2008 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 2008. 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.

- 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:

- An optimized real-time commitment system to start gas turbines and schedule external transactions economically. Other RTOs generally rely on operators to start gas turbines.
- 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 2008.

A. Overview of Market Trends and Highlights

This sub-section provides an overview of key market trends and highlights from 2008. Wholesale electricity prices rose by an average 20 percent from $74 per megawatt-hour ("MWh") in 2007 to $89 per MWh in 2008. The increases in electricity prices were primarily due to the increases in natural gas and fuel oil prices, which increased by an average of 19 percent and 40 percent, respectively. The effects of higher fuel prices were partly offset by milder weather and poor economic conditions, which led to lower load levels in 2008 than in 2007. Accordingly, the frequency of real-time operating reserve shortages in eastern New York declined from 219 intervals in 2007 to 181 intervals in 2008.

The emergence of circuitous transaction scheduling around Lake Erie in the first seven months of 2008 increased the volume of clockwise loop flows through New York, leading to congestion from Western New York to Eastern New York and increased uplift charges to NYISO market participants. The average price difference between in Western New York and Eastern New York increased from 37 percent in 2007 to 50 percent in 2008. The pattern of loop flows was the primary cause of the $252 million increase in uplift charges related to congestion revenue shortfalls from 2007 to 2008. To address the costs to NYISO market participants of these schedules, the NYISO filed under exigent circumstances to prohibit circuitous transaction scheduling after July 22, 2008.

In the NYISO capacity markets, existing capacity that was previously withheld from the New York City market began to be sold in March 2008. The increased capacity sales caused the New York City spot auction price to decrease more than 80 percent from February to March 2008. The increased sales in 2008 can be attributed to new mitigation measures, approved in March 2008 and intended to address both buyer-side and seller-side market power in the capacity market, and to a merger condition placed on a large supplier in New York City.

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. **Prices and Market Outcomes**

Wholesale electricity prices rose in the day-ahead market from a load-weighted average of $74 per MWh in 2007 to $89 per MWh in 2008 primarily due to the increase in fuel prices. On average, natural gas prices increased 19 percent and fuel oil prices increased 40 percent from 2007 to 2008. The correlation between natural gas prices and electricity prices is expected in a well-functioning market because fuel costs constitute the vast majority of most generators' marginal costs, and natural gas-fired units are frequently on the margin (setting the market price) in New York.

In 2008, day-ahead prices averaged $67 per MWh in Western New York and $100 per MWh in Eastern New York. The average price difference between in Western New York and Eastern

New York increased from 37 percent in 2007 to 50 percent in 2008, reflecting increased congestion across the west-to-east transmission interfaces. The increase in congestion was primarily due to increased clockwise loop flows around Lake Erie in the first seven months of 2008. When loop flows move clockwise around Lake Erie, they use a portion of the available west-to-east transmission capability of key flowgates, thereby reducing the portion of transmission capability available for scheduling flows in the NYISO's real-time market.

The effects of higher fuel prices were partly offset by milder weather and poor economic activity, which led to lower load levels in 2008 than in 2007. There were just 24 hours when New York load exceeded 30 GW in 2008, compared to 47 such hours in 2007. As a result, the frequency of real-time operating reserve shortages in eastern New York declined from 219 intervals in 2007 to 181 intervals in 2008.

Day-Ahead to Real-Time Price Convergence and Virtual Trading

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.

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.

We find that there were several nodes in New York City and Long Island where average day-ahead prices were substantially different from average real-time prices. We discuss factors that contribute to such inconsistencies, including three that were particularly significant in 2008. First, generators not scheduled in the day-ahead market may have difficulty obtaining natural gas and are more likely to use oil if scheduled in the real-time market. This increases the cost of supply in the real-time market in load pockets that rely on duel-fueled quick start generators.

Second, commitments are made in the Supplemental Resource Evaluation ("SRE") process after the day-ahead market on most days, which increases the supply of online energy and reserves in the real-time market and lowers real-time prices. Third, there are differences between the constraints modeled in the day-ahead market and the real-time market in the New York City load pockets.

The NYISO has worked on market enhancements that are expected to improve the consistency between the day-ahead and real-time markets. In February 2009, the NYISO modified the day-ahead market process to reduce the amount of capacity committed through the SRE process. Under the new process, more of the reliability criteria that had required SRE commitments are satisfied in the day-ahead market by committing Day-Ahead Reliability Units ("DARUs"). This is expected to reduce pricing and scheduling inconsistencies between the day-ahead market and the real-time market. Finally, 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 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. Under most conditions, day-ahead clearing prices are higher than real-time clearing prices. Day-ahead clearing prices are higher than real-time clearing prices partly as a result of SRE commitments. Hence, we expect the new process that commits DARUs to improve the consistency between day-ahead and real-time reserve clearing prices. Additionally, when suppliers expect day-ahead prices to be lower than real-time prices (which is most likely under peak conditions when the probability of a real-time shortage is non-trivial), the opportunity cost of selling reserves in the day-ahead market increases. In response, suppliers are expected to raise their day-ahead reserve offer prices to reflect these opportunity costs. However, the mitigation measures limit the day-ahead reserve offers of some suppliers, so we recommend the NYISO consider modifying the mitigation measures to ensure suppliers can offer competitively.

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.

This comparison for 2008 shows that the Vernon/Greenwood load pocket within New York City is likely the only area of New York where an investment in a new combustion turbine might have been profitable.[1] The estimated net revenues are substantially higher for a new combined cycle than a new combustion turbine. Depending on the CONE for combined cycle technology, it may be economic to build in some areas of New York under the current market conditions. However, we would note that the increased congestion caused by scheduling activity around Lake Erie increased net revenues in Eastern New York in 2008.

Prospective investors must consider that net revenues are likely to change in subsequent years for several reasons. First, the retirement of nearly 1 GW of New York City capacity before the Summer 2010 capability period will substantially increase net revenues from the capacity market and, to a lesser degree, the energy and reserves markets. Second, net revenues tend to rise with natural gas prices, so if natural gas prices decline from 2008 levels, it is likely to reduce net revenues. Third, clockwise loop flows around Lake Erie tend to increase energy and reserves prices in Eastern New York, so the decline in those loop flows will contribute to lower net revenues for generators in Eastern New York.

C. 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. Based on the results of these analyses, we find that the

[1] Based on the CONE estimates in Proposed NYISO Installed Capacity Demand Curves For Capability Years 2008/2009, 2009/2010, and 2010/2011.

markets performed competitively in 2008. Recently, concerns were raised about the competitiveness of the New York electricity market and whether the uniform-clearing price design is in the best interests of consumers. However, we find very little evidence that suppliers have either economically or physically withheld resources to raise energy or ancillary services prices in the market.[2] Although nominal prices for electricity increased in 2008, the rise is attributable to the substantial increase in fuel prices. Because fuel costs constitute the vast majority of the marginal cost of producing electricity, increased fuel costs usually translate into increased offer prices and market clearing prices for electricity.

In certain constrained areas, most of which are in the New York City area, 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.

D. 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 2008, the emergence of circuitous transaction scheduling around Lake Erie increased the volume of clockwise loop flows through New York, leading to congestion from Western New York to Eastern New York and increasing uplift charges to NYISO market participants. To reduce the costs to NYISO market participants, the NYISO filed under exigent circumstances to prohibit circuitous transaction scheduling after July 22, 2008. However, other inter-control area transactions continue to cause clockwise loop flows through New York, which NYISO s addressing by using the Transmission Loading Relief (“TLR”) process to limit the effects of these transactions. The NYISO is also considering pricing mechanisms to improve the efficiency

[2] For a discussion and analysis of these concerns, see the letter to Chairman Cahill and Chairman Brodsky from the NYISO sent on May 1, 2009, which is posted at “www.nyiso.com”.

of transaction scheduling between control areas around Lake Erie. We recommend in this report that the NYISO develop scheduling and settlement mechanisms that would improve consistency between the costs caused and the charges assessed for inter-control area transactions.

Our evaluation of external transactions between New York and three adjacent markets indicates that scheduling by market participants does 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 by market participants tends to improve convergence, but significant opportunities remain to improve the interchange between regions. In particular, efforts to reduce scheduling lead times would likely facilitate more efficient interchange, reduce price-volatility, and lower overall prices.

Improvements to market participant scheduling between regions, while desirable, would not achieve full utilization of the external interfaces. Uncertainty, imperfect information, and a lack of coordination limit the ability of market participants to arbitrage fully the prices between regions. Hence, we continue to recommend that the NYISO work with neighboring control areas to better utilize the transfer capability between regions, ideally by directly coordinating the physical interchange. Some have argued that this would constitute involving the ISOs 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 transmission interfaces inside both markets.

We note that the NYISO is working with PJM to coordinate congestion management. This would allow one control area to redispatch resources within its footprint to alleviate congestion in the other control area. We support such efforts to coordinate congestion management, which would result in more efficient nodal prices and reduced congestion management costs.

E. **Uplift Charges**

The NYISO recovers cost 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 – These occur when the congestion revenues collected from the day-ahead market are not sufficient to cover payments to the holders of Transmission Congestion Contracts ("TCCs") by the NYISO. These arise when the flow modeled in the TCC market across a particular line or interface exceeds the flow scheduled in the day-ahead market during periods of congestion. Day-ahead congestion revenue shortfalls rose from $93 million in 2007 to $179 million in 2008.

Balancing congestion revenue shortfalls – These occur when the congestion revenues collected from buyers in the real-time market are not sufficient to cover congestion payments by the NYISO to sellers. These arise when the flow scheduled in the day-ahead market across a particular line or interface exceeds the transfer capability available for scheduling resources in the real-time market during periods of congestion. Balancing congestion revenue shortfalls rose from $159 million in 2007 to $325 million in 2008.

Guarantee payments – These occur when generators are scheduled but do not recoup their as-bid costs from the day-ahead or real-time markets. Total guarantee payments to generators rose from $331 million in 2007 to $422 million in 2008.

The primary factor that led to the increase in congestion revenue shortfalls in 2008 was the rise in clockwise loop flows around Lake Erie. These loop flows use transmission capability in New York and reduce the share of transmission capability available for the NYISO market. Accordingly, 90 percent of the congestion revenue shortfalls in 2008 occurred during the seven months from January to July. The NYISO made two changes that helped reduce the effects of the loop flows. In late May 2008, the NYISO began making more timely updates of the loop flow assumptions used in the day-ahead market, which reduced the balancing congestion shortfalls resulting from the loop flows. In late July 2008, the NYISO prohibited the scheduling of circuitous transactions, which dramatically reduced Lake Erie loop flows and the associated shortfalls.

The rise in fuel prices was also a significant contributor to the increased uplift charges in 2008. The increased fuel prices lead to larger congestion-related price differences between regions. Since congestion revenue shortfalls are correlated with price differences between regions, the rise in fuel prices contributed to the increases in congestion revenue shortfalls. In addition, higher fuel prices tend to result in proportional increases in the guarantee payments to generators. Hence, the decline in fuel prices after 2008 should help lower uplift charges to NYISO market participants.

In 2008, 61 percent of the uplift charges from guarantee payments were paid to generators that were committed for local reliability. In February 2009, the NYISO implemented a new process for committing units for local reliability which should reduce the uplift charges from maintaining local reliability. The new process integrates most commitments for local reliability into the economic pass of the day-ahead market model, thereby improving the efficiency of the economic commitments and reliability commitments. This should help reduce the uplift and market inefficiencies that result from local reliability commitments.

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.

Real-Time Scheduling and Pricing

In this report, we evaluate the efficiency of gas turbine commitment and external transaction scheduling. These 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 2008 was economic. In our evaluation of external transaction scheduling, we find that the quantity of price-sensitive bids and offers submitted for real-time scheduling grew 150 percent from 2005 to 2008, indicating that market participants are relying increasingly on RTC to determine when it will be economic to schedule power between control areas. We also found that a high portion (81 percent) of price-sensitive import offers and export bids were scheduled consistent with real-time prices at the primary interface with New England in 2008.

We also analyze price volatility, finding that price volatility is high at the top of the hour during the morning and evening ramp-up and ramp-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, in particular large adjustments to import and export schedules at the top of the hour and changes in the operating modes of pumped storage units. These factors and the others identified in the report can cause the NYISO to temporarily be short of reserves or regulation. We recommend that the NYISO perform a more complete evaluation factors that may contribute to unnecessary real-time price volatility.

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. Hence, the mild weather in 2008 led to less frequent shortages than in 2007.

The importance of setting efficient real-time price signals during shortages of operating reserves was recently affirmed by FERC in Order 719, which identifies two provisions in the NYISO's market design that facilitate shortage pricing and serve as a model for other ISOs.[3] First, the NYISO uses operating reserve demand curves to set real-time clearing prices during operating

[3] Order No. 719, 73 Fed. Reg. 64,100 (Oct. 28, 2008), FERC Stats. & Regs. ¶ 31,281 (2008), 125 FERC ¶ 61,071 (2008).

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 find that reserve shortage pricing occurred in 68 percent of the periods with physical shortages in 2008. 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. We also find that transmission constraint modeling improvements made in 2007 have greatly improved pricing when transmission limits are violated. We did not evaluate pricing during activations of emergency demand response because they were not activated for reliability in 2008.

Commitment for Local Reliability

Supplemental commitment for local reliability can adversely affect the market because it tends to mute price signals and cause uplift charges that are difficult for participants to hedge. Supplemental commitment primarily occurs when the Day-Ahead Local Reliability Pass of SCUC commits generators after the economic commitment or the Supplemental Resource Evaluation ("SRE") process is used to commit generators after the day-ahead market. In both cases, the commitments are generally 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 local reliability in New York City exceeded 1,300 MW in 2008. The uplift charges resulting from supplemental commitment for local reliability rose from approximately $200 million in 2007 to $260 million in 2008. The increase in uplift charges resulted primarily from higher fuel prices for generators committed for local reliability.

In February 2009, the NYISO implemented a new process for committing units for local reliability, which should substantially reduce the market effects of maintaining local reliability. SRE commitments have been integrated in the economic pass of the day-ahead market model, thereby improving the efficiency of the economic commitments and reliability commitments.

This enhancement is expected to reduce the uplift charges that result from committing generation to satisfy the local reliability rules. .

G. Capacity Market

The capacity market is intended 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 Rest-of-State. The clearing prices in New York City and Long Island are generally much higher than those in the Rest-of-State.

Capacity Market Results

We evaluate the performance of the capacity market from May 2007 through February 2009, a time span including four six-month capability periods from the Summer 2007 capability period through the Winter 2008-09 capability period. During this period, clearing prices in the Rest-of-State area ranged from $0.75 to $3.50 per kW-month primarily due to seasonal changes in generating capability variations in the levels of imports and exports. The Installed Reserve Margin ("IRM") for NYCA was reduced from 116.5 percent to 115 percent, which caused capacity clearing prices to decline in Rest-of-State beginning in May 2008.

In Long Island, seasonal changes in capability accounted for the most significant variations in prices during the period. However, capacity clearing prices also decreased substantially from approximately $7.50 per kW-month in summer 2007 and $4.10 per kW-month for winter 2007-2008 to $2.6 per kW-month in summer 2008 and $1.8 per kW-month for winter 2008-2009. The decline in prices was primarily due to the reduction of the Local Capacity Requirement ("LCR") in Long Island. The LCR decreased from 99 percent to 94 percent starting in May 2008 to recognize the reliability benefits from the Neptune HVDC line between eastern PJM and Long Island.

In New York City, a significant amount of existing capacity did not clear in the capacity market due to high capacity offer prices prior to March 2008. However, capacity sales increased in

March 2008, leading the New York City spot auction price to decrease more than 80 percent from February to March 2008. These changes can be attributed to the implementation of new market power mitigation measures designed to address competitive concerns on both the supply and demand side, as well as a merger condition placed on a large supplier in New York City. Seasonal variations in capability account for most of the other changes in the clearing prices. Since March 2008, clearing prices have averaged approximately $2 per kW-month in the winter and $6 per kW-month in the summer in New York City.

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 Rest-of-State. 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 not be "deliverable" 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. Because the failure of the deliverability test can substantially affect investment incentives, it is critical that it use realistic assumptions.

If the deliverability test determines that new units or imports are not deliverable due to transmission constraints between large areas on the system, a new capacity zone is likely needed to efficiently distinguish the value of capacity on either side of the constraint. Several problems or inefficiencies occur if capacity is deemed to not be deliverable and a new zone is not created:

- The capacity market will not send the signals necessary to build new capacity if it is needed in the congested area, particularly important when the cost of new entry is higher in the congested areas than in the uncongested areas;

- New suppliers or importers on the uncongested side of the transmission constraint may be inefficiently foreclosed from the market, which will generally raise capacity costs for New York consumers and reduce competition; and

- Suppliers that can provide capacity and reliability benefits to the areas of the NYCA on the unconstrained side of the constraint (or all of NYCA when constraints are not binding) will not receive efficient investment incentives.

Given the initial indications that some capacity in western New York may not be deliverable to eastern New York or southeast New York, we recommend the NYISO consider whether one or more new capacity zones are needed in eastern New York. As discussed above, this would likely reduce capacity costs for New York consumers and improve the incentives for investment that is beneficial for reliability. Creating new zones will also ensure that investment incentives and incentives to import or export capacity will be efficient on both sides if the key transmission constraints in New York.

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. For these reasons, the FERC recently required ISOs to take steps in several areas to encourage the development of demand response in Order 719.[4] 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.

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

4 Order No. 719, 73 Fed. Reg. 64,100 (Oct. 28, 2008), FERC Stats. & Regs. ¶ 31,281 (2008), 125 FERC ¶ 61,071 (2008),.

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 more than 2 GW of demand response resources in New York are emergency demand response.

In June 2008, the NYISO established the Demand-Side Ancillary Services Program (“DSASP”) to allow demand-side resources to offer operating reserves and regulation service in the wholesale market. This should increase the amount of resources that provide reserves and regulation services, bolstering competition, reducing costs, and enhancing reliability. Although no resources have qualified yet as DSASP resources, several resources are expected to qualify once the necessary telemetry is installed.

The fastest growing demand response program operated by the NYISO is the SCR program, whose participation grew to almost 1800 MW in 2008. 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. This may allow loads that have shut down their facilities to make sales as SCRs (although they cannot respond if scheduled). Hence, we recommend that the NYISO revisit the baseline calculation and testing processes for SCRs to ensure they have the capability to respond when called in real time.

Future Developments and Barriers to Participation

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 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. Second, Aggregators of Retail Customers

("ARCs") are currently able to participate in four of the NYISO's five demand response programs, but ARCs are not able to participate in the DSASP program because they do not satisfy the applicable telemetry and communication requirements. 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, and it will report the status of this evaluation to FERC in October 2009.

Despite these efforts, there remain significant barriers to participation in the wholesale market by loads. In this report, we discuss two significant barriers to participation. First, retail rate reform is needed to provide efficient incentives for loads to respond to changes in wholesale electricity prices. 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. If the regulatory reform necessary to implement dynamic retail pricing does not occur, New York could consider other options for providing real-time economic demand response resources the same incentives that they would have under a dynamic retail pricing regime. For example, a real-time price responsive demand program that would make an efficient payment equal to the difference between the wholesale LBMP and the retail customer's rate is one option for addressing this economic barrier. Paying this amount would align the loads' incentives with the value of the energy to the system. The costs of these payments could be allocated to the corresponding LSE, who might otherwise receive a windfall when its load curtails. However, such programs would require significant efforts by the ISO to monitor and measure performance of demand resources.

Second, major barrier to participation in the wholesale market by loads is related to the metering and other infrastructure that would be needed to support it. To accommodate the characteristics and requirements of most demand response resources, ISOs generally need specialized procedures to quantify the amount of the response and settlement rules to compensate the participant efficiently. These would be more accurate if retail customers had interval recorders that provided more frequent data on the customers' real-time consumption. In addition to advanced metering, demand response is facilitated by other enabling infrastructure, including communications and control devices. Hence, the NYISO is supportive of efforts to increase penetration of Smart Grid technology, which includes such infrastructure.

I. List of Recommendations and Recent Enhancements

Our analysis in this report indicates that the NYISO electricity markets performed well in 2008. However, the report finds that additional improvements can be made and that the NYISO:

1. Consider defining a new capacity zone or zones in eastern New York. To the extent that capacity is deemed undeliverable from western New York to locations in eastern New York, new zones would: (i) allow consumers in the rest of New York to benefit from lower capacity costs and increased reliability that western resources and capacity imports provide, and (ii) ensure loads in eastern New York only purchase capacity that is deliverable to those locations and provide necessary price signals to invest in new generation, transmission, or demand response resources in those areas when needed.

2. Continue its work with neighboring control areas to better utilize the transfer capability between regions, ideally by directly coordinating the physical interchange and management of congestion. This would help ensure that power is efficiently transmitted to the highest-value locations. In addition to the substantial economic savings for customers, optimizing the use of the interface would improve the efficiency of the markets' price signals and reliability.

3. Evaluate factors that contribute to real-time price volatility, including assumptions used in the real-time commitment model ("RTC") and real-time dispatch model ("RTD"), or other market rules.

4. Consider a real-time economic demand response program to better align the incentives of retail customers with the needs of the system if retail rate reform is not anticipated soon.

5. Revisit the baseline method and testing procedures for Special Case Resources ("SCRs") to ensure they have the ability to respond when called in real-time.

6. Modify two mitigation provisions that may limit competitive day-ahead 10-minute reserves offers, which should improve convergence of day-ahead and real-time ancillary services prices. The two provisions are 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.

7. Raise the offer limit for real-time import and exports from -$1000 per MWh to a level more consistent with the avoided costs of curtailment, which would limit balancing congestion revenue shortfalls when they must be curtailed.

8. Continue the work that is underway to enable market participants to schedule virtual trades at a more disaggregated level. Currently, virtual trading is allowed at only the zonal level.

II. Day-Ahead and Real-Time Prices and Market 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 2008 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 2008 Outcomes

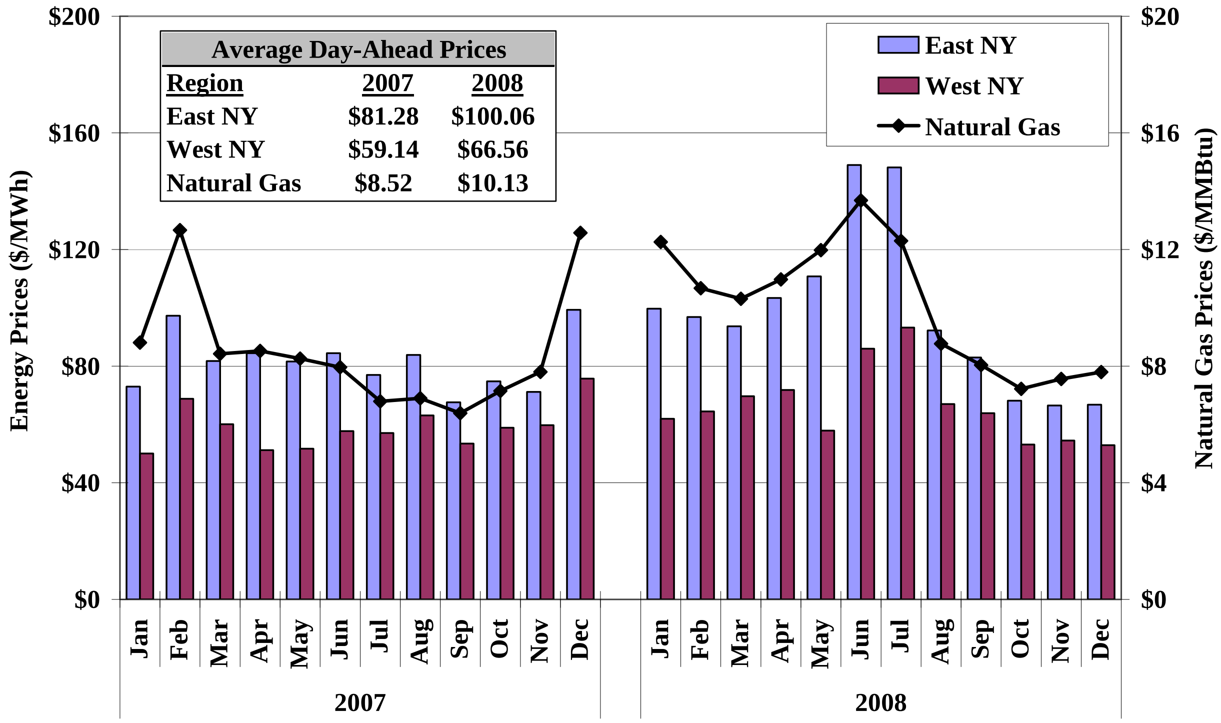
In this sub-section, we summarize market outcomes in 2008, including: energy prices, congestion patterns, fuel prices, load levels, and ancillary services prices.

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 2007 and 2008. Although much of the electricity used by New York consumers is generated from hydro, nuclear, and coal-fired generators, natural gas and oil 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.

In 2008, monthly average power prices peaked in June and July due to high fuel prices and the seasonal increase in electricity demand. From 2007 to 2008, average natural gas prices rose 19 percent, while both diesel and residual fuel oil prices increased 40 percent. The increase in fuel costs was the primary cause of the 23 percent increase in Eastern New York electricity prices and the 12 percent increase in Western New York electricity prices.

Figure 1: Day-Ahead Energy and Natural Gas Prices
2007 – 2008



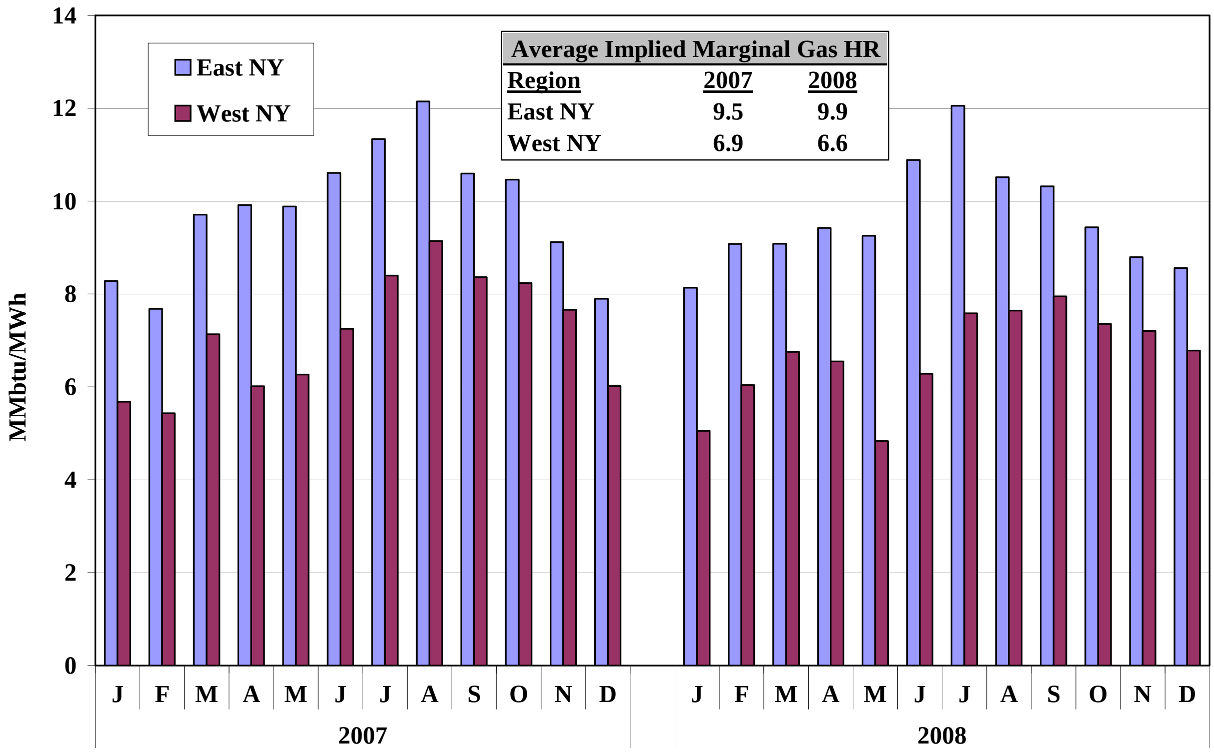
Price separation between Eastern and Western New York increased in the first half of 2008, reflecting greater transmission congestion and losses. Average prices in Eastern New York were 50 percent higher than average prices in Western New York in 2008, a substantial increase from the 37 percent difference in 2007. The increase in congestion from Western New York to Eastern New York was partly due to increased clockwise loop flows around Lake Erie in the first seven months of 2008.[5] When loop flows move clockwise around Lake Erie, they use a portion of the available west-to-east transmission capability of key flowgates, thereby reducing the portion of transmission capability available for scheduling flows in the NYISO's real-time market. Since less power can be scheduled from west-to-east in the real-time market, the effect is similar to a reduction in west-to-east transmission capability. After the volume of loop flows declined at the end of July 2008, price separation between Western New York and Eastern New

[5] Loop flows refer to unscheduled power flows resulting from scheduling in other control areas in the Eastern Interconnect (i.e., loop flow = actual power flow minus scheduled power flow). Clockwise loop flows around Lake Erie refer to instances when the prevailing direction of unscheduled power flows move in a clockwise pattern around Lake Erie.

York decreased substantially. The scheduling patterns that led to increased loop flows are discussed in Section IV, while the effects of the loop flows on congestion patterns and uplift charges are discussed in Section IV.

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. Figure 2 shows the load-weighted average implied marginal heat rate for Eastern and Western New York by month in 2007 and 2008.

Figure 2: Average Implied Marginal Heat Rate
Based on Day-Ahead Electricity and Natural Gas Prices, 2007 – 2008



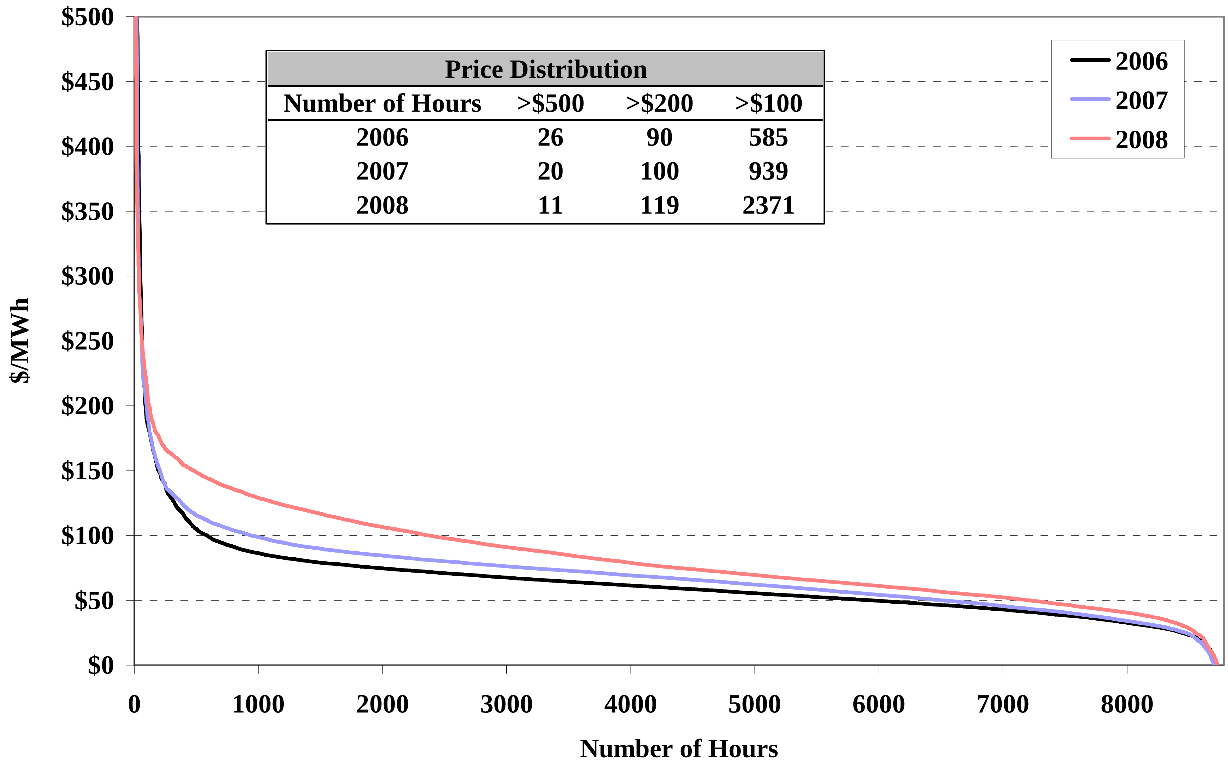
Average Implied Marginal Gas HR		
Region	2007	2008
East NY	9.5	9.9
West NY	6.9	6.6

Figure 2 shows 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 by the effects of higher ambient temperatures on the capability of thermal units. Demand was moderate in the summers of 2007 and 2008 compared with previous summers, limiting the increase in prices associated with increased demand.

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. From January to July 2008, there was a particularly large number of hours when such units were on the margin, due in part to the pattern of increased clockwise loop flows around Lake Erie discussed above.

The following two figures illustrate how prices vary across hours in each year. Figure 3 shows several price duration curves, which show the number of hours on the horizontal axis in which the market settled at or above the price level shown on the vertical axis. One curve is shown for each year from 2006 to 2008. This allows us to compare the distribution of prices from year to year. The prices shown are the load-weighted average real-time price for New York State.

Figure 3: Price Duration Curve
Statewide Average Real-Time Price, 2006 – 2008



The price duration curves show the characteristic distribution of prices in wholesale power markets. Most hours are priced moderately, but there are a small number of very high priced hours. During periods of shortage, 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 from 2006 to 2008. This decline was partly due to the substantial decrease in the number of hours when load reached super-peak levels (e.g., above 30 GW) in 2008. Additionally, there has been no evidence of artificial shortages due to withholding, supporting our opinion that the New York market has been competitive.

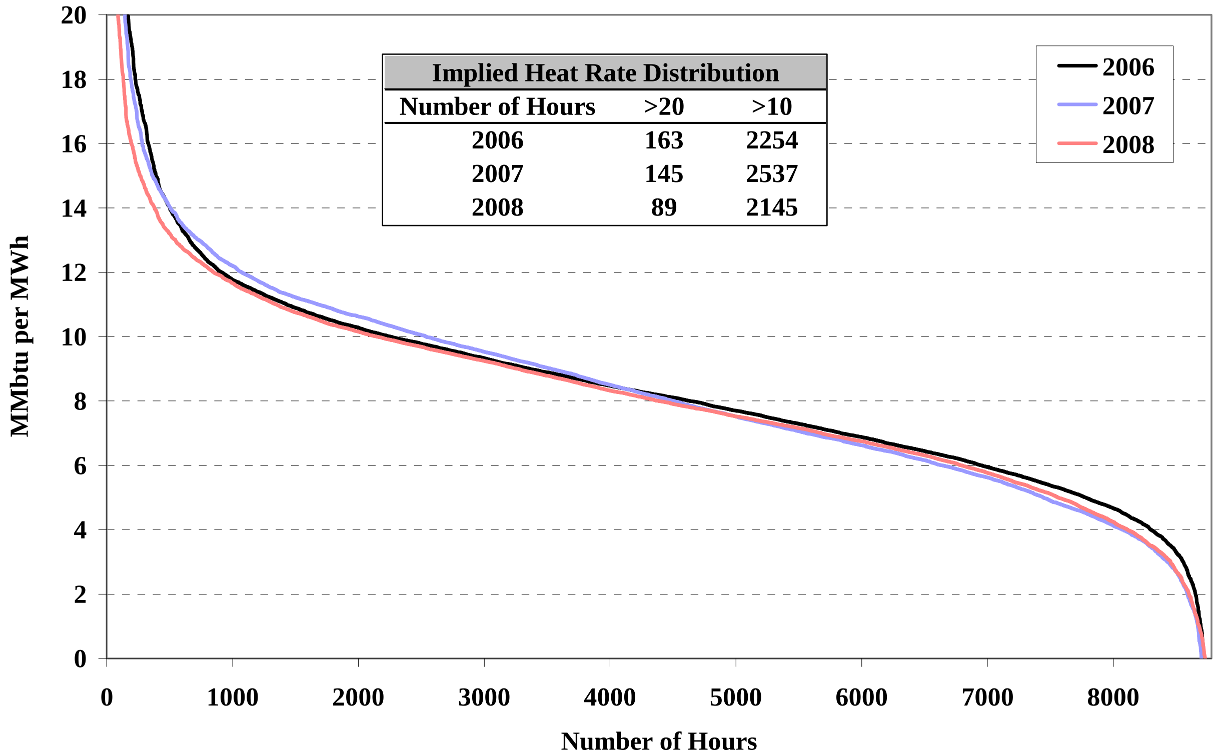
Fuel price changes from year to year are revealed by the flatter portion of the price duration curve, since fuel price changes affect power prices in almost all hours. The figure shows the effects of the general trend of rising natural gas prices from 2006 to 2008. The average natural gas price increased 15 percent from 2006 to 2007 and 19 percent from 2007 to 2008. The rise in natural gas prices is also evident from the increase in the number of hours when the price exceeded $100 per MWh from 585 hours in 2006 to 2,371 hours in 2008.

