2007 State of the Market Report
New York ISO

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Table of Contents

List of Figures

Executive Summary

This report assesses the efficiency and competitiveness of New York's wholesale electricity markets in 2007. 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.
- "Ex-ante" locational prices that are consistent with the real-time market dispatch. Other RTOs use an "ex-post" pricing method that can result in less efficient prices that are not consistent with dispatch signals.
- 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 2007.

A. Introduction and Summary of Findings

In addition to providing a summary of market outcomes in 2007, this report includes findings in two primary areas: the competitive performance of the market and the long-term price signals provided by the markets. The findings in these two areas are summarized below.

Competitive Performance of the Market

We analyzed 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 markets performed competitively in 2007. We found little evidence that suppliers were either economically or physically withholding resources to raise energy or ancillary services prices in the market. Although nominal prices for electricity increased in 2007, 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.

The only competitive concern identified in the NYISO markets relates to the results in the installed capacity market. In both 2006 and 2007, a significant amount of existing capacity did not clear in the capacity market due to high capacity offer prices. This conduct maintained capacity clearing prices in New York City near the cap for divested generation owners in the City.[1] These prices are substantially higher than the prices that would have prevailed if all capacity had been sold, which raises significant competitive concerns. However, the New York ISO filed mitigation provisions to address these competitive concerns in October 2007 that were approved by the Commission in March 2008.[2]

These mitigation provisions and a merger condition imposed on Keyspan-Ravenswood has caused conduct in the capacity market to change significantly in 2008. In March 2008, virtually all of the capacity in New York City was sold, leading the New York City spot auction price to decrease by more than 80 percent from February to March 2008. The increased sales have continued into the summer months, dramatically reducing the clearing prices in New York City relative to the previous summer capability period.

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1 A cap on both offer prices and revenue were established for the suppliers that purchased the capacity in New York City from Consolidated Edison.

2 See FERC Docket No. EL07-39-000.

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 2007 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 could have been profitable. [3] Although there are no publicly available 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. 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, there is considerable uncertainty both about the net revenue that would be earned over the life investment. Prospective investors must consider the effects of new generation investment, load growth, and participation by price responsive demand before making capacity investments. The decline in net revenue for a generator in Astoria East in 2006 due to the installation of new combined cycle generation shows that market participants must consider how new investment will affect future market revenues.

One location where long-term reliability concerns have arisen is in Southeast New York, outside New York City and Long Island.[4] Based on the 2008 Comprehensive Reliability Plan, additional resources will likely be needed in this area between 2013 and 2014. However, there is currently no mechanism in the capacity market for distinguishing the value of capacity in Southeast New

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3 For the CONE estimates, see *Proposed NYISO Installed Capacity Demand Curves For Capability Years 2008/2009, 2009/2010, and 2010/2011*.

4 Includes the Hudson Valley, Millwood, and Dunwood zones.

York from the value of capacity in the rest of up-state New York. If it is more costly to build new generation in this area, the lack of capacity market signals that reflect this need may prevent suppliers from having adequate incentives to build there.

If capacity margins in Southeast New York decline to unreliable levels, the planning process would call for regulated investment. This form of regulatory intervention in the market can be very damaging to the market and adversely affects the expectations of private investors in the future. Therefore, it is important to address any market issues that cause price signals to be understated, rather than to rely on regulated solutions to meet the reliability needs of the system. Defining an additional capacity zone may allow the market to more accurately reveal the value of resources throughout the state. Hence, we recommend that the NYISO study this issue to determine whether a new capacity zone is warranted.

Conclusions and Recommendations

We conclude that the markets performed competitively in 2007. However, we make several recommendations to improve the performance of the New York market. These recommendations generally involve modifications to certain operating procedures and rules that should increase the efficiency of the New York markets. The recommendations are listed at the end of the executive summary.

B. Summary of Market Outcomes in 2007

In 2007, electricity prices increased 6 to 12 percent in most areas in New York. This increase was primarily due to increasing oil and natural gas prices. Natural gas prices increased 15 percent in 2007. The correlation between natural gas prices and electricity prices is consistent with a well-performing market given that: a) fuel costs constitute the vast majority of most generators' marginal costs, and b) natural gas-fired units are frequently on the margin (setting the market price) in New York.

The effects of higher fuel prices were partly offset by milder summer weather in 2007. There were just 2 hours when New York load exceeded 32 GW in 2007, compared to 28 such hours in

2006. As a result, the frequency of real-time operating reserve shortages in eastern New York declined 80 percent from the summer of 2006 to the summer of 2007.

In addition, substantial new transmission capacity was added from New Jersey to Long Island in July 2007 when the Neptune line was energized. The additional 660 MW of new import capability reduced the power flows and congestion on the transmission interfaces from up-state New York to New York City and Long Island. The reduced congestion contributed to a 3 percent decline in Long Island prices in spite of the rise in fuel prices.

Congestion and Transmission Rights

Prices vary at locations throughout the state in both the day-ahead and real-time markets due to transmission congestion and losses. The primary transmission constraints in New York occur at the following four locations:

- The Central-East interface that separates eastern and western New York;
- The transmission paths connecting the Capital region to the Hudson Valley;
- The transmission interfaces into load pockets inside New York City; and
- The interfaces into Long Island.

As a result of transmission congestion and losses, there was considerable variation in clearing prices across the system. In the day-ahead market, eastern up-state prices were 27 percent higher than average prices in western New York, New York City prices were 8 percent higher than average prices in the eastern up-state region, and Long Island prices were 22 percent higher than average prices in the eastern up-state region.

Total congestion costs declined from $770 million in 2006 to $740 million in 2007. The reduced congestion costs in 2007 were largely due to: a) mild summer weather, which reduced the frequency of shortage conditions; and b) the installation of 660 MW of new transmission capacity from New Jersey to Long Island, which reduced congestion on the interface between up-state New York and Long Island. These cost reductions were partly offset by higher fuel costs, which tend to increase congestion because they increase the re-dispatch costs incurred to manage network congestion. The report also shows that the value of real-time congestion across the Central-East interface has been rising since 2004, reaching $190 million in 2007.

These total congestion costs should not be interpreted as the efficiency benefits or savings that consumers could expect from investing in new transmission. Efficiency benefits of transmission are generally much lower than the total congestion costs. Transmission investment should only occur when the efficiency benefits are larger than the investment costs.

In a well-functioning market, the price for a Transmission Congestion Contract ("TCC") should reflect a reasonable expectation of day-ahead congestion. The auction prices from the auction of 6-month TCCs during the 2007 summer capability period reflected reasonable expectations of congestion by market participants. The results of this analysis show that the west-to-east TCCs were generally under-valued, while TCCs from Hudson Valley to New York City were over-valued. This indicates that the shift from 2006 to 2007 in congestion from the Hudson Valley corridor to the Central-East interface was not fully anticipated by market participants in the TCC auction. We also find that the TCC auctions over-valued congestion from the New York City zone to Vernon/Greenwood and Greenwood/Staten Island.

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

The day-ahead market allows participants to make forward purchases and sales of power for delivery in the real-time. The market is a valuable financial mechanism that allows participants to hedge their portfolios and manage risk. 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. For example, if day-ahead prices were predictably higher than real-time prices, buyers would shift more of their purchases to the real-time. If day-ahead prices were foreseeably lower than real-time prices, buyers would be attracted to the day-ahead market. In each case, sellers would tend to shift in the opposite direction.

Price convergence between prices in the day-ahead and real-time markets is important because the day-ahead market plays an important role in determining which resources are started each day. We find that convergence between day-ahead and real-time zonal energy prices continues to be good. However, convergence of the energy prices at specific locations within New York City was not as good as at the zonal level. The NYISO is considering a proposal to address this issue which is discussed at the end of this section. We also find that convergence between day-ahead and real-time operating reserve prices has improved since the introduction of co-optimized energy and ancillary services markets in 2005. However, the operating reserve prices still exhibit relatively poor convergence under certain circumstances which are discussed below.

Ancillary Services Markets

The NYISO operates day-ahead and real-time markets for operating reserves and regulation. In addition to satisfying the operating reserve requirements in real-time while setting efficient prices for these services, these markets play an important role in the shortage pricing that occurs in the energy market. The economic value of each class of reserves is reflected in "demand curves" for the reserves. When the system is in a shortage and reserve requirements cannot be satisfied, the economic value of the reserve sets the reserve price and is reflected as part of the energy price. Similarly, because the ancillary services markets are co-optimized with the energy markets, the clearing prices reflect the costs to the system of diverting resources to provide ancillary services that would otherwise provide energy.

As indicated above, convergence between day-ahead and real-time prices has been poor for 10-minute spinning reserves and 10-minute non-spinning reserves in eastern New York. 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, competitive 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. We find that the mitigation measures limit some offers from some suppliers below competitive levels. Hence, we recommend the NYISO reconsider the provisions in the mitigation measures that may limit competitive reserve offers in the day-ahead market.

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.

Our evaluation of external transactions between New York and three adjacent ISO-run 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 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.

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.

Uplift Charges

It is important to minimize uplift charges, because they are difficult to hedge and do not provide transparent economic signals to market participants and potential investors. When markets reflect the full reliability requirements of the system and are functioning well, uplift charges should be relatively low. This report evaluates uplift charges resulting from balancing congestion revenue shortfalls and from guarantee payments to generators that operate but do not recoup their as-bid costs from NYISO markets

Balancing congestion revenue shortfalls 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 modeled in the day-ahead market across a particular line or interface exceeds the actual transfer capability during periods of real-time congestion. Balancing congestion revenue shortfalls declined from \$171 million in 2006 to \$159 million in 2007. Despite the general rise in electricity prices, balancing congestion revenue shortfalls declined due to milder summer weather, reduced congestion into Long Island, and two enhancements to the real-time scheduling system, which are discussed in Section VI.

Uplift charges resulting from guarantee payments to generators rose from \$245 million in 2006 to \$331 million in 2007 due to higher costs to maintain local reliability. Approximately 75 percent of the increase resulted from committing generators for local reliability after the day-ahead market. The NYISO is developing a process to integrate local reliability constraints that require supplemental commitments into the initial economic commitment pass of the day-ahead market. This should reduce the uplift and market inefficiencies that result from local reliability commitments. Most of the remainder of the uplift increase was from payments to generators under the Minimum Oil Burn program, which was implemented in May 2007. Under this program, generators are paid to burn fuel oil when natural gas is less expensive in order to satisfy New York City local reliability requirements related to natural gas supply contingencies.

C. 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

One key operational area that affects the performance of the market is the commitment of peaking resources in the real-time market and the effect of these resources on real-time prices. The Real Time Commitment model ("RTC") is primarily responsible for committing gas turbines and other quick-start resources that can start from an offline status and ramp to their maximum output within 10 minutes or 30 minutes of receiving an instruction. RTC also schedules external transactions for the next hour based on bids and offers submitted by participants. RTC executes every 15 minutes, looking across a two-and-a-half hour time horizon to determine whether it will be economic to start-up or shut-down generation. Most other RTOs rely on market operators to manually make these determinations based on reliability rules, rather than economic optimization, which leads to less efficient commitment and use of peaking resources.

Efficient use of peaking resources is important, because it can have a significant effect on market outcomes, particularly in New York City and Long Island where peaking resources constitute nearly 30 percent of the installed capacity. Excess commitment of peaking resources depresses real-time prices and increases uplift charges. Alternatively, if peaking resources are not committed when they are economic, it can cause inefficient price spikes. In this report, we find that 58 percent of gas turbine starts were economic in 2007 during the period evaluated. The share of commitments that were economic declined slightly from 2006 to 2007 after improving dramatically from 2004 to 2006 due to several software enhancements.

More generally, inconsistencies between RTC prices and actual real-time prices raise concerns because they may indicate that gas turbines and external transactions are not being scheduled efficiently. In this report, we evaluate the overall consistency between RTC prices and actual real-time prices, finding that the largest divergences occur at the top of the hour during the morning and evening ramp-up and ramp-down periods. Moreover, in these periods, actual real-time clearing prices are highly volatile. We identify several inconsistencies between RTC and the real-time dispatch model that likely contribute to the volatility of real-time prices. However, a more complete evaluation is necessary to more fully identify the causes of volatility. Hence, we recommend the NYISO evaluate potential changes to the real-time scheduling system to make them more consistent and to improve the management of ramp capability at the top of the hour.

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 summer weather in 2007 led to much less frequent shortages than in 2006. While there were 28 hours when load exceeded 32 GW in 2006, there were just 2 such hours in 2007. Due to the relatively low demand levels, most of the shortages that occurred in 2007 affected localized areas rather than all of New York state.

The importance of setting efficient real-time price signals during shortages of operating reserves was recently affirmed by FERC in its Notice of Proposed Rule-Making ("NOPR"). The NOPR 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 reserves shortages. [5] Second, the NYISO allows demand response resources to set clearing prices when an operating reserve shortage is avoided by the activation of demand response. [6]

In this report, we evaluate the operation of the market and resulting prices during three types of shortage conditions:

- Operating reserve shortages;
- Transmission constraint violations; and
- Emergency demand response activations.

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[5] See P. 125. Wholesale Competition in Regions with Organized Electric Markets, 122 FERC ¶ 61,167 (2008) ("NOPR").

[6] See P. 45. Wholesale Competition in Regions with Organized Electric Markets, 122 FERC ¶ 61,167 (2008) ("NOPR").

Reserve shortage pricing occurred in 72 percent of the periods with physical shortages of eastern 10-minute reserves. The NYISO is considering a proposal to address a modeling issue that leads to some instances when physical shortages are not accompanied by shortage pricing.

In June 2007, the NYISO improved the modeling of transmission constraints during periods of extremely high re-dispatch costs. This has dramatically reduced the frequency of price corrections when transmission constraints are violated. Price-certainty is especially important during shortage conditions.

In July 2007, the NYISO implemented the Targeted Demand Response Program ("TDRP"), which enables the local transmission owner to activate small blocks of TDRP resources for local reliability issues. Previously, the transmission owner activated all of the resources in the zone when it had a local problem. This lead to uneconomic curtailments, depressed energy prices, and increased uplift. This report includes one recommendation to further improve pricing during the activation of demand response.

Price Corrections

All real-time energy markets are subject to some level of price corrections to account for metering errors, data input problems, flaws in the market operations software, and other issues that lead prices to be calculated erroneously. Accurate prices are critical for settling market transactions fairly and for sending reliable real-time price signals to market participants. Less frequent price 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.

The rate of corrections spiked in 2005 due to issues associated with the implementation of new real-time market software under SMD 2.0. Once the initial software issues were addressed by NYISO, the frequency of price corrections fell sharply, and in 2006, the prices were corrected in only 0.6 percent of the intervals. In June 2007, the NYISO further reduced the frequency of price corrections by improving the modeling of transmission constraints during periods of extremely high re-dispatch costs. During intervals when transmission constraint shadow costs were $4,000/MWh or more, the rate of price corrections declined from 98 percent in the last seven months of 2006 to 2 percent in the last seven months of 2007.

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 increased from 1,150 MW in 2006 to 1,370 MW in 2007, leading to an increase in the associated uplift charges from $140 million in 2006 to $200 million in 2007. The increase in uplift charges resulted from more frequent supplemental commitment for local reliability and higher fuel prices.

In recent years, non-local reliability uplift has declined due to several market design enhancements, while local reliability uplift has increased due to more frequent commitment for local reliability. To minimize the negative effects of local reliability requirements on the overall market, it is important to satisfy the reliability requirements as efficiently as possible. Hence, we support the NYISO's plan to incorporate local reliability constraints that require supplemental commitments into the initial economic commitment pass of the day-ahead market.

D. 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. Load Serving Entities ("LSEs") can meet their capacity obligations by self-scheduling, bilateral purchasing, or through one of the NYISO's forward procurement auctions. Any remaining obligations are settled against the NYISO's monthly spot auction where clearing prices are determined by a capacity demand curve. Currently, the capacity auctions have three distinct locations within New York: 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 2006 through March 2008, a time span including four six-month capability periods from the Summer 2006 capability period through the Winter 2007-08 capability period. Over this period, clearing prices in the Rest-of-State area have ranged from just above $1/kW-month to $3.50/kW-month, depending on variations in imports and exports as well as seasonal changes in generating capability.

In New York City, seasonal variations in capability accounted for most of the changes in the clearing prices and quantities sold prior to March 2008. Clearing prices were near $6/kW-month in the winter capability periods and near $13/kW-month in the summer capability periods. The clearing prices were close to the revenue caps imposed on the Divested Generation Owners ("DGOs") that purchased the capacity from ConEd when it was required to divest most of its generation in 1998. A significant amount of existing capacity was not sold in the UCAP market due to the suppliers' offer prices. Given the low marginal cost of selling capacity from resources that are remaining in operation and the substantial effect this conduct has had on capacity clearing prices, the conduct raised significant competitive concerns.

These competitive concerns have been addressed because in March 2008, FERC approved the NYISO's proposal 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 expected 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.

In March 2008, the amount of unsold capacity in New York City was virtually eliminated. As a result, the New York City spot auction price dropped from $5.77/kW-month in February 2008 to $1.05/kW-month in March 2008. Hence, the increased sales had a dramatic effect on the auction clearing price in New York City, and they have continued into the summer months. The increased sales resulted from conditions placed on the merger of National Grid and KeySpan-Ravenswood by the Public Service Commission.

Capacity Market Configuration

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.

One location where long-term reliability concerns have arisen is in Southeast New York (which includes Zones G through I), the portion of Rest-Of-State (which includes Zones A through I) that is closest to New York City and Long Island. Based on the 2008 Comprehensive Reliability Plan (“CRP”), additional resources will likely be needed in Southeast New York between 2013 and 2014. Furthermore, a recent analysis by the NYISO indicates that some capacity in Zones A through F will not be deliverable to Southeast New York by 2012. This may require the NYISO to use non-market measures to reduce sales of capacity in Zones A to F, because there is currently no mechanism in the capacity market for distinguishing the value of capacity located in Zones A to F from the value of capacity located in Southeast New York.

If it is more costly to build new generation in Southeast New York than in Zones A through F, we can expect investors to build in Zones A to F rather than Southeast New York, unless energy and ancillary services price signals are sufficiently higher in Southeast New York to offset the additional cost. However, our net revenue analysis suggests that the markets may not be providing sufficient economic signals to attract investment to Southeast New York.

If the surplus in Rest-Of-State continues while capacity margins in Southeast New York decline to unreliable levels, the Rest-Of-State capacity price will not provide efficient incentives for investment in Southeast New York. Such a failure of the market could lead to regulated investment in order to maintain reliability in certain areas. This form of regulatory intervention can be very damaging to the market and adversely affects the expectations of private investors in the future. Therefore, it is important to address any market issues that could lead market signals to be understated, rather than rely on regulated solutions to meet the reliability needs of the system. Hence, we recommend that the NYISO initiate an assessment to determine whether a new capacity zone with local requirements is warranted in Southeast New York to address the reliability requirements.

E. Demand Response Programs

Demand response resources participate in both the capacity and energy markets in New York. New York has close to 1,800 MW of real-time demand response resources. Real-time demand response resources can be activated to maintain operating reserves or for local reliability. In 2007, demand resources sold capacity of approximately 420 MW in New York City, 220 MW in Long Island, and 700 MW in the Rest of State zones. These resources increase the competitiveness of the capacity market, particularly in New York City and Long Island where ownership of generation is relatively concentrated.

Prior to 2007, when demand resources were activated for reliability, the market rules required all resources within the zone be activated. This has led to inefficiencies when resources were needed for a local reliability issue within a particular zone. To address this issue, the NYISO created the Targeted Demand Response Program ("TDRP") in July 2007, which allows local transmission owners to target a request for load relief to resources in specific load pockets within New York City. TDRP resources have been activated twice since the program was created in 2007. In both cases, demand response was called to address a local issue in a small portion of New York City.

The NYISO is working on several initiatives to increase the responsiveness of demand to prices in the wholesale market. First, the NYISO worked with stakeholders on a proposal to allow demand-side resources to offer operating reserves and regulation service in the wholesale market. In March 2008, these efforts culminated in a filing to FERC of proposed Tariff changes to allow demand response resources to provide ancillary services. The proposed changes should increase the amount of resources that provide reserves and regulation services, which should enhance competition, reduce costs, and enhance reliability by reducing the likelihood of reserve shortages.

Second, the NYISO proposes to move forward with the Demand Response Program Automation project, which will replace existing manually-intensive process. 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. The automated system will substantially reduce the administrative burdens on both the NYISO and the program participants. These improvements should encourage participation in demand response programs by reducing the costs to participate.

F. Summary of Recommendations

Our analysis in this report indicates that the NYISO electricity markets performed very well in 2007. However, the report finds that additional improvements can be made and provides the following recommendations:

1. Continue the work with neighboring control areas to better utilize the transfer capability between regions, ideally by directly coordinating the physical interchange.

This recommendation would assure that power is efficiently transmitted to the highest-value locations. In addition to the substantial economic savings for customers in both markets and the improvement in the price signals, optimizing the use of the interface will improve reliability.

2. Evaluate potential improvements to the real-time commitment model ("RTC") and the real-time dispatch model ("RTD") to improve their consistency and improve the management of ramp capability at the top of the hour.

The use of RTD and RTC in real-time scheduling has delivered substantial benefits. However, the report identifies some inconsistencies between RTC and the real-time market that can affect commitment and scheduling by RTC, particularly at the top of the hour in the morning and evening ramp hours. Additionally, ramp constraints frequently lead to price spikes at the top of the hour in the morning and evening due to changes in external schedules, hourly generation schedules, and generator commitments and decommitments. A re-evaluation of the assumptions and periods used in RTD and RTC could potentially improve the ramp management and reduce price volatility.

3. Evaluate changing two provisions in the mitigation measures that may limit competitive 10-minute reserves offers in the Day-Ahead Market.

One provision limits the reference levels of quick-start gas turbines to $2.52/MWh. Another provision limits the 10-minute spinning reserves offers of generators in New York City to $0/MWh. This changes should facilitate better convergence between the day-ahead and real-time ancillary services prices.

4. Consider whether additional capacity zones are needed outside of New York City and Long Island.

This may be necessary to allow the markets' economic signals to reflect that resources will be needed relatively soon in Southeast New York. To determine whether an additional zone is needed, the NYISO will need to evaluate the differences in the cost of entry at various locations and the transmission limits that affect the deliverability of capacity throughout the state.

5. Evaluate whether it is feasible to enable the NYISO Reliability Based Emergency Demand Response resources to set clearing prices in local areas when they are needed to maintain transmission system reliability.

These resources are already allowed to set clearing prices when they are needed to avoid a shortage of 30-minute reserves at the state level or 10-minute reserves in eastern New York. It may be appropriate for these resources to set clearing prices when they are needed to avoid shortages in other areas as well.

Enhancements Currently Under Consideration

The NYISO has work underway in response to recommendations from prior years. The results in 2007 continue to suggest that these changes would be beneficial:

1. Improve the modeling of local reliability rules in New York City to include them in the initial day-ahead commitment.

Commitments by the local reliability pass of the day-ahead market and by ISO operators after the day ahead are often required to meet local requirements in NYC, and as a result uplift expenses are higher throughout the state.

2. Re-calibrate the dispatch levels in the real-time market's pricing model for units that are not responding to dispatch signals.

Further improvements to the consistency of the pricing and physical dispatch passes of RTD could improve the efficiency of NYISO's energy and ancillary services pricing (particularly during shortages) and reduce uplift.

3. Allow virtual trading at a more disaggregated level.

This recommendation is designed to improve price convergence at various locations throughout the state and would allow participants additional flexibility for managing congestion-related risk. It should be particularly valuable in the New York City load pockets because it would allow virtual sales and purchases within the load pockets in the day-ahead market to arbitrage the relatively large day-ahead to real-time price differences that have prevailed historically.

I. Energy Market Prices and Outcomes

The New York ISO operates a multi-settlement wholesale market system consisting of financially-binding day-ahead markets and real-time markets for energy, operating reserves, and regulation (i.e. automatic generator 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 2007 and evaluates the performance of these markets. This evaluation includes an assessment of the long-term economic signals provided by the New York markets that govern new investment and retirement decisions. Subsequent sections examine individual aspects of the market in greater detail.

In 2007, the most significant factor affecting electricity prices was the increase in fuel costs, although this was partly offset by mild summer weather and the addition of new transmission into Long Island. From 2006 to 2007, natural gas prices increased an average of 15 percent, while fuel oil prices increased an average of 20 percent. However, electricity prices increased just 6 to 12 percent in most of New York and declined 3 percent in Long Island. Mild summer weather led to relatively infrequent real-time reserve shortages, lowering prices during the summer months. Substantial new transmission capacity (660 MW) was added from New Jersey to Long Island in July 2007, greatly reducing the severity of congestion into Long Island.

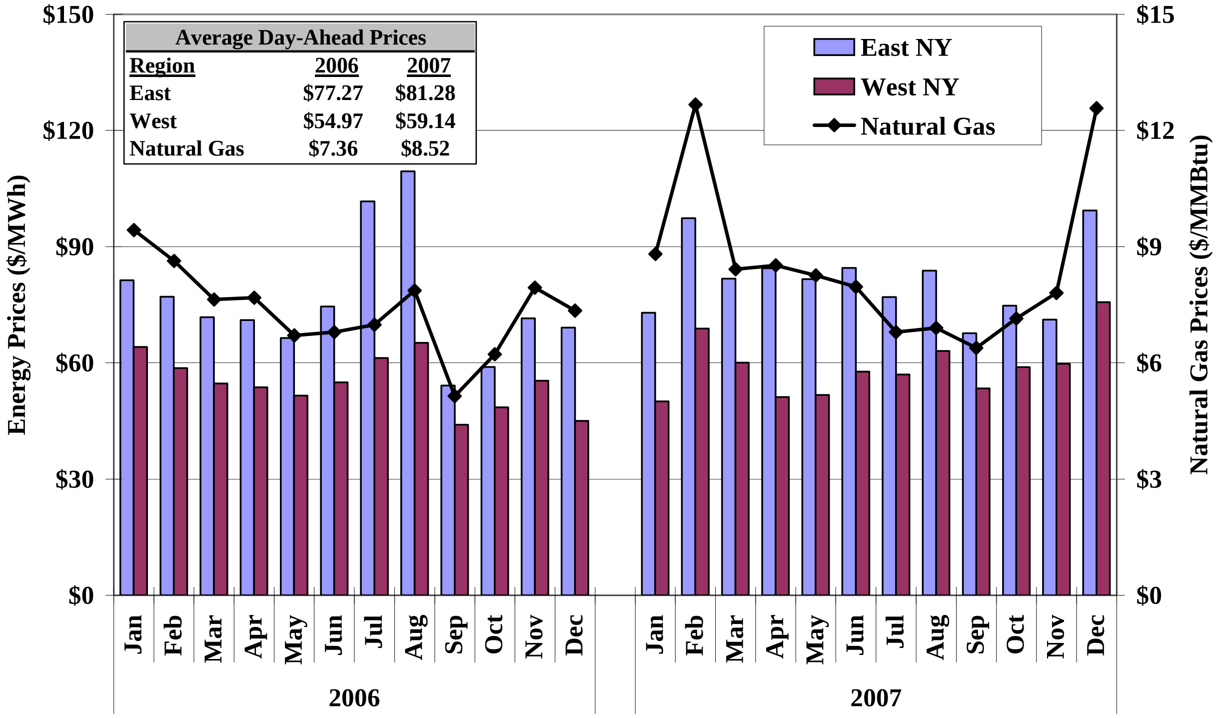
A. Summary of 2007 Outcomes

In this sub-section, we summarize market outcomes in 2007, including: energy prices, congestion patterns, fuel prices, load levels, and total market expenses.

1. Energy Prices

Figure 1 shows average natural gas prices and electricity prices on a monthly basis during 2006 and 2007. Electricity prices are shown for east New York, which is a load-weighted average of the six zones east of the Central-East Interface, and west New York, which is a load-weighted average of the other five zones. Even though 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 setting prices in the market, especially in east New York. Therefore, changes in these prices directly affect electricity prices.

Figure 1: Electricity and Natural Gas Prices 2006 – 2007



Note: The electricity prices are load-weighted averages.

Figure 1 shows that changes in electricity prices are strongly correlated with changes in natural gas prices. In 2007, monthly average power prices peaked in February and December due to spikes in natural gas prices. From 2006 to 2007, average natural gas prices rose 15 percent, which led to increased electricity prices, although electricity prices rose by only 5 percent in east New York and 8 percent in west New York due to offsetting factors which are discussed below.

There continue to be large price differences between east and west New York due to transmission congestion and losses. In 2006 and in 2007, average prices in east New York were $22/MWh higher than average prices in west New York. In 2007, more frequent congestion across the Central-East Interface contributed to price differences between east and west New York. However, the activation of the Neptune cable in July 2007, which links Long Island to New Jersey, substantially reduced congestion into Long Island and lowered average prices in east New York.

The highest demand levels occur during the hot summer months and typically result in elevated electricity prices, as peaking resources are used to meet the peak load and reserves requirements. In July and August 2006, day-ahead electricity prices increased with expectations of more frequent real-time reserve shortages on the highest demand days. In comparison, the summer of 2007 experienced relatively few periods with very high demand levels, and hence, relatively few price spikes.

To highlight changes in electricity prices that are not driven by changes in natural gas prices, the following figure shows 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 east and west New York by month in 2006 and 2007.

Figure 2: Average Implied Marginal Heat Rate
Based on Day-Ahead Electricity and Natural Gas Prices
2006 – 2007

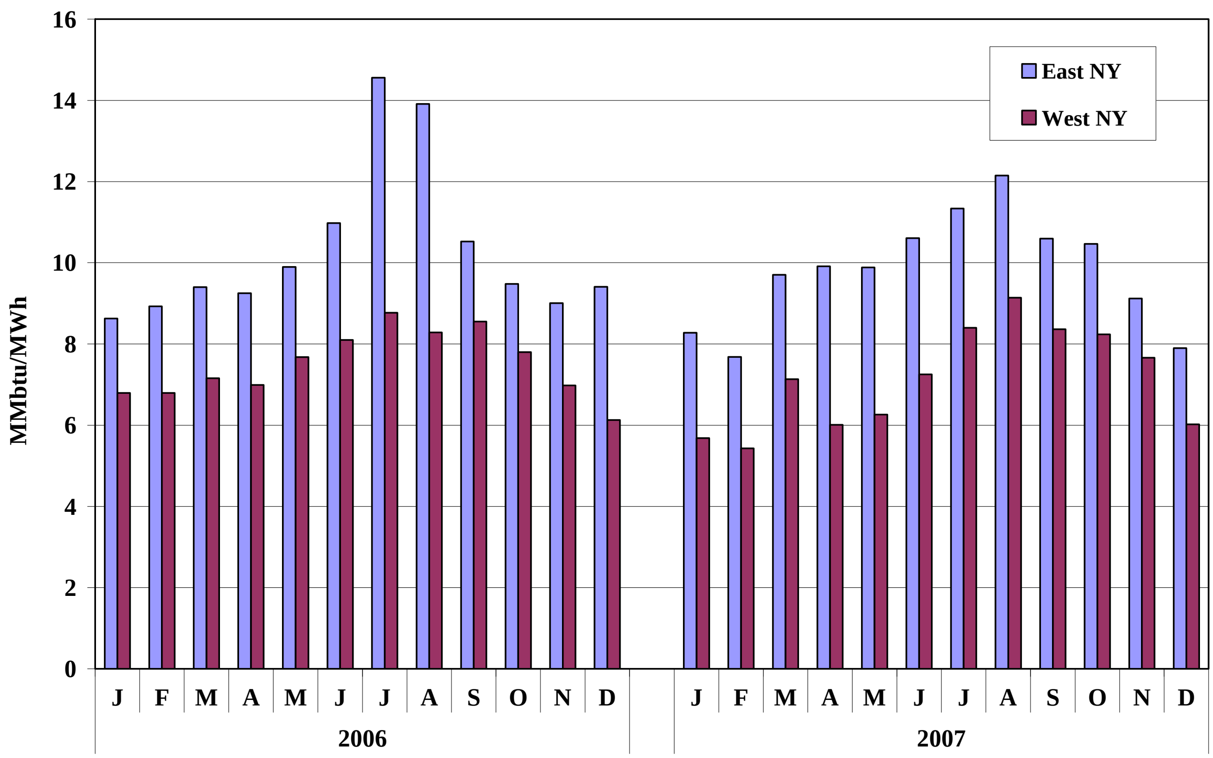
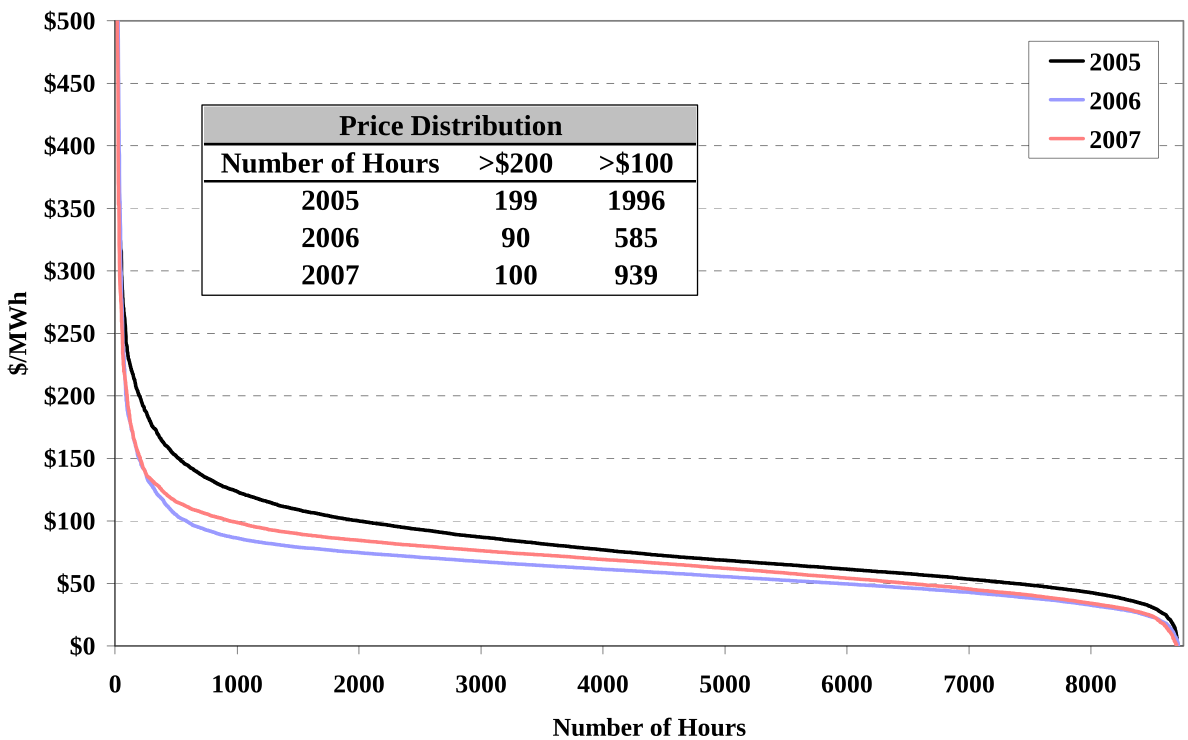


Figure 2 shows that implied marginal heat rates were highest in the summer due to high demand levels and the effects of high ambient temperatures on generating capability. However, in 2007, relatively mild summer weather led to small increases in the implied marginal heat rate compared with 2006.

