POTOMAC ECONOMICS

2009 State of the Market Report
New York ISO

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I. Executive Summary

This report assesses the efficiency and competitiveness of New York's wholesale electricity markets in 2009. The NYISO operates competitive wholesale markets to satisfy the electricity needs of New York. The NYISO operates the most complete set of electricity markets in the U.S. These markets include:

- Day-ahead and real-time markets that jointly optimize energy, operating reserves and regulation;
- A capacity market that ensures the NYISO markets produce efficient long-term economic signals to govern decisions to invest in new generation and demand response resources (and 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 in prices at each location on the network. They deliver significant benefits by coordinating the commitment and dispatch of generation to ensure that the lowest-cost resources are started and dispatched each day to meet the systems demands at the lowest cost.

The coordination that is 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 other areas. The NYISO was the first RTO market to:

- Jointly optimize energy and operating reserves, which efficiently allocates resources to provide these products.

- An optimized real-time commitment system to start gas turbines and schedule external transactions economically. Most other RTOs still rely on operators to start gas turbines.
- 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.
- Operating reserve demand curves that contribute to efficient prices during shortage conditions when resources are insufficient to satisfy both the energy and operating reserve needs of the system.

In addition to its leadership in these areas, the NYISO remains the only market to have:

- A mechanism that allows gas turbines to set energy prices when they are economic. Gas turbines frequently do not set prices in other areas, which distorts the energy prices.
- A real-time dispatch system that is able to optimize over multiple periods (up to one hour). The market anticipates upcoming needs and moves resources to efficiently satisfy the needs.
- 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.

In summary, 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. The remainder of this executive summary discusses the performance and outcomes of the NYISO markets in 2009.

A. Overview of Market Trends and Highlights

This sub-section provides an overview of key market trends and highlights from 2009. Wholesale electricity prices averaged approximately $45 per MWh in 2009, down almost 50 percent from 2008. Electricity prices fell primarily due to the decline in fuel prices, particularly natural gas prices, which decreased an average of 52 percent from 2008 to 2009. The decline in electricity prices was also partly attributable to decreased load levels in 2009, which were driven primarily by milder weather and poor economic conditions. Accordingly, the frequency of real-time operating reserve shortages in Eastern New York fell from 181 intervals in 2008 to 31 intervals in 2009.

These factors also led to much lower levels of transmission congestion. The average price difference between in Western New York and Eastern New York fell from 50 percent in 2008 to 36 percent in 2009 due primarily to the following factors. The lower fuel prices in 2009 generally reduced the costs of redispatching resources to manage congestion. Lower load levels in 2009 reduced the need to import power to congested areas in Eastern New York, leading to less congestion. Additionally, clockwise loop flows around Lake Erie that load key transmission interfaces in New York decreased considerably in 2009.

Capacity prices were relatively low in 2009 due to significant capacity surpluses in each of the three capacity zones. Monthly spot prices averaged $4.78/kW-month in New York City where the average surplus was 1.1 GW, $2.48/kW-month in Long Island where the average surplus was 0.7 GW, and $2.22/kW-month in NYCA where the average surplus was 3.4 GW. Additionally, new supply-side market power mitigation measures ensured that available capacity in New York City is not withheld from the capacity market.

The remainder of this Executive Summary provides a detailed summary of our assessment of the wholesale market. We conclude the Executive Summary with a list of recommended market enhancements and a discussion of recently implemented enhancements.

B. Summary of Prices and Competitive Performance of the Market

1. Summary of Prices in 2009

Wholesale electricity prices in the day-ahead market averaged approximately $36 per MWh in Western New York and $49 per MWh in Eastern New York, down 46 percent and 51 percent from 2008, respectively. The reduction in electricity prices was primarily due to the decline in all key fuel prices:

- Natural gas prices fell 52 percent on average from 2008 to 2009.
- Average diesel oil (No.2 oil) prices fell 42 percent and average residual fuel oil (No. 6 oil) prices fell 32 percent, and
- Average eastern coal prices fell 52 percent.

In a competitive market, suppliers will face strong incentives to offer their supply at prices close to their short-run marginal costs of production, the vast majority of which are fuel costs for most generators. The continuing close correspondence of energy prices and fuel prices in New York is a demonstration of the competitiveness of NYISO's markets.

Wholesale electricity prices were also driven lower by mild summer weather and poor economic conditions, which led to lower average and peak load levels in 2009 than in 2008:

- Average load fell 4 percent from 2008 to 2009.
- Peak load exceeded 30 GW for just 13 hours in 2009, down from 24 hours in 2008.

The peak load reductions contributed to less frequent real-time operating reserve shortages in Eastern New York, which declined from 181 intervals in 2008 to only 31 intervals in 2009, resulting in fewer real-time price spikes.

The average price difference between Western New York and Eastern New York fell from 50 percent in 2008 to 36 percent in 2009, reflecting decreased congestion into and within eastern New York. The decrease in congestion was primarily due to several factors. First, lower fossil fuel prices in 2009 reduced the cost of generation in eastern areas more than in western areas (where more supply is from hydro, wind, and nuclear generation). Second, lower load levels in 2009 reduced the need to import power to congested areas in Eastern New York, resulting in less congestion. Third, the effects of unscheduled clockwise loop flows around Lake Erie were reduced by: (i) the prohibition on circuitous transactions in July 2008, and (ii) the increased use of the Transmission Loading Relief ("TLR") procedures by the NYISO in 2009.

2. Competitive Performance of the Market

We analyze the competitive performance of the overall market in New York, as well as a number of constrained areas within the market, and we find that the markets performed competitively in 2009. Electricity prices fell considerably in 2009 consistent with the large decline in fuel prices. This is positive because a close relationship between electricity prices and fuel prices is expected in a competitive market, since fuel costs constitute the vast majority of the marginal cost of producing electricity.

In certain constrained areas, most of which are in New York City, some suppliers have local market power because their resources are needed to manage congestion or satisfy local reliability requirements. In these cases, however, the market power mitigation measures effectively limit their ability to exercise market power. In New York City, the mitigation measures are automated, which limits the potential harm from attempts to exercise market power, while in other areas, the mitigation measures are generally not automated. In September 2009, the NYISO filed with FERC to address the conduct of three generators in upstate New York that consistently raised their offer prices when committed for reliability, which increased their guarantee payments. FERC approved a specialized mitigation measure to address the conduct of the three generators thereafter. The NYISO has proposed a more generalized mitigation measure to address similar conduct in the future by other generators outside New York City, which we support.

3. 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 and comparing it to the levelized Cost of New Entry (“CONE”). Net revenue is the total revenue that a generator would earn in the New York markets less its variable production costs.

In the Installed Capacity Demand Curve Reset Process, the levelized Cost of New Entry (“CONE”) for a new peaking unit was estimated at $203 per kW-year in New York City, $180 per kW-year on Long Island, and $109 per kW-year in upstate New York for the 2009/10 capability year. There were no areas of New York where the net revenue levels in 2009 were as high as the estimated levelized CONE for a new combustion turbine.

The estimated net revenues are substantially higher for a new combined-cycle unit than a new combustion turbine. In most areas of Eastern New York, the estimated net revenues for a new combined-cycle unit were $40 to $50 per kW-year higher than those for a new combustion turbine in 2009. Although we do not have precise estimates of the CONE for a new combined-cycle unit in New York, it is unlikely that investment in a combined-cycle unit at a new site would be profitable based on the 2009 net revenues.

Overall, the net revenues in 2009 were consistent with fundamental supply and demand conditions. It is unsurprising that neither type of unit would likely have recovered net revenues in 2009 exceeding their CONE because load levels were particularly low and substantial surplus capacity prevailed in New York City, in Long Island, and in the rest of the state. We find no evidence of market design flaws or other problems that would lead to distorted or otherwise inefficient market signals in 2009.

C. Transmission Congestion and TCCs

Congestion arises when the transmission network does not have sufficient capacity to dispatch the least expensive generators to satisfy the load. 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. 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. This report evaluates the overall congestion patterns, as well as day-ahead and real-time congestion shortfalls.

Day-ahead congestion revenue fell 61 percent from 2008 to 2009, which was due primarily to:

- Lower fuel prices, which reduced congestion-related price differences between regions;
- Lower load levels, particularly during the summer months, which reduced transmission flows into import-constrained areas; and
- Elimination of circuitous schedules, which then reduced clockwise Lake Erie circulation.

These factors also contributed to a reduction in day-ahead congestion shortfalls of more than $80 million to a total of $97 million in 2009.[1] The NYISO has a process for allocating the day-ahead shortfalls resulting from transmission outages to specific transmission owners. However, just 31 percent of day-ahead congestion shortfalls were allocated in 2009. The NYISO has developed

1 Day-ahead congestion shortfalls occur when day-ahead congestion revenues collected by the NYISO are less than entitlements of TCC holders. Shortfalls 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.

performance metrics that are reviewed with Market Participants monthly to identify additional factors that contribute to day-ahead congestion shortfalls.

Additionally, transmission owners have not chosen to model planned transmission outages in the TCC market, even when the outages are scheduled in advance of the capability period. The NYISO should determine (i) the extent to which modeling these outages would enhance the overall efficiency of the TCC auction and (ii) whether the transmission owners have incentives to schedule outages when it is efficient to do so.

Our analyses of the TCC prices compared to day-ahead congestion indicated that the TCC prices reflected a reasonable expectation of day-ahead conditions. None of the differences between the TCC prices and day-ahead congestion were indicative of an issue with the market's performance.

Balancing congestion shortfalls decreased by $250 million in 2009.[2] This reduction is mainly attributable to the decreased effects of loop flows around Lake Erie that resulted when the NYISO prohibited circuitous scheduling in July 2008. However, other factors contributed to this reduction as well, including less frequent use of simplified interfaces into New York City load pockets in the real-time market, and more timely updates of loop flow assumptions and other assumptions in the day-ahead market.

D. Day-Ahead Market Performance

The day-ahead market enables participants to make forward purchases and sales of power for delivery in the 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 systematically diverge. 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.

[2] Balancing congestion shortfalls occur when day-ahead scheduled flows over a facility exceed what can flow over the facility in real-time. In this case, the NYISO must redispatch generation to reduce the flow over the constraint, the costs of which are recovered through uplift.

Price convergence is desirable because it promotes the efficient commitment of generating resources, procurement of natural gas, and scheduling of external transactions. We find that convergence between day-ahead and real-time energy prices continues to be good at the zone level due, in part, to efficient scheduling by virtual traders.

Convergence generally improved at the nodal level from 2008 to 2009, although there were several nodes in New York City and Long Island where average day-ahead prices were substantially different from average real-time prices. Several factors contributed to the improvement in 2009 by reducing inconsistencies between the day-ahead and real-time markets:

- The assumed day-ahead market transfer capability into the area around the Gowanus plant in New York City was modified to better reflect the expected real-time capability.
- SRE commitments (which increase commitment after day-ahead market) have been less frequent due to changes that allow transmission owners to commit units for reliability prior to the day-ahead market (i.e., DARU commitment).
- Simplified New York City interface constraints (which are never used in the day-ahead market) were used less frequently in real-time to manage congestion.

The NYISO is developing a proposal to allow virtual trading at a more granular level than the zonal virtual trading that is currently allowed. This change should further improve the convergence between day-ahead and real-time prices.

We find that convergence between day-ahead and real-time operating reserve prices has improved in recent years, but is still poor under certain circumstances. Day-ahead prices are higher than real-time prices in most hours, but the day-ahead prices were systematically lower than real-time prices during peak conditions when real-time shortage are more likely. This difference should cause suppliers to raise their day-ahead offers in peak hours to arbitrage the difference. However, the mitigation measures limit the day-ahead reserve offers of some suppliers. We recommend the NYISO modify the mitigation measures to ensure suppliers can offer competitively.

E. External Transactions and Price Convergence

Efficient use of transmission interfaces between regions allows customers to be served by external resources that are lower-cost than available native resources. New York imports substantial amounts of power from PJM, Quebec, Ontario, and New England, which reduces wholesale power costs for electricity consumers in New York. In 2009, the NYISO imported an average of 3.1 GW during peak hours (i.e., Monday through Friday, 6 am to 10 pm).

Our evaluation of external transactions between New York and three adjacent markets indicates that scheduling by market participants did not fully utilize the external interfaces or achieve all of the potential benefits available from inter-regional trading. Improving the efficiency of flows between regions is particularly important during shortages or very high-priced periods when modest adjustments to the physical interchange can reduce prices significantly. We find that the external transaction scheduling process was functioning properly and that scheduling by market participants tended to improve convergence. However, significant opportunities remain to improve the interchange between regions. Additionally, clockwise loop flows around Lake Erie have risen in recent years, increasing congestion and uplift for NYISO participants. This has highlighted the importance of efforts to manage the congestion created by unscheduled loop flows more efficiently. The NYISO has been working with the other ISOs in the Broader Regional Market ("BRM") initiative to identify additional mechanisms to improve the efficiency of external transaction scheduling.

We performed analyses to estimate the potential benefits that could be gained from improving the efficiency of: (i) the net scheduled interchange between control areas, and (ii) congestion management of flowgates that are affected by the operation of adjacent control areas. We estimate potential production cost savings of almost $200 million annually from more efficient use of the NYISO's internal and external interfaces and more than $360 million annually from all interfaces around Lake Erie. Given these sizable potential savings, we recommend the NYISO continue working with adjacent ISOs to better utilize the transfer capability between regions.

F. Market Operations

This section covers several areas related to the operation of the day-ahead and real-time markets, including the market consequences of certain operating procedures and the scheduling actions.

1. Real-Time Scheduling and Pricing

We evaluate the efficiency of gas turbine commitment and external transaction scheduling in the real-time market, which are important because excess commitment and net import scheduling result in depressed real-time prices and higher uplift costs, while under-commitment and inefficiently low net imports lead to unnecessary price spikes. In our evaluation of gas turbine commitment, we find the majority of capacity committed in 2009 was economic and the overall efficiency was consistent from 2008 to 2009. Moreover, the amount of gas turbine commitment fell approximately 40 percent in New York State and 63 percent in New York City from 2008 to 2009 primarily due to the lower load levels in 2009. In our evaluation of external transaction scheduling, we found that a high portion (77 percent) of price-sensitive import offers and export bids were scheduled consistent with real-time prices at the primary interface with New England in 2009. Although the external transaction scheduling process has functioned reasonably well, this result highlights the importance of the NYISO's efforts to work with neighboring RTOs to improve coordination of the interchange between regions.

2. Real-Time Price Volatility

We also analyze price volatility, finding that price volatility was high at the top of the hour during the morning ramping-up and evening ramping-down periods. Volatile prices can be an efficient signal of the value of flexible resources, although unnecessary volatility imposes excessive costs on market participants, making it important to identify the causes of volatility. In this report, we identify several factors that contribute to these large price changes at the top of the hour during ramping hours, particularly large adjustments to import and export schedules at the top of the hour, changes in hourly schedules of the inflexible units, and changes in the operating modes of pumped storage units. These factors and the others discussed in the report frequently lead to transient shortages of reserves or regulation and price spikes. The NYISO also performed an analysis in 2009 to evaluate and address factors that contribute to unnecessary real-time price volatility and has identified six proposed or on-going projects that should help address the causes of unnecessary real-time price volatility.

3. Market Performance during Shortage Conditions

Prices that occur under shortage conditions are an important contributor to efficient long-term price signals. Efficient prices also provide suppliers and demand response resources with incentives to help improve the reliability of real-time operations during shortages. Shortage conditions occur most frequently when demand reaches extremely high levels, so the low demand in 2009 led to less frequent shortages than in previous years.

The importance of setting efficient real-time price signals during shortages of operating reserves has been well recognized. The NYISO has two mechanisms 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 allows demand response resources to set clearing prices when an operating reserve shortage is avoided by the activation of demand response.

Based on our evaluation of shortage pricing in this report, we found that reserve shortage pricing occurred in 69 percent of the periods with physical shortages in 2009. To improve real-time pricing during periods with operating reserve shortages, the NYISO modified the treatment of ramp limitations in the real-time market’s pricing model for units that are not responding to dispatch signals in March 2009. This enhancement has led to more efficient pricing of energy and ancillary services (particularly during shortages). Furthermore, it has also contributed to the reduction in physical shortages in 2009 because the real-time models are more likely to recognize when a GT should be started to avoid a shortage. We did not evaluate pricing during activations of emergency demand response because they were not activated for reliability in 2009.

4. Supplemental Commitment 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: (i) 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; (ii) Day-Ahead Local Reliability Rule (“LRR”) commitment that takes place during the economic commitment within the day-ahead market process; and (iii) Supplemental Resource Evaluation ("SRE") commitment, which occurs after the day-ahead market closes.

Generators that are committed for reliability are generally not economic at market prices. They can adversely affect the market by muting price signals and causing uplift charges that are difficult for participants to hedge. Supplemental commitments are largely made to satisfy local reliability requirements, primarily in New York City and result in day-ahead or real-time local reliability uplift.

The average amount of supplemental commitment for reliability exceeded 1,200 MW in New York City and 300 MW in other areas in 2009. The overall amount of supplemental commitment was consistent from 2008 to 2009. However, the associated uplift charges for guarantee payments fell from $430 million in 2008 to $250 million in 2009 primarily due to the reduction in fuel prices.

In February 2009, the NYISO made the following two enhancements to improve the efficiency of reliability commitments:

- Transmission owners were allowed to commit units prior to economic commitment of SCUC (i.e., DARU), so that SRE commitments are generally not needed unless there is a change in operating conditions after the day-ahead market; and
- New York City LRR constraints were included in the economic commitment of SCUC so that commitments necessary to satisfy these constraints are not made after the economic commitment.

These enhancements have led to overall more efficient commitment, resulting in less uplift charges. However, supplemental commitments in western New York for bulk power system reliability and local reliability increased in 2009, partly offsetting the reduction in uplift charges.

5. Uplift Charges

The NYISO recovers its costs through uplift charges when it makes payments to certain market participants that are not recouped from the market. 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. This report evaluates uplift charges resulting from day-ahead congestion revenue shortfalls, balancing congestion revenue shortfalls, and other guarantee payments. The two classes of congestion shortfalls are summarized in sub-section C above.

The final class of uplift costs related to guarantee payments occur when generators are scheduled, but do not recoup their as-offered costs from the day-ahead or real-time markets. Total guarantee payments to generators fell from $430 million in 2008 to $250 million in 2009. This reduction was primarily attributable to the decline in fuel prices, which reduced the payments needed to ensure a generator covers its costs. Guarantee payments were also reduced as a result of changes to the processes for committing generators for reliability in the day-ahead market, which allow transmission owners to commit units for local reliability needs before the day-ahead market runs. However, more frequent commitments in the upstate for bulk power system reliability and local reliability occurred in 2009, which partly offset the decrease in uplift.

G. Capacity Market

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 operating reserve markets. Currently, the capacity auctions determine clearing prices for three distinct locations: New York City, Long Island, and NYCA. The clearing prices in New York City are generally much higher than those in Long Island and NYCA.

1. Capacity Market Results

We evaluated outcomes in the capacity market and found that capacity prices were relatively low in 2009, reflecting that significant surpluses exist relative to the capacity requirements in each of the three capacity zones and that there was no significant withholding of capacity.

In New York City, virtually all internal capacity was sold in each month of 2009. Hence, withholding of supply has not been significant partly due to new supply-side market power mitigation measures. Seasonal variations in capability accounted for most variations in the clearing prices during the period. The spot price averaged $8.27 per kW-month in the summer months and $1.29 per kW-month in the winter months. The average capacity surplus was 753 MW in the summer months and 1,540 MW in the winter months, reflecting that most generators have higher capability at lower ambient temperatures. Average spot prices increased 38 percent from the summer of 2008 to the summer of 2009 due to reductions in DMNC values of internal generators and SCRs, the annual escalation of the capacity demand curve, and a modest increase in the peak load forecast for New York City.

In Long Island, the spot price averaged $3.80 per kW-month in the summer months and $1.17 per kW-month in the winter. The Long Island clearing price was equivalent to the NYCA clearing price during nine of the months in 2009, indicating that the Local Capacity Requirement ("LCR") was not binding in these months. The Long Island LCR was binding from May 2009 to July 2009 due to an increase in the LCR from 94 percent to 97.5 percent starting May 2009. The LCR was no longer binding after July 2009 because 300 MW of new capacity entered the market in August 2009.

In NYCA, the spot price averaged $3.28 per kW-month in the summer months and $1.17 per kW-month in the winter due to seasonal changes in internal capability between the summer and winter capability periods. However, these changes were partly offset by variations in net imports, which were higher during the summer capability period. Spot prices rose from the summer of 2008 to the summer of 2009 because net imports fell due to higher capacity prices in PJM beginning in June 2009, and because the Installed Reserve Margin ("IRM") for NYCA increased from 115 percent to 116.5 percent in May 2009. These factors were partly offset by capacity additions during the later portion of 2009.

2. Capacity Market Configuration

The capacity market provides investment signals to help New York state meet its planning reserve margin requirements. Currently, there are three local capacity regions: New York City, Long Island, and NYCA. By setting a distinct clearing price in each capacity region, the capacity market guides investment to areas where it is most valuable.

New capacity or imports that are deemed to be "undeliverable" under a new test being implemented by the NYISO will not be able to sell capacity in New York unless they pay to upgrade the transmission system or acquire deliverability rights from another market participant. The new deliverability test creates several significant efficiency and competitive concerns:

- It does not provide efficient incentives in constrained areas to invest in supply resources, demand resources, and transmission facilities, or for the maintenance of existing resources;
- It creates a substantial barrier to entry by competitive new supplies and imports in unconstrained areas, reducing competition in the market.

These issues are exacerbated by the fact that the deliverability test is unrealistic and can raise deliverability concerns even when transmission capability is sufficient to allow "undeliverable" resources to contribute to satisfying statewide reliability needs. Lastly, it will likely raise capacity costs unnecessarily for New York consumers.

The report illustrates these inefficiencies and explains why it would be far more efficient to address the perceived deliverability issue by creating additional capacity zones. Creating a new capacity zone or zones would be beneficial because it would distinguish the value of capacity in southeast New York from the value of capacity in other areas. This would:

- Allow the capacity market to signal where new capacity would be most beneficial. This may be particularly important in southeast New York where the cost of new entry is likely higher than in other areas.
- Enable more suppliers to sell capacity outside the new zone(s), thereby lowering capacity costs for New York consumers in those areas. If new capacity is not needed immediately in the new zone, creating the zone will likely reduce overall capacity costs statewide.

Hence, we recommend that the NYISO make preparations to implement a new capacity market zone in parallel with developing the criteria for creating a new zone in 2010. These preparations should include developing CONE estimates, demand curves, and other details necessary to implement a new zone(s).

Some have argued that applying the deliverability tests and rules as currently envisioned will encourage transmission investment. However, creating new zones should not reduce the likelihood that investments will be made to upgrade the transmission system when it is economically efficient. If those that invest in new transmission capability between capacity zones have access to the economic property right corresponding to the difference in the capacity prices between the zones, then creating new zones will provide investors in transmission with clear economic signals and incentives to invest efficiently in transmission.

H. 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, discuss the on-going efforts of the NYISO to facilitate more participation, and identify barriers to additional participation.

1. Existing Demand Response Programs

This report evaluates participation in each of the NYISO's five demand response programs. 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 emergency demand response resources that are called when the NYISO forecasts a shortage. Currently, nearly all of the 2.4 GW of demand response resources in New York are emergency demand response.

The NYISO established the Demand-Side Ancillary Services Program ("DSASP") in June 2008 to allow demand-side resources to offer operating reserves and regulation service in the wholesale market. The first DSASP resource completed its enrollment as an Ancillary Service provider in late November 2009. The resource will be eligible to offer Regulation and/or Reserves in the NYISO markets once prequalification is completed in 2010. Hence, no resources have fully qualified as DSASP resources yet. Some resources have experienced delays related to setting up communications with the NYISO through the local Transmission Owner. To expedite the process, the NYISO is exploring ways to communicate directly with resources rather than through the local Transmission Owner.

The fastest growing demand response program operated by the NYISO is the SCR program, whose participation grew to over 2 GW in 2009. This growth is likely due to the fact that SCRs can sell capacity in the NYISO's capacity market. Given the reliance on Special Case Resources ("SCRs") for satisfying reliability needs, it is important to ensure that SCRs can perform when called. The current SCR baseline methodology is based on their monthly peak loads from the prior year, although the NYISO is conducting an evaluation of the baseline methods used for existing SCRs to determine whether they should be revised.

2. Efficient Design of a Real-Time Price Responsive Load Program

Despite these efforts, there remain significant barriers to participation in the wholesale market by loads. The most significant barrier to participation is that most retail loads are served by load serving entities that charge retail prices that are unrelated to real-time prices in the wholesale market. Although a form of dynamic real-time pricing could be established to align retail consumers' incentives with the true costs of their consumption to the system, the NYISO has committed to begin working with stakeholders in 2010 to create a real-time economic demand response program in the wholesale market. We agree that creating a program to facilitate participation by loads in the real-time market would be beneficial in several ways. It would contribute to reliability in the short-term and resource adequacy in the long-term, reduce price volatility and other market costs, and mitigate supplier market power. Additionally, price-responsive demand has the potential to produce sizable savings by enhancing wholesale market efficiency.

To provide the greatest possible benefit, a real-time demand response program must give loads incentives to reduce consumption when it is efficient to do so. The elements of an efficient program are discussed at length in the comments filed by Potomac Economics to the NOPR.[3] The key element is that it is important for a load resource to receive a total net payment that is equal to the LBMP where the total net payment is equal to (a) the payment received from the NYISO plus (b) any charge from the LSE that is avoided for not consuming. This will ensure that the load resource curtails at the point when the value of its consumption is equal to the LBMP. This can be accomplished in at least two ways.

First, the load resource could receive a payment from the NYISO equal to the difference between the wholesale LBMP and the load's retail rate. Paying this amount would align the load's incentives with the value of the energy to the system because the payment would make up the difference between what the load saved on its retail bill and the value of energy to the wholesale market. It would be important to allocate the cost of the payments from the NYISO to the corresponding LSE, who might otherwise receive a windfall when its load curtails.

Second, the demand resource could receive the full real-time LBMP as suggested by the recent NOPR. However, it would be important: (a) for the LSE to be charged the real-time LBMP for the increment of load that was curtailed, and (b) for the retail customer associated with the load resource to continue to be charged the retail rate by the LSE. This alternative would provide efficient incentives to the demand resource and result in a settlement that is comparable to supplying the load from a supply resource.

Either of these approaches would allow an economic demand response program to facilitate efficient entry of demand response, as well as efficient curtailments of the demand response in the real-time market. The NYISO's programs in this area will be governed by the outcome of the Commission's rulemaking process that may deviate from this principle.

I. List of Recommendations and Recent Enhancements

Our analysis in this report indicates that the NYISO electricity markets performed well in 2009, although the report recommends additional improvements that should be made by the NYISO. We believe that first three recommendations should be prioritized the highest.

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[3] Comments of Potomac Economics, Ltd., Docket Nos. RM10-17-000 and EL09-68-000, May 13, 2010.

W*e* recommend the NYISO prepare to define a new capacity zone(s) in eastern New York to allow the capacity market to efficiently reflect the transmission issues indicated by the new deliverability test. The NYISO will be working with stakeholders in 2010 to develop criteria for designating new capacity zones, but we recommend the NYISO work in parallel to develop potential demand curves and other details necessary to implement the new zone(s). The new zone(s) will provide appropriate price signals in each location for investment in new generation, transmission, or demand response resources.

1. *We recommend the NYISO continue working with adjacent ISOs to better utilize the transfer capability between regions, ideally by directly coordinating the physical interchange or facilitating intra-hour trading to achieve efficient interchange.* The NYISO is working with neighboring control areas on several proposals to improve the efficient use of the interfaces. This change will increase economic efficiency and lower overall costs to consumers.

2. *We support the NYISO's development of a real-time demand response program to better align the incentives of retail customers with the needs of the system.* Retail rate reform is one means to give retail loads incentives to respond to prices. However, there are other ways the ISO may provide these incentives. The NYISO plans to propose a concept for enabling participation by demand response resources in the real-time market in 2010. Under such a program, we recommend the following settlements for the curtailed load because they would provide efficient incentives to the customer and avoids uplift costs:

   - ✓ Pay the price-responsive customer the LBMP;
   - ✓ Charge the LSE serving the customer the LBMP; and
   - ✓ The LSE continue to charge the customer the applicable retail rate.

3. *We recommend addressing several factors that have been shown to contribute to excess real-time price volatility during ramping hours.* The NYISO has identified six proposed market and operational enhancements that would help reduce unnecessary price volatility.

4. *We recommend NYISO modify two mitigation provisions that may limit competitive 10-minute reserves offers in the day-ahead market.* This should improve convergence of day-ahead and real-time reserve prices.

5. *We recommend the offer floor for real-time imports and exports be raised from -$1000/MWh to a level more consistent with the avoided costs of curtailment.* This would limit balancing congestion shortfalls when they must be curtailed. In March 2010, the NYISO changed the default offer for import transactions with day-ahead priority from -$999.70/MWh to -$0.01/MWh. We will evaluate in future reports how well this change addresses the balancing congestion shortfalls that can result from negative-priced offers.

6. *We recommend enabling market participants to schedule virtual trades at a more disaggregated level.* Currently, virtual trading is allowed at only the zonal level. This change would improve day-ahead to real-time price convergence in New York City load pockets. NYISO has a project to expand the set of locations where virtual trading is allowed.

7. *We recommend the NYISO review the details regarding its uneconomic entry mitigation for the capacity market to ensure that it will be effective without hindering efficient entry.* The NYISO is preparing filings that will address these issues.

8. *We recommend that the NYISO revisit the baseline method and testing procedures for SCRs to ensure their response is accurately measured.* The NYISO is conducting an evaluation of the baseline methods used for existing SCRs to determine whether they should be revised.

II. 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.

This section of the report provides a review of market results in 2009 and evaluates the performance of these markets. This evaluation includes an assessment of the long-term economic signals that govern new investment and retirement decisions in New York. Subsequent sections examine individual aspects of the market in greater detail.

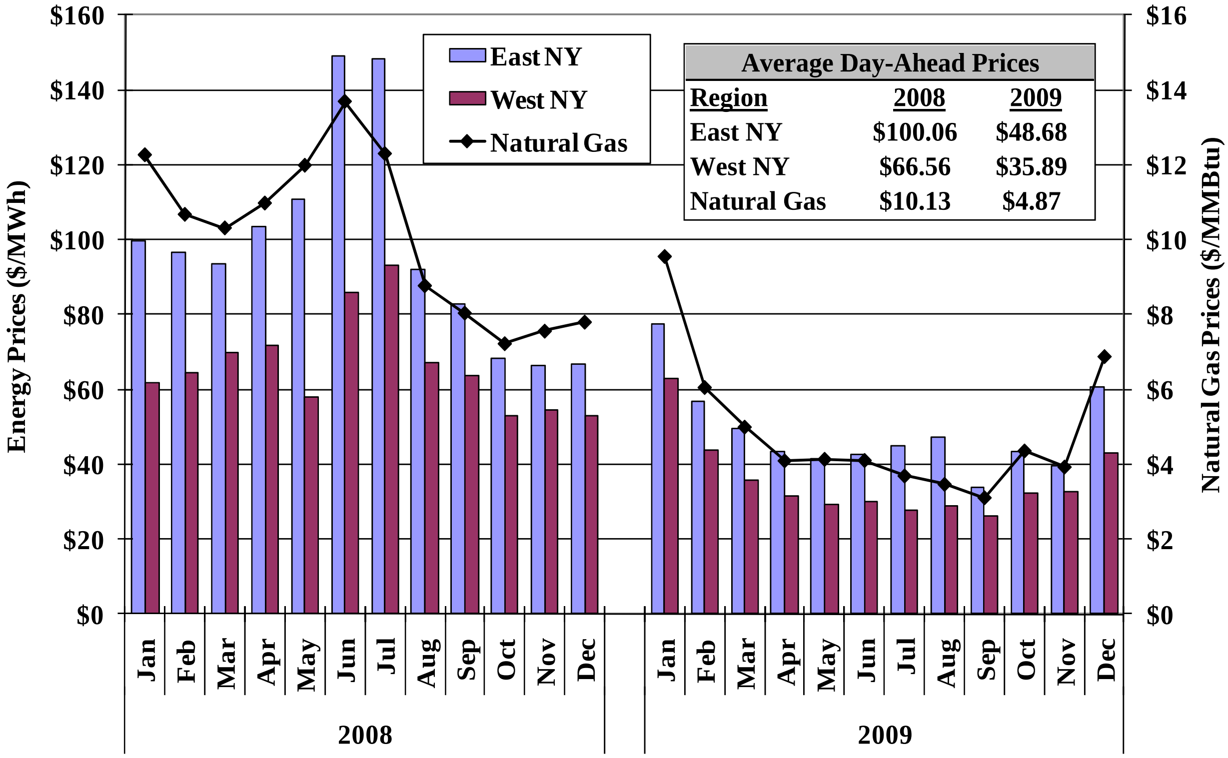
A. Summary of Outcomes in 2009

1. Energy Prices

Figure 1 shows monthly average natural gas prices and load-weighted average day-ahead energy prices for Eastern and Western New York in 2008 and 2009. 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 generation units that set market clearing prices, especially in Eastern New York. This is evident from the strong correlation of electricity prices with natural gas prices shown in the figure.

The figure shows that electricity prices in the day-ahead market decreased substantially from 2008 to 2009. In 2009, the electricity prices averaged approximately \$36 per MWh and \$49 per MWh in Western and Eastern New York, down 46 percent and 51 percent from 2008, respectively. The reduction in electricity prices was primarily due to the decline in natural gas prices. Average natural gas prices fell 52 percent from 2008 to 2009. Likewise, average diesel oil (No.2 oil) prices fell 42 percent and average residual fuel oil (No. 6 oil) prices fell 32 percent from 2008 to 2009. The strong correlation of electricity prices with natural gas prices is expected, since fuel costs constitute the majority of variable production costs for most generators, and gas units are on the margin in most hours.

Figure 1: Day-Ahead Energy and Natural Gas Prices
2008 – 2009



Transmission congestion became less prevalent in 2009, leading to smaller differences in prices between Eastern and Western New York. The average price in Eastern New York was 36 percent higher than the average price in Western New York in 2009, down significantly from the 50 percent difference in 2008. The decrease in congestion from Western New York to Eastern New York was due to several factors. First, substantially lower fuel prices in 2009 reduced redispatch costs to resolve congestion between Western and Eastern New York. Second, load was milder in 2009 than in 2008, which reduced the need for importing generation from Western New York into Eastern New York, leading to less congestion. Third, the effects on congestion of clockwise loop flows around Lake Erie decreased considerably in 2009.[4]

When loop flows move clockwise around Lake Erie, they use a portion of the available west-to-east transmission capability of key interfaces, thereby reducing the portion of transmission

[4] Loop flows refer to unscheduled power flows generally resulting from scheduling in other control areas (i.e., loop flow = actual power flow minus scheduled power flow). Clockwise loop flows travel through New York from Ontario to PJM and tend to load the Central East interface.

capability available for scheduling flows in the NYISO's real-time market. Since clockwise loop flows reduce the amount of power that can be scheduled from west-to-east, the effect is equivalent to a reduction in west-to-east transmission capability. The volume of clockwise loop flows was elevated in the first half of 2008 and then declined at the end of July 2008. As a result, price separation between Western New York and Eastern New York decreased substantially.[5]

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 divided by the natural gas price measured in MMbtu. Thus, if the electricity price is $50 per MWh and the natural gas price is $5 per MMbtu, this would imply that a generator with a 10.0 MMbtu per MWh heat rate is on the margin. Figure 2 shows the load-weighted average implied marginal heat rate for Eastern and Western New York in each month during 2008 and 2009.

By adjusting for the variation in natural gas prices, the implied marginal heat rate shows more clearly the seasonal variation in electricity prices. Figure 2 shows that implied marginal heat rates typically rise in the summer. High demand levels occur during the hot summer months, resulting in elevated electricity prices as high-cost peaking resources are used more frequently to satisfy load and reserve requirements. Furthermore, the supply of generation is reduced because higher ambient temperatures reduced the output capability of thermal units. The months with the highest average implied marginal heat rates were July 2008 and August 2009, which were also the months with the highest average loads. Demand was moderate in the summers of 2008 and 2009 compared with previous summers, limiting the increase in prices associated with increased demand.

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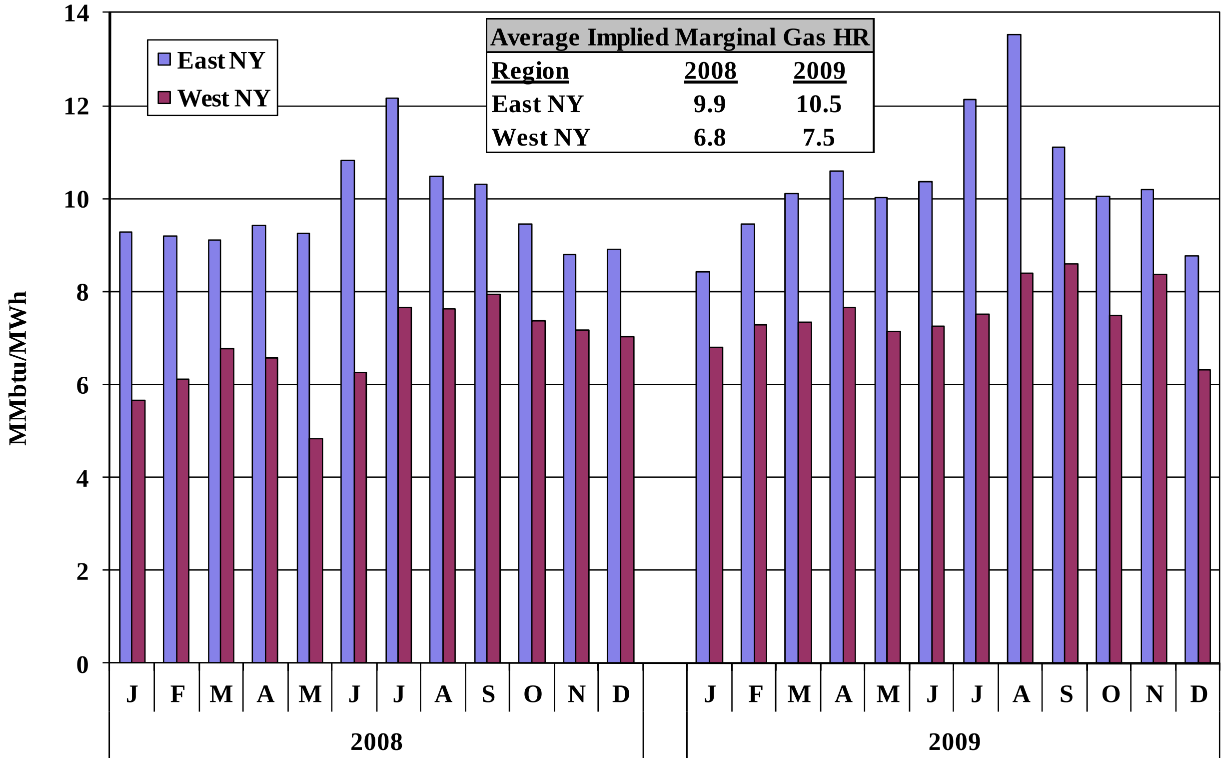
5 The scheduling pattern that led to changes in loop flows and the effects of the loop flows on congestion patterns are discussed in detail in 2008 State of the Market Report, August 2009, Potomac Economics.

Figure 2: Average Implied Marginal Heat Rate

Based on Day-Ahead Electricity and Natural Gas Prices, 2008 – 2009

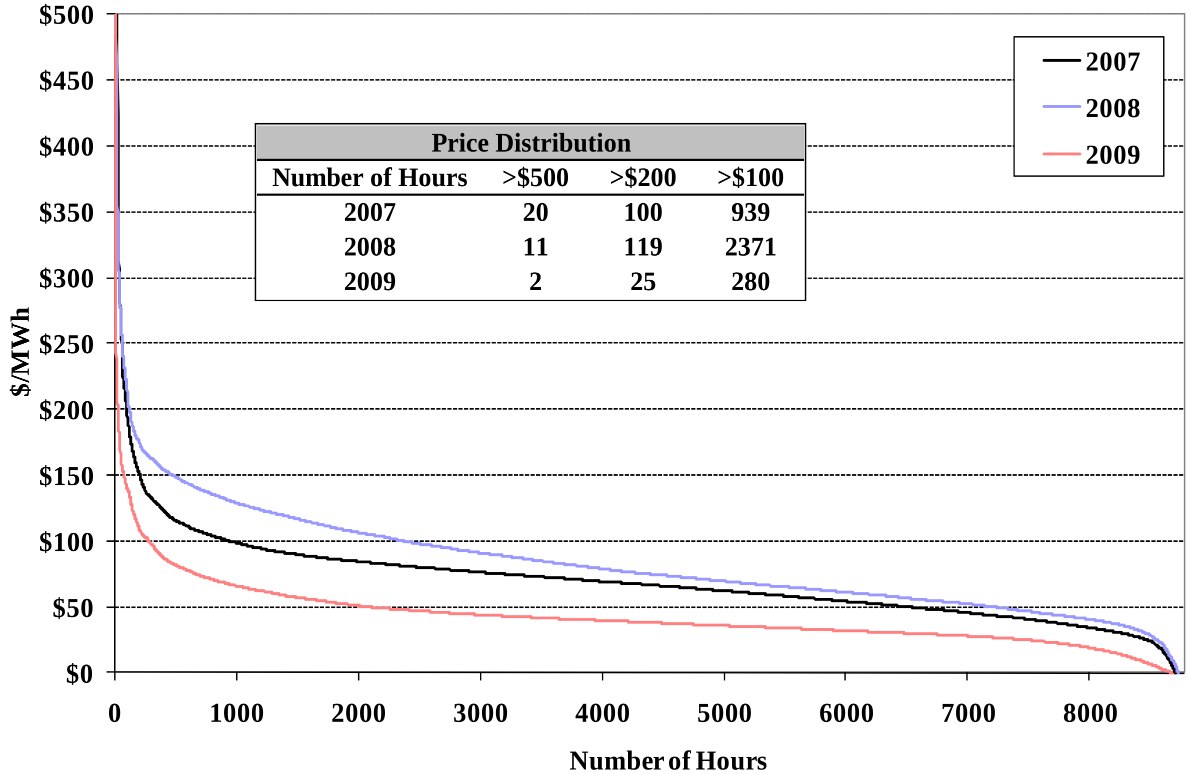


In some of the months shown in Figure 2, the implied marginal heat rate in Western New York declined to levels below the heat rate of the most efficient gas-burning generators. This occurred in months when there were a substantial number of hours when less expensive fuels were on the margin, such as coal or hydro.

