2006 State of the Market Report
New York ISO

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Table of Contents

Table of Figures

Executive Summary

In 2006, electricity prices decreased 20 to 30 percent in the markets operated by the New York ISO ("NYISO"). We attribute the decline to:

- Lower fuel costs;
- Generator additions within transmission-constrained locations within New York City;
- Lower average load levels (despite the new peak load record in 2006); and
- Continued improvements to the NYISO markets.

Ancillary service expenses were substantially higher in 2006 due to rules changes providing for more efficient pricing of reserves. These higher expenses were more than offset by lower energy prices, reduced congestion costs, and more efficient market operations. In general, energy and ancillary services markets have performed well with no evidence of significant market power abuse or manipulation by market participants in 2006.

This report assesses the efficiency and competitiveness of New York's wholesale electricity markets during 2006. The NYISO operates competitive wholesale electricity markets to satisfy the electricity requirements of New York. With the implementation of the new real-time spot markets on February 1, 2005, the NYISO now operates the most complete and efficient set of electricity markets in the U.S. These markets include:

- Day-ahead and real-time energy markets for the wholesale purchase and sale of electricity with prices that reflect the value of electricity at each location;
- A market for transmission rights that allow participants to hedge the congestion costs associated with delivering power to a location that is constrained by the limits of the transmission network;
- Day-ahead and real-time operating reserves markets intended to ensure that sufficient resources are available to produce electricity when a generator outage or other system contingency occurs;
- A regulation market to procure the ability to instruct specially-equipped generators to increase or decrease output on a moment-by-moment basis to keep supply and demand in balance;
- An installed capacity market that is intended to assure that the long-term market signals result in efficient new investment and the maintenance of existing resources that are needed to meet the reliability needs of the region; and

- A commitment model that runs each 15 minutes to optimize the use of peaking resources and the scheduling of imports and exports.

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. Although it is difficult to quantify some of these benefits, particularly the long-term benefits, they are considerable because the markets coordinate the decisions and actions of numerous buyers and sellers of electricity. Good coordination is essential due to the physical characteristics of electricity and the transmission network used to deliver the electricity to customers. This coordination affects not only the prices and costs of electricity, but also the reliability with which it is delivered.

The New York energy markets efficiently dispatch generation on the basis of supply offers to satisfy energy demand and operating reserve requirements, while preventing power flows on the network from exceeding transmission constraints. The markets establish location-based marginal prices ("LBMPs") that reflect the marginal system cost of serving load at each location on the network. When the market is functioning well, these prices 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.

Regarding the last benefit, relying on private investment made in response to competitive price signals 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.

A. Introduction and Summary of Findings

In addition to providing a summary of market outcomes in 2006, this report includes findings in two primary areas: the competitive performance of the market and long-term signals provided by the markets. The findings in each of these areas are discussed 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 have performed competitively in 2006. We found little evidence that any suppliers were either economically or physically withholding resources to raise energy or ancillary services prices in the market. Although nominal prices for electricity have been higher in recent years than they were historically, this is almost entirely attributable to the substantial increase in fuel prices. Because fuel costs constitute the vast majority of the marginal costs of producing electricity, increases in fuel costs will translate directly to increases in offer prices and market clearing prices for electricity. While fuel costs were generally lower in 2006 than in 2005, fuel costs remained higher than they were historically.

In close to 30 hours during 2006, shortages occurred that caused real-time energy prices to rise close to $1000/MWh. These shortages generally resulted from periods of very high demand during particularly hot periods in the summer or during thunderstorms that reduce the NYISO capability to deliver power downstate. We examined the conduct during this period very closely and did not find any significant potential economic withholding of generating resources. There was also little evidence of physical withholding as forced outages and other deratings were at relatively low levels during this period. However, we did find that inefficient transmission flows between New York and New England contributed to the shortages on these days. This report includes a recommendation for addressing this issue.

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 remaining competitive issue identified in the NYISO markets relates to the recent results in the installed capability market. After the addition of approximately 1000 MW of new capacity in 2006, the capacity market clearing prices remained virtually unchanged. A significant amount of existing capacity did not clear in the UCAP market due to the capacity offer prices. This issue and other issues related to the New York City capacity market are being addressed in a litigated proceeding at the FERC.

Long-Term Economic Signals

This analysis shows that net revenues in 2006 might support the installation of new combustion turbines in Long Island and new combined cycles in Long Island, New York City, and the Hudson Valley. However, there is considerable uncertainty both about the cost of new investment and the 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 outcomes.

In recent reliability needs assessments ("RNA"), a need for additional capacity has been identified in the lower Hudson Valley, which is within the "rest-of-state" installed capacity zone ("ROS"). To the extent that generation is more costly to build in that area and the market signals are likely to continue to be less than this cost, a separate capacity zone may be warranted in this area. The comprehensive reliability planning ("CRP") calls for regulated backstop solutions to be constructed if market-based solutions do not come forward that will address the identified reliability needs. 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 could cause market signals to be understated, rather than relying on regulated solutions to meet the reliability needs of the system. Defining additional zones in the ROS area may be needed to 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 new capacity zones are warranted.

Our analysis also shows that market signals have tended to shift in favor of investment in baseload and intermediate resources that, while more costly to build, produce electricity at a relatively low cost. This change indicates that, over time, the markets provide efficient incentives to invest in a diverse array of resources. In particular, a well-functioning market will support investment in various types of generating resources, demand response resources, and transmission.

To preserve the credibility and effectiveness of the market in supporting these investments, policymakers should take great care in utilizing the regulatory process to prompt new investment. A useful principle in this regard is that any investments that receive regulatory support should be consistent with the market signals, except to the extent that they provide benefits not reflected in market prices (e.g., environmental benefits).

The report contains some recommendation for potential improvements to the New York markets. These recommendations generally involve modifications to certain operating procedures and rules that should increase the efficiency of the New York markets. The recommendations are described in the following sections along with a summary of the report's findings and conclusions in each area.

B. Summary of Market Outcomes in 2006

In 2006, prices decreased by 20 to 30 percent in most areas in New York. These reductions were primarily due to lower natural gas prices, which fell by more than 25 percent in 2006. 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.

In addition, substantial new generation was added in New York City in 2006. Close to 1000 MW of new capacity was added in the City, which reduced the power flows and congestion on transmission interfaces leading to and within the City. The reduced congestion contributed to the lower prices in eastern New York and in New York City.

Finally, while the New York ISO system saw record peak loads in July and August 2006 load levels were lower in 2006 than in 2005 on average. Lower load levels contributed to the lower average prices in 2006, although they played a much smaller role than the reduction in fuel prices.

Market Performance during Shortage Conditions

Although average loads were lower during the summer of 2006, peak load levels were higher. For example, there were 28 hours when load exceeded 32 GW in 2006 versus only 3 such hours in 2005. These super-peak demand levels frequently lead to shortage conditions. Prices that occur under shortage conditions are an important contributor to efficient long-term price signals. The markets produced relatively accurate shortage pricing in 2006 – i.e., shortage pricing occurred when resources were insufficient to meet both the energy and operating reserves needs of the system.

The 2006 performance improved versus the performance in 2005. In 2005, there were a significant number of pricing intervals in which eastern New York was physically short of 10-minute reserves, but shortage pricing did not occur. In fact, only about 50 percent of the intervals in which the NYISO was physically short of resources actually had shortage pricing. This discrepancy was caused by inconsistencies between the NYISO's physical dispatch model and its real-time pricing model. In May 2006, the NYISO addressed the largest cause of the inconsistency between the pricing and physical dispatch models, which led to a substantial reduction in the number of physical shortages of operating reserves not accompanied by shortage prices. However, this change did not completely resolve the issue and the report includes an additional recommendation.

A significant portion of the shortages in eastern New York result from reliability procedures invoked when the NYISO calls a "Thunderstorm Alert" ("TSA"). TSAs result in the NYISO redispatching downstate generation to reduce south-bound power flows on the network into New York City.

Demand Response and Shortage Pricing

The NYISO has some of the most successful demand response programs in the country, which have led to a sizable quantity of demand response capability. The development of this capability is good for the market and for reliability. The two key programs are the emergency demand response program ("EDRP") and special case resources ("SCR"). EDRP resources are paid the higher of $500/MWh or the clearing price when called by the operator. SCR resources are paid the higher of their strike price, typically $500/MWh, or the clearing price. The NYISO must give advanced notice of at least two hours before calling on SCR and EDRP resources, and resources must be curtailed for at least four hours.

EDRP and SCR resources must be called in advance based on projections of operating conditions, and since they are not dispatchable by the real-time model, there is no guarantee that they will be “in-merit.” After EDRP and SCR resources are curtailed, if adequate resources are available to the system in real-time, clearing prices can be well below $500/MWh. The NYISO has partially addressed this concern by implementing shortage pricing rules that allow EDRP and SCR resources to “set price” when their curtailment enables the ISO to avoid a shortage of eastern or state-wide reserves.

There were 35 hours over five different days when EDRP and SCRs were curtailed in one or more zones. In each case, the resources were curtailed to address a local issue rather than a large-scale shortage of NYCA reserves or eastern reserves. An analysis indicates that the $500/MWh EDRP and SCR resources were only economic part of the time when curtailments were called. To minimize the impact of “out of merit” SCR and EDRP resources, the NYISO has proposed to develop the capability to call these resources in blocks smaller than an entire zone. We support this proposal and the development of rules to enable these resources to set prices in local areas when they are needed to avoid a local shortage.

Uplift Costs

Minimizing uplift costs is important because these costs 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 costs should be relatively low.

Uplift costs decreased by $53 million from 2005 to 2006, a reduction of about 20 percent. These costs are associated with Bid Production Cost Guarantee Payments (“BPCG”) made to generators when they are dispatched, but do not recoup their as-bid costs from NYISO markets.

The reduction in these costs is primarily due to more efficient use of peaking resources, which can be attributed to the improved real-time market software implemented in early 2005. We estimate that this software saved participants approximately $32 million in 2006. Other factors that contributed to the reduction in uplift expenses include: lower natural gas prices in 2006 and the more detailed network modeling of the New York City system in the real-time market, implemented by the NYISO in May 2006.

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 New York City and the load pockets within the City; and
- The interfaces into Long Island.

Congestion on the transmission paths into and within New York City resulted in average energy prices in the City that were 14 percent higher than in the eastern upstate region. Likewise eastern upstate prices were 23 percent higher than average prices in west New York, although much of this difference can be attributed to transmission losses.

Total congestion costs decreased by more than $200 million in 2006. Day-ahead and real-time congestion costs totaled more than $770 million in 2006 compared to $990 million in 2005. The reductions in congestion costs in 2006 were largely due to lower fuel costs and the new capacity added in New York City. Lower fuel prices reduce congestion because they decrease the redispatch costs incurred to manage network congestion. Regarding the second factor, the addition of close to 1000 MW of generating capacity in New York City has significantly reduced the congestion into and within the City, which accounts for a large share of the total congestion in the state. The report shows that the value of real-time congestion into and within New York City fell from close to $400 million in 2005 to less than $150 million in 2006.

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 summer capability period for 2006 were reasonable reflections of participants' expectations of congestion. The results of this analysis show that the west-to-east TCCs were generally under-valued, while TCCs sinking in New York City were generally over-valued. The latter class of TCCs was likely over-valued because participants did not expect congestion to decrease as sharply as it did when the new generation entered the market in 2006.

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. Convergence in the energy markets improved markedly in 2006 as participants gained experience with the new real-time markets deployed early in 2005. However, convergence in the energy markets at specific locations within New York City was not as good as at most locations in the State.

Convergence in the operating reserve market in eastern New York was relatively poor during the summer, when reserve shortages in the real-time market caused the real-time prices to increase substantially compared to day-ahead prices. The report recommends potential changes for the NYISO to consider that may improve the liquidity of reserves markets and improve convergence.

External Transactions and Price Convergence

Convergence between the NYISO and adjacent markets is also important because it assures that the power will flow between markets such that costs in both markets are minimized and prices are efficient. Our evaluation of the external transactions indicates that market participants are not effectively arbitraging the price differences between New York and adjacent markets by scheduling transactions that modify the power flows between the markets. This lack of coordination is particularly important during shortages or very high-priced periods because modest changes in the physical interchange can substantially affect the market outcomes in both New York and the neighboring market.

Price convergence has been especially poor during price spikes in eastern New York. In a number of hours, power was flowing out of New York, even though the New York price was substantially higher than the price in New England. In fact, some of the shortages that occurred in New York could have been prevented with better utilization of the New York-New England transmission interface. Similarly, in some hours power was flowing into New York during shortage pricing events in New England, even though the New York price was well below the New England price. These cases reveal that the lack of coordination between neighboring areas leads to higher costs to loads and reserve shortages.

On the basis of these results, we continue to recommend that the ISO develop provisions to better coordinate the physical interchange between New York and New England. These provisions would facilitate a more seamless market in the Northeast, which would: ensure that power is efficiently transmitted to the highest-value locations, achieve substantial economic savings for customers in the region, and improve reliability. Some have argued that this recommendation would constitute involving the ISOs in the market. This is not the case. The ISOs would be using the bids and offers submitted by participants in each market to establish the optimal interchange between the markets in the same way they do to establish the optimal flows across transmission interfaces inside both markets.

C. Market Operations

This section covers a wide variety of areas related to the operation of the SMD markets, including the market consequences of certain operating procedures and the scheduling actions of participants.

Real-Time Commitment and Pricing of Peaking Resources

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. Peaking units are generally capable of starting from an offline status and ramping to their maximum output within 10 minutes or 30 minutes of receiving an instruction.

The Real Time Commitment model ("RTC"), implemented as part of the SMD 2.0 in 2005, is primarily responsible for committing gas turbines and other quick-start resources. 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 the market outcomes. The excess commitment of peaking resources will generally depress real-time prices and increased uplift costs. Alternatively, when peaking resources are not committed when they are economic, it can cause inefficient price spikes.

The report assesses the efficiency of real-time commitment and scheduling decisions by RTC. Decisions to start or not start gas turbines continued to improve in 2006, particularly for gas turbines with longer start times (i.e. 30-minute gas turbines). More efficient real-time commitment of gas turbines has led to reduced uplift charges for BPCG payments to gas turbines that are started by the ISO and turn out to be uneconomic. This improvement is largely attributable to the implementation of SMD 2.0, which includes the RTC model. We estimated that SMD 2.0 resulted in savings of $22 million in 2005 due to improved real-time operations. In 2006, the estimated savings rose to $32 million.

Supplemental Commitment and Out-of Merit Dispatch

Supplemental commitments and out-of-merit energy dispatch can adversely affect the market because they tend to mute the market signals and cause uplift costs 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 and result in day-ahead or real-time local reliability uplift.

Both types of supplemental commitments increased in 2006 versus 2005. The capacity committed through the SRE process (generally at the request of a transmission owner) increased slightly, but the uplift costs of these commitments deceased from $75 million in 2005 to $70 million in 2006. The local reliability commitments in the day-ahead market increased more substantially – up from 304 MW in 2005 to 427 MW in 2006. However, the uplift costs associated with these commitments decreased from $74 million to $69 million. In both cases, the reduction in fuel prices was a primary reason for the reduction in uplift costs. Most supplemental commitments occur in New York City.

Although it would require some changes in the cost allocation rules in New York, we continue recommend that the local reliability and NOx constraints be included in the initial economic commitment pass of SCUC. Including these constraints in the economic pass would reduce the inefficiency and uplift associated the supplemental commitments and lead to prices that better reflect energy and reliability demands on the system, resulting in significant market benefits.

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. The rate of corrections spiked to 8.8 percent of intervals 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. In 2006, the prices were corrected in only 0.6 percent of the intervals, the lowest level in recent years.

D. Ancillary Services Markets

The NYISO operates day-ahead and real-time markets for operating reserves and regulation. The real-time component of these markets was implemented as part of SMD 2.0 in 2005. 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.

Ancillary Services Market Expenses

Ancillary services expenses rose substantially from 2005 to 2006 due to a 30 percent increase in regulation costs and almost a 40 percent increase in reserves procurement costs. Higher expenses were expected in 2006 as a result of SMD 2.0. In a co-optimized market, the prices of ancillary services reflect the tradeoffs between using a resource for ancillary service or energy. Failure to do this raises the risk that a supplier will be harmed by providing reserves. This risk can discourage suppliers from offering reserves to the market and result in a less efficient dispatch of energy and reserves.

The report finds that regulation expenses remained relatively high in 2006 after increasing significantly in late 2005. As discussed below, this increase was largely due to an increase in offer prices by large suppliers of regulation.

Ancillary Services Offer Patterns

The quantity of offers to supply 10-minute spinning reserves and 30-minute operating reserves rose substantially from 2004 to 2006, which we attribute to the improved incentives under SMD 2.0 and the day-ahead offer requirements. Previously, the day-ahead clearing prices were set by the highest-priced accepted offer, so it was possible for the price to be lower than the opportunity cost of not providing energy. Thus, generators risked losing profits in the energy market by providing reserves. There is no such risk under the new design since the reserves clearing price is always greater than or equal to the opportunity cost of generators scheduled for reserves. In other words, generators are always selected to provide whichever is more profitable (assuming they submit energy and ancillary services offers consistent with their marginal costs).

Although participation in reserves markets increased with the introduction of SMD 2.0, offer patterns also changed significantly after the implementation of SMD 2.0. In a multi-settlement market, selling a resource in a day-ahead market precludes the supplier from selling in the real-time market. Therefore, if there are periodic price spikes in the real-time market, foregoing the opportunity to sell at the high prices must be included in the day-ahead offer. Hence, these increases in offer prices are justified.

Pricing these shortages in the energy and reserves markets in both the real-time and day-ahead markets represents a significant improvement (even though it has resulted in higher prices and ancillary services expenses).

Finally, regulation offers from two large suppliers of regulation remained elevated in 2006. The ownership of regulation-capable capacity is relatively concentrated, raising concerns that certain market participants may have the incentive to raise their offer prices above marginal cost. However, the NYISO's MMU investigated this conduct and found that it did not warrant mitigation under the NYISO Tariff.

E. Capacity Market

The capacity market is intended to ensure that sufficient capacity is available to reliably meet New York's electricity demands. 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.

We evaluate the performance of the capacity market from May 2006 through March 2007, a time span including four six-month capability periods from the Summer 2005 capability period through the Winter 2006-07 capability period. Over this period, clearing prices in the Rest-of-State area have ranged from just above $0 per kW-month to $3 per kW-month, depending on modest variations in imports and exports as well as the timing of retirements and new investments. Clearing prices in New York City have been consistently close to $7 per kW-month during the winter capability periods and near $12 per kW-month during the summer capability periods. The New York City prices correspond to the price cap on the Divested Generation Owners ("DGOs") that purchased the capacity from ConEd when it was required to divest most of its generation in 1998.

The results in New York City raise potential concerns because substantial new capacity became available in New York City in 2006, yet the prices remained near the DGO price cap due to suppliers' offer patterns. These offer patterns caused a significant amount of existing capacity to not clear in the capacity market. Currently a proceeding at FERC is addressing this and other issues related to the capacity market in New York City.

Additionally, the NYISO is currently conducting a review and update of its capacity demand curves. This update occurs every three years and is intended to allow the market to reflect changes in the costs of building new capacity at three locations: New York City, Long Island, and the Rest-of-State area.

Long-term reliability concerns have arisen in the lower Hudson Valley, which is located in the Rest-of-State area. The past two Reliability Needs Assessments have identified this area as requiring new capacity in the relatively short-term horizon. It is likely more costly to build new generation in this area than further upstate or in western New York. However, it is not clear from our analysis of the long-term price signals that the markets are providing economic signals that would cause an investor to build generation in the Hudson Valley.

A similar issue is addressed in New York City and Long Island by the definition of local capacity requirements. In contrast, Hudson Valley is in the "rest-of-state" area with no local capacity requirements. This report recommends that the NYISO initiate an assessment to determine whether a new capacity zone with local requirements is warranted to address the Hudson Valley reliability requirements.

F. Summary of Recommendations

Our analysis in this report indicates that the NYISO electricity markets performed very well in 2006, improving in a number of areas in comparison to recent years. However, the report finds that additional improvements can be made and provides the following recommendations:

1. Evaluate the feasibility of virtual trading of ancillary services.

Virtual trading would address poor convergence between some types of day-ahead and real-time ancillary services prices. This change could promote convergence of ancillary services prices and reduce physical suppliers' incentive to raise their offer prices. However, the change would need to be carefully studied to ensure it will not have unintended consequences on day-ahead commitment.

2. Consider allowing virtual trading at a more disaggregated level or identify other means of improving convergence in the load pockets.

Price convergence has improved in NYC load pockets due, in part, to the introduction of modeling individual transmission lines and contingencies in NYC (rather than simplified interfaces) in the real-time market. However, the report shows that some NYC load pocket prices still do not converge as well as zonal prices.

3. Evaluate several areas of potential improvements the report suggests for the real-time commitment model ("RTC").

RTC, which was deployed in 2005, has resulted in significant improvements to the efficiency of commitment and scheduling during real time. However the report identifies some inconsistencies between RTC and the real-time market that can affect commitments and schedules from RTC.

4. Consider re-calibrating 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. These would improve the accuracy of shortage pricing, as well as improving pricing in normal hours.

5. Implement changes to transmission pricing that limit the marginal re-dispatch costs to a maximum of $4,000/MWh.

Transmission constraint shadow prices can reach extremely high levels for brief periods when re-dispatch options are unavailable or relatively ineffective. Excessive shadow prices may result in re-dispatch that provides little reliability benefit, and in some cases may actually make the system less reliable. To reduce the incidence of such situations, in June 2007, the NYISO implemented a limit of $4,000/MWh to the marginal re-dispatch costs that can be incurred to relieve transmission constraints. We agree with this change. We will continue to evaluate congestion management under the new methodology including the appropriateness of the $4,000/MWh limit.

6. Improve the modeling of local reliability rules and NOx constraints 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 expense is higher throughout the state. In the short-run, we continue to recommend that the ISO allow operators to pre-commit certain units that are known to be needed prior to the day-ahead market. Ultimately, the NYISO should incorporate these reliability rules and environmental constraints into the economic pass of the day-ahead market. Both of these changes require that the NYISO first work with participants to revise the cost-allocation methodology for uplift associated with the local reliability requirements.

7. Continue the work with ISO-New England to develop means to better use the transfer capability between regions.

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.

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

One or more additional capacity zones may be necessary to allow the markets' economic signals to be consistent with the fact that resources are needed in the near-term in downstate areas. To determine whether additional zones are 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.

9. Develop rules to lessen the impact of "out of merit" SCR and EDRP resources that are used to address local shortages and to set prices in the local areas when they are called.

To minimize the impact of "out of merit" SCR and EDRP resources, the NYISO has implemented the capability to call these resources in blocks smaller than an entire zone. We support this change and the development of rules to enable these resources to set prices in local areas when they are needed to avoid a local shortage.

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.

Three of the most significant factors affecting energy market prices in 2006 were declining fuel costs, moderated peak demand levels, and the addition of significant amounts of new capacity within New York City. Natural gas prices were approximately 26 percent lower on average in 2006 than in 2005. While 2006 saw the NYCA set record peak load levels, the NYCA exhibited lower load levels during most of the peak hours. Approximately one gigawatt of new capacity was added within the heavily congested New York City zone, which contributed to sharply lower the costs of congestion in New York City. In addition, in 2006 the NYISO continued to refine the market enhancements made under Standard Market Design 2.0 ("SMD 2.0"), which was implemented on February 1, 2005. The effects of these and other market changes were reduced uplift costs and more efficient energy prices.

This section of the report provides an overview of market results in 2006 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.

A. Summary of 2006 Outcomes

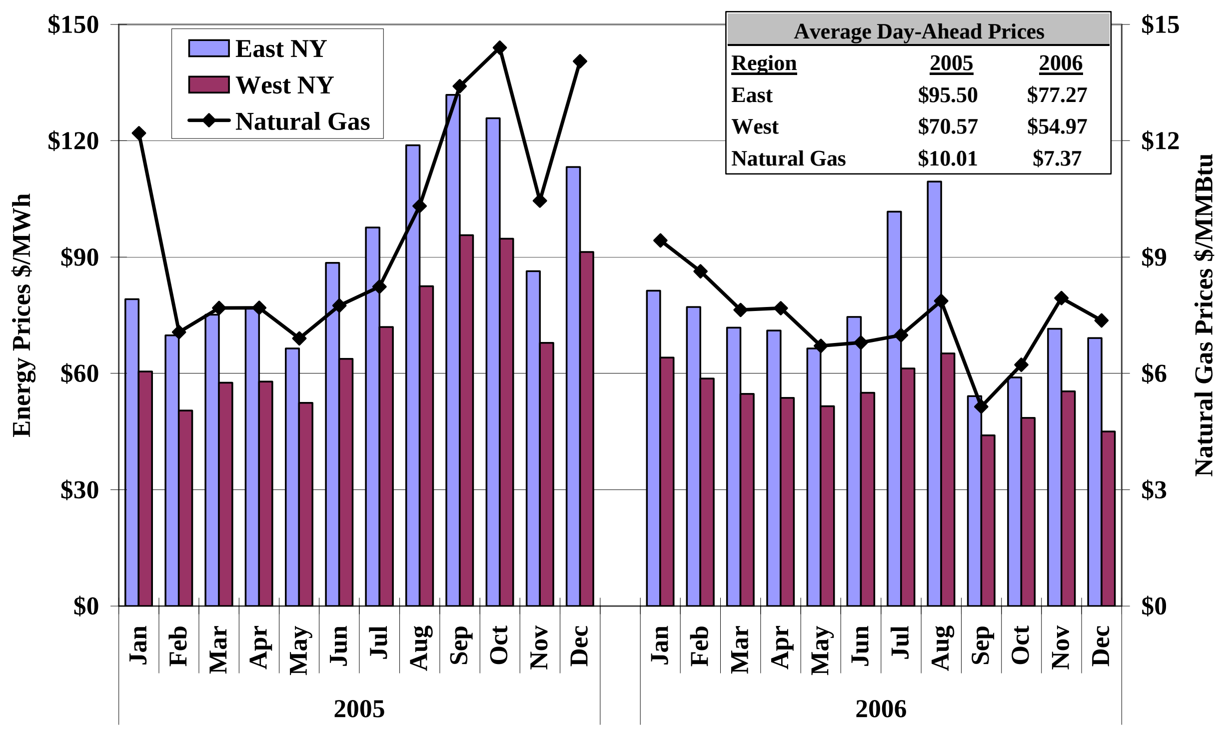
We begin in this sub-section by summarizing the 2006 energy price trends, load levels, and trends in individual components of the market expenses.

1. Energy Prices

Changes in fuel prices and load continue to be the most important factors explaining trends in energy prices. Energy prices in NYISO markets were significantly lower in 2006 than in 2005, due to a reversal of 2005's increase in the prices of natural gas and other fuels, and to lower load conditions in most peak hours. Although the NYISO system set records on July 17, 2006, and again on August 1 and August 2, the system exhibited lower average loads in peak hours during 2006 than in 2005.

Figure 1 shows average natural gas prices and electricity prices on a monthly basis during 2005 and 2006. 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 during peak hours. Therefore, changes in these prices directly affect market prices.

Figure 1: Electricity and Natural Gas Prices 2005 – 2006



Average Day-Ahead Prices		
Region	2005	2006
East	$95.50	$77.27
West	$70.57	$54.97
Natural Gas	$10.01	$7.37

Figure 1 shows that monthly average electricity prices are closely correlated with natural gas prices. Gas prices in New York were approximately 27 percent lower in 2006 than in 2005. Hurricane damage in late summer and fall 2005 reduced the flow of natural gas from the Gulf Coast region, but production levels recovered over the course of 2006 and exerted downward pressure on prices. June, July, and August diverge from the general pattern of tightly correlated natural gas and power prices, because the shortage conditions associated with super-peak load levels led to very high energy prices.

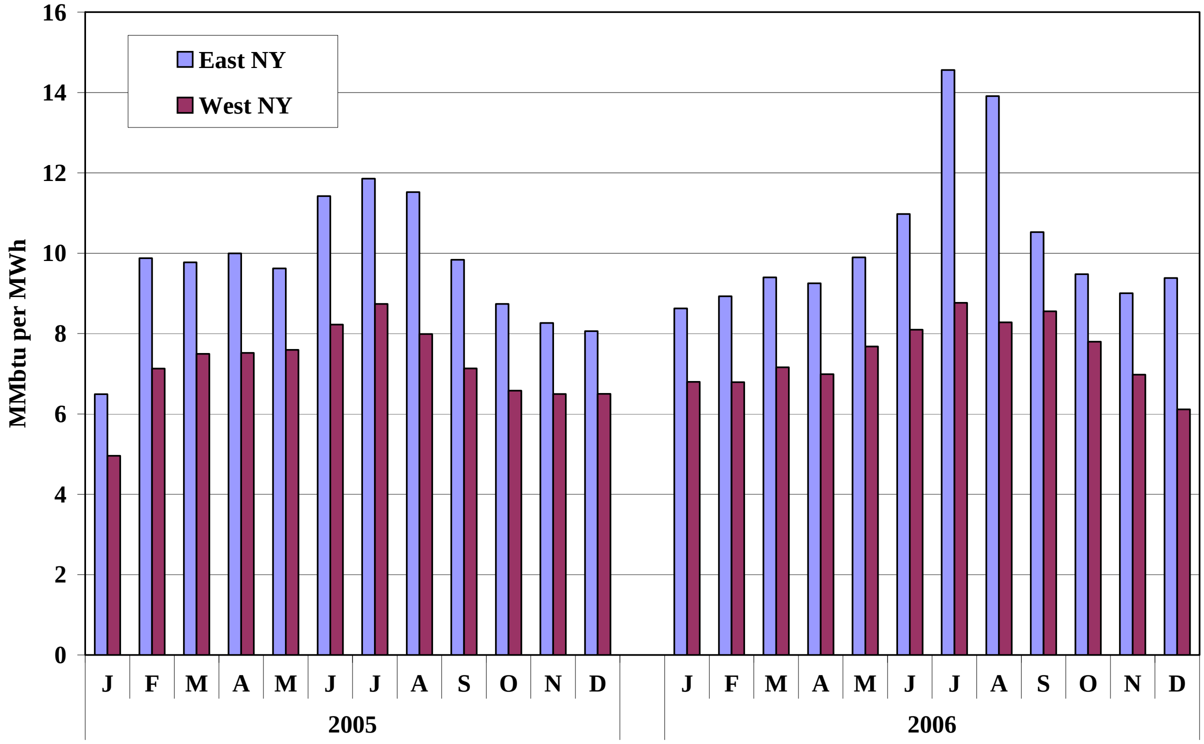
The highest demand levels occur during the hot summer months and typically result in elevated electricity prices, as peaking resources are used to meet the peak load and reserves requirements. During periods of shortage, prices can rise to more than 10 times the average price levels. Hence, a small number of hours with price spikes can have a significant effect on average price levels. Conversely, the effects of fuel costs are felt in the majority of hours. In 2006, there were a several hours of record-setting loads, but fuel costs were substantially lower than in 2005. Figure 1 illustrates the combined effects of these countervailing factors in 2006.

Prices remained significantly higher in East New York due to transmission congestion and losses. Prices in East New York were $22 per MWh higher on average (33 percent) than in the West. New capacity added in New York City contributed to lower congestion into the New York City zone, while the price differences between Long Island and the rest of the state increased during the year. Additional examination of the changing price patterns in the state, including more detailed analysis of New York City and Long Island price patterns, is provided later in this report.

To identify changes in energy 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. The Implied Marginal Heat Rate is shown for East and West New York on a monthly average basis for 2005 and 2006 in Figure 2.

Adjusting for the effects of changes in gas prices, Figure 2 reveals the effects of high demand levels in the East during July and August 2006. Except for the results of these two months, implied heat rates were similar in both East and West New York for 2005 and 2006. The effects of high demand levels on day-ahead prices were smaller in 2005 than in 2006 because of poor convergence between day-ahead and real-time energy prices in 2005. The day-ahead market did not fully anticipate the severity of real-time price spikes during peak demand conditions, and consequently, average day-ahead prices were 15 percent lower than real-time prices in July and August 2005.

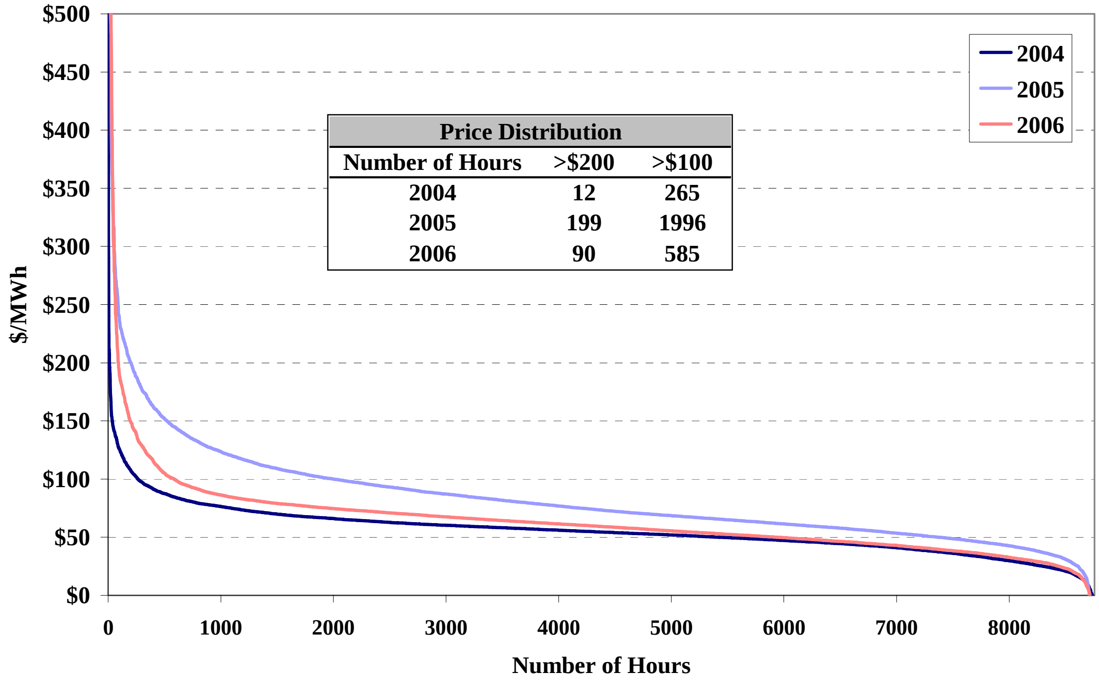
Figure 2: Average Implied Marginal Heat Rate
Based on Day-Ahead Electricity and Natural Gas Prices
2005 – 2006



Additional perspective on prices and loads in the NYISO is provided in the following two figures, a price duration curve and an implied marginal heat rate duration curve. Figure 3 presents the price duration curve, which shows the number of hours on the x-axis in which the market settled at or above the price level shown on the y-axis.