In some months, the implied marginal heat rate declines to levels that are below the heat rate of the most efficient gas-burning generators. This occurs because there were a substantial number of hours when less expensive fuels were on the margin. For instance, exceptionally high natural gas prices in February and December 2007 led to unusually low implied heat rates as some dual-fueled units switched to burning less expensive residual fuel oil. Likewise, there were many hours when the marginal supply to west New York was a coal or hydro unit.

The following two figures show how prices vary across hours in each year. Figure 3 shows several price duration curves, which show the number of hours on the x-axis in which the market settled at or above the price level shown on the y-axis.

Figure 3: Price Duration Curve
State-wide Average Real-Time Price
2005 – 2007



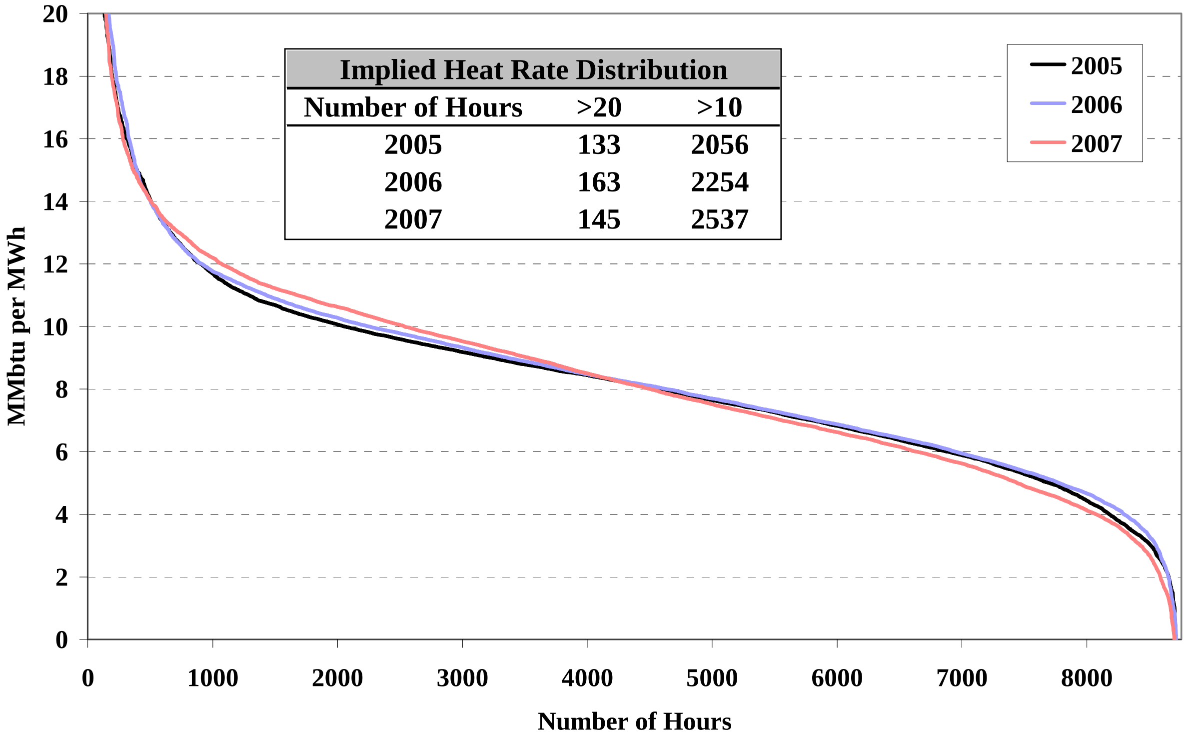
Price Distribution		
Number of Hours	>$200	>$100
2005	199	1996
2006	90	585
2007	100	939

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 10 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 frequency of very high prices dropped considerably after 2005 due to the installation of new capacity in New York City in 2006.

Fuel price changes are revealed by the flatter portion of the price duration curve, since fuel prices affect power prices in almost all hours. The figure shows the effects of the sharp fall in natural gas prices from 2005 to 2006 and moderate rise in natural gas prices from 2006 to 2007.

To identify factors affecting power prices other than fuel price changes, the following figure shows the implied marginal heat rate duration curves for 2005, 2006, and 2007. These show the number of hours on the x-axis in which the market settled at or above a given implied marginal heat rate level shown on the y-axis. In this case, the implied marginal heat rate is the state-wide average real-time price divided by the natural gas price.

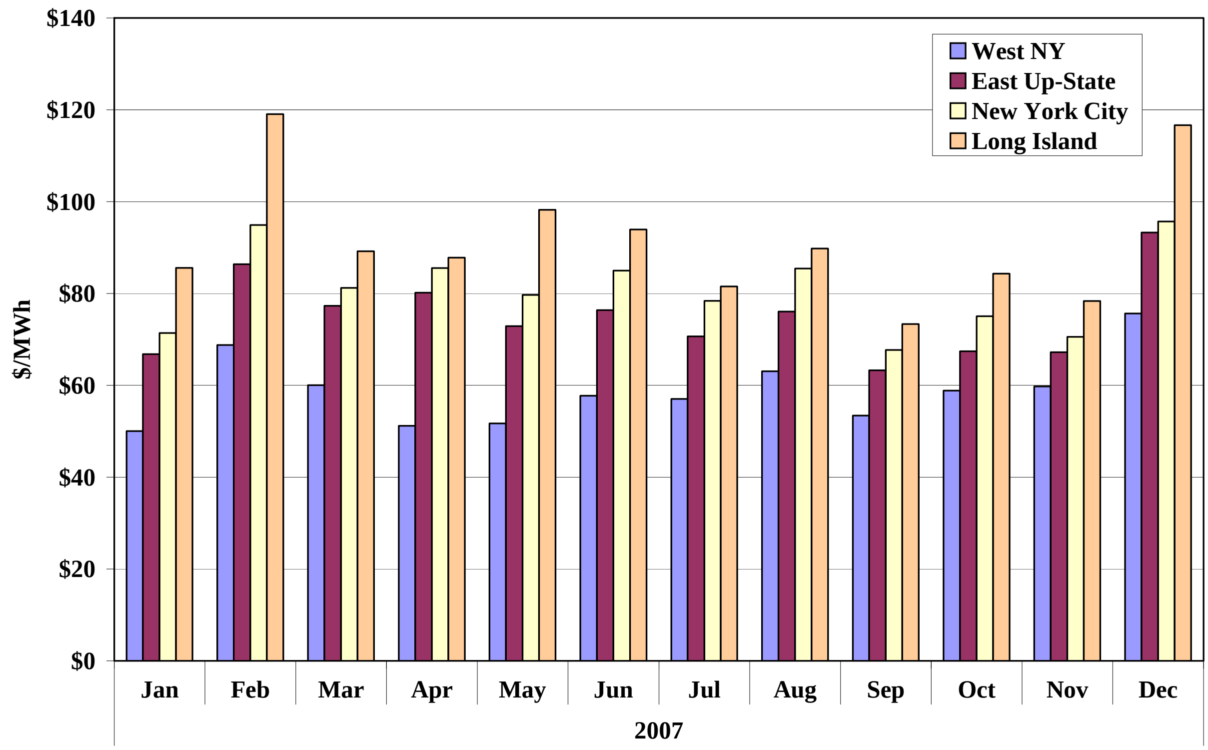
Figure 4: Implied Marginal Heat Rate Duration Curves
Based on State-wide Average Real-Time Price and Natural Gas Price
2005 – 2007



Implied marginal heat rates have been very consistent over the last three years. This shows that adjusting for changes in fuel prices virtually eliminates differences from year-to-year in the state-wide average price. However, the state-wide average price does not show localized price variations resulting from changes in the pattern of transmission congestion.

Figure 5 shows the load-weighted average day-ahead energy prices in four regions of New York by month in 2007. Prices are lowest in west New York, which exports significant amounts of power to Eastern New York. Prices are highest in New York City and Long Island, which import large portions of their consumption. Most of the power that flows from Western New York to New York City and Long Island passes through the east up-state portion of the New York system. These west-to-east flows result in significant transmission losses and congestion.

Figure 5: Day-Ahead Energy Prices by Region 2007



The price difference between west New York and east up-state New York was primarily due to transmission congestion across the Central-East interface. However, transmission losses as well as transmission congestion across the West-Central Interface and the Leeds-Pleasant Valley interface were responsible for much of the difference. The difference rose from $12/MWh in 2006 to $16/MWh in 2007 primarily due to more frequent congestion across the Central-East Interface during the spring.

The average prices on Long Island were increased by congestion on imports from east up-state New York and some local congestion. Price differences between Long Island and east up-state New York declined from $27/MWh in 2006 to $16/MWh in 2007. The primary cause of the decline was the installation of the Neptune cable in July 2007, which reduced the need for imports from up-state New York.

The average prices in New York City are generally elevated by congestion into the local load pockets within the City. Price differences between New York City and east up-state New York declined from an average of $16/MWh in 2005 to $9/MWh in 2006 to $6/MWh in 2007. The reduced congestion into New York City resulted from capacity additions in the City, improved modeling of local transmission constraints, and the operation of the Neptune cable.

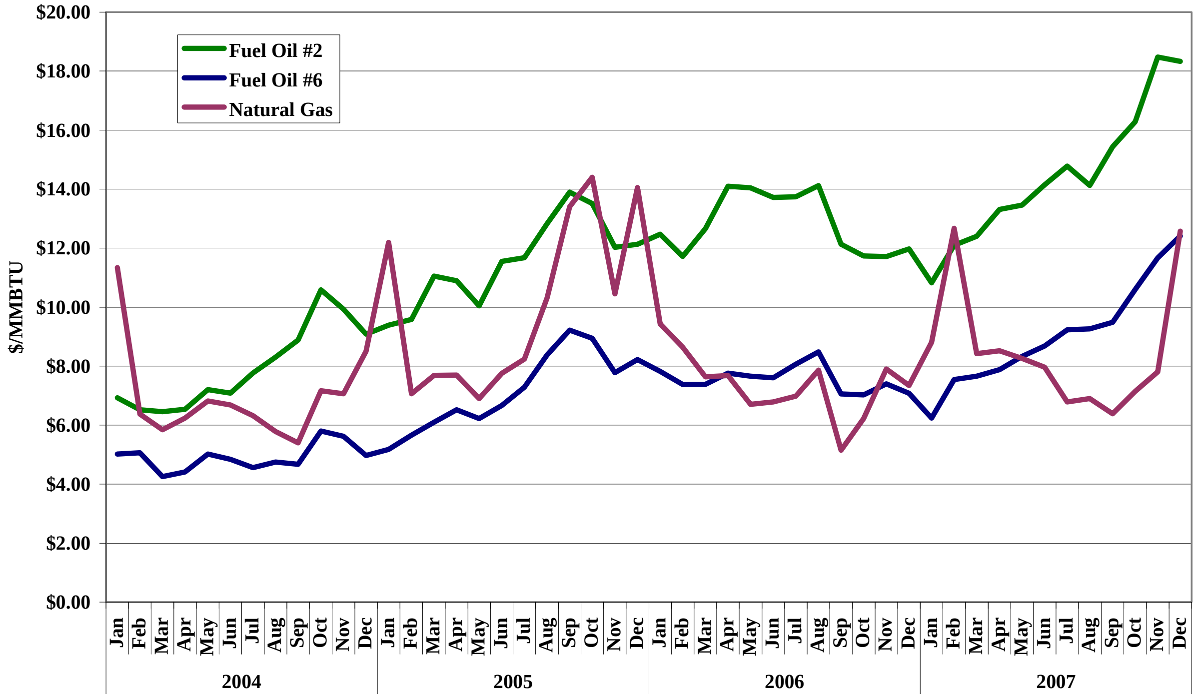
2. Fuel Prices

In recent years, fossil fuel price fluctuations have been the primary driver of changes in wholesale power prices. This is because most of the variable production costs of fossil generators are fuel costs. Although much of the electricity generated in New York is from hydro, nuclear, and coal-fired generators, natural gas and oil units are usually the marginal source of generation, setting market clearing prices. Hence, oil and natural gas price changes 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 (#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 2004 to 2007. Prices are shown for natural gas, diesel fuel oil (#2), and residual fuel oil (#6).

Figure 6: Natural Gas and Oil Price Trends 2004-2007



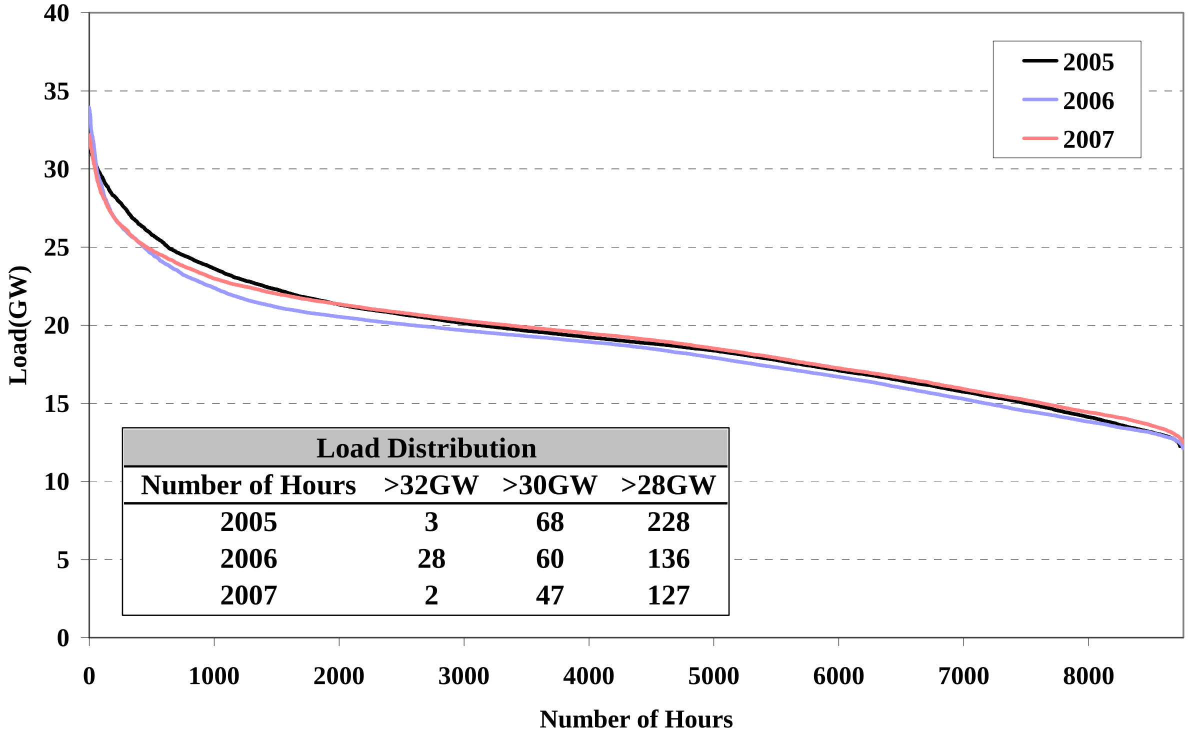
In 2007, natural gas prices rose sharply in February and December to the highest levels since late 2005. Otherwise, natural gas prices generally ranged from $6 to $9/MMbtu, consistent with 2006. Fuel oil prices increased steadily throughout 2007, making fuel oil #6 more expensive than natural gas during most of the year.

The use of natural gas has been limited by the "minimum oil burn provisions", which require some units in New York City to burn oil in order 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. Hence, the use of oil for reliability is not reflected in market clearing prices. These provisions generated $21 million of local reliability uplift costs in 2007, and they are discussed further in Section VII.C.

3. Energy Demand

The interaction of electric supply and consumer demand drive price movements in New York. Because the amount of available supply changes relatively slowly from year to year, changing electricity demand explains 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 x-axis in which the state-wide load was greater than or equal to the level shown on the y-axis.

Figure 7: Load Duration Curves
2005 to 2007



Load Distribution			
Number of Hours	>32GW	>30GW	>28GW
2005	3	68	228
2006	28	60	136
2007	2	47	127

In general, electricity demand grows slowly over time, tracking the growth of the population and economic activity. Hence, Figure 7 shows that 2005 experienced unusually high demand. During 2006, however, New York experienced 28 hours with load levels in excess of 2005's annual peak of 32,075 MW. In most hours, load grew modestly from 2006 to 2007, although there were considerably fewer peak load hours in 2007 due to milder summer weather.

4. Total Market Costs: All-In Price

Next, we examine the all-in price for electricity which 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 2005 – 2007

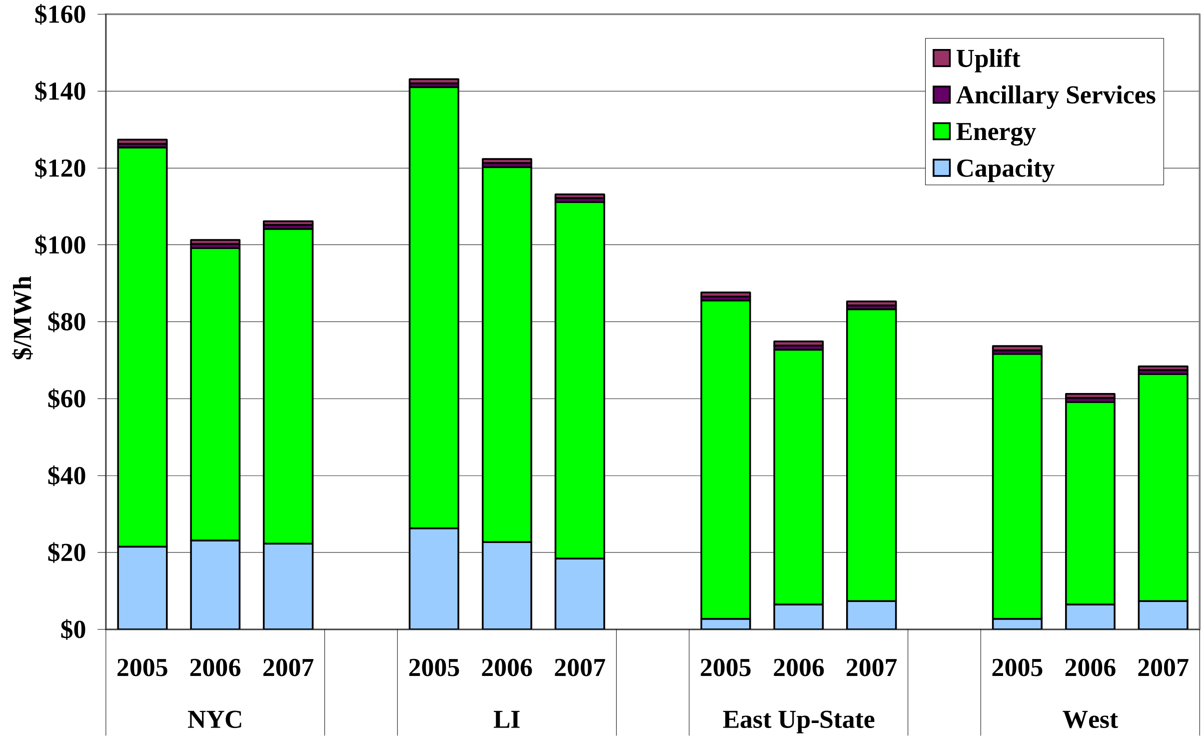


Figure 8 shows that the all-in price decreased substantially from 2005 to 2006 in each of the four regions due to two factors. First, fuel prices and load levels were generally lower in 2006. Second, capacity additions in New York City in 2006 reduced energy prices throughout New York State and particularly in New York City. However, the amount of capacity sold in New York City did not change significantly after the capacity additions, so capacity prices were not affected by the new additions. The capacity market is discussed further in Section VIII.

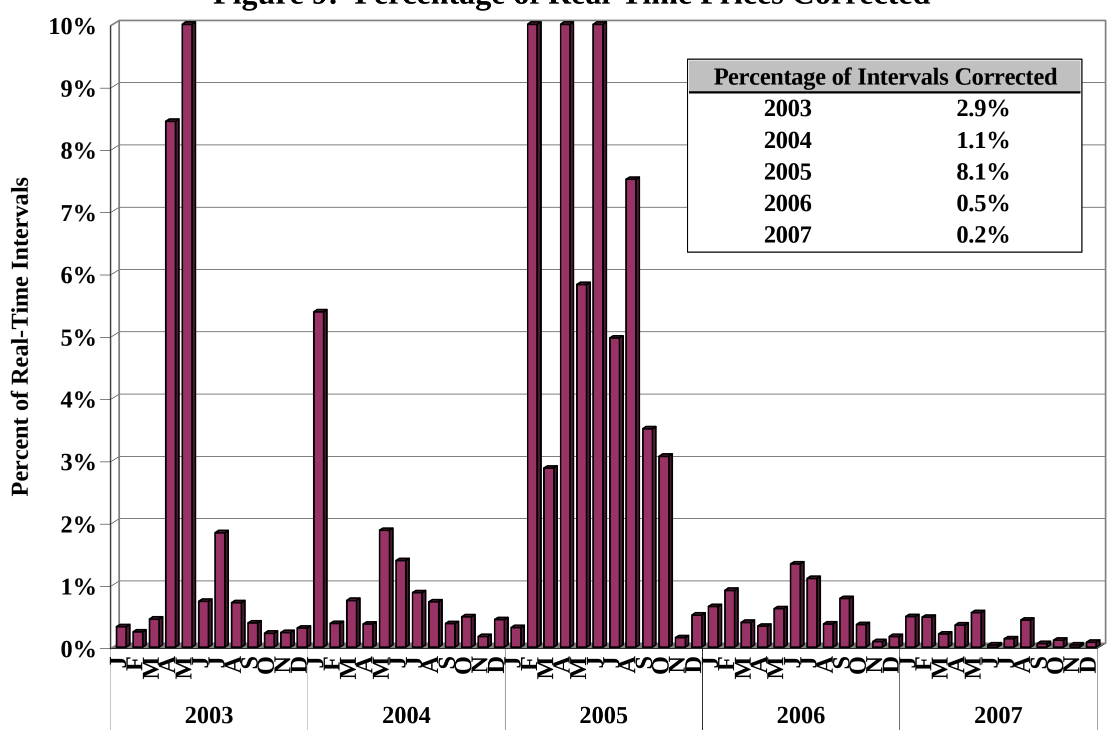
From 2006 to 2007, all-in prices declined in Long Island and increased modestly in the other areas. These changes were driven by several factors. First, higher fuel prices in 2007 led to increased production costs. Second, milder summer weather in 2007 resulted in fewer shortage events. Third, the addition of the Neptune cable has reduced power prices in eastern New York, particularly in Long Island.

The figure shows that energy costs are by far the most significant component of market costs. Capacity costs are also significant contributors to the all-in cost in New York City and Long Island, but ancillary services costs and uplift costs are relatively insignificant contributors to the all-in costs borne by wholesale consumers. However, the ancillary services markets have significant indirect effects on energy prices, because the ancillary services requirements compete for scarce generation resources. To the extent that generation is used to provide ancillary services when it would also be economic to provide energy, it raises the price of energy.

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 from 2003 to 2007.

Figure 9: Percentage of Real-Time Prices Corrected



The rate of price corrections spiked in 2005 due to issues with the new real-time market software that was implemented under SMD 2.0. Temporary spikes in the frequency of price corrections have typically occurred after major software modifications in the past, and the changes in 2005 were no exception.

In June 2007, the NYISO further reduced the frequency of price corrections by improving the modeling of transmission constraints during periods of extremely high re-dispatch costs. During intervals when transmission constraint shadow costs were $4,000/MWh or more, the rate of price corrections declined from 98 percent in the last seven months of 2006 to 2 percent in the last seven months of 2007. The modeling change is discussed in Section VII.B.2.

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/or
- Market rules are causing revenues to be reduced inefficiently.

Likewise, 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. If a revenue shortfall persists for an extended period, without an excess of capacity, this is a strong signal that the market needs to be modified.

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.[7] We estimate the net revenue the markets would have provided to two different types of units at these locations in the last four years. The two types of units are:

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

1. *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.
2. *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

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

in the real-time market. Ignoring real-time profits tends to under-state net revenues. The enhanced method addresses these limitations of the standard net revenue analysis.[8]

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.

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

Figure 10: Enhanced Net Revenue: Combined Cycle Unit

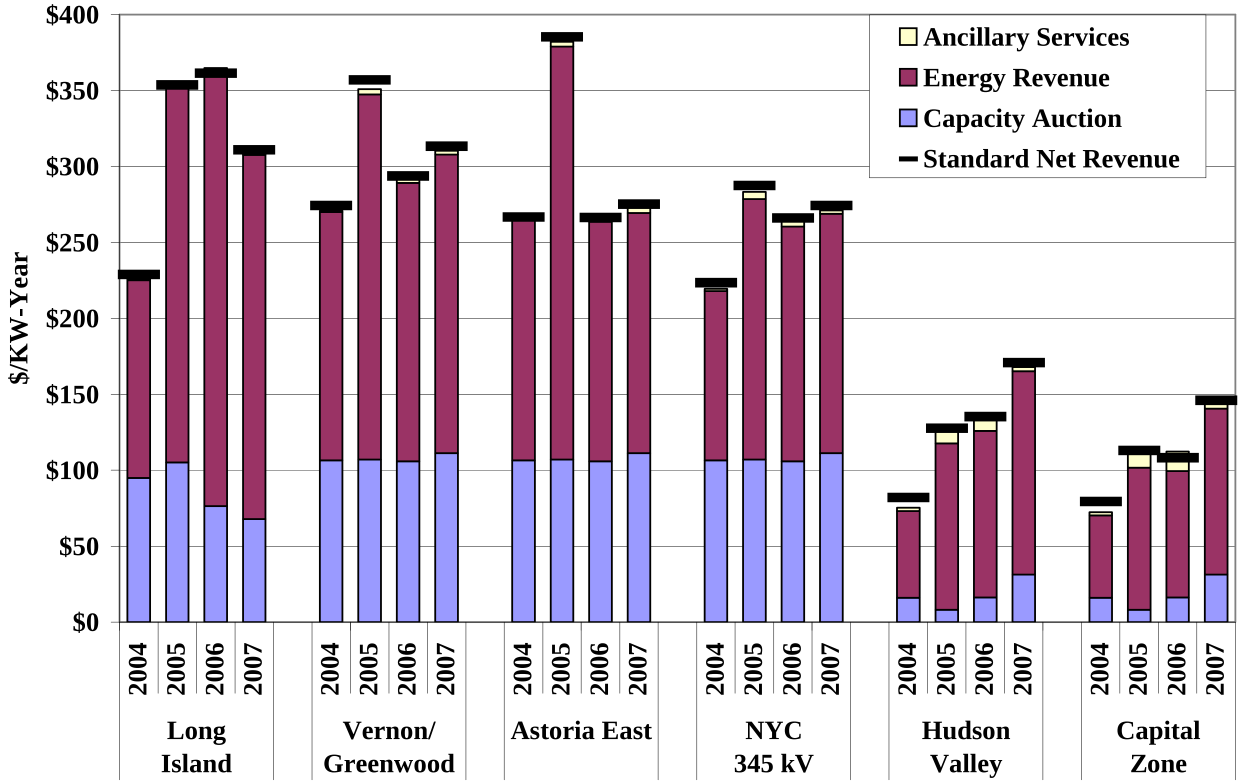
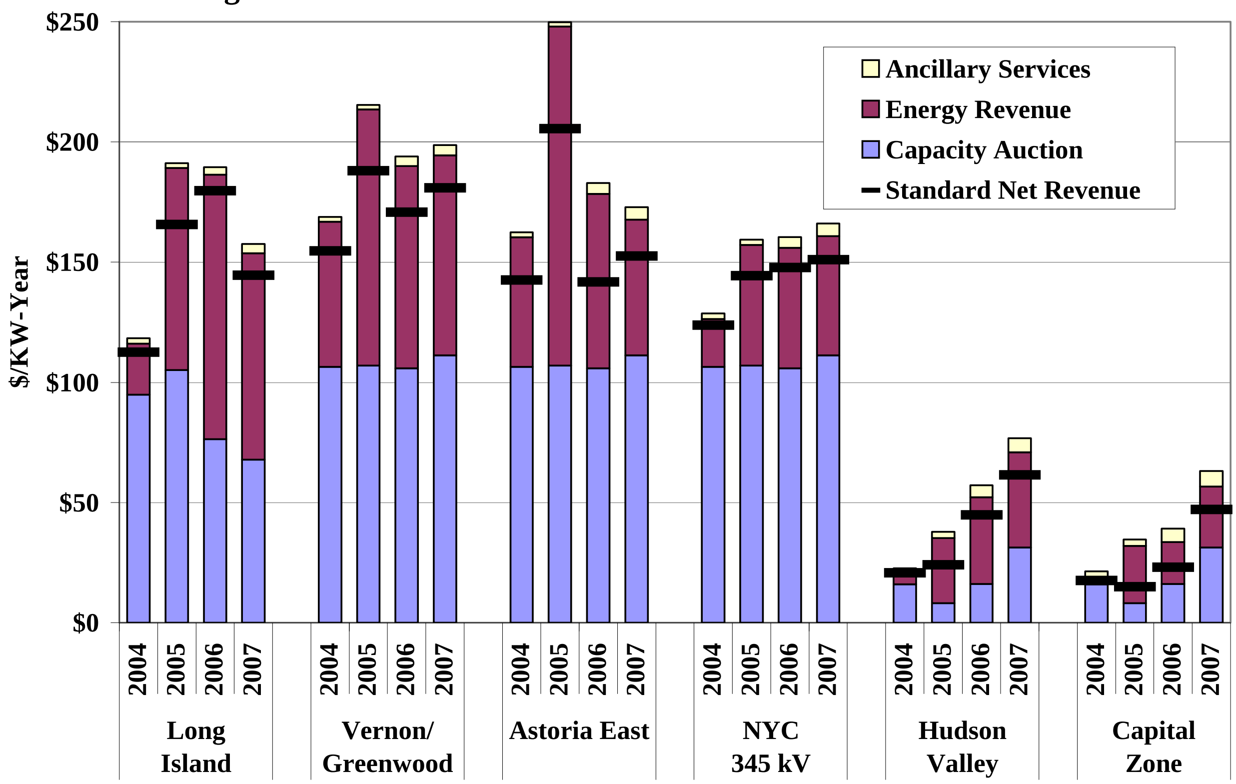


Figure 11: Enhanced Net Revenue: Combustion Turbine Unit



In 2007, the net revenues that a hypothetical combustion turbine or combined cycle generator on Long Island would have received from selling energy and ancillary services was substantially reduced. This reduction was primarily due to the introduction of new supply from New Jersey across the Neptune cable reduced congestion into Long Island.

From 2006 to 2007, net revenues rose moderately in the Hudson Valley and Capital zones for two reasons. First, transmission congestion became more frequent across the Central-East interface. Second, capacity prices in up-state New York (known as "Rest-Of-State") rose as a result of reduced net imports of capacity from other control areas. In December 2006, ISO New England implemented new capacity payments that has attracted some capacity that was previously sold into the New York market.

From 2004 to 2006, there was a substantial increase in the net revenues that would have been received by a generator at all of the locations shown above. In 2005, net revenues rose significantly due to higher load and more frequent shortage conditions. The shortages frequently resulted in very high energy prices due to the shortage pricing provisions implemented under SMD 2.0. In 2006, net revenues generally rose by a small margin outside New York City due to better convergence between day-ahead and real-time prices and improved pricing during shortage conditions. In New York City, net revenues declined, in some cases dramatically, due to the installation of new capacity and enhanced modeling of transmission constraints.

The analysis shows how net revenues are affected by new investment. For instance, Astoria East was one of the most constrained load pockets prior to the installation of new capacity in early 2006. After the new capacity was installed, the estimated net revenues for Astoria East declined in 2006 by 31 percent for both combined cycle units and combustion turbines. Hence, investors should expect prices to decrease substantially in areas where they build new capacity, making new investment somewhat less attractive than historical net revenues would suggest.

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 at most locations. 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. 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/kW-year in New York City, $167/kW-year on Long Island, and $101/kW-year in the Capital zone for the 2008/2009 capability year.[9] Based on the net revenue levels in 2007 and these estimates of CONE, Vernon/Greenwood is likely the only area of New York where an investment in a new combustion turbine could have been profitable.

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 up-state areas, the estimated net revenues for a new combined cycle were more than double those for a new combustion turbine in 2007. In New York City, the estimated net revenues for a new combined cycle were more than $100/kW-year higher than those for a new combustion turbine in 2007. 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.

One location where long-term reliability concerns have arisen is in Southeast New York.[10] Based on the 2008 Comprehensive Reliability Plan, additional resources will likely be needed in Southeast New York between 2013 and 2014. However, there is currently no mechanism in the capacity market for distinguishing the value of capacity in Southeast New York from the value of capacity in the rest of up-state New York. If it is more costly to build new generation in Southeast New York, the lack of capacity market signals may not give suppliers adequate incentives to build there. If capacity margins in Southeast New York decline to unreliable levels,

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[9] See *Proposed NYISO Installed Capacity Demand Curves For Capability Years 2008/2009, 2009/2010, and 2010/2011*.

[10] Includes the Hudson Valley, Millwood, Dunwood, New York City, and Long Island zones.

regulated investment may become necessary. This form of regulatory intervention can be very damaging to the market and adversely affects the expectations of private investors in the future. Therefore, it is important to address any market issues that could lead market signals to be understated, rather than rely on regulated solutions to meet the reliability needs of the system. We discuss long-term reliability and market signals further in Section VIII.

II. External Transactions

This section examines the scheduling of imports and exports between New York and adjacent regions. In 2007, New York was a net importer from each of the four adjacent control areas: New England, PJM, Ontario, and Quebec. Power was exported to New England, PJM, and Quebec under limited market conditions, while power was rarely exported to Ontario. 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 normally used to import up to 1,100 MW directly to Long Island. The total transfer capability between New York and the adjacent regions is large 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 several aspects of transaction scheduling between New York and adjacent control areas. Sub-section A summarizes power flows between New York and adjacent areas in 2007. Sub-section B evaluates the efficiency of scheduling by market participants by examining the degree of price convergence between regions. When scheduling between regions is efficient, prices should be consistent unless transmission constraints limit flows between the regions. Section C presents an estimate of the benefits that would result from direct ISO coordination of interchange between New York and New England. This section also discusses efforts to reduce barriers to efficient scheduling and identifies additional changes that could further improve scheduling across the “seams” between New York and the adjacent markets. The final section summarizes our conclusions and recommends ways to improve scheduling between regions.