Overall, the average implied marginal heat rate rose approximately 6 percent in Eastern New York and 10 percent in Western New York from 2008 to 2009. Several factors contributed to the increase in the average implied heat rate. First, some of the generation costs (e.g., variable operating and maintenance expenses) are not related to fuel prices, leading the implied heat rate to rise as fuel prices fall. Second, the differential between natural gas prices and oil prices increased in 2009 (as a proportion of the natural gas price), increasing the effect on the implied heat rate of periods when oil-fired generation was on the margin. Third, generators incurred additional costs to produce power in 2009 due to the Regional Greenhouse Gas Initiative ("RGGI") compliance obligations, which require fossil fuel-fired generators to purchase allowances to cover their emissions beginning in January 2009.

The following two figures illustrate how prices varied across hours in each year. Figure 3 shows three price duration curves, one for each year from 2007 to 2009. Each curve shows the number of hours on the horizontal axis when the load-weighted average real-time price for New York State was greater than the level shown on the vertical axis. This allows us to compare the distribution of prices from year to year.

Figure 3: Real-Time Price Duration Curve
NYCA, 2007 – 2009



The price duration curves show the characteristic distribution of prices in wholesale power markets. Most hours are priced moderately, but a small number of hours exhibited very high prices, which are typically associated with shortages. During periods of 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. The number of extremely high-priced hours (e.g., when price exceeded $500 per MWh) declined over the past three years, from approximately 20 hours in 2007, to 11 hours in 2008, and to 2 hours in 2009. This decline was partly due to the substantial decrease in the number of hours when load reached very high levels (e.g., above 28 GW) in 2009. Additionally, there has been no indication that artificial shortages have resulted from withholding, supporting our opinion that the New York market has been competitive.

Fuel price changes from year to year are revealed by the flatter portion of the price duration curve, since fuel price changes affect power prices in almost all hours. The figure shows that the electricity prices rose from 2007 to 2008 and then fell substantially in 2009. Similarly, the average natural gas price increased 19 percent from 2007 to 2008 and then decreased 52 percent from 2008 to 2009. The change in natural gas prices was also evident from the change in the number of hours when the electricity price exceeded $100 per MWh, which increased from 939 hours in 2007 to 2,371 hours in 2008 and then fell to 280 hours in 2009.

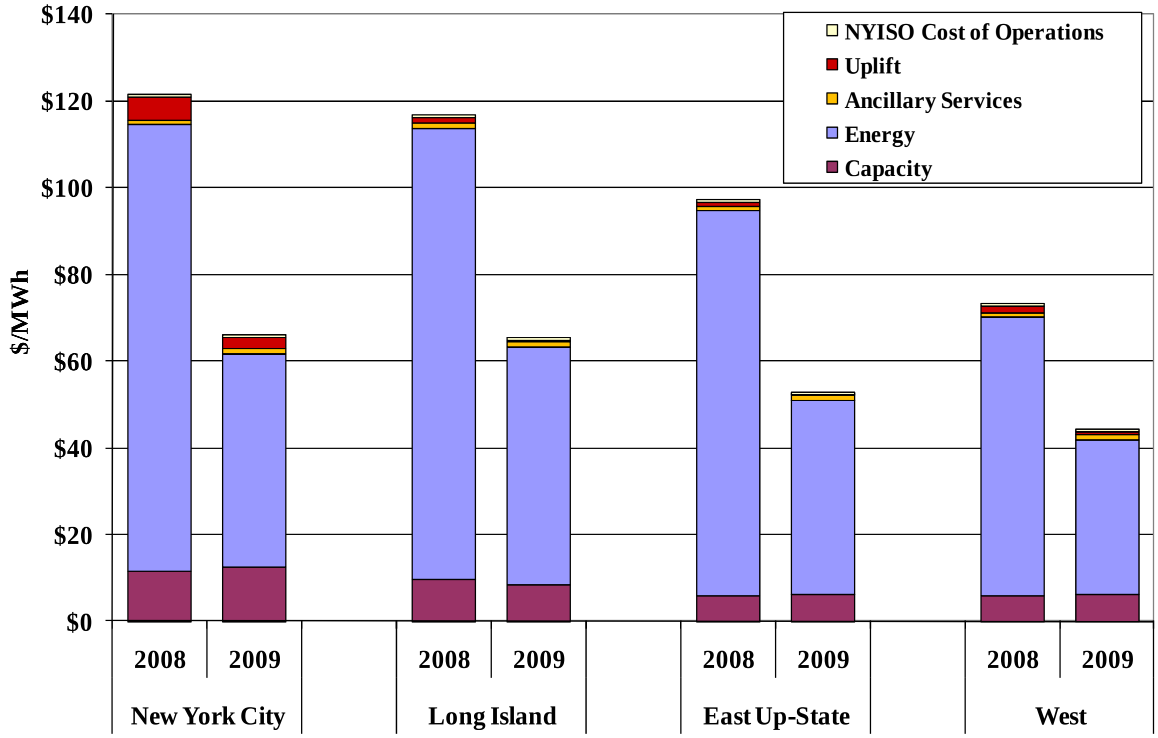
2. Total Market Costs: All-In Price

The next analysis summarizes changes in energy prices and other 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 by multiplying the average prices in the monthly spot auctions by the capacity obligations in each capacity zone, and then dividing by total energy consumption in that area. The uplift component is based on local and statewide uplift, 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 4 shows the average all-in price at four locations over the past two years. This figure shows the all-in price decreased substantially from 2008 to 2009 in each of the four regions. The largest reduction occurred in New York City, where the average all-in price fell 46 percent from 2008 to approximately $66 per MWh in 2009. The smallest reduction occurred in Western New York, where the average all-in price decreased 40 percent from 2008 to roughly $44 per MWh in 2009.

Figure 4: All-In Prices by Region
2008 – 2009



Overall, all-in prices decreased by 44 percent from 2008 to 2009. The decrease in all-in prices from 2008 to 2009 was largely due to the decline in energy costs, which resulted primarily from lower natural gas prices and fuel oil prices. This is particularly true in Eastern New York where more of the generating capacity is fired by natural gas.

The decrease in all-in prices was partly driven by the decline in uplift charges from 2008 to 2009, which occurred for several reasons. First, lower fuel prices contributed to lower balancing congestion residual charges and lower guarantee payments to generators committed for reliability. Second, the consistency of scheduling between day-ahead and real-time markets improved in 2009, contributing to lower balancing congestion residual charges. This was partly due to the improved assumptions related to clockwise loop flows around Lake Erie in the day-ahead market. Balancing congestion residual charges are evaluated in Section V.A.

3. Fuel Prices

In recent years, fossil fuel price fluctuations have been the primary driver of changes in wholesale power prices because most of the variable production costs of fossil generators are fuel costs. Although much of the electricity generated in New York is from hydro, 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 oil. The following figure shows average coal, natural gas, and oil prices by month from 2006 to 2009.

Figure 5: Natural Gas, Oil, and Coal Price Trends
2006 – 2009

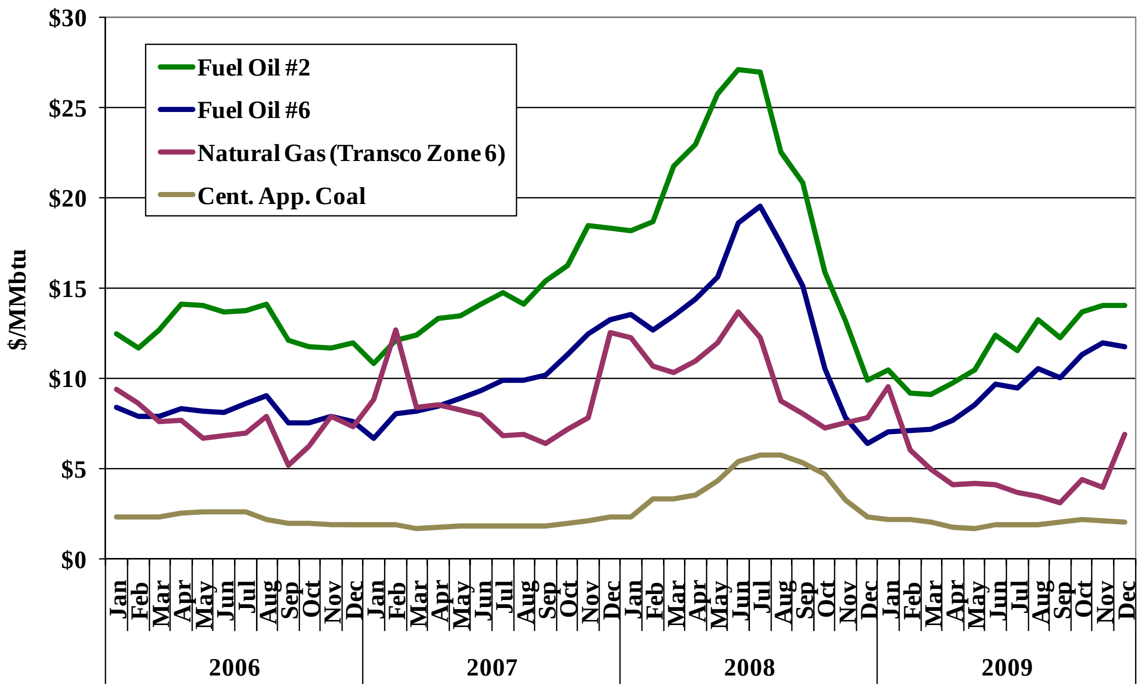


Figure 5 shows that all four fossil fuel prices reached record levels in the summer of 2008 and fell precipitously afterwards. From 2008 to 2009, average natural gas prices fell 52 percent, average diesel fuel oil prices fell 42 percent, average residual fuel oil prices fell 32 percent, and average coal prices fell 52 percent.

The rise in oil prices relative to natural gas prices has decreased the use of oil for electricity production in recent years. Prior to 2006, residual oil was often less expensive than natural gas, allowing oil-fired steam units to be relatively economic compared with gas-fired combined cycle units. However, oil prices have risen such that natural gas was priced lower than fuel oil the vast majority of the time during the past four years. In 2009, natural gas was priced lower than residual oil (No. 6) on 92 percent of the days and lower than diesel oil (No. 2) on 96 percent of the days. Regardless, the dual-fuel capability of many units in New York moderates the effects on electricity prices of transitory spikes in natural gas prices. This was particularly true in January 2009 when natural gas prices were higher than residual oil (No. 6) prices on 84 percent of the days and higher than diesel oil (No. 2) prices on 35 percent of the days.

The use of oil is increased by the Minimum Oil Burn rules, which require some units in New York City and Long Island to burn oil to limit the exposure of the power system to natural gas supply contingencies during high load conditions. Such units are able to choose either: (i) to submit offer prices that reflect the increased fuel cost, or (ii) to submit offer prices that reflect the cost of running on natural gas and participate in the Minimum Oil Burn Compensation ("MOBC") program. When units submit offer prices that reflect the increased fuel cost, the additional fuel costs are sometimes reflected in market clearing prices and higher guarantee payments to generators.

When units participate in the MOBC program, they receive out-of-market payments to make up the difference between the cost of natural gas and the cost of fuel oil. Accordingly, the additional costs are not reflected in market clearing prices. The uplift from MOBC payments declined from approximately $18 million in 2008 to $10 million in 2009, due primarily to reduced residual fuel oil (No. 6) prices and lower load levels. The uplift costs resulting from guarantee payments and MOBC payments are discussed further in Section VI.D.

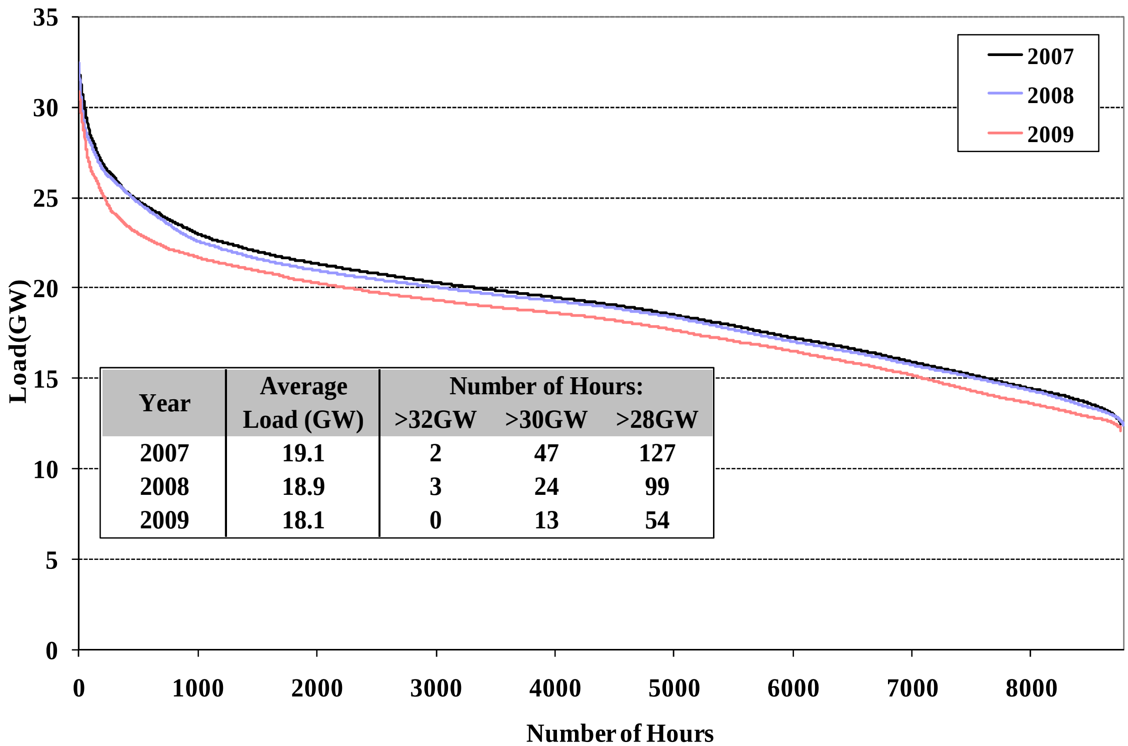
The figure also shows that the difference between natural gas prices and coal prices fell in 2009, particularly from April to November 2009. This was caused by the considerable decline in natural gas prices. When the natural gas price gets close to the coal price, gas-fired combined cycle units become more competitive with coal-fired steam units, reducing the use of coal-fired generation.

4. Energy Demand

The interaction between electric supply and consumer demand 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 day-to-day variation 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.

The following figure 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.

Figure 6: Load Duration Curves
2007 – 2009



Year	Average Load (GW)	Number of Hours: >32GW	>30GW	>28GW
2007	19.1	2	47	127
2008	18.9	3	24	99
2009	18.1	0	13	54

In general, electricity demand grows slowly over time, tracking population growth and economic activity. However, Figure 6 shows that load declined slightly from 2007 to 2008 and more substantially from 2008 to 2009 across a wide range of hours. On average, load decreased roughly 1 percent from 2007 to 2008 and 4 percent from 2008 to 2009. The decreased load levels in 2009 were driven primarily by mild summer weather in 2009 and by poor economic conditions that reduced demand for electricity.

The mild weather led to even more significant reductions during the peak demand hours over the past two years. Load exceeded 30 GW during just 13 hours in 2009, down from 24 hours in 2008 and 47 hours in 2007. Load never exceeded 32 GW during 2009 compared to 3 such hours in 2008 and 2 such hours in 2007. As a result, there were less frequent shortage conditions in 2009, resulting in fewer real-time price spikes.

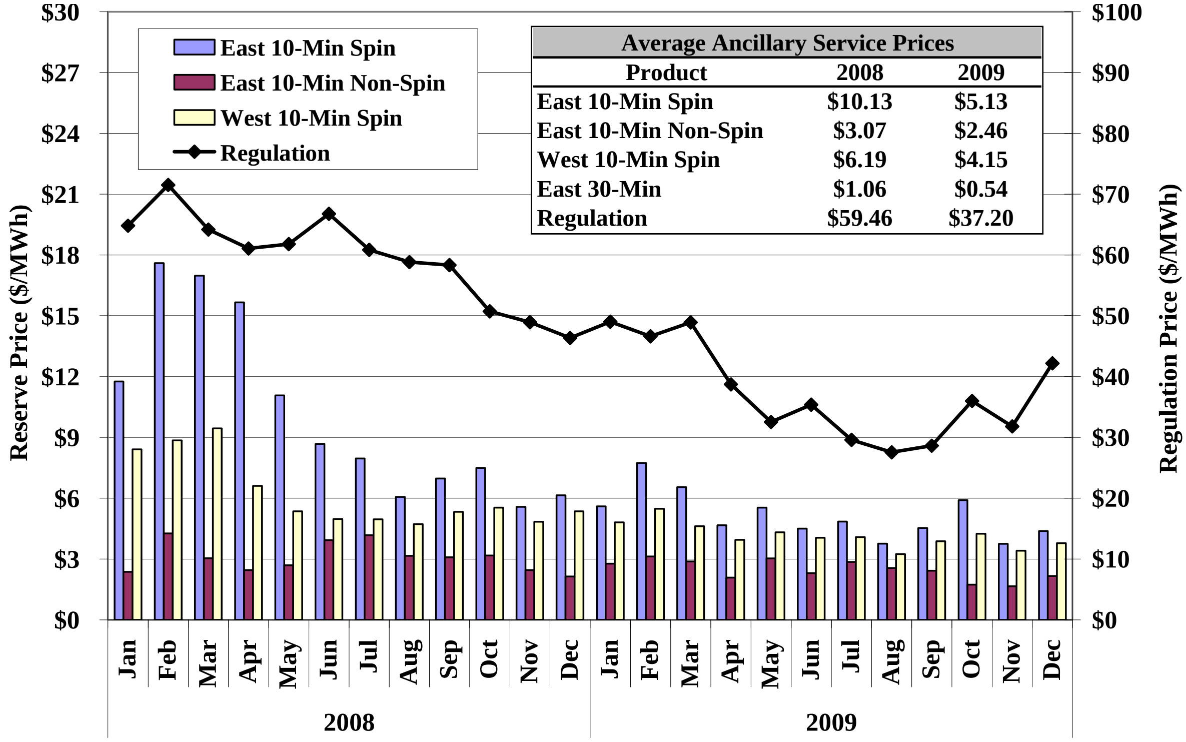
5. Ancillary Services Prices

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 prices reflect the costs to the system of diverting resources to provide ancillary services that would otherwise provide energy, and vice versa. Hence, ancillary services prices generally rise and fall with the price of energy.

In this part of the section we summarize the prices of several key ancillary services products in the day-ahead market in 2008 and 2009. 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 7 shows the monthly average day-ahead prices of 10-minute spinning reserves and 10-minute total reserves in Eastern New York, 10-minute spinning reserves in Western New York, and regulation.

Figure 7: Day-Ahead Ancillary Services Prices

2008 – 2009



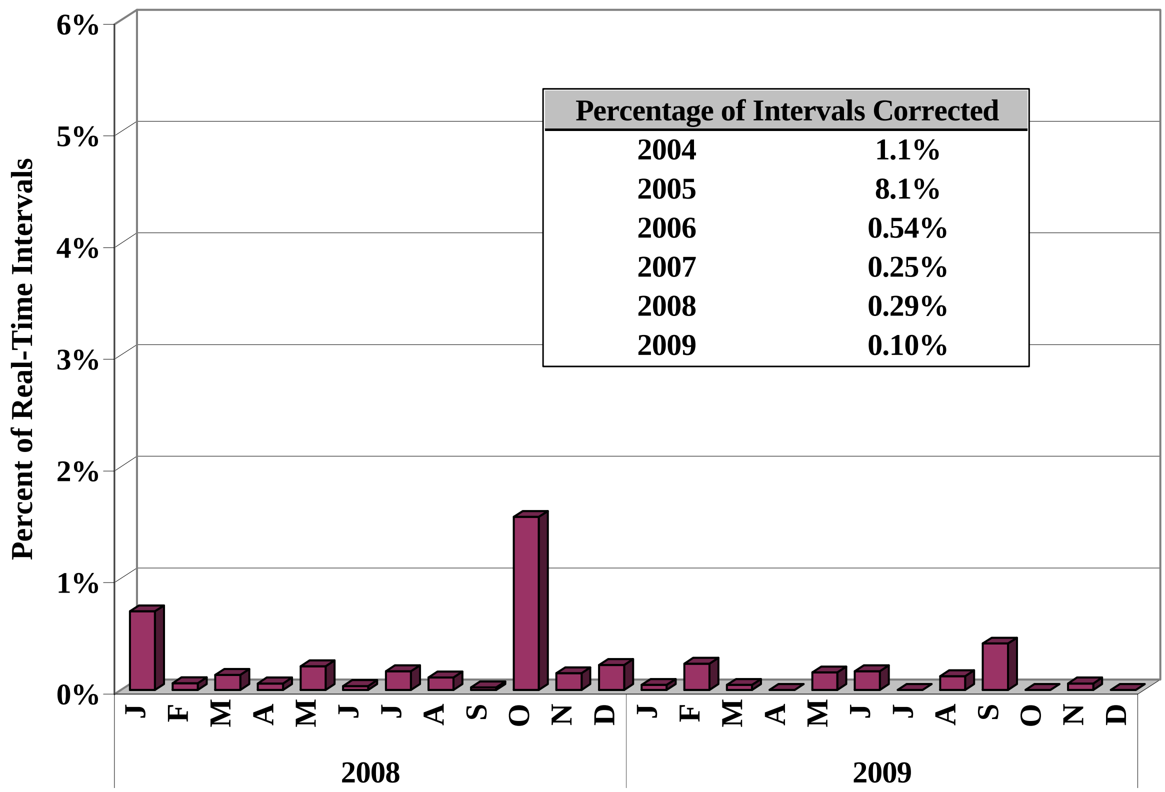
To the extent that ancillary services are scheduled on capacity that would otherwise be economic to produce energy, decreases in energy prices decrease the cost of providing ancillary services. Figure 7 shows that regulation prices and 10-minute spinning reserve prices have declined since early 2008. On average, regulation prices decreased to roughly $37 per MWh in 2009 from nearly $60 per MWh in 2008 and 10-minute spinning reserve prices in Eastern New York fell to $5 per MWh in 2009 from around $10 per MWh in 2008. The decreases are consistent with the decline in fuel prices and energy prices from 2008 to 2009. In 2009, lower load levels generally reduced the frequency of reserve and regulation shortages, resulting in fewer price spikes for these products and contributing to lower average reserve and regulation prices.

The figure also shows that differences between Eastern and Western 10-minute spinning reserves prices decreased after the first half of 2008, which is consistent with the reduced congestion from west to east during the same period. For example, when lower congestion reduces the need for online generators in Eastern New York to produce energy, they have more capacity available to provide spinning reserves, leading to lower spinning reserves prices in Eastern New York.

B. 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 8 summarizes the frequency of price corrections in the real-time energy market in each month of 2008 and 2009.

Figure 8: Percentage of Real-Time Prices Corrected
2008 – 2009



The table in Figure 8 indicates that the frequency of price corrections has declined considerably since 2005 when a high frequency of price corrections occurred after extensive changes were made to the real-time scheduling software under SMD 2.0. The frequency of price corrections has been less than 0.3 percent of real-time pricing intervals in the past three years, and was particularly low in 2009 at only 0.1 percent. Furthermore, the number of pricing locations that were affected has also decreased over years.

In September 2009, the rate of price corrections was somewhat higher than in other months. This was because of an issue that only affected one proxy generator bus, so the market impact of the issue was limited to a small segment of the market. Overall, the frequency of corrections and the significance of the corrections have declined to very low levels.

C. Net Revenue Analysis

Revenues from the energy, ancillary services, and capacity markets provide the signals for investment in new generation and 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 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 may be present:

- 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 are causing revenues to be reduced inefficiently.

If a revenue shortfall persists for an extended period without an excess of capacity, this may indicate a potential problem with the market rules or operating procedures. On the other hand, if prices provide excessive revenues in the short-run, it might indicate a shortage of capacity, unusually high load conditions, or market rules or conduct resulting in inflated prices.

1. Methodology

In this section, we analyze the net revenues that would have been received by various types of generators at seven different locations: Long Island, the Vernon/Greenwood load pocket in New York City, the Astoria East load pocket in New York City, the 345kV portion of New York City, the Hudson Valley Zone, the Capital Zone, and the West Zone.[6] We estimate the net revenues the markets would have provided to two different types of units at these locations: a hypothetical combustion turbine unit and a hypothetical combined-cycle unit.

We use the following two methods to estimate the net revenues for both types of units:

- Standard method – The assumptions have been standardized by FERC and the market monitors of the various markets to provide a basis for comparison of net revenues between markets. This method assumes that net revenues are earned whenever the assumed cost of the unit is less than the day-ahead market clearing price at its location, regardless of the units' physical parameters. It also assumes:
  - The hypothetical combined-cycle unit has a heat rate of 7 MMBtu per MWh and a variable operating and maintenance ("VOM") cost of $3 per MWh; and
  - The hypothetical combustion turbine has a heat rate of 10.5 MMbtu per MWh and a VOM cost of $1 per MWh.
- Enhanced method – This method is similar to the standard method, but it assumes:
  - Commitment costs, minimum run times, minimum generation levels, and other physical limitations are honored;
  - Combined cycles may sell energy, 10-minute spinning reserves and 30-minute reserves; while combustion turbines may sell energy and 30 minute reserves;
  - Offline combustion turbines may be committed and online combined cycles may have their run-time extended based on RTC prices;[7]
  - Online units are dispatched in real-time consistent with the hourly integrated real-time price and settle with the ISO on the deviation from their day-ahead schedule.
  - Regional Greenhouse Gas Initiative ("RGGI") compliance costs are considered beginning January 2009.
  - The Enhanced Method uses the cost assumptions listed in the following table:

6 For all net revenue analyses: the Long Island calculations are based on prices for Zone K, the Vernon/ Greenwood calculations are based on prices at the NYPA/Kent bus, the Astoria East calculations are based on prices at the Astoria GT2/1 bus, the New York City 345 kV area calculations are based on prices at the Poletti bus, the Hudson Valley calculations are based on prices for Zone G, Capital Zone calculations are based on prices for Zone F, and West Zone calculations are based on prices for Zone A.

7 The enhanced method assumes that such a unit is committed for an additional hour if the average LBMP in RTC at its location is greater than or equal to the applicable minimum generation and/or incremental energy cost of the unit for one hour. This uses the RTC LBMPs posted on the NYISO's website.

Table 1: Unit Parameters for Enhanced Net Revenue Estimates

Characteristics	CC	Upstate CT	Downstate CT
Size	500 MW	165 MW	100 MW
Startup Cost (Dollars)	$8,000	$11,000	$0
Startup Cost (MMBTUs)	5,000	360	215
Heat Rate (HHV)	8,100 to 7,250	10,700	9,100
Min Run Time / Min Down Time	5 hours	1 hour	1 hour
Variable O+M	$0 / MWh	$1 / MWh	$5 / MWh

Note: For the two unit types, both methods assume a forced outage rate of 5 percent.

The net revenue estimates produced using the standard method may differ from the actual net revenues earned by market participants for several reasons. First, it doesn't consider that combustion turbines have start-up costs or that combined cycles have start-up costs, lengthy start-up lead times, and minimum run time requirements that exceed one hour. Ignoring these factors tends to over-state net revenues. Second, the standard method uses day-ahead clearing prices exclusively, although generators can earn additional profits by adjusting their production in the real-time market. Ignoring real-time profits tends to understate net revenues. The enhanced method addresses these limitations of the standard net revenue analysis.[8] Lastly, the different heat rate assumptions in the standard method and in the enhanced method create additional differences in net revenues.

2. Net Revenue Results

The following figures summarize net revenue estimates using the enhanced method, with a marker showing net revenue estimates using the standard method for comparison. Figure 9 shows net revenues for a hypothetical combined-cycle generator, and Figure 10 shows net revenues for a hypothetical combustion turbine. Note that the capacity auction revenues are based on the clearing prices in the spot auctions.

8 Another factor that leads to inaccurate net revenue estimates is that fuel expenses in the analysis are based on day-ahead natural gas price indices, although some generators may incur higher costs to obtain natural gas. Combustion turbines frequently purchase natural gas in the intraday market, which generally trades at a slight premium. Combined-cycle units may also incur additional fuel charges when the amount of fuel they burn in real time differs from the amount of fuel they nominate day-ahead. This issue is not addressed by the enhanced method.

Figure 9: Enhanced Net Revenue: Combined Cycle Unit
2006 – 2009

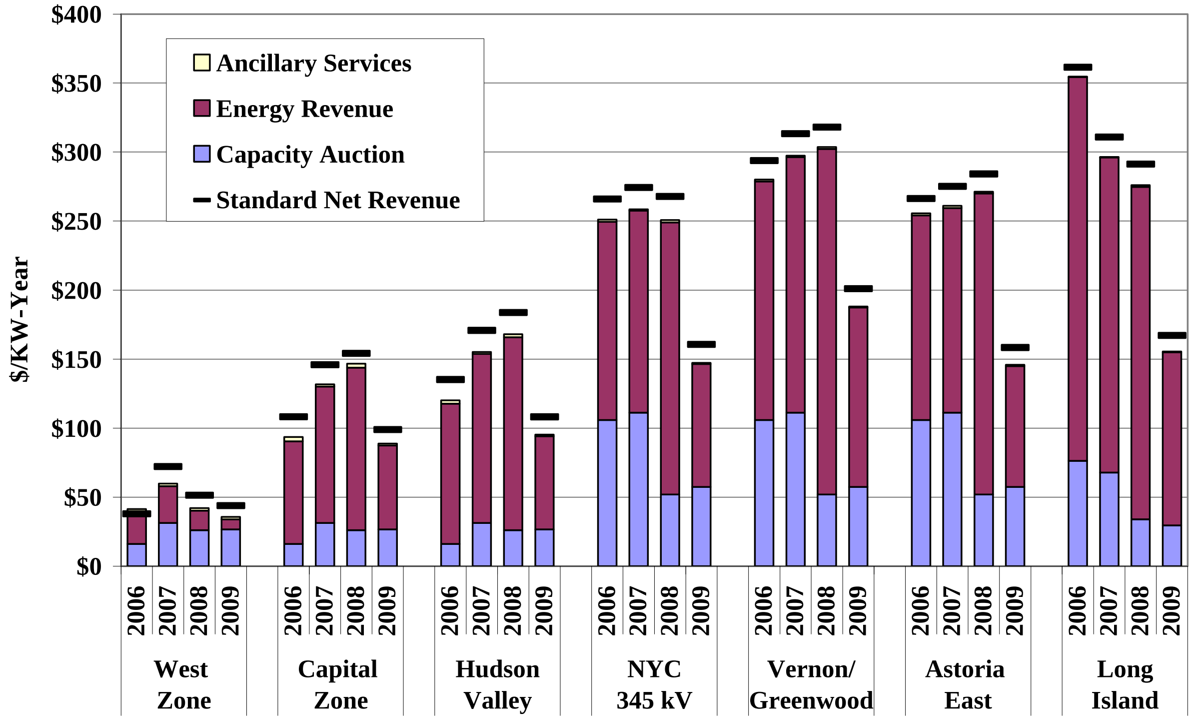
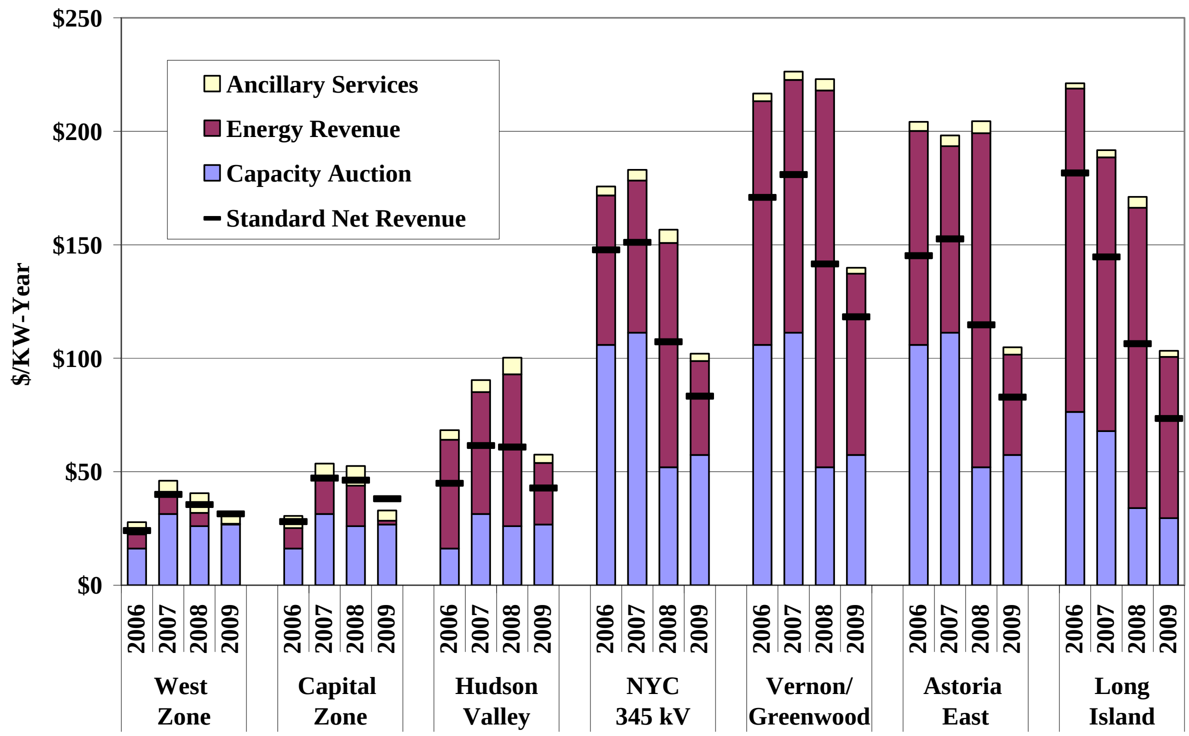


Figure 10: Enhanced Net Revenue: Combustion Turbine Unit
2006 – 2009



Both figures show that net revenues declined sharply in 2009 throughout the state, down roughly 40 percent from 2008. This reduction was due to a number of factors. First, the decline in fuel prices contributed to lower energy net revenues. Changes in fuel prices lead to proportionate changes in the spreads between wholesale energy prices and the costs of production, which has a larger effect on the net revenues of more efficient units (i.e., units with lower heat rates). Second, net revenues declined in Eastern New York due to the reduced effects of clockwise loop flows around Lake Erie in 2009. Clockwise loop flows reduce the west-to-east transmission capability available to the market, thereby increasing the amount of generation required in Eastern New York, which leads to increased LBMPs in Eastern New York.

The results of the enhanced method are comparable to the results of the standard method. For a combined-cycle generator, the enhanced net revenue estimates are slightly lower than under the standard method. The differences are primarily due to reductions in net revenue resulting from start-up costs and minimum runtime restrictions, and small offsetting gains in net revenue from the arbitrage of differences between day-ahead and real-time prices. For a combustion turbine, the enhanced method produces higher net revenue estimates than the standard method. Under the enhanced method, the additional net revenues arise from hours when the generator would be committed after the day-ahead market, although this was partly offset by the inclusion of start-up costs in the analysis.

3. Net Revenue Conclusions

In the recent Installed Capacity Demand Curve Reset Process, the levelized Cost of New Entry ("CONE") for a new peaking unit was estimated at $203 per kW-year in New York City, $180 per kW-year on Long Island, and $109 per kW-year in upstate New York for the 2009/10 capability year. There were no areas of New York where the net revenue levels in 2009 were as high as the estimated CONE for a combustion turbine.

The estimated net revenues are substantially higher for a new combined-cycle unit than a new combustion turbine. In most areas of Eastern New York, the estimated net revenues for a new combined-cycle unit were $40 to $50 per kW-year higher than those for a new combustion turbine in 2009. However, although we do not have precise estimates of the CONE for a new combined-cycle unit in New York, it is unlikely that investment in a new combined-cycle unit could be profitable based on the 2009 net revenues.

Overall, the net revenues in 2009 were consistent with fundamental supply and demand conditions. It is not surprising that neither type of unit would likely have recovered net revenues in 2009 exceeding their CONE because load levels were relatively low and substantial surplus capacity prevailed in New York City, in Long Island, and in the rest of the state. We find no evidence of market design flaws or other problems that would lead to distorted or otherwise inefficient market signals in 2009.

D. Convergence of Day-Ahead and Real-Time Prices

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). Historically, average day-ahead prices have been consistent with average real-time prices in New York and other regions with multi-settlement markets, although it has been common for day-ahead prices to carry a slight premium over real-time prices.

Price convergence is desirable because it promotes the efficient commitment of generating resources, procurement of natural gas, 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.

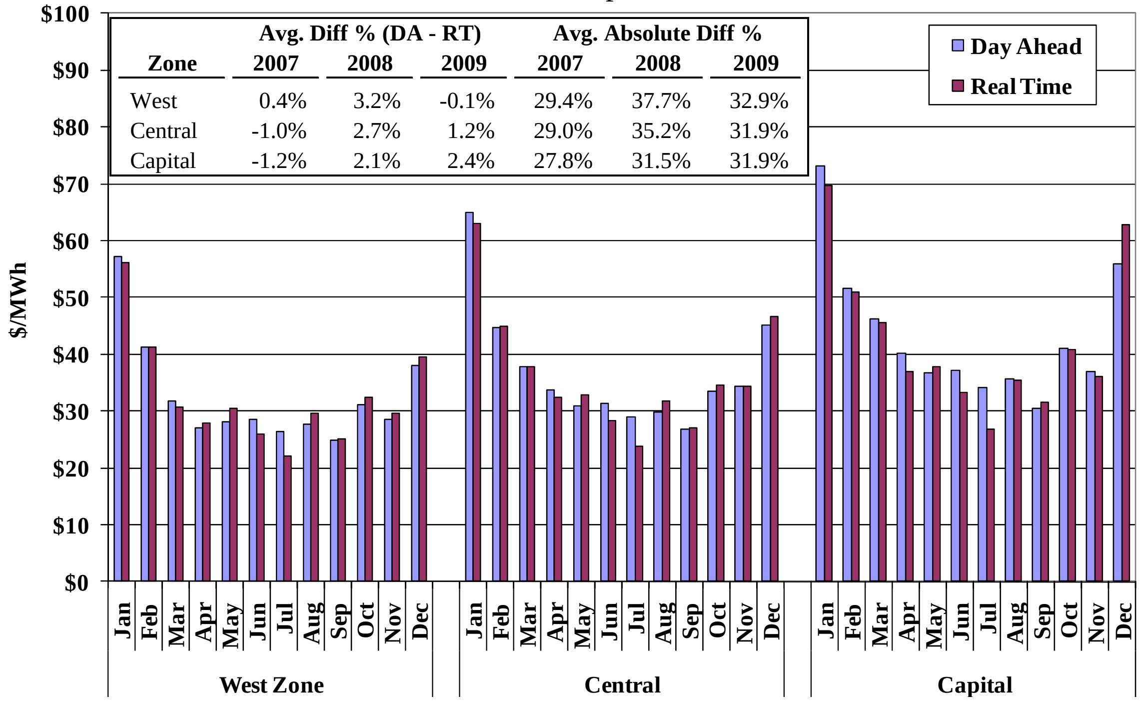
There are two types inconsistencies between day-ahead and real-time prices: random variation resulting from unanticipated changes in supply and demand between the two markets, versus persistent differences between day-ahead and real-time prices. In this section, we evaluate three aspects of convergence 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. Third, we compare average day-ahead and real-time ancillary services prices by time of day.

1. Energy Price Convergence

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. Finally, day-ahead prices reflect the probability-weighted expectation of infrequent high-priced events in the real-time market.

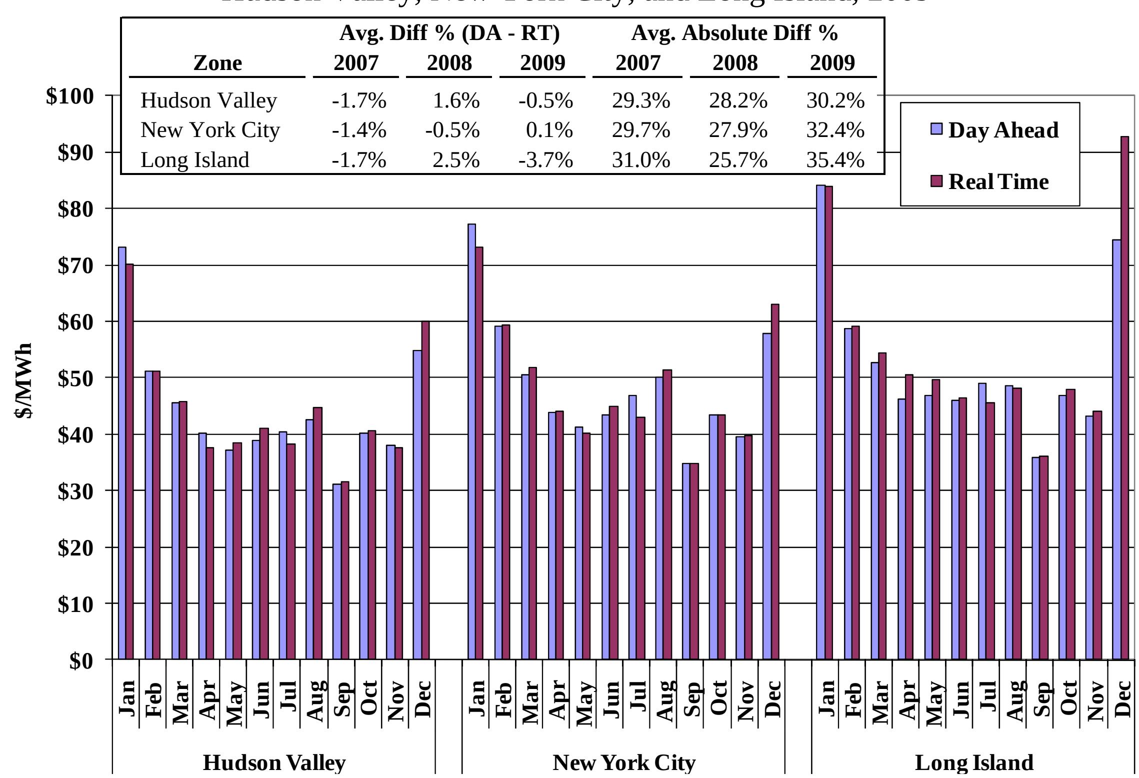
Figure 11 and Figure 12 compare day-ahead and real-time energy prices in West zone, Central zone, Capital zone, Hudson Valley, New York City, and Long Island. These figures are intended to reveal whether there are persistent systematic differences between the average level of day-ahead prices and the average level of 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 2009. 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. 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 11: Day-Ahead and Real-Time Energy Price Convergence
West, Central, and Capital Zones, 2009



Zone	Avg. Diff % (DA - RT) 2007	2008	2009	Avg. Absolute Diff % 2007	2008	2009
West	0.4%	3.2%	-0.1%	29.4%	37.7%	32.9%
Central	-1.0%	2.7%	1.2%	29.0%	35.2%	31.9%
Capital	-1.2%	2.1%	2.4%	27.8%	31.5%	31.9%

Figure 12: Day-Ahead and Real-Time Energy Price Convergence
Hudson Valley, New York City, and Long Island, 2009



Zone	Avg. Diff % (DA - RT) 2007	2008	2009	Avg. Absolute Diff % 2007	2008	2009
Hudson Valley	-1.7%	1.6%	-0.5%	29.3%	28.2%	30.2%
New York City	-1.4%	-0.5%	0.1%	29.7%	27.9%	32.4%
Long Island	-1.7%	2.5%	-3.7%	31.0%	25.7%	35.4%

Figure 11 and Figure 12 show that price convergence was generally very good at the zone level in 2009. The difference between average day-ahead and average real-time prices was less than 2.5 percent at all locations except Long Island. In the West and New York City, the difference was as small as one tenth of one percent. These results are slightly improved over 2008 in most areas. The figures also show that the average absolute difference between day-ahead and real-time prices ranged from 30 to 35 percent in the areas. These differences reflect the real-time price volatility, which is typical in wholesale electricity markets.

