benefits.

First, the amount of Zone K operating reserves that can be used to satisfy operating reserve requirements for SENY, Eastern NY, and NYCA can be increased in many cases. Internal transmission constraints sometimes limit the extent to which Long Island can export to upstate New York, so the NYISO limits the amount of reserves that can be scheduled on Long Island resources to help satisfy the reserve requirements for SENY, East of Central-East, and NYCA to an amount between 270 and 540 MW. However, Long Island frequently imports more than 1 GW from upstate, so it is frequently possible for a larger amount of reserves on Long Island to support the requirements for SENY, East of Central-East, and NYCA. This is because converting Long Island reserves to energy will simply reduce imports to Long Island, thereby reducing the amount of power that must be generated outside. Hence, we recommend that the NYISO modify the market software to optimize the upper limit on the amount of reserves that can be held on Long Island.[180]

Second, the amount of operating reserves that must be held on internal resources can be reduced when there is unused import capability into SENY and Eastern NY. 10-minute operating reserves are held in eastern NY to ensure that if a large contingency in Eastern New York results in a sudden overload of the Central East Interface, sufficient reserves can be deployed to reduce flows in order to maintain security. This need could also be met partly by reducing flows across Central East before the contingency occurs. In some cases, it may be more costly to schedule reserves on resources in Eastern New York than it would be to simply reduce flows across the Central East Interface. Accordingly, we recommend the NYISO modify the market models to optimize the amount of reserves that should be held in

180 The basis for this recommendation is discussed in Section III.F.

Eastern NY considering that the need can also be met by reducing pre-contingent flows over the Central-East Interface. Likewise, we recommend the NYISO optimize the amount of reserves that should be held in SENY considering that the need can also be met by reducing pre-contingent flows over the UPNY-SENY interface.[181]

17. When a transmission constraint cannot be satisfied, utilize graduated transmission demand curves to set constraint shadow prices. (Scoping/Future)

At the inception of organized wholesale markets, transmission constraints that could not be resolved were "relaxed" (i.e., the limit was raised to a level that would allow the software to find a solution). However, this sort of relaxation procedure does not lead to efficient real-time prices that reflect the true severity of the constraint. To address this pricing concern, some organized wholesale market operators have enhanced their shortage pricing by using transmission demand curves that set the constraint shadow prices when a constraint cannot be resolved. The NYISO has begun to use a graduated transmission demand curve to set prices during some transmission shortages. However, the majority of transmission shortages are still resolved by relaxation rather than the use of a demand curve to set prices. We recommend that the NYISO document the current process and replace it with a process where transmission constraint violations are resolved with graduated transmission demand curves that can vary according to the importance, severity, and/or duration of the transmission constraint violation.[182]

Energy Market Enhancements – BPCG Eligibility Criteria

18. Work with generators in NOx bubbles to ensure their RACT compliance plans use the most economic compliance option available.

Our analyses indicate that in 2015 the NOx bubble constraints did not lead to reductions in NOx emissions and may have actually led to higher overall NOx emissions. These commitments also result in uplift that is socialized to other parties and distorted clearing prices from the commitment of out-of-market resources. Owners of generation in NOx

181 The basis for this recommendation is discussed in Section IX.A.1.

182 The basis for this recommendation is discussed in Section IX.A.2.

bubbles likely have additional RACT compliance options, which may result in lower emissions at lower cost. Hence, we recommend that the NYISO work with generators in NOx bubbles to determine whether they have other available options for NOx RACT compliance that would result in more efficient operation of their units.[183]

Energy Market Enhancements – Fuel Assurance

19. Consider allowing generators to submit offers that reflect certain energy storage and fuel supply constraints in the day-ahead market. (Current Effort, Scoping/Future)

There are at least two types of fuel supply constraint that cannot be adequately reflected in the day-ahead generator offers. First, during periods of high gas demand, generators may be subject to hourly OFOs that require them to schedule a specific quantity of gas in each hour of a 24-hour period. A supplier that offers a flexible range between its minimum and maximum generation level in the day-ahead market is at risk of being scheduled at its maximum generation level for a small number of hours. This would require the generator to schedule enough gas to run at its maximum generation level for the 24-hour gas day, which may be far more than is necessary to meet the day-ahead schedule. This subjects the generator to significant financial risks when it is scheduled in the day-ahead market and it is likely to respond by reflecting these costs in other offer parameters or by reducing its availability. Hence, allowing generators to submit offers that are scheduled subject to an inter-temporal constraint would reduce the OFO-based risks of being available.

Second, during periods of high gas prices, oil-fired and dual-fueled generators provide significant economic and reliability benefits to the system. Many such generators are limited by air permit restrictions and/or by low oil inventories. It would be beneficial for the generator to be able to conserve their limited oil-fired generation for periods when it is most valuable. Currently, the day-ahead market allows Generators to reflect these quantity limitations by raising offer prices, but this is an imprecise method that requires generators to guess what offer price levels are needed to achieve the targeted level of fuel consumption

183 The basis for this recommendation is discussed in Section IX.F.2.

over the day. This leads to both foregone opportunities and unnecessary depletion of oil inventories for limited run hours. Hence, allowing generators to submit offers in the day-ahead market that reflect quantity limitations over the day would allow such generators to be scheduled more efficiently when they are subject to fuel or other production limitations. This capability would also be beneficial at other times of year for hydro-electric and other generators that also have significant energy limitations.[184]

20. Enhance recognition of gas system limitations when scheduling resources to provide operating reserves. (Scoping/Future)

Our analysis suggests that real-time reserve clearing prices (and LBMPs) may have been understated during periods with hourly OFOs. Consequently, the energy market may not provide adequate incentives for generators to make reserve capacity available by maintaining oil inventories and equipment necessary to operate on oil. To address these concerns, we recommend that the NYISO implement procedures that would allow it to identify unloaded capacity that is not capable of responding reliably in the event of a reserve pick-up. This may require generators to provide necessary information in real-time and/or for pipeline operators to indicate when the pipeline has limited capability to support a large pick-up in gas-fired generation over a ten-minute period. Thus, additional scoping is necessary to evaluate the extent of these limitations and the relative costs and benefits of addressing them in the real-time scheduling.[185]

Energy Market Enhancements – DAM Scheduling

21. Improve assumptions in the commitment logic of the DAM to avoid scheduling uneconomic gas turbines.

We have identified several key assumptions and processes in the day-ahead market optimization that cause some uneconomic gas turbines to be scheduled when they are not economic. Because this commitment is not efficient, this process results in lower day-ahead prices in import-constrained load pockets. Hence, we recommend the NYISO modify key

184 The basis for this recommendation and the NYISO's current effort are discussed in Section IX.B.2.

185 The basis for this recommendation is discussed in Section IX.B.2.

assumptions and processes in the day-ahead market commitment logic to avoid scheduling uneconomic gas turbines.[186]

C. Discussion of Recommendations Made in Previous SOM Reports

During the development of each State of the Market Report, we review the progress that has been made toward the evaluation and/or implementation of recommendations made in previous reports. Normally, we remove a recommendation from the list if the NYISO has responded to the substance of the recommendation by modifying an operating practice or by filing market rule changes and the Commission has accepted them (or they are largely uncontested). In some cases, we remove a recommendation from the list if it becomes apparent that the cost of implementation would be significantly greater than originally anticipated, there is a material change in the underlying drivers for the recommendation, or there is little prospect of its being adopted.

1. Market Developments Since the 2014 SOM Report

The NYISO has moved forward with market reforms in response to the following recommendations from the 2014 State of the Market Report.

#6 – *Work with adjacent ISOs on rules to better utilize the transfer capability between regions by coordinating intra-hour transactions.* The NYISO responded to this high priority recommendation with several significant reforms in recent years, most notably by implementing the M2M congestion management process with PJM in January 2013, the CTS process with PJM in November 2014, and the CTS process with ISO New England in December 2015. [187]

#11 – *Adopt Comprehensive Scarcity Pricing*. The Commission accepted the NYISO's proposed changes for implementation before the summer of 2016. [188] Comprehensive Scarcity Pricing is a

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186 The basis for this recommendation is discussed in Section V.A.

187 The performance of these market processes is discussed in Sections VII.D and IX.D.

188 This project is discussed in Section X.

multi-faceted project that addresses the substance of three recommendations that were made in the 2013 SOM Report:

- #9 – *Modify real-time pricing during demand response activations*. This recommendation was to avoid over-pricing energy and reserves during some DR activations and to avoid perverse incentives for scheduling external transactions in the day-ahead and real-time markets when scarcity pricing was in effect.
- #10a – *Create a SENY 30-minute operating reserve zone to reflect the requirements of NYSRC Rule F-R1c*. Although the Comprehensive Shortage Pricing project created this reserve zone, the Comprehensive Scarcity Pricing project will set the reserve demand curve at a level that reflects the need to satisfy this reliability rule. [189]
- #10c – *Increase NYCA 30-minute operating reserve demand curve from $50/$100/$200 to $100/$250/$500 per MWh*. The Comprehensive Scarcity Pricing project will set this demand curve to more appropriate levels during tight system conditions. [190]

#16 – *Require Generators to provide timely information on fuel availability (e.g., on-site inventory, scheduled deliveries, & nominations)*. The NYISO implemented a process before the 2015-16 winter season to collect information from generators regarding their fuel supplies leading up to periods of cold weather.

2. Other Recommendations Not Included on the List for 2015

Previous state of the market reports have discussed other recommendations that are not included in this report. First, 2012 State of the Market Report recommendation #4 was to *Select the most economic generating technologies to establish the demand curves in the current demand curve reset process for the capacity market and modify the criteria for setting the excess level*. The proxy unit technology should be selected balancing the following two factors. There is some advantage to using a peaker as the proxy unit in the demand curve reset partly because it can be built more quickly and on a smaller scale than most other technologies and because it is more reliant on capacity market revenues than other technologies. On the other hand, the demand curve unit must also be reasonably competitive with other technologies. The 2012

189 Under the reorganized NYSRC Reliability Rules & Compliance Manual, this rule is now in Section C.2 Transmission Operation: Post-Contingency Operation, Requirement R1.

190 The underlying reliability need is based on: NYSRC Reliability Rules & Compliance Manual, Version 35, Section E.1 Operating Reserves: Establishing the Minimum Level of Operating Reserve, Requirement R6.

recommendation was originally made when the LMS 100 was thought to be the most economic peaking unit that could be built in a non-attainment area and a combined cycle unit was known to be far more economic under a wide range of circumstances.[191] However, since the emergence of Frame 7 units that can be equipped with selective catalytic reduction to control emissions, there is no longer a compelling reason to use a combined cycle as the demand curve unit, so we removed this recommendation in subsequent reports.

Second, the state of the market reports from 2002 to 2012 recommended that the NYISO adopt virtual trading at the sub-zonal level. Since its introduction in November 2001, virtual trading at the zone level has consistently helped improve day-ahead scheduling decisions when systematic differences in modeling and/or behavior between the day-ahead and real-time markets would have otherwise led to under/over-commitment in the day-ahead market.[192] Virtual trading at the subzone level would likely improve the efficiency of day-ahead commitments, fuel procurement decisions, and consistency between day-ahead and real-time prices in areas with persistent differences. Although we continue to see significant persistent differences between day-ahead and real-time prices and associated scheduling inefficiencies that could be ameliorated by virtual trading at the subzone level, we removed the recommendation from the list after the 2012 report because the proposal did not make significant progress in the stakeholder process in the previous eleven years.

Third, recent state of the market reports have identified that high prices occasionally occur during low demand periods when a large number of transmission and generation outages are scheduled to occur at the same time.[193] It can be difficult for market participants to anticipate when scheduled outages will lead to high prices since individual market participants usually do not know when competing resources will be on outage. Since the NYISO receives advanced notice of all planned outages, there may be some beneficial role for the NYISO to play in helping

191 Appendix Section I.G shows that the combined cycle unit has a slightly higher CONE, but it would earn much higher energy and ancillary services net revenue than an LMS 100.

192 Beginning in 2002, each state of the market report has discussed the effects of virtual trading and inconsistencies between day-ahead and real-time market outcomes that would be addressed by virtual trading at the sub-zone level.

193 See for example Section IV.A in this report.

to coordinate outage scheduling based on economic criteria, not just reliability criteria. However, this type of role would require the NYISO to develop new and potentially complex processes, to consider the incentives for market participants to provide biased or unreliable information to the process, and to assess the potential for other unintended consequences. Given the significant cost of evaluating these issues, the current frequency of high price conditions that are caused by planned outages does not justify making a recommendation related to this issue at this time.

Analytic Appendix

2015 State of the Market Report
For the
New York ISO Markets

I. Market Prices and Outcomes

The New York ISO operates a multi-settlement wholesale market system consisting of financially-binding day-ahead and real-time markets for energy, operating reserves, and regulation. Through these markets, the NYISO commits generating resources, dispatches generation, procures ancillary services, schedules external transactions, and sets market-clearing prices based on supply offers and demand bids. The NYISO also operates markets for transmission congestion contracts and installed capacity, which are evaluated in Sections III and VI of the Appendix.

This section of the appendix summarizes the market results and performance in 2015 in the following areas:

- Wholesale market prices;
- Fuel prices, generation by fuel type, and load levels;
- Fuel usage under tight gas supply conditions;
- Ancillary services prices;
- Price corrections;
- Long-term economic signals governing new investment and retirement decisions;
- Day-ahead energy market performance; and
- Day-ahead ancillary services market performance.

A. Wholesale Market Prices

Figure A-1: Average All-In Price by Region

The first analysis summarizes the energy prices and other wholesale market costs by showing the all-in price for electricity, which reflects the total costs of serving load from the NYISO markets. The all-in price includes the costs of energy, uplift, capacity, ancillary services, and NYISO cost of operations. The all-in price is calculated for various locations in New York State because capacity and energy prices vary substantially by location.

The energy prices in this metric are load-weighted average real-time energy prices. The capacity component is calculated based on clearing prices in the monthly spot auctions and capacity obligations in each area, allocated over the energy consumption in that area. The uplift component is based on local and statewide uplift from Schedule 1 charges, allocated over the energy consumed in the area. For the purposes of this metric, costs associated with ancillary services are distributed evenly across all locations. Figure A-1 shows the average all-in prices along with the average natural gas prices from 2009 to 2015 at the following seven locations: (a) the West Zone (i.e., Zone A); (b) the North Zone (i.e., Zone D); (c) Central New York (i.e., Zones B, C, and E); (d) the Capital Zone (i.e., Zone F); (e) the Lower Hudson Valley region, which includes three load zones (i.e., Zones G, H, and I); (f) New York City (i.e., Zone J); and

(g) Long Island (i.e., Zone K). The majority of congestion in New York occurs between and within these regions.

Natural gas prices are based on the following gas indices (plus a transportation charge of $0.20 per MMbtu): (a) the Dominion North index for the West Zone and areas in Central New York; (b) the Iroquois Waddington index for North Zone; (c) the Iroquois Zone 2 index for the Capital Zone and Long Island; (d) the average of Iroquois Zone 2 index and the Texas Eastern M3 index for Lower Hudson Valley; and (e) the Transco Zone 6 (NY) index for New York City. A 6.9 percent tax rate is also reflected in the natural gas prices for New York City.

Figure A-1: Average All-In Price by Region
2009-2015

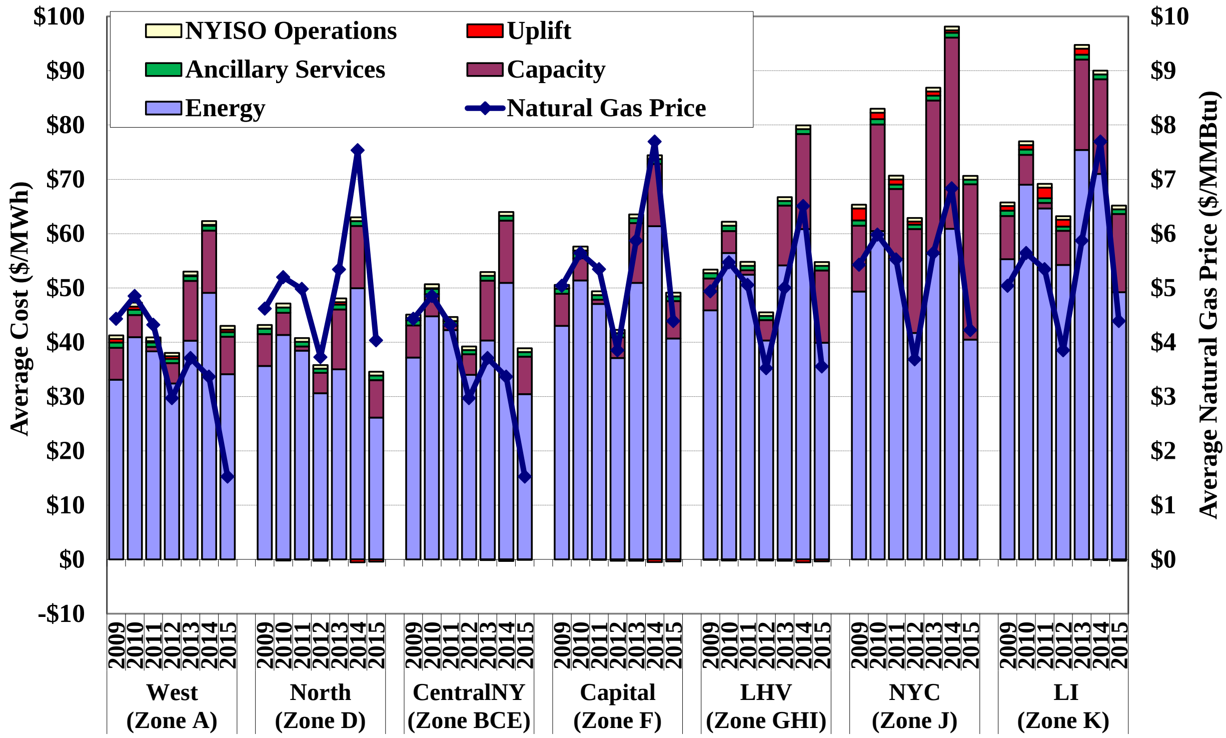


Figure A-2: Day-Ahead Electricity and Natural Gas Costs

Figure A-2 shows load-weighted average natural gas costs and load-weighted average day-ahead energy prices in each month of 2015 for the seven locations shown in Figure A-1. The table in the chart shows the annual averages of these quantities for 2014 and 2015. Although much of the electricity used by New York consumers is generated from hydro and nuclear generators, natural gas units usually set the energy price as the marginal units, especially in Eastern New York. This is evident from the strong correlation of electricity prices with natural gas costs shown in the figure.

Figure A-2: Day-Ahead Electricity Prices and Natural Gas Costs
By Month, 2015

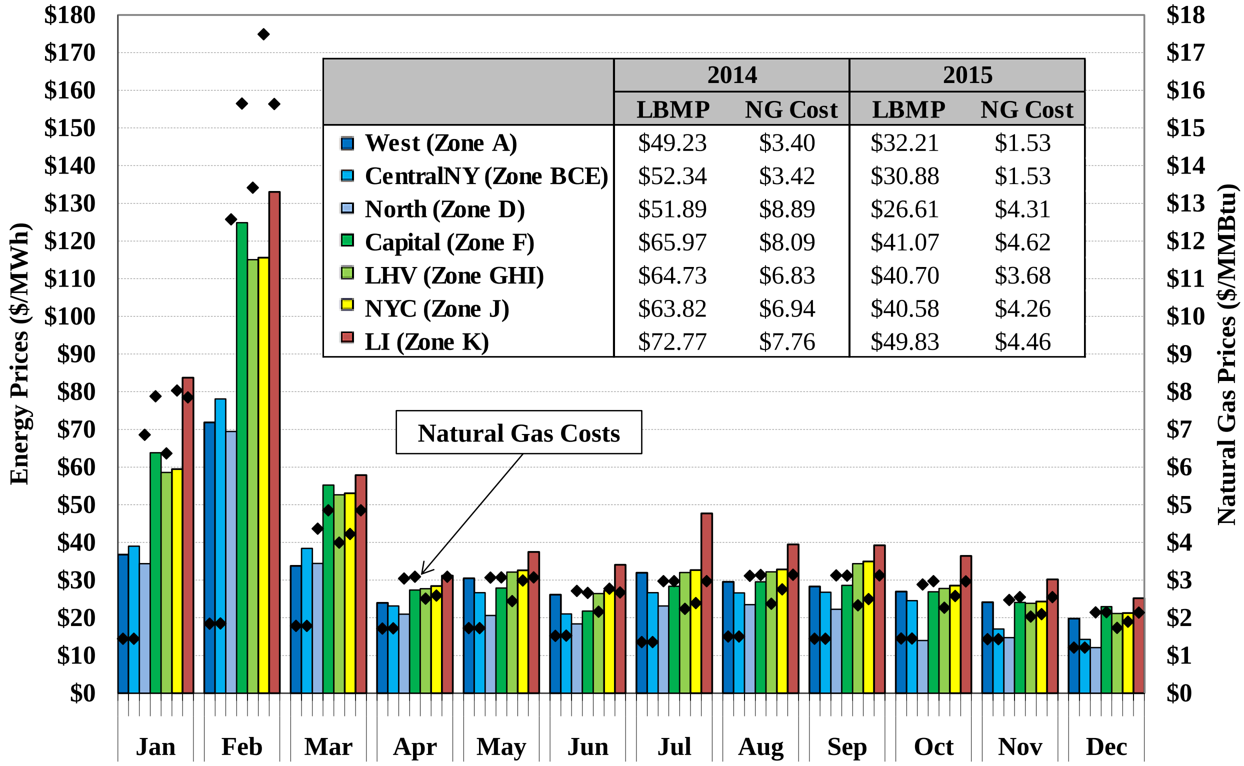


Figure A-3: Average Monthly Implied Marginal Heat Rate

To highlight changes in electricity prices that are not driven by changes in fuel prices, the following figure summarizes the monthly average marginal heat rate that would be implied if natural gas were always on the margin.

The *Implied Marginal Heat Rate* equals the day-ahead electricity price minus a generic unit Variable Operations and Maintenance ("VOM") cost then divided by the fuel cost that includes the natural gas cost and greenhouse gas emission cost (i.e., RGGI Allowance Cost).[194] Thus, if the electricity price is $50 per MWh, the VOM cost is $3 per MWh, the natural gas price is $5 per MMbtu, and the RGGI clearing price is $3 per CO_2 allowance, this would imply that a generator with a 9.1 MMbtu per MWh heat rate is on the margin.[195]

Figure A-3 shows the load-weighted average implied marginal heat rate in each month of 2015 for the seven locations shown in Figure A-1 and in Figure A-2. The table in the chart shows the annual averages of the implied marginal heat rates in 2014 and in 2015 at these seven locations.

194 The generic VOM cost is assumed to be $3 per MWh in this calculation.

195 In this example, the implied marginal heat rate is calculated as ($50/MWh – $3/MWh) / ($5/MMbtu + $3/ton * 0.06 ton/MMbtu emission rate), which equals 9.1 MMbtu per MWh.

By adjusting for the variation in natural gas prices, the implied marginal heat rate shows more clearly the seasonal variation in electricity prices.

Figure A-3: Average Monthly Implied Marginal Heat Rate
Day-Ahead Market, 2015

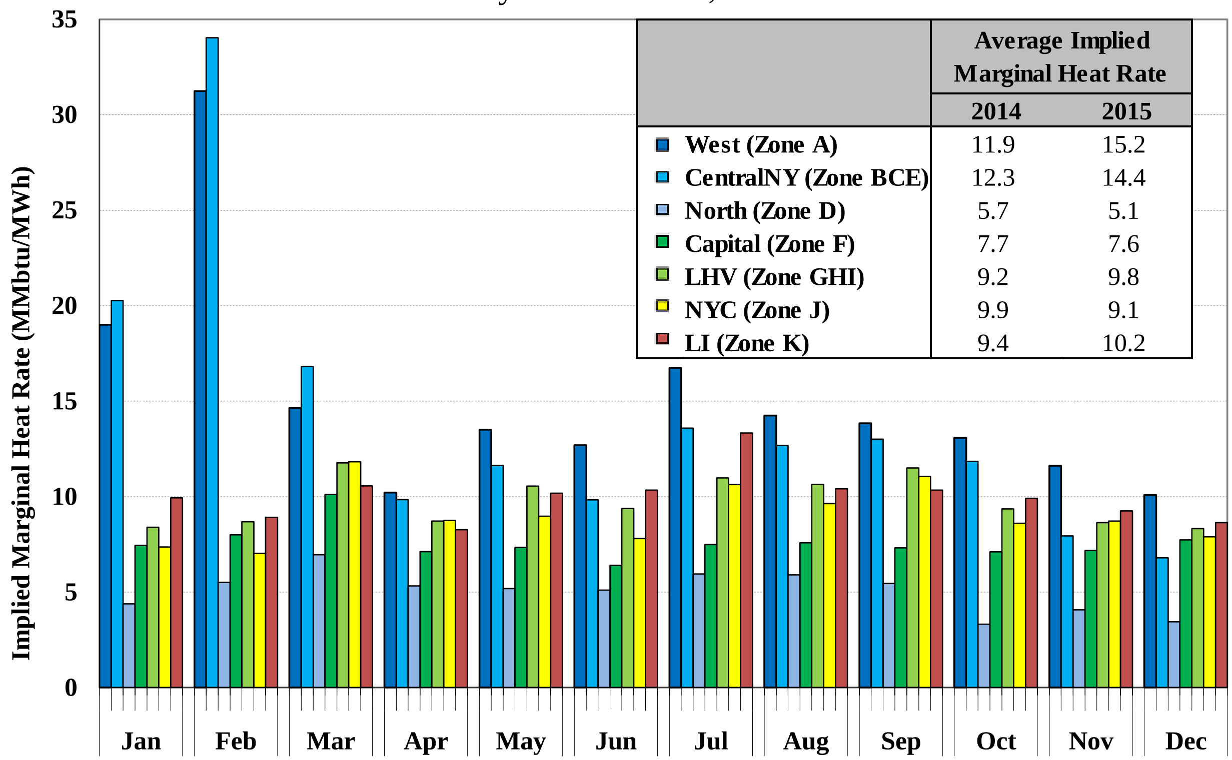
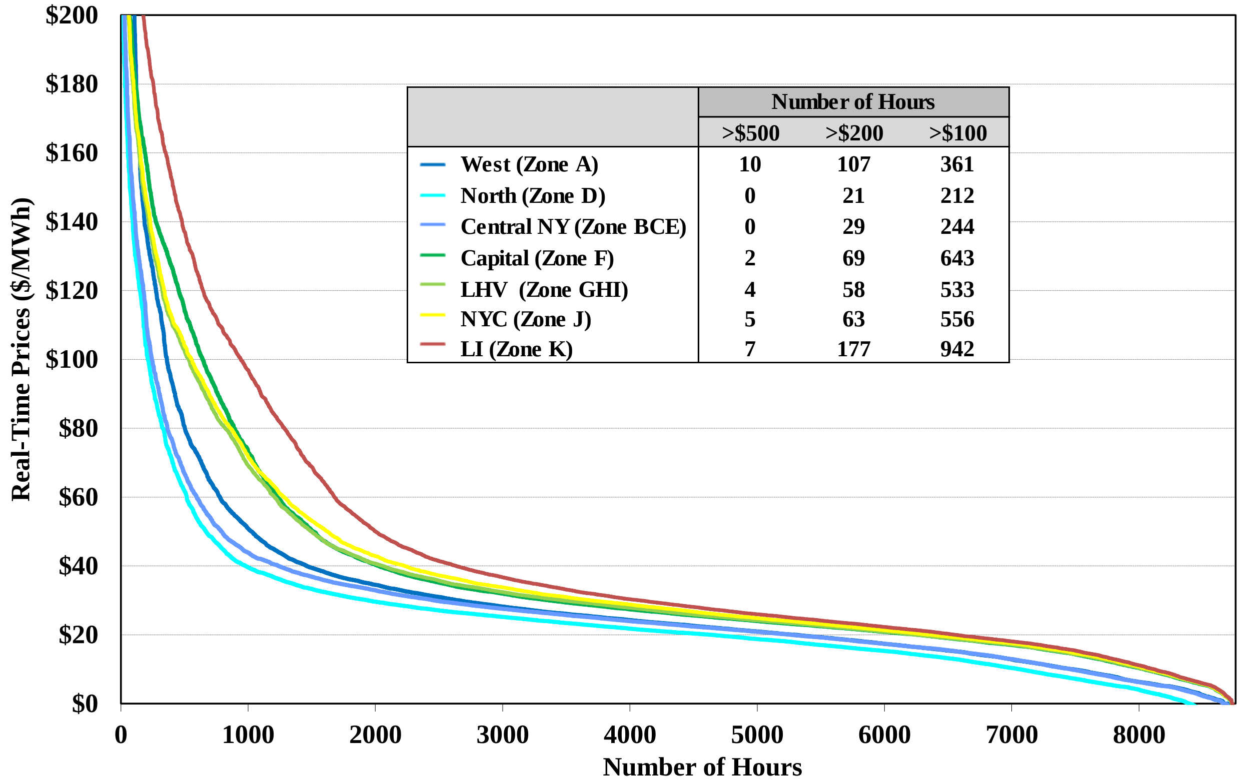


Figure A-4 – Figure A-5: Price Duration Curves and Implied Heat Rate Duration Curves

The following two analyses illustrate how prices varied across hours in recent years and at different locations. Figure A-4 shows seven price duration curves for 2015, one for each of the following locations: (a) the West Zone (i.e., Zone A); (b) the North Zone (i.e., Zone D); (c) Central New York (i.e., Zones B, C, and E); (d) the Capital Zone (i.e., Zone F); (e) the Lower Hudson Valley region, which includes three load zones (i.e., Zones G, H, and I); (f) New York City (i.e., Zone J); and (g) Long Island (i.e., Zone K). Each curve in Figure A-4 shows the number of hours on the horizontal axis when the load-weighted average real-time price for each region was greater than the level shown on the vertical axis. The table in the chart shows the number of hours in 2015 at each location when the real-time price exceeded $100, $200, and $500 per MWh.

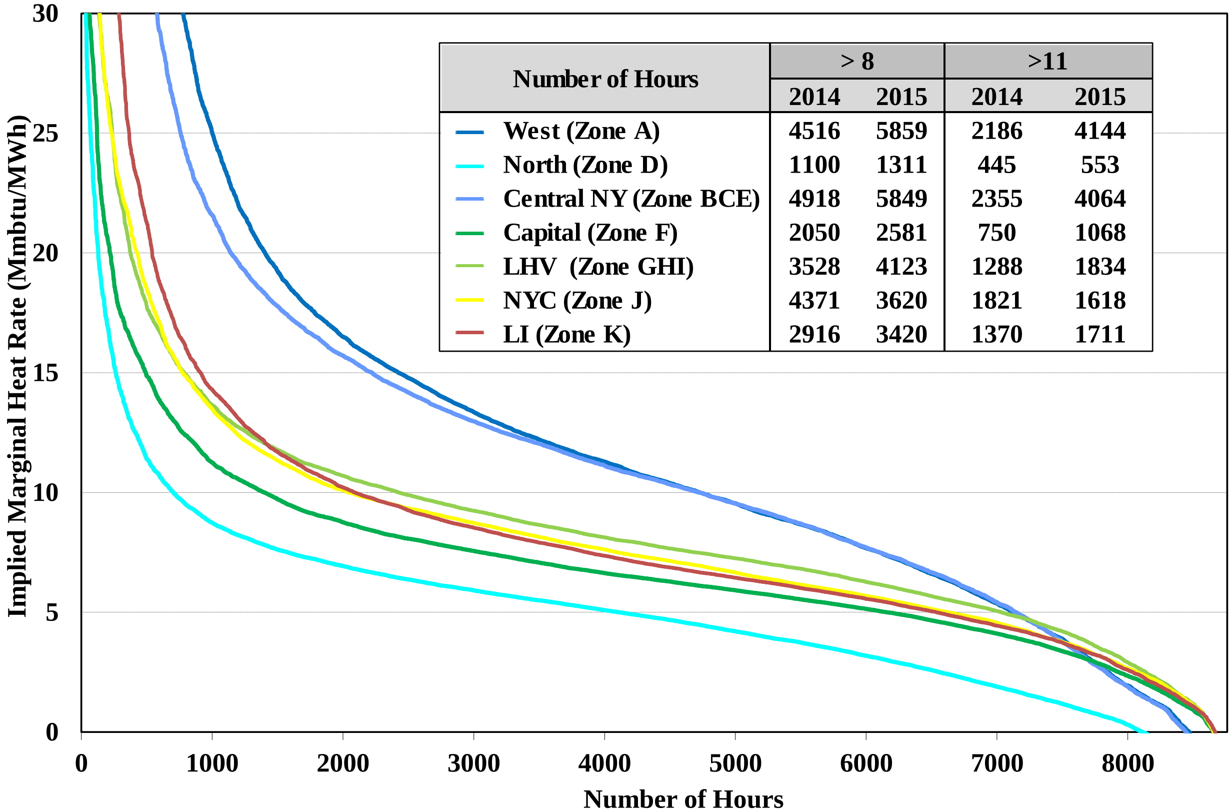
The price duration curves show the characteristic distribution of prices in wholesale power markets, in which a small number of hours exhibited very high prices that are typically associated with shortages. During shortages, prices can rise to more than ten times the average price level, so a small number of hours with price spikes can have a significant effect on the average price level. Fuel price changes from year to year can be revealed by the flatter portion of the price duration curve, since fuel price changes affect power prices in almost all hours.

Figure A-4: Real-Time Price Duration Curves by Region
2015



To identify factors affecting power prices other than fuel price changes, Figure A-5 shows corresponding implied marginal heat rate duration curves at each location during 2015. Each curve shows the number of hours on the horizontal axis when the implied marginal heat rate for each sub-region was greater than the level shown on the vertical axis. The calculation of the implied marginal heat rate is similar to the one in Figure A-3 except that this is based on real-time prices. The inset table compares the number of hours in each region when the implied heat rate exceeded 8 and 11 MMbtu per MWh between 2014 and 2015.

Figure A-5: Implied Heat Rate Duration Curves by Region
2015



Number of Hours	> 8		>11	
	2014	2015	2014	2015
West (Zone A)	4516	5859	2186	4144
North (Zone D)	1100	1311	445	553
Central NY (Zone BCE)	4918	5849	2355	4064
Capital (Zone F)	2050	2581	750	1068
LHV (Zone GHI)	3528	4123	1288	1834
NYC (Zone J)	4371	3620	1821	1618
LI (Zone K)	2916	3420	1370	1711

Key Observations: Wholesale Market Prices

- Average all-in prices fell roughly 27 percent in the downstate areas (i.e., New York City and Long Island) from 2014 to 2015 and fell 30 to 44 percent in the upstate regions.
  - The decreases were mainly attributable to significant reductions in prices for both energy and capacity
  - However, the decrease in energy prices was more pronounced and energy accounts for the vast majority of the all-in price in all of the regions.
- Capacity costs accounted for 40 percent of the all-in price in New York City and 14 to 24 percent of the all-in price in the other six regions.
  - Higher capacity costs in New York City reflect that: a) there is generally more excess installed capacity outside New York City than inside New York City; and b) the Reference Point on the capacity demand curve is higher for New York City than for other areas.
- Average energy prices decreased by 31 to 48 percent across all New York regions from 2014 to 2015.
  - Most of the annual reductions occurred in the first quarter of 2015, driven primarily by significantly lower natural gas prices than from a year ago (see Section I-B).

   – Milder winter weather also led to decreased peaking conditions and higher imports from Ontario and Quebec, also contributing to lower energy prices in the first quarter of 2015 (see Section I-D and Section IV-A.

- The reduction in energy prices in the other three quarters of 2015 was much less pronounced. It was also attributable to a (much-less-pronounced) reduction in natural gas prices (see Section I-B).
   – However, the reduced gas prices were partly offset by higher load levels, particularly in the summer months (see Section I-D).

- Average capacity costs decreased notably in all regions from 2014 to 2015, which fell 17 percent in Long Island, 19 percent in New York City, 24 percent in the Lower Hudson Valley (i.e., Zones G-I), and 40 percent in the Rest of State.
   - The primary driver was the increase in installed capacity of more than 1,100 MW over the period as multiple units returned to service and new wind capacity additions.
   - Increased SCR sales and lower ICAP requirements in most capacity zones also contributed to the decreases in capacity costs.
   - However, the reduction of capacity prices in the G-J Locality was partly offset by a significant increase in the ICAP requirement (see Section VI-E).
- Unlike in the prior years, the West Zone exhibited: a) the highest average energy prices in Western New York (i.e., including Zones A to E); and b) the largest number of hours (i.e., 10 hours) when real-time prices exceeded $500 per MWh in all areas.
   - This was driven by significantly increased congestion on the 230 kV facilities in the West Zone in 2015 (see Section III).
   - Transmission congestion in the West Zone could not be resolved using available physical resources in roughly 2 percent of all intervals in 2015, resulting in transmission shortages and very high congestion costs in this area during these intervals (see Sections V-E and V-H).
- Although high energy prices occurred less frequently in 2015 than in 2014, the implied marginal heat rate rose in most areas.
   - The increase generally reflected higher load levels and lower natural gas prices on an average basis.
   - The implied marginal heat rates in the West Zone and Central New York (including Zones B, C, E) rose significantly from 2014. This was because:
      – Generators in Western New York and the adjacent markets are less reliant on natural gas than Eastern New York, so lower natural gas prices do not have as much effect on electricity prices in Western New York; and
      – Energy prices in Western New York often rose to the levels in Eastern New York when the Central-East interface was not fully constrained, while natural gas prices for most of Western New York (indexed to Dominion North trading hub in this

report) were still very low. This was most significant during the first quarter of 2015.

- The average implied marginal heat rate in the North Zone was low, indicating that gas-fired resources in this area were rarely economic.
- The average implied marginal heat rate fell modestly in New York City from 2014.
  - The higher heat rate in 2014 was partly attributable to larger gas spreads between New York City and the rest of Eastern New York in the summer of 2014, which lowered the costs of New York City generation relative to other generation in Eastern New York during this period.

B. Fuel Prices and Generation by Fuel Type

Figure A-6 – Figure A-8: Monthly Average Fuel Prices and Generation by Fuel Type

In recent years, fossil fuel price fluctuations have been the primary driver of changes in wholesale power prices because most of the marginal production costs of fossil fuel generators are fuel costs. Although much of the electricity generated in New York is from hydroelectric and nuclear generators, natural gas units are usually the marginal source of generation. Hence, natural gas prices more directly affect wholesale power prices.

Some generators in New York have dual-fuel capability, allowing them to burn either oil or natural gas. These generators usually burn the most economic fuel, although some may burn oil even when it is more expensive if natural gas is difficult to obtain on short notice or if there is uncertainty about its availability. In addition, New York City and Long Island reliability rules (which are discussed further in Section V-I) sometimes require that certain units burn oil in order to limit the exposure of the electrical grid to possible disruptions in the supply of natural gas. Since most large steam units can burn residual fuel oil (No.6) or natural gas, the effects of natural gas price spikes on power prices are partly mitigated by generators switching to fuel oil.

Natural gas prices are normally relatively consistent between different regions in New York. However, bottlenecks on the natural gas system can sometimes lead to significant differences in delivered gas costs by area, which can produce comparable differences in energy prices when network congestion occurs. The natural gas price differences generally emerge by pipeline and zone. We track natural gas prices for the following pipelines/zones, which serve different areas in New York.

- Tennessee Zone 6 prices are representative of gas prices in portions of New England;
- Transco Zone 6 (NY) prices are representative of natural gas prices in New York City;
- Iroquois Zone 2 prices are representative of gas prices in Capital Zone and Long Island;
- Iroquois Zone 2 prices and Texas Eastern M3 prices are generally representative of natural gas prices in the Lower Hudson Valley; and
- Dominion North prices are representative of prices in portions of Western New York.

Figure A-6 shows average coal, natural gas, and fuel oil prices by month from 2012 to 2015. The table compares the annual average fuel prices for these four years.

Figure A-6: Monthly Average Fuel Index Prices [196]
2012 – 2015

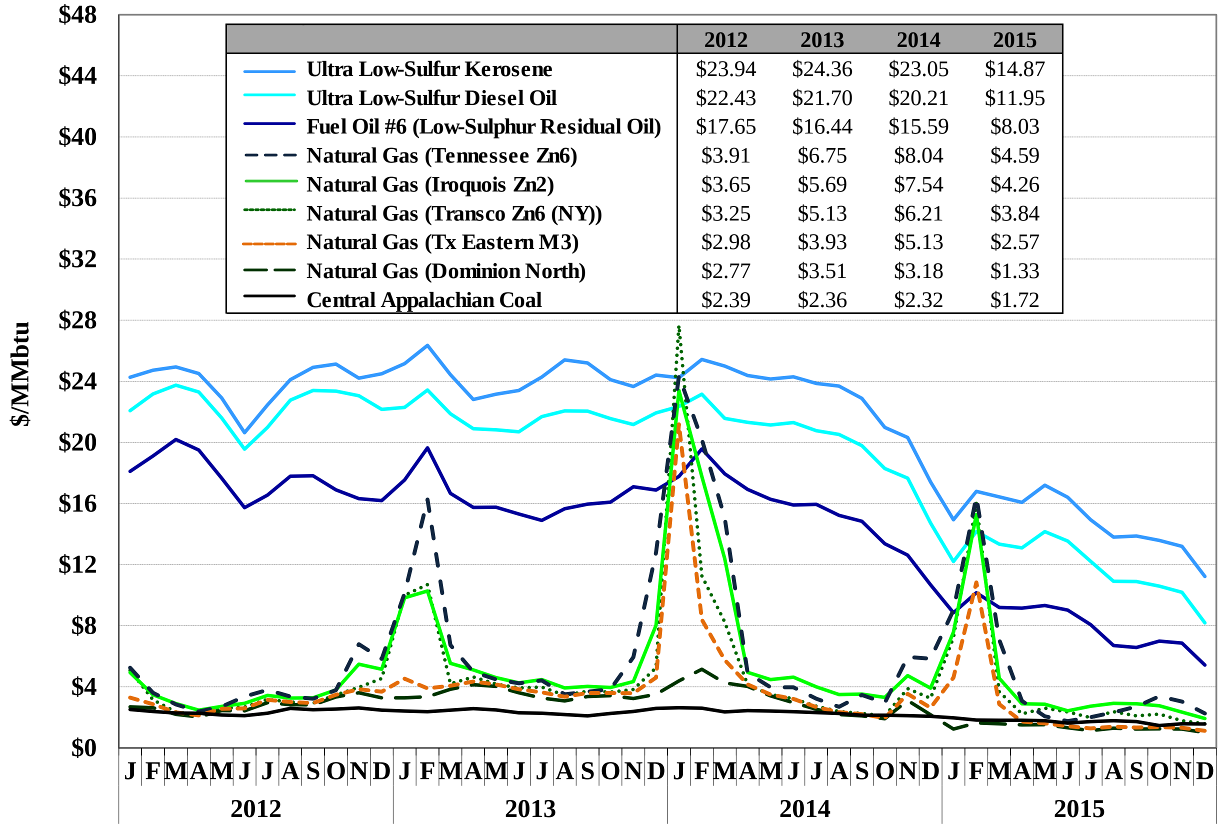


Figure A-7 shows the quantities of generation by fuel type in seven regions of New York in each quarter of 2015 along with the same numbers for the whole NYCA. [197] The table in the chart shows the annual averages of generation by fuel type from 2013 to 2015.

Figure A-8 summarizes how frequently each fuel type was on the margin and setting real-time energy prices in New York State and in each region of the state during 2015. More than one type of unit may be marginal in an interval, particularly when a transmission constraint is binding (different fuels may be marginal in the constrained and unconstrained areas). Hence, the total for all fuel types may be greater than 100 percent. For example, if hydro units and gas units were both on the margin in every interval, the total frequency shown in the figure would be 200 percent. When no unit is on the margin in a particular region, the LBMPs in the region are set

196 These are index prices that do not include transportation charges or applicable local taxes.

197 Pumped-storage resources in pumping mode are treated as negative generation. The “Other” category includes methane, refuse, solar, and wood.

by: (a) generators in other regions in the vast majority of intervals; or (b) shortage pricing of ancillary services or transmission constraints in a small share of intervals.

The fuel type for each generator in both charts is based on its actual fuel consumption reported to the U.S. Environmental Protection Agency ("EPA") and the U.S. Energy Information Administration ("EIA").

Figure A-7: Generation by Fuel Type in New York
By Quarter by Region, 2015

Year	Internal Generation by Fuel Type in NYCA (GW)								
	Nuclear	Hydro	Coal	NG-CC	NG-Other	Oil	Wind	Other	Total
2013	5.06	2.71	0.53	4.93	1.52	0.10	0.40	0.32	15.56
2014	4.90	2.84	0.52	4.96	1.61	0.24	0.45	0.32	15.84
2015	5.06	2.81	0.25	5.19	1.66	0.21	0.45	0.31	15.94

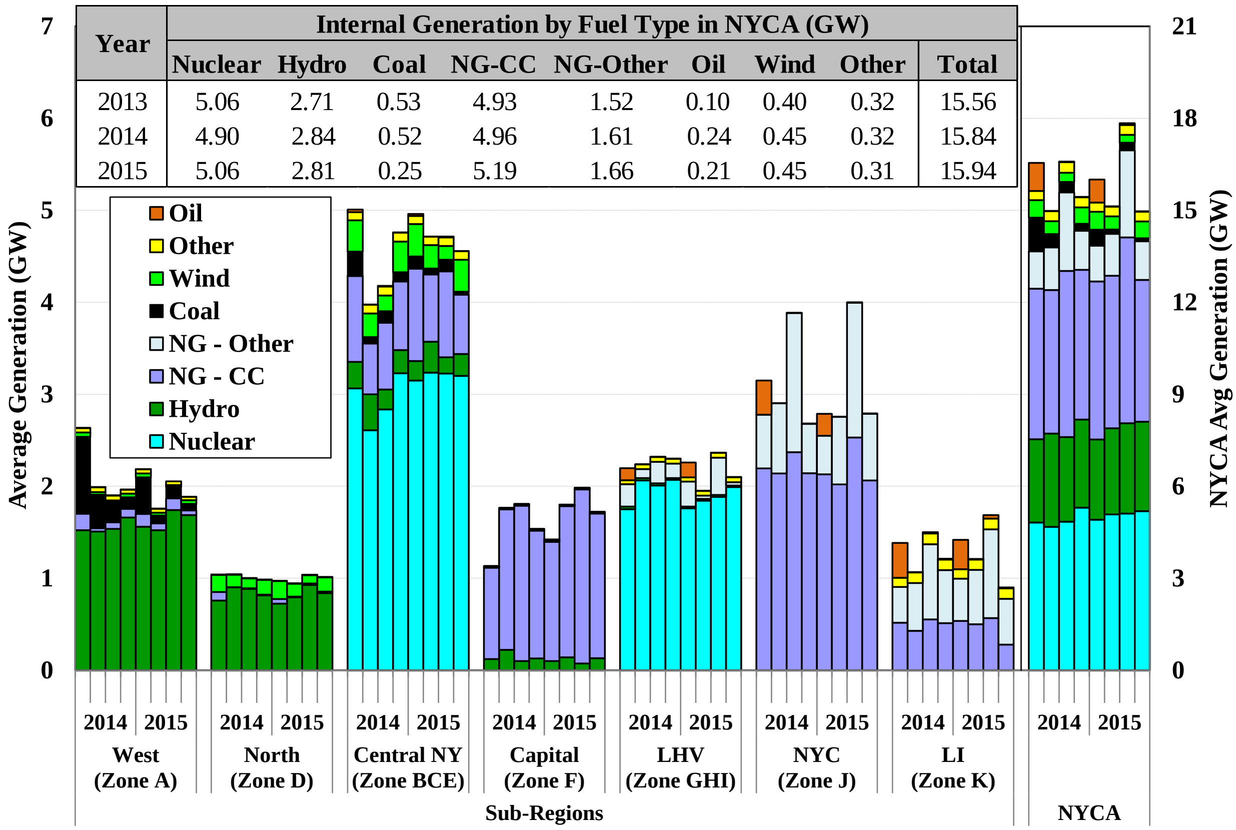
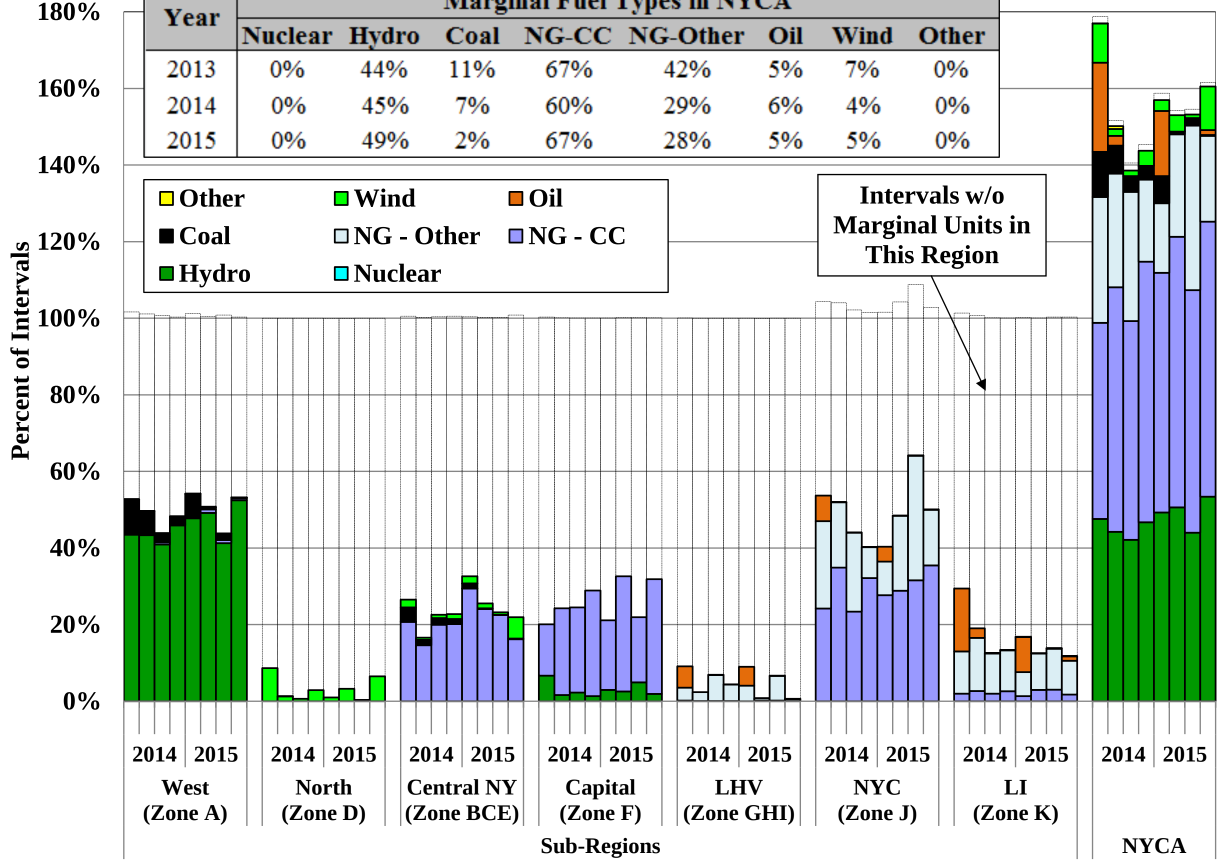


Figure A-8: Fuel Types of Marginal Units in the Real-Time Market in New York
By Quarter by Region, 2015



Year	Marginal Fuel Types in NYCA							
	Nuclear	Hydro	Coal	NG-CC	NG-Other	Oil	Wind	Other
2013	0%	44%	11%	67%	42%	5%	7%	0%
2014	0%	45%	7%	60%	29%	6%	4%	0%
2015	0%	49%	2%	67%	28%	5%	5%	0%

Key Observations: Fuel Prices and Generation by Fuel Type

- 2015 was a year marked by notable decreases in prices for all reported fuels.
- On average, reported fuel oil prices fell 35 to 49 percent from 2014 to 2015.
  - After four years of stability, fuel oil prices started to fall in the middle of 2014 and continued the downward movement throughout 2015.
    - By the end of 2015, fuel oil prices had declined by 54 to 66 percent over the one-and-a-half-year period from June 2014.
  - Lower fuel oil prices helped reduce the severity of natural gas price spikes during winter operations.
- After years of relative stability, Central Appalachian coal prices also started a downward movement in 2015, falling 26 percent from 2014 to 2015 on an annual average basis.
- Natural gas prices, which have the strongest effect on wholesale energy prices, exhibited the most variation over time and between regions in recent years.
  - These variations affected generation patterns, import levels, congestion patterns, energy price spreads, and uplift charges, which are discussed throughout the report.

- Natural gas prices and gas spreads between regions (e.g., between Western and Eastern New York) exhibited a typical seasonal pattern, rising in the winter months as a result of higher demand.
  - Natural gas prices in Eastern New York rose to an average of $6 to $11 per MMBtu in the first quarter of 2015, up significantly from an average of less than $3 per MMBtu in the rest of the year.
  - Similarly, gas spreads between Western and Eastern New York averaged 310 to 630 percent in the first quarter of 2015, up notably from an average of 67 to 107 percent in other quarters.
- Natural gas prices also showed notable year-over-year variations from 2014 to 2015, which fell by an average of 58 percent in most of Western New York, 38 percent in New York City, and 43 to 50 percent in rest of Eastern New York.
  - Natural gas prices fell to multi-year lows in 2015 across the system, driven primarily by increased production from the Marcellus and Utica shales.
  - The reductions in the winter months were also attributable to lower fuel oil prices and more LNG imports to the region (from mid-Atlantic up to New Brunswick).
- Gas-fired (43 percent), nuclear (32 percent), and hydro (18 percent) generation accounted for more than 90 percent of all internal generation in New York during 2015.
  - Average nuclear generation rose 160 MW from 2014, reflecting fewer planned and forced outages.
  - Average coal-fired generation fell by more than 50 percent from 2014 largely because low natural gas prices in Western New York made coal production less economic.
  - Gas-fired generation rose modestly from 2014, reflecting higher load levels and lower natural gas prices in 2015.
    - Gas-fired steam turbine generators produced notably more in the third quarter of the year in both New York City and Long Island than in the other quarters.
    - This generally reflected higher load levels and associated higher needs for local reliability in the downstate area during the summer season.
  - Average oil-fired generation fell modestly from 2014.
    - Similar to 2014, more than 90 percent of the annual production in 2015 occurred in the first quarter during periods of high natural gas prices.
    - However, lower natural gas prices and higher gas supply in the first quarter of 2015 led to a 20 percent reduction in oil-fired generation from a year ago.
  - Average generation from wind, hydro, and other renewable resources did not vary significantly from 2014 to 2015.
- Gas-fired resources (67 percent for combined cycle units) and hydro resources (49 percent) were on the margin most frequently during 2015.

- Most hydro units on the margin have storage capacity, leading them to offer based partly on the opportunity cost of foregone sales in other hours (when gas units are marginal). Thus, the price levels set by hydro units are also affected by natural gas prices.
- The frequency of price-setting by hydro units increased noticeably in 2015 as a result of increased congestion in the West Zone that was often relieved by redispatching hydro resources."
- Both gas-fired and hydro units were on the margin slightly more frequently than a year ago, reflecting more frequent congestion in 2015.
  - However, coal units were on the margin much less frequently despite increased congestion in the West Zone because most coal-fired generation was dispatched out-of-merit.

C. Fuel Usage Under Tight Gas Supply Conditions

The supply of natural gas is usually tight in the winter season due to increased demand for heating. Extreme weather conditions often lead to high and volatile natural gas prices. A large share of generators in Eastern New York have dual-fuel capability, allowing them to switch to an alternative fuel when natural gas becomes expensive or unavailable. However, the increase of oil-fired generation during such periods may be limited by several factors, including:

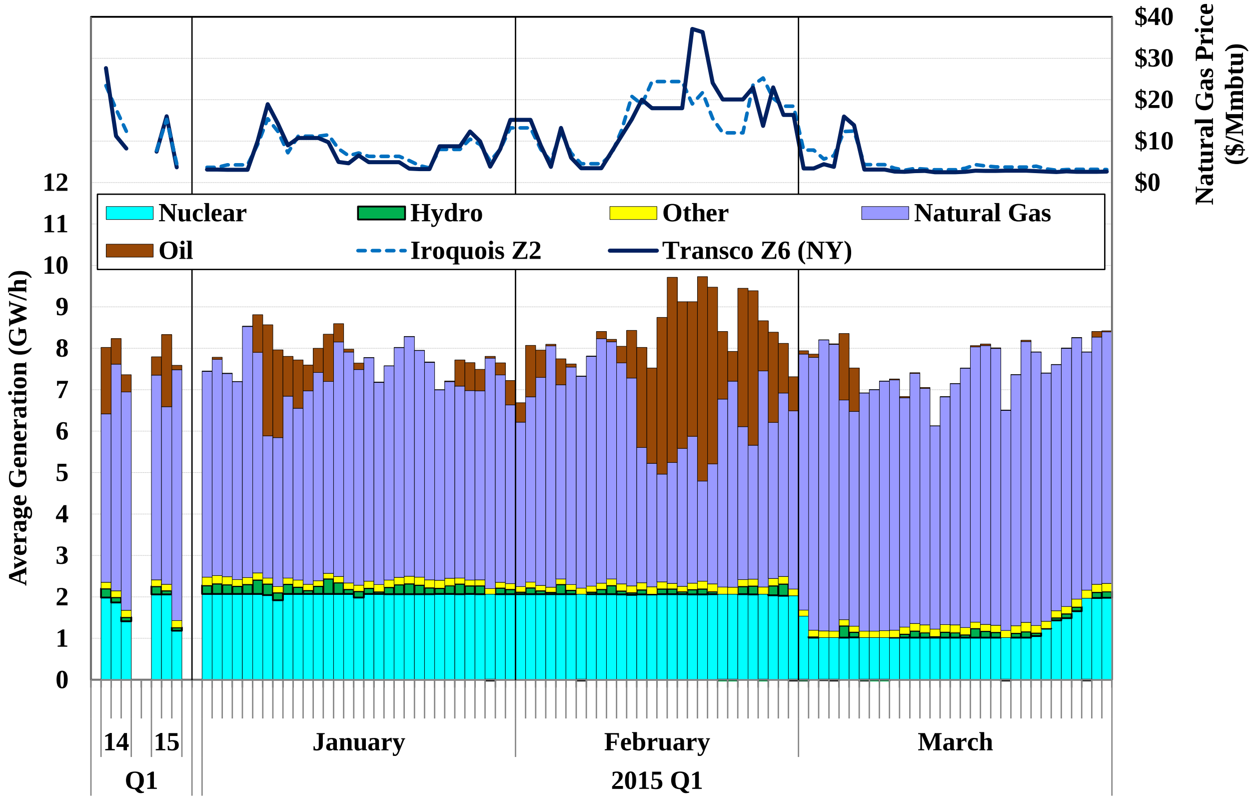
- Not having the necessary air permits;
- Low on-site oil inventory; and
- Physical limitations and gas scheduling timeframes that may limit the flexibility of dual-fueled units to switch from one fuel to the other.

This sub-section examines actual fuel usage in the winter of 2015, focusing on days when supply of natural gas was very tight. This had a big impact on the system operations, especially in Eastern New York.

Figure A-9: Actual Fuel Use and Natural Gas Prices in the Winter

Figure A-9 summarizes the average hourly generation by actual fuel consumed in Eastern New York on a daily basis during the first quarter of 2015. The figure shows actual generation for the following fuel categories: (a) oil; (b) natural gas; (c) hydro; (d) nuclear; and (e) all other fuel types as a group. In addition, the figure shows the day-ahead natural gas price index for Iroquois Zone 2 and Transco Zone 6 (NY). The figure also compares these quantities by month between the first quarter of 2014 and 2015. Each day in the chart represents a 24-hour gas day, which starts from 10 am on each calendar day and ends at 10 am on the next calendar day.

Figure A-9: Actual Fuel Use and Natural Gas Prices
Eastern New York, First Quarter of 2015



Key Observations: Fuel Usage Under Tight Gas Supply Conditions

- Cold weather led natural gas prices for Transco Z6 NY and/or Iroquois Z2 to rise above $15 per MMbtu on 22 days in Eastern New York in the first quarter of 2015.
  - Oil-fired generation rose sharply on these days, averaging over 2.2 GW.
  - Gas prices exceeded $15 per MMbtu on 17 consecutive days from mid to late February because of extreme cold weather conditions.
    - This 17-day period accounted for 68 percent of oil-fired generation in the quarter.
    - The large amount of oil use in a single period illustrates the difficulty in predicting (before the winter) how much oil will be needed over the entire winter season.
- Oil-fired generation in Eastern New York totaled roughly 1.5 million MWh in the first quarter of 2015, down from 1.9 million MWh in the first quarter of 2014.
  - Patterns of weather and oil consumption were different between the two quarters.
    - In the first quarter of 2014, January was the coldest month, accounting for 62 percent of all quarterly oil production.
    - January 2014 and January 2015 exhibited similar average temperatures, but January 2014 had more extreme temperatures.

    - February 2015 was the coldest month in the last ten years, accounting for 75 percent of all oil production in the first quarter of 2015.
  - Natural gas prices and fuel oil prices were significantly lower than a year ago.
    - Natural gas prices fell 41 to 48 percent despite colder weather conditions this quarter for the reasons discussed earlier.
- The widespread use of oil indicates that the market performed relatively well in conserving the available supply of natural gas under the tight gas supply conditions.
  - The NYISO's day-ahead market generally helped coordinate decisions by generators about whether to operate on natural gas, oil, or a blend.
  - Nonetheless, for many units, actual production from oil was still significantly lower than would have been optimal based on gas prices and LBMPs.
- Several factors reduced the use of oil by generators in the first quarter.
  - Timing differences between gas and electric markets sometimes lead generators to commit to burning natural gas when oil would have been economic in retrospect.
  - Oil-fired generation availability was reduced by:
    - Planned and forced outages – Major maintenance outages led several units to be unavailable throughout the first quarter;
    - Non-maintenance of permits and/or equipment for burning oil;
    - Low oil inventories – Given the cost of working capital, the risk of holding excess oil after the winter limits the inventory of most generators; and
    - Air permit restrictions – These limit the run hours and/or grades of fuel that may be used.

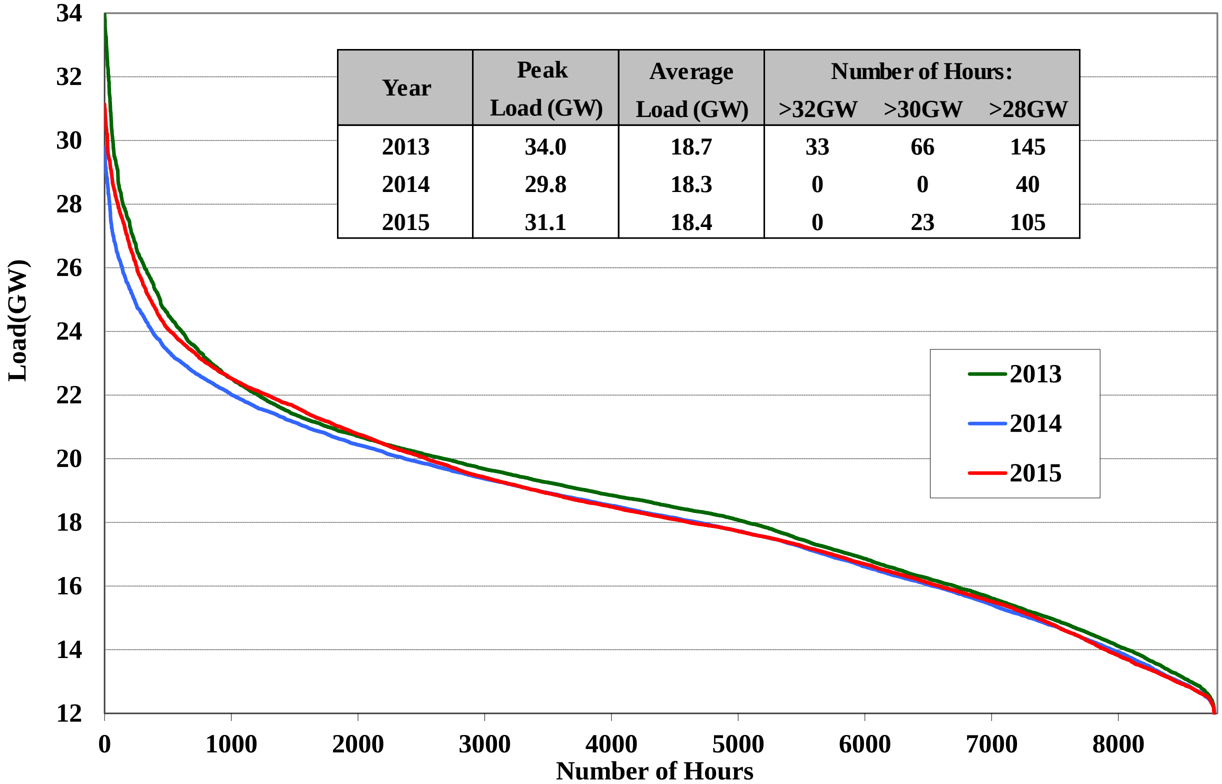
D. Load Levels

Figure A-10: Load Duration Curves for New York State

The interaction between electric supply and consumer demand also drives price movements in New York. The amount of available supply changes slowly from year to year, so fluctuations in electricity demand explain much of the short-term variations in electricity prices. 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.

Figure A-10 illustrates the variation in demand during each of the last three years by showing load duration curves. Load duration curves show the number of hours on the horizontal axis in which the statewide load was greater than or equal to the level shown on the vertical axis. The table in the figure shows the average load level on an annual basis for the past three years and also the number of hours in each year when the system was under high load conditions (i.e., load exceeded 28, 30, and 32 GW).

Figure A-10: Load Duration Curves for New York State
2013 – 2015



Year	Peak Load (GW)	Average Load (GW)	Number of Hours:		
			>32GW	>30GW	>28GW
2013	34.0	18.7	33	66	145
2014	29.8	18.3	0	0	40
2015	31.1	18.4	0	23	105

<u>Key Observations: Load Levels</u>

- Load levels rose modestly in 2015 from 2014, which had the lowest loads since 2009.
  - Average load rose roughly 1 percent from 2014 and peak load rose nearly 5 percent, reflecting warmer weather conditions in the summer.
  - However, load levels were still lower than those from 2010 to 2013.
- Winter peak load (24.6 GW) fell 4 percent from the all-time high winter peak set in 2014.
  - Weather was milder in January and March than from a year ago, while February was the coldest month in recent history.
  - Average load in February 2015 exceeded average load in January 2014.

E. Day-Ahead Ancillary Services Prices

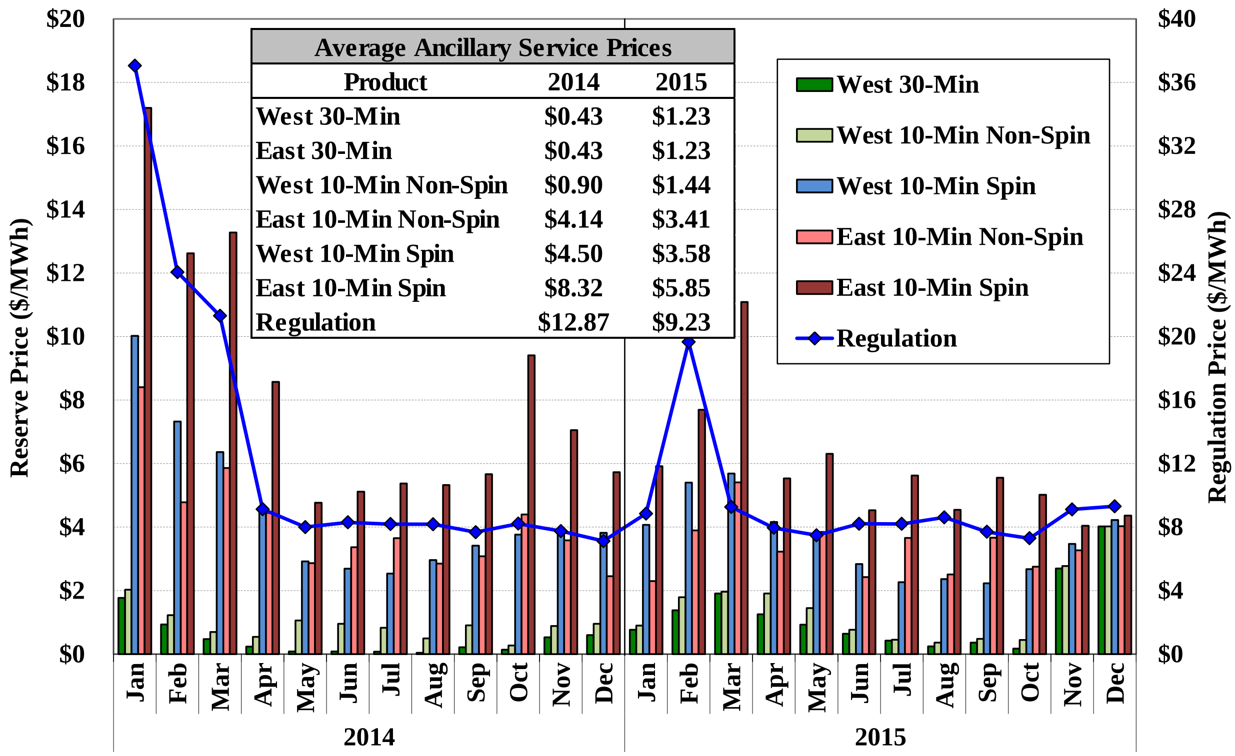
Figure A-11: Day-Ahead Ancillary Services Prices

The NYISO schedules resources to provide energy, operating reserves, and regulation service in the day-ahead and real-time markets. The NYISO co-optimizes the scheduling of these products such that the combined cost of all products is minimized. Given that available supplies must satisfy energy demand and ancillary services requirements simultaneously, energy and ancillary services prices both reflect the costs to the system of diverting resources to provide ancillary services that would otherwise provide energy. Hence, ancillary services prices generally rise and fall with the price of energy because it influences the level of these opportunity costs.

The NYISO has four ancillary services products: 10-minute spinning reserves, 10-minute total reserves, 30-minute reserves, and regulation. In addition, the NYISO has locational reserve requirements that result in differences between Western, Eastern, and Southeastern New York reserve prices.

Figure A-11 shows the average prices of the following six ancillary services products in the day-ahead market in each month of 2014 and 2015: (a) 30-minute total reserves in Western New York; (b) 10-minute total reserves in Western New York; (c) 10-minute spinning reserves in Western New York; (d) 10-minute total reserves in Eastern New York; (e) 10-minute spinning reserves in Eastern New York; and (f) Regulation.

Figure A-11: Day-Ahead Ancillary Services Prices
2014-2015



Key Observations: Day-ahead Ancillary Service Prices

- The average prices for most classes of ancillary services fell from 2014 to 2015.
  - The variations in average prices for ancillary services were generally in line with the variations in average energy prices in both years.
  - This is because the cost of providing ancillary services is for many generators driven by the opportunity cost of not providing energy during tight market conditions.

- However, the prices for 30-minute operating reserves rose notably in November and December 2015.
  - The price increases occurred after changes in the procurement of NYCA 30-minute reserves on November 4, 2015, which were made to better align prices with the cost of operator actions to secure the system under peak demand conditions. Two key changes have been primarily responsible for the increase in prices at the end of 2015:
    - The NYCA 30-minute reserve requirement rose from 1,965 MW to 2,620 MW.
    - The quantity of 30-minute reserves that can be scheduled on Long Island is now limited to 270 to 540 MW (depending on the hour of the day) to ensure that reserves scheduled there would be fully deliverable. However, this limit may be overly restrictive, so we will evaluate the effects of this limit in 2016.
- A new 30-minute reserve requirement for Southeast New York was effective in November 2015 as well.
  - This reserve requirement has rarely been binding, indicating that there is generally a large excess of 30-minute reserves in this area.

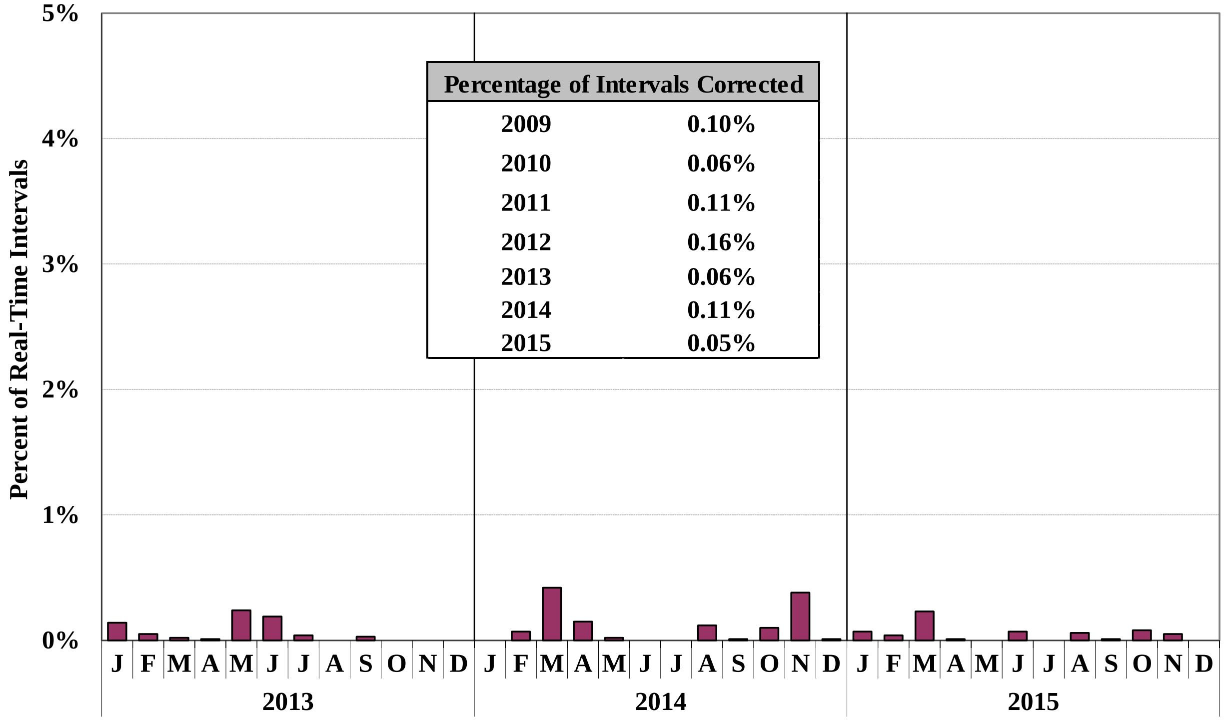
F. Price Corrections

Figure A-12: Frequency of Real-Time Price Corrections

All real-time energy markets are subject to some level of price corrections to account for metering errors and other data input problems. Moreover, price corrections are required when flaws in the market operations software or operating procedures lead prices to be calculated erroneously. Accurate prices are critical for settling market transactions fairly and sending reliable real-time price signals. Less frequent corrections reduce administrative burdens and uncertainty for market participants. Hence, it is important to resolve problems that lead to price corrections quickly to maximize price certainty.

Figure A-12 summarizes the frequency of price corrections in the real-time energy market in each month from 2013 to 2015. The table in the figure indicates the change of the frequency of price corrections over the past several years.

Figure A-12: Frequency of Real-Time Price Corrections
2013-2015



Key Observations: Price Corrections

- Overall, the frequency of corrections and the significance of the corrections have been at very low levels, around 0.1 percent of real-time pricing intervals in each of the past six years.
- In 2015, the frequency of price corrections was slightly higher in March because of software errors.
  - However, the effects of these errors on the market outcomes were not substantial.

G. Net Revenue Analysis

Revenues from the energy, ancillary services, and capacity markets provide the signals for investment in new generation and the retirement of existing generation. The decision to build or retire a generation unit depends on the expected net revenues the unit will receive. Net revenue is defined as the total revenue (including energy, ancillary services, and capacity revenues) that a generator would earn in the New York markets less its variable production costs.

If there is not sufficient net revenue in the short-run from these markets to justify entry of a new generator, then one or more of the following conditions exist:

- New capacity is not needed because sufficient generation is already available;

- Load conditions are below expectations due to mild weather or reduced demand, leading to lower energy prices than expected; and
- 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. Therefore, the evaluation of the net revenues produced from the NYISO's markets is one of our principal means for assessing whether the markets are designed to provide efficient long-run economic signals.

We estimate the net revenues the markets would have provided to: (a) new and existing gas-fired units, (b) new utility-scale solar PV units, (c) new onshore wind units, and (d) existing nuclear plants. Net revenues vary substantially by location, so we estimate the net revenues that each unit would have received at a number of locations across New York.

Table A-1 to Table A-6 and Figure A-13 to Figure A-15: Net Revenues for Gas-Fired Units

We estimate the net revenues the markets would have provided to three types of older existing gas-fired units and to the four types of new gas-fired units that have constituted most of the new generation in New York over the past few years:

- *Hypothetical new units*: (a) a 1x1 Combined Cycle ("CC 1x1") unit, (b) a 2x1 Combined Cycle ("CC 2x1") unit, (c) a LMS 100 aeroderivative combustion turbine ("LMS") unit, and (d) 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.

We estimate the net energy and ancillary services revenues for gas-fired units based on prices at two locations in Long Island, the 345kV portion of New York City, the Hudson Valley Zone, the Capital Zone, and the West Zone. We also use location-specific capacity prices from the NYISO's spot capacity markets.

Energy and ancillary services revenues for units in the Capital Zone and West Zone, energy prices are based on average zonal LBMPs. For Long Island, results are shown for the Caithness CC1 generator bus, which is representative of most areas of Long Island, and for the Barrett 1 generator bus, which is representative of the Valley Stream load pocket. For New York City, results are shown for the Ravenswood GT3/1 generator bus, which is representative of most areas of the 345kV system in New York City. For the Hudson Valley zone, results are shown for the average of LBMPs at the Roseton 1 and Bowline 1 generator buses, since these are representative of areas in the Hudson Valley zone that are downstream of the UPNY-SENY interface.

Our methodology for estimating net revenues for gas-fired units is based on the following assumptions:

- 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.
- Combustion turbines (including older gas turbines) are committed in real-time based on RTC prices.[198] Combustion turbines settle with the ISO according to real-time market prices and the deviation from their day-ahead schedule. To the extent that these combustion turbines are committed uneconomically by RTC, they receive DAMAP and/or Real-Time BPCG payments. Consistent with the NYISO tariffs, DAMAP payments are calculated hourly, while Real-Time BPCG payments are calculated over the operating day.
- 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, for the ST unit, a limitation on its ramp capability is assumed to keep the unit within a certain margin of the day-ahead 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.
  - Combined-cycle units and new combustion turbines are assumed to use diesel oil, older gas turbines are assumed to use ultra-low sulfur diesel oil, and steam turbines are assumed to use low-sulfur residual oil.
  - During hourly OFOs in New York City and Long Island, generators are assumed to be able to operate in real-time above their day-ahead schedule on oil (but not on natural gas). Dual-fueled steam turbines are assumed to be able to run on a mix of oil and gas, while dual-fueled combined-cycle units and combustion turbines are assumed to run on one fuel at a time.
  - During hourly OFOs in New York City and Long Island, generators are assumed to offer in the day-ahead market as follows:

198 Our method assumes that such a unit is committed for an hour if the average LBMP in RTC at its location is greater than or equal to the applicable start-up and incremental energy cost of the unit for one hour. This uses the RTC LBMPs posted on the NYISO's website.

Table A-1: Day-ahead Fuel Assumptions During Hourly OFOs[199]

Technology	Gas-fired	Dual Fuel
Combined Cycle	Min Gen only	Oil
Gas Turbine	No offer	Oil
Steam Turbine	Min Gen only	Oil/ Gas**

- Fuel costs assume a 6.9 percent natural gas excise tax for New York City units, a one percent gas excise tax for Long Island units, and transportation and other charges on top of the day-ahead index price as shown in the table below. Intraday gas purchases are assumed to be at a premium due to gas market illiquidity and balancing charges, while intraday gas sales are assumed to be at a discount for these reasons. The analysis assumes a premium/discount as shown in the table.