To identify factors affecting power prices other than fuel price changes, the following figure shows the implied marginal heat rate duration curves for 2006 through 2008. These show the number of hours on the horizontal axis in which the market settled at or above a given implied marginal heat rate level shown on the vertical axis. In this case, the implied marginal heat rate is the statewide average real-time price divided by the natural gas price.

Implied marginal heat rates have been very consistent over the last three years. This shows adjusting for changes in fuel prices virtually eliminates differences from year-to-year in the statewide average price. The figure does show that there has been a substantial decline from 2006 to 2008 in the number of very high-cost hours (e.g., when the implied marginal gas heat rate exceeded 20 MMBtu per MWh). Mild summer weather contributed to fewer very high-cost hours in 2008.

Figure 4: Implied Marginal Heat Rate Duration Curves

Based on Statewide Average Real-Time Price and Natural Gas Price, 2006 – 2008



Although the implied heat rate duration curves are very similar from year to year, significant price variations occur in local areas due to changes in the pattern of transmission congestion. For instance, Figure 4 shows average implied heat rates rose in Eastern New York and fell in Western New York from 2007 to 2008. However, in the statewide averages, these local variations tend to offset one another.

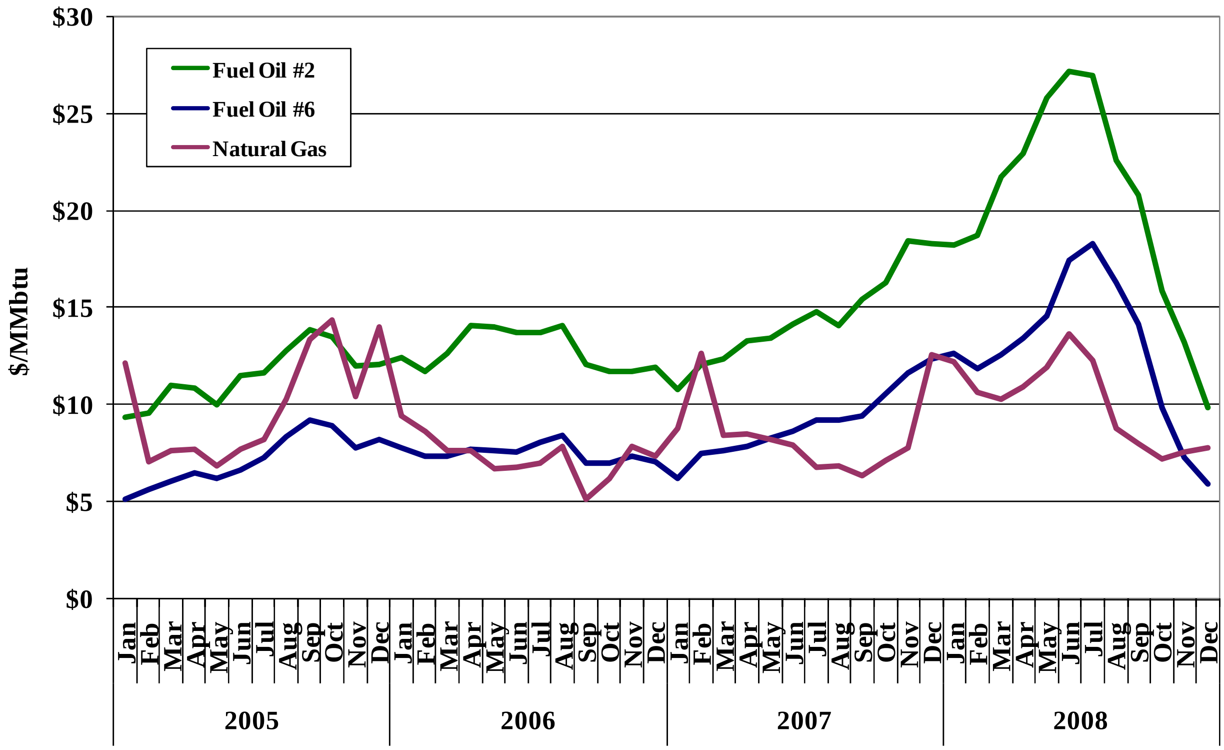
2. Fuel Prices

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, they are usually not the marginal source of generation. Rather, oil units and, more often, natural gas units are usually the marginal source of generation. Hence, oil and 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. 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 fuel prices by month from 2005 to 2008. Prices are shown for natural gas, diesel fuel oil (No. 2), and residual fuel oil (No. 6).

Figure 5 shows natural gas prices continued to be highly volatile in 2008. On average, natural gas prices rose 19 percent from 2007 to 2008. Fuel oil prices also reached record levels in the summer of 2008, but then fell precipitously during the remainder of 2008.

Figure 5: Natural Gas and Oil Price Trends
2005 – 2008



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 residual oil on

84 percent of the days in 2008. Likewise, natural gas was priced lower than diesel oil on 98 percent of the days in 2008. Regardless, the availability of oil still moderates the effects on electricity prices of spikes in natural gas prices.

The use of oil is increased by the “minimum oil burn provisions”, which require some units in New York City to burn oil to limit the exposure of the power system to natural gas supply contingencies. These provisions provide out-of-market payments to generators that burn a more expensive fuel for reliability reasons. Accordingly, the additional costs incurred from using oil for reliability reasons are not reflected in market clearing prices. Despite the rise in oil prices, the uplift from these payments declined from $21 million in 2007 to $18 million in 2008. This decline was partly due to revisions to the applicable local reliability rules. The revisions narrowed the circumstances when generators are required to burn oil for New York City reliability. The uplift costs resulting from these payments are discussed further in Section VI.C.

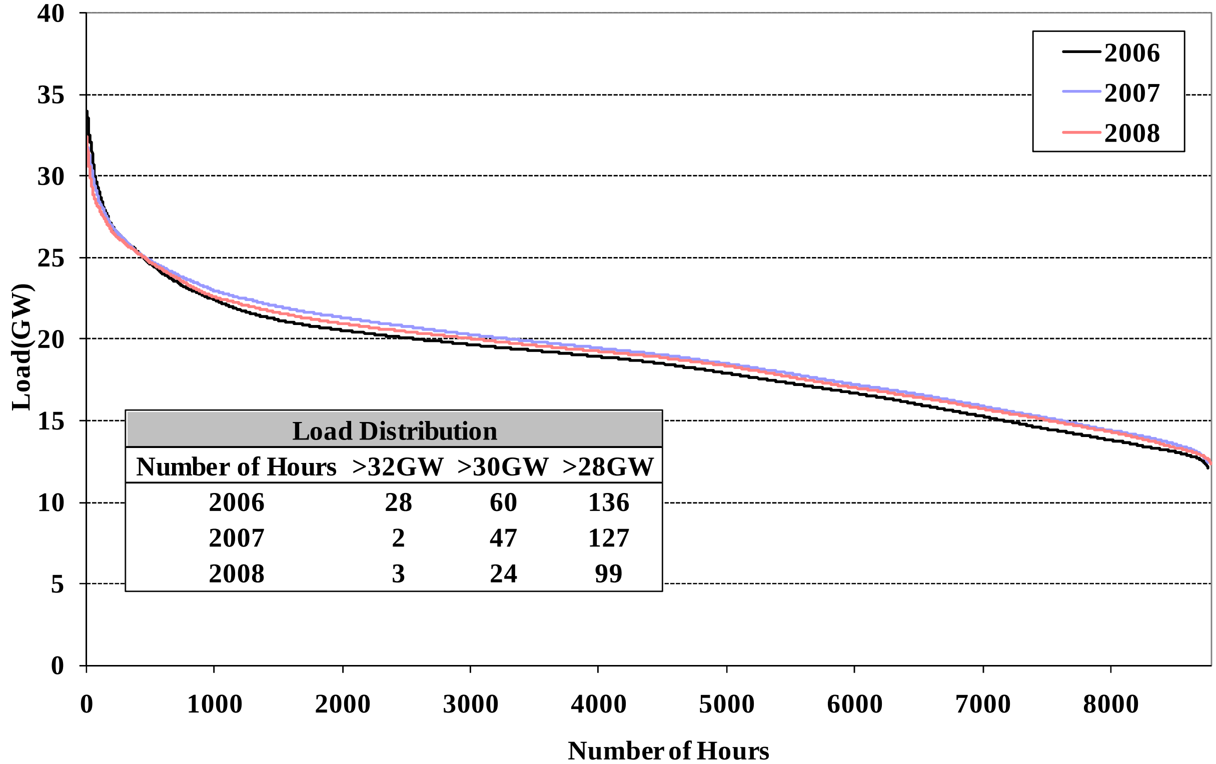
3. Energy Demand

The interaction of electric supply and consumer demand drive 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 movement 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 shows the variation in demand during each of the last three years. These 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.

In general, electricity demand grows slowly over time, tracking population growth and economic activity. Figure 6 shows load generally increased from 2006 to 2007 and declined slightly from 2007 to 2008. For instance, the number of hours when load exceeded 20 GW increased from approximately 2,600 hours in 2006 to 3,350 hours in 2007 and decreased to 3,050 hours in 2008.

Figure 6: Load Duration Curves
2006 – 2008



Load Distribution			
Number of Hours	>32GW	>30GW	>28GW
2006	28	60	136
2007	2	47	127
2008	3	24	99

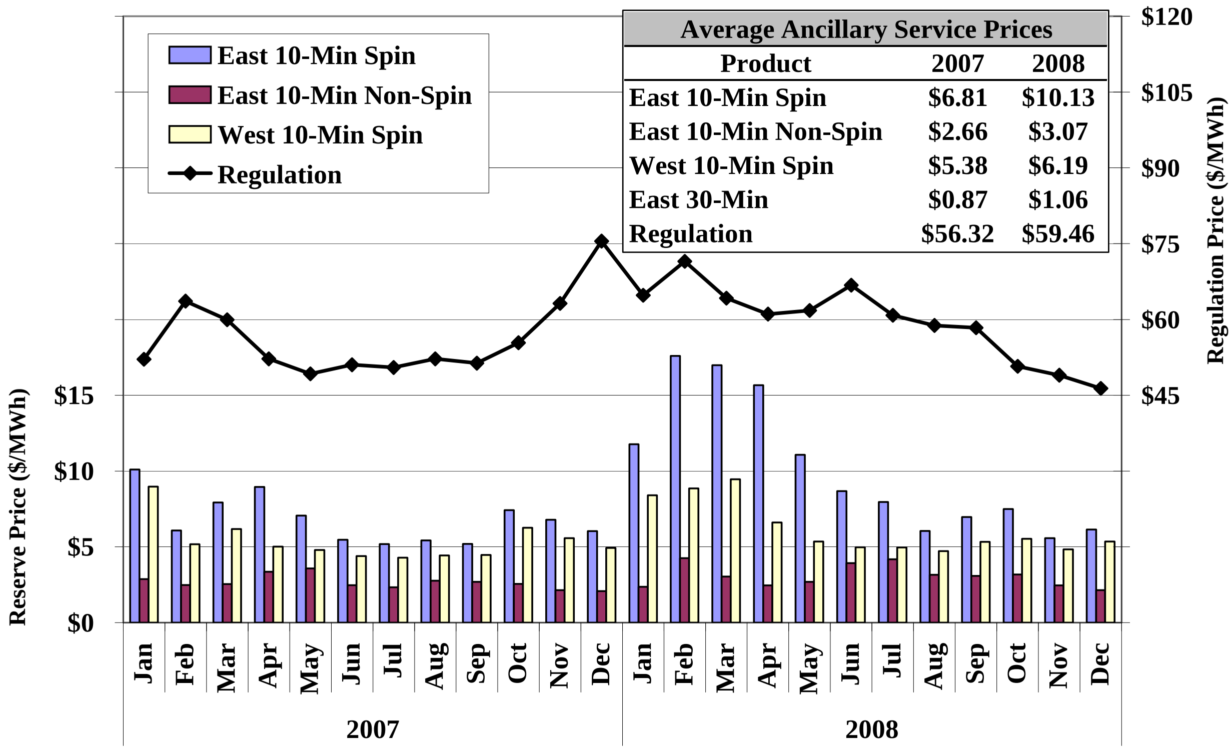
The comparatively mild summers in 2007 and 2008 resulted in a lower number of high load hours and less frequent shortage conditions. For example, load exceeded 30 GW during just 24 hours in 2008, down from 47 hours in 2007 and 60 hours in 2006. Load exceeded 32 GW during just 3 hours in 2008 compared to 2 hours in 2007 and 28 hours in 2006. Hence, there were fewer real-time price spikes related to shortage conditions as a result of less frequent high load periods.

4. 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 2007 and 2008. 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, 10-minute total reserves, and 30-minute reserves in Eastern New York; 10-minute spinning reserves in Western New York; and regulation.

Figure 7: Day-Ahead Ancillary Services Prices
2007 – 2008



To the extent that ancillary services are scheduled on capacity that would otherwise be economic to produce energy, increases in energy prices increase the cost of providing ancillary services. Figure 7 shows regulation prices and 10-minute spinning reserve prices increased in the first half of 2008, consistent with the general rise in energy prices during the same period.

Differences between Eastern and Western 10-minute reserves prices increased in the first half of 2008, reflecting the increase in congestion from west to east during the same period. For example, when congestion increases the need for online generators in Eastern New York to produce energy, they have less capacity available to provide spinning reserves, leading to higher spinning reserves prices in Eastern New York.

5. 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, congestion, and losses. The all-in price is calculated for various locations within New York because both capacity and energy prices vary substantially by location. The energy prices used for this metric are load-weighted average real-time energy prices. The capacity component is calculated by multiplying the average prices in the spot auction by the capacity obligations in each capacity zone, and then dividing by total energy consumption. For the purposes of this metric, costs other than energy and capacity are distributed evenly for all locations.

Figure 8: All-In Prices by Region
2007 – 2008

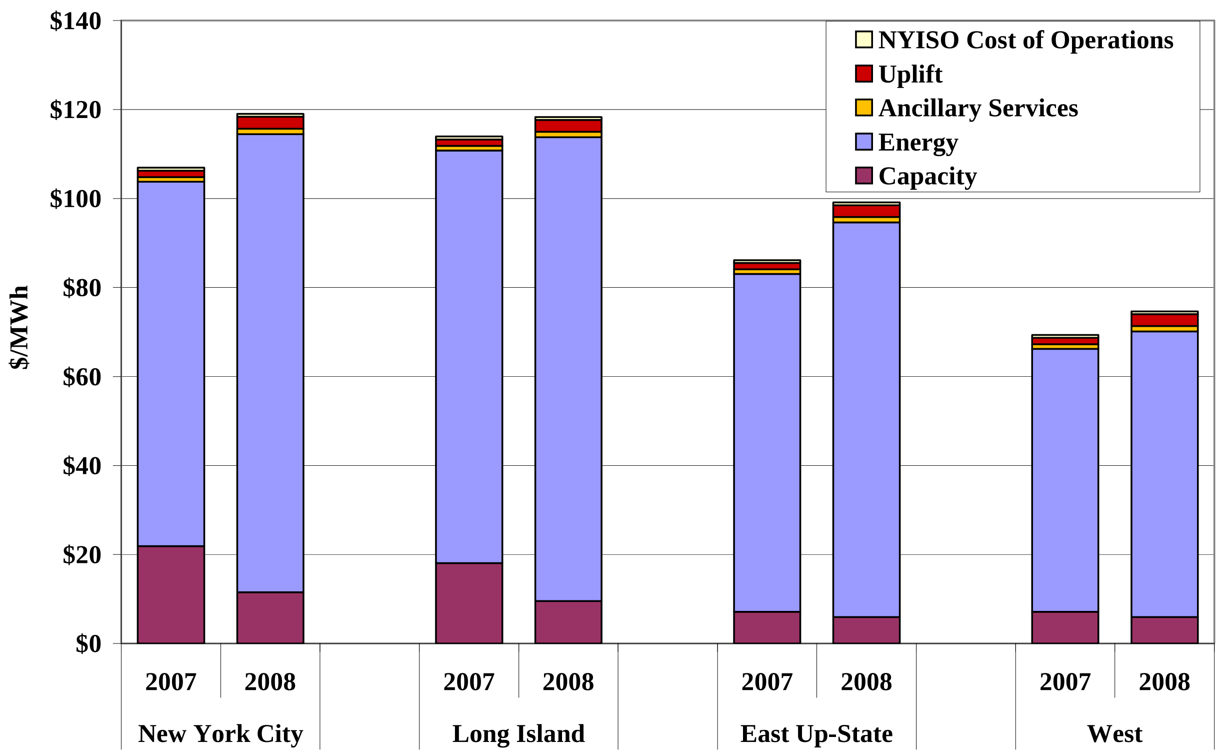


Figure 8 shows the all-in price increased from 2007 to 2008 in each of the four regions. The increase can be attributed to two factors. First, increased fuel prices have increased energy costs, particularly in Eastern New York where more generation relies on natural gas and fuel oil. Second, balancing congestion residual charges increased primarily due to the increase in clockwise loop flows around Lake Erie in the first half of 2008. The increase in balancing congestion residual charges was the principal driver of the 85 percent rise in total uplift charges from 2007 to 2008. Balancing congestion residual charges are evaluated in Section V.D.

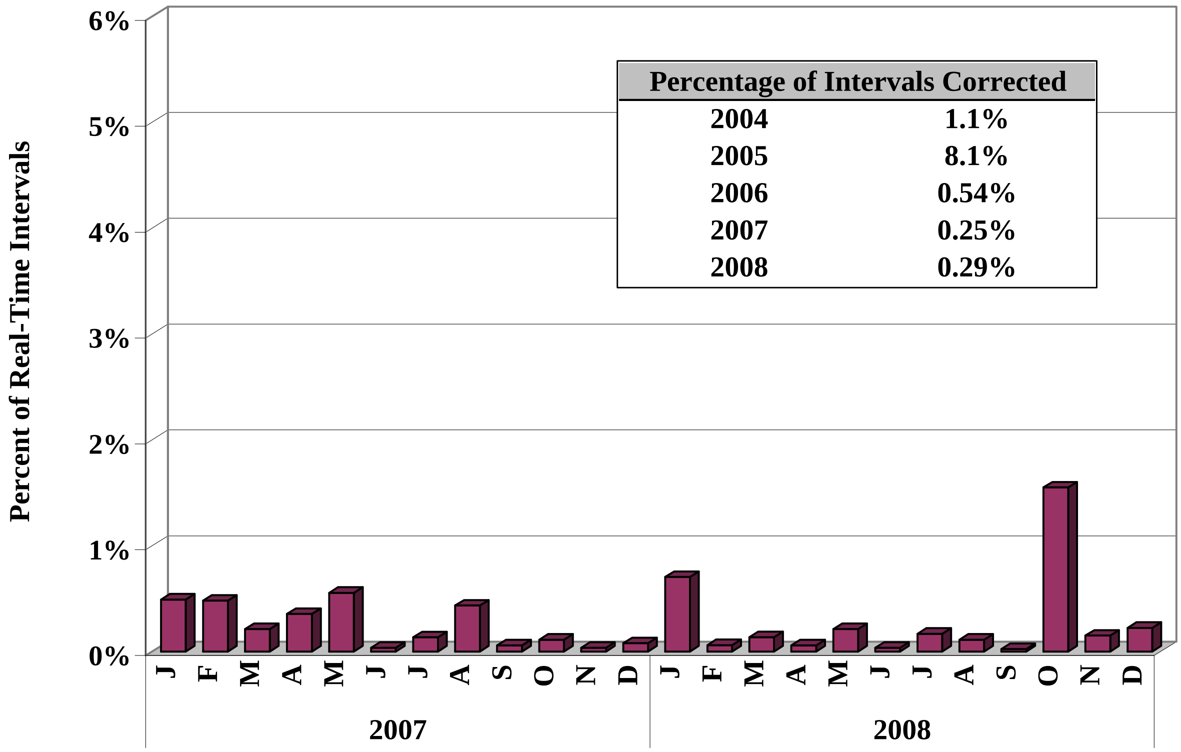
There were three factors that partially offset the increases in all-in prices. First, capacity prices decreased in New York City due to the sale of capacity that had been previously withheld. Second, capacity prices decreased in Long Island due to a reduction in the local capacity requirement. The local capacity requirement was reduced in order to recognize that the Neptune cable (which enables up to 660 MW of power to flow from New Jersey to Long Island) reduces the amount of power that must be generated within Long Island under very high demand conditions. Third, there were fewer very high load hours in 2008 than in previous years, which led to fewer real-time shortage pricing events.

While natural gas prices rose 19 percent from 2007 to 2008, real-time energy prices in Western New York increased only 9 percent. Price increases in Western New York were partly offset by clockwise loop flows around Lake Erie, which increased west-to-east congestion through Upstate New York. The loop flows caused more unscheduled power to flow over key interfaces, thereby reducing the amount of transmission capability available for scheduling flows from Western to Eastern New York. With less Western New York generation scheduled to serve load in Eastern New York, energy prices were lower in Western 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 9 summarizes the frequency of price corrections in the real-time energy market by month for 2007 and 2008.

Figure 9: Percentage of Real-Time Prices Corrected
2007 – 2008



The table in Figure 9 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. In 2007 and 2008, price corrections occurred in less than 0.3 percent of real-time pricing intervals.

In June 2007, the frequency of price corrections decreased as a result of improved modeling when transmission constraints are not resolved. Such intervals occur during extremely tight operating conditions when the available supply may not be sufficient to meet demand, schedule ancillary services, and resolve congestion simultaneously. To the extent shortages of transmission capability occur, it is important for real-time price signals to reflect accurately the scarcity of supply.

In 2008, there were two months when the rate of price corrections was significantly higher than in other months. In January, the frequency of price corrections was elevated due to a metering error that affected several hours. In October, the frequency of price corrections increased due to an issue that only affected prices at a single location. Overall, the frequency of corrections and the significance of the corrections have declined to extremely 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 there is sufficient generation 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 six 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, and the Capital Zone.[6] We estimate the net revenue the markets would

[6] For all net revenue analyses: the Long Island calculations are based on prices for Zone K, the Vernon/

have provided to two different types of units at these locations in the last five years. The two types of units are:

- A new combined-cycle unit: assumes a heat rate of 7 MMbtu per MWh and variable O&M expenses of $3 per MWh, and
- A new combustion turbine: assumes a heat rate of 10.5 MMbtu per MWh and variable O&M expenses of $1 per MWh.

For both unit types, the analysis assumes a forced outage rate of 5 percent.

In this part of the section, we calculate net revenue for a hypothetical combustion turbine unit and a hypothetical combined cycle unit using two methods:

- 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. Under this method, net revenue is equal to the day-ahead price minus variable production cost in hours when the price is greater than the variable production cost.
- Enhanced method – This method is similar to the standard method, but it also considers commitment costs, minimum run times, minimum generation levels, and other physical limitations. This method also considers that generators participate in day-ahead and real-time markets.

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.[7]

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, and Capital Zone calculations are based on prices for Zone F.

[7] 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.

For combined cycle units, the enhanced method assumes the unit is committed based on prices in the day-ahead market, considering start-up costs, minimum run times, and a limited dispatchable range with 10-minute and 30-minute spinning reserve capability. This method also assumes that an online generator is able to arbitrage between day-ahead prices and hourly average real-time prices by increasing or decreasing production based upon real-time price signals.

For combustion turbine units, the enhanced method assumes the unit is initially committed based on prices in the day-ahead market, considering start-up costs, a one-hour minimum run time, a one-hour minimum downtime, and 30-minute reserve capability. This method also assumes the unit may be committed for additional hours based on prices calculated by the real-time commitment software (RTC or BME), but it assumes the unit is paid the hourly average real-time price.

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 10 shows net revenues for a new combined cycle generator, and Figure 11 shows net revenues for a new combustion turbine. Note that the capacity auction revenues are based on the clearing prices in the spot auctions.

Figure 10 and Figure 11 highlight changes in the New York wholesale markets over the last five years.

- Net revenues rose significantly from 2004 to 2005 due to higher load, more frequent shortages and better shortage pricing under SMD 2.0.
- In New York City, net revenues declined considerably in 2006 due to the installation of 1 GW of new generating capacity in the 138kV system.

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 nominated day-ahead. This issue is not addressed by the enhanced method.

- From 2006 to 2008, net revenue levels rose moderately in the Hudson Valley and Capital zones due to additional congestion across the Central-East interface and increased capacity prices resulting partly from the introduction of a new capacity market by ISO New England in December 2006, which attracted some capacity that was previously sold into the NYISO market.
- In July 2007, the Neptune cable from New Jersey to Long Island introduced new supply which resulted in substantially reduced net revenues from energy for generators on Long Island.

Figure 10: Enhanced Net Revenue: Combined Cycle Unit
2004 – 2008

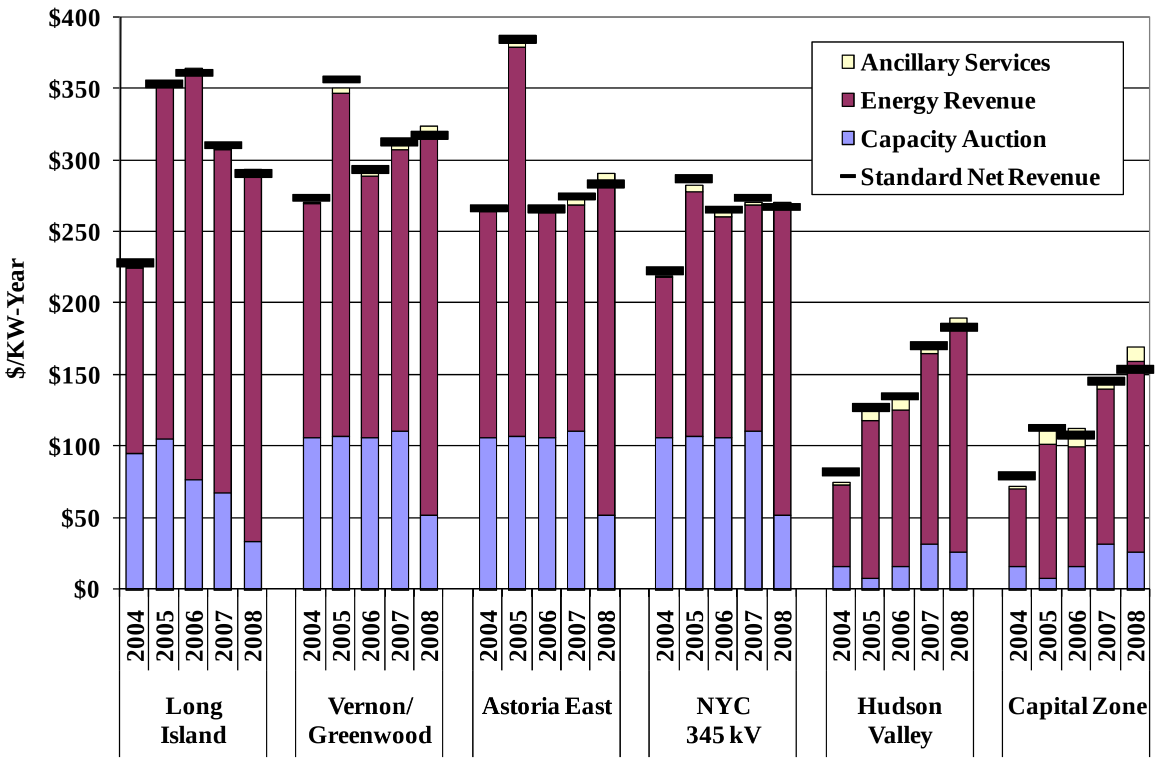
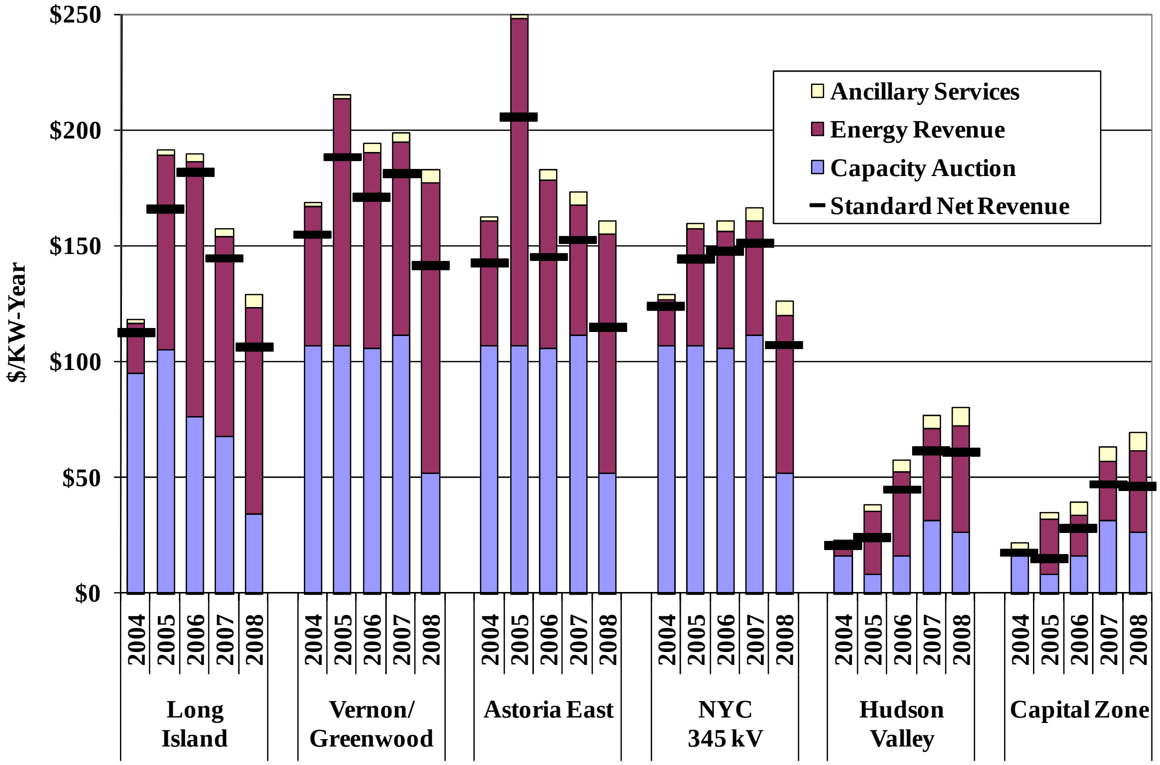


Figure 11: Enhanced Net Revenue: Combustion Turbine Unit
2004 – 2008



In 2008, net revenues declined in most areas of New York City and Long Island and increased in Eastern Upstate New York due to several factors. The increase in fuel prices from 2007 to 2008 contributed to increased energy net revenues throughout New York State. This is because rising fuel prices lead to proportionate increases in the spreads between wholesale energy prices and the costs of production. Furthermore, energy net revenues for natural gas generators in New York City were driven higher in periods when LBMPs were set by high-cost oil-fired peaking generation.

Net revenues were generally increased in Eastern New York as a result of the high volume of clockwise loop flows around Lake Erie in 2008. The loop flows reduced the west-to-east transmission capability available to the market, thereby increasing the amount of generation required in Eastern New York. This, in turn, increased LBMPs in Eastern New York.

The increases in energy net revenues were generally offset by decreased capacity net revenues throughout New York State. In New York City, in-service capacity that was previously unsold began to be scheduled in March 2008, leading to a sharp decline in capacity prices. In Long Island, the addition of the Neptune cable led to downward adjustment in the local capacity requirement, which reduced capacity prices. In upstate areas, capacity prices were reduced by increased capacity sales in New York City, since sales in local capacity zones also count toward the statewide capacity requirement.

Overall, 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 $188 per kW-year in New York City, $167 per kW-year on Long Island, and $101 per kW-year in the Capital zone for the 2008 per 2009 capability year. Vernon/Greenwood is the only area of New York where net revenue levels were as high as the estimated CONE for a combustion turbine.

Although we have no estimates of CONE for a new combined cycle in New York, the estimated net revenues are substantially higher for a new combined cycle than a new combustion turbine. In upstate areas, the estimated net revenues for a new combined cycle were more than double those for a new combustion turbine in 2008. In New York City, the estimated net revenues for a new combined cycle were more than $100 per kW-year higher than those for a new combustion turbine in 2008. Depending on the CONE for combined cycle technology, it may be economic to build in some areas of New York under the current market conditions.

However, prospective investors can expect net revenues to decline in the first few years following new entry due to the effects of new supply on energy and capacity prices. For example, after 1 GW of new combined cycle capacity was placed in 138kV system of New York City in 2006, energy net revenues declined from the previous year by 49percent for a new combustion turbine and by 42 percent for a new combined cycle unit in Astoria East. The effect was smaller but still significant in the 345kV system of New York City where energy net revenues declined 10 percent for a new combined cycle unit from the previous year. Capacity net revenues were not initially affected by the new entry due to withholding in the capacity market, but after the withholding ended in 2008, capacity net revenues declined 53 percent from the previous year.

Overall, the net revenues in 2008 were consistent with fundamental supply and demand conditions. Hence, we find no evidence of market design flaws or other problems that would lead to distorted or otherwise inefficient market signals in 2008.

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 generator on an unprofitable day since the day-ahead auction market will only accept their offer 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.[8] 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. Also, persistent differences between day-ahead and real-time prices can undermine incentives for suppliers to offer their resources at marginal cost.

In this section, we evaluate three aspects of convergence in prices between day-ahead and real-time markets. 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.

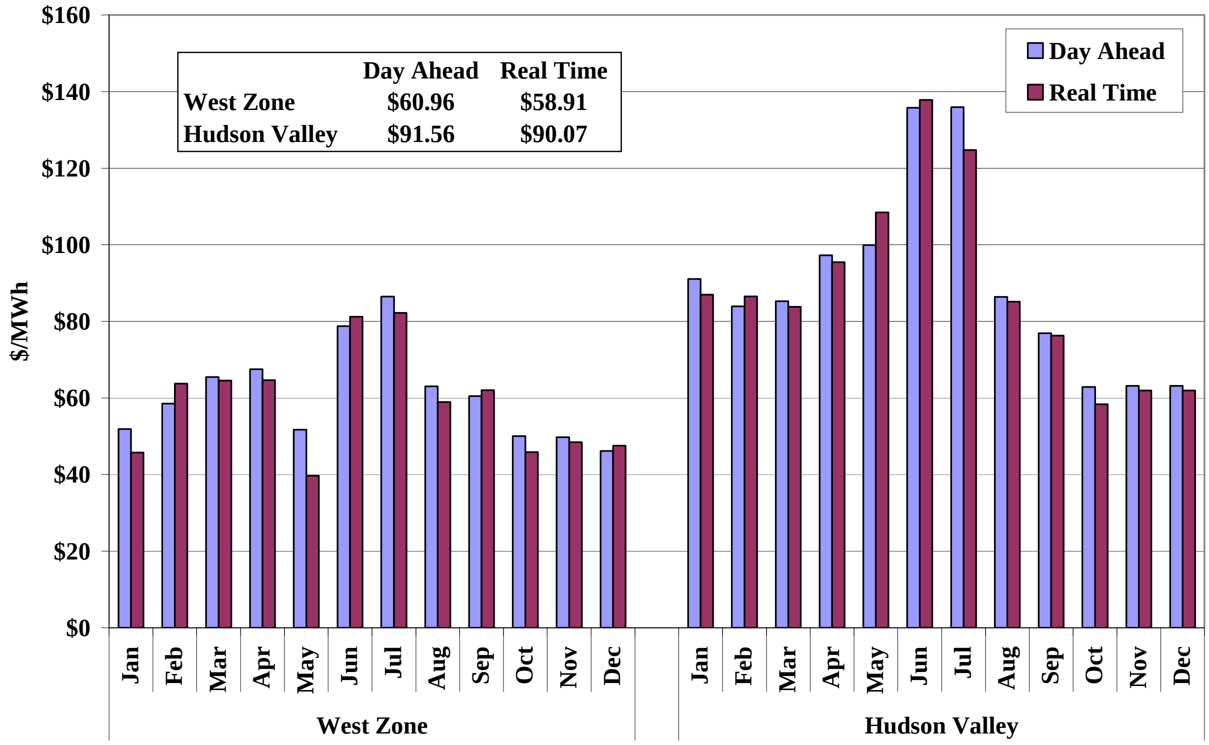
1. Energy Price Convergence

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. 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 12 and Figure 13 compare the average day-ahead and real-time energy prices in West zone, Hudson Valley, New York City, and Long Island in each month of 2008. This is 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.

