2013 STATE OF THE MARKET REPORT FOR THE NEW YORK ISO MARKETS

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May 2014

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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 *2013 State of the Market Report* presents our assessment of the operation and performance of the wholesale electricity markets administered by the NYISO in 2013. This executive summary provides an overview of market outcomes and highlights and a list of recommended market enhancements.

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. The installed capacity market provides incentives that help the NYISO ensure that the planning criteria are met over the long-term.

A. Key Developments and Market Highlights in 2013

The Day-Ahead and Real-Time Markets provide competitive incentives for resources to perform efficiently and reliably. The Installed Capacity Market provides incentives for investment in new resources and retirement of older uneconomic resources, with the objective of ensuring sufficient capacity to maintain reliability during annual peak load conditions. The market power mitigation rules effectively limit anticompetitive conduct that would undermine the benefits of competitive markets. This subsection focuses on key developments and highlights in these areas in 2013.

Day-Ahead and Real-Time Markets

Day-ahead and real-time energy prices increased 20 to 39 percent in 2013 at different locations in New York. Higher natural gas prices were the main reason for higher electricity prices in 2013, particularly in the winter months when tight gas supplies in Eastern New York increased generation costs. Congestion from west to east on the New York gas transmission system led to similar congestion patterns in the electricity market as the overall value of congestion rose to

$664 million in the day-ahead market, up 121 percent from 2012. The electricity market performed well under tight gas conditions, providing incentives for suppliers to conserve gas and switch to fuel oil. Although East New York has adequate non-gas resources to satisfy electricity demand and reliability criteria under peak winter conditions, we find that low oil inventories, the limits of the oil supply chain, and environmental limits on oil usage reinforce the important role of the market in ensuring that scarce fuel is used efficiently. (See Recommendations 11 & 12 at the end of this section, which relate to these issues.)

A heat wave in mid-July required the deployment of reliability Demand Response resources on five consecutive days for statewide and/or Southeast New York reliability, culminating in a new record peak demand level of nearly 34.0 GW on July 19. New Scarcity Pricing rules bolstered the incentives for reliable supplier performance by ensuring that energy and ancillary services prices rose to levels that generally reflected the tight system conditions.

Market-to-Market ("M2M") congestion management with PJM commenced in January 2013 and immediately provided relief during periods of congestion on interfaces into East and Southeast New York. The real-time operation of the Ramapo Line, which is heavily influenced by the M2M process, reduced overall production costs between NYISO and PJM by an estimated $17 million in 2013. Extended outages led the Ramapo Line to be derated by an average of nearly 60 percent in 2013, so the benefits of M2M coordination will likely increase in 2014. Given the benefits of M2M, we continue to recommend placing a high priority on moving forward with market enhancements that would coordinate interchange with both ISO New England and PJM, as well as between New York City and Long Island to minimize production costs. (See Recommendations 4 & 5.)

Installed Capacity Market and Investment Signals

Capacity prices rose in 2013 in all three capacity regions mainly because of retirements and mothballs of older generators and because of higher Local Capacity Requirements ("LCRs"). Under the current rules, the New York City and Long Island LCRs are raised to maintain adequate resources in Southeast New York. Therefore, the New York City and Long Island LCRs were increased in 2013 to compensate for the retirement of capacity in the Hudson Valley. Although the NYISO will begin to model a new Locality in Southeast New York in 2014, the reliability needs of Southeast New York will continue to be reflected by adjustments in the New York City and Long Island LCRs rather than the LCR of the new Locality. We are recommending a change in the capacity demand curves that will lower the costs of satisfying the planning requirements to address the fact that the current LCRs do not reflect where capacity in most beneficial for reliability. (See Recommendation 1c.)

Recent retirements and mothballs also present challenges for meeting reliability criteria in the planning horizon. Increased use of out-of-market Reliability Support Services Agreements ("RSSAs") in West New York reinforce the importance of capacity and energy market reforms that enable the value of resources 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 Recommendations 1a, 7, 8, 9, & 10.)

Following the recent retirements and mothballs, net revenues for new and existing generators rose in 2013 due to higher energy and capacity revenues (after netting out higher fuel costs). Net revenues have not been sustained at levels sufficient to support investment in new generation capacity. This is appropriate given the current capacity surpluses in each region. Dual-fueled units began to earn modest amounts of additional net revenues (compared with similar gas-only units) in 2013 due to tighter gas market conditions. So, the potential returns from dual-fuel capability are sufficient for some such units to retain this capability and maintain modest inventories of oil.

The Buyer-Side Mitigation rules limited the effects of uneconomic new entry as two projects were subject to Offer Floor mitigation. However, additional reforms are recommended to strengthen the protections against buyer-side market power, while ensuring the market-driven new entry is not detered. (See Recommendation 2.)

B. Summary of Market Outcomes and Prices in 2013

Average energy prices rose 20 to 39 percent from 2012 to 2013, which was primarily due to higher natural gas prices that increased over the same period by 27 to 72 percent for various gas trading hubs in New York. Higher natural gas prices lowered the share of electricity production from natural gas from 45 percent in 2012 to 41 percent in 2013. The correlation 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 83 percent of the intervals in New York in 2013. Increased load levels also contributed to higher energy prices in 2013, but this was partly offset by an average of 460 MW of additional nuclear generation and by new supply in New York City (i.e., 490 MW Bayonne Plant in June 2012 and 660 MW HTP Line in June 2013).

Average load levels rose modestly to 18.7 GW in 2013, while peak load levels rose significantly in both the winter and the summer months. The highest winter peak in five years was set on January 24 at 24.7 GW, and a new summer peak was set at 33,956 MW on July 19. Due to high temperatures in July, there were significantly more hours with extreme load conditions in 2013 than in recent years (e.g., load exceeded 32 GW for 33 hours in 2013 versus 6 hours in 2012). Higher load levels led to more reserve shortages, activations of demand response, congestion, and uplift charges.

Transmission congestion and losses led real-time prices to vary from an average of $40 per MWh in Western New York to $75 per MWh in Long Island in 2013. Congestion increased considerably as congestion revenues collected in the day-ahead market rose to $664 million in 2013, up 121 percent from the previous year. Higher natural gas prices led to increased congestion for two reasons. First, higher generation costs increase the redispatch costs incurred to manage congestion. Second, larger spreads in gas prices between Western and Eastern New York increased west-to-east congestion. In addition, congestion into Long Island was exacerbated by lengthy outages affecting the Neptune Cable and the two transmission lines from Upstate New York. Congestion from west-to-east through the West Zone also became more frequent in 2013 because of multiple unit retirements and mothballs, several transmission and generation outages, and inefficient utilization of some generation in the West Zone. However, the use of Ramapo PAR Coordination in the M2M congestion management process with PJM helped reduce the severity of congestion in the NYISO in 2013, particularly on the Central-East Interface and the interface into Southeast New York.

Average capacity costs (per MWh of load) rose 48 percent in New York City, 166 percent in Long Island, and 194 percent in other regions from 2012 to 2013. In 2013, UCAP spot auction clearing prices averaged $11.31 per kW-month in New York City, $4.86 per kW-Month in Long Island, and $4.14 per kW-month in Rest of State. The increases in capacity prices were driven primarily by: a) the retirement or mothballing of 1.4 GW of internal capacity in New York; and b) higher installed capacity requirements for New York City (332 MW), Long Island (320 MW), and NYCA (314 MW). These factors were partly offset by the entry of 500 MW of new resources in New York City and an uprate of 110 MW on a nuclear unit in Western New York in June 2012.

Overall, our evaluation indicates that although net revenues for new and existing generators rose in 2013 because of higher energy and capacity revenues (net of higher fuel costs), they were still below levels that would support investment in new generation capacity in areas outside Long Island. This is expected because there are relatively large capacity surpluses in New York City and statewide. In Long Island, net revenues that a new unit would have received in 2013 were generally comparable to the estimated CONE. This does not necessarily signal for investment if net revenues in future years are not expected to be as high as in 2013. Our evaluation also shows that the additional revenues for dual fuel units capable of switching to oil were modest compared to the other components of the net revenue. Nonetheless, it is likely that the potential returns from dual-fuel capability are sufficient for many such units to retain this capability and maintain modest inventories of oil.

C. 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.

At the zonal level, average day-ahead prices were lower than average real-time prices by 1 to 2 percent in most regions and 6.5 percent in Long Island. The convergence in prices in most areas indicates relative good performance of the day-ahead market, although we normally expect a slight day-ahead premium because of the risks associated with buying in the real-time market. The large real-time price premium in Long Island was driven by real-time price volatility that was accentuated by transmission outages, generator retirements, inefficient utilization of some generating capacity in Long Island, and real-time fluctuations in the volume exports to New York City from Long Island.

At the nodal level, convergence was poor at several locations in New York City and Long Island because of inconsistent congestion patterns between the day-ahead and real-time markets. The most significant example was the Valley Stream load pocket in Long Island, which exhibited average real-time prices that were 33 percent higher than average day-ahead prices. The large and persistent real-time premium was caused by the high frequency and severity of real-time price spikes due to: (a) the inefficient utilization of generating capacity in the Valley Stream load pocket in real time; and (b) real-time fluctuations in the volume of exports to New York City from the Valley Stream load pocket.

Virtual trading activity helps align day-ahead prices with real-time prices, particularly when modeling and other differences between the day-ahead and real-time markets would otherwise lead to inconsistent prices. Overall, virtual traders earned profits of $45 million in 2013, indicating that they generally improved convergence between day-ahead and real-time prices.

Convergence between day-ahead and real-time prices for operating reserves showed modest improvements during afternoon and early evening hours in 2013. The improvement was partly attributable to the revisions of two day-ahead market reserve mitigation provisions in 2013 that inhibited price convergence in the past.

D. Competitive Performance of the Market

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 2013 as the conduct of suppliers was generally consistent with expectations in a competitive market and the mitigation measures were generally effective in limiting conduct that would raise LBMPs above competitive levels.

However, we found that one large supplier scheduled lengthy planned outages for significant amounts of capacity when the capacity would have been economic. Although it can be challenging for a competitive supplier to schedule necessary maintenance outages while maximizing the availability of generation at times when it is economic, it is likely that this supplier’s planned outages could have been scheduled more efficiently in 2013.

The frequency of automated mitigation in New York City has fallen considerably as congestion has become less frequent and less severe with the introduction of new generation and transmission. "Unmitigation" of generators that were initially mitigated by the AMP software was very uncommon in 2013, reflecting that the NYISO has improved its processes for administering reference levels. These include allowing suppliers to update the fuel costs used in reference levels on a more timely basis. This is important because mitigating generators below marginal cost with the AMP software leads to inefficient generation and fuel-consumption and distorts market clearing prices, which cannot be undone when the generator is unmitigated.

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.

E. Real-Time Market Operations

We evaluate several aspects of market operations, focusing on the efficiency of scheduling and whether real-time prices provide appropriate incentives, particularly during tight operating conditions.

Fuel Usage Under Tight Gas Supply Conditions

Extreme cold weather led to high and volatile gas prices on many days in January and February 2013. During these periods, uncertainty about natural gas prices and the availability of other fuels led to high electricity price volatility. 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; (b) limited availability of oil-fired generation because of low oil inventories, air permit restrictions, and equipment issues; and (c) inefficient interface deratings because of uncertainty regarding the gas supply to particular generators. We observed better operations and market performance in these areas during the first quarter of 2014 despite more challenging conditions. Nonetheless, we identify some areas that may warrant changes in the market design and the market rules and recommend several improvements in this report.

Efficiency of M2M Coordination with PJM

Coordinated congestion management between NYISO and PJM under the M2M process commenced in January 2013. This process allows each RTO to more efficiently relieve internal congestion with re-dispatch from the other RTO's resources when it is less costly to do so. M2M includes two types of coordination: Re-dispatch Coordination and Ramapo PAR Coordination. Our evaluation found:

- Re-dispatch Coordination was used very infrequently (in less than 180 hours).
- Ramapo PAR Coordination provided significant congestion relief to New York and lowered production costs between the two markets.

Despite its relative efficiency, the use of Ramapo PAR Coordination was limited by several factors that included lengthy equipment outages and PJM's suspension of coordination on TSA flowgates. We expect more efficient utilization of the PARs going forward when these issues are resolved.

Drivers of Cyclical Real-Time Price Volatility

Despite some improvements in the recent two years, real-time prices remained relatively volatile in 2013. Most of the price volatility was observed at certain times of day or under certain market conditions. As we show in this report, this volatility can be attributed to the incidence of a limited number of factors, the most significant of which include: large changes in inflexible resources (e.g., self-scheduled units and external transactions), unforeseen changes in the flows across PAR-controlled lines, and the de-commitment of gas turbines. Such changes can create brief shortages or over-generation conditions when flexible generators cannot ramp quickly enough to compensate for the change, leading to sharp changes in LBMPs. Volatility during ramping hours became less pronounced in 2013 because of the additional flexibility that has been provided by 15-minute external transaction scheduling, which was enabled at the PJM interface in 2012. However, we recommend several improvements that better align RTC and RTD to further address these issues.

Market Performance Under Shortage Conditions

The impact of shortage conditions was substantial in 2013, particularly in Eastern New York where shortage conditions accounted for 7 to 8 percent of the average annual real-time LBMP. Likewise, shortage pricing accounted for a large share of the net revenues that a generator could use to recoup capital investment costs, contributing up to $37 per kW-year for a generator in the Hudson Valley and $53 per kW-year for a generator in Long Island (if the unit was fully utilized during shortage conditions in 2013). We evaluated the market during three types of shortages:

- *Operating reserve and regulation shortages* – These occurred in a small share of intervals, but had significant real-time price effects. They increased the annual average real-time price in Eastern New York by 4 to 5 percent in 2013.

- *Transmission shortages* – These were also infrequent, but made significant contributions to real-time prices, including 4 percent of the annual average real-time price in Long Island, 2 percent in New York City, and 3 percent in the West Zone in 2013.

- *Reliability demand response deployments* – These were deployed on five days for reliability in Southeast New York and statewide. The Enhanced Scarcity Pricing Rule was triggered in the majority of deployment intervals, increasing the annual average real-time price in Eastern New York by 1 percent in 2013.

Overall, the market performed reasonably well during shortages, although we identify some shortcomings that are addressed in our recommendations.

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 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) resulted in significant increases in production costs and other market effects in 2013. Hence, the report recommends that NYISO work with these parties to explore opportunities to improve the operation of these lines.

F. Supplemental Commitment and Guarantee Payment Uplift

Guarantee payments to generators, which account for a large share of Schedule 1 uplift charges, rose from the prior year by 13 percent to a total of $164 million in 2013. This increase was consistent with higher natural gas prices, which increased the commitment costs of gas-fired units needed for reliability. However, this increase was offset by a reduction in overall supplemental commitments for reliability, which fell 14 percent from 2012 to 2013.

New York City accounted for the largest increase ($13 million) in uplift costs in 2013. Reliability commitment in New York City rose 16 percent in 2013 as LRR commitments for the NOx Bubble requirements increased. Reliability commitments in Long Island and Western New York fell by 41 percent from 2012 to 2013 as units that are frequently needed for local reliability were committed economically by the market more often in 2013 because of higher prices.

Extreme weather led to increased guarantee payment uplift in 2013. Due to cold weather, January 20 to 27 accounted for $12 million in guarantee payment uplift as natural gas prices rose as high as $35 per MMbtu. Due to hot weather, July 15 to 19 accounted for $13 million in guarantee uplift as a new all-time peak load record was set.

G. 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. In 2013, capacity clearing prices were set at three distinct locations: New York City, Long Island, and NYCA. Beginning with the Summer 2014 Capability Period, the NYISO has added the G-J Locality, which includes all of Southeast New York except Zone K (i.e., Long Island). While the creation of the new

Locality is a positive market development, it is 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 over time.

With the creation of the G-J Locality, the NYISO showed that Zone K capacity is not fully fungible with capacity in Zones G-J for maintaining reliability in Southeast New York because of export limitations, although resources in Zone K do provide reliability benefits to the G-J Locality. To address this issue, we recommend improvements in the market framework to more accurately model and price the locational reliability value that resources provide.

Finally, the current demand curves do not attract capacity to areas where it is most valuable for reliability, leading to higher overall costs. Therefore, reforming the demand curve or LCR setting process to consider the marginal reliability benefit of capacity in each area would lead capacity to be distributed in a manner that is most cost-effective for maintaining reliability.

H. Recommendations

The NYISO markets generally performed well in 2013. 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 NYISO is addressing in the 2014 Project Plan or in some other effort.

Recommendation	Current Effort	High Priority/ Benefit
Capacity Market		
1. Create a dynamic and efficient framework for reflecting locational planning requirements, including three key aspects: a) Pre-define interfaces/zones that address potential resource adequacy needs and highway deliverability constraints to allow prices to accurately reflect the locational value of capacity; b) Grant internal capacity deliverability rights between zones when private investors upgrade transmission into a local area; c) Modify the demand curves to minimize the cost of satisfying planning requirements.	✓	✓
2. Enhance Buyer-Side Mitigation measures to deter uneconomic entry while ensuring that economic entrants are not mitigated. a) Grant a Competitive Entry Exemption from the buyer-side mitigation measures for a purely market based investment; b) Reform Offer Floor for mitigated projects; c) Modify definition of the Starting Capability Period; d) Modify treatment of units being replaced, mothballed, and retired in forecasts of ICAP prices and net revenues; e) Adopt a Buyer-Side Mitigation measure to address the effects of uneconomic transmission investment.	✓	✓
3. Modify the pivotal supplier test to prevent a large supplier from circumventing supply-side mitigation by selling capacity in the forward auctions.		
Real-Time Market Operations		
4. Work with adjacent ISOs on rules to better utilize the transfer capability between regions by coordinating intra-hour transactions.	✓	✓
5. Operate PAR-controlled lines to minimize production costs and create financial rights that compensate affected transmission owners	✓	✓
6. Adjust timing of the look-ahead evaluations in RTD and RTC to be more consistent with ramping periods for external transactions.		
Real-Time Pricing		

7. Modify criteria for gas turbines to set prices in the real-time market.		
8. Implement a graduated Transmission Demand Curve.	✓	
9. Modify real-time pricing during demand response activations.	✓	
10. Modify the operating reserve demand curves to reflect reliability needs that lead to out-of-market actions under high load conditions. a) Create a SENY 30-minute operating reserve zone to reflect the requirements of NYSRC Rule F-R1c. b) Modify NYCA 30-minute operating reserve requirement to reflect the requirements of NYSRC Rule D-R4. c) Increase NYCA 30-minute operating reserve demand curve from $50/$100/$200 to $100/$250/$500 per MWh.	✓	✓
Winter Market Operations		
11. Consider ways to allow Generators to submit offers that reflect certain fuel supply constraints in the day-ahead market.		✓
12. Require Generators to provide daily information on fuel availability (e.g., on-site inventory, scheduled deliveries, & nominations).	✓	

I. Introduction

This report assesses the efficiency and competitiveness of New York's wholesale electricity markets in 2013.[1] The NYISO operates competitive wholesale markets to satisfy the electricity needs of New York. These markets include:

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

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

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

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:

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1 NYISO MST 30.10.1 states: "The [MMU] 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."

- 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; and

- 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.

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

- A mechanism that allows demand-response resources to set energy prices when they are needed. This is essential for ensuring that price signals are efficient during shortages. 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 X of the report provides a number of recommendations that are intended to achieve these objectives.

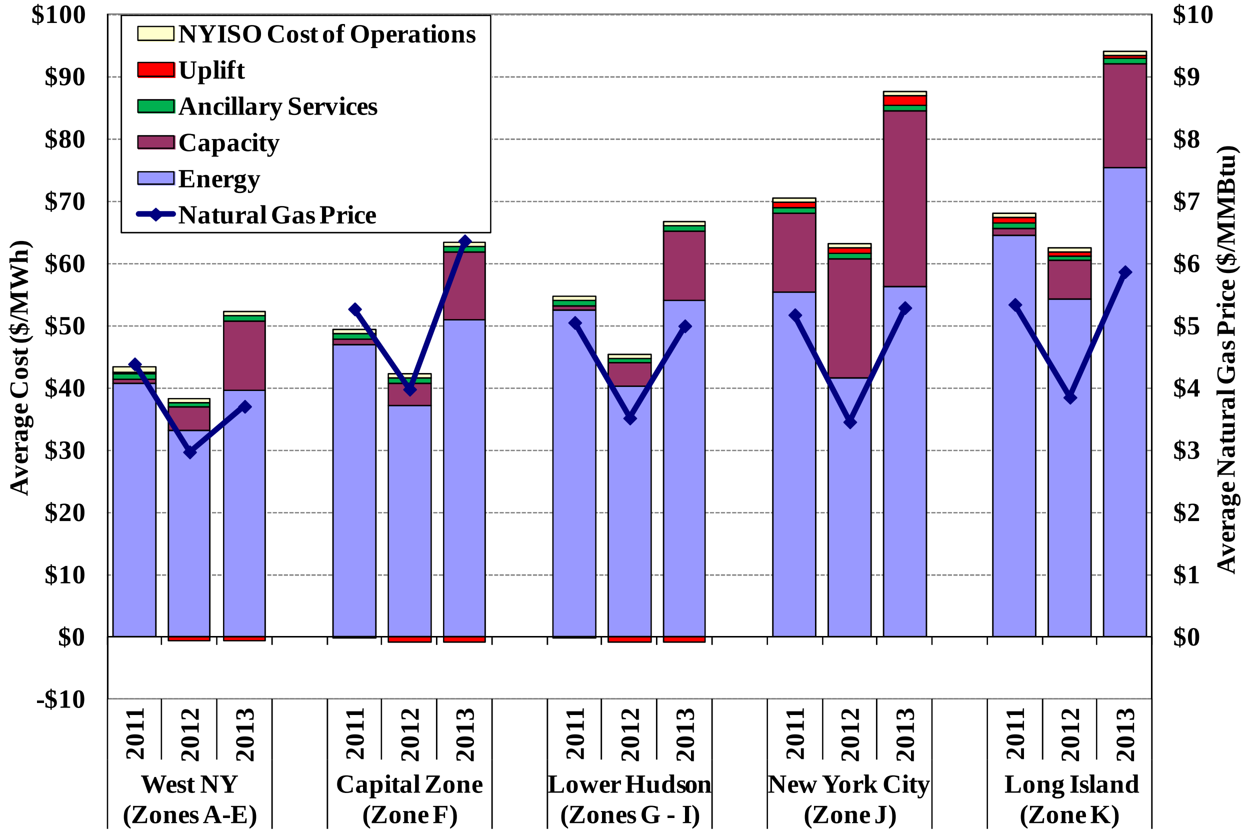
II. Overview of Market Trends and Highlights

A. Total Wholesale Market Costs

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

Figure 1: Average All-In Price by Region

2011-2013



Average all-in prices of electricity ranged from $52 per MWh in West New York to $94 per MWh in Long Island in 2013. Energy was the largest component of the all-in price, ranging from an average of $40 per MWh in West New York to $75 per MWh in Long Island. Energy costs accounted for 64 percent of the all-in price in New York City and 77 to 82 percent of the

2 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.

Average electricity prices rose substantially from 2012 to 2013, increasing 20 to 39 percent in the five regions of New York State. These increases were driven primarily by the changes in natural gas prices, which rose 27 to 72 percent from 2012 to 2013, especially during the winter months (i.e, January, February, and December). The largest increases in natural gas prices were experienced in Eastern New York, which led to more west-to-east congestion. In addition, record high load levels in July 2013 led to demand response deployments that triggered new Scarcity Pricing Rules on five days, which contributed to the increase in average electricity prices.[3]

Electricity prices in Long Island were significantly higher than in the rest of the State in 2013, which reflected the effects of: (a) lower import levels from upstate New York and PJM because of lengthy deratings and outages of 345kV transmission facilities into Long Island and the Neptune Cable; (b) tighter supply due to several generator retirements and inefficient utilization of some generation resources; (c) the uneconomic use of controllable lines, which routinely export power to New York City; and (d) the relatively high cost of natural gas supplies to Long Island.[4]

Average capacity costs rose 48 percent in New York City, 166 percent in Long Island, and more than 194 percent in other regions from 2012 to 2013. In 2013, UCAP spot auction clearing prices averaged $11.31 per kW-month in New York City, $4.86 per kW-Month in Long Island, and $4.14 per kW-month in Rest of State. The increases in capacity prices were driven primarily by: (a) the retirement of 1.4 GW of internal capacity in New York; and (b) higher installed capacity requirements for New York City, Long Island, and NYCA.[5]

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3 The new Scarcity Pricing Rules are evaluated in Section VIII.A.

4 These issues are discussed further in Section V.A (345kV outages), Section VI.A (Neptune Cable), Section III.A (inefficient use of generation), and Section VIII.E (exports to New York City).

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

The seasonal patterns of electricity prices and natural gas prices were typical for most of 2012 and 2013. Electricity prices rose in the summer months as a result of high electricity demand and in the winter months as a result of high natural gas prices, particularly in Eastern New York.[6]

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 on an annual basis from 2011 to 2013.[7] The table also shows average real-time energy prices across New York State over the same period.

Table 1: Average Fuel Prices and Energy Prices
2011-2013

				Change from Prior Year	
	2011	**2012**	**2013**	**2012**	**2013**
Fuel Prices ($/MMBtu)					
Fuel Oil #2	$20.99	$21.54	$20.80	3%	-3%
Fuel Oil #6	$17.98	$18.09	$16.85	1%	-7%
NG - Dominion North	$4.12	$2.77	$3.51	-33%	27%
NG - Tx Eastern M3	$4.56	$2.98	$3.93	-35%	32%
NG - Transco Z6 (NY)	$4.98	$3.25	$5.13	-35%	58%
NG - Iroquois Z2	$5.15	$3.65	$5.69	-29%	56%
NG - Tennessee Zn6	$5.01	$3.91	$6.74	-22%	72%
Cent. App. Coal	$2.95	$2.39	$2.36	-19%	-1%
Energy Prices ($/MWh)					
West New York	$40.71	$33.16	$39.72	-19%	20%
Capital Zone	$47.04	$37.11	$50.94	-21%	37%
Lower Hudson VL	$52.45	$40.31	$54.14	-23%	34%
New York City	$55.39	$41.71	$56.25	-25%	35%
Long Island	$64.64	$54.24	$75.42	-16%	39%

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 three years.

Natural gas price spreads are usually small between different regions in New York. However, bottlenecks on the natural gas system can lead to large price differences between locations,

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

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

especially in the winter when the demand for natural gas is highest. Locational spreads between different natural gas indices increased notably in 2013 from prior years. In 2013:

- Iroquois Zone 2 prices (which affect fuel costs in Long Island and portions of Eastern Upstate New York) were 62 percent higher on average than Dominion North prices (which affect fuel costs in Western New York), up from 32 percent in 2012.
- The Transco Zone 6 (NY) prices (which drive fuel costs in New York City) were 46 percent higher than Dominion North prices, up from 18 percent in 2012.

These locational variations in natural gas prices led to comparable variations in energy prices between Western New York and Eastern New York due to frequent west-to-east congestion. These gas spreads were largest in the winter months.

C. Generation Fuel Type

Relatively low natural gas prices and the additions of new gas-fired generation in recent years have led to considerable changes in the mix of fuels used to generate electricity in New York. Table 2 summarizes the actual usage of fuels by New York generators on an annual basis from 2011 to 2013, 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.[8] The percentages showing the type of units that are marginal will 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
2011-2013

Fuel Type	Average Internal Generation						% of Intervals being Marginal		
	GW/hour			% of Total					
	2011	2012	2013	2011	2012	2013	2011	2012	2013
Nuclear	4.9	4.6	5.1	31%	30%	33%	0%	0%	0%
Hydro	3.0	2.7	2.7	19%	17%	17%	42%	39%	44%
Coal	1.1	0.5	0.5	7%	3%	3%	22%	10%	11%
Natural Gas	6.0	7.0	6.5	38%	45%	41%	73%	83%	83%
Fuel Oil	0.09	0.05	0.10	0.6%	0.3%	0.6%	4%	3%	5%
Wind	0.3	0.3	0.4	2%	2%	3%	1%	1%	7%
Other	0.4	0.3	0.3	2%	2%	2%	0%	0%	0%

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

The combined generation from gas-fired, nuclear, and hydro resources accounted for more than 90 percent of all internal generation from 2011 to 2013. The share of electricity production from nuclear generators rose 460 MW on average from 2012 to 2013 primarily because of the uprate of one Nine Mile unit and fewer planned and forced outages of nuclear resources. The share from gas-fired generators fell 600 MW on average from 2012 to 2013 in response to the higher production from nuclear units and higher natural gas prices.

Coal production did not increase in 2013 despite higher natural gas prices (which makes coal generation more economic) because several coal units were recently retired or mothballed. Hydro production was consistent with the previous year, although there were periods when severe congestion in the West Zone limited the output from the Niagara facility. Oil production, although still small, doubled from 2012 to 2013. Oil generation rose notably in New York City and Long Island on several days in January and February when gas prices in Eastern New York were substantially higher than oil prices.[9]

Gas-fired and hydro resources were most frequently on the margin in recent years. Gas-fired resources were on the margin in 83 percent of the intervals during 2013. Hydro resources set the prices in 44 percent of the intervals in 2013, up modestly from 2012 as a result of increased congestion in the West Zone that was often relieved by backing-down hydro resources.

Other fuel types were less frequently on the margin. Oil units set the price occasionally during very high-load periods or on days when natural gas prices were substantially higher than oil prices in January. Price-setting by wind units became more frequent in 2013 because new wind capacity additions have led to more frequent congestion from the North Zone to the rest of New York.

D. Demand Levels

Demand is another key driver of wholesale market outcomes. In 2013, load averaged 18.7 GW, up modestly from 2012. However, peak load conditions rose significantly in 2013 because of

9 Figure A-11 to Figure A-13 in the Appendix summarize the generation patterns by fuel type in Long Island, New York City, and the entire Eastern New York during several periods in the winter when the natural gas prices in Eastern New York rose above residual oil prices.

extreme weather in both the winter and the summer. In the winter, load peaked on January 24 at 24.7 GW, which was the highest winter peak in the past five years and was 4 percent higher than the 2012 winter peak. In the summer, load peaked at a new all-time high of 33,956 MW on July 19, which was up 17 MW from the previous all-time peak in 2006 and was approximately 1.5 GW higher than the 2012 annual peak. Due to a unusual heat wave in July, New York experienced significantly more hours with very high load conditions (e.g., load exceeding 30 GW) in 2013 than in recent years.[10] These high load levels led to very tight system conditions, resulting in reserve shortages, activations of demand response, high congestion, and high uplift costs, all of which are discussed in the report.

E. Transmission Congestion Patterns

Transmission congestion costs increased considerably from 2012 to 2013. Congestion revenues collected by the NYISO in the day-ahead market (where the vast majority of congestion revenue is collected) totaled roughly $664 million in 2013, up 121 percent from $301 million in 2012.[11] This section also evaluates the value of congestion in the real-time market because it indicates where physical constraints occur on the network during the operating day, although very little of real-time congestion is collected by NYISO.[12] In a well-functioning market, the value of congestion in the day-ahead and real-time markets should converge.

Figure 2 shows the value and frequency of congestion along major transmission lines in the day-ahead and real-time markets in 2012 and 2013.[13]

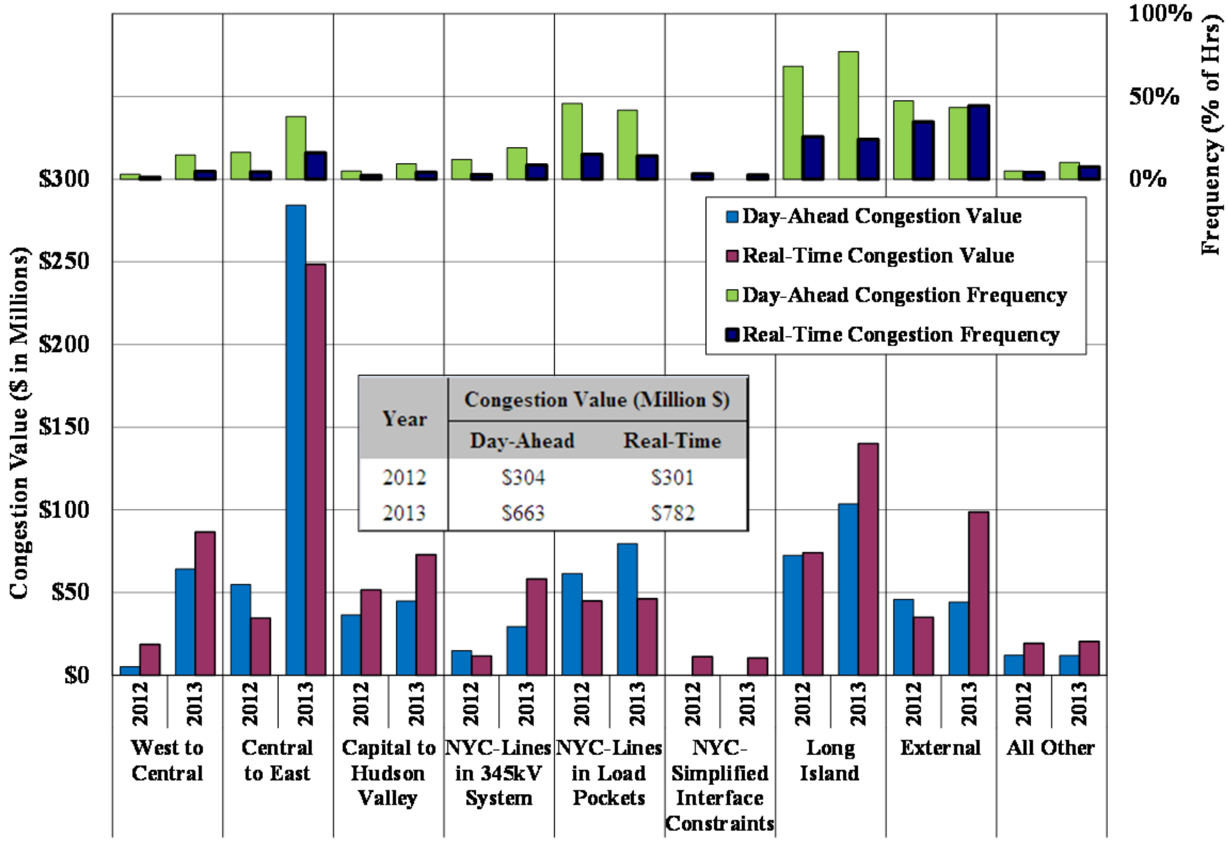
10 Section I.D in the Appendix shows the load duration curves from 2011 to 2013.

11 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.

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

13 Section V.A discusses the congestion patterns in greater detail.

Figure 2: Day-Ahead and Real-Time Congestion by Transmission Path
2012-2013



Both the value and frequency of congestion rose from 2012 to 2013 on most transmission paths because:

- Higher natural gas prices generally increased redispatch costs for managing congestion;
- Larger spreads in natural gas prices between Western New York and Eastern New York increased flows on interfaces between the two regions, leading to increased west-to-east congestion;
  - Congestion across the Central-East interface rose substantially from 2012 to 2013, accounting for nearly 40 percent of congestion values in both day-ahead and real-time markets in 2013,
- Congestion across the external interfaces also increased in 2013, reflecting higher exports across the primary interface with New England, particularly in the winter months when natural gas prices in New England were significantly higher than in Eastern New York;
- Congestion on the 230kV lines in the West Zone became more frequent in 2013 partly because of: (a) the retirement or mothballing of several coal units that relieve this congestion, (b) several lengthy transmission and generation outages, (c) changes in the TLR process due to the operation of the Ontario-Michigan PARs that prevent the NYISO

from curtailing transactions that exacerbate congestion, and (d) inefficient utilization of some generation in the West Zone; [14] and

- Congestion into Long Island was also exacerbated by lengthy outages and deratings of the Neptune Cable and the 345kV transmission facilities from Upstate New York to Long Island.

The NYISO and PJM implemented the Market-to-Market coordinated congestion management process in January 2013, which includes:

- Re-dispatch Coordination – that allows the two RTOs to redispatch individual generators that materially affect flows on binding constraints in the adjacent market.
- Ramapo PAR Coordination – that adjusts flows on the Ramapo PARs to minimize congestion on both RTO systems.

The use of Re-dispatch Coordination has been very limited because of limited effects of individual generators on the coordinated flowgates. The use of Ramapo PAR Coordination has significantly reduced the severity of congestion in the NYISO, particularly congestion across the Central-East interface and into Southeast New York. Nonetheless, usage of this process was limited by the extended outages of the Ramapo PARs and PJM's suspension of coordination on TSA flowgates beginning July 12, 2013.[15]

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 2012 and 2013.[16]

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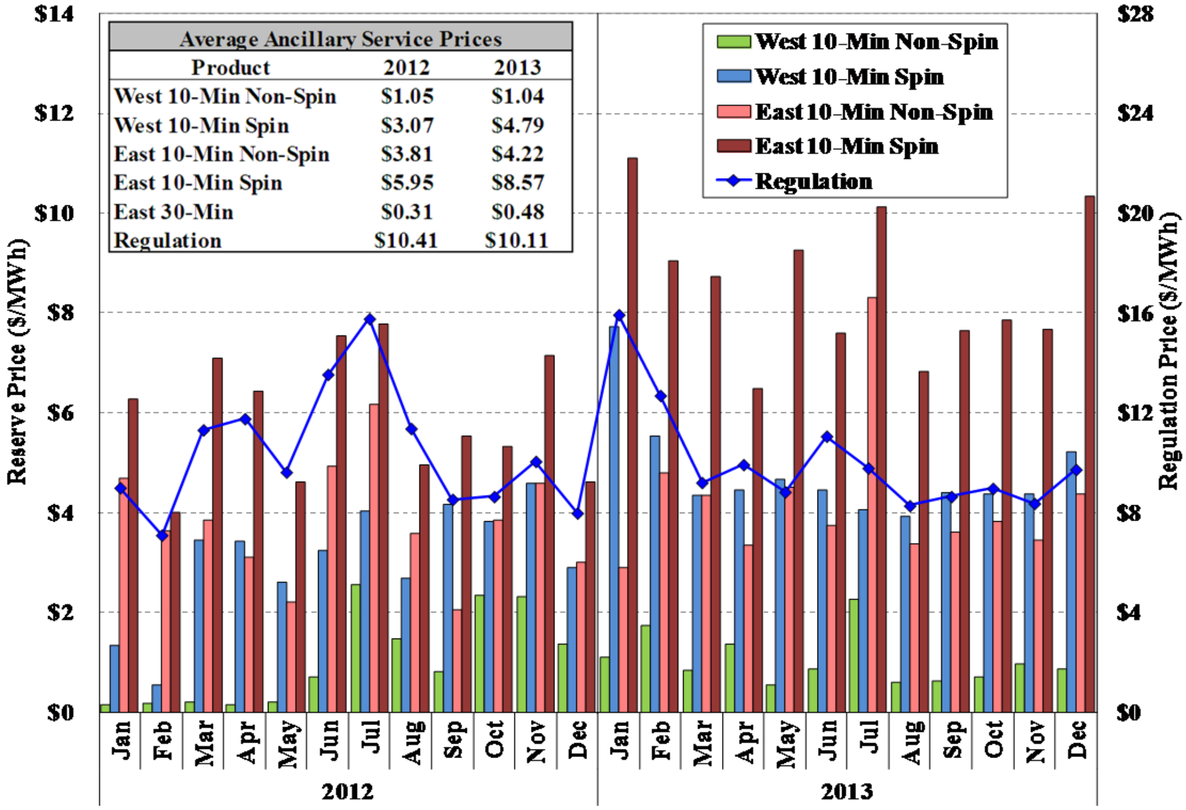
14 See discussion in *Quarterly Report on the New York ISO Electricity Markets Third Quarter 2013* by Potomac Economics, Slide 60.

15 See Section V.B of the Appendix for our evaluation on the M2M Coordination with PJM.

16 See Sections I.I and I.J of the Appendix provide additional information regarding the ancillary services markets.

Figure 3: Average Day-Ahead Ancillary Services Prices
2012-2013



The average prices for most classes of ancillary service increased from 2012 to 2013, consistent with energy price trends over the same period. The scheduling of ancillary services and energy is co-optimized, so a major cost of providing ancillary services for most generators is the opportunity cost of not providing energy when it otherwise would be economic to do so. Co-optimized scheduling is beneficial because it ensures that the foregone profits from backing down generation to provide reserves is properly reflected in LBMPs and reserve clearing prices. Hence, the ancillary services markets provide additional 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.

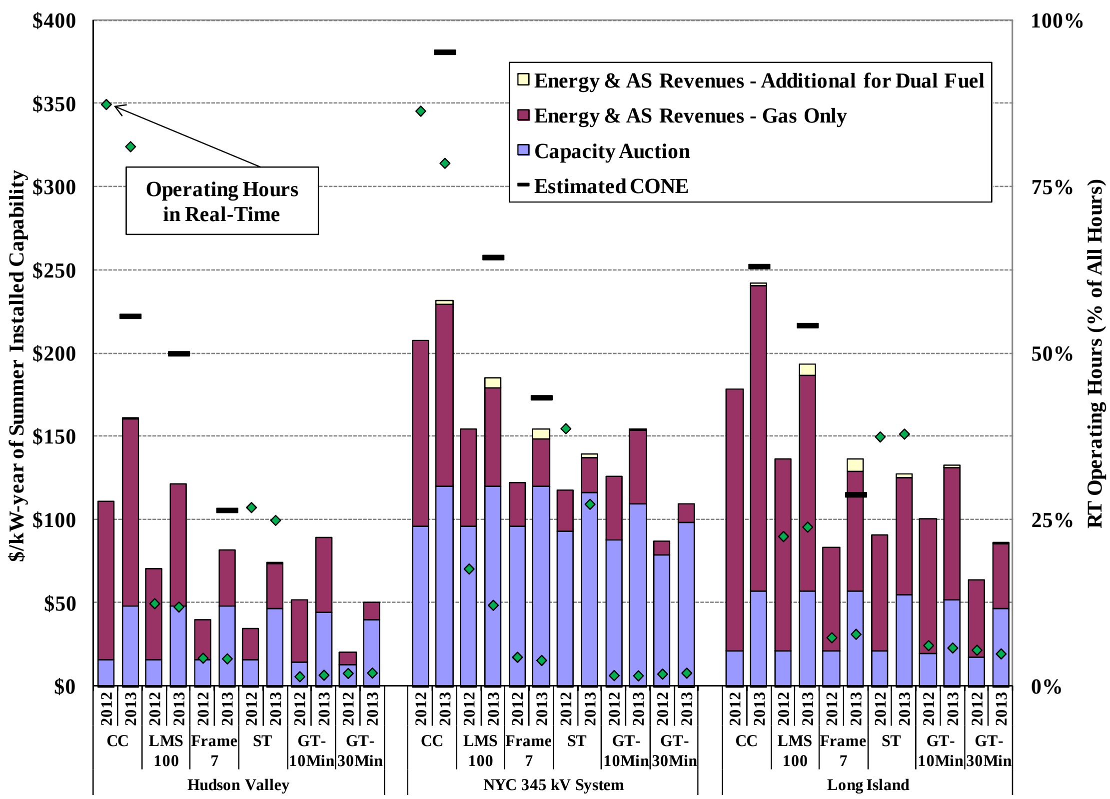
Average day-ahead regulation capacity prices fell slightly from 2012 to 2013 despite higher opportunity cost driven by higher gas prices. The new regulation market, which began on June 26, 2013, allows participants to offer regulation movement cost separately from regulation capacity cost, leading to lower regulation capacity prices following the implementation.

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 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 three new unit types in 2012 and 2013, as well as three common older unit types in New York.[17] 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.

Figure 4: Net Revenue and CONE by Location for Various Technologies
2012-2013



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

Net revenues increased substantially from 2012 to 2013 in most locations because of reduced supply and changes in capacity requirements. In Upstate New York, capacity net revenues rose as a result of generator retirements, lower capacity sales from demand response resources, and higher capacity requirements. The results were similar in Long Island where capacity prices have cleared near the level of NYCA prices in recent years. In New York City, capacity net revenues rose largely because of the increase in the LCR. Capacity prices are discussed further in Section VII.A.

Energy net revenues rose in 2013 as a result of more frequent peak load conditions in the summer and the winter, leading to more frequent shortage pricing events. For new units, the estimated net revenues were lower than the cost of new entry ("CONE") with the exception of the net revenues for a new Frame 7 unit in Long Island. These results are consistent with expectations since entry would occur if market participants anticipated net revenues would be elevated for a significant period. The Frame 7 unit may not be as economic in future years if the relatively high prevailing net revenues do not continue. One reason these net revenues may fall is that the demand curves for Long Island, New York City, and NYCA will be reduced in May 2014 to reflect the fact that the Frame 7 unit has a lower net CONE than the previous demand curve unit.

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 results also indicate that the additional revenues attributable to dual fuel capability became significant in 2013 in New York City and Long Island because of more hourly operational flow orders (i.e., gas system constraints) and natural gas price spikes. The estimated net revenues from dual-fuel capability ranged from $6 to $8 per kW-year for new LMS100 and Frame 7 units and from $2 to $3 per kW-year for new combined cycles and older steam turbines. So, the additional revenues for dual fuel units were still modest compared to the other components of the net revenue. However, it is likely that the potential returns from dual-fuel capability were sufficient for many units in New York City and Long Island to retain the capability and maintain modest inventories of oil.

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 and a discussion of recently implemented enhancements.

III. 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 2013 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 2013.

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. Hence, 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.[18,19]

Figure 5 and Figure 6 evaluate the two withholding measures relative to load levels and participant size.[20] 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.

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 the expectation in a competitive market. However, the portion of capacity that was both derated and economic rose considerably in Eastern New York from 5 percent in 2012 to 9 percent in 2013. The increase in deratings of economic capacity was attributable to one of the two largest suppliers.

The figure shows that the two largest suppliers in Eastern New York exhibited much 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), 10 percent of the capacity of the largest two suppliers was economic and derated compared to just 4 percent for all other suppliers; and

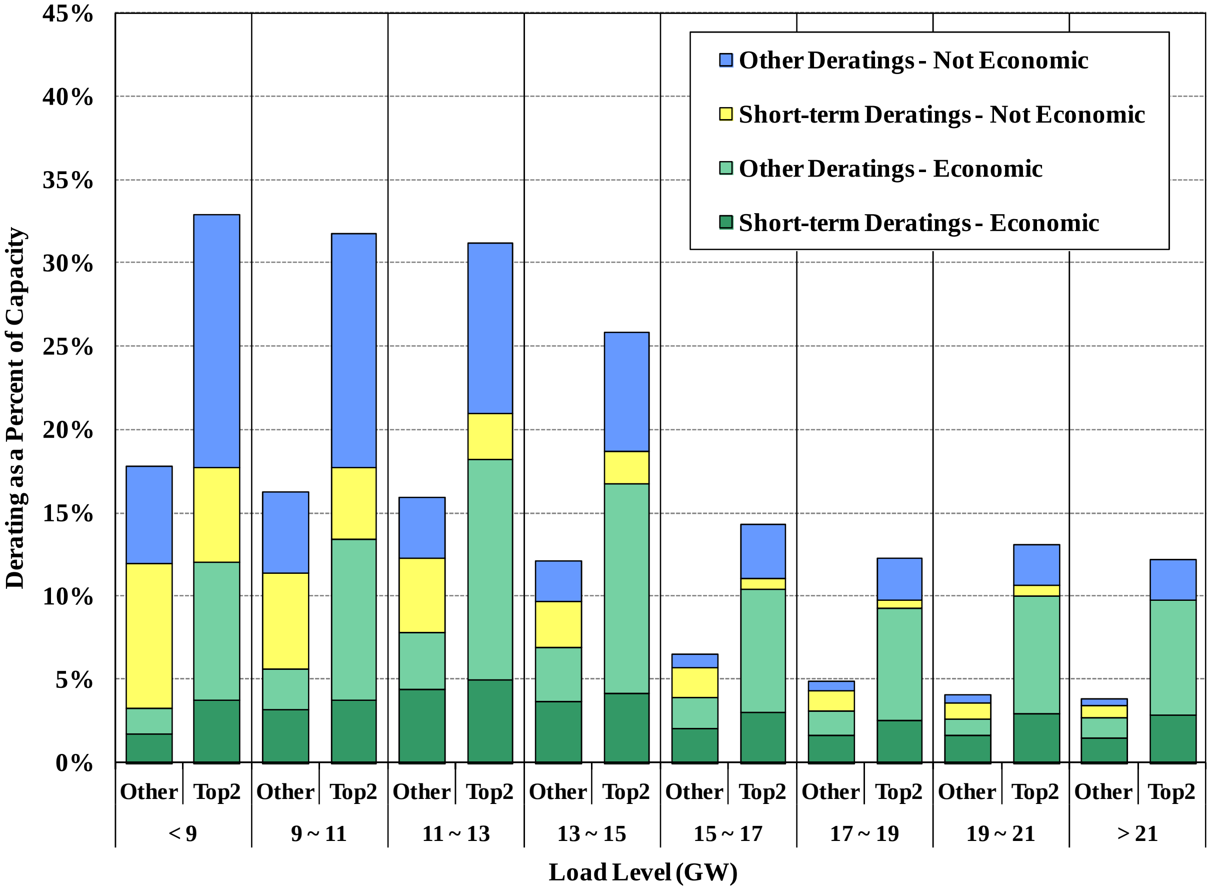
18 Physical withholding is when a resource is derated or not offered into the market when it would be economic for the resource to produce energy (i.e., when the market clearing price exceeds the marginal cost of the resource). Suppliers may also physically withhold by providing inaccurate information 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.

19 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.

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

- During low to moderate load levels (i.e., < 17 GW), 14 percent of the capacity of the largest two suppliers was economic and derated compared to just 7 percent for all other suppliers.

Figure 5: Deratings by Supplier by Load Level
Eastern New York, 2013



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. The high rates of deratings for the largest two suppliers are not explained by differences in the characteristics of the generator that were derated, so they raise significant concerns about the efficiency of long-term outage scheduling of some resources.

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 consider expanding its outage scheduling authority.

Figure 6: Output Gap by Supplier by Load Level
Eastern New York, 2013

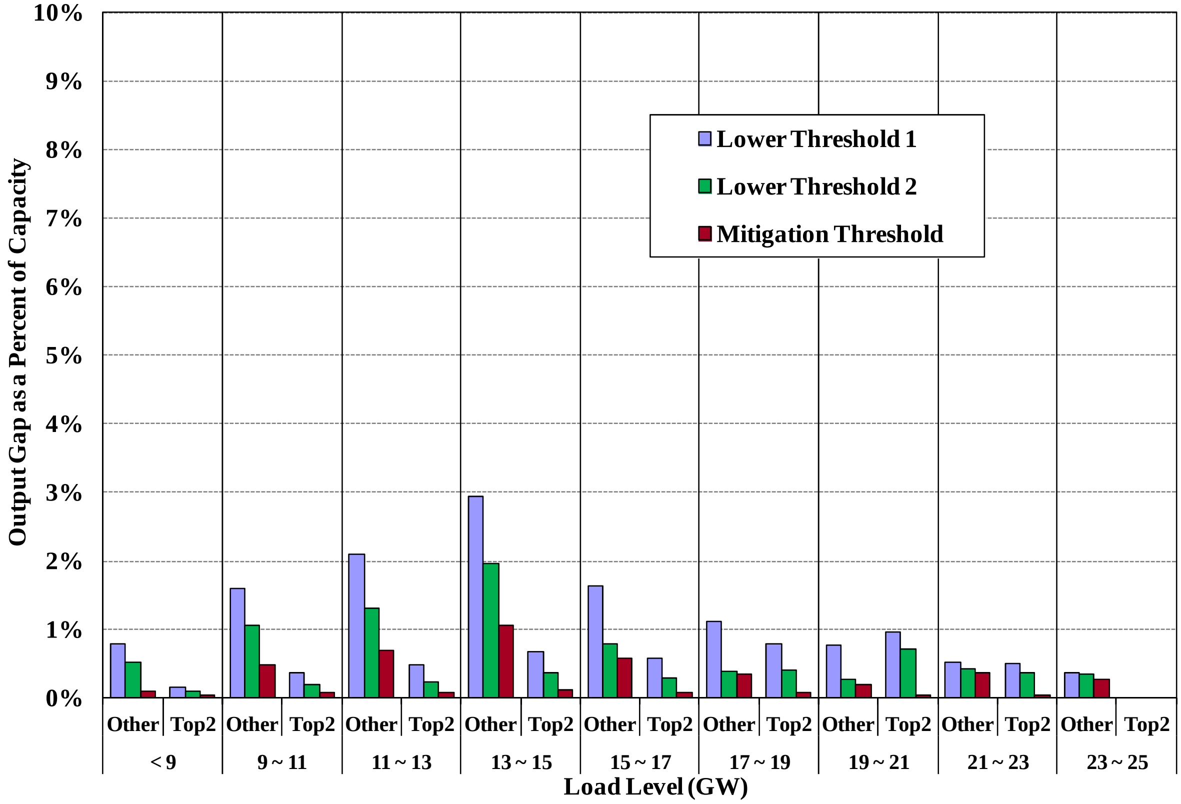


Figure 6 shows that the output gap averaged under 0.5 percent as a share of total capacity for both large and small suppliers in Eastern New York at the statewide mitigation threshold during 2013. At the lowest threshold evaluated (i.e., $25 per MWh or 50 percent above reference), the output gap averaged less than 1.5 percent. These levels are low and raise very few competitive concerns. In general, it is 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.

Overall, the patterns of output gap were generally consistent with expectations in a competitive market and did not raise significant concerns regarding potential economic withholding under most conditions.[21] However, the pattern of day-ahead deratings shown in Figure 5 reflects the

21 Although the amount of output gap was relatively small in 2013, 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

fact that one supplier scheduled lengthy planned outages of generating units that would have been economic.[22] 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. However, this supplier's planned outages could have been scheduled more efficiently in 2013, and the NYISO should consider expanding its authority to coordinate outages.

B. Automated Mitigation in the Energy Market

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

- Automated Mitigation Procedure ("AMP") in New York City – This is used in the day-ahead and real-time markets to mitigate offer prices of generators that are substantially above their reference levels (i.e., estimated marginal costs) when their offers would significantly raise the energy prices in transmission-constrained areas.[23]

- 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.

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.

22 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.

23 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.

Generators were sometimes mitigated in the day-ahead or real-time market and then subsequently unmitigated after consultation with the NYISO for several reasons.[24] First, a generator's reference level on a particular day was lower than the consultative reference level that the NYISO approved for the generator before the generator was mitigated.[25] Second, the generator attempted to inform the NYISO of a fuel price change prior to being scheduled in the day-ahead or real-time market, but the generator was still mitigated.[26] Third, a generator's fuel cost changed by time of day, although the day-ahead market software is unable to use reference levels that vary by time of day. Fourth, the Reference Level Software ("RLS") had a limited number of fuel price index locations that it could use, causing some generators' reference levels to be based on a fuel price that was inaccurate.[27]

Figure 7 summarizes the amount of mitigation that occurred in the day-ahead and the real-time markets in 2012 and 2013 as well as the amount of capacity that was unmitigated after consultation with NYISO.[28]

Most mitigation occurs in the day-ahead market, since that is where most supply is scheduled. In 2013, 92 percent of AMP mitigation occurred in the day-ahead market, primarily in the 138kV sub-pockets in New York City. Likewise, 91 percent of reliability mitigation occurred in the day-ahead market, primarily for DARU and local reliability (LRR) commitments in New York City. The frequency of AMP mitigation in New York City decreased substantially in the past two years. The average capacity that was AMP-mitigated fell from over 250 MW in 2011 to roughly 95 MW in 2012 and 55 MW in 2013. These reductions were mostly attributable to less frequent and severe transmission congestion in New York City, particularly in the 138kV load pockets. These reductions in congestion were partly due to generation additions and transmission upgrades in recent years.

24 NYISO Market Services Tariff, Section 23.3.3 lays out the requirements for consultation.

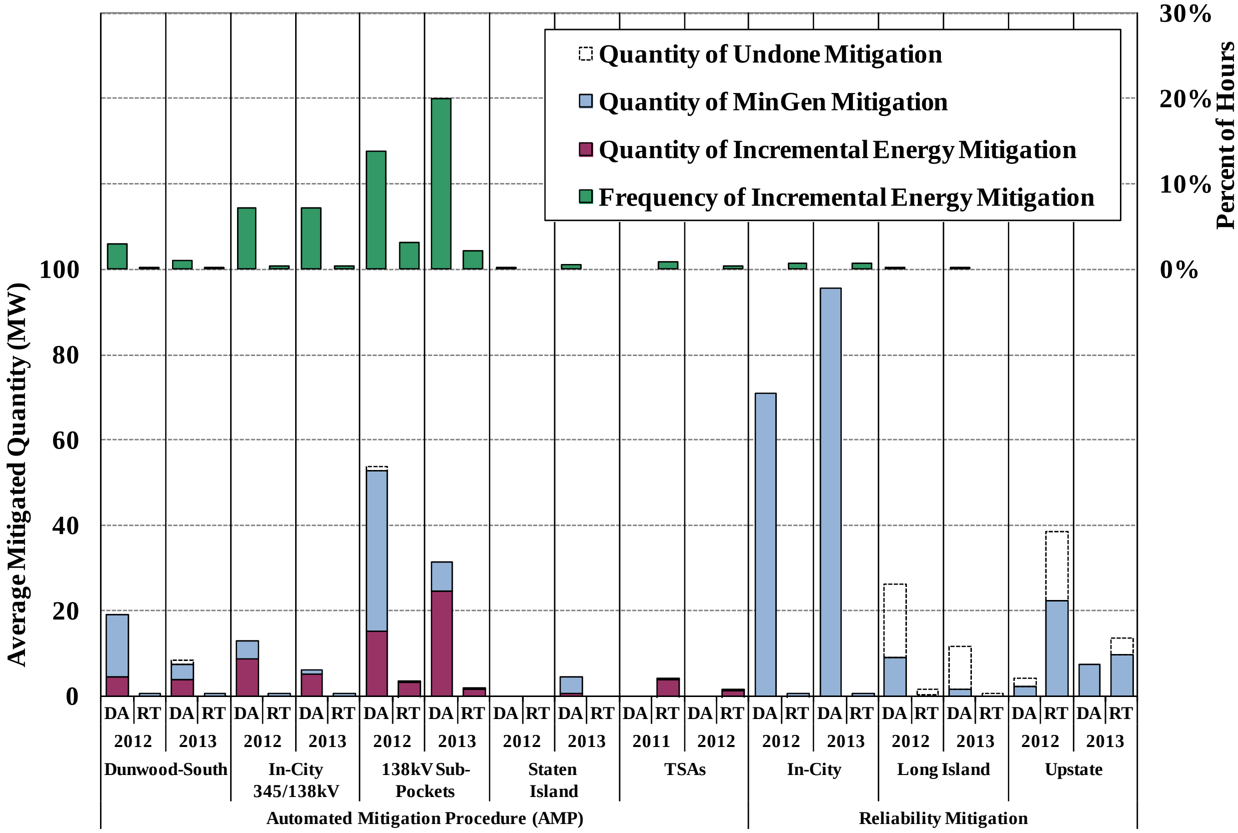
25 This includes when the NYISO approves the consultative reference level submission after the mitigation because the submission was made prior to mitigation.

26 See NYISO Market Services Tariff, Section 23.3.1.4.7.7.

27 The set of fuel price indices was expanded in March 2013.

28 See Section I.C in the Appendix for additional description of the figures.

Figure 7: Summary of Day-Ahead and Real-Time Mitigation
2012 & 2013



Reliability commitments fell in Long Island and upstate New York, leading to reduced mitigation in these categories from 2012 to 2013. Units that were frequently committed for reliability in these areas became more economic in 2013 because of higher LBMPs driven primarily by higher natural gas prices (transmission outages and deratings were also an important contributing factor in Long Island). However, in New York City, reliability commitment for NOx Bubble constraints rose in 2013, leading to more frequent mitigation of local reliability commitments.

Unmitigation of generators that were initially mitigated by the AMP software was very uncommon in 2012 and continued to decrease in 2013 as the NYISO improved its processes for administering reference levels. This is important because mitigating generators below marginal cost with the AMP software leads to inefficient scheduling and distorted market clearing prices, which cannot be undone when the generator is unmitigated.[29]

29 Undoing reliability mitigation is much less concerning, since it does not affect schedules or prices. This is

The NYISO introduced the Increasing Bids in Real-Time ("IBRT") capability in October 2010, which allows generators to update the fuel prices used to calculate their real-time reference levels until 75 minutes ahead of a particular hour. This allows generators to reflect their fuel costs more accurately and leads to more efficient dispatch and price signals. Until the third quarter of 2013, limits on fuel-price adjustments prevented generators from reflecting: (a) the full price of gas on days with intra-day price volatility and (b) routine intra-day gas balancing charges.[30] Consequently, generators that were not scheduled in the day-ahead market sometimes switched to more expensive fuels or stopped offering altogether in real-time to avoid being dispatched below cost. Ultimately, these natural responses caused more expensive generators to be scheduled in their place, leading energy prices to be higher than if the full cost of gas had been properly reflected in the generators' reference levels. The NYISO introduced generator-specific IBRT thresholds in the third quarter of 2013 to better enable suppliers to reflect their fuel costs, but relatively few suppliers have taken advantage of this to date.

As gas market conditions lead to increased gas price volatility, the potential for generators to be mitigated in the day-ahead market below their expected marginal costs increases as well. Currently, day-ahead reference levels are based on the price indices for the gas trading day on the day before the day-ahead market runs. For example, the bid window for the day-ahead market for Wednesday closes on Tuesday at 5 am. The RLS software uses the gas price index from the Monday gas trading day for gas that will flow on the Tuesday gas flow day, which can lead to two problems. First, gas market conditions can change significantly from the close of the Monday gas trading day to 5 am the next morning. Second, when the weather is expected to change between Tuesday and Wednesday, natural gas prices may also be expected to change. Hence, using the gas price for the Tuesday flow date will lead to inaccurate reference levels when scheduling generation for Wednesday.

For these reasons, the NYISO improved its procedures in 2013 for allowing generators to consult on the fuel price used to calculate reference levels in the 24-hours before the close of the bid window for the day-ahead market. The enhanced procedures have been beneficial during recent

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.

30 See NYISO Market Services Tariff, Section 23.3.1.4.7.6.

periods of volatile natural gas prices, since over-scheduling gas-fired generation leads to even tighter gas market conditions. To better facilitate the use of accurate fuel price information in the day-ahead market, the NYISO plans to streamline the process for suppliers to submit fuel price information before the day-ahead market when there is a reasonable basis to expect fuel prices to be substantially higher than the index that would be used to calculate reference levels.[31]

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 both new and existing generation, transmission, and demand response. Buyer-side mitigation measures were adopted for New York City to prevent entities from artificially depressing prices below competitive levels by subsidizing the entry of uneconomic capacity.[32] Supply-side mitigation measures were adopted in New York City to prevent a large supplier from inflating prices above competitive levels by withholding economic capacity.[33] Given the sensitivity of prices in New York City to both of these actions, we believe that these mitigation measures are essential for ensuring that capacity prices in the City are efficient. This section discusses issues related to the use of the capacity market mitigation measures in 2013.

1. Application of the Buyer-Side Mitigation Measures

The NYISO performed Mitigation Exemption Tests for several Class Year 2011 ("CY11") projects in 2013, including the Berrians I/II Project (which is a proposed 250 MW combined cycle project in Zone J), the CPV Valley Energy Center (which is a proposed 700 MW combined cycle project in Zone G), and Taylor Biomass Energy (which is a proposed 20 MW renewable

31 See *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.

32 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.

33 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.

project in Zone G). [34] The CPV Valley Energy Center received an exemption from buyer-side mitigation, so it will be able to sell capacity if the developer moves forward with the project. The Berrians I/II Project and Taylor Biomass Energy both did not pass the mitigation exemption test and will be subject to Offer Floor mitigation if the developers move forward with the projects.[35]

The NYISO also re-tested the Hudson Transmission Partners ("HTP") project as directed by the Commission in 2013.[36] HTP entered into a long-term power purchase agreement with NYPA following one of its requests for proposals. HTP failed to receive an exemption each time it has been tested under the buyer-side mitigation rules, but HTP began normal operations in June 2013 and has been subject to an offer floor.[37] Although the offer floor prevents HTP from clearing in the capacity market at prices below its offer floor, it still affected prices by increasing the amount of emergency assistance deemed to be available from PJM. This results in lower capacity requirements and prices. This is a shortcoming of the current buyer-side mitigation measures that we are recommending the NYISO address. Since the purpose of the buyer-side mitigation measures is to deter uneconomic entry that is intended to depress prices below competitive levels, the start of operations by HTP suggests that the buyer-side mitigation measures may not be sufficiently effective. This is discussed further in the next part of this section.

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34 In 2012, the NYISO performed Mitigation Exemption Tests for Astoria Energy II, Bayonne Energy Center, and Hudson Transmission Partners. These are discussed further in *2012 State of the Market Report for the New York ISO Markets* ("2012 SOM.Report"), Section III.C.

35 The Mitigation Exemption Tests for these three projects are discussed in detail in the following reports: *Assessment of the Buyer-Side Mitigation Exemption Test for the Berrians Facility*, October 15,2013 ("BSM Report for Berrians"); *Assessment of the Buyer-Side Mitigation Exemption Test for the Taylor Biomass Energy Project*, March 7, 2014 ("BSM Report for Taylor Biomass"); and *Assessment of the Buyer-Side Mitigation Exemption Test for the CPV Valley Energy Center Project*, March 7, 2014 ("BSM Report for CPV Valley").

36 In November 2013, the Commission ordered the NYISO to re-test the HTP Project using alternative financing cost parameters. See *Hudson Transmission Partners, LLC v. New York Independent System Operator, Inc.*, 145 FERC ¶ 61,156, at P 112.

37 See *Assessment of the Buyer-Side Mitigation Exemption Test for the Hudson Transmission Partners Project*, February 21, 2014.

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.

Market-Based Investment Exemption

One issue that is particularly difficult to address accurately in future price forecasts is the issue of generation retirements. The recent series of generator retirements highlights the need for the Buyer-Side Mitigation measures to function appropriately when the retirement of existing facilities creates profitable opportunities for new investment. Nearly 2 GW of capacity has been retired or mothballed since the beginning of 2012, and it is uncertain how long the Indian Point nuclear units will be licensed to operate. Additional retirements are expected over the coming decade given the age of many existing generators, but the timing of individual retirements may be hard to predict.[38]

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 difficult, however, for these forecasts to account for uncertainty regarding unit retirements. Currently, the forecasted capacity prices assume that only suppliers that have submitted a retirement notice (and not just a mothball notice) to the PSC will retire, which is only required to be submitted six months from the retirement date. To the extent that other significant retirements are likely, the Buyer-Side Mitigation Exemption test will tend to understate the forecasted prices and over-mitigate competitive entry.

To address these concerns, we recommend the NYISO amend the rules to grant exemptions to suppliers engaged in purely private investment. This would allow merchant investors to invest based on their own expectations of whether additional retirements (beyond those that have been

[38] See *Market Monitoring Unit Review of the NYISO's 2012 Comprehensive Reliability Plan ("CRP"),* March 7, 2013.

noticed to the PSC) were likely to occur. Such a rule would help ensure that competitive market-based investments are not precluded by the buyer-side mitigation rules.

Offer Floors for Mitigated Projects

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

- Default Net CONE ("DNC") – a level 25 percent lower than Mitigation Net CONE ("MNC") in the first year of the project's operation, where MNC is intended to 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") – a level set at the estimated net CONE of the project over the first three years of the project's operation (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 DNC and UNC. The use of DNC, which is 25 percent less than the annualized Net CONE of a new resource, 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 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 or the 100 percent of the MNC.

Assumptions Used in the Mitigation Exemption Test

The reports evaluating the Mitigation Exemption Tests for HTP and the three CY11 projects have identified concerns with the following assumptions that are used in the exemption test and that are required by the NYISO MST.

First, the Starting Capability Period is when a project is assumed to begin operating for the purposes of the exemption test. It is important because the timing of entry affects the load forecast and other assumptions. If the Starting Capability Period is significantly earlier than an Examined Facility would likely begin operating, it can depress the ICAP price forecasts, thereby increasing the likelihood of mitigating an economic resource. In the exemption tests for all three

CY11 projects, we found that the Starting Capability Period was not well-aligned with when the Examined Facility would likely become operational, making the facility appear less economic than it actually would be at the time it would enter.[39] We recommend the NYISO consider modifying the tariff so that the Starting Capability Period is better aligned with when the Examined Facilities would actually begin operating.

Second, the set of generators that is assumed to be in service for the purposes of the exemption test is important because the 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 mothballed resources that are unlikely to re-enter.[40] This will also compel the NYISO to exclude resources that have submitted a retirement notice, but that retain the ability to re-enter the market.[41] 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 prevailing prices. This includes excluding mothballed units that are not expected to be available.

Uneconomic Transmission Investment

Recent Mitigation Exemption Tests have highlighted a shortcoming in the current BSM rules, which is that the buyer-side mitigation rules do not prevent an entity from building uneconomic transmission to reduce LCRs and depress capacity prices below competitive levels.[42] This includes both projects that increase transmission capability on internal NYISO interfaces and projects that interconnect other areas to the NYISO and may increase the emergency assistance credited to the external area. We recommend the NYISO consider buyer-side mitigation rules to deter uneconomic transmission investment.

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39 See BSM Report for CPV Valley, Section III.A.

40 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.

41 See BSM Report for CPV Valley, Section III.B.

42 See BSM Report for CPV Valley, Section III.C.

3. Supply-Side Mitigation Measures

The supply-side mitigation measures for New York City limit the offers of a pivotal supplier in the spot capacity auction based on the Going Forward Costs of its generators. In previous State of the Market Reports, we have identified circumstances when a large supplier with an incentive to withhold capacity would not be subject to the supply-side mitigation measures.[43]

To address this concern, we recommended modifying the pivotal supplier test to prevent a large supplier from circumventing the mitigation rules by selling capacity in the forward capacity auctions (i.e., the strip and monthly auctions), thereby avoiding designation as a pivotal supplier.[44] The current definition of a pivotal supplier effectively assumes that selling capacity in the forward auctions eliminates the incentive for a large supplier to withhold in the spot auction. However, increased spot capacity prices affect the expectations of other market participants, increasing the clearing prices in subsequent forward auctions. This allows a large supplier to benefit from withholding in the spot capacity auction even if it does not meet the definition of a pivotal supplier in the supply-side mitigation measures because it has sold most of its capacity in the forward auctions. Hence, we recommend modifying the pivotal supplier criteria to include in the evaluation for a particular supplier any capacity that it sold prior to the spot auction.

[43] See 2012 SOM Report, Section III.C.3.

[44] For the purposes of the capacity mitigation measures, pivotal suppliers are defined in MST Section 23.2.1.

IV. Day-Ahead Market Performance

A. 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 generating resources, procurement of natural gas, and scheduling of external transactions.

Convergence of Zonal Energy Prices

Table 3 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 from 2011 to 2013.[45]

Table 3: Price Convergence between Day-Ahead and Real-Time Markets
Select Zones, 2011-2013

	Avg. Diff % (DA - RT)			Avg. Absolute Diff %		
Zone	**2011**	**2012**	**2013**	**2011**	**2012**	**2013**
West	1.4%	0.0%	-1.9%	24.0%	26.4%	36.3%
Central	1.1%	0.6%	1.3%	25.7%	25.5%	29.5%
Capital	2.6%	2.9%	4.5%	28.1%	27.0%	33.1%
Hudson Valley	0.9%	0.9%	-0.8%	30.0%	29.9%	33.9%
New York City	1.8%	0.8%	-1.4%	32.4%	31.4%	35.0%
Long Island	0.9%	1.7%	-6.5%	35.5%	42.1%	46.5%

As measured by the average difference in day-ahead and real-time prices, energy price convergence was fair in most areas in 2013. Convergence in 2013 was worse than in 2012. Inconsistencies between day-ahead and real-time prices were increased by higher real-time price volatility in 2013, particularly:

[45] Section I.G in the Appendix shows monthly variations of average day-ahead and real-time energy prices.

- From July 15 to 19, when a heat wave led to the activation of demand response and the Scarcity Pricing rule; and

- From January 19 to 27, when extreme cold weather led to high and volatile gas prices and frequent gas pipeline OFOs, which increased cost uncertainty for electricity suppliers in the day-ahead market.

In Long Island, which already exhibited the largest spreads between day-ahead and real-time energy prices, the average absolute spread rose from 36 percent in 2011 to 42 percent in 2012 and 46 percent in 2013, reflecting increased real-time price volatility. In addition to the factors discussed above that affected a number of areas in New York, higher real-time volatility in Long Island was also attributable to:

- Tight supply conditions that were driven by the reduction in imports on the Neptune line and the retirement of 330 MW of steam turbine generation; and

- Inefficient utilization of some generators, which led to more frequent operation of relatively inefficient gas-fired generators and oil-fired generators.[46]

Convergence of Nodal Energy Prices

Certain generator nodes exhibited less consistency between average day-ahead and real-time prices than zonal prices did in 2013. 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 33 percent higher than average day-ahead prices in 2013.[47] These large and persistent real-time premiums were attributable to:

- The inefficient utilization of generating capacity in the Valley Stream load pocket in the real-time market;[46] and

- 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

46 Section III.A discusses factors that contributed to inefficient utilization of generating capacity.

47 See Figure A-27 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 in the 2012 SOM Report, Section VIII.C.2.

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 VIII.E.