A. Summary of Imports and Exports

The following two figures summarize the flows across each interface in 2007. Figure 12 displays average net imports across the primary interfaces in western New York and eastern New York by time of day. The left side of the figure groups the three interfaces in western New York: PJM, Ontario, and Hydro-Quebec.[11] The right side of the figure shows the primary AC interface with New England, which is in eastern New York. Bars are shown for all days and separately for the top ten load days to show that flows change under peak load conditions. The scale for the New England interface on the right side of the chart differs from the scale for PJM, Ontario and Hydro-Quebec, reflecting the larger power flows across these interfaces.

Figure 12: Average Net Imports across Primary External Interfaces 2006 – 2007

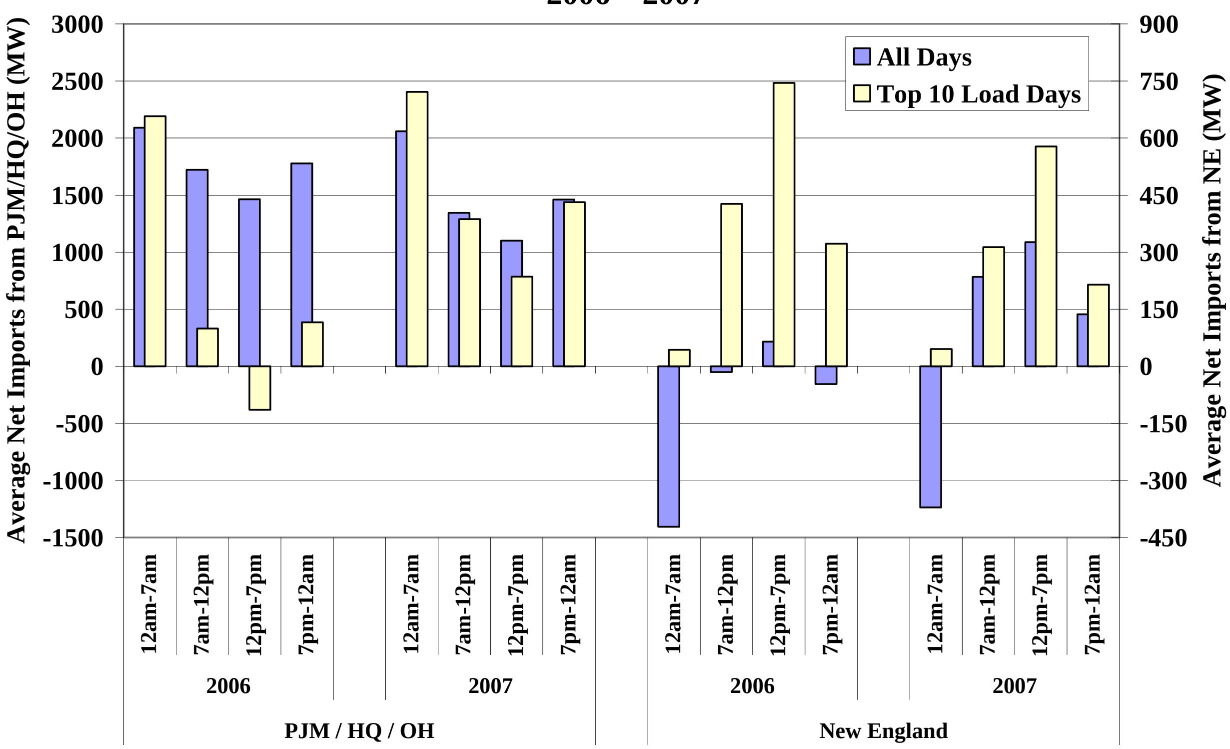


Figure 12 shows that New York imported substantial amounts of power across the western interfaces in 2007, with somewhat higher levels of imports during off-peak hours. Compared to

[11] PJM is also connected to eastern New York by several controllable lines, although the flows across these lines are determined in accordance with PJM and NYISO operating procedures. See Attachment M-1 of the NYISO Markets and Services Tariff, *Operating Protocol for the Implementation of Commission Opinion No. 476 (Docket No. EL02-23-000 (Phase II))*.

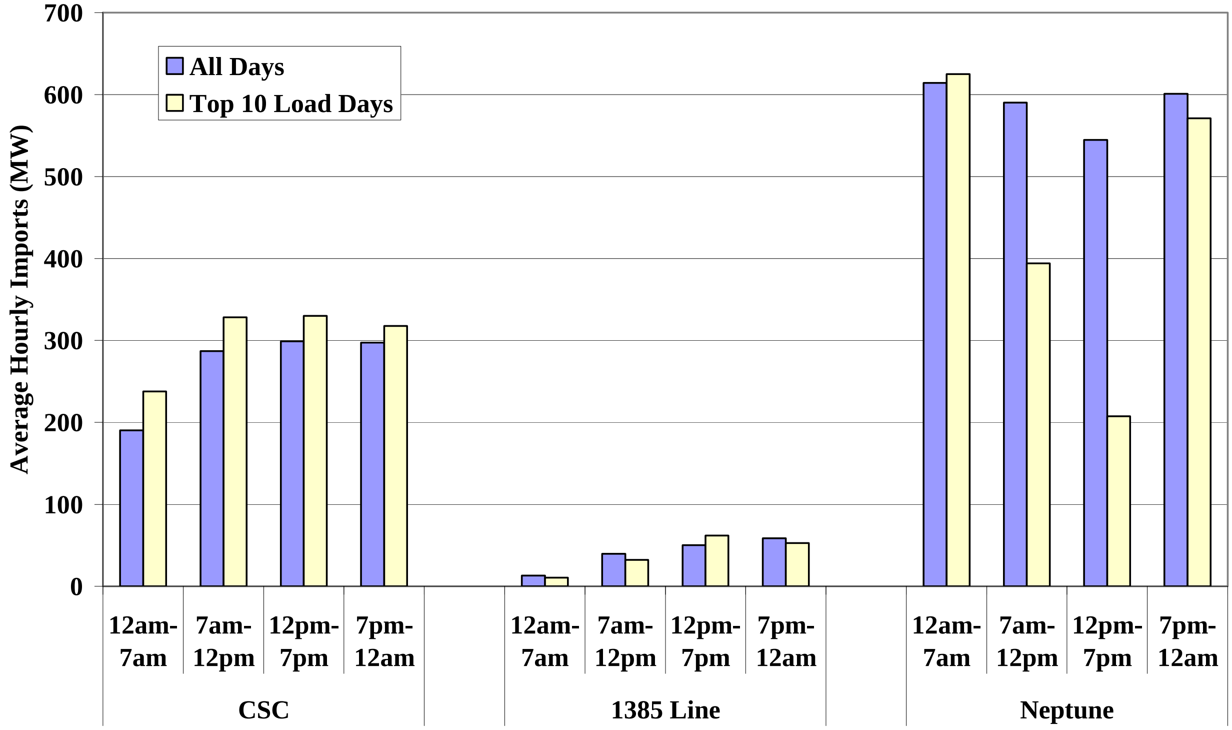
2006, imports were 250 MW lower on average in 2007. However, on the 10 highest load days in each year, imports were generally lower, especially in 2006 when New York was a slight net exporter during afternoon hours. Flows between PJM and New York account for most of the variation between 2006 and 2007 on high load days; New York generally exported to PJM in 2006 and imported from PJM in 2007.

Across the primary interface with New England, net imports increased significantly from 2006 to 2007. The direction of flows shifts according to the time of day, with New York exporting to New England at night and importing during the day. In 2006 and 2007, the volume of imports from New England was considerably higher on the high load days, which is likely the response of market participants to more frequent shortage conditions in eastern New York than in New England.

Figure 13 summarizes flows across the three controllable lines between Long Island and adjacent control areas in 2007. The Cross Sound Cable is a DC line connecting New Haven, Connecticut to Shoreham on Long Island. The 1385 Line is an AC line that is controlled with a phase angle regulator and that connects Norwalk, Connecticut to Northport on Long Island. Prior to June 27, 2007, the 1385 Line was treated as part of the primary interface between New England and New York. Since September 10, 2007, the 1385 Line has been on a planned outage. The Neptune Cable is a DC line connecting Sayerville, New Jersey to Levittown on Long Island. It began normal operation on July 1, 2007. While any market participant can schedule transactions across the 1385 Line in the day-ahead market or real-time market, scheduling across the Cross Sound Cable and Neptune Cable uses a separate system of advance reservations.[12]

[12] Transmission service over the Cross-Sound Cable is done in accordance with Schedule 18 and the Schedule 18 Implementation Rule of the ISO New England Markets and Services Tariff. Transmission service over the Neptune Cable is done in accordance with Section 44B of the PJM Interconnection Open Access Transmission Tariff.

Figure 13: Net Imports to Long Island from External Areas 2007



Flows across the Cross Sound Cable tend to be relatively stable across various market conditions, averaging about 260 MW into Long Island in 2007. In its first three months of operation as a separately scheduled interface, the 1385 Line was used to import power to Long Island, primarily during day-time hours. Since being brought in service on July 1, the Neptune Cable has significantly increased import capability to Long Island. The Neptune Cable, which has a transfer capability of 660 MW, imported an average of 540 MW during the last six months of 2007. On average, Long Island imports an average of 900 MW from neighboring control areas, which is approximately 28 percent of its total consumption.

B. Price Convergence between New York and Other Markets

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

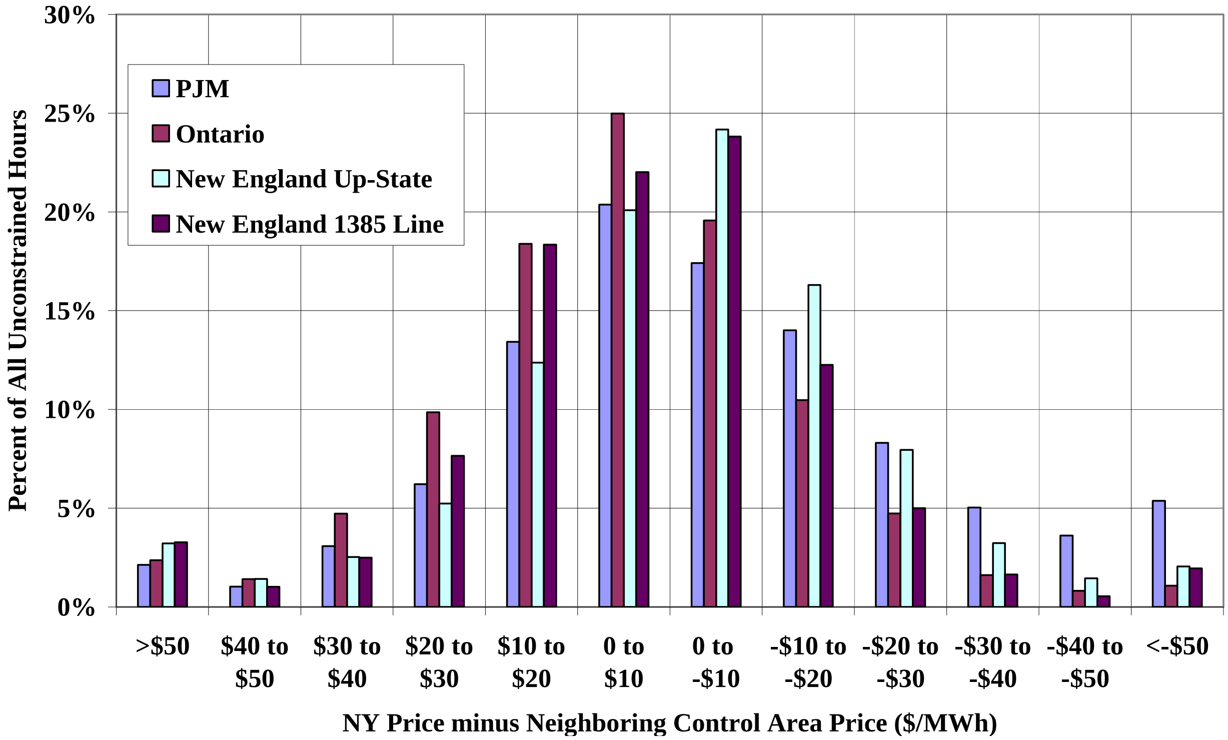
During peak demand conditions, it is especially important to schedule flows efficiently between control areas. Frequently during such conditions, a small amount of additional imports can substantially reduce prices.

This sub-section evaluates the efficiency of scheduling between New York and the adjacent ISO-run markets across interfaces with open scheduling. 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. PJM, New England, and Ontario are ISO-run markets.

Figure 14 summarizes price differences between New York and adjacent ISO-run during unconstrained hours across the four interfaces with open scheduling. The x-axis indicates the price difference between New York and the adjacent region at the border. The heights of the bars indicate the fraction of hours in each price difference category.

The results shown in the figure indicate that the current process does not maximize the utilization of the interface. While the price differences center approximately at zero, for every interface a substantial number of hours have price differences exceeding $10/MWh. The price difference exceeds $10/MWh across the primary interface with PJM in 62 percent of unconstrained hours, across the interface with Ontario in 55 percent of unconstrained hours, across the primary interface with New England in 56 percent of unconstrained hours, and across the 1385 line in 54 percent of 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.

Figure 14: RT Price Convergence Between NY and Adjacent ISO Markets Unconstrained Hours, 2007

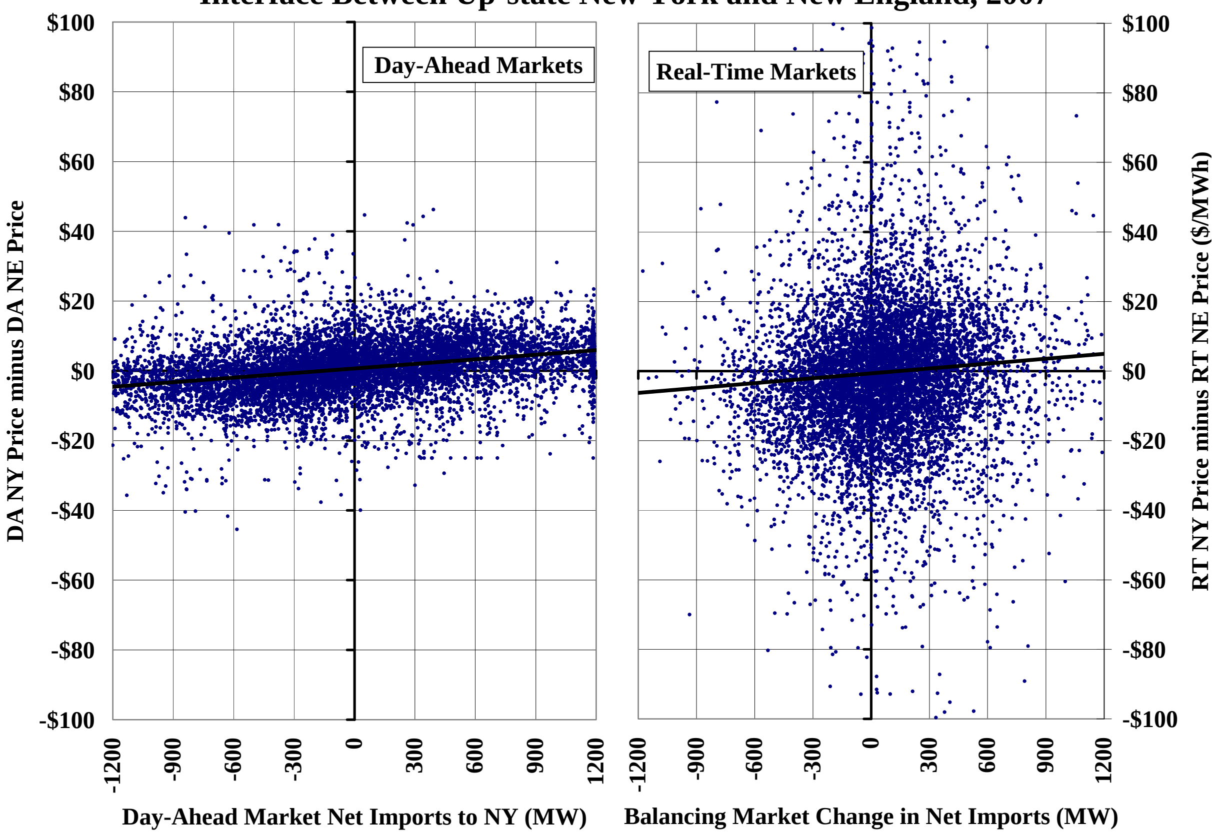


Several factors prevent real-time prices from being fully arbitraged. First, market participants do not operate with perfect foresight of future market conditions at the time that transaction bids must be submitted. Without explicit coordination between the markets by the ISOs, complete arbitrage will 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.

Although scheduling by market participants does not fully exhaust the potential benefits from use the interfaces between regions, the following two analyses 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. While the analysis is only shown for the primary interface with New England, it is reasonable to assume that reducing barriers to scheduling across other interfaces would likewise improve the efficiency of flows.

Figure 15 shows net scheduled flows versus price differences between New England and up-state NY. 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 15: Efficiency of Scheduling in the Day-Ahead and Real-Time Market Interface Between Up-state New York and New England, 2007



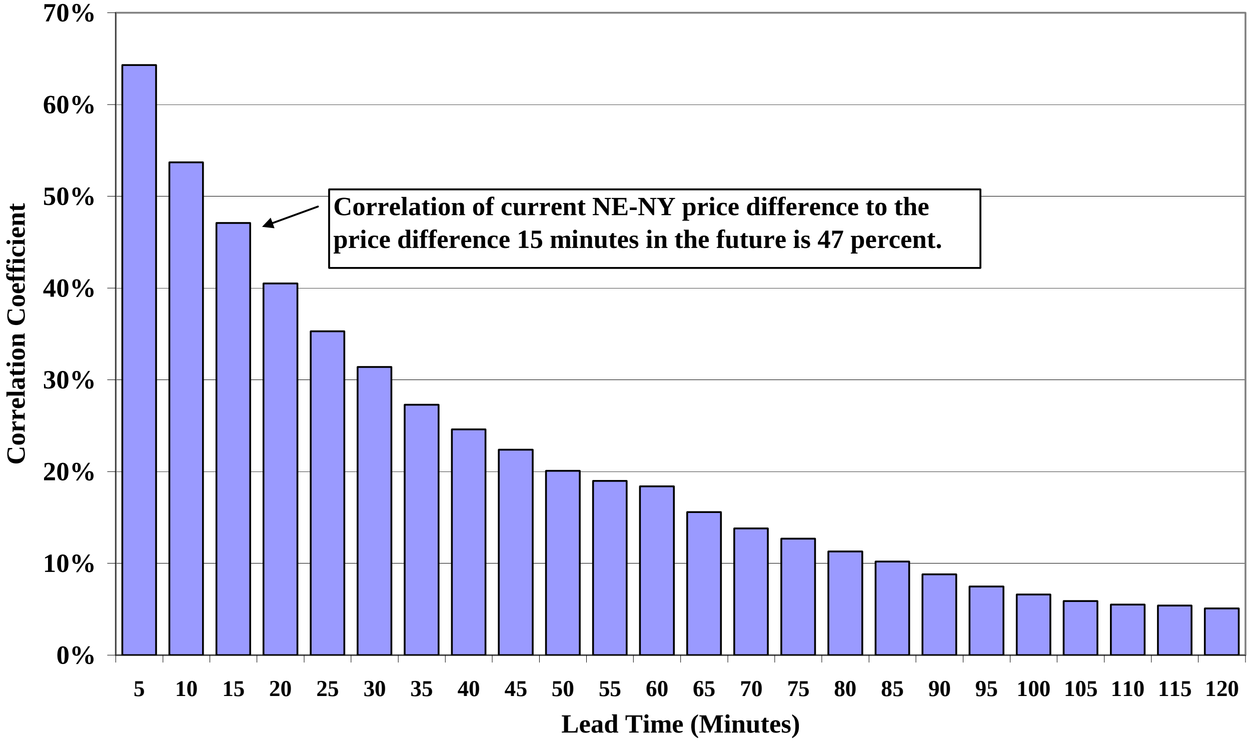
The dark trend lines presented in each panel of the figure show statistically significant positive correlations between the price difference and the direction of scheduled flows in the day-ahead and real-time markets. A positive correlation indicates that the scheduling of market participants tends to respond to price differences, by increasing net flows scheduled into the higher priced region in the day ahead and in the real time. Total net profits from cross-border scheduling in 2007 was $14.1 million in the day-ahead market and $4.5 million in the real-time market (not including transaction costs). The fact that significant profits 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-five 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, Figure 15 shows that there remains considerable room for improvement. This suggests that reducing barriers to scheduling should enable market participants to schedule more efficiently.

The following analysis examines the correlation between the lead times for scheduling transactions and the predictability of price differences between adjacent markets. Figure 16 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-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 47 percent in 2007.

Figure 16: Correlation of Price Difference to Lead Time Interface Between Up-state NY and New England, 2007



Not surprisingly, Figure 16 shows that 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.

C. Inter-regional Dispatch Coordination

Incomplete price convergence between New York and adjacent markets suggests that more efficient scheduling of flows between markets would produce 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 utilize 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 in 2006 and 2007. 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 Up-state NY and New England, 2006-2007

	2006	2007
Estimated Production Cost Net Savings (in Millions)	$17	$21
Estimated Consumer Net Savings (in Millions):		
New England Customers	$61	$22
New York Customers	$59	$177
Total for New England and New York Customers	$120	$199
During Reserve Shortage Hours	$16	$75

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 convex 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. Estimated consumer net savings that would have been obtained by consumers in New England were $61 million in 2006 and $22 million in 2007. The simulations estimate that a higher proportion of the savings would be received by New York consumers in 2007, primarily because the New York system experienced more frequent reserve shortages and slightly higher average energy prices than New England in 2007.

Shortage pricing provisions in both the New York and New England markets have contributed to more efficient pricing of resources within each market. One consequence of these provisions is that large price spikes occur when reserve shortages occur. Coordination of physical interchange between the ISOs can be especially useful in helping to resolve such shortage conditions, suggesting that the value of more efficient use of external interfaces only increases as the ISOs improve the efficient pricing of resources within their markets. 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 and $75 million in 2007.

The estimated production cost net savings, while not insignificant, naturally tend to be smaller than estimated consumer net savings. Better coordination of flows between regions would not affect most generators. Rather, in most cases, a few higher-cost generators in the higher-price region would be displaced by a few lower-cost generators in the lower-priced region.

D. 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.

Our evaluation of external transactions between New York and three adjacent ISO-run 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 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.

III. 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 market participants, the day-ahead coordinates the least-cost commitment of resources to satisfy the next day's needs.

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. Sellers would show the opposite tendencies. Historically, average day-ahead prices tend to be relatively consistent with the average real-time prices in New York and in multi-settlement markets in other regions, 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 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 within the load pockets in New York City. Third, we compare average day-ahead and real-time ancillary services prices by time of day.

A. Energy Price Convergence

Figure 17 compares the average day-ahead and real-time energy prices in the West zone, Hudson Valley, New York City zone, and Long Island in each month of 2007. 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. It shows that average real-time prices exhibited a slight premium over day-ahead prices in eastern New York in 2007.

Average monthly day-ahead and real-time prices can be heavily affected significantly 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 though the Hudson Valley on May 16, and therefore, day-ahead prices were much lower than real-time prices on that day. The real-time price premium on this day increased the real-time price premium for the month of May by $7.23/MWh. Shortage conditions on August 8 produced another substantial real time price premium for the month of August. The added lines in Figure 17 show what the monthly average day-ahead and real-time prices would have been without the effects of the May 16 and August 8 price spikes.

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 June and July 2007, typically arise when real-time scarcity conditions occur less frequently than market participants anticipated.

Figure 17: Day-Ahead and Real-Time Energy Price Convergence
West Zone and Hudson Valley, 2007

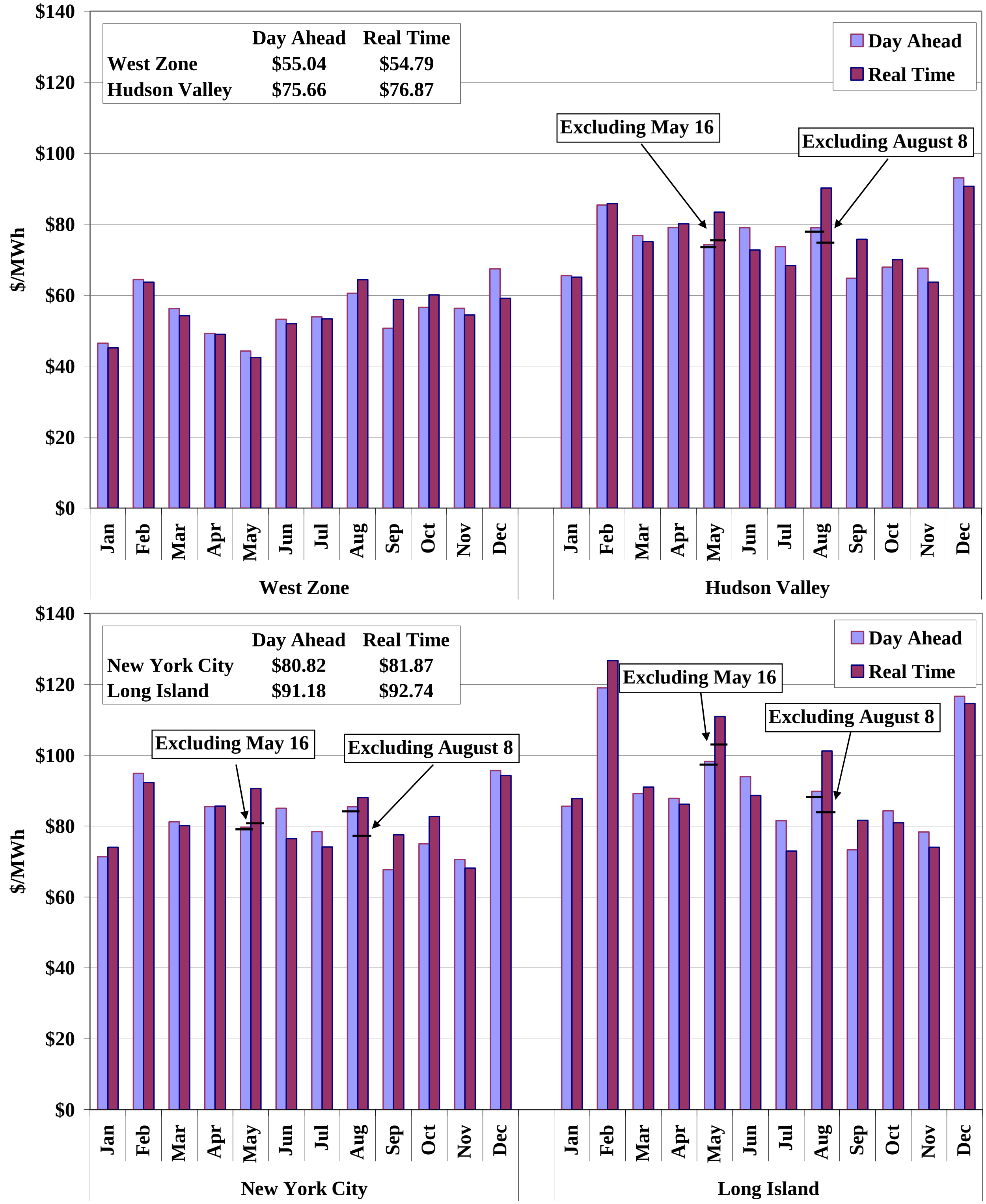
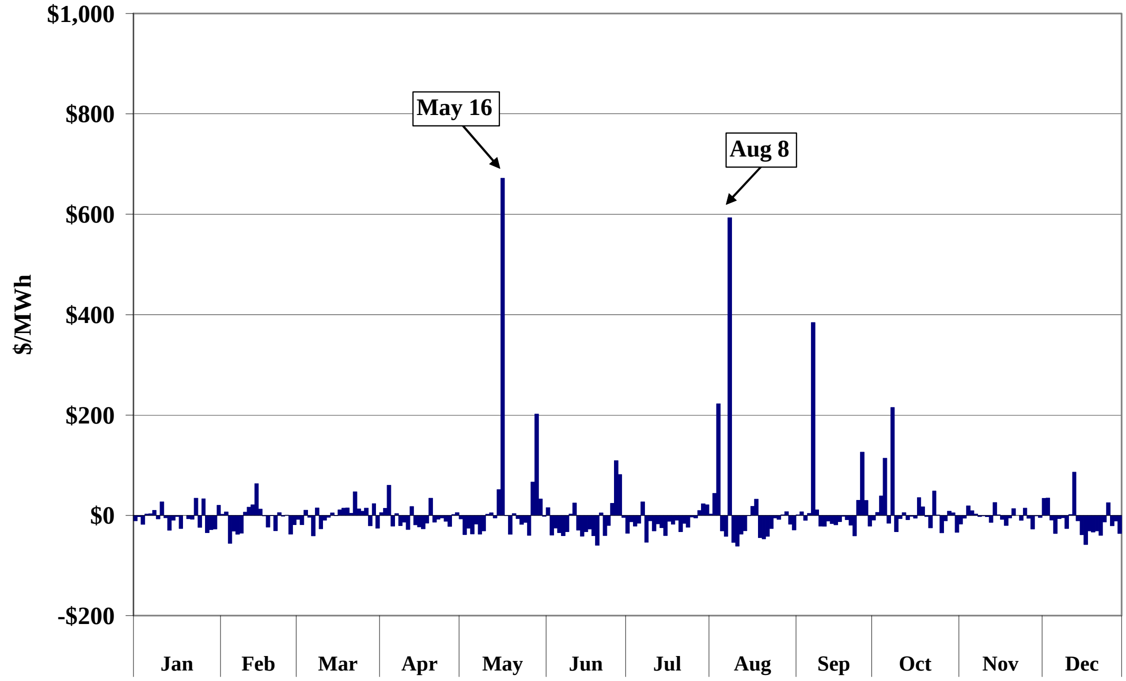


Figure 18 shows the variation in these differences on a daily basis in New York City and Long Island zone during weekday afternoon hours in 2007. A positive number represents a real-time market price premium, while a negative number represents a day-ahead price premium.

Figure 18: Average Daily Real-Time Energy Price Premium
1 p.m. to 7 p.m., Weekdays, 2007, New York City



Long Island

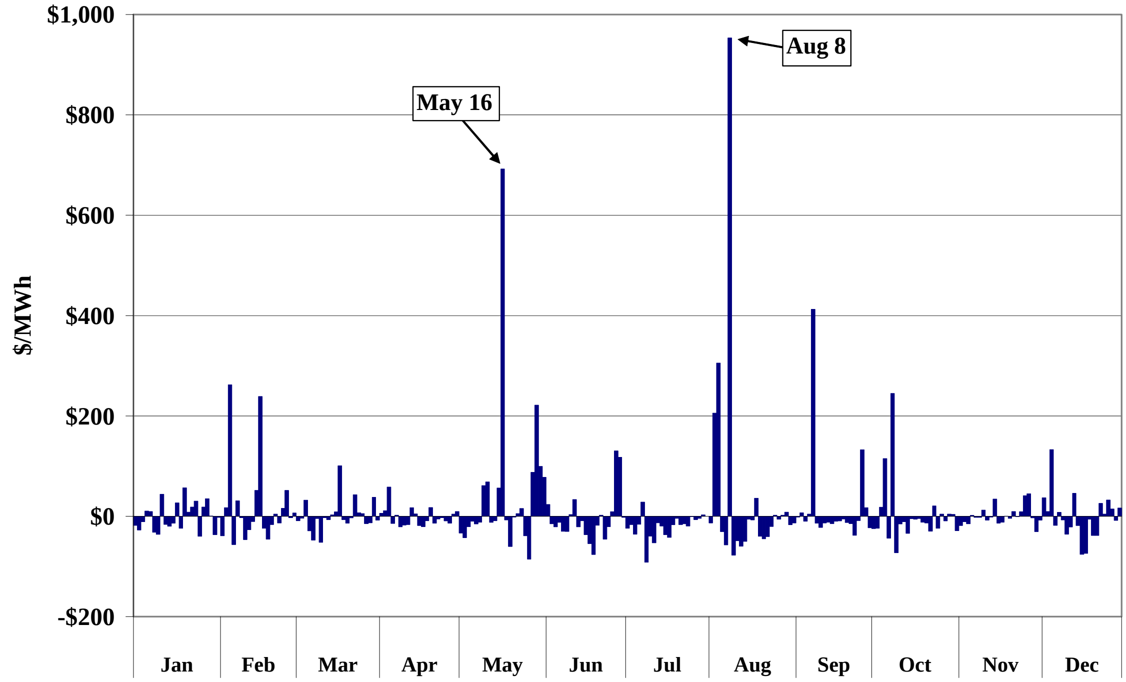


Figure 18 shows that day-ahead prices are higher than real-time prices on most afternoons. For example, in both New York City and Long Island day-ahead prices were higher on 64 percent of summer afternoons. However, very high prices are more frequent in the real-time market. No afternoons produced day-ahead price premiums of greater than $100/MWh, but real-time price premiums exceeded $100/MWh on 9 afternoons in New York City and 15 afternoons in Long Island.

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 directly affect real-time market outcomes. TSAs only affect day-ahead market outcomes indirectly, to the extent that market participants can anticipate the probability of a TSA and can adjust bids accordingly. However, TSAs alter the capability of the transmission system in ways that are difficult for virtual traders to arbitrage in the day-ahead market. The real-time price spikes on May 16 occurred when a TSA reduced the flows allowed on the transmission lines running through the Hudson Valley toward New York City and Long Island.

Good price convergence is facilitated by virtual trading. 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 V.B.