The chart uses the state-wide average of real-time prices. In 2006, there were 585 hours with prices above $100 per MWh, compared with 1,997 such hours in 2005. Similarly, there were 90 hours with prices above $200 per MWh, compared with 199 hours in 2005. Both changes reflect lower fuel costs, which translated into lower power prices over most hours in 2006. However, 2006 showed 25 hours with prices above $500 per MWh, compared with 21 hours above $500 per MWh in 2005. Despite the lower average price level in 2006 as compared to 2005, in 2006 there were slightly more hours with prices above $500 per MWh primarily due to significant improvements in the efficiency of pricing during shortage conditions. The improvements in shortage pricing are described and evaluated in Section VI.

Figure 3: Price Duration Curve
Average Real-Time Price
2004 – 2006



To identify factors affecting prices other than fuel price changes, the following figure shows the implied heat rate duration curve for 2004 to 2006. This shows the number of hours on the x-axis in which the market settled at or above a given implied heat rate level shown on the y-axis. In this case, the implied heat rate is the state-wide average real-time price divided by the natural gas price.

The implied heat rates were comparable between 2005 and 2006. Milder weather, the new capacity in New York City, and lower load levels in most hours were offset to some degree by the effects of lower gas prices on the calculation, resulting in moderate increase in the number of hours when the implied heat rate exceeded 10 MMbtu per MWh. The few days of record setting load combined with better recognition of reserves shortages by the real-time software led to a rise in hours when the implied heat rate exceeded 20 MMbtu per MWh.

Figure 4: Implied Heat Rate Duration Curves
Based on State-wide Average Real-Time Price and Natural Gas Price
2004 - 2006

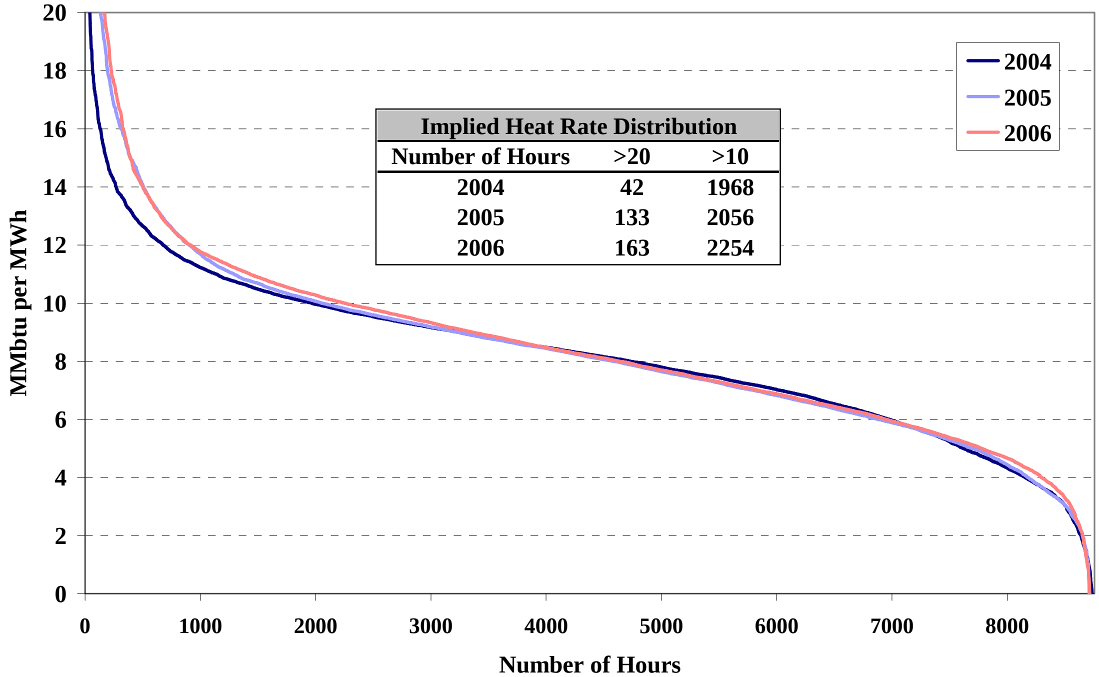
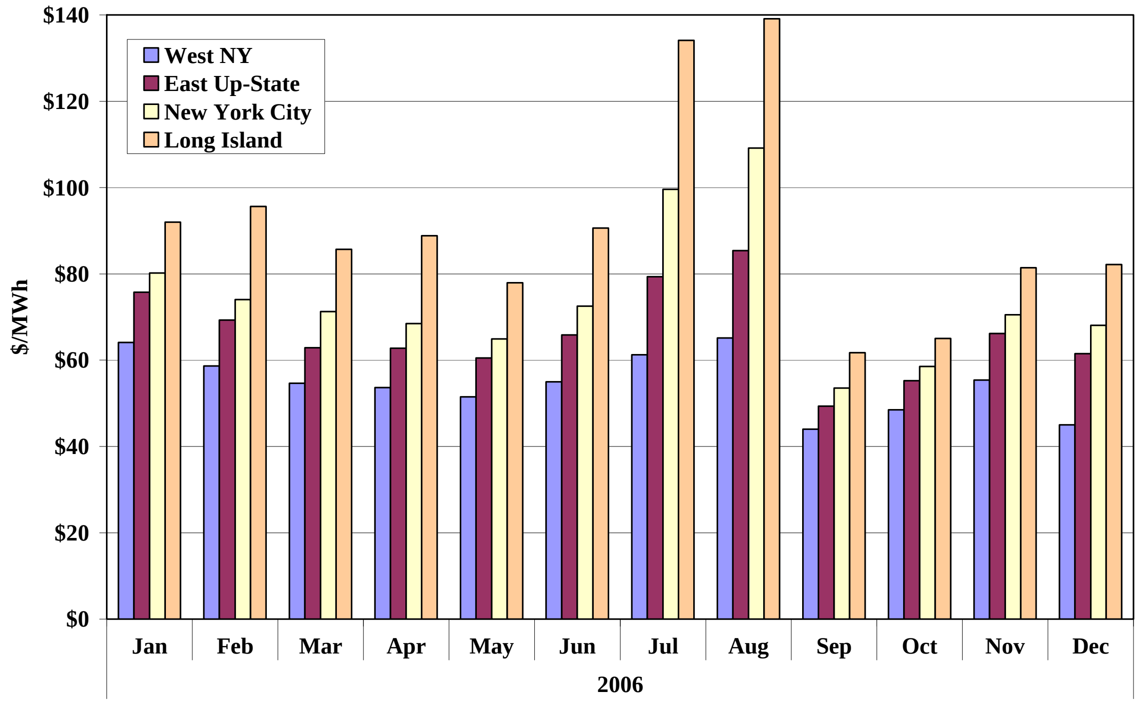


Figure 5 presents the monthly day-ahead energy prices in four regions in the State for 2006. Prices are lowest in Western New York, which exports significant amounts of power to Eastern New York. The prices are highest in New York City and Long Island which import a large portion of their power. Most of the power that flows from Western New York to New York City and Long Island passes through the Eastern upstate portion of the New York system. These west-to-east flows result in transmission losses and congestion that cause the pricing patterns shown in the figure.

Historically, energy prices in New York City and Long Island have tended to move together, both reflecting local imbalances between load and generation resources and the effects of transmission constraints that limit imports of lower-cost power from West New York under high load conditions. Beginning in early 2006, average day-ahead prices in New York City dropped below Long Island prices and began to more closely move with prices in the up-state portions of eastern New York. In January and May 2006, two 500 MW generators came online in New York City. One consequence of the additional capacity has been to reduce the number of hours that the interface into New York City has been congested. Additionally, improvements in 2006 to the modeling of transmission constraints within New York City has allowed more efficient use of the transmission system and correspondingly lower congestion costs. The modeling improvements are summarized and discussed in Section VI.

Figure 5: Day-Ahead Energy Prices by Region 2006

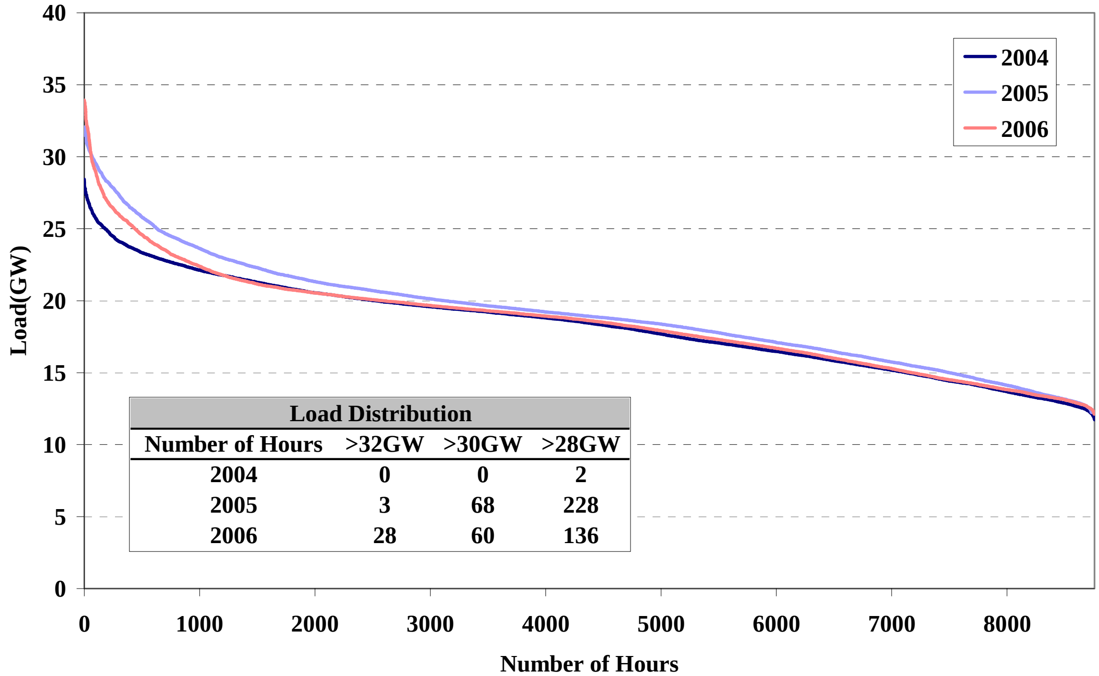


2. Energy Demand

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. Figure 6 shows load duration curves for 2004 to 2006.

The figure shows that load was lower in most hours in 2006 than in 2005. During 2006, however, New York experienced 25 hours with load levels in excess of 2005's previous record peak of 32,075 MW. Figure 6 reports that while 2005 had more hours than 2006 with loads above 30 GW, only 3 hours in 2005 exceeded 32 GW of load while 28 hours in 2006 exceeded that level. Moderate weather conditions during the summer of 2004 produced similarly moderate electrical load during the year. [1]

Figure 6: Load Duration Curves 2004 to 2006



Load Distribution			
Number of Hours	>32GW	>30GW	>28GW
2004	0	0	2
2005	3	68	228
2006	28	60	136

3. 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 real-time energy prices. The capacity component is calculated by multiplying the average capacity price (based on a weighted average of the six-month strip, monthly, and spot auctions) by the capacity obligations in each area, and dividing by total energy consumption. For the purposes of this metric, costs other than energy and capacity are distributed evenly for all locations.

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1 A similar picture is revealed by data on Cooling Degree Days, a conventional measure of the weather-driven component of fuel demand reported by the U.S. Department of Commerce, National Oceanic and Atmospheric Administration. Cooling degree days over the three years were: 594 CDD in 2004, 944 CDD in 2005, and 737 CDD in 2006. See http://lwf.ncdc.noaa.gov/oa/documentlibrary/hcs/hcs.html.

Figure 7: Average All-In Price
2005 – 2006

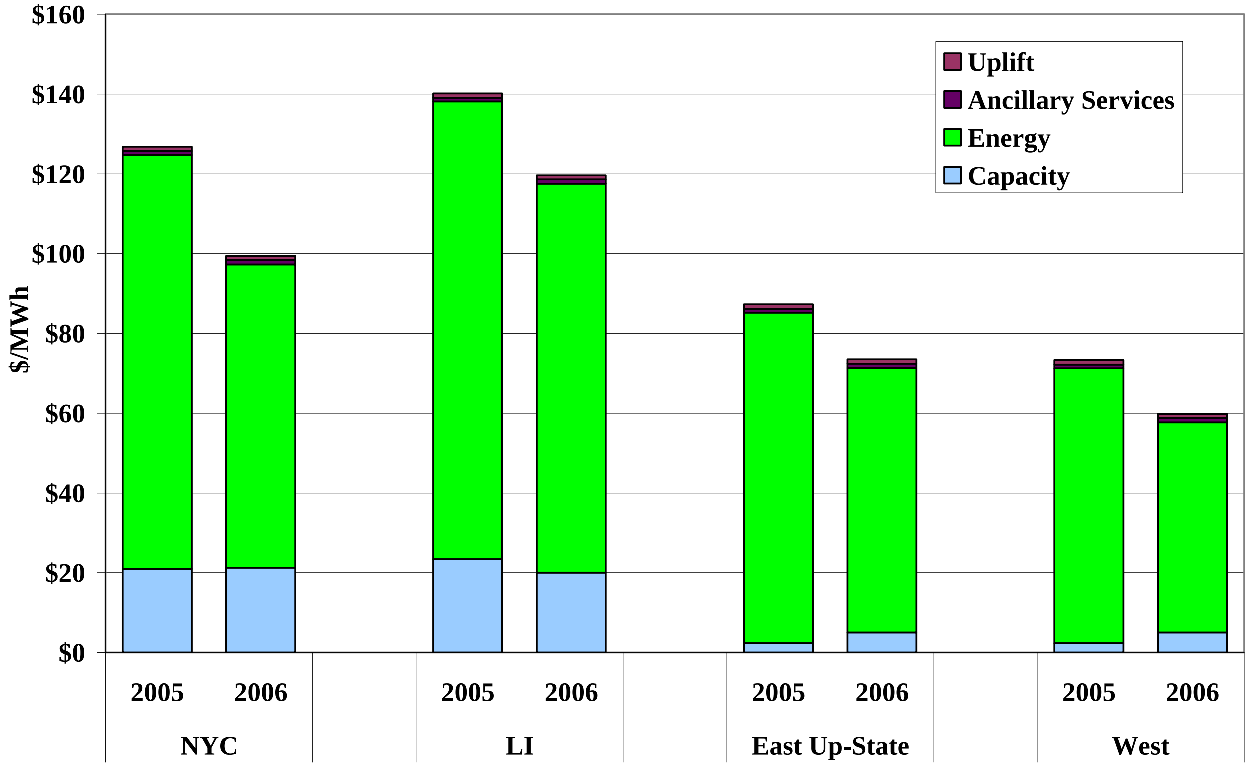
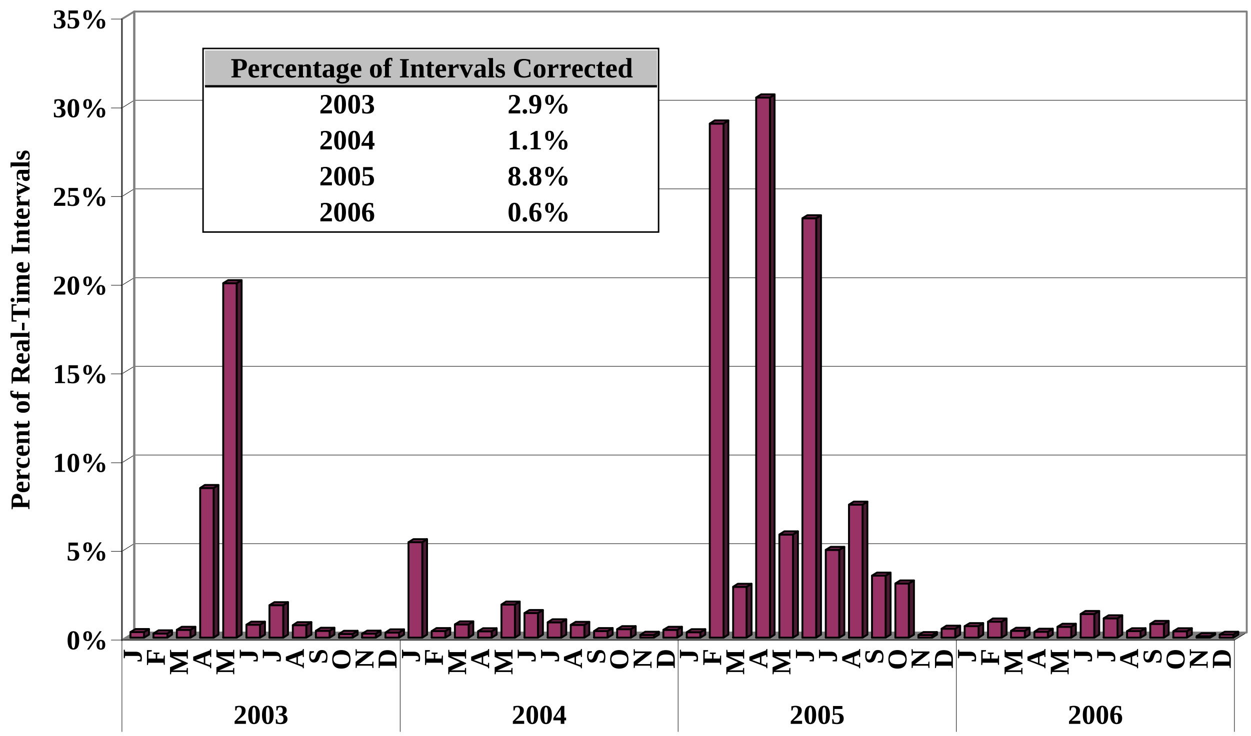


Figure 7 shows that the all-in price decreased from 2005 to 2006 in each of the four regions. These reductions are due to the lower fuel prices and loads in 2006 that were described earlier in this section. The figure shows that energy costs are by far the most significant component of market costs. 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 will raise 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. Accurate prices are critical not only for the obvious need to settle market transactions fairly, but also for sending reliable real-time price signals to market participants. Price corrections are required when flaws in the market software or flaws in operating procedures cause prices to be posted erroneously. It is important to resolve these errors as quickly as possible to maximize price certainty. Figure 8 summarizes the frequency of price corrections in the real-time energy market from 2003 to 2006.

Figure 8: Percentage of Real-Time Prices Corrected



The rate of corrections spiked in 2005 due to issues associated with the implementation of new real-time market software 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. Several significant software issues were identified and resolved in February 2005. Remaining software issues surfaced from March to June and were addressed by October. Once these initial software issues were addressed by NYISO, the frequency of price corrections fell to more typical levels. In fact, as Figure 11 shows, in 2006 price corrections were reduced to just 0.6 percent of real time intervals.

C. Net Revenue Analysis

Revenues from the energy, ancillary services, and capacity markets provide the key 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 in the market from sales of energy, ancillary services, and capacity. 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 imply the opposite of one of these factors. If a revenue shortfall persists for an extended period, without an excess of capacity, this is a strong signal that markets need modifications.

1. Standard Analysis and Discussion of Market Signals

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.[2] We calculated the net revenue the markets would have provided to two different types of units at these locations for the last three years. The two types of units are:

- Gas combined-cycle: assumes a heat rate of 7 MMBTU per MWh and variable O&M expenses of $3 per MWh, and
- New gas turbine: assumes a heat rate of 10.5 MMBTU per MWh and variable O&M expenses of $1 per MWh.

For both unit types, the analysis assumes a forced outage rate of 5 percent. In this analysis, net revenue is equal to the average hourly real-time price minus variable production expenses in

2 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.

hours when the price is greater than the variable production expenses. The assumptions for this analysis have been standardized by FERC and the market monitors in the various markets to provide a comparable basis for comparison of the net revenue values from the different markets.

Figure 9: Estimated Net Revenue in the Day-Ahead Market
Combined Cycle Unit

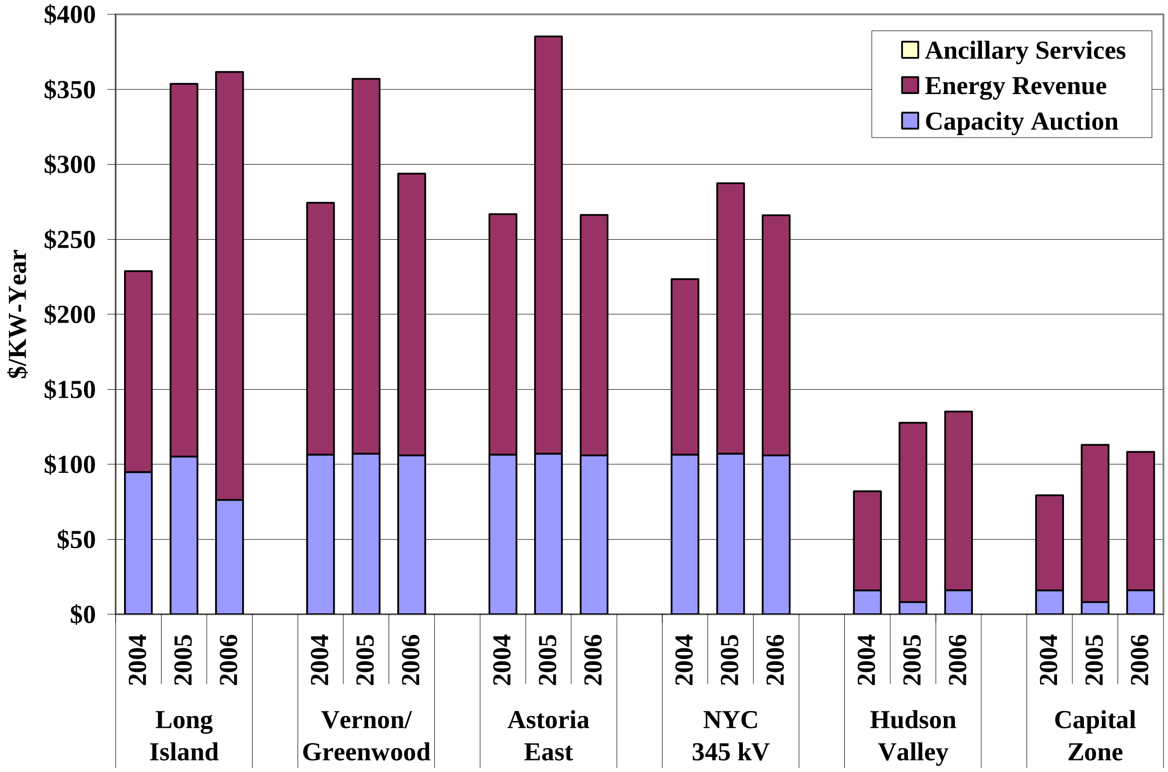
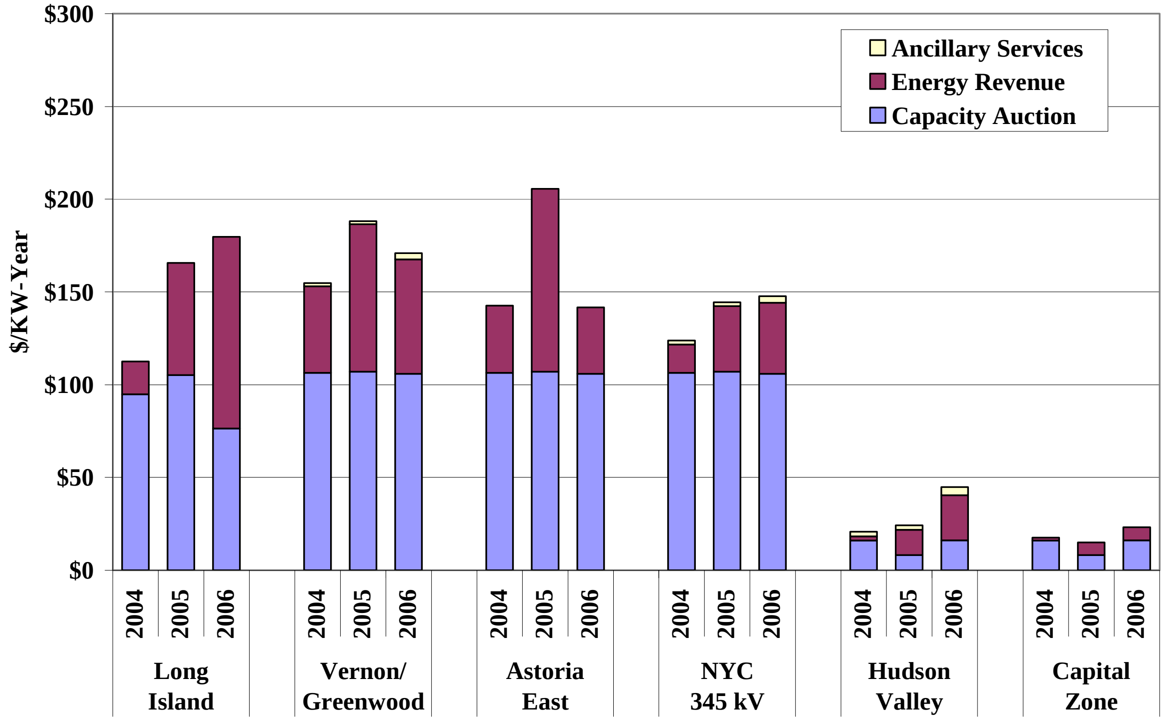


Figure 9 and Figure 10 show net revenue estimates for six locations in New York from 2004 to 2006. Figure 9 shows the estimates for a new combined cycle generator, while Figure 10 shows the estimates for a new combustion turbine. Note that the capacity auction values reflected in the Net Revenue charts are from the capacity strip auctions in all regions except for Long Island. For Long Island, the average spot auction price is used because the low quantities traded in the Long Island strip and monthly auctions result in prices that may not reflect overall capacity market revenues available in the zone.

Figure 10: Estimated Net Revenue in the Day-Ahead Market
Gas Turbine Unit



From 2004 to 2006, there was a substantial increase in the net revenues that would have been received by a hypothetical combustion turbine or combined cycle generator at the six 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 analyses clearly show how net revenues are affected by new investment. In New York City, Astoria East was one of the most constrained load pockets prior to the installation of new capacity in 2006. As a result, the estimated net revenues for Astoria East declined in 2006 by 31 percent for both combined cycle units and combustion turbines. Net revenues in Vernon/Greenwood and the 345 kV area also decreased, but by smaller amounts. In the Capital Zone, approximately 1,800 MW of new capacity was installed in 2004 and 2005, contributing to more frequent price separation between the Capital Zone and the Hudson Valley. In 2004, a combined cycle unit could expect to earn 3 percent more net revenue in the Hudson Valley than in the Capital Zone. By 2006, the difference increased to 25 percent due to more frequent congestion.

This analysis shows that net revenues in 2006 might support the installation of new combustion turbines in Long Island and new combined cycles in Long Island, New York City, and the Hudson Valley. However, there is considerable uncertainty both about the cost of new investment and the 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 shows that market participants must consider how the investment will affect the market outcomes.

There are several factors that are likely to cause significant changes in net revenue in the near-term. First, the Neptune line, which is scheduled to come into service in 2007, will increase import capability into Long Island from New Jersey by 660 MW. Second, if more of the existing installed capacity in New York City is sold into the capacity market, capacity prices will decrease substantially, which will reduce net revenue.

In recent reliability needs assessments (“RNA”), a need for additional capacity has been identified in the lower Hudson Valley, which is within the “rest-of-state” installed capacity zone (“ROS”). To the extent that generation is more costly to build in that area and the market signals are likely to continue to be less than this cost, a separate capacity zone may be warranted in this area. The comprehensive reliability planning (“CRP”) calls for regulated backstop solutions to be constructed if market-based solutions do not come forward that will address the identified reliability needs. 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 could cause market signals to be understated, rather than relying on regulated solutions to meet the reliability needs of the system. Defining additional zones in the ROS area may be needed to 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 new capacity zones are warranted.

Our analysis also shows that market signals have tended to shift in favor of investment in baseload and intermediate resources that, while more costly to build, produce electricity at a relatively low cost. This change indicates that, over time, the markets provide efficient incentives to invest in a diverse array of resources. In particular, a well-functioning market will support investment in various types of generating resources, demand response resources, and transmission.

To preserve the credibility and effectiveness of the market in supporting these investments, policymakers should take great care in utilizing the regulatory process to prompt new investment. A useful principle in this regard is that any investments that receive regulatory support should be consistent with the market signals, except to the extent that they provide benefits not reflected in market prices (e.g., environmental benefits).

2. Enhanced Net Revenue Analysis

The net revenue estimates produced using the standardized net revenue assumptions described above may differ from the actual net revenues earned by market participants for several reasons. First, the assumptions over-simplify certain aspects of the operations of combined cycles and gas turbines. Gas turbines have significant start-up costs, while combined cycle generators have significant start-up costs, lengthy start-up lead times, and minimum run time requirements that exceed one hour. Because net revenue is calculated on an hourly basis, ignoring commitment considerations, the net revenues shown may be overstated.

Second, the variable fuel expenses in this analysis are based on day-ahead natural gas price indices, although some generators may incur higher costs to obtain natural gas. Gas turbines frequently purchase natural gas in the intraday market, which generally trades at a slight premium to the day-ahead price used in this analysis. Therefore, the net revenue for gas turbines is likely to be slightly higher than an actual new unit would realize. 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.

Third, the net revenue estimates are based entirely on day-ahead clearing prices, although certain generators make the substantial portion of their sales in the real-time market. While combined cycle generators sell most of their output in the day-ahead market because it allows them to ensure that they will recoup their commitment costs, gas turbines have less substantial commitment costs and generally sell a large share of output into the real-time market.

To address limitations in the standard net revenue analysis, we conducted an enhanced assessment. Figure 11 and Figure 12 show the effect of addressing these issues on the calculation of net revenues. Included in both figures are markers indicating comparable results from the standard analysis.

Overall, the results of the enhanced analysis are comparable to the results of the standard analysis. Several assumptions are added in the enhanced analysis:

- *Combined Cycle* – 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 spinning reserve and 30-minute reserve capability. Assumes online generators arbitrage between day-ahead and real-time prices by increasing or decreasing its scheduled production based upon real-time price signals.
- *Combustion Turbine* – 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. Assumes the unit may be committed for additional hours based on RTC (or BME) prices, but the unit is paid the hourly average real-time price.

The enhanced net revenue estimates for a combined cycle unit are slightly lower than under the standard analysis. The differences are primarily due to reductions in net revenue resulting from start-up costs and minimum runtime restrictions, and some small offsetting gain in net revenue from arbitrage of differences between day-ahead and real-time prices.

The estimates for a combustion turbine are higher than in the standard analysis for most locations. The differences arise from gains in net revenue in hours in which the generator is committed after the day-ahead market, offset to a small degree by the inclusion of start-up costs in the analysis.

Figure 11: Enhanced Net Revenue Analysis Combined Cycle Unit

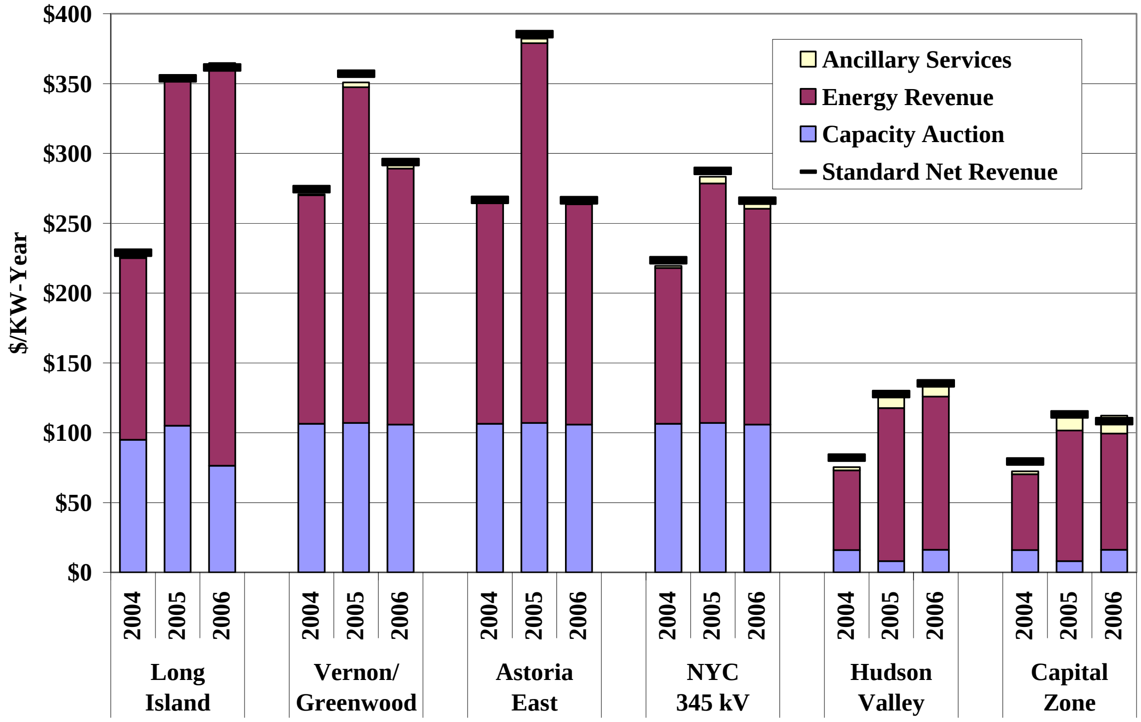
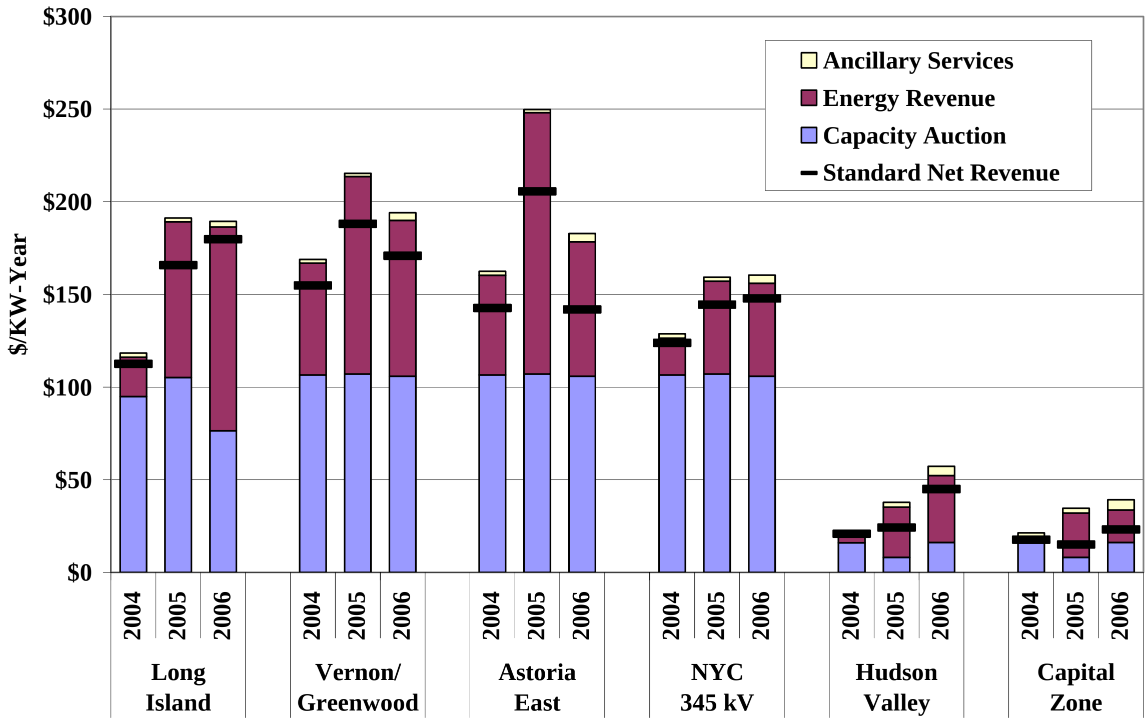


Figure 12: Enhanced Net Revenue Analysis, Gas Turbine Unit



While the enhanced analysis generates results that better reflect the interaction of system conditions and unit operating practices, the results do not substantially change the findings of the standard analysis.

