2014 STATE OF THE MARKET REPORT FOR THE NEW YORK ISO MARKETS

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Table of Contents

List of Figures

Figures in Report

Figures in Appendix

List of Tables

Tables in Report

Tables in Appendix

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 *2014 State of the Market Report* presents our assessment of the operation and performance of the wholesale electricity markets administered by the NYISO in 2014. 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 installed capacity market 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 2014

This subsection focuses on key developments and highlights in these areas in 2014.

Day-Ahead and Real-Time Markets

The first quarter of 2014 was characterized by extreme cold weather and tight natural gas market conditions[1], while the last three quarters exhibited particularly mild weather and low natural gas

[1] These weather conditions were known as a Polar Vortex that resulted in record cold temperatures throughout the Eastern Interconnect.

prices. Consequently, day-ahead and real-time energy prices increased 55 to 119 percent in the first quarter of 2014 from the previous year and decreased 14 to 34 percent in the last three quarters of 2014. The net effect of these changes in energy prices was an overall increase of 8 to 27 percent from 2013 outside Long Island, while average natural gas prices increased 21 to 33 percent at the key trading hubs. The strong relationship between energy and natural gas prices is expected in a well-functioning, competitive market because natural gas-fired resources were the marginal source of supply in more than three quarters of all intervals in 2014.[2]

Transmission congestion and losses led real-time prices to vary from an average of $50 per MWh in Western New York to $71 per MWh in Long Island in 2014. Congestion revenues collected in the day-ahead market fell to $573 million in 2014, down 14 percent from the previous year largely because of the mild summer conditions. Congestion patterns in the NYISO were driven primarily by congestion on the natural gas pipeline system. The most significant congestion appeared on the Central-East Interface, which flows power from Western New York to Eastern New York. West-to-east congestion was also significant through the West Zone, limiting deliveries from the Niagara hydro plant and inexpensive imports from Ontario.

The electricity market performed well despite the challenging gas market conditions presented by the Polar Vortex as many suppliers conserved scarce natural gas by switching to fuel oil. Although Eastern New York has adequate non-gas capacity to satisfy electricity demand and reliability criteria under peak winter conditions, oil usage was limited in 2014 by low oil inventories, generator maintenance outages, and environmental limitations. The day-ahead market provides price signals and scheduling information that enables suppliers to make better fuel purchasing and consumption decisions. This underscores the importance of the NYISO markets in helping coordinate the efficient use of scarce fuel supplies during cold weather conditions. (See Recommendations 14 & 15.)

2 Average energy prices fell 6 percent in Long Island in 2014 despite a 33 percent increase in natural gas prices in the area. This occurred because Long Island had endured substantial outages of gas-fired generation, the Neptune Cable, and the 345kV transmission lines from Upstate New York in 2013. The availability of these facilities was much higher in 2014.

Average and Peak Loads in 2014

Average load levels fell from 18.7 GW in 2013 to 18.3 GW in 2014 because of unusually mild summer conditions. Likewise, peak load levels fell dramatically in the summer months from approximately 34.0 GW in 2013 to 29.8 GW in 2014. The low summer demand resulted in relatively few reserve shortages, low congestion and uplift charges, and no activations of demand response. However, the Polar Vortex conditions during the winter caused NYISO to set a new winter peak of 25,738 MW on January 7, 2014. This peak was up 1,080 MW from the 2013 winter peak and 197 MW from the previous all-time winter peak that was set in 2004.

Installed Capacity Market

The new capacity zone (known as "G-J Locality") was initially modeled in May 2014, resulting in a 59 percent increase in overall capacity costs for the Lower Hudson Valley from 2013 to 2014. The return to service of the existing 480 MW Danskammer plant helped mitigate price increases in the Lower Hudson Valley toward the end of the year.

Capacity costs rose 24 percent in New York City in 2014 (to average $13.96 per kW-month), primarily because higher forecasted peak load resulted in higher capacity requirements. The New York City Local Capacity Requirement ("LCR") of 85 percent remained higher than levels prior to 2013. Under the current rules, the New York City LCR is inflated partly to maintain adequate resources in Southeast New York. Therefore, the New York City LCR will tend to fall if additional capacity locates or returns to operation in the Lower Hudson Valley. The rules used to determine the LCR and IRM are not optimal and we recommend changes in the rules that will lower the costs of satisfying NYISO's planning requirements. (See Recommendation 1.)

Recently retired and mothballed generators present challenges for meeting reliability criteria in the planning horizon. Increased use of out-of-market Reliability Support Services Agreements ("RSSAs") in Western New York reinforce the importance of capacity and energy market reforms that enable the value of resources at each location to be reflected as comprehensively as possible. Accordingly, we continue to recommend improving locational price signals in the capacity, energy, and operating reserve markets to distinguish the value of resources that are most beneficial for reliability. (See especially Recommendation 12.)

Long Run Price 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 in most areas rose significantly in 2014 because of higher energy net revenues and higher capacity net revenues (for the Lower Hudson Valley and New York City). Most of the energy net revenues accrued in the first quarter when very cold weather led to higher natural gas prices and larger gas spreads between regions. The high gas prices also produced substantially higher net revenues for dual fuel units in 2014 in Eastern New York. These net revenues provide incentives for generators to maintain dual-fuel capability and oil inventory levels. Our evaluation indicates that the estimated net revenues for a new gas turbine were higher than the annual levelized cost of new entry ("CONE") at all locations with the exception of Long Island. However, this is unlikely to induce new investment if developers perceive net revenues are elevated by temporary increases in the Local Capacity Requirements ("LCRs") or abnormally tight winter conditions.

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 zones in Eastern New York in 2014, particularly in the first quarter. A large portion of the difference was accounted for by the Polar Vortex from January 22 to 29 as rapid changes in weather patterns, natural gas prices, and supplemental commitments after the day-ahead market led to much lower real-time prices on these days. In general, convergence was worse in most regions in the first quarter because of more frequent peaking conditions and significantly higher and more volatile natural gas prices.

Price convergence improved most on Long Island, which exhibited less price volatility in real-time because of fewer transmission outages. However, Western New York exhibited significantly more price volatility in the first quarter of 2014 because prices in that region often rose to the levels in Eastern New York during periods of high gas prices (when the Central-East interface was not congested).

Virtual trading helped align day-ahead prices with real-time prices, particularly when modeling and other differences between the day-ahead and real-time markets would otherwise have led to inconsistent prices. Overall, virtual traders earned a gross profit of $42 million at the eleven load zones in 2014, indicating that they generally improved convergence between day-ahead and real-time prices at the zonal level.

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 Valley Stream load pocket in Long Island, which exhibited average real-time prices that were nearly 10 percent higher than average day-ahead prices in 2014. This was largely attributable to inconsistencies between day-ahead schedules and real-time flows across the 901 Line.
- The Niagara generation pocket in the West Zone, which exhibited average day-ahead prices that were 7.5 percent higher than average real-time prices in 2014. 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 volatile loop flows around Lake Erie. (See Recommendations 7 & 9.)

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 2014 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 our evaluation of potential physical withholding, the amount of economic generation that was unavailable because of an outage fell in 2014, and more generation was available during both the winter and summer peaking periods in 2014. The high energy prices during peak winter and summer periods in 2013 and early 2014 have improved incentives for generators to be available on days when tight conditions are anticipated.

In the capacity market, there were several key developments that highlight the need for changes in market rules to address buyer-side market power more effectively. The report discusses these issues and recommends several improvements to address them. (See Recommendations 4 & 5.)

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

Extreme cold weather in the first quarter, particularly during the Polar Vortex, 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 led to highly volatile energy prices. This fuel uncertainty 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 reasonably well under the tight gas supply conditions by increasing the use of oil and conserving the available supply of natural gas.

However, several notable issues arose that affected market performance, including: (a) uncertainty about day-ahead gas prices; and (b) limited availability of oil-fired generation because of low oil inventories, air permit restrictions, and equipment issues. We observed better operations and market performance in these areas during the first quarter of 2014 than in the prior winters despite more challenging conditions. Nonetheless, we identify some areas that may warrant changes in the market design and rules. (See Recommendations 14 & 16.)

In addition, we found that during the 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 15.)

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. Despite significant improvements over the past several years, real-time prices were volatile in 2014. We performed an evaluation of the drivers of price volatility and found the following drivers were most significant:

- Large changes in output of self-scheduled units and external interchange;
- Unforeseen variations in flows across PAR-controlled lines because of inconsistency between actual PAR operations and assumed PAR operations in NYISO's models;
- Volatile loop flows around Lake Erie; and
- The simultaneous de-commitment of multiple generators by RTC.

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 several improvements that better align RTC and RTD to further address these issues. (See Recommendations 8 & 9.)

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

The NYISO implemented CTS with PJM in November 2014, which 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.

We assessed the performance of CTS-PJM in the first four months. We estimated $6 million of production cost savings based on information at the time that RTC determined final interchange schedules. However, only a modest portion 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 to address this issue. (See Recommendation 8.)

Market Performance Under Shortage Conditions

The impact of shortage conditions was substantial in 2014, particularly in Eastern New York where shortage conditions accounted for more than 5 percent of the average annual real-time energy price. 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 $30 to $70 per kW-year, depending on the zone. We evaluated the market during three types of shortages:

- *Operating reserve and regulation shortages* – occurred in 3 percent of intervals in 2014 and increased the annual average real-time price in Eastern New York by 5 to 6 percent.
- *Transmission shortages* – occurred in 4 to 5 percent of intervals in 2014. Although average constraint shadow prices were relatively high during shortages, they frequently did not fully reflect the severity of the shortage.
- *Reliability demand response deployments* – deployed only on one day for statewide capacity needs. The Enhanced Scarcity Pricing Rule was active during the entire event, but had a limited effect because prices would have been high without the rule.

Recently, the NYISO has conducted several market design initiatives to enhance the pricing efficiency during the three types of shortages.[3] We support the NYISO's efforts in these areas and anticipate the resulting enhancements will more accurately reflect: (a) locational differences in value of the shortage; and (b) the severity of the shortage conditions.

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 300 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

3 The Comprehensive Shortage Pricing, Graduated Transmission Demand Curve, and Comprehensive Scarcity Pricing projects are discussed in Section IX.A.

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 $34 million in 2014 and contributed to price volatility and balancing congestion uplift. Hence, the report recommends that NYISO work with these parties to improve the operation of these lines and create a financial right to allow the parties to retain the benefits of the current agreement. (See Recommendation 7.)

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 10 percent to a total of $147 million in 2014. This decrease was consistent with lower natural gas prices in most months of 2014, which reduced the commitment costs of gas-fired units needed for reliability.

In addition, supplemental commitments for reliability fell 12 percent and out-of-merit (“OOM”) dispatch fell nearly 40 percent from 2013 to 2014, 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. In New York City, the reduction reflected: (a) lower natural gas prices (than the rest of Eastern New York), which made several steam units that were often needed for reliability more economic; and (b) updates in the modeling of NOx bubble constraints that now requires less steam turbine capacity to satisfy the NOx bubble requirements.

The purpose of NOx bubble commitments is to lower overall NOx emissions by running steam turbines so that older gas turbine units with higher NOx emission rates do not run as frequently. However, we found that: (a) the commitment of steam turbines for NOx bubble constraints generally crowded-out production from new generators with selective catalytic reduction equipment that have very low NOx emission rates; and (b) the NOx bubble commitments likely did very little to reduce the operation of older gas turbines with very high emission rates. Hence, NOx bubble constraints led to higher costs and may have actually led to higher overall NOx emissions as well. (See Recommendation 13 to address this issue.)

Despite the reduction in other regions, reliability commitment and OOM dispatch in Western New York rose from 2013. Several units that were often needed to manage congestion on 115kV facilities in the West Zone and the Central Zone became less economic because of lower load levels and lower natural gas prices in most of 2014. (See Recommendation 12.)

Guarantee payment uplift rose significantly in the first quarter of 2014, accounting for $98 million (or 67 percent of the annual total) and partially offsetting the overall reduction. Substantially elevated natural gas prices were the primary driver of high guarantee payments in the first quarter. Extreme cold weather contributed to increased guarantee payment uplift in the first quarter as well. For example, Polar Vortex conditions from January 22 to 28 accounted for $30 million in guarantee payment uplift as natural gas prices averaged over $50 per MMbtu in Eastern New York.

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.

In addition to a number of improvements to the market power mitigation measures, we identify reforms to better reflect the locational aspects of the market. Beginning with the Summer 2014 Capability Period, the NYISO added the G-J Locality, which includes all of Southeast New York except Zone K (i.e., Long Island). 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 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.)

Finally, 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 could be reformed to consider the marginal reliability benefit of capacity in each area, which would lead capacity to be distributed in a manner that is most cost-effective for maintaining reliability. (See Recommendation 1001.)

G. Overview of Recommendations

The NYISO markets generally performed well in 2014. 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 2015 Project Plan or in some other effort. The table also identifies recommendations as scoping/future if there is significant uncertainty regarding the scope of the appropriate solution, work necessary to evaluate potential solutions before deciding on the priority level, and/or the anticipated benefits would be smaller in the short-term than in the long-term. The detailed discussion of each recommendation and the criteria for designating a recommendation as "High Priority" are in Section XI.

List of Recommendations

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.B		X	X
(2) Grant financial capacity transfer rights between zones when investors upgrade the transmission system and help satisfy planning reliability needs.	VIII.C			X
(3) Pre-define interzonal interfaces or zones that address potential reliability needs and/or deliverability constraints to allow prices to accurately reflect the locational value of capacity.	VIII.D			X
(4) Enhance buyer-side mitigation measures to deter uneconomic entry while ensuring that economic entrants are not mitigated.				
(a) Reform Offer Floor for mitigated projects.	IV.C.2			
(b) Modify treatment of units being replaced, mothballed, and retired in forecasts of ICAP prices and net revenues.	IV.C.2	X		
(5) Evaluate the need to expand buyer-side mitigation measures to address other actions that can suppress capacity prices.	IV.C.2			X
Broader Regional Markets				
(6) Work with adjacent ISOs on rules to better utilize the transfer capability between regions by coordinating intra-hour transactions.	VII.D	X	X	

RECOMMENDATION	Discussed in	Current Effort	High Priority	Scoping/Future
Energy Market Enhancements - RT Market Operations				
(7) Operate PAR-controlled lines to minimize production costs and create financial rights that compensate affected transmission owners.	IX.D		X	
(8) Adjust RTD and RTC look ahead evaluations to be consistent with timing of external transaction ramp and gas turbine commitment.	IX.E			X
(9) Consider enhanced 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
Energy Market Enhancements - RT Pricing				
(10) Modify criteria for gas turbines to set prices in the real-time market.	IX.C			
(11) Adopt Comprehensive Scarcity Pricing.	IX.A	X		
(12) Consider modeling 100+ kV transmission constraints in the DA and RT markets using economic commitment and dispatch software.	IX.F.3			X
Energy Market Enhancements - Reliability Commitment				
(13) 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				
(14) Consider allowing generators to submit offers that reflect certain energy storage and fuel supply constraints in the day-ahead market.	IX.B.2	X		
(15) Enhance recognition of gas system limitations when scheduling resources to provide operating reserves.	IX.B.2			X
Gas-Electric Coordination				
(16) Require Generators to provide timely information on fuel availability (e.g., on-site inventory, scheduled deliveries, & nominations).	IX.B.2	X		

II. Introduction

This report assesses the efficiency and competitiveness of New York's wholesale electricity markets in 2014.[4] 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.

4 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. The locational requirements 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 shortage conditions when resources are insufficient to satisfy both the energy and operating reserve 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
- Introducing 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.

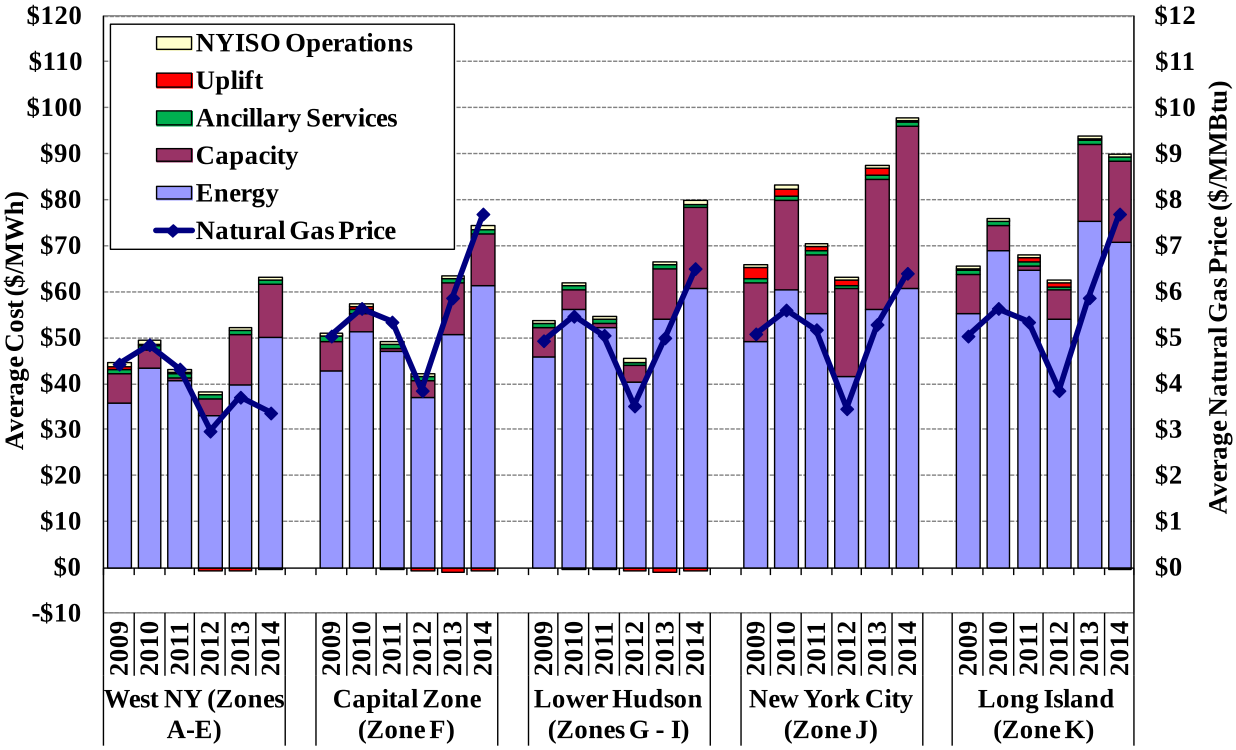
These markets provide substantial benefits to the region by ensuring that the lowest-cost supplies are used to meet demand in the short-term and by establishing transparent, efficient price signals that govern investment and retirement decisions in the long-term. However, it is important for the markets 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

A. Total Wholesale Market Costs

Figure 1 evaluates wholesale market costs during the past six 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.[5]

Figure 1: Average All-In Price by Region
2009-2014



Average all-in prices of electricity ranged from $63 per MWh in West New York to $98 per MWh in New York City in 2014. Energy was the largest component of the all-in price, ranging from an average of $50 per MWh in West New York to $71 per MWh in Long Island. Energy costs accounted for 62 percent of the all-in price in New York City and 77 to 83 percent of the

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

all-in price in the other four regions. Capacity costs were the second largest component in each region, accounting for nearly all of the remaining wholesale market costs.

The seasonal patterns of energy prices and natural gas prices were typical, but the winter months were particularly cold and the summer was unusually mild. Polar Vortex conditions in the first quarter of 2014 contributed to unusually high loads and volatile natural gas prices, particularly in Eastern New York.[6] The resulting high energy prices during the first quarter of 2014 were the primary cause of annual average price increases from 2013 ranging from 8 to 27 percent in the four regions outside Long Island. These increases in the first quarter were partly offset by lower energy prices in the rest of the year as a result of lower natural gas prices and load levels.

Western New York exhibited the largest energy price increase (27 percent) among these four regions outside Long Island. Energy prices in Western New York often converged with prices in Eastern New York when the Central-East interface was not constrained. This occurred frequently during February and March of 2014 when imports from Ontario and Quebec fell from typical levels because those areas were experiencing unusually high loads.

Unlike other regions, energy prices in Long Island fell modestly (6 percent) from 2013 to 2014. This reduction reflected the effects of: (a) increased import levels from upstate New York and PJM because of less frequent deratings and outages affecting the Neptune Cable and the 345kV transmission lines from Upstate New York to Long Island; and (b) more efficient utilization of some generation resources (e.g., less capacity on maintenance during peak demand season).[7]

Average capacity costs rose from 2013 to 2014:

- By 24 percent in New York City to average $13.96 per kW-month,
- By 59 percent in Lower Hudson Valley (i.e., Zones G-I) to average $8.08 per kW-month, and
- By around 5 percent in other regions to average $4.98 per kW-Month in Long Island and $4.51 per kW-month in Rest of State.

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

7 These issues are discussed further in Section III.B (345kV and Neptune Cable outages) and Section II.A (more efficient use of generation) in the Appendix.

The increases in capacity prices were driven primarily by higher installed capacity requirements for New York City, Long Island, and NYCA. In addition, NYISO began modeling the G-J Locality as a separate capacity zone starting in May 2014, which resulted in higher capacity prices in Lower Hudson Valley (compared to the Rest of State capacity prices).[8]

B. Fuel Prices

In recent years, fossil fuel price fluctuations have been the primary driver of changes in wholesale energy prices because most of the marginal costs of thermal generators are fuel costs. Table 1 summarizes fossil fuel prices in 2013 and 2014 on an annual basis and separately for the first quarter and the rest of the year as well.[9] The table also shows average real-time energy prices in five regions of New York State over the same time periods. Representative gas price indices are associated with each of the five regions.

Table 1: Average Fuel Prices and Real-Time Energy Prices
2013-2014

	Annual Average			Q1 Average			Q2 - Q4 Average		
	2013	2014	% Change	2013	2014	% Change	2013	2014	% Change
Fuel Prices ($/MMBtu)									
Ultra Low-Sulfur Kerosene	$24.36	$23.05	-5%	$25.31	$24.89	-2%	$24.05	$22.44	-7%
Ultra Low-Sulfur Diesel Oil	$21.70	$20.21	-7%	$22.53	$22.36	-1%	$21.43	$19.50	-9%
Fuel Oil #6	$16.44	$15.59	-5%	$17.95	$18.43	3%	$15.93	$14.64	-8%
NG - Dominion North	$3.51	$3.18	-9%	$3.49	$4.59	32%	$3.52	$2.71	-23%
NG - Tx Eastern M3	$3.93	$5.13	31%	$4.16	$11.78	183%	$3.85	$2.91	-24%
NG - Transco Z6 (NY)	$5.13	$6.21	21%	$8.30	$15.72	89%	$4.07	$3.05	-25%
NG - Iroquois Z2	$5.69	$7.54	33%	$8.54	$17.85	109%	$4.74	$4.11	-13%
NG - Tennessee Z6	$6.75	$8.04	19%	$11.04	$19.87	80%	$5.32	$4.10	-23%
Energy Prices ($/MWh)									
West New York (Dominion)	$39.72	$50.32	27%	$43.74	$95.71	119%	$38.29	$33.06	-14%
Capital Zone (Iroquois)	$50.94	$61.38	20%	$74.03	$134.24	81%	$43.24	$35.21	-19%
Lw. Hudson(TxEastern/Iroq.)	$54.14	$60.83	12%	$68.02	$128.27	89%	$49.75	$37.26	-25%
New York City (Transco)	$56.25	$60.89	8%	$74.12	$133.70	80%	$50.85	$37.57	-26%
Long Island (Iroquois)	$75.42	$70.97	-6%	$97.26	$150.56	55%	$68.78	$45.40	-34%

8 Section VI of the Appendix summarizes capacity market outcomes in detail.

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

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.

Natural gas prices and gas 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. This phenomenon was particularly notable in 2014 due to the Polar Vortex conditions:

- Natural gas prices in Eastern New York rose to an average of $12 to $20 per MMBtu in the first quarter, compared to an average of $3 to $4 per MMBtu during the rest of the year.
- Similarly, gas spreads between Western and Eastern New York averaged 160 to 340 percent in the first quarter, up significantly from an average of 10 to 50 percent during the rest of the year.

Natural gas prices and gas spreads between regions also showed a notable year-over-year variation in 2014. In the first quarter, average natural gas prices rose 32 percent in Western New York and 80 to 183 percent in Eastern New York from 2013 to 2014 because of higher demand associated with the unusually cold weather. However, in the other three quarters, average natural gas prices fell 13 to 25 percent across New York State from 2013. It is particularly notable that natural gas prices in New York City reached historic low levels in the summer of 2014 (averaging $2/MMbtu and 34 percent lower than in the prior summer) because of increased natural gas production in the Marcellus region.[10]

These locational variations in natural gas prices led to comparable variations in generation and congestion patterns, import levels, uplift charges, and energy price spreads between Western New York and Eastern New York, all of which are discussed throughout the report.

10 Section I.B in the Appendix shows the monthly variations in the Transco Z6 (NY) gas price index for New York City.

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 2012 to 2014, 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.[11] The marginal 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
2012-2014

Fuel Type	Average Internal Generation						% of Intervals being Marginal		
	GW/hour			% of Total					
	2012	2013	2014	2012	2013	2014	2012	2013	2014
Nuclear	4.6	5.1	4.9	30%	33%	31%	0%	0%	0%
Hydro	2.7	2.7	2.8	17%	17%	18%	39%	44%	45%
Coal	0.5	0.5	0.5	3%	3%	3%	10%	11%	7%
Natural Gas	7.0	6.5	6.6	45%	41%	41%	83%	83%	76%
Fuel Oil	0.05	0.10	0.24	0.3%	0.6%	1.5%	3%	5%	6%
Wind	0.3	0.4	0.5	2%	3%	3%	1%	7%	4%
Other	0.3	0.3	0.3	2%	2%	2%	0%	0%	0%

Gas-fired generation accounted for the largest share of electricity production (more than 40 percent) from all internal generating resources in each year of 2012 to 2014. Gas-fired generation rose slightly from 2013, despite lower load levels and higher generation from other fuels. This increase was largely due to the lower average net imports in 2014. It is notable that gas-fired generation rose in New York City and fell in other areas of Eastern New York (particularly in the third quarter of 2014) as a result of the unusually low in-City gas price in 2014.

11 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).

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 in 2014 was consistent with the prior years despite retirements and mothballs at several plants over the period. Coal-fired generation rose substantially in the first quarter of 2014 (averaging roughly 1,100 MW per hour) because high natural gas prices made coal generation more economic. This was offset by reduced coal-fired generation in the other months of the year when natural gas prices were much lower.

Oil-fired generation, although still small, more than doubled from 2013 to 2014. Oil generation rose notably in Eastern New York on many days from January through early March when natural gas prices in Eastern New York were substantially higher than oil prices.[12] However, oil-fired generation fell in Long Island after the first quarter (as compared with the same period in the previous year). This was caused by the low summer load levels and transmission upgrades in Long Island that reduced the need for oil-fired units during summer peak conditions.[13] Wind generation has increased steadily over the past three years, reflecting new capacity additions over the period.

Gas-fired and hydro resources were most frequently on the margin in recent years, setting the price in 80 percent and 45 percent of the intervals during 2014, respectively. Most hydro units on the margin have storage capacity, leading them to offer based on the opportunity cost of foregone sales in other hours (generally when gas units are marginal). The frequency of price-setting by hydro units increased modestly in the last two years 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 (e.g., in the first quarter of 2014). Price-setting by wind units in the North Zone became less frequent in

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

13 Section V.I in the Appendix discusses transmission upgrades in Long Island in greater detail.

2014 because of transmission upgrades that increased transfer capability from this area, reducing the frequency of curtailments of wind generation.

D. Demand Levels

Demand is another key driver of wholesale market outcomes. In 2014, load averaged 18.3 GW and never exceeded 30 GW. Both the peak level and the average level were the lowest levels in the past five years, reflecting very mild summer weather conditions in 2014.[14] Average load was down 6 percent in July and August compared to a year ago and peak load was approximately 4.2 GW (or 12 percent) lower than the annual peak in 2013.[15]

Although load levels fell on average from 2013, average load rose in the winter season relative to the previous winter due to the Polar Vortex conditions that occurred throughout the Eastern Interconnect. The NYISO set a new winter peak of 25,738 MW on January 7, 2014 because of extreme weather conditions. This peak was up 1,080 MW from the 2013 winter peak and 197 MW from the previous all-time winter peak that was set in 2004.

Low load levels in the summer and high load levels in the winter (along with high demand for natural gas) resulted in concomitant changes in congestion patterns that are discussed in the next subsection of this report.

E. Transmission Congestion Patterns

Transmission congestion costs fell from 2013 to 2014. Congestion revenues collected by the NYISO in the day-ahead market (where the vast majority of congestion revenue is collected) totaled roughly $578 million in 2014, down 13 percent from $664 million in 2013.[16] This section also evaluates the value of congestion in the real-time market because it indicates where

14 Section I.D in the Appendix shows the load duration curves from 2012 to 2014.

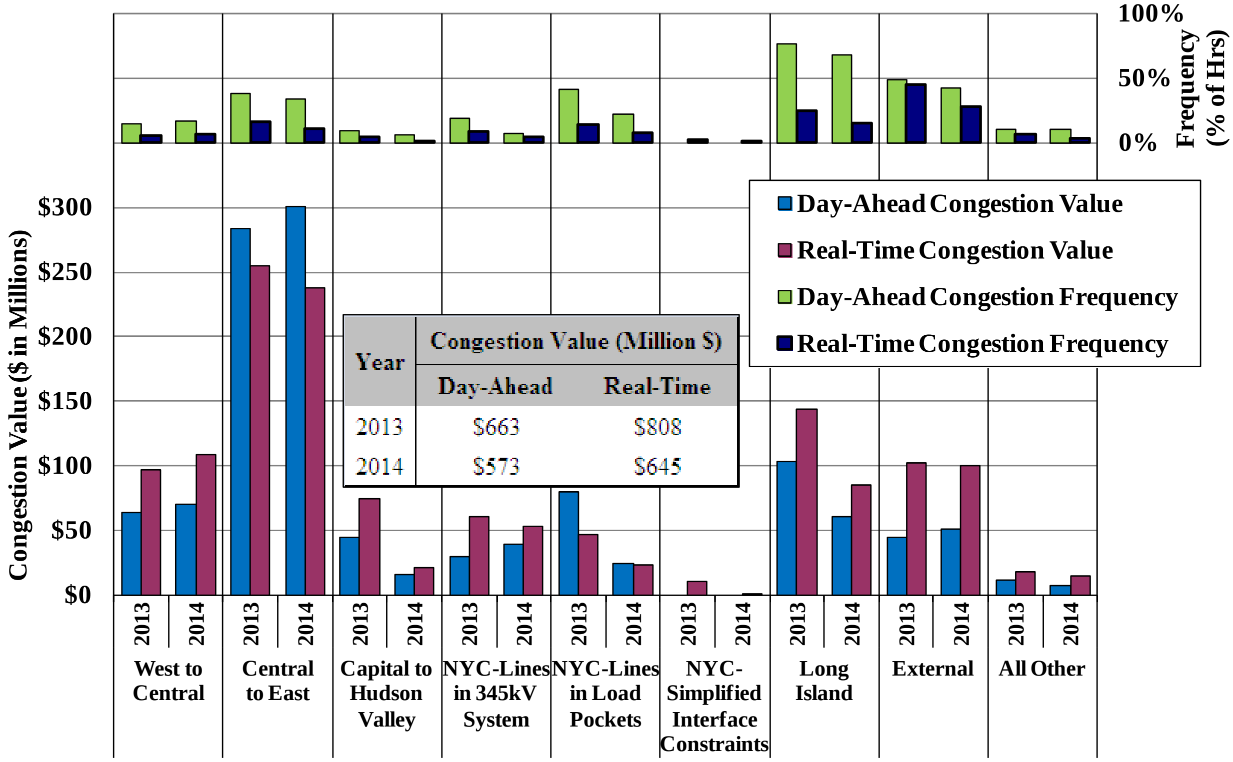
15 The annual peak of 33,956 MW in 2013 was the all-time high peak load in New York.

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

physical constraints occur on the network during the operating day.[17] In a well-functioning market, the value of congestion in the day-ahead and real-time markets should be consistent.

Figure 2 shows the value and frequency of congestion along major transmission lines in the day-ahead and real-time markets in 2013 and 2014.[18]

Figure 2: Day-Ahead and Real-Time Congestion by Transmission Path
2013-2014



Both the value and frequency of congestion fell from 2013 to 2014 on most transmission paths because of lower load levels and lower natural gas prices in most months of 2014. Day-ahead congestion value fell 56 percent in the second through fourth quarters from 2013 to 2014. This

17 Most congestion settlements occur in through 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.

18 Section III.B in the Appendix discusses the congestion patterns in greater detail.

was partly offset by the increase of 34 percent in the first quarter.[19] These patterns were consistent with the variations in load and natural gas prices during these periods.

Congestion across the Central-East interface accounted for the largest share of total congestion value in both 2013 and 2014. In 2014, the Central-East interface accounted for more than 50 percent of congestion value in the day-ahead market and nearly 40 percent in the real-time market. The majority of this congestion occurred in the first quarter of 2014 when larger spreads in natural gas prices between Western New York and Eastern New York increased flows across the interface and resulted in more frequent and costly west-to-east congestion. The Ramapo Line returned to its full capability at the beginning of 2014. This provided additional congestion relief on the interface under the Market-to-Market ("M2M") coordinated congestion management process between PJM and New York. Otherwise, congestion across the Central-East interface would have been higher than in 2013.

Congestion in Long Island fell nearly 40 percent in 2014. In addition to the variations of natural gas prices and load levels discussed above, the reduction was also attributable to higher imports over the Neptune line and increased import capability from upstate New York because of fewer outages and deratings of the 345kV transmission facilities from that area.

Congestion into Southeast New York fell nearly 70 percent in 2014. A large share of this reduction can be attributed to the fact that milder weather conditions in the spring and summer caused Thunder Storm Alert ("TSA") events to be declared 50 percent less often than in 2013. When TSAs were declared, their impact was greatly reduced by lower load levels, lower natural gas prices, the return to full capability of the Ramapo line, and enhancements in the M2M process that have re-enabled the use of the Ramapo Line to relieve TSA congestion.[20]

Congestion on 230kV lines in the West Zone rose slightly from 2013 to 2014, despite reduced congestion on most other transmission facilities. Most of this congestion occurred on the Niagara-Packard, Packard-Sawyer, and Huntley-Sawyer transmission lines. These facilities have

19 Section III.B in the Appendix shows the congestion patterns in each quarter of 2014.

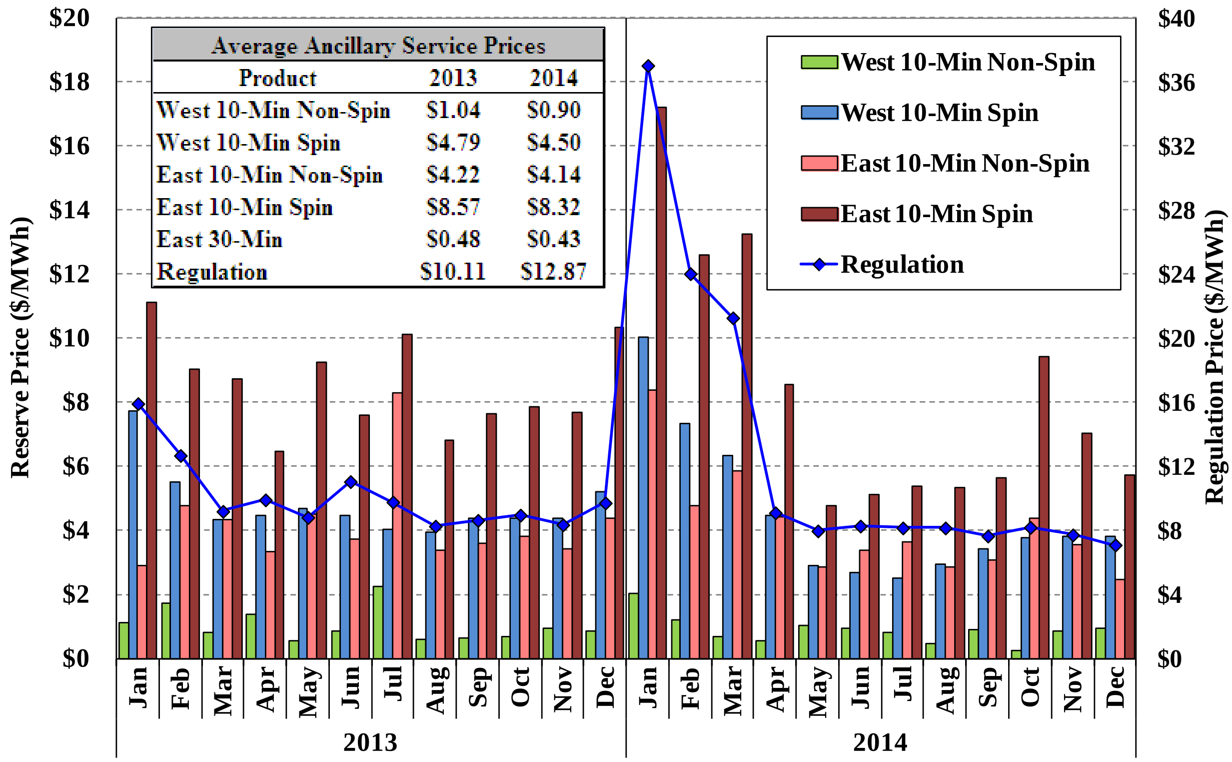
20 The use of the M2M process during TSA events was suspended on July 12, 2013. The process was re-enabled before the summer of 2014. See Section V.B of the Appendix for our evaluation on the M2M Coordination with PJM.

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 since 2013 is also attributable to changes in the Transmission Loading Relief ("TLR") process (following the start of operation of the Ontario-Michigan PARs in 2012). The NYISO is unable to use TLRs to manage congestion resulting from loop flows when the IESO-Michigan PARs are deemed in "regulate" mode.

F. Ancillary Services Market

Figure 3 shows the average prices of five key ancillary services products in the day-ahead market in each month of 2013 and 2014.[21]

Figure 3: Average Day-Ahead Ancillary Services Prices
2013-2014



Ancillary services and energy scheduling is co-optimized. 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

21 See Sections I.E and I.I Appendix provide additional information regarding the ancillary services markets.

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 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 2013 to 2014. The decrease was mostly attributable to lower load levels during most of 2014, particularly in the summer months. However, reserve prices rose significantly in the first quarter of 2014, offsetting the overall reduction. Volatile natural gas prices during this period led to higher energy prices and higher opportunity costs to provide reserves.

Additionally, fuel issues contributed to lower generation availability during some of the winter peak conditions early in 2014. Nonetheless, the number of reserve shortages in Eastern New York fell modestly in the first quarter of 2014 compared to the prior year, despite much tighter winter peaking conditions. This is likely partly attributable to the fact reserves were held on units that may not have had access to fuel if deployed. Our analysis of reserve scheduling during peak winter conditions suggests that this issue may have caused reserve prices to be understated.[22] The NYISO has been working with pipeline companies to ensure that generators' reference levels are set using appropriate criteria during periods when they are not authorized to withdraw gas from the pipeline.

Average day-ahead regulation prices rose 27 percent in 2014, driven primarily by the substantial increase in regulation shortages in the first quarter. Regulation prices fell after the first quarter, consistent with operating reserve and energy prices.

G. Long-Term Economic Signals

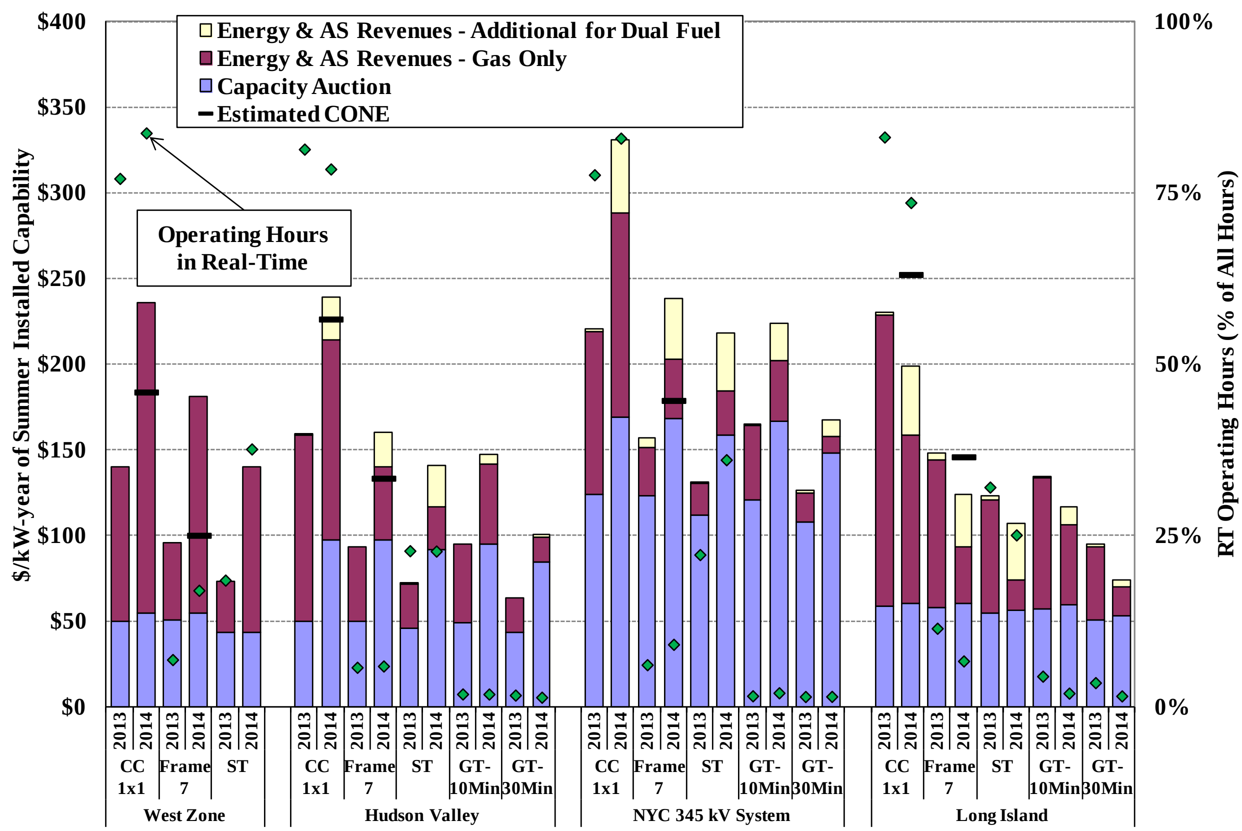
A well-functioning wholesale market establishes transparent price signals that provide efficient incentives to guide generation and transmission investment and retirement decisions. We evaluate the long-term price signals by calculating the net revenue that a new unit would have

[22] See Section IX.B.2 for our evaluation of this issue and the associated recommendation.

received from the NYISO markets by comparing it to the levelized Cost of New Entry ("CONE"). We also examine the incremental profitability from dual-fuel capability for several new and old generator types. 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 2013 and 2014, as well as common older unit types in New York.[23] Both figures show 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.[24]

Figure 4: Net Revenue and CONE by Location for Various Technologies
2013-2014



Net revenues for all unit types increased substantially from 2013 to 2014 in all locations (except for Long Island) largely because of higher energy net revenues. Energy net revenues rose at

23 The CONE values shown in the figure are based on the 2014-2017 Demand Curve Reset process.

24 Section I.G of the Appendix provides detailed net revenue results for additional locations and technologies using various gas price assumptions, and run hours are provided by fuel type for dual-fueled units.

most locations in 2014 primarily because congestion on the gas pipeline system led generators in most areas to experience higher spark spreads on days when natural gas prices rose sharply.[25] Dual-fueled generators earned particularly large net revenues on these days because they were able to switch fuels to oil when natural gas prices were higher.

Higher capacity prices also raised net revenues in New York City and the Lower Hudson Valley (i.e., Zones G to I). The creation of a new capacity zone for the G-J Locality led a large increase in capacity revenues for units in the Hudson Valley area. Capacity revenues increased for units in New York City because of a temporary (12-month) increase in the Local Capacity Requirement ("LCR"). This report recommends improvements in NYISO's method for calculating these LCRs. Capacity prices and requirements are discussed further in Section VIII.A.

The estimated net revenues for a new Frame 7 unit were higher than the annual levelized cost of new entry ("CONE") at all locations with the exception of Long Island. However, this is unlikely to induce new investment in a Frame 7 unit in the short run if developers believe net revenues are elevated by a temporary increase in the LCR or unusually tight winter conditions. Net revenues could fall in the future if LCRs decrease or upgrades to the gas pipeline system mitigate congestion on the gas system.

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. Therefore, units capable of providing 10-minute reserves earn the highest revenue. The net revenue estimates for a steam turbine in 2014 were comparable to the estimates for a 10-minute gas turbine because of significant additional revenues for steam turbine units from dual-fuel capability during the winter.

Our net revenue analysis indicates that the additional revenues from dual-fuel capability were significantly higher in 2014 in the downstate zones because of more frequent hourly operational

25 In general, generators experienced higher spark spreads in western New York, the Lower Hudson Valley, and in New York City, while generators in the Capital Zone and Long Island (which rely on the Iroquois Zone 2 trading hub) did not.

flow orders (i.e., gas system constraints) and natural gas price spikes during the winter months. The estimated net revenues from dual-fuel capability in the downstate zones ranged from $21 to $35 per kW-year for new Frame 7 units and from $24 to $43 per kW-year for new combined cycles and older steam turbines. It is likely that the high potential returns from dual-fuel capability are sufficient for many units to retain the capability and maintain modest inventories of oil. However, the actual use of oil for generation was much lower than the optimal levels calculated in our analysis in 2014 because of generator outages, low oil inventories, and air permit restrictions. The actual oil-based capacity factor for combined cycle units and steam turbines in New York City was only 30 to 35 percent of the optimal oil-based generation for such units based on our simulations.[26] The foregone profits of running during these highly profitable periods in 2014 should provide incentives for suppliers to address some of these issues in future winters.

The remainder of this report provides a detailed summary of our assessment of the wholesale market. We conclude the report with a list of recommended market enhancements in Section XI.

[26] See *Quarterly Report on the New York ISO Electricity Markets First Quarter 2014,* slide 12.

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 2014 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 New York City capacity market and the use of the market power mitigation measures in 2014.

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 generator deratings, and potential economic withholding by estimating an "output gap". The output gap is the estimated output that is economic at the clearing price but is not produced because the supplier's offer prices (start-up, minimum generation, and incremental energy) exceed the reference level by a given threshold.[27,28]

Figure 5 and Figure 6 evaluate the two withholding measures relative to season, load level, and the supplier's portfolio size.[29,30] Deratings are measured based on the generator's availability in the day-ahead market, so generating capacity that is derated or not offered in the real-time market is not considered in this evaluation. These quantities are shown according to whether they are short-term (i.e., less than 30 days) or long-term, and whether the derated capacity would have been economic at the day-ahead price levels.

The left portion of Figure 5 shows that although the amount of short-term deratings was relatively consistent between 2013 and 2014 in the winter and summer peak seasons, the amount of long-term deratings fell significantly. This is because some large suppliers improved their outage scheduling practices in 2014 and made more economic capacity available during peak conditions. Some suppliers may have been motivated to make more capacity available in 2014 (particularly in January, February, and the summer months) after their experiences with very tight market conditions in January, February, and July of 2013.

The right portion of Figure 5 shows that the two 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. In addition, the portion of capacity that was both long-term derated and economic fell in Eastern New York

27 Physical withholding is 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. A supplier with market power can profit from withholding when its losses from selling less output are offset by its gains from increasing LBMPs.

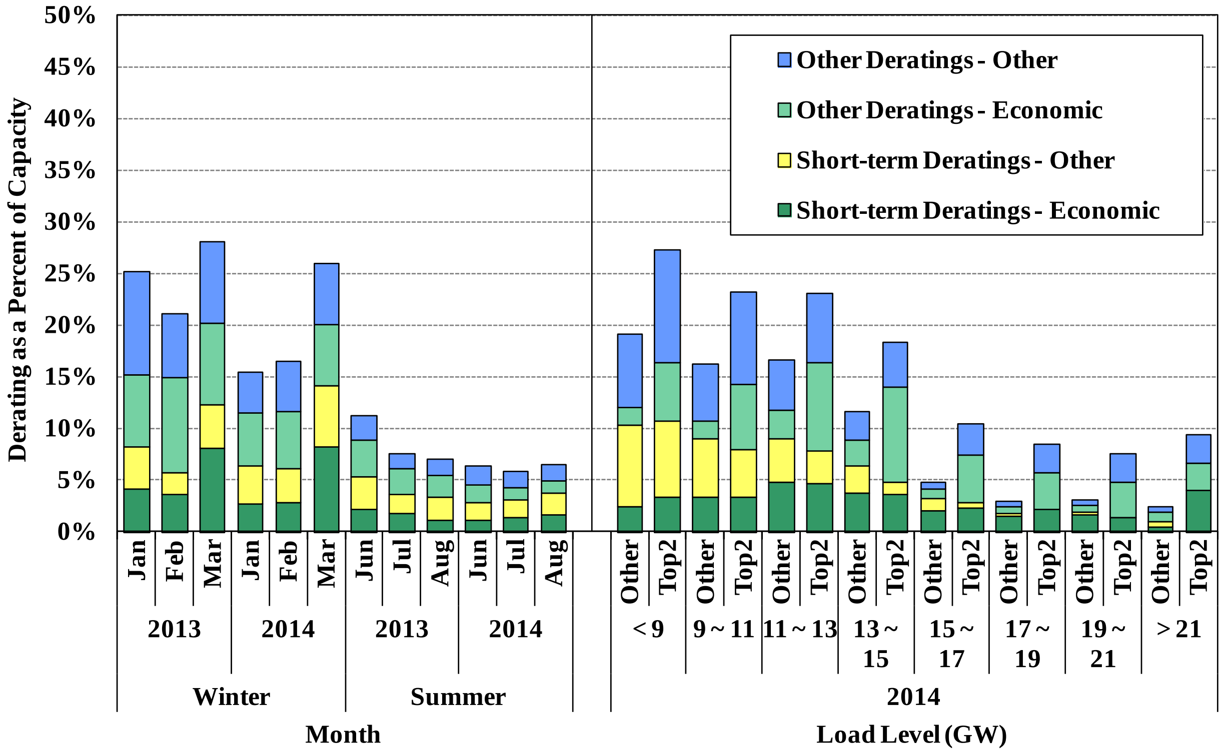
28 The output gap calculation excludes capacity that is more economic to provide ancillary services. In this report, the Mitigation Threshold refers to the threshold used for statewide mitigation, which is the lower of $100 per MWh or 300 percent of the reference level, the Lower Threshold 1 is the lower of $25 per MWh or 50 percent of the reference level, and Lower Threshold 2 is the lower of $50 per MWh or 100 percent of the reference level.

29 Both evaluations exclude capacity from hydro and wind resources.

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

from 6 percent in 2013 to 4 percent in 2014 because of improved outage scheduling practices by some suppliers.

Figure 5: Deratings in Eastern New York



The figure shows that the two largest suppliers in Eastern New York exhibited higher levels of deratings of economic capacity than other suppliers at all load levels. In particular:

- During high load levels (i.e., load > 17 GW), 6 percent of the capacity of the largest two suppliers was economic and derated compared to just 2 percent for other suppliers; and
- During low to moderate load levels (i.e., load < 17 GW), 10 percent of the capacity of the largest two suppliers was economic and derated compared to just 5 percent for other suppliers.

These differences between the top two suppliers and other suppliers are almost entirely accounted for by differences in long-term rather than short-term deratings of economic capacity. While higher deratings for the largest two suppliers were partly driven by different generator characteristics (e.g., age, prime mover, cogeneration use, etc.), they were partly attributable to different outage scheduling practices. Although long-term deratings are not likely to reflect withholding, inefficient long-term outage scheduling of some resources (i.e., scheduling an outage during a period when a resource is likely to be economic) is concerning because it still raises wholesale market costs.

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 address outage scheduling that is not consistent with competitive behavior. It would be beneficial for the NYISO to monitor outage scheduling patterns going forward and consider whether its role could be expanded to enable more efficient outage scheduling.

Figure 6: Output Gap in Eastern New York

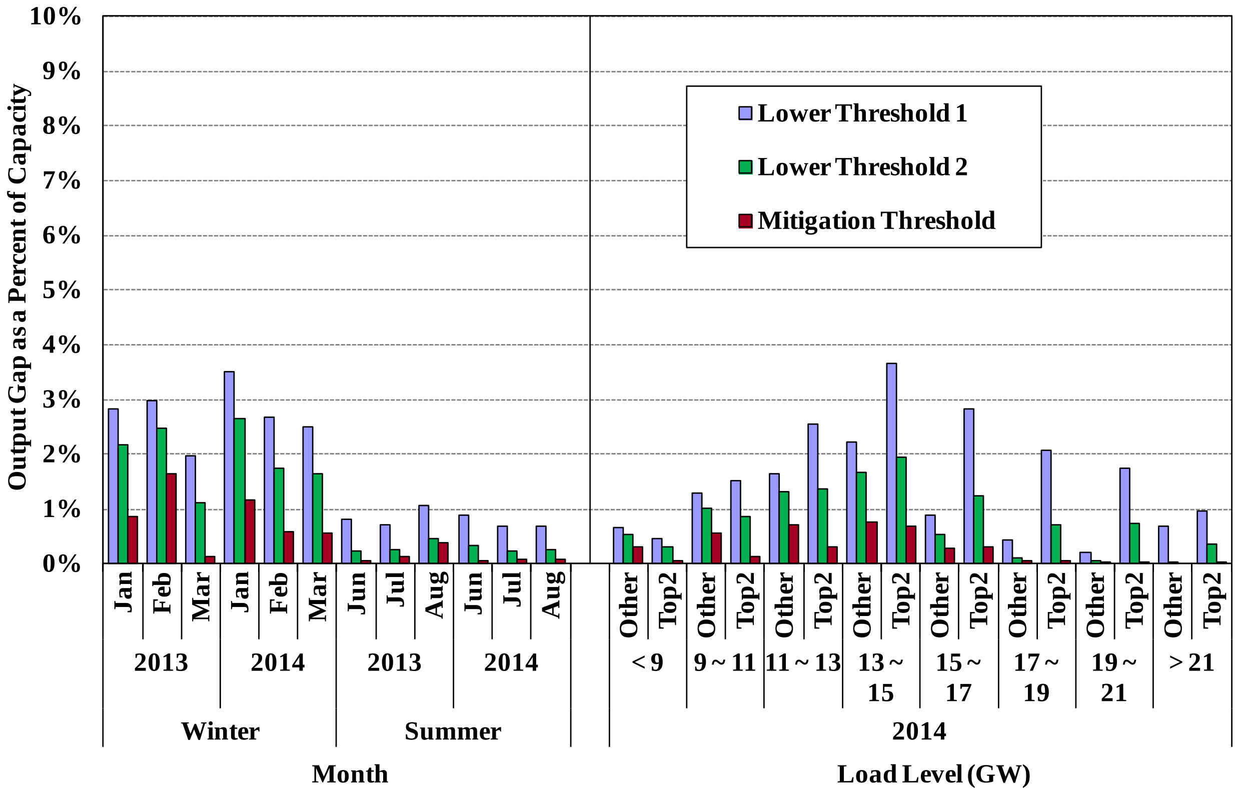


Figure 6 shows that the output gap averaged roughly 0.5 percent as a share of total capacity for both large and small suppliers in Eastern New York at the statewide mitigation threshold during 2014. At the lowest threshold evaluated (i.e., $25 per MWh or 50 percent above reference), the output gap averaged less than 2 percent. These levels were low, consistent with levels observed in 2013. Most of the output gap in 2014 occurred on units that are: (a) co-generation resources; and/or (b) owned by suppliers with small portfolios. 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. In addition, it is generally a positive indicator that the output gap declined as load increases for most suppliers and was especially low under high load conditions when the market is most vulnerable to the exercise of market power.

Therefore, the overall 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.[31] However, the pattern of day-ahead deratings shown in Figure 5 reflects some inefficient long-term outage scheduling practices.[32] For a competitive supplier, it can be challenging to schedule necessary maintenance outages while maximizing the availability of generation at times when it is economic. Accordingly, the NYISO should consider expanding its role in outage scheduling in order to avoid outages: (a) that would take economic capacity out of service during relatively high load conditions, or (b) when the amount of economic capacity requesting outages would lead to high market costs during moderate load 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.

31 Although the amount of output gap was relatively small in 2014, there were instances when the NYISO invoked the non-automated market power mitigation measures for generators that had output gap. (See NYISO MST Section 23.4.2.) Furthermore, there were instances when the NYISO invoked market power mitigation measures to address the inappropriate use of the functionality that allows suppliers to adjust their reference levels as a result of fuel price changes up until the close of the bid window for the real-time market. (See NYISO MST Section 23.3.1.4.7.8.) Inappropriate use of this functionality is not captured in the output gap metric, since the output gap is based on the generator's reference level.

32 There were instances when the NYISO invoked market power mitigation measures to address physical withholding in the real-time market. (See NYISO MST Section 23.4.3.2.) Such conduct is not captured in Figure 5, since it shows only day-ahead deratings.

- 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.[33]

- 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 7 summarizes the amount of mitigation that occurred in the day-ahead and the real-time markets in 2013 and 2014 as well as the amount of capacity that was unmitigated after consultation with NYISO.[34]

Most mitigation occurs in the day-ahead market, since that is where most supply is scheduled. Approximately 90 percent of AMP mitigation occurred in the day-ahead market in 2014, similar to 2013. Likewise, 84 percent of reliability mitigation occurred in the day-ahead market in 2014, primarily for DARU and LRR commitments in New York City. Reliability mitigation accounted for 83 percent of all mitigation in 2014. Unlike AMP mitigation, these mitigations generally affected guarantee payment uplift but not energy prices.

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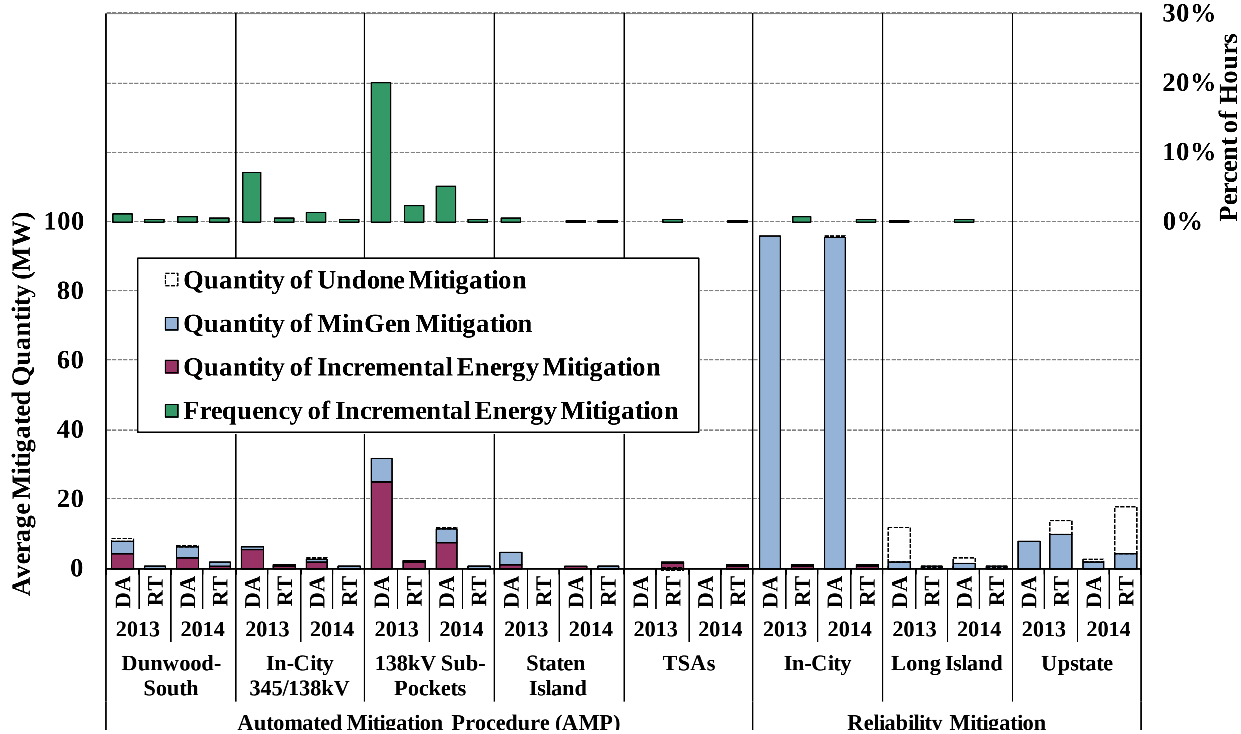
33 The conduct and impact thresholds used by AMP are determined by the formula provided in the NYISO Market Services Tariff, Section 23.3.1.2.2.1.

34 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.

Figure 7: Summary of Day-Ahead and Real-Time Mitigation
2013-2014



The frequency of AMP mitigation in New York City has decreased substantially in the past three years. The average capacity that was AMP-mitigated fell from over 250 MW in 2011 to just 25 MW in 2014. These reductions were mostly attributable to less frequent transmission congestion in New York City, particularly in the 138kV load pockets. Congestion has been reduced primarily by generation additions and transmission upgrades in recent years. 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 2014, contributing to further reductions in New York City congestion and associated AMP-mitigation in 2014.

Unmitigation of generators that were initially mitigated by the AMP software was very uncommon in 2013 and 2014 because of improvements in the NYISO's processes for administering reference levels. The improved procedures have been particularly valuable during periods of volatile natural gas prices and low oil inventories during the winter months. These improvements are important because mitigating generators below marginal cost with the AMP software can lead to inefficient scheduling of generation, distorted market clearing prices, and wasting scarce fuel supplies.[35]

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.[36] Supply-side mitigation measures prevent a large supplier from inflating prices above competitive levels by withholding economic capacity in these areas.[37] 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 2014.

1. Application of the Buyer-Side Mitigation Measures

The NYISO performed Mitigation Exemption Tests for several Class Year 2012 ("CY12") projects in 2014, including the Berrians GT III Project (which is a proposed 250 MW combined cycle project in Zone J), the Champlain Hudson Power Express Project (which is a proposed 1000 MW merchant transmission project running from US-Canada border to Zone J), and Cricket Valley Energy Center Project (which is a proposed 950 MW combined cycle project in Zone G).[38] The NYISO evaluated the three CY12 Examined Facilities and confidentially

[35] Undoing reliability mitigation is much less concerning, since it does not affect schedules or prices. This is because the mitigation takes place after the market runs in the settlement process, although it may be administratively burdensome for the NYISO and some market participants.

[36] 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.

[37] 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.

[38] In March 2014, the NYISO also completed the Mitigation Exemption Tests for the two CY11 Projects located in the G-J Locality. These results are discussed in *2013 State of the Market Report for the New York ISO Markets* ("2013 SOM.Report"), Section III.C.

provided a BSM determination to each developer prior to the Initial Project Cost Allocation. The Champlain Hudson Power Express Project and the Cricket Valley Energy Center Project each rejected its Project Cost Allocation and dropped out of CY12. Therefore, at the end of the Initial Decision Round, the Berrians GT III Project was the only Examined Facility remaining in CY12.

The Berrians GT III Project was determined not to be exempt in the Mitigation Exemption Test in the Final Decision Round and will be subject to Offer Floor mitigation if the developer moves forward with the project.[39]

2. Improvements to the Buyer-Side Mitigation Measures

Continued efforts to refine the methodology that is used to test new resources for exemption from the buyer-side mitigation offer floor are very important, 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.

Competitive Entry Exemption

The Mitigation Exemption Test is conducted three years in advance of the unit entering the market, and it evaluates whether the unit appears uneconomic based on the forecasted conditions at the time of its entry. It is particularly difficult for future price forecasts to account for uncertainty regarding unit retirements. Consequently, the Buyer-Side Mitigation Exemption Test procedure that relies on retirement notices submitted to the PSC will tend to understate the forecasted prices and over-mitigate competitive entry.

In response to a complaint, FERC ordered the NYISO to address this concern by amending its Tariff to grant exemptions to suppliers engaged in purely private investment.[40] Beginning with Class Year 2015 of the interconnection process, this rule will allow merchant investors to enter the market based on their own expectations of generation retirements. This should ensure that competitive market-based investments are not precluded by the buyer-side mitigation rules.

39 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").

40 See *Consolidated Edison Company of New York, Inc., et al v. New York Independent System Operator, Inc.*, 150 FERC ¶ 61,139.

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 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 the 100 percent of the MNC.[41]

Treatment of Units being Replaced, Mothballed, and Retired in Price Forecasts

The set of generators that is assumed to be in service for the purposes of the exemption test 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 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.[42] The Tariff also compels the NYISO to exclude resources that have submitted a retirement notice but retain the ability to re-enter the market.[43] We recommend the NYISO

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41 See Recommendation 4(a) in Section XI.

42 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.

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

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.[44]

Potential Expansion of Buyer-Side Mitigation Measures

In response to a recent complaint by the Independent Power Producers of New York, FERC recognized that the current buyer-side mitigation measures do not address all potential conduct that may suppress capacity prices.[45] To determine whether the buyer-side mitigation measures should be expanded to address additional classes of conduct, the NYISO should evaluate the incentives to suppress capacity prices with this conduct. In response to FERC's Order on the IPPNY complaint, we understand that NYISO intends to perform such an evaluation. We anticipate reviewing and providing comments on the analyses and conclusions of this study.

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's evaluation should consider how to effectively address these issues.

44 See Recommendation #4(b) in Section XI.

45 See *Independent Power Producers of New York, Inc. v. New York Independent System Operator, Inc.*, Docket No. EL13-62-000.

V. Day-Ahead Market Performance

A. Day-Ahead to Real-Time Price Convergence

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. This is because if day-ahead prices are predictably higher or lower than real-time prices, market participants will shift some of their purchases and sales to arbitrage the prices. Price convergence is desirable also because it promotes the efficient commitment of generation, procurement of natural gas, and scheduling of external transactions. We evaluate convergence of energy prices at the zone level and node level and convergence of ancillary services prices.

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 2013 and 2014.[46] These statistics are shown on an annual basis and also separately for the first quarter and the rest of the year.

Table 3: Price Convergence between Day-Ahead and Real-Time Markets
Select Zones, 2013-2014

	Annual Average (DA - RT)				Q1 Average (DA - RT)				Q2-Q4 Average (DA - RT)			
	Avg. Diff		Avg. Abs. Diff		Avg. Diff		Avg. Abs. Diff		Avg. Diff		Avg. Abs. Diff	
Zone	2013	2014	2013	2014	2013	2014	2013	2014	2013	2014	2013	2014
West	-1.9%	0.4%	36.3%	39.9%	-0.2%	1.6%	29.3%	41.7%	-2.5%	-0.8%	38.8%	38.3%
Central	1.3%	3.6%	29.5%	33.4%	0.0%	3.8%	29.8%	38.4%	1.8%	3.3%	29.4%	27.8%
Capital	4.5%	7.2%	33.1%	32.9%	6.5%	9.0%	38.7%	36.8%	3.3%	4.8%	29.9%	27.4%
Hudson Valley	-0.8%	6.4%	33.9%	31.8%	5.5%	7.9%	34.3%	35.3%	-3.9%	4.5%	33.7%	27.3%
New York City	-1.4%	5.1%	35.0%	31.2%	3.1%	5.7%	37.7%	34.4%	-3.5%	4.4%	33.7%	27.5%
Long Island	-6.5%	3.5%	46.5%	38.1%	-8.2%	4.0%	47.9%	35.1%	-5.9%	3.1%	45.9%	41.4%

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

Day-ahead prices were much higher on average than real-time prices in most areas of eastern New York in 2014, particularly in the first quarter. A large portion of the difference can be accounted for by the Polar Vortex (January 22 to 29) as rapid changes in weather patterns, natural gas prices, and supplemental commitments after the day-ahead market led to much lower real-time prices on these days.

As measured by the average absolute difference between hourly day-ahead and real-time prices, energy price convergence improved modestly in most areas from 2013 to 2014. The improvement was most evident in the period from the second quarter to the fourth quarter of 2014, which reflected lower load levels and less volatile natural gas prices. However, convergence was worse in most regions in the first quarter of 2014 primarily because of more frequent peaking conditions and significantly higher and more volatile natural gas prices (relative to the first quarter of 2013).

Price convergence improved most on Long Island in 2014. In addition to the factors discussed above, outages of major transmission lines occurred less frequently in 2014, reducing congestion and price volatility in Long Island.

Western New York exhibited significantly more price volatility in the first quarter of 2014 than in the previous year. Prices in Western New York were often low because of the low production costs of resources there. But when excess supply in Western New York was insufficient to congest the Central-East Interface, prices in Western New York often rose to the levels in Eastern New York during periods of high natural gas prices. As a result, prices were more volatile in Western New York than in Eastern New York. Prices were particularly high and volatile in the West Zone during periods of congestion on 230kV lines downstream of Niagara as discussed below in Part 2.

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 2014. The most significant example of poor convergence between day-ahead and real-time prices was the Valley Stream load pocket in the western portion of Long Island, which exhibited average real-time prices that were nearly 10 percent higher than average day-ahead prices in 2014.[47] This pattern reflects that there was 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.[48]

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.

Another notable example of poor convergence between day-ahead and real-time prices was the Niagara generation pocket in the West Zone, which exhibited average day-ahead prices that were 7.5 percent higher than average real-time prices in 2014. 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 given price level) from Ontario and Niagara after the day-ahead market as well as volatile loop flows around Lake Erie.

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. 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 usually higher in real-time when congestion was not reflected in the

47 See Figure A-25 in the Appendix for additional results.

48 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 V.E in the Appendix.

day-ahead market. 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

We evaluate the convergence between day-ahead and real-time prices for three important reserve products: 10-minute spinning reserves in Western New York, 10-minute spinning reserves in Eastern New York, and 10-minute non-spin reserves in Eastern New York.[49] Convergence is measured by the difference between average day-ahead price and the average real-time prices as a percent of average day-ahead prices as well as the average absolute value of the difference between day-ahead and real-time prices.

Reserve price convergence generally improved under high load conditions from 2013 to 2014 primarily because of the milder summer weather conditions. Both the average price difference and average absolute price difference between day ahead and real time improved for the three key reserve products. Revisions to the following two day-ahead market reserve mitigation provisions in 2013 and 2014 likely contributed to better convergence under high load conditions:

- On January 23, 2013, the first phase of the revision raised: (a) the reference level cap for 10-minute non-spin reserves from $2.52 to $5 per MW; and (b) the offer cap for 10-minute spinning reserves for New York City generators from $0 to $5 per MW;
- On September 25, 2013, the second phase of the revision raised both caps to $10 per MW; and
- On August 26, 2014, the final phase of the revision eliminated both caps.[50,51]

49 Figure A-26 to Figure A-28 in the Appendix show our evaluation in more detail.

50 The day-ahead 10-minute spinning reserves offers of NYC units were limited to $0 per MWh by NYISO Market Services Tariff Section 23.5.3.3. The reference levels for day-ahead 10-minute non-spinning reserves offers were limited to $2.52 per MWh by NYISO Market Services Tariff Section 23.3.1.4.5.

51 See New York Independent System Operator, Inc., *Proposed Amendments to its Market Power Mitigation Measures revising Mitigation Measures for 10-Minute Non-Synchronized Reserves and New York City Day-Ahead Market Spinning Reserves*, Docket No. ER13-298-000.

During non-peak periods, reserve price convergence was generally comparable between 2013 and 2014. Day-ahead price premiums increased modestly during low load periods, which was partly attributable to changes in offer caps.[52] The day-ahead premiums are generally expected in a competitive market without virtual trading.

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 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 4 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 2013 and 2014 for various regions in New York State.[53] Overall, net scheduled load in the day-ahead market was nearly 94 percent of actual NYCA load in 2014, comparable to 2013. Day-ahead net load scheduling patterns in each of the sub-regions were generally consistent between 2013 and 2014 as well.