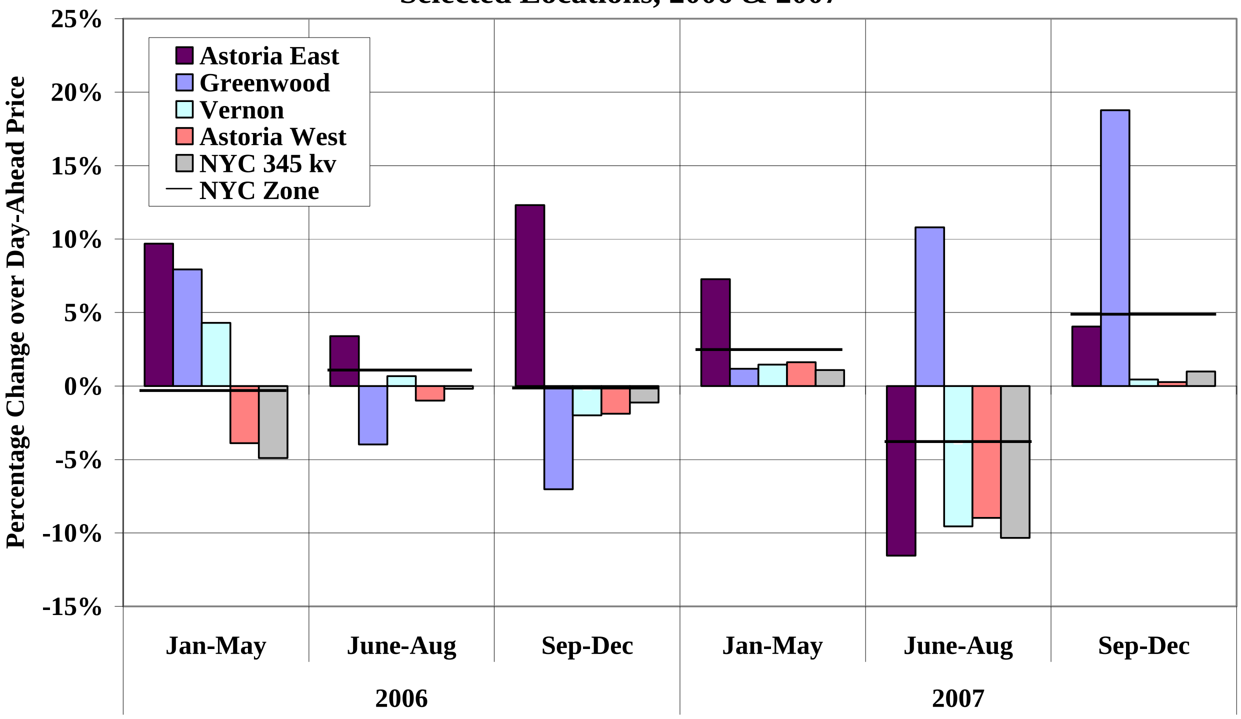
B. Price Convergence in New York City Load Pockets

The New York City zone price is a load-weighted average of nodal prices within the City. Transmission congestion can be significant within New York City, leading to a wide variation in prices across the zone. Even though the day-ahead price may be consistent with real-time prices at the level of the City zone price, some locations within the City may experience significant divergence in day-ahead and real-time prices that are offset by divergences in the opposite direction at other locations in the zone.

In general, virtual trading and price-sensitive load bidding help improve convergence by facilitating arbitrage of 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.

This sub-section examines price statistics for New York City load pockets to assess the extent to which day-ahead and real-time prices converge at that level. Figure 19 shows average real-time price premiums for five areas which account for the majority of the load within New York City. The average New York City zonal real-time price premium is also indicated in the figure. Reported price differences are load-weighted average price differences, using day-ahead forecasted load.

Figure 19: Real Time Price Premiums in New York City
Selected Locations, 2006 & 2007



Note: Individual generator buses were used to represent the areas listed in the figure: Astoria GT 2/1 for Astoria East, Gowanus GT 1/1 for Greenwood, Ravenswood 1 for Vernon, Astoria GT 10 for Astoria West, and Poletti for the NYC 345kV area. Reported price differences are load-weighted average price differences, using day-ahead forecasted load.

Day-ahead and real-time price premiums were smaller in 2006 and 2007 than in previous years due to at least two factors. First, new capacity was installed in Astoria East and Astoria West in early 2006, substantially reducing congestion within New York City. Second, since May 2006, the NYISO has increasingly used a more detailed network model for real-time scheduling, which was previously used in the day-ahead market only. This has improved the consistency of congestion management in the day-ahead and real-time markets.

Even when the same network model is used in both markets, congestion patterns may differ between the day-ahead and real-time for the following 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, 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. Third, transmission forced outages, changes in transmission maintenance, and differences in phase angle regulator settings can result in different congestion patterns. Fourth, generators may be committed or decommitted after the day-ahead market, which changes transmission flows.

While price convergence in New York City load pockets has improved since 2005, it could be improved further. The NYISO is working on two initiatives that are expected to improve convergence in at the load pocket level. The NYISO is considering a proposal to allow virtual trading at a disaggregated level. Currently, virtual trading and price-capped load bidding are limited to the zone level, which prevents market participants from arbitraging price differences within New York City.

C. Ancillary Services Price Convergence

Under SMD 2.0, the New York ISO integrated real-time ancillary services markets with the existing real-time energy market, complementing the day-ahead market which has included markets for energy, reserves, and regulation since 1999. 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 price statistics 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 20 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 21 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 models use “demand curves” that place an economic value of $500/MWh on meeting each of these requirements.

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

Figure 20: Day-Ahead and Real-Time 10-Minute Reserves Prices Eastern New York, 2007

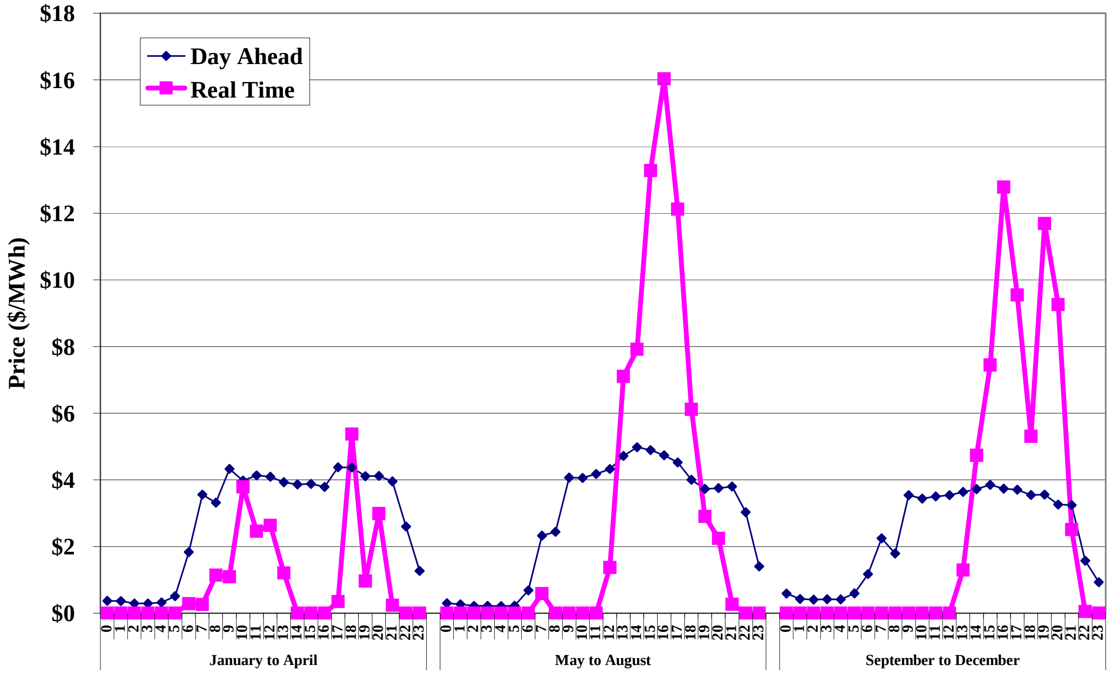
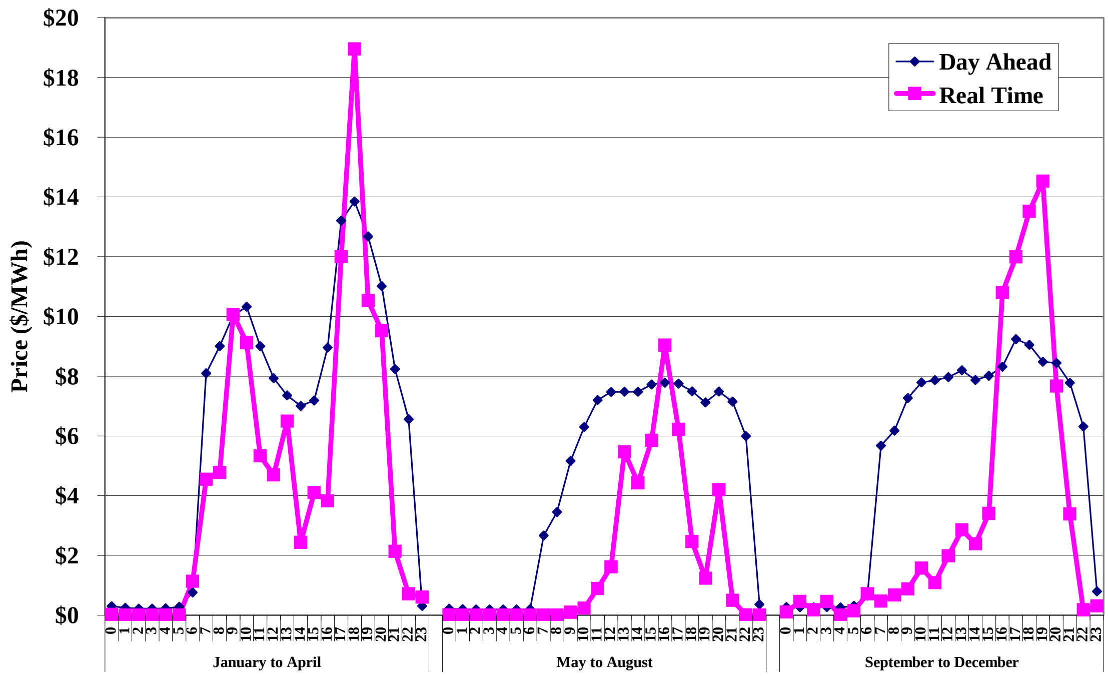


Figure 21: Day-Ahead and Real-Time 10-Minute Spinning Reserves Prices Western New York, 2007



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/MWh in a substantial share of hours. In 2007, real-time 10-minute reserves prices were $0/MWh in over 98 percent of intervals, but rose significantly in the remaining intervals. Hence, the $16/MWh average price in the peak afternoon hour of the summer is an average across the many hours in which the price was zero or near zero and a small number of peak pricing events. The volatility is difficult for market participants to predict in the day-ahead market, and based on the figure above, the day-ahead market systematically under-valued 10-minute reserves in the east during the summer and fall.

It is perhaps counterintuitive that western 10-minute spinning reserves prices decrease during the summer, when most products become more expensive. However, western 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.

Convergence between day-ahead and real-time reserve prices has improved since the introduction of SMD 2.0 markets in 2005. 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 relatively 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 relatively 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 the next section.

IV. Ancillary Services Markets

Ancillary services are bought and sold in the NYISO's day-ahead and real-time markets. The NYISO was the first wholesale market operator to co-optimize the scheduling of energy and ancillary services every five minutes in the real-time market and to use demand curves for real-time ancillary services procurement under shortage conditions. In a co-optimized market, clearing prices reflect the costs to the system of diverting resources to provide ancillary services that would otherwise provide energy, and vice versa. When the system is short of resources and unable to fully satisfy the reserve requirements, the reserve clearing price is based on the economic value of the reserve demand curve and this value is also reflected in the energy price. The FERC's recent Notice of Proposed Rule-Making identified this provision as a way to set efficient real-time prices during shortage conditions. [13] This section evaluates the performance of the ancillary services markets in 2007.

A. Background

1. Operating Requirements

New York procures three types of operating reserves: 10-minute spinning reserves, 10-minute total reserves, and 30-minute reserves. 10-minute spinning reserves are held on on-line generating units that can provide additional output within 10 minutes. 10-minute total reserves can be supplied by 10-minute spinning resources or 10-minute non-spin resources, which are typically off-line gas turbines that can be turned on and produce within 10 minutes. 30-minute reserves may be supplied by any unit that can be ramped-up in 30-minutes or that can start-up and produce within 30 minutes. In each hour, the NYISO purchases approximately 1,800 MW of operating reserves. Of this 1,800 MW, at least 1,200 MW must be 10-minute reserves and at least 600 MW must be spinning reserves.

Reserves procurement is subject to locational requirements that ensure the reserves are located where they can respond to system contingencies. The NYISO procures a substantial portion of

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[13] See P. 45. Wholesale Competition in Regions with Organized Electric Markets, 122 FERC ¶ 61,167 (2008) ("NOPR").

the reserves in the region east of the Central-East Interface. Of the required total 10-minute reserves, 1,000 MW must be purchased east of the Central-East Interface. The NYISO obtains 200 MW of 10-minute reserves through a reserve sharing agreement with New England. The NYISO procures at least 300 MW of 10-minute spinning reserves from eastern portion of New York. It also procures at least 60 MW of 10-minute spinning, 120 MW of total 10-minute, and 540 MW of total reserves from within Long Island. The relative importance of each locational requirement is indicated by its demand curve value. The total 10-minute reserve requirement for eastern New York currently has a demand curve value of $500/MWh, while the other locational requirements for eastern New York and Long Island have demand curve values of $25/MWh.

Regulation service is necessary to continuously balance generation with load and help maintain interconnection frequency close to 60 Hz. The NYISO purchases 150 to 275 MW of regulation depending upon season and time of day from generators anywhere within the New York Control Area. The amount of regulating capability a generating resource may sell is equal to the amount it can ramp in five minutes. In addition, to qualify as a regulating unit, the unit must be able to receive and respond to a continual dispatch signal.

2. Ancillary Services Market Design

As mentioned above, the New York ancillary services market design has two elements that lead to improved efficiency. First, reserves and regulation are co-optimized with energy in the real-time market. Every five minutes, the model re-evaluates the most efficient allocation of resources to energy and ancillary services based on supplier offers and real-time operating conditions. Clearing prices reflect the marginal cost of energy and ancillary services to the system, given the level of demand and transmission constraints. When system conditions change quickly and unexpectedly, this allows the real-time market to shift reserves to the areas where it is needed.

Second, the real-time market uses demand curves to limit the costs of procuring ancillary services and to better reflect the value of ancillary services and energy in prices under shortage conditions. Without demand curves, the model would incur unlimited costs in order to satisfy the reserve requirements and the regulation requirement. In cases when sufficient reserves do not exist, a model without demand curves fails to reflect the reserve shortage in the clearing prices for energy or ancillary services. But in the NYISO market, the real-time model reduces reserves and regulation purchases when the procurement costs rise to extreme levels. The demand curves provide the model with a rational basis for prioritizing high-value reserves over lower-value reserves under shortage conditions and setting prices appropriately.

All generators offering to sell energy in real-time must also offer to provide reserves with a $0/MWh availability bid. As a result, the real-time clearing price for each reserve product is equal to the opportunity cost of not providing another product (i.e., energy or regulation). Frequently, it is not necessary to re-dispatch generators in real-time to meet reserves requirements because excess reserve capacity is available from on-line units. During these periods, reserve clearing prices drop to $0/MWh because it costs nothing to maintain reserves.

The NYISO runs a two-settlement system, which consists of a spot market (i.e. real-time market) and a forward financial market (i.e. day-ahead market), whereby day-ahead financial obligations must be reconciled in the real-time market. A generator that is paid to sell reserves in the day-ahead market must either (i) physically provide reserve capacity in real-time or (ii) buy reserves back in the real-time market. Generators that sell reserves in the day-ahead market and are dispatched by the ISO to provide energy in the real-time market are paid the real-time clearing price for energy but must still buy back reserves in the real-time market. Since reserves are co-optimized with energy in the real-time market, normally the supplier's profit from selling energy exceeds the replacement price of the reserves. [14]

However, under certain circumstances, it is possible for a generator to be selected to provide energy when it would have been more profitable to provide reserves, or vice versa. This is the result of Hybrid Pricing, which is used by the NYISO's market models to allow gas turbines to set prices even though they are block-loaded (i.e. physically inflexible). In the real-time market, Hybrid Pricing consists of: (i) a physical dispatch that determines dispatch instructions, and (ii) a

[14] Suppose a generator is at a location where the price of energy is $150 per MWh and the price of spinning reserves is $10 per MWh, and it offers to supply energy for $100 per MWh. The real-time model would dispatch the generator for energy since it would earn $50 per MWh based on its offer and this is greater than the value of spinning reserves. This determination is made independent of whether the generator sold energy or reserves in the day-ahead market. If the generator sold spinning reserves in the day-ahead market, it would be paid $150 per MWh for energy in real-time, but it would still have to purchase back its spinning reserves obligation at $10 per MWh.

pricing dispatch that determines clearing prices treating gas turbines as flexible. The potential for losses by generators that are selected to provide the less profitable service underscores the need to eliminate unnecessary inconsistencies between the physical and pricing dispatches of the real-time model. This is discussed in greater detail in later in this report.[15] When generators are not selected to provide the most profitable service, the financial harm to them is partly alleviated by Day-Ahead Margin Assurance Payments ("DAMAP payments"). When a generator is dispatched below its day-ahead schedule for energy, the generator receives a DAMAP payment to make it whole for losses it incurs from following instructions that cause it to buy back energy in the real-time market. The payments reduce the risk that suppliers may face incentives to deviate from instructions in ways that degrade reliability or impose additional costs on other market participants.

B. Ancillary Services Expenses

The NYISO procures operating reserves and regulation through the market, so expenditures for these services are expected to fluctuate in response to market conditions. The NYISO procures voltage support service through contract agreements with generators. The nature of these agreements makes voltage support expenditures consistent throughout the year. Figure 22 shows monthly expenses for regulation, voltage support, and operating reserves from 2005 to 2007.

Total expenses for voltage, regulation, and operating reserves increased approximately 20 percent from 2005 to 2006, and did not change substantially from 2006 to 2007. The increased expenses from 2005 to 2006 are attributable to at least two factors. First, regulation offer prices rose substantially in September 2005 due to a change in behavior by two suppliers, although the effects were partly mitigated by the entry of new supply in spring 2006.

Second, changes in the pattern of convergence between day-ahead and real-time prices for ancillary services, particularly 10-minute spinning and non-spinning reserves, contributed to higher expenses. The NYISO purchases the required quantity of reserves in the day-ahead market, so expenses primarily depend on day-ahead prices rather than real-time prices. In 2005,

[15] See Section VII.B.1.

average day-ahead prices were substantially lower than average real-time prices. Expenses for reserves increased in 2006 and 2007 because day-ahead prices rose relative to real-time prices.

Figure 22: Ancillary Services Costs
2005 – 2007

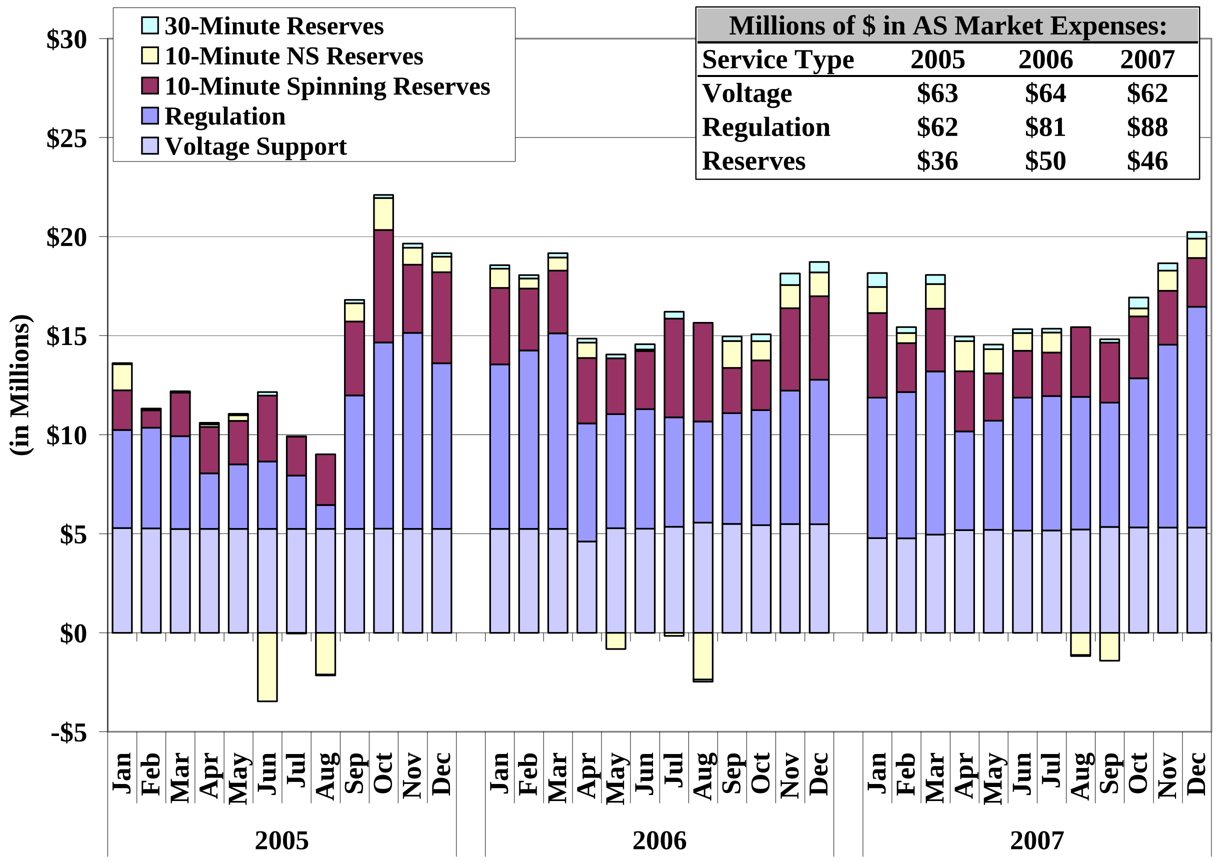

Figure 22 also shows that net expenses were negative for 10-minute non-spinning reserves in several months. This phenomenon occurs when generators sell reserves at low day-ahead prices and buy back the reserve obligation in real-time at higher prices when dispatched to produce energy. Ordinarily, the ISO purchases reserves from another generator in real-time to meet reserve requirements, resulting in no net change in reserve expenses. However, when the ISO was not able to find sufficient reserves during reserve shortages, the resulting income was sufficient to more than offset expenses for 10-minute non-spin reserves in those few months.[16]

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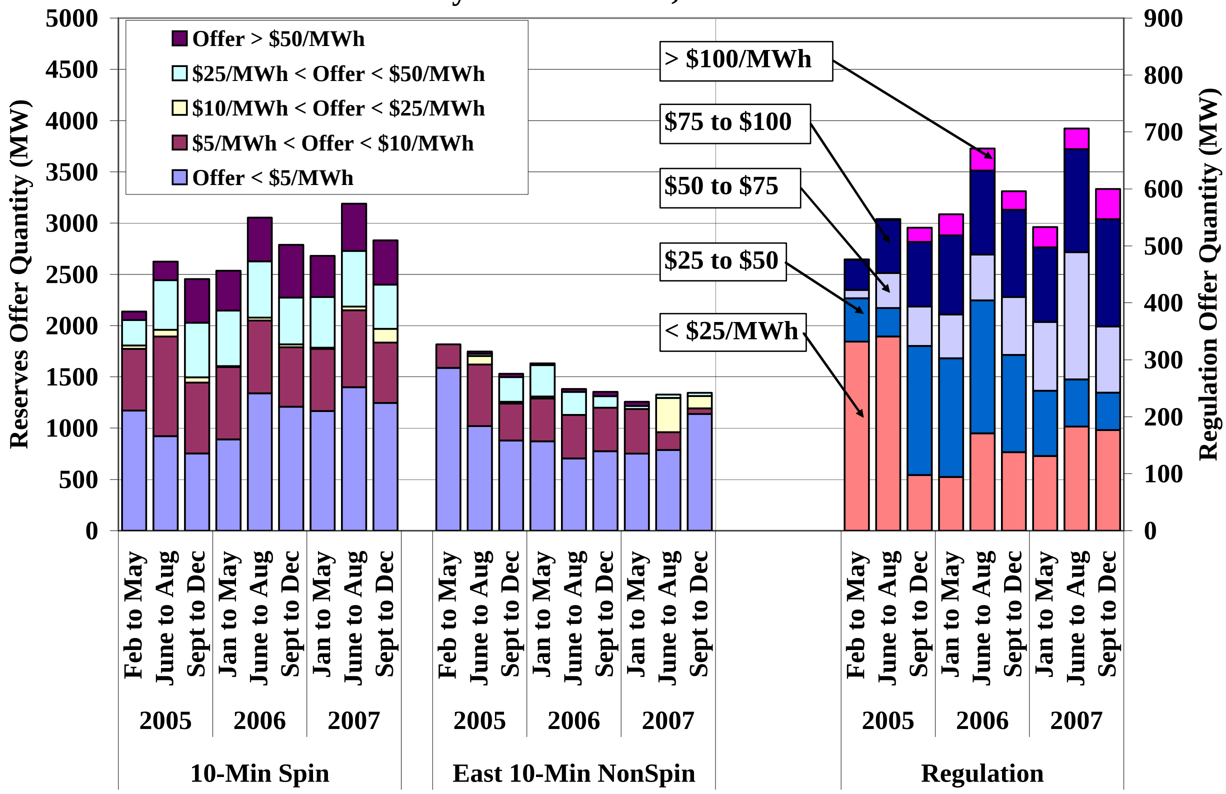
[16] For example, assume that a gas turbine sells 20 MW of reserves for $5 per MWh in the day-ahead market, but is dispatched to provide energy in real-time when the price of the same reserves product is $500 per MWh. In this case, the ISO would have paid $100 (= 20 MW * $5 per MWh) to the generator for reserves in the day-ahead, and collected $10,000 (= 20 MW * $500 per MWh) back from the generator for reserves in the real-time, generating a net surplus of $9,900.

Alternatively, there are cases when the ISO maintains sufficient reserves by purchasing a higher value service from another generator, so that a surplus in one type of reserves may be offset by an increased expense for the higher value service.

C. Day-ahead Offer Patterns

This sub-section evaluates ancillary services offer patterns in the day-ahead market to determine how participation has changed in recent years. The following figure summarizes day-ahead offers to supply three categories of ancillary services from 2005 to 2007: (i) 10-minute spinning reserves, (ii) 10-minute total reserves in eastern New York, and (iii) regulation. Offer quantities are shown according to offer price level.

Figure 23: Summary of Ancillary Services Offers
Day-ahead Market, 2005-2007



Note: Spinning and non-spinning offers are an average of 1pm to 7pm, while regulation includes all hours.

The figure shows several notable changes in regulation offers over the period. In September 2005, regulation offer prices rose due to changes in behavior by several market participants. In June 2006, several generators that did not previously provide regulation began to submit approximately 100 MW of low-priced offers. In 2007, some of the capacity previously offered at less than $50/MWh began offering at higher prices. These changes contributed to corresponding changes in regulation expenses which are shown in Figure 22.

Offers to supply 10-minute spinning reserves at prices below $5/MWh increased substantially from late 2005 to 2006. This was primarily due to the installation of new combined cycle generation in New York City in early 2006. Under the current mitigation rules, generators in New York City are required to offer 10-minute spinning reserves at $0/MWh in the day-ahead market. The figure shows that nearly 50 percent of the 10-minute spinning reserves is offered at less than $5/MWh. Given that most generators outside New York City offer at higher price levels, it is likely that this rule forces the offer prices of suppliers below competitive levels. The quantity of 10-minute spinning offers did not change significantly from 2006 to 2007, except for seasonal variations due to planned outages during shoulder months.

For eastern 10-minute non-spinning reserves, Figure 23 shows that offer quantities have decreased while the offer prices have increased over the past three years. This may be a competitive response to poor convergence between day-ahead and real-time reserve prices, which are evaluated in Section IV.C. When suppliers predict real-time prices will be higher than day-ahead prices, they avoid selling into the day-ahead market and shift sales to the real-time market by raising their day-ahead offer prices and/or reducing their day-ahead offer quantities. However, these suppliers are limited by two market rules. First, the mitigation rules restrict the reference levels of 10-minute non-spinning reserve providers to a maximum of $2.52/MWh. Second, the ICAP rules require Non-PURPA ICAP units that have 10-minute non-spinning reserve capability to offer in the day-ahead market.

D. Ancillary Services – Conclusions and Recommendations

The NYISO was the first market operator to make two key enhancements to its ancillary services markets. First, the NYISO co-optimizes the scheduling of energy and ancillary services in real-time, which improves market efficiency by allowing the real-time model to consider the costs of ancillary services procurement in the prices of energy, and vice versa. This guarantees that the clearing prices of energy, reserves, and regulation fully reflect the opportunity cost of not providing the other services. Second, the NYISO uses demand curves for ancillary services, which establish an economic value for reserves that is reflected in energy prices when energy demand and reserves requirements compete for scarce supply resources. These two enhancements have improved the operation of the system and enabled prices to better reflect the economic value of reliability.

Convergence between day-ahead and real-time prices has been poor for 10-minute spinning reserves and 10-minute non-spin reserves in eastern New York. 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, competitive 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. We conclude that the mitigation measures likely limit the offers of some suppliers below competitive levels.

- 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/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/MWh.

If convergence between day-ahead and real-time operating reserves prices remains poor, we recommend the NYISO evaluate the feasibility of virtual trading of ancillary services in the day-ahead market. This change would promote convergence of ancillary service prices and reduce the incentive for physical suppliers to raise their offer prices for operating reserves above marginal cost. However, the proposal would need to be carefully studied to ensure it will not have unintended consequences on the day-ahead commitment.

V. Analysis of Energy Bids and Offers

In this section, we examine bidding patterns to evaluate whether market participant conduct is consistent with effective competition. On the supply side, the analysis seeks to identify potential attempts to withhold generating resources as part of a strategy to increase prices. On the demand side, we evaluate load-bidding behavior to determine whether load bidding has been conducted in a manner consistent with competitive expectations. We also analyze virtual trading. Our analysis does not raise concerns that the wholesale market was affected by physical and economic withholding.

A. Analysis of Supply Offers

The majority of wholesale electricity production comes from base-load and intermediate-load generating resources. Relatively high-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 relatively 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 holding 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 is economic to do so. Economic withholding occurs when a supplier raises the offer price of a resource to reduce its output below competitive levels or to otherwise raise the market price.

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 profits from withholding during periods when the market supply curve becomes steep (i.e., at high-demand periods). Therefore, examining the relationship between potential withholding metrics and demand levels allows us to test whether the conduct in the market 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. By eliminating planned outages, we implicitly assume that planned outages are legitimate and are not aimed at exercising market power.[17]

In Figure 24, deratings are measured relative to the most recent Dependable Maximum Net Capability ("DMNC") test value of each generator. In Figure 25, we focus on short-term deratings by excluding deratings that last for more than 30 days. Short-term deratings are more likely to reflect attempts to physically withhold since it is more costly to withhold via long-term deratings or outages. We focus on peak hours (week day, non-holiday afternoon hours from noon to 6pm) when demand is highest, because withholding is more likely to be effective as demand increases. The following analyses evaluate 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.

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[17] 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 24: Relationship of Deratings to Actual Load
Day-Ahead Market - East New York
Peak Hours, Summer 2007

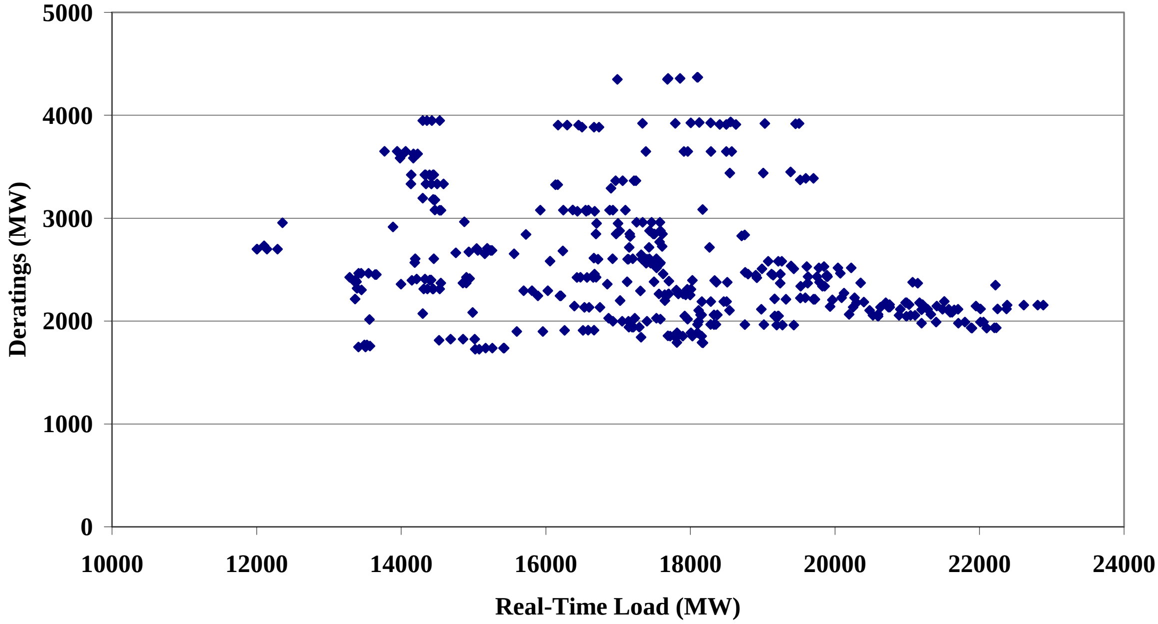

Figure 25: Relationship of Short-Term Deratings to Actual Load
Day-Ahead Market – East New York
Peak Hours, Summer 2007

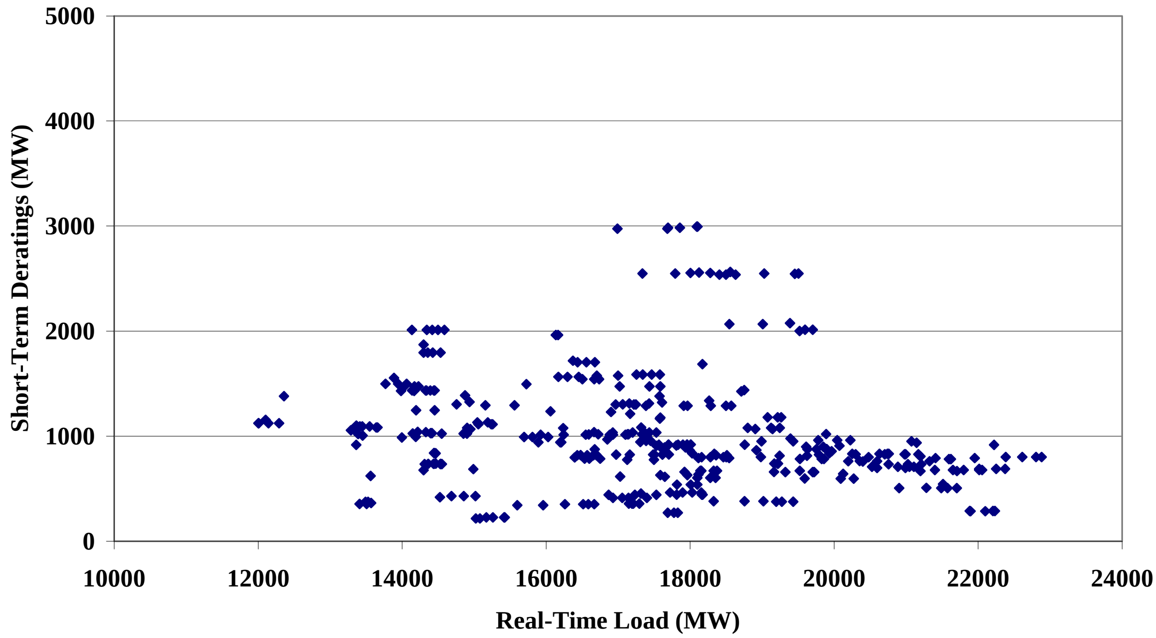

Figure 24 and Figure 25 show that total deratings and short-term deratings generally decline as demand reaches very high levels. This is an indication of competitive performance since the incentive to physically withhold resources generally increases under high demand conditions for participants with market power. Furthermore, although deratings do not increase with demand, forced outages are expected to rise under peak demand conditions when the ISO calls on units to operate more frequently. Therefore, we find that the overall pattern of outages and deratings was consistent with workable competition during the summer of 2007.