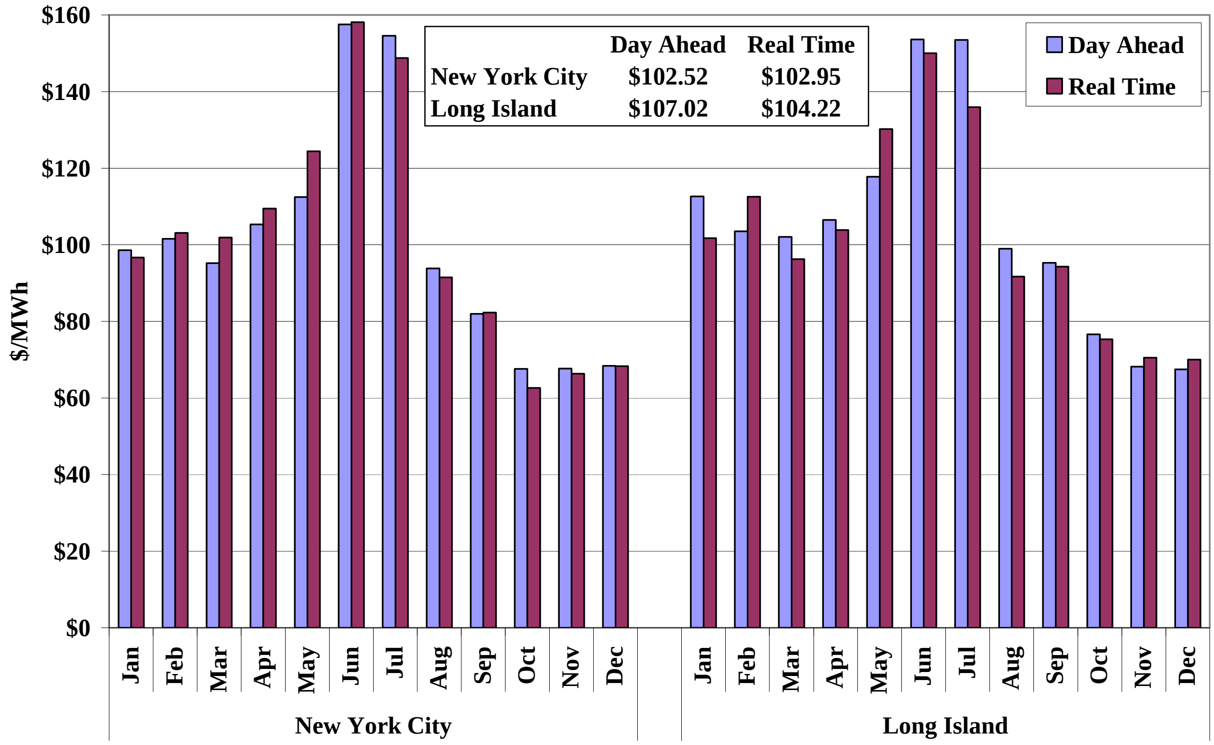
[8] Sellers would show the opposite tendencies.

Figure 12: Day-Ahead and Real-Time Energy Price Convergence
West Zones and Hudson Valley, 2008



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, the day-ahead market did not fully anticipate acute congestion over the Leeds-to-Pleasant Valley line on May 27. Therefore day-ahead prices were significantly lower than real-time prices in Southeast New York and much higher than real-time prices outside Southeast New York on May 27.

Figure 13: Day-Ahead and Real-Time Energy Price Convergence
New York City and Long Island, 2008



Both Figure 12 and FigureFigure 13 show that a day-ahead premium prevailed in 2008 at all four locations. Historically, it has been common for day-ahead prices to carry a slight premium over real-time prices for several reasons. Some loads have a preference for the lower volatility of day-ahead prices and may be willing to pay a small premium in the day-ahead market. Some generators face significant risk of having an outage after selling in the day-ahead market, which would obligate them to buy power in the real-time market. Hence, such generators may incorporate a small risk premium in their day-ahead offer.

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 2008, typically arise when real-time scarcity conditions occur less frequently than market participants anticipate.

Figure 14 show the variation in these differences on a daily basis in New York City and Long Island zone during weekday afternoon hours in 2008. A positive number represents a real-time market price premium, while a negative number represents a day-ahead price premium.

Figure Figure 15 shows day-ahead prices are higher than real-time prices on most afternoons. For example, in New York City, day-ahead prices were higher than real-time prices on 63 percent of the afternoons. However, very high price spikes are more frequent in the real-time market. For example, in New York City, there were two afternoons when the day-ahead price premium exceeded $100 per MWh compared to six afternoons when the real-time price premium exceeded $100 per MWh.

A substantial portion of real-time price spikes occur 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. One such event occurred on May 27, the day with the largest real-time price premium in 2008. A TSA on that day reduced the power flows on the transmission lines running through the Hudson Valley toward New York City and Long Island, leading to five hours of acute real-time congestion.

Figure 14: Average Daily Real-Time Energy Price Premium
1 p.m. to 7 p.m., Weekdays, 2008, New York City

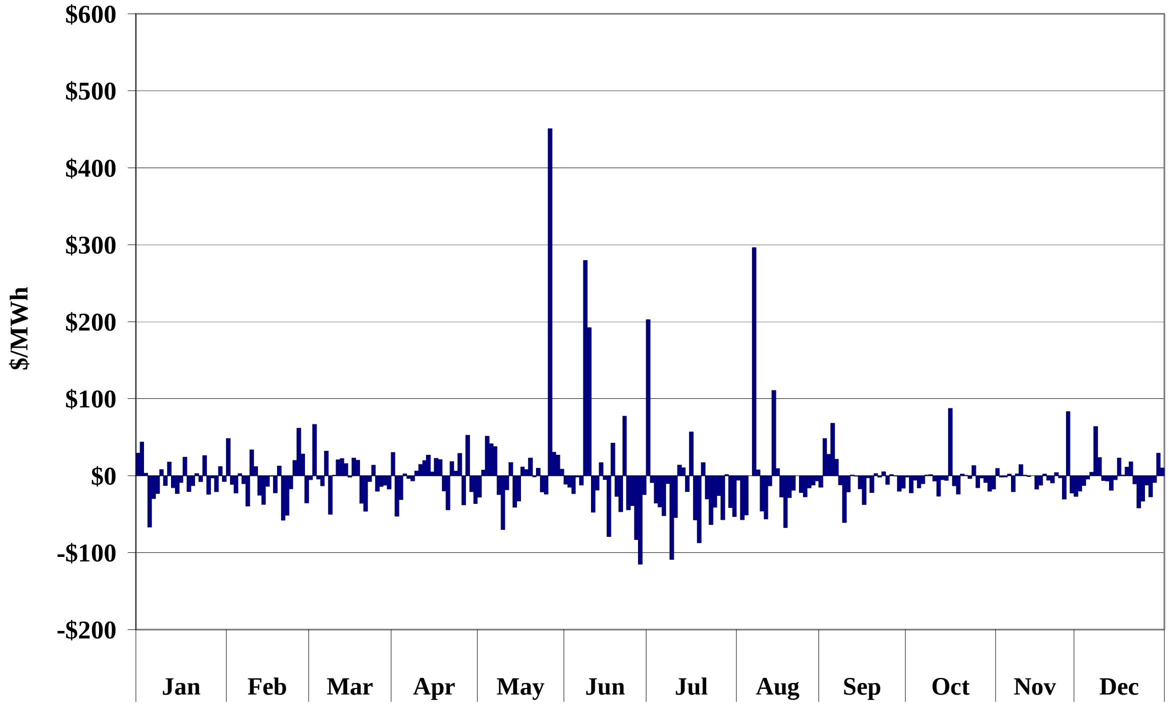
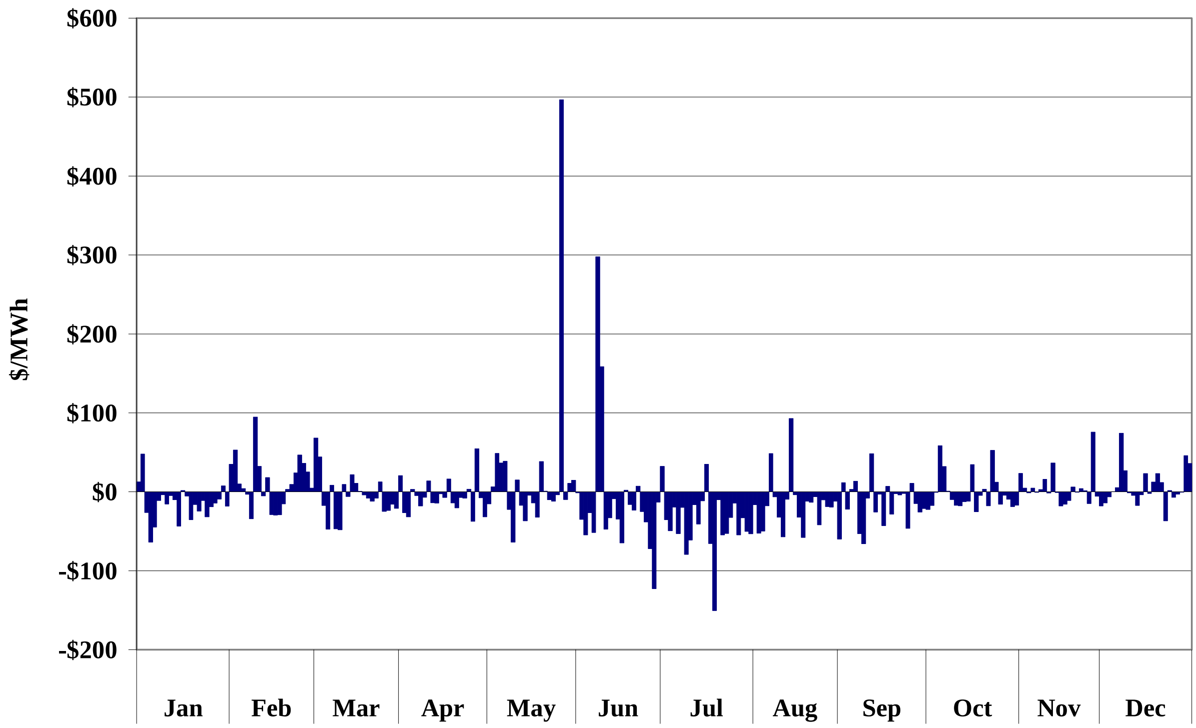


Figure 15: Average Daily Real-Time Energy Price Premium
1 p.m. to 7 p.m., Weekdays, 2008, Long Island



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.

2. Price Convergence at Individual Pricing Nodes

Sub-section 1 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 real-time market, leading to poor convergence at individual nodes even if convergence is good at the zone level.

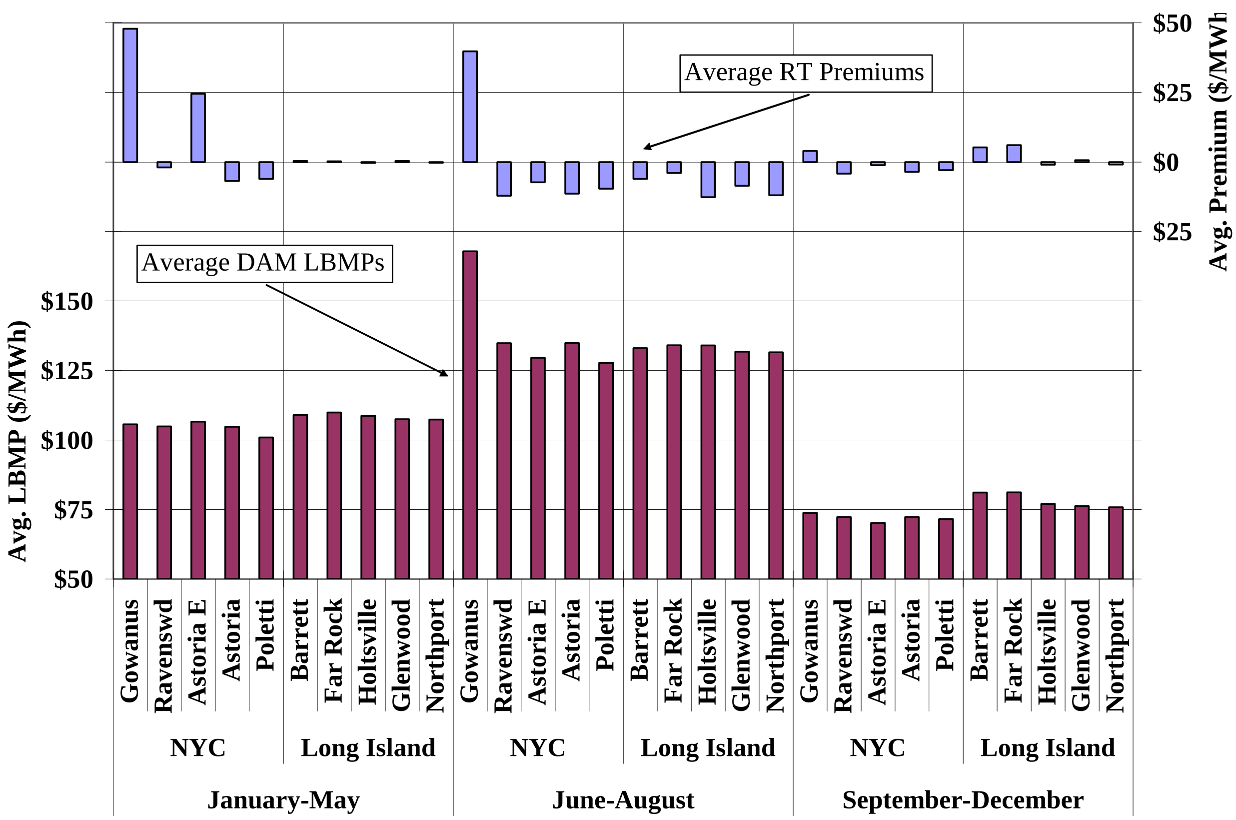
The pattern of congestion may change between the day-ahead market and the real-time market for many reasons. First, generators that are not scheduled in the day-ahead market may change their offers. This is common during periods of fuel price volatility or when natural gas is more easily procured day-ahead. 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 16 shows average day-ahead prices and real-time price premiums in 2008 for a selection of locations in New York City and Long Island that have historically exhibited high levels of intra-zonal congestion. 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 good day-ahead to real-time convergence at the nodal level in up-state areas.

Figure 16: Real-Time Price Premiums at Individual Nodes

Selected Nodes in New York City and Long Island, 2008



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 16 shows certain areas experienced substantial real-time congestion that was not fully reflected in the day-ahead market. The most notable example was at the Gowanus plant from June to August when the difference between the average LBMP at the Gowanus plant and other areas of New York City was approximately $30 per MWh in the day-ahead market and $80 per MWh in the real-time market. Hence, there was far more congestion into this load pocket in the real-time market than in the day-ahead market. Virtual trading at a more disaggregated level would allow market participants to arbitrage these differences.

The large difference between oil and natural gas prices likely contributed to inconsistencies between day-ahead and real-time prices in 2008. Generators that are not scheduled in the day-ahead market may have difficulty obtaining natural gas intra-day and are, therefore, more likely to use fuel oil if scheduled in the real-time market. This is particularly important for dual-fueled quick start generators, which usually burn the most expensive grades of fuel oil (e.g., diesel oil or kerosene) when natural gas is unavailable. Hence, the cost of supply may be higher in the real-time market than in the day-ahead market in load pockets that frequently rely on duel-fueled quick start generators.

In New York City, there are two additional factors that likely contributed to inconsistencies between day-ahead and real-time prices. First, Supplemental Resource Evaluation ("SRE") commitments were made after the day-ahead market on most days, which increased supply in the real-time market compared with the day-ahead market. SRE-committed generators accounted for an average of 910 MW of the online capacity and 250 MW of energy production in New York City in 2008. In February 2009, the NYISO made enhancements to the day-ahead market process to reduce the amount of capacity committed through the SRE process. Under the new process, more of the reliability criteria that had required SRE commitments are satisfied in the day-ahead market process.[10] This reduced the need for SRE commitments and is expected to reduce pricing and scheduling inconsistencies between the day-ahead market and the real-time market.

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10 These enhancements are described in Tech Bulletin #182 on the NYISO website.

Second, interface constraints were sometimes used in the real-time market to maintain reliability in New York City load pockets, while more detailed line constraints were always used in the day-ahead market. In 2008, 64 percent of the real-time binding constraints in New York City were interface constraints, while interface constraints were never used in the day-ahead market. Detailed line constraints allow the market models to manage congestion more efficiently than when the simpler interface constraints are used. Accordingly, the use of interface constraints in the real-time market but not the day-ahead market leads to pricing and scheduling inconsistencies between the day-ahead market and the real-time market.

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 to average day-ahead prices that were substantially different from average real-time prices at several nodes. The NYISO has made changes to the day-ahead market that are expected to improve consistency between the day-ahead and real-time markets. The NYISO is also developing a proposal to allow virtual trading at a more granular level than the zonal virtual trading that is currently allowed. This proposal is expected to improve convergence between day-ahead and real-time prices.

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 17 shows 10-minute 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 18 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. 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 these reserves.

Both figures show that average day-ahead prices are systematically higher or lower than average real-time prices under various circumstances. For instance, for 10 minute non-spinning reserves average real-time prices tend to be higher than average day-ahead prices during the afternoon peak in summer months, while average day-ahead prices tend to be higher than average real-time prices at most other times.

The average prices in the figures above 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 the majority of hours, excess reserves are available on on-line generators and off-line quick start resources, leading the real-time price of reserves to be $0 per MWh in a substantial share of hours. In 2008, real-time 10-minute reserves prices were $0 per MWh in 99 percent of intervals, but rose significantly in the remaining intervals. Hence, the $16 per MWh average price in the peak afternoon hour of 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, but the volatility is difficult for market participants to predict in the day-ahead market. Based on Figure 17 , the day-ahead market systematically under-valued 10-minute reserves in the east during the summer in the afternoon.

Figure 17: Day-Ahead and Real-Time 10-Minute Reserves Prices
Eastern New York, 2008

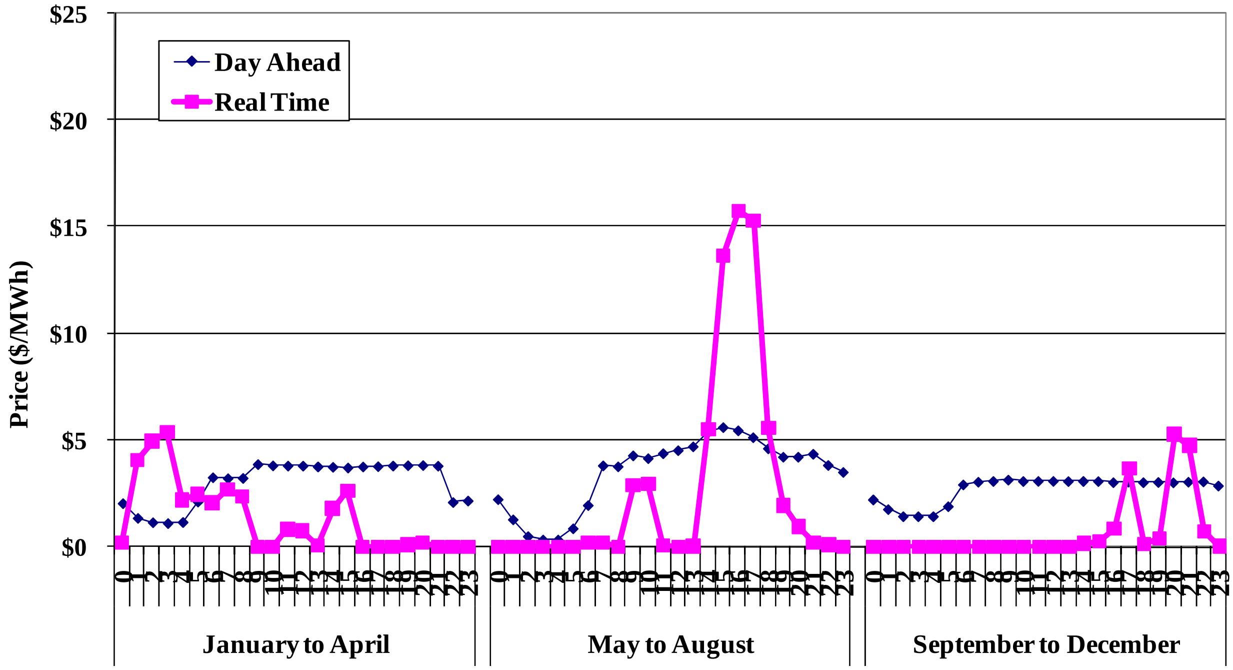
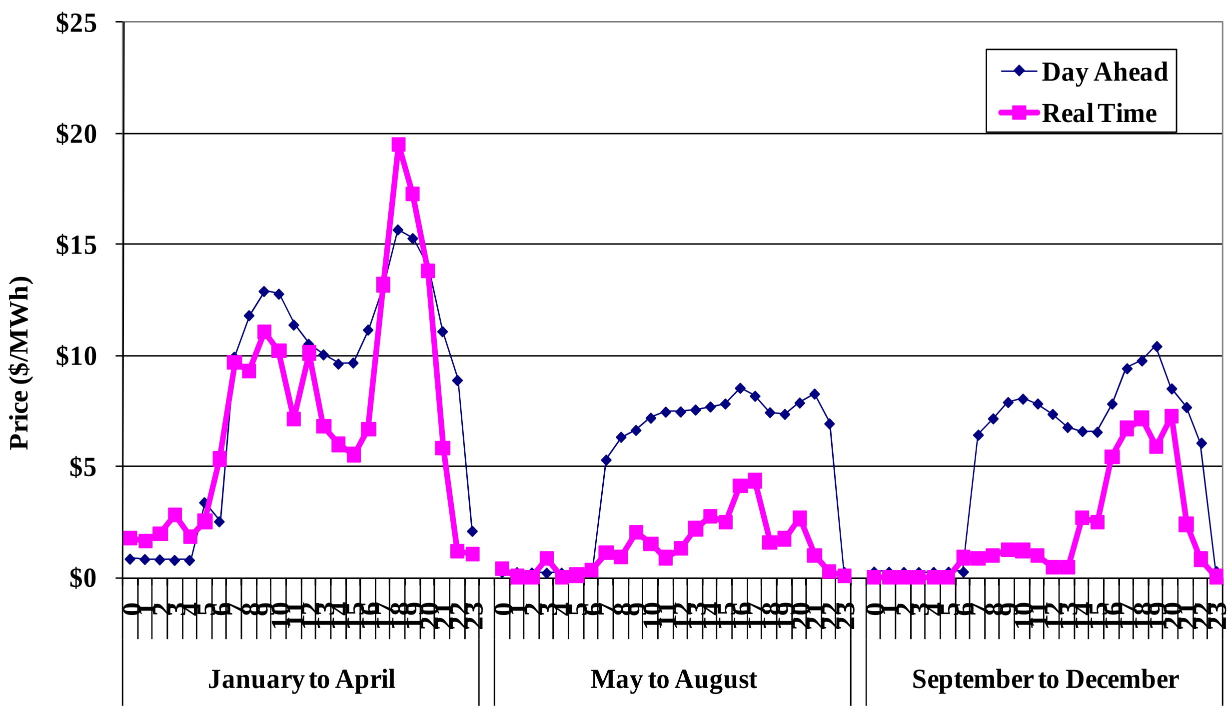


Figure 18: Day-Ahead and Real-Time 10-Minute Spinning Reserves Prices
Western New York, 2008



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.

The practice of committing generation through the SRE process likely contributes to inconsistencies between day-ahead and real-time reserves prices at certain times. SRE commitments are made after the day-ahead market on most days, thereby increasing the supply of online energy and reserves in the real-time market compared with the day-ahead market. As discussed in Section VI, the NYISO made enhancements to the day-ahead market process to reduce the amount of capacity committed through the SRE process in February 2009. This enhancement is expected to reduce pricing and scheduling inconsistencies between the day-ahead market and the real-time market.

Convergence between day-ahead and real-time reserve prices has improved over the last several years. However, the results presented indicate that the prices continue to not converge well much of the time. Poor convergence between day-ahead and real-time prices raises concerns, because it can lead to inefficient unit commitment. For instance, when reserves are under-valued in the day-ahead market, it may lead units that are comparatively good providers of reserves to not be committed and available in real-time. Likewise, when reserves are over-valued in the day-ahead market, it may lead to the inefficient commitment of comparatively expensive resources that can provide reserves, but that do not provide sufficient value to the system.

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.

III. Analysis of Energy and Ancillary Services Bids and Offers

In this section, we examine 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 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 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). 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 cost of production 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.

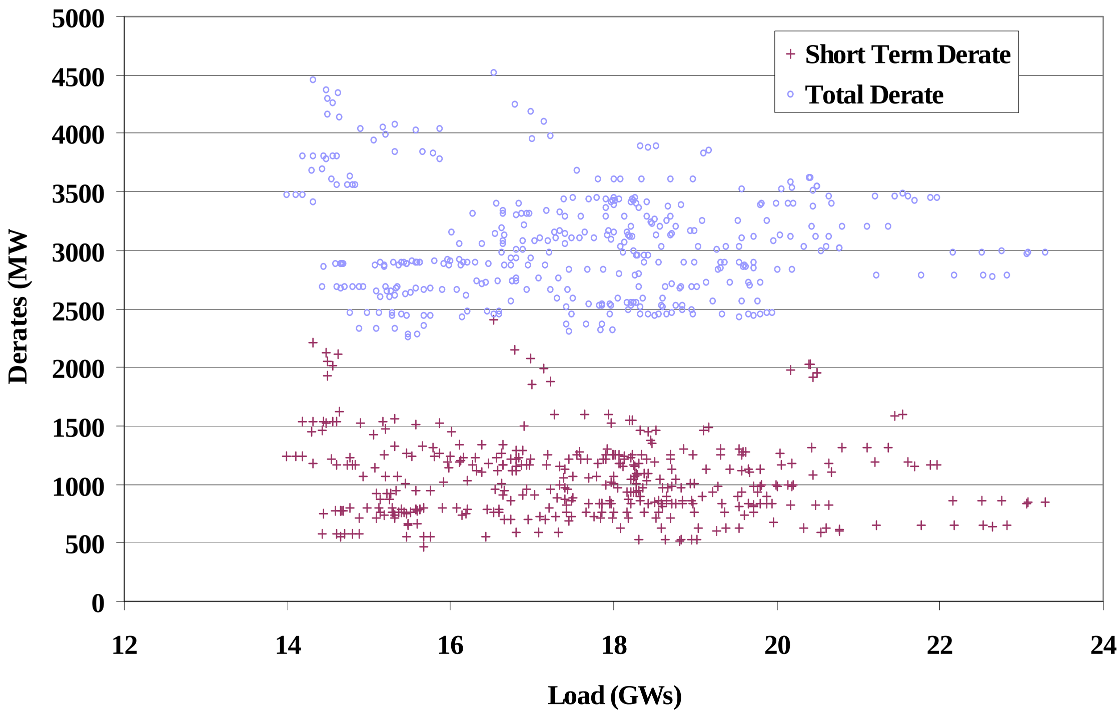
To distinguish between strategic and competitive conduct, we evaluate potential withholding in light of the market conditions and participant characteristics that would tend to create the ability and incentive to exercise market power. Under competitive conditions, suppliers maximize profits by increasing their offer quantities during the highest load periods to sell more power at the higher peak prices. 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 occur during the summer when demand is highest. By eliminating planned outages, we implicitly assume that planned outages are legitimate and are not aimed at exercising market power.[11]

In Figure 19, 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 19: Day-Ahead Deratings vs. Actual Load in East New York
Peak Hours in Summer 2008*



* Peak hours are defined as hours on weekdays from noon to 6pm.

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11 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 19 indicates that neither Total Derates nor Short-Term Derates rise substantially under high load conditions. This is a positive sign since the incentive to physically withhold resources generally increases under high demand 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 demand conditions when the ISO calls on relatively high-cost units to operate that generally do not operate in other hours. In addition, the high ambient temperatures that typically contribute to peak load conditions reduce the capability (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,

However, total derates increased 15 percent from the summer of 2007 to the summer of 2008 on average. The primary reason for this increase was that a single generator experienced a long-term forced outage that lasted the entire summer.

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.[12] An offer parameter is considered above the competitive level if it exceeds the reference level by a given threshold.

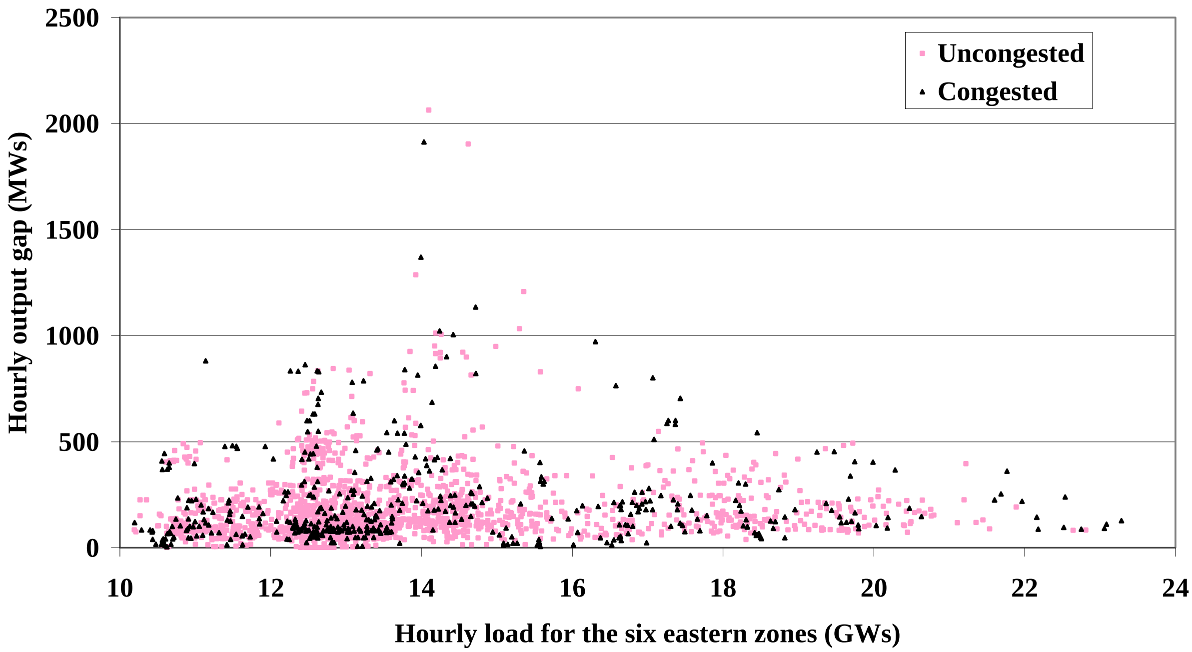
We measure potential economic withholding by estimating an "output gap" for units that submit start-up, minimum generation, and incremental energy offer parameters that are above the reference level by a given threshold. The output gap is the amount of generation that is

[12] 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.

economic at the market clearing price, but is not producing output due to the owner's offer price.[13]

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 20 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 21 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 20: Real-Time Output Gap at Mitigation Threshold vs. Actual Load
East New York -- Peak Hours in 2008*



* Peak hours are defined as hours on weekdays from noon to 6pm.

[13] The output gap calculation excludes capacity that is more economic to provide ancillary services.

Figure 21: Real-Time Output Gap at Low Threshold vs. Actual Load
East New York -- Peak Hours in 2008*

* Peak hours are defined as hours on weekdays from noon to 6pm.

The figures indicate that the output gap does not rise substantially under high load conditions. Also the figures show that the output gap does not increase substantially during periods of congestion. These are good results 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 2008.

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.[14]

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 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.[15] 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 2008. In both figures, the line indicates the percent of hours when 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. Mitigated quantities are shown separately for the flexible output ranges of units (i.e. Energy) and the non-flexible portions (i.e. MinGen/Start-Up).[16]

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14 See NYISO Market Services Tariff, Attachment H.

15 Threshold = (0.02 * Average Price * 8760) / Constrained Hours

16 Mitigation of gas turbine capacity is shown in the Energy category when the energy offer is mitigated, while it is shown in the Mingen/Start-up category when the start-up offer is mitigated but the energy offer is not.

Figure 22: Frequency of Day-Ahead Mitigation in the NYC Load Pockets
2008

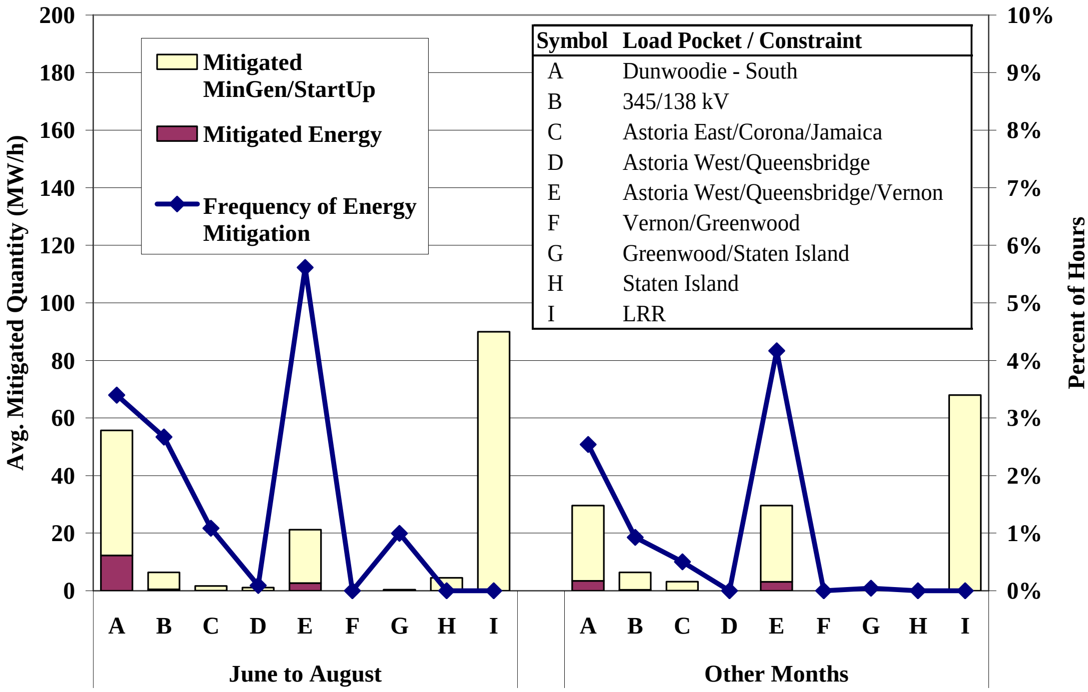


Figure 22 indicates that day-ahead mitigation is infrequent. The majority of day-ahead mitigation was on generators committed to satisfy Local Reliability Requirements ("LRR"). The start-up and MinGen offers of LRR units are mitigated whenever they exceed the reference level.[17] The Astoria West/Queens/Vernon interface exhibited most frequent energy mitigation, although mitigation in this load pocket only occurred during 4 to 6 percent of hours.

The majority of capacity mitigated in the day-ahead market is associated with the start-up and MinGen parameters, while relatively little is 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 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

[17] LRRs are developed by the NYISO to maintain system reliability in local areas. The day-ahead market will commit additional units, which otherwise would not be economic, to meet the LRRs. 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.

run time, while its incremental energy parameter would be mitigated only in the hour with impact.

Figure 23: Frequency of Real-Time Mitigation in the NYC Load Pockets
2008

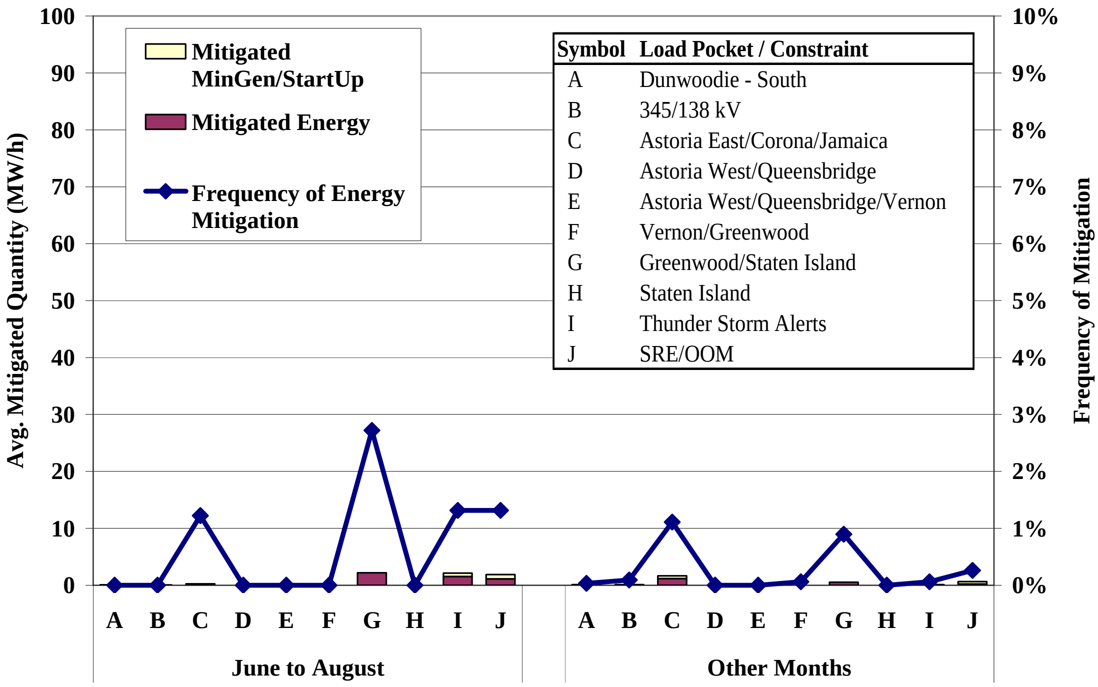


Figure 23 shows the most frequent real-time mitigation occurred for the Greenwood/Staten Island load pocket, which is in the 138 kV portion of New York City. The load pocket is dominated by one supplier and experiences frequent real-time congestion making it more susceptible to the exercise of market power. The majority of real-time mitigation was associated with incremental energy bid parameters rather than MinGen bid parameters. This is because a large share of real-time mitigation is of gas turbines, which do not submit MinGen offers. 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 less than of 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 throughout this report. Section II.A summarizes ancillary service prices in the day-ahead market in 2007 and 2008, 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 in under some operating conditions. Section VI.B evaluates the efficiency of prices during shortage conditions, showing significant improvement since the use of demand curves was introduced in 2005.