Average monthly day-ahead and real-time prices can be heavily affected by a single price spike event, as can occur when real-time conditions differ from expectations. For instance, extreme real-time congestion occurred into Long Island on December 16 due to the outage of the Sprainbrook-to-East Garden City line. Since the outage was not expected in the day-ahead market, it led to a large real-time premium for the month of December 2009.

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. Monthly day-ahead price premiums, such as resulted in July 2009, typically arise when real-time scarcity conditions occur less frequently than market participants anticipate.

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 2009. A positive number represents a real-time market price premium, while a negative number represents a day-ahead price premium. Figure 13 and Figure 14 show that day-ahead prices were higher than real-time prices on most afternoons. Average day-ahead prices were higher than average real-time prices on 60 percent of the afternoons in New York City and 56 percent of the afternoons in Long Island. However, very high price spikes were more frequent in the real-time market. In New York City, the day-ahead price premium never exceeded $50 per MWh, while the real-time price premium exceeded $50 per MWh in five afternoons. In Long Island, the day-ahead price premium exceeded $50 per MWh in four afternoons, while the real-time price premium exceeded $50 per MWh in nine afternoons.

Figure 13: Average Daily Real-Time Energy Price Premium
1 p.m. to 7 p.m., Weekdays, 2009, New York City

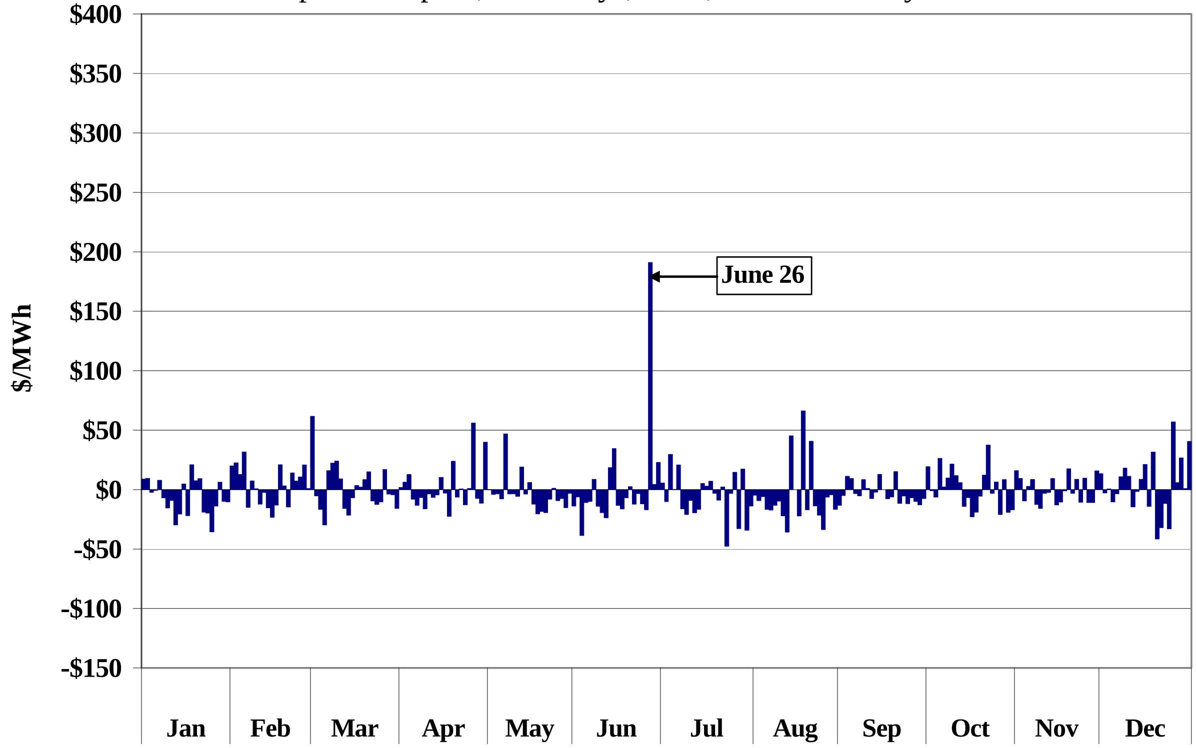
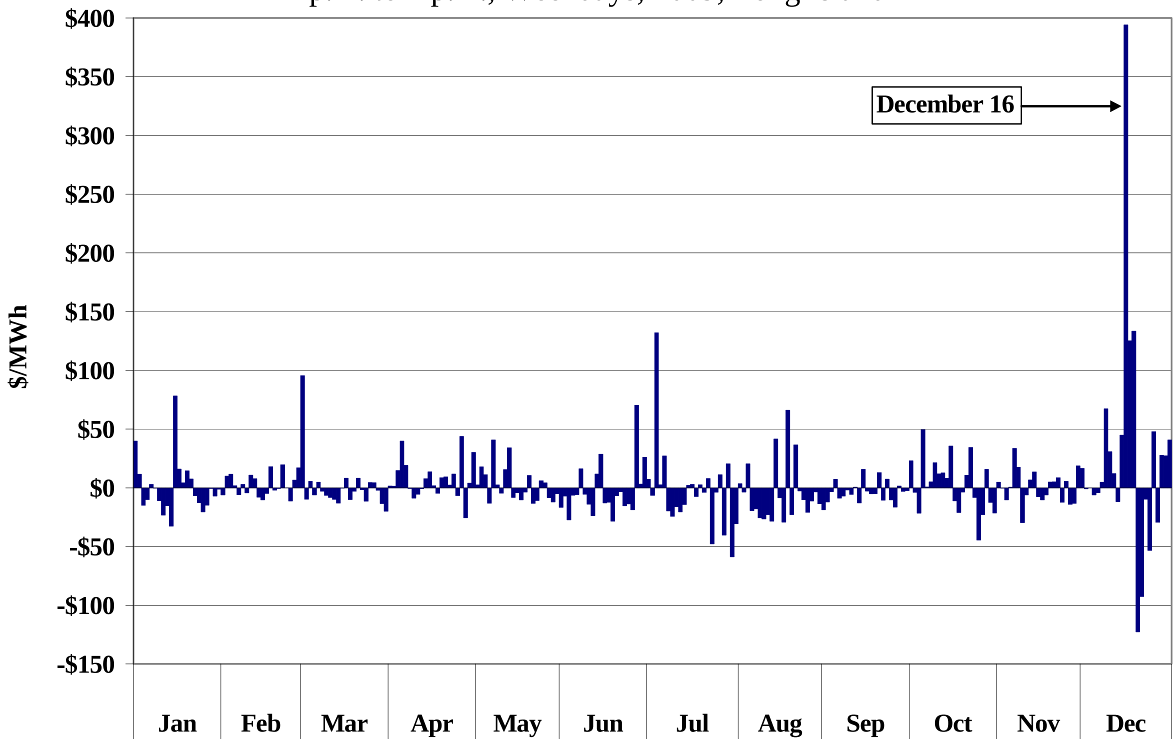


Figure 14: Average Daily Real-Time Energy Price Premium
1 p.m. to 7 p.m., Weekdays, 2009, Long Island



A substantial portion of real-time price spikes occurred during Thunder Storm Alerts ("TSAs"). TSAs require double contingency operation of the ConEd overhead transmission system, which is particularly costly when the TSAs coincide with high load conditions. TSAs require real-time operational changes based on weather conditions as they develop, so they directly affect real-time market outcomes. TSAs also indirectly affect day-ahead market outcomes because market participants can estimate the probability of a TSA and adjust their bids accordingly. However, TSAs alter the real-time capability of the transmission system in ways that are difficult for virtual traders to arbitrage in the day-ahead market. In New York City, the largest real-time price premium of 2009 occurred on the afternoon of June 26 when the Leeds-to-Pleasant Valley line exhibited acute congestion for four hours during a TSA.

Virtual trading facilitates good price convergence. Virtual transactions allow market participants to offer non-physical generation and load into the day-ahead market and settle those transactions in the real-time market. The resulting additional liquidity in the day-ahead energy market reduces the sensitivity of day-ahead prices to changes in day-ahead purchases and sales by participants with physical supply and load. Improved consistency between day-ahead and real-time prices brings about a more efficient commitment of resources, which lowers the cost of providing power in real-time. Virtual trading is discussed further in Section III.C.

2. Price Convergence at Individual Pricing Nodes

The previous sub-section shows day-ahead prices are generally consistent with real-time prices at the zonal level, although individual nodes may still exhibit significant divergence between day-ahead and real-time prices. 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.

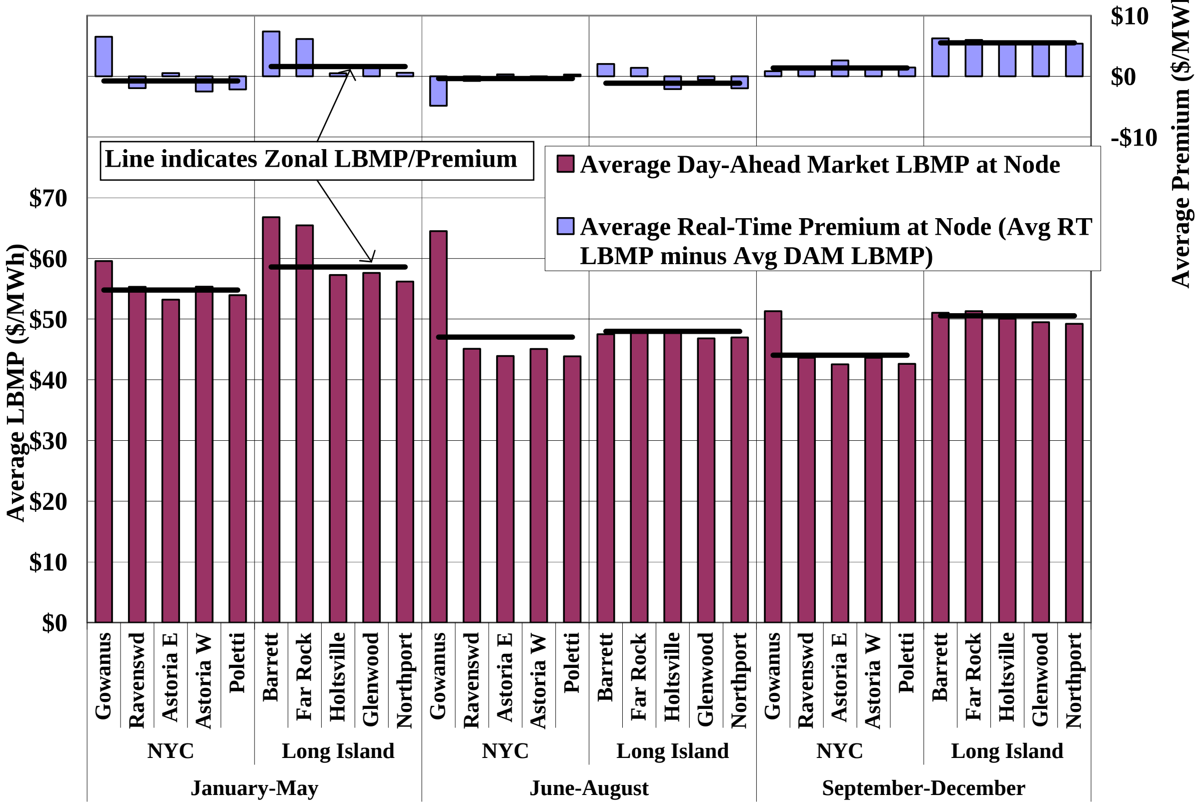
The pattern of intrazonal congestion may change between the day-ahead market and the real-time market for many reasons. First, generators that are not scheduled in the day-ahead market may change their offers. This is common during periods of fuel price volatility or when natural gas is more easily procured day-ahead. Second, generators may be committed or de-committed after the day-ahead market, changing the pattern of transmission flows. Third, there may be differences between the constraints used to manage congestion in the day-ahead and real-time markets. Fourth, 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. Fifth, 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, so good convergence at the zonal level may mask a significant lack of convergence within the zone. The NYISO is currently developing a proposal to allow virtual trading at a more disaggregated level that would likely improve convergence between day-ahead and real-time nodal prices.[9] This sub-section examines price statistics for selected nodes in New York City and Long Island to assess price convergence at the nodal level.

Figure 15 shows average day-ahead prices and real-time price premiums in 2009 for a selection of locations in New York City and Long Island. These are load-weighted averages based on the day-ahead forecasted load. The New York City and Long Island zones are shown because they have exhibited the highest levels of intra-zonal congestion historically, and a review of similar data indicates better day-ahead to real-time convergence at the nodal level in upstate areas. For comparison, the figure also shows the average day-ahead LBMP and the average real-time price premium at the zone level.

[9] See Disaggregated Virtual Trading Concept Design, presented by Michelle Gerry at the June 26, 2009 meeting of the NYISO Market Issues Working Group.

Figure 15: Real-Time Price Premiums at Individual Nodes
Selected Nodes in New York City and Long Island, 2009



The bottom portion of the figure shows several nodes that exhibited higher average LBMPs than the zone level in the day-ahead market, indicating nodes that were more import-constrained than other areas in the zone. From January to May, these nodes also exhibited higher average real-time price premiums than the zone, indicating they were more import-constrained in real-time than in the day-ahead market. During the subsequent periods, this pattern was reversed in New York City at the Gowanus node due to a change in day-ahead modeling assumptions that was made in July to correct for the issue observed from January to May. The change reduced the assumed transfer capability into the Greenwood/Staten Island Load Pocket in the day-ahead market because the area sometimes exhibited reduced transfer capability in real-time.[10]

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[10] See Greenwood/Staten Island Load Pocket DAM Modeling Discussion, presented by Robb Pike at the December 3, 2009 meeting of the NYISO Market Issues Working Group.

In most areas of New York, convergence between day-ahead and real-time prices is good at the nodal level. However, there are several areas in the New York City and Long Island zones where the pattern of intrazonal congestion was significantly different in the day-ahead and real-time markets. This led average day-ahead prices to differ substantially from average real-time prices at several nodes. Nevertheless, convergence improved between day-ahead and real-time prices at the nodal level from 2008 to 2009. For example, the average real-time price premium at the Gowanus location decreased from 45 percent of the average day-ahead LBMP in June to August 2008 to -8 percent in the same months of 2009. The following factors contributed to better convergence in 2009:

- The change in assumptions used in the day-ahead market related to the transfer capability into the area around the Gowanus plant likely improved convergence.
- SRE commitments (which increase commitment after day-ahead market) have been less frequent due to changes that allow Transmission Owners to commit units for reliability prior to the day-ahead market (i.e., DARU commitment).
- Simplified New York City interface constraints (which are never used in the day-ahead market) were used less frequently in real-time to manage congestion.

Regarding the third factor, the share of binding New York City constraints that were simplified interface constraints (rather than line constraints) decreased from 67 percent in 2008 to 43 percent in 2009. Detailed line constraints allow the market models to manage congestion more efficiently than when the simpler interface constraints are used.

Currently, virtual trading is allowed at only the zonal level, although the NYISO has developed a concept for allowing virtual trading at a more disaggregated level. If implemented, this concept would improve convergence in New York City load pockets by allowing market participants to arbitrage day-ahead to real-time prices at the nodal level.

3. Ancillary Services Price Convergence

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. This sub-section examines ancillary services prices to assess how well day-ahead and real-time prices converge.

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, 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.

The following two figures summarize day-ahead and real-time clearing prices for the two most important reserve products in New York. Figure 16 shows 10-minute non-spinning reserve prices in Eastern New York, which are primarily based on the requirement to hold 1,000 MW of 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. Figure 17 shows 10-minute spinning reserve prices in Western New York, which are primarily based on the requirement to hold 600 MW of 10-minute spinning reserves in New York State. In both figures, average prices are shown by season and by hour of day. The market uses “demand curves” that place an economic value of $500 per MWh on both reserve products.

Figure 16: Day-Ahead and Real-Time 10-Minute Non-Spinning Reserves Prices
Eastern New York, 2009

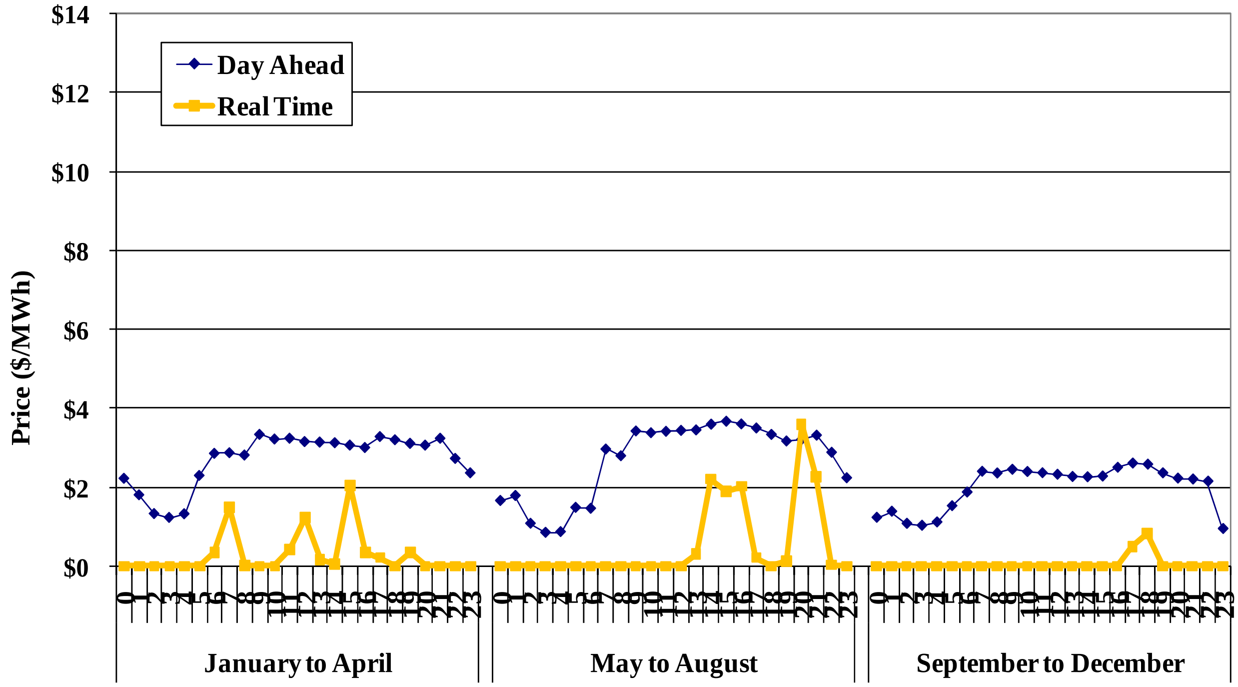
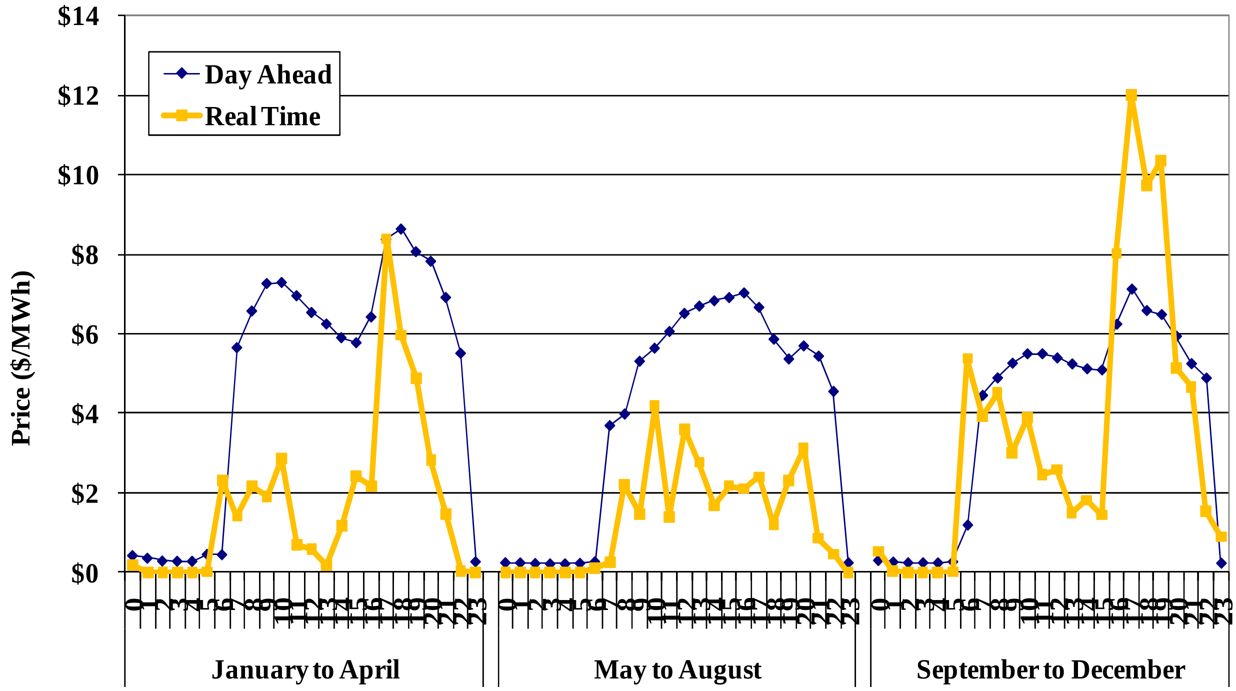


Figure 17: Day-Ahead and Real-Time 10-Minute Spinning Reserves Prices
Western New York, 2009



Both figures show that average day-ahead prices were generally higher than average real-time prices. However, these average prices mask the substantial variability in real-time prices. The real-time price is based on the opportunity costs of generators whose energy production is backed-down in order to provide reserves. In most hours, excess reserves are available on on-line units and off-line quick-start units, leading the real-time price of reserves to be $0 per MWh in a substantial share of hours. In 2009, real-time 10-minute non-spinning reserves prices were $0 per MWh in 99 percent of intervals, but rose significantly in the remaining intervals. Hence, the $4 per MWh average price in hour 20 during the summer in Eastern New York is an average across the many hours in which the price was zero or near zero and a small number of peak pricing events.

Day-ahead reserve prices tend to fluctuate based on the expected likelihood of a real-time price spike, although day-ahead reserve prices are also affected by the risks that suppliers face from the high volatility of real-time prices. If a supplier sells reserves in the day-ahead market and the real-time price spikes unexpectedly, the supplier can incur substantial losses or foregone profits. Accordingly, the day-ahead premium during most periods may reflect the risks faced by suppliers. Nevertheless, the fact that day-ahead prices were consistently higher than real-time prices during periods when real-time price spikes are particularly unlikely suggests that participants may also have over-estimated the frequency of real-time price spikes.

It may be counterintuitive that Western New York 10-minute spinning reserves prices decrease during the summer, when most products become more expensive. However, Western New York 10-minute spinning reserve prices are driven by the indirect effects of scheduling patterns in Eastern New York. Under tight operating conditions, quick start gas turbines in New York City and Long Island are frequently called on to provide energy. This requires the real-time dispatch model to meet some of the Eastern 10-minute reserves requirement by backing down steam units, which helps relieve state-wide 10-minute synchronous reserves constraints. These actions reduce the amount of 10-minute synchronous reserves that must be held in Western New York.

Market participants can be expected to respond to systematically different day-ahead and real-time prices by bidding up or down the clearing price in the day-ahead market. However, the current market rules do not allow load serving entities and virtual traders to arbitrage day-ahead to real-time price differences by adjusting their ancillary services purchases or by submitting price-sensitive bids. Only generators have the ability to submit price-sensitive offers to the ancillary services markets in the day-ahead market. However, the mitigation rules limit the ancillary services offers of some generators in the day-ahead market, which may inhibit price convergence. This is discussed further in Section III.B.

III. 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. In the first sub-section, the analysis reviews energy offers and mitigation patterns, and it seeks to identify potential attempts to withhold generating resources to increase prices. The analysis does not raise concerns that the wholesale market was affected by physical and economic withholding. In the second sub-section, we evaluate offers to supply regulation and 10-minute operating reserves in the day-ahead market. In the last sub-section, we evaluate load-bidding and virtual trading behavior to determine whether they have been conducted in a manner consistent with competitive expectations.

A. Analysis of Energy Supply Offers

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, (as an almost vertical demand curve shifts along the supply curve) prices remain relatively stable until demand approaches peak levels, where 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.

Suppliers that have market power can exert that power 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.

In the NYISO's Location-Based Marginal Pricing ("LBMP") 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.

An analysis of withholding must distinguish between strategic withholding aimed at exercising market power and competitive conduct that could appear to be strategic withholding. Measurement errors and other factors can erroneously identify competitive conduct as market power. For example, a forced outage of a generating unit may be legitimate or it may be an attempt to raise prices by physically withholding the unit.

To distinguish between strategic and competitive conduct, we evaluate potential 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.[11] 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. Therefore, examining the relationship between potential withholding metrics and demand levels allows us to test whether the conduct of market participants is consistent with workable competition.

1. Potential Physical Withholding

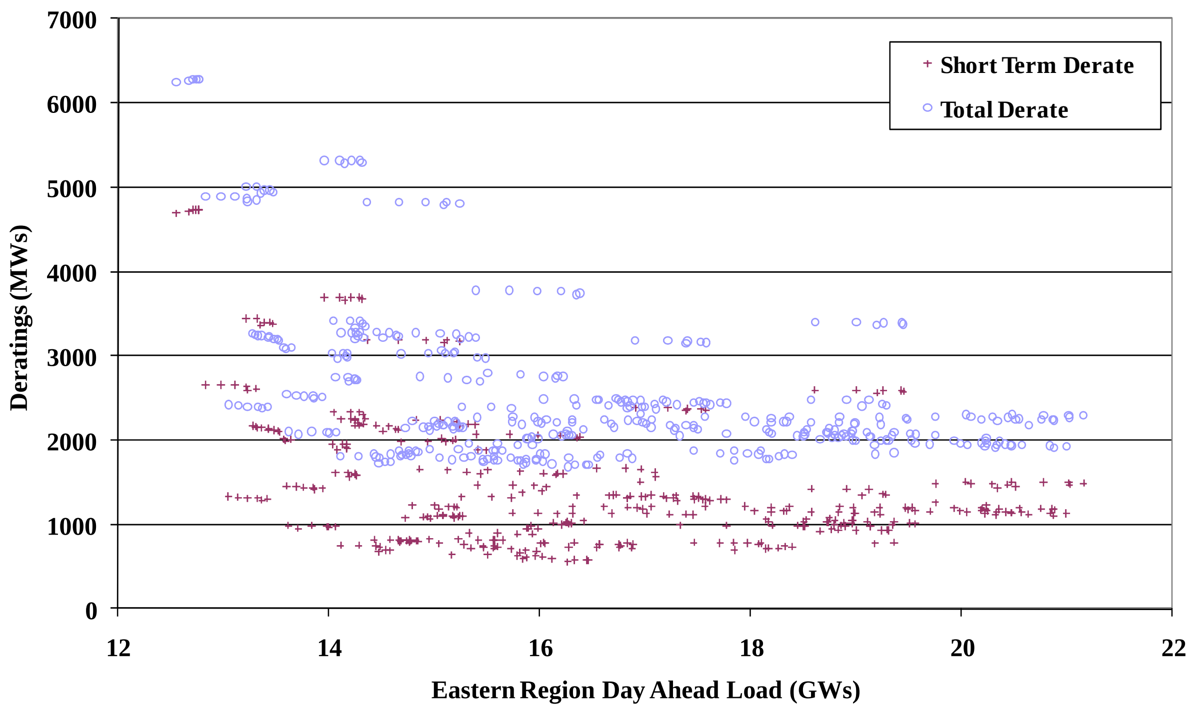
We evaluate potential physical withholding by analyzing generator deratings. A derating occurs when a participant reduces the maximum output available from the plant. This can occur for a planned outage, a long-term forced outage, or a short-term forced outage. A derating can be partial (maximum output is reduced, but is greater than zero) or complete (maximum output is zero). We evaluate the summer months to exclude the effects of planned outages, which rarely

11 However, 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.

occur during the summer when demand is highest. By eliminating planned outages, we implicitly assume that planned outages are legitimate.[12]

In Figure 18, Total Derates measure the difference between the quantity offered and the most recent Dependable Maximum Net Capability ("DMNC") test value of each generator, while Short-Term Derates exclude capacity that is derated for more than 30 days. Short-term derates are more likely than long-term derates to reflect attempts to physically withhold because 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. We focus on the hours from noon to 6 pm when demand is highest because that is when withholding is more likely to be effective. The figure also focuses on suppliers in Eastern New York, which includes two-thirds of the State's load, has limited import capability, and is more vulnerable to the exercise of market power than western New York.

Figure 18: Day-Ahead Deratings vs. Actual Load in Eastern New York
Noon to 6 pm on Weekdays -- June to August, 2009



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12 Planned outages are usually scheduled far in advance, and are almost always scheduled for a period during the year when demand is historically at low levels, in New York, typically spring and autumn months.

Figure 18 indicates that neither Total Derates nor Short-Term Derates rose substantially under high load conditions in 2009. This is a positive sign since the incentive to physically withhold resources generally increases under high load conditions for participants with market power. The pattern of derates is particularly positive when we consider that genuine forced outages are expected to rise under peak load conditions when the NYISO calls on relatively high-cost units that generally do not operate in other hours. In addition, the high ambient temperatures that typically contribute to peak load conditions reduce the capability (i.e., increase the deratings) of many thermal generators. Therefore, because the deratings do not rise significantly as load rises, these results do not raise concerns about anti-competitive conduct.

2. Potential Economic Withholding

Economic withholding is an attempt by a supplier to raise its offer price substantially above competitive levels in order to raise LBMPs above competitive levels. A supplier without market power maximizes profit by offering resources at marginal cost, because excessive offers lead the unit not to be dispatched when it would have been profitable, and thus, cost the owner lost profits. 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.[13] An offer parameter is considered above the competitive level if it exceeds the reference level by a given threshold.

We measure potential economic withholding by estimating an "output gap" for units that submit start-up, minimum generation, and incremental energy offer parameters that are above the reference level by a given threshold. 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.[14]

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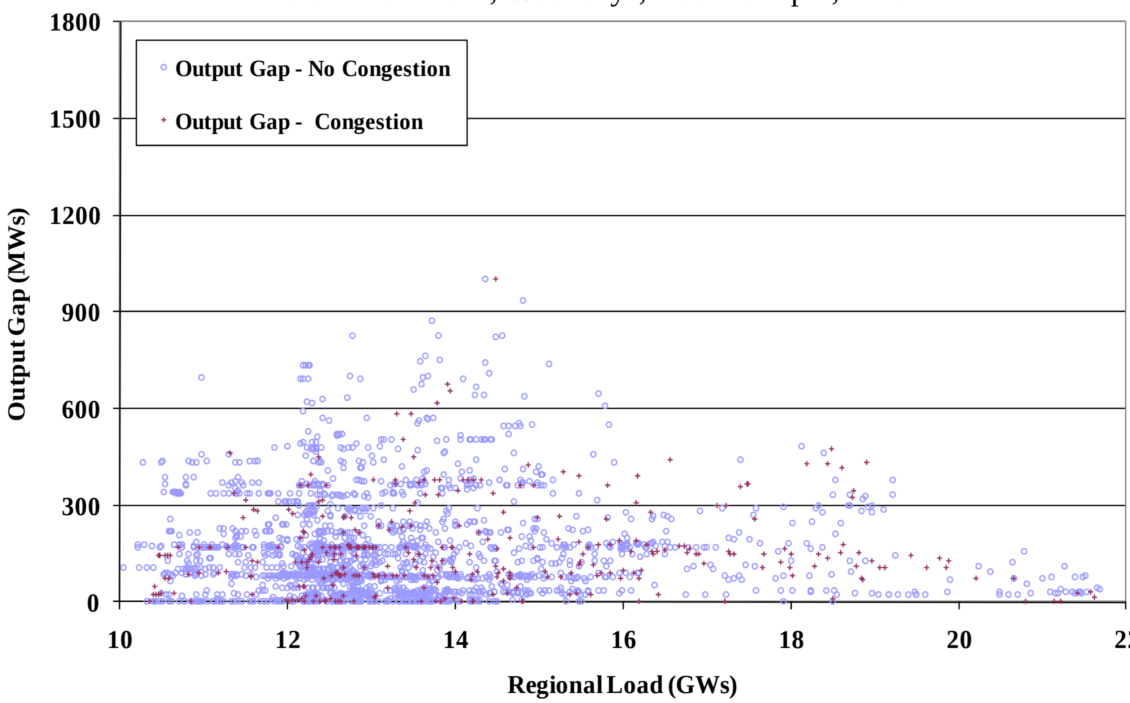
13 The method of calculating reference levels is described in NYISO Market Services Tariff, Attachment H – NYISO Market Monitoring Plan-Market Mitigation Measures, Section 3.1.4. For most generators, the reference levels are based on an average of the generators' accepted bids during competitive periods 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.

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

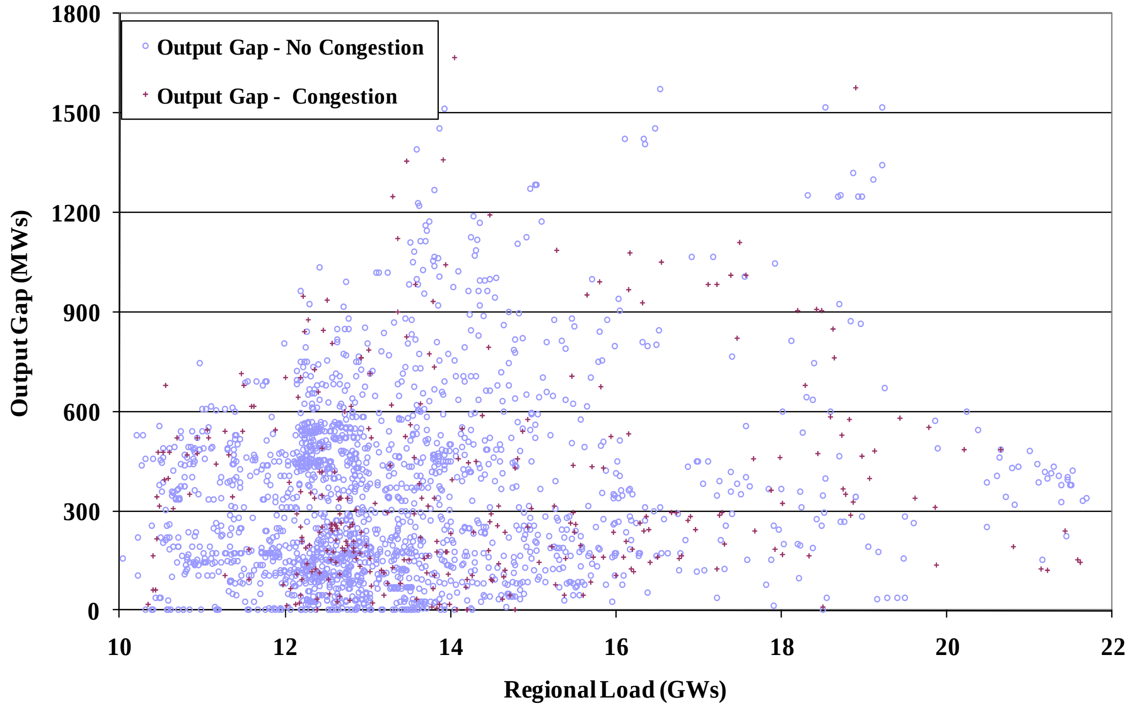
Like the prior analysis of derates, we examine the relationship of the output gap to the market demand level. We focus our analysis on Eastern New York where market power is most likely, and on weekday afternoon hours when demand is highest. Figure 19 shows the output gap using the state-wide mitigation threshold, which is the lower of $100 per MWh or 300 percent of a generator's reference level. Figure 20 shows the output gap results using a lower threshold, which is the lower of $50 per MWh or 100 percent of a generator's reference level. The second analysis is included to assess whether there have been attempts to withhold by offering energy just below the state-wide mitigation threshold. Finally, the figures show congested and non-congested hours separately to show whether the output gap increases during periods of congestion when some suppliers are more likely to have market power.

Figure 19: Real-Time Output Gap at Mitigation Threshold vs. Actual Load
Eastern New York, Weekdays, Noon to 6 pm, 2009



The figures indicate that the output gap did not rise substantially under high load conditions in 2009. The figures also show that the output gap did not increase substantially during periods of congestion. These are good signs because the market is most vulnerable to the exercise of market power during high load periods and in congested areas. Additionally, the output gap is generally low as a share of the real-time load in Eastern New York. The results are particularly notable for the lower threshold because such conduct is not subject to mitigation. These output gap results are consistent with the expectations for a competitive market and do not raise significant concerns about economic withholding during 2009.

Figure 20: Real-Time Output Gap at Low Threshold vs. Actual Load
Eastern New York, Weekdays, Noon to 6 pm, 2009



3. 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 participant 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.[15]

The day-ahead and real-time market software is automated to perform most mitigation according to the conduct and impact thresholds. The mitigation measures are designed to allow prices to

15 See NYISO Market Services Tariff, Attachment H.

rise efficiently to reflect legitimate supply shortages while effectively mitigating inflated prices associated with artificial shortages that result from physical or 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.[16] 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 conduct are tested for price impact by the market software, and if their price impact exceeds the threshold, they are mitigated.

The following two figures summarize the amount of mitigation in New York City that occurred in the day-ahead and the real-time markets in 2009. In both figures, the line indicates the percent of hours when incremental energy offer mitigation was imposed on one or more units in each category, while the bars indicate the average amount of capacity mitigated in hours when mitigation occurred. In the day-ahead market, mitigated quantities are shown separately for the flexible output ranges of units (i.e. Incremental Energy) and the non-flexible portions (i.e. MinGen). Mitigated quantities are shown separately for incremental energy and gas turbine startups in the real-time market.[17]

[16] Threshold = (0.02 * Average Price * 8760) / Constrained Hours

[17] Mitigation of gas turbine capacity is shown in the Incremental Energy category whenever the incremental energy offer is mitigated, while it is shown in the Startup category when the startup offer is mitigated but the incremental energy offer is not.

Figure 21: Frequency of Day-Ahead Mitigation in the NYC Load Pockets
2009

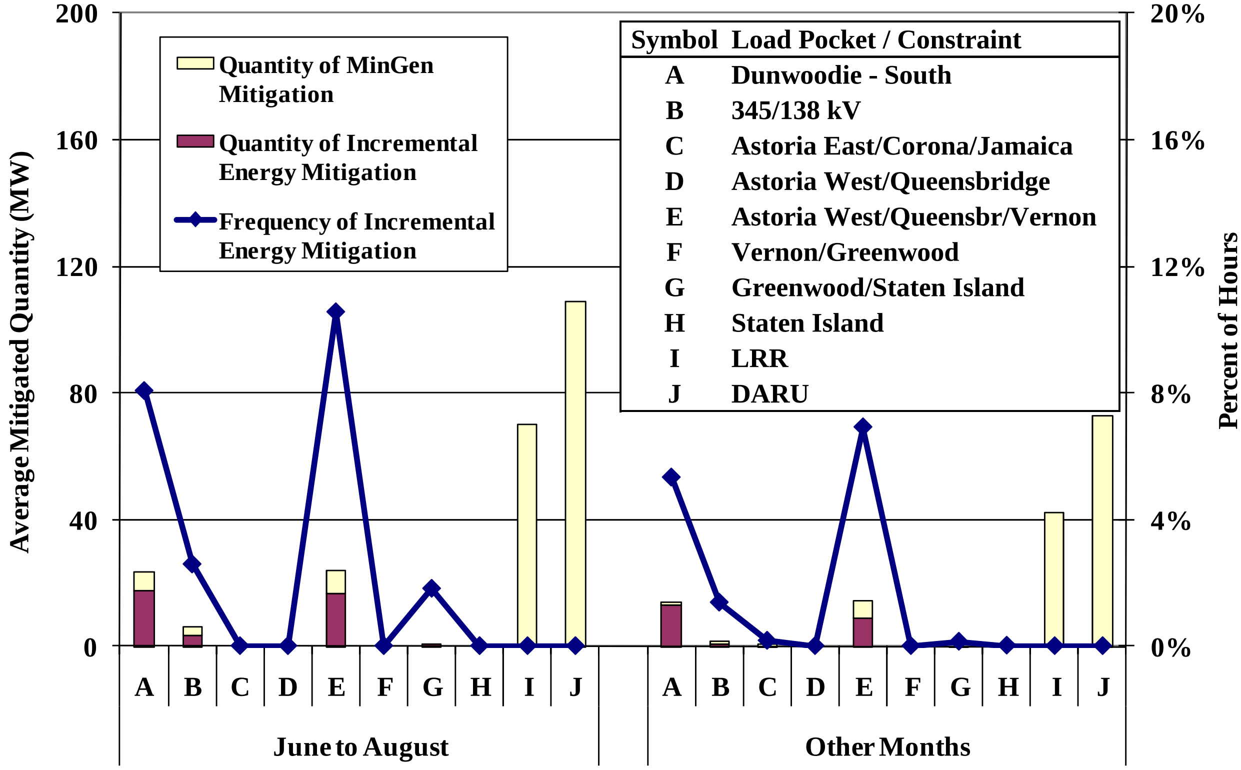


Figure 21 indicates that day-ahead mitigation was infrequent in 2009. The majority of day-ahead mitigation was on generators committed to satisfy Local Reliability Rules ("LRR") or on Day Ahead Reliability Units ("DARU"). The Startup and MinGen offers of LRR and DARU units are mitigated whenever they exceed the reference level.[18] The Astoria West/Queens/Vernon interface exhibited most frequent incremental energy mitigation, although mitigation in this load pocket only occurred during 7 to 10 percent of hours.