Table A-2: Gas and Oil Price Indices and Other Charges by Region

Region	Gas Price Index	Transportation & Other Charges ($/MMBTU)			Intraday Premium/ Discount
		Natural Gas	*Diesel/ ULSD*	*Residual Oil*	
West	Dominion North	$0.27	$2.00	$1.50	10%
Central	Dominion North	$0.27	$2.00	$1.50	10%
Capital	Iroquois Zn2	$0.27	$2.00	$1.50	10%
Hudson Valley	50% Iroquois Zn2, 50% Tetco M3	$0.27	$1.50	$1.00	10%
New York City	Transco Zn6	$0.20	$1.50	$1.00	20%
Long Island	Iroquois Zn 2	$0.25	$1.50	$1.00	30%

- The minimum generation level is 206 MW for the CC 1x1 unit, 454 MW for the CC 2x1 unit, and 90 MW for the ST unit. The heat rate is 7,639 btu/kWh at the minimum output level for the CC 1x1 unit, 7457 btu/kWh for the CC 2x1 unit and 13,000 btu/kWh for ST unit. 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 considered for all years. However, the older GT-30 unit is assumed not to have RGGI compliance costs because the RGGI program does not cover units below 25 MW.
- We also use the modified operating and cost assumptions listed in the following tables:

199 **Dual-fuel STs are assumed to offer Min Gen on the least expensive fuel and to offer incremental energy on residual oil in the DAM.

Table A-3: New Gas-fired Unit Parameters for Net Revenue Estimates[200,201]

Characteristics	CC 1x1	CC 2x1	LMS	Frame 7 with SCR	Frame 7 no SCR
Summer Capacity (MW)	303	668	185	211	206
Winter Capacity (MW)	326	704	200	225	226
Summer Heat Rate (Btu/kWh)	7203	7028	9252	10707	10823
Winter Heat Rate (Btu/kWh)	7081	6900	9083	10254	10358
Min Run Time (hrs)	4	4	1	1	1
Variable O&M ($/MWh)	$1.1	$2.4	$5.4	$0.5	$1.7
Startup Cost ($)	$9,269	$0	$0	$9,151	$9,341
Startup Cost (MMBTU)	1688	3700	430	450	450
EFORd	2.17%	2.50%	2.17%	2.17%	2.17%

Table A-4: Existing Gas-fired 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	$4.5
Startup Cost ($)	$6,000	$1,200	$519
Startup Cost (MMBTU)	2000	50	60
EFORd	5.14%	10.46%	19.73%

The following three figures summarize our net revenue and run hour estimates for gas-fired units in various locations across New York. They also indicate the levelized Cost of New Entry ("CONE") estimated in the Installed Capacity Demand Curve Reset Process for comparison. Levelized CONE estimates are not available for some locations and technologies. Net revenues and CONE values are shown per kW-year of Summer Installed Capability. Table A-5 shows our estimates of net revenues and run hours for all the locations and gas unit types in 2015. Table Table A-6 shows a detailed breakout of quarterly net revenues and run hours for all gas-fired units in 2015.

200 These parameters are based on technologies studied as part of the 2013 ICAP Demand Curve reset. The CC2x1 unit parameters are based on the Cost of New Entry Estimates for Combined Cycle Plants in PJM. The CONE estimate for gas-fired units in West Zone are based on data from Zone C in the 2013 ICAP Demand Curve reset study.

201 The CC 2x1 unit parameters are based on estimates of CONE parameters developed for PJM in 2014. See Cost of New Entry Estimates for Combustion Turbine and Combined Cycle Plants in PJM, 2014, prepared by The Brattle Group and Sargent & Lundy.

Figure A-13: Net Revenue for New Combined Cycle Units
2013-2015

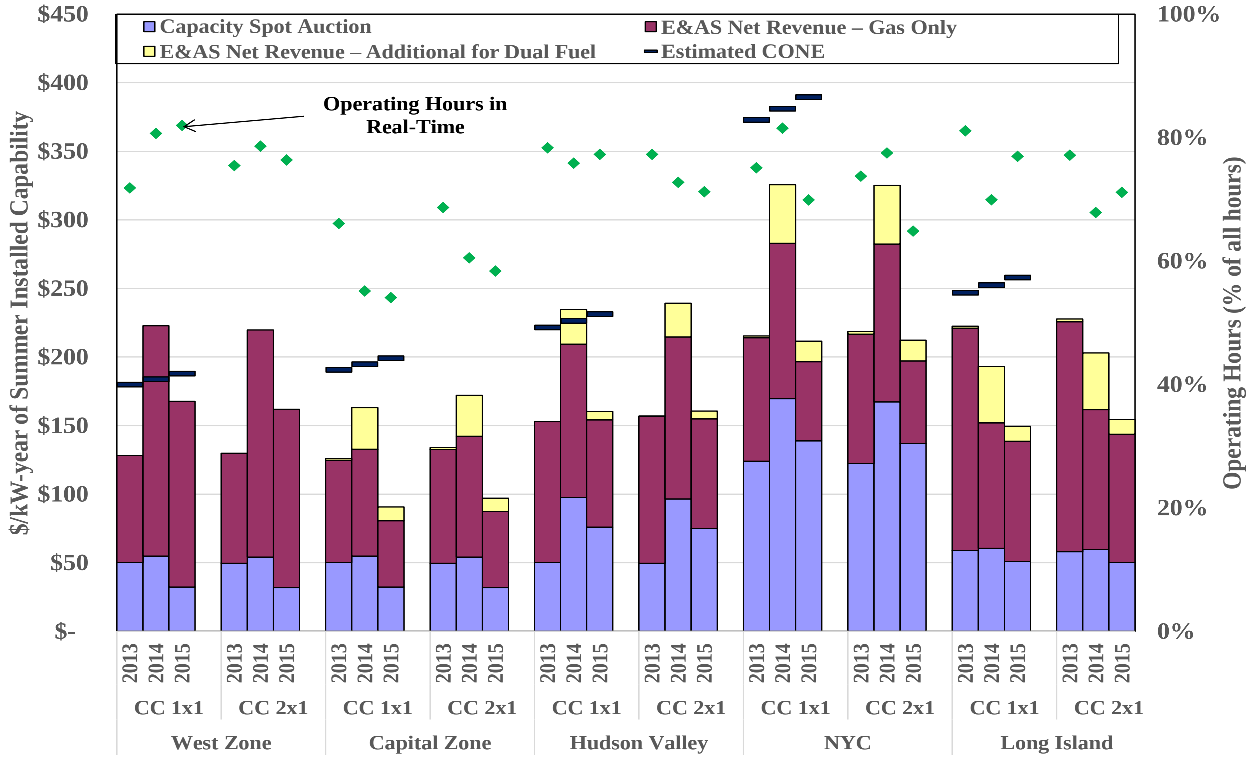


Figure A-14: Net Revenue for New Combustion Turbine Units
2013-2015

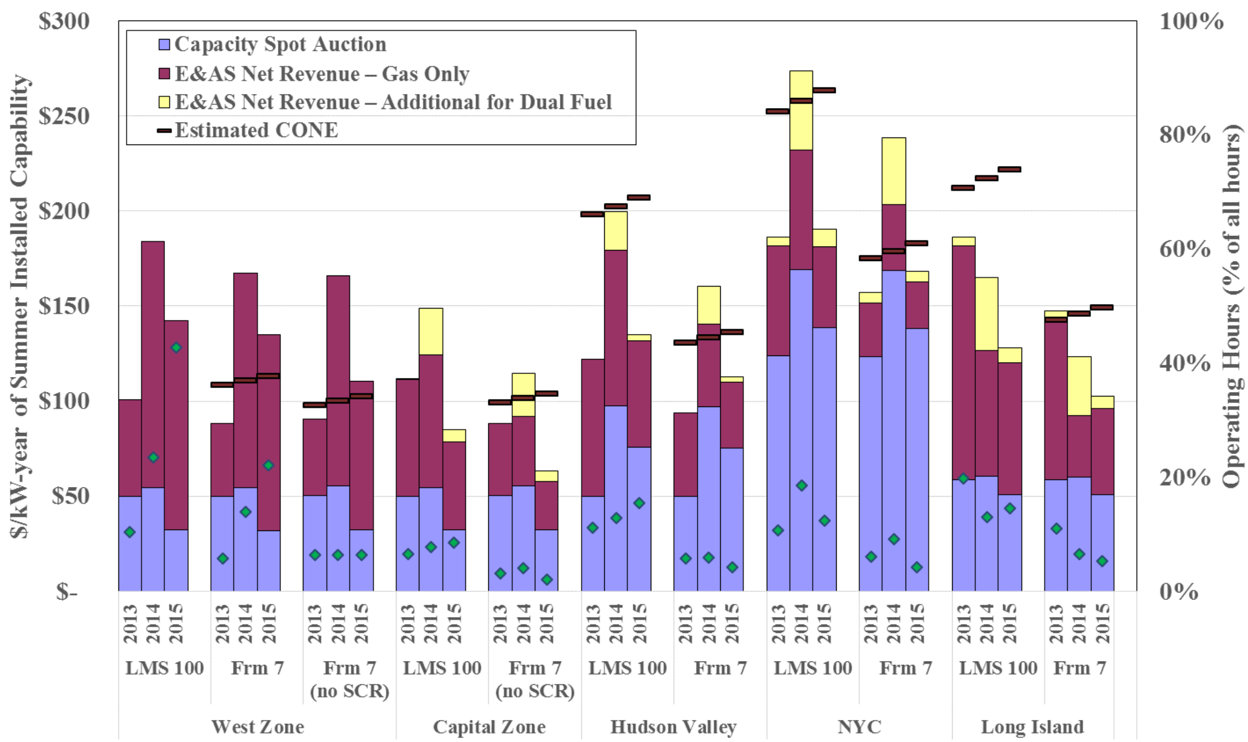


Figure A-15: Net Revenue for Existing Gas-fired and Dual Fuel Units
2013-2015

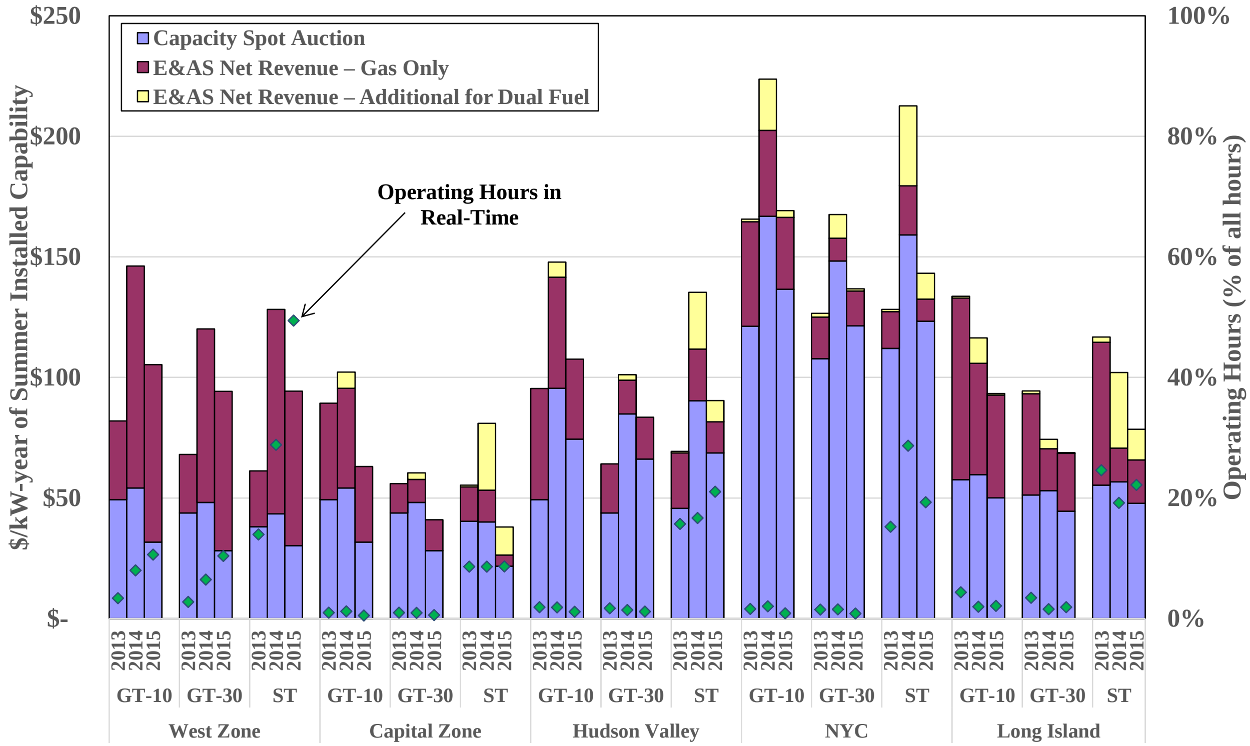


Table A-5: Net Revenue for Gas-Fired and Dual Fuel Generators
2015

Location	Unit Type	Capacity	2015 Net Revenue ($/kW-yr)			Real Time Run Hours			
			Gas Only	Dual Fuel Additional	Dual Fuel Total	Gas Only Unit	DF Unit on Gas	DF Unit on Oil	DF Unit Total
Capital Zone	CC 1x1	$32	$48	$10	$91	4593	4420	315	4735
	CC 2x1	$32	$55	$10	$97	5010	4799	316	5115
	CT - Frame 7 (no SCR)	$33	$25	$6	$63	158	161	18	179
	CT - LMS100	$32	$46	$6	$85	668	668	74	743
West Zone	CC 1x1	$32	$135	$0	$168	7181	7181	0	7181
	CC 2x1	$32	$130	$0	$162	6691	6691	0	6691
	CT - Frame 7	$32	$103	$0	$135	1937	1937	0	1937
	CT - Frame 7 (no SCR)	$33	$78	$0	$111	1057	1057	0	1057
	CT - LMS100	$32	$110	$0	$142	3745	3745	0	3745
	ST	$30	$64	$0	$94	4331	4331	0	4331
Hudson Valley (Iroquois-Zn2 Gas)	CC 1x1	$76	$46	$8	$130	4709	4598	265	4864
	CC 2x1	$75	$53	$8	$135	4843	4723	283	5005
	CT - Frame 7	$76	$24	$3	$102	164	167	7	174
	GT - 10 Min	$74	$32	$0	$106	58	58	0	58
	GT - 30 Min	$66	$15	$0	$81	62	62	0	62
	CT - LMS100	$76	$45	$4	$125	625	625	51	676
	ST	$51	$6	$9	$66	639	611	291	902
Hudson Valley	CC 1x1	$76	$78	$6	$160	6694	6521	249	6770
	CC 2x1	$75	$80	$6	$161	6166	5966	275	6241
	CT - Frame 7	$76	$35	$3	$113	369	369	9	378
	GT - 10 Min	$74	$33	$0	$108	99	99	0	99
	GT - 30 Min	$66	$17	$0	$84	100	100	0	100
	CT - LMS100	$76	$56	$4	$135	1312	1306	49	1355
	ST	$69	$13	$9	$90	1627	1556	288	1844
Hudson Valley (TETCO-M3 Gas)	CC 1x1	$76	$123	$4	$203	7612	7458	176	7635
	CC 2x1	$75	$118	$3	$196	7168	7012	191	7203
	CT - Frame 7	$76	$65	$2	$143	933	930	9	939
	GT - 10 Min	$74	$40	$0	$114	266	266	0	266
	GT - 30 Min	$66	$23	$0	$89	262	262	0	262
	CT - LMS100	$76	$80	$3	$158	3300	3291	48	3339
	ST	$71	$34	$8	$113	4108	4007	238	4245
Long Island	CC 1x1	$51	$88	$11	$150	6571	6428	312	6741
	CT - Frame 7	$51	$45	$7	$103	453	451	17	468
	GT - 10 Min	$50	$43	$1	$93	181	180	3	183
	GT - 30 Min	$44	$24	$0	$69	166	165	2	166
	CT - LMS100	$51	$69	$8	$128	1201	1198	73	1272
	ST	$48	$18	$13	$79	1671	1562	379	1942
Long Island (VS/ Barrett Load Pocket)	CC 1x1	$51	$168	$17	$236	6860	6598	345	6943
	CT - Frame 7	$51	$106	$20	$177	1050	970	130	1101
	GT - 10 Min	$50	$91	$9	$150	476	464	68	533
	GT - 30 Min	$44	$60	$6	$111	388	381	29	410
	CT - LMS100	$51	$138	$21	$210	1807	1716	183	1899
	ST	$48	$71	$31	$149	2885	2511	594	3105
NYC	CC 1x1	$139	$58	$15	$212	5920	5751	372	6123
	CC 2x1	$137	$60	$15	$212	5507	5246	436	5682
	CT - Frame 7	$138	$25	$6	$168	361	361	13	374
	GT - 10 Min	$137	$30	$3	$169	77	77	0	77
	GT - 30 Min	$121	$14	$1	$137	74	74	0	74
	CT - LMS100	$139	$43	$9	$191	997	997	91	1088
	ST	$123	$9	$11	$143	1310	1312	378	1690

Table A-6: Net Revenue and Run Hours for Gas-Fired and Dual Fuel Generators

2015

Location	Unit Type	Gas-Only Units								Dual Fuel Units			
		E&AS Revenue ($/kW-yr)				Real Time Run Hours				E&AS Revenue ($/kW-yr)		Real Time Run Hours	
		Qtr 1	Qtr 2	Qtr 3	Qtr 4	Qtr 1	Qtr 2	Qtr 3	Qtr 4	Qtr 1	Qtr 4	Qtr 1	Qtr 4
Capital Zone	CC 1x1	$30	$5	$8	$5	1527	834	1065	1168	$40	$5	1669	1168
	CC 2x1	$33	$7	$10	$7	1607	970	1177	1257	$42	$7	1711	1257
	CT - Frame 7 (no SCR)	$12	$4	$3	$6	49	34	62	14	$18	$6	69	14
	CT - LMS100	$20	$8	$10	$9	267	95	186	120	$26	$9	341	120
West Zone	CC 1x1	$68	$20	$30	$17	2116	1614	2146	1305	$68	$17	2116	1305
	CC 2x1	$64	$20	$28	$18	2106	1403	1938	1244	$64	$18	2106	1244
	CT - Frame 7	$51	$17	$17	$18	891	303	503	240	$51	$18	891	240
	CT - Frame 7 (no SCR)	$38	$13	$11	$16	439	205	257	155	$38	$16	439	155
	CT - LMS100	$50	$20	$19	$20	1488	609	1051	597	$50	$20	1488	597
	ST	$37	$8	$12	$7	1634	693	1102	901	$37	$7	1634	901
Hudson Valley (Iroquois-Zn2 Gas)	CC 1x1	$22	$8	$12	$4	1365	1016	1391	937	$30	$4	1519	937
	CC 2x1	$23	$10	$14	$5	1414	1057	1353	1018	$31	$5	1577	1018
	CT - Frame 7	$8	$5	$6	$6	23	52	76	13	$11	$6	33	13
	GT - 10 Min	$9	$7	$8	$8	5	26	22	5	$9	$8	5	5
	GT - 30 Min	$3	$4	$3	$5	3	26	27	6	$3	$5	3	6
	CT - LMS100	$16	$10	$11	$9	180	139	224	82	$20	$9	231	82
	ST	$2	$1	$2	$0	154	152	334	0	$11	$0	416	0
Hudson Valley	CC 1x1	$35	$13	$21	$9	1765	1487	1992	1450	$41	$9	1842	1450
	CC 2x1	$36	$14	$21	$9	1832	1296	1710	1328	$42	$9	1907	1328
	CT - Frame 7	$13	$7	$8	$6	104	84	159	22	$16	$6	113	22
	GT - 10 Min	$9	$8	$8	$8	12	33	44	10	$9	$8	12	10
	GT - 30 Min	$3	$5	$4	$5	6	32	52	10	$3	$5	6	10
	CT - LMS100	$21	$12	$13	$10	389	266	457	200	$24	$10	432	200
	ST	$5	$3	$5	$0	577	301	613	137	$14	$0	794	137
Hudson Valley (TETCO-M3 Gas)	CC 1x1	$55	$20	$32	$15	1998	1732	2152	1729	$59	$15	2021	1729
	CC 2x1	$55	$19	$30	$14	2002	1565	2038	1563	$58	$14	2037	1563
	CT - Frame 7	$25	$12	$18	$10	373	126	378	57	$27	$10	379	57
	GT - 10 Min	$13	$8	$10	$8	99	43	112	12	$13	$8	99	12
	GT - 30 Min	$7	$5	$7	$5	73	42	129	18	$7	$5	73	18
	CT - LMS100	$32	$15	$20	$12	924	652	1117	607	$35	$12	964	607
	ST	$15	$5	$11	$3	1215	800	1342	751	$23	$3	1352	751
Long Island	CC 1x1	$37	$15	$25	$12	1743	1505	1855	1468	$48	$12	1912	1468
	CT - Frame 7	$11	$12	$12	$11	84	112	169	88	$17	$11	99	88
	GT - 10 Min	$9	$12	$11	$10	17	63	66	35	$10	$10	19	35
	GT - 30 Min	$3	$7	$7	$7	10	64	60	32	$3	$7	10	32
	CT - LMS100	$20	$18	$17	$15	372	184	395	250	$28	$15	442	250
	ST	$6	$3	$7	$2	534	277	597	264	$19	$2	804	264
Long Island (VS/ Barrett Load Pocket)	CC 1x1	$102	$19	$29	$18	1913	1524	1897	1526	$120	$18	1995	1526
	CT - Frame 7	$63	$14	$16	$14	462	192	251	145	$83	$14	513	145
	GT - 10 Min	$38	$15	$14	$23	192	100	111	74	$47	$23	248	74
	GT - 30 Min	$22	$10	$9	$19	128	91	101	68	$28	$19	150	68
	CT - LMS100	$75	$21	$22	$20	666	307	478	355	$96	$20	758	355
	ST	$49	$5	$11	$6	932	447	758	747	$80	$6	1153	747
NYC	CC 1x1	$19	$11	$20	$8	1238	1235	2017	1431	$34	$8	1441	1431
	CC 2x1	$19	$12	$20	$9	1389	1175	1659	1282	$34	$9	1565	1282
	CT - Frame 7	$7	$5	$7	$6	119	60	157	25	$12	$6	132	25
	GT - 10 Min	$7	$8	$8	$8	20	24	25	7	$10	$8	20	7
	GT - 30 Min	$2	$4	$3	$5	12	24	30	7	$3	$5	12	7
	CT - LMS100	$11	$10	$13	$9	288	163	392	154	$21	$9	379	154
	ST	$3	$2	$4	$0	349	167	642	152	$14	$0	729	152

Key Observations: Net Revenue for Gas-fired Units

- The results show that overall net revenues decreased sharply from 2014 to 2015 in all locations for all gas-fired units.
  - The decrease in estimated net E&AS revenues in 2015 can largely be attributed to the drop in natural gas prices and to the lower winter load levels. These two factors had a particularly large impact on the first quarter revenues, which were unusually high in 2014 due to the severe winter conditions. The average first quarter net E&AS revenue received by 1x1 CC units fell by $50/kW-year from 2015 to 2014. This decrease accounted for over 96 percent of the total year-over-year reduction in average net E&AS revenues for the 1x1 CC units we modeled. (See Table A-6)
  - In Long Island, the milder winter conditions in 2015 resulted in less tight gas supply conditions and fewer days during which hourly OFOs occurred (4 days in 2015 relative to 19 days in 2014). Consequently, the additional revenue from dual-fuel capability decreased significantly from 2015 to 2014. For instance, a 1x1 CC with dual fuel capability on Long Island received $35/kW-year less E&AS net revenue on OFO days in 2015 compared to 2014. This accounted for over 80 percent of the year-over-year reduction in net revenues for the 1x1 CC unit.
  - The drop in estimated net E&AS revenues in 2015 was the largest for units in NYC. This was driven by smaller gas spreads between NYC and the rest of Eastern New York and by smaller and less frequent winter gas price spikes in NYC, where the gas price volatility was particularly severe in 2014 (see Section I.A of the Appendix). The capacity revenues for units in NYC also dropped in 2015 because of: (a) an increase in internal supply from generation and SCRs, and (b) a decrease in the ICAP requirement stemming from a decline in the LCR requirement from 85 to 83.5 percent (see Section VI.E of the Appendix for additional details).
  - The G-J Locality was modeled as a new capacity zone starting in May 2014, leading to higher capacity net revenues in the Hudson Valley zone. However, capacity prices in the G-J Locality fell by 58 percent from 2014 to 2015 because multiple generators returned to service. Gas-fired units in the Hudson Valley also received less E&AS net revenue in 2015 because of lower spark spreads (relative to 2014) between LBMPs and the TETCO-M3 gas index price. Table A-5 shows additional sensitivities around the gas prices seen by units in Hudson Valley.
  - In the West Zone, the estimated E&AS net revenue did not fall commensurate with the reduction in gas prices (58 percent in the West Zone) because there was more congestion on the gas pipeline system than on the electricity transmission system between western and eastern New York. For instance, while the average day-ahead LBMP in the Hudson Valley location was 29 percent higher than the LBMP in the West Zone location, the average gas price in Hudson Valley was 157 percent more than the West Zone average.[202] Capacity revenues to units in western New York in

[202] See Table A-2 for gas price index assumptions at various locations.

2015 also decreased by over 40 percent, primarily because new wind generators entered and some older units returned to service.

- For new gas-fired units, the estimated net revenues in 2015 were generally lower than the CONE in all areas except for new Frame 7 units in the West Zone. However, investors decide whether to build based on projected net revenues over the economic life of the unit.
  - The net revenues were generally consistent with the heat rate of each new technology.[203]
  - The estimated net revenues were higher than the CONE for Frame 7 units (with and without SCR) in the West Zone in 2014 and 2015.[204] However, the estimated net revenues for a Frame 7 unit at this location would not have been sufficient to cover its CONE from 2011 through 2013.[205]
  - Additionally, the proposed transmission build out in the western New York is aimed at reducing electric system congestion and would likely lower the West Zone energy prices over the future years.[206] So, it is uncertain whether a Frame 7 unit in the West zone would earn sufficient net revenue to be economic over the long-term.
- For older existing gas-fired units, the estimated net revenues were likely higher than the annualized "going-forward costs" in areas where such units are in operation. Retirements should occur if net revenues fell below going-forward costs for a significant period.
  - Among older technologies, the estimated net revenues were highest for a GT-10 unit because of the revenue it receives from providing 10-minute reserves while off-line.

203 The only exception to this ordering of units by E&AS net revenues was in the West zone. E&AS net revenues for the new 1x1 CC unit in the West zone were 4 percent higher than for the new 2x1 CC unit. This is driven by the persistently low Dominion North index gas prices which averaged $1.33 per MMBtu in 2015. Consequently, the heat rate advantage for the 2x1 CC is offset by the higher variable operating costs when compared to the 1x1 CC unit, resulting in slightly higher net revenues for the 1x1 CC unit.

204 The estimated run hours for a Frame 7 unit without SCR in the West Zone were higher than the annual operating hour restrictions to avoid LAER/ BACT requirements for NOx emissions. Therefore, we estimated the net revenue for a new Frame 7 unit with SCR in the West Zone. We also modeled a new Frame 7 unit without SCR and restricted the run hours to 1058 hours in 2014 and 2015. The results indicate that both types of Frame 7 units (with and without SCR) earned sufficient revenues to meet their CONE in 2015.

205 See Section I.G of the Appendix of 2013 State of the Market Report for the New York ISO Markets.

206 The New York Public Service Commission's order addressing the Western New York Public Transmission Need can be found at: http://www.nyiso.com/public/webdocs/markets_operations/services/planning/Planning_Studies/Public_Policy_Documents/Public_Policy_Transmission_Needs/2015_07_20_PSC_Order_NYISO_Pblc_Plcy_Trnsmssn_Nds_14-E-0454.pdf. The NYISO's solicitation and baseline results for the related study can be found at: at:http://www.nyiso.com/public/markets_operations/services/planning/planning_studies/index.jsp.

- The estimated net revenues for a ST unit included moderate potential returns from dual-fuel capability in 2015. The ST unit revenues, unlike older GTs' revenues, are driven primarily by energy and not reserve prices. Consequently, dual-fuel capability allowed ST units to benefit from the higher LBMPs during the winter months.
- Although the total net revenues for a GT-30 unit fell in 2015 across all locations, the E&AS net revenues were higher in 2015 when compared to 2014. This is due to the increase in the average 30-minute reserve prices, which rose from $0.43 per MWh in 2014 to $1.23 per MWh in 2015 (see Section I.E of the Appendix).

- The results for 2015 indicate that the additional revenues from the dual fuel capability dropped significantly for all technologies in Downstate and the Capital zone from 2014 levels because of milder winter conditions in 2015.
  - The potential returns from dual-fuel capability were highest for CCs in NYC and Long Island and were in the range of $11 to $15 per kW-year. These returns are likely to be sufficient to make it economic for many such units to retain dual-fuel capability and maintain modest inventories of oil during the winter months.[207]
  - Additional revenues from dual-fuel capability in the West and Central zones were minimal for all the technologies in 2015 because of the low Dominion North gas prices.

Table A-7- and Figure A-16: Net Revenues for Nuclear Plants

We estimated the net revenues the markets would have provided to nuclear plants in the Genesee, Central and Hudson Valley Zones. We estimated the net E&AS revenues for the nuclear plant in the Genesee Zone using LBMPs at the Ginna generator bus. For the Central zone, our results are based on the average of LBMPs at the Fitzpatrick and Nine Mile Unit 1 generator buses. Lastly, we calculated the net E&AS revenues for the nuclear plant in the Hudson Valley Zone using LBMPs at the Indian Point 2 bus. Our estimates for net revenues received by nuclear plants 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 percent, and a capacity factor of 67 percent during March and April to account for reduced output during refueling.[208]
- GFCs for nuclear plants are highly plant-specific and vary significantly based on several factors that include number of units at the plant, technology, age and location. Our

207 The levelized annual cost of installing dual-fuel capability at new CC units is in the range of $9-12/kW-year. See Eastern Interconnection Planning Collaborative (2014). *Gas-Electric System Interface Study*. Levitan & Associates, Inc.

208 The refueling cycle for nuclear plants is typically 18-24 months. We assume a reduced capacity factor in March and April every year in order to enable a year over year comparison of net revenues.

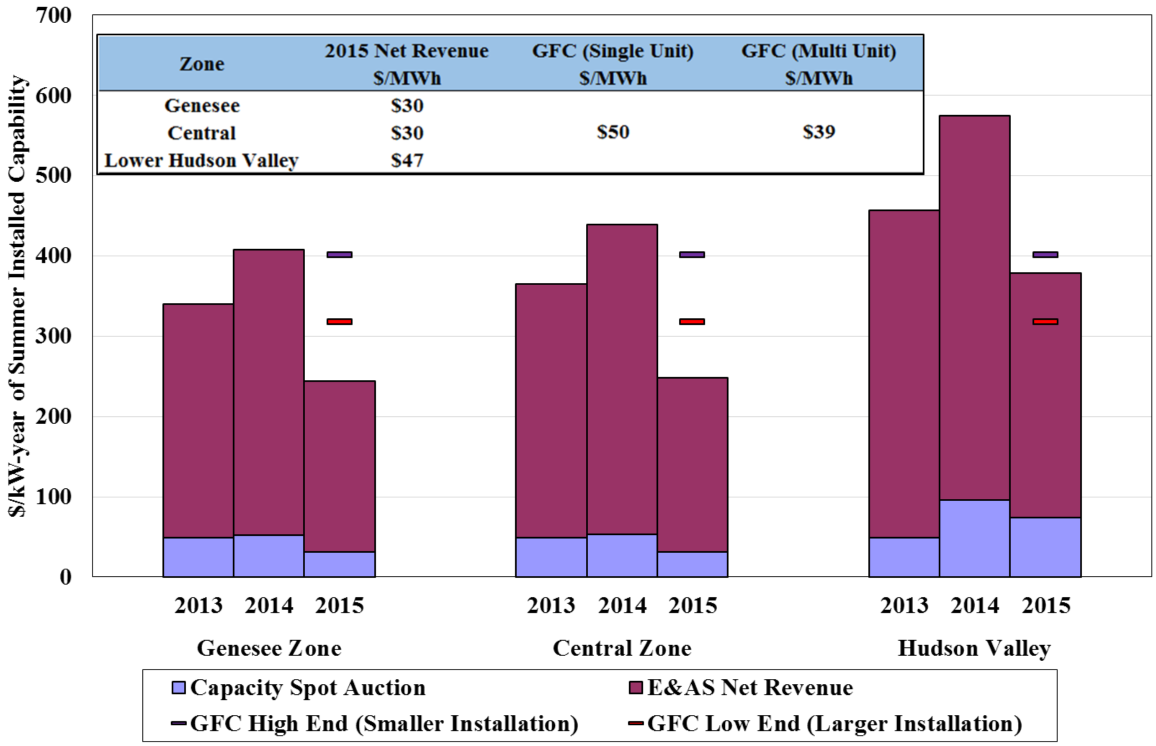
assumptions for representative GFCs (and the equivalent all-in costs) for average single-unit and larger nuclear plants in New York are shown in Table A-7. All O&M (variable and fixed) costs, fuel costs and capital expenditures are included in the estimated GFCs.

Table A-7: Average Going Forward Costs for Nuclear Plants in New York[209]

Technology	Going Forward Costs	
	$/kW-yr	$/MWh
Single-unit	$401	$50*
Multi-unit	$318	$39

Figure A-16 shows our estimates for net revenues received by nuclear plants at three different locations in New York.

Figure A-16: Net Revenue of Existing Nuclear Units
2013-2015



209 * Several data sources reported higher GFCs for smaller installations. For instance, one study of the Ginna plant reported an all-in cost as high as $64/MWh. The values reported in Table A-7 are based on the all-in cost estimates by UBS analysts for the four nuclear plants in New York. See: (a) Cost estimates for Ginna by UBS Investment Research for 2015 from Figure 1: Ginna mini-model of "*US Electric Utilities & IPPs Nuclear Lifeline in [Upstate] NY*", February 3rd 2016, (b) Cost estimates for Fitzpatrick by UBS Investment Research for 2015 from Figure 5: Fitzpatrick Estimated Economics of "*US Electric Utilities & IPPs De-Nuclearizing the Northeast*", October 13, 2015, (c) Cost estimates for Indian Point by UBS Investment Research on page 1 of "*Entergy Corp. Industrial 'Evolution*", February 22nd 2016, and (d) Cost estimates for Nine Mile by UBS Investment Research for 2015 from Figure 2: Nine Mile Point Mini Model of "*US IPP Weekly Power Points Putting a Bid Back into Power*", April 4th 2016.

Key Observations: Net Revenue for Nuclear Units

- The estimated net revenues for nuclear units indicate a significant decrease from 2014 to 2015 in all the three locations we studied. This result is in line with the overall drop in energy and capacity prices, as discussed in the previous sub-section.
- Energy revenues constitute the majority of the revenue received by nuclear plants and accounted for 86 percent of the estimated net revenue over the last three years, much higher than the levels energy share for all other types of units. Consequently, the decision to retire or to continue to operate a nuclear unit is likely to be driven by the expected LBMPs more than the expected capacity prices.
- The results indicate that the estimated net revenues were lower than the GFCs for single-unit nuclear plants in all the locations shown in 2015. Moreover, the average Central Zone and West Zone all-in prices for 2009 through 2015 (see Section I.A of the Appendix) were lower than the all-in costs for single-unit plants in five of the last seven years. Based on recent electricity forward contract prices, single-unit nuclear plants outside Southeast New York are unlikely to recoup their operating costs from the wholesale market over the next five years.[210]

Figure A-17: Net Revenues for Solar and Onshore Wind Units

We estimated the net revenues the markets would have provided to utility-scale solar PV and onshore wind plants in the Central, North, Hudson Valley, New York City and Long Island Zones. For onshore wind units in Central and North zones, we calculated the net E&AS revenues using the capacity-weighted average of LBMPs at major wind installations in zone. Our net E&AS revenues estimates for onshore wind units in other locations and all utility-scale solar PV units are based on the same LBMPs we used for estimating the gas-fired units net revenues.

Our methodology for estimating net revenues and the CONE for utility-scale solar PV and onshore wind units is based on the following assumptions:

- Net E&AS revenues are calculated using real time energy prices.
- The energy produced 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 (although we find that capacity factors from the EIA were about 9 percent higher on average than actual production from similarly situated resources in upstate New York).
- The capacity revenues for solar PV and onshore wind units are calculated using prices from the spot capacity market. The capacity values of solar PV and wind resources are based on the factors (30 and 46 percent for Winter Capability Periods and 10 and 2

210 Around-the-Clock electricity forward prices (annual strip as reported by SNL on 3/31/2016) for Central Zone over the 2017-2021 timeframe were between $29 and $36 per MWh.

percent for Summer Capability Periods for wind and solar, respectively) specified in the February 2016 NYISO Installed Capacity Manual.[211]

- We estimated the value of environmental attributes produced by utility-scale solar PV and onshore wind units using the weighted average prices of RPS Attributes from the NYSERDA's last three Main Tier program procurements.[212]
- 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 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.[213] We incorporate the value of these federal incentives as an additional revenue stream for solar PV and wind units.[214]
- 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 A-8 shows a high and low investment cost estimate for solar PV and an average cost estimate for onshore wind units. The data shown are based on our review of studies published in 2015.[215] Table A-8 also presents the operating and cost assumptions we used for calculating net revenues for utility-scale solar PV and onshore wind plants.

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211 The factors are available in Section 4.5.b of the ICAP Manual in the tables labeled Unforced Capacity Percentage – Wind and Unforced Capacity Percentage – Solar. See http://www.nyiso.com/public/webdocs/markets_operations/documents/Manuals_and_Guides/Manuals/Operations/icap_mnl.pdf.

212 For more information on the recent Main Tier procurements, see http://www.nyserda.ny.gov/All-Programs/Programs/Main-Tier/Main-Tier-Solicitations.

213 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.

214 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 York. 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. We assumed that these units will be subject to the property tax treatment that is specified in the most recent ICAP demand curve reset study.

215 The studies reviewed for developing the range of utility-scale solar PV costs are:

a) NREL, 2015, *Annual Technology Baseline and Standard Scenarios*, See http://www.nrel.gov/analysis/data_tech_baseline.html
b) Lazard, 2015, *LAZARD'S LEVELIZED COST OF ENERGY ANALYSIS —VERSION 9.0*, See https://www.lazard.com/media/2390/lazards-levelized-cost-of-energy-analysis-90.pdf
c) MIT Energy Initiative, 2015, *The future of Solar Energy*, See https://mitei.mit.edu/futureofsolar
d) Bloomberg New Energy Finance, 2015, American PV Market Outlook

Table A-8: Utility-Scale Solar and Onshore Wind Parameters for Net Revenue Estimates

Parameter	Utility-Scale Solar PV	Onshore Wind
Investment Cost ($/kW AC basis)	*Upstate NY*: $2297 mid ($1936 low to $2554 high) *Long Island*: $3408 mid ($2873 low to $3790 high)	*Upstate NY*: 2044 $/kW *Long Island*: 2527 $/kW
Fixed O&M ($/kW-yr)	$17 mid ($10 low to $21 high)	$55
Variable O&M ($/MWh)	-	$0.60
Project Life	20 years	
Depreciation Schedule	5-years MACRS	
Average Annual Capacity Factor	Long Island/ NYC/ LHV: 22.8% Upstate NY: 22.1%	Long Island/ NYC/ LHV: 38% Upstate NY: 38.1%
Unforced Capacity Percentage	Summer: 46% Winter: 2%	Summer: 10% Winter: 30%
RPS Attributes Prices ($/MWh)	***2015*** - $24.57 ***2014*** - $22.96 ***2013(10 year term)*** - $34.95	

Assuming the operating and cost parameters shown in the table above, Figure A-17 shows the net revenues for the past three years for each technology, as well as the estimated CONE.

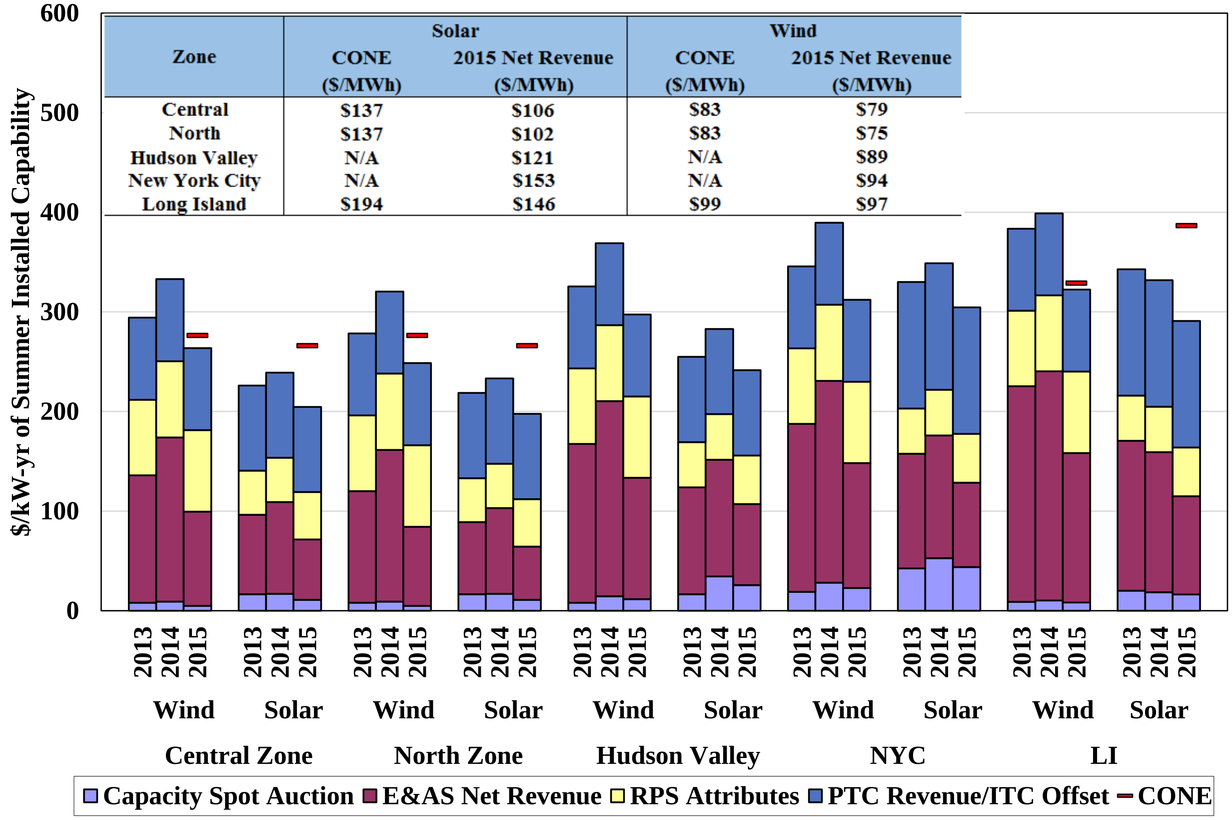
The onshore wind costs are based on a NYSERDA study on Large-Scale Renewable Energy Development in New York. See Table 5 in the following study: http://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId={26BD68A2-48DA-4FE2-87B1-687BEC1C629D}

Solar PV costs are reported in direct current ("DC") terms in most studies. However, the alternating current ("AC") rating of capacity is a more appropriate basis for utility-scale solar PV costs, since the investment costs for all other generation technologies are also reported on an AC basis. The average investment cost for solar PV was converted to AC basis using the costs from a representative solar PV project built in 2014. See page 17 of the following study: https://emp.lbl.gov/sites/all/files/lbnl-1000917.pdf

The average investment costs (on an AC basis) for solar PV and onshore wind were converted to location-specific costs using regional cost multipliers from the EIA. See Table 4 in the following study: http://www.eia.gov/analysis/studies/powerplants/capitalcost/pdf/updated_capcost.pdf

Interconnections costs for wind and solar units can vary significantly from project to project. The CONE estimates shown do not include interconnection costs. The SUFs allocated to the most recent onshore wind-based entrant would have added $9/kW-yr (or $2.80/MWh) to the net CONE of the project.

Figure A-17: Net Revenue of Renewable Units[216]
2013-2015



Zone	Solar CONE ($/MWh)	Solar 2015 Net Revenue ($/MWh)	Wind CONE ($/MWh)	Wind 2015 Net Revenue ($/MWh)
Central	$137	$106	$83	$79
North	$137	$102	$83	$75
Hudson Valley	N/A	$121	N/A	$89
New York City	N/A	$153	N/A	$94
Long Island	$194	$146	$99	$97

<u>Key Observations: Net Revenues for Utility-scale Solar PV and Onshore Wind Plants</u>

- Renewable energy projects in New York receive a significant portion of their net revenues from state and federal programs in addition to revenues from the markets administered by the NYISO. The results indicate that a new solar PV project would have earned 58 percent to 69 percent of its 2015 net revenues from RECs and ITC, depending on the location. Similarly, onshore wind units would have received 51 percent to 66 percent of their 2015 net revenues from state and federal programs. The value of these incentives shows only a modest change across years due to the relatively small change in the average REC prices.
- Given the relatively low capacity value of solar PV and onshore wind units, energy market revenues constitute a large majority of the revenues these units receive from the NYISO markets. Consequently, the results indicate a drop in the estimated net revenues

216 The CONE and ITC offset for solar PV projects is calculated based on the average investment costs in Table A-8. In the absence of reliable investment cost estimates in NYC and Lower Hudson Valley, the value of ITC offsets at those locations are based on investment costs in LI and Upstate NY, respectively. The actual value of ITC in NYC is likely to be higher as the investment costs are likely to be higher.

for solar PV and wind units from 2014 to 2015 in all the locations we studied because of the sharp reduction in energy prices.

- The 2015 results indicate that solar PV units would not have received sufficient net revenues to meet their average estimated CONE.[217] However, the investment costs for solar PV units have been falling rapidly over the last few years and there is a significant variation in cost estimates for solar PV across recent studies. Our analysis indicates that the net revenues received by utility-scale solar PV units would have exceeded the estimated CONE in Upstate zones in 2014 if the CONE were based on cost estimates that were at the lower end of the data shown in Table A-8.
- Although onshore wind units generally earned more revenue than solar PV units in 2015, the estimated net revenues for these units were not sufficient to meet their estimated CONE in all the locations we studied. Moreover, wind units are particularly exposed to curtailment risks and the actual revenues realized might be lower than the estimated revenues shown in Figure A-17.

H. Day-Ahead Energy Market Performance

The day-ahead market allows participants to make forward purchases and sales of power for delivery in real-time. Participants can use the day-ahead market to hedge risks associated with the real-time market. Loads can insure against price volatility in the real-time market by purchasing in the day-ahead market. Suppliers can avoid the risk of starting-up their generators on an unprofitable day since the day-ahead auction market will only accept their offers when they will profit from being committed. In addition to the value it provides individual market participants, perhaps the greatest value of the day-ahead market is that it coordinates the overall commitment of resources to satisfy the next day's needs at least cost.

In a well-functioning system with day-ahead and real-time markets, we expect that day-ahead and real-time prices will not systematically diverge from one another. If day-ahead prices were predictably higher than real-time prices, buyers will increase purchases in real-time. Alternatively, if day-ahead prices were foreseeably lower than real-time prices, buyers will increase purchases day-ahead (vice versa for sellers).

Price convergence is desirable because it promotes the efficient commitment of generating resources, procurement of fuel, and scheduling of external transactions. In addition, persistent differences between day-ahead and real-time prices can undermine incentives for suppliers to offer their resources at marginal cost in the day-ahead market. We expect random variations resulting from unanticipated changes in supply and demand between the two markets on an hour-to-hour basis, but persistent systematic differences between day-ahead and real-time prices would raise potential concerns.

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217 The CONE for solar PV and onshore wind units was calculated using the financing parameters and tax rates specified in the most recent ICAP demand curve reset study.

In this section, we evaluate two aspects of convergence in prices between day-ahead and real-time markets and look for evidence of persistent differences. First, we examine the consistency of average day-ahead energy prices with average real-time energy prices at the zone level. Second, we evaluate the consistency of average day-ahead and real-time energy prices at individual nodes throughout the state.

Figure A-18 & Figure A-19: Average Day-Ahead and Real-Time Energy Prices

In general, day-ahead prices are based on the expectations of real-time market outcomes and are influenced by several uncertainties. First, demand can be difficult to forecast with precision and the availability of supply may change due to forced outages or numerous other factors. For example, the operators may commit additional generation for reliability after the day-ahead market, increasing the supply available to the real-time market. Second, special operating conditions, such as thunderstorm alerts, may alter the capability of the transmission system in ways that are difficult to arbitrage in day-ahead markets. Accordingly, day-ahead prices reflect the probability-weighted expectation of infrequent high-priced events in the real-time market.

Figure A-18 and Figure A-19 compare day-ahead and real-time energy prices in West zone, Central zone, Capital zone, and Hudson Valley, New York City, and Long Island. The figures are intended to reveal whether there are persistent systematic differences between the load-weighted average day-ahead prices and real-time prices at key locations in New York. The bars compare the average day-ahead and real-time prices in each zone in each month of 2015. The inset tables report the percentage difference between the average day-ahead price and the average real-time price, as well as the average absolute value of the difference between hourly day-ahead and real-time prices in the past three years. The latter metric measures the typical difference between the day-ahead and real-time prices in each hour, regardless of which is higher. This metric is substantially affected by real-time price volatility.

Figure A-18: Average Day-Ahead and Real-Time Energy Prices outside SENY
West, Central, and Capital Zones - 2015

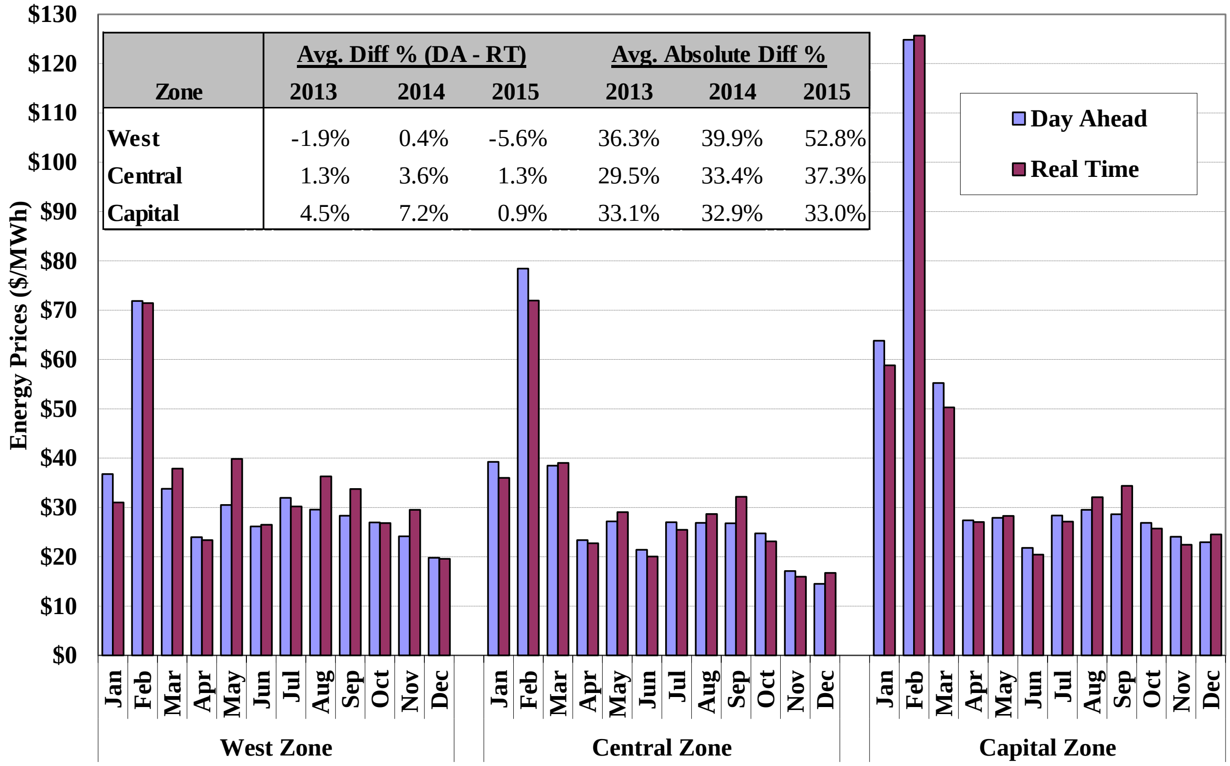


Figure A-19: Average Day-Ahead and Real-Time Energy Prices in SENY
Hudson Valley, New York City, and Long Island - 2015

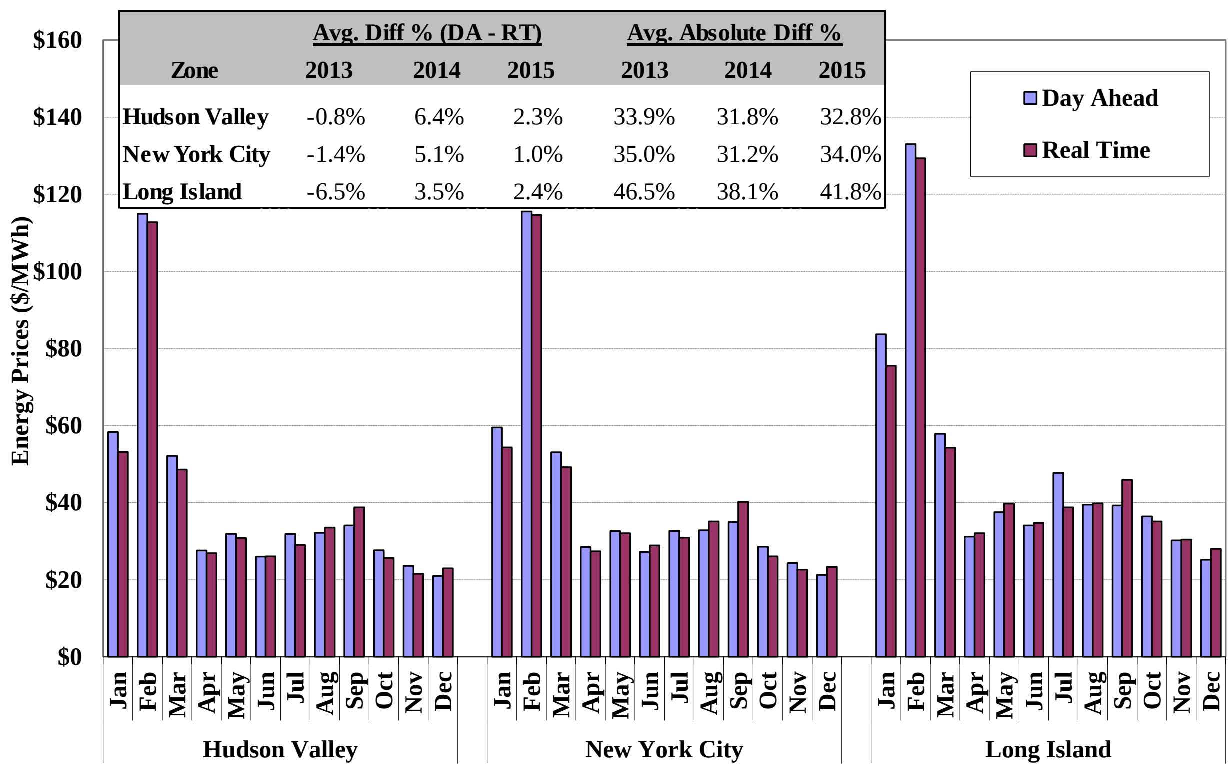


Figure A-20: Average Real-Time Price Premium at Select Nodes

Transmission congestion can lead to a wide variation in nodal prices within a particular zone, while the price of each zone is a load-weighted average of the nodal prices in the zone. Hence, the pattern of intrazonal congestion may differ between the day-ahead market and the real-time market, leading to poor convergence at individual nodes even though convergence is good at the zone level.

The pattern of intrazonal congestion may change between the day-ahead market and the real-time market for many reasons:

- Generators that are not scheduled in the day-ahead market may change their offers. This is common during periods of fuel price volatility or when natural gas is more easily procured day-ahead.
- Generators may be committed or de-committed after the day-ahead market, changing the pattern of transmission flows.
- Constraint limits used to manage congestion may change from the day-ahead market to the real-time market.
- Transmission constraints that are sensitive to the level of demand may become more or less acute after the day-ahead market due to differences between expected load and actual load.
- Transmission forced outages, changes in the scheduled transmission maintenance, and differences in phase angle regulator settings can result in different congestion patterns.

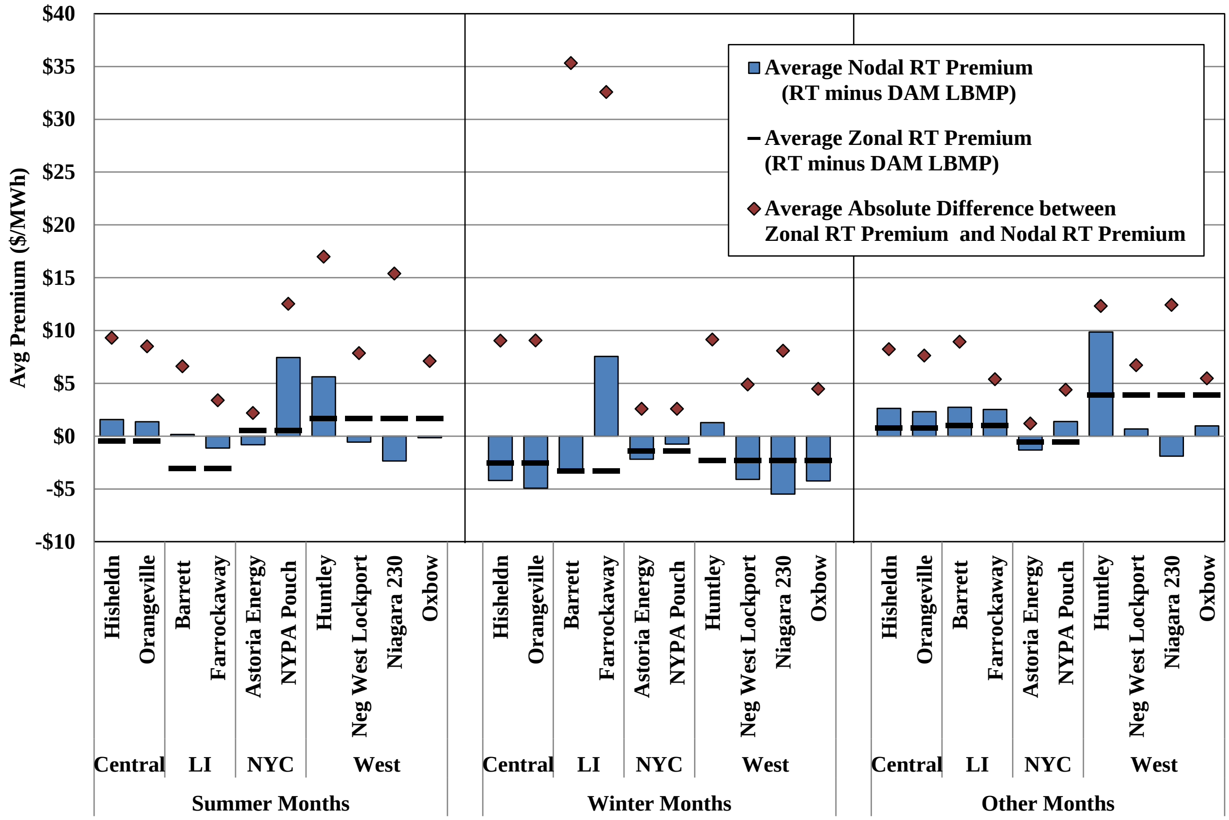
In general, virtual trading and price-sensitive load bidding help improve convergence by facilitating arbitrage between day-ahead and real-time prices. But the NYISO is currently unable to allow market participants to submit virtual trades and price sensitive load bids at the load pocket level or more disaggregated level, so good convergence at the zonal level may mask a significant lack of convergence within the zone. The NYISO has proposed to allow virtual trading at a more disaggregated level and this would likely improve convergence between day-ahead and real-time nodal prices. This analysis examines price statistics for selected nodes throughout New York State to assess price convergence at the nodal level.

Figure A-20 shows average day-ahead prices and real-time price premiums in 2015 for selected locations in New York City, Long Island, and Upstate New York.[218] These are load-weighted averages based on the day-ahead forecasted load. The figure includes nodes in several regions that generally exhibited less consistency between average day-ahead and average real-time prices than other nodes. These are shown separately for the summer months (June to August), the

218 In New York City, Astoria Energy is the Astoria Energy II bus and NYPA Pouch is the NYPA Pouch GT 1 bus. In Long Island, Barret is the Barrett 1 bus and Farrockaway is Farrockaway ST 4 bus. In Upstate, Orangeville and Hisheldn are two wind turbine locations in the Central Zone, Huntley 67, NEG West Lockport, Niagara 230kV, and Oxbow represent generator locations in the West Zone.

winter months (December, January, and February), and other months because the congestion patterns typically vary by season.

Figure A-20: Average Real-Time Price Premium at Select Nodes
2015



Key Observations: Convergence of Day-Ahead and Real-Time Energy Prices

- Energy price convergence (as measured by the mean absolute difference between hourly day-ahead and real-time prices) was slightly worse in most regions from 2014 to 2015.
  - Price volatility increased in 2015 because of more frequent congestion, particularly in the real-time market (for reasons discussed in Section III-B and Section V-E).
  - This is particularly true for the West Zone, which exhibited the worst price convergence among all areas in 2015.
- At the zonal level, average day-ahead energy prices were higher than average real-time prices by a modest margin in most regions in 2015.
  - However, the West Zone exhibited an average real-time price premium of 5.6 percent because of notably higher real-time congestion on the 230 kV system.
  - Most regions exhibited worse price convergence in the winter and summer months when rapid changes in natural gas prices and/or weather and load patterns led to significant changes in prices between day-ahead and real-time markets.

- At the nodal level, a few locations exhibited notably less consistency between average day-ahead and real-time prices. Most notably:
  - In Long Island, the Valley Stream load pocket (represented by the Barrett and Farrockaway locations) often exhibited a higher real-time price premium than the zonal real-time price premium.
    - This pattern reflects that there is frequent real-time congestion on the East Garden City-to-Valley Stream line that is not well-reflected in the day-ahead market. The primary cause is that power is exported from this pocket to New York City across the 901 line and that the differential between day-ahead and real-time exports is volatile. When exports increase substantially from the day-ahead to real-time market, severe congestion can occur on the East Garden City-to-Valley Stream line.
  - In the West Zone, the average price premiums at the Huntley location and the Niagara 230 kV bus deviated significantly from the zonal average price premiums. For example, in the shoulder months, the Huntley location exhibited a real-time price premium of nearly $10 per MWh while the Niagara 230 kV bus exhibited a day-ahead price premium of roughly $2 per MWh, compared to a real-time zonal price premium of roughly $4 per MWh.
    - This pattern reflects that there is frequent real-time congestion on the 230kV transmission system that limits Ontario imports and Niagara generation from flowing east and that is not well-reflected in the day-ahead market. This pattern is driven by several factors, including increases in the economic supply from Ontario and renewable generation after the day-ahead market, as well as volatile loop flows around Lake Erie.
  - When severe real-time congestion is not anticipated in the day-ahead market, the most efficient generation resources may not be committed or may not schedule enough natural gas to be fully available in real-time. Consequently, the cost of congestion management is generally higher in real-time when congestion was not reflected in the day-ahead market.
  - Allowing disaggregated virtual trading in these areas would address these differences by allowing participants the opportunity to arbitrage them.

I. Day-Ahead Ancillary Service Market Performance

As in the day-ahead energy market, a well-performing day-ahead ancillary service market will produce prices that converge well with real-time market prices. The NYISO co-optimizes the scheduling of energy, operating reserves, and regulation service such that the combined production cost of all products is minimized in the day-ahead and real-time markets. The energy and ancillary services markets place demand on the same supply resources, so prices for energy and ancillary services are highly correlated, and scarcity in the energy market is generally accompanied by a scarcity of ancillary services.

In the market for energy, virtual trading improves convergence between day-ahead and real-time prices, which helps the ISO commit an efficient quantity of resources in the day-ahead market. In the ancillary services markets, on the other hand, only ancillary services suppliers participate directly and no virtual trading of ancillary services is allowed. Procurement of ancillary services is managed by the ISO, which obtains the same amounts of ancillary services in the day-ahead and real-time markets based on reliability criteria and without regard to price. Therefore, when systematic differences arise between day-ahead and real-time ancillary services prices, ancillary services suppliers are the only entities able to arbitrage them and improve convergence.

To evaluate the performance of the day-ahead ancillary service markets, the following four figures summarize day-ahead and real-time clearing prices for two important reserve products in New York.

Figure A-21 – Figure A-23: 10-Minute Spinning and Non-Spinning Reserve Prices

Figure A-21 shows 10-minute non-spinning reserve prices in Eastern New York, which are primarily based on the requirement to hold 1,200 MW of total 10-minute reserves east of the Central-East Interface. The market uses a "demand curve" that places an economic value of $775 per MW on satisfying this requirement. [219]

Figure A-22 shows 10-minute spinning reserve prices in Western New York, which are primarily based on the requirement to hold 655 MW of 10-minute spinning reserves in New York State. Therefore, this represents the base price for spinning reserves in New York before locational premiums for satisfying eastern 10-minutes requirement are added. A demand curve is used that places an economic value of $775 per MW on satisfying this requirement. [220]

Figure A-23 shows 10-minute spinning reserve prices in Eastern New York, which are primarily based on the requirement to hold 330 MW of 10-minute spinning reserves east of the Central-East Interface. A demand curve is used that places an economic value of $25 per MW on satisfying this requirement. This reserve product is the most costly reserve product in New York's market.

In these figures, average day-ahead and real-time prices are shown by daily peak load level and different time of day for 2014 and 2015. The inset tables show the percent of days in each load range in 2014 and 2015.

Table A-9 reports the percentage difference between the average day-ahead price and the average real-time price (as a percentage of average day-ahead price), as well as the average absolute value of the difference between hourly day-ahead and real-time prices in 2014 and 2015. The latter metric measures the typical difference between the day-ahead and real-time prices in each hour, regardless of which is higher. This metric is substantially affected by real-

[219] This demand curve value was set at $500 per MW before November 4, 2015.

[220] This demand curve value was set at $500 per MW before November 4, 2015.

time price volatility. The two metrics are reported separately for peaking and non-peaking periods. Peaking periods include afternoon hours (i.e., hours 14 to 20) on days when daily peak load exceeded 23 GW and non-peaking periods include all other hours.

Figure A-21: 10-Minute Non-Spinning Reserve Prices in East New York
By Daily East NY Peak Load Level and Time of Day, 2014 - 2015

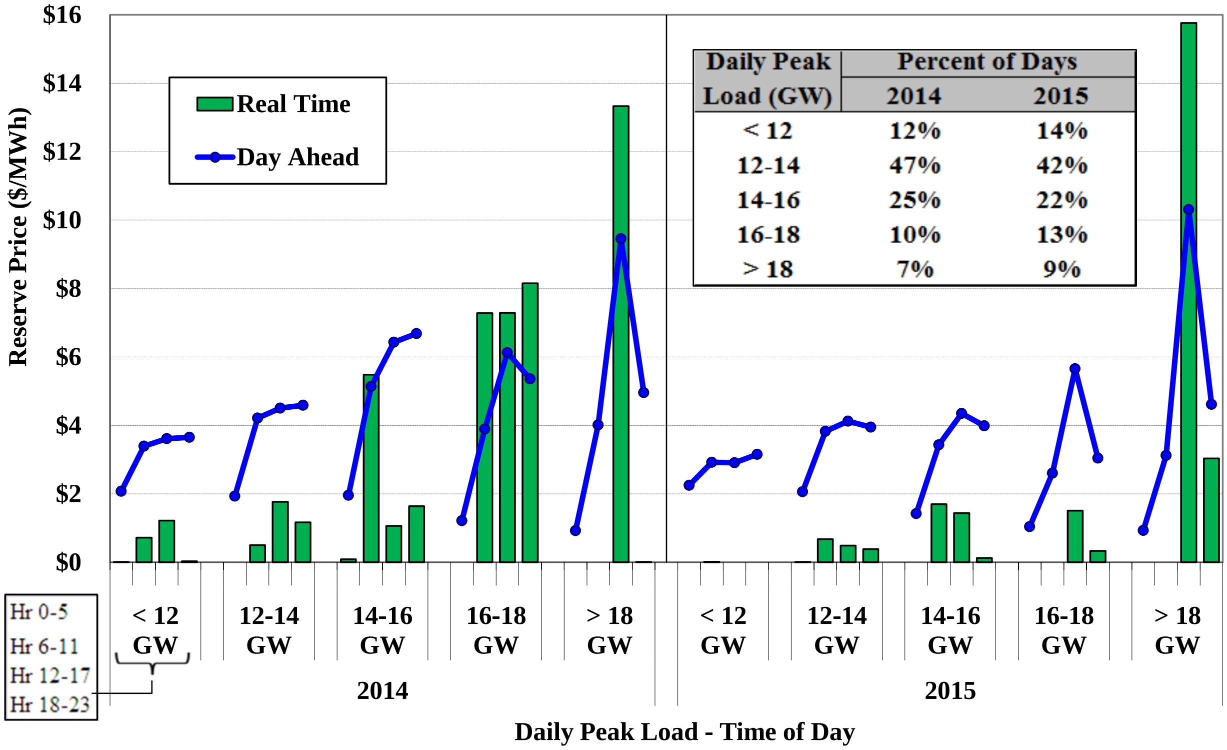


Figure A-22: 10-Minute Spinning Reserve Prices in West New York
By Daily NYCA Peak Load Level and Time of Day, 2014 - 2015

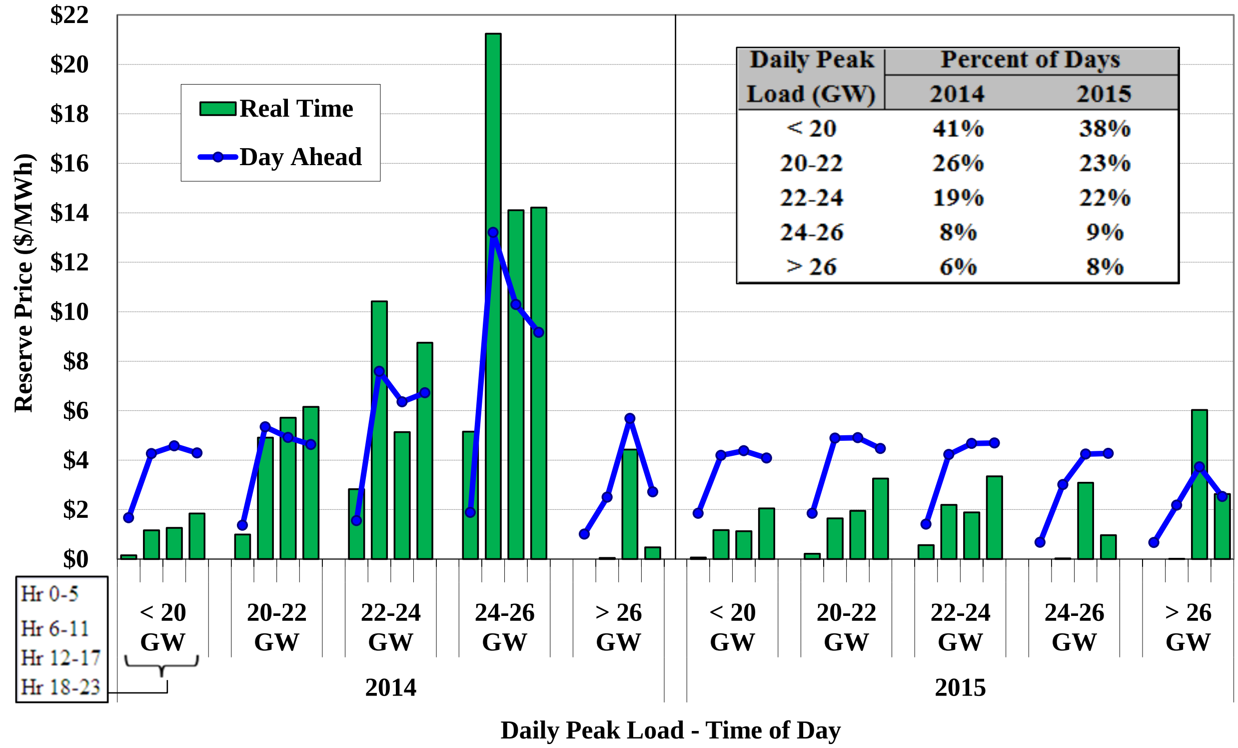


Figure A-23: 10-Minute Spinning Reserve Prices in East New York
By Daily East NY Peak Load Level and Time of Day, 2014 - 2015

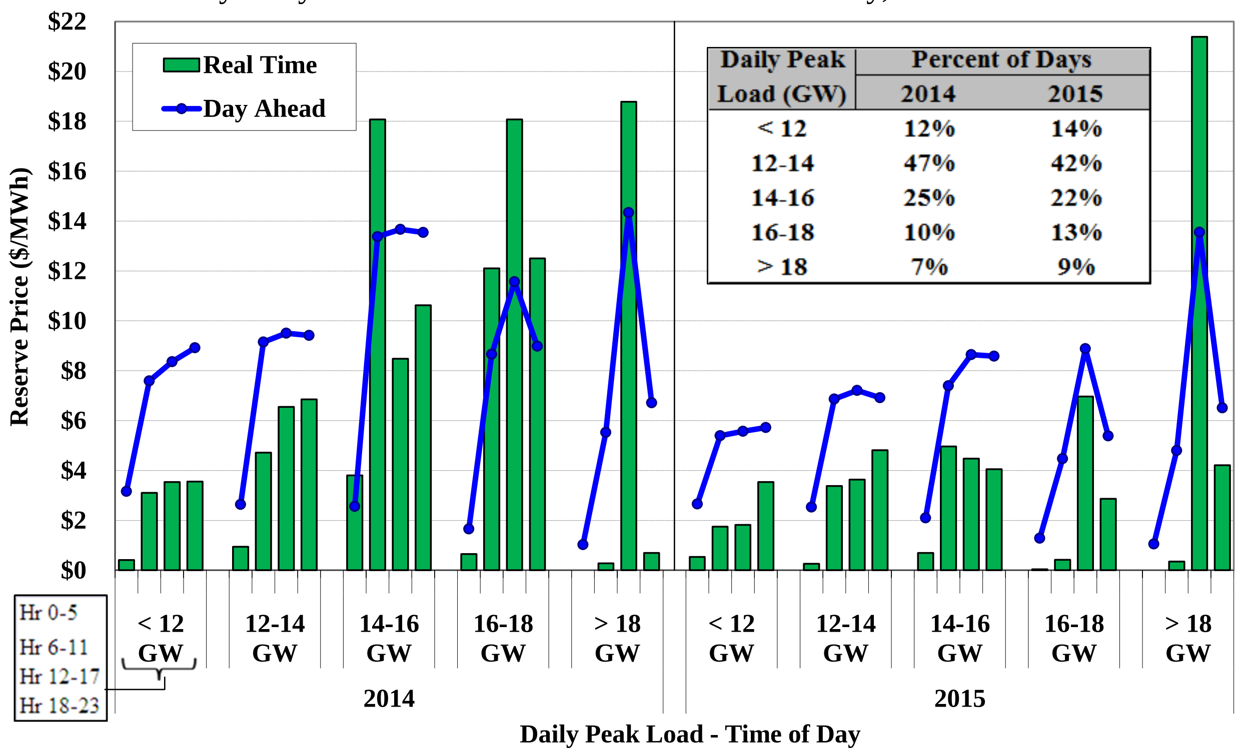


Table A-9: Price Convergence Between Day-Ahead and Real-Time Reserve Prices
2014 – 2015

Reserve Product	Avg. (DA-RT) Price as a % of Avg. DA Price				Absolute Avg. (DA-RT) Price as a % of Avg. DA Price			
	Peak Periods		Other Periods		Peak Periods		Other Periods	
	2014	2015	2014	2015	2014	2015	2014	2015
West 10-Min Spin	-24%	8%	15%	63%	159%	163%	150%	120%
East 10-Min Non-Spin	18%	4%	65%	90%	163%	175%	131%	108%
East 10-Min Spin	-4%	-10%	27%	54%	138%	154%	123%	110%

<u>Key Observations: Convergence of Day-Ahead and Real-Time Ancillary Service Prices</u>

- Reserve price convergence was worse in 2015 than in 2014, which is generally consistent with the pattern of energy price convergence discussed earlier.
- Day-ahead price premiums increased modestly during Other (i.e., non-peak) Periods.
  - Although the day-ahead premiums are expected in a competitive market without virtual trading, the increase for 10-minute spinning reserves was likely affected by the elimination of the offer cap for New York City generators in August 2014 (ancillary service offer patterns are evaluated in Section I-D).
  - These changes allowed higher day-ahead offers, leading day-ahead prices to be more consistent with real-time prices under peaking conditions.
    - This was evident from the improvement of average price difference between day-ahead and real time during Peak Periods from 2013 to 2015.
    - However, because of relatively mild summer weather conditions in both 2014 and 2015, load rarely exceeded 31 GW, making it impossible to evaluate how the market would perform under very high load conditions.

J. Regulation Market Performance

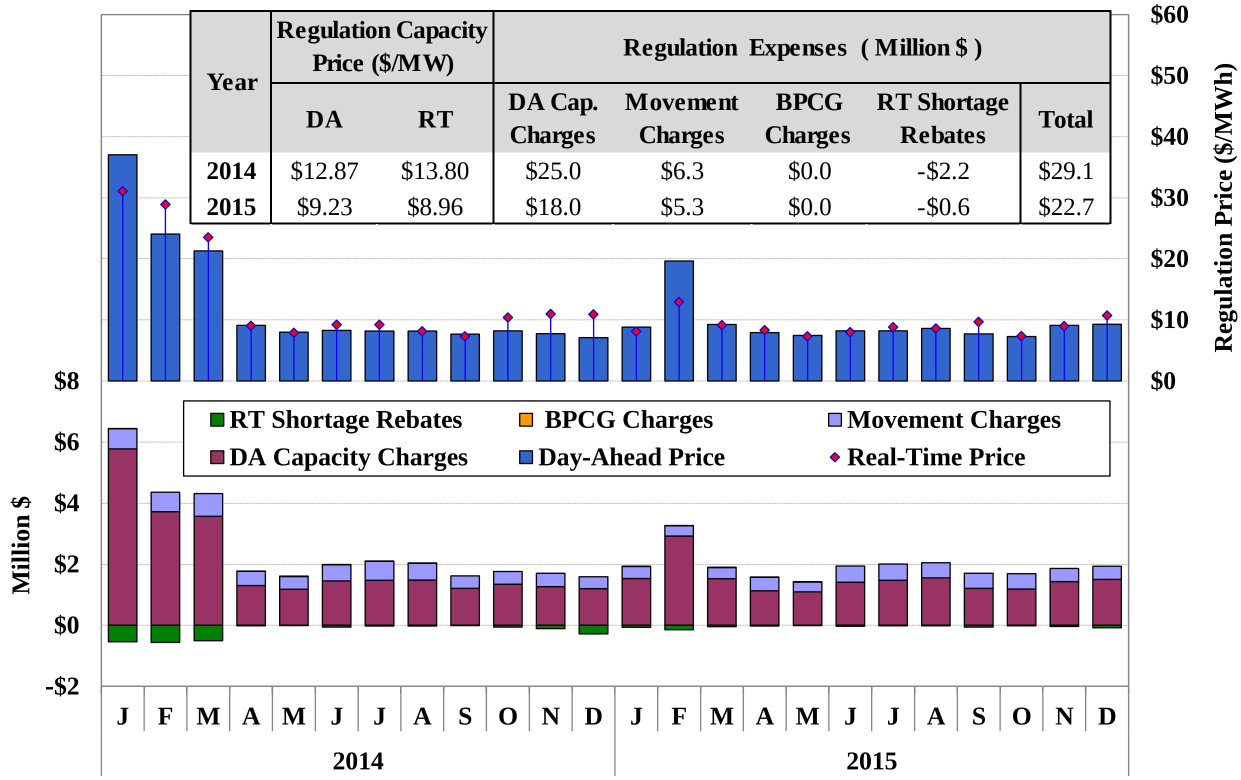
Figure A-24 – Regulation Prices and Expenses

Figure A-24 shows the regulation prices and expenses in each month of 2014 and 2015. The upper portion of the figure compares the regulation capacity prices in the day-ahead and real-time markets. The lower portion of the figure summarizes regulation costs to NYISO customers, which include:

- Day-Ahead Capacity Charge – This equals day-ahead capacity clearing price times regulation capacity procured in the day-ahead market.