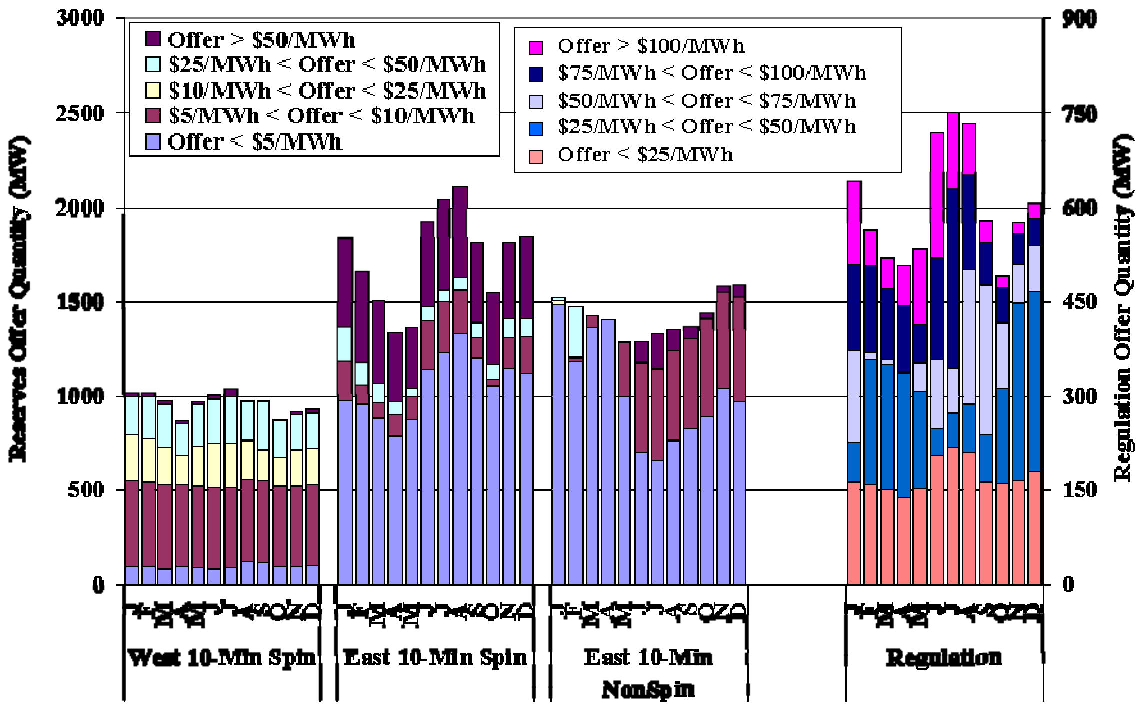
This sub-section evaluates the efficiency of ancillary services offer patterns, particularly in light of the relationship between day-ahead and real-time ancillary markets. Under the current market rules, only generators have the ability to submit ancillary services offers in the day-ahead market. In 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.[18] However, the high volatility of real-time reserves clearing prices makes them difficult for market participants to predict in the day-ahead market and is a source of risk for generators that sell reserves in the day-ahead market (i.e., that the generator will have foregone scarcity revenues it would have otherwise received in the real-time market). Some suppliers may reduce their exposure to this risk by raising their reserves offer prices in the day-ahead market.

18 Specifically, we expect suppliers to raise their day-ahead offer prices when day-ahead prices are expected to be lower than real-time prices, and we expect them to lower their day-ahead offer prices when day-ahead prices are expected to be higher than real-time prices.

1. Summary of Offers

Figure 24 summarizes the ancillary services offers for generators in the day-ahead market in each month of 2008. 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 24: Summary of Ancillary Services Offers
Day-Ahead Market, 2008



All four categories of ancillary services offers shown in Figure 24 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; and
- Several generators in the Eastern New York were offered with a lower minimum generating level in the summer, thereby increasing their flexible operating range and the capacity available to provide ancillary services.

10-minute non-spinning reserves offer quantities gradually declined from the beginning of the year until the summer, and then gradually rose until the end of the year. 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 offer prices 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 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 24 shows approximately 300 to 500 MW of 10-minute spinning reserves in Eastern New York is offered above $50 per MWh throughout the year. This likely indicates that some suppliers 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 reserves at the real-time clearing price in order to satisfy its obligations from selling day-ahead. Hence, some suppliers may reduce their exposure by raising their reserves offer prices in the day-ahead market.

The offer prices of 10-minute non-spinning reserves increased significantly after the spring. In May and June, approximately 500 MW of gas turbine capacity shifted from being offered below $5 per MWh to being offered between $5 and $10 per MWh in most hours and above $50 per MWh under peak load conditions. This rise in offer prices may have been a rational response by

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

[20] See Section Chapter I.A.3, which evaluates the convergence between day-ahead and real-time prices.

suppliers who expected real-time clearing prices to be higher on average than day-ahead clearing prices for 10-minute non-spinning reserves in the summer afternoons.[21] When real-time clearing prices are predictably higher than day-ahead clearing prices, generators incur an opportunity cost to sell reserves in the day-ahead market, so we expect generators to raise their day-ahead offer prices. Hence, the increase in day-ahead offer prices helped to better reflect the value of reserves in the day-ahead market, leading to improved convergence between day-ahead and real-time prices during these hours.

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 can lead to convergence issues.

2. Conclusions

In sub-section 3, we found that convergence between day-ahead and real-time reserves prices has been poor under certain conditions. Under some conditions, day-ahead clearing prices appear to be systematically higher on average than real-time clearing prices, while the opposite is true under other conditions. When suppliers expect day-ahead prices to be lower than real-time prices, it increases the opportunity cost of selling reserves in the day-ahead market. In response, suppliers are expected to raise their day-ahead reserve offer prices, which is consistent with the decreased offer quantities and increased offer prices that we observed in this section.

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[21] 10-minutes non-spinning reserves clearing prices were substantially higher on average in the real-time market than in the day-ahead market in the afternoons in the summers of 2005, 2006, and 2007.

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 physical and economic withholding, buyer behavior can strategically influence energy prices. Therefore, evaluating whether load bidding is consistent with workable competition is a part of market monitoring. Load can be purchased in one of the following five 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. It does not represent the entirety of the bilateral contracting in New York, however, 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.[22]

Virtual Load Bids

22 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.

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.

Virtual Supply Offers

These 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 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 deciding to commit 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 part of the section evaluate the consistency of 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 2007 and 2008 at various locations in New York. Virtual load scheduling has the same effect on day-ahead prices and resource commitment as physical load scheduling, hence 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 2007 and 2008. This is shown for New York City and Long Island in Figure 25, Eastern Upstate New York in Figure 26Figure, and Western Upstate New York in Figure 27. For each period, it shows scheduled and unscheduled 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 25: Composition of Day-Ahead Load Schedules versus Actual Load
New York City and Long Island, 2007 – 2008

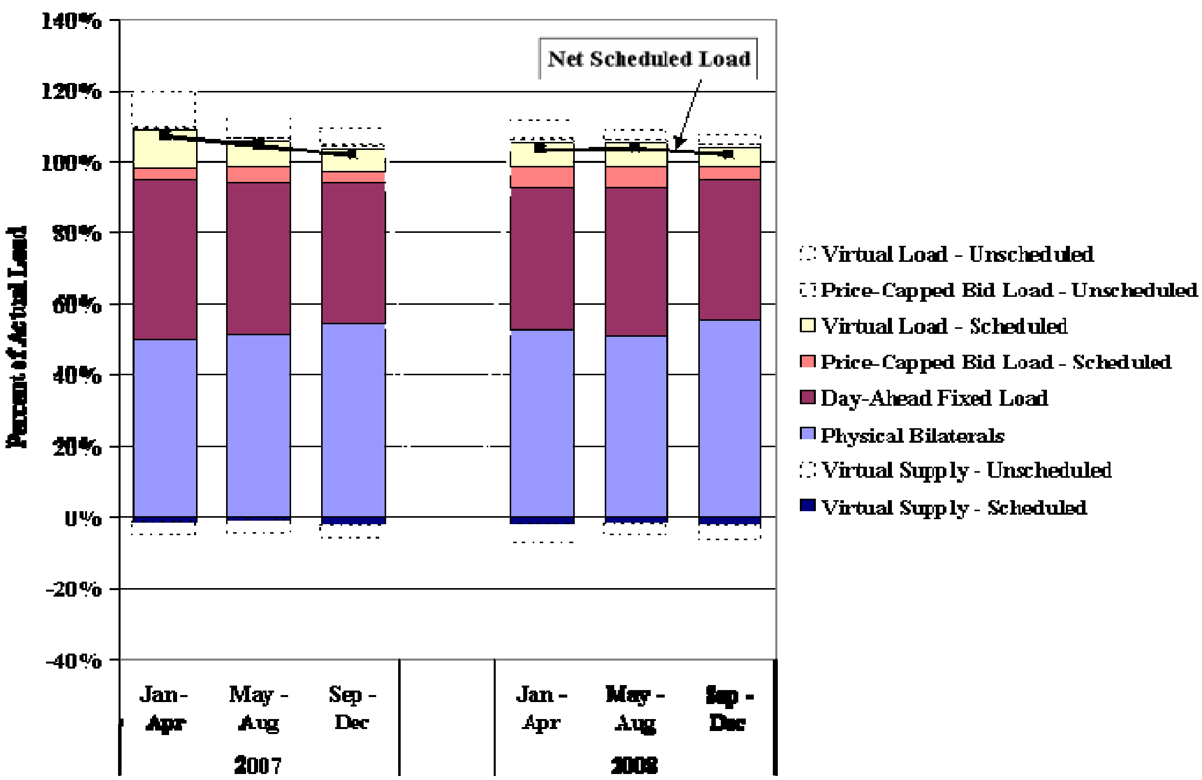


Figure 26: Composition of Day-Ahead Load Schedules versus Actual Load
Eastern Up-State New York, 2007 – 2008

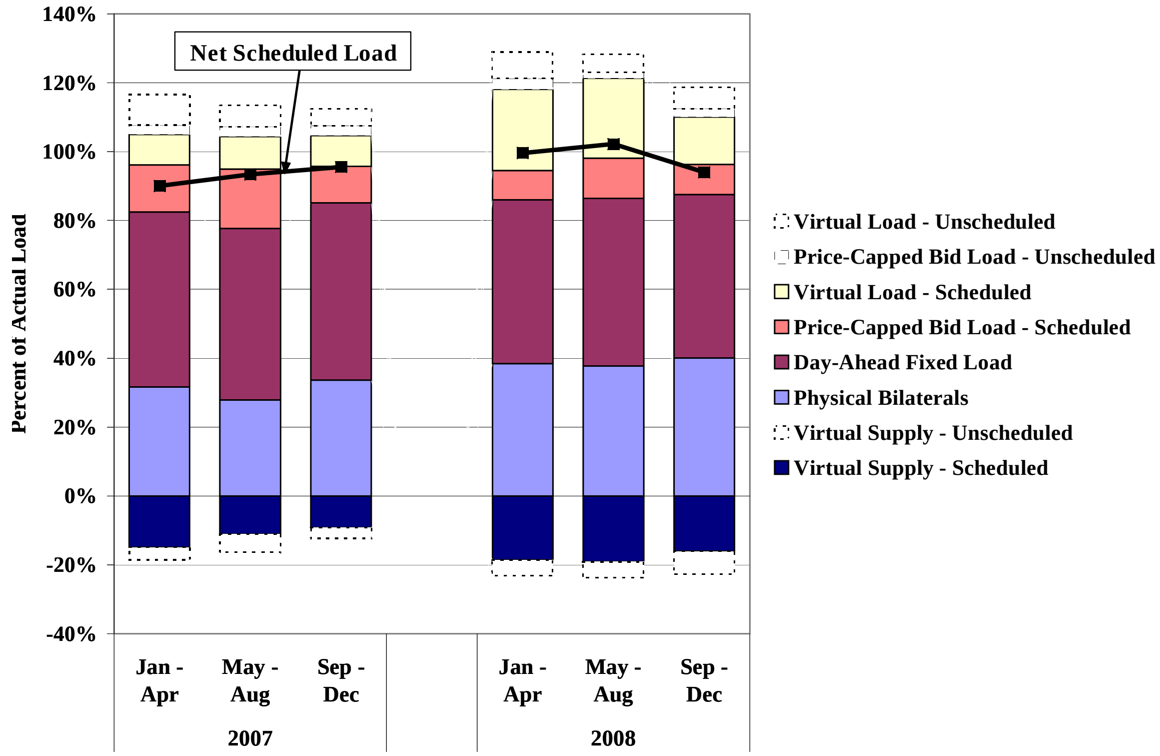
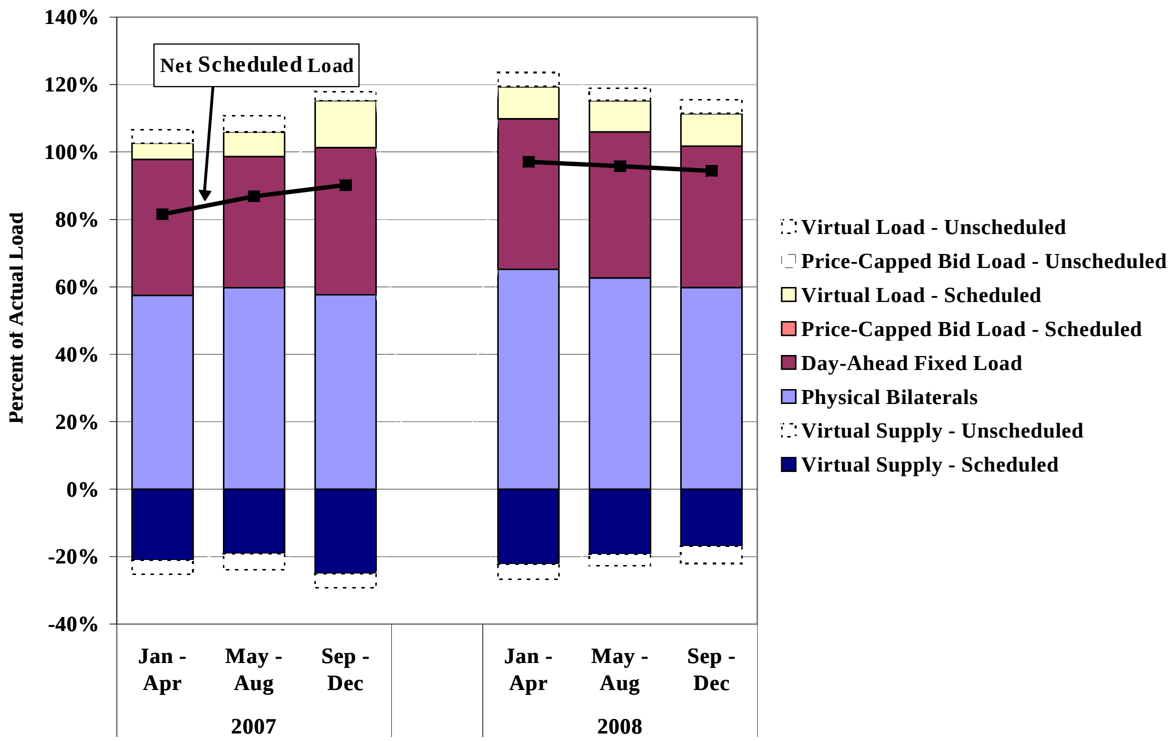


Figure 27: Composition of Day-Ahead Load Schedules versus Actual Load
Western Up-State New York, 2007 – 2008



Day-ahead load was slightly (2 to 4 percent) over-scheduled in New York City and Long Island relative to actual load in 2008. This is an improvement compared to 2007 when day-ahead load was over-scheduled (by as much as 10 percent from January to April). Over-scheduling in New York City and Long Island implies that more imports were scheduled into downstate areas in the day-ahead market than in the real-time market.

Figure 26 and Figure 27 summarize load scheduling in up-state areas, which contrasts with the pattern in New York City and Long Island. In up-state areas, load was generally under-scheduled in 2007 and 2008, although the amount by which load was under-scheduled declined from 2007 to 2008. These load scheduling patterns are likely a response by the market to the differences between day-ahead LBMPs and real-time LBMPs. For example, day-ahead LBMPs were higher on average than real-time LBMPs in Western New York. This inconsistency induces participants to under-schedule load (or schedule more virtual supply) in the day-ahead market in Western New York.

2. Virtual Trading

Virtual trading allows participation in the day-ahead market by entities other than LSEs and generators. This improves convergence between the day-ahead and real-time markets and provides flexibility to market participants in managing risk. Virtual energy sales or purchases in the day-ahead market settle in the real-time market, allowing participants to arbitrage price differences between the day-ahead and real-time markets. For example, a participant can make virtual purchases in the day-ahead market if the participant expects prices to be higher in the real-time market, and then sell the purchased energy back into the real-time market. The result of this inter-temporal arbitrage would raise the day-ahead price to a level more consistent with the real-time price.

We analyzed the quantities of virtual load and supply that have been offered and scheduled on a bi-monthly basis from 2006 to 2008. The average quantities are shown for New York City and Long Island in Figure 28 and up-state New York in Figure 29.

Figure 28: Hourly Virtual Load and Supply
New York City and Long Island, 2006 – 2008

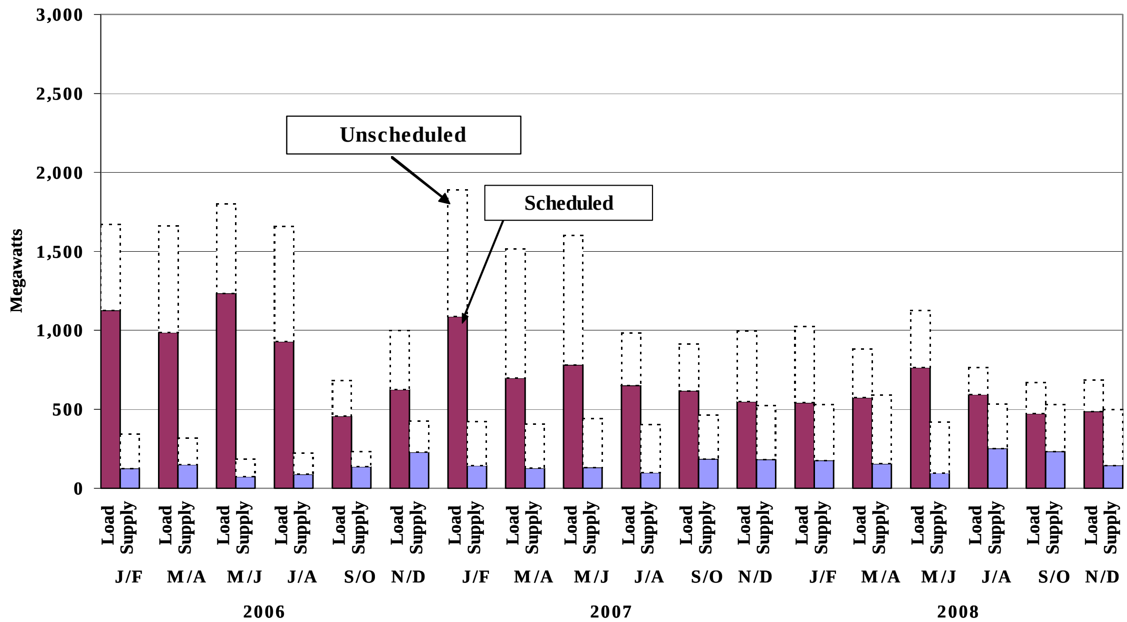


Figure 29: Hourly Virtual Load and Supply
Outside New York City and Long Island, 2006 – 2008

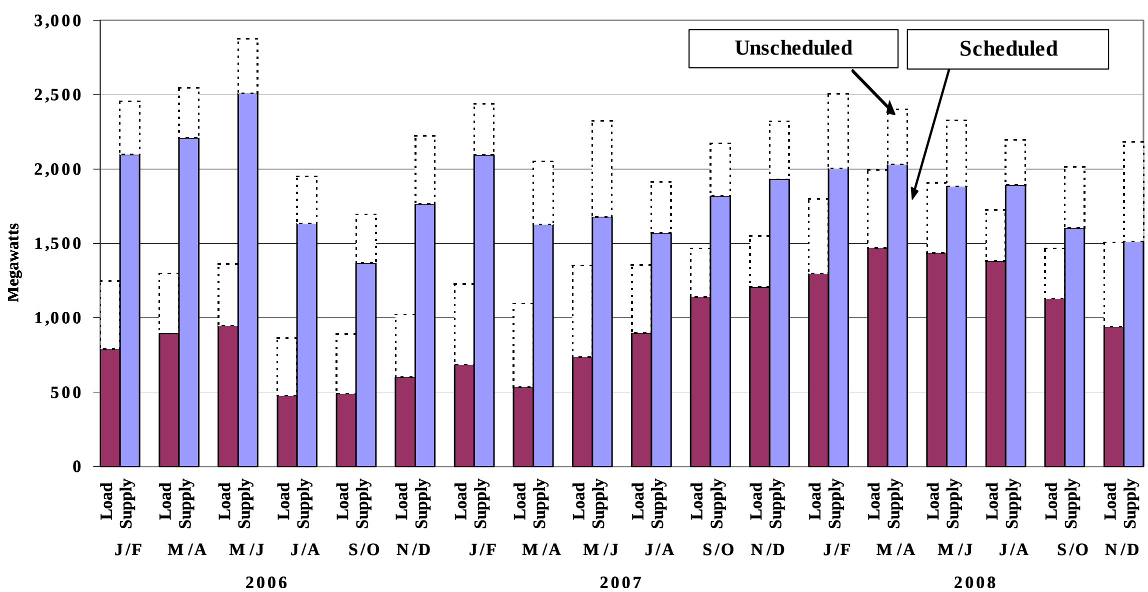


Figure 28 and Figure 29 show that there have been substantial net virtual purchases in New York City and Long Island and net virtual sales in up-state New York during the past three years. This has contributed to the pattern of over-scheduling in the down-state areas and under-scheduling in the up-state areas.. However, the amount of over- and under-scheduling decreased substantially from 2006 to 2008. In up-state areas, the average net virtual sale declined from 1,230 MW in

2006 to 770 MW in 2008. In New York City and Long Island, the average net virtual purchase declined from 760 MW in 2006 to 310 MW in 2008.

In New York City and Long Island, the pattern of net virtual load scheduling indicate that market participants expected higher real-time prices (or more frequent shortages) than actually occurred. Outside New York City and Long Island, however, the pattern of virtual trading market was generally consistent with the average relationship between day-ahead and real-time prices.

IV. External Transaction Scheduling

This section examines the scheduling of imports and exports between New York and adjacent regions. In both 2007 and 2008, 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 is directly connected to PJM and New England across three controllable lines: the Cross Sound Cable, the 1385 Line, and the Neptune Cable. The controllable lines are collectively able to import more than 1 GW directly to Long Island. 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. Low-cost internal resources also 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:[23]

- Scheduling patterns between New York and adjacent areas,
- The pattern of transaction scheduling around Lake Erie in 2008,
- Convergence of prices between New York and neighboring control areas,
- Benefits of external interface scheduling by market participants, and
- Benefits of ISO-coordinated interchange between control areas.

[23] Additionally, Section VI.A.2. 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 scheduled interchange between New York and the adjacent control areas in 2007 and 2008. The scheduled interchange does not include unscheduled power flows (i.e., loop flows). For each interface, average scheduled net imports are shown by month for peak (i.e. 6 am to 10 pm on weekdays) and off-peak hours. This is shown for the primary interfaces with Ontario and PJM in Figure 30, the primary interfaces with Quebec and New England in Figure 31, and the controllable lines connecting Long Island with PJM and New England in Figure Figure 32.

Figure 30: Scheduling Across Primary Interfaces with Ontario and PJM
2007 – 2008

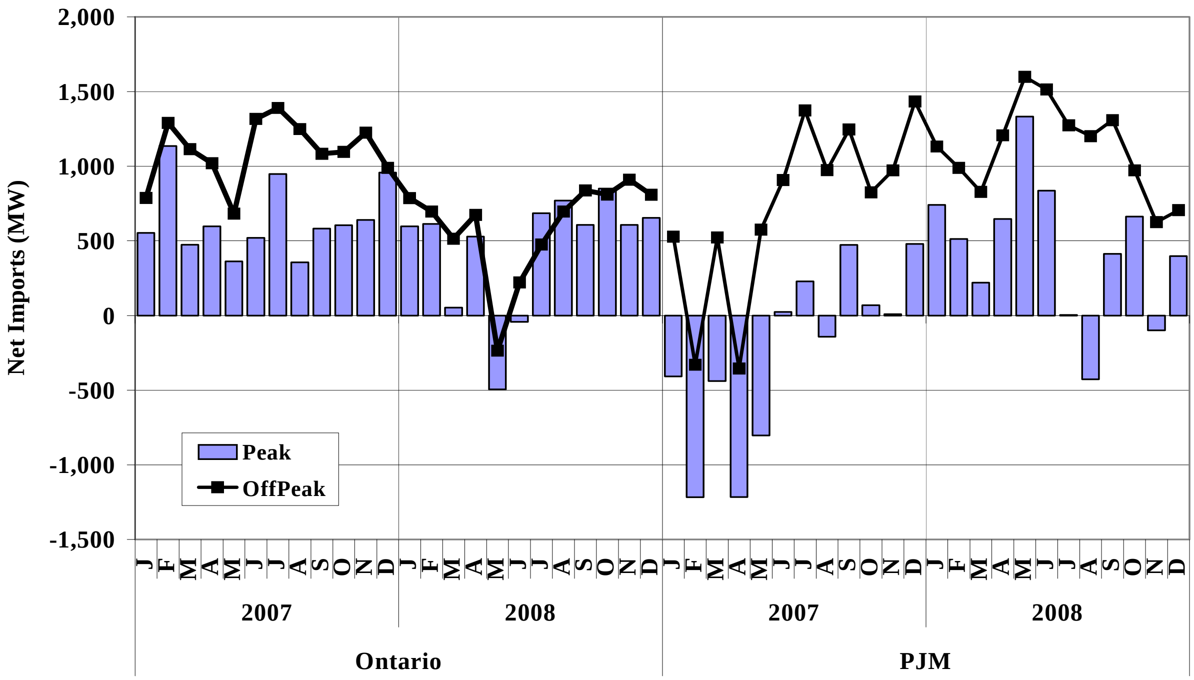
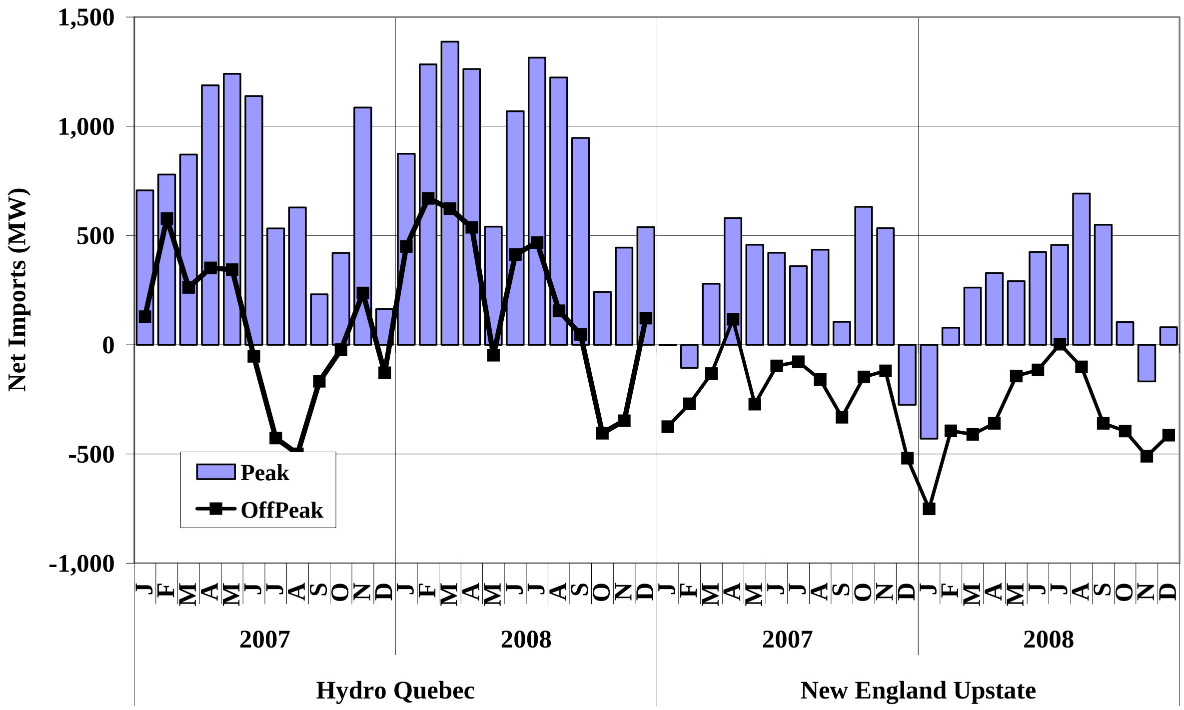


Figure 30 shows New York generally imports across the interfaces with Ontario and New York, particularly during off-peak hours. The only notable exception was in the first half of 2007 when New York exported an average of 680 MW to PJM. However, in June 2007, the NYISO began to calculate prices for the PJM interface that considered flows between the two areas across lines in Eastern New York that are controlled by phase-angle regulators ("PARs").[24] This change led to higher LBMPs at the NYISO's PJM interface, attracting higher levels of imports from PJM. Accordingly, the average net imports scheduled from PJM in peak hours rose to 190 MW in the last six months of 2007 and 720 MW in the first six months of 2008.

The pattern of scheduling across the primary interface with Ontario was affected by the scheduling of circuitous transactions around Lake Erie. The average net imports scheduled from Ontario in peak hours declined from 640 MW in 2007 to 210 MW in the first six months of 2008, and then increased to 700 MW in the last six months of 2008. The decline in early 2008 was associated with the circuitous transactions scheduled from New York to PJM counter-clockwise around Lake Erie via Ontario and the Midwest ISO. These transactions, which were not permitted after July 22, 2008, are discussed further in Section IV.B.

Figure 31: Scheduling Across Primary Interfaces with Quebec and New England
2007 – 2008



24 The change is described in Tech Bulletin 152 – PJM Proxy Bus Pricing and Scheduling.

Figure 31 shows 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 during off-peak periods. Even the pattern of scheduling across the primary interface between New England and New York is affected by 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 32: Scheduling Across Cross Sound Cable and Neptune Cable
2007 – 2008

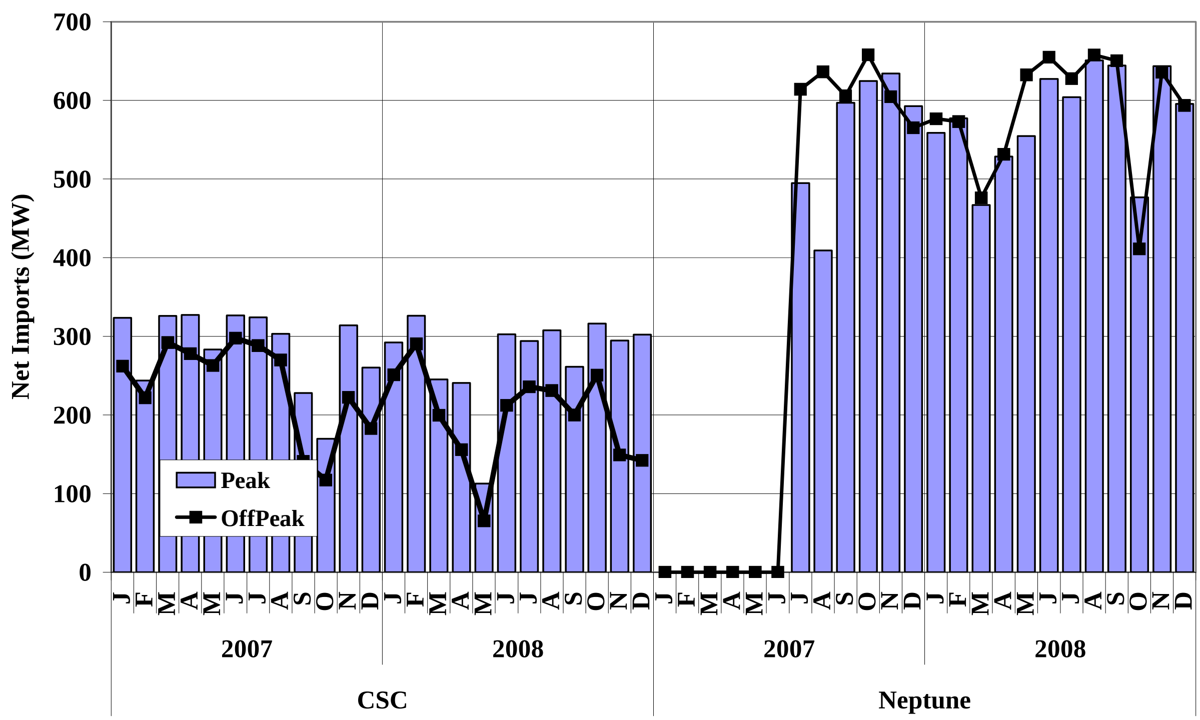


Figure 32 shows a substantial share of the imports to New York State came directly to Long Island via the Cross Sound Cable and the Neptune Cable. The Cross Sound Cable ("CSC"), which connects Long Island to Connecticut, is frequently used to import up to 330 MW to New York. Likewise, the Neptune Cable, which has connected Long Island to New Jersey since July 2007, is frequently used to import up to 660 MW to New York. The figure does not show the 1385 Line, which connects Long Island to Connecticut with a transfer capability of 100 MW, because it was out-of-service for most of 2007 and 2008 due to cable replacement work and problems with the phase shifter. The 1385 line came back into service at the beginning of January 2009.

B. Circuitous Transaction Scheduling Around Lake Erie

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. On average, loop flows moved around Lake Erie in a counter-clockwise direction in the several years prior to 2007. However, the prevailing direction of loop flows reversed at the end of 2007 primarily due to the emergence of circuitous transaction scheduling around Lake Erie.

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. For example, the most commonly scheduled circuitous transaction in 2008, which was known as a “Path 1 transaction”, sourced in New York, wheeled through Ontario and the Midwest ISO, and sunk 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, using valuable west-to-east transmission capability in New York without paying the associated congestion and losses charges. Due to the costs imposed on New York participants, the NYISO filed under exigent circumstances to prohibit circuitous transaction scheduling after July 22, 2008.[25]

This sub-section summarizes the volume of circuitous transactions in 2008 and the estimated congestion and loss charges not borne by the circuitous transactions as a result of scheduling on

[25] It was filed on July 21, 2008.

an indirect path. At the end of this sub-section, there is a discussion of other types of transactions that have contributed to clockwise loop flows in New York since the circuitous transactions were prohibited. Section IV of this report evaluates the effects of circuitous transaction scheduling on congestion patterns and congestion revenue shortfalls in 2008.

C. Summary of Circuitous Transaction Scheduling

Although Path 1 was the most commonly scheduled circuitous transaction path, the NYISO filed to prohibit scheduling on eight potential paths after July 22, 2008. The eight paths are:

- Path 1 - source in New York, wheel through Ontario and the MISO, and sink in PJM.
- Path 2 - source in New York, wheel through PJM and the MISO, and sink in Ontario.
- Path 3 - source in Ontario, wheel through the MISO and PJM, and sink in the New York.
- Path 4 - source in PJM, wheel through the MISO and Ontario, and sink in New York.
- Path 5 - source in PJM, wheel through New York and Ontario, and sink in the MISO.
- Path 6 - source in the MISO, wheel through Ontario and New York, and sink in PJM.
- Path 7 - source in Ontario, wheel through New York and PJM, and sink in the MISO.
- Path 8 - source in the MISO, wheel through PJM and New York, and sink in Ontario.

These eight paths include every possible scheduling path around Lake Erie that includes four control areas. Four paths are in the clockwise direction, and four paths are in the counter-clockwise direction.

Figure Figure 33 summarizes the volume of circuitous transactions scheduled around Lake Erie in each month from July 2007 through December 2008. The figure shows the period beginning in July 2007 because market participants had less incentive to schedule circuitous transactions prior to this. In June 2007, the NYISO altered its pricing methodology for the PJM interface to consider flows between the two areas across lines in Eastern New York that are controlled by phase-angle regulators (“PARs”).[26] As a result, the LBMPs at the NYISO’s PJM interface more accurately reflect that exports to PJM increase west-to-east flows through New York. Accordingly, the change led to higher LBMPs at the NYISO’s PJM interface, making it less

[26] The change is described in Tech Bulletin 152 – PJM Proxy Bus Pricing and Scheduling.

attractive to export power directly to PJM and more attractive to schedule power to PJM along Path 1.