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 the market clearing price. 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 so cost the owner lost profits. Hence, we analyze economic withholding by comparing actual supply offers with a competitive benchmark. To determine whether an offer may be above the competitive level, we compare it with the generator's reference level, which is an estimate of marginal cost that is used for market power mitigation.[18] 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 capacity that is economic at the market clearing price, but is not running due to the owner's offer price or is setting the LBMP substantially above the competitive level.[19]

Like the prior analysis of deratings, 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 focus on week day afternoon hours when demand is highest. Figure 26 shows the output gap using the state-wide mitigation thresholds of $100/MWh or 300 percent. Figure 27 shows the output gap results using a lower threshold of $50/MWh or 100 percent. The second analysis is

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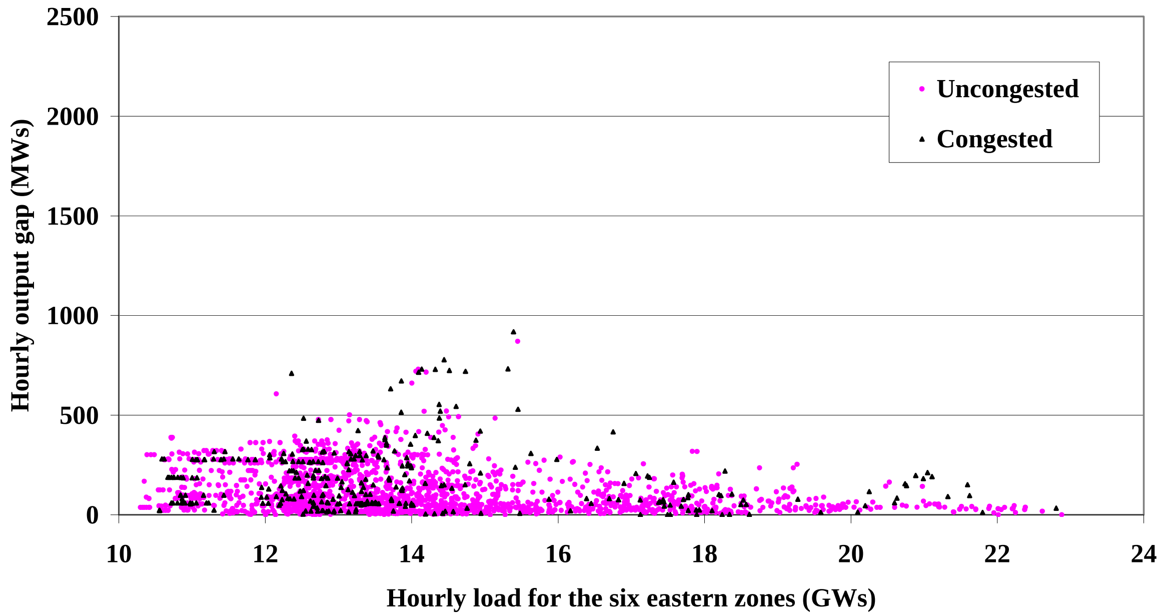
18 See *NYISO Market Services Tariff, Attachment H – NYISO Market Monitoring Plan-Market Mitigation Measures*, Section 3.1.4

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

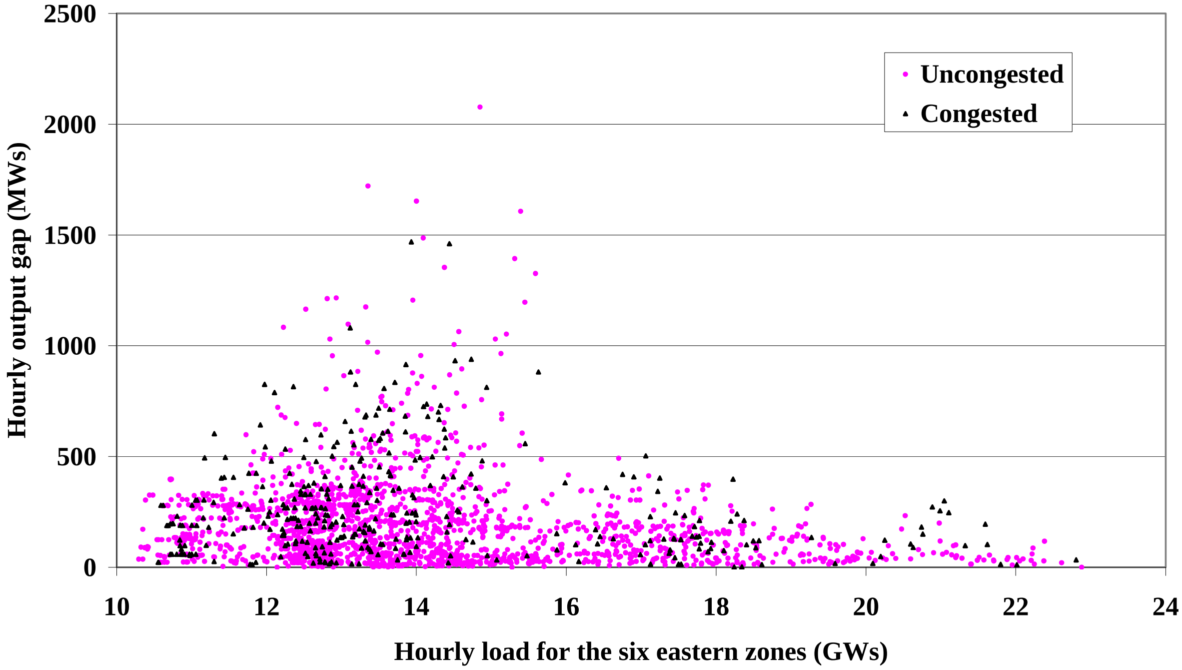
included in order to assess whether there have been attempts to withhold by offering energy just below the state-wide mitigation threshold.

**Figure 26: Relationship of Output Gap at Mitigation Threshold to Actual Load
Real Time Market – East New York
Weekdays, Noon to 6 PM, 2007**



Both figures show that the output gap quantities tend to decrease to relatively low levels under the highest load conditions; and the output gap does not increase significantly during periods of congestion. The market is most vulnerable to the exercise of market power during peak load periods and congested hours. Hence, the tendency for the output gap to decrease as load increases is a positive sign for the competitiveness of the market. These results are particularly notable for the lower threshold because they include conduct that is not subject to mitigation. Some of the output gap shown in the two figures could be the result of actual withholding, but the quantities are relatively small compared to the total load in eastern New York and are negatively correlated with load. Therefore, these output gap results are consistent with the expectations for a competitive market and do not raise significant concerns about economic withholding during 2007.

Figure 27: Relationship of Output Gap at Low Threshold to Actual Load
Real Time Market – East New York
Weekdays, Noon to 6 PM, 2007



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.[20]

The day-ahead and real-time market software automatically performs much of the conduct and impact mitigation testing, particularly in New York City. The mitigation measures are designed to allow prices to rise efficiently to reflect legitimate supply shortages while effectively

20 See *NYISO Market Services Tariff, Attachment H.*

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.[21] 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 2007. 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).[22]

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21 $$\text{Threshold} = \frac{2\% * \text{Avg. Price} * 8760}{\text{Constrained Hours}}$$

22 Mitigation of gas turbine capacity is shown in the Energy category when the energy offer is mitigated or the Mingen/Start-up category when only the start-up offer is mitigated.

Figure 28: Frequency of Day-ahead Mitigation in the NYC Load Pockets 2007

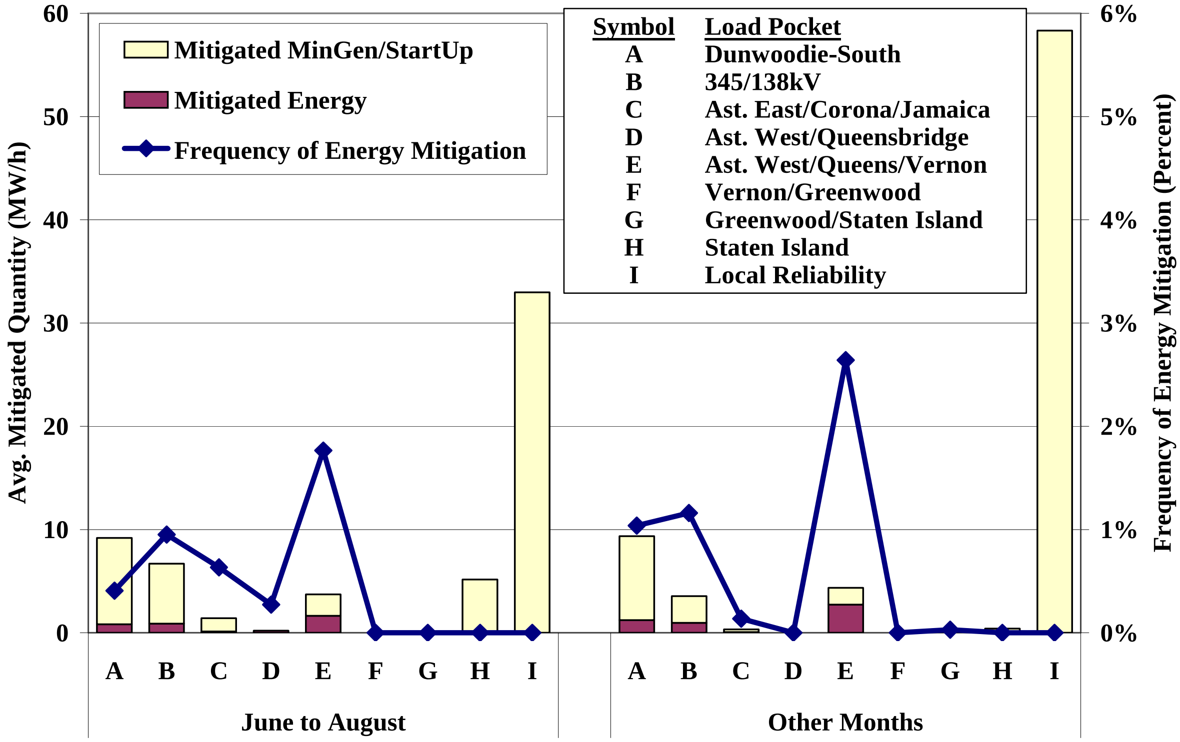


Figure 28 shows that the majority of day-ahead mitigation was on generators committed to satisfy Local Reliability Requirements ("LRR").[23] The start-up and MinGen offers of LRR units are mitigated whenever they exceed the reference level. The figure indicates that day-ahead mitigation is infrequent. The Astoria West/Queens/Vernon interface exhibited most frequent energy mitigation, although mitigation in this load pocket only occurred during 2 to 3 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 relationship shows that units with significant minimum run times are sometimes mitigated for price impact in a relatively small number of hours. For instance, a unit with a 24 hour minimum run time might raise its MinGen bid parameter above the conduct threshold. However, if this conduct would cause the unit to not be committed resulting in a price impact above the

[23] LRRs are developed by transmission owners and adopted 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.

applicable threshold for one hour, the unit's MinGen parameter would be mitigated for the duration of its minimum run time, while its incremental energy parameter would be mitigated only in the hour with impact.

Figure 29: Frequency of Real-Time Mitigation in the NYC Load Pockets 2007

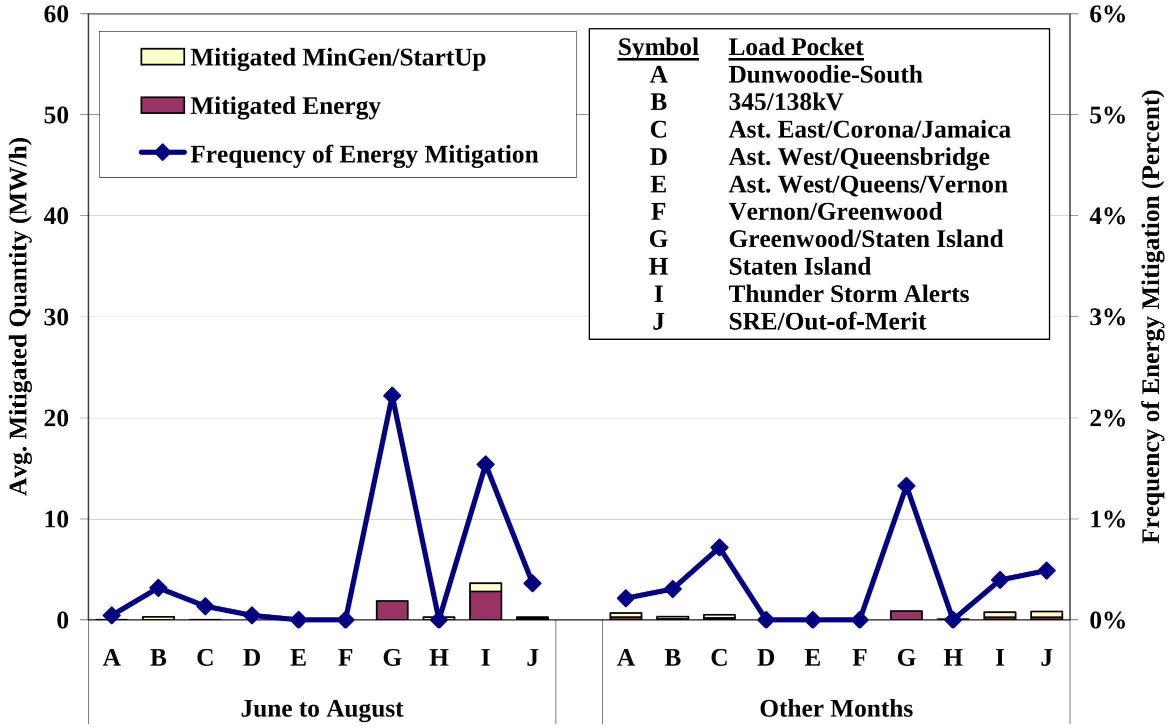


Figure 29 shows that the most frequent real-time mitigation occurred for the Greenwood/ Staten Island load pocket within the 138 kV portion of New York City. The load pocket is dominated by one supplier and experiences frequent real-time congestion making it more susceptible to the exercise market power. 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. 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 constructing identical arrangements by other means that would settle through the NYISO. In particular, participants may sign a "contract-for-differences" ("CFD") with a counterparty to make a bilateral purchase. Financial bilateral contracts such as CFDs are settled privately and generally would 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[24]. If the load is actually realized in real-time, it would be served with energy purchased in the real-time market. This is a more rational form of load-bidding than the non-price sensitive fixed load schedules. However, price-capped load bidding is only allowed at the zonal level while fixed load bidding is allowed at the bus level.

Virtual Load Bids. These are bids to purchase energy in the day-ahead market with a bid price indicating the maximum amount the bidder is willing to pay. Virtual load scheduled in the day-ahead market is automatically sold back to the real-time market. So, the virtual buyer earns the quantity of the purchase in megawatt-hours multiplied by the real-time price minus the day-ahead price. This is currently allowed at the zonal level but not 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

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

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 megawatt-hours multiplied by the day-ahead price minus the real-time price. This is currently allowed at the zonal level but not the bus level.

1. Day-Ahead Scheduling

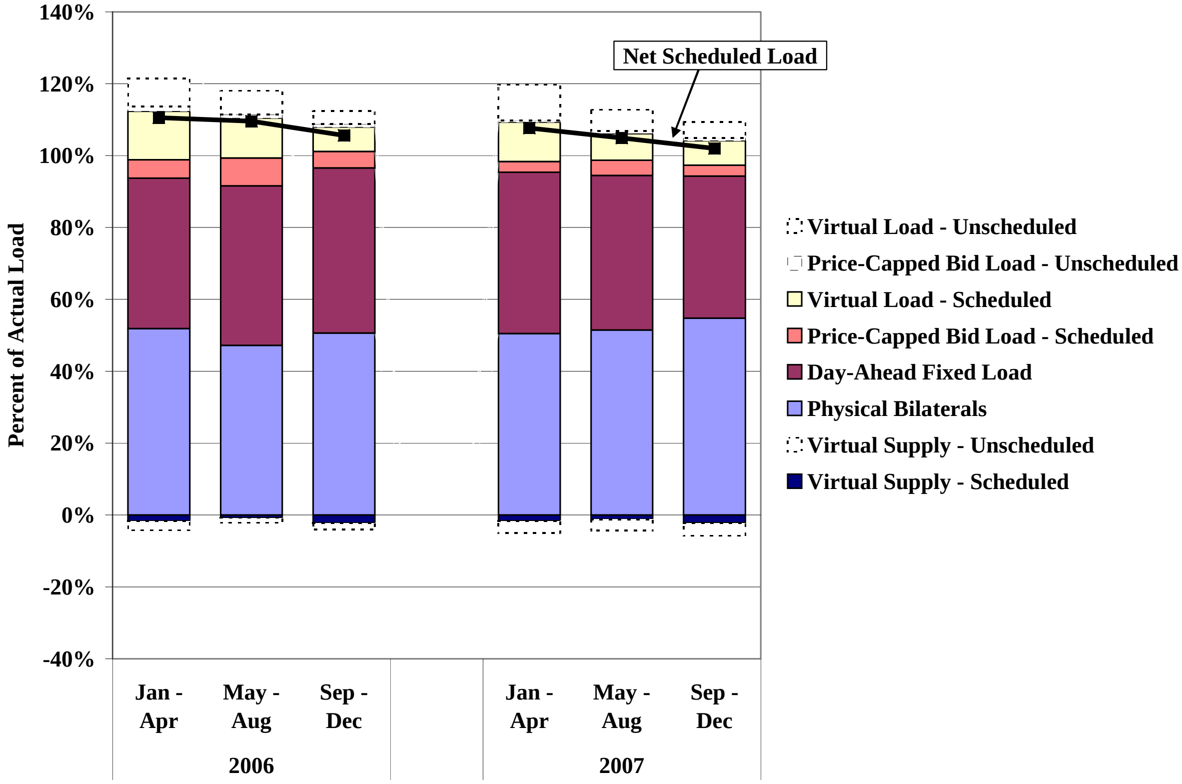
Many generating units have long lead times and substantial commitment costs. Their owners must decide whether to commit well in advance of real-time before they can be certain that the unit will be economic. The day-ahead market provides these suppliers with a way of deciding to commit only when it is 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 offers as a percent of real-time load during 2006 and 2007 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.

Figure 30 shows a comparison of day-ahead load scheduling to actual load in New York City and Long Island on a seasonal basis in 2006 and 2007. 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 30: Composition of Day-Ahead Load Schedules versus Actual Load
New York City and Long Island, 2006 – 2007



Load is generally over-scheduled by 5 to 10 percent in New York City and Long Island relative to actual load. The over-scheduling implies a higher level of imports to constrained areas in the day-ahead market than in real-time. This raises day-ahead prices and lowered real-time prices, bringing them into better convergence. The pattern of over-scheduling was likely induced by the relatively low day-ahead prices.

This pattern of over-scheduling is partly attributable to modeling inconsistencies between the day-ahead and real-time markets which have sometimes allowed less transfer capability in the real-time market than in the day-ahead market. This is because a detailed model of the New York City transmission system is used in the day-ahead market, while a set of simplified interface constraints is sometimes used in the real-time market. In May 2006, the NYISO began to use the detailed model sometimes in the real-time market. The increased use of the detailed in-city transmission model has contributed to reducing real-time congestion and has contributed to the decline in net over-scheduling of load in the day-ahead market in New York City.

The next two figures compare day-ahead load scheduling to actual load in areas outside New

York City and Long Island by season in 2006 and 2007. Figure 31 shows this comparison for East Up-State New York, and Figure 32 shows this comparison for West New York.

Figure 31: Day-Ahead Load Schedules vs. Actual Load: East Up-State New York

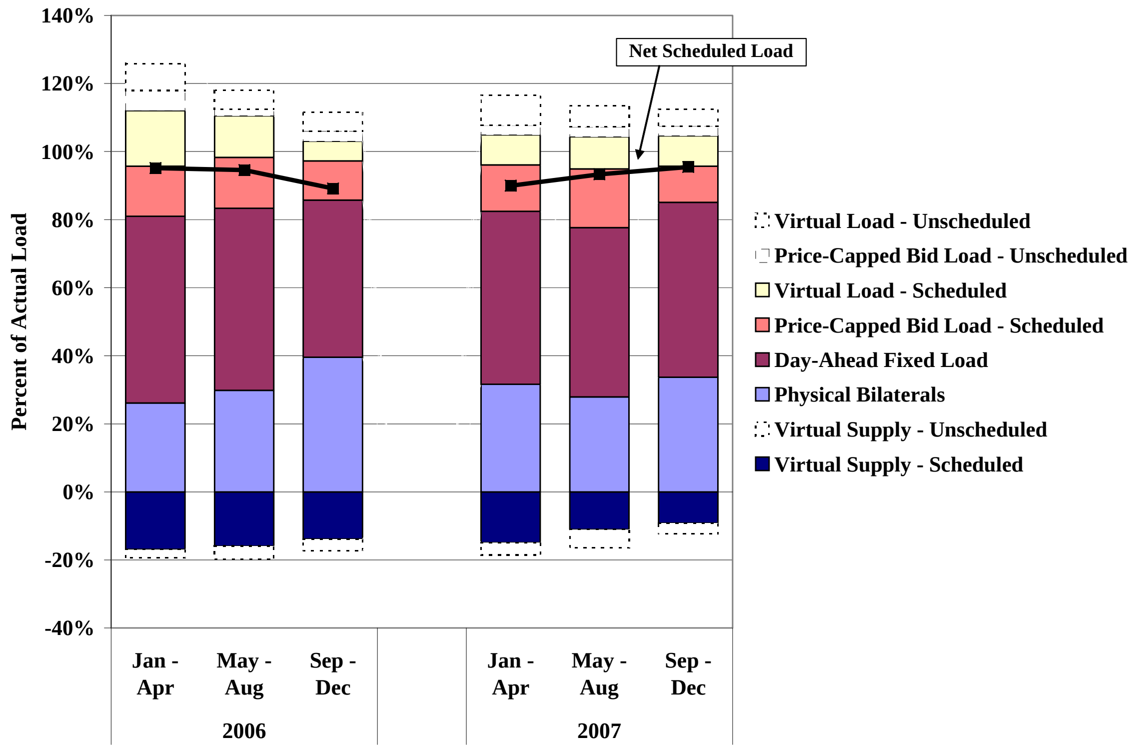


Figure 32: Day-Ahead Load Schedules vs. Actual Load: West Up-State New York

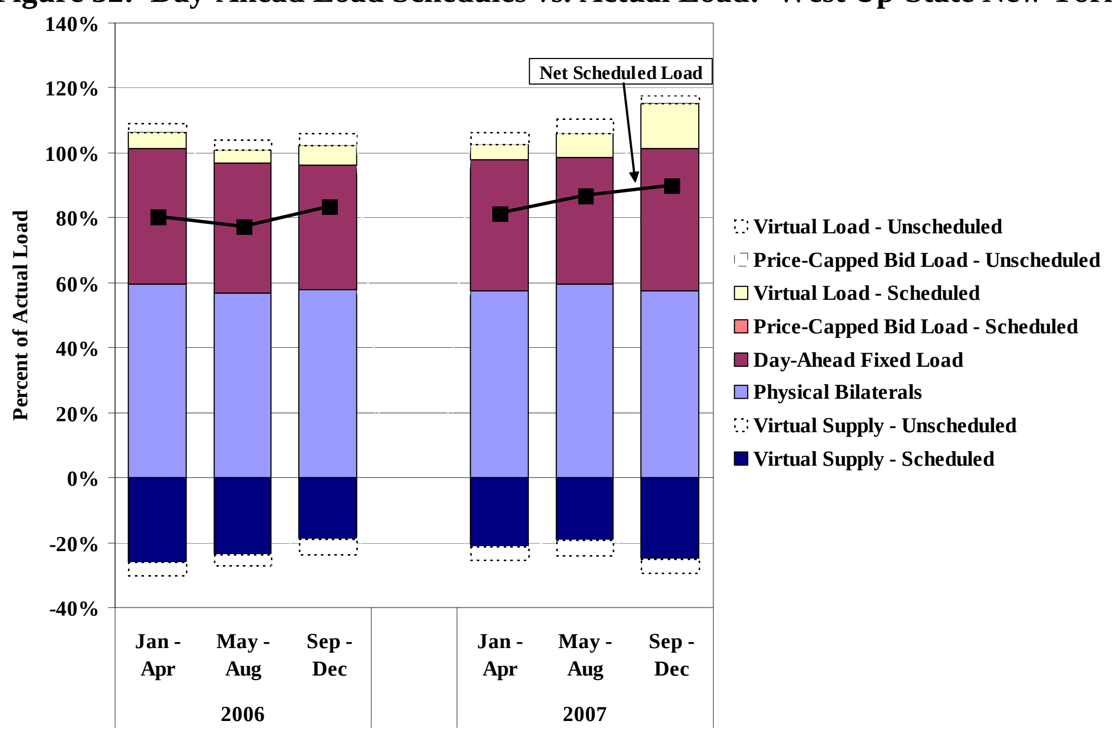


Figure 31 and Figure 32 summarize load scheduling in up-state areas, which contrasts with the pattern in Figure 30 New York City and Long Island. Although the sum of physical and virtual load exceeded actual load in up-state New York on average, large amounts of virtual supply led to net under-scheduling of load. This decreases day-ahead prices, bringing them into better convergence with real-time prices. This is discussed further in Section III.A. Thus, the lack of scheduling convergence in up-state New York from virtual trading activity has improved price convergence.

2. Virtual Trading

Virtual trading was introduced in November 2001 to allow participation in the day-ahead market by entities other than LSEs and generators. The motivation was to improve arbitrage between the day-ahead and real-time markets, as well as allowing flexibility for all 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 slightly and decrease the real-time price slightly to improve convergence.

We analyzed the quantities of virtual load and supply that have been offered and scheduled on a bi-monthly basis from 2005 to 2007. The average quantities are shown for New York City and Long Island in Figure 33 and up-state New York in Figure 34.

The figures indicate that there have been substantial net virtual sales in up-state New York and net virtual purchases in New York City and Long Island 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, and is consistent with the pattern of imports into down-state areas being higher in the day-ahead market than in the real-time market.

Figure 33: Hourly Virtual Load and Supply
New York City and Long Island, 2005 – 2007

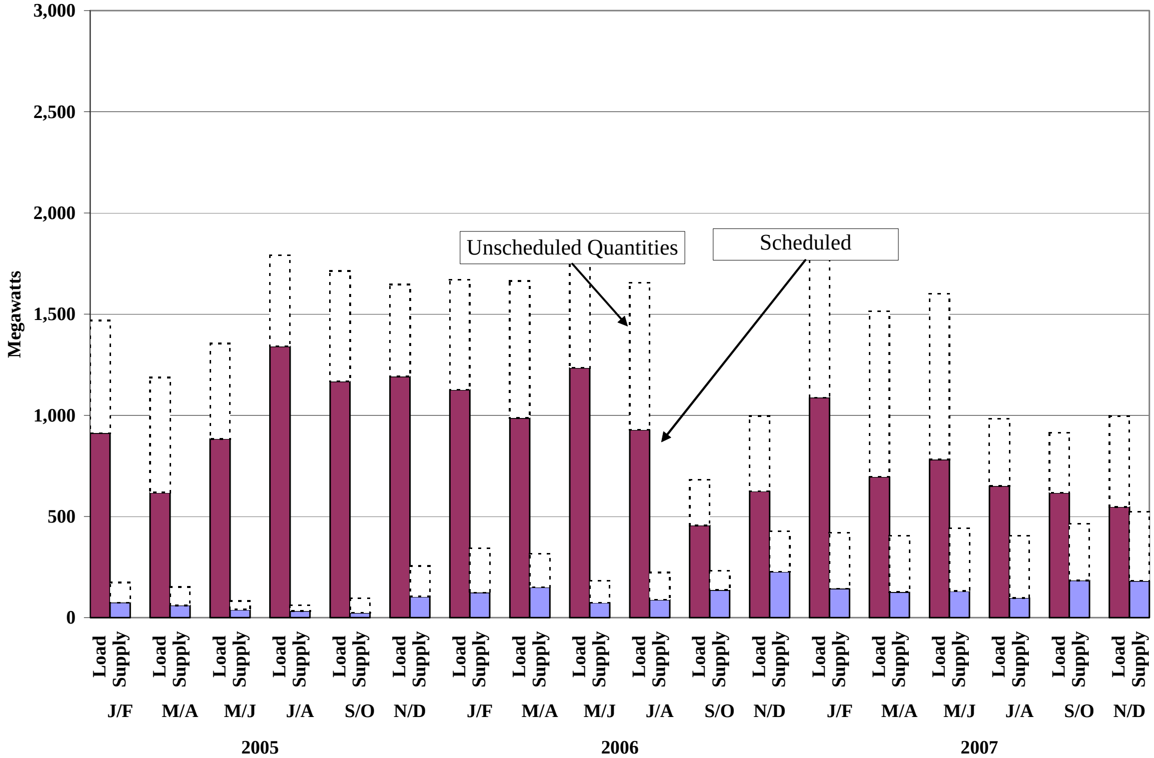
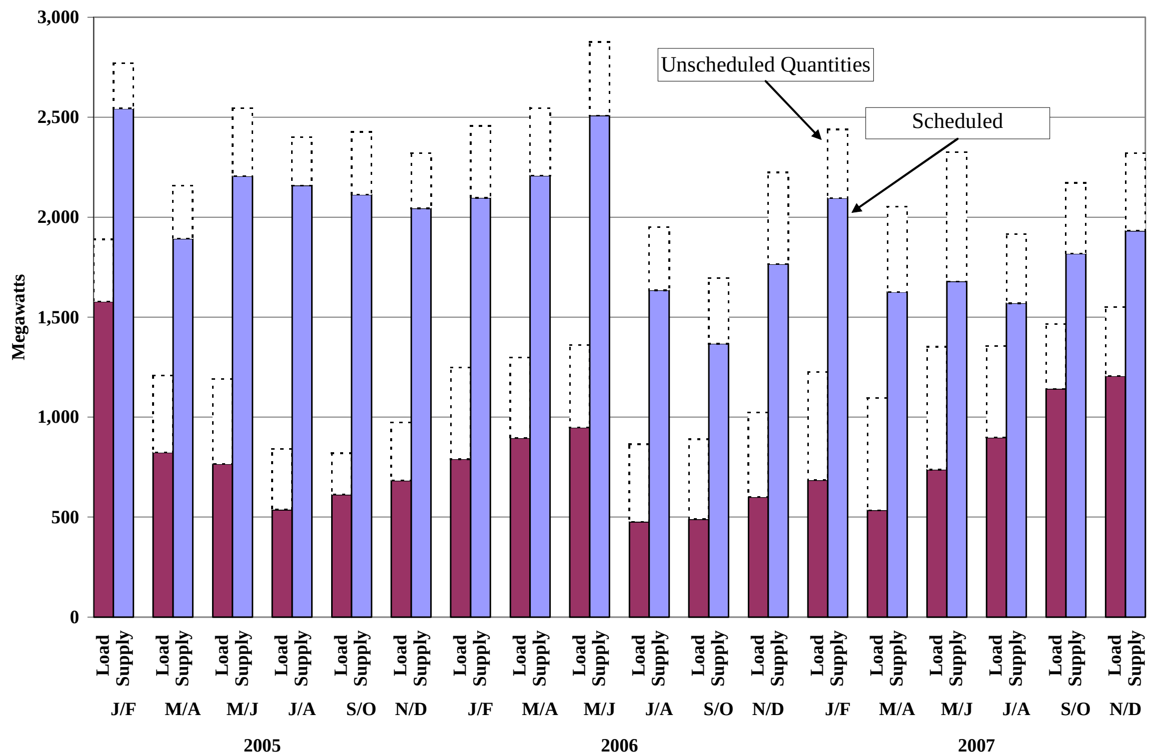


Figure 34: Hourly Virtual Load and Supply
Outside New York City and Long Island, 2005 – 2007



The average net virtual sales in the up-state areas and average net virtual purchases in New York City and Long Island have contributed to better convergence between the day-ahead and real-time prices, however, the net scheduled quantities decreased from 2005 to 2007. In up-state areas, the average net virtual sale declined from 1,320 MW in 2005 to 920 MW in 2007. In New York City and Long Island, the average net virtual purchase declined from 960 MW in 2005 to 580 MW in 2007. These trends are partly due to the following two factors. First, the use of detailed constraint modeling in New York City has reduced inconsistencies between day-ahead and real-time transmission modeling, thereby reducing arbitrage opportunities available to virtual traders. Second, the installation of new combined cycle generation in New York City in 2006 and new transmission capability from New Jersey to Long Island in 2007 reduced congestion from up-state New York to downstate areas. The reduced congestion has reduced the significance of transmission modeling inconsistencies between the day-ahead and real-time markets.

VI. Transmission Congestion

Congestion arises when the transmission network does not have sufficient capacity to transfer power to consumers from the least expensive generators. When congestion occurs, the market software establishes clearing prices based on 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 available 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. 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 losses, a participant can perfectly hedge its bilateral contract if it owns a TCC between the same two points over which it has scheduled the bilateral contract.

Transactions not scheduled in the day-ahead market are assessed real-time congestion charges. As in the day-ahead market, charges for bilateral transactions are based on the difference between the locational prices at the two locations of the bilateral contract. For real-time spot market transactions, the congestion charge is paid by the purchaser through the congestion component of the LMP. There are no TCCs for real-time congestion since most power is scheduled through the day-ahead market.