II. 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 the real-time. Participants can use the day-ahead markets to hedge risks associated with real-time markets, and the system operator uses day-ahead bids and offers to improve 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. However, suppliers that sell in the day-ahead market are exposed to some risk, because they are committed to deliver physical quantities in the real-time market and an outage could force them to purchase replacement energy from the spot market during a price spike.

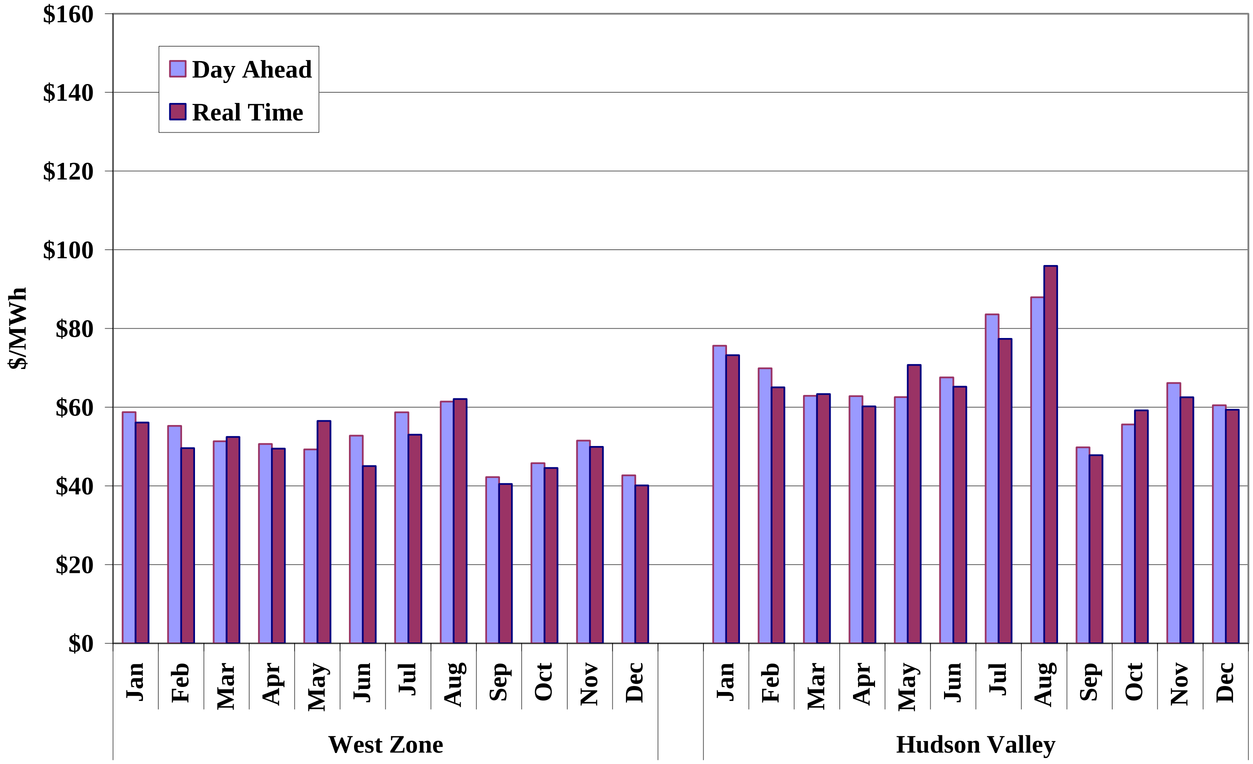
In a well functioning system with day-ahead and real-time markets, we expect that day-ahead and real-time prices will not systematically diverge from one another. If day-ahead prices were predictably *higher* than real-time prices, buyers would increase purchases in real-time. Alternatively, if day-ahead 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 at marginal cost. A review of 2006 market outcomes shows improvement in the convergence of day-ahead and real-time energy prices in most zones. In-City transmission constraints have led to substantial price differences at the nodal level within the New York City zone, but such intra-zonal differences were also improved in 2006 versus 2005. In this section, we evaluate three aspects of convergence in prices between day-ahead and real-time markets: (i) energy prices at the zone level, (ii) energy prices in load pockets within the New York City zone, and (iii) ancillary services prices.

A. Energy Price Convergence

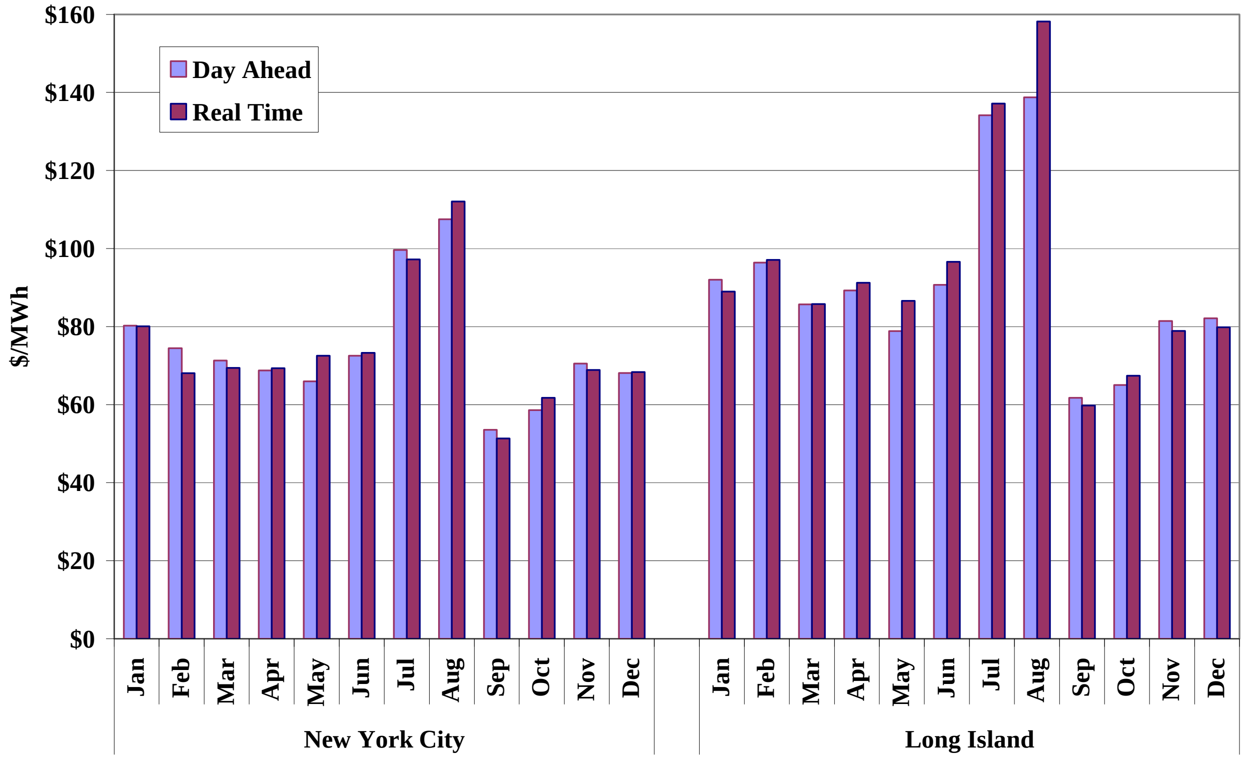
Figure 13 and Figure 14 show monthly comparisons of the average day-ahead and real-time energy prices in the West zone, Hudson Valley, New York City zone, and Long Island during 2006.

Figure 13: Day-Ahead and Real-Time Energy Price Convergence West Zone and Hudson Valley, 2006



Outside the summer months, day-ahead prices exhibited a slight premium over real-time prices for each of the four zones shown, with the exception of Long Island. During the summer of 2006, the day-ahead premium increased substantially in the West, while the slight day-ahead premium decreased in the Hudson Valley and there was a slight real-time premium in New York City. Long Island showed a slight real-time premium outside of the summer and a more substantial real-time premium during the summer. However, the sizes of the day-ahead and real-time premiums were generally much smaller in 2006 than in 2005. In other words, convergence between day-ahead and real-time prices improved considerably in 2006. The exception was in the West zone, in which the summer day-ahead premium in 2006 was larger than in 2005 in both absolute terms and as a percentage of average prices.[3]

Figure 14: Day-Ahead and Real-Time Energy Price Convergence New York City and Long Island, 2006



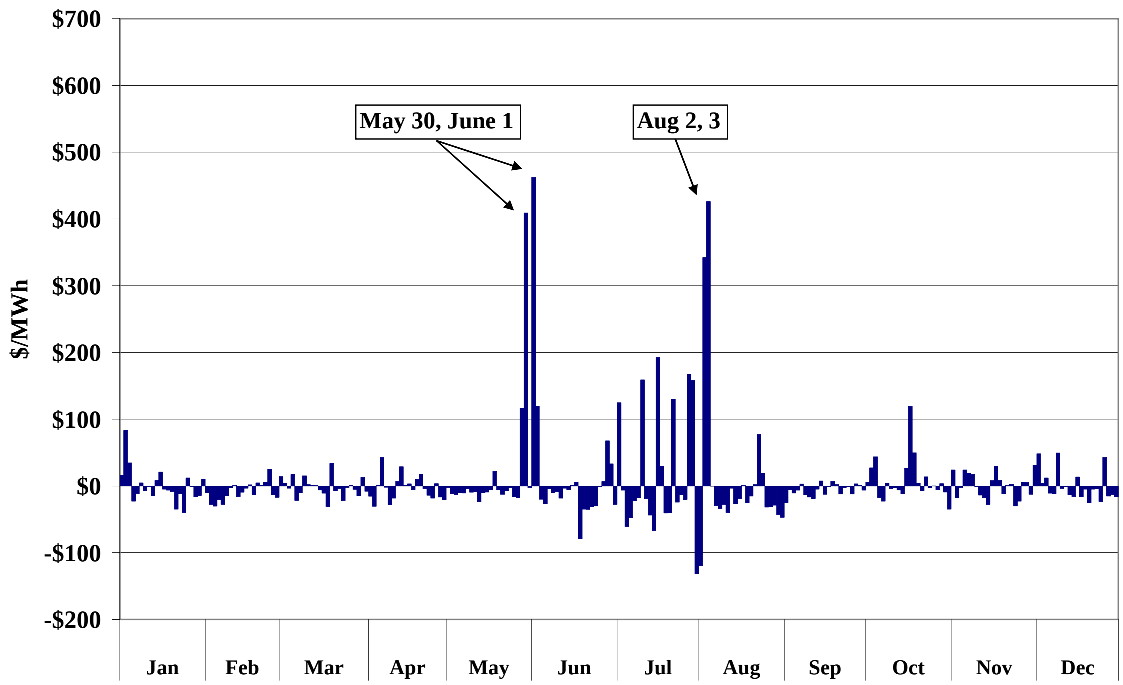
During the summer of 2005, the market experienced many more price spikes than previously due to hotter weather, Thunder Storm Alert ("TSA") operations, and reserve shortages. For example, 2005 faced numerous periods of high energy prices due to reserve shortages, while there were no periods of shortage pricing in 2003 or 2004. In addition, 2005 saw the implementation of SMD 2.0 that introduced several changes into the relationship between day-ahead and real-time prices, including a two-settlement system for ancillary services. As market participants gained experience with the new design in 2005 and 2006, real-time prices were predicted more accurately by day-ahead prices and differences between day-ahead and real-time prices

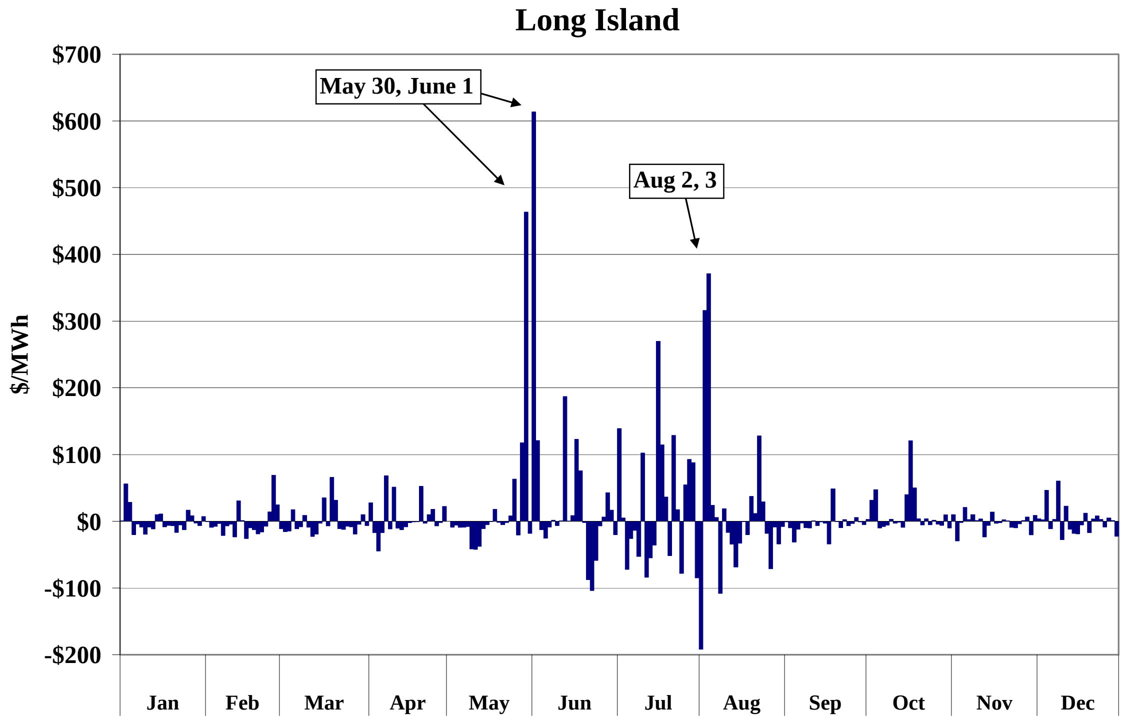
3 In 2005, the West zone showed a $2.66 average real-time price premium, which represented about a 3.6 percent change in prices; in 2006 the zone had a $4.75 average day-ahead premium, which was about an 8.2 percent change in prices.

decreased. The additional experience accounts for much of the improved convergence between day-ahead and real-time prices in 2006.

The factors that dictate real-time prices on a particular day are inherently random and 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. Figure 15 shows the variation in these differences on a daily basis in New York City and Long Island zone during weekday afternoon hours in 2006. A positive number represents a real-time market price premium – the real-time price is higher than the day-ahead price – while a negative number represents a day-ahead price premium.

**Figure 15: Average Daily Real-Time Energy Price Premium
1 p.m. to 7 p.m., Weekdays – 2006
New York City**





Day-Ahead market prices are higher than real-time prices most afternoons. For example, in New York City day-ahead prices were higher almost 70 percent of summer afternoons and Long Island day-ahead prices were higher on just over half of the afternoons. However, very high prices are more frequent in the real-time market. On summer afternoons when the difference between average day-ahead and real-time prices exceeded $100 per MWh, the real-time price was higher on 10 out of 12 afternoons in the New York City zone, and on 12 out of 15 afternoons on Long Island.

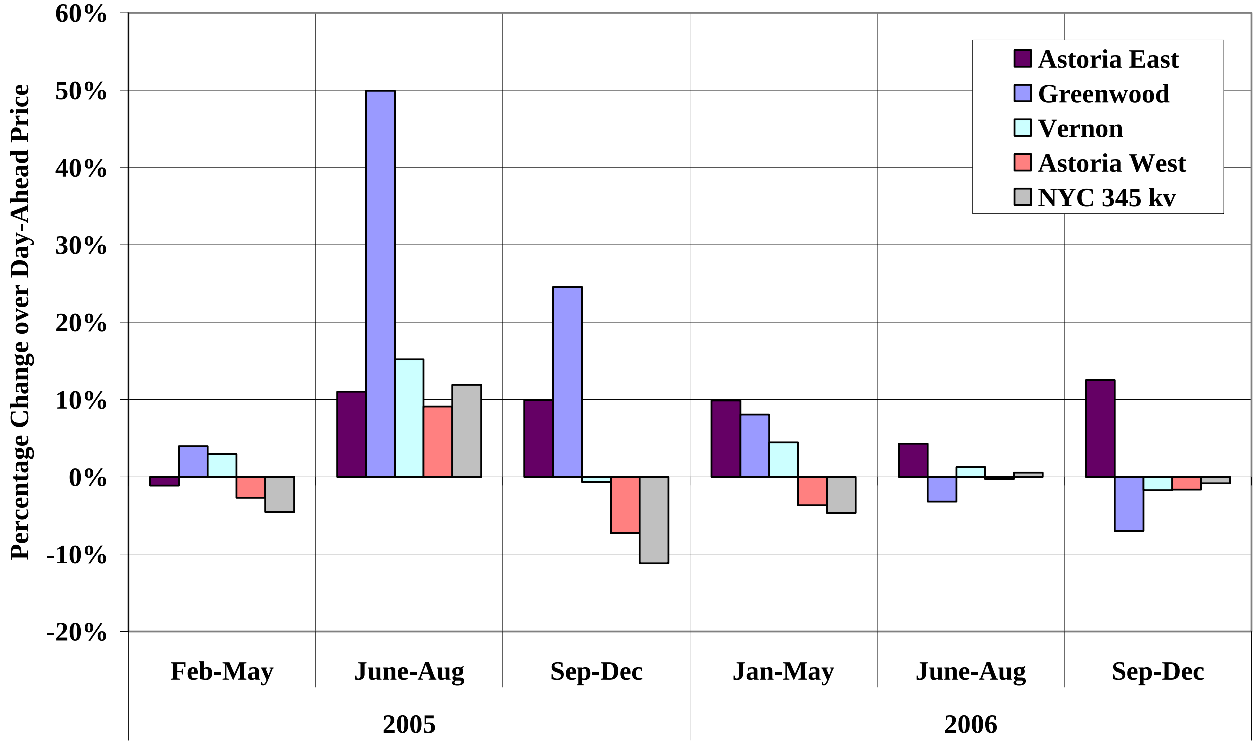
A large number of price spikes resulted from TSAs, which require double contingency operation of the ConEd overhead transmission system, and TSAs can be particularly costly when they coincide with high load conditions. Because TSAs are operational changes called in response to weather conditions as they develop, they 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. As participants continue to gain experience with market performance under high load levels, convergence should continue to improve.

Price convergence has been 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.

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. At times, some locations experience significant divergence in day-ahead and real-time prices that are off-set 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 improved 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 16 shows average real-time price premiums for five areas which account for the majority of the load within New York City.

Figure 16: Real Time Price Premiums within New York City Selected Locations, 2005 & 2006



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.

Systematic differences between day-ahead and real-time prices at specific locations within New York City were generally smaller in 2006 than in 2005. Three developments during 2006 directly contributed to improved convergence within the New York City zone. First, a significant amount of new capacity was installed in Astoria West in January 2006. Second, in May 2006 another substantial addition of capacity came online in Astoria East. These capacity additions substantially reduced congestion within the zone. Third, in May 2006 the NYISO began to use the same detailed network model of the city for real-time scheduling as was used in the day-ahead Market. Using the same model for day ahead and real time markets eliminated a significant barrier to convergence between the markets. The use of the more detailed transmission model in real-time scheduling also results in more efficient use of the transmission network.

While in-City convergence has improved, price convergence in load pockets could be improved by introducing virtual trading and permitting price-capped load bids within the New York City load pockets. Limiting price-capped load bidding and virtual trading to the zonal level in New York City limits the ability of participants to arbitrage large price differences in specific load pockets. Allowing virtual trading at the load pocket or nodal level would likely improve convergence inside New York City load pockets.

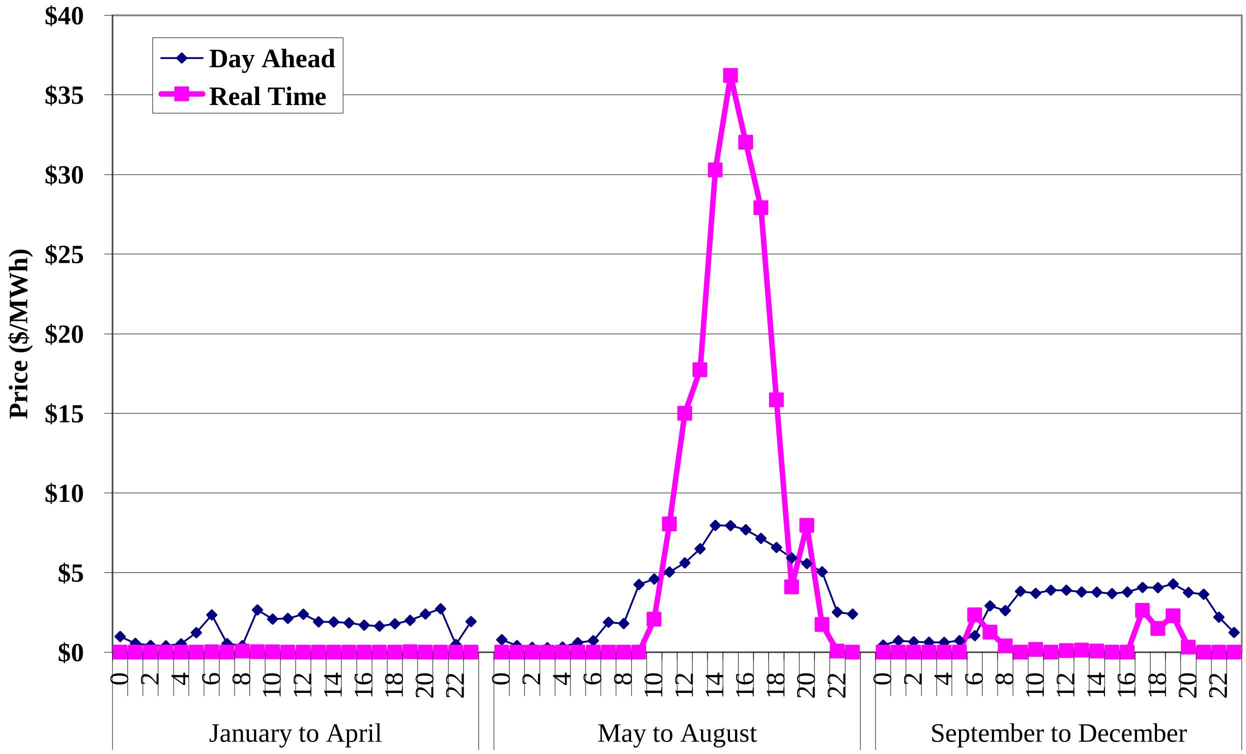
C. Ancillary Services Price Convergence

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.

Unlike the market for energy, when systematic differences arise between day-ahead and real-time prices, ancillary services suppliers are the only entities that arbitrage them by shifting sales to the higher priced market. However, when ancillary services suppliers increase their offer prices in the day-ahead market, it can lead to less efficient day-ahead commitment patterns. Load serving entities cannot submit price sensitive bids to purchase ancillary services in the day-ahead market. The same amounts of ancillary services are purchased in the day-ahead and real-time markets, based on reliability criteria and without regard to price, thereby preventing market participants from arbitraging day-ahead to real-time ancillary services price differences. Moreover, virtual trading of ancillary services products is not currently allowed, so market participants without physical resources cannot arbitrage day-ahead to real-time price differences.

The following chart shows day-ahead and real-time 10-minute reserves prices in eastern New York by hour of the day for several periods during 2006. The eastern 10-minute reserves price is important because the ISO requires 1,000 MW of 10-minute reserves east of the Central-East interface.[4] This particular requirement is typically the most costly reserve requirement for the ISO to satisfy due to the relative scarcity of capacity in eastern New York.

Figure 17: Day-Ahead and Real-Time 10-Minute Reserves Prices
Eastern New York, 2006



During the summer, average real-time prices for 10-minute reserves were significantly higher than other times of year, while day-ahead prices rose only modestly.[5] During daytime hours, average day-ahead prices ranged from $2 to $8 per MWh, while average real-time prices ranged from $0 to $37 per MWh. While the real-time 10-minute reserves price is higher on average, the average value masks substantial variability in the real-time price. Typically, real-time reserves prices are very close to zero, but under conditions of near-shortage, prices can rapidly rise to hundreds of dollars per MWh. The $37 per MWh average price in the peak afternoon hour of the summer is an average across many days when the price was zero or near zero and a small

4 The NYISO actually requires 1,200 MW of 10-minute reserves in eastern New York, however, 200 MW of this requirement is generally satisfied through a reserves sharing agreement with New England.

5 For this discussion, "summer" includes the months of May through August. TSAs are a prominent factor affecting ancillary price convergence. While TSAs can be called in any month of the year, they appear with more frequency and are of more economic significance during high load times from May to August.

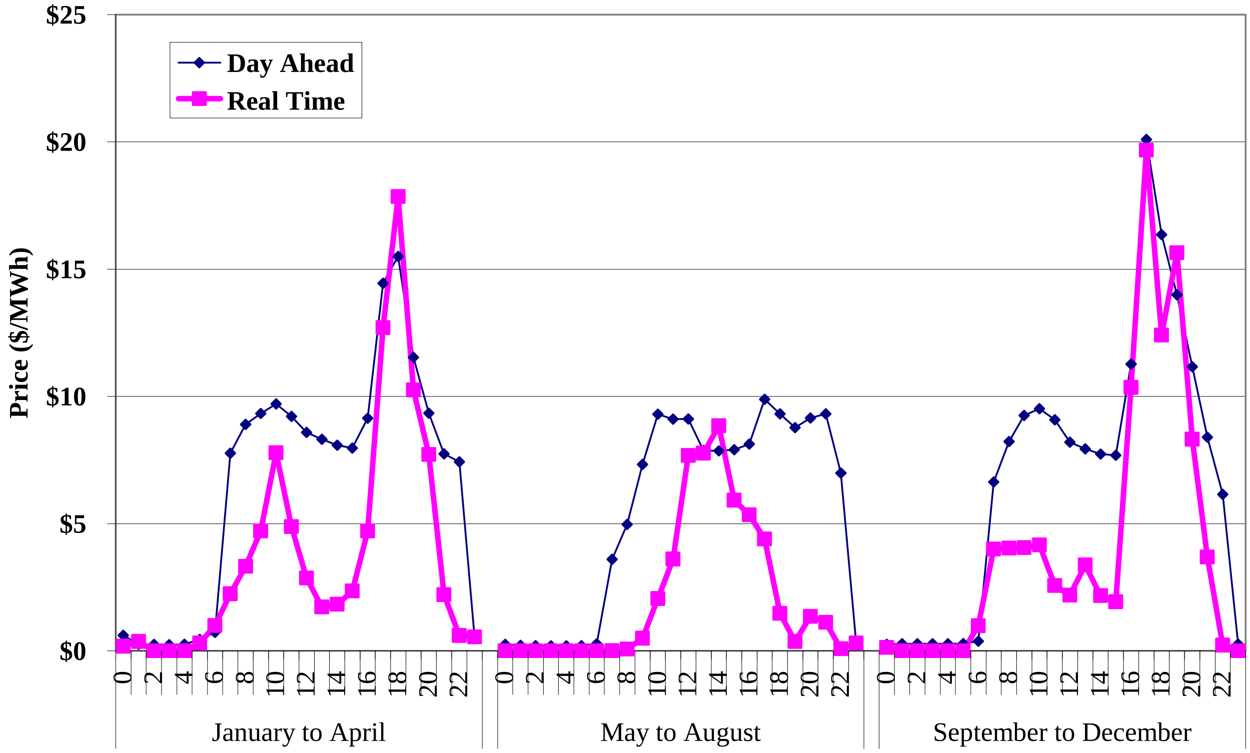
number of peak pricing events.[6] This volatility is difficult for market participants to predict in the day-ahead market, and based on the figure above, the day-ahead market systematically under-valued 10-minute reserves in the east during the summer.

The spring and fall price pattern was the reverse of the summertime pattern, with average real-time prices being lower than average day-ahead prices. Average real-time prices were low due to the infrequency of real-time peak pricing events. Since reserves suppliers must submit $0 per MWh availability offers in the real-time market, 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 close to $0. Reserves suppliers are able to submit availability offers to the day-ahead market that exceed $0.

The following figure shows day-ahead and real-time 10-minute synchronous reserves prices in western New York by hour of the day for several periods during 2006. This price depends primarily on the state-wide 10-minute synchronous reserves requirement of 600 MW. We show western rather than eastern New York because the eastern New York price is heavily influenced by other reserves requirements, while the western New York price is primarily based on the state-wide 10-minute synchronous reserves requirement.

6 The 10-minute reserve price was $0 in 2848 hours of the 2952 hours from May 1 through August 31, 2006, and only 58 hours had prices above $100 per MWh. The maximum hourly price was approximately $855 per MWh in hour 15 of August 1, 2006.

**Figure 18: Day-Ahead and Real-Time 10-Minute Spinning Reserves Prices
Western New York, 2006**



The relationship between day-ahead and real-time prices varied greatly by time of day and the season. In spring and fall, day-ahead prices were higher than real-time prices on average from the morning ramp up through mid-day, but prices converge well at other times. During the summer, day-ahead prices substantially exceeded real-time prices during the morning and evening hours but converged well with real-time prices at mid-day.

It is counterintuitive that western 10-minute synchronous reserves prices decrease during the summer, which is when most products become more expensive. This is the indirect effect 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 upon 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. This reduces the amount of 10-minute synchronous reserves that must be held in western New York.

Figure 19 shows day-ahead and real-time regulation prices in New York by hour of the day for several periods during 2006. This price depends primarily on the state-wide regulation requirement which typically varies between 150 MW to 275 MW according to the time of day. More regulating capability is needed in the morning when the system is ramping up and in the evening when the system is ramping down.

Figure 19: Day-Ahead and Real-Time Regulation Prices
State-wide Price, 2006

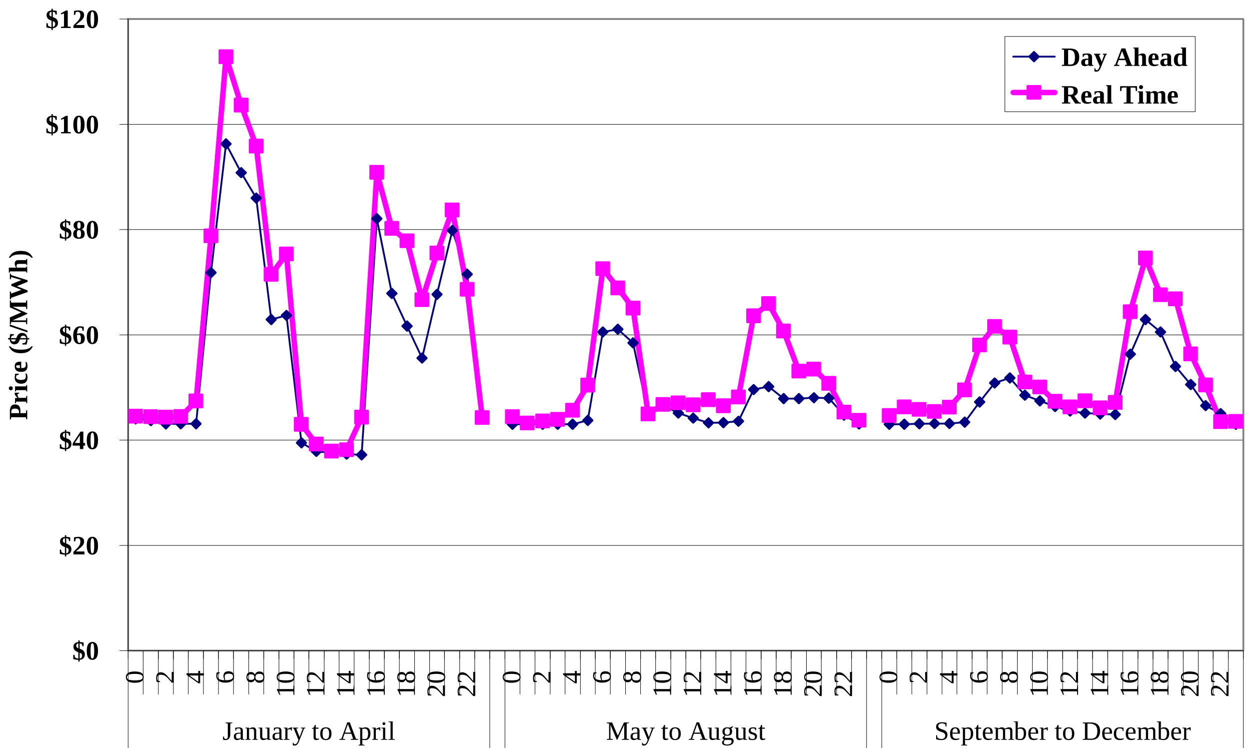


Figure 19 shows that regulation clearing prices fluctuate significantly as the requirement varies according to the time of day. Day-ahead and real-time regulation prices are highly correlated to one another across the day, with real-time prices being on average slightly higher than day-ahead prices. This pattern may reflect that real-time spikes in the regulation price occur with greater frequency than spikes in the day-ahead price.

Figure 19 also shows a moderating of regulation prices after the spring, with summer and fall prices both lower on average and less variable across the day. Beginning in June 2006, approximately 100 MW of low-priced offers by generators not previously offering regulation began participating in the market. However, regulation prices in 2006 remained higher on average than regulation prices in 2005 before a September change in offer strategies resulted in increased regulation prices. This pattern is discussed in greater detail in the following section.

Overall, the analyses in this sub-section indicate that day-ahead and real-time ancillary services prices did not converge well in 2006. For eastern 10-minute reserves, day-ahead prices were consistently higher than real-time prices under all circumstances except afternoons in the summer when average real-time prices were far greater than average day-ahead prices. For 10-minute spinning reserves, the cost of which is reflected in the price for western New York, average day-ahead prices were higher than average real-time prices under a variety of conditions. For regulation, real-time prices were consistently higher than day-ahead prices at all times of the day in each season.

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 commitment of expensive resources that are well suited to 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 no 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. Persistent differences between day-ahead and real-time prices give generators an incentive to raise or lower their day-ahead offer price, which can further reduce the efficiency of the day-ahead commitment. The following section examines ancillary services offer patterns to determine whether their behavior is influenced by the poor convergence between day-ahead and real-time prices.