Figure 33: Circuitous Transaction Scheduling Around Lake Erie
July 2007 – December 2008

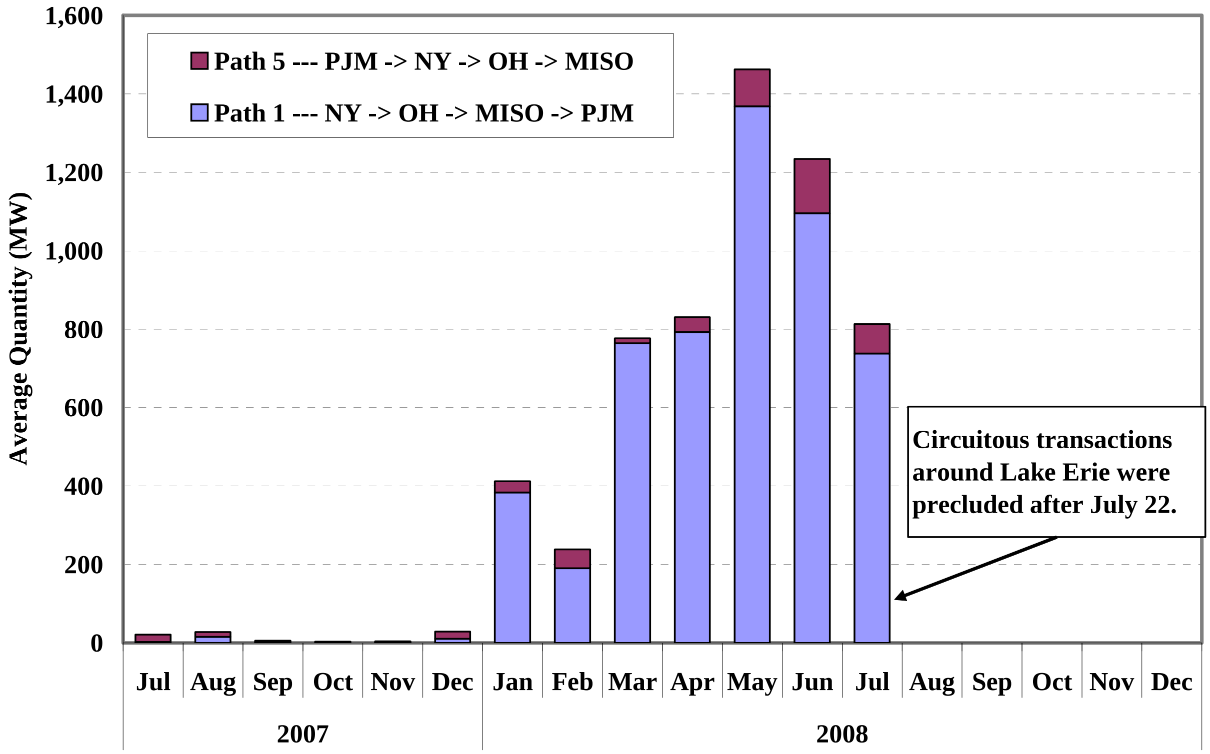


Figure 33 shows the circuitous transactions scheduled over Path 1 and Path 5, and reveals that no transactions were scheduled along the other six paths. The Path 1 transactions accounted for 92 percent of all circuitous transactions during the study period, while the transactions over Path 5 accounted for the remaining 8 percent. Circuitous transactions were not significant in the last six months of 2007, averaging 15 MW. However, the volume 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.

D. Estimated Charges Not Borne by Circuitous Transactions

Market participants were attracted to scheduling transactions on circuitous paths rather than direct paths because doing so allowed them to avoid charges (or collect revenues) related to congestion and losses. Path 1 transactions caused power to flow directly from New York to PJM, although Path 1 transactions settled with the NYISO as if the power flowed from New York to Ontario. Hence, whenever the price for exporting at the PJM interface was greater than the price for exporting at the Ontario interface plus the charges for wheeling through Ontario and the Midwest ISO, market participants had an incentive to schedule from New York to PJM along Path 1 (rather than the direct path between control areas).[27] In this manner, Path 1 transactions avoided paying congestion and loss charges for exporting at the PJM interface by scheduling the transaction to flow out of New York via the Ontario interface.

Path 5 transactions caused power to flow directly from PJM to the Midwest ISO, although Path 5 transactions settled with the NYISO as if the power flowed into New York at the PJM interface and out of New York at the Ontario interface. Hence, whenever the price at the NYISO's PJM interface was greater than the price at the NYISO's Ontario interface, Path 5 transactions were paid as if they relieved congestion and losses in New York.

The following analysis estimates the amounts of congestion and losses that were not borne (i.e., avoided or collected) by the circuitous transactions, while the resulting uplift charges are evaluated in Section IV. Figure 34 shows estimated congestion and loss charges that were not borne by circuitous transactions in each month of 2008. Prior to May 23, all of the charges were associated with congestion and losses in the real-time market. Starting on May 23, the NYISO began to adjust the amount of loop flows assumed in the day-ahead market in response to the circuitous transaction scheduling, shifting most of the effects of the loop flows from the real-time market to the day-ahead market.

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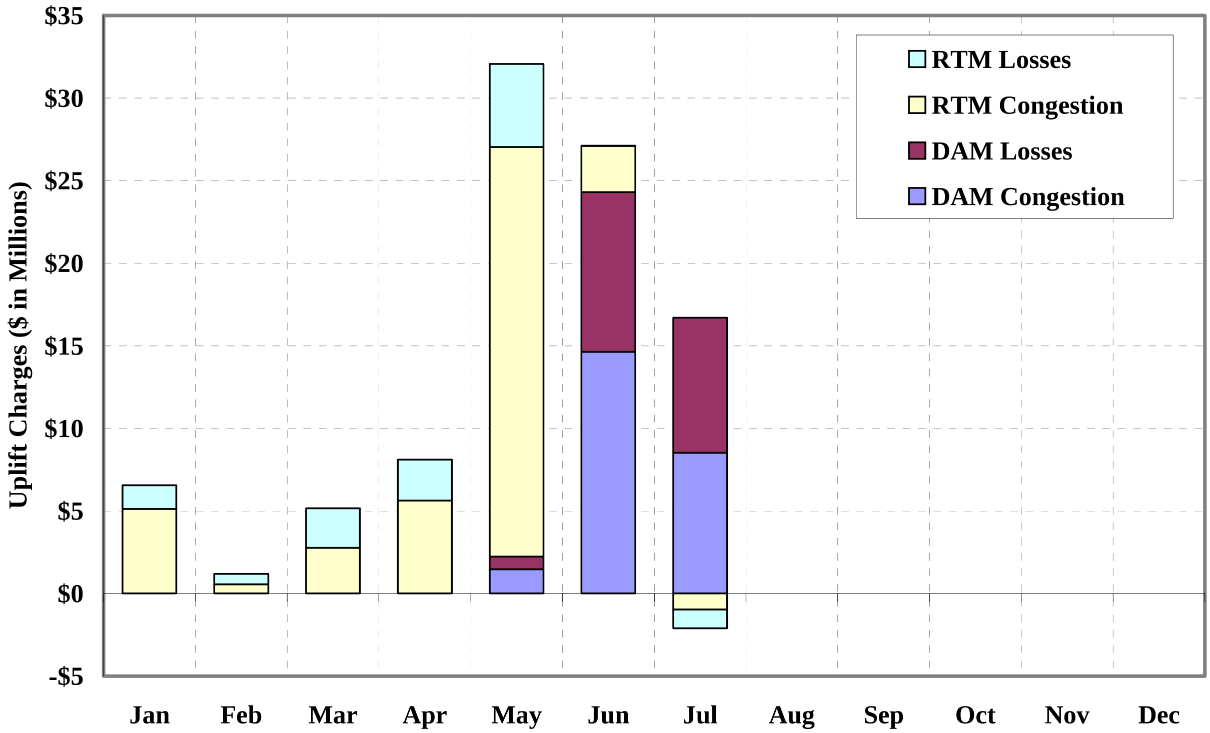
[27] The PJM pricing methodology for external transactions considers the source control area and the sink control area, but not the scheduling path. Hence, PJM settled both types of transaction at the same price.

Figure 34: Charges Not Borne by Circuitous Transactions
2008



We estimated a total of $96 million in charges that were not borne by circuitous transactions scheduled from January 1 to July 22, 2008. This includes $25 million of congestion and $19 million of losses in the day-ahead market, and $41 million of congestion and $11 million of losses in the real-time market. Consistent with the monthly average volumes of circuitous transactions shown in Figure 33, the charges not borne peaked in May 2008 at $32 million.

E. Other Schedules around Lake Erie

Circuitous transaction scheduling increased clockwise loop flows around Lake Erie, generating additional uplift charges for NYISO market participants and increasing congestion related price differences between eastern and western New York. 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 is considering additional mechanisms to improve the efficiency of transaction scheduling between control areas around Lake Erie. 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.[28] We support such settlement mechanisms that improve consistency between the costs caused and the charges assessed for inter-control area transactions.

F. 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.

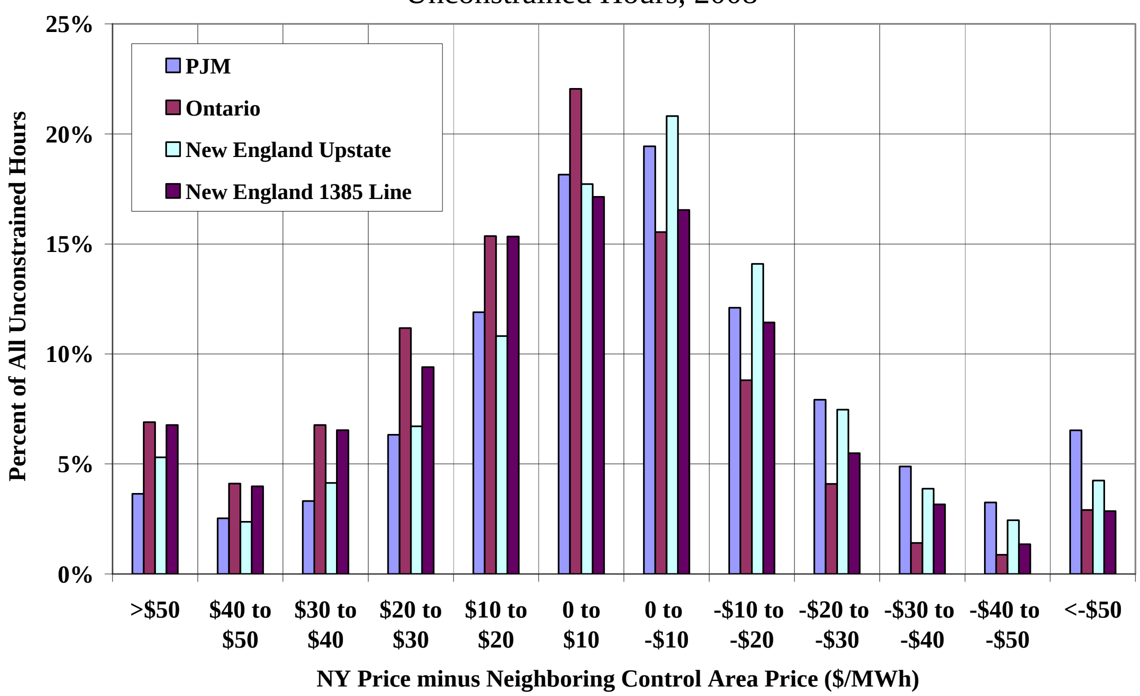
[28] See presentation by Robert Pike titled “Buy-Through of Congestion” given at the NYISO Market Issues Working Group meeting on July 8, 2009.

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.[29] ISO-run markets have real-time spot 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 35 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.

Figure 35: RT Price Convergence Between NY and Adjacent ISO Markets
Unconstrained Hours, 2008



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29 The Neptune Cable and the Cross Sound Cable are omitted because an alternate system is used to allocate transmission reservations for scheduling on them.

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 $20 per MWh. The price difference exceeds $20 per MWh across the interfaces with adjacent control areas in 37 to 40 percent of the unconstrained hours. 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.

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 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.

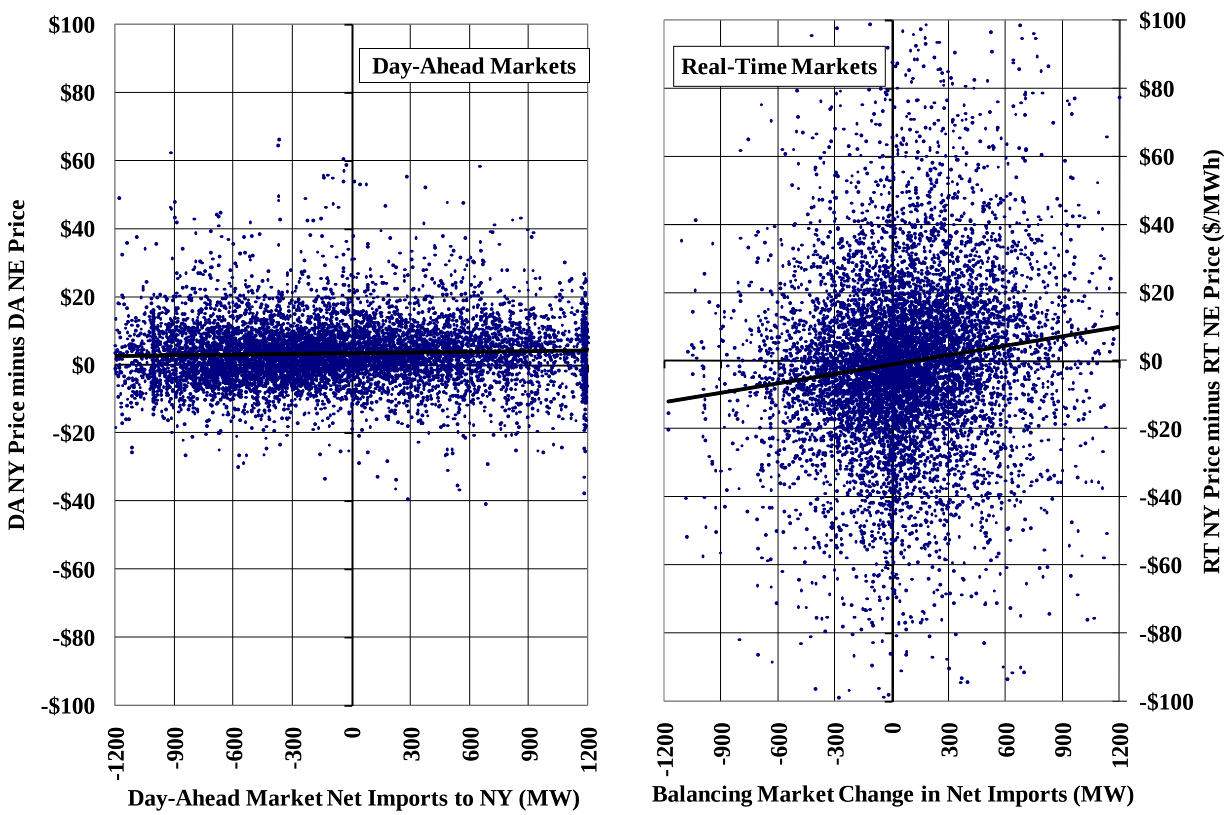
G. **External Interface Scheduling by Market Participants**

It has proven 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 36 and Figure 37 show that scheduling by market participants does improve price convergence between New York and New England. Hence, reducing barriers to scheduling by market participants would likely result in more efficient scheduling between regions. The analyses are only shown for the primary interface with New England, but it is reasonable to assume that reducing barriers to scheduling across other interfaces would likewise improve the efficiency of flows.

Figure 36 shows the net scheduled flow across the interface versus the difference in prices between New England and Upstate New York for each hour in 2008. The left side of the figure shows price differences in the day-ahead market on the vertical axis versus net imports scheduled in the day-ahead market on the horizontal axis. The right side of the figure shows hourly price differences in the real-time market on the vertical axis versus the change in the net scheduled imports after the day-ahead market on the horizontal axis. For example, if day-ahead net scheduled imports for an hour are 300 MW and real-time net scheduled imports are 500 MW, the change in net scheduled imports after the day-ahead market would be 200 MW.

Figure 36: Efficiency of Scheduling in the Day-Ahead and Real-Time Market
Interface Between Upstate New York and New England, 2008



The trend line in the left panel does not show a positive or negative correlation between the price difference and direction of scheduling in the day-ahead market. However, the trend line in the right panel does show a statistically significant positive relationship between the price difference and the direction of scheduling in the real-time market. This positive relationship indicates that the scheduling of market participants generally responds to price differences by increasing net flows scheduled into the higher price region, which improves efficiency.

Total net revenues from cross-border scheduling in 2008 was $10 million in the real-time market (not including transaction costs).[30] The fact that significant revenues were earned from the external transactions provides additional support for the conclusion that market participants generally help improve the convergence of prices between regions, although the arbitrage of prices is far from complete.

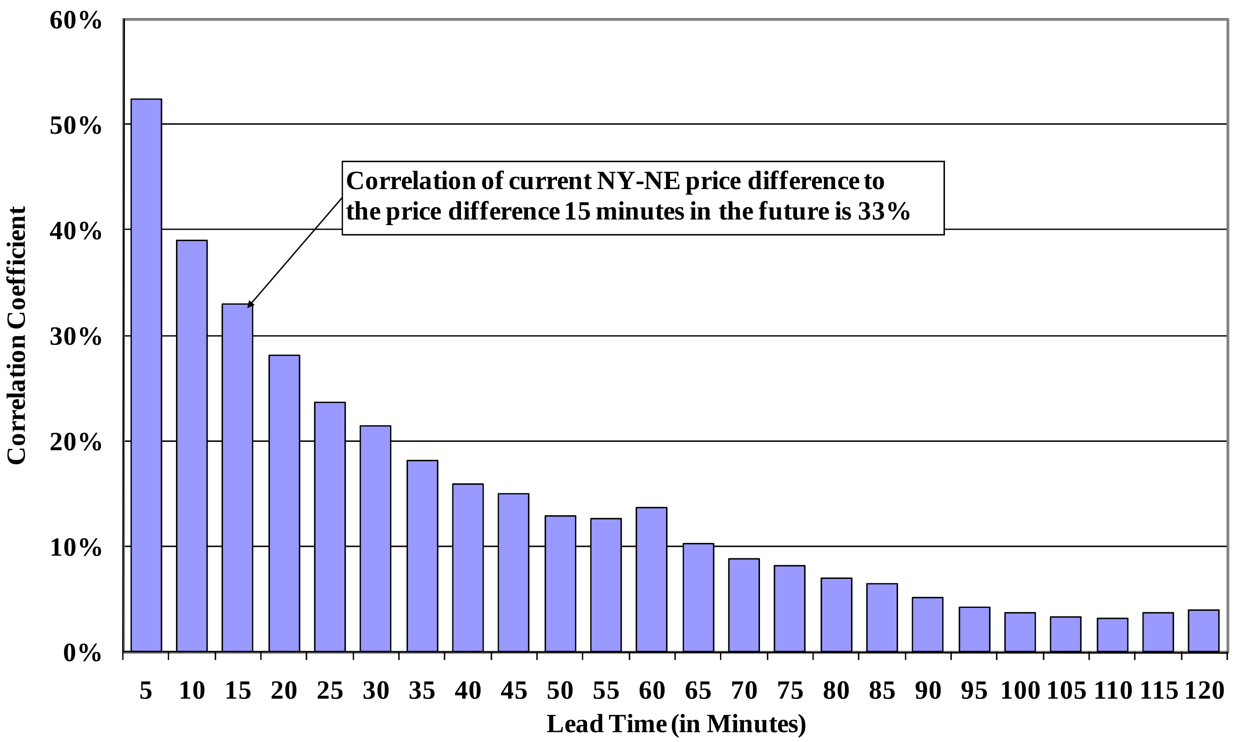
The greater dispersion of points around the trendline in the right side of the figure reflects that real-time price differences between regions are harder to predict than day-ahead price differences. Forty-four percent of the points in the real-time market panel are in unprofitable quadrants – upper left and lower right – indicating hours when the net real-time adjustment by market participants shifted scheduled flows in the unprofitable direction (increasing output in the high-priced market and reducing output in the low-priced market). Although market participant scheduling has helped converge prices between adjacent markets, the large dispersion in points in the right pane of Figure 36 shows there remains considerable room for improvement.

The following analysis examines the correlation between the lead times for scheduling transactions and the predictability of price differences between adjacent markets. Figure 37 shows the correlation coefficient of the real-time price difference across the primary interface between New England and New York between the current period and each subsequent five-

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

minute period over two hours. For example, the correlation of the price difference at the current time and the price difference 15 minutes in the future was 33 percent in 2008.

Figure 37: Correlation of Price Difference to Lead Time
Interface Between Upstate New York and New England, 2008



Not surprisingly, Figure 37 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 between New York and New England, 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 analysis suggests that reducing the lead times for scheduling would enable market participants to schedule more efficiently.

H. Inter-regional Dispatch Coordination

Incomplete price convergence between New York and adjacent markets suggests that more efficient scheduling of flows between markets would result in production cost savings and substantial benefits to consumers. Although past efforts to reduce barriers to market participant scheduling between regions have improved the efficiency of flows, and additional such efforts would lead to further improvements, uncertainty and risk are inherent in the market participant scheduling process. Hence, even with such improvements, one cannot reasonably expect the current process to fully use the interface. As is the case for efficient scheduling of the transmission capability within ISO regions, optimal use of transmission capability between ISO regions requires explicit coordination of interchange by the ISOs.

We employed simulations to estimate the benefits of optimal hourly scheduling of the primary interface between New England and New York from 2006 to 2008. The benefits of efficient scheduling include reduced production costs and lower prices for consumers. The production cost net savings represent the increased efficiency of generator operations over the two regions as additional production from lower-cost generators displaces production from higher-cost generators. The net consumer savings arise because improved coordination between the ISOs tends to lower prices on average in both regions. Table 1 summarizes the results of this analysis.

Table 1: Estimated Benefits of Coordinated External Interface Scheduling
Interface Between Upstate NY and New England, 2006 – 2008

[redacted]

The simulations indicate that better coordination would lead to lower average prices and net savings for consumers in both regions. Adjacent regions are brought into better convergence by increasing production in the low-price region and by decreasing production in the high-price region. In each hour, better convergence would lead to higher prices for one group of consumers and lower prices for the other group of consumers. However, our simulations indicate that both groups of consumers would benefit because there would be a tendency for prices to fall farther in the high-price region than they rise in the low-price region due to the nonlinear shape of the supply curve in electricity markets. In New York, estimated consumer net savings would have increased from $59 million in 2006 to $177 million in 2007 and $127 in 2008. Estimated consumer net savings that would have been obtained by consumers in New England were $61 million in 2006, $22 million in 2007, and $25 million in 2008.

The simulations estimate that a higher proportion of the savings would be received by New York consumers in 2007 and 2008 for two reasons. First, the New York system experienced more frequent reserve shortages than New England in 2007 and 2008. Second, the portion of the New York system that is closest to the interface experienced slightly higher average energy prices than the portion of the New England system that is closest to the interface in 2007 and 2008, leading the simulations to increase flow from New England to New York on average. In some hours, the price at New York's proxy bus is lower than the internal price in the portion of the New York system that is closest to the interface because ramp constraints are binding on imports in the NYISO's real-time scheduling model. Hence, changes in schedules by participants that cause ramp constraints to bind can contribute to price divergence.

Shortage pricing provisions in both the New York and New England markets have contributed to more efficient pricing when reserve shortages occur. Coordination of physical interchange between the ISOs can be especially important in avoiding or resolving shortage conditions. The estimates in Table 1 suggest that ISO coordination of external flows would have reduced consumer costs incurred during reserve shortages by $16 million in 2006, $75 million in 2007, and $31 million in 2008. Hence, as capacity margins decrease and the frequency of shortages increases, the total savings for New England customers could increase substantially.

Production cost effects represent the net efficiency benefits of improving coordination between areas. The estimated production cost net savings naturally tend to be smaller than estimated consumer net savings. Better coordination of flows between regions would not affect the production levels of most generators. In most cases, a small quantity of higher-cost generation in the higher-price region would be displaced by a small quantity of lower-cost generation in the lower-priced region. Hence, the producer cost effects are smaller than the price effects, but still total more than $50 million over the three year period.

I. 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 2008, the emergence of circuitous transaction scheduling around Lake Erie increased the volume of west-to-east loop flows through New York, increasing congestion and uplift for NYISO participants. Due to the costs imposed on NYISO participants, the NYISO filed under exigent circumstances to prohibit circuitous transaction scheduling after July 22, 2008. However, other types of transactions continue to cause clockwise loop flows in New York. The NYISO is considering pricing mechanisms to improve the efficiency of transaction scheduling between control areas around Lake Erie. 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 in the TLR process. We support settlement mechanisms that would improve consistency between the costs caused and the charges assessed for inter-control area transactions.

Our evaluation of external transactions between New York and three adjacent ISO-run markets indicates that scheduling by market participants does 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 is functioning properly and that scheduling by market participants tends to improve convergence, but significant opportunities remain to improve the interchange between regions. Proposals have been made to allow market participants to schedule transactions within the hour when prices diverge at the interface between the two markets. By reducing scheduling lead times, such a change would facilitate more efficient interchange and reduce inefficiencies caused by poor convergence. Moreover, better arbitrage would cause prices in both regions to be less volatile and lower overall.

Elimination of remaining barriers to market participant scheduling between regions, while desirable, would not achieve full utilization of the external interfaces. Uncertainty, imperfect information, and a lack of coordination limit the ability of market participants to arbitrage fully the prices between regions. Hence, we continue to recommend that the NYISO work with neighboring control areas to better utilize the transfer capability between regions, ideally by directly coordinating the physical interchange.

Some have argued that this would constitute involving the ISOs 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.

While our review has focused on the efficiency of flows between New England and New York, we note that the NYISO is working with PJM to coordinate congestion management. This would allow one control area to redispatch resources within its footprint to alleviate congestion in the other control area. We support such efforts to coordinate congestion management, which would result in more efficient nodal prices and reduced congestion management costs.

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 Transmission Congestion Contracts ("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 number of megawatts ("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 congestion price at zone B less the congestion price at location A. Excepting transmission losses, a participant can perfectly hedge a bilateral contract between two points if it owns a TCC between the same two 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 four aspects of transmission congestion management and locational pricing:

- Real-Time Congestion on Major Transmission Interfaces: This analysis summarizes changes in the frequency and value of congestion on major interfaces during the past seven years.
- TCC Prices and Day-Ahead Market Congestion: We review the consistency of TCC prices and congestion prices in the day-ahead market, which determine payments to TCC holders.
- Day-Ahead Congestion Revenue Shortfalls: We evaluate congestion revenues collected in the day-ahead market by the NYISO and the shortfalls that arise when the revenues are not sufficient to cover payments to TCC holders.
- Balancing Congestion Revenue Shortfalls: Balancing congestion shortfalls arise when day-ahead scheduled flows exceed real-time transmission capability. In this sub-section, we examine the shortfalls and identify major factors that affect the size of the shortfalls.

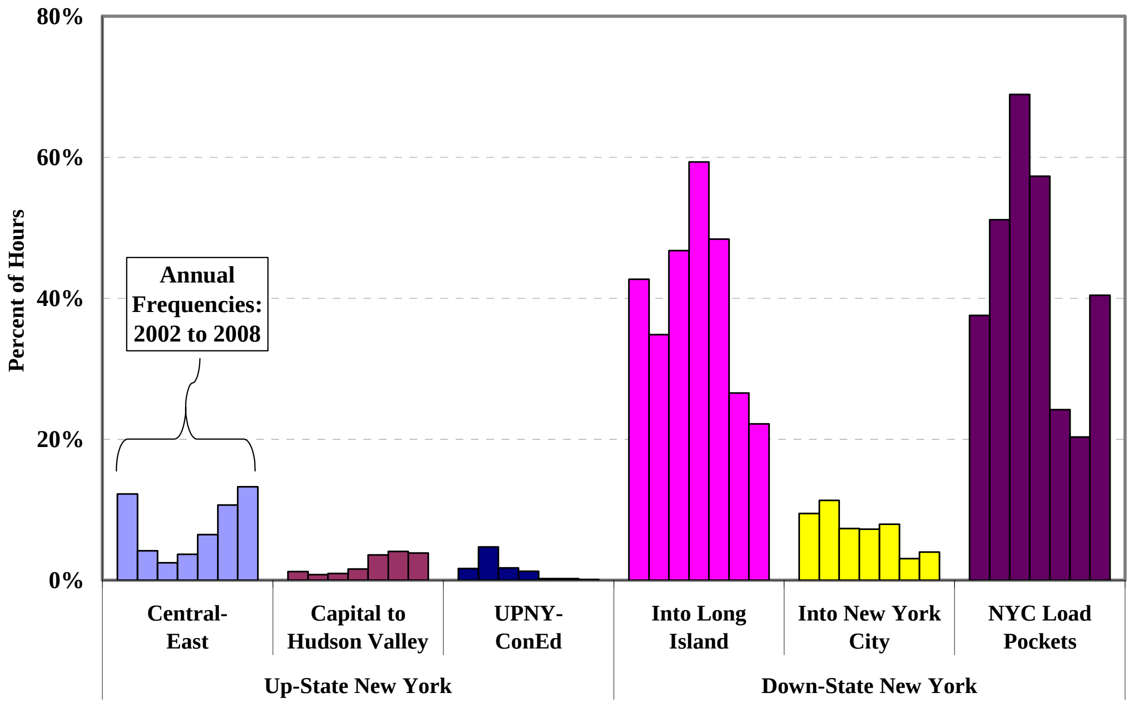
A. Real-Time Congestion on Major Transmission Interfaces

Supply resources in New York City and Long Island generally are more expensive than in Up-state New York. Hence, the transmission capability to move power from the low-cost to high-cost parts of the state provides considerable value. It is important that the transmission planning process and incentives for transmission investment lead to efficient new investment. The analyses in this sub-section summarize the frequency and value of congestion on several key interfaces in New York.

Figure 38 shows the frequency of congestion on select interfaces in Up-state and Down-state New York. From Up-state New York, the figure includes constraints that (i) are part of the Central-East Interface, (ii) limit southward flows from the Capital region through the Hudson Valley, and (iii) make up the interface between up-state New York and the Con Ed transmission area. From Down-state New York, the figure includes (i) transmission constraints from Up-state New York into Long Island, (ii) the Dunwoodie-South constraint that limits flows from Up-state New York into New York City, and (iii) the group of constraints that limit flows within New

York City. This analysis excludes constraints within Western New York and also within the Long Island zone.

Figure 38: Frequency of Real-Time Congestion on Major Interfaces
2002 – 2008



The preponderance of congestion occurred into and within down-state areas, although up-state congestion became more frequent from 2005 to 2008. Congestion into and within down-state areas became substantially less frequent after 2005. The frequency of congestion into Long Island decreased significantly from 2006 to 2008. Within New York City, congestion increased due to a substantial increase in the frequency of congestion into the Astoria East and Greenwood areas from 2007 to 2008.

At least four factors contributed to the trends in congestion shown above. First, clockwise loop flows around Lake Erie increased in 2008, leading to increased congestion across the Central-East interface.[31] When loop flows move clockwise around Lake Erie, they use a portion of the

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31 Loop flows refer to unscheduled power flows resulting from scheduling in other control areas in the Eastern Interconnect (i.e., loop flow = actual power flow minus scheduled power flow). Clockwise loop flows around Lake Erie refer to instances when the prevailing direction of unscheduled power flows move in a clockwise

transmission capability across Central-East. They also lead to adjustments in phase-angle regulator settings that result in increased flows across the Central-East interface. These effects reduced the transmission capability available for dispatching flows across Central-East in the NYISO's real-time market, thereby increasing the frequency of congestion. The effects of the loop flows on congestion patterns and uplift charges are discussed further in this section.

Second, developments in the market models have affected the frequency of congestion in New York. In May 2006, the NYISO began to model individual transmission lines in New York City rather than using exclusively the more simplified load pocket interface constraints for real-time dispatch. This has led to a more effective use of the transmission system and less congestion. However, in 2008, the more simplified interface constraints were used more frequently under certain conditions, which contributed to the more frequent congestion together with transmission outages.

Third, Thunder Storm Alert ("TSA")-related constraints have become more frequent since 2005, resulting in more congestion on the up-state interfaces shown above. TSAs require double contingency operation of the ConEd overhead transmission system in real-time. This effectively reduces the amount of power that can flow from up-state New York through the Hudson Valley to New York City and Long Island, resulting in more frequent congestion.

Fourth, generation and transmission capacity additions have influenced congestion patterns. The Neptune Cable, which began operation in July 2007, substantially reduced congestion into Long Island and New York City. One gigawatt ("GW") of new combined cycle capacity installed in 2006 dramatically reduced the amount of congestion in New York City load pockets. The Athens and Bethlehem plants in the Capital region began operation during 2004 and 2005, which have helped reduce flows over the Central-East interface and shifted more congestion to the corridor between the Capital region and the Hudson Valley. In addition, higher net imports to western New York from neighboring control areas that tend to constrain the Central-East interface contributed to increased congestion in 2007.

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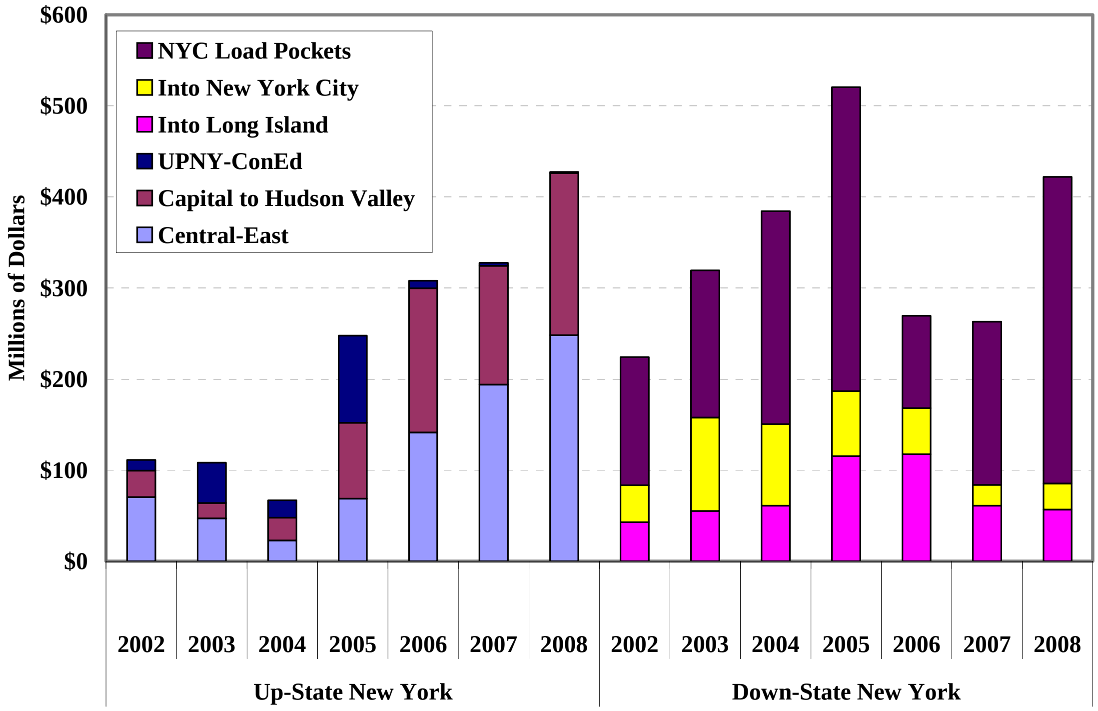
pattern around Lake Erie.

In addition to the frequency of congestion, the value of transmission capacity also depends on the volume of power that is transferred between regions and the difference in clearing prices between regions. Figure 39 measures the approximate value of congestion in real-time for the interfaces shown in the previous figure. For this analysis, the value of congestion is measured as the shadow price[32] of the interface in the real-time market multiplied by the flow.

Figure 39: Value of Real-Time Congestion on Major Interfaces
2002 – 2008



The value of congestion on the Up-state and Down-state transmission interfaces increased notably from 2007 to 2008. In the Up-state areas, the value of congestion across the Central-East interface increased from approximately $195 million in 2007 to $250 million in 2008, while the value of congestion from the Capital Zone to Hudson Valley increased from $130 million in 2007 to $180 million in 2008.[33]

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[32] The shadow price of a transmission constraint represents the marginal value to the system of one MW of transfer capability. However, during intervals with real-time price corrections, the real-time location-based marginal prices may not be consistent with constraint shadow prices. In such cases, this analysis estimates the value of congestion from location-based marginal prices rather than constraint shadow prices.

[33] These totals do not equal actual congestion costs paid by market participants because the analysis values

In the Down-state areas, the value of congestion increased substantially inside New York City but did not change significantly into New York City and Long Island. Within New York City load pockets, the value of congestion increased from approximately $180 million in 2007 to nearly $340 million in 2008. This was primarily attributable to more frequent congestion in the Astoria East and Greenwood areas in 2008.

The considerable shift in the value of congestion on various interfaces during recent years was generally due to several factors. First, variations in the frequency of congestion, which are shown in Figure 39, have led to corresponding changes in the value of congestion. Second, fuel price fluctuations have led to proportional changes in the value of congestion. The rise in congestion values from 2002 to 2005 and from 2007 to 2008 and the decline in congestion costs from 2005 to 2006 were consistent with changes in overall prices for electricity, which were largely driven by the fluctuations in oil and natural gas prices. Third, the high cost of redispatch during TSAs and eastern 10-minute reserve shortages has had a significant impact on the congestion costs in the Capital to Hudson Valley corridor since 2005, even though TSAs and reserve shortages are infrequent. Fourth, modeling individual transmission lines in New York City rather than more simplified load pocket interface constraints improved the efficiency of congestion management in New York City load pockets after 2005. However, simplified interface constraints were used more frequently in 2008, increasing the redispatch costs associated with congestion.