Average net load scheduling tends to be higher in locations where volatile real-time congestion is more common. Net load scheduling in the Capital Zone rose in the winter months because of frequent congestion across the Central-East interface. Net load scheduling was highest in New York City and Long Island because they are downstream of most congested interfaces. Net load scheduling has risen in the West Zone in the past two years because of increased congestion on the 230kV system in the West Zone compared to prior years. Although not shown separately in the table, net scheduled load in the West Zone averaged 110 percent of actual load in 2014.

52 Offer patterns are evaluated in Section II.D in the Appendix.

53 Figure A-44 to Figure A-50 in the Appendix also show these quantities on a monthly basis at these locations in New York.

Table 4: Day-Ahead Load Scheduling versus Actual Load
By Region, 2013-2014

Region	Year	Bilateral + Fixed Load	Price-Capped Load	Virtual Supply	Virtual Load	Virtual Import	Virtual Export	Net Scheduled Load
West NY	2013	118.9%	0.0%	-28.3%	5.2%			95.7%
	2014	119.7%	0.0%	-29.8%	6.7%			96.6%
North	2013	96.3%	0.0%	-37.3%	0.8%			59.8%
	2014	97.6%	0.0%	-48.6%	1.0%			50.0%
Capital	2013	102.3%	0.0%	-14.9%	3.9%			91.2%
	2014	101.9%	0.0%	-17.7%	4.0%			88.2%
Lower Hudson	2013	90.4%	14.2%	-21.4%	7.2%			90.4%
	2014	81.4%	16.9%	-12.2%	5.1%			91.1%
New York City	2013	93.6%	4.6%	-0.6%	2.8%			100.4%
	2014	93.5%	4.4%	-0.5%	2.1%			99.5%
Long Island	2013	96.6%	0.0%	-0.5%	12.1%			108.3%
	2014	99.1%	0.0%	-0.5%	10.8%			109.4%
NYCA	2013	102.0%	3.2%	-13.8%	5.3%	-3.7%	0.3%	93.3%
	2014	101.6%	3.4%	-13.6%	5.1%	-3.3%	0.4%	93.7%

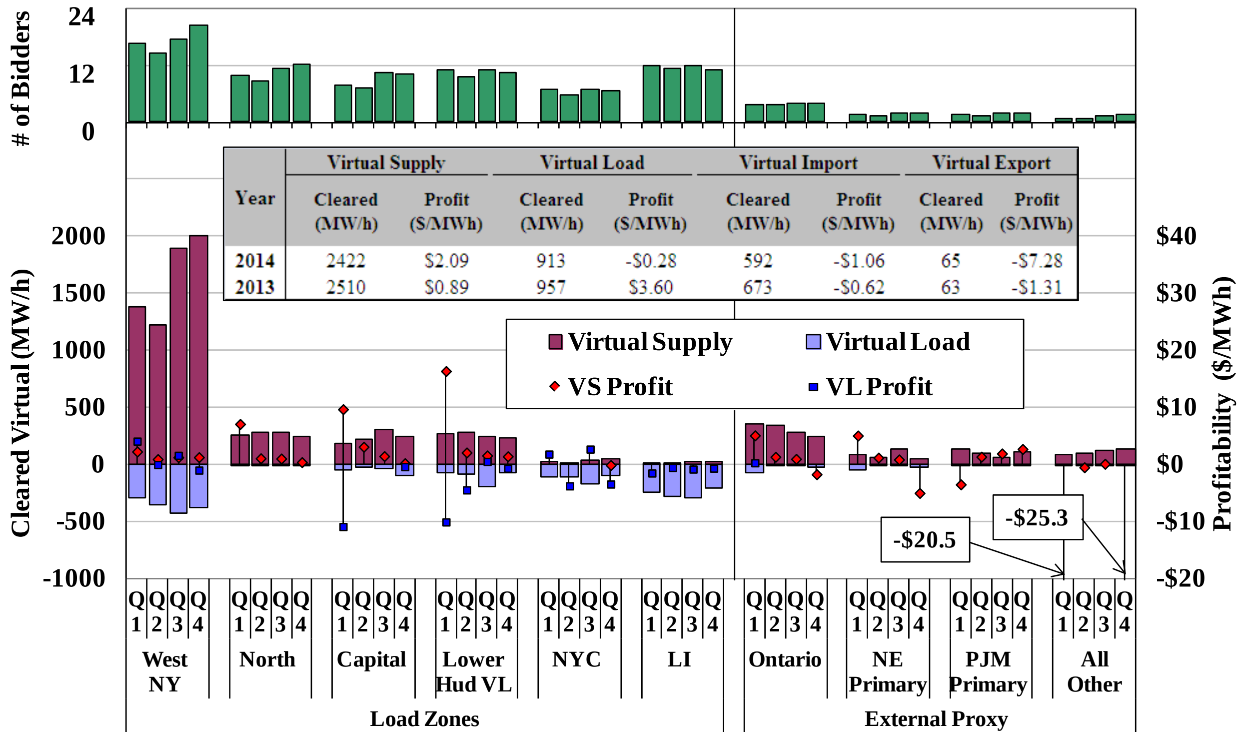
Load was typically under-scheduled in the North Zone by a large margin primarily in response to the scheduling patterns of wind resources in this area. Wind generators typically operate in real-time above their day-ahead schedules. Likewise, other renewable generators exhibit a tendency to operate above their day-ahead schedule in real-time. In 2014, renewable generators added an average of 520 MW of additional energy supply in real-time, satisfying nearly 8 percent of the average real-time load outside Southeast New York. Also, net imports tend to increase in real-time from Ontario, which does not operate a day-ahead market, making it riskier for importers from Ontario to sell into the NYISO's day-ahead market. These increases in physical supply after the day-ahead market provide opportunities to profit from scheduling of virtual supply and virtual imports.

In general, the patterns of day-ahead scheduling have helped improve convergence between day-ahead and real-time prices. In 2014, all regions exhibited day-ahead premiums, which also suggests that further under-scheduling in most regions would likely have been profitable.

The following figure summarizes virtual trading by geographic region in 2014, which includes virtual trading at the eleven load zones and virtual imports and exports at the proxy buses.[54]

Figure 8: Virtual Trading Activity

by Region by Quarter, 2014



The figure shows that a large number of market participants regularly submitted virtual bids and offers. In 2014, on average, 27 participants submitted virtual trades at the load zones and 8 participants submitted virtual imports and exports at the proxy buses.

At the load zones, virtual traders generally scheduled more virtual load in downstate areas (i.e., New York City and Long Island) and more virtual supply in upstate areas in 2014. This pattern was consistent with the day-ahead load scheduling patterns discussed earlier for similar reasons. At the proxy buses, 90 percent of scheduled virtual transactions were virtual imports, primarily at the three primary interfaces with PJM, New England, and Ontario. Since these three interfaces are primarily interconnected with the regions in upstate New York, these virtual imports are consistent with the pattern of virtual supply scheduled in these regions.

54 See Figure A-52 in the Appendix for a detailed description of the chart.

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.[55] However, in aggregate, virtual traders netted approximately $33 million of gross profits in 2014, down from the $45 million in 2013.[56] Overall, virtual traders have been profitable in the past two years, indicating that they have generally improved convergence between day-ahead and real-time prices. Good price convergence, in turn, facilitates an efficient commitment of generating resources.

55 Figure A-51 in the Appendix also shows wide variations in profits and losses on a monthly basis.

56 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 from the figure, so they account for a large share of the losses reported for virtual imports and exports, particularly in the "All Other" interface category.

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.

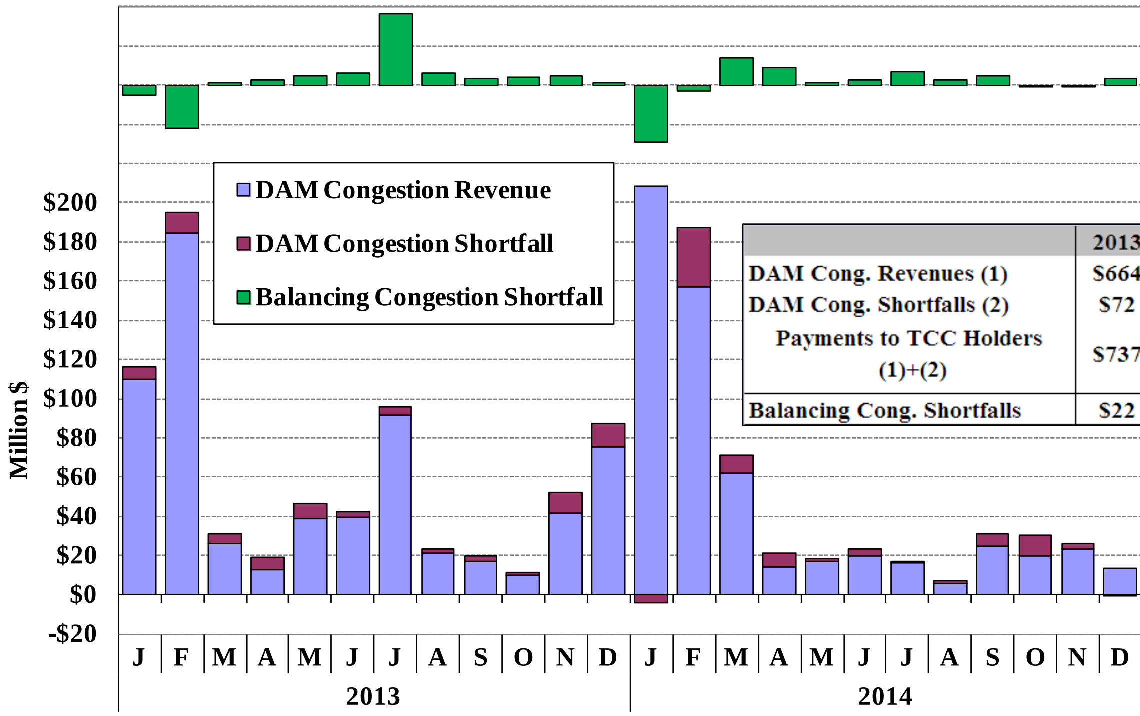
Congestion charges are applied to purchases and sales (including bilateral transactions) in the day-ahead and real-time markets based on the congestion components of the day-ahead LBMPs and the real-time LBMPs, respectively.[57] Market participants can hedge congestion charges in the day-ahead market 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 the following three categories of congestion costs:

- 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 – These occur 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 – These arise when day-ahead scheduled flows over a constraint exceed what can flow over the same constraint in the real-time market.

[57] 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 9: Congestion Revenues and Shortfalls
2013 – 2014



	2013	2014
DAM Cong. Revenues (1)	$664	$578
DAM Cong. Shortfalls (2)	$72	$69
Payments to TCC Holders (1)+(2)	$737	$647
Balancing Cong. Shortfalls	$22	$5

The figure shows that the overall congestion revenues and shortfalls fell from 2013 to 2014. Congestion revenues collected in the day-ahead market fell by 13 percent from 2013 to $578 million in 2014. Similarly, day-ahead and balancing congestion revenue shortfalls fell by 21 percent to a total of $74 million in 2014.

1. Day-Ahead Congestion Revenues

The decrease in day-ahead congestion revenues in 2014 was mostly attributable to lower load levels and lower natural gas prices during most of 2014, particularly in the summer months. In general, lower load levels decreased flows across the network and resulted in less frequent transmission bottlenecks, and lower natural gas prices reduced the costs of gas-fired units that were dispatched to manage congestion.

- Day-ahead congestion revenue rose 34 percent year-over-year in the first quarter of 2014 because: (a) average load rose nearly 3 percent; and (b) average natural gas prices increased 32 percent in Western New York and 80 to 183 percent in Eastern New York over the same period.

- However, day-ahead congestion revenue fell 56 percent year-over-year in the second through fourth quarters of 2014 as: (a) average natural gas prices fell 13 to 25 percent across New York State; and (b) average load levels fell nearly 3.5 percent over the same period.

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

- $300 million (or 52 percent) of day-ahead congestion revenues accrued on the Central-East interface in 2014, up modestly from $284 million in 2013.[58]

- $421 million (or 73 percent) of day-ahead congestion revenues accrued in the first quarter of 2014, when gas price spreads were largest.

Congestion in Southeast New York fell notably in 2014. In Long Island, congestion fell nearly 40 percent from 2013 to 2014 partly because of higher Neptune imports and increased imports from upstate New York. From Capital to Hudson Valley, congestion fell nearly 70 percent from 2013 to 2014, attributable to less frequent TSA events and their reduced impact on congestion.[59]

Congestion on 230kV lines in the West Zone rose slightly from 2013 to 2014 despite reduced congestion on most other transmission facilities. 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 since 2013 was also attributable to changes that have made the TLR process less effective since 2012 when the Ontario-Michigan PARs were placed in service.[60] Overall, flows from the western-most areas to central New York accounted for $70 million (or 12 percent) of day-ahead congestion revenues in 2014.

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58 Figure A-54 in the Appendix shows the day-ahead and real-time congestion by interface in 2013 and 2014. Figure A-8 shows monthly natural gas prices for several regions in New York.

59 Section III.B in the Appendix discusses contributing factors to reduced congestion in Southeast New York in greater detail.

60 Section III.B in the Appendix discusses the West Zone congestion, and Section VII.B discusses changes in the TLR ("Transmission Loading Relief") process.

2. Day-Ahead Congestion Shortfalls

As described above, 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. Day-ahead congestion shortfalls fell slightly from $72 million in 2013 to $69 million in 2014. Table 1 shows total day-ahead congestion shortfalls in 2014 by selected transmission facility groups.[61]

Table 5: Day-Ahead Congestion Shortfalls
By Facility, 2014

Facility Group	Annual Shortfalls ($ Million)
Long Island Lines	$20
New York City Lines	$19
Ramapo PARs	$17
West Zone Lines	$10
Excess LI GFTCC Allocations	$6
901/903 PARs	-$9
All Other	$6

Transmission outages were a primary driver of day-ahead congestion shortfalls in 2014. Long Island and New York City each accounted for approximately $20 million of total shortfalls. On Long Island, the vast majority of shortfalls accrued in early January, during the entire month of February, during most of August, and from late October to early November. During these periods, the transfer capability into Long Island was significantly reduced because of transmission outages of the 345kV transmission facilities from Upstate to Long Island. In New York City, nearly 80 percent of shortfalls accrued from January to March when multiple transmission outages reduced transfer capacity on the 345 kV system and in the Greenwood load pocket. The two Ramapo PARs were out of service from February 7 to 23, which led to substantial reductions in PJM imports and higher internal flows from west-to-east, contributing a $17 million shortfall during periods of congestion over the Central-East interface.

61 Figure A-57 in the Appendix summarizes the day-ahead congestion shortfalls on major transmission facilities for 2013 and 2014 on a monthly basis. Section III.C in the Appendix also provides detailed description for these transmission facility groups.

The NYISO has a process for allocating the day-ahead congestion shortfalls that result from transmission outages to specific transmission owners.[62] In 2014, the NYISO allocated 106 percent of day-ahead congestion shortfalls in this manner.[63] 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.[64]

Other modeling inconsistencies between the TCC auction and the day-ahead market contributed to congestion shortfalls (or surpluses) in the day-ahead market. Notable examples in 2014 included:

- Grandfathered TCCs that exceed the actual transfer capability from Dunwoodie (Zone I) to Long Island.[65] This resulted in a shortfall of $6 million in 2014, down from $13 million in 2013.
- The difference in the schedule assumptions 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 205 MW in that direction in 2014. 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 contributed a surplus of $9 million in 2014 and $8 million in 2013.

3. Balancing Congestion Shortfalls

Balancing congestion shortfalls result from reductions in the transmission capability from the day-ahead market to the real-time market. Unlike day-ahead congestion shortfalls, balancing congestion shortfalls are socialized through Rate Schedule 1 charges. Balancing shortfalls fell substantially from $22 million in 2013 to $5 million in 2014. Table 6 shows total balancing

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

63 In 2014, 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.

64 Transmission outages 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.

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

congestion shortfalls accrued in the real-time market in 2014 for selected transmission facility groups.[66]

Table 6: Balancing Congestion Shortfalls[67]
By Facility, 2014

Facility Group	Annual Shortfalls ($ Million)
External Interface	**$11**
Capital to Hud VL (TSAs)	**$5**
901/903 PARs	**$5**
Ramapo PARs & M2M Payment	**-$7**
All Other	**-$6**

Balancing congestion shortfalls fell roughly 70 percent from 2013 to 2014 primarily because of the reduction in TSA-related shortfalls, which decreased from $23 million in 2013 to just $5 million in 2014. In prior years, the majority of balancing congestion shortfalls accrued from May to September when TSA events are most frequent. TSAs require the NYISO to reduce transmission flows into Southeast New York significantly below day-ahead scheduled levels. However, the TSA events were declared much less frequently in 2014 because of milder weather conditions and their impact on congestion was also greatly reduced (for the reasons discussed in Section III.B in the Appendix). In 2014, external interfaces accounted for the largest share of shortfalls, most of which accrued on a small number of days in March when the primary NY-NE interface was frequently derated in real-time because of transmission outages in New England.

Unlike in the day-ahead market, 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.

66 Figure A-58 in the Appendix summarizes the balancing congestion shortfalls on major transmission facilities for 2013 and 2014 on a monthly basis. Section III.C in the Appendix also provides detailed description for these transmission facility groups and a variety of reasons that their actual flows deviated from their day-ahead flows.

67 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; (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.

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 more volatile. Therefore, when flows rose above the day-ahead assumption, they often contributed to high prices in Long Island.[68] 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 $5 million in 2014 ($6 million in 2013).

The overall net balancing congestion shortfall was reduced by balancing congestion surpluses generated from the operation of Ramapo PARs under the M2M Coordination with PJM. The NYISO received a net settlement of $4.2 million from PJM in 2014 under the M2M JOA when the real-time flows across the PAR-controlled lines were lower than the target flows in hours when the NYISO experienced congestion on its coordinated flowgates. Another $2.5 million of surpluses resulted when actual real-time flows across these lines exceeded the day-ahead scheduled flows.

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 2013/14 and Summer 2014 Capability Periods (i.e., November 2013 to October 2014). Table 7 summarizes TCC cost and profit for the evaluation period separately for inter-zonal and intra-zonal TCCs.[69] 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

68 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.

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

for each category, where the total TCC profit is measured as a percentage of total TCC value (i.e., TCC payment).

Our evaluation includes TCCs sold in the following auction rounds during the 12-month period: (a) four rounds of one-year auctions for the 12-month period; (b) four rounds of six-month auctions for the Winter 2013/14 Capability Period; (c) four rounds of six-month auctions for the Summer 2014 Capability Period; and (d) twelve reconfiguration auctions for each month of the 12-month Capability Period.

Table 7: TCC Cost and Profit
Winter 2013/14 and Summer 2014 Capability Periods

	TCC Cost ($ Million)	TCC Profit ($ Million)	Profit as a Percent of Cost
Inter-Zone			
One Year	$23	$25	107%
Six-Mth: Winter	$51	$104	204%
Six-Mth: Summer	$22	-$7	-31%
Reconfig: Winter	$25	$10	39%
Reconfig: Summer	$3	-$1	-40%
Total	**$125**	**$131**	**105%**
Intra-Zone			
One Year	$17	$17	98%
Six-Mth: Winter	$8	$12	162%
Six-Mth: Summer	$21	-$9	-44%
Reconfig: Winter	$8	$12	154%
Reconfig: Summer	$4	-$2	-56%
Total	**$58**	**$30**	**52%**

Market participants purchasing TCCs in the auctions covering the 12-month period from November 2013 to October 2014 netted a total gross profit of $161 million. Overall, the profitability for TCC holders in this period was 88 percent (as a weighted percentage of the original TCC prices).

The vast majority of profit accrued in the Winter 2013/14 Capability Period, during which the value of day-ahead market congestion was well above TCC prices for most transmission paths, particularly between areas across the Central-East interface. This indicates that the high levels of congestion that were driven by higher natural gas prices and larger gas spreads were generally not anticipated by participants in the TCC auctions. This is understandable because the auctions occurred well before the escalation in natural gas prices.[70,71]

However, TCC buyers netted overall losses in the Summer 2014 Capability Period. The value of day-ahead market congestion was lower than TCC prices for most transmission paths during this period. Overall, the lower congestion levels in the summer that were driven by lower natural gas prices and lower load levels were not anticipated at the time of TCC auctions. In addition, congestion into Southeast New York and into Long Island fell well below the levels in the prior summer (for the reasons discussed earlier), contributing to the losses.

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. 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.

70 Nearly all of the transmission capability for the Winter 2013/14 Capability Period was sold prior to October 2013.

71 Section III.D of the Appendix shows our analyses regarding TCC auction results and day-ahead congestion.

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 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. 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 8 summarizes the net scheduled imports between New York and neighboring control areas in 2013 and 2014 during peak (i.e., 6 am to 10 pm, Monday through Friday) hours.[72]

Table 8: Average Net Imports from Neighboring Areas
Peak Hours, 2013 – 2014

Year	Hydro Quebec	Ontario	PJM	New England	CSC	Neptune	1385	VFT	HTP	Total
2013	1,296	808	489	-463	245	371	99	124	46	3,016
2014	1,152	768	352	-702	173	528	56	43	68	2,438

72 Figure A-61 to Figure A-64 in the Appendix show more detailed on net scheduled interchange between New York and neighboring areas by month by interface.

Total net imports from neighboring areas averaged slightly over 2.4 GW during peak hours in 2014, down roughly 580 MW from 2013. Net imports fell on most interfaces from 2013 to 2014.

1. Controllable Interfaces

Imports from neighboring control areas satisfied a large share (30 percent) of the demand on Long Island in 2014, up modestly from 28 percent in 2013. The increase was primarily due to increased net imports across the Neptune line, which rose 42 percent from 2013 because the line was only partially available (up to 375 MW) in the first half of 2013 and returned to full operation (up to 660 MW) in July of 2013. Although the full capabilities of the other two controllable interfaces were frequently used to import, two factors reduced imports significantly during portions of 2014.[73] First, the Cross Sound Cable was out of service from late October throughout the end of 2014, limiting the amount of imports from Connecticut during this period. Second, net imports over the Cross Sound Cable and the Northport-Norwalk line were significantly lower in the winter months when natural gas prices in New England were significantly higher than natural gas prices in Long Island.

Net imports to New York City over the Linden VFT and the HTP interfaces were modest, averaging 110 MW during peak hours in 2014.[74] 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

Net imports fell during peak hours across each primary interface from 2013 to 2014. Average net imports from Ontario fell modestly from 2013 to 2014, net imports were higher for most of 2014 because of the large price spread between Ontario and Western New York. Average real-time prices were roughly $11.80 per MWh higher on the NYISO side of the interface than on the Ontario side during 2014. However, imports fell in the winter, particularly in late February and

[73] Capabilities are 330 MW for Cross Sound Cable and 200 MW for the 1385 Line.

[74] The HTP interface began its normal operations in June 2013 with a capability of 660 MW. Linden VFT has a capability of 315 MW.

early March, when Ontario imported a substantial amount of power from New York because natural gas prices in Ontario were significantly higher than in Western New York.

Average net exports to New England across the primary interface rose by more than 50 percent (or 240 MW) from 2013 to 2014. The increase was consistent with increased natural gas price spreads between New England and Eastern New York, particularly in the summer (because of lower natural gas prices in New York City).

Net imports from Hydro Quebec to New York accounted for 73 percent of net imports across all primary interfaces in 2014. In the past, flows from Hydro Quebec typically rose in the summer months and during periods of high natural gas prices, reflecting the flexibility of their hydroelectric generation to export power to New York when it was most valuable to do so. From 2013 to 2014, net imports from Hydro Quebec fell 12 percent. Most of the reduction occurred in the winter because of more frequent extreme cold weather conditions that led to limited hydro production and increased winter peaking load in Hydro Quebec. The reduction in the winter had significant price effects in Western New York.

Net imports from PJM fell 28 percent from 2013 to 2014, averaging roughly 350 MW during peak hours of 2014. Despite the overall reduction, net imports actually rose in the first quarter from 2013 to 2014 for two reasons. First, the Ramapo PARs returned to full capability in 2014, which increased transfer capability across the portion of the interface between New York and New Jersey. This led to a corresponding increase in LBMPs on the NYISO side of the interface to reflect that more power flowed into the higher price eastern New York region, increasing the incentive to import from PJM.[75] Second, natural gas prices were substantially higher on the New York side of the interface in the first quarter. After the first quarter of 2014, net imports fell during the summer because natural gas prices in the Northeast were significantly lower than in the rest of the country, reducing incentives to import to New York from PJM.

75 When two PARs are in service, the interface price is a weighted average of 39 percent locations in western New York and 61 percent in eastern New York. When one PAR was in service during most of 2013, the interface price was a weighted-average of 60 percent locations in western New York and 40 percent in eastern New York.

B. Unscheduled Power Flows

Unscheduled power flows (i.e., loop flows) through New York can significantly affect the pattern of congestion. Clockwise loop flows around Lake Erie, which exacerbate west-to-east congestion in New York, decreased substantially in the last three years. On average, clockwise Lake Erie loop flows have fallen from 151 MW in 2011 to near 0 MW in each year of 2012 to 2014.[76] However, large hourly variations still occur as clockwise circulation exceeded 200 MW in 13 percent of the hours in 2014. The primary factor that contributed to the change in loop flows is the operation of phase angle regulators ("PARs") to control the flows across the four lines that make up the Ontario-to-Michigan interface beginning in April 2012. [77,78]

When clockwise loop flows increase, the NYISO may use Transmission Loading Relief ("TLR") procedures to ameliorate their effects on congestion in New York.[79] The recent reduction in clockwise loop flows has contributed to a substantial reduction in the frequency of TLRs called by the NYISO: from almost 2,000 hours in 2011 to less than 25 hours in 2014. The frequency of TLRs was also reduced by changes made in the TLR process when the Ontario to Michigan PARs began operating. This was because the PARs were often deemed to be in "regulate" mode (which prevents the use of a TLR to address loop flows from Ontario to MISO or Ontario to PJM transactions), even though clockwise circulation substantially exceeded 200 MW and contributed to congestion in New York. In addition, congestion on the 230kV lines in the West Zone limited flows from Western New York to Eastern New York much more frequently in 2013 and 2014 than in previous years. This congestion was often exacerbated by sporadic clockwise loop flows. Overall, west-to-east congestion occurred in New York in roughly 30 to 40 percent of hours

76 Figure A-65 in the Appendix summarizes the pattern of loop flows around Lake Erie for each month of 2011 to 2014.

77 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.

78 The use of these PARs since April 2012 is discussed extensively in Commission Docket No. ER11-1844-002.

79 In general, the TLR process manages congestion much less efficiently than optimized generation dispatch in a nodal market, because: (a) the TLR process provides less timely system control; (b) it frequently leads to more curtailment than needed; and (c) it does not curtail transactions in economic merit order (i.e., from most expensive to least expensive).

when the clockwise circulation rose above 200 MW. However, during such periods of congestion, the NYISO was generally unable to use the TLR process to moderate clockwise loop flows around Lake Erie, since the PARs were almost always deemed to be in "regulate" mode.

To manage the congestion created by unscheduled loop flows more efficiently, the NYISO and PJM implemented the Market-to-Market coordinated congestion management process on January 16, 2013.[80] We evaluated the performance of this process and found that the coordination of Ramapo PARs helped alleviate real-time congestion in New York and reduced balancing congestion shortfalls in 2013 and 2014.[81]

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 2014. 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 9 summarizes our analysis showing that the external transaction scheduling process generally functioned properly and improved convergence between markets during 2014.[82]

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 most interfaces between New York and neighboring markets during 2014.

80 See Schedule D of Attachment CC to the NYISO OATT.

81 See Section III.C in the Appendix for a detailed evaluation of this process.

82 See Section IV.C in the Appendix for a detailed description of this table.

Table 9: Efficiency of Inter-Market Scheduling
Over Primary Interfaces and Scheduled Lines – 2014

	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	-614	$1.34	46%	-$2	-43	$1.11	58%	$19
Ontario					816	$11.79	79%	$95
PJM	485	-$2.25	53%	$18	-117	-$2.42	62%	$26
Controllable Ties								
1385 Line	48	$1.96	70%	$3	-3	-$2.93	59%	$3
Cross Sound Cable	171	$3.61	72%	$8	-0.2	-$1.67	57%	$0
Neptune	519	$9.70	77%	$50	-7	$8.48	54%	-$1
HTP	48	-$2.84	67%	$4	12	-$2.56	55%	$0
Linden VFT	54	-$0.26	67%	$5	-4	$0.45	53%	$3

In the day-ahead market, the share of hours with efficient scheduling ranged from 67 to 77 percent across the five controllable ties, notably higher than over the free-flowing ties. A total of $70 million in day-ahead production cost savings was achieved in 2014 across the five controllable ties. The Neptune Cable accounted for more than 70 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 nearly $10/MWh in 2014. The share of hours with efficient scheduling ranged from 46 to 53 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 nearly $12/MWh in 2014. As a result, a total of $95 million in production cost savings was achieved across the Ontario interface. Market participants also frequently responded to real-time price variations by increasing net flows into the higher-prices region in 58 to 62 percent of hours across the PJM and New England primary interfaces, resulting in a total of $45 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 (e.g., $1 million increase in product costs on the Neptune interface).

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.

D. Intra-Hour Scheduling and CTS with PJM

Although scheduling by market participants tends to improve convergence, significant opportunities remain to improve the interchange between regions. The NYISO has been working on several initiatives to improve the utilization of its interfaces with neighboring RTOs. Frequent scheduling (i.e., 15-minute scheduling) was available at five interfaces with Hydro Quebec and PJM during 2014, and Coordinated Transaction Scheduling ("CTS") was introduced at the PJM interfaces in November 2014. However, we find that intra-hour scheduling changes occurred frequently only at the primary PJM interface in 2014.[83]

The NYISO implemented CTS with PJM in November 2014 and plans on implementing CTS with ISO New England by the end of 2015. 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 PJM'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 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.

83 Section IV.D in the Appendix examines the pattern of transaction bids and offers across these five interfaces in each month of 2013 and 2014.

This section provides our initial assessment of the performance of CTS since the NYISO and PJM first implemented it in November 2014. In particular, Table 10 evaluates the efficiency of this process at the primary PJM interface during the first four months of implementation.[84]

Table 10: Efficiency of Intra-Hour Scheduling Under CTS
Over Primary PJM Interface, November 2014 – February 2015

			Adjustments in the Export Direction (NY to PJM)	Adustments in the Import Direction (PJM to NY)	Total
% of All Intervals			39%	45%	
Average Flow Adjustment (MW)			-97	99	
Production Cost Savings ($ Million)	Projected at Scheduling Time		$4.2	$2.0	**$6.2**
	Unrealized Savings Due to:	NY Fcst. Err.	-$0.7	-$0.5	**-$1.1**
		PJM Fcst. Err.	-$2.2	-$1.6	**-$3.8**
		Other	-$0.4	-$0.2	**-$0.6**
	Actual		$1.0	-$0.4	**$0.7**
Interface Prices ($/MWh)	NY	Actual	$53.13	$51.90	
		Forecast	$48.84	$52.34	
	PJM	Actual	$57.13	$56.42	
		Forecast	$62.30	$48.18	
Price Forecast Errors ($/MWh)	NY	Fcst. - Act.	-$4.29	$0.44	
		Abs. Val.	$13.46	$14.73	
	PJM	Fcst. - Act.	$5.17	-$8.24	
		Abs. Val.	$25.70	$19.21	

Our analyses show $6.2 million in production cost savings for the four months from November 2014 to February 2015 based on information at the time when RTC determined final interchange schedules. However, a relatively small portion was realized because of inaccurate price forecasts in both markets. Price forecast errors on the New York side accounted for a reduction of $1.1 million in production cost savings, and price forecast errors on the PJM side accounted for an additional reduction of $3.8 million.[85] Average forecast errors were generally much smaller on the New York side than on the PJM side. During the examined period, average RTC forecast

[84] Section IV.E in the Appendix describes this table in greater detail.

[85] 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).

prices were persistently lower than average RTD prices, while average PJM IT SCED forecast prices deviated more widely from average real-time prices in both directions.

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.[86]

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 100 MW. During the examined period:[87]

- RTC-assumed net imports exceeded RTD net imports by 100 MW or more in 12 percent of the quarter-hours, during which the RTD price exceeded the RTC price by an average of $11.40/MWh and the mean absolute difference was $24.20/MWh.
- Similarly, RTD net imports exceeded RTC-assumed net imports by 100 MW or more in 9 percent of the quarter-hours, during which the RTD price was less than the RTC price by an average of $7.70/MWh and the mean absolute difference was $16.40/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 $8.50/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.

An additional factor that discourages external transactions and provides incentives for CTS bidders to increase their bid prices is that transactions that flow 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

86 Figure A-73 in Section IV.E in the Appendix illustrates the ramp profiles that are assumed by RTC and RTD for external transaction.

87 See Section IV.E in the Appendix for our evaluation in more detail.

schedule. These fees greatly reduce the profitability for firms to schedule transactions from the low-priced market to the high-priced market, so firms likely forego opportunities to schedule when the direction of the price differential is predictable but the magnitude is not sufficient to compensate them for the applicable fees.

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. We will continue to monitor the performance of CTS between PJM and the NYISO.

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 2014 and discusses the need to account for additional zones and interfaces in the capacity market.

A. Capacity Market Results in 2014

Seasonal variations result in significant changes in clearing prices in spot capacity 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 increased capability contributes to significantly lower prices in the winter than in the summer of the same Capability Year.

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 that were in effect in the 2014-15 Capability Year (i.e., the 2014 Summer Capability Period and the 2014-15 Winter Capability Period), a one percent change in capacity supply or demand would change the clearing price by: $0.74/kW-month in NYCA, $0.81/kW-month in the G-J Locality, $1.03/kW-month in New York City, and $0.44/kW-month in Long Island.

1. Capacity Market Results: NYCA

In NYCA, the spot price averaged $5.96 per kW-month in the Summer 2014 Capability Period and $2.68 per kW-month in the Winter 2014-15 Capability period (excluding March and April 2015). These prices increased from $5.80 in the summer but fell from $3.10 in the winter during the previous Capability Year because of changes in both capacity requirements and capacity supply.

On the demand side, the ICAP requirement rose 453 MW (or 1.2 percent) from the May 2013-April 2014 Capability Year to the May 2014-April 2015 Capability Year because of an increase of 387 MW in the peak load forecast.

On the supply side, the following changes affected the statewide capacity prices:

- Internal capacity supply in Western New York *fell* roughly 170 MW following the retirement and mothballing of several units at Dunkirk (75 MW) and Syracuse (70MW).
- New York City capacity supply was *reduced* by approximately 100 MW from Summer 2013 to Summer 2014 primarily because some generators have discontinued the practice of performing DMNC tests at a peak firing temperature.
- Average sales from external resources *increased* roughly 300 MW in the summer and 470 MW in the winter, primarily from ISO-NE and PJM.
- Several units at the Danskammer plant in the Hudson Valley Zone returned to service from damage caused by Superstorm Sandy in 2012, *adding* 480 MW to the supply of capacity between October 2014 and January 2015.

Hence, overall supply increased by a net of 500 MW by the end of the study period as a result of these changes.

2. Capacity Market Results: New York City

In New York City, spot prices averaged $18.51 per kW-month in the Summer 2014 Capability period, up 15 percent from the previous summer. Spot prices averaged $8.89 per kW-month in the Winter 2014-15 Capability period (excluding March and April 2015), down 9 percent from the previous winter.

On the demand side, the ICAP requirement rose 138 MW (or 1.4 percent) from the 2013/14 Capability Year to the 2014/15 Capability Year. The increase resulted from an increase of nearly

300 MW in the forecasted peak load, but this was partly offset by a decrease in the Local Capacity Requirement ("LCR") from 86 percent to 85 percent.

The following changes on the supply-side also affected capacity prices in New York City:

- ICAP supply was reduced by approximately 100 MW from Summer 2013 to Summer 2014. This reduction occurred primarily because some generators have discontinued the practice of performing DMNC tests at a peak firing temperature.
- The total DMNC capability of existing NYC generators increased by 230 MW in the Winter 2014/15 Capability Period from the previous winter. This occurred primarily because of a change in the ambient temperature conditions assumed for the purpose of adjusting the test results of each generator.

Hence, the overall supply of capacity decreased in the summer and increased in the winter.

In addition, the UCAP demand curve was reduced by 7 percent from the 2013-14 Capability Year to the 2014-15 Capability Year because the demand curve proxy unit technology was changed to a Frame 7 CT, which has a lower net CONE than the previous technology (the LMS 100 CT). This partly offset the price increase in Summer 2014 and contributed to the price decrease in Winter 2014/15.

3. Capacity Market Results: Long Island

In Long Island, the spot price averaged $6.51 per kW-month in the Summer 2014 Capability Period and $3.26 per kW-month in the Winter 2014-15 Capability Period (excluding March and April 2015). These represented decreases of 9 percent and 3 percent, respectively, from the previous Summer and Winter Capability Periods.

Although the LCR for Long Island rose from 105 percent for the 2013/14 Capability Year to 107 percent for the 2014/15 Capability Year, spot prices fell over the period primarily because the UCAP demand curve was reduced by more than 20 percent when the demand curve proxy unit technology was changed from an LMS 100 CT to a Frame 7 CT.

4. Capacity Market Results: the G-J Locality

The spot prices averaged $12.16 per kW-month during the Summer 2014 Capability Period, and $4.62 per kW-month during the Winter 2014-2015 Capability Period (excluding March and

April 2015). These prices were 110 percent and 49 percent higher than the comparable periods in the previous year.

Prices increased because the G-J Locality was modeled as a separate capacity zone starting in the Summer 2014 Capability Period. The higher prices reflect more accurately the value of capacity that helps secure the UPNY-SENY interface. The higher prices also provide signals for investment in new and existing resources in this area.

The capacity price increase was smaller in the winter than in the summer. This was partly because several units at the Danskammer plant in the Hudson Valley Zone returned to service from damage caused by Superstorm Sandy in 2012, adding 480 MW to the supply of capacity between October 2014 and January 2015.

B. 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."[88] 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 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 current IRM/LCRs by comparing the marginal reliability value of capacity in each region. 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

[88] See *Locational Minimum Installed Capacity Requirements Study Covering the New York Balancing Authority Area for the 2015 – 2016 Capability Year*, January 15, 2015.

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.[89]

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:

- *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.[90]
- *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

[89] 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.

[90] 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.

from placing capacity in the area when the excess capacity margin is equal to the Excess Level in all Localities.[91, 92]

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.
- *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 11: 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

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

92 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.

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.[93]

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.

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, 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.[94]

93 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.

94 See Recommendation #1 in Section XI.

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 11 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 11) is the same in all four areas, indicating no further capacity cost reduction is possible. Call this the "optimal scenario".

The LCRs could be determined taking this optimal scenario and proportionately increasing load until the system reaches 0.1 LOLE. However, this would result in a particularly high allocation of capacity charges to Zone K. 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.[95]

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

95 A concept for modeling an export-constrained capacity zone is discussed further in Section VII.C of *2013 State of The Market Report for the New York ISO Markets*.

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 on LOLE from additional MW in the zone for the as-cleared system.[96] This approach would require fewer approximations and simplifying assumptions and, thus, would be less resource-intensive prior to the spot capacity auction.

C. 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:[97]

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

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

96 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.

97 *Ibid.*, Slides 23-25.

zones when investors upgrade the transmission system and help satisfy planning reliability needs.[98]

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.

D. 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 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.

98 See Recommendation #2 in Section XI.

- 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.[99] 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.[100] 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.

99 See Recommendation #3 in Section XI.

100 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).

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. Rewards 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. Three types of shortage conditions can occur in the real-time market:

- 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 power flows (as modeled in the market systems) exceed the limit of a transmission constraint. Clearing prices for energy in the constrained area are set according to several methods.[101]

- Reliability demand response deployments – When the NYISO anticipates a reliability or security issue, it can deploy demand response resources for a minimum of four hours, typically at a cost of $500 per MWh.

In our evaluation, we find that:

- Regulation shortages occurred in 3 percent of intervals in 2014, far more frequently than operating reserve shortages. 10-minute Eastern reserve shortages were the next most frequent, occurring in 0.2 percent of all intervals. Together, these two products increased annual average LBMPs in Eastern New York by 5 to 6 percent in 2014.[102]

- Transmission shortages occurred in roughly 4 to 5 percent of intervals in 2014. Although average constraint shadow prices were relatively high during shortages and tended to increase as the shortage quantity became bigger, shadow prices frequently did not reflect the severity of the shortage.[103]

- The NYISO deployed reliability demand response resources on just one day in 2014, January 7, during which SCR and EDRP resources in all zones were deployed from 16:00 through 22:00 for system-wide capacity needs. The Enhanced Scarcity Pricing Rule was

[101] Section V.F in the Appendix describes these methods in greater detail.

[102] See Section V.F in the Appendix for this analysis.

[103] See Section V.F in the Appendix for this analysis.

active during the entire event and set the LBMPs across the system at a level greater than or equal to $500 per 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 per MWh during the event if the rule had not been in place.

Overall, shortage pricing accounted for a substantial share of the net revenue that a generator could use to recoup capital investment costs.

Recently, the NYISO has conducted several market design initiatives related to shortage pricing:

- Comprehensive Shortage Pricing – This set of changes sets prices during reserve shortage conditions and transmission shortages that better reflect the value of resources in each region and create a new reserve zone in Southeast New York;[104]
- Graduated Transmission Demand Curve – These will result in constraint shadow prices that better reflect the significance of a transmission constraint violation and set real-time prices accordingly;[105]
- Comprehensive Scarcity Pricing – This set of changes will lead to better consistency between pricing and scheduling outcomes during demand response deployments at internal locations and at external proxy buses.[106]

We support the NYISO's efforts in these areas and anticipate the resulting enhancements will: (a) better enable the market to reflect different kinds of shortages and at different locations; and (b) more accurately reflect the severity of the shortage conditions.

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

104 See *Comprehensive Shortage Pricing*, Presented by Mike DeSocio, December 17, 2014 Management Committee Meeting.

105 See *Graduated Transmission Demand Curve (GTDC)*, Presented by Mike DeSocio, December 18, 2013 Management Committee Meeting.

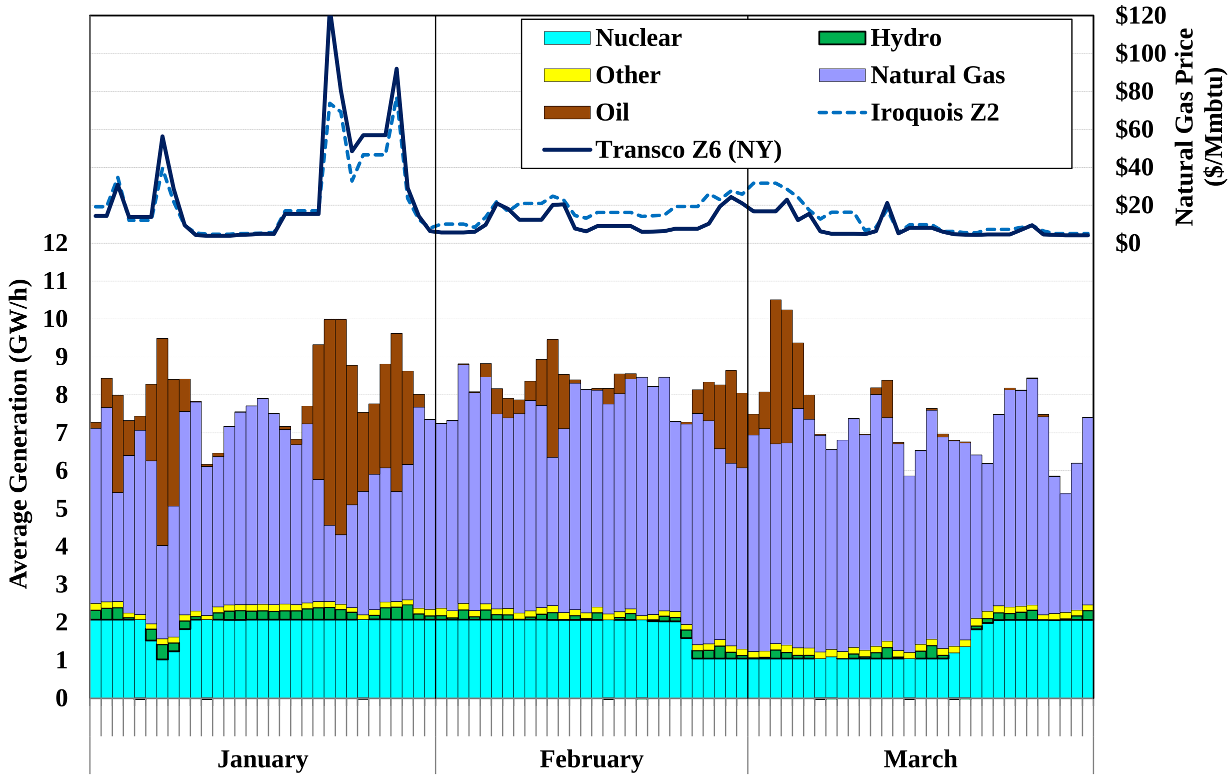
106 See *Comprehensive Scarcity Pricing*, Presented by Ethan Avallone, April 23, 2015 Market Issues Working Group Meeting.

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

Extreme cold weather led to high and volatile gas prices on many days in the first quarter of 2014. During these periods, gas supplies to electric generators were limited by high demand from other gas customers, which led natural gas prices to rise above $20 per MMbtu on 27 days in Eastern New York. 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. Figure 10 summarizes the average hourly generation by actual fuel consumed in Eastern New York on a daily basis in the first quarter of 2014.[107] It also shows the day-ahead natural gas price index for Iroquois Zone 2 and Transco Zone 6 (NY) on these days.

Figure 10: Actual Fuel Use and Natural Gas Prices in Eastern New York
January to March, 2014



107 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.

The figure shows that production from oil, which normally averages less than 100 MW in Eastern New York, rose significantly on many days in the first quarter of 2014. Hourly production from oil averaged 2.4 GW on days when natural gas prices in Eastern New York exceeded $20 per MMBtu. Production from oil was particularly high from January 21 to 29 when natural gas prices averaged over $60 per MMBtu. Average hourly production from oil reached 5.7 GW on January 23, and the total amount of oil-fired generation during this 9-day period accounted for 40 percent of total oil-fired generation during the entire first quarter. The large amount of oil use in a single 9-day period illustrates the difficulty in predicting (before the winter) how much oil will be needed over the entire winter season.

The NYISO's day-ahead market provides pricing information that helps coordinate decisions by generators about whether to operate on natural gas, oil, or a blend. However, actual production from oil was still significantly lower than would have been optimal based on gas prices and LBMPs. For example, in the first quarter of 2014, our simulations indicated that as a group oil-capable combined cycle units and steam turbine units in New York City burned approximately 30 to 35 percent of the amount of oil that would have been optimal (based on day-ahead and real-time clearing prices and natural gas prices).[108]

Several factors reduced the use of oil by generators in the first quarter of 2014. First, timing differences between gas and electric markets sometimes lead generators to commit to burning natural gas when oil would have been economic in retrospect. Second, oil-fired generation availability was reduced by the following factors:

- Planned and forced outages – Major maintenance outages led several units to be unavailable throughout the first quarter;
- 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.

Nonetheless, we have observed better operations and market performance in these areas in the 2013/14 winter despite more challenging conditions than in previous winters. First, generators tracked gas market conditions closely over weekends (when the timing difference between gas

[108] See *Quarterly Report on the New York ISO Electricity Markets First Quarter 2014,* slides 23-28.

and electric markets were normally the largest) and frequently requested reference level adjustments to account for high expected gas prices. The NYISO has streamlined the process for allowing such reference level adjustments.[109] These reference level adjustments resulted in more efficient generator scheduling and LBMPs that reflected anticipated fuel prices more accurately. Second, many dual-fueled generators became more prepared to generate on fuel oil from the winter of 2012/13 to the winter of 2013/14, although this was offset by increased demand for oil-fired generation.

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

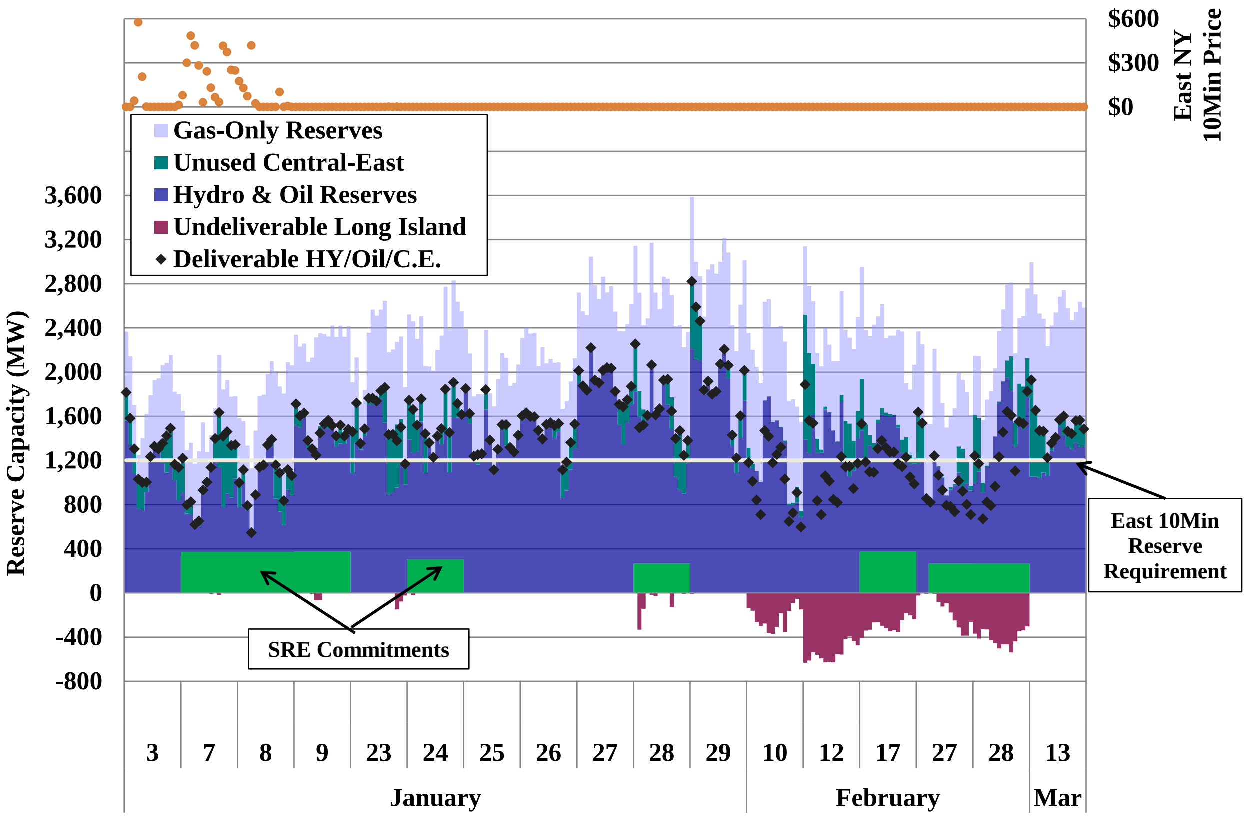
Hourly Operational Flow Orders ("OFOs") are often declared on the days when gas supply is very tight. During hourly OFOs, many generators that are reliant on natural gas may be unable to start-up or ramp-up if deployed in response to a sudden large contingency. Even if generators are authorized to take 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 11 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 examines: (a) whether the Eastern 10-minute reserve requirement was satisfied by dependable reserve capability that was

109 See for example, *Generator Submittal of Alternative Fuel Type or Price for DAM Energy Bids*, presented by Mark W. French to the Management Committee on December 18, 2013.

not affected by gas supply constraint; and (b) if not, whether the reserve prices reasonably reflected tight gas supply conditions.[110]

Figure 11: 10-minute Reserve Capacity in Eastern New York
On Cold Days with Hourly OFOs, 2014



The figure shows that there were 72 hours (with hourly OFOs) on these days when the NYISO relied on some gas-only capacity to satisfy the Eastern 10-minute reserve requirement. However, Eastern 10-minute reserve prices cleared at $0 per MWh in 53 of these hours and averaged just $190 per MWh in another 19 hours. In addition, an average of roughly 300 MW of capacity was SRE-committed on eight of the days for Eastern New York reserve needs, but Eastern 10-minute reserve prices cleared at $0 per MWh during most hours on these eight days. These results suggest that, in 2014, 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.

110 See Section V.F in the Appendix for more detailed description of this analysis.

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 11 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 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.[111]

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.[112]

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. It would be beneficial for the generator to be able to conserve its limited oil-fired generation 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

[111] Section XI, Recommendation #15 is related to this issue.

[112] Section XI, Recommendation #14 is related to this issue. The NYISO project to address this issue is discussed in *Fuel Assurance: Energy Market Design Concepts*, Presented by Cristy Sanada, April 2, 2015 Market Issues Working Group Meeting.

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.[113] This capability would also be beneficial at other times of year for hydro-electric and other generators that also have significant energy limitations.

Fourth, the NYISO needs to have reasonably accurate forecasts of the availability of generating capacity in the intra-day, day-ahead, and seven-day forecast time frames. Given the potential for natural gas supply limitations, environmental limitations on certain fuels, and the lead times necessary for non-gas fuel delivery, it is essential for the NYISO to have enhanced information on fuel availability. Such information would help maintain reliability and reduce the need for out-of-market actions (e.g., committing a generator with firm fuel supply due to uncertainty about fuel availability for other generators). Although the NYISO has instituted procedures for suppliers to provide such information voluntarily, it may be necessary to require generators to provide information on a daily basis regarding fuel availability, particularly on-site fuel inventory, scheduled deliveries, and nominations and schedules for natural gas.[114]

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 48 percent of capacity committed by the real-time market model in 2014 was clearly economic over the initial commitment period and this was consistent with recent years.[115] 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

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113 See Footnote 112.

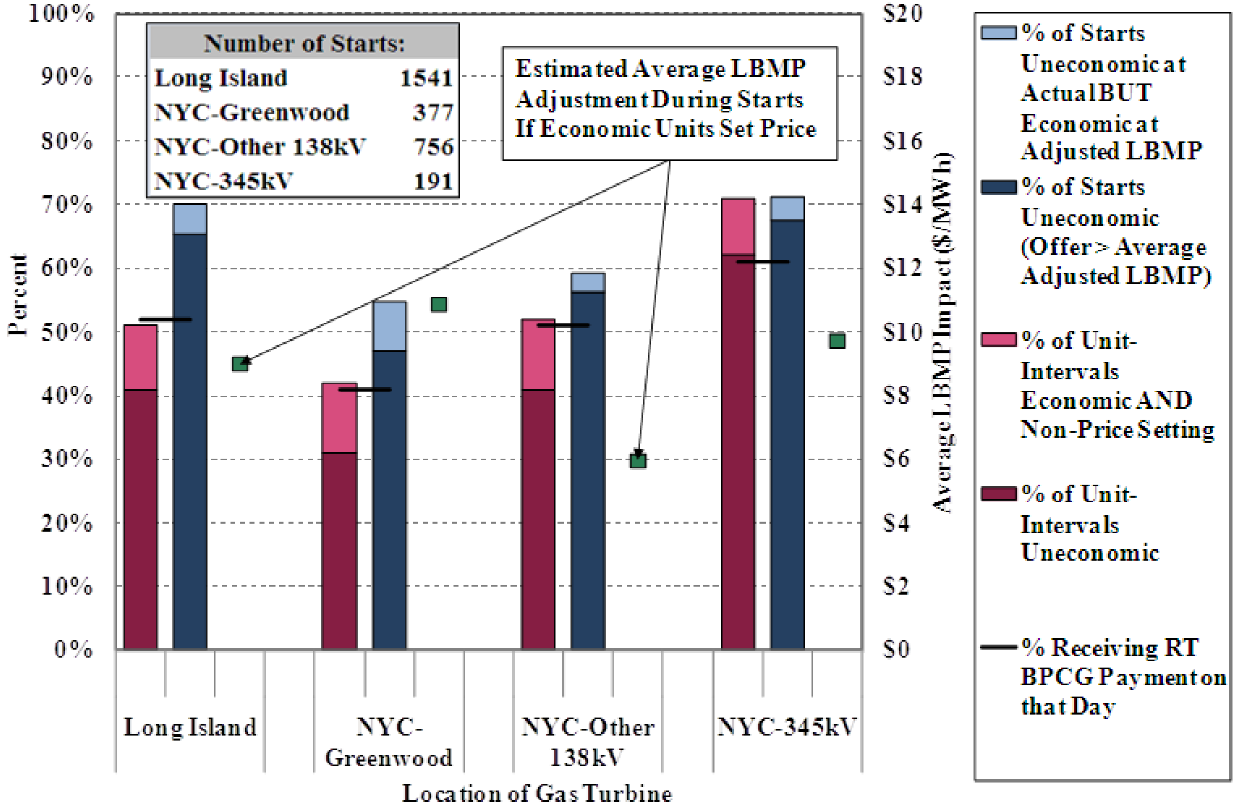
114 See Section XI, Recommendation #16. See 2015 Project Plan: *Fuel Availability and Self Reporting*.

115 See Figure A-76 in the Appendix for details of this analysis.

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.[116]

Figure 12 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.[117]

Figure 12: Hybrid Pricing and Efficiency of Gas Turbine Commitment
2014



We found that gas turbines that were committed in merit order in 2014 were clearly economic in roughly 40 to70 percent of the five-minute intervals during their initial one-hour commitment period. However, the units did not set the LBMP in 9 to 11 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 $6 to $11 per MWh for each start in New York City and Long Island in 2014. Averaged over the year, this would increase LBMPs by an average of $0.50 to $1.50 per MWh with the largest effect in Long Island.

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

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

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. Hence, we recommend the NYISO modify the hybrid pricing logic to better allow economic gas turbines to set the energy prices. Furthermore, it would 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-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.[118]

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.[119] Such lines are evaluated in Section VII.C, which evaluates external transaction scheduling. Second, "optimized" PAR-controlled lines are optimized in the

118 See Recommendation #10 in Section XI.

119 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.

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 2014. 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 scheduled in the day-ahead market versus the portion that is from balancing adjustments in the real-time market.[120]

Table 12: Efficiency of Scheduling on Non-Optimized PAR Controlled Lines[121, 122]
2014

	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	$13.09	53%	$7
New England to NYCA								
Sand Bar	-87	-$17.07	85%	$13	-1	-$18.44	53%	$0
PJM to NYCA								
Waldwick	-904	$3.17	38%	-$22	48	$2.70	50%	$0
Ramapo	276	$7.11	68%	$45	151	$5.46	56%	$6
Farragut	714	-$0.32	50%	-$1	-54	-$0.48	51%	-$1
Goethals	194	$1.10	61%	$3	55	$2.49	49%	-$1
Long Island to NYC								
Lake Success	153	-$7.00	3%	-$9	-6	-$8.33	68%	$1
Valley Stream	52	-$12.39	2%	-$5	2	-$19.59	32%	-$2

120 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.

121 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.

122 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 vast majority of power is scheduled in the day-ahead market, while small balancing adjustments are typically made in the real-time market. Consequently, the average flows and production cost savings are generally much larger in the day-ahead market than in the real-time market. Hourly price differentials between markets are generally smaller in the day-ahead market because real-time prices are more volatile than day-ahead prices, reflecting that fewer resources are available in real-time to respond to unforeseen changes in system conditions.

In the day-ahead market between New York and neighboring markets, our analysis shows that power was scheduled in the efficient direction (from the low-priced area to the high-priced area) in the majority of hours on all of the groups of PAR-controlled lines except the Waldwick lines. The Waldwick lines generally flowed power from NYCA to PJM due to the ConEd-PSEG wheeling agreement, although the price on the PJM side was generally lower by an average of $3.17 per MWh in 2014.[123] We estimated that the controllable lines between NYCA and neighboring control areas achieved a total of $60 million in net production cost savings in the day-ahead market in 2014, excluding the Waldwick lines. However, the use of the Waldwick lines to support the ConEd-PSEG wheeling agreement *increased* DAM production costs by an estimated $22 million in 2014. Hence, significant additional production cost savings could be achieved by incorporating the Waldwick lines into the M2M process.

Between Long Island and New York City, the day-ahead scheduling of the PAR-controlled lines (i.e., the 901 and 903 lines) was highly inefficient with power scheduled in the inefficient direction in 97 to 98 percent of hours in 2014, which was comparable to the results in recent years. The use of these lines *increased* DAM production costs by an estimated $14 million in 2014 because prices on Long Island were typically higher than those in New York City where the 901 and 903 lines connect.[124]

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.

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123 The Waldwick lines connect New Jersey in the PJM system with the Hudson Valley (Zone G) in the NYISO system. Normally, the ConEd-PSEG wheel agreement requires approximately 1 GW to flow from the NYISO to PJM across the Waldwick lines and then back into New York City across the Farragut and Goethels lines. See NYISO OATT Section 35.22.

124 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.

Restrictions on the output of these New York City generators sometimes increases prices 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 sometimes operated in order to manage 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 12 reports the production cost savings for balancing adjustments considering congestion on all flowgates. In 2014, the production cost savings were reduced by an estimated $4 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). Hence, excluding the effects of balancing adjustments of the Ramapo line on constraints in Western New York, the production cost savings reported in Table 12 would likely have exceeded $10 million.

These results indicate that significant opportunities remain to improve the operation of these lines, particularly the Waldwick 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.[125] However, it would be highly beneficial to

125 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.

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).[126] Hence, we recommend the NYISO work with the parties to these contracts to explore potential changes.[127]

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 2014. 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 less than 2 percent of all intervals in 2014, 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.

126 The proposed financial right is described in Section III.E of the Appendix.

127 See Recommendation #7 in Section XI.

1. Drivers of Transient Real-Time Price Volatility

Table 13 summarizes the most significant factors that contributed to real-time price volatility in 2014 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.[128]

Table 13: Drivers of Transient Real-Time Price Volatility
2014

Key Contributors to Transient Spikes	% of Total Contributions to the Price Spikes				
	Power Balance	West Zone 230kV Lines	Central East	Dunwoodie-Shore Rd 345 kV	East Garden City - Valley Stream 138 kV
External Interchange	34%	7%	18%	45%	2%
Fixed Schedule PARs	0%	9%	23%	15%	71%
Loop Flows & Other Non-Market	0%	69%	10%	7%	6%
RTC Shutdown Resource	16%	0%	12%	17%	11%
Self Sched Shutdown/Dispatch	15%	0%	12%	2%	4%
All Other	36%	15%	24%	14%	6%

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. Fifty-one percent of the transient price spikes for these three categories occurred in interval-ending :00 or :05 because large hourly schedule changes caused price spikes in many intervals when generation was ramp-limited in responding to the adjustment in interchange. CTS-PJM and CTS-NE provide additional opportunities for market participants to schedule transactions such that they will tend to reduce the size of the adjustment around the top-of-the-hour.[129]

Fixed-schedule PAR-controlled line flow variations were also a key driver of price spikes. Specifically, flow variations on lines making-up the ConEd-PSEG wheel were a key driver for the Central-East Interface, while lines making-up the ConEd-LIPA wheel were a key driver for the Dunwoodie-to-Shore Road and East Garden City-to-Valley Stream lines. These PARs

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

129 Notwithstanding, our initial assessment of the performance of CTS with PJM indicates that inconsistencies between RTC and RTD related to the assumed external transaction ramp profile likely contribute to price volatility when the total net interchange varies significantly (e.g., >200 MW) from one 15-minute interval to the next. See Section IV.E in the Appendix for more details of this analysis.

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. When the PAR is not adjusted promptly, the telemetered value can change significantly, resulting in transitory price spikes. In many cases, severe congestion occurred when low-cost resources were available to relieve the constraint but the low-cost resources 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. 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 on facilities that are 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 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.

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 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 other generation can ramp 15 minutes from one evaluation period to another, RTC may not anticipate that shutting-down several gas turbines simultaneously will result in a transient shortage. 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.

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).

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:[130]

- 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.

To reduce unnecessary price volatility from variations in loop flows and fixed schedule PAR flows, we recommend the NYISO consider the following:[131]

- 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 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

[130] See Recommendation #8 in Section XI .

[131] See Recommendation #9 in Section XI.

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).

Furthermore, Section 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 and to use a more detailed model of the Niagara generator that reflects the effects of its interconnection points on the 115kV and 230kV systems.[132] 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 at the Niagara plant more efficiently to relieve congestion. Currently, any such re-dispatch occurs through less precise out-of-market instructions.[133]

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 frequently 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

132 See Recommendation #12 in Section XI.

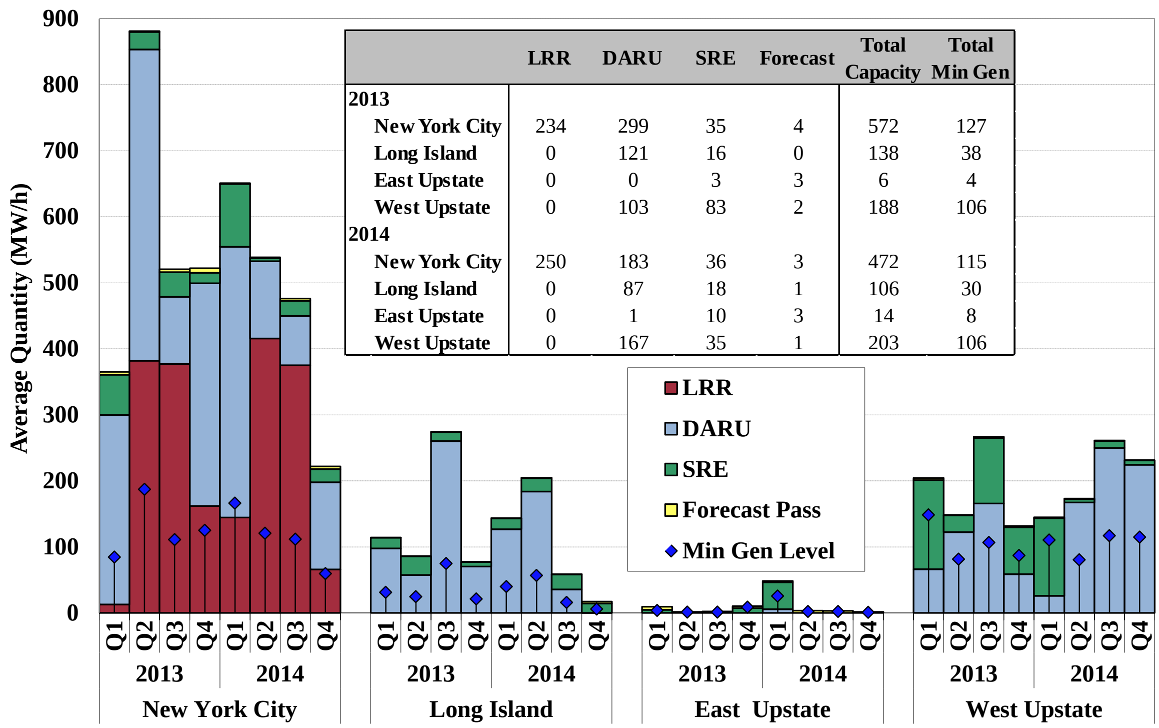
133 See *Quarterly Report on the New York ISO Electricity Markets Third Quarter 2014,* slides 63-66.

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 2013 and 2014. 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 13: Supplemental Commitment for Reliability in New York
By Category and Region, 2013 – 2014



	LRR	DARU	SRE	Forecast	Total Capacity	Total Min Gen
2013						
New York City	234	299	35	4	572	127
Long Island	0	121	16	0	138	38
East Upstate	0	0	3	3	6	4
West Upstate	0	103	83	2	188	106
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

The figure shows that roughly 800 MW of capacity was committed on average for reliability in 2014, down roughly 100 MW (or 12 percent) from 2013. Of this total, 59 percent of reliability commitment was in New York City, 13 percent was in Long Island, and 26 percent was in Western New York.

In Western New York, reliability commitment increased moderately from 2013, averaging slightly more than 200 MW in 2014. DARU commitments increased after the first quarter of 2014 when several units that were often needed to manage congestion on 115 kV facilities in Zones A and C became less economic because of lower load levels and natural gas prices. Nonetheless, SRE commitments were virtually eliminated in Western New York after March 2014 (when transmission upgrades in the North Zone were completed). The transmission upgrades greatly reduced the effects of key transmission contingencies and associated needs for supplemental commitments.

In Long Island, reliability commitments fell 23 percent 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 (IR-5).

In New York City, reliability commitment fell 17 percent to an average of 470 MW in 2014. The reduction was driven partly by low natural gas prices in New York City (relative to other areas in eastern New York) after the first quarter, which made several steam units that were often needed for reliability more economic. Most reliability commitments in 2014 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 for the Freshkills load pocket increased in the first quarter of 2014 when multiple transmission facilities were taken out of service for transmission work at the Goethals Bus.

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.[134] These NOx bubble constraints require the operation of a steam turbine unit in order to reduce the overall NOx emission rate from a portfolio containing higher-emitting gas turbine units. Such commitments occur only during the five-month ozone season (May to September) of each year.

Since these commitments of steam turbines are necessary for the associated gas turbines to operate (or even provide non-spinning reserves), they are categorized as for local reliability and the resulting out-of-market costs are uplifted to the market. NOx bubble commitments accounted for a significant share (17 percent) of reliability commitment in New York City in 2014.

Based on our review of market outcomes in 2014, it appears likely that NOx bubble commitments 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 14 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 2014 by load level.[135]

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

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

Table 14: Energy Production from NOx Bubble Generators
2014

Daily Load Levels	Generation Output from GTs in NOx Bubble	Generation Output from STs Committed for NOx
Low	7%	97%
Medium	23%	3%
High	70%	0%
Total	100%	100%

Our analysis finds that in 2014, 93 percent of energy production from the gas turbines in the NOx Bubbles occurred on days with medium to high load levels, while 97 percent of the energy production from steam units committed for the NOx constraints occurred on low-load days. This indicates that most of the NOx bubble commitments were made on low-load days when older gas turbines rarely operate. 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:[136]

- An average of nearly 1.5 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 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 2014 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.

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

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.[137]

3. Out of Merit Dispatch

Table 15 summarizes the frequency (i.e., the total station-hours) of Out-of-Merit actions in 2013 and 2014 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. [138]

Table 15: Frequency of Out-of-Merit Dispatch
By Region, 2013 2014

Region	OOM Station-Hours		
	2013	2014	% Change
West Upstate	714	2031	184%
East Upstate	348	189	-46%
New York City	1649	241	-85%
Long Island	2501	701	-72%

OOM actions fell the most (by 1800 station-hours) in Long Island from 2013 to 2014. Long Island used to account for the largest share of OOM station-hours, most of which were called to manage local reliability on the East End of Long Island during high load conditions. However, OOM dispatch fell in 2014 primarily because transmission improvements (particularly the installation of West Bus and Wildwood DRSS) greatly reduced the need to dispatch peaking generators to manage voltage constraints on the East End of Long Island.

OOM actions in New York City also fell 85 percent from 2013 to 2014 partly because of lower load levels and increased in-city generation as a result of lower natural gas prices. OOM actions in New York City were often associated with transmission outages. For example, in 2013, the Narrows and Gowanus GTs accounted for 40 percent of OOM actions in New York City, primarily in July when the market software was not able to properly model a "split ring bus"

137 See Recommendation #13 in Section XI.

138 Figure A-87 in the Appendix shows our analysis on a quarterly basis and shows top two stations that had most frequent OOM dispatches in 2014 for each region.

during a transmission outage in the Greenwood area. In 2014, there were fewer such transmission outages, which contributed to the reduction in OOM actions.

However, OOM actions increased 184 percent in Western New York from 2013 to 2014, accounting for the largest share of OOM station-hours in 2014. The increase occurred primarily because the Dunkirk, Olean, and Milliken units were needed more frequently to prevent post-contingency overloading on several 115 kV transmission facilities. 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.[139] Including these unlogged OOM dispatches, Niagara was OOM dispatched more frequently than any other generator in 2014. We recommend the NYISO consider managing up-state 115kV transmission constraints in the day-ahead and real-time markets.[140]

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.