- Real-Time Shortage Rebate – This arises when a regulation shortage occurs in the real-time market and regulation suppliers have to buy back the shortage quantity at the real-time prices.
- Movement Charge – This is the compensation to regulation resources for dispatching up and down to provide regulation service. The payment amount equals the product of: (i) the real-time regulation movement price; (ii) the instructed regulation movement; and (iii) the performance factor calculated for the regulation service provider.
- BPCG Charge – This is the guarantee payment to demand side resources that provide regulation service to cover their as-bid costs.

Figure A-24: Regulation Prices and Expenses
by Month, 2014-2015



Year	Regulation Capacity Price ($/MW)		Regulation Expenses (Million $)				
	DA	RT	DA Cap. Charges	Movement Charges	BPCG Charges	RT Shortage Rebates	Total
2014	$12.87	$13.80	$25.0	$6.3	$0.0	-$2.2	$29.1
2015	$9.23	$8.96	$18.0	$5.3	$0.0	-$0.6	$22.7

Key Observations: Regulation Market Performance

- Average day-ahead regulation capacity prices were generally consistent with average real-time capacity prices in 2015 on a monthly basis.
  - However, some months exhibited a relatively larger inconsistency primarily because of unexpected real-time conditions on several days. Most notably,
    - Real-time conditions (e.g., weather, gas prices) were a lot milder than anticipated in the day-ahead market on several days in February 2015, leading to high day-ahead premiums on these days and a resulting average monthly day-ahead premium.

- Regulation costs totaled nearly $23 million in 2015, down 22 percent from 2014.
  - The decrease accrued primarily in the first quarter of 2015 when lower energy prices (due to less frequent peaking conditions and lower natural gas prices) resulted in lower opportunity costs for providing regulation.
  - Real-time regulation shortages also decreased significantly in the first quarter, leading to lower shortage rebates, which partly offset the decrease in the overall cost.
  - In the first quarter of 2014, regulation shortages were particularly high because of elevated opportunity costs to provide the service.
    - In most of these cases, the model scheduled less regulation than the requirement when the marginal cost exceeded the lowest demand curve value of $80.
- Average day-ahead regulation capacity prices fell 28 percent from 2014 to 2015, generally in line with the reduction in energy prices over the same period.
  - The opportunity cost of not providing energy or reserves during tight market conditions accounts for a significant portion of the clearing price for regulation capacity, and this opportunity cost falls as energy prices fall.
  - However, regulation movement charges did not vary in similar proportion to the natural gas prices and/or load levels.
    - The clearing price for regulation movement is determined by the regulation movement offer price of the marginal resource, so it is not directly affected by the opportunity cost of not providing energy and/or reserves.

II. Analysis of Energy and Ancillary Services Bids and Offers

In this section, we examine energy and ancillary services bid and offer patterns to evaluate whether the market is functioning efficiently and whether market participant conduct is consistent with effective competition. This section evaluates the following areas:

- Potential physical withholding;
- Potential economic withholding;
- Market power mitigation;
- Ancillary services offers in the day-ahead market;
- Load-bidding patterns; and
- Virtual trading behavior.

Suppliers that have market power can exercise it in electricity markets by withholding resources to increase the market clearing price. Physical withholding occurs when a resource is derated or not offered into the market when it would be economic for the resource to produce energy (i.e., when the market clearing price exceeds the marginal cost of the resource). Suppliers may also physically withhold by providing inaccurate information regarding the operating characteristics of a resource (e.g., ramp rate and minimum down time). Economic withholding occurs when a supplier raises the offer price of a resource in order to reduce its output below competitive levels or otherwise raise the market clearing price. Potential physical and economic withholding are evaluated in subsections A, and B.

In the NYISO's market design, the competitive offer of a generator is the marginal cost of producing additional output. Absent market power, a supplier maximizes profits by producing output whenever the production cost is less than the LBMP. However, a supplier with market power profits from withholding when its losses from selling less output are offset by its gains from increasing LBMPs. Accordingly, the NYISO's market power mitigation measures work by capping suppliers' offers at an estimate of their marginal costs when they offer resources substantially above marginal cost if the uncapped offers would have a substantial impact on LBMPs. Market power mitigation by the NYISO is evaluated in Section C.

The NYISO co-optimizes the scheduling of energy and ancillary services in the day-ahead and real-time markets. This co-optimization causes the prices of both energy and ancillary services to reflect the costs to the system of diverting resources to provide ancillary services that would otherwise provide energy. Co-optimization also reduces the potential for suppliers to exercise market power in a particular ancillary service product market because it allows the market the flexibility to shift resources between products and effectively increases the competition to provide each product. Ancillary services offer patterns are evaluated in Section D.

In addition to screening the conduct of suppliers, it is important to evaluate how the behavior of buyers influences energy prices. Under-scheduling load generally leads to lower day-ahead prices and insufficient commitment for real-time needs. Over-scheduling tends to raise day-ahead prices above real-time prices. Thus, market participants have incentives to schedule amounts of load consistent with real-time load. The consistency of day-ahead load scheduling with actual load is evaluated in Section E.

Virtual trading plays an important role in overall market efficiency by improving price convergence between day-ahead and real-time markets, thereby promoting efficient commitment and scheduling of resources in the day-ahead market. When virtual trading is profitable, it generally promotes convergence between day-ahead and real-time prices and tends to improve the efficiency of resource commitment and scheduling. The efficiency of virtual trading is evaluated in Section F.

This report includes several enhancements to the analysis of potential physical and economic withholding. Generally, the enhancements reflect improvements in the criteria we use to identify capacity that would have been economic to produce energy. These enhancements include:

- Taking into account start-up costs;
- Using interval-level real-time prices instead of hourly-integrated prices;
- Considering the effects of ramp-constraints on commitment and dispatch;
- Using RTC prices to determine when gas turbines would have been economic to start-up and shut-down;
- Taking into account (reference level) minimum downtime constraints.

A. Potential Physical Withholding

We evaluate potential physical withholding by analyzing day-ahead and real-time generator deratings of economic capacity, as well as economic capacity that is unoffered in real-time. A derating occurs when a participant reduces the maximum output available from the plant. This can occur for a planned outage, a long-term forced outage, a short-term forced outage, or without any logged outage record. A derating can be partial (maximum output is reduced, but is greater than zero) or complete (maximum output is zero).

Economic capacity unoffered in real-time includes quickstart units that do not offer in real-time and online baseload units that offer less than their full capability. The figures in this section show the quantity of deratings and unoffered real-time capacity as a percent of total Dependable Maximum Net Capability ("DMNC") from all generators in a given region based on the most recent DMNC test value of each generator. *Short-term Deratings* include capacity that is derated for seven or fewer days. The remaining derates are shown as *Long-Term Deratings*.[221]

We focus particularly on short-term deratings and real-time unoffered capacity because they are more likely to reflect attempts to physically withhold than long-term deratings, since it is less costly to withhold a resource for a short period of time. Taking a long-term forced outage would

221 For our analyses of physical and economic withholding, we exclude unoffered capacity from hydro, solar. wind, landfill-gas and biomass generators.

cause a supplier to forego the opportunity to earn profits during more hours when the supplier does not have market power. Nevertheless, the figures in this section evaluate long-term deratings as well, since they still may be an indication of withholding.

We focus on suppliers in Eastern New York, since this area includes roughly two-thirds of the State's load, contains several areas with limited import capability, and is more vulnerable to the exercise of market power than Western New York.

We also focus on economic capacity, since derated and unoffered capacity that is uneconomic does not raise prices above competitive levels and therefore, is not an indicator of potential withholding.

The figures in this section show the portion of derated and unoffered capacity that would have been economic based on Reference Levels and market prices.[222] This assessment determines economic commitment of baseload units based on day-ahead prices, considering start-up, minimum generation, and incremental costs. Economic dispatch of baseload units is based on RTD prices considering ramp rate limitations.[223] Quickstart units that were economic to commit must have been economic at both forecast RTC prices and settlement RTD prices.[224]

Figure A-25 & Figure A-26: Unoffered Economic Capacity by Month

Figure A-25 and Figure A-26 show the broad patterns in deratings and real-time unoffered capacity in New York State and Eastern New York in each month of 2014 and 2015.

222 This evaluation also includes a modest threshold, which is described in Subsection B as "Lower Threshold 1."

223 If a baseload unit was committed by the DAM, optimal dispatch and potential physical withholding of incremental energy ranges was evaluated at RTD prices, even if the units DAM reference costs were above the DAM prices.

224 In this paragraph "prices" refers to both energy and reserves prices.

Figure A-25: Unoffered Economic Capacity by Month in NYCA
2014 – 2015

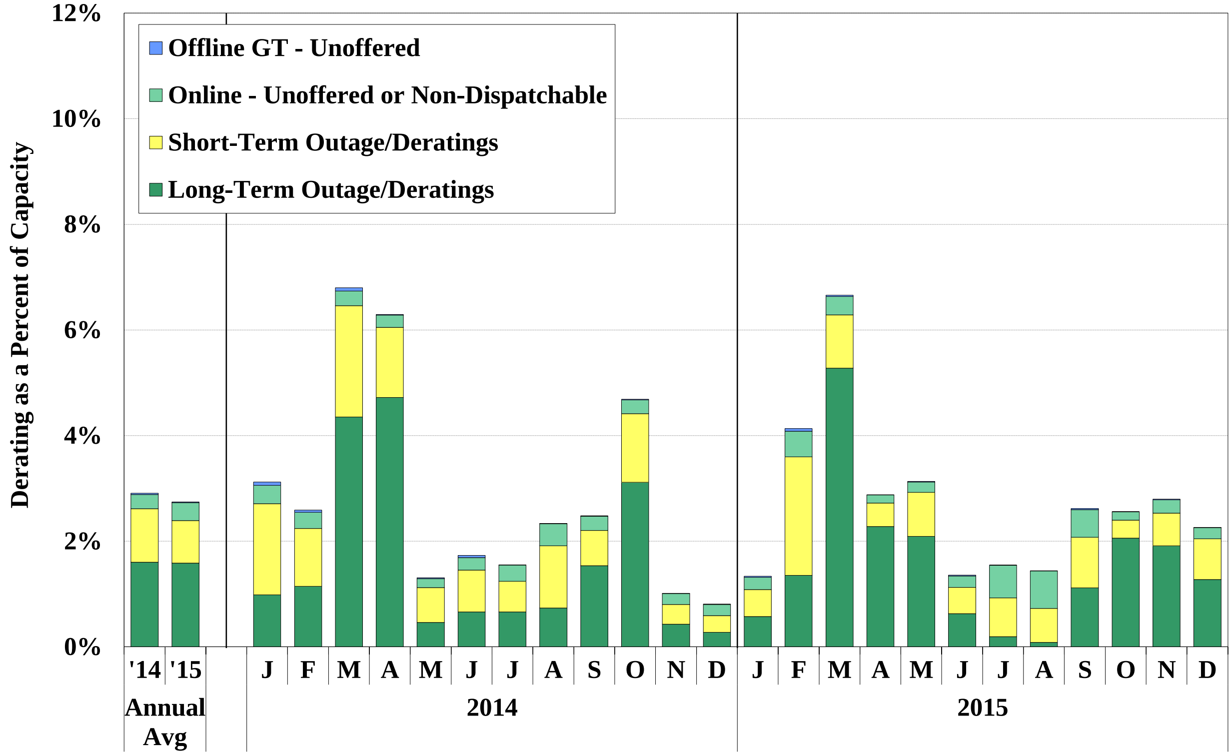


Figure A-26: Unoffered Economic Capacity by Month in East New York
2014 - 2015

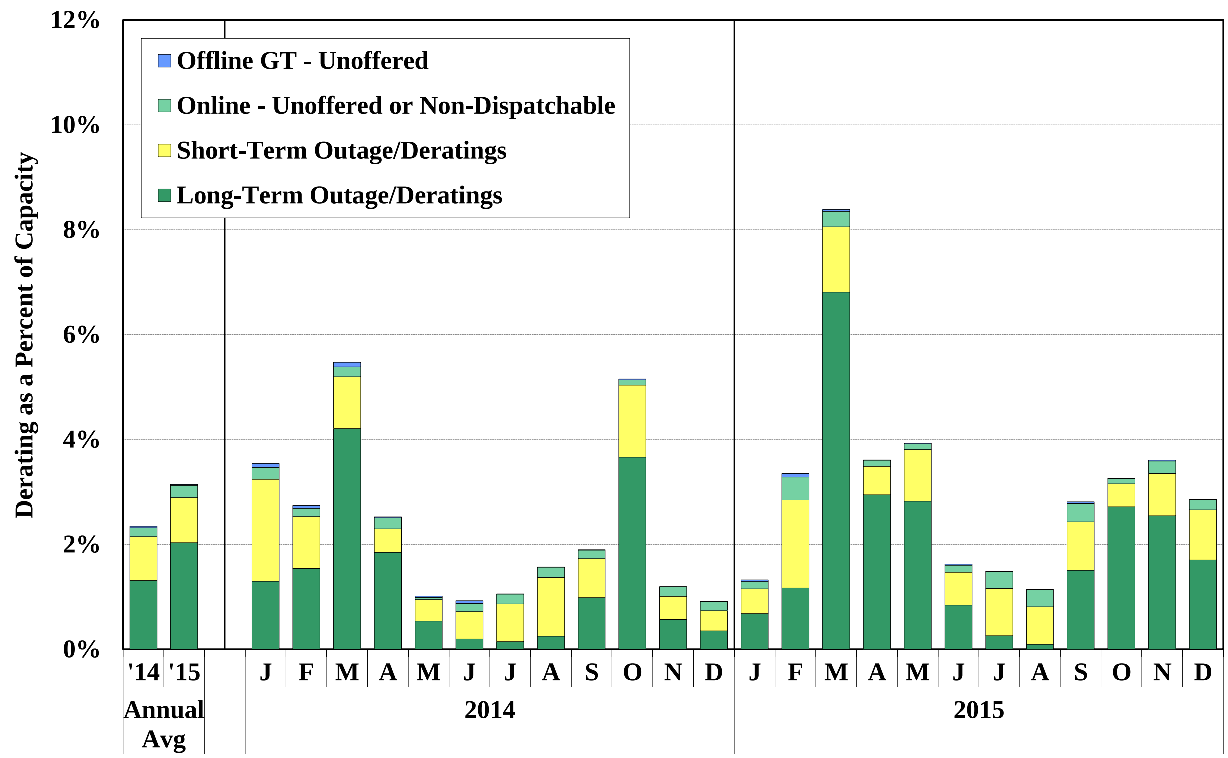


Figure A-27 & Figure A-28: Unoffered Economic Capacity by Load Level & Portfolio Size

The majority of wholesale electricity production comes from base-load and intermediate-load generating resources. Higher-cost resources are used to meet peak loads and constitute a very small portion of the total supply. This causes the market supply curve to be comparatively flat at low and moderate output levels and steeply sloped at high output levels. Therefore, as demand increases from low load levels, prices rise gradually until demand approaches peak levels, at which point prices can increase quickly as the more costly units are required to meet load. The shape of the market supply curve has implications for evaluating market power, namely that suppliers are more likely to have market power in broad areas under higher load conditions.

To distinguish between strategic and competitive conduct, we evaluate potential physical withholding in light of the market conditions and participant characteristics that would tend to create the ability and incentive to exercise market power. Under competitive conditions, suppliers maximize profits by increasing their offer quantities during the highest load periods to sell more power at the higher peak prices. Thus, we expect competitive suppliers to schedule maintenance outages during low-load periods, whenever possible. Nonetheless, more frequent operation of generators during high load periods increases the frequency of forced outages, which can reduce the amount of capacity offered into the market. Capacity that is on forced outage is more likely to be economic during high-load periods than during low-load periods.

Alternatively, a supplier with market power is most likely to profit from withholding during periods when the market supply curve becomes steep (i.e., at high-demand periods) because that is when prices are most sensitive to withholding. Hence, we evaluate the conduct relative to load and participant size in Figure A-27 and Figure A-28 to determine whether the conduct is consistent with workable competition.

Figure A-27: Unoffered Economic Capacity by Supplier by Load Level in New York
2014 – 2015

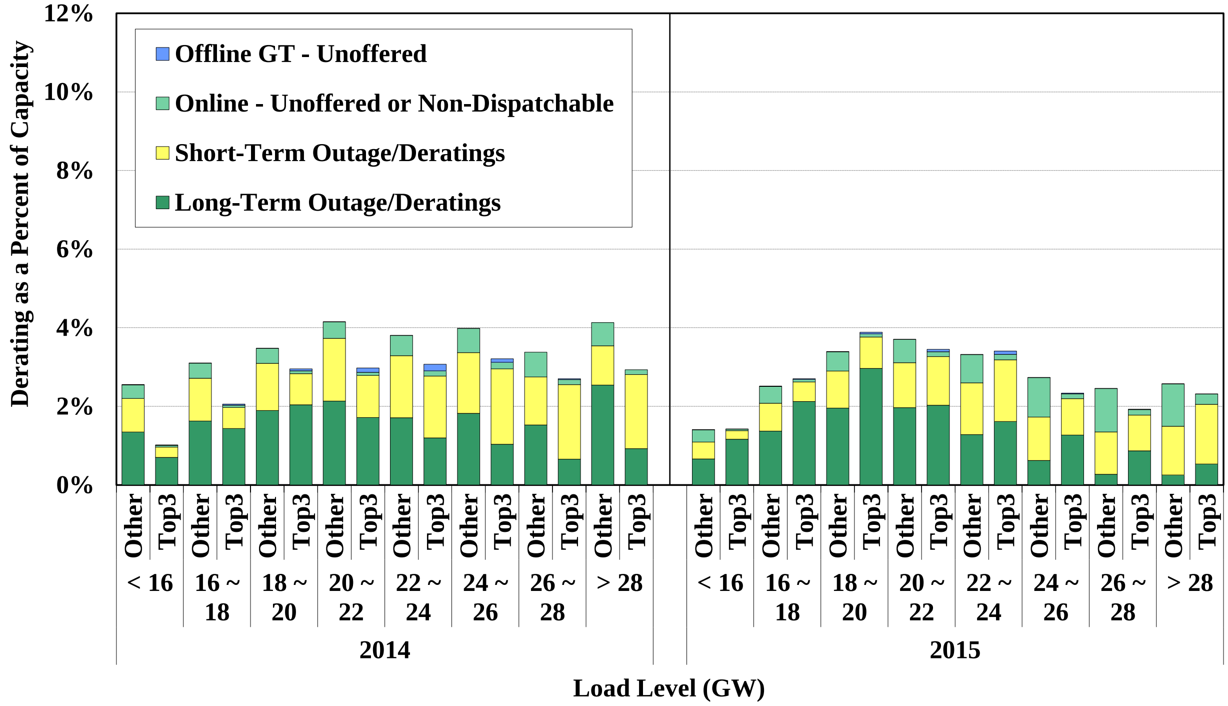
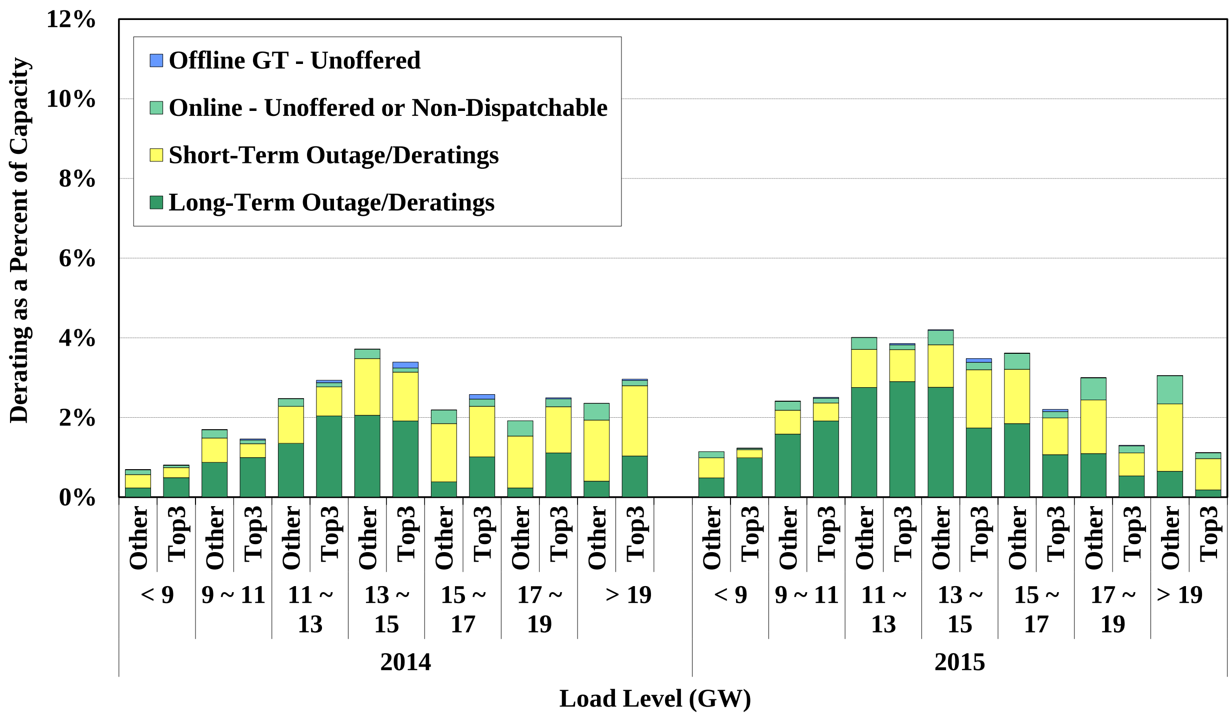


Figure A-28: Unoffered Economic Capacity by Supplier by Load Level in East New York
2014 – 2015



<u>Key Observations: Unoffered Economic Capacity</u>

- The general pattern of deratings was reasonably consistent with expectations for a competitive market in both 2014 and 2015.
  - Derated and unoffered economic capacity averaged 2.7 percent of total DMNC in NYCA, and 3.1 percent in Eastern New York in 2015.
  - Derated and unoffered economic capacity was mostly attributable to long-term maintenance deratings (58 percent in NYCA and 56 percent in Eastern New York in 2015).
  - Most of this economic capacity on long-term maintenance was scheduled during shoulder months (78 percent in NYCA and 80 percent in East).
  - Short-term deratings, driven largely by forced outages, were more consistent across load levels, but highest during the coldest winter months.
  - During the summer months (i.e., June to August) of 2015, total economic deratings and unoffered capacity was about one and a half percent of total DMNC in both NYCA and Eastern New York.
- The amount of short-term economic deratings was consistent with 2014, while economic long-term deratings increased moderately in Eastern New York from 2014 to 2015.
  - The increase in long-term deratings occurred primarily in the shoulder months when maintenance is normally done.
  - The increase in economic long-term deratings within Eastern New York occurred among suppliers outside of the Top Three.
- Although long-term deratings are not likely to reflect withholding, inefficient long-term outage scheduling (i.e., to schedule an outage during a period that the capacity is likely economic in a significant portion of the time) raises significant efficiency concerns.
  - The NYISO can require a supplier to re-schedule a planned outage for reliability reasons, but the NYISO cannot require a supplier to re-schedule for economic reasons, and there are no mitigation measures that would address outage scheduling that is not consistent with competitive behavior. It would be beneficial for the NYISO to consider expanding its authority to reject outage requests that would take economic capacity out-of-service during relatively high load conditions.

B. Potential Economic Withholding: Output Gap Metric

Economic withholding is an attempt by a supplier to inflate its offer price in order to raise LBMPs above competitive levels. A supplier without market power maximizes profit by offering its resources at marginal cost because inflated offer prices or other offer parameters prevent the unit from being dispatched when it would have been profitable. Hence, we analyze economic withholding by comparing actual supply offers with the generator’s reference levels, which is an estimate of marginal cost that is used for market power mitigation.[225, 226] An offer parameter is generally above the competitive level if it exceeds the reference level by a given threshold.

Figure A-29 and Figure A-30: Output Gap by Month

One useful metric for identifying potential economic withholding is the "output gap". The output gap is the amount of generation that is economic at the market clearing price, but is not producing output due to the owner's offer.[227] We assume that the unit's competitive offer price is equal to its reference level. To determine whether a unit is economic, we evaluate whether it would have been economic to commit based on day-ahead prices and whether its incremental energy would have been economic to produce based on real-time prices. Since gas turbines can be started in real-time, they are evaluated based on real-time prices. Like the prior analysis of potential physical withholding, we examine the broad patterns of output gap in New York State and Eastern New York, and also pay special attention to the relationship of the output gap to the market demand level and participant size.

The following four figures show the output gap using three thresholds: the state-wide mitigation threshold (i.e., the standard conduct threshold used for mitigation outside New York City), which is the lower of $100 per MWh or 300 percent of a generator's reference level; and two additional lower thresholds. Lower Threshold 1 is 25 percent of a generator's reference level, and Lower Threshold 2 is 100 percent of a generator's reference level. The two lower thresholds are included to assess whether there may have been abuse of market power that does not trigger the thresholds specified in the tariff for imposition of mitigation measures by the ISO.

225 The method of calculating reference levels is described in NYISO Market Services Tariff, Attachment H – NYISO Market Monitoring Plan-Market Mitigation Measures, Section 3.1.4. For some generators, the reference levels are based on an average of the generators' accepted bids during competitive periods over the previous 90 days. The theory underlying this approach is that competitive conditions that prevail in most hours provide a strong incentive for suppliers to offer marginal costs. Hence, past accepted offers provide a benchmark for a generator's marginal costs. For some generators, the reference level is based on an estimate of its fuel costs, other variable production costs, and any other applicable costs.

226 Due to the Increasing Bids in Real Time (IBRT) functionality, a generator's reference level can now be adjusted directly by a generator for a particular hour or day to account for fuel price changes. The NYISO monitors these generator-set IBRT reference levels and may request documentation substantiating a generator IBRT.

227 The output gap calculation, like our potential physical withholding calculation, excludes capacity that is more economic to provide ancillary services.

Figure A-29: Output Gap by Month in New York State
2014 – 2015

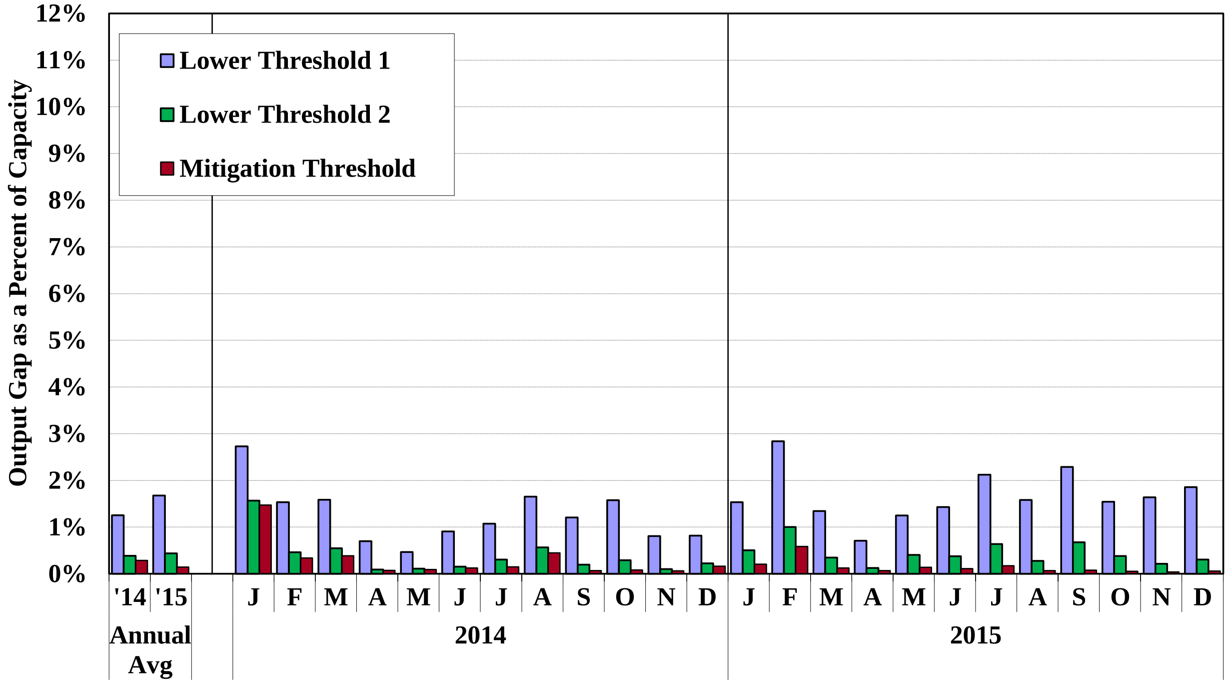


Figure A-30: Output Gap by Month in East New York
2014 - 2015

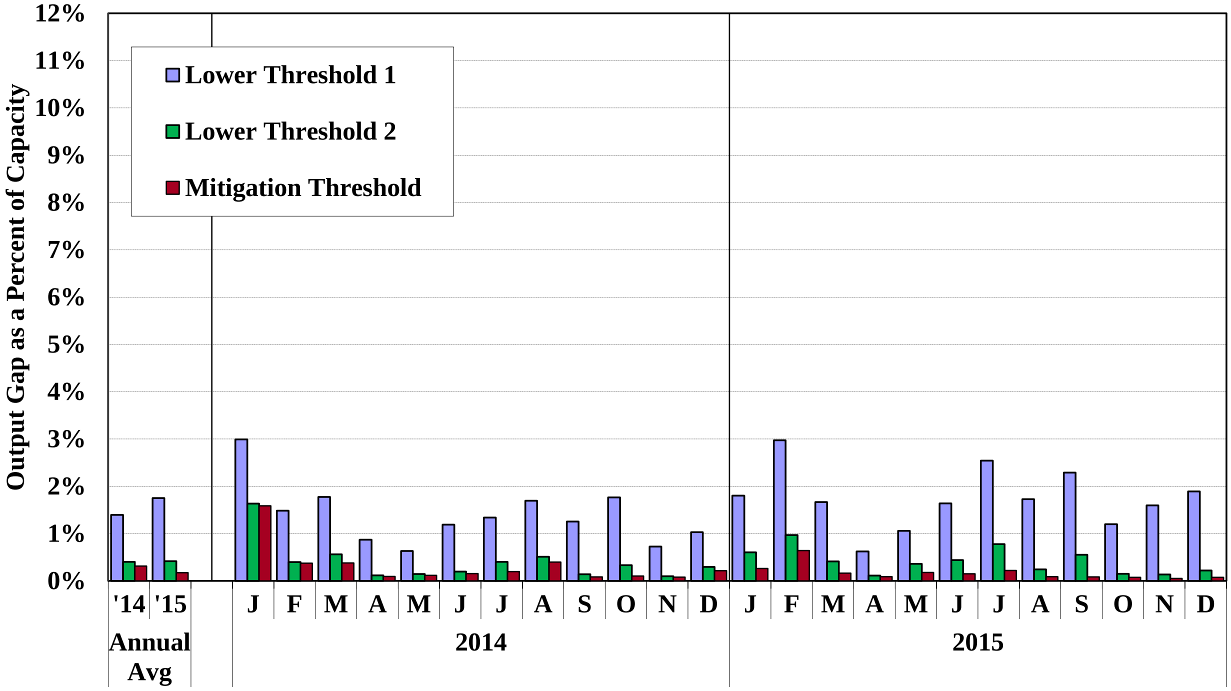


Figure A-31 & Figure A-32: Output Gap by Supplier and Load Level

Like the analysis of deratings in the prior subsection, it is useful to examine the output gap by load level and size of supplier because the incentive to economically withhold resources is positively correlated with these factors. Hence, these figures indicate how the output varies as load increases and whether the largest two suppliers exhibit substantially different conduct than other suppliers.

Figure A-31: Output Gap by Supplier by Load Level in New York State
2015

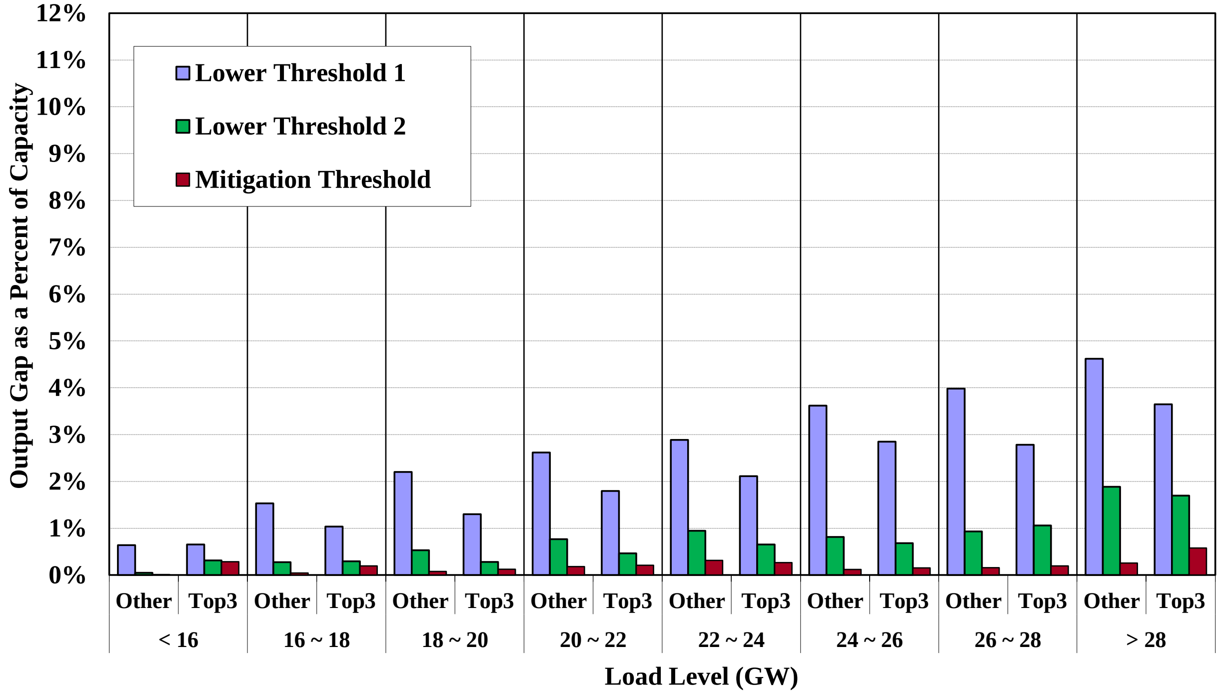
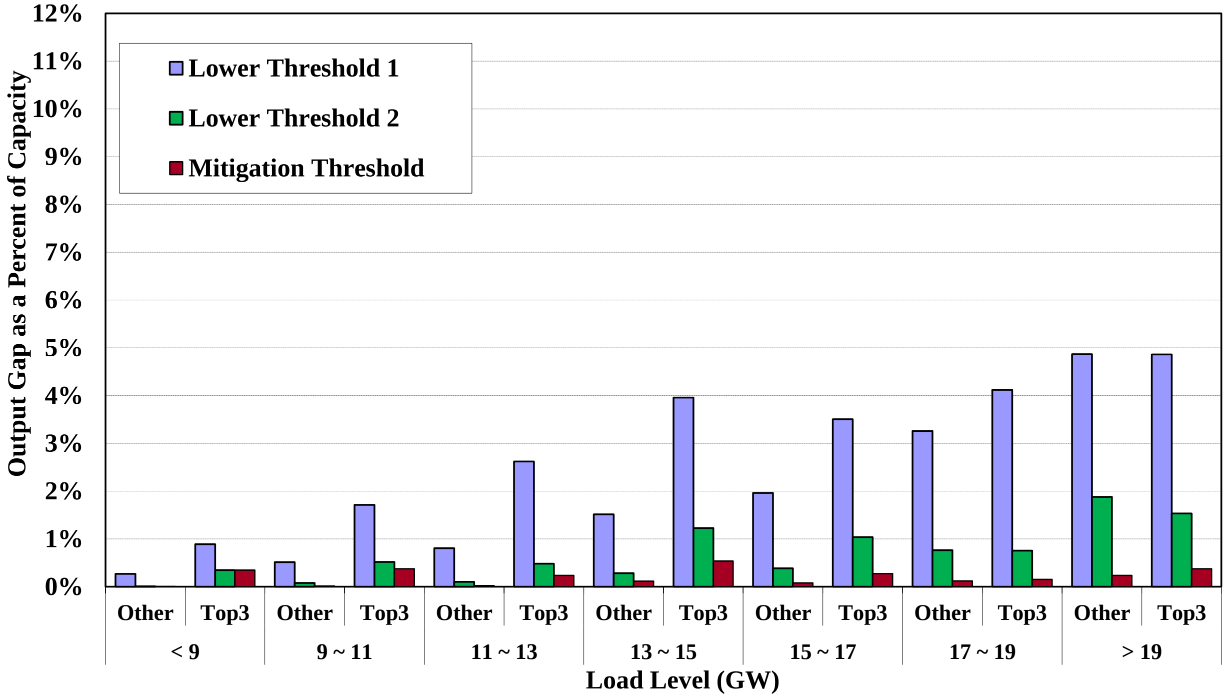


Figure A-32: Output Gap by Supplier by Load Level in East New York
2015



Key Observations: Economic Withholding – Generator Output Gap

- The amount of output gap averaged less than 0.25 percent of total capacity at the mitigation threshold and roughly 1.75 percent at the lowest threshold evaluated (i.e., 25 percent) in 2015.
- For higher load levels, output gap was generally consistent between the top three suppliers and other suppliers.
- Output Gap did rise as load rose. This was due to the following factors:
  - As load rises, some units face gas pressure limitations that increase based on the commitment status of other units around them. These costs are not incorporated in reference levels.
  - The Output Gap takes market prices as fixed. However, committing extra units would lower Day-Ahead prices, especially at high loads. Therefore, uncommitted units in our Output Gap estimate may not truly have been economic to commit.
  - Prices are generally higher at higher load levels, which substantially increases the total quantity of resources that are economic and, therefore, could potentially be included in the Output Gap.
  - Some units, predominantly co-generation resources, consistently offer inflexibly, reducing market commitment and dispatch. This uncommitted capacity appears economic (and shows up as Output Gap) increasingly at high-load periods.

- Most co-generation resources operate in a relatively inflexible manner because of the need to divert energy production to non-electric uses. Small portfolio owners generally do not have an incentive to withhold supply.

C. Day-Ahead and Real-Time 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 NYISO applies a conduct-impact test that can result in mitigation of a participant's bid parameters (i.e., incremental energy offers, start-up and minimum generation offers, and physical parameters). The mitigation measures are only imposed when suppliers' conduct exceeds well-defined conduct thresholds and when the effect of that conduct on market outcomes exceeds well-defined market impact thresholds.[228] This framework prevents mitigation when it is not necessary to address market power, while allowing high prices during legitimate periods of shortage.

The day-ahead and real-time market software is automated to perform the conduct and impact tests and implement the mitigation. The mitigation measures are designed to allow prices to rise efficiently to reflect legitimate supply shortages while effectively mitigating inflated prices associated with artificial shortages that result from economic withholding in transmission-constrained areas.

When a transmission constraint is binding, one or more suppliers may be in the position to exercise market power due to the lack of competitive alternatives in the constrained area. For this reason, more restrictive conduct and impact thresholds are used for import-constrained load pockets in New York City. The in-city load pocket conduct and impact thresholds are determined by a formula that is based on the number of congested hours experienced over the preceding twelve-month period.[229] This approach permits the in-city conduct and impact thresholds to increase as the frequency of congestion decreases, whether due to additional generation or increases in transmission capability. An in-city offer fails the conduct test if it exceeds the reference level by the threshold or more. In-city offers that fail the conduct test are tested for price impact by the market software. If their price impact exceeds the threshold, they are mitigated.

When local reliability criteria necessitate the commitment of additional generation, one or more suppliers may be in the position to exercise market power due to the lack of competitive alternatives in the local area. For this reason, the NYISO filed in 2010 to implement more restrictive conduct and impact thresholds when a single supplier is pivotal for satisfying local

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228 See NYISO Market Services Tariff, Sections 23.3.1.2 and 23.3.2.1.

229 Threshold = (0.02 * Average Price * 8760) / Constrained Hours. This threshold is defined in the NYISO Market Services Tariff, Section 23.3.1.2.2.1.

reliability criteria outside New York City.[230] The Rest-Of-State Reliability conduct and impact thresholds limit the start-up cost and minimum generation cost offers of such units to conduct thresholds of the higher of $10 per MWh or 10 percent of the reference level.[231]

Beginning in late 2010, it became more common for a generator to be mitigated initially in the day-ahead or real-time market and for the generator to be unmitigated after consultation with the NYISO.[232] Reversing a mitigation can occur for several reasons:

- A generator's reference level is inaccurate and the supplier initiated consultation with the NYISO to increase the reference level before the generator was mitigated.
- A generator's reference level on a particular day is lower than the consultative reference level that the NYISO approved for the generator before the generator was mitigated.[233]
- The generator took appropriate steps to inform the NYISO of a fuel price change prior to being scheduled (either through IBRT or some other means), but the generator was still mitigated.
- A generator's fuel cost may change significantly by time of day, although the day-ahead market software is unable to use reference levels that vary by time of day, so such a generator may be mitigated in a particular hour of the day-ahead market and then unmitigated once the proper reference level is reflected.

Figure A-33 & Figure A-34: Summary of Day-Ahead and Real-Time Mitigation

Figure A-33 and Figure A-34 summarize the amount of mitigation in New York that occurred in the day-ahead and the real-time markets in 2014 and 2015. These figures do not include guarantee payment mitigation that occurs in the settlement system.

The bars in the upper panel of the figures indicate the percent of hours when incremental energy offer mitigation was imposed on one or more units in each category, while the bars in the lower panel indicate the average amount of capacity mitigated in hours when mitigation occurred (as well as the portion that was unmitigated). Mitigated quantities are shown separately for the flexible output ranges of units (i.e. Incremental Energy) and the non-flexible portions (i.e.

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230 More restrictive conduct and impact thresholds already existed for New York City generators when they were committed for local reliability. The start-up cost and minimum generation cost offers of such units are effectively subject to $0 thresholds. See NYISO Market Services Tariff, Section 23.5.2.1.

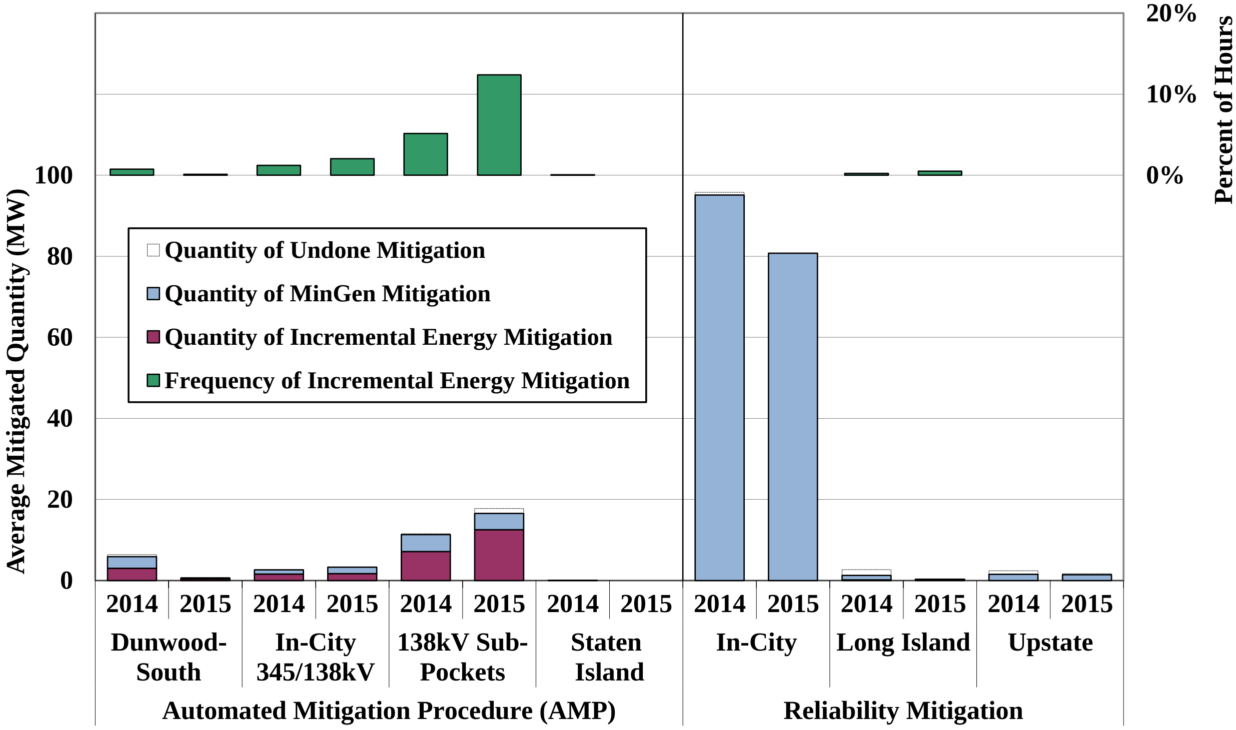
231 See NYISO Market Services Tariff, Section 23.3.1.2.3.

232 NYISO Market Services Tariff, Section 23.3.3 lays out the requirements for consultation. This occurs after the market date, so any effect of the mitigation on LBMPs is unchanged by unmitigation.

233 The hierarchy of information that is used to calculate reference levels is provided in NYISO Market Services Tariff, Section 23.1.4. It is possible for a generator to have a bid-based or LBMP-based reference level that is less accurate than the reference level determined through consultation.

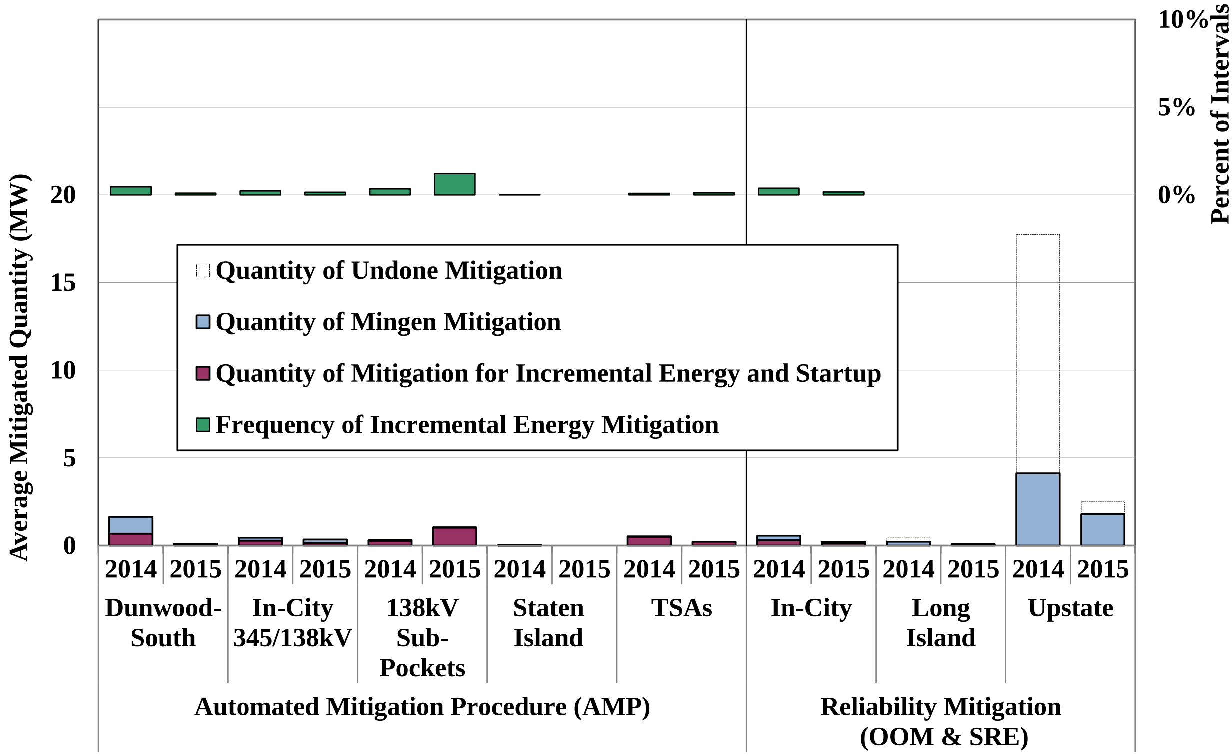
MinGen).[234] In each figure, the left portion shows the amount of mitigation by the Automated Mitigation Procedure ("AMP") on the economically committed units in load pockets of New York City, and the right portion shows the amount of mitigation on the units committed for reliability in New York City, Long Island, and the upstate area.

Figure A-33: Summary of Day-Ahead Mitigation
2014 – 2015



234 Mitigation of gas turbine capacity is shown in the Incremental Energy category whenever the incremental energy offer or the startup offer is mitigated.

Figure A-34: Summary of Real-Time Mitigation
2014 - 2015



Key Observations: Day-ahead and Real-time Mitigation

- The majority of mitigation occurs in the day-ahead market, since this is where most supply is scheduled. In 2015:
  - 96 percent of mitigation occurred in the day-ahead market, of which nearly 80 percent for the local reliability (i.e., DARU and LRR) units.
    - Most reliability commitment occurs in the day-ahead market, making the instances of reliability commitment mitigation more prevalent in the day-ahead market.
    - These mitigations generally affected guarantee payment uplift but not LBMPs.
  - Mitigation for local reliability fell modestly from 2014 to 2015, consistent with the decrease in reliability commitments in 2015.
- The amount of AMP mitigation fell substantially in recent years largely because of less frequent congestion in New York City.
  - The hourly average MW that was AMP-mitigated fell from over 250 MW in 2011 to less than 25 MW in both 2014 and 2015.
  - Generation additions and transmission upgrades in recent years led to less frequent and severe transmission congestion in New York City, particularly in the 138kV load pockets.

  - In addition, natural gas prices in New York City have fallen relative to other regions of the state and summer load levels were low in the recent two years, contributing to further reductions in New York City congestion and associated AMP-mitigation in 2014 and 2015.
  - Nonetheless, AMP mitigation rose modestly in the 138 kV load pockets from 2014 to 2015, reflecting more frequent congestion in these areas.
- Unmitigation of generators became less common in 2015.

D. Ancillary Services Offers

The NYISO co-optimizes the scheduling of energy and ancillary services in the day-ahead and real-time market. This co-optimization causes the prices of both energy and ancillary services to reflect the costs to the system of diverting resources to provide ancillary services that would otherwise provide energy.

The ancillary services markets also include ancillary services demand curves that represent the economic value placed on each class of reserves. When the reserve requirements cannot be satisfied at a cost of less than the demand curve, the system is in a shortage and the reserve demand curve value will be included in both the reserve price and the energy price. This approach is recognized for producing efficient prices during shortages of reserves because it provides a mechanism for reflecting the value of reserves in the price of energy during shortages.

This sub-section evaluates the efficiency of ancillary services offer patterns, particularly in light of the relationship between day-ahead and real-time ancillary services markets. In an efficient market, we expect suppliers to respond to predictable differences between day-ahead and real-time ancillary service prices by raising or lowering their offer prices in the day-ahead market. However, the high volatility of real-time reserves clearing prices makes them difficult for market participants to predict in the day-ahead market. High volatility of real-time prices is a source of risk for suppliers that sell reserves in the day-ahead market, since suppliers must forego real-time scarcity revenues if they have already sold reserves in the day-ahead market. Some suppliers may reduce their exposure to this risk by raising their reserves offer prices in the day-ahead market.

Figure A-35 to Figure A-39: Summary of Ancillary Services Offers

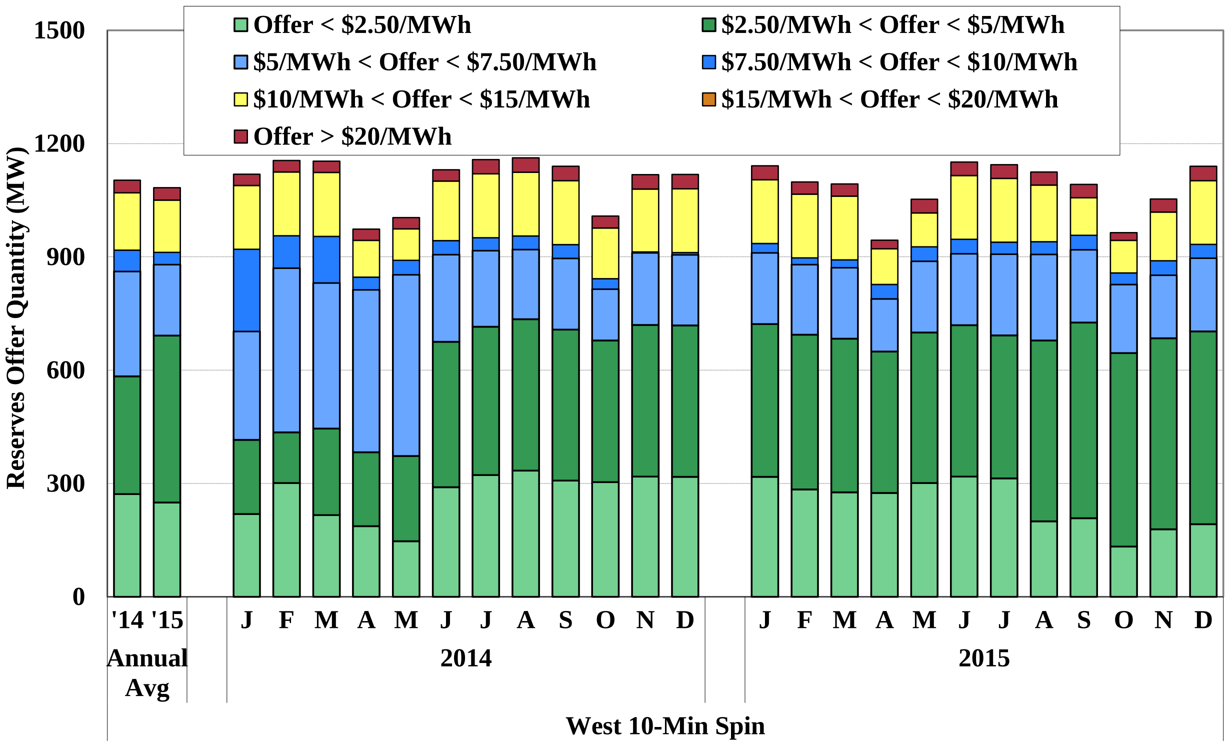
The following five figures compare the ancillary services offers for generators in the day-ahead market for 2014 and 2015 on a monthly basis as well as on an annual basis. The quantities offered are shown for the following categories:

- 10-minute spinning reserves in Western New York,
- 10-minute spinning reserves in Eastern New York,
- 10-minute non-spinning reserves in Eastern New York,

- 30-minute operating reserves in NYCA,[235] and
- Regulation.

Offer quantities are shown according to offer price level for each category. Offers for the five ancillary services products from all hours are included in this evaluation.

Figure A-35: Summary of West 10-Minute Spinning Reserves Offers
Day-Ahead Market, 2014-2015



235 This category only includes the reserve capacity that can be used to satisfy the 30-minute reserve requirements but not the 10-minute reserve requirements. That is, the reported quantity in this chart excludes the 10-minute spinning and 10-minute non-spin reserves from the total 30-minute reserve capability.

Figure A-36: Summary of East 10-Minute Spinning Reserves Offers
Day-Ahead Market, 2014-2015

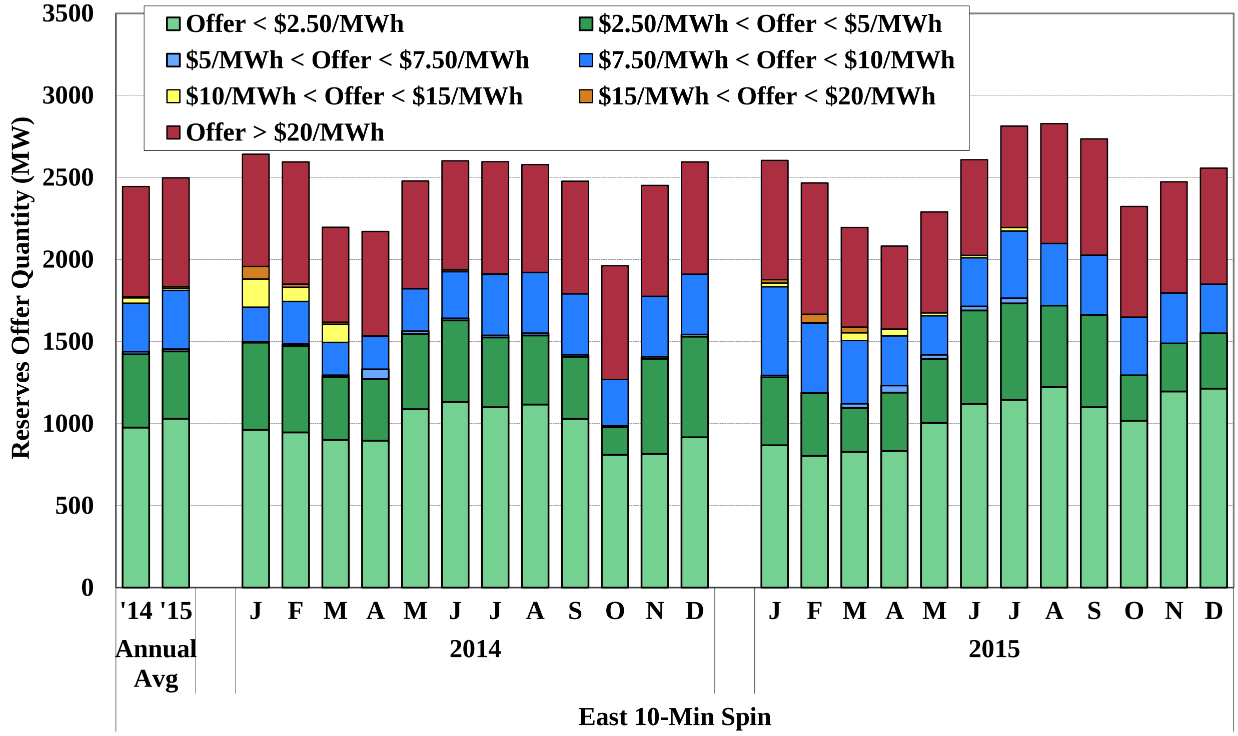


Figure A-37: Summary of East 10-Minute Non-Spin Reserves Offers
Day-Ahead Market, 2014-2015

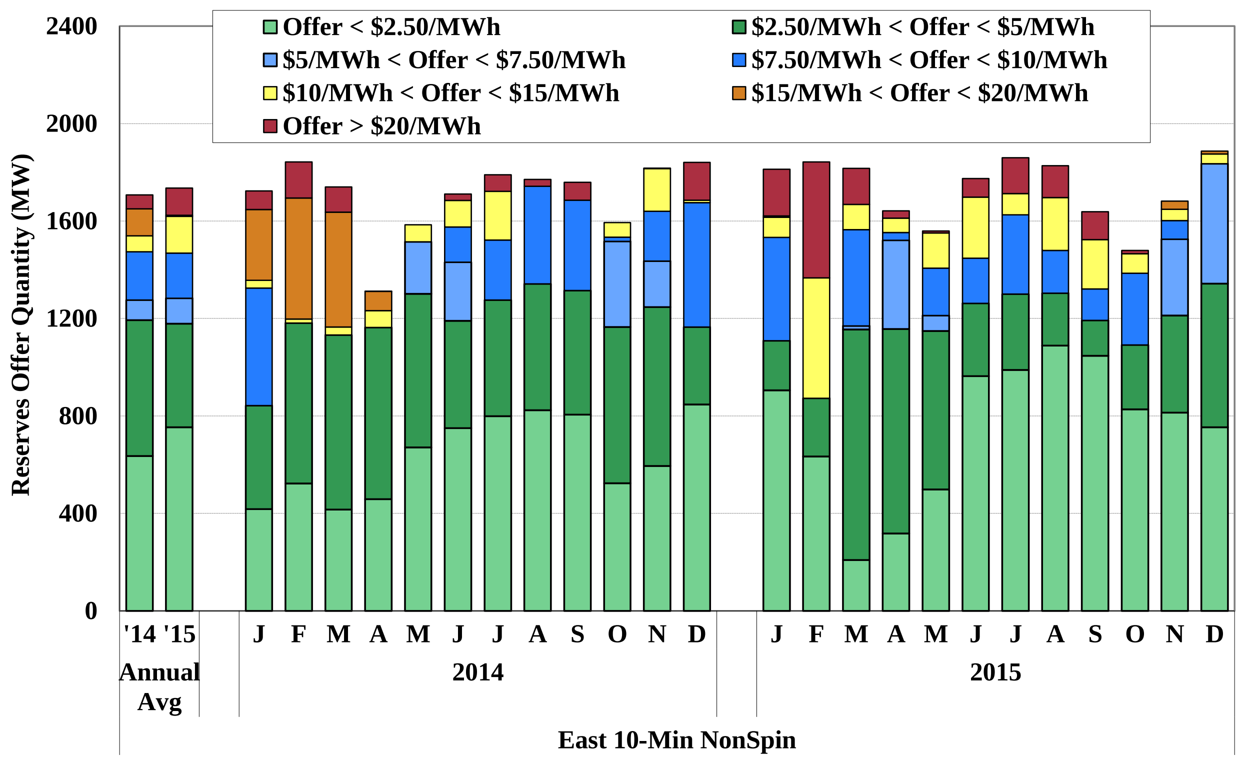


Figure A-38: Summary of NYCA 30-Minute Operating Reserves Offers
Day-Ahead Market, 2014-2015

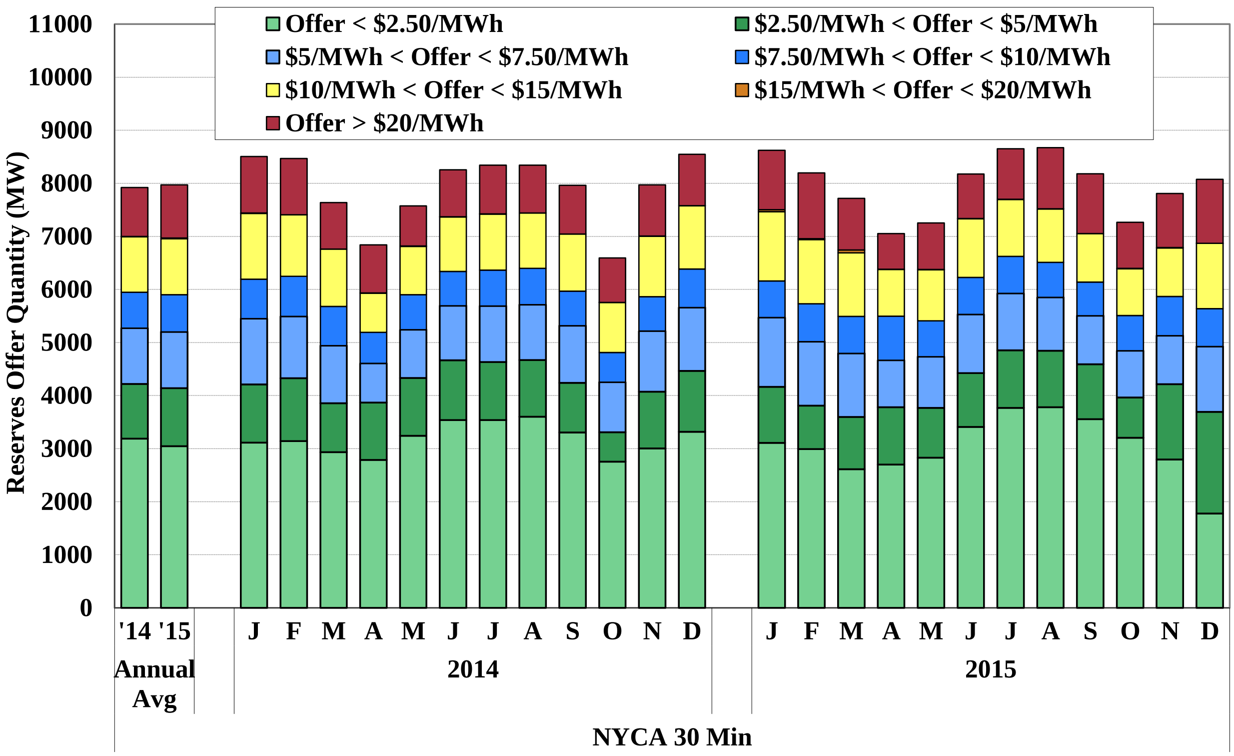
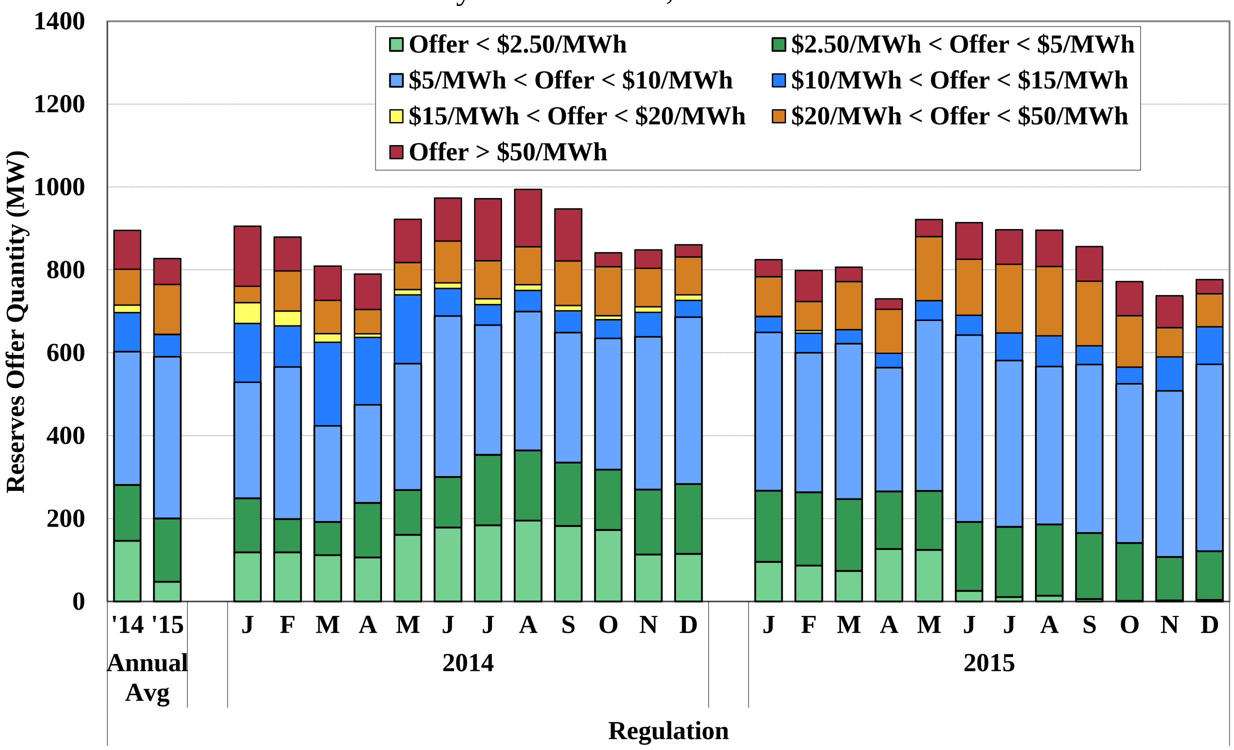


Figure A-39: Summary of Regulation Capacity Offers
Day-Ahead Market, 2013-2014



Key Observations: Ancillary Services Offers

- The amount of ancillary services offers from all five categories exhibited typical seasonal variations in both 2014 and 2015.
  - Reserves and regulation offer quantities were lower in the spring and fall than in the summer and winter because most planned outages occur in shoulder months when supply is less valuable.
- Since the phased revisions of two day-ahead mitigation provisions, we have not found changes in offer patterns that raise withholding concerns in the reserves markets.
  - The average amounts of offers for 10-minute and 30-minute reserves were relatively consistent between 2014 and 2015.
- The average prices of offers were relatively consistent between 2014 and 2015, despite lower average energy prices in 2015.
  - Suppliers normally increased their offer prices under conditions when average real-time prices had a tendency to exceed day-ahead prices (e.g., during the period in the first quarter of 2015 when gas prices were more volatile).
    - This behavior is similar to behavior in 2014, although the magnitude of the offer price increases was muted given less natural gas price volatility in winter 2015.
  - The average prices of 30-minute reserves rose following the increases in the NYCA 30-minute reserve requirement and its demand curve values, particularly in December 2015.
- The amount of offers for ancillary services products normally far exceeds their requirements, which contributes to the competitiveness of the markets for these products. For example:
  - The total amount of 10-minute spinning and non-spinning reserve capacity offered in Eastern New York averaged more than 4,000 MW, compared to the 1,200 MW requirement of 10-minute operating reserves for this region.

E. Analysis of Load Bidding and Virtual Trading

In addition to screening the conduct of suppliers for physical and economic withholding, it is important to evaluate how the behavior of buyers influences energy prices. Therefore, we evaluate whether load bidding is consistent with workable competition. Load can be scheduled in one of the following five ways:

- *Physical Bilateral Contracts* – These schedules allow participants to settle transmission charges (i.e., congestion and losses) with the NYISO between two points and to settle on the commodity sale privately with their counterparties. It does not represent all of the bilateral contracting in New York because participants have the option of entering into bilateral contracts that are settled privately (e.g., contracts for differences).

- *Day-Ahead Fixed Load* – This represents load scheduled in the day-ahead market for receipt at a specific bus regardless of the day-ahead price. It is the equivalent of a load bid with an infinite bid price.
- *Price-Capped Load Bids* – This is load bid into the day-ahead market with a bid price indicating the maximum amount the Load-Serving Entity ("LSE") is willing to pay.[236]
- *Virtual Load Bids* – These are bids to purchase energy in the day-ahead market with a bid price indicating the maximum amount the bidder is willing to pay. Virtual load scheduled in the day-ahead market is sold back in the real-time market. The virtual buyer earns or pays the difference between the day-ahead and real-time prices. Virtual trading is currently allowed at the load zone level in New York but not at a more disaggregated level.
- *Virtual Exports* – These are external transactions in the export direction that are scheduled in the day-ahead market but are withdrawn or bid at high price levels in real time. They are similar to virtual load bids, but they are placed at the external proxy buses rather than at the eleven load zones.

The categories of load listed above are important because they each tend to increase the amount of physical resources that are scheduled in the day-ahead market. Virtual supply and virtual imports, on the other hand, tend to reduce the amount of physical resources that are scheduled in the day-ahead market. Virtual supply is energy that is offered for sale in the day-ahead market with an offer price indicating the minimum amount the market participant is willing to accept. Virtual supply sold in the day-ahead market is purchased back from the real-time market.

Figure A-40 to Figure A-47: Day-Ahead Load Schedules versus Actual Load

Many generating units have long lead times and substantial commitment costs. Their owners must decide whether to commit them well in advance of real-time before they can be certain that the unit will be economic. The day-ahead market provides these suppliers with a means of being committed only when it is economic to do so. These suppliers are willing to sell into the day-ahead market if day-ahead prices are generally consistent with real-time prices. Thus, efficient unit commitment relies on consistency between the day-ahead and the real-time markets. The following figures help evaluate the consistency between day-ahead load scheduling patterns and actual load, providing an indication of the overall efficiency of the day-ahead market.

We expect day-ahead load schedules to be generally consistent with actual load in a well-functioning market. Under-scheduling load generally leads to lower day-ahead prices and insufficient commitment for real-time needs. Over-scheduling tends to raise day-ahead prices above real-time prices. Thus, market participants have incentives to schedule amounts of load consistent with real-time load.

236 For example, a LSE may make a price-capped bid for 500 MW at $60 per MWh. If the day-ahead clearing price at its location is above $60, the bid would not be accepted in the day-ahead market.

The following eight figures show day-ahead load schedules and bids as a percent of real-time load during daily peak load hours in 2014 and 2015 at various locations in New York on a monthly average basis. Virtual load (including virtual exports) scheduling has the same effect on day-ahead prices and resource commitment as physical load scheduling, so they are shown together in this analysis. Conversely, virtual supply (including virtual imports) has the same effect on day-ahead prices and resource commitment as a reduction in physical load, so it is treated as a negative load for the purposes of this analysis. For each period, physical load and virtual load are shown by bars in the positive direction, while virtual supply is shown by bars in the negative direction. Net scheduled load, indicated by the line, is the sum of scheduled physical and virtual load minus scheduled virtual supply. The inset table shows the overall changes in scheduling pattern from 2014 to 2015. Virtual imports and exports are shown for NYCA only and are not shown for any of the sub-areas in New York.