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

Convergence of Ancillary Service Prices

Table 4 evaluates 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. These quantities are shown for afternoon hours (i.e., hour 14 to 20) in three seasonal periods (i.e., January to April, May to August, and September to December) of 2012 and 2013.

[49] Figure A-28 to Figure A-33 in the Appendix show our evaluation in more detail.

Table 4: Price Convergence Between Day-Ahead and Real-Time Reserve Prices
Afternoon & Evening Hours (HB 14-20), 2012-2013

Months	(DA-RT) Price as a Percent of DA Price		
	West 10-Min Spin	East 10-Min Non-Spin	East 10-Min Spin
2013			
Jan - Apr	24%	2%	-1%
May - Aug	6%	-30%	-28%
Sep - Dec	14%	42%	12%
Average	15%	5%	-5%
2012			
Jan - Apr	-5%	96%	35%
May - Aug	24%	-35%	-41%
Sep - Dec	42%	30%	-16%
Average	21%	30%	-7%

The table shows that convergence between day-ahead and real-time operating reserve prices improved generally during afternoons and evenings from 2012 to 2013. This was at least partly attributable to the revisions of the following two day-ahead market reserve mitigation provisions in 2013.

- 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; and

- On September 25, 2014, the second phase of the revision raised both caps to $10 per MW.[50,51]

This modest improvement is notable given that price convergence between day-ahead and real-time energy prices was generally was worse in 2013 than in 2012 because energy and reserves prices tend to be correlated.

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.

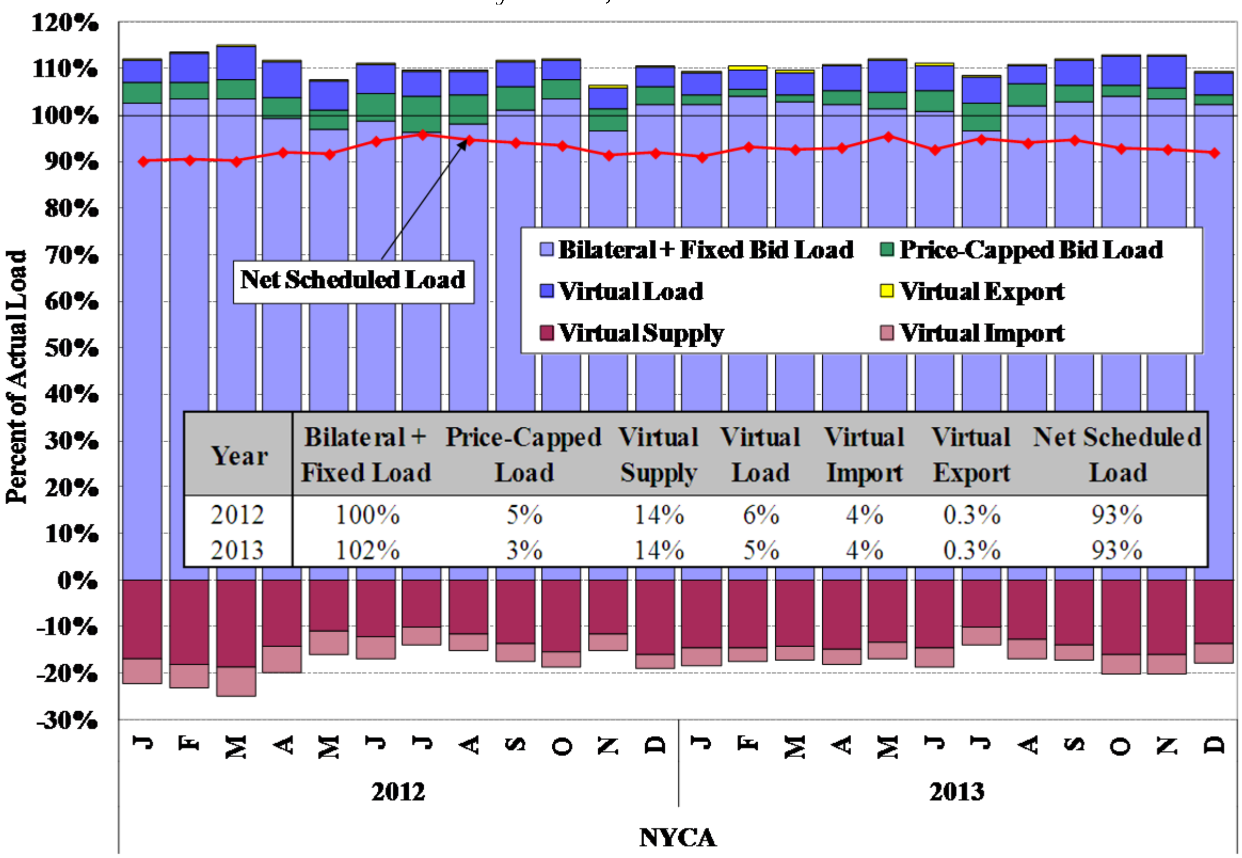
51 See New York Independent System Operator, Inc., *Proposed Amendments to its Market Power Mitigation Measures revising Mitigation Measures for 10-Minute Non-Synchronized Reserves and New York City Day-Ahead Market Spinning Reserves*, Docket No. ER13-298-000.

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.

Figure 8 shows the day-ahead schedules of physical load, virtual trades, and virtual imports and exports as a percent of real-time load on a monthly basis in 2012 and 2013 for NYCA.[52]

Figure 8: Day-Ahead Load Scheduling versus Actual Load in NYCA
by Month, 2012-2013



Year	Bilateral + Fixed Load	Price-Capped Load	Virtual Supply	Virtual Load	Virtual Import	Virtual Export	Net Scheduled Load
2012	100%	5%	14%	6%	4%	0.3%	93%
2013	102%	3%	14%	5%	4%	0.3%	93%

52 Figure A-51 to Figure A-57 in the Appendix also show these quantities at various locations in New York.

The figure shows that the overall load in the day-ahead market was scheduled at 93 percent of actual load in NYCA in 2013, comparable to 2012. The under-scheduling of load was likely a response to some inconsistencies between the scheduling of resources in the day-ahead and real-time markets. For instance, wind and hydro resources in upstate New York normally scheduled substantially more output in the real-time market than in the day-ahead market. In both 2012 and 2013, this scheduling pattern added an average of over 500 MW of additional energy supply in real-time. Likewise, imports from Ontario (which does not have a day-ahead market) typically increase in real-time relative to the day-ahead schedules. Hence, this net load scheduling pattern helped ensure that physical resources were not over-committed in the day-ahead market.

In our evaluation of load scheduling in various regions of New York, we found that the historic pattern of under-scheduling outside Southeast New York and over-scheduling in Southeast New York became less clearly evident in 2013. Long Island was the only load zone that was consistently over-scheduled in 2013, reflecting the response of market participants to tight operating conditions and high real-time price events there. However, the amount of over-scheduling in other parts of Southeast New York has fallen over the past two years. In Lower Hudson Valley, the amount of scheduling fell from 108 percent in 2011 to 90 percent in 2013. Likewise, in New York City, the amount of scheduling fell from 103 percent in 2011 to 100 percent in 2013. These reductions likely resulted from less frequent periods of acute real-time congestion into Southeast New York and New York City, which were attributable to:

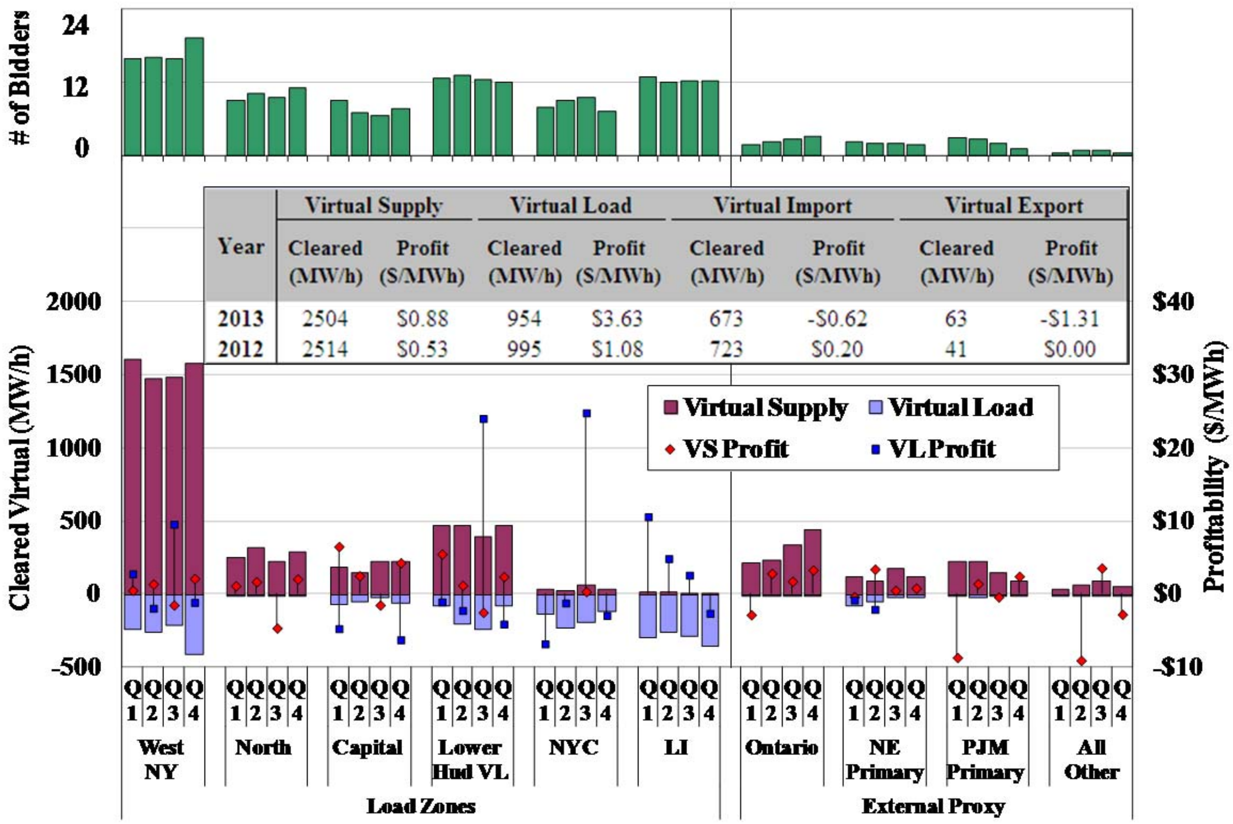
- More effective use of PARs between New Jersey and New York to manage congestion into Southeast New York. This was the result of operational improvements and the introduction of Market-to-Market congestion management with PJM; and

- The addition of new generation and new transmission facilities in New York City in the past two years.

In general, the patterns of day-ahead scheduling have helped improve convergence between day-ahead and real-time prices. In 2013, regions outside Southeast New York exhibited day-ahead premiums, while most regions in Southeast New York exhibited real-time premiums. This suggests that further under-scheduling outside Southeast New York and further over-scheduling in Southeast New York would likely have been profitable.

The following figure summarizes virtual trading by geographic region in 2013, which includes virtual trading at the eleven load zones and virtual imports and exports at the proxy buses.[53]

Figure 9: Virtual Trading Activity
by Region by Quarter, 2013



The figure shows that a large number of market participants regularly submitted virtual bids and offers. In 2013, on average, 28 participants submitted virtual trades at the load zones and 7 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 2013. This pattern was consistent with the day-ahead load scheduling patterns discussed earlier for similar reasons. At the proxy buses, more than 90 percent of scheduled virtual transactions were virtual imports, primarily at the three primary interfaces with PJM, New England, and Ontario. Since these three

53 See Figure A-59 in the Appendix for a detailed description of the chart.

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.

The profits and losses of virtual load and supply have varied widely from quarter to quarter, reflecting the difficulty of predicting volatile real-time prices.[54] However, in aggregate, virtual traders netted approximately $45 million of gross profits in 2013. Overall, virtual traders 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 an efficient commitment of generating resources.

54 Figure A-58 in the Appendix also shows wide variations in profits and losses on a monthly basis.

V. 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.

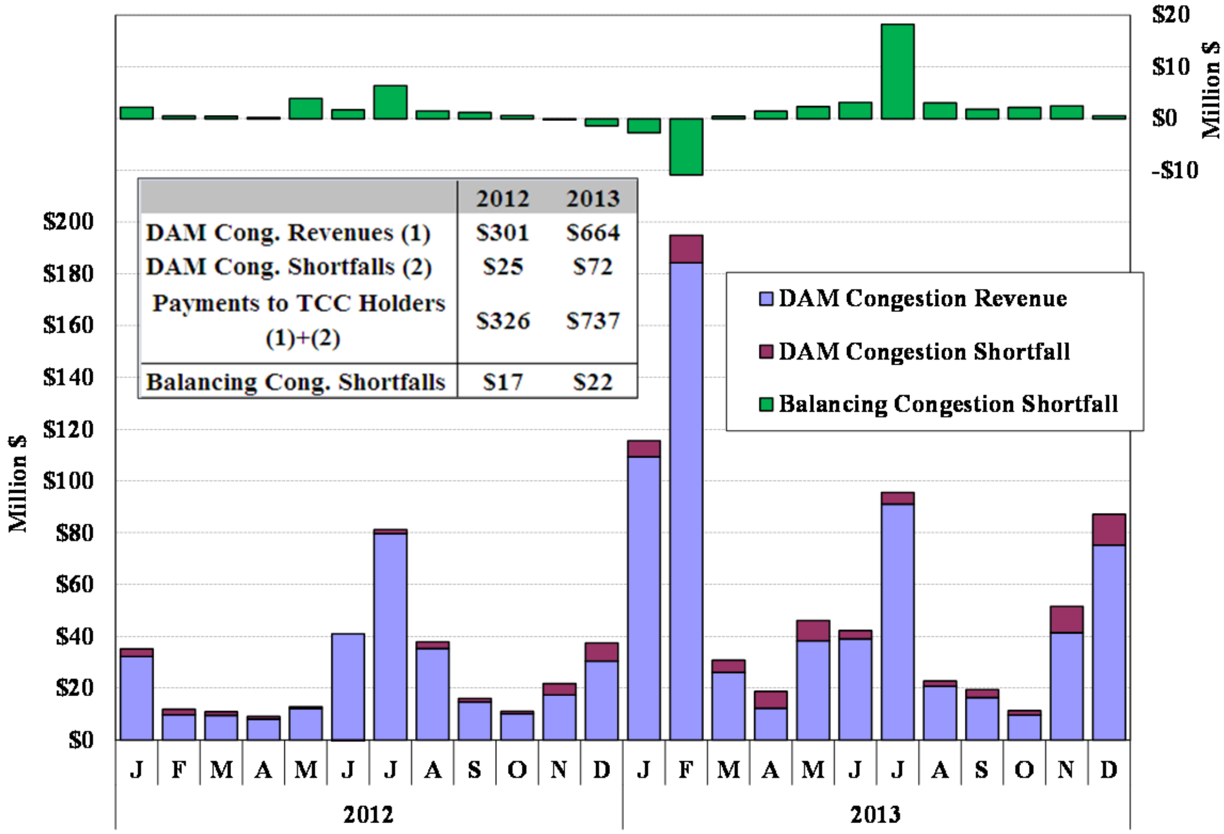
Congestion charges are applied to purchases and sales (including bilateral transactions) in the day-ahead and real-time markets based on the congestion components of the day-ahead LBMPs and the real-time LBMPs, respectively.[55] Market participants can hedge congestion charges in the day-ahead market 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.

[55] 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). While congestion charges to other purchases and sales are based on the congestion component of the LBMP at the purchasing or selling location.

Figure 10: Congestion Revenues and Shortfalls
2012 – 2013



The figure shows that the overall congestion revenues and shortfalls rose substantially from 2012 to 2013. Congestion revenues collected in the day-ahead market rose by 121 percent from 2012 to $664 million in 2013. Similarly, day-ahead and balancing congestion revenue shortfalls increased by 124 percent to a total of $94 million in 2013.

Day-Ahead Congestion Revenues

The increase in natural gas prices was the primary driver of the increase in day-ahead congestion revenues in 2013, particularly during the winter months. Higher natural gas prices increased the redispatch costs incurred to manage congestion. Higher spreads in natural gas prices between Western and Eastern New York resulted in higher levels of west-to-east congestion. Accordingly:

- $284 million (43 percent) of day-ahead congestion revenues accrued on the Central-East interface in 2013, up from $55 million in 2012.[56]
- $369 million (56 percent) of day-ahead congestion revenues accrued in the three winter months of December, January, and February when gas price spreads were largest, up from $73 million in 2012 when the winter weather was milder.

Transmission flows from west-to-east through the West Zone became much more congested in 2013 due to the combined effects of mothballing units at the Dunkirk plant, planned and forced outages of transmission and generation in the West Zone, issues with the modeling of the Niagara plant, and changes that have made the TLR process less effective since 2012 when the Ontario-Michigan PARs were placed in service.[57] Overall, flows from the western-most areas to central New York accounted for $64 million (or 10 percent) of day-ahead congestion revenues in 2013, up from just $6 million in 2012.[58]

In 2013, significant day-ahead congestion revenues continued to accrue on flows into Southeast New York (7 percent), in New York City (16 percent), in Long Island (16 percent). Congestion in these areas was most significant during the summer months on high load days and days with anticipated Thunderstorm Alerts (“TSAs”).[59]

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 rose 188 percent from 2012 to $72 million in 2013, which was driven partly by the significant increase in day-ahead congestion.

56 Figure A-61 in the Appendix shows the day-ahead and real-time congestion by interface in 2012 and 2013. Figure A-8 shows monthly natural gas prices for several regions in New York.

57 Section III.B in the Appendix discusses the West Zone congestion, and Section VI.B discusses changes in the TLR (“Transmission Loading Relief”) process.

58 The NYISO first incorporated these lines into the congestion pricing and dispatch model in May 2012 to manage the congestion more efficiently. Previously, this congestion was resolved with a combination of out-of-merit dispatch and interface constraints that did not clearly distinguish units that could relieve the congestion by ramping-up from units that could relieve the congestion by ramping-down.

59 The Thunderstorm Alert procedure requires the NYISO to secure the transmission system into Southeast New York based on a larger contingency than normal, which reduces imports into Southeast New York. See *NYSRC Reliability Rules*, Rule I-R4.

Transmission outages were also a key driver of high day-ahead congestion shortfalls in 2013, particularly in New York City and Long Island, which accounted for the vast majority ($70 million) of total shortfalls. From January to May, planned outages were taken to support the installation of a new PAR-controlled line connecting West 49th Street (on the 345kV system) with Vernon (on the 138kV system), reducing transfer capability into the Vernon pocket during this period. In July and early-August, forced outages reduced capability in the Greenwood load pocket in the 138kV system of New York City. From January to May and from September to October, the transfer capability into Long Island was significantly reduced on most days because of planned and forced outages and deratings of the 345kV transmission facilities from Upstate to Long Island.[60]

The NYISO has a process for allocating the day-ahead congestion shortfalls that result from transmission outages to specific transmission owners.[61] In 2013, the NYISO allocated 109 percent of day-ahead congestion shortfalls in this manner, up from 72 percent in 2012 and 44 percent in 2011.[62] 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.[63]

Balancing Congestion Shortfalls

Balancing congestion shortfalls result from reductions in the transmission capability from the day-ahead market to the real-time market. Balancing shortfalls rose modestly from $17 million in 2012 to $22 million in 2013. In both years, the majority of balancing congestion shortfalls accrued from May to September when TSA events are most frequent. TSAs require the NYISO

60 Figure A-62 in the Appendix summarizes the day-ahead congestion shortfalls on major transmission facilities for 2012 and 2013 on a monthly basis.

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

62 In 2013, the NYISO allocated $79 million of day-ahead congestion shortfalls to transmission owners while the total shortfalls were only $72 million, because some transmission facilities generated congestion surpluses during the year.

63 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 VIII.H) are assigned to the transmission owner.

to reduce transmission flows into Southeast New York significantly below day-ahead scheduled levels.[64]

The balancing congestion shortfall was reduced by balancing congestion surpluses on several transmission paths in 2013. First, surpluses frequently accrue when the output from wind generation is limited by transmission bottlenecks out of the North Zone in the real time market. This contributed a surplus of nearly $6 million in 2013.

Second, the operations of PAR-controlled lines between New Jersey and New York contributed $12 million of surpluses in 2013 primarily due to M2M Coordination with PJM. The NYISO received a net settlement of $7 million from PJM in 2013 under the M2M JOA as the real-time flows across the PAR-controlled lines were often lower than the target flows in hours when the NYISO experienced congestion on its coordinated flowgates. Another $5 million of surpluses resulted when actual real-time flows across these lines exceeded the day-ahead scheduled flows. This occurred primarily in the first few weeks of M2M coordination with PJM (in late-January and February) when the distribution of PJM-to-NYISO interface flows in the day-ahead market was inconsistent with the real-time operation of the interface under the M2M JOA.[65]

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 2012/13 and Summer 2013 Capability Periods (November 2012 to October 2013). We find that the value of day-ahead market congestion was well above TCC prices for most transmission paths in the Winter 2012/13 Capability Period, indicating that the high levels of congestion that were driven by natural gas prices 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.[66,67]

64 Figure A-63 in the Appendix summarizes the balancing congestion shortfalls on major transmission facilities for 2012 and 2013 on a monthly basis.

65 Tech Bulletin #152 describes these day-ahead modeling changes and when they occurred.

66 Nearly all of the transmission capability for the Winter 2012/13 Capability Period was sold prior to October 2012.

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

Since congestion in the day-ahead market generally exceeded the TCC prices, market participants purchasing TCCs in the auctions covering the 12-month period from November 2012 to October 2013 netted a total gross profit of $112 million. Overall, the profitability for TCC holders in this period was nearly 100 percent (as a weighted percentage of the original TCC prices).[68]

TCC profits totaled $60 million for inter-zonal components of the TCCs during the assessed 12-month period. Most of these profits accrued over the Winter 2012/13 Capability Period because higher than anticipated natural gas prices led to unexpectedly substantial increases in inter-zonal congestion, particularly between zones across the Central-East interface. Inter-zonal TCC profits were relatively modest during the Summer 2013 Capability Period, reflecting that the TCC prices were relatively consistent with expectations in the TCC auctions.

Intra-zonal components of the TCCs were highly profitable in each period as the total payouts ($91 million) exceeded the original net purchase costs by 130 percent. This reflects that the factors that contribute to more localized congestion (e.g., generation and transmission outages that have more impact in local regions, changes in constraint modeling in load zones) are typically undervalued in the TCC auctions. For instance, large intra-zonal TCC profits accrued on the transmission constraints in the West Zone because the congestion that became prevalent there in the summer of 2013 was not well anticipated until the monthly Reconfiguration Auction for August 2013.

68 Section I.D of the Appendix shows additional detail regarding the profitability of TCCs and how TCCs are broken into inter-zonal and intra-zonal components.

VI. 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 5 summarizes the net scheduled imports between New York and neighboring control areas in 2012 and 2013 during peak (i.e., 6 am to 10 pm, Monday through Friday) hours.[69]

Table 5: Average Net Imports from Neighboring Areas
Peak Hours, 2012 – 2013

Year	Hydro Quebec	Ontario	PJM	New England	CSC	Neptune	1385	VFT	HTP	Total
2012	1,294	666	572	-239	268	267	120	64	0	3,012
2013	1,296	808	489	-463	245	371	99	124	46	3,016

69 Figure A-66 to Figure A-69 in the Appendix show more detailed net scheduled interchanges between New York and neighboring areas by month by interface.

Total net imports from neighboring areas did not change significantly from 2012 to 2013, averaging slightly over 3 GW during peak hours in both years. However, net imports across individual interfaces varied more substantially over the period.

Controllable Interfaces

Imports from neighboring control areas accounted for a large share of the supply (i.e., 28 percent of the load) to Long Island in 2013, up from 25 percent in 2012. Although the full capabilities of the three controllable interfaces were frequently used to import, two factors reduced imports significantly during portions of 2013.[70] First, imports across the Neptune line were limited in the first half of 2013 due to an outage that reduced its transfer capability by 40 percent from August 2012 to June 2013. Second, net imports over the Cross Sound Cable and the Northport-Norwalk line were significantly lower in the winter, particularly in December 2013, 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 170 MW during peak hours in 2013.[71] The lower level of imports was generally consistent with the lower LBMPs in the 345 kV system of New York City (relative to Long Island LBMPs). However, net imports across these two controllable interfaces rose notably in the winter months (e.g., averaging nearly 500 MW during peak hours in December 2013) when natural gas prices in New York City were frequently higher than in New Jersey.

Primary Interfaces

In contrast to the controllable interfaces, the interchange across the primary interfaces was more variable. Net imports from Ontario rose 21 percent (or roughly 140 MW) from 2012 to 2013 partly because of more attractive energy prices in New York. Average real-time prices were roughly $9.10 per MWh higher on the NYISO side of the interface than on the Ontario side during 2013, up from $6.70 per MWh in 2012.

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70 Capabilities are 660 MW for Neptune, 330 MW for Cross Sound Cable, and 200 MW for the 1385 Line.

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

Average net exports to New England across the primary interface rose by nearly 94 percent (or 225 MW) in 2013. The increase occurred primarily during the winter months when the spread in natural gas prices between New England and New York increased sharply. However, the interface was usually used to import from New England during the summer months.

Net imports from Hydro Quebec to New York were relatively consistent from 2012 to 2013, averaging 1,300 MW and accounting for more than 60 percent of net imports across all primary interfaces in 2013. 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.

Net imports from PJM fell 14 percent from 2012 to 2013, averaging roughly 490 MW during peak hours of 2013. The decrease was partly due to the extended outages of the two Ramapo PARs, which reduced transfer capability across the portion of the interface between New York and New Jersey. These outages caused a shift in flows across the primary NYISO-PJM interface such that more would flow from Western Pennsylvania to Western New York rather than from New Jersey to New York City and the Hudson Valley. The shift in flows led to a corresponding decrease in LBMPs on the NYISO side of the interface, which reduced the incentives for scheduling power from PJM to the NYISO.

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 past three years. On average, clockwise Lake Erie loop flows have fallen from 151 MW in 2011 to near 0 MW in both 2012 and 2013.[72] However, large hourly variations still occur as clockwise circulation exceeded 200 MW in 13 percent of the hours in 2013. Clockwise circulation around Lake Erie has been reduced by multiple factors, including changes in scheduling patterns in the surrounding markets.

72 Figure A-70 in the Appendix summarizes the pattern of loop flows around Lake Erie for each month of 2012 and 2013.

One 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. 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.[73]

When clockwise loop flows increase, the NYISO may use Transmission Loading Relief ("TLR") procedures to ameliorate their effects on congestion in New York. However, the TLR process manages congestion much less efficiently than optimized generation dispatch in a nodal market because the TLR process provides less timely system control, it frequently leads to more curtailment than needed, and it does not curtail transactions in economic merit order (i.e., from most expensive to least expensive). The recent reduction in clockwise loop flows has contributed to a reduction in the frequency of TLRs called by the NYISO: from 23 percent of all hours in 2011 to 8 percent in 2012 and only 0.3 percent in 2013. The frequency of TLRs was also reduced by changes in the TLR process that began 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 than in previous years. 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.[74] We evaluated the performance of this process and found that the

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

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

coordination of Ramapo PARs helped alleviate real-time congestion in New York and reduced balancing congestion shortfalls in 2013.[75]

The NYISO is also planning to work with ISO New England to coordinate congestion management between the two markets in the future. This should improve congestion management on transmission paths from Capital Zone to Hudson Valley Zone that can be affected by unscheduled power flows from New England.

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 2013. 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 6 summarizes our analysis showing that the external transaction scheduling process generally functioned properly and improved convergence between markets during 2013.[76]

Table 6: Efficiency of Inter-Market Scheduling
Over Primary Interfaces and Scheduled Lines – 2013

	Average Net Imports (MW/h)	Avg Internal Minus External Price ($/MWh)	Percent in Efficient Direction
Free-flowing Ties			
New England	-485	-$1.57	53%
Ontario	853	$9.05	82%
PJM	515	-$0.41	54%
Controllable Ties			
1385 Line	86	-$0.33	54%
Cross Sound Cable	241	$6.02	54%
Neptune	365	$20.46	68%
HTP	52	$3.65	65%
Linden VFT	131	$7.51	64%

75 See Section V.B in the Appendix for a detailed evaluation of this process.

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

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 slightly over half of the hours on most interfaces between New York and neighboring markets during 2013. The share of hours with efficient scheduling ranged from 53 percent on the New England primary interface to 82 percent on the Ontario-New York interface. Nonetheless, 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.

Although scheduling by market participants tended 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, 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 2013, 15-minute scheduling (which is discussed in Section D) had been enabled at five interfaces with Hydro Quebec and PJM. The NYISO anticipates implementing CTS with PJM by the end of 2014 and with ISO New England by the end of 2015. The next section highlights some of the benefits of 15-minute scheduling. Ultimately, however, we expect that full implementation of CTS with its adjacent markets is essential for NYISO to capture the economic and reliability benefits of well-utilized external interfaces.

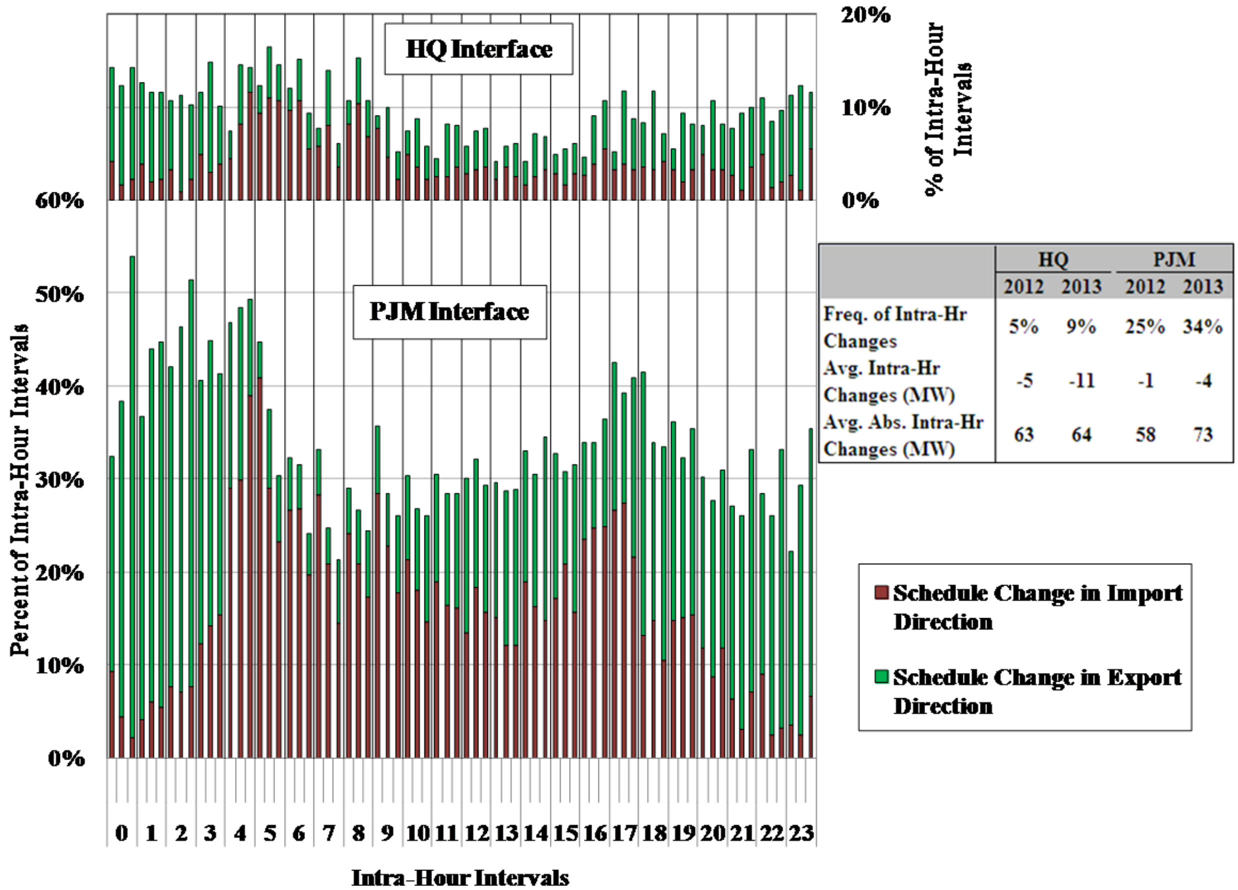
D. Intra-Hour Scheduling with Adjacent Control Areas

Currently, the NYISO allows 15-minute scheduling across five interfaces. On July 27, 2011, the NYISO first activated 15-minute scheduling on the primary interface between New York and Hydro-Quebec. Later, the NYISO and PJM activated 15-minute scheduling on their four interfaces: (a) the primary interface on June 27, 2012; (b) the Neptune Scheduled Line on October 30, 2012; (c) the Linden VFT Scheduled Line on November 28, 2012; and (d) the HTP Scheduled Line on June 3, 2013.

To evaluate the effects of 15-minute intra-hour scheduling, this section assesses the scheduling patterns on the primary interfaces with HQ and PJM in 2013.[77] Figure 11 shows the frequency of quarter-hour schedule changes (not including schedule changes at the top of the hour) by time of day at the primary HQ and PJM interfaces in 2013.

Figure 11: Distribution of Quarter-Hour Schedule Changes by Time of Day

Primary Interfaces with PJM and HQ, 2013



The horizontal axis shows all quarter-hour intervals (i.e., :15, :30, and :45 intervals of each hour) and excludes top of the hour schedule changes to focus on the transactions that were facilitated by the scheduling changes. The vertical axis shows the percent of intervals when the net schedules change from the previous interval in the import direction and the export direction for each interface. The table in the chart compares the overall frequency and the magnitude of these quarter-hour changes at the two interfaces from 2012 to 2013.

77 Section IV.D in the Appendix provides additional analysis for 15-minute scheduling.

Figure 11 shows that intra-hour schedule changes occurred during approximately 9 percent of all quarter-hour intervals on the primary HQ interface in 2013, much less frequently than the 34 percent of all quarter-hour intervals on the primary PJM interface. Several factors likely account for this difference. First, like the NYISO, PJM runs a real-time spot market that allows market participants to buy and sell from the market and to be more responsive to price changes. In contrast, market participants must find a counterparty in HQ with whom to transact, which may increase the difficulty of responding to arbitrage opportunities. Second, the prices at the PJM proxy bus were generally more volatile than prices at the HQ proxy bus, which increases the incentives to schedule intra-hour. Third, the economic direction in which to flow power changes more frequently between the NYISO and PJM than between the NYISO and HQ. For these reasons, a much larger share of the transactions at the PJM interface were offered price-sensitively than at the HQ interface. In 2013, 26 percent of real-time offers were based on 15-minute scheduling and were relatively price-sensitive (i.e., between $0 and $500 per MWh) at the PJM interface, compared to only 5 percent of such offers at the HQ interface.[78]

The figure also shows that intra-hour schedules were typically adjusted in ways that generally reduce price volatility at the top of these hours. In particular, intra-hour schedules are generally adjusted in the export direction during hours when the system is typically ramping-down (e.g., hours-beginning 21 to 23 and hours 0 to 3) and in the import direction during hours when the system is typically ramping-up (e.g., hours-beginning 5 to 10). This is an efficient response to the pattern of real-time prices, which typically move: (a) upward within each ramping-up hour before dropping sharply at the top of the next hour; and (b) downward within each ramping-down hour before rising sharply at the top of the next hour. The table in the chart shows an increase in the frequency of intra-hour schedule changes from 2012 to 2013, which was driven partly by higher and more volatile LBMPs in 2013 and partly by the increase of price-sensitive bids and offers that are based on 15-minute scheduling. Hence, these intra-hour transactions have helped moderate real-time price volatility in the ramping hours.[79]

78 Figure A-73 in the Appendix shows the average bid and offer quantities across the primary HQ and PJM interfaces in each month of 2013.

79 Figure 15 shows the moderating effects from intra-hour schedule changes.

Although intra-hour scheduling has been beneficial, substantial inefficiencies remain in the utilization of the external interfaces between NYISO and the adjacent markets. Given the potential benefits from more efficient coordination of the external interfaces, we recommend that the NYISO continue to place a high priority on the initiatives to improve the utilization of its interfaces with neighboring RTOs.

VII. 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. In 2013, the capacity auctions set clearing prices for three distinct locations: New York City, Long Island, and NYCA. Beginning with the Summer 2014 Capability Period, the capacity auctions will incorporate 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 facilitates investment in areas where it is most needed. This section summarizes the capacity market results in 2013 and discusses the need to account for additional zones and interfaces in the capacity market.

A. Capacity Market Results in 2013

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 2013-14 Capability Year, a one percent change in capacity supply or demand would change the clearing price by: $0.76/kW-month in NYCA, $1.10/kW-month in New York City, and $0.57/kW-month in Long Island.

1. Capacity Market Results: NYCA

In NYCA, the spot price averaged $5.80 per kW-month in the Summer 2013 Capability Period and $3.51 per kW-month in the Winter 2013-14 Capability period (excluding March and April 2014). These prices increased from $2.27 (summer) and $2.09 (winter) per kW-month during the previous Capability Year due to significant changes in both capacity requirements and capacity supply.

On the demand side, the ICAP requirement rose 314 MW (or 0.8 percent) from the May 2012-April 2013 Capability Year to the May 2013-April 2014 Capability Year because of an increase in the IRM from 16 percent to 17 percent. This was offset by a slight decrease in the peak load forecast.

On the supply side, the following changes also increased the statewide capacity prices:

- Sales from internal resources fell 1.4 GW (or 3.5 percent) over the Capability Year because of the retirement and mothballing of generation, including: a) 330 MW on Long Island in July 2012; b) 370 MW in Western New York in September 2012; c) 500 MW in Hudson Valley in January 2013; and d) 150 MW in Western New York in June 2013.

- Sales from SCRs fell by an average of 470 MW from the Summer 2012 to the Summer 2013, driven by a combination of increased auditing of resources, attrition, and changing market conditions.

- However, these factors were partly offset by the entry of 500MW of new resources in New York City and an uprate of 110 MW on a nuclear unit in Western New York in June 2012.

2. Capacity Market Results: New York City

In New York City, spot prices averaged $16.07 per kW-month in the Summer 2013 Capability period, up 35 percent from the previous summer. Spot prices averaged $9.72 per kW-month in the Winter 2013-14 Capability period (excluding March and April 2014), up 109 percent from the previous winter. These increases were driven primarily by the changes in demand factors.

On the demand side, the ICAP requirement rose 332 MW (or 3.5 percent), which was primarily due to an increase in the Local Capacity Requirement ("LCR") from 83 percent to 86 percent. The increased LCR resulted primarily from the loss of generating capacity in the Hudson Valley, which requires more capacity in the New York City and Long Island Localities to maintain security of the UPNY-SENY interface. Raising the LCRs in New York City and Long Island is less efficient than modeling a Capacity Locality that includes the Hudson Valley and setting the LCR in the new Locality at a level that accurately reflects the reliability benefits of placing capacity there. Hence, modeling the new G-J Locality will better enable the market to provide efficient investment signals. Nonetheless, the effects of the increased LCR were partly offset by increased emergency energy assistance from the new HTP Line.

Supply-side changes also affected capacity prices in New York City. In June 2012, a 500 MW new resource entered service in New York City, lowering capacity prices from $17.16/kW-month in May 2012 to $11.54/kW-month in June 2012. Beginning in December 2012, buyer-side mitigation was imposed on the 550 MW Astoria Energy II facility, resulting in the imposition of an Offer Floor. As a result, the amount of unsold capacity rose and the clearing price was $4.91 per kW-month from December 2012 to April 2013, up from $3.36 per kW-month in November 2012. However, there has not been a significant amount of unsold capacity since April 2013, implying that the capacity from AEII facility was fully sold after April 2013.

3. Capacity Market Results: Long Island

In Long Island, the spot price averaged $7.14 per kW-month in the Summer 2013 Capability Period and $3.67 per kW-month in the Winter 2013-14 Capability Period (excluding March and April 2014). These represented increases of 124 percent and 84 percent, respectively, from the previous Summer and Winter Capability Periods. These price changes were driven in part by the increase in rest-of-state capacity prices and in part by changes in demand factors.

In the Winter Capability Period months, the local capacity requirement for Long Island was rarely binding in recent years, reflecting that Long Island generally has far more capacity than needed to satisfy its local capacity requirement in the winter. As a result, the spot prices in Long Island were equal to the rest-of-state capacity prices during the majority of the winter months. Therefore, the increased clearing prices in Long Island resulted from factors discussed in Part 1 of this sub-section.

In the Summer 2013 Capability Period, spot prices in Long Island rose significantly above rest-of-state prices due to changes in both demand and supply factors.   On the demand side, the Long Island ICAP Requirement rose 320 MW (or 5.8 percent), primarily because the LCR rose from 99 percent to 105 percent (for the same reason of the increase in the New York City LCR).[80] On

80 The increased LCR resulted primarily from the loss of generating capacity in the Hudson Valley, which requires more capacity in the New York City and Long Island Localities to maintain security of the UPNY-

the supply side, three units totaling 330 MW were retired in July 2012. Accordingly, higher demand and lower supply contributed to elevated capacity prices in the summer.

B. Demand Curve Reset Unit Technology

The capacity market is designed to ensure that efficient investments recover sufficient revenues to be profitable. Ideally, the capacity market would efficiently govern investment and retirement decisions such that the NYISO would satisfy planning requirements with a minimum amount of surplus.

To do this, demand curves are established that should allow suppliers to recover the Net CONE for the investments over the long term. To establish a demand curve, the technology of a hypothetical new entrant must be chosen and the current tariff specifies that this is a peaking unit. In long-run equilibrium, all types of resources (baseload, intermediate, peaking) should be equally economic, but this may not always be the case in the short-run based on the relative levels of capacity, energy, and ancillary services prices.

It is important for the default resource upon which the capacity demand curves are based to always be among the most economic and realistic investment choices, given regulatory and environmental restrictions. When a demand curve is developed to support investment in a unit that is not the most economic type of unit, investors still invest in the most economic type of unit. As a result, the capacity market may provide incentives to invest when additional investment is not necessary. This could lead to a sustained surplus that would dissipate only when the default resource is among the most economic investments once again. Until this happens, the capacity market may motivate inefficiently large quantities of investment and raise overall market costs.

Following the demand curve reset study for the 2014/15, 2015/16, and 2016/17 capability periods, the NYISO concluded that the Net CONE of a new Frame 7 peaking installation is lower than for a combined cycle installation under most circumstances, indicating that a peaking

SENY interface. However, raising the LCRs in New York City and Long Island is less efficient than modeling a Capacity Locality that includes the Hudson Valley and setting the LCR in the new Locality at a level that accurately reflects the reliability benefits of placing capacity there. The LCR-setting methodology is discussed further in Section C.4.

unit is the most economic technology for a new unit. (The most economic choice of technology is the one that renders the lowest demand curve reference point when the excess level of the locality is considered.) However, market conditions and/or the availability and cost of new technology may change in the future such that a peaking unit is no longer the most economic technology. If this happens, it will be important to modify the technology of the hypothetical demand curve unit accordingly.

C. Capacity Market Design and 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.

In 2013, capacity clearing prices were set at three distinct locations: New York City, Long Island, and NYCA. Beginning with the Summer 2014 Capability Period, the NYISO has added the G-J Locality, which includes all of Southeast New York, except Zone K (i.e., Long Island). While the creation of the new Locality is a positive market development, this section discusses potential market enhancements that would further improve locational signals in the capacity market. Part 1 discusses the deficiencies with the current rules for creating new capacity zones. Part 2 provides an alternative framework where zones are pre-defined rather than added over time. Part 3 provides a concept for modeling Zone K and other export constrained areas in the capacity market. Part 4 discusses how the current demand curves do not attract capacity to the areas where it is most valuable for reliability, resulting in higher overall costs.

1. Deficiencies in the Current Process for New Zone Creation

The new capacity zone for the G-J Locality in Southeast New York (“SENY”) will greatly enhance the efficiency of the capacity market signals, but it is overdue. The delay in creating the SENY capacity zone 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.

- 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.

- Finally, waiting until 2014 to model the G-J Locality has resulted in a sharper increase in prices for customers in Zones G, H, and I, rather than a gradual increase that would have occurred with modest changes in consumption behavior or demand response. (In the Summer 2014 Strip Auction, the clearing price was $9.96 per kW-month, up 72 percent from Spot Auction prices in the Summer 2013 Capability Period.)

In summary, the creation of the G-J Locality before 2014 would have facilitated more efficient investment in both new and existing resources where the 2012 Reliability Needs Assessment identified resources are necessary for resource adequacy over the next ten years. It would also have avoided the sizable change in prices that the delayed implementation of the new zone will cause.

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.

Due to 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. This framework is discussed in the next part of this sub-section.

2. Pre-defining Constraints/Zones and Creating Capacity Transfer Rights

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.

When developers make transmission upgrades, they should receive capacity transfer rights ("CTRs") to provide efficient incentives for such investment. Likewise, adverse impacts on deliverability constraints from a new generation project should result in capacity transfer obligations (i.e., negative-value CTRs). In some cases, it would be more efficient (i.e., cost-effective) for a project developer to accept negative CTRs than make transmission upgrades (if the value of upgrading the transmission system was lower than the cost of the upgrades).

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.[81] 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. For each interface that is reflected in the capacity market, it will be necessary to define an LCR for the Locality that is downstream of the constraint.[82] The following part of this sub-section discusses how the zones might be defined and modeled, while Part 4 of this sub-section discusses how the demand curves and LCRs of new Localities might be determined.

3. Modeling Zone K and Other Export-Constrained Capacity Zones

The G-J Locality was created because of transmission constraints that limit the delivery of power from resources in upstate New York into Southeast New York across the UPNY-SENY interface. Zone K is interconnected in Southeast New York downstream of the UPNY-SENY interface, but is not included in the NCZ because transmission constraints limit exports from

81 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).

82 For example, Zones F to K are downstream of the Central-East+Fraser-Gilboa Interface. A list of interfaces that are considered in the RNA is shown in Slide 6 of the NYISO Presentation at the February 26, 2014 Technical Conference in Docket AD14-6-000.

Zone K to the G-J Locality. This subsection discusses Zone K to highlight improvements that could be made more accurately account for capacity in export constrained areas.

The NYISO has shown that Zone K capacity is not fully fungible with capacity in Zones G-J for maintaining reliability in Southeast New York due to these export limitations. However, Zone K capacity is clearly beneficial, and additional capacity in Zone K reduces the amount of capacity that must be located in Zones G-J.

The reason Zone K capacity is beneficial, but not fully fungible with Zone G-J capacity has to do with the probabilistic nature of the resource adequacy models. These models assess the likelihood that forced outages of transmission and generation will lead to shedding firm load (i.e., Loss of Load Expectation ("LOLE")). In the NYISO's LOLE model, increasing the amount of Zone K capacity increases the likelihood of scenarios where transmission bottlenecks limit exports from Zone K to support Southeast New York reliability. However, increasing the amount of Zone K capacity still provides benefits under many scenarios. This is a general issue that will exist when export constraints potentially limit the deliverability between zones that can be addressed through an improved capacity market framework.

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. The most straightforward way to quantify the value of additional capacity is with the LOLE metric, which is the annual probability of having a load shedding event as estimated by the RNA. Hence, capacity prices should be proportional to the incremental reliability benefits of adding capacity in that zone (as measured by the LOLE) versus other zones.

To reconcile these factors, we recommend the NYISO:

- Set an Export Limit on the amount of capacity that can be exported from a capacity zone at the point where additional Zone K capacity is no longer fully fungible with capacity in the adjacent zone. When the amount of capacity sold in the zone is less than this limit, this excess could be counted as clearing supply against the adjacent zone's Demand Curve (i.e., the Benefit Ratio would be 1.0).

- When the zone's supply exceeds the Export Limit, a Benefit Ratio could be defined that quantifies the relative benefit of capacity in the zone in question for satisfying the requirement for the adjacent zone as measured by the NYISO's LOLE model. So, if 100 MW of capacity in one zone reduces the LOLE by the same amount as 60 MW of

> capacity in the adjacent zone, then the Benefit Ratio would be 0.6. In calculating a Benefit Ratio, it would be important to consider that the actual change in LOLE from additional capacity changes based on the distribution of capacity within NYCA, as well as the overall level of capacity.[83]

In the case of Zone K, the use of an Export Limit and a Benefit Ratio to reflect the benefits of Zone K capacity for satisfying the needs of the G-J Locality would affect the capacity auctions in two ways. First, any excess capacity sold in Zone K above the requirement would contribute towards satisfying the G-J Locality requirement, thereby reducing the amount that would need to be sold from resources in Zones G-J. Second, under certain circumstances, the clearing price for Zone K would be determined based on the clearing price for the G-J Locality and the Benefit Ratio.[84] These interactions would result in more stable and efficient capacity prices for both Zone K and the G-J Locality. These benefits would be extended to other areas as additional zones are defined.

4. Capacity Prices as a Market Signal of Reliability

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."[85] 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. 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 LCRs or capacity demand curves that reflect the marginal reliability value of additional capacity in each locality

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83 See *Post-Technical Conference Comments of Potomac Economics Ltd. New York ISO Market Monitoring Unit*, March 27, 2014 in Docket AD14-6-000.

84 For example, if the Benefit Ratio was 0.6 and the G-J Locality clearing price was $9 per kW-month, the clearing price in Zone K would be $5.40 per kW-month (unless the Zone K or NYCA Demand Curves cleared at a higher price).

85 See *Locational Minimum Installed Capacity Requirements Study Covering the New York Balancing Authority Area for the 2013 – 2014 Capability Year*, January 17, 2013.

would provide incentives for more efficient investment, which would tend to lower overall capacity costs.

The following analysis illustrates the potential benefits from modifying the capacity demand curve for each Locality to consider the estimated reliability benefits from placing capacity in each Locality under a particular scenario. For each Locality, the following table shows:

(1) The Monthly Reference Point for the 2014/15 Demand Curve, which is the clearing price that results when total capacity sales equal the LCR/IRM (i.e., 0 percent excess capacity).

(2) The estimated reliability benefit from placing additional capacity in the Locality when the excess capacity margin is 0 percent in all Localities. 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 to the G-J Locality would lower the annual LOLE from 10 percent to 9.1 percent in this scenario.[86]

(3) The ratio of (1) to (2), which is the annual levelized investment cost of a 1 percent improvement in the LOLE from placing capacity in the Locality when the excess capacity margin is 0 percent in all Localities.[87]

Hence, the table summarizes the cost of improving reliability from adding capacity in different Localities for the scenario when the amount of capacity equals the requirement in all Localities.

Table 7: Cost of Improving Reliability from Additional Capacity
By Locality, 2014/15 Capability Year

Locality	Monthly Demand Curve Reference Point ($/kW-mo) (1)	Annual Change in LOLE from 100 MW Capacity Addition (2)	Annual Cost of 1 Percent LOLE Improvement =(1)/(2)
G-J Locality	**$12.14**	**0.9%**	**$12 Million**
NYCA	**$8.84**	**0.3%**	**$27 Million**
Zone J (New York City)	**$18.55**	**1.0%**	**$17 Million**
Zone K (Long Island)	**$7.96**	**1.0%**	**$7 Million**

86 LOLEs are normally expressed as a number of days per year, so an annual LOLE improvement from 10 percent to 9.1 percent would be expressed as a change from 0.100 days/year to 0.091 days/year.

87 This ratio assumes that if the locality clears at the Monthly Demand Curve Reference Point in the summer, it would clear at 50 percent of that level in the winter. For example, for the G-J Locality: $12.14/kW-mo × (6 summer months + 6 winter months × 50%) × 1000kW/MW ÷ (0.9%LOLEchange/100MW) × 1.0%LOLEchange = $12,140,000.

The table shows large disparities between different Localities in the annual levelized cost of improving reliability when the system is at criteria. To improve the overall NYCA annual LOLE from 10 percent to 9 percent when the system is at criteria, the annual levelized cost of new investment would be $27 million in NYCA and $17 million in Zone J (New York City), while comparable benefits could be achieved at a cost of just $12 million in the Hudson Valley and just $7 million in Long Island.

Although the table above provides the analysis for just one scenario, the large disparities between Localities in the costs of additional reliability 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.

If the LCRs for the scenario shown in the table for the G-J Locality and Zone K were increased to reflect the low relative cost of reliability from capacity there, it would allow for reductions in the LCR for Zone J (New York City) and the IRM for NYCA. Alternatively, the demand curves could be adjusted without changing the LCRs. For example, increasing the demand curves for the G-J Locality and Zone K to reflect the higher relative value of capacity there would allow for significant reductions in the demand curves for Zone J and NYCA.

If these cost-benefit considerations were taken into account in determining the LCRs and/or the capacity demand curves for each Locality, it would reduce the overall costs of satisfying reliability criteria over the planning horizon. Hence, we recommend the NYISO modify its processes for establishing the LCRs or capacity demand curves so that the capacity prices are consistent with the marginal reliability benefits (i.e., improvement in LOLE) from placing additional capacity in each Locality.

VIII. 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 seven 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
- Fuel Usage Under Tight Gas Supply Conditions
- Efficiency of Gas Turbine Commitments
- Efficiency of M2M Coordination with PJM
- Operations of Non-Optimized PAR-Controlled Lines
- Drivers of Cyclical 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.[88]
- 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.

This section: a) summarizes the three types of shortage pricing outcomes during 2013 and b) evaluates the efficiency of real-time prices during the demand response deployments.

1. Summary of Shortage Pricing in 2013

Table 8 summarizes the frequency of shortage conditions and the resulting pricing outcomes in 2013. Operating reserves that have a demand curve value of $25 per MWh are not included in this evaluation because they are not based on reserve requirements. The table also shows approximately how each type of shortage was reflected in energy LBMPs in West Zone, Capital

88 Transmission shortages can occur in the following three ways: 1) 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; 2) if the marginal redispatch cost needed to resolve a constraint exceeds the $4,000/MWh Transmission Shortage Cost, RTD foregoes more costly redispatch options; and 3) 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. In such cases, the marginal costs of the resources actually dispatched are lower than the shadow price set by the offline gas turbine (which is not actually dispatched). Data is not available that would indicate when the first type of transmission shortage occurs.

Zone, Hudson Valley Zone, New York City, and Long Island. It also shows the potential contribution from these periods to the net revenues of a generator.

Table 8: Summary of Real-time Shortages and Price Impacts[89]
2013

	Shortage Frequency (# of Intervals)	Avg Shortage Price ($/MWh)	Impact on Zone Prices ($/MWh)				
			West	Capital	Hudson	NYC	LI
Ancillary Services Shortages							
10-Minute East	246	$445		$1.04	$1.04	$1.04	$1.04
Regulation	1349	$165	$1.46	$1.46	$1.46	$1.46	$1.46
Other NYCA Requirements	87	$306	$0.25	$0.25	$0.25	$0.25	$0.25
Transmission Shortages							
Dunwoodie - Shore Road	110	$974					$1.02
E. Garden City - Valley Stream	297	$3,310					$0.54
Leeds-Pleasant Valley	53	$2,664		$0.03	$0.41	$0.49	$0.49
Other Facilities	363	$2,721	$1.01	$0.33	$0.29	$0.58	$0.57
Scarcity Pricing During DR Activation							
NYCA	124		$0.39	$0.33	$0.27	$0.23	$0.24
Southeast New York	148				$0.47	$0.43	$0.44
Total			$3.12	$3.44	$4.20	$4.49	$6.05
Potential Net Revenue ($/kW-year):			$27	$30	$37	$39	$53

The table shows that, in 2013:

- The most significant ancillary services shortages were for eastern 10-minute reserves and regulation. These increased annual average LBMPs in Eastern NY by 3 to 5 percent.
- The price impact from transmission shortages was still the largest in Eastern NY, ranging from $0.35 per MWh in the Capital Zone to $2.61 per MWh in Long Island. However, the price impact in the West Zone rose notably from prior years, averaging more than $1 per MWh in 2013 because of increased congestion in the West Zone.
- Scarcity pricing during demand response deployments, which we evaluate below, raised the average zonal LBMP by $0.33 to $0.74 per MWh.
- The overall impact of shortage pricing was substantial, accounting for $3.12 to $6.05 per MWh (or 7 to 8 percent) of the average LBMP in different regions of the State.
- Shortage pricing accounts for a large share of the net revenue that a generator could use to recoup capital investment costs, contributing up to $53 per kW-year for a generator that is fully utilized during shortage conditions.

In evaluating the shortages, we also found many intervals when gas turbines were not dispatched to relieve a constraint even though their marginal cost was lower than the Transmission Shortage

89 V.E, V.F, and V.G in the Appendix provide additional details about pricing during shortages. Section II.G evaluates net revenues for various types of generators.

Cost of $4,000 per MWh.[90] This suggests that the reliability value of preventing many transmission shortages is lower than $4,000 per MWh. We support the NYISO's current effort to implement a graduated Transmission Demand Curve in the fourth quarter of 2014 that will more accurately reflect the severity of the shortage conditions.[91]

2. Reliability Demand Response Deployments

Reliability demand response resources provide significant economic and reliability benefits to the system. Demand response resources help satisfy demand for energy and operating reserves on very high load days, reducing overall production costs in the real-time market. However, the high cost of reliability demand response resources (usually $500 per MWh) combined with their inflexibility in real-time operations creates at least two significant challenges. First, it is difficult to deploy the appropriate amount of demand response resources, since they must be deployed with significant lead times and the amount of demand response needed can be difficult to predict when there is still considerable uncertainty about the needs of the system. Second, it is difficult to ensure that real-time prices are efficient when reliability demand response is deployed, since such resources are typically the system's most costly resources but such resources do not ordinarily set the LBMP (unless special pricing rules are used). Hence, if too much demand response is deployed or the demand response resources do not set LBMPs, LBMPs may not accurately reflect the cost of maintaining reliability. The sub-section evaluates these two aspects of market outcomes on the days when demand response resources were deployed during 2013:

- The amount of demand response that was deployed compared with the amount of resources that were ultimately available in each real-time interval during the event.
- Whether real-time energy prices reflected the costs of deploying demand response to maintain reliability given that most SCR and EDRP resources are paid $500 per MWh to curtail their load.

Reliability demand response resources were deployed by the NYISO on five days in 2013. On July 15, 16, and 17, SCR and EDRP resources were deployed in load zones G through K from 1:00 pm through 6:00 pm (HB 13 – HB 17) for transmission security operations in Southeast

90 The Transmission Shortage Cost works similar to a "demand curve," indicating the maximum value that the market model will incur to relieve a transmission constraint.

91 See *Graduated Transmission Demand Curve (GTDC)* Presented to the December 18, 2013 Management Committee by Michael DeSocio.

New York, which require to restore system power flows to within normal operating limits within 30 minutes after the largest contingency. On July 18 and 19, SCR and EDRP resources were deployed: (a) in load zones G through K from 12:00 pm to 6:00 pm (HB 12 – HB 17) for transmission security operations in Southeast New York, which require to restore system power flows to within normal operating limits within 30 minutes after the largest contingency; and (b) in load zones A through F from 1:00 pm to 6:00 pm (HB 13 – HB 17) for statewide capacity requirements.

The NYISO implemented an Enhanced Scarcity Pricing Rule in the summer of 2013, which was designed to ensure real-time prices better reflect real-time shortages. Our evaluation suggests that the new Scarcity Pricing Rule was generally applied when demand response was actually needed, which is a significant improvement over the previous Scarcity Pricing Rule.[92, 93]

However, Scarcity Pricing is only applied to internal locations, resulting in large differences at real-time prices at internal versus external interfaces (proxy buses). When Demand Response calls are likely, participants have inefficient incentives to import day ahead and buy back at non-scarcity real-time prices. This contributes to under commitment, since the increase in day-ahead imports will displace the commitment of internal resources in the day-ahead market. Hence, we support the NYISO's evaluation of extending Scarcity Pricing to external interfaces, although it should be implemented in a manner that does not override the proxy bus pricing rules that are designed to reflect real-time congestion at the interfaces.[94]

The use of demand response resources is limited by scheduling lead times and other inflexibilities. The NYISO must determine how much demand response to deploy when there is still considerable uncertainty about the needs of the system, and the demand response may not be needed for the entire duration of the deployment period. Hence, the inflexibility of DR resources can lead NYISO to deploy an amount of DR that results in substantial excess capacity during a portion of the event. Moderating the quantities of DR that are deployed would help ensure that

92 Figure A-86 and Figure A-87 in the Appendix show our evaluation in detail.

93 If the Scarcity Pricing rules are extended to the external proxy buses (as we propose in the following paragraph), it will attract additional real-time imports, which will, in turn,lead to higher levels of available capacity and make Scarcity Pricing less frequent.

94 See MST Section 17.1.6.

LBMPs better reflect the cost of maintaining reliability and that uplift charges are minimized. This might be possible by: (a) market design changes that enable some DR resources to be scheduled more flexibly (i.e., with shortened lead times and/or shut-down periods); and (b) staggering the timing of the deployment of DR resources (to the extent possible).

3. Operating Reserve Requirements and Demand Curves

Our evaluation of Scarcity Pricing during demand response deployments also found several inconsistencies between NYISO's reserve needs and its market requirements. First, the New York State Reliability Council ("NYSRC") Rule F-R1c requires the NYISO to commit sufficient resources to reduce the loading on a facility to the normal rating within 30 minutes following the largest contingency. Hence, this requires additional resources beyond what is necessary to satisfy N-1 security constraints. Demand response was called in Southeast New York to satisfy this particular requirement during these five days. However, currently, there is no explicit market requirement to reflect such reserve needs in Southeast New York. Hence, we recommend defining a market requirement in Southeast New York to reflect its 30-minute reserve needs.[95]

Second, the NYSRC Rule D-R4 requires the NYISO to commit sufficient resources to restore NYCA 10-minute reserves within 30 minutes following the largest contingency. Hence, this requires sufficient NYCA 30-minute reserves to respond to the largest two contingencies. Currently, the NYISO procures an amount of 30-minute reserves that is equal to the size of the largest contingency plus half size of the second largest contingency. Under normal operating conditions, sufficient surplus capacity is usually available and needed additional capacity can be procured within 30 minutes for little cost. However, on very high load days, such as July 18 and 19, current market requirement for NYCA 30-minute reserves cannot ensure that sufficient reserves are readily available to satisfy this NYSRC requirement, which often leads to costly actions by operators (e.g., supplemental commitment, and/or demand response calls). Hence, we recommend ensuring that the NYCA 30-minute reserve demand curve fully reflects NYISO's reserve needs, particularly on high load days.[96]

95 See Recommendation #10(a) in Section X.

96 See Recommendation #10(b) in Section X.

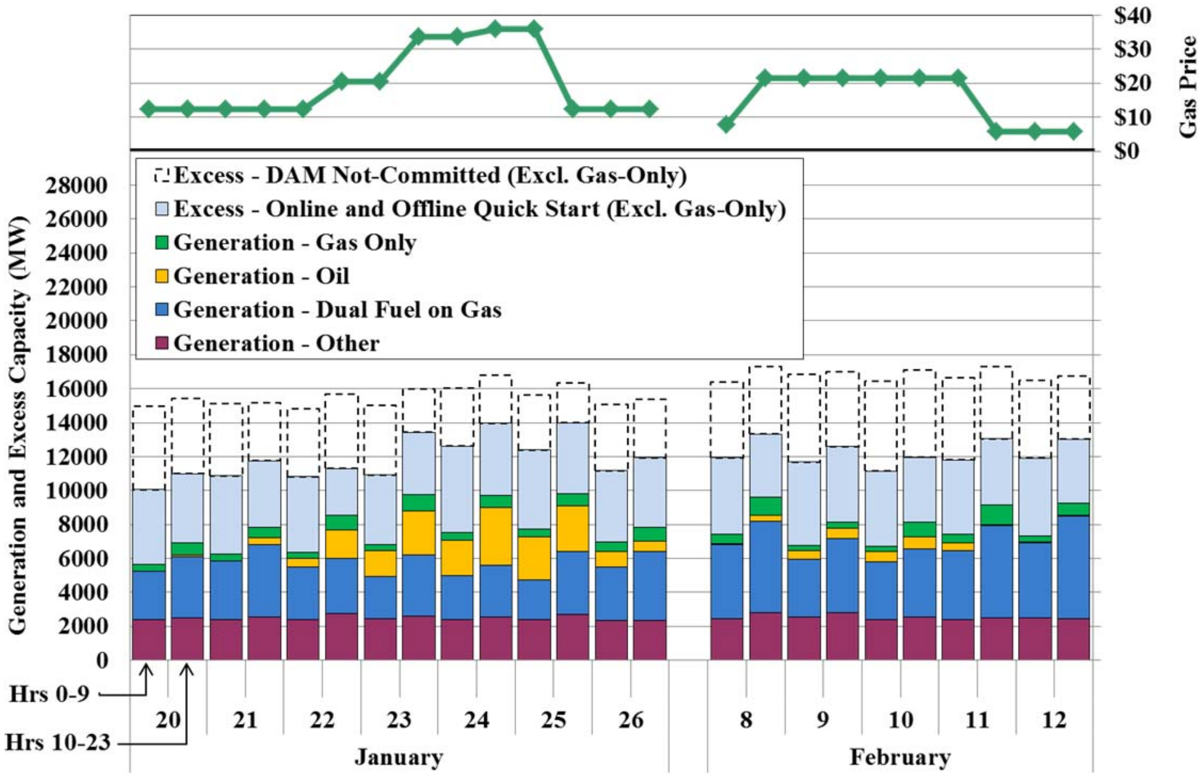
B. Fuel Usage Under Tight Gas Supply Conditions

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

Extreme cold weather led to high and volatile gas prices on many days in January and February 2013. 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 residual (#6) fuel oil prices by as much as $19 per MMbtu (on January 24). 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 12 examines fuel usage under these tight gas supply conditions, which had a large impact on the system operations in Eastern New York.[97] It also shows the day-ahead natural gas price index for Iroquois Zone 2 on these days.

97 See Section I.C in the Appendix for a more detailed description of this analysis. Figure A-11 and Figure A-12 in the Appendix also show these patterns separately for New York City and Long Island.

Figure 12: Fuel Use and Excess Capacity on Winter Peak Days in Eastern New York
High Day-Ahead Gas Price Periods, 2013



The figure shows that production from oil, which normally averages less than 100 MW in Eastern New York, rose significantly during these periods. On the coldest days, average production from oil rose as high as 2.7 GW in January and 700 MW in February as a result of higher natural gas prices. The widespread use of oil indicates that the market performed reasonably well in conserving the available supply of natural gas under the tight gas supply conditions. However, several notable issues arose that affected market performance.

- Day-Ahead Gas Price Uncertainty – Substantial amounts of oil were used on January 21 (Monday) and 22 (Tuesday) when "day-ahead" gas prices were lower than oil prices. "Day-ahead" gas prices on these two days ($12-16 per MMbtu in Eastern New York) were determined on January 18 (Friday) before the 3-day holiday weekend. However, these prices were lower than the actual cost of natural gas on January 21 and 22. Thus, the timing difference between the NYISO's day-ahead market and the natural gas market contributed to day-ahead LBMPs being too low for a generator to recoup the cost of oil on January 21 and 22, leading fewer generators to be committed on oil in the day-ahead market and increasing the use of natural gas.

- Oil-Fired Generation Availability – On the two days when natural gas prices rose above $30 per MMbtu (January 24 and 25), it would have been economic for more dual-fueled generators to switch from natural gas to oil. However, fuel switching was limited by low oil inventories, air permit restrictions, and equipment issues.

- Operational Flow Orders ("OFOs") – Severe congestion into New York City from January 21 to 24 was exacerbated when several gas-only generators with spinning reserve and non-spinning reserve capability were derated due to a lack of gas supply. The resulting reduction in available reserves caused the interface into New York City to be operated under a tighter criteria that reduced overall imports (in order to hold reserves on the interface) and increased the severity of congestion for over 40 hours.[98] Hence, the lack of fuel supply for several units actually led to an increase in the overall fuel consumption within New York City.

In the winter of 2013/14, we have observed better operations and market performance in these three areas despite more challenging conditions. Regarding day-ahead gas price uncertainty, we have observed that generators track gas market conditions more closely over weekends and more frequently request reference level adjustments to account for high expected gas prices. The NYISO has streamlined the process for RT reference level adjustments and filed tariff changes that will better enable generators to incorporate high expected gas prices into their day-ahead reference levels.[99] In the NYISO's day-ahead market, these reference level adjustments result in more efficient generator scheduling and in LBMPs that accurately reflect anticipated fuel prices. Regarding the availability of oil-fired generation, we have observed that many dual-fueled generators became more prepared to generate from fuel oil from the winter of2012/13 to the winter of 2013/14, although this was offset by increased demand for oil-fired generation. Regarding OFOs, there were fewer instances in the winter of 2013/14 when severe congestion resulted from a transmission derating that was caused by OFO-related fuel limitations on generators with reserve capability.

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, 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

98 This congestion is discussed in *Quarterly Report on the New York ISO Electricity Markets First Quarter 2013* by Potomac Economics, Slide 26.

99 See *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.

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.[100]

Second, 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 their 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 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.[101] This capability would also be beneficial at other times of year for hydro-electric and other generators that also have significant energy limitations.

Third, 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

100 Section X, Recommendation #11 is related to this issue.

101 Section X, Recommendation #11 is related to this issue.

provide information on a daily basis regarding fuel availability, particularly on-site fuel inventory, scheduled deliveries, and nominations and schedules for natural gas.[102]

Notwithstanding the concerns regarding fuel uncertainty day-to-day, Figure 12 indicates there is a substantial excess of installed capacity with equipment for burning oil compared to what is needed to satisfy reliability criteria under winter peak operating conditions. For instance, on January 25, 2013, which set a winter demand record at 25.3 GW, there was always at least 5 to 6 GW of unloaded capacity in Eastern New York on units that are not gas-dependent. Much of this capacity might have been unavailable or limited by lack of oil inventory and/or air permit restrictions, but the sufficiency of oil-capable installed capacity indicates that fuel supply constraints primarily pose challenges in the short-term scheduling and commitment timeframe currently, rather than in the planning timeframe.

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 nearly 51 percent of capacity committed by the real-time market model in 2013 was clearly economic over the initial commitment period and this was consistent with recent years.[103] This evaluation deemed a gas turbine clearly economic if the as-offered cost was less than the LBMP revenue earned over the initial commitment period (usually one hour). However, this criterion likely understates the share of gas turbine commitments that are efficient for two reasons. First, the efficient commitment of a gas turbine reduces LBMPs in some cases such that the LBMP revenue it receives is less than its offer. Second, in some cases, a gas turbine that is committed efficiently may still not set the LBMP due to the manner in which the real-time pricing methodology determines whether a gas turbine is eligible to set the LBMP.[104]

102 Section X, Recommendation #12 is related to this issue.

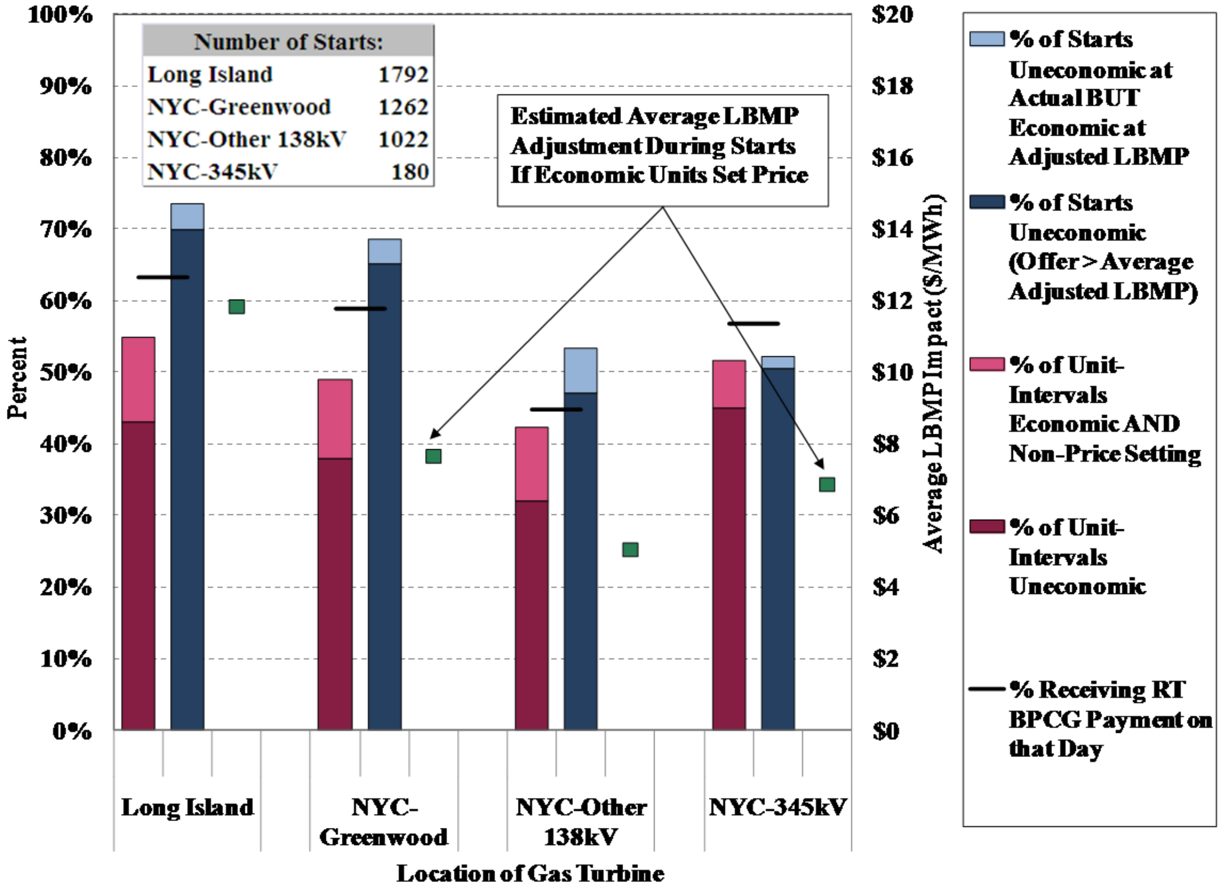
103 See Figure A-76 in the Appendix for details of this analysis.