This section evaluates three aspects of transmission congestion management and locational pricing:

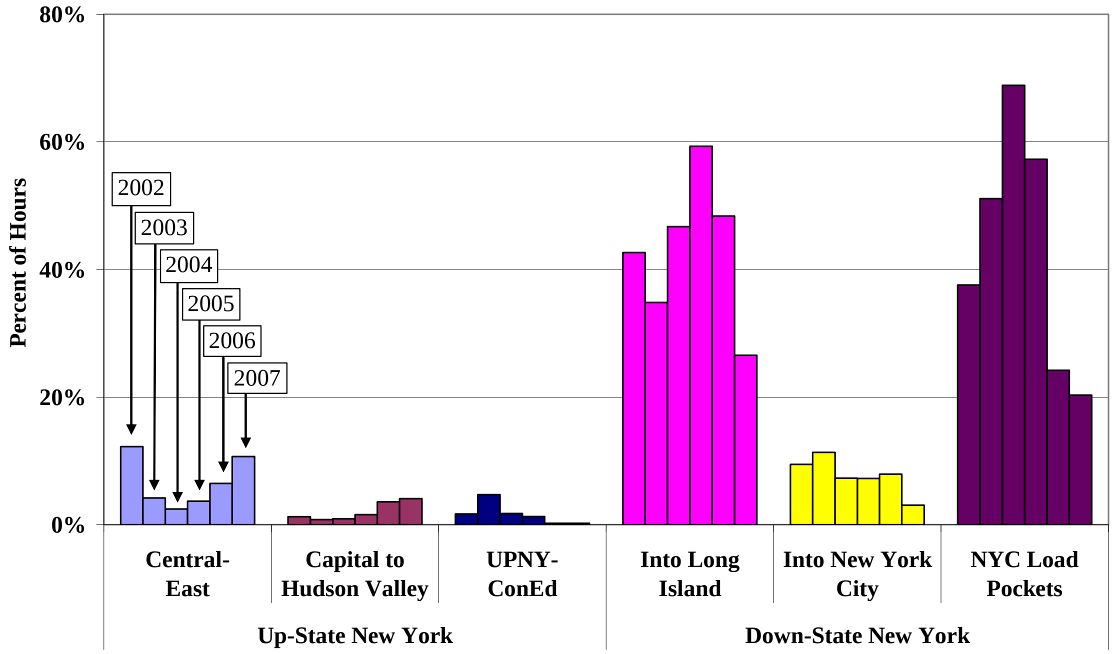
- *Real-Time Congestion on Major Transmission Interfaces*: This analysis summarizes changes in the frequency and value of congestion on major interfaces during the past six years.
- *Congestion Revenue Shortfalls*: Congestion revenues collected in the day-ahead and real-time market by the NYISO are sometimes not sufficient to cover payments to TCC holders. We examine the shortfalls and identify factors that affect the size of the shortfalls.
- *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.

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 35 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 35: Frequency of Real-Time Congestion on Major Interfaces 2002 – 2007



The preponderance of congestion occurs into and within down-state areas, although up-state congestion became more frequent in 2006 and 2007. In particular, the Central-East Interface has exhibited more frequent congestion associated with voltage limitations.

Congestion into and within down-state areas became substantially less frequent after 2005. Congestion into Long Island and New York City decreased significantly (by almost 50 percent) from 2006 to 2007. Within New York City load pockets, congestion decreased dramatically from 2005 to 2006.

At least three factors contributed to the trends in congestion shown above. First, 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 exclusively using the more simplified load pocket interface constraints for real-time dispatch. This has led to a more effective use of the transmission system, and therefore, less congestion.

Second, 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.

Third, 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 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, while a substantial amount of new generation was installed in New England in 2003 and 2004. These new additions have helped reduce flows over the Central-East interface and tend to shift 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 have contributed to increased congestion in 2007.

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 36 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[25] of the interface in the real-time market multiplied by the flow.

The value of congestion on the up-state and down-state transmission interfaces did not change substantially from 2006 to 2007. In the down-state areas, the value of congestion did not change significantly, even though the frequency of congestion decreased significantly from 2006 to 2007. This was partly due to the effects of rising fuel costs in 2007, which contributed to the increased value of flows across constrained interfaces. Within New York City load pockets, the value of congestion increased notably (from $100 million in 2006 to $180 million in 2007).[26] This was attributable to more frequent congestion into the Greenwood area in 2007.

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[25] The shadow price of a transmission constraint represents the marginal value to the system of one megawatt 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.

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

Figure 36: Value of Real-Time Congestion on Major Interfaces 2002 – 2007

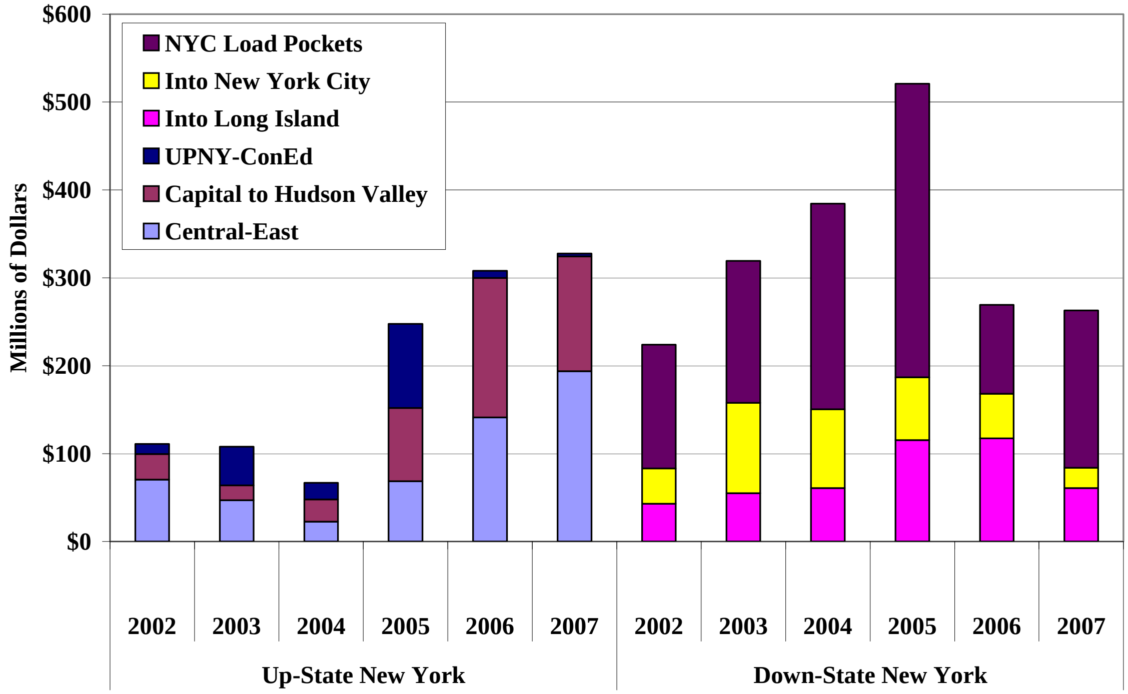

Figure 36 shows that the value of congestion on various interfaces has shifted considerably in recent years for several reasons. First, variations in the frequency of congestion, which are shown in Figure 35, have led to corresponding changes in the value of congestion. Second, fuel price fluctuations have lead to proportional changes in the value of congestion. The rise in congestion costs from 2002 to 2005 and the decline in congestion costs from 2005 to 2006 were consistent with changes in overall prices for electricity, which were driven by the fluctuations in oil and natural gas prices.

Third, TSAs and eastern 10-minute reserve shortages have had a significant impact on the congestion costs in the Capital to Hudson Valley corridor since 2005. The intervals with TSAs account for approximately $60 million of the congestion costs in the up-state areas in 2005, $80 million in 2006, and $65 million in 2007. Shortage intervals (without TSAs) added an additional $12 million in 2005, $40 million in 2006, and $18 million in 2007. This indicates that the

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congestion based only on the real-time market results which differ from day-ahead results.

double-contingency criteria used during TSAs and costly re-dispatch during reserve shortages added significantly to congestion costs, although such conditions are infrequent.

Fourth, for real-time dispatch, modeling individual transmission lines in New York City rather than more simplified load pocket interface constraints has improved the efficiency of congestion management in New York City load pockets. More efficient congestion management generally reduces the difference between clearing prices in New York City load pockets and clearing prices in other areas, thereby reducing the congestion value of transmission interfaces into and within New York City. The installation of new generating capacity in New York City in 2006 and the introduction of new transmission capacity from New Jersey to Long Island in 2007 also contributed to the decease in the value of congestion into New York City and Long Island.

B. Congestion Revenue Shortfalls

This sub-section evaluates the congestion revenue shortfalls that arise from differences between the real-time market, the day-ahead market, and the TCC market. Congestion revenue shortfalls can be divided into two categories:

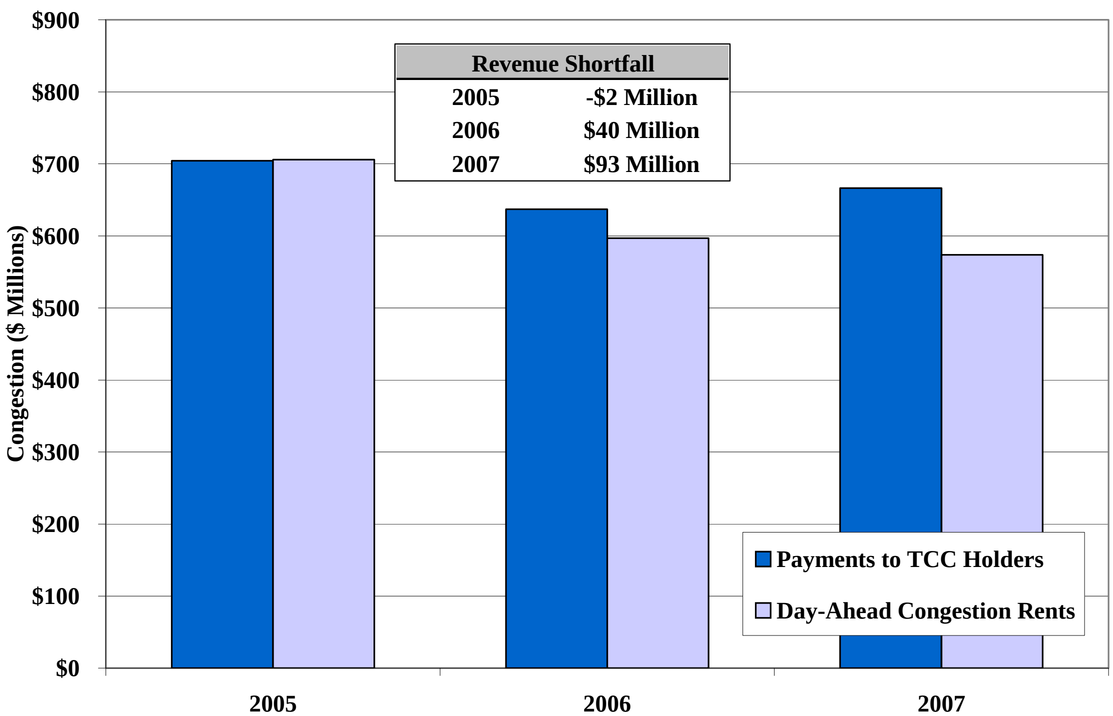
- *Day-ahead Congestion Revenue Shortfalls*: When the revenues collected by the NYISO from congestion in the day-ahead market are less than the payments by the NYISO to the holders of TCCs. These arise when the quantity of TCCs sold for a particular path exceeds the transfer capability of the path as modeled in the day-ahead market during periods of day-ahead congestion.
- *Balancing Congestion Revenue Shortfalls*: 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 modeled in the day-ahead across a particular line or interface exceeds the actual transfer capability during periods of real-time congestion.

Figure 37 shows the significance of day-ahead congestion revenue shortfalls, while Figure 38 reveals the magnitude of balancing congestion revenue shortfalls.

The NYISO conducts auctions to sell the TCCs to market participants. In order to determine the maximum quantity of TCCs that can be sold in a TCC Auction, the transmission system must be modeled to ensure that the TCCs 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 rents collected should be sufficient to fully fund awarded TCCs.

If transmission outages occur that were not modeled in the TCC auction, then the congestion rents collected may be insufficient to meet TCC obligations. To fully fund TCCs under these conditions, the congestion rent shortfall is charged to transmission owners and passed through to end customers through the transmission owners' service charge. To the extent that these charges are "socialized," they do not provide efficient incentives to minimize the congestion effects of transmission outages. To evaluate the significance of day-ahead congestion revenue shortfall amounts over the past three years, Figure 37 shows day-ahead congestion costs and TCC payments.

Figure 37: Day-Ahead Congestion Costs and TCC Payments 2005-2007



Day-ahead congestion rents fell after 2005 primarily due to less frequent congestion in New York City and Long Island. Other notable drivers of the reduction of congestion were declining summer load conditions, new generation capacity installed in New York City in 2006, and new transmission capacity from New Jersey to Long Island added in 2007. Lower fuel prices in 2006 relative to 2005 further contributed to low day-ahead congestion rents in 2006. However, factors that reduced the frequency of congestion in 2007 were offset by rising fuel costs.

Figure 37 indicates that congestion revenue shortfalls in the day-ahead market have increased since 2005. Congestion revenue shortfalls occurred because the transmission capability assumed in the TCC auction generally exceeded the capability modeled in the day-ahead market. Transmission and generation outages[27] that are not known at the time of the TCC auction, and therefore not modeled in the TCC auction, lead to reduced transmission capability in the day-ahead market and contributed to larger congestion revenue shortfalls.

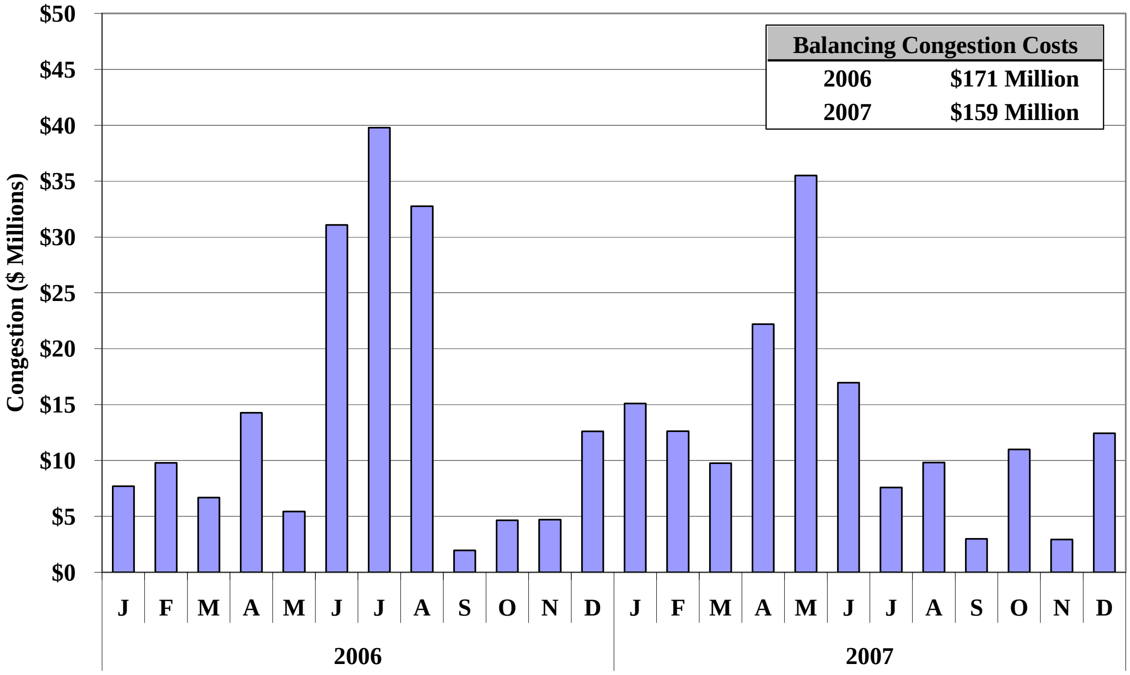
The next analysis summarizes congestion revenue shortfalls that occurred in the real-time market. Balancing congestion shortfalls arise when the flow modeled day-ahead across a particular line or interface exceeds the actual transfer capability during real-time. When this occurs, the ISO must purchase additional generation in the constrained area and sell back energy in the unconstrained area (i.e., purchase counter-flow to offset the day-ahead schedule). The cost of this re-dispatch is collected from loads through uplift charges.

Actual transfer capability can be lower than the day-ahead modeled capability for several reasons. First, transmission and generation outages may occur after the day-ahead market. Second, changes in unit commitment after the day-ahead market may increase the size of the largest contingency relative to a particular transmission interface or facility. Third, current 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 actual operation. These factors force the NYISO to purchase counter flows in the real-time market to make up the difference between the day-ahead scheduled flows and the actual real-time flows.

The following figure summarizes balancing congestion revenue shortfalls on a monthly basis in 2006 and 2007.

27 Since transmission flow limits are normally set low enough to ensure reliable operations in the event of a contingency, generation outages can affect the transfer capability of the transmission system.

Figure 38: Balancing Congestion Revenue Shortfalls 2006 - 2007



Following a substantial decrease from 2005 to 2006, balancing congestion costs declined modestly from $171 million in 2006 to $159 million in 2007. Most of this uplift is allocated to load throughout the state, although 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.

The decline in balancing congestion costs, particularly the significant reduction following the spring of 2007, can be attributed to three factors. First, there was a significant decline in the amount of congestion overall, which led to correspondingly lower balancing congestion shortfalls. The most notable driver of reduced congestion was the transmission capacity that was added between New Jersey and Long Island in July 2007. Second, the increased use of a more detailed network model in New York City improved the consistency of transmission modeling between the day-ahead and real-time market, which helps decrease balancing congestion revenue shortfalls.

Third, beginning in June 2007, the real-time dispatch model limits the marginal re-dispatch costs that may be incurred to resolve a transmission constraint to a maximum of $4,000/MWh.

Previously, transmission constraint shadow prices would occasionally reach extraordinary levels when the available re-dispatch options were relatively 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 shortfalls.[28] The new methodology is discussed later in Section VII.B.2 in greater detail.

C. TCC Prices and Day-ahead Congestion Prices

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.

Figure 39 compares the auction prices from the auction of 6-month TCCs during the 2007 summer capability period to the day-ahead congestion that actually occurred. TCCs are defined by their source and sink locations. The left side of Figure 39 shows TCCs sourcing at three locations in the state and sinking in New York City (Zone J). Two of the source locations are in the 345kV system within New York City, so these show that there is often substantial congestion within New York City. The right side of the figure also shows prices for TCCs sourcing at Zone J and sinking in several load pockets on the 138kV system in Zone J.

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28 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/MWh for one hour, it would result in a balancing congestion shortfall of $4 million (= $10,000/MWh * (2,000 MWh – 1,600 MWh)). Under the new methodology, the shadow price would be $4,000/MWh, resulting in a balancing congestion shortfall of $1.6 million (assuming the real-time flows did change).

Figure 39: TCC Prices and Day-Ahead Congestion
May to October 2007

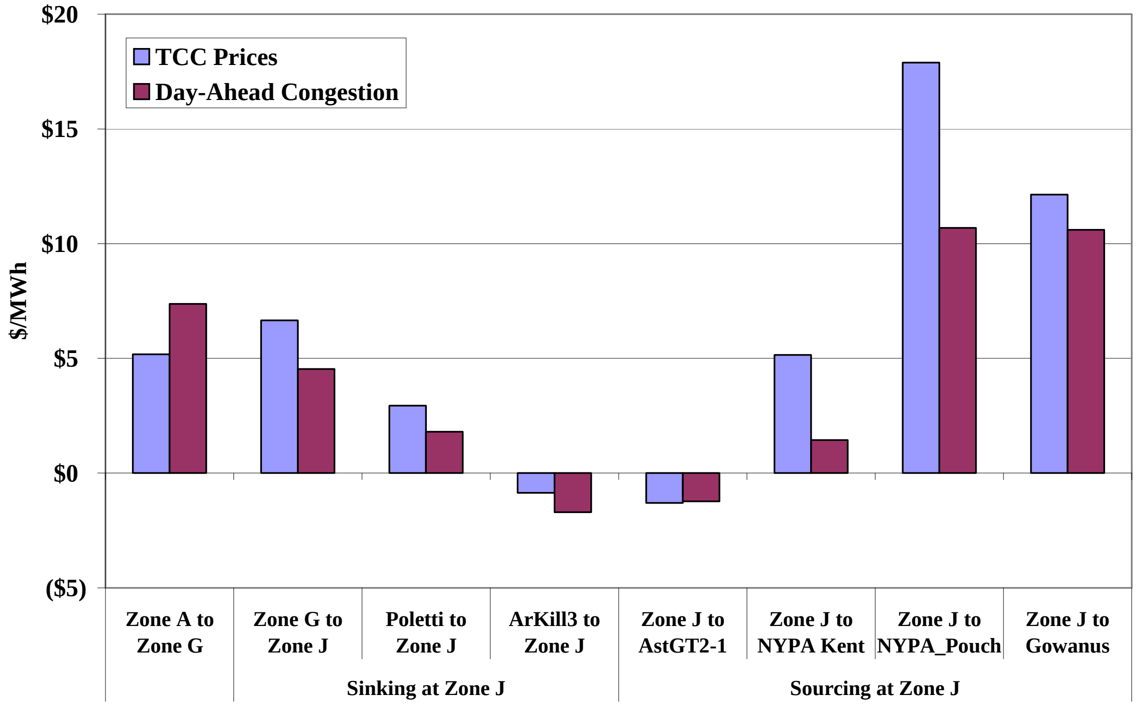

Figure 39 indicates that the TCC auctions under-valued west-to-east congestion, as shown by the Zone A to Zone G TCC, and over-valued Hudson Valley to New York City congestion, as shown by the Zone G to Zone J TCC. This reflects a shift in congestion from the Hudson Valley corridor to the Central-East interface relative to what market participants expected when the TCC auctions were held in the spring of 2007.

The pattern of congestion within New York City was significantly different between the TCC auctions and the day-ahead market. TCCs sourcing in the 345kV area of New York City and sinking at Zone J were generally over-valued. TCCs sourcing at Zone J and sinking in Astoria East (Astoria GT2/1) were priced consistent with the day-ahead congestion prices. However, TCCs sourcing at Zone J and sinking in Vernon/Greenwood (NYPA_Kent) and Greenwood/Staten Island (NYPA Pouch and Gowanus) were over-valued. It is likely that the mild summer weather and the new transmission capacity between New Jersey and Long Island led to less congestion in New York City than market participants anticipated in the TCC auction. However, there is no evidence that there are any impediments or other flaws that have contributed to the differences between the TCC prices and actual realized congestion.

VII. 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 2007. 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 meet demand and 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.[29] 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 gas turbine will be economic to start or when a generator should begin ramping in anticipation of a constraint in a future interval.

Second, the Real Time Commitment model ("RTC") executes every 15 minutes, looking across a two-and-a-half hour time horizon. RTC is primarily responsible for scheduling resources that are not flexible enough to be dispatched by RTD. RTC starts-up and shuts-down quick-start GTs and 30-minute GTs when it is economic to do so.[30] RTC also schedules bids and offers to export, import, and wheel-through power in the subsequent hour 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 an economic value for the reserves and regulation. This provides an efficient means of setting prices during shortage conditions. The use of demand curves during shortage conditions is discussed further in sub-section I.B.

Convergence between RTC and RTD is important because a lack of convergence can result in uneconomic commitment of generation, particularly of gas turbines, and inefficient scheduling of external transactions. When RTC commits or schedules excess resources, it 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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29 Quick-start GTs can start quickly enough to provide 10-minute non-synchronous reserves.

30 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 consistency between scheduling by RTC and actual real-time market outcomes.

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 ISO has made several improvements to the commitment process since 2004, which have helped improve the efficiency of decisions to start GTs. These improvements are discussed following the summary of our evaluation in Figure 40.

The following analysis measures the efficiency of GT commitment by comparing the offer price (energy plus start-up) 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 while the offer price components of off-line GTs are generally higher 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. Likewise, when the decision not to commit a GT is efficient, it is possible for the offer price components to be less than the LBMP. Thus, the following analysis tends to understate the fraction of decisions that were economic.

The left panel of Figure 40 shows the volume of gas turbines that were started between June and December from 2004 to 2007. These are broken into the following categories according to the sum of 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. The right panel of Figure 40 shows the quantity of gas turbines that were not started but most likely would been economic if they had been committed. These are off-line gas turbines with energy and start-up offers that were lower than the LBMP for the minimum commitment period of one hour.

Figure 40: Efficiency of Gas Turbine Commitment
June to December, 2004 to 2007

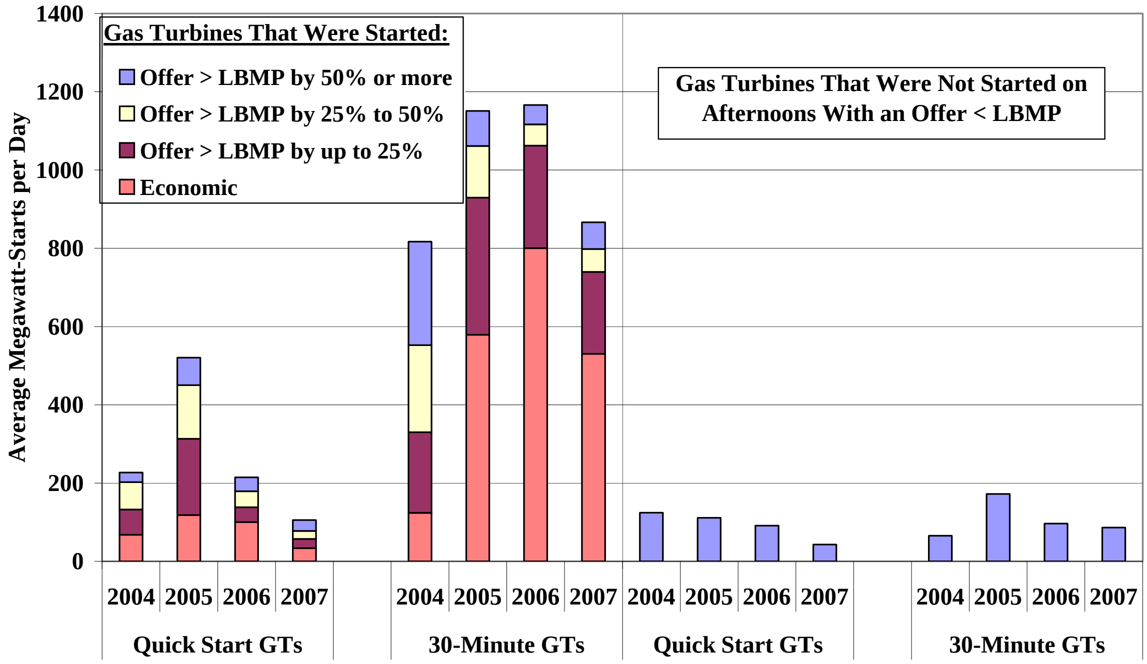


Figure 40 indicates that gas turbine commitment improved considerably from 2004 to 2006 and worsened slightly from 2006 to 2007. The share of gas turbine starts that were clearly economic rose from 18 percent in 2004 to 65 percent in 2006 and declined to 58 percent in 2007. To the extent that gas turbines were started when their offers were greater than the LBMP, the average margin between the offer and the LBMP exhibited a similar pattern. The fraction of gas turbine starts that occurred when the offer exceeded the LBMP by at least 25 percent improved from 55 percent in 2004 to 13 percent in 2006, but rose to 18 percent in 2007. The right panel of Figure 40 indicates that the average quantity of off-line gas turbines that would most likely have been economic if they had been started grew from 2004 to 2005, which is not surprising given that the higher loads and more frequent congestion led to a similar increase in the number of gas turbines that were started. From 2005 to 2007, the average quantity of off-line gas turbines that would most likely have been economic declined significantly.

Figure 40 shows that the most significant gains were in the efficiency of decisions to start 30-minute gas turbines. Prior to the implementation of SMD 2.0 in February 2005, these units were usually committed by the Balancing Market Evaluation ("BME"), which ran 75 minutes before the beginning of the hour that it was evaluating. The BME committed resources from the top of one hour to the top of the next hour and did not have the capability to start-up or shutdown a unit midway through the hour. Under SMD 2.0, RTC makes the decision to start these units 45 minutes before the time they are expected to reach full output. RTC repeats this evaluation every 15 minutes, while BME did so only once per hour.

The on-going improvements to RTC and RTD have also led to more efficient commitment of gas turbines. First, in August 2005, RTD was modified to allow it to start quick-start resources. Second, since May 2006, RTD and RTC sometimes rely on a detailed representation of transmission system in New York City rather than simplified interface constraints. 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. Third, discrepancies between RTC and RTD have likely been reduced by the changes made to improve the consistency between the physical and pricing passes of RTD.

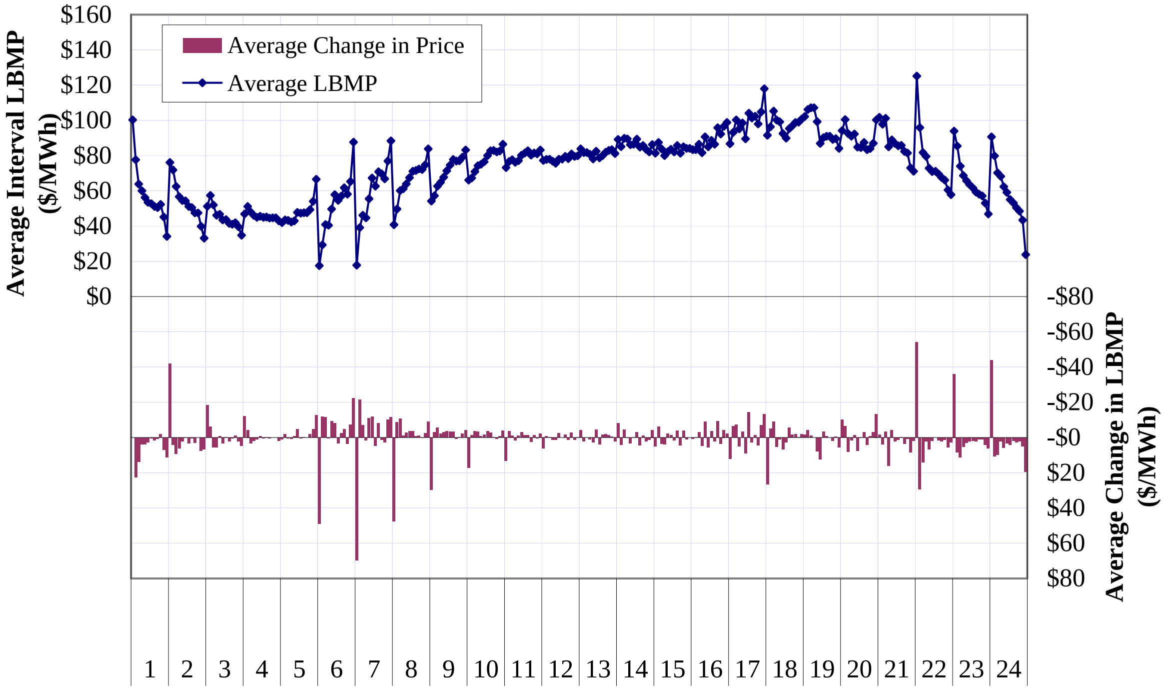
2. Real-Time Price Volatility

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 substantial excess, leading to very low or even negative prices. This part of the section evaluates patterns of price volatility in the real-time market.

Volatile real-time prices can be an efficient signal of the value of flexible generation. These signals give market participants incentives to invest in making their generators more flexible and to offer that flexibility into the real-time market. However, price volatility can also be a sign of inefficient market operations if generators are being cycled unnecessarily. Real-time price volatility also raises concerns because it increases risks for market participants, although market participants can hedge this risk by buying and selling in the day-ahead market and in the bilateral contract 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 that a substantial portion of the real-time price fluctuations occur based on the time of day. Figure 41 shows the average clearing price in each five-minute interval of the day in 2007. The data is shown for the Hudson Valley zone, although the results are similar in other zones.

Figure 41: Five Minute Pricing by Time of Day
Hudson Valley Zone, 2007



This figure shows that prices are generally more volatile at the top of the hour during ramp-up and ramp-down hours. In ramp-up hours, the clearing price tends to spike up in the last five-minute interval of the hour and to spike down in the first five-minute interval of the hour. The opposite pattern is observed in ramp-down hours. 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. In other words, system conditions change more quickly than generators are able to adjust their output.

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 and/or regulation.

RTC and RTD are designed to look beyond the next scheduling interval to recognize needs in future periods. This enables RTC and RTD to commit resources and/or begin ramping online units in anticipation of a future need when it is economic. In this regard, it is important for RTC and RTD to use accurate assumptions to schedule efficiently. The next sub-section compares RTC and RTD scheduling to identify factors that contribute to real-time price volatility.

3. Comparison of RTC and RTD Prices

Real-time scheduling is accomplished by two models: RTD and RTC. 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.

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. This part of the section examines the overall consistency between RTC and RTD prices. The following two analyses highlight three factors that contribute to systematic differences between RTC and RTD prices, and also contribute to real-time price volatility.

The first figure shows the differences between RTC and RTD in (i) the quantity of load that is scheduled, (ii) the amount of net exports that is forecasted, and (iii) the state-wide average clearing price. Loads and net exports are inputs that jointly determine the quantity of internal resources that must be scheduled by RTC and RTD. Thus, the figure indicates that differences between RTC and RTD in the amounts of load and net exports contribute to different prices. The second figure compares differences between the load forecasts used by RTC and RTD to the net estimated regulation deployment by time of day. The operators reduce the need for regulation deployment by making incremental adjustments to the load forecast that compensate for under-production or over-production by generators. To the extent these adjustments are determined after RTC executes, it will lead to over-scheduling or under-scheduling by RTC relative to RTD. At the end of this section, we discuss several recommendations that could reduce systematic differences between RTC and RTD.

Figure 42 compares several quantities from RTC and RTD by time of day during the summer of 2007. In particular, it compares the amount of scheduled load, the level of net exports, and energy prices in RTC and RTD. Each RTC execution optimizes across ten 15-minute intervals, and therefore, produces ten sets of advisory clearing prices. The figure compares energy prices from the first of the ten periods (the one closest to the time RTC executes) to the real-time energy prices produced by RTD.

Figure 42: Prices, Loads, and Net Exports in RTC and RTD
June to August 2007

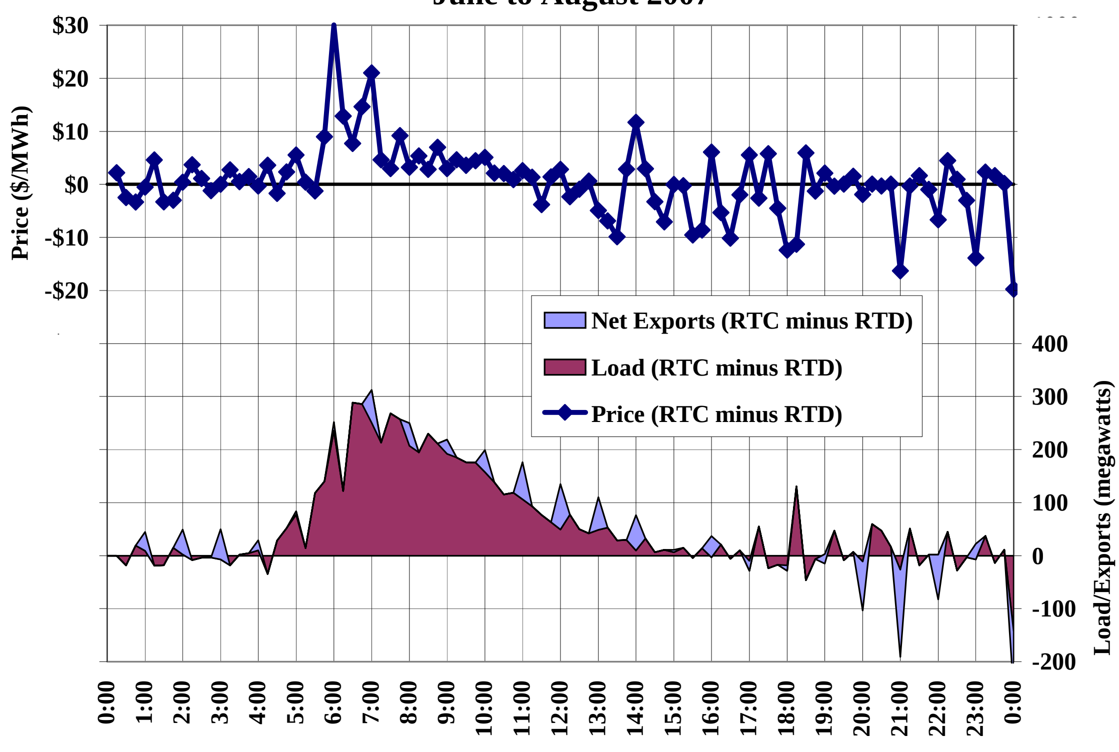


Figure 42 indicates that some systematic differences between RTC and RTD prices are correlated with differences between RTC and RTD values of load and net exports. Such differences can lead to either uneconomic commitments or unnecessary transient price spikes. There are at least two factors that lead to systematic differences between RTC and RTD. First, 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.