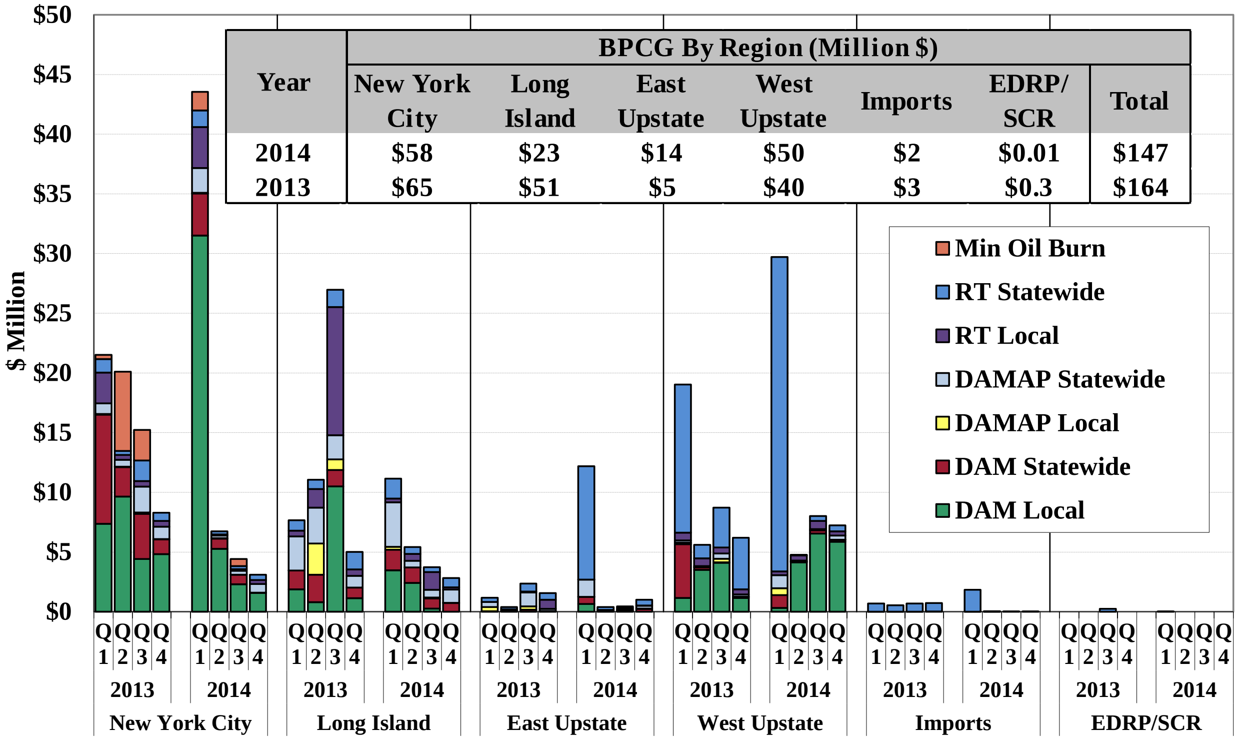
The following figure shows guarantee payment uplift for four local reliability categories and three non-local reliability categories in 2013 and 2014 on a quarterly basis.[141]

139 See *Quarterly Report on the New York ISO Electricity Markets Third Quarter 2014,* slides 63-66.

140 See Recommendation #12in Section XI.

141 See Figure A-88 and Figure A-89 in the Appendix for a more detailed description of this analysis.

Figure 14: Uplift Costs from Guarantee Payments in New York
By Category and Region, 2013 – 2014



Year	BPCG By Region (Million $)						
	New York City	Long Island	East Upstate	West Upstate	Imports	EDRP/ SCR	Total
2014	$58	$23	$14	$50	$2	$0.01	$147
2013	$65	$51	$5	$40	$3	$0.3	$164

The figure shows that the guarantee payment uplift totaled $147 million in 2014, down roughly 10 percent from 2013.[142] The reduction was driven primarily by:

- Decreased supplemental commitment and OOM dispatch in New York City and Long Island from 2013 to 2014, which are discussed in detail in the previous sub-section; and
- Lower natural gas prices in most months of 2014 also decreased the commitment costs of gas-fired units that were needed for reliability.

Other important contributing factors include:

- Min Oil Burn Compensation program payments fell by $8 million from 2013 to 2014 because of the following factors that reduced the need to burn oil to protect New York City from a loss of gas: (a) lower load levels in the summer; (b) increased reliance on auto-switching units; and (c) NOx bubble constraint modeling improvements that reduced the commitment of steam turbine units.
- Real-time state-wide guarantee payment uplift in Western New York fell substantially after the first quarter of 2014. Most of the uplift accrued on one gas-fired unit that was frequently needed for reliability. However, transmission upgrades completed in the first

142 The 2014 number was based on billing data available at the time of reporting, which may be different from final settlement.

quarter of 2014 greatly reduced the need for this unit and associated guarantee payment uplift in this category.

However, guarantee payment uplift was particularly high in the first quarter of 2014, accounting for $98 million (or 67 percent of the annual total). Substantially elevated natural gas prices were the primary driver of high guarantee payments in the first quarter. In particular, the portion of 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.

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 93 percent of the 1.2 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 more than 1.1 GW of resources participating in 2014. The primary incentive to participate in this program is that SCRs can sell capacity in the NYISO's capacity market. In the Summer 2014 Capability Period, SCRs made contributions to resource adequacy by satisfying:

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

- 3.1 percent of the UCAP requirement for NYCA.

However, the registered quantity of reliability program resources has fallen considerably since 2010. The annual reductions were 13 percent in 2011, 13 percent in 2012, 33 percent in 2013, and 4 percent in 2014. 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 2014 is based on 40 hours from Summer 2013). 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 2014.

Day-Ahead Demand Response Program

No resources participated in the DADRP program in the last three 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.

XI. Recommendations

Our analysis in this report indicates that the NYISO electricity markets performed well in 2014, although the report finds additional improvements that we recommend to improve market performance. The recommendations are presented in the following seven categories:

- Capacity Market Enhancements (#1 – #5)
- Broader Regional Markets (#6)
- Energy Market Enhancements - RT Market Operations (#7 – #9)
- Energy Market Enhancements - RT Pricing (#10 – #12)
- Energy Market Enhancements - Reliability Commitment (#13)
- Energy Market Enhancements - Fuel Assurance (#14 & #15)
- Gas-Electric Coordination (#16)

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.

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. We do not base our recommendations on measures of short-term consumer savings or some other benefit to a particular group of market participants. This is because, while markets exist to serve consumers and regulators should seek to enhance consumer welfare, measures that benefit consumers in the short-run at the expense of another group of market participants without production cost savings or investment cost savings will not benefit consumers in the long-run. This is because investors will perceive that investment is riskier, requiring higher expected returns from investment and higher costs in the long-run. For example, regulators can always produce short-term consumer savings by arbitrarily lowering the ROE of a regulated company. In the short-run, this reduces consumer costs, but in the long-run, it leads to higher capital costs for investors, which can ultimately raise costs to consumers.

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 $10+ billion per year wholesale market for electricity. With the majority of wholesale market costs going to pay for input fuel and other inputs, it can be difficult to substantially lower the overall cost of production or investment. 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, Scoping/Future)**

   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 benefits from additional capacity in each Locality. The resulting capacity prices do not provide efficient signals for investment, which raises the overall cost of satisfying the capacity requirements. Setting capacity prices that reflect the marginal reliability value of additional 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, so additional scoping is necessary.[143]

This recommendation is designated as a high priority because more accurate price signals would lead to large investment cost savings and more price stability. Although we have not been able to perform a comprehensive estimate of the potential savings, Section VIII.B summarizes an analysis showing that even very limited adjustments in the 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. (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 investment in transmission when it is less costly than generation and demand response 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 investment in transmission.[144]

3. Pre-define interzonal interfaces and zones that address potential future reliability needs and deliverability constraints to allow prices to accurately reflect the locational value of capacity. (Scoping/Future)

143 The basis for this recommendation is discussed in Section VIII.B.

144 The basis for this recommendation is discussed in Section VIII.C.

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. 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. 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.[145]

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 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.

[145] The basis for this recommendation is discussed in Section VIII.D.

b. Modify the treatment of units being replaced, mothballed, and retired in forecasts of ICAP prices and net revenues. (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. We recommend the NYISO modify the definition of Expected Retirements to allow the forecasted prices to reflect capacity that is expected to be available at the prevailing prices. This includes excluding mothballed units not expected to be available.[146]

5. Evaluate the need to expand buyer-side mitigation measures to address other actions that can suppress capacity prices. (scoping/future)

FERC recently recognized that the current buyer-side mitigation measures do not address all potential conduct that may suppress capacity prices. To determine whether the buyer-side mitigation measures should be expanded to address additional classes of conduct, the NYISO should evaluate the incentives to suppress capacity prices with this conduct. In response to a FERC order, we understand that NYISO intends to perform such an evaluation.

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's evaluation should consider how to effectively address these issues.[147]

146 Section IV.C discusses the basis for this recommendation and a current NYISO initiative to address it.

147 Section IV.C discusses the basis for this recommendation.

Broader Regional Markets

6. Work with adjacent ISOs to implement rules that will better utilize the transfer capability between regions by coordinating the intra-hour transactions. (Current Effort, High Priority)

The NYISO is working towards implementing Coordinated Transaction Scheduling ("CTS") with ISO-NE in the fourth quarter of 2015. In previous studies, we estimated annual production cost savings of over $10 million from implementation of CTS with ISO-NE.[148] Given the large potential benefits and that the project is nearly complete, we recommend the NYISO continue to place a high priority on implementing this recommendation on time.

Energy Market Enhancements – Real-Time Market Operations

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

Significant efficiency savings may be achieved by improving the operation of the following PAR-controlled lines that are scheduled to a contract-based level in the day-ahead and real-time markets:

- The 901 and 903 lines between New York City and Long Island, which were scheduled in the day-ahead market in the inefficient direction (i.e., from the high-priced area to the low-priced area) 97 to 98 percent of the time in 2014. The operation of these lines *increased* production costs by an estimated $15 million.
- The J and K lines between New York and New Jersey, which were scheduled in the day-ahead market in the inefficient direction 62 percent of the time in 2014. The operation of these lines *increased* production costs by an estimated $22 million.
- The A, B, and C lines between New York and New Jersey, which generally flow in the efficient direction but not necessarily at the optimal level.

When these lines flow in the inefficient direction, it leads to inefficient prices between regions and can restrict production by economic generation.

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, the three groups of

148 For example, see our *2010 State of the Market Report for the New York ISO Markets*, Section IV.E.

lines listed above were among the most significant factors causing transient price volatility on the Central East Interface and in Long Island in 2014. 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 $5 million to balancing congestion shortfall uplift which are socialized through Rate Schedule 1 charges.[149] The problems that arise from the operation of these lines will be difficult to address without operating the lines more efficiently.

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. 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.E of the Appendix.

8. Adjust look ahead evaluations of RTD and RTC to be more consistent with the timing of external transaction ramp and gas turbine commitment. (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 prices forecasted by RTC.

149 Section IX.D discusses the estimates of production cost increases. Section IX.E.1 discusses their effects on transient price volatility. Section IV.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.

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.[150]

9. 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. (Scoping/Future)

Variations in loop flows and in flows across certain PAR-controlled lines were among the leading causes of transient price spikes in 2014. To reduce unnecessary price volatility 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 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).

Additional scoping is necessary to evaluate the relative complexity, costs, and benefits of these and other potential solutions to this recommendation.[151]

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

Energy Market Enhancements – Real-Time Pricing

10. 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.

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. Furthermore, it would 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-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.[152]

11. Adopt Comprehensive Scarcity Pricing Proposal. (Current Effort)

Demand response has become increasingly important for satisfying the reliability needs of the system under peak load conditions in recent years. The inflexibility of these resources presents significant challenges for efficient real-time pricing, which is critical to provide incentives for suppliers to be available and perform reliably. Previous reports have identified two specific shortcomings of NYISO's Scarcity Pricing.[153] First, the lack of Scarcity Pricing at the External Proxy Buses leads to inefficient imports and exports, resulting in higher production costs and increased uplift. Second, it is important for the Scarcity Pricing to allow demand response to set prices only when it is needed to satisfy the system needs. The NYISO's Comprehensive Scarcity Pricing proposal would address these issues by better incorporating Scarcity Pricing into Hybrid Pricing logic of the RTD and RTC software.[154]

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151 The basis for this recommendation is discussed in Section IX.E.

152 The basis for this recommendation is discussed in Section IX.D.

153 See our *2013 State of the Market Report for the NYISO Markets*, Section VIII.A.2.

154 The NYISO's current effort to address this is discussed in Section IX.A.

12. Consider modeling 100+ kV transmission constraints in the DA and RT markets using economic commitment and dispatch software. (Scoping/Future)

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. This has contributed to the need for cost-of-service contracts to keep older capacity in service. Hence, we recommend the NYISO consider managing up-state 115kV transmission constraints in the day-ahead and real-time markets.[155] 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.

Energy Market Enhancements – BPCG Eligibility Criteria

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

Our analyses indicate that in 2014 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 determine whether they have other available options for NOx RACT compliance that would result in more efficient operation of their units.[156]

Energy Market Enhancements – Fuel Assurance

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

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

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

[156] The basis for this recommendation is discussed in Section IX.F.2.

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 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.[157]

15. 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

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

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.[158]

Gas-Electric Coordination

16. Require Generators to provide timely information on fuel availability, particularly on-site fuel inventories and natural gas schedules. (Current Effort)

In its role of securing the bulk power system and maintaining reliability, the NYISO must have reasonably accurate forecasts of the availability of generating capacity in the intra-day, day-ahead, and near-term forecast time frames. The NYISO has already instituted procedures for suppliers to provide such information voluntarily. Given the potential for natural gas supply limitations, environmental limitations on certain fuels, and the lead times necessary for non-gas fuel delivery, it would be beneficial for the NYISO to have better information on fuel availability. Not only would such information assist the NYISO in maintaining reliability, but it would also reduce the need for out-of-market actions (e.g., committing a generator with firm fuel supply due to uncertainty about fuel availability for other generators).[159]

[158] The basis for this recommendation is discussed in Section IX.B.

[159] The basis for this recommendation and the NYISO’s current effort are discussed in Section IX.B.

Analytic Appendix

2014 State of the Market Report for the New York ISO Markets

Appendix – Table of Contents

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 (i.e., automatic generation control). 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 2014 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 2014 at the following five locations: (a) Western New York, which includes five load zones (i.e., Zones A through E); (b) the Capital

Zone (i.e., Zone F); (c) the Lower Hudson Valley region, which includes three load zones (i.e., Zones G, H, and I); (d) New York City (i.e., Zone J); and (e) Long Island (i.e., Zone K). The majority of congestion in New York occurs between these five 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 West NY; (b) the Iroquois Zone 2 index for Capital; (c) the average of Iroquois Zone 2 index and the Texas Eastern M3 index for Lower Hudson Valley; (d) the Transco Zone 6 (NY) index for New York City; and (e) the Iroquois Zone 2 index for Long Island.

Figure A-1: Average All-In Price by Region
2009-2014

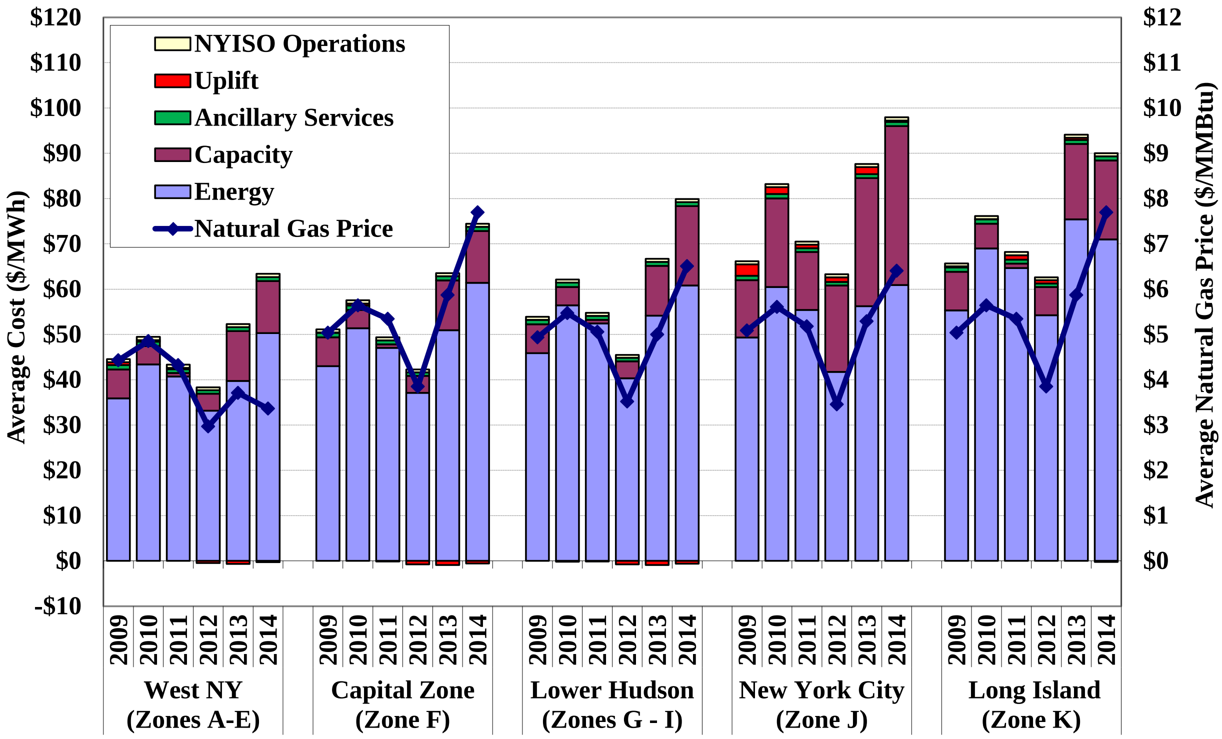


Figure A-2: Day-Ahead Electricity and Natural Gas Prices

Figure A-2 shows average natural gas prices and load-weighted average day-ahead energy prices in each month of 2014 for the five locations shown in Figure A-1. The table in the chart shows the annual averages of these quantities for 2013 and 2014. Although much of the electricity used by New York consumers is generated from hydro, nuclear, and coal-fired generators, natural gas units are usually the marginal units that set energy prices, especially in Eastern New York. This is evident from the strong correlation of electricity prices with natural gas prices shown in the figure.

Figure A-2: Day-Ahead Electricity and Natural Gas Prices
By Month, 2014

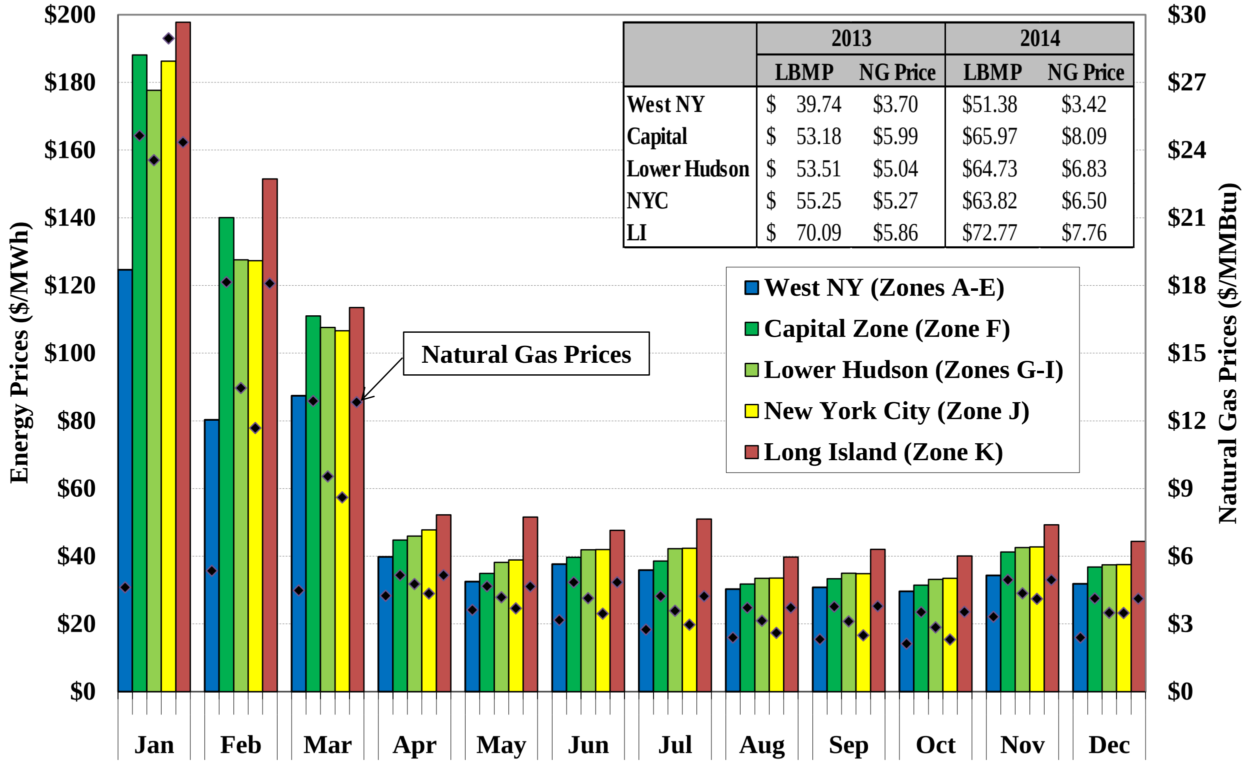


Figure A-3: Average Monthly Implied Marginal Heat Rate

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).[160] 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.[161]

Figure A-3 shows the load-weighted average implied marginal heat rate in each month of 2014 for the five locations shown in Figure A-1 and Figure A-2. The table in the chart shows the annual averages of the implied heat rates in 2013 and 2014 at these five locations. By adjusting for the variation in natural gas prices, the implied marginal heat rate shows more clearly the seasonal variation in electricity prices.

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

161 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.

Figure A-3: Average Monthly Implied Heat Rate
Day-Ahead Market, 2014

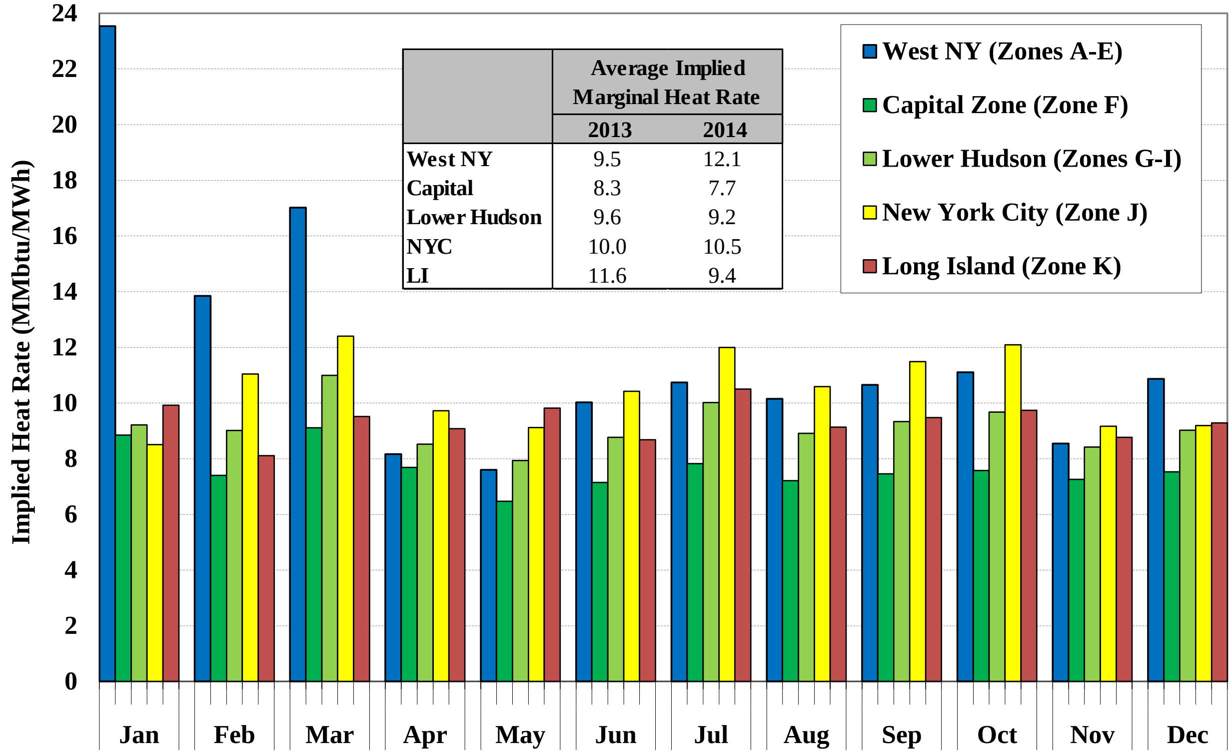


Figure A-4 – Figure A-7: Price Duration Curves and Implied Heat Rate Duration Curves

The following four analyses illustrate how prices varied across hours in recent years and at different locations. Figure A-4 shows three price duration curves, one for each year from 2012 to 2014. Figure A-5 shows five price duration curves for 2014, one for each of the following locations: (a) Western New York, which includes five load zones (Zones A through E); (b) the Capital Zone (Zone F); (c) the Lower Hudson Valley region, which includes three load zones (Zones G, H, and I); (c) New York City (Zone J); and (e) Long Island (Zone K). Each curve in Figure A-4 and Figure A-5 shows the number of hours on the horizontal axis when the load-weighted average real-time price for New York State or each sub-region was greater than the level shown on the vertical axis. The table in the chart shows the number of hours in each year or 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 for New York State
2012-2014

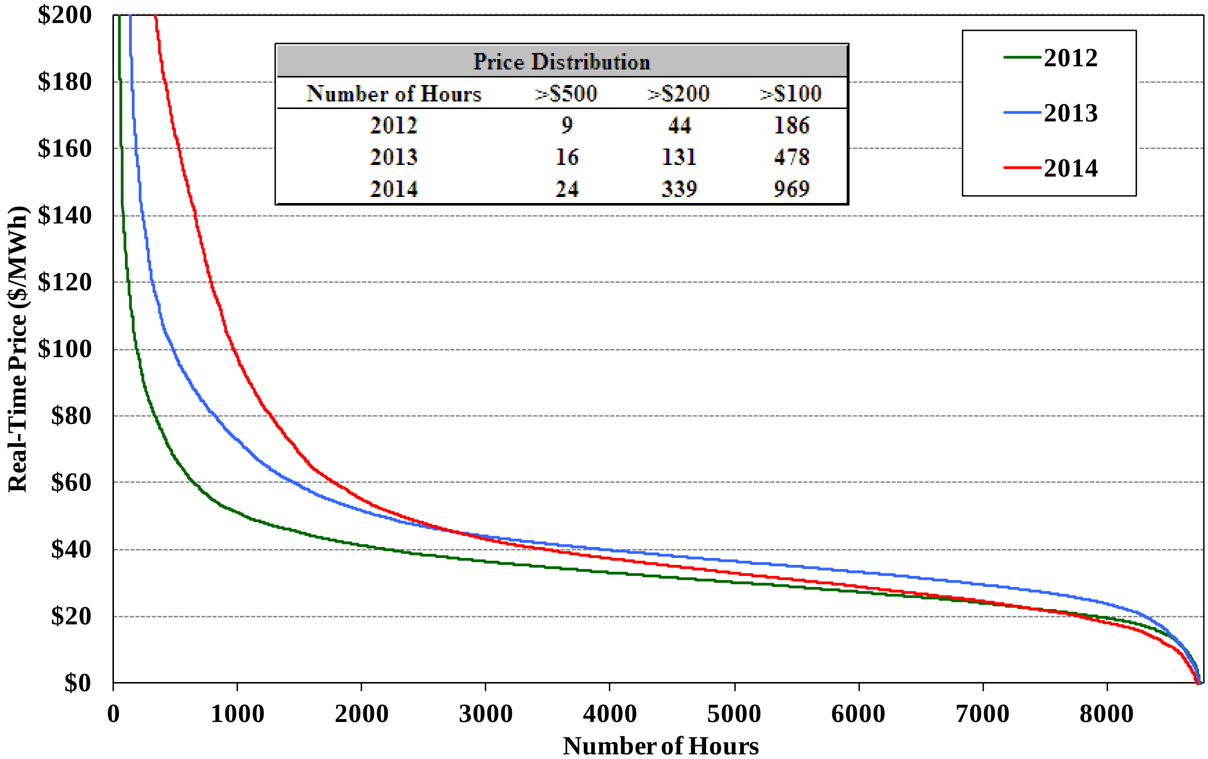
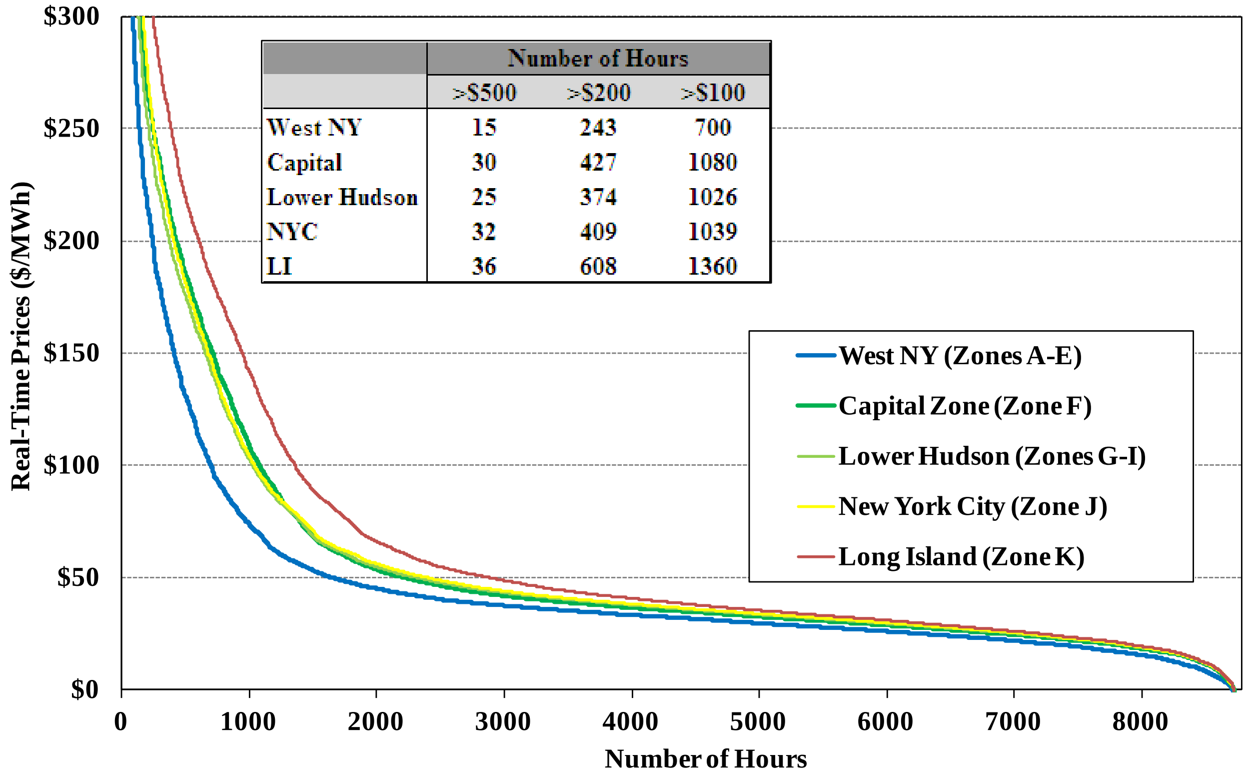


Figure A-5: Real-Time Price Duration Curves by Region
2014



To identify factors affecting power prices other than fuel price changes, Figure A-6 and Figure A-7 show corresponding implied heat rate duration curves in each year from 2012 to 2014 and at each location during 2014. Each curve shows the number of hours on the horizontal axis when the implied heat rate for New York State or each sub-region was greater than the level shown on the vertical axis. In this case, the implied marginal heat rate is the region-wide average real-time price divided by the natural gas price. Natural gas prices are based on the following gas indexes (plus a transportation charge of $0.2 per MMbtu): (a) the Dominion North index for West NY; (b) the Iroquois Zone 2 index for Capital; (c) the average of Iroquois Zone 2 index and the Texas Eastern M3 index for Lower Hudson Valley; (d) the Transco Zone 6 (NY) index for New York City; and (e) the Iroquois Zone 2 index for Long Island. The inset table shows the number of hours in each year or in each region when the implied heat rate exceeded 10, 20, and 30 MMbtu per MWh.

Figure A-6: Implied Heat Rate Duration Curves by New York State 2012-2014

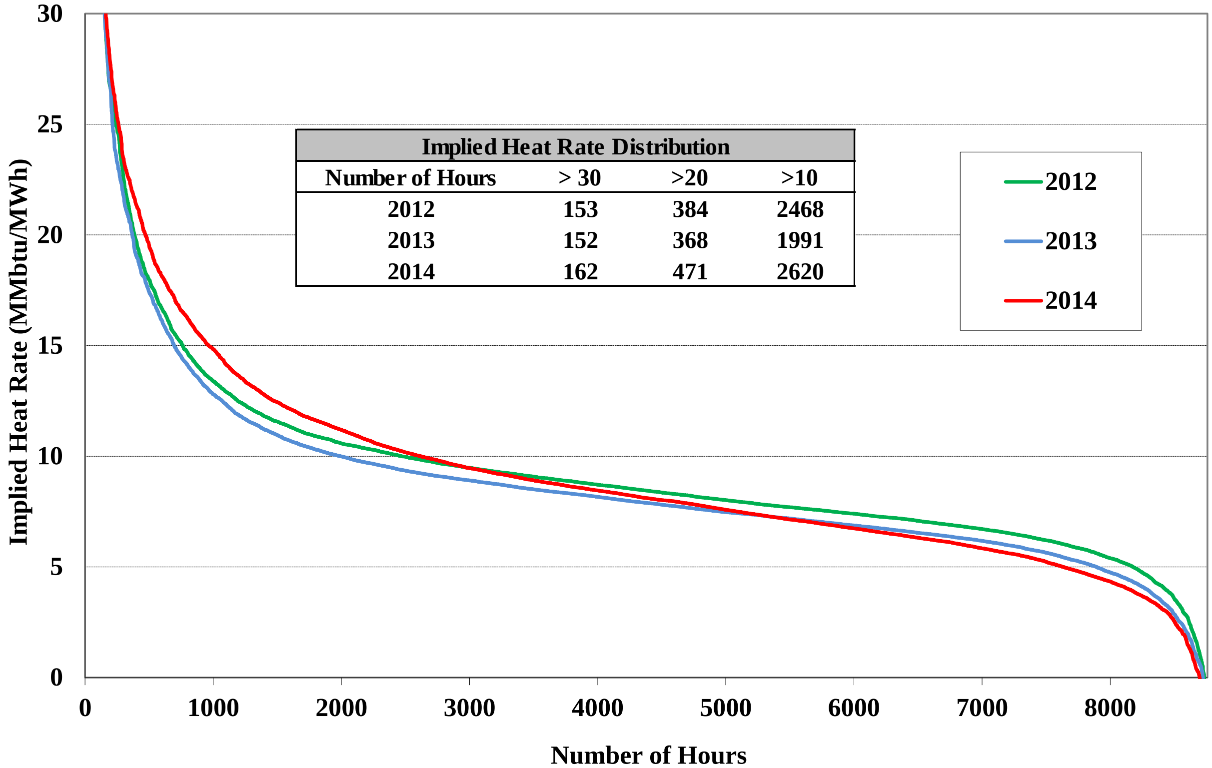
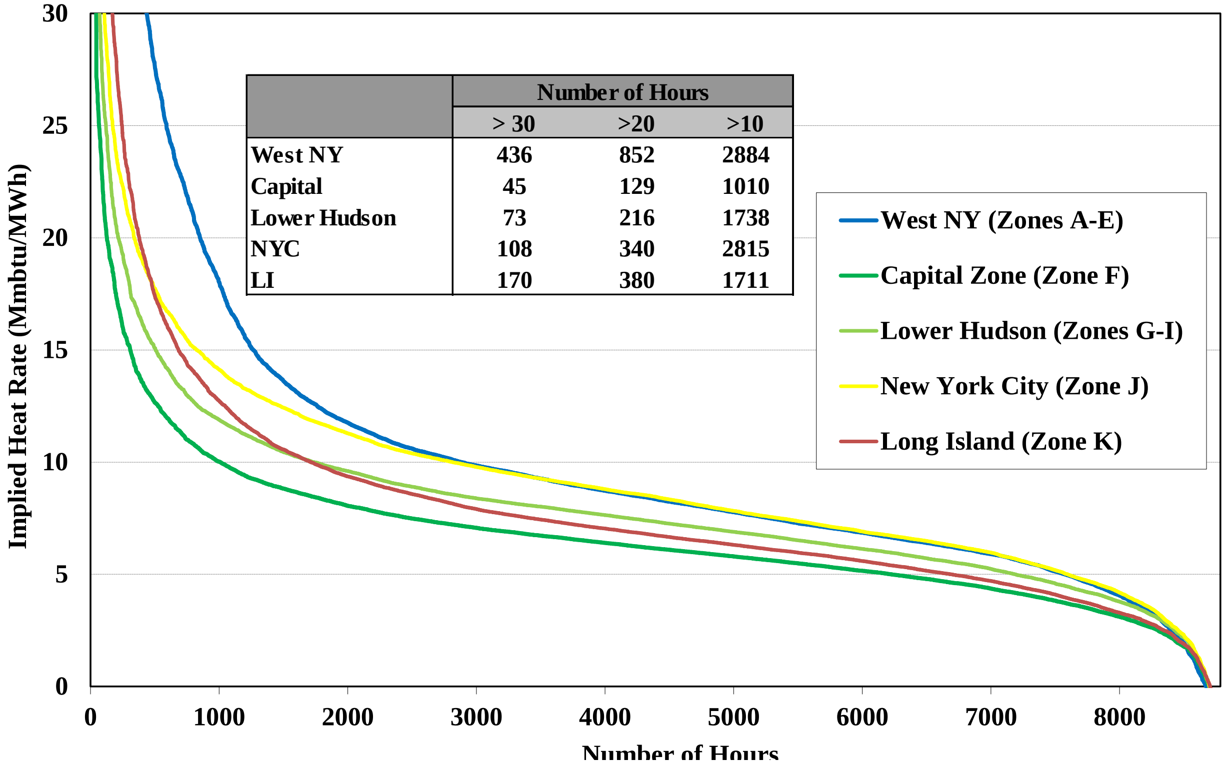


Figure A-7: Implied Heat Rate Duration Curves by Region
2014



	Number of Hours		
	> 30	>20	>10
West NY	436	852	2884
Capital	45	129	1010
Lower Hudson	73	216	1738
NYC	108	340	2815
LI	170	380	1711

Key Observations: Wholesale Market Prices

- Average all-in prices of electricity ranged from approximately $63 per MWh in West New York to $98 per MWh in New York City in 2014.
    - Energy costs accounted for 62 percent of the all-in price in New York City and 77 to 83 percent of the all-in price in the other four regions.
    - Capacity costs accounted for 36 percent of the all-in price in New York City and 16 to 22 percent of the all-in price in the other four regions, reflecting that there is substantial excess installed capacity outside New York City and that the excess is smaller inside New York City. Higher capacity costs in New York City also reflect that the Reference Point on the capacity demand curve is higher for New York City than for other areas.
- Average all-in prices rose 12 to 22 percent in most regions of New York in 2014 except on Long Island where average all-in prices fell 5 percent from 2013.
- Average energy prices rose 8 to 27 percent outside Long Island but fell 6 percent on Long Island from 2013 to 2014.
    - The annual average price increased in most regions because of higher prices in the first quarter, although the increase was partly offset by lower prices in the rest of the

year. This pattern was generally consistent with variations in natural gas prices and load levels (see subsection B and D for more discussions).

- Western New York exhibited the largest increase (27 percent) from 2013 to 2014. The increase was driven primarily by higher energy prices in the first quarter of 2014 compared to the first quarter of 2013.
- Although average natural gas prices did not rise significantly in Western New York, energy prices often rose to the levels of prices in Eastern New York when the Central-East interface was not fully constrained. This was most significant during February and March when imports from Ontario and Quebec fell because those areas were experiencing peak demand conditions.
- However, energy prices fell modestly on Long Island from 2013 because of the following factors:
  - Increased Neptune imports (since it fully returned after July 2013);
  - Increased imports from upstate because of less frequent transmission outages into Long Island; and
  - More efficient utilization of Long Island generating capacity.

- Average capacity costs rose substantially in New York City (24 percent) and the Lower Hudson Valley (i.e., Zones G-I, 59 percent) and rose modestly in other regions (roughly 5 percent) from 2013 to 2014.
  - These increases were driven primarily by increases in the installed capacity requirements. (Other contributing and offsetting factors are discussed in Section VI.)
  - From 2013 to 2014, the ICAP requirement (in MWs) rose:
    - 1.2 percent in the entire New York State;
    - 1.4 percent in New York City; and
    - 1.6 percent in Long Island.
  - The G-J Locality was modeled as a capacity zone starting in May 2014, resulting in higher capacity prices compared to the Rest-Of-State capacity prices.
- Although high energy prices occurred more frequently in 2014 (e.g., real-time state-wide prices exceeded $200/MWh in 339 hours in 2014 compared to 44 hours in 2012 and 131 hours in 2013), implied heat rates (as calculated in this report) fell slightly in most areas.
  - The decrease generally reflected lower load levels and higher natural gas prices on an average basis.
  - The average implied heat rate also rose modestly in New York City. This was because natural gas prices in New York City reached historic lows during the

summer, lowering the costs of New York City generation relative to other generation in Eastern New York.

B. Fuel Prices and Generation by Fuel Type

Figure A-8 – Figure A-10: 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, nuclear, and coal-fired 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 (known as Minimum Oil Burn rules) 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.

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

Figure A-8 shows average coal, natural gas, and fuel oil prices by month from 2011 to 2014. The table compares the annual average fuel prices for these four years.

Figure A-8: Monthly Average Fuel Prices [162]
2011 - 2014

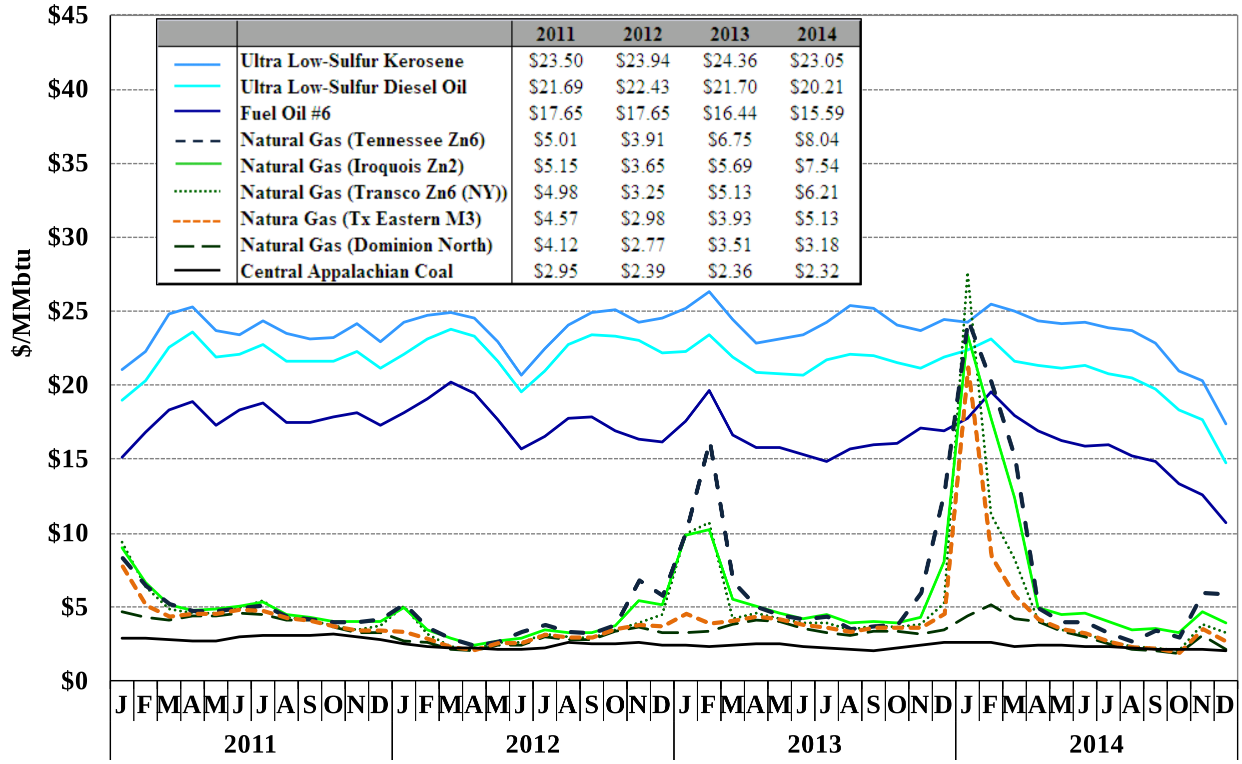


Figure A-9 shows the quantities of generation by fuel type in five regions of New York in each quarter of 2014. [163] The table in the chart shows the annual averages of generation by fuel type from 2012 to 2014.

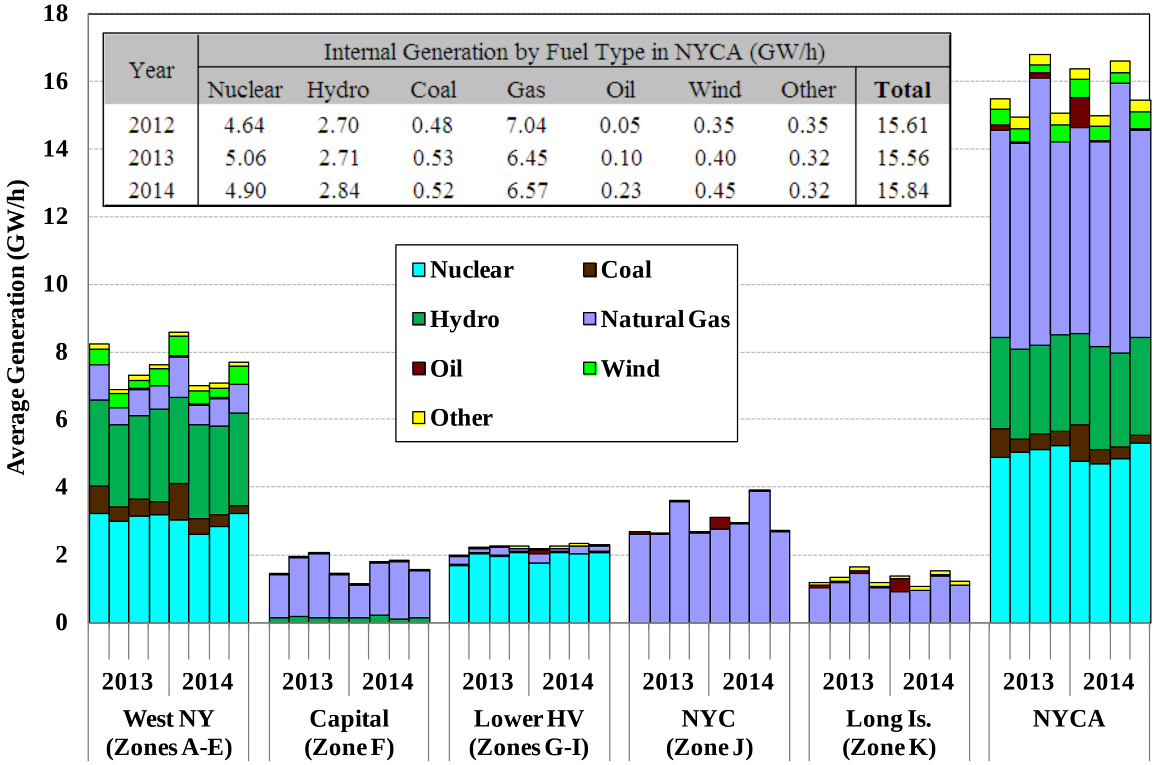
Figure A-10 summarizes how frequently each fuel type was on the margin and setting real-time energy prices in New York State and in each region of the state during 2014. More than one type of unit may be marginal in an interval, particularly when a transmission constraint is binding (different fuels 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 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").

162 These are index prices that do not include transportation charges.

163 Pumped-storage resources in pumping mode are treated as negative generation. The "Other" category includes methane, refuse, solar, and wood.

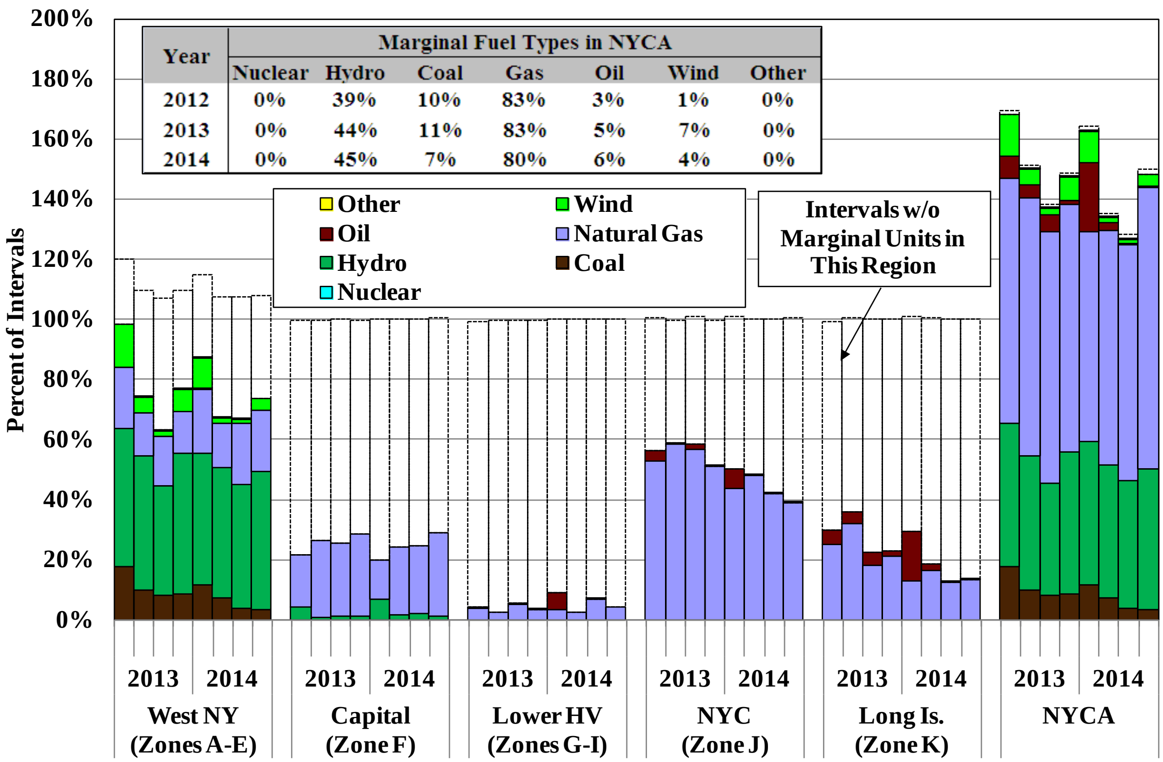
Figure A-9: Generation by Fuel Type in New York
By Quarter by Region, 2014



Internal Generation by Fuel Type in NYCA (GW/h)

Year	Nuclear	Hydro	Coal	Gas	Oil	Wind	Other	Total
2012	4.64	2.70	0.48	7.04	0.05	0.35	0.35	15.61
2013	5.06	2.71	0.53	6.45	0.10	0.40	0.32	15.56
2014	4.90	2.84	0.52	6.57	0.23	0.45	0.32	15.84

Figure A-10: Fuel Types of Marginal Units in the Real-Time Market in New York
By Quarter by Region, 2014



Marginal Fuel Types in NYCA

Year	Nuclear	Hydro	Coal	Gas	Oil	Wind	Other
2012	0%	39%	10%	83%	3%	1%	0%
2013	0%	44%	11%	83%	5%	7%	0%
2014	0%	45%	7%	80%	6%	4%	0%

Key Observations: Fuel Prices and Generation by Fuel Type

- On average, fuel oil prices fell 5 to 7 percent from 2013 to 2014.
  - After four years of stability, fuel oil prices started to fall in the middle of 2014.
  - Reported fuel oil prices fell 28 to 33 percent from June 2014 to December 2014.
  - Lower fuel oil prices helped reduce the severity of natural gas price spikes during winter operations.
- Central Appalachian coal prices have been stable in recent years, varying little from month to month and averaging $2.32/MMBtu for the year of 2014.
- Natural gas prices, which have the strongest effect on wholesale energy prices, exhibited the most variation over time and between regions in recent years.
  - Natural gas prices and gas spreads between regions (e.g., between Western and Eastern New York) exhibited a typical seasonal pattern. They tended to rise in the winter months as a result of higher demand. For example:
    - Natural gas prices in Eastern New York rose to an average of $11 to $19/MMBtu in the 2013/14 Winter (i.e., December 2013 to February 2014), up significantly from an average of $3 to $5/MMBtu in other seasons.
    - Similarly, gas spreads between Western and Eastern New York averaged 160 to 340 percent in the 2013/14 Winter, up notably from an average of 10 to 75 percent in other seasons.
  - Natural gas prices and gas spreads between regions also showed a notable year-over-year variation from 2013 to 2014.
    - Natural gas prices rose over 30 percent in Western New York and 75 to 95 percent in most of Eastern New York from the 2012/13 Winter to the 2013/14 Winter because of higher demand associated with colder weather.
    - However, natural gas prices fell sharply in the second and third quarters of 2014, particularly in New York City where natural gas prices reached historic low levels in the summer (which was 34 percent lower than in the prior summer) driven largely by increased production in the Marcellus region.
  - These variations affected generation patterns, import levels, congestion patterns, energy price spreads, and uplift charges, which are discussed throughout the report.
- Gas-fired (42 percent), nuclear (31 percent), and hydro (18 percent) generation accounted for more than 90 percent of all internal generation in New York during 2014.
  - Average nuclear generation fell 160 MW from 2013 due to increased planned and forced outages and deratings.

  - Average hydro generation rose 130 MW (primarily in Western New York) from 2013, offsetting the decrease in nuclear generation.
  - Gas-fired generation rose modestly from 2013 despite lower load levels and higher combined generation from other resources in 2014.
    - This reflected lower levels of average net imports in 2014.
    - Gas-fired generation rose in New York City and fell in the rest of Eastern New York (particularly in the third quarter of 2014), reflecting increased gas spreads between the two areas from the prior year.
  - Average coal-fired generation was consistent with in the prior years despite retirements and mothballs at several plants over the period.
    - Coal-fired generation averaged roughly 1,100 MW/h in the first quarter of 2014, which was up significantly from other periods and was driven by significantly elevated natural gas prices.
  - Average oil-fired generation rose from 2013 to 2014. This was largely attributable to the increase in the first quarter of 2014 during periods of high natural gas prices.
    - However, oil-fired generation fell in Long Island after the first quarter (as compared with the same period in the previous year), reflecting low summer load levels and transmission upgrades in Long Island that reduced the need for oil units.[164]
  - Wind generation increased over the previous year because of new capacity additions.
- Gas-fired resources (80 percent) and hydro resources (45 percent) were on the margin most frequently during 2014.
  - Most hydro units on the margin have storage capacity, leading them to offer based on the opportunity cost of foregone sales in other hours (when gas units are marginal).
  - Increased congestion in the West Zone has increased the frequency of price-setting by hydro units in the last two years.
  - Price-setting by wind units in the North Zone became less frequent over the past year because of transmission upgrades that increased transfer capability from this area, reducing the frequency of curtailments of wind generation.

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

164 See Section V of the appendix for additional discussion of these upgrades.

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:

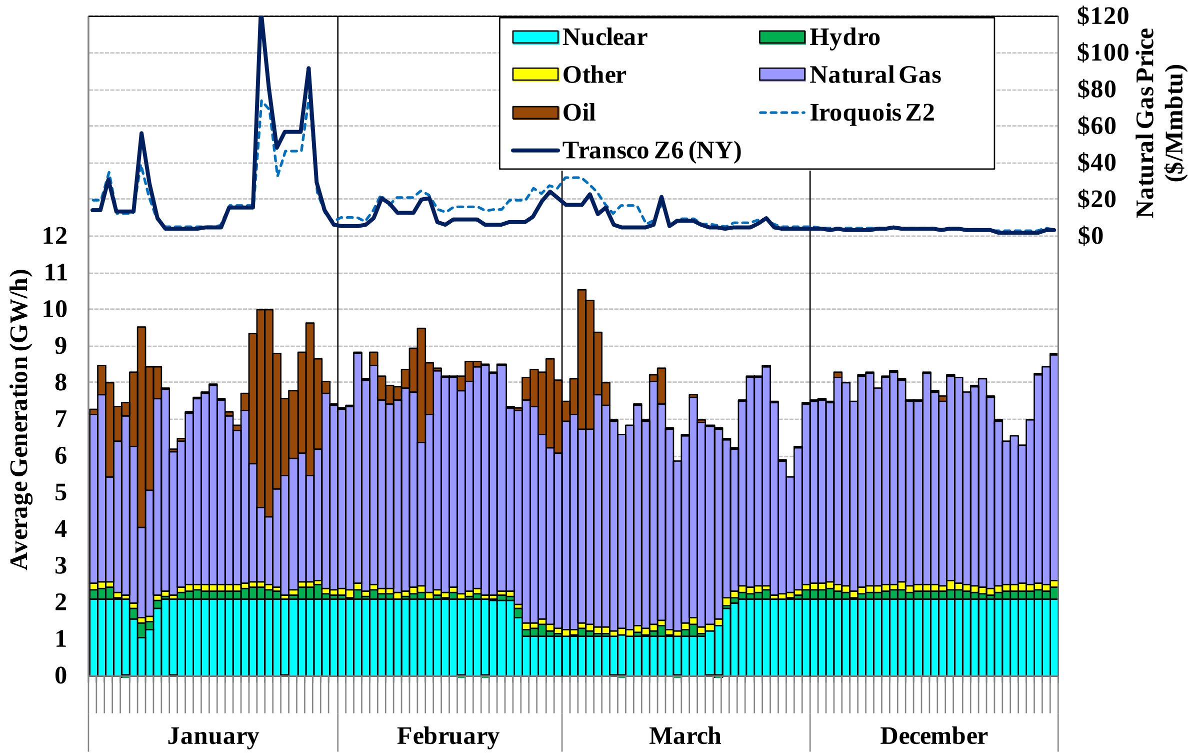
- Not having the necessary air permits;
- Low on-site oil inventory; and
- Physical limitations and gas scheduling timeframes that may limit the flexibility of dual-fueled units to switch from one fuel to the other.

This sub-section examines actual fuel usage in the winter of 2014, 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-11: Actual Fuel Use and Natural Gas Prices in the Winter

Figure A-11 summarizes the average hourly generation by actual fuel consumed in Eastern New York on a daily basis for four months in 2014, which include the three typical winter months (i.e., January, February, December) and March (which had cold weather this year). 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). 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-11: Actual Fuel Use and Natural Gas Prices
Eastern New York, Winter 2014



Key Observations: Fuel Usage Under Tight Gas Supply Conditions

- Extreme weather conditions led to very high and volatile gas prices on many days in the first quarter of 2014. During these periods:
  - The availability of gas to electric generators were reduced by high demand from other customers.
  - Natural gas prices exceeded $20/MMBtu on 27 days in Eastern New York.
- Production from oil (which averages less than 100 MW in Eastern New York on a typical day) rose significantly during these periods. On the 27 days:
  - Hourly production from oil rose significantly, averaging 2.4 GW and reaching a maximum of 5.7 GW on January 23.
  - Production from oil was particularly high from January 21 to 29 when natural gas prices averaged over $60/MMBtu, accounting for 40 percent of total oil-fired generation during the quarter.
    - The large amount of oil use in a single 9-day period illustrates the difficulty in predicting (before the winter) how much oil will be needed over the entire winter season.
- On a few days, oil was only used after the available pipeline capability into Eastern New York and New England was fully utilized. For example:
  - On January 2, gas pipeline flows into Eastern New York reached nearly 7 million MMBtus.
    - 44 percent flowed into New England;
    - 40 percent went to serve core gas demand in Eastern New York; and
    - 16 percent was consumed by generators in Eastern New York.
  - This illustrates how moderate variations in core gas demand have large effects on the availability of fuel to generators.
- On most days when oil was used, pipeline capability into Eastern New York was not fully utilized because the import-constrained area (for gas) was larger than Eastern New York.
  - January 6-8 & 21-29 – Gas pipeline constraints occurred into the entire Atlantic coastal region, resulting in high gas prices in a multi-state region and providing incentives for generators in Eastern New York to use fuel oil when gas was available at a higher price.
  - March 1-5 – Gas flow into Eastern New York was reduced because of high demand in Canada, leading generators in Eastern New York to use fuel oil as the NYISO exported power to Ontario and Quebec in many hours.

- 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, actual production from oil was still significantly lower than would have been optimal based on gas prices and LBMPs. For example, in the first quarter of 2014, we found that as a group oil-capable combined cycle units and steam turbine units in New York City burned approximately 30 to 35 percent of the amount of oil that would have been optimal (based on day-ahead and real-time clearing prices and natural gas prices) according to our market simulations.[165]
- 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;
    - 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

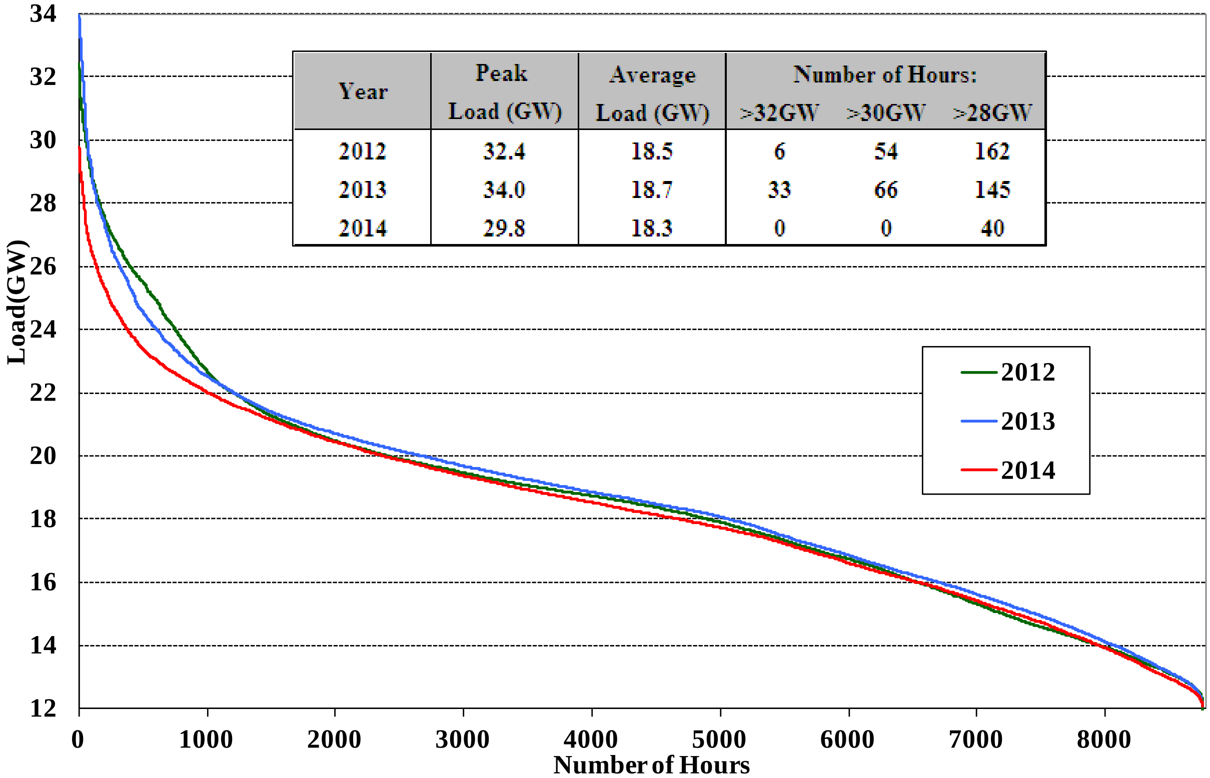
Figure A-12: Load Duration Curves for New York State

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-12 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).

165 See *Quarterly Report on the New York ISO Electricity Markets First Quarter 2014,* slides 22-28.

Figure A-12: Load Duration Curves for New York State
2012 – 2014



Year	Peak Load (GW)	Average Load (GW)	Number of Hours: >32GW	>30GW	>28GW
2012	32.4	18.5	6	54	162
2013	34.0	18.7	33	66	145
2014	29.8	18.3	0	0	40

Key Observations: Load Levels

- Load averaged 18.3 GW in 2014 and never exceeded 30 GW.
- Both the peak level and the average level were the lowest in the past five years, mostly attributable to mild summer weather conditions in 2014.
- Load was particularly low in the summer of 2014.
  - Average load was down 6 percent in July and August from the previous year. Peak load was approximately 4.2 GW (or 12 percent) lower than the annual peak in 2013 (which was the all-time annual peak).
  - Although load levels fell on average from 2013, average load rose in the winter season relative to the previous.
  - NYISO set a new winter peak of 25,738 MW on January 7, 2014 because of extreme weather conditions. This peak was up 1,080 MW from the 2013 winter peak and 197 MW from the previous all-time winter peak that was set in 2004.

E. Day-Ahead Ancillary Services Prices

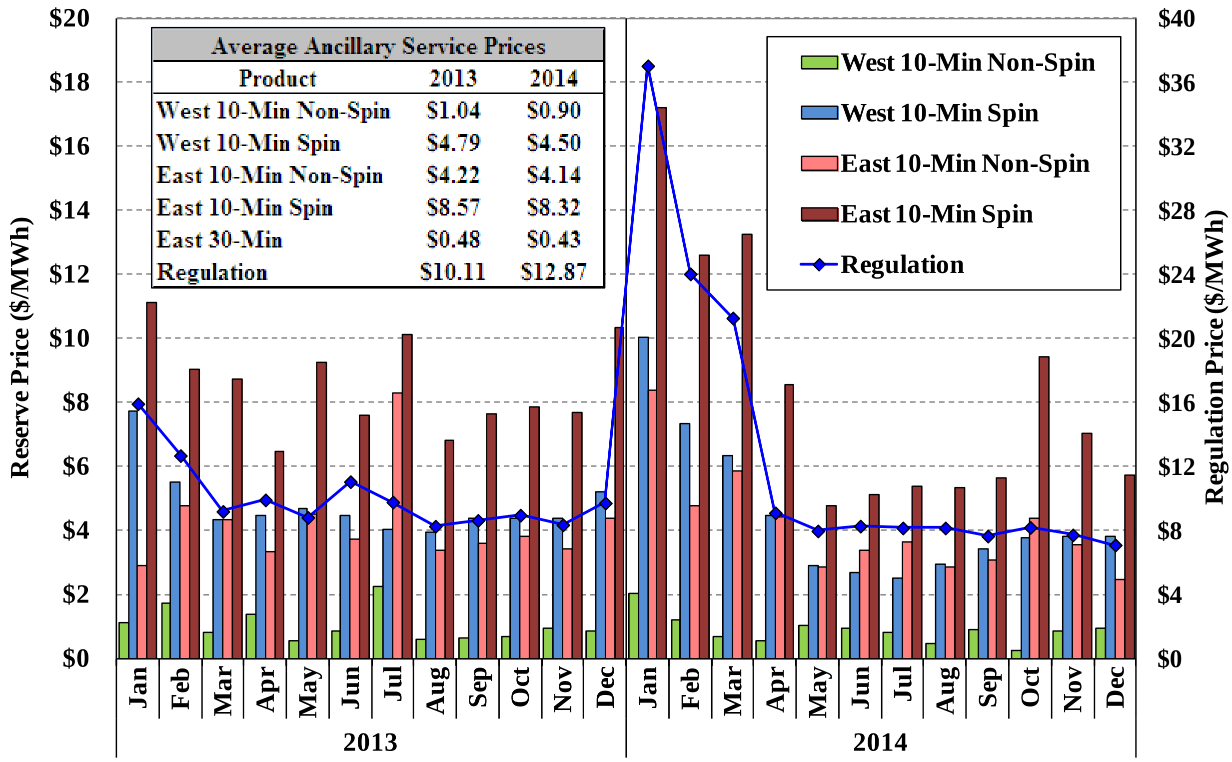
Figure A-13: Day-Ahead Ancillary Services Prices

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 Eastern and Western New York reserve prices.

Figure A-13 shows the average prices of the following five key ancillary services products in the day-ahead market in each month of 2013 and 2014: (a) 10-minute total reserves in Western New York; (b) 10-minute spinning reserves in Western New York; (c) 10-minute total reserves in Eastern New York; (d) 10-minute spinning reserves in Eastern New York; and (e) Regulation.

Figure A-13: Day-Ahead Ancillary Services Prices
2013-2014



Key Observations: Day-ahead Ancillary Service Prices

- The average prices for most classes of operating reserves decreased modestly in 2014.
  - The decrease was mostly attributable to lower load levels during most months of 2014 (especially in the summer), which led to less frequent peaking conditions.
  - However, reserve prices rose significantly in the first quarter of 2014, offsetting the overall reduction. Severe winter weather led to tighter system conditions and higher opportunity costs (associated with higher energy prices) to provide reserves.
  - The number of reserve shortages in Eastern New York fell modestly in the first quarter from a year ago despite increased winter peaking conditions and substantially higher and more volatile natural gas prices.
    - This reflected that the dispatch model generally faced energy limitations (from limited fuel) rather than capacity limitations in Eastern New York in this quarter.
    - This has casted doubt on the actual availability of reserves that were scheduled on the resources with limited fuel.
- Average day-ahead regulation capacity prices rose 27 percent from 2013 to 2014.
  - The number of regulation shortages increased substantially in 2014, most of which occurred in the first quarter because of frequent tight system conditions (see Figure A-82 for more discussion).
  - Regulation prices fell after the first quarter for the similar reasons that caused reserve prices to fall. But the reduction was overweighed by the increase in the first quarter, leading to an annual increase from 2013.

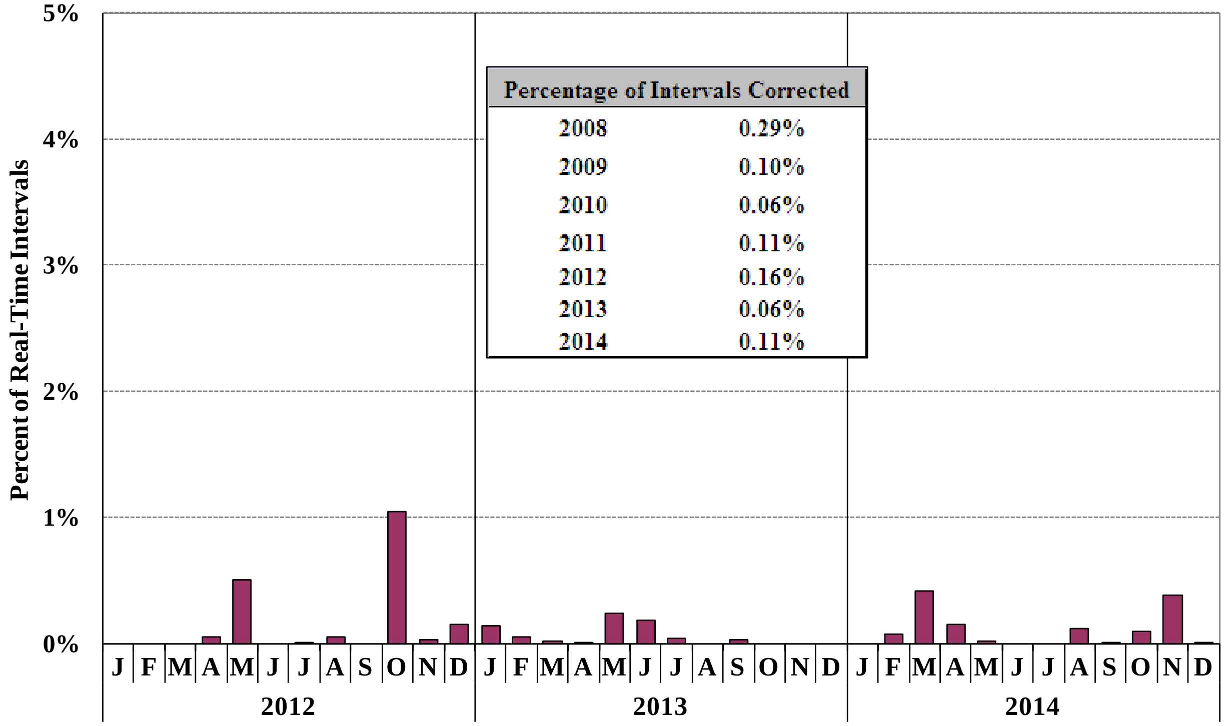
F. Price Corrections

Figure A-14: 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-14 summarizes the frequency of price corrections in the real-time energy market in each month of 2012 and 2014. The table in the figure indicates the change of the frequency of price corrections over the past several years.