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

Figure 13 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.[105]

Figure 13: Hybrid Pricing and Efficiency of Gas Turbine Commitment

2013



We found that gas turbines that were committed in merit order in 2013 were clearly economic in 55 to 68 percent of the five-minute intervals during their initial one-hour commitment period. However, the units did not set the LBMP in 7 to 12 percent of the intervals when they were economic. We estimated that allowing these economic gas turbines to set prices would have increased the real-time LBMPs by an average of $5 to $12 per MWh for each start in New York City and Long Island in 2013.

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

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

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.[106]

D. Efficiency of M2M 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.[107] 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 use of Re-dispatch Coordination was very limited in 2013. It was activated for the Central-East interface in a total of less than 160 hours and the Dysinger East interface in roughly 20 hours, which resulted in a total payment of $119k from PJM and the NYISO. However, the use of Ramapo PAR Coordination had far more significant impacts on the market in 2013. Hence, we focus our M2M evaluation on the efficiency of the operation of Ramapo PARs.

We found that actual flows across Ramapo PARs were lower than the targets that are used for settlement purposes during most intervals of 2013 when M2M constraints in New York were binding.[108] This resulted in a total payment of $7.2 million from PJM to the NYISO in 2013,

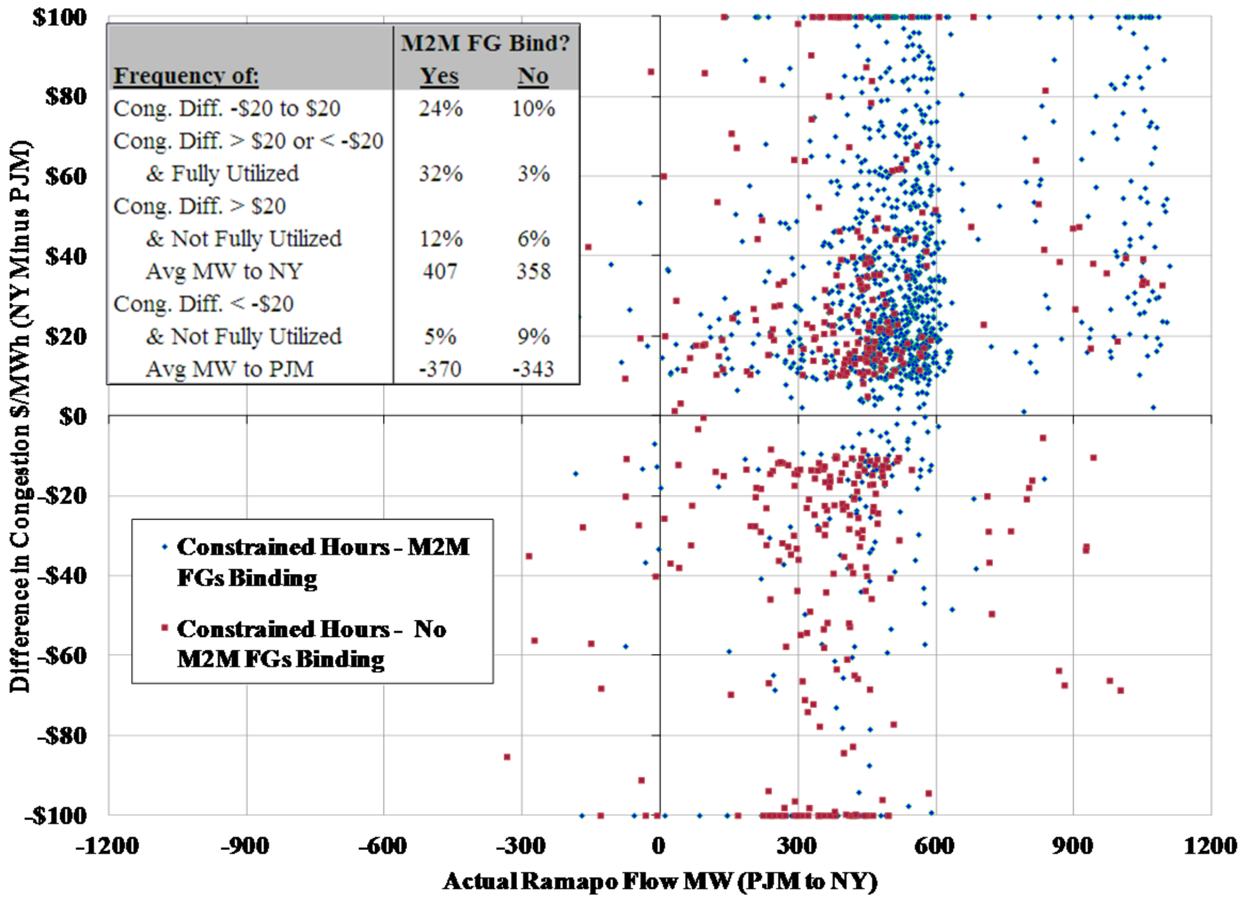
106 See Recommendation #7 in Section X.

107 The terms of M2M coordination are set forth in NYISO OATT Section 35.23, which is Schedule D to Attachment CC.

108 The Ramapo PARs are adjusted by the operators to minimize overall congestion on M2M flow gates in the two markets. However, the Ramapo Target Flow (which is defined in the M2M Coordination Agreement), is used to determine settlements between PJM and the NYISO. Figure A-78 in the Appendix compares the actual flows on the Ramapo PAR-controlled line with the Ramapo Target Flows in each week of 2013.

which offset roughly 25 percent of total balancing congestion shortfalls.[109] Figure 14 shows marginal effect of Ramapo flows on congestion in PJM and the NYISO during constrained hours in 2013.[110]

Figure 14: Marginal Effect of Ramapo on NY/PJM Congestion and Actual Ramapo Flow
During Constrained Hours, 2013



Our evaluation found that, in 2013:

- In 68 percent of hours, flows across the Ramapo PARs were reasonably efficient (i.e., when the congestion difference between PJM and the NYISO was within $20 per MWh, or when the lines were fully utilized to relieve congestion in the market with higher congestion costs);

- In another 18 percent of hours when the Ramapo PARs were not fully optimized while New York congestion was higher than PJM congestion (by $20 per MWh or more), the

109 Balancing congestion shortfalls and congestion settlements between PJM and the NYISO are evaluated in Sections III.C and V.B of the Appendix.

110 Section V.B in the Appendix describes this analysis in detail.

Ramapo PARs still provided substantial benefits to New York by flowing an average of 390 MW of power into New York in most of these hours; and

- In the remaining 14 percent of hours, PJM congestion was higher than New York congestion (by $20 per MWh or more) while the Ramapo PARs usually flowed an average of 350 MW of power out of PJM.

Therefore, the Ramapo PAR Coordination was relatively efficient in 2013 and has provided significant congestion relief to New York. However, usage of this process was limited by several factors. First, Ramapo PARs experienced extended outages in 2013. One of the two Ramapo PARs was out of service from early-February through the end of the year, during which approximately half of the Ramapo transfer capability was available for coordination. This outage explains why a large number of hours are shown in Figure 14 with flows between 400 and 600 MW, indicating hours when the reduced capability of the line was fully utilized to flow power into the NYISO. The other Ramapo PAR was out of service three times during the year for a total of three months, during which time Ramapo Coordination was not available. Greater benefits are likely to be achieved going forward when both Ramapo PARs are in service.

Second, beginning mid-July of 2013, PJM unilaterally suspended the coordination for TSA flowgates, which are heavily congested transmission paths into Southeast New York in the summer. Ramapo PARs provided valuable congestion relief to New York before the suspension. The NYISO and PJM have worked out a resolution to this issue that will allow the PARs to be fully utilized to manage TSA congestion when it is efficient to do so, while reducing PJM's exposure to congestion charges during TSAs.[111]

In addition, there were times when the congestion difference between PJM and New York was significant when no M2M constraints were binding. In some cases, this resulted from periods of transient congestion when the Ramapo PARs would not have been capable of providing significant benefit. However, other cases suggest that it would be beneficial to bring some additional flow gates into the M2M coordination process. More efficient utilization of the PARs is expected as the list of coordinated flowgates is refined over time.

111 See *M2M Coordination Storm Watch Update and JOA Amendments*, Presented by David Edelson to April 11, 2014 Management Committee.

E. 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.[112] Such lines are evaluated in Section VI.C, which evaluates external transaction scheduling. Second, "optimized" PAR-controlled lines are optimized in the sense that they are normally adjusted in order to reduce generation redispatch (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 focused 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 2013. 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.[113]

112 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.

113 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

Table 9: Efficiency of Scheduling on Non-Optimized PAR Controlled Lines[114, 115]
2013

	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					14	$10.12	55%	$5
New England to NYCA								
Sand Bar	-77	-$18.97	88%	$11	-2	-$22.64	54%	$2
PJM to NYCA								
Waldwick	-948	$7.20	27%	-$60	47	$6.90	55%	$0
Ramapo	237	$12.28	84%	$40	51	$12.26	53%	$17
Farragut	727	$5.39	67%	$37	-57	$6.94	46%	-$5
Goethals	240	$8.31	76%	$13	65	$9.99	56%	$2
Long Island to NYC								
Lake Success	153	-$12.60	1%	-$18	-13	-$16.66	72%	$2
Valley Stream	64	-$16.54	1%	-$10	5	-$31.15	37%	-$3

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 besides 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

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 Ontario, the analysis assumes a day-ahead schedule of 0 MW since Ontario does not operate a day-ahead market.

114 Note, this table reports the estimated production cost savings that actually resulted from the use of these transmission lines in 2013. They do *not* estimate the production cost savings that could have been realized if the lines were used optimally.

115 As discussed further in Section V.C of the Appendix, the methodology used for this evaluation tends to under-estimate the production cost savings from lines that flow from the low-price region to the high-price region. However, it tends to over-estimate the production cost increases from lines that flow from the high-price region to the low-price regions. Nonetheless, this metric provides a useful indicator of the relative scheduling efficiency of individual lines.

$7.20 per MWh in 2013.[116] We estimated that the controllable lines between NYCA and neighboring control areas achieved a total of $101 million in net production cost savings in the day-ahead market in 2013, 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 $60 million in 2013. Hence, significant additional production cost savings could be achieved by improving the scheduling and operation of these lines.

Between Long Island and New York City, the day-ahead scheduling of the PAR-controlled lines was highly inefficient with power scheduled in the inefficient direction in 99 percent of hours in 2013, which was comparable to the results in 2011 and 2012. The use of these lines *increased* DAM production costs by an estimated $28 million in 2013 because prices on Long Island were typically higher than those in New York City (particularly the portion of New York City where the 901 and 903 lines connect).[117] In addition to increasing production costs, these transfers: a) depress prices in New York City; and b) can restrict output from generators in the Astoria East/Corona/Jamaica pocket where the lines connect. Restrictions on the output of these 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).

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 explicitly operated in order to manage congestion efficiently.

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

116 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.

117 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.

limited by the long-standing contracts between scheduling parties that pre-date open access transmission tariffs and the NYISO's markets.[118] However, it would be highly beneficial to modify these contracts or find other ways under the current contracts to operate the lines efficiently. Since more efficient operation would benefit one party financially at the expense of the other, it would be reasonable to create a financial settlement mechanism to compensate the party that would be losing some of the benefits from the current operation. Hence, we recommend the NYISO work with the parties to these contracts to explore potential changes.[119]

F. Drivers of Cyclical 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 cyclical patterns of price volatility that tend to occur predictably at certain times of day.

These patterns typically arise when flexible generators on the system lack the ramp capability to compensate for large changes in external transaction schedules or changes in the output of generators that are self-scheduled, starting-up, or shutting-down. Figure 15 shows the average 5-minute price for each interval during ramping hours of the day in the summer of 2013. The table in the upper portion of the figure compares the average size of upward and downward spikes in LBMPs 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 2011 to 2013. These periods exhibit the most cyclical price volatility. The table in the lower portion of the figure summarizes the average size of upward and downward movements of five categories of inflexible supply that contribute to these price changes at the top of the hour.[120]

High price volatility during morning and evening ramp periods is largely caused by changes in inflexible supply at the top of each hour. If inflexible supply changes were distributed more

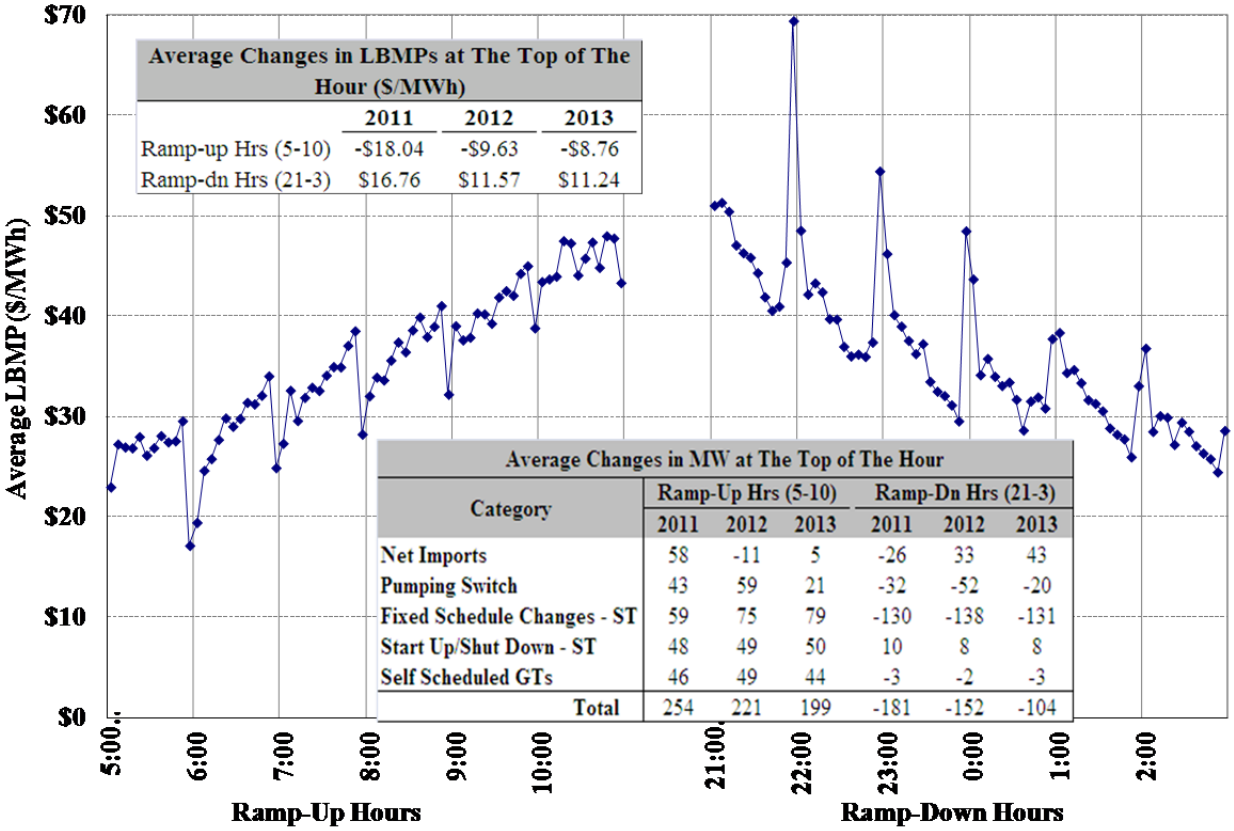
118 See NYISO OATT Section 18, Table 1 A - Long Term Transmission Wheeling Agreements, Contract #9 governs the operation of the lines between New York City and Long Island.

119 See Recommendation #5 in Section X.

120 See Section V.D in the Appendix for a more detailed description of this analysis.

evenly throughout each hour, price volatility would be diminished. Generators that change their fixed schedules or that switch from pumping to generating at the top of the hour would benefit from making such changes mid-hour. However, many generators still make their schedule changes at the top of the hour, which increases the need to ramp flexible generators.

Figure 15: Cyclical Statewide Real-Time Price Volatility
During Ramping Hours, June to August 2013



	2011	2012	2013
Ramp-up Hrs (5-10)	-$18.04	-$9.63	-$8.76
Ramp-dn Hrs (21-3)	$16.76	$11.57	$11.24

Category	Ramp-Up Hrs (5-10)			Ramp-Dn Hrs (21-3)		
	2011	2012	2013	2011	2012	2013
Net Imports	58	-11	5	-26	33	43
Pumping Switch	43	59	21	-32	-52	-20
Fixed Schedule Changes - ST	59	75	79	-130	-138	-131
Start Up/Shut Down - ST	48	49	50	10	8	8
Self Scheduled GTs	46	49	44	-3	-2	-3
Total	254	221	199	-181	-152	-104

Although Figure 15 shows large price fluctuations frequently occur at specific times of day, the average size of upward and downward spikes at the top of the hour during ramping hours has fallen considerably in recent years. From 2011 to 2013, the average upward spikes at the top of the hour during the ramp-down hours fell 33 percent, while the average downward spikes at the top of the hour during the ramp-up hours fell 51 percent. These reductions would be even greater if we adjusted for the increase in natural gas prices from 2011 to 2013.

The principal cause of reduced price fluctuations was likely the introduction of 15-minute scheduling at several external interfaces after 2011 (particularly at the primary PJM interface), because it has enabled market participants to avoid large schedule changes at the top of the hour.

This reduces the ramp demand on the system by spreading the changes in external schedules over the hour. In addition, pumped-storage units, which used to switch between pumping and generating only at the top of the hour, have started to switch at quarter-hour intervals more frequently. These changes have reduced how much internal generation must be ramped in the five-minute dispatch around the top of the hour.

Despite the improvements in recent years, inflexible scheduling practices by some generators, large external transaction schedule changes, and commitment and decommitment of gas turbines were still the most significant contributing factors to cyclical price spikes at the top of the hour in 2013. The look ahead evaluations of RTD and RTC help schedule flexible resources to respond to these variations. Hence, the ability of these models to anticipate the ramp demand and schedule the system efficiently has a substantial effect the system's price volatility. These scheduling decisions are particularly important for committing and decommitting gas turbines, and for scheduling external transactions as described below.

Regarding gas turbines, 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 in a five-minute interval. When RTD solves for 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.

Regarding external transactions, large adjustments in external transaction schedules in the export direction often led to severe 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 transactions ramp over 10-minute periods from five minutes before the quarter-hour to five minutes after (e.g., from :55 to :05, from :10 to :20, etc). Hence, RTD and RTC generally perform well in scheduling resources in the first five minutes of each ten-minute external interchange ramp period. However, RTD and RTC do not anticipate transient shortages that occur in the second five minutes of each ten-minute external interchange ramp period (i.e., at intervals-ending :05, :20, :35, and :50).

To address this concern and reduce unnecessary price volatility, we recommend: a) modifying the intervals in RTD to always model each five-minute interval in which external transactions are ramping (e.g., intervals :55, :00, and :05); and b) evaluating the cost and feasibility of improvements to RTC that would allow it to better recognize NYISO's ramping demands and be consistent with RTD.[121]

G. 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 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.

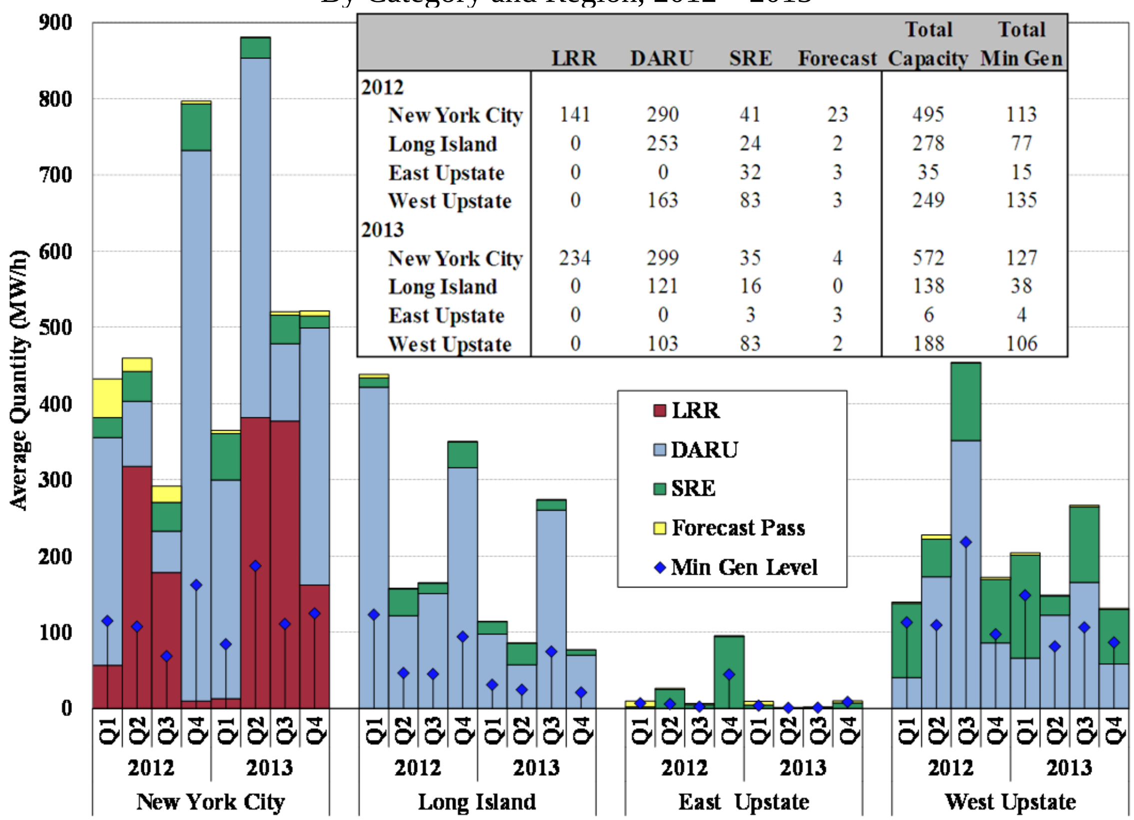
121 See recommendation #6 in Section X.

1. Supplemental Commitment

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 2012 and 2013. The first three types of commitment are primarily for local reliability needs. The last category, Forecast Pass, represents the additional commitment in the forecast pass of SCUC that occurs after the economic pass. 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 16: Supplemental Commitment for Reliability in New York
By Category and Region, 2012 – 2013



	LRR	DARU	SRE	Forecast	Total Capacity	Total Min Gen
2012						
New York City	141	290	41	23	495	113
Long Island	0	253	24	2	278	77
East Upstate	0	0	32	3	35	15
West Upstate	0	163	83	3	249	135
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

The figure shows that roughly 900 MW of capacity was committed on average for reliability in 2013, down 14 percent from 2012. Of this total, 63 percent of reliability commitment was in New York City, 15 percent was in Long Island, and 21 percent was in Western New York.

In Western New York, reliability commitment averaged 190 MW in 2013, down 24 percent from 2012. The reduction was primarily because: (a) several coal units retired or were mothballed that had often been DARUed for local reliability; and (b) higher natural gas prices and increased West Zone congestion led the remaining coal units to be committed economically more frequently.

In Long Island, reliability commitments fell about 50 percent from an average of approximately 280 MW in 2012 to an average of 140 MW in 2013. Units that are frequently needed for local reliability were committed economically more often because of the higher LBMPs, which were driven by higher natural gas prices, transmission outages, generator retirements, and inefficient utilization of some generating capacity.[122]

In New York City, however, reliability commitment increased by 16 percent from 2012 to an average of 570 MW in 2013. Reliability need for the 345 kV system has fallen notably in recent years, which was mostly attributable to new generating supply and new transmission facilities added from 2011 to 2013. Therefore, most DARU commitments in 2013 were made for the sub-regions in the 138 kV system, primarily the Astoria West/Queensbridge/Vernon load pocket.

LRR commitments in New York City rose in 2013, accounting for the majority of the overall increase in reliability commitment in the City from 2012. Most of the LRR commitments were made to satisfy the NOx bubble requirements that 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. The increase was partly because steam units that satisfy NOx Bubble constraints were committed economically less often due to lower day-ahead LBMPs (relative to fuel prices) in New York City. Hence, these units had to be committed for reliability more often. However, the output from these steam turbine units sometimes displaced output from newer cleaner

122 These factors are discussed in Section II.A.

generation in New York City and displaced imports to the city. Hence, the commitment of these steam turbines may actually increase NOx emissions.

2. Out of Merit Dispatch

In our evaluation of OOM dispatch, we found that Long Island accounted for the largest share of OOM station-hours in both 2012 (40 percent) and 2013 (48 percent).[123] Most were called to manage local reliability on the East End of Long Island during high load conditions, particularly in the third quarter of each year. In 2013, more than 70 percent of these OOM actions occurred in July when load levels were particularly high.

New York City accounted for 32 percent of OOM station-hours in 2013, down from 35 percent in 2012. The reduction was partly due to the fact that OOM dispatch had been elevated in the fourth quarter of 2012 following Superstorm Sandy when numerous transmission outages required unusually high levels of OOM dispatch. Most of OOM actions in 2013 were associated with transmission outages. In particular, the Narrows and Gowanus GTs accounted for 40 percent of OOM actions in New York, primarily in July when the market software was not able to properly model a "split ring bus" during a transmission outage in the Greenwood area, leading to higher production costs, uplift charges, and LBMPs.

Western New York accounted for 14 percent of OOM station-hours in 2013. OOM actions have fallen substantially in recent two years because Huntley and Niagara units were rarely dispatched out of merit by the NYISO to manage congestion on 230kV lines in the West Zone following the modeling improvement of these lines in May 2012

H. Guarantee Payment Uplift Charges

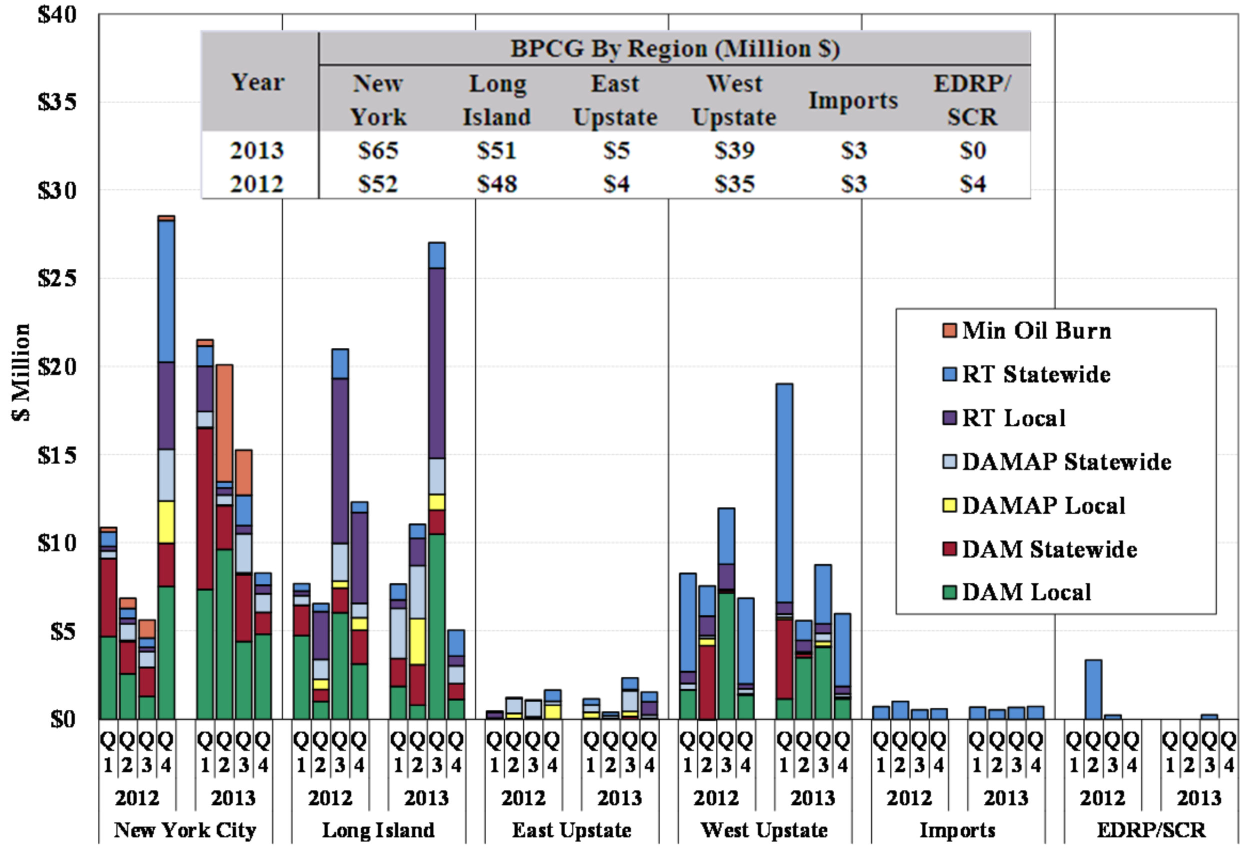
The NYISO recovers the payments it makes to certain market participants that are not recouped from LBMP and other market revenues through uplift charges. It is important to minimize uplift charges because they are difficult to hedge and do not provide transparent economic signals to market participants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

123 See Figure A-89 in the Appendix for this analysis.

The following figure shows guarantee payment uplift for four local reliability categories and three non-local reliability categories in 2012 and 2013 on a quarterly basis.[124]

Figure 17: Uplift Costs from Guarantee Payments in New York

By Category and Region, 2012 – 2013



The figure shows that the guarantee payment uplift totaled $164 million in 2013, up 13 percent from 2012.[125] Day-ahead uplift accounted for the majority of the increase, up $16 million from 2012 to 2013, which was due largely to higher natural gas prices that increased the commitment costs of gas-fired units needed for reliability. However, the increase was offset by overall modest reductions in reliability commitments and OOM dispatch from 2012 to 2013.

New York City accounted for the largest increase in uplift costs in 2013, while the increases in other regions were relatively modest. These results were consistent with the changes in reliability commitments and OOM dispatch from 2012 to 2013, which are discussed in detail in

124 See Figure A-90 and Figure A-91 in the Appendix for a more detailed description of this analysis.

125 The 2013 number was based on billing data available at the time of reporting, which may be different from final settlement.

the previous sub-section. In addition, a significant portion of the increase in New York City was associated with the Min Oil Burn requirement, which generated high charges in late-May and June when some capacity with automatic fuel swapping capability was not available, resulting in the need to have other units actually burn a mix of oil and gas.

Several notable events also led to large amounts of guarantee payment uplift during their occurrences in both 2012 and 2013:

- The landfall of Superstorm Sandy led to widespread transmission outages, OOM dispatch, and supplemental commitment from October 30 to mid-November of 2012, accounting for $20 million in guarantee payment uplift, primarily in New York City.
- The cold weather period from January 20-27, 2013 accounted for $12 million in guarantee payment uplift when gas prices rose as high as $35 per MMbtu.
- The hot weather period from July 15-19, 2013 accounted for $13 million in guarantee payment uplift when a new all-time peak load record was set.

IX. 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 95 percent of the 1.3 GW of demand response resources registered in New York are reliability demand response resources.

Special Case Resources Program

The SCR program is the most significant demand response program operated by the NYISO with nearly 1.2 GW of resources participating in 2013. The primary incentive to participate in this program is that SCRs can sell capacity in the NYISO’s capacity market. In the Summer 2013 Capability Period, SCRs made contributions to resource adequacy by satisfying:

- 3.6 percent of the UCAP requirement for New York City;
- 1.4 percent of the UCAP requirement for Long Island; and
- 3.0 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, and 33 percent in 2013. 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 2013 is based on 40 hours from Summer 2012). 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.

In addition, 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 100 MWs of DSASP resources are participating in the market, providing considerable value by reducing the cost of ancillary services in the New York market.

Day-Ahead Demand Response Program

No resources participated in the DADRP program during the twenty-four-month period from September 2011 to August 2013. 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..

X. List of Recommendations

Our analysis in this report indicates that the NYISO electricity markets performed well in 2013, although the report finds additional improvements that we recommend be made by the NYISO.

Capacity Market

1. **Create a dynamic and efficient framework for reflecting the NYISO's locational planning requirements in its capacity market, which includes three key aspects. (High Priority/Value)**

   a. Pre-define interfaces and zones that address potential resource adequacy needs and highway deliverability constraints to allow prices to accurately reflect the locational value of capacity.

   The existing NCZ creation rules 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. Improved modeling of the capacity interfaces or zones would also allow capacity prices in each zone to better reflect the reliability benefits resources in the zone provide to other zones.

   b. Grant internal capacity deliverability rights between zones when private investors upgrade the transmission system to expand the capability into a local area.

   This is comparable to the NYISO's current provision to provide Transmission Congestion Contracts ("TCCs"). Creating these internal capacity transfer rights will help: a) provide efficient incentives for economic investment in transmission, 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.

   c. Modify the capacity demand curves so they are consistent with the marginal reliability benefit from adding capacity to a particular Locality.

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. Setting capacity demand curves that reflect the marginal reliability value of additional capacity in each locality would provide incentives for more efficient investment, which would tend to lower overall capacity costs.

Locational capacity market signals are discussed in Section VII.C.

Implementation Efforts:

- 2014 Project Plan: *Model export constraints in the ICAP Auction* – Market Design Concept
- 2014 Project Plan: *Predefine Capacity Zones* – Market Design Concept
- These projects are designed to address (a).

2. **Enhance Buyer-Side Mitigation measures to deter uneconomic entry that is designed to lower prices below competitive levels while ensuring that economic entrants are not mitigated. (High Priority/Value)**

   a. Grant a Competitive Entry Exemption from the buyer-side mitigation measures for a purely market based investment.

The Buyer-Side Mitigation Exemption test is conducted three years in advance based on a forecast of conditions at the time of entry. However, it is difficult for such forecasts to account for uncertainty regarding unit retirements and mothballing. To the extent these occur, the Buyer-Side Mitigation Exemption test will likely understate the forecasted prices and over-mitigate competitive entry. Granting an exemption to suppliers engaged in purely private investment would allow merchant investors to make investment decisions based on their own expectations of the increased capacity revenues that would occur if additional retirements occur (beyond those that have been noticed to the PSC).

   b. Reform the Offer Floor for mitigated projects.

A new project is exempted from mitigation if capacity prices are forecasted to be higher than: (i) Default Net CONE ("DNC") – a level 25 percent lower than Mitigation Net CONE ("MNC"), where MNC is intended to equal 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 project. If a project fails both of these criteria, an Offer Floor is imposed at a level equal to the lower of DNC and UNC. The DNC 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 true 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.

c. Modify the definition of the Starting Capability Period to coincide with anticipated entry of Examined Facility

Under the current rules, the Starting Capability Period (i.e., when a project is assumed to begin operating for the purposes of the mitigation exemption test) is often earlier than an Examined Facility would likely begin operating. This depresses the forecast of capacity revenues for the Facility, thereby increasing the likelihood of mitigating the Facility even if it is economic. We recommend tariff changes to align the Starting Capability Period with when the Examined Facility would actually begin operating.

d. Modify the treatment of mothballed units, units relinquishing CRIS rights, and recently retired units in the forecasts of ICAP prices and net revenues.

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.

e. Adopt a Buyer-Side Mitigation measure to address the effects of uneconomic transmission investment.

The current rules do not prevent an entity from building uneconomic transmission to reduce LCRs and depress capacity prices below competitive levels. This includes internal transmission projects and projects interconnecting other areas that may increase the emergency assistance credited to the external area. We recommend the NYISO adopt buyer-side mitigation rules to deter uneconomic transmission investment.

The Buyer-Side Mitigation Exemption tests and Offer Floors are discussed in Section VII.C.2.

Implementation Efforts:

- The NYISO is currently working with stakeholder committees on the *Competitive Entry Exemption and Offer Floor Change* proposal, which is designed to address (a) and (b).

3. **Modify the pivotal supplier test in the Tariff to prevent a large supplier from circumventing the mitigation rules by selling capacity in the forward capacity auctions (i.e., the strip and monthly auctions) to avoid being designated as a pivotal supplier.**

The current definition of a pivotal supplier effectively assumes that selling capacity in the forward auctions eliminates the incentive for a large supplier to withhold in the spot auction. However, increased spot capacity prices affect the expectations of other market participants, increasing the clearing prices in subsequent forward auctions. This allows a large supplier to benefit from withholding in the spot capacity auction even if it does not meet the definition of a pivotal supplier in the supply-side mitigation measures because it has sold most of its capacity in the forward auctions. Hence, we recommend modifying the pivotal supplier criteria to include in the evaluation for a particular supplier any capacity that it sold prior to the spot auction. The pivotal supplier criteria are discussed in Section VII.C.3.

Real-Time Market Operations

4. **Work with adjacent ISOs to implement rules that will better utilize the transfer capability between regions by coordinating the intra-hour transactions. (High Priority/Value)**

Utilization of the external interfaces is evaluated in Section VI.C.

Implementation Efforts:

- *Coordinated Transaction Scheduling with PJM* – Deployment in November 2014
- *Coordinated Transaction Scheduling with ISO-NE* – Deployment in 2015-Q4

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

Significant efficiency savings may be achieved by improving the operation 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) 99 percent of the time in 2013.
- The J and K lines between New York and New Jersey, which were scheduled in the day-ahead market in the inefficient direction 73 percent of the time in 2013.
- 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 the production of economic generation. 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 may be reasonable to create a financial settlement mechanism to compensate the party that would be giving up some of the benefits from the current operation. Utilization of these PAR-controlled lines is evaluated in Section VIII.E.

6. Adjusting the timing of the look ahead evaluations of RTD and RTC to be more consistent with the timing of the ramping periods for external transactions.

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). This inconsistency contributes to transient shortage conditions and unnecessary price volatility. We recommend the NYISO:

- Modify the intervals in RTD to always model each 5 minute interval in which external transactions are ramping (e.g., intervals :55, :00, and :05); and
- Evaluate the cost and feasibility of improvements to RTC that would allow it to better recognize NYISO's ramping demands and be consistent with RTD.

Contributors to unnecessary real-time price volatility are discussed in Section VIII.F.

Real-Time Pricing

7. **Modify criteria for GTs to set prices in the real-time market: (i) by always allowing RTC-committed GTs to be eligible to set price in the final pricing pass and (ii) by retaining Hybrid Pricing treatment for GTs dispatched out-of-merit and other GTs.**

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 retain this step only for GTs that are not committed economically by the Real Time Commitment model. The real-time commitment of and price-setting by gas turbines is discussed in Section VIII.C.

8. **Implement a graduated Transmission Demand Curve.**

RTD limits the redispatch costs that may be incurred to $4000 per MWh when managing congestion. However, this level is excessive for certain shortages (e.g., ones that are brief or small relative to the limit on the constraint). Moderating the Transmission Demand Curve will lead the NYISO to more efficient dispatch and commitment actions, and set more efficient prices. Transmission shortage pricing is discussed in Section VIII.A.1.

Implementation Efforts:

- 2014 Project Plan: *Scheduling & Pricing: Graduated Transmission Demand Curve* – Deployment in 2014-Q4.

9. Modify real-time pricing during demand response activations (i.e., Scarcity Pricing) by: (i) extending Scarcity Pricing to External Proxy Buses and (ii) incorporating Scarcity Pricing into the Hybrid Pricing logic of RTD.

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. This report identifies two specific shortcomings of NYISO's Scarcity Pricing. 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. To ensure this, we recommend that the NYISO incorporate Scarcity Pricing into Hybrid Pricing logic of Real-Time Dispatch software. Real-time pricing during deployments of demand response for reliability is discussed in Section VIII.A.2.

Implementation Efforts:

- 2014 Project Plan: *Scheduling & Pricing: Comprehensive Shortage Pricing Review* – Market Design Approval

10. Modify the operating reserve demand curves to better reflect reliability needs that lead the NYISO to take out-of-market actions under high load conditions.

a. Create a SENY 30-minute operating reserve zone to reflect the requirements of NYSRC Rule F-R1c.

The NYISO deploys demand response and schedules generation out-of-market to maintain sufficient resources in Southeast New York under peak load conditions. Creating a SENY reserve zone and reserve demand curve would better allow the market to satisfy reliability needs there. The SENY reserve requirement should be sufficient to account for the largest two contingencies and be priced consistent with the need to deploy demand response at $500 per MWh.

b. Modify the NYCA 30-minute operating reserve requirement to reflect the requirements of NYSRC Rule D-R4.

The NYISO deploys demand response and schedules generation out-of-market to maintain sufficient resources to withstand the largest two contingencies in NYCA under peak load conditions. The market should be structured to satisfy and price the NYISO's reliability requirements. Hence, the NYCA 30-minute reserve requirement should be sufficient to account for the largest two contingencies and set prices consistent with the need to activate DR at $500 per MWh.

c. Modify the NYCA 30-minute operating reserves under normal conditions from $50, $100, and $200 to $100, $250, and $500 per MWh.

The current NYCA 30-minute reserve demand curve ranges from $50 to $200 per MWh. We believe that these levels cause the real-time market to forego opportunities to schedule imports and internal generators that would efficiently satisfy the 30-minute reserve requirement, particularly during high load conditions. Hence, raising the demand curve for this product would result in better consistency between pricing and scheduling outcomes when the operators must take actions to satisfy the NYCA 30-minute reserve requirement. Additionally, the NYISO's current demand curve is substantially lower than ISO-NE's for 30-minute reserves, which is set at $500 per MWh. This can result in inefficient interchange and diminish reliability in New York. Raising the demand curve for 30-minute reserves would improve both efficiency and reliability.

Real-time pricing during high load periods when out-of-market actions are necessary to maintain adequate reserves is discussed in Section VIII.A.3.

Implementation Efforts:

- 2014 Project Plan: *Scheduling & Pricing: Comprehensive Shortage Pricing Review* – Market Design Approval

Winter Market Operations

11. Consider ways to allow suppliers to submit offers that more accurately reflect certain fuel supply constraints in the day-ahead market.

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 houly OFOs that require them to schedule a specific quantity of gas in each hour of a 24 hour period. A supplier that offers a flexible range between its minimum and maximum generation level in the day-ahead market is at risk of being scheduled at its maximum generation level for a small number of hours. This would require the generator to schedule enough gas to run at its maximum generation level for the 24-hour gas day, which may be far more than is necessary to meet the day-ahead schedule. This subjects the generator to significant financial risks when it is scheduled in the day-ahead market and it is likely to respond by reflecting these costs in other offer parameters or by reducing its availability. Hence, allowing generators to submit offers that are scheduled subject to an inter-temporal constraint would reduce the OFO-based risks of being available.

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

Generator scheduling during tight natural gas conditions is discussed in Section VIII.B.

12. Require Generators to provide information on a daily basis regarding fuel availability, particularly on-site fuel inventories and natural gas schedules.

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). Generator scheduling during tight natural gas conditions is discussed in Section VIII.B.

ANALYTIC APPENDIX

2013 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 2013 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 2011 to 2013 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 average of Iroquois Zone 2 index and Tennessee Zone 6 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
2011-2013

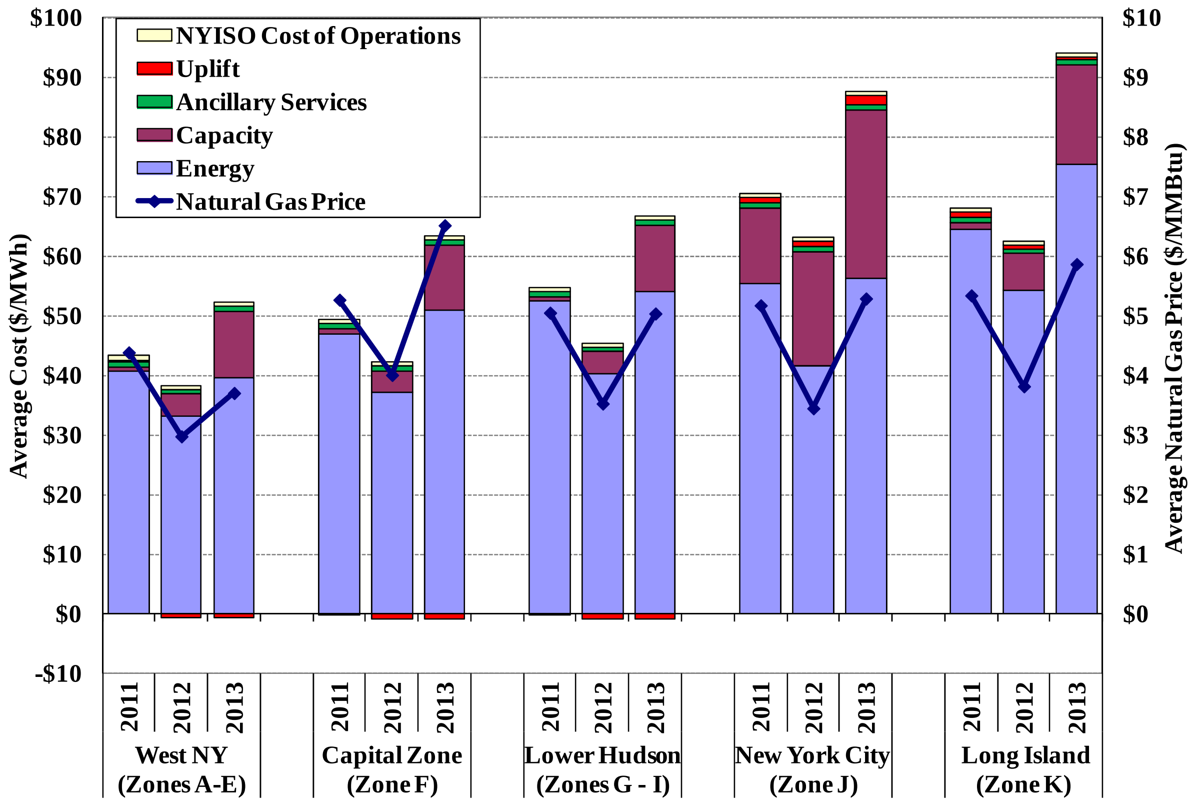


Figure A-2: Day-Ahead Electricity and Natural Gas Prices

Figure A-2 shows average natural gas prices and load-weighted average day-ahead energy prices in each month of 2013 for the five locations shown in Figure A-1. The table in the chart shows the annual averages of these quantities for 2012 and 2013. 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
2013

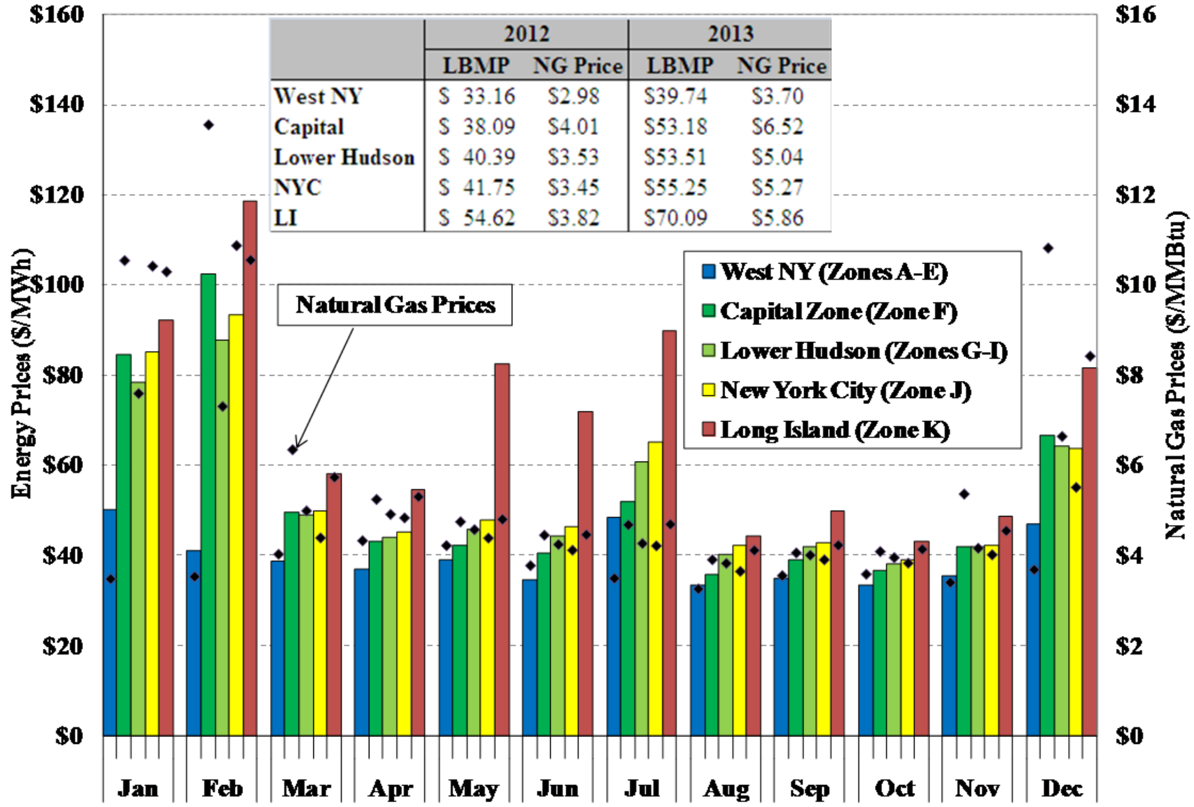


Figure A-3: Average Monthly Implied Marginal Heat Rate

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).[126] 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.[127]

Figure A-3 shows the load-weighted average implied marginal heat rate in each month of 2013 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 2012 and 2013 at these five locations. By adjusting

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

127 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.

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

Figure A-3: Average Monthly Implied Heat Rate
Day-Ahead Market, 2013

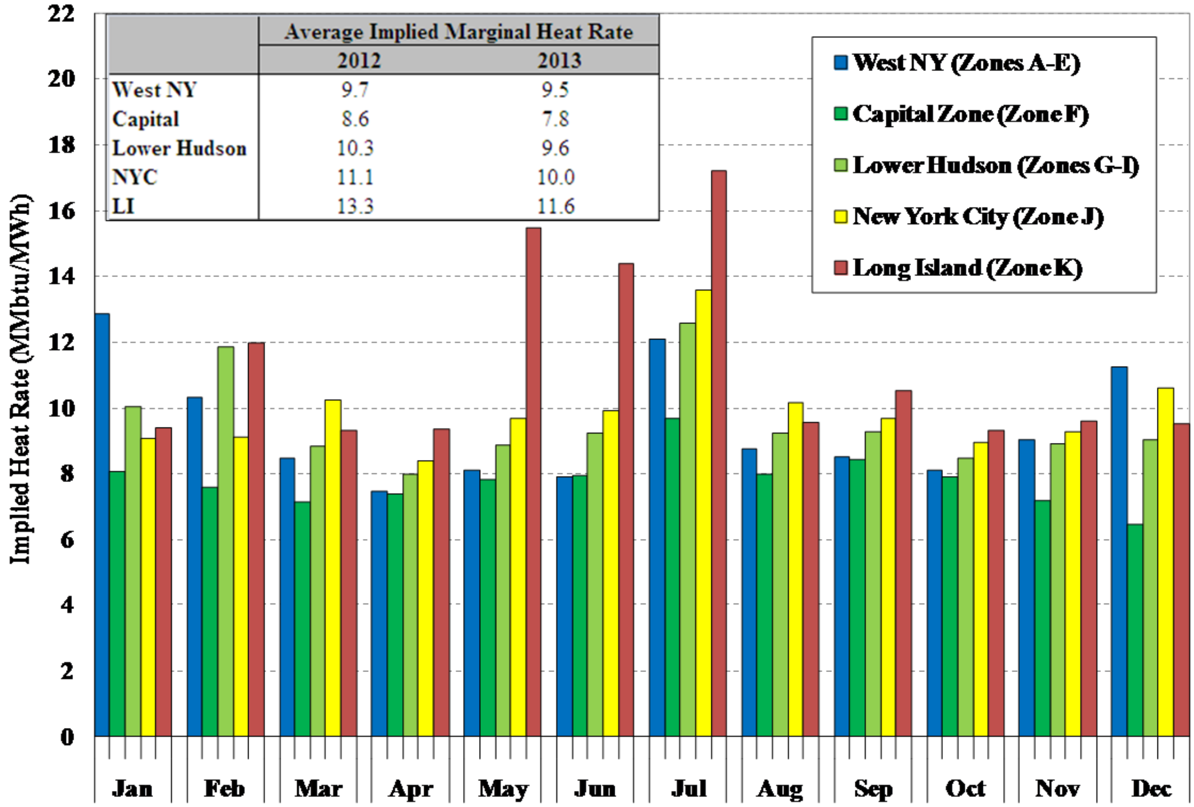
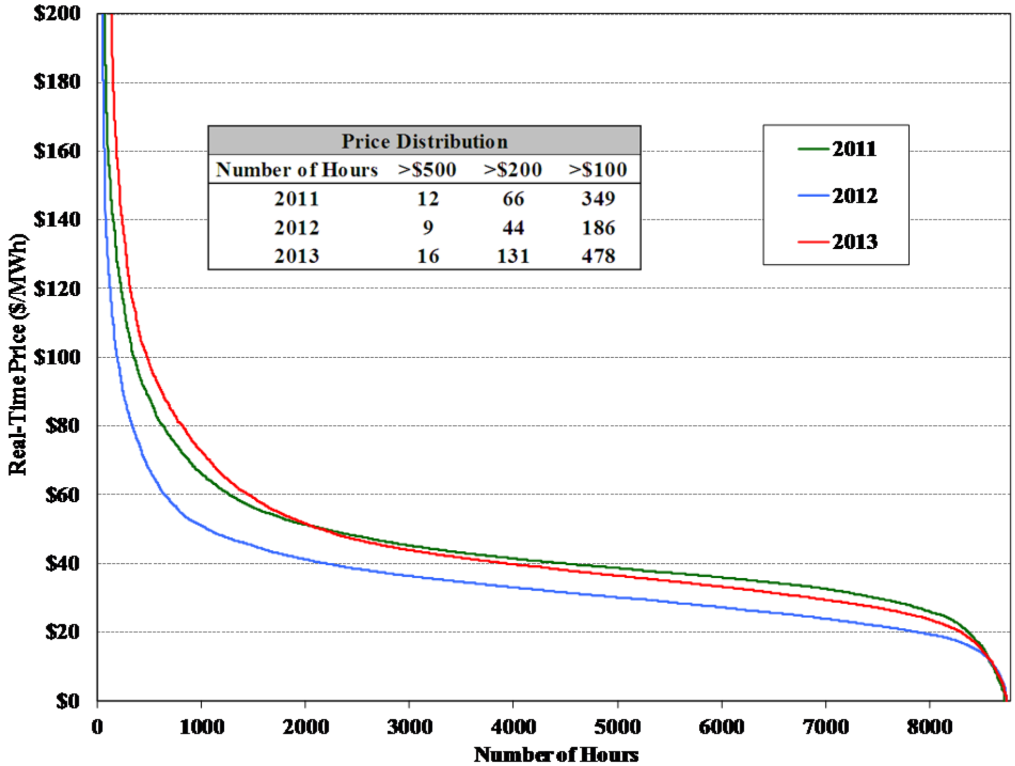


Figure A-4 – Figure A-7: Price Duration Curves and Implied Heat Rate Duration Curves

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 2011 to 2013. Figure A-5 shows five price duration curves for 2013, 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.

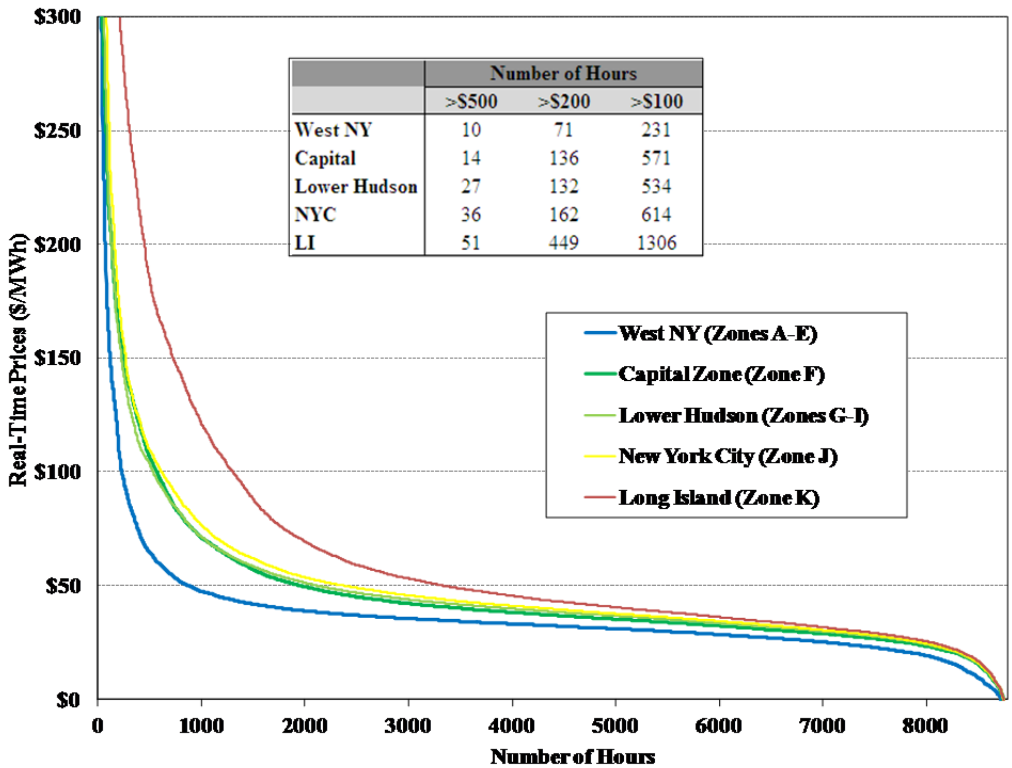
The price duration curves show the characteristic distribution of prices in wholesale power markets, in which a small number of hours exhibited very high prices that are typically associated with shortages. During shortages, prices can rise to more than ten times the average price level, so a small number 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
2011-2013



Price Distribution			
Number of Hours	>$500	>$200	>$100
2011	12	66	349
2012	9	44	186
2013	16	131	478

Figure A-5: Real-Time Price Duration Curves by Region
2013



	Number of Hours		
	>$500	>$200	>$100
West NY	10	71	231
Capital	14	136	571
Lower Hudson	27	132	534
NYC	36	162	614
LI	51	449	1306

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 2011 to 2013 and at each location during 2013. 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 average of Iroquois Zone 2 index and Tennessee Zone 6 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 for New York State
2011-2013

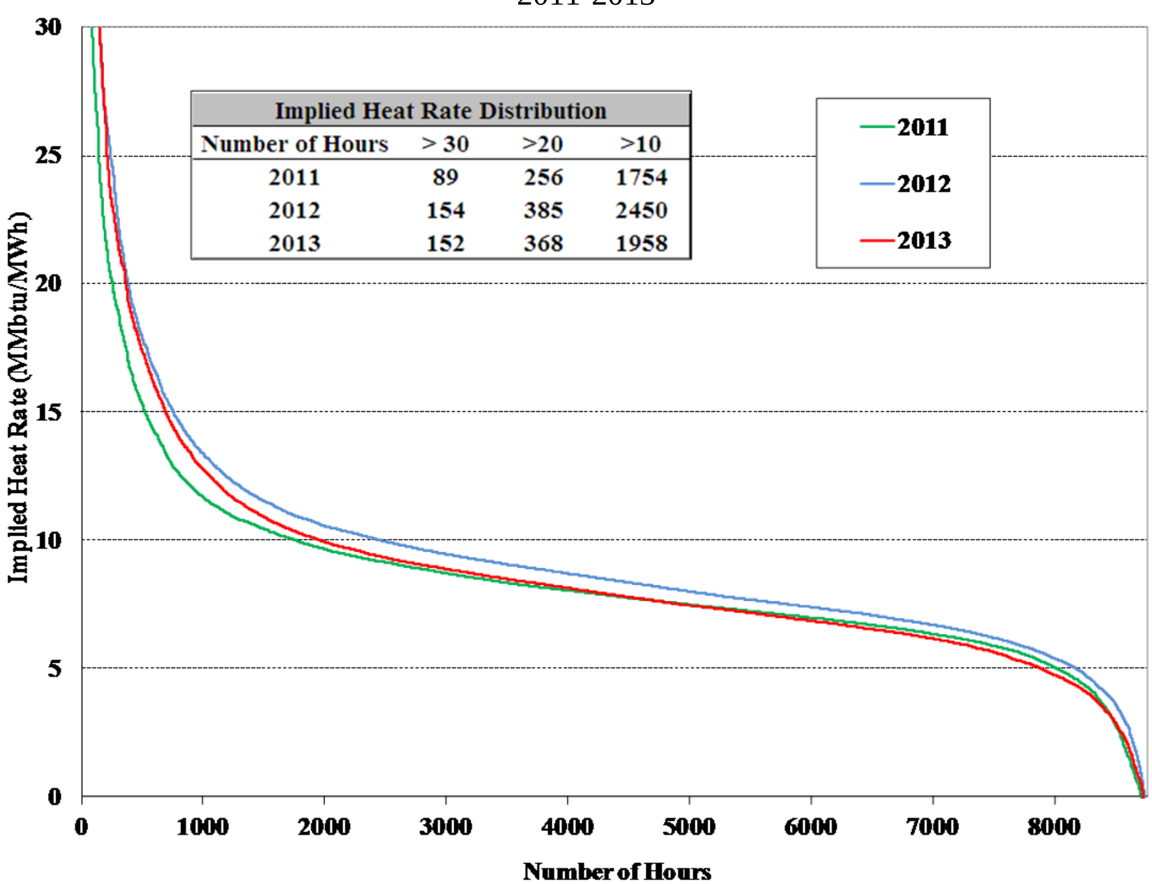
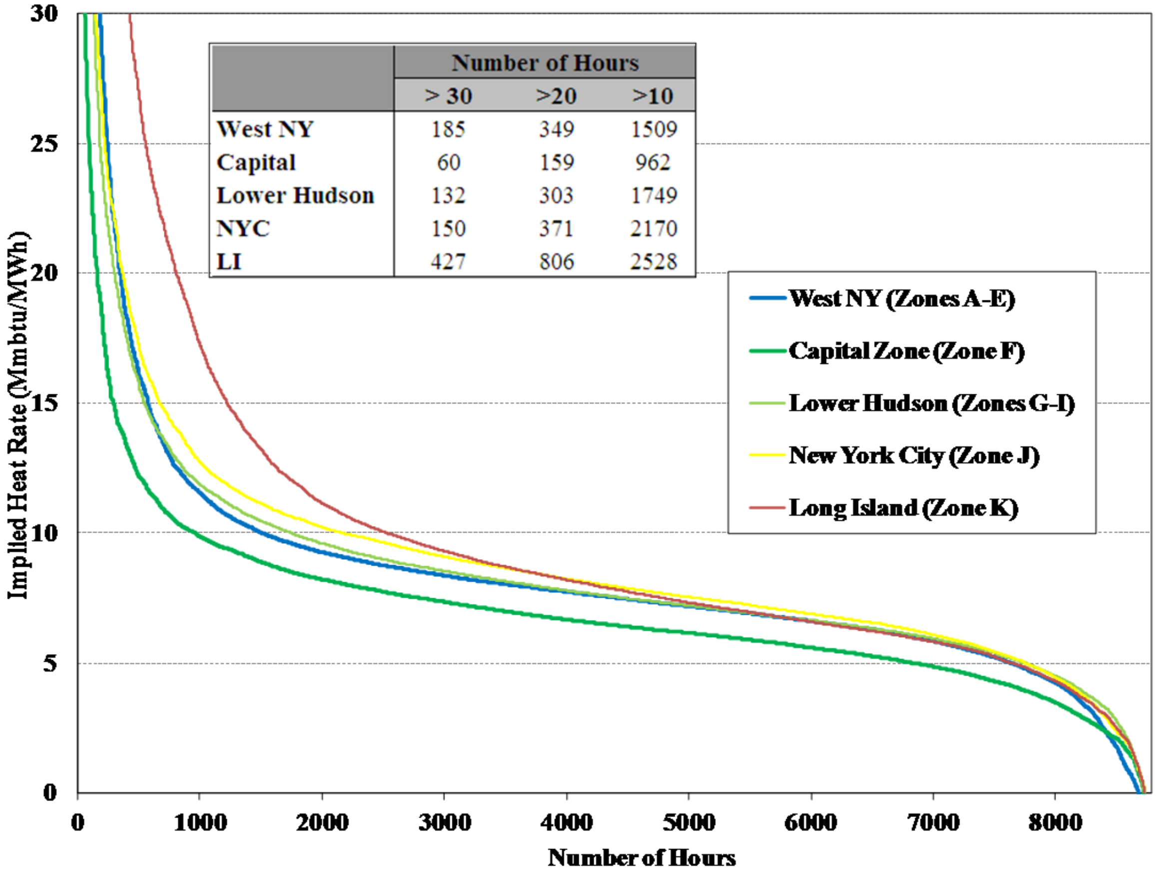


Figure A-7: Implied Heat Rate Duration Curves by Region
2013



	Number of Hours		
	> 30	>20	>10
West NY	185	349	1509
Capital	60	159	962
Lower Hudson	132	303	1749
NYC	150	371	2170
LI	427	806	2528

Key Observations: Wholesale Market Prices

- Average all-in prices of electricity ranged from approximately \$52 per MWh in West New York to \$94 per MWh in Long Island in 2013.
  - Energy costs accounted for 64 percent of the all-in price in New York City and 77 to 82 percent of the all-in price in the other four regions.
  - Capacity costs accounted for 32 percent of the all-in price in New York City and 17 to 21 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 in New York City.
- Average electricity prices rose 20 to 39 percent in the five regions of New York State from 2012 to 2013. These increases were consistent with the change in natural gas prices, which rose 27 to 72 percent from 2012 to 2013.
- Average capacity costs rose substantially from 2012 to 2013, up 48 percent in New York City, 166 percent in Long Island, and 194 percent in other regions. These increases were driven primarily by:

  - Reduced internal supply of capacity due to multiple retirements from 2012 to 2013 totaling 1.4 GW; and
  - Increases in the installed capacity requirements in all capacity regions, due to:
    - The LCR for New York City rose from 83 percent to 86 percent;
    - The LCR for Long Island rose from 99 percent to 105 percent; and
    - The IRM for NYCA rose from 16 percent to 17 percent.
    - These increases occurred despite slight decreases in forecasted peak load from the previous year..
- The seasonal patterns of electricity prices and natural gas prices were typical for most of 2013 as electricity prices rose in the winter months as a result of tight natural gas supplies and in the summer months as a result of high electricity demand.
  - In particular, (a) average natural gas prices in the winter of 2013 were the highest among the recent several winters; and (b) unusual heat waves in July set a new all-time peak load in New York, which resulted in many high price spikes during these periods.
  - In addition, electricity prices in Long Island were significantly higher than the rest of state, particularly in the first half of 2013, reflecting:
    - Lengthy deratings and outages of 345kV transmission facilities into Long Island and the Neptune Cable. .
    - Tight supply associated with generator outages, multiple unit retirements, and set inefficient utilization of some generation resources.
- Implied heat rates (as calculated in this report) fell from 2012 to 2013, reflecting increased nuclear generation and higher natural gas prices.
- Price spreads between trading hubs on the natural gas pipeline system affected transmission congestion patterns in the energy markets, particularly during the winter months.
  - Natural gas costs were 11 to 72 percent higher on average in Eastern New York than in most of Western New York in 2013. This contributed to congestion across the Central-East interface, which resulted in LBMPs in the Capital Zone exceeding those in Western New York by 30 percent on average.
  - High natural gas costs reduced the output of gas-fired generation in the Capital Zone, while lower relative input costs increased the output of gas-fired generation in the Lower Hudson Valley and New York City.

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 Long Island;
- The Iroquois Zone 2 price and Tennessee Zone 6 price are generally representative of natural gas prices in the Capital Zone;
- 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 2010 to 2013. The table compares the annual average fuel prices for these four years.

Figure A-8: Monthly Average Fuel Prices[128]
2010 - 2013

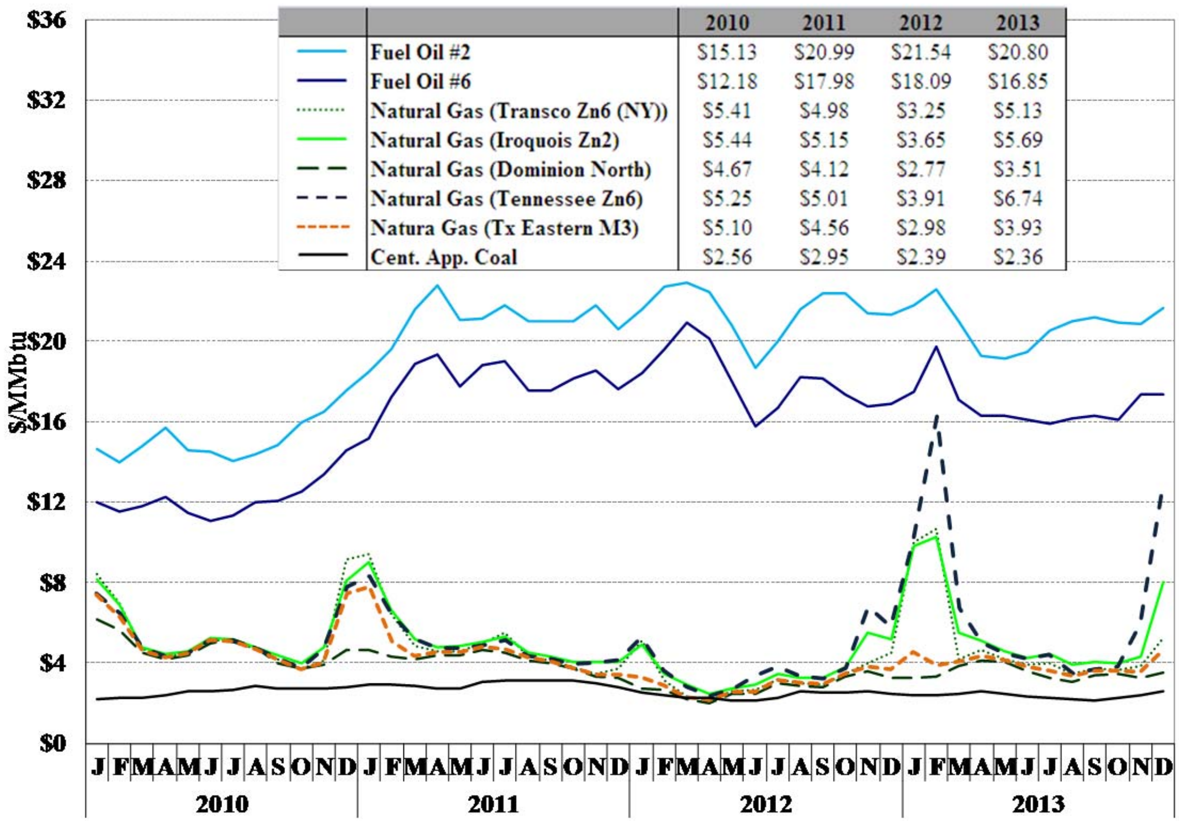


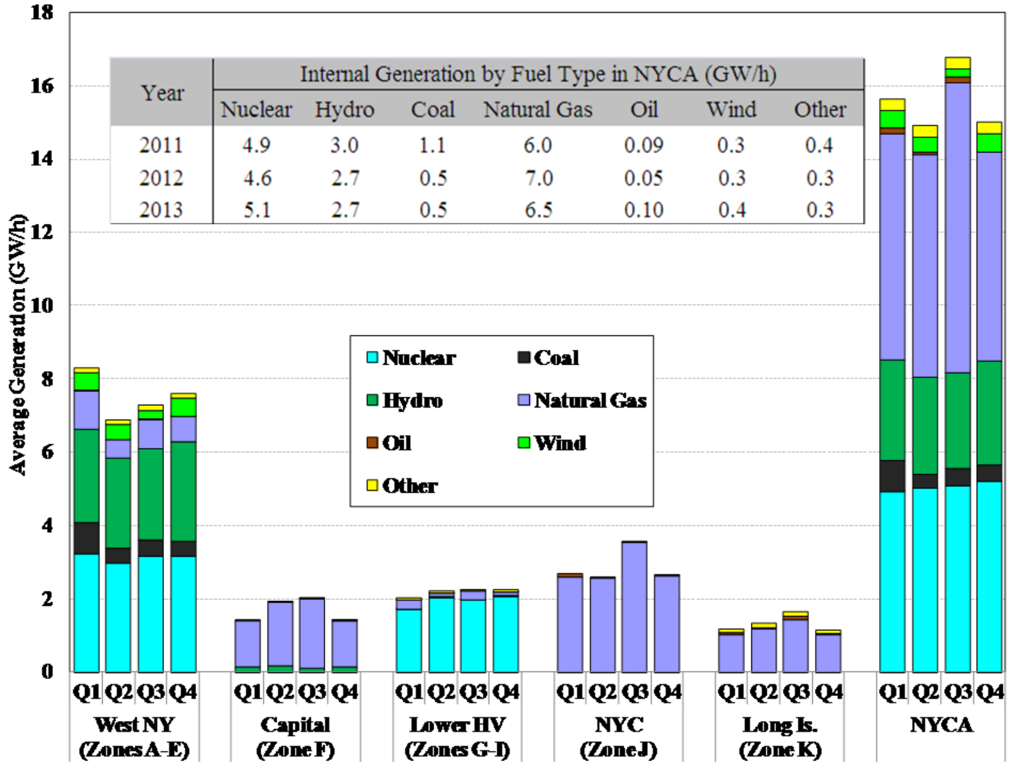
Figure A-9 shows the quantities of generation by fuel type in five regions of New York in each quarter of 2013. The table in the chart shows the annual averages of generation by fuel type from 2011 to 2013.