III. Ancillary Services Markets

The NYISO operates ancillary services markets in conjunction with day-ahead and real-time energy markets. Under the SMD 2.0 market enhancements, the NYISO became the first wholesale market operator to co-optimize 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. Because ancillary services markets are co-optimized with energy markets, clearing prices reflect the costs to the system of diverting resources to provide ancillary services that would otherwise provide energy. When the system is short of resources and unable to fully satisfy reserve requirements, the reserve price is based on the economic value of the reserve demand curve and this value is reflected in the energy price. These initiatives substantially improved the efficiency of energy and ancillary service dispatch levels and prices in real time, particularly during shortage conditions. This section reviews the performance of the ancillary services markets in 2006, highlighting the effect of the changes in market design.

As expected, net expenses for ancillary services have increased with the SMD 2.0 changes. Total expenses for regulation, voltage services, and operating reserves increased from $124 million in 2004, to $161 million in 2005, and $195 million in 2006.[7] The prices for regulation and operating reserves now better reflect the value of the services to the system, including the opportunity costs of a resource called upon to provide reserves rather than energy. Because the shortages that occur in real-time are real and reflect diminished reliability, pricing these shortages in the energy and reserves markets in both the real-time and day-ahead markets represents a significant market improvement even though it has resulted in higher prices and ancillary services expenses. The costs of providing ancillary services also has increased due to higher fuel costs and changes in participant offer patterns.

[7] The SMD 2.0 market design changes were implemented in February 2005.

A. Background

1. Operating Requirements

New York procures three types of operating reserves: ten-minute spinning reserves, ten-minute total reserves, and 30-minute reserves. Ten-minute spinning reserves are held on generating units that are on-line and can provide additional output within 10 minutes. Ten-minute total reserves can be supplied by ten-minute spinning resources or ten-minute non-spinning resources, which are typically gas turbines that are not on-line but can be turned on and be producing within 10 minutes. 30-minute reserves may be supplied by any unit that can be ramped up in 30-minutes or that can be on-line and be producing within 30 minutes. In each hour, the New York ISO purchases approximately 1800 MW of operating reserves. Of this 1800 MW, at least 1200 MW must be ten-minute reserves (at least 600 MW must be spinning reserves and the balance may be either spinning or non-spinning).

The procurement of reserves is subject to locational requirements to ensure that the reserves will be available to respond to possible system contingencies. Because the Central-East Interface is often constrained, maintaining reliability requires that a substantial portion of the reserves be procured in Eastern New York. Likewise, transfer limits on the interface between Long Island and the rest of New York dictate that a certain amount of operating reserves be purchased from within Long Island. For total ten-minute reserves (spinning and non-spinning), 1200 MW must be purchased east of the Central-East constraint. The NYISO obtains 200 MW of this requirement through a reserve sharing agreement with New England, leaving 1000 MW to be purchased within the eastern portion of New York. The NYISO generally seeks to obtain at least 300 MW of ten-minute spinning reserves from eastern portion of New York. It also procures at least 60 MW of ten-minute spinning, 120 MW of total ten-minute, and 540 MW of total reserves from within Long Island.

New York also purchases regulation services, which are necessary for the continuous balancing of resources (generation and NY Control Area interchange) with load and to assist in maintaining scheduled interconnection frequency at 60 Hz. This service is accomplished by committing on-line generators whose output is raised or lowered (predominately through the use of Automatic Generation Control) as necessary to follow moment-by-moment changes in load.

Regulation capability can be purchased from anywhere within the New York Control Area. The NYISO purchased 275 MW of regulation during high-ramp hours and 150 MW during low-ramp hours in 2006. The amount of regulating capability a generating resource may sell is equal to the amount of output it can produce within 5 minutes (ramp rate per minute times 5). 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

The design of the ancillary services markets and their interaction with the energy market changed significantly with the implementation of SMD 2.0. First, reserves and regulation are co-optimized with energy in the real-time spot market auction. 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. Prior to SMD 2.0, reserves and regulation allocations were determined on an hourly basis. Since system conditions can change quickly and unexpectedly, this sometimes resulted in reserves being held inefficiently or in areas that could not provide reliability benefit.

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 maintain each megawatt of reserves or regulation. In cases in which sufficient reserves do not exist, a model without demand curves would fail to reflect the reserve shortage in the clearing prices for energy or ancillary services. In shortage conditions under SMD 2.0, 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.

Under SMD 2.0, all dispatchable generators offering to sell energy in real-time must also offer to provide reserves with a $0 per MWh availability bid. Thus, the real-time clearing prices for reserves are 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, the clearing prices of reserves drop to $0 per MWh because it costs nothing to maintain reserves.

The new market design added ancillary services to the two-settlement system that has existed for energy since 1999. A two-settlement system consists of a spot market (i.e. real-time) and a forward financial market (i.e. day-ahead), 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 will exceed the replacement price of the reserves.[8]

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 a physical optimization that determines dispatch instructions, and a pricing optimization 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 optimizations of the real-time model. This is discussed in greater detail in the Market Operations chapter of this report. When generators are not selected to provide the most profitable service, the financial harm to them is partly alleviated by DAM Contract Balancing payments. When a generator is

8 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.

dispatched below its day-ahead schedule for energy, the generator receives a DAM Contract Balancing 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

Since there are markets for operating reserves and regulation, expenditures for these services fluctuate in response to market conditions. The NYISO also procures voltage support as an ancillary service, but voltage support is procured through contract agreements with generators. The nature of these agreements makes voltage support expenditures consistent throughout the year. Figure 20 shows expenses for regulation, voltage support, and operating reserves on a monthly basis for 2004, 2005, and 2006.

Figure 20: Ancillary Services Costs
2004 – 2006

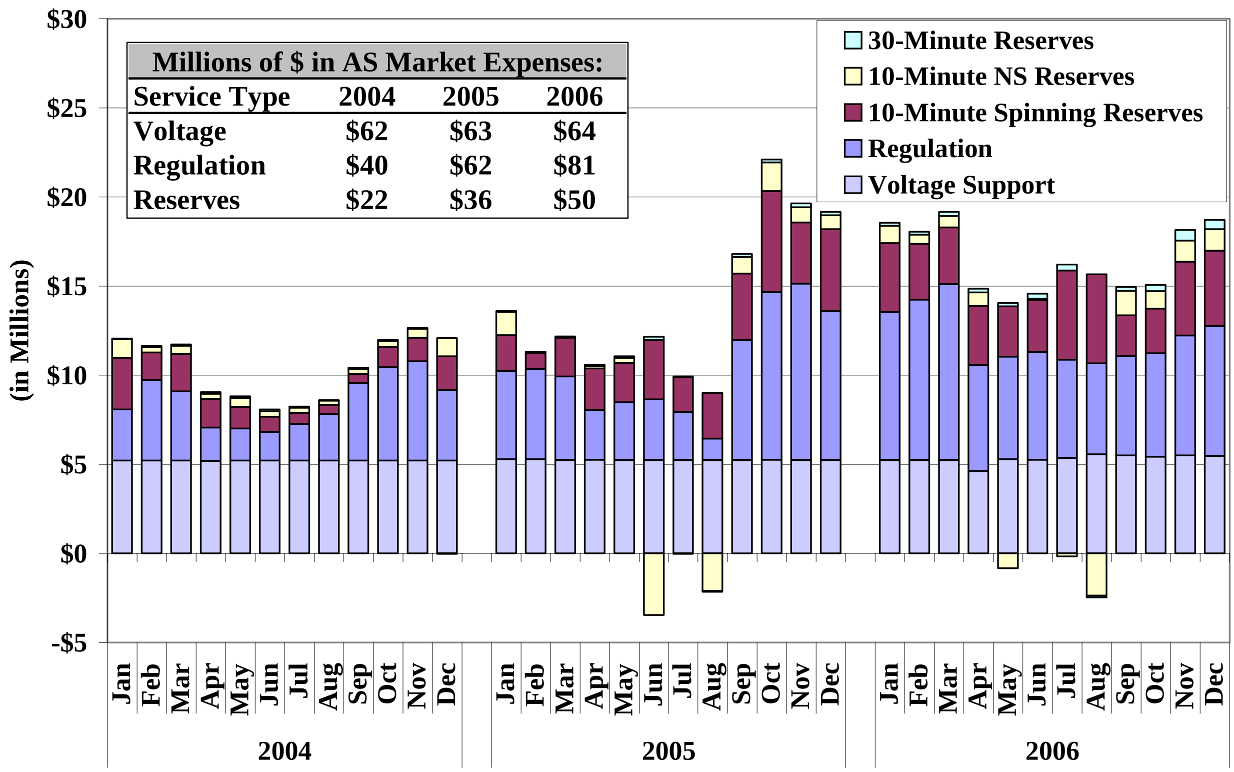


Figure 20 shows that ancillary services expenses rose considerably in September 2005 and remained high in 2006. The increase was driven primarily by much higher regulation expenses, although the expenses for reserves have also risen substantially. The increased expenses are attributable to at least three factors. First, higher fuel prices, particularly from September 2005 to January 2006, increased the opportunity costs of low-cost units providing ancillary services rather than energy. Second, regulation offer prices rose substantially in September 2005 due to a change in behavior by two suppliers, although this was moderated by the entry of new supply in June 2006. Offer patterns are discussed later in this section in greater detail.

Third, changes in the pattern of convergence between day-ahead and real-time prices for ancillary services have led to higher expenses for ancillary services. The ISO purchases the full requirement of each ancillary service in the day-ahead market, so normally real-time prices do not directly affect the level of expenses. In 2005, eastern 10-minute spinning and non-spinning reserve prices in eastern New York were much lower in the day-ahead market than in the real-time market. In 2006, convergence improved, resulting in higher expenses for 10-minute spinning and non-spinning reserves.

Figure 20 also shows that net expenses were negative for 10-minute non-spinning reserves in a few months of 2005 and 2006. 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 is not able to find sufficient reserves available to purchase during reserve shortages, the resulting income was sufficient to more than offset expenses for 10-minute non-spin reserves in those few months.[9] Alternatively, there are periods 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.

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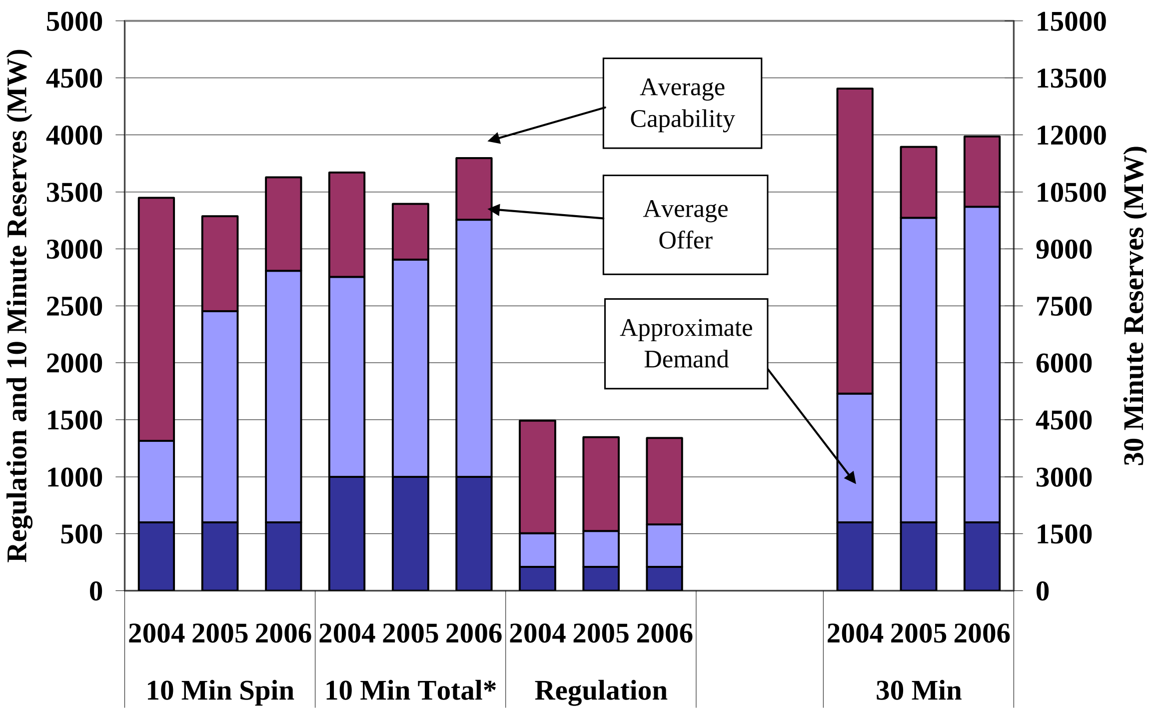
[9] For example, assume that a gas turbine sells 20 MW of reserves for $5 per MWh in the day-ahead market, but is dispatched to provide energy in real-time when the price of the same reserves product is $500 per MWh. In this case, the ISO would have paid $100 (= 20 MW * $5 per MWh) to the generator for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

C. Offer Patterns

Prior to the introduction of SMD 2.0, a substantial portion of ancillary services capability was not offered in the day-ahead market. This section examines ancillary services offer patterns to determine how participation has changed since the introduction of SMD 2.0. Figure 21 summarizes the average levels of capacity, offers to supply, and demand for reserves and regulation in the day-ahead market from 2004 to 2006. Because of the nature of the locational requirements, ten-minute reserves are shown only for the region east of the Central-East Interface.

Figure 21: Summary of Ancillary Services Capacity and Offers Day-Ahead Market, 2004 – 2006



* Eastern side of the Central-East Interface only

The quantity of offers to supply 10-minute spinning reserves and 30-minute operating reserves rose substantially from 2004 to 2006, which we attribute to the improved incentives under SMD 2.0 and the installation of new capacity in New York City that is subject to a day-ahead offer requirement.[10] Previously, day-ahead clearing prices were set by the highest-priced accepted

10 NYISO Services Tariff, Attachment H, Section 5.3.c.: "In addition, In-City generators must bid zero ($0) for the availability portion of Day-Ahead Spinning Reserves Bids. The implementation of this mitigation

offer, and it was possible for the price to be lower than the opportunity cost of not providing energy. Thus, generators risked losing profits in the energy market by providing reserves. There is no such risk under the new design since suppliers are selected to provide whichever service is the more profitable (assuming suppliers submit energy and ancillary services offers consistent with marginal costs).

The new combined cycle units that came online in the New York City zone in 2006 contributed to the increases from 2005 to 2006 in average quantities offered in 10-minute spinning reserve and eastern total 10-minute reserve markets. The New York City-based units are required to offer 10-minute spinning reserves at $0 per MW in the day-ahead market.

Participation in the eastern 10-minute non-spinning reserves market did not change significantly from 2004 to 2006. This is because non-PURPA generators in eastern New York that have capacity obligations and are capable of providing 10-minute non-spinning reserve service are required to offer 10-minute non-spinning reserves in the day-ahead market.[11]

Regulation participation is still relatively low and did not change significantly after the implementation of SMD 2.0, although higher prices paid for regulation did attract some additional regulation offer quantities beginning in June 2006. The low rate of participation may be because generators must incur fixed costs to make their facilities ready to provide regulation and may rationally choose not to make the necessary investment if they do not anticipate significant profits from participating in the market.

The following figure summarizes day-ahead offers to supply three ancillary services market requirements during the 2005 and 2006. Offer quantities are shown in categories according to offer price level.

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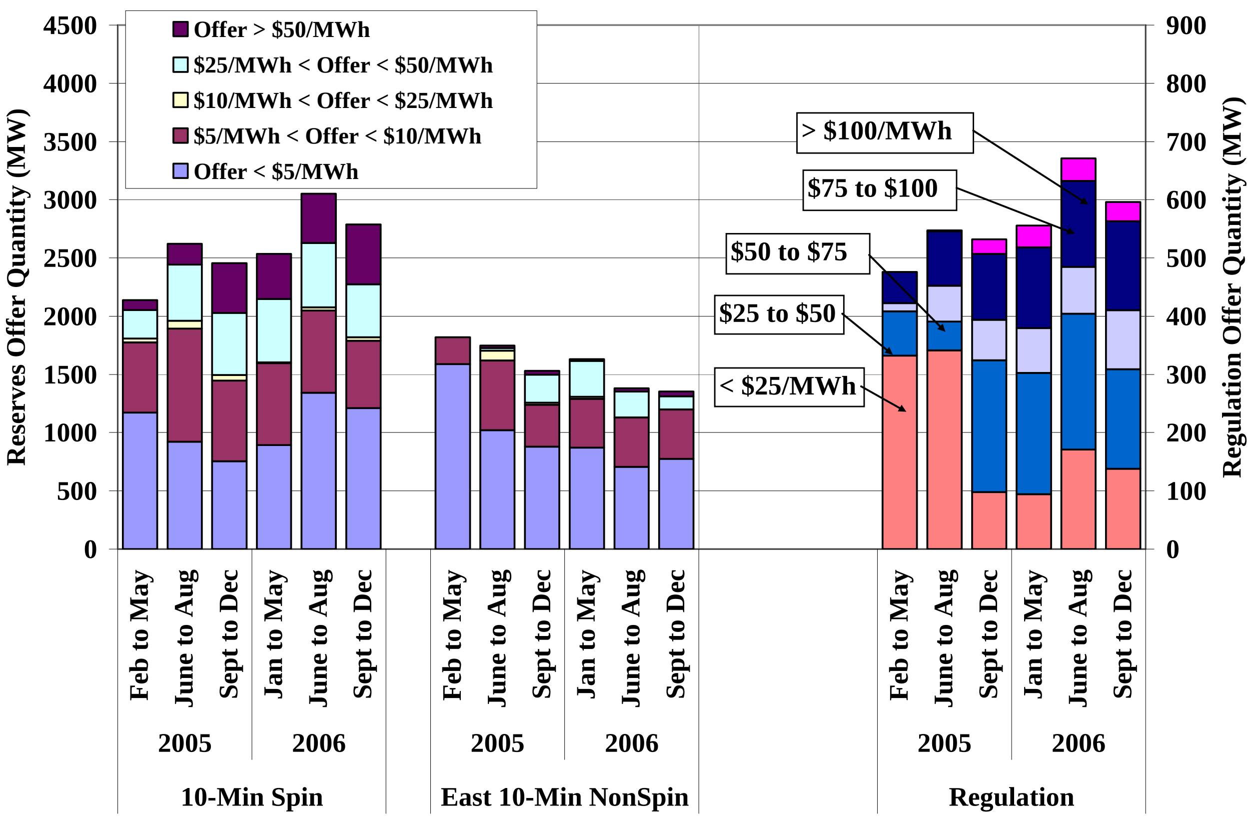
measure will have no effect on the ability of a Generator located in New York City to recover the market clearing price established by the ISO for the sale of Spinning Reserves."

11 Section 5.13.1 of the NYISO Services Tariff: "Unforced Capacity associated with In-City generation that is subject to FERC-approved capacity market mitigation measures is required to be offered for sale in the ICAP Spot Market Auction to the extent that such Unforced Capacity has not sold in prior auctions for the Obligation Procurement Period."

Figure 22: Summary of Ancillary Services Offers in the Day-ahead Market Afternoon Hours, 2005-2006



The rise in regulation offer prices is attributable to changes in behavior by several market participants. In September and October 2005, two market participants substantially raised their offer prices. The New York ISO's market monitoring staff reviewed the rise in offer prices and concluded that the behavior does not warrant mitigation under the NYISO Tariff. However, due to limited participation in the market by regulation-capable capacity, the ownership of resources that participate in the market is relatively concentrated. The effects of higher offer prices were partially offset by the entry in June 2006 of approximately 100 MW of low-priced offers from generators that did not previously offer regulation.

The rising offer prices for 10-minute spinning and non-spinning reserves and the decreasing quantity of 10-minute non-spinning reserves offers are attributable to changes in offers by several market participants. These changes in offer prices do not raise significant competitive concerns, since a review of the offers from each supplier reveals that the shares of reserves capability held by these market participants are not large enough to confer market power under normal market conditions. The most likely explanation for the pattern of rising offer prices is that market participants are responding competitively to poor convergence between day-ahead and real-time reserves prices. If suppliers predict real-time prices will be higher than day-ahead prices, we can expect they will seek to avoid selling into the day-ahead market and shift sales to the real-time market. One way to do this is for them to raise day-ahead offer prices.

While market power is not a significant concern in the markets for 10-minute reserves, the pattern of escalating offer prices raises concerns that market participants are submitting reserves offers above marginal costs, because such behavior negatively effects market efficiency. The day-ahead market commits and schedules resources for energy and ancillary services in economic merit order, resulting in an efficient commitment when suppliers offer their resources at marginal cost. When suppliers raise their offer prices above marginal costs, other more costly resources may be committed in their place. Thus, it is important for overall market efficiency to address issues that undermine the incentives of suppliers to offer their resources at marginal cost.

D. Conclusions

SMD 2.0 has lead to two major enhancements to the markets for reserves and regulation. First, co-optimization of energy and ancillary services in real-time 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. It guarantees that the clearing prices of energy, reserves, and regulation fully reflect the opportunity cost of not providing the other services. Second, pricing during shortage conditions under SMD 2.0 is governed by reserve demand curves. The demand curves establish an economic value for reserves that are reflected in energy prices at times when the energy market must bid scarce resources away from the reserve markets. Reserves prices are based on the shadow prices of reserves constraints, but reserves purchases are reduced when necessary to prevent the shadow prices from exceeding the prices set forth by the demand curves.[12] The demand curve values have been set at levels that are consistent with the actions normally taken by the NYISO operators in reserve shortage conditions. This practice improves

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12 The total value of a reserve in a location is the sum of the reserve demand curve values for each reserve requirement constraint that the reserve contributes to relieving. In other words, because reserves should generally be substituted to maintain the highest quality reserve, the total value of a specific reserve type generally includes the sum of the demand curve values of the lower quality reserves.

consistency between clearing prices and the operation of the system, and better reflects the economic value of reliability.

Since the introduction of SMD 2.0, there have been several notable changes in market outcomes. First, the new design has induced greater participation from operating reserves suppliers. Relative to the year preceding the implementation of SMD 2.0, the average quantity of day-ahead offers for 10-minute spinning reserves has increased 110 percent, while the quantity of 30-minute operating reserves offers increased 95 percent. Second, regulation expenses rose in late 2005, primarily as a result of higher offers from two suppliers of regulation. The ownership of regulation-capable capacity is relatively concentrated raising concerns that, in the short-term, certain market participants may have incentives to raise their offer prices above marginal cost. In response to the higher prices, some additional regulation-capable suppliers began participating in the market during 2006, and prices did moderate somewhat during 2006.

Third, poor convergence of 10-minute reserves prices in eastern New York (i.e., real-time prices were higher than day-ahead prices) has increased the opportunity cost of selling reserves in the day-ahead market. This is consistent with expectations of a competitive market when day-ahead prices are systematically lower than real-time prices. The rise in 10-minute reserve offer prices has helped correct the lack of convergence between day-ahead and real-time prices. However, the higher reserve offer prices can undermine the efficiency of day-ahead commitment.

If convergence between day-ahead and real-time operating reserves prices remains poor, suppliers of operating reserves will continue to have an incentive to raise their offer prices, which may undermine the efficiency of unit commitment. If this continues, 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. The proposal would need to be carefully studied to ensure it will not have unintended consequences on the day-ahead commitment.

IV. Analysis of Energy Bids and Offers

In this section, we examine bidding patterns to evaluate whether market participant conduct is consistent with efficient and 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. The marginal cost of base-load and intermediate-load resources do not vary substantially relative to the marginal cost of resources used at peak times. 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 critical 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. Physically 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 either legitimate or a strategic 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 that possesses market power will find withholding to be profitable during periods when the market supply curve becomes steep (i.e., at high-demand periods). Therefore, examining the relationship between the measures of potential withholding and demand levels will allow us to test whether the conduct in the market is consistent with workable competition.

1. Deratings and Physical Withholding

We first consider potential physical withholding by analyzing generator deratings. A derating occurs when a participant reduces the maximum output available from the plant. This could be for planned outages, long-term forced outages, or short-term forced outages. A derating could be partial (maximum output is reduced, but is greater than zero) or complete (maximum output is zero). We analyze only the summer months to effectively eliminate planned outages from our data. By eliminating planned outages, we implicitly assume that planned outages are legitimate and are not aimed at exercising market power.[13]

In Figure 23, deratings are measured relative to the most recent Dependable Maximum Net Capability ("DMNC") test value of each generator. In Figure 24, 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) which have higher demand because, under a hypothesis of market power, we would expect to find that withholding increases as demand increases. We also limited ourselves to the locations east of the

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13 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.

Central-East interface, as this area, which includes two-thirds of the State's load, has limited import capability, and is more vulnerable to the exercise of market power.

Figure 23: Relationship of Deratings to Actual Load Day-Ahead Market - East New York Peak Hours, Summer 2006

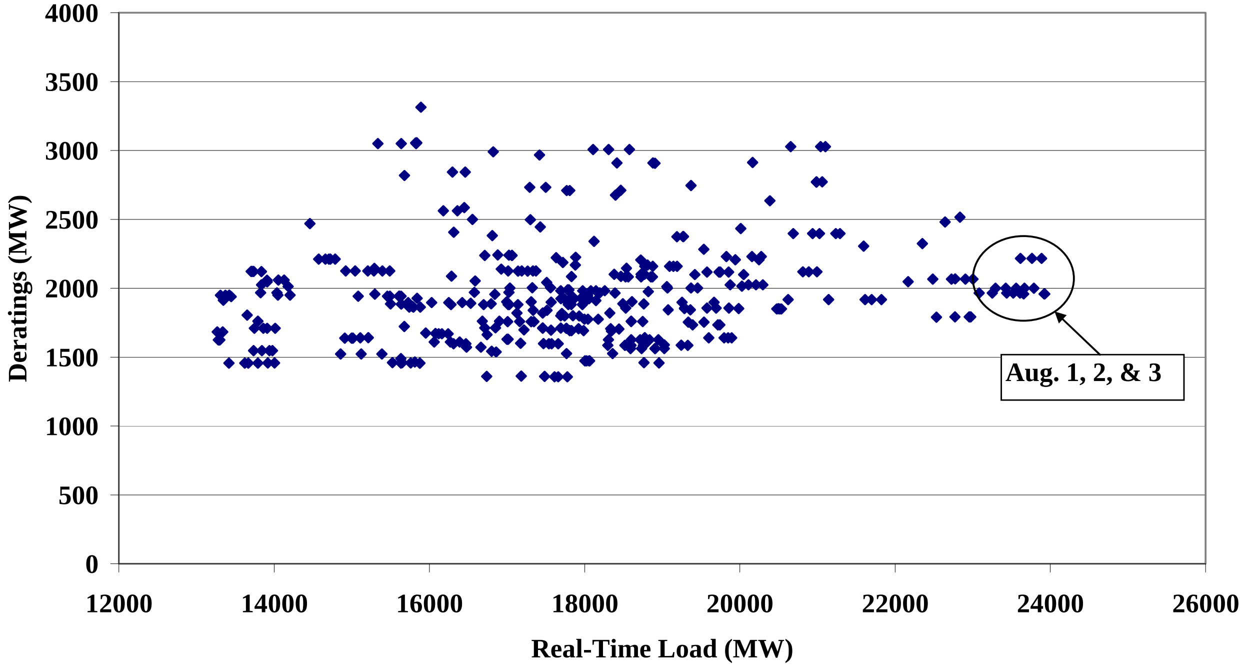


Figure 24: Relationship of Short-Term Deratings to Actual Load Day-Ahead Market – East New York Peak Hours, Summer 2006

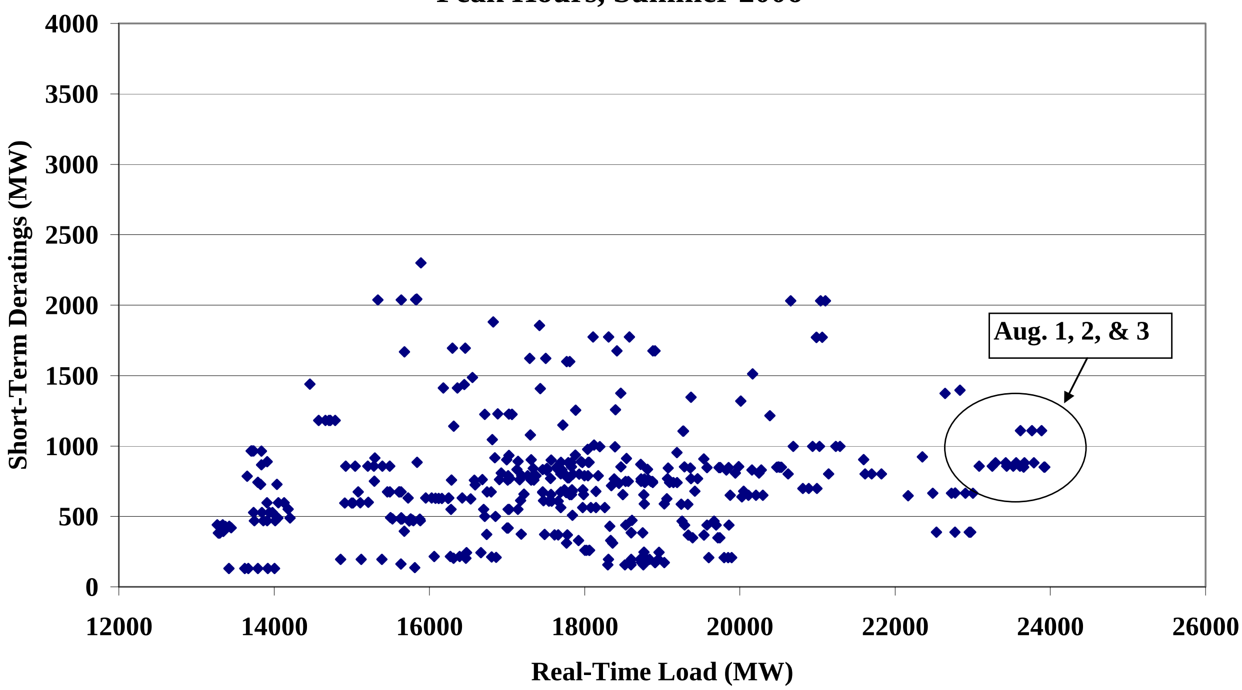
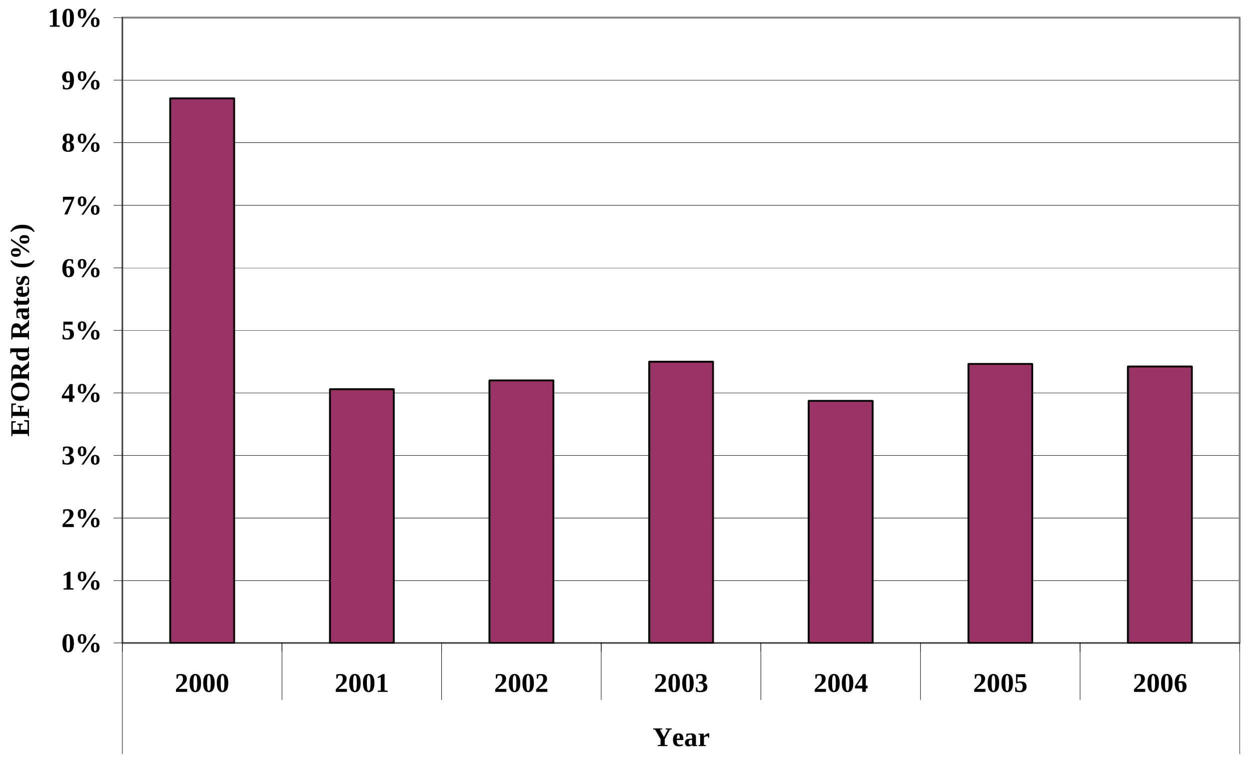


Figure 23 and Figure 24 both show a slight positive correlation between all deratings and load. Though the relationship is slight, such a pattern can be an indication of physical withholding. We therefore conducted additional analysis of deratings by supplier on the highest load days and found no cause for significant competitive concerns. We find that the overall pattern of outages and deratings was consistent with workable competition during the summer of 2006.

2. Forced Outages

We examined the trend in forced outages in the New York markets to ascertain if generators are responding to economic incentives to increase availability of their units. Figure 25 shows the Equivalent Forced Outage Rate ("EFOR"), which is used as a measure of forced outages. The EFOR is the portion of time a unit is unavailable due to forced outages, expressed as equivalent hours of full forced outage at its maximum net dependable capability.

Figure 25: Equivalent Demand Forced Outage Rates
2000 – 2006



EFOR declined substantially following the implementation of the NYISO markets. This is consistent with the incentives the deregulated markets provide to maximize availability, particularly during high load conditions. EFOR was relatively high in 2000 due to the outage of an Indian Point nuclear unit. After the Indian Point outage, the EFOR has been consistently close to 4 percent – much lower than the outage rates that prevailed prior to the implementation of the NYISO markets. In 2006, the EFOR was approximately 4.4 percent, about the same as in 2005.

3. Output Gap and Economic Withholding

To evaluate economic withholding, we calculated the hourly "output gap". The output gap is the quantity of generation 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 with an offer price substantially above competitive levels.[14] This withholding can be accomplished through high start-up cost offers, high minimum generation offers, and/or high incremental energy offers.