Figure A-14: Frequency of Real-Time Price Corrections
2012-2014



<u>**Key Observations: Price Corrections**</u>

- 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 2014, the frequency of price corrections was slightly higher in March and November 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 the three types of new units and three types of older existing 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.

Net revenues vary substantially by location, so we estimate the net revenues that would have been received at two locations in Long Island, , the 345kV portion of New York City, the Hudson Valley Zone, the Capital Zone, the Central Zone and the West Zone. For the Capital Zone, Central, 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. We also use location-specific capacity prices from the NYISO's spot capacity markets.

The method we use to estimate net revenues uses 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.[166] 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:

Table A-1: Day-ahead Fuel Assumptions During Hourly OFOs[167]

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 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.

166 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.

167 **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-2: Fuel Indices and Other Charges by Region

Region	Gas Price Index	Transportation & Other Charges ($/MMBTU)			Intraday Premium/
		Natural Gas	*Diesel/ ULSD*	*Residual Oil*	Discount
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:

Table A-3: New Unit Parameters for Enhanced Net Revenue Estimates[168,169]

Characteristics	CC 1x1	CC 2x1	LMS	Downstate Frame 7	Upstate Frame 7
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 ($/MWh)	1.1	2.4	5.4	0.5	1.7
Startup Cost ($)	9269	0	0	9151	9341
Startup Cost (MMBTU)	1688	3700	430	450	450
EFORd	2.17%	2.50%	2.17%	2.17%	2.17%

168 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.

169 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.

Table A-4: Existing Unit Parameters for Enhanced Net Revenue Estimates

Characteristics	ST	GT-10	GT-30
Summer Capacity (MW)	360	32	16
Winter Capacity (MW)	360	40	20
Heat Rate (Btu/kWh)	10000	15000	17000
Min Run Time (hrs)	16	1	1
Variable O&M ($/MWh)	8.0	4.0	4.5
Startup Cost ($)	6000	1200	519
Startup Cost (MMBTU)	2000	50	60
EFORd	5.14%	10.46%	19.73%

Table A-5 shows our estimates of net revenues and run hours for all the locations and unit types in 2014. The following figures summarize net revenue estimates using our method, and they show 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.

Figure A-15: Net Revenue Generators in the West Zone

2012-2014

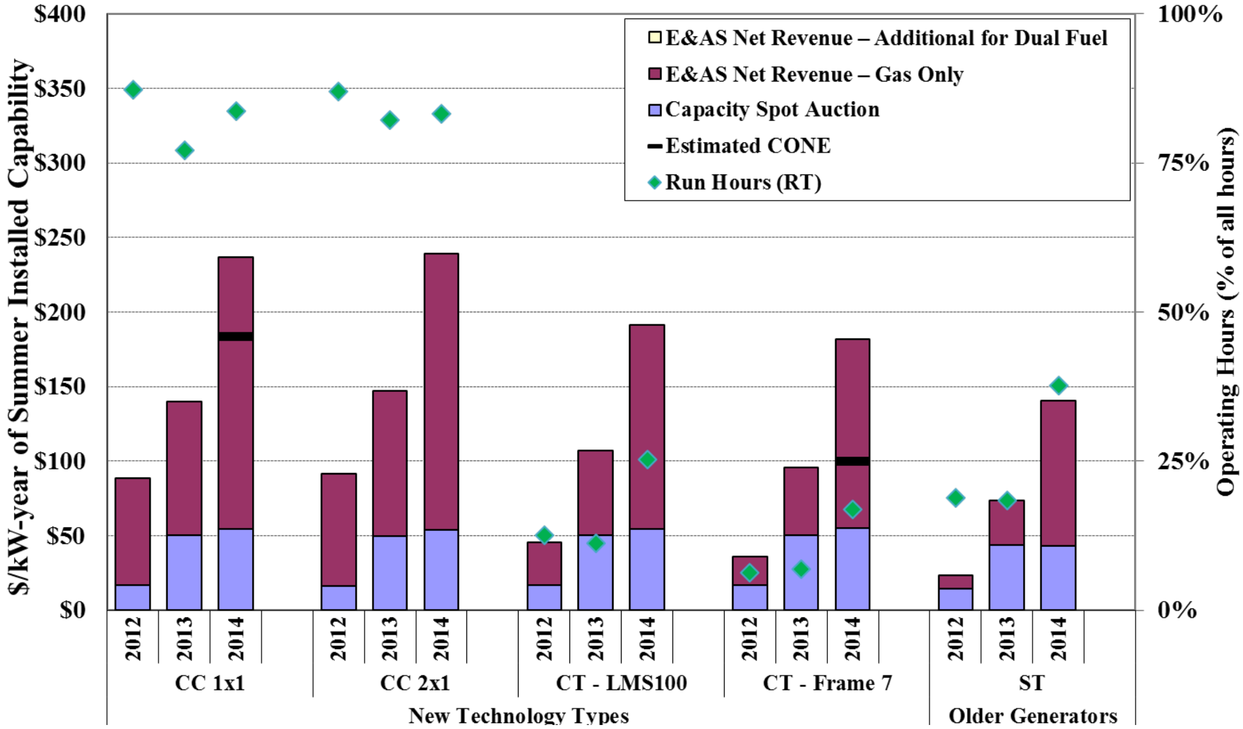


Figure A-16: Net Revenue Generators in the Capital Zone
2012-2014

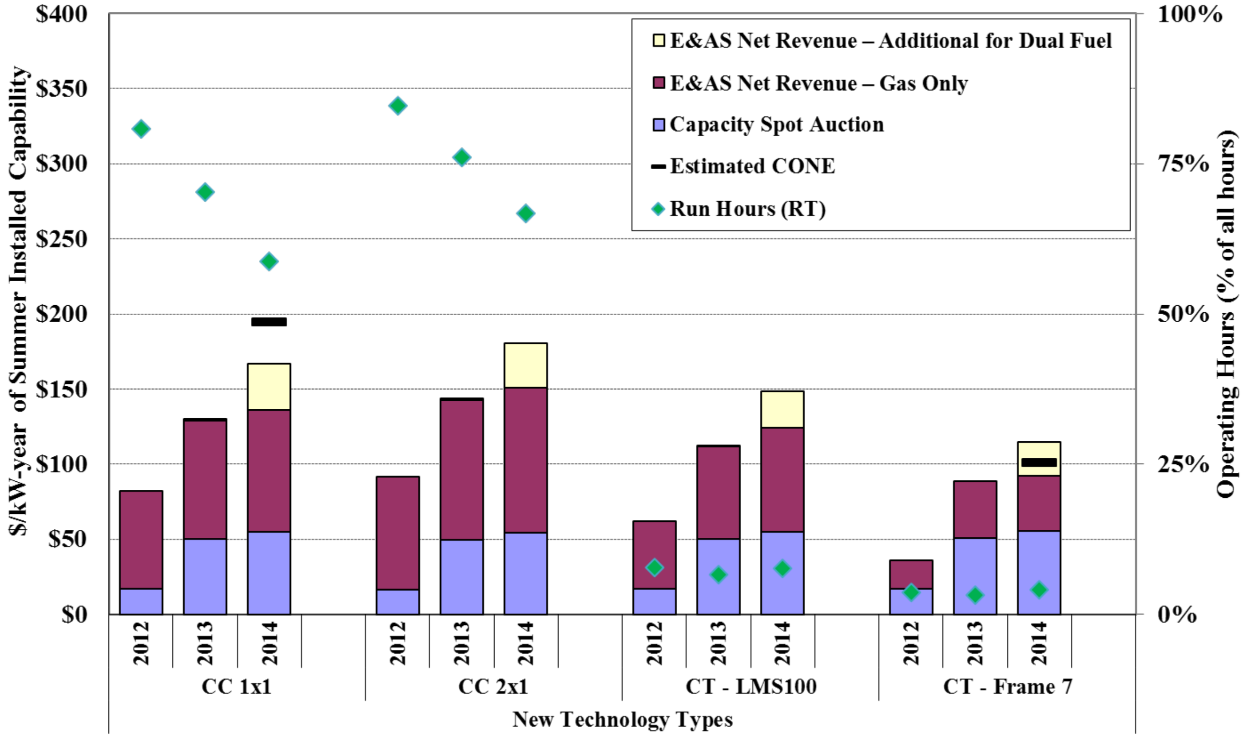


Figure A-17: Net Revenue for Generators in the Central Zone
2012-2014

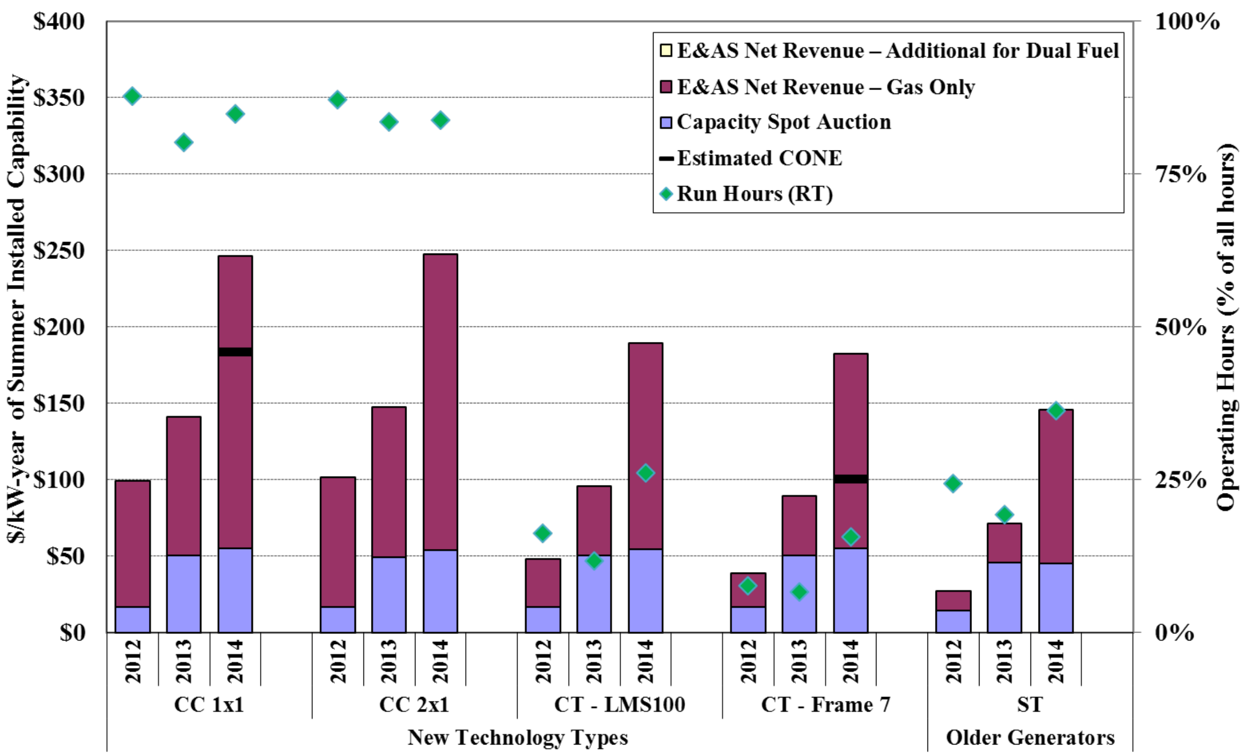


Figure A-18: Net Revenue for Generators in the Hudson Valley
Based on Roseton/Bowline Generator Buses, 2012-2014

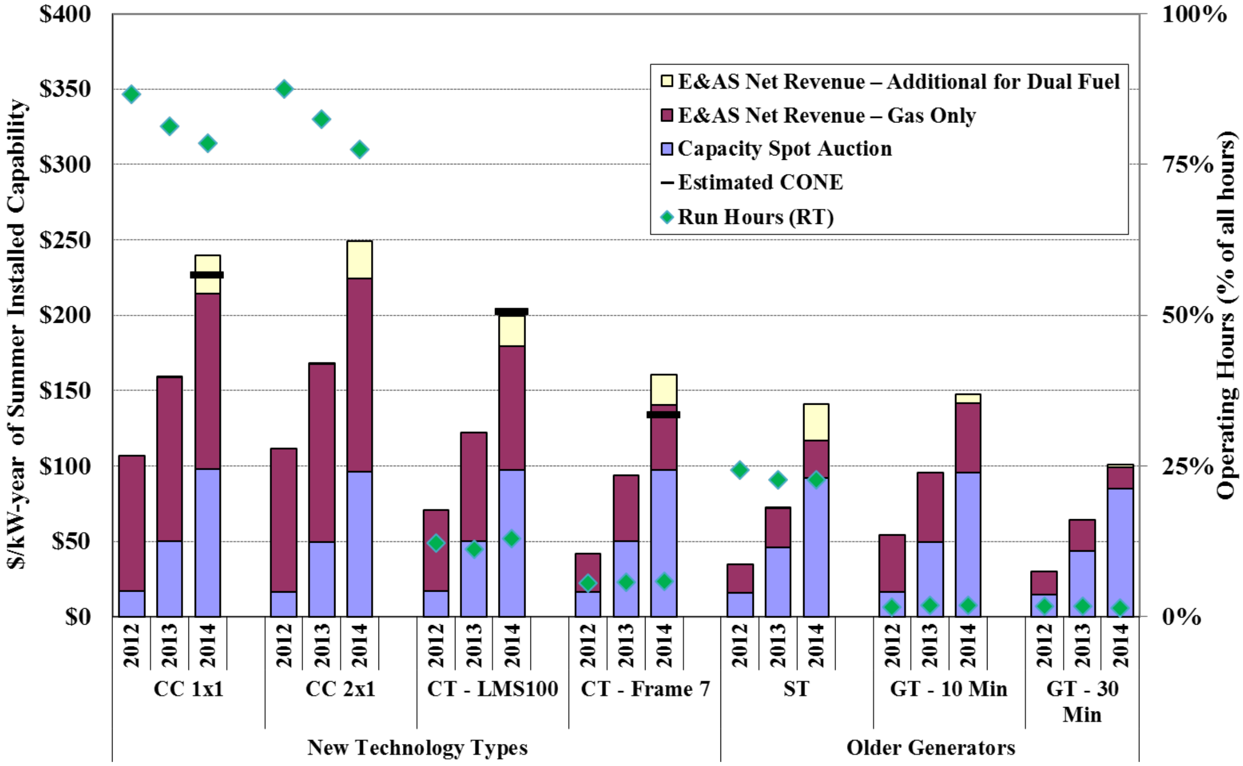


Figure A-19: Net Revenue for Generators in the NYC 345kV System
Based on Ravenswood GT3/1 Generator Bus, 2012-2014

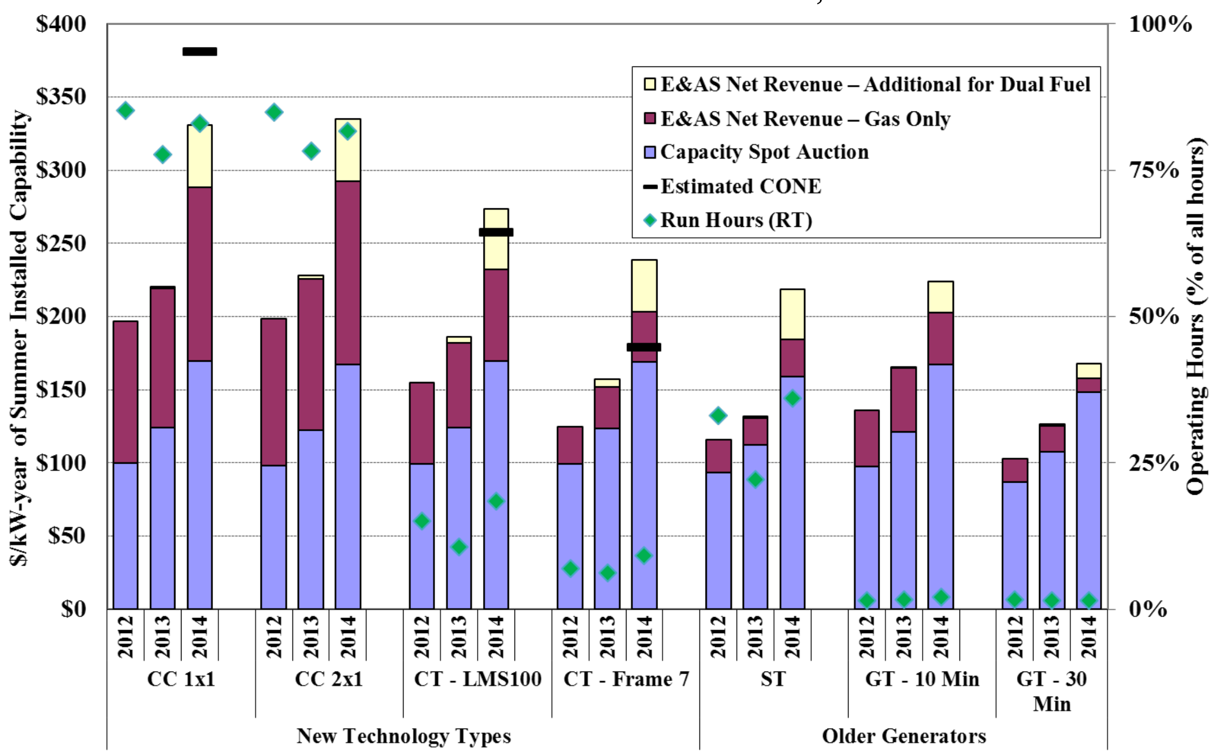


Figure A-20: Net Revenue for Generators in Long Island
Based on Caithness CC 1 Generator Bus, 2012-2014

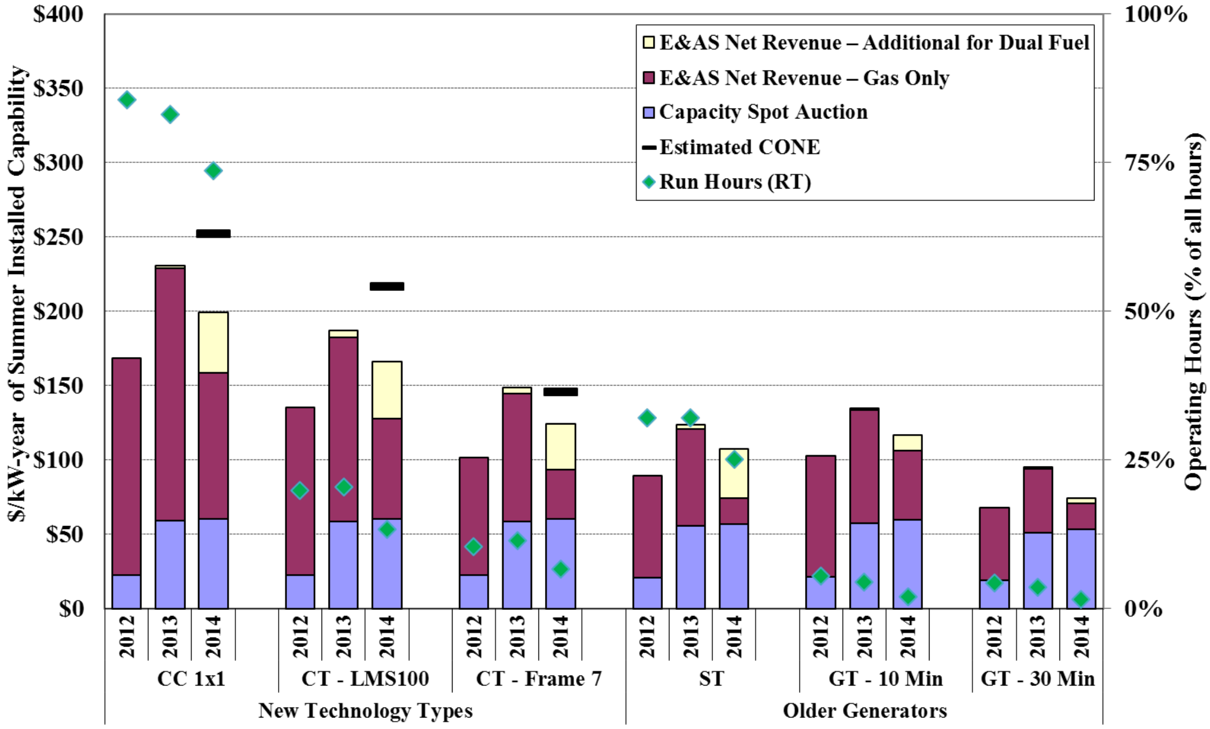


Table A-5: Net Revenue for Generators in 2014

Location	Unit Type	Capacity	2014 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	55	81	30	167	4917	4741	401	5142
	CC 2x1	54	97	30	181	5676	5443	405	5848
	CT - Frame 7	55	37	22	114	278	259	94	353
	CT - LMS100	55	70	24	149	554	516	159	675
Central Zone	CC 1x1	55	191	0	246	7431	7431	0	7431
	CC 2x1	54	194	0	248	7343	7343	0	7343
	CT - Frame 7	55	127	0	182	1373	1373	0	1373
	CT - LMS100	55	135	0	190	2293	2293	0	2293
	ST	45	101	0	146	3182	3182	0	3182
West Zone	CC 1x1	55	182	0	237	7334	7334	0	7334
	CC 2x1	54	185	0	239	7295	7295	0	7295
	CT - Frame 7	55	126	0	182	1489	1489	0	1489
	CT - LMS100	55	137	0	191	2219	2219	0	2219
	ST	43	97	0	141	3295	3295	0	3295
Hudson Valley (Iroquois-Zn2 Gas)	CC 1x1	98	71	28	196	4810	4665	388	5053
	CC 2x1	96	86	27	210	5388	5209	403	5612
	CT - Frame 7	97	31	23	152	247	230	84	314
	GT - 10 Min	95	41	6	143	96	90	20	110
	GT - 30 Min	85	11	3	99	77	74	13	86
	CT - LMS100	98	65	22	185	546	514	136	650
	ST	86	11	25	122	653	642	317	959
Hudson Valley	CC 1x1	98	117	25	240	6703	6586	288	6874
	CC 2x1	96	128	25	249	6643	6501	291	6791
	CT - Frame 7	97	43	20	161	470	454	68	521
	GT - 10 Min	95	46	6	148	153	149	14	163
	GT - 30 Min	85	14	2	101	116	114	8	122
	CT - LMS100	98	82	20	200	1061	1031	99	1130
	ST	92	25	24	141	1761	1718	272	1990
Hudson Valley (TETCO-M3 Gas)	CC 1x1	98	186	25	309	7561	7487	235	7722
	CC 2x1	96	189	25	311	7424	7333	234	7567
	CT - Frame 7	97	89	21	207	1226	1220	55	1275
	GT - 10 Min	95	69	6	171	410	410	7	417
	GT - 30 Min	85	32	3	120	290	289	8	297
	CT - LMS100	98	123	20	240	2272	2265	81	2346
	ST	92	71	23	186	3975	3902	256	4158
Long Island	CC 1x1	61	98	41	199	6229	5892	553	6445
	CT - Frame 7	60	33	31	124	430	428	158	586
	GT - 10 Min	60	46	10	117	143	141	33	175
	GT - 30 Min	53	17	4	74	118	116	23	139
	CT - LMS100	60	68	38	166	947	937	226	1163
	ST	57	17	33	107	1752	1684	513	2197
Long Island (VS/ Barrett Load Pocket)	CC 1x1	61	177	51	289	6529	6046	579	6625
	CT - Frame 7	60	121	46	227	935	898	273	1171
	GT - 10 Min	60	124	51	235	456	443	131	574
	GT - 30 Min	53	80	37	170	362	353	78	431
	CT - LMS100	60	169	55	284	1574	1513	334	1847
	ST	57	75	53	185	2724	2532	585	3117
NYC	CC 1x1	170	119	43	331	7058	6803	465	7268
	CC 2x1	167	125	43	335	7004	6680	468	7148
	CT - Frame 7	169	34	35	239	676	662	136	798
	GT - 10 Min	167	36	21	224	135	134	45	179
	GT - 30 Min	148	9	10	168	109	109	24	133
	CT - LMS100	169	63	41	273	1437	1424	196	1620
	ST	159	25	34	219	2751	2693	465	3158

Key Observations: Net Revenue

- The figures show that overall net revenues increased from 2013 to 2014 in all locations except for Long Island. These changes were mainly due to the following factors:
  - The reduction in transmission line outages and higher imports into Long Island has resulted in lower LBMPs in Long Island (see Section I.A of the Appendix). Consequently, the estimated net revenues for all the units in Long Island dropped in 2014.
  - In New York City, capacity net revenues rose in 2014 because of the low excess capacity sales and resulting high capacity prices during the Summer Capability period (see Section VI.B of the Appendix). The estimated net revenues from the E&AS markets for units in NYC also increased in 2014 because Transco Z6 NY gas prices rose less than other gas pricing hubs, resulting in a cost advantage for units operating in NYC. The daily average of Transco Z6 NY gas prices rose by 18 percent while Iroquois Zone 2 prices rose by 32 percent.
  - The G-J Locality was modeled as a new capacity zone starting in May 2014 and subsequently, the 2014 annual capacity net revenues in the Hudson Valley zone rose by 95% percent. The units modeled in the Hudson Valley location also benefited from an increased spread between LBMPs and the TETCO-M3 gas index price. Additional sensitivities around the gas prices seen by units in the Hudson Valley zone indicate that a CC 2x1 unit with access to gas priced at TETCO-M3 index would earn up to 89 percent more in E&AS revenue than a similar unit that procures gas at the Iroquois Zone 2 index (see Table A-5).
  - Between western New York and Eastern New York, there was more congestion on the gas pipeline system than on the electricity transmission system in 2014. As a result, the spread between electricity and natural gas prices rose considerably in western New York in 2014 from 2013. For example, the daily average Dominion North gas price dropped by 10 percent, while the average day-ahead LBMPs in the West Zone rose by 23 percent from 2013 to 2014.
- For some new unit technologies, the estimated net revenues in 2014 were higher than the cost of new entry ("CONE") in all areas except for Long Island.[170] However, investors decide whether to build based on projected net revenues over the economic life of the unit. Therefore, unusually high net revenues during one year of plant operations alone are not likely to incent new entry into the market.
  - Consistent with the heat rate of each new technology, estimated net revenues were highest for a new CC 2x1 unit, followed by a CC 1x1 unit, an LMS unit, and then a Frame 7 unit in all areas. The new CC 1x1 unit has the highest annualized levelized capital cost while the new Frame 7 unit has the lowest CONE.

[170] The results in the Valley Stream/Barrett load pocket in Long Island indicate substantially higher net revenues for units in this location when compared to other Long Island units. The estimated net revenues in the load pocket are well above the respective CONE values for all the units.

- The estimated net revenues for a Frame 7 unit were higher than the estimated CONE in all the locations except for Long Island in 2014. On the other hand, the estimated net revenues were lower than the CONE for a Frame 7 unit in most locations in 2012 and 2013. So, it is uncertain whether a Frame 7 unit would be earn sufficient net revenue to be economic over the long-term.

- For older existing units, the estimated net revenues were likely higher than the annualized "going-forward costs" in areas where such units are in operation. This is because retirements would 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. The older technologies are online for fewer hours during the year (given the high heat rates) and thus the unit which provides 10-minute reserves while off-line provides the highest revenue.

  - The estimated net revenues for a ST unit included significant potential returns from dual-fuel capabilities in 2014. The ST unit revenues, unlike older GT units' revenues, are driven primarily by the energy and not reserve prices. Consequently, the dual-fuel capability allowed ST units to benefit significantly from the higher LBMPs during the winter months.

- The results for 2014 indicate that the additional revenues from the dual fuel capability were significant for all technologies in the Downstate and Capital zones.

  - The potential returns from dual-fuel capability were highest for CCs and STs in NYC and LI and were in the range of $33-43/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.

  - However, the actual use of oil for generation (and returns from dual-fuel capability) was reduced in 2014 due to generator outages, low oil inventories, and air permit restrictions. The actual oil-based capacity factor for CCs and STs in NYC was only 30 to 35 percent of the optimal oil-based generation for such units based on our simulations.[171]

  - Additional revenues from dual-fuel capability in the West and Central zones were minimal for all the technologies in 2014 because Dominion North gas prices were low relative to other indices.

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, and the system operator uses day-ahead bids and offers to improve the

[171] See *Quarterly Report on the New York ISO Electricity Markets First Quarter 2014,* slide 12.

commitment of resources. 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 would increase purchases in real-time. Alternatively, if day-ahead prices were foreseeably lower than real-time prices, buyers would 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.

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-21 & Figure A-22: 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-21 and Figure A-22 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 2014. 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-21: Average Day-Ahead and Real-Time Energy Prices outside SENY

West, Central, and Capital Zones - 2014

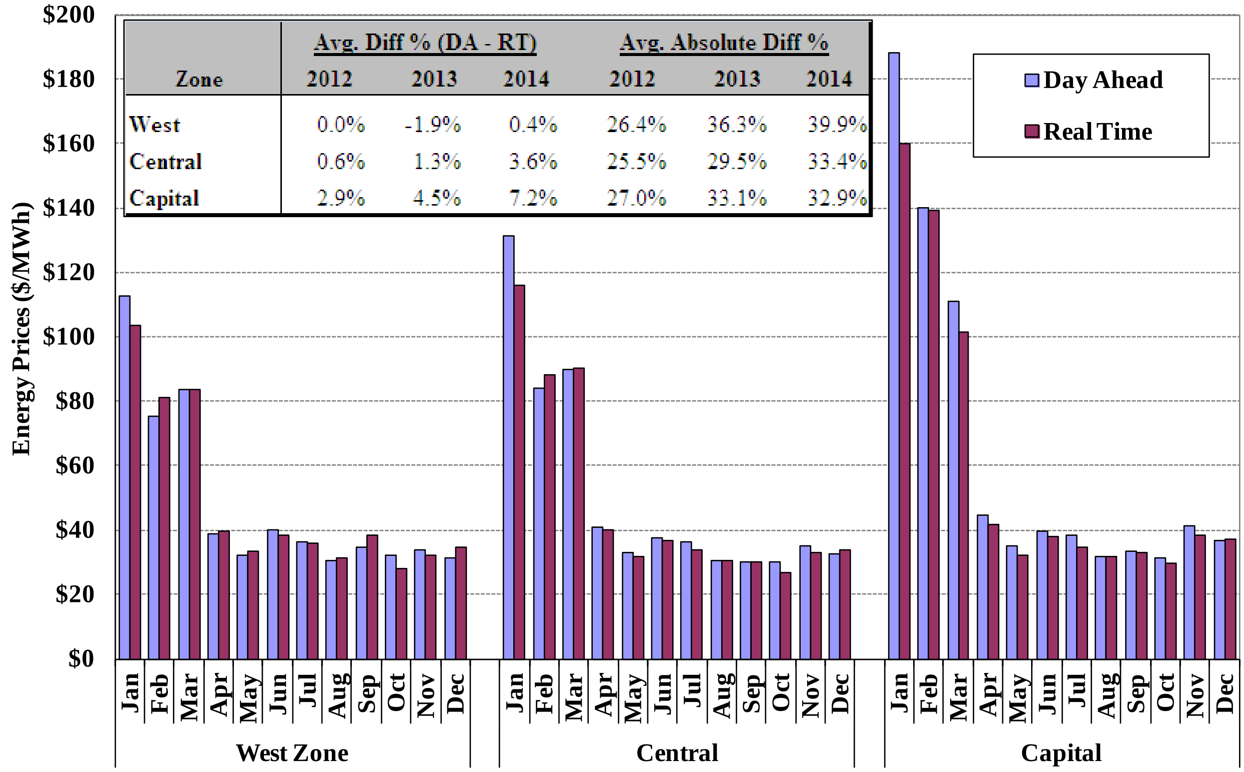
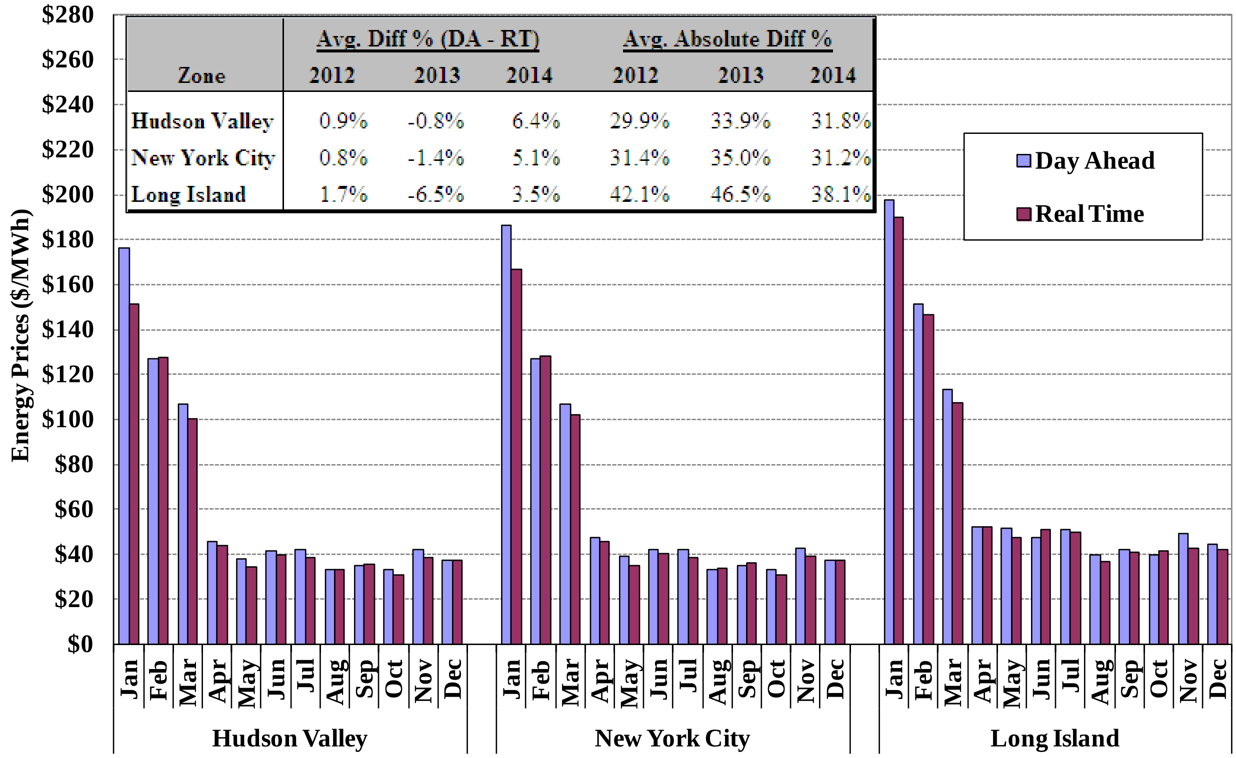


Figure A-22: Average Day-Ahead and Real-Time Energy Prices in SENY
Hudson Valley, New York City, and Long Island - 2014



Zone	Avg. Diff % (DA - RT) 2012	2013	2014	Avg. Absolute Diff % 2012	2013	2014
Hudson Valley	0.9%	-0.8%	6.4%	29.9%	33.9%	31.8%
New York City	0.8%	-1.4%	5.1%	31.4%	35.0%	31.2%
Long Island	1.7%	-6.5%	3.5%	42.1%	46.5%	38.1%

Figure A-23 & Figure A-24: Average Daily Real-Time Price Premium

The factors that dictate real-time prices on some days are inherently difficult to predict, leading day-ahead and real-time prices to differ significantly from one another on individual days even if prices are converging on average. Substantial day-ahead or real-time price premiums in individual months can occur randomly when real-time prices fluctuate unexpectedly. Large real-time premiums can arise when real-time scarcity is not fully anticipated in the day-ahead market. Transmission forced outages or unforeseen congestion, due to TSA events in particular, have led to very high real-time locational prices. Monthly day-ahead price premiums typically arise when real-time scarcity conditions occur less frequently than market participants anticipate in the day-ahead market.

The following two figures show the differences between day-ahead and real-time prices on a daily basis in New York City and Long Island during weekday afternoon hours in 2014. A positive number represents a real-time market price premium, while a negative number represents a day-ahead price premium.

Figure A-23: Average Daily Real-Time Price Premium in NYC
1 p.m. to 7 p.m. Weekdays, 2014

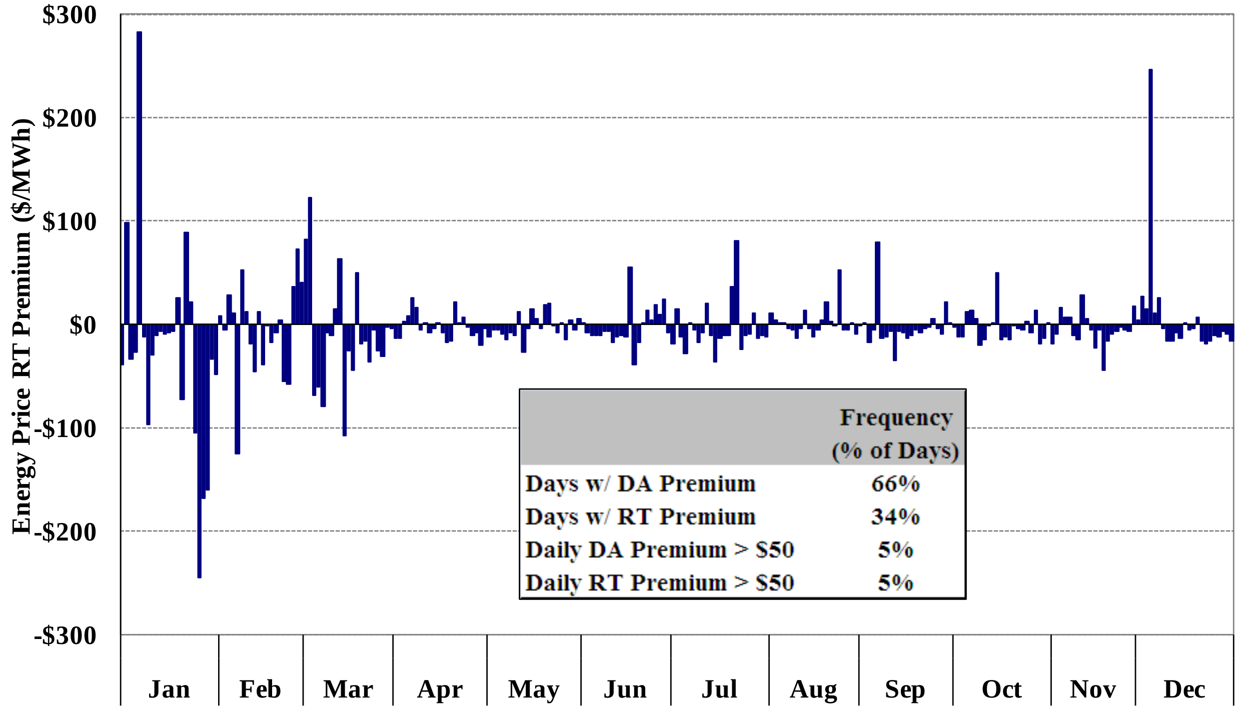


Figure A-24: Average Daily Real-Time Price Premium in Long Island
1 p.m. to 7 p.m. Weekdays, 2014

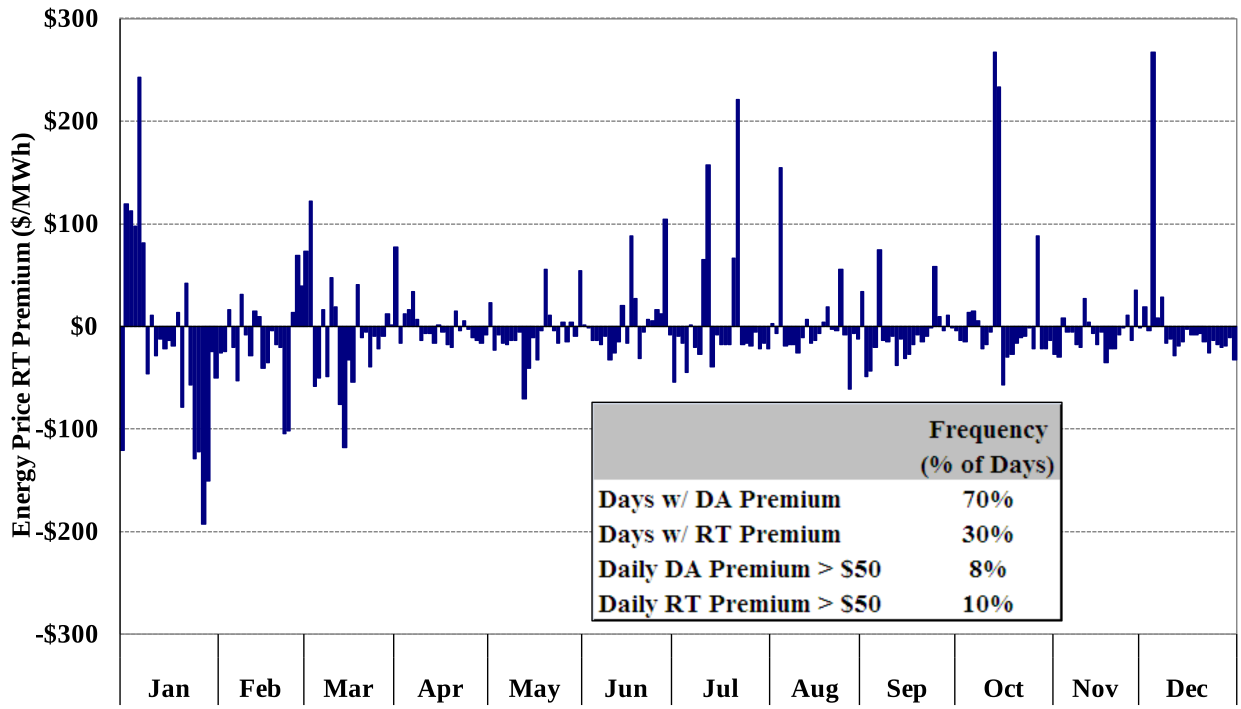


Figure A-25: Average Real-Time Price Premium at Select Nodes

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.

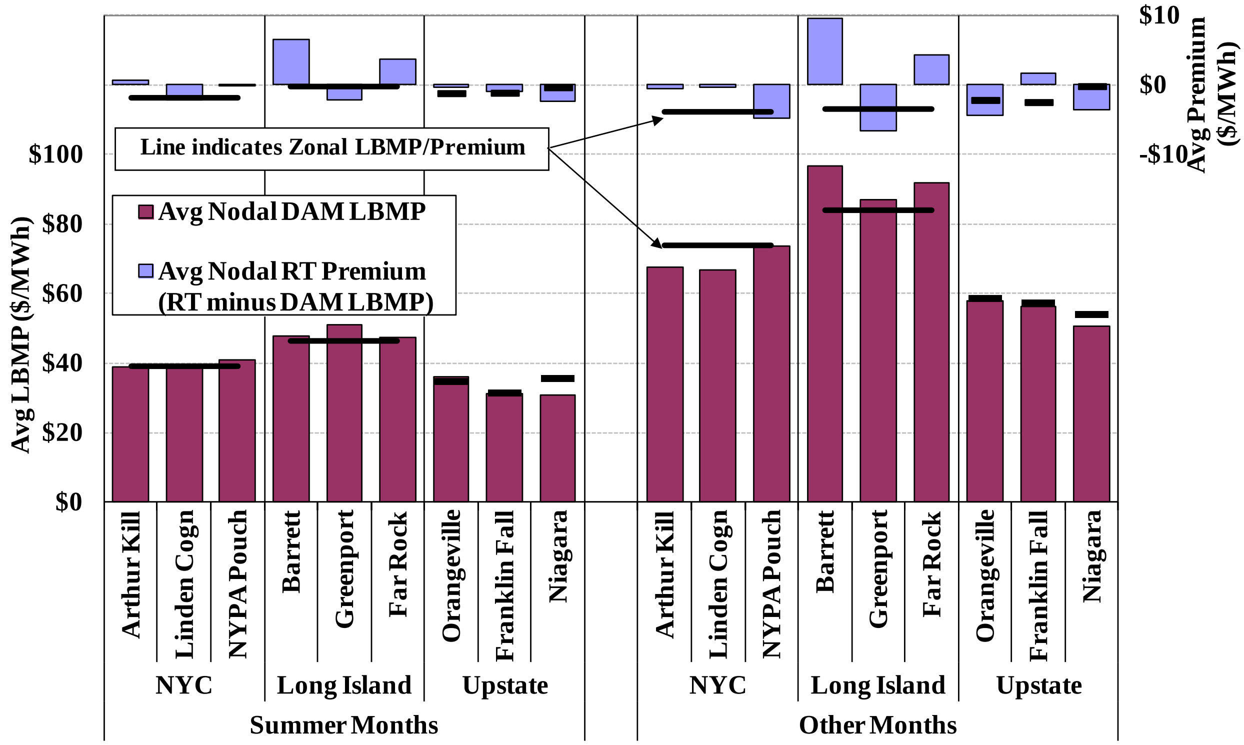
In general, virtual trading and price-sensitive load bidding help improve convergence by facilitating arbitrage between day-ahead and real-time prices. But the NYISO is currently unable to allow market participants to submit virtual trades and price sensitive load bids at the load pocket level or more 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-25 shows average day-ahead prices and real-time price premiums in 2014 for selected locations in New York City, Long Island, and Upstate New York.[172] These are load-weighted averages based on the day-ahead forecasted load. The figure includes nodes in each region that generally exhibited less consistency between average day-ahead and average real-time prices than other nodes. For comparison, the figure also shows the average day-ahead LBMP and the

172 In New York City, Arthur Kill is the Arthur Kill 3 bus and NYPA Pouch is the NYPA Pouch GT 1 bus. In Long Island, Barret is the Barrett 1 bus and Far Rock is FPL Far Rock GT 1 bus. In Upstate, Orangeville is a wind turbine in the Central Zone, Franklin Fall is a hydro generator in the North Zone, and Niagara is in the West Zone.

average real-time price premium at the zone level. These are shown separately for the summer months (June to August) and other months because the congestion patterns typically vary by season.

Figure A-25: Average Real-Time Price Premium at Select Nodes
2014



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) improved modestly in most regions from 2013 to 2014.
  - This reflected lower load levels and lower natural gas prices in most months of 2014, particularly in the summer.
    - However, convergence was worse in the first quarter of 2014 because of highly volatile natural gas prices, partly offsetting the overall improvement.
  - Convergence improved the most on Long Island. In addition to the reasons mentioned above, the further improvement was attributable to increased Neptune imports and upstate imports, which reduced the frequency of congestion into Long Island.
  - However, Western New York (especially the West Zone) exhibited worse convergence, which was due largely to higher real-time volatility associated with increased real-time congestion (for reasons discussed in Section III).

- At the zonal level, average day-ahead energy prices were higher than average real-time prices by a modest margin in most regions during most months of 2014.
  - Most regions exhibited the largest average day-ahead premium in January. Most day-ahead premiums occurred on days from January 22 to 29 as rapid changes in weather patterns and natural gas prices and supplemental commitments after the day-ahead market greatly reduced real-time prices on these days.
- At the nodal level, a few locations exhibited less consistency between average day-ahead and real-time prices. Most notably:
  - In Long Island, the Valley Stream load pocket (represented by the Barrett location) exhibited a real-time price premium of $9.65 per MWh outside the summer months, compared to a day-ahead zonal price premium of $3.55 per MWh. 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 real-time exports exceed day-ahead exports by a significant margin, it can result in severe congestion across the East Garden City-to-Valley Stream line.
  - In Upstate New York, the Niagara generation pocket exhibited a day-ahead price premium of roughly $3.50 per MWh outside the summer months, compared to a day-ahead zonal price premium of only $0.15 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 amount of supply (offered at a given price) from Ontario and Niagara 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 usually 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-26 – Figure A-28: 10-Minute Spinning and Non-Spinning Reserve Prices

Figure A-26 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 $500 per MW on satisfying this requirement.

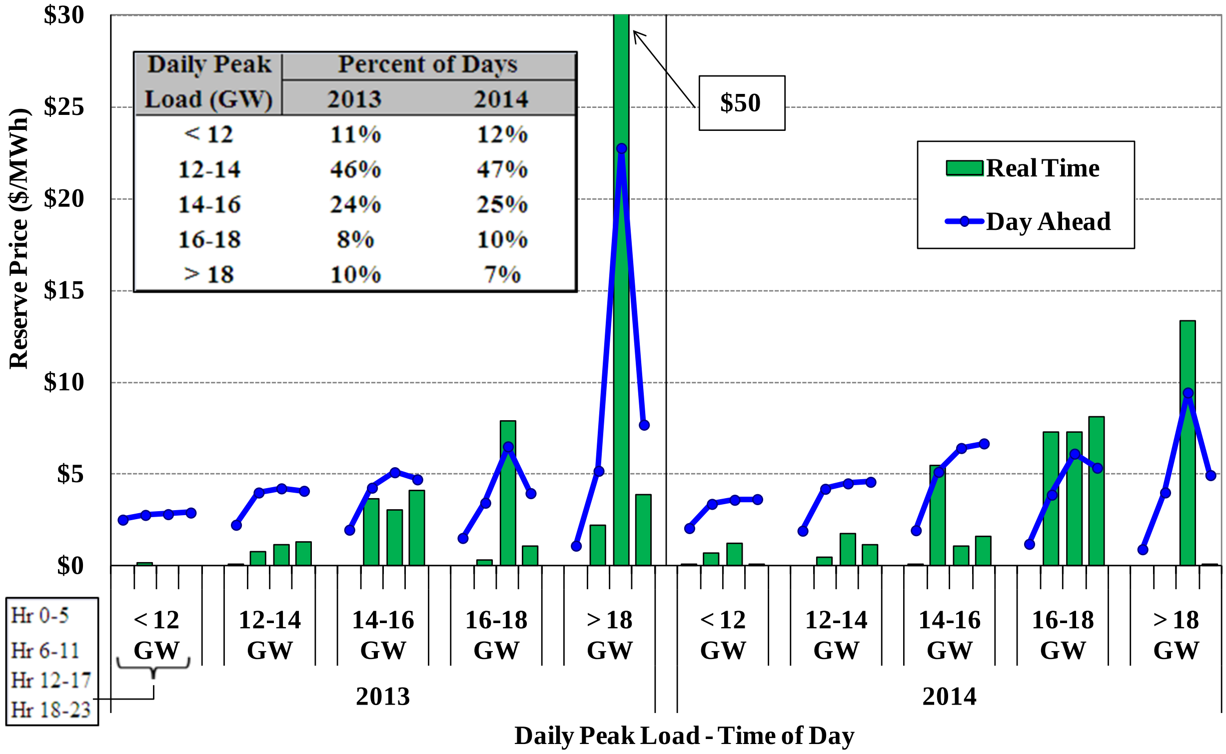
Figure A-27 shows 10-minute spinning reserve prices in Western New York, which are primarily based on the requirement to hold 655 MW of 10-minute spinning reserves in New York State. Therefore, this represents the base price for spinning reserves in New York before locational premiums for satisfying eastern 10-minutes requirement are added. A demand curve is used that places an economic value of $500 per MW on satisfying this requirement.

Figure A-28 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 2013 and 2014. The inset tables show the percent of days in each load range in 2013 and 2014.

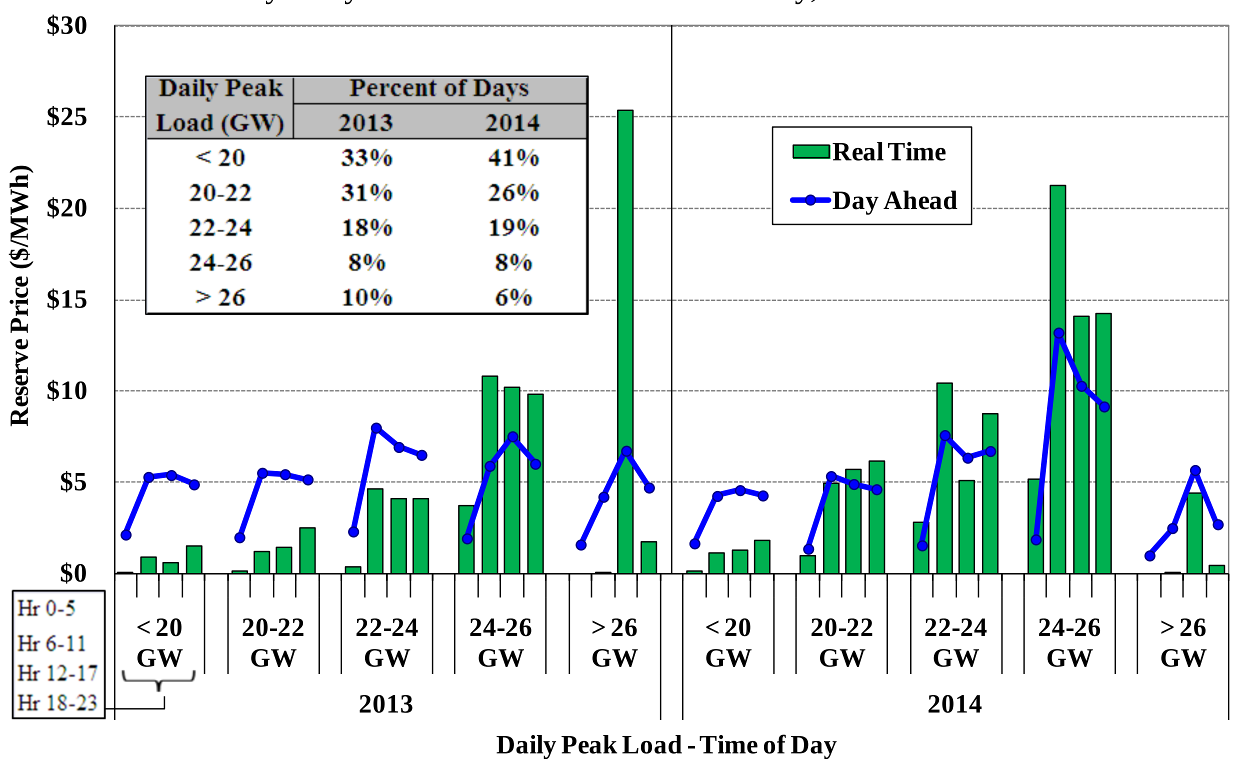
Table A-6 reports the percentage difference between the average day-ahead price and the average real-time price (as a percentage of average day-ahead price), as well as the average absolute value of the difference between hourly day-ahead and real-time prices in 2013 and 2014. The latter metric measures 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. 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-26: 10-Minute Non-Spinning Reserve Prices in East NY
by Daily Peak Load Level and Time of Day, 2013 - 2014



Daily Peak Load (GW)	Percent of Days 2013	Percent of Days 2014
< 12	11%	12%
12-14	46%	47%
14-16	24%	25%
16-18	8%	10%
> 18	10%	7%

Figure A-27: 10-Minute Spinning Reserve Prices in West NY
by Daily Peak Load Level and Time of Day, 2013 - 2014



Daily Peak Load (GW)	Percent of Days 2013	Percent of Days 2014
< 20	33%	41%
20-22	31%	26%
22-24	18%	19%
24-26	8%	8%
> 26	10%	6%

Figure A-28: 10-Minute Spinning Reserve Prices in East NY
by Daily Peak Load Level and Time of Day, 2013 - 2014

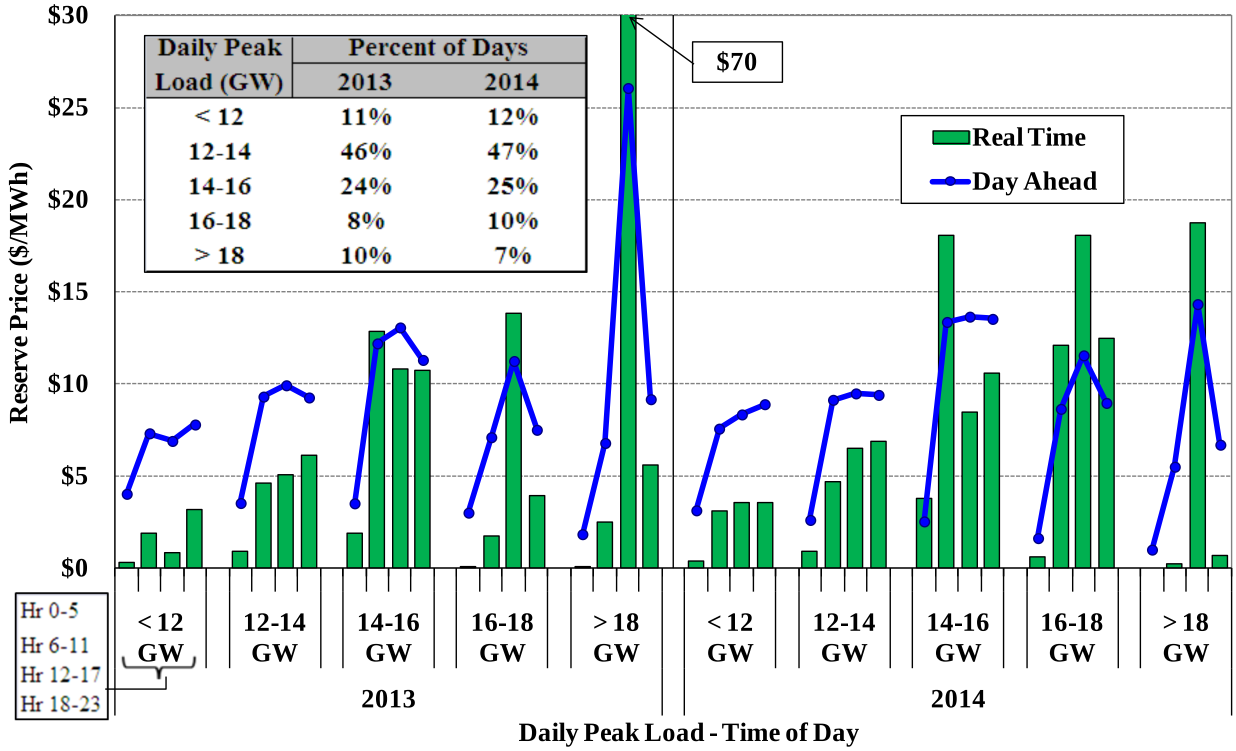


Table A-6: Price Convergence Between Day-Ahead and Real-Time Reserve Prices
2013 – 2014

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	
	2013	2014	2013	2014	2013	2014	2013	2014
West 10-Min Spin	-72%	-24%	60%	15%	222%	159%	121%	150%
East 10-Min Non-Spin	-70%	18%	64%	65%	181%	163%	128%	131%
East 10-Min Spin	-70%	-4%	38%	27%	176%	138%	110%	123%

Key Observations: Convergence of Day-Ahead and Real-Time Ancillary Service Prices

- Reserve price convergence generally improved under peaking conditions from 2013 to 2014.
  - Both average price difference and average absolute price difference between day ahead and real time improved notably for the three reported reserve products.
  - The revision of two day-ahead market reserve mitigation provisions likely contributed to the improvement.

    - On January 23, 2013, the first phase of the revision raised: (a) the reference cap of 10-minute non-spin reserves from $2.52 to $5 per MW; and (b) the offer cap of 10-minute spinning reserves for New York City generators from $0 to $5 per MW.
    - On September 25, 2013, the second phase of the revision raised both caps to $10 per MW.
    - On August 26, 2014, the final phase of the revision eliminated both caps.
  - These changes allowed higher day-ahead offers under peaking conditions, leading day-ahead prices to be more consistent with real-time prices.
  - However, because of mild summer weather conditions in 2014, there were no hours when load exceeded 30 GW, making it impossible to evaluate how the market would perform under very high load conditions.
- Overall, reserve price convergence was comparable to 2013 during Other (i.e., non-Peak) Periods.
  - The difference between average day-ahead and average real-time prices improved, while the average absolute difference was modestly worse for spinning reserves.
    - Day-ahead price premiums increased modestly during low load periods, which were affected by changes in offer caps. Offer patterns are evaluated in Section II.
    - The day-ahead premiums are generally expected in a competitive market without virtual trading.

J. Regulation Market Performance

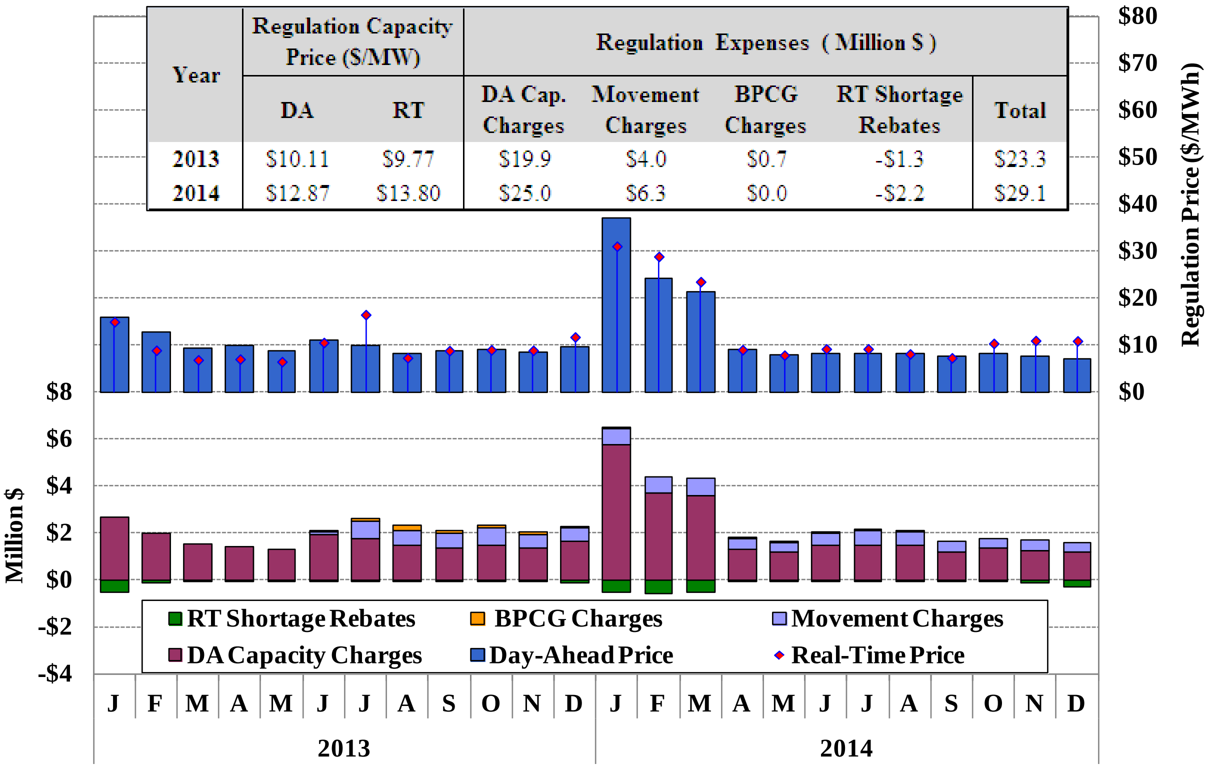
Figure A-29 – Regulation Prices and Expenses

Figure A-29 shows the regulation prices and expenses in each month of 2013 and 2014. 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-29: Regulation Prices and Expenses
by Month, 2013-2014



Year	Regulation Capacity Price ($/MW)		Regulation Expenses (Million $)				
	DA	RT	DA Cap. Charges	Movement Charges	BPCG Charges	RT Shortage Rebates	Total
2013	$10.11	$9.77	$19.9	$4.0	$0.7	-$1.3	$23.3
2014	$12.87	$13.80	$25.0	$6.3	$0.0	-$2.2	$29.1

Key Observations: Regulation Market Performance

- New regulation market design was implemented in late June of 2013, which introduced a two-part bid in the real-time market to separately reflect the movement cost and the capacity cost of providing regulation service.

- Day-ahead regulation capacity prices were more consistent with real-time capacity prices in most of months after the implementation of the new regulation market.

  - However, some months exhibited a relatively larger inconsistency primarily because of unexpected real-time conditions on several days. For example,

    – Real-time conditions (e.g., weather, gas prices) were a lot milder than anticipated in the day-ahead market in late January 2014, leading to high day-ahead premiums on these days and a resulting average monthly day-ahead premium.

    – Capacity deficiency on December 4, 2014 (driven by unexpected transmission outages in Hydro Quebec) resulted in very high real-time prices on this day and consequently an average real-time premium for the month.

- Regulation costs totaled $29 million in 2014, up 24 percent from 2013.

- The increase accrued primarily in the first quarter of 2014 when higher energy prices (due to higher load levels and higher natural gas prices) resulted in higher opportunity costs for providing regulation.
- Real-time regulation shortages also increased significantly in the first quarter, leading to higher shortage rebates, which partly offset the increase in the overall cost.
- Unlike capacity prices, regulation movement charges did not vary in similar proportion to the natural gas prices and/or load levels. This is because the clearing price for regulation capacity is driven primarily by the opportunity cost of not providing energy or reserves during tight market conditions (rather than the regulation capacity offer price). On the other hand, 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 and it would otherwise 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.

A. Potential Physical Withholding: Generator Deratings

We evaluate potential physical withholding by analyzing day-ahead generator deratings. 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, or a short-term forced outage. A derating can be partial (maximum output is reduced, but is greater than zero) or complete (maximum output is zero). The figures in this section show the quantity of day-ahead deratings as a percent of total Dependable Maximum Net Capability ("DMNC") from all resources, where deratings measure the difference between the quantity offered in the day-ahead market and the most recent DMNC test value of each generator. *Short-term Deratings* include capacity that is derated for less than 30 days, and the remaining derates are shown as *Other Deratings.* [173, 174]

We focus particularly on short-term deratings 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 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 still evaluate long-term deratings, 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 deratings of economic capacity, since deratings of uneconomic capacity do not raise prices above competitive levels and therefore, are not an indicator of potential withholding.

173 For our analyses of physical withholding, we include the difference between the DMNC capability and the Normal Upper Operating Limit offered into the DAM as a derating. Hence, units that offer an Emergency Upper Operating Limit that is greater than the Normal Upper Operating Limit will have a small derating for the purposes of this analysis of withholding, although they will not be derated for the purposes of calculating EFORd. Note, capacity that is consistently offered between the Emergency Upper Operating Limit and the Normal Upper Operating Limit will be categorized as "Other Deratings" rather than "Short-term Deratings."

174 For our analyses of physical withholding, we exclude unoffered capacity from hydro and wind-powered generators.

The figures in this sections how the portion of derated capacity that would have been economic in the day-ahead market. This assessment of economic capacity is based on generators' Minimum Generation and Incremental Energy cost reference levels and day-ahead LBMPs, but it does not consider start-up costs. Hence, the figures in this section generally over-estimate the portion of deratings that would be economic in the day-ahead market.

Figure A-30 & Figure A-31: Generator Deratings by Month

Figure A-30 and Figure A-31 show the broad patterns in outages and deratings in New York State and Eastern New York in each month of 2013 and 2014.

Figure A-30: Deratings by Month in NYCA
2013 – 2014

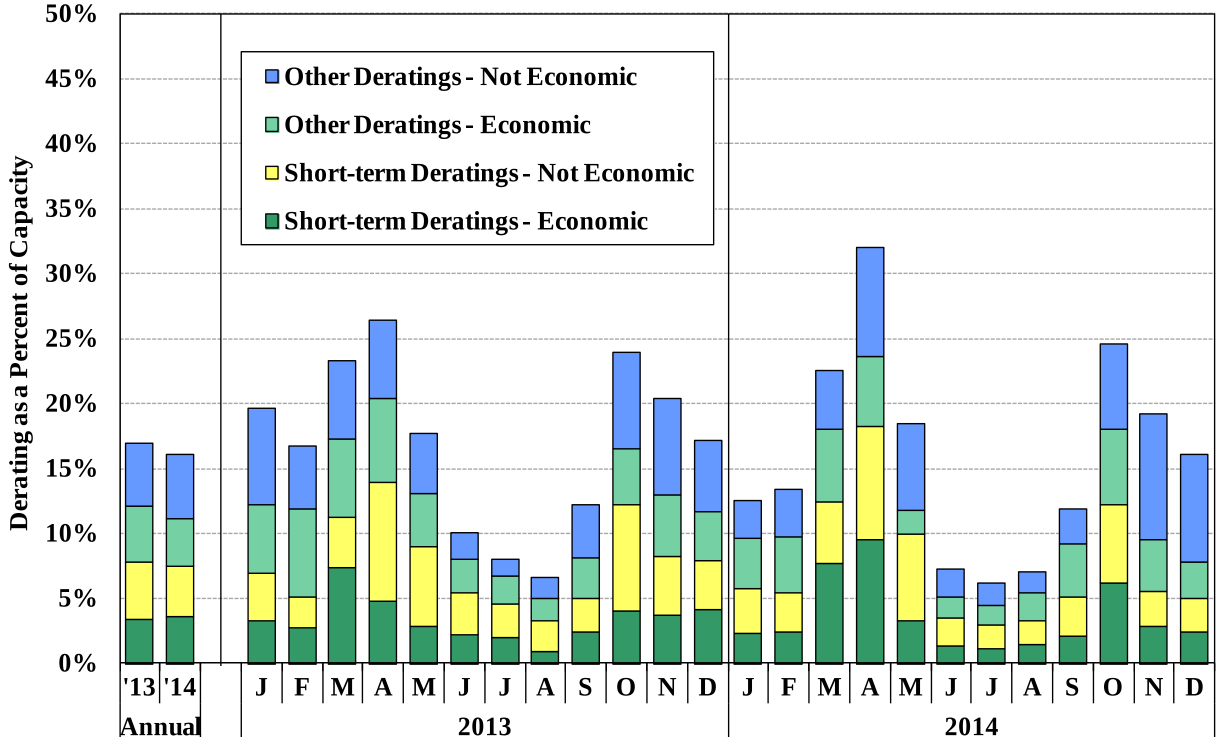


Figure A-31: Deratings by Month in East New York
2013 - 2014

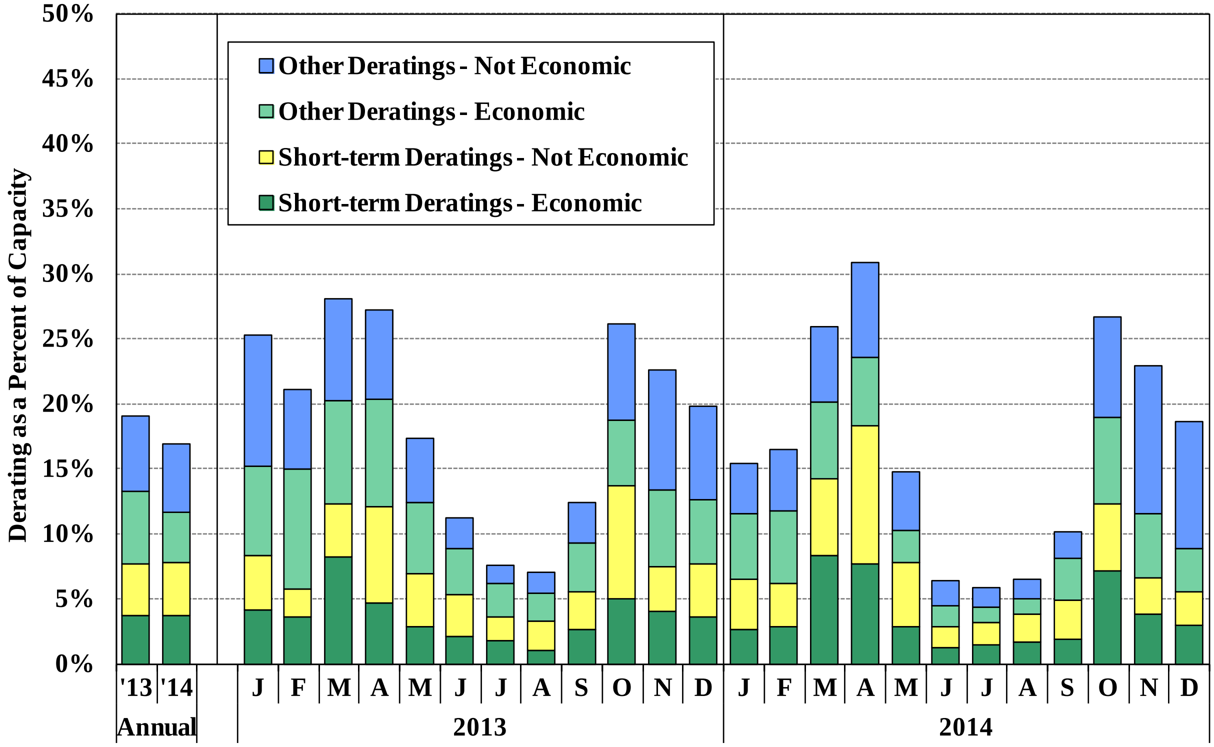


Figure A-32 & Figure A-33: Generator Deratings by Load Level and Portfolio Size

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 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.) 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-32 and Figure A-33 to determine whether the conduct is consistent with workable competition.