The majority of capacity mitigated in the day-ahead market during 2009 was associated with the MinGen parameter, while relatively little was for Incremental Energy parameters. This is because generators with long minimum run times are sometimes mitigated for LBMP impact in a small number of hours. For instance, a generator with a 24 hour minimum run time might raise

[18] LRRs and DARUs are developed by the NYISO to maintain system reliability, particularly in local areas. The day-ahead market commits additional units, which otherwise would not be economic, to meet the reliability requirements. If a unit is committed for this purpose, the mitigation rules require its start-up and minimum generation bids to be set to the lower of the submitted offers and their applicable reference levels.

its MinGen bid parameter above the conduct threshold. However, if this conduct would cause the generator to not be committed resulting in a LBMP impact above the applicable threshold for one hour, the generator's MinGen parameter would be mitigated for the duration of its minimum run time, while its incremental energy parameter would be mitigated only in the hour with impact.

Figure 22: Frequency of Real-Time Mitigation in the NYC Load Pockets

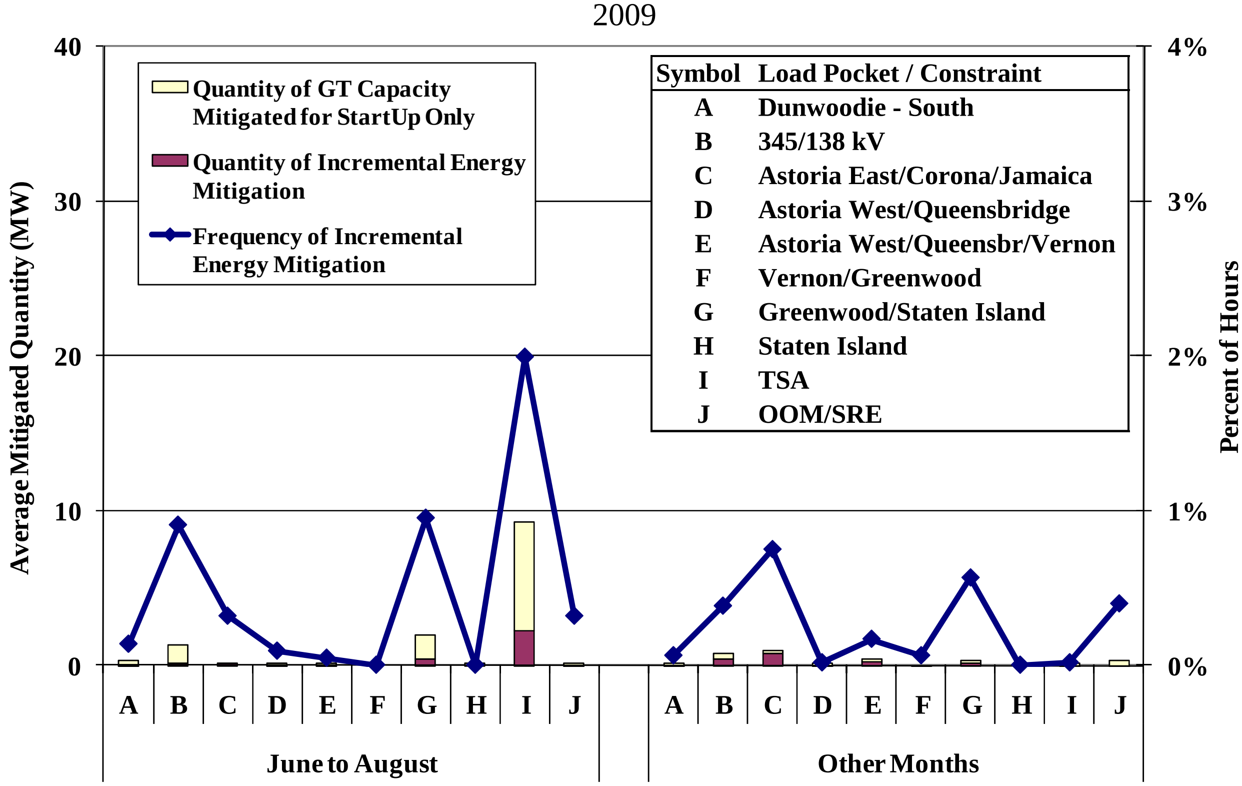


Figure 22 shows the most frequent real-time mitigation occurred as a result of transmission constraints related to Thunderstorm Alerts ("TSAs"). These constraints usually reduce flows from the Capital zone to Hudson Valley, which increases the need for generators in Southeast New York to increase output. The majority of real-time mitigation was associated with the startup bid parameters of gas turbines rather than the incremental energy bid parameters.

Overall, the majority of mitigation occurred in the day-ahead market rather than the real-time market. One factor that reduces the need for real-time mitigation is that day-ahead mitigated offers are carried into the real-time up to the unit's day-ahead schedule.

B. 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 in the energy prices. 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.

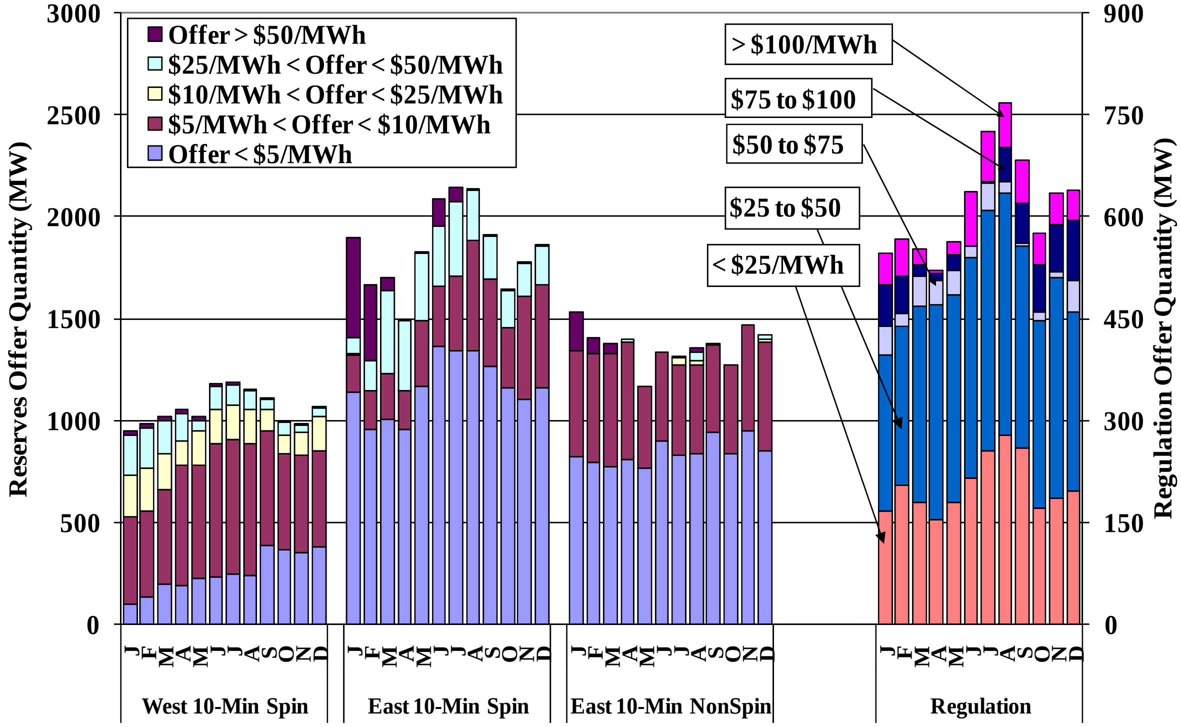
The ancillary services markets are evaluated in several sections of this report. Section II.A summarizes ancillary service prices in the day-ahead market in 2008 and 2009, finding that ancillary services prices have been correlated with energy prices, rising and falling with the price of natural gas. Section II.D evaluates the degree of convergence between day-ahead and real-time ancillary services prices. Although it has improved in recent years, convergence between day-ahead and real-time reserves prices remains poor under some operating conditions. Section VI.C evaluates the efficiency of prices during shortage conditions, showing significant improvement since the demand curves were introduced in 2005.

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. Under the current market rules, only generators have the ability to submit ancillary services offers in the day-ahead market. 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 generators that sell reserves in the day-ahead market, since generators 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.

1. Summary of Offers

Figure 23 summarizes the ancillary services offers for generators in the day-ahead market in each month of 2009. The quantities offered are shown for the following categories: (i) 10-minute spinning reserves in Western New York, (ii) 10-minute spinning reserves in Eastern New York, (iii) 10-minute non-spinning reserves in Eastern New York, and (iv) Regulation. Offer quantities are shown according to offer price level for each category. Only spinning and non-spinning reserve offers for peak hours are included (from 1 pm to 7 pm), while regulation offers are included for all hours.

Figure 23: Summary of Ancillary Services Offers
Day-Ahead Market, 2009



All four categories of ancillary services offers shown in Figure 23 vary according to the season. 10-minute spinning reserves and regulation offer quantities were lower in the spring and fall than in the summer and winter. This was primarily because most planned outages occur in the shoulder months, reducing the amount of available capacity.

Figure 23 also shows that 10-minute spinning reserve offer prices decreased significantly during 2009 in both eastern and western New York. For example, the quantity offered below $10/MWh increased from an average of 1,850 MW in January to 2,520 MW in December. The reduction in offer prices was likely driven by lower fuel prices and energy prices.

Additionally, 10-minute non-spinning reserves offer quantities were generally 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.[19]

The offer prices of 10-minute spinning reserves were generally higher in Western New York than in Eastern New York. The primary reason for this is that New York City generators are required to offer 10-minute spinning reserves at $0 per MWh, while there is no offer cap for generators outside New York City. Higher offers for 10-minute spinning reserves tend to increase the clearing prices of 10-minute spinning reserves in the day-ahead market relative to the real-time market. It is notable that the evaluation in the previous section found that day-ahead 10-minute spinning reserves prices were higher on average than real-time prices in Western New York during afternoons for most of the year.[20] In contrast, day-ahead and real-time 10-minute spinning reserves prices were more consistent in Eastern New York.

Figure 23 shows approximately 500 MW of 10-minute spinning reserves in Eastern New York was offered above $25 per MWh in the first quarter of 2009, although the amount fell to less than 200 MW by the last quarter of 2009. Suppliers normally submit such high offers when they prefer not to provide 10-minute spinning reserves in the day-ahead market. The volatility of real-time reserves prices makes it risky for a generator to sell reserves in the day-ahead market because if the generator is dispatched to provide energy rather than reserves in the real-time market, it will have to buy back reserves at the real-time clearing price in order to satisfy its obligations from selling day-ahead. Although the generator will be paid according to the real-

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19 The capability of thermal generators varies inversely with the ambient temperature, so generating capability is higher in the winter than in the summer.

20 See Section II, which evaluates the convergence between day-ahead and real-time prices.

time energy price, the generator will earn less overall than if it was not scheduled for reserves in the day-ahead market. Hence, the decline in offer prices may indicate that some suppliers believed that real-time reserve prices had become less volatile by the end of 2009.

To the extent suppliers would prefer to raise their day-ahead offer prices for 10-minute non-spinning reserves (or not offer at all), they are limited by two factors. First, offer prices are limited by the mitigation rules, which cap the reference levels of 10-minute non-spinning reserve units at $2.52 per MWh. Second, decreases in offer quantities are limited by the ICAP rules, which require non-PURPA ICAP units that have 10-minute non-spinning reserve capability to offer it in the day-ahead market. Hence, suppliers that are capable of providing 10-minute non-spinning reserves cannot avoid the mitigation rules simply by not offering in the day-ahead market. These restrictions prevent generators from rationally arbitraging the day-ahead and real-time prices when real-time prices are expected to be higher (or the probability of real-time shortages is non-trivial). Unfortunately, only generators are currently able to arbitrage these prices so these restrictions may contribute to poor convergence between the day-ahead and real-time markets.

2. Ancillary Services Offer Conclusions

In Section II.D, we found that convergence between day-ahead and real-time reserves prices has been poor under certain conditions. Under most conditions, day-ahead clearing prices appear to be higher on average than real-time clearing prices. This is consistent with the risks suppliers face from selling in the day-ahead market. However, during afternoon hours in the summer months, average real-time prices are higher than average day-ahead prices. Systematically lower day-ahead prices in these hours increase the opportunity cost of selling reserves in the day-ahead market. Reserve suppliers should respond by increasing their day-ahead offer prices, which would likely improve convergence between day-ahead and real-time.

However, we find that the mitigation measures likely limit the offers of suppliers below competitive levels under peak demand conditions. Hence, we recommend the NYISO reconsider the following two provisions in the mitigation measures, which may limit competitive offers in the day-ahead market:

- The $2.52 per MWh limit on 10-minute non-spinning reserve reference levels; and

- The requirement for New York City generators to offer 10-minute spinning reserves at $0 per MWh.

C. 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 purchased in one of the following four ways:

Physical Bilateral Contracts

These are schedules that the NYISO allows participants to settle transmission charges (i.e., congestion and losses) with the ISO and to settle on the commodity sale privately with their counterparties. However, it does not represent the entirety of the bilateral contracting in New York because participants have the option of entering into bilateral contracts that are settled privately and generally show up as day-ahead fixed load.

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 represents load bid into the day-ahead market with a bid price indicating the maximum amount the Load-Serving Entity ("LSE") is willing to pay.[21]

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 automatically sold back to the real-time market. So, the virtual buyer earns the quantity of the purchase in megawatt-hours ("MWh") multiplied by the real-time price minus the day-ahead price. This is currently allowed at the zonal level but not at the bus level.

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

The 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, on the other hand, is also important because it tends to reduce the amount of physical resources that are scheduled in the day-ahead market. Virtual supplies are offers to sell energy 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 automatically purchased back from the real-time market. So, the virtual seller earns the quantity of the sale in MWh multiplied by the day-ahead price minus the real-time price. This is also currently allowed at the zonal level but not at the bus level.

1. Day-Ahead Scheduling

Many generating units have long lead times and substantial commitment costs. Their owners must decide whether to commit 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 way 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 market and the real-time market. The analyses in this sub-section 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 figures show day-ahead load schedules and bids as a percent of real-time load during 2008 and 2009 at various locations in New York. Virtual load 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 has the same effect on day-ahead prices and resource commitment as a reduction in physical load, so it is treated as a negative load for the purposes of this analysis.

The following three figures compare day-ahead load scheduling to actual load on a seasonal basis in 2008 and 2009. This is shown for New York City and Long Island in Figure 24, Eastern Upstate New York in Figure 25, and Western Upstate New York in Figure 26. For each period, it shows scheduled quantities of physical load, virtual load, and virtual supply. 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.

Figure 24: Composition of Day-Ahead Load Schedules versus Actual Load
New York City and Long Island, 2008 – 2009

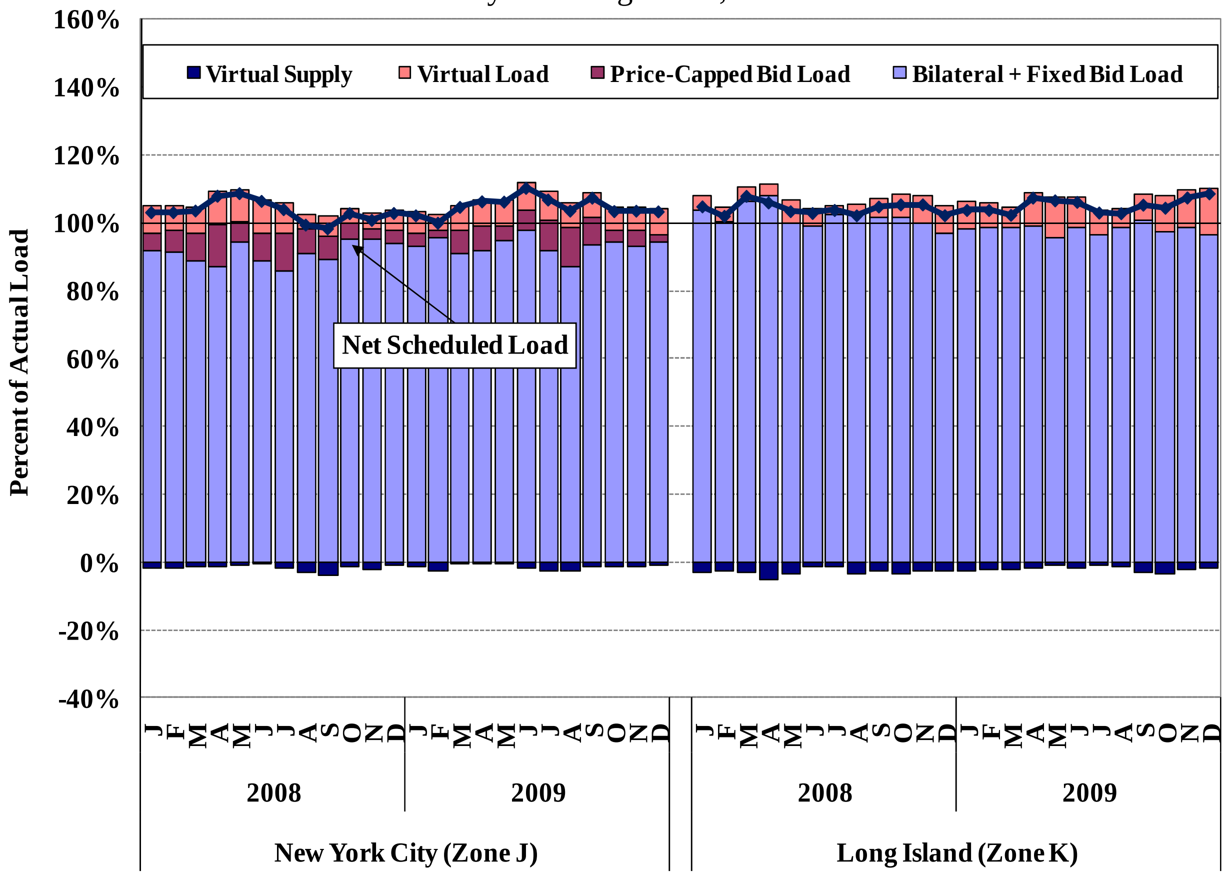


Figure 25: Composition of Day-Ahead Load Schedules versus Actual Load
Eastern Upstate New York, 2008 – 2009

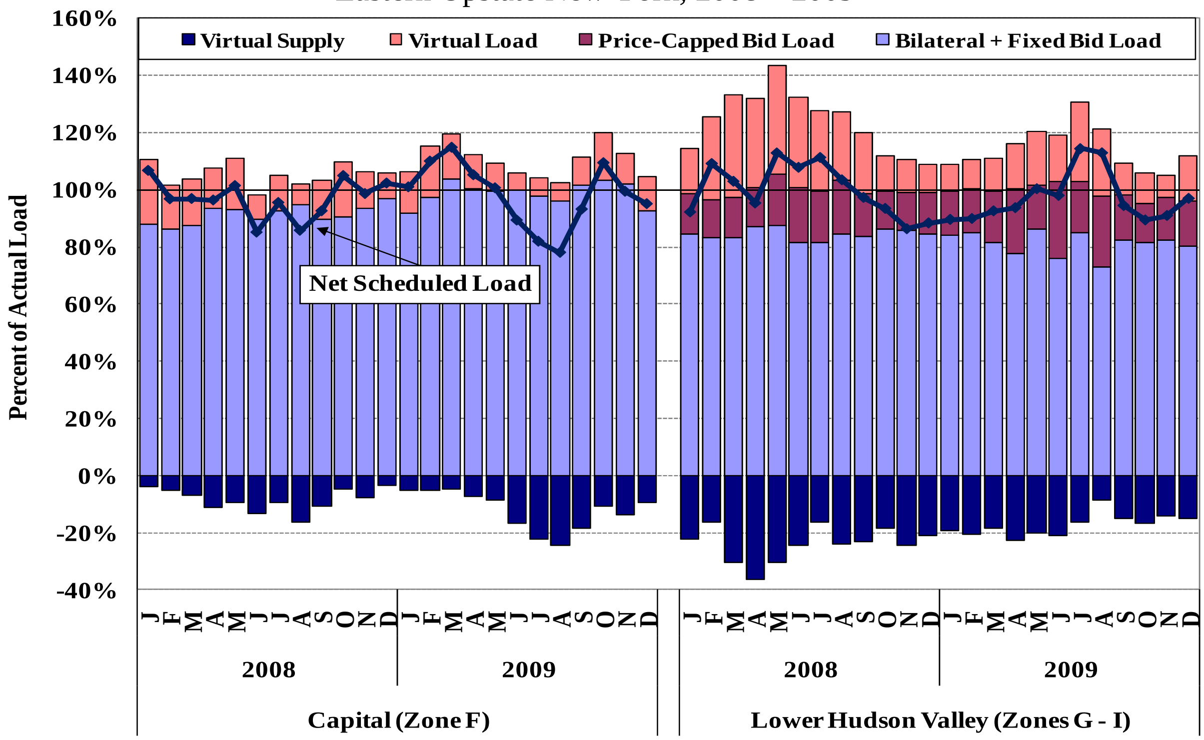
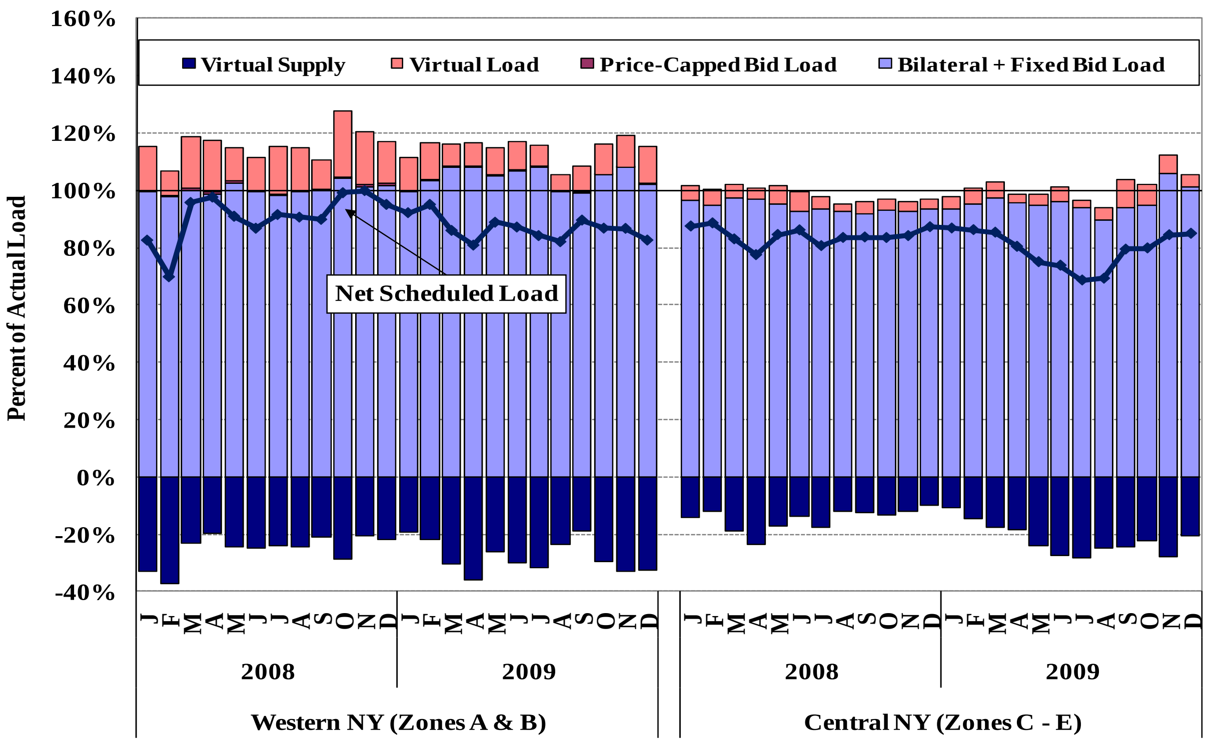


Figure 26: Composition of Day-Ahead Load Schedules versus Actual Load
Western Upstate New York, 2008 – 2009



On a state-wide basis, the average amount of load scheduled in the day-ahead market was slightly lower than the average amount of real-time load. The ratio of average net load scheduled in the day-ahead market to average real-time load was 97 percent in 2008 and 96 percent in 2009. Since price convergence was relatively good at the zonal level in 2009, we conclude that the slight under-scheduling does not raise efficiency concerns. Rather, the under-scheduling likely reflects that additional supply is sometimes committed after the day-ahead market.

There were larger differences between day-ahead scheduling and real-time load in individual regions. In New York City and Long Island, load was consistently over-scheduled, which indicates that the day-ahead market generally scheduled more imports into New York City and Long Island than the real-time market. However, in western New York, load was consistently under-scheduled, which implies that the day-ahead market typically scheduled more exports from these areas than the real-time market.

These figures also show seasonal variations in the day-ahead load scheduling. In the summer months of 2009, the average ratio of net scheduled load to actual load was 109 percent in Zones G to I, 83 percent in the Capital zone, and 70 percent in Zones C to E. In the other months of 2009, this average ratio changed to 93 percent in Zones G to I, 103 percent in the Capital zone, and 83 percent in Zones C to E. These patterns indicate that the market generally responds rationally to differences between the congestion patterns in the day-ahead and real-time markets. Thunderstorm Alerts become more frequent in the summer, resulting in transmission limits from the Capital Zone to the Hudson Valley that are tighter in the real-time market than in the day-ahead market. This provides incentives for market participants to schedule virtual load in Southeast New York (Zones G to K) in anticipation of higher real-time prices, and to schedule virtual supply outside Southeast New York (Zones A to F) in anticipation of lower real-time prices.

IV. External Transaction Scheduling

This section examines the scheduling of imports and exports between New York and adjacent regions. In both 2008 and 2009, New York was a net importer from each of the four adjacent control areas: New England, PJM, Ontario, and Quebec, although New York exported power to these areas under certain market conditions. In addition to the four primary interfaces with adjacent regions, Long Island and New York City directly connected to PJM and New England across four controllable lines: the Cross Sound Cable, the 1385 Line, the Linden VFT Line, and the Neptune Cable. The controllable lines are collectively able to import more than 1.3 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.

Consumers benefit from the efficient use of external transmission interfaces. 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. The ability to draw on neighboring systems for emergency power, reserves, and capacity helps lower the costs of meeting reliability standards in the New York system. Wholesale markets 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: [22]

- 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
- Potential benefits from market enhancements proposed under the Broader Regional Markets initiative.

[22] Additionally, Section VI.A evaluates the efficiency of external transaction scheduling by RTC.

The final sub-section summarizes our conclusions and recommends ways to improve scheduling between regions.

A. Summary of Scheduled Imports and Exports

The following three figures summarize the net scheduled interchanges between New York and the adjacent control areas in 2008 and 2009. The net scheduled interchanges do 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 on weekdays) and off-peak hours. This is shown for the primary interfaces with Ontario and PJM in Figure 27, the primary interfaces with Quebec and New England in Figure 28, and the controllable lines connecting Long Island and New York City with PJM and New England in Figure 29.

Figure 27: Monthly Average Net Imports from Ontario and PJM
2008 – 2009

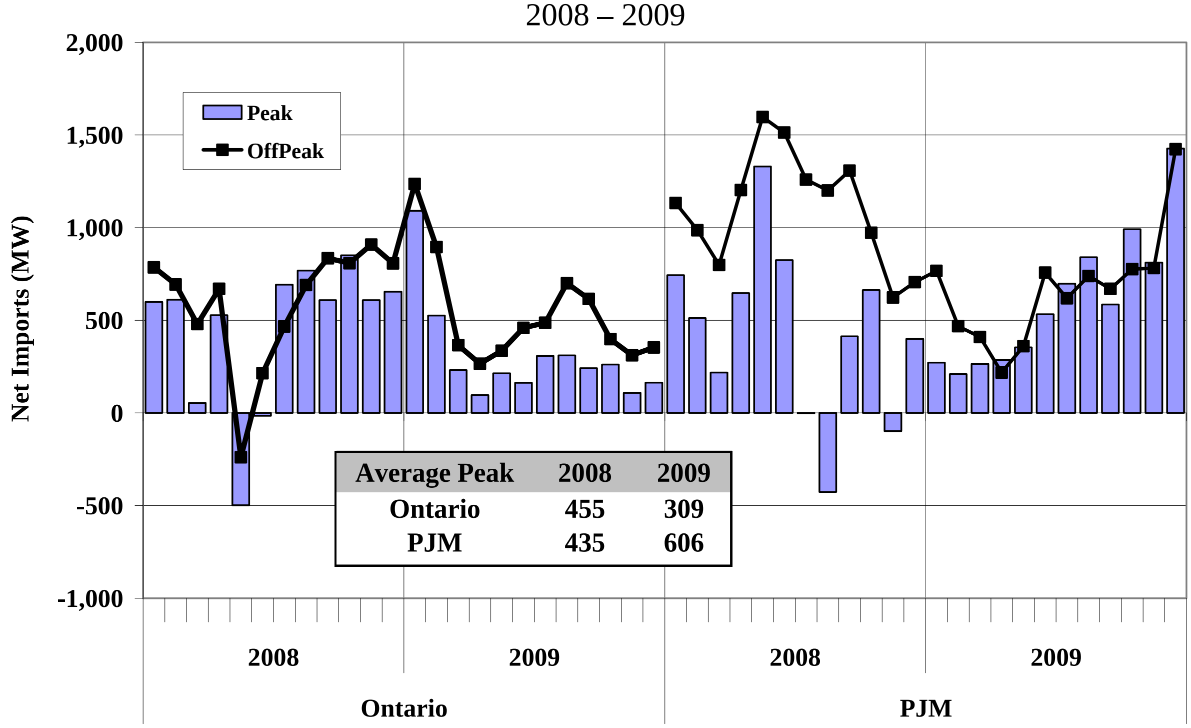


Figure 27 shows that New York generally imports across the interfaces with PJM and Ontario, particularly during off-peak hours. In both peak and off-peak hours, the average volume of imports from PJM steadily increased throughout 2009. During peak hours, the average net imports from PJM rose from 435 MW in 2008 to 606 MW in 2009.

Scheduling between New York and Ontario was affected by the scheduling of circuitous transactions around Lake Erie in the first half of 2008. The average net imports scheduled from Ontario in peak hours rose from 280 MW in the first seven months of 2008 to nearly 700 MW in the last five months of 2008. This is because net imports had been reduced by the circuitous transactions scheduled from New York to PJM around Lake Erie via Ontario and the Midwest ISO. These transactions were not permitted after July 22, 2008.

Scheduling between New York and Ontario was also affected by transmission outages in 2008 and 2009. The Beck to Packard line (a 230 kV line between New York and Ontario) has been out-of-service since January 2008, which has reduced transfer capability between regions. As a result of several transmission outages coinciding with the Beck to Packard line outage, interface capability was reduced to 0 MW for several weeks in March, April, and November 2009.

Figure 28: Monthly Average Net Imports from Quebec and New England
2008 – 2009

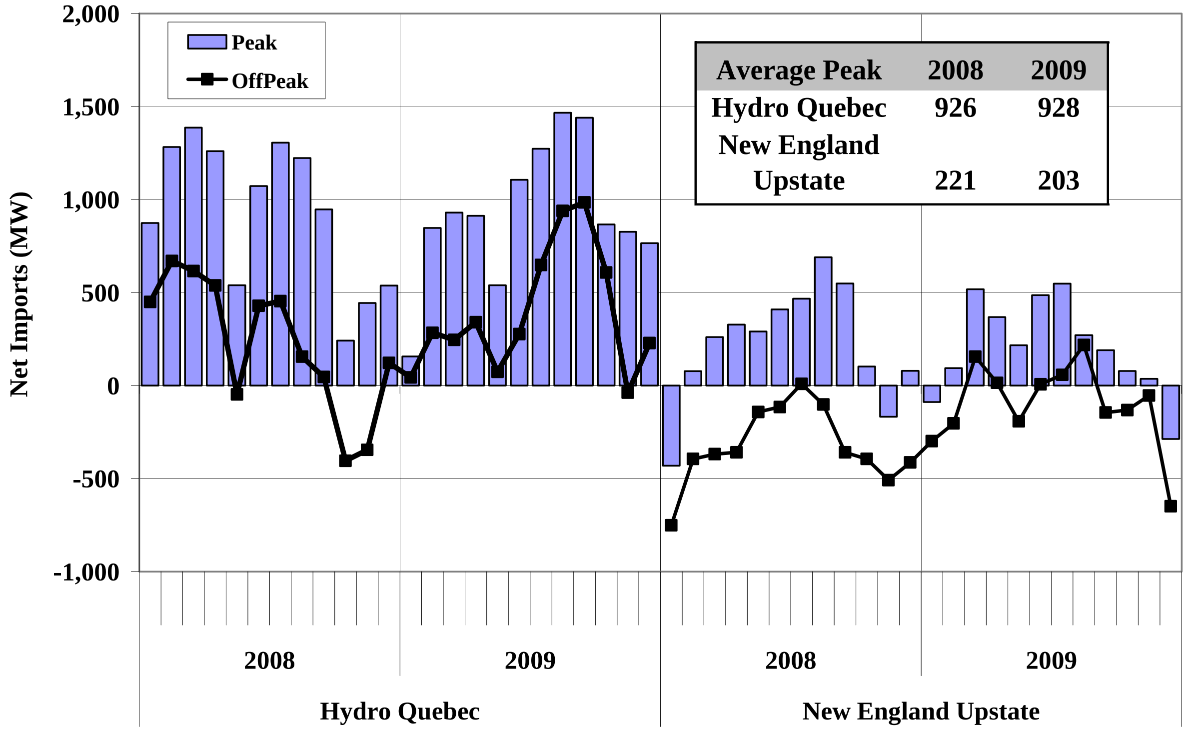


Figure 28 shows that New York generally imports across the interfaces with Quebec and New England during peak hours. The pattern of scheduling from Quebec reflects the flexibility of their hydroelectric generation, which allows Quebec to export power to New York when it is most valuable. Accordingly, flows from Quebec to New York generally rise in the summer months and in periods of high natural gas prices. Similarly, imports from Quebec decline in the winter and during off-peak periods.

Flows from New England to New York also generally rise in the summer months. This is partly because New England is more reliant on natural gas generation, which typically becomes more expensive during the winter months. The pattern of scheduling between New England and New York is also affected by production in Quebec. This is because Quebec schedules a large volume of power to New England during peak hours, which helps support flows from New England to New York.

Figure 29: Monthly Average Net Imports into New York City and Long Island
2008 – 2009

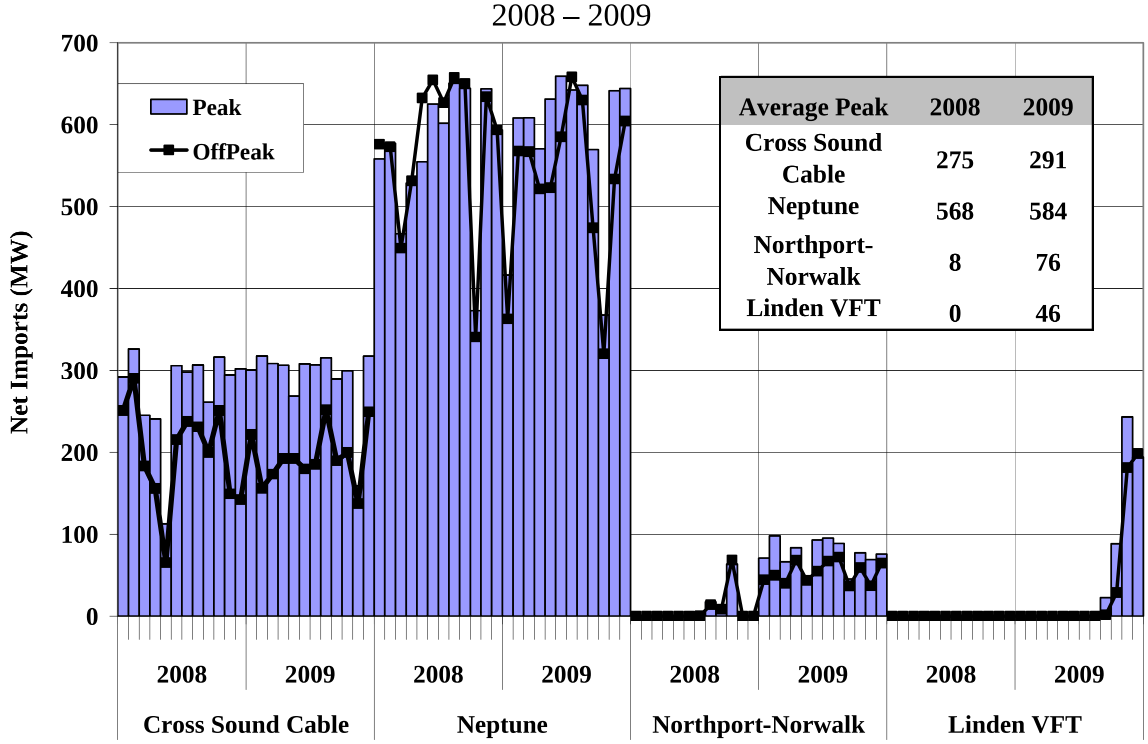


Figure 29 shows that a substantial share of the imports to New York State came directly to Long Island via the Cross Sound Cable and the Neptune Cable. The Cross Sound Cable ("CSC"), which connects Long Island to Connecticut, is frequently used to import up to 330 MW to New York. Likewise, the Neptune Cable, which connects Long Island to New Jersey, is frequently used to import up to 660 MW to New York. The 1385 Line, which connects Long Island to

Connecticut, is frequently used to import up to 100 MW, although the line was out-of-service for most of 2008 due to cable replacement work and problems with the phase shifter. The Linden VFT Line, which connects New York City to PJM with a transfer capability of 300 MW, began normal operation in November 2009.

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 38 percent of the load in Long Island in 2009. Unlike the primary interfaces, the interchange over these direct interfaces was generally relatively consistent.

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. Loop flows generally moved around Lake Erie in a counter-clockwise direction in the several years prior to 2008. However, the prevailing direction of loop flows reversed at the beginning of 2008 when the phenomenon of circuitous transaction scheduling around Lake Erie became significant.[23] Although circuitous transaction scheduling was prohibited after July 2008, loop flows usually continue to flow in clockwise direction around Lake Erie due to the scheduling patterns of market participants in the surrounding ISOs.

The direction and volume of circulation around Lake Erie has a significant effect on real-time congestion management in New York. The cost of real-time congestion management partly

[23] 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. In 2008, the most commonly scheduled circuitous transaction (known as "Path 1 transactions") sourced in New York, wheeled through Ontario and the Midwest ISO, and sank in PJM. Path 1 transactions caused power to move directly from New York to PJM (i.e., in the clockwise direction around Lake Erie), although they financially settled as if they moved through Ontario and the Midwest ISO (i.e., in the counter-clockwise direction around Lake Erie). This inconsistency increased clockwise loop flows around Lake Erie. The NYISO filed under exigent circumstances to prohibit circuitous transaction scheduling after July 22, 2008. This issue was discussed in detail in the 2008 State of the Market report, August 2009, Potomac Economics.

depends on whether an efficient set of generators is committed in the day-ahead market. Therefore, accurate assumptions in the day-ahead market regarding the direction and volume of loop flows reduce the costs of congestion management in real-time and improve consistency between the day-ahead and real-time markets.

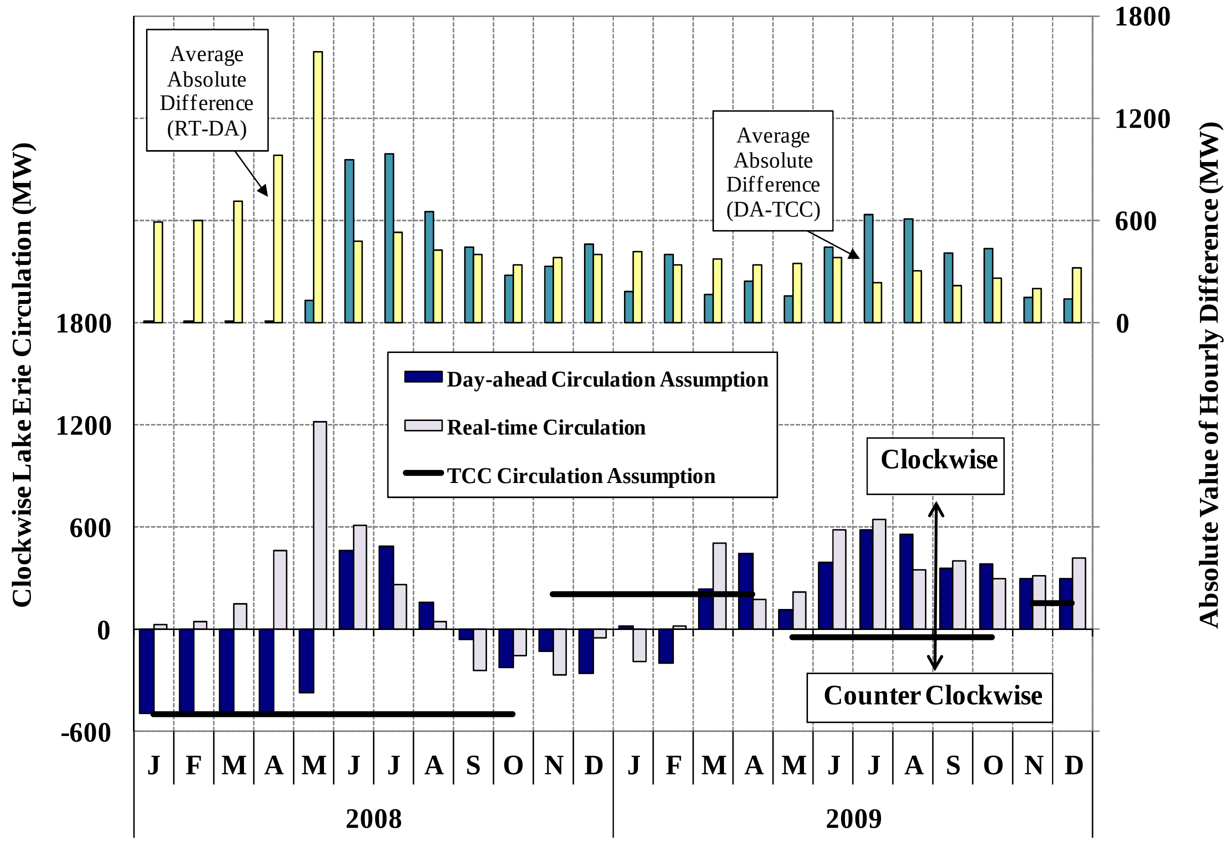
When clockwise loop flows are under-estimated in the day-ahead market, day-ahead schedules tend to be infeasible in the real-time market. The redispatch costs to resolve this infeasibility is collected as balancing congestion shortfall uplift, which is discussed further in Section V.A. When clockwise loop flows are over-estimated in the day-ahead market, the day-ahead schedules tend to under-use transmission capability, leading to inefficient real-time operations.