To determine whether an offer is above competitive levels, we compare it with the generator's reference level, which is an estimate of marginal cost that is used for market power mitigation.[15] A supplier without market power maximizes profits by offering into the market at levels near marginal cost, because excessive offers will cause the unit not to be dispatched when it would have been profitable and so cost the owner lost profits. An offer parameter is considered above competitive levels if it exceeds the reference values by a given threshold.[16] We conduct two analyses: first, with thresholds matching the conduct threshold used by the state-wide automated mitigation procedure ($100/MWh or 300 percent, whichever is lower), and second, using a lower threshold ($50/MWh or 100 percent, whichever is lower). The second analysis is included in order to assess whether there have been attempts to withhold by offering energy just below the state-wide mitigation threshold.

Like our 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

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14 The output gap calculation excludes capacity scheduled to provide ancillary services.

15 NYISO Market Administration and Control Area Services Tariff, Attachment H – ISO Market Power Mitigation Measures, Section 3.1.4

16 We allow considerable tolerance in our threshold.

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.

These figures both show that the output gap tends to decrease to relatively low levels under the highest load conditions. As peak hours are periods when the market is most vulnerable to market power, the tendency for the output gap to decrease as load increases indicates economic withholding was not a significant factor in the market. Some of the output gap shown in the two figures could be the result of actual withholding, although the quantities are relatively small compared to the total load in Eastern New York and are negatively correlated with load. Thus, the output gap analysis supports the view that the market generally functioned competitively under peak demand conditions and does not raise significant concerns about economic withholding during 2006.

Figure 26: Relationship of Output Gap at Mitigation Threshold to Actual Load
Real Time Market – East New York
Weekdays, Noon to 6 PM, 2006

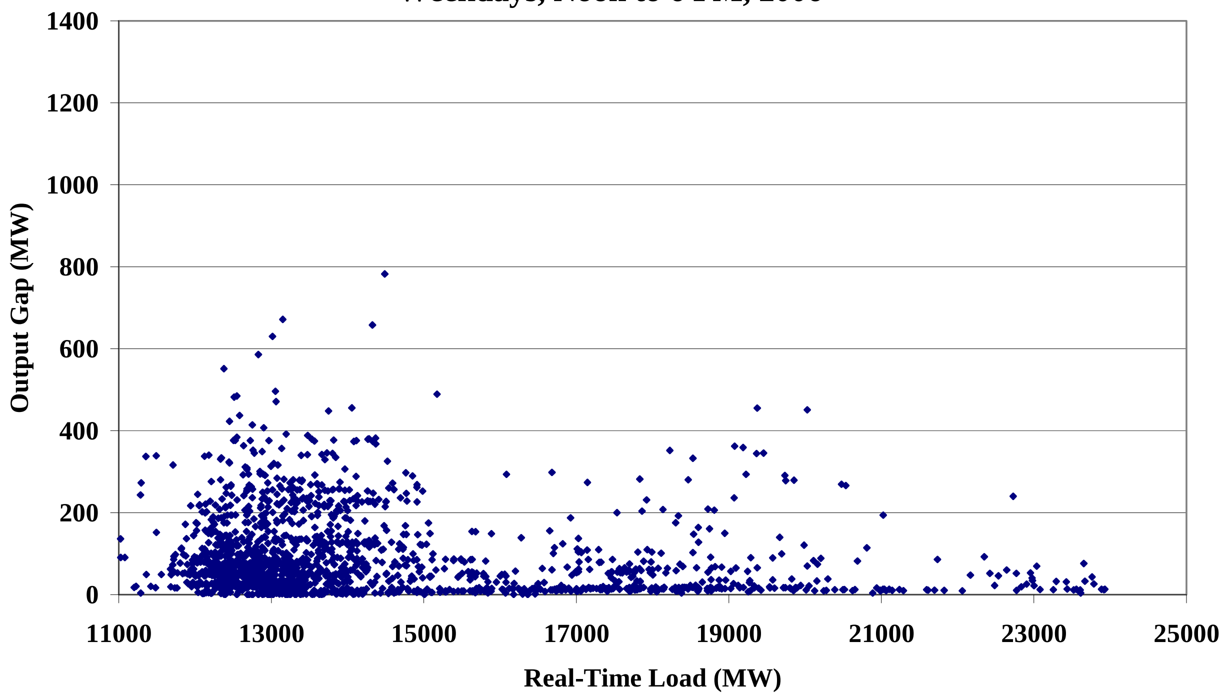
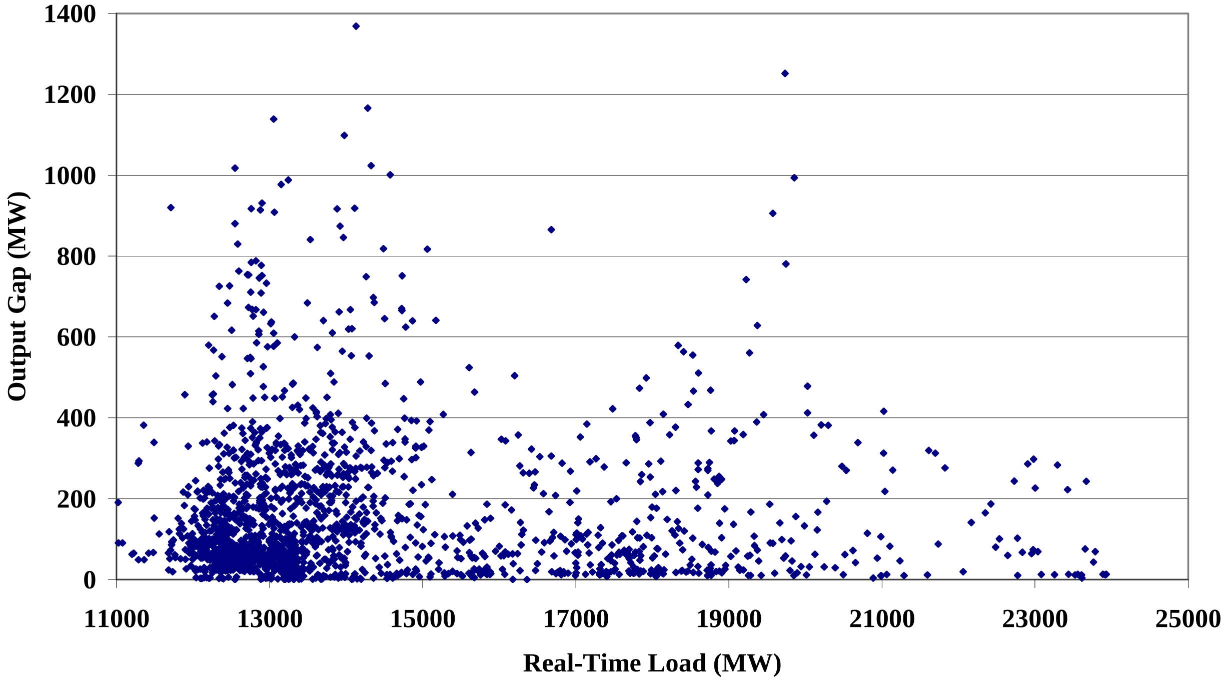


Figure 27: Relationship of Output Gap at Low Threshold to Actual Load
Real Time Market – East New York
Weekdays, Noon to 6 PM, 2006



4. Market Power Mitigation

The NYISO applies a conduct-impact test that can result in mitigation of participant bid parameters (i.e., energy offers, start-up and no-load offers, and physical parameters). The conduct test first determines whether bid parameters exceed pre-defined conduct thresholds. If at least one of the participant's bid parameters exceeds a conduct threshold, the bid parameter may be mitigated if the conduct results in a significant impact on the energy price. The NYISO tariff allows for mitigation to be invoked manually according to pre-defined criteria, although this is infrequent. Instead, the day-ahead and real-time market software is automated to perform most mitigation according to pre-defined conduct and impact thresholds.

Mitigation is applied in the real-time market for units in certain load pockets within New York City using the NYISO's conduct and impact approach. The in-city load pocket conduct and impact thresholds are set using a formula that is based on the number of congested hours experienced over the preceding twelve-month period.[17] 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 bid fails the conduct test if it exceeds the reference level by the threshold or more. In-city bids that fail conduct are tested for price impact by the real-time software, and if their price impact exceeds the threshold, they are mitigated.

Prior to May 1, 2004, the day-ahead software did not use the conduct and impact test framework for determining whether to mitigate in New York City. In New York City, the day-ahead software would mitigate all units to their reference level (based on variable production expenses) whenever it detected at least a small amount of congestion between Indian Point and New York City. These mitigation procedures were referred to as the Consolidated Edison or “Con Ed” mitigation procedures as they were developed when Con Ed divested its generation. Under the Con Ed procedures, mitigation occurred nearly every day.

The Con Ed procedures were replaced on May 1, 2004 by the conduct and impact mitigation framework which was already being applied to the rest of the state. This framework significantly reduced the frequency of mitigation by making it more focused on potential market power in the NYC load pockets. This prevents mitigation from occurring when it is not necessary to address market power and allows high prices to occur during legitimate periods of shortage.

Figure 28 summarizes the extent of day-ahead mitigation in 2006 by load pocket. For each load pocket shown in the figure below, the line indicates the percent of hours when mitigation was imposed on one or more units, while the bars indicate the average amount of capacity mitigated in hours when mitigation occurred.

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

Figure 28: Frequency of Day-ahead Mitigation in the NYC Load Pockets 2006

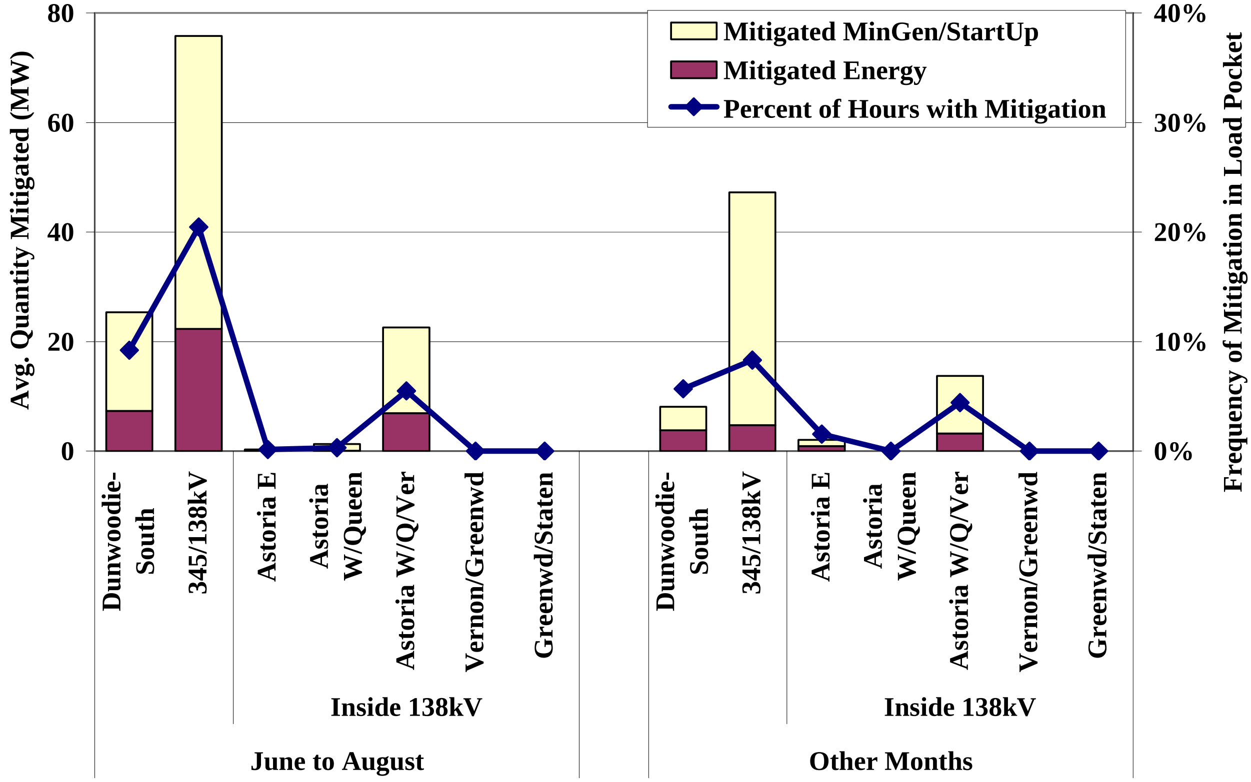


Figure 28 shows that day-ahead mitigation was most commonly associated with the Dunwoodie-South interface, which brings power into New York City from up-state, and the 345/138 kV interface which brings power into the 138 kV portions of New York City. The same pattern for day-ahead mitigation prevailed in 2005.

Figure 28 also indicates that 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 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 summarizes the extent of real-time mitigation in 2006 according to load pocket. For each load pocket shown in the figure below, the line indicates the percent of hours when mitigation was imposed on one or more units. 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).[18]

Figure 29: Frequency of Real-Time Mitigation in the NYC Load Pockets 2006

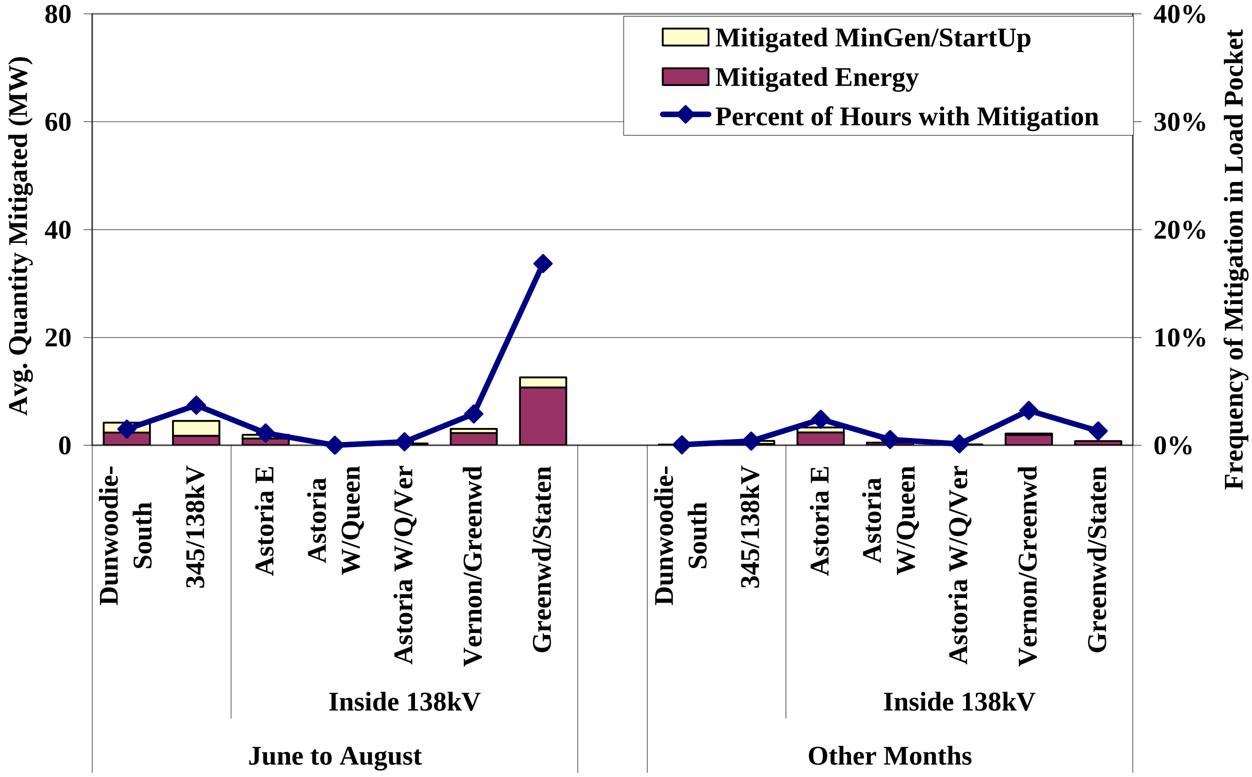


Figure 29 shows that most real-time mitigation occurred during the summer for the Greenwood/ Staten Island load pocket within the 138 kV portion of New York City. The load pocket is dominated by one supplier and experiences frequent real-time congestion making them more susceptible to the exercise market power. The majority of real-time mitigation was associated with incremental energy bid parameters rather than MinGen bid parameters. This pattern results because a large share of real-time mitigation was of gas turbines, which do not submit MinGen

18 For modeling purposes, gas turbines are treated as flexible from zero to full output, although they generally run at full output when on-line.

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.

Outside the Greenwood/Staten Island sub-load pocket, real-time mitigation was much less frequent in 2006. The installation of new capacity has significantly reduced congestion into the sub-load pocket areas inside the 138 kV system, thereby reducing the need for real-time mitigation. In addition, the introduction of detailed line modeling has improved use of transmission into the load pockets and tends to reduce congestion and therefore tends to reduce the impact of generators' offer prices on LBMPs.

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 an important focus of market monitoring. Load can be purchased in one of the following four ways:

Physical Bilateral Contracts. These are schedules that the NYISO provides to participants that allow them 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.

When the CFD is combined with a TCC, the participant can create a fully-hedged forward energy purchase. Therefore, the trends in the quantity of physical bilateral contracts scheduled with the NYISO do not indicate the full extent of forward contracting.

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, which is difficult to rationalize from an economic perspective.

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. For example, an LSE may make a price-capped bid for 500 MW at $60 per MWh. If the day-ahead market at its location clears above $60, the energy would not be purchased in the day-ahead market. 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 load in the day-ahead market with a bid price indicating the maximum amount the bidder is willing to pay. Virtual load purchased in the day-ahead market is automatically sold back to the real-time market. So, the virtual load purchaser earns the quantity of the purchase in megawatt-hours multiplied by the real-time price minus the day-ahead price. Like price-capped load bidding, 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 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. Like virtual load, this is currently allowed at the zonal level but not the bus level.

1. Day-Ahead Scheduling

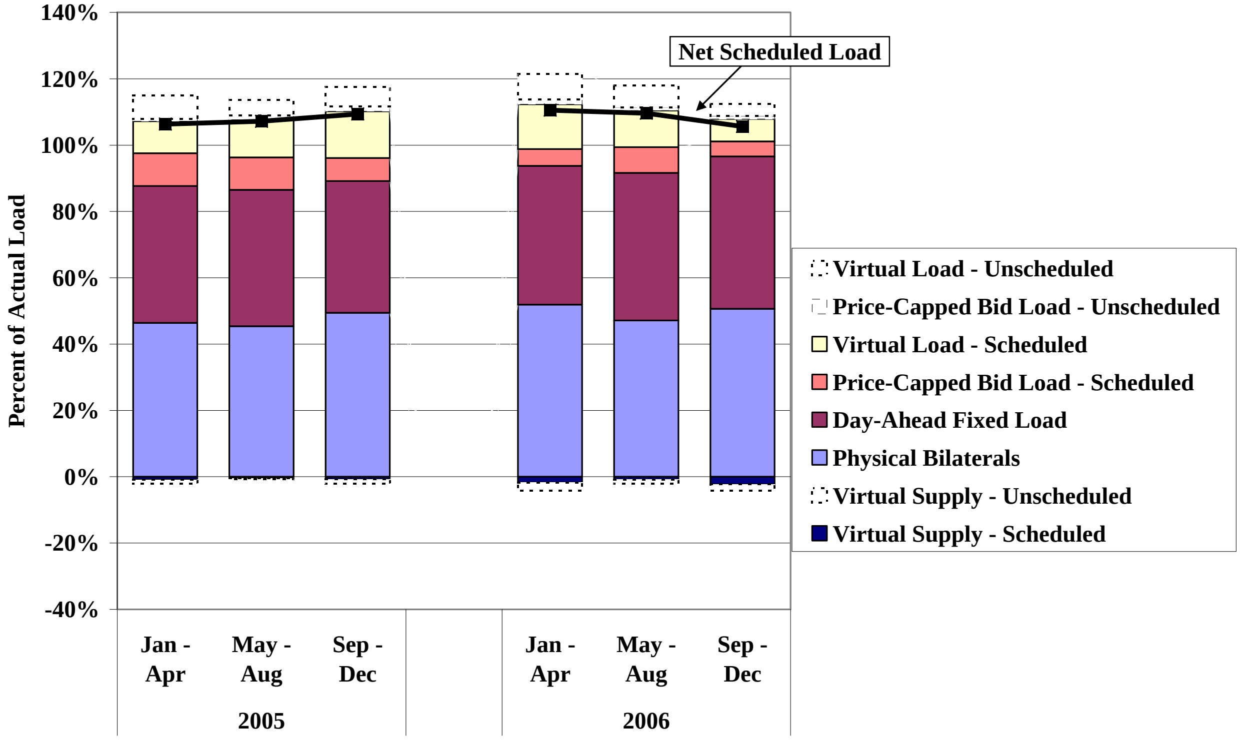
Many generating units have lengthy start-up times and substantial commitment costs. Their owners must decide whether to commit well in advance of real-time before they can be certain that the unit will be economic. The day-ahead market provides these suppliers with a way of deciding to commit only when 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 subsection examine the consistency of day-ahead load scheduling patterns and actual load which provide an indication of the over efficiency of the day-ahead market.

We expect that day-ahead load schedules will be generally consistent with actual load in a well-functioning market. Under-scheduling load leads to day-ahead prices that are lower than real-time prices and insufficient commitment for real-time needs. Over-scheduling tends to bid up day-ahead prices above the level of real-time prices. Thus, market participants have incentives to schedule amounts of load that are consistent with real-time load. The following figures show day-ahead load schedules and offers as a fraction of real-time load during 2005 and 2006 at various locations in New York. Virtual load and load schedules of LSEs have the same effect on day-ahead prices and resource commitment, so virtual load is treated the same for this analysis. Conversely, virtual supply has the same effect on day-ahead prices and resource commitment as a reduction in physical load, so we treat it 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 2005 and 2006. For each period, it shows scheduled and unscheduled quantities of physical load and virtual load. Scheduled and unscheduled virtual supply is shown by bars in the negative direction because they have the same effect on day-ahead commitment and pricing as a reduction in scheduled load. Net scheduled load, indicated by the line, is the sum of physical and virtual load minus virtual supply.

Load is generally over-scheduled by 5 to 10 percent in New York City and Long Island relative to actual load. While this pattern might be expected to raise day-ahead prices above real-time prices, day-ahead prices were generally lower than real-time prices in both years. Thus, the pattern of over-scheduling is induced by depressed day-ahead prices and actually contributes to better price convergence by bidding up day-ahead prices. The over-scheduling implies a higher level of imports to constrained areas in the day-ahead market than in real time.

Figure 30: Composition of Day-Ahead Load Schedules
New York City and Long Island, 2005 - 2006



As discussed in the Market Operations section of this report, these pricing and scheduling patterns are partly the result of modeling inconsistencies between the day-ahead and real-time markets. Prior to 2006, the day-ahead market used a detailed model of the New York City transmission system, while the real-time market used a set of simplified interface constraints. Beginning in May 2006, the NYISO has phased-in the use of the detailed model in the real-time market. The resulting improvements in use of the in-city transmission system have contributed to reducing congestion and may account for the decline in net over-scheduling in New York City and Long Island, visible in the rightmost bar in the chart. The decrease in net over-scheduling is due primarily to a reduction in virtual load scheduling.

The next two figures compare day-ahead load scheduling to actual load in areas outside New York City and Long Island on a seasonal basis in 2005 and 2006. This comparison is shown for East Up-State New York in Figure 31 and Western New York in Figure 32.

Figure 31: Composition of Day-Ahead Load Schedules
East Up-State New York, 2005 - 2006

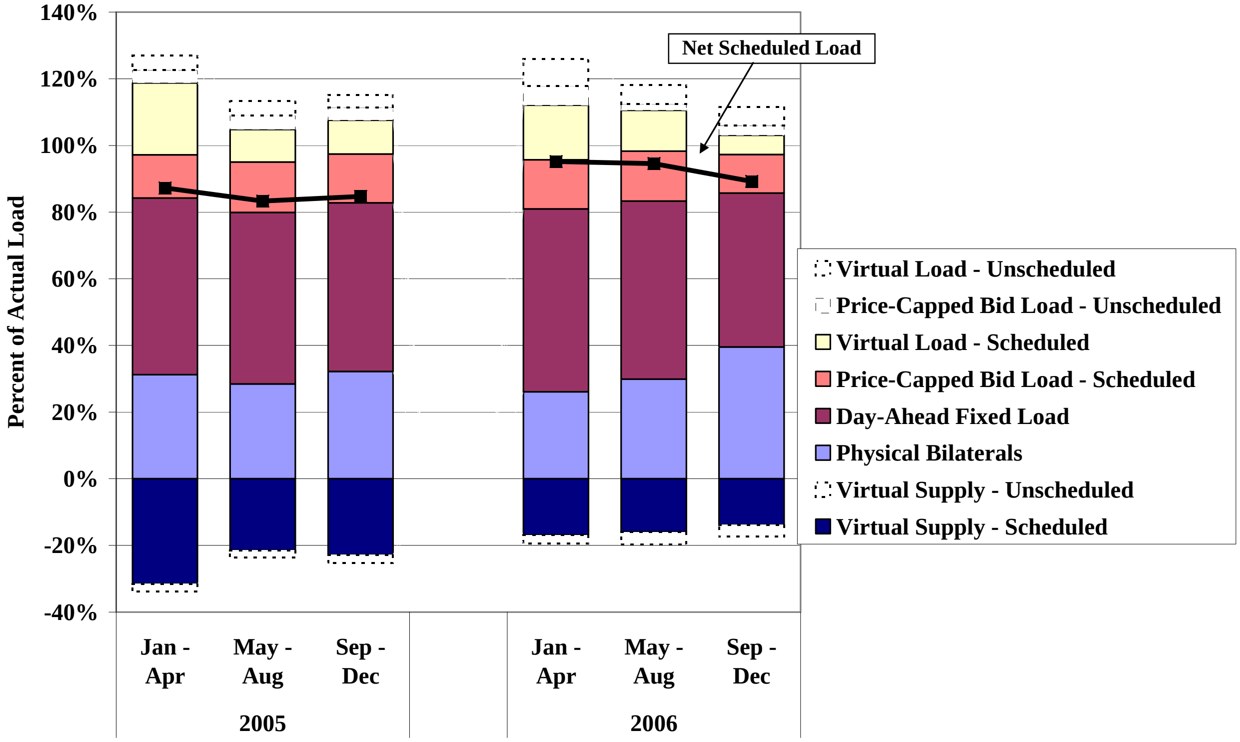


Figure 32: Composition of Day-Ahead Load Schedules
West New York, 2005 - 2006

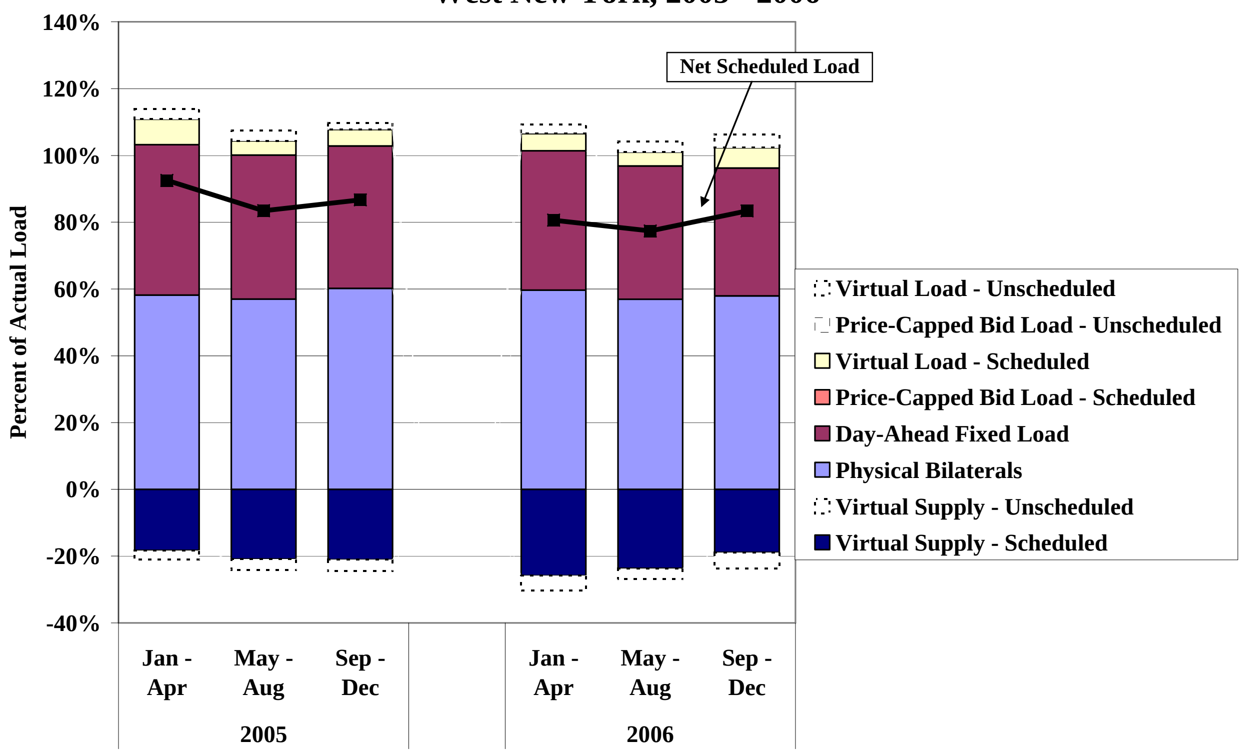


Figure 31 and Figure 32 show a pattern of load scheduling in up-state areas, which contrasts sharply with the pattern in Figure 30 for New York City and Long Island. Although the sum of physical and virtual load exceeded actual load in up-state New York on average, large amounts of virtual supply led to net under-scheduling of load. While this might be expected to lead to depressed day-ahead prices, it is actually a response to the persistent day-ahead price premium discussed in the chapter on Convergence of Day Ahead and Real Time Prices. Thus, the lack of scheduling convergence in up-state New York caused by virtual trading activity has improved price convergence. Explanations for these pricing and scheduling patterns are discussed further in the Market Operations chapter of this report. In New York as a whole, load was under-scheduled in the day-ahead market by an average of about 4 percent in 2006.

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 intertemporal arbitrage would be to 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 monthly basis during the past two years. The average quantities are shown for New York City and Long Island in Figure 33 and up-state New York in Figure 34.

Figure 33: Hourly Virtual Load and Supply New York City and Long Island 2005 – 2006

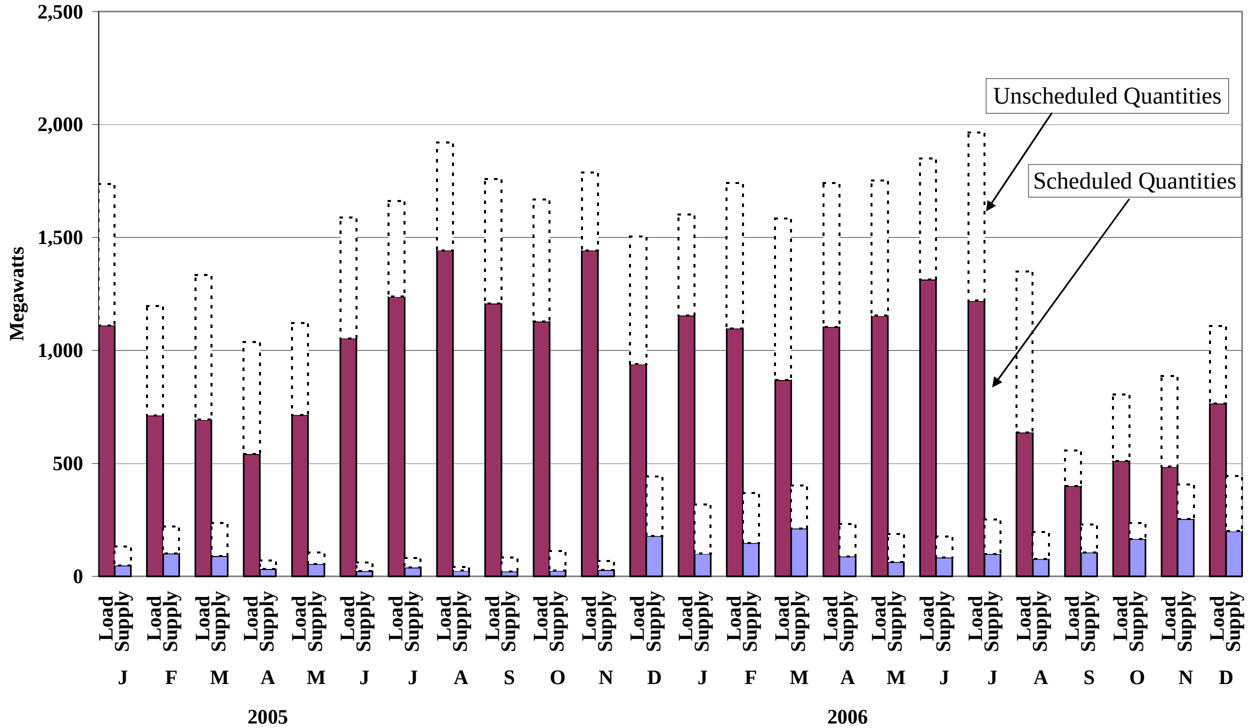
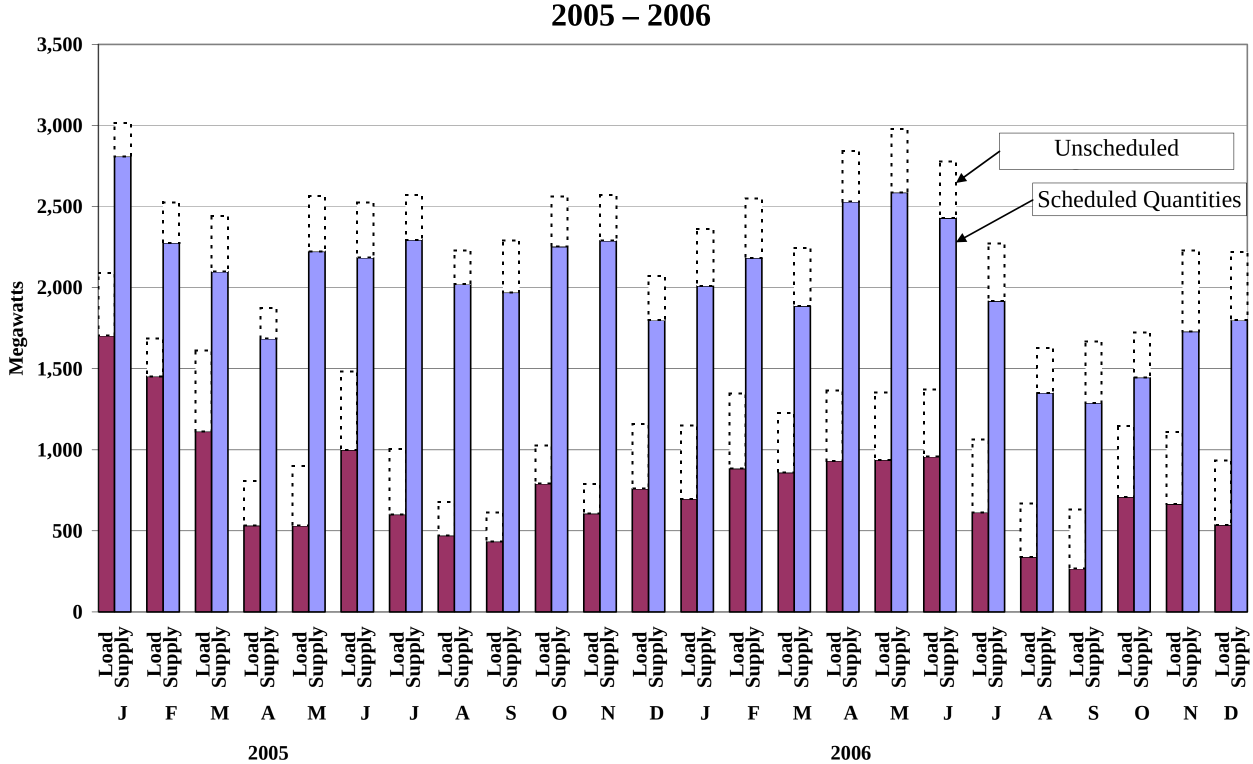


Figure 34: Hourly Virtual Load and Supply in Up-state New York 2005 – 2006



In New York City and Long Island, virtual load schedules rose during the summer of 2005 and remained at high levels through July 2006. Virtual trading declined in Up-State New York in beginning in July 2006 compared with levels prevailing earlier in 2006 and in 2005. The figures show that a substantial share of the virtual bids and offers in New York City and Long Island were not scheduled, while a much smaller portion of the virtual bids and offers in up-state New York were not scheduled.