B. 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.

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congestion based only on the real-time market results which differ from day-ahead results. In addition, congestion associated with loop flows are included in the value of congestion, but not in the congestion settlements.

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 40 compares the TCC prices during the 2008 Summer Capability Period to the corresponding congestion prices in the day-ahead market. The figure shows the average TCC prices over five 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 40: TCC Prices and Day-Ahead Congestion
Summer 2008 Capability Period

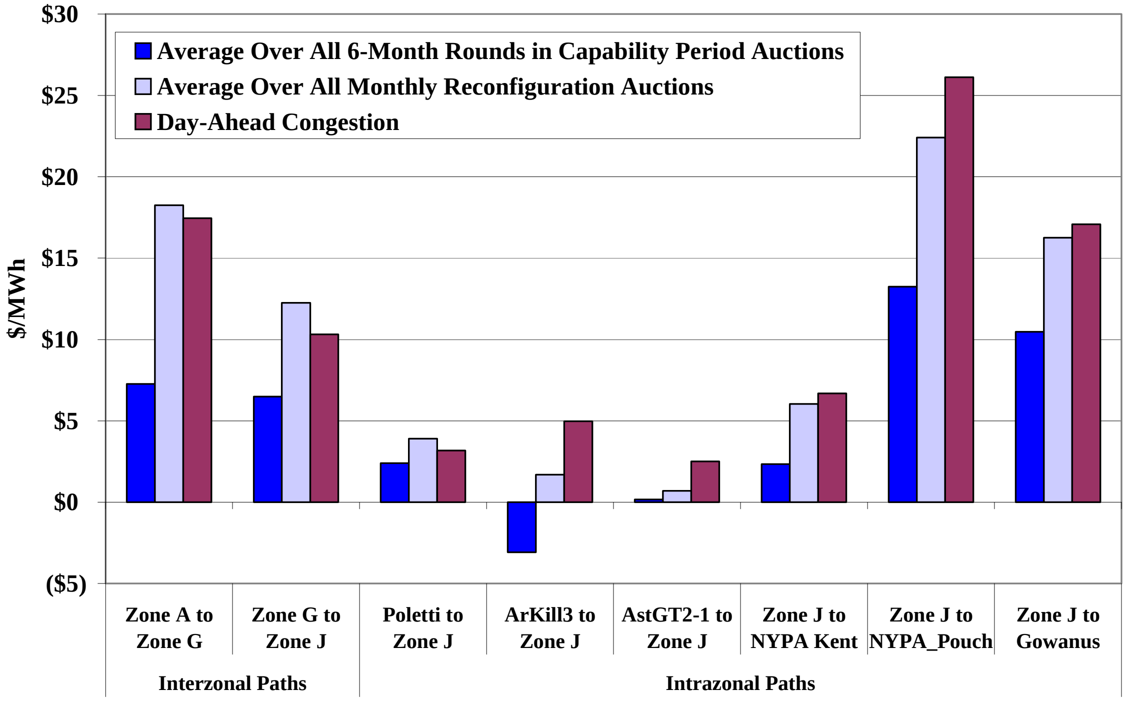

Figure 40 indicates that the 6-month TCC auctions under-valued congestion across all of the paths shown. This reflects what market participants expected when the 6-month TCC auctions were held in the spring of 2008. The average prices in the monthly Reconfiguration Auctions were more consistent with day-ahead congestion, 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 about the state of the transmission system is available.

Overall, the figure shows more congestion occurred in the day-ahead market than was anticipated prior to the 6-month auctions. Unexpectedly high volumes of west-to-east loop flows due to the pattern of circuitous transactions scheduled around Lake Erie increased congestion from Zone A to Zone G. In addition, the figure suggests that market participants did not expect the increase in congestion within New York City from 2007 to 2008.

C. Day-Ahead Congestion Revenue Shortfalls

The New York ISO collects day-ahead congestion revenue whenever power is scheduled across congested interfaces in the day-ahead market. Since day-ahead congestion can be volatile, TCCs provide market participants with a mechanism for hedging this volatility. The New York ISO sells TCCs in the forward auction on behalf of the Transmission Owners, which creates a liability for the payments to TCC holders based on day-ahead congestion.[34]

Day-Ahead congestion revenue shortfalls occur when the day-ahead congestion revenues collected by the NYISO are less than the entitlements to the holders of TCCs. 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 quantity of TCCs in the forward auction that is approximately equal to the expected transfer capability of the system. In addition, transmission owners can reduce the probability of substantial 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.

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[34] TCC holders are entitled to a stream of revenues (or liabilities) between two locations for a certain timeframe based on prices in the day-ahead market.

This sub-section evaluates some of the factors that contribute to day-ahead congestion revenue shortfalls and surpluses. Figure 41 shows the net payments to TCC holders and the day-ahead congestion revenue shortfalls (or surpluses) in each month of 2007 and 2008.

Figure 41: TCC Payments and Day-Ahead Congestion Revenue
2007 – 2008

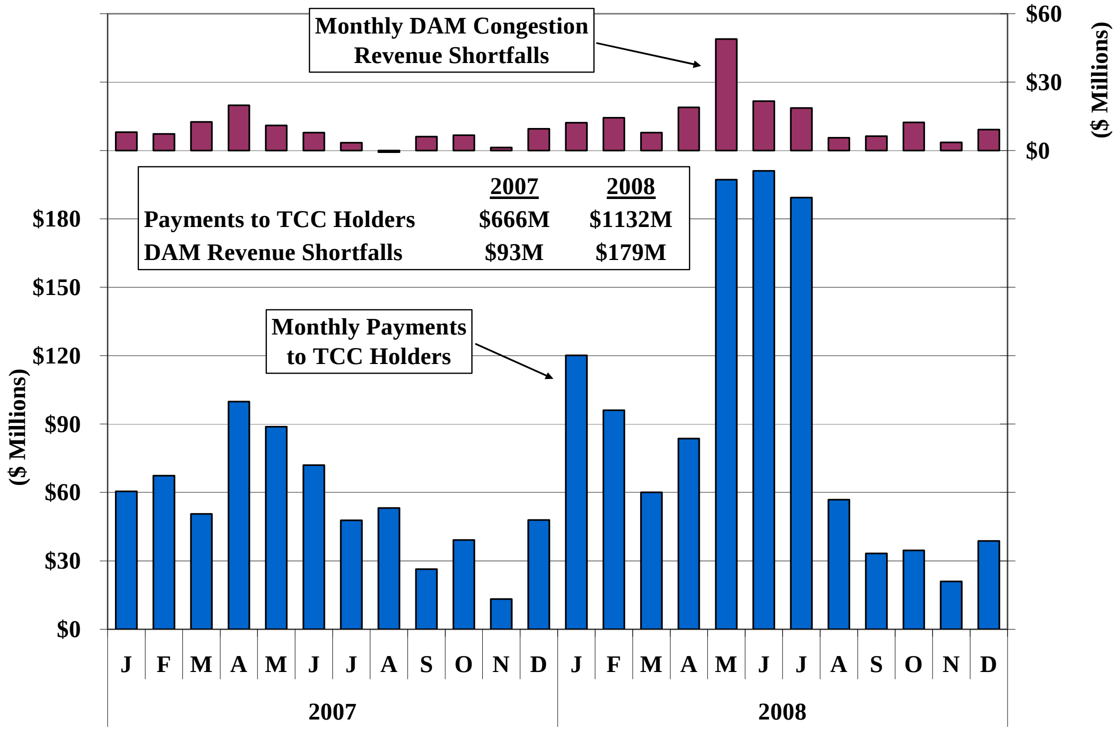


Figure 41 indicates that congestion revenue shortfalls in the day-ahead market increased from 2007 to 2008. The rise in congestion value in the day-ahead market from 2007 to 2008 led to a $566 million increase in payments to TCC holders, which exceeded the $480 million increase in the day-ahead congestion revenue. Accordingly, the day-ahead congestion revenue shortfalls rose from $93 million in 2007 to $179 million in 2008.

Congestion revenue shortfalls arise when the available transmission capability that is assumed in the TCC auction exceeds the available transmission capability modeled in the day-ahead market. Transmission and generation outages[35] that are not known by the NYISO at the time of the TCC

[35] Generation outages can sometimes affect the transfer capability of the transmission system.

auction (and therefore not modeled in the TCC auction) lead to reduced transmission capability in the day-ahead market and contribute to congestion revenue shortfalls.

The NYISO has a process for allocating day-ahead congestion revenue shortfalls to specific transmission outages, which are attributable to specific transmission owners. Through this process, 43 percent of the day-ahead congestion shortfall in 2008 was charged to specific transmission owners for transmission equipment outages and derates. Transmission owners can avoid allocations of day-head congestion revenue shortfalls from specific transmission outages by electing to incorporate them in the TCC auction assumptions. Although many of the transmission outages were scheduled before the TCC auctions, none of the transmission owners elected to incorporate them in the TCC auctions in 2008.

The remaining 57 percent of day-ahead congestion revenue shortfalls in 2008 were not associated with specific transmission outages and were, therefore, shared by all transmission owners. These were attributable to different modeling assumptions between the TCC auctions and the day-ahead market, including assumptions regarding the schedules of phase-angle regulators and unscheduled loop flows through the system. Reductions in modeled day-ahead transfer capability that are made by the NYISO to account for expected loop flows (which do not pay for the congestion they contribute to) contribute to TCC shortfalls.

In 2008, the pattern of clockwise loop flows around Lake Erie contributed to the day-ahead congestion revenue shortfalls. Clockwise loop flows use a portion of the west-to-east transmission capability in New York, thereby reducing the capability available for scheduling in the NYISO market. The magnitude of clockwise loop flows was increased substantially in the Spring of 2008 as the quantity of circuitous transactions increased. Since the assumptions used in the TCC auctions were determined months before the assumptions used in the day-ahead market auctions, the unexpected increase in clockwise loop flows were not reflected in the TCC auctions.[36] As a result, the quantity of TCCs sold in the auctions generally exceeded the

[36] Most TCCs are sold in the Capability Period Auctions for the six months of the summer capability period (from May to October) or the winter capability period (from November to April). The assumptions used in the Capability Period Auctions are determined several months in advance of the capability period.

available west-to-east transmission capability in the day-ahead market auctions, leading to significantly higher day-ahead congestion revenue shortfalls.

D. 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.

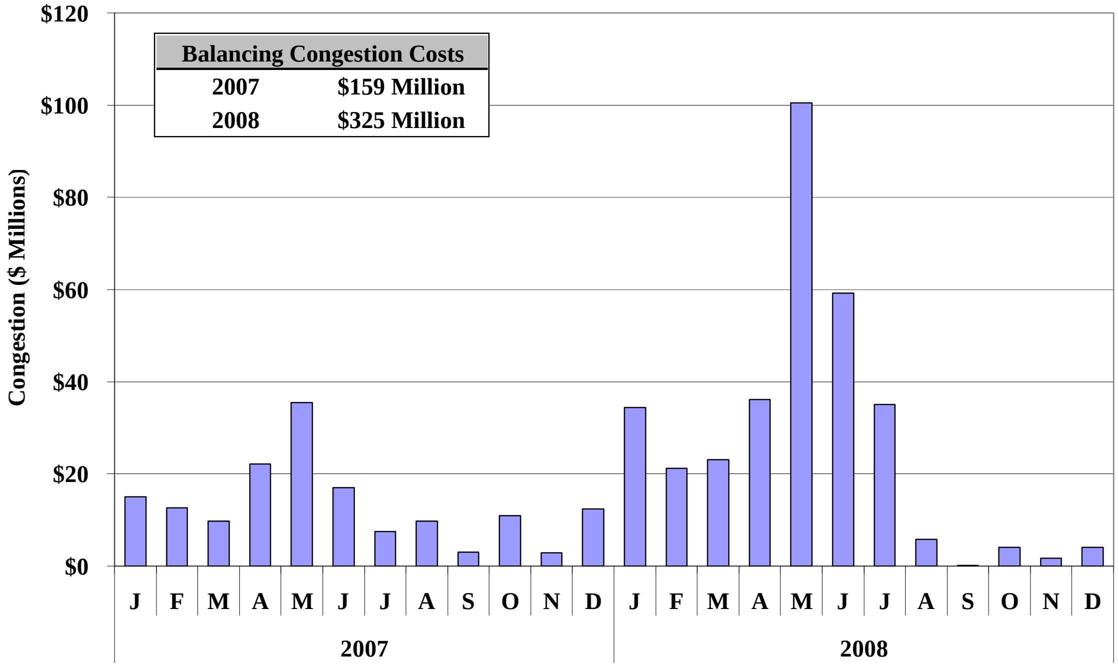
This sub-section summarizes balancing congestion revenue shortfalls over the past two years and identifies significant contributing factors in 2008. The final part of this sub-section provides a summary of our conclusions and recommendations.

E. Summary of Balancing Congestion Revenue Shortfalls

Figure 42 shows the balancing congestion revenue shortfalls incurred in each month of 2007 and 2008. The figure shows balancing congestion revenue shortfalls rose from $159 million in 2007 to $325 million in 2008. Figure 42 shows that balancing congestion revenue shortfalls averaged $19 million per month in the first six months of 2007 before declining to an average of $8 million per month in the last six months of 2007.

Figure 42: Balancing Congestion Revenue Shortfalls

2007 – 2008



The reduction in balancing congestion revenue shortfalls was primarily driven by two factors. First, Neptune cable came into service in July 2007, increasing imports from New Jersey to Long Island by 660 MW in most hours. This led to a substantial decline in congestion and led to a proportional decline in balancing congestion revenue shortfalls.

Second, the real-time dispatch model was modified to limit the marginal re-dispatch costs that may be incurred to resolve a transmission constraint to a maximum of $4,000 per MWh in June 2007. Previously, transmission constraint shadow prices would occasionally reach extraordinary levels when the available re-dispatch options were ineffective. This improvement has reduced the balancing congestion revenue shortfalls that occur during acute shortages of transmission. Such shortages often result from a reduction in the transfer capability of a constrained interface after the day-ahead market (such as during a TSA event). Under such circumstances, the new re-dispatch cost limit results in much lower balancing congestion revenue shortfalls.[37]

[37] For example, if the day-ahead market scheduled 2,000 MW to flow across a particular interface and the real-time market reduced flows to 1,600 MW and the shadow price was $10,000 per MWh for one hour, it would result in a balancing congestion shortfall of $4 million (= $10,000 per MWh * (2,000 MWh – 1,600

Balancing congestion revenue shortfalls rose in 2008 from to $325 million from $159 million in 2007. The largest portion of this increase occurred in early 2008, which was driven by the increase in circuitous transaction scheduling around Lake Erie and the general rise in fuel prices. The significance of these and other factors are evaluated in greater detail in following part of the sub-section.

F. Categories of Balancing Congestion Revenue Shortfalls

Balancing congestion revenue shortfalls can occur when the available transfer capability of a particular 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, other reliability criteria result in 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.[38]

MWh)). Under the new methodology, the shadow price would be $4,000 per MWh, resulting in a balancing congestion shortfall of $1.6 million (assuming the real-time flows did change).

[38] For example, assume that the day-ahead market schedules 1,000 MW to flow into a load pocket and the

Phase Angle Regulator ("PAR") settings – the flows across PAR-controlled lines are adjusted in real-time operations, which can result in PAR settings that are very different from the day-ahead assumptions. These differences can affect available transfer capability of multiple interfaces.

Loop flows around Lake Erie form circuitous transaction scheduling – loop flows use a portion of the transmission capability across many interfaces in New York, reducing the portion of transmission capability available for scheduling in the NYISO market in the direction of the loop flows.[39] A balancing congestion revenue shortfall occurs when the amount of loop flow assumed in the day-ahead market is lower than the actual amount of loop flow on interfaces that are congested in real time. Circuitous transaction scheduling is examined in Section IV.B.

The following two figures provide monthly detail on significant categories of balancing congestion shortfalls in 2008.[40] Figure 42 shows the balancing congestion shortfalls related to transfer capability changes of specific interfaces between the day-ahead and the real-time for the following interfaces:

- Leeds-to-Pleasant Valley line during TSA operations;
- Simplified New York City load pocket interfaces;
- Dysinger-East, West-Central, and Central-East interfaces;
- Other internal interfaces and line constraints; and
- External interfaces.

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real-time market starts a 50 MW gas turbine inside the load pocket to balance a 10 MW load increase not anticipated by the day-ahead market. The gas turbine produces 50 MW, causing the flow over the interface to decline by 40 MW. If the shadow price of the interface into the load pocket is $50 per MWh in real-time, it results in an unutilized transfer capability of 40 MW and a balancing congestion shortfall of $2,000 per hour (=$50 per MWh*40 MW).

39 However, loop flows actually increase the available transmission capability in the opposite direction.

40 Note that the actual net balancing congestion revenue shortfalls were $30 million lower than those shown in the two figures because the figures exclude the following items (some of which generated balancing congestion surpluses in 2008): (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 43 shows balancing congestion shortfalls associated with other changes from the day-ahead to the real-time that directly affected multiple interfaces, including:

- Assumptions regarding Lake Erie loop flows; and
- Flows across the following PAR-controlled lines: the Waldwick PARs and the Branchburg-Ramapo PARs, which affect flows between the Hudson Valley and New Jersey; the Farragut and Linden PARs, which affect flows between New York City and New Jersey; and all other PARs.

Figure 43: Balancing Congestion Revenue Shortfalls by Category
Transfer Capability Change Categories, 2008

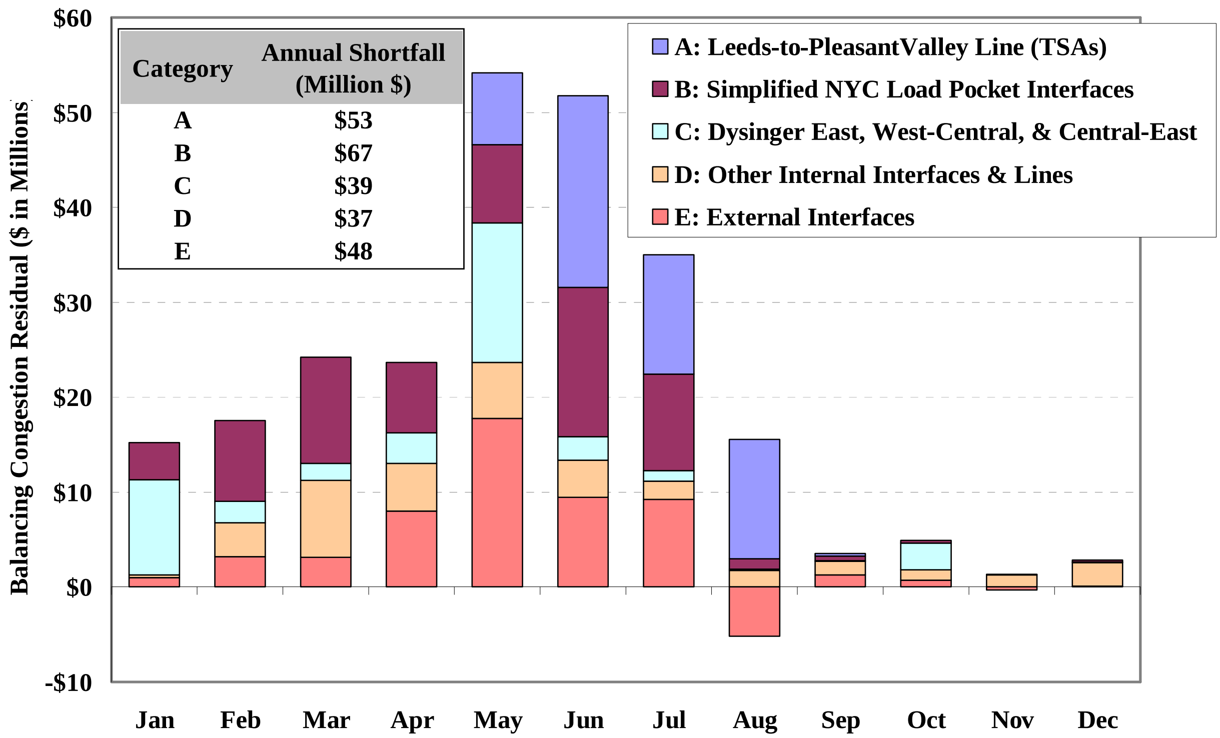

Figure 44: Balancing Congestion Revenue Shortfalls by Category
Other Categories, 2008

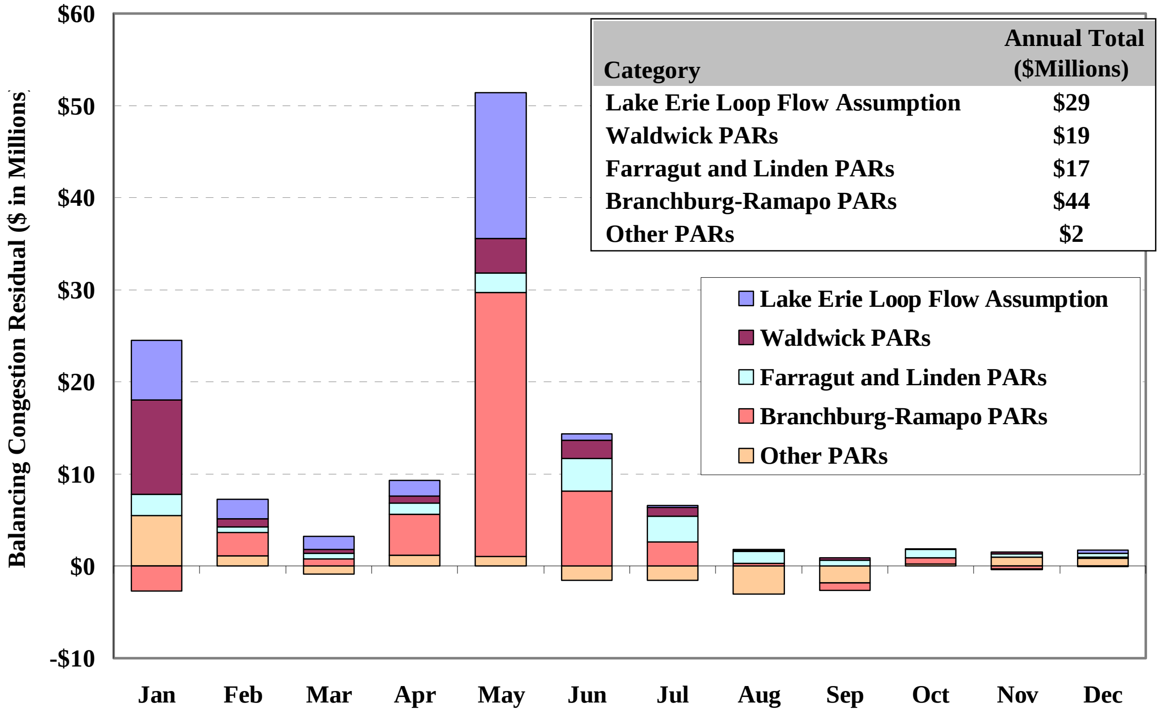

Figure 44 shows the use of simplified interface constraints in New York City load pockets resulted in $67 million of balancing congestion shortfalls during 2008, the most among all listed categories. Compared with the more detailed transmission modeling in the day-ahead market, using simplified interface constraints in the real-time market generally results in reduced transfer capability in New York City. Congestion across the Astoria East and Greenwood/Staten Island interface constraints accounted for most of the $67 million shortfall.

The second largest category was the Leeds-to-Pleasant Valley line during TSA operations, which accounted for a shortfall of $53 million. TSAs require double contingency protection of the Leeds-to-Pleasant Valley line, effectively reducing the transfer capability of the system from the day-ahead to the real-time. The associated shortfall occurred primarily during the summer months when TSAs are most frequent.

The increased clockwise loop flows around Lake Erie contributed to several categories of balancing congestion revenue shortfalls described below:

First, Figure 44 shows differences between day-ahead assumptions and real-time operations related to the amount of loop flows directly led to a shortfall of $29 million.

Second, the loop flows caused large differences between scheduled real-time transactions and actual real-time flows between NYISO and PJM, leading the operation of the Branchburg-Ramapo PARs to be significantly different from the assumption in the day-ahead market. Hence, a large portion of the $44 million shortfall associated with the Branchburg-Ramapo PARs can be attributed to the circuitous transactions.

Third, the figure shows west-to-east congestion across the Dysinger-East, West-Central, and Central-East interfaces accounted for $39 million in balancing congestion revenue shortfalls. Since loop flows around Lake Erie and the resulting operation of the Branchburg-Ramapo PARs led to increased flow across these interfaces, the balancing congestion revenue shortfalls related to these interfaces were larger as a result of the circuitous transaction scheduling.

Fourth, Figure 44 shows $48 million of the shortfalls occurred when the external interface flows were constrained in real-time below the day-ahead scheduled level. Such constraints became more frequent during the period of increased loop flows around Lake Erie as a result of TLR events that were called by PJM and IESO. Hence, a large portion of the $48 million shortfall associated with the external interfaces was related to the circuitous transaction scheduling.

The NYISO implemented two measures to limit the effect of circuitous transaction scheduling. First, in late May 2008, the NYISO implemented a more timely update of the Lake Erie loop flow assumption used in the day-ahead market. Although it did not eliminate the loop flows around Lake Erie, it helped reduce the associated balancing congestion revenue shortfalls. In late July 2008, the NYISO prohibited the scheduling of circuitous transactions, which dramatically reduced Lake Erie loop flows and the associated shortfalls.

Figure 44 shows changes between the day-ahead and the real-time related to Waldwick, Farragut, and Linden PARs accounted for an additional $36 million shortfall. Incorrect inputs were used in the day-ahead market to represent the expected flows across the Waldwick PARs for 12 days in January, leading the day-ahead market to over-schedule flows across the Central-East interface. Approximately 55 percent of the $19 million shortfall associated with the

Waldwick PARs is attributable to this event. The Waldwick, Farragut, and Linden PARs are set to support the wheel of up to 1 GW of power from upstate New York through New Jersey to New York City. Although the amount of flow in real-time may be reduced under certain circumstances, the NYISO normally expects 1 GW will flow in the day-ahead market. Hence, partial curtailments of the wheel in real-time can cause balancing congestion revenue shortfalls.

G. Conclusions and Recommendations

Balancing congestion revenue shortfalls rose substantially in the first seven months of 2008, accounting for 95 percent of the total shortfalls in 2008. The rise in shortfalls coincided with the increase in circuitous transaction scheduling around Lake Erie, and the general rise in fuel prices that contributed to larger congestion-related price differences between regions. All shortfall categories declined significantly in the last five months of 2008, primarily due to smaller day-ahead to real-time transfer capability differences, lower fuel prices, and the prohibition imposed on circuitous scheduling. The NYISO improved operating procedures that helped reduce balancing congestion shortfalls related to the PJM and Ontario interfaces when neighboring control areas declare TLRs. In May 2008, the NYISO began making more timely updates of the day-ahead loop flow assumptions, which reduced the shortfalls resulting from the loop flows. In July 2008, the NYISO precluded the scheduling of circuitous transactions, which reduced the volume of loop flows.

Balancing congestion shortfalls also arise when external interface capability is reduced in real-time below the day-ahead scheduled level. In such hours, the resulting shortfalls are increased when the proxy bus LBMP is set by a negative offer price (e.g. the offer price limit is -$999.70 per MWh). There are limited benefits of allowing participants to submit extremely low offer prices. Hence, we recommend that the current offer limit for real-time import transactions be adjusted from -$999.70 per MWh to a level more consistent with the avoided costs of curtailing the import (e.g., -$50 per MWh or $0 per MWh). This should also improve the performance of the market during over-generation conditions.

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 2008. This section examines three areas:

- Real-Time Scheduling and Pricing – This sub-section evaluates the consistency of real-time pricing with real-time commitment and dispatch decisions.
- 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 and they tend to dampen market signals.

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.[41] 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.[42] 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 VI.B.

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

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

42 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:

- Efficiency of Real-Time Commitment of Gas Turbines;
- Efficiency of Real-Time Scheduling of External Transactions;
- Consistency of Inputs Used in RTC and RTD; and
- Real-Time Price Volatility.

The following subsections provide our evaluation and discussion in each of these four 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 45 shows the average quantity of GT capacity started each day in 2008.[43] 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

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[43] The average quantity shown in this report is significantly lower than in the 2007 report that included self scheduled gas turbines.

City and Long Island, and based on whether they were started by RTC, RTD, RTD-CAM,[44] or by an out-of-merit (OOM) instruction.

Figure 45: Efficiency of Gas Turbine Commitment 2008

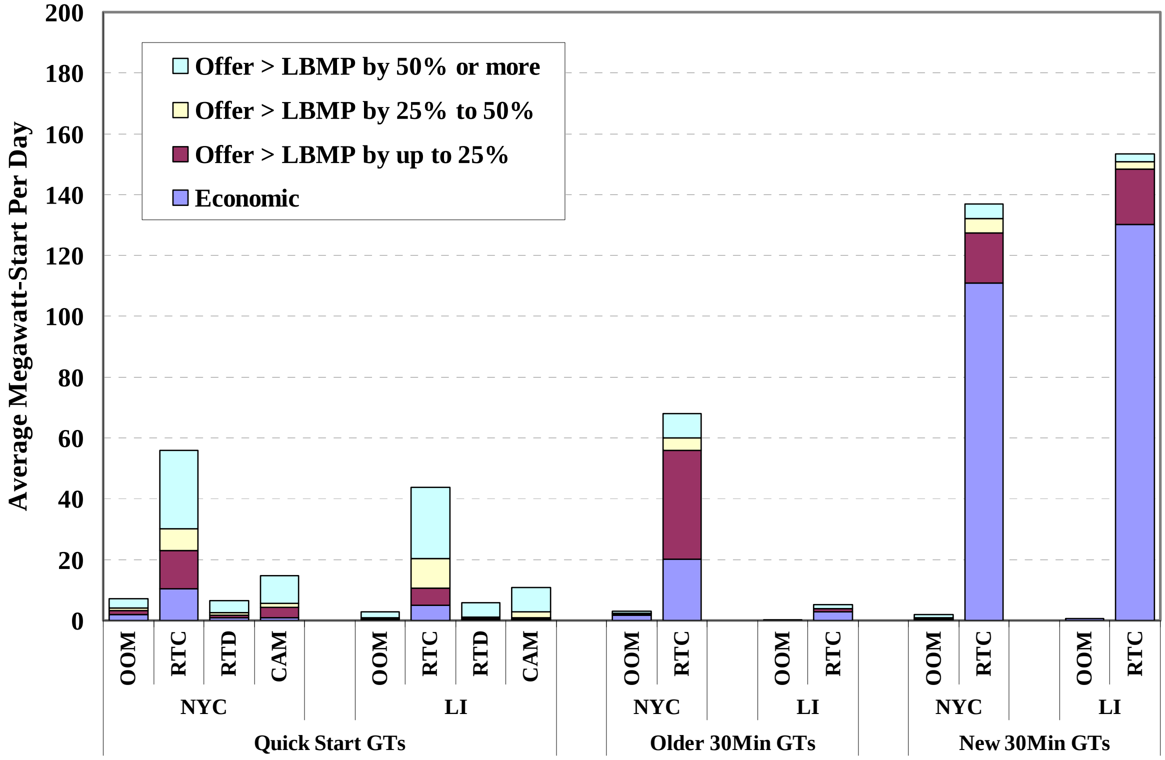

Figure 45 indicates that nearly 90 percent of the GT-capacity started during 2008 was committed by RTC, with an additional 7 percent by RTD and RTD-CAM, and the remaining 3 percent by OOM instructions. 56 percent of the GT-capacity that started was clearly economic. However, some GTs with offers greater 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.

[44] 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.

The figure shows new 30-minute GTs (those installed after 2000) accounted for approximately 57 percent of the GT capacity started in 2008, 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. 83 percent of starts of newer GTs were clearly economic as opposed to 33 percent of the 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.

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. In 2008, 64 percent of the binding constraints in RTD in New York City were simplified interface constraints rather than the more detailed constraints. Less frequent use of the simplified network representation in New York City load pockets would likely improve 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.[45] 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.

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[45] 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).

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 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.[46]

"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.[47]

Figure 46 shows the consistency and profitability of external transaction scheduling across the primary AC interface between New York and New England from 2005 to 2008 using the import/export bid and offer prices and the real-time LBMP at the border. 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 46 shows price-sensitive offers to import and export in four categories of stacked bars:

- Scheduled and consistent – RTC schedules these consistent with real-time LBMPs. However, if these are unprofitable, it implies that they cause power to flow inefficiently from the high-priced control area to the low-priced control area.

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[46] 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.

[47] 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.

- Scheduled and not consistent – RTC schedules these inconsistent with real-time LBMPs. However, if these are profitable, it implies that they cause power to flow efficiently from the high-priced control area to the low-priced control area.
- Not scheduled and not consistent – These are not scheduled by RTC but apparently should have been.
- Not scheduled and consistent – These 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 46: Efficiency of External Transaction Scheduling
Primary Interface with New England, 2005 – 2008

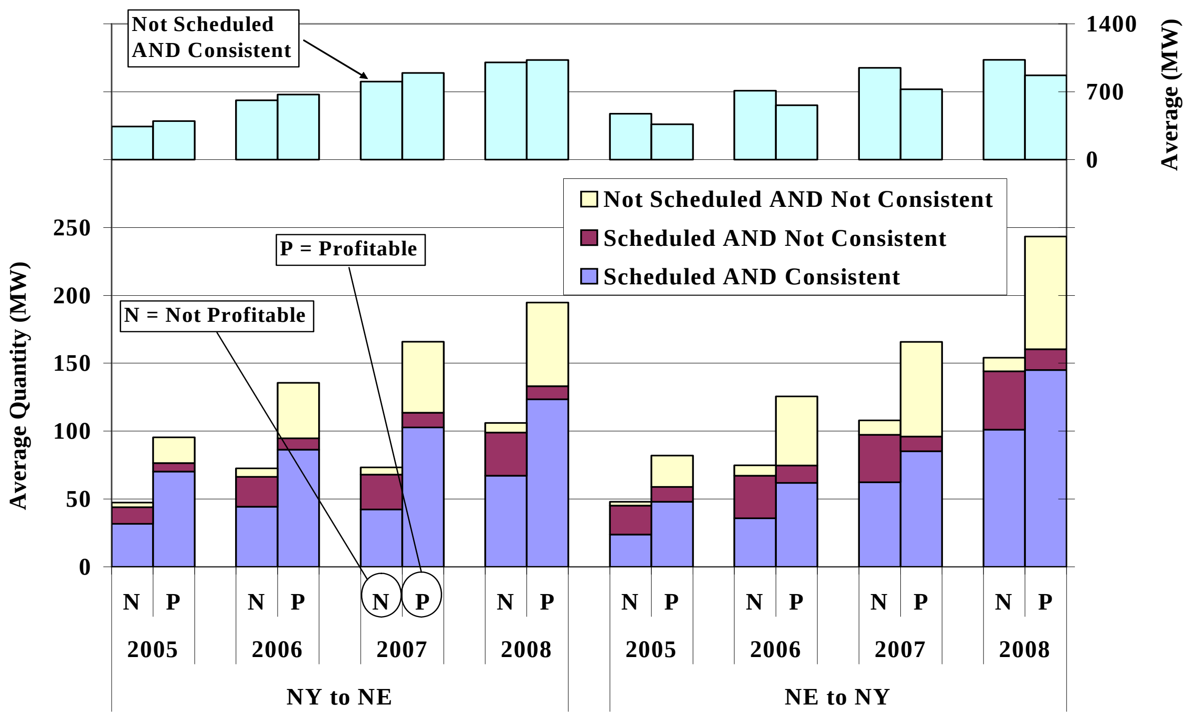


Figure 46 shows the volume of price-sensitive transactions over the primary interface between New York and New England rose substantially from 2005 to 2008. The average volume of price-sensitive imports increased nearly 140 percent in three years, from 970 MW in 2005 to 2,300 MW in 2008. The average volume of price-sensitive exports increased approximately 165 percent, from 880 MW in 2005 to 2,330 MW in 2008. This increase suggests that market participants have increasingly relied on RTC to determine when it will be economic to schedule between adjacent control areas. However, only a small fraction of price-sensitive offers were scheduled -- 10 to 12 percent from 2005 to 2008.

In 2008, 81 percent of scheduled transactions were consistent, and 96 percent of offers not scheduled were also consistent. These levels are comparable to results from 2005 to 2007 and are an indication of relatively good performance by RTC.

The analysis shows imports and exports that are scheduled consistently tend to be profitable, while those scheduled inconsistently tend to be unprofitable. The analysis indicates that 61 percent of transactions that were "scheduled and consistent" were also profitable in 2008. Hence, even when RTC performed well by scheduling transactions in accordance with real-time LBMPs, 39 percent of them were still unprofitable.

Alternatively, 25 percent of transactions that were "scheduled and not consistent" were profitable in 2008. Even when RTC performed poorly, 25 percent of the transactions were still profitable.

The analysis suggests that good performance by RTC helps improve the efficiency of external transaction scheduling, but efficient scheduling also depends on the predictability of real-time price differences between markets. There are several potential means to improve the efficiency of external transaction scheduling by RTC:

Improving the assumptions used in RTC and making them more consistent with RTD. The next part of this sub-section evaluates the consistency of some key assumptions used in RTC and RTD.