Likewise, the assumptions in the TCC market regarding the direction and volume of loop flows are important because differences between the TCC and day-ahead market assumptions contribute to poor convergence between TCC prices and day-ahead congestion prices, resulting in day-ahead congestion revenue shortfalls or surpluses.

Figure 30 summarizes the pattern of loop flows around Lake Erie in each month in 2008 and 2009. The lower portion of the figure shows the monthly averages of: (i) actual real-time loop flows in the clockwise (or counter-clockwise, if negative) direction, (ii) loop flows assumed in the day-ahead market, and (iii) loop flows assumed in the TCC auctions. The upper portion of the figure shows the average of the absolute value of the hourly differences between the day-ahead market assumption and the actual real-time quantity and between the TCC market assumption and the day-ahead market assumption.

The figure shows the increase in loop flows that was associated with circuitous transaction scheduling, which rose sharply in 2008, averaging 830 MW from January to July 2008. Circuitous transaction scheduling peaked in May at an average of 1,460 MW. The circuitous transactions were eliminated after July 22, 2008 when the NYISO filed under exigent circumstances to prohibit circuitous transactions.

Figure 30: Lake Erie Circulation
2008 –2009



During this period, the difference between the day-ahead market assumption and the actual real-time quantity rose from an average of 600 MW in January 2008 to more than 1500 MW in May 2008. In late-May 2008, the NYISO improved the procedures for updating the Lake Erie loop flow assumption. The day-ahead assumption now tracks actual loop flow much more closely as indicated by the lower average differences and average absolute differences since June 2008. These improvements reduced the market effects of loop flows, especially balancing congestion shortfall uplift.

The NYISO also improved the procedures for updating the Lake Erie loop flow assumptions in the TCC auctions, although these could not be implemented until the auctions for the Winter 2008/09 capability period, which began in November 2008. These improvements reduced the amount of day-ahead congestion shortfall uplift.

In 2009, the prevailing direction of loop flows around Lake Erie has been in the clockwise direction, averaging 200 to 600 MW in most months. The effects of the loop flows on congestion management in New York have been mitigated substantially by increased use of the Transmission Loading Relief procedures, beginning in March 2009.

Although circuitous transactions were prohibited in July 2008, loop flows continue to move in a clockwise direction around Lake Erie, primarily due to large volumes of transactions that are scheduled from Ontario to PJM via the Midwest ISO ("Ontario-to-MISO-to-PJM transactions"). Ontario-to-MISO-to-PJM transactions are not considered circuitous transactions because they are scheduled along the most direct path available between Ontario and PJM, which is counter-clockwise around Lake Erie. However, nearly half of the physical power flows clockwise around Lake Erie through the NYISO. As a result, these transactions tend to increase congestion and losses through New York without paying congestion and loss charges to the NYISO. Since Ontario-to-MISO-to-PJM transactions are not scheduled with the NYISO, the only mechanism the NYISO currently has to address the congestion they cause is its Transmission Loading Relief ("TLR") procedure, which allows the NYISO to curtail the transactions.

The NYISO has been working with the other ISOs in the Broader Regional Market ("BRM") initiative to identify additional mechanisms to improve the efficiency of transaction scheduling between control areas around Lake Erie. One mechanism proposed in the BRM initiative (known as the "Buy-Through of Congestion" proposal) would augment the TLR process by allowing non-NYISO transactions (e.g., Ontario-to-MISO-to-PJM transactions) to pay NYISO congestion charges in order to avoid curtailment via the TLR process. In Section IV.E, we evaluate the potential benefits of this and other mechanisms identified in the BRM initiative.

C. Price Convergence between New York and Adjacent Markets

The performance of New York's wholesale electricity markets depends not only on the efficient use of internal resources, but also the efficient use of transmission interfaces between New York and other areas. Trading between neighboring markets tends to bring prices together as participants arbitrage the price differences. When an interface is used efficiently, prices in adjacent areas should be consistent unless the interface is constrained. For example, when prices are higher in New York than in PJM, imports from PJM should continue until prices have converged or until the interface is fully scheduled. A lack of price convergence indicates that resources are being used inefficiently, because 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.

During peak demand conditions, it is especially important to schedule flows efficiently between control areas. Frequently during such conditions, a small amount of additional imports can substantially reduce prices.

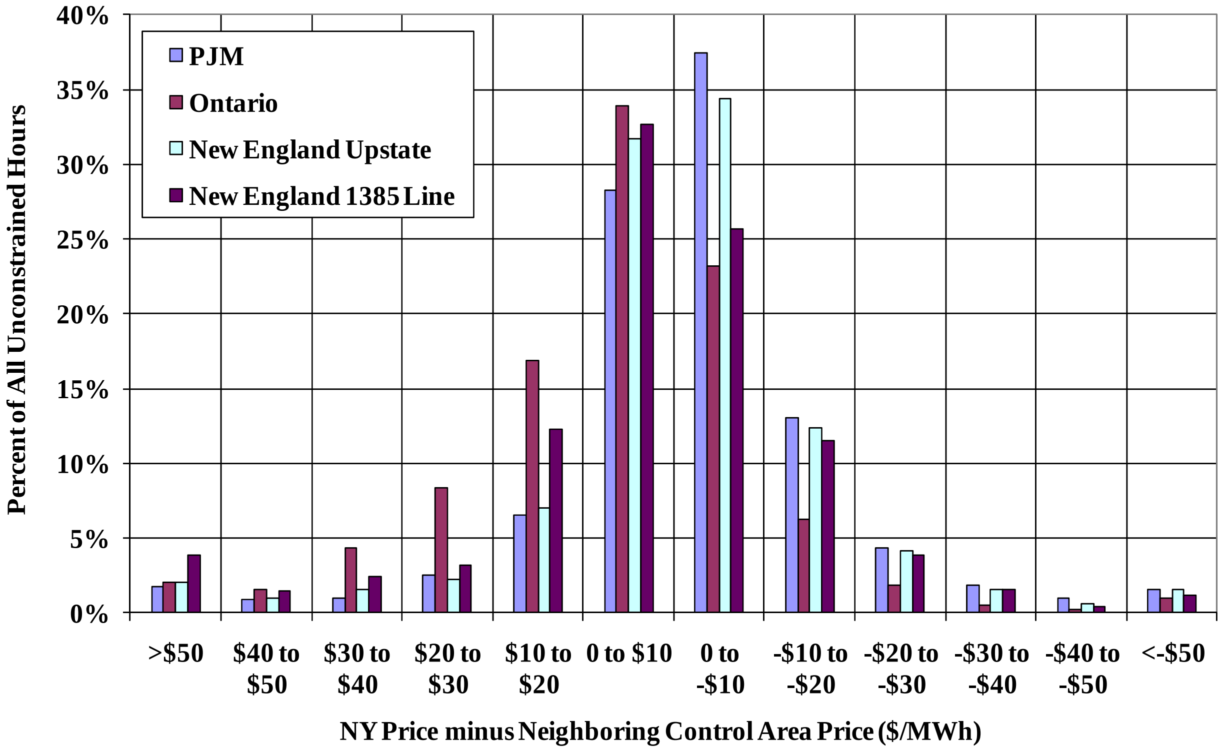
This sub-section evaluates the efficiency of scheduling between New York and the adjacent ISO-run markets across interfaces with open scheduling.[24] ISO-run markets have real-time markets, which allow participants to schedule market-to-market transactions based on transparent price signals in each region. Based on the prevailing prices in each market, we can evaluate whether the interface is scheduled efficiently.

Figure 31 summarizes price differences between New York and adjacent ISOs during unconstrained hours across the four interfaces with open scheduling. The horizontal axis indicates the price difference between New York and the adjacent region at the border. The heights of the bars indicate the fraction of hours in each price difference category.

The results shown in the figure indicate that the current process does not maximize the utilization of the interface. While the price differences center approximately at zero, for every interface a substantial number of hours have price differences exceeding $10 per MWh. The price difference exceeded $10 per MWh across the interfaces with adjacent control areas in 34 to 43 percent of the unconstrained hours during 2009. The Ontario results were slightly worse than the other interfaces and the price differences were skewed toward higher prices in New York and lower prices in Ontario.

[24] The Neptune Cable, the Linden VFT Line, and the Cross Sound Cable are omitted because alternate systems are used to allocate transmission reservations for scheduling on them.

Figure 31: RT Price Convergence Between NY and Adjacent ISO Markets
Unconstrained Hours[25], 2009



The large number of hours with significant price differences between regions indicates that additional efforts are needed to improve real-time interchange between New York and adjacent regions. 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.

Several factors prevent real-time prices from being fully arbitraged. First, 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. Second, differences in scheduling procedures and timing in the markets serve as barriers to full arbitrage. Third, there are transaction costs associated with scheduling imports and exports that diminish the returns from arbitrage. Participants cannot be

25 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 ISO from scheduling transactions or transaction curtailments.

expected to schedule additional power between regions unless they anticipate a price difference greater than these costs. Last, the risks associated with curtailment and congestion reduce participants' incentives to schedule external transactions when expected price differences are small. Given these factors, one cannot expect that trading by market participants alone will optimize the use of the interface.

D. Efficiency of External Interface Scheduling by Market Participants

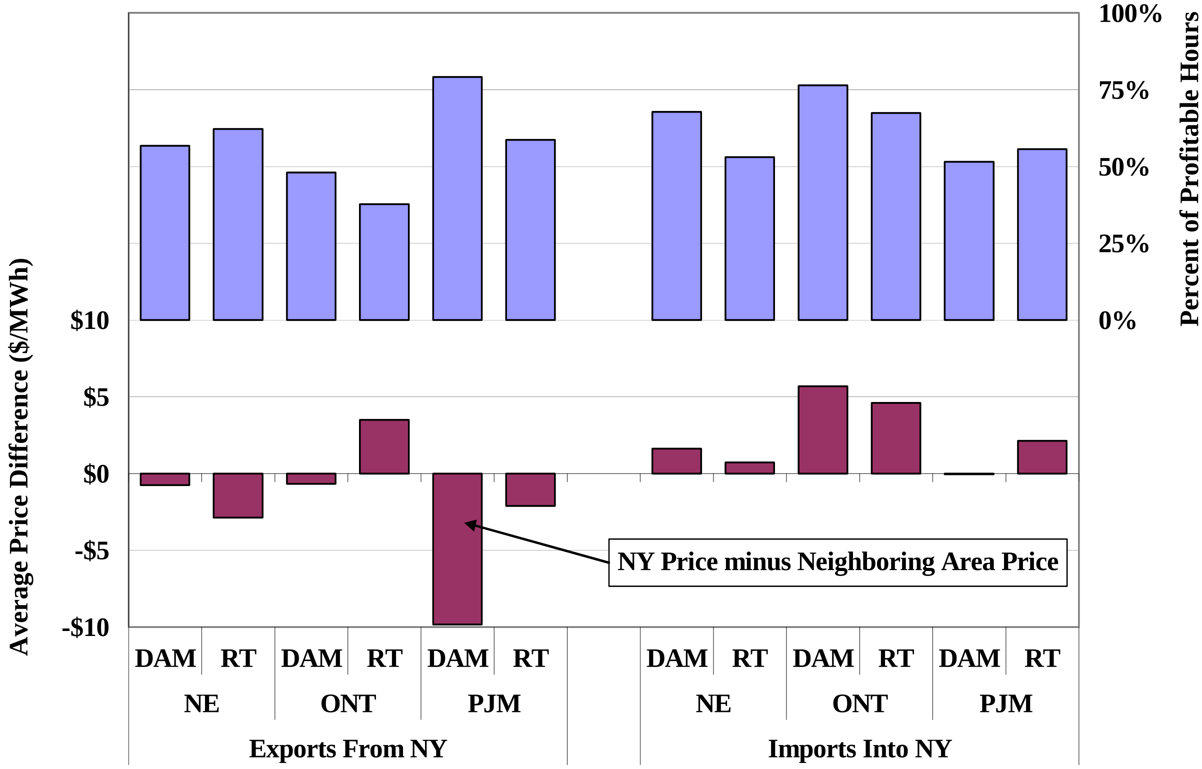
The prior analyses show that it is difficult to achieve real-time price convergence with adjacent markets through the transaction scheduling of market participants. Uncertainty, imperfect information, and required offer lead times limit the ability of participants to capitalize on real-time arbitrage opportunities. Furthermore, transaction costs from uplift allocations and export fees reduce or eliminate the expected profits from arbitrage.

Although scheduling by market participants does not fully exhaust the potential benefits from using the interfaces between regions, Figure 32 and Figure 33 show that scheduling by market participants does improve price convergence between New York and the neighboring markets. Hence, reducing barriers to scheduling by market participants would likely result in more efficient scheduling between regions.

Figure 32 evaluates the consistency of the direction of external transaction scheduling and price differences across the primary interfaces between New York and New England, PJM, and Ontario in 2009. Hours when power was scheduled in the export direction are shown on the left and hours when power was scheduled in the import direction are shown on the right.

The upper portion of the figure reports the share of these hours when power was scheduled in the profitable direction (i.e., from the lower-price market to the higher-priced market). If more than 50 percent of the hours are profitable, then the market schedules power to flow in the efficient direction in the majority of hours. The lower portion of the figure summarizes price differences between markets during these hours. It is efficient for New York to export in hours when the clearing price in New York is lower than in the adjacent area (i.e., the bar is negative), and to import when the clearing price in New York is higher (i.e., the bar is positive). This analysis separately evaluates: (i) day-ahead schedules and clearing prices (categorized by "DAM" on the horizontal axis), and (ii) incremental changes in schedules in the real-time market relative to the day-ahead schedules (categorized by "RT" on the horizontal axis).

Figure 32: Efficiency of Inter-Market Scheduling
Over Primary Interfaces – 2009

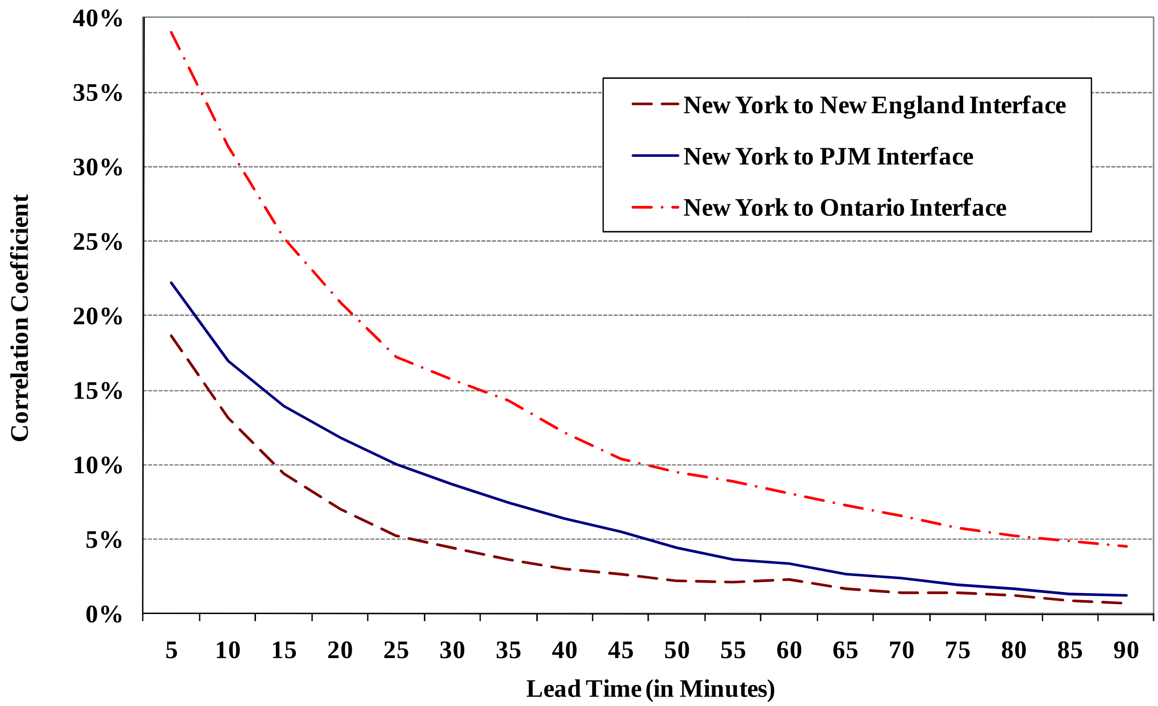


The upper portion of the figure shows that power was scheduled in the profitable direction in more than half of hours for 10 of the 12 categories of transactions shown on the horizontal axis. The two exceptions were DAM and RT exports to Ontario, which were profitable less than 50 percent of the time. Although transactions flowed in the profitable (i.e., efficient) direction in the majority of hours, there were still a large share of hours when power flowed from the high-priced market to the low-priced market (40 to 50 percent on a number of the interfaces).

The lower portion of the figure shows for most of the categories on the horizontal axis that the average clearing price was lower in New York when exports were scheduled and higher in New York when imports were scheduled. The lone exception was for RT exports to Ontario, which tended to be scheduled when New York prices were higher. Although the scheduling was not predictably profitable, the results indicate that participants generally respond to price differences by increasing net flows scheduled into the higher-price region. This improves efficiency by allowing lower-cost resources in one area to displace higher-cost resources in the adjacent area.

To better understand why the prices in adjacent markets were not more effectively arbitraged, we next evaluate the potential effects of the lead time for transaction scheduling. The following analysis examines the correlation between the lead times for scheduling transactions and the predictability of price differences between New York and adjacent markets. Figure 33 shows the correlation coefficient between the current five-minute price difference between New York and an adjacent market and the actual differences that occurred up to 90 minutes earlier.

Figure 33: Correlation of Price Differences Between Markets to Lead Time
Primary Interfaces with Adjacent Markets – 2009



Not surprisingly, Figure 33 shows actual price differences are more strongly correlated to price differences in periods near in time than to price differences in periods more distant in time. Currently, to schedule transactions, market participants must submit their offers 75 minutes before the start of an hour, which is 75 to 135 minutes before the power actually flows since transactions are scheduled in one-hour blocks at the top of the hour. This may contribute to participants' inability to fully arbitrage the difference in prices between adjacent markets.

However, the correlation coefficient is less than 10 percent for a 30 minute lead time at New York's primary interfaces with PJM and New England, although the analysis likely underestimates the predictability of price differences between control areas because participants can use more sophisticated techniques for forecasting, as well as make use of the economic evaluation of transactions by RTC. Nonetheless, since 30 minutes are the shortest scheduling time used currently by any of the markets, the results of the analysis suggest that shortening lead times for scheduling would likely capture only a portion of the available benefits from utilizing the external interfaces for efficiently.

The two previous analyses show that scheduling by market participants generally improves the efficiency of power flows between markets, although substantial improvement is possible. Hence, we continue to recommend that the NYISO modify its market design to achieve more efficient interchange with adjacent markets. This can be accomplished by coordinating its interchange with adjacent markets based on the prevailing real-time price in each area (adjusting the interchange on a 5-minute basis to increase the flow from the lower-priced market to the higher-priced market). Some have argued that this would constitute the ISOs participating in the market, but this is not the case. The ISOs would rely upon bids and offers submitted by participants in each market to establish the optimal interchange between the markets in the same way that they establish optimal power flows across each transmission interface inside both markets.

However, an alternative for achieving the same benefits is to allow intra-hour scheduling in real-time to achieve better utilization of the interfaces. This would involve participants submitting "spread bids and offers" that would indicate their willingness to import or export power for 15-minutes based on the ISOs' short-term forecast of the difference in real-time prices between the two adjacent markets. If the ISOs' forecast is accurate, participants' bids and offers should approach zero, which would allow prices to converge almost completely.

Such improvements are being considered in the BRM initiative. We evaluate the potential benefits from improved interchange in the next sub-section.

E. Potential Benefits of Improved Coordination Between ISOs

Section IV.B summarizes the pattern of unscheduled loop flows around Lake Erie, which usually impose costs on market participants in New York. Sections IV.C and IV.D evaluate the incomplete price convergence between New York and adjacent markets, which suggests that more efficient scheduling of interchange between markets would result in production cost savings and substantial benefits to consumers. Past efforts by the NYISO have improved the efficiency of transaction scheduling by market participants and power flows. However, optimal use of transmission capability between ISO regions requires better coordination by the ISOs (as is the case for efficient scheduling of the transmission capability within each ISO region). The NYISO is working with neighboring ISOs in the Broader Regional Market ("BRM") initiative to identify enhancements to market rules and operating practices that would improve the efficiency of power flows between regions.

The BRM initiative is a collaborative effort by IESO, MISO, NYISO, and PJM to develop solutions to the challenges created by loop flows. The package of physical and market solutions that are under development in the BRM initiative has the potential to substantially improve the efficiency of scheduling and pricing throughout the four ISO regions. Several proposed market enhancements are particularly likely to improve the efficiency of power flows between regions. The "Buy-Through Congestion" and "Market-to-Market Coordination" proposals would provide incentives for market participants to consider the effects of their internal and external scheduling decisions on the costs of congestion management in neighboring areas. The "Enhanced Interregional Transaction Coordination" proposal would better enable power to flow from low-priced regions to high-priced regions.[26]

This section summarizes our assessment of the potential benefits of the BRM initiatives. In particular, we estimate the production cost savings that may be achieved through:

- Improved coordination of congestion management around Lake Erie; and

[26] See the NYISO's Broader Regional Market report filed on January 12, 2010 in Docket ER08-1281-004, and Comments filed by Potomac Economics on the report on February 2, 2010.

- Improved utilization of New York's external interfaces, as well as the interfaces between MISO, PJM and Ontario.

We evaluate the estimated production cost savings because it is the most accurate measure of the improvement in economic efficiency. However, in most cases, the short-term consumer savings (resulting from price effect of the initiatives) would be substantially higher.

Benefits of Coordinated Congestion Management around Lake Erie

The economic effects of loop flows depend on the costs of re-dispatching generation to manage the resulting congestion. For example, if a flowgate is constrained with a $200 per MWh shadow price and 150 MW of flowgate capability is used by loop flows in the forward direction, the economic value of capability used by the loop flows will be $30,000 per hour. This economic value is equal to the congestion charges that would be collected if the 150 MW of flow resulted from transactions scheduled internally. The economic value of flowgates that are affected by loop flows also provides insight about the potential benefits from proposed enhancements, such as Buy Through Congestion and Market-to-Market Coordination, which would result in better incentives for market participants to schedule transactions efficiently.

There are two kinds of pricing inefficiencies resulted from loop flows:

- Under-priced Congestion: this occurs when transactions are not charged for their loop flows, or where the value of the flowgate exceeds the costs incurred by non-monitoring ISOs to help manage it.
- Over-priced Congestion: this occurs when transactions that are more valuable than the flowgate capability are curtailed, or when non-monitoring ISOs incur higher re-dispatch costs to help manage the congestion than the value of the flowgate.

Since we did not have the data to estimate the over-priced congestion, we have estimated only the under-priced congestion, which is the economic value of NYISO flowgate capability that was used by loop flows in the forward and reverse directions.[27] The estimates include loop flows resulting from inter-control area transactions where the NYISO was not on the contract path as well as loop flows from internal generation-to-load scheduling in PJM, MISO, and Ontario. The following table shows these estimates for the period from November 2008 through October

[27] Forward loop flows exacerbate congestion, while reverse loop flows relieve congestion.

2009. The results are most likely lower than would otherwise be expected due to the very low fuel prices and mild demand conditions that prevailed during the period.

Table 1: Estimated Value of NYISO Transmission Used by Loop Flows

NYISO Forward Loop Flows	$79
NYISO Reverse Loop Flows	$61

Forward and reverse loop flows have significant effects on congested flowgates in the NYISO. The total gross value of the loop flows was $140 million for NYISO flowgates and over $430 million including the flowgates on the PJM, MISO, and Ontario systems for the study period.

The BRM initiatives would capture a portion of this value by providing more efficient incentives to schedule transactions and dispatch resources to minimize costs throughout the four ISOs' systems. This portion is very difficult to estimate because it depends on the ability of other ISOs and market participants to provide relief on NYISO flowgates at a lower cost than the NYISO's real-time dispatch. We believe a reasonable range for this portion is 10 to 20 percent. Assuming that the BRM initiative would reduce the cost of congestion management by 10 percent, the production costs for the NYISO would have fallen by $14 million during the study period.

These results may be understated for several reasons. First, fuel prices were very low during the study period, which reduces the value of congestion. Second, we have no data on TLR-based curtailments and, therefore, have not identified cases where transactions were curtailed when the value of the transaction exceeded the value of the flowgate. Third, it does not identify the potential efficiency gains from scheduling additional transactions in the reverse direction to relieve congestion. Nonetheless, the production cost savings are significant.

1. Analysis of External Interface Utilization

Under the BRM initiative, proposals have been developed to improve the efficiency of the scheduled interchange between New York and neighboring areas. Efficient interchange scheduling reduces production costs and lowers prices for consumers. Production costs are reduced when an adjustment in scheduled interchange allows low-cost generation in one market to ramp-up and displace high-cost generation in another market. Consumers save because improved interchange coordination tends to lower prices on average in both regions.

We performed analyses to estimate the potential benefits that could be gained from *optimal* scheduling of the interfaces between the markets. However, the portion of the potential savings that is ultimately realized depends on how well the proposed market enhancements perform in producing efficient interchange levels. Real-time coordination of the net scheduled interchange by the ISOs (originally called "virtual regional dispatch") would likely capture most of the savings, while the analysis in Figure 33 suggests that simply shortening the scheduling timeframes for participants would capture a much smaller share of the potential benefits.

We performed analyses for each of the following interfaces with the NYISO:

- Ontario and PJM Interfaces – We used an econometric model to estimate how prices in each ISO respond to changes in the scheduled interchange ("NSI") over the interface, recognizing that this price response varies as prices increase or when there is congestion between the interface and internal areas, and controlling for changes in the NSI over other external interfaces.[28] These estimates were used to determine the optimal interchange over each of the four inter-ISO interfaces around Lake Erie, given the external interface limits.
- New England Interfaces and the Neptune Cable – We performed simulations to estimate the optimal interchange on an hourly basis, using the actual generator offers in New York and New England and estimated costs for generators in PJM, and recognizing the real-time binding constraints in each market.
- HQ Interface – We have not estimated the benefits from dynamically dispatching the HQ interface. However, the NYISO estimated how this would likely reduce or eliminate uplift charges that are currently incurred when the NYISO lacks the flexibility necessary to manage flows over the interface.

For the Ontario, PJM, and New England interfaces, we then estimated the production costs savings achieved by the NSI adjustments. Production cost savings result when relatively high-cost resources in one region are displaced by lower-cost resources in the adjacent region. The production costs savings are the total efficiency savings captured by the NYISO and the

28 However, we did not have the congestion component of PJM's real-time prices so the element was not included for the PJM interfaces.

adjacent RTOs. The following table shows the estimated production costs savings from our analyses of the Ontario, PJM, and New England interfaces.

Table 2: Estimated Production Cost Savings by Interface
2009

Coordination of Scheduled Interchange	Estimated Benefits
New York - Ontario	$66
New York - PJM	$46
New York - New England	$10
New York - HQ (Balancing Congestion Reduction)	$8
New York - HQ (Uplift Reduction)	$11
Long Island Ties to CT and NJ	$5
Total	**$146**

Table 2 shows approximately $146 million in potential production cost savings in 2009. The largest savings were typically on the primary interfaces with adjacent ISOs, although the benefits shown for the primary interface with New England were the lowest at $10 million. However, this value was lower than we had estimated in prior years. We estimated that production cost savings ranged from $17 to $21 million annually from 2006 to 2008. The estimates were lower in 2009 due to the lower fuel prices and milder demand conditions. Coordination of the interface over the New England interface would likely have a large effect on prices and reliability, since the NSI with New England affects the supply in Eastern New York where reserve shortages are more frequent.

For the HQ interface, the NYISO identified categories of uplift charges that would be reduced by dynamically dispatching interface. These include $8 million per year of balancing congestion shortfall uplift and $11 million per year of bid-production cost guarantee payments that have resulted from negative price events in Western New York.

2. Summary of Potential Benefits

Under the BRM initiative, several significant enhancements are being considered to market rules and operating procedures. These are expected to improve the efficiency of the net scheduled interchange between control areas and congestion management of flowgates that are affected by scheduling in other control areas. These enhancements promise significant potential economic efficiencies, although the benefits of improving the net scheduled interchange are larger.

Table 3 summarizes the estimated annual potential benefits that could be achieved. The production costs savings associated with NYISO external and internal interfaces are shown in blue, while other savings are shown in black.

Table 3: Summary of Estimated BRM Production Cost Savings

2009

Coordination of Scheduled Interchange			**Estimated Benefits**	**Fuel-Price Adj. Benefits***
New York - Ontario			$66	$81
New York - PJM			$46	$57
New York - New England			$10	$12
Ontario - MISO			$61	$75
MISO - PJM			$48	$59
New York - HQ (Balancing Congestion Reduction)			$8	$8
New York - HQ (Uplift Reduction)			$11	$11
Long Island Ties to CT and NJ			$5	$6
			$255	**$309**
Coordinated Congestion Management	**Total**	**Assumed Savings**	**Estimated Benefits**	**Fuel-Price Adj. Benefits***
Under-priced Congestion				
NYISO Forward Loop Flows	$79	10%	$8	$10
NYISO Reverse Loop Flows	$61	10%	$6	$8
PJM Forward Loop Flows	$37	10%	$4	$5
PJM Reverse Loop Flows	$33	10%	$3	$4
MISO Forward Loop Flows	$19	10%	$2	$2
MISO Reverse Loop Flows	$19	10%	$2	$2
Ontario Forward Loop Flows	$30	10%	$3	$4
Ontario Reverse Loop Flows	$32	10%	$3	$4
Over-Priced Congestion				
Ontario Forward Loop Flows	$59	10%	$6	$7
Ontario Reverse Loop Flows	$58	10%	$6	$7
	$427		**$43**	**$53**
Total Estimated Savings - NYISO Interfaces/Constraints			**$160**	**$193**
Total Estimated Savings - All Interfaces/Constraints			**$297**	**$362**

Savings on NYISO's External Interfaces and Internal Constraints

* Adjusted to a $6 per MMBTU Natural Gas Price

Table 3 shows that the total potential annual production cost savings from the BRM initiatives are substantial, totaling $160 million on the NYISO interfaces and constraints, and almost $300 million on all of the interfaces and constraints on the ISO systems around Lake Erie. However, these potential benefits may be understated due to the low demand levels, high surplus capacity, and low fuel prices that prevailed in 2009. The low fuel prices in 2009 can be addressed by adjusting the benefits to correspond to a more typical natural gas price. The benefits are highly correlated to natural gas prices because gas-fired units are on the margin in most periods in New York and the adjacent markets. The table shows that at a $6 per MMBTU natural gas price, the estimated production cost savings would rise to almost $200 million for the NYISO interfaces and over $360 million for all interfaces.

F. External Transactions – Conclusions and Recommendations

Efficient use of transmission interfaces between regions allows customers to be served by external resources that are lower-cost than available native resources. New York imports substantial amounts of power from PJM, Quebec, Ontario, and New England, which reduces wholesale power costs for electricity consumers in New York. In 2009, the NYISO imported an average of 3.1 GW during peak hours (i.e., Monday through Friday, 6 am to 10 pm).

Our evaluation of external transactions between New York and three adjacent ISO-run markets indicates that scheduling by market participants did not fully use the external interfaces or achieve all of the potential benefits available from inter-regional trading. Improving the efficiency of flows between regions is particularly important during shortages or very high-priced periods when modest adjustments to the physical interchange can reduce prices significantly. We find that the external transaction scheduling process was functioning properly and that scheduling by market participants tended to improve convergence, but significant opportunities remain to improve the interchange between regions.

The volume of clockwise loop flows around Lake Erie has risen in recent years, increasing congestion and uplift for NYISO participants. This has highlighted the importance of efforts to manage the congestion created by unscheduled loop flows more efficiently. The NYISO is collaborating with neighboring ISOs in the Broader Regional Markets initiative to improve the use of the external interfaces.

We performed analyses to estimate the potential benefits that could be gained from improving the efficiency of: (i) the net scheduled interchange between control areas, and (ii) congestion management of flowgates that are affected by scheduling in other control areas. We estimate potential production cost savings of almost $200 million annually from more efficient use of the NYISO's internal and external interfaces and more than $360 million annually from all interfaces around Lake Erie. Given these sizable potential savings, we recommend the NYISO continue working with adjacent ISOs to better utilize the transfer capability between regions, ideally by directly coordinating the net scheduled interchange and congestion management.

V. Transmission Congestion

Congestion arises when the transmission network does not have sufficient capacity to dispatch the least expensive generators to satisfy the load. 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 market 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 point A to zone B, this participant is entitled to 150 times the difference between the congestion prices at zone B and location A. Excepting transmission losses, a participant can perfectly hedge a bilateral contract between two points if it owns a TCC between the points.

Transactions not scheduled in the day-ahead market are assessed real-time congestion charges. 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. For real-time spot market transactions, the congestion charge is paid by the purchaser through the congestion component of the LMP. There are no TCCs for real-time congestion since most power is scheduled through the day-ahead market.

This section evaluates 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. Congestion Revenue and Shortfalls

Day-ahead congestion revenues 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.[29,30]

Day-ahead congestion shortfalls occur when day-ahead congestion revenues collected by the NYISO are less than entitlements of TCC holders. Shortfalls 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.[31] Day-ahead congestion shortfalls are equal to the difference between payments to TCC holders and day-ahead congestion revenues.

Balancing congestion shortfalls occur when day-ahead scheduled flows over a facility exceed what can flow over the facility in real-time.[32] 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

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

30 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).

31 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 a 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).

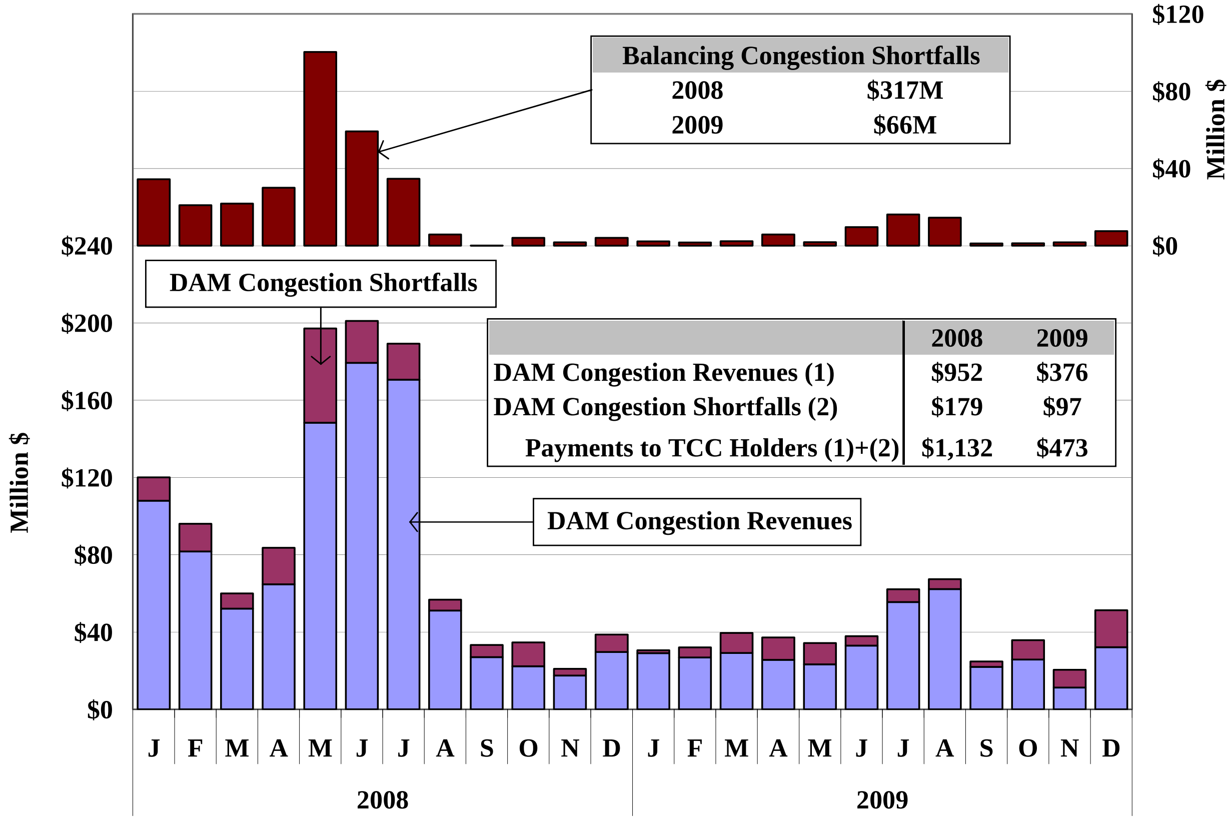
32 For example, suppose 100 MW is scheduled to flow across a particular line in the day-ahead market. If 90 MW flows across the line when it has a shadow price of $70/MWh in a hour in the real-time market, the NYISO will have a balancing congestion shortfall of $700 in that hour ((100 MW – 90 MW) * $70/MWh).

reduce generation on the export-constrained side of the constraint. These redispatch costs (i.e., the difference between the LBMPs in the two areas) is the balancing congestion shortfall that is recovered through uplift. This sub-section summarizes and discusses: day-ahead congestion revenues, day-ahead congestion shortfalls, and balancing congestion shortfalls.

1. Summary of Congestion Revenue and Shortfalls

Figure 34 summarizes day-ahead congestion revenue, day-ahead congestion shortfalls, and balancing congestion shortfalls in each month in 2008 and 2009. The lower portion of the figure shows day-ahead congestion revenues collected by the NYISO and day-ahead congestion shortfalls. The sum of these two categories is equal to the total net payments to TCC holders in each month. The tables in the figure report these categories on an annual basis.

Figure 34: Congestion Revenue and Shortfalls
2008 – 2009



The most dramatic change in 2009 was the $250 million reduction in balancing congestion shortfalls. This reduction is mainly attributable to the decrease in loop flows around Lake Erie that resulted when the NYISO prohibited circuitous scheduling in July 2008. However, other factors contributed to this reduction as well, including less frequent use of simplified interfaces into New York City load pockets in the real-time market, and more timely updates of loop flow assumptions and other assumptions in the day-ahead market.

Figure 34 also shows that day-ahead congestion revenue fell 61 percent from 2008 to 2009, which was due primarily to:

- Lower fuel prices, which reduced congestion-related price differences between regions;
- Lower load levels, particularly during the summer months, which reduced transmission flows into import-constrained areas; and
- Elimination of circuitous schedules, which that reduced clockwise Lake Erie circulation.

Figure 34 also shows that day-ahead congestion revenue and balancing congestion shortfalls rose during the summer months. Higher load levels lead to larger congestion-related price differences between regions during the summer, which increases both of these categories. Thunderstorm Alerts ("TSAs") also become frequent in the summer months. This leads to higher balancing congestion shortfalls because the NYISO is required to operate the transmission system more conservatively during TSAs.

Finally, the figure shows that day-ahead congestion shortfalls were highest in the spring and fall months. This is typical because transmission outages (that are reflected in the day-ahead market but generally not in the TCC auctions) are more frequent in shoulder months. 56 percent of the day-ahead congestion shortfall in 2009 accrued in the shoulder months in the Spring and Fall.

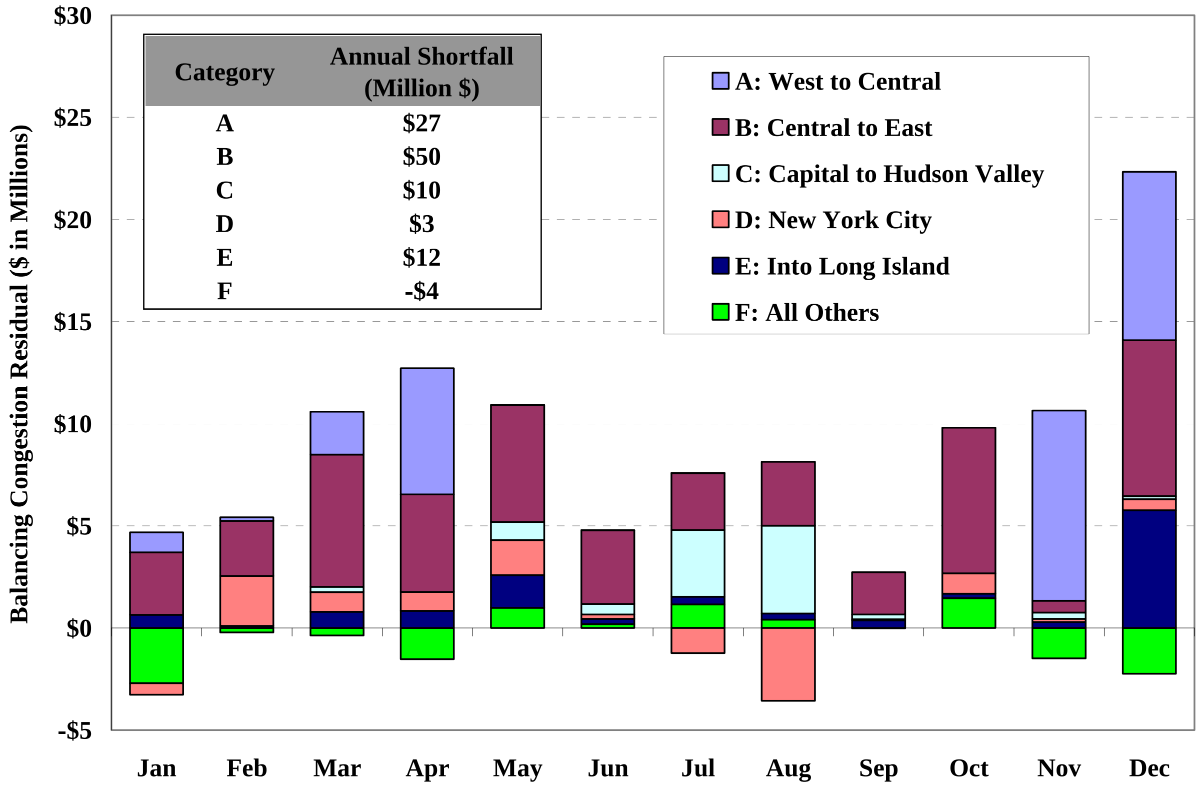
2. Day-Ahead Congestion Revenue Shortfalls

Day-ahead congestion revenue shortfalls generally arise when the quantity of TCCs sold for a particular path exceeds the transfer capability of the path as 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 a TCCs in the forward auction that reflects the expected transfer capability of the system. In addition, transmission owners can reduce potential day-ahead congestion revenue shortfalls by restricting the quantity of TCCs that are offered by the NYISO.