Figure A-40: Day-Ahead Load Schedules versus Actual Load in West Zone
Zone A, 2014 – 2015

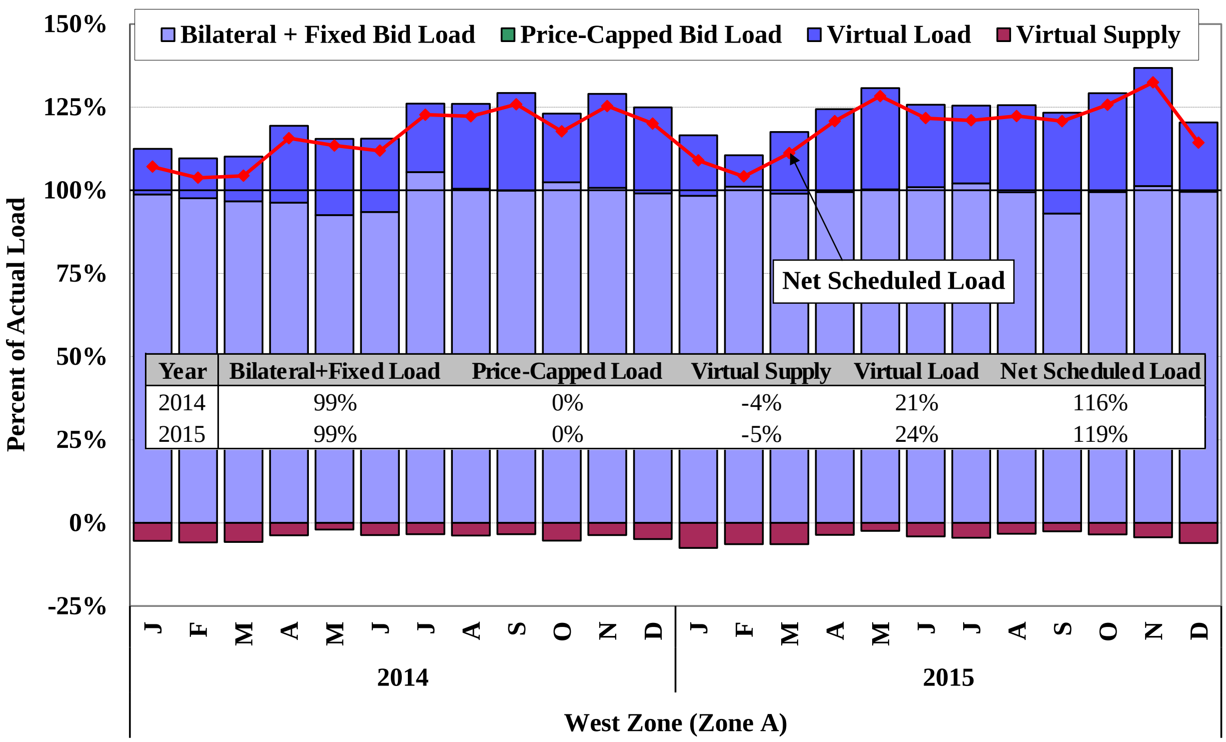
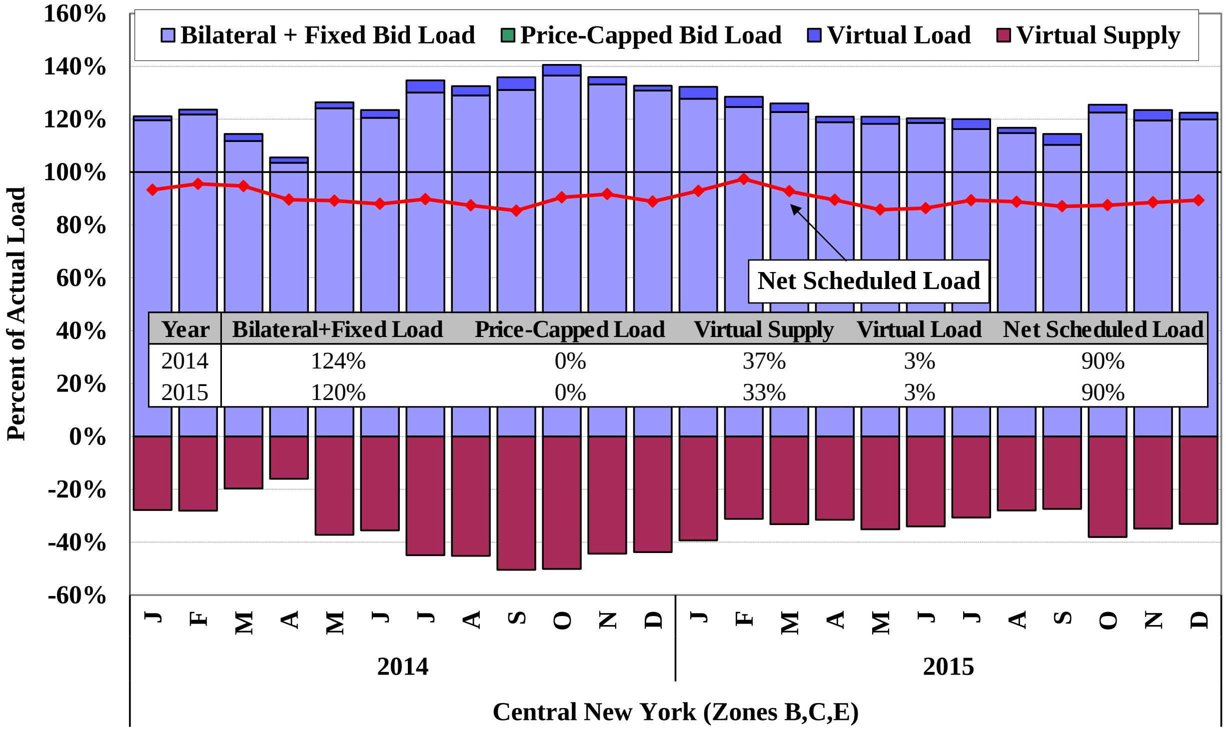
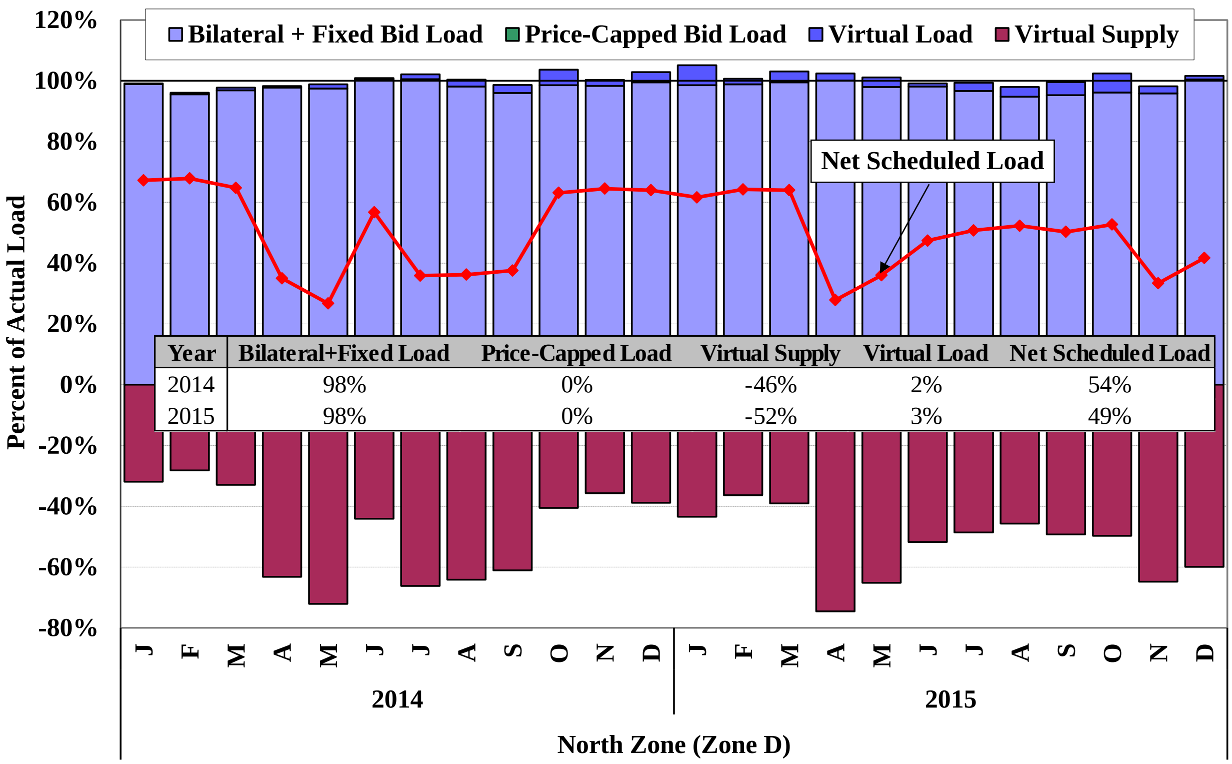


Figure A-41: Day-Ahead Load Schedules versus Actual Load in Central New York
Zones B, C, & E, 2014 – 2015



Year	Bilateral+Fixed Load	Price-Capped Load	Virtual Supply	Virtual Load	Net Scheduled Load
2014	124%	0%	37%	3%	90%
2015	120%	0%	33%	3%	90%

Figure A-42: Day-Ahead Load Schedules versus Actual Load in North Zone
Zone D, 2014 – 2015



Year	Bilateral+Fixed Load	Price-Capped Load	Virtual Supply	Virtual Load	Net Scheduled Load
2014	98%	0%	-46%	2%	54%
2015	98%	0%	-52%	3%	49%

Figure A-43: Day-Ahead Load Schedules versus Actual Load in Capital Zone
Zone F, 2014 – 2015

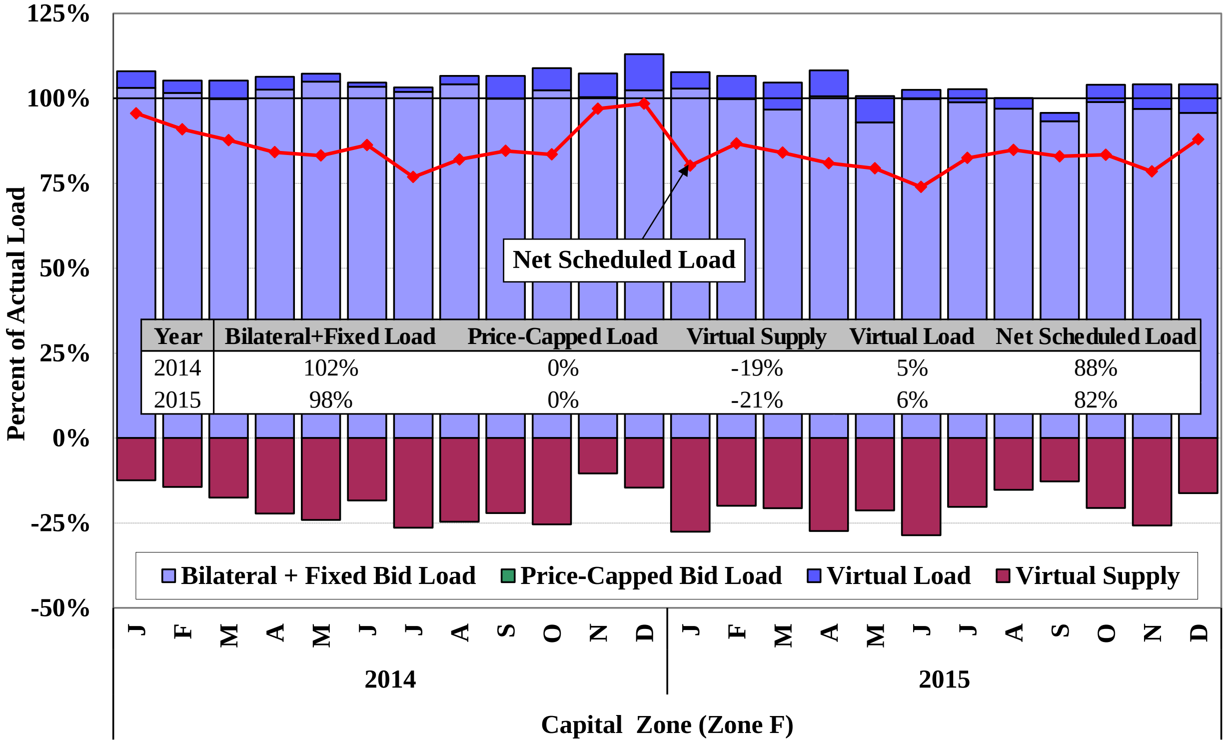


Figure A-44: Day-Ahead Load Schedules versus Actual Load in the Lower Hudson Valley
Zones G, H, & I, 2014 – 2015

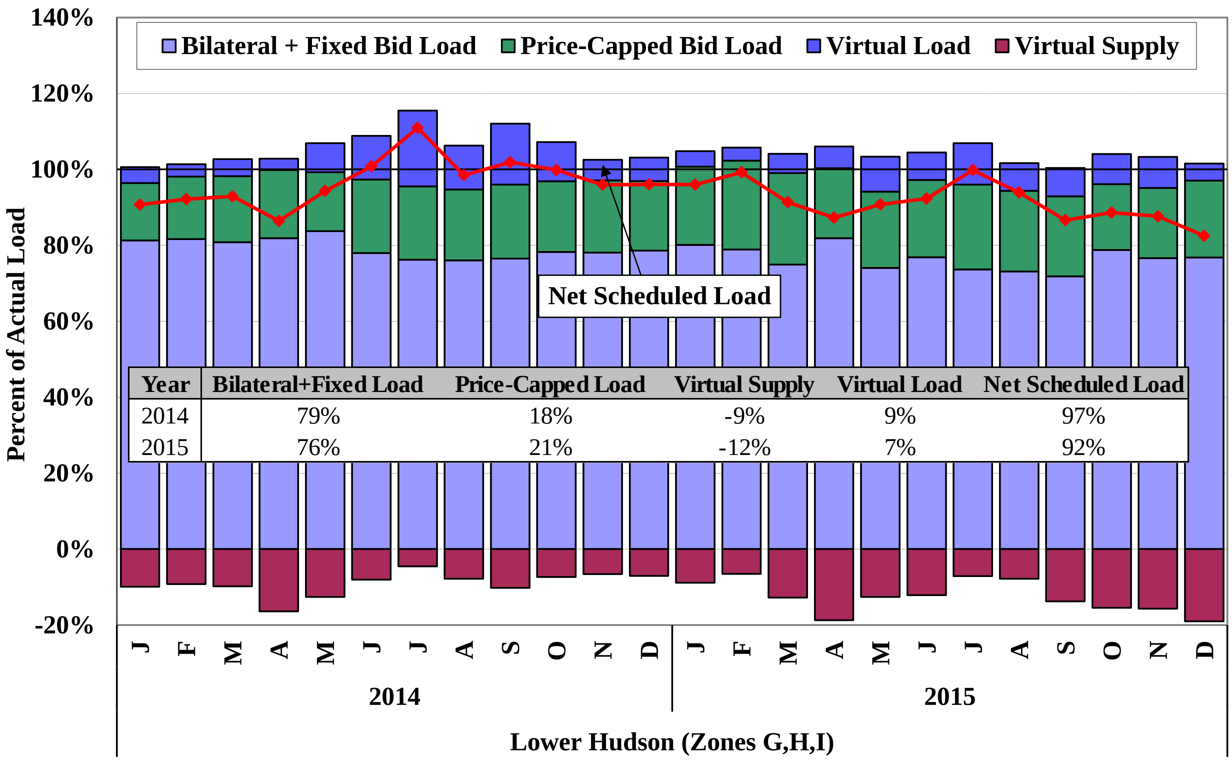
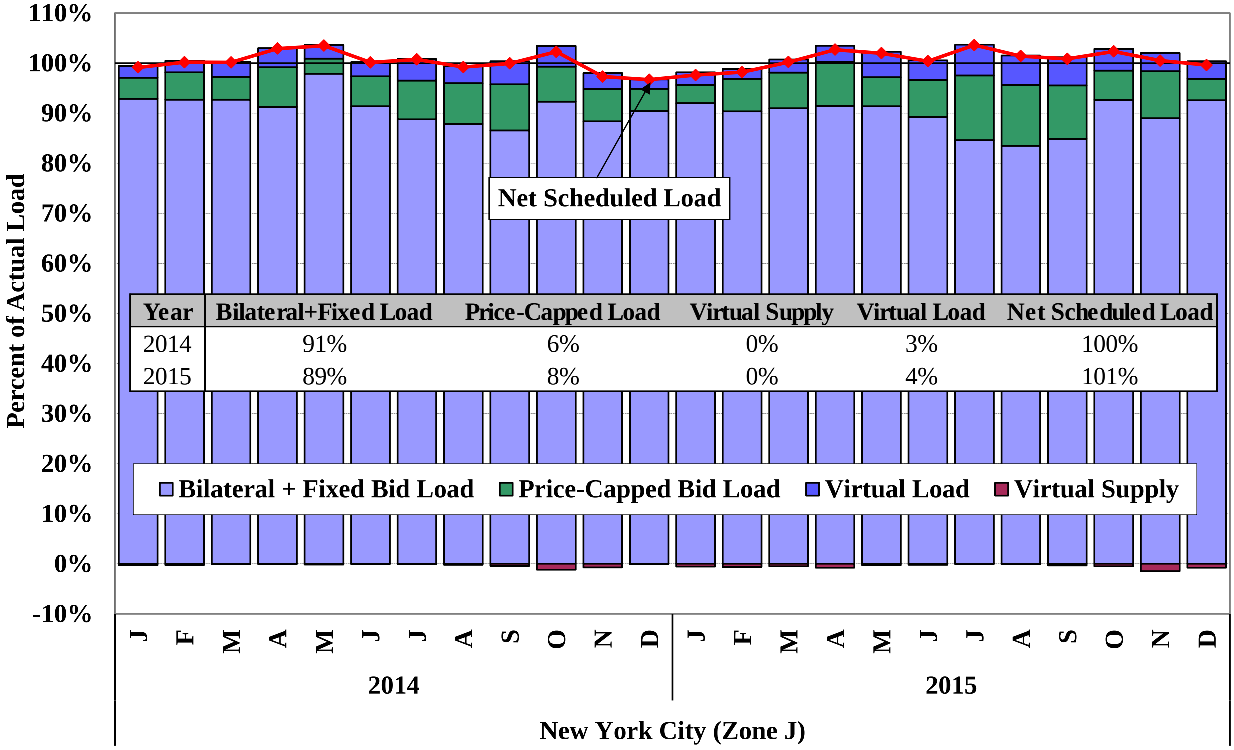
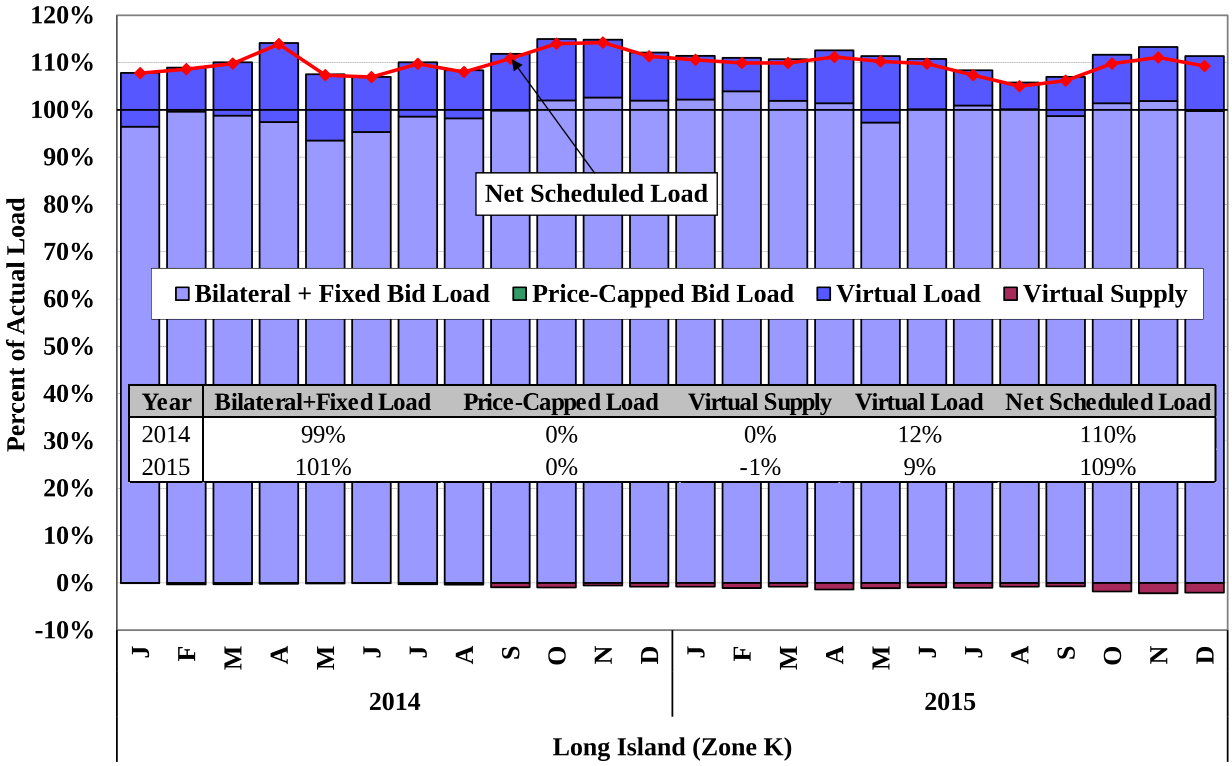


Figure A-45: Day-Ahead Load Schedules versus Actual Load in New York City
Zone J, 2014 – 2015



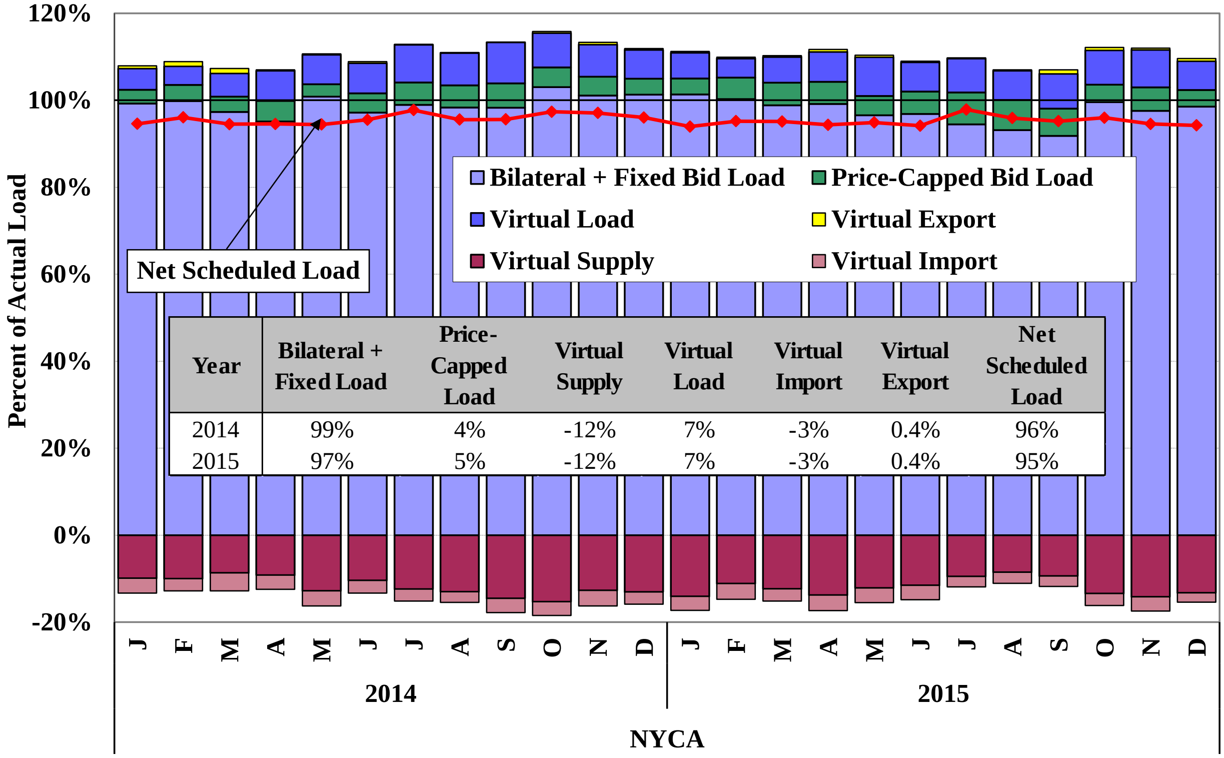
Year	Bilateral+Fixed Load	Price-Capped Load	Virtual Supply	Virtual Load	Net Scheduled Load
2014	91%	6%	0%	3%	100%
2015	89%	8%	0%	4%	101%

Figure A-46: Day-Ahead Load Schedules versus Actual Load in Long Island
Zone K, 2014 – 2015



Year	Bilateral+Fixed Load	Price-Capped Load	Virtual Supply	Virtual Load	Net Scheduled Load
2014	99%	0%	0%	12%	110%
2015	101%	0%	-1%	9%	109%

Figure A-47: Day-Ahead Load Schedules versus Actual Load in NYCA
2014 – 2015



Year	Bilateral + Fixed Load	Price-Capped Load	Virtual Supply	Virtual Load	Virtual Import	Virtual Export	Net Scheduled Load
2014	99%	4%	-12%	7%	-3%	0.4%	96%
2015	97%	5%	-12%	7%	-3%	0.4%	95%

Key Observations: Day-ahead Load Scheduling

- Overall, load in the day-ahead market was scheduled at roughly 95 percent of actual load in NYCA during daily peak load hours in 2015, down slightly from 2014.
  - The scheduling pattern in each of the sub-regions was generally consistent between 2014 and 2015 as well.
- Average load scheduling tends to be higher in import-constrained locations and/or at times when acute real-time congestion is more likely.
  - This has led to a seasonal pattern in some regions. For example:
    - Load-scheduling in the Capital Zone typically rose in the winter months because of much higher congestion across the Central-East interface.
    - Load-scheduling in Lower Hudson Valley generally increased in the summer months when acute real-time congestion into Southeast New York was more prevalent (due partly to frequent TSA events).
  - This has also resulted in locational differences between regions.
    - Average load scheduling was generally higher in New York City, Long Island, and the West Zone than the rest of New York because congestion was typically more prevalent in these areas.

  - This was particularly true for the West Zone in recent years because of increased congestion on the 230 kV system. Day-ahead load scheduling was the highest in the West Zone, averaging nearly 120 percent in 2015.

- Under-scheduling was still prevalent in West Upstate outside the West Zone.
  - This is generally consistent with the tendency for renewable generators to increase real-time output above their day-ahead schedules.
  - For example, load was typically under-scheduled in the North Zone by a large margin. This was primarily in response to the scheduling patterns of wind resources in this area.
  - In 2015, this added an average of 510 MW of additional energy supply in real-time, satisfying roughly 6 percent of the average real-time load outside Southeast New York.
- Overall, the patterns of day-ahead scheduling generally improved convergence between day-ahead and real-time prices.
  - In 2015, most regions exhibited a small average day-ahead premium while the West Zone exhibited an average real-time premium.
  - This also suggests that further over-scheduling in the West Zone and further under-scheduling in most of other regions would likely have been profitable.

F. Virtual Trading in New York

Virtual trading plays an important role in overall market efficiency by improving price convergence between day-ahead and real-time markets, thereby promoting efficient commitment and scheduling of resources in the day-ahead market. Virtual trading in the day-ahead market consists of purchases or sales of energy that are not associated with physical load or physical resources. Virtual bids and offers provide liquidity to the day-ahead market because they constitute a substantial share of the price-sensitive supply and demand that establish efficient day-ahead prices.

Virtual transactions that are scheduled in the day-ahead market settle against real-time energy prices. Virtual demand bids are profitable when the real-time energy price is higher than the day-ahead price, while virtual supply offers are profitable when the day-ahead energy price is higher than the real-time price. If prices are lower in the day-ahead market than in the real-time market, a virtual trader may purchase energy in the day-ahead market and sell it back in the real-time market, which will tend to increase day-ahead prices and improve price convergence with the real-time market. Hence, profitable virtual transactions improve the performance of the day-ahead market. The New York ISO currently allows virtual traders to schedule transactions to arbitrage the price differences at the load zone level between day-ahead and real-time.

Market participants can schedule virtual-type transactions at the external proxy buses, which are referred to as *Virtual Imports* and *Virtual Exports* in this report. These types of external transactions act the same way as the virtual bids placed at the load zones (i.e., the imports and exports that are scheduled in the day-ahead market do not flow in real-time). Since the virtual imports and exports have a similar effect on scheduling and pricing as virtual load and supply, they are evaluated as part of virtual trading in this section.

Figure A-48: Virtual Trading Volumes and Profitability

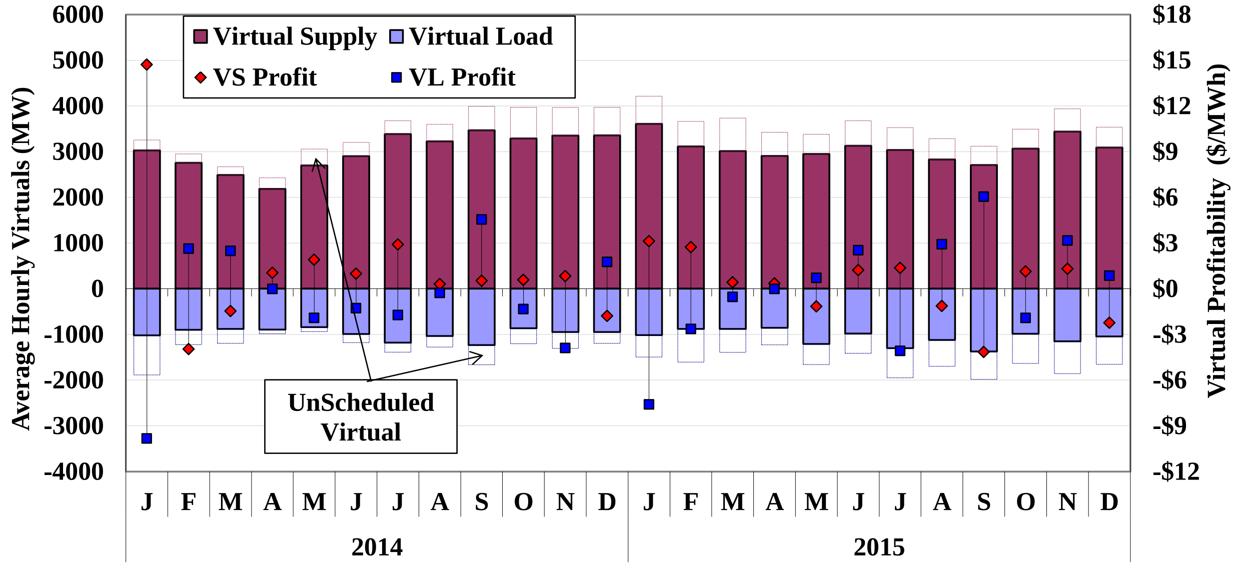
Figure A-48 summarizes recent virtual trading activity in New York by showing monthly average scheduled quantities, unscheduled quantities, and gross profitability for virtual transactions in 2013 and 2014. The amount of scheduled virtual supply in the chart includes scheduled virtual supply at the load zones and scheduled virtual imports at the external proxy buses. Likewise, the amount of scheduled virtual load in the chart includes scheduled virtual load at the load zones and scheduled virtual exports at the external proxy buses. Gross profitability is the difference between the price at which virtual traders bought and sold positions in the day-ahead market compared to the price at which these positions were covered in the real-time market.[237, 238]

The table below the figure shows a screen for relatively large profits or losses, which identifies virtual transactions with gross profits (or losses) larger than 50 percent of the average zone (or proxy bus) price. For example, an average of 739 MW of virtual transactions (or 18 percent of all virtual transactions) netted profits larger than the 50 percent of their zone (or proxy bus) prices in January of 2014. Large profits may be an indicator of a modeling inconsistency, while a systematic pattern of losses may be an indicator of potential manipulation of the day-ahead market.

237 The gross profitability shown here does not account for any other related costs or charges to virtual traders.

238 The calculation of the gross profitability for virtual imports and exports does not account for the profit (or loss) related to price differences between day-ahead and real-time in the neighboring markets.

Figure A-48: Virtual Trading Volumes and Profitability
2014 - 2015



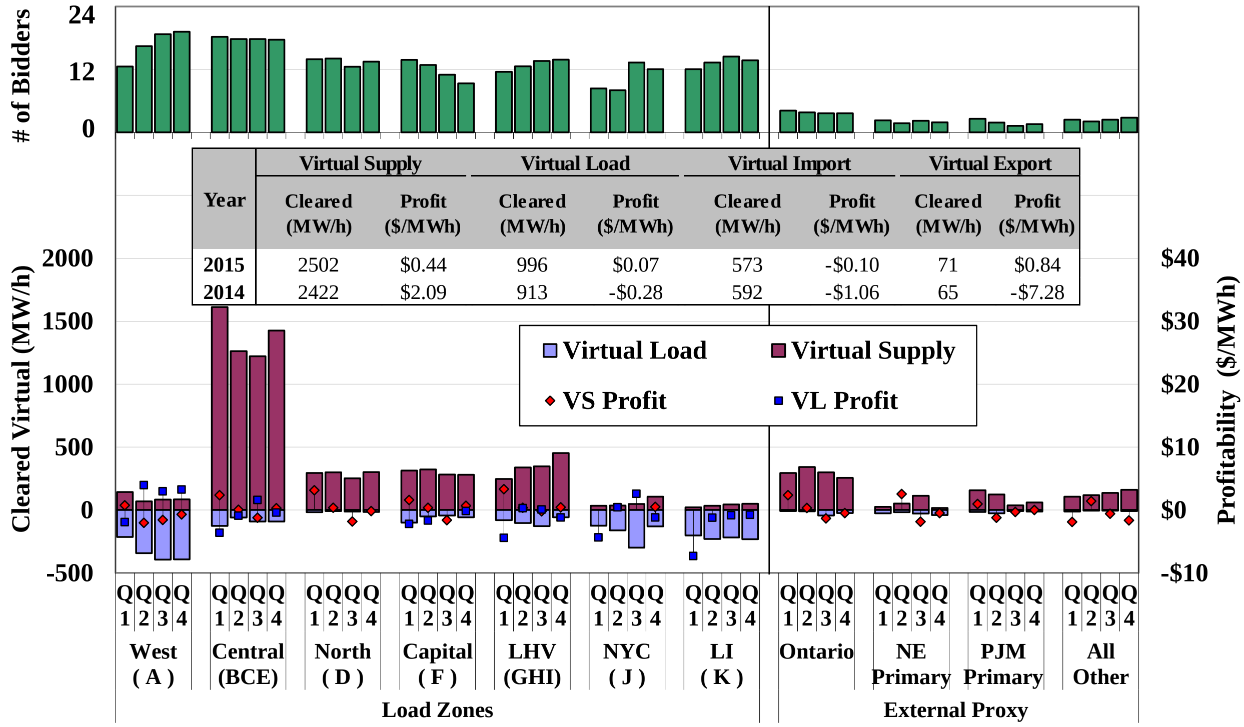
Profit > 50% of Avg. Zone Price	MW	739	348	345	116	217	187	524	159	333	587	433	380	537	562	315	296	561	763	471	284	239	375	1078	627
	%	18%	10%	10%	4%	6%	5%	11%	4%	7%	14%	10%	9%	12%	14%	8%	8%	13%	19%	11%	7%	6%	9%	23%	15%
Loss > 50% of Avg. Zone Price	MW	532	432	351	107	229	234	395	212	333	508	455	370	460	445	373	335	667	680	489	296	336	368	698	752
	%	13%	12%	10%	3%	6%	6%	9%	5%	7%	12%	11%	9%	10%	11%	10%	9%	16%	17%	11%	7%	8%	9%	15%	18%

Figure A-49: Virtual Trading Activity

Figure A-49 below summarizes virtual trading by geographic region. The eleven zones in New York are broken into seven geographic regions based on typical congestion patterns. Zone A (the West Zone) is shown separately because of increased congestion on the 230 kV system in recent years. Zone D (the North Zone) is shown separately because generation in that zone exacerbates transmission congestion on several interfaces, particularly the Central-East interface. Zone F (the Capital Zone) is shown separately because it is constrained from Western New York by the Central-East Interface and from Southeast New York by constraints in the Hudson Valley. Zones J (New York City) and K (Long Island) are shown separately because congestion frequently leads to price separation between them and other areas. The chart also summarizes trading activities related to virtual imports and exports with neighboring control areas. The Ontario proxy bus, the primary PJM proxy bus (i.e., the Keystone proxy bus), and the primary New England proxy bus (i.e., the Sandy Pond proxy bus) are evaluated separately from all other proxy buses.

The lower portion of the figure shows average quantities of scheduled virtual supply and virtual load and their gross profitability for the six regions and four groups of external proxy buses in each quarter of 2015. The upper portion of the figure shows the average number of virtual bidders in each location. The table in the middle compares the overall virtual trading activity in 2015 and 2014.

Figure A-49: Virtual Trading Activity[239]
by Region by Quarter, 2015



Year	Virtual Supply Cleared (MW/h)	Virtual Supply Profit ($/MWh)	Virtual Load Cleared (MW/h)	Virtual Load Profit ($/MWh)	Virtual Import Cleared (MW/h)	Virtual Import Profit ($/MWh)	Virtual Export Cleared (MW/h)	Virtual Export Profit ($/MWh)
2015	2502	$0.44	996	$0.07	573	-$0.10	71	$0.84
2014	2422	$2.09	913	-$0.28	592	-$1.06	65	-$7.28

Key Observations: Analysis of Virtual Trading

- A large number of market participants regularly submitted virtual bids and offers in 2015. On average:
  - 33 participants submitted virtual trades at the internal load zones; and
  - 10 participants submitted virtual imports and exports at the proxy buses.
  - These numbers rose modestly from 2014 to 2015.
- The volume of virtual trading did not change much from month to month in 2015, generally consistent with 2014. The pattern of virtual scheduling was similar as well.
  - Virtual traders generally scheduled more virtual load in the West Zone and downstate areas and more virtual supply in other regions.
  - This was consistent with typical load scheduling patterns (which are discussed in subsection E).
  - Participation of virtual trading and the volume of scheduled virtual load in the West Zone rose over the course of 2015, reflecting increased recognition of frequent volatile and acute real-time congestion in this area.

239 Profits or losses are not shown for a category if the average scheduled quantity is less than 50 MW.

- Nearly 90 percent of scheduled virtual imports/exports at the proxy buses were virtual imports in 2015.
  - Some of the import and export transactions that are classified as "virtual" were actually physical day-ahead transactions that did not flow in real-time because the transmission service was not available in the neighboring market or the transaction was curtailed. Such transactions are not systematically excluded and they account for a portion of the losses accrued on virtual imports and exports.
  - More than 50 percent of virtual imports were scheduled at the Ontario proxy bus, which exhibited an average day-ahead premium in 2015 because of higher real-time congestion on the 230 kV transmission facilities in the West Zone from Niagara-to-Packard and Packard-to-Sawyer.
- In aggregate, virtual traders netted approximately $10 million of gross profits in 2015, down 68 percent from 2014.
  - Virtual supply and virtual imports netted a gross profit of $9 million, accounting for the majority of profits and reflecting prevalent day-ahead price premiums in most regions during 2015.
    - The reduction in profits for virtual supply in 2015 was attributable to the decrease in average day-ahead price premiums from 2014 to 2015.
  - Overall, virtual transactions have been profitable over the period, indicating that they have generally improved convergence between day-ahead and real-time prices.
    - Good price convergence, in turn, facilitates efficient day-ahead market outcomes and commitment of generating resources.
  - However, profits and losses of virtual trades have varied widely by time and location, reflecting the difficulty of predicting volatile real-time prices. For example:
    - On February 21, 2015, virtual supply netted a loss of over $3 million because of unexpected system-wide real-time price spikes, driven by large imports curtailment and significant load under-scheduling in the day-ahead market.
- Only small quantities of virtual transactions generated substantial losses in 2015, which is significant because they could indicate potential manipulation. Most of these losses were caused by real-time price volatility and did not raise significant manipulation concerns.

III. Transmission Congestion

Congestion arises when the transmission network does not have sufficient capacity to dispatch the least expensive generators to satisfy the demands of the system. When congestion occurs, the market software establishes clearing prices that vary by location to reflect the cost of meeting load at each location. These Location-Based Marginal Prices ("LBMPs") reflect that higher-cost generation is required at locations where transmission constraints prevent the free flow of power from the lowest-cost resources.

The day-ahead market is a forward market that facilitates financial transactions among participants. The NYISO allows market participants to schedule transactions in the day-ahead market based on the predicted transmission capacity, resulting in congestion when some bids to purchase and offers to sell are not scheduled in order to reduce flows over constrained facilities. Congestion charges are applied to purchases and sales in the day-ahead and real-time markets based on the congestion component of the LBMP. Bilateral transactions scheduled through the ISO are charged the difference between the LBMPs of the two locations (i.e., the price at the sink minus the price at the source).

Market participants can hedge congestion charges in the day-ahead market by owning TCCs, which entitle the holder to payments corresponding to the congestion charges between two locations. A TCC consists of a source location, a sink location, and a quantity (MW). For example, if a participant holds 150 MW of TCC rights from zone A to zone B, this participant is entitled to 150 times the difference between the congestion prices at zone B and zone A. Excepting transmission losses, a participant can perfectly hedge a bilateral contract between two points if it owns a TCC between the points.

Incremental changes in generation and load from the day-ahead market to the real-time market are subject to congestion charges or payments in the real-time market. As in the day-ahead market, charges for bilateral transactions are based on the difference between the locational prices at the two locations of the bilateral contract. There are no TCCs for real-time congestion.

This section summarizes three aspects of transmission congestion and locational pricing:

- *Congestion Revenue and Shortfalls* – We evaluate the congestion revenues collected by the NYISO from the day-ahead market, as well as the congestion revenue shortfalls in the day-ahead and real-time markets and identify major causes of these shortfalls.
- *Congestion on Major Transmission Paths* – This analysis summarizes the frequency and value of congestion on major transmission paths in the day-ahead and real-time markets.
- *TCC Prices and Day-Ahead Market Congestion* – We review the consistency of TCC prices and day-ahead congestion, which determine payments to TCC holders.

A. Summary of Congestion Revenue and Shortfalls in 2015

In this section, we summarize the congestion revenues and shortfalls that are collected and settled through the NYISO markets. The vast majority of congestion revenues are collected through the day-ahead market, which we refer to as *day-ahead congestion revenues.* These are collected by the NYISO when power is scheduled to flow across congested interfaces in the day-ahead market. The revenue collected is equal to the marginal cost of relieving the constraint (i.e., constraint shadow price) in the day-ahead market multiplied by the scheduled flow across the constraint in the day-ahead market.[240]

In addition to day-ahead congestion revenues, the NYISO incurs two types of shortfalls that occur when there are inconsistencies between the transmission capability modeled in the TCC market, the day-ahead market, and the real-time market:

- *Day-ahead Congestion Shortfalls* – These occur when the day-ahead congestion revenues collected by the NYISO are less than the payments to TCC holders. Shortfalls generally arise when the quantity of TCCs sold on a path exceeds the transfer capability of the path modeled in the day-ahead market when it is congested.[241] Day-ahead congestion shortfalls are equal to the difference between payments to TCC holders and day-ahead congestion revenues. These shortfalls are partly offset by the revenues from selling excess TCCs.
- *Balancing Congestion Shortfalls* – These arise when day-ahead scheduled flows over a constraint exceed what can flow over the constraint in the real-time market.[242] To reduce flows in real time below the day-ahead schedule, the ISO must increase generation on the import-constrained side of the constraint and reduce generation on the export-constrained side of the constraint. These redispatch costs (i.e., the difference between the payments for increased generation and the revenues from reduced generation in the two areas) is the balancing congestion shortfall that is recovered through uplift.

Figure A-50: Congestion Revenue Collections and Shortfalls

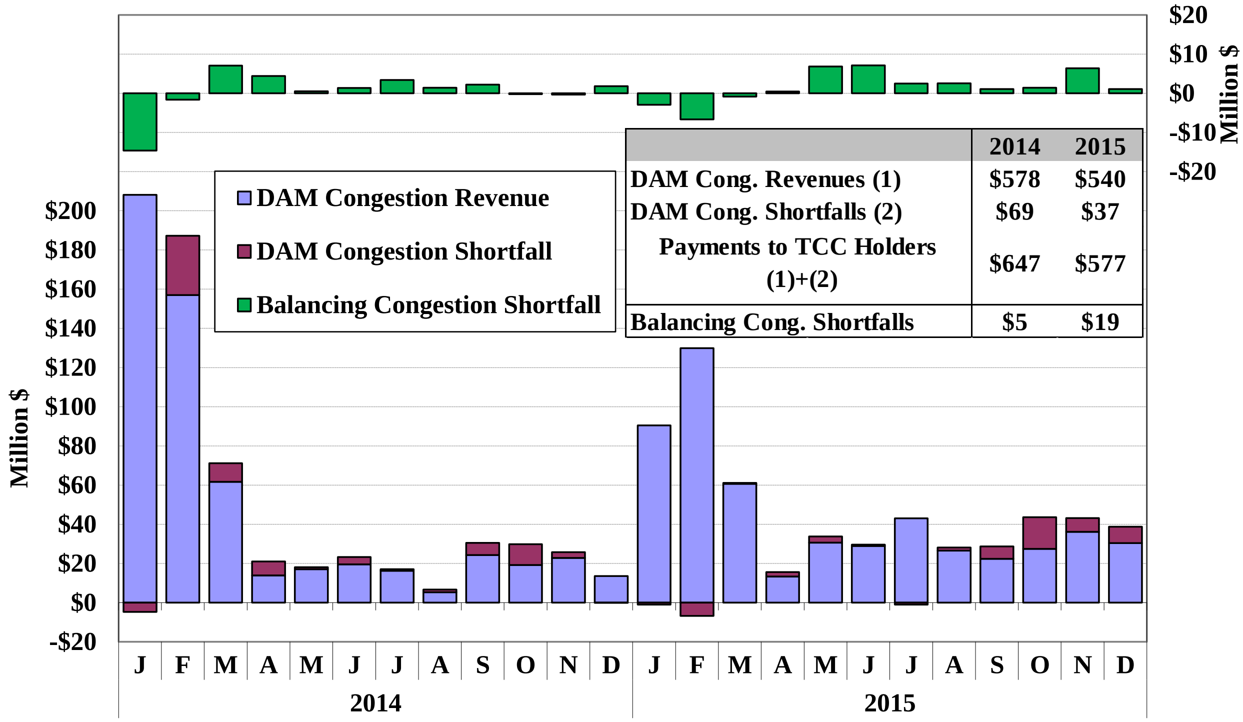
Figure A-50 shows day-ahead congestion revenue and the two classes of congestion shortfalls in each month of 2014 and 2015. The upper portion of the figure shows balancing congestion revenue shortfalls. The lower portion of the figure shows day-ahead congestion revenues collected by the NYISO and day-ahead congestion shortfalls. The sum of these two categories is equal to the total net payments to TCC holders in each month. The tables in the figure report these categories on an annual basis.

240 The shadow price of a transmission constraint represents the marginal value to the system of one MW of transfer capability. For example, if 100 MW is scheduled to flow across a constrained line with a shadow price of $50/MWh in a particular hour in the day-ahead market, the NYISO collects $5,000 in that hour (100 MW * $50/MWh).

241 For example, suppose 120 MW of TCCs are sold across a particular line. If 100 MW is scheduled to flow when the constraint has a shadow price of $50/MWh in an hour in the day-ahead market, the NYISO will have a day-ahead congestion shortfall of $1,000 in that hour ((120 MW – 100 MW) * $50/MWh).

242 For example, suppose 100 MW is scheduled to flow across a particular line in the day-ahead market. If 90 MW flows across the line when it has a shadow price of $70/MWh in an hour in the real-time market, the NYISO will have a balancing congestion shortfall of $700 in that hour ((100 MW – 90 MW) * $70/MWh).

Figure A-50: Congestion Revenue Collections and Shortfalls
2014-2015



	2014	2015
DAM Cong. Revenues (1)	$578	$540
DAM Cong. Shortfalls (2)	$69	$37
Payments to TCC Holders (1)+(2)	$647	$577
Balancing Cong. Shortfalls	$5	$19

Key Observations: Summary of Congestion Revenues and Shortfalls

- Day-ahead congestion revenues totaled roughly $540 million in 2015, down 7 percent (or $38 million) from 2014. Key drivers of changes in congestion over the period include:
  - a) Variations in natural gas prices and gas price spreads between areas;
    - Congestion typically rose during periods of higher natural gas prices and larger gas price spreads between Western New York and Eastern New York (normally in the winter months) as a result of:
      - Increased flows from Western New York to Eastern New York (where gas is the primary input fuel) and higher redispatch costs for gas-fired units in Eastern New York that were used to manage congestion.
    - The majority of day-ahead congestion revenues (74 percent in 2014 and 52 percent in 2015) accrued during the period from January through March when average natural gas prices in Eastern New York were several times higher than in the rest of the year.
      - Day-ahead congestion revenues fell 34 percent from the first quarter of 2014 to the first quarter of 2015, consistent with the 45 to 70 percent reduction in natural gas prices across the state over the same period.
  - b) Variations in load levels;

- Congestion increased during periods of higher load (i.e., the winter and summer peak months) when the increased demand results in more frequent bottlenecks on the transmission network.
  - Day-ahead congestion revenues rose 139 percent from the third quarter of 2014 to the third quarter of 2015, reflecting a six percent increase in average load and a five percent increase in peak load.
- c) Variations in transmission and generation outages.
  - Transmission and generation outages affect transfer capability of transmission facilities and redispatch options to manage congestion.
  - Congestion can often be related to these outages, particularly in the shoulder seasons when most planned outages occur. This is discussed for major transmission facilities in Subsection B.

- Day-ahead and balancing congestion shortfalls totaled $56 million in 2015, down 24 percent from 2014.
  - The locations and causes of these shortfalls are analyzed in Subsection C.

B. Congestion on Major Transmission Paths

Supply resources in Eastern New York are generally more expensive than those in Western New York, while the majority of the load is located in Eastern New York. Hence, the transmission lines that move power from the low-cost to high-cost parts of the state provide considerable value. Consequently, transmission bottlenecks arise as power flows from Western New York to Eastern New York, leading to significant congestion-related price differences between regions. This sub-section examines congestion patterns in the day-ahead and real-time markets.

In the day-ahead market, the NYISO schedules generation and load based on the bids and offers submitted by market participants and the assumed transfer capability of the transmission network. When scheduling between regions reaches the limits of the transmission network, congestion price differences arise between regions in the day-ahead market.

Market participants submit bids and offers in the day-ahead market that reflect their expectations of real-time prices and congestion, so day-ahead congestion prices are generally consistent with real-time congestion prices. To the extent that differences arise between day-ahead and real-time congestion patterns, it suggests that unexpected operating conditions may have occurred in the real-time market. Consistency between day-ahead and real-time prices is beneficial for market efficiency because it helps ensure that the resources committed each day are the most efficient ones to satisfy the needs of the system in real-time. Therefore, it is useful to evaluate the consistency of congestion patterns in the day-ahead and real-time markets.

Figure A-51 - Figure A-53: Day-Ahead and Real-Time Congestion by Path

Figure A-51 to Figure A-53 show the value and frequency of congestion along major transmission lines in the day-ahead and real-time market. Figure A-51 compares these quantities in 2014 and 2015 on an annual basis, while Figure A-52 and Figure A-53 show the quantities separately for each quarter of 2015.

The figures measure congestion in two ways:

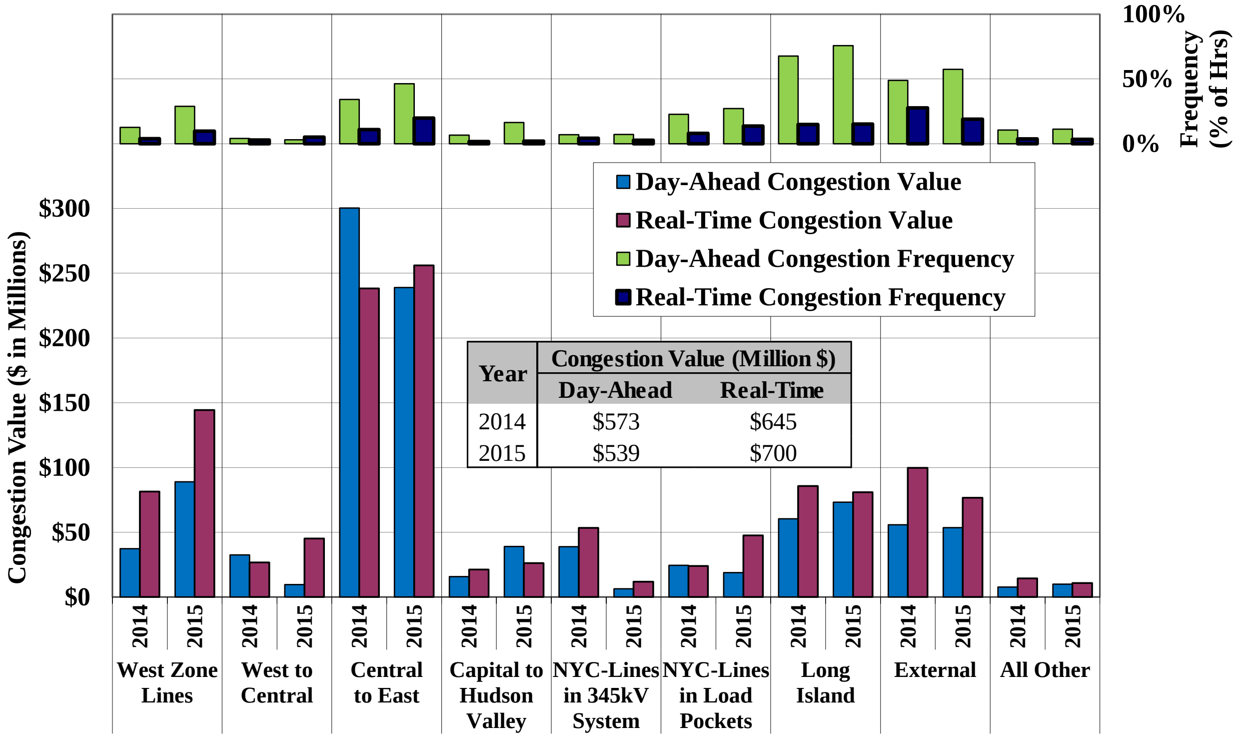
- The frequency of binding constraints; and
- The value of congestion, which is equal to the marginal cost of relieving the constraint (i.e., constraint shadow cost) multiplied by the scheduled flow across the constraint.[243]

In the day-ahead market, the value of congestion equals the congestion revenue collected by the NYISO, which is the primary funding source for TCC payments. In the real-time market, the value of congestion does not equal the congestion revenue collected by the NYISO, since most real-time power flows settle at day-ahead prices rather than real-time prices. Nonetheless, the real-time congestion value provides the economic significance of congestion in the real-time market. The figure groups congestion along the following transmission paths:

- West Zone Lines: Transmission lines in the West Zone on the 230 kV system.
- West to Central: Primarily West-to-Central interface, Dysinger East interface, and transmission facilities in the Central Zone.
- Central to East: Primarily the Central-to-East interface.
- Capital to Hudson Valley: Primarily lines leading into Southeast New York (e.g., the New Scotland-to-Leeds Line, the Leeds-to-Pleasant Valley Line).
- NYC Lines in 345 kV system: Lines leading into and within the New York City 345 kV system.
- NYC Lines in Load Pockets: Lines leading into and within New York City load pockets and groups of lines to New York City load pockets that are modeled as interface constraints.
- Long Island: Lines leading into and within Long Island.
- External Interface: Congestion related to the total transmission limits or ramp limits of the external interfaces.
- All Other: All of other line constraints and interfaces.

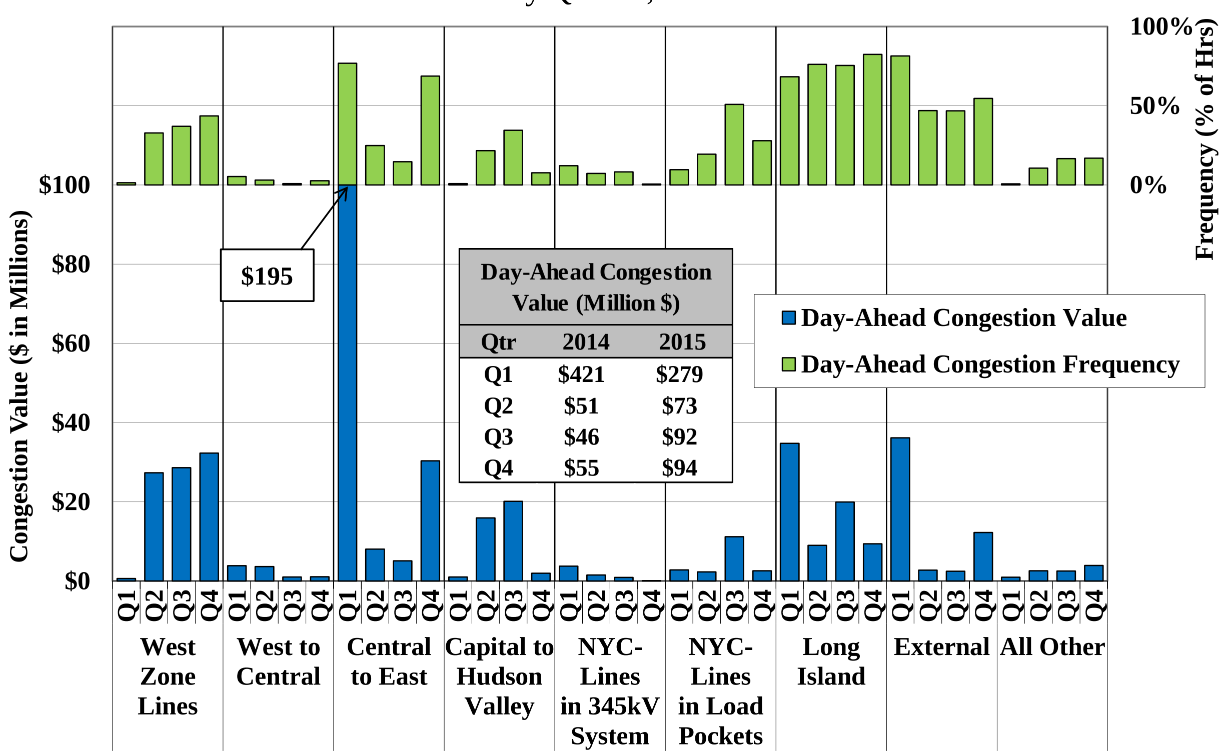
243 The shadow price of a transmission constraint represents the marginal value to the system of one MW of transfer capability.

Figure A-51: Day-Ahead and Real-Time Congestion by Transmission Path
2014 – 2015



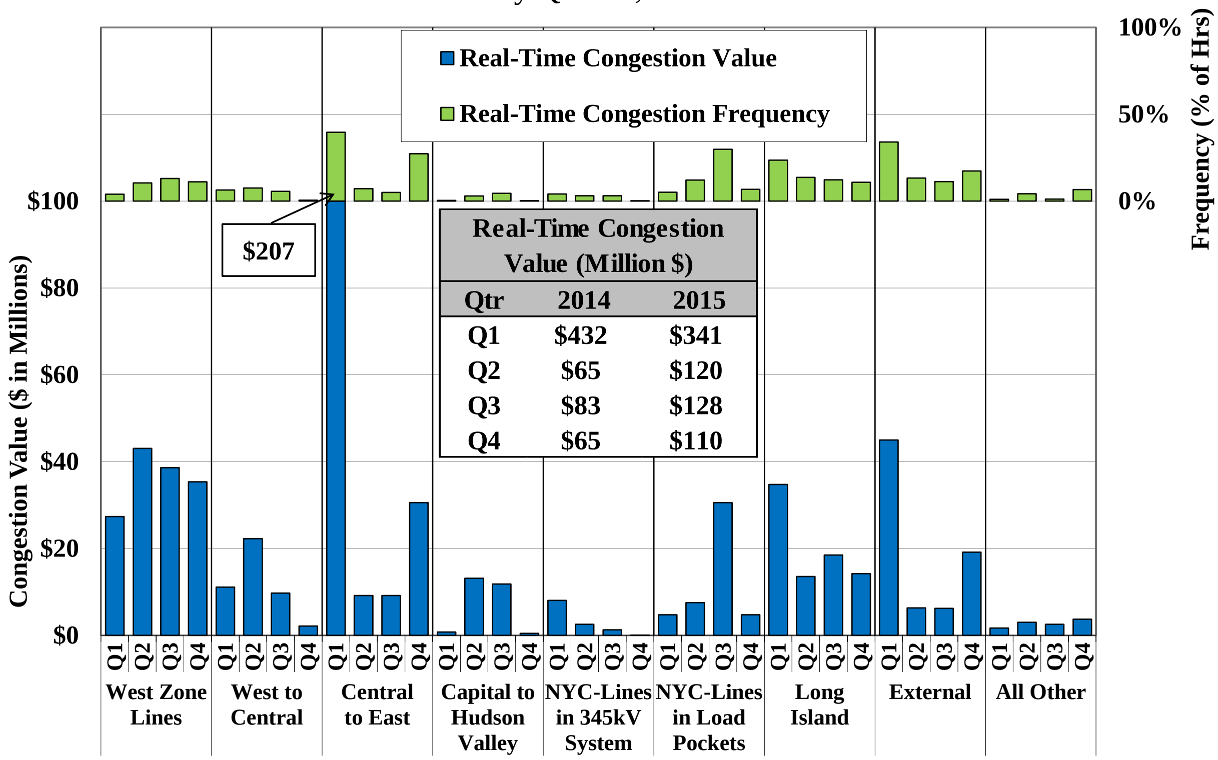
Year	Congestion Value (Million $)	
	Day-Ahead	Real-Time
2014	$573	$645
2015	$539	$700

Figure A-52: Day-Ahead Congestion by Transmission Path
By Quarter, 2015



Day-Ahead Congestion Value (Million $)		
Qtr	2014	2015
Q1	$421	$279
Q2	$51	$73
Q3	$46	$92
Q4	$55	$94

Figure A-53: Real-Time Congestion by Transmission Path
By Quarter, 2015



Key Observations: Congestion Revenues by Path

- Congestion is more frequent in the day-ahead market than in the real-time market, but the shadow prices of constraints are generally lower in the day-ahead market. This is expected because the day-ahead market reflects an expectation of the probability-weighted congestion value in the real-time market, which tends to be more episodic.
- Congestion across the Central-East interface accounted for the largest share of congestion value in both day-ahead and real-time markets in 2014 and 2015.
  - In 2015, the Central-East interface accounted for 44 percent of congestion value in the day-ahead market and 37 percent in the real-time market.
  - As explained above, the majority of this congestion occurred in the first quarter of 2015 when natural gas prices and gas price spreads between Western and Eastern New York were significantly elevated.
  - Congestion also rose in the fourth quarter of 2015, driven primarily by lengthy transmission outages (including transmission lines and capacitors) that reduced the interface's voltage stability limit in November and December by as much as 900 MW.
- Congestion on 230kV lines in the West Zone rose notably from 2014 to 2015, accounting for the second largest share of congestion value in both day-ahead (17 percent) and real-time (21 percent) markets in 2015.

- The increase reflected higher load levels, higher Ontario imports and reduced PJM imports (both of which increase flows over these lines), lower coal-fired production in the West Zone (which is located downstream of these lines), and more transmission outages.

- Real-time congestion on external interfaces has increased in the recent years.
  - During the winter months, more than 60 percent in 2014 and 70 percent in 2015 of the real-time congestion was associated with the primary New England interface as exports to New England were often scheduled up to the transfer limit on days when natural gas prices in New England were substantially higher than in New York.
- Congestion in Southeast New York was mild over the last two years, reflecting low natural gas prices, low load levels, less frequent summer peaking conditions because of mild weather, and increased utilization of the Ramapo line to relieve this congestion under the M2M process.
  - Nonetheless, congestion in Southeast New York rose modestly from 2014 to 2015 partly because of higher load levels and more transmission outages.
- Congestion was generally more severe in the real-time market than in the day-ahead market on some intra-zonal transmission paths.[244]
  - In the West Zone, congestion on 230kV facilities often rose in real-time because of several factors:
    - Lake Erie circulation, which is highly variable and difficult for the NYISO to predict, has a significant effect on flows across these transmission facilities. When clockwise circulation is higher than assumed in the day-ahead market and/or increases suddenly, it can result in severe real-time congestion that must be resolved with very costly resources. However, when clockwise circulation is lower than assumed, it usually results in no congestion. So, volatile circulation around Lake Erie tends to result in higher real-time congestion costs.
    - Generation and imports upstream of these constraints is typically offered at much lower prices in the real-time market than in the day-ahead market, increasing congestion in real-time.
    - Redispatch options are often limited by parallel constraints on the 115 kV system, which are currently managed with Out-of-Merit dispatch instructions and by taking certain lines out of service to divert some power flows away from congested facilities (see Figure A-86).
    - Operation of the ABC, JK, and Ramapo PARs (to relieve Central-to-East and Capital-to-Hudson Valley congestion) increased flows over constraints in the

244 The related inconsistencies between day-ahead and real-time LBMPs are evaluated in Appendix Section IV-D. Factors that contribute to transient periods of extreme real-time congestion are evaluated in Appendix Section V-E.

West Zone. In November 2015, operating procedures were modified to reduce the effects of these PAR control actions on congestion in Western New York.

- For the West to Central category, congestion increased in RT as a result of changes in offer patterns between the DAM and RT. While the magnitude of this RT congestion appears large based on the method used in Figure A-51 to Figure A-53, this congestion (primarily across the Scriba-to-Volney lines) arose when very small amounts of generation could not be delivered across a large interface, so the effect of the congestion on the overall market was very small.
- In New York City, congestion into the Greenwood load pocket often rose in real-time because of:
  - Changes in some generators' offer patterns between the day-ahead market and the real-time market;
  - The tendency for brief small transmission constraint violations to cause very high (~$4,000) shadow prices in real-time; and
  - Scheduling of uneconomic gas turbines in the day-ahead market, which resulted from software changes that were made in conjunction with the introduction of the MIP ("Mixed Integer Program") software in the day-ahead market. The NYISO is currently considering software modifications to address this issue.
- In Long Island, acute congestion often occurred in real-time as a result of short-term ramping limitation caused by:
  - Large schedule changes in imports across the Scheduled Lines (i.e., Neptune, Cross Sound Cable, and the 1385 Line);
  - Sudden flow variations on PAR-controlled lines (e.g., 901/903 lines); and
  - Shut-down of gas turbines that would have been economic to remain online.

C. West Zone Congestion and Niagara Generation

Transmission constraints on the 230kV network in the West Zone have become more frequent in the past two years, limiting the flow of power towards Eastern New York. Besides many factors discussed above, this subsection discusses issues related to the modeling of the Niagara Power Plant that has had significant effects on congestion management in the West Zone.

The Niagara Power Plant has a total of 13 run-of-river and 12 pump-storage water turbines. Three run-of-river turbines are electrically connected to the 115 kV West Buses, four run-of-river turbines are connected to the 115 kV East Buses, and the rest six run-of-river turbines and twelve pump-storage turbines are connected to the 230 kV Buses. The units at the 115 kV Buses generally help relieve congestion on the most congested 230 kV transmission lines in the West Zone, while units at the 230 kV Buses tend to exacerbate these transmission constraints. However, these impacts are not considered by the optimization engine that schedules generation at the Niagara plant. Instead, these 25 units are currently modeled as one single generator for pricing and dispatch with a marginal congestion impact measured based on the 230 kV units.[245] Often times, NYISO procedures use manual instructions to shift generation among the individual units at the Niagara plant to alleviate congestion. These circumstances lead to events when the transmission system in the West Zone is not utilized as efficiently as possible.

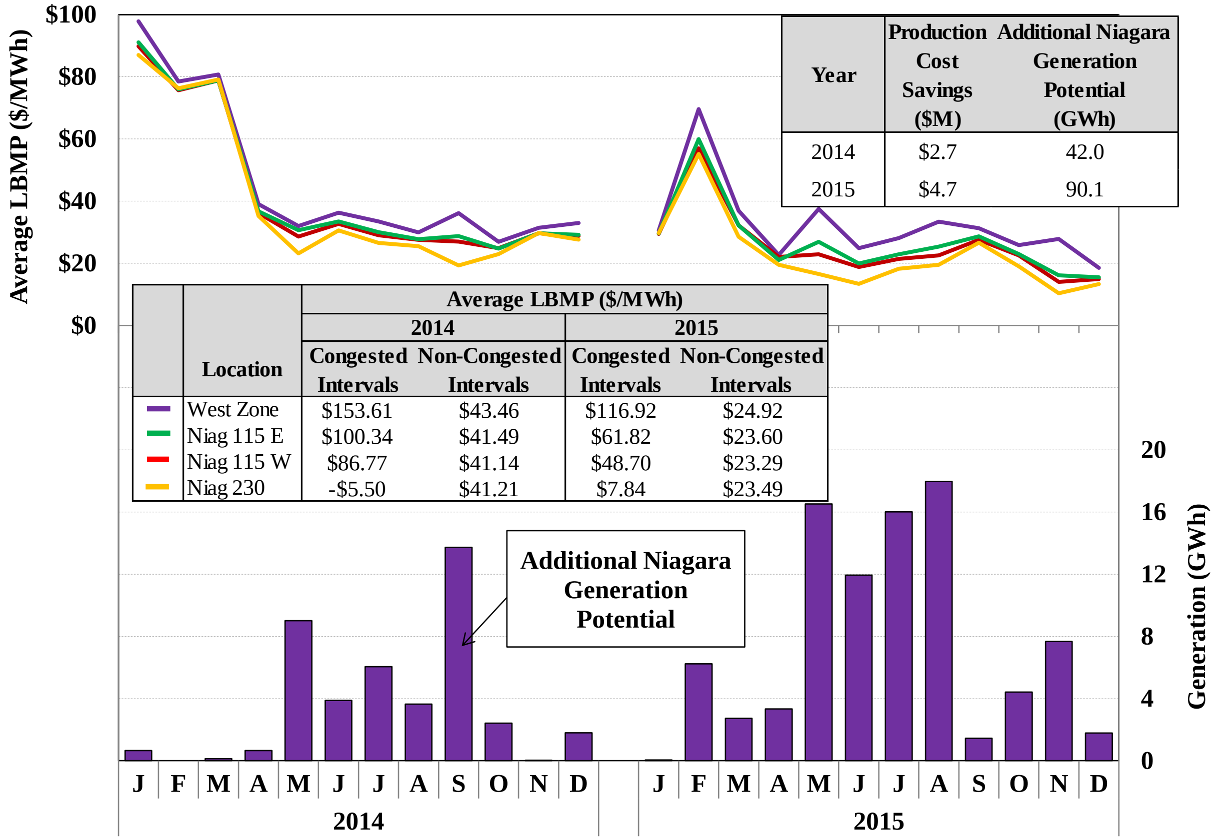
Figure A-54: West Zone Congestion and Niagara Generation

Figure A-54 estimates the remaining benefits that might have occurred if the distribution of generation at Niagara was optimized in each month of 2014 and 2015 by showing:

- Production Cost Savings – Estimated savings from reducing congestion by shifting generation from 230kV units to 115kV units that have available head room at the Niagara plant.
- Additional Niagara Generation Potential – Additional Niagara generation (in MWhs) that would be deliverable from the entire plant if output from the 115kV units was maximized.
- Average estimated LBMPs for the West Zone, Niagara 230 kV Bus, Niagara East 115 kV Bus, and Niagara West 115 kV Bus – This illustrates the impact of shifting generation among individual Niagara units.

245 Note, although the individual units are not considered in the pricing and dispatch component of RTD, they are considered in the Network Security Analysis ("NSA") portion of RTD. A presentation was provided by the NYISO on this issue at the April 5, 2016 Market Issues Working Group meeting: see *Niagara Generation Modeling Update*, presented by David Edelson.

Figure A-54: West Zone Congestion and Niagara Generation
By Month, 2014- 2015



Year	Production Cost Savings ($M)	Additional Niagara Generation Potential (GWh)
2014	$2.7	42.0
2015	$4.7	90.1

Location	Average LBMP ($/MWh) 2014 Congested Intervals	2014 Non-Congested Intervals	2015 Congested Intervals	2015 Non-Congested Intervals
West Zone	$153.61	$43.46	$116.92	$24.92
Niag 115 E	$100.34	$41.49	$61.82	$23.60
Niag 115 W	$86.77	$41.14	$48.70	$23.29
Niag 230	-$5.50	$41.21	$7.84	$23.49

Key Observations: West Zone Congestion and Niagara Generation

- Although LBMPs at the Niagara 115 kV and 230 kV Buses were very similar when West Zone congestion was not present, LBMP differences were significant during periods of congestion.
  - West Zone 230 kV congestion occurred in roughly 2.4 and 7.7 percent of all real-time intervals in 2014 and 2015.
  - On average, LBMPs were $92 to $106 per MWh higher at the Niagara 115 kV Buses than at the Niagara 230 kV Buses during these intervals in 2014 and $41 to $54 per MWh higher in 2015.
- We estimate that if the distribution was fully optimized (while considering both 115kV and 230kV constraints in the West Zone): [246]

246 Note, these estimates likely under-state the true potential increase in deliverable generation and improvement in production costs. This is because our estimates to not consider the amount of additional water that is used when individual water turbines operate above or below the optimal operating point (i.e., where cubic feet of water per MWh is lowest). This is substantial during uncongested intervals when the 115kV generators are over-utilized by a manual dispatch instruction relative to the optimal operating point of the turbine.

- Production costs would have been reduced by an additional $2.7 million in 2014 and $4.7 million in 2015 (assuming no changes in the constraint shadow costs).
  - However, this does not consider the control system upgrade costs required to fully optimize the resource.
- An additional 42 and 90 GWh of Niagara generation would have been deliverable in 2014 and 2015. This would have reduced LBMPs in other zones as well, although we have not estimated the effect on statewide average LBMPs.

- Nonetheless, the existing NYISO manual procedures that shift the distribution of generation at the Niagara plant (between 115kV and 230kV units) substantially reduced congestion costs on days with congestion in the West Zone.

D. Lake Erie Circulation and West Zone Congestion

The pattern of loop flows around Lake Erie has a significant effect on power flows in the surrounding control areas. Loop flows that move in a clockwise direction around Lake Erie generally exacerbate west-to-east transmission constraints in New York, leading to increased congestion costs in New York, while counter-clockwise loop flows alleviate west-to-east congestion in New York.

Phase angle regulators ("PARs") were installed at the interface between the MISO and IESO in April 2012 partly to control loop flows around Lake Erie. In general, these PARs are used to maintain loop flows at the MISO-IESO interface to less than 200 MW in either direction. Because of the configuration of surrounding systems, the volume and direction of loop flows at the MISO-IESO interface is comparable to the loop flows at the IESO-NYISO interface. The volume of loop flows has been reduced since the PARs were installed in 2012, but excursions outside the 200 MW band still occur on a daily basis, so loop flows continue to have significant effects on congestion patterns in the NYISO.

Figure A-55: Pattern of Clockwise Lake Erie Circulation

Figure A-55 summarizes the pattern of loop flows for each month of 2012 to 2015. The lower portion of the figure shows the percent of intervals in each month when average clockwise loop flows were greater than 200 MW. Intervals with West-to-Central congestion (including congestion in the West Zone and across the West-Central interface) and intervals without West-to-Central congestion are flagged separately. The upper portion of the figure shows the percent of intervals in each month when loop flows changed by more than 50 MW in the clockwise direction from one 5-minute interval to the next 5-minute interval. Similarly, intervals with and without West-to-Central congestion are separately flagged. The inset table compares these statistics on an annual basis between 2012 and 2015.

Figure A-55: Pattern of Clockwise Lake Erie Circulation
2012 – 2015

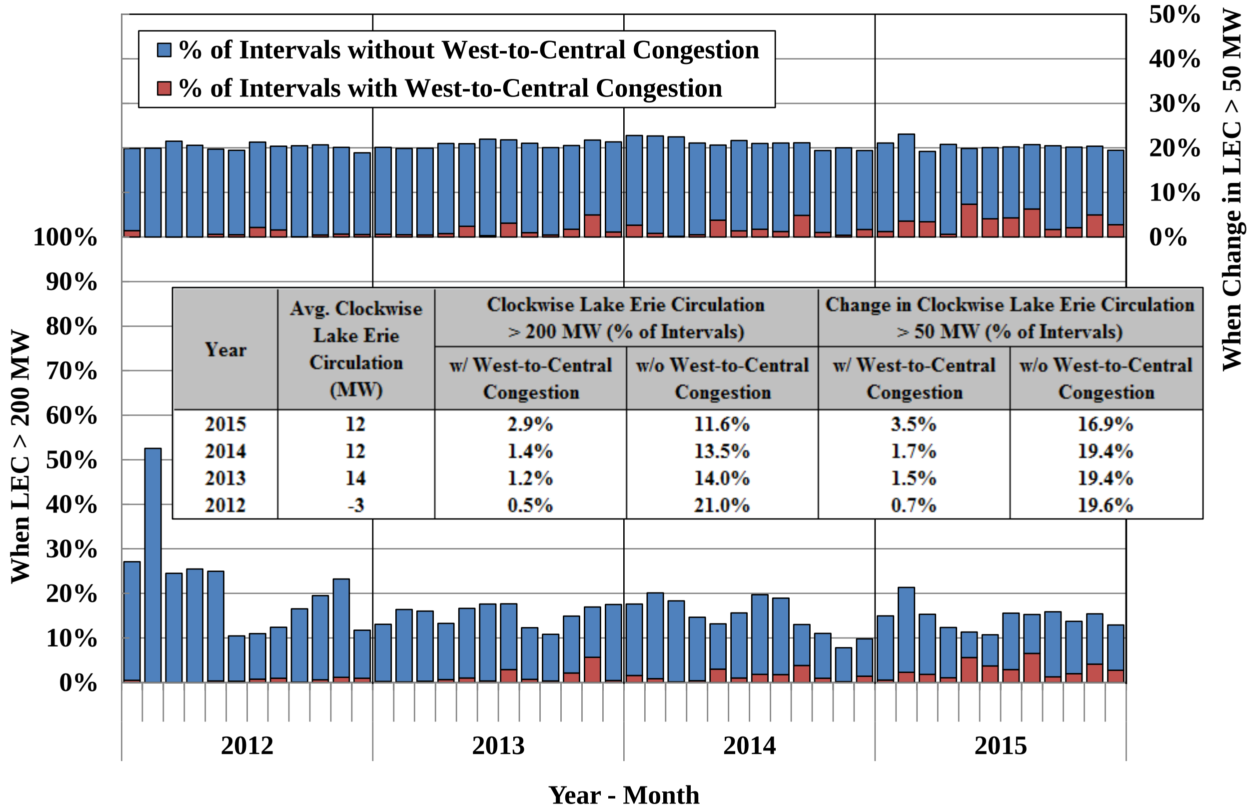


Figure A-56: Clockwise Loop Flows and West Zone Congestion

Unscheduled clockwise loop flows are primarily of concern in the congested intervals, when they reduce the capacity available for scheduling internal generation to satisfy internal load and increase congestion on the transmission paths in Western New York, particularly in the West Zone.

Figure A-56 illustrates how and to what extent unscheduled loop flows affected congestion on West Zone 230 kV constraints during 2015. The bottom portion of the chart shows the average amount of: (a) unscheduled loop flows (the blue bar); and (b) changes in unscheduled loop flows from the prior 5-minute interval (the red line) during the intervals when real-time congestion occurred on the West Zone 230 kV constraints. The congested intervals are grouped based on the following ranges of congestion values: (a) less than $10,000; (b) between $10,000 and $20,000; (c) between $20,000 and $50,000; (d) between $50,000 and $100,000; (e) between $100,000 and $200,000; and (f) more than $200,000.[247] For a comparison, these numbers are also shown for the intervals with no congestion.

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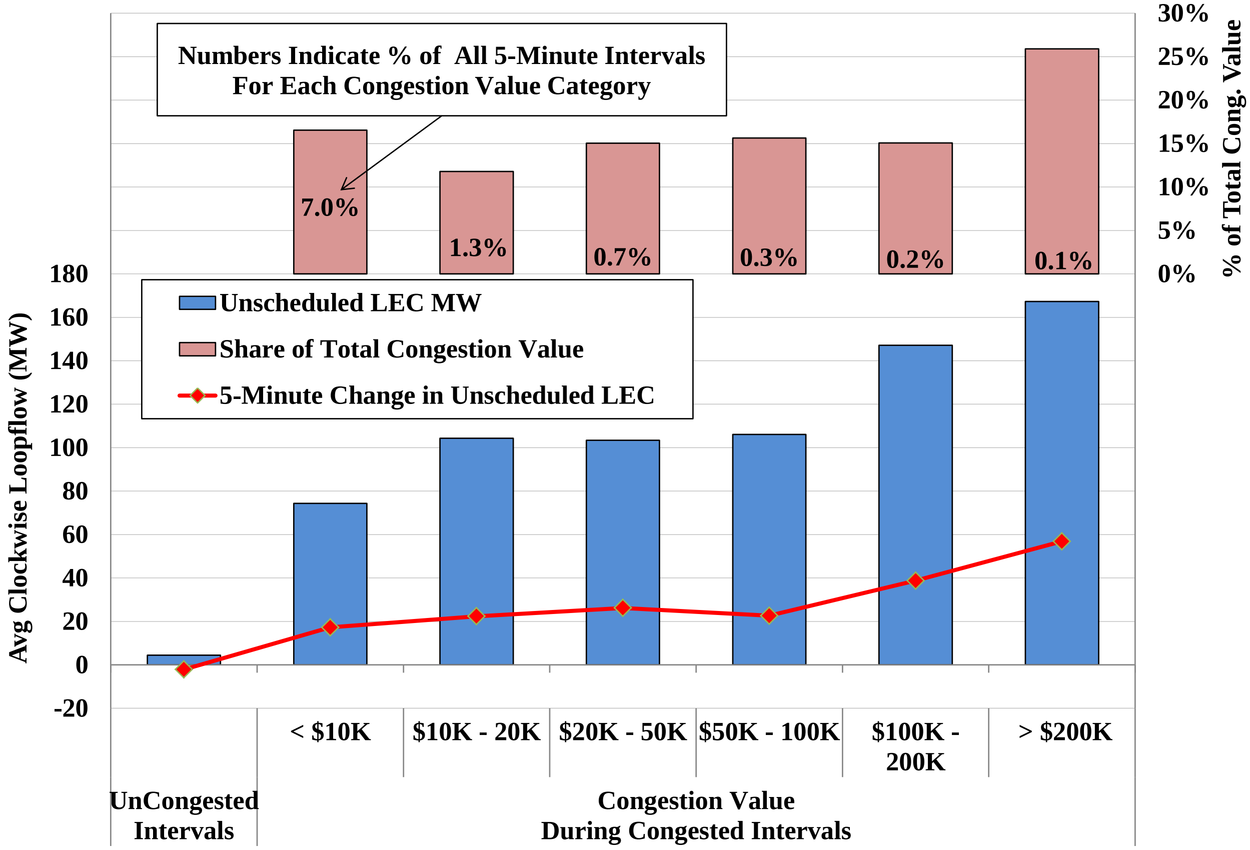
247 The congestion value for each 230 kV constraint is calculated as (constraint flow × constraint shadow cost × interval duration). Then this is summed up for all binding 230 kV constraints for the same interval. For

In the top portion of the chart, the bar shows the percent of total congestion values that each congestion value group accounted for in 2015 and the number in each bar indicates how frequently each congestion value group occurred. For example, the chart shows that the congestion value was less than $10,000 during 7 percent of all intervals, which accounted for 17 percent of total congestion value in the West Zone in 2015.

Figure A-56: Clockwise Lake Erie Circulation and West Zone Congestion
2015



Key Observations: Lake Erie Circulation and West Zone Congestion

- Average clockwise circulation has fallen notably since the IESO-Michigan PARs went in service in April 2012.[248]
  - Clockwise loop flows exceeded 200 MW during roughly 15 percent of all intervals in each year from 2013 to 2015, down substantially from prior years.[249]

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example, if a 900 MW line binds with a $300 shadow price and a 700 MW line binds with a $100 shadow price in a single 5-minute interval, the resulting congestion value is $28,333 = (900MW × $300/MWh + 700MW × $100/MWh) * 0.083 hours.

248 The PARs are stated to be capable of controlling up to 600 MW of loop flows around Lake Erie. The use of these PARs since April 2012 is discussed extensively in Commission Docket No. ER11-1844-002.

- Nonetheless, rapid and large fluctuations in loop flows were common, both before and after the PARs were installed. For example, loop flows have risen from one 5-minute interval to the next by more than 50 MW in the clockwise direction in approximately 20 percent of the intervals in each month from 2012 to 2015.
- West Zone congestion has become increasingly common since these lines were first modeled in the pricing and scheduling software in 2012.

- Unscheduled clockwise loop flows have had significant impact on congestion in Western New York in the recent years.
  - A correlation was apparent between the severity of West Zone congestion (measured by congestion value) and the magnitude of unscheduled loop flows and the occurrence of sudden changes from the prior interval.
  - There was no West Zone congestion in roughly 90 percent of intervals in 2015. In these intervals, the average amount of clockwise loop flow was approximately 0 MW.
  - However, West Zone congestion is more prevalent when loop flows are clockwise or happen to swing rapidly in the clockwise direction.
    - Congestion value on the West Zone 230 kV constraints exceeded $200,000 in only 0.1 percent of all intervals, but these intervals accounted for over 25 percent of the total congestion value in the West Zone in 2015.
    - During these intervals, unscheduled clockwise loop flows averaged over 160 MW and changes of unscheduled loop flows in the clockwise direction averaged nearly 60 MW.

E. Day-Ahead and Balancing Congestion Shortfalls by Path or Constraint

Congestion shortfalls generally occur as a result of inconsistent modeling of the transmission system between markets. Day-ahead congestion shortfalls indicate inconsistencies between the TCC and day-ahead market, while balancing congestion shortfalls indicate inconsistencies between the day-ahead market and the real-time market. These two classes of shortfalls are evaluated in this subsection.

Figure A-57: Day-Ahead Congestion Revenue Shortfalls

Day-ahead congestion revenue shortfalls generally arise when the quantity of TCCs sold for a particular path exceeds the transfer capability of the path modeled in the day-ahead market during periods of congestion. Similarly, surpluses occur when the quantity of TCCs sold for a path is less than the transfer capability of the path in the day-ahead market during periods of congestion. The NYISO minimizes day-ahead congestion revenue surpluses and shortfalls by offering TCCs in the forward auction that reflect the expected transfer capability of the system.

249 The PARs are generally not adjusted until the loop flows exceed or are expected to exceed 200 MW for a substantial period of time.

In addition, transmission owners can reduce potential day-ahead congestion revenue shortfalls by restricting the quantities of TCCs that are offered by the NYISO.