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 2013. 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").

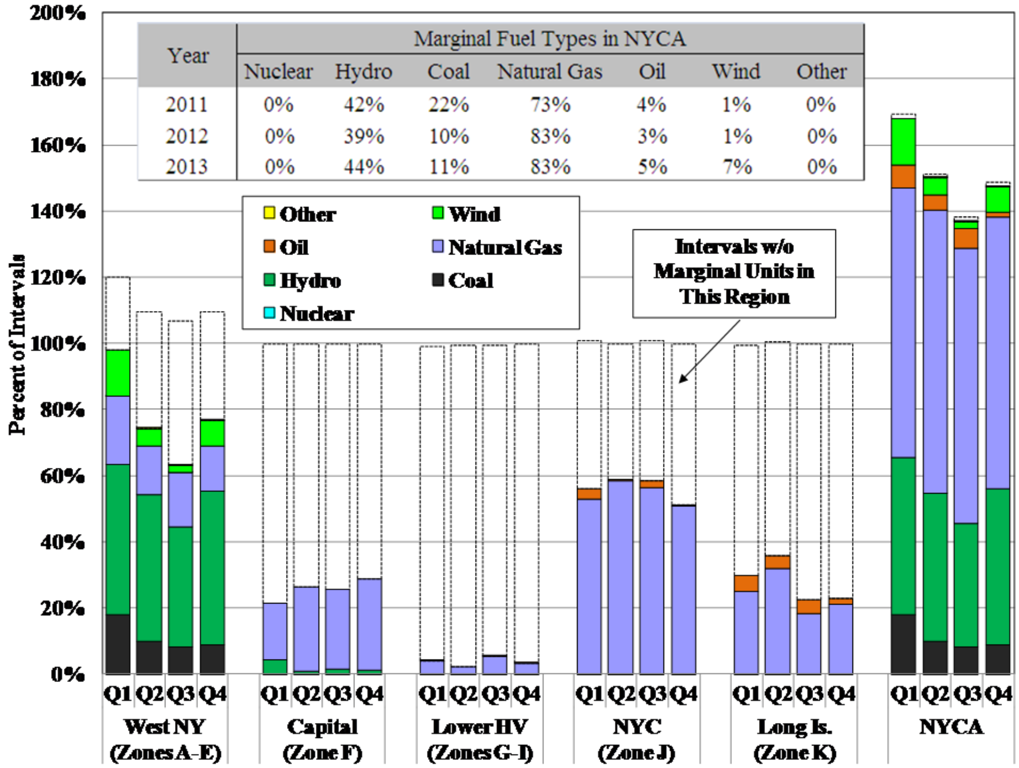
128 These are index prices that do not include transportation charges.

Figure A-9: Generation by Fuel Type in New York
By Quarter by Region, 2013



Year	Internal Generation by Fuel Type in NYCA (GW/h)						
	Nuclear	Hydro	Coal	Natural Gas	Oil	Wind	Other
2011	4.9	3.0	1.1	6.0	0.09	0.3	0.4
2012	4.6	2.7	0.5	7.0	0.05	0.3	0.3
2013	5.1	2.7	0.5	6.5	0.10	0.4	0.3

Figure A-10: Fuel Types of Marginal Units in the Real-Time Market in New York
By Quarter by Region, 2013



Year	Marginal Fuel Types in NYCA						
	Nuclear	Hydro	Coal	Natural Gas	Oil	Wind	Other
2011	0%	42%	22%	73%	4%	1%	0%
2012	0%	39%	10%	83%	3%	1%	0%
2013	0%	44%	11%	83%	5%	7%	0%

Key Observations: Fuel Prices and Generation by Fuel Type

- Fuel oil prices and coal prices fell modestly from 2012 to 2013.
  - Diesel fuel oil (No. 2) prices averaged $20.80/MMBtu, down 3 percent from 2012.
  - Residual fuel oil (No. 6) prices averaged $16.85/MMBtu, down 7 percent from 2012.
  - Central Appalachian coal prices averaged $2.36/MMBtu, down slightly from 2012.
- Natural gas prices, which more directly affected wholesale energy prices, increased significantly from 2012 to 2013.
  - In Western New York, natural gas prices averaged roughly $3.5/MMBtu, up more than 25 percent from 2012.
  - In Eastern New York, natural gas prices averaged from roughly $4.0 to $6.7/MMBtu, up 32 to 72 percent from 2012.
  - Likewise, the locational spreads between natural gas prices increased from 2012 to 2013.
    - Gas spreads between Western New York and Southeast New York averaged 46 to 62 percent, up from 18 to 32 percent in 2012.
    - The winter months (January, February, December) accounted for the vast majority of the gas price spreads.
    - Increased spreads between regions affect generation patterns, contributing to congestion and associated energy price spreads..
- Gas-fired (42 percent), nuclear (33 percent), and hydro (17 percent) generation accounted for more than 90 percent of all internal generation in New York during 2013.
  - Average nuclear generation rose 420 MW from last year due to the uprate of one Nine Mile unit and fewer planned and forced outages.
  - Gas-fired generation fell roughly 600 MW from 2012 primarily because of increased nuclear generation and higher natural gas prices.
  - Coal production has fallen in recent years as units have been retired and mothballed.
  - Oil production, although still small, rose modestly: (a) on high-gas-price days in January and February in New York City and Long Island; and (b) on high-load days in July in Long Island when generation supply was very tight.
- Gas-fired resources and hydro resources were on the margin most of time in New York..
  - Gas-fired resources were on the margin in 83 percent of the intervals during 2013.
  - Hydro resources set the prices in 44 percent of the intervals in 2013.

  - Some hydro resources have storage capability, allowing them to offer price-sensitively based on the opportunity cost of foregoing sales later (these opportunity costs are heavily dependent on natural gas prices).
  - Increased congestion in the West Zone has increased the frequency of price-setting by hydro units.
- Price-setting by wind units in the North Zone has become more frequent over the past year, primarily because of new additions of wind capacity.

C. Fuel Usage Under Tight Gas Supply Conditions

Supply of natural gas is usually tight in the winter season due to increased demand for heating. Extreme weather conditions often lead to high and volatile natural gas prices. A large share of generators in Eastern New York have dual-fuel capability, allowing them to switch to an alternative fuel when natural gas becomes expensive or unavailable. However, the increase of oil-fired generation during such periods may be limited by several factors, including:

- Not having the necessary air permits;
- Low on-site oil inventory; and
- Timing difference between the day-ahead electricity market and the natural gas market that sometimes lead day-ahead LBMPs to not reflect day-ahead gas prices.

This sub-section examines fuel usage under tight gas supply conditions in the winter of 2013, which had a big impact on the system operations, especially in Eastern New York.

Figure A-14 – Figure A-13: Generation and Excess Capacity by Fuel Type

The following three figures summarize the generation and commitment patterns by fuel type in Long Island, New York City, and the entire Eastern New York during several periods in January, February, and December when the natural gas prices in Eastern New York rose above residual (#6) oil prices.

The figures show the actual generation for the following categories: (a) oil-fired units that include both oil-only and dual-fuel units; (b) gas-fired dual-fuel units (i.e., units capable of burning oil); (c) gas-fired gas-only units; and (d) all other fuel types (e.g., hydro, nuclear, and other renewable). In addition, the figures show excess generating capacity from: (a) online and offline quick-start capacity; and (b) slow-start units that are not committed in the day-ahead market. Gas-only capacity and non-fossil-fuel capacity are not included in the excess generating capacity. For each day in the chart, these quantities are shown as hourly averages, separately for the periods before 10 am (which is the starting time of each 24-hour gas day) and after 10 am.

Figure A-11: Fuel Use and Excess Capacity on Winter Peak Days in New York City

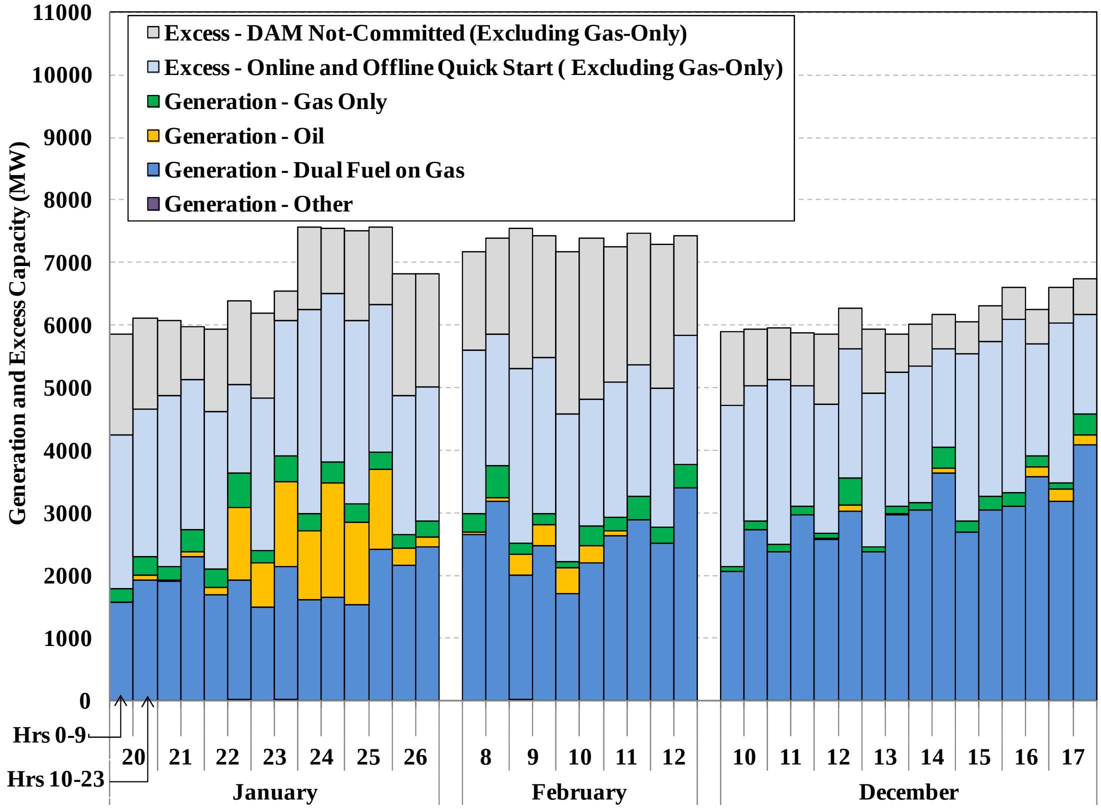


Figure A-12: Fuel Use and Excess Capacity on Winter Peak Days in Long Island

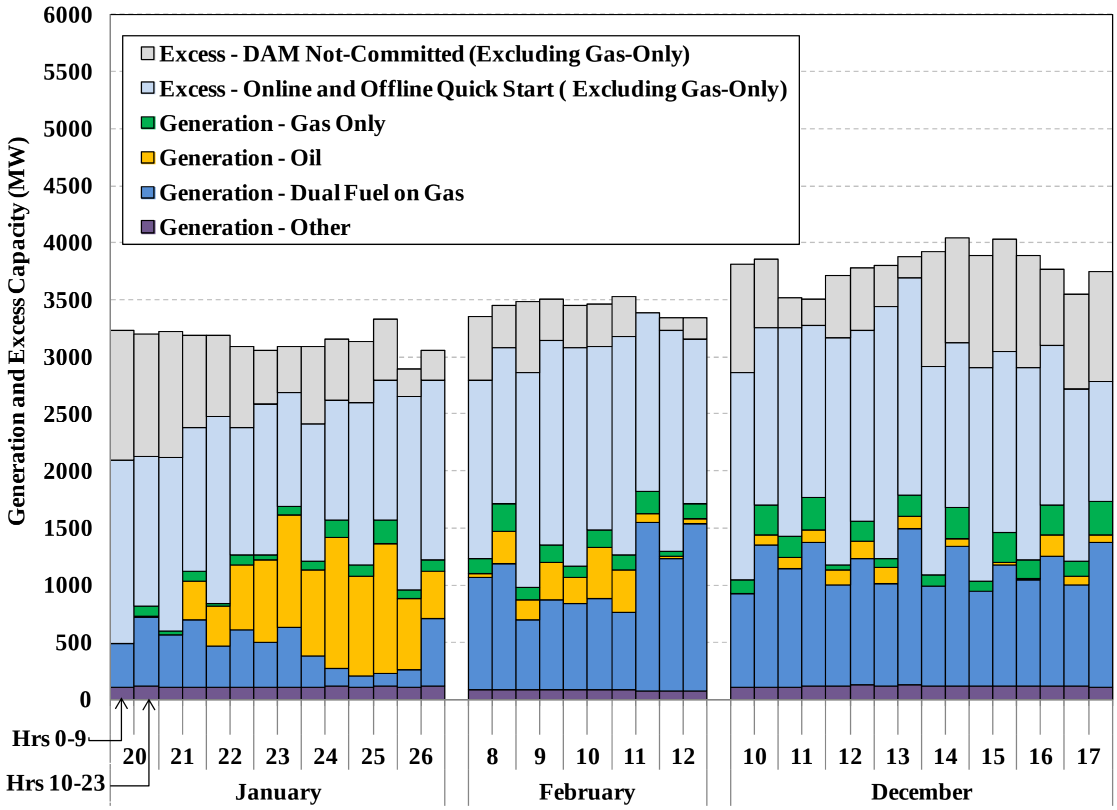
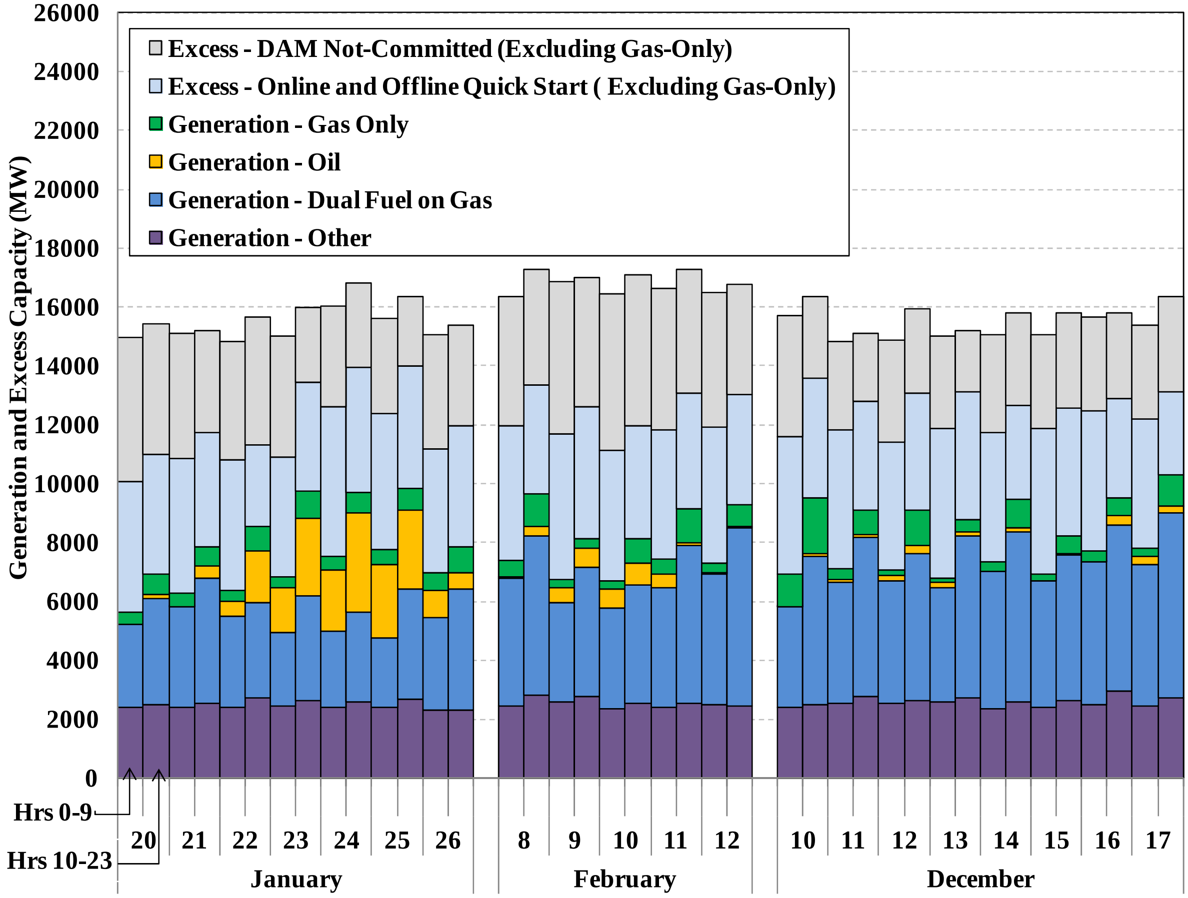


Figure A-13: Fuel Use and Excess Capacity on Winter Peak Days in East New York



Key Observations: Fuel Usage Under Tight Gas Supply Conditions

- Extreme weather conditions led to very high and volatile gas prices on many days in January and February of 2013. During these periods:
  - Gas supplies to electric generators were limited by high demand of other customers.
  - Natural gas prices rose above residual (#6) oil prices by as much as $19 per MMbtu (on January 25th).
- Production from oil (which normally averages less than 100 MW in Eastern New York) rose significantly during these periods. On the coldest days:
  - Natural gas prices rose as high as $36/MMbtu in January and $21/MMbtu in February (based on the day-ahead indices for Transco Z6 (NY) and Iroquois Z2).
  - Average production from oil rose as high as 2.7 GW in January and 700 MW in February as a result of the increased natural gas prices.
- The widespread use of oil under the tight gas supply conditions indicates that the market performed relatively well in conserving the available supply of natural gas.

  - However, during the two-day period when natural gas prices rose above $30/MMbtu on January 24 and 25, it would have been economic for more dual-fueled generators to switch from natural gas to oil. Fuel switching was limited by low oil inventories, air permit restrictions (and expirations), and equipment issues.
  - Substantial amounts of dual-fueled capacity in Eastern New York were burning gas, scheduled for operating reserves, or not committed (8 GW or more) during these periods, suggesting that there are sufficient resources not dependent on natural gas to satisfy system needs under extreme winter operating conditions.
- Substantial amounts of oil was used on three days when day-ahead gas prices were lower than oil prices (January 21-22 & 26).
  - Day-ahead gas prices for January 21 & 22 were determined on January 18 before the 3-day weekend. The use of oil on these days suggests that the day-ahead gas prices ($12-16 per MMbtu in Eastern New York) were lower than the actual cost of natural gas. Day-ahead LBMPs were not high enough to recoup the cost of oil-fired generation on January 21 & 22, which led fewer generators to be committed on oil.
  - Severe congestion into New York City from January 21 to 24 was exacerbated when several gas-only generators with spinning reserve and non-spinning reserve capability were derated due to a lack of gas supply.
    - Due to the lack of available reserves, the interface into New York City was operated under a tighter criteria that reduced overall imports (to hold reserves on the interface).
    - This resulted in online resources producing more within New York City.
    - Hence, the lack of fuel supply for several units led to an increase in the overall fuel consumption within New York City.
  - Towards the end of the week, some dual-fueled generators were derated after their oil inventories were depleted.

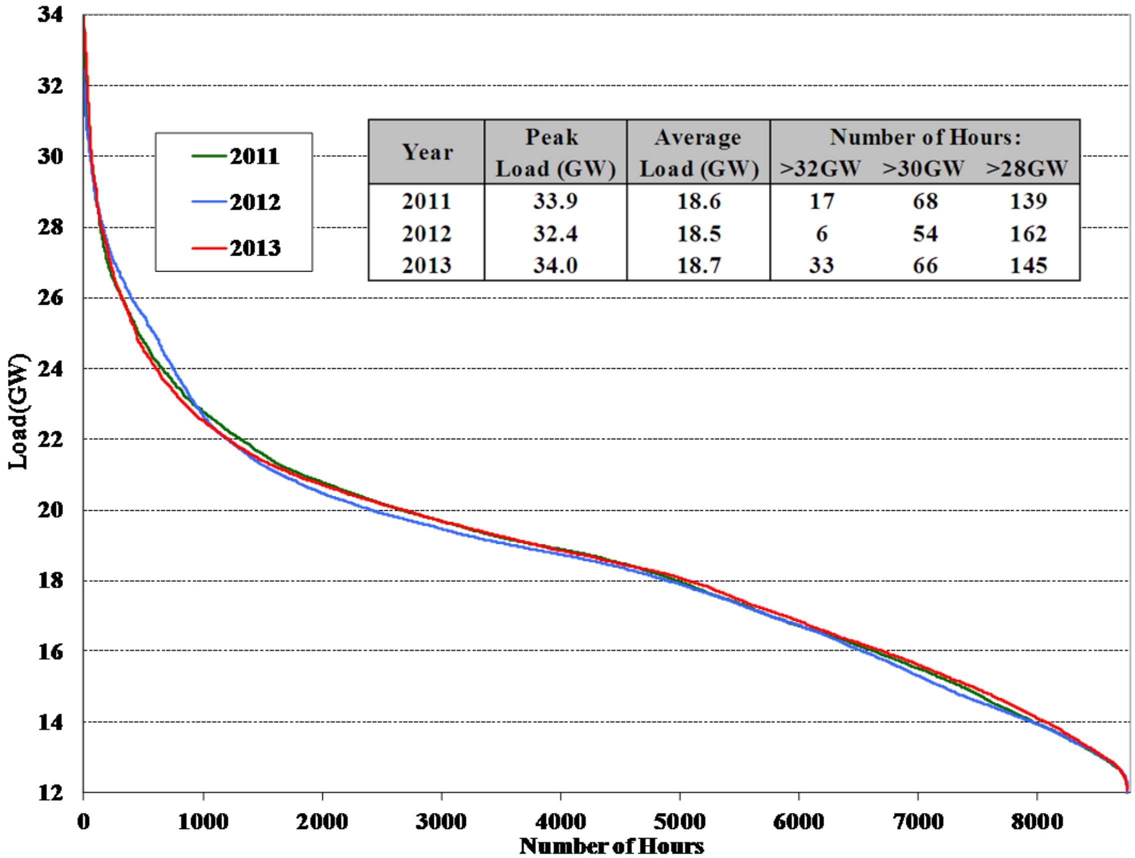
D. Load Levels

Figure A-14: 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-14 illustrates the variation in demand during each of the last three years by showing load duration curves. Load duration curves show the number of hours on the horizontal axis in which the statewide load was greater than or equal to the level shown on the vertical axis. The table in the figure shows the average load level on an annual basis for the past three years and also the number of hours in each year when the system was under high load conditions (i.e., load exceeded 28, 30, and 32 GW).

Figure A-14: Load Duration Curves for New York State
2011 – 2013



Year	Peak Load (GW)	Average Load (GW)	Number of Hours: >32GW	>30GW	>28GW
2011	33.9	18.6	17	68	139
2012	32.4	18.5	6	54	162
2013	34.0	18.7	33	66	145

<u>Key Observations: Load Levels</u>

- Load averaged 18.7 GW in 2013, up modestly (0.7 percent) from 2012.

- The system had more hours with extremely high load conditions (i.e., when load exceeded 32 GW) in 2013 due to the extreme heat waves in the summer of 2013.

  - Load peaked at a new all-time high of 33,956 MW on July 19, 2013, which was up 17 MW from the previous all-time peak in 2006.

  - This peak was approximately 1.5 GW higher than the annual peak in 2012.

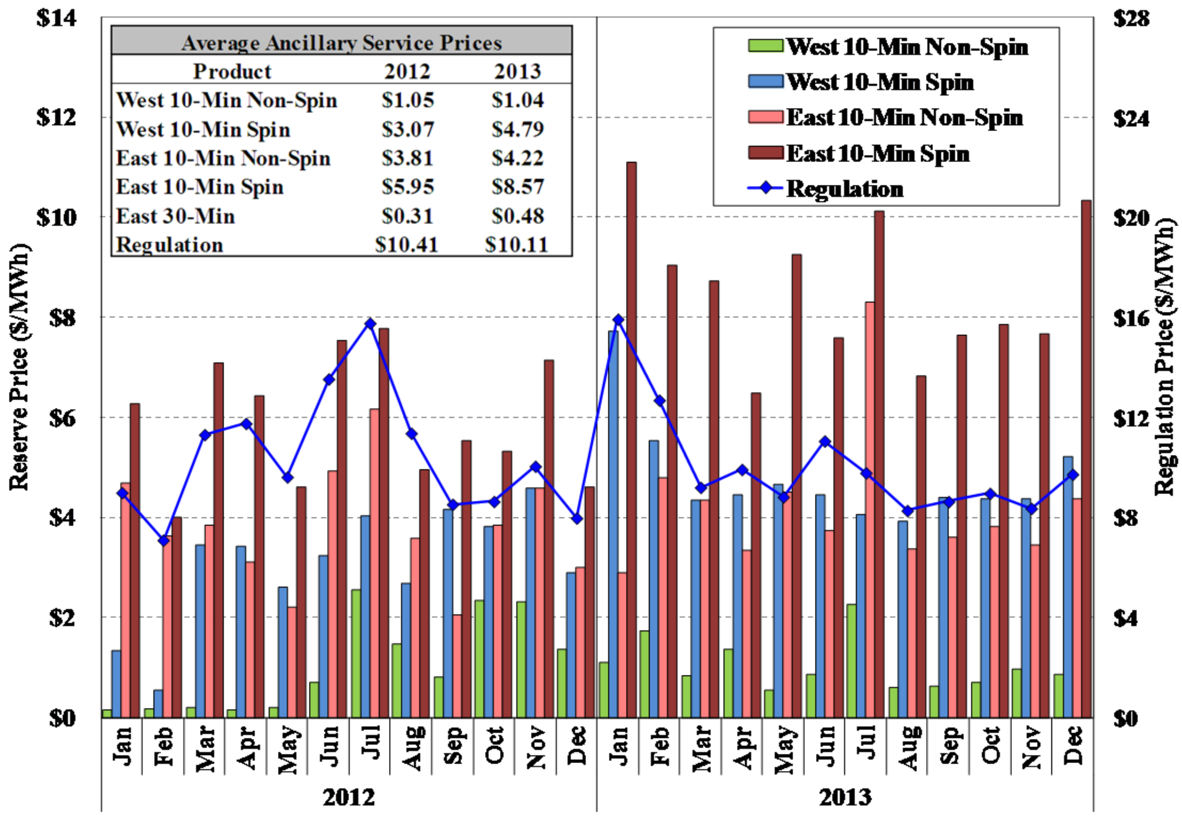
E. Day-ahead Ancillary Services Prices

Figure A-15: 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-15 shows the average prices of the following five key ancillary services products in the day-ahead market in each month of 2012 and 2013: (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-15: Day-Ahead Ancillary Services Prices
2012-2013



Key Observations: Day-ahead Ancillary Service Prices

- The average prices for most classes of ancillary services increased from 2012 to 2013.
  - The increase was largely driven by higher opportunity cost associated with higher energy prices.
- The increase in the operating reserve requirements in mid-2012 also contributed to the increase in reserves prices.
  - On June 27, 2012, several reserve requirements increased following an uprate in Nine Mile nuclear unit #2 to 1,310 MW, which increase in the size of the NYCA system's largest single supply contingency from 1,200 MW to 1,310 MW. This caused the following requirements to increase:
    - 10-minute spinning reserves in Eastern New York from 300 MW to 330 MW;
    - 10-minute spinning reserves in NYCA from 600 MW to 655 MW;
    - 10-minute total reserve requirement in NYCA from 1,200 MW to 1,310 MW;
    - 30-minute total reserves in NYCA increased from 1,800 MW to 1,965 MW.
- Average day-ahead regulation capacity prices fell slightly from 2012 to 2013 despite higher opportunity cost due to higher gas prices.
  - The new regulation market, which began on June 26, 2013, allows participants to offer regulation movement costs separately from regulation capacity costs. This led to lower regulation capacity prices following the implementation.

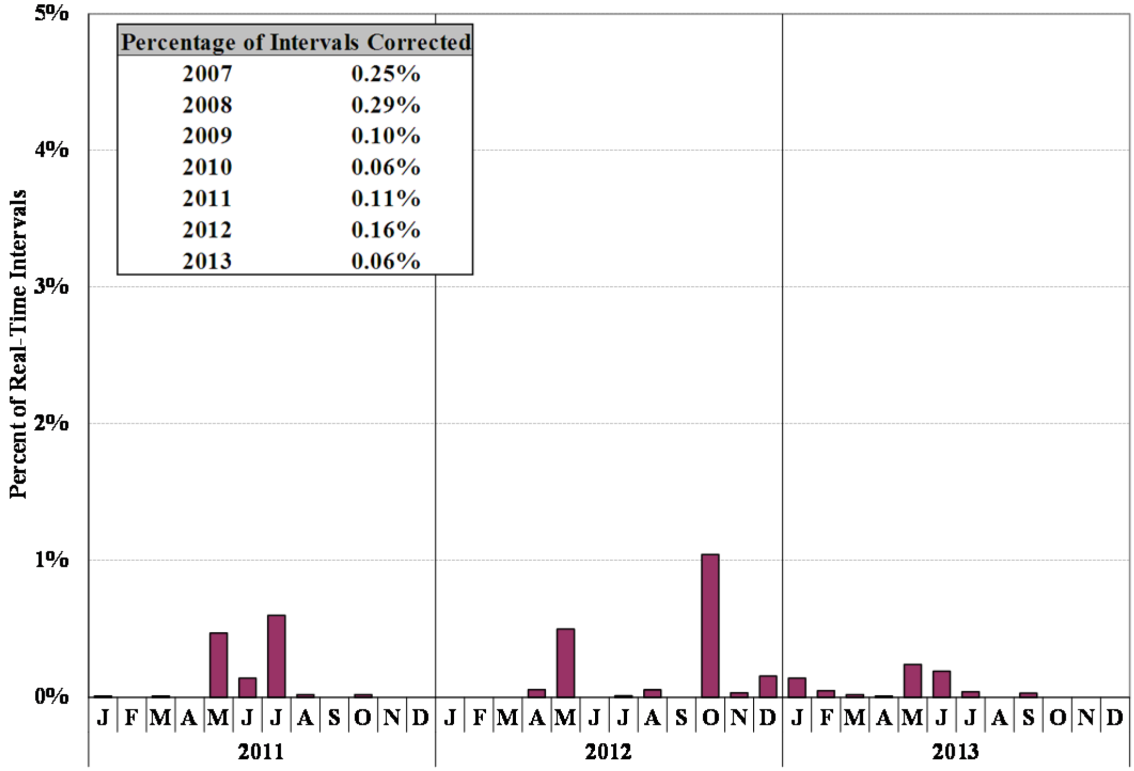
F. Price Corrections

Figure A-16: 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-16 summarizes the frequency of price corrections in the real-time energy market in each month of 2011 and 2013. The table in the figure indicates the change of the frequency of price corrections over the past several years.

Figure A-16: Frequency of Real-Time Price Corrections
2011-2013



Key Observations: Price Corrections

- Overall, the frequency of corrections and the significance of the corrections have declined to very low levels, around 0.1 percent of real-time pricing intervals in each of the past five years.
- In 2013, the frequency of price corrections was slightly higher in May (which was due largely to data errors that only affected prices at two proxy buses on two days) and June (which was due largely posting errors on one day).
  - The overall 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 1x1x1 Combined Cycle ("CC") unit, (b) a LMS 100 aeroderivative combustion turbine ("LMS") unit, and (c) a frame-type F-Class simple-cycle combustion turbine ("Frame 7") unit; and
- *Hypothetical existing units*: (a) a Steam Turbine ("ST") unit, (b) a 10-minute Gas Turbine ("GT-10") unit, and (c) a 30-minute Gas Turbine ("GT-30") unit.

Because net revenues can vary substantially by location, we estimate the net revenues that would have been received at six different locations: Long Island, the Vernon/Greenwood load pocket in New York City, the 345kV portion of New York City, the Hudson Valley Zone, the Capital Zone, and the West Zone. We utilize the zone-level energy prices for the zonal locations and a representative generator bus for the Vernon/Greenwood load pocket in New York City. 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.[129] Combustion turbines settle with the ISO according to real-time market

129 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.

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[130]

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.

130 ** 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/ Discount
		Natural Gas	*Diesel/ ULSD*	*Residual Oil*	
West	Dominion North	0.27	2.00	1.50	10%
Capital	50% Iroquois Zn2, 50% Tennessee Zn6	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 CCs and 90 MW for ST units. The heat rate is 7,639 btu/kWh at the minimum output level for CCs, and 13,000 btu/kWh for ST units. The heat rate and capacity for a unit on a given day are assumed to vary linearly between the summer values on August 1 and the winter values on February 1. The summer and winter values are shown in the following two tables.

- Regional Greenhouse Gas Initiative ("RGGI") compliance costs are 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[131]

Characteristics	CC	LMS	Upstate Frame 7	Downstate Frame 7
Summer Capacity (MW)	303	185	206	211
Winter Capacity (MW)	326	200	226	225
Summer Heat Rate (Btu/kWh)	7203	9252	10823	10707
Winter Heat Rate (Btu/kWh)	7081	9083	10358	10254
Min Run Time (hrs)	4	1	1	1
Variable O&M ($/MWh)	1.1	5.4	1.7	0.5
Startup Cost ($)	9269	0	9341	9151
Startup Cost (MMBTU)	1688	430	450	450
EFORd	2.17%	2.17%	2.17%	2.17%

131 These parameters are based on technologies studied as part of the 2013 ICAP Demand Curve reset.

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%

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-17: Net Revenue for Generators in the West Zone

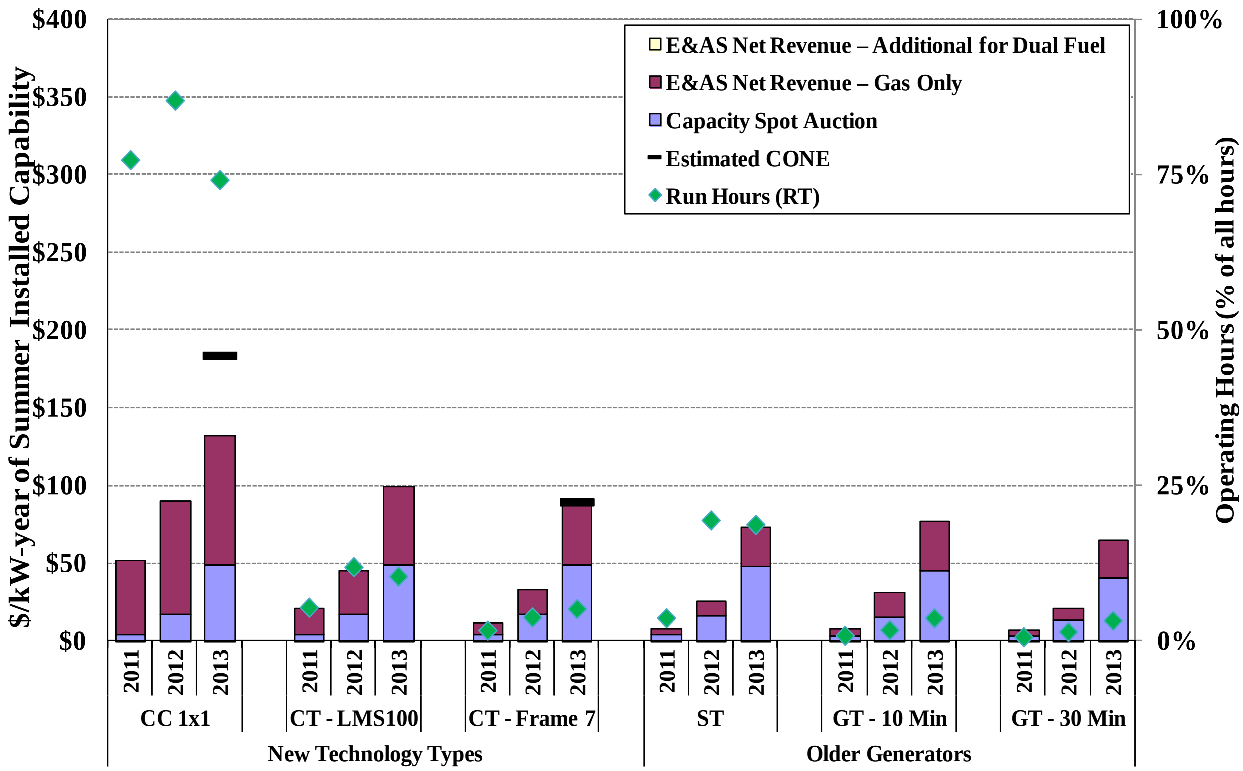


Figure A-18: Net Revenue Generators in the Capital Zone

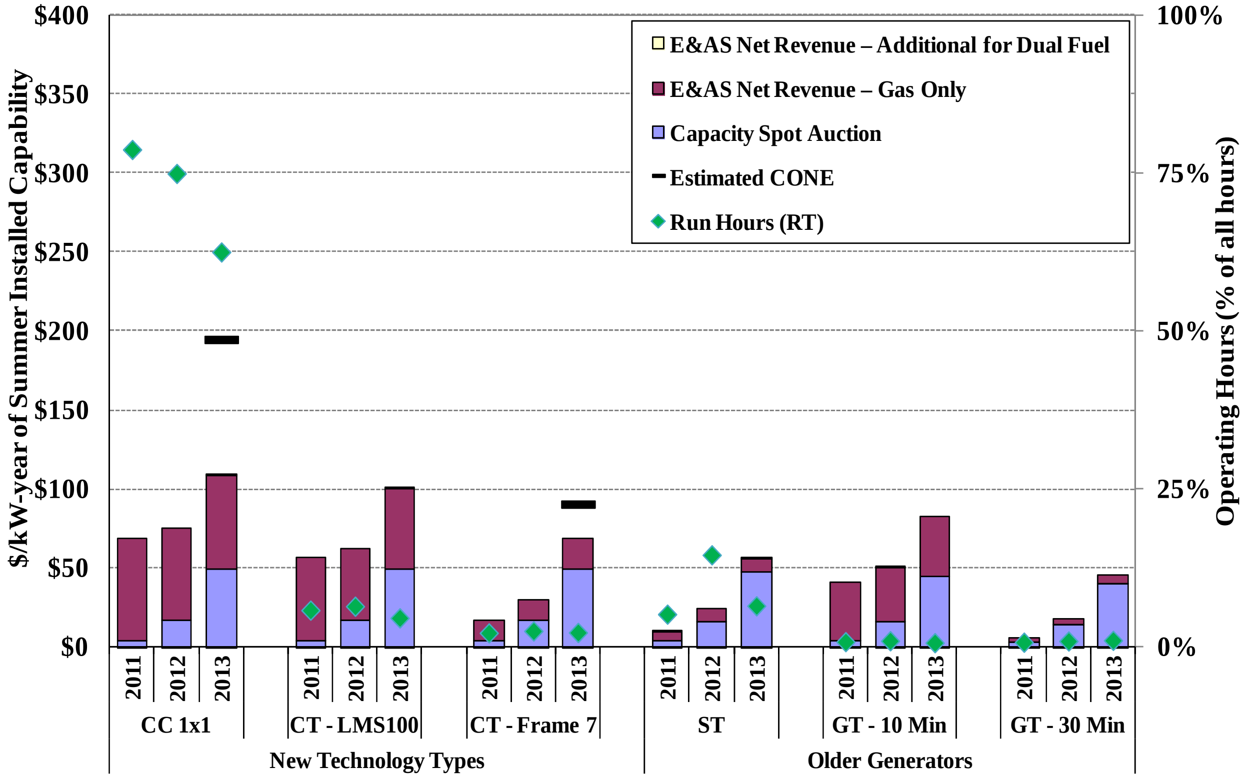


Figure A-19: Net Revenue for Generators in the Hudson Valley

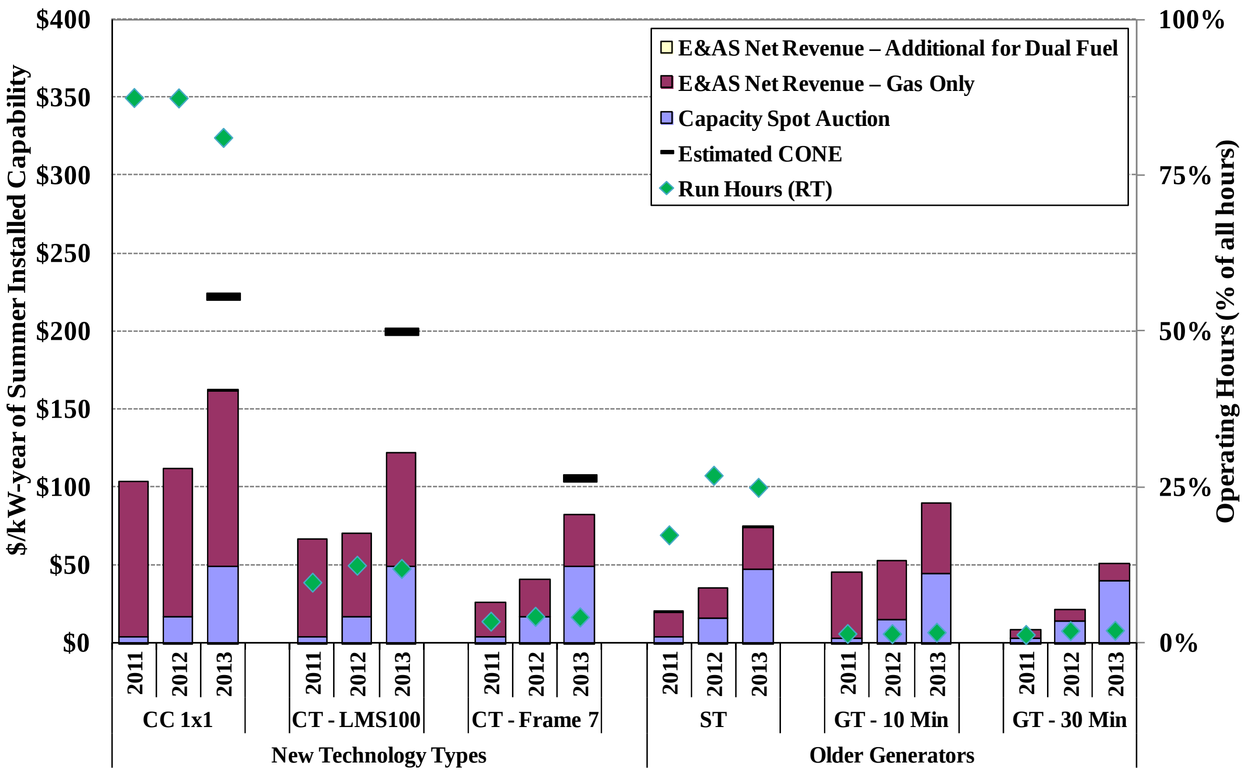


Figure A-20: Net Revenue for Generators in the NYC 345kV System

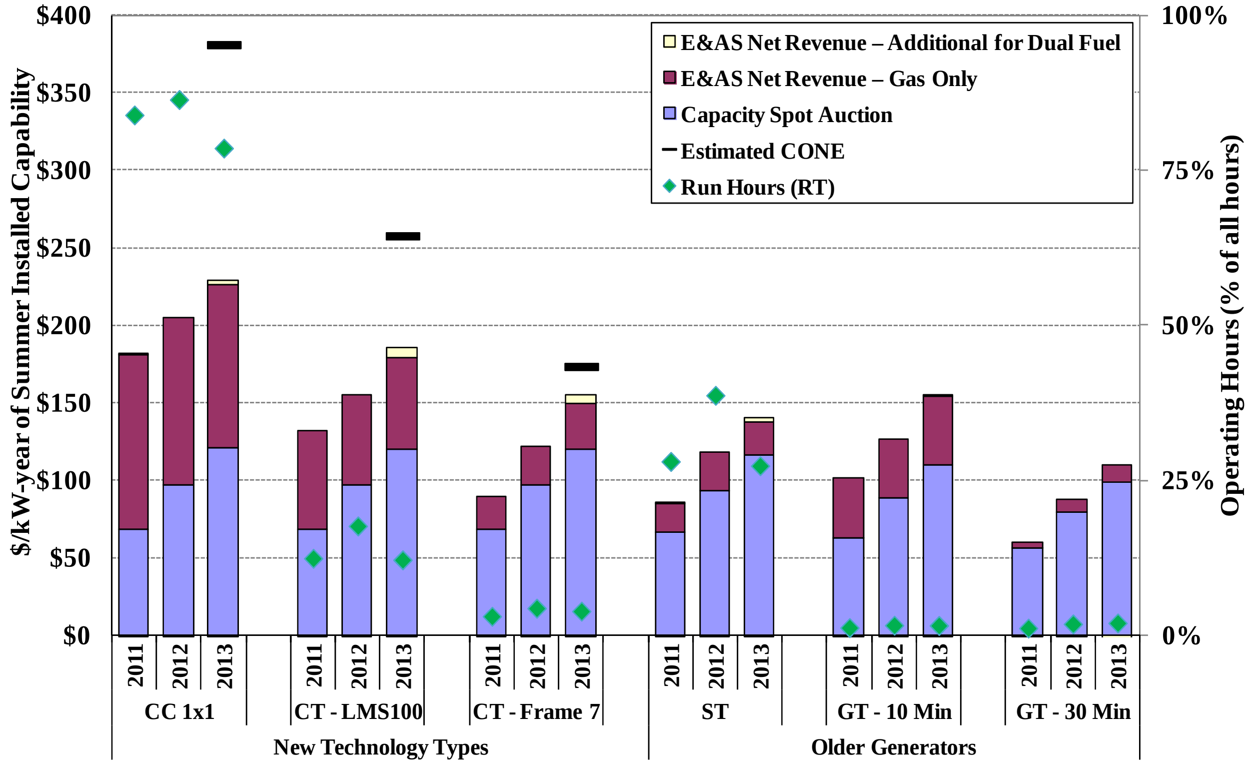
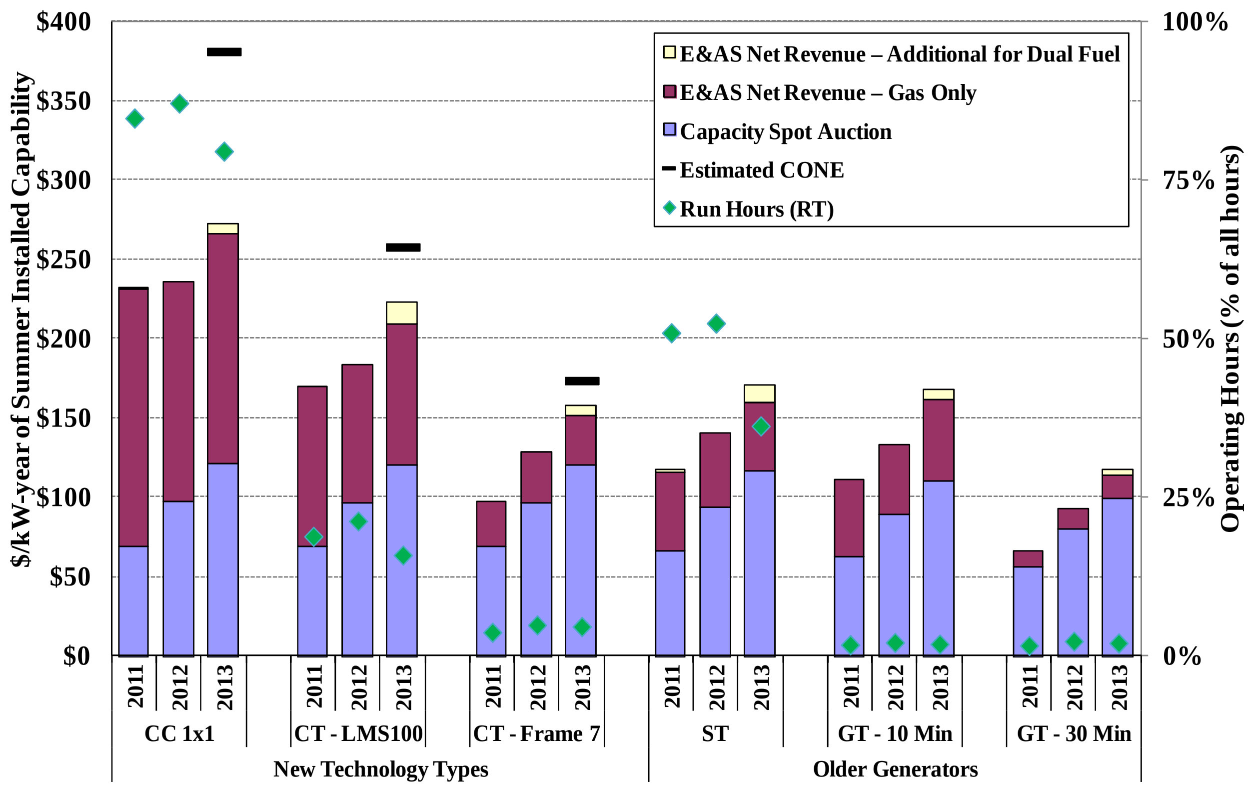
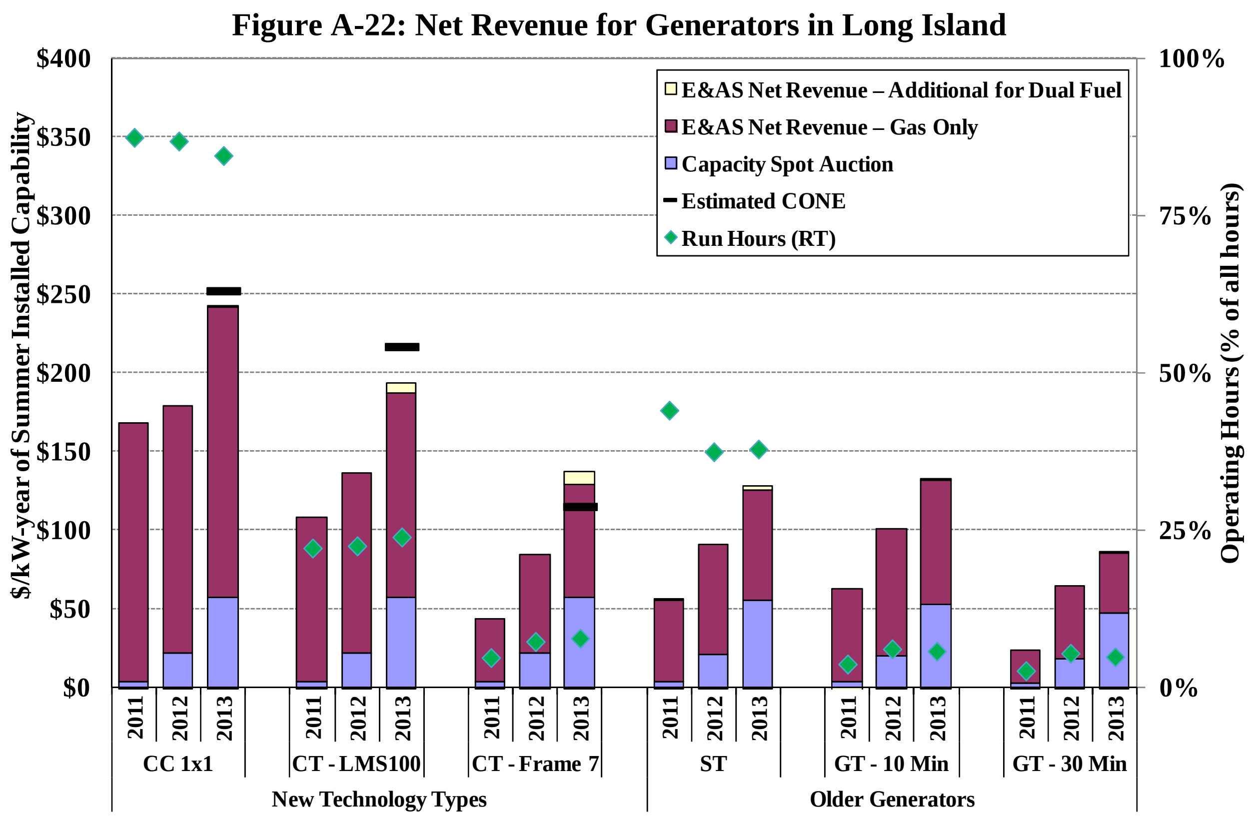


Figure A-21: Net Revenue for Generators in the Vernon/Greenwood Pocket





Key Observations: Net Revenue

- The figures show that both of the major components of net revenues (capacity as well as energy and ancillary services revenues) increased from 2012 to 2013 in all locations. These changes were mainly due to the following factors:

  - In Upstate New York, annual capacity net revenues were higher in 2013 than in any other year since the Capacity Spot Auction was implemented and were twice the ten-year average. The increase resulted from multiple retirements, lower capacity sales from demand response resources, and higher capacity requirement.
  - Long Island has cleared on the NYCA capacity demand curve in recent years, so Long Island experienced a capacity net revenue increase similar to Upstate New York.
  - In New York City, capacity net revenues rose in 2013 largely due to the increase in the LCR for Zone J. Capacity prices and the LCRs are discussed further in Section VI of the Appendix.
  - In most areas, energy net revenues rose in 2013 due to more frequent peak load conditions in the summer and the winter, which led to more frequent shortage pricing events. However, in the Capital Zone, energy net revenues fell because of rising natural gas prices (relative to LBMPs) in the zone.

- For new units, the estimated net revenues are lower than the cost of new entry ("CONE") in most areas. This is expected since entry would occur if net revenues were elevated for a significant period.
  - Consistent with the heat rate of each new technology, estimated net revenues were highest for a new CC unit, followed by an LMS unit, then followed by a Frame 7 unit in all areas. The annualized levelized capital costs exhibit a similar pattern with a new CC being highest and a new Frame 7 unit being lowest.
  - The estimated net revenues for a Frame 7 unit were higher than the estimated CONE in Long Island and in Vernon-Greenwood for 2013 only. So, a Frame 7 unit may not be as economic in the long term if net revenues do not continue to be as high as in 2013. One reason is that the demand curves for Long Island, New York City, and NYCA will be reduced in May 2014 to reflect that the Frame 7 unit has a lower net CONE than the previous demand curve unit.
- 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 provides the highest revenue.
- The results also indicate that the additional revenues brought about by dual fuel capability were de minimis in 2011 and 2012 because of low gas prices. In 2013, additional revenues for dual fuel units rose in New York City and Long Island because of more frequent hourly OFOs and natural gas price spikes. The additional revenues for dual fuel units were still modest compared to the other components of the net revenue. However, it is likely that the potential returns from dual-fuel capability were sufficient to make it economic for many such units to retain the capability and maintain modest inventories of oil.

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 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.

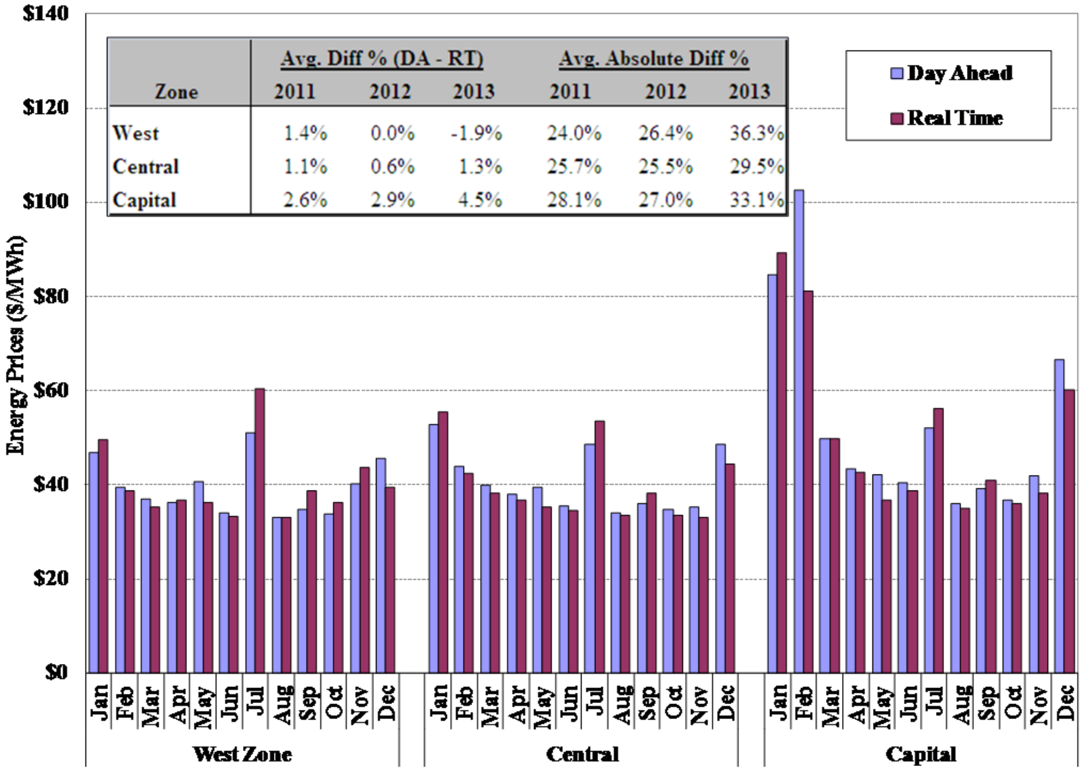
In this section, we evaluate two aspects of convergence in prices between day-ahead and real-time markets and look for evidence of persistent differences. First, we examine the consistency of average day-ahead energy prices with average real-time energy prices at the zone level. Second, we evaluate the consistency of average day-ahead and real-time energy prices at individual nodes throughout the state.

Figure A-23 & Figure A-24: 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.

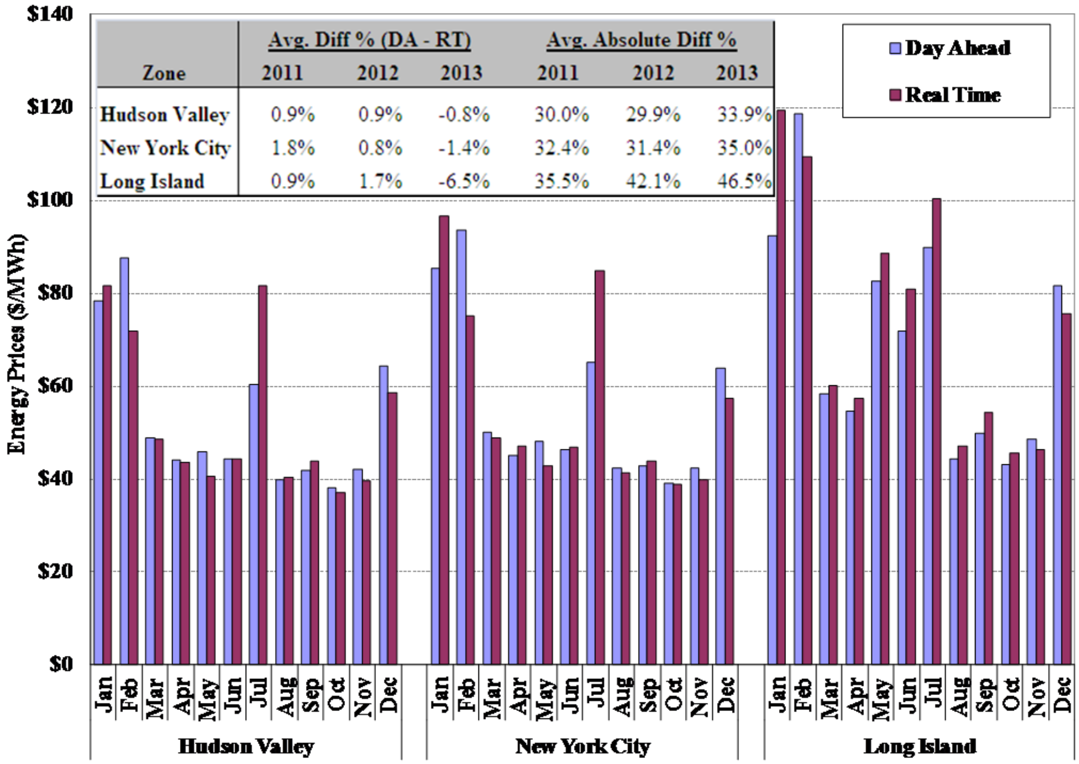
Figure A-23 and Figure A-24 compare day-ahead and real-time energy prices in West zone, Central zone, Capital zone, and Hudson Valley, New York City, and Long Island. The figures are intended to reveal whether there are persistent systematic differences between the load-weighted average day-ahead prices 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 2013. 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-23: Average Day-Ahead and Real-Time Energy Prices outside SENY
West, Central, and Capital Zones - 2013



Zone	Avg. Diff % (DA - RT) 2011	2012	2013	Avg. Absolute Diff % 2011	2012	2013
West	1.4%	0.0%	-1.9%	24.0%	26.4%	36.3%
Central	1.1%	0.6%	1.3%	25.7%	25.5%	29.5%
Capital	2.6%	2.9%	4.5%	28.1%	27.0%	33.1%

Figure A-24: Average Day-Ahead and Real-Time Energy Prices in SENY
Hudson Valley, New York City, and Long Island - 2013



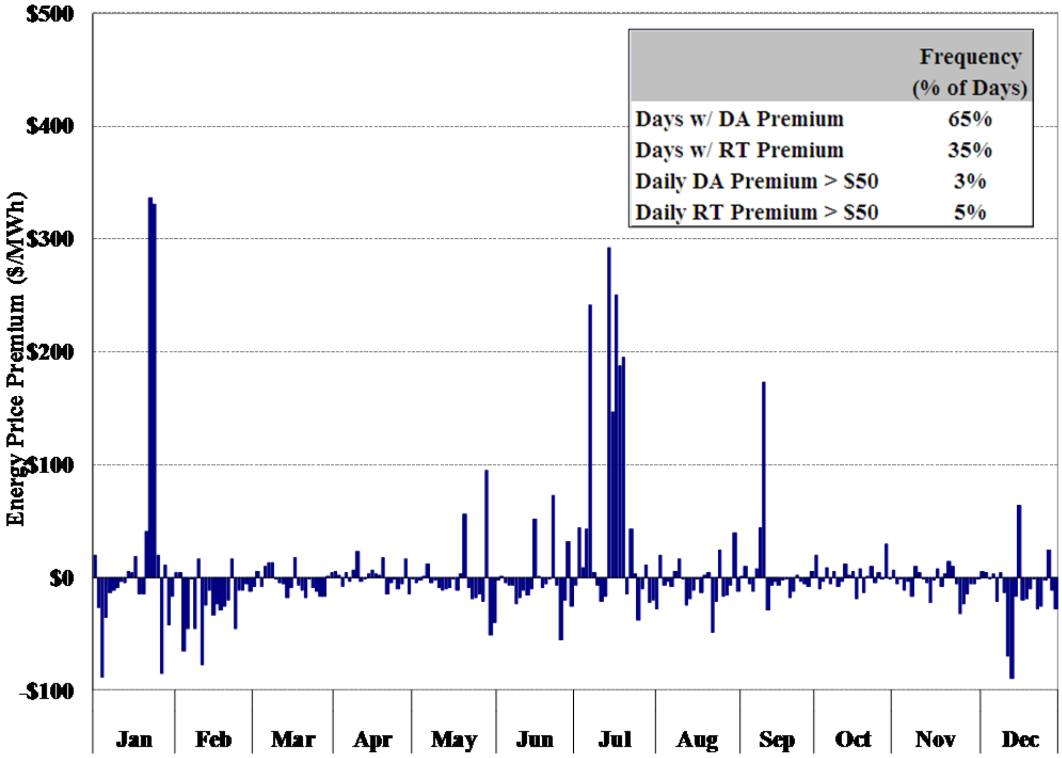
Zone	Avg. Diff % (DA - RT) 2011	2012	2013	Avg. Absolute Diff % 2011	2012	2013
Hudson Valley	0.9%	0.9%	-0.8%	30.0%	29.9%	33.9%
New York City	1.8%	0.8%	-1.4%	32.4%	31.4%	35.0%
Long Island	0.9%	1.7%	-6.5%	35.5%	42.1%	46.5%

Figure A-25 & Figure A-26: 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 2013. A positive number represents a real-time market price premium, while a negative number represents a day-ahead price premium.

Figure A-25: Average Daily Real-Time Price Premium in NYC
1 p.m. to 7 p.m. Weekdays, 2013



	Frequency (% of Days)
Days w/ DA Premium	65%
Days w/ RT Premium	35%
Daily DA Premium > $50	3%
Daily RT Premium > $50	5%

Figure A-26: Average Daily Real-Time Price Premium in Long Island
1 p.m. to 7 p.m. Weekdays, 2013

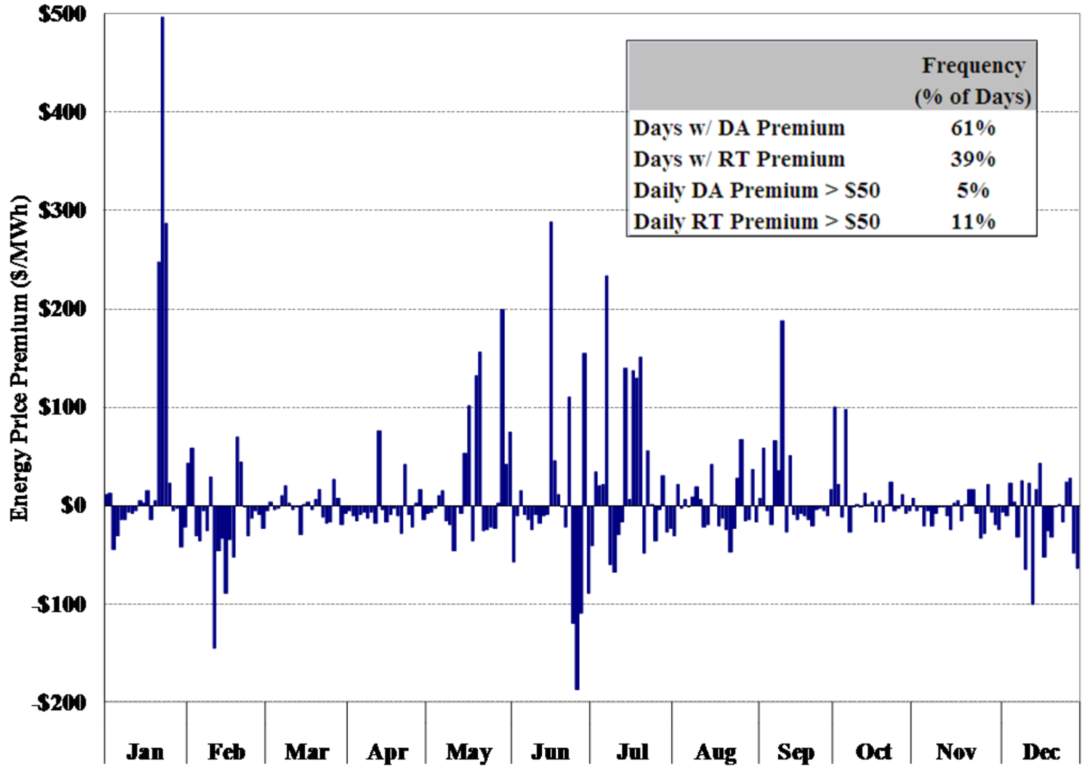


Figure A-27: Average Real-Time Price Premium at Select Nodes

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.

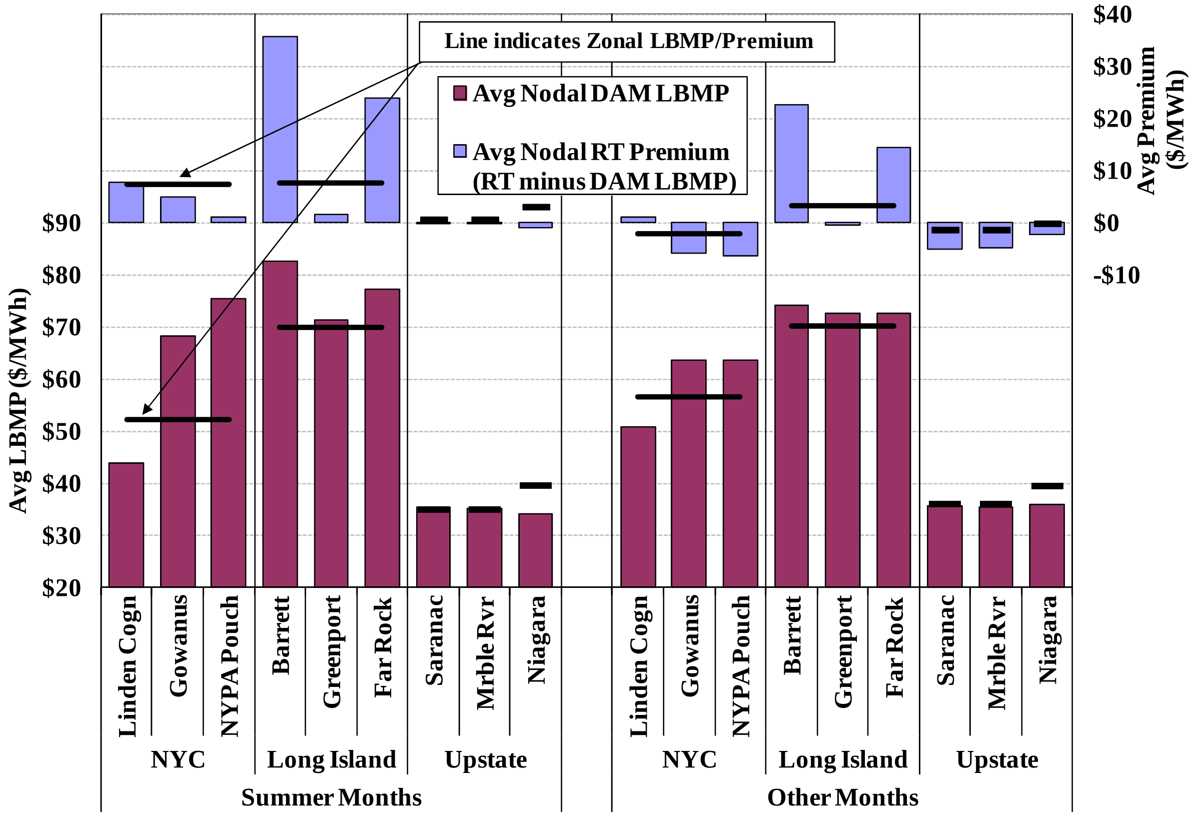
- Transmission forced outages, changes in the scheduled transmission maintenance, and differences in phase angle regulator settings can result in different congestion patterns.

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-27 shows average day-ahead prices and real-time price premiums in 2013 for selected locations in New York City, Long Island, and Upstate New York.[132] 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 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.

132 In New York City, Gowanus is the Gowanus GT 1 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, Marble River is the Marble River Wind Generator bus in the North Zone, Saranac is also in the North Zone, and Niagara is in the West Zone.

Figure A-27: Average Real-Time Price Premium at Select Nodes
2013



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

- Energy price convergence was slightly worse in most areas in 2013 than in 2012. Differences between day-ahead and real-time prices because real-time price volatility increased in 2013, particularly:
  - From July 15 to 19, when a heat wave led to the activation of demand response and the Scarcity Pricing rule; and
  - From January 19 to 27, when extreme cold weather led to high and volatile gas prices and frequent gas pipeline OFOs, which increased cost uncertainty for electric suppliers in the day-ahead market.
- Locations in Long Island exhibited the largest spreads between day-ahead and real-time energy prices among all areas.
  - The average spread rose to 46 percent in 2013, up notably from 36 percent in 2011 and 42 percent in 2012.
  - In addition to the reasons mentioned above, higher real-time volatility in Long Island was also attributable to:
    - Tight supply conditions that were driven by the reduction in imports on the Neptune line and the retirement of 330 MW of steam turbine generation; and

  - Inefficient utilization of some resources in the real-time market, which decreased the dispatch of lower-cost gas-fired generators and increased reliance on oil-fired generators..

- At the zonal level, average day-ahead energy prices were higher than average real-time prices by a small margin in most regions during most months of 2013.

  - However, most areas in Southeast New York exhibited a yearly real-time premium, which was due primarily to the high real-time premiums in January and July (for reasons discussed earlier).