Reducing unnecessary volatility in RTD prices. RTD price volatility (which is evaluated later in this sub-section) reduces the efficiency of external transaction scheduling by RTC. Inefficient transaction scheduling may, in turn, contribute to RTD price volatility.

Increasing the predictability of price differences between New York and adjacent markets. One way to do this is to reduce the lead time for scheduling external transactions, which is discussed in Section IV.D.

3. Comparison of RTC and RTD Inputs

Real-Time scheduling is accomplished by two models: RTD and RTC. Normally, RTD is responsible for balancing generation with load and allocating ancillary services every five minutes. RTC schedules resources that are not flexible enough to be deployed on a five-minute basis such as external transactions and off-line gas turbines. Like RTD, RTC performs an economic evaluation that commits and schedules the least expensive resources available to meet forecasted demand and ancillary services requirements. RTC executes every 15 minutes, and each execution of RTC produces advisory schedules and clearing prices for each 15 minute interval over a two hour and thirty minute horizon (ten 15-minute intervals).

Inconsistencies between RTC and RTD prices raise concerns because they may indicate that gas turbines and external transactions are not being scheduled efficiently. Excess commitment and scheduling of uneconomic resources by RTC can lead to increased uplift costs and depressed real-time prices. On the other hand, failure by RTC to commit resources can lead to unnecessary price spikes. The following analysis evaluates two factors that could contribute to systematic differences between RTC and RTD prices.

The following figure compares several quantities from RTC and RTD by time of day during the summer of 2008. In particular, it compares the amount of scheduled load, the level of net exports, and energy prices in RTC versus RTD at 15-minute intervals (i.e., at 15, 30, and 45 minutes past the hour and at the top of the hour). The figure also compares energy prices from the first of the ten intervals (the one closest to the time RTC executes) to the real-time energy prices produced by RTD. Scheduled loads and net exports are inputs that jointly determine the quantity of internal resources that must be scheduled by RTC and RTD. Increasing load and net exports requires additional internal generation, generally leading to higher prices. Thus, net exports and loads are stacked in the figure to show their cumulative effect on price differences between RTC and RTD.

Figure 47: Prices, Loads, and Net Exports in RTC and RTD
June to August, 2008

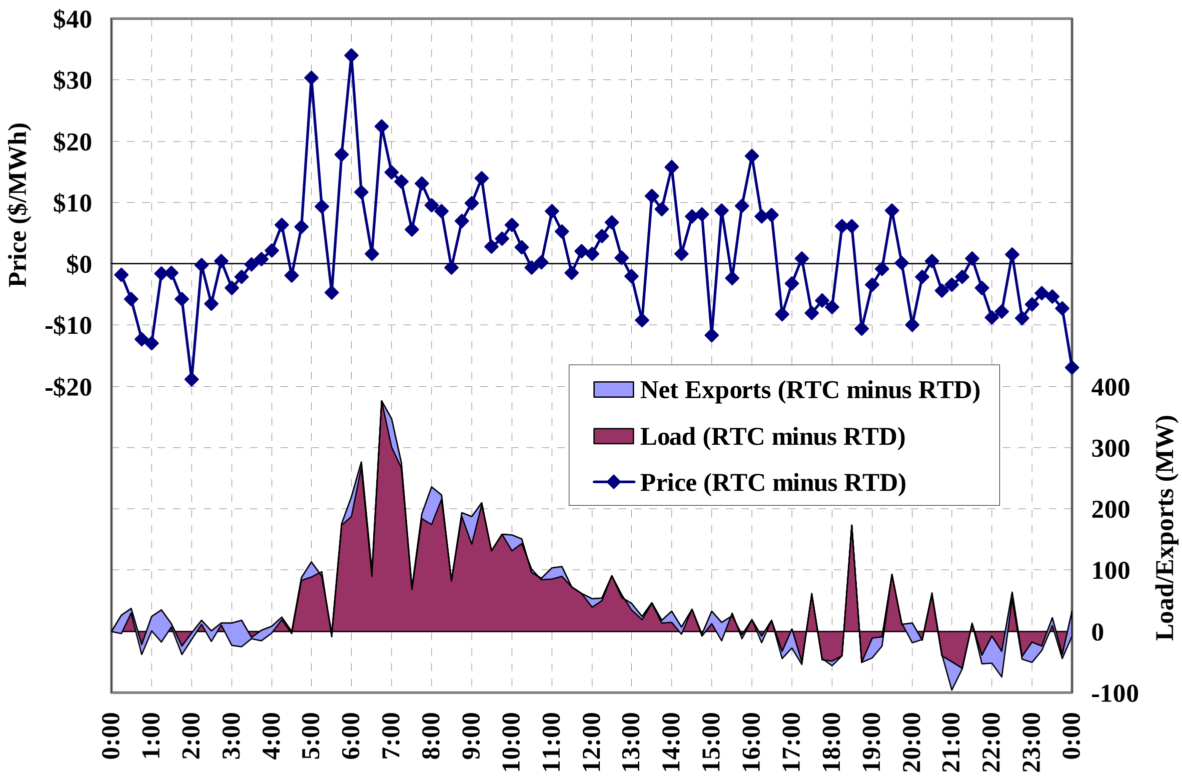


Figure 47 indicates that some systematic differences between RTC and RTD prices are correlated with differences between RTC and RTD values of load. Such differences can lead to either uneconomic commitments or unnecessary transient price spikes. RTC load is consistently higher than RTD load during the morning ramp period, leading to correspondingly higher RTC prices. RTC schedules resources at time t using the highest of the load forecasts from (i) time t, (ii) time t plus five minutes, and (iii) time t plus ten minutes. As a result, RTC load is approximately ten minutes ahead of the load forecast during the morning ramp period.

The figure indicates that the assumptions that RTC and RTD used about net exports were not systematically different in 2008, suggesting that they are not a significant source of inconsistency between RTC and RTD prices. This is a significant improvement over previous years that is attributable to a modification made by the ISO to RTC in January 2008. The modification causes RTC to assume that each external interface schedule "ramps" at a constant rate from 15 minutes before the top of the hour to 15 minutes after the top of the hour. Before the modification, RTC assumed that each external interface “ramped” to its next hour schedule at the top of the hour. For example, suppose net exports increase from 200 MW in the hour beginning at 8:00 to 800 MW in the hour beginning at 9:00. RTC previously assumed that net exports were 800 MW at 9:00. With the modifications, RTC now assumes that net exports are 200 MW at 8:45, 500 MW at 9:00, and 800 MW at 9:15. This revision results in the same schedule for RTC and RTD at the top of the hour, making RTC more consistent with RTD.[48] This has likely contributed to improved convergence between RTC and RTD. However, inconsistencies still exist since RTD assumes a constant ramp rate from :55 to :05, while RTC assumes a constant ramp rate from :45 to :15.

The remaining differences between the net export schedules in RTC and RTD result from transaction curtailments that occur after the initial determination of external transaction schedules. These may occur when a transaction scheduled with the NYISO does not pass check-out with another control area or when the transaction is curtailed by the NYISO or another control area (for reliability reasons or pursuant to TLR procedures). Figure 47 indicates that curtailments have not led to large systematic differences between net export schedules in RTC and RTD, although individual curtailments may still lead to large differences in particular intervals.

The analysis in this section identifies one factor that undermines convergence during ramp-up hours. RTC schedules resources at time t using the highest of the load forecasts at time t, time t plus five minutes, and time t plus ten minutes. This leads RTC prices to be higher than RTD prices during the morning ramp period. Such differences can lead to uneconomic commitments or uneconomic scheduling of external transactions. To reduce systematic differences between RTC and RTD, we recommend the NYISO evaluate alternative methods of determining the load used in RTC. It should, however, be noted that since RTC is responsible for committing sufficient resources to satisfy demand, any changes to eliminate predictable differences between RTC load and RTD load must still allow RTC to ensure sufficient resources are available.

48 RTD assumes that each interface ramps at a constant rate from five minutes before the top of the hour to five minutes after (i.e., from :55 to :05). In this example, RTD will assume that net exports are 200 MW at 8:55, 500 MW at 9:00, and 800 MW at 9:05

4. Real-Time Price Volatility

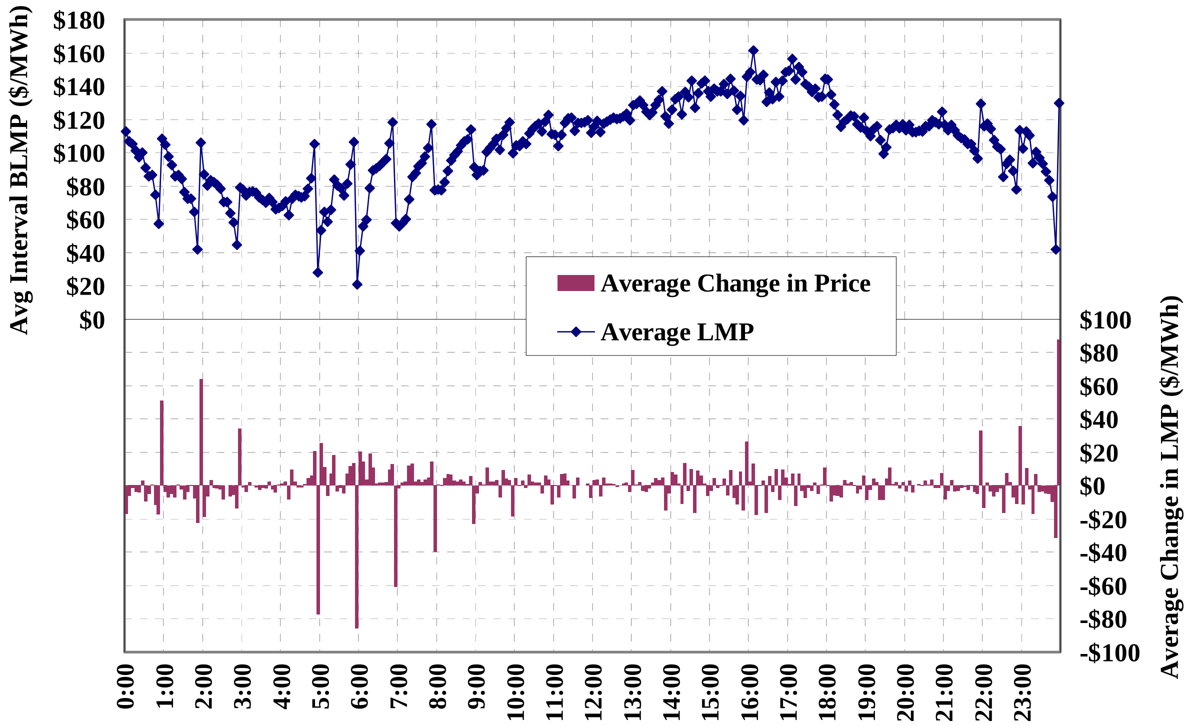
The New York ISO usually dispatches the real-time system and updates clearing prices once every five minutes. Real-Time clearing prices can be quite volatile in wholesale electricity markets, even when sufficient supply is online. Generators (and demand response resources) are sometimes unable to adjust 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 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 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 48 shows the average clearing price in each five-minute interval of the day during the summer months of 2008. The data shows the load-weighted average price 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 $40 per MWh to more than $80 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 48: Average Five-Minute Price by Time of Day
Load-Weighted System Average LBMP, June to August 2008



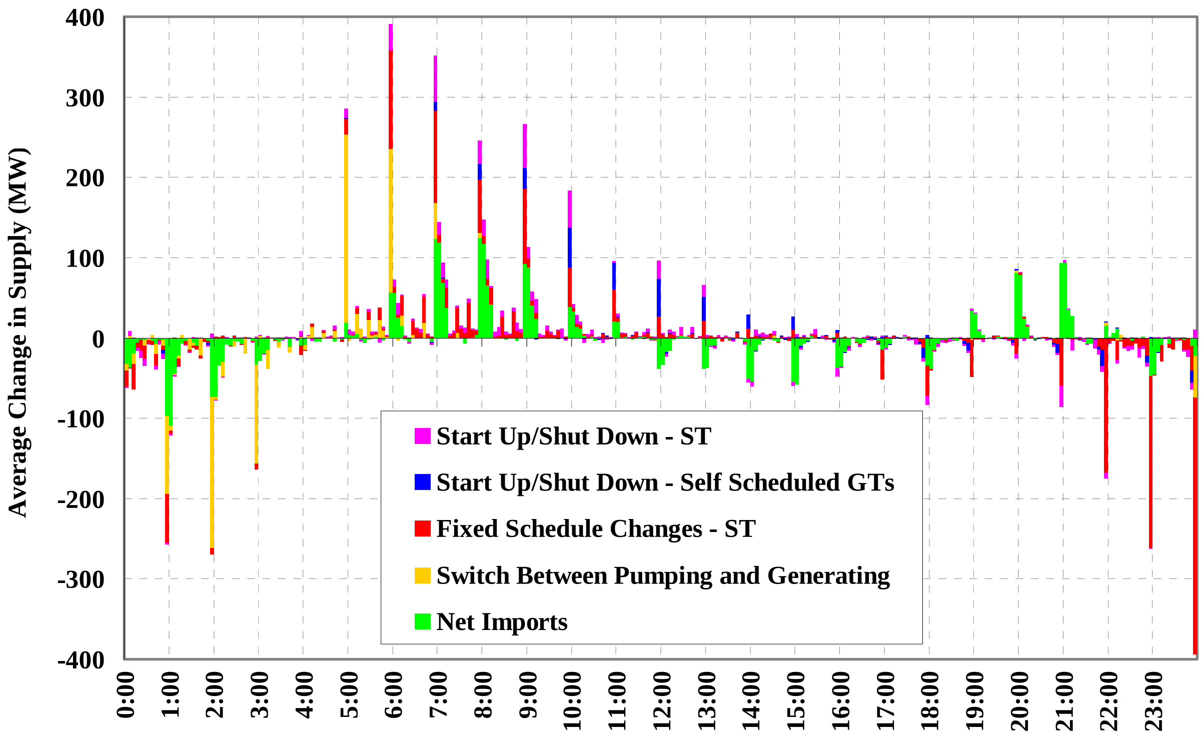
Changes in prices from one interval to the next largely depend on how flexible generators (i.e., generators that can be dispatched by RTD according to their offer) respond to fluctuations: (i) electricity demand, (ii) net export schedules (which are determined prior to RTD), and (iii) generation schedules of self scheduled and other non-flexible generation. Generally, prices increase as a result of increased load, increased net exports, and decreased non-flexible generation. 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 49.

Figure 49 shows the average net changes from one interval to the next for the following five categories of inflexible supply:

- Net imports – Net imports ramp at a constant rate from five minutes prior to the top of the hour (:55) to five minutes after the top of the hour (:05). Otherwise, net imports only change as a result of an intra-hour external transaction curtailment.

- 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 49: Factors Contributing to Real-Time Price Volatility
June to August, 2008



The figure shows adjustments in net imports, pumped storage units switching between pumping and generating, and adjustments in fixed generation schedules account for the most significant changes in inflexible supply from interval-to-interval. For example, from 5:55 am to 6:00 am, the average net increase in inflexible supply from imports, pumped storage units, and fixed scheduled units was 357 MW, coinciding with an $86 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 the hours, it is likely that 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 between $20 per MWh and $60 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, load changes most rapidly during ramping hours. Second, import and export schedules adjust at the top of the hour. Third, generators are committed and decommitted frequently at the top of the hour during ramping hours. Fourth, 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.

We recommend the ISO perform an evaluation of factors that contribute to real-time price volatility, and determine whether it can be reduced by modifying the real-time scheduling software or by other improvements. Currently, the NYISO is working on a project to evaluate and address factors that lead to unnecessary price volatility. Under this project, the NYISO recently identified several factors that contributed significantly to interval-to-interval price changes of $100 per MWh or more:

- Frequent curtailment of external transactions after they are scheduled by RTC but before the start of the dispatch hour;
- Differences between the RTC and RTD load forecasts, and
- Changes in the operating modes of pump storage units.

The NYISO has identified that the following planned or on-going projects should help address these three issues: (i) the Broader Regional Markets initiative, (ii) the Load Forecaster Enhancements project, and (iii) the Enhanced Storage Optimization concept.[49]

B. 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 – In Part Chapter I.A.1 of this sub-section, we evaluate the consistency between real-time reserve prices and the availability of 10-minute reserves in Eastern New York. In Part 2 of this sub-section, we examine factors that lead to inconsistencies between clearing prices and the adequacy of reserves in the real-time market.
- Transmission constraint violations – Part 3 of this sub-section discusses a market rule change that has reduced unnecessary costs from periods of extremely scarce transmission capability.
- Demand response activations – There were no activations of demand response for reliability in 2008. The NYISO's demand response programs are evaluated in Section VIII.

The importance of setting efficient real-time price signals during shortages of operating reserves was recently affirmed by FERC in Order 719, which identifies two provisions in the NYISO's market design that facilitate shortage pricing and serve as a model for other ISOs. First, the NYISO uses operating reserve demand curves to set real-time clearing prices during operating

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

reserves shortages.[50] 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. When the real-time dispatch model ("RTD") cannot satisfy both the energy demand and ancillary services requirements with the available resources, the demand curves for ancillary services cause prices to reflect the value of foregone ancillary services. This sub-section 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 and Long Island, where gas turbines account for nearly 30 percent of installed capacity. Thus, Hybrid Pricing is particularly important for setting efficient price signals in constrained load pockets.

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: (i) clearing prices reflect scarcity under physical shortage conditions, and (ii) shortage prices are only set when the system is physically in shortage of either energy or ancillary services. We found that a substantial number of such inconsistencies occurred after the implementation of the operating reserve demand curves in February 2005.[51] However, the NYISO made several improvements to

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[50] Order No. 719, 73 Fed. Reg. 64,100 (Oct. 28, 2008), FERC Stats. & Regs. ¶ 31,281 (2008), 125 FERC ¶ 61,071 (2008).

[51] See 2005 State of the Market Report, New York ISO, August 2006, Potomac Economics.

the market software to address the lack of consistency between the physical dispatch and pricing dispatch, which led to much more consistent results in 2006 and 2007.[52] The analyses in this section continue to examine the occurrences of such inconsistencies in 2008.

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 50 below shows the amount of Eastern New York 10-minute reserves that were physically scheduled during shortage pricing intervals in 2008.

Figure 50: Scheduling of 10-Minute Reserves in Eastern New York
During Shortage Pricing Intervals, 2008

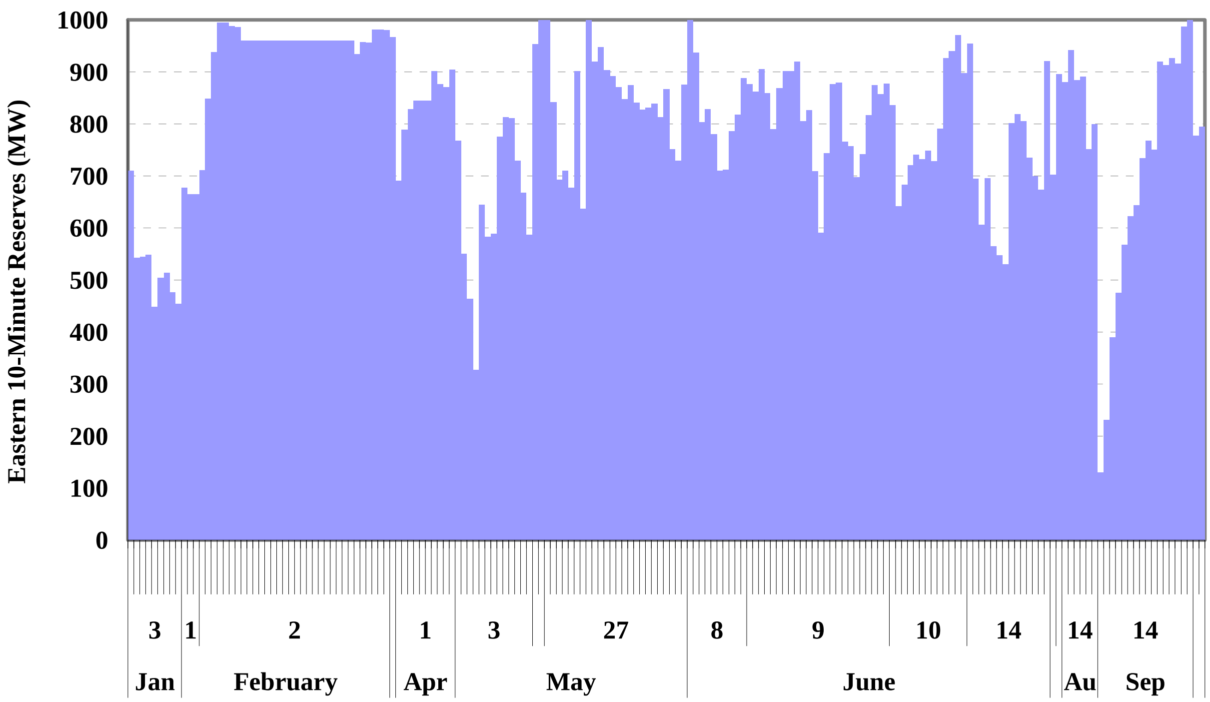

Figure 50 shows 181 intervals with shortage pricing of Eastern 10-minute reserves, which is a decline from 219 such intervals in 2007. The figure shows Eastern New York was in a physical shortage in 97 percent of the shortage pricing intervals in 2008, which is comparable to the high levels observed in 2006 and 2007. These results indicate that almost all shortage pricing

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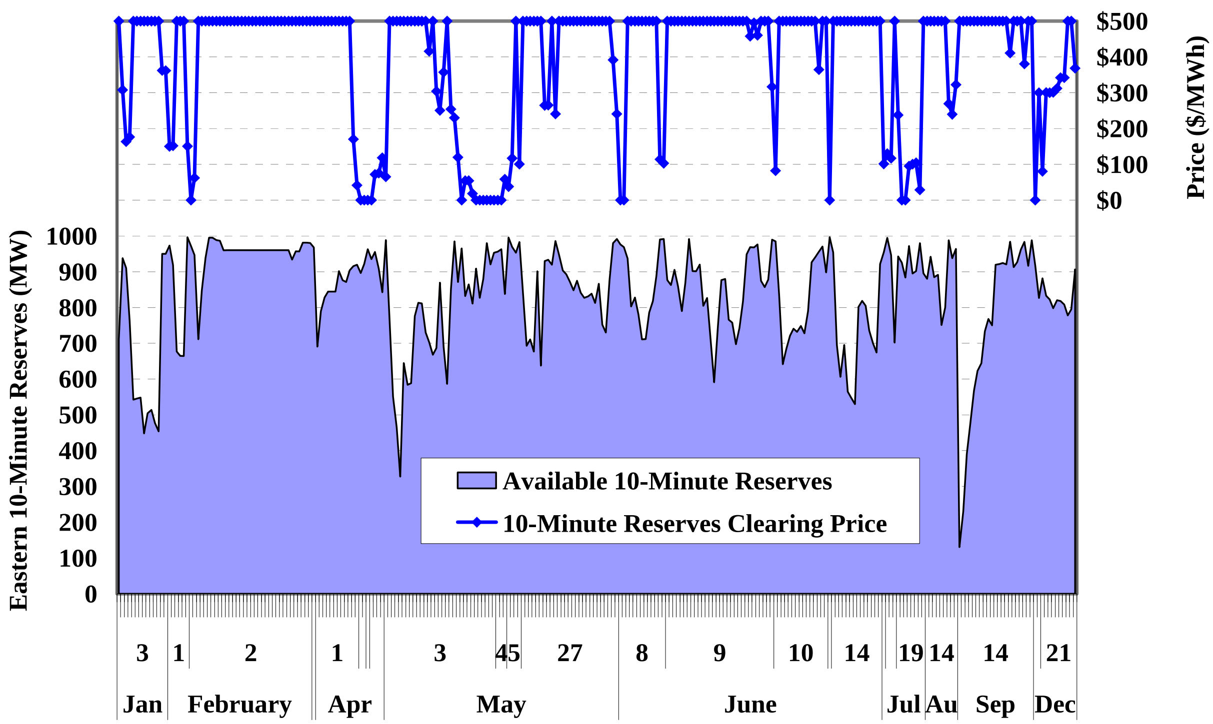
[52] See 2006 State of the Market Report, New York ISO, July 2007, Potomac Economics, and 2007 State of the Market Report, New York ISO, August 2008, Potomac Economics.

intervals associated with the Eastern 10-minute reserves requirement occurred during authentic periods of physical shortage in 2008.

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 51 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 51: Scheduling and Pricing of 10-Minute Reserves in Eastern New York
During Physical Shortage Intervals, 2008



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

Figure 51 shows 84 out of 266 intervals (or 32 percent) with physical shortages were not accompanied by shortage pricing in 2008. This percentage is comparable to the 28 percent level observed in 2007. In these intervals, the Eastern 10-minute reserve prices averaged $164 per MWh and the shortage quantity was less than 100 MW in almost two-thirds intervals. This slight increase in 2008 indicates that the consistency between the pricing dispatch and the physical dispatch passes of RTD during Eastern 10-minute reserve shortage periods declined slightly from 2007.

The efficiency of real-time energy and ancillary services pricing is enhanced by the co-optimization of energy and ancillary services scheduling and by the use of operating reserve demand curves. However, a significant number of intervals occur when there are physical reserve shortages that are not reflected in reserve clearing prices. The following discussion of Hybrid Pricing discusses factors that contribute to the inconsistencies.

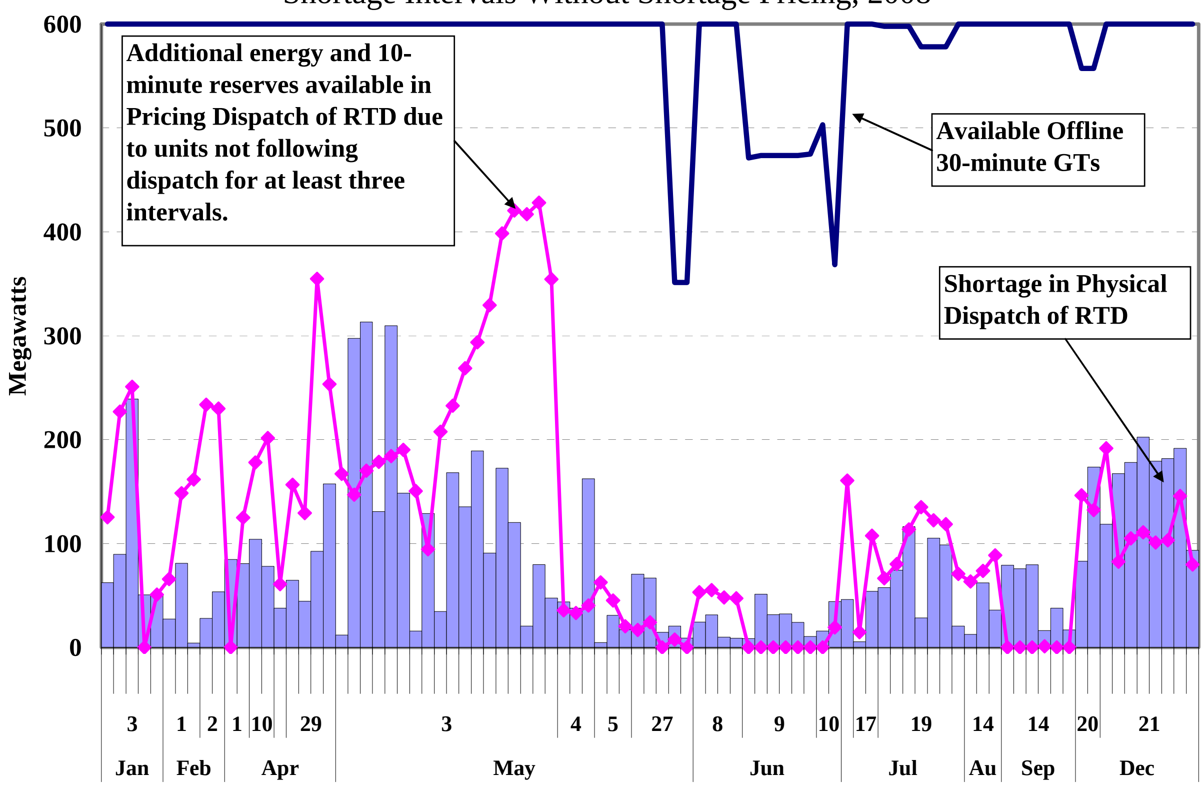
2. Hybrid Pricing

Hybrid Pricing was designed to address the problems posed by inflexible generation (primarily gas turbines) in a marginal cost pricing market. 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 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.

Ramp rate constraints are another factor that accounts for why the output levels of individual resources are not always consistent between the two dispatches of RTD. 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. In contrast, the pricing dispatch constrains 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. Although Hybrid Pricing was designed this way to facilitate treating gas turbines as flexible in the pricing dispatch, large inconsistencies can arise when a steam unit does not respond immediately to its physical dispatch instructions. The following analysis examines whether the inconsistent treatment of units not following dispatch instructions has led to instances when physical shortages are not reflected in market clearing prices.

Figure 52 below summarizes the potential effect of units persistently not following dispatch instructions on Eastern 10-minute reserves prices during the 84 intervals when there was a physical shortage and no shortage pricing. The bars indicate the shortage quantity in the physical dispatch of RTD. The pink line indicates the additional energy and 10-minute reserves available in the pricing dispatch due to inconsistencies in the treatment of units not following dispatch instructions. The blue line indicates the amount of available capacity from offline 30-minute gas turbines, which would have been able to come online if RTC deemed them economic. Quantities exceeding 600 MW are shown as 600 MW in the figure.

Figure 52: Impact of Units Not Following Dispatch Instructions
Shortage Intervals Without Shortage Pricing, 2008



The figure above shows in most intervals more supply was available to the pricing dispatch than the physical dispatch due to a generator not following dispatch instructions for at least three intervals. This quantity was greater than the physical shortage in 52 of the 89 intervals shown and in 12 of the 25 intervals when the shortage exceeded 100 MW. Overall, the inconsistent treatment of units not following dispatch instructions explains a majority of the instances when the physical dispatch perceived a shortage of reserves while the pricing dispatch did not. In all of the intervals shown in the figure, available capacity from offline 30-minute gas turbines exceeded the physical shortage quantity by a substantial margin. This may indicate that if units not following dispatch instructions were treated consistently in the physical and pricing dispatches, RTC would be more likely to start 30-minute gas turbines when shortage conditions were expected. Consequently, some of these physical shortages would not have occurred.

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. Improvements to the consistency of the pricing dispatch and the physical dispatch of RTD and RTC should lead to more efficient pricing of energy and ancillary services (particularly during shortages), thereby reducing uplift. This should also result in fewer physical shortages because RTC will be more likely to start 30-minute GTs in anticipation of a shortage.

In March 2009, NYISO made enhancements to reduce divergences between the physical dispatch and pricing dispatch that are caused by units not following dispatch instructions by re-calibrating the ramp rate limits for such units. These enhancements were made under the "Real-Time Scheduling & Performance Phase 2" project. In future reports, we will evaluate whether these enhancements lead to greater consistency between the occurrence of reserve shortages and shortage pricing.

3. 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. In June 2007, the NYISO began limiting transmission constraint re-dispatch costs to a maximum of $4,000 per MWh to address problems that can 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. Historically, very high transmission price spikes were often accompanied by price corrections, which harm the efficiency of real-time prices. In Section VI.B, we report that the frequency of price corrections was reduced after the modeling changes to transmission constraints in June 2007.

The imposition of the shadow cost limit substantially improved the dependability of real-time price signals during periods of extreme transmission scarcity. In addition, the shadow cost limit has not significantly undermined reliability since re-dispatch usually provides little or no reliability benefit when shadow costs exceed $4,000 per MWh. 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.

C. Supplemental Commitment for Reliability

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 summarize uplift charges that result from guarantee payments received by generators, which are primarily caused by supplemental commitments for local reliability. Second, we examine the primary forms of supplemental commitments for local reliability.

1. Uplift Expenses from Guarantee Payments

The analysis presented in Figure 53 below 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 charges are allocated to a particular load serving entity, while non-local reliability uplift charges are allocated to loads throughout New York. There are three categories of local reliability guarantee payment uplift.

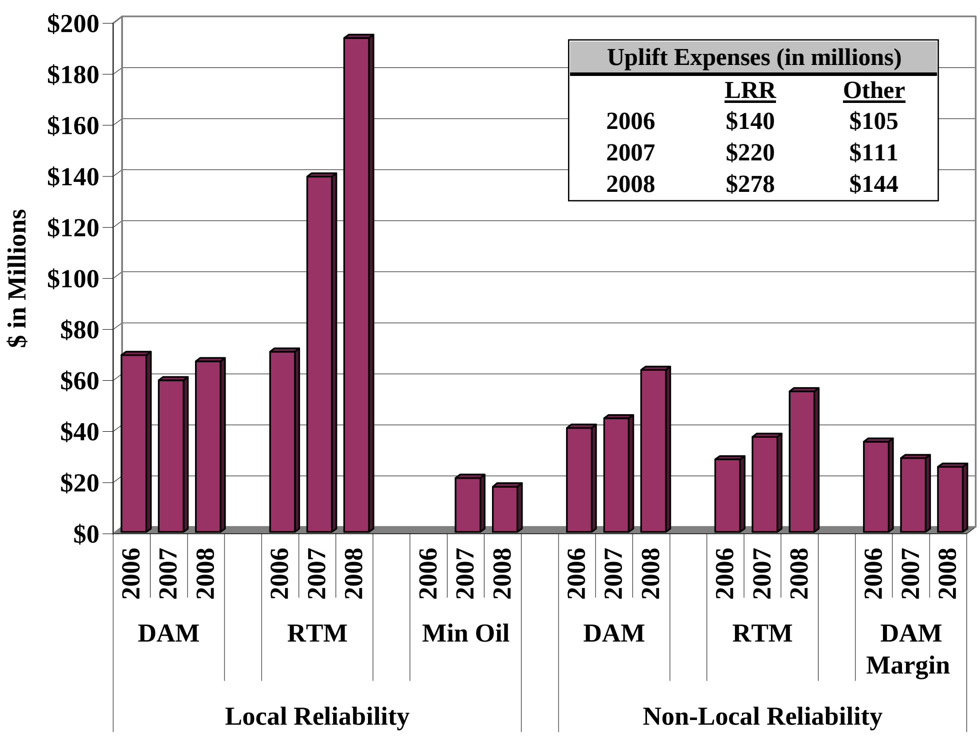
- Day-Ahead Market – The local reliability pass of SCUC commits generators out-of-merit to meet local reliability requirements for New York City. Although the uplift from payments to these units is allocated to the local area, these commitments tend to decrease day-ahead prices. As a result of lower prices, more (non-local reliability) uplift is paid to generators that are economically committed before the local reliability pass.

- Real-Time Market – Guarantee payments are made to generators committed and 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.
- Minimum Oil Burn – Guarantee payments are made to generators that burn fuel oil to help maintain reliability in the ConEd territory because of potential natural gas supply disruptions.

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

- Day-Ahead Market – This includes guarantee payments to generators that are economically committed before the local reliability pass of SCUC. 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).
- Real-Time Market – Guarantee payments are made to generators 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.
- Day-Ahead Margin Assurance – These payments are made to generators that are forced to buy out of a day-ahead schedule in a manner that reduces their day-ahead margin.
- These six categories of uplift costs are shown in Figure 53 below for 2006 to 2008.

Figure 53: Uplift Expenses from Guarantee Payments
2006 – 2008



Local reliability uplift charges increased $58 million from 2007 to 2008, primarily from the rise in real-time guarantee payment uplift. Real-Time guarantee payment uplift increased by 39 percent from 2007 to 2008 due to higher natural gas prices and the increased price of residual fuel oil relative to the price of natural gas. Many of the generators committed for local reliability burn residual fuel oil, which was often priced less than natural gas in previous years.

The Minimum Oil Burn program was implemented in May 2007 to compensate generators that burn fuel oil in order to protect New York City loads from a natural gas supply contingency. Minimum Oil Burn program expenses are correlated with load and the spread between residual fuel oil and natural gas. Although the spread between residual fuel oil and natural gas increased from 2007 to 2008, there was little change in the uplift associated with the Minimum Oil Burn program from 2007 to 2008 because the reliability requirements changed in 2008 and because one large owner of generation stopped participating in the program. The change in reliability requirements resulted in less frequent instances when generators must burn oil.. Non-local reliability uplift increased 30 percent from 2007 to 2008, primarily due to the increased generation costs resulting from increased prices of natural gas and fuel oil.

Overall, total expenses for guarantee payments increased substantially from 2006 to 2008 due primarily to the increase in local reliability uplift. This suggests that improving the efficiency of commitment for local reliability would substantially reduce uplift for guarantee payments. Moreover, more efficient supplemental commitment for local reliability would also reduce the pricing inefficiencies that result from excess out-of-merit capacity.