The NYISO determines the quantities of TCCs to offer in a TCC auction by modeling the transmission system to ensure that the TCCs sold are simultaneously feasible. The NYISO uses a power flow model that includes an assumed configuration of the transmission system. The simultaneous feasibility condition requires that the TCCs awarded be feasible in a contingency constrained economic dispatch of the NYISO transmission system. If this condition is satisfied, the congestion revenues collected should be sufficient to fully fund awarded TCCs. However, if transmission outages occur that were not modeled in the TCC auction or the assumptions used in the TCC auctions (e.g., assumptions related to PAR schedules and loop flows) are otherwise not consistent with the assumptions used in the day-ahead market, the congestion revenues collected may be insufficient to meet TCC obligations.

Figure A-57 shows day-ahead congestion shortfalls by transmission path or facility in each month of 2014 and 2015. Positive values indicate shortfalls, while negative values indicate surpluses. The shortfalls are shown for the following paths:

- West Zone Lines: Transmission lines in the West Zone.
- North Zone Lines: Transmission lines in the North Zone and the Moses-South Interface.
- Central to East: Primarily the Central-East interface.
- New York City Lines: Lines leading into and within New York City.
- Long Island Lines: Lines leading into and within Long Island.
- External: Congestion related to the total transmission limits or ramp limits of the external interfaces.
- All Others: All other types of constraints collectively.

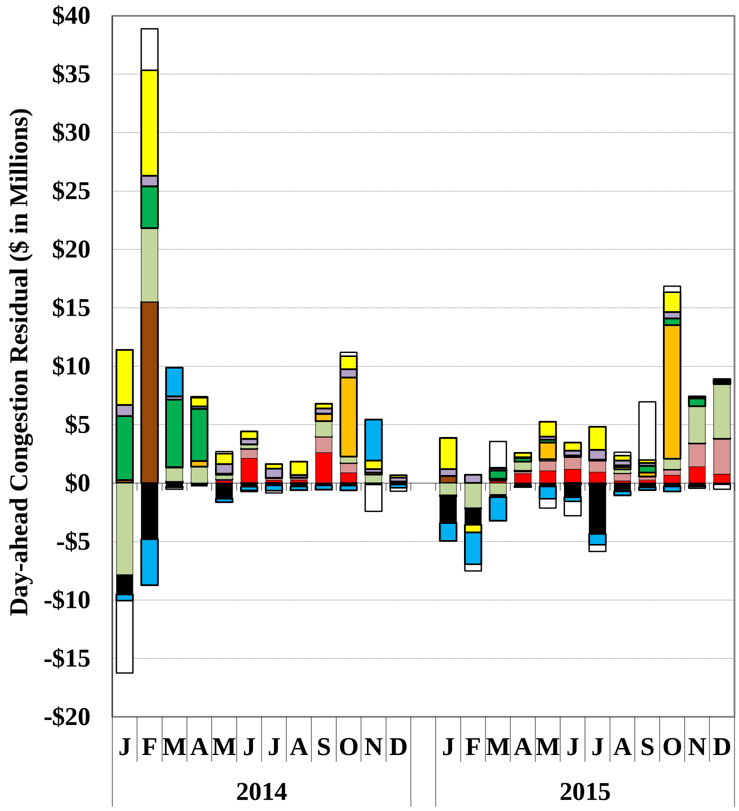
The figure also shows the shortfalls resulted from some unique factors separately from other reasons for select transmission paths.

- For West Zone lines, the figure shows separately the shortfalls resulted from differences in assumed generation at the Niagara 115 kV Buses between the TCC auction and the day-ahead market (labeled as "Niagara Modeling Assumption").
- For the Central-East interface, the figure shows separately the shortfalls resulted from differences in assumed flows on the PAR controlled lines between New York and New Jersey (including Ramapo, ABC, and JK PARs) between the TCC auction and the day-ahead market.
- For Long Island lines, the figure shows separately the shortfalls resulted from:
  - Grandfathered TCCs ("GFTCC") that exceed the transfer capability of the system from Dunwoodie (Zone I) to Long Island (Zone K); and

- Differences in assumed schedules across the two PAR controlled lines between Lake Success and Valley Stream in Long Island and Jamaica in New York City (i.e., 901/903 lines) between the TCC auction and the day-ahead market.

Figure A-57: Day-Ahead Congestion Shortfalls

2014 – 2015



	Category	Annual Shortfall ($M) 2014	2015
	West Zone Lines		
	Niagara Modeling Assumption	$6.4	$7.5
	Other Factors	$3.5	$9.7
	Central to East		
	Ramapo, ABC & JK PARs	$16.0	$0.9
	Other Factors	$4.5	$5.7
	North Zone Lines	$8.1	$13.6
	NYC Lines	$19.3	$3.1
	Long Island Lines		
	901/903 PARs	-$9.6	-$11.3
	Excess GFTCC Allocations	$6.4	$4.4
	Other Factors	$20.0	$8.7
	External	-$1.0	-$9.6
	All Other Facilities	-$5.0	$4.3

Figure A-58: Balancing Congestion Revenue Shortfalls

Like day-ahead congestion shortfalls, balancing congestion revenue shortfalls arise when day-ahead scheduled flows across a particular line or interface exceed its real-time transfer capability. When this occurs, the ISO must redispatch in real time by purchasing additional generation in the import-constrained area (where real-time prices are high) and selling back energy in the export-constrained area (where real-time prices are low). The balancing congestion shortfall is the cost of this redispatch. The changes in transfer capability between the day-ahead and real-time markets are most often related to:

- Deratings and outages of transmission lines – When these occur after the day-ahead market, they reduce the transfer capability of relevant transmission interfaces or facilities. They may also change the size of the largest contingency relative to a particular transmission interface or the distribution of flows over the transmission system, thereby reducing the available transfer capability of other transmission facilities.
- Constraints not modeled in the day-ahead market – Reliability rules require the NYISO to reduce actual flows across certain key interfaces during TSA events. Since TSA events are not modeled in the day-ahead market, they generally result in reduced transfer

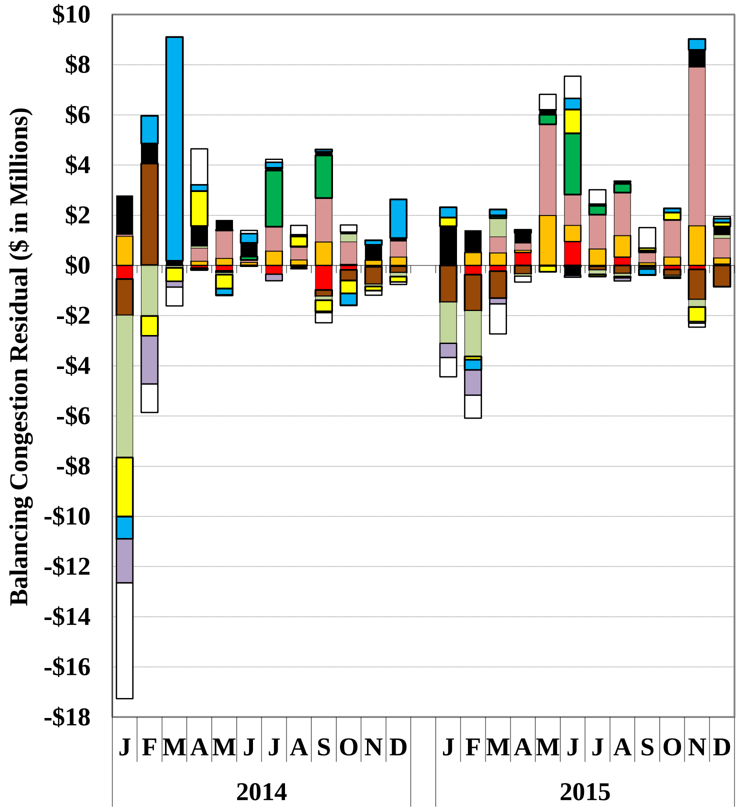
capability between the day-ahead market and real-time operation. The imposition of simplified interface constraints in New York City load pockets in the real-time market that are not modeled comparably in the day-ahead market also results in reduced transfer capability between the day-ahead market and real-time operation.

- Hybrid Pricing – This methodology treats physically inflexible gas turbines as flexible in the pricing logic of the real-time market model. Differences between the physical dispatch logic and the pricing logic can lead to unutilized transfer capability on interfaces that are congested in real time, leading to balancing congestion revenue shortfalls.
- PAR Controlled Line Flows – The flows across PAR-controlled lines are adjusted in real-time operations, which can result in flows that are very different from the day-ahead assumptions. These differences can affect the flows across multiple interfaces. This includes flow adjustments on PAR-controlled lines that result from the Coordinated Congestion Management ("M2M") process between NYISO and PJM.
- Unscheduled loop flows – loop flows from other regions use a portion of the transmission capability across many interfaces in New York, reducing the portion of transmission capability available to the NYISO market in the direction of the loop flows. A balancing congestion revenue shortfall occurs when the loop flows assumed in the day-ahead market are lower than the actual loop flows on congested interfaces in real time.

The net cost of the redispatch in real-time due to changes from day-ahead (i.e., balancing congestion shortfalls) is collected from loads through uplift charges, most of which is allocated to load throughout the state. However, a portion associated with facilities that require special operation during TSA events is charged to Consolidated Edison whose customers benefit most directly from the additional reliability.

Similar to Figure A-57, Figure A-58 shows balancing congestion shortfalls by transmission path or facility in each month of 2014 and 2015. For select transmission paths, the figure also shows the shortfalls resulted from some unique factors separately from other reasons. Positive values indicate shortfalls, while negative values indicate surpluses.

Figure A-58: Balancing Congestion Shortfalls[250]
2014 – 2015



	Category	Annual Shortfall ($M) 2014	2015
	West Zone Lines		
	Niagara Modeling Assumption	-$2.4	$0.9
	Ramapo, ABC & JK PARs	$4.1	$7.6
	Other Factors	$6.5	$17.8
	Central to East		
	Ramapo, ABC & JK PARs	$0.8	-$7.2
	Other Factors	-$7.8	-$3.4
	Capital to HVL (TSAs)	$4.1	$3.7
	Long Island Lines		
	901/903 PARs	$5.2	$3.8
	Other Factors	-$3.8	$0.9
	External	$11.2	$1.3
	PJM M2M Payment	-$4.3	-$2.1
	All Other Facilities	-$4.9	-$0.3

Key Observations: Congestion Shortfalls

Day-Ahead Congestion Shortfalls

- Day-ahead congestion shortfalls totaled $37 million in 2015, down 46 percent from 2014 primarily because of fewer costly transmission outages in 2015.[251]
- Nonetheless, transmission outages still accounted for a large share of day-ahead congestion shortfalls in 2015. Most of these shortfalls accrued on the following transmission facilities:
  - In the North Zone ($14 million):

250 The balancing congestion shortfalls estimated in this figure may differ from actual balancing congestion shortfalls because the figure: (a) is partly based on real-time schedules rather than metered injections and withdrawals; (b) assumes the energy component of the LBMP is the same at all locations including proxy buses (while the actual proxy bus LBMPs are not calculated this way under all circumstances before April 2014); and (c) uses the original constraint shadow costs from the dispatch model therefore does not reflect the effect of price corrections and Scarcity Pricing Adjustments.

251 See pages A-87 to A-89 of the *2014 State of The Market Report* for a list of significant transmission outages in 2014.

    - One 765 kV transmission line was out of service during most of October, which reduced the transfer capability on the Moses-South interface by more than 2,000 MW and accounted for over 80 percent of these shortfalls.
  - On Long Island ($9 million):
    - The vast majority of these shortfalls accrued when transmission outages from upstate to Long Island reduced import capacity into Long Island.
    - The Y50 line was operating at reduced capacity from mid to late January because of one breaker outage at the Shore Road 345/115kV transformer, and the line was forced out of service from mid-June until early August.
    - The Y49 line was operating at reduced capacity from late April to mid-June and from mid to late October because of one East Garden City PAR outage, and it was completely out of service from early to mid-October for planned maintenance.
  - In the West Zone ($10 million):
    - Several facilities around the Niagara 115 kV bus were out of service intermittently during the second and fourth quarters. Several facilities were taken out of service in most of November and December for the transmission work to put the new Five Mile Road substation in service.
      - These led to transmission bottlenecks on 230kV lines in the West Zone, accounting for a significant portion of the $10 million in shortfalls.
      - The primary driver of the remaining shortfalls was different assumptions regarding unscheduled loop flows between the TCC auction and the day-ahead market.
  - On the Central-East Interface ($6 million):
    - Multiple transmission outages in the fourth quarter reduced interface transfer capability by up to 900 MW, accounting for most of the $9 million shortfalls that accrued in the fourth quarter.
    - However, this was offset by $3 million of surpluses that accrued in the first quarter on very cold days when changes in the commitment pattern led to increased voltage transfer limits for the interface.
- A portion of day-ahead shortfalls resulted from grandfathered TCCs that exceed the transfer capability of the system from Dunwoodie (Zone I) to Long Island. [252]
  - This resulted in $6 million of shortfalls in 2014 and $4 million of shortfalls in 2015.
- The two PAR-controlled lines between New York City and Long Island (i.e., the 901 and 903 lines) consistently caused congestion surpluses, which offset the total shortfalls. [253]

[252] This is categorized as "Excess GFTCC Allocations" under "Long Island Lines" in the figure.

- This was due to the differences in the schedule assumptions on these two lines between the TCC auction and the day-ahead market.
  - The TCC auctions typically assumed a total of 286 MW flow from Long Island to New York City across the two lines while the day-ahead market assumed an average of 205 MW in that direction in 2014 and 193 MW in 2015.
  - Since flows from Long Island to New York City across these lines are generally uneconomic and raise production costs, reducing the assumed flow from the TCC auction to the day-ahead market led to significant surplus congestion revenue.
- This difference led to a surplus of $9 million in 2014 and $11 million in 2015.
  - More than $5 million of surpluses were generated when the Y50 line was out of service from mid-June to early August in 2015, during which the 901 and 903 lines were scheduled to flow 0 MW.
  - These large congestion surpluses reinforce the notion that scheduling the 901 and 903 lines in an efficient manner would substantially reduce production costs.

- Differences between the TCC auction and the day-ahead market in the assumed amount of 115 kV Niagara generation consistently caused congestion shortfalls on 230 kV transmission lines in the West Zone. [254]
  - On average, the assumed amount of 115 kV Niagara generation in the TCC auction was higher than in the day-ahead market by more than 300 MW. Since 115 kV Niagara generation generally help relieve congestion on the 230 kV constraints in the West Zone (but this generation is priced in the day-ahead market as if it were located at the 230kV bus), the reduction in the day-ahead market led to notable congestion shortfalls.
  - This difference led to a shortfall of $6 million in 2014 and $7 million in 2015.
- External interfaces accounted for nearly $10 million of surpluses in 2015, offsetting the total shortfalls.
  - Most of these surpluses accrued in the first quarter because imports on most interfaces increased in the day-ahead market from the TCC auction in many hours.

Balancing Congestion Shortfalls

- Balancing congestion shortfalls rose roughly $14 million from 2014 to 2015, most of which was associated with transmission facilities in the West Zone.
- A net $26 million of shortfalls accrued on 230 kV transmission facilities in the West Zone in 2015, up $18 million from 2014.

253 This is categorized as "901/903 PARs" under "Long Island Lines" in the figure.

254 This is categorized as "Niagara Modeling Assumption" under "West Zone Lines" in the figure.

- The primary drivers were line deratings and unexpected changes in loop flows, which accounted for nearly $18 million of shortfalls.
  - These shortfalls were partly offset by the operation of the Dunkirk-South Ripley and Warren-Falconer lines, which were frequently taken out of service to maintain reliability on the 115 kV system (an operating practice which also helps to relieve 230 kV congestion).

- The operation of Ramapo PAR under the M2M JOA with PJM has provided significant benefit to the NYISO in managing congestion on coordinated transmission flowgates,
  - Additional flows (into New York) across the Ramapo, ABC, & JK PAR-controlled lines contributed an estimated $8 million of surpluses primarily on the Central-East interface ($7.2 million) and the Leeds-to-Pleasant Valley line during TSA events ($0.6 million, which is not shown separately in the figure).
  - However, in hours with congestion in the West Zone, these additional flows contributed to nearly $8 million of shortfalls on the West Zone lines (currently not under M2M JOA).
    - The NYISO has recognized this issue and modified its operating practice in November 2015 to limit use of the Ramapo congestion coordination process to periods when the NYISO does not expect constraints in Western New York to be active. [255]

- The two PAR-controlled lines between New York City and Long Island (i.e., the 901 and 903 lines) consistently contributed to congestion shortfalls in the real-time market.
  - This was due to the differences between the schedule assumptions on the two lines in the day-ahead markets and their actual flows in real-time.
  - On average, real-time flows from Long Island to New York City on the two lines were similar to the average day-ahead assumptions. However, real-time flows across these lines are volatile, so when flows rise above the day-ahead assumption, it contributes to high prices in Long Island. For example, real-time flows from Long Island to New York City on the 901 line exceeded the day-ahead assumption by an average of 20 percent during intervals with real-time congestion.
  - The operation of these lines contributed to the balancing congestion shortfalls by $5 million in 2014 and $4 million in 2015.

F. TCC Prices and DAM Congestion

In this sub-section, we evaluate whether clearing prices in the TCC auctions were consistent with congestion prices in the day-ahead market. TCCs provide an entitlement to the holder for the day-ahead congestion between two points. In a well-functioning market, the price for the TCC

255 See NYISO Management Committee meeting minutes for the December 17, 2015 meeting.

should reflect a reasonable expectation of the day-ahead congestion. Perfect convergence cannot be expected because many factors affecting congestion are not known at the time of the auctions, including forced outages of generators and transmission, fuel prices, weather, etc. There are two types of TCC auctions: Centralized TCC Auctions and Reconfiguration Auctions.

- *Centralized TCC Auctions* – TCCs are sold in these auctions as 6-month products for the Summer Capability Period (May to October) or the Winter Capability Period (November to April), as 1-year products for two consecutive capability periods, and as 2-year products for four consecutive Capability Periods.[256] Most transmission capability is auctioned as 6-month products. The Capability Period auctions consist of a series of rounds, in which a portion of the capability is offered, resulting in multiple TCC awards and clearing prices. Participants may offer TCCs for resale or submit bids to purchase additional TCCs in these auctions.
- *Reconfiguration Auctions* – The NYISO conducts a Reconfiguration Auction once every month for the following month for which the TCC will be effective. Participants may offer TCCs for resale or submit bids to purchase additional TCCs in the Reconfiguration Auction. Each monthly Reconfiguration Auction consists of only one round.

Figure A-59: TCC Cost and Profit by Auction Round and Path Type

Figure A-59 summarizes TCC cost and profit for the Winter 2014/15 and Summer 2015 Capability Periods (i.e., the 12-month period from November 2014 through October 2015). The *TCC Cost* measures what market participants paid to obtain TCC rights from the TCC auctions. For a particular path, the *TCC Cost* is equal to the purchased TCC MW multiplied by the TCC price for that path. The *TCC Profit* measures the difference between the *TCC Payment*, which is equal to the TCC MW between two points multiplied by the congestion cost difference in the day-ahead market between the two points, and the *TCC Cost*.

The figure shows the TCC costs and profits for each round of auction in the 12-month period, which includes: (a) three rounds of one-year auctions for the exact same 12-month Capability Period; (b) four rounds of six-month auctions for the Winter 2014/15 Capability Period; (c) three rounds of six-month auctions for the Summer 2015 Capability Period; and (d) twelve reconfiguration auctions for each month of the 12-month Capability Period. The figure only evaluates the TCCs that were purchased by Market Participants in these auctions.

For the purposes of the figure, each TCC is broken into inter-zonal and intra-zonal components, making it possible to identify portions of the transmission system that generate the most revenue in the TCC auction and that are most profitable for the buyers of TCCs. Each TCC has a Point-Of-Injection ("POI") and a Point-Of-Withdrawal ("POW"). The POI and POW may be a generator bus, a NYCA Zone, the NYISO Reference Bus, or an external proxy bus. For the purpose of this analysis, all transacted TCCs in the auctions are unbundled into the following standard components: (a) POI to the Zone containing the POI (POI Zone), (b) POI Zone to the

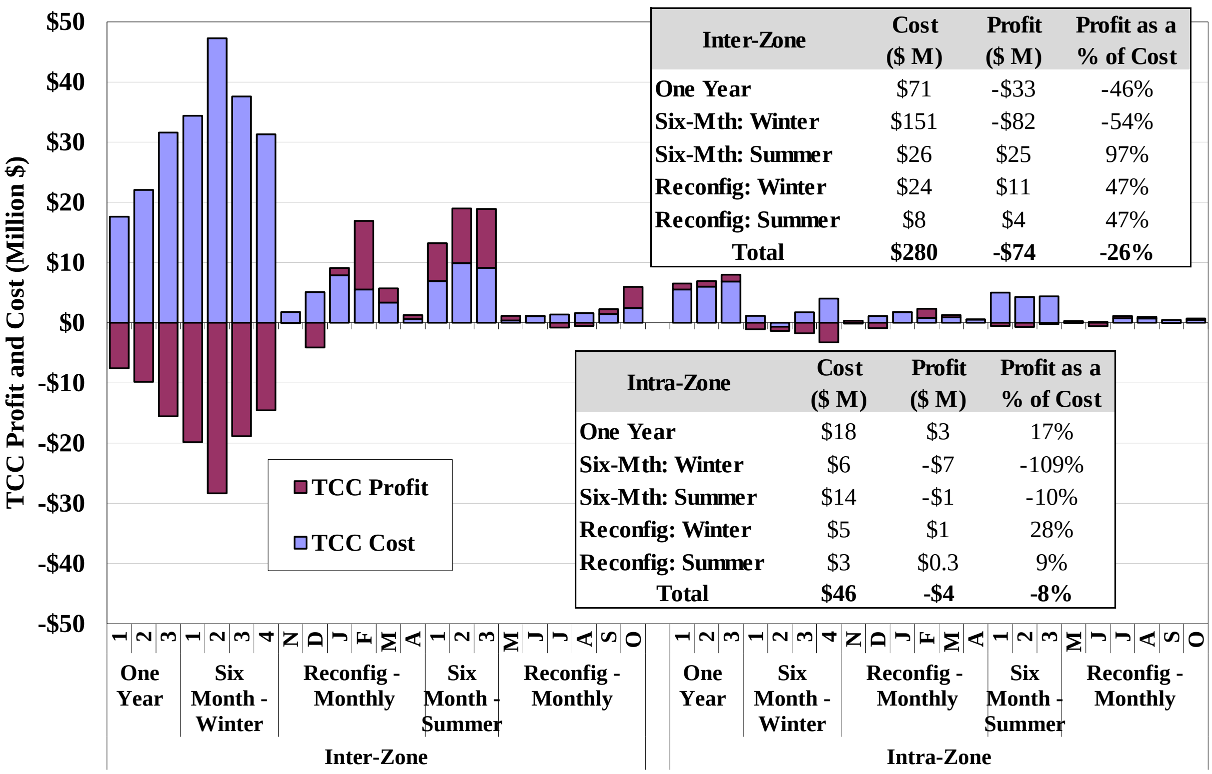
256 2-year TCCs were first sold in the Autumn 2011 auctions for the period from November 2011 to October 2013.

Zone containing the POW (POW Zone), and (c) POW Zone to POW. When a TCC is unbundled into standard components for this analysis, the original TCC is replaced by up to three TCCs. The three standard components are further grouped into two categories: (a) inter-zone TCCs, which include all unbundled POI Zone to POW Zone TCCs; and (b) intra-zone TCCs, which include POI to POI Zone TCCs and POW Zone to POW TCCs.[257]

The figure shows the costs and profits separately for the intra-zone and inter-zone components of TCCs. The table in the figure summarizes the TCC cost, profit, and profitability for each type of TCC auction for the two categories of TCC paths. The profitability is measured by the total TCC profit as a percentage of total TCC cost.

Figure A-59: TCC Cost and Profit by Auction Round and Path Type

Winter 2014/15 and Summer 2015 Capability Periods



Inter-Zone	Cost ($ M)	Profit ($ M)	Profit as a % of Cost
One Year	$71	-$33	-46%
Six-Mth: Winter	$151	-$82	-54%
Six-Mth: Summer	$26	$25	97%
Reconfig: Winter	$24	$11	47%
Reconfig: Summer	$8	$4	47%
Total	**$280**	**-$74**	**-26%**

Intra-Zone	Cost ($ M)	Profit ($ M)	Profit as a % of Cost
One Year	$18	$3	17%
Six-Mth: Winter	$6	-$7	-109%
Six-Mth: Summer	$14	-$1	-10%
Reconfig: Winter	$5	$1	28%
Reconfig: Summer	$3	$0.3	9%
Total	**$46**	**-$4**	**-8%**

Table A-1 & Table A-2: TCC Cost and Profit by Path

The following two tables compare TCC costs with TCC profits for both intra-zonal paths and inter-zonal paths during the Winter 2014/15 and Summer 2015 Capability Periods (i.e., the 12-month period from November 2014 through October 2015). Each pair of POI and POW

257 For example, a 100 MW TCC from Indian Point 2 to Arthur Kill 2 is unbundled to three components: (a) A 100 MW TCC from Indian Point 2 to Millwood Zone; (b) A 100 MW TCC from Millwood Zone to New York City Zone; and (c) A 100 MW TCC from New York City Zone to Arthur Kill 2. Components (a) and (c) belong to the intra-zone category and Component (b) belongs to inter-zone category.

represents all paths sourcing from the POI and sinking at the POW. Inter-zonal paths are represented by pairs with different POI and POW, while intra-zonal paths are represented by pairs with the same POI and POW. TCC costs and profits that are higher than $2 million are highlighted with green, while TCC costs and profits that are lower than -$2 million are highlighted with light red.

Table A-1: TCC Cost by Path
Winter 2014/15 and Summer 2015 Capability Periods

POI \ POW	WEST	GENESE	CENTRL	MHK VL	NORTH	CAPITL	HUD VL	MILLWD	DUNWOD	N.Y.C.	LONGIL	O H	H Q	NPX	PJM	Total
WEST	$15	-$6	$0	$0	$0	$2	$16	$0	$0	$0	$0	-$3	$0	$0	$0	**$25**
GENESE	$3	$1	$2	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	**$6**
CENTRL	$6	-$1	$22	$0	$0	$0	$6	$0	$0	$0	$0	$0	$0	$0	$0	**$34**
MHK VL	$3	$0	$0	-$21	$0	$3	$3	$0	$0	$0	$0	$0	$0	$1	$0	**-$11**
NORTH	$3	$0	$4	$20	$0	$0	$1	$0	$0	$0	$0	$0	$0	$0	$0	**$29**
CAPITL	$0	$0	$0	-$6	$0	$1	-$2	$0	$0	$0	$1	$0	$0	$0	$0	**-$5**
HUD VL	-$2	$0	$0	$0	$0	$19	$0	$0	$0	$14	$0	$0	$0	$77	-$2	**$107**
MILLWD	$0	$0	$0	$0	$0	$4	$0	$0	$0	$2	$0	$0	$0	$0	$0	**$5**
DUNWOD	$0	$0	$0	$0	$0	$0	$0	$0	$0	$7	$0	$0	$0	$0	$0	**$7**
N.Y.C.	$0	$0	$0	$0	-$1	$1	-$1	$0	$0	$20	$1	$0	$0	$0	$0	**$20**
LONGIL	-$1	$0	$0	$0	$0	$0	-$1	$0	-$3	$0	$6	$0	$0	$0	$0	**$2**
O H	$7	$2	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$1	$0	**$10**
H Q	$0	$0	$0	$12	$0	$0	$0	$0	$0	$0	$0	$0	$0	$2	$0	**$15**
NPX	-$6	$0	$0	-$1	$0	-$7	-$1	$0	$0	$0	-$2	$0	$0	$0	$0	**-$17**
PJM	-$1	$0	-$2	-$1	$0	$1	$55	$0	$0	$0	$0	$0	$0	$49	$0	**$101**
Total	**$28**	**-$4**	**$25**	**$2**	**-$1**	**$25**	**$76**	**$1**	**-$3**	**$43**	**$8**	**-$3**	**$0**	**$131**	**-$2**	**$326**

Table A-2: TCC Profit by Path
Winter 2014/15 and Summer 2015 Capability Periods

POI \ POW	WEST	GENESE	CENTRL	MHK VL	NORTH	CAPITL	HUD VL	MILLWD	DUNWOD	N.Y.C.	LONGIL	O H	H Q	NPX	PJM	Total
WEST	$4	-$4	-$1	$0	$0	$3	-$1	$0	$0	$0	$0	-$1	$0	$0	$0	**-$1**
GENESE	$2	$0	-$1	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	**$1**
CENTRL	$8	$0	-$6	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	**$3**
MHK VL	$1	$0	$0	$5	$0	$1	$0	$0	$0	$0	$0	$0	$0	$1	$0	**$8**
NORTH	$2	$1	$1	$3	$0	$0	$1	$0	$0	$0	$0	$0	$0	$0	$0	**$7**
CAPITL	$0	$0	$0	$2	$0	-$2	$6	$0	$0	$0	$0	$0	$0	$1	$0	**$7**
HUD VL	$1	$0	$0	$0	$0	-$3	$0	$0	$0	-$7	$0	$0	$0	-$48	$1	**-$55**
MILLWD	$0	$0	$0	$0	$0	-$1	$0	$0	$0	-$1	$0	$0	$0	$0	$0	**-$2**
DUNWOD	$0	$0	$0	$0	$0	$0	$0	$0	$0	-$5	$0	$0	$0	$0	$0	**-$5**
N.Y.C.	$0	$0	$0	$0	$0	$0	$0	$0	$0	-$10	$0	$0	$0	$0	$0	**-$10**
LONGIL	$0	$0	$0	$0	$0	$0	$0	$0	$1	$0	$4	$0	$0	$0	$0	**$6**
O H	$2	-$1	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	**$2**
H Q	$0	$0	$0	$5	-$1	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	**$5**
NPX	$4	$0	$0	$1	$0	$5	$1	$0	$0	$0	$2	$0	$0	$0	$0	**$13**
PJM	$0	$0	$0	$0	$0	$0	-$25	$0	$0	$0	$0	$0	$0	-$33	$0	**-$57**
Total	**$25**	**-$4**	**-$6**	**$17**	**-$1**	**$3**	**-$16**	**$0**	**$2**	**-$23**	**$5**	**-$1**	**$0**	**-$79**	**$1**	**-$78**

Key Observations: TCC Prices and Profitability

- TCC buyers netted a loss of $78 million in the TCC auctions during the 12-month period (November 2014 to October 2015), resulting in an average profitability (profit as a percent of TCC cost) of *negative* 24 percent.[258]

258 The reported profits exclude profits and losses from TCC sellers (i.e., firms that initially purchased TCCs and then sold back a portion in a subsequent auction). In addition, purchases in the TCC auctions that

- More than 55 percent (or $181 million) of purchase costs were spent on paths along the transmission corridor from PJM to Hudson Valley Zone to New England.
  - TCC buyers netted a 58 percent (or $105 million) of loss on these transmission paths because of much lower-than-expected congestion along this corridor.
  - The day-ahead congestion between areas across the Central-East interface was well below the TCC prices in the TCC auctions, particular during the Winter 2014/15 Capability Period.
    - As explained above, natural gas prices and gas spreads between areas were much lower than expected, particularly at the time of the one-year and six-month TCC auctions, contributing to lower-than-anticipated west-to-east congestion.
    - This has resulted in much lower-than-anticipated congestion price at the New England proxy bus.
  - Day-ahead congestion in the West Zone rose notably from the prior year for the reasons discussed in subsection B.
    - This has resulted in higher-than-anticipated congestion price at the PJM proxy bus (which reflects roughly 40 percent of congestion cost in Western New York).
- Day-ahead congestion into and within the 345 kV system in New York City fell significantly in 2015.
  - The much lower-than-anticipated congestion cost in this area led to a net 53 percent (or $23 million) loss on transmission paths sinking at New York City.
- However, TCC buyers netted sizable profit on transmission paths sinking at the West Zone, consistent with higher-than-anticipated congestion in this area.
- The results of the TCC auctions indicate that the level of congestion was increasingly recognized by the markets from the annual auction to the six-month auction and from the six-month auction to the reconfiguration auction.
  - This is expected since more accurate information is available about the state of the transmission system and likely market conditions as the auctions occur closer to the actual operating period.

G. Potential Design of Financial Transmission Rights for PAR Operation

This subsection describes how a financial right could be created to compensate ConEd if the lines between NYC and Long Island were scheduled efficiently (rather than according to a fixed schedule) in accordance with Recommendation #11, which is described in Section XI. An

include months outside the evaluated 12-month period are not included as well. Therefore, this evaluation does not include any two-year TCC auctions nor the two one-year TCC auctions that were conducted in the Spring of 2014 and 2015. This is because it is not possible to identify the portion of the purchase cost for such a TCC that was based on its expected value during the period from November 2014 to October 2015.

efficient financial right should compensate ConEd: (a) in accordance with the marginal production cost savings that result from efficient scheduling, and (b) in a manner that is revenue adequate such that the financial right should not result in any uplift for NYISO customers. Note, this new financial transmission right would not alter the TCCs possessed by any market party.

Concept for Financial Transmission Right

An efficient financial right should compensate ConEd for the quantity of congestion relief provided at a price that reflects the marginal cost of relieving congestion on each flow gate in the day-ahead and real-time markets. These are the same principles upon which generators are paid and load customers are charged. Hence, a transmission right holder should be paid:

DAM Payment =

$$\sum_{\boldsymbol{l=901,903}} \left([\boldsymbol{DAM\ MW_l - TCC\ MW_l}] \times \sum_{\boldsymbol{c=constraint}} [-\boldsymbol{DAM\ SF_{l,c}} \times \boldsymbol{DAM\ SP_c}] \right)$$

RTM Payment =

$$\sum_{\boldsymbol{l=901,903}} \left([\boldsymbol{RTM\ MW_l - DAM\ MW_l}] \times \sum_{\boldsymbol{c=constraint}} [-\boldsymbol{RTM\ SF_{l,c}} \times \boldsymbol{RTM\ SP_c}] \right)$$

Total Payment = DAM Payment + RTM Payment, where a negative payment would result in a charge to ConEd. To illustrate, suppose there is congestion in the DAM on the interface from upstate to Long Island (Y50 Line), from upstate to NYC (Dunwoodie), and into the Valley Stream load pocket (262 Line) while the 901 Line flows are reduced below the contract amount:

- TCC MW_{901} = 96 MW
- DAM MW_{901} = 60 MW
- DAM SP_{Y50} = \$10/MWh
- DAM $SP_{Dunwoodie}$ = \$5/MWh
- DAM SP_{262} = \$15/MWh
- DAM $SF_{901,\ Y50}$ = 100%
- DAM $SF_{901,\ Dunwoodie}$ = -100%
- DAM $SF_{901,\ 262}$ = 100%
- DAM $Payment_{901}$ = \$720 per hour = [60 MW – 96 MW] x {[-100% x \$10/MWh] + [100% x \$5/MWh] + [-100% x \$15/MWh]}

Since DAM payments are made for deviations from the TCC modeling assumptions, the new financial transmission right would not alter the TCCs possessed by any market party.

Revenue Adequacy

Just as the LBMP compensation to generators is generally revenue adequate, the new financial transmission right would also be revenue adequate. This is illustrated by the following scenarios:

- Basecase Scenario – Provides an example of the current market rules where the NYISO receives revenues from loads that exceed payments to generators, thereby contributing to DAM congestion revenues.
- PAR Relief Scenario – Shows how a PAR-controlled line could be used to reduce congestion, allowing the owner of the line to be compensated without increasing uplift from DAMCRs.
- PAR Loading Scenario – Shows how the owner of the line would be charged if the DAM schedule increased congestion relative to the TCC schedule assumption.

These scenarios use a simplified four node network, including: Upstate, NYC, Valley Stream, and Rest of Long Island. The four nodes are interconnected by four interfaces:

- The Dunwoodie interface from Upstate to NYC,
- The Y50 Line from Upstate to Rest of Long Island,
- The 262 Line from Rest of Long Island to Valley Stream, and
- The PAR-controlled 901 Line from Valley Stream to NYC.

For simplicity, the 901 Line contract amount that is used in the TCC auction is rounded to 100 MW.

The Base Case Scenario shows that a net of $22,500 of DAM congestion revenue is collected from scheduling by generators and loads. The table also shows the amount of DAM congestion revenue that accrues on each constrained facility. In this example, DAMCR equals $0 because the flows on each constrained facility are equal to the capability/assumption in the TCC model. Since the 901 Line contract moves power from a high LBMP area to a low LBMP area, it reduces congestion revenue by $2,000, but it does not cause DAMCR because it is consistent with the TCC auction.

The PAR Relief Scenario shows that if the 901 Line flow is reduced from 100 MW to 10 MW, it reduces the generation needed in Valley Stream and increases generation in NYC, reducing overall production costs by $1,800 as compared to the Basecase Scenario. Since LBMPs do not change in this example, payments by loads are unchanged and $1,800 of additional congestion revenues are collected. The collection of additional congestion revenues allows the NYISO to compensate ConEd $1,800 for the PAR adjustment, and DAMCR remains at $0.

The PAR Relief Scenario shows that if the 901 Line flow is increased from 100 MW to 120 MW, it increases the generation needed in Valley Stream and reduces generation in NYC, increasing overall production costs by $400 as compared to the Basecase Scenario. Since LBMPs do not change in this example, payments by loads are unchanged and $400 less congestion revenue is collected. The collection of less congestion revenue requires the NYISO to charge ConEd $400 for exceeding the contract amount, and DAMCR remains at $0.

BASECASE SCENARIO

	Node	LBMP	Load	Generation	Load Revenue	Generator Payments
Gen/Load	Upstate	$25	10000	13000	$250,000	$325,000
Payments	NYC	$30	4000	1900	$120,000	$57,000
	Valley Stream	$50	350	150	$17,500	$7,500
	Rest of Long Is.	$35	2500	1800	$87,500	$63,000
	Total		16850	16850	$475,000	$452,500
	Net (Gen minus Load)			0		$22,500

	Interface	Shadow Price	Interface Flow	Congestion Revenue
Transmission	Dunwoodie	$5	2000	$10,000
Revenue	Y50	$10	1000	$10,000
	262 Line	$15	300	$4,500
	901 Line Contract	-$20	100	-$2,000
	Total			$22,500
	DAMCR (Gen minus Load minus Congestion)			$0

PAR RELIEF SCENARIO (901 Line Flow Reduced from 100 MW to 10 MW)

	Node	LBMP	Load	Generation	Load Revenue	Generator Payments
Gen/Load	Upstate	$25	10000	13000	$250,000	$325,000
Payments	NYC	$30	4000	1990	$120,000	$59,700
	Valley Stream	$50	350	60	$17,500	$3,000
	Rest of Long Is.	$35	2500	1800	$87,500	$63,000
	Total		16850	16850	$475,000	$450,700
	Net (Gen minus Load)			0		$24,300

	Interface	Shadow Price	Interface Flow	Congestion Revenue
Transmission	Dunwoodie	$5	2000	$10,000
Revenue	Y50	$10	1000	$10,000
	262 Line	$15	300	$4,500
	901 Line Contract	-$20	100	-$2,000
	901 Line Adjust	-$20	-90	$1,800
	Total			$24,300
	DAMCR (Gen minus Load minus Congestion)			$0

PAR LOADING SCENARIO (901 Line Flow Increased from 100 MW to 120 MW)

	Node	LBMP	Load	Generation	Load Revenue	Generator Payments
Gen/Load	Upstate	$25	10000	13000	$250,000	$325,000
Payments	NYC	$30	4000	1880	$120,000	$56,400
	Valley Stream	$50	350	170	$17,500	$8,500
	Rest of Long Is.	$35	2500	1800	$87,500	$63,000
	Total		16850	16850	$475,000	$452,900
	Net (Gen minus Load)			0		$22,100

	Interface	Shadow Price	Interface Flow	Congestion Revenue
Transmission	Dunwoodie	$5	2000	$10,000
Revenue	Y50	$10	1000	$10,000
	262 Line	$15	300	$4,500
	901 Line Contract	-$20	100	-$2,000
	901 Line Adjust	-$20	20	-$400
	Total			$22,100
	DAMCR (Gen minus Load minus Congestion)			$0

IV. External Interface Scheduling

New York imports a substantial amount of power from four adjacent control areas; New England, PJM, Ontario, and Quebec. In addition to the four primary interfaces with adjacent regions, Long Island and New York City connect directly to PJM and New England across five controllable lines: the Cross Sound Cable, the 1385 Line, the Linden VFT Line, the HTP Line, and the Neptune Cable. The controllable lines are collectively able to import nearly 2.2 GW directly to downstate areas.[259,260] The total transfer capability between New York and the adjacent regions is substantial relative to the total power consumption in New York, making it important to schedule the interfaces efficiently.

Efficient use of transmission interfaces between regions is beneficial in at least two ways. First, the external interfaces allow access to external resources, which lowers the cost of serving load in New York to the extent that lower-cost external resources are available. Likewise, lower-cost internal resources gain the ability to compete to serve load in adjacent regions. Second, the ability to draw on neighboring systems for emergency power, reserves, and capacity helps lower the costs of meeting reliability standards in each control area. Wholesale markets should facilitate the efficient use of both internal resources and transmission interfaces between control areas.

This section evaluates the following five aspects of transaction scheduling between New York and adjacent control areas:

- Scheduling patterns between New York and adjacent areas;
- Convergence of prices between New York and neighboring control areas;
- Scheduling patterns across the interfaces that allow intra-hour scheduling (i.e., 15-minute scheduling).; and
- The efficiency of Coordinated Transaction Scheduling.

A. Summary of Scheduled Imports and Exports

259 The Cross Sound Cable (“CSC”), which connects Long Island to Connecticut, is frequently used to import up to 330 MW to New York. Likewise, the Neptune Cable, which connects Long Island to New Jersey, is frequently used to import up to 660 MW to New York. The Northport-to-Norwalk line (“1385 Line”), which connects Long Island to Connecticut, is frequently used to import up to 200 MW (the capability increased from 100 MW to 200 MW in May 2011 following an upgrade to the facility). The Linden VFT Line, which connects New York City to PJM with a transfer capability of 315 MW (this increased from 300 MW on November 1, 2012), began normal operation in November 2009. The Hudson Transmission Project (“HTP Line”) connects New York City to New Jersey with a transfer capability of 660 MW, which began its normal operation in June 2013.

260 In addition to the controllable lines connecting New York City and Long Island to adjacent control areas, there is a small controllable line between upstate New York and Quebec that is known as the “Dennison Scheduled Line” and which is scheduled separately from the primary interface between New York and Quebec.

Figure A-60 to Figure A-63 : Average Net Imports from Ontario, PJM, Quebec, and New England

The following four figures summarize the net scheduled interchanges between New York and neighboring control areas in 2014 and 2015. The net scheduled interchange does not include unscheduled power flows (i.e., loop flows). For each interface, average scheduled net imports are shown by month for peak (i.e., 6 am to 10 pm, Monday through Friday) and off-peak hours. This is shown for the primary interfaces with Ontario and PJM in Figure A-60, the primary interfaces with Quebec and New England in Figure A-61, and the controllable lines connecting Long Island and New York City with PJM and New England in Figure A-62 and Figure A-63.

Figure A-60: Monthly Average Net Imports from Ontario and PJM
2014 – 2015

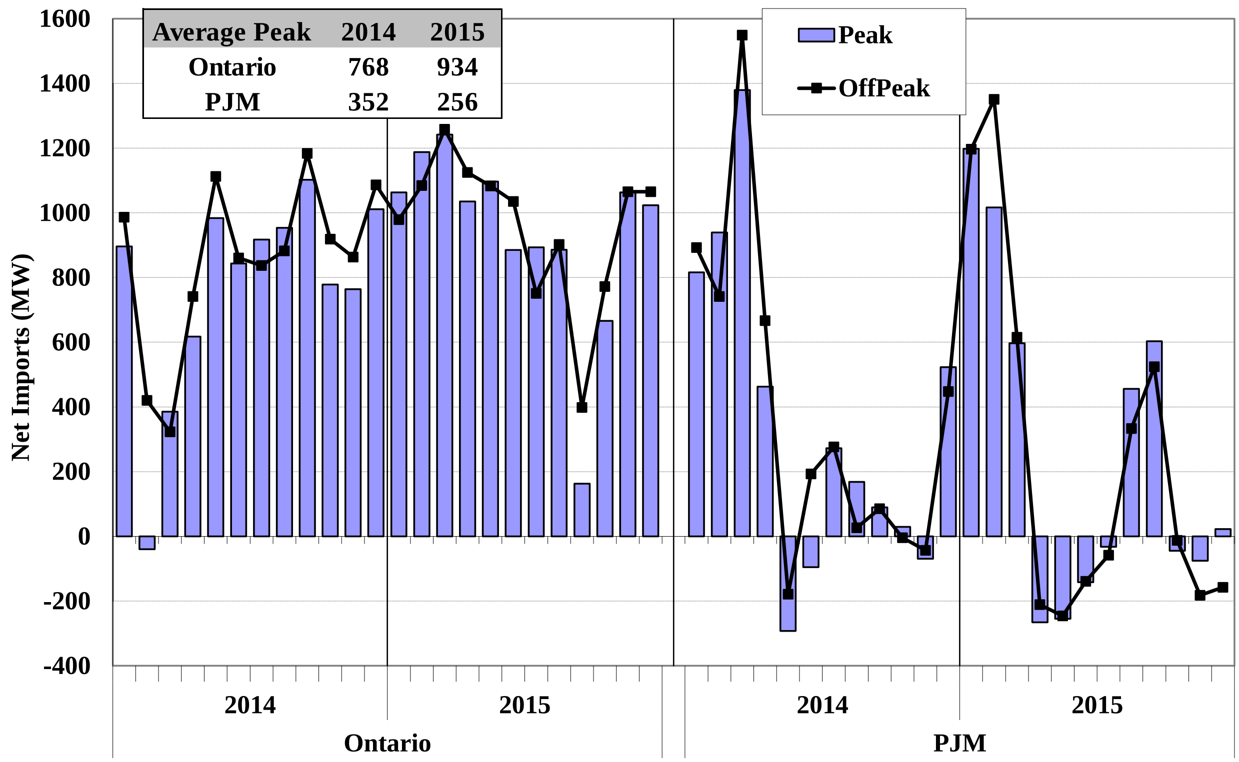


Figure A-61: Monthly Average Net Imports from Quebec and New England
2014 – 2015

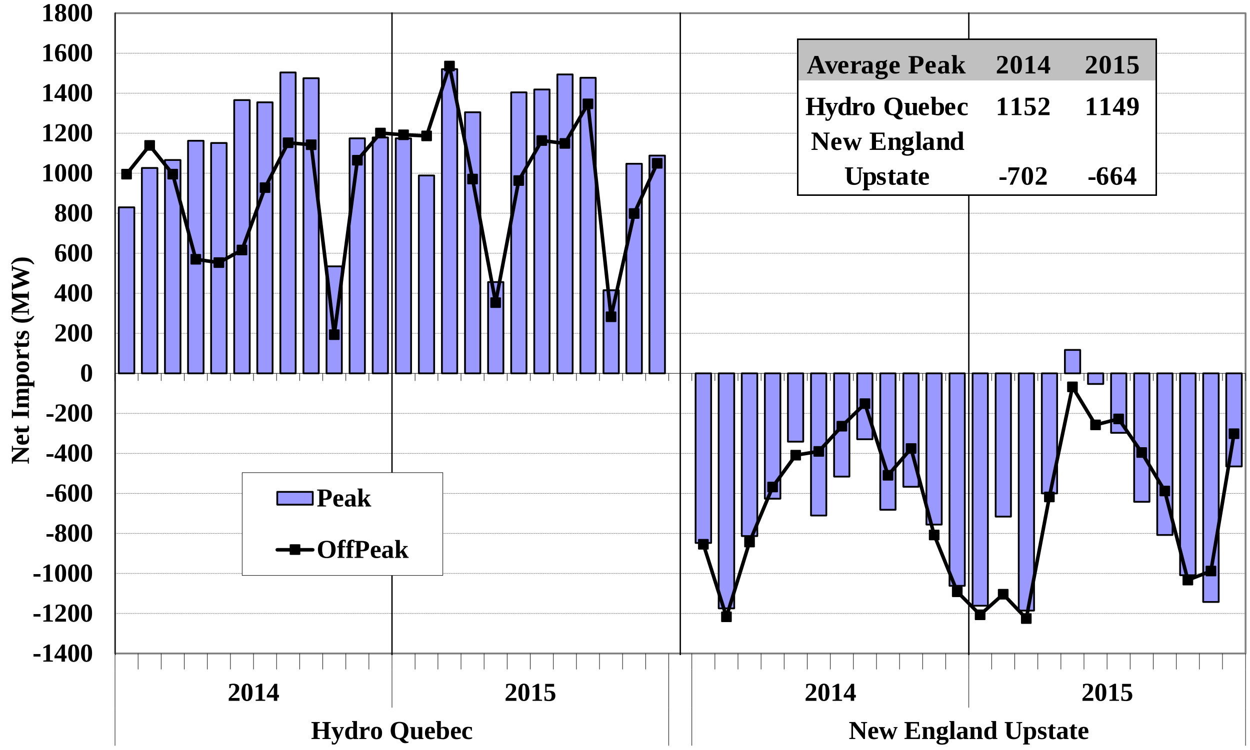


Figure A-62: Monthly Average Net Imports into New York City
2014 – 2015

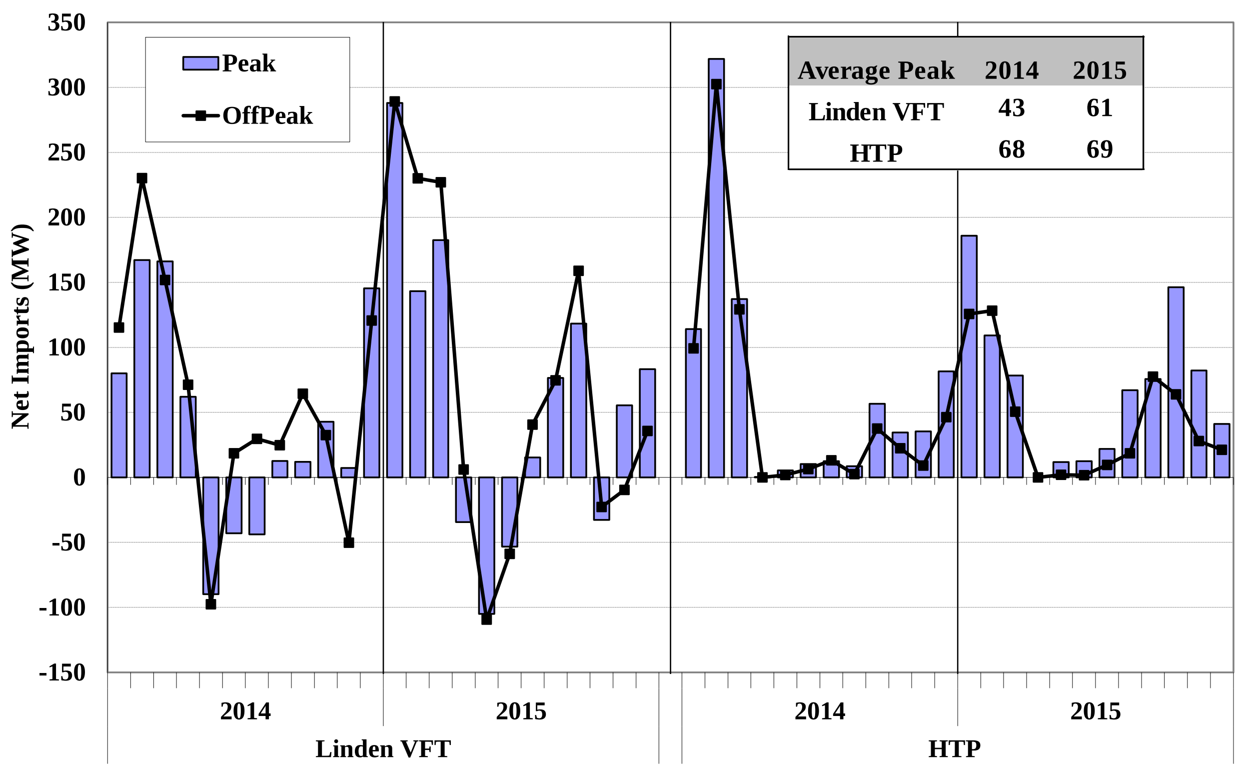
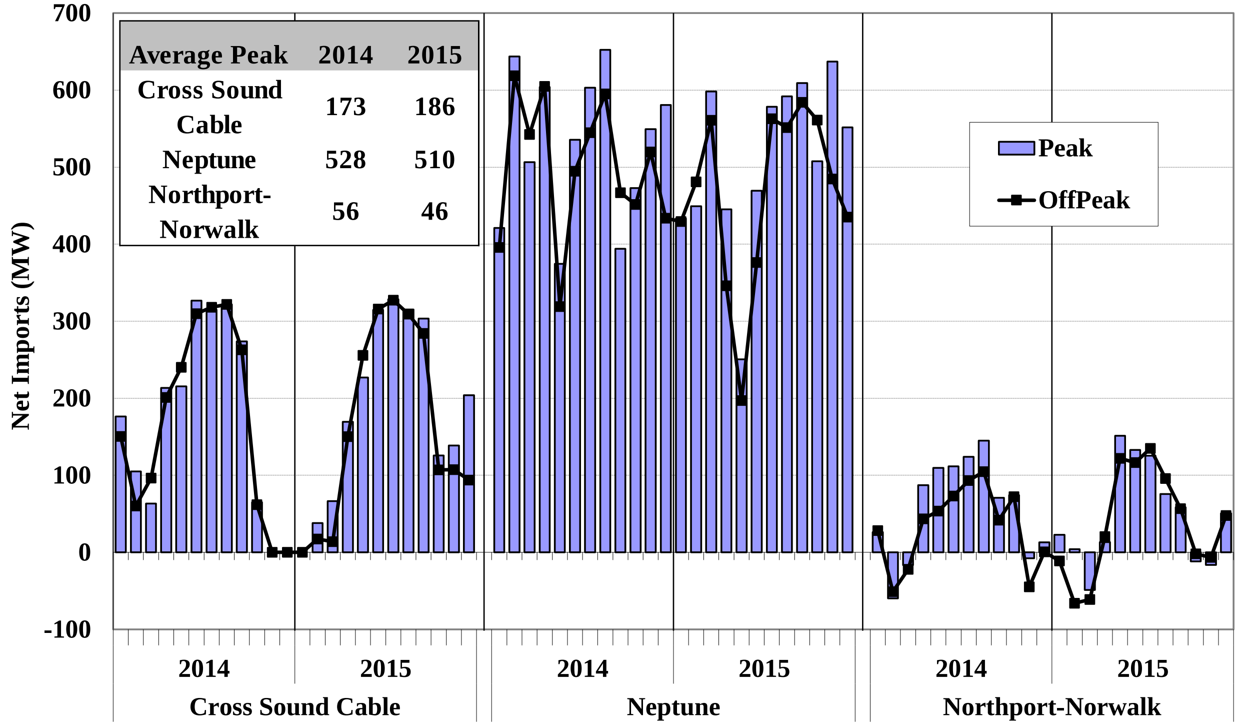


Figure A-63: Monthly Average Net Imports into Long Island
2014 – 2015



Key Observations: Average Net Imports

- Average net imports from neighboring areas across the primary interfaces increased marginally from 1,570 MW in 2014 to 1,675 MW in 2015 during the peak hours.
  - Net imports from Hydro Quebec averaged roughly 1,150 MW, accounting for 69 percent of net imports across the primary interfaces in 2015.
    - Average net imports rose over 20 percent in the first quarter of 2015 from a year ago, reflecting less frequent winter peaking conditions in Quebec this year.
    - However, the increases were largely offset by lower imports in May and October when this interface was out of service during most of these two months.
  - Average net imports from Ontario increased more than 20 percent from 2014 to 2015, which had significant effects on operations and LBMPs in the West Zone.
    - The majority of the increase occurred in the first quarter of 2015 (up by an average of 740 MW from a year ago), reflecting less frequent peaking conditions and lower natural gas prices than in the prior winter in Ontario.
    - Net imports fell notably in September, which coincided with nuclear outages (~4 GW) in Ontario and offset the overall annual increase. This helped reduce congestion on the 230 kV lines in the West Zone.

  - Net imports from PJM and New England across their primary interfaces varied widely by month, normally closely tracking the variations in gas spreads between these regions. For example,
    - New York normally had higher net imports from PJM and higher net exports to New England in the winter season, consistent with the spreads in natural gas prices between these markets in the winter (i.e., NE > NY > PJM).
    - Net exports to New England fell sharply in May and June of 2015 because New York imported power from New England on many days during the two months when gas prices were cheaper on the New England side.
- Average net imports from neighboring areas into Long Island over the three controllable interfaces averaged about 740 MW during peak hours in 2015, down slightly from 2014.
  - The Cross Sound Cable was out of service from late September 2014 to early February 2015, reducing net imports from New England to Long Island during this period.
  - Imports from neighboring control areas account for a large share of the supply to Long Island.
    - The Cross Sound Cable, the 1385 line, and the Neptune Cable satisfied approximately 30 percent of the load in Long Island in both 2014 and 2015.
- Average net imports from New Jersey to New York City over the Linden VFT and the HTP interfaces averaged roughly 130 MW during peak hours in 2015, up modestly from the prior year.
  - Scheduling patterns across the two interfaces were generally consistent with the scheduling pattern across the primary PJM interface, driven by similar factors.

B. Price Convergence and Efficient Scheduling with Adjacent Markets

The performance of New York's wholesale electricity markets depends not only on the efficient use of internal resources, but also on the efficient use of transmission interfaces between New York and neighboring control areas. Trading between neighboring markets tends to bring prices together as participants arbitrage price differences. When an interface is used efficiently, prices in adjacent areas should be consistent unless the interface is constrained. A lack of price convergence indicates that resources are being used inefficiently, as 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. Efficient scheduling is particularly important during shortages when flows between regions have the largest economic and reliability consequences. Moreover, efficient scheduling can also alleviate over-generation conditions that can lead to negative price spikes.

However, one cannot expect that trading by market participants alone will optimize the use of the interface. Several factors prevent real-time prices from being fully arbitraged.

- Market participants do not operate with perfect foresight of future market conditions at the time that transaction bids must be submitted. Without explicit coordination between the markets by the ISOs, complete arbitrage will not be possible.
- Differences in scheduling procedures and timing in the markets serve as barriers to full arbitrage.
- There are transaction costs associated with scheduling imports and exports that diminish the returns from arbitrage. Participants cannot be expected to schedule additional power between regions unless they anticipate a price difference greater than these costs.
- The risks associated with curtailment and congestion reduce participants' incentives to schedule external transactions when expected price differences are small.

Figure A-64: Price Convergence Between New York and Adjacent Markets

Figure A-64 evaluates scheduling between New York and adjacent RTO markets across interfaces with open scheduling. The Neptune Cable, the Linden VFT Line, the HTP Line, and the Cross Sound Cable are omitted because these are Designated Scheduled Lines and alternate systems are used to allocate transmission reservations for scheduling on them. RTOs have real-time markets, which allow participants to schedule market-to-market transactions based on transparent price signals in each region. Based on the prevailing prices in each market, we can evaluate whether the interface is scheduled efficiently.

Figure A-64 summarizes price differences between New York and neighboring markets during unconstrained hours in 2015. In these hours, there were no NYISO constraints that prevented scheduling. However, in some of these hours, there may have been constraints that prevented the other ISOs from scheduling transactions. In the figure, the horizontal axis shows the range of price differences between New York and the adjacent control areas at the border. The heights of the bars represent the fraction of hours in each price difference category.

Figure A-64: Price Convergence Between New York and Adjacent Markets
Unconstrained Hours in Real-Time Market, 2015

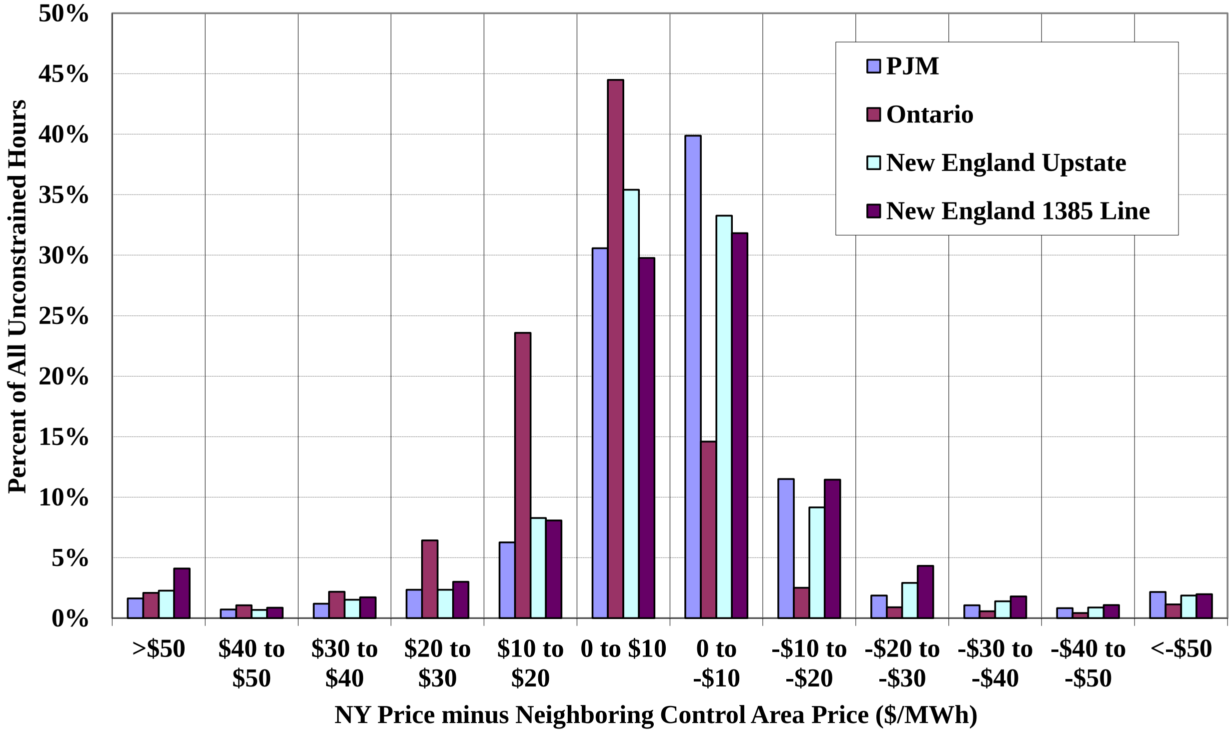


Table A-10: Efficiency of Inter-Market Scheduling

Table A-10 evaluates the consistency of the direction of external transaction scheduling and price differences between New York and New England, PJM, and Ontario during 2015. It evaluates transaction schedules and clearing prices between New York and the three markets across the three primary interfaces and five scheduled lines (i.e., the 1385 Line, the Cross Sound Cable, the Neptune Cable, the HTP Line, and the Linden VFT interface).

The table shows the following quantities:

- Average hourly flows between neighboring markets and New York. A positive number indicates a net import from neighboring areas to New York.
- Average price differences between markets for each interface. A positive number indicates that the average price was higher on the New York side than the other side of the interface.
- The share of the hours when power was scheduled in the efficient direction (i.e., from the lower-price market to the higher-priced market).

- The estimated production cost savings that result from the flows across each interface. The estimated production cost savings in each hour is based on the price difference across the interface multiplied by the scheduled power flow across the interface. [261]

The vast majority of power is scheduled in the day-ahead market, while small balancing adjustments are typically made in the real-time market. So, this analysis is shown separately for the portion of flows scheduled in the day-ahead market versus the portion that is from balancing adjustments in the real-time market.[262] However, for Ontario, the analysis assumes a day-ahead schedule of 0 MW since Ontario does not operate a day-ahead market.

Table A-10 evaluates the efficiency of the hourly net scheduled interchange rather than of individual transactions. Individual transactions may be scheduled in the inefficient direction, but this will induce other firms to schedule counterflow transactions, thereby offsetting the effect of the individual transaction. Ultimately, the net scheduled interchange is what determines how much of the generation resources in one control area will be used to satisfy load in another control area, which determines whether the external interface is used efficiently.

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261 For example, if 100 MW flows from PJM to New York across its primary interface during one hour, the price in PJM is $50 per MWh, and the price in New York is $60 per MWh, then the estimated production cost savings is $1,000 (=100 * $10). This is because each MW of flow saves $10 by allowing a $60 per MWh resource in New York to ramp down and be replaced by a $50 per MWh resource in PJM. This method of calculating production cost savings tends to under-estimate the actual production cost savings when power flows from the low-priced region to the high-priced region, since if flows in the efficient direction were reduced, the cost of the marginal resource in the importing region would rise while the cost of the marginal resource in the exporting region would fall. However, this method of calculating production cost savings tends to over-estimate the actual production cost increases when power flows from towards the low-priced region, since if flows were reduced, the cost differential between the marginal resources in each region would converge.

262 For example, if 100 MW is scheduled from the low-priced region to the high-priced region in the day-ahead market, the day-ahead schedule would be considered *efficient direction*, and if the relative prices of the two regions was switched in the real-time market and the flow was reduced to 80 MW, the adjustment would be shown as -20 MW and the real-time schedule adjustment would be considered *efficient direction* as well.

Table A-10: Efficiency of Inter-Market Scheduling
Over Primary Interfaces and Scheduled Lines – 2015

	Day-Ahead Market				Adjustment in Real-Time			
	Average Net Imports (MW/h)	Avg Internal Minus External Price ($/MWh)	Percent of Hours in Efficient Direction	Estimated Production Cost Savings (Million $)	Average Net Imports (MW/h)	Avg Internal Minus External Price ($/MWh)	Percent of Hours in Efficient Direction	Estimated Production Cost Savings (Million $)
Free-flowing Ties								
New England	-660	-$0.20	54%	$9	-4	$1.74	56%	$8
Ontario					947	$8.01	79%	$72
PJM	339	-$1.55	62%	-$1	-91	-$1.48	64%	$21
Controllable Ties								
1385 Line	74	$0.93	69%	$4	-32	$1.12	53%	$1
Cross Sound Cable	181	$3.70	76%	$9	-5	$1.67	66%	$0
Neptune	488	$7.22	83%	$34	-1	$7.35	56%	$1
HTP	43	-$1.29	59%	-$2	12	-$5.52	59%	-$1
Linden VFT	69	$2.44	71%	$7	-3	$2.88	58%	$1

Key Observations: Efficiency of Inter-Market Scheduling

- The distribution of price differences across New York's external interfaces indicates that the current process does not maximize the utilization of the interfaces.
  - While the price differences are relatively evenly distributed around $0, a substantial number of hours had price differences exceeding $20 per MWh for every interface.
    - For each interface shown, the price difference between New York and the adjacent control area exceeded $20 per MWh in 12 to 19 percent of unconstrained hours in 2015.
- Transactions scheduled by market participants flowed in the efficient (i.e., from the low-priced area to the high-price area) direction in more than half of the hours across all interfaces between New York and neighboring markets during 2015.
  - Transactions scheduled between Ontario and New York flowed in the efficient direction in nearly 80 percent of hours, significantly higher than on the free-flowing interfaces with PJM and New England.
    - As a result, a total of $72 million in production cost savings was achieved across the Ontario interface in 2015, higher than the combined savings of $37 million over the PJM and New England free-flowing ties.
    - This was partly due to the fact that the price on the New York side was higher by an average of nearly $8/MWh in 2015 (compared to an average of only $1.50 to $1.75/MWh across the PJM and New England interfaces).
    - In many hours, additional Ontario imports were limited by the transfer capability of the Ontario-to-New York interface, the congestion on the 230 kV system in the West Zone, and/or the relatively high charges assessed to export transactions ($3 to $4 per MWh in 2015).

- In the day-ahead market, the share hours scheduled in the efficient direction was higher over the controllable lines than over the free-flowing ties, reflecting generally less uncertainty in predicting price differences across these controllable lines in 2015.
- Real-time adjustments in flows were generally higher and more frequent across the free-flowing ties, since market participants generally responded to real-time price variations by increasing net flows into the higher-prices region across these ties.
  - A total of $29 million in real-time production cost savings was achieved in 2015 from the real-time adjustments over the PJM and New England free-flowing interfaces.
- Many of the real-time adjustments across the controllable tie lines resulted from curtailments or checkout failures of a day-ahead transaction rather than a firm's desire to schedule. Nonetheless, the resulting production cost increases were small overall because real-time adjustments were infrequent at these interfaces.

- Overall, there was a large share of hours when power flowed inefficiently from the higher-priced market to the lower-priced market. Even in hours when power is flowing in the efficient direction, the interface is rarely fully utilized.
  - These scheduling results indicate the difficulty of predicting changes in real-time market conditions, the lack of coordination among schedulers, and the other costs and risks that interfere with efficient interchange scheduling.

C. Intra-Hour Scheduling with Adjacent Control Areas

The NYISO has been working on several initiatives to improve the utilization of its interfaces with neighboring RTOs, including more frequent scheduling (i.e., 15-minute scheduling) and Coordinated Transaction Scheduling ("CTS"). By the end of 2015, 15-minute scheduling had been enabled at six interfaces and CTS had been implemented at all four interfaces with PJM and at the primary interface with New England. [263]

Figure A-65 to Figure A-70: Bidding Patterns at the 15-minute Scheduling Interfaces

The following analyses examine the pattern of transaction bids and offers across the interfaces that allow changes at the quarter-hours (i.e., at :15, :30, and :45 past each hour) in 2015. The figures show the average bid and offer quantities across these interfaces in each month of 2014 and 2015.

[263] On July 27, 2011, 15-minute scheduling was activated between New York and Hydro-Quebec across its primary interface (i.e., at the HQ-Chateauguay proxy bus). The NYISO activated 15-minute scheduling across: a) the primary interface (i.e., at the Keystone proxy bus) on June 27, 2012; b) the Neptune and Linden VFT scheduled line interfaces on October 30 and November 28, 2012; and c) the HTP Scheduled Line on June 3, 2013. CTS with PJM was activated on November 4, 2014. CTS on the primary interface with ISO New England was activated on December 15, 2015.

Bids and offers are grouped and shown in the following five categories: 1) hourly LBMP-based bids and offers that were priced between $0 and $300/MWh; 2) hourly LBMP-based bids and offers that were priced below$0/MWh or above $300/MWh; 3) 15-minute LBMP-based bids and offers that were priced between $0 and $300/MWh; 4) 15-minute LBMP-based bids and offers that were below $0/MWh or above $300/MWh; and 5) 15-minute CTS bids and offers. Positive MW values indicate transaction offers in the import direction and negative MW values indicate transaction bids in the export direction. The figure also compares these quantities between 2014 and 2015 on an annual basis. Bids and offers that are priced between $0 and $300/MWh are considered to be relatively price-sensitive, while bids and offers that are priced outside this range are deemed as price-insensitive in this analysis. However, CTS bids are not categorized as price-sensitive or price-insensitive here and will be examined in more detail in the next subsection.

Figure A-65: Transaction Bids and Offers at Primary HQ Interface
2014-2015

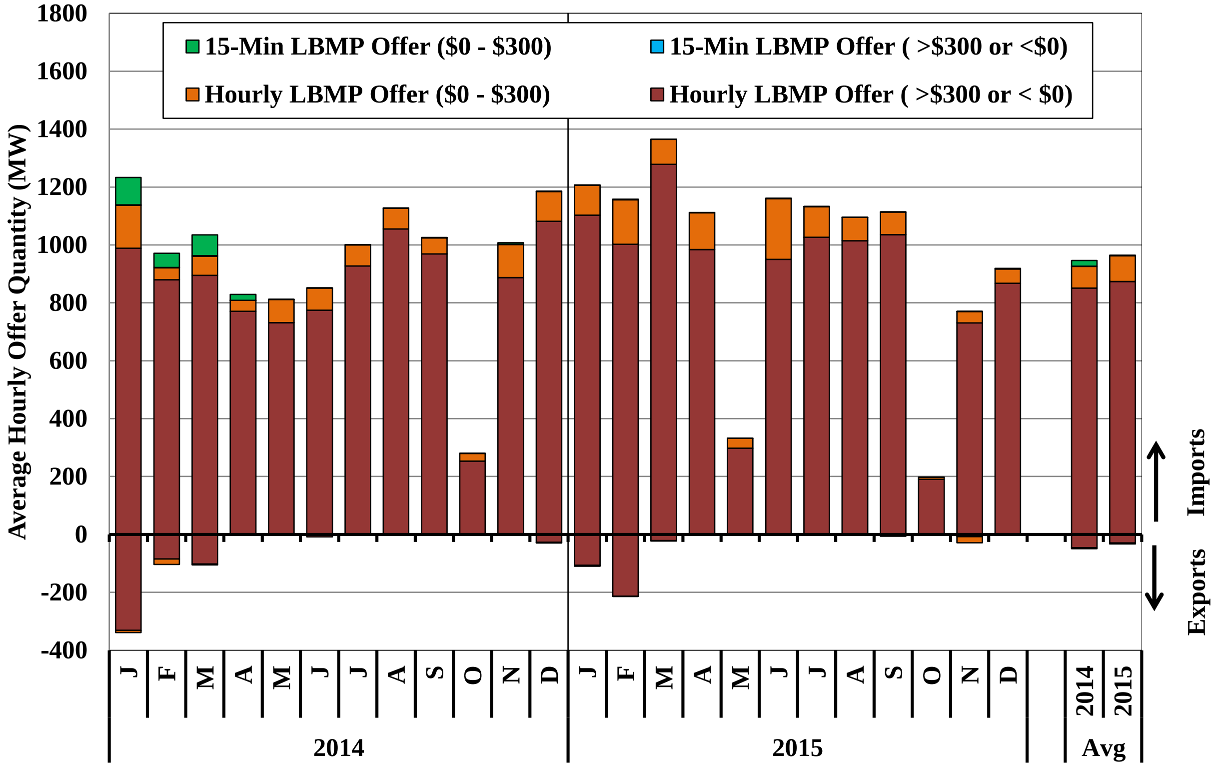


Figure A-66: Transaction Bids and Offers at Primary New England Interface
2014-2015

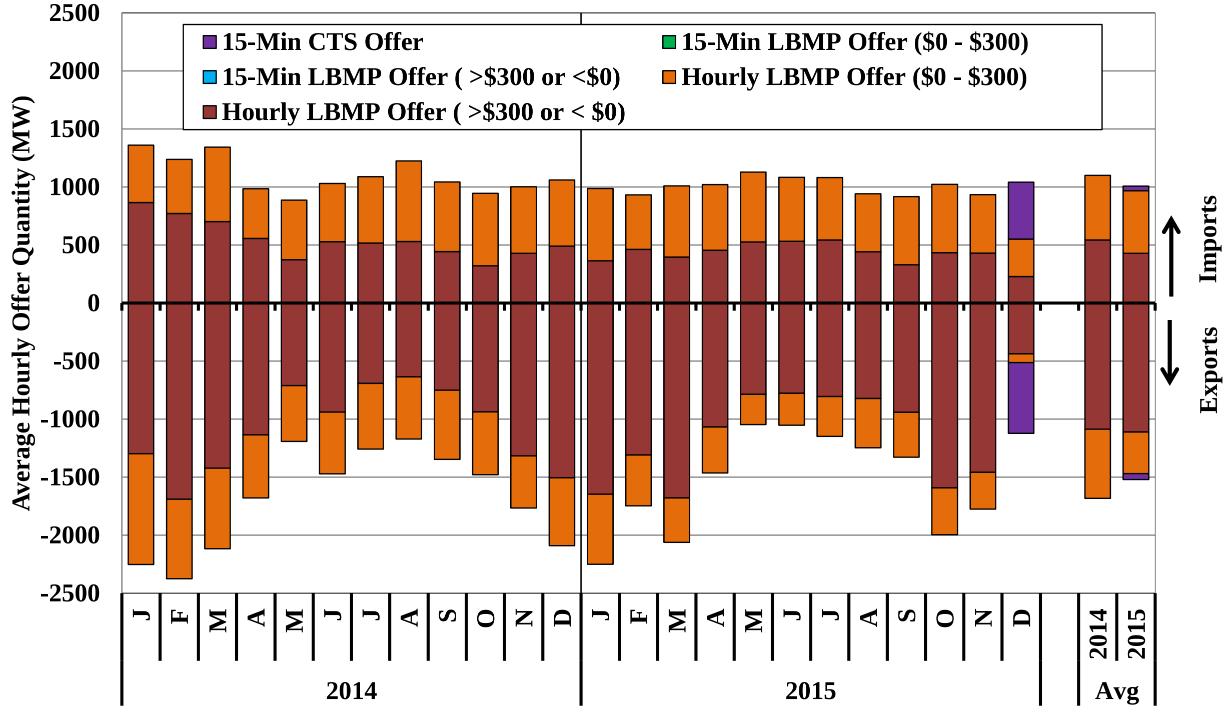


Figure A-67: Transaction Bids and Offers at Primary PJM Interface
2014-2015

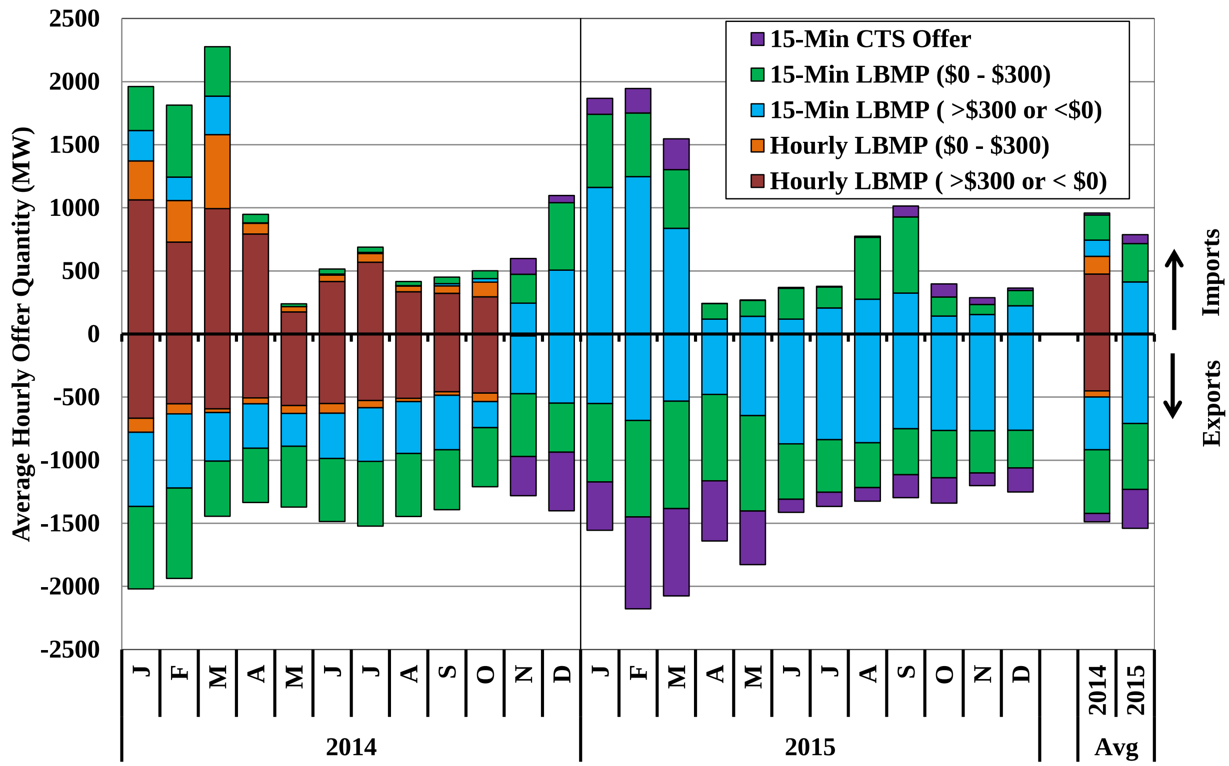


Figure A-68: Transaction Bids and Offers across Neptune Scheduled Line
2014-2015

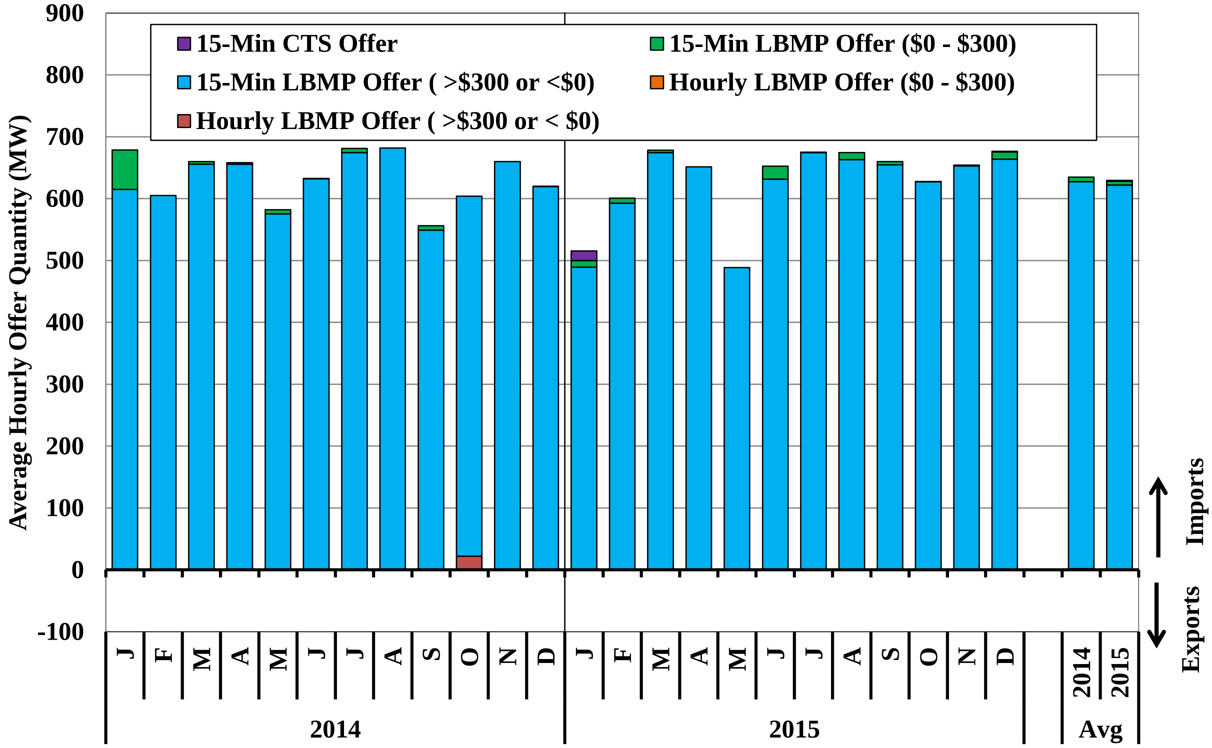


Figure A-69: Transaction Bids and Offers across HTP Scheduled Line
2014-2015

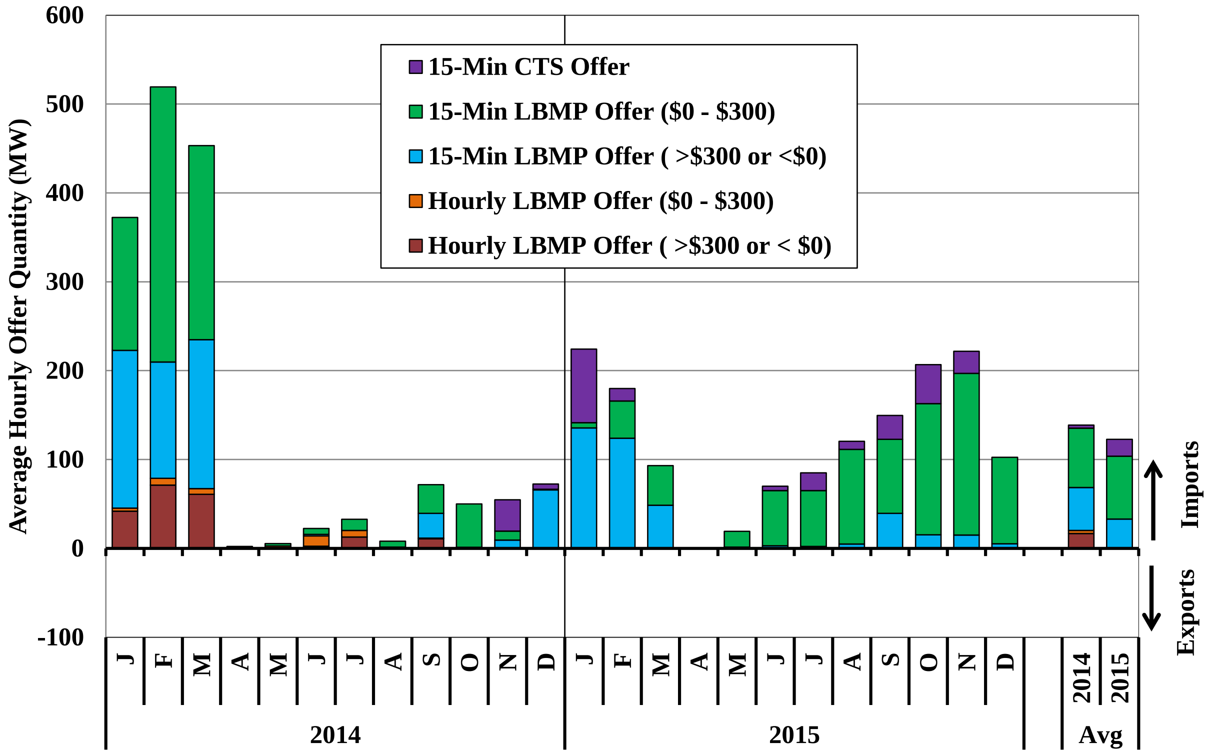
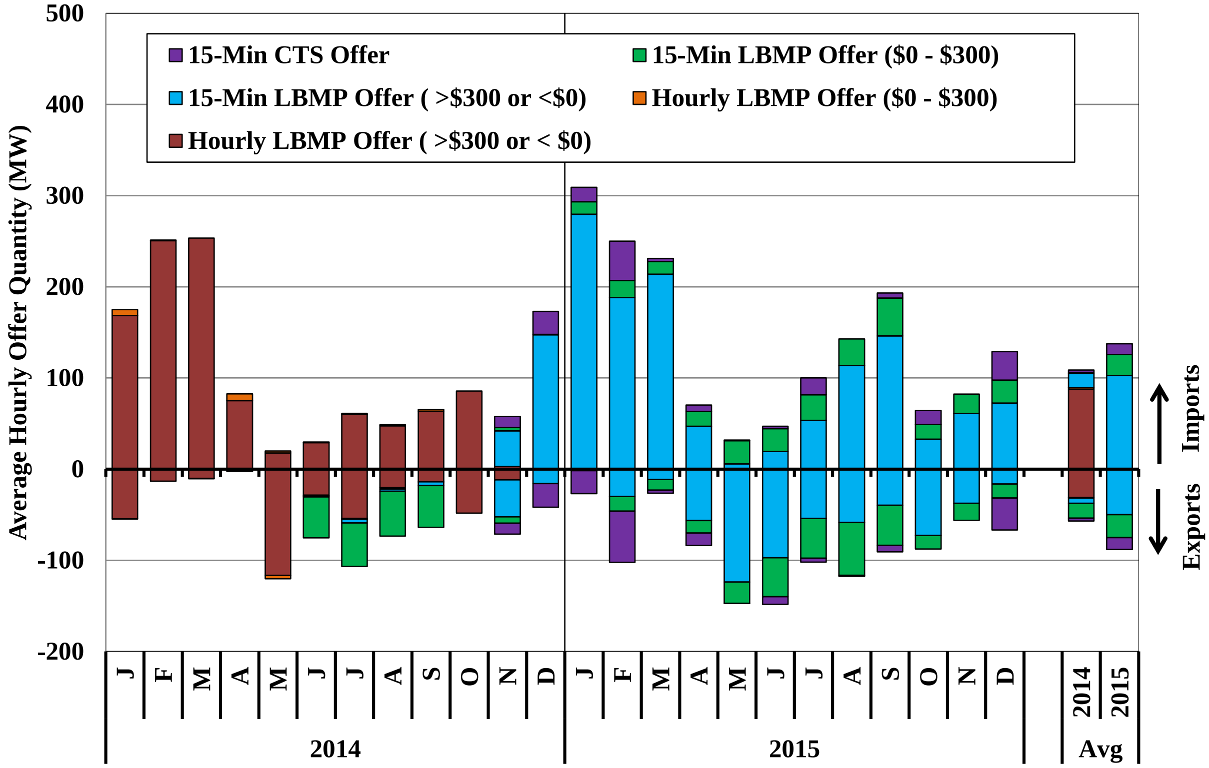


Figure A-70: Transaction Bids and Offers across Linden VFT Scheduled Line
2014-2015



Key Observations: Intra-Hour Scheduling with Adjacent Control Areas

- Intra-hour scheduling rarely occurred at the primary HQ interface as market participants rarely submitted offers for 15-minute scheduling.
  - This is largely because normal intra-hour variations of LBMPs on the New York side do not affect the economics of bringing power from Quebec to New York.
  - More flexible offers did appear when the system condition on the HQ side was very tight, such as in the first quarter of 2014.
- The Neptune interface was normally operated in a way that was consistent with its day-ahead schedules. Therefore, although nearly all of real-time offers were based on 15-minute scheduling, they were normally not offered at levels that differed from the day-ahead schedules (i.e., they were normally not price-sensitive).
- Intra-hour scheduling across the two controllable interfaces between New Jersey and New York City became more frequent in 2015 because of a higher amount of flexible bids (i.e., 15-minute and price-sensitive).
  - Nonetheless, the amount of flexible bids was still very limited, averaging roughly 75 MW at the Linden VFT interface and 90 MW at the HTP interface (including both imports and exports). In particular, the average amount of CTS bids was less than 25 MW at both interfaces.