- At the nodal level, a few locations exhibited less consistency between average day-ahead and real-time prices. Most notably:

  - In New York City, the NYPA Pouch location exhibited a day-ahead price premium of \$6.5 per MWh outside the summer months, compared to a day-ahead zonal price premium of only \$2 per MWh.
  - In Long Island, the Valley Stream load pocket (represented by the Barrett location) exhibited a real-time price premium of almost \$36 per MWh in the summer, compared to a day-ahead zonal price premium of \$7.5 per MWh.
  - In the Upstate, the Niagara location exhibited a day-ahead price premium of nearly \$1 per MWh in the summer, compared to a real-time zonal price premium of \$3 per MWh.
  - 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-28 – Figure A-33: 10-Minute Spinning and Non-Spinning Reserve Prices

Figure A-28 and Figure A-29 show 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. This particular requirement is typically the most costly reserve requirement for the ISO to satisfy due to the relative scarcity of capacity in Eastern New York. The market uses a "demand curve" that places an economic value of $500 per MW on satisfying this requirement.

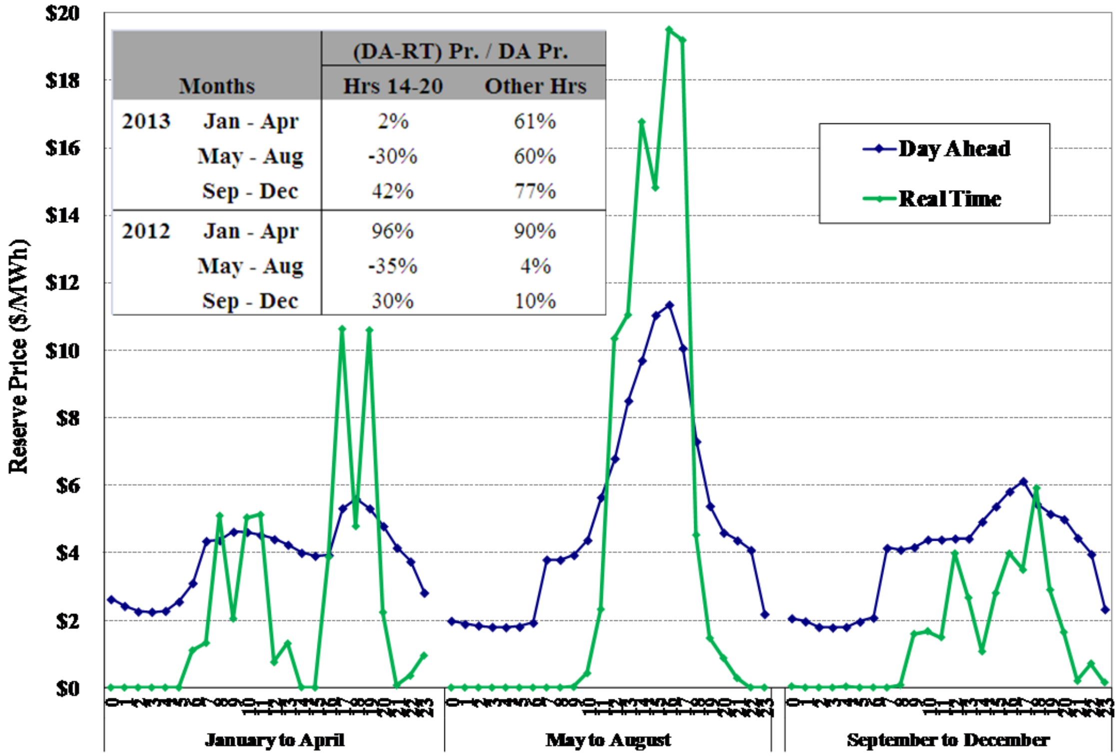
Figure A-30 and Figure A-31 show 10-minute spinning reserve prices in Western New York, which are primarily based on the requirement to hold 655 MW of 10-minute spinning reserves in New York State. Therefore, this represents the base price for spinning reserves in New York before locational premiums 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-32 and Figure A-33 show 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 Figure A-28, Figure A-30, and Figure A-32, average prices are shown by season and by hour of day in 2013. The inset tables compare average differences between day-ahead and real-time prices as a percent of average day-ahead prices during afternoon hours (i.e., hour 14 to 20) and other hours for 2012 and 2013.

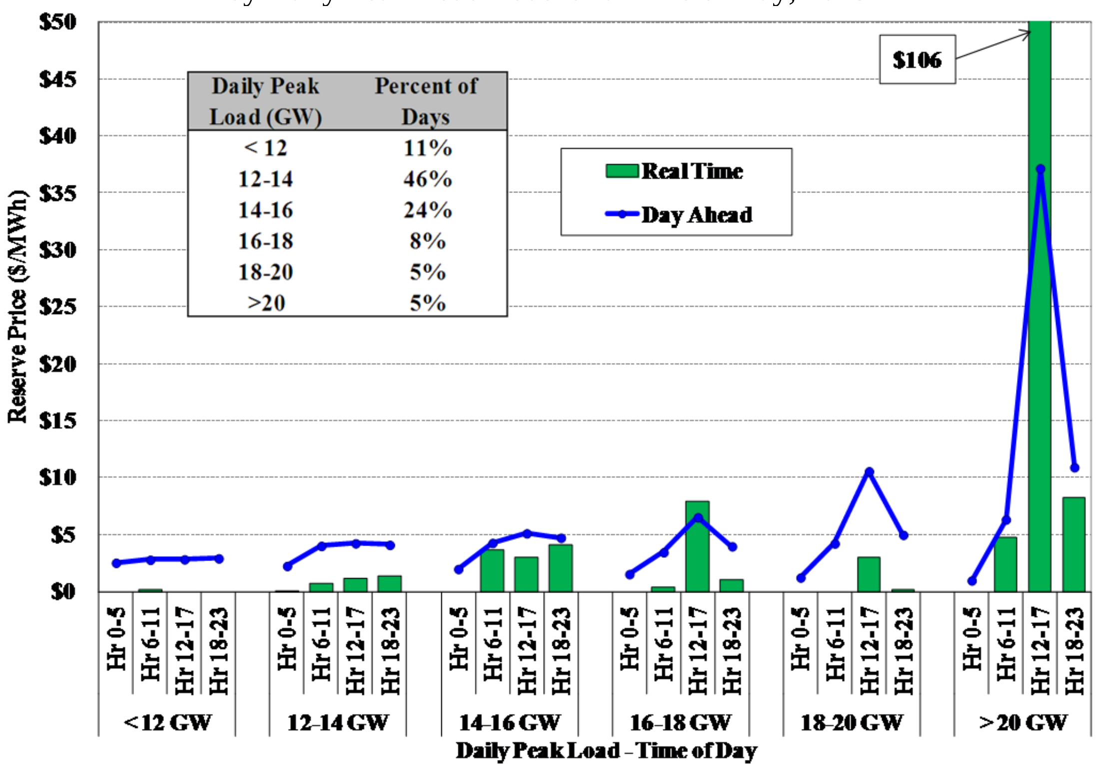
In Figure A-29, Figure A-31, and Figure A-33, average prices are shown based on daily peak load levels and different time of day in 2013. The inset tables show the percent of days in each load range in 2013.

Figure A-28: 10-Minute Non-Spinning Reserve Prices in East NY
by Season and Hour of Day, 2013



Months		(DA-RT) Pr. / DA Pr. Hrs 14-20	Other Hrs
2013	Jan - Apr	2%	61%
	May - Aug	-30%	60%
	Sep - Dec	42%	77%
2012	Jan - Apr	96%	90%
	May - Aug	-35%	4%
	Sep - Dec	30%	10%

Figure A-29: 10-Minute Non-Spinning Reserve Prices in East NY by Load
by Daily Peak Load Level and Time of Day, 2013



Daily Peak Load (GW)	Percent of Days
< 12	11%
12-14	46%
14-16	24%
16-18	8%
18-20	5%
>20	5%

Figure A-30: 10-Minute Spinning Reserve Prices in West NY
by Season and Hour of Day, 2013

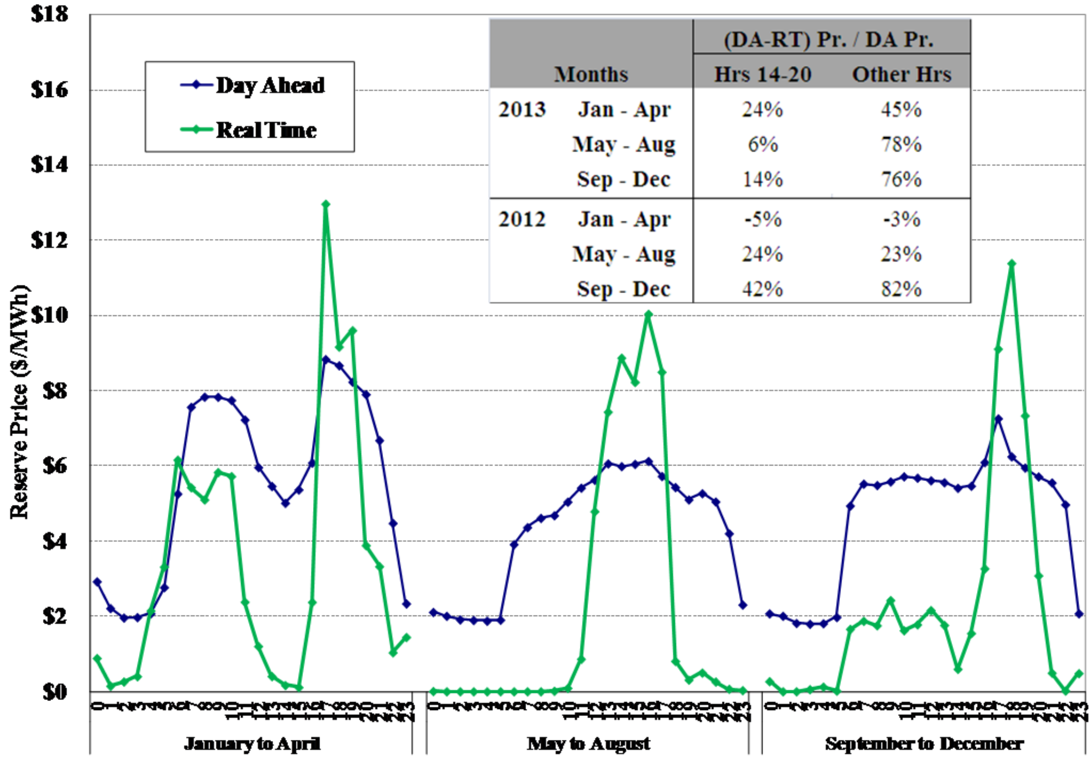


Figure A-31: 10-Minute Spinning Reserve Prices in West NY by Load
by Daily Peak Load Level and Time of Day, 2013

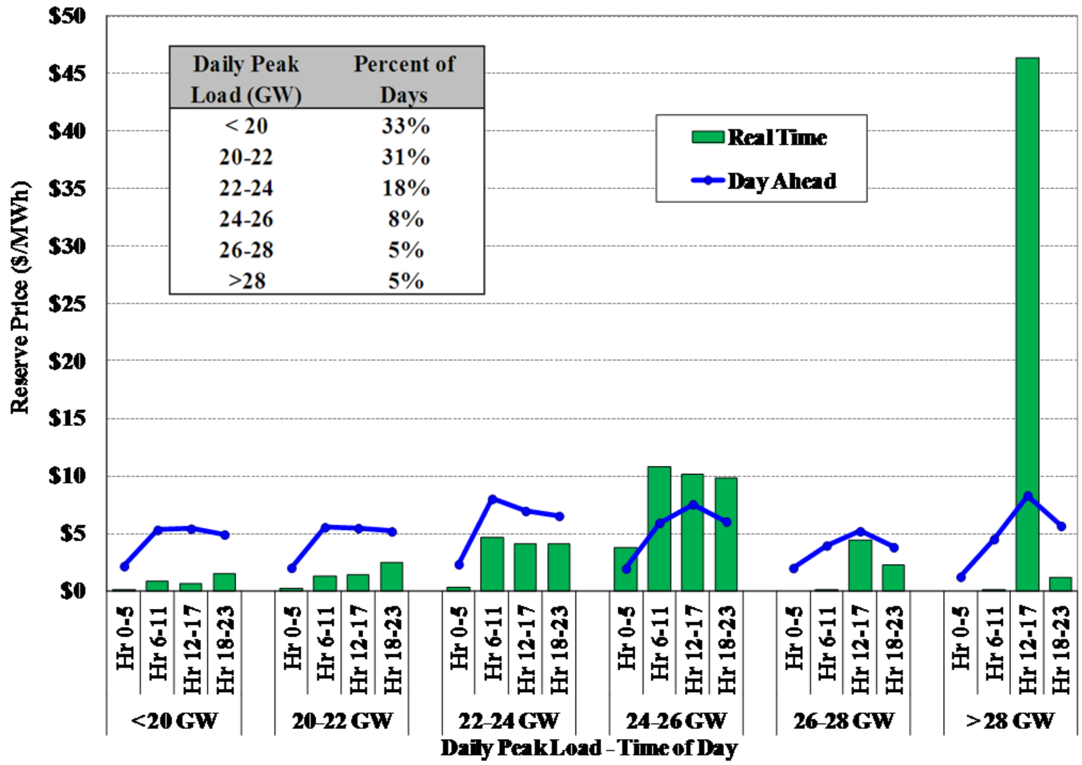


Figure A-32: 10-Minute Spinning Reserve Prices in East NY
by Season and Hour of Day, 2013

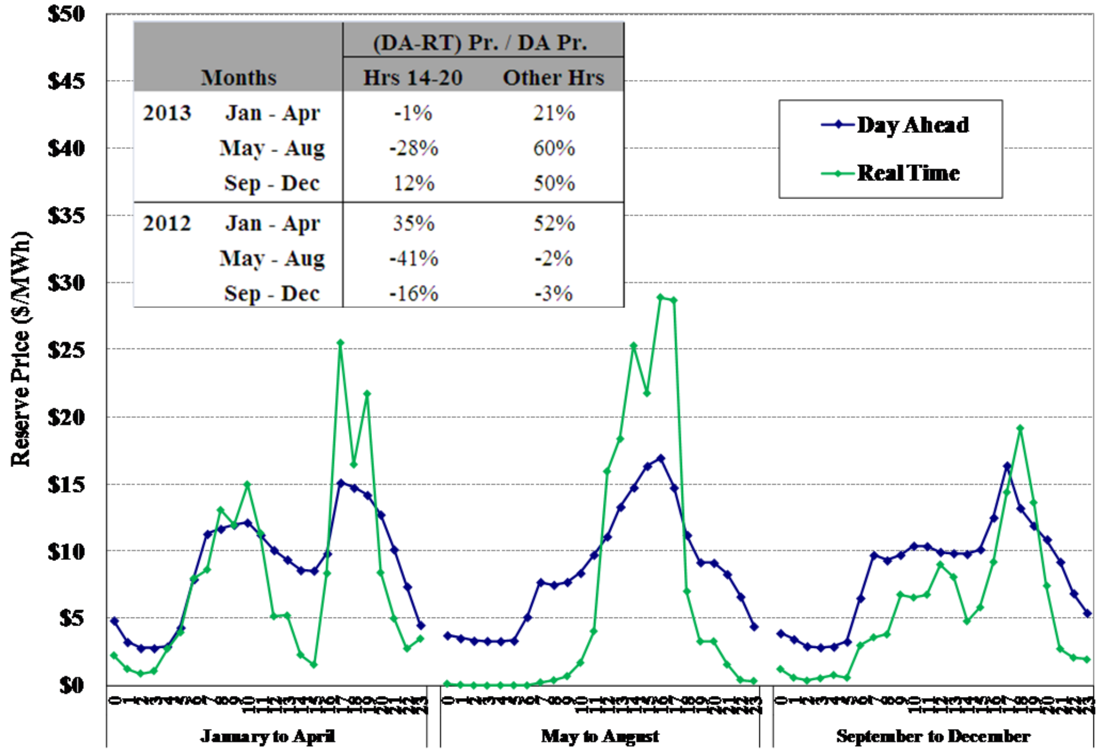
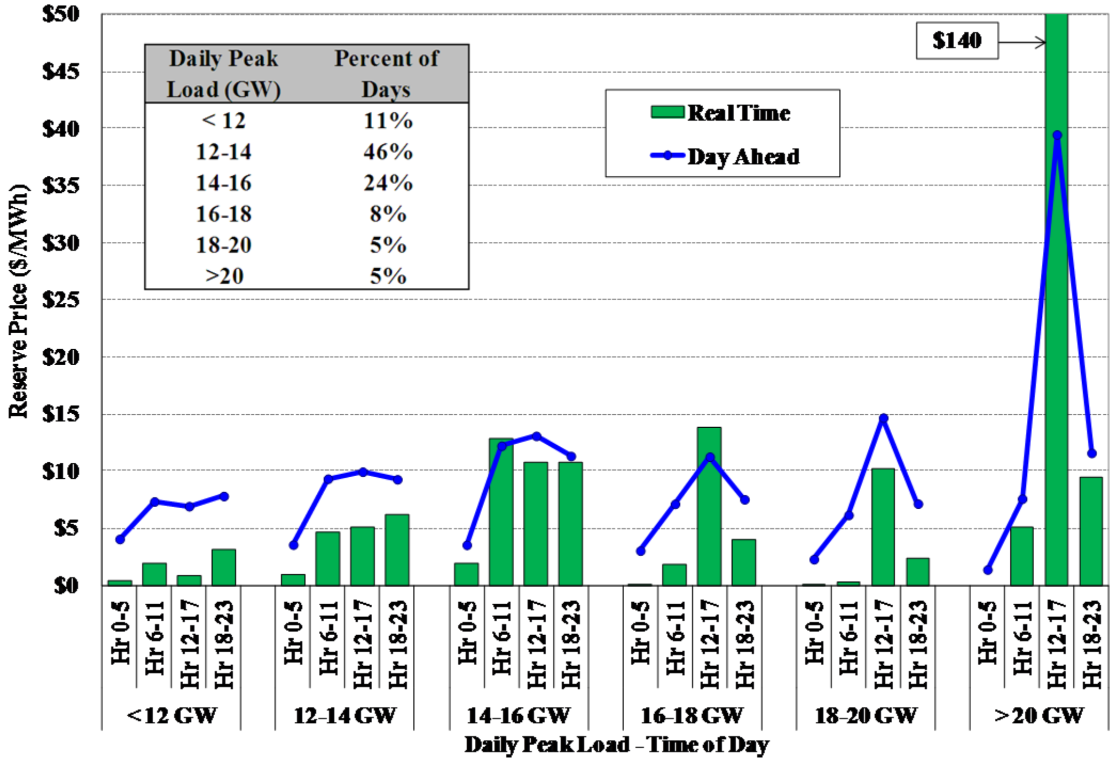


Figure A-33: 10-Minute Spinning Reserve Prices in East NY by Load
by Daily Peak Load Level and Time of Day, 2013



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

- Reserve price convergence generally improved during afternoon peak hours from 2012 to 2013.
- This improvement was partly due to revision of two day-ahead market reserve mitigation provisions during 2013.
  - On January 23, 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, the second phase of the revision raised both caps to $10 per MW. .
  - These changes facilitated better price convergence, despite higher and more volatile natural gas prices.

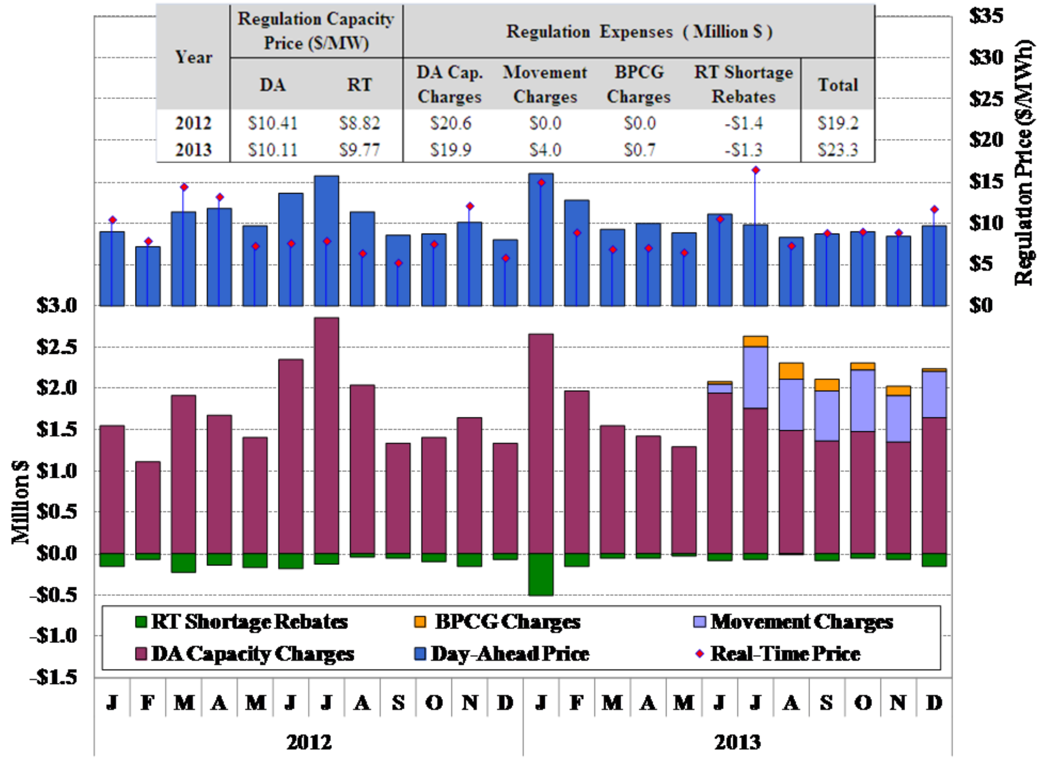
J. Regulation Market Performance

Figure A-34 – Regulation Prices and Expenses

Figure A-34 shows the regulation prices and expenses in each month of 2012 and 2013. 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-34: Regulation Prices and Expenses
by Month, 2013



Year	Regulation Capacity Price ($/MW)		Regulation Expenses (Million $)				
	DA	RT	DA Cap. Charges	Movement Charges	BPCG Charges	RT Shortage Rebates	Total
2012	$10.41	$8.82	$20.6	$0.0	$0.0	-$1.4	$19.2
2013	$10.11	$9.77	$19.9	$4.0	$0.7	-$1.3	$23.3

Key Observations: Regulation Market Performance

- Overall, the new regulation market performed in line with expectations in the first six months following its implementation.
- Price convergence between the day-ahead and real-time regulation markets improved in 2013 from 2012.
  - Day-ahead regulation capacity prices were more consistent with real-time capacity prices following the implementation of the new regulation market in June 2013.
- Regulation costs totaled $23 million in 2013, up 21 percent from 2012, reflecting: (a) higher natural gas prices; and (b) separate regulation movement charges and additional BPCG payments under the new market design.
  - The new charges for regulation movement and BPCG uplift were a combined 34 percent of the total regulation costs (based on July to December 2013).

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.*

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.

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-35 & Figure A-36: Generator Deratings by Month

Figure A-35 and Figure A-36 show the broad patterns in outages and deratings in New York State and Eastern New York in each month of 2012 and 2013.

Figure A-35: Deratings by Month in NYCA

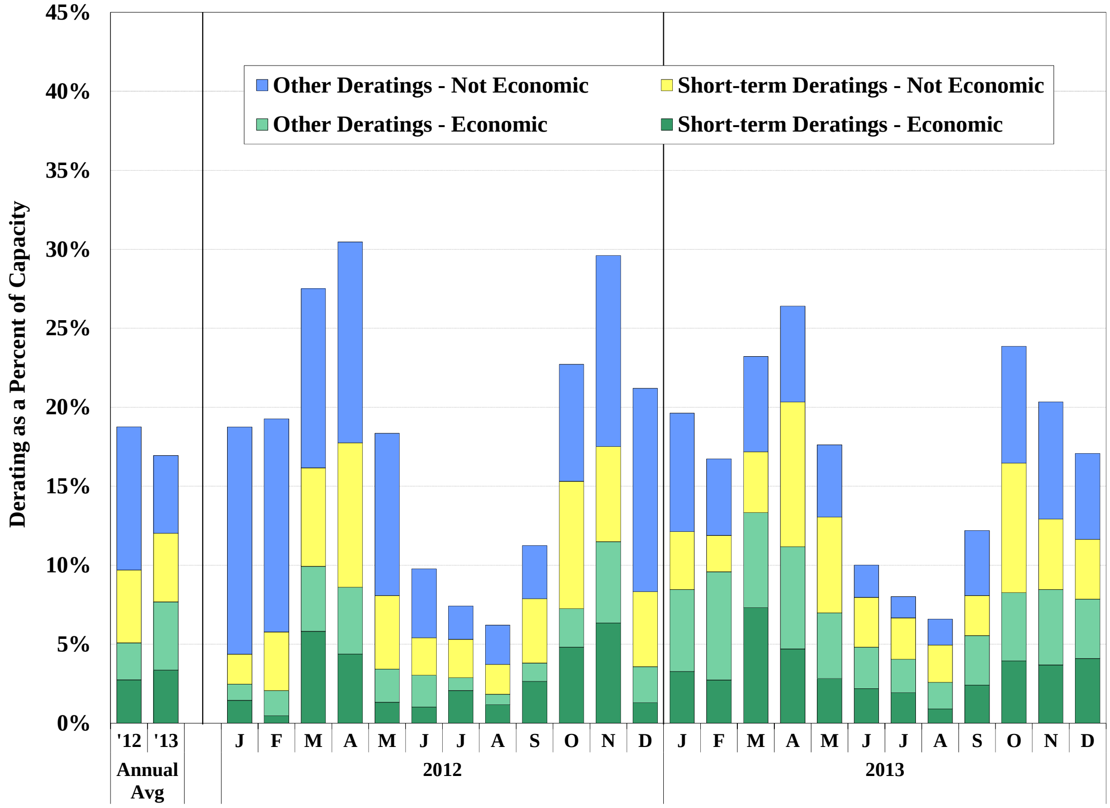


Figure A-36: Deratings by Month in East New York

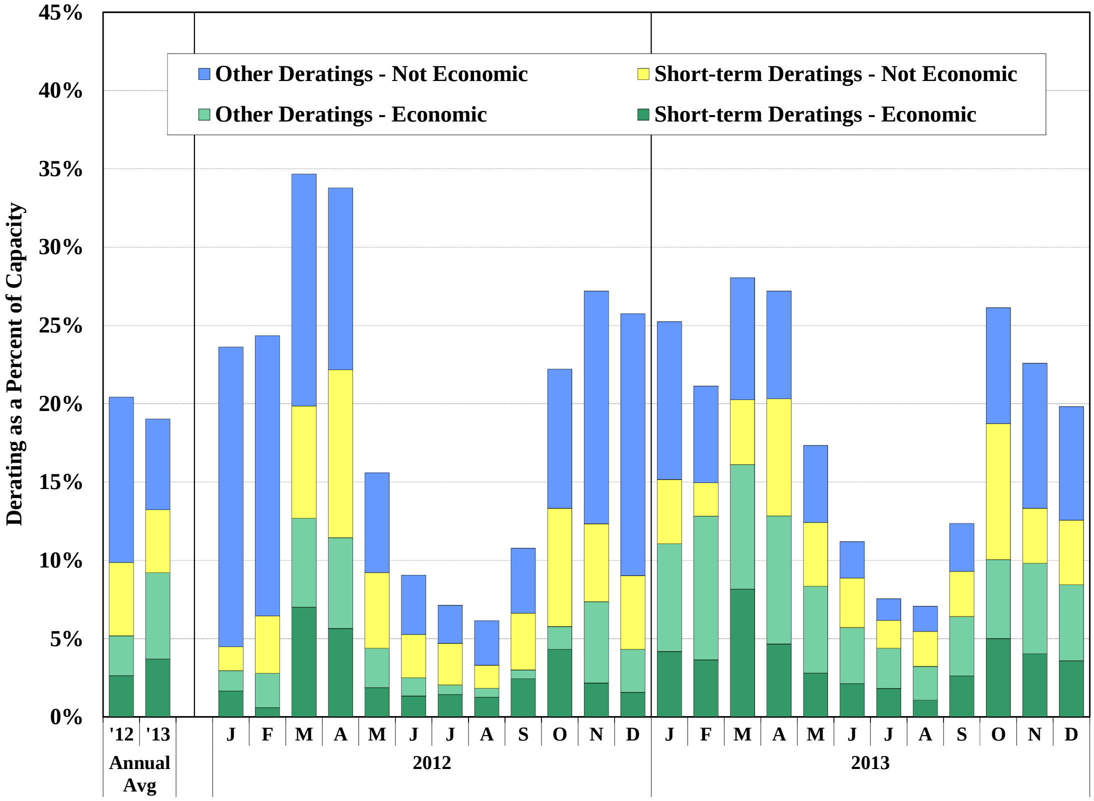


Figure A-37 & Figure A-38: Generator Deratings by Load Level and Portfolio Size

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-37 and Figure A-38 to determine whether the conduct is consistent with workable competition.

Figure A-37: Deratings by Supplier by Load Level in New York

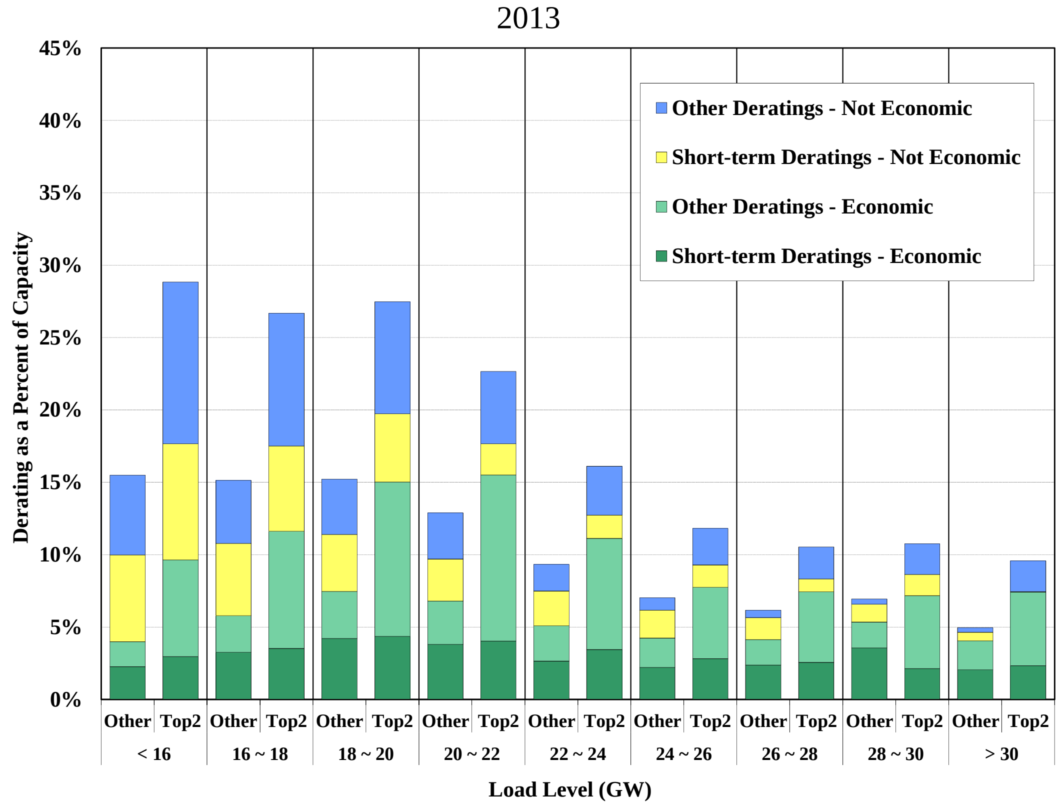
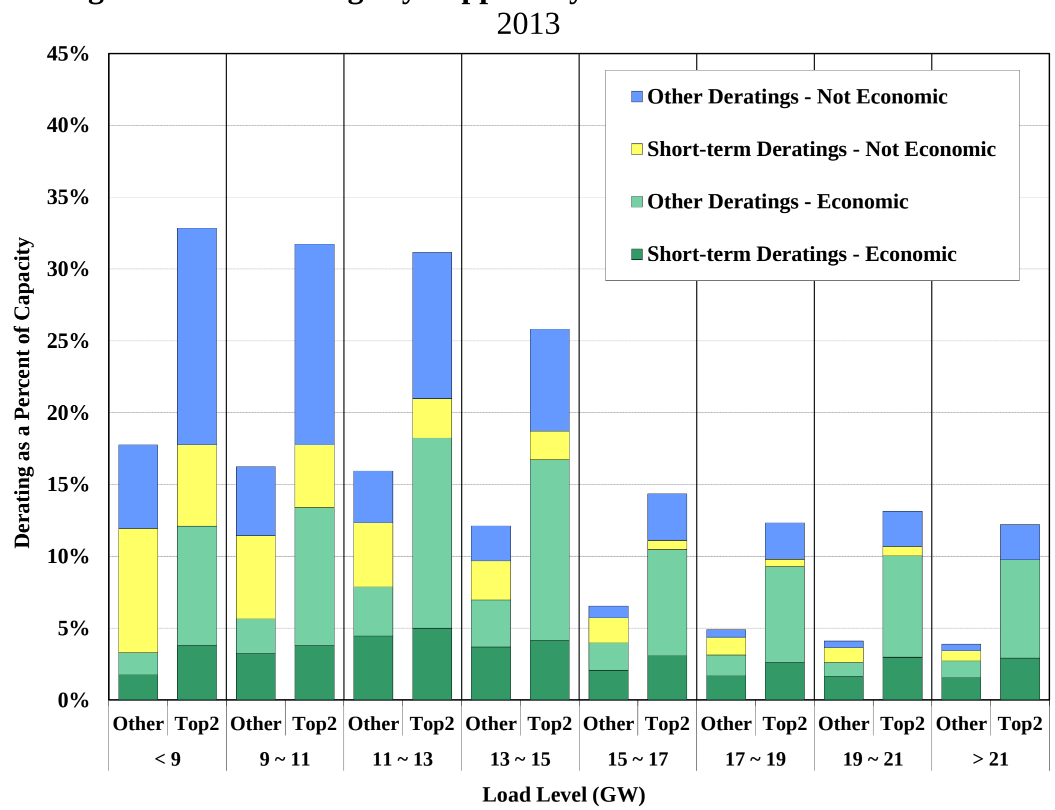


Figure A-38: Deratings by Supplier by Load Level in East New York



Key Observations: Generator Deratings

- The general pattern of deratings in 2013was consistent with expectations in a competitive market.
  - In NYCA, average deratings were the lowest during the summer months when average load was the highest. Total deratings were 7 to 10 percent of total DMNC during the summer months, and economic deratings constituted 3 to 5 percent of DMNC during the summer months. Average total deratings were highest during the low-load shoulder months. High levels of deratings outside the summer generally reflect planned outages for maintenance.
  - Long-term deratings fell modestly from 2012 to 2013 because of mothballing and retirement of several units over the period (out-of-service units are excluded from the figures).
  - However, the portion of capacity that was both derated and economic rose considerably in Eastern New York from 5 percent in 2012 to 9 percent in 2013. This increase was attributable to an increase in deratings of economic capacity by one of the two largest suppliers.
- The largest suppliers exhibited much higher levels of deratings of economic capacity than other suppliers, particularly in Eastern New York. In Eastern New York:
  - During high load levels (i.e., load > 17 GW), 10 percent of the capacity of the largest two suppliers was economic and derated compared to just 4 percent for all other suppliers; and
  - During low to moderate load levels (i.e., < 17 GW), 14 percent of the capacity of the largest two suppliers was economic and derated compared to just 7 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.
  - These inconsistencies are not explained by differences in the characteristics of installed capacity for the two largest suppliers (compared to other suppliers), so they raise significant concerns about the efficiency of long-term outage scheduling of some capacity. Although the NYISO can require a supplier to re-schedule a planned outage for reliability reasons, 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.

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.[133,134] An offer parameter is generally above the competitive level if it exceeds the reference level by a given threshold.

Figure A-39 and Figure A-40: 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.[135] 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 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.

133 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.

134 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.

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

Figure A-39: Output Gap by Month in New York State

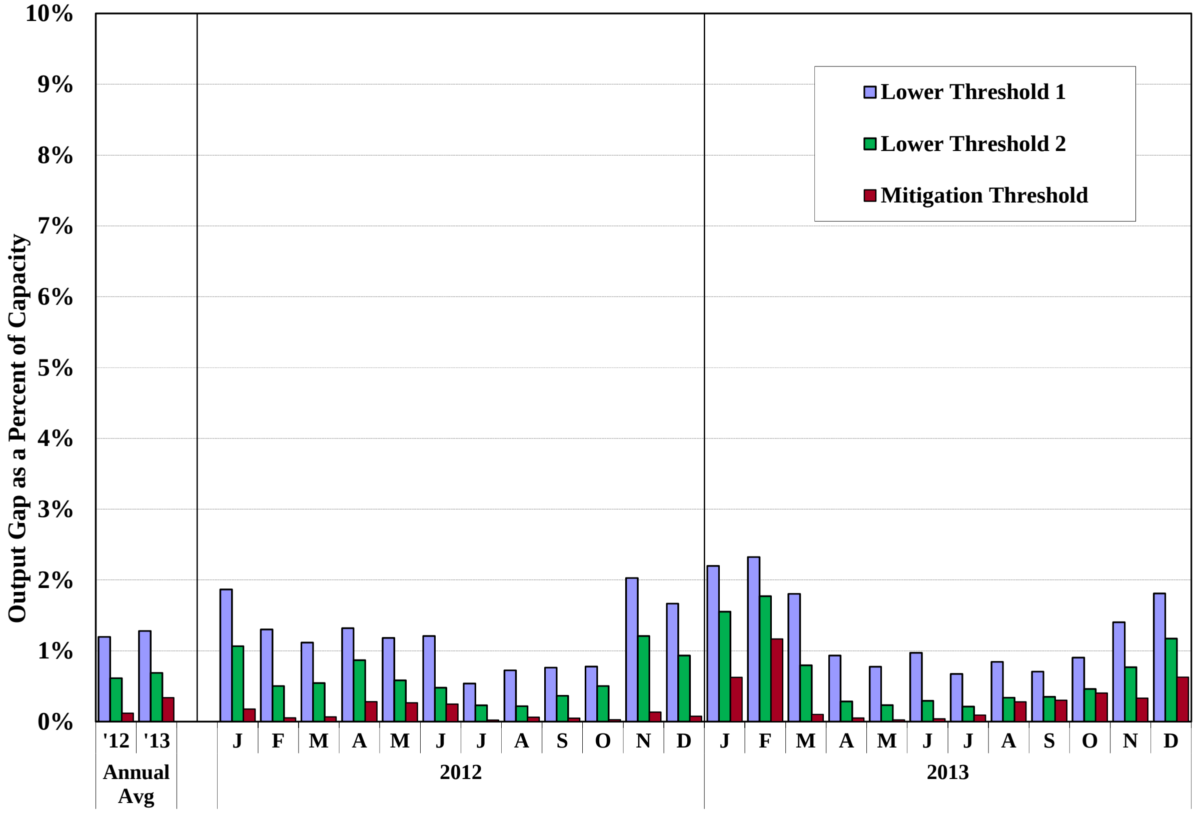


Figure A-40: Output Gap by Month in East New York

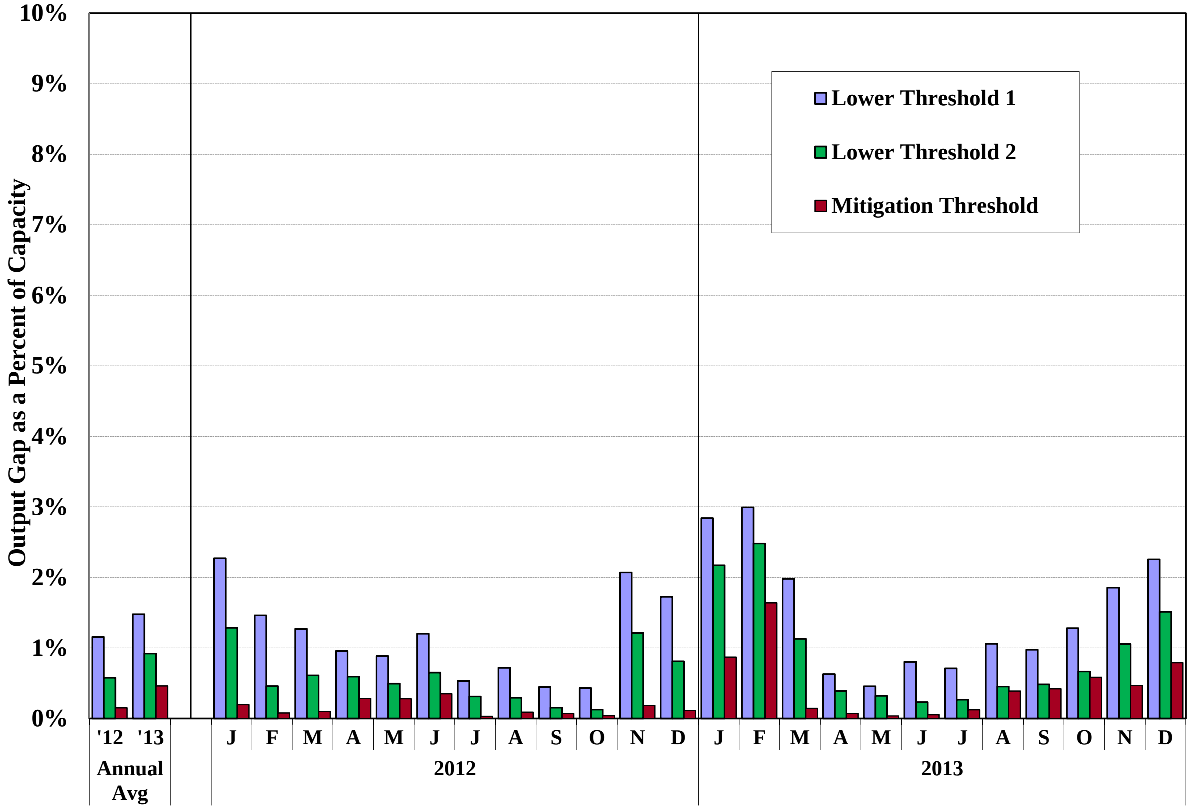


Figure A-41 & Figure A-42: Output Gap by Supplier and Load Level

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-41: Output Gap by Supplier by Load Level in New York State
2013

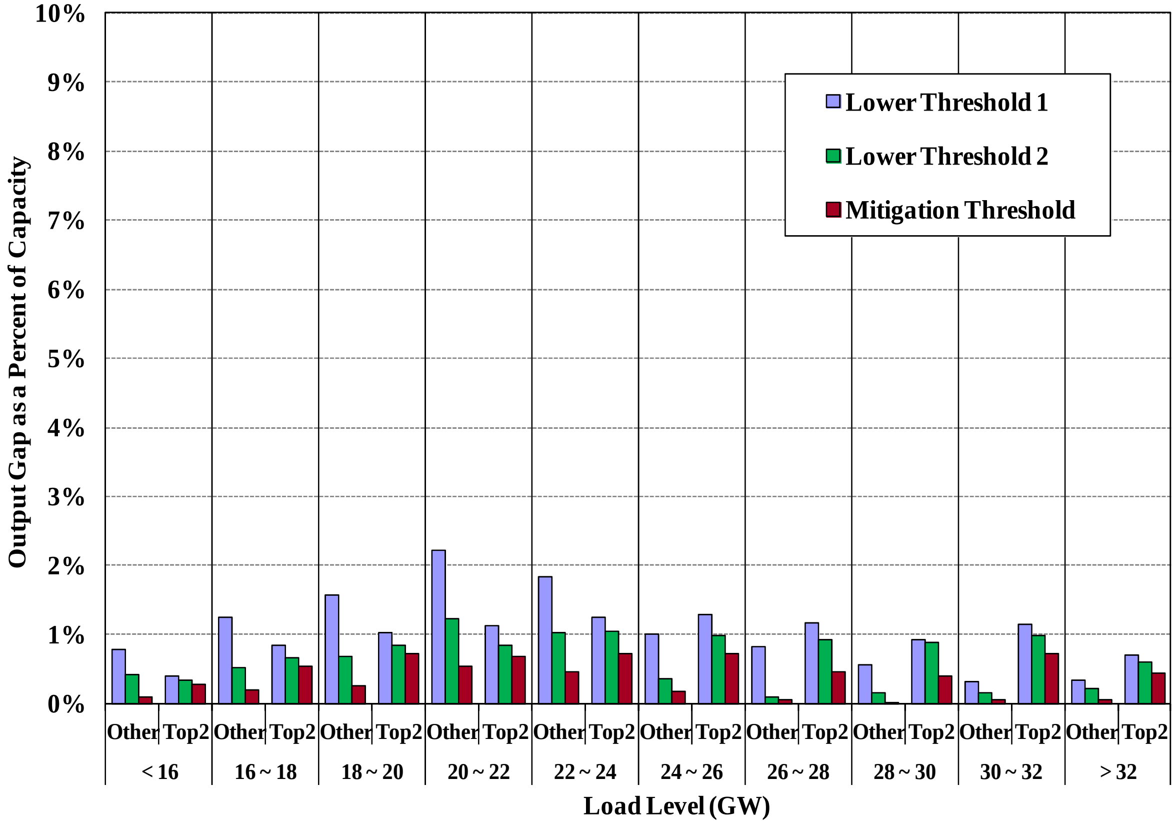
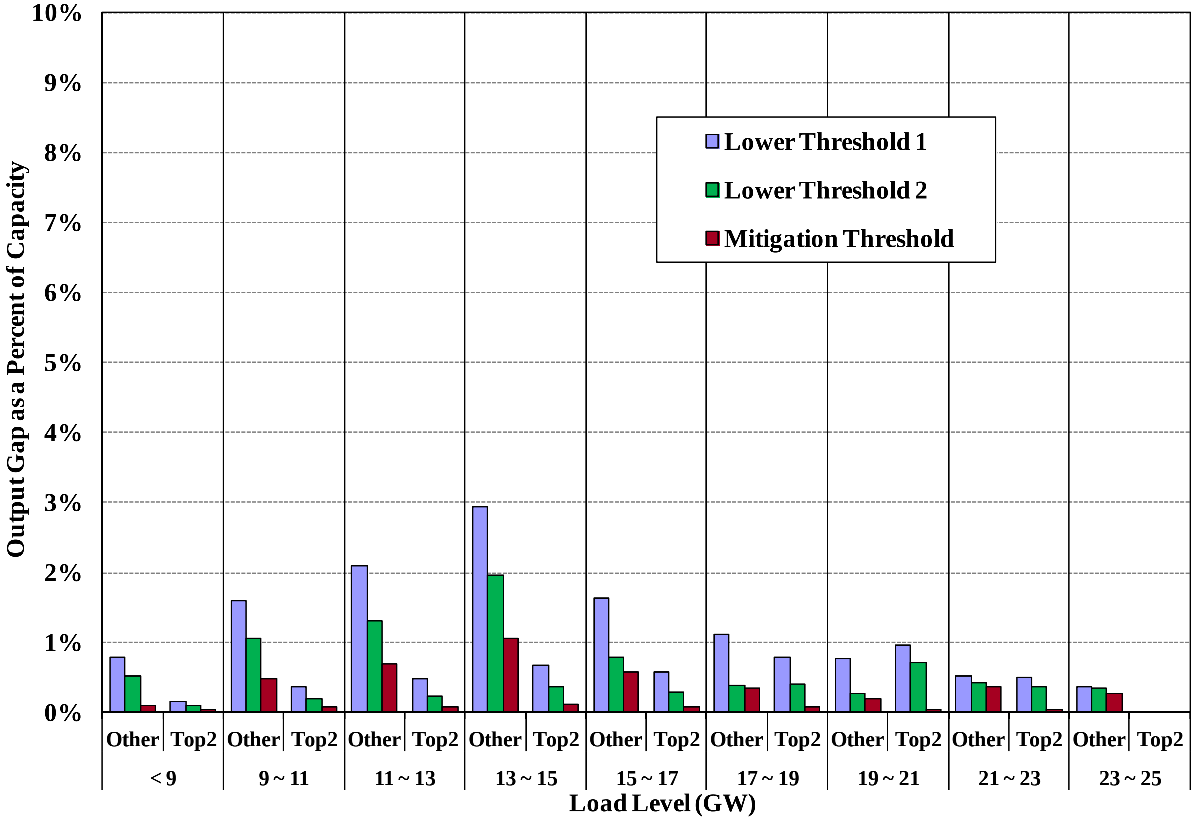


Figure A-42: Output Gap by Supplier by Load Level in East New York
2013



Key Observations: Economic Withholding – Generator Output Gap

- The overall pattern of output gap in 2013was consistent with expectations in a competitive market and did not raise significant concerns regarding potential economic withholding.
  - The average output gap was low as a percentage of total capacity. At the mitigation threshold, the output gap averaged just under 0.5 percent in Eastern New York.
  - At the lowest threshold evaluated (i.e., $25 per MWh or 50 percent), the output gap averaged under 1.5 percent.
- In general, it is a positive indicator that the output gap generally declines as load increases for most suppliers and is especially low under high load conditions when the market is most vulnerable to the exercise of market power. However, the output gap for the largest two suppliers rose modestly with load in Eastern New York.
  - In this case, the pattern of increased output gap was driven primarily by the IR-5 reliability rule, which requires some units to burn a blend of oil and natural gas under higher load conditions.[136]

136 Generators that participate in the Minimum Oil Burn Compensation program for Local Reliability Rules

- Although the amount of output gap shown is relatively small, there were instances when the NYISO invoked the market power mitigation measures for generators that had output gap in 2013.

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 the market 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.[137] This framework prevents mitigation when it is not necessary to address market power, while allowing high prices during legitimate periods of shortage.

The day-ahead and real-time market software is automated to perform the conduct and impact tests and implement the mitigation. The mitigation measures are designed to allow prices to rise efficiently to reflect legitimate supply shortages while effectively mitigating inflated prices associated with artificial shortages that result from economic withholding in transmission-constrained areas.

When a transmission constraint is binding, one or more suppliers may be in the position to exercise market power due to the lack of competitive alternatives in the constrained area. For this reason, more restrictive conduct and impact thresholds are used for import-constrained load pockets in New York City. The in-city load pocket conduct and impact thresholds are determined by a formula that is based on the number of congested hours experienced over the preceding twelve-month period.[138] 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 necessitates 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

IR-3 and IR-5 offer based on the cost of natural gas and receive compensation for the difference between the cost of oil and the cost of natural gas, but generators that do not participate in the program can be expected to offer at the full cost of the blend of oil and natural gas.

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

138 Threshold = (0.02 * Average Price * 8760) / Constrained Hours. This threshold is defined in the NYISO Market Services Tariff, Section 23.3.1.2.2.1.

reliability criteria outside New York City.[139] 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.[140]

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.[141] 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.[142]
- The generator took appropriate steps to inform the NYISO of a fuel price change prior to being scheduled (either through IBRT or some other means), but the generator was still mitigated.
- A generator's fuel cost may change significantly by time of day, although the day-ahead market software is unable to use reference levels that vary by time of day, so such a generator may be mitigated in a particular hour of the day-ahead market and then unmitigated once the proper reference level is reflected.

Figure A-43 & Figure A-44: Summary of Day-Ahead and Real-Time Mitigation

Figure A-43 and Figure A-44 summarize the amount of mitigation in New York that occurred in the day-ahead and the real-time markets in 2012 and 2013. 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).[143] In each figure, the left portion shows the amount of mitigation by the Automated

139 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.

140 See NYISO Market Services Tariff, Section 23.3.1.2.3.

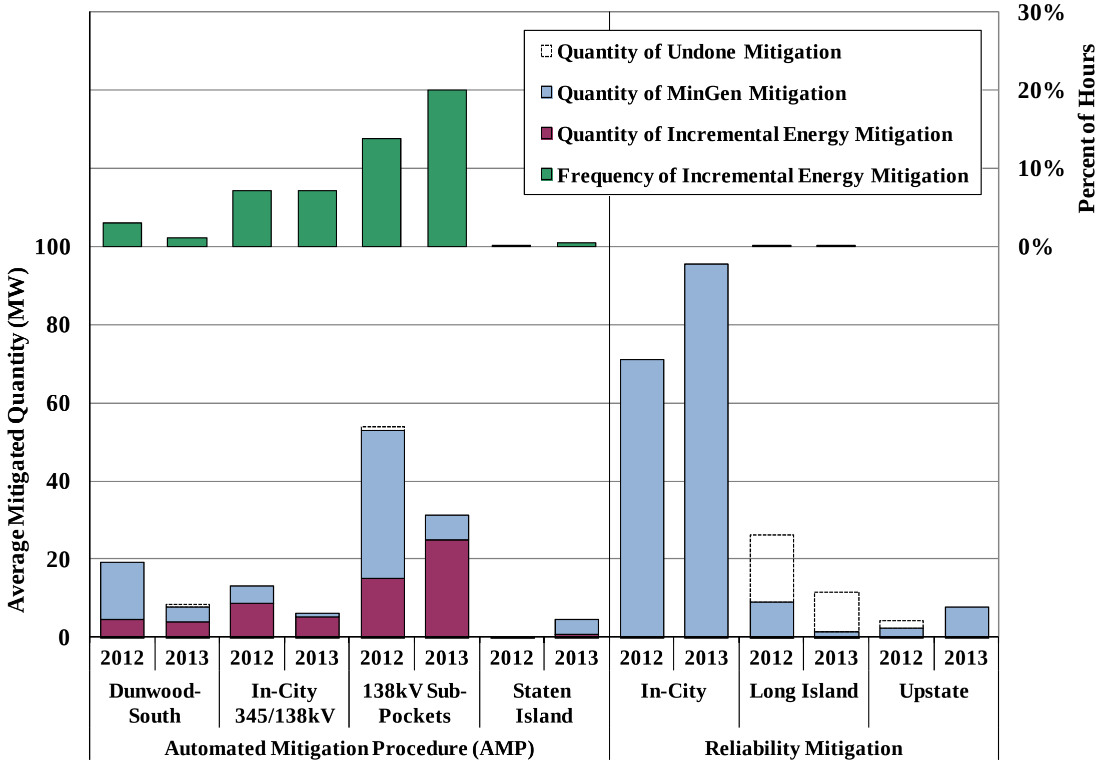
141 NYISO Market Services Tariff, Section 23.3.3 lays out the requirements for consultation. This occurs after the market date, so any effect of the mitigation on LBMPs is unchanged by unmitigation.

142 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.

143 Mitigation of gas turbine capacity is shown in the Incremental Energy category whenever the incremental

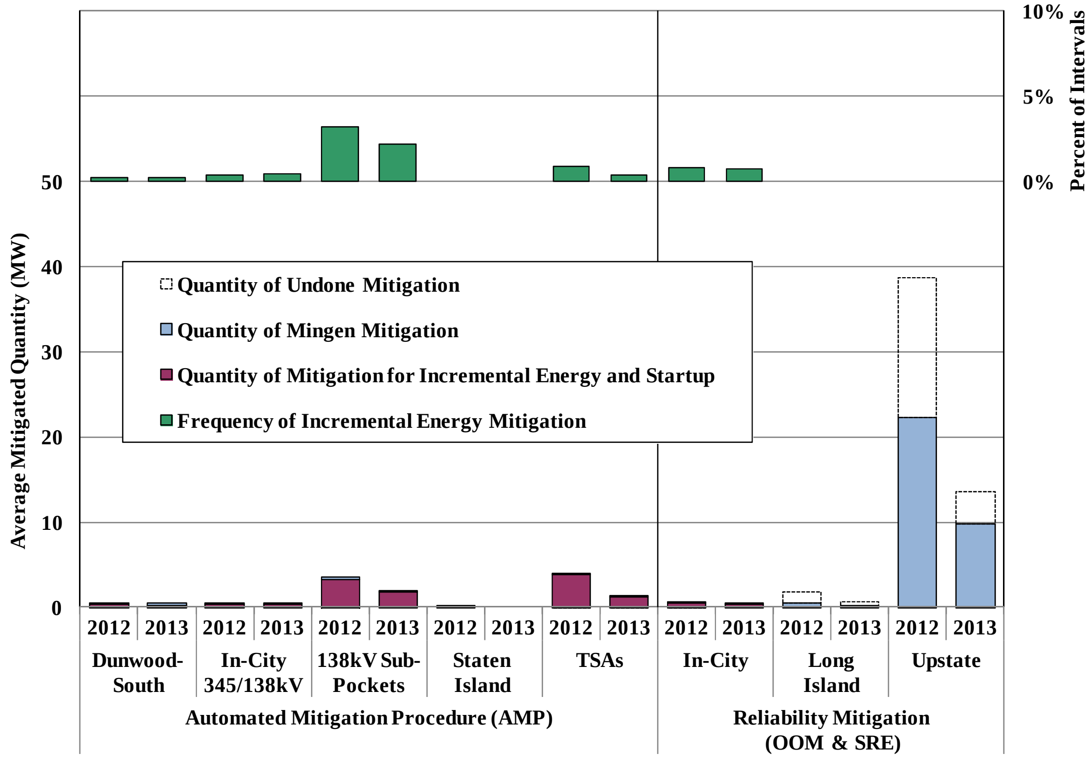
Mitigation Procedure ("AMP") on the economically committed units in load pockets of New York City, and the right portion shows the amount of mitigation on the units committed for reliability in New York City, Long Island, and the upstate area.

Figure A-43: Summary of Day-Ahead Mitigation
2012 & 2013



energy offer or the startup offer is mitigated.

Figure A-44: Summary of Real-Time Mitigation
2012 & 2013



Key Observations: Day-ahead and Real-time Mitigation

- The majority of mitigation occurred in the day-ahead market.
  - In 2013, 92 percent of all AMP mitigation occurred in the day-ahead market, primarily for generators in the 138kV load pockets.
  - Most reliability commitment occurs in the day-ahead market, making the instances of reliability commitment mitigation more prevalent in the day-ahead market.
- The amount of AMP mitigation fell substantially in the past two years.
  - The hourly average MW that was AMP-mitigated fell from over 250 MW in 2011 to roughly 95 MW in 2012 and 55 MW in 2013.
  - 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.
- Reliability commitments fell in Long Island and upstate New York, leading to reduced mitigation in these categories.
  - Units that were frequently committed for reliability became more economic because of high LBMPs driven primarily by high natural gas prices (transmission outages and deratings were also an important contributing factor in Long Island).

  - One unit in Upstate New York that was previously SRE-committed was DARU-committed during February 2013, leading to increased day-ahead reliability mitigation in upstate New York.

- Reliability commitment for NOx Bubble constraints rose in New York City in 2013, leading to more frequent mitigation of local reliability commitment.
- Unmitigation of generators became less common in 2012 and continued to decrease in 2013 as the NYISO improved its processes for administering reference levels.

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-45 to Figure A-48: Summary of Ancillary Services Offers

The following four figures compare the ancillary services offers for generators in the day-ahead market for 2012 and 2013 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-45: Summary of West 10-Minute Spinning Reserves Offers

Day-Ahead Market, 2012-2013

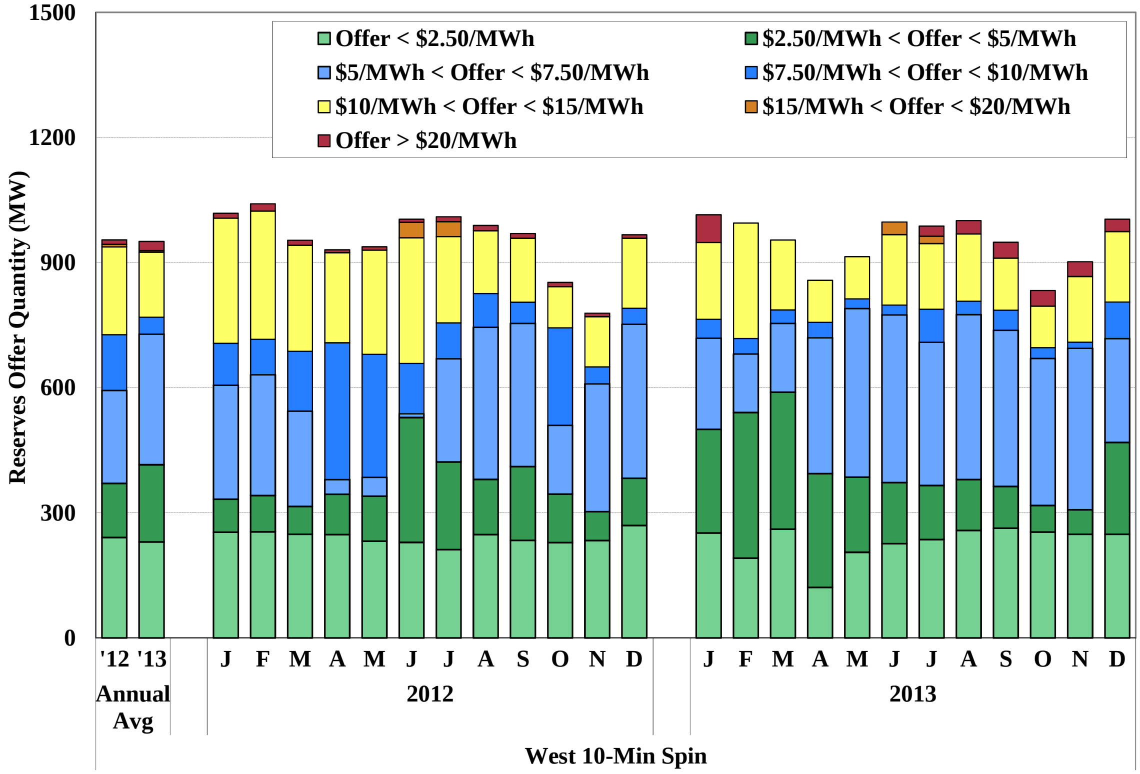


Figure A-46: Summary of East 10-Minute Spinning Reserves Offers
Day-Ahead Market, 2012-2013

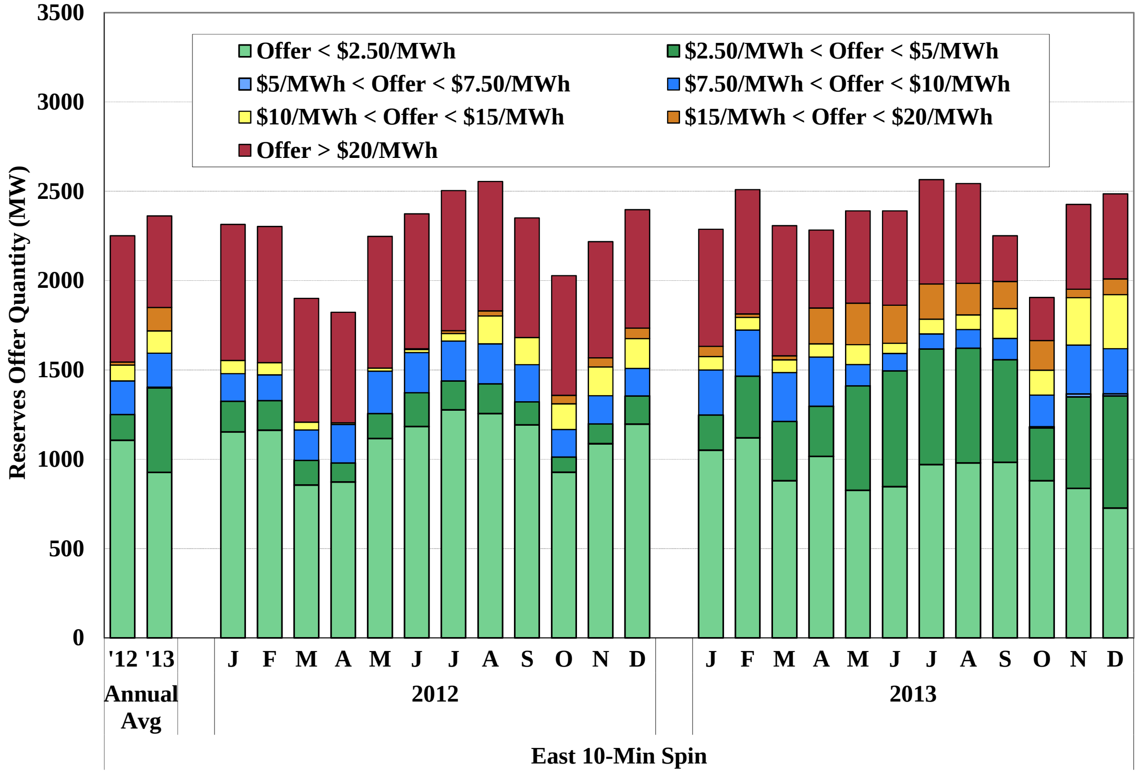


Figure A-47: Summary of East 10-Minute Non-Spin Reserves Offers
Day-Ahead Market, 2012-2013

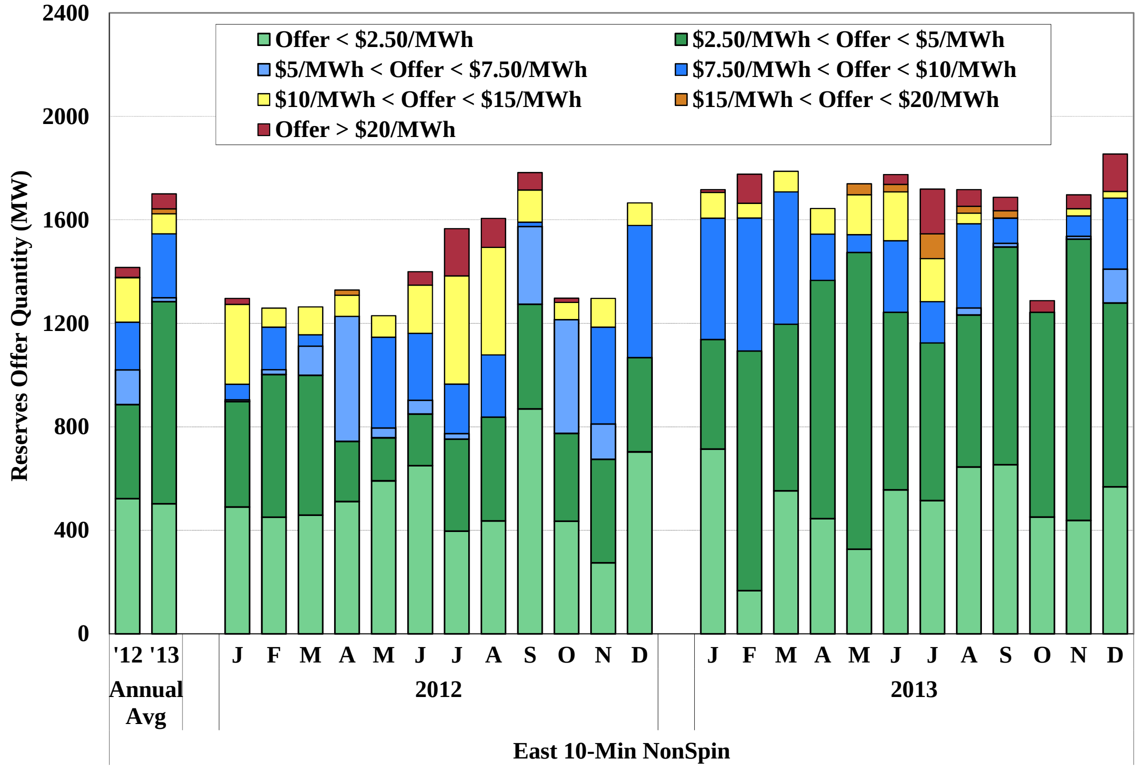


Figure A-48: Summary of Regulation Capacity Offers
Day-Ahead Market, 2012-2013

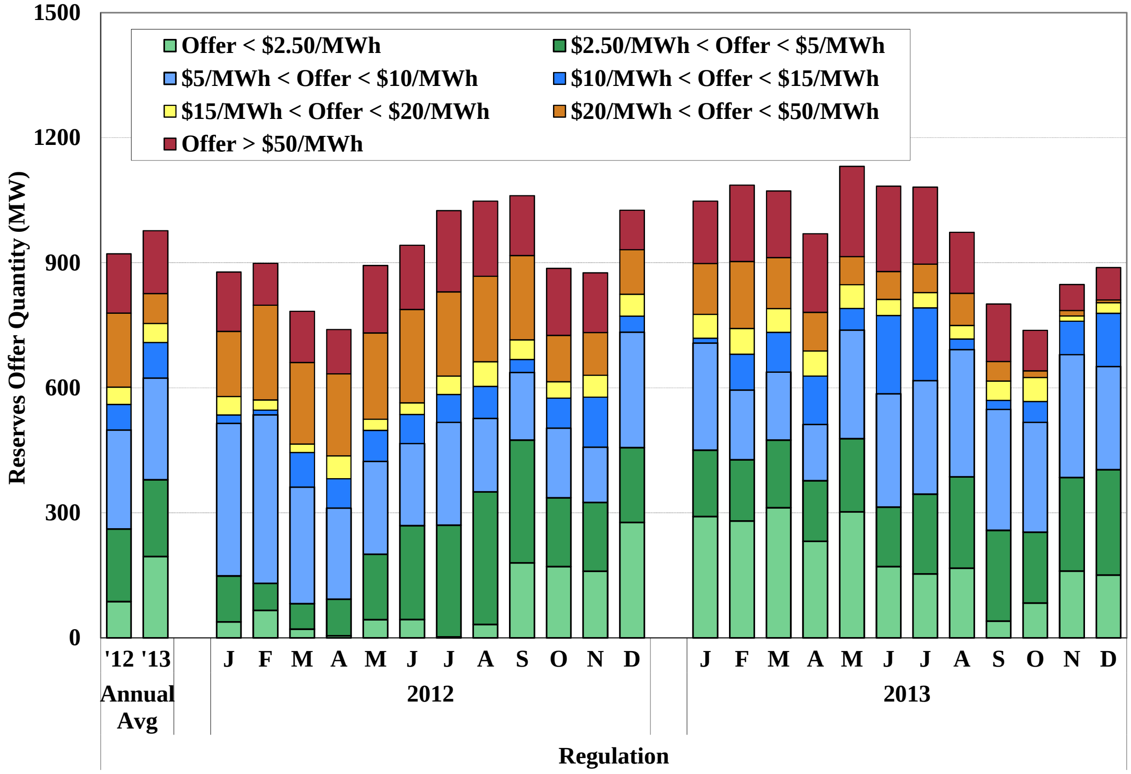


Figure A-49 to Figure A-50: Day-ahead Offer Patterns Under New Mitigation Rules

The NYISO modified two day-ahead ancillary services mitigation provisions in 2013. On January 23, the NYISO implemented the first phase of the revision, which 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, the NYISO implemented the second phase of the revision, which raised both caps from $5 to $10 per MW.

The following analyses evaluate the competitiveness of reserve markets following the implementations of the two mitigation revisions. Accordingly, Figure A-49 compares day-ahead 10-minute non-spinning reserve offers from Eastern New York generators between 2012 and 2013. Figure A-50 compares day-ahead 10-minute spinning reserve offers from New York City generators between 2012 and 2013.

Both figures show average offer quantities for each reserve category based on offer price level. Quantities are shown separately for: (a) different times of day (i.e., hour beginning 0-5, 6-11, 12-17, and 18-23); (b) different daily peak load levels in Eastern New York; and (c) different phases of the calendar year (i.e., January 23 to September 24 corresponds to phase one of the rule change, while September 25 to December 31 corresponds to phase two of the change). The inset tables summarize the percent of days when daily peak load in Eastern New York fell into each load category in 2012 and 2013.