The net virtual purchases in New York City and Long Island and net virtual sales in up-state New York contribute to the pattern of over-scheduling down-state and under-scheduling up-state. These virtual trading patterns have contributed to better convergence between the day-ahead and real-time prices. These scheduling patterns imply that the day-ahead market routinely schedules greater flows from net exporting up-state areas to net importing down-state areas than actually occurs in real-time. Improvements in modeling have reduced the arbitrage opportunities available to virtual trading, and hence reduced the amount of virtual trading toward the end of 2006. This pattern is consistent with the transmission modeling changes discussed in the next section.

V. Transmission Congestion

Congestion arises when the transmission network does not have sufficient capacity to allow the least expensive generators to serve load. When there is congestion, the market software establishes clearing prices, which are 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 based on the predicted capacity of the transmission network, 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 less 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 megawatt value. 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 because the real-time spot market is a balancing market where congestion charges should be zero on average.

This section addresses several aspects of transmission congestion management and locational pricing. It examines the following three areas:

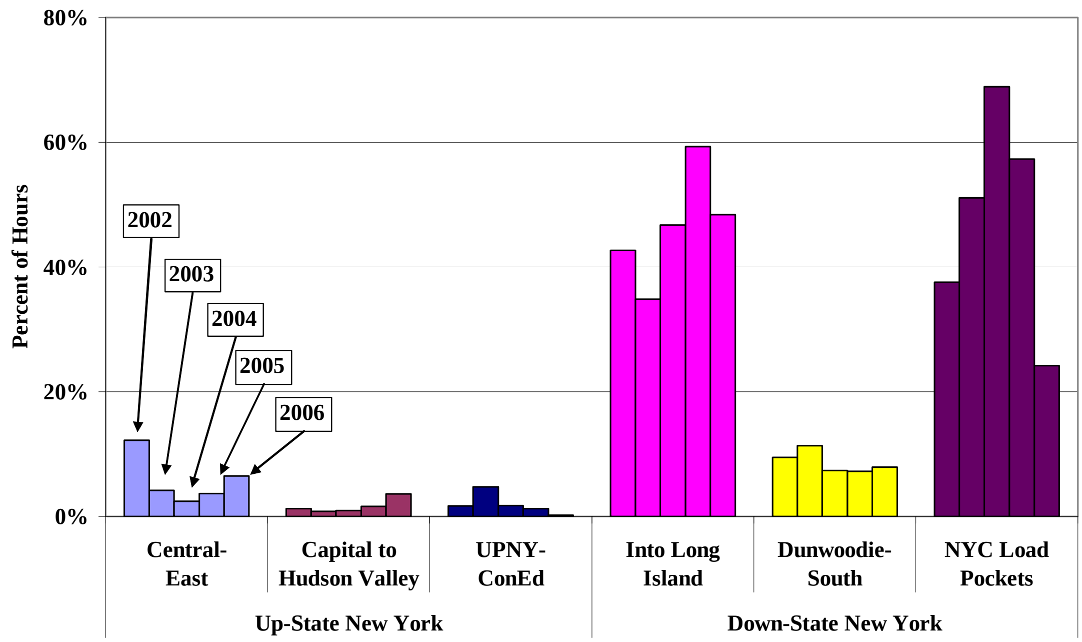
- Congestion Across Major Transmission Interfaces: This analysis summarizes growth in the frequency and value of congestion across major interfaces during the past five years.
- Congestion Revenue Shortfalls: Congestion revenues collected in the day-ahead and real-time market by the NYISO are sometimes not sufficient to cover congestion payments. We examine the size of these shortfalls, discuss factors that increase shortfalls, and highlight steps taken by the NYISO to reduce shortfalls.
- Price Convergence Between TCCs and Day-ahead Market Congestion: We review the consistency of prices paid for TCCs and congestion prices in the day-ahead market that determine payments to TCC holders.

A. Congestion Across Major Transmission Interfaces

Supply resources in New York City and Long Island generally have higher costs than in up-state New York. Because of this cost difference, the transmission system capability to move power from the low cost to high cost parts of the state provides considerable value. Thus, 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 upstate 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 – 2006



The results of Figure 35 show the preponderance of congestion occurs into and within down-state areas. Congestion into New York City load pockets increased for several years but decreased from 2004 to 2005. Congestion in Long Island became substantially more frequent in 2005. While congestion became more frequent across the three pathways shown for Up-State New York above, congestion was still far less frequent in up-state areas than in down-state areas. At least three factors influence the trends in congestion shown above.

First, developments in the market models have affected the frequency of congestion in New York. The costs of congestion within New York City have been relatively apparent since load pocket modeling was introduced in June 2002. Previously, transmission constraints in New York City were managed through out-of-merit dispatch. In May 2006, the NYISO began to model individual transmission lines in New York City rather than more simplified load pocket interface constraints. This has led to a more effective use of the transmission system and therefore less congestion.

Second, increasingly frequent TSAs resulted in more congestion on the up-state interfaces shown above. Since the blackout of August 2003, TSAs have required 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, generating capacity additions and other changes in supply have influenced congestion patterns. In New York City, the installation of one gigawatt of new combined cycle capacity 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, imports from Hydro-Quebec, which tend to constrain the Central-East interface, had a greater effect on congestion in 2002 and 2006 than in other years.

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

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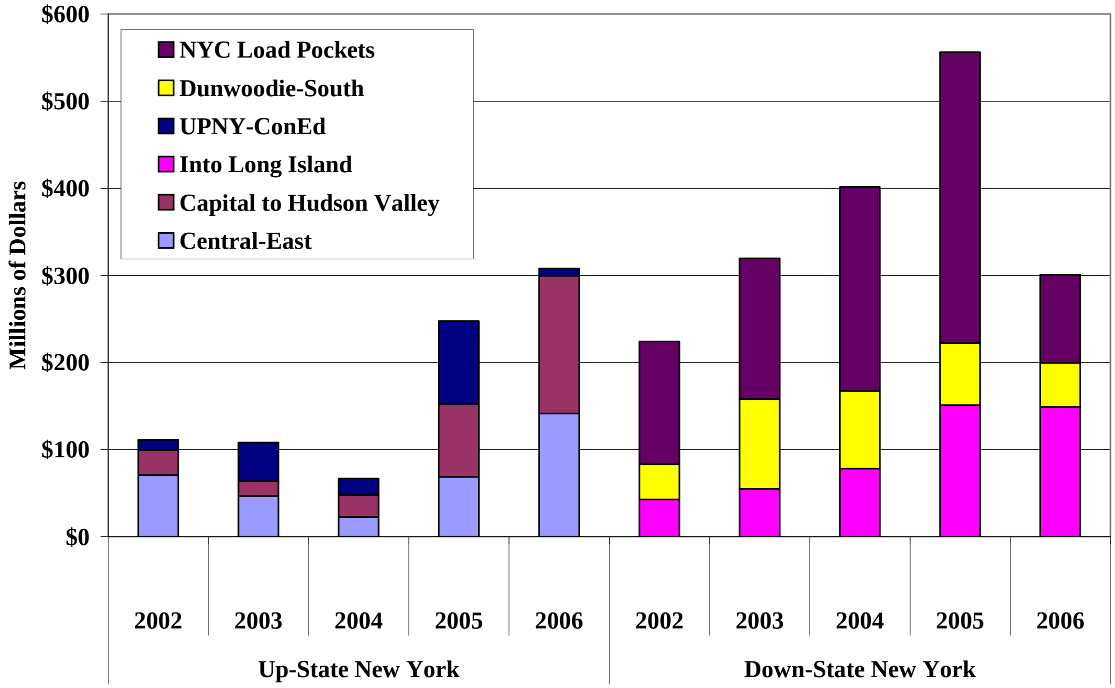
19 The shadow price of a transmission constraint represents the marginal value to the system of one megawatt of transfer capability. However, during intervals with real-time price corrections, the real-time location-based marginal prices may not be consistent with constraint shadow prices. In such cases,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

Figure 36: Value of Real-Time Congestion on Major Interfaces 2002 – 2006



In 2006, the value of the congestion on both the up-state and down-state transmission interfaces was approximately $300 million.[20] In recent years, the value of congestion on various interfaces has shifted considerably. First, variations in the frequency of congestion have led to corresponding changes in the value of congestion. Second, 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, there were hundreds of real-time intervals with acute congestion on the Leeds-to-Pleasant Valley transmission line resulting from TSA operation in 2005 and 2006. These intervals account for approximately $140 million of the congestion costs incurred in the Capital to Hudson Valley corridor over those two years. This indicates that the double-contingency criteria used during TSAs added significantly to congestion costs, although they occurred in a very small number of hours.

20 These totals do not equal actual congestion costs paid by market participants because the analysis values congestion based only on the real-time market results which can differ from day-ahead results.

Fourth, 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 capacity and improved modeling of the transmission system in New York City have shifted the economic signals for transmission investment to other areas.

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. In this section, we examine the two sources of congestion revenue shortfalls:

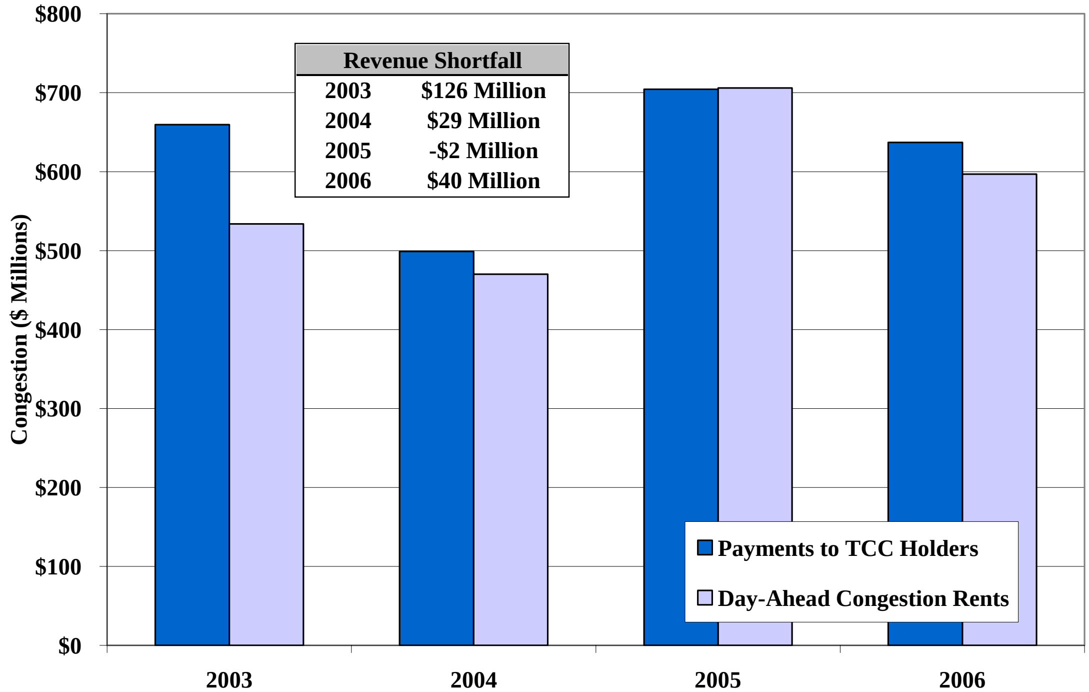
- Day-ahead Congestion Revenue Shortfalls: Revenues collected by the NYISO from congestion in the day-ahead market compared with payments by the NYISO to the holders of TCCs. These arise when the quantity of TCCs sold for a particular path exceeds the transfer capability of the path as modeled in the day-ahead market during periods of congestion.
- Balancing Congestion Revenue Shortfalls: 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 final 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 four years, Figure 37 shows day-ahead congestion costs and TCC payments.

Figure 37: Day-Ahead Congestion Costs and TCC Payments 2003-2006



Congestion revenues generated in the day-ahead market were substantially lower than payments to TCC holders until 2004. This occurred because the transmission capability assumed in the TCC auction generally exceeded the capability modeled in the day-ahead market. The pattern of consistent congestion revenue shortfalls decreased significantly in 2004 due to several actions taken by the NYISO.

- First, a large share of the shortfall was due to excess TCCs mistakenly sold from up-state New York to New York City. The excess TCCs were repurchased in July 2004.
- Second, on December 15, 2003, the FERC approved NYISO's proposal to employ cost-causation principles in assigning responsibility for TCC revenue shortfalls and surpluses to transmission owners ("TOs"). The NYISO now assesses shortfall costs resulting from

maintenance to individual transmission owners. This encourages TOs to schedule outages in a manner that minimizes their market effect.

- Third, the NYISO implemented two mechanisms that allow TOs to retain up to 5 percent of transmission capacity in the form of six-month TCCs not made available in TCC Auctions. The first mechanism permits TOs that hold Existing Transmission Capacity for Native Load ("ETCNL")[21] to reserve a limited amount of this capacity. The second mechanism allows all TOs to reserve a limited portion of the residual transmission capacity22 between contiguous pairs of load zones. Congestion payments for the reserved TCCs help to offset the TOs' share of a Congestion Rent Shortfall. The FERC approved these measures, subject to minor changes, effective February 2, 2004.

Figure 37 shows that the series of actions taken by the NYISO reduced congestion revenue shortfalls in 2004 and eliminated them in 2005, although they rebounded somewhat in 2006. Congestion revenue shortfalls still occur when transmission and generation outages[23] that were not known at the time of the TCC auction reduce the capability of the transmission system. This includes most forced outages, but many planned outages are also not scheduled until after the seasonal TCC auctions.

The next analysis summarizes congestion revenue shortfalls that occurred in the real-time market (balancing congestion costs). Balancing congestion costs 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

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21 TOs were allocated ETCNLs to facilitate the transition to locational marginal pricing.

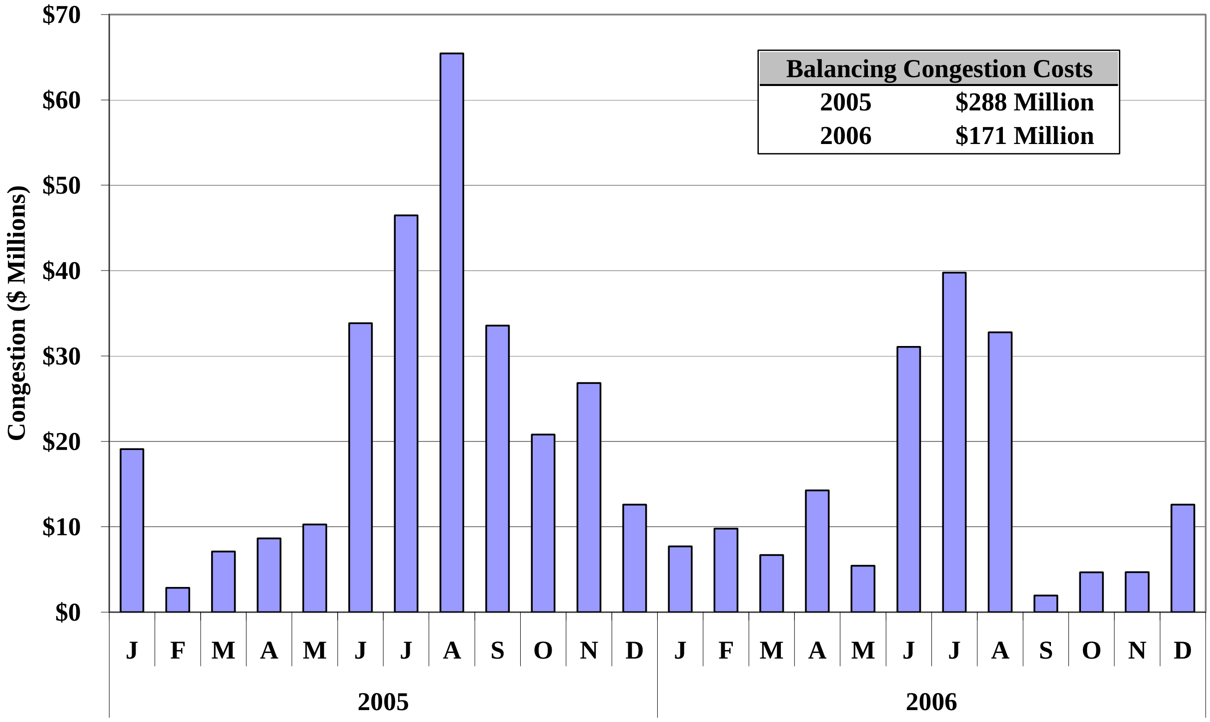
22 Once ETCNLs and grandfathered transmission rights are accounted for, the NYISO sells any remaining transmission capacity as Residual TCCs.

23 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.

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.

We examined the congestion revenue shortfall incurred in the balancing market on a monthly basis during 2005 and 2006 in the following figure.

Figure 38: Balancing Congestion Revenue Shortfalls



Balancing congestion costs declined 41 percent from $288 million in 2005 to $171 million in 2006. 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 portion of balancing congestion costs that is charged directly to Consolidated Edison increased from $20 million in 2005 to $28 million in 2006. Hence, excluding the balancing congestion costs that are attributable to TSA operation, balancing congestion costs decreased 47 percent from 2005 to 2006.

The decline in balancing congestion costs can be attributed to at least two factors. First, there was a significant decline in the amount of congestion overall that led to correspondingly lower balancing congestion costs. The most notable drivers of reduced congestion were lower fuel prices and capacity additions in New York City. Second, the NYISO has reduced differences between day-ahead and real-time transmission modeling that have contributed to higher effective interface capability in the day-ahead market. Until May 2006, the day-ahead market model used a detailed network of line constraints and a contingency analysis to determine the feasible flows across the network in New York City, while the real-time model used a more simplified network of interface constraints to determine actual flows. The use of a more detailed network has allowed the day-ahead model to more fully utilize transfer capability. In May 2006, the NYISO began to phase-in the use of the more detailed network in the real-time model to manage New York City congestion. Use of the more detailed network allows greater transmission usage and helps decrease balancing congestion revenue shortfalls.

The NYISO made an additional enhancement to the real-time market software that should contribute to lower balancing congestion revenue shortfalls. 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 software change is expected to help lower balancing congestion revenue shortfalls that arise during acute shortages of transmission, which typically 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 dispatch methodology results in much lower balancing congestion shortfalls.[24] The new methodology is discussed later in Section VI in greater detail.

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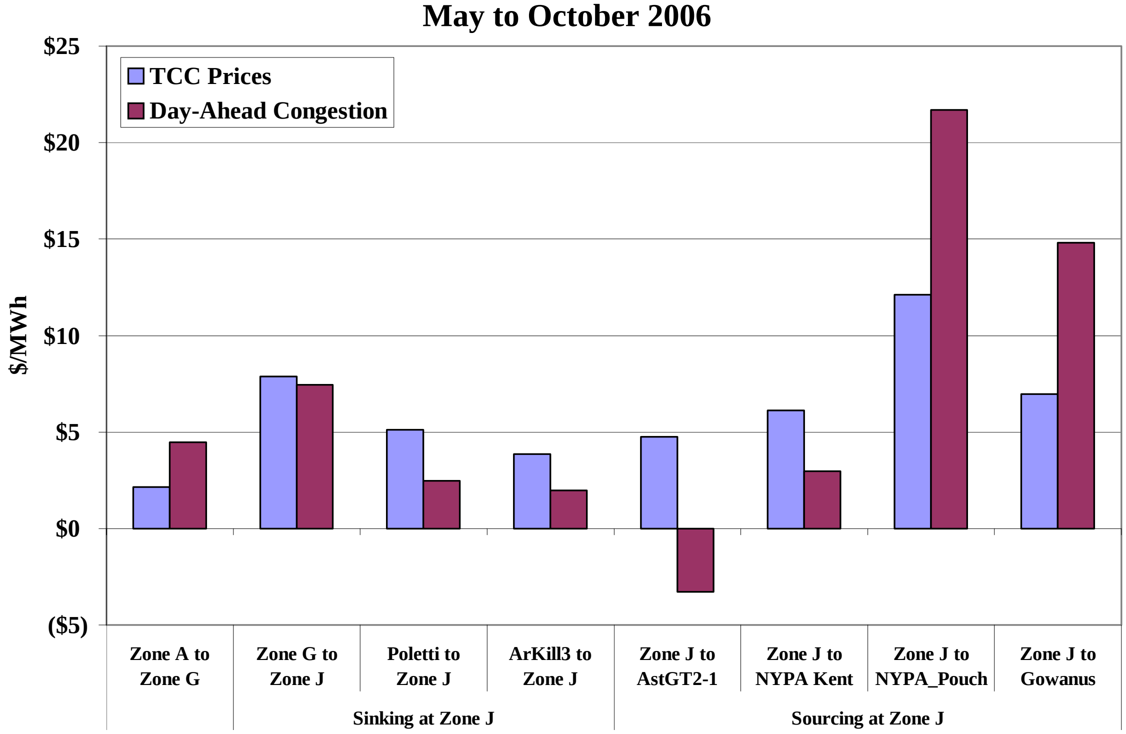
24 For example, if the day-ahead market scheduled 2,000 MW to flow across a particular interface and the real-time market reduced flows to 1,600 MW and the shadow price was $10,000/MWh for one hour, it would result in a balancing congestion shortfall of $4 million (= $10,000/MWh * (2,000 MWh – 1,600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

C. Price Convergence Between TCCs and the Day-ahead Market

Our final analysis of TCCs evaluates whether TCC prices that have emerged from the NYISO's markets converge with the outcomes in the day-ahead energy 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.

To evaluate this, Figure 39 compares the auction prices from the auction of 6-month TCCs during the 2006 summer capability period to the day-ahead congestion that actually occurred. TCCs are locational, defined by their source and sink locations.

Figure 39: TCC Prices and Day-Ahead Congestion May to October 2006



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 actually in the 345kV system within New York City, which is meaningful because 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.

The results of this analysis show that west-to-east congestion, as shown by the Zone A to Zone G product, was under-valued. The overall level of congestion between Zone G and Zone J was consistent with the expectations in the TCC auctions. However, 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 NYC and sinking at Zone J were generally over-valued. TCCs sourcing at Zone J into Astoria East (Astoria GT2/1) and Vernon/Greenwood (NYPA_Kent) were over-valued, while congestion into Greenwood/Staten Island (NYPA Pouch and Gowanus) was under-estimated. It is likely that the additions of capacity in Astoria East and Astoria West affected congestion patterns in ways not fully 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.

VI. Market Operations

Aside from operating the spot markets, a primary role of the ISO's operations is to ensure safe and reliable grid operation. In this regard, many of the ISO's operating functions can have a substantial effect on market outcomes, especially during peak demand conditions. Operating functions that affect clearing prices and other market outcomes include:

- Modeling a security-constrained transmission system in the day-ahead and real-time markets;
- Real-time commitment and dispatch of gas turbines;
- Operations during shortages of contingency reserves; and
- Supplemental commitment to maintain reserves in local areas;

Reliability requires that operators carry out these functions, but they should be done in a way that promotes efficient market pricing and behavior. This section evaluates operating functions and examines how they affect market outcomes.

One significant change in the NYISO's markets was the implementation of SMD 2.0 in February 2005, which included several key features that enhanced the NYISO's real-time commitment and scheduling processes. Under SMD 2.0, the new Real Time Commitment model ("RTC") is primarily responsible for committing gas turbines and other resources that cannot be dispatched by the real-time dispatch model, and is a significant improvement over its predecessor. The new Real Time Dispatch model, ("RTD"), co-optimizes the procurement of energy and ancillary services on a 5-minute basis, while its predecessor, the Security Constrained Dispatch model ("SCD"), optimized energy only. Co-optimization is beneficial for several reasons. First, RTD reduces production costs by efficiently reallocating resources to provide energy and ancillary services every five minutes, while SCD simply dispatched resources to provide energy using a fixed set of ancillary service schedules that were produced hourly by BME. Second, RTD is able to incorporate the costs of maintaining ancillary services into the price of energy by co-optimizing energy and ancillary services. These costs were not reflected in energy prices prior to SMD 2.0. Third, demand curves rationalize the pricing of energy and ancillary services during shortage periods by establishing an economic value for the reserves and regulation. The enhancements introduced in RTD provide a more efficient means of setting prices during shortage conditions than the shortage pricing rules that were used with SCD.

A. Real-Time Commitment and Scheduling

The NYISO's real-time commitment software has been significantly enhanced in the last three years. Since the initial implementation of SMD 2.0 in February 2005, RTC has been primarily responsible for committing gas turbines and other resources with short start times such as external transactions. 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. RTC is a significant improvement over its predecessor, the Balancing Market Evaluation model ("BME") that ran every 60 minutes and evaluated commitment for just one hour. In May 2006, the NYISO began to model individual lines in the RTC rather than using simplified interfaces to represent New York City. This enhancement has helped RTC determine more accurately whether gas turbines will be economic to be online in real-time.

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 excess resources are committed or scheduled by RTC, the results are depressed real-time prices and increased uplift costs. Alternatively, when RTC commits insufficient resources, it leads to unnecessary scarcity and price spikes. This section of the report includes several analyses that evaluate the consistency between scheduling by RTC and actual real-time market outcomes.

1. Efficiency of Real-Time Commitment and Scheduling

The following two analyses show that the efficiency of real-time commitment and scheduling decisions has improved considerably since the implementation of SMD 2.0. The first analysis, shown in Figure 40, evaluates decisions to start and to not start gas turbines from 2004 to 2006. This shows substantial improvement, particularly for gas turbines with longer start times (i.e. 30-minute gas turbines). The second analysis, shown in Figure 41, evaluates decisions after the day-ahead market to schedule and to not schedule imports and exports. Although this shows modest improvement, the amount of import and export offers submitted by market participants is small compared with the transfer capability of the external interfaces.

The following figure measures the efficiency of gas turbine commitment by comparing the offer price (energy plus start-up) to the real-time LBMP over the unit's commitment period. When these decisions are efficient, the offer price components of committed turbines are usually lower than the real-time LBMP while the offer price components of off-line turbines are generally higher than the real-time LBMP. However, when a gas turbine that is committed efficiently is close to the margin, it is possible for the offer price components to be greater than the LBMP. Thus, the following figure 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 in 2004, 2005, and 2006. Based on the comparison of the sum of offer price components and the real-time LBMP over the initial commitment period, these are broken into several categories: (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. Some of the gas turbines in the latter three categories (i.e. with offers greater than the LBMP) were also economic, because gas turbines that are started efficiently may sometimes not recover their start-up offer. 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 2006

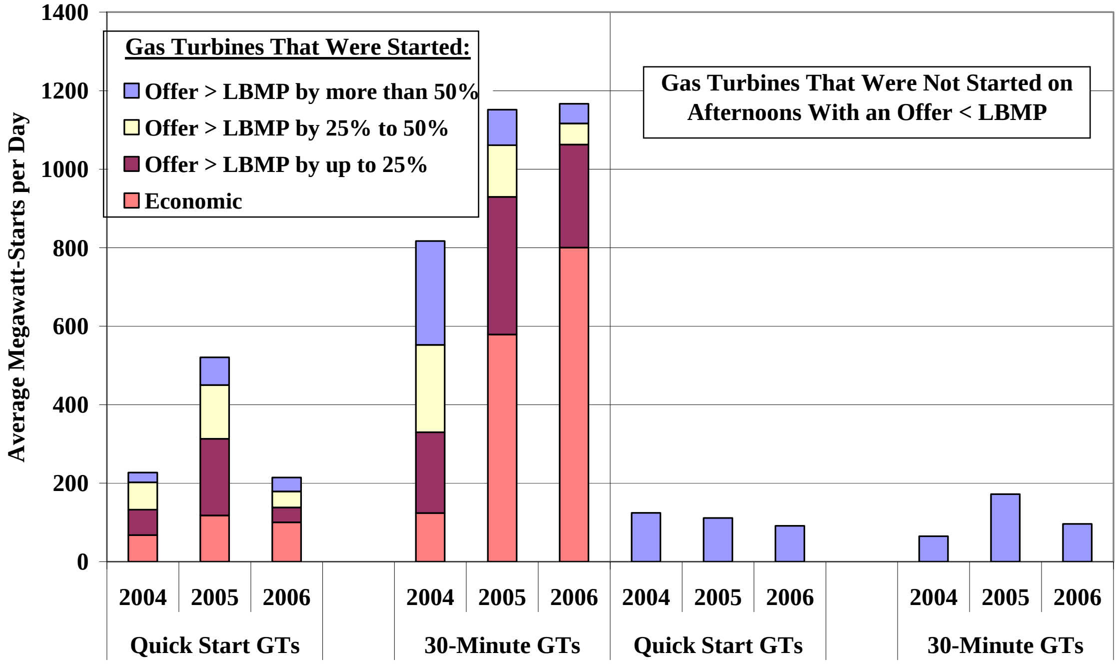


Figure 40 indicates that gas turbine commitment improved considerably with the implementation of SMD 2.0 in 2005 and improved further in 2006. The share of gas turbine starts that were clearly economic grew from 18 percent in 2004 to 42 percent in 2005 to 65 percent in 2006. To the extent that gas turbines were started when their offers were greater than the LBMP, the average margin between the offer and the LBMP declined in both 2005 and 2006. In 2004, the fraction of gas turbine starts that occurred when the offer exceeded the LBMP by at least 25 percent exceeded 55 percent. This fraction decreased to 26 percent in 2005 and just 13 percent in 2006. 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 by 50 percent 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. In 2006, the average quantity of off-line gas turbines that would most likely have been economic declined significantly.

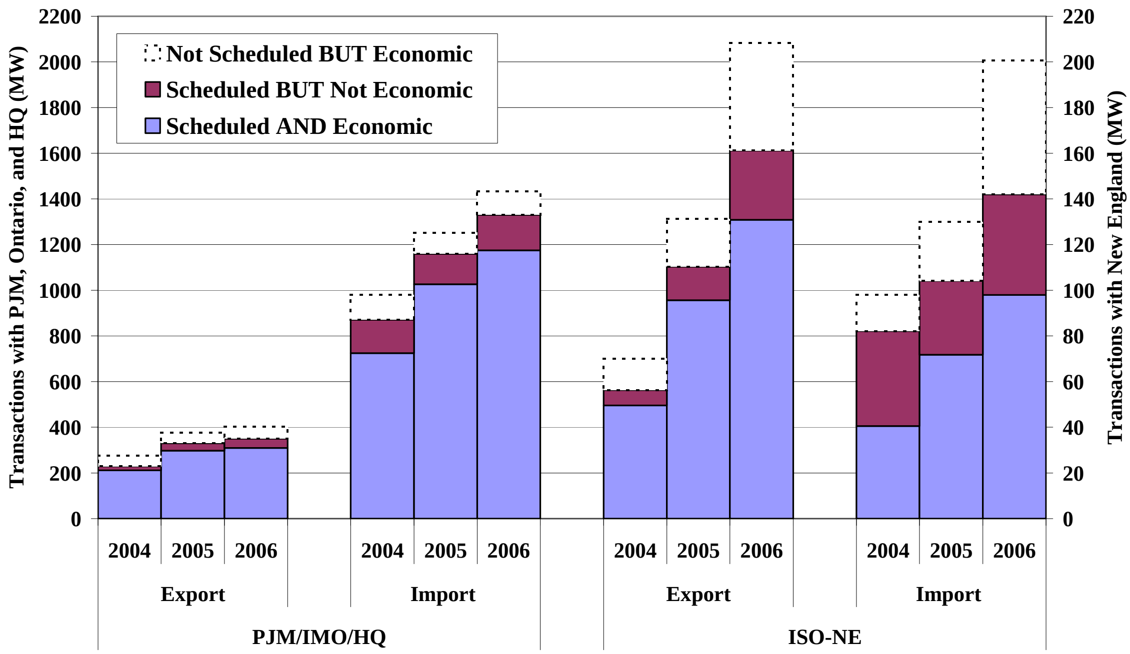
Figure 40 shows that the most significant gains were in the efficiency of decisions to start 30-minute gas turbines. Prior to SMD 2.0, these units were usually committed by the BME, which ran 75 minutes before the beginning of the hour that it was evaluating. The BME committed resources from the top 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 commitment of quick-start gas turbines became much less frequent in 2006. Some of the quick-start gas turbines are located in the same load pockets as the combined cycle units that were installed in 2006. Frequent operation of the combined cycle units has decreased reliance on gas turbines in these areas. In addition, more efficient commitment of 30-minute gas turbines reduces the need to start quick-start gas turbines, which are generally more costly to operate. With improved evaluation under the RTC, the system is better able to adapt to changing conditions and less likely to resort to expensive quick-start gas turbines.

Several improvements to RTC and RTD since the initial implementation of SMD 2.0 have led to more efficient commitment of gas turbines. First, in August 2005, RTD was modified to allow it to start quick-start resources. Second, in May 2006, RTD and RTC began to model the transmission system in New York City using a detailed representation of the network and replacing a set of simplified interface constraints. RTD now re-dispatches generators more efficiently when constraints are binding, while RTC must frequently commit generation before constraints are actually binding. The detailed line model of New York City 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.

The changes associated with implementing the RTC have also allowed the system to better schedule price sensitive external transactions. Figure 41 measures the efficiency of external transaction scheduling by comparing the import and export offer prices to the real-time LBMP at the border. The importance of efficient external transaction scheduling in New York is diminished by the fact that most offers to import or export are submitted to the real-time market in a non-price sensitive manner, although the figure suggests that price sensitive offers are becoming more common. The analysis evaluates offers submitted in a price sensitive manner, those with offer prices between $0 and $300 per MWh. Three categories of price sensitive offers to import and export are shown in the figure below: (a) offers that are scheduled by RTC and economic at the real-time price, (b) offers that are scheduled by RTC but not economic at the real-time price, and (c) offers that are not scheduled by RTC but would have been economic at the real-time price. The first category includes offers that were scheduled efficiently, while the second and third categories indicate instances when RTC did not make an efficient decision.