The NYISO determines the quantity 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 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 35 shows the monthly day-ahead congestion revenue shortfalls by transmission path or facility in 2009. Positive values indicate shortfalls, while negative values indicate surpluses.

Figure 35: Day-ahead Congestion Shortfalls by Transmission Path
2009



Category	Annual Shortfall (Million $)
A	$27
B	$50
C	$10
D	$3
E	$12
F	-$4

Figure 35 shows that the West to Central and Central to East paths accounted for 79 percent of the total day-ahead congestion revenue shortfalls in 2009. These paths exhibited substantial day-ahead congestion revenue shortfalls in each month when the paths were frequently congested. This suggests that the transfer capability between regions in the day-ahead market is consistently lower than the amount of TCCs sold between regions. Several factors led to reduced transfer capability on paths from west-to-east.

First, transmission outages were frequently reflected in the day-ahead market but not in the TCC auctions, reducing transfer capability in the day-ahead market below the assumed capability in the TCC auctions. The NYISO has a process for attributing day-ahead congestion revenue shortfalls to outages that allow the shortfalls to be allocated to specific transmission owners. Under this process, 31 percent of the day-ahead congestion revenue shortfalls were charged to specific transmission owners in 2009. Transmission owners can avoid allocations of day-ahead congestion revenue shortfalls from specific outages by electing to incorporate them in the TCC auction assumptions. Although many of the outages were scheduled before the TCC auctions, none of the transmission owners elected to incorporate them in the TCC auctions in 2009. Depending on the duration of a particular outage, it may be more efficient to incorporate the outage in TCC auction than to leave it out. Hence, the NYISO should evaluate whether the transmission owners have incentives to schedule outages when it is efficient to do so.

Second, there were differences in the assumed unscheduled loop flows around Lake Erie in the TCC auctions and the day-ahead market. Clockwise loop flows use a portion of the west-to-east transmission capability in New York without any payment to NYISO. This reduces the capability available for the NYISO market. In 2009, clockwise loop flows assumed in the day-ahead market were higher on average by approximately 330 MW than those assumed in the TCC auctions. As a result, the quantity of TCCs sold in the auctions generally exceeded the available west-to-east transmission capability in the day-ahead market auctions, contributing to day-ahead congestion revenue shortfalls.

Third, there were significant differences in modeling assumptions between the TCC auctions and the day-ahead market regarding the commitment status of individual generators and the flows across PAR-controlled lines. The commitment status of some generators affects the transfer capability of the transmission system, particularly the Central-East interface. Flows over PAR-controlled lines can either relieve or exacerbate congestion, so differences in PAR assumptions between the TCC auctions and the day-ahead market can result in day-ahead congestion shortfalls.

Long Island accounted for a large share of the day-ahead congestion shortfalls in December. This was primarily due to the outage of the Sprainbrook-to-East Garden City line, one of the two 345kV lines connecting Long Island to Up-State New York. Once the outage was reflected in the assumptions used in the day-ahead market, day-ahead transfer capability was much lower than assumed in the TCC auctions.

3. Balancing Congestion Revenue 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 re-dispatch 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 net cost of this re-dispatch is collected from loads through uplift charges, most of which is allocated to load throughout the state. However, the portion associated with facilities that require special operation during TSA events is charged to Consolidated Edison whose customers benefit most directly from the additional reliability.

This sub-section summarizes balancing congestion revenue shortfalls and identifies significant contributing factors in 2009. Balancing congestion revenue shortfalls occur when the available transfer capability of a line or interface changes between day-ahead and real-time. Such changes can be 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. Likewise, 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.

- 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 transfer capability of multiple interfaces.
- Unscheduled loop flows around Lake Erie – loop flows 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.

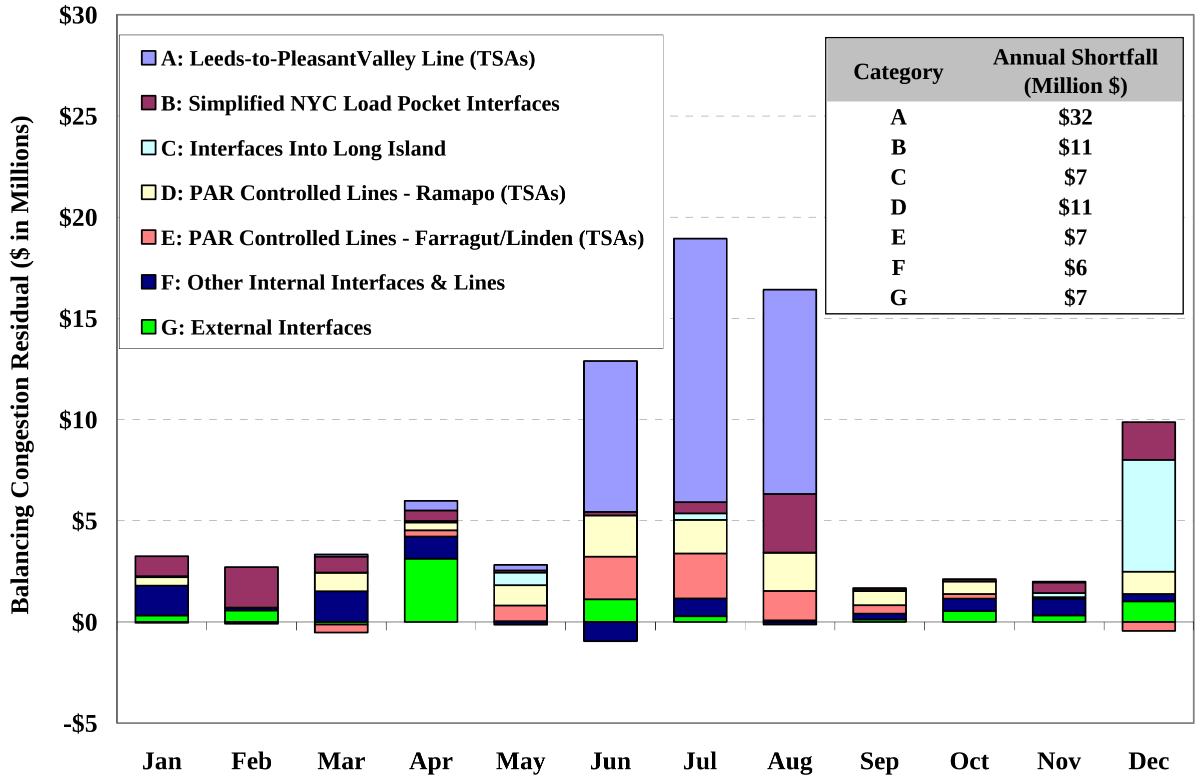
Figure 36 provides monthly detail on significant categories of balancing congestion shortfalls in 2009.[33] Positive values in the figure indicate balancing congestion shortfalls while negative values indicate balancing congestion surpluses. This figure shows the balancing congestion shortfalls for the following categories:

- Leeds-to-Pleasant Valley line (primarily during TSA operations);
- Simplified New York City load pocket interfaces;
- Interfaces into Long Island;
- PAR-controlled Ramapo line (primarily during TSA operations);
- PAR-controlled Farragut and Linden lines (primarily during TSA operations);
- Other internal interfaces and line constraints; and
- External interfaces.

[33] Note that the actual net balancing congestion revenue shortfalls were $15 million lower than those shown in the figure because the figure excludes the following items (some of which generated balancing congestion surpluses in 2009): (i) differences between the generators’ base-points (used in our analysis) and their actual output levels (which determine financial settlements) during each interval; (ii) differences between the amount of load scheduled by RTD (used in our analysis) and the amount of actual metered load (which determines financial settlements) during each interval; and (iii) balancing congestion revenue surpluses for certain interfaces that had unused transfer capability in the day-ahead market.

Figure 36: Balancing Congestion Shortfalls by Transmission Path

2009



The Leeds-to-Pleasant Valley line accounted for $32 million (or 41 percent) of balancing congestion shortfalls during 2009, the most among all listed categories. This occurred primarily during TSAs events, which require double contingency protection of the Leeds-to-Pleasant Valley path, effectively reducing the real-time transfer capability of the path.

Several PAR-controlled lines between New Jersey and New York (Ramapo, Farragut, and Linden) accounted for 28 percent of balancing congestion revenue shortfalls, mostly during TSA events. TSAs may suddenly require generators in Southeast New York to increase production before the PAR-settings can be adjusted accordingly. This reduces net flows into NYCA across the PAR-controlled lines, which results in a revenue shortfall.

The simplified interface constraints in New York City accounted for 13 percent or $11 million of the balancing congestion revenue shortfalls. Compared with the more detailed transmission modeling in the day-ahead market, using simplified interface constraints in the real-time market generally results in reduced transfer capability in New York City. Congestion across the

Greenwood/Staten Island interface constraint accounted for most of the shortfall. The shortfall was substantially reduced relative to previous years due in part to changes to the modeling assumptions used in the day-ahead market. These changes effectively reduced the available transfer capability into the Greenwood area in New York City.

Long Island accounted for approximately 70 percent of balancing congestion shortfalls in December. This was primarily due to the outage of the Sprainbrook-to-East Garden City line, one of the two 345kV lines connecting Long Island to Up-State New York. This resulted in large reductions in transfer capability in real-time compared to the assumptions used in the day-ahead market for two days before the day-ahead market assumptions were changed to account for the outage.

4. Conclusions

Overall, day-ahead and balancing congestion shortfalls decreased $333 million (67 percent) from 2008 to 2009. The decline was partly due to the reduction in congestion-related price differences resulting from lower fuel prices and lower load levels. Balancing congestion shortfalls were reduced by measures that improved consistency between day-ahead and real-time modeling, including:

- Improved interface scheduling procedures when other control areas declare TLRs;
- Procedures for promptly evaluating the causes of shortfalls and for adjusting market operations accordingly on a timely basis (e.g., more timely updates to the day-ahead assumptions regarding loop flows);
- The prohibition on the scheduling of circuitous transactions; and
- Less frequent use of simplified interface constraints in New York City.

As a result of the reduction in balancing congestion shortfalls, day-ahead congestion shortfalls now account for the majority of the congestion shortfalls. The NYISO has a process for allocating the uplift charges resulting from transmission outages to specific transmission owners. However, just 31 percent of day-ahead congestion shortfalls were charged to specific transmission owners in 2009. Due to the large amount of day-ahead congestion shortfalls that are not attributable to a specific transmission owner, the NYISO is conducting a review of recent scheduling to identify additional factors that contribute to day-ahead congestion shortfalls.

Additionally, transmission owners have not chosen to model planned transmission outages in the TCC market, even when the outages are scheduled in advance of the capability period. The NYISO should determine (i) the extent to which modeling these outages would enhance the overall efficiency of the TCC auction and (ii) whether the transmission owners have incentives to schedule outages when it is efficient to do so.

B. Congestion on Major Transmission Paths

Supply resources in eastern New York, especially New York City and Long Island, are generally more expensive than those in western 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 price differences between regions. This sub-section examines congestion patterns in the day-ahead and real-time markets in the past two years.

The two analyses in this sub-section measure congestion in two ways. First, they quantify the frequency of binding constraints. Second, they quantify 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.[34] In the day-ahead market, the value of congestion equals the congestion revenue collected by the NYISO in the day-ahead market. In the real-time market, the value of congestion does not equal the congestion revenue collected by the NYISO in the real-time market, since most real-time power flows settle at day-ahead prices rather than real-time prices. Nonetheless, the real-time congestion value provides a sense of the economic significance of congestion in the real-time market.

1. Day-Ahead Congestion by Transmission Path

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

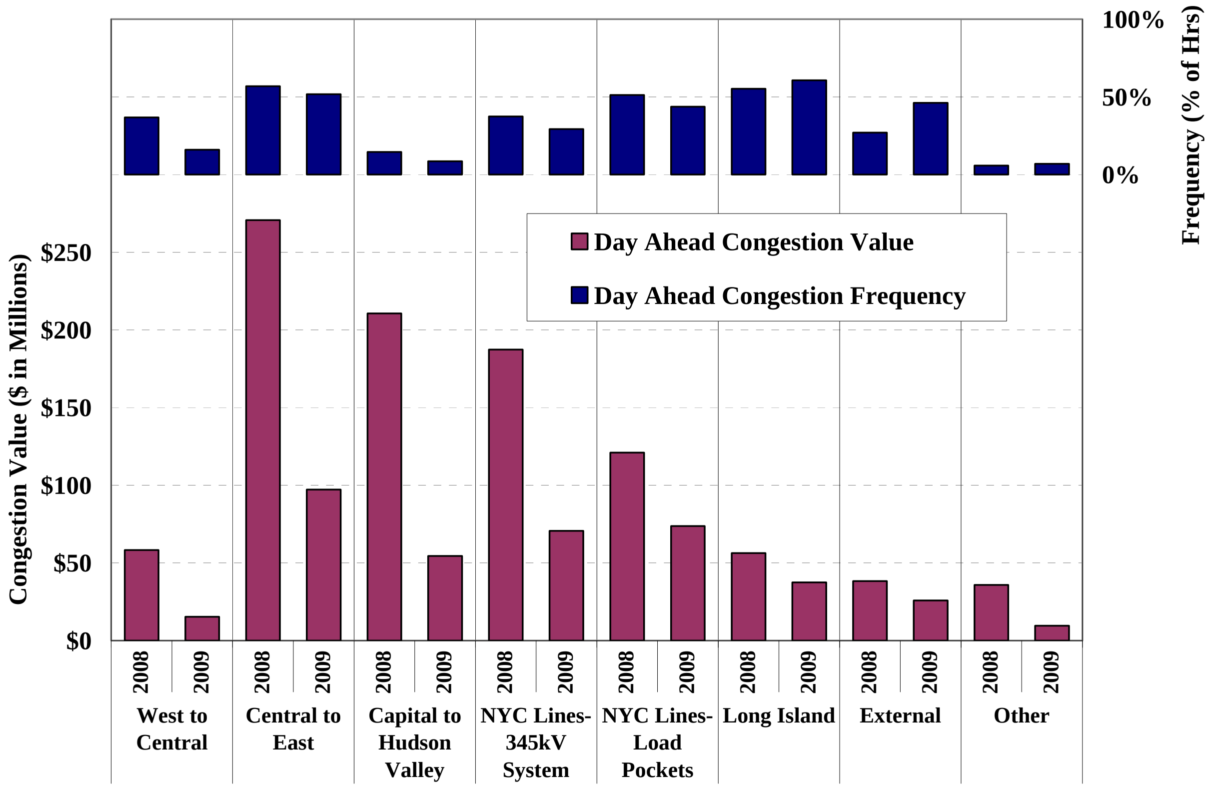
[34] The shadow price of a transmission constraint represents the marginal value to the system of one MW of transfer capability.

transmission facility determine the amount of trading that can occur between regions in the day-ahead market. When trading 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 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 important to evaluate the consistency of congestion patterns in the day-ahead and real-time markets.

Figure 37 summarizes the frequency of congestion and the congestion revenues collected by the NYISO in the day-ahead market for eight groups of transmission facilities in 2008 and 2009.

Figure 37: Day-Ahead Congestion by Transmission Path
2008 – 2009



In 2009, the majority of day-ahead congestion revenue was collected on the following paths:

- In New York City (38 percent) – The lines into and within New York City are divided into two groups: (a) lines on the 345kV system and (b) lines leading into or within the load pockets (i.e., the 138kV system). The majority of the congestion associated with the load pockets was on the lines into the Greenwood area.
- From Central to East (25 percent) – The Central-East Interface limits flows from western New York to the Capital Zone.
- From Capital to Hudson Valley (14 percent) – This is primarily associated with congestion on the Leeds-to-Pleasant Valley line, which carries power from the Capital Zone into Southeast New York.

The general pattern of congestion in 2009 was similar to 2008, although the total congestion revenue in 2009 was more than 60 percent lower ($580 million lower) than in 2009. The sharp declines in the value of congestion were primarily due to the substantial decrease in fuel prices, which leads to lower redispatch costs and correspondingly smaller congestion-related price differences. The frequency of congestion on each path was comparable from 2008 to 2009.

The day-ahead congestion patterns summarized in Figure 37 were generally similar to the real-time congestion patterns summarized below in the next subsection. However, the Capital to Hudson Valley path, exhibited less congestion in the day-ahead market due to the tighter criteria used in the real-time market during Thunderstorm Alerts. In addition, lines into the Greenwood/Staten Island load pocket exhibited more congestion in the day-ahead market. This was partly due to day-ahead modeling assumptions that reduced transfer capability into New York City load pockets that sometimes exhibit reduced transfer capability in real-time. This change was intended to allow the day-ahead assumptions to be more consistent with average real-time capability.

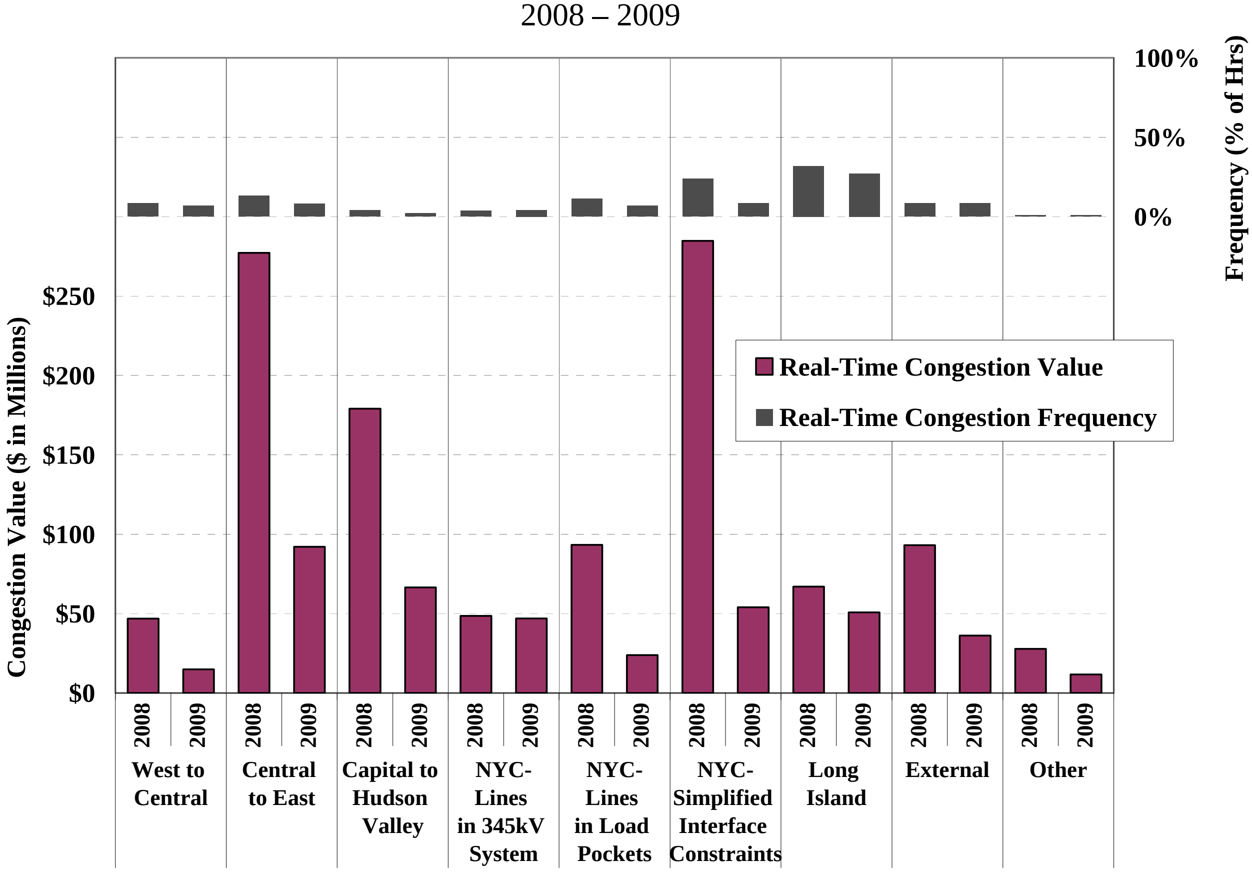
Congestion is typically more frequent in the day-ahead market than in real-time, but shadow prices of constrained interfaces are generally lower in the day-ahead. This is not unexpected because real-time congestion is more uncertain and volatile. For example, if market participants forecast a 20 percent probability of congestion that would lead to a $40 price difference between regions in the real-time market, the expected value of congestion would be $8 ($40*20%). In this case, market participants might be expected to bid up prices in the day-ahead market nearly 100 percent of the time by an amount close to the $8 expected value of congestion.

2. Real-Time Congestion by Transmission Path

This sub-section examines congestion patterns in the real-time market. Figure 38 summarizes the value and frequency of congestion by transmission path in the real-time market for 2008 and 2009. The figure examines the same transmission paths as in the day-ahead market figure above, although New York City congestion is also shown for simplified interface constraints.

Simplified interface constraints are constraints in the real-time market model that represent multiple lines as a single interface with a single transfer limit. Because the simplified interfaces are a much less detailed and accurate representation of the network, use of these interfaces reduces the utilization of the transmission capability. The real-time market uses line constraints and simplified interface constraints, while the day-ahead market always uses line constraints.

Figure 38: Real-Time Congestion by Transmission Path
2008 – 2009



Most real-time congestion (71 percent) occurred on the following transmission paths in 2009:

- New York City lines and interface constraints (31 percent) – The use of simplified interface constraints decreased from 2008 to 2009, which substantially reduced the share of the real-time congestion value associated with simplified interface constraints.
- Central to East (23 percent) – This was primarily associated with the Central-East Interface.
- Capital to Hudson Valley (17 percent) – Most of this occurred during TSA events in the summer. They occur less frequently than other categories, but they account for a relatively large share of the congestion value because they frequently result in very high re-dispatch costs.

December exhibited the most congestion of any month ($52 million) in 2009. This was partly due associated with the Central-East interface, the Greenwood load pocket in New York City. The increase in congestion was partly due to higher fuel prices, which tend to increase redispatch costs. In addition, an outage of one of the two major lines between Up-State New York and Long Island increased congestion substantially into Long Island.

C. TCC Prices and Day-Ahead Congestion

In this sub-section, we evaluate whether clearing prices in the TCC auctions are 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:

- Capability Period Auctions – TCCs are sold in these auctions as 6-month products for the summer capability period or the winter capability period, and as 1-year products for two consecutive capability periods. Typically, 33 percent of transmission capability is auctioned in the form of 1-year TCC products, and the remaining 67 percent of transmission capability is auctioned in the form of 6-month products. The 1-year and 6-month product auctions consist of a series of rounds. In each round, a portion of the transmission capability is offered, resulting in multiple TCC awards and clearing prices.
- Reconfiguration Auctions – The NYISO conducts a Reconfiguration Auction once in the month preceding 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.

The following analysis evaluates whether clearing prices in each type of TCC auction are consistent with the congestion prices in the day-ahead market. Figure 39 compares the TCC prices during the 2009 Summer Capability Period to the corresponding congestion prices in the day-ahead market. The figure shows the average TCC prices over four rounds in the 6-month Capability Period Auctions and the average TCC prices of the six monthly Reconfiguration auctions during the Summer Capability Period. The figure shows two TCC paths that source and sink in different zones (interzonal paths) and six paths that source and sink in the New York City zone (intrazonal paths). The two interzonal TCC paths are between the three zones commonly used for bilateral trading (Zones A, G, and J). Two of the New York City TCC paths source within the 345kV system of New York City and sink in Zone J (see Poletti to Zone J and Arthur Kill 3 to Zone J). Four of the New York City TCC paths source in the 138kV system of New York City and sink in Zone J, or vice versa.

Figure 39: TCC Prices and Day-Ahead Congestion
Summer 2009 Capability Period

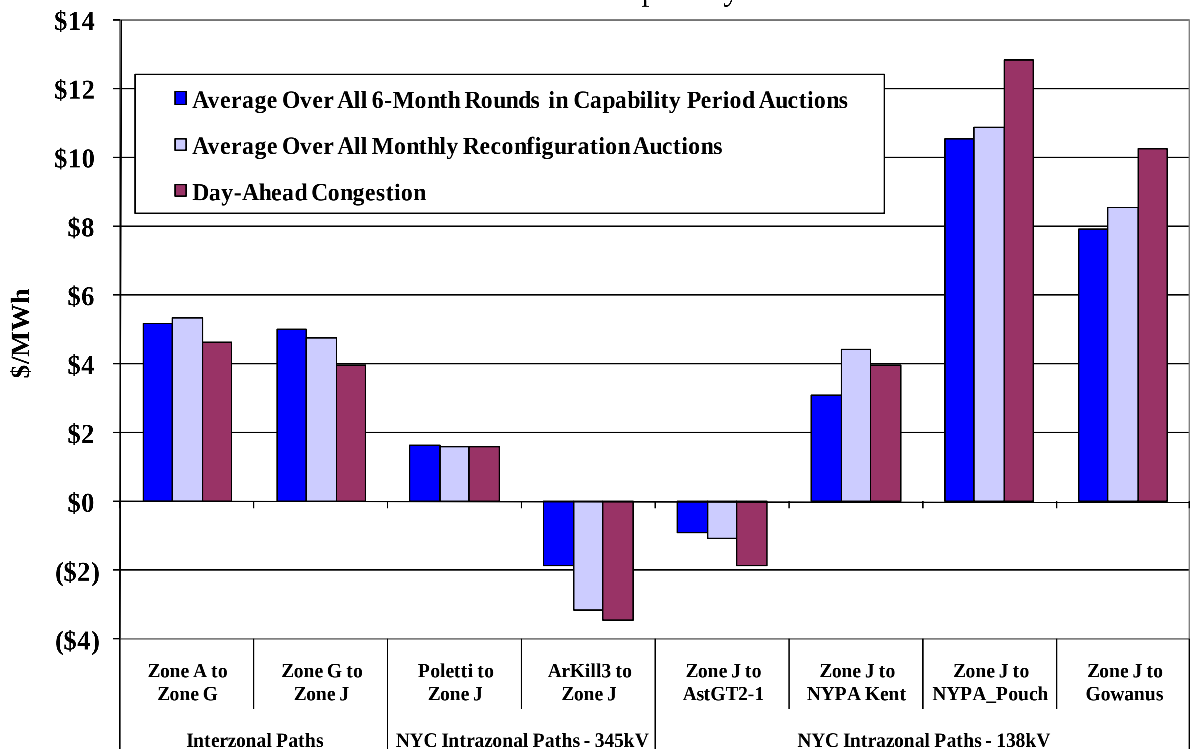


Figure 39 indicates that the average prices in the monthly reconfiguration auctions were more consistent with day-ahead congestion than were the averages of the capability period auction prices, although individual monthly reconfiguration auctions substantially under- or over-valued day-ahead congestion. This is expected since the monthly reconfiguration auctions occur closer to the actual operating period when more accurate information is available about the state of the transmission system and likely market conditions.

Overall, the figure shows interzonal TCC prices were generally higher than the day-ahead congestion price differences, suggesting that participants expected more day-ahead congestion. In New York City, intrazonal TCC prices were generally lower than the day-ahead congestion price differences, suggesting that they expected less day-ahead congestion. However, none of these differences were unusually large or indicative of an issue with the market's performance.

VI. 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 ISO maintain reliability and set clearing prices that reflect the shortage of resources. Efficient 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 needed most.

In this section, we evaluate several aspects of wholesale market operations in 2009. This section examines four areas:

- Real-Time Scheduling and Pricing – This sub-section evaluates the consistency of real-time pricing with real-time commitment and dispatch decisions.
- Real-Time Price Volatility – This sub-section evaluates the factors that lead to transient price spikes in the real-time market.
- Operations 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: operating reserve shortages, local shortages resulting from scarce transmission capability, and periods when demand response is activated.
- Supplemental Commitment for Reliability – These are necessary when the market does not provide incentives for suppliers to satisfy local reliability requirements. They raise concerns because they indicate the market does not provide sufficient incentives, tend to dampen market signals, and increase uplift charges.

In these areas, we provide several recommendations to improve wholesale market operations.

A. Real-Time Scheduling and Pricing

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 ("GTs") when it is economic to do so.[35] RTD models the dispatch across a one-hour time horizon (rather than just the next five minutes), which better enables it to determine when a GT 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 GTs and 30-minute GTs when it is economic to do so.[36] 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 sub-section A.C.

Convergence between RTC and RTD is important because a lack of convergence can result in uneconomic commitment of generation, particularly of GTs, and inefficient scheduling of external transactions. When RTC commits or schedules excess resources, it results in depressed real-time prices and increased uplift costs. Alternatively, when RTC commits insufficient resources, it leads to unnecessary scarcity and price spikes. This section includes several

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

36 30-minute GTs can start quickly enough to provide 30-minute non-synchronous reserves, but not quickly enough to provide 10-minute reserves.

analyses that evaluate the efficiency of real-time commitment and scheduling in the following areas:

- Commitment of Gas Turbines; and
- Scheduling of External Transactions;

The following subsections provide our evaluation and discussion in these two areas.

1. Efficiency of Real-Time Commitment of Gas Turbines

The efficient commitment of GTs is important because excess commitment results in depressed real-time prices and increased uplift costs, while under-commitment leads to unnecessary scarcity and price spikes. This is particularly important in New York City and Long Island where GTs account for nearly 30 percent of the installed capability.

The following analysis measures the efficiency of GT 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 GTs are usually lower than the real-time LBMP. However, when a GT 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 40 shows the average quantity of GT capacity started each day in 2009. 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: (a) offer < LBMP (these commitments were clearly economic), (b) offer > LBMP by up to 25 percent, (c) offer > LBMP by 25 to 50 percent, and (d) offer > LBMP by more than 50 percent. Starts are shown separately for quick start GTs, older 30-minute GTs, and new 30-minute GTs. Starts are also shown separately for New York City and Long Island, and based on whether they were started by RTC, RTD, RTD-CAM,[37] or by an out-of-merit (OOM) instruction.

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[37] 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.

Figure 40: Efficiency of Gas Turbine Commitment
2009

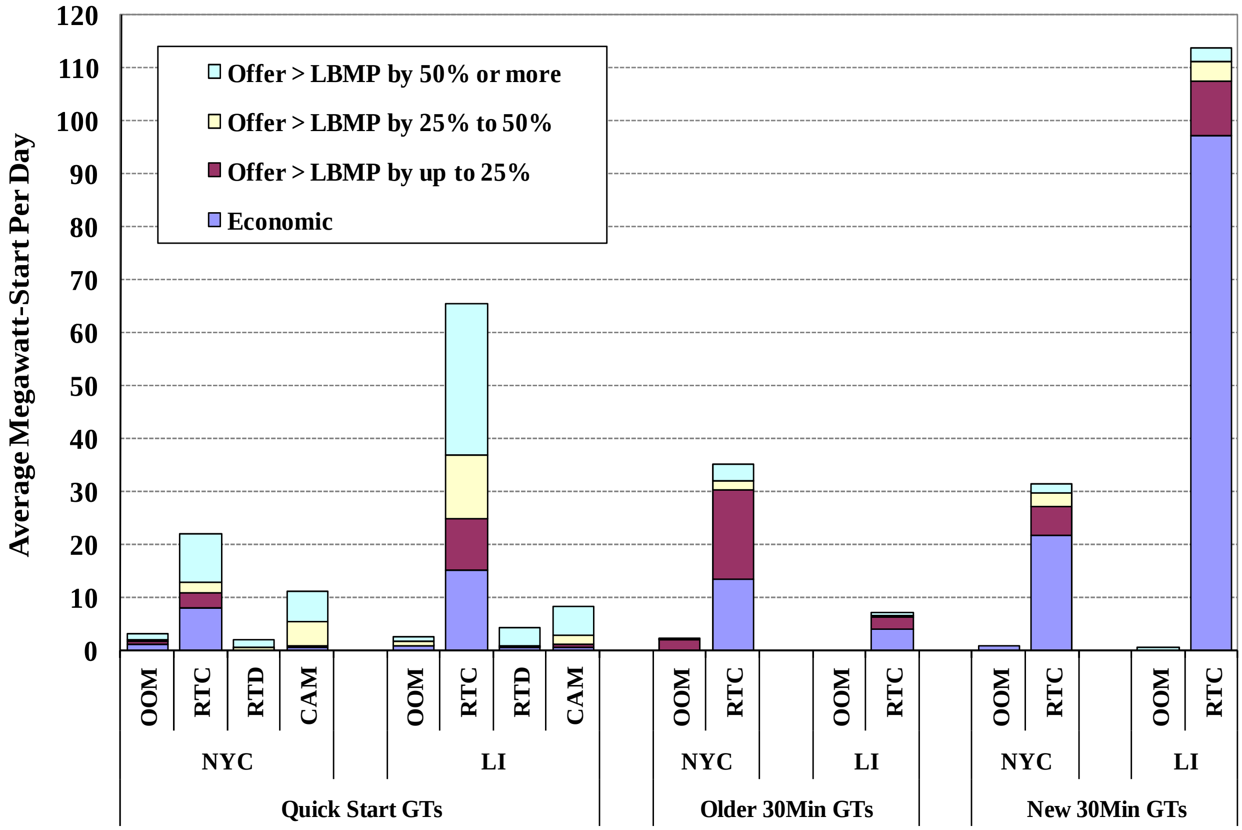

Figure 40 indicates that 89 percent of the GT-capacity started during 2009 was committed by RTC, with an additional 8 percent by RTD and RTD-CAM, and the remaining 3 percent by OOM instructions. 53 percent of the GT-capacity that started was clearly economic. However, some GTs with offers greater than the LBMP can also be efficient for at least two reasons. First, GTs that are started efficiently and set the LBMP at their location do not earn additional revenues needed to recover their start-up offer. Second, GTs that are started efficiently to address a transient shortage (e.g., transmission constraint violation) may lower LBMPs substantially and, as a consequence, appear uneconomic over the commitment period.

The figure shows new 30-minute GTs (those installed after 2000) accounted for approximately 47 percent of the GT capacity started in 2009, although they only represented 28 percent of the total GT capacity in New York state. These new 30-minute GTs run more frequently because they are generally more fuel efficient than the older GTs. They also tended to be started far more economically. 82 percent of starts of newer GTs were clearly economic as opposed to 41 percent of the older 30-minute GTs. Quick-start GTs appeared more uneconomic in the figure because they often are started to address a transient transmission shortage. The overall efficiency of gas turbine commitment was comparable in 2009 to 2008. The average amount of gas turbine commitment fell approximately 40 percent in all of New York State and 63 percent in New York City from 2008 to 2009, which was primarily due to the lower load levels in 2009.

Another factor that tends to reduce the overall efficiency of GT commitment is the use of simplified interface constraints in New York City load pockets rather than the more detailed model of transmission capability. The more detailed representation of the network allows RTD to re-dispatch generators more efficiently when constraints are binding. It also enables RTC to better anticipate congestion, leading to more efficient commitment. The use of simplified interface constraints decreased substantially as a share of the binding real-time constraints in New York City (from 64 percent in 2008 to 44 percent in 2009). Less frequent use of the simplified network representation in New York City load pockets improves the efficiency of GT commitment.

2. Efficiency of External Transaction Scheduling

Market participants submit offers to import and bids to export at least 75 minutes ahead of each real-time hour. RTC schedules imports and exports in economic merit order based on their offer/bid prices and a forecast of system conditions. This sub-section evaluates the performance of external transaction scheduling based on two criteria:

- Consistency – This refers to whether the transaction was scheduled (or not scheduled) consistent with real-time prices. For example, it is considered “not consistent” when RTC schedules an export but the real-time LBMP is ultimately greater than the export bid price.[38] Likewise, it is considered “not consistent” when RTC does not schedule an export but the real-time LBMP is ultimately less than the export bid price.
- Profitability – This refers to whether the transaction would be profitable if scheduled based on the real-time proxy bus LBMPs on either side of the border. Transactions that RTC schedules “consistent” with real-time LBMPs are not always profitable. For example, if a $50 per MWh export is scheduled by RTC and the real-time LBMP is

[38] An export bid expresses a willingness to pay up to the bid price to export power. So, if RTC forecasts a $45 per MWh LBMP at the proxy bus and accordingly schedules an export with a $50 per MWh bid price, and if the real-time LBMP is ultimately $55 per MWh, it is considered “not consistent” because the real-time LBMP exceeds the export bid price (i.e., willingness to pay).

ultimately $45 per MWh, it would be "consistent." However, if the price on the other side of the border was $40 per MWh, the export would be unprofitable.[39]

"Consistent" scheduling indicates that RTC is performing well, accurately forecasting real-time conditions in New York. However, the "profitability" of scheduling indicates whether the scheduling of external transactions is efficient. Transactions are profitable when they flow from the low-priced control area to the high-priced control area.[40]

Figure 41 shows the consistency and profitability of external transaction scheduling across the primary AC interface between New York and New England from 2005 to 2009 using the import/export offer and bid prices and the real-time LBMP at the border.[41] Most imports and exports are not submitted price-sensitively in real-time, although the use of price sensitive offers is becoming more prevalent. The figure evaluates real-time offers submitted in a price-sensitive manner, which excludes transactions with day-ahead priority, exports bid above $300 per MWh, and imports offered below -$300 per MWh.

Figure 41 shows price-sensitive offers and bids to import and export in four categories of stacked bars:

- Scheduled and consistent – RTC schedules these transactions consistent with real-time LBMPs. However, if these transactions are unprofitable, it implies that they cause power to flow inefficiently from the high-priced control area to the low-priced control area.
- Scheduled and not consistent – RTC schedules these transactions inconsistent with real-time LBMPs. However, if these transactions are profitable, it implies that they cause power to flow efficiently from the low-priced control area to the high-priced control area.
- Not scheduled and not consistent – These transactions are not scheduled by RTC but apparently should have been.

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39 The export would pay $45 per MWh for the power in the NYISO and receive $40 per MWh for the power in the adjacent control area, losing $5 per MWh.

40 Although this is generally true, there are exceptions due to the way that LBMPs are determined when there is congestion at the interface. For example, if LBMPs within New York are $60 per MWh and LMPs within New England are $50 per MWh, transactions that export from New England and import to New York are efficient. However, if New York has import congestion and the LBMP on the New York side of the border is set by a $45 per MWh import, efficient transactions will be unprofitable.

41 We analyze the New England interface due to its importance in servicing eastern areas in New York. We would expect similar results for PJM and Ontario.

- Not scheduled and consistent – These transactions are not scheduled by RTC apparently in accordance with real-time LBMPs. Most bids and offers fall into this category, so they are shown on the secondary y-axis.

Transactions that would be profitable if scheduled based on the real-time proxy bus LBMPs on either side of the border are shown separately from ones that would not be profitable.

Figure 41: Efficiency of External Transaction Scheduling
Primary Interface with New England, 2005 – 2009

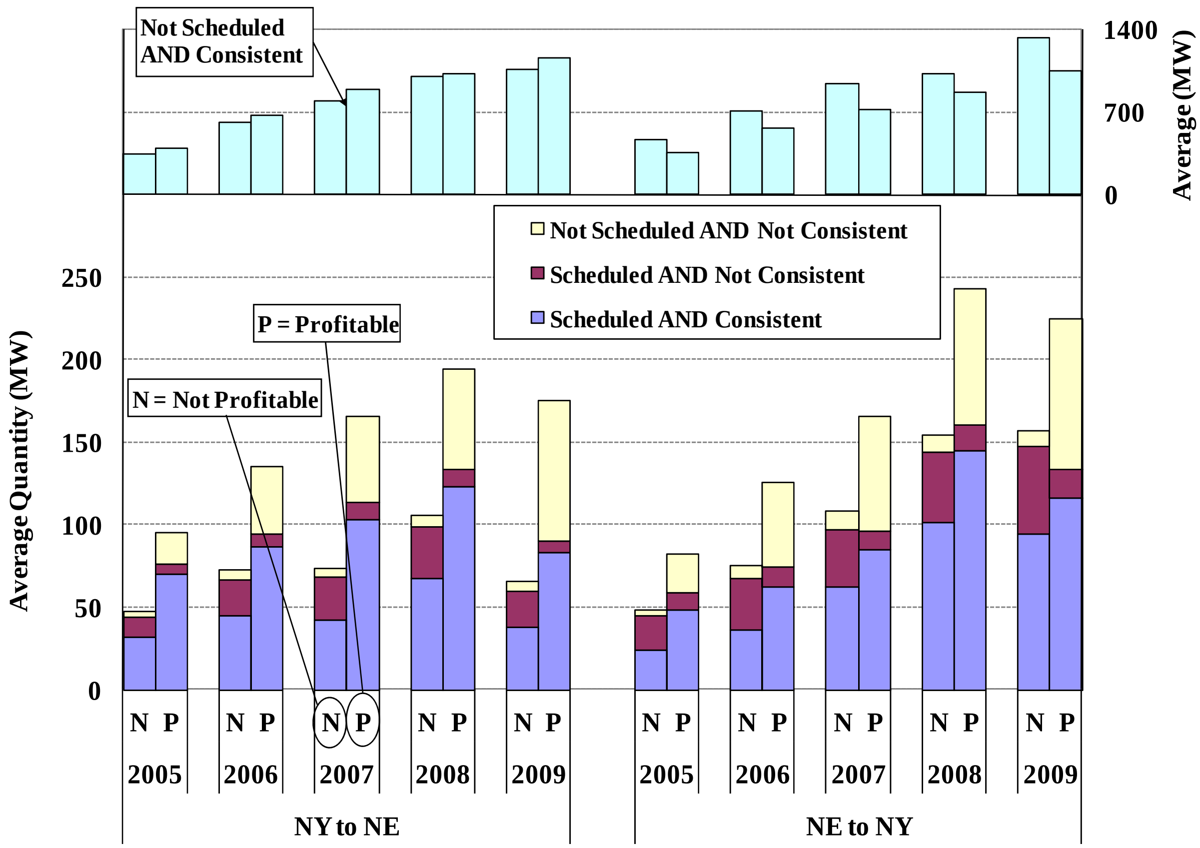


Figure 41 shows the volume of price-sensitive transactions over the primary interface between New York and New England rose gradually from 2005 to 2009. The average volume of price-sensitive imports increased roughly 187 percent over the past five years, from 970 MW in 2005 to 2,770 MW in 2009. The average volume of price-sensitive exports increased approximately 180 percent, from 880 MW in 2005 to 2,470 MW in 2009. The increases suggest that market participants have increasingly relied on RTC to determine when it will be economic to schedule transactions between adjacent control areas. However, only a small fraction of price-sensitive offers and bids were scheduled (8 to 12 percent from 2005 to 2009), and the share of price-sensitive offers and bids that were scheduled fell from 2008 to 2009.