  - Although the utilization of the HTP interface by market participants improved in 2015, the average amount of bids was still low compared to the total interface capability.

- The two primary interfaces with PJM and New England showed the largest amounts of flexible bids.
  - On average, more than 1,000 MW of bids (including both imports and exports) at each of two interfaces were relatively price-sensitive.
  - However, the amount of CTS bids at the primary PJM interface was still very limited, compared to the primary New England interface. This is discussed further in the next subsection.

D. Evaluation of Coordinated Transaction Scheduling

Coordination Transaction Scheduling ("CTS") is a novel market design concept whereby two wholesale 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 hourly LBMP-based scheduling system. First, CTS bids have greater potential to be scheduled accounting for changes in system conditions in the adjacent market compared with LBMP-based bids. Market participants must forecast market prices in the adjacent market (up to 135 minutes in advance) in order to formulate LBMP-based bids, while CTS bids are evaluated relative to the ISO's forecast of prices. Second, RTC is now able to schedule transactions much closer to operating time. Previously, hourly schedules were established almost one hour in advance, while schedules are now determined 30 minutes ahead when more accurate system information is available. Third, interface flows can be adjusted every 15 minutes instead of every 60 minutes, which allows for much quicker response to real-time events.

The CTS was first implemented with PJM on November 4, 2014 and then with ISO-NE on December 15, 2015. This subsection focuses on the performance of CTS with PJM, since it has been in operation longer than CTS with ISO-NE. The first two figures in this subsection evaluate CTS bidding patterns and measure the efficiency of the resulting interchange schedules. The last three figures in this subsection evaluate some of the assumptions used in RTC when it schedules transactions between NYISO and PJM.

Figure A-71: Bidding Patterns and Efficiency of CTS at the Primary PJM Interface

The following two analyses evaluate transaction scheduling since the implementation of CTS between NYISO and PJM in 2015. Given that most intra-hour scheduling occurred at the primary interface between New York and PJM, the analyses focus on the scheduling performance at this particular interface. The first analysis also evaluates CTS with ISO-NE during the first two-and-a-half months of operation.

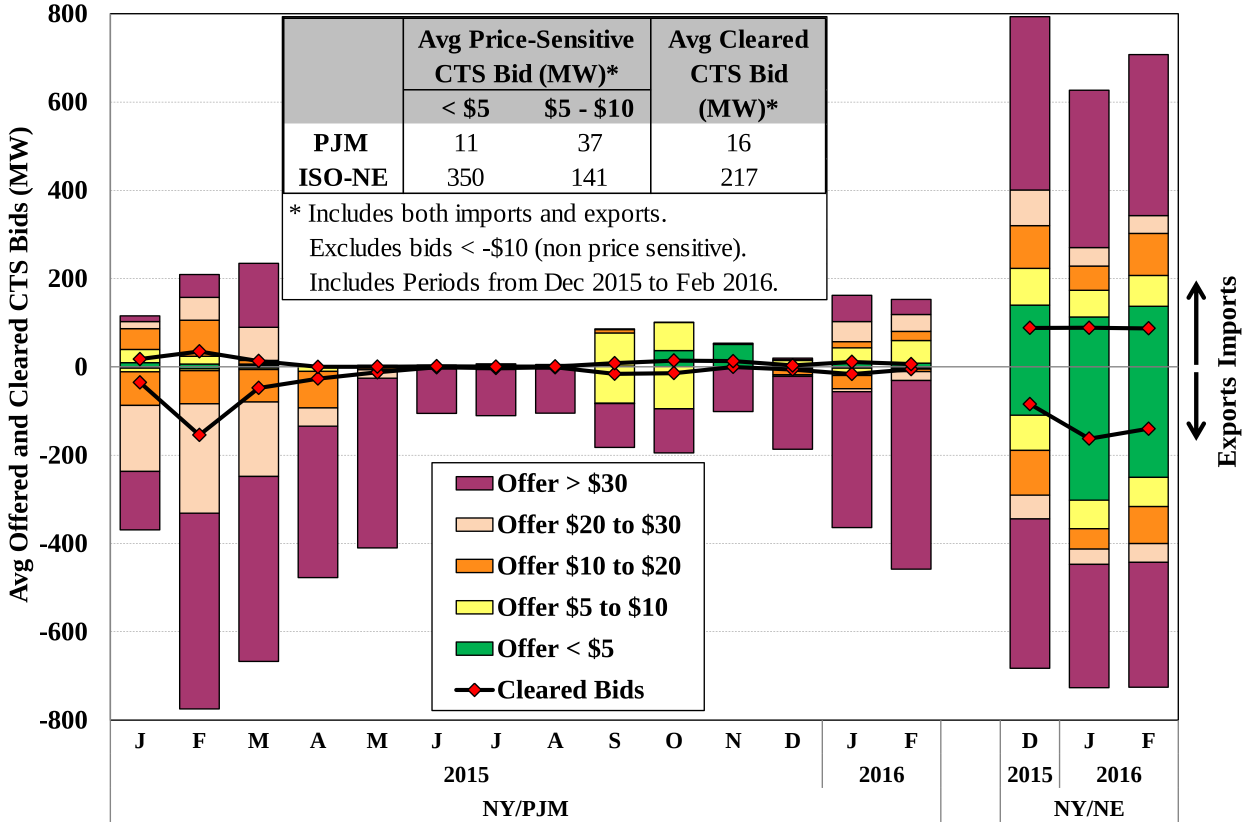
The first analysis examines the trading volumes of CTS transactions in 2015. In particular, Figure A-71 shows the average amount of CTS transactions at the primary PJM interface during peak hours (i.e., HB 7 to 22) by month from January 1, 2015 through the end of February 2016.

Positive numbers indicate import offers to New York and negative numbers represent export bids to PJM. Stacked bars show the average quantities of price-sensitive CTS bids (bids that are offered below -$10/MWh are considered price insensitive for this analysis) for the following five price ranges: (a) less than $5/MWh; (b) between $5 and $10/MWh; (c) between $10 and $20/MWh; (d) between $20 and $30/MWh; (e) more than $30/MWh. RTC evaluates whether to schedule a CTS bid to import assuming it has a cost equal to the sum of: (a) the bid and (b) PJM's forecast 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) PJM's forecast marginal price. The two black lines in the chart indicate the average scheduled price-sensitive CTS imports and exports in each month during the examined period.

For a comparison, the figure also shows these quantities for the primary New England interface during the first two and a half months following the activation of CTS on December 15, 2015. [264] The table in the figure summarizes for the two CTS-enabled interfaces: a) the average amount of CTS bids with low offer prices, which are either less than $5/MWh or between $5 and $10/MWh; and b) the average cleared CTS bids in the months of December 2015 to February 2016. Both imports and exports are included in these numbers.

264 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.

Figure A-71: Average CTS Transaction Bids and Offers by Month
PJM and NE Primary Interfaces



The second analysis evaluates the efficiency of the CTS-enabled intra-hour scheduling process (relative to an hourly scheduling mechanism) with PJM during 2015. To estimate the adjustment in the interchange schedule attributable to the new intra-hour scheduling process, it is first necessary to estimate a base interchange schedule that would have flowed if the intra-hour process was not in place. We estimate the base interchange schedule by calculating the average of the four advisory quarter-hour schedules during the hour for which RTC_{15} determined final schedules at each hourly-scheduling interface.[265]

Table A-11 examines the performance of the intra-hour scheduling process under CTS at the primary PJM interface. For each quarter of 2015, the table shows the following quantities:

265 RTC_{15} is the RTC run that posts the results by the time 15 minutes past each hour. The first interval of each RTC_{15} is ending at 30 minutes past each hour. For each hourly-scheduling interface, each RTC_{15} makes binding schedules for the second calendar hour in its two-and-a-half optimization period. For example, the first RTC_{15} of each day posts market results by 0:15 am; the first interval of its two-and-a-half optimization period is ending at 0:30 am; and it makes binding transaction schedules for all hourly-scheduling interfaces for the hour beginning at 1:00 am.

- % of All Intervals – This shows the percent of quarter-hour intervals in each quarter during which the interface flows were adjusted (relative to the base schedule) in the scheduling RTC interval.
- Average Flow Adjustment – This measures the difference between the base schedule and the final schedule. Positive numbers indicate flow adjustments in the import direction (i.e., from PJM to New York) and negative numbers indicate flow adjustments in the export direction (i.e., from New York to PJM).
- Production Cost Savings – This measures the market efficiency gains that resulted from the CTS-enabled intra-hour scheduling using LBMPs as an estimate of marginal production costs for both PJM and New York markets.
  - Projected Savings at Scheduling Time – This measures the expected production cost savings at the time when RTC determines the interchange schedule between PJM and New York across its primary interface.[266]
  - Unrealized Savings – This measures production cost savings that are not realized once the following factors are taken into account:
    - New York Forecast Error[267] - Transactions are scheduled based on forecast prices. If the forecast price deviates significantly from the actual price, transactions may be over-scheduled or under-scheduled and/or may not be scheduled in the efficient direction. This measures the portion of savings that are unrealized once price forecast errors on the New York side are considered.
    - PJM Forecast Error[268] - Similarly, this measures the portion of savings that are unrealized savings once price forecast errors on the PJM side are considered.
    - Real-time Curtailment[269] - 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.

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266 This is calculated as (final RTC schedule – base schedule)*(RTC price at the PJM proxy – PJM IT SCED price at the NYIS proxy). PJM IT SCED is the PJM price forecasting engine. An adjustment was also made to this estimate, which is described in Footnote 272.

267 This is calculated as (final RTC schedule – base schedule)*(RTD price – RTC price).

268 This is calculated as (final RTC schedule – base schedule)*(PJM IT SCED price – PJM RT price).

269 This is calculated as (final RTD schedule – final RTC schedule with ramping assumption at the top of quarter-hour interval)*(RTD price at the PJM proxy – PJM RT price at the NYIS proxy).

  - Interface Ramping[270] - RTD and RTC have different assumptions regarding interface schedule ramping. In RTD, interface flows start to ramp at 5 minutes before each quarter-hour interval and reach the target level at 5 minutes after. RTC assumes that the target flow level is reached at the top of the quarter-hour interval. Therefore, an inherent difference exists between RTD flows and RTC flows at the top of each quarter-hour interval, which will lead a portion of projected savings to be unrealized in real time.
- Actual Savings[271,272] – This is equal to (Projected Savings – Unrealized Savings).

- Interface Prices – These show actual prices (i.e., RTD prices and PJM RT prices) and forecasted prices at the time of RTC scheduling (i.e., RTC prices and PJM IT SCED 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.

270 This is calculated as (final RTC schedule with ramping assumption at the top of quarter-hour interval – final RTC schedule without ramping assumption)*(RTD price at the PJM proxy – PJM RT price at the NYIS proxy).

271 This is also calculated as (final RTD schedule – base schedule)*(RTD price at the PJM proxy – PJM RT price at the NYIS proxy) + an Adjustment (as described below).

272 The marginal cost of production is estimated from LBMPs that result from scheduling a transaction, but the marginal cost of production varies as the interface schedule is adjusted. For example, if 100 MW is scheduled to flow from PJM to NYISO, reducing the price spread between markets from $12/MWh to $5/MWh, our unadjusted production cost savings estimate from the transaction would be $500/hour (= 100 MW x $5/MWh). However, if the change in production costs was linear in this example, the true savings would be $850/hour (= 100 MW x Average of $5 and $12/MWh). We make a similar adjustment to our estimate of marginal cost of production assuming that: a) the supply curve was linear in both markets; and b) a 100 MW movement in the supply curve changes the marginal cost by 7.5 percent of NY LBMP in the New York market and 2.5 percent of PJM LBMP in the PJM market.

Table A-11: Efficiency of Intra-Hour Scheduling Under CTS
Primary PJM Interface, 2015

			Export (NY to PJM)				Import (PJM to NY)				Average/ Total
			Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	
% of All Intervals			40%	32%	30%	33%	44%	36%	40%	39%	**73%**
Average Flow Adjustment (MW)			-119	-77	-60	-59	122	74	65	64	**7 (Net) / 82 (Gross)**
Production Cost Savings ($ Million)	Projected at Scheduling Time		$4.78	$2.06	$0.59	$0.66	$2.15	$1.67	$1.29	$0.31	**$13.5**
	Unrealized Savings Due to:	NY Fcst. Err.	-$0.78	-$0.36	-$0.21	-$0.23	-$0.58	-$1.22	-$0.66	-$0.27	**-$4.3**
		PJM Fcst. Err.	-$2.19	-$1.59	-$0.42	-$0.38	-$2.24	$0.09	-$0.26	$0.00	**-$7.0**
		Other	-$0.34	-$0.02	-$0.04	-$0.03	-$0.16	-$0.05	-$0.03	-$0.02	**-$0.7**
	Actual		$1.47	$0.09	-$0.08	$0.03	-$0.83	$0.48	$0.34	$0.03	**$1.5**
Interface Prices ($/MWh)	NY	Actual	$62.06	$25.98	$28.33	$20.76	$58.84	$29.23	$33.35	$21.28	**$36.23**
		Forecast	$57.53	$22.59	$25.80	$17.42	$59.35	$35.50	$36.73	$22.48	**$36.07**
	PJM	Actual	$68.44	$28.08	$27.51	$22.00	$69.03	$27.31	$31.04	$21.75	**$38.41**
		Forecast	$74.13	$38.40	$34.98	$27.21	$56.11	$27.84	$30.60	$21.58	**$39.72**
Price Forecast Errors ($/MWh)	NY	Fcst. - Act.	-$4.54	-$3.40	-$2.53	-$3.34	$0.51	$6.27	$3.39	$1.21	**-$0.16**
		Abs. Val.	$15.45	$9.60	$6.75	$7.18	$15.57	$16.04	$14.56	$10.18	**$12.27**
	PJM	Fcst. - Act.	$5.69	$10.32	$7.46	$5.21	-$12.93	$0.53	-$0.45	-$0.18	**$1.31**
		Abs. Val.	$33.47	$16.84	$13.84	$10.33	$26.50	$8.60	$10.81	$6.86	**$16.36**

Figure A-72: Forecast Assumptions Used by RTC to Schedule CTS Transactions

RTC schedules gas turbines and external transactions shortly in advance of the 5-minute real-time market, so its assumptions regarding the load profile and the ramp profile of individual resources are important. The following analyses examine how the particular assumptions regarding the ramp profile of external transactions affect the accuracy of RTC's price forecasting. Figure A-72 provides an illustration of the ramp profiles that are assumed by RTC and RTD. The different ramp profiles lead to inconsistencies between RTC and RTD in the level of net imports, which contribute to differences between the RTC price forecast and actual 5-minute RTD clearing prices. These inconsistencies are evaluated in Figure A-73 and Figure A-74

Figure A-72 illustrates the ramp profiles that are assumed by RTC and RTD for external transactions. RTD's assumption is based on the actual scheduled interchange at the end of each 5-minute period. Transactions are assumed to move over a 10-minute period from one scheduling period to the next for both hourly and 15-minute interfaces. 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, RTC schedules transactions as if they reach their schedule at the top-of-the-hour or quarter-hour, which is five minutes earlier than RTD. Green arrows are used to show intervals when RTD imports exceed the assumption used in RTC. Red arrows are used to shown intervals when imports assumed in RTC exceed the RTD imports.

Figure A-72: Illustration of External Transaction Ramp Profiles in RTC and RTD

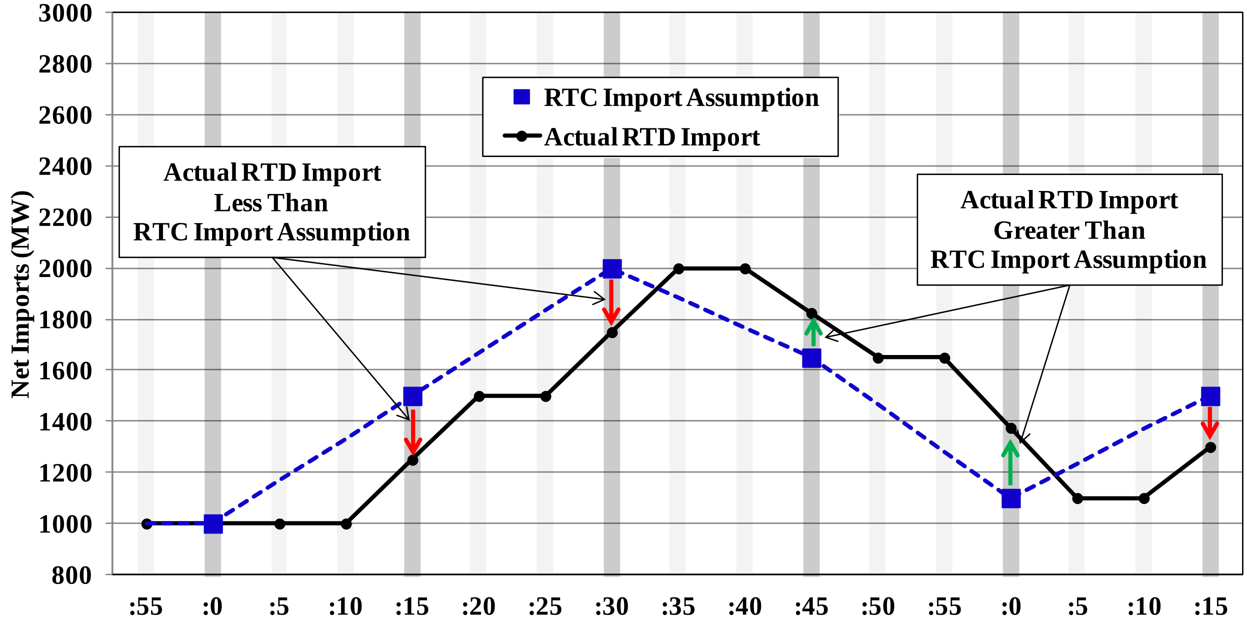


Figure A-73 shows a histogram of the resulting differences in 2015 between (a) the RTC assumed net interchange and (b) the actual net interchange reflected in RTD at the quarter-hour. For each tranche of the histogram, the figure summarizes the accuracy of the RTC price forecast by showing the average RTC LBMP minus the average RTD LBMP, the median of the RTC LBMP minus the RTD LBMP, and the mean absolute difference between the RTC and RTD LBMPs. LBMPs are shown at the NYISO Reference Bus location.

Figure A-73: Histogram of Differences Between RTC and RTD Prices and Schedules
2015

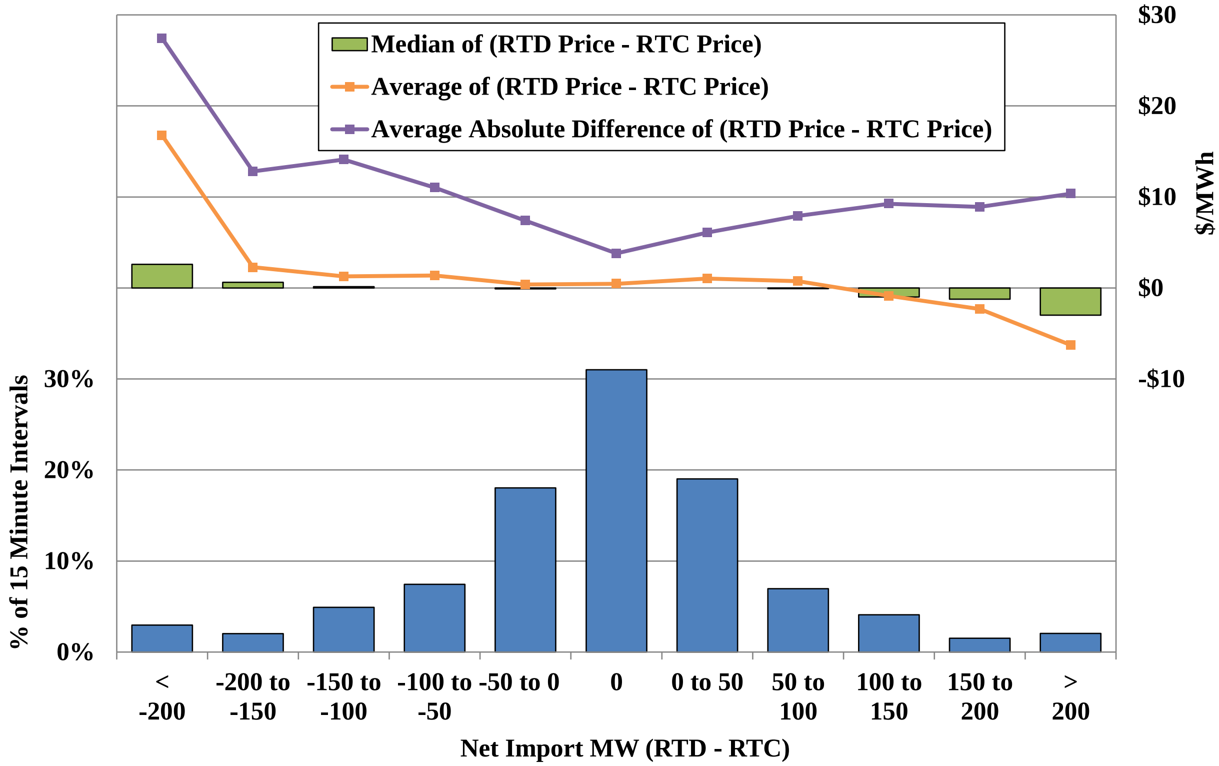
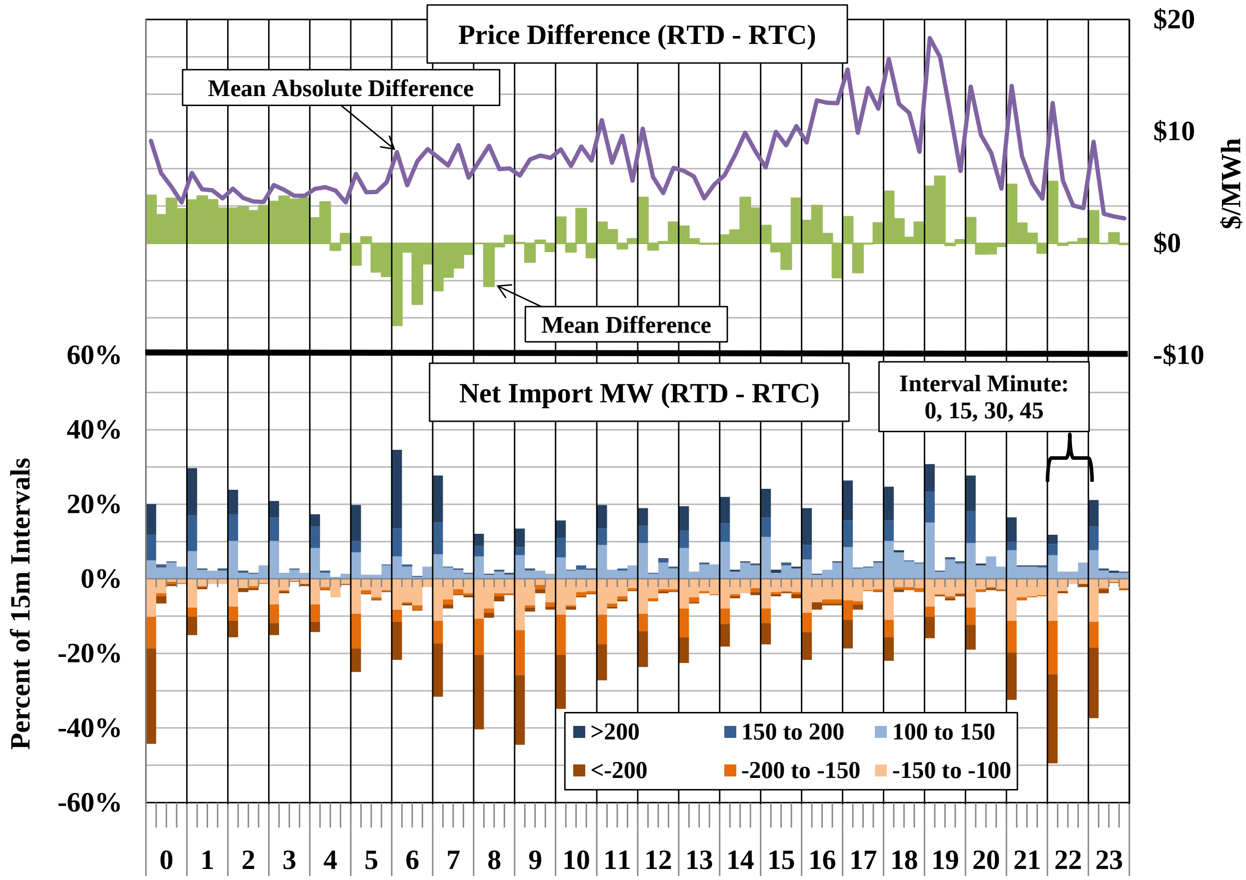


Figure A-74 summarizing these pricing and scheduling differences by time of day. The stacked bars in the lower portion of the figure show the frequency, direction, and magnitude of differences between RTC and RTD net import levels that exceed 100 MW by time of day, while the upper portion summarizes the accuracy of the RTC price forecast by showing the average RTD LBMP minus the average RTC LBMP and the mean absolute difference between the RTD and RTC LBMPs by time of day.

Figure A-74: Differences Between RTC and RTD Prices and Schedules by Time of Day
2015



Key Observations: CTS-enabled Intra-Hour Scheduling at the Primary PJM Interface

- In general, the amount of CTS bids submitted at the primary PJM interface was small relative to its size, and most of these CTS bids were submitted with substantial margins above $0.
  - During the examined period, an average of just 11 MW of CTS bids (including both imports and exports) were offered at less than $5/MWh and an average of 37 MW were offered between $5 and $10/MWh.
  - These were substantially lower than 350 MW and 141 MW offered in the same two price ranges at the primary New England interface.
- One factor that discourages external transactions and provides incentives for CTS bidders to increase their bid prices is that transactions that flow across the PJM interface must pay substantial transmission service charges ("TSCs") and fees to cover uplift charges.
  - The NYISO charges fees that typically average $3 to 5/MWh to firms that flow exports from New York to PJM. PJM charges fees that average $3 to $10/MWh to firms with "real-time deviations," which include imports and exports with a real-time schedule that is higher or lower than the day-ahead schedule.

  - These higher charges serve as an economic barrier to achieving potential benefits through the CTS process, as large and uncertain charges led participants to substantially increase their CTS offer prices at the PJM border and/or not submit offers if they do not expect meaningful profits.
- On the other hand, there are no transmission charges and little or no uplift charges in either direction on the CTS transactions between New York and New England.
  - Even though the CTS with ISO-NE is relatively new (liquidity tends to increase as participants gain experience), the quantity of offers have been much higher and the offer prices have been much lower.
- Most of the transactions that cleared on the ISO-NE border were offered at less than $5/MWh. Given that the PJM charges are uncertain and can often be expected to exceed $5/MWh, it is not surprising that almost no CTS transactions were offered at prices in this range.
  - This clearly demonstrates that imposing substantial charges on low-margin trading activity has a dramatic effect on the liquidity of the CTS process.
  - We believe much of this extremely large difference in the performance of the two CTS processes is explained by charges that are imposed on the CTS transactions at the PJM interface and therefore recommend to eliminate these charges.

- Our estimate of production cost savings tends to under-estimate actual savings for the following reason. The base schedules we use in our evaluation as an estimate of what would have been scheduled under the previous scheduling process are derived from actual 15-minute LBMP-based bids and CTS bids.
  - Although the base schedules are derived from an earlier run of RTC, they still make use of CTS bids and LBMP-based bids that are able to vary every 15 minutes, so the estimated base schedules may be more efficient than what would have actually occurred.
  - It is very difficult to assume a reasonable "but-for" base schedule under the hourly LBMP-based scheduling system for the purpose of evaluating efficiency gains.
- Our analyses show that sizable benefits (measured by production cost savings) were projected at the time of scheduling, but a relatively small portion was realized primarily because of price forecast errors in both markets.
  - In 2015, a total of $13.5 million in production cost savings was estimated at the time when RTC determined final schedules. However, price forecast errors on:
    - The New York side accounted for $4.3 million of unrealized projected savings;
    - The PJM side accounted for $7 million of additional unrealized projected savings.
  - On the New York side, forecast errors generally increased during periods of real-time congestion, particularly in the West Zone where congestion prices were highly volatile. On the PJM side, forecast errors became smaller after the first several months of CTS implementation.

   - Although not shown in this report, our analyses observed similar patterns at the other three smaller interfaces between PJM and New York (i.e., Neptune, Linden VFT, and HTP).

- Our evaluation of RTC price forecast error suggests that inconsistencies in the ramp assumptions used in RTC and RTD contribute to forecasting errors on the NYISO side of the interface.
   - RTC-assumed net imports exceeded RTD net imports by 100 MW or more in 10 percent of the quarter-hours during the period. At these times, the RTD price exceeded the RTC price by an average of $6.10/MWh and the mean absolute difference was $17.85/MWh.
   - RTD net imports exceeded RTC-assumed net imports by 100 MW or more in 8 percent of the quarter-hours during the period. At these times, the RTD price was less than the RTC price by an average of $2.60/MWh and the mean absolute difference was $9.50/MWh.
   - When RTC-assumed net imports were within 100 MW of RTD net imports, the mean absolute difference between RTC and RTD prices was just $6.10/MWh.
   - Hence, RTC price forecasts are less accurate when the level of net imports changes by a large amount in response to market conditions, thereby reducing the efficiency gains from CTS.
- The foundation of CTS-enabled intra-hour scheduling is sound, but additional benefits to the market may be realized if enhancements are made to the process.
   - Improving the accuracy of the forecast assumptions by NYISO and PJM would lead to more efficient interchange scheduling.

V. Market Operations

The objective of the wholesale market is to coordinate resources efficiently to satisfy demand while maintaining reliability. The day-ahead market should commit the lowest-cost resources to meet expected conditions on the following day, and the real-time market should deploy the available resources efficiently. Clearing prices should be consistent with the costs of deploying resources to satisfy demand while maintaining reliability. Under shortage conditions, the real-time market should provide incentives for resources to help the NYISO maintain reliability and set clearing prices that reflect the shortage of resources.

The operation of the real-time market plays a critical role in the efficiency of the market outcomes because changes in operations can have large effects on wholesale market outcomes and costs. Efficient real-time price signals are beneficial because they encourage competitive conduct by suppliers, participation by demand response, and investment in new resources and transmission where they are most valuable.

In this section, we evaluate the following aspects of wholesale market operations in 2015:

- *Efficiency of Gas Turbine Commitment* – This sub-section evaluates the consistency of real-time pricing with real-time gas turbine commitment and dispatch decisions.
- *M2M Coordination* – This sub-section evaluates real-time flows across the Ramapo PAR-controlled lines under market-to-market coordination ("M2M") between PJM and the NYISO.
- *Operation of Controllable Lines* – This sub-section evaluates the efficiency of real-time flows across controllable lines.
- *Real-Time Price Volatility* – This sub-section evaluates the factors that lead to both cyclical and transient price volatility in the real-time market.
- *Pricing Under Shortage Conditions* – Efficient operations better enable the existing resources to satisfy demand and maintain reliability under peak demand conditions, and they provide efficient signals for investment. We evaluate three types of shortage conditions: (a) shortages of operating reserves and regulation, (b) transmission shortages, and (c) shortages of operating reserves when gas-fired generators are subject to Operational Flow Orders ("OFOs").
- *Supplemental Commitment for Reliability* – Supplemental commitments are necessary when the market does not provide incentives for suppliers to satisfy certain reliability requirements. However, supplemental commitments raise concerns because they indicate the market does not provide sufficient incentives, they dampen market signals, and they lead to uplift charges.
- *Out-of-Merit Dispatch* – Out-of-merit ("OOM") dispatch is necessary to maintain reliability when the real-time market does not provide incentives for suppliers to satisfy certain reliability requirements or constraints. Like supplemental commitment, OOM dispatch may indicate the market does not provide efficient incentives.

- *BPCG Uplift Charges* – This sub-section evaluates BPCG uplift charges resulted primarily from supplemental commitment and out-of-merit dispatch.

A. Efficiency of Gas Turbine Commitments

The ISO schedules resources to provide energy and ancillary services using two models in real-time. First, the Real Time Dispatch model ("RTD") usually executes every five minutes, deploying resources that are flexible enough to adjust their output every five minutes. RTD also starts quick-start gas turbines when it is economic to do so.[273] RTD models the dispatch across roughly a one-hour time horizon (rather than just the next five minutes), which better enables it to determine when a gas turbine will be economic to start or when a generator should begin ramping in anticipation of a constraint in a future interval.

Second, the Real Time Commitment model ("RTC") executes every 15 minutes, looking across a two-and-a-half hour time horizon. RTC is primarily responsible for scheduling resources that are not flexible enough to be dispatched by RTD. RTC starts-up and shuts-down quick-start gas turbines and 30-minute gas turbines when it is economic to do so.[274] RTC also schedules bids and offers for the subsequent hour to export, import, and wheel-through power to and from other control areas.

The scheduling of energy and ancillary services is co-optimized, which is beneficial for several reasons. First, co-optimization reduces production costs by efficiently reallocating resources to provide energy and ancillary services every five minutes. Second, the market models are able to incorporate the costs of maintaining ancillary services into the price of energy by co-optimizing energy and ancillary services. This is important during periods of acute scarcity when the demand for energy and the ancillary services requirements compete for supply. Third, demand curves rationalize the pricing of energy and ancillary services during shortage periods by establishing a limit on the costs that can be incurred to maintain reserves and regulation. This also provides an efficient means of setting prices during shortage conditions. The use of demand curves during shortage conditions is discussed further in Section I.

Convergence between RTC and RTD is important because a lack of convergence can result in uneconomic commitment of generation, particularly of gas turbines, and inefficient scheduling of external transactions. When RTC commits or schedules excess resources, it leads to depressed real-time prices and increased uplift costs. Alternatively, when RTC commits insufficient resources, it leads to unnecessary scarcity and price spikes. This section evaluates the efficiency of real-time commitment and scheduling of gas turbines.

273 Quick-start GTs can start quickly enough to provide 10-minute non-synchronous reserves.

274 30-minute GTs can start quickly enough to provide 30-minute non-synchronous reserves, but not quickly enough to provide 10-minute reserves.

Figure A-75 – Figure A-76: Efficiency of Gas Turbine Commitment

Figure A-75 measures the efficiency of gas turbine commitment by comparing the offer price (energy plus start-up costs amortized over the commitment period) to the real-time LBMP over the unit's initial commitment period. When these decisions are efficient, the offer price components of committed gas turbines are usually lower than the real-time LBMP. However, when a gas turbine that is committed efficiently is close to the margin, it is possible for the offer price components to be greater than the LBMP. Thus, the following analysis tends to understate the fraction of decisions that were economic.

Figure A-75 shows the average quantity of gas turbine capacity started each day in 2015. These are broken into the following categories according to the sum of the offer price components and the real-time LBMP over the initial commitment period:

- Offer < LBMP (these commitments were clearly economic);
- Offer > LBMP by up to 25 percent;
- Offer > LBMP by 25 to 50 percent; and
- Offer > LBMP by more than 50 percent.

Gas turbines with offers greater than the LBMP can be economic for several reasons. First, gas turbines that are started efficiently and that set the LBMP at their location do not earn additional revenues needed to recover their start-up offer. Second, gas turbines that are started efficiently to address a transient shortage (e.g. transmission constraint violation lasting less than one hour) may lower LBMPs and appear uneconomic over the commitment period. Third, gas turbines that are economic sometimes do not set the LBMP and, thus, appear to be uneconomic, which is evaluated in Figure A-76.

Starts are shown separately for quick start gas turbines, older 30-minute gas turbines, and new 30-minute gas turbines. Starts are also shown separately for New York City and Long Island, and based on whether they were started by RTC, RTD, RTD-CAM,[275] or by an out-of-merit (OOM) instruction.

The real-time market software uses a three-pass mechanism for the purpose of dispatching and pricing. The first pass is a physical dispatch pass, which produces physically feasible base points that are sent to all resources. In this pass, the inflexibility of the gas turbines are modeled accurately with most of these units being "block loaded" at their maximum output levels once turned on. The second pass is a hybrid dispatch pass, which treats gas turbines as flexible resources that can be dispatched between zero and the maximum output level. The third pass is a pricing pass, which produces LBMPs for the market interval. gas turbines that are not economic (i.e., dispatched at zero) in the hybrid pass, but are still within their minimum run times, are forced on and dispatched at the maximum output level in the pricing pass. Consequently, when

275 The Real-Time Dispatch – Corrective Action Mode (RTD-CAM) is version of RTD that NYISO operators can run on-demand to address abnormal or unexpected system conditions.

uneconomic gas turbines are forced on in the pricing pass, it may lead some economic gas turbines to not set the LBMP in the pricing pass.

Figure A-75: Efficiency of Gas Turbine Commitment
2015

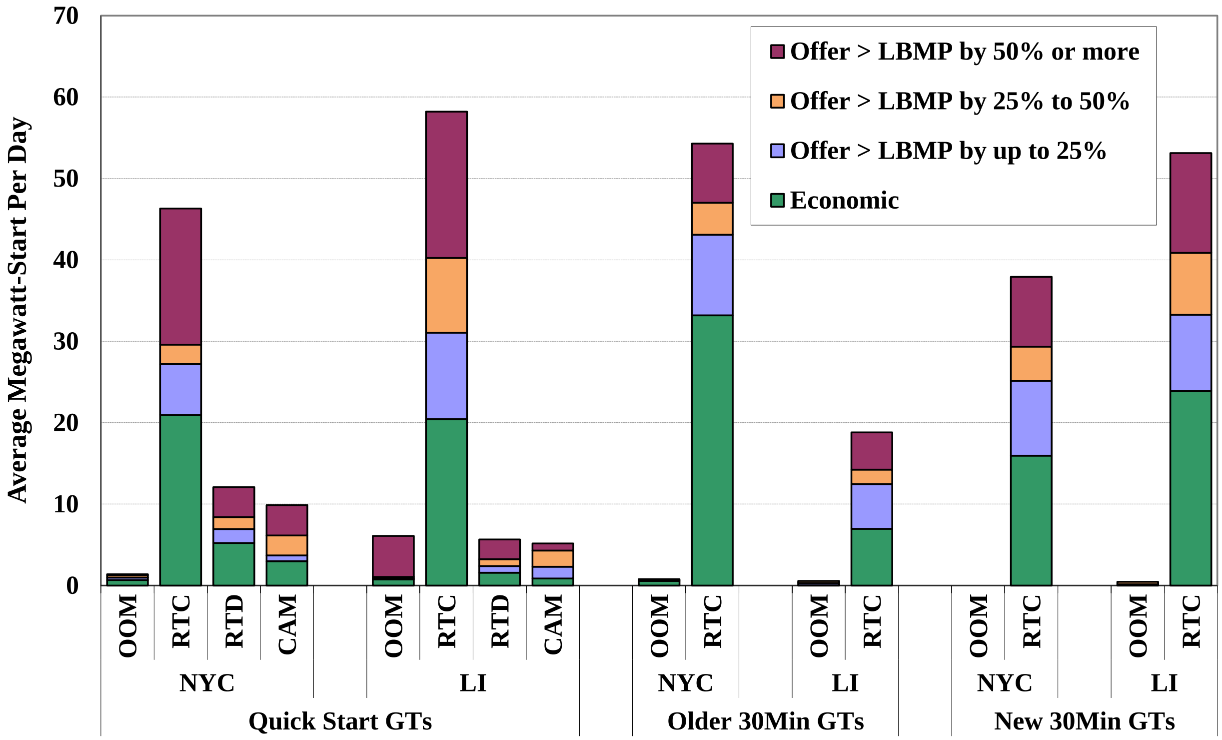


Figure A-76 evaluates the extent to which gas turbines were economic but appeared to be uneconomic because they did not set the LBMP during a portion of the initial commitment period. In particular, we examine every market interval in the initial commitment period of a gas turbine start, which excludes starts via OOM, and report the following seven quantities:

- *Number of Starts* – Excludes self-scheduled and local reliability units.
- *Percent Receiving RT BPCG Payment on that Day* – Share of gas turbine commitments that occurred on days when the unit received a RT BPCG payment for the day.
- *Percent of Unit-Intervals Uneconomic* – Share of intervals during the initial commitment period when the unit was displacing less expensive capacity.
- *Percent of Unit-Intervals Economic AND Non-Price Setting* – Share of intervals during the initial commitment period when the unit was displacing more expensive capacity, but not setting the RT LBMP.
- *Estimated Average LBMP Adjustment During Starts* – Average upward adjustment in LBMPs during starts if economic gas turbines always set the RT LBMP.
- *Percent of Starts Uneconomic (Offer > Average Adjusted LBMP)* – Share of starts when gas turbine's offer was greater than the average "Adjusted LBMP" over the initial

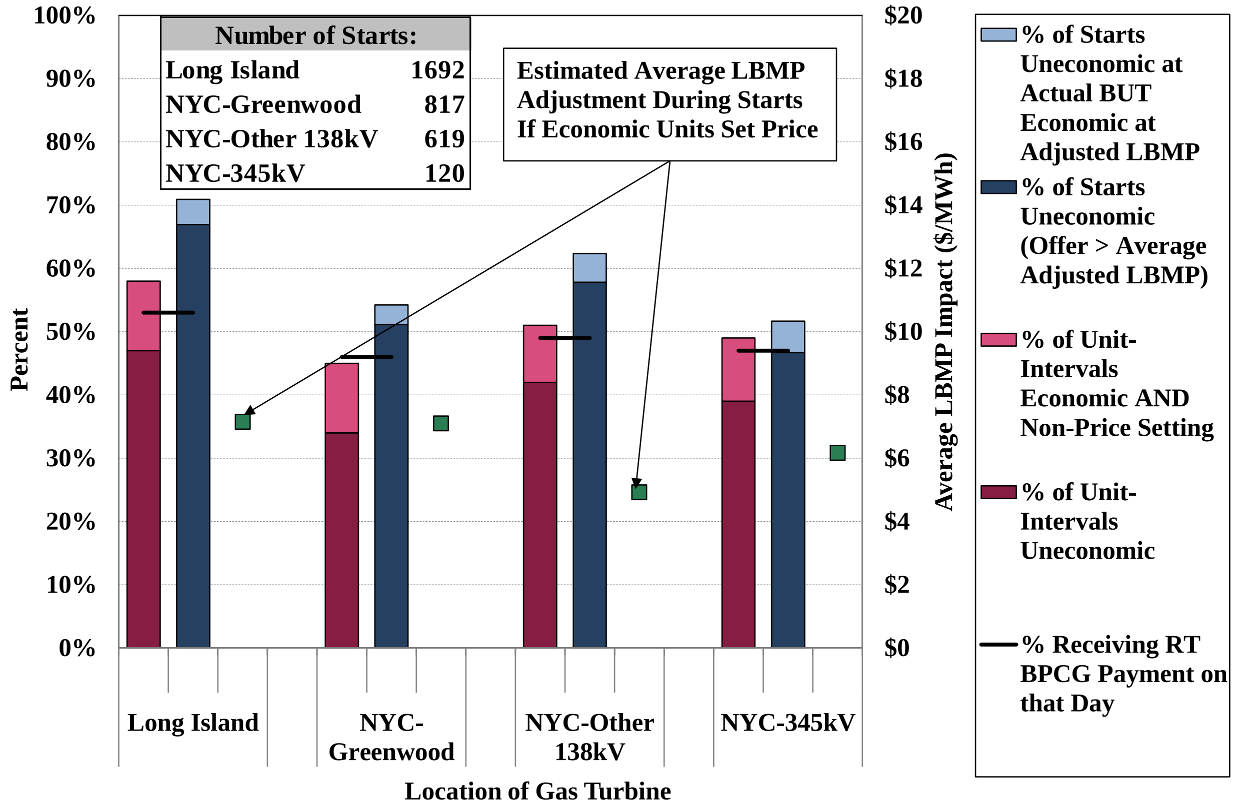
commitment period. (The "Adjusted LBMP" is the price that would have been set if economic gas turbines at the same market location always set the RT LBMP).

- *Percent of Starts Uneconomic at Actual BUT Economic at Adjusted LBMP* – Share of starts when gas turbine's offer was (a) greater than the average actual LBMP but (b) less than the average Adjusted LBMP over the initial commitment period.

These quantities are shown separately for gas turbines in four areas: (a) Long Island, (b) the areas outside the 138kV load pocket in New York City (i.e., the In-City 345kV region), (c) the Greenwood load pocket in New York City (which is part of the In-City 138kV load pocket), and (d) other areas inside the 138kV load pocket in New York City.

Figure A-76: Hybrid Pricing and Efficiency of Gas Turbine Commitment

2015



Key Observations: Efficiency of Gas Turbine Commitment

- Of the gas turbine capacity that was started during 2015, 86 percent was committed by RTC, 11 percent by RTD and RTD-CAM, and the remaining 3 percent through OOM instructions.
  - RTC commitments rose modestly from 2014 to 2015 because of increased congestion in the Greenwood load pocket of New York City, where only 30-minute GTs are available for effective congestion relief.
- The overall efficiency of gas turbine commitments was consistent with recent years.

  - Forty-three percent of all gas turbine commitments were clearly economic in 2015.
  - An additional 18 percent of all gas turbine commitments were cases when the gas turbine offer was within 125 percent of LBMP in 2015.
  - Hence, the NYISO's real-time market models are relatively effective in committing gas turbines efficiently.
- Gas turbine capacity was started more frequently in 2015, reflecting increased needs for such capacity to manage congestion and/or satisfy reserve requirements in real time.
  - From 2014 to 2015, the frequency of starts rose roughly 18 percent in New York City and 8 percent in Long Island.
  - The increases were attributable to more frequent peaking conditions and more frequent congestion on Long Island and in the Greenwood load pocket of New York City (for reasons discussed in Section I-B).
- Once committed, gas turbines were economic in 58 percent of the five-minute intervals during their initial one-hour commitment period (excluding self-schedules and local reliability commitments) in 2015. (We consider gas turbines to be economic when their output is displacing output from more expensive resources).
  - However, economic gas turbines do not always set the real-time LBMP. In 2015, economic gas turbines did not set LBMP in 9 to 11 percent of intervals during their initial commitment period. This is partly due to the effects of NYISO's Hybrid Pricing methodology in the real-time market.
  - We estimate that allowing these economic gas turbines to set prices would have increased the LBMPs by an average of \$5 to \$7 per MWh for each start in New York City and Long Island in 2015. This would increase annual average LBMPs by an average of \$0.35 to \$1.40 per MWh with the largest effect in Long Island.
    - The higher LBMPs would be more reflective of the costs of satisfying demand, security, and reliability requirements in the real-time market.
    - Higher LBMPs would increase energy net revenues for resources that are frequently scheduled during relatively tight conditions when gas turbines are needed to serve load and manage congestion. This would reduce dependence on the installed capacity market to retain flexible resources.
    - However, the analysis under-estimates the effects of allowing gas turbines to set the real-time LBMP in intervals when they are economic because it assumes that the real-time LBMP impact is limited to nodes in the same area (out of the four areas shown) that have similar LBMP congestion component. In fact, the LBMPs over a wider area can be affected, depending on congestion.
  - These results suggest that the hybrid pricing logic should be evaluating to identify changes that would more effectively allow economic gas turbines to set prices in the real-time markets.

B. Market-to-Market Coordination with PJM

Coordinated congestion management between NYISO and PJM ("M2M") commenced in January 2013. This process allows each RTO to more efficiently relieve congestion on its constraints with re-dispatch from the other RTO's resources when it is less costly for them to do so.[276] M2M includes two types of coordination:

- Re-dispatch Coordination – If one of the pre-defined flowgates becomes congested in the monitoring RTO, the non-monitoring RTO will re-dispatch its generation to help manage congestion when economic.
- Ramapo PAR Coordination – If certain pre-defined flowgates become congested in one or both RTOs, the Ramapo PARs are adjusted to reduce overall congestion.

The NYISO and PJM have an established process for identifying constraints that will be on the list of pre-defined flowgates for Re-dispatch Coordination and Ramapo PAR Coordination.[277]

Figure A-77: M2M Coordination with PJM

The use of Re-dispatch Coordination was infrequent since inception, while the use of Ramapo PAR Coordination had far more significant impacts on the market. Hence, the following analyses focus on the operation of Ramapo PARs in 2015.

- Figure A-77 compares the actual flows on Ramapo PARs with their M2M operational targets in 2015. The M2M target flow has the following components:
- Share of PJM-NY Over Ramapo – Based on the share of PJM-NY flows that were assumed to flow across the Ramapo Line.[278]
- 80% RECo Load – 80 percent of telemetered Rockland Electric Company load.
- ABC & JK Wheel Deviations – The total flow deviations on the ABC and JK PAR-controlled lines from schedules under the ConEd-PSEG Wheeling agreement.[279]

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276 The terms of M2M coordination are set forth in NYISO OATT Section 35.23, which is Attachment CC Schedule D.

277 The list of pre-defined flowgates is posted at http://www.nyiso.com/public/webdocs/markets_operations/market_data/reports_info/CoordinatedFlowgatesandEntitlements.mht.

278 This assumed share is 61 percent when both Ramapo PARs are in service and 46 percent when one of the two PARs is out of service.

279 The ConEd-PSEG Wheeling Agreement ordinarily provides for 1,000 MW to be wheeled from NYISO Zone G ("Hudson Valley") across the J & K lines into the PSEG territory in New Jersey and back into NYISO Zone J ("New York City") across the A, B, & C lines. The operation of the ConEd-PSEG wheel is set forth in NYISO OATT Section 35.22, which is Schedule C to Attachment CC.

- JK Auto Correction Factor – The JK interface Auto Correction component of the JK interface real-time desired flow. This represents a "pay-back" MW generated from cumulative deviations on the JK interface from previous days. [280]
- ABC Auto Correction Factor - The ABC interface Auto Correction component of the ABC interface real-time desired flow. This represents a "pay-back" MW generated from cumulative deviations on the ABC interface from previous days. [281]

The figure shows these average quantities over intervals when M2M constraints for Ramapo Coordination were binding on a weekly basis. The weeks with less frequent binding M2M constraints (i.e., less than 20 hours) are highlighted.

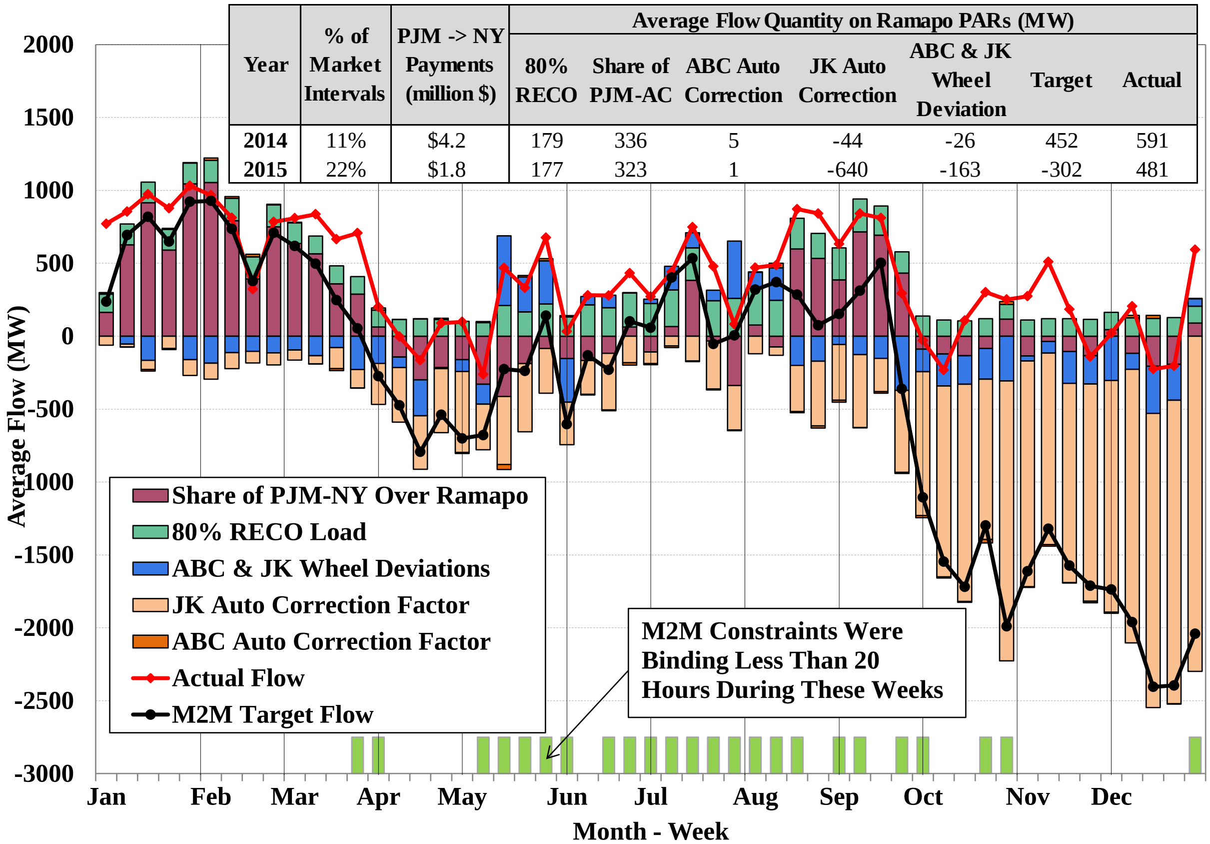
The table in the figure summarizes the percent of market intervals during which at least one M2M constraint was binding and the total payments from PJM to the NYISO under the M2M agreement in 2014 and 2015. In addition, the table compares the average amount of flows for each component described above for the two years.

280 See NYISO OATT Section 35.22, Attachment CC Schedule C Appendix 3 for detailed description of auto correction factors.

281 See NYISO OATT Section 35.22, Attachment CC Schedule C Appendix 3 for detailed description of auto correction factors.

Figure A-77: Actual and Target Flows for the Ramapo Line
During the Intervals with Binding M2M Constraints, 2015

Year	% of Market Intervals	PJM -> NY Payments (million $)	Average Flow Quantity on Ramapo PARs (MW)						
			80% RECO	Share of PJM-AC	ABC Auto Correction	JK Auto Correction	ABC & JK Wheel Deviation	Target	Actual
2014	11%	$4.2	179	336	5	-44	-26	452	591
2015	22%	$1.8	177	323	1	-640	-163	-302	481



Key Observations: M2M Coordination with PJM

- The use of Re-dispatch Coordination continued to be limited in 2015.
  - It was activated for the Central-East interface in a total of 378 hours and the Dysinger East interface in roughly 24 hours, resulting in a total payment of $237k from PJM to the NYISO.
- Active Ramapo Coordination (i.e., when M2M constraints were binding) occurred during 22 percent of intervals in 2015, up notably from 2014.
  - The increase was consistent with more frequent congestion on the M2M constraints (e.g., the Central-East interface and transmission paths from Capital to Hudson Valley) than from a year ago (for the reasons discussed in Section III-B).
- Average actual flows across Ramapo PARs were lower in 2015 than in 2014 (when M2M constraints were binding).
  - However, the net flows from PJM to New York delivered across the Ramapo, ABC, and JK PARs (which equals Actual Flow minus ABC & JK Wheel Deviation) were similar in the two years.

  - Power was under-delivered from New York to PJM across the JK interface by an average of 163 MW in 2015, compare to only 26 MW in 2014, offsetting the reduction in Ramapo flows.
- The cumulative negative deviations on the JK PARs have become large since April and reached thousands of MWs in the end of 2015.
  - This has greatly reduced the Target Flow across the Ramapo PARs, resulting in a reduction in M2M payments from PJM to New York from 2014 to 2015.
  - Ninety percent of total M2M payment occurred in the first quarter of 2015 when JK flow deviations were small.

- The operation of the Ramapo PARs under the M2M JOA with PJM has provided significant benefit to the NYISO in managing congestion on coordinated transmission flow gates, The balancing congestion surpluses that result from the operation of these PARs provide an indication of how real-time flow adjustments (relative to the day-ahead schedule) reduce production costs by managing congestion. On the other hand, balancing congestion shortfalls are an indication of PAR operations that increase production costs and congestion overall.
  - Additional flows (into New York) across the Ramapo, ABC, & JK PAR-controlled lines contributed an estimated $8 million of surpluses on the coordinated flow gates.
    - However, these were largely offset by shortfalls generated on the West Zone lines, which are currently not under M2M JOA (see Figure A-58).
  - After recognizing the effects of PAR operations on non-coordinated flow gates, the NYISO modified its operating practice in November 2015 to limit the use of Ramapo Coordination process to periods when the NYISO does not expect constraints in Western New York to be active. [282]

C. Operation of Controllable Lines

The majority of transmission lines that make up the bulk power system are not controllable, and thus, must be secured by redispatching generation in order to maintain flows below applicable limits. However, there are still a significant number of controllable transmission lines that source and/or sink in New York. This includes High Voltage Direct Current ("HVDC") transmission lines, Phase-Angle Regulator ("PAR") –controlled lines, and Variable Frequency Transformer ("VFT") –controlled lines. Controllable transmission lines allow power flows to be channeled along paths that lower the overall cost of satisfying the system's needs. Hence, they can provide greater benefits than conventional AC transmission lines.

Controllable transmission lines that source and/or sink in NYCA are scheduled in three ways. First, some controllable transmission lines are scheduled as external interfaces using external

282 See minutes from December 2015 Management Committee Meeting.

transaction scheduling procedures.[283] Such lines are analyzed in Section I of the Appendix, which evaluates external transaction scheduling. Second, "optimized" PAR-controlled lines are optimized in the sense that they are normally adjusted by the local TO in order to reduce generation redispatch (i.e., to minimize production costs) in the day-ahead and real-time markets. Third, "non-optimized" PAR-controlled lines are scheduled according to various operating procedures that are not primarily focused on reducing production costs in the day-ahead and real-time markets. This sub-section evaluates the use of non-optimized PAR-controlled lines.

Table A-12 and Figure A-78: Scheduling of Non-Optimized PAR-Controlled Lines

PARs are commonly used to control line flows on the bulk power system. Through control of tap positions, power flows on a PAR-controlled line can be changed in order to facilitate power transfer between regions or to manage congestion within and between control areas. This sub-section evaluates efficiency of PAR operations during 2015.

Table A-12 evaluates the consistency of the direction of power flows on non-optimized PAR-controlled lines and LBMP differences across these lines during 2015. The evaluation is done for the following eleven PAR-controlled lines:

- Two between IESO and NYISO: St. Lawrence – Moses PARs (L33 & L34 lines).
- One between ISO-NE and NYISO: Sand Bar – Plattsburgh PAR (PV20 line).
- Six between PJM and NYISO: Two Waldwick PAR-controlled lines (J & K lines), one Branchburg-Ramapo PAR-controlled line (5018 line), two Hudson-Farragut PARs (B & C lines), and one Linden-Goethals PAR (A line).
    - The 5018 line was scheduled in accordance with the M2M coordination agreement, which is discussed in Subsection B.
    - The A, B, C, J, & K lines support the operation of the ConEd-PSEG wheeling agreement whereby 1,000 MW is ordinarily scheduled to flow out of NYCA on the J & K lines and 1,000 MW is scheduled to flow into New York City on the A, B, & C lines.
- Two between Long Island and New York City: Lake Success-Jamaica PAR (903 line) and Valley Stream-Jamaica PAR (901 line).
    - The 901 & 903 lines are ordinarily scheduled to support a wheel of up to 300 MW from upstate New York through Long Island and into New York City.

For each group of PAR-controlled lines, Table A-12 shows:

- Average hourly net flows into NYCA or New York City;

283 This includes the Cross Sound Cable (an HVDC line), the Neptune Cable (an HVDC line), the HVDC line connecting NYCA to Quebec, the Dennison Scheduled Line (partly VFT-controlled), the 1385 Scheduled Line (PAR-controlled), and the Linden VFT Scheduled Line.

- Average price at the interconnection point in the NYCA or New York City minus the average price at the interconnection point in the adjacent area (the external control area or Long Island);
- The share of the hours when power was scheduled in the efficient direction (i.e., from the lower-price market to the higher-price market); and
- The estimated production cost savings that result from the flows across each line. The estimated production cost savings in each hour is based on the price difference across the line multiplied by the scheduled power flow across the line.[284]

This analysis is shown separately for the portion of flows scheduled in the day-ahead market versus the portion that is from balancing adjustments in the real-time market.[285] For Ontario, the analysis assumes a day-ahead schedule of 0 MW since Ontario does not operate a day-ahead market. The vast majority of power is scheduled in the day-ahead market, while small balancing adjustments are typically made in the real-time market.

284 For example, if 100 MW flows from Lake Success to Jamaica during one hour, the price at Lake Success is $50 per MWh, and the price at Jamaica is $60 per MWh, then the estimated production cost savings is $1,000 (=100 * $10). This is because each MW of flow saves $10 by allowing a $60 per MWh resource in New York City to ramp down and be replaced by a $50 per MWh resource in Long Island. This method of calculating production cost savings tends to under-estimate the actual production cost savings when power flows from the low-priced region to the high-priced region, since if flows in the efficient direction were reduced, the cost of the marginal resource in the importing region would rise while the cost of the marginal resource in the exporting region would fall. However, this method of calculating production cost savings tends to over-estimate the actual production cost increases when power flows from towards the low-priced region, since if flows were reduced, the cost differential between the marginal resources in each region would converge.

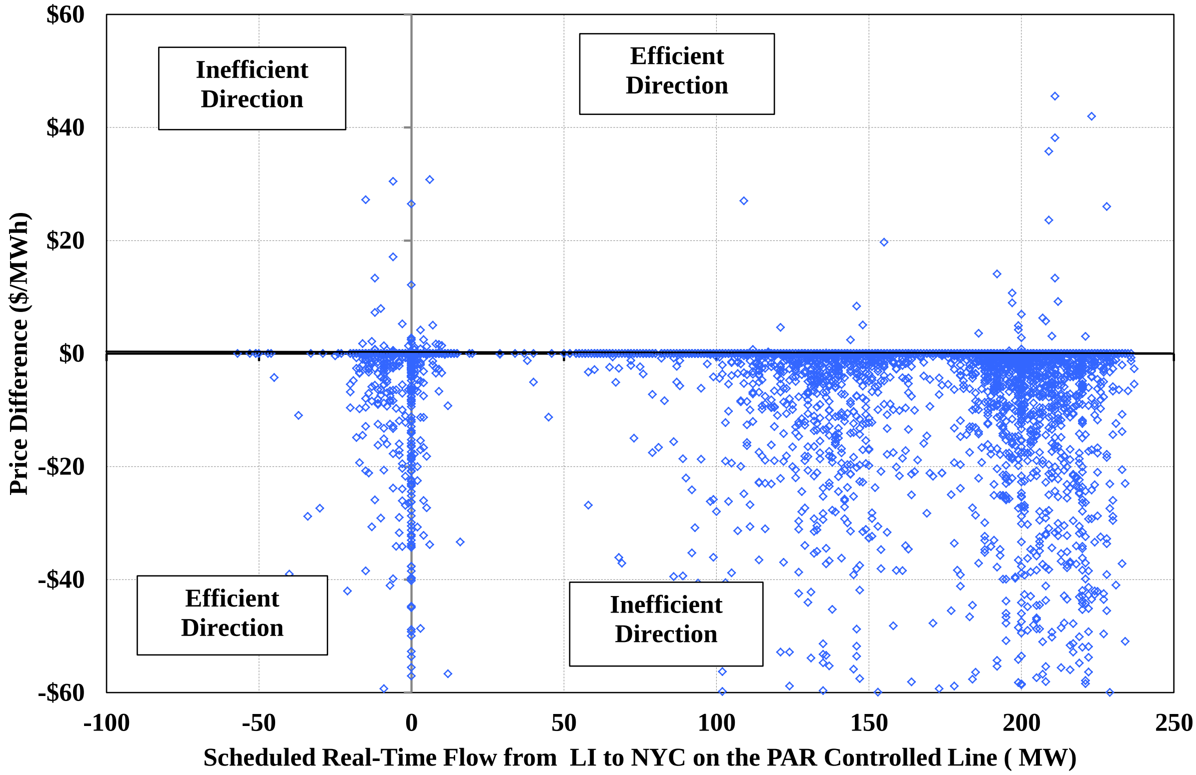
285 For example, if 100 MW is scheduled from the low-priced region to the high-priced region in the day-ahead market, the day-ahead schedule would be considered *efficient direction*, and if the relative prices of the two regions was switched in the real-time market and the flow was reduced to 80 MW, the adjustment would be shown as -20 MW and the real-time schedule adjustment would be considered *efficient direction* as well.

Table A-12: Efficiency of Scheduling on Non-Optimized PAR Controlled Lines
2015

	Day-Ahead Market Schedule				Adjustment in Real-Time			
	Avg Flow (MW/h)	Avg NYCA Price minus Avg Outside Price ($/MWh)	Percent of Hours in Efficient Direction	Estimated Production Cost Savings (Million $)	Avg Flow (MW/h)	Avg NYCA Price minus Avg Outside Price ($/MWh)	Percent of Hours in Efficient Direction	Estimated Production Cost Savings (Million $)
Ontario to NYCA								
St. Lawerence					**2**	**$7.16**	**56%**	**$4**
New England to NYCA								
Sand Bar	**-77**	**-$15.75**	**91%**	**$11**	**-1**	**-$14.89**	**53%**	**$1**
PJM to NYCA								
Waldwick	**-862**	**$2.47**	**39%**	**-$19**	**152**	**$1.98**	**52%**	**$1**
Ramapo	**196**	**$3.78**	**68%**	**$30**	**157**	**$4.35**	**50%**	**$6**
Farragut	**645**	**-$2.60**	**45%**	**-$15**	**-66**	**-$6.47**	**50%**	**$0**
Goethals	**224**	**$2.60**	**62%**	**$5**	**67**	**$3.08**	**50%**	**$1**
Long Island to NYC								
Lake Success	**145**	**-$8.20**	**1%**	**-$9**	**-9**	**-$8.47**	**70%**	**$1**
Valley Stream	**48**	**-$13.19**	**1%**	**-$6**	**4**	**-$16.71**	**34%**	**-$2**

Figure A-78 provides additional detail on the efficiency of scheduling for one of the lines in the table. The figure is a scatter plot of power flows versus price differences across the Lake Success-Jamaica line. The figure shows hourly price differences in the real-time market on the vertical axis versus power flows scheduled in the real-time market on the horizontal axis. Points in the top-right and bottom-left quadrants of the figure are characterized as scheduled in the efficient direction. Power scheduled in the efficient direction flows from the lower-priced market to the higher-priced market. Similarly, points in the top-left and bottom-right quadrants are characterized as scheduled in the inefficient direction, corresponding to power flowing from the higher-priced market to the lower-priced market. Good market performance would be indicated by a large share of hours scheduled in the efficient direction.

Figure A-78: Efficiency of Scheduling on PAR Controlled Lines
Lake Success-Jamaica Line –2015



Key Observations: Efficiency of Scheduling over PAR-Controlled Lines

- In the day-ahead market, the scheduling of PAR-controlled lines that are used to support contractual wheeling agreements was less efficient than other PAR-controlled lines.
  - Under the ConEd-PSEG wheeling agreement, the Waldwick lines are used to wheel power (up to 1000 MW) from Hudson Valley to PJM, and then the Goethals/Farragut lines are used to wheel power back from PJM to New York City. In 2015,
    - Power flowed in the inefficient direction in 61 percent of hours across the Waldwick lines and in 55 percent of hours across the Farragut lines.
    - The prices on the sending side were higher than on the receiving side by an average of $2.47/MWh across the Waldwick lines and an average of $2.60/MWh across the Farragut lines.
    - These led to an estimated net *increase* of $29 million in day-ahead production costs (an increase of $34 million accrued on the Waldwick and Farragut lines, offset by a reduction of $5 million accrued on the Goethals line). [286]

286 For the reasons noted in Footnote 261, this method of estimating production cost savings tends to over-estimate the costs from inefficient scheduling.

- Under the ConEd-LIPA wheeling agreement, the 901/903 lines are used to wheel roughly half of the power flowed on the Y50 line (from upstate to Long Island) back to New York City. In 2015,
  - Power flowed in the inefficient direction in 99 percent of hours, much inefficient than any of other PAR-controlled lines.
  - The use of these lines increased day-ahead production costs by an estimated $15 million in 2015 because prices on Long Island were typically higher than those in New York City (particularly where the 901 and 903 lines connect in the Astoria East/Corona/Jamaica pocket, which is sometimes export-constrained).
  - In addition to increasing production costs, these transfers can restrict output from economic generators in the Astoria East/Corona/Jamaica pocket and at the Astoria Annex. Restrictions on the output of these generators sometimes adversely affects a much wider area (e.g., when there is an eastern reserve shortage or during a TSA event).

- Real-time adjustments in flows were generally small relative to day-ahead scheduled flows, since most of these PAR-controlled lines were operated to the same schedule in the day-ahead and real-time markets.
  - However, the Ramapo line and St. Lawrence line showed relatively significant production cost savings in real-time because these lines were operated: (a) to flow a share of the external transactions between control areas that are submitted by traders and (b) to manage real-time congestion.
    - Although the Ramapo line is scheduled under the M2M process to minimize congestion across PJM and New York, the process only considers congestion on certain pre-defined interfaces. Table A-12 reports the production cost savings for balancing adjustments considering congestion on all flowgates. This includes balancing adjustments that result from external transaction scheduling and those that result from the M2M process.
    - In 2015, the production cost savings were reduced by an estimated $7.6 million when additional Ramapo flows into New York increased production costs on non-M2M constraints in Western New York (e.g., the Niagara-Packard line).[287] Hence, excluding the effects of balancing adjustments of the Ramapo line on constraints in Western New York, the production cost savings reported in Table A-12 would likely have exceeded $13 million.

- These results indicate that significant opportunities remain to improve the operation of these lines, particularly the Waldwick and Farragut/Goethals lines and the lines between New York City and Long Island.

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287 This estimate is based on the balancing congestion shortfalls that may be attributed to the effects of Ramapo PAR operations on constraints in western New York, which are reported in Figure A-58.

- These lines are all scheduled according to the terms of long-standing contracts that pre-date open access transmission tariffs and the NYISO's markets. It would be highly beneficial modify these contracts or find other ways under the current contracts to operate the lines efficiently.
- Under the ConEd-LIPA wheeling agreement, ConEd possesses a physical right to receive power across the 901 and 903 lines. To compensate ConEd during periods when it does not receive power across these lines, ConEd should be granted a financial right that would compensate it based on LBMPs when the lines are redispatched to minimize production costs (similar to a generator). [288]
- Under the ConEd-PSEG wheeling agreement, ConEd has the right to wheel power from the Hudson Valley through PJM into New York City. However, ConEd has indicated that it may choose not to renew this agreement in 2017, so it may be possible to schedule the associated lines more efficiently in the future.