Figure 41: Efficiency of External Transaction Scheduling Evaluation of Price Sensitive Offers*, 2004 to 2006



* Includes real-time offers to import or export that are priced between $0 and $300/MWh.

Figure 41 shows that the volume of price sensitive offers that were scheduled grew significantly from 2004 to 2006, particularly for exports to New England, which grew from an average of 70 MW in 2004 to 208 MW in 2006. The fraction of price sensitive offers that were both scheduled and economic stayed relatively consistent for each category of transactions from 2004 to 2006. A smaller share of price sensitive offers was both scheduled and economic at the New England interface than at the other external interfaces. Overall, the figure above shows that market participants are taking greater advantage of the ability to offer imports and exports in a price sensitive manner. However, the amount of price sensitive offers is still relatively small compared with the total transfer capability of the interfaces.

2. Uplift Costs from Uneconomic Commitment

Since the introduction of SMD 2.0, the ISO has substantially improved the economic efficiency of gas turbine commitment in real-time. This has led to reduced uplift charges for Bid-Production Cost Guarantee ("BPCG") payments to gas turbines that are started by the ISO and turn out to be uneconomic because real-time prices are lower than their offer prices. We performed an analysis of real-time commitment decisions before and after the implementation of SMD 2.0 to estimate how much of the uplift cost reduction was attributable to the new commitment software. We estimate savings of $22 million in 2005 and $32 million in 2006 as a result of improved real-time operations under the new market software. The findings of this analysis are summarized in the following three figures.

To estimate the uplift savings from more efficient gas turbine commitment under SMD 2.0, we quantify the improved efficiency while controlling for fluctuations in natural gas prices, higher demand levels, and more frequent price spikes. In the first analysis, we examine how frequently gas turbines ran when their offer (including average start-up cost) was greater than the LBMP, and we find that the fraction of production that was economic grew in 2005 and again in 2006. In the second analysis, we show that the vast majority of uplift derives from occasions when the gas turbine's offer is far above the LBMP (i.e. LBMP is less than 60 percent of the gas turbine's offer). In the third analysis, we show how gas turbines that run for a mix of economic and uneconomic hours on a particular day receive substantially lower BPCG payments per unit of uneconomic production than gas turbines that are uneconomic in all hours. The importance of these factors to the estimated savings is discussed below in greater detail.

The following figure summarizes the efficiency of gas turbine production by comparing the offer prices (energy plus average start-up) of on-line gas turbines to the average hourly real-time LBMP. Each megawatt-hour is classified according to the ratio of the real-time LBMP to the offer price. For instance, if the real-time LBMP is $100 per MWh and an on-line gas turbine has a $150 per MWh offer price, its output will appear in the "60% to 70%" category in the figure below. The analysis allows us to assess the change in the efficiency of gas turbine production from 2004 to 2006.

Figure 42: Efficiency of Production by Gas Turbines Based on Comparison of LBMPs and Offer Prices February to December, 2004 to 2006

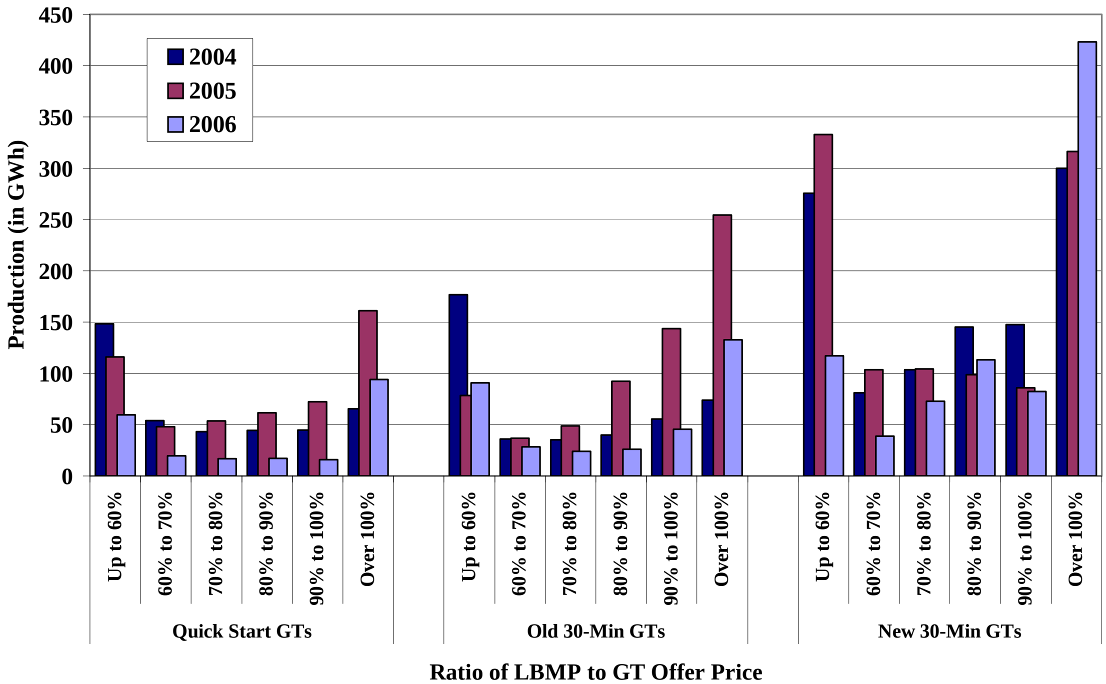
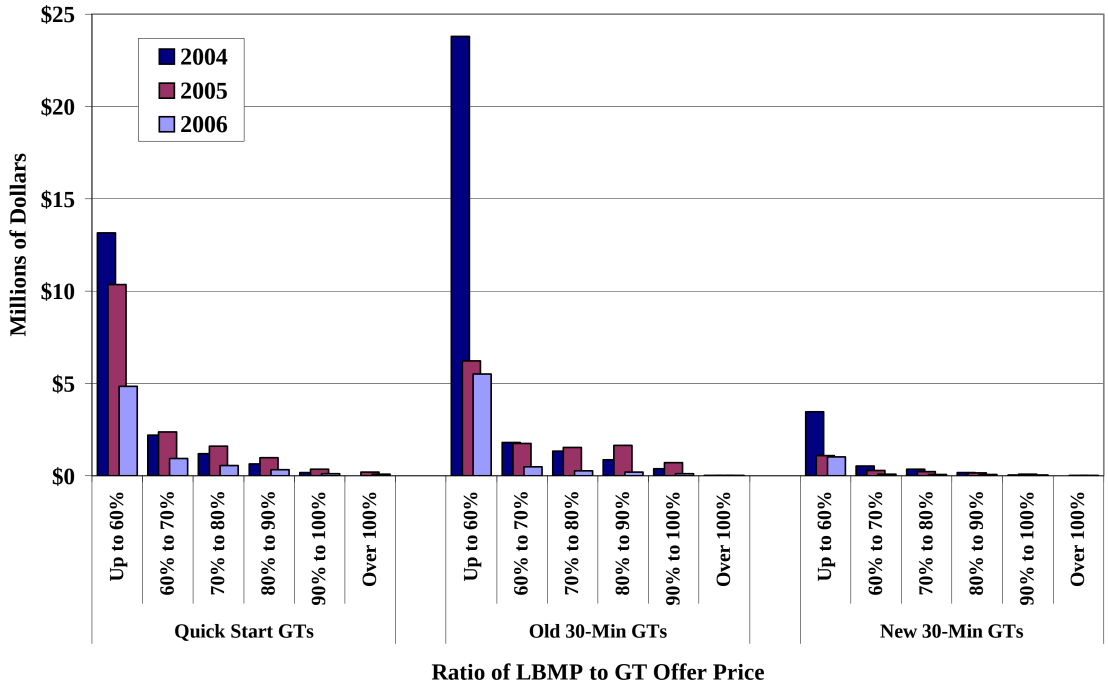


Figure 42 shows that production by the three categories of gas turbines became increasingly efficient in 2005 and in 2006. For instance, in 2005 and 2006, older 30-minute gas turbines produced much more output in hours that were clearly economic (i.e. when the LBMP was greater than their offer price) and much less output in hours that were most clearly uneconomic (i.e. when the LBMP was less than 60 percent of their offer price). In 2006, efficiency improved significantly for newer 30-minute gas turbines (i.e. ones installed since 2001), which are characterized by lower running costs than older gas turbines. While these account for just 13 percent of the gas turbine capacity in New York, they account for a large share of the total output from gas turbines because of their relatively low costs. They accounted for 47 percent of the total output from gas turbines in 2005 and this share increased to 60 percent in 2006

BPCG payments are calculated on a daily basis for gas turbines that are started by the ISO but do not receive sufficient revenue to recoup their as-bid costs. Since the calculation is performed daily, a generator does not receive a BPCG payment if its losses in one hour are exceeded by its gains in another hour. However, to assess factors contributing to uplift costs, we have allocated the uplift costs of BPCG payments to the hourly level for each unit.[25] The following figure summarizes these uplift costs according to the efficiency of gas turbine production for three categories of gas turbines from 2004 to 2006. Like the previous figure, efficiency is based on the ratio of the LBMP and the gas turbine's offer price in each hour.

Figure 43: Summary of BPCG Payments to Uneconomic GTs Based on Comparison of LBMPs and Offer Prices February to December, 2004 to 2006



The majority of uplift for BPCG payments comes from hours when gas turbines are producing while the LBMP is less than 60 percent of the gas turbine's offer price. These hours accounted for a disproportionately high share of the uplift in each year: 81 percent in 2004, 60 percent in 2005, and 77 percent in 2006. In 2005, there was a dramatic reduction in BPCG payments associated with these hours, particularly for older 30-minute gas turbines. There were additional declines in BPCG payments in 2006, particularly for quick-start gas turbines. These reductions in BPCG payments were primarily driven by the more efficient production shown in Figure 42.

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25 For generators that are uneconomic in each hour of a particular day, this is simply the difference in each hour between (i) the real-time energy revenue and (ii) the as-bid cost of the generator with the start-up cost amortized over the run time. For generators that are economic for at least one hour of a particular day, the BPCG payments in uneconomic hours are offset by the gains from economic hours. These gains are allocated evenly across megawatt-hours produced in uneconomic hours.

An additional factor that helped reduce the uplift from uneconomic commitment in 2006 was that an increasing share of energy sales from gas turbines was made in the day-ahead market. The percent of gas turbine production that was sold in the day-ahead market rose from 35 percent in 2004 to 39 percent in 2005 to 61 percent in 2006. Units that are scheduled economically in the day-ahead market do not receive BPCG payments.

In order to estimate the effect of the new market software on uplift costs for uneconomic production by gas turbines, it is necessary to control for exogenous factors. In 2005, electricity demand and natural gas prices were significantly higher than in the previous year. In 2006, fuel prices declined and generation capacity was added in New York City. To isolate changes in uplift resulting from these factors, we examined statistics on the average uplift cost per megawatt of uneconomic production under various circumstances.

The following figure shows BPCG payments per megawatt-hour of uneconomic production according to the ratio of the LBMP to the gas turbine's offer price. Average uplift costs from BPCG payments are shown separately for hours that occurred on days when at least one other hour was economic. The uplift costs are lower for hours that occurred on days when at least one other hour was economic, because BPCG payments are calculated on a daily basis and gains from high-priced hours go to defray losses from low-priced hours.

Figure 44: Summary of BPCG Payments to Uneconomic GTs
Payments per Unit of Uneconomic Production
February to December, 2004 to 2006

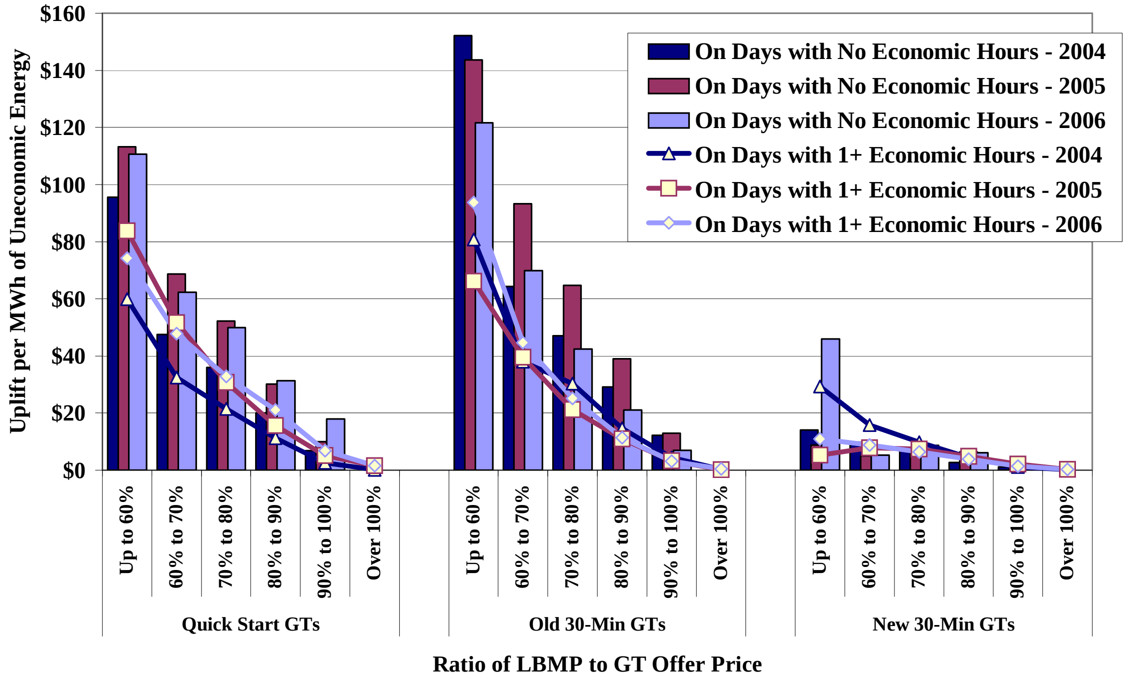


Figure 44 highlights two conclusions regarding uplift costs for uneconomic commitment that apply across time and unit-type. First, uplift costs for BPCG payments were significantly lower per megawatt-hour on days when the gas turbine was economic for at least one hour. For instance, in hours when the LBMP was less than 60 percent of the offer price during 2006, quick start gas turbines received an average of $111 per MWh on days where the unit was not economic in any hour and $74 per MWh on days where the unit was economic for at least one hour. Second, due to higher fuel prices, BPCG payments were higher per megawatt-hour for most categories of uneconomic production in 2005 than in either 2004 and 2006. For instance, in hours when the LBMP was less than 60 percent of the offer price on days where the unit was not economic in any hour, quick start gas turbines received an average of $113 per MWh in 2005 compared with $95 per MWh in 2004 and $111 per MWh in 2006. Although BPCG payments per unit of uneconomic production rose considerably from 2004 to 2005 due to higher fuel prices, total BPCG payments declined due to a reduction in the volume of uneconomic production.

Three general conclusions may be drawn from the analyses regarding the efficiency of gas turbine commitment under SMD 2.0. First, the frequency of uneconomic commitment and production decreased, particularly for older 30-minute gas turbines, which resulted in lower BPCG payments. Second, BPCG payments per unit of inefficient production were higher in 2005 and 2006, largely due to higher fuel prices. Third, the new capacity additions in New York City reduced the need for output from gas turbines, thereby reducing both the uplift from uneconomic production by gas turbines and the savings that could be attributed to the SMD 2.0 software upgrades.

We estimated the uplift savings from more efficient gas turbine commitment under SMD 2.0 in 2005 and 2006. This was done by estimating the BPCG payments that would have occurred using the old market software based on the rate of commitment efficiency in 2004 compared to 2005 and 2006, while accounting for changes in fuel prices. Based on this analysis, we estimate that the implementation of SMD 2.0 reduced uplift by $22 million in 2005 and $32 million in 2006, with most of the reductions coming from more efficient commitment of older 30-minute gas turbines.

3. Convergence Between RTC and RTD Prices

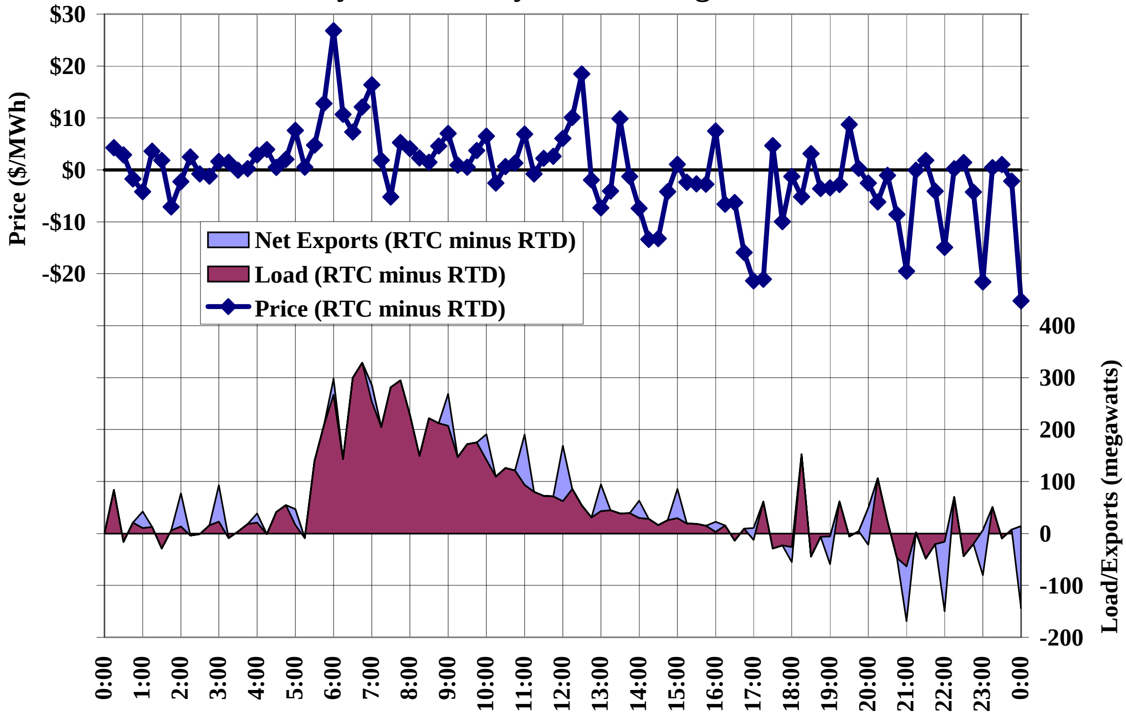
Under SMD 2.0, real-time scheduling is accomplished by two models: RTD, which is responsible for matching generation with load and allocating ancillary services on a five-minute basis, and RTC, which executes prior to RTD and schedules resources that are not flexible enough to be deployed on a five-minute basis. External transactions are scheduled prior to each hour for the duration of one hour and must be coordinated with the neighboring control area. Off-line gas turbines may take several intervals to start-up and reach full output. RTC executes every 15 minutes committing resources and producing advisory schedules across a two-and-a-half hour window. Consistent with RTD, RTC performs an economic evaluation that commits and schedules the least expensive resources available to meet forecasted demand and ancillary services requirements. This evaluation produces advisory clearing prices for each 15 minute interval across the scheduling horizon. Lack of convergence between RTC and RTD prices can be a substantial concern because large price differences point to inconsistencies that can result in external transactions and off-line gas turbines being scheduled inefficiently; resulting in increased uplift costs and inefficient real-time prices.

With the introduction of SMD 2.0, RTC replaced BME, which previously scheduled external transactions and committed gas turbines. RTC is a significant improvement over the BME, which executed hourly producing one set of schedules for one hour. This should lead to closer convergence with the real-time market. One aspect that did not change with the upgrade from the BME to the RTC is that both models co-optimize energy and ancillary services. This differs from the upgrade of the real-time dispatch software, because RTD co-optimizes energy and ancillary services while its predecessor model optimized energy and assumed fixed ancillary services schedules. This enhancement should also contribute to better convergence between RTC and the real-time market.

The two analyses in this section highlight several factors that lead to systematic differences between RTC and RTD prices. 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 shows that differences between RTC and RTD in the amounts of load and net exports lead 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 45 compares several quantities from RTC and RTD by time of day during the summer of 2006. 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 energy prices. The following 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 45: Energy Prices, Loads, and Net Exports in RTC and RTD by Time of Day, June to August 2006



In general, Figure 45 indicates that systematic differences between RTC and RTD prices are correlated with differences between RTC and RTD values of load and net exports. 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, at the top of each hour, RTC and RTD have different expectations 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, whereas RTC assumes that each interface meets the next hour schedule at the top of the hour. For example, suppose net exports increase from 200 MW in the hour beginning at 8:00 to 800 MW in the hour beginning at 9:00. 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. 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 regulation procurement costs. 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 analysis 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 2006. 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). The figure shows the difference between the load forecast used by RTD and the load forecast used by RTC. Positive values indicate that the RTD load forecast was higher while negative values indicate that the RTD load forecast was lower.

Figure 46: Regulation Deployment and Load Forecasts Used in RTC and RTD by Time of Day, June to August 2006

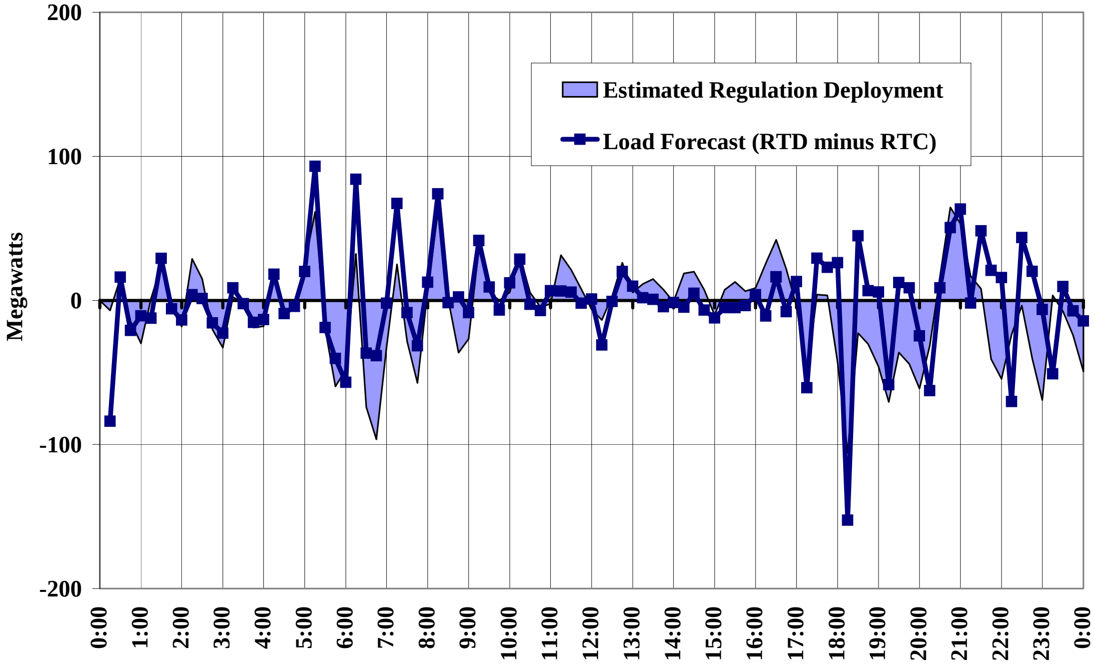


Figure 46 shows a strong correlation between variations in regulation deployment and the difference between the load forecasts used by RTD and RTC. For example, from 5:00 to 5:15, regulating units are usually being instructed to increase output, and at the same time, the difference between the RTD load 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, it would allow the operator to make adjustments to the load forecast used by RTC, which 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 practice consistently 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 expected 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 make 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 consistent to eliminate differences at the top of each hour; and
- Predictable adjustments to the RTD load forecast, which are made to minimize regulation deployment, can be reflected more quickly in the RTC load forecast.

B. Market Operations under Shortage Conditions

Many ISO operating functions have a substantial effect on market outcomes, particularly during peak demand conditions. While a degree of operator flexibility is necessary to maintain system reliability, the market rules must be designed to ensure that necessary operator actions do not unduly undermine efficient price signals. The region relies on prices to coordinate market participant interaction on the system. Prices should encourage generators to produce energy to meet demand and resolve congestion when it is economic for them to do so. Prices should incent suppliers to provide the ancillary services that are necessary for reliability. In the long-run, prices should signal to market participants where and when new investment 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 four aspects of market operations during shortage conditions. First, we evaluate the consistency between reserves prices in the real-time market and the actual physical scarcity of reserves. The Eastern 10-minute reserves constraint was chosen for this analysis because it generally exhibits the highest market value of any reserves requirement. Second, we examine aspects of “Hybrid Pricing” that lead to inconsistencies between clearing prices and the adequacy of reserves in the real-time market. Third, we review real-time clearing prices for energy in areas where emergency demand response resources were deployed. Fourth, we discuss market rule changes that have been implemented to reduce unnecessary costs that arise during shortages of transmission capability.

1. Real-Time Pricing and Dispatch under Shortage Conditions

As described earlier, the NYISO improved the efficiency of shortage pricing with the implementation of SMD 2.0. When the co-optimized real-time market 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.

Co-optimization of energy and reserves has been integrated with Hybrid Pricing, which has been a key element of the real-time market software since 2002 and can significantly affect the shortage pricing. Hybrid Pricing was specially designed 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, where gas turbines account for 28 percent of dispatchable capacity, and in the 138kV load pocket, where gas turbines account for 42 percent of dispatchable capacity. Thus, Hybrid Pricing is particularly important to setting efficient price signals in New York City load pockets.

The Hybrid Pricing methodology treats gas turbines as inflexible resources for the purpose of determining physical dispatch instructions and as flexible resources for pricing purposes. 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. These inconsistencies should be limited such that: (i) prices reflect scarcity during physical shortage conditions, and (ii) high prices are only set when the system is physically in shortage of either energy or ancillary services. Previous reports found that a substantial number of such inconsistencies occurred after the implementation of SMD 2.0.[26] However, the NYISO has made several improvements to the market software to address the lack of consistency between the physical dispatch and pricing dispatch. The analyses in this section assess whether such inconsistencies occurred frequently during 2006.

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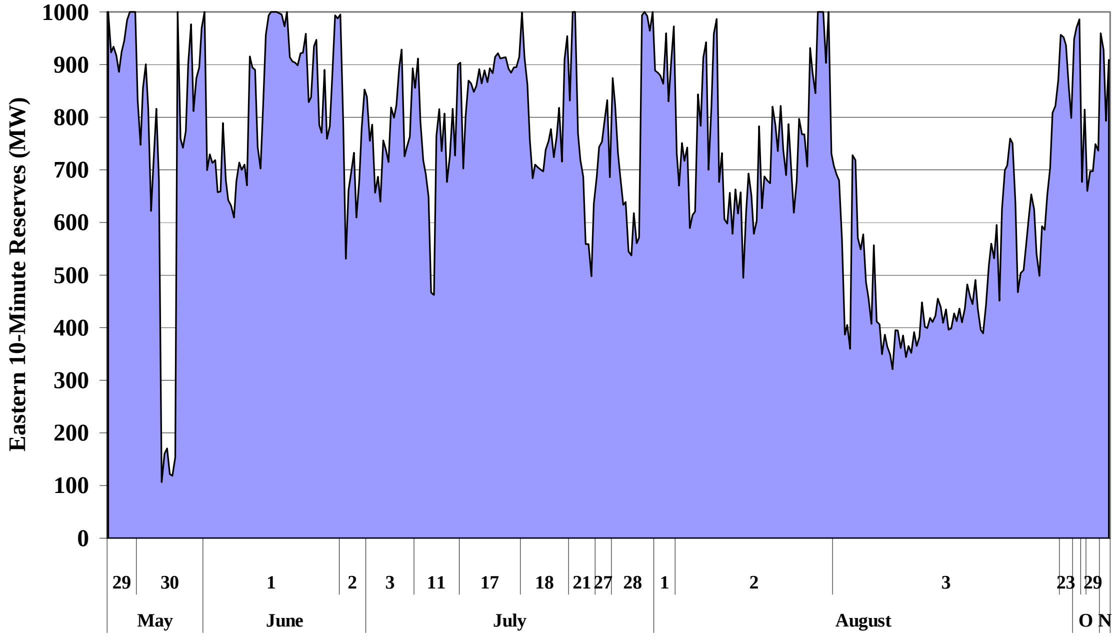
26 See *2005 State of the Market Report, New York ISO*, August 2006, Potomac Economics.

The first analysis in this section assesses whether high prices have only been set when the system was physically short of a key reserves requirement. Figure 47 shows the amount of Eastern 10-minute reserves that were physically available during intervals of shortage pricing during 2006.

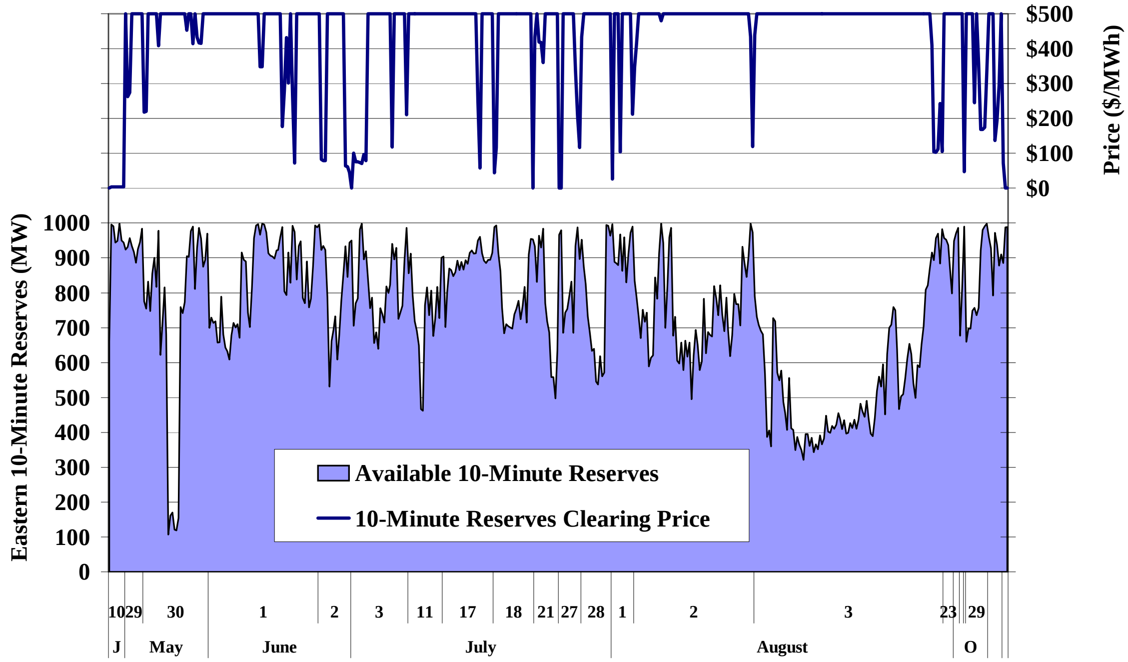
Figure 47: Scheduling of 10-Minute Reserves in East New York During Shortage Pricing Intervals, 2006



The figure shows 376 intervals with shortage pricing of Eastern 10-minute reserves during the study period. Based on the amount of physically available 10-minute reserves, Eastern New York was short in 96 percent of these intervals. This shows modest improvement over the previous year when 89 percent of shortage pricing intervals occurred during periods of physical shortage. The results in the figure above indicate that the vast majority of shortage pricing intervals associated with the Eastern 10-minute reserves requirement occurred during authentic periods of physical shortage.

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 amount of available reserves during physical shortages of Eastern 10-minute reserves. It also shows a line indicating intervals with Eastern 10-minute reserves shortage pricing.

Figure 48: Scheduling and Pricing of 10-Minute Reserves in East New York During Physical Shortage Intervals, 2006



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

For Eastern 10-minute reserves, Figure 48 shows the real-time clearing prices and the available quantity during physical shortage intervals. This figure shows that 85 (or approximately 19 percent) of the intervals with physical shortages were not accompanied by shortage pricing in 2006. The shortage quantity was less than 100 MW in 67 percent of these intervals. During 2005, there were 235 intervals with physical reserves shortages that were not accompanied by Eastern 10-minute reserves shortage pricing. These results demonstrate a significant improvement in consistency between the pricing dispatch and the physical dispatch passes of RTD during periods when the East is short of 10-minute reserves.

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. This change is explained below in greater detail.

The efficiency of real-time energy and ancillary services pricing has greatly improved since RTD was implemented under SMD 2.0. RTD replaced the prior real-time market model, which did not consider how the provision of ancillary services affects the cost of energy. The software changes made prior to the summer of 2006 have substantially improved the performance of RTD.

2. Hybrid Pricing

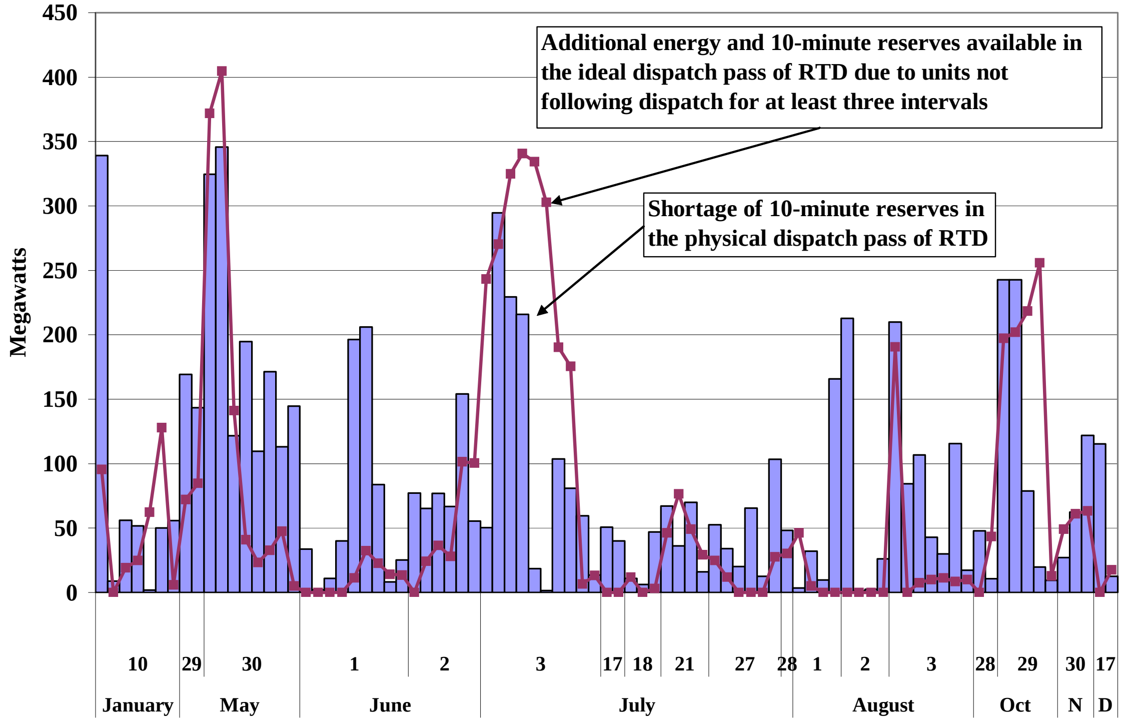
Hybrid Pricing was specially designed to address the problems posed by gas turbines in a marginal cost pricing market. Hybrid Pricing treats gas turbines as inflexible resources for the purpose of determining physical dispatch instructions and as flexible resources for pricing purposes. For instance, in a case where 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 pass, which leads the steam unit to be the marginal resource. If clearing prices were based on the incremental cost of the steam unit, the price would be lower than the running costs of the gas turbine. So RTD’s pricing pass treats the gas turbine as capable of reducing its output, which allows it to be the marginal resource and set the clearing price. Under these circumstances, the steam unit has a higher output level in the pricing pass than in the physical dispatch pass, while the gas turbine has a correspondingly lower output level in the pricing pass than in the physical dispatch pass. This illustrates one of several reasons that output levels for individual resources are not consistent between the two passes of RTD.