Figure A-32: Deratings by Supplier by Load Level in New York
2013 – 2014

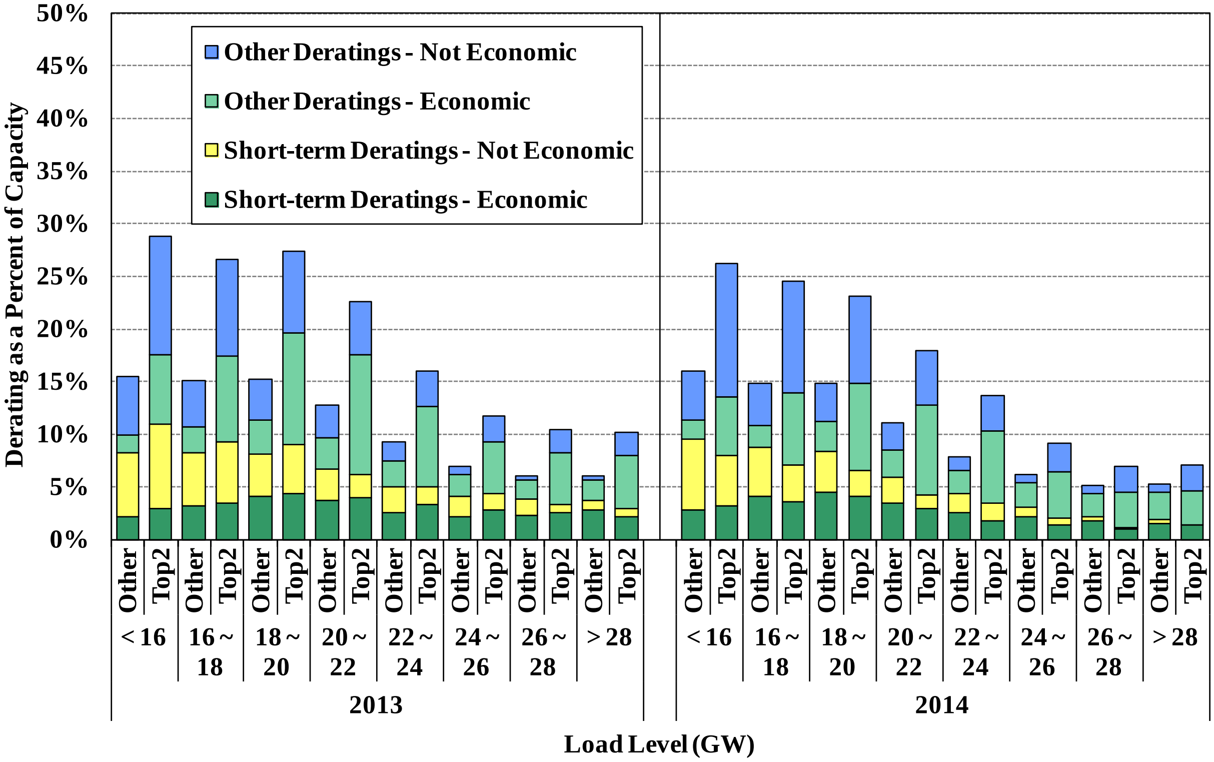
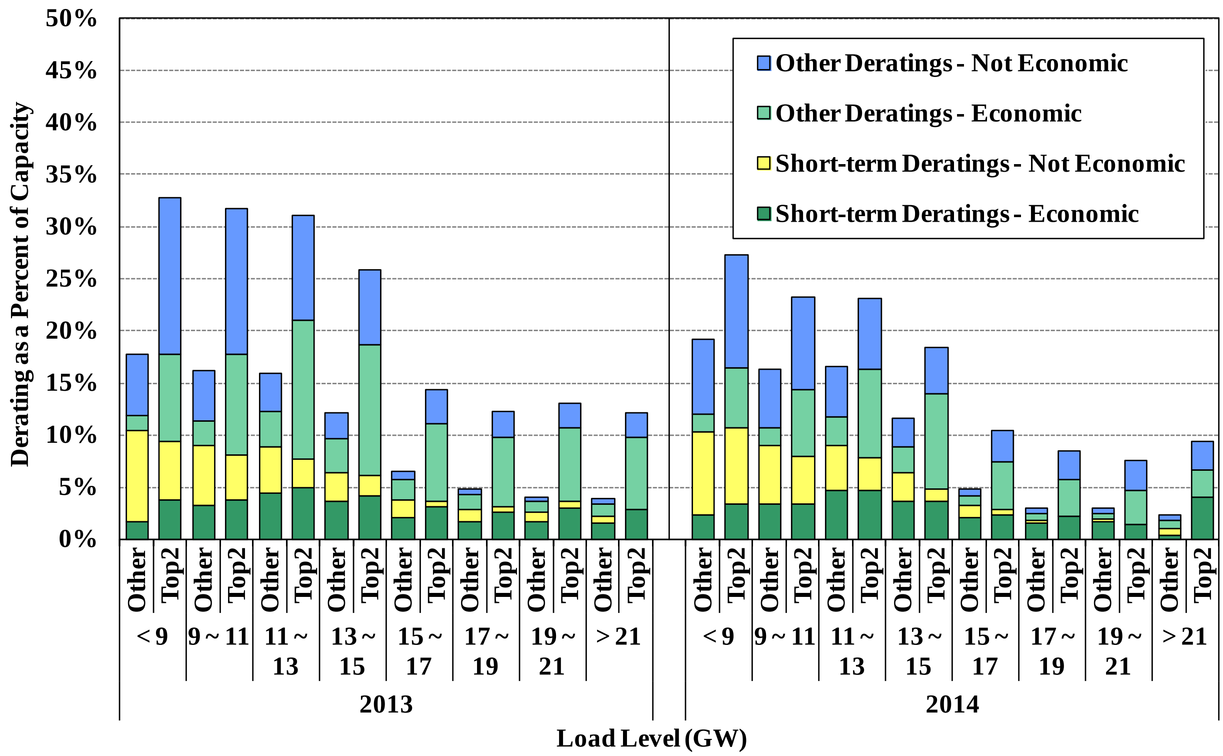


Figure A-33: Deratings by Supplier by Load Level in East New York
2013 – 2014



Key Observations: Generator Deratings

- The general pattern of deratings was reasonably consistent with expectations for a competitive market in both 2013 and 2014.
  - Average deratings were lowest during the summer months when average load was the highest, and deratings also fell during the coldest winter months (January and February). Average deratings were highest during the low-load shoulder months.
  - During the summer months (i.e., June to August) of 2014, total deratings were 6 to 7 percent of total DMNC and deratings of economic capacity constituted just 3 to 4 percent of total DMNC.
  - Higher levels of deratings outside the summer generally reflected planned outages for maintenance.
- The amount of short-term deratings was consistent with 2013, while long-term deratings fell moderately from 2013 to 2014.
  - The reduction in long-term deratings occurred primarily in the winter and summer peak seasons.
  - Some large suppliers improved their outage scheduling practices in 2014 and made more economic capacity available during peak conditions.
  - Peak market conditions were significantly tighter in January, February, and July 2013 than in previous years. This likely motivated suppliers to make more capacity available in 2014, particularly in January, February, and from June to August.
- Despite the improvement, the largest suppliers still exhibited higher levels of deratings of economic capacity than other suppliers. This was particularly true in Eastern New York, where:
  - During high load levels (i.e., load > 17 GW), 6 percent of the capacity of the largest two suppliers was economic and derated compared to just 2 percent for all other suppliers; and
  - During low to moderate load levels (i.e., load < 17 GW), 10 percent of the capacity of the largest two suppliers was economic and derated compared to just 5 percent for all other suppliers.
  - These differences between the top two suppliers and other suppliers are almost entirely accounted for by differences in long-term rather than short-term deratings of economic capacity. While higher deratings for the largest two suppliers are partly driven by different generator characteristics (e.g., age, prime mover, cogeneration use, etc.), they are partly attributable to different outage scheduling practices.
- 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 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 level, which is an estimate of marginal cost that is used for market power mitigation.[175, 176] An offer parameter is generally above the competitive level if it exceeds the reference level by a given threshold.

Figure A-34 and Figure A-35: 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 price.[177] 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 deratings, 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

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175 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 most 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.

176 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.

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

lower thresholds. The first additional threshold is the lower of $50 per MWh or 100 percent of a generator's reference level, and the second additional threshold is the lower of $25 per MWh or 50 percent of a generator's reference level. The two lower thresholds are included to assess whether there have been attempts to withhold by offering energy at prices inflated by less than the state-wide mitigation threshold.

Figure A-34: Output Gap by Month in New York State
2013 – 2014

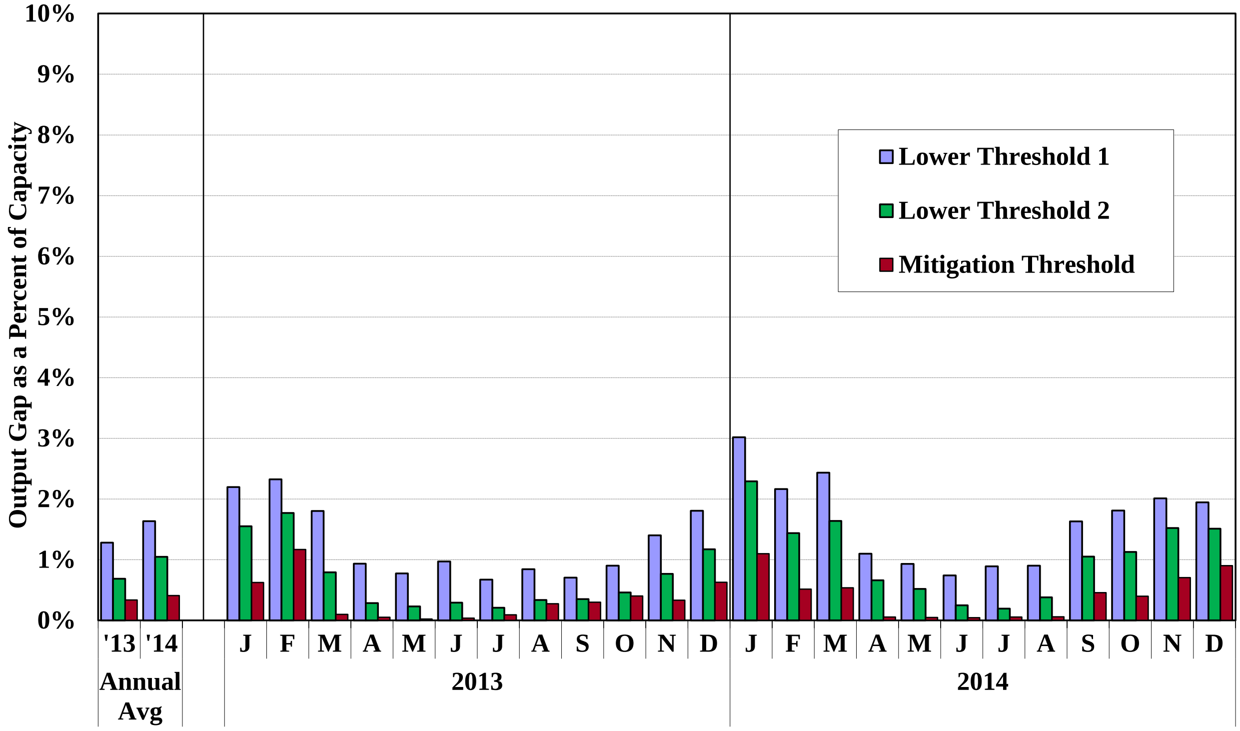


Figure A-35: Output Gap by Month in East New York
2013 - 2014

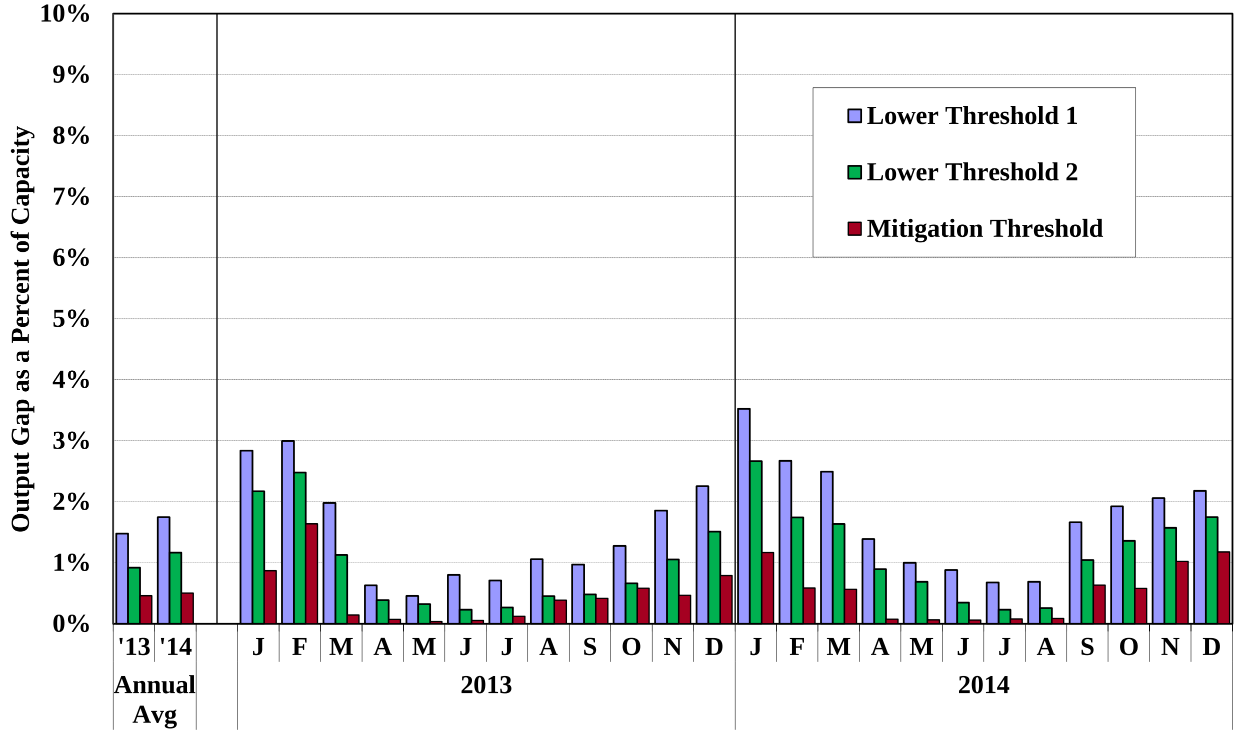


Figure A-36 & Figure A-37: Output Gap by Supplier and Load Level

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-36: Output Gap by Supplier by Load Level in New York State
2014

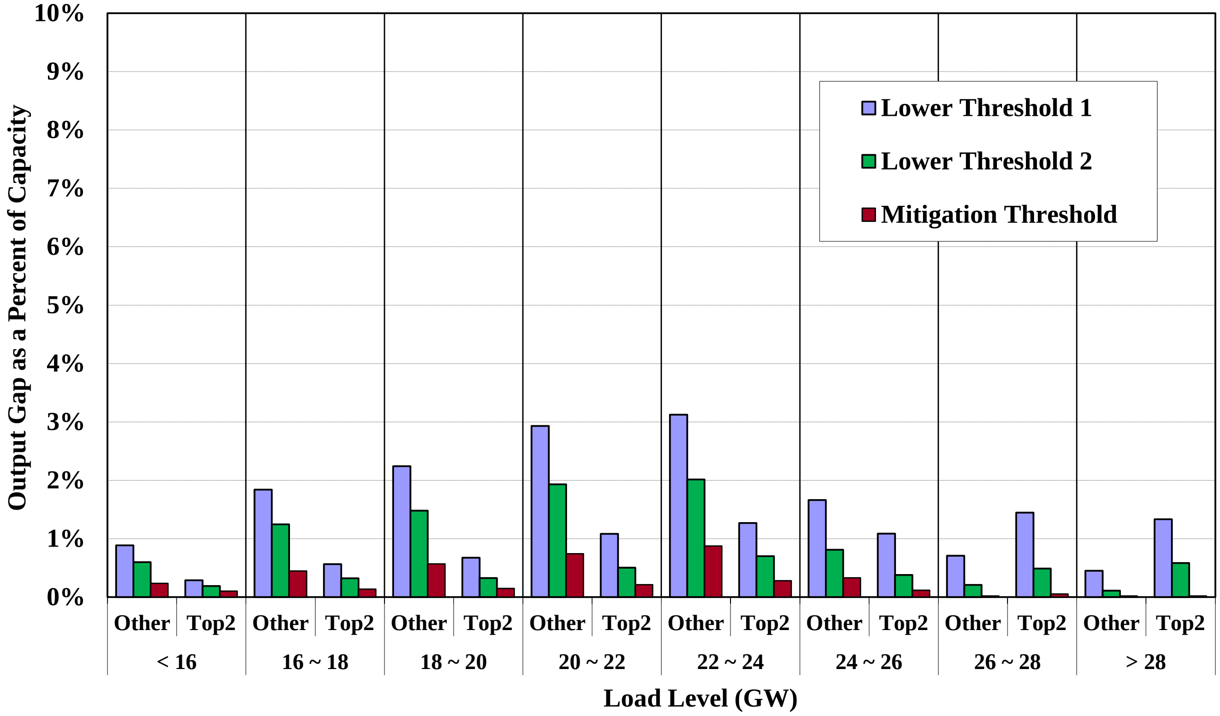
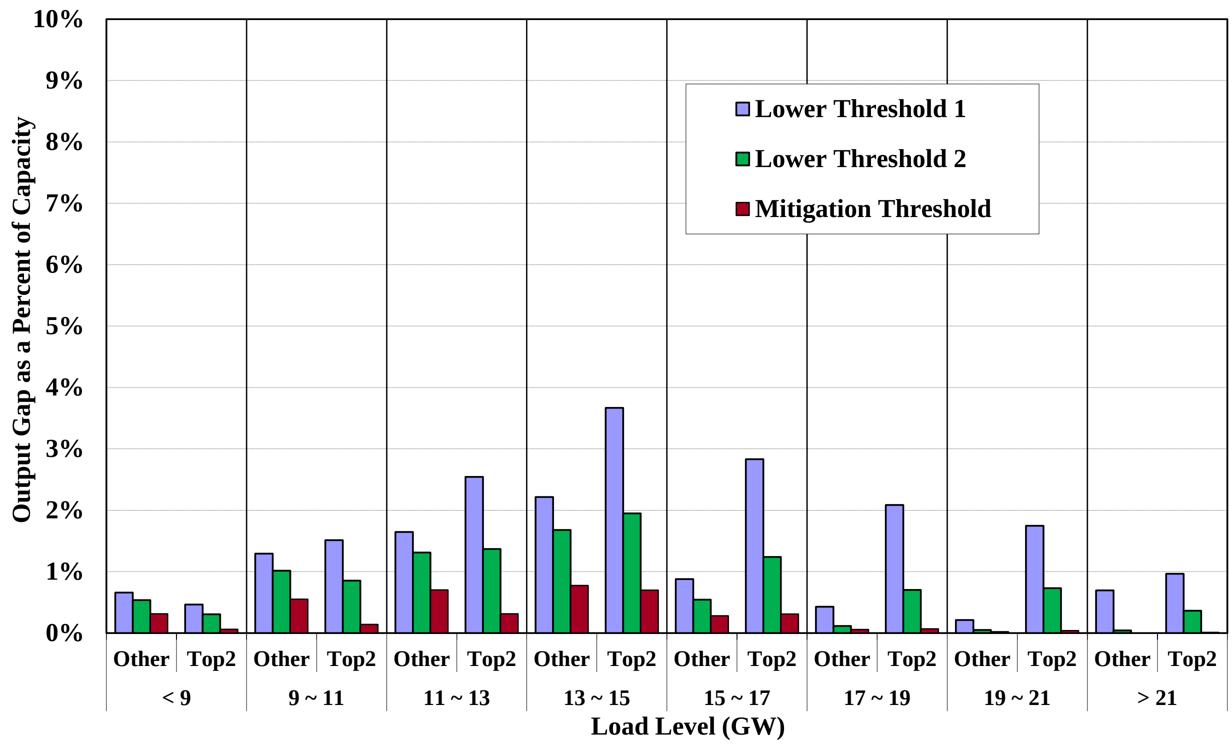


Figure A-37: Output Gap by Supplier by Load Level in East New York
2014



Key Observations: Economic Withholding – Generator Output Gap

- The amount of output gap averaged less than 1 percent of total capacity at the mitigation threshold and roughly 2 percent at the lowest threshold evaluated (i.e., $25/MWh or 50 percent) in 2014.

- Despite the modest increase from 2013, the overall pattern of output gap in 2014 was consistent with expectations in a competitive market and did not raise significant concerns regarding potential economic withholding.
  - The Capital Zone accounted for most of the increase from 2013.
  - Most of the output gap in 2014 occurred on units that are: (a) co-generation resources; and/or (b) owned by suppliers with small portfolios. 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.
  - In general, it is a positive indicator that the output gap generally declines as load increases for most suppliers and is low under high load conditions when the market is most vulnerable to the exercise of market power.

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.[178] 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

178 See NYISO Market Services Tariff, Sections 23.3.1.2 and 23.3.2.1.

preceding twelve-month period.[179] 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 reliability criteria outside New York City.[180] 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.[181]

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.[182] 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.[183]
- 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.

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179 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.

180 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.

181 See NYISO Market Services Tariff, Section 23.3.1.2.3.

182 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.

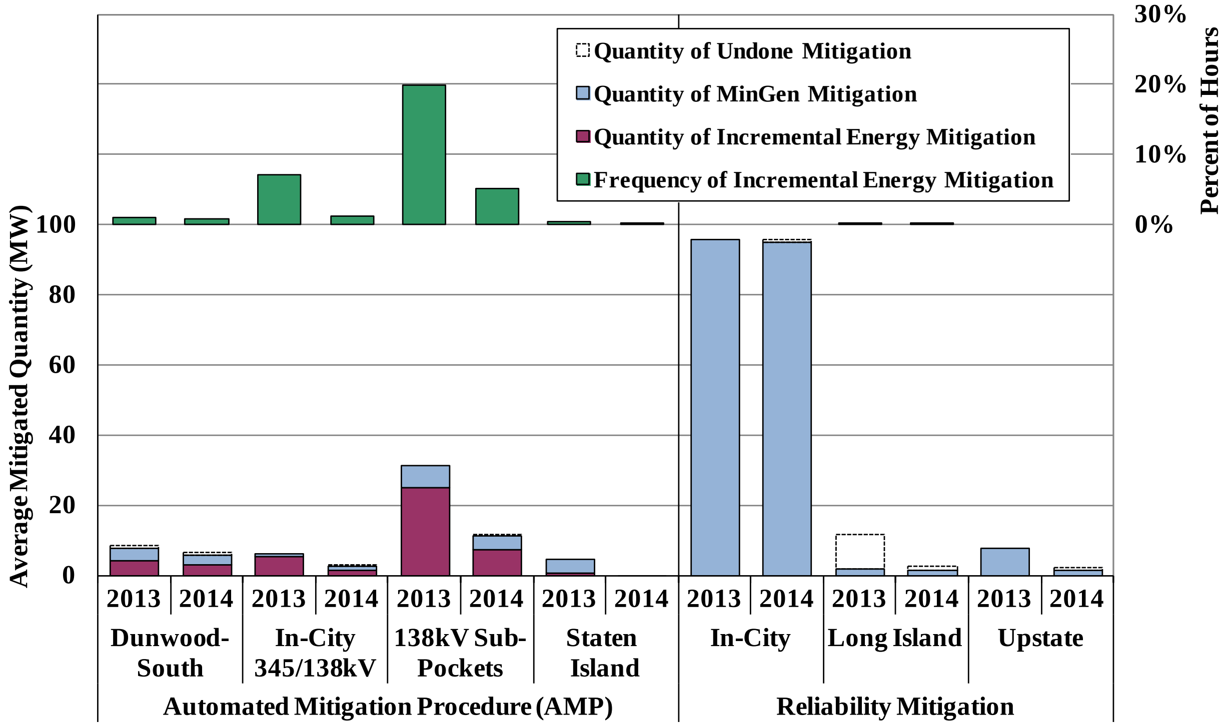
183 The hierarchy of information that is used to calculate reference levels is provided in NYISO Market Services Tariff, Section 23.1.4. It is possible for a generator to have a bid-based or LBMP-based reference level that is less accurate than the reference level determined through consultation.

Figure A-38 & Figure A-39: Summary of Day-Ahead and Real-Time Mitigation

Figure A-38 and Figure A-39 summarize the amount of mitigation in New York that occurred in the day-ahead and the real-time markets in 2013 and 2014. These figures do not include guarantee payment mitigation that occurs in the settlement system.

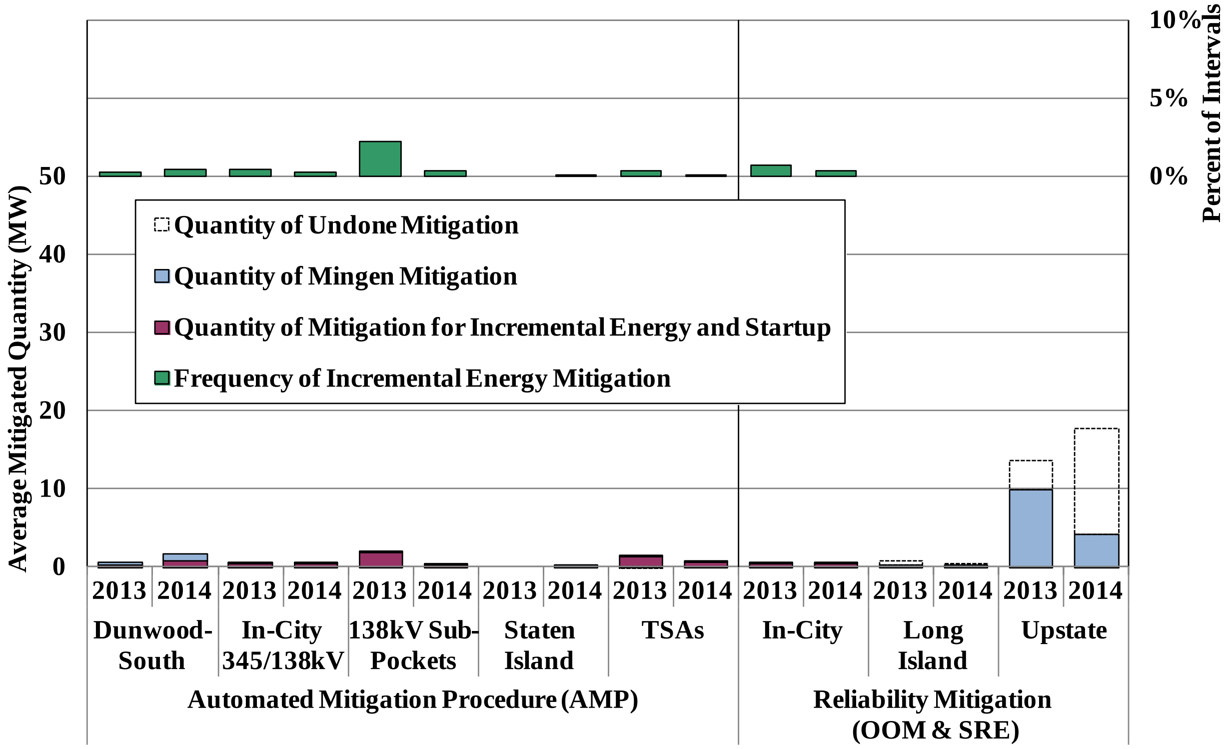
The bars in the upper panel of the figures indicate the percent of hours when incremental energy offer mitigation was imposed on one or more units in each category, while the bars in the lower panel indicate the average amount of capacity mitigated in hours when mitigation occurred (as well as the portion 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. MinGen).[184] 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-38: Summary of Day-Ahead Mitigation
2013 - 2014



184 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-39: Summary of Real-Time Mitigation
2013 - 2014



Key Observations: Day-ahead and Real-time Mitigation

- The majority of mitigation occurred in the day-ahead market.
  - In 2014, 88 percent of all AMP mitigation occurred in the day-ahead market, over 50 percent of which was for generators in the 138kV load pockets.
  - Local reliability (i.e., DARU and LRR) units accounted for more than 80 percent of all day-ahead mitigation,
  - 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.
- The amount of AMP mitigation fell substantially in recent years.
  - The hourly average MW that was AMP-mitigated fell from over 250 MW in 2011 to just 25 MW in 2014.
  - 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 2014, contributing to further reductions in New York City congestion and associated AMP-mitigation in 2014.

- Unmitigation of generators was relatively uncommon in 2013 and 2014.

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-40 to Figure A-43: Summary of Ancillary Services Offers

The following four figures compare the ancillary services offers for generators in the day-ahead market for 2013 and 2014 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, and
- Regulation.

Offer quantities are shown according to offer price level for each category. Offers for the four ancillary services products from all hours are included in this evaluation.

Figure A-40: Summary of West 10-Minute Spinning Reserves Offers
Day-Ahead Market, 2013-2014

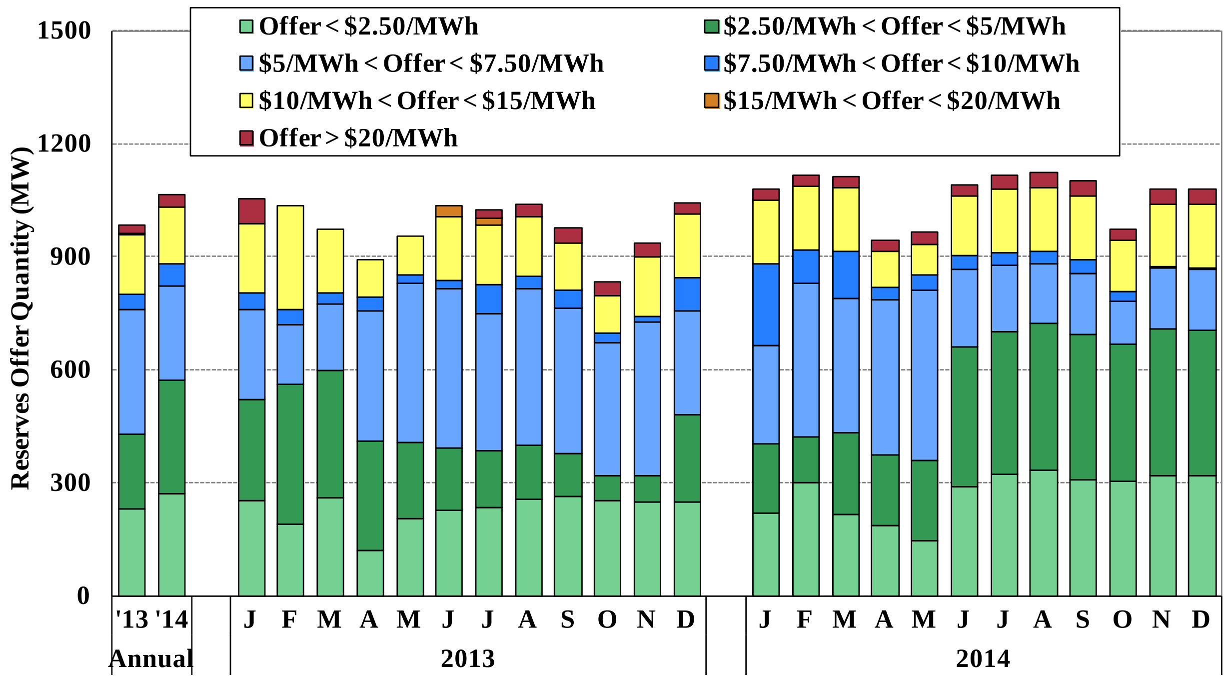


Figure A-41: Summary of East 10-Minute Spinning Reserves Offers
Day-Ahead Market, 2013-2014

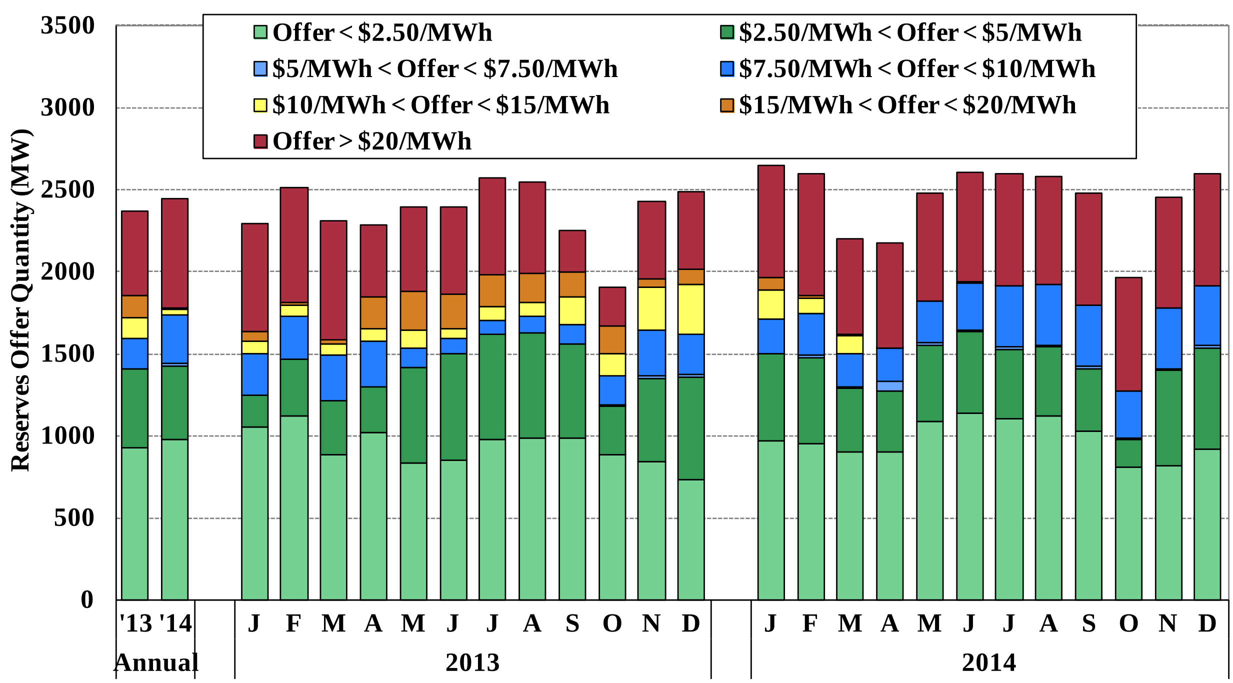


Figure A-42: Summary of East 10-Minute Non-Spin Reserves Offers
Day-Ahead Market, 2013-2014

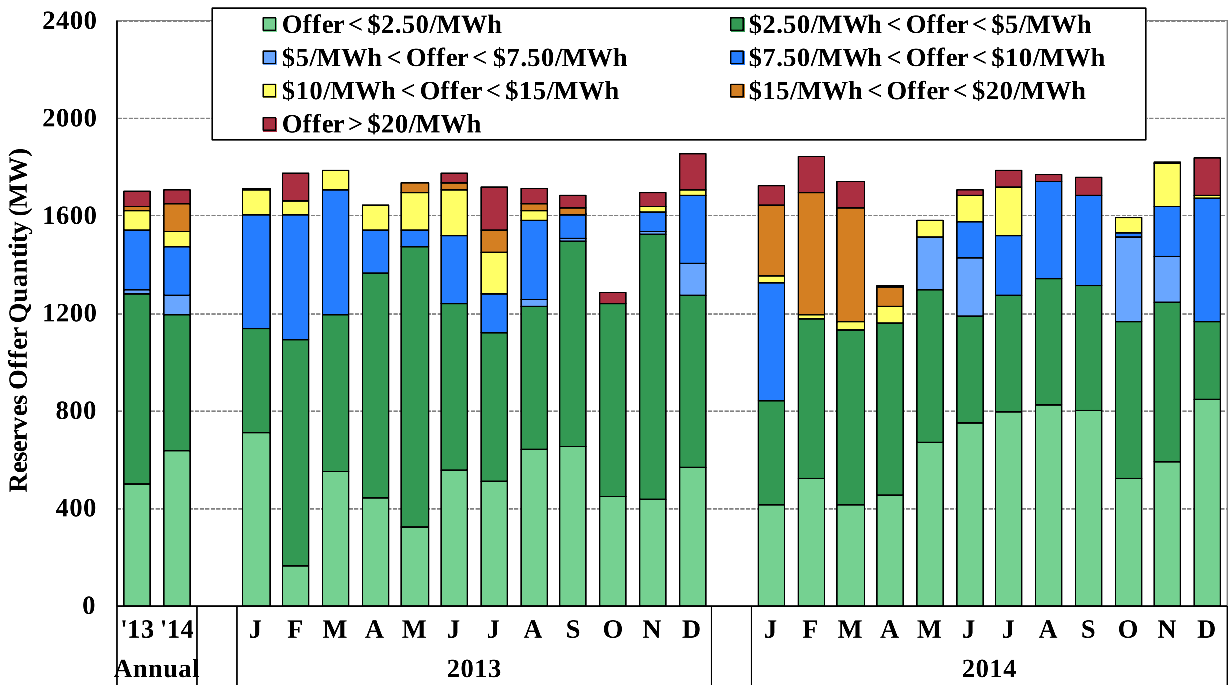
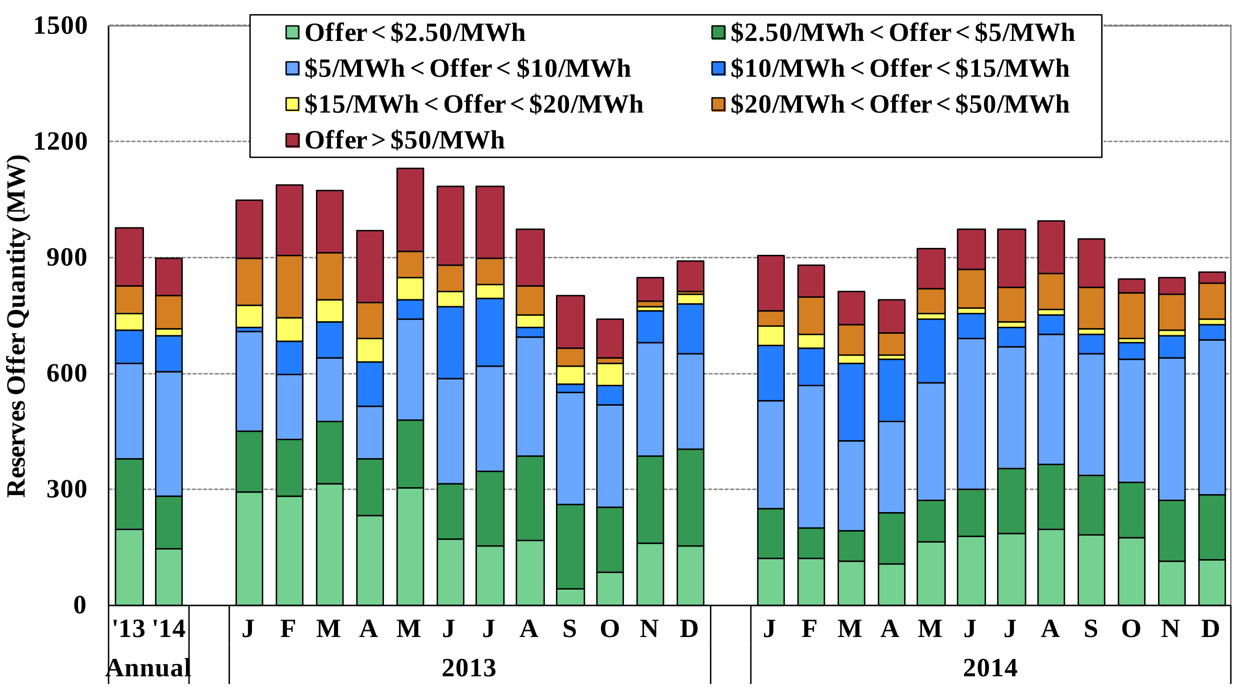


Figure A-43: Summary of Regulation Capacity Offers
Day-Ahead Market, 2013-2014



Key Observations: Ancillary Services Offers

- The amount of ancillary services offers from all four categories exhibited typical seasonal variations:
  - 10-minute spinning 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.
  - 10-minute non-spinning reserves offer quantities were lower in the summer than in the winter. This pattern is consistent with the effects of ambient temperature variations on the capability of gas turbines, which provide the majority of non-spinning reserves in Eastern New York.
- Since the phased revisions of two day-ahead mitigation provisions, we have not found offer patterns that raise withholding concerns in the reserves markets.
  - The average amounts of offers for 10-minute spinning and non-spin reserves actually rose modestly from 2013 to 2014, which was due partly to increased supply in the winter and summer months because less capacity was unavailable because of deratings and outages.
  - The average prices of offers were relatively consistent between 2013 and 2014 despite higher average energy prices in 2014.
  - However, suppliers did increase 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 2014 when gas prices were highly volatile).
    - Such increases are consistent with competitive behavior and generally help improve convergence between day-ahead and real-time prices.
- The total amount of 10-minute spinning and non-spinning reserve capacity offered in Eastern New York (> 4 GW on average) far exceeds the 10-minute operating reserve requirement in Eastern New York (1.2 GW), which contributes to the competitiveness of the markets for these products.

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.[185]
- *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-44 to Figure A-50: 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

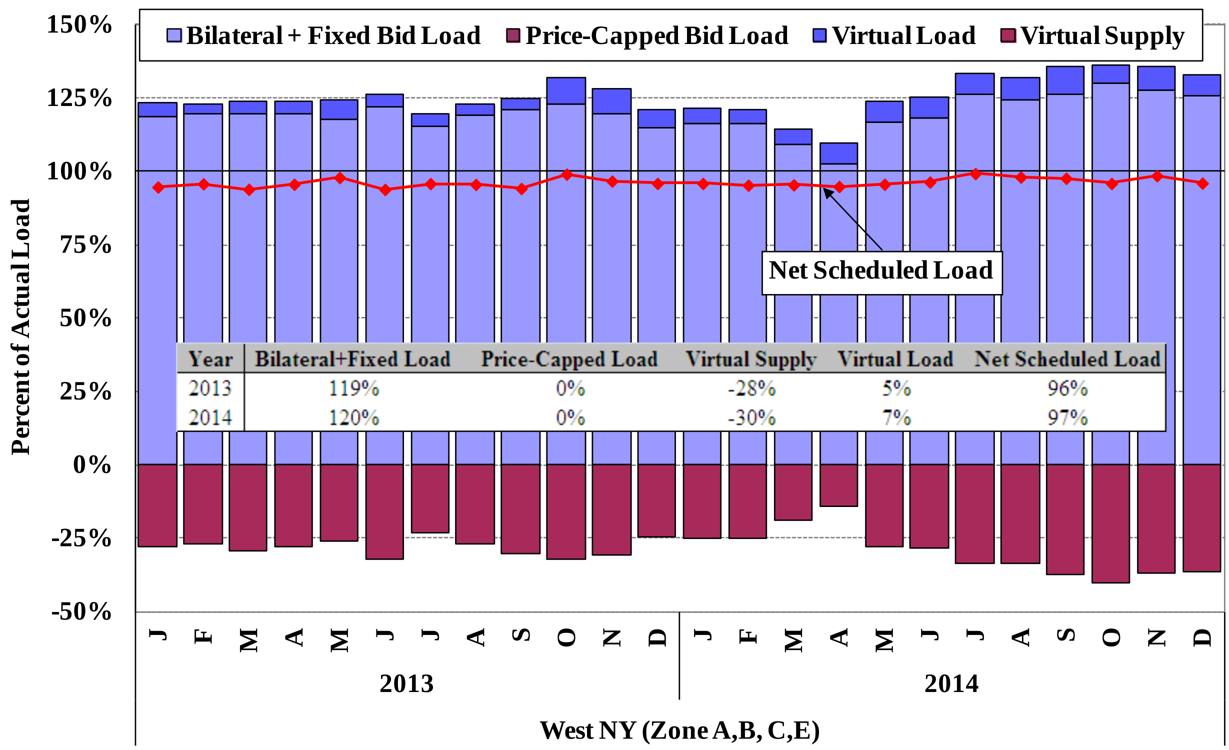
185 For example, a LSE may make a price-capped bid for 500 MW at $60 per MWh. If the day-ahead clearing price at its location is above $60, the bid would not be accepted in the day-ahead market.

above real-time prices. Thus, market participants have incentives to schedule amounts of load consistent with real-time load.

The following seven figures show day-ahead load schedules and bids as a percent of real-time load during 2013 and 2014 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 2013 to 2014. Virtual imports and exports are shown for NYCA only and are not shown for any of the sub-areas in New York.

Figure A-44: Day-Ahead Load Schedules versus Actual Load in West New York

Zones A, B, C, & E, 2013 – 2014



Year	Bilateral+Fixed Load	Price-Capped Load	Virtual Supply	Virtual Load	Net Scheduled Load
2013	119%	0%	-28%	5%	96%
2014	120%	0%	-30%	7%	97%

Figure A-45: Day-Ahead Load Schedules versus Actual Load in North Zone
Zone D, 2013 – 2014

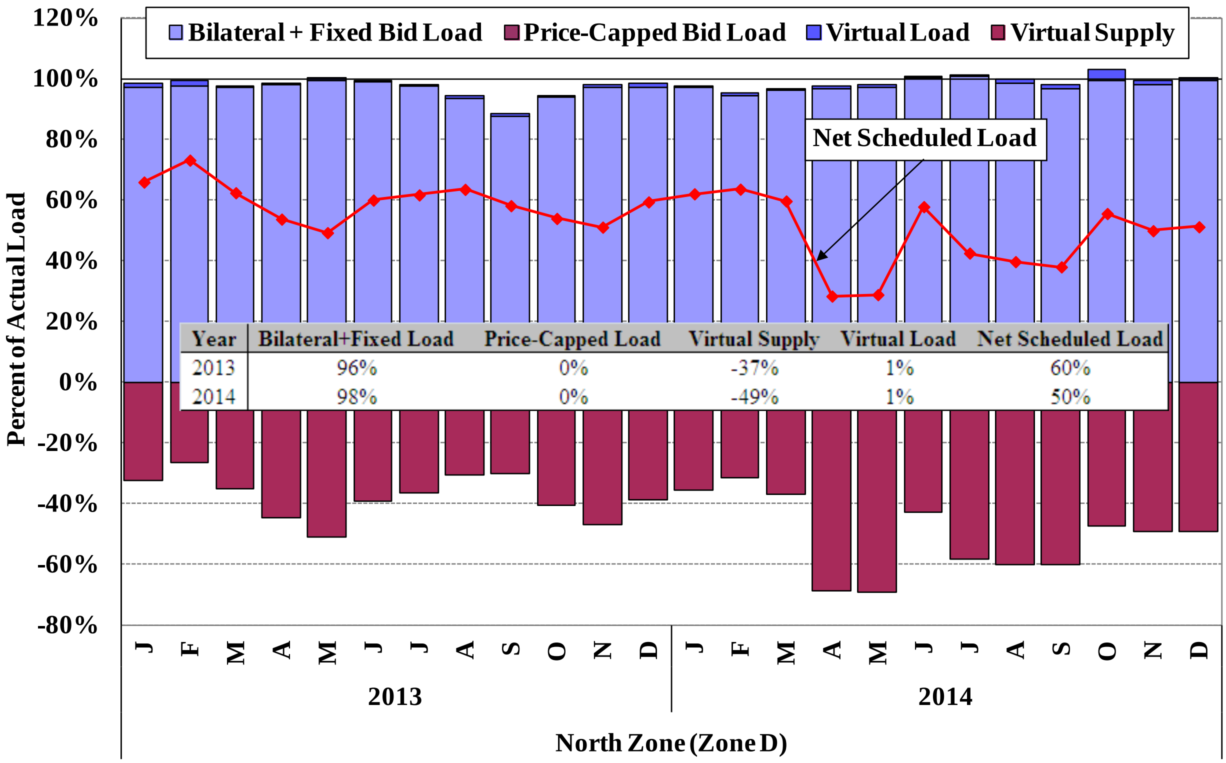


Figure A-46: Day-Ahead Load Schedules versus Actual Load in Capital Zone
Zone F, 2013 – 2014

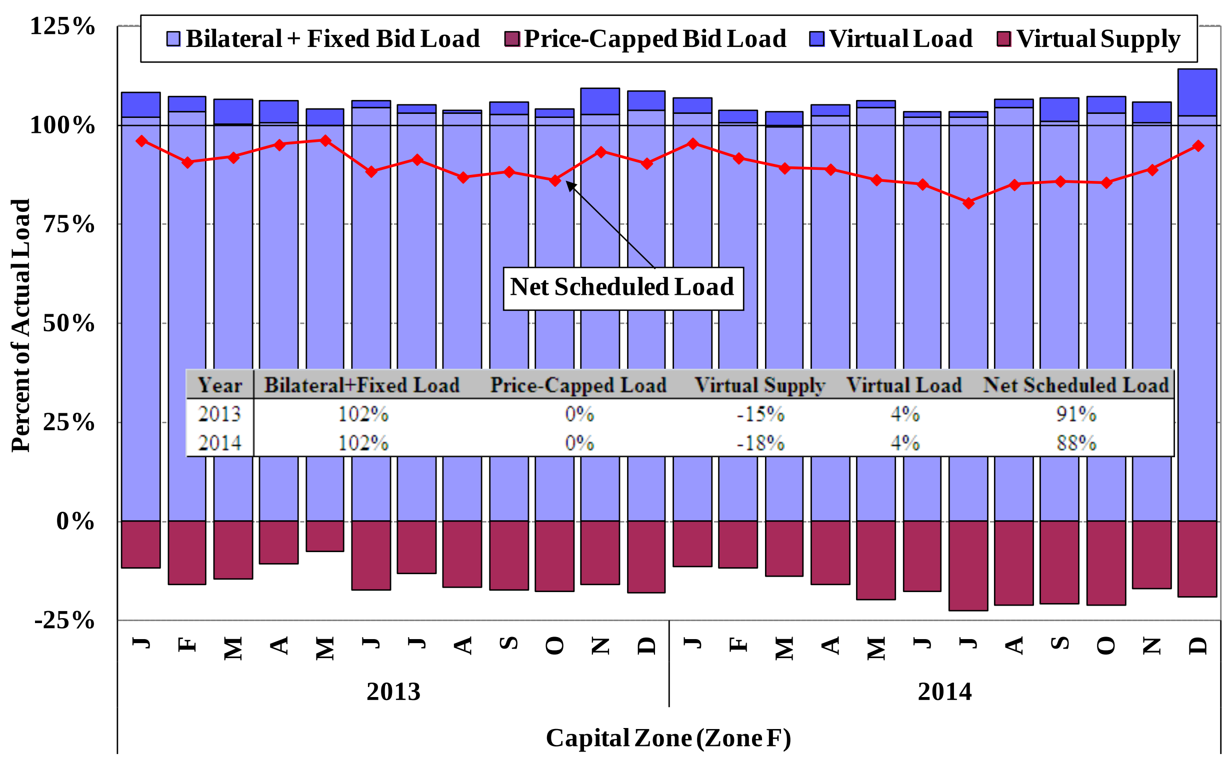
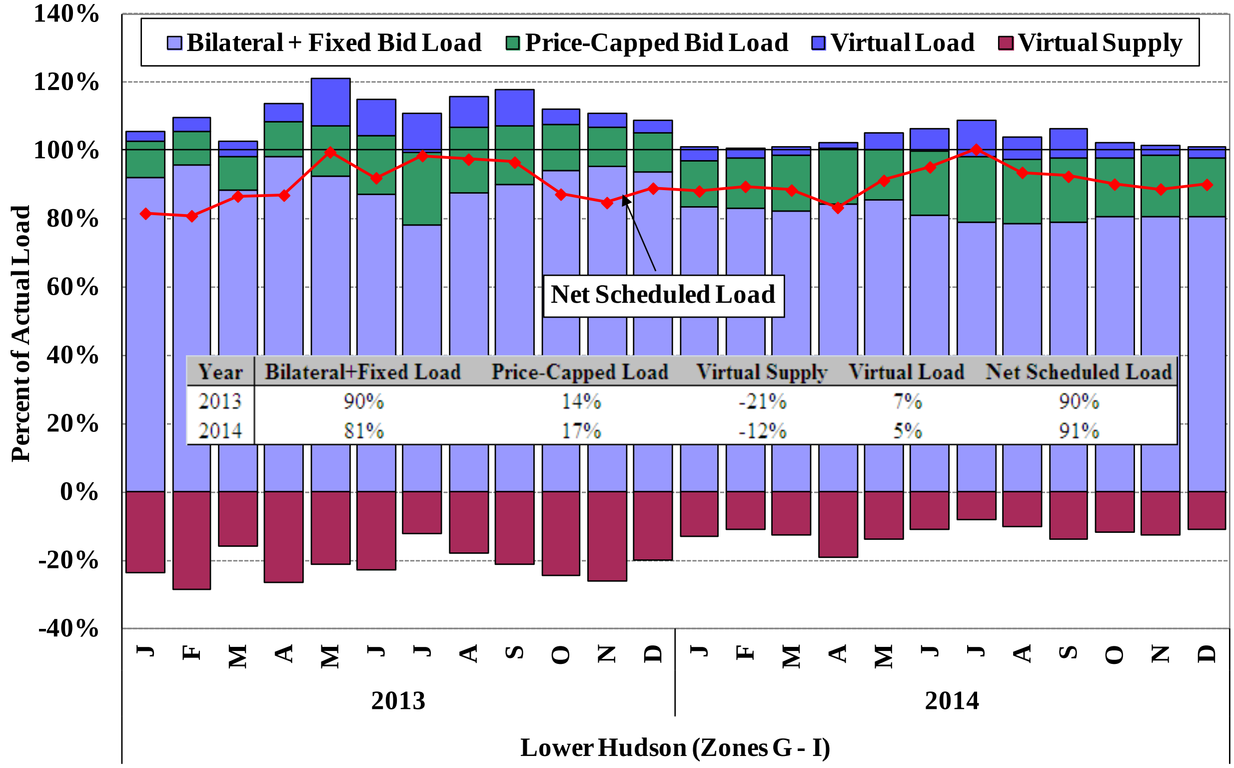


Figure A-47: Day-Ahead Load Schedules versus Actual Load in the Lower Hudson Valley

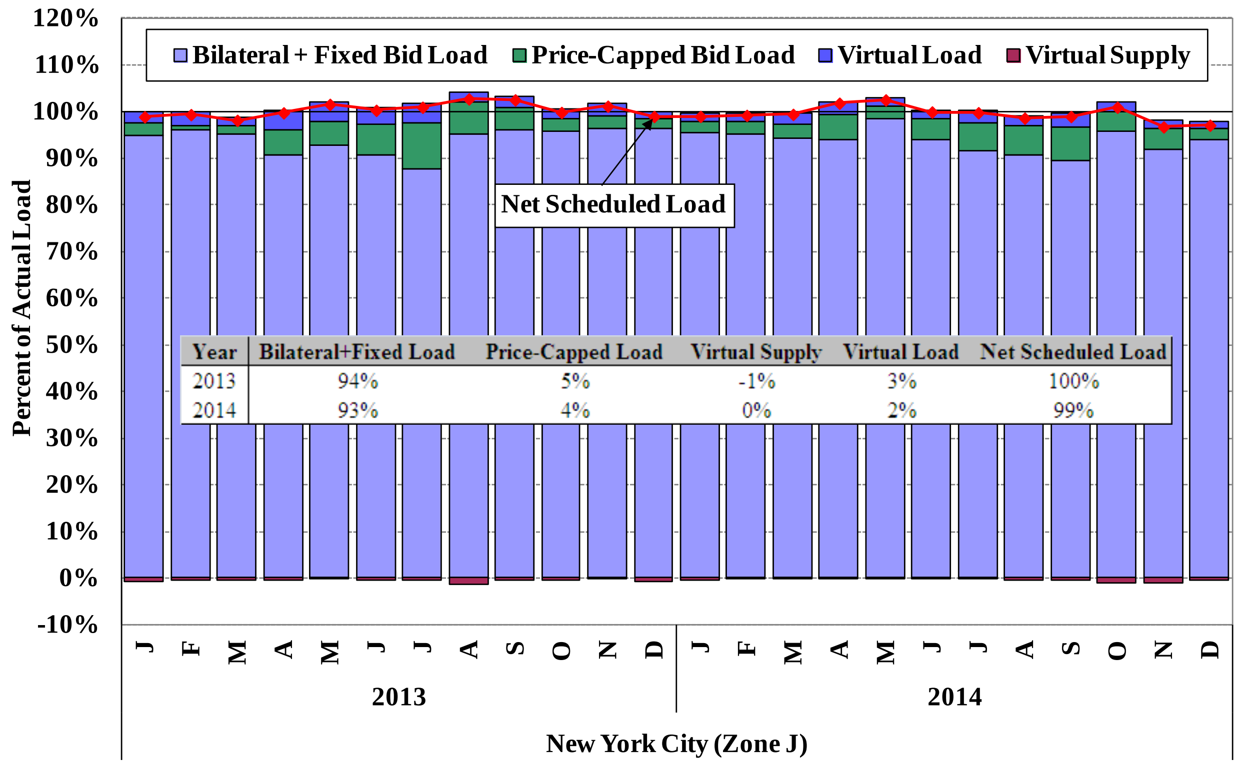
Zones G, H, & I, 2013 – 2014



Year	Bilateral+Fixed Load	Price-Capped Load	Virtual Supply	Virtual Load	Net Scheduled Load
2013	90%	14%	-21%	7%	90%
2014	81%	17%	-12%	5%	91%

Figure A-48: Day-Ahead Load Schedules versus Actual Load in New York City

Zone J, 2013 – 2014



Year	Bilateral+Fixed Load	Price-Capped Load	Virtual Supply	Virtual Load	Net Scheduled Load
2013	94%	5%	-1%	3%	100%
2014	93%	4%	0%	2%	99%

Figure A-49: Day-Ahead Load Schedules versus Actual Load in Long Island
Zone K, 2013 – 2014

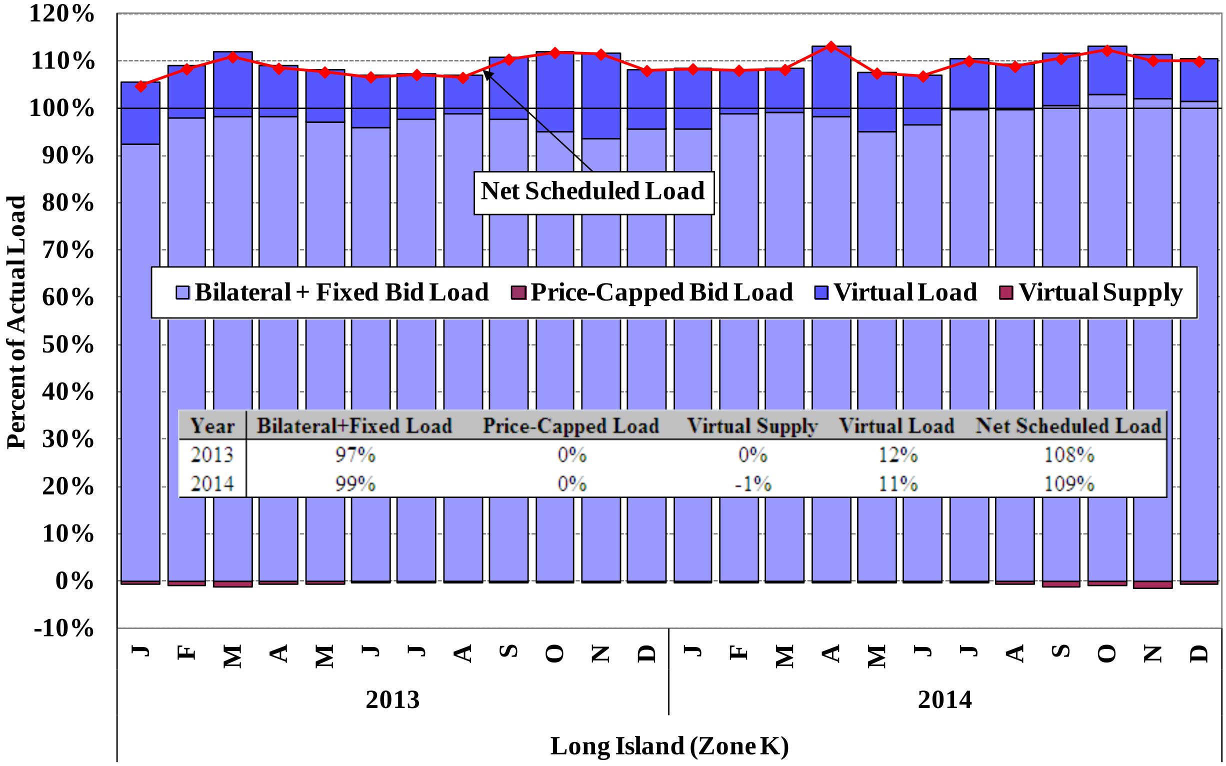
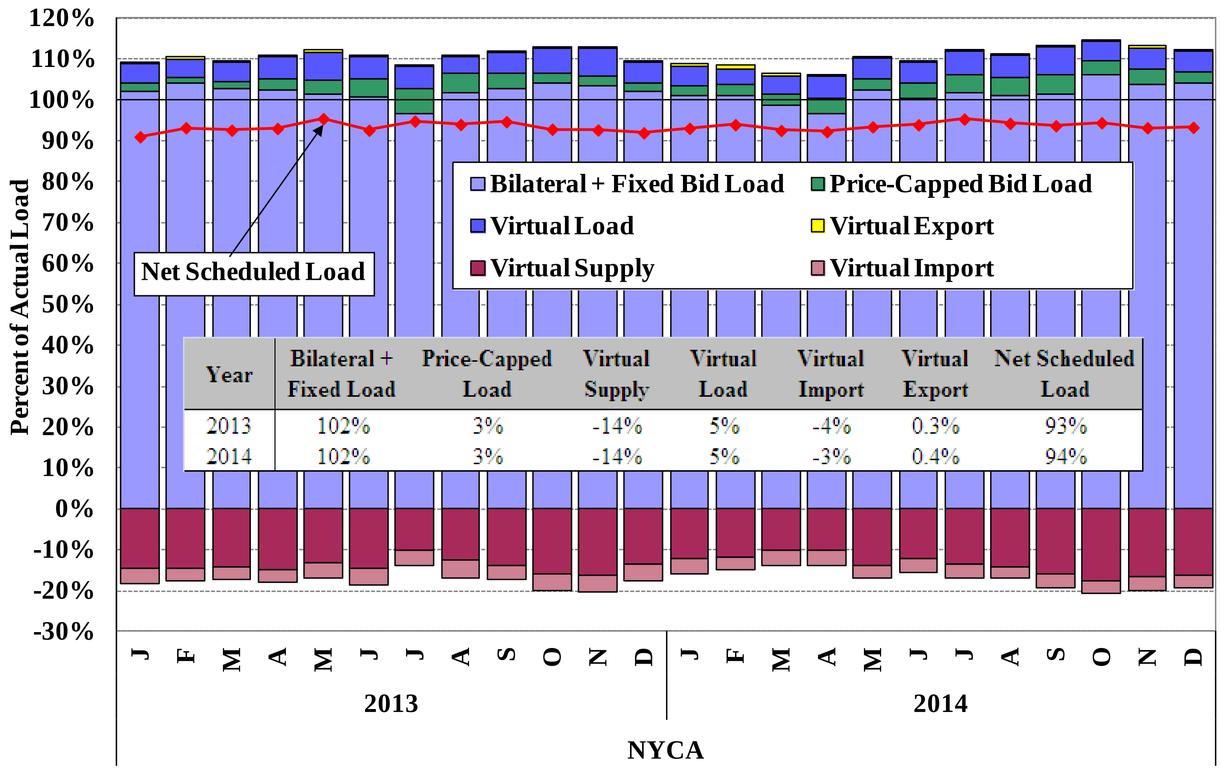


Figure A-50: Day-Ahead Load Schedules versus Actual Load in NYCA
2013 – 2014



Key Observations: Day-ahead Load Scheduling

- Overall, load in the day-ahead market was scheduled at roughly 94 percent of actual load in NYCA in 2014, up slightly from 2013.
  - Scheduling pattern in each of the sub-regions was generally consistent between 2013 and 2014 as well.
- Average load scheduling tends to be higher in locations 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 and Long Island than the rest of New York because congestion was typically more prevalent in the downstate areas.
  - This was particularly true for Long Island, which had the highest congestion among all areas, therefore was consistently over-scheduled.
- Pattern of load scheduling in some areas has changed in recent years.
  - The historic pattern of over-scheduling in Southeast New York (i.e., Lower Hudson Valley, New York City, and Long Island) was less clearly evident in 2013 and 2014.
  - The amount of scheduling fell to roughly 90 percent in Lower Hudson Valley and below 100 percent in New York City.
  - This reduction likely resulted from less frequent periods of acute real-time congestion into Southeast New York and into and within New York City (for the reasons discussed in Section III).
  - Although under-scheduling was still prevalent outside Southeast New York, load scheduling in West Upstate rose from prior years.
  - Although not shown separately, the net scheduled load in the West Zone averaged 110 percent of actual load in 2014. This reflected increased congestion on the 230kV system in the West Zone compared to prior years, which is discussed further in Section III.
  - 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.

  - Wind and other renewable generation typically rose in real-time above their day-ahead schedules.
  - In 2014, this added an average of 520 MW of additional energy supply in real-time, satisfying roughly 8 percent of the average real-time load outside Southeast New York.
- The patterns of day-ahead scheduling generally improved convergence between day-ahead and real-time prices.
  - In 2014, all regions exhibited day-ahead premiums, which also suggests that further under-scheduling in most 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.

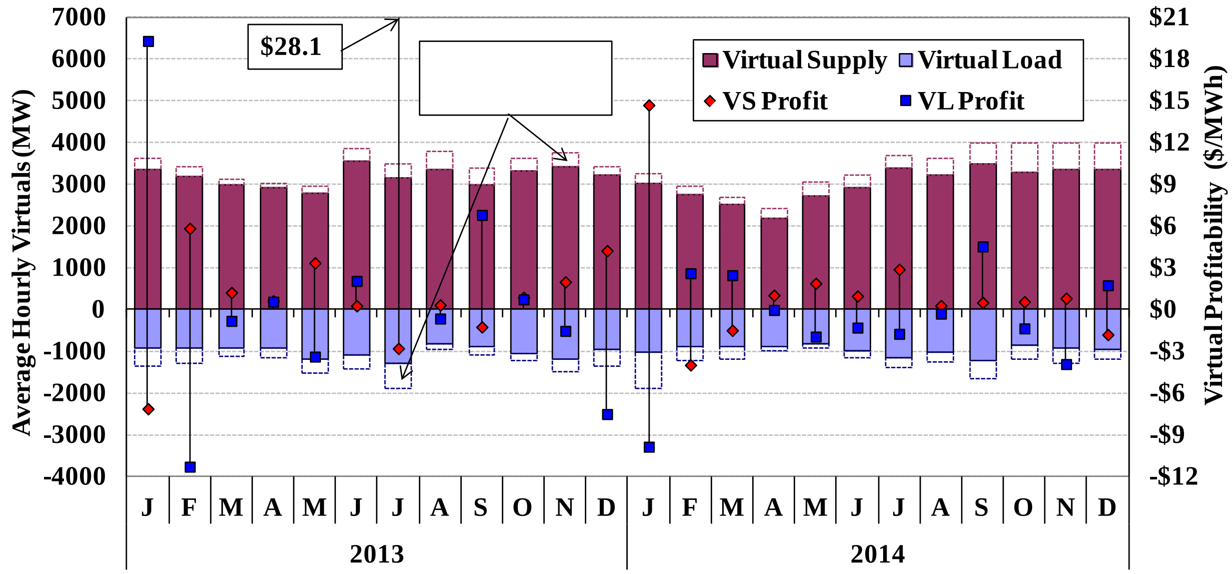
Market participants can schedule virtual-type transactions at the external proxy buses, which are referred to as *Virtual Imports* and *Virtual Exports* in this report. These types of external transactions act the same way as the virtual bids placed at the load zones (i.e., the imports and exports that 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-51: Virtual Trading Volumes and Profitability

Figure A-51 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.[186, 187]

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.