In 2009, 77 percent of scheduled transactions were consistent, and 96 percent of offers and bids not scheduled were also consistent. These levels are comparable to results from 2005 to 2008 and are an indication of relatively good performance by RTC.

This analysis shows that imports and exports that were scheduled consistently tend to be profitable, while those scheduled inconsistently tend to be unprofitable. The analysis indicates that 60 percent of transactions that were "scheduled and consistent" were also profitable in 2009 and the remaining 40 percent were unprofitable even though RTC performed well by scheduling these transactions in accordance with real-time LBMPs. Alternatively, 24 percent of transactions that were "scheduled and not consistent" were profitable in 2009, even though RTC performed poorly by scheduling these transactions that were not consistent with real-time LBMPs.

Overall, the analysis suggests that good performance by RTC (i.e., good consistency of RTC with RTD) helps improve the efficiency of external transaction scheduling, but efficient scheduling also depends on the predictability of the differences in real-time prices between New York and neighboring markets. There are several potential means to improve the efficiency of external transaction scheduling by RTC:

- Improve the assumptions that are used in RTC to be more consistent with RTD, including those related to load forecasting and the ramping of generators and transactions.
- Reduce unnecessary volatility in RTD prices. RTD price volatility (which is evaluated later in the next sub-section) reduces the efficiency of external transaction scheduling by RTC. Inefficient transaction scheduling may, in turn, contribute to RTD price volatility.

Although we find that the external transaction scheduling process has functioned reasonably well and that scheduling by market participants tends to improve convergence, significant opportunities remain to improve the interchange between New York and adjacent areas. Accordingly, the NYISO is collaborating with ISO-NE and HQ to improve the use of these interfaces.[42] In the longer-run, collaboration with Ontario and PJM would yield additional

[42] The NYISO's Broader Regional Market report filed on January 12, 2010 in Docket ER08-1281-004 discusses this collaboration.

savings. We estimated the potential benefits that could be gained from improving the efficiency of: (i) the net scheduled interchange between control areas, and (ii) congestion management of flowgates that are affected by scheduling in the other ISO footprint. These are summarized in Section IV.E. Given the potential benefits from improved scheduling, we recommend the NYISO continue working with HQ, ISO-NE, and other adjacent RTOs to improve the efficiency of the net scheduled interchange and congestion management.

B. 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 part of the section evaluates patterns of price volatility in the real-time market.

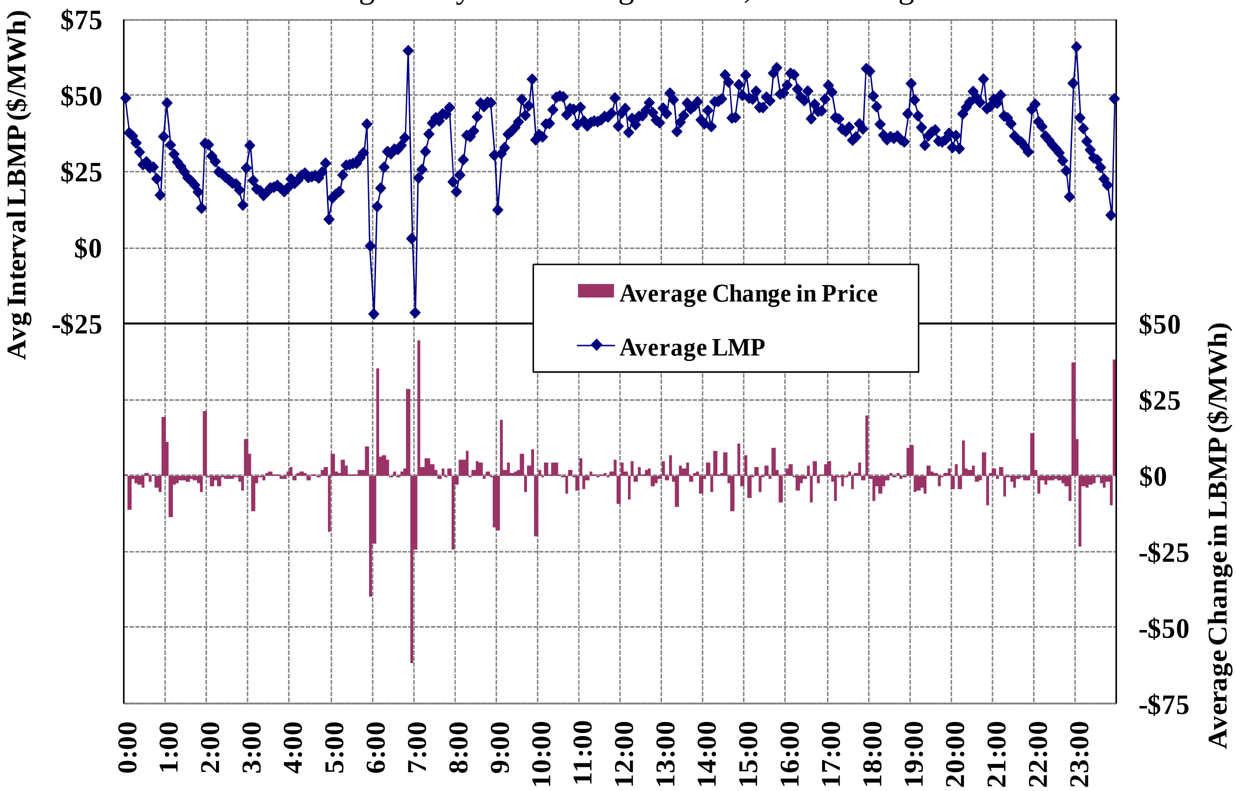
Volatile real-time prices can be an efficient signal of the value of flexible generation. These signals give market participants incentives to invest in making their generators more flexible and to offer that flexibility into the real-time market. However, price volatility can also be a sign of inefficient market operations if generators are being cycled unnecessarily. Real-Time price volatility also raises concerns because it increases risks for market participants, although market participants can hedge this risk by buying and selling in the day-ahead market and/or in the bilateral market. Generally, the ISO should seek ways to reduce unnecessary price volatility while maintaining efficient signals for generators to be flexible in real-time.

The following analysis shows most real-time price fluctuations occur predictably at particular times of the day. Figure 42 shows the average clearing price in each five-minute interval of the day during the summer months of 2009. The data shows the load-weighted average prices for the entire system, although the results are similar in each individual zone.

This figure shows prices were generally more volatile at the top of the hour during ramp-up and ramp-down hours than at other times. In the last interval of the hour, clearing prices dropped substantially in ramp-up hours, and rose substantially in ramp-down hours. The upward and downward price spikes at the top of the hour ranged from approximately $20 per MWh to more than $60 per MWh during ramp-up and ramp-down hours, while most other interval-to-interval price changes were less than $5 per MWh. The upward and downward price spikes in these hours frequently occur when sufficient capacity is online. In such cases, ramp rate limitations prevent generators from responding quickly enough to accommodate changes in conditions.

Figure 42: Average Five-Minute Price by Time of Day

Load-Weighted System Average LBMP, June to August 2009

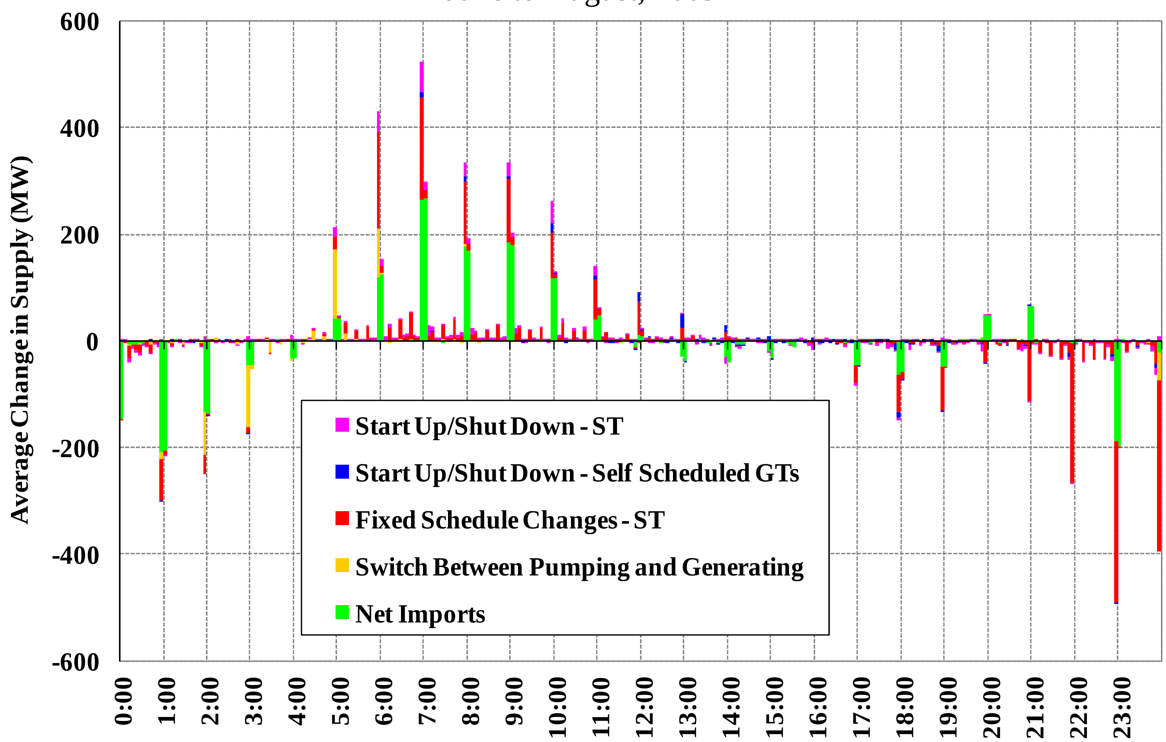


Changes in prices from one interval to the next largely depend on how flexible generators (i.e., generators that can be dispatched by RTD according to their offer) respond to fluctuations in: (i) electricity demand, (ii) net export schedules (which are determined by RTC prior to RTD), (iii) generation schedules of self scheduled and other non-flexible generation, and (iv) transmission congestion patterns. Generally, prices increase as a result of increased load, increased net exports, decreased non-flexible generation, and increased congestion. Large changes in the clearing prices from one interval to the next are normally an indication of substantial fluctuations in at least one of these factors. The next analysis evaluates major factors that may have contributed to the price volatility shown in Figure 43.

Figure 43 shows the average net changes from one interval to the next for the following five categories of inflexible supply:

- Net imports – Net imports normally 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). They can change unexpectedly as a result of curtailments and TLRs before and 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 generators 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 must be accommodated.

Figure 43: Factors Contributing to Real-Time Price Volatility
June to August, 2009



The figure shows adjustments in net imports and adjustments in fixed generation schedules account for the most significant changes in inflexible supply from interval-to-interval. For example, from 6:55 am to 7:00 am, the average net increase in inflexible supply from imports and fixed scheduled units was more than 450 MW, coinciding with a $62 per MWh decrease in real-time clearing prices on average.

High price volatility during the morning and evening ramp periods is likely exacerbated by large changes in inflexible supply around the top of each hour. If inflexible supply changes were distributed more evenly throughout each hour, price volatility would be diminished. Market participants who change their fixed schedules or switch from pumping to generating at the top of the hour would benefit from making such changes mid-hour. For instance, units starting at 6:00 am sold their output at prices averaging from -$20 per MWh to $20 per MWh in the first 15 minutes of operation. For many units, it would have been more profitable to wait until 6:15 am to start or increase output.

In summary, there are several factors that contribute to large price changes at the top of the hour during ramping hours. First, import and export schedules adjust at the top of the hour. Second, generators are committed and decommitted frequently at the top of the hour during ramping hours. Third, non-dispatchable generators typically adjust 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 NYISO performed an analysis in 2009 to evaluate and address factors that contribute to unnecessary real-time price volatility.[43] The NYISO identified several additional factors that contributed to volatility, including:

- Changes in the load forecast during the two hours leading up to each real-time interval; and
- Adjustments in the amount of regulation capacity required by the ISO

[43] Scheduling & Pricing Phase 3 – Ramping Improvements, presented by Michael DeSocio on July 30, 2009 at the Market Issues Working Group meeting.

The NYISO has identified that the following proposed, planned, or on-going projects should help address the causes of unnecessary real-time price volatility. These include:

- Load Forecaster Enhancements – This is intended to correct systematic forecast errors during ramping periods;
- Regulation Requirement Changes – This will reduce the size of changes in the amount of regulation scheduled from one hour to the next;
- Enhanced Storage Optimization – This would improve the modeling of energy-limited generation such as pumped storage units;
- Real-Time Increasing of Bids – This would allow generators facing energy-limitations and/or fuel price changes to offer more flexibly;
- Enhanced Shortage Pricing – This would adjust the regulation demand curve to appropriately price small and/or transient shortages of regulation; and
- Broader Regional Markets initiative – This is likely to reduce real-time price volatility in two ways: (i) scheduling the primary interface with Hydro Quebec every five minutes rather than on an hourly basis will greatly increase the amount of flexible supply in western New York; and (ii) better coordination of external transaction scheduling with neighboring areas should reduce the price spikes resulting from curtailments and TLRs.

C. Market Operations under Shortage Conditions

Prices that occur under shortage conditions are an important contributor to efficient long-term price signals. Under shortage conditions, prices should encourage generators to help satisfy the reliability needs of the system. 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. This section evaluates the operation of the market and resulting prices when the system is in shortage.

Efficient real-time pricing is important during the three types of shortage conditions:

- Operating reserve shortages – This sub-section first evaluates the consistency between real-time reserve prices and the availability of 10-minute reserves in Eastern New York.
- Transmission constraint violations – We also discuss market operations during periods when the transmission limits are exceeded by schedules in the real-time market.
- Demand response activations – There were no activations of demand response for reliability in 2009. The NYISO's demand response programs are evaluated in Section VIII.A.

The importance of setting efficient real-time price signals during shortages of operating reserves has been well recognized. Currently, there are two provisions in the NYISO's market design that facilitate shortage pricing, which serve as a model for other ISOs. First, the NYISO uses operating reserve demand curves to set real-time clearing prices during operating reserves shortages. Second, the NYISO allows demand response resources to set clearing prices when an operating reserve shortage is avoided by the activation of demand response.

1. Real-Time Pricing During Operating Reserve Shortages

The NYISO's approach to efficient pricing during operating reserve shortages uses operating reserve 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 reserves 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 reserves. This subsection evaluates the performance of the market and the resulting prices under shortage conditions.

In addition to co-optimizing the scheduling of energy and ancillary services, the NYISO uses a technique called "Hybrid Pricing" to address the problems posed by gas turbines in a marginal cost pricing market. While gas turbines can be started quickly, they are inflexible in the variable operating range. This creates challenges for pricing energy efficiently when the gas turbines are the marginal source of supply, particularly in New York City. Gas turbines account for 28 percent of the dispatchable capacity in New York City and 42 percent of the dispatchable capacity in the 138 kV load pocket in New York City. Thus, Hybrid Pricing is particularly important for setting efficient price signals in constrained areas.[44]

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[44] Hybrid Pricing consists of a physical dispatch, which governs the physical deployment of resources, and a pricing dispatch, which determines the prices of energy and ancillary services. The physical dispatch treats online gas turbines as inflexible resources, which are blocked at their maximum output level. The pricing dispatch treats them as flexible from zero to maximum. For example, if the two most expensive on-line resources are a steam unit and a more expensive gas turbine, the steam unit is the most expensive unit that can be backed down in the physical dispatch so the steam unit is the marginal resource. If clearing prices were based on the incremental cost of the steam unit, the price would be lower than the costs of the gas

Hybrid Pricing works by treating gas turbines as inflexible resources when determining physical dispatch instructions and as flexible resources when determining clearing prices. While this facilitates marginal cost pricing when gas turbines are deployed in-merit order, it results in certain inconsistencies between the physical dispatch and the pricing dispatch. A key market design objective is that unnecessary inconsistencies be limited such that:

- Clearing prices reflect scarcity under physical shortage conditions, and
- Shortage prices are only set when the system is physically in shortage of either energy or ancillary services.

Our initial assessment of the NYISO's shortage pricing indicated a number of instances after the implementation of the operating reserve demand curves in February 2005 when excessive inconsistencies undermined this objective and led to inaccurate shortage pricing.[45]

In response to these findings, the NYISO made several improvements to the market software to address the unnecessary inconsistencies between the physical dispatch and pricing dispatch. These improvements led to more accurate shortage pricing from 2006 to 2008.[46] The analyses in this section continue to evaluate the accuracy of the NYISO's shortage pricing in 2009.

The first analysis in this section assesses whether shortage prices have only been set when the system was physically short of a key reserves requirement. Figure 44 below shows the amount of Eastern New York 10-minute reserves that were physically scheduled during shortage pricing intervals in 2009. The real-time software maintains 1,000 MW of 10-minute reserves in the Eastern New York up to a marginal cost of $500 per MWh.

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turbine. Hence, the pricing dispatch treats the gas turbine as capable of backing down, which allows it to be the marginal resource and set the clearing price. In this case, the steam unit has a higher output level in the pricing dispatch than in the physical dispatch, while the gas turbine has a correspondingly lower output level in the pricing dispatch than in the physical dispatch.

45 For example, see 2005 State of the Market Report, New York ISO, August 2006, Potomac Economics.

46 See 2006 State of the Market Report, New York ISO, July 2007, Potomac Economics; 2007 State of the Market Report, New York ISO, August 2008, Potomac Economics; and 2008 State of the Market Report, New York ISO, August 2009, Potomac Economics.

Figure 44: Scheduling of 10-Minute Reserves in Eastern New York
During Shortage Pricing Intervals, 2009

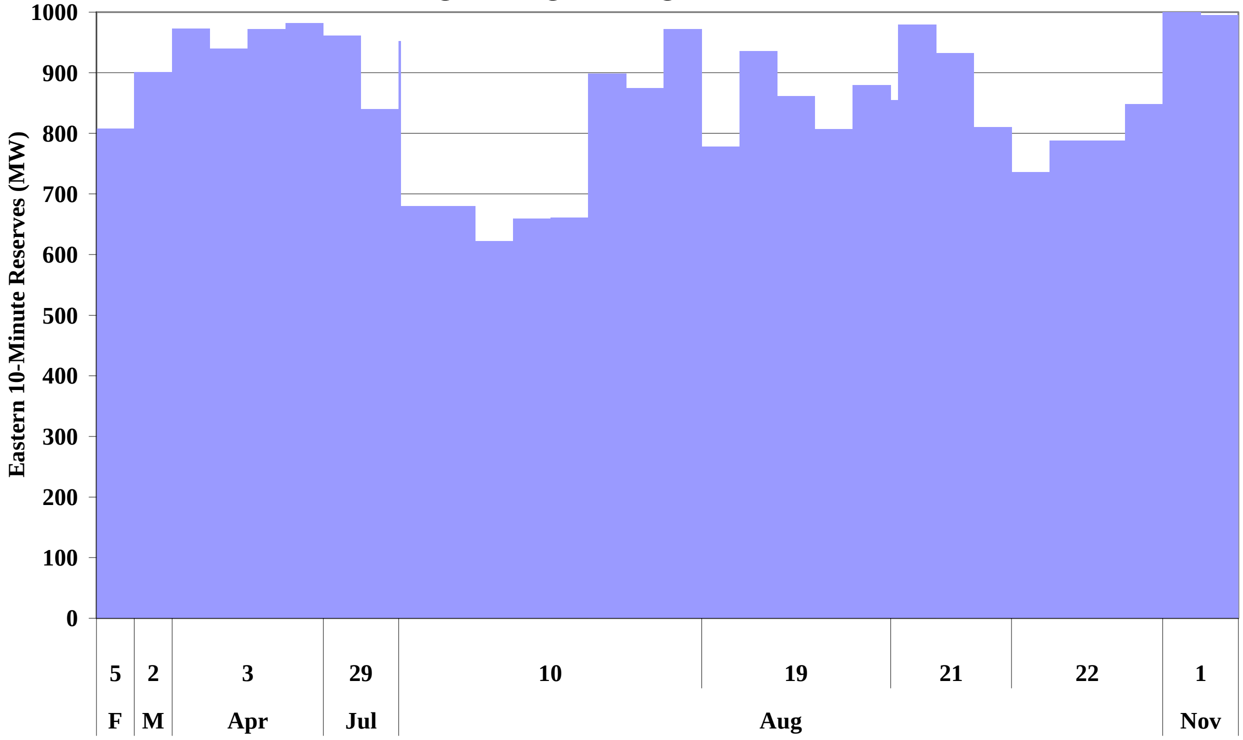

Figure 44 shows 31 intervals with shortage pricing of Eastern 10-minute reserves, which is a substantial decline from 181 such intervals in 2008 and 219 such intervals in 2007. The reduction was likely due to two factors. First, an enhancement was made to the ramp rate constraints of generators not following dispatch in March 2009. This has improved the recognition by RTC of impending shortages, enabling them to schedule resources needed to avoid the shortages.[47] Second, mild load conditions in 2009 reduced the frequency of tight operating conditions, contributing to the decline in shortage intervals. The figure also shows that Eastern New York was in a physical shortage in all of the 31 intervals during 2009. Therefore, the shortage pricing was accurate because all of these intervals occurred during authentic periods of physical shortage in 2009.

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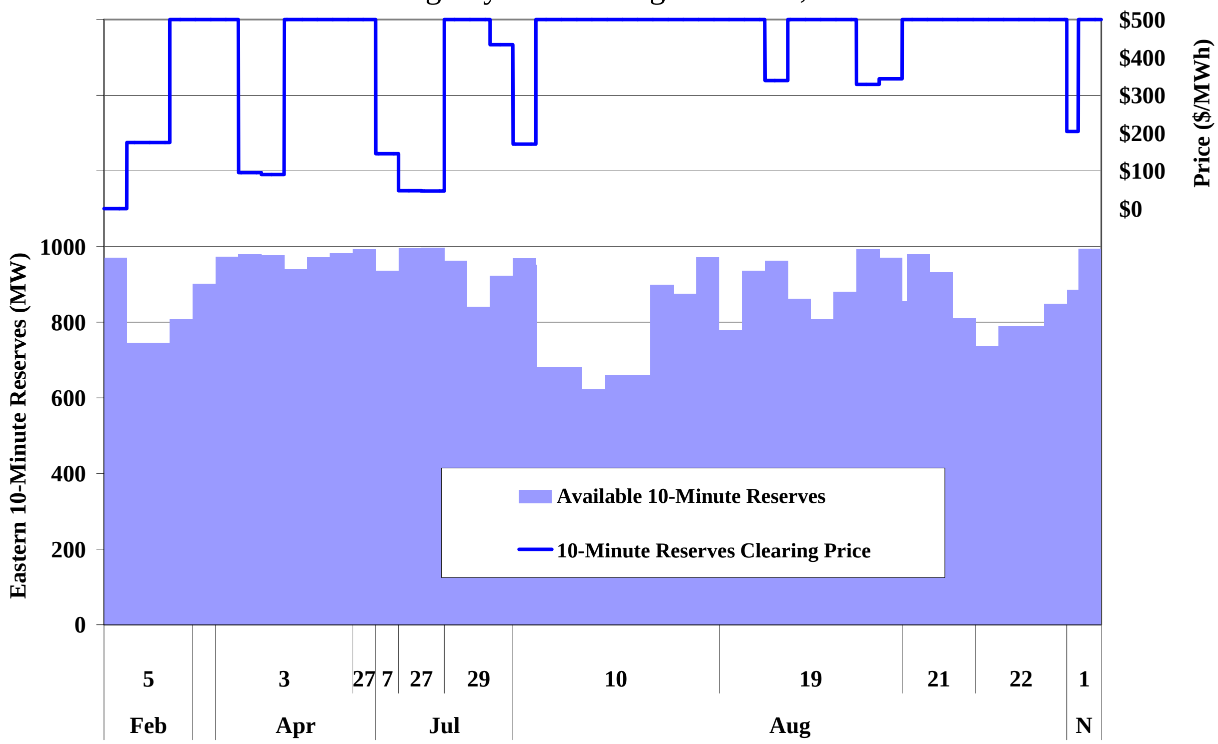
47 Ramp rate constraints are formulated differently in the physical dispatch and the pricing dispatch. The physical dispatch constrains the instructed output level of each resource according to its ramp rate offer relative to its actual output level. Prior to March 2009, the pricing dispatch constrained the output level of each resource according to its ramp rate offer relative to its output level in the previous RTD interval's pricing dispatch without considering the unit's actual output level. Since March 2009, the pricing dispatch also takes into consideration the amount by which a units is under or over-generating.

The previous figure examines shortage pricing intervals to determine how frequently they occurred during physical shortages, while the next figure examines physical shortages intervals to determine how frequently they were accompanied by shortage prices. Figure 45 shows the real-time price and the quantity of available Eastern 10-minute reserves during physical shortages of Eastern 10-minute reserves. In the figure, the line indicates the Eastern 10-minute reserve clearing prices, while the area shows the quantity of available reserves.

Figure 45: Scheduling and Pricing of 10-Minute Reserves in Eastern New York
During Physical Shortage Intervals, 2009



Note: Eastern 10-Minute Non-Spin prices exceeding $500 per MWh are shown as $500 in the figure.

Figure 45 shows 14 out of 45 intervals (or 31 percent) with physical shortages were not accompanied by shortage pricing in 2009. This percentage is comparable to the 32 percent level observed in 2008. During these intervals in 2009, the Eastern 10-minute reserve prices averaged $204 per MWh and the shortage quantities averaged only 50 MW. These shortage periods were brief, lasting for just one or two consecutive intervals. Consistency between the pricing dispatch and the physical dispatch is typically better during shortages of longer duration. Hence, it is notable that the share of intervals exhibiting shortage pricing did not decrease even though the average duration of physical shortages was substantially shorter in 2009. Overall, these results indicate that the consistency between the pricing dispatch and the physical dispatch passes of RTD during Eastern 10-minute reserve shortage periods improved from 2008 to 2009. The improvement in the performance of the real-time model is likely due to the enhancement described below.

Some differences between the pricing dispatch pass and the physical dispatch pass of RTD are necessary for the Hybrid Pricing methodology to work as intended. Ideally, these differences should be limited to those that are needed to allow gas turbines to set energy prices in the real-time market. Other differences should be minimized because they may lead to inefficient real-time energy prices and increased uplift under certain circumstances. In March 2009, NYISO made enhancements to RTD and RTC to reduce divergences between the physical dispatch and pricing dispatch that are caused by units not following dispatch instructions. This has led to (i) more efficient pricing of energy and ancillary services (particularly during shortages), and (ii) fewer physical shortages because are better able to schedule resources needed to avoid a shortage. .

2. Real Time Pricing During Transmission Scarcity

Real-Time transmission price spikes occur when the re-dispatch costs necessary to resolve a transmission constraint reach extremely high levels. The shadow price of a transmission constraint indicates the marginal cost to the system of resolving the constraint. High transmission constraint shadow prices contribute significantly to the severity of real-time energy and reserves price spikes, and to balancing congestion shortfalls which are recovered through uplift charges.

Shadow prices of transmission constraints can spike to extraordinary levels for brief periods when there is not sufficient ramp capability within a transmission-constrained area. When only remote generators are available to be re-dispatched, large amounts of generation may be re-dispatched at a high cost, providing very little relief of the transmission constraint. Relieving the transmission constraint by re-dispatching hundreds of MW may cause shortages of operating reserves or exacerbate shortages of transmission capability on other interfaces. Hence, the actions taken to maintain reliability by resolving a transmission constraint may actually undermine reliability.

Depending on the reason the transmission limit, it may be possible to safely violate the limit for a period of time without a significant degradation of reliability. In such cases, it is beneficial to avoid extremely costly re-dispatch by imposing a ceiling on the re-dispatch costs that can be incurred to manage the transmission constraint. The NYISO limits transmission constraint re-dispatch costs to a maximum of $4,000 per MWh to avoid problems that would arise from incurring extraordinary re-dispatch costs.

Extreme transmission shortages are infrequent, however, it is important for wholesale markets to set efficient prices that reflect the acute operating conditions during such periods. Efficient prices provide generation and demand response resources incentives to respond to maintain reliability. Efficient prices also provide signals that attract new investment when and where needed. The imposition of the shadow cost limit generally improves the efficiency of the dispatch and prices during periods of extreme transmission scarcity. Nonetheless, we will continue to evaluate the efficiency of congestion management and pricing under this methodology, including the appropriateness of the $4,000 per MWh limit.

D. Uplift and Supplemental Commitment

When the wholesale market does not meet all forecasted load and reliability requirements, the NYISO or individual transmission owners commit additional resources to ensure sufficient resources will be available in real-time. Such commitments generate expenses that are uplifted to the market and increase the amount of supply available in real-time, depressing real-time market prices and leading to additional uplift. Hence, out-of-market commitment tends to undermine market incentives for meeting reliability requirements, so it is important for supplemental commitments 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. First, we examine the primary forms of supplemental commitments for reliability. Second, we summarize uplift charges that result from guarantee payments received by generators, which are primarily caused by supplemental commitments for local reliability.

1. Supplemental Commitment for Reliability

Supplemental commitment occurs when a generator is not committed economically in the day-ahead market but is needed for reliability. Supplemental commitment primarily occurs in three ways:

- 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;
- Day-Ahead Local Reliability Rule ("LRR") commitment that takes place during the economic commitment within the day-ahead market process; and
- The Supplemental Resource Evaluation ("SRE") commitment, which occurs after the day-ahead market closes.

Generators that are committed for reliability are generally not economic at prevailing market prices. They affect the market by: (i) reducing LBMPs from levels that would result from a purely economic dispatch; and (ii) 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.

In February 2009, the NYISO made enhancements to improve the efficiency of reliability commitments, which: (i) allow transmission owners to commit units prior to economic commitment of SCUC (i.e., DARU), so that SRE commitments are generally not needed unless there is a change in operating conditions after the day-ahead market; and (ii) commit units for New York City LRR constraints within the economic commitment of SCUC, rather than afterward. To the extent LRR constraints in SCUC reflect the reliability requirements in New York City, the local transmission owner does not need to make DARU and SRE commitments. LRR commitments are generally more efficient than DARU and SRE commitments, which are selected without considering of the economic factors evaluated in SCUC.

Due to the price-effects of out-of-merit capacity, it is important to evaluate the reliability commitment process. Figure 46 shows the quarterly quantities of capacity committed for reliability by type of commitment and region in 2008 and 2009. Four types of commitments are shown in the figure: DARU, LRR, SRE, and FCT. The first three are primarily for local reliability needs. The last category, FCT, represents the additional commitment in the forecast pass of SCUC, which occurs after the economic pass. The forecast pass ensures sufficient physical resources are committed in the day-ahead market to meet forecasted load.

Figure 46: Supplemental Commitment for Reliability
by Category and Region, 2008 – 2009

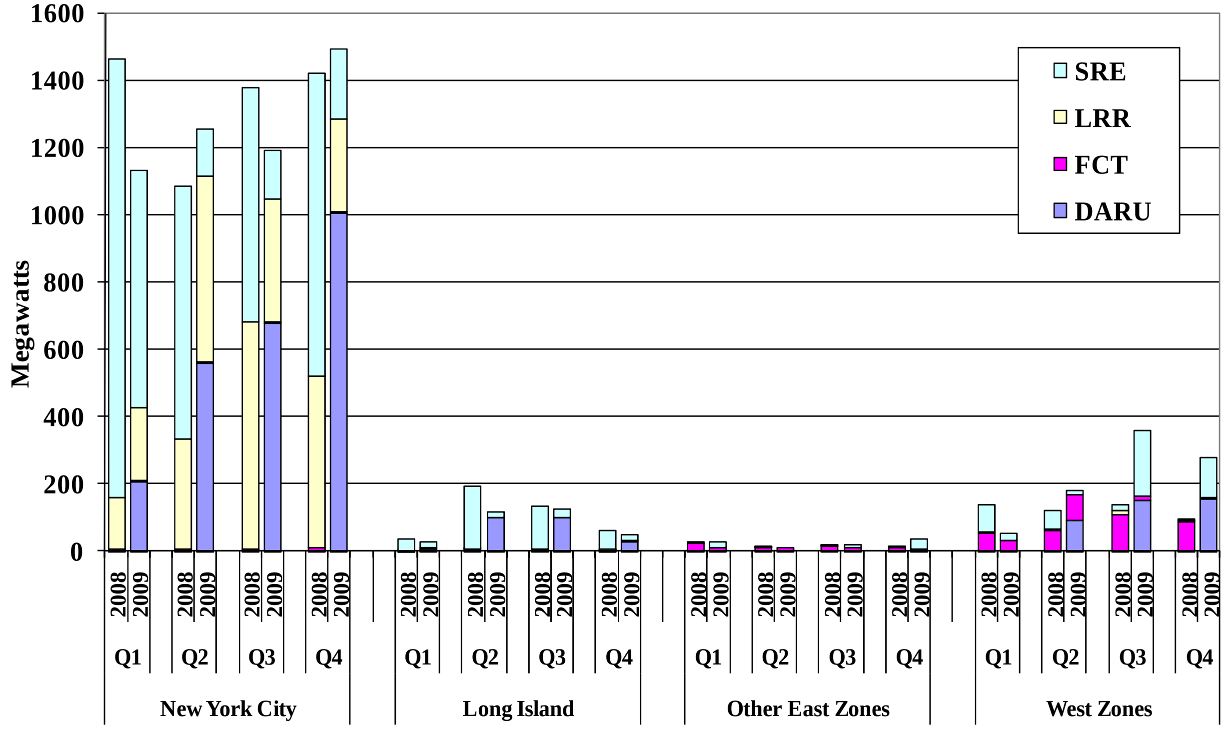


Figure 46 indicates that more than 1,500 MW of capacity was committed on average for reliability in 2009. Of this total, 80 percent of reliability commitment was in New York City, 14 percent was in western New York, and 5 percent was in Long Island. The amount of reliability commitment fell 7 percent in New York City and Long Island from 2008 to 2009. SRE quantities fell the most (700 MW on average), since most local reliability commitment now occurs in the day-ahead market (i.e., DARU & LRR commitments).

Reliability commitments rose 100 MW on average in West New York in 2009 primarily because:

- SRE commitments for bulk power system reliability began to occur more frequently in 2009, which had not been necessary for several years; and
- Several other units were more frequently committed for local reliability due, in part, to transmission outages and changes in commitment patterns resulting from lower natural gas prices.

It is also notable that commitments for forecasted load decreased 50 percent from 2008 to 2009. This is primarily because the local reliability commitment is now done in the day-ahead market (i.e., DARU and LRR) prior to the commitment for forecasted load. In many cases, local reliability commitments have the effect of satisfying reliability requirements that are evaluated in the forecast pass, thereby reducing the need to commit generation in the forecast pass.

2. Uplift Charges from Guarantee Payments

The analysis presented in the following figure shows the magnitude of uplift charges for six categories of guarantee payments in the past three years. These charges accrue from the operation of individual generators for local reliability and non-local reliability reasons in both the day-ahead and real-time markets. Local reliability uplift is are allocated to a particular load serving entity, while non-local reliability uplift is are allocated to loads throughout New York.

There are three categories of local reliability guarantee payment uplift.

i. 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.

ii. Real-Time Market – Guarantee payments are made to generators committed and re-dispatched 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.

iii. Minimum Oil Burn Program – Guarantee payments are made to generators that burn fuel oil to help maintain reliability in New York City due to potential natural gas supply disruptions.

There are three categories of non-local reliability guarantee payment uplift.

i. 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 sum of their as-bid costs (includes start-up, minimum generation, and incremental costs).[48]

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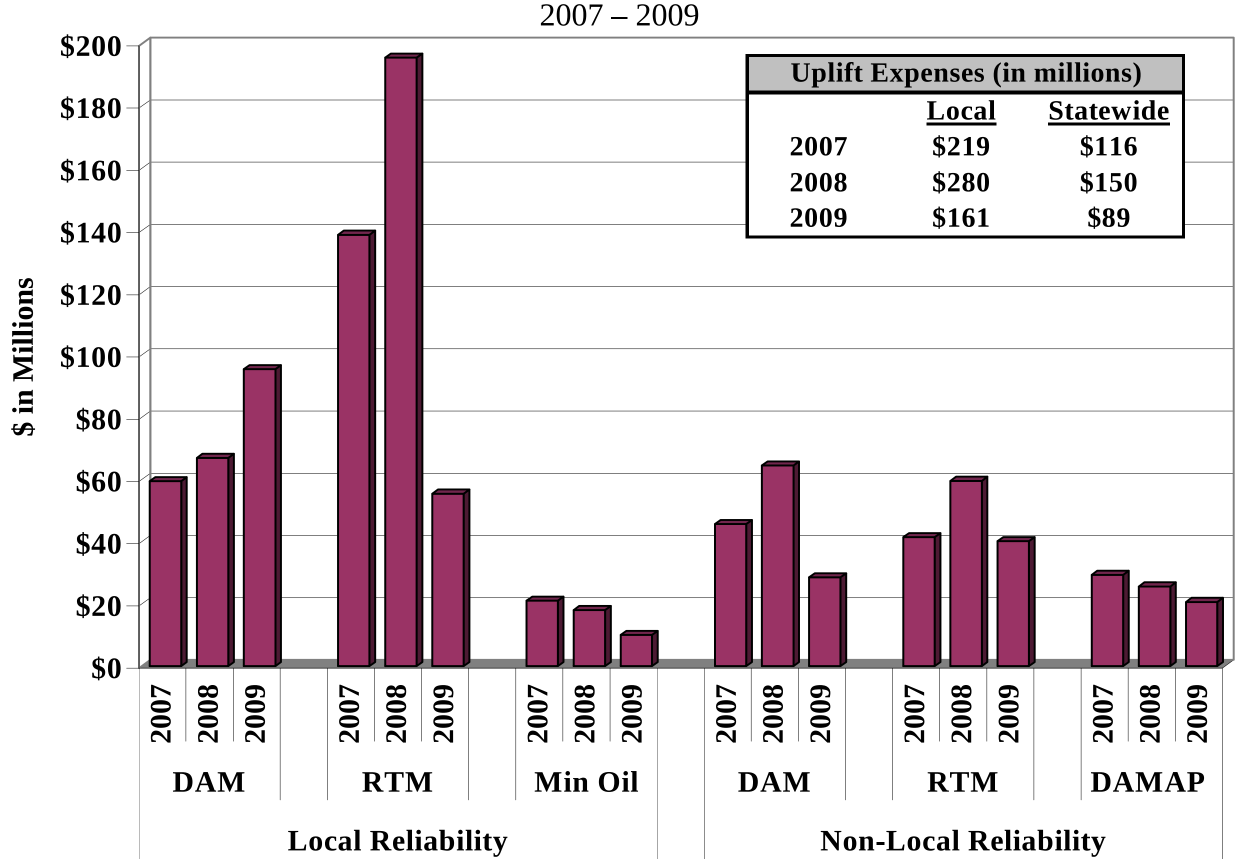
[48] When a DARU unit is committed by the NYISO for statewide reliability, the resulting guarantee payments are uplifted statewide. However, these account for a very small portion of DARU capacity.

ii. 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, and b) imports that are scheduled with an offer price greater than the real-time LBMP.

iii. Day-Ahead Margin Assurance – These payments are made to generators compelled to buy out of a day-ahead schedule in a manner that reduces their day-ahead margin.[49]

These six categories of uplift costs are shown in Figure 47 below for 2007 to 2009. The figure shows that total uplift fell sharply in 2009, from $430 million in 2008 to $250 million in 2009. This reduction was comprised of a reduction in local reliability uplift of almost $120 million and a reduction in statewide uplift charges of more than $60 Million.

Figure 47: Uplift Expenses from Guarantee Payments
2007 – 2009



49 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 sharp reduction in uplift charges from 2008 to 2009 was attributable to two main factors. First, fuel prices fell substantially in 2009. From 2008 to 2009, average natural gas prices fell 52 percent, average diesel fuel oil prices fell 42 percent, average residual fuel oil prices fell 32 percent, and average coal prices fell 52 percent. The reduction in fuel prices generally reduces the payments needed to ensure a generator covers its costs.

Second, the NYISO made changes in the processes for committing generators for reliability in the day-ahead market, which allow transmission owners to commit units for local reliability needs before the day-ahead market runs. This led to more efficient commitment overall and less uplift charges. This change caused the share of local reliability uplift associated with the real-time market to decrease from 70 percent in 2008 to 34 percent in 2009, and also explains the corresponding increase in day-ahead local reliability uplift.

As discussed earlier, more frequent SRE commitments in the upstate for bulk power system reliability occurred in 2009, which partly offset the reduction in uplift charges.

E. Market Operations – Conclusions and Recommendations

The NYISO has the difficult task of operating day-ahead and real-time markets while maintaining reliability on the transmission system. For this reason, the NYISO's markets are designed to give market participants strong incentives to help satisfy the reliability needs of the system, particularly under shortage conditions. This sub-section summarizes the conclusions and recommendations from our evaluation of market operations in 2009.

In this section, we evaluate the efficiency of gas turbine commitment and the efficiency of external transaction scheduling. These are important because excess commitment or net imports result in depressed real-time prices and higher uplift costs, while under-commitment and inefficiently low net imports lead to unnecessary price spikes. In our evaluation of gas turbine commitment, we find the majority of capacity committed in 2009 was clearly economic. The commitment of newer vintage low-cost gas turbines was more economic than the commitment of older vintage high-cost gas turbines.

In our evaluation of external transaction scheduling, we find that the volume of price-sensitive bids and offers submitted for real-time scheduling increased more than 180 percent from 2005 to 2009, indicating that market participants increasingly prefer to rely on RTC to determine when it will be economic to schedule power between control areas. In 2009, we found that a high portion of price-sensitive import offers and export bids (77 percent) were scheduled consistent with real-time prices at the primary interface with New England. Nonetheless, significant improvement is possible from increased coordination between the NYISO and adjacent systems. These potential improvements are discussed further in Section IV.E.

Clearing prices are volatile in the real-time market, particularly at the top of the hour during the morning and evening ramp-up and ramp-down periods. Although price volatility can be an efficient signal of the value of flexible resources, unnecessary volatility imposes excessive costs on market participants. We discuss several factors that have been identified that likely contribute to the volatility of real-time prices. We recommend that the NYISO move forward with six proposed, planned, and on-going market and operational enhancements that should help reduce unnecessary price volatility. These are listed in Section VI.B.