Second, systematic differences between RTC and RTD prices tend to be larger at the top of each hour (i.e, at :00) than in the middle of the hour (i.e., at :15, :30, or :45). These are partly driven by different assumptions that RTC and RTD use regarding the level of exports. 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), whereas RTC assumes that each interface meets the next hour schedule at the top of the hour (i.e., at :00). 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. RTD will assume that net exports are 200 MW at 8:55, 500 MW at 9:00, and 800 MW at 9:05. RTC will assume that net exports are 800 MW at 9:00.[31] Hence, when net exports increase from the previous hour, RTC will over-schedule generation. When net exports decrease from the previous hour, RTC will under-schedule generation.

The next analysis examines the relationship between regulation deployments and differences between the load forecasts used in RTC and RTD. To minimize regulation deployment, the operators make incremental adjustments to the real-time load forecast. When generators under-produce in real-time, the operator can compensate by raising the load forecast. Likewise, when generators over-produce in real-time, the operator can compensate by lowering the load forecast. These adjustments enable the NYISO to reduce regulation requirements, leading to lower

31 In January 2008, the NYISO changed RTC to assume the interface is halfway between its previous hour and next hour schedule at the top of the hour. This change results in the same schedule for RTC and RTD at the top of the hour. However, inconsistencies still arise since RTD assumes a constant ramp rate from :55 to :05 while RTC assumes a constant ramp rate from :45 to :15.

regulation procurement costs. Reduced deployment of regulation will also result in less out-of-merit generation. However, RTC looks further into the future than RTD, so adjustments to the load forecast are reflected "sooner" in RTD than in RTC. Such differences can lead to RTC over-schedule or under-schedule relative to RTD.

The following figure compares differences between the load forecasts used by RTC and RTD to the net estimated regulation deployment by time of day during the summer of 2007. In the figure, positive values of regulation deployment indicate when supply is insufficient (e.g. generators are under-producing), while negative values of regulation deployment indicate when there is excess supply (e.g. generators are over-producing). Positive values of load forecast differences indicate that the RTD load forecast was higher while negative values indicate that the RTD load forecast was lower.

Figure 43: Regulation Deployment and Load Forecasts Used in RTC and RTD by Time of Day, June to August 2007

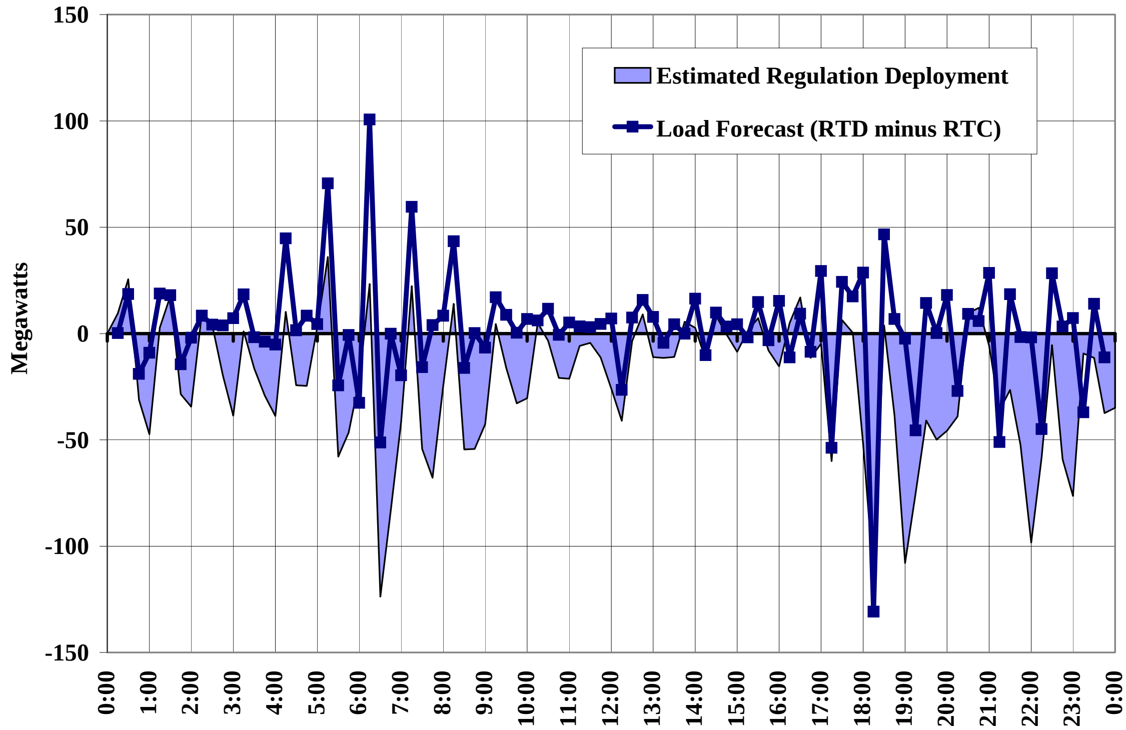


Figure 43 shows a strong correlation between variations in regulation deployment and the difference between the load forecasts used by RTD and RTC. For example, from 5:00 to 5:15, regulating units are usually being instructed to increase output. At the same time, the difference between the RTD load forecast and the RTC load forecast shifts in the positive direction. The additional load scheduled by RTD reduces the amount of regulation that must ultimately be deployed. The consistency of the pattern in the figure above suggests that some regulation deployments may be predictable when RTC executes. If this is the case, allowing the operator to make adjustments to the load forecast used by RTC would reduce differences between RTC and RTD.

The analyses in this section identify three factors that undermine convergence during ramping hours. First, 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. Second, RTC and RTD use different assumptions about the level of net exports. RTD assumes that each interface “ramps” at a constant rate from five minutes before the top of the hour to five minutes after, whereas RTC assumes that each interface meets the next hour schedule at the top of the hour. Third, the load forecast is adjusted in real-time to reduce the need for regulation deployment, which results in differences between RTC and RTD load.

To reduce systematic differences between RTC and RTD, we recommend the NYISO evaluate whether:

- There is an alternative to RTC using the highest of three five-minute load forecasts;
- The assumptions about external transaction ramp can be made more consistent to eliminate differences at the top of each hour; and
  - In January 2008, the NYISO changed RTC to assume the interface is halfway between its previous hour and next hour schedule at the top of the hour. This should reduce the inconsistency.
  - However, a fundamental inconsistency remains because RTD assumes each interface ramps at a constant rate for 10 minutes from minute :55 to :05, while RTC assumes that each interface ramps at a constant rate for 30 minutes from minute :45 to :15.
- Predictable adjustments to the RTD load forecast, which are made to minimize regulation deployment, can be reflected more quickly in the RTC load forecast.

The consistency of ramp assumptions in RTC and RTD can be improved, particularly at the top of the hour, when changes in hourly schedules or the commitment and decommitment of generating units normally occur. We plan to do a more complete assessment of factors that undermine consistency between RTC and RTD and that contribute to unnecessary real-time price volatility.

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.

This section evaluates real-time prices during three types of shortage conditions:

- *Operating reserve shortages* – We evaluate the consistency between real-time reserve prices and the availability of 10-minute reserves in eastern New York. We also examine factors that lead to inconsistencies between clearing prices and the adequacy of reserves in the real-time market.
- *Transmission constraint violations* – Market rule changes have reduced unnecessary costs that arise during periods of extremely scarce transmission capability. They have also increased real-time price certainty by reducing the frequency of price corrections.
- *Demand response activations* – Market rule changes have reduced the amount of uneconomic demand response that is activated during reliability events.

The importance of setting efficient real-time price signals during shortages of operating reserves was recently affirmed by FERC in its Notice of Proposed Rule-Making ("NOPR"). The NOPR 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 reserves shortages.[32] Second, the NYISO allows demand response resources to set clearing prices when an operating reserve shortage is avoided by the activation of demand response.[33]

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[32] See P. 125. Wholesale Competition in Regions with Organized Electric Markets, 122 FERC ¶ 61,167 (2008) ("NOPR").

[33] Id., P. 45.

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 relatively 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.[34] However, the NYISO has made several improvements to the market software to address the lack of consistency between the physical dispatch and pricing dispatch, which led to much more consistent results during 2006.[35] The analyses in this section continue to examine the occurrences of such inconsistencies during 2007.

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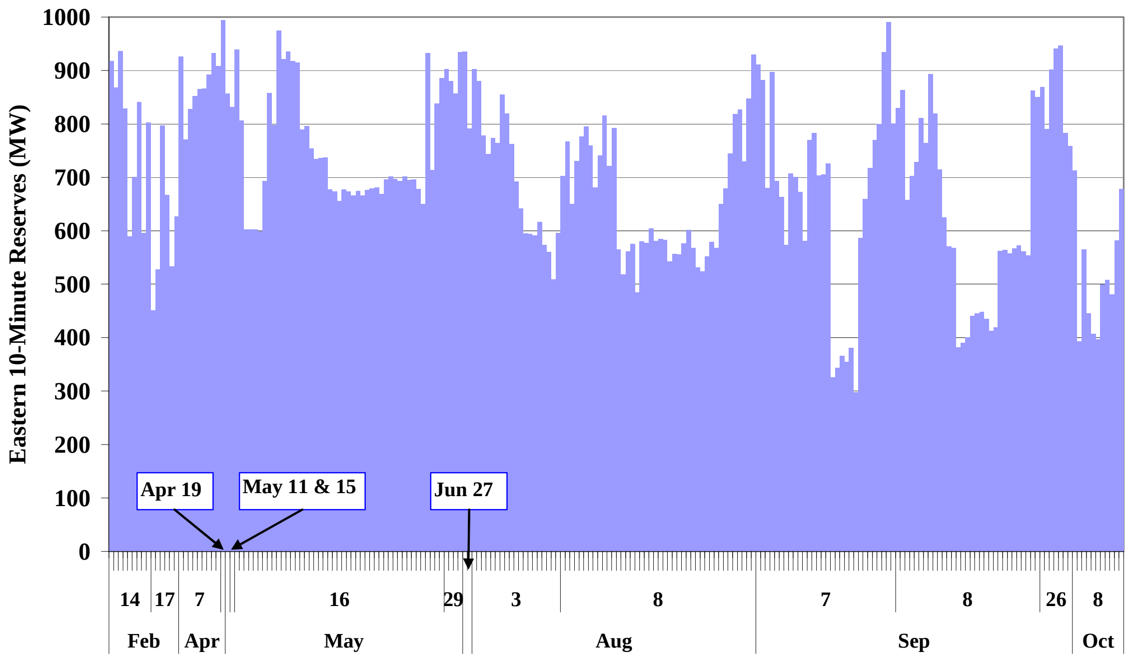
34 See *2005 State of the Market Report, New York ISO,* August 2006, Potomac Economics.

35 See *2006 State of the Market Report, New York ISO,* July 2007, Potomac Economics.

The first analysis in this section assesses whether shortage prices have only been set when the system was physically short of a key reserves requirement. Figure 44 shows the amount of Eastern 10-minute reserves that were physically scheduled during shortage pricing intervals in 2007.

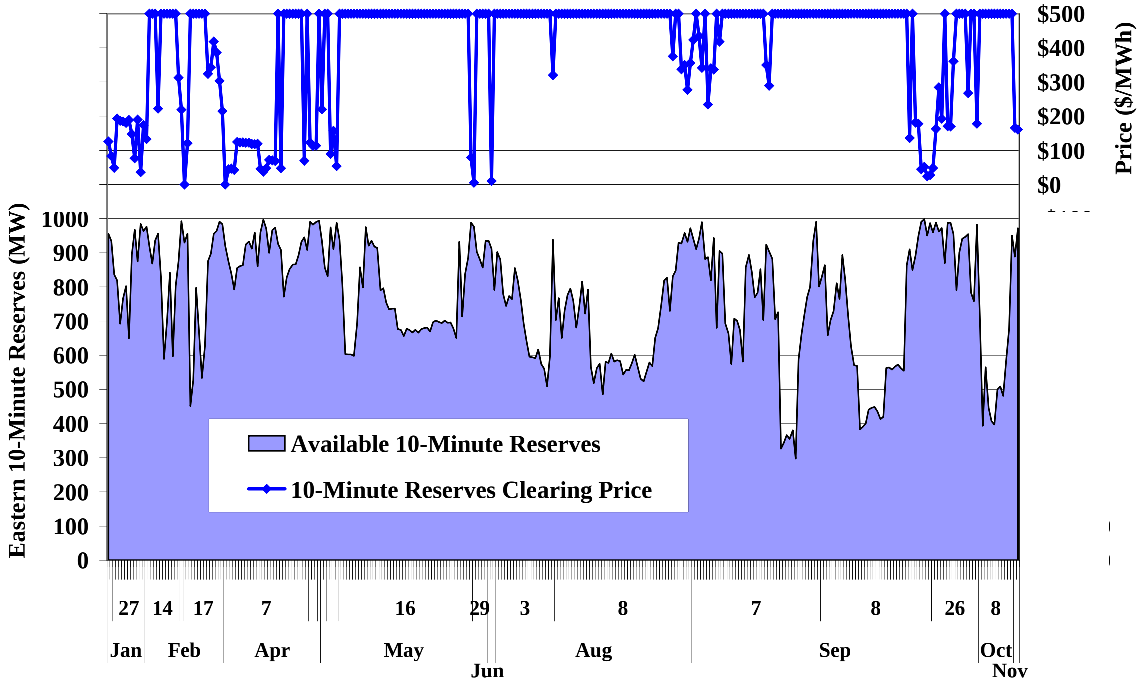
Figure 44: Scheduling of 10-Minute Reserves in East New York During Shortage Pricing Intervals, 2007



The figure shows 219 intervals with shortage pricing of Eastern 10-minute reserves, which is a decline from 376 such intervals in 2006. The lower frequency is primarily due to milder summer load conditions in 2007. There were 326 intervals in the summer of 2006 when shortage pricing was invoked, compared to 63 intervals in the summer of 2007 due to the milder weather. There has been significant improvement in the consistency between pricing and physical dispatch passes of RTD during shortage pricing intervals since 2005. The figure shows that eastern New York was in a physical shortage in 100 percent of the shortage pricing intervals in 2007, which is an improvement from 89 percent in 2005 and 96 percent in 2006. The results indicate that all shortage pricing intervals associated with the Eastern 10-minute reserves requirement occurred during authentic periods of physical shortage in 2007.

The second analysis in this section assesses how frequently physical shortages of Eastern 10-minute reserves are accompanied by shortage prices. The following figure shows the real-time price and quantity of available Eastern 10-minute reserves during physical shortages of Eastern 10-minute reserves. In the figure, the line indicates the Eastern 10-minute reserve clearing prices, while the area shows the quantity of available reserves.

Figure 45: Scheduling and Pricing of 10-Minute Reserves in East New York During Physical Shortage Intervals, 2007



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

Figure 45 shows that 88 (or 28 percent) of the intervals with physical shortages were not accompanied by shortage pricing in 2007. In these intervals, the Eastern 10-minute reserve prices averaged $174/MWh and the shortage quantity was less than 100 MW 73 percent of the time. In 2007, the consistency between the pricing dispatch and the physical dispatch passes of RTD during Eastern 10-minute reserve shortage periods declined slightly from 2006 but was still much better than 2005. In 2005, 50 percent of the intervals with physical shortages were not accompanied by Eastern 10-minute reserves shortage pricing. In 2006, only 19 percent of the intervals with physical shortages were not accompanied by Eastern 10-minute reserve shortage pricing.

Prior to the summer of 2006, two software changes were made that better enable the real-time market model to set efficient clearing prices. First, in mid-August 2005, enhancements were made to allow RTD to consider off-line quick-start gas turbines in the co-optimization of energy and 10-minute non-spinning reserves. Second, in May 2006, a change was made to eliminate inconsistencies between the physical and pricing passes of RTD that arise when the capability of gas turbines is reduced by high ambient temperature conditions.

The efficiency of real-time energy and ancillary services pricing was greatly improved in 2005 by the co-optimization of energy and ancillary services scheduling and by the use of operating reserve demand curves. Additionally, the software changes made prior to the summer of 2006 substantially improved the efficiency of real-time prices during operating reserve shortages. However, a significant number of intervals remain when there are physical reserve shortages that are not reflected in reserve clearing prices. The following discussion of Hybrid Pricing explains factors that contribute to the inconsistencies.

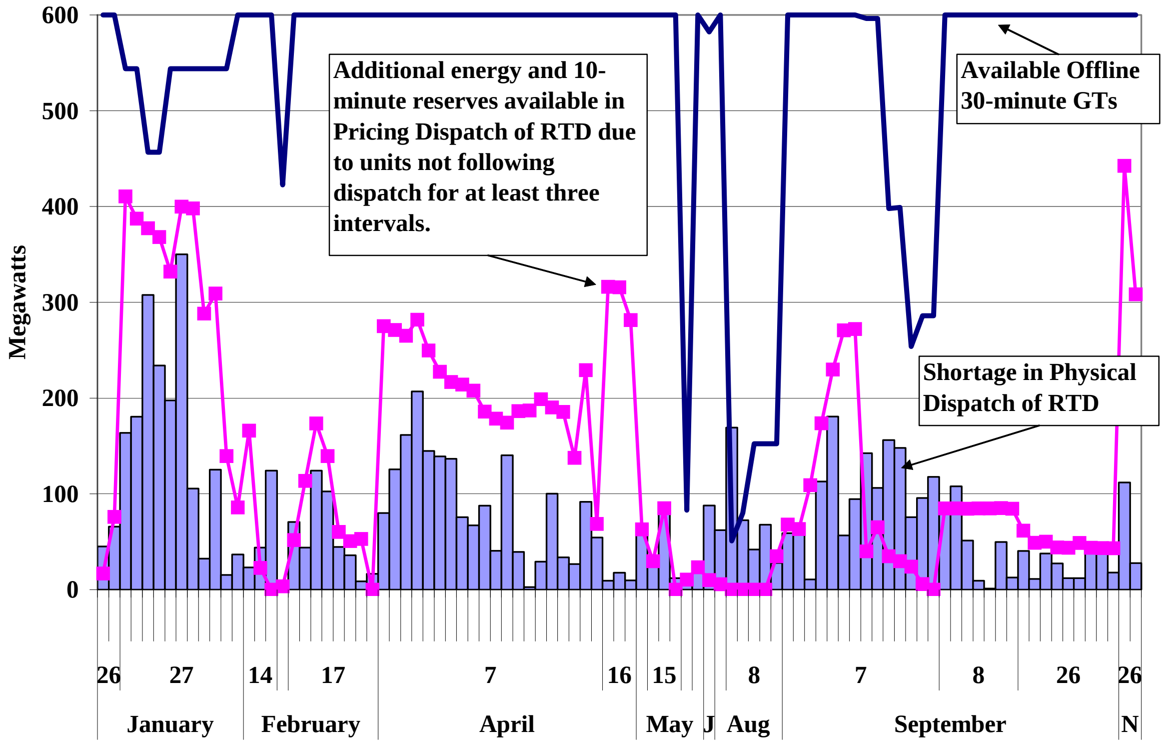
Hybrid Pricing

Hybrid Pricing was designed to address the problems posed by 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 46 summarizes the potential effect of units persistently not following dispatch instructions on Eastern 10-minute reserves prices during the 93 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. The quantity exceeding 600 MW is shown as 600 MW in the figure.

Figure 46: Impact of Units Not Following Dispatch Instructions Shortage Intervals Without Shortage Pricing, 2007



The figure above shows that 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 66 of the 93 intervals shown and in 21 of the 29 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 but one 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 pass and the physical dispatch pass of RTD are necessary for the Hybrid Pricing methodology. 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 and physical dispatches of RTD should lead to more efficient pricing of energy and ancillary services, particularly during shortages. Comparable improvements in RTC will likely result in fewer physical shortages in real-time market because RTC will be more likely to start 30-minute gas turbines in anticipation of a shortage. To address the inconsistencies that arise when generators do not follow dispatch instructions, we recommend the NYISO consider re-calibrating the output and/or ramp limits in the pricing dispatch for such units.

2. Real Time Pricing During Transmission Scarcity

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

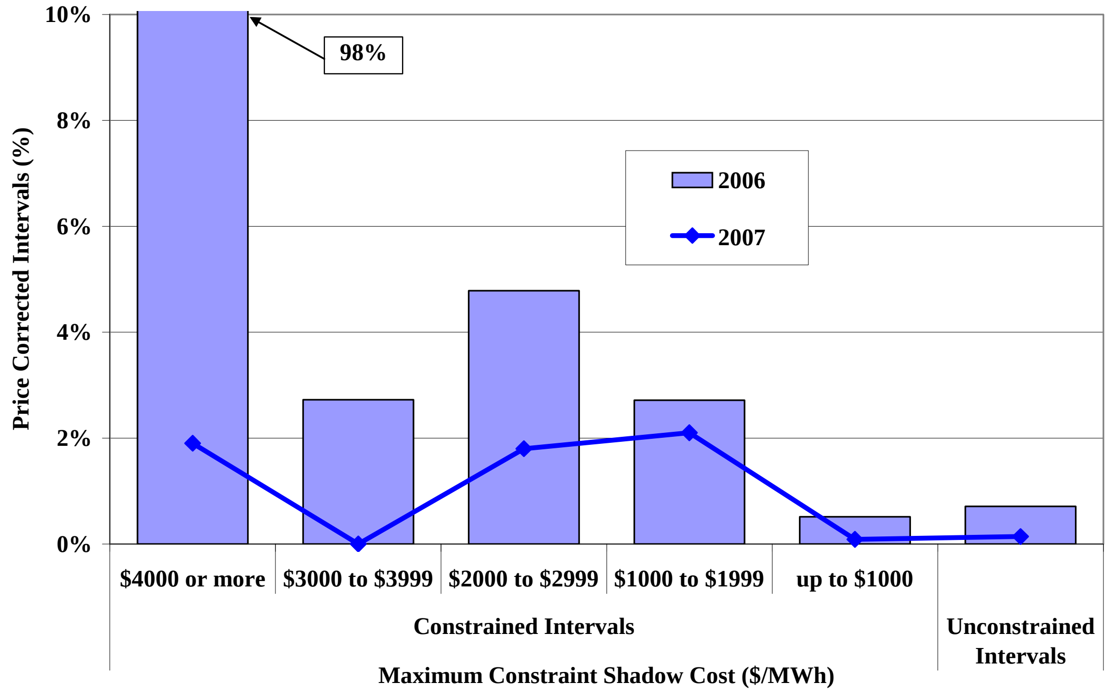
Shadow prices of transmission constraints can spike to extraordinary levels for brief periods when there is not sufficient ramp capability within a transmission-constrained area. When only remote generators are available to be re-dispatched, large amounts of generation may be re-dispatched at a high cost, providing very little relief of the transmission constraint. Relieving the transmission constraint by re-dispatching hundreds of megawatts 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/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.

The following figure evaluates the rate of price corrections in intervals when marginal re-dispatch costs reach high levels. The figure compares the rate of price corrections before and after the shadow cost limit was implemented in June 2007.

Figure 47: Price Correction Frequency by Shadow Price
June to December, 2006-2007



The rate of price corrections decreased considerably from 2006 to 2007. During intervals when transmission shadow costs were below $4,000/MWh (including unconstrained intervals), the rate of price corrections was relatively small in both 2006 and 2007. The majority were due to reasons such as data error or software failure. During intervals when transmission constraint shadow costs were $4,000/MWh or more, the rate of price corrections declined from 98 percent in 2006 to 2 percent in 2007. There were 205 such intervals from June to December 2006 and 98 such intervals for the same months in 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 should not undermine reliability since re-dispatch usually provides little or no reliability benefit when shadow costs exceed $4,000/MWh. We will continue to evaluate the efficiency of congestion management and pricing under the new methodology, including the appropriateness of the $4,000/MWh limit.

3. Demand Response and Shortage Pricing

The NYISO has two real-time demand response programs: the Special Case Resource (“SCR”) program and the Emergency Demand Response Program (“EDRP”). When the ISO anticipates reserve shortages on the bulk power system, the ISO can activate SCR and EDRP resources to curtail. Local transmission owners can also activate SCR and EDRP resources when they anticipate reliability issues on their local system. Operators must give such resources advanced notice of at least two hours and if they curtail resources, it must be for no less than four hours.[36] The EDRP and SCR programs, which have a total registration of approximately 1,600 MW of resources, have been effective in achieving actual load reductions during peak conditions.

When called upon, EDRP resources are paid the higher of $500/MWh or the clearing price. SCR resources are paid the higher of their strike price, which is typically $500/MWh, or the clearing price. In an efficient market, clearing prices should reflect the cost of deploying resources to meet 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. 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/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 have improved 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/MWh within the region (unless they already exceed that level). This rule helps reflect in real-time clearing prices the cost of

[36] On the previous day, the NYISO must notify demand response resources that they might be called.

maintaining adequate reserve levels. The FERC's NOPR recently identified this provision as a way to improve the efficiency of real-time prices during shortage conditions. [37]

Second, to further 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. [38] 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.

TDRP resources were activated twice during the summer of 2007 to address local issues in New York City load pockets. The ability to activate TDRP resources greatly reduced the inefficiencies of "out-of-merit" demand response resources by limiting curtailment to the affected area. On July 19, approximately 10 percent of the resources in New York City were activated, and, on August 3, approximately 15 percent of the resources in New York City were activated. Previously, the operators would have activated all of the resources in the New York City zone, which would have resulted in far more "out-of-merit" resources.

The growth of demand response is a positive development that reduces the cost of operating the system reliably, particularly during peak periods. However, it is challenging to set efficient prices during periods when demand response resources are activated. The New York market has two rules that reduce the incidence of "out-of-merit" demand response. These rules encourage demand response participation and preserve the incentives of suppliers to satisfy the needs of the system during peak operating conditions. In the future, the wholesale market is likely to rely on demand response resources to greater extent, making it essential for the NYISO to develop additional mechanisms for demand response resources to set clearing prices efficiently. Hence,

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[37] See P. 45. Wholesale Competition in Regions with Organized Electric Markets, 122 FERC ¶ 61,167 (2008) ("NOPR").

[38] See NYISO Technical Bulletin *TB164 – Targeted Zone J Demand Response*. TDRP resources are simply EDRP and SCR resources that choose to participate. In NYC, there are currently nine distinct local areas where TDRPs can be called.

we recommend the NYISO consider the development of rules to enable demand response resources to set prices in local areas when they are needed to avoid a local shortage.

C. Supplemental Commitment for Reliability

When the wholesale market does not meet all forecasted load and reliability requirements, the NYISO and/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 48 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 market and the real-time market. 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/or 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.

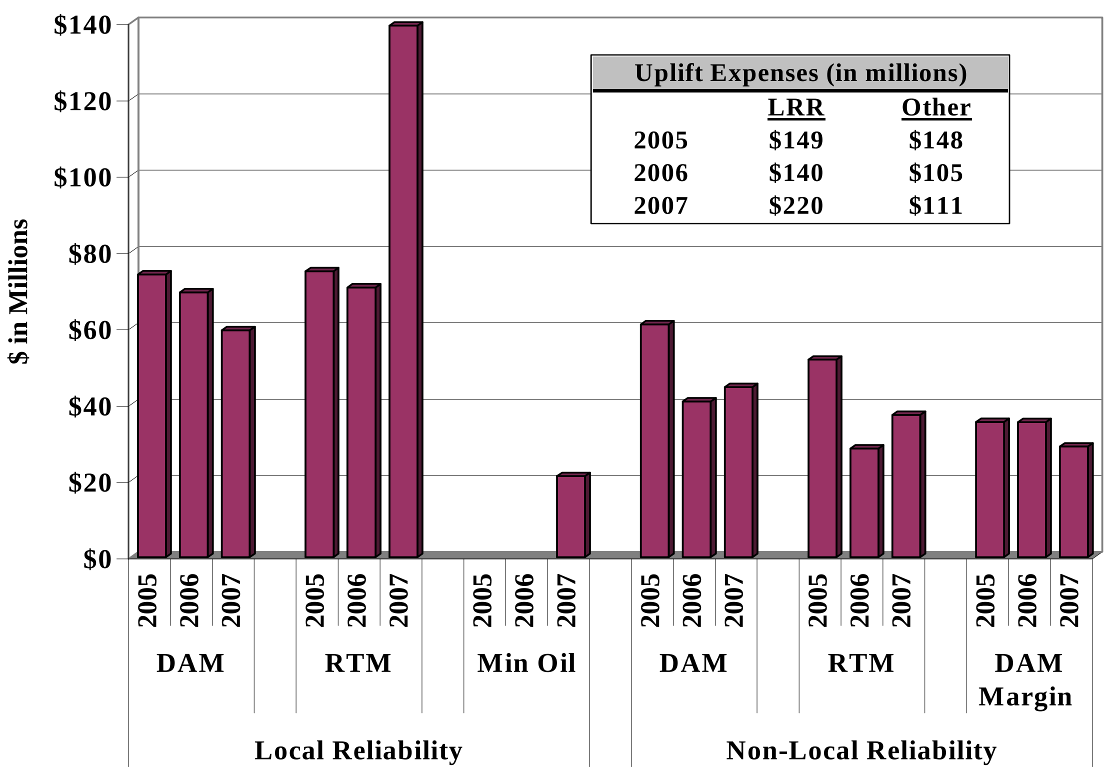
- *Minimum Oil Burn* – Guarantee payments are made to generators that burn fuel oil to help maintain reliability in the ConEd territory because of the potential for natural gas supply disruptions.

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 48 for 2005 to 2007.

Figure 48: Uplift Expenses from Guarantee Payments 2005 – 2007



Local reliability uplift charges increased $80 million from 2006 to 2007, primarily from the rise in real-time guarantee payment uplift, but also from the charges resulting from the Minimum Oil Burn program. Real-time guarantee payment uplift doubled as a result of a 75 percent increase in the amount of SRE committed capacity 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.

Non-local reliability uplift did not change significantly in 2007 after dropping substantially from 2005 to 2006. Natural gas price fluctuations contributed to the substantial decline in uplift from 2005 to 2006 and the modest rise from 2006 to 2007. Improvements to the efficiency of gas turbine commitment in late 2005 and early 2006 contributed substantially to the decline in real-time uplift charges from 2005 to 2006.[39]

Overall, total expenses for guarantee payments increased substantially from 2006 to 2007 due 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: 1) local reliability commitment by the day-ahead model, which takes place during the day-ahead market process; and 2) SRE commitment, which occurs after the day-ahead market closes. The day-ahead local reliability commitment is an element of the SCUC market

[39] These improvements are discussed in Part A.1 of this section.

process whereby units that are not committed economically may be committed to meet certain 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.

When the operators undertake SRE commitments, these actions are logged and reported on the NYISO website. Such supplemental commitments do not directly affect the day-ahead prices. 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 tends to reduce real-time prices. Due to the price-effects of out-of-merit capacity, it is important to evaluate the SRE process. Figure 49 shows the average quantity of SRE commitments made from 2004 to 2007 in New York City, Long Island, and upstate New York.