Figure A-51: Virtual Trading Volumes and Profitability
2013 - 2014



		J	F	M	A	M	J	J	A	S	O	N	D	J	F	M	A	M	J	J	A	S	O	N	D
Profit > 50% of Avg. Zone Price	MW	462	481	210	220	422	295	465	187	217	269	553	417	739	348	345	116	217	187	524	159	333	587	433	380
	%	11%	12%	5%	6%	11%	6%	10%	4%	6%	6%	12%	10%	18%	10%	10%	4%	6%	5%	11%	4%	7%	14%	10%	9%
Loss > 50% of Avg. Zone Price	MW	472	405	149	183	302	196	313	206	220	234	422	310	532	432	351	107	229	234	395	212	333	508	455	370
	%	11%	10%	4%	5%	8%	4%	7%	5%	6%	5%	9%	7%	13%	12%	10%	3%	6%	6%	9%	5%	7%	12%	11%	9%

Figure A-52: Virtual Trading Activity

Figure A-52 below summarizes virtual trading by geographic region. The eleven zones in New York are broken into six geographic regions based on typical congestion patterns. 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

186 The gross profitability shown here does not account for any other related costs or charges to virtual traders.

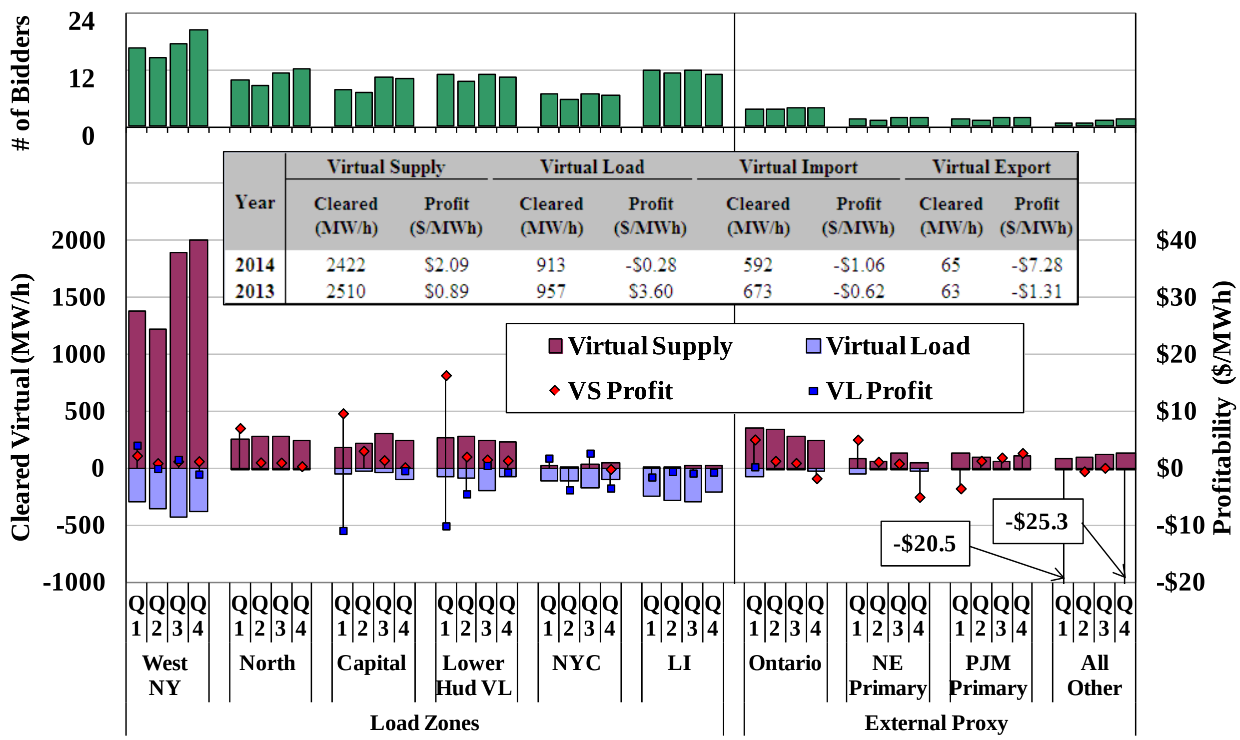
187 The calculation of the gross profitability for virtual imports and exports does not account for the profit (or loss) related to price differences between day-ahead and real-time in the neighboring markets.

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 2014. 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 2014 and 2013.

Figure A-52: Virtual Trading Activity[188]

by Region by Quarter, 2014



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)
2014	2422	$2.09	913	-$0.28	592	-$1.06	65	-$7.28
2013	2510	$0.89	957	$3.60	673	-$0.62	63	-$1.31

Key Observations: Analysis of Virtual Trading

- A large number of market participants regularly submitted virtual bids and offers in 2014. On average:
  - 27 participants submitted virtual trades at the internal load zones; and
  - 8 participants submitted virtual imports and exports at the proxy buses.

188 Profits or losses are not shown for a category if the average scheduled quantity is less than 50 MW.

- The overall pattern of virtual trades did not change much from 2013 to 2014.
  - Nonetheless, scheduled virtual supply in Western New York fell in the first and second quarter of 2014, coinciding with decreased bilateral load scheduling in Western New York during the same period. (Some firms make bilateral load purchases and use virtual supply to sell energy in the day-ahead market.)
- Most of the virtual imports and exports were submitted at three proxy buses: the primary PJM proxy bus, the primary NE proxy bus, and the Ontario proxy bus.
  - Ninety percent of all virtual imports/exports were virtual imports in 2014.
  - The three proxy buses where virtual imports are common are primarily interconnected with the regions outside Southeast New York. These virtual imports are consistent with the prevalence of virtual supply scheduled in these regions.
  - 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 from Figure A-51 and so they account for a large share of the losses reported for virtual imports and exports in Figure A-52, particularly for the "All Other" interface category.
- In aggregate, virtual traders netted approximately $33 million of gross profits in 2014, down 28 percent from 2013.
  - Virtual supply and virtual imports netted a gross profit of $39 million, reflecting prevalent day-ahead price premiums in most regions during 2014.
  - 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 January 7, 2014, virtual supply netted a loss of $8 million and virtual load netted a profit of $10 million because of a unit trip and gas constraints (including a Force Majeure event on the Texas Eastern pipeline in Pennsylvania), which led to substantially elevated real-time prices in most regions.
- Only small quantities of virtual transactions generated substantial losses in 2014, 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 2014

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.[189]

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.[190] 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.[191] 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-53: Congestion Revenue Collections and Shortfalls

Figure A-53 shows day-ahead congestion revenue and the two classes of congestion shortfalls in each month of 2013 and 2014. 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.

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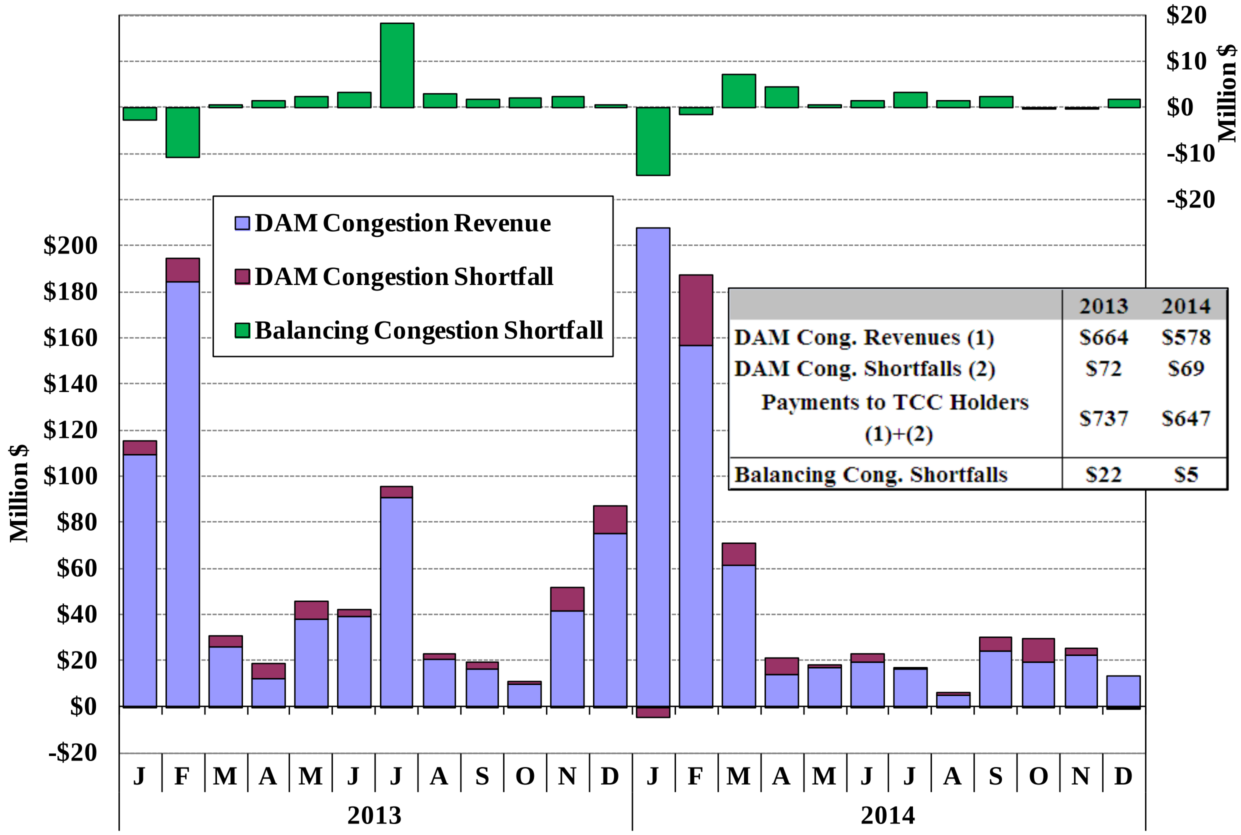
189 The shadow price of a transmission constraint represents the marginal value to the system of one MW of transfer capability. For example, if 100 MW is scheduled to flow across a constrained line with a shadow price of $50/MWh in a particular hour in the day-ahead market, the NYISO collects $5,000 in that hour (100 MW * $50/MWh).

190 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).

191 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-53: Congestion Revenue Collections and Shortfalls
2013-2014



	2013	2014
DAM Cong. Revenues (1)	$664	$578
DAM Cong. Shortfalls (2)	$72	$69
Payments to TCC Holders (1)+(2)	$737	$647
Balancing Cong. Shortfalls	$22	$5

Key Observations: Summary of Congestion Revenues and Shortfalls

- Day-ahead congestion revenues totaled roughly $578 million in 2014, down 13 percent (or $86 million) from 2013.
  - Variations in natural gas prices, gas price spreads between areas, and load levels (particularly during winter and summer peaking conditions) were the primary drivers of changes in congestion over the period.
- Congestion typically rose during periods of higher natural gas prices and larger gas price spreads between Western New York and Eastern New York.
  - These factors led to: a).increased flows and congestion from Western New York to Eastern New York (where gas is the primary input fuel), and b) higher redispatch costs for gas-fired units in Eastern New York that were used to manage congestion.
  - In 2014, 74 percent of total day-ahead congestion revenues accrued during the period from January through March when average natural gas prices in Eastern New York were three to four times higher than in the rest of the year.
  - Significant changes were observed from 2013 to 2014:

- For the months of January to March, day-ahead congestion value increased by more than 30 percent from the previous year as average natural gas prices rose 31 percent in Western New York and 83 to 185 percent in Eastern New York.
- For the months of April to December, day-ahead congestion value fell by more than 40 percent as average natural gas prices fell 25 percent from the previous year.

- Congestion also 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.
  - The 2013/14 Winter was one of the coldest winter in recent years, setting a new winter peak of 25,738 MW in January 2014.
  - The 2013 Summer experienced unusual heat waves and set an all-time peak of 33,956 MW in July 2013.
  - Thunderstorms occurred much more frequently on hot summer days, causing transmission interfaces to be derated and leading to acute congestion into Southeast New York.
- Congestion levels were also affected by other factors (e.g., transmission and generation outages), which are discussed for major transmission facilities in subsection B.
- Day-ahead and balancing congestion shortfalls totaled $74 million in 2014, down 21 percent from 2013.
  - Congestion shortfalls tend to rise and fall in proportion to overall congestion revenues.
  - 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 past two years.

In the day-ahead market, the NYISO schedules generation and load based on the bids and offers submitted by market participants. The transmission network allows generation in one area to serve load in another area, so the assumptions that the NYISO makes about the status of each transmission facility determine the amount of power that can be scheduled between regions in the day-ahead market. 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-54 - Figure A-56: Day-Ahead and Real-Time Congestion by Path

Figure A-54 to Figure A-56 show the value and frequency of congestion along major transmission lines in the day-ahead and real-time market. Figure A-54 compares these quantities in 2013 and 2014 on an annual basis, while Figure A-55 and Figure A-56 show the quantities separately for each quarter of 2014.

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.[192]

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 to Central: Lines in the West Zone that flow power from west-to-east and interfaces from the West Zone to the Central Zone.
- Central to East: Primarily the Central-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 – 345 kV system: Lines leading into and within the New York City 345 kV system.
- NYC Lines – Load Pockets: Lines leading into and within New York City load pockets.

192 The shadow price of a transmission constraint represents the marginal value to the system of one MW of transfer capability.

- NYC Simplified Interface Constraints: 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.

Figure A-54: Day-Ahead and Real-Time Congestion by Transmission Path
2013 – 2014

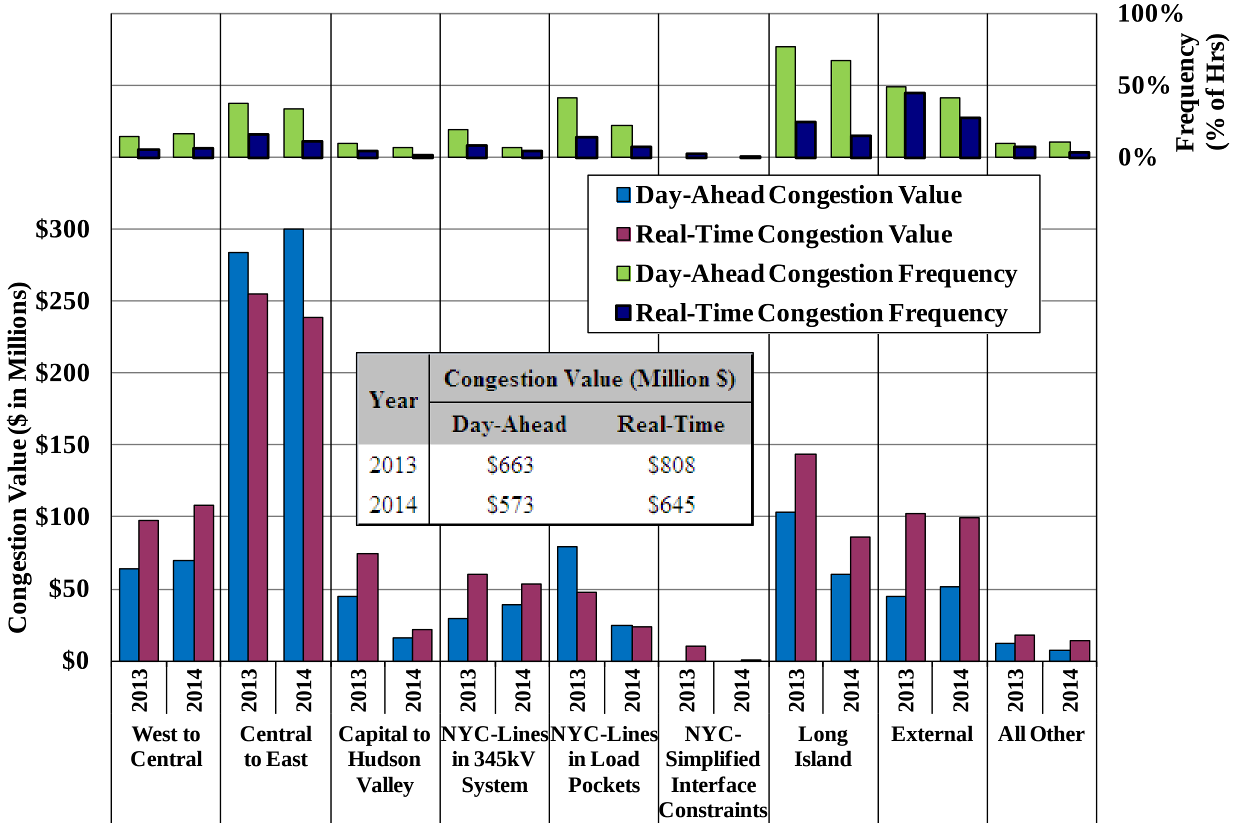


Figure A-55: Day-Ahead Congestion by Transmission Path
By Quarter, 2014

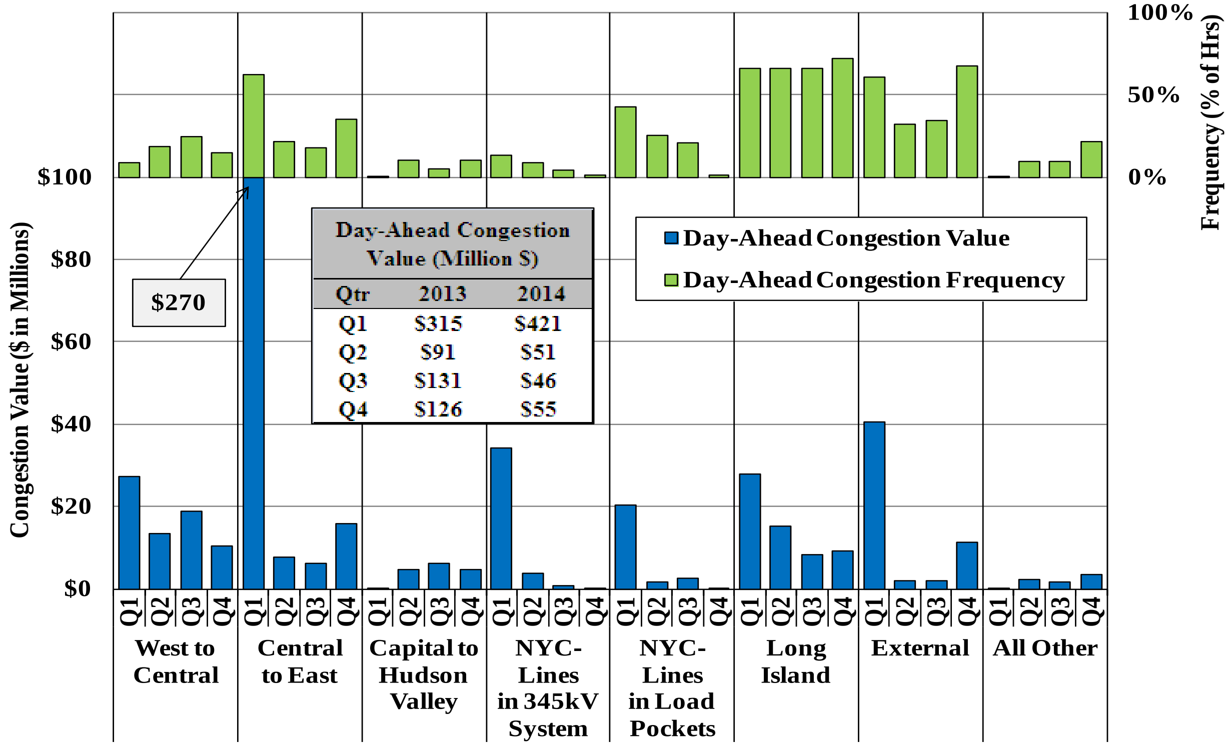
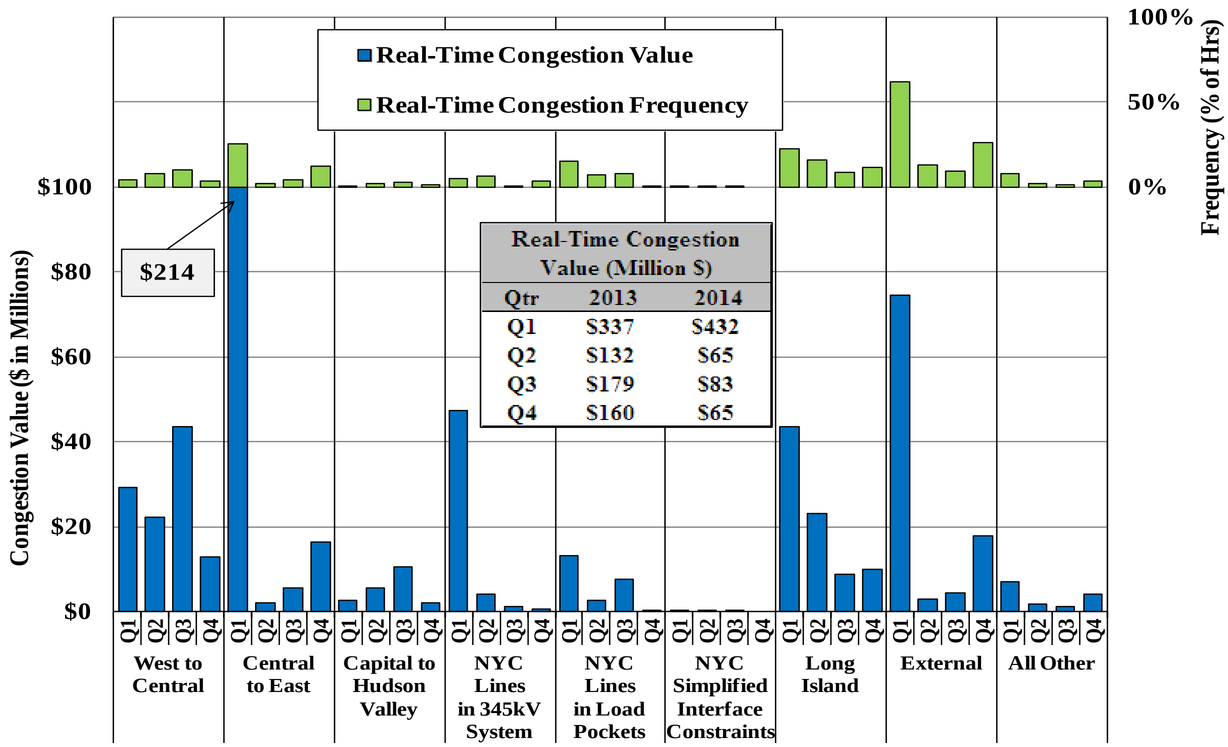


Figure A-56: Real-Time Congestion by Transmission Path
By Quarter, 2014



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 value of congestion in the real-time market, which tends to be more episodic.

- Overall, congestion occurred less frequently in 2014 than in 2013 on most transmission paths. From 2013 to 2014, total congestion value fell by roughly 15 percent in the day-ahead and real-time markets.

  - Total congestion value increased more than 30 percent in the first quarter of 2014 but fell 50 to 60 percent in the remaining three quarters of 2014 for the reasons discussed in subsection A.

- Congestion across the Central-East interface accounted for the largest share of congestion value in both day-ahead and real-time markets in 2013 and 2014.

  - In 2014, the Central-East interface accounted for more than 50 percent of congestion value in the day-ahead market and nearly 40 percent in the real-time market.

  - As explained above, the majority of this congestion occurred in the first quarter of 2014 when natural gas prices and gas price spreads between Western and Eastern New York were significantly elevated.

- Real-time congestion on external interfaces increased notably in the last two years.

  - Nearly 50 percent in 2013 and more than 60 percent in 2014 was associated with the primary New England interface in the winter months as exports to New England were often fully scheduled on days when natural gas prices in New England were substantially higher than in New York.

- Congestion on 230kV lines in the West Zone rose modestly from 2013 to 2014 despite reduced congestion on most other transmission facilities. .

  - Most of this congestion occurred along the Niagara-Packard 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.

  - Congestion increased in June and September of 2014 when several planned transmission outages reduced transfer limits on in-service lines and several generating units that are effective in managing congestion were out of service.

  - Congestion also rose mid-year when hydro production in the West Zone increased, imports from Ontario increased, and exports to PJM increased.

  - Congestion in the West Zone was generally more severe in the real-time market than in the day-ahead market 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 (see Figure A-87).

- Congestion in Southeast New York fell the most from 2013 to 2014. In addition to the variations of natural gas prices and load levels discussed above,
  - The reduction in Long Island was also attributable to:
  - Increased Neptune imports (since it fully returned after July 2013);
  - Increased import capability from upstate New York because of fewer days with transmission outages into Long Island; and
  - Long Island generating capacity being utilized more efficiently than in 2013.
  - The reduction into Southeast New York was partly because:
  - TSAs were declared almost 50 percent less often than in the prior summer because of milder weather conditions; and
  - The impact of TSAs was also reduced by lower load levels, lower gas prices, the return to full capability of the Ramapo line, and enhancements in the M2M process that now allow the Ramapo line to relieve TSA congestion.

C. Day-Ahead and Balancing Congestion Shortfalls by Path or Constraint

Congestion Shortfalls generally occur when inconsistencies arise between the 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. 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 2013 and 2014. Positive values indicate shortfalls, while negative values indicate surpluses. The shortfalls are shown for the following paths or types of constraints:

- 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.
- 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).
- New York City Lines: Lines leading into and within New York City
- Long Island Lines: Lines leading into and within Long Island.
- Ramapo PARs: The two PAR controlled lines between Hopatcong in New Jersey and Ramapo in New York.
- 901/903 PARs: The two PAR controlled lines between Lake Success and Valley Stream in Long Island and Jamaica in New York City.
- External: Congestion related to the total transmission limits or ramp limits of the external interfaces.
- All Others: All other types of constraints collectively.

Figure A-57: Day-Ahead Congestion Shortfalls
2013 – 2014

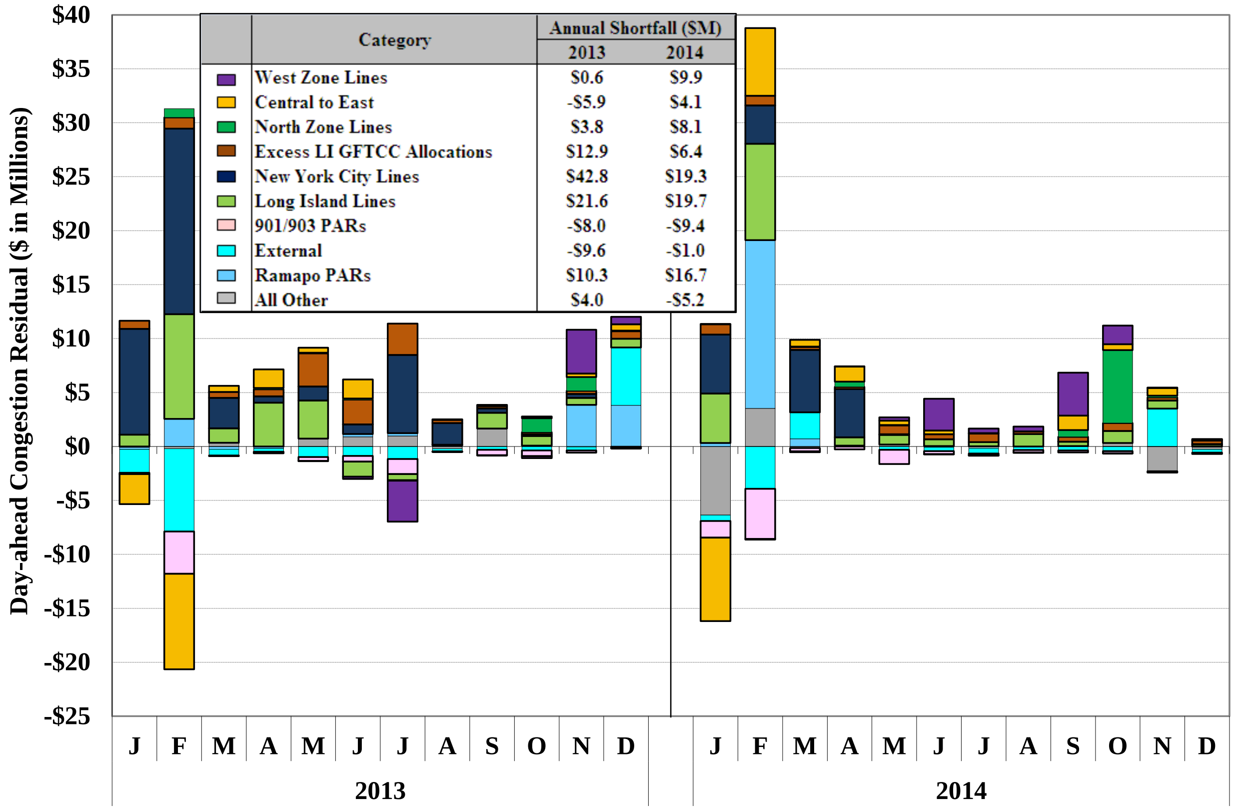


Figure A-58: Balancing Congestion Revenue Shortfalls

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.

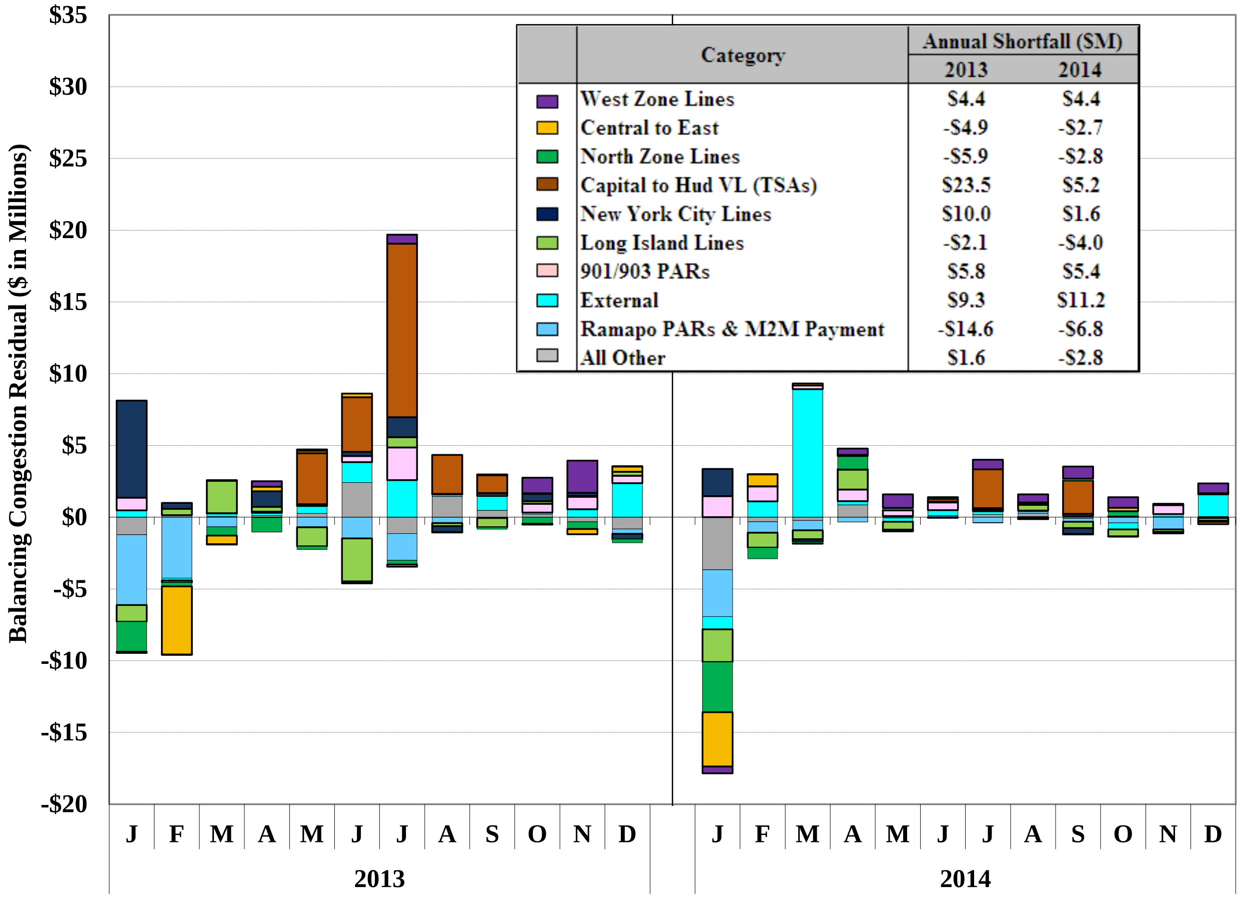
- PAR Controlled Line Flows – The flows across PAR-controlled lines are adjusted in real-time operations, which can result in flows that are very different from the day-ahead assumptions. These differences can affect the flows across multiple interfaces. This includes flow adjustments on PAR-controlled 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.

Figure A-58 shows balancing congestion shortfalls by transmission path or facility in each month of 2013 and 2014. Positive values indicate shortfalls, while negative values indicate surpluses.

Figure A-58: Balancing Congestion Shortfalls[193]
2013 – 2014



Key Observations: Congestion Shortfalls

Day-Ahead Congestion Shortfalls

- The majority of day-ahead congestion shortfalls in 2013 and 2014 were associated with transmission outages.
  - Outage-related shortfalls are allocated to the responsible Transmission Owners.
- In 2014, the following transmission outages accounted for the majority of day-ahead congestion shortfalls.

193 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 (e.g., the Scarcity Pricing Adjustment on July 15 to 19 of 2013 had the effect of increasing the actual shortfalls by roughly $1.5 million above what is shown in the figure).

  - In New York City ($19 million):
    - Multiple transmission outages from January to March reduced transfer capacity into the 345 kV system and in the Greenwood load pocket ($15 million).
    - Transmission outages in the Gowanus-Goethals area from early April to early May caused reduced transfer capability in the Freshkills sub-pocket ($4 million).
  - On Long Island ($20 million):
    - The vast majority of shortfalls accrued when transmission outages from upstate to Long Island reduced import capacity into Long Island in early January, during the entire month of February, during most of August, and from late October to early November.
  - Across the Ramapo PAR-controlled lines ($17 million):
    - The two Ramapo PARs were out of service from February 7 to 23, which led to substantial reductions in PJM imports and higher internal flows from west to east and contributed a $17 million shortfall on the Central-East interface.
  - In the West Zone ($10 million):
    - Several facilities around the Niagara 115 kV bus were out of service in late May to mid June, in mid to late September, and from October to December. One of the transmission lines at the Niagara 345 kV bus was out of service in mid to late October. These led to transmission bottlenecks on 230kV lines in the West Zone.
  - In the North Zone ($8 million):
    - One 765 kV transmission line was out of service during most of October, greatly reducing the transfer capability on the Moses-South 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. [194]
  - This resulted in $13 million of shortfalls in 2013 and $6 million of shortfalls in 2014.
- 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.
  - 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. Since flows from Long Island to New York City across these lines are

194 This is categorized as “Excess LI GFTCC Allocations” in the figure.

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 $8 million in 2013 and $9 million in 2014.

Balancing Congestion Shortfalls

- Balancing congestion shortfalls fell roughly 70 percent from 2013 to 2014.
  - This was primarily because of the reduction in TSA-related shortfalls, which decreased from $23 million in 2013 to just $5 million in 2014 (for reasons discussed in subsection B).
- External interfaces accounted for the largest share of shortfalls ($11 million) in 2014, most of which accrued on several days in March when the primary NY-NE interface was frequently derated in real-time because of transmission outages in New England.
- A net $14 million of surplus accrued in January as a result of changes in generation patterns after the day-ahead market on several peak days during the month.
  - Most notably, January 7 accounted for nearly half of the total surplus, driven by changes in generation patterns after a unit in Eastern New York tripped and tight conditions in PJM reduced imports by 1500 MW after the day-ahead market.
  - When the transmission system is operated efficiently, balancing congestion surpluses are to be expected as a result of changes in generation and load patterns between the day-ahead and real-time markets.
- 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 shortfall by $6 million in 2013 and $5 million in 2014.
- The operation of Ramapo PARs under the M2M JOA with PJM has provided significant benefit to the NYISO in managing congestion and reducing balancing congestion shortfalls.

- Combined with M2M settlements between PJM and the NYISO, this reduced shortfalls by $15 million in 2013 and $7 million in 2014. [195]

D. 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 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.[196] 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 in the month that precedes the 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 Path Type

Figure A-59 summarizes TCC cost and profit for the Winter 2013/14 and Summer 2014 Capability Periods (i.e., the 12-month period from November 2013 through October 2014). 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 lower portion of the figure shows the TCC costs and profits for each round of auction in the 12-month period, which includes: (a) Four rounds of one-year auctions for the exact same 12-month Capability Period; (b) Four rounds of six-month auctions for the Winter 2013/14 Capability Period; (c) Four rounds of six-month auctions for the Summer 2014 Capability Period; and (d) Twelve reconfiguration auctions for each month of the 12-month Capability

[195] To the extent that the PAR-controlled lines between New Jersey and New York flowed less than the Ramapo Target MW value, NYISO received a net settlement from PJM (i.e., M2M payment).

[196] 2-year TCCs were first sold in the Autumn 2011 auctions for the period from November 2011 to October 2013.

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 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.[197] The figure shows the costs and profits separately for the intra-zone and inter-zone components of TCCs.

The upper portion of the chart shows the profitability for each category, where the total TCC profit is measured as a percentage of total TCC value (i.e., TCC payment), for the intra-zone TCCs and inter-zone TCCs in each round of the auctions. 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.

197 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.

Figure A-59: TCC Cost and Profit by Path Type
Winter 2013/14 and Summer 2014 Capability Periods

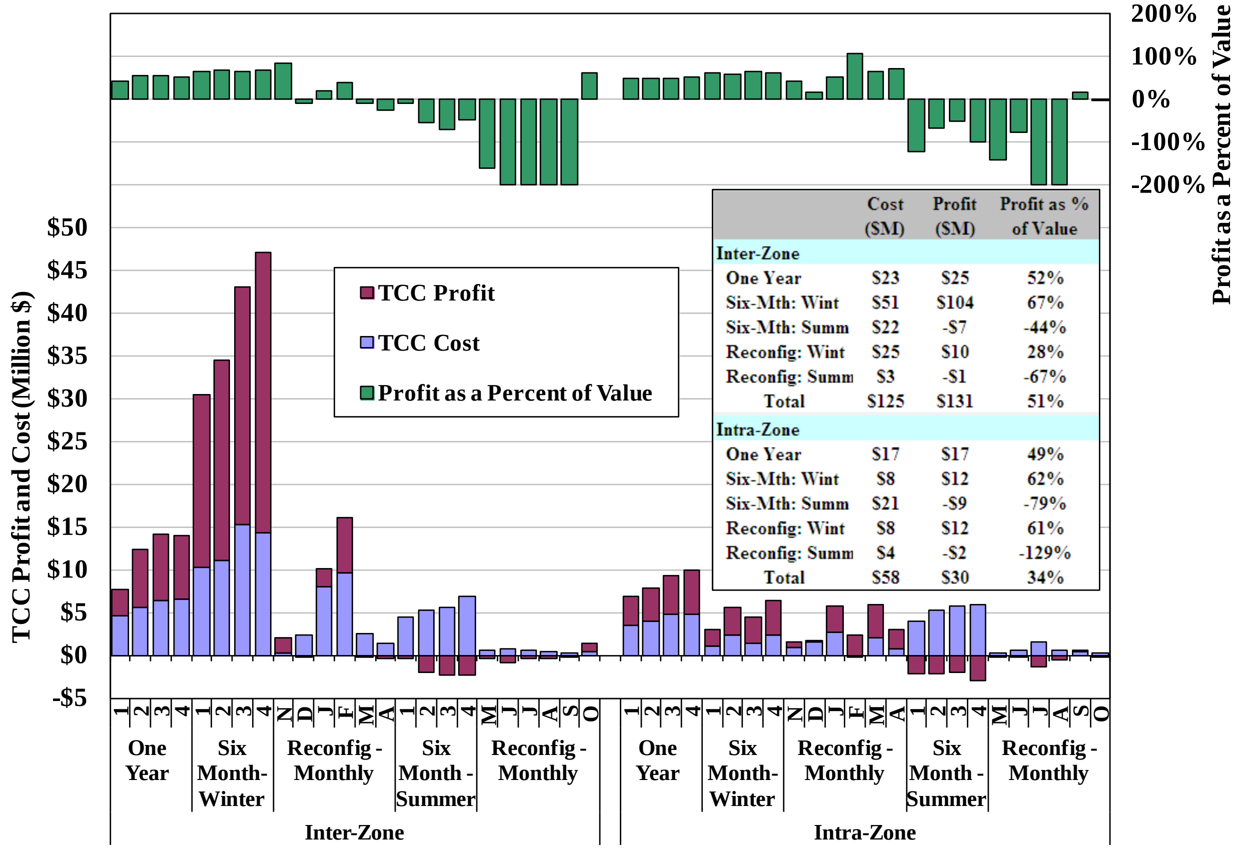


Figure A-60: TCC Prices and Day-ahead Congestion by Zone

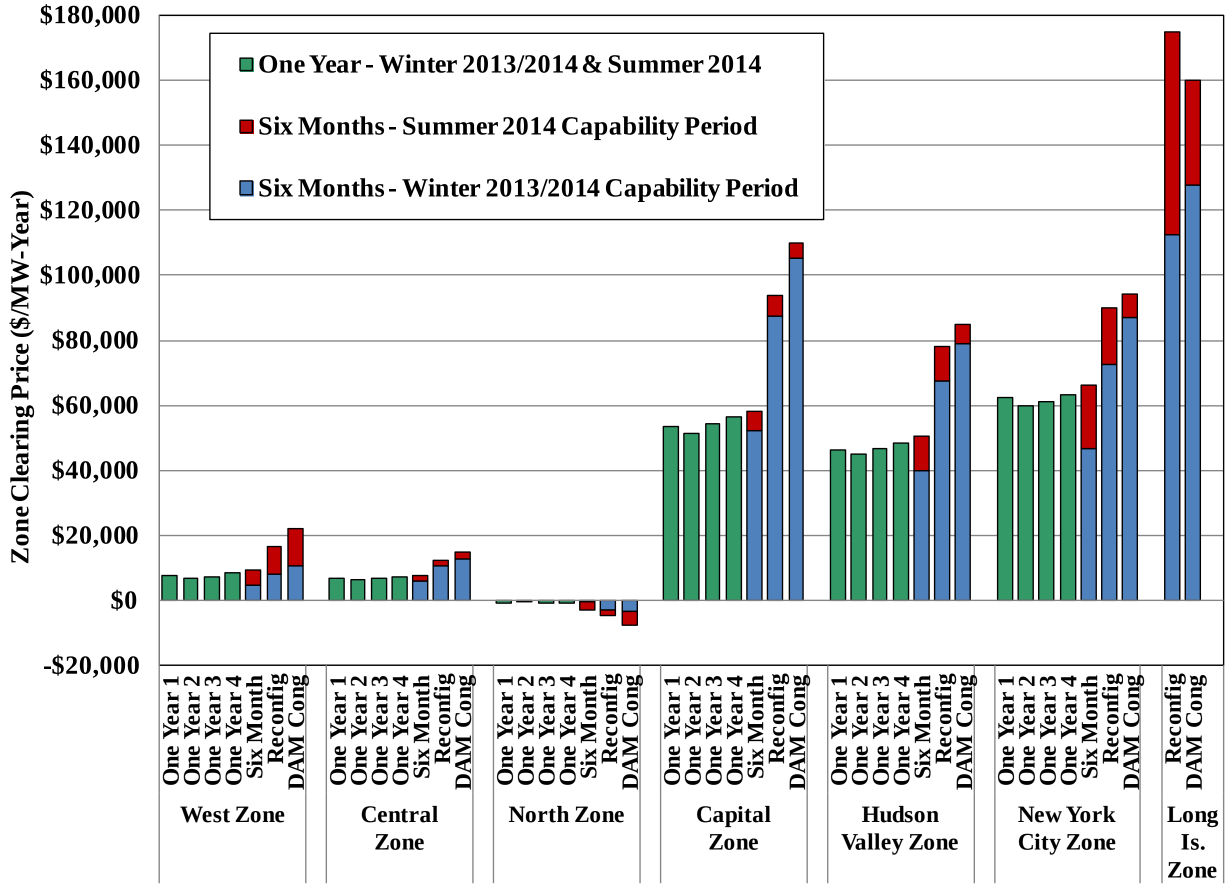
The following analysis evaluates whether clearing prices in each type of TCC auction were consistent with the congestion prices in the day-ahead market at the zonal level during 2014. Figure A-60 compares the TCC prices for the Winter 2013/14 and Summer 2014 Capability Periods (i.e., the 12-month period from November 2013 through October 2014) to the corresponding congestion prices in the day-ahead market. The figure shows the following values:

- *One-year TCC prices* – These are shown for the four auction rounds where TCCs were sold for the period, which occurred in August and September 2013.
- *Six-month TCC prices* – These are the sum of average TCC prices for the four rounds in the Winter Capability Period Auction and the four rounds in the Summer Capability Period Auction.
- *Reconfiguration TCC prices* – These are the sum of TCC prices from the six monthly Reconfiguration auctions during the Winter and the Summer Capability Periods.
- *Day-ahead congestion prices* – These are the sum of congestion prices in the day-ahead market for the 12-month period.

Figure A-60 shows these values for seven zones across New York State. Each price is shown relative to the reference bus at Marcy in the Central Zone. Prices are not shown for Long Island in the one-year and six-month TCC auctions because the NYISO typically sells a very limited amount of TCCs that source or sink in Long Island in those auctions.

Figure A-60: TCC Prices and DAM Congestion by Zone

Winter 2013/14 and Summer 2014 Capability Periods



Key Observations: TCC Prices and Profitability

- TCC buyers netted a profit of $161 million in the TCC auctions during the 12-month period (November 2013 to October 2014), resulting in an average profitability (profit as a percent of TCC payout) of 47 percent. [198]

- The vast majority of profit accrued in the Winter 2013/14 Capability Period.

198 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 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 2013 and 2014. 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 2013 to October 2014.

  - The day-ahead congestion, particularly between areas across the Central-East interface, was well above the TCC prices in the TCC auctions during this period.
  - As explained above, natural gas prices and gas spreads between areas were much higher than expected, particularly at the time of the one-year and six-month TCC auctions, contributing to larger-than-anticipated congestion across the system.
- However, TCC buyers netted overall losses in the Summer 2014 Capability Period.
  - The day-ahead congestion into and within Southeast New York was lower than anticipated at the time of TCC auctions for reasons discussed in subsection B.
- 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.

E. 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 #7, which is described in Section XI. An 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.

<u>Concept for Financial Transmission Right</u>

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 =

$$\sum_{l=901,903}\left([DAM\ MW_l - TCC\ MW_l] \times \sum_{c=constraint}\left[-DAM\ SF_{l,c} \times DAM\ SP_c\right]\right)$$

RTM Payment =

$$\sum_{l=901,903}\left([RTM\ MW_l - DAM\ MW_l] \times \sum_{c=constraint}\left[-RTM\ SF_{l,c} \times RTM\ SP_c\right]\right)$$

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.[199,200] 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;
- The pattern of loop flows around Lake Erie;
- Convergence of prices between New York and neighboring control areas;
- The efficiency of external interface scheduling by market participants; and
- Scheduling patterns across the interfaces that allow intra-hour schedules (i.e., 15-minute scheduling).

199 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.

200 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.

A. Summary of Scheduled Imports and Exports

Figure A-61 to Figure A-64 : 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 2013 and 2014. 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-61, the primary interfaces with Quebec and New England in Figure A-62, and the controllable lines connecting Long Island and New York City with PJM and New England in Figure A-63 and Figure A-64.

Figure A-61: Monthly Average Net Imports from Ontario and PJM
2013 – 2014

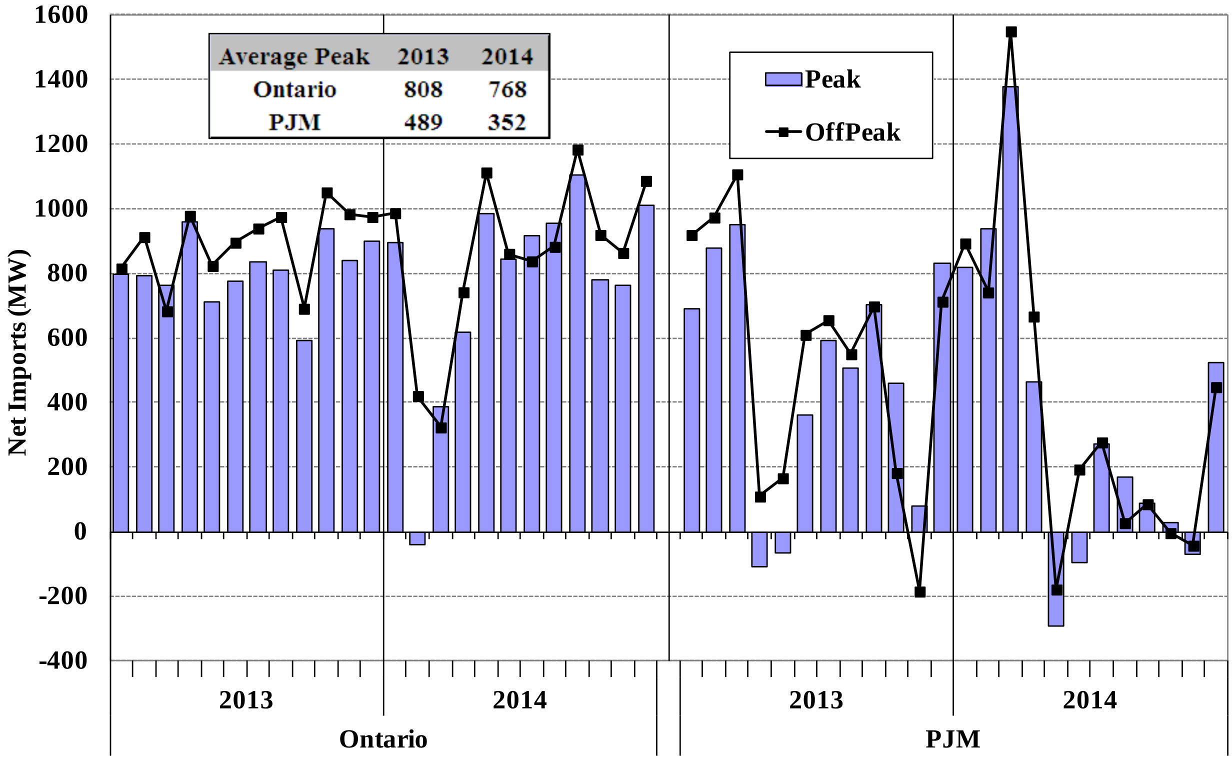


Figure A-62: Monthly Average Net Imports from Quebec and New England
2013 – 2014

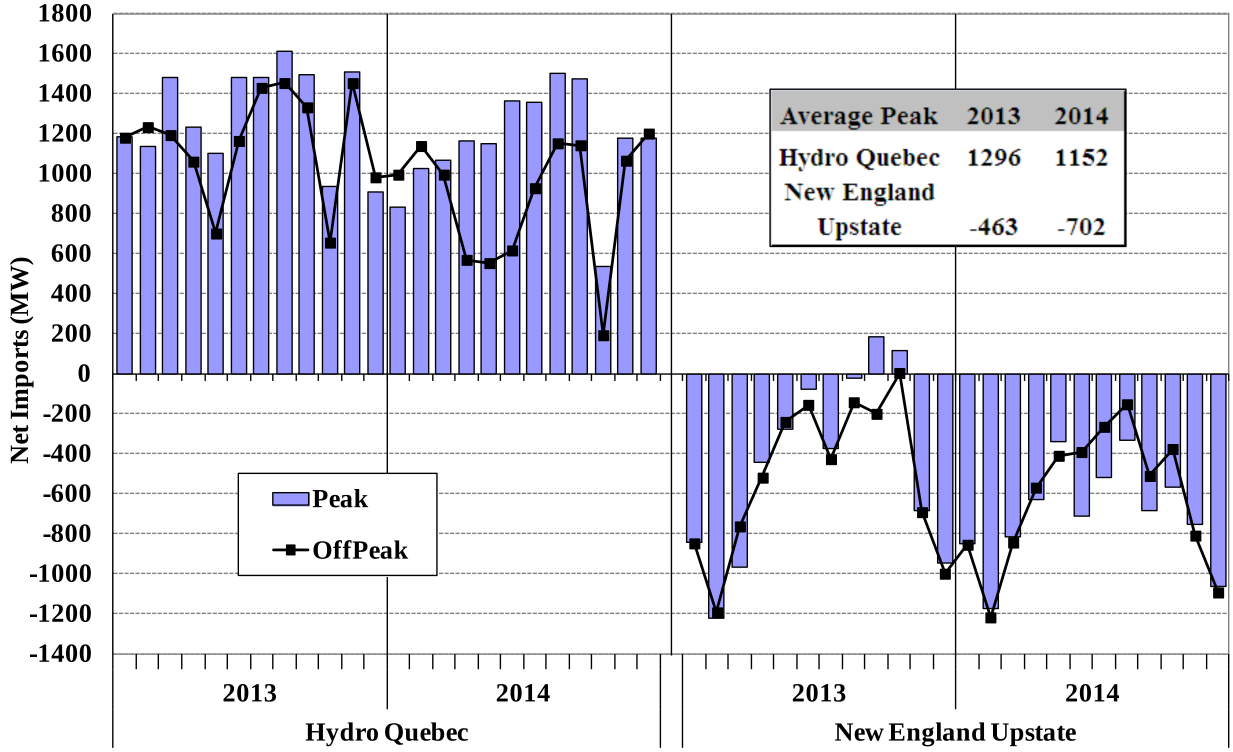


Figure A-63: Monthly Average Net Imports into New York City
2013 – 2014

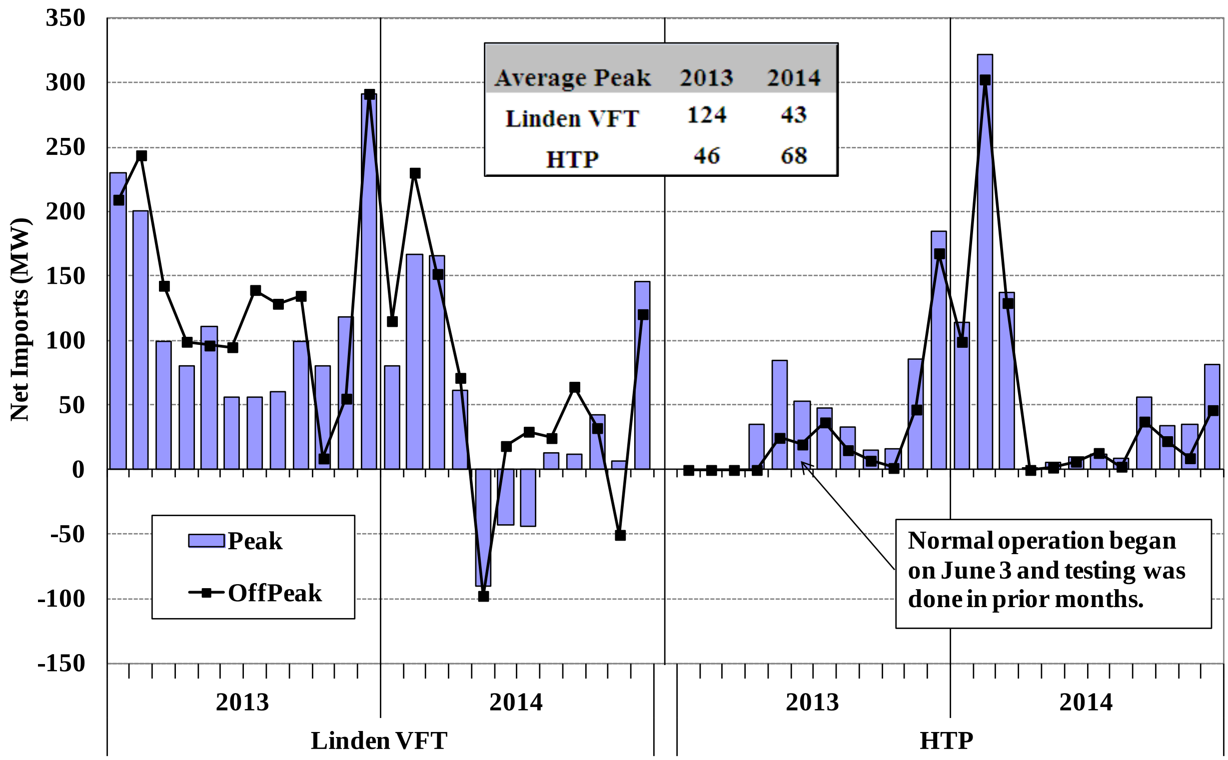
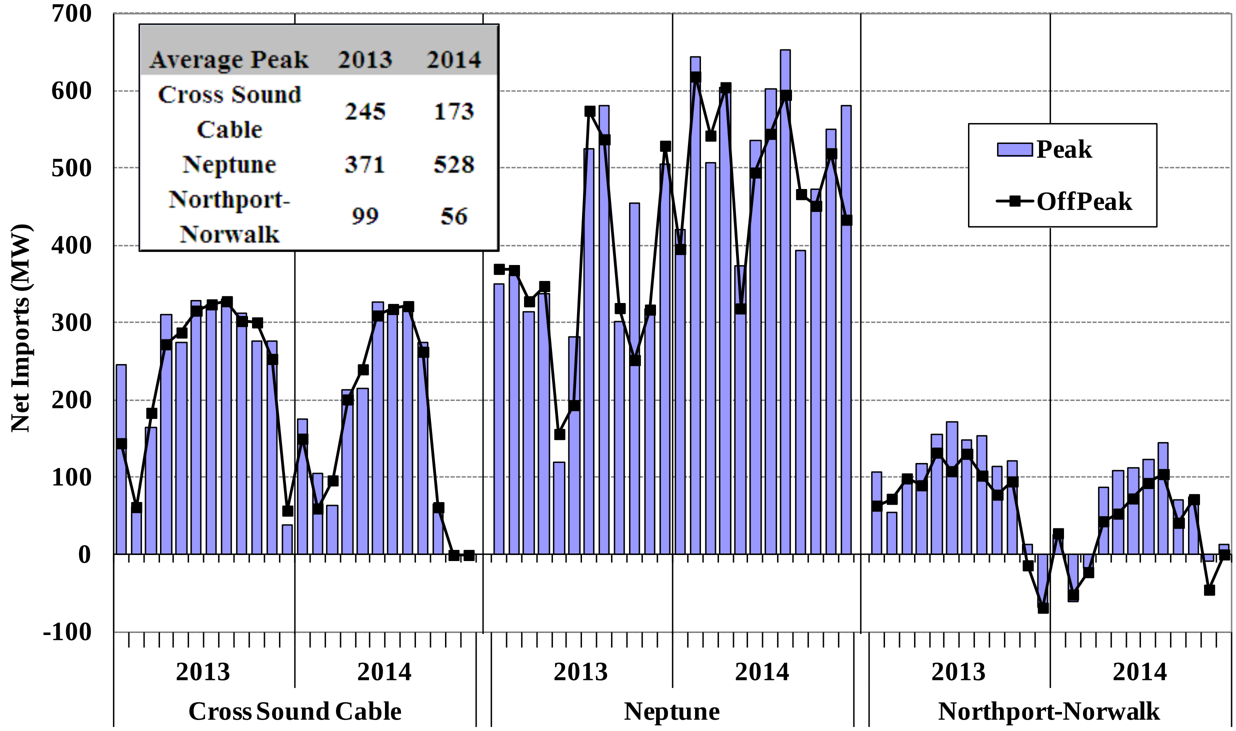


Figure A-64: Monthly Average Net Imports into Long Island
2013 – 2014



Key Observations: Average Net Imports

- Average net imports from neighboring areas across the primary interfaces fell notably from 2,131 MW in 2013 to 1,569 MW in 2014 during the peak hours.
  - Net imports from Hydro Quebec averaged roughly 1,150 MW, accounting for 73 percent of net imports across the primary interfaces.
    - Net imports fell 12 percent from last year. Most of the reduction occurred in the winter because of more frequent extreme cold weather conditions that led to limited hydro production and increased winter peaking load in Hydro Quebec.
    - The reduction in the winter had significant price effects in Western New York.
  - Net imports from Ontario fell modestly in 2014 largely because of reduced imports in the winter.
    - Ontario imported a substantial amount of power from New York in late February and early March when natural gas prices in Ontario were significantly higher than in Western New York.
  - Net imports from PJM fell 28 percent from the prior year, averaging roughly 350 MW during peak hours.
    - Net imports fell during most months of 2014 after the first quarter because natural gas prices in Western New York and most of Eastern New York (particularly

New York City) were low compared to the rest of the country, which reduced incentives to import to New York.

    – However, this decrease was partly offset by higher net imports in the first quarter because of higher natural gas prices on the New York side of the border.

  - Net exports to New England across the primary interface increased more than 50 percent (or 240 MW) in 2014.

    – The increase was consistent with increased natural gas price spreads between New England and Eastern New York, particularly in the summer.

- Average net imports from neighboring areas into Long Island over the three controllable interfaces averaged nearly 760 MW during peak hours in 2014, up modestly from 2013.

  - Net imports across the Neptune line rose 42 percent from 2013 to 2014 because the line was only partially available (up to 375 MW) in the first half of 2013 and returned to full operation (up to 660 MW) in July of 2013.

  - However, the increase was partly offset by decreased net imports over the Cross Sound Cable and the Northport-Norwalk Line because of higher natural gas prices (and energy prices) in Connecticut in most months.

    – The Cross Sound Cable was out of service from late October throughout the end of year, contributing to the reduction as well.

  - 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 2014, up modestly from 28 percent in 2013.

- Average net imports from New Jersey to New York City over the Linden VFT and the HTP interfaces averaged roughly 110 MW during peak hours in 2014, down 35 percent from the prior year.

  - The reduction was occurred primarily from May to October when natural gas prices in New York City fell relative to most areas in PJM.

B. Lake Erie Circulation

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. Large clockwise loop flows emerged in 2008 when the phenomenon of "circuitous transaction scheduling" around Lake Erie became significant.[201] Although circuitous transaction scheduling was prohibited after July 2008, loop flows have still generally moved clockwise around Lake Erie in recent years.

The Transmission Loading Relief ("TLR") procedure is used by the NYISO to curtail transactions in other control areas when loop flows contribute significantly to congestion on its internal flowgates. This NERC Procedure is an Eastern Interconnection-wide process that allows reliability coordinators to mitigate potential or actual operating security limit violations while respecting transmission service reservation priorities. When a constraint is binding, the NYISO's real-time scheduling models manage its market flows over the constrained transmission facility by economically redispatching New York generation and by economically scheduling external transactions that source or sink in New York. If total loop flow accounts for a significant portion (i.e., more than 5 percent) of flow on a facility, the NYISO can invoke the TLR procedure to ensure that external transactions that are not scheduled with the NYISO are curtailed to reduce flow over the constrained facility.[202]

Figure A-65: Lake Erie Circulation

Figure A-65 summarizes the pattern of loop flows for each month of 2011 to 2014. The lower portion of the figure shows the percent of hours in each month when average clockwise loop flows were greater than 200 MW. Hours with West-to-East congestion (including congestion in the West Zone, across the West-Central and Central-East interfaces) and hours without West-to-East congestion are flagged separately. Loop flows are primarily of concern in the former case, when they reduce the capacity available for scheduling internal generation to satisfy internal load and increase congestion on the transmission paths from Western New York to Eastern New York. The upper portion of the figure shows the percent of hours in each month when TLRs with Level 3a and above were called by the NYISO. TLR Level 3a allows the NYISO to prevent some Non-Firm Point-to-Point transactions from being scheduled in the subsequent hour in other control areas. The inset table compares these statistics on an annual basis between 2011 and 2014.

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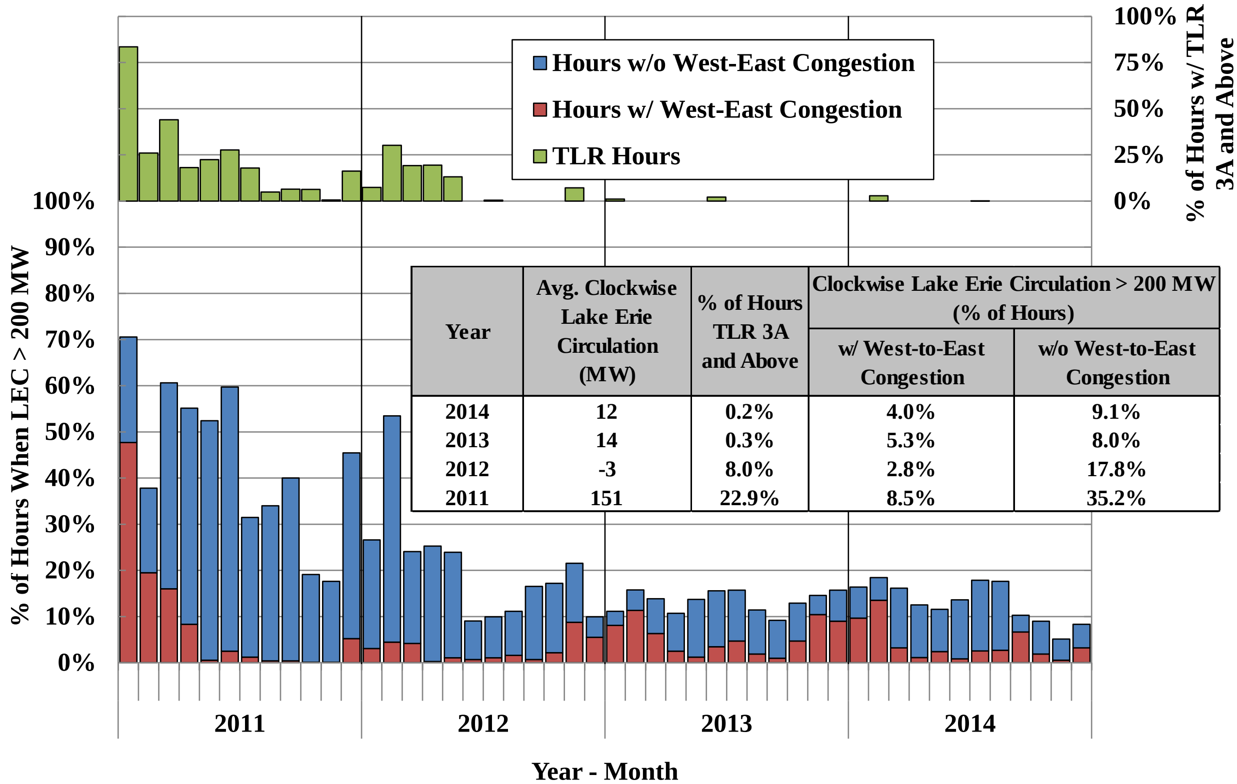
201 Circuitous transactions are transactions that are scheduled from one control area to another along an indirect path when a more direct path exists. Circuitous transactions cause physical power flows that are not consistent with the scheduled path of the transaction. The NYISO filed under exigent circumstances to prohibit circuitous transaction scheduling after July 22, 2008. This issue was discussed in detail in 2008 State of the Market Report, August 2009, Potomac Economics.

202 The TLR process manages congestion much less efficiently than optimized generation dispatch through LMP markets. The TLR process provides less timely system control and frequently leads to more curtailment than needed. However, most external transactions that cause loop flows are not scheduled with the NYISO, so in most cases, the only mechanism the NYISO currently has to address the congestion they cause is the TLR procedures it uses to curtail the transactions. Since the implementation of Coordinated Congestion Management ("M2M") with PJM in January 2013, the NYISO can use the M2M process to manage congestion on interfaces that are Coordinated Flow Gates to the extent that it is affected by transactions scheduled with PJM.

Figure A-65: Lake Erie Circulation
2011 – 2014



Year	Avg. Clockwise Lake Erie Circulation (MW)	% of Hours TLR 3A and Above	Clockwise Lake Erie Circulation > 200 MW (% of Hours)	
			w/ West-to-East Congestion	w/o West-to-East Congestion
2014	12	0.2%	4.0%	9.1%
2013	14	0.3%	5.3%	8.0%
2012	-3	8.0%	2.8%	17.8%
2011	151	22.9%	8.5%	35.2%

Key Observations: Lake Erie Circulation

- Average hourly clockwise circulation has fallen notably since the IESO-Michigan PARs went in service in April 2012. [203]
  - Clockwise loop flows exceeded 200 MW during roughly 13 percent of all hours in both 2013 and 2014, down substantially from prior years.[204]
- The reduction in clockwise loop flows around Lake Erie (which contribute to west-to-east congestion on flowgates in upstate New York) led to a substantial reduction in TLRs called by NYISO.
  - TLRs (level 3A and above) were called in fewer than 25 hours in both 2013 and 2014, down from almost 2,000 hours in the last calendar year before the PARs became operational.

[203] 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.

[204] The PARs are generally not adjusted until the loop flows exceed or are expected to exceed 200 MW for a substantial period of time.

- West-to-East congestion occurred in New York in roughly 30 to 40 percent of hours when the clockwise circulation rose above 200 MW. This has been true both before and after the PARs became operational.
  - Congestion on 230kV lines in the West Zone limited flows from west-to-east frequently in 2013 and 2014. This congestion is often exacerbated by sporadic clockwise loop flows.
  - However, during such periods of congestion, the NYISO was generally unable to use the TLR process to moderate clockwise loop flows around Lake Erie, since the PARs were almost always deemed to be in "regulate" mode. [205]

C. 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.

205 When the NYISO calls a TLR and the IESO-Michigan PARs are deemed to be in "regulate" mode, transactions scheduled across the IESO-Michigan interface are not subject to the TLR.

Figure A-66: Price Convergence Between New York and Adjacent Markets

Figure A-66 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-66 summarizes price differences between New York and neighboring markets during unconstrained hours in 2014. 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-66: Price Convergence Between New York and Adjacent Markets
Unconstrained Hours in Real-Time Market, 2014

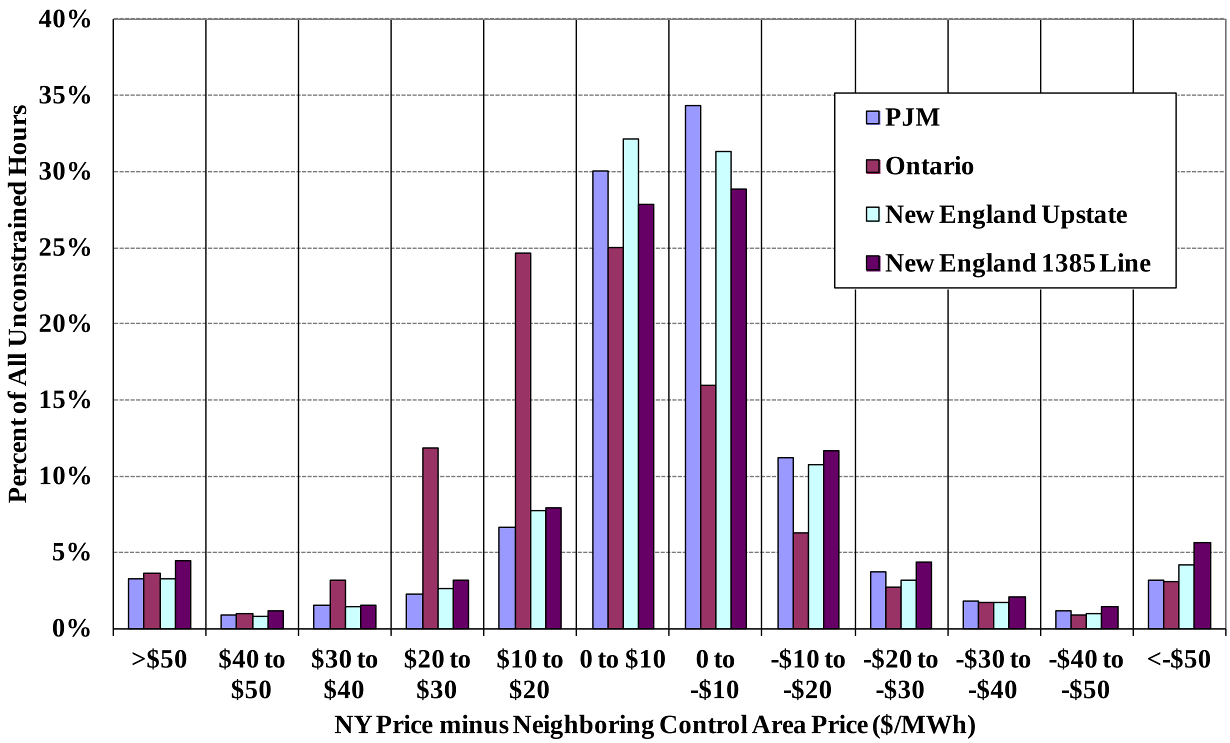


Table A-7: Efficiency of Inter-Market Scheduling

Table A-7 evaluates the consistency of the direction of external transaction scheduling and price differences between New York and New England, PJM, and Ontario during 2014. 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. [206]

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.[207] However, for Ontario, the analysis assumes a day-ahead schedule of 0 MW since Ontario does not operate a day-ahead market.

Table A-7 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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206 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.

207 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-7: Efficiency of Inter-Market Scheduling
Over Primary Interfaces and Scheduled Lines – 2014

	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	-614	$1.34	46%	-$2	-43	$1.11	58%	$19
Ontario					816	$11.79	79%	$95
PJM	485	-$2.25	53%	$18	-117	-$2.42	62%	$26
Controllable Ties								
1385 Line	48	$1.96	70%	$3	-3	-$2.93	59%	$3
Cross Sound Cable	171	$3.61	72%	$8	-0.2	-$1.67	57%	$0
Neptune	519	$9.70	77%	$50	-7	$8.48	54%	-$1
HTP	48	-$2.84	67%	$4	12	-$2.56	55%	$0
Linden VFT	54	-$0.26	67%	$5	-4	$0.45	53%	$3

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 18 to 28 percent of unconstrained hours in 2014.
- 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 most interfaces between New York and neighboring markets during 2014.
  - 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 $95 million in production cost savings was achieved across the Ontario interface in 2014, higher than the combined savings of $61 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 $12/MWh in 2014 (compared to an average of only $1 to $2/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.