D. Cyclical Real-Time Price Volatility

The New York ISO usually dispatches the real-time system and updates clearing prices once every five minutes. Real-Time clearing prices can be quite volatile in wholesale electricity markets, even when sufficient supply is online. Generators (and demand response resources) are sometimes unable to adjust quickly enough to rapidly changing system conditions. As a result, wholesale markets experience brief periods of shortage, leading to very high prices; as well as brief periods of excess, leading to very low or even negative prices. This sub-section evaluates patterns of price volatility in the real-time market.

Volatile real-time prices can be an efficient signal of the value of flexible generation. These signals give market participants incentives to invest in making their generators more flexible and to offer that flexibility into the real-time market. However, price volatility can also be a sign of inefficient market operations if generators are being cycled unnecessarily. Real-time price volatility also raises concerns because it increases risks for market participants, although market participants can hedge this risk by buying and selling in the day-ahead market and/or in the bilateral market. Generally, the ISO should seek ways to reduce unnecessary price volatility while maintaining efficient signals for generators to be flexible in real-time.

This sub-section analyzes cyclical patterns of price volatility in real time that tend to occur predictably at certain times of day, while the next sub-section focuses on transient patterns of price volatility that may or may not occur repetitively at certain times.

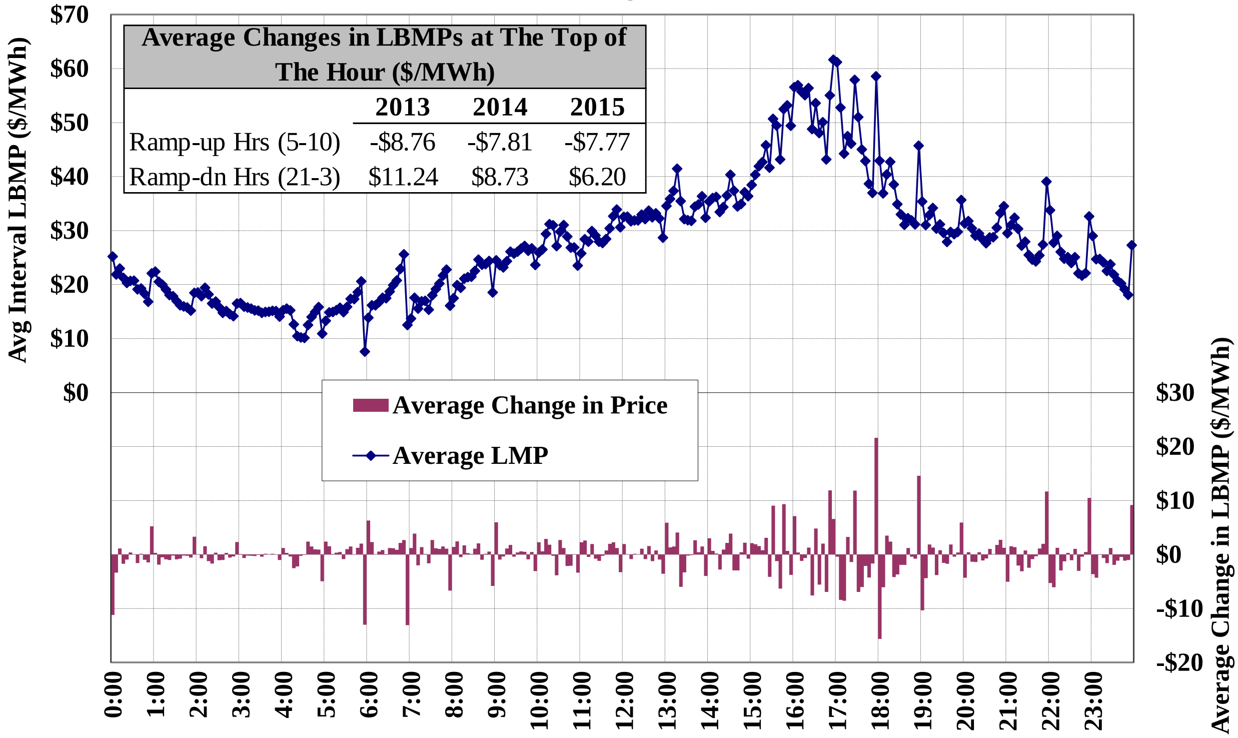
Figure A-79 & Figure A-80: Cyclical Real-Time Price Volatility

Figure A-79 evaluates cyclical patterns of price volatility that occur predictably at certain times of day, showing the average prices in each five-minute interval of the day in the summer of

[288] The proposed financial right is described in Section III.G of the Appendix.

2015. The figure shows the load-weighted average prices for all of New York, although the results are similar in each individual zone. The table compares the average size of upward and downward spikes that typically occur at the top of the hour during the ramp-up hours (i.e., hours 5 to 10) and ramp-down hours (i.e., hours 0-3 and hours 21-23) in the past three years.

Figure A-79: Statewide Average Five-Minute Prices by Time of Day
June to August, 2015



Changes in LBMPs from one interval to the next depend on how much dispatch flexibility the system has to respond to fluctuations in the following factors: electricity demand, net export schedules (which are determined prior to RTD by RTC or by transaction curtailments), generation schedules of self-scheduled and other non-flexible generation, and transmission congestion patterns.

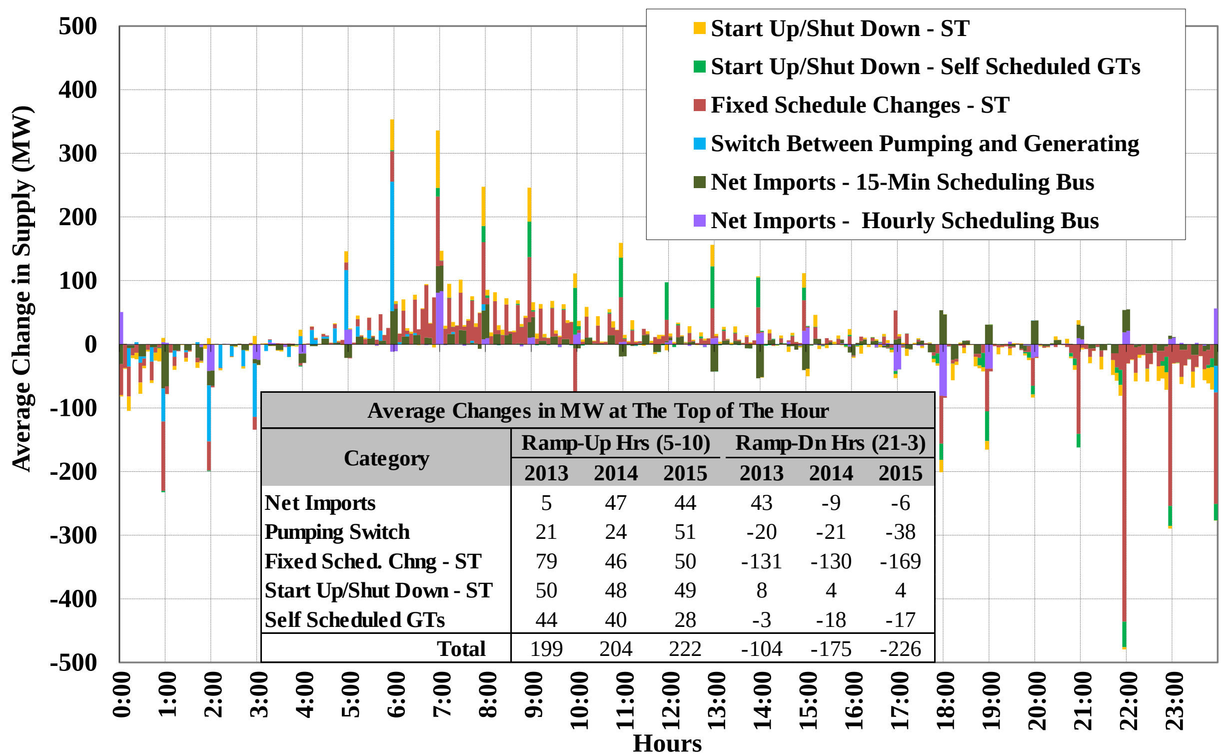
Figure A-80 shows the average net changes from one interval to the next for the following five categories of inflexible supply:

- *Net imports* – Net imports ramp at a constant rate from five minutes prior to the top of the hour (:55) to five minutes after the top of the hour (:05). Net imports across the interfaces that allow 15-minute scheduling also ramp from five minutes prior to each quarter-hour interval (i.e., :10, :25, :40) to five minutes after the quarter-hour interval (i.e., :20, :35, :50). In addition, they can change unexpectedly due to curtailments and TLRs before or during the hour.
- *Switches between pumping and generating* – This is when pump storage units switch between consuming electricity and producing electricity.

- *Fixed schedule changes for online non-gas-turbine units* – Many units are not dispatchable by the ISO and produce according to their fixed generation schedule.
- *Start-up and shutdown of self-scheduled gas turbines*– These gas turbines are not dispatchable by the ISO, starting-up and shutting-down according to their fixed schedule.
- *Start-up and shutdown of non-gas-turbine units*– These units are not dispatchable during their start-up and shut-down phases of operation. In addition, the minimum generation level on these units is inflexible supply that much be accommodated.

The table compares the average size of upward and downward movement of these five categories of inflexible supply that typically occur at the top of the hour during the ramp-up hours (i.e., hours 5 to 10) and ramp-down hours (i.e., hours 0-3 and hours 21-23) in the past three years.

Figure A-80: Factors Contributing to Cyclical Real-Time Price Volatility
June to August, 2015



Average Changes in MW at The Top of The Hour						
Category	Ramp-Up Hrs (5-10)			Ramp-Dn Hrs (21-3)		
	2013	2014	2015	2013	2014	2015
Net Imports	5	47	44	43	-9	-6
Pumping Switch	21	24	51	-20	-21	-38
Fixed Sched. Chng - ST	79	46	50	-131	-130	-169
Start Up/Shut Down - ST	50	48	49	8	4	4
Self Scheduled GTs	44	40	28	-3	-18	-17
Total	199	204	222	-104	-175	-226

Key Observations: Cyclical Real-Time Price Volatility

- Most cyclical real-time price fluctuations occurred predictably near the top of the hour during ramp-up and ramp-down hours.
  - In the last interval of each hour, clearing prices dropped substantially in ramp-up hours and rose substantially in ramp-down hours.
- Several factors generally contributed to large price changes at the top of the hour during ramping hours:

  - Hourly-scheduled imports and exports tend to exacerbate the need to ramp around the top of the hour, although there were some hours in which net imports were adjusted in a direction that moderated the amount by which the ISO had to ramp (e.g., at 22:00, there tends to be a sudden reduction in supply from self-scheduled units, which is offset by an increase in hourly-scheduled net imports);
  - Pumped-storage units typically switched between pumping and generating at the top of hour;
  - Generators were committed and decommitted frequently at the top of the hour during ramping hours; and
  - Non-dispatchable generators typically adjusted their schedules at the top of each hour.
  - Taken together, these factors can create a sizable ramp demand on the system that can sometimes cause the NYISO to temporarily be short of reserves or regulation.
  - Generators that prefer to operate in real-time consistent with their day-ahead schedule tend to make large schedule changes at the top of the hour. Hence, allowing day-ahead schedules to vary on a 15-minute or 30-minute basis rather than hourly basis would likely reduce the occurrence of large predictable price swings around the top of the hour.
- The average size of upward and downward spikes at the top of the hour during ramping hours has fallen notably after 2011 largely because: [289]
  - 15-minute scheduling was enabled at more external interfaces in recent years, which allowed external schedule changes to occur throughout the hour, rather than only at the top of each hour; and
  - Pumped-storage units, which used to switch between pumping and generating only at the top of the hour, started to switch at quarter-hour intervals more frequently in recent years.
  - Nonetheless, the average size of spikes (relative to average LBMPs) rose modestly from 2014 to 2015, reflecting higher amount of pumping switch and fixed schedule changes at the top of the hour.
- Our assessment of the performance of CTS with PJM (see Section IV-D) indicates that inconsistencies between RTC and RTD related to the assumed external transaction ramp profile likely contributes to price volatility when the total net interchange varies significantly (e.g., >200 MW) from one 15-minute interval to another.
  - These inconsistent ramp assumptions can:
    - Lead RTC to schedule more or less than the efficient amount of interchange at the PJM interface given the limited ability of internal resources to ramp up or down in response to variations in imports; and

[289] See the Section V-D in our 2014 State of the Market Report for these statistics reported for 2011 and 2012.

  - Prevent RTD's look-ahead evaluation from anticipating an upcoming scarcity of ramp capability such that RTD does not ramp resources sufficiently in advance of the impending need.

- This issue contributes to price volatility observed in Figure A-79 around the top of the hour when external transaction schedule changes are largest.
- Potential solutions to this issue are discussed at the end of Subsection E.

E. Transient Real-Time Price Volatility

This sub-section evaluates scheduling patterns that led to transient spikes in real-time prices for individual transmission constraints and the power-balance constraint (i.e., the requirement that supply equal demand) in 2015. The effects of transient transmission constraints tend to be localized, while transient spikes in the power-balance constraint affect prices throughout NYCA.

A spike in the shadow price of a particular transmission constraint is considered *"transient"* if it satisfies both of the following criteria:

- It exceeds $150 per MWh; and
- It increases by at least 100 percent from the previous interval.

A spike in the shadow price of the power-balance constraint (known as the "reference bus price") affects prices statewide rather than in a particular area. A statewide price spike is considered "transient" if:

- The price at the reference bus exceeds $100 per MWh; and
- It increases by at least 100 percent from the previous interval.

Although the price spikes meeting these criteria account for just 4.0 percent of the real-time pricing intervals in 2015, these intervals are important because they account for a disproportionately large share of the overall market costs. Furthermore, analysis of factors that lead to the most sudden and severe real-time price spikes provides insight about factors that contribute to less severe price volatility under a wider range of market conditions. In general, price volatility makes it more difficult for market participants, the NYISO, and neighboring system operators to commit quick-start resources and schedule external transactions efficiently. Hence, reducing unnecessary price volatility will lead to more efficient interchange between markets, lower production costs across markets, and less uplift from BPCG and DAMAP payments.

Table A-13: Transient Real-Time Price Volatility

Table A-13 summarizes transient real-time price spikes by constraint (including transmission facilities and power-balance constraints) in 2015 for facilities exhibiting the most volatility. The table reports the frequency of transient price spikes, the average shadow price during the spikes, and the average transfer limit during the spikes.

The table also analyzes major factors that contributed to price volatility in these price spike intervals. These factors are grouped into three categories:

- Flows from resources Scheduled by RTC
- Flow Changes from Non-Modeled Factors
- Other Factors

Specifically, the table shows factors that contributed to an increase in flows from the previous five-minute interval. For the power-balance constraint, the table summarizes factors that contributed to an increase in demand and/or reduction in supply. This analysis quantifies contributions from the following factors, which are listed in order of significance:

- External Interchange – This adjusts as often as every 15 minutes, depending on the interface. The interchange at each interface is assumed to "ramp" over a 10-minute period from five minutes before the quarter hour (i.e., :55, :10, :25, :40) to five minutes after the quarter hour (i.e., :05, :20, :35, :50). Interchange schedules are determined before each 5-minute interval, so RTD must schedule internal dispatchable resources up or down to accommodate adjustments in interchange.
- Fixed Schedule PARs – These include PARs that are operated to a fixed schedule (as opposed to optimized PARs, which are operated to relieve congestion). The fixed schedule PARs that are the most significant drivers of price volatility include the A, B, C, J, & K lines (which are used to support the ConEd-PSEG wheeling agreement) and the 901 and 903 lines (which are used to support the ConEd-LIPA wheeling agreement).[290] RTD and RTC assume the flow over these lines will remain fixed in future intervals at the most recent telemetered value, but their flow is affected by changes in generation and load and changes in the settings of the fixed schedule PAR or other nearby PARs. Hence, RTD and RTC do not anticipate changes in flows across fixed schedule PARs in future intervals, which can lead to sudden congestion price spikes when RTD recognizes the need to redispatch internal resources in response to unforeseen changes in flows across a fixed schedule PAR.
- RTC Shutdown Peaking Resource – This includes gas turbines and other capacity that is brought offline by RTC based on economic criteria. When RTC shuts-down a significant amount of capacity in a single 5-minute interval, it can lead to a sudden price spike if dispatchable internal generation is ramp-limited.
- Loop Flows & Other Non-Market Scheduled – These include flows that are not accounted for in the pricing logic of the NYISO's real-time market. These result when other system operators schedule internal facilities and external transactions to satisfy their internal load, causing loop flow across the NYISO system. These also result from differences between the shift factors assumed by the NYISO for pricing purposes and the actual flows that result from adjustments in generation, load, interchange, and PAR controls.

290 These lines are discussed further in Subsection C.

- Self-Scheduled Generator – This includes online generators that are moving in accordance with a self-schedule, resources shut-down in accordance with a self-schedule, and resources that are shut down because they did not submit a RT offer.
- Load – This includes the effects of changes in load.
- Generator Trip/Derate/Dragging – Includes adjustments in output when a generator trips, is derated, or is not following its previous base point.
- Wind – This includes the effects of changes in output from wind turbines.
- Redispatch for Other Constraint (OOM) – Includes adjustments in output when a generator is logged as being dispatched out-of-merit order. Typically, this results when a generator is dispatched manually for ACE or to manage a constraint that is not reflected in the real-time market (i.e., in RTD or RTD-CAM).
- Ramapo PARs – The primary determinant of flows across the Ramapo PAR-controlled line is the interchange between PJM and NYISO across the primary interface, 61 percent of which is expected to flow across the Ramapo line. Under M2M Coordination with PJM, the Ramapo line can carry additional flows in order to manage congestion on M2M flow gates. This category includes the impacts of adjustments in the deviation between the actual Ramapo flow and the 61 percent assumption.[291]
- Re-Dispatch for Other Constraint (RTD) – Multiple constraints often bind suddenly at the same time because of some common causal factors. For example, the sudden trip of a generator could lead to a power-balance constraint and a shortage of 10-minute spinning reserves. In such cases, some units are dispatched to provide more energy, while others may be dispatched to provide additional reserves, so the units dispatched to provide additional reserves would be identified in this category. The analysis does not include this category in the total row of Table A-13, since this category includes the responses to a primary cause that is reflected in one of the other rows.

The contributions from each of the factors during transient spikes are shown in MWs and as a percent of the total contributions to the price spike for the facility.[292] For each constraint category, we highlight the category of aggravating factors that most contributed to the transient price spikes in green.

[291] Ramapo M2M coordination is discussed further in Subsection B.

[292] The West Zone 230kV Lines category includes the Niagara-to-Packard, Packard-to-Sawyer, Gardenville-to-Stolle Rd, Huntley-to-Sawyer, and Sawyer-to-SUNY Buffalo transmission lines.

Table A-13: Drivers of Transient Real-Time Price Volatility
2015

	Power Balance		West Zone 230kV Lines		Central East		Dunwoodie - Shore Rd 345kV		Intra-Long Island Constraints	
Average Transfer Limit	**n/a**		**637**		**2564**		**719**		**273**	
Number of Price Spikes	**557**		**1279**		**351**		**591**		**1311**	
Average Constraint Shadow Price	**$219**		**$810**		**$319**		**$521**		**$872**	
Source of Increased Constraint Cost:	**(MW)**	**(%)**	**(MW)**	**(%)**	**(MW)**	**(%)**	**(MW)**	**(%)**	**(MW)**	**(%)**
Scheduled By RTC	**174**	**65%**	**2**	**7%**	**66**	**45%**	**43**	**60%**	**5**	**25%**
External Interchange	113	42%	2	7%	36	25%	26	36%	1	7%
RTC Shutdown Resource	37	14%	0	0%	18	13%	13	19%	3	13%
Self Scheduled Shutdown/Dispatch	24	9%	0	0%	12	8%	4	6%	1	5%
Flow Change from Non-Modeled Factors	**9**	**4%**	**18**	**81%**	**59**	**40%**	**20**	**28%**	**14**	**72%**
Loop Flows & Other Non-Market	0	0%	14	63%	11	7%	7	9%	3	14%
Fixed Schedule PARs (excl. Ramapo)	0	0%	3	12%	29	20%	13	18%	11	56%
Ramapo PARs	0	0%	1	7%	16	11%	0	0%	0	0%
Redispatch for Other Constraint (OOM)	9	4%	0	0%	3	2%	1	1%	0	1%
Other Factors	**86**	**32%**	**3**	**11%**	**21**	**14%**	**9**	**12%**	**1**	**3%**
Load	53	20%	1	4%	11	8%	6	8%	0	1%
Generator Trip/Derate/Dragging	17	6%	0	0%	8	6%	3	4%	0	2%
Wind	16	6%	2	7%	1	1%	0	0%	0	0%
Total	**270**	**100%**	**22**	**100%**	**146**	**100%**	**72**	**100%**	**20**	**100%**
Redispatch for Other Constraint (RTD)	**106**		**1**		**34**		**9**		**1**	

Key Observations: Transient Real-Time Price Volatility

- Transient shadow price spikes (as defined in this report) occurred in about 4 percent of all intervals in 2015.
  - For the power-balance constraint, the primary drivers were external interchange adjustments, decommitment of generation by RTC, and increases in load.
  - For the West Zone 230kV Lines, the primary driver was from loop flow and other non-market scheduled factors. The vast majority is loop flow around Lake Erie that emanates from other control areas, but a portion of the non-market scheduled flows results from simplified modeling of the Niagara generator bus in the pricing model of the real-time market. [293]
  - For the Central-East Interface, the primary drivers were from external interchange adjustments and fixed-schedule PAR flow adjustments (particularly from the A, B, C, J, and K lines). Generator shutdowns by RTC and Ramapo PAR flow adjustments were also significant contributors.

293 This accounts for the fact that the EMS software recognizes that the Niagara plant consists of 25 generators that are connected to two locations on the 115kV system and two locations on the 230kV system, while the pricing model represents the entire plant as connected to the 230kV system.

- For the Dunwoodie-to-Shore Road 345kV line from upstate to Long Island (i.e., the "Y50" line), the primary drivers were from external interchange adjustments (especially the Neptune line), fixed schedule PAR flow adjustments (particularly from the 901 and 903 lines), and the shutdown of generation by RTC.
- For constraints internal to Long Island (the majority of which were for the 138kV East Garden City-to-Valley Stream line), the primary driver was fixed-schedule PAR flow adjustments (particularly from the 901 line). The shutdown of peaking units by RTC and other non-market factors were also significant contributors.

- External interchange variations were a key driver of transient price spikes for the Central-East Interface, the Dunwoodie-to-Shore Road 345kV line, and the power-balance constraint.
  - Large schedule changes caused price spikes in many intervals when generation was ramp-limited in responding to the adjustment in interchange.
  - CTS with PJM and ISO-NE provide additional opportunities for market participants to schedule transactions such that it will tend to reduce the size of the adjustment around the top-of-the-hour.
    - However, our assessment of the performance of CTS with PJM (see Appendix Section I-D) indicates that inconsistencies between RTC and RTD related to the assumed external transaction ramp profile likely contributes to price volatility when the total net interchange varies significantly (e.g., >200 MW) from one 15-minute interval to another.
- Fixed-schedule PAR-controlled line flow variations were a key driver of price spikes. The A, B, C, J, and K lines were a key driver for the Central-East Interface, the 901 and 903 lines were a key driver for the Dunwoodie-to-Shore Road line, and the 901 line was the primary driver for the East Garden City-to-Valley Stream line.
  - These PARs are modeled as if they fully control pre-contingent flow across the PAR-controlled line, so RTD and RTC assume the flow across these lines will remain fixed at the most recent telemetered values.
  - However, this assumption only holds true if the PAR is adjusted in response to variations in generation, load, interchange, and other PAR adjustments. When the PAR is not adjusted promptly, the telemetered value can change significantly, resulting in transitory price spikes.
  - In many cases, severe congestion occurs when low-cost resources that are available to relieve the constraint are under-utilized because they are not scheduled to ramp-up soon enough.
- Loop flows and other non-market factors were the primary driver of constraints across the West Zone 230kV Lines.
  - Clockwise circulation around Lake Erie puts a large amount of non-market flow on these lines. Circulation can be highly volatile and difficult to predict, since it depends on facilities scheduled outside the NYISO market.

- Generators that are shut down by RTC and/or self-scheduled in a direction that exacerbates a constraint were a significant driver of statewide, Central East, and Long Island price spikes.
  - A large amount of generation may be scheduled to go offline simultaneously, which may not cause ramp constraints in the 15-minute evaluation by RTC but which may cause ramp constraints in the 5-minute evaluation by RTD.

Discussion of Potential Solutions

- When gas turbines and other units are in the process of shutting-down, they may reduce output quickly. When decommitments are not staggered, it sometimes results in a transitory statewide or local price spike.
  - RTC evaluates system conditions at each quarter-hour (i.e., at :00, :15, :30, and :45) and determines when it is economic to shut-down gas turbines.
  - Since RTC assumes a 15-minute ramp capability from one evaluation period to another, RTC may not anticipate that shutting-down several gas turbines simultaneously will result in a transient shortage within the 15-minute period.
  - However, when RTD solves each five-minute market interval, it is unable to delay the shut-down of a gas turbine even if it would be economic to do so.
- Figure A-80 shows that external interchange typically adjusts in the real-time market in a direction that reduces the ramp requirements of internal generators over the day. However, large adjustments from one hour to the next may lead to sudden price spikes.
  - The "look ahead" evaluations in RTD and RTC evaluate system conditions at each quarter-hour (i.e., at :00, :15, :30, and :45), while external interchange schedules ramp over 10-minute periods from five minutes before the quarter-hour to five minutes after (i.e., from :55 to :05, from :10 to :20, etc.).
  - Hence, RTC may schedule resources that require a large amount of ramp in one 5-minute portion of the 10-minute external interchange ramp period, and RTD may not anticipate transient shortages that occur in the second five minutes of each 10-minute external interchange ramp period (i.e., at intervals-ending :05, :20, :35, and :50).
- *Addressing RTC/RTD Inconsistencies* – To reduce unnecessary price volatility that results from ramping external interchange and shutting-down generation, we recommend the NYISO consider one or more of the following enhancements to improve the modeling of ramp in RTC and RTD: [294]
  - Add two near-term look-ahead evaluations to RTC and RTD besides the quarter-hour, so that it could anticipate when a de-commitment or interchange adjustment would lead to a five-minute shortage of ramp. For example, for the RTC that evaluates CTS transactions for interval-ending :15, evaluations could be added at :10 and :20.

[294] See Recommendation #12 in Section XI.

  - Adjust the timing of the look-ahead evaluations of RTD and RTC to be more consistent with the ramp cycle of external interchange. This could be done by evaluating intervals-ending :05, :20, :35, and :50 rather than :00, :15, :30, and :45.
  - Enable RTD to delay the shut-down of a gas turbine for five minutes when it is economic to remain on-line.
  - Discount the ramp rate assumed in the look-ahead evaluations of RTC and RTD for steam turbines generators, which often ramp at a rate that is lower than their claimed ramp rate capability.
- *Addressing Non-Modeled Factors* – To reduce unnecessary price volatility from variations in loop flows and other factors not explicitly modeled such as fixed-schedule PAR flow changes, we recommend the NYISO consider the following: [295]
  - Adjust the last telemetered flow on a fixed-schedule PAR in RTD and RTC to account for variations in generation, load, interchange, and other PARs that are located in the NYISO footprint. (In each RTD and RTC run, this adjustment could be made before each iteration of the pricing and scheduling component of the model based on the results of the network security analysis component. This is already done to some extent for the estimate of loop flows around Lake Erie).
  - Develop mechanism for forecasting additional adjustments from the telemetered value for loop flows and fixed-schedule PAR flows that result from factors not scheduled by the NYISO. This forecast should be "biased" to account for the fact that the cost resulting from forecast errors is asymmetric (i.e., the cost of an over-forecast may be much greater than the cost of an under-forecast of the same magnitude).
- Section IX.F.3 discusses our recommendation for the NYISO to consider modeling 115kV transmission constraints in upstate New York in the day-ahead and real-time markets. This would also reduce unnecessary price volatility on 230kV transmission constraints in the West Zone because it would allow the NYISO real-time market to re-dispatch generation more efficiently to relieve congestion. Currently, any such re-dispatch occurs through less precise out-of-market instructions.

F. Market Operations under Shortage Conditions

Prices that occur under shortage conditions (i.e., when resources are insufficient to meet the energy and operating reserves needs of the system while satisfying transmission security constraints) are an important contributor to efficient price signals. In the long-run, prices should signal to market participants where and when new investment in generation, transmission, and demand response would be most valuable to the system. In the short-run, prices should provide market participants with incentives to commit sufficient resources in the day-ahead market to satisfy anticipated system conditions the following day, and prices should give suppliers and

[295] See in Recommendation #13 in Section XI.

demand response resources incentives to perform well and improve the reliability of the system, particularly during real-time shortages. However, it is also important that shortage pricing only occurs during legitimate shortage conditions rather than as the result of anticompetitive behavior or inefficient market operations.

The importance of setting efficient real-time price signals during shortages has been well-recognized. Currently, there are three provisions in the NYISO's market design that facilitate shortage pricing. First, the NYISO uses operating reserve demand curves to set real-time clearing prices during operating reserves shortages. Second, the NYISO uses a transmission demand curve to set real-time clearing prices during a portion of transmission shortages. Third, the NYISO allows demand response resources to set clearing prices when an operating reserve shortage is avoided by the deployment of demand response.

In this section, we evaluate the operation of the market and resulting prices when the system is in the following two types of shortage conditions: [296]

- Shortages of operating reserves and regulation (are evaluated in this subsection and the next subsection); and
- Transmission shortages (are evaluated in Subsection H).

Figure A-81: Real-Time Prices During Physical Ancillary Services Shortages

The NYISO's approach to efficient pricing during operating reserves and regulation shortages is to use ancillary services demand curves. The real-time dispatch model ("RTD") co-optimizes the procurement of energy and ancillary services, efficiently allocating resources to provide energy and ancillary services every five minutes. When RTD cannot satisfy both the energy demand and ancillary services requirements with the available resources, the demand curves for ancillary services rationalize the pricing of energy and ancillary services during shortage periods by causing prices to reflect the value of foregone ancillary services. The demand curves also set limits on the costs that can be incurred to maintain operating reserves and regulation.

Figure A-81 summarizes physical ancillary services shortages and their effects on real-time prices in 2014 and 2015 for the following five categories:

- 30-minute NYCA – The ISO is required to hold 2,620 MW of 30-minute operating reserves in the state and has a demand curve value of $25/MWh if the shortage is less than 300 MW, $100/MWh if the shortage is between 300 and 655 MW, $200/MWh if the

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296 Our prior reports also evaluated market operations during reliability demand response deployments. In 2015, the NYISO did not deploy reliability demand response resources, so the effect of the scarcity pricing is not evaluated in this report.

shortage is between 655 and 955 MW, and $750/MWh if the shortage is more than 955 MW. [297]

- 10-minute NYCA – The ISO is required to hold 1,310 MW of 10-minute operating reserves in the state and has a demand curve value of $750/MWh. [298]
- 10-Spin NYCA – The ISO is required to hold 655 MW of 10-minute spinning reserves in the state and has a demand curve value of $775/MWh. [299]
- 10-minute East – The ISO is required to hold 1200 MW of 10-minute operating reserves in Eastern New York and has a demand curve value of $775/MWh. [300]
- Regulation – The ISO is required to hold 150 to 300 MW of regulation capability in the state and has a demand curve value of $25/MWh if the shortage is less than 25 MW, $400/MWh if the shortage is between 25 and 80 MW, and $775/MWh if the shortage is more than 80 MW. [301]

The top portion of the figure shows the frequency of physical shortages. The bottom portion shows the average shadow price during physical shortage intervals and the current demand curve level of the requirement. The changes in the demand curves for these ancillary services products on November 4, 2015 are reflected in the chart. The dark green bars represent old demand curve values that are replaced after November 4, the pattern-filled bars represent old demand curve values that are kept in this reset process, and the light green bars represent new demand curve values effective on November 4.

The table shows the average shadow prices during physical shortages multiplied by the frequency of shortages, indicating the overall price impact of the shortages by product and in total by region. The table also shows the cumulative effect of all ancillary services shortages on average real-time energy clearing prices in:

- Western New York – This is based on the sum of shadow prices of the NYCA reserve requirements as well as the effects of positive and negative regulation spikes; and
- Eastern New York – This equals the Western New York effect plus the sum of shadow prices of eastern reserve requirements.

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297 Prior to November 4, 2015, the ISO was required to hold 1,965 MW of 30-minute operating reserves in the state and had a demand curve value of $50/MWh if the shortage was less than 200 MW, $100/MWh if the shortage was between 200 and 400 MW, and $200/MWh if the shortage was more than 400 MW.

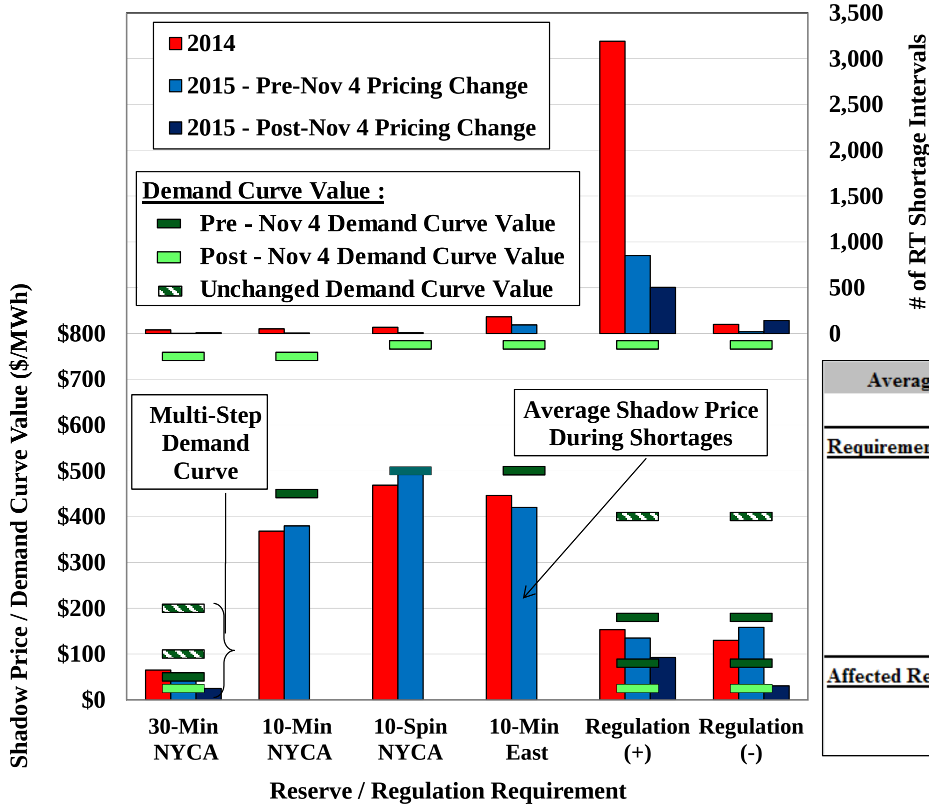
298 Prior to November 4, 2015, this demand curve value was $450/MWh.

299 Prior to November 4, 2015, this demand curve value was $500/MWh.

300 Prior to November 4, 2015, this demand curve value was $500/MWh.

301 Prior to November 4, 2015, this demand curve value was $80/MWh if the shortage was less than 25 MW, $180/MWh if the shortage was between 25 and 80 MW, and $400/MWh if the shortage was more than 80 MW.

Figure A-81: Real-Time Prices During Ancillary Services Shortages
2014 – 2015



Average Contribution to Energy Price			
		2014	2015
Requirement:	30-Min NYCA	$0.02	$0.00
	10-Min NYCA	$0.18	$0.01
	10-Spin NYCA	$0.30	$0.04
	10-Min East	$0.77	$0.37
	Regulation (+)	$3.44	$1.02
	Regulation (-)	-$0.09	-$0.01
Affected Region:	West NY	$3.86	$1.07
	East NY	$4.63	$1.44

Key Observations: Real-Time Prices During Physical Ancillary Services Shortages

- The frequency of physical shortage conditions fell from 2014 to 2015 for all ancillary services products.
  - Shortage conditions fell roughly 44 to 87 percent in the first quarter of 2015 from a year ago, accounting for the majority of annual reductions. The following factors contributed to the first-quarter reductions in shortages:
    - Lower and less volatile natural gas prices;
    - Less frequent peaking (i.e., load > 24 GW) conditions; and
    - Higher net imports from Ontario and Quebec.
- The table shows that regulation shortages and 10-minute Eastern reserve shortages had the largest effects on real-time prices.
  - Regulation shortages were most frequent in both years, occurring in 3.1 percent of all intervals in 2014 and 1.4 percent in 2015.
    - Regulation shortages were particularly high in the first quarter of 2014 (over 70 percent of all regulation shortages in 2014) because of elevated opportunity costs to provide this service.

    – The model "chose" to be short of regulation when the cost to provide regulation exceeded the lowest demand curve value of $80/MWh.

  – Likewise, regulation shortages occurred more frequently after November 4, 2015 when the lowest demand curve value was reduced from $80 to $25/MWh.

- 10-minute Eastern reserve shortages were the next most frequent in both years, occurring around 0.2 percent of all intervals in 2014 and 0.1 percent in 2015.

- The average shadow price during physical shortages was close to the demand curve level for each class of reserves, indicating that real-time prices generally reflected these shortage conditions accurately in 2014 and 2015.[302]

- Several changes were made to shortage pricing of ancillary services products on November 4, 2015.
  - NYCA 30-minute reserve requirement was increased to 2,620 MW, reflecting the requirement to restore 10-minute reserves to 1,310 MW within 30 minutes following the system's largest supply contingency of 1,310 MW. [303]
  - Demand curves for some ancillary services products were restructured to better align with the cost of operator actions to maintain reserves.
  - A 30-minute reserve requirement was created for Southeast New York, reflecting the requirement to restore flows below the normal rating within 30 minutes following a contingency. [304]

G. Availability of Reliable Eastern 10-Minute Reserves on Hourly OFO Days

The supply of natural gas is usually tight in the winter season because of increased demand for heating. On the tightest days, interstate gas pipelines and Local Distribution Companies ("LDCs") issue hourly Operational Flow Orders ("OFOs"), during which gas customers must: (a) consume the same amount of gas every hour of the gas day and (b) consume strictly in line with their scheduled gas quantity. Violating these rules causes a generator to incur punitive unauthorized use charges and may cause the gas operator to physically curtail gas to the generator.

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302 In previous state of the market reports, we have identified periods when real-time prices did not reflect that the system was in a physical shortage (although this has been uncommon since modeling enhancements were implemented in 2009). This can happen because RTD performs a pricing optimization that is distinct from the physical optimization that is used to determine dispatch instructions. The pricing optimization is employed so that block loaded generators (i.e., gas turbines) are able to set the clearing price under certain circumstances.

303 See *NYSRC Reliability Rules & Compliance Manual*, Version 35, See Section E.1 Operating Reserves: Establishing the Minimum Level of Operating Reserve, Requirement R6.

304 See *NYSRC Reliability Rules & Compliance Manual*, Version 35, See Section C.2 Transmission Operation: Post-Contingency Operation, Requirement R1.

During hourly OFOs, many gas-only generators may be unable to start-up or ramp-up if deployed in response to a contingency. While some generators may be able to procure additional gas or may be authorized by the pipeline operator to start-up on gas, simultaneous activation of a large amount of off-line gas-fired reserve units may be infeasible for the pipeline. This analysis evaluates the extent to which the NYISO relied on gas-only units to meet its Eastern 10-minute reserve requirement on certain days when hourly OFOs were declared by at least one LDC in New York City and Long Island.

Offline gas-only 10-minute gas turbines tend to continue offering reserves in real-time during hourly OFOs. The NYISO requires that they offer these reserves, or take a capacity derate which increases their EFORd and lowers their capacity payments. These suppliers may choose to continue offering reserves in real-time if they believe they could secure authorized gas in the event of a contingency. However, such suppliers may have no way of knowing whether gas would suddenly become unavailable if their units were committed simultaneously along with other units.

Figure A-82: 10-minute Reserve Capacity in Eastern New York on Cold Days

Figure A-82 shows hourly data for Hours Beginning (HB) 7-20 on selected tight gas-system days in 2014 and 2015. The top portion of the chart shows hourly average prices for Eastern 10-minute reserves. The bottom portion of the chart shows the capacity in Eastern New York that is capable of providing 10-minute reserves (including scheduled and not-scheduled but available) on these days. The reserve capacity is shown in the following categories:

- Hydro and oil-capable reserves (including oil-only and dual-fueled units).
- Unused import capability on the Central-East Interface.
- Gas-only reserves (including oil-fired gas turbines that must start on gas).
- Undeliverable reserves in Long Island – This is defined as reserve capacity in excess of the amount of imported energy from upstate to Long Island. [305]

The black marker in the chart represents the total of deliverable reserves from hydro and oil-capable resources (i.e., total hydro and oil-capable reserves minus undeliverable reserves in Long Island) and unused import capability on the Central-East interface. This indicates the level of reserve capacity that is not dependent on the availability of gas. For a comparison, the white line in the chart flags the Eastern 10-minute reserve requirement, which is currently set at 1,200MW. The bottom portion of the chart also shows the amount of capacity committed via Supplemental Resource Evaluation (SRE) on each day, since these SRE commitments were made to ensure the NYISO would have adequate reserves in Eastern New York.

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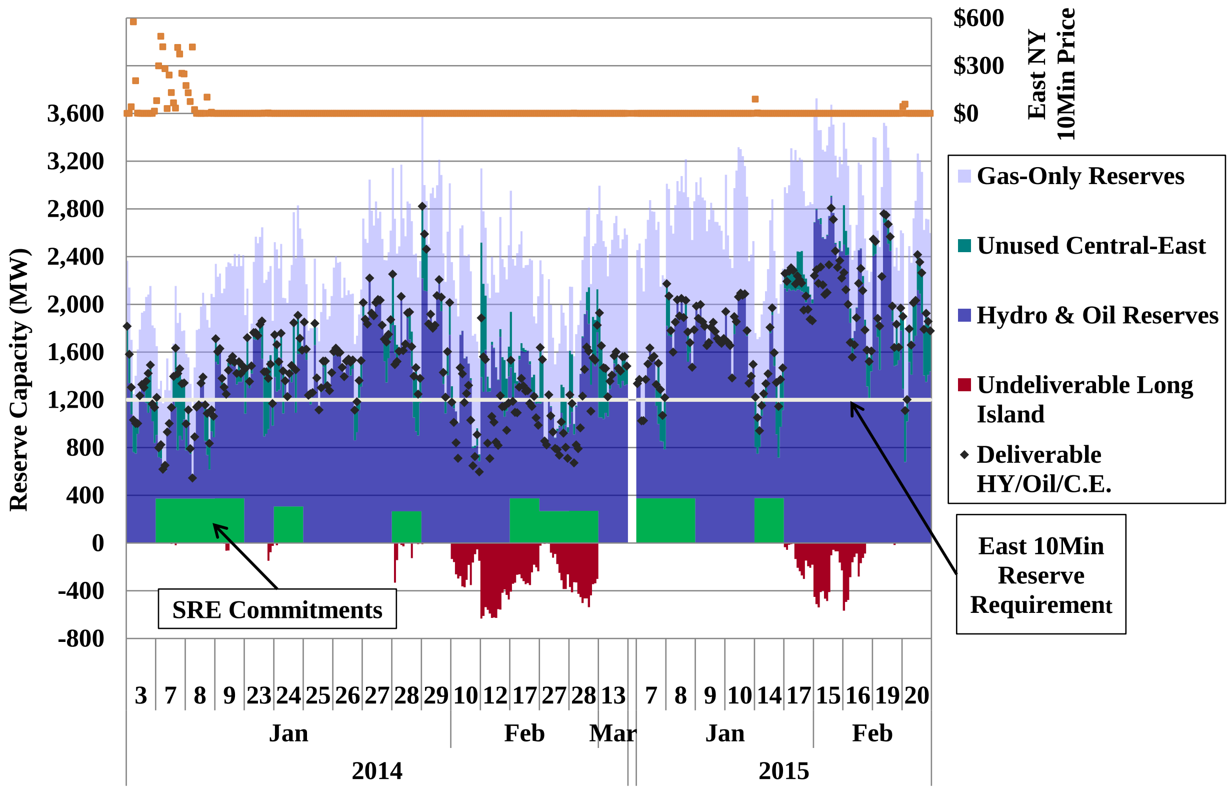
305 This assumes that, post-contingency, Long Island could maintain exports across the ties between Long Island and New York City while reducing flows from upstate New York to Long Island down to 0 MW. Thus, this analysis assumes that flows could not move from Long Island to Upstate New York across the Y49 and Y50 lines after the contingency.

Figure A-82: 10-minute Reserve Capacity in Eastern New York
On Cold Days with Hourly OFOs, 2014 - 2015



Key Observations: Availability of Eastern 10-Minute Reserves on Hourly OFO Days

- On days when the natural gas system is constrained, reserve clearing prices do not always reflect the limited availability of operating reserves nor do they reflect the costs of supplemental commitments to maintain reserves.
  - There were 8 hours on hourly-OFO days in the first quarter of 2015 when the NYISO relied on some gas-only capacity to satisfy the Eastern 10-minute reserve requirement.
    - However, Eastern 10-minute reserve prices averaged just $8/MWh in these hours.
    - This was down from the first quarter of 2014 when we identified 72 such hours, during which Eastern 10-minute reserve prices cleared at $0/MWh in 53 hours and averaged just $190/MWh in the other 19 hours.
  - SRE commitments of 300 to 400 MW occurred on eight of these days in 2014 and three of these days in 2015 for Eastern reserve needs. However, Eastern 10-minute reserve prices were $0/MWh during most hours on these eleven days.
    - The SRE commitments generally occurred on days when the NYISO would have otherwise relied on some gas-only capacity to satisfy the Eastern 10-minute reserve requirement. The timing of these commitments was consistent with

operators being uncertain of whether gas-only reserve capacity could be deployed reliably in the event of a large contingency.

- These results suggest that prices may be understated in some hours on OFO days when generators are subject to fuel limitations.
  - This reduces the incentives for generators to incur costs necessary to provide reserves (and energy) more reliably during tight winter conditions.

H. Real-Time Prices During Transmission Shortages

Transmission shortages occur when power flows exceed the limit of a transmission constraint. Transmission shortages have widely varying reliability implications. In some cases, they can compel the ISO to shed firm load to maintain system security. However, in many cases, transmission shortages can persist for many hours without damaging transmission equipment. During transmission shortages, it is important for wholesale markets to set efficient prices that appropriately reflect the acuteness of operating conditions. Efficient prices provide generation and demand response resources incentives to respond to maintain reliability.

The real-time dispatch model ("RTD") manages transmission constraints by redispatching available capacity, which includes online units that can be ramped in five minutes and offline quick-start gas turbines that can be started and brought online within 10 minutes. Transmission shortages arise in one or more of the following three ways:

- Constraint Limit Relaxation – If the available capacity is not sufficient to resolve a transmission constraint, RTD will relax the constraint by increasing the limit to a level that can be resolved. This process changed in November 2015 and February 2016 with the implementation of the Comprehensive Shortage Pricing project:
  - Before November 4, 2015: RTD determined the flow level that could be achieved by solving the market using an extremely high transmission constraint penalty cost. If this achievable flow was greater than the original limit, RTD would then set a relaxed limit equal to the achievable flow plus 8.0 MW.
  - From November 4, 2015 to February 12, 2016: RTD determined the flow level that could be achieved by solving the market using a transmission constraint penalty cost of $8,000/MWh for basecase constraints and $4,500/MWh for contingency constraints. If this achievable flow was greater than the original limit, RTD set a relaxed limit equal to the achievable flow plus 0.2 MW.
  - After February 12, 2016: RTD continues to relax constraints as from November 4, 2015 to February 12, 2016, but the Graduated Transmission Demand Curve ("GTDC") is now used for some constraints.
    - For constraints where GTDC is used: RTD determines the flow level that can be achieved while treating the first 20 MW of the Graduated Transmission Demand Curve as a resource that can relieve the constraint.

  - Criteria for using the GTDC for a particular transmission constraint in the relaxation procedure of a particular interval: If the amount of potential relief from rampable output ranges of dispatchable resources (at a cost lower than the applicable transmission constraint penalty cost of $8,000 or $4,500) is sufficient to reduce flow below the original limit. Otherwise, the GTDC is not used.

- Set by Transmission Shortage Cost – If the marginal redispatch cost needed to resolve the relaxed constraint limit exceeds the Transmission Shortage Cost, RTD foregoes more costly redispatch options and sets the shadow price at the level of the Transmission Shortage Cost.
  - Before February 12, 2016: This process used a Transmission Shortage Cost equal to $4,000/MWh for all constraints.
  - After February 12, 2016 for constraints that used the GTDC in the relaxation procedure (above): This process uses a Transmission Shortage Cost of $350/MWh for the first 5 MWs, $2,350/MWh for the next 15 MWs, and $4,000/MWh thereafter.
  - After February 12, 2016 for constraints that did not use the GTDC in the relaxation procedure (above): This process continues to use a Transmission Shortage Cost of $4,000/MWh.
- Set by Offline GT – If the available capacity from an offline quick-start gas turbine is counted towards resolving a transmission constraint, but the gas turbine is not given a startup instruction. [306] In such cases, the marginal cost of resources actually dispatched to relieve the constraint is lower than the shadow price set by the offline gas turbine (which is not actually started).

  Table A-14: Real- Time Prices During Transmission Shortages

Table A-14 summarizes transmission shortage events by transmission facility during 2015. For each group of transmission facilities, the table summarizes the number of shortage intervals and associated average constraint shadow prices under four shortage scenarios, which are based on the combination of: (a) whether or not the constraint limit was relaxed; (b) whether or not congestion-relieving offline gas turbine was started; and (c) whether or not the transmission demand curve was used to set the price.

The table shows these quantities for the top eight groups of transmission facilities that had the most frequent shortages during 2015. All of other transmission facilities are shown as a separate group. For each transmission facility and each shortage scenario, the frequency of shortages and average shadow costs are shown separately for the intervals during which the shortage quantity

306 Offline quick-start gas turbine is usually the most expensive available capacity due to their commitment costs, so offline gas turbines are usually not counted towards resolving the constraint unless all available online generation has already been scheduled. If a gas turbine is scheduled by RTD but does not satisfy the start-up requirement (i.e., economic for at least three intervals and scheduled at the full output level for all five intervals), it will not be instructed to start-up after RTD completes execution.

was: (a) less than 5 MW; (b) between 5 and 20 MW; and (c) more than 20 MW. [307] The relative economic significance of these shortages may be measured by the average shadow price during transmission shortages multiplied by the frequency of shortages.

[307] These segments are consistent with the break points in the Graduated Transmission Demand Curve that was implemented in February 2016.

Table A-14: Real-Time Prices During Transmission Shortages
2015

Transmission Facilities	Constraint Relaxation	Offline GT Relief	Demand Curve	Transmission Shortage MW: < 5 MW # Intervals	< 5 MW Avg Shadow Price ($/MWh)	5 - 20 MW # Intervals	5 - 20 MW Avg Shadow Price ($/MWh)	> 20 MW # Intervals	> 20 MW Avg Shadow Price ($/MWh)	Total # Intervals	Total Avg Shadow Price ($/MWh)
West Zone	Y	Y	N								
230kV Lines	Y	N	N	95	$548	1232	$438	950	$547	2277	$488
	N	Y	N								
			Y	30	$4,000	32	$4,000	98	$4,000	160	$4,000
	Total			**125**	**$1,376**	**1264**	**$528**	**1048**	**$870**	**2437**	**$719**
ConEd - LIPA	Y	Y	N					3	$716	3	$716
345 kV Lines	Y	N	N			1	$323	7	$549	8	$520
	N	Y	N	365	$233	748	$232	535	$303	1648	$255
			Y			3	$4,000			3	$4,000
	Total			**365**	**$233**	**752**	**$247**	**545**	**$309**	**1662**	**$264**
E. Garden City	Y	Y	N			35	$990	30	$995	65	$992
- Valley	Y	N	N	48	$993	291	$741	154	$791	493	$781
Stream	N	Y	N	449	$463	473	$379	39	$378	961	$418
			Y	59	$4,000	49	$4,000	9	$4,000	117	$4,000
	Total			**556**	**$884**	**848**	**$738**	**232**	**$872**	**1636**	**$807**
Lines into	Y	Y	N								
Greenwood	Y	N	N	106	$198	862	$74	246	$62	1214	$82
Load Pocket	N	Y	N								
			Y	108	$4,000	10	$4,000			118	$4,000
	Total			**214**	**$2,117**	**872**	**$119**	**246**	**$62**	**1332**	**$429**
Central East	Y	Y	N					1	$21	1	$21
Interface	Y	N	N			1	$422	1	$669	2	$545
	N	Y	N	277	$103	403	$100	255	$180	935	$122
			Y	1	$4,000					1	$4,000
	Total			**278**	**$117**	**404**	**$100**	**257**	**$181**	**939**	**$127**
Astoria Annex -	Y	Y	N								
Astoria East	Y	N	N			467	$12	3	$3	470	$12
	N	Y	N								
			Y								
	Total					**467**	**$12**	**3**	**$3**	**470**	**$12**
North Zone	Y	Y	N								
Lines	Y	N	N	7	$139	71	$195	246	$77	324	$104
	N	Y	N								
			Y	1	$4,000					1	$4,000
	Total			**8**	**$621**	**71**	**$195**	**246**	**$77**	**325**	**$116**
Leeds -	Y	Y	N					4	$2,642	4	$2,642
Pleasant	Y	N	N			2	$1,716	1	$1,695	3	$1,709
Valley	N	Y	N	43	$194	136	$271	68	$466	247	$312
			Y					3	$4,000	3	$4,000
	Total			**43**	**$194**	**138**	**$292**	**76**	**$736**	**257**	**$407**
All Other	Y	Y	N					1	$360	1	$360
Facilities	Y	N	N	59	$196	179	$152	109	$227	347	$183
	N	Y	N	71	$626	50	$598	32	$998	153	$695
			Y	64	$4,000	27	$4,000	11	$4,000	102	$4,000
	Total			**194**	**$1,608**	**256**	**$645**	**153**	**$660**	**603**	**$959**
All NYCA	Y	Y	N			35	$990	39	$1,101	74	$1,049
Facilities	Y	N	N	315	$423	3106	$280	1717	$412	5138	$333
	N	Y	N	1205	$311	1810	$254	929	$308	3944	$284
			Y	263	$4,000	121	$4,000	121	$4,000	505	$4,000
	Grand Total			**1783**	**$875**	**5072**	**$364**	**2806**	**$542**	**9661**	**$510**

Key Observations: Real-Time Prices During Transmission Shortages

- Transmission shortages occurred in roughly 9 percent of all intervals in 2015. The Transmission Shortage Cost was used to set constraint shadow price at $4,000/MWh in only 5 percent of these shortage intervals. Of the remaining shortage intervals:

    - Constraint relaxation occurred in 56 percent of intervals;
    - Offline GTs were treated as scheduled for LBMP-calculation purposes but not started in 43 percent of intervals.
    - Both of the above occurred in 1 percent of intervals.

- Transmission shortages occurred most frequently on Long Island and in the West Zone during 2015.
    - The two 345 kV lines from upstate NY to Long Island and the East Garden City-to-Valley Stream line on Long Island accounted for 34 percent of all transmission shortages in 2015.
        - Severe congestion across these lines frequently occurred because of ramping limitations on Long Island. These ramp limitations generally occurred because of large changes in external interface schedules between Long Island and other regions, large changes in PAR-controlled line flows between Long Island and New York City, and/or when gas turbines were shutdown. [308]
        - More than 80 percent of time, offline GTs were counted towards resolving congestion but were not started because of the transient nature of the congestion.
    - The 230 kV transmission lines in the West Zone along the Niagara-Packard-Sawyer-Huntley transmission paths accounted for 25 percent of transmission shortages in 2015.
        - Acute congestion has occurred more frequently on these lines in recent years. The constraint limit was relaxed in almost every shortage interval because of the small number of flexible resources in the West Zone that can be dispatched to manage congestion.
    - Transmission lines into Greenwood load pocket in New York City accounted for 14 percent of transmission shortages in 2015.
        - The constraint limit was relaxed in almost every shortage interval because of a lack of flexible resources (i.e. 10-minute GTs) in the Greenwood load pocket for managing congestion.
    - The Central-East interface accounted for nearly 10 percent of shortages in 2015.
        - Shortage prices for this constraint were almost always set by offline GTs, because a large amount of such units were usually available in Eastern New York (making them capable of relieving Central-East congestion).
- Although average constraint shadow prices were relatively high during shortages, shadow prices often did not properly reflect the severity of the shortage.

308 These contributors to transient price spikes are evaluated in Section V-E.

 - For example, the shadow price averaged over $2,000/MWh when transmission shortages occurred in the Greenwood load pocket of New York City when the constraint was violated by 5 MW or less, but the shadow price averaged less than $200/MWh when the constraint was violated by more than 5 MW.
 - Shadow prices were generally uncorrelated with the shortage amount, the duration of the constraint, or any other measure of the severity of the shortage.
- The new graduated transmission demand curve that was implemented on February 11, 2016 was designed to provide price signals that are more consistent with the severity of shortages.
 - The new Graduated Transmission Demand Curve ("GTDC") is set at $350/MWh for shortages of less than 5 MW, $2,350/MWh for shortages of 5 to 20 MW, and $4,000/MWh for shortages of more than 20 MW.

I. Supplemental Commitment and Out of Merit Dispatch

When the wholesale market does not meet all forecasted load and reliability requirements, the NYISO (or an individual transmission owner) commits additional resources to ensure that sufficient resources will be available in real-time. Similarly, the NYISO and local transmission owners sometimes dispatch generators out-of-merit order ("OOM") in order to: (a) manage constraints of high voltage transmission facilities that are not fully represented in the market model; or (b) maintain reliability of the lower voltage transmission system and the distribution system.

Supplemental commitments increase the amount of supply available in real-time, while OOM dispatch causes increased production from capacity that is frequently uneconomic, which displaces production from economic capacity. Both types of out-of-market action lead to distorted real-time market prices, which tend to undermine market incentives for meeting reliability requirements and generate expenses that are uplifted to the market. Hence, it is important for supplemental commitments and OOM dispatches to be as limited as possible.

In this section, we evaluate several aspects of market operations that are related to the ISO's process to ensure that sufficient resources are available to meet the forecasted load and reliability requirements. In this sub-section, we examine: (a) supplemental commitment for reliability and focus particularly on New York City where most reliability commitments occur; and (b) the patterns of OOM dispatch in several areas of New York. In the next sub-section, we summarize uplift charges that result from guarantee payments received by generators, which are primarily caused by supplemental commitments for local reliability.

Figure A-83: Supplemental Commitment for Reliability in New York

Supplemental commitment occurs when a generator is not committed by the economic pass of the day-ahead market but is needed for reliability. Supplemental commitment primarily occurs in three ways: (a) Day-Ahead Reliability Units ("DARU") Commitment typically occurs at the request of local Transmission Owner prior to the economic commitment in SCUC; (b) Day-Ahead Local Reliability ("LRR") Commitment takes place during the economic commitment pass in SCUC to secure reliability in New York City; and (c) Supplemental Resource Evaluation ("SRE") Commitment occurs after the day-ahead market closes.

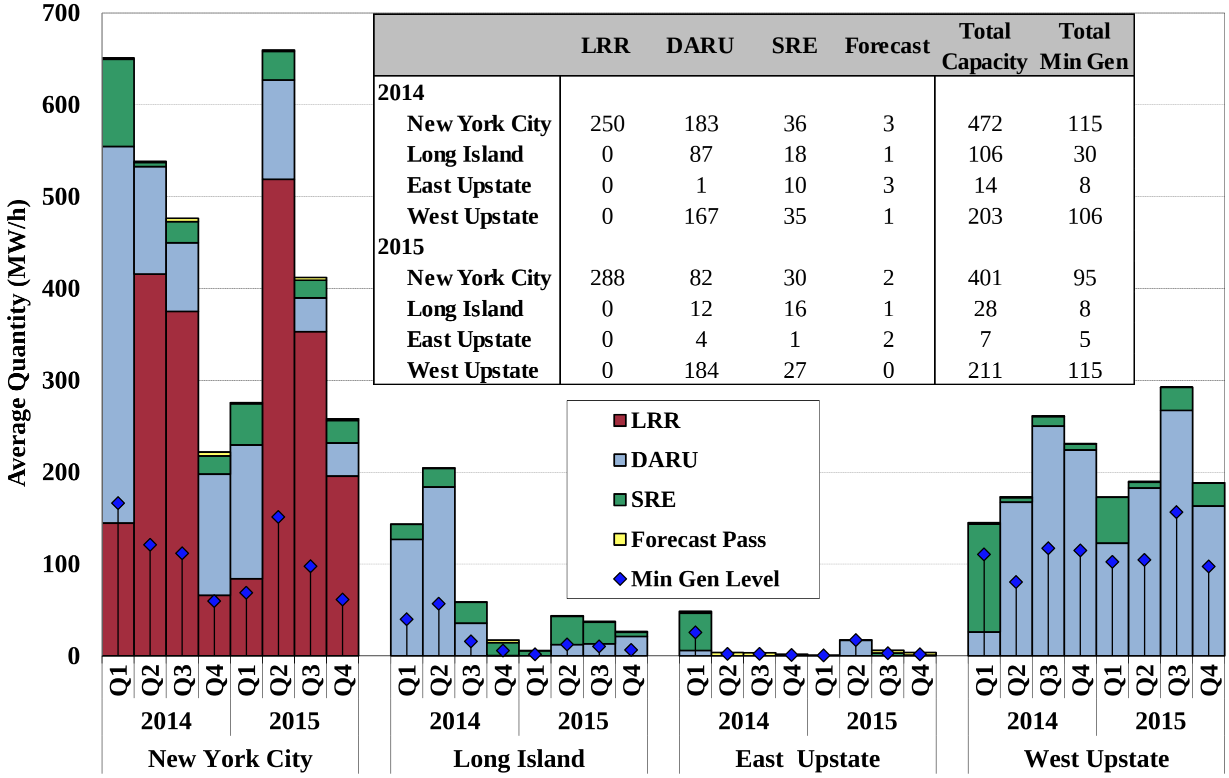
Generators that are committed for reliability are generally not economic at prevailing market prices, but they affect the market by: (a) reducing prices from levels that would otherwise result from a purely economic dispatch; and (b) increasing non-local reliability uplift since a portion of the uplift caused by these commitments results from guarantee payments to economically committed generators that do not cover their as-bid costs at the reduced LBMPs. Hence, it is important to commit these units as efficiently as possible.

To the extent LRR constraints in SCUC reflect the reliability requirements in New York City, the local Transmission Owner does not need to make DARU and SRE commitments. LRR commitments are generally more efficient than DARU and SRE commitments, which are selected outside the economic evaluation of SCUC. However, in order to commit units efficiently, SCUC must have accurate assumptions regarding the needs in each local reliability area.

Figure A-83 shows the quarterly quantities of total capacity (the stacked bars) and minimum generation (the markers) committed for reliability by type of commitment and region in 2014 and 2015. Four types of commitments are shown in the figure: DARU, LRR, SRE, and Forecast Pass. The first three are primarily for local reliability needs. The Forecast Pass, represents the additional commitment in the forecast pass of SCUC after the economic pass. The forecast pass ensures that sufficient physical resources are committed in the day-ahead market to meet forecasted load. The figure shows these supplemental commitments separately for the following four regions: (a) West Upstate, which includes Zones A through E; (b) East Upstate, which includes Zones F through I; (c) New York City, which is Zone J; and (d) Long Island, which is Zone K. The table in the figure summarizes these values for 2014 and 2015 on an annual basis.

Figure A-83: Supplemental Commitment for Reliability in New York

By Category and Region, 2014 – 2015



	LRR	DARU	SRE	Forecast	Total Capacity	Total Min Gen
2014						
New York City	250	183	36	3	472	115
Long Island	0	87	18	1	106	30
East Upstate	0	1	10	3	14	8
West Upstate	0	167	35	1	203	106
2015						
New York City	288	82	30	2	401	95
Long Island	0	12	16	1	28	8
East Upstate	0	4	1	2	7	5
West Upstate	0	184	27	0	211	115

Figure A-84: Supplemental Commitment for Reliability in New York City

In 2014 and 2015, most supplemental commitment for reliability occurred in New York City. Figure A-84 summarizes an analysis that identifies the causes for the reliability commitments in New York City. Specifically, Figure A-84 shows the minimum generation committed for reliability by reliability reason and by location in New York City during 2014 and 2015.

Based on our review of the reliability commitment logs and LRR constraint information, each hour of commitment that was flagged as DARU, LRR, or SRE was categorized as committed for one of the following reliability reasons: [309]

- NOx Only – If needed for NOx bubble and no other reason. [310]

309 A unit is considered to be committed for a LRR constraint if the constraint would be violated without the unit's capacity.

310 The New York Department of Environmental Conservation ("NYDEC") promulgates Reasonably Available Control Technology ("RACT") emissions standards for NOx and other pollutants, under the federal Clean Air Act. The NYDEC NOx standards for power plants are defined in the Subpart 227-2.4 in the Chapter III of Regulations : "Reasonably Available Control Technology (RACT) For Major Facilities of Oxides Of Nitrogen (NOx) - Control Requirements", which is available online at: http://www.dec.ny.gov/regs/4217.html#13915.

- Voltage – If needed for Application of Reliability Rule ("ARR") 26 and no other reason except NOx.
- Thermal – If needed for ARR 37 and no other reason except NOx.
- Loss of Gas – If needed to protect NYC against a sudden loss of gas supply and no other reason except NOx. [311]
- Multiple Reasons – If needed for two or three out of ARR 26, ARR 37, and Loss of Gas. The capacity is shown for each separate reason in the bar chart.

For voltage and thermal constraints, the capacity is shown for the load pocket that was secured, including:

- AELP - Astoria East Load Pocket
- AWLP - Astoria West/Queensbridge Load Pocket
- AVLP - Astoria West/ Queens/Vernon Load Pocket
- ERLP - East River Load Pocket
- FRLP - Freshkills Load Pocket
- GSLP - Greenwood/Staten Island Load Pocket; and
- SDLP - Sprainbrook Dunwoodie Load Pocket.

The pie chart in the figure shows the portion of total capacity committed under different reasons for 2015 only.

311 See *NYSRC Reliability Rules & Compliance Manual*, Version 35, See Section G.2 Local Area Operation: Loss of Gas Supply – New York City, Requirement R1.

Figure A-84: Supplemental Commitment for Reliability in New York City
By Category and Region, 2014 – 2015

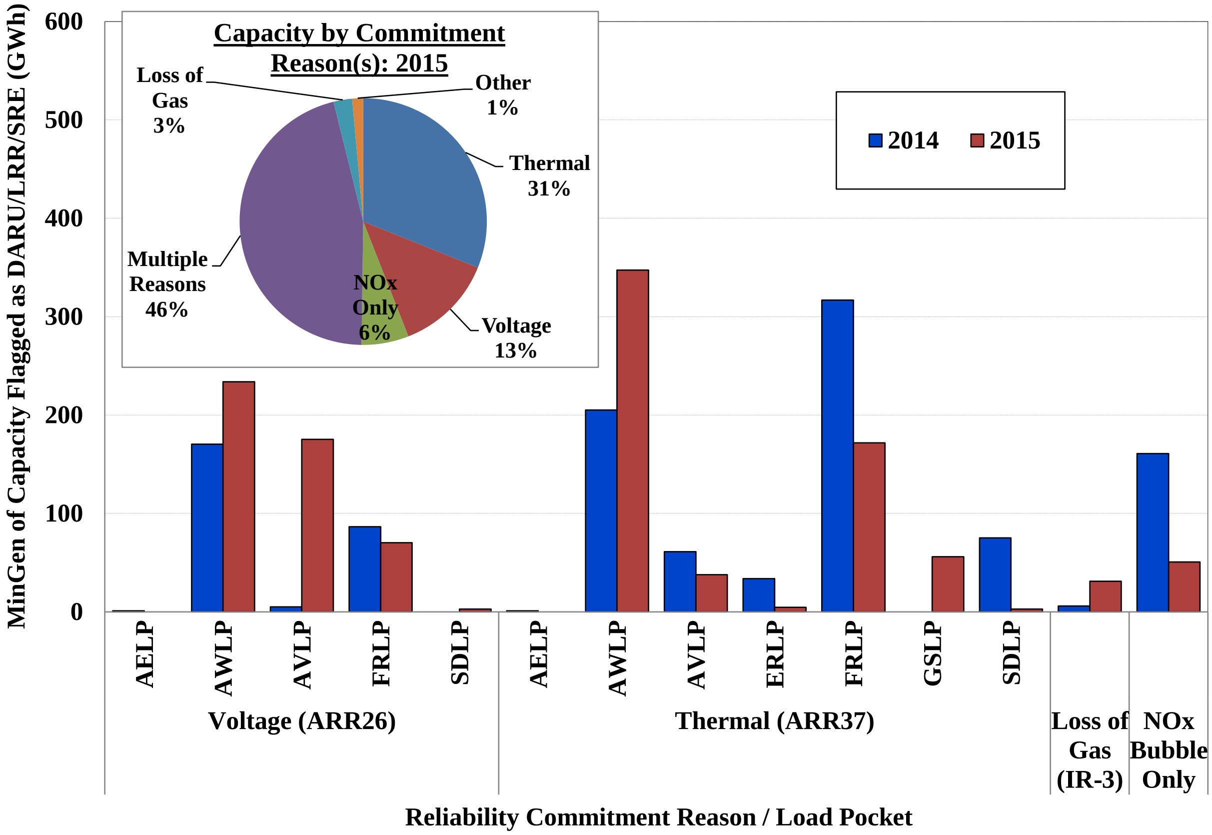


Figure A-85: NOx Emissions from Units in New York City NOx Bubbles

Supplemental commitments for the NOx Bubble constraint occur during the five-month Ozone season (i.e., from May to September) each year. The following analysis evaluates the overall efficiency of such commitments.

Many simple-cycle gas turbines in New York City emit NOx at rates that exceed the presumptive RACT limits.[312] For owners of generators that emit beyond the presumptive RACT limits, they have the following three "compliance options": [313, 314]

- Fuel Switching Option;

312 See 9 NYCRR III , §227-2.4 "Control Requirements" for these presumptive limits.

313 See 9 NYCRR III , §227-2.5(a) - (c) for more details.

314 A fourth compliance option, "shutdown of an emission source," is also listed in 9 NYCRR III , §227-2.5(d).

- System Averaging Plan – This allows a "weighted average permissible emission rate" across multiple generators; and
- Higher source-specific emission limit – This may be allowed if "the applicable presumptive RACT emission limit is not economically or technically feasible." [315, 316]

In "System Averaging Plan", the generation owners request that their steam generators and gas turbines be measured for compliance together. Since the steam units emit below the presumptive RACT limits, having a steam unit online when a gas turbine is operating will result in a lower average NOx rate than if the gas turbines operates alone.

For generation portfolios with approved System Averaging Plans, the NYISO has in turn established an LRR constraint for each generation portfolio. These LRR constraints require that at least one steam unit from each portfolio be committed each day during the five-month Ozone season. [317] This is to ensure that the NOx emission limits won't be violated if gas turbines are committed in real-time. This LRR rule provides uplift payments to the generation owners when the steam commitments are uneconomic at day-ahead LBMPs.

Figure A-85 presents energy production and NOx emissions from different generation types for New York City, by time of day and by load level. The bottom section shows average hourly energy production for NOx Bubble gas turbines and steam units and average hourly offline available capacity from combined cycles and simple cycle turbines with Selective Catalytic Reduction ("SCR") equipment. The top section of the chart shows average hourly NOx emissions for NOx Bubble gas turbines and steam units.

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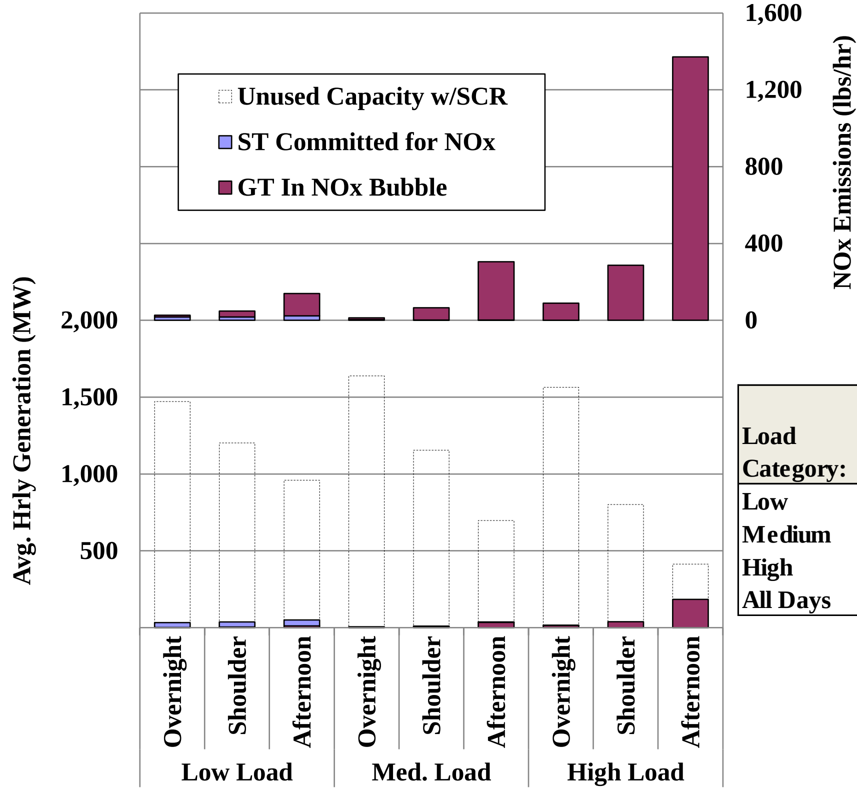
315 The current economic feasibility threshold in the NYDEC regulations is $5,000 per ton of NOx reduced. This threshold was first introduced as $3,000 per ton of NO_x reduced (based on a 1994 finding). The NYDEC elaborates "$3,000.00 dollars in 1994 equates to $4,637.73 dollars in 2012, which is then rounded up to $5,000 by the Department to ensure a level of conservatism." See DAR-20 Economic and Technical Analysis for Reasonably Available Control Technology (RACT).

316 The NYDEC provides a template for calculating the cost of emissions controls per ton of NOx reduced at http://www.dec.ny.gov/docs/air_pdf/dar20table1.pdf.

317 In May 2014, the NYISO updated one of three NOx LRR constraints to reflect that one portfolio could use a combined cycle unit instead of a steam unit to balance the simple-cycle turbines. See "Ravenswood Generating Station Nitrogen Oxide Emission Control Strategy for Compliance with 6 NYCRR Subpart 227-2."

Figure A-85: NOx Emissions and Energy Production from NOx Bubble Generators
By Time of Day, by Load Category, for 2015



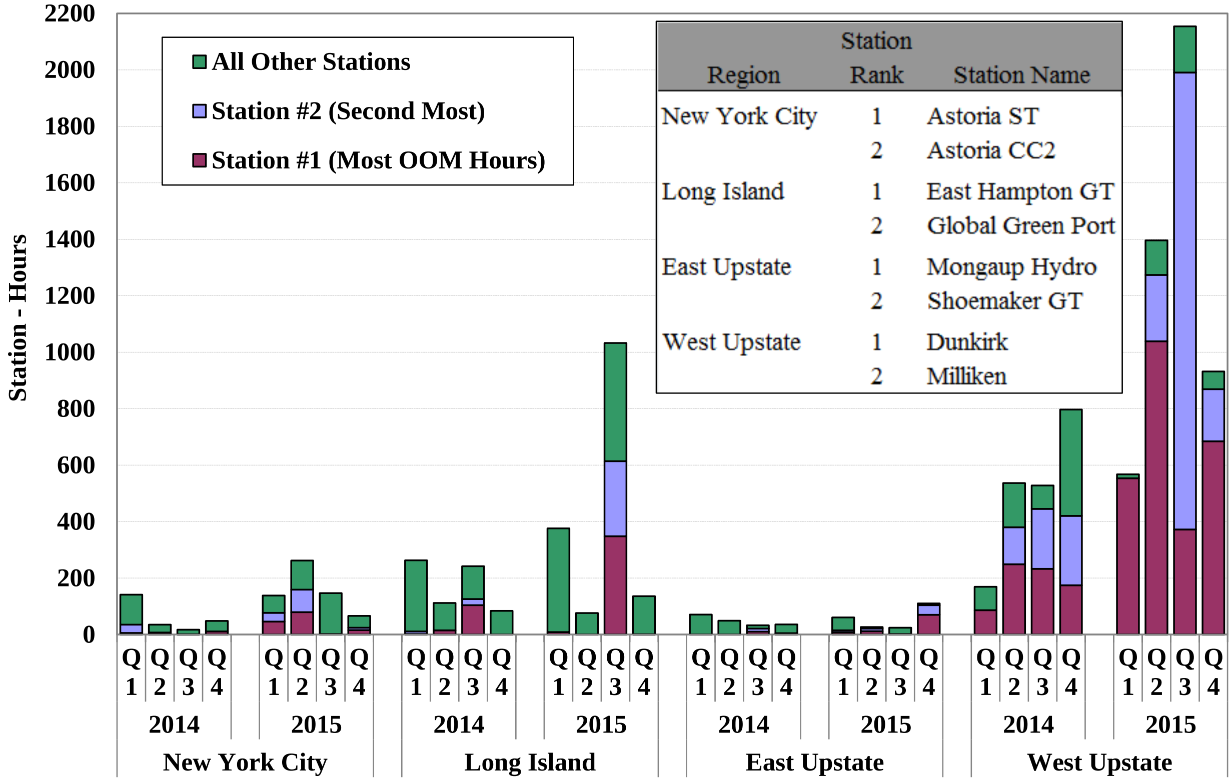
Load Category:	Output from GTs in NOx Bubble	Output from STs Committed for NOx
Low	10%	92%
Medium	25%	8%
High	65%	0%
All Days	100%	100%

Figure A-86: Frequency of Out-of-Merit Dispatch

Figure A-86 summarizes the frequency (i.e., the total station-hours) of OOM actions on a quarterly basis in 2014 and 2015 for the following four regions in New York: (a) West Upstate, which includes Zones A through E; (b) East Upstate, which includes Zones F through I; (c) New York City, which is Zone J; and (d) Long Island, which is Zone K.

In each region, the two stations with the highest number of OOM dispatch hours during 2015 are shown separately from other stations (i.e., "Station #1" is the station with the highest number of OOM hours in that region during 2015, and "Station #2" is the station with the second-highest number of OOM hours). The figure also excludes OOMs that prevent a generator from being started, since these usually indicate transmission outages that make the generator unavailable.

Figure A-86: Frequency of Out-of-Merit Dispatch
By Region by Quarter, 2014 - 2015



Key Observations: Supplemental Commitment and OOM Dispatch for Reliability

- On average, nearly 650 MW of capacity was committed each hour for reliability in 2015, down 19 percent from 2014.
  - Of the capacity committed for reliability in 2015, 62 percent was in New York City, 33 percent was in Western New York, and only 4 percent was in Long Island.
- Despite the reduction in other regions, reliability commitment in Western New York increased moderately from 2014, averaging 210 MW in 2015.
  - The West Zone and Central Zone accounted for the vast majority of DARU commitments as several coal-fired and gas-fired units were often needed to manage post-contingency flows on the 115kV facilities.
    - These units were DARUed more frequently in 2015 because they were less often economic as a result of low LBMPs.
  - However, SRE commitments fell from 2013 and early 2014 because of transmission upgrades in the North Zone (which were completed in March 2014). These upgrades reduced the size of key transmission contingencies.
- Reliability commitments fell notably from 2014 to 2015 on Long Island.

- DARU commitments rarely occurred because of transmission upgrades (including the installation of the West Bus Distributed Reactive Sources (“DRSS”) and Wildwood DRSS) in early 2014, which have reduced the need to:
  - Commit generation for voltage constraints (see ARR 28); and
  - Burn oil to protect Long Island from a loss of gas contingency.[318]
- SRE commitments mainly kept steam turbine units online during overnight hours.