Figure 49: Supplemental Resource Evaluation
2004 – 2007

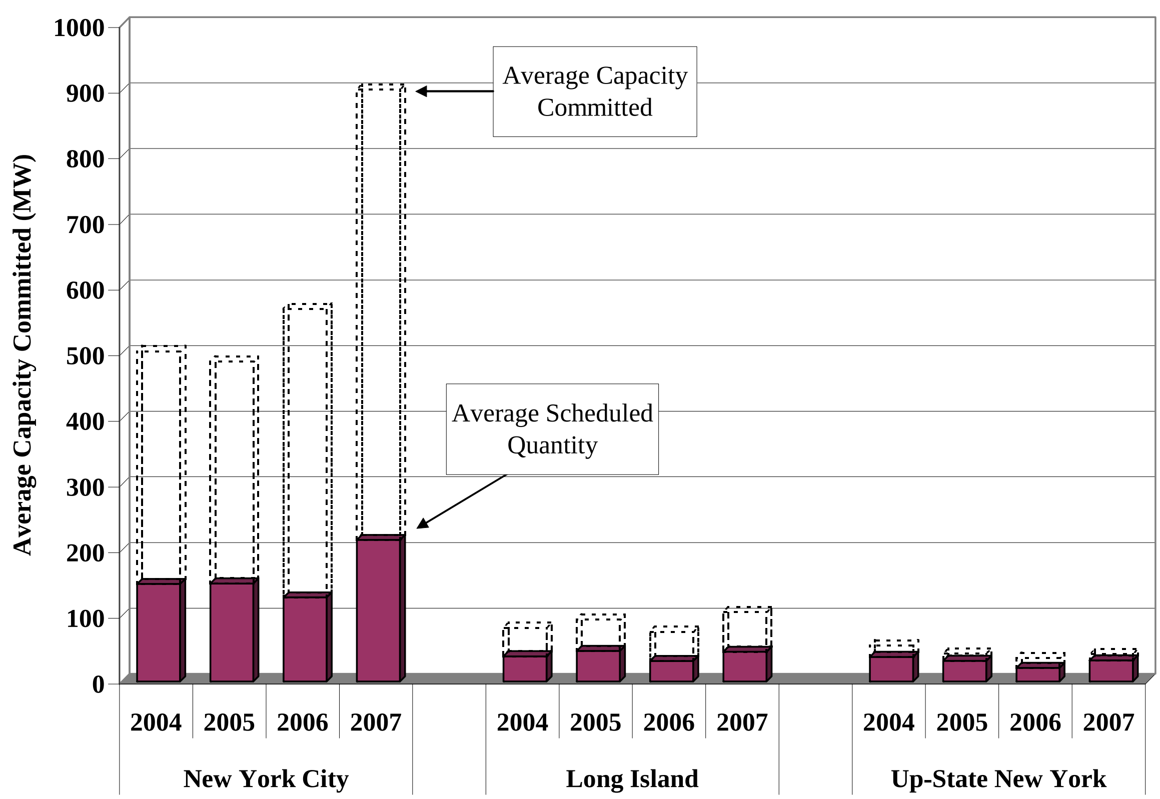


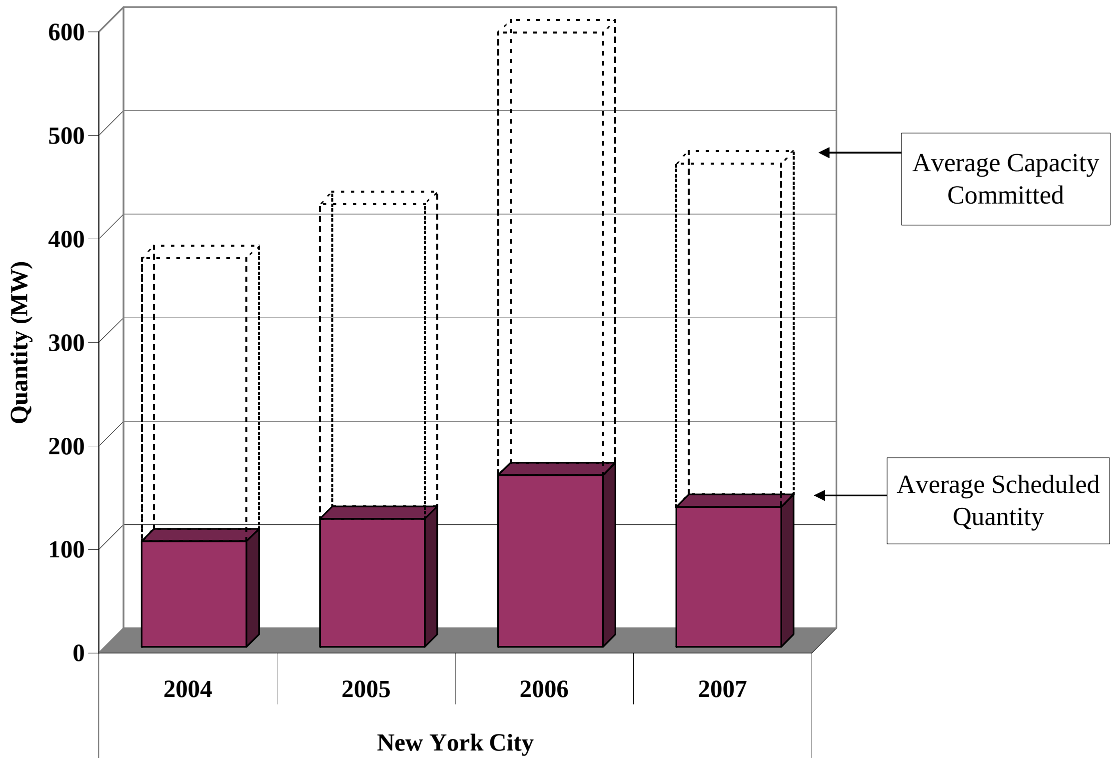
Figure 49 indicates that the majority of SRE committed capacity was in New York City, while 15 to 20 percent of SRE committed capacity was in Long Island and Up-State New York. Over the past four years, the commitment pattern in Long Island and Up-State New York remained relatively unchanged. In New York City, however, the average quantity of capacity committed through the SRE process increased by approximately 75 percent in 2007. The increased need for SREs was partly due to reduced economic commitment of oil-fired generators that are needed for local reliability.

The figure also shows that most of the units committed through the SRE process were dispatched at close to their minimum generation levels (i.e., 25 to 35 percent of the maximum capacity). In 2007, nearly 900 MW of capacity was committed in New York City, but only 215 MW of additional energy per hour was produced due to these commitments on average. These units also provided substantial quantities of 10-minute and 30-minute reserves. To the extent that SRE resources are not fully scheduled in the real-time market, it reduces the effects on the markets.

The next analysis focuses on commitments made in the day-ahead market (i.e., by SCUC) to meet local reliability requirements. These commitments are generally not economic at day-ahead market prices. They affect the market because: 1) they reduce prices from levels that could result from a purely economic dispatch; and 2) they can increase non-local reliability uplift since a portion of the uplift caused by these commitments is incurred to market guarantee payments to other generators that will not cover their as-bid costs at the reduced prices. Figure 50 shows the average capacity committed in the day-ahead market for local reliability and the day-ahead scheduled quantity from 2004 to 2007.

The figure shows that the average capacity committed for local reliability was 470 MW for the period shown in 2007, which is a substantial decrease from 2006. 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 140 MW in 2007. The amount of capacity committed for local reliability in the day-ahead market declined significantly from 2006 to 2007, although this was more than offset by the increased SRE commitment.

Figure 50: SCUC Local Reliability Pass Commitment 2004 – 2007



Supplemental commitments have been rising for several years. The average amount of capacity committed for local reliability in New York City exceeded 1300 MW in 2007. It would be more efficient for these units to be committed before or within the economic pass of day-ahead market model. Committing additional units after the economic pass of the day-ahead market model causes some economically committed units to no longer be economic. This leads to excess capacity, lower clearing prices, and additional uplift.

3. Conclusion

Supplemental commitments have significant market effects. Most importantly, they inefficiently reduce prices in both the day-ahead market and real-time market. When this occurs in a constrained area, it inefficiently dampens the apparent congestion into the area. Supplemental commitments also increase non-local reliability uplift payments, because generators committed based on economic criteria are less likely to recover their full offer production costs in the spot market.

To minimize the negative effects on the market from supplemental commitment for local reliability, the NYISO plans to incorporate local reliability constraints that require supplemental commitments into the initial economic commitment pass of SCUC. This enhancement, which is planned for fall 2008, will enable the ISO to maintain reliability, while substantially reducing the negative effects from local reliability commitment. Hence, we support the NYISO's efforts to implement this change in 2008.

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 its recent Notice of Proposed Rule-Making, the FERC recognized the NYISO's leadership in this aspect of market design.[40] This part of the section summarizes the conclusions and recommendations from our evaluation of market operations in 2007.

In this section, we evaluate the efficiency of gas turbine commitment, which is important because excess commitment results in understated real-time prices and higher uplift costs, while under-commitment leads to unnecessary price spikes. This is particularly important in New York City and Long Island where gas turbines account for nearly 30 percent of the installed capability. We find that the portion of GTs were committed economically have increased substantially over the past 3 years, although it declined slightly in 2007.

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. Price volatility can be an efficient signal of the value of flexible resources, but unnecessary volatility imposes excessive costs on market participants. We identify several inconsistencies between RTC and RTD that likely contribute to

[40] See P. 45 and 125. Wholesale Competition in Regions with Organized Electric Markets, 122 FERC ¶ 61,167 (2008) ("NOPR").

the volatility of real-time prices, however, a more complete evaluation is necessary to more fully identify the causes of volatility.

- Hence, we recommend that the NYISO evaluate potential changes to the Real-Time Commitment ("RTC") and the Real-Time Dispatch ("RTD") models to make them more consistent and to improve the management of ramp capability at the top of the hour.

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 during shortage conditions. In this section, we evaluate market operations during three types of shortages: (i) operating reserve shortages, (ii) transmission constraint violations, and (iii) emergency demand response activations. Reserve shortage pricing occurred in 72 percent of the periods with physical shortages of eastern 10-minute reserves. Transmission constraint modeling improvements have greatly improved price-certainty in import-constrained areas during periods when transmission limits are violated. The new Targeted Demand Response Program ("TDRP") dramatically reduced the amount of uneconomic demand response that was activated for the reliability of the local distribution system.

- To improve real-time pricing during periods with operating reserve shortages, we recommend that the NYISO re-calibrate the dispatch levels in the real-time market's pricing model for generators that are not responding to dispatch signals.
- To improve real-time pricing when emergency demand response is activated, we recommend that the NYISO evaluate whether it is feasible to enable the NYISO Reliability-Based Demand Response resources to set clearing prices in local areas when they are needed to maintain transmission system reliability.

Uplift charges accrue when the NYISO gives guarantee payments to generators that do not fully recoup their operating costs from the day-ahead or real-time market. In 2007, $220 million was paid for local reliability uplift and $111 million was paid for non-local reliability uplift. Non-local reliability uplift has declined in recent years due to several market design enhancements, while local reliability uplift has increased due to more frequent commitment for local reliability. To minimize the negative effects of local reliability requirements on the overall market, it is important to satisfy the reliability requirements as efficiently as possible.

- Hence, we support the NYISO's plan to incorporate local reliability constraints that require supplemental commitments into the initial economic commitment pass of the day-ahead market.

VIII. 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.[41] 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.[42] Since the NYISO operates an Unforced Capacity ("UCAP") market, the ICAP requirements are translated into UCAP requirements, using location-wide forced outage rates.[43] The obligations to satisfy the

41 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 declined to 16.5 percent. For the period from May 2008 to April 2009, the IRM declined to 15 percent.

42 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.

43 Capacity payments are made for UCAP, which is a measure of resource availability adjusted to reflect forced outages. 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.[44]

B. Capacity Market Results

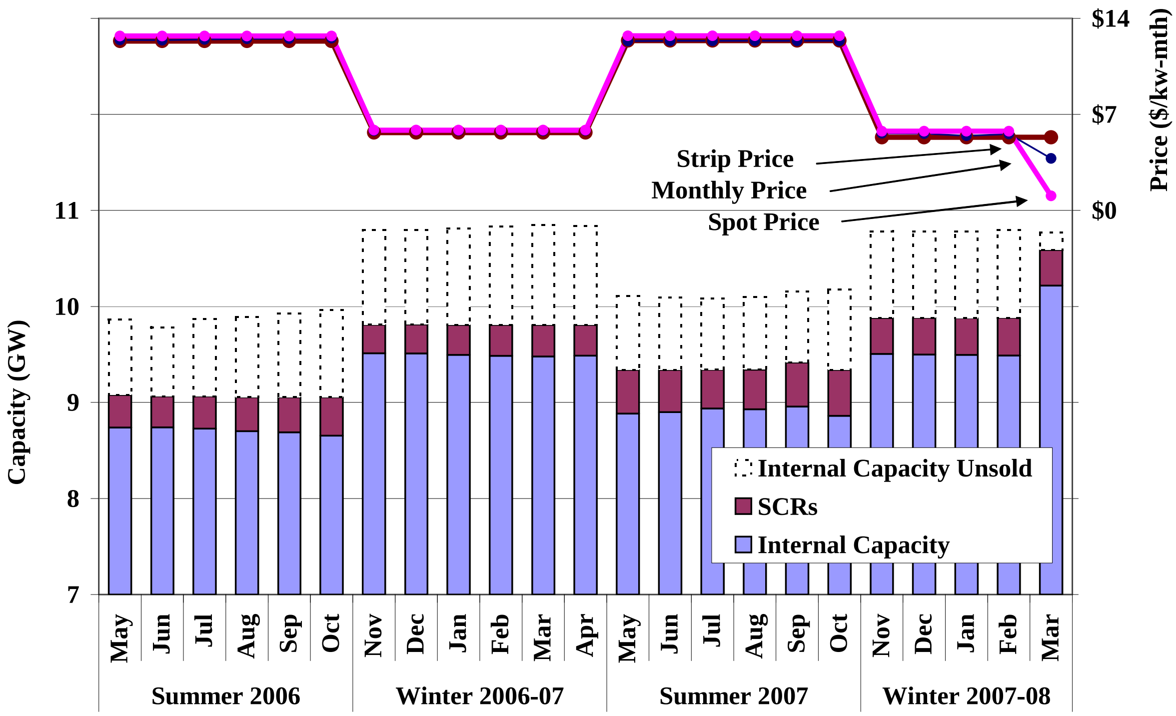
To evaluate the performance of the capacity market, the following three figures show capacity market results from May 2006 through March 2008. This includes four six-month capability

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

periods from the Summer 2006 capability period through the Winter 2007-08 capability period (excluding April 2008). 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 51 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 51: Capacity Market Results for New York City
May 2006 to March 2008



Before March 2008, seasonal variations in capability accounted for most of the changes in the clearing prices and quantities sold in New York City. Clearing prices were near $6/kW-month in the winter capability periods and $12/kW-month in the summer capability periods. The clearing prices were close to the revenue caps imposed on the Divested Generation Owners ("DGOs") that purchased the capacity from ConEd when it was required to divest most of its generation in 1998.

This pattern persisted even after a surplus emerged in New York City when approximately 1000 MW were added in 2006. Prices remained near the revenue caps because a significant amount of existing capacity was not sold in the UCAP market due to the suppliers' offer prices.[45] Since the unsold capacity participated in the energy market, significant competitive concerns were raised regarding the highly concentrated New York City capacity market.

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 expected 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. These measures will have been implemented in 2008, and we plan to evaluate their effectiveness in subsequent reports.

In March 2008, the amount of unsold capacity in New York City was virtually eliminated.[46] As a result, the New York City spot auction price dropped from $5.77/kW-month in February 2008 to $1.05/kW-month in March 2008, which was the same as the Rest-of-State clearing price. This happens when sufficient capacity is sold in New York City at the Rest-of-State clearing price, and no additional sales are required at that clearing price to satisfy the quantity for New York City. Hence, the increased sales had a dramatic effect on the auction clearing price in New York City, and the increased sales have continued into the summer months.

The following figure shows the amount of resources on Long Island that are available to provide UCAP, the amounts actually scheduled, and the UCAP prices that cleared in the NYISO-run spot 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 period.

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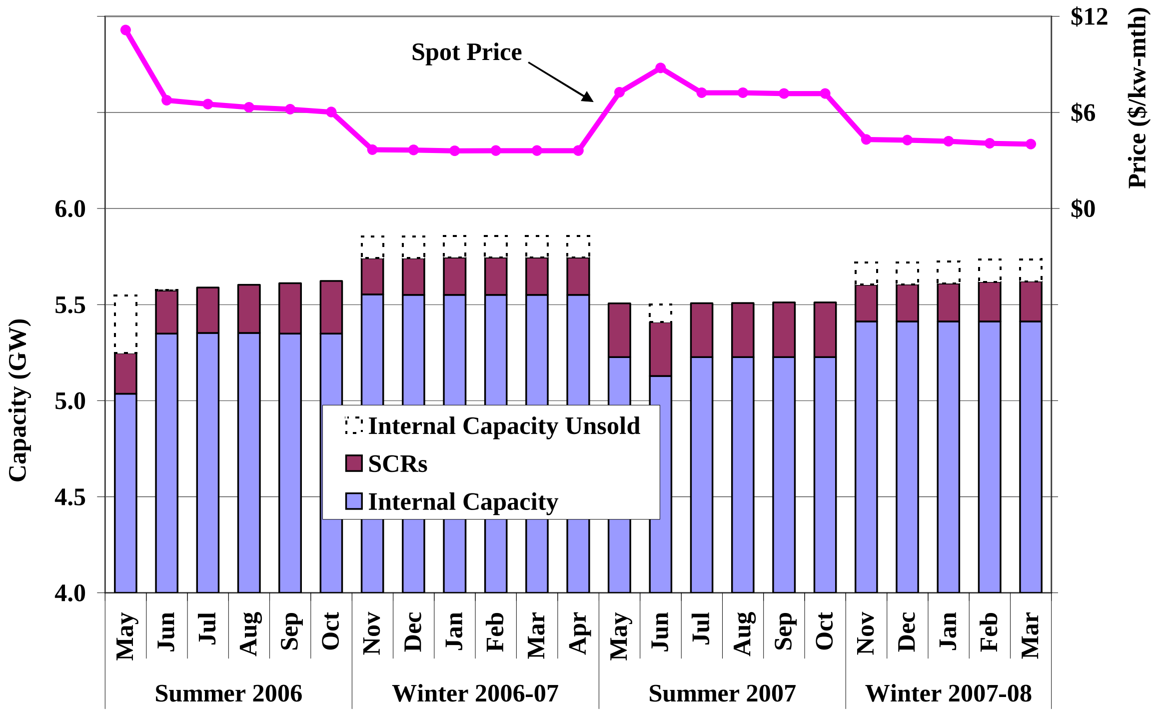
45 Market power mitigation measures were imposed as part of the divestiture. The measures consisted of caps on the revenue that each DGO could earn on the divested capacity from the capacity market, and a requirement to offer the capacity in the NYISO's auction at a price no higher than the cap. This provision was intended to mitigate the DGO's market power, but it allowed the DGOs to raise prices substantially above competitive level under conditions when New York City has surplus capacity.

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

Seasonal changes in capability account for the most significant variations in prices during the period. In May 2006, the spot price was higher than in subsequent months because a portion of capacity qualified to sell in Long Island was not offered to the market. Since May 2006, virtually all of the existing capacity was sold.

Figure 52: Capacity Market Results for Long Island
May 2006 to March 2008

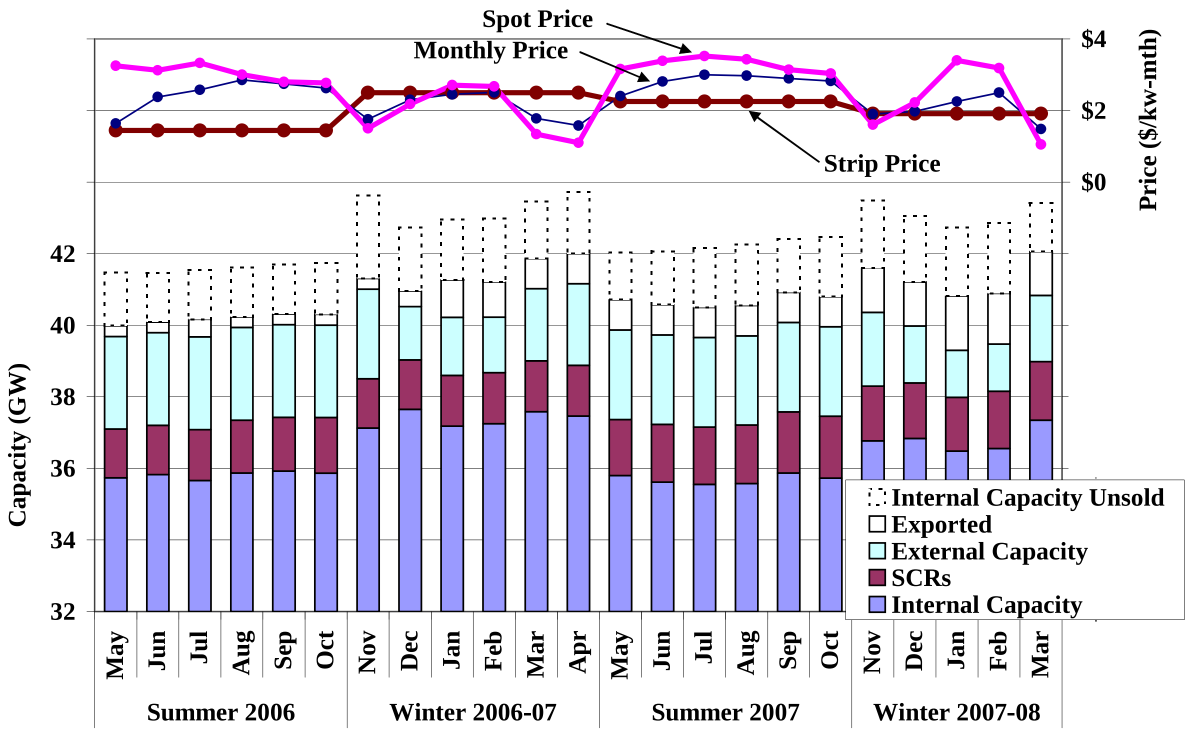


Note: Unforced Deliverability Rights ("UDRs") are included in "Internal Capacity."

Other than seasonal changes, the amount of Long Island capacity qualified to sell UCAP did not change significantly during the period. Demand response increased just 70 MW over the period. Furthermore, after the Neptune cable began operation in July 2007, the amount of capacity qualified to sell into Long island did not change significantly.

Figure 53 shows the resources that are available to provide UCAP to New York State versus the amounts actually scheduled. The bars show the quantities of internal capacity sales, sales from SCR resources, 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 53: Capacity Market Results for NYCA
May 2006 to March 2008



Note: Unforced Deliverability Rights ("UDRs") are included in "Internal Capacity."

The figure shows that most capacity is supplied by internal generation, although external suppliers and SCRs each provide significant amounts of capacity. Changes in the supply of UCAP from resources in up-state New York were relatively small during the period shown in the figure. The most significant changes in sales from internal resources came from seasonal changes in capability and the 370 MW increase in participation by SCRs.

Although New York is still a net importer of capacity, net imports declined over the period shown in the figure above. In the summer periods, net imports declined from 2,290 MW in the summer of 2006 to 1,650 MW in the summer 2007. In the winter periods, net imports peaked at 2,210 MW in November 2006 and dropped to a low point of -200 MW (i.e. 200 MW of net exports) in January 2008. Most fluctuations in capacity prices were related to variations in the quantities of imports and exports.

Market rule changes in neighboring control areas have affected the capacity market in New York. Beginning in December 2006, increased payments for capacity resources in the New

England market reduced sales into New York from external resources and increased exports of internal resources. Suppliers have been attracted by fixed capacity payments of $3.05/kW-month, which are paid under New England's transition to a Forward Capacity Market. The change in New England market rules contributed to a 1,700 MW decline in net imports from November 2006 to January 2007. Additionally, the clearing price of capacity in PJM's capacity market (called "RPM") has risen to levels that might lead to future reductions in net imports from PJM.

The reduction of the IRM in May 2007 from 18 percent to 16.5 percent lowered the NYCA ICAP requirement by approximately 500 MW. This helped offset the effects of reduced net imports. The latest IRM reduction in May 2008 to 15 percent has also reduced capacity prices in the Rest-Of-State area.

The clearing price in the Rest-Of-State area was affected by sales of capacity in the local capacity zones, since local capacity also counts toward the NYCA requirement. In March 2008, the increased UCAP sales in New York City contributed to the decline in the Rest-Of-State spot price from $3.18/kW-month in February 2008 to $1.05/kW-month in March 2008.

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 guides investment to areas where it is most valuable.

One location where long-term reliability concerns have arisen is in Southeast New York (Zones G to I), which is the portion of Rest-Of-State that is closest to New York City and Long Island. Based on the 2008 Comprehensive Reliability Plan ("CRP"), additional resources will likely be needed in Southeast New York between 2013 and 2014, which is several years before they will be needed in Zones A to F. Furthermore, a recent analysis by the NYISO indicates that some capacity in Zones A to F will not be deliverable to Southeast New York by 2012, which is a problem because there is currently no mechanism in the capacity market for distinguishing the value of capacity located in Zones A to F from the value of capacity located in Southeast New York.

In addition, it is likely more costly to build new generation in Southeast New York than in Zones A to F. Hence, we can expect investors to build in Zones A to F before they build in Southeast New York, unless energy and ancillary services price signals are sufficiently higher in Southeast New York to offset the additional cost. However, our net revenue analysis suggests that the markets may not be providing sufficient economic signals.[47] Market signals currently reflect a modest difference in the value of resources between Zone F and Zone G. For a new combustion turbine in 2007, net revenue was $77/kW-year in Zone G versus $63/kW-year in Zone F. Both levels are substantially lower than the estimated entry costs for a new peaking resource in the Zone F. For a new combined cycle in 2007, net revenue was $168/kW-year in Zone G versus $147/kW-year in Zone F. These differences may not give suppliers adequate incentives to build in Southeast New York.

If the surplus in Rest-Of-State continues while capacity margins in Southeast New York decline to unreliable levels, the Rest-Of-State capacity price will not provide efficient incentives for investment in Southeast New York. Such results could lead to regulated investment in order to maintain reliability in certain areas.[48] This form of regulatory intervention can be very damaging to the market and adversely affects the expectations of private investors in the future. Therefore, it is important to address any market issues that could lead market signals to be understated to avoid relying on regulated solutions to meet the reliability needs of the system.

- Hence, we recommend that the NYISO initiate an assessment to determine whether a new capacity zone with local requirements is warranted in Southeast New York to address the reliability requirements.

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47 See Section I.C. The net revenue analysis evaluates price signals from capacity, energy, and ancillary services.

48 The CRP Process calls for regulated backstop solutions to be constructed if market-based solutions do not come forward to address reliability needs.

IX. Demand Response Programs

The NYISO operates four 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/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/MWh) or the real-time clearing price. These resources sell capacity in the capacity market, so they are obligated to respond when called.[49]
  - Targeted Demand Response Program ("TDRP") – This program pays EDRP and SCR resources the higher of $500/MWh or the real-time clearing price to respond for local reliability reasons. 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 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.

EDRP and SCR resources can be deployed to maintain the reliability of the bulk power system or the local transmission owner's facilities, while TDRP resources can only be deployed to maintain the reliability of the local transmission owner's facilities. The DADRP program is designed to encourage retail loads to respond to wholesale price signals.

When resources are activated under the EDRP and SCR programs, the market rules require all resources within the zone be activated. This has led to inefficiencies when resources were needed for a local reliability issue within a particular zone. To address this issue, the NYISO created the TDRP program in July 2007, which allows local transmission owners to target a request for load relief to EDRP and SCR resources (that choose to participate in the TDRP program) in specific load pockets within New York City.

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

As participation in demand response programs grows, it becomes increasing important to design market rules that lead to efficient real-time prices during demand response activations. When emergency demand response resources are activated under shortage conditions, the real-time market should set clearing prices that accurately reflect operating conditions. 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. This was recently affirmed by FERC in its Notice of Proposed Rule-Making ("NOPR"), which identifies a NYISO market rule that facilitates efficient pricing during such conditions. The rule allows demand response resources to set clearing prices when an operating reserve shortage is avoided by activating EDRP and SCR resources.[50]

In this section, we summarize participation in the existing demand response programs, discuss the challenge of pricing efficiently when demand response is activated, and review initiatives to enhance the responsiveness of loads to wholesale market prices.

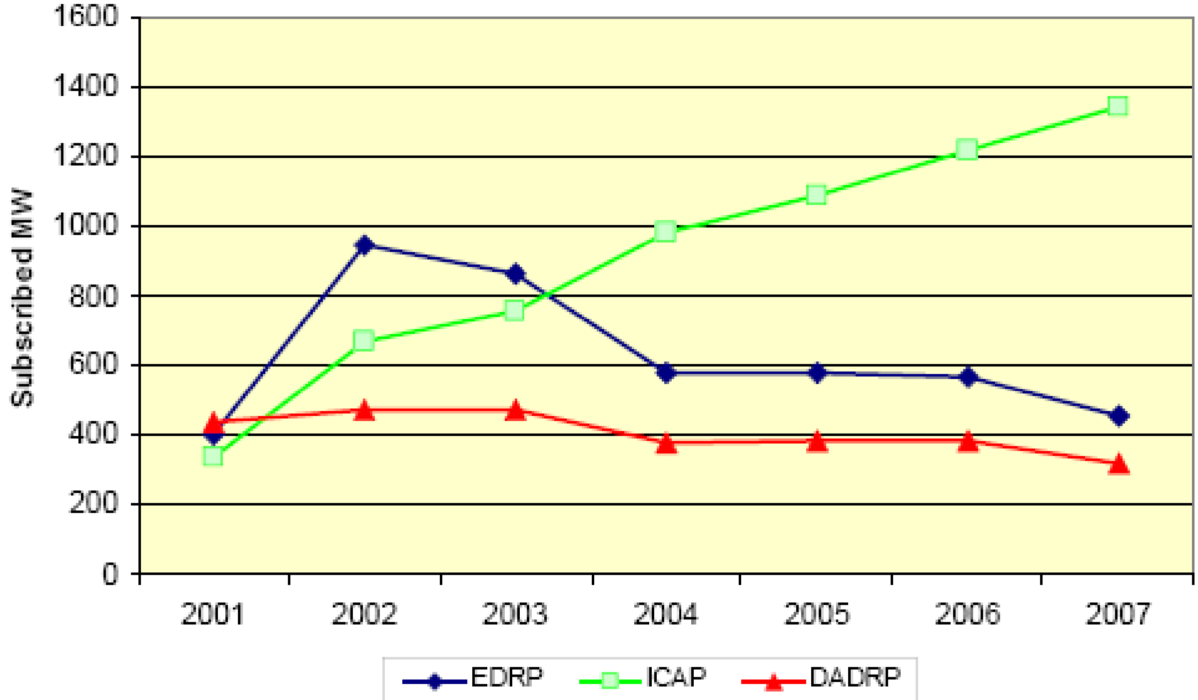
A. Demand Response Programs in 2007

This sub-section discusses participation in each of the NYISO's four demand response programs. The following figure summarizes registration in three of the programs on an annual basis from 2001 to 2007. Since EDRP and SCR resources in New York City participate in the TDRP program on a voluntary basis, TDRP resources are not shown separately.

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 2007, total registration in the EDRP and SCR programs included 2,705 participants providing just over 1,800 MWs of demand response capacity. EDRP and SCR resources in New York City are automatically registered in the TDRP program.

[50] See P. 45. Wholesale Competition in Regions with Organized Electric Markets, 122 FERC ¶ 61,167 (2008) ("NOPR").

Figure 54: Registration in NYISO Demand Response Programs 2001 - 2007



Note: Figure reproduced from the NYISO's January 15, 2008 Demand Response Compliance Report.

Demand response programs provide incentives for retail loads to participate in the wholesale market. When resources are activated under the EDRP, SCR, and TDRP programs, they are paid the higher of $500/MWh or the LBMP for the amount of the load reduction.[51] This is greater than the marginal value of consumption for many loads during peak periods. Such loads have an incentive to respond, even though they are served under regulated or otherwise fixed rates that cause them not to pay the wholesale price of electricity.[52] However, to the extent that some resources have a marginal value of consumption exceeding $500/MWh, they would be more likely to participate in demand response programs if they were allowed to submit strike prices exceeding $500/MWh.

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51 SCRs receive the higher of their strike price or the LBMP, although more than 90 percent submit strike prices at the maximum level of $500/MWh.

52 While the average regulated rate paid by load is much lower than $500/MWh, the value of power at peak times is typically much higher than the average. Therefore, in the absence of the NYISO's payments for load reductions, load that is interrupted would save only the regulated rate, which does not reflect the marginal system cost of serving the load as reflected in the wholesale LBMPs.

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 helps reduce capacity prices. In 2007, SCR resources sold capacity of approximately 420 MW in New York City, 220 MW in Long Island, and 700 MW in the Rest of State zones. These resources increase the competitiveness of the capacity market, particularly in New York City and Long Island where ownership of generation is relatively concentrated.

TDRP resources have been activated twice since the program was created in 2007. Load was curtailed for 15 hours on July 19 and for almost 5 hours on August 3. In both cases, demand response was called to address a local issue in a small portion of New York City. On July 19, resources were activated in the Vernon-Greenwood sub-zone from 8am to 11pm, providing an average of 14 MW of load reduction. On August 3, resources were activated the Farragut/Rainey sub-zone from 7:30pm to midnight, providing an average of 7 MW of load reduction. In 2007, resources were not activated for the EDRP and SCR program due to relatively mild summer weather. However, in 2006, the NYISO activated EDRP and SCR resources on five days for a total of 35 hours.

The DADRP program allows retail customers to offer load curtailment in the day-ahead market in a manner similar to generation supply offers. From September 2006 to August 2007, 4,150 MWh of DADRP resources were scheduled in the day-ahead market. This was a 19 percent increase over the previous 12-month period. Nonetheless, the DADRP program provides load reductions in periods when load curtailment is considerably less valuable than when load is curtailed under the other programs.

In 2004, the NYISO's governance structure was revised to reflect the increasing role of demand response providers and distributed generation owners. The revisions placed each demand response provider and distributed generation owner in one of three voting categories: generation owners, other suppliers, or end use consumers. Each entity is placed in the group that is most consistent with its purpose in participating in the market. Some intervenors raised concerns that the new resources would have interests that were fundamentally opposed to the interests of the group where they were placed. However, based on our review of the voting records of the

NYISO Management Committee in 2007, we do not find a consistent pattern of demand response resources or distributed generators voting differently than the other market participants in their category.

B. Demand Response and Shortage Pricing

In an efficient market, clearing prices should reflect the cost of deploying resources to meet 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/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 have improved 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/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. The FERC's NOPR recently identified this provision as a way to improve the efficiency of real-time prices during shortage conditions. [53]

Second, to further 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

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[53] See P. 45. Wholesale Competition in Regions with Organized Electric Markets, 122 FERC ¶ 61,167 (2008) ("NOPR").

quantities of demand response were activated that provided no reliability benefit, depressed real-time prices, and increased uplift.

The ability to activate TDRP resources greatly reduced the inefficiencies of “out-of-merit” demand response resources in 2007 by limiting curtailment to the affected area. On July 19, only 10 percent of the resources in New York City were activated, and, on August 3, only 15 percent of the resources in New York City were activated. Previously, the operators would have activated all of the resources in the New York City zone, which would have resulted in far more “out-of-merit” resources.

The growth of demand response is a positive development that reduces the cost of operating the system reliably, particularly during peak periods. However, it is challenging to set efficient prices during periods when demand response resources are activated. The New York market has two rules that reduce the incidence of “out-of-merit” demand response. These rules encourage demand response participation and preserve the incentives of suppliers to satisfy the needs of the system during peak operating conditions. In the future, the wholesale market is likely to rely on demand response resources to a greater extent, making it essential for the NYISO to develop additional mechanisms for demand response resources to set clearing prices efficiently.

- Hence, we recommend the NYISO consider the development of rules to enable demand response resources to set prices in local areas when they are needed to avoid a local shortage.

C. Future Development of Demand Response Programs

Price-responsive demand has great potential to enhance wholesale market efficiency. Modest reductions in consumption by end-users during high-price periods can significantly reduce the costs of committing and dispatching generation. Price-responsive demand mitigates market power, improves power system reliability, and reduces the need for new investment in generation. Furthermore, price-responsive demand can facilitate the implementation of public policy initiatives such as the Renewable Portfolio Standard, since demand-side flexibility eases the integration of intermittent resources. These benefits underscore the need to design wholesale markets that provide transparent economic signals that generate interest in demand response programs and time-of-day pricing for end-users.

The NYISO is working on several initiatives to increase the responsiveness of demand to prices in the wholesale market. First, the NYISO worked with stakeholders on a proposal to allow demand-side resources to offer operating reserves and regulation service in the wholesale market. In March 2008, these efforts culminated in a filing to FERC of proposed Tariff changes to allow demand response resources to provide ancillary services. The proposed changes should increase the amount of resources that provide reserves and regulation services. This should enhance competition, reduce costs, and enhance reliability by reducing the likelihood of reserve shortages.[54]

Second, the NYISO plans to move forward with the Demand Response Program Automation project, which will replace existing manually-intensive process. 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. The automated system will substantially reduce the administrative burdens on both the NYISO and the program participants. These improvements should encourage participation in demand response programs by reducing the costs to participate.

[54] On May 23, 2008, FERC accepted in part and rejected in part the proposed changes, asking the NYISO to continue efforts to accommodate batch loads and energy storage technologies, revise Bid Production Cost Guarantee language to prevent double compensation, and clarify application of certain market monitoring provisions and creditworthiness standards. See *New York Independent System Operator, Inc.* 123 FERC ¶ 61,203 (2008).