  - In the day-ahead market, the efficiency of scheduling over the controllable lines was generally better than over the free-flowing ties, reflecting generally less uncertainty in predicting price differences across these controllable lines in 2014.
  - 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 $45 million in real-time production cost savings was achieved in 2014 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.

D. 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"). These market enhancements are being implemented in phases under the Enhanced Interregional Transaction Coordination ("EITC") project. By the end of 2014, 15-minute scheduling had been enabled at five interfaces, CTS had been implemented at all four interfaces with PJM, and substantial progress had been made on CTS with New England.

EITC Phase 1 was activated on July 27, 2011, allowing 15-minute scheduling between New York and Hydro-Quebec across its primary interface (i.e., at the HQ-Chateauguay proxy bus). The NYISO initially set the quarter-hour interchange ramp limit to 25 MW and gradually increased it to 200 MW.[208, 209]

208 The quarter-hour ramp limit at HQ-Chateauguay bus was raised from 25 MW to 50 MW on November 2, 2011, to 100 MW on December 1, 2011, to 150 MW on February 9, 2012, to 175 MW on April 18, 2012, and to 200 MW on May 31, 2012.

209 EITC Phase 2 evaluates the appropriateness of expanding the Interregional Transaction Coordination Concept by scheduling operating reserves and/or regulation service with the HQ control area.

EITC Phase 3 allowed 15-minute transaction scheduling between New York and PJM. The NYISO activated 15-minute scheduling across the primary interface (i.e., at the Keystone proxy bus) on June 27, 2012. The NYISO activated 15-minute scheduling for the Neptune and Linden VFT scheduled line interfaces on October 30 and November 28, 2012. 15-minute scheduling was activated for the HTP Scheduled Line when it began normal operation on June 3, 2013. Unlike the primary HQ interface, these four PJM interfaces are not subject to an individual quarter-hour ramp limit, although the NYISO utilizes a NYCA-wide ramp limit of 300 MW to manage the total quarter-hour schedule changes across all 15-minute scheduling interfaces.

EITC Phase 4 will implement CTS on the primary interface with ISO New England based on Tariff provisions that were approved by the Commission on April 19, 2012. Implementation is scheduled to occur by the end of 2015.

EITC Phase 5 implemented CTS with PJM based on Tariff provisions that were approved by the Commission on February 20, 2014. Implementation occurred in November 2014.

Figure A-67 to Figure A-71: 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 2014. The figures show the average bid and offer quantities across these interfaces in each month of 2013 and 2014. 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 $500/MWh; 2) hourly LBMP-based bids and offers that were priced below than $0/MWh or above $500/MWh; 3) 15-minute LBMP-based bids and offers that were priced between $0 and $500/MWh; 4) 15-minute LBMP-based bids and offers that were below $0/MWh or above $500/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 2013 and 2014 on an annual basis.

Figure A-67: Average Transaction Bids and Offers by Type by Month
HQ Primary Interface, 2013-2014

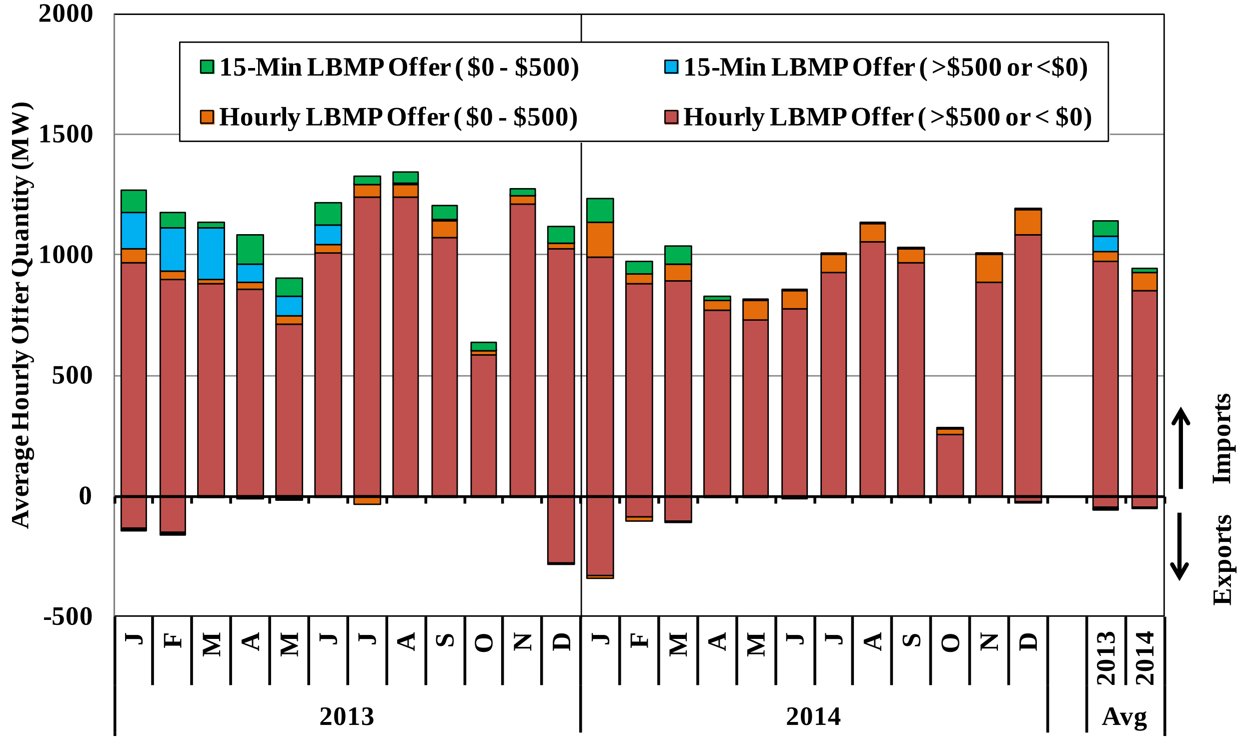


Figure A-68: Average Transaction Bids and Offers by Type by Month
PJM Primary Interface, 2013-2014

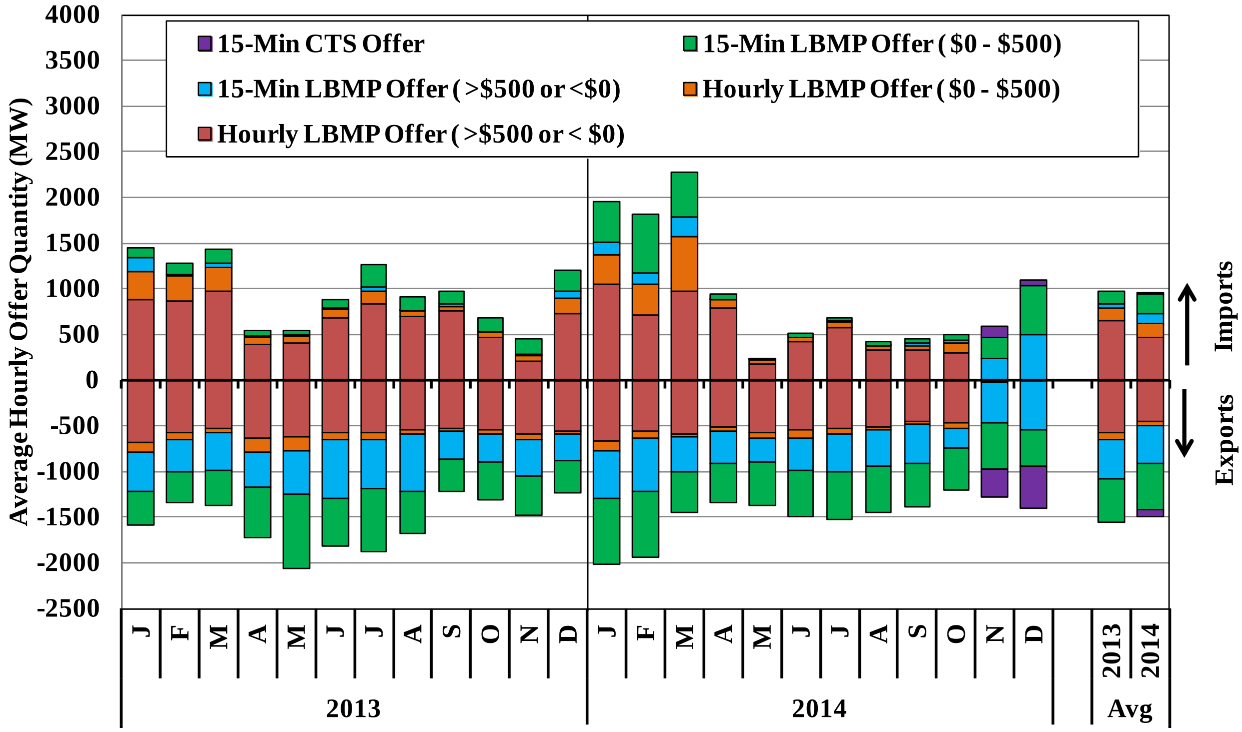


Figure A-69: Average Transaction Bids and Offers by Type by Month
Neptune Scheduled Line, 2013-2014

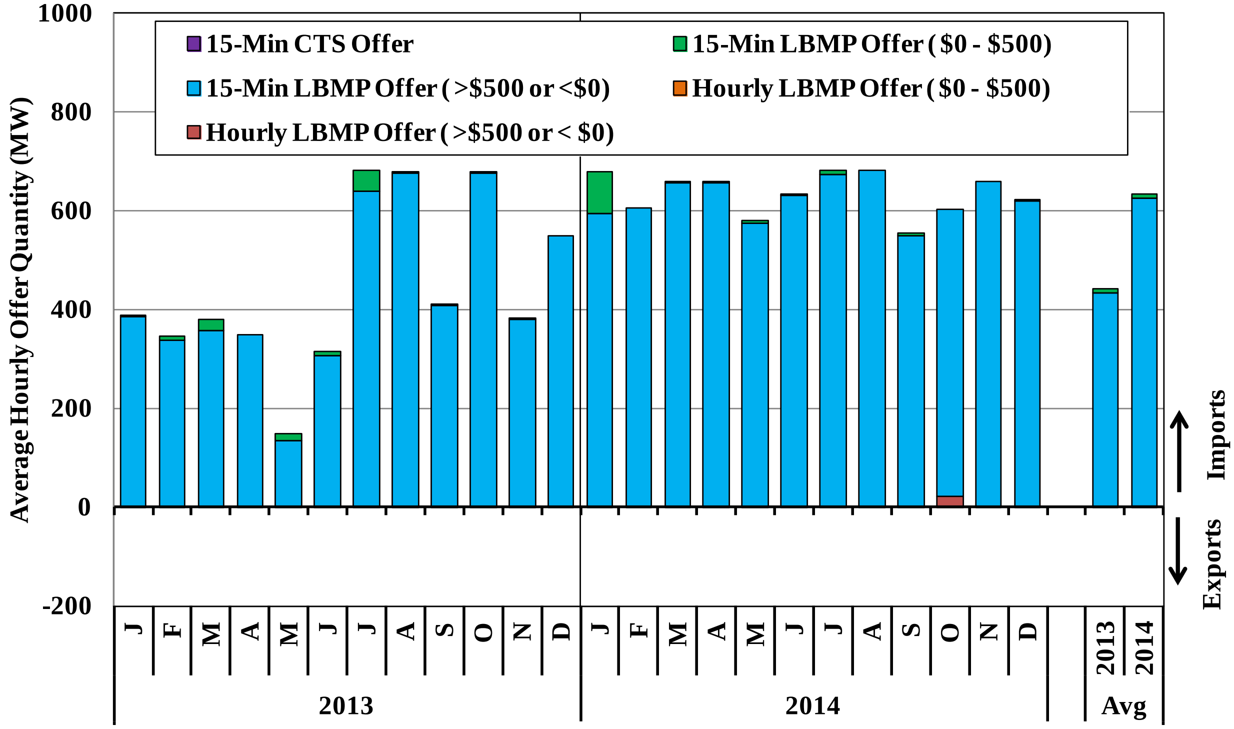


Figure A-70: Average Transaction Bids and Offers by Type by Month
HTP Scheduled Line, 2013-2014

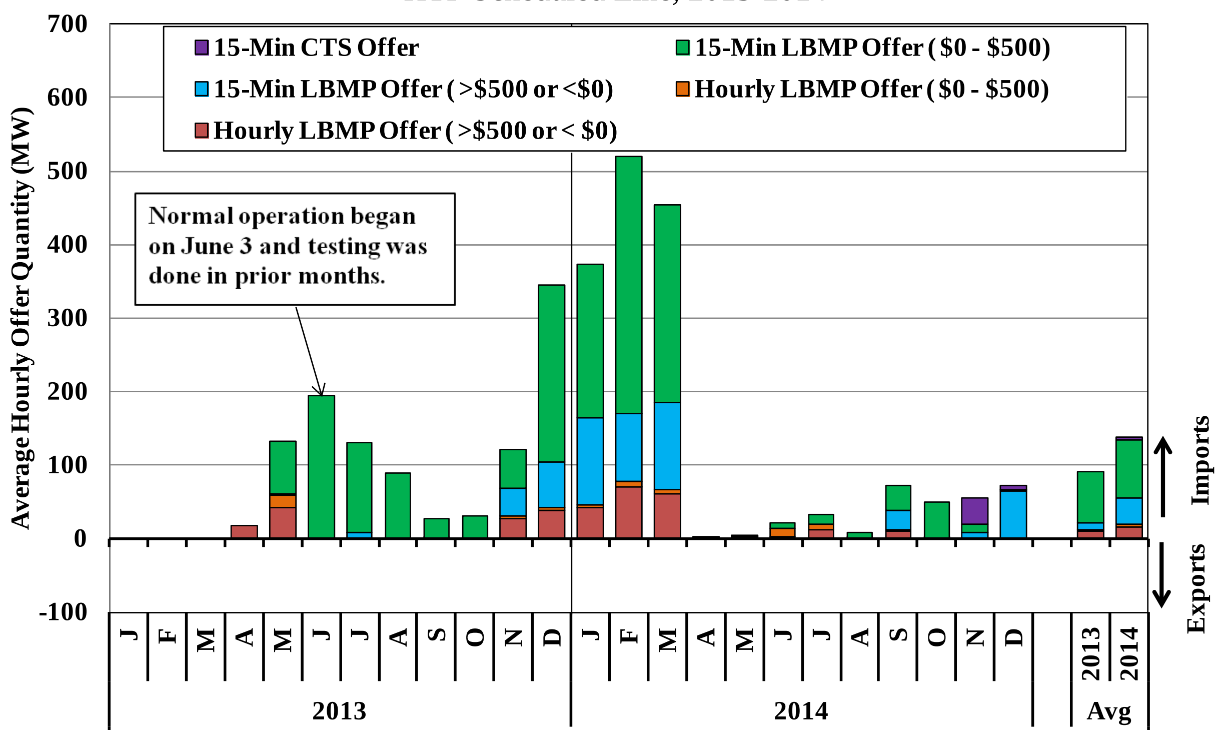
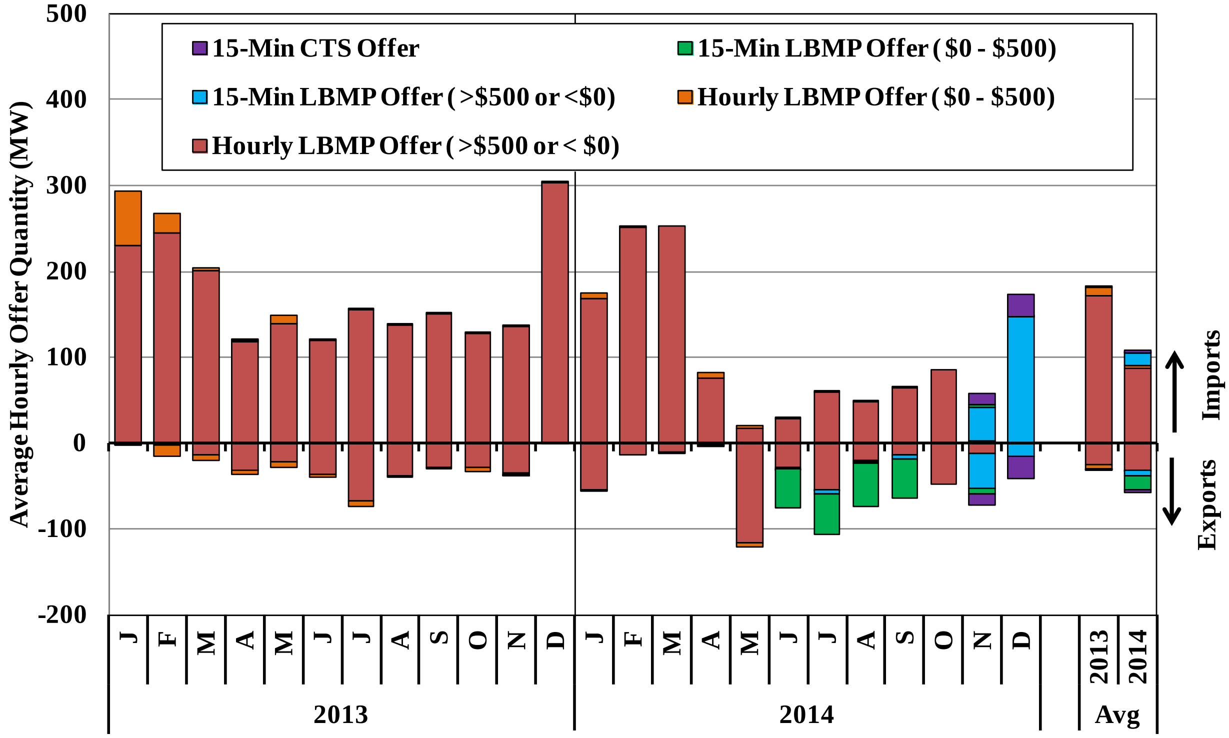


Figure A-71: Average Transaction Bids and Offers by Type by Month
Linden VFT Scheduled Line, 2013-2014



Key Observations: Intra-Hour Scheduling with Adjacent Control Areas

- Intra-hour scheduling changes occurred often at the primary PJM interface but much less frequently at other interfaces. In 2014,
  - At the primary HQ interface, only 2 percent of real-time offers were based on 15-minute scheduling and were relatively price-sensitive (i.e., between $0 and $500/MWh).
  - At the Neptune interface, 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).
  - At the Linden VFT interface, market participants had not taken advantage of the 15-minute scheduling until mid 2014 (which was one and a half year later since its activation). The amount of relatively price-sensitive 15-minute bids was still very limited, averaging less than 50 MW/h.
  - At the HTP interface, the average amount of offers was limited for most of the year except the first quarter of 2014 when rapid price changes occurred more frequently.

E. Evaluation of Coordinated Transaction Scheduling with PJM

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 PJM'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.

This section provides our initial assessment of the performance of CTS since NYISO and PJM first implemented it in November 2014. 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.

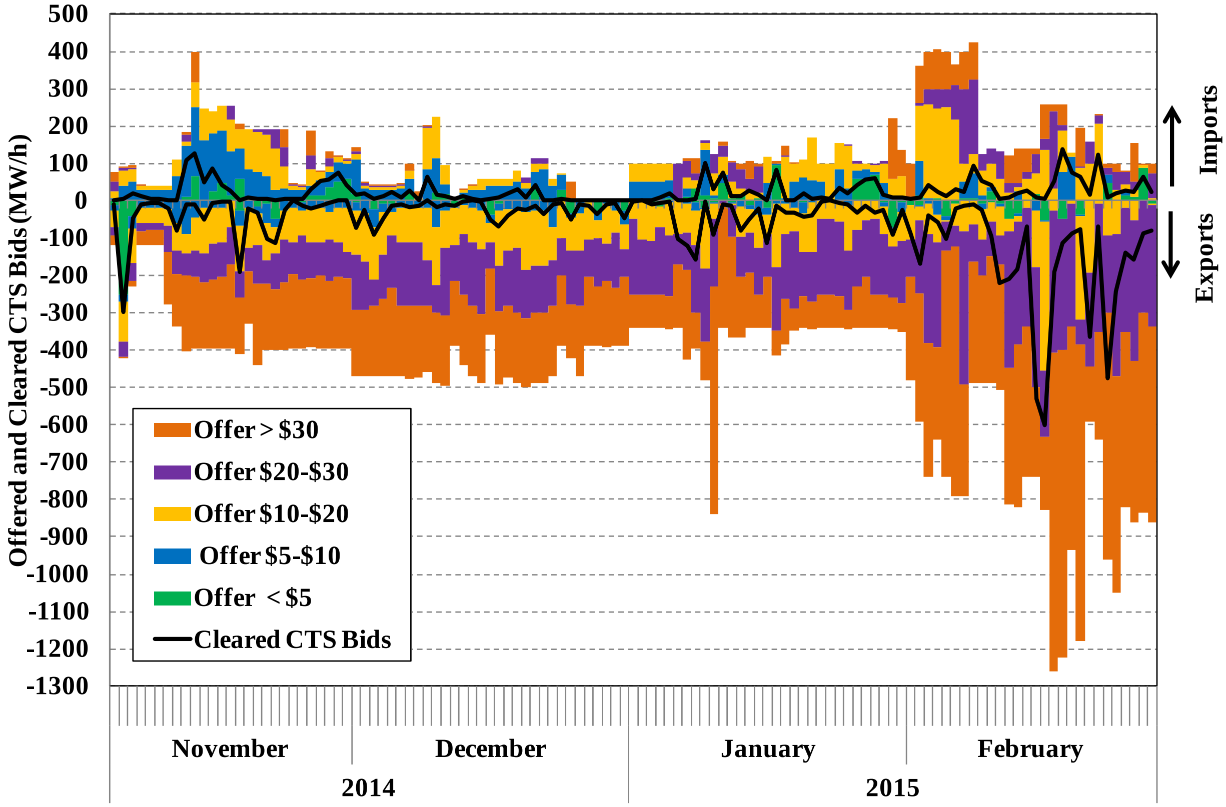
Figure A-72: Bidding Patterns and Efficiency of CTS at the Primary PJM Interface

The following two analyses evaluate transaction scheduling since the implementation of CTS between NYISO and PJM in November 2014. 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 examines the trading volumes of CTS transactions during the first four months following the activation of CTS on November 4, 2014. In particular, Figure A-72 shows the average amount of CTS transactions at the primary PJM interface during peak hours (i.e., HB 7 to 22) on each day from November 4, 2014 through the end of February 2015. Positive numbers indicate import offers to New York and negative numbers represent export bids to PJM. Stacked bars show the average quantities of CTS bids 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; and (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 CTS imports and exports on each day of the examined period.

Figure A-72: Average CTS Transaction Bids and Offers by Day

PJM Primary Interface, Hours 7-22



The second analysis evaluates the efficiency of the CTS-enabled intra-hour scheduling process (relative to an hourly scheduling mechanism) during the first four months after its implementation. 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. [210]

Table A-8 examines the performance of the intra-hour scheduling process under CTS at the primary PJM interface. For each of four months from November 2014 to February 2015, the table shows the following quantities:

- % of All Intervals – This shows the percent of quarter-hour intervals in each month during which the interface flows were adjusted (relative to the base schedule) in the scheduling RTC interval.

210 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.

- 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.[211]

  - Unrealized Savings – This measures production cost savings that are not realized once the following factors are taken into account:

    – New York Forecast Error[212] - 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[213] - Similarly, this measures the portion of savings that are unrealized savings once price forecast errors on the PJM side are considered.

      – Real-time Curtailment[214] - Some of RTC scheduled transactions may not actually flow in real-time for various reasons (e.g., check-out failures, real-time cuts for security and reliability concerns, etc.). The reduction of flows in the efficient direction reduces market efficiency gains.

      – Interface Ramping[215] - 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

211 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 216.

212 This is calculated as (final RTC schedule – base schedule)*(RTD price – RTC price).

213 This is calculated as (final RTC schedule – base schedule)*(PJM IT SCED price – PJM RT price).

214 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).

215 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).

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[216,217] – 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.

Table A-8: Efficiency of Intra-Hour Scheduling Under CTS

Primary PJM Interface

			Export (NY to PJM)				Import (PJM to NY)				Total
			Nov-14	Dec-14	Jan-15	Feb-15	Nov-14	Dec-14	Jan-15	Feb-15	
% of All Intervals			41%	35%	39%	41%	47%	44%	43%	46%	
Average Flow Adjustment (MW)			-77	-71	-90	-150	68	71	90	170	
Production Cost Savings ($ Million)	Projected at Scheduling Time		$0.57	$0.34	$0.84	$2.47	$0.08	$0.66	$0.17	$1.05	**$6.2**
	Unrealized Savings Due to:	NY Fcst. Err.	-$0.08	-$0.12	-$0.06	-$0.42	$0.01	-$0.46	-$0.02	$0.01	**-$1.1**
		PJM Fcst. Err.	-$0.39	-$0.09	-$0.51	-$1.17	-$0.14	-$0.20	-$0.22	-$1.07	**-$3.8**
		Curtailment	$0.00	$0.00	-$0.02	-$0.20	$0.00	$0.00	-$0.05	-$0.09	**-$0.4**
		Ramping	-$0.03	-$0.02	-$0.02	-$0.07	-$0.02	-$0.04	-$0.01	-$0.02	**-$0.2**
	Actual		$0.08	$0.11	$0.23	$0.61	-$0.07	-$0.03	-$0.13	-$0.12	**$0.7**
Interface Prices ($/MWh)	NY	Actual	$36.99	$35.37	$43.27	$96.48	$36.62	$34.35	$44.54	$93.61	
		Forecast	$33.39	$31.94	$41.09	$88.42	$36.09	$39.44	$42.97	$92.06	
	PJM	Actual	$38.73	$39.63	$47.78	$101.88	$39.14	$36.35	$48.27	$103.65	
		Forecast	$44.28	$37.28	$52.42	$114.43	$35.12	$29.60	$41.65	$87.94	
Price Forecast Errors ($/MWh)	NY	Fcst. - Act.	-$3.60	-$3.43	-$2.18	-$8.06	-$0.54	$5.09	-$1.57	-$1.55	
		Abs. Val.	$9.40	$10.48	$9.28	$24.78	$9.69	$15.60	$10.46	$23.19	
	PJM	Fcst. - Act.	$5.54	-$2.35	$4.64	$12.55	-$4.02	-$6.75	-$6.62	-$15.71	
		Abs. Val.	$15.69	$15.97	$19.44	$51.49	$9.62	$12.15	$14.42	$41.28	

216 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).

217 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.

Figure A-73: 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-73 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-74 and Figure A-75

Figure A-73 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-73: Illustration of External Transaction Ramp Profiles in RTC and RTD

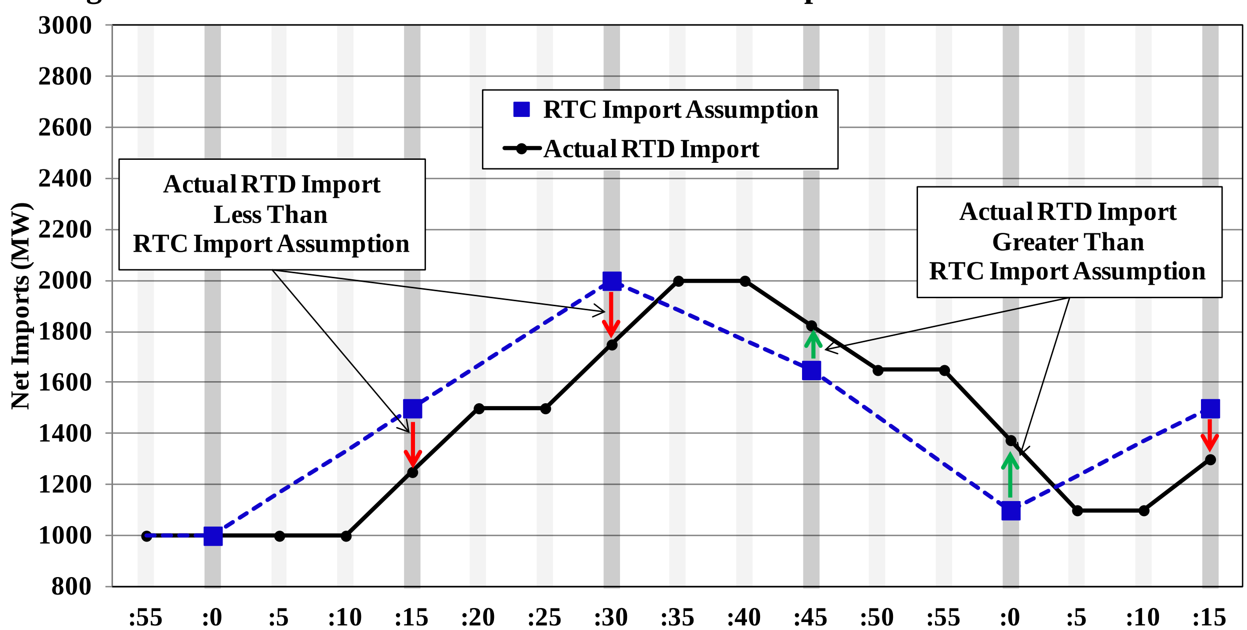


Figure A-74 shows a histogram of the resulting differences between (a) the RTC assumed net interchange and (b) the actual net interchange reflected in RTD at the quarter-hour. For each tranche of the histogram, the figure summarizes the accuracy of the RTC price forecast by showing the average RTC LBMP 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. The analysis is shown for the period from November 4, 2014 through the end of February 2015.

Figure A-74: Histogram of Differences Between RTC and RTD Prices and Schedules
November 4, 2014 to February 28, 2015

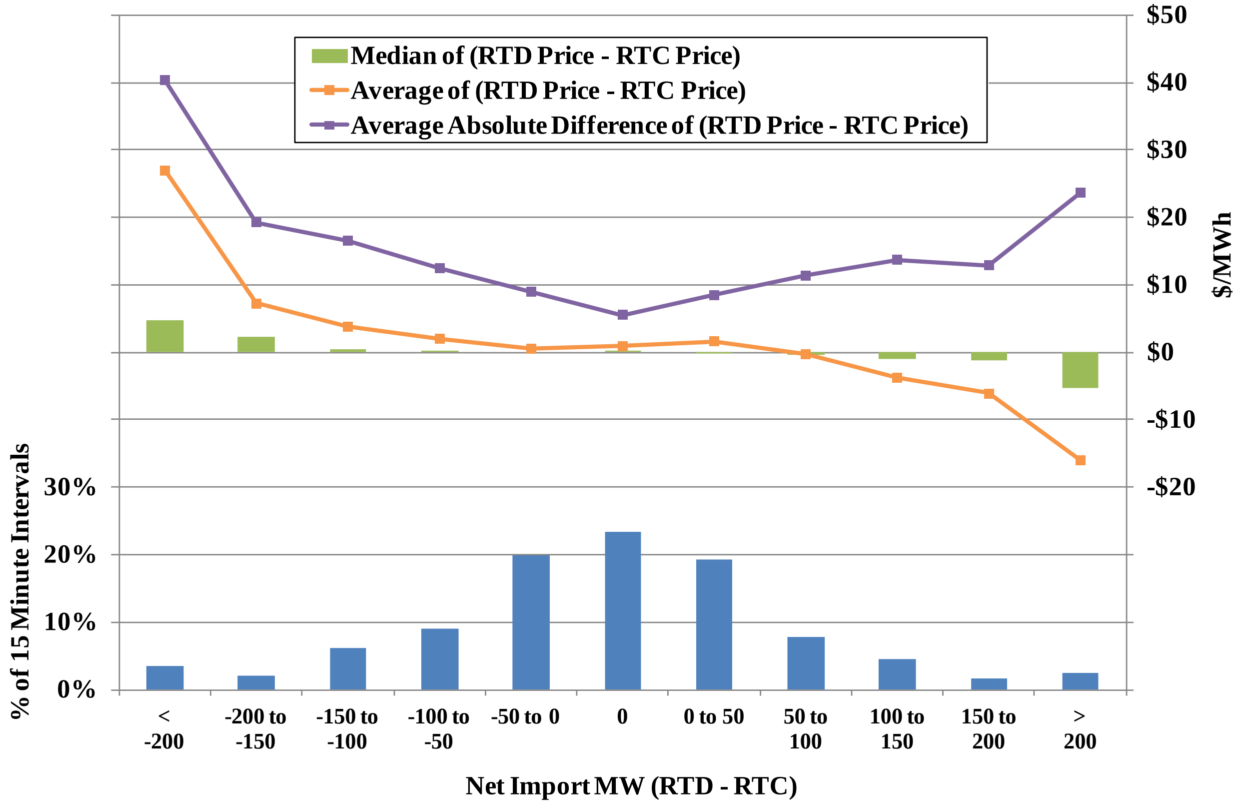
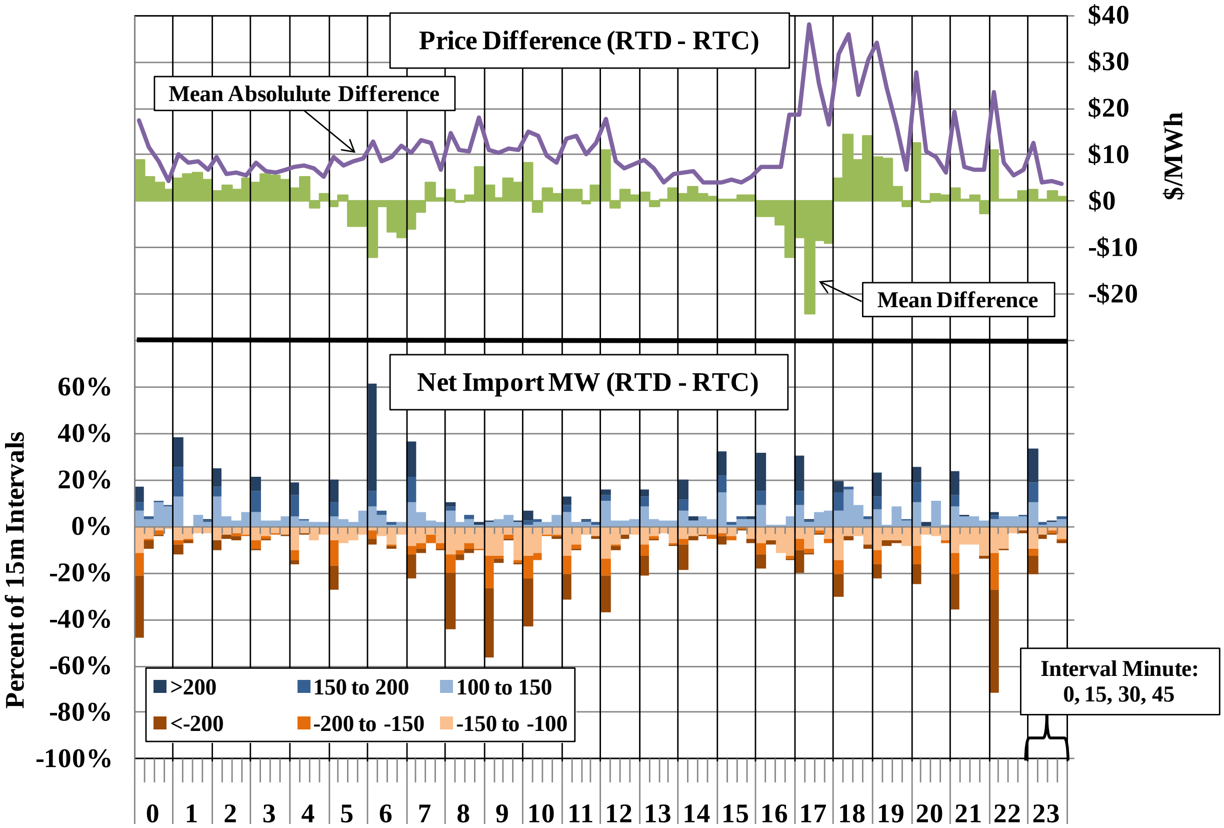


Figure A-75 summarizing these pricing and scheduling differences by time of day. The stacked bars in the lower portion of the figure show the frequency, direction, and magnitude of differences between RTC and RTD net import levels that exceed 100 MW by time of day, while the upper portion summarizes 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-75: Differences Between RTC and RTD Prices and Schedules by Time of Day

November 4, 2014 to February 28, 2015



Key Observations: CTS-enabled Intra-Hour Scheduling at the Primary PJM Interface

- During the examined period (i.e., peak hours in the four-month period from November 2014 to February 2015), the amount of CTS bids submitted was modest relative to the size of the interface between PJM and New York. In general, CTS bids were submitted with substantial margins above $0.
  - The amount of CTS import bids averaged roughly 130 MW per hour and an average of 25 MW were scheduled. Eight percent of CTS import bids were offered at less than $5/MWh, 27 percent between $5 and $10/MWh, and 36 percent between $10 and $20/MWh.
  - The amount of CTS export bids averaged roughly 485 MW per hour and an average of 65 MW was scheduled each hour. Five percent of CTS export bids were offered at less than $10/MWh, 17 percent between $10 and $20/MWh, and 31 percent between $20 and $30/MWh.
  - The amount of CTS bids rose in February 2015 when real-time price volatility rose in both markets.
  - One factor that discourages external transactions and provides incentives for CTS bidders to increase their bid prices is that transactions that flow 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.

- 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.
  - From November 2014 to February 2015, a total of $6.2 million in production cost savings was estimated at the time when RTC determined final schedules.
  - However, price forecast errors on the New York side account for a reduction of $1.1 million in savings, and price forecast errors on the PJM side account for an additional reduction of $3.8 million.
  - Average forecast errors were generally smaller on the New York side than on the PJM side. During the examined period:
    - Average RTC forecast prices were persistently lower than average RTD prices.
    - Average PJM IT SCED forecast prices deviated more widely from average real-time prices at both directions.
  - 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 12 percent of the quarter-hours during the period. At these times, the RTD price exceeded the RTC price by an average of $11.40/MWh and the mean absolute difference was $24.20/MWh.

    - RTD net imports exceeded RTC-assumed net imports by 100 MW or more in 9 percent of the quarter-hours during the period. At these times, the RTD price was less than the RTC price by an average of $7.70/MWh and the mean absolute difference was $16.40/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 $8.50/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.
    - Elimination or reduction in the fees charged to transactions by NYISO and PJM would likely lead to increased participation and 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 2014:

- *Efficiency of Gas Turbine Commitment* – This sub-section evaluates the consistency of real-time pricing with real-time gas turbine commitment and dispatch decisions.
- *Efficiency of M2M Coordination* – This sub-section evaluates the efficiency of 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.[218] 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.[219] 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 V.

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 and the next sub-section contains a similar evaluation of external transactions.

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218 Quick-start GTs can start quickly enough to provide 10-minute non-synchronous reserves.

219 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-76 – Figure A-77: Efficiency of Gas Turbine Commitment

Figure A-76 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-76 shows the average quantity of gas turbine capacity started each day in 2014. 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-77.

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,[220] 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

220 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-76: Efficiency of Gas Turbine Commitment
2014

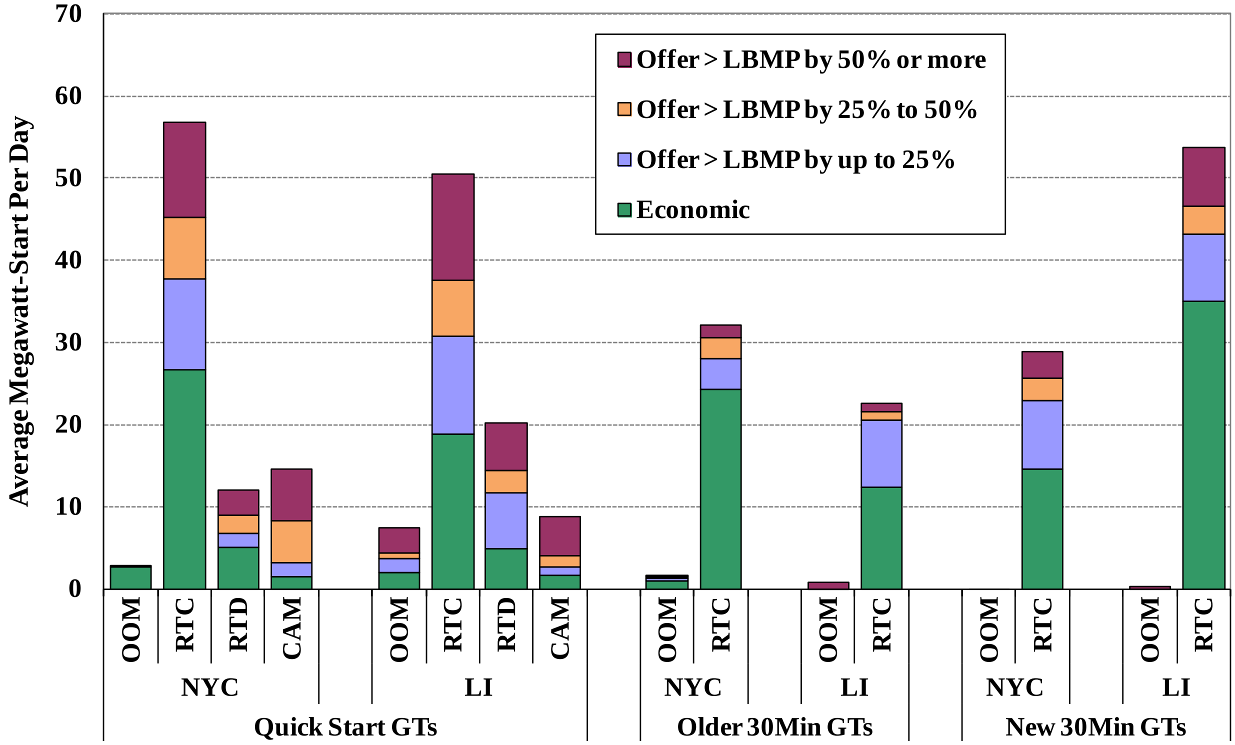


Figure A-77 evaluates the extent to which gas turbines were economic but appeared to be uneconomic because they did not set the LBMP during a portion of the initial commitment period. In particular, we examine every market interval in the initial commitment period of a gas turbine start, which excludes starts via OOM, and report the following seven quantities:

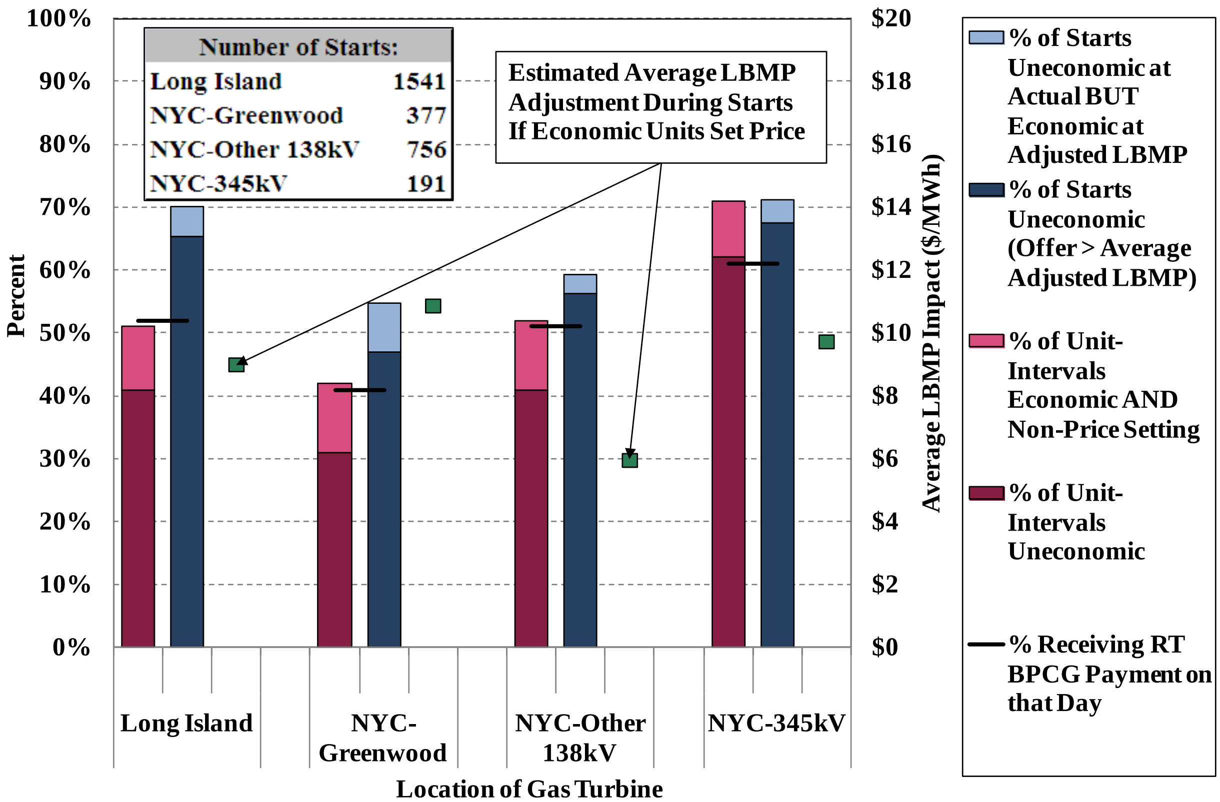
- *Number of Starts* – Excludes self-scheduled and local reliability units.
- *Percent Receiving RT BPCG Payment on that Day* – Share of gas turbine commitments that occurred on days when the unit received a RT BPCG payment for the day.
- *Percent of Unit-Intervals Uneconomic* – Share of intervals during 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-77: Hybrid Pricing and Efficiency of Gas Turbine Commitment
2014



Key Observations: Efficiency of Gas Turbine Commitment

- Of the gas turbine capacity that was started during 2014, 78 percent was committed by RTC, 18 percent by RTD and RTD-CAM, and the remaining 4 percent through OOM instructions.

- The overall efficiency of gas turbine commitments was consistent with recent years.

- 48 percent of all gas turbine commitments were clearly economic in 2014.
- An additional 21 percent of all gas turbine commitments were cases when the gas turbine offer was within 125 percent of LBMP in 2014.
- Hence, the NYISO's real-time market models are relatively effective in committing gas turbines efficiently.

- Gas turbine capacity was started less frequently in 2014, reflecting the reduced needs for such capacity to manage congestion and/or satisfy reserve requirements in real time.
  - From 2013 to 2014, the frequency of starts fell 30 percent in New York City and 8 percent in Long Island.
  - The reductions were attributable to less frequent peaking conditions and less frequent congestion during the summer (particularly in New York City for reasons discussed in Section III).
- Once committed, gas turbines were economic in nearly 60 percent of the five-minute intervals during their initial one-hour commitment period (excluding self-schedules and local reliability commitments) in 2014. (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 2014, 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 \$6 to \$11 per MWh for each start in New York City and Long Island in 2014. This would increase annual average LBMPs by an average of \$0.5 to \$1.5 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.
    - 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. Efficiency of 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.[221] 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 .[222]

Figure A-78: Efficiency of 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 2014.

Figure A-78 compares the actual flows on Ramapo PARs with their M2M operational targets in 2014. 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.[223]
- 80% RECo Load – 80 percent of telemetered Rockland Electric Company load.
- ABC & JK Flow Deviations – The total flow deviations on the ABC and JK PAR-controlled lines from schedules under the ConEd-PSEG Wheeling agreement.[224]

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221 The terms of M2M coordination are set forth in NYISO OATT Section 35.23, which is Schedule D to Attachment CC.

222 The list of pre-defined flowgates is posted at http://www.nyiso.com/public/webdocs/markets_operations/market_data/reports_info/CoordinatedFlowgatesandEntitlements.mht.

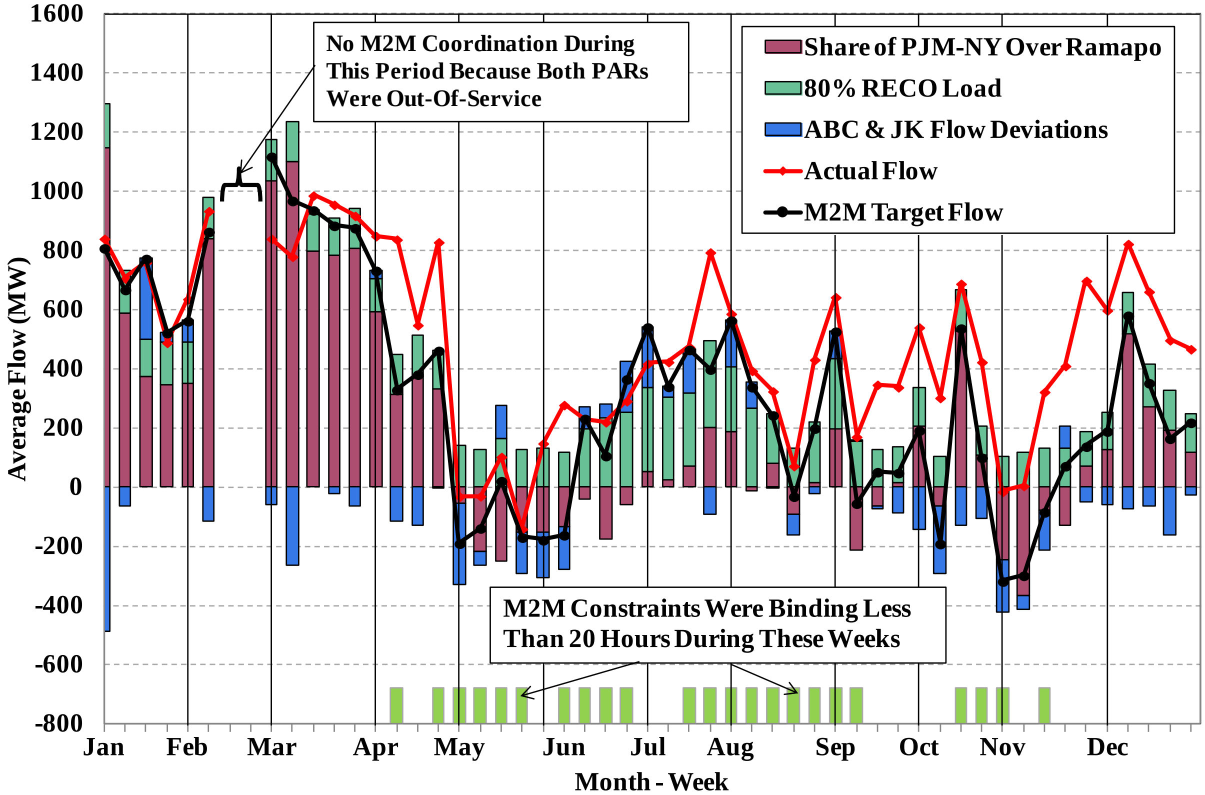
223 This assumed share was 61 percent in 2014 when both Ramapo PARs were in service most of time. However, this was 46 percent from May 2013 to December 2013 because one of the two Ramapo PARs was out of service during this period.

224 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.

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.

Figure A-78: Actual and Target Flows for the Ramapo Line

During the Intervals with Binding M2M Constraints, 2014



Key Observations: Efficiency of M2M Coordination with PJM

- The use of Re-dispatch Coordination continued to be very limited in 2014.
  - It was activated for: (a) the Central-East interface in a total of 145 hours, primarily in the first quarter of 2014; (b) PJM's Black Oak–Bedington interface in nearly 30 hours; and (c) the Dysinger East interface in roughly 2 hours.
  - These resulted in a total payment of $57k from PJM to the NYISO.
- The use of Ramapo PAR Coordination was less frequent in 2014 than in 2013, reflecting less congestion on M2M constraints because of lower natural gas prices and load levels after the first quarter of the year.
- Average actual flows across Ramapo PARs were higher (by more than 170 MW) than the M2M Target Flows in 2014 (when M2M constraints were binding).
  - This increased from 2013 when M2M Target Flow was usually lower than actual flow because:

  – The obligation to make RECo deliveries was reduced because of lower load levels; and

  – The share of PJM-NY interchange fell because of decreased net imports from PJM.

- Average actual flows into New York rose from 2013 because:

  – Both Ramapo PARs were in service during most of 2014 (while one PAR was out of service in most of 2013), better enabling the line to satisfy the operational targets on most days.

  – M2M process enhancements reactivated coordination for TSA flowgates in early 2014 following its suspension on July 12, 2013. Under the new process, PJM can avoid settlements associated with TSA flowgates if they are making efforts to adjust flows on certain PAR-controlled lines during a TSA.

- The additional flow beyond the Target helped the NYISO relieve congestion on M2M Flowgates and also reduced the M2M payments made by PJM to the NYISO from $7 million in 2013 to $4 million in 2014.

  – Most of the $4 million in payments accrued on several days in late January, late February, and early March during periods of under delivery from PJM (i.e., when actual flow < target flow) with acute west-to-east congestion in the NYISO.

  – M2M constraints in PJM were rarely binding on days when PJM over-delivered (i.e., actual flow > target flow), therefore only limited amount of payments was made by NYISO to PJM.

- Although Ramapo PAR Coordination provided congestion relief that was very beneficial for managing congestion on the Central-East interface, the Leeds-to-Pleasant Valley line, and the Dysinger East interface, there were times when additional flows across Ramapo contributed to congestion in western New York. This is discussed further in Section C.

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 transaction scheduling procedures.[225] Such lines are analyzed in Section IV 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-9 and Figure A-79: 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 2014.

Table A-9 evaluates the consistency of the direction of power flows on non-optimized PAR-controlled lines and LBMP differences across these lines during 2014. The evaluation is done for the following eleven PAR-controlled lines:

- Two between IESO and NYISO: St. Lawerence – 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 were 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-9 shows:

- Average hourly net flows into NYCA or New York City;

[225] 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.[226]

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.[227] 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.

226 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.

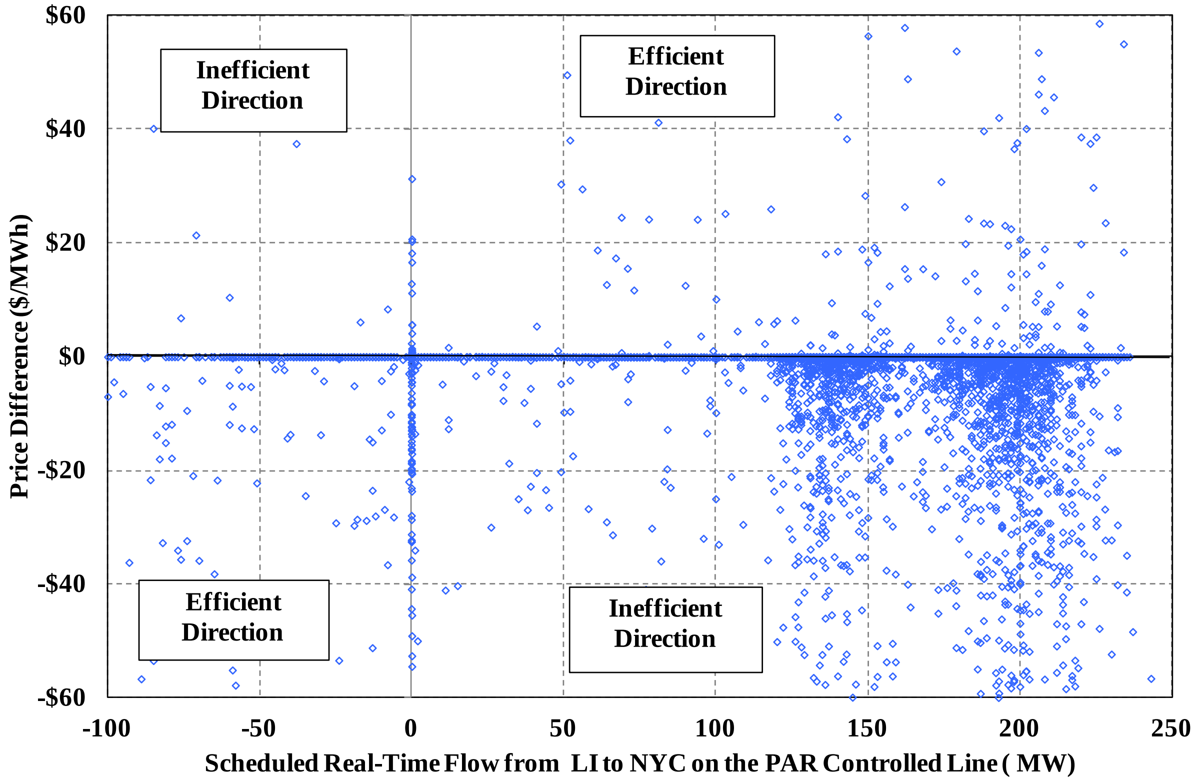
227 For example, if 100 MW is scheduled from the low-priced region to the high-priced region in the day-ahead market, the day-ahead schedule would be considered *efficient direction*, and if the relative prices of the two regions was switched in the real-time market and the flow was reduced to 80 MW, the adjustment would be shown as -20 MW and the real-time schedule adjustment would be considered *efficient direction* as well.

Table A-9: Efficiency of Scheduling on Non-Optimized PAR Controlled Lines
2014

	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	$13.09	53%	$7
New England to NYCA								
Sand Bar	-87	-$17.07	85%	$13	-1	-$18.44	53%	$0
PJM to NYCA								
Waldwick	-904	$3.17	38%	-$22	48	$2.70	50%	$0
Ramapo	276	$7.11	68%	$45	151	$5.46	56%	$6
Farragut	714	-$0.32	50%	-$1	-54	-$0.48	51%	-$1
Goethals	194	$1.10	61%	$3	55	$2.49	49%	-$1
Long Island to NYC								
Lake Success	153	-$7.00	3%	-$9	-6	-$8.33	68%	$1
Valley Stream	52	-$12.39	2%	-$5	2	-$19.59	32%	-$2

Figure A-79 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-79: Efficiency of Scheduling on PAR Controlled Lines
Lake Success-Jamaica Line – 2014



Key Observations: Efficiency of Scheduling over PAR-Controlled Lines

- The vast majority of flows across these PAR-controlled lines was scheduled in the day-ahead market, while small balancing adjustments were typically made in the real-time market.
- In the day-ahead market, power flowed in the efficient direction (from the lower-priced area to the higher-priced area) in the majority of hours on all but one PAR-controlled line between New York and neighboring markets during 2014.
  - The share of hours with power flowing in the efficient direction ranged from 38 percent for the Waldwick lines to 85 percent for the Sand Bar (i.e. PV-20) line.
  - The Waldwick lines generally flowed power from NYCA to PJM due to the ConEd-PSEG wheeling agreement, although the price on the PJM side was lower by an average of $3.17 per MWh during 2014.
  - We estimate that the controllable lines between NYCA and adjacent control areas achieved a total of $60 million in day-ahead production cost savings in 2014, excluding the Waldwick lines.

  - However, use of the Waldwick lines to support the ConEd-PSEG wheeling agreement *increased* day-ahead production costs by an estimated $22 million in 2014.[228]
  - Significant additional production cost savings could be achieved by incorporating the Waldwick lines into the M2M process.

- The scheduling of the PAR-controlled lines from Long Island into New York City was much less efficient than any of the other PAR-controlled lines.
  - In the day-ahead market, power flowed in the inefficient direction in 97 to 98 percent of hours on the two PAR-controlled lines between Long Island and New York City during 2014, comparable to the results in recent years.
  - The use of these lines increased day-ahead production costs by an estimated $14 million in 2014 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 frequently 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 sometimes operated in order 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-9 reports the production cost savings for balancing adjustments considering congestion on all flowgates.
    - In 2014, the production cost savings were reduced by an estimated $3.8 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). 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-9 would likely have exceeded $10 million.

[228] For the reasons noted in Footnote 206, this method of estimating production cost savings tends to over-estimate the costs from inefficient scheduling.

- These results indicate that significant opportunities remain to improve the operation of these lines, particularly the Waldwick lines and the lines between New York City and Long Island.
  - 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. The Waldwick lines are scheduled in accordance with the ConEd-PSEG wheeling agreement, while the lines between New York City and Long Island are scheduled in accordance with the ConEd-LIPA wheeling agreement. 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).[229]

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.

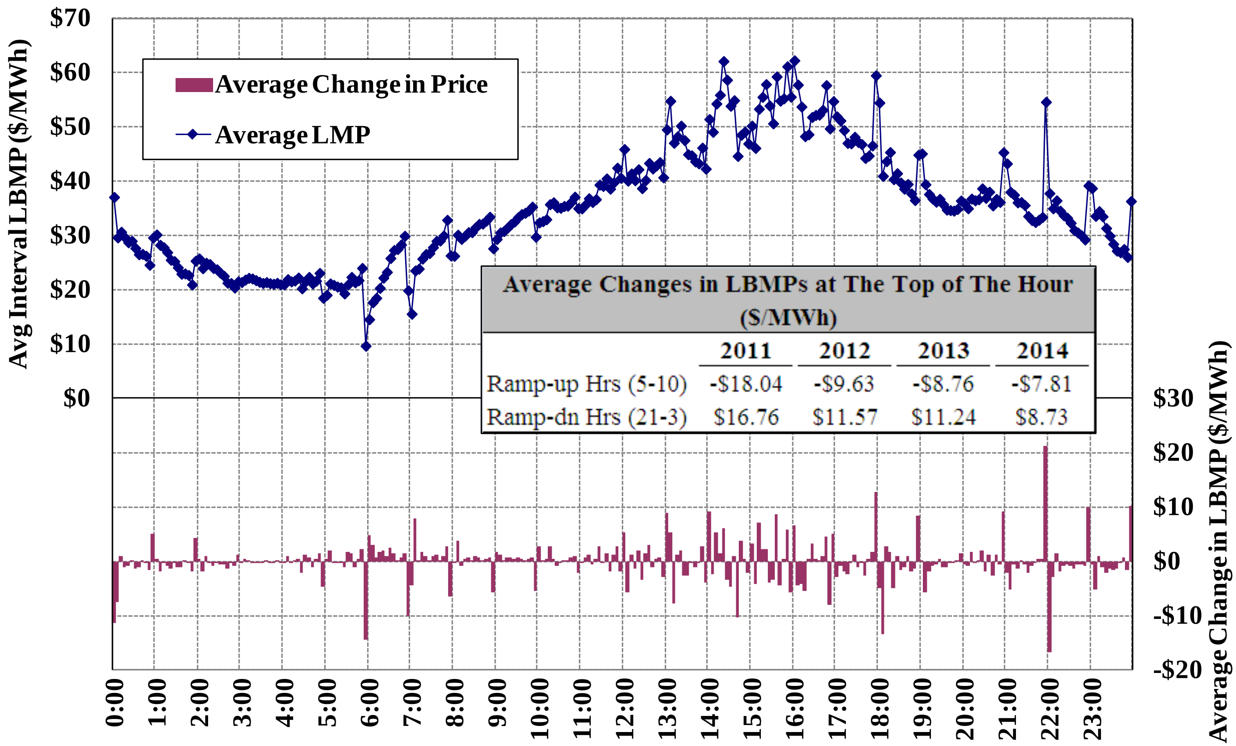
This sub-section analyzes cyclical patterns of price volatility in real time that tend to occur predictably at certain times of day, while the next sub-section focuses on transient patterns of price volatility that may or may not occur repetitively at certain times.

[229] The proposed financial right is described in Section III.E of the Appendix.

Figure A-80 & Figure A-81: Cyclical Real-Time Price Volatility

Figure A-80 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 2014. 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 four years.

Figure A-80: Statewide Average Five-Minute Prices by Time of Day
June to August, 2014



Average Changes in LBMPs at The Top of The Hour ($/MWh)

	2011	2012	2013	2014
Ramp-up Hrs (5-10)	-$18.04	-$9.63	-$8.76	-$7.81
Ramp-dn Hrs (21-3)	$16.76	$11.57	$11.24	$8.73

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.

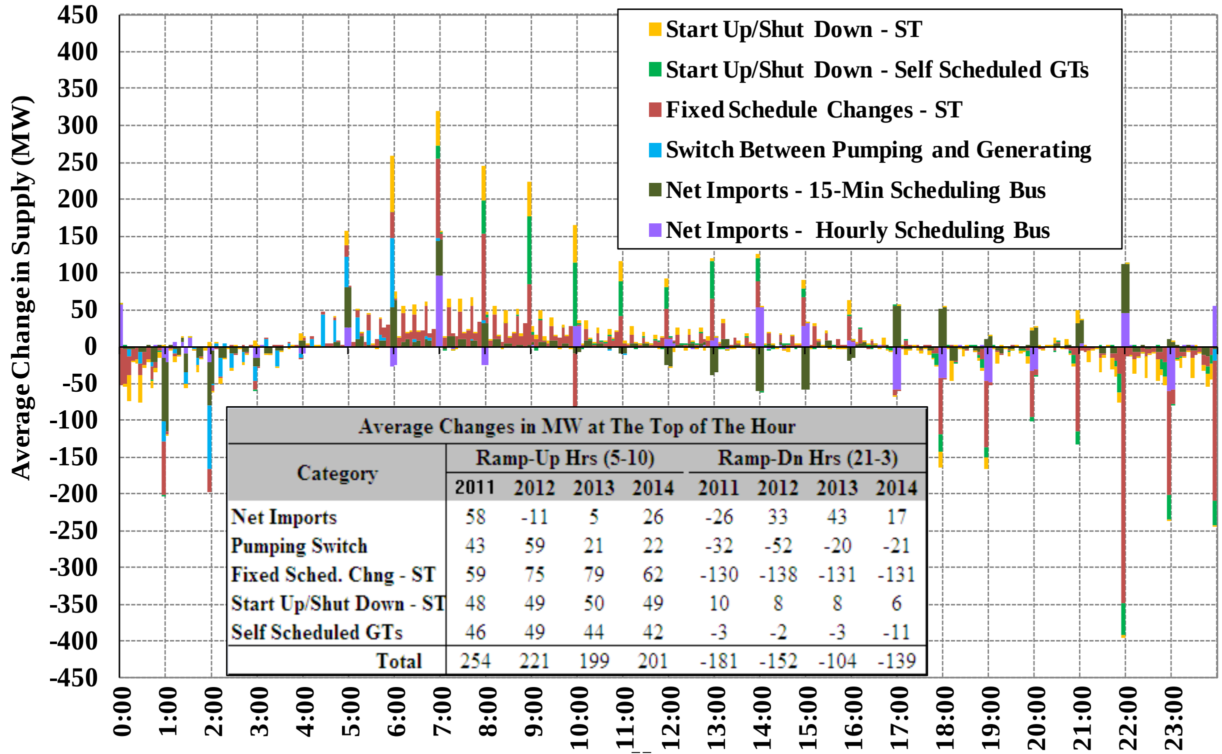
Figure A-81 shows the average net changes from one interval to the next for the following five categories of inflexible supply:

- *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 four years.

Figure A-81: Factors Contributing to Cyclical Real-Time Price Volatility
June to August, 2014



Category	Ramp-Up Hrs (5-10)				Ramp-Dn Hrs (21-3)			
	2011	2012	2013	2014	2011	2012	2013	2014
Net Imports	58	-11	5	26	-26	33	43	17
Pumping Switch	43	59	21	22	-32	-52	-20	-21
Fixed Sched. Chng - ST	59	75	79	62	-130	-138	-131	-131
Start Up/Shut Down - ST	48	49	50	49	10	8	8	6
Self Scheduled GTs	46	49	44	42	-3	-2	-3	-11
Total	254	221	199	201	-181	-152	-104	-139

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 in recent years.
  - From 2011 to 2014, the average size of upward spikes at the top of the hour during the ramp-down hours fell from roughly \$17 to \$9/MWh; while the average downward spikes at the top of the hour during the ramp-up hours fell from roughly \$18 to \$8/MWh.
  - The reduction has been primarily attributable to two changes in resource scheduling:
    - 15-minute scheduling (which was evaluated Section IV) has been activated at several external interfaces since 2011, allowing external schedule changes to occur throughout the hour, rather than only at the top of each hour.
    - 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 after 2012.
  - The further reduction from 2013 to 2014 was also partly because of much less severe peaking conditions and lower natural gas prices in the summer.

- Our initial assessment of the performance of CTS with PJM (see Section IV) 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
    - 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-75 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 energy-balance constraint (i.e., the requirement that supply equal demand) in 2014. The effects of transient transmission constraints tend to be localized, while transient spikes in the energy-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 $300 per MWh; and
- It increases by at least 200 percent from the previous interval.

A spike in the shadow price of the energy-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 $150 per MWh; and
- It increases by at least 200 percent from the previous interval.

Although the price spikes analyzed in this subsection account for just 1.8 percent of the real-time pricing intervals in 2014, 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-10: Transient Real-Time Price Volatility

Table A-10 summarizes transient real-time price spikes by constraint (including transmission facilities and power-balance constraints) in 2014 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. 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).[230] 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 to 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.

- 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.

[230] These lines are discussed further in Subsection C.

- 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.

- 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 shutdown 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 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. [231]

- Limit Decreased/Unrelaxed – This includes instances when the constraint limit changes from the previous interval. It also includes reductions in the effective limit if a transmission shortage occurred in the previous interval, leading it to be relaxed by an amount larger than in the current interval. [232]

- Re-Dispatch for Other Constraint (RTD) – Multiple constraints often bind suddenly at the same time because of some common causal factor. 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-10, since this category includes the responses to a primary cause that is reflected in one of the other rows.

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231 Ramapo M2M coordination is discussed further in Subsection B.

232 Relaxation of transmission constraints is described further in Subsection H.

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. [233] A particular source is shaded for a particular constraint category if the source accounted for at least 10 percent of all of the MW contributions to the constraint during price spike intervals.

Table A-10: Drivers of Transient Real-Time Price Volatility

2014

	Power Balance		West Zone 230kV Lines		Central East		Dunwoodie - Shore Rd 345kV		East Garden City - Valley Str 138kV	
Average Transfer Limit	n/a		683		2517		747		252	
Number of Price Spikes	289		336		165		170		889	
Average Constraint Shadow Price	$320		$1,868		$653		$747		$1,151	
Source of Increased Constraint Cost:	(MW)	(%)	(MW)	(%)	(MW)	(%)	(MW)	(%)	(MW)	(%)
External Interchange	98	34%	2	7%	26	18%	54	45%	0	2%
Fixed Schedule PARs	0	0%	3	9%	33	23%	18	15%	15	71%
Loop Flows & Other Non-Market	0	0%	20	69%	14	10%	9	7%	1	6%
RTC Shutdown Resource	45	16%	0	0%	18	12%	20	17%	2	11%
Self Scheduled Shutdown/Dispatch	42	15%	0	0%	17	12%	2	2%	1	4%
Load	35	12%	1	3%	7	5%	7	6%	0	1%
Generator Trip/Derate/Dragging	28	10%	0	0%	14	9%	8	7%	1	3%
Wind	22	8%	1	5%	1	1%	0	0%	0	0%
Redispatch for Other Constraint (OOM)	17	6%	0	0%	4	2%	0	0%	0	0%
Ramapo PARs	0	0%	1	3%	7	5%	0	0%	0	0%
Limit Decreased/Unrelaxed	0	0%	1	3%	3	2%	2	2%	0	2%
Total	286	100%	29	100%	143	100%	119	100%	21	100%
Redispatch for Other Constraint (RTD)	121		9		46		9		1	

Key Observations: Transient Real-Time Price Volatility

- Transient shadow price spikes occurred in about 1.8 percent of all intervals in 2014.
  - For the power-balance constraint, the primary drivers were external interchange adjustments, decommitment of generation by RTC, and self-scheduled generators reducing output.
  - 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. [234]
  - 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).

233 The West Zone 230kV Lines category includes the Niagara-to-Packard, Packard-to-Sawyer, and Huntley-to-Sawyer transmission lines.

234 This accounts for the fact that the EMS software recognizes that the Niagara plant consists of 25 generators that are interconnected 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, 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 the East Garden City-to-Valley Stream 138kV line in Long Island, the primary drivers were from fixed schedule PAR flow adjustments (particularly from the 901 line) and the shutdown of peaking units by RTC.