Figure A-49: Day-Ahead Non-Spin Reserve Offers Under New Mitigation Rules
Eastern 10-Minute Non-Spinning Reserves, 2012-2013

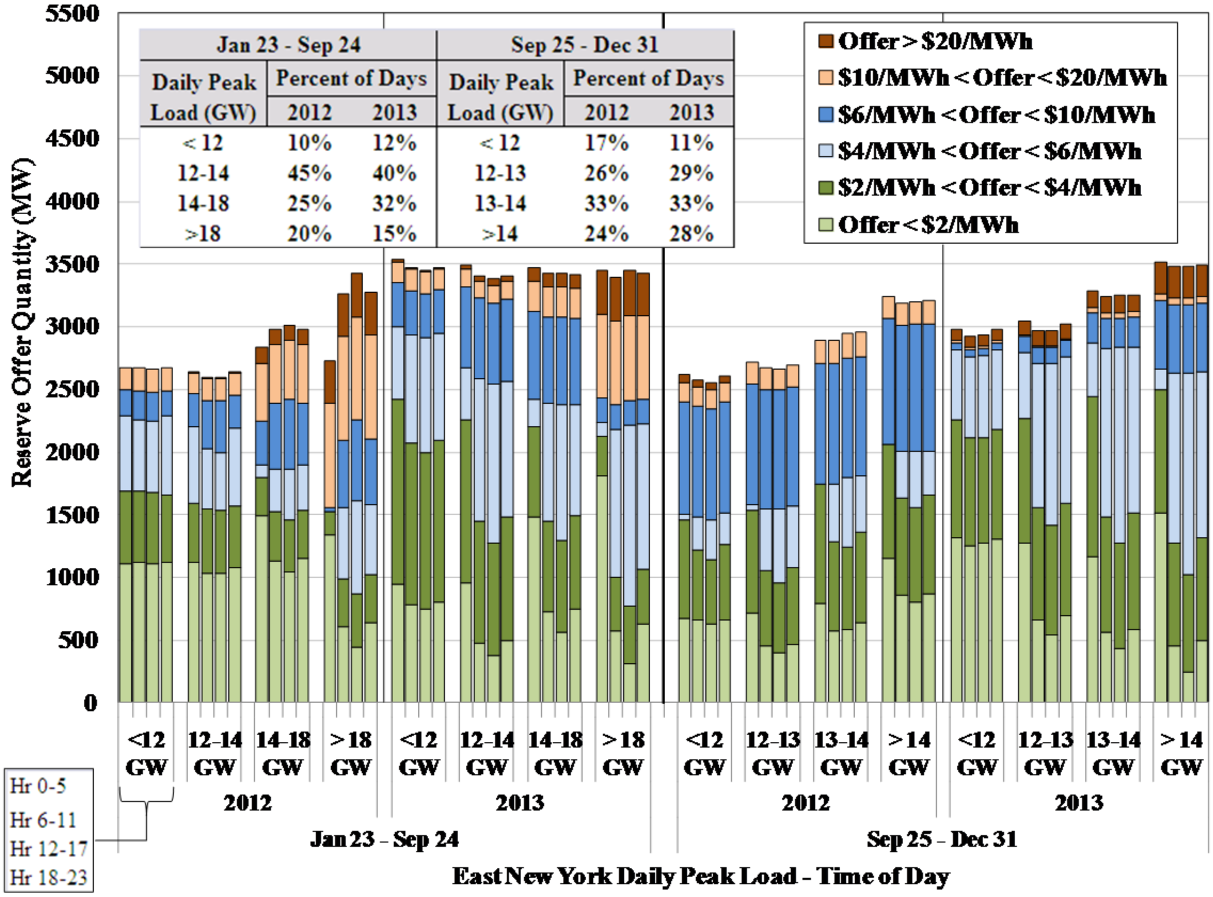
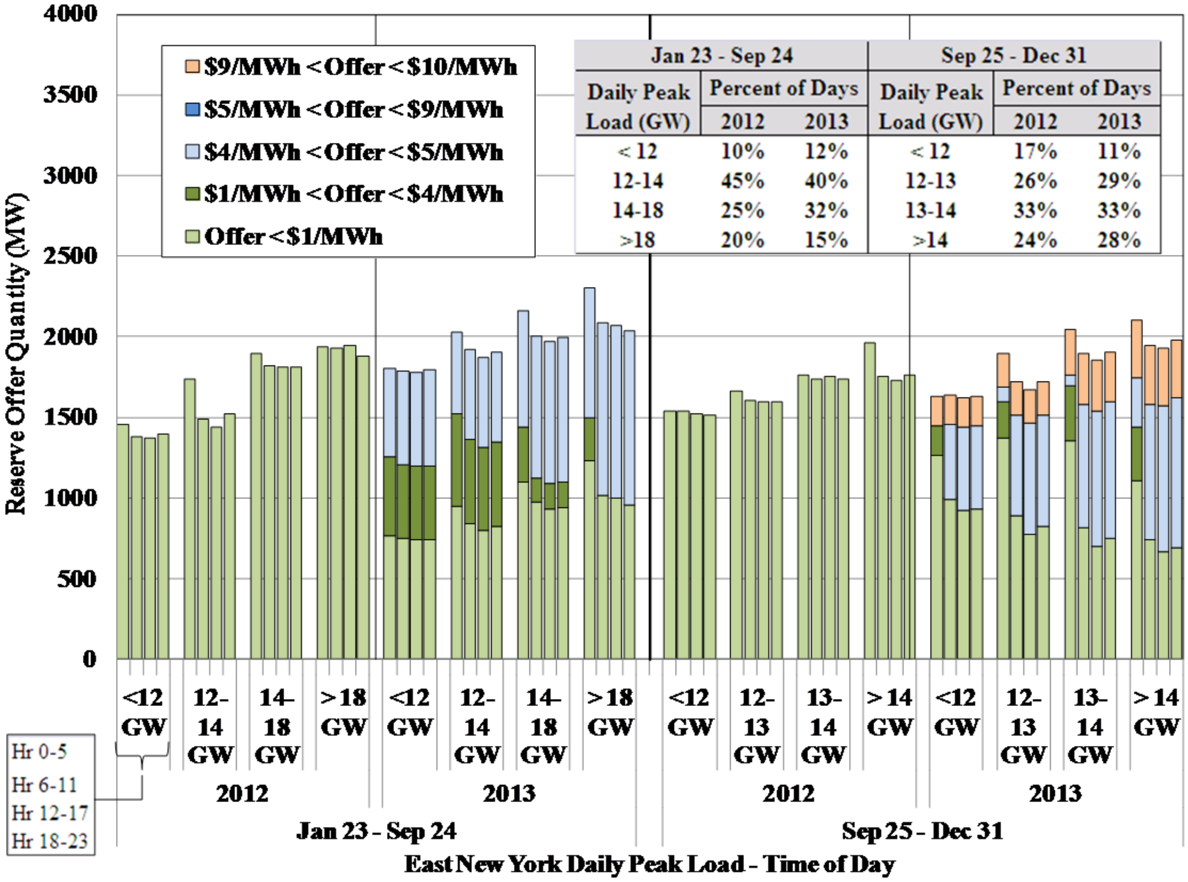


Figure A-50: Day-Ahead Spinning Reserve Offers Under New Mitigation Rules

New York City 10-Minute Spinning Reserves, 2012-2013



Jan 23 - Sep 24			Sep 25 - Dec 31		
Daily Peak Load (GW)	Percent of Days 2012	2013	Daily Peak Load (GW)	Percent of Days 2012	2013
< 12	10%	12%	< 12	17%	11%
12-14	45%	40%	12-13	26%	29%
14-18	25%	32%	13-14	33%	33%
>18	20%	15%	>14	24%	28%

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.
- The amount of 10-minute non-spinning reserve offers in Eastern New York increased significantly after the entry of the new Bayonne peaking facility (which added nearly 500 MW of installed capacity) in the summer of 2012.
- The average amounts of offers in all four categories of ancillary services were affected by the new entry and retirement of generation in 2012 and 2013.

- Offers for regulation and reserves in Eastern New York increased from 2012 to 2013 following the new entry of the Bayonne peaking facility in June 2012.
- Offers for reserves in Western New York fell from 2012 to 2013 following several retirements and mothballings of generation.

- The reduction in average prices of regulation capacity offers was also attributable to increased lower-cost capacity offers following the implementation of the two-part bidding in late-June 2013, which allowed participants to bid movement-related costs separately from capacity costs.

- In our evaluation of the competitiveness of the 10-minute spinning and non-spin reserves markets following the phased revisions of two day-ahead mitigation provisions, we have not found offer patterns that raise withholding concerns.
  - Many suppliers have increased their offer prices consistent with expectations, particularly under conditions when average real-time prices have a tendency to exceed day-ahead prices, particularly times of day with high load levels (e.g., hours 12-17) and on high load days (e.g., east New York peak load > 18 GW).
    - Such increases are consistent with competitive behavior when the real-time clearing price is expected to be higher than the day-ahead clearing price. Furthermore, such increases 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.[144]

- *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-51 to Figure A-57: Day-Ahead Load Schedules versus Actual Load

Many generating units have long lead times and substantial commitment costs. Their owners must decide whether to commit them well in advance of real-time before they can be certain that the unit will be economic. The day-ahead market provides these suppliers with a means of being committed only when it is economic to do so. These suppliers are willing to sell into the day-ahead market if day-ahead prices are generally consistent with real-time prices. Thus, efficient unit commitment relies on consistency between the day-ahead and the real-time markets. The following figures help evaluate the consistency between day-ahead load scheduling patterns and actual load, providing an indication of the overall efficiency of the day-ahead market.

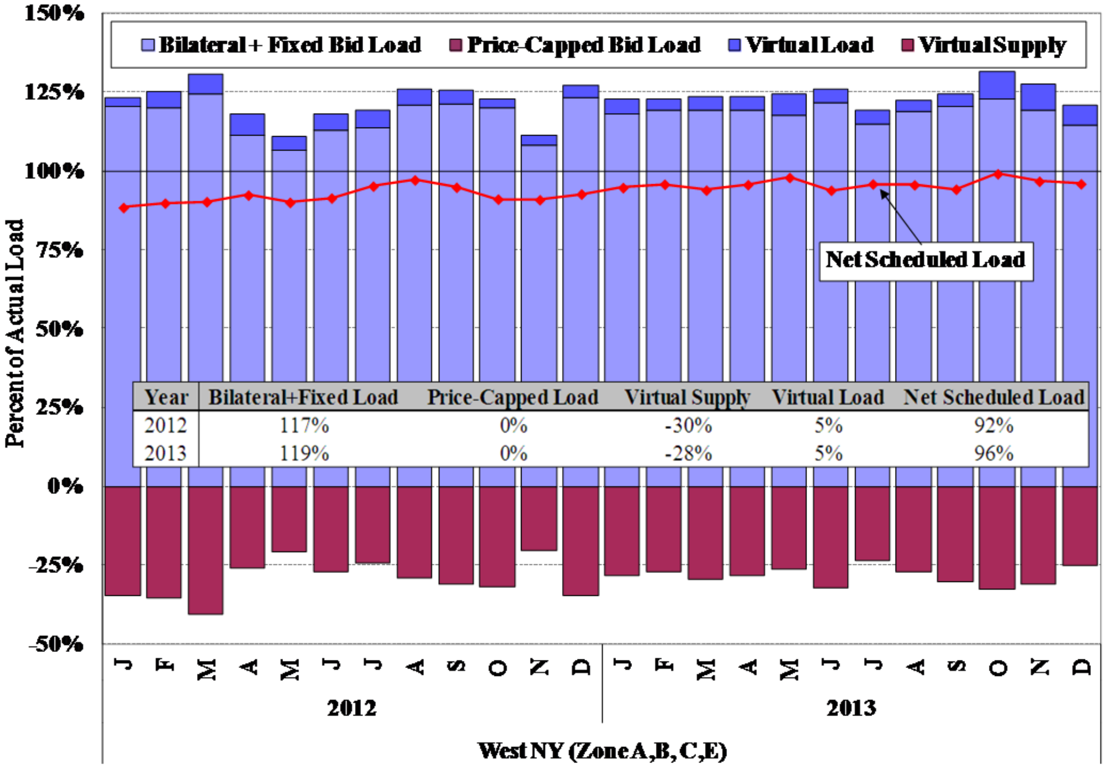
We expect day-ahead load schedules to be generally consistent with actual load in a well-functioning market. Under-scheduling load generally leads to lower day-ahead prices and insufficient commitment for real-time needs. Over-scheduling tends to raise day-ahead prices above real-time prices. Thus, market participants have incentives to schedule amounts of load consistent with real-time load.

The following seven figures show day-ahead load schedules and bids as a percent of real-time load during 2012 and 2013 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

[144] 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.

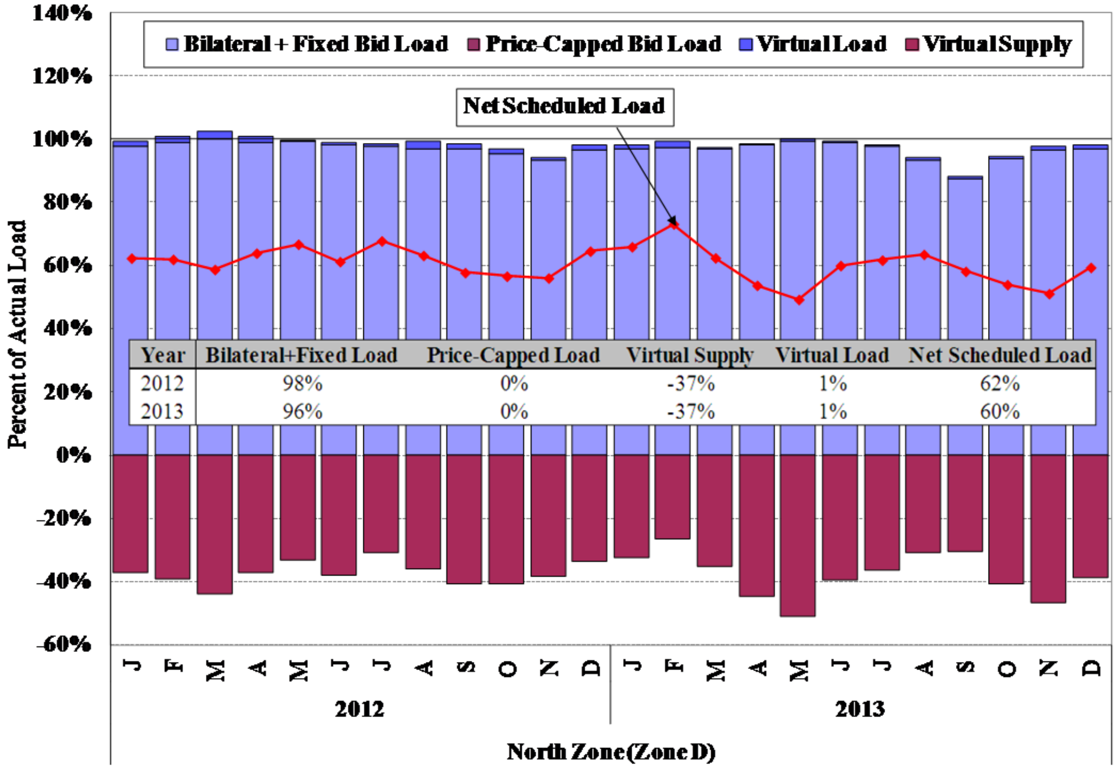
and resource commitment as a reduction in physical load, so it is treated as a negative load for the purposes of this analysis. For each period, physical load and virtual load are shown by bars in the positive direction, while virtual supply is shown by bars in the negative direction. Net scheduled load, 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 2012 to 2013. Virtual imports and exports are shown for NYCA only and are not shown for any of the sub-areas in New York.

Figure A-51: Day-Ahead Load Schedules versus Actual Load in West New York
Zones A,B,C, & E, 2012 – 2013



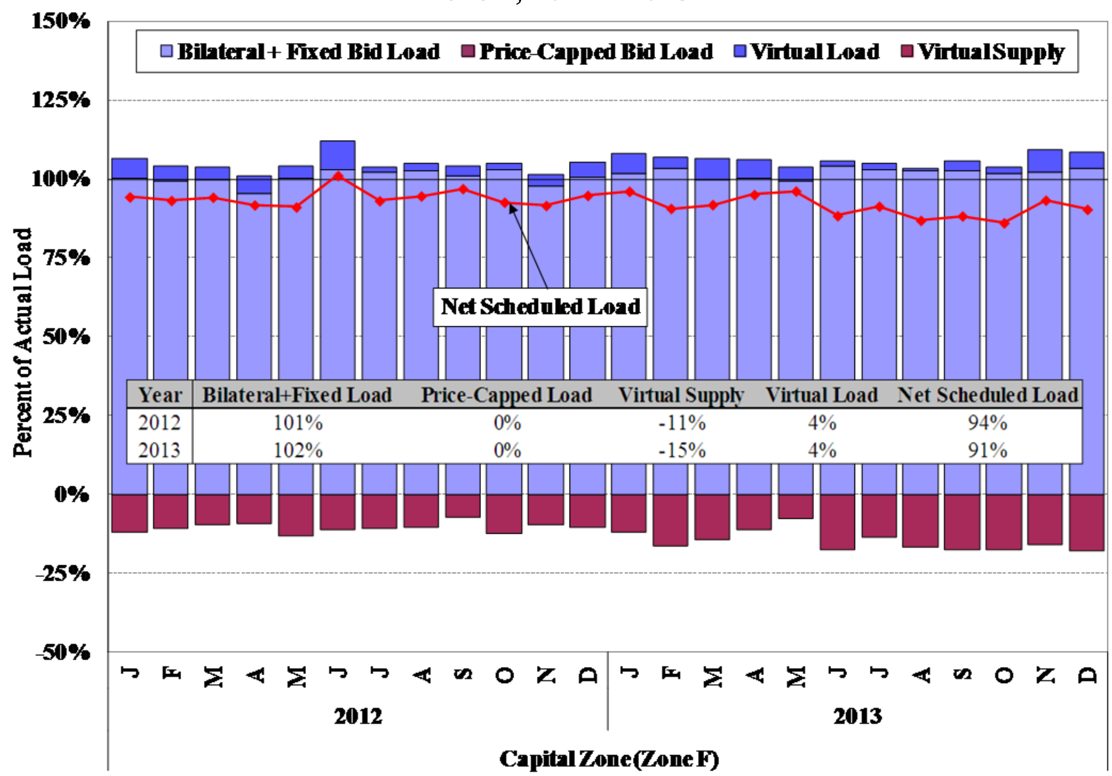
Year	Bilateral+Fixed Load	Price-Capped Load	Virtual Supply	Virtual Load	Net Scheduled Load
2012	117%	0%	-30%	5%	92%
2013	119%	0%	-28%	5%	96%

Figure A-52: Day-Ahead Load Schedules versus Actual Load in North Zone
Zone D, 2012 – 2013



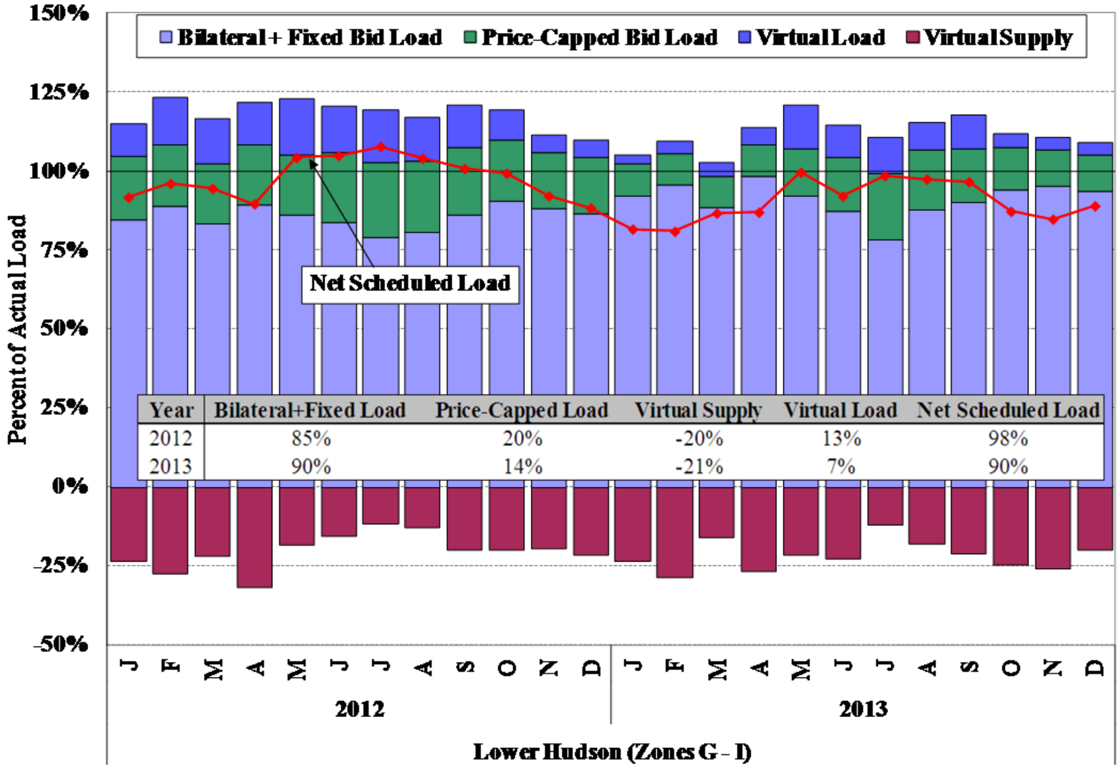
Year	Bilateral+Fixed Load	Price-Capped Load	Virtual Supply	Virtual Load	Net Scheduled Load
2012	98%	0%	-37%	1%	62%
2013	96%	0%	-37%	1%	60%

Figure A-53: Day-Ahead Load Schedules versus Actual Load in Capital Zone
Zone F, 2012 – 2013



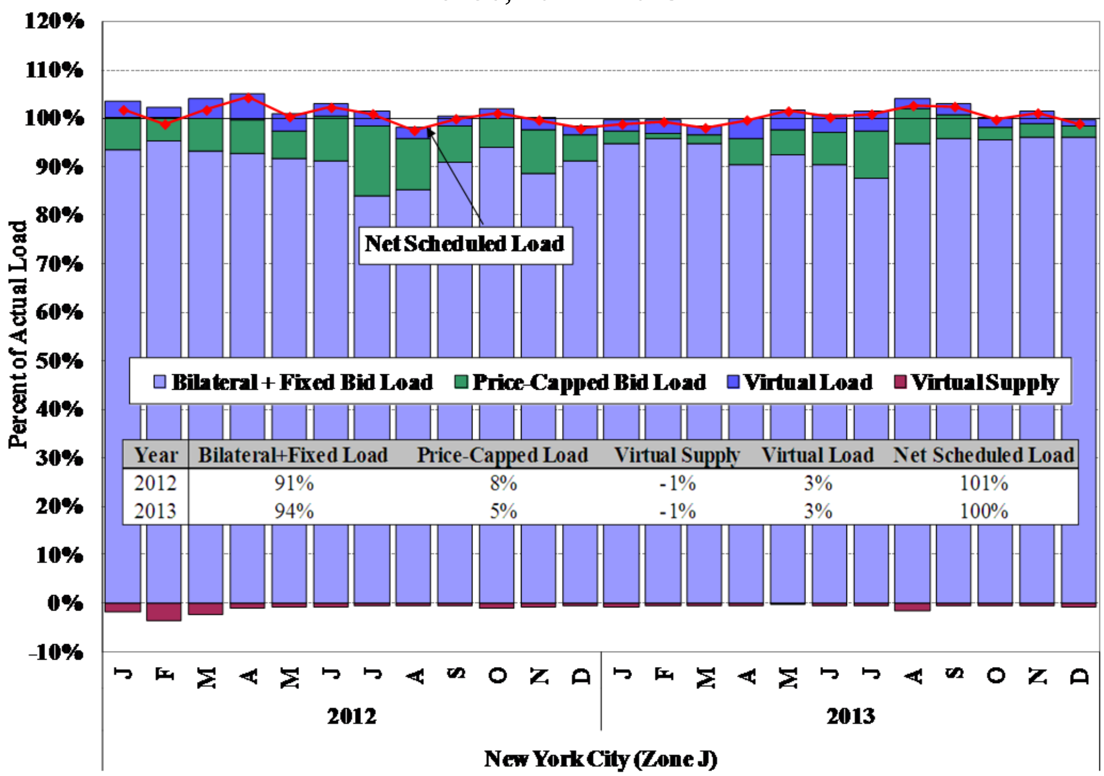
Year	Bilateral+Fixed Load	Price-Capped Load	Virtual Supply	Virtual Load	Net Scheduled Load
2012	101%	0%	-11%	4%	94%
2013	102%	0%	-15%	4%	91%

Figure A-54: Day-Ahead Load Schedules versus Actual Load in the Lower Hudson Valley
Zones G, H, & I, 2012 – 2013



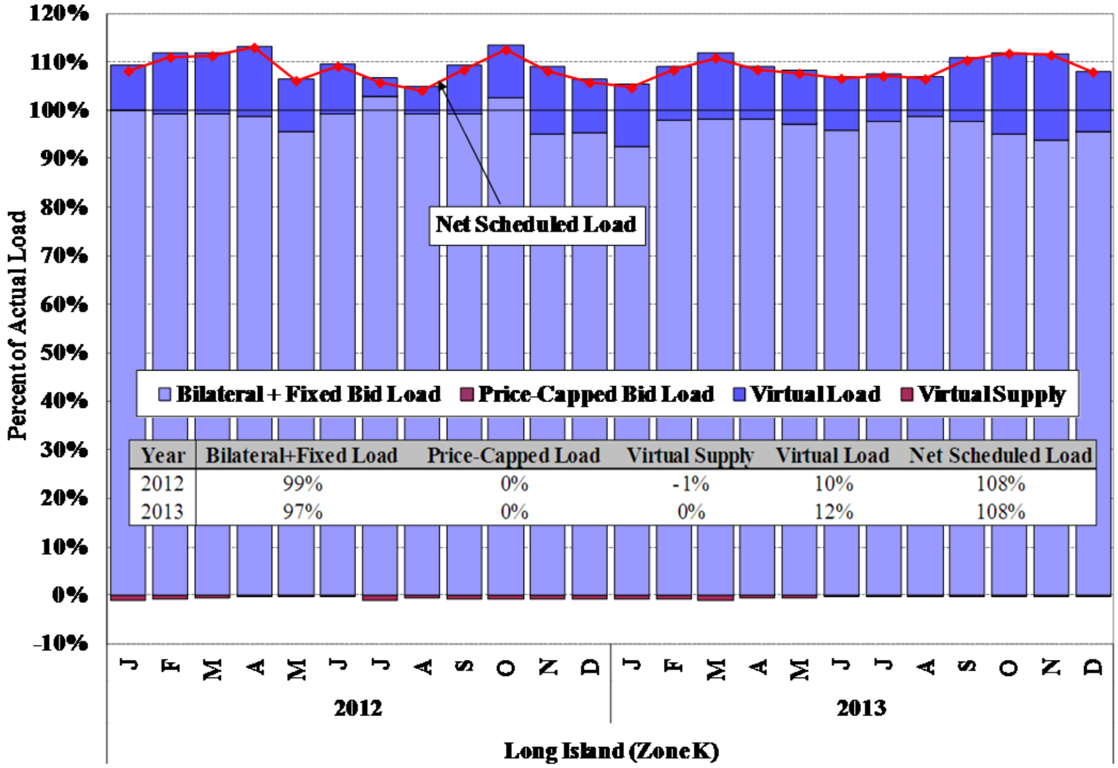
Year	Bilateral+Fixed Load	Price-Capped Load	Virtual Supply	Virtual Load	Net Scheduled Load
2012	85%	20%	-20%	13%	98%
2013	90%	14%	-21%	7%	90%

Figure A-55: Day-Ahead Load Schedules versus Actual Load in NYC
Zone J, 2012 – 2013



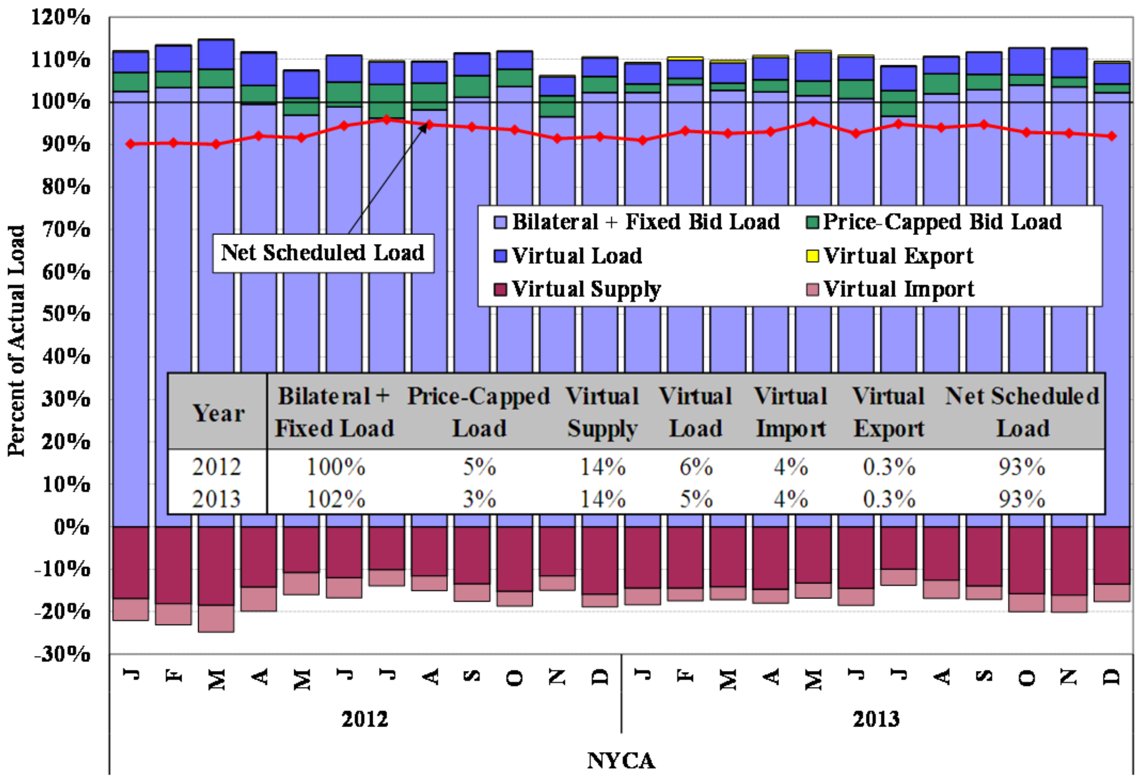
Year	Bilateral+Fixed Load	Price-Capped Load	Virtual Supply	Virtual Load	Net Scheduled Load
2012	91%	8%	-1%	3%	101%
2013	94%	5%	-1%	3%	100%

Figure A-56: Day-Ahead Load Schedules versus Actual Load in Long Island
Zone K, 2012 – 2013



Year	Bilateral+Fixed Load	Price-Capped Load	Virtual Supply	Virtual Load	Net Scheduled Load
2012	99%	0%	-1%	10%	108%
2013	97%	0%	0%	12%	108%

Figure A-57: Day-Ahead Load Schedules versus Actual Load in NYCA
2012 – 2013



Year	Bilateral + Fixed Load	Price-Capped Load	Virtual Supply	Virtual Load	Virtual Import	Virtual Export	Net Scheduled Load
2012	100%	5%	14%	6%	4%	0.3%	93%
2013	102%	3%	14%	5%	4%	0.3%	93%

Key Observations: Day-ahead Load Scheduling

- Overall, load in the day-ahead market was scheduled at 93 percent of actual load in NYCA in 2013, comparable to 2012.

- The historic pattern of under-scheduling outside Southeast New York (i.e., West Upstate and Capital Zone) and over-scheduling in Southeast New York (i.e., Other East Upstate New York City and Long Island) was less clearly evident in 2013.

  - Long Island was the only load zone that was consistently over-scheduled in 2013. In other parts of Southeast New York:

    - The amount of scheduling fell to 90 percent in 2013 from 98 percent in 2012 and 108 percent in 2011 in Lower Hudson Valley. However, average load scheduling was higher during the summer months when real-time congestion into Southeast New York becomes more prevalent.

    - The amount of scheduling fell to 100 percent in 2013 from 101 percent in 2012 and 103 percent in 2011 in New York City.

  - This reduction in over-scheduling in Lower Hudson Valley and New York City likely resulted from less frequent periods of acute real-time congestion into Southeast New York and into and within New York City, due to:

    - The more effective use of PAR-controlled lines between New Jersey and New York to manage congestion into Southeast New York due to operational improvements and the introduction of Market-to-Market congestion management with PJM; and

    - The addition of new generation capacity and new transmission facilities in New York City.

  - Under-scheduling was still prevalent outside Southeast New York in 2013, which occurs partly in response to the following scheduling patterns of individual generators:

    - Hydro and wind resources outside Southeast New York generally increase output in real-time above their day-ahead scheduled level, adding an average of over 500 MW of additional energy supply in real-time.

    - The additional real-time output from these resources satisfies roughly 3 percent of average real-time load in the NYCA and 8 percent of the average real-time load outside Southeast New York in 2013.

- The patterns of day-ahead scheduling generally improved convergence between day-ahead and real-time prices.

  - In 2013, regions outside Southeast New York exhibited day-ahead premiums and most regions in Southeast New York exhibited real-time premiums.

- This also suggests that further under-scheduling outside Southeast New York and further over-scheduling in Southeast New York 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-58: Virtual Trading Volumes and Profitability

Figure A-58 summarizes recent virtual trading activity in New York by showing monthly average scheduled quantities, unscheduled quantities, and gross profitability for virtual transactions in 2012 and 2013. 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.[145, 146]

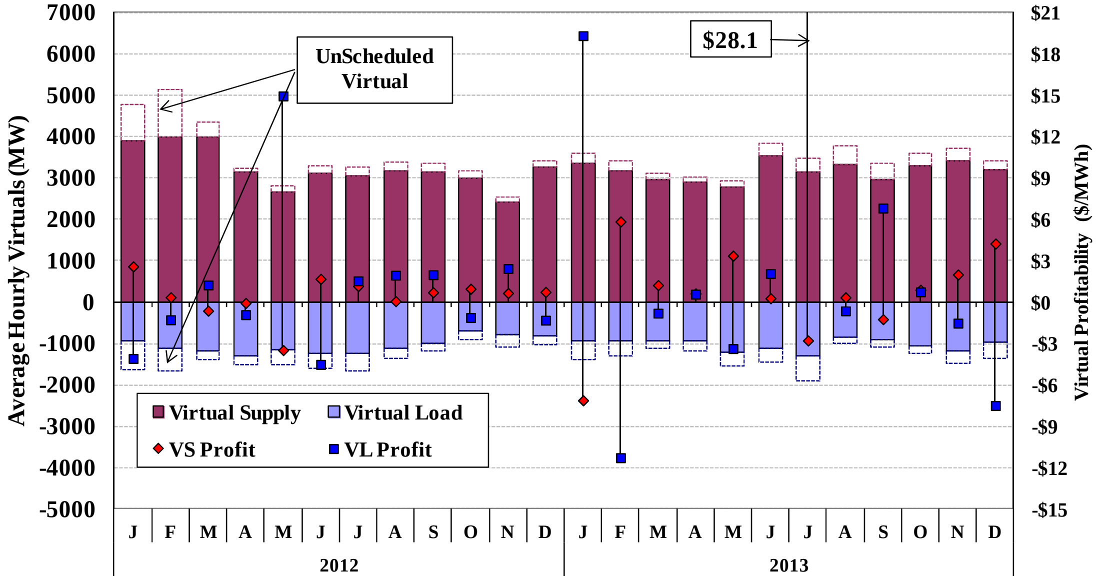
145 The gross profitability shown here does not account for any other related costs or charges to virtual traders.

146 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.

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 465 MW of virtual transactions (or 10 percent of all virtual transactions) netted profits larger than the 50 percent of their zone (or proxy bus) prices in July 2013. 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-58: Virtual Trading Volumes and Profitability

January 2012 to December 2013



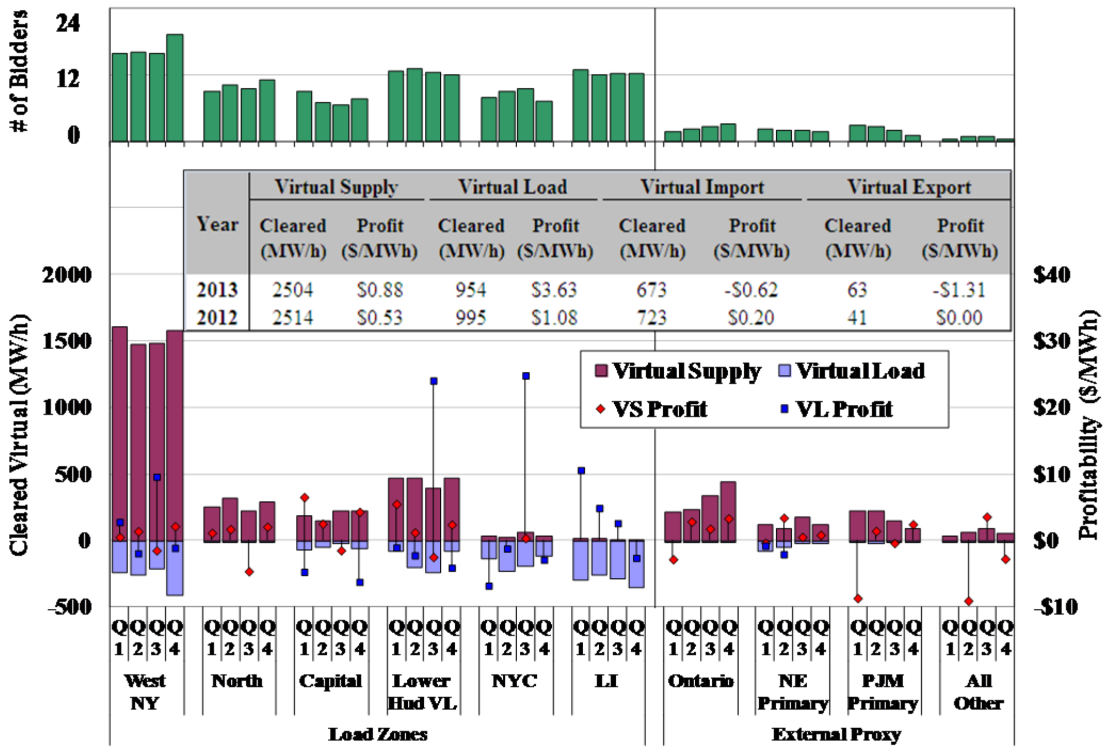
Profit > 50% of Avg. Zone Price	MW	356	117	268	264	150	440	380	255	181	191	278	222	462	481	210	220	422	295	465	187	217	269	553	417
	%	7%	2%	5%	6%	4%	10%	9%	6%	4%	5%	9%	5%	11%	12%	5%	6%	11%	6%	10%	4%	6%	6%	12%	10%
Loss > 50% of Avg. Zone Price	MW	216	158	341	312	169	429	396	261	159	124	216	222	472	405	149	183	302	196	313	206	220	234	422	310
	%	4%	3%	7%	7%	4%	10%	9%	6%	4%	3%	7%	5%	11%	10%	4%	5%	8%	4%	7%	5%	6%	5%	9%	7%

Figure A-59: Virtual Trading Activity

Figure A-59 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 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 2013. 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 2013 and 2012.

Figure A-59: Virtual Trading Activity[147]
by Region by Quarter, 2013



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)
2013	2504	$0.88	954	$3.63	673	-$0.62	63	-$1.31
2012	2514	$0.53	995	$1.08	723	$0.20	41	$0.00

Key Observations: Analysis of Virtual Trading

- A large number of market participants regularly submitted virtual bids and offers at the load zone level in 2013.
  - On average, seven or more participants submitted virtual trades in each region and 28 participants submitted virtual trades somewhere in the state.
- The number of market participants that regularly submitted virtual imports and exports at the proxy buses was smaller than at the internal load zones, averaging seven in 2013.
- Nearly all 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-one percent of all virtual imports/exports were virtual imports.

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

  - 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.

- In aggregate, virtual traders netted approximately $45 million of gross profits in 2013, up 102 percent from 2012.

  - The increase generally reflected high price volatility in 2013 driven largely by high natural gas prices.

  - In particular, virtual load netted a gross profit of nearly $30 million in the third quarter of 2013.

    - This was primarily attributable to real-time price spikes on several days when demand response was activated (July 15 to 19) or when TSAs occurred during high load conditions.

    - However, the profits and losses of virtual load and supply and virtual imports and exports have varied widely over time, reflecting the difficulty of predicting volatile real-time prices.

  - 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.

- Only small quantities of virtual transactions generated substantial losses in 2013, 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 2013

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.[148]

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.[149] 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.[150] 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-60: Congestion Revenue Collections and Shortfalls

Figure A-60 shows day-ahead congestion revenue and the two classes of congestion shortfalls in each month of 2012 and 2013. The upper portion of the figure shows balancing congestion revenue shortfalls. The lower portion of the figure shows day-ahead congestion revenues

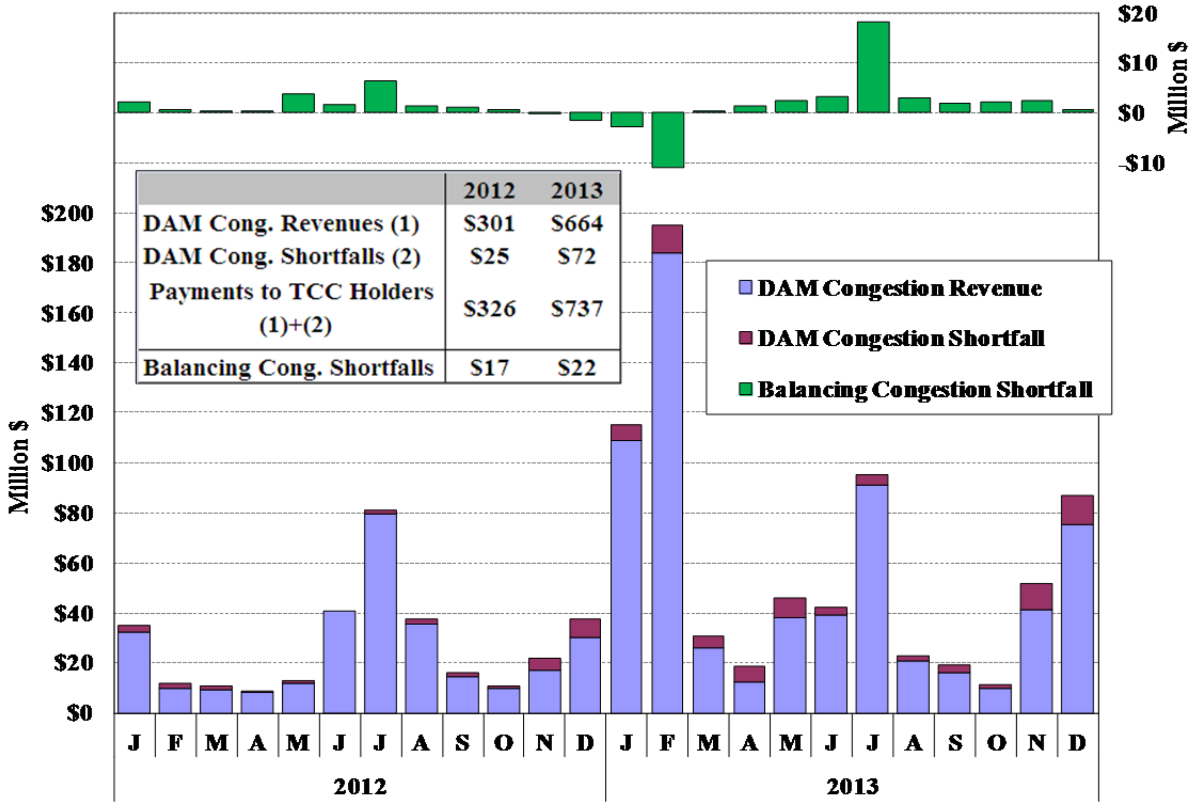
148 The shadow price of a transmission constraint represents the marginal value to the system of one MW of transfer capability. For example, if 100 MW is scheduled to flow across a constrained line with a shadow price of $50/MWh in a particular hour in the day-ahead market, the NYISO collects $5,000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

149 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).

150 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).

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.

Figure A-60: Congestion Revenue Collections and Shortfalls
2012-2013



Key Observations: Day-Ahead Congestion Revenues

- Day-ahead congestion revenues totaled roughly $664 million in 2013, up 121 percent (or $363 million) from 2012.
  - Higher natural gas prices in 2013 contributed to the increase because higher natural gas prices tend to increase net imports to Eastern New York (where gas is the primary input fuel) and also increase the redispatch costs incurred to manage congestion.
  - Higher natural gas price spreads between Western New York and Eastern New York in 2013 were the primary driver of increased congestion, since they increased the cost of generation in the eastern areas, resulting in much higher levels of congestion.
    - 82 percent of the increase in day-ahead congestion revenues accrued in the winter months (December, January, February) when average natural gas prices in Eastern New York rose more than 100 percent from the prior winter.
  - Congestion rose notably in the West Zone in 2013, contributing to the overall increase as well (the causes are discussed in subsection B).

  - In both 2012 and 2013, over 75 percent of congestion revenues were collected in the winter peak (i.e., December, January, and February) and summer peak (i.e., June to August) months. This is expected because:
    - The relatively high loads in these months often result in higher transmission flows;
    - Thunderstorms occur much more frequently during the summer, causing transmission interfaces to be derated and leading to acute congestion into Southeast New York; and
    - Larger spreads in natural gas prices between eastern and western New York during periods of high demand (typically in the winter) can lead to increased imports and congestion into eastern New York.
- Day-ahead and balancing congestion shortfalls totaled $94 million in 2013, up substantially from $42 million in 2012.
  - 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-61: Day-Ahead and Real-Time Congestion by Path

Figure A-61 shows the value and frequency of congestion along major transmission lines in the day-ahead and real-time market. The figures measure congestion in two ways:

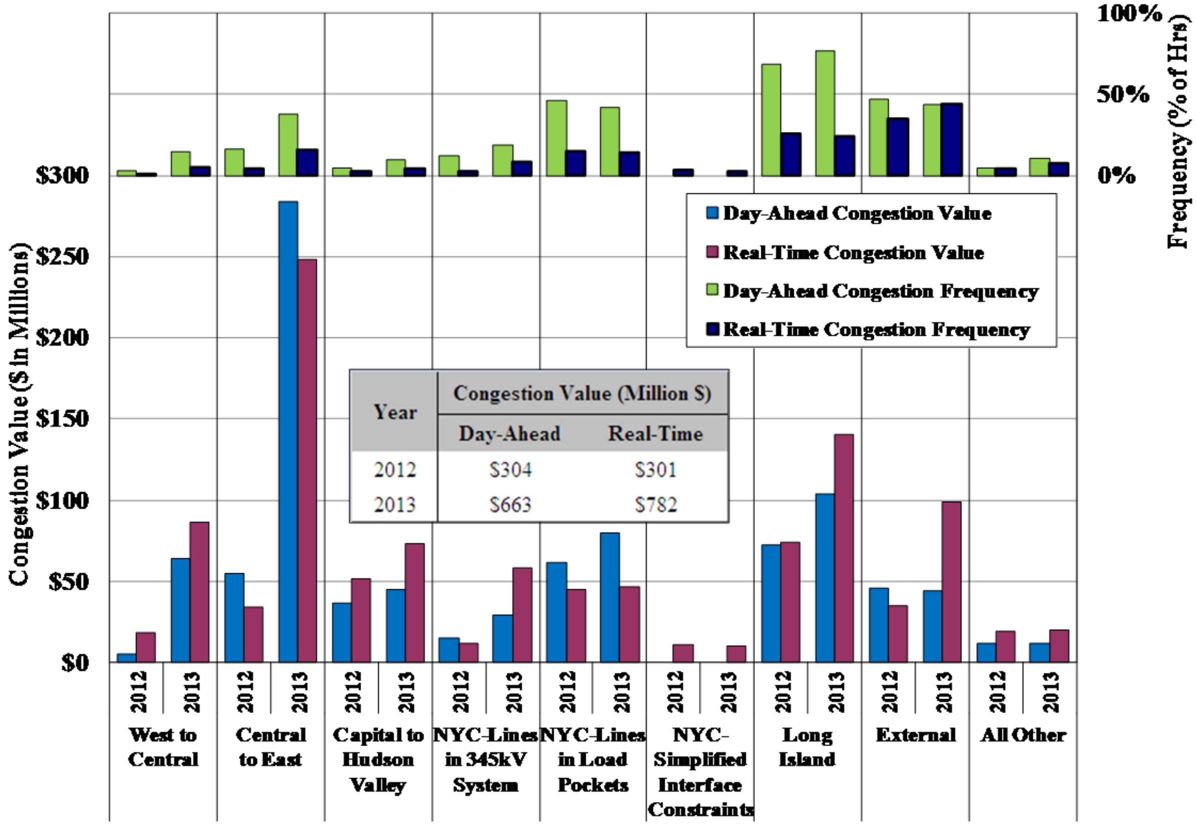
- The frequency of binding constraints; and
- The value of congestion, which is equal to the marginal cost of relieving the constraint (i.e., constraint shadow cost) multiplied by the scheduled flow across the constraint.[151]

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.
- 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.

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

Figure A-61: Day-Ahead and Real-Time Congestion by Transmission Path
2012 - 2013



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.

- Congestion occurred more frequently in 2013 than in 2012 on most transmission paths. From 2012 to 2013, total congestion value rose by more than 100 percent in the day-ahead and real-time markets.

  - Higher natural gas prices and larger spreads in natural gas prices between Eastern and Western New York and between New England and New York were a key driver of the increases.

- Congestion across the Central-East interface occurred in 38 percent of hours in the day-ahead market in 2013, up significantly from 16 percent in 2012 (in the real-time market, such frequency rose from 4 percent in 2012 to 16 percent in 2013).

  - The Central-East interface accounted for nearly 40 percent of congestion value in both day-ahead and real-time markets in 2013.

- Real-time congestion on external interfaces increased notably in 2013.
  - Nearly 50 percent 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 (which the NYISO first incorporated into the congestion pricing and dispatch model in May 2012) rose in 2013 due to;
  - The retirement of several Dunkirk units, which had previously helped relieve congestion in the West Zone;
  - Transmission outages, which reduced transfer limits on in-service lines;
  - Generation outages of units that are effective in managing congestion; and
  - Aggregated modeling of the Niagara plant in the market software, which does not calculate LBMPs and dispatch signals for the 25 individual units at the plant. Some units at the plant are interconnected where they can provide relief for these 230kV constraints, while other units at the plant tend to increase congestion.
- Congestion into Long Island was also exacerbated by:
  - The lengthy outages and deratings of the Neptune Cable that occurred from late May 2012 through early July 2013; and
  - The outages and deratings on the 345kV transmission facilities from Upstate New York to Long Island during most of the periods between January and May and between September and October.

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-62: 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-62 shows day-ahead congestion shortfalls by transmission path or facility in each month of 2012 and 2013. Positive values indicate shortfalls, while negative values indicate surpluses. The shortfalls are shown for the following paths or types of constraints:

- West to Central: Lines in the West Zone 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).
- New York City Lines: Lines leading into and within New York City
- Long Island Lines: Lines leading into and within Long Island.
- NJ to NY PARs: These are PAR controlled lines between New York and New Jersey, which include two Ramapo lines, three Waldwick lines, two Hudson-Farragut lines, and one Linden-Goethals line.
- 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-62: Day-Ahead Congestion Shortfalls
2012 – 2013

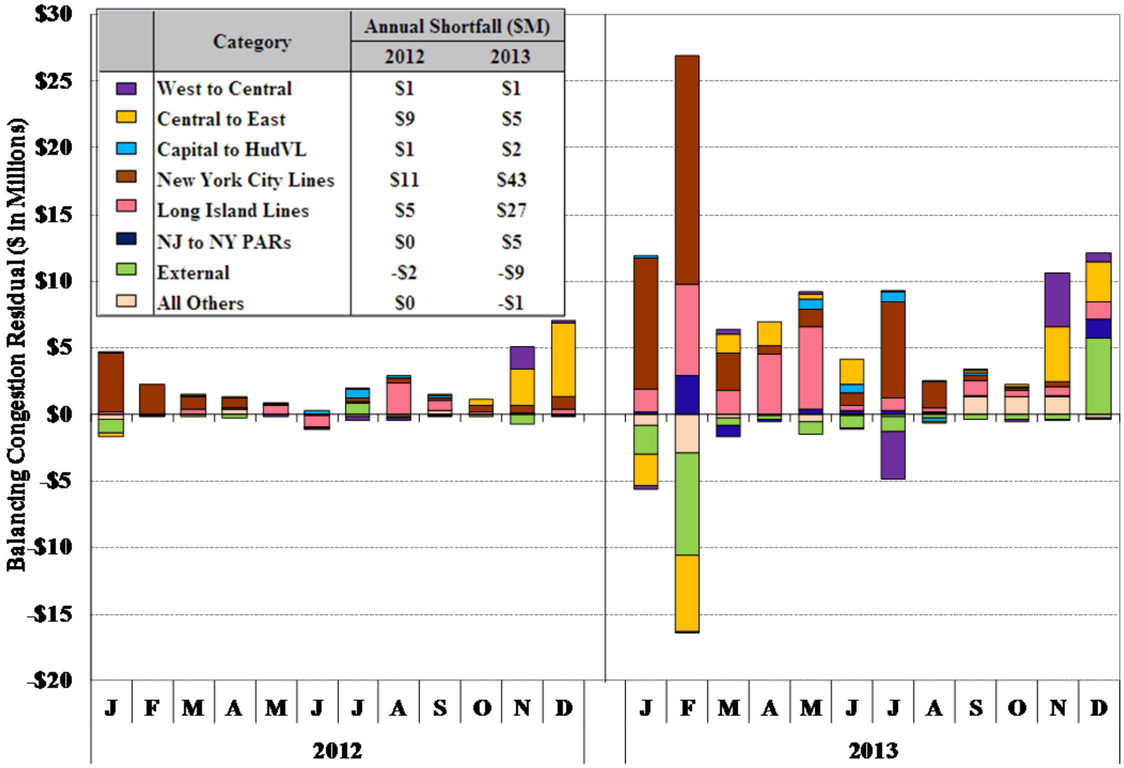


Figure A-63: Balancing Congestion Revenue Shortfalls

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.

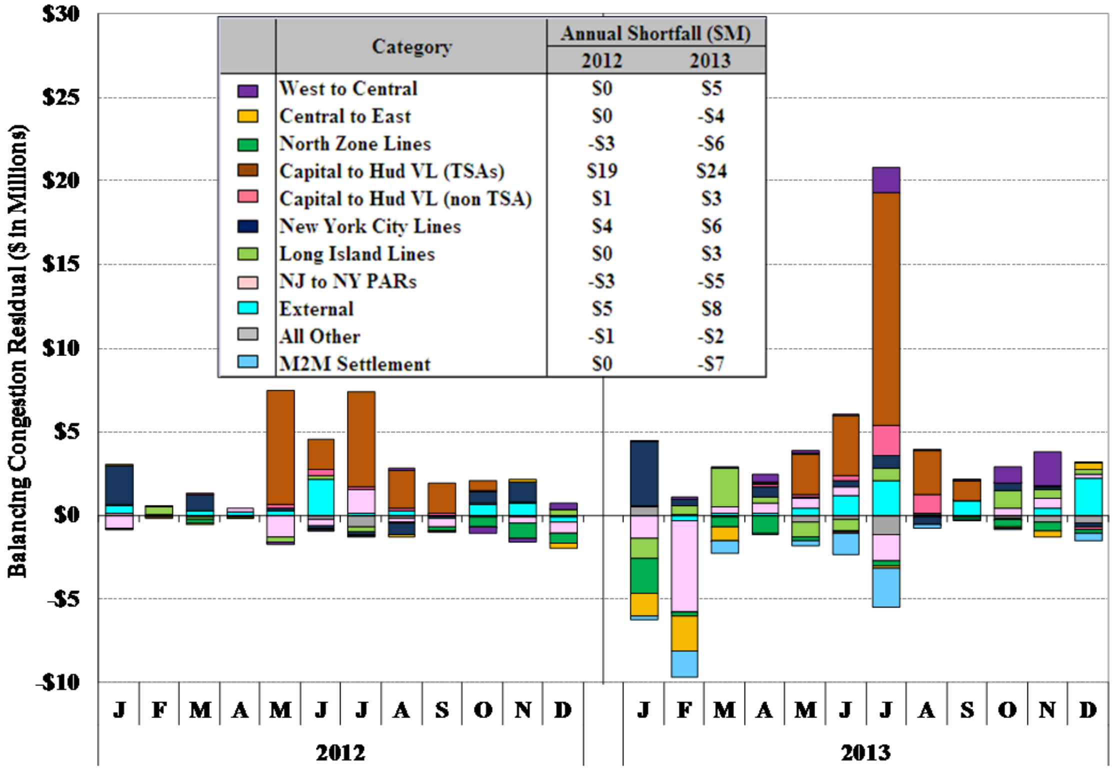
- PAR Controlled Line Flows – The flows across PAR-controlled lines are adjusted in real-time operations, which can result in flows that are very different from the day-ahead assumptions. These differences can affect the flows across multiple interfaces. This includes flow adjustments on PAR-controlled 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 Transmission Customers in Load Zone J whose customers benefit most directly from the additional reliability.

Figure A-63 shows balancing congestion shortfalls by transmission path or facility in each month of 2012 and 2013. Positive values indicate shortfalls, while negative values indicate surpluses.

Figure A-63: Balancing Congestion Shortfalls[152]
2012 – 2013



Key Observations: Congestion Shortfalls

Day-Ahead Congestion Shortfalls

- The majority of day-ahead congestion shortfalls in 2013 were associated with transmission outages.
  - Outage-related shortfalls are allocated to the responsible Transmission Owners.
- Lines in New York City and into Long Island accounted for the vast majority of day-ahead congestion shortfalls ($70 million or 98 percent) in 2013 due primarily to transmission outages.

152 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); 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 (in 2012, the Scarcity Pricing Adjustment on May 29 had the effect of reducing the actual balancing congestion costs by approximately $2 million below what is shown in the figure; while in 2013, the Scarcity Pricing Adjustment on July 15 to 19 had the effect of increasing the actual shortfalls by roughly $1.5 million above what is shown in the figure.).

  - Transmission outages were called to support the installation of a new PAR-controlled line connecting West 49th Street (on the 345kV system) with Vernon (on the 138kV system) from January to May, reducing transfer capability into Vernon pocket during this period.
  - Transmission outages in July and early-August reduced capability in the Greenwood load pocket in the 138kV system of New York City. These were exacerbated because the market software's pricing and dispatch logic does not accurately model certain contingencies at ring buses.
  - The transfer capability into Long Island was significantly reduced on most days from January to May and from September to October due to outages and deratings of the 345kV transmission facilities from Upstate to Long Island.
- Transfer capability on the Central-East interface was significantly reduced due to: 1) transmission outages in early-April, early-June, and early-November to mid-December, and 2) generation outages in mid-April to mid-May, contributing an additional $11 million to the total shortfalls during these periods.
  - However, this was largely offset by a surplus of $8 million in January and February when higher utilization of voltage regulating equipment (e.g., capacitors and automated voltage regulators, etc.) was scheduled in the day-ahead market than in historic periods.

Balancing Congestion Shortfalls

- Similar to 2012, the majority of the balancing congestion shortfalls in 2013 accrued during the periods when TSAs were frequently called, because TSAs cause the transfer capability into Southeast New York to be greatly reduced.
- The majority of $6 million of congestion shortfalls that accrued on New York City lines occurred on four days in January when the 345kV transmission capability into New York City was reduced due to uncertainty regarding availability of gas supply to some units.
- Congestion from the North Zone to the rest of state became frequent during periods of excess wind generation, contributing a surplus of nearly $6 million in 2013.
- PAR-controlled lines between New Jersey and New York contributed a net surplus of $5 million. This resulted primarily from differences between the Ramapo flow assumed in the day-ahead market and the actual operation of the Ramapo line from late-January to late February.
  - This difference occurred for several weeks after the beginning of M2M Ramapo Coordination between NYISO and PJM because the assumed distribution of PJM-NYISO flows on to the Ramapo line was updated in the Real-Time market in

conformance with the JOA on January 22 and in the Day-Ahead Market on February 11.[153]

- 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 of $7 million.[154]

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 Oct.) or the Winter Capability Period (Nov. to Apr.), as 1-year products for two consecutive capability periods, and as 2-year products for four consecutive capability periods.[155] 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 the Auction.

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 Auction. Each monthly Reconfiguration Auction consists of only one round.

Figure A-64: TCC Cost and Profit by Path Type

Figure A-64 summarizes TCC cost and profit for the Winter 2012/13 and Summer 2013 Capability Periods (i.e., the 12-month period from November 2012 through October 2013). 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*.

153 See Technical Bulletin #152.

154 The settlement formulae are provided in Section 8.2 of NYISO OATT Section 35.22.

155 2-year TCCs were first sold in the Autumn 2011 auctions for the period from November 2011 to October 2013.

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 12-month Capability Period; (b) Four rounds of six-month auctions for the Winter 2012/13 Capability Period; (c) Four rounds of six-month auctions for the Summer 2013 Capability Period; and (d) Twelve reconfiguration auctions for each month of the 12-month Capability Period.

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.[156] 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.

156 For example, a 100 MW TCC from Indian Point 2 to Arthur Kill 2 will be 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. Component No.1 and No. 3 belong to the intra-zone category and Component No. 2 belongs to inter-zone category.

Figure A-64: TCC Cost and Profit by Path Type
Winter 2012/13 and Summer 2013 Capability Periods

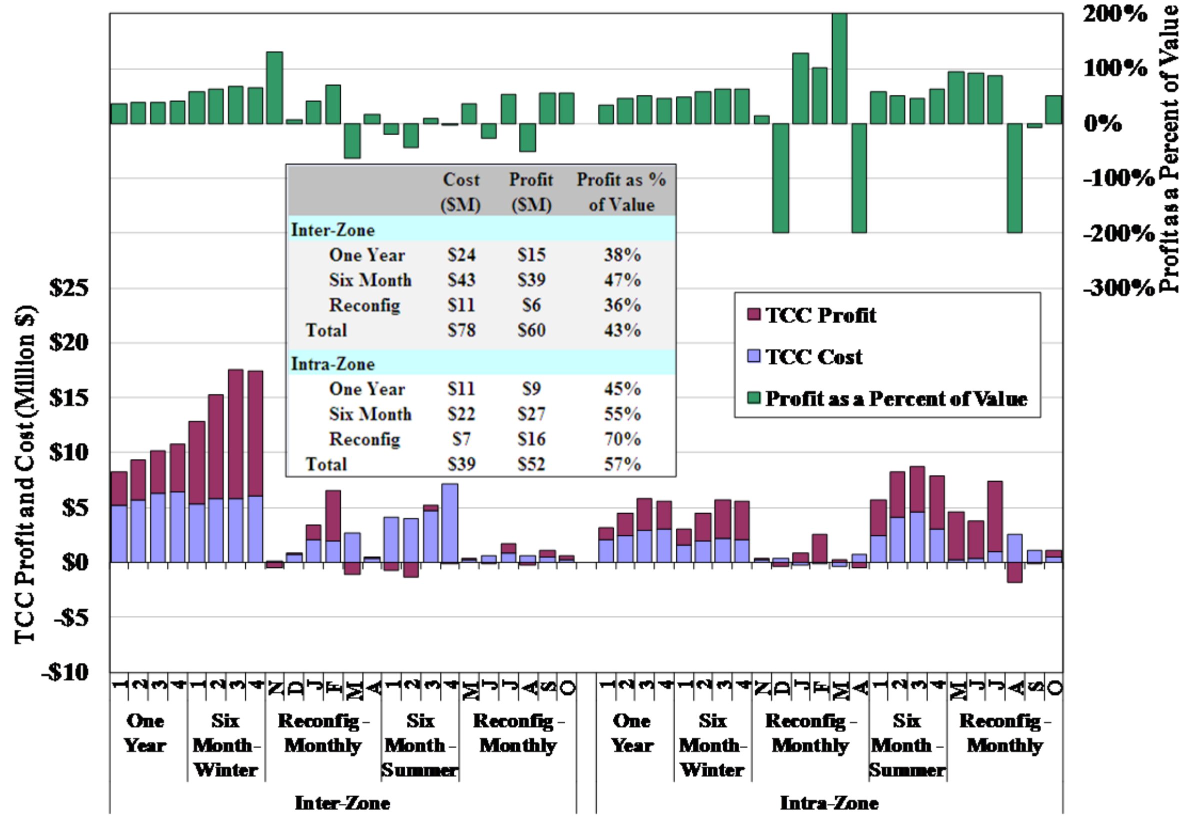


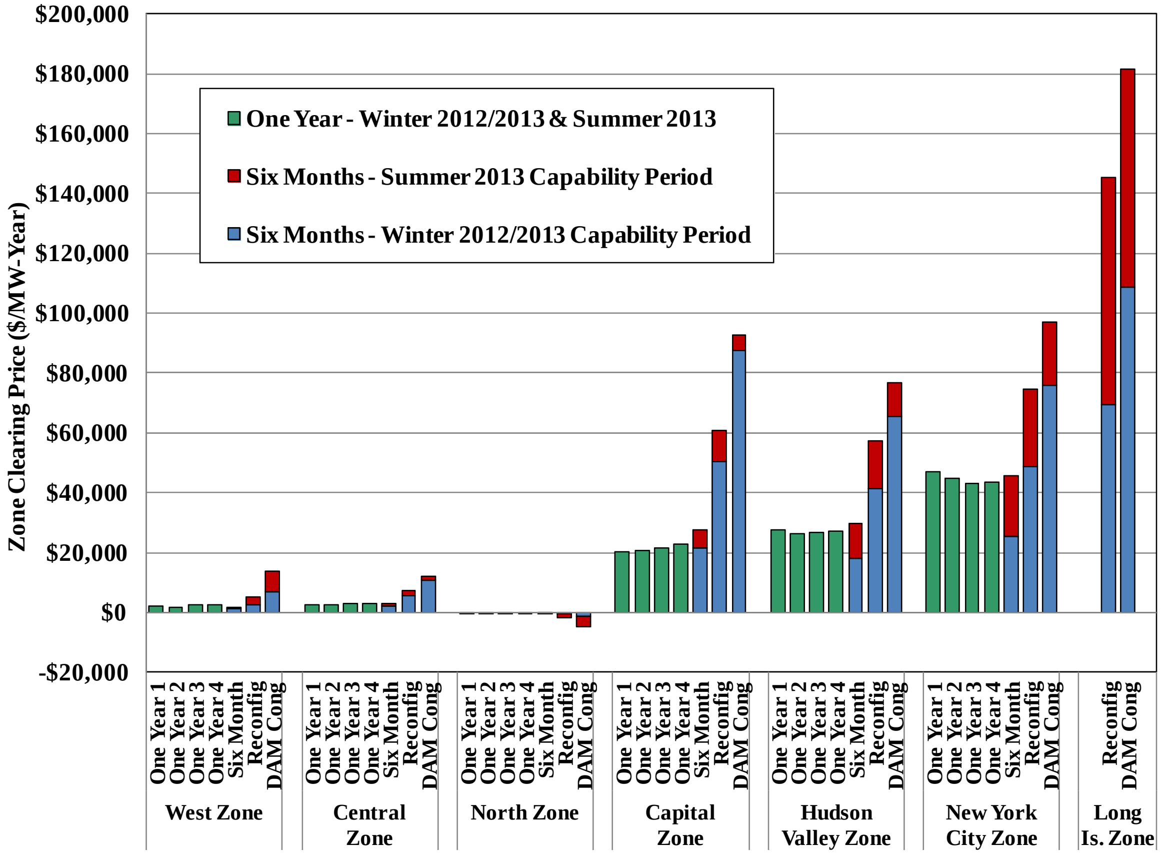
Figure A-65: TCC Prices and Day-ahead Congestion by Zone

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 2013. Figure A-65 compares the TCC prices for the Winter 2012/13 and Summer 2013 Capability Periods (i.e., the 12-month period from November 2012 through October 2013) 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 2012.
- *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-65 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 does not sell TCCs that source or sink in Long Island in those auctions.

Figure A-65: TCC Prices and DAM Congestion by Zone
Winter 2012/13 and Summer 2013 Capability Periods



Key Observations: TCC Prices and Profitability

- Overall, the day-ahead congestion was well above the TCC prices in all of the TCC auctions, which led to substantial profits for the TCC buyers.
  - These results indicate that the sharp increase in congestion that occurred in 2013 was not anticipated by the participants in the TCC markets.
  - As explained above, the increase in overall congestion was largely associated with higher natural gas prices and larger spreads in natural gas prices between Western and Eastern New York and between New York and New England.
  - The results of the TCC auctions indicate that the level of congestion was increasingly recognized by the markets as the TCC prices increased from the annual auction to the auction of six-month TCCs, and rose further in the reconfiguration auction.

- Traders netted a profit of $112 million in the TCC auctions during the 12-month period (November 2012 to October 2013).
  - Profitability (profit as a percent of TCC payout) averaged nearly 49 percent, although it varied widely from auction to auction and among different types of TCCs (inter-zone vs. intra-zone).
  - Over the winter 2012/13 capability period, natural gas prices were generally higher than anticipated at the time of the one-year and six-month TCC auctions, contributing to larger than expected congestion-related inter-zonal LBMP differences, particularly between zones across the Central-East interface.
  - Over the summer 2013 capability period, the profitability of inter-zonal TCCs were modest overall, reflecting the inter-zonal TCC prices were relatively consistent with expectations in the TCC auctions.
  - A significant share of Intra-zonal TCC profits accrued on the transmission constraints in the West Zone, as the congestion pattern was not anticipated at the time of TCC auctions for reasons discussed in subsection B.

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.[157,158] 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).

157 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.

158 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-66 to Figure A-69: 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 2012 and 2013. 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-66, the primary interfaces with Quebec and New England in Figure A-67, and the controllable lines connecting Long Island and New York City with PJM and New England in Figure A-68 and Figure A-69.