2. Summary of Supplemental Commitment

Supplemental commitment occurs when a generator is not committed in the economic pass of the day-ahead market but is needed for local reliability. Supplemental commitment primarily occurs in two ways: (i) local reliability commitment that takes place during the day-ahead market process; and (ii) SRE commitment, which occurs after the day-ahead market closes. The day-ahead local reliability commitment is an element of the SCUC market process whereby units that are not committed economically may be committed to meet specific reliability requirements, including second-contingency requirements in New York City. The SRE is a process by which additional resources are committed after the day-ahead market closes in order to meet reliability requirements not included in the SCUC. SRE commitments are ordinarily made by local transmission owners, although the NYISO has the ability to make SRE commitments when necessary.

When SRE commitments are made, they are logged and reported on the NYISO website. Such supplemental commitments do not directly affect the day-ahead LBMPs. However, they influence outcomes in the day-ahead market to the extent that they are anticipated by the day-ahead market. In addition, SRE commitments make additional out-of-merit capacity available in real-time, which tend to reduce real-time LBMPs. Due to the price-effects of out-of-merit capacity, it is important to evaluate the SRE process. Figure 54 shows the average quantity of SRE commitments made from 2006 to 2008 in New York City, Long Island, and Upstate New York.

Figure 54: Supplemental Resource Evaluation
2006 – 2008

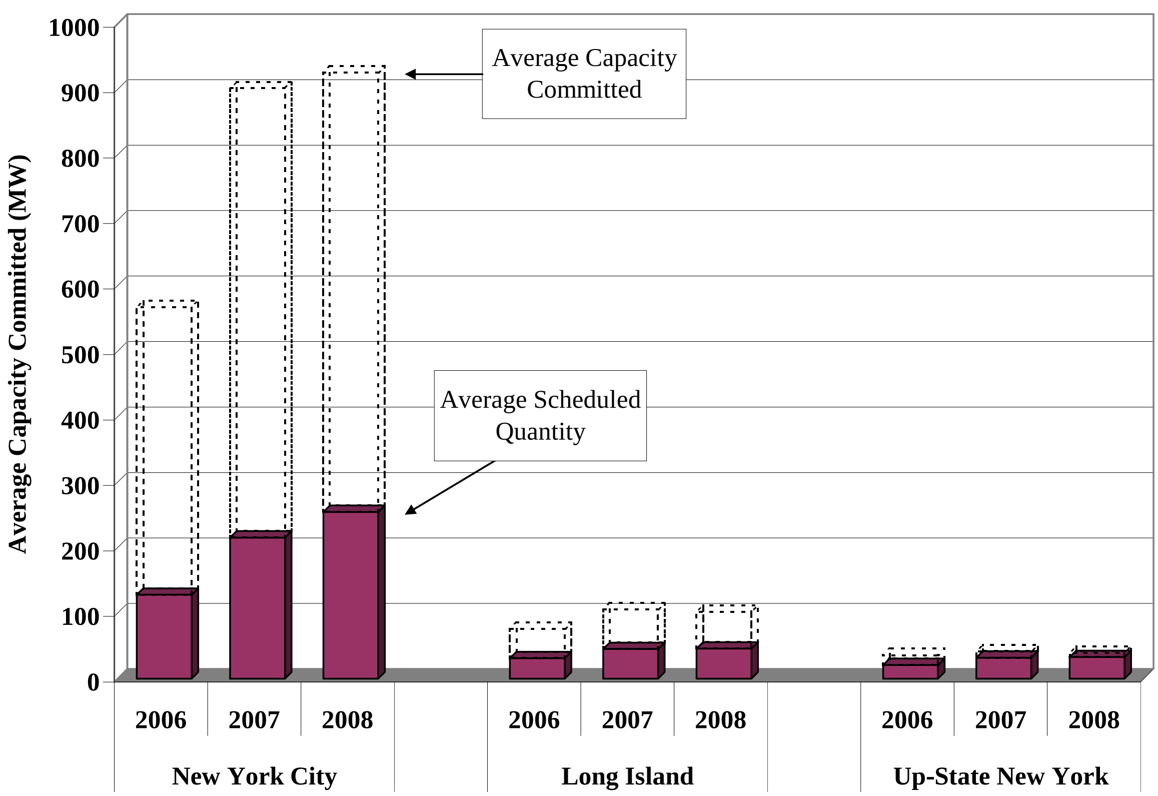


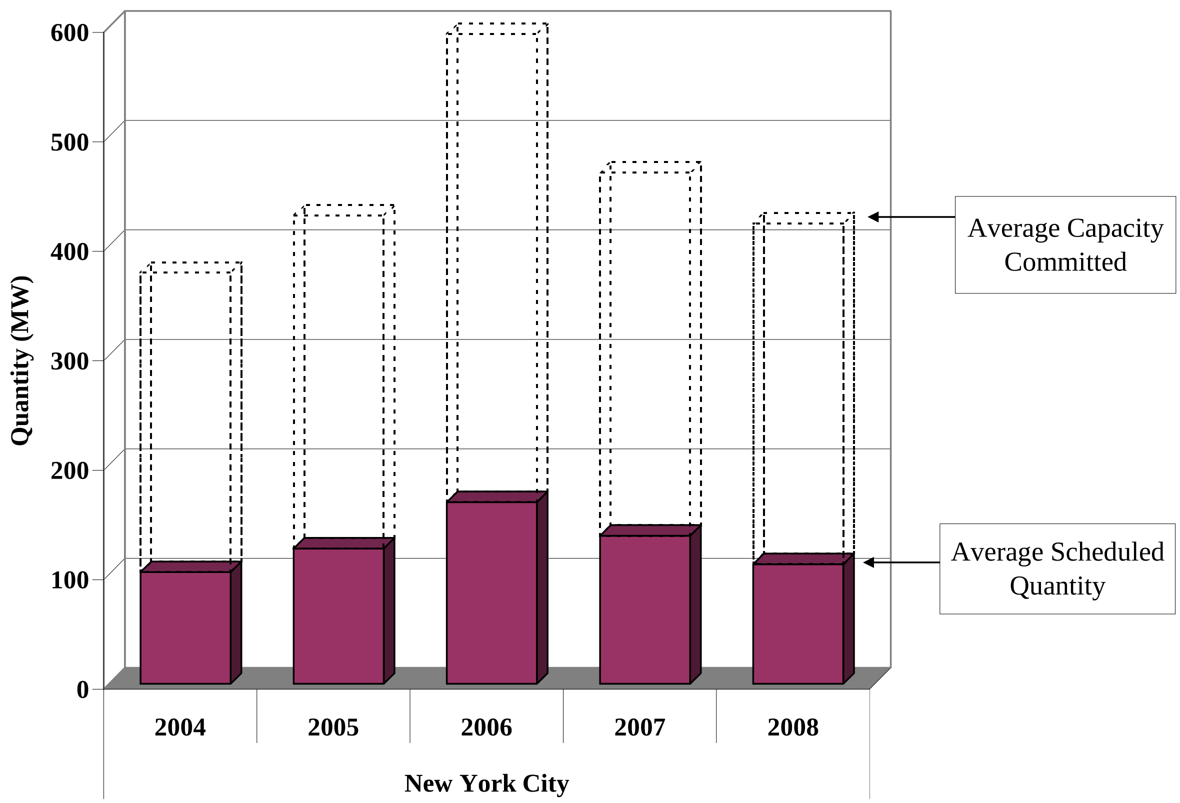
Figure 54 indicates 87 percent of SRE committed capacity was in New York City in 2008, while 10 percent was in Long Island and 3 percent was in Up-State New York. Over the past three years, the SRE commitment pattern in Long Island and Up-State New York remained largely unchanged. In New York City. the average quantity of capacity committed through the SRE process did not change significantly from 2007 to 2008 after increasing 58 percent from 2006 to 2007. The increased need for SREs after 2006 in New York City was partly due to reduced economic commitment of oil-fired generators that are needed for local reliability.

Figure 54 also shows most of the units committed through the SRE process were dispatched at close to their minimum generation levels (25 to 40 percent of the maximum capacity). In 2008, an average of 925 MW of capacity was committed in New York City, but only 255 MW of energy was produced by these generators on average. These generators also provided substantial quantities of 10-minute and 30-minute spinning reserves. To the extent that SRE resources are not fully scheduled to provide energy and ancillary services in the real-time market, it reduces their effect on the market.

The next analysis focuses on commitments made in the day-ahead market (by SCUC) to meet local reliability requirements. These commitments are generally not economic at day-ahead LBMPs. They affect the market because: (i) they reduce LBMPs from levels that would result from a purely economic dispatch; and (ii) they increase 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. Figure 55 below shows the average capacity committed in the day-ahead market for local reliability and the day-ahead scheduled quantity from 2005 to 2008.

Figure 55 shows the average capacity committed for local reliability was 420 MW for the period shown in 2008, which is a decrease of 10 percent from 2007. These units received much lower day-ahead schedules, indicating they are generally scheduled at their minimum generation level. The amount of energy scheduled from such commitments averaged 110 MW in 2008.

Figure 55: SCUC Local Reliability Pass Commitment
2004 – 2008



The amount of capacity committed for local reliability in the day-ahead market declined significantly from 2006 to 2008, although this decline was offset by additional SRE commitments. The average amount of capacity committed for local reliability, including SRE commitments and SCUC commitments, in New York City exceeded 1,300 MW in 2007 and 2008.

In February 2009, the NYISO implemented a new process for committing units for local reliability that should substantially reduce the market effects of maintaining local reliability. SRE commitments have been integrated in the economic pass of the day-ahead market model, which should improve the efficiency of the economic commitments and reliability commitments. This enhancement is expected to reduce the uplift charges that result from committing generation to satisfy the local reliability requirements.

D. 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. In Order 719, the FERC recognized the NYISO's leadership in this aspect of market design.[53] This sub-section summarizes the conclusions and recommendations from our evaluation of market operations in 2008.

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 2008 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 150 percent from 2005 to 2008, indicating that market participants increasingly prefer to rely on RTC to determine when it will be economic to schedule power between control areas. In 2008, we found that a high portion of price-sensitive import offers and export bids (81 percent) were scheduled consistent with real-time prices at the primary interface with New England.

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 identify several factors that likely contribute to the volatility of real-time prices, although a more complete evaluation is necessary to identify the most significant causes of unnecessary volatility.

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[53] Order No. 719, 73 Fed. Reg. 64,100 (Oct. 28, 2008), FERC Stats. & Regs. ¶ 31,281 (2008), 125 FERC ¶ 61,071 (2008), at P 45 and 125.

- We recommend that the NYISO evaluate factors that contribute to unnecessary real-time price volatility, including the assumptions used in the Real-Time Commitment ("RTC") and the Real-Time Dispatch ("RTD") models as well as other market rules.[54]

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 68 percent of the periods with physical shortages of Eastern 10-minute reserves in 2008. 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. We will evaluate in future reports how effective this modification has been in improving the performance of the shortage pricing.

We also find that transmission constraint modeling improvements made in 2007 have greatly improved price certainty in import-constrained areas during periods when transmission limits are violated. We did not evaluate pricing during activations of emergency demand response because they were not activated for reliability in 2008.

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 2008, $278 million was paid for local reliability uplift and $144 million was paid for non-local reliability uplift. To minimize the negative effects of local reliability requirements on the overall

[54] The NYISO has begun evaluating causes of price volatility under the Scheduling & Pricing 3 – Ramping Improvements project.

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 should reduce the market effects of maintaining local reliability. The new process integrates most commitments for local reliability into the economic pass of the day-ahead market model, thereby improving the efficiency of the economic commitments and reliability commitments.

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 recent rule changes, and recommend one change 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.[55] Additionally, the NYISO 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.[56] Since the NYISO operates an Unforced Capacity ("UCAP") market, the ICAP requirements are translated into UCAP requirements, using location-wide forced outage rates.[57] The obligations to satisfy the

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[55] The ICAP requirement = (1 + IRM) * Load Forecast. Prior to May 2007, the IRM was set to 18 percent. For the period from May 2007 to April 2008, the IRM was lowered to 16.5 percent. For the period from May 2008 to April 2009, the IRM was lowered to 15 percent.

[56] The locational ICAP requirement = LCR * Load Forecast for the location. For the period from May 2007 to April 2008, the New York City LCR was 80 percent and the Long Island LCR was 99 percent. For the period from May 2008 to April 2009, the New York City LCR remained at 80 percent and the Long Island LCR declined to 94 percent.

[57] Capacity payments are made for UCAP, which is a measure of resource availability adjusted to reflect the expected forced outage rate. Thus, a unit with a high probability of a forced outage 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 a forced outage probability of seven percent would be able to sell 93 MW of UCAP. This gives suppliers a strong incentive to provide reliable performance.

UCAP requirements are allocated to the LSEs in proportion to their annual peak load in each area.

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 varies depending on the clearing price for UCAP, which 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 low-cost capacity is available, and it may purchase less than the UCAP requirement when capacity is relatively scarce.

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 equals the UCAP requirement. 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.[58]

B. Capacity Market Results

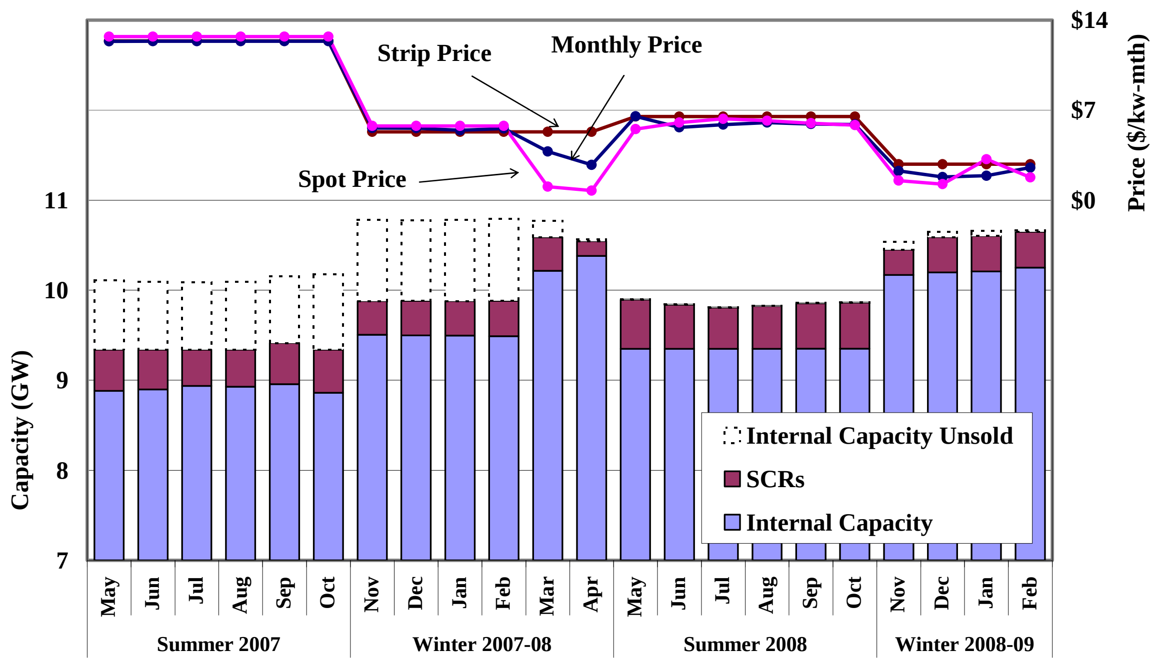
To evaluate the performance of the capacity market, the following three figures show capacity market results from May 2007 through February 2009. This includes four six-month capability

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

periods from the Summer 2007 capability period through the Winter 2008-09 capability period (excluding March and April 2009). These figures show the sources of UCAP supply and the quantities purchased in each month. They also summarize the clearing prices in the strip, monthly, and spot auctions for each month.

Figure 56 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 NYISO-run auctions.

Figure 56: Capacity Market Results for New York City
May 2007 to February 2009



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, resulting in significantly lower prices than in the summer. The average amount of available capability in New York City was 9.9 GW during the Summer 2008 capability period, nearly 0.8 GW lower than in the Winter 2008-2009 capability period. As a result, clearing prices decreased from approximately $6 per kW-month in summer 2008 to less than $3 per kW-month in winter 2008-2009.

Clearing prices were generally consistent between the strip, monthly, and spot auctions in New York City. The lone exceptions were in March and April of 2008 when the capacity prices decreased substantially between the strip auction and the monthly and spot auctions. The decreases in the spot prices that began in these months were caused by the sale of capacity in New York City that had previously not been sold. In March 2008, the amount of unsold capacity in New York City was virtually eliminated.[59] As a result, the New York City spot auction price dropped from $5.77 per kW-month in February 2008 to $1.05 per kW-month in March 2008. The increased sales had a dramatic effect on the auction clearing prices in New York City and continued in the subsequent months.

The increased sales were largely due to the implementation of new mitigation measures and a merger condition placed a large supplier in New York City. In March 2008, FERC ordered the NYISO to implement market power mitigation measures to address buyer-side and seller-side market power. The purpose of the measures is to ensure that future capacity market results are competitive. The measures are intended to improve the efficiency of capacity price signals and provide prospective entrants greater certainty that future capacity prices will reflect the balance of supply and demand in the market. The effectiveness of the supply-side mitigation is evident when one compares the capacity market results from the summer capability periods in 2007 and 2008. Virtually all of the available capacity was sold in 2008 and the clearing price was roughly one half of the price that prevailed in 2007 when a sizable quantity of capacity was unsold.

These substantial price decreases occurred despite the fact that the total available capacity (UCAP) reduced from summer 2007 and winter 2007-2008 to summer 2008 and winter 2008-2009. The capacity reduction was primarily due to a large forced outage of one unit. However, the effect of reduced supply was more than offset by the elimination of unsold capacity in March 2008.

The following figure 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 NYISO-run spot

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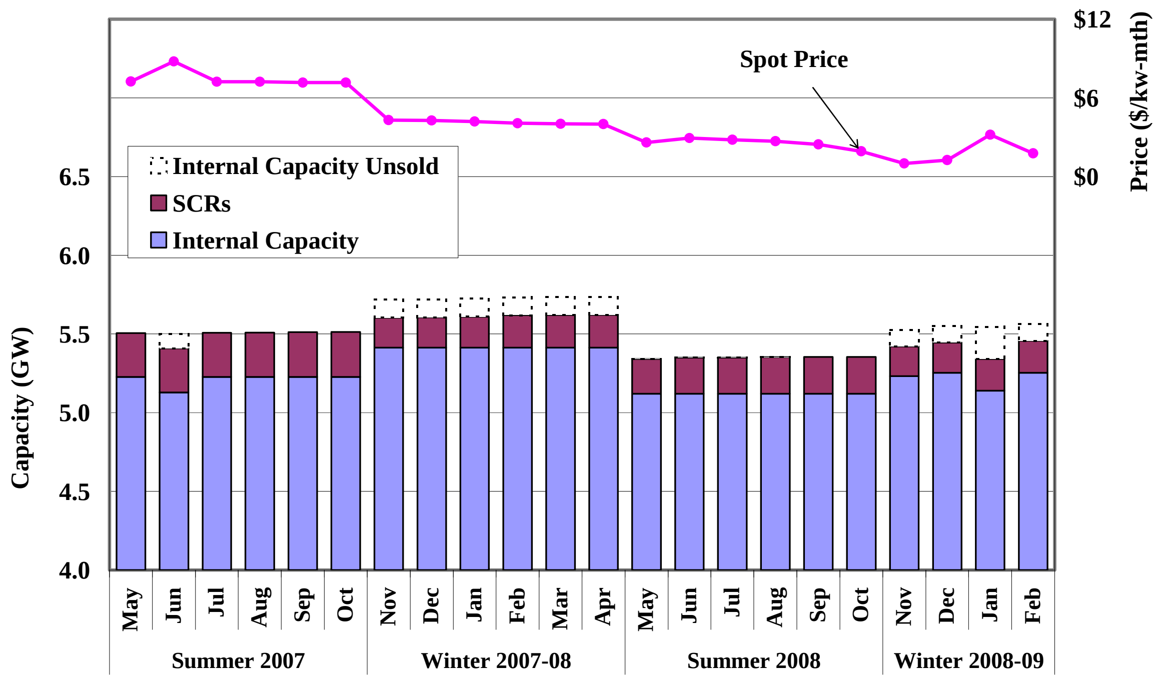
[59] The increased sales resulted from conditions placed on the merger of National Grid and KeySpan-Ravenswood by the Public Service Commission.

auctions. Clearing prices are only shown for the spot auctions, because the volumes transacted through the strip auctions and the monthly auctions were very small during the study period from May 2007 to February 2009.

Figure 57: Capacity Market Results for Long Island
May 2007 to February 2009



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

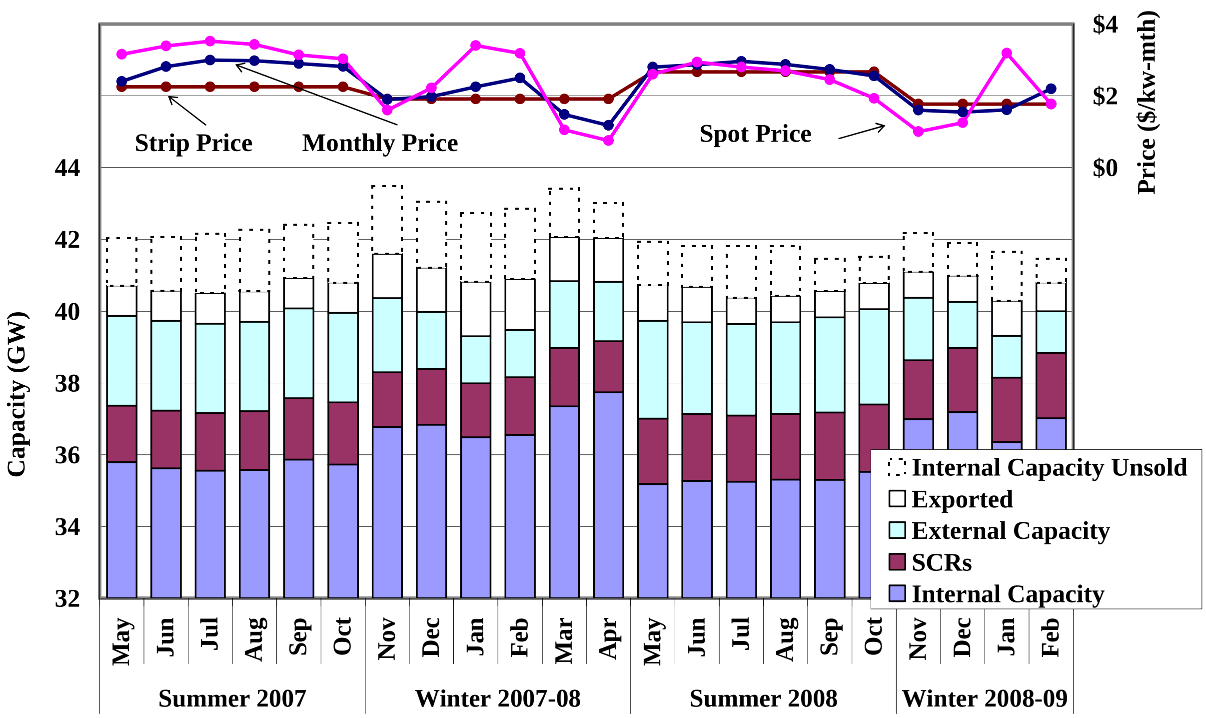
Similar to the auction results in New York City, seasonal changes in capability accounted for the most significant variations in prices in Long Island during the examined period. Overall, the spot prices decreased from 2007 to 2008. The average monthly spot price decreased from $7.5 per kW-month in summer 2007 and $4.1 per kW-month for winter 2007-2008 to $2.6 per kW-month in summer 2008 and $1.8 per kw-month for winter 2008-2009.

The substantial decline in spot prices was primarily due to the reduction of the Local Capacity Requirement ("LCR") in Long Island. The LCR decreased from 99 percent of the peak load to 94 percent, beginning in May 2008. The LCR reduction recognizes the reliability benefits from the Neptune HVDC line between eastern PJM and Long Island.

Total UCAP supply in Long Island declined modestly from summer 2007 to summer 2008 due to a 3 percent increase in the average forced outage rate. However, this did not affect the clearing price because the LCR was also adjusted downward by the forced outage rate to determine the UCAP requirement. Hence, the reduction in UCAP supply was offset by a comparable reduction in the UCAP requirement.

Figure 58 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,[60] 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 in New York or in any adjacent market. The figure also shows UCAP clearing prices in Rest-of-State (i.e., the price applicable to capacity outside New York City and Long Island).

Figure 58: Capacity Market Results for NYCA
May 2007 to February 2009



60 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."

Note: 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 capability between the summer and winter capability periods resulted in significant changes in the capacity sold and the prices.

Several other factors significantly affected capacity prices and sales during the period shown above. First, sales from SCRs increased approximately 200 MW. Second, the available capacity from internal resources declined in Summer 2008 compared to Summer 2007, primarily due to an increase in forced outages in Long Island and New York City.

Third, the clearing price in the Rest-Of-State area was affected by increased sales of capacity in the local capacity zones since local capacity also counts toward the NYCA requirement. In spring 2008, the increased UCAP sales in New York City discussed above contributed to the decline in the Rest-Of-State spot price from $3.18 per kW-month in February 2008 to $0.75 per kW-month in April 2008.

Fourth, the quantity of net imports varied significantly over the period. In the summer periods, average net imports increased from 1,650 MW in the summer of 2007 to 1,800 MW in the summer of 2008. In the winter periods, the average net imports increased from 330 MW in the winter of 2007 to 530 MW in the winter of 2008. Most fluctuations in capacity prices in the winter capability periods were related to variations in the quantities of imports and exports. For instance, net imports dropped to below -100 MW in January and February 2008, leading to a substantial increase in spot prices in both months. The increase of spot price in January 2009 was also in part due to the decline of cleared net imports in this month.

Fifth, the reduction in the IRM for NYCA reduced capacity prices in the Rest-Of-State area in the summer 2008 and the winter 2008-2009. The IRM for NYCA declined from 16.5 percent in the period from May 2007 to April 2008 to 15 percent in the period from May 2008 to April 2009, leading to an effective reduction in the installed capacity requirement of approximately 500 MW.

C. 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 (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 that are most valuable.

A new "deliverability" test is being implemented, which indicates generation outside of these areas may not be deliverable in the near future. If some capacity is deemed to be undeliverable, some new resources in western New York and some imports that have historically supplied the capacity market will be prevented from selling capacity in New York unless they pay for transmission upgrades.

Because the failure of the deliverability test can substantially affect investment incentives, it is important to use realistic assumptions in the deliverability test, so that the test determines whether capacity is deliverable under realistic conditions. However, the deliverability test is not currently designed to represent a realistic case, so its results may not be reliable. Accordingly, the test should be revised to correspond to a real potential set of contingencies, so that it will determine whether incremental supply in each area can respond to maintain the reliability of the system.

If the deliverability test determines that new units or imports are not deliverable due to transmission constraints between large areas on the system, a new capacity zone is likely needed to efficiently distinguish the value of capacity on either side of the constraint. Several problems or inefficiencies occur if capacity is deemed to not be deliverable and a new zone is not created:

- The capacity market will not send the signals necessary to build new capacity if it is needed in the congested area. This may be particularly important when the cost of new entry is higher in the congested areas than in the uncongested areas.
- New suppliers or importers on the uncongested side of the transmission constraint may be inefficiently foreclosed from the market when building new transmission to relieve the

constraint is not economically efficient. Foreclosing this capacity will generally raise capacity costs for New York consumers and reduce competition.

- Suppliers that can provide capacity and reliability benefits to the areas of the NYCA on the unconstrained side of the constraint (or all of NYCA when constraints are not binding) will not receive any revenue. This will distort the investment incentives in those areas.

Given the initial indications that some capacity in western New York may not be deliverable to eastern New York or southeast New York, we recommend the NYISO consider whether one or more new capacity zones are needed in eastern New York. As discussed above, this would likely reduce capacity costs for New York consumers and improve the incentives for investment that is beneficial for reliability. Creating new zones will also ensure that investment incentives and incentives to import or export capacity will be efficient on both sides if the key transmission constraints in 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. However, those that invest in new transmission capability between capacity zones should have access to the economic property right corresponding to the difference in the capacity prices between the zones.

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 enable 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.[61]
- Targeted Demand Response Program ("TDRP") – This program pays EDRP and SCR resources the higher of $500 per MWh 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 resources with curtailable load 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 accordance with its offer 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.

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

The NYISO continues to encourage loads to participate in these programs as it evaluates additional means for price-responsive demand to participate in the wholesale market. As participation in demand response programs grows, it is important to ensure that the market rules lead to efficient real-time prices during demand response activations, particularly when emergency demand response resources are activated under shortage conditions. The NYISO allows demand response resources to set clearing prices when an operating reserve shortage is avoided by activating EDRP and SCR resources. This mechanism is one of the four shortage pricing approaches endorsed by the FERC in Order 719.[62]

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,
- Initiatives to enhance the responsiveness of loads to wholesale market prices, and
- Remaining barriers to participation by price-responsive load.

A. Demand Response Programs in 2008

This sub-section discusses 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, DADRP and 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 -- EDRP, SCR, and TDRP – are emergency demand response resources that are called when the NYISO forecasts a shortage. Currently, nearly all of the demand response resources in New York are emergency demand response.

The following figure summarizes registration in three of the programs on an annual basis from 2001 to 2008. Since EDRP and SCR resources in New York City participate in the TDRP program on a voluntary basis, TDRP resources are not shown separately.

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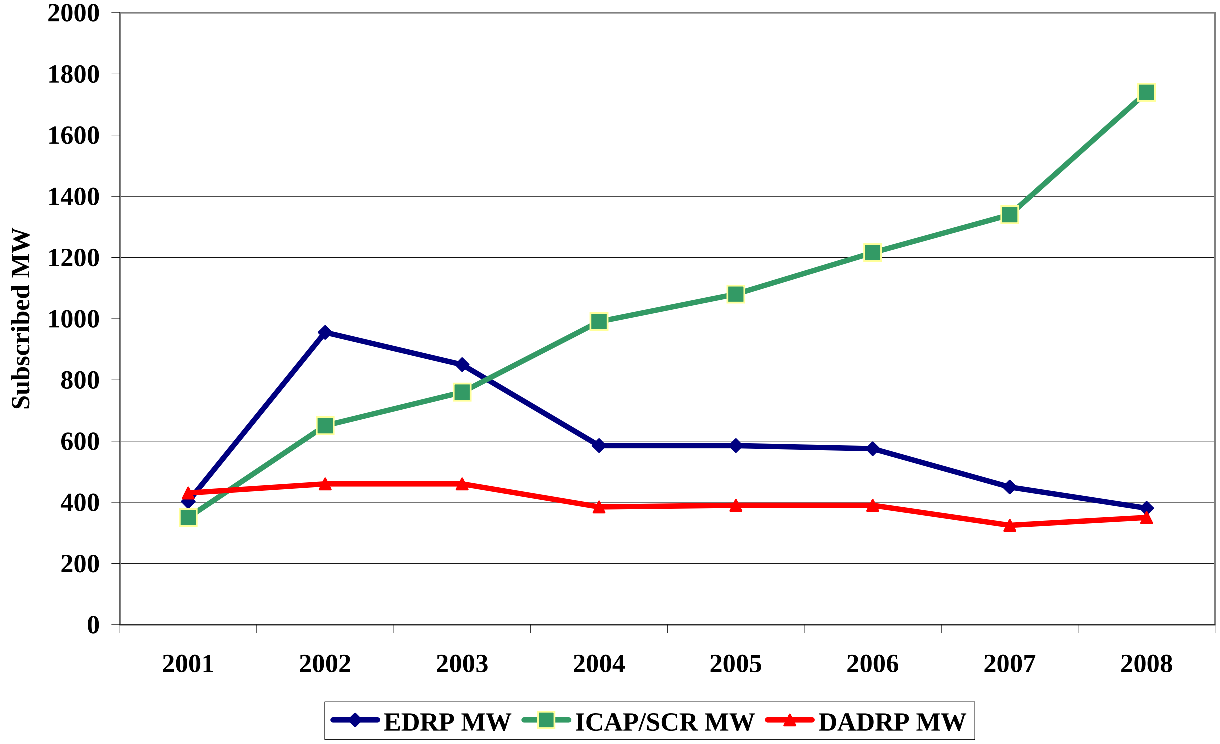
[62] Order No. 719, 73 Fed. Reg. 64,100 (Oct. 28, 2008), FERC Stats. & Regs. ¶ 31,281 (2008), 125 FERC ¶ 61,071 (2008).

Figure 59: Registration in NYISO Demand Response Programs
2001 - 2008



Note: Figure reproduced from the NYISO's January 15, 2009 Demand Response Compliance Report.

Figure 59 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 2008, total registration in the EDRP and SCR programs included approximately 3,700 participants providing over 2,100 MWs of demand response capacity. EDRP and SCR resources in New York City are automatically registered in the TDRP program.

B. Emergency Demand Response Programs

When 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.[63] This is

[63] 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 2008, 98 percent of the SCR strike prices were at or above $490 per MWh.

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.[64] 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 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. SCR resources add to the total supply in the capacity market, which reduces capacity prices. In 2008, SCR resources sold capacity of approximately 410 MW in New York City, 215 MW in Long Island, and 1,100 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 ability of the SCRs to respond if called in the current year. Hence, we recommend that the NYISO revisit the baseline calculation and testing processes for SCRs to ensure they have the capability to respond when called in real time.

C. 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. 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

[64] 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.

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 DAM 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 DAM and the Real-Time Market price of energy. From September 2007 to August 2008, an average of 0.9 MW of DADRP resources were scheduled in the day-ahead market. Hence, the quantities scheduled under the DADRP program are still 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. No resources have yet qualified as DSASP resources, although several resources are expected to qualify once the necessary telemetry is installed. The difficulty that some stakeholders have reported in qualifying their facilities as DSASP resources is discussed in sub-section 2.

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 5.4 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.

D. 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 in real-time clearing prices the cost of maintaining adequate reserve levels. In Order 719, the FERC affirmed that this provision helps improve 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") in July 2007, which enables local transmission owners 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 2008, demand response resources were not activated under emergency conditions, 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.

E. Future Development of Demand Response Programs

1. 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. For these reasons, the FERC recently required ISOs to take steps in several areas to encourage the development of demand response in Order No. 719.[65] The NYISO has several on-going initiatives to facilitate participation in the wholesale market by loads, which were discussed at length in its compliance filing to Order No. 719.[66]

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. DRIS implementation is targeted for 2010. 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.

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.

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65 Order No. 719, 73 Fed. Reg. 64,100 (Oct. 28, 2008), FERC Stats. & Regs. ¶ 31,281 (2008), 125 FERC ¶ 61,071 (2008), at P 15.

66 See *New York Independent System Operator, Inc.*, Compliance Filing filed on May 15, 2009, Docket Nos. RM07-19-000 and AD07-7-000, issued October 17, 2008, 125 FERC ¶ 61,071 (2008).

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. The NYISO will report the status of this evaluation to FERC in October 2009.

2. Other Remaining Barriers and Challenges for Demand Response

Despite these efforts, there remain significant barriers to participation in the wholesale market by loads. These barriers were discussed at length in the comments filed by Potomac Economics to Order 719. This sub-section discusses two significant barriers to participation by demand response.

First, retail rate reform is needed to provide efficient incentives for loads to respond to changes in wholesale electricity prices. Electricity industry restructuring has resulted in a hybrid market structure with a competitive wholesale market and a retail market that retains many characteristics of a regulated market. Linking retail rates to real-time wholesale market energy prices would encourage price-responsiveness by retail customers. This is often referred to as dynamic real-time pricing. However, most retail loads are served by load serving entities that charge retail prices that are unrelated to real-time prices in the wholesale market.[67] 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.

If the regulatory reform necessary to implement dynamic retail pricing does not occur, New York could consider other options for providing real-time economic demand response resources the same incentives that they would have under a dynamic retail pricing regime. For example, a

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[67] The 5.4 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.

real-time price responsive demand program that would make an efficient payment equal to the difference between the wholesale LBMP and the retail customer's rate is one option for addressing this economic barrier. Paying this amount aligns the loads' incentives with the value of the energy to the system. The costs of these payments could be allocated to the corresponding LSE, who might otherwise receive a windfall when its load curtails. However, such programs would require significant efforts by the ISO to monitor and measure performance of the demand resources.

The second major barrier to participation in the wholesale market by loads is related to the metering and other infrastructure that would be needed to support it. To accommodate the characteristics and requirements of most demand response resources, ISOs generally need specialized procedures to quantify the amount of the response and settlement rules to compensate the participant efficiently. Moreover, these programs usually depend on the ISO to estimate what customers' demands would have been had they not reduced consumption as demand response resources. This estimate is known as the customer's "baseline" consumption. Measuring the baseline would be more accurate if retail customers had interval recorders that provided more frequent data on the customers' real-time consumption. As an alternative to enhanced metering, statistical methods can be used to measure the performance of demand response resources that are under direct load control by the ISO, utility, or Curtailment Service Provider ("CSP"). However, the adequacy of these types of measures depends on the service being provided, the ISO's performance requirements, and the administrative costs necessary to integrate them in ISO operations.

In addition to advanced metering, demand response is facilitated by other enabling infrastructure, including communications and control devices. While larger industrial customers may have such metering and other devices, the penetration of these devices is limited among most retail customers. Since such infrastructure facilitates participation by the demand-side in the market, the lack of this infrastructure is a barrier to participation. Hence, the NYISO is supportive of efforts to increase penetration of Smart Grid technology, which provide more information to retail customers about the cost of wholesale power.