- 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.
  - 51 percent of the transient price spikes for these three categories occurred in interval-ending :00 or :05.
  - Large hourly schedule changes caused price spikes in many intervals when generation was ramp-limited in responding to the adjustment in interchange.
  - CTS with PJM and CTS with 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 initial assessment of the performance of CTS with PJM (see Section IV) 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 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 value.
  - 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 are available to relieve the constraint but the low-cost resources 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 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 price spikes.

  - 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 other generation can ramp 15 minutes from one evaluation period to another, RTC may not anticipate that shutting-down several gas turbines simultaneously will result in a transient shortage.

  - 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-81 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).

- 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: [235]

  - 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

[235] See Recommendation #8 in Section XI.

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.

- To reduce unnecessary price volatility from variations in loop flows and fixed schedule PAR flows, we recommend the NYISO consider the following: [236]
    - 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 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 XI discusses our recommendation for the NYISO to consider modeling 115kV transmission constraints in upstate New York in the day-ahead and real-time markets and to use a more detailed model of the Niagara generator that reflects the effects of its interconnection points on the 115kV and 230kV systems. [237] 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 at the Niagara plant more efficiently to relieve congestion. Currently, any such re-dispatch occurs through less precise out-of-market instructions. [238]

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

[236] See in Recommendation #9 in Section XI.

[237] See in Recommendation #12 in Section XI.

[238] See Section V.I in the Appendix for more discussion on out-of-merit dispatch for West Zone 115 kV lines.

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 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 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: [239]

- Shortages of operating reserves and regulation; and
- Transmission shortages.

Figure A-82: 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-82 summarizes physical ancillary services shortages and their effects on real-time prices in 2013 and 2014 for the following six categories:

[239] Our prior reports also evaluated market operations during reliability demand response deployments. In 2014, the NYISO deployed reliability demand response resources only on one day, January 7. 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. Even if the scarcity pricing rule was not invoked, LBMPs would have averaged more than $400/MWh during the event as a result of very high natural gas prices. So the effect of the scarcity pricing was modest on this day.

- 30-minute NYCA – The ISO is required to hold 1,965 MW of 30-minute operating reserves in the state and has a demand curve value of $50/MWh if the shortage is less than 200 MW, $100/MWh if the shortage is between 200 and 400 MW, and $200/MWh if the shortage is more than 400 MW.

- 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 $450/MWh.

- 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 $500/MWh.

- 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 $500/MWh.

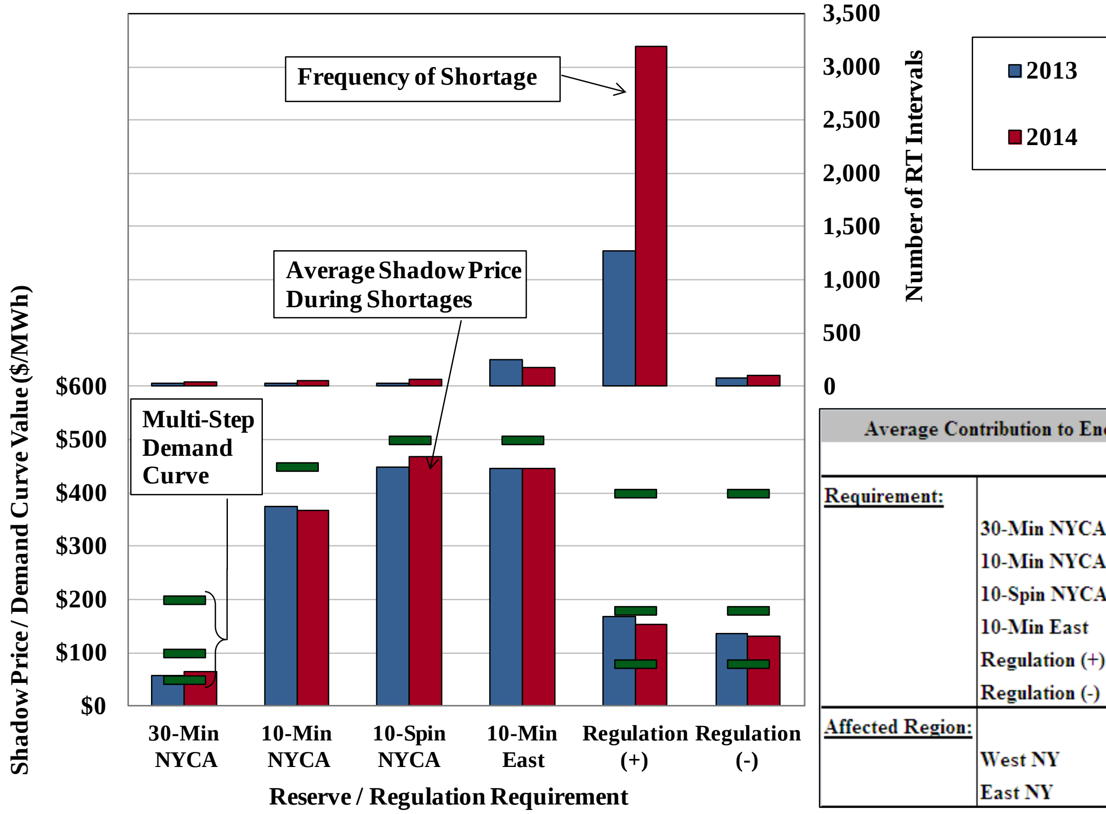
- Regulation – The ISO is required to hold 150 to 250 MW of regulation capability in the state and has a demand curve value of $80/MWh if the shortage is less than 25 MW, $180/MWh if the shortage is between 25 and 80 MW, and $400/MWh if the shortage is more than 80 MW.

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 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.

Figure A-82: Real-Time Prices During Ancillary Services Shortages
2013 – 2014



Average Contribution to Energy Price			
		2013	2014
Requirement:			
	30-Min NYCA	$0.01	$0.02
	10-Min NYCA	$0.13	$0.18
	10-Spin NYCA	$0.11	$0.30
	10-Min East	$1.04	$0.77
	Regulation (+)	$1.53	$3.44
	Regulation (-)	-$0.07	-$0.09
Affected Region:			
	West NY	$1.72	$3.86
	East NY	$2.76	$4.63

Key Observations: Real-Time Prices During Physical Ancillary Services Shortages

- The incidence of physical shortage conditions (i.e., the frequency and the average shadow cost of shortages) was comparable between 2013 and 2014 for most reserve products.
  - Regulation shortages were most frequent in both years. However, regulation shortages occurred much more frequently in 2014 than in 2013 (i.e., 3 percent of all intervals in 2014 compared to 1 percent in 2013).
    - The increase occurred primarily in the first quarter, which accounted for more than 70 percent of all regulation shortages in 2014.
    - The cost to provide regulation service rose significantly in the first quarter when increased peaking conditions and substantially higher natural gas prices led to similarly elevated opportunity costs (associated with high energy prices) to provide regulation.
    - The model “chose” to be short of regulation when the cost to provide regulation exceeded the lowest demand curve value of $80/MWh.
  - 10-minute eastern reserve shortages were the next most frequent, occurring around 0.2 percent of all intervals in each of 2013 and 2014.

  - These two ancillary services shortages had the largest effects on real-time prices.

- 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 2013 and 2014.[240]

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.

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-83: 10-minute Reserve Capacity in Eastern New York on Cold Days

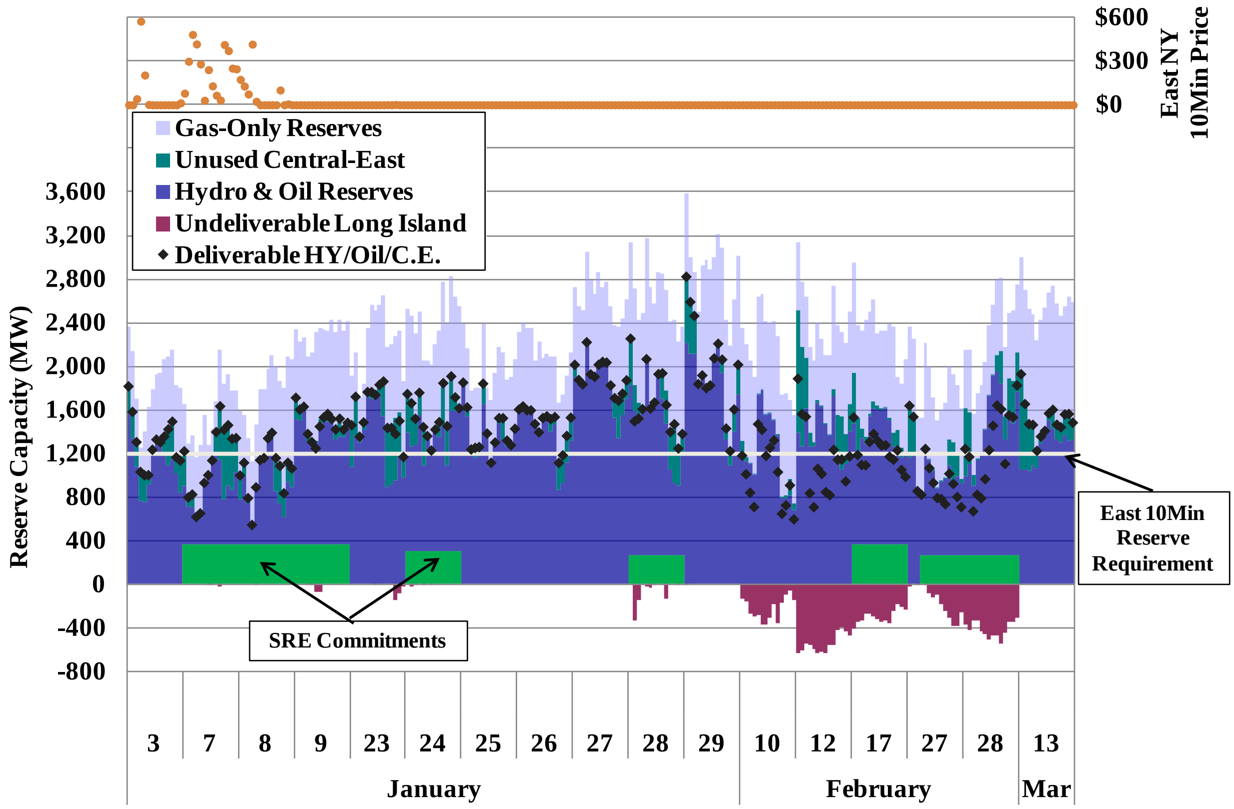
Figure A-83 shows hourly data for Hours Beginning (HB) 7-20 on selected tight gas-system days. The top portion of the chart shows hourly average prices for Eastern 10-minute reserves. The bottom portion of the chart shows the capacity in Eastern New York that is capable of providing 10-minute reserves (including scheduled and not-scheduled but available) on these days. The reserve capacity is shown in the following categories:

240 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.

- 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. [241]

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 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.

Figure A-83: 10-minute Reserve Capacity in Eastern New York
On Cold Days with Hourly OFOs, 2014



241 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.

<u>Key Observations: Availability of Eastern 10-Minute Reserves on Hourly OFO Days</u>

- 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 72 hours (with hourly OFOs) on these days when the NYISO relied on some gas-only capacity to satisfy the Eastern 10-minute reserve requirement. However:
    - Eastern 10-minute reserve prices cleared at \$0/MWh in 53 of these hours; and
    - Eastern 10-minute reserve prices averaged just \$190/MWh in the other 19 hours.
  - An average of roughly 300 MW of capacity was SRE-committed on eight of the days for Eastern New York reserve needs, while Eastern 10-minute reserve prices were \$0/MWh during most hours on these eight days.
- Deliverable non-gas-dependent 10-minute reserves were most restricted in Eastern New York on several days in February (e.g., the 10^{th}, 12^{th}, 27^{th}, and 28^{th}) because:
  - Oil-fired generation increased significantly on these days, averaging 1.4 to 2.4 GW. This significantly reduced the amount of oil-fired capacity that was available to provide 10-minute reserves.
  - The Central-East interface was heavily loaded on these days, leaving little unused transfer capability in most hours.
  - A significant amount of reserves (150MW to 550MW) from Long Island resources was not deliverable in most hours.

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. During transmission shortages, prices can be set in one of the following three ways:

- Constraint 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. In such cases, the shadow price is set by the marginal re-dispatch costs necessary to satisfy the relaxed limit.

- Set by Transmission Demand Curve – If the marginal redispatch cost needed to resolve a constraint exceeds the $4,000/MWh Transmission Shortage Cost, RTD foregoes more costly redispatch options.

- 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. [242] 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-11: Real- Time Prices During Transmission Shortages

Table A-11 summarizes transmission shortage events by transmission facility during 2014. For each transmission facility, 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 nine transmission facilities that had the most frequent shortages during 2014. 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 was: (a) less than 5 MW; (b) between 5 and 20 MW; and (c) more than 20 MW. [243] The relative economic significance of these shortages may be measured by the average shadow price during transmission shortages multiplied by the frequency of shortages.

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[242] 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.

[243] These segments are consistent with the break points in the proposed new transmission demand curve that will be implemented in 2015.

Table A-11: Real-Time Prices During Transmission Shortages
2014

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)
E. Garden City - Valley Stream	Y	Y	N			22	$665	11	$620	33	$650
	Y	N	N	209	$433	383	$721	161	$1,563	753	$821
	N	Y	N	307	$610	257	$812	23	$1,462	587	$732
	N	N	Y	55	$4,000	2	$4,000			57	$4,000
	Total			**571**	**$872**	**664**	**$764**	**195**	**$1,498**	**1430**	**$907**
Dunwoodie - Shore Road	Y	Y	N					14	$573	14	$573
	Y	N	N	6	$245	12	$339	41	$263	59	$276
	N	Y	N	230	$205	373	$228	306	$478	909	$306
	N	N	Y								
	Total			**236**	**$206**	**385**	**$231**	**361**	**$457**	**982**	**$308**
Niagara - Packard	Y	Y	N								
	Y	N	N	117	$202	159	$849	158	$1,219	434	$809
	N	Y	N								
	N	N	Y	33	$4,000					33	$4,000
	Total			**150**	**$1,037**	**159**	**$849**	**158**	**$1,219**	**467**	**$1,035**
Central East Interface	Y	Y	N								
	Y	N	N					1	$184	1	$184
	N	Y	N	89	$204	165	$303	169	$529	423	$373
	N	N	Y								
	Total			**89**	**$204**	**165**	**$303**	**170**	**$527**	**424**	**$372**
Packard - Sawyer	Y	Y	N								
	Y	N	N	108	$276	171	$398	111	$369	390	$356
	N	Y	N								
	N	N	Y	5	$4,000					5	$4,000
	Total			**113**	**$440**	**171**	**$398**	**111**	**$369**	**395**	**$402**
Foxhill - Greenwood	Y	Y	N								
	Y	N	N	117	$164	82	$110	28	$119	227	$139
	N	Y	N								
	N	N	Y	1	$4,000					1	$4,000
	Total			**118**	**$196**	**82**	**$110**	**28**	**$119**	**228**	**$156**
Huntley - Sawyer	Y	Y	N								
	Y	N	N	31	$783	69	$1,858	58	$2,154	158	$1,756
	N	Y	N								
	N	N	Y	6	$4,000	2	$4,000			8	$4,000
	Total			**37**	**$1,304**	**71**	**$1,918**	**58**	**$2,154**	**166**	**$1,864**
Greenwood Vernon	Y	Y	N								
	Y	N	N	60	$67	37	$161	1	$38	98	$102
	N	Y	N								
	N	N	Y	28	$4,000	1	$4,000			29	$4,000
	Total			**88**	**$1,319**	**38**	**$262**	**1**	**$38**	**127**	**$992**
Leeds - Pleasant Valley	Y	Y	N			1	$85	3	$1,802	4	$1,372
	Y	N	N	37	$100	9	$172	2	$706	48	$138
	N	Y	N	7	$1,189	12	$159	18	$543	37	$540
	N	N	Y	1	$4,000					1	$4,000
	Total			**45**	**$356**	**22**	**$161**	**23**	**$721**	**90**	**$401**
All Other Facilities	Y	Y	N			1	$84	3	$1,643	4	$1,253
	Y	N	N	94	$268	104	$321	128	$530	326	$387
	N	Y	N	68	$584	84	$570	85	$712	237	$625
	N	N	Y	9	$4,000					9	$4,000
	Total			**171**	**$590**	**189**	**$430**	**216**	**$617**	**576**	**$548**
All NYCA Facilities	Y	Y	N			24	$616	31	$812	55	$727
	Y	N	N	779	$285	1026	$645	689	$1,007	2494	$632
	N	Y	N	701	$429	891	$442	601	$565	2193	$471
	N	N	Y	138	$4,000	5	$4,000			143	$4,000
	Grand Total			**1618**	**$664**	**1946**	**$560**	**1321**	**$801**	**4885**	**$660**

Key Observations: Real-Time Prices During Transmission Shortages

- Transmission shortages occurred in roughly 4 to 5 percent of intervals in 2014, of which:
  - Constraint relaxation occurred in 51 percent of shortage intervals;
  - Congestion-relieving offline GTs were not started in 45 percent of shortage intervals;
  - Both of the above occurred in 1 percent of shortage intervals; and
  - None of the above occurred in the remaining 3 percent of shortage intervals.
    - In these cases, the transmission demand curve was used and set the constraint shadow price at $4000/MWh.
- Transmission shortages occurred most frequently in Long Island, in the West Zone, and across the Central-East interface in 2014.
  - The East Garden City-to-Valley Stream line and the Dunwoodie-to-Shore Road line on Long Island accounted for nearly 50 percent of all transmission shortages in 2014.
    - Severe congestion across the two 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 and/or when gas turbines were shutdown.
    - In most cases, offline GTs were counted towards resolving congestion but were not started because of the transient nature of the congestion.
  - Several 230 kV transmission lines in the West Zone along the Niagara-Packard-Sawyer-Huntley transmission paths accounted for more than 20 percent of transmission shortages in 2014.
    - Acute congestion occurred more frequently on these lines in the last two years. The constraint limit was relaxed in almost every shortage interval because of a lack of flexible resources (i.e. GTs) in the West Zone for managing congestion.
  - The Central-East interface accounted for nearly 10 percent of shortages in 2014.
    - 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 (capable of relieving Central-East congestion).
- Although average constraint shadow prices were relatively high during shortages and tended to increase as the shortage quantity became bigger, shadow prices often did not properly reflect the severity of the shortage.
  - For example, shadow costs averaged less than $200/MWh when transmission shortages occurred in New York City load pockets or into Southeast New York (e.g., across the Leeds-Pleasant Valley line) when the constraint was relaxed by 20 MW or less.

  - 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 transmission demand curve (scheduled for implementation soon) will provide price signals that are more consistent with the severity of shortages.
  - The new Graduated Transmission Demand Curve ("GTDC") will be set a $350/MWh for shortages of less than 5 MW, $1,175/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-84: 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.

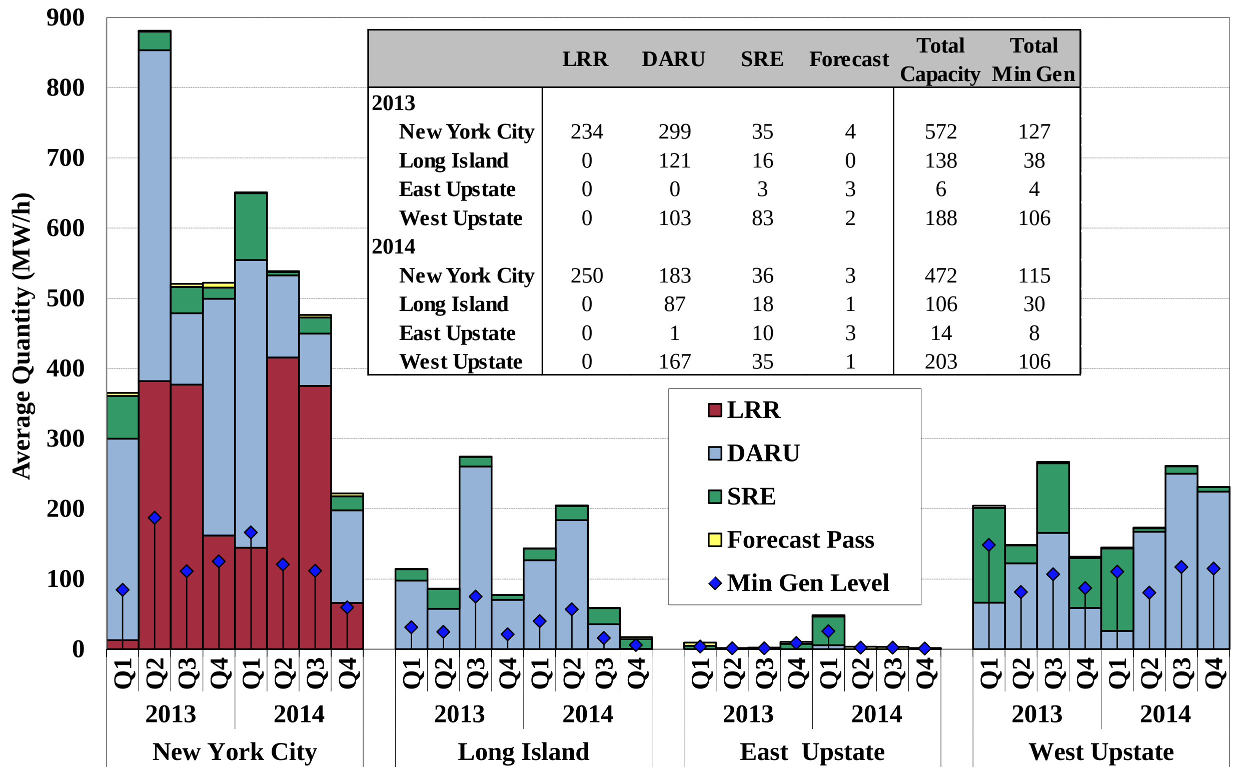
Generators that are committed for reliability are generally not economic at prevailing market prices, but they affect the market by: (a) reducing prices from levels that would otherwise result from a purely economic dispatch; and (b) increasing non-local reliability uplift since a portion of the uplift 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 NYC, 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-84 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 2013 and 2014. 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 2013 and 2014 on an annual basis.

Figure A-84: Supplemental Commitment for Reliability in New York

By Category and Region, 2013 – 2014



	LRR	DARU	SRE	Forecast	Total Capacity	Total Min Gen
2013						
New York City	234	299	35	4	572	127
Long Island	0	121	16	0	138	38
East Upstate	0	0	3	3	6	4
West Upstate	0	103	83	2	188	106
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

Figure A-85: Supplemental Commitment for Reliability in New York City

In 2013 and 2014, most supplemental commitment for reliability occurred in New York City. Figure A-85 summarizes an analysis that identifies the causes for the reliability commitments in New York City. Specifically, Figure A-85 shows the minimum generation committed for reliability by reliability reason and by location in New York City during 2013 and 2014.

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: [244]

- NOx Only – If needed for NOx bubble and no other reason. [245]
- 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 for IR-3 and no other reason except NOx.
- Multiple Reasons – If needed for two or three out of ARR 26, ARR 37, and IR-3. 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.

244 A unit is considered to be committed for a LRR constraint if the constraint would be violated without the unit's capacity.

245 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.

The pie chart in the figure shows the portion of total capacity committed under different reasons for 2014 only.

Figure A-85: Supplemental Commitment for Reliability in New York City
By Category and Region, 2013 – 2014

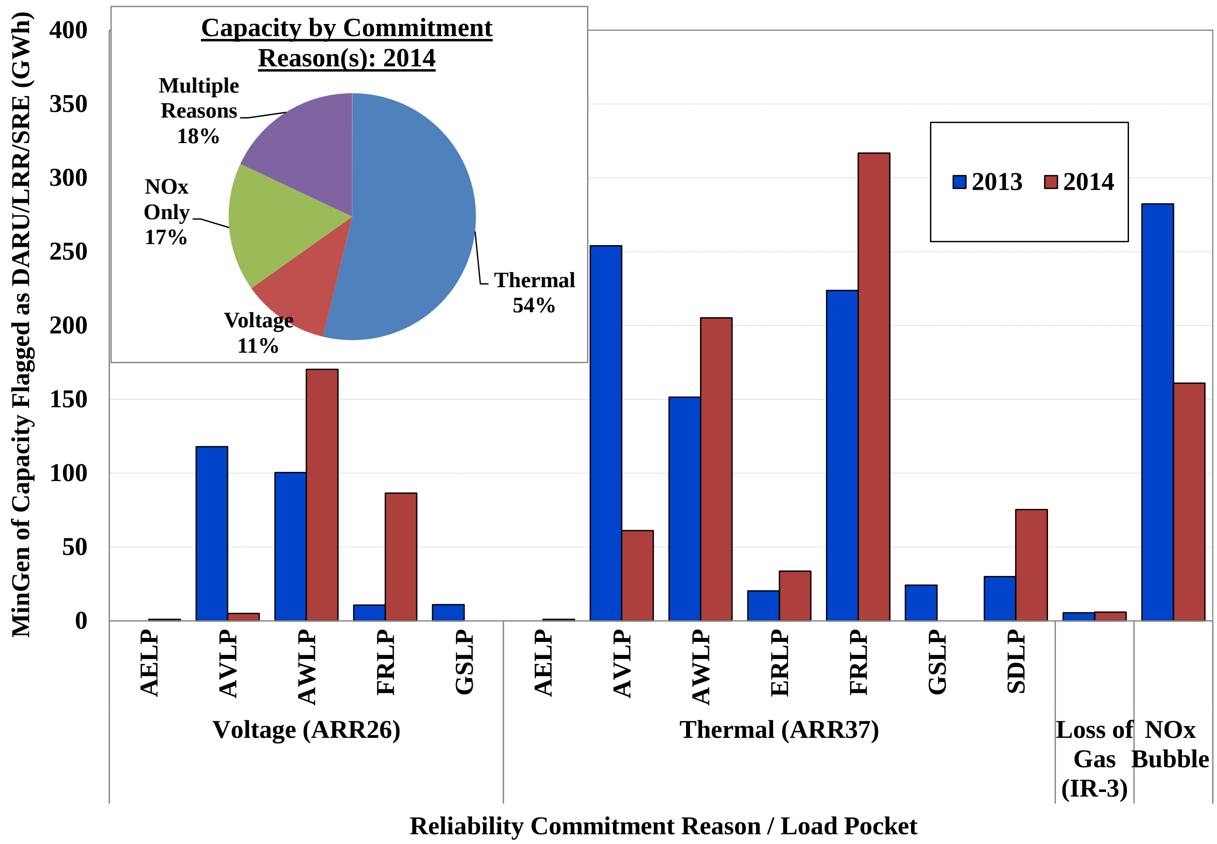


Figure A-86: NOx Emissions from Units in New York City NOx Bubbles

Although supplemental commitments for the NOx Bubble constraint fell in 2014, they still accounted for a significant share of all supplemental commitments during the five-month Ozone reason (i.e., from May to September). 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.[246] For owners of generators that emit beyond the presumptive RACT limits, they have the following three "compliance options":[247, 248]

[246] See Subpart 227-2.4 (e) of Chapter III in the NYDEC Regulations for these limits. The document is available online at: http://www.dec.ny.gov/regs/4217.html#13915.

[247] See Subpart 227-2.5 (a) –(c) of Chapter III in the NYDEC Regulations for more details. The document is available online at: http://www.dec.ny.gov/regs/4217.html#13915.

[248] A fourth compliance option, "shutdown of an emission source," is also listed in 227-2.5(d).

- Fuel Switching Option;
- 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."[249, 250]

Three generation portfolio owners in New York City have submitted emissions plans to the NYDEC selecting "System Averaging Plan" as their compliance option. In these plans, 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. The NYDEC has approved these plans.

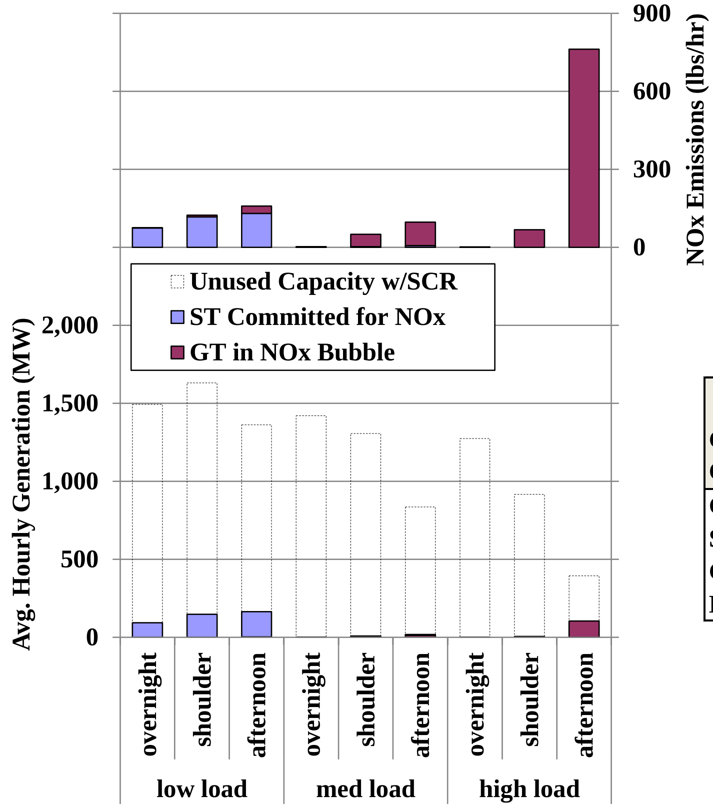
The NYISO has in turn established an LRR constraint for each generation portfolio, requiring that at least one steam unit from each portfolio be committed each day during the five-month Ozone season. This is to ensure that the NOx emission limits won't be violated if gas turbines are committed in real-time. This LRR rule provides uplift payments to the generation owners when the steam commitments are uneconomic at DAM LBMPs.

Figure A-86 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 energy production in average hourly MW for NOx Bubble gas turbines and steam units as well as 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.

249 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." From DAR-20 Economic and Technical Analysis for Reasonably Available Control Technology (RACT), available online at http://www.dec.ny.gov/chemical/91851.html.

250 The NYDEC provides a template for calculating the cost of emissions controls per ton of NO_x reduced at http://www.dec.ny.gov/docs/air_pdf/dar20table1.pdf.

Figure A-86: NOx Emissions And Energy Production from NOx Bubble Generators
By Time of Day, by Load Category, for 2014



Load Category:	Output from GTs in NOx Bubble	Output from STs Committed for Nox
Low	7%	97%
Medium	23%	3%
High	70%	0%
All Days	100%	100%

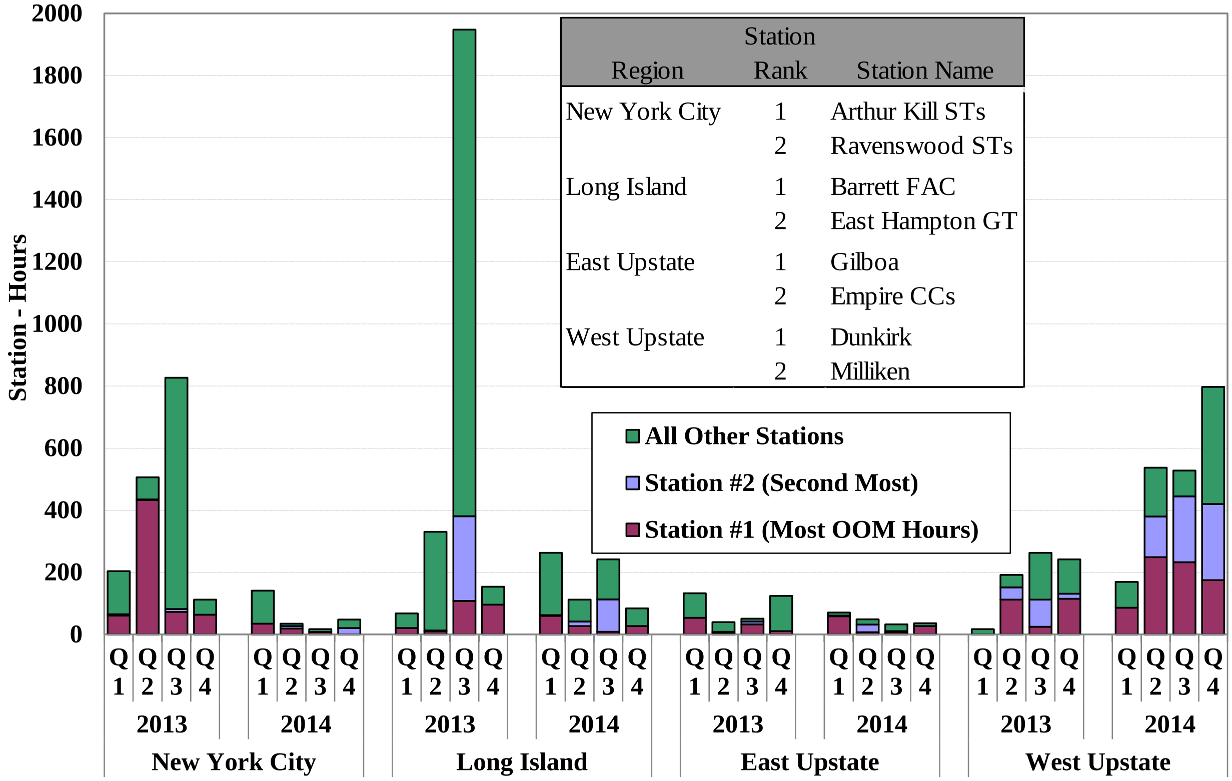
Generator Category:	Share of Generation	Share of NOx Emissions
GT in NOx Bubble	0.3%	8%
Steam Turbine	29%	80%
Generator w/SCR	71%	12%
NYC Total	100%	100%

Figure A-87: Frequency of Out-of-Merit Dispatch

Figure A-87 summarizes the frequency (i.e., the total station-hours) of OOM actions on a quarterly basis in 2013 and 2014 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 2013 are shown separately from other stations (i.e., "Station #1" is the station with the highest number of OOM hours in that region during 2013, 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-87: Frequency of Out-of-Merit Dispatch
By Region by Quarter, 2013-2014



Key Observations: Supplemental Commitment and OOM Dispatch for Reliability

- On average, nearly 800 MW of capacity was committed each hour for reliability in 2014, down roughly 100 MW (or 12 percent) from 2013.
  - Of this total, 59 percent of reliability commitment was in New York City, 13 percent was in Long Island, and 26 percent was in Western New York.
- Despite the reduction in other regions, reliability commitment in Western New York increased moderately from 2013, averaging slightly more than 200 MW in 2014.
  - DARU commitments increased after the first quarter of 2014 when several units that were often needed to manage congestion on 115 kV facilities in Zones A and C became less economic because of lower load levels and natural gas prices.
  - SRE commitments were virtually eliminated in Western New York after March 2014 (when transmission upgrades in the North Zone were completed).
    - The transmission upgrades greatly reduced the effects of key transmission contingencies and associated needs for supplemental commitments.
- Overall, reliability commitment in Long Island fell 23 percent from an average of approximately 140 MW in 2013 to an average of 105 MW in 2014.

  - DARU commitments fell notably in the second half of 2014 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 (IR-5).

- Reliability commitment in New York City fell 17 percent from 2013 to an average of roughly 470 MW in 2014.
  - Reliability commitments fell after the first quarter of 2014, partly because natural gas prices in New York City were lower than the rest of Eastern New York during this period, which made several steam units that were often needed for reliability more economic.
  - 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, reliability commitments for the Freshkills load pocket increased notably in the first quarter of 2014 when multiple transmission facilities were taken out of service for transmission work at the Goethals Bus.
  - Reliability commitments for NOx bubble constraints fell in 2014.
    - Such commitments occurred only during the five-month ozone season (May to September) of each year. In 2014, these commitments accounted for roughly 17 percent of all supplemental commitments, down from the 26 percent in 2013.
    - The reduction was primarily due to the updates in the NOx bubble constraint modeling in SCUC, which now requires less steam turbine capacity to satisfy the NOx bubble requirements in the LRR pass.
    - However, one steam turbine that satisfies the NOx bubble requirements was committed economically less often (because of lower day-ahead LBMPs relative to fuel prices). Therefore, this generator was committed for reliability more often, partly offsetting the overall reduction in reliability commitment.

- Our analysis indicates that in 2014 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, nearly 1.5 GW of offline capacity from newer and cleaner generators (equipped with emission-reducing device) were available and unutilized on days when steam units were committed 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 turbine units with high emissions rates.
    - In 2014, 93 percent of output from the NOx Bubble gas turbines occurred on days with medium to high load levels, while 97 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.

- Out-of-Merit ("OOM") dispatch fell notably in Eastern New York in 2014 but rose considerably in Western New York. From 2013 to 2014,
  - OOM actions fell 85 percent in New York City, partly because of lower load levels, increased in-city generation because of lower natural gas prices, and fewer transmission outages in the Greenwood area (that could not be modeled accurately in the real-time market software).
  - OOM actions fell 72 percent in Long Island, primarily because of transmission improvements (particularly the installation of West Bus and Wildwood DRSS) which greatly reduced the need to dispatch peaking generators to manage voltage constraints on the East End of Long Island.
  - However, OOM actions increased 184 percent in Western New York primarily because the Dunkirk, Olean, and Milliken units were needed more frequently to prevent post-contingency overloading on several 115 kV transmission facilities.
    - 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.[251] Including these unlogged OOM dispatches, Niagara was OOM dispatched more frequently than any other generator in 2014.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-88 and Figure A-89 summarize the three categories of non-local reliability uplift that

[251] See *Quarterly Report on the New York ISO Electricity Markets Third Quarter 2014,* slides 63-66.

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.

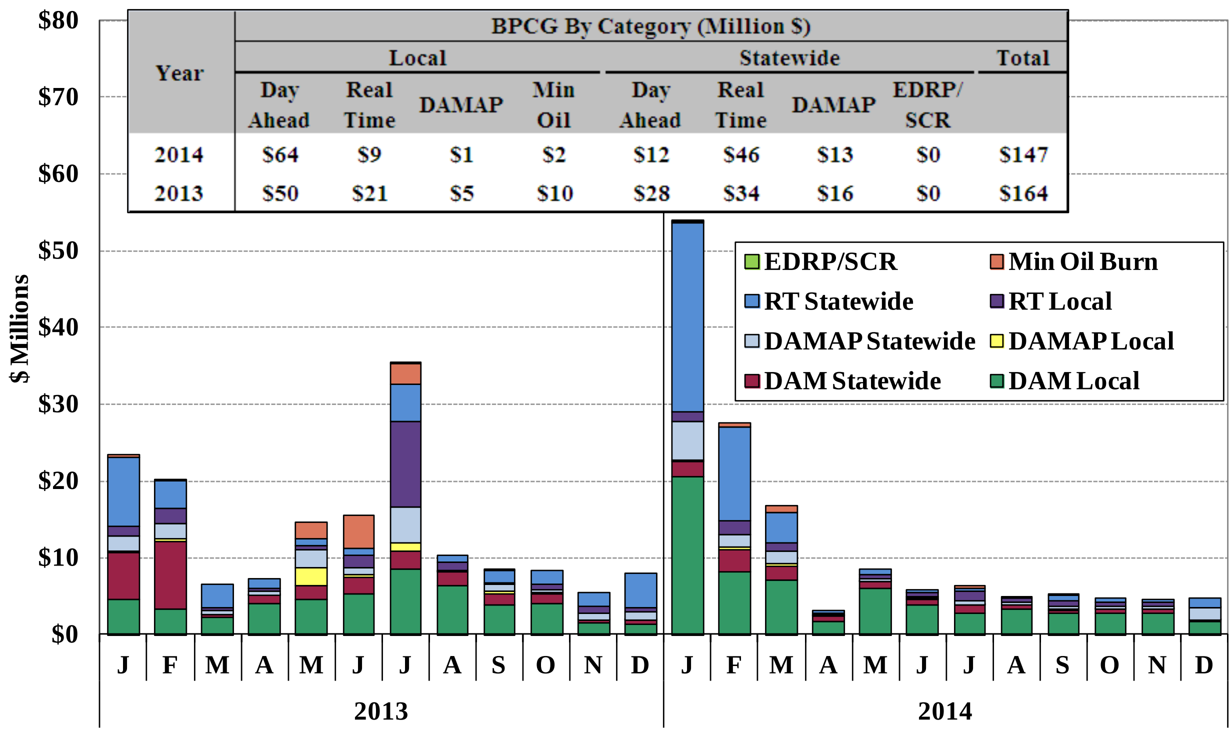
- Day-Ahead Margin Assurance Payment – Guarantee payments made to cover losses in margin for generators dispatched out-of-merit for local reliability reasons below their day-ahead schedules.

Figure A-88 & Figure A-89: Uplift Costs from Guarantee Payments

Figure A-88 shows the seven categories of uplift costs associated with guarantee payments on a monthly basis for 2013 and 2014. 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-89 shows the seven categories of uplift charges on a quarterly basis in 2013 and 2014 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.

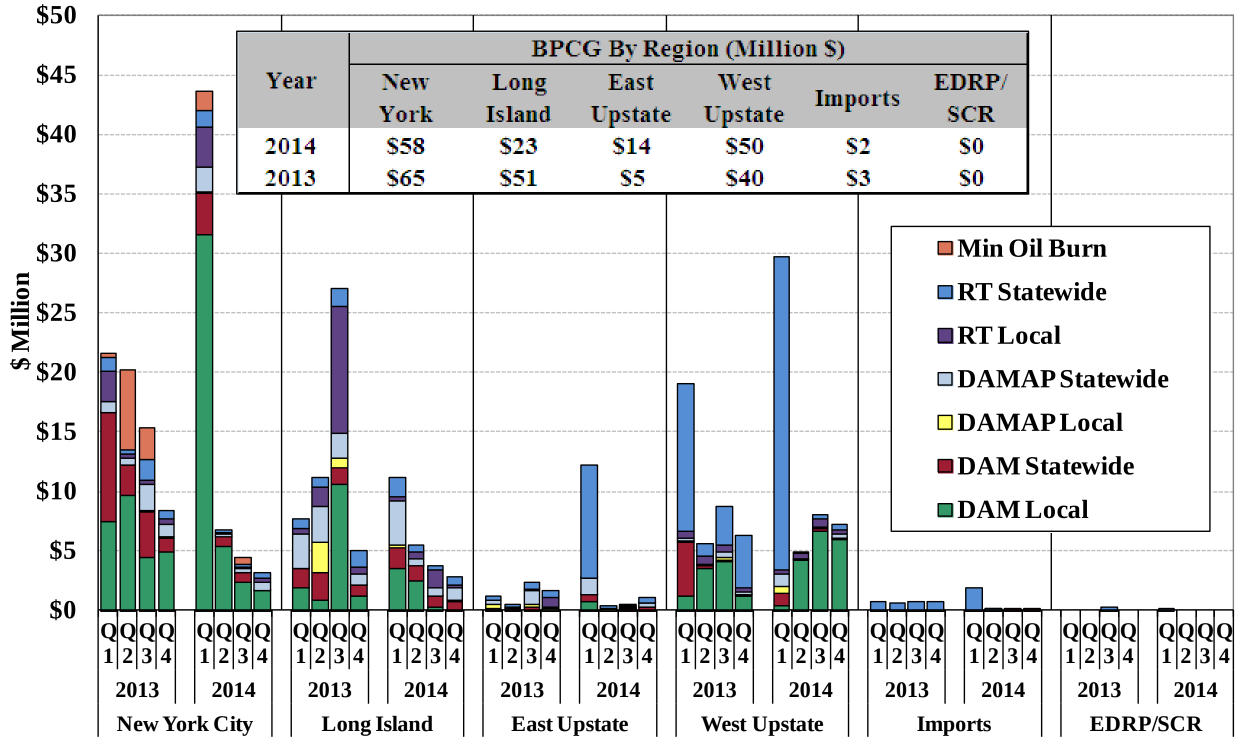
It is also noted that Figure A-88 and Figure A-89 are based on information available at the reporting time and do not include some manual adjustments resulting from mitigation consultations, hence, they can be different from final settlements.

Figure A-88: Uplift Costs from Guarantee Payments by Month
2013 – 2014



Year	BPCG By Category (Million $)								
	Local				Statewide				Total
	Day Ahead	Real Time	DAMAP	Min Oil	Day Ahead	Real Time	DAMAP	EDRP/ SCR	
2014	$64	$9	$1	$2	$12	$46	$13	$0	$147
2013	$50	$21	$5	$10	$28	$34	$16	$0	$164

Figure A-89: Uplift Costs from Guarantee Payments by Region
2013 – 2014



Key Observations: Uplift Costs from Guarantee Payments

- Total guarantee payment uplift fell roughly 10 percent, from $164 million in 2013 to $147 million in 2014.
  - The reduction was driven by decreased supplemental commitment and OOM dispatch in New York City and Long Island (for the reasons discussed earlier).
  - Lower natural gas prices in most months of 2014 also decreased the commitment costs of gas-fired units that were needed for reliability.
  - However, guarantee payment uplift rose significantly in the first quarter of 2014, accounting for $98 million (or 67 percent of the annual total) and partially offsetting the overall reduction.
    - Increased supplemental commitment, OOM dispatch, and elevated natural gas prices were the primary drivers of high guarantee payments in the first quarter.
- Of the total guarantee payment uplift in 2014:
  - Local reliability uplift accounted for 52 percent, while non-local reliability uplift accounted for the remaining 48 percent.
  - New York City accounted for 39 percent, Western New York accounted for 34 percent, and Long Island accounted for 16 percent.

- Large amounts of guarantee payment uplift often accrues under extreme weather conditions. For example:
  - The hot weather period from July 15-19, 2013 accounted for $13 million in guarantee payments when a new all-time peak load record was set.
- The cold weather period from January 22-28, 2014 accounted for $30 million in guarantee payment when gas prices averaged over $50/MMbtu in Eastern New York.Min Oil Burn Compensation program payments fell by $8 million from 2013 to 2014 because the following factors reduced the need to burn oil to protect New York City from a loss of gas:
  - Lower load levels in the summer, increased reliance on auto-switching units, and NOx Bubble constraint modeling improvements that reduced the commitment of steam turbine units.
- Most of real-time state-wide guarantee payment uplift in Western New York accrued on one gas-fired unit that was frequently needed for reliability.
  - However, transmission upgrades completed in the first quarter of 2014 greatly reduced the need for this unit and associated guarantee payment uplift.

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.[252] 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.[253]

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.[254] 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.

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252 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 2013 to April 2014 and the period from May 2014 to April 2015). NYSRC's annual IRM reports may be found at "http://www.nysrc.org/NYSRC_NYCA_ICR_Reports.asp".

253 The locational ICAP requirement = LCR * Forecasted Peak Load for the location. The Long Island LCR was 105 percent in the period from May 2013 to April 2014 and 107 percent in the period from May 2014 to April 2015. The New York City LCR was 86 percent in the period from May 2013 to April 2014 and 85 percent in the period from May 2014 to April 2015. The LCR for the newly implemented G-J Locality was set at 88 percent in the period from May 2014 to April 2015. 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".

254 The UCAP of a resource is equal to the installed capability of a resource adjusted to reflect the availability of the resource. Thus, a generator with a high frequency of forced outages over the preceding two years would not be able to sell as much UCAP as a reliable unit of the same installed capacity. For example, a unit with 100 MW of tested capacity and an equivalent forced outage rate ("EFORd") of 7 percent would be able to sell 93 MW of UCAP. This gives suppliers a strong incentive to provide reliable performance. Renewable generators' availability rates are based on their performance during peak load hours, and SCR's availability rates are based on the performance during tests and events. For each locality, a Derate 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. The Derate 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". Comparable calculations are performed to account for SCRs and intermittent resources in the Derate Factor.

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 purchased in each locality in each monthly UCAP spot auction. [255] 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.[256]

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). [257] 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.

To evaluate the performance of the capacity market, the figures in this section show capacity market results from May 2013 through February 2015. The figures 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. The first sub-section evaluates NYCA overall, and the second sub-section evaluates the performance in the local capacity zones.

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[255] 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.

[256] 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".

[257] The NYISO began to model the "G-J Locality" in May 2014.

A. Capacity Market Results: NYCA

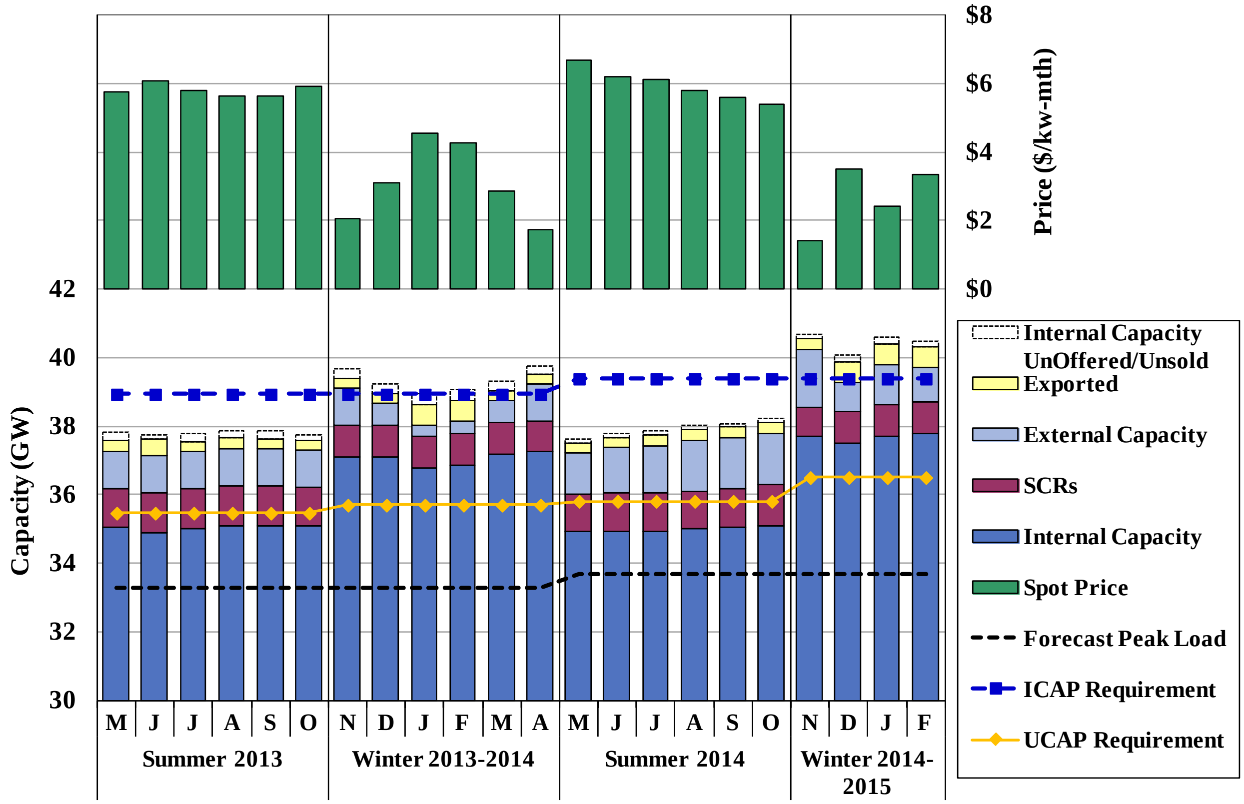
Figure A-90: Capacity Sales and Prices in NYCA

Figure A-90 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.[258] 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-90 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-90 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-90 also shows the forecasted peak load and the ICAP requirements.

258 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-90: UCAP Sales and Prices in NYCA
May 2013 to February 2015



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.
- The spot price averaged $5.96/kW-month in the Summer 2014 Capability Period, which was up 3 percent from the prior summer, and $2.68/kW-month in the Winter 2014/15 Capability Period (excluding March and April 2015), which was down 14 percent from the prior winter.

- These price changes were due to significant changes in capacity requirements and the supply of capacity. The following changes in requirements affected statewide capacity prices in 2014: [259]
  - The ICAP Requirement rose 453 MW (1.2 percent) from the 2013/14 Capability Year to the 2014/15 Capability Year, which was due to an increase of 387 MW in the peak load forecast.
    - However, the UCAP Requirement rose 346 MW (1.0 percent) in the Summer Capability Period and 805 MW (2.3 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.
- The following changes in supply also affected the statewide capacity market results:
  - Internal capacity supply in Western New York fell roughly 170 MW following the retirement and mothballing of several units, including ones at Dunkirk (75 MW) in June 2013 and Syracuse (70MW) in September 2013.
  - New York City capacity supply was reduced by approximately 100 MW from Summer 2013 to Summer 2014 primarily because some generators have discontinued the practice of performing DMNC tests at a peak firing temperature.
  - Average sales from external resources increased roughly 300 MW in the summer and 470 MW in the winter. The additional sales came primarily from growth in imports from ISO-NE and PJM.
  - Several units at the Danskammer plant in the Hudson Valley Zone returned to service from damage caused by Superstorm Sandy in 2012, adding 480 MW to the supply of capacity between October 2014 and January 2015.

B. Capacity Market Results: Local Capacity Zones

Figure A-91 - Figure A-93: Capacity Sales and Prices in NYC, LI, and the G-J Locality

Figure A-91 to Figure A-93 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

[259] ICAP Requirements are fixed for an entire Capability Year, so the same requirements were used in the 2013/14 and 2014/15 Capability Periods. UCAP Requirements are fixed for a six-month Capability Period, since the Derating Factor for each locality is updated every six months.

quantities as Figure A-90 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-91: UCAP Sales and Prices in New York City
May 2013 to February 2015

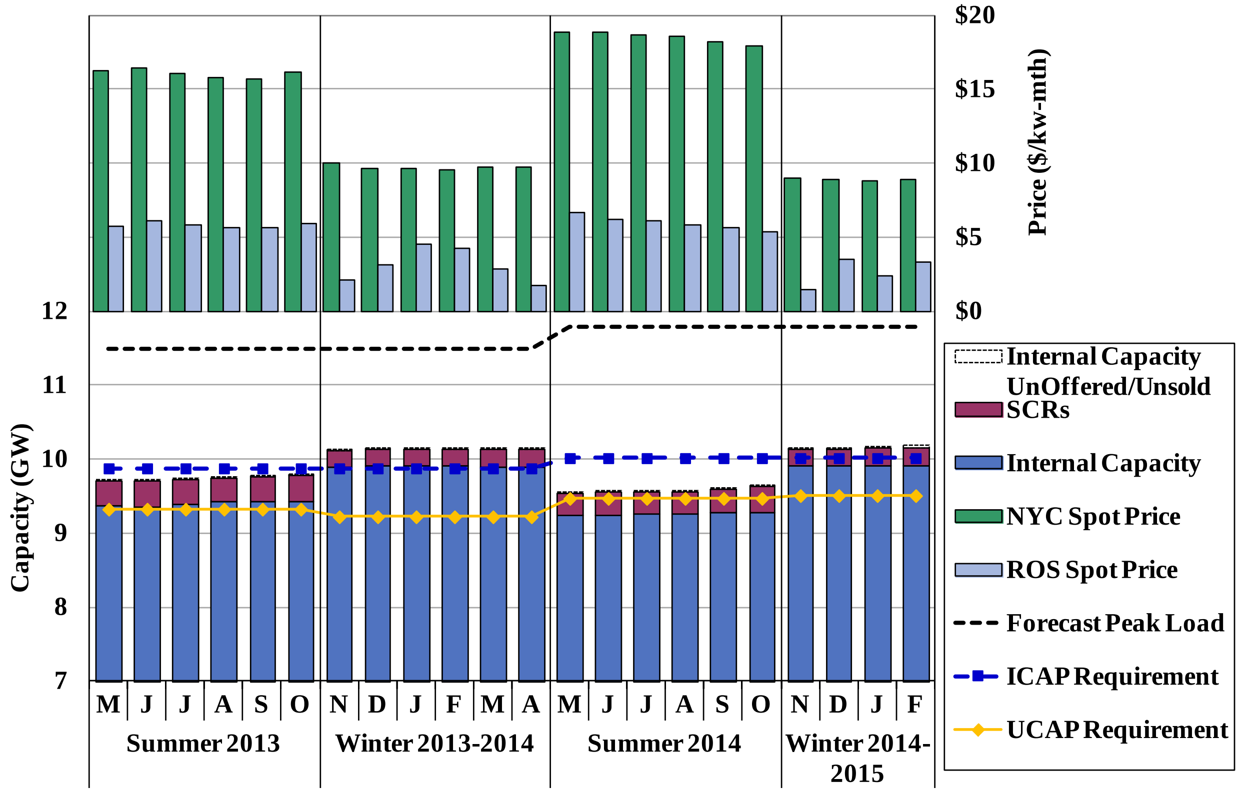


Figure A-92: UCAP Sales and Prices in Long Island
May 2013 to February 2015

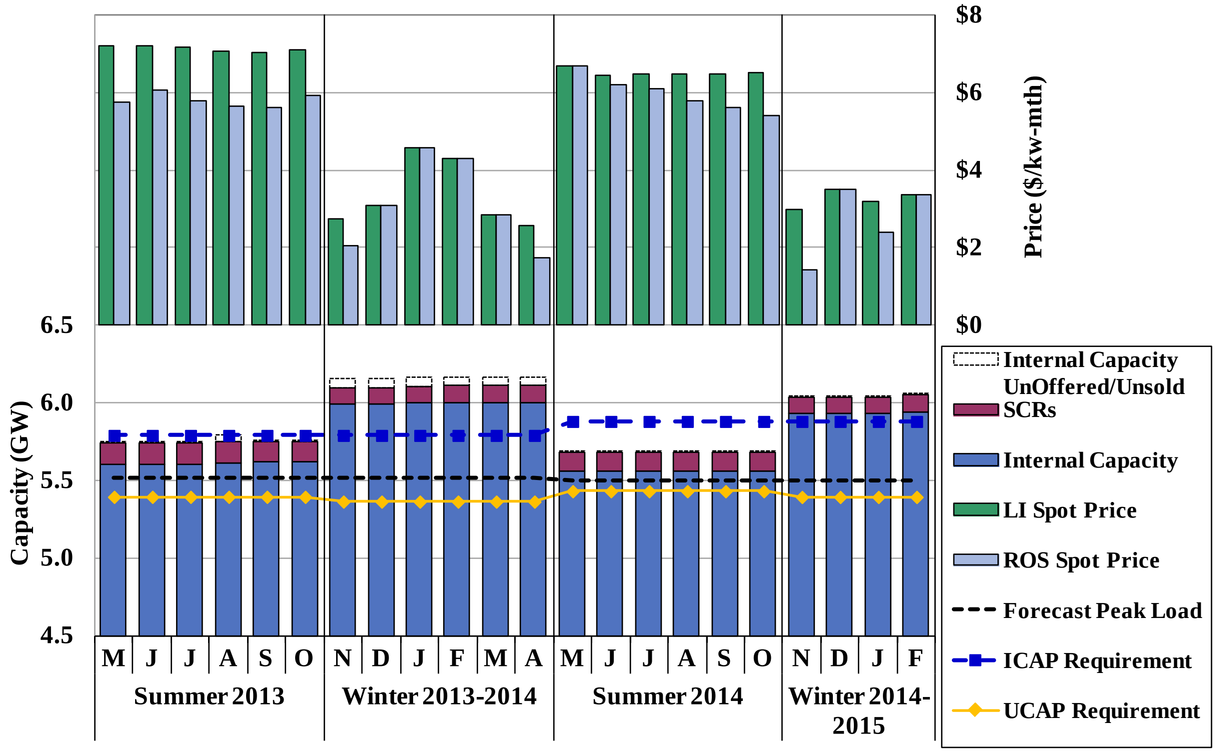
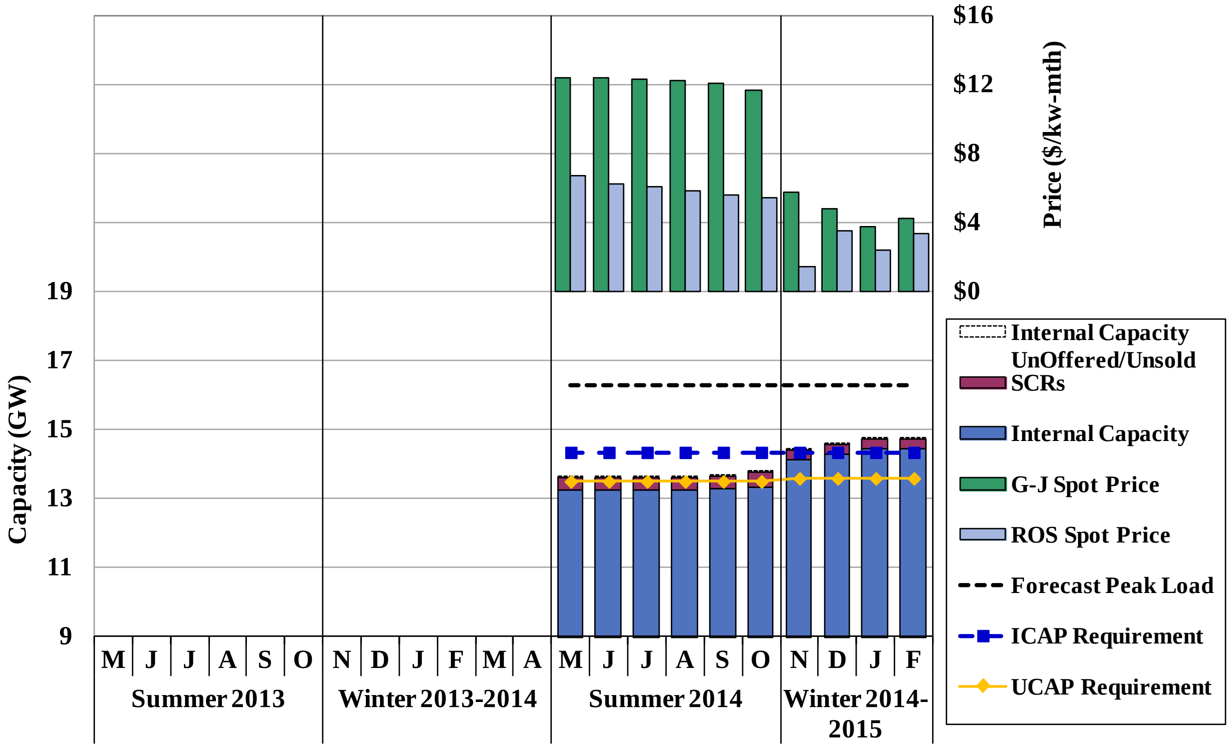


Figure A-**93**: UCAP Sales and Prices in the G-J Locality
May 2013 to February 2015



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.
- In New York City, spot capacity prices increased in the Summer 2014 Capability Period from the previous summer but fell moderately in the Winter 2014/15 Capability Period from the previous winter.
  - The spot price averaged $18.51/kW-month in the summer, which was up 15 percent from the previous summer, and $8.89/kW-month in the winter (excluding March and April 2015), which was down 9 percent from the prior winter.
  - On the demand side, the ICAP Requirement rose 138 MW (1.4 percent) from the 2013/14 Capability Year, which was primarily due to an increase of nearly 300 MW in forecasted peak load. [260]
    - However, the increase in the forecast load was partly offset by a decrease in the LCR from 86 percent to 85 percent. [261]
  - Supply-side changes also affected capacity prices in New York City:
    - ICAP supply was reduced by approximately 100 MW from Summer 2013 to Summer 2014. This reduction occurred primarily because some generators have discontinued the practice of performing DMNC tests at a peak firing temperature.
    - During the latter portion of the Summer 2014 Capability Period, the clearing price fell modestly because of the return to service of a small generator and increased SCR capability.
    - The total DMNC capability of existing NYC generators increased by 230 MW in the Winter 2014/15 Capability Period from the previous winter. This occurred primarily because of a change in the ambient temperature conditions assumed for the purpose of adjusting the test results of each generator.
  - The UCAP demand curve was reduced by 7 percent from the 2013/14 Capability Year to the 2014/15 Capability Year because the demand curve proxy unit technology was changed to a Frame 7 CT, which has a lower net CONE than the previous technology (which was the LMS 100 CT).

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260 Due to changes in the Derating Factor, the UCAP Requirement for New York City rose 146 MW (1.6 percent) in the Summer of 2014 and rose 286 MW (3.1 percent) in the Winter of 2014-2015, which deviated modestly from the increase 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.

261 The change in New York City LCR was due to multiple factors, which are discussed in details in "http://www.nyiso.com/public/webdocs/markets_operations/services/planning/Documents_and_Resources/Resource_Adequacy/Resource_Adequacy_Documents/LCR2014_Report.pdf".

- In Long Island, capacity prices fell moderately both in the Summer and in the Winter Capability Periods.
  - The spot price averaged $6.51/kW-month in the Summer 2014 Capability Period, which was down 9 percent from the previous summer, and averaged $3.26/kW-month in the Winter 2014/15 Capability Period (excluding March and April 2015), which was down 3 percent from the prior winter.
  - The reduction in Long Island capacity prices in the winter was generally consistent with the reduction in Rest-Of-State capacity prices over the same period.
    - The Local Capacity Requirement for Long Island bound much less frequently during the Winter Capability Periods.
    - As a result, the spot prices in Long Island were equal to the Rest-Of-State capacity prices during most of the winter months.
  - Spot prices were significantly above Rest-of-State prices during the Summer Capability Periods in 2013 and 2014 because the LCR was binding during the vast majority of the summer months.
    - The spot prices fell from the prior summer because the UCAP demand curve was reduced by more than 20 percent from the 2013/14 Capability Year to the 2014/15 Capability Year because the demand curve proxy unit technology was changed to a Frame 7 CT, which has a lower net CONE than the previous technology (which was the LMS 100 CT).
    - This was offset by a 90 MW increase (1.6 percent) in the Long Island ICAP requirement because of an increase in the LCR from 105 percent to 107 percent.[262]
- The G-J Locality was modeled as a capacity zone starting in May 2014.
  - The spot prices averaged $12.16/kW-month during the Summer 2014 Capability Period, and $4.62/kW-month during the Winter 2014-2015 Capability Period.
    - These capacity prices were significantly higher than the Rest-Of-State capacity prices, better reflecting the reliability need to secure the UPNY-SENY interface and greatly enhancing the efficiency of the market to provide investment signals in this area.
  - Several units at the Danskammer plant in the Hudson Valley Zone returned to service from damage caused by Superstorm Sandy in 2012, adding 480 MW to the supply of capacity between October 2014 and January 2015.

[262] The change in Long Island LCR was due to multiple factors, which are discussed in details in "http://www.nyiso.com/public/webdocs/markets_operations/services/planning/Documents_and_Resources/Resource_Adequacy/Resource_Adequacy_Documents/LCR2014_Report.pdf".

- There was virtually no unsold capacity in the G-J Locality, New York City, and Long Island in 2014.

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.[263]

- 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.[264]

- 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 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.

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263 Resources participate in EDRP through Curtailment Service Providers ("CSPs"), which serve as the interface between the NYISO and resources.

264 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.

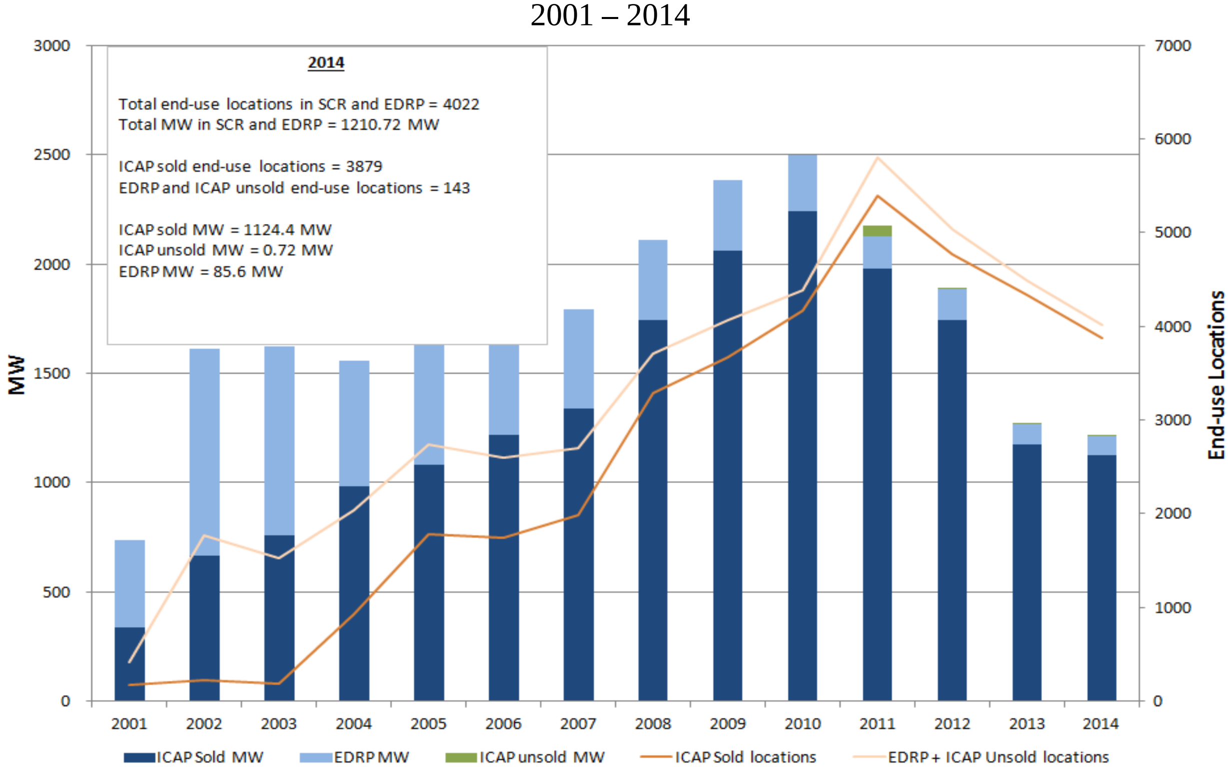
A. Reliability Demand Response Programs

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-94: Registration in NYISO Demand Response Reliability Programs

Figure A-94 summarizes registration in two of the reliability programs on an annual basis at the end of each summer from 2001 to 2014 as reported in the NYISO's annual 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-94: Registration in NYISO Demand Response Reliability Programs
2001 – 2014



Key Observations: NYISO Demand Response Reliability Programs

- 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 2014, total registration in the EDRP and SCR programs included 4,022 end-use locations enrolled, providing a total of 1,211 MW of demand response capability. SCR resources accounted for 96 percent of the total reliability program enrollments and 93 percent of the enrolled MWs.
- In the Summer 2014 Capability Period, SCRs contributed to resource adequacy by satisfying:
  - 3.3 percent of the UCAP requirement for New York City;
  - 2.8 percent of the UCAP requirement for the G-J Locality;
  - 2.2 percent of the UCAP requirement for Long Island; and
  - 3.1 percent of the UCAP requirement for NYCA.
- The registered quantity of reliability program resources has fallen considerably since 2010. The annual reductions were 13 percent in 2011, 13 percent in 2012, 33 percent in 2013, and 4 percent in 2014. These reductions have occurred for several reasons:
  - The NYISO modified the baseline calculation method for SCRs in 2011 to estimate more accurately the capability of the resource to respond if deployed. The NYISO 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 2014 will be based on 40 hours from Summer 2013). Since it is more accurate, the new baseline calculation has reduced the amount of capacity that some SCRs qualify to sell.
  - The NYISO audits the baselines of resources after each capability period to identify resources that might have had an "Unreported Change in 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.
  - The number of participating resources has fallen since 2011 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 the enhanced auditing and baseline methodology.

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, 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, they settle the energy consumption with their load serving entity rather than with the NYISO.

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 three 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.
  - Since the capability was introduced, several DSASP resources in Upstate New York (with a combined capability around 130 MW) have actively participated in the market. These resources were capable of providing up to 19 percent of the NYCA 10-minute spinning reserve requirement in 2014.
- 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. [265]

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 two years, related operations and pricing are not evaluated in this report.

Key Observations: Scarcity Pricing

- In 2013, the Scarcity Pricing Rule set real-time clearing prices at $500/MWh in SENY during three events from July 15 to 17 and in the entirety of NYCA during two events on July 18 and 19. [266] All of the events were mandatory.

265 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.

266 These events were evaluated in the 2013 State of the Market Report, Section VIII.A

- 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.