Figure A-66: Monthly Average Net Imports from Ontario and PJM
2012 – 2013

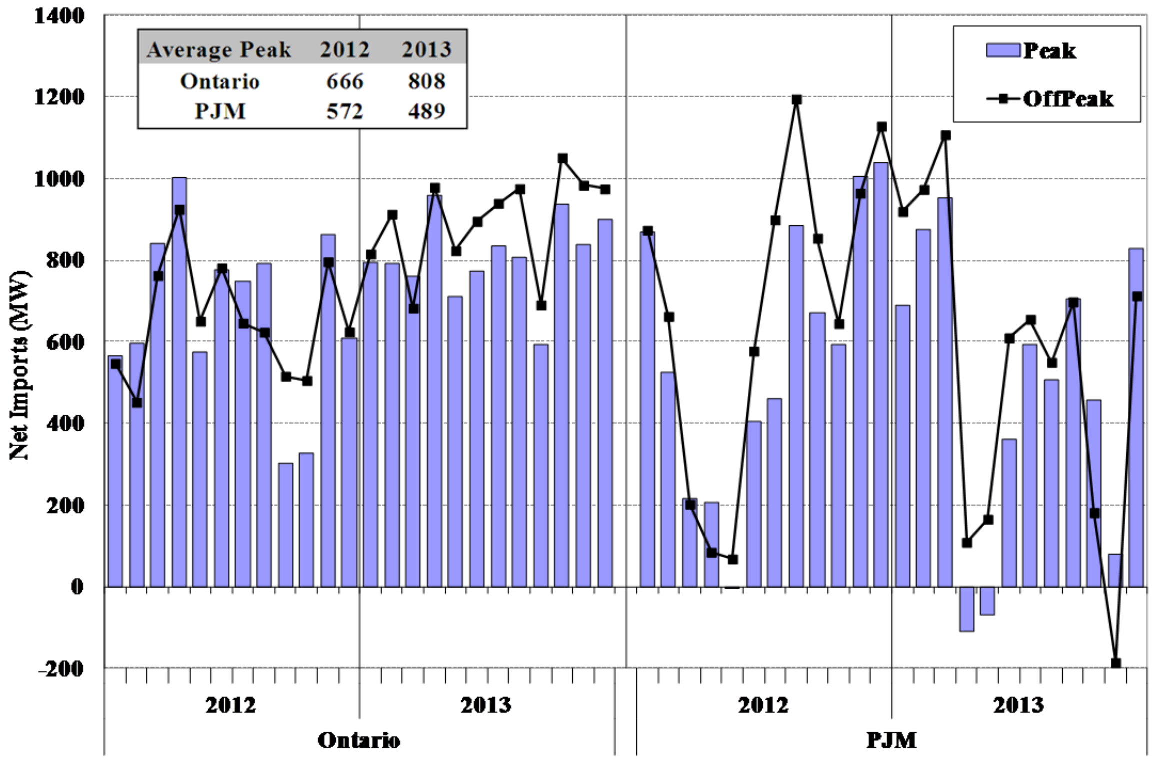


Figure A-67: Monthly Average Net Imports from Quebec and New England
2012 – 2013

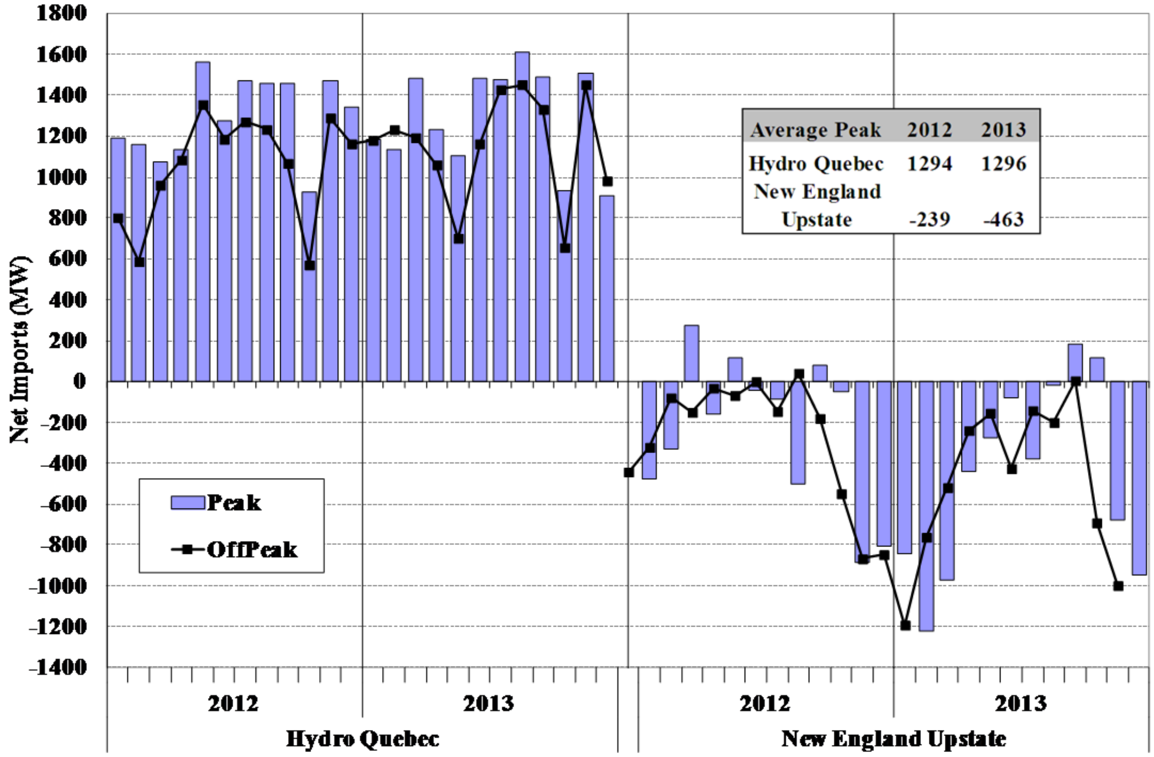


Figure A-68: Monthly Average Net Imports into New York City
2012 – 2013

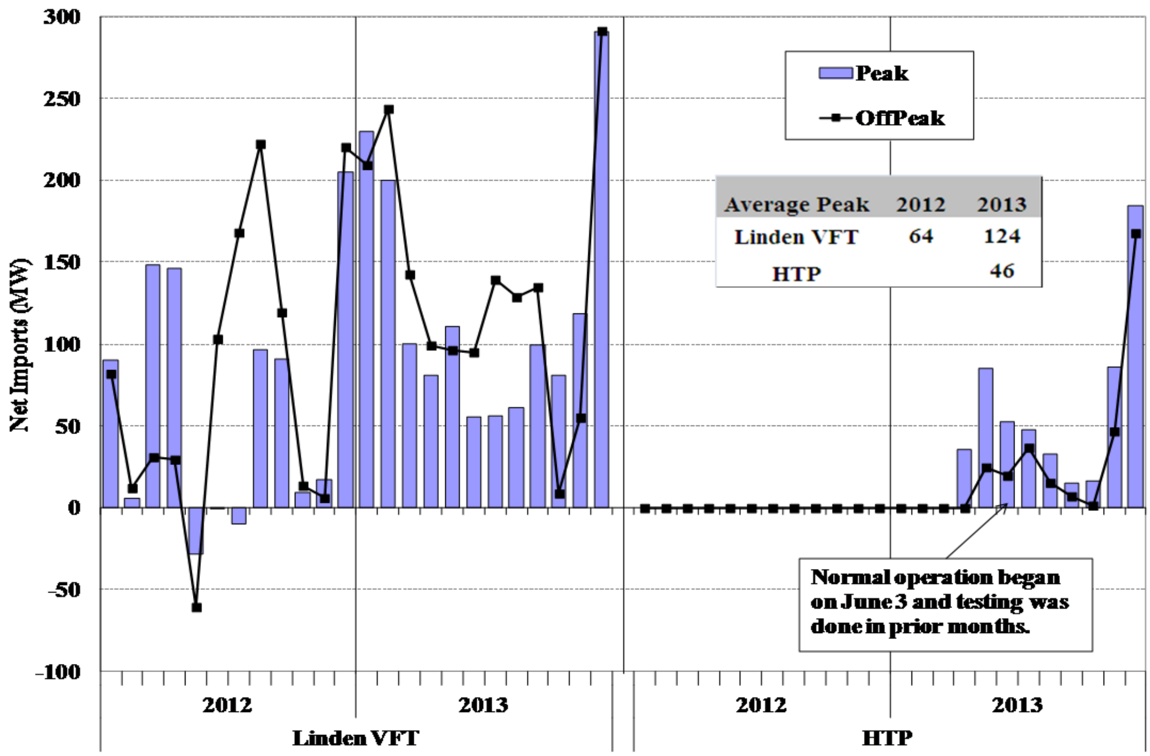
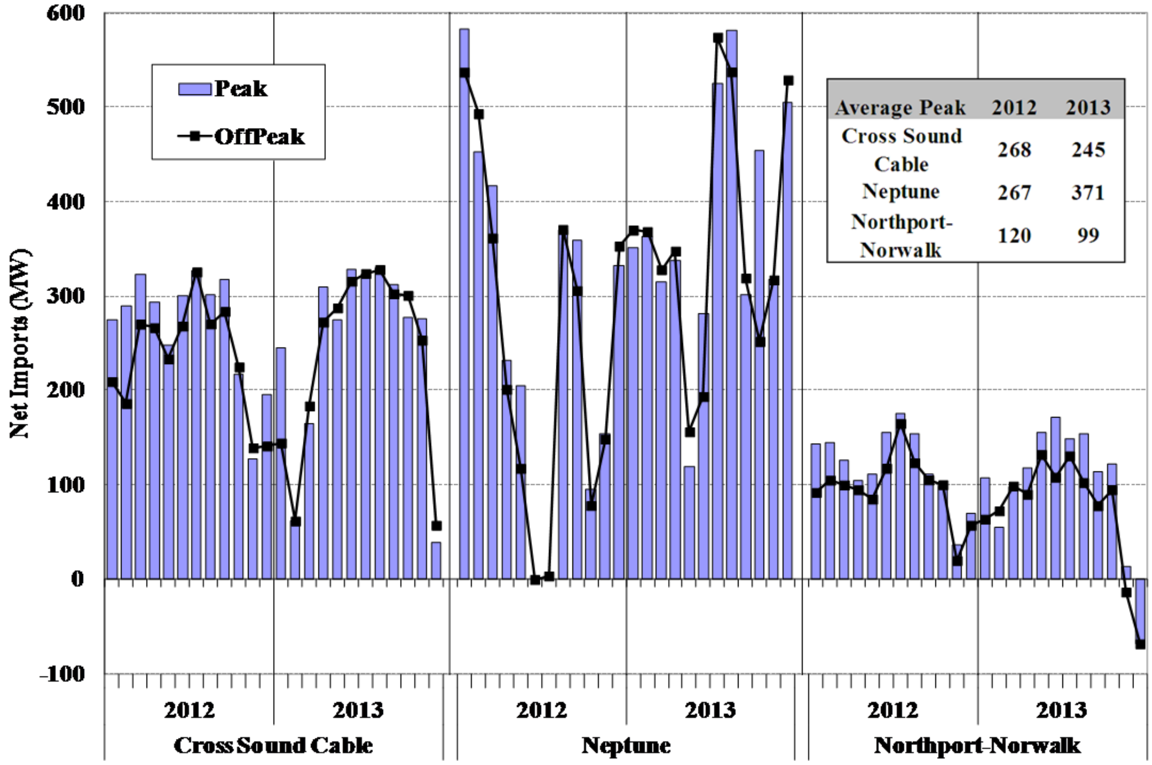


Figure A-69: Monthly Average Net Imports into Long Island
2012 – 2013



Key Observations: Average Net Imports

- Average net imports from neighboring areas across the primary interfaces fell modestly from 2,293 MW in 2012 to 2,131 MW in 2013 during the peak hours.
  - Net imports from Hydro Quebec averaged nearly 1,300 MW, accounting for 61 percent of net imports across the primary interfaces.
  - Net imports from Ontario rose in 2013 by 21 percent (or roughly 140 MW) partly because of more attractive energy prices in New York. Average real-time energy prices were approximately $9/MWh higher on the NYISO-side of the interface than on the Ontario side (see Table A-5). .
  - Net imports from PJM fell 14 percent in 2013 from 2012, averaging roughly 490 MW during peak hours. The decrease was partly affected by extended outages of two PAR-controlled lines between New York and New Jersey (i.e., the Ramapo lines).
    - The outages caused the shift of flows across the primary NYISO-PJM interface such that more would flow from western Pennsylvania to western New York rather than from New Jersey to New York City and the Hudson Valley.

    – The shift in flows led to a corresponding decrease in LBMPs on the NYISO side of the interface, which reduced the incentives for scheduling power from PJM to the NYISO.

  - Net exports to New England across the primary interface increased nearly 94 percent (or 225 MW), which occurred primarily in the winter months when the spread in natural gas prices between New England and New York rose notably from the rest of year and the prior winter as well.

- Average net imports from neighboring areas into Long Island over the three controllable interfaces averaged 715 MW during peak hours in 2013.

  - Net imports across the Neptune line rose in the second half of 2013 because the line fully returned to service in early July from a year-long outage (the transfer capability was only 375 MW from August 2012 to June 2013).

  - Net imports over the Cross Sound Cable and the Northport-Norwalk Line were normally consistent from month to month absent of transmission outages. However, they fell significantly in the winters of both 2012 and 2013, when natural gas prices in New England rose significantly above the natural gas prices in Long Island.

  - 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 28 percent of the load in Long Island in 2013, up modestly from 25 percent in 2012.

- Average net imports from New Jersey to New York City over the Linden VFT and the HTP interfaces averaged 170 MW during peak hours in 2013.

  - Net imports across the two controllable interfaces typically rose in the winter months when constraints of gas supply were more frequent in New York City and led to elevated energy prices.   .

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.[159] Although circuitous

[159] 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.

transaction scheduling was prohibited after July 2008, loop flows have still generally moved clockwise around Lake Erie in recent years.

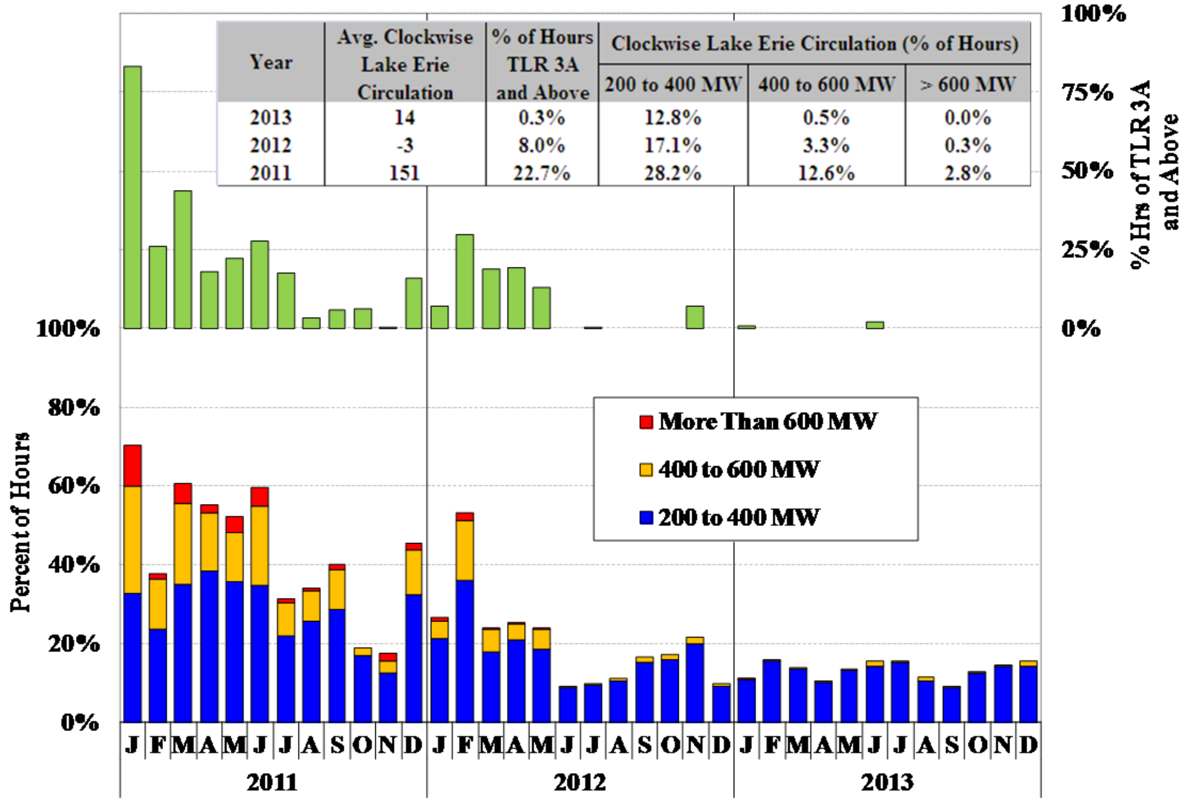
The Transmission Loading Relief ("TLR") procedure is used by the NYISO to curtail transactions in other control areas when loop flows contribute significantly to congestion on its internal flowgates. This NERC Procedure is an Eastern Interconnection-wide process that allows reliability coordinators to 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.[160]

Figure A-70: Lake Erie Circulation

Figure A-70 summarizes the pattern of loop flows for each month of 2011 to 2013. The lower portion of the figure shows the percent of hours in each month when clockwise loop flows were, on average: (a) between 200 and 400 MW, (b) between 400 and 600 MW, and (c) more than 600 MW. 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 2013.

160 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 the only mechanism the NYISO currently has to address the congestion they cause is the TLR procedures it uses to curtail the transactions.

Figure A-70: Lake Erie Circulation
2011 – 2013



<u>Key Observations: Lake Erie Circulation</u>

- Clockwise loop flows decreased substantially in the past three years.
  - Average hourly clockwise circulation fell from 151 MW in 2011 to near 0 MW in both 2012 and 2013.
  - The percent of hours when clockwise circulation exceeded 400 MW also fell notably from 15 percent in 2011 to 4 percent in 2012 and less than 1 percent in 2013.
- 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 during only 23 hours (or 0.3 percent of all hours in 2013, down significantly from 1,993 hours (or 23 percent of all hours) in 2011 and 699 hours (or 8 percent of all hours) in 2012.

- IESO-Michigan PARs, which MISO and IESO have stated are capable of controlling up to 600 MW of loop flows around Lake Erie, began operating in April 2012, contributing to the decrease in clockwise loop flows from prior years.[161]
  - The PARs are generally not adjusted until the loop flows exceed or are expected to exceed 200 MW for a substantial period of time.
  - When the NYISO calls a TLR and the PARs are deemed to be in "regulate" mode, transactions scheduled across the IESO-Michigan interface are not subject to the TLR.
    - There were times in 2012 and 2013 when the clockwise circulation rose above 200 MW for several hours, contributing to congestion on a NYISO flow gate, but the NYISO was unable to use the TLR process to manage the congestion or the use of the TLR process was delayed because the PARs were deemed to be in "regulate" mode, further reducing the frequency of TLRs.
    - Congestion on 230kV lines in the West Zone limited flows from west-to-east much more frequently in 2013 than in previous years. 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.

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.

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

- Differences in scheduling procedures and timing in the markets serve as barriers to full arbitrage.
- There are transaction costs associated with scheduling imports and exports that diminish the returns from arbitrage. Participants cannot be expected to schedule additional power between regions unless they anticipate a price difference greater than these costs.
- The risks associated with curtailment and congestion reduce participants' incentives to schedule external transactions when expected price differences are small.

Figure A-71: Price Convergence Between New York and Adjacent Markets

Figure A-71 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-71 summarizes price differences between New York and neighboring markets during unconstrained hours in 2013. 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-71: Price Convergence Between New York and Adjacent Markets
Unconstrained Hours in Real-Time Market, 2013

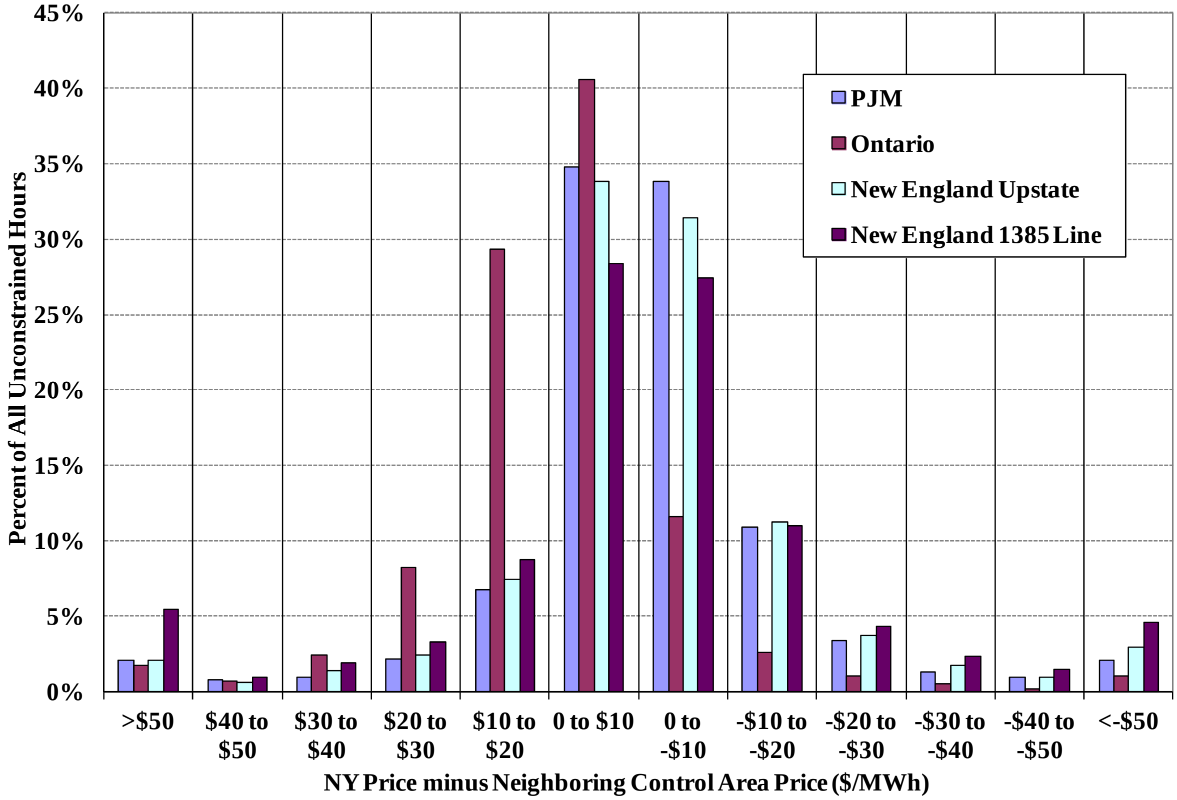


Table A-5 and Figure A-72: Efficiency of Inter-Market Scheduling

Table A-5 evaluates the consistency of the direction of external transaction scheduling and price differences between New York and New England, PJM, and Ontario during 2013. It evaluates real-time 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 average hourly real-time flows between neighboring markets and New York. A positive number indicates a net import from neighboring areas to New York. The table also shows the average real-time 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. Additionally, the table reports 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).

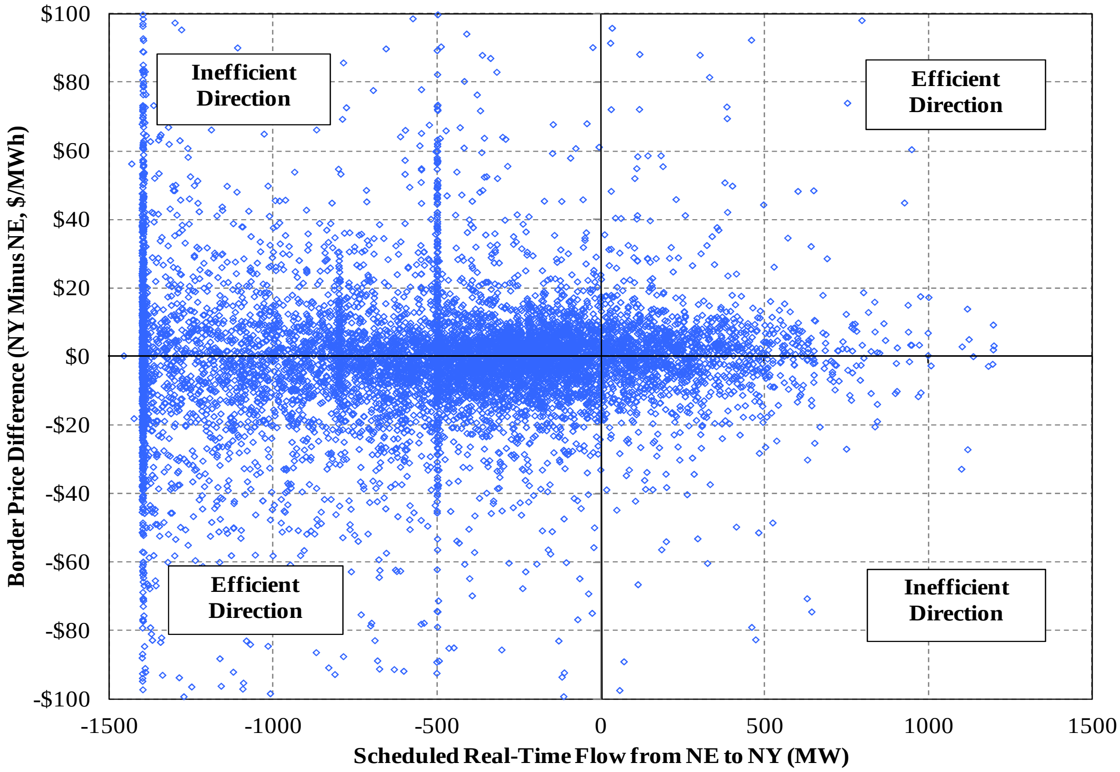
Figure A-72 shows a scatter plot of net scheduled flows versus price differences between New England and New York across the primary interface. The figure shows hourly price differences in the real-time market on the vertical axis versus net imports scheduled in the real-time market (which include day-ahead schedules) on the horizontal axis. Points in the top-right and bottom-left quadrants of the figure are characterized as scheduled in the efficient direction, that is, power was scheduled in the correct direction 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, that is, power was scheduled in the wrong direction from the higher-priced market to the lower-priced market. Good market performance would be indicated by the predominance of the hours scheduled in the efficient direction.

Both Table A-5 and Figure A-72 evaluate 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.

Table A-5: Efficiency of Inter-Market Scheduling
Over Primary Interfaces and Scheduled Lines – 2013

	Average Net Imports (MW/h)	Avg Internal Minus External Price ($/MWh)	Percent in Efficient Direction
Free-flowing Ties			
New England	-485	-$1.57	53%
Ontario	853	$9.05	82%
PJM	515	-$0.41	54%
Controllable Ties			
1385 Line	86	-$0.33	54%
Cross Sound Cable	241	$6.02	54%
Neptune	365	$20.46	68%
HTP	52	$3.65	65%
Linden VFT	131	$7.51	64%

Figure A-72: Efficiency of Inter-Market Scheduling
Over Primary Interface from New England to New York – 2013



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 14 to 24 percent of unconstrained hours in 2013.
  - Transactions scheduled by market participants flowed in the profitable (i.e., efficient) direction in slightly over half of the hours on most interfaces between New York and neighboring markets during 2013.
    - For example, power was scheduled in the profitable direction in 54 and 53 percent of the hours over the PJM and New England interfaces, respectively.
    - The efficiency of scheduling over the controllable lines exhibited similar scheduling efficiency, ranging from 54 percent on the 1385 Line to 68 percent on the Neptune Cable.

  - Hence, 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 2013, 15-minute scheduling had been enabled at five interfaces and substantial progress had been made on CTS with PJM and ISO 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.[162,163]

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 will implement CTS on the primary interface with PJM based on Tariff provisions that were approved by the Commission on February 20, 2014. Implementation is scheduled to occur in November 2014.

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162 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.

163 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.

Figure A-73 – Figure A-75: Bidding and Scheduling Patterns at the 15-minute Scheduling Interfaces

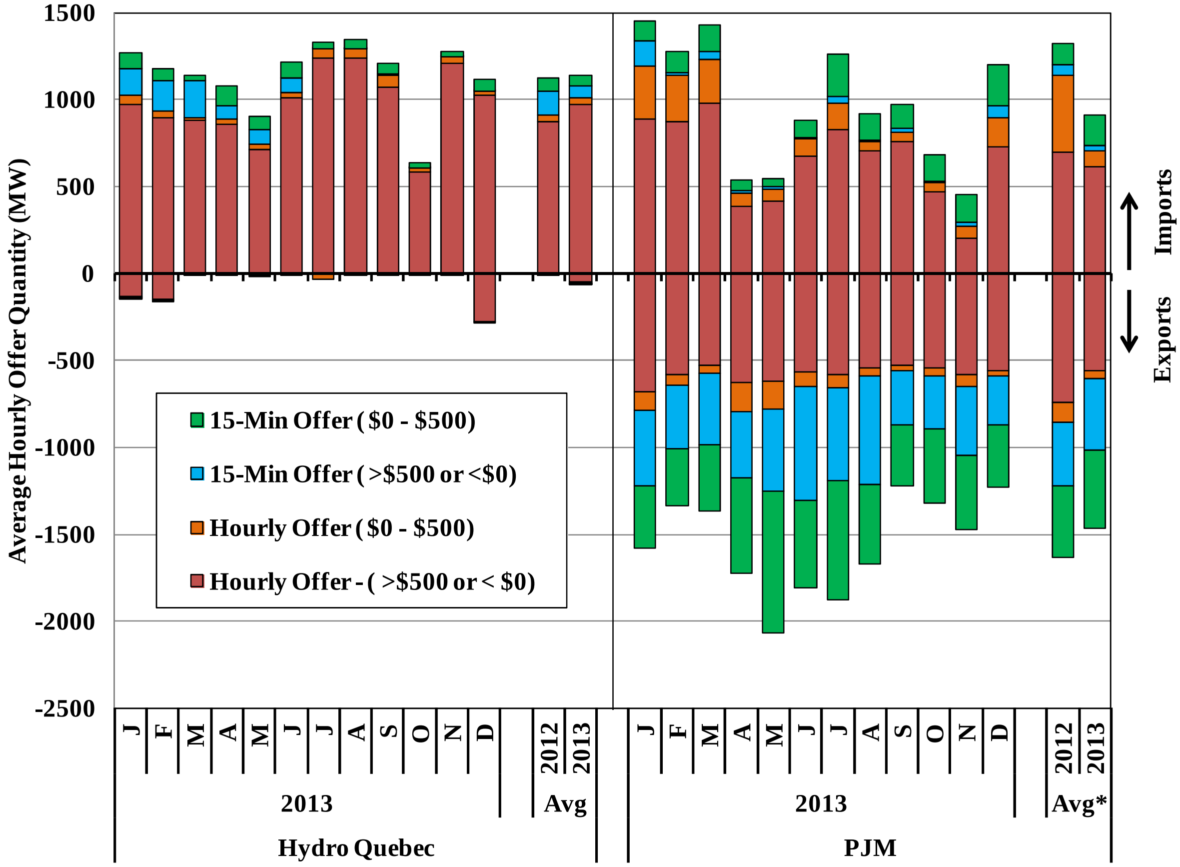
The following analyses examine the pattern of transaction bids, offers, and schedules across the interfaces that allow changes at the quarter-hours (i.e., at :15, :30, and :45 past each hour) in 2013. At the Neptune interface, real-time transactions are normally not offered at levels that differ from the day-ahead schedules. At the Linden VFT interface, participants have not taken advantage of the 15-minute scheduling, and almost all the real-time offers are still hourly-scheduling based. At the HTP interface, the amount of scheduled transactions was very limited for most of 2013. Therefore, these analyses focus on the two primary interfaces with HQ and PJM.

Figure A-73 shows the average bid and offer quantities across the primary HQ and PJM interfaces in each month of 2013. Bids and offers are grouped and shown in the following four categories: 1) hourly-scheduling based bids and offers that were priced between $0 and $500/MWh; 2) hourly-scheduling based bids and offers that were priced below than $0/MWh or above $500/MWh; 3) 15-minute-scheduling based bids and offers that were priced between $0 and $500/MWh; and 4) 15-minute-scheduling based bids and offers that were below $0/MWh or above $500/MWh. 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 2012 and 2013 on an annual basis for the two interfaces.

Figure A-74 shows the distribution of the size and direction of schedule changes at the quarter-hours across the primary HQ and PJM interfaces in 2013. The analysis excludes changes that occur at the top of the hour (i.e., at :00). The bars in the chart show the percent of quarter-hour intervals for each MW-range (i.e., the quarter-hour intervals that do not have a schedule change are not included in the chart). The table in the chart shows the overall frequency and the magnitude of these quarter-hour changes at the two interfaces. Positive numbers indicate schedule changes in the import direction (i.e., more imports into New York or less exports from New York) and negative numbers indicate schedule changes in the export direction (i.e., more exports from New York or less imports into New York).

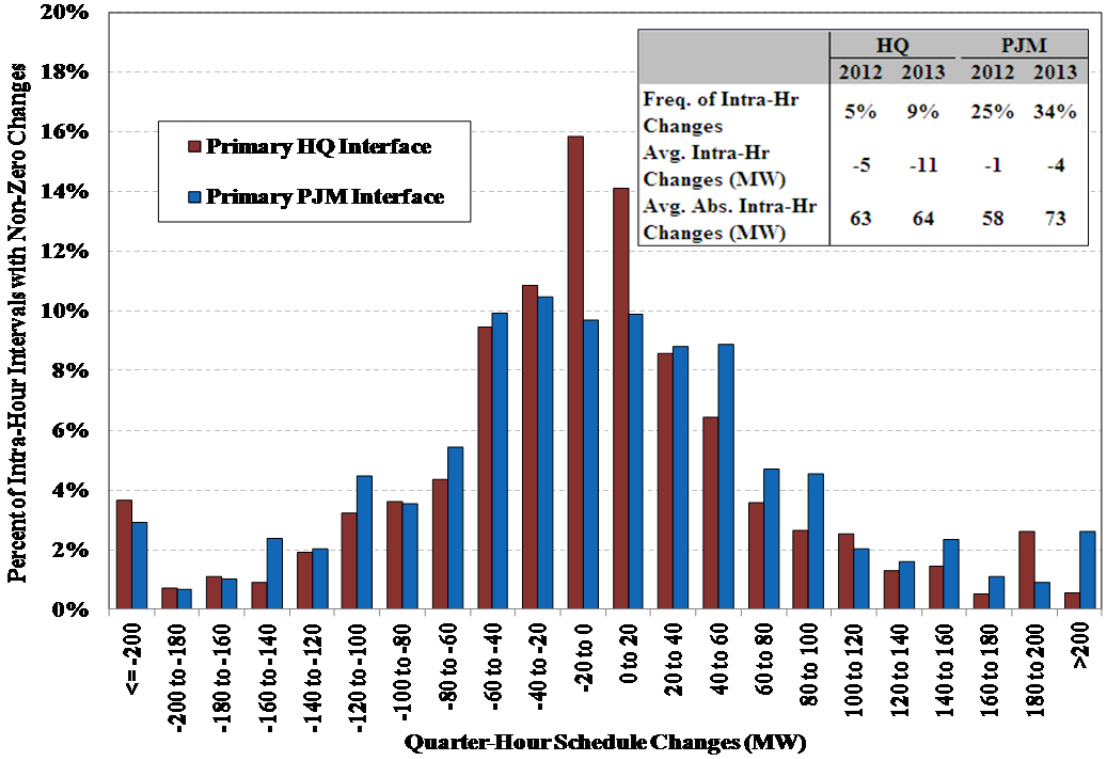
Figure A-75 shows the frequency of quarter-hour schedule changes at different times of day at the primary HQ and PJM interfaces in 2013. The horizontal axis shows all quarter-hour intervals (i.e., :15, :30, and :45 intervals of each hour) and exclude top of hour schedule changes. The vertical axis shows the percent of intervals when the net schedules change from the previous interval in the import direction and the export direction for each interface.

Figure A-73: Average Transaction Bids and Offers by Type by Month[164]
Primary Interfaces with PJM and HQ, 2012-2013



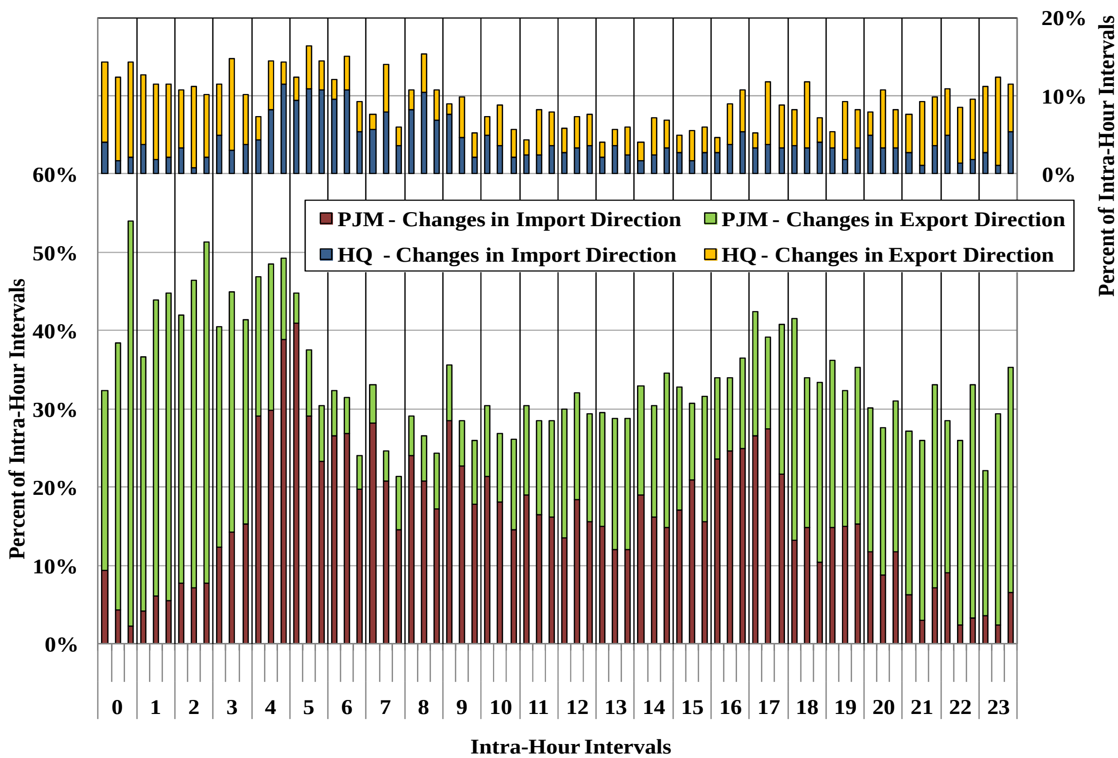
164 To make a more direct comparison, the annual averages for PJM are based on offers from July to December of 2012 and 2013, since 15-minute scheduling started at the end of June 2012.

Figure A-74: Distribution of Quarter-Hour Schedule Changes by Quantity
Primary Interfaces with PJM and HQ, 2013



	HQ		PJM	
	2012	2013	2012	2013
Freq. of Intra-Hr Changes	5%	9%	25%	34%
Avg. Intra-Hr Changes (MW)	-5	-11	-1	-4
Avg. Abs. Intra-Hr Changes (MW)	63	64	58	73

Figure A-75: Distribution of Quarter-Hour Schedule Changes by Time of Day
Primary Interfaces with PJM and HQ, 2013



Key Observations: Intra-Hour Scheduling with Adjacent Control Areas

- Intra-hour schedule changes occurred during approximately 9 percent of all quarter-hour intervals at the primary HQ interface and 34 percent of all quarter-hour intervals at the primary PJM interface in 2013, up from 5 and 25 percent in 2012.
  - A much larger share of the transactions at the PJM interface are offered price-sensitively than at the HQ interface.
    - 26 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 PJM interface in 2013, up from 18 percent in 2012. At the HQ interface, only 5 percent in 2013 and 7 percent in 2012 were relatively price-sensitive.
  - Like the NYISO, PJM runs a real-time spot market that allows market participants to buy and sell from the market, which allows them to be more responsive to price changes. In contrast, market participants must find a counterparty in HQ with whom to transact;
  - The prices at the PJM proxy bus are generally more volatile than prices at the HQ proxy bus; and
  - The economic direction in which to flow power changes more frequently between NYISO and PJM than between the NYISO and HQ.
- Intra-hour schedules were typically adjusted in ways that generally reduce price volatility at the top of these hours.
  - Figure A-73 shows that a large volume of bids and offers are submitted that could change every 15-minutes, while Figure A-74 shows the actual size and frequency of intra-hour changes is much smaller. This is because many bids and offers that are capable of changing intra-hour only change when the transaction scheduling model, RTC, forecasts a significant change in market conditions. Hence, the presence of bids and offers that are capable of changing every 15-minutes moderates price volatility and large changes in system conditions.
  - Intra-hour schedules generally adjusted in the export direction during hours when the system is typically ramping-down (e.g., hours-beginning 21 to 23 and hours 0 to 3) and in the import direction during hours when the system is typically ramping-up (e.g., hours-beginning 5 to 10).
  - As shown in Figure A-75, the real-time prices typically move:
    - In an upward direction within each ramping-up hour before dropping sharply at the top of each ramping-up hour; and
    - In a downward direction within each ramping-down hour before rising sharply at the top of each ramping-down hour.

- As shown in Figure A-83, scheduling additional imports at the quarter-hour intervals tends to moderate real-time price variations during ramping-up hours, as do additional exports in ramping-down hours.

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 2013:

- *Efficiency of Gas Turbine Commitment* – This sub-sections 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 line 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 transient price spikes 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) ancillary services shortages, (b) transmission shortages, and (c) periods when reliability demand response is deployed.
- *Supplemental Commitment for Reliability* – Supplemental commitments are necessary when the market does not provide incentives for suppliers to satisfy local reliability requirements. However, supplemental commitments raise concerns because they indicate the market does not provide sufficient incentives, they tend to 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.[165] 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.[166] 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 E.

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.

[165] Quick-start GTs can start quickly enough to provide 10-minute non-synchronous reserves.

[166] 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 2012. 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,[167] 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

[167] 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
2013

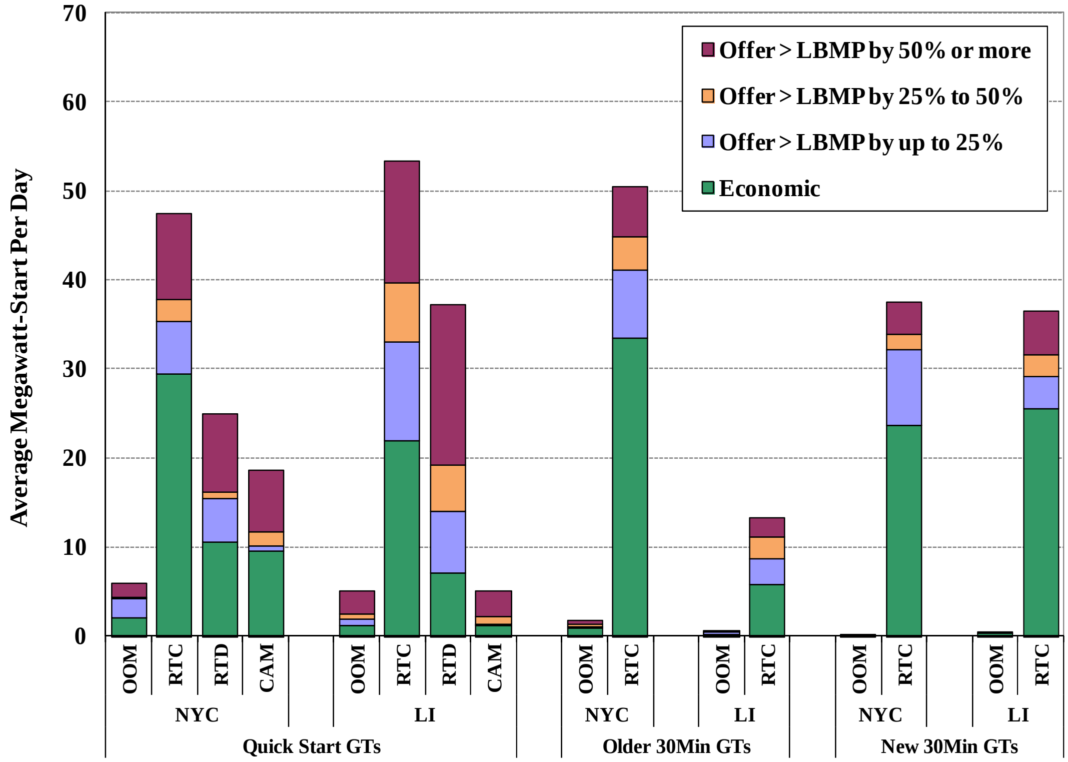


Figure A-77 evaluates the extent to which gas turbines were economic but appeared to be uneconomic because they did not set the LBMP during a portion of the initial commitment period. In particular, we examine every market interval in the initial commitment period of a gas turbine start, which excludes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

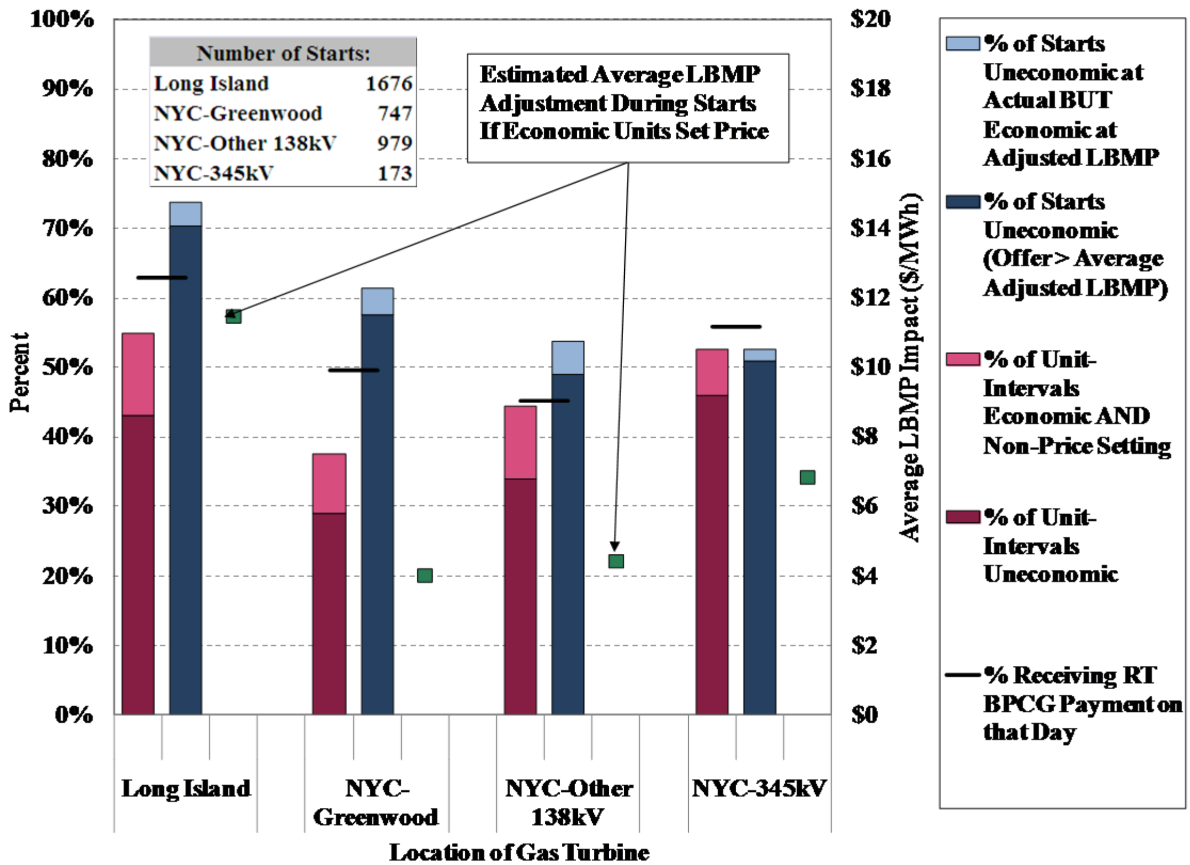
- *Percent of Starts Uneconomic (Offer > Average Adjusted LBMP)* – Share of starts when gas turbine's offer was greater than the average "Adjusted LBMP" over the initial commitment period. (The "Adjusted LBMP" is the price that would have been set if economic gas turbines at the same market location 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

2013



<u>Key Observations: Efficiency of Gas Turbine Commitment</u>

- 71 percent of the gas turbine capacity that was started during 2013 was committed by RTC, with an additional 25 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.
    - 51 percent of all gas turbine commitments were clearly economic in 2013.
    - An additional 17 percent of all gas turbine commitments were cases when the gas turbine offer was within 125 percent of LBMP in 2013.
    - Hence, the NYISO's real-time market models are relatively effective in committing gas turbines efficiently.
- Once committed, gas turbines were economic in 55 to 68 percent of the five-minute intervals during their initial one-hour commitment period (excluding self schedules and local reliability commitments) in 2013. (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 2013, economic gas turbines did not set LBMP in 7 to 12 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 $4 to $12 per MWh for each start in New York City and Long Island in 2013.
        - The higher LBMPs would generally 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.[168] M2M includes two types of coordination:

168 The terms of M2M coordination are set forth in NYISO OATT Section 35.23, which is Schedule D to Attachment CC.

- 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 PAR-controlled line is adjusted to reduce overall congestion.

Figure A-78 – Figure A-80: Efficiency of M2M Coordination with PJM

The use of Re-dispatch Coordination was infrequent in 2013, 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 2013.

Figure A-78 compares the actual flows on Ramapo PARs with their M2M operational targets in 2013. 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.[169]
- 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.[170]

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.

[169] This assumed share changed from 61 percent to 46 percent in May and remained at this lower level throughout the rest of 2013 due to the outage of one of the two Ramapo PARs.

[170] 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.

Figure A-78: Actual and Target Flows for the Ramapo Line
During the Intervals with Binding M2M Constraints, 2013

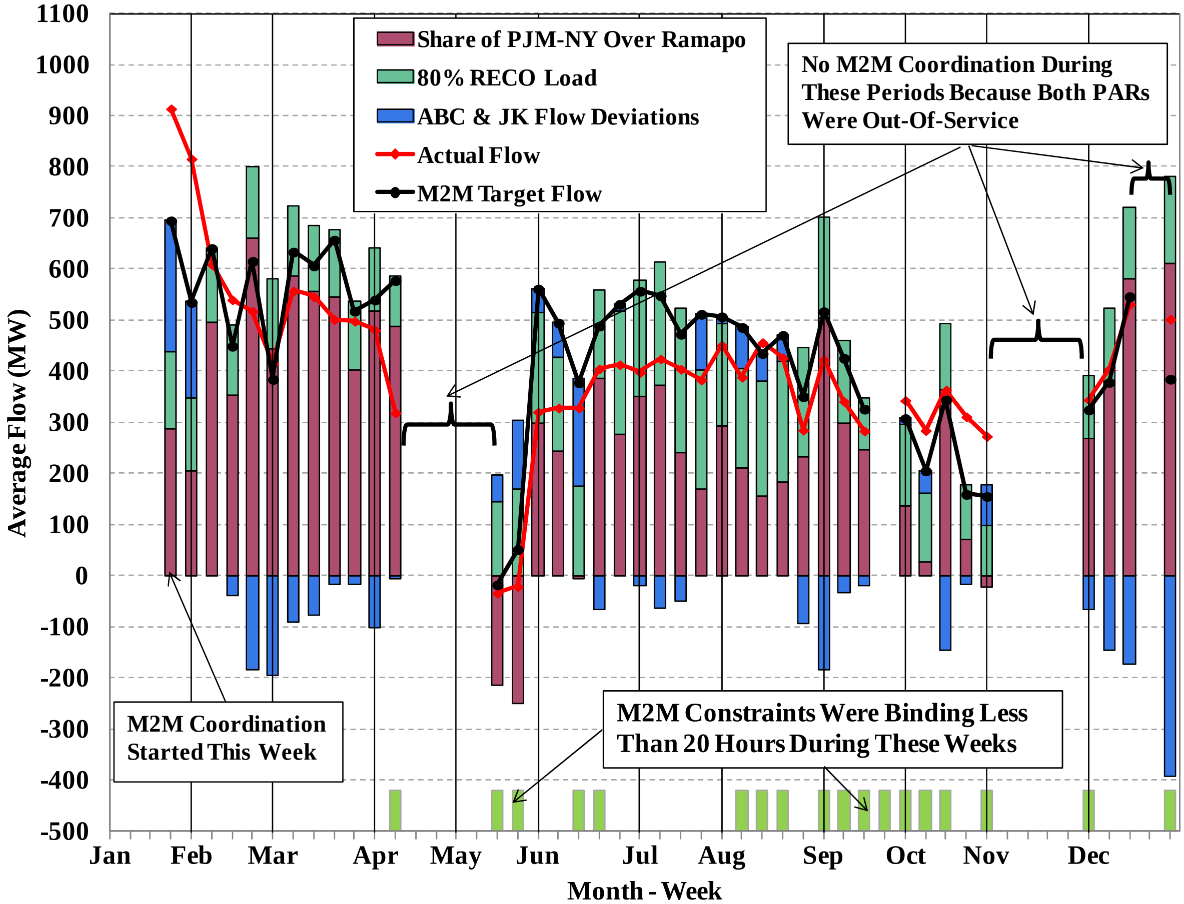


Figure A-79 is a scatter plot of actual Ramapo flow versus the estimated marginal effect of flows across the Ramapo Line on congestion in New York and PJM. The marginal effect is measured as: (a) its marginal effect on congestion in New York minus (b) its marginal effect on congestion in PJM.[171] Negative numbers indicate when it is economic to move power from New York to PJM. The figure includes congestion on both M2M and non-M2M flowgates, so the figure excludes hours when both markets had very little real-time congestion (i.e., marginal effect of Ramapo was less than $10 per MWh in both markets). Hours when the difference exceeded $100 are shown at $100, while hours when the difference was less than -$100 are shown at -$100. The inset table provides summary statistics on the efficiency of Ramapo flows. An hour is deemed relatively efficient if: (a) the marginal effect of Ramapo flows between the two markets was within $20 per MWh, or (b) if the line was approaching its operational limit (i.e., flow on line > 450 MW when one Ramapo PAR was in service, and flow on line > 900 MW when two Ramapo PARs were in service).

171 This measurement does not adjust for the LBMP effects of Scarcity Pricing in New York from July 15 to July 19 when demand response was activated.

Figure A-79: Marginal Effect of Ramapo on NY/PJM Congestion and Actual Ramapo Flow
During Constrained Hours, 2013

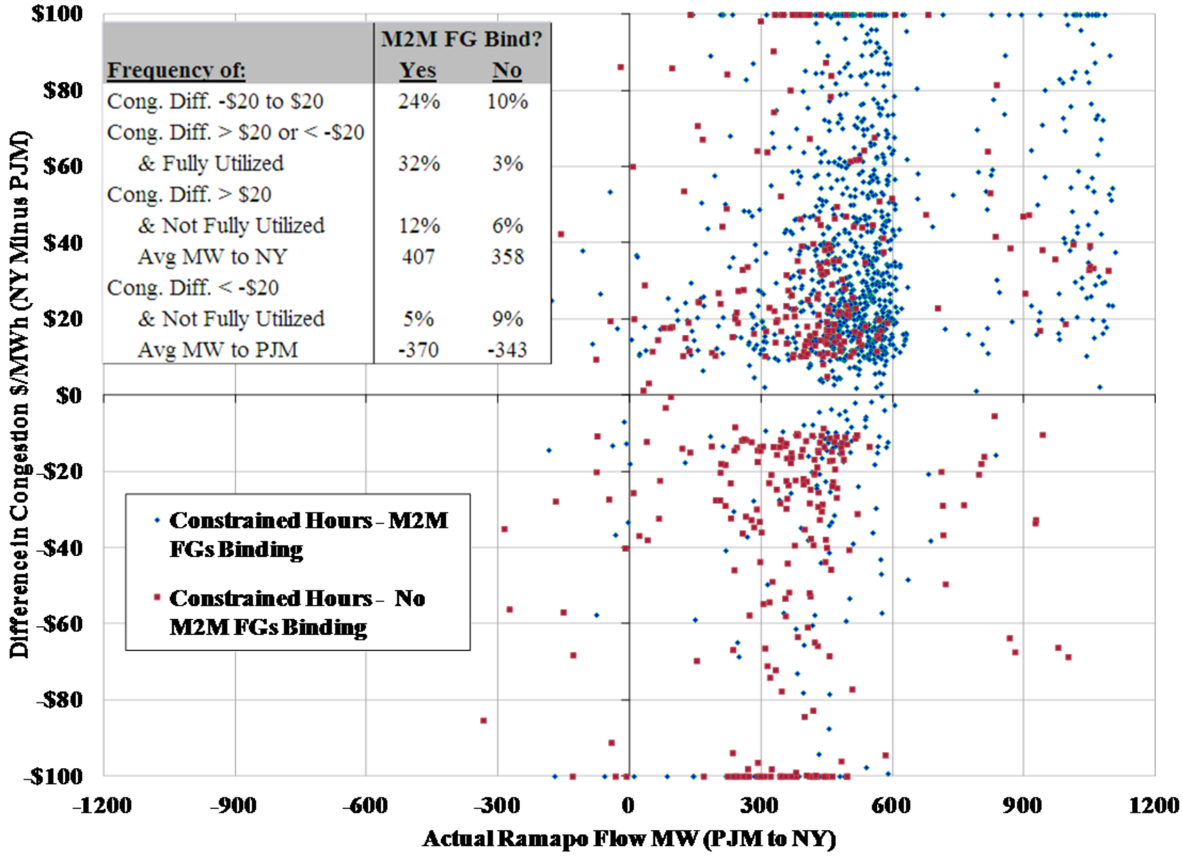
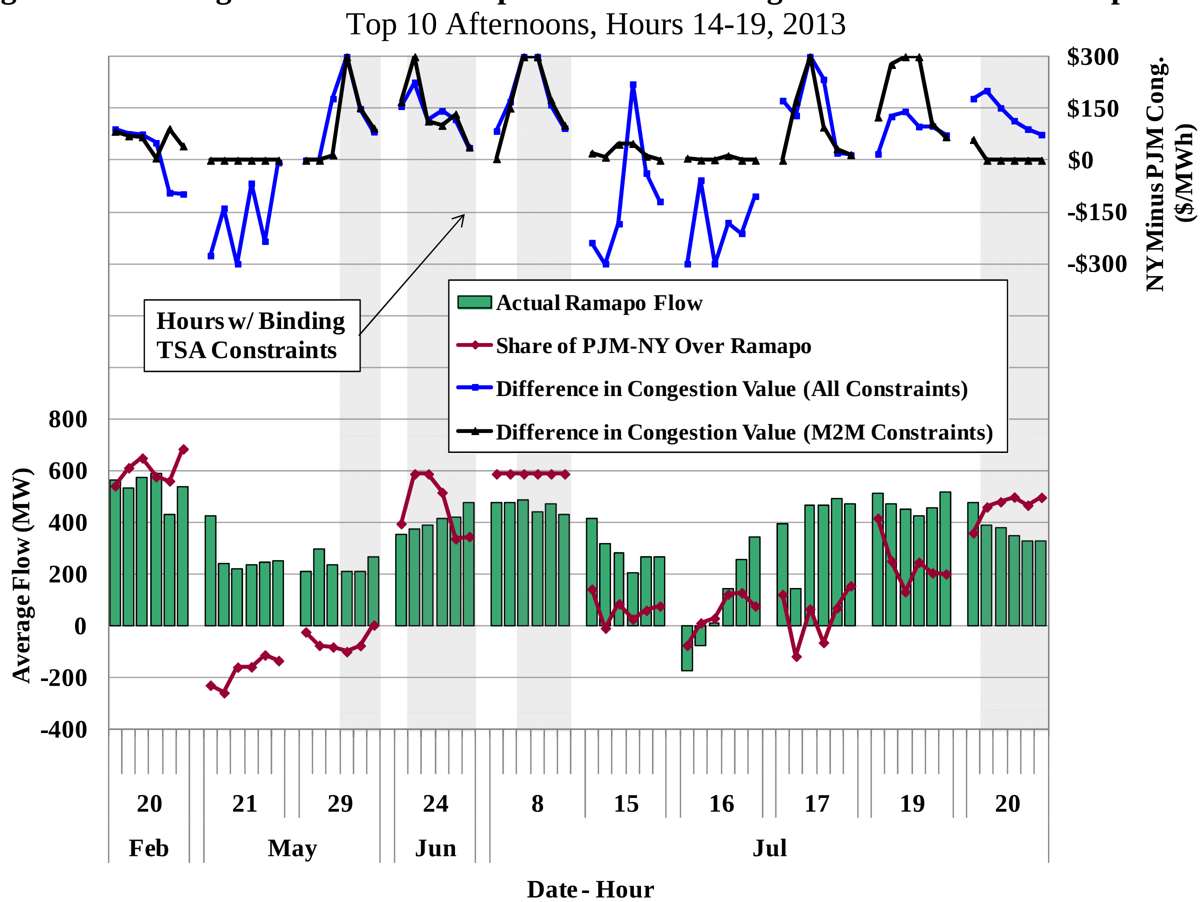


Figure A-80 summarizes the evaluation in Figure A-79 on afternoons (HB 14-19) on ten days of 2013 when congestion was greatest (excluding days when the Ramapo line was out of service). The marginal effect of Ramapo flows are shown separately considering: (a) all binding constraints; and (b) only binding M2M constraints. Hours with binding TSA (Thunderstorm Alert) constraints are shaded.

Figure A-80: Marginal Effect of Ramapo on NY/PJM Congestion and Actual Ramapo Flow



Key Observations: Efficiency of M2M Coordination with PJM

- The use of Re-dispatch Coordination was very limited in 2013. It was activated for: (a) the Central-East interface in a total of less than 160 hours, primarily in the first quarter of 2013; and (b) the Dysinger East interface in roughly 20 hours.
  - These resulted in a total payment of $119k from PJM to the NYISO.
- The use of Ramapo PAR Coordination had far more significant impacts on the market in 2013. However, usage of this process was limited by:
  - The lengthy outages of Ramapo PARs (one PAR was out of service from February 4 through the end of 2013 and the second PAR was out three times for a total of three months); and
  - PJM's suspension of coordination for TSA flowgates since July 12, 2013.
- Actual flow across Ramapo was lower than Target Flow during most intervals of 2013 when M2M constraints were binding.

  - The sum of the components of the Ramapo Target Flow exceeded the physical capability of the Ramapo Line to support an 80 percent share of RECo deliveries, a 46 percent share of PJM-NYISO interchange, and any imbalance on the ConEd-PSEG Wheel on many days.
  - M2M constraints in PJM were rarely binding.
  - Consequently, $7.2 million of M2M payments were made by PJM to NYISO during periods of under delivery (i.e., when actual flow < target flow).
- Of hours with congestion in NYISO or PJM (i.e., when the marginal effect of Ramapo flow was greater than $10 per MWh in one or both markets), Ramapo Line flows were:
  - Reasonably efficient in 68 percent of the hours.
  - Not fully optimized while New York congestion was higher than PJM congestion (by $20 per MWh or more) in 18 percent of the hours.
    - The Ramapo Line still provided substantial benefits to New York in most of these hours.
    - Flows into New York were generally higher in hours with M2M flow gates binding, averaging 407 MW in hours with M2M flow gates binding and 358 MW in other hours.
  - Not fully optimized while PJM congestion was higher than New York congestion (by $20 per MWh or more) in 14 percent of the hours. In these hours:
    - The PJM congestion was more frequently on non-M2M flowgates;
    - The New York congestion was sometimes negative due to West Zone constraints, which can lead LBMPs in the West Zone to exceed those in the Hudson Valley (so that flows across Ramapo into the NYISO actually increase congestion rather than relieve it); and
    - The Ramapo Line usually flowed power out of PJM in these hours (averaging roughly 350 MW).
- On the Top 10 afternoons shown in Figure A-80 the Ramapo line had significant impacts.
  - On six days shown, the Ramapo Line provided relief to the NYISO during periods of significant: (a) Leeds-to-Pleasant Valley congestion (May 29, June 24, July 8, 17, & 19); and (b) Central-East congestion (February 20).
    - The congestion was reflected in the M2M coordination process.
  - On three days shown (May 21, July 15, 16), additional flows into PJM would have been economic due to unusually severe congestion patterns in the West Zone of the NYISO (rather than congestion in PJM).

  - However, the benefit of using the Ramapo Line to relieve West Zone congestion would have been limited because the effectiveness of Ramapo flow adjustments on West Zone constraints is relatively small.

- On the remaining day (July 20), additional flows into New York would have been economic. However,
  - On July 20, congestion occurred on TSA flowgates in New York, whose coordination was suspended by PJM on July 12. PJM's suspension of TSA flowgates will diminish the efficiency of congestion management across the two markets.[172]

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.[173] Such lines are analyzed in Section IV.C 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-6 and Figure A-81: 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 2013.

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[172] The NYISO and PJM have agreed on a proposal to reinstate M2M coordination for TSA flowgates that could be implemented as early as June 2014. See *M2M Coordination: TSA Update and JOA Amendments*, presented by David Edelson to Market Issues Working Group on March 4, 2014.

[173] 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.

Table A-6 evaluates the consistency of the direction of power flows on non-optimized PAR-controlled lines and LBMP differences across these lines during 2013. 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 D.
  - 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-6 shows:

- Average hourly real-time net flows into NYCA or New York City;
- Average real-time price at the interconnection point in the NYCA or New York City minus the average real-time 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.[174]

[174] 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

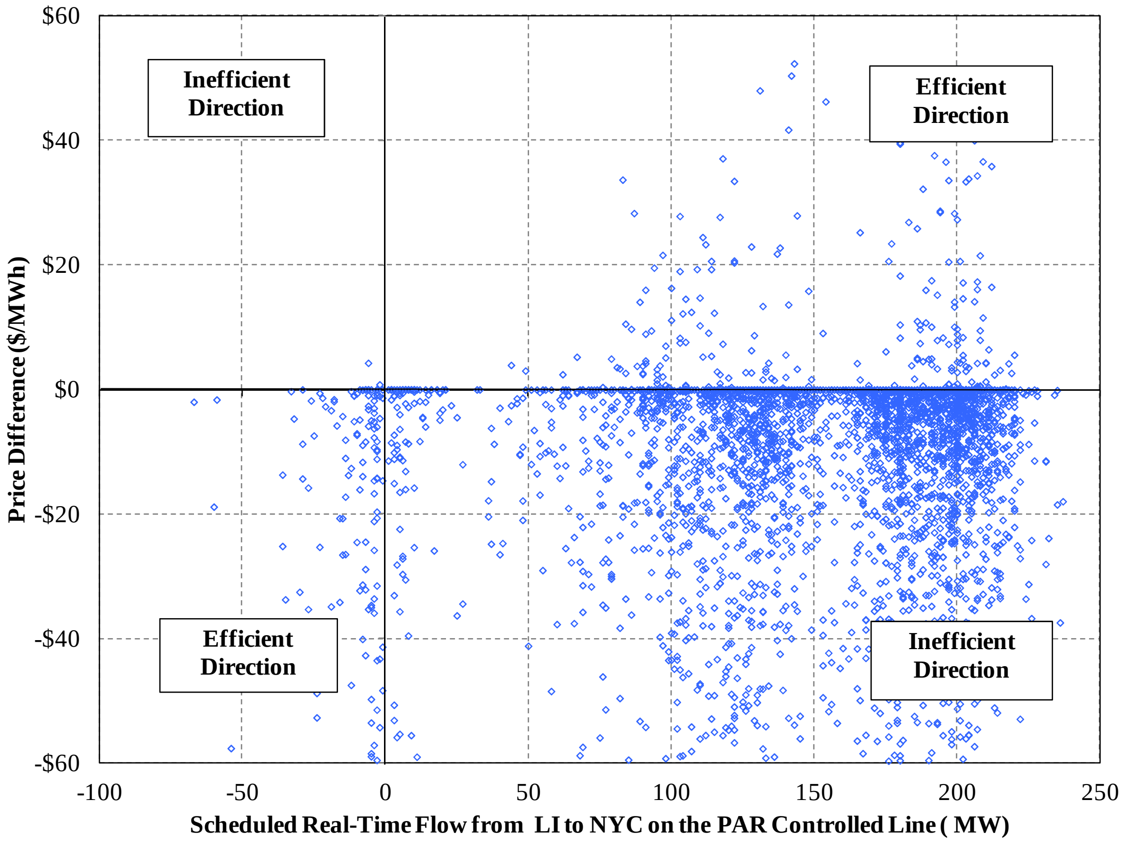
Table A-6: Efficiency of Scheduling on Non-Optimized PAR Controlled Lines
2013

	Average Flow (MW/h)	Avg NYCA Price minus Avg. Price Outside ($/MWh)	Pct of Hours in Efficient Direction	Est. Production Cost Savings
Ontario to New York				
St. Lawerence	14	$10.12	55%	$5
New England to New York				
Sand Bar	-79	-$22.64	76%	$15
PJM to New York				
Waldwick	-901	$6.90	38%	-$58
Ramapo	288	$12.26	69%	$53
Farragut	670	$6.94	62%	$42
Goethals	305	$9.99	64%	$17
Long Island to New York City				
Lake Success	141	-$16.66	10%	-$22
Valley Stream	69	-$31.15	8%	-$21

Figure A-81 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.

region, since if flows were reduced, the cost differential between the marginal resources in each region would converge.

Figure A-81: Efficiency of Scheduling on PAR Controlled Lines
Lake Success-Jamaica Line – 2013



Key Observations: Efficiency of Scheduling over PAR-Controlled Lines

- Power flowed in the efficient direction in the majority of hours on all but one PAR-controlled line between New York and neighboring markets during 2013.
  - The share of hours with power flowing in the efficient direction (from the lower-priced area to the higher-priced area) ranged from 38 percent for the Waldwick lines to 76 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 $6.90 per MWh during 2013.
  - We estimate that the controllable lines between NYCA and adjacent control areas achieved a total of $133 million in net production cost savings, excluding the Waldwick lines.
    - However, the use of the Waldwick lines to support the ConEd-PSEG wheeling agreement *increased* production costs by an estimated $58 million in 2013.[175]

[175] For the reasons noted in Footnote 174, this method of estimating production cost savings tends to over-

   – Significant additional production cost savings could be achieved by improving the scheduling and operation of these lines.

- 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.
   - Power flowed in the inefficient direction in more than 90 percent of hours on the two PAR-controlled lines between Long Island and New York City during 2013, which was comparable to the results in 2011 and 2012.
   - The use of these lines increased production costs by an estimated $43 million in 2013 because prices on Long Island were typically higher than those in New York City (particularly in the Astoria East/Corona/Jamaica pocket where the 901 and 903 lines connect, which is frequently export-constrained).[175]
   - In addition to increasing production costs, these transfers: (a) depress prices in New York City; and (b) can restrict output from economic generators in the Astoria East/Corona/Jamaica pocket. 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).
- 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. It would be highly beneficial modify these contracts or find other ways under the current contracts to operate the lines efficiently.

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

estimate the costs from inefficient scheduling.

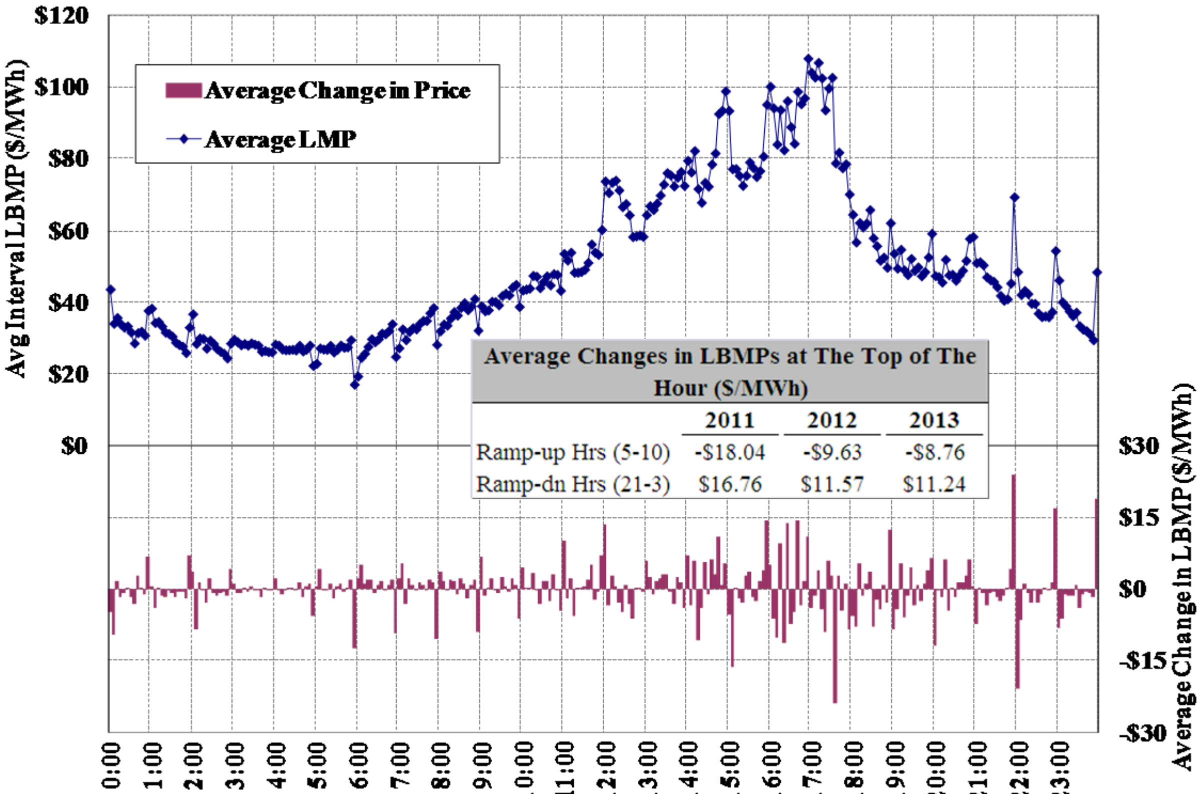
bilateral market. Generally, the ISO should seek ways to reduce unnecessary price volatility while maintaining efficient signals for generators to be flexible in real-time. This sub-section analyzes cyclical patterns of price volatility in real time that tend to occur predictably at certain times of day.[176]

Figure A-82 & Figure A-83: Cyclical Real-Time Price Volatility

Figure A-82 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 2013. The figure shows the load-weighted average prices for all of New York, although the results are similar in each individual zone. The table compares the average size of upward and downward spikes that typically occur at the top of the hour during the ramp-up hours (i.e., hours 5 to 10) and ramp-down hours (i.e., hours 0-3 and hours 21-23) in the past three years.

Figure A-82: Statewide Average Five-Minute Prices by Time of Day

June to August, 2013



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.

176 The *2012 State of the Market Report* also analyzed patterns of transient price volatility in Section VIII.C.2.

Figure A-83 shows the average net changes from one interval to the next for the following five categories of inflexible supply:

- *Net imports* – Net imports ramp at a constant rate from five minutes prior to the top of the hour (:55) to five minutes after the top of the hour (:05). Net imports across the interfaces that allow 15-minute scheduling also ramp from five minutes prior to each quarter-hour interval (i.e., :10, :25, :40) to five minutes after the quarter-hour interval (i.e., :20, :35, :50). In addition, they can change unexpectedly due to curtailments and TLRs before or during the hour.

- *Switches between pumping and generating* – This is when pump storage units switch between consuming electricity and producing electricity.

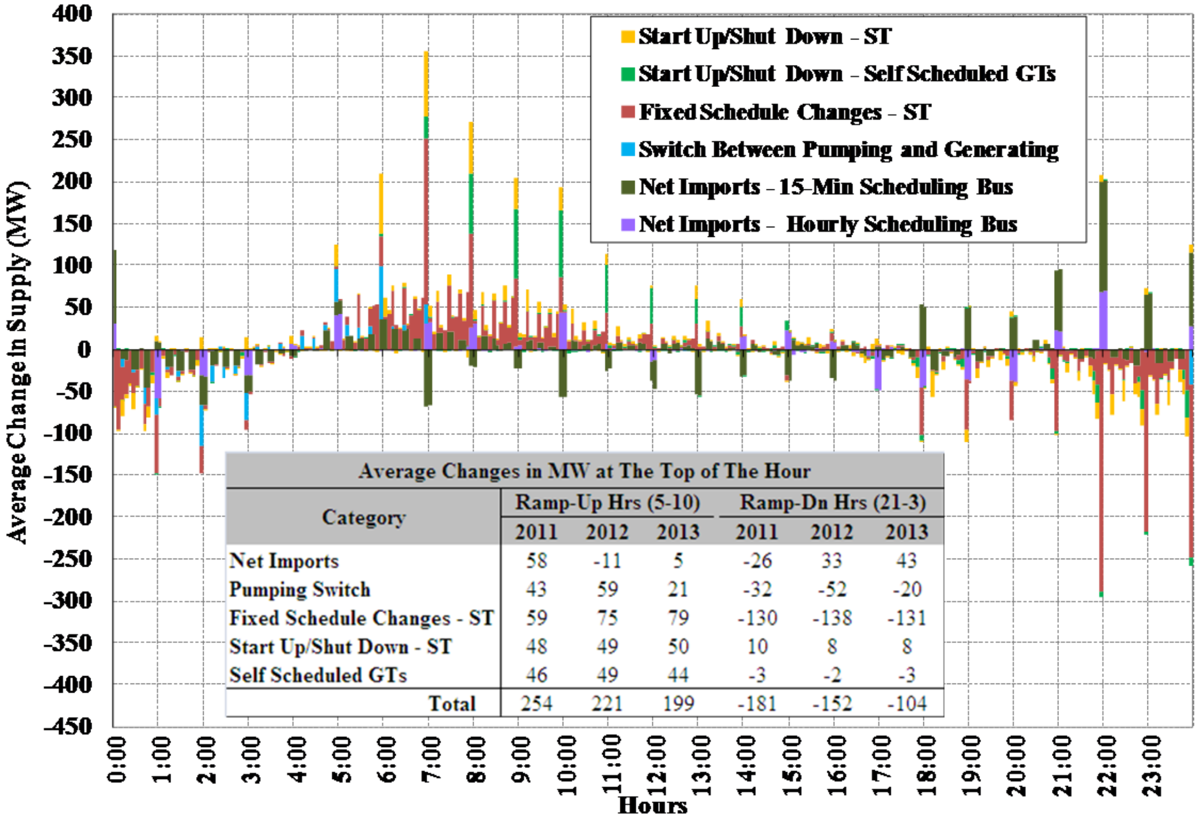
- *Fixed schedule changes for online non-gas-turbine units* – Many units are not dispatchable by the ISO and produce according to their fixed generation schedule.