Prices that occur under shortage conditions are an important contributor to efficient long-term price signals. Accordingly, the NYISO's markets are designed to produce efficient clearing prices under the following types of shortage conditions: (i) operating reserve shortages, (ii) transmission constraint violations, and (iii) emergency demand response activations. We find that reserve shortage pricing occurred in 69 percent of the periods with physical shortages of Eastern 10-minute reserves in 2009.

To improve real-time pricing during periods with operating reserve shortages, the NYISO modified the treatment of ramp limitations in the real-time market's pricing model for units that are not responding to dispatch signals in March 2009. The enhancement has led to more efficient pricing of energy and ancillary services (particularly during shortages). The enhancement also has resulted in fewer physical shortages because RTD and RTC are more likely to start gas turbines or ramp-up slow moving generation in anticipation of a shortage. However, the NYISO should continue to seek means to improve the accuracy of its shortage pricing.

When insufficient capacity is available to serve demand and satisfy the reliability requirements of the NYISO and local transmission owners, additional capacity is committed out-of-merit. These commitments have significant market effects, which include reducing prices in the day-ahead and real-time markets and increasing uplift charges from guarantee payments to generators that do not fully recoup their operating costs from the day-ahead or real-time market. When this occurs in a constrained area, it inefficiently dampens the apparent congestion into the area. Hence, it is important to monitor and evaluate these commitments.

In 2009, $161 million was paid for local reliability uplift and $89 million was paid for non-local reliability uplift, which are sharply lower than uplift levels in 2008. To minimize the negative effects of local reliability requirements on the overall market, it is important to satisfy the reliability requirements as efficiently as possible. In February 2009, the NYISO implemented a new process for committing units for local reliability that has helped to reduce the market inefficiencies of maintaining local reliability. The new process integrates most commitments for local reliability into the economic pass of the day-ahead market model, leading to improved efficiency of the economic commitments and reliability commitments and reduced uplift charges.

VII. 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, discuss the issues arise from the new deliverability test, and recommend changes to improve the efficiency of the market.

A. Background

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.[50] 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.[51] Since the NYISO operates an Unforced Capacity ("UCAP") market, the ICAP requirements are translated into UCAP requirements, using location-wide availability rates.[52] The obligations to satisfy the UCAP requirements are allocated to the LSEs in proportion to their annual peak load in each area.

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[50] The ICAP requirement = (1 + IRM) * Load Forecast. For the period from May 2008 to April 2009, the IRM was set to 15 percent. For the period from May 2009 to April 2010, the IRM was increased to 16.5 percent.

[51] The locational ICAP requirement = LCR * Load Forecast for the location. The Long Island LCR was 94 percent for the period from May 2008 to April 2009, and rose to 97.5 percent for the period from May 2009 to April 2010. The New York City LCR was set to 80 percent for all periods from May 2008 to April 2010.

[52] Capacity payments are made for UCAP, which 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 of seven 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

LSEs can satisfy their UCAP requirements by contracting for capacity bilaterally, by self-scheduling, or by purchasing in the NYISO-run auctions. 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 location in each spot auction. The amount of UCAP purchased is determined by the intersection of UCAP supply offers and the demand curve. Hence, the spot auction may purchase more than 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.[53]

B. Capacity Market Results

To evaluate the performance of the capacity market, the following three figures show capacity market results from May 2008 through February 2010. This includes four six-month capability periods from the Summer 2008 Capability period through the Winter 2009-10 Capability period (excluding March and April 2010). These figures show the sources of UCAP supply and the

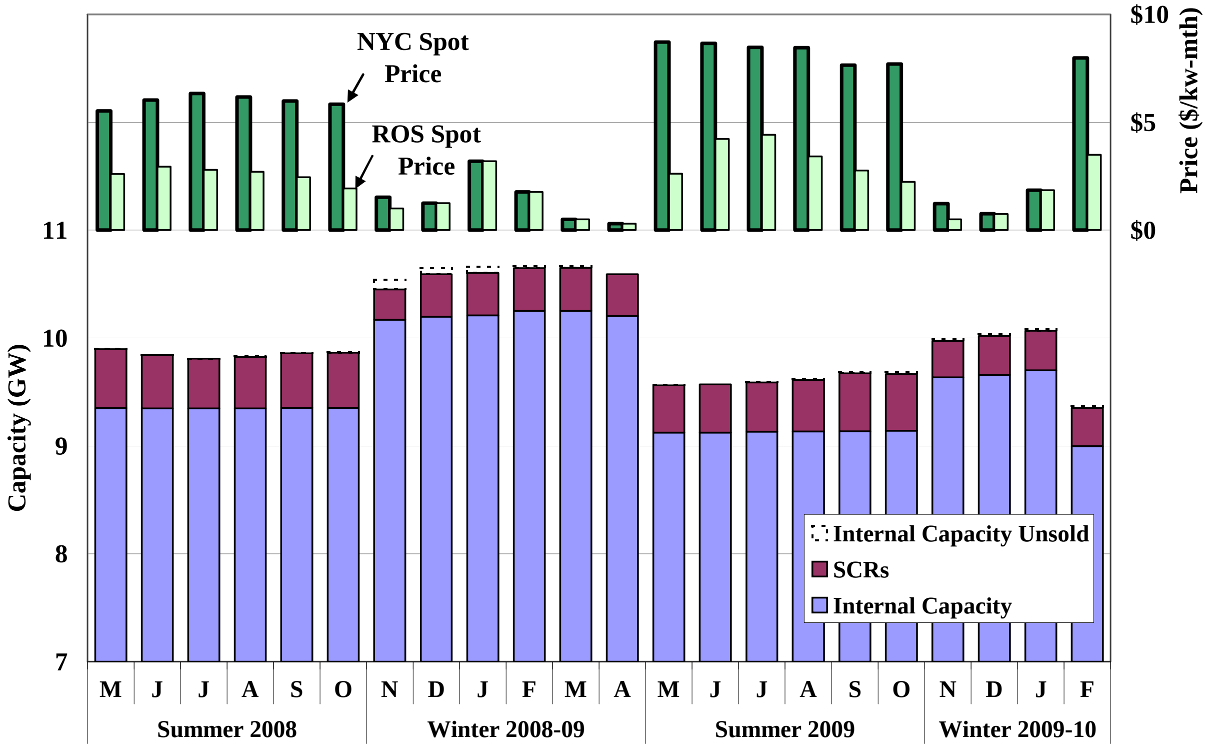
load hours, and SCR's availability rates are based on the performance during tests and events.

53 The demand curves also have maximum price levels which apply when UCAP procured falls substantially below the UCAP requirement.

quantities purchased in each month. They also summarize the clearing prices in the monthly spot auctions.

Figure 48 shows the amount of resources in New York City available to provide UCAP, the amounts actually scheduled, and the UCAP prices that cleared in the spot auctions for New York City and for Rest of State ("ROS").

Figure 48: Capacity Market Results for New York City
May 2008 to February 2010



Note: Sales related to Unforced Deliverability Rights ("UDRs") are shown as "Internal Capacity."

Figure 48 shows that virtually all internal capacity has been sold in each month during the period, so withholding of supply has not been a significant concern. Withholding has not been a concern since the NYISO implemented the supply-side market power mitigation measures that have effectively addressed economic withholding in this market.

The figure also shows that significant changes in the clearing prices resulted from seasonal variations in the quantities of capacity offered in New York City. Additional capability was available in the Winter Capability periods due to lower ambient temperatures, resulting in significantly lower prices than in the summer. In six of the ten winter months shown, the New York City price fell to the level of the NYCA price, indicating the local requirement was not binding in these months.

New York City clearing prices in the spot auctions rose from an average of $5.98 per kW-month in the Summer 2008 Capability period to an average of $8.27 per kW-month in the Summer 2009 Capability Period, which was primarily due to:

- An 8 percent increase in the capacity demand curve as determined when the curves were updated for May 2007 to April 2010;
- Modest reductions in the DMNC values of generators and SCRs in New York City;
- A 0.7 percent increase in the peak load forecast for New York City; and
- A reduction in the UCAP supply in New York City caused by higher equivalent forced outage rates for some generators, although the price effect was offset by a corresponding reduction in the UCAP requirement due to the higher overall derating factor.[54]

Finally, capacity prices in New York City rose from $1.85 per kW-month in January 2010 to $7.98 per kW-month in February 2010. The increase was primarily driven by the retirement of the Poletti steam unit in February 2010, which reduced UCAP supply by over 800 MW.

Figure 49 shows the amount of resources in Long Island that are available to provide UCAP, the amounts actually scheduled, and the UCAP prices that cleared in the monthly spot auctions for Long Island and for Rest of State ("ROS").

The local capacity requirement for Long Island was not binding during most of the period, so the Long Island clearing price was equivalent to the ROS clearing price in 19 of the 22 months shown. This reflects that Long Island generally has more capacity than needed to satisfy the local capacity requirement. The Long Island requirement was binding for the three months from May 2009 to July 2009 as UCAP levels were relatively low due to due to an increase in the LCR from 94 percent to 97.5 percent starting May 2009. Capacity levels increased approximately 300

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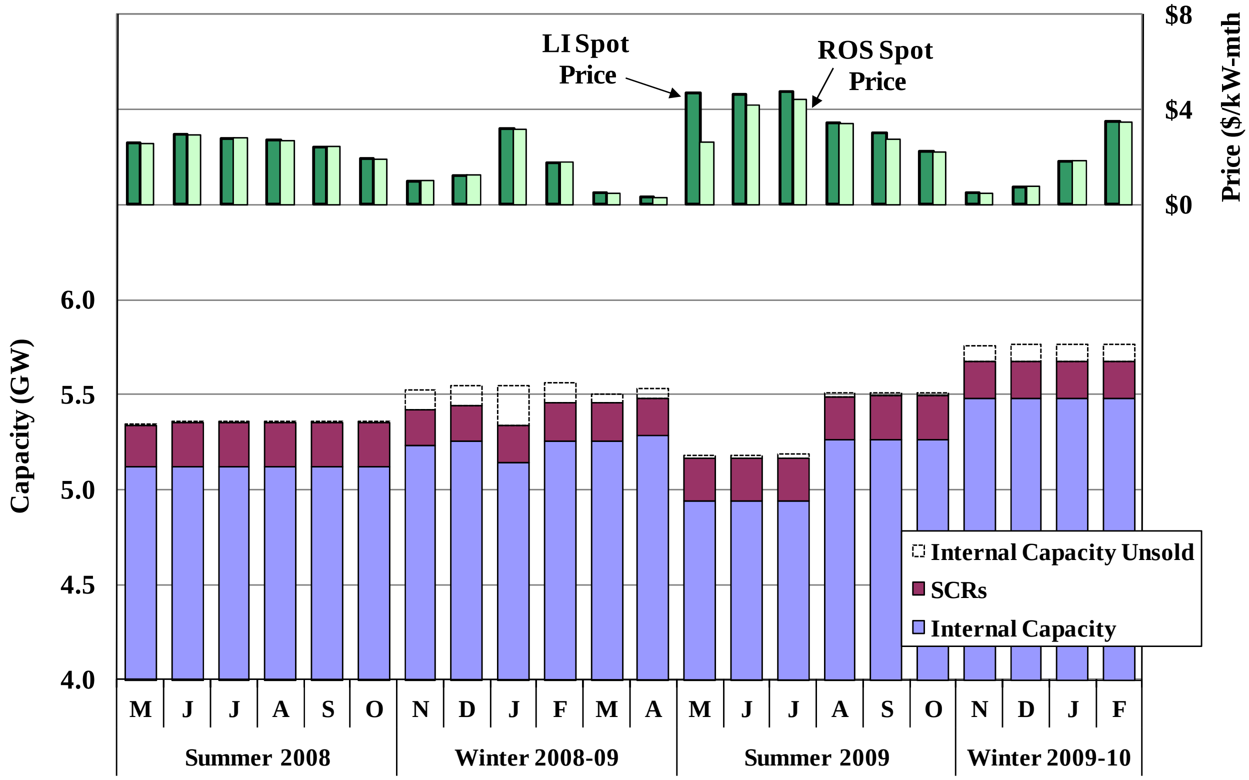
54 The derating factor is used to translate the ICAP requirement to a UCAP requirement. Since the derating factor is based on an average of the equivalent forced outage rates of generators in the area, increases in equivalent forced outage rates lead to reductions in the UCAP requirement.

MW in August 2009 due to the start of operation of the Caithness combined-cycle generation plant.

Figure 49: Capacity Market Results for Long Island
May 2008 to February 2010

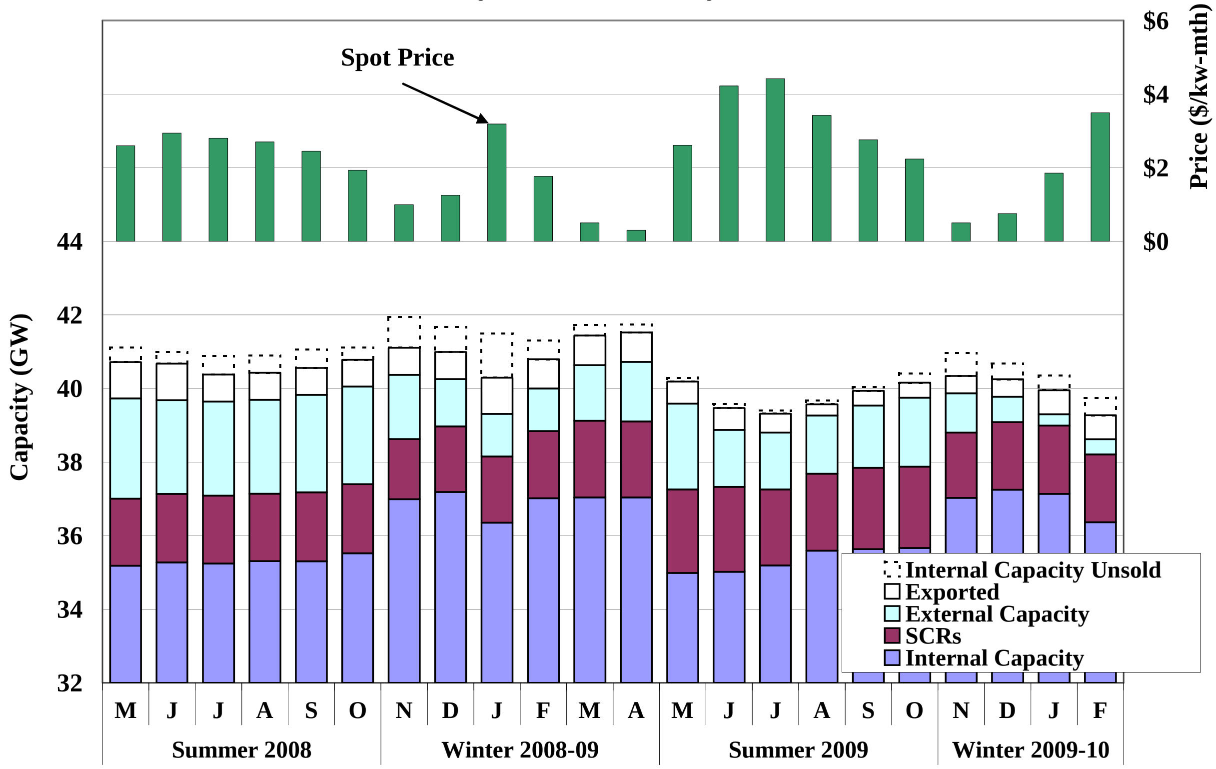


Note: Sales related to Unforced Deliverability Rights ("UDRs") are shown as "Internal Capacity."

Figure 50 shows the resources available to provide UCAP to New York State and the amounts actually scheduled. The bars show the quantities of internal capacity sales, sales from SCRs,[55] sales from external capacity resources into New York, and exports of internal capacity to other control areas. The hollow portion of each bar represents the In-State capacity not sold (including capacity not offered) in New York or in any adjacent market. The figure also shows UCAP spot clearing prices in NYCA (i.e., the price applicable to capacity outside New York City and Long Island).

[55] Special Case Resources ("SCRs") are end-use loads capable of being interrupted upon demand, and distributed generators, both of which must be rated 100 kW or higher and are invisible to the ISO's Market Information System."

Figure 50: Capacity Market Results for NYCA
May 2008 to February 2010



Note: Sales related to Unforced Deliverability Rights (“UDRs”) are shown as “Internal Capacity.”

The figure shows most capacity is supplied by internal generation, although external suppliers and SCRs each provide significant amounts of capacity. Like the local areas, seasonal changes in internal capability between the summer and winter capability periods resulted in higher prices in the summer than in the winter. However, these changes were partly offset by variations in net imports, which were higher during the summer capability period. However, the quantity of net imports declined significantly over the period. In the summer periods, average net imports decreased from 1.8 GW in the summer of 2008 to 1.3 GW in the summer of 2009. In the winter periods, the average net imports decreased from 0.6 GW in the winter of 2008/09 to 0.1 GW in the winter of 2009/10. The decline in net imports was driven primarily by a significant increase in PJM capacity prices beginning in June 2009.

NYCA clearing prices were affected by retirements and new entry during the period. Poletti’s retirement in February 2010 reduced UCAP supply nearly 900 MW, contributing to a $1.64/kW-month increase in the NYCA clearing price.

The amount of unsold capacity briefly rose by over 500 MW in January 2009, contributing to a $1.94/kW-month increase in the NYCA clearing price. We reviewed the factors that led to the increase and they did not raise competitive concerns.

C. Capacity Market Mitigation

In early 2008, new market power mitigation measures were implemented for New York City to address the withholding of capacity by suppliers to raise capacity prices (supplier-side mitigation) and uneconomic investment designed to depress capacity prices (load-side mitigation). As the preceding figures show, very little capacity remains unsold in New York City, which indicates that the supply-side mitigation measure (i.e., an offer cap) has been effective.

The load-side mitigation measure is an offer floor that is intended to deter uneconomic entry by preventing the uneconomic entrant from selling capacity. It is too early to conclude whether the offer floor has been effective, although we have reviewed the detailed thresholds and testing procedures used to implement the offer floor and find that the tariff is ambiguous in some places and raises potential concerns in others. Hence, we recommend that the NYISO review the thresholds and procedures used to implement the offer floor, and identify ones that may cause uneconomic entry to be exempted from the offer floor, or erect an inefficient barrier to economic entry.

D. Capacity Market Configuration

The capacity market provides economic signals to facilitate investment that will allow New York State to meet its planning reserve margin requirements. Transmission constraints limit the ability of the system to deliver supplies from upstate New York to New York City and Long Island, so these areas have local planning requirements. Accordingly, three regions are represented as separate zones in the capacity market: New York City (Zone J), Long Island (Zone K), and Rest-of-State (Zones A to I). By setting a distinct clearing price in each capacity region, the capacity market provides incentives to invest in areas where it is needed.

The NYISO recently implemented a new "deliverability test" to determine when resources in one location cannot be fully delivered to another location in the same zone. The deliverability test has indicated issues related to transmission constraints within the Rest-of-State zone that prevent capacity outside Southeast New York from serving load in Southeast New York. In order to be able to sell capacity in the market, new resources or imports that are deemed undeliverable must either pay to upgrade the transmission network so that they can be fully delivered or acquire deliverability rights from another market participant.[56]

The new deliverability test creates several significant efficiency and competitive concerns. First, it does not provide efficient incentives in constrained areas to invest in supply resources, demand resources, and transmission facilities, and for the maintenance of existing resources. Second, it creates a substantial barrier to entry by competitive new supplies and imports in unconstrained areas, reducing competition in the market. These issues are exacerbated by the fact that the deliverability test is unrealistic and can raise deliverability concerns when transmission capability is sufficient to allow "undeliverable" resources to contribute to satisfying reliability needs statewide. Lastly, it will likely raise capacity costs unnecessarily for New York consumers. The following subsections illustrate and discuss these inefficiencies and explain why it would be far more efficient to address the deliverability problem by creating additional capacity zones.

1. Market Effects from the Deliverability Test

This subsection illustrates the effects of the deliverability test by examining two examples:

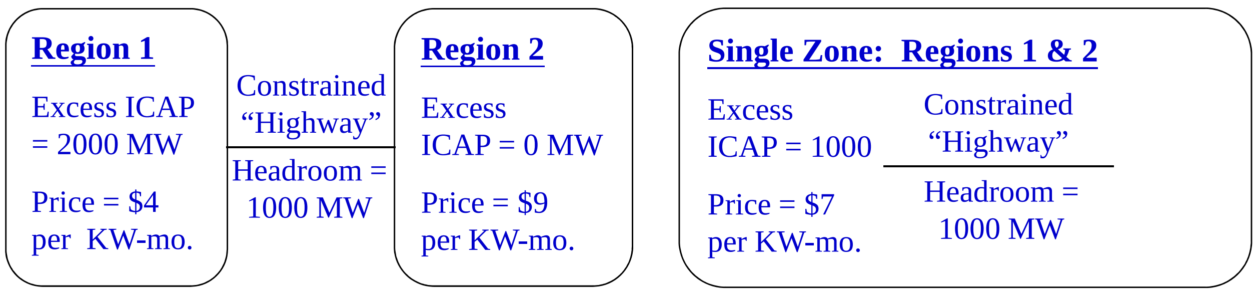
- Example 1 (the multiple zone case) shows how deliverability issues are addressed efficiently in a market with multiple capacity zones.
- Example 2 (the single zone case) shows how deliverability issues can lead to insufficient or inefficient investment in a market with a single capacity zone.

Both examples assume a system where there is 2000 MW of excess capacity. The excess capacity is located in one region, while a second region has 0 MW of excess capacity. To meet

56 The new deliverability test was implemented by the NYISO and used to determine that projects outside Southeast New York were deemed undeliverable, beginning with Class Year 2008 projects and including all future class years. To sell capacity, these suppliers must pay to upgrade transmission into the Hudson Valley at a cost of over $170/kW or acquire rights from existing suppliers.

its reliability needs, the second region relies on 1000 MW of transmission capability to deliver capacity from the first region. The scenario is summarized in Figure 51; Example 1 is shown on the left side and Example 2 is shown on the right side.

Figure 51: Illustration of Deliverability Issues
Multiple Zone and Single Zone Examples



Example 1: Multiple Zones **Example 2: Single Zone**

In Example 1, the price in Region 1 clears at $4/kW-month, which is based on the demand curve for the system and the fact that there is a capacity surplus of 2000 MW in the system. The price in Region 2 clears at $9/kW-month, the level that supports new entry because Region 2 has 0 MW of excess capacity. All of the capacity is deemed deliverable.

In Example 2, 1000 MW of the capacity in Region 1 cannot sell capacity because it is deemed undeliverable. As a result, the price in both regions clears at $7/kW-month, which is based on the demand curve for the system and the fact that there is a capacity surplus of 1000 MW in the system because 1000 MW is undeliverable. The differences in market outcomes shown in the two examples translate to substantially different economic signals and incentives for market participants. The next table uses four cases to show how these changes in market outcomes translate to different investment decisions regarding whether to expand the transmission system and/or build new resources in Region 1 and/or Region 2.

Figure 52 shows how investment decisions are affected by whether an area with transmission bottlenecks is represented as multiple zones or a single zone. Each row of the table summarizes one of the four cases. The two left-most columns summarize the cost assumptions used for each case. The three right-most columns summarize how the investment decisions are affected by whether the area is represented as multiple zones or a single zone.

Figure 52: Incentives Resulting from Capacity Zone Configuration

Four Cases

	Cost Assumptions ($/KW-Mo.)		*Results*		
	Interface Upgrades	**New Resources**	**Zones**	**Expected Outcomes**	**Evaluation**
Case 1	Greater than $5	Region 1: $9 Region 2: $9	Multi-Zone	New resources in Region 2	Efficient
			Single Zone	No investment	Inefficient
Case 2	Greater than $5	Region 1: < $4 Region 2: $9	Multi-Zone	New resources in Region 1	Efficient
			Single Zone	No investment	Inefficient
Case 3	Less than $5	Region 1: $9 Region 2: $9	Multi-Zone	Build transmission	Efficient
			Single Zone	No investment	Inefficient
Case 4	Less than $5	Region 1: < $4 Region 2: $9	Multi-Zone	New resources and transmission in Region 1	Efficient
			Single Zone	Invest if new resources in Region 1 + tx upgrades < $7	Likely Inefficient

In the multi-zone alternatives, each of the four cases results in incentives that would be expected to facilitate efficient investment in new resources and transmission. The locational capacity price accurately reflects the needs and surpluses in each area, providing signals regarding when and where to build transmission and resources. In Case 1 for example, the cost of building new resources is $9/kW-month in Region 1 where the clearing price is $4/kW-month, and the cost of building new resources is $9/kW-month in Region 2 where the clearing price is $9/kW-month. It is economic for new resources to be built in Region 2, which is what occurs in the multi-zone alternative. In contrast, no resources are built in the single zone alternative for Case 1 because the cost of building new resources exceeds the clearing price of $7/kW-month.

In the single-zone alternatives, investors are presented with inefficient incentives and barriers to new investment in transmission and resources, which have several negative implications. First, some new resources and imports in Region 1 are deemed to be undeliverable within a single zone, which raises capacity costs to consumers in Region 1. Second, new investment in Region 2 will only occur when the single zone price rises to the Region 2 net CONE, which imposes unnecessary costs on Region 1. Third, a single zone does not provide the efficient signals to invest in new transmission, while the multi-zone alternative does (see Case 3).

2. Conclusions Regarding Capacity Zone Configuration

The preceding examples illustrate why a determination that new capacity is not deliverable on a "highway" facility should be the primary criteria for determining that a new zone is necessary in the capacity market. Recognizing the problems with the new deliverability test, FERC has required the NYISO to work with its stakeholders to develop and file criteria for defining new capacity zones by fall 2010. Given that the deliverability test shows that new resources cannot be delivered fully to southeast New York, we recommend that the NYISO make preparations to implement a new capacity market zone in parallel with developing the criteria for creating a new zone in 2010. These preparations include developing CONE estimates, demand curves, and other details necessary to implement a new zone(s).

Creating a new capacity zone would be beneficial because it would distinguish the value of capacity in southeast New York from the value of capacity in other areas. This would:

- Allow the capacity market to signal where new capacity would be most beneficial. This may be particularly important in southeast New York where the cost of new entry is likely higher than in other areas.
- Enable more suppliers to sell capacity outside the new zone(s), thereby lowering capacity costs for New York consumers in those areas.

Based on the results of recent Reliability Needs Assessments, additional new capacity is not likely to be needed in southeast New York. Hence, creating the new zone(s) would likely lower overall capacity costs in New York by allowing more supply provide capacity outside of New York City and Long Island without raising costs substantially in southeast New York.

Some have argued that applying the deliverability tests and rules as currently envisioned will encourage transmission investment. However, creating new zones should not reduce the likelihood that investments will be made to upgrade the transmission system when it is economically efficient. If those that invest in new transmission capability between capacity zones have access to the economic property right corresponding to the difference in the capacity prices between the zones, then creating new zones will provide investors in transmission with clear economic signals and incentives to invest efficiently in transmission.

VIII. 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.

The New York ISO operates five demand response programs, which allow retail loads to participate in the New York wholesale market:

- Three programs curtail loads in real-time for reliability reasons with two hours notice:
  - ✓ Emergency Demand Response Program ("EDRP") – These resources are paid the higher of $500 per MWh or the real-time clearing price. These resources are not required to respond.
  - ✓ Special Case Resource ("SCR") program – These resources are paid the higher of their strike price (which can be up to $500 per MWh) or the real-time clearing price. These resources sell capacity in the capacity market, so they are obligated to respond when called.[57]
  - ✓ Targeted Demand Response Program ("TDRP") – This program pays EDRP resources the higher of $500 per MWh or the real-time clearing price and SCR resources the higher of their strike price or the real-time clearing price to respond for reliability reasons at the sub-zone level in New York City. These resources are not required to respond.
- Day-Ahead Demand Response Program ("DADRP") – This program allows curtailable loads to offer into the day-ahead market (with a floor price of $75 per MWh) like any supply resource. If the offer clears in the day-ahead market, the resource must curtail its load in real-time accordingly and it is paid the day-ahead clearing price.
- Demand Side Ancillary Services Program ("DSASP") – This program allows resources to offer regulation and reserves in the day-ahead and real-time markets.

Nevertheless, there remain significant barriers to participation in the wholesale market by loads. The most significant is that most retail loads have no incentive to respond to real-time prices

57 There is an obligation only if the resource is informed on the previous day that it might be needed.

even when they exceed their marginal value of consumption. FERC highlighted this problem in its recent Notice Of Proposed Rulemaking ("NOPR") on demand response.[58] We agree that creating a program to facilitate participation by loads in the real-time market would be beneficial, although it is important that such a program provide efficient incentives to demand response resources.

In this section, we evaluate the demand response programs in New York. In particular, this section discusses the following four areas:

- Participation in the existing demand response programs,
- Efficient real-time pricing when demand response is activated during a shortage,
- Ongoing initiatives to facilitate demand response, and
- Designing an efficient real-time price response load program

A. Demand Response Programs in 2009

Demand response programs provide incentives for retail loads to participate in the wholesale market. Two of the programs, DADRP and DSASP provide a means for economic demand response resources to participate in the day-ahead energy market and ancillary services markets (day-ahead and real-time), respectively. The other three programs, EDRP, SCR, and TDRP, are emergency demand response resources that are called when the NYISO forecasts a reliability issue. Currently, nearly 90 percent of the demand response resources in New York are reliability demand response resources.

This sub-section discusses participation in each of the NYISO's five demand response programs. The first part summarizes participation in the reliability demand response programs, while the second part discusses participation in the economic demand response programs.

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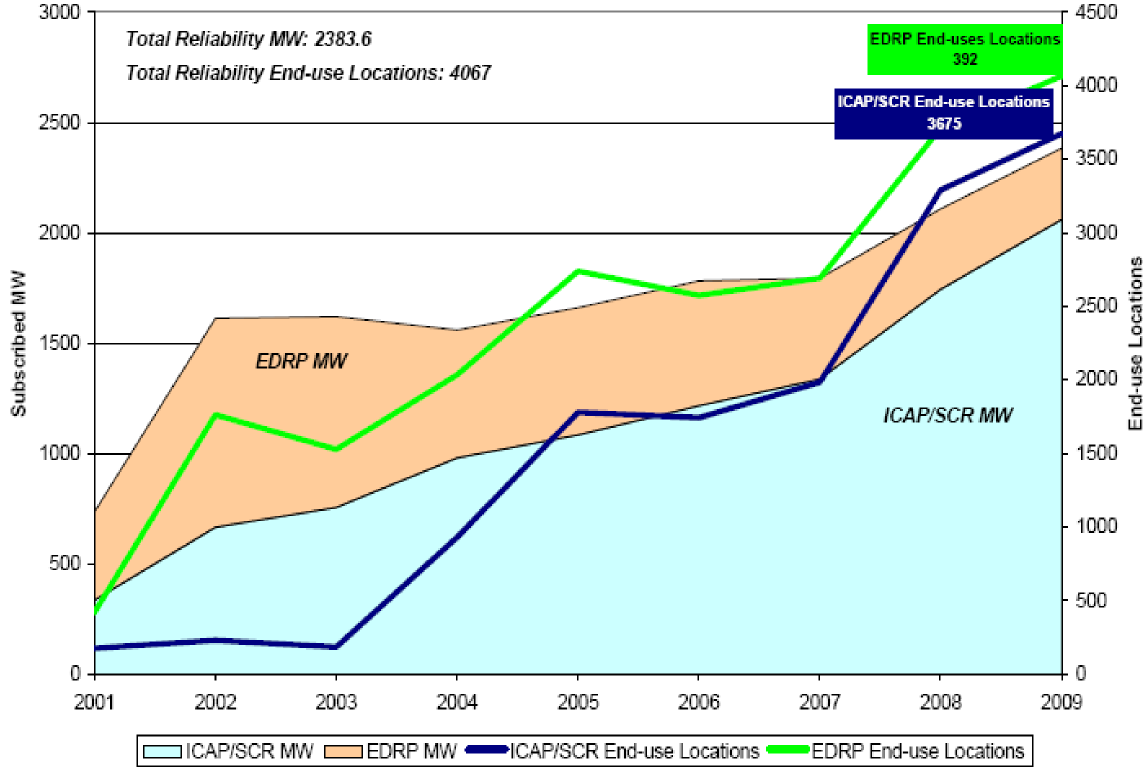
[58] *Demand Response Compensation in Organized Wholesale Energy Markets*, Docket Nos. RM10-17-000 and EL09-68-000, May 18, 2010 (hereinafter, "Demand Response NOPR").

3. Reliability Demand Response Programs

The following figure summarizes registration in two of the reliability programs on an annual basis from 2001 to 2009. 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 53: Registration in NYISO Demand Response Reliability Programs
2001 – 2009



Note: Figure reproduced from the NYISO's January 15, 2010 Demand Response Compliance Report.

Figure 53 shows SCR program registration has grown steadily since 2001, 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 2009, total registration in the EDRP and SCR programs included 4,067 end-user locations providing 2,384 MWs of demand response capacity. EDRP and SCR resources in New York City are automatically registered in the TDRP program.

When EDRP resources are activated under the emergency programs (SCR, EDRP, and TDRP), they are paid the higher of $500 per MWh or the LBMP for the amount of the load reduction.[59] When SCR resources are activated under the emergency programs (SCR, EDRP, and TDRP), they are paid the higher of their strike price or the LBMP for the amount of the load reduction. This is greater than the marginal value of consumption for many loads during peak periods. Such loads have an incentive to respond, even though they are served under regulated or otherwise fixed rates that cause them not to pay the wholesale price of electricity.[60] However, to the extent that some resources have a marginal value of consumption exceeding $500 per MWh, they would be more likely to participate in demand response programs if they were allowed to submit strike prices exceeding $500 per MWh.

In addition to receiving payments for curtailing in real-time, SCR resources can sell their curtailable load in the capacity market in exchange for an obligation to respond when called. Accordingly, these resources are counted towards meeting the planning reserve margin requirement for NYCA, as well as for New York City and Long Island. These resources provide substantial benefits by reducing the overall cost of meeting the planning requirements since the requirements would otherwise need to be met by building more costly generation resources and/or transmission facilities. In 2009, SCR resources sold capacity of approximately 430 MW in New York City, 215 MW in Long Island, and 1,400 MW in the Rest of State zones on average. These resources increase the competitiveness of the capacity market, particularly in New York City and Long Island where ownership of generation is relatively concentrated.

Given the growing reliance on SCRs to meet the state's capacity needs, it is increasingly important to ensure that SCRs can perform when called. The current SCR baseline methodology is based on their monthly peak loads from the prior year. This may not accurately indicate the

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59 SCRs receive the higher of their strike price or the LBMP, although more than 90 percent submit strike prices at or very close to the maximum level of $500 per MWh. In 2009, 98 percent of the SCR strike prices were at or above $490 per MWh.

60 While the average regulated rate paid by load is much lower than $500 per MWh, the value of power at peak times is typically much higher than the average. Hence, if the NYISO did not pay for load reductions, the interrupted loads would save only the regulated rate, which does not reflect the marginal system cost of serving the load as reflected in the wholesale LBMPs.

ability of the SCRs to respond if called in the current year. The ISO is reviewing the methods for calculating baselines for SCR resources to ensure they have the capability to curtail the expected quantity when called in real-time.[61]

2. 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 per MWh.[62] Like a generation resource, DADRP program participants may specify minimum and maximum run times and the hours they are available. They are eligible for bid production cost guarantee payments to make up for any difference between the market price received and their block bid price across the day. 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. From September 2008 to August 2009, an average of 2.1 MW of DADRP resources was scheduled each hour in the day-ahead market. Hence, the quantities scheduled under the DADRP program are relatively small.

The NYISO established the DSASP program in June 2008 to enable demand response resources to provide ancillary services. As participation increases, this program will increase the amount of resources that provide reserves and regulation services, enhancing competition, reducing costs, and improving reliability. Under this program, resources must qualify to provide reserves or regulation under the same requirements as generators. To the extent that these resources increase or decrease consumption when deployed for regulation or reserves, they settle the energy consumption with their load serving entity rather than the NYISO. The first DSASP resource completed its enrollment as an Ancillary Service provider in late November 2009. The resource will be eligible to offer Regulation and/or Reserves in the NYISO markets once prequalification is completed in 2010. Hence, no resources have fully qualified as DSASP

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[61] Analysis of Alternative Baselines for SCR Results, presented by Donna Pratt on July 27, 2010 at the ICAP working group meeting.

[62] Prior to November 1, 2004, the offer price had to be $50 per MWh or higher. As of November 1, 2004, the offer floor price for DADRP has been set at $75 per MWh.

resources yet. Some resources have experienced delays related to setting up communications with the NYISO through the local Transmission Owner. To expedite the process, the NYISO is exploring ways to communicate directly with resources rather than through the local Transmission Owner.

In addition to the opportunities that loads have under the five demand response programs administered by the NYISO, some loads are also encouraged to respond to wholesale market prices under the New York Public Service Commission's Mandatory Hourly Pricing program ("MHP"). Under the MHP, retail customers as small as 400 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. Currently, approximately 6 GW of retail load customers are under this program. This program gives 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. In the future, some retail customers as small as 100 kW will be under the MHP, which should increase the total participation in the MHP program and its overall benefits to New York.

B. 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. Since 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 they will be "in-merit" relative to the real-time clearing price, and their deployment may actually depress prices. Prices can be well below $500 per MWh after EDRP and SCR resources are curtailed, if adequate resources are available to the system in real-time. The NYISO has two market rules that improve the efficiency of real-time prices when demand response resources are activated.

First, the NYISO has special shortage pricing rules for periods when demand response resources are deployed. When a shortage of state-wide or eastern reserves is prevented by the activation of demand response, real-time clearing prices are set to $500 per 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.

Second, to minimize the price-effects of "out-of-merit" demand response resources, the NYISO implemented the Targeted Demand Response Program ("TDRP") since July 2007, which enables the local transmission owner in New York City to call EDRP and SCR resources in blocks smaller than an entire zone. Previously, 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 activated that provided no reliability benefit, depressed real-time prices, and increased uplift.

In 2009, demand response resources were not activated for reliability, so there were no instances of shortage pricing related to demand response. In the future, however, the NYISO may need to rely on demand response resources to a greater extent, making it essential for the NYISO to have mechanisms for setting efficient prices when demand response resources are activated.

C. Ongoing Initiatives to Facilitate Demand Response

Price-responsive demand has great potential to enhance wholesale market efficiency because modest reductions in consumption by end-users during high-price periods can significantly reduce the costs of committing and dispatching generation. Furthermore, price-responsive demand mitigates market power, improves power system reliability, and reduces the need for new investment in generation. The NYISO has several on-going initiatives to facilitate participation in the wholesale market by loads.

First, the NYISO is developing the Demand Response Information System (DRIS), which will automate the NYISO's manual processes that support the participation of demand response. The automated system will directly interface with other NYISO software systems, track performance, enable participants to submit data more easily, and provide more timely settlements. It will also automate SCR/ICAP processing and the event performance, management and settlement preparation calculations. The automated system will substantially reduce the administrative burdens on both the NYISO and the program participants, and it will have the flexibility to support new demand response products and evolving market rules. These improvements should facilitate participation in demand response programs by reducing the costs of participation and administration. Some core functions in DRIS have been deployed in phases since November 2009.

Second, aggregators of retail customers ("ARCs") are currently able to participate in the reliability-based demand response programs (EDRP, SCR, TDRP) and the DADRP program. ARCs are not able to participate in the DSASP program because they do not satisfy the applicable telemetry and communication requirements. However, the NYISO is working with stakeholders to evaluate the potential of ARCs to provide ancillary services if alternative methods are used to verify performance and conduct communications.

D. Efficient Design of a Real-Time Price Responsive Load Program

Despite the efforts discussed in this section, there remain significant barriers to participation in the wholesale market by loads. The most significant barrier to participation is that most retail loads are served by load serving entities that charge retail prices that are unrelated to real-time prices in the wholesale market.[63] Hence, most retail loads have no incentive to respond to real-time prices even when they exceed their marginal value of consumption. Dynamic retail pricing would generally require retail regulatory reform, as well as enabling infrastructure to measure and control real-time load. Until those steps are taken, the fact that most retail loads pay prices that are unaffected by the short-term fluctuations in wholesale prices serves as a barrier to demand response because it removes the incentive for the loads to respond.

FERC highlighted this problem in its recent Demand Response NOPR. Likewise, the NYISO has committed to begin working with stakeholders in 2010 to create a real-time economic demand response program. We agree that creating a program to facilitate participation by loads in the real-time market would be beneficial in several ways. It would contribute to reliability in

[63] The 6 GW of retail load in New York under the Mandatory Hourly Pricing program are charged according to day-ahead market LBMPs, which are strongly correlated with real-time market LBMPs.

the short-term and resource adequacy in the long-term, reduce price volatility and other market costs, and mitigate supplier market power. Additionally, price-responsive demand has the potential to produce sizable savings by enhancing wholesale market efficiency.

To provide the greatest possible benefit, a real-time demand response program must give loads incentives to reduce consumption when it is efficient to do so. The elements of an efficient program are discussed at length in the comments filed by Potomac Economics to the NOPR.[64] The key element is that it is important for a load resource to receive a total net payment that is equal to the LBMP where the total net payment is equal to (a) the payment received from the NYISO plus (b) any charge from the LSE that is avoided for not consuming. This will ensure that the load resource curtails at the point when the value of its consumption is equal to the LBMP. This can be accomplished in at least two ways.

First, the load resource could receive a payment from the NYISO equal to the difference between the wholesale LBMP and the load's retail rate. Paying this amount would align the load's incentives with the value of the energy to the system because the payment would make up the difference between what the load saved on its retail bill and the value of energy to the wholesale market. It would be important to allocate the cost of the payments from the NYISO to the corresponding LSE, who might otherwise receive a windfall when its load curtails.

Second, the demand resource could receive the full real-time LBMP as suggested by the recent NOPR. However, it would be important: (a) for the LSE to be charged the real-time LBMP for the increment of load that was curtailed, and (b) for the retail customer associated with the load resource to continue to be charged the retail rate by the LSE. This alternative would provide efficient incentives to the demand resource and result in a settlement that is comparable to supplying the load from a supply resource.

Either of these approaches would allow an economic demand response program to facilitate efficient entry of demand response, as well as efficient curtailments of the demand response in

[64] Comments of Potomac Economics, Ltd., Docket Nos. RM10-17-000 and EL09-68-000, May 13, 2010.

the real-time market. However, the NYISO's programs in this area will be governed by the outcome of the Commission's rulemaking process, which may deviate from this principle.