- Reliability commitment in New York City fell 15 percent from 2014 to an average of roughly 400 MW in 2015.
  - Most of reliability commitments were made for the Freshkills, Astoria West/Queensbridge, and Astoria West/Queensbridge/Vernon load pockets in New York City to ensure facilities into these load pockets would not be overloaded if the largest two generation or transmission contingencies were to occur.
    - Reliability commitments for this purpose typically rose when significant generation and/or transmission outages occurred in these load pockets. For example:
      - In the first quarter of 2014, reliability commitments for the Freshkills load pocket increased notably when multiple transmission facilities were taken out of service for transmission work at the Goethals Bus.
      - In the second quarter of 2015, reliability commitments rose when transmission line outages increased needs in the Greenwood/Staten Island load pocket and generation outages increased needs in the Astoria West/Queensbridge load pocket.
  - Reliability commitments for NOx bubble constraints fell notably after 2013.
    - Such commitments occurred only during the five-month ozone season (May to September) of each year. The share of NOx-only commitment fell from 26 percent in 2013 to only 6 percent in 2015.
    - The reduction was primarily due to the updates in the NOx bubble constraint modeling in SCUC in 2014, which now requires less steam turbine capacity to satisfy the NOx bubble requirements in the LRR pass. These modeling changes were made to reflect changes in the NOx compliance plans of generating companies in New York City.[319]

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318 See *NYSRC Reliability Rules & Compliance Manual*, Version 35, See Section G.3 Local Area Operation: Loss of Gas Supply – Long Island, Requirement R1.

319 See “Ravenswood Generating Station Nitrogen Oxide Emission Control Strategy for Compliance with 6 NYCRR Subpart 227-2.”.

- In addition, units were flagged less frequently for NOx-Only commitments in 2015 than in 2014.
  - The units that are required to satisfy the NOx Bubble requirements were often needed at the same time for local voltage and/or thermal requirements in the Freshkills and Astoria West/Queensbridge load pockets in 2015, reflecting higher needs associated with higher load levels and increased peaking conditions.

- Our analysis indicates that in 2015 the NOx bubble constraints did not lead to efficient reductions in NOx emissions and may have actually led to higher overall NOx emissions.
  - When steam turbine units were committed for the NOx Bubble constraints, the output from the steam turbine units usually displaced output from newer cleaner generation in New York City and/or displaced imports to the city.
  - On average, over 1.1 GW of offline capacity from newer and cleaner generators (equipped with emission-reducing equipment) were available and unutilized on hours when steam units were committed only for the NOx bubble constraint.
  - The steam units emit approximately 13 times more NOx per MWh produced than the newer generators with emission-reduction equipment.
  - Committing steam turbines for the NOx Bubble constraints rarely reduced output from gas turbines with high emissions rates.
    - In 2015, 90 percent of output from the NOx Bubble gas turbines occurred on days with medium to high load levels, while 92 percent of the output from steam units committed for the NOx constraint occurred on low-load days.
    - Hence, the commitment of steam turbines for NOx Bubble constraints rarely coincided with the operation of gas turbines. In virtually all cases where a steam turbine was running at the same time as a gas turbine, the steam turbine was already committed for economics or some other reliability need.

- Generators were dispatched Out-of-Merit ("OOM") for approximately 7,505 station-hours, up 137 percent from 2015.
  - The increase primarily occurred in Western New York, where OOM dispatch accounted for 67 percent of all OOM station-hours in 2015 and rose 149 percent from 2014 to 2015.
    - Dunkirk was usually dispatched to secure the 115 kV Gardenville-to-Dunkirk lines for the loss of both 230 kV Gardenville-to-Dunkirk lines.
      - The NYISO also frequently managed these constraints by taking certain lines out of service on the primary PJM-NYISO interface. In 2015, the Dunkirk-to-South Ripley line was taken out for 690 hours and the Warren-to-Falconer line was taken out for 1,780 hours. Shifting the distribution of flows across the PJM-NYISO interface can reduce the loadings on the 115 kV Gardenville-to-Dunkirk lines.

    - Milliken was usually dispatched to secure the 115 kV Elbridge-to-State St. lines for various contingencies.
    - Lower LBMPs led to more frequent OOM dispatch of these units in 2015.
  - OOM dispatch in Long Island also rose notably from a year ago, primarily in the third quarter of 2015 because of higher load levels and more frequent peaking conditions.
    - Most of these OOM instructions were to dispatch peaking generators to manage voltage constraints on the East End of Long Island.
  - Furthermore, the Niagara generator was often manually instructed to shift output between the generators at the 115kV station and the generators at the 230kV station in order to secure certain 115kV and/or 230kV transmission facilities.
    - However, these were not classified as OOM in hours when the NYISO did not adjust the UOL or LOL of the Resource.
    - In 2015, this manual shift was required in 950 hours to manage 115 kV constraints and in 2,330 hours to manage 230 or 345 kV constraints.

J. Uplift Costs from Guarantee Payments

Uplift charges from guarantee payments accrue from the operation of individual generators for local reliability and non-local reliability reasons in both the day-ahead and real-time markets. Figure A-87 and Figure A-88 summarize the three categories of non-local reliability uplift that are allocated to all Load Serving Entities ("LSEs") and the four categories of local reliability that are allocated to the local Transmission Owner.

The three categories of non-local reliability uplift are:

- Day-Ahead Market – This primarily includes guarantee payments to generators that are economically committed in the day-ahead market. These generators receive payments when day-ahead clearing prices are not high enough to cover the total of their as-bid costs (includes start-up, minimum generation, and incremental costs). When a DARU unit is committed by the NYISO for statewide reliability, the resulting guarantee payments are uplifted statewide. However, these account for a very small portion of DARU capacity.
- Real-Time Market – Guarantee payments are made primarily to gas turbines that are committed by RTC and RTD based on economic criteria, but do not receive sufficient revenue to cover start-up and other running costs over their run time. Guarantee payments in the category are also made for: a) SRE commitments and out-of-merit dispatch that are done for bulk power system reliability; b) imports that are scheduled with an offer price greater than the real-time LBMP; and c) demand response resources (i.e., EDRP/SCRs) that are deployed for system reliability.
- Day-Ahead Margin Assurance Payment – Guarantee payments made to cover losses in margin for generators dispatched by RTD below their day-ahead schedules. When a unit has been dispatched or committed for local reliability, any day-ahead margin assurance

payments it receives are allocated as local reliability uplift. However, the majority of day-ahead margin assurance payments are allocated as non-local reliability uplift.

The four categories of local reliability uplift are:

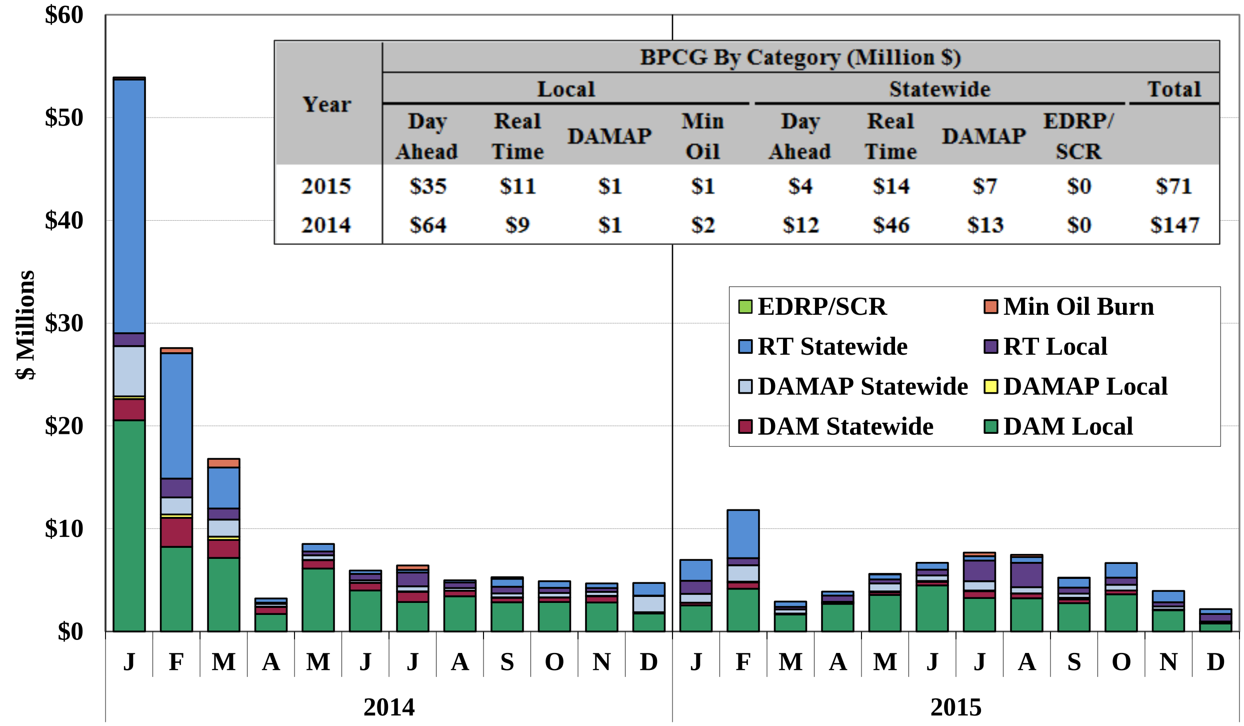
- Day-Ahead Market – Guarantee payments are made to generators committed in the SCUC due to Local Reliability Rule ("LRR") or as Day-Ahead Reliability Units ("DARU") for local reliability needs at the request of local Transmission Owners. Although the uplift from payments to these units is allocated to the local area, these commitments tend to decrease day-ahead prices. As a result of lower prices, more (non-local reliability) uplift is paid to generators that are economically committed before the local reliability pass.
- Real-Time Market – Guarantee payments are made to generators committed and redispatched for local reliability reasons after the day-ahead market. While this can occur for a variety of reasons, the majority of this uplift is related to Supplemental Resource Evaluation ("SRE") commitments.
- Minimum Oil Burn Compensation Program – Guarantee payments made to generators that cover the spread between oil and gas prices when generators burn fuel oil to help maintain reliability in New York City due to potential natural gas supply disruptions.
- Day-Ahead Margin Assurance Payment – Guarantee payments made to cover losses in margin for generators dispatched out-of-merit for local reliability reasons below their day-ahead schedules.

Figure A-87 & Figure A-88: Uplift Costs from Guarantee Payments

Figure A-87 shows the seven categories of uplift costs associated with guarantee payments on a monthly basis for 2014 and 2015. The uplift costs associated with the EDRP/SCR resources are shown separately from other real-time statewide uplift costs. The table summarizes the total uplift costs under each category on an annual basis for these two years. Figure A-88 shows the seven categories of uplift charges on a quarterly basis in 2014 and 2015 for four regions in New York: (a) West Upstate, which includes Zones A through E; (b) East Upstate, which includes Zones F through I; (c) New York City, which is Zone J; and (d) Long Island, which is Zone K. The uplift costs paid to import transactions from neighboring control areas and EDRP/SCR resources are shown separately from the generation resources in these four regions in the chart. The table summarizes the total uplift costs in each region on an annual basis for these two years.

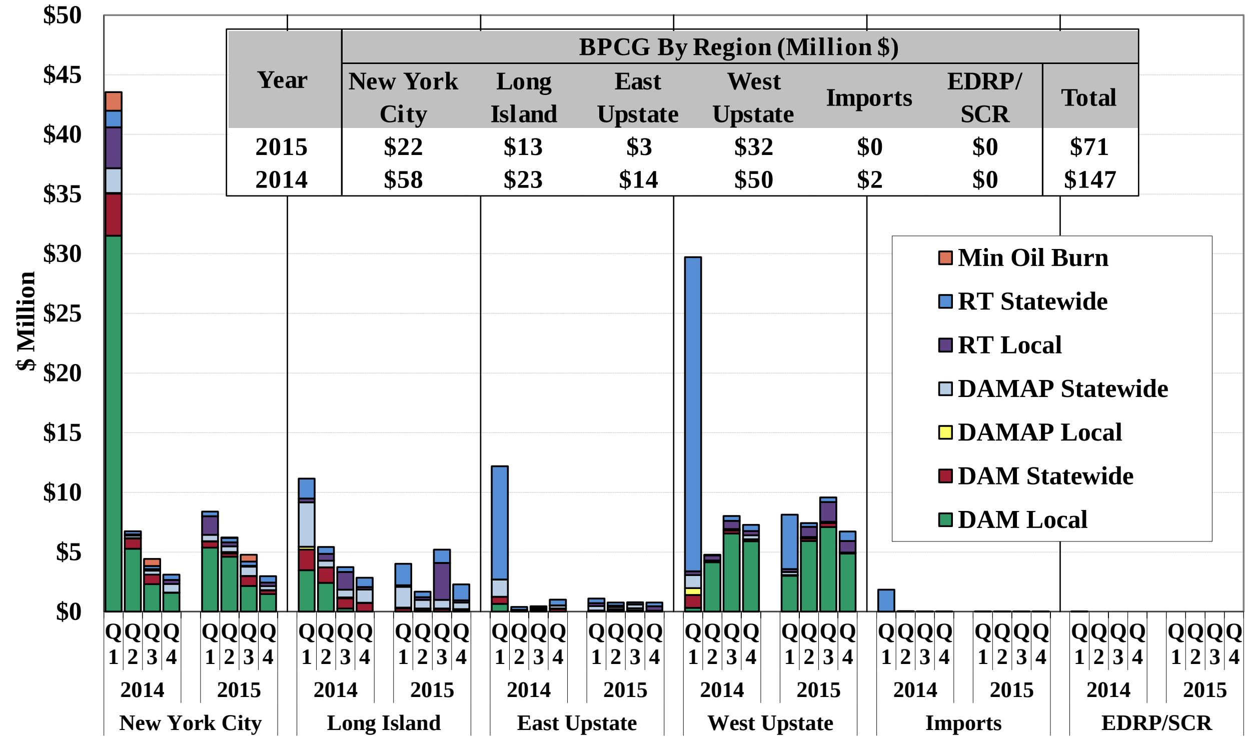
It is also noted that Figure A-87 and Figure A-88 are based on information available at the reporting time and do not include some manual adjustments resulting from mitigation consultations, hence, they can be different from final settlements.

Figure A-87: Uplift Costs from Guarantee Payments by Month
2014 – 2015



Year	BPCG By Category (Million $)								
	Local				Statewide				Total
	Day Ahead	Real Time	DAMAP	Min Oil	Day Ahead	Real Time	DAMAP	EDRP/ SCR	
2015	$35	$11	$1	$1	$4	$14	$7	$0	$71
2014	$64	$9	$1	$2	$12	$46	$13	$0	$147

Figure A-88: Uplift Costs from Guarantee Payments by Region
2014 – 2015



Year	BPCG By Region (Million $)						
	New York City	Long Island	East Upstate	West Upstate	Imports	EDRP/ SCR	Total
2015	$22	$13	$3	$32	$0	$0	$71
2014	$58	$23	$14	$50	$2	$0	$147

<u>Key Observations: Uplift Costs from Guarantee Payments</u>

- Total guarantee payment uplift fell roughly 52 percent, from $147 million in 2014 to $71 million in 2015.
  - The vast majority of the reduction occurred in the first quarter of 2015 because of:
    - Decreased supplemental commitment in New York City and Long Island; and
    - Much lower natural gas prices, which greatly decreased the commitment costs of gas-fired units that were needed for reliability.
      - For example, the period from January 22-28, 2014 accounted for $30 million in guarantee payment when gas prices averaged over $50/MMbtu in Eastern New York; while there were no such periods in 2015.
  - Guarantee payment uplift was generally comparable in the rest three quarters between 2014 and 2015 as lower natural gas prices that reduced commitment costs of gas-fired units were offset by higher OOM dispatches.
- Of the total guarantee payment uplift in 2015:
  - Local reliability uplift accounted for 66 percent, while non-local reliability uplift accounted for the remaining 34 percent.
  - Western New York accounted for 45 percent (which was higher than New York City for the first time), New York City accounted for 32 percent, and Long Island accounted for 19 percent.
- Min Oil Burn Compensation program payments fell substantially after 2013 because of increased reliance on auto-switchable combined-cycle units rather than steam turbines running on a blend of oil and gas (on days when gas prices were lower than oil prices).
- Local uplift in Western New York totaled nearly $25 million, accounting for 35 percent of total guarantee uplift in 2015.
  - 95 percent of the local uplift was paid to several units that were committed for reliability and/or OOMed to manage congestion on the 115 kV transmission facilities

VI. Capacity Market

The capacity market is designed to ensure that sufficient capacity is available to satisfy New York's planning reserve margin requirements. The capacity market provides economic signals that supplement the signals provided by the NYISO's 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. In this section, we evaluate the performance of the capacity market.

The New York State Reliability Council ("NYSRC") determines the Installed Reserve Margin ("IRM") for NYCA, which is the amount of planning reserves necessary to meet the reliability standards for New York State. The NYISO uses the IRM in conjunction with the annual peak load forecast to calculate the Installed Capacity ("ICAP") requirement for NYCA.[320] The NYISO also determines the Minimum Locational Installed Capacity Requirements ("LCRs") for New York City and Long Island, which it uses in conjunction with the locational annual peak load forecast to calculate the locational ICAP requirement.[321]

Since the NYISO operates an Unforced Capacity ("UCAP") market, the ICAP requirements are translated into UCAP requirements, using location-wide availability rates known as Derating Factors. The obligations to satisfy the UCAP requirements are allocated to the LSEs in proportion to their annual coincident peak load in each area. LSEs can satisfy their UCAP requirements by purchasing capacity through bilateral contracts, by self-scheduling their own capacity, or by participating in UCAP market auctions run by the NYISO.

The NYISO conducts three UCAP auctions: a forward strip auction where capacity is transacted in six-month blocks for the upcoming capability period, a monthly forward auction where capacity is transacted for the remaining months of the capability period, and a monthly spot auction. The two forward markets are voluntary, but all requirements must be satisfied at the conclusion of the spot market immediately prior to each month. Market participants that have purchased more than their obligation prior to the spot auction may sell the excess into the spot auction. The capacity demand curves are used to determine the clearing prices and quantities

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320 The ICAP requirement = (1 + IRM) * Forecasted Peak Load. The IRM was set at 17 percent in the preceding two Capability Years (i.e., the period from May 2014 to April 2015 and the period from May 2015 to April 2016). NYSRC's annual IRM reports may be found at "http://www.nysrc.org/NYSRC_NYCA_ICR_Reports.asp".

321 The locational ICAP requirement = LCR * Forecasted Peak Load for the location. The Long Island LCR was 107 percent in the period from May 2014 to April 2015 and 103.5 percent in the period from May 2015 to April 2016. The New York City LCR was 85 percent in the period from May 2014 to April 2015 and 83.5 percent in the period from May 2015 to April 2016. The LCR for the newly implemented G-J Locality was set at 88 percent in the period from May 2014 to April 2015 and 90.5 percent in the period from May 2015 to April 2016. Each IRM Report recommends Minimum LCRs for New York City, Long Island, and the G-J Locality, which the NYISO considers before issuing recommended LCRs in its annual Locational Minimum Installed Capacity Requirements Study, which may be found at "http://www.nyiso.com/public/markets_operations/services/planning/planning_studies/index.jsp".

purchased in each locality in each monthly UCAP spot auction.[322] The amount of UCAP purchased is determined by the intersection of UCAP supply offers in the spot auction and the demand curve (adjusted for capacity sales through bilateral contracts and forward auctions). Hence, the spot auction may purchase more capacity than is necessary to satisfy the UCAP requirement when more capacity is available.

Every three years, the NYISO updates the capacity demand curves. The demand curves are set so that the demand curve price equals the levelized cost of a new peaking unit (net of estimated energy and ancillary services revenue) when the quantity of UCAP procured exceeds the UCAP requirement by a small margin. The demand curve price equals $0 when the quantity of UCAP procured exceeds the UCAP requirement by 12 percent for NYCA, 15 percent for the G-J Locality, and 18 percent for both New York City and Long Island. The demand curve is defined as a straight line through these two points.[323]

This report evaluates a period when there were four capacity market Localities: G-J Locality (Zones G to J), New York City (Zone J), Long Island (Zone K), and NYCA (Zones A to K).[324] New York City, Long Island and the G-J Locality are each nested within the NYCA Locality. New York City is additionally nested within the G-J Locality. Distinct requirements, demand curves, and clearing prices are set in each individual capacity market Locality, although the clearing price in a nested Locality cannot be lower than the clearing price in the surrounding Locality.

Figure A-89 through Figure A-92 in sub-sections VI.A –VI.C summarize: (a) variations of installed capacity by technology, (b) levels of capacity imports and exports from neighboring control areas, and (c) equivalent forced outage rates ("EFORd") of gas and oil-fired units.

To evaluate the performance of the capacity market, the figures in the rest of the section show the capacity market results from May 2014 through February 2016. Figure A-93 through Figure A-96 summarize the categories of capacity supply and the quantities purchased in each month in UCAP terms as well as the clearing prices in the monthly spot auctions. Sub-section VI.D evaluates NYCA overall, and sub-section VI.E evaluates the performance in the local capacity zones.

A. Installed Capacity of Generators in NYCA

322 The capacity demand curves are not used in the forward strip auction and the forward monthly auction. The clearing prices in these two forward auctions are determined based on participants' offers and bids.

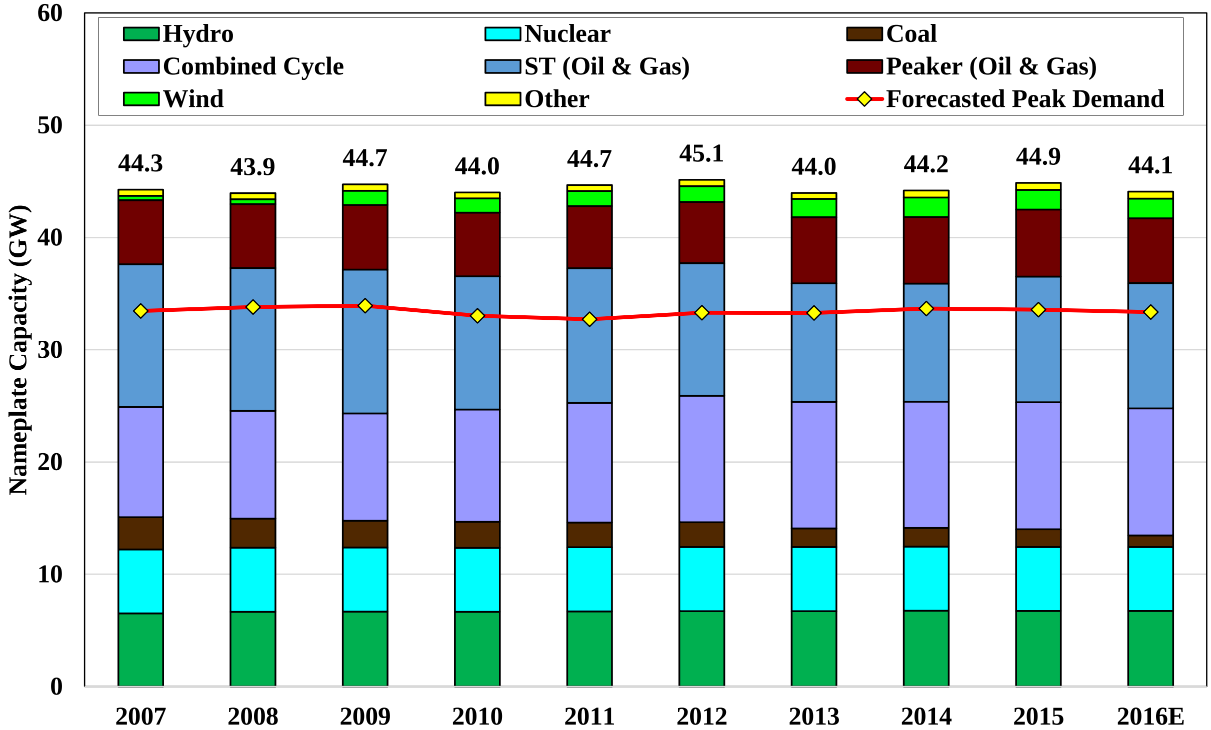
323 The demand curves also have maximum price levels which apply when UCAP procured falls substantially below the UCAP requirement. The demand curves for the 2013/2014, 2014/2015, 2015/2016, and 2016/2017 Capability Years may be found in NYISO MST 5.14.1.2. The demand curves are defined as a function of the UCAP requirements in each locality, which may be found at "http://icap.nyiso.com/ucap/public/ldf_view_icap_calc_selection.do".

324 The NYISO began to model the "G-J Locality" in May 2014.

Figure A-89 - Figure A-90: Installed Capacity Nameplate and Forecasted Peak Demand

Figure A-89 shows the total installed capacity of generation (by prime mover) and the forecasted summer peak demand for the New York Control Area for the years 2007 through 2016.[325] Figure A-90 shows a regional distribution of generation resources and the forecasted non-coincident peak demand level for each region over the same timeframe. The installed capacity shown for each year is based on the nameplate capacity of resources that are operational at the beginning of the Summer Capability Period of that year (i.e., capacity online by May 1 of each given year).

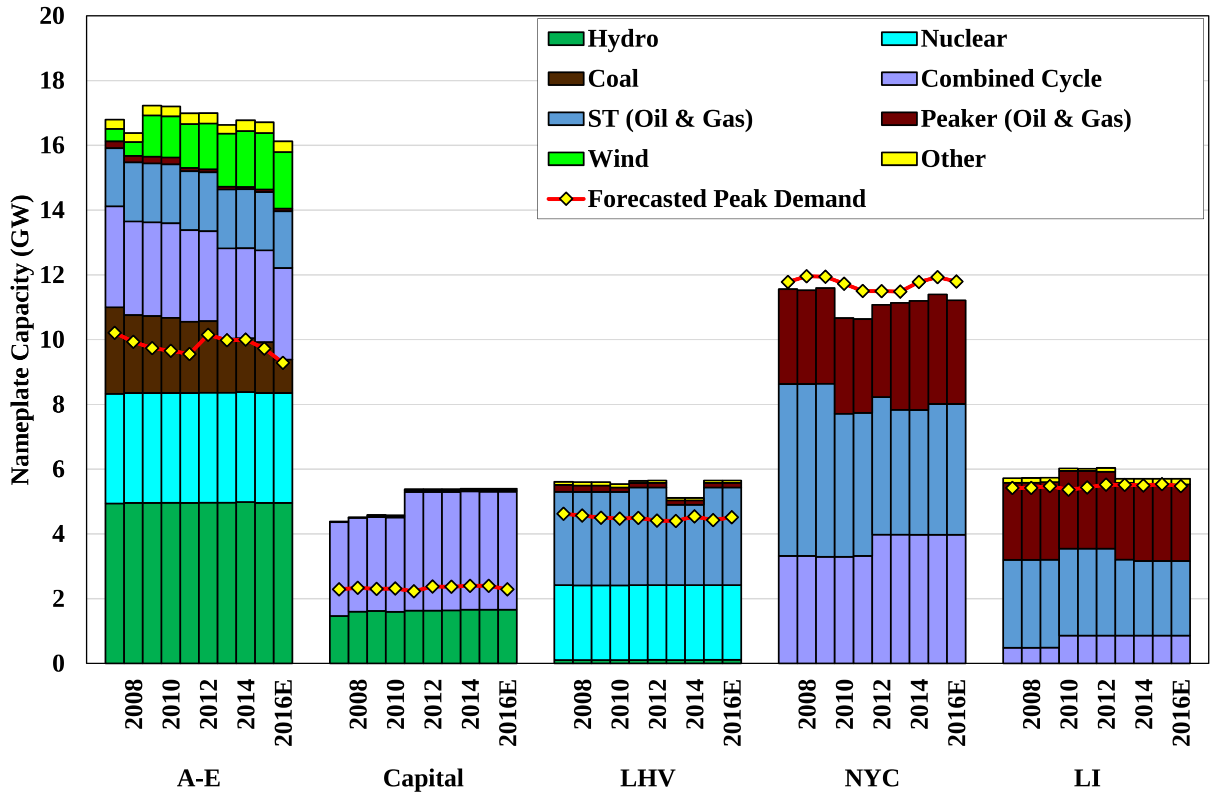
Figure A-89: Installed Capacity Nameplate of Generation by Prime Mover
May 1, 2007 to 2016[326]



325 The summer peak demand shown is based on the forecasted NYCA coincident peak demand from the Gold Book of each year. The installed capacity shown is based on data from the 2015 NYISO Gold Book. The actual UCAP available is lower than the nameplate ICAP due to the seasonal variations in available capacity and due to various forced or unforced outages that reduce the actual generation capacity.

326 Data for the 2016 calendar year represents the capacity from the 2015 Gold Book updated with information from the March 2016 Generator Status Update file. See http://www.nyiso.com/public/webdocs/markets_operations/services/planning/Documents_and_Resources/Generator_Status_Updates/Updates_since_4-24-2015/Generator%20Status%20Update%20-%2003-09-2016.xls

Figure A-90: Installed Capacity Nameplate of Generation by Region and by Prime Mover
May 1, 2007 to 2016



Key Observations: Installed Capacity in NYISO

- The current generation mix in the NYISO Control Area is dominated by oil and gas resources with combined cycle, steam turbine and combustion turbine units comprising 64 percent of the total installed capacity in 2016. Hydro and nuclear generating units make up 15 percent and 13 percent of the total capacity in 2016, respectively.
- The total generating capacity in the NYISO remained relatively flat at 44 GW (nameplate) between 2007 and 2016.[327] However, a number of generating facilities have entered and exited the market during this period.
  - A combination of low gas prices and stronger environmental regulations have led to the retirement of the majority of coal-fired generating facilities in New York. The capacity associated with coal units has shrunk from 3.2 GW in 2007 to 1 GW in 2016, a 68 percent decrease. Other notable retirements include Poletti 1 in NYC in 2010. Astoria 4 in NYC in 2012, and the Glenwood 04 and 05 units in Long Island in 2012.[328]

327 Capacity numbers listed in this section are nameplate values, unless otherwise noted.

328 Retirements during a calendar year are most often represented in the following year's Gold Book data.

- As indicated by the drop in total capacity in 2016 in Figure A-89, nearly 800 MW of generating capacity has announced its intention to retire or enter into mothballed or ICAP Ineligible Forced Outage states since the publication of the 2015 Gold Book. The bulk of this capacity being taken out of service is made up of coal (the Huntley and Dunkirk units in Western NY) and older peaking units (several Astoria GTs in NYC).[329]
- The new capacity that entered the ICAP market between 2007 and 2016 has primarily been gas-fired and wind generation facilities. Significant investments, totaling over 1.4 GW, were made in new wind generation facilities in Zones A through E.[330] The entry of two major gas-fired facilities during this period (Astoria Energy II in 2011 and Bayonne Energy Center in 2012) added 1.2 GW of capacity to NYC.
- The NYISO's interconnection queue contains a list of proposed projects that have entered into an Interconnection Agreement and are, therefore, in an advanced stage of development. Such projects include a 680 MW combined cycle facility in Zone G (CPV Valley Energy Center) and over 136 MW of renewable generation across NYCA.

- As shown in Figure A-90, the generating capacity located in A-E Zones is based on a fairly diverse fuel mix. However, the fuel mix is not very diverse in the remaining zones with a vast majority (about 84 percent in 2016) of the generating facilities located in F-K Zones being gas or oil-fired units. The only major facility that is not gas or oil-fired in eastern New York is the Indian Point nuclear facility in Zone H.
- State-wide installed capacity levels relative to the forecasted peak demand have ranged from 130 percent to 137 percent over the years 2007 to 2016. Installed capacity levels relative to peak loads are typically higher in Zones A-F. The ICAP margins are tighter in New York City and Long Island. These Localities account for about 51 percent of the total forecasted peak load in 2016. However, these two zones accounted for just 38 percent of the total installed capacity in 2016.

B. Capacity Imports and Exports

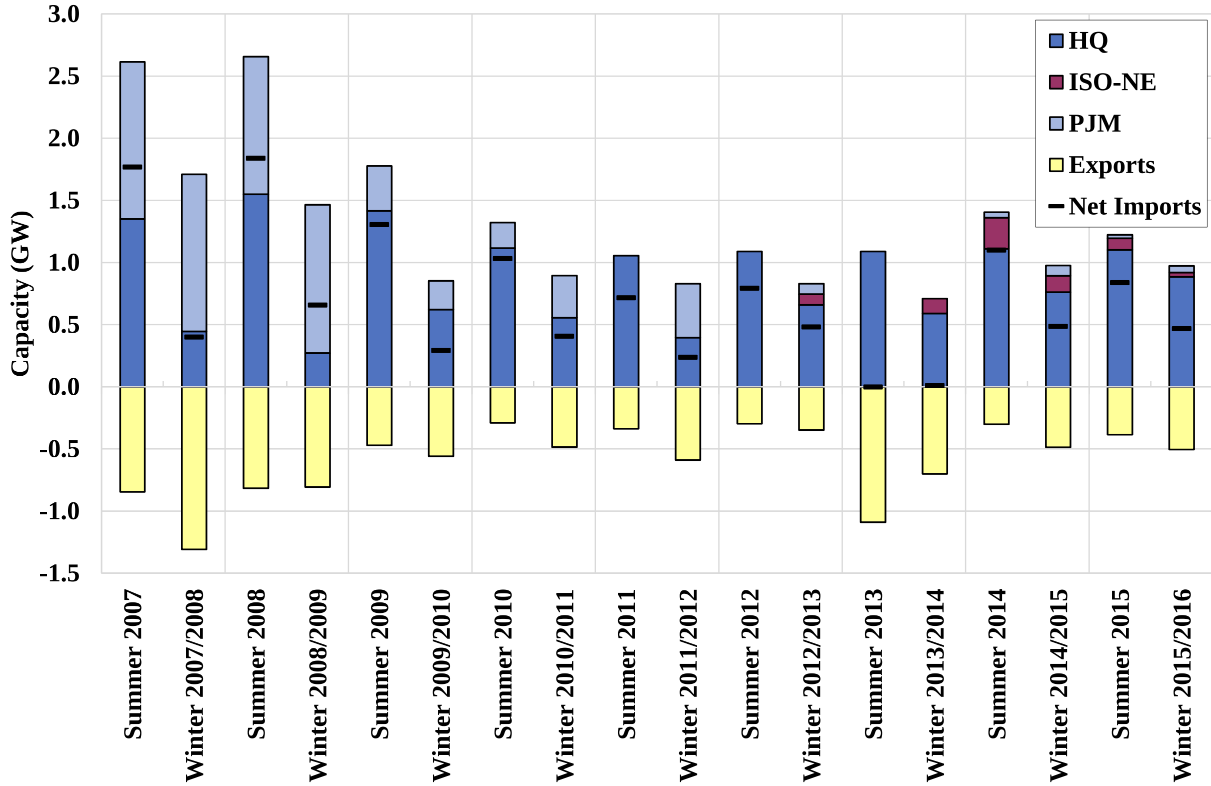
329 The announced retirement of Fitzpatrick nuclear unit is not incorporated into the 2016 installed capacity data, since the unit will be available for the 2016 Summer Capability Period.

330 This number is representative of the ICAP capacity from wind units. Seasonal deratings to account to peak availability bring that number closer to 140 MW, i.e. 10% of ICAP, as UCAP capacity added to the market based on wind being non-dispatchable.

Figure A-91: Net Imports Levels into NYISO

Figure A-91 shows the monthly average of net capacity imports into the NYISO from neighboring control areas from Summer 2007 through Winter 2015/16.[331] Capacity imports into the NYCA primarily originate from three external areas: (a) PJM; (b) ISO-NE, and (c) Hydro Quebec ("HQ"). The capacity imported from each region is shown by the positive value stacked bars, while the total capacity exported from the NYCA is shown as negative value bars. The chart also shows the total net capacity imported into the NYCA.

Figure A-91: NYISO Capacity Imports by Interface and Total Exports
Summer 2007– Winter 2015/16



Key Observations: Capacity Imports and Exports

- Capacity imports have fluctuated significantly during the years 2007 through 2015, with a high of over 1.8 GW in Summer 2008 to almost zero net imports in Summer 2013.
  - The largest source of change from 2007 to current level of imports stems from the near-disappearance of imports from PJM.
  - The seasonal variation in capacity imports from external control areas can largely be attributed to the pattern of imports from HQ. HQ is a large exporter of hydro capacity with an internal load profile that peaks in the winter. As such, summer

331 This data shown is the monthly average of capacity imported/ exported over the capability period.

imports from HQ are routinely at their maximum allocated value, while exports during winter months dip due to HQ's internal needs.

- Generators located in ISO-NE have exported 90 to 250 MW of capacity to the NYISO starting from Winter 2012/13. No capacity located in the ISO-NE footprint was exported to the NYISO in the capability periods prior to Winter 2012/13. This was largely driven by a recovery of the NYCA capacity prices to $0.82 per kW-month in Winter 2012/13 following the slump to $0.15 per kW-month in the previous winter.

C. Equivalent Forced Outage Rates and Derating Factors

The UCAP of a resource is equal to the installed capability of a resource adjusted to reflect the availability of the resource, as measured by its Equivalent Forced Outage Rate on demand ("EFORd"). A generator with a high frequency of forced outages over the preceding two years (i.e. a unit with a high EFORd) would not be able to sell as much UCAP as a reliable unit (i.e. a unit with a low EFORd) of the same installed capacity. For example, a unit with 100 MW of tested capacity and an EFORd of 7 percent would be able to sell 93 MW of UCAP. [332] This gives suppliers a strong incentive to provide reliable performance.

As discussed previously, the Locality-specific Derating Factors are used to translate ICAP requirements into UCAP requirements for each capacity zone. The NYISO computes the derating factor for each capability period based on the weighted-average EFORd of the capacity resources that are electrically located within the zone. For each Locality, a Derating Factor is calculated from the six most recent 12-month rolling average EFORd values of resources in the Locality in accordance with Sections 2.5 and 2.7 of the NYISO's Installed Capacity Manual.[333]

Table A-15: Historic Derating Factors by Locality

Table A-15 shows the Derating Factors the NYISO calculated for each capacity zone from Summer 2011 onwards.

[332] The variables and methodology used to calculate EFORd for a resource can be found at http://www.nerc.com/pa/RAPA/gads/DataReportingInstructions/Appendix_F%20-%20Equations.pdf

[333] The Derating Factor used in each six-month capability period for each Locality may be found at: "http://icap.nyiso.com/ucap/public/ldf_view_icap_calc_detail.do".

Table A-15: Derating Factors by Locality
Summer 2011 – Winter 2015/16

Locality	Summer 2015	Summer 2014	Summer 2013	Summer 2012	Summer 2011	Winter 2015/ 16	Winter 2014/ 15	Winter 2013/ 14	Winter 2012/ 13	Winter 2011/ 12
G-I	3.40%	6.86%	N/A	N/A	N/A	4.24%	5.72%	N/A	N/A	N/A
LI	7.83%	7.65%	6.84%	9.31%	8.41%	9.02%	8.28%	7.37%	9.34%	9.54%
NYC	6.92%	5.44%	5.59%	6.79%	5.30%	10.49%	5.06%	6.63%	5.11%	5.29%
A-F	10.21%	10.92%	N/A	N/A	N/A	9.43%	8.50%	N/A	N/A	N/A
NYCA	8.54%	9.08%	8.91%	9.18%	8.20%	9.06%	7.32%	8.31%	7.17%	7.95%

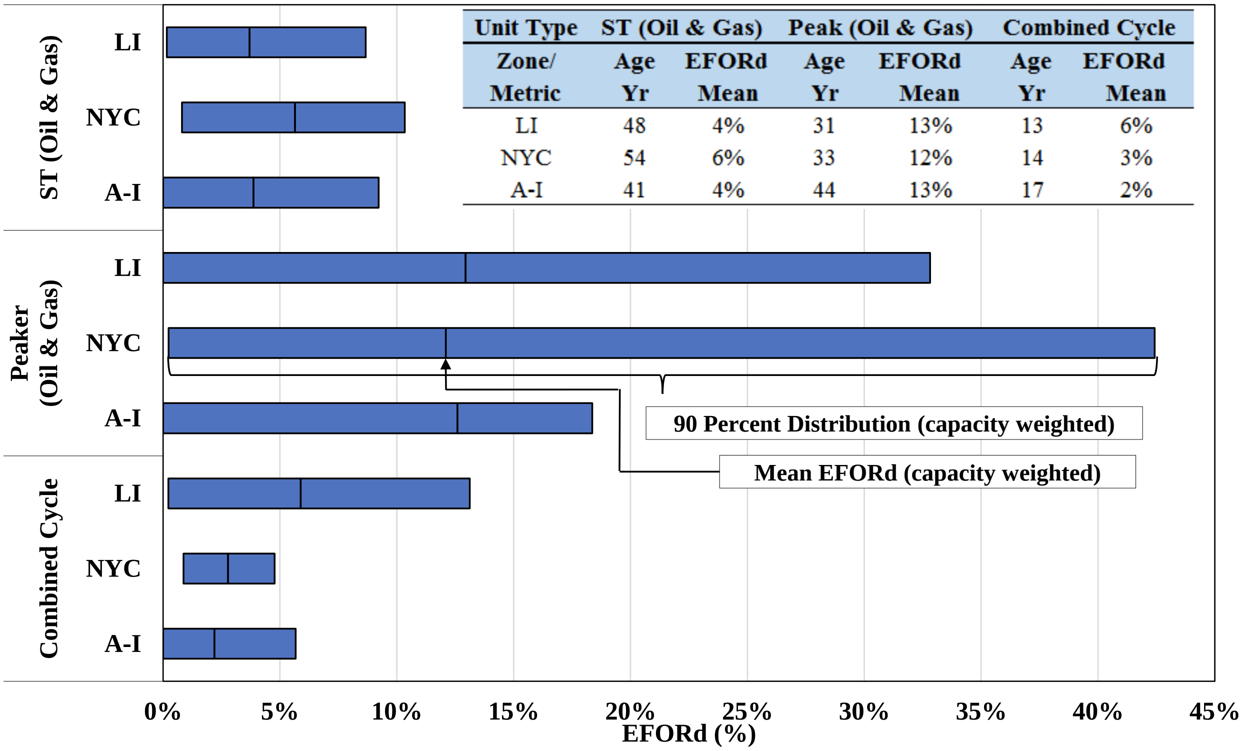
Key Observations: Equivalent Forced Outage Rates

- The NYCA-wide Derating Factor fell slightly from Summer 2014 to Summer 2015 while the Derating Factor for the Winter 2015/16 Capability Period increased 1.74 percentage points from the Winter 2014/15 Capability Period. The change in NYCA-wide winter Derating Factors can largely be attributed to the significant jump in Derating Factor for the NYC Locality. The slight drop in NYCA-wide summer Derating Factor is mainly driven by the drop in the EFORd of generation located in Zones G-I.
- The Derating Factor for Zones A-F is generally higher than the values observed in other zones. As shown in Figure A-90, nearly 10 percent of the installed generating facilities located in Zones A-F are intermittent in nature. Consequently, the average EFORd of capacity resources located in Zones A-F is higher than the average EFORd for other zones, where the resources are predominantly gas, oil-fired or nuclear units.
- The overall mix of capacity resources located in Long Island, as shown in Figure A-90, has a high proportion (84 percent) of older steam and peaking units, when compared to NYC (65 percent). A number of relatively new combined cycle units (over 2.2 GW of capacity that is less than 10 years old) are also located in NYC. As a result, the Derating Factors for Long Island have generally been higher than those for NYC.

Figure A-92: Gas and Oil-Fired EFORds by Technology Type and Region

The rest of this sub-section discusses the distribution of the EFORd values for combined cycle gas, steam turbines, and oil and gas-fired peaking units in various regions. The EFORd range shown for each technology type and region (Figure A-92) excludes the top and bottom 5 percent of the capacity ordered by EFORd. For example, if the left-most limit and right-most limit of the range shown for steam turbines in a region are 1 and 8 percent, respectively, then that indicates that 90 percent of the total steam turbine capacity in that region has an EFORd between those two values.

Figure A-92: EFORd of Gas and Oil-fired Generation by Zone
Summer 2015



Unit Type	ST (Oil & Gas)		Peak (Oil & Gas)		Combined Cycle	
Zone/ Metric	Age Yr	EFORd Mean	Age Yr	EFORd Mean	Age Yr	EFORd Mean
LI	48	4%	31	13%	13	6%
NYC	54	6%	33	12%	14	3%
A-I	41	4%	44	13%	17	2%

Key Observations: EFORd of Gas and Oil Units

- As shown in Figure A-92, the EFORd values vary broadly across technology type and age of the generation facilities.
  - Combined cycle units have the lowest average age and as a result, also tend to have lower EFORd values than the older steam turbine and peaking units. The mean EFORd for combined cycle units in New York is consistent with estimated national average EFORd of 5.42 percent for these type of units.[334]
  - Steam units, though older, tend to have a lower EFORd than peaking plants. The methodology for calculating EFORd relies on a number of factors, including the number of hours during which the plant generates power. In situations where two units have similar operating profiles insofar as the outage frequency, outage duration, and the number of starts, the EFORd calculation favors the unit that runs for more hours per start. Consequently, steam units have lower EFORds than peaking units.
  - The EFORd values for peaking units tend to be higher on an average and also exhibit a greater degree of variance when compared to other types of units. The large variance in EFORd values for peaking units can be explained by the distribution of

334 National average EFORd values represent findings from the 2014 GADS Generating Statistical Brochure available at: http://www.nerc.com/pa/RAPA/gads/Reports/Generating%20Unit%20Statistical%20Brochure%203%2020 10-2014-Units%20Reporting%20Events.pdf

the ages of the facilities and by the relatively low number of hours during these units are called on to run.

- First, the reliability (and EFORd) of a unit is likely to be affected by the age of the facility and consequently, the distribution of facility ages can partially explain the large spread in EFORds of peaking units. The age of peaking units in NYC ranges from four years to 49 years.
- Second, peaking units tend to have higher operating costs than other units and are likely to be committed for fewer hours a year. In other words, the number of sample hours over which the relevant observations (for calculating the EFORd) are made is small. Consequently, the variance in estimated EFORd across peaking units is high. Therefore, for units that are equally likely to being in a forced outage, the EFORd calculation methodology is likely to result in a greater variance in EFORds for inefficient units, when compared to the variance in EFORds for a group of more efficient units.

D. Capacity Market Results: NYCA

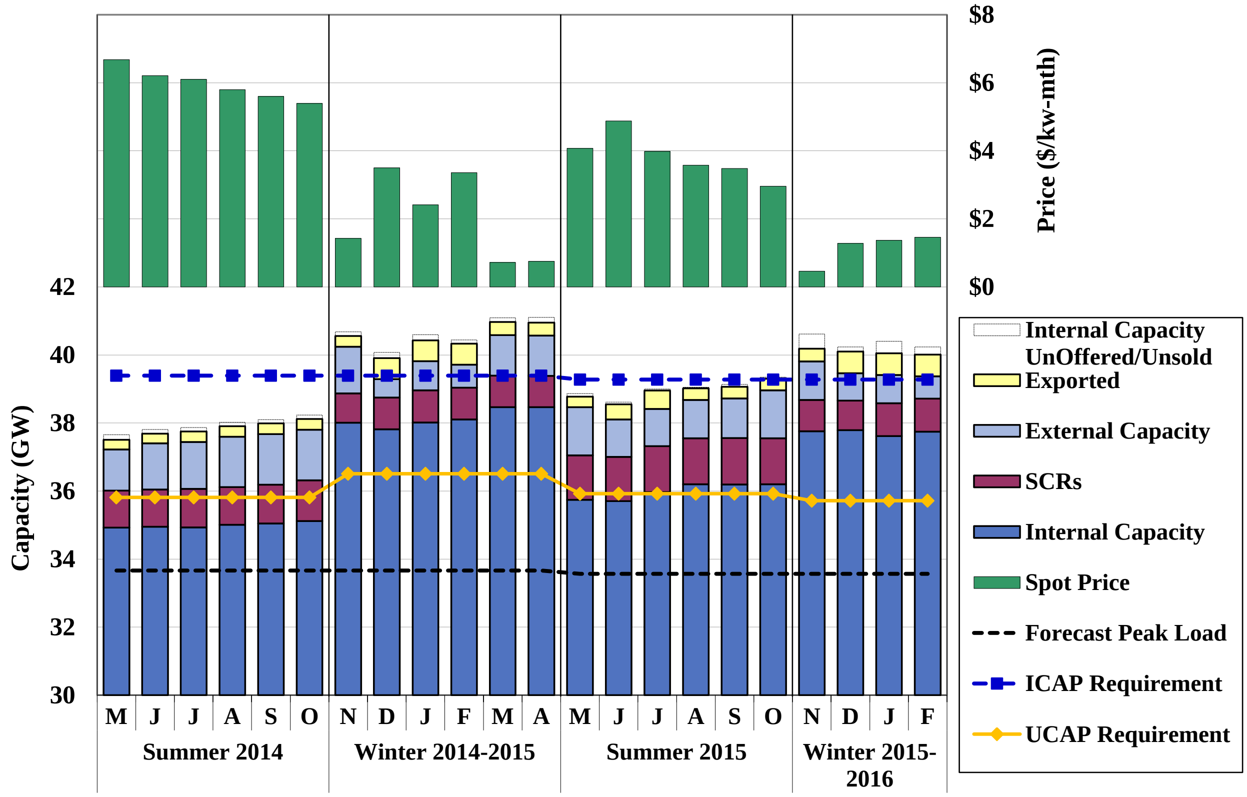
Figure A-93: Capacity Sales and Prices in NYCA

Figure A-93 shows capacity market results in the NYCA for the past four six-month Capability Periods. In the lower portion of each figure, the bars show the quantities of internal capacity sales, which include sales related to Unforced Deliverability Rights ("UDRs") and sales from SCRs.[335] The hollow portion of each bar represents the In-State capacity in each region not sold (including capacity not offered) in New York or in any adjacent market. The line indicates the capacity requirement for each Capability Period for NYCA. Additionally, Figure A-93 shows sales from external capacity resources into NYCA and exports of internal capacity to other control areas. The upper portion of the figure shows clearing prices in the monthly spot auctions for NYCA (i.e., the Rest of State).

The capacity sales and requirements in Figure A-93 are shown in the UCAP terms, which reflect the amount of resources available to sell capacity. The changes in the UCAP requirements are affected by changes in the forecasted peak load, the minimum capacity requirement, and the Derating Factors. To better illustrate these changes over the examined period, Figure A-93 also shows the forecasted peak load and the ICAP requirements.

[335] Special Case Resources ("SCRs") are Demand Side Resources whose Load is capable of being interrupted upon demand, and/or Demand Side Resources that have a Local Generator, which is not visible to the ISO's Market Information System and is rated 100 kW or higher, that can be operated to reduce Load from the NYS Transmission System and/or the distribution system at the direction of the NYISO.

Figure A-93: UCAP Sales and Prices in NYCA
May 2014 to February 2016



Key Observations: UCAP Sales and Prices in New York

- Seasonal variations resulted in significant changes in clearing prices in spot auctions.
  - Additional capability is typically available in the Winter Capability Periods due to lower ambient temperatures, which increase the capability of some resources to produce electricity. This contributes to significantly lower prices in the winter than in the summer.
  - Capacity imports from Quebec typically fall in the coldest winter months (i.e., December through March), since Quebec is a winter peaking region. This reduction partially offsets the decreases in clearing prices during these months.
- UCAP spot prices fell significantly in Rest of State in the 2015/16 Capability Year from the prior periods.
  - The spot price averaged $3.83/kW-month in the Summer 2015 Capability Period, which was down 36 percent from the prior summer, and $1.14/kW-month in the Winter 2015/16 Capability Period (excluding March and April 2016), which was down 44 percent from the prior winter.
  - These reductions were due primarily to the increase in internal supply of capacity, which rose:

  - A total of 480 MW in Hudson Valley as the four Danskammer units returned to service at different times between October 2014 and January 2015;
  - Over 100 MW in Western New York as a result of the return-to-service of the Binghamton co-gen unit in the first quarter of 2015 and additions of new wind capacity;
  - 170 MW in New York City as the Astoria Unit 2 returned to service in March 2015; and
  - 375 MW in Hudson Valley as the Bowline Unit 2 returned to full capability (after several years of partial availability) in July 2015.
- On the demand side, the ICAP requirement fell 115 MW (0.3 percent) from the 2014/15 Capability Year because of a modest decrease in the peak load forecast, also contributing to lower spot prices in the 2015/16 Capability Year.[336]
  - However, the UCAP Requirement rose 107 MW (0.3 percent) in the Summer Capability Period while fell 790 MW (2.2 percent) in the Winter Capability Period because of the variations in Derating Factor over the period.
  - In the short-term, spot capacity prices are affected most by the ICAP Requirement in each locality (as opposed to the UCAP Requirement), since variations in the Derating Factor closely track variations in the weighted-average EFORd values of resources.
  - However, in the long-term, higher Derating Factors tend to increase the IRM and the LCRs because the IRM Report incorporates EFORd values on a five-year rolling average basis.
- In addition, SCR sales rose by an average of 210 MW in the 2015 summer from the previous summer, contributing to lower prices as well. However, these were largely offset by an average decrease of 180 MW of sales from external resources during the same period.

E. Capacity Market Results: Local Capacity Zones

Figure A-94 - Figure A-96: Capacity Sales and Prices in NYC, LI, and the G-J Locality

Figure A-94 to Figure A-96 show capacity market results in New York City, Long Island, and the G-J Locality for the past four six-month Capability Periods. These charts display the same

[336] ICAP Requirements are fixed for an entire Capability Year, so the same requirements were used in the 2015 Summer and 2015/16 Winter Capability Periods. UCAP Requirements are fixed for a six-month Capability Period, since the Derating Factor for each locality is updated every six months, causing differences in the UCAP requirements during the summer and winter capability periods for the given year.

quantities as Figure A-93 does for the NYCA region and also compare the spot prices in each Locality to the Rest-Of-State prices.

In addition to the changes that affect the NYCA capacity requirements (e.g., forecasted peak load and the Derating Factors), requirements in the local capacity zones can also be affected by changes in the Local Capacity Requirement that are unrelated to load changes.

Figure A-94: UCAP Sales and Prices in New York City

May 2014 to February 2016

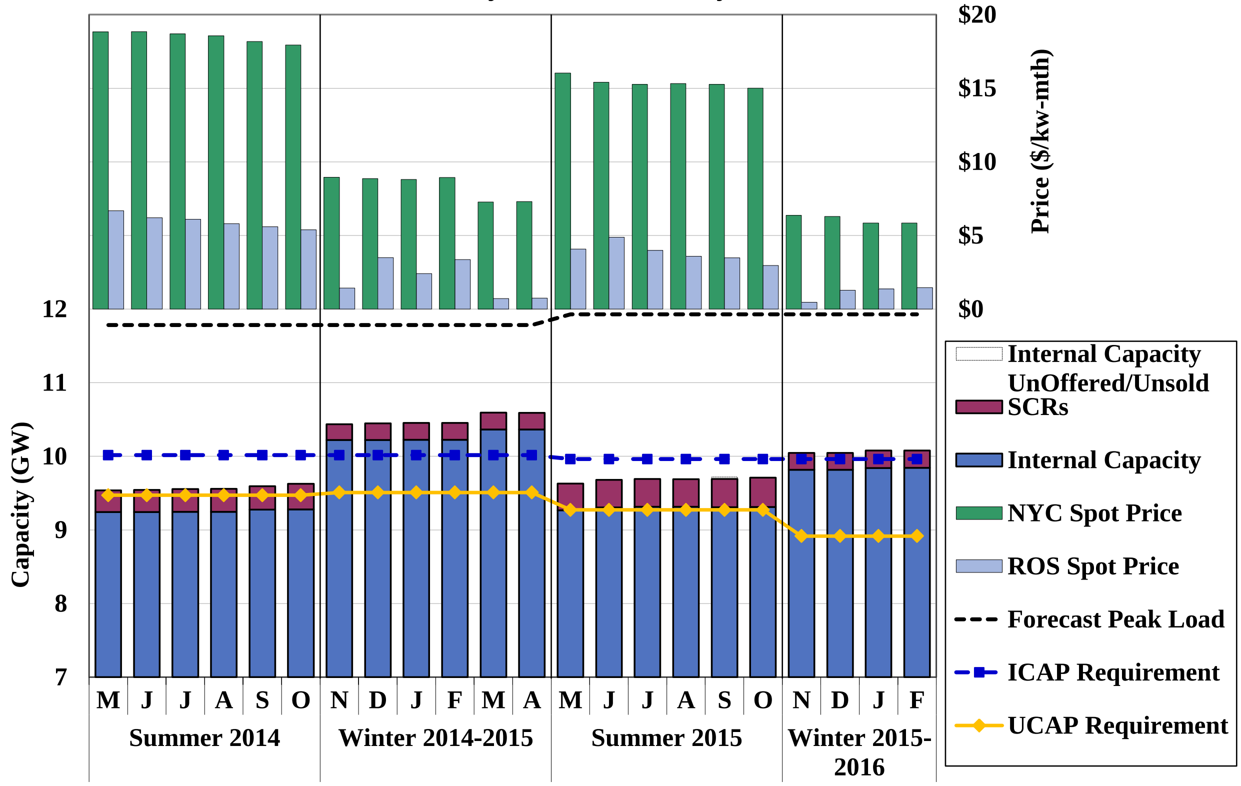


Figure A-95: UCAP Sales and Prices in Long Island
May 2014 to February 2016

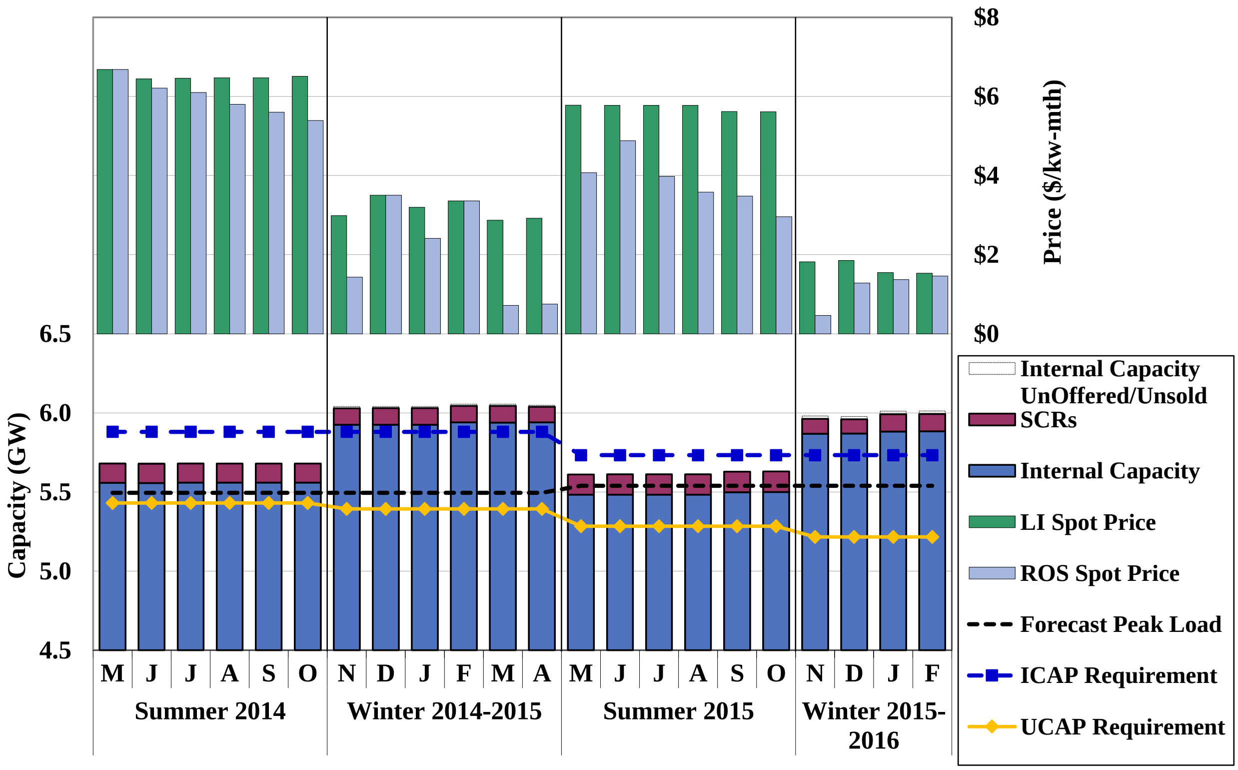
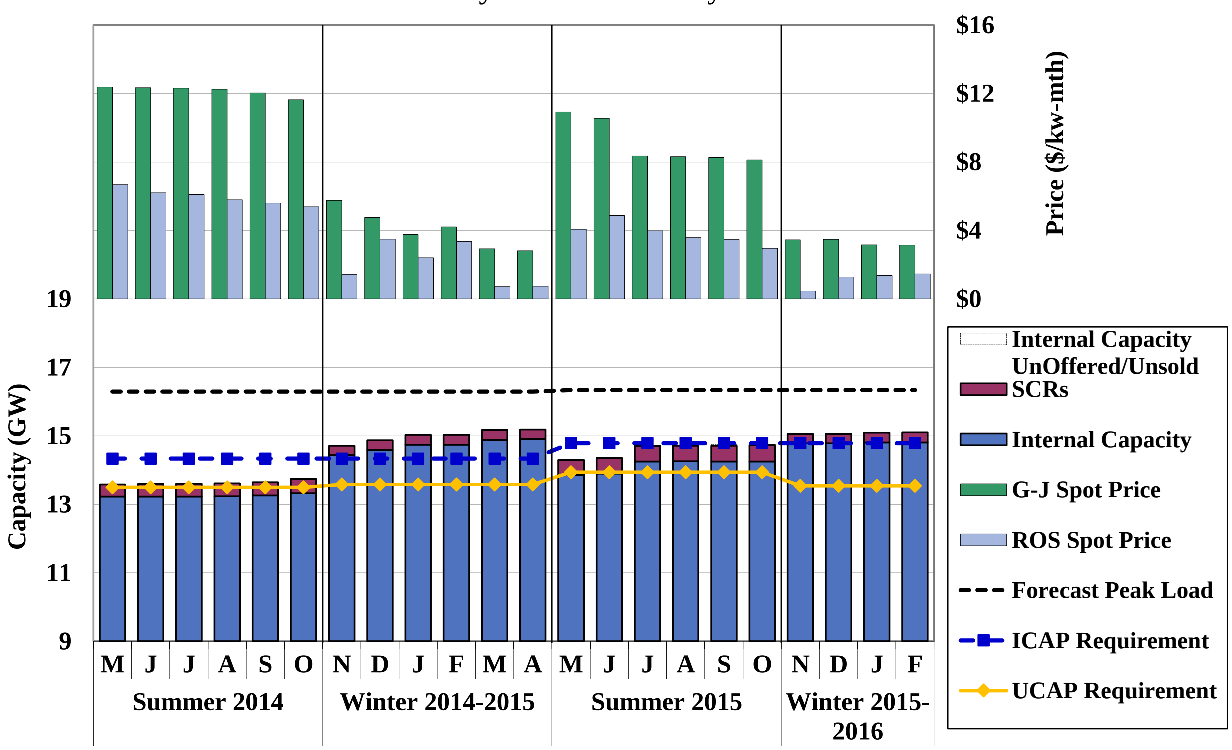


Figure A-96: UCAP Sales and Prices in the G-J Locality
May 2014 to February 2016



Key Observations: UCAP Sales and Prices in Local Capacity Zones

- As in the statewide market, seasonal variations substantially affect the market outcomes in the local capacity zones.
- Similar to Rest-of-State, UCAP spot prices fell in all local capacity zones in the 2015/16 Capability Year from the prior Capability Year. In particular,
  - New York City spot prices fell: (a) 17 percent to an average of $15.38/kW-month in the Summer 2015 Capability Period; and (b) 27 percent to an average of $6.09/kW-month in the Winter 2015/16 Capability Period (excluding March and April 2016).
  - Long Island spot prices fell: (a) 12 percent to an average of $5.72/kW-month in the Summer 2015 Capability Period; and (b) 46 percent to an average of $1.69/kW-month in the Winter 2015/16 Capability Period (excluding March and April 2016).
  - The G-J Locality spot prices fell: (a) 25 percent to an average of $9.10/kW-month in the 2015 Summer Capability Period; and (b) 18 percent to an average of $3.31/kW-month in the Winter 2015/16 Capability Period (excluding March and April 2016).
- The spot prices in New York City fell largely because:
  - Astoria Unit 2 returned to service in early 2015, adding roughly 170 MW of installed capacity supply and causing the spot price to fall from $8.94/kW-month in February 2015 to $7.28/kW-month in March 2015.
  - The ICAP requirement fell by 54 MW (or 0.5 percent) from the 2014/15 Capability Year to the 2015/16 Capability Year, which was primarily due to a decrease in the LCR requirement from 85 to 83.5 percent. [337]
    - However, the decrease in the LCR was partly offset by a 147 MW (or 1.2 percent) increase in the peak load forecast.
  - SCR sales rose by an average of 65 MW in the 2015 summer from the previous summer, contributing to lower prices in the 2015 summer.
- The spot prices fell in Long Island primarily because the ICAP requirement fell by 148 MW (or 3 percent) in the 2015/16 Capability Year because of a decrease in the LCR from 107 percent to 103.5 percent.
  - Long Island spot prices cleared above the Rest-of-State prices much more frequently in 2014 and 2015 than in prior years.
  - Reduced capacity supply because of retirements and increased LCR requirements (from prior years) were the primary factors of price separation between Long Island and Rest-of-State.

[337] Due to changes in the Derating Factor, the UCAP Requirement for New York City fell 199 MW (2.1 percent) in the Summer of 2015 and fell 592 MW (6.2 percent) in the Winter of 2015/16, which deviated notably from the decrease in the ICAP Requirement. Nonetheless, since UCAP supply varied by a comparable amount, the change in the ICAP Requirement had more impact on the Spot Auction clearing price.

- The spot prices in the G-J Locality fell largely because:
  - Four units at the Danskammer plant returned to service at different times between October 2014 and January 2015, adding a total of 480 MW of capacity supply in the Hudson Valley Zone and causing the spot prices to fall by nearly \$2/kW-month from November 2014 to January 2015.
  - Astoria Unit 2 returned to service, adding roughly 170 MW of capacity supply in New York City and causing the spot price to fall by more than \$1/kW-month from February to March 2015.
  - Bowline Unit 2 returned to full service, adding additional 375 MW of capacity supply in the Hudson Valley Zone and causing the spot price to fall by more than \$2/kW-month from June to July 2015.
  - SCR sales rose by an average of 80 MW in the 2015 summer from the previous summer, contributing to lower prices in the 2015 summer.
  - However, the G-J ICAP requirement rose 451 MW (or 3%) because of an increase in the LCR from 88 percent to 90.5 percent and a modest increase in forecasted peak load. This partly offset the decrease of UCAP prices in the G-J Locality.
- The capacity additions in the Hudson Valley Zone (discussed above) was the primary factor that led to: (a) lower LCRs for New York City and Long Island; and (b) a higher LCR for the G-J Locality for the period from May 2015 to April 2016.
- Overall, very little capacity was unsold in the G-J Locality, New York City, and Long Island in 2015.

VII. Demand Response Programs

Participation by demand response in the market is beneficial for many reasons. Demand response contributes to reliable system operations, long-term resource adequacy, lower production costs, decreased price volatility, and reduced supplier market power. Even modest reductions in consumption by end users during high-price periods can significantly reduce the costs of committing and dispatching generation to satisfy the needs of the system. These benefits underscore the value of designing wholesale markets that provide transparent economic signals and market processes that facilitate demand response.

The New York ISO operates five demand response programs that allow retail loads to participate in NYISO wholesale electricity markets. Three of the programs allow NYISO to curtail loads in real-time for reliability reasons:

- Emergency Demand Response Program ("EDRP") – These resources are paid the higher of $500/MWh or the real-time clearing price. There are no consequences for enrolled EDRP resources that fail to curtail.[338]
- Installed Capacity/Special Case Resource ("ICAP/SCR") Program – These resources are paid the higher of their strike price (which can be up to $500/MWh) or the real-time clearing price. These resources sell capacity in the capacity market in exchange for the obligation to respond when deployed.[339]
- Targeted Demand Response Program ("TDRP") – This program curtails EDRP and SCR resources when called by the local Transmission Owner for reliability reasons at the sub-load pocket level, currently only in New York City. EDRP resources are paid the higher of $500/MWh or the real-time clearing price. SCRs are paid the higher of their strike price or the real-time clearing price. Response from these resources is voluntary.

Two additional programs allow demand response resources to participate in the day-ahead energy market or in the ancillary services markets:

- Day-Ahead Demand Response Program ("DADRP") – This program allows curtailable loads to offer into the day-ahead market (with a floor price of $75/MWh) like any supply resource. If the offer clears in the day-ahead market, the resource is paid the day-ahead clearing price and must curtail its load in real-time accordingly.
- Demand Side Ancillary Services Program ("DSASP") – This program allows resources to offer regulation and operating reserves in the day-ahead and real-time markets.

338 Resources participate in EDRP through Curtailment Service Providers ("CSPs"), which serve as the interface between the NYISO and resources.

339 Special Case Resources participate through Responsible Interface Parties ("RIPs"), which interface between the NYISO and resources. Resources are obligated to curtail when called upon to do so with two hour notice, provided that the resource is informed on the previous day of the possibility of such a call.

Despite these programs, significant barriers to participation in the wholesale market by loads remain. The most significant barrier is that most retail loads have no incentive to respond to real-time prices even when they exceed their marginal value of consumption. Hence, developing programs to facilitate participation by loads in the real-time market could be beneficial, although it is important that such a program provide efficient incentives to demand response resources.

In this section, we evaluate three areas: (a) the reliability demand response programs, (b) the economic demand response programs, and (c) the ability for demand response to set prices during shortage conditions.

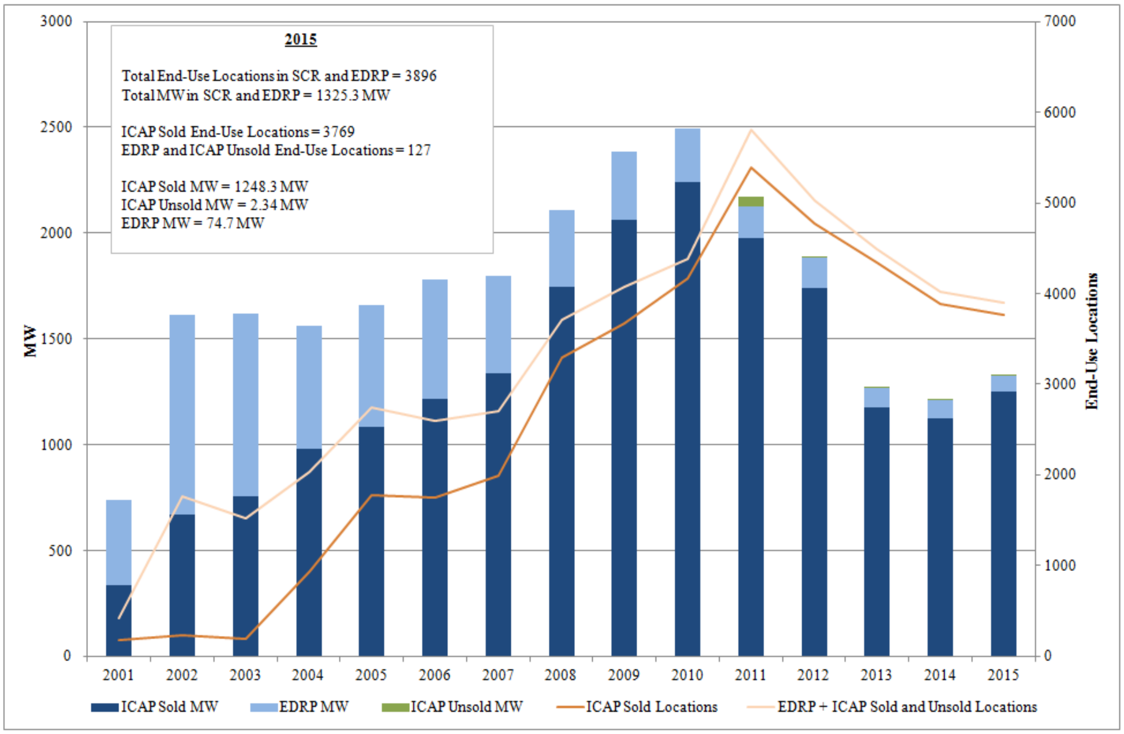
A. Reliability Demand Response Programs

Demand response programs provide incentives for retail loads to participate in the wholesale market. The EDRP, SCR, and TDRP programs enable NYISO to deploy reliability demand response resources when it forecasts a reliability issue.

Figure A-97: Registration in NYISO Demand Response Reliability Programs

Figure A-97 summarizes registration in two of the reliability programs at the end of each summer from 2001 to 2015 as reported in the NYISO's annual demand response report to FERC. The stacked bar chart plots enrolled MW by year for each program. The lines plot the number of end-use locations by year for each program. Since EDRP and SCR resources in New York City participate in the TDRP program on a voluntary basis, TDRP resources are not shown separately.

Figure A-97: Registration in NYISO Demand Response Reliability Programs [340]
2001 – 2015



<u>Key Observations: NYISO Demand Response Reliability Programs</u>

- Since 2001, SCR program registration has grown considerably, while EDRP program registration has gradually declined since 2002.
  - These trends reflect that many resources have switched from the EDRP program to the SCR program in order to earn revenue from the capacity market.
  - In 2015, total registration in the EDRP and SCR programs included 3,896 end-use locations enrolled, providing a total of 1,325 MW of demand response capability. SCR resources accounted for 97 percent of the total reliability program enrollments and 94 percent of the enrolled MWs.
- In the Summer 2015 Capability Period, SCRs contributed to resource adequacy by satisfying:
  - 4.1 percent of the UCAP requirement for New York City;
  - 3.3 percent of the UCAP requirement for the G-J Locality;
  - 2.4 percent of the UCAP requirement for Long Island; and

340 This figure is excerpted from the compliance filing report to FERC: *NYISO 2015 Annual Report on Demand Response Programs*, January 12, 2016.

  - 3.7 percent of the UCAP requirement for NYCA.

- The registered quantity of reliability program resources has fallen considerably since 2010, down nearly 50 percent from 2010 to 2015.
  - The reduction occurred primarily as a result of the enhanced auditing and baseline methodology for SCRs in 2011. These have resulted in more accurate baselines for some resources, reducing the amount of capacity they are qualified to sell.
  - The reduction was also partly due to business decisions that have been driven by low capacity prices in some areas in recent years and reduced revenues as a result of lower qualified capacity.

B. Economic Demand Response Programs

The DADRP program allows retail customers to offer load curtailment in the day-ahead market in a manner similar to generation supply offers, currently subject to a bid floor price of $75/MWh. Like a generation resource, DADRP participants may specify minimum and maximum run times and hours of availability. Load reductions scheduled in the day-ahead market obligate the resource to curtail the next day. Failure to curtail results in the imposition of a penalty for each such hour equal to the product of the MW curtailment shortfall and the greater of the corresponding day-ahead and the real-time price of energy.

The DSASP program was established in June 2008 to enable demand response resources to provide ancillary services. This program has the potential to increase the amount of resources that provide operating reserves and regulation services, which enhances competition, reduces costs, and improves reliability. Under this program, resources must qualify to provide operating reserves or regulation under the same requirements as generators, and they are paid the same market clearing prices as generators for the ancillary service products they provide. To the extent that DSASP resources increase or decrease consumption when deployed for regulation or reserves in the real-time, they settle the energy consumption with their load serving entity rather than with the NYISO. But they are eligible for a Day-Ahead Margin Assurance Payment (“DAMAP”) to make up for any balancing differences between their day-ahead operating reserves or regulation service schedule and real-time dispatch, subject to their performance for the scheduled service.

The Mandatory Hourly Pricing (“MHP”) program encourages loads to respond to wholesale market prices, which intends to shift customer load to less expensive off-peak periods and reduce electric system peak demand. The MHP program is administered at the retail load level, so it is regulated under the New York Public Service Commission. Under the MHP program, retail customers as small as 200 kW (depending on their load serving entity) pay for electric supply based on the day-ahead market LBMP in their load zone in each hour. In the future, some retail customers as small as 100 kW are expected to participate in the MHP program.

Key Observations: Economic Demand Response Programs

- No resources participated in the DADRP program in the past four years.

- Given that loads may hedge with virtual transactions that are very similar to DADRP schedules, the value of this program is doubtful.

- DSASP resources have experienced difficulty setting up communications with the NYISO through the local Transmission Owner since the inception of the DSASP program in 2008. Consequently, no DSASP resources were fully qualified until 2012 when the NYISO introduced the capability for resources to communicate directly with the NYISO.
  - Three DSASP resources in Upstate New York (with a combined capability of nearly 130 MW) actively participated in the market in 2015 as providers of operating reserves. These resources were capable of providing up to 19 percent of the NYCA 10-minute spinning reserve requirement in 2015.
- Over 7 GW of retail load customers are under the MHP program.
  - The program gives retail loads strong incentives to moderate their demand during periods when it is most costly to serve them, resulting in lower costs for all customers and more efficient consumption decisions.

C. Demand Response and Scarcity Pricing

In an efficient market, clearing prices should reflect the cost of deploying resources to satisfy demand and maintain reliability, particularly under shortage conditions. Ordinarily, to be involved with setting prices in the real-time market, resources must be dispatchable by the real-time market model on a five-minute basis. EDRP and SCR resources must be called in advance based on projections of operating conditions; they are not dispatchable by the real-time model. Hence, there is no guarantee that these resources will be "in-merit" relative to the real-time clearing price, and their deployment can actually lower prices. Prices can be well below $500/MWh after EDRP and SCR resources are curtailed, if adequate resources are available to the system in real-time. NYISO currently has two market rules that improve the efficiency of real-time prices when demand response resources are deployed.

First, NYISO has special scarcity pricing rules for periods when demand response resources are deployed. Generally, when a shortage of state-wide or eastern reserves is prevented by the deployment of demand response, real-time clearing prices are set to $500/MWh within the region (unless they already exceed that level). This rule helps reflect the cost of maintaining adequate reserve levels in real-time clearing prices and improves the efficiency of real-time prices during shortage conditions. Since demand response resources were frequently deployed to secure an area other than NYCA or the entire eastern New York area (e.g., Southeast New York), the NYISO implemented an Enhanced Scarcity Pricing Rule in July 2013. Under this rule, LBMPs are almost always set to $500/MWh in the area where demand response resources are deployed.[341]

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[341] See http://www.nyiso.com/public/webdocs/markets_operations/committees/mc/meeting_materials/2012-12-18/agenda_07_Enhanced%20Scarcity%20Pricing.pdf in the December 18, 2012 Management Committee materials.

Second, to minimize the price-effects of "out-of-merit" demand response resources, NYISO implemented the TDRP in 2007. This program is currently available in New York City, which enables the local transmission owner in New York City to call EDRP and SCR resources in blocks smaller than an entire zone. Prior to July 2007, local transmission owners called all of the EDRP and SCR resources in a particular zone to address local issues on the distribution system. As a result, substantial quantities of demand response were deployed that provided no reliability benefit, depressed real-time prices, and increased uplift. Since no TDRP was deployed in the past three years, related operations and pricing are not evaluated in this report.

Key Observations: Scarcity Pricing

- In 2014, the NYISO deployed reliability demand response resources on just one day, January 7, when SCR and EDRP resources in all zones were deployed from HB 17 to HB 21 for system-wide capacity needs. Response from SCRs in this event was voluntary.
  - The Enhanced Scarcity Pricing Rule was active during the entire event and set the LBMPs across the system at a level that was equal to or higher than $500/MWh in nearly every market interval. However, the rule had a limited effect because high fuel prices and tight system conditions would have resulted in average LBMPs above $400/MWh during the event if the rule had not been in place.
- In 2015, the NYISO did not deploy EDRP and SCR resources, therefore related operations and pricing are not evaluated in this report.
- Nonetheless, there are several issues in the current scarcity pricing methodology.
  - It adopts an *ex-post* logic, which tends to cause inconsistencies between resource schedules and pricing outcomes, resulting in potential uplift costs.
  - It does not apply to the Proxy Buses, which may result in inefficient scheduling of imports and exports during EDRP/SCR activations.
  - The NYISO's Comprehensive Scarcity Pricing reforms will address these two issues and implementation is expected before July 2016. [342]

[342] See NYISO filing in Docket No. ER16-425-000, *Proposed Revisions to Services Tariff and OATT to Implement Improved Scarcity Pricing*, November 30, 2015.