- *Start-up and shutdown of self-scheduled gas turbines*– These gas turbines are not dispatchable by the ISO, starting-up and shutting-down according to their fixed schedule.

- *Start-up and shutdown of non-gas-turbine units*– These units are not dispatchable during their start-up and shut-down phases of operation. In addition, the minimum generation level on these units is inflexible supply that much be accommodated.

The table compares the average size of upward and downward movement of these five categories of inflexible supply that typically occur at the top of the hour during the ramp-up hours (i.e., hours 5 to 10) and ramp-down hours (i.e., hours 0-3 and hours 21-23) in the past three years.

Figure A-83: Factors Contributing to Cyclical Real-Time Price Volatility
June to August, 2013



Average Changes in MW at The Top of The Hour

Category	Ramp-Up Hrs (5-10)			Ramp-Dn Hrs (21-3)		
	2011	2012	2013	2011	2012	2013
Net Imports	58	-11	5	-26	33	43
Pumping Switch	43	59	21	-32	-52	-20
Fixed Schedule Changes - ST	59	75	79	-130	-138	-131
Start Up/Shut Down - ST	48	49	50	10	8	8
Self Scheduled GTs	46	49	44	-3	-2	-3
Total	254	221	199	-181	-152	-104

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.
- The average size of upward and downward spikes at the top of the hour during ramping hours has fallen notably in recent years.
  - The average upward spikes at the top of the hour during the ramp-down hours fell from roughly $17 per MWh in 2011 to $11 per MWh in 2013.
  - The average downward spikes at the top of the hour during the ramp-up hours fell from roughly $18 per MWh in 2011 to $9 per MWh in 2013.
  - These reductions would be even greater if we adjusted for the increase in natural gas prices from 2011 to 2013.
- The following two factors helped moderate upward and downward spikes at the top of the hour:
  - 15-minute scheduling was introduced at several external interfaces since 2011, which has allowed external schedule changes throughout the hour, rather than only at the top of each hour.
    - The 15-minute scheduling of the external interfaces is evaluated in Section IV.D of this Appendix.
  - Pumped-storage units, which used to switch between pumping and generating only at the top of the hour, have started to switch at quarter-hour intervals more frequently.
- Changes in generator output and hourly-scheduled external transactions were the most significant factors contributing to cyclical price spikes at the top of the hour in 2013.
  - 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.
    - Hence, it would be beneficial to: (a) adjust the timing of the look ahead evaluation of RTC so that it could anticipate when a de-commitment would lead to a five-minute shortage of ramp and (b) enable RTD to delay the shut-down of a gas turbine when it is economic to remain on-line.

- Figure A-83 shows that external transaction schedules typically adjust in the real-time market in a direction that reduces the ramp requirements of internal generators, However, large adjustments in external transaction schedules in the export direction suddenly reduce supply and may lead to acute price spikes in some hours.
  - 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 ten 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, RTD and RTC generally perform well in scheduling resources in the first five minutes of each ten-minute external interchange ramp period. However, RTD and RTC do not anticipate transient shortages that occur in the second five minutes of each ten-minute external interchange ramp period (i.e., at intervals-ending :05, :20, :35, and :50).
- We recommend that the NYISO adjust the timing of the look-ahead evaluations of RTD and RTC to be more consistent with the timing of significant operating factors, such as the ramp cycle of external interchange and the start-up and shut-down cycles of generation.

E. Market Operations under Shortage Conditions

Prices that occur under shortage conditions (i.e., when resources are insufficient to meet the energy and operating reserves needs of the system while satisfying transmission security constraints) are an important contributor to efficient price signals. In the long-run, prices should signal to market participants where and when new investment in generation, transmission, and demand response would be most valuable to the system. In the short-run, prices should provide market participants with incentives to commit sufficient resources in the day-ahead market to satisfy anticipated system conditions the following day, and prices should give suppliers and 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 three types of shortage conditions:

- Shortages of operating reserves and regulation;

- Transmission shortages; and
- Reliability demand response deployments.

Figure A-84: Real-Time Prices During 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-84 summarizes ancillary services shortages and their effects on real-time prices in 2012 and 2013 for the following six categories:

- 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.[177]
- 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.[178]
- 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.[179]
- 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.[180]

The top portion of the figure shows the frequency of shortages. The bottom portion shows the average shadow price during shortage intervals and the current demand curve level of the

177 The 30-minute NYCA requirement was 1,800 MW before June 27, 2012.

178 The 10-minute NYCA requirement was 1,200 MW before June 27, 2012, and the demand curve value was set to $150/MWh before May 19, 2011.

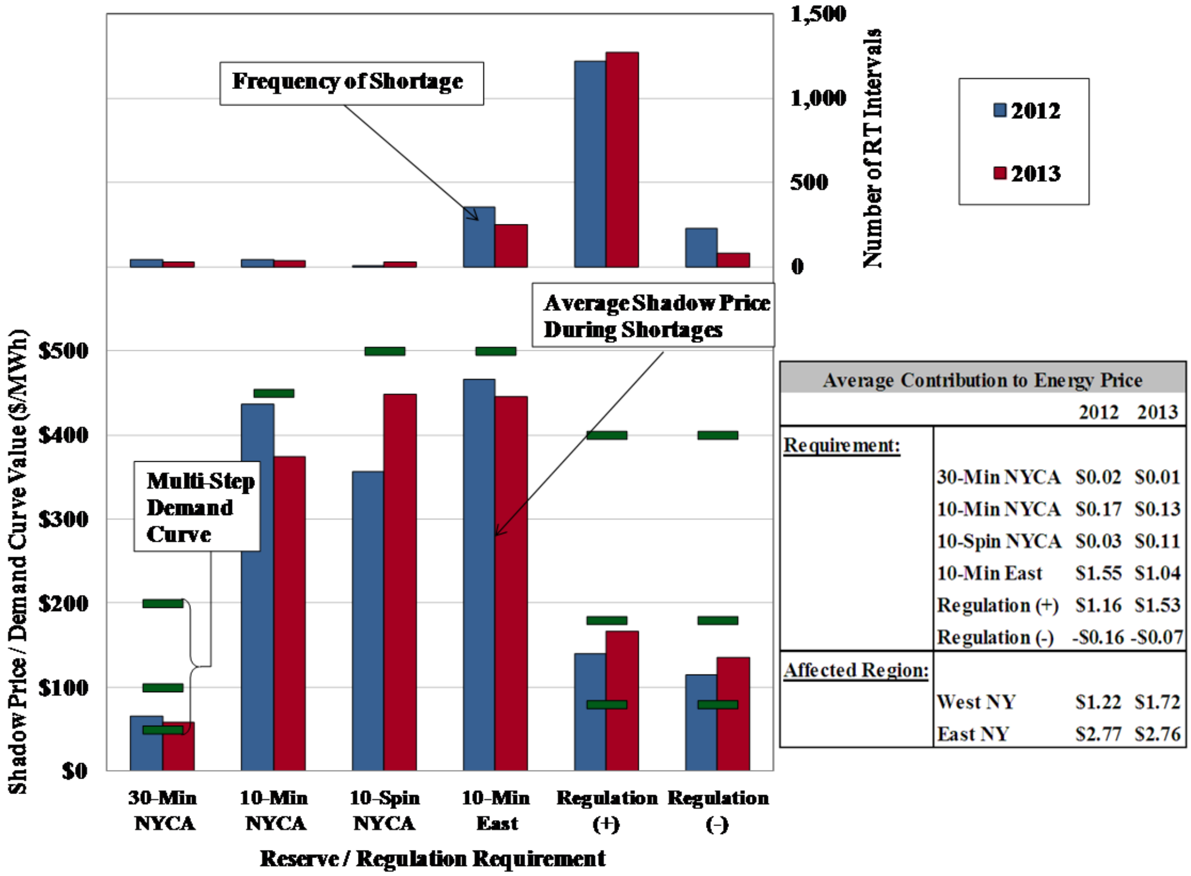
179 The 10-minute spinning NYCA requirement was 600 MW before June 27, 2012,

180 The regulation demand curve values before May 19, 2011 were set to $250/MWh when the shortage is less than 25 MW and $300/MWh when the shortage exceeds 25 MW.

requirement. The table shows the average shadow prices during 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-84: Real-Time Prices During Ancillary Services Shortages
2012 - 2013



Average Contribution to Energy Price			
		2012	2013
Requirement:			
	30-Min NYCA	$0.02	$0.01
	10-Min NYCA	$0.17	$0.13
	10-Spin NYCA	$0.03	$0.11
	10-Min East	$1.55	$1.04
	Regulation (+)	$1.16	$1.53
	Regulation (-)	-$0.16	-$0.07
Affected Region:			
	West NY	$1.22	$1.72
	East NY	$2.77	$2.76

Key Observations: Real-Time Prices During Ancillary Services Shortages

- The incidence of shortage conditions (i.e., the frequency and the average shadow cost of shortages) was comparable between 2012 and 2013 for most reserve products. In both years:
  - Regulation shortages were most frequent, occurring in slightly over 1 percent of all intervals;

  - 10-minute eastern reserve shortages were the second most frequent, occurring around 0.2 to 0.3 percent of all intervals; and
  - These two ancillary services shortages had the largest effects on real-time prices.
- Overall, real-time prices generally reflected system conditions accurately.[181]
  - The average shadow price during physical shortages was close to the demand curve level for each class of reserves.

F. 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 equipments. During transmission shortages, it is important for wholesale markets to set efficient prices that appropriately reflect the acuteness of operating conditions. Efficient prices provide generation and demand response resources incentives to respond to maintain reliability.

The real-time dispatch model ("RTD") manages transmission constraints by redispatching available capacity, which includes online units that can be ramped in five minutes and offline quick-start gas turbines that can be started and brought online within 10 minutes. Transmission shortages can occur in the following three ways:

- 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.
- If the marginal redispatch cost needed to resolve a constraint exceeds the $4,000/MWh Transmission Shortage Cost, RTD foregoes more costly redispatch options.
- 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.[182] In such cases, the marginal cost of resources actually dispatched to relieve the constraint are lower than the shadow price set by the offline gas turbine (which is not actually started).

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[181] 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.

[182] 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.

Data is not available regarding the frequency of the first type of transmission shortage, so the following analysis focuses on the second and third types of transmission shortage. The third type of shortage is most common because RTD usually finds an available quick-start gas turbine that can be scheduled before it reaches the $4,000/MWh transmission shortage cost limit.

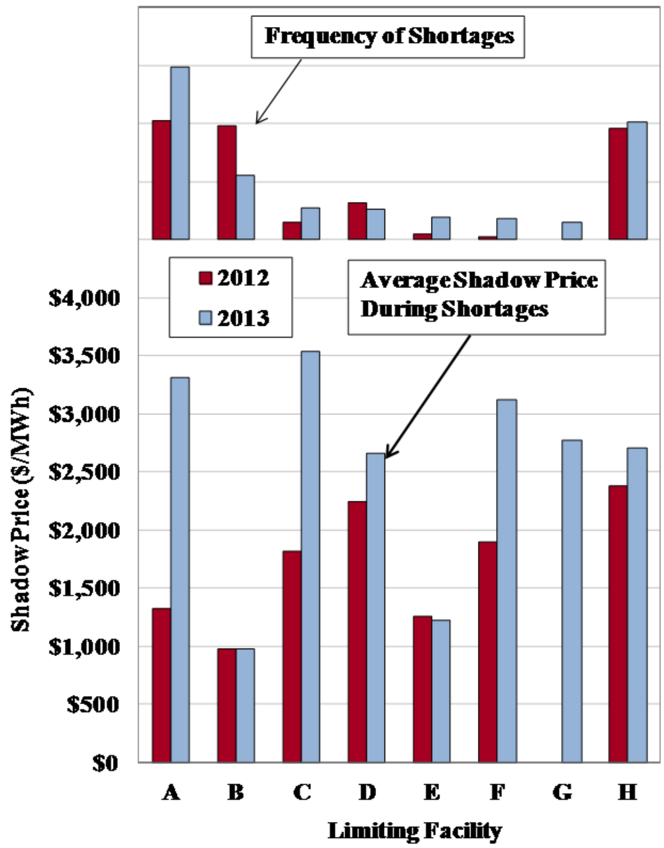
Figure A-85: Real- Time Prices During Transmission Shortages

Figure A-85 summarizes events when a transmission constraint has a large effect on real-time LBMPs, since this often coincides with a transmission shortage. Since no data is retained on precisely when transmission shortages occur, the figure shows likely transmission shortages, which we define as intervals when: (a) a transmission constraint shadow price was $4,000 per MWh, or (b) a transmission constraint shadow price was greater than $500 per MWh and an offline GT was marginal and not started.

The upper right table shows the share of these intervals when an offline gas turbine was counted by RTD towards resolving the constraint and marginal (i.e., setting the shadow price) but not actually started.[183] The lower right table shows the average shadow price during likely transmission shortages multiplied by the frequency of shortages over the year, indicating the relative economic significance of the shortages. The table also shows the overall contribution of all likely transmission shortages to the energy prices in each zone.

[183] The analysis evaluates each interval separately, so a gas turbine that is not started in one interval might then be started in the next interval.

Figure A-85: Real-Time Prices During Transmission Shortages
2012-2013



Price Set by Offline GT During Transmission Shortages in 2013		
	# of Intervals	Pct of Shortages
A	171	58%
B	110	100%
C	12	22%
D	37	70%
E	39	100%
F	21	57%
G	21	72%
H	136	67%

	2012	2013
Average Shadow Price Over All Intervals:		
A: E. Garden City-Valley Stream	$2.60	$9.35
B: Dunwoodie-Shore Road	$1.82	$1.02
C: Niagara-Packard	$0.50	$1.85
D: Leeds-Pleasant Valley	$1.35	$1.34
E: Central-East	$0.12	$0.45
F: Packard-Sawyer	$0.11	$1.10
G: Northport-Pilgrim	$0.00	$0.77
H: Other	$4.32	$5.22
Affected Zone:		
Long Island	$2.83	$2.61
NYC	$0.87	$1.07
Capital	$0.12	$0.35
Hudson Valley	$0.52	$0.70
West	$0.16	$1.01

Key Observations: Real-Time Prices During Transmission Shortages

- The East Garden City-to-Valley Stream line ("EGVS" line), the Dunwoodie-to-Shore Road transmission line ("DSR" line), and the Leeds-to-Pleasant Valley transmission line ("LPV" line) exhibited the most significant transmission shortages in 2012 and 2013.
  - Much of the severe congestion on the LPV line occurred during TSAs that substantially reduce available transfer capability on this path and lead to shortages.
  - Severe congestion across the EGVS and DSR lines frequently occurred because of ramping limitations on Long Island. These ramp limitations generally bind when large hourly schedule changes across the interfaces between Long Island and external markets or during the periods when gas turbines were turned off.
  - The DSR line had extended outages in the first half of 2013, leading to increased transmission shortages on the EGVS line.
- Overall, downstate areas experienced the most significant price impacts from these likely transmission shortages in 2013.
  - In New York City, the total price impact was $1.07 per MWh on average in 2013, roughly 80 percent of which was caused by the LPV and Central-East shortages.

- In Long Island, the total price impact was $2.61 per MWh on average in 2013, nearly 60 percent of which was caused by the DSR and EGVS shortages.
- The price impact in the West Zone rose substantially from $0.16 per MWh in 2012 to $1.01 per MWh in 2013, over 80 percent of which was caused by the Niagara-Packard and Packard-Sawyer shortages.
  - The increase of congestion in the West Zone is discussed in Section III.B of the Appendix.

- An offline gas turbine was scheduled (i.e., counted towards resolving the constraint) and was a marginal resource but was not actually started in 67 percent of all likely transmission shortage intervals in 2013. Hence, the primary mechanism for setting prices during shortage intervals is with offline gas turbines.

G. Real-Time Prices During Reliability Demand Response Deployments

The NYISO provides demand resources with two programs that compensate them for providing additional flexibility to the energy market. These programs include the Emergency Demand Response Program (EDRP) and the ICAP/SCR program. Resources enrolled in these programs typically earn the higher of $500/MWh or the real-time LBMP when called upon. Given the high costs associated with the programs, it would only be efficient to call upon these resources when all of the cheaper generation has been dispatched. Furthermore, it is important to set real-time prices that reflect the costs of maintaining reliability when reliability demand response resources are deployed.

NYISO deployed demand response (EDRP and SCRs) on five days during 2013:

- On July 15, 16, and 17, SCR and EDRP resources were deployed in load zones G through K from 1:00 pm to 6:00 pm (HB 13 – HB 17) for transmission security operations in Southeast New York, which require to restore system power flows to within normal operating limits within 30 minutes after the largest contingency.

- On July 18 and 19, SCR and EDRP resources were deployed: (a) in load zones G through K from 12:00 pm to 6:00 pm (HB 12 – HB 17) for transmission security operations in Southeast New York, which require to restore system power flows to within normal operating limits within 30 minutes after the largest contingency; and (b) in load zones A through F from 1:00 pm to 6:00 pm (HB 13 – HB 17) for statewide capacity requirements. .

Figure A-86 – Figure A-87: Evaluation of Reliability Demand Response Deployments

The following analysis evaluates two aspects of market outcomes on the days when demand response resources were deployed:

- The amount of demand response that was deployed compared with the amount of resources that were ultimately available in each real-time interval during the event.

- Whether real-time energy prices reflected the costs of deploying demand response to maintain reliability given that most SCR and EDRP resources are paid $500 per MWh to curtail their load.

Figure A-86 summarizes system conditions in Southeast New York during the three deployments on July 15 through 17, 2013. Figure A-87 summarizes system conditions in NYCA during the two deployments on July 18 and 19, 2013. Both figures report the following quantities in each interval during the events for the relevant region:

- The Quantity of Demand Response Resources that were reported by RIPs as responding plus market requirement for 30-minute reserves;[184]

- The Quantity of Demand Response Resources that were reported by RIPs as responding plus actual need for 30-minute reserves;

- The Available Internal Capacity in real-time, which includes unloaded capacity of online units and the capacity of offline peaking units up to the unit's Upper Operating Limit ("UOL") . This capacity is divided and shown as the following three categories:

  - 30-Minute Reserves – Scheduled: this is the unloaded capacity that is scheduled by the market model as 30-minute reserves;

  - 30-Minute Reserves – Unscheduled: this is the unloaded capacity this is capable of providing 30-minute reserves but is not scheduled by the market model; and

  - Additional Available Capacity: this is the remaining capacity that is available beyond 30 minutes of ramping.

- The LBMP of the least import-constrained zone in the region that was secured by the demand response deployment (i.e., the Central Zone for the statewide deployments and the Millwood Zone for the Southeast New York deployments). LBMPs higher than $500 per MWh are shown as $500 per MWh; and

- Whether the interval was affected by the Scarcity Pricing Rules, which are applied when the DR deployment prevents a reserve shortage for the target region (based on the criteria in Section 17.1.2 of the Market Service Tariff Attachment B).

184 These are estimates provided by Responsible Interface Parties ("RIPs") in response to event notification, which are also used as the inputs for the Scarcity Pricing Rule. These numbers are different from the enrolled MWs or the response MWs estimated by the NYISO based on metering information. See Market Issues Working Group meeting presentation for August 6, 2013, *EDRP/SCR Scarcity Pricing Outcomes: July 15th 2013 – July 19th 2013*.

Figure A-86: RT Prices and Available Capacity During DR Deployments in SENY
Southeast New York, July 15-17, 2013

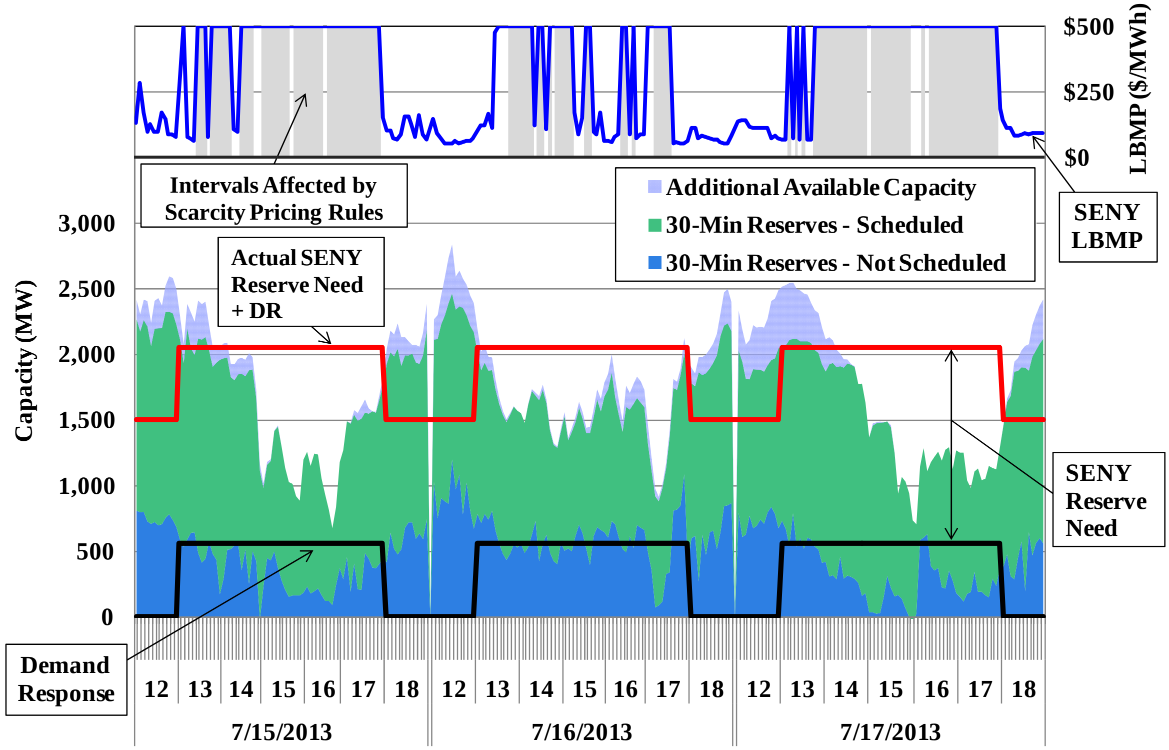
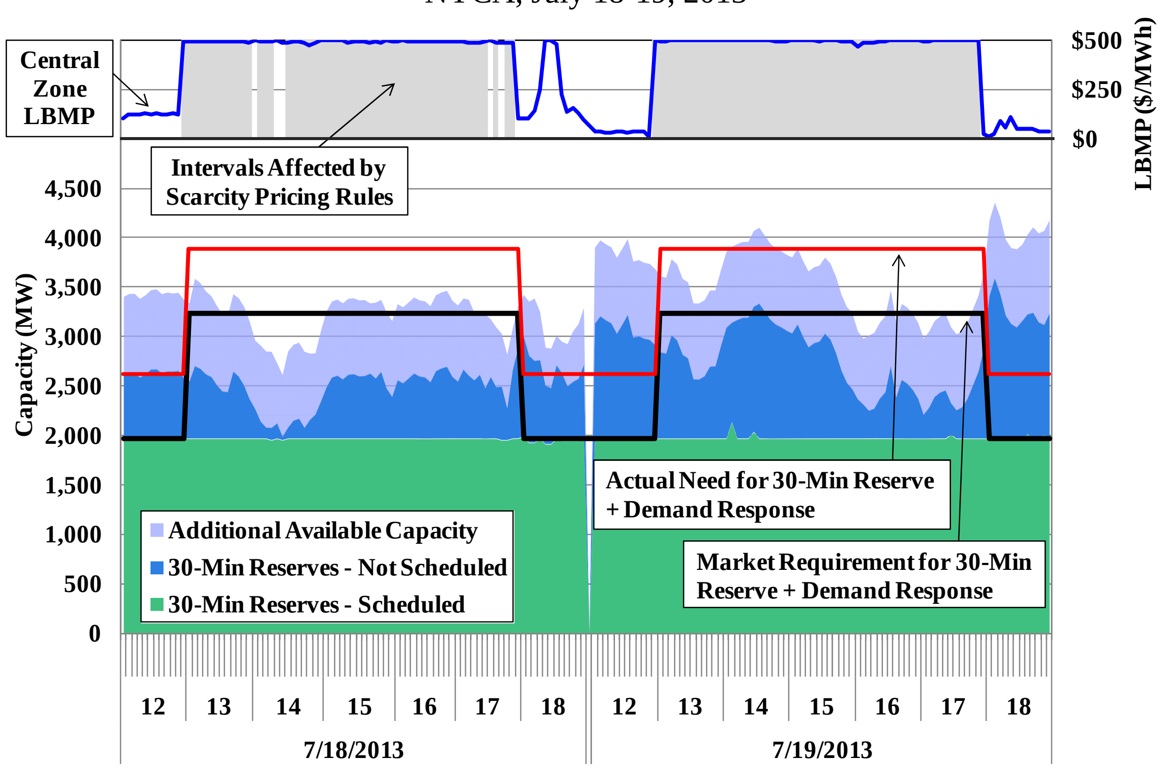


Figure A-87: RT Prices and Available Capacity During DR Deployments in NYCA
NYCA, July 18-19, 2013



Key Observations: Reliability Demand Response Deployments

- The NYISO implemented an Enhanced Scarcity Pricing Rule in the summer of 2013, which was designed to ensure real-time prices better reflect real-time shortages.
- Our evaluation suggests that the new Scarcity Pricing Rule was generally applied when demand response was actually needed, a significant improvement over the previous Scarcity Pricing Rule.
  - Scarcity Pricing was triggered for 118 intervals in Southeast New York of the 145 intervals in which it was needed to satisfy capacity needs (i.e., red line > height of all areas).
  - In NYCA, it was triggered in 116 intervals and demand response was needed in 111 intervals.
- However, Scarcity Pricing only applies to internal locations, resulting in large differences at real-time prices at internal versus external interfaces (proxy buses).
  - When demand Response calls are likely, participants have inefficient incentives to import day ahead and buy back at non-scarcity real-time prices. This contributes to under commitment, since the increase in day-ahead imports will displace the commitment of internal resources in the day-ahead market.
  - Hence, we support NYISO's evaluation of extending Scarcity Pricing to external interfaces, although this should not override the proxy bus pricing rules that are designed to reflect real-time congestion at the interfaces.
- We also support improving the consistency between NYISO's reserve needs and its market requirements, which include:
  - Defining a market requirement to reflect Southeast York's 30-minute reserve needs;[185] and
  - Ensuring that the NYCA 30-minute reserve demand curve fully reflects NYISO's reserve needs on high load days.[186]
- The use of demand response resources is limited by scheduling lead times and other inflexibilities.

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185 New York State Reliability Council ("NYSRC") Rule F-R1c requires the NYISO to commit sufficient resources to reduce the loading on a facility to the normal rating within 30 minutes following the largest contingency. Hence, this requires additional resources beyond what is necessary to satisfy N-1 security constraints.

186 NYSRC Rule D-R4 requires the NYISO to commit sufficient resources to restore NYCA 10-minute reserves within 30 minutes following the largest contingency. Hence, this requires sufficient NYCA 30-minute reserves to respond to the largest two contingencies.

- The NYISO must determine how much demand response to deploy when there is still considerable uncertainty about the needs of the system, and the demand response may not be needed for the entire duration of the deployment period.
- Hence, the inflexibility of DR resources can lead NYISO to deploy an amount of DR that results in substantial excess capacity during a portion of the event.
- Moderating the quantities of DR that are deployed would help ensure that LBMPs better reflect the cost of maintaining reliability and that uplift charges are minimized. This might be possible by:
  - Market design changes that enable some DR resources to be scheduled more flexibly (i.e., with shortened lead times and/or shut-down periods); and
  - Staggering the timing of the deployment of DR resources (to the extent possible).

H. 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 (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-88: Supplemental Commitment for Reliability in New York

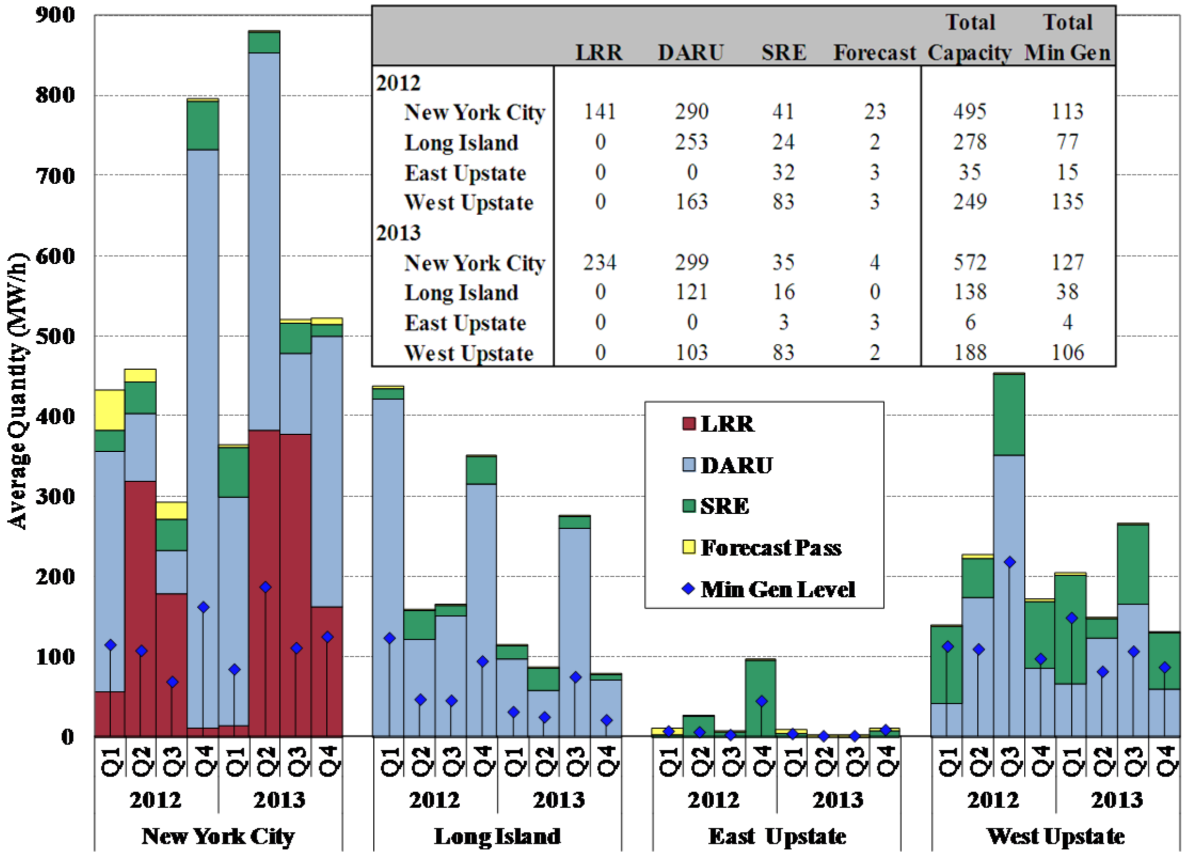
Supplemental commitment occurs when a generator is not committed by the economic pass of the day-ahead market but is needed for reliability. Supplemental commitment primarily occurs in three ways: (a) Day-Ahead Reliability Units ("DARU") Commitment – typically occurs at the request of local Transmission 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-88 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 2012 and 2013. 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 2012 and 2013 on an annual basis.

Figure A-88: Supplemental Commitment for Reliability in New York
By Category and Region, 2012 – 2013



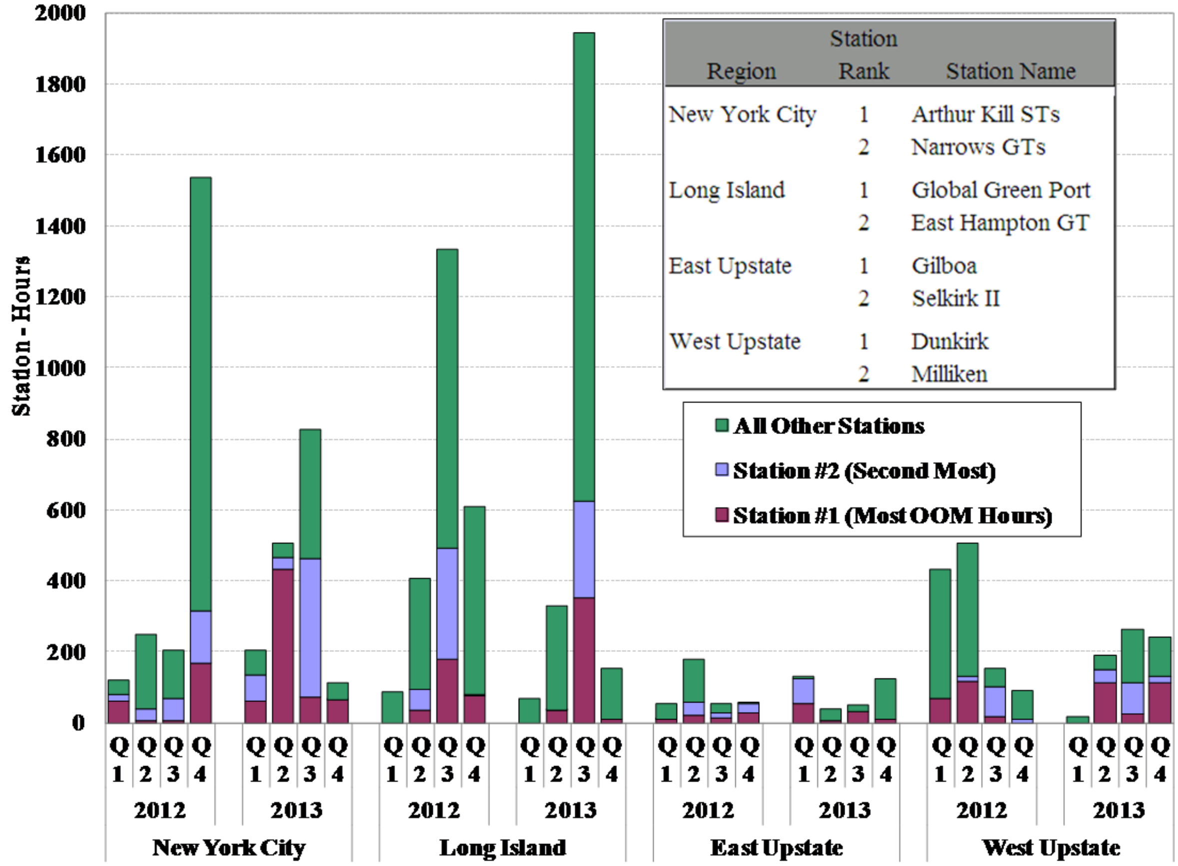
	LRR	DARU	SRE	Forecast	Total Capacity	Total Min Gen
2012						
New York City	141	290	41	23	495	113
Long Island	0	253	24	2	278	77
East Upstate	0	0	32	3	35	15
West Upstate	0	163	83	3	249	135
2013						
New York City	234	299	35	4	572	127
Long Island	0	121	16	0	138	38
East Upstate	0	0	3	3	6	4
West Upstate	0	103	83	2	188	106

Figure A-89: Frequency of Out-of-Merit Dispatch

Figure A-89 summarizes the frequency (i.e., the total station-hours) of OOM actions on a quarterly basis in 2012 and 2013 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-89: Frequency of Out-of-Merit Dispatch
By Region by Quarter, 2012-2013



Key Observations: Supplemental Commitment and OOM Dispatch for Reliability

- Roughly 900 MW capacity was committed on average for reliability in 2013, down 14 percent from 2012.
  - Of this total, 63 percent of reliability commitment was in New York City, 15 percent was in Long Island, and 21 percent was in Western New York.
- Reliability commitment in Western New York averaged 190 MW in 2013, down 24 percent from 2012. DARU commitments decreased because:
  - Several coal units retired or mothballed that had often been DARUed for local reliability; and
  - Higher gas prices and increased West Zone congestion led the remaining coal units to be committed economically more often.
- Reliability commitment in Long Island fell about 50 percent from an average of approximately 280 MW in 2012 to an average of 140 MW in 2013.
  - Units that are frequently needed for local reliability were committed economically more often because of the higher LBMPs, which were driven by higher natural gas

prices, transmission outages, generator retirements, and inefficient utilization of some generating capacity (these factors are discussed in Section I of the Appendix).

- Unlike other regions, reliability commitment in New York City rose 16 percent from 2012 to an average of 570 MW in 2013.
  - Reliability need for the 345 kV system has fallen notably in recent years, which was mostly attributable to new generating supply and new transmission facilities added from 2011 to 2013.
  - Most of DARU commitments were made for the Astoria West/Queensbridge/Vernon load pocket, particularly during periods with significant transmission or generation outages (e.g., in the second quarter of 2013).
    - These supplemental commitments were to ensure facilities into this pocket will not be overloaded if the largest two generation or transmission contingencies were to occur.
  - LRR commitments rose from 2012, most of which were made to satisfy NOx bubble requirements that 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.
    - The increase was partly because steam units that satisfy NOx Bubble constraints were committed economically less often due to lower day-ahead LBMPs (relative to fuel prices) in New York City. Hence, these units had to be committed for reliability more often.
    - However, the output from these steam turbine units sometimes displaced output from newer cleaner generation in New York City and displaced imports to the city. Hence, the commitment of these steam turbines may actually increase NOx emissions.
- Long Island accounted for the largest share of OOM station-hours in both 2012 (40 percent) and 2013 (48 percent).
  - In 2013, more than 70 percent of OOM actions occurred in July when high load levels led more units to be called to manage local reliability on the East End of Long Island.
  - Such units were dispatched economically more often in 2012 (so less OOM dispatch was required then).
- New York City accounted for 32 percent of OOM station-hours in 2013, down from 35 percent in 2012.
  - OOM dispatch fell partly because it had been elevated in the fourth quarter of 2012 following Superstorm Sandy, which led to numerous transmission outages and increased BPCG uplift.

  - An Arthur Kill steam unit accounted for nearly 40 percent of OOM actions in New York City, most of which occurred from mid-April to mid-May when its output was often limited by breaker outages at Freshkills.
  - The Narrows and Gowanus GTs accounted for another 40 percent of OOM actions.
    - These occurred primarily in July when the market software was not able to properly model a "split ring bus" during a transmission outage in the Greenwood area. In these cases, the split ring bus led to the formation of a small load pocket within the Greenwood/Staten Island load pocket. This in turn resulted in two inefficient scenarios:
      - When the marginal resource did not set LBMP because it was dispatched for a transmission constraint that could not be modeled, resulting in additional BPCG charges; and
      - When an expensive resource that was dispatched to resolve congestion in the sub-load pocket set LBMP in a wider area than appropriate, resulting in higher LBMPs and balancing congestion shortfalls.
      - Furthermore, managing congestion through OOM dispatch is less efficient than managing it with the day-ahead and real-time market models, so the inability to model these constraints also raises production costs.
    - Unfortunately, the project to correct this problem was not approved for the 2014 Project Plan. The lack of capability to model split ring bus contingencies will likely result in increased production costs, uplift charges, and LBMPs.
- Western New York accounted for 14 percent of OOM station-hours in 2013.
  - OOM actions in Western New York have fallen substantially because Huntley and Niagara units were rarely OOMed by the NYISO to manage congestion on 230 kV lines in the West Zone following the transmission constraint modeling improvements in May 2012.

I. 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-90 and Figure A-91 summarize the three categories of non-local reliability uplift that are allocated to all Load Serving Entities ("LSEs") and the four categories of local reliability that are allocated to the local Transmission Owner.

The three categories of non-local reliability uplift are:

- Day-Ahead Market – This primarily includes guarantee payments to generators that are economically committed in the day-ahead market. These generators receive payments when day-ahead clearing prices are not high enough to cover the total of their as-bid costs (includes start-up, minimum generation, and incremental costs). When a DARU unit is committed by the NYISO for statewide reliability, the resulting guarantee payments are uplifted statewide. However, these account for a very small portion of DARU capacity.

- Real-Time Market – Guarantee payments are made primarily to gas turbines that are committed by RTC and RTD based on economic criteria, but do not receive sufficient revenue to cover start-up and other running costs over their run time. Guarantee payments in the category are also made for: a) SRE commitments and out-of-merit dispatch that are done for bulk power system reliability; b) imports that are scheduled with an offer price greater than the real-time LBMP; and c) demand response resources (i.e., EDRP/SCRs) that are deployed for system reliability.

- Day-Ahead Margin Assurance Payment – Guarantee payments made to cover losses in margin for generators dispatched by RTD below their day-ahead schedules. When a unit has been dispatched or committed for local reliability, any day-ahead margin assurance payments it receives are allocated as local reliability uplift. However, the majority of day-ahead margin assurance payments are allocated as non-local reliability uplift.

The four categories of local reliability uplift are:

- Day-Ahead Market – Guarantee payments are made to generators committed in the SCUC due to Local Reliability Rule (“LRR”) or as Day-Ahead Reliability Units (“DARU”) for local reliability needs at the request of local Transmission Owners. Although the uplift from payments to these units is allocated to the local area, these commitments tend to decrease day-ahead prices. As a result of lower prices, more (non-local reliability) uplift is paid to generators that are economically committed before the local reliability pass.

- Real-Time Market – Guarantee payments are made to generators committed and redispatched for local reliability reasons after the day-ahead market. While this can occur for a variety of reasons, the majority of this uplift is related to Supplemental Resource Evaluation (“SRE”) commitments.

- Minimum Oil Burn Compensation Program – Guarantee payments made to generators that cover the spread between oil and gas prices when generators burn fuel oil to help maintain reliability in New York City due to potential natural gas supply disruptions.

- Day-Ahead Margin Assurance Payment – Guarantee payments made to cover losses in margin for generators dispatched out-of-merit for local reliability reasons below their day-ahead schedules.

Figure A-90 & Figure A-91: Uplift Costs from Guarantee Payments

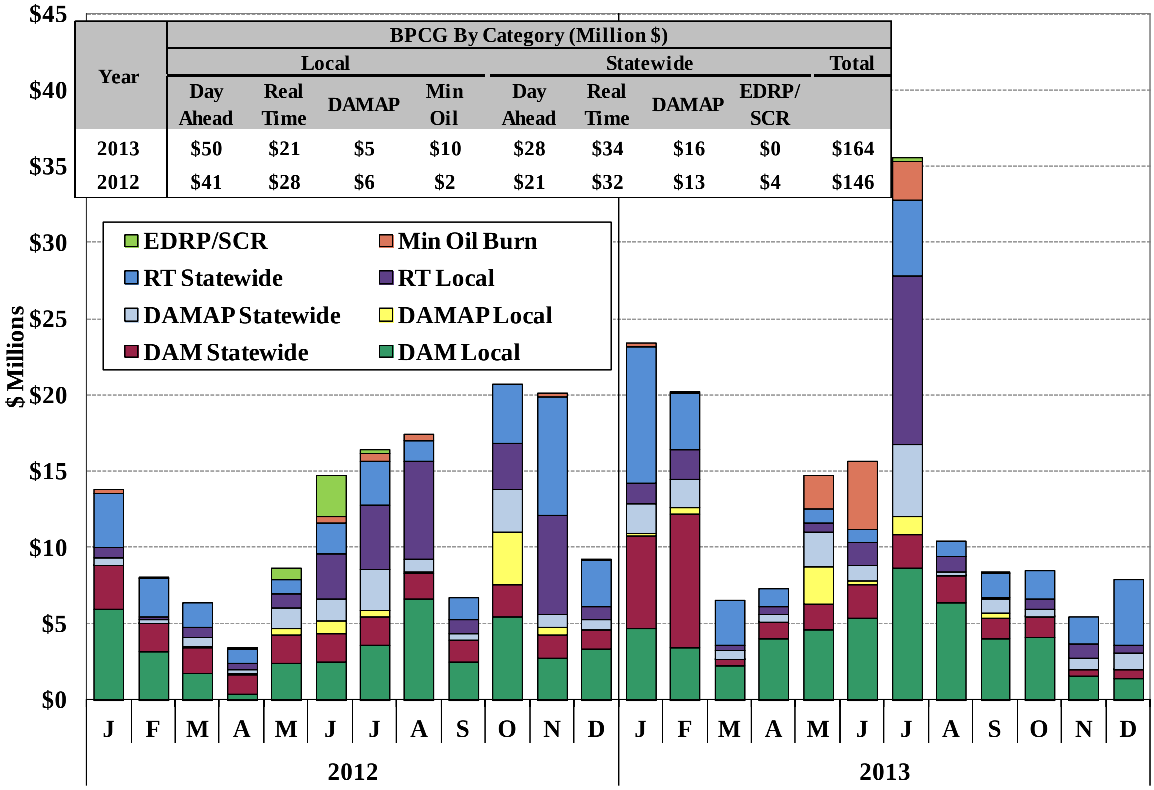
Figure A-90 shows the seven categories of uplift costs associated with guarantee payments on a monthly basis for 2011 and 2012. The uplift costs associated with the EDRP/SCR resources are shown separately from other real-time statewide uplift costs. The table summarizes the total uplift costs under each category on an annual basis for these two years.

Figure A-91 shows the seven categories of uplift charges on a quarterly basis in 2011 and 2012 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-90 and Figure A-91 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-90: Uplift Costs from Guarantee Payments by Month

2012 – 2013

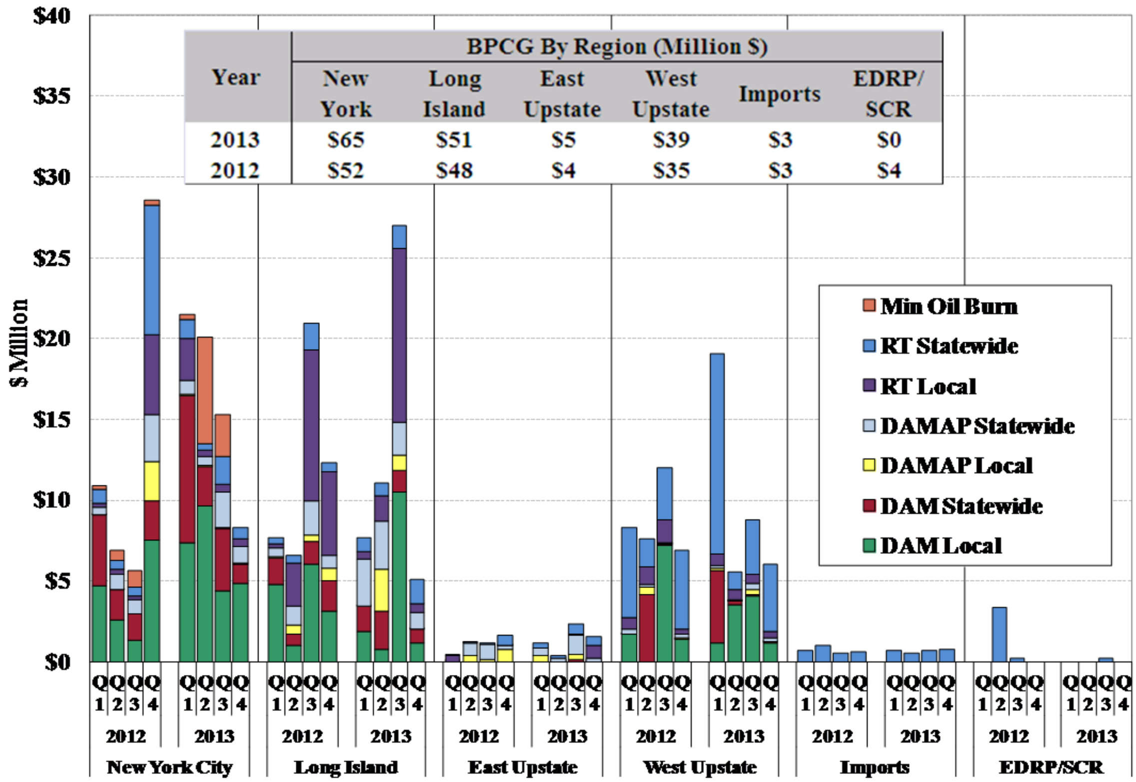


Year	Local: Day Ahead	Local: Real Time	Local: DAMAP	Local: Min Oil	Statewide: Day Ahead	Statewide: Real Time	Statewide: DAMAP	Statewide: EDRP/SCR	Total
2013	$50	$21	$5	$10	$28	$34	$16	$0	$164
2012	$41	$28	$6	$2	$21	$32	$13	$4	$146

BPCG By Category (Million $)

Figure A-91: Uplift Costs from Guarantee Payments by Region

2012 – 2013



Year	New York	Long Island	East Upstate	West Upstate	Imports	EDRP/SCR
2013	$65	$51	$5	$39	$3	$0
2012	$52	$48	$4	$35	$3	$4

BPCG By Region (Million $)

Key Observations: Uplift Costs from Guarantee Payments

- Total guarantee payment uplift increased 13 percent, from $146 million in 2012 to $164 million in 2013. Day-ahead uplift rose $16 million, accounting for the majority of the overall increase.
  - Higher natural gas prices contributed to the increase in the commitment costs of gas-fired units that were needed for reliability from 2012 to 2013, particularly in the winter months of January and February.
- Of the total guarantee payment uplift in 2013:
  - Local reliability uplift accounted for 52 percent, while non-local reliability uplift accounted for the remaining 48 percent.
  - New York City accounted for 40 percent, Long Island accounted for 31 percent, and Western New York accounted for 24 percent.
- Several notable events led to large amounts of guarantee payment uplift in both 2012 and 2013:
  - The landfall of Superstorm Sandy led to widespread transmission outages, OOM dispatch, and supplemental commitment from October 30 through the end of November 2012. This period accounted for $30 million in guarantee payment uplift compared with $6 million during the same period in 2013.
  - The cold weather period from January 20-27, 2013 accounted for $12 million in guarantee payment uplift when gas prices rose as high as $35/MMbtu.
  - The hot weather period from July 15-19, 2013 accounted for $13 million in guarantee payment when a new all-time peak load record was set.
- New York City accounted for the largest increase in guarantee payment uplift in 2013, while the increases in other regions were relatively modest.
  - These were consistent with the changes in reliability commitments and OOM dispatches from 2012 to 2013 in these regions, which were discussed in detail in the prior sub-section.
  - In addition, a significant portion of the increase in New York City was associated with the Min Oil Burn requirement, which generated high charges in late-May and June when some capacity with automatic fuel swapping capability was not available, resulting in the need to have other units actually burn a mix of oil and gas.
- Long Island accounted for approximately 65 percent of real-time local reliability uplift in both 2012 and 2013.
  - Frequent OOM dispatches were needed, particularly in the third quarter, to manage congestion on the East End of Long Island. Some generators in this area burn oil because they do not have a source of natural gas.

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.[187] 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.[188]

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.[189] 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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187 The ICAP requirement = (1 + IRM) * Forecasted Peak Load. The IRM increased from 16 percent in the period from May 2012 to April 2013 to 17 percent in the period from May 2013 to April 2014. NYSRC's annual IRM reports may be found at "http://www.nysrc.org/NYSRC_NYCA_ICR_Reports.asp".

188 The locational ICAP requirement = LCR * Forecasted Peak Load for the location. The Long Island LCR was 99 percent in the period from May 2012 to April 2013 and 105 percent in the period from May 2013 to April 2014. The New York City LCR was 83 percent in the period from May 2012 to April 2013 and 86 percent in the period from May 2013 to April 2014.. Each IRM Report recommends Minimum LCRs for New York City and Long Island, 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".

189 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 Generators 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. LSEs 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.[190] 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 and 18 percent for New York City and Long Island. The demand curve is defined as a straight line through these two points.[191]

This report evaluates a period when there were three capacity market Localities: New York City (Zone J), Long Island (Zone K), and NYCA (Zones A to K). New York City and Long Island are nested within the NYCA Locality. Distinct requirements, demand curves, and clearing prices are set in each capacity market Locality, although the clearing price in a nested Locality cannot be lower than the clearing price in the surrounding Locality. In May 2014, the NYISO will begin to model the "G-J Locality" which will include Zones G to J and be nested within the NYCA Locality, while the New York City Locality will be nested within the G-J Locality.

To evaluate the performance of the capacity market, the figures in this section show capacity market results from May 2012 through February 2014. 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.

190 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.

191 The demand curves also have maximum price levels which apply when UCAP procured falls substantially below the UCAP requirement. The demand curves for the period from May 2011 to April 2014 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".

A. Capacity Market Results: NYCA

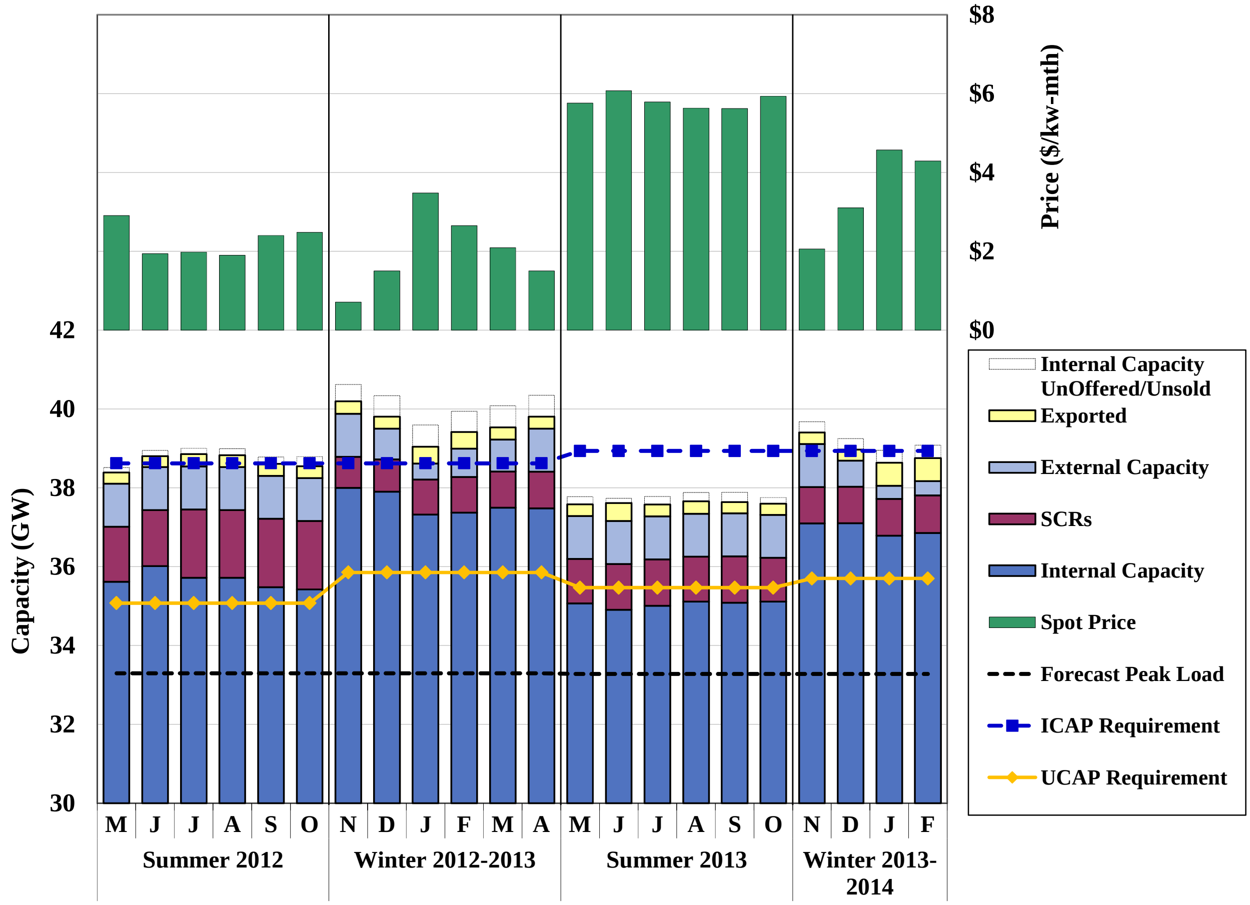
Figure A-92: Capacity Sales and Prices in NYCA

Figure A-92 show capacity market results in the NYCA for the past four 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.[192] 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 each region. Additionally, Figure A-92 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-92 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-92 also shows the forecasted peak load and the ICAP requirements.

[192] 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-92: UCAP Sales and Prices in NYCA
May 2012 to February 2014



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 generally contributes to significantly lower prices in the winter than in the summer.
  - Capacity imports from Quebec typically fall in the coldest winter months, since Quebec is a winter peaking region.
- The spot price averaged $5.80/kW-month in the Summer 2013 Capability period and $3.51/kW-month in the Winter 2013-14 Capability period (excluding March and April 2014), up 156 percent and 76 percent from the previous Capability periods, respectively.

- These price increases were due to significant changes in both capacity requirements and the supply of capacity. The following changes in requirements affected statewide capacity prices in 2013:[193]
  - The ICAP Requirement rose 314 MW (0.8 percent) due to an increase in the IRM from 16 to 17 percent, which was offset by a slight decrease in the peak load forecast.
  - However, the UCAP Requirement rose 391 MW (1.1 percent) in the Summer Capability Period and fell 152 MW (0.4 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 EFORd values of the 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:
  - Sales from internal resources fell 1.4 GW over the Capability Year because of the retirement and mothballing of generation, including:
    - 330 MW on Long Island in July 2012,
    - 370 MW in Western New York in September 2012,
    - 500 MW in Hudson Valley in January 2013, and
    - 150 MW in Western New York in June 2013.
  - Sales from SCRs fell by an average of 470 MW from the Summer 2012 to the Summer 2013 due to a combination of increased auditing of resources, attrition, and changing market conditions.
  - However, these factors were partly offset by the entry of 500 MW of new resources in New York City and an uprate of 110 MW on a nuclear unit in Western New York in June 2012.

B. Capacity Market Results: Local Capacity Zones

Figure A-93 & Figure A-94: Capacity Sales and Prices in NYC and Long Island

Figure A-93 and Figure A-94 show capacity market results in New York City and Long Island for the past four capability periods. It shows the same quantities as Figure A-92 does for the

193 ICAP Requirements are fixed for an entire capability year, so the same requirements were used in the 2012/13 and 2013/14 Capability Periods. UCAP Requirements are fixed for a six-month capability period, since the Derating Factor for each locality is updated every six months.

NYCA region. 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-93: UCAP Sales and Prices in New York City

May 2012 to February 2014

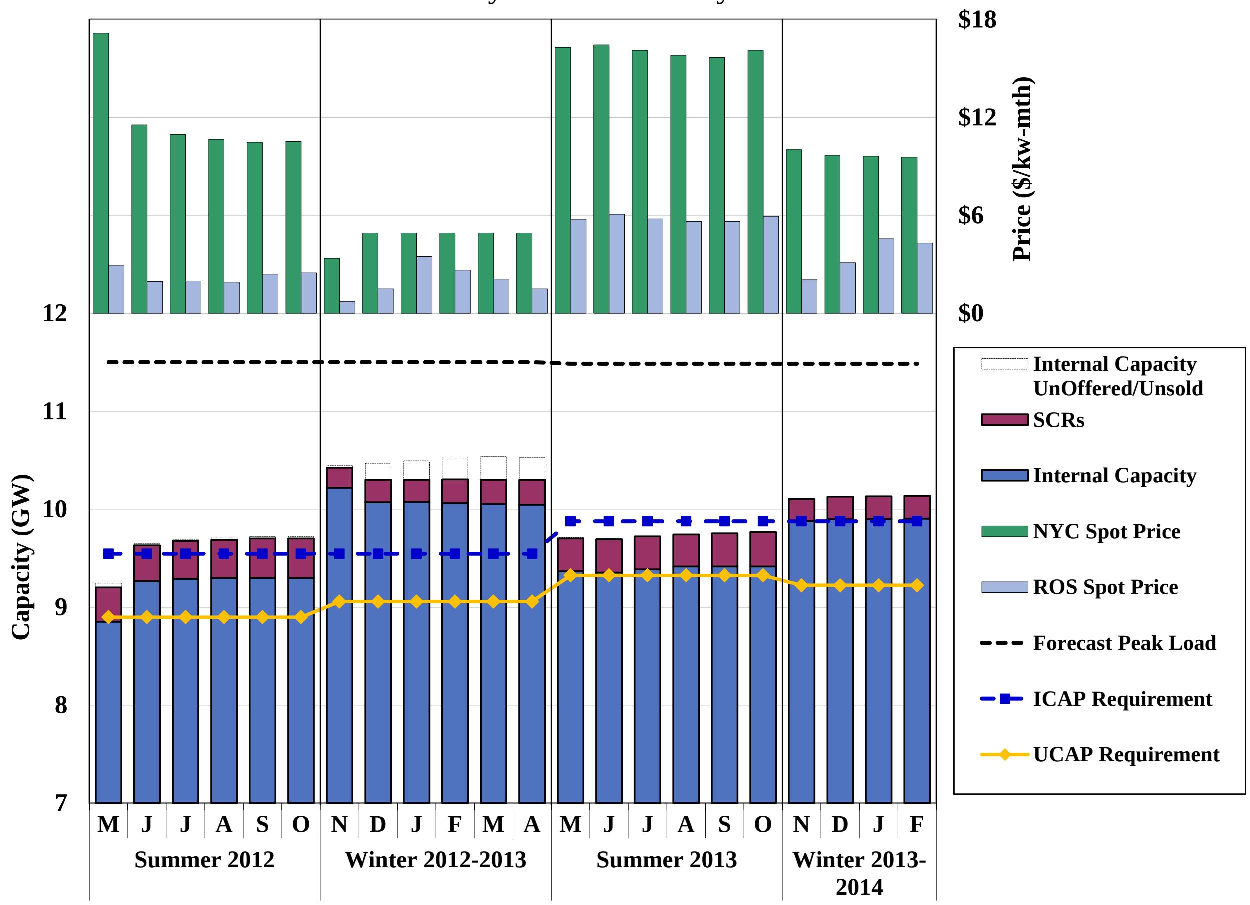
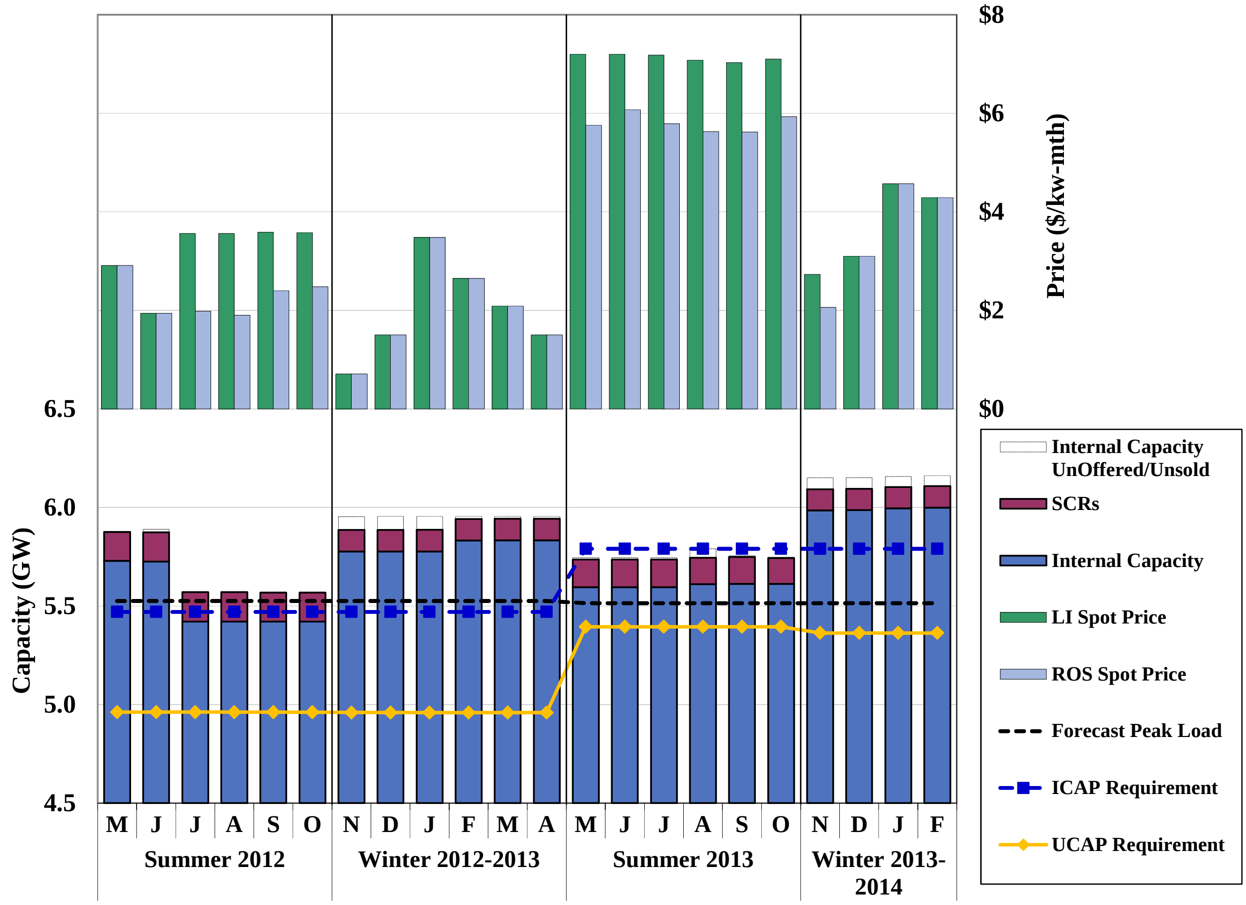


Figure A-94: UCAP Sales and Prices in Long Island
May 2012 to February 2014



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 both capability periods due primarily to changes in demand factors.
  - The spot price averaged $16.07/kW-month in the Summer 2013 Capability period, which was up 35 percent from the previous summer, and $9.72/kW-month in the Winter 2013-14 Capability period (excluding March and April 2014), which was up 109 percent from the prior winter.
  - On the demand side, the ICAP Requirement rose 332 MW (3.5 percent), which was primarily due to an increase in the LCR from 83 percent to 86 percent.[194]

[194] Due to changes in the Derating Factor, the UCAP Requirement for New York City rose 428 MW (4.8 percent) in the Summer of 2013 and rose 165 MW (1.8 percent) in the Winter of 2013-2014, 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

  - The increased LCR resulted primarily from the loss of generating capacity in the Hudson Valley, which requires more capacity in the New York City and Long Island Localities to maintain security of the UPNY-SENY interface.
    - However, raising the LCRs in New York City and Long Island is less efficient than modeling a capacity Locality that includes the Hudson Valley and setting the LCR in the new Locality at a level that accurately reflects the reliability benefits of placing capacity there.
    - Hence, modeling the new G-J Locality will better enable the market to provide efficient investment signals.
  - However, the effects of increased requirements were partly offset by increased emergency energy assistance from the new HTP Line.[195]
- Supply-side changes also affected capacity prices in New York City.
  - In June 2012, a new 500 MW resource entered in New York City, which led the spot price to fall from $17.16/kW-month in May 2012 to $11.54/kW-month in June 2012.
  - Beginning in December 2012, buyer-side mitigation was imposed on the 550 MW AEII facility, resulting in the imposition of an Offer Floor. From December 2012 to April 2013, the amount of unsold capacity rose and the clearing price was $4.91/kW-month. However, there has not been a significant amount of unsold capacity since April 2013, implying that the capacity from AEII facility was fully sold after April 2013.

- In Long Island, capacity prices also rose substantially, driven in part by the increase in rest-of-state capacity prices and in part by changes in demand factors.
  - The spot price averaged $7.14/kW-month in the Summer 2013 Capability period, which was up 124 percent from the previous summer, and averaged $3.67/kW-month in the Winter 2013-14 Capability period (excluding March and April 2014), which was up 84 percent from the prior winter.
  - The local capacity requirement for Long Island was rarely binding during the Winter Capability Periods in 2012 and 2013, reflecting that Long Island generally has far more capacity than needed to satisfy its LCR in the winter.
    - As a result, the spot prices in Long Island were equal to the rest-of-state capacity prices during the majority of the winter months.

price.

195 Before each Capability Year, a controllable line can elect to receive Unforced Deliverability Rights ("UDRs"). If it does not elect to receive UDRs, the resource's capability does not appear in the Internal Capacity category in Figure A-92, Figure A-93, and Figure A-94 and the resource is included in the IRM study in a way that increases the benefits of emergency assistance from a neighboring control area.

- However, spot prices rose significantly above rest-of-state prices during the Summer Capability Periods in 2012 and 2013, driven by changes in both demand and supply.
  - On the supply side, three units totaling 330 MW were retired in July 2012. The spot price rose from $1.94 per kW-month in June 2012 to $3.56 per kW-month in July 2012.
  - On the demand side, the Long Island ICAP Requirement rose 320 MW (5.8 percent) primarily because the LCR rose from 99 percent to 105 percent (for reasons similar to the ones for the increase in New York City LCR).

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.[196]

- 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.[197]

- 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.

196 Resources participate in EDRP through Curtailment Service Providers ("CSPs"), which serve as the interface between the NYISO and resources.

197 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.

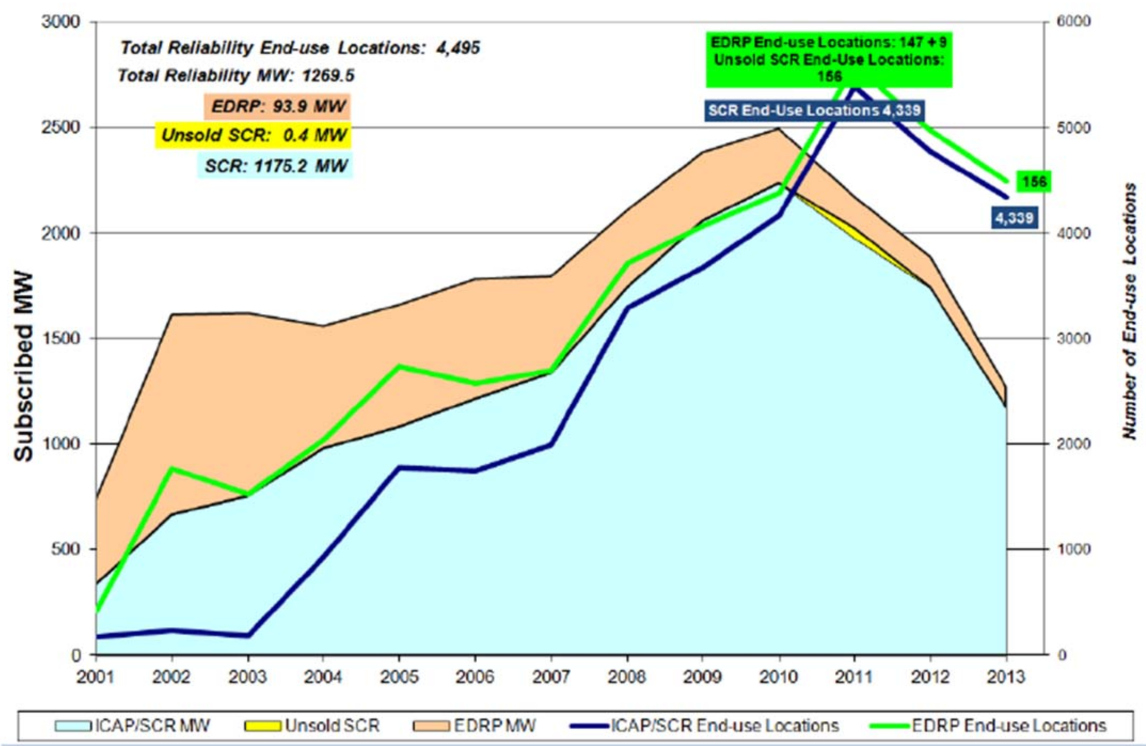
A. Reliability Demand Response Programs

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-95: Registration in NYISO Demand Response Reliability Programs

Figure A-95 summarizes registration in two of the reliability programs on an annual basis at the end of each summer from 2001 to 2013 as reported in the NYISO's annual report to FERC. The stacked areas plot 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-95: Registration in NYISO Demand Response Reliability Programs
2001 – 2013



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 2013, total registration in the EDRP and SCR programs included 4,495 end-use locations enrolled, providing a total of 1,270 MW of demand response capability. SCR resources accounted for 97 percent of the total reliability program enrollments and 93 percent of the enrolled MWs.
- In the Summer 2013 Capability Period, SCRs made significant contributions to resource adequacy by satisfying:
    - 3.6 percent of the UCAP requirement for New York City;
    - 2.5 percent of the UCAP requirement for Long Island; and
    - 3.2 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, and 33 percent in 2013. 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 2013 will be based on 40 hours from Summer 2012). 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 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.
    - 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, enhancing competition, reducing costs, and improving 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. The MHP program is administered at the retail load level, and 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 during the twenty-four-month period from September 2011 to August 2013.
  - Given that the scheduled quantities are extremely small and 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, two DSASP resources in western New York (with a combined capability exceeding 100 MW) have actively participated in the market.
- 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 Shortage 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 shortage 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. This allowed demand response resources to set real-time clearing prices at $500/MWh within any transmission-constrained area.[198] The NYISO deployed reliability demand response resources on five days in 2013: July 15 through 19. The real-time pricing under the new rule during these events is evaluated in Section V.E of the Appendix.

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 2013, related operations and pricing are not evaluated in this report.

[198] 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.