In addition to the primary difference between the pricing and physical dispatch passes under Hybrid Pricing (i.e., the flexible treatment of gas turbines in the pricing pass), two other elements have contributed to the low clearing prices that sometimes accompany reserves shortages. The first element involves the treatment of gas turbines that have reduced capability due to high ambient temperatures, and the second concerns the treatment of ramp rate constraints. Since the output capability of gas turbines is inversely related to ambient air temperatures, gas turbine capability tends to be lowest on hot summer days, especially during the afternoon. Given the difficulty of predicting weather, this creates uncertainty about how much capacity is available to RTD. To ensure that RTD matches load with the correct amount of generation, the physical dispatch pass of RTD uses a reduced upper operating limit for gas turbines that appear to be limited by the ambient temperature for several intervals after starting up. Prior to a software change in May 2006, the pricing pass of RTD used the upper operating limit submitted by the market participant, which was typically higher than the ambient temperature limit. This treatment led to a greater availability of supply in the pricing pass than in the physical dispatch pass. Since the software change in May 2006, the pricing pass of RTD uses the same upper operating limit as the physical pass. This change is the primary reason for the dramatic improvement in consistency between the two passes in 2006.

The second issue is that RTD formulates ramp rate constraints differently in the physical pass and the pricing pass. The physical dispatch pass constrains the instructed output level of each resource according to its ramp rate offer relative to its actual output level. In contrast, the pricing pass 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 pass. Although Hybrid Pricing was designed this way to facilitate treating gas turbines as flexible in the pricing pass, 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 49.summarizes the effect of units persistently not following dispatch instructions on Eastern 10-minute reserves prices during the 85 intervals when there was a physical shortage and no shortage pricing. The bars indicate the shortage quantity in the physical dispatch pass of RTD. The line indicates the additional energy and 10-minute reserves available in the ideal dispatch pass due to inconsistencies in the treatment of units not following dispatch instructions.

Figure 49: Impact of Units Not Following Dispatch Instructions Shortage Intervals Without Shortage Pricing, 2006



The figure above shows that there were intervals when more supply was available to the pricing dispatch pass than the physical dispatch pass as a result of a generator not following dispatch for at least three intervals. This quantity was greater than the physical shortage in 24 of the 85 intervals shown and in 6 of the 28 intervals when the shortage exceeded 100 MW. Overall, the inconsistent treatment of units not following dispatch instructions explains a modest share of the instances when the physical dispatch pass perceived a shortage of reserves and the pricing dispatch pass did not.

Some inconsistencies between the pricing pass and the physical dispatch pass of RTD are inherent to 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 such differences may lead real-time energy prices to be inefficient under certain circumstances.

In May 2006, the NYISO made a software change to address the inconsistent treatment of gas turbines under ambient temperature restrictions. This change has greatly improved the efficiency of prices during Eastern 10-minute reserves shortages. Additional improvements to the consistency of the pricing and physical dispatch passes of RTD would lead to more efficient pricing of energy and ancillary services, particularly during shortages. To address the inconsistencies that arise when generators do not follow dispatch instructions, we recommend the NYISO assess the feasibility of re-calibrating the dispatch levels in the pricing pass for such units.

3. Demand Response and Shortage Pricing

When the operators anticipate reserve shortages in advance, they are able to call upon Special Case Resources ("SCRs") and Emergency Demand Response Program ("EDRP") resources to curtail. 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.[27] EDRP resources are paid the higher of $500 per MWh or the clearing price. SCR resources are paid the higher of their strike price, which is typically $500 per MWh, or the clearing price.

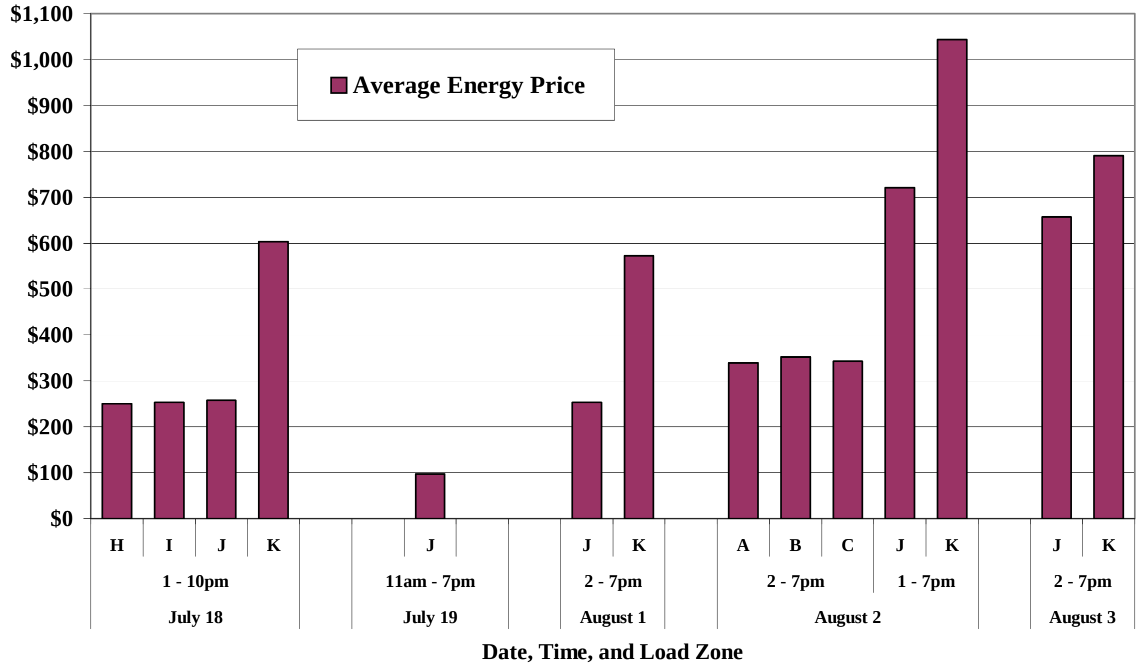
In an efficient market, clearing prices should reflect the cost of deploying resources to meet demand and maintain reliability. To be involved with setting prices in the real-time market, resources must be dispatchable by the real-time market model on a five-minute basis. Since EDRP and SCR resources 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 per MWh after EDRP and SCR resources are curtailed, if adequate resources are available to the system in real-time.

Special shortage pricing rules have been developed to set more efficient prices when demand response is deployed. Whenever a shortage of state-wide or eastern reserves is prevented by the activation of demand response, real-time clearing prices are administratively set to $500 per MWh within the region unless they already exceed that level. This rule helps reflect in real-time clearing prices the cost of maintaining adequate reserve levels. The following analysis examines real-time clearing prices during deployments of demand response to determine whether prices adequately reflect scarcity.

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

The following figure shows the average real-time energy prices in each zone during each curtailment of EDRP and SCR resources in 2006. There were 35 hours on five days when EDRP and SCRs were curtailed in one or more zones. In each case, they were curtailed to address a local issue rather than a large-scale shortage of reserves in the state as a whole or in the eastern region.

Figure 50: Real-Time Energy Prices During EDRP/SCR Activation 2006



On each of the five days shown in Figure 50, demand response was activated in a subset of the eleven zones in the state. This is because the demand response was called for local constraints rather than widespread reserve shortages in the state or the eastern region. The figure indicates that the $500 per MWh EDRP and SCR resources were economic in Zone K (Long Island) on all four days curtailed and economic in Zone J (New York City) on two of the five days curtailed. EDRP and SCR resources were uneconomic on the two days when they were activated outside Zone J and Zone K. When SCR and EDRP resources were economically out-of-merit, real-time energy prices were still relatively high, averaging between $200 per MWh and $400 per MWh. However, prices would have been higher if they had not been activated.

In many hours, the shortage pricing rules were not triggered because the EDRP and SCR resources were activated to address a local shortage. The smallest area for which the shortage pricing rules can be triggered is the area east of the Central-East Interface, which includes Zones F, G, H, I, J, and K. To minimize the effect on real-time prices of "out of merit" SCR and EDRP resources, the NYISO developed the capability to call these resources in blocks smaller than an entire zone. We support this change and the development of additional shortage pricing rules to enable these resources to set prices in local areas when they are needed to avoid a local shortage.

4. Transmission Shortages and Congestion Price Spikes

Real-time transmission price spikes occur when the re-dispatch costs necessary to resolve a transmission constraint reach extremely high levels. During 2006, there were 1,314 intervals when shadow prices exceeded $1,000 per MWh on one or more constraints and 214 intervals when they exceeded $4,000 per MWh. The shadow price of a transmission constraint indicates the marginal cost to the system of resolving the constraint. High shadow prices during these intervals contributed significantly to the severity of real-time energy and reserves price spikes and balancing congestion shortfalls, which are recovered through uplift charges.

Spikes in the shadow prices of transmission constraints can occur for brief periods when there is not sufficient ramp capability within a transmission-constrained area. This may result in large amounts of re-dispatch that provide little reliability benefit when only remote generators are available to be re-dispatched. For instance, there are cases where RTD must re-dispatch 100 MW or more in order to provide one megawatt of relief to a transmission constraint. In such cases, 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. Therefore, the actions taken to maintain reliability by resolving a transmission constraint may actually undermine reliability.

To address problems that can arise from incurring extraordinary re-dispatch costs, the NYISO has made a change to real-time operations by limiting the marginal re-dispatch costs to a maximum of $4,000 per MWh. We support this change, which the NYISO implemented on June 21, 2007. We will continue to evaluate the efficiency of congestion management and pricing under the new methodology including the appropriateness of the $4,000 per MWh limit.

C. Uplift and Out-of-Merit Commitment

In this section of the report, we evaluate patterns of uplift and out-of-merit actions that occurred in 2006. This evaluation is an important component of our overall assessment of the performance of the NYISO's markets because it indicates the extent to which the markets satisfy New York's operational requirements.

1. Bid Production Cost Guarantee Payments

The first analysis presented in Figure 51 shows the magnitude of uplift costs for four categories of BPCG payments in the last two years. The figure includes payments for local reliability and non-local reliability operation in both the day-ahead market and the real-time market.

There are two categories of day-ahead market uplift, which is paid to units committed by SCUC that do not recoup their as-bid costs from the day-ahead clearing prices. First, uplift is paid to units committed economically that do not receive sufficient revenue to cover start-up costs and minimum generation costs over their entire run time. Second, uplift is also paid to generators committed in the local reliability pass of SCUC, which commits generators out-of-merit in New York City to protect against second contingencies. These commitments for local reliability by SCUC have a tendency to decrease day-ahead prices. As a result of lower prices, more uplift is paid to generators committed before the local reliability pass. Only uplift paid to units committed in the local reliability pass is allocated to the local area, while approximately half of the day-ahead market uplift is assessed market-wide.

There are two categories of real-time market uplift, which is paid to units committed by the NYISO after the day-ahead market that do not recoup their as-bid costs from the real-time clearing prices. First, uplift is paid to generators committed and/or re-dispatched for local reliability reasons. While this can occur for a variety of reasons, the majority of this uplift is related to Supplemental Resource Evaluation ("SRE") commitments. Second, uplift for BPCG payments goes to units committed economically by RTC and RTD that do not receive sufficient revenue to cover start-up costs and other running costs over their entire run time.

Figure 51: Day-Ahead and Real-Time Uplift from BPCG Payments 2005 – 2006

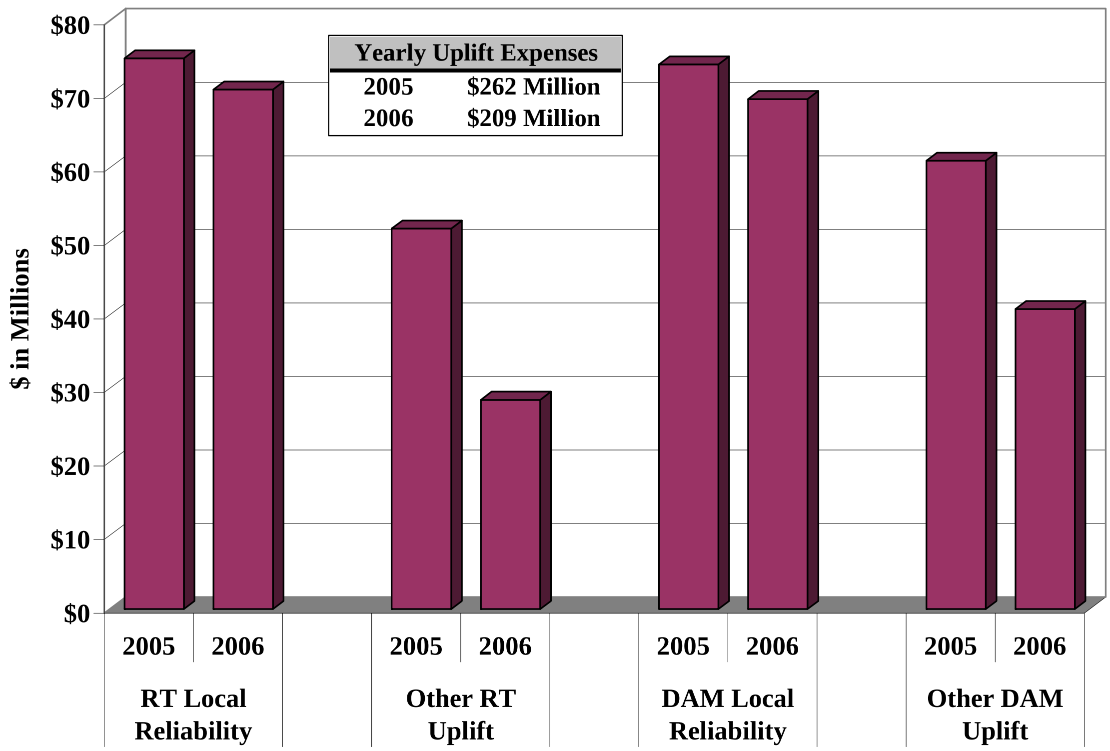


Figure 51 shows that day-ahead and real-time local reliability uplift decreased approximately 6 percent, while the total non-local reliability uplift actually decreased 39 percent. Local reliability uplift expenses stayed relatively constant as the benefits of lower fuel costs were partially offset by more frequent commitment for local reliability. Non-local reliability uplift declined due to a combination of factors including lower fuel costs, reduced deployment of gas turbines resulting from the capacity additions in New York City, and more efficient commitment of gas turbines due to the use of a more detailed network for modeling transmission constraints in New York City. These factors were discussed in greater detail in Section VI of this chapter.

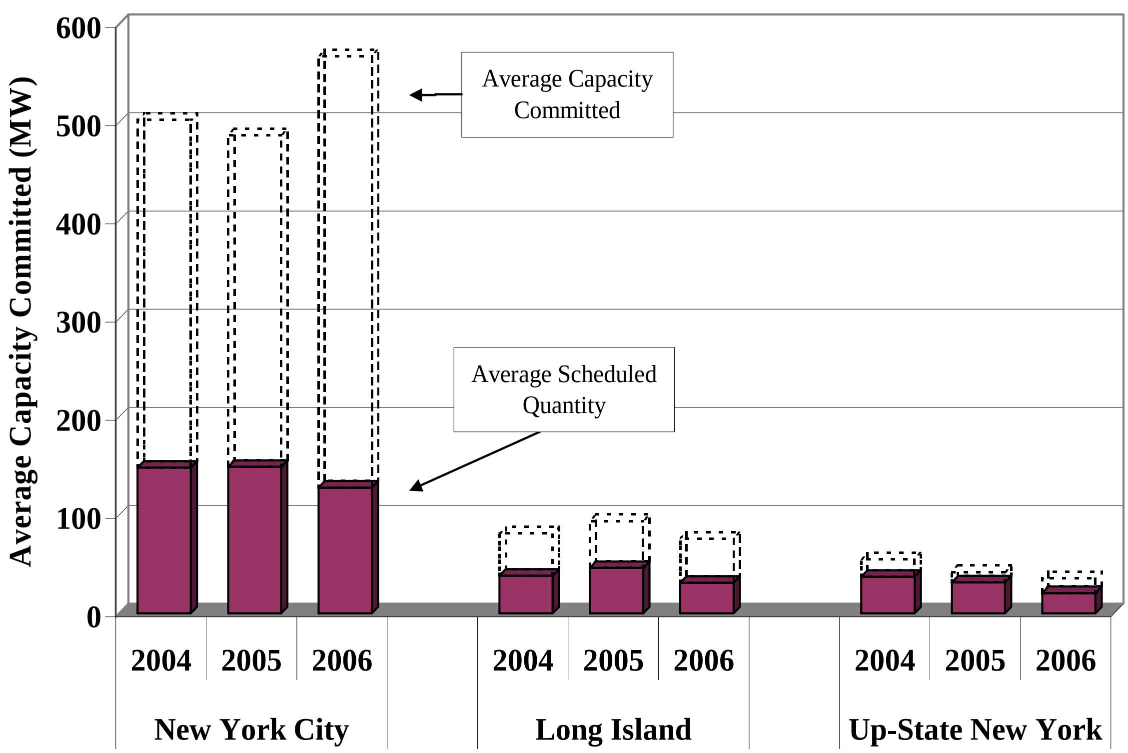
Overall, total expenses for BPCG payments declined from 2005 to 2006, and the allocation of these expenses shifted significantly. Local reliability uplift is charged to specific transmission owners or load serving entities while non-local reliability uplift is allocated to all loads in the New York Control Area. Hence, the fraction of uplift that is allocated locally increased from 57 percent in 2005 to 67 percent in 2006.

2. Out-of-Merit Commitment

There are two types of OOM commitment: local reliability commitment by the day-ahead model and SRE commitment. Day-ahead local reliability commitment is a form of out-of-merit commitment that takes place during the day-ahead market process, while the SRE that occurs after the day-ahead market closes. The day-ahead local reliability commitment is an element of the SCUC market process whereby units that are not committed economically may be committed to meet certain specific reliability requirements, particularly 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.

Our first analysis in this section, Figure 52, shows the average quantity of SRE commitments made from 2004 to 2006 in New York City, Long Island, and upstate New York.

Figure 52: Supplemental Resource Evaluation
2004 – 2006

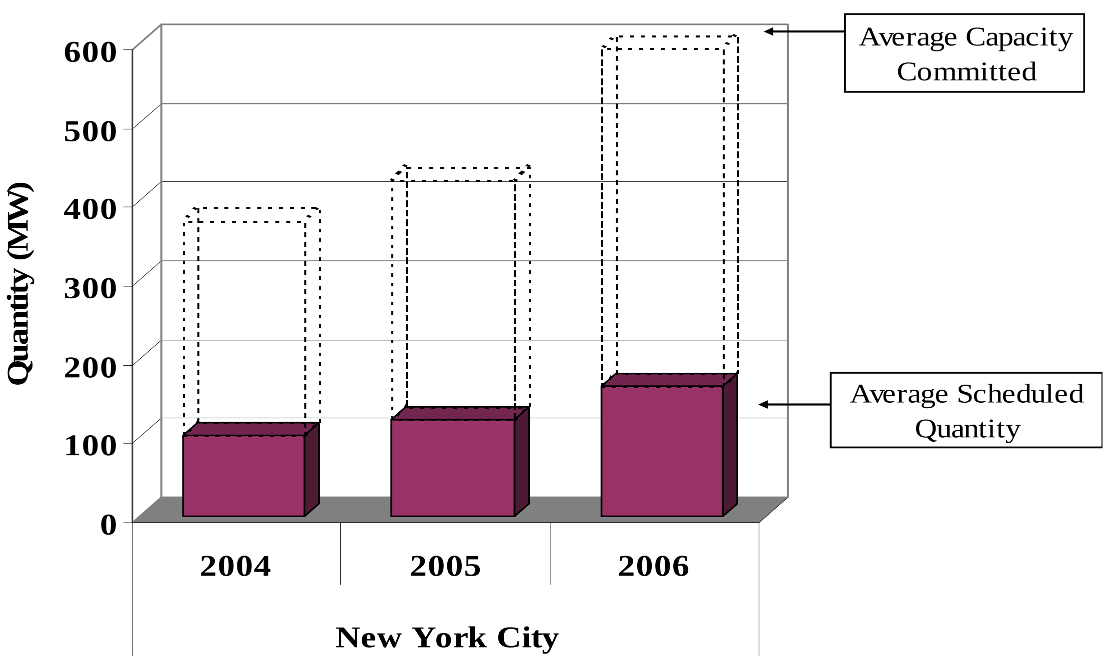


When the operators undertake SRE commitments these actions are logged and reported on the NYISO website. Such supplemental commitments do not directly affect the day-ahead prices, but instead make additional resources available in real-time, and, therefore, may reduce real-time prices as a result of additional units operating at their minimum generation levels. Because of the potential for price distortion as a result of these actions, it is important to evaluate the SRE process and its effects.

Figure 52 indicates that most of the units committed through the SRE process are dispatched at close to their minimum generation levels (i.e., 25 to 35 percent of the maximum capacity). Hence, although nearly 570 MW of capacity is committed in the City, only 120 MW of additional energy is produced due to these commitments on average. This reduces the effects of these commitments on the NYISO energy markets.

The next analysis focuses on local reliability commitments made in the day-ahead market (i.e., by SCUC). Figure 53 shows the average capacity committed in the day-ahead market for local reliability and the day-ahead scheduled quantity from 2004 to 2006.

Figure 53: SCUC Local Reliability Pass Commitment
2004 – 2006

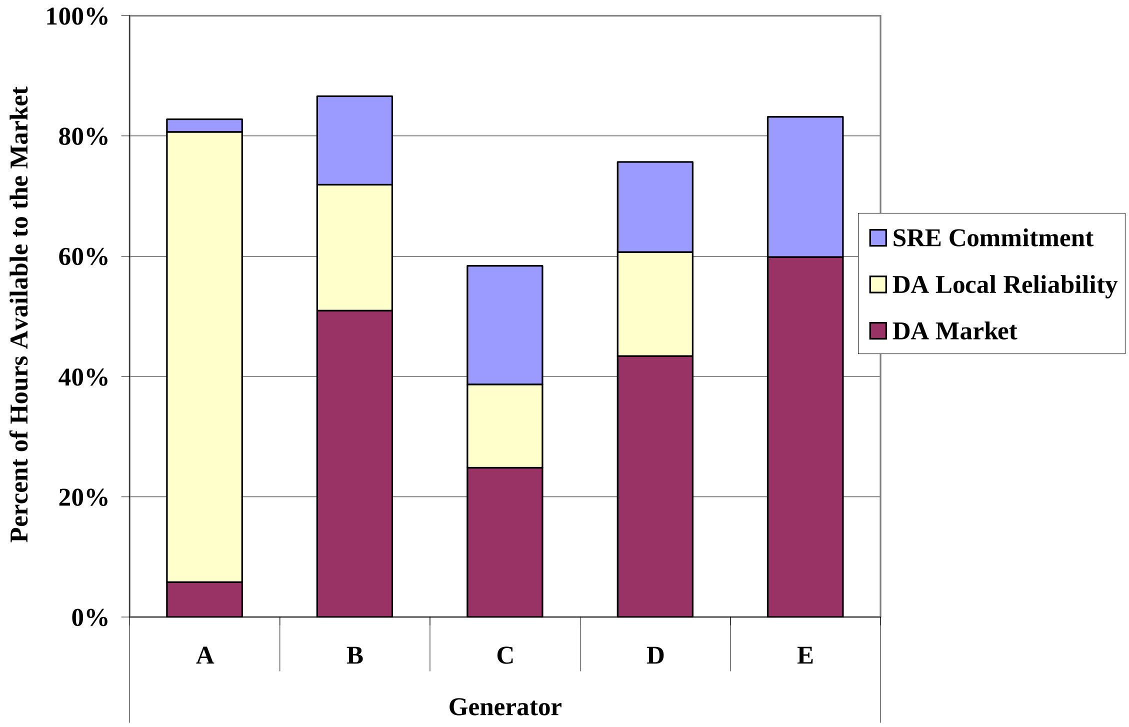


The commitments shown in Figure 56 tend to reduce prices from levels that would result from a purely economic dispatch; and can increase uplift incurred to make guarantee payments to other generators that will not cover their as-bid costs at the reduced price levels. The figure shows that the average capacity committed for local reliability was nearly 600 MW for the period shown in

2006, which is a substantial increase from 2005. These units received much lower day-ahead schedules, indicating they are generally scheduled at their minimum generation level. This is the quantity of energy that will affect the day-ahead prices.

In our final analysis of the OOM commitment, we evaluate the frequency of these commitments at the individual unit level. Figure 54 shows five units that were frequently committed for local reliability by the day-ahead model or through the SRE process. The values shown are the hours that each unit is committed as a percent of the hours that the unit is available (i.e., not on outage). The units in the figure accounted for a substantial share of the uplift costs for local reliability in the day-ahead and real-time. All five of these units are located in New York City.

Figure 54: Units Most Frequently Committed for Local Reliability and SRE in 2006



Note: DA Market Based included periods when the unit is committed economically in the day-ahead market.

The figure above shows that these nine units were committed for local reliability in a large share of the hours when they were not otherwise committed economically. For instance, Generator A was committed economically in the day-ahead market in 6 percent of hours. However, this generator was committed in 82 percent of the remaining hours by the local reliability pass of SCUC or through the SRE process. In hours when these five units were available but not committed economically, they were committed in the local reliability pass of SCUC or through SRE at least 40 percent of the time. Based on this analysis, it seems clear that under certain operating conditions certain generators are predictably needed for local reliability, and will be committed for reliability if they are not economically committed.

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, depressed clearing prices, and additional uplift.

3. Conclusions

Out-of-merit generation has significant market effects. Primarily, it inefficiently reduces prices in both the day-ahead market and real-time market. When this occurs in a constrained area, it will inefficiently dampen the apparent congestion into the area. OOM commitments also may increase uplift payments as units committed economically will be less likely to recover their full bid production costs in the spot market.

Out-of-merit commitment by the local reliability pass of the day-ahead market model increased significantly in 2006. In the long-run, it would be superior to include local reliability constraints into the initial economic commitment pass of SCUC. In the short-run, we recommend that the ISO consider the feasibility and benefits of allowing operators to pre-commit units needed for predictable market conditions.

Both of these recommendations would require the NYISO to work with participants to revise the cost allocation methodology for uplift associated with the local reliability requirements. Currently, the uplift costs for BPCG payments to units committed for local reliability are allocated locally, while BPCG payments to other units are allocated throughout NYCA. If the recommendations were implemented, a methodology would need to be developed to identify units that were committed as a result of the local reliability requirements.

VII. Capacity Market

The capacity market is intended to ensure that sufficient capacity is available to meet New York's electricity demands reliably. This market provides economic signals that supplement the signals provided by the NYISO's energy and operating reserve markets. In this section we assess the design and competitive performance of the capacity market. Capacity markets in New York have faced a number of significant changes in 2006, from concerns over unsold New York City capacity to reduced capacity imports and an increase in capacity exports as a result of changes in the New England capacity market. These changes are described in more detail below.

A. Background

Since 2001, capacity payments in New York have been made for Unforced Capacity ("UCAP") rather than Installed Capacity ("ICAP"). UCAP 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 nameplate capacity and a forced outage probability of seven percent would be able to sell 93 MW of UCAP. This creates a mechanism that attaches an explicit value to investments in reliability and gives suppliers a strong incentive to provide reliable performance.

The New York Reliability Council has recommended certain installed capacity margins for the NYISO in order to achieve NERC's one-day-in-ten-years outage standard. Since these recommendations are stipulated in terms of ICAP, the NYISO uses a control area-wide forced outage rate to convert this recommendation into UCAP terms. An LSE could contract for capacity bilaterally, self-schedule, or rely on the NYISO-run auctions to fulfill its UCAP requirements. 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. However, all requirements must be satisfied at the conclusion of the spot market immediately prior to each month.

Starting in June 2003, the New York state-wide ICAP purchases were no longer fixed at 118 percent of peak load. Instead, the amount of ICAP purchased varies depending on the market price for ICAP in the spot capacity auction, which is determined by the interaction of capacity supply offers and an ICAP Demand Curve. The ICAP Demand Curve replaced what was, in effect, a fixed requirement that was independent of the availability and cost of supply offers. The new requirement varies to obtain more capacity at lower prices when more low cost capacity is available, but obtains less capacity and pays higher prices when capacity is relatively scarce. In addition, the fixed deficiency charge was replaced with a variable charge equal to the ICAP price that results from the spot auction.

For the state-wide capacity requirement, the ICAP Demand Curve was set so that at a capacity of 118 percent of peak load (or the UCAP equivalent in the UCAP deficiency auction), the demand price would be set equal to the annualized cost of a new peaking unit. The demand price would reach zero at 132 percent of peak load, and rise to a maximum of twice the annualized cost of the new peaking unit if capacity declines below the 118 percent. The ICAP Demand Curves for Long Island and New York City work in a similar manner, but they are adapted to the specific requirements for native generation in those areas. The ICAP Demand Curve for Long Island ranges from the annualized cost of a peaking unit at 99 percent of peak load to zero at 117 percent of peak load. The ICAP Demand Curve for New York City ranges from the annualized cost of a peaking unit at 80 percent of peak load to zero at 94 percent of peak load. Should sales of ICAP in New York City exceed 94 percent, the New York City UCAP price would be equal to the UCAP price in the rest of New York State.

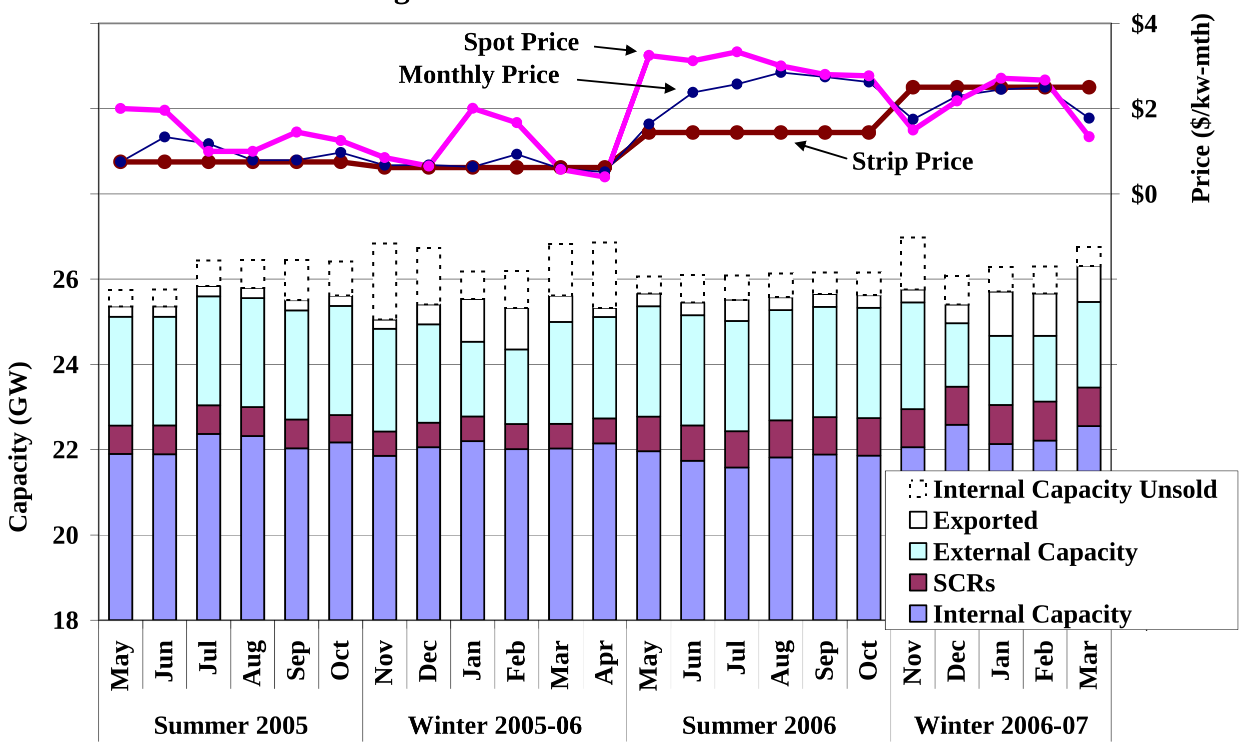
The results of the monthly spot UCAP auction determine each LSE's obligation for the following month. The aggregate UCAP requirement and the associated UCAP price are established at the point where the supply curve of offers crosses the Demand Curve. All UCAP resources accepted in the auction, including resources offered by LSEs, are paid the applicable market-clearing UCAP price, and all LSEs pay the applicable market-clearing UCAP price for their UCAP requirement.

B. Capacity Market Results

To evaluate the performance of the capacity market, Figure 55 and Figure 56 show capacity market results during the two-year period from May 2005 through April 2007. This includes four six-month capability periods from the Summer 2005 capability period through the Winter 2006-07 capability period. These figures show the sources of UCAP supply and the quantities purchased in each month.

The amounts shown in Figure 55 include all capacity offered by New York capacity suppliers outside New York City and Long Island into the New York capacity market. The hollow portion of each bar represents the in-State capacity not sold in New York or in any adjacent market. Figure 55 shows UCAP prices in the "rest-of-state" area (i.e., the price applicable to capacity outside New York City and Long Island).

Figure 55: UCAP Sales – Rest of State



The figure shows that most of the capacity requirement is satisfied by internal generation, although external suppliers (in the rest-of-state area) and alternative capacity suppliers (including special case resources and load management) each provide a significant amount of capacity in this market. Over this period, clearing prices in the Rest-of-State area have ranged from just above $0 per kW-month to $3 per kW-month, depending on the levels of imports and exports, the timing of retirements and new investments, and load growth. Approximately 600 MW was retired in early 2005, although this has been replaced by 700 MW of new capacity that came online in July 2005. Statewide demand for UCAP rose approximately 1500 MW from the summer of 2005 to the summer of 2006 due to an increase in the peak load forecast.

Although New York is a net importer of capacity, net imports to New York declined substantially in January and February 2007, leading to a rise in the spot auction price. Beginning in December 2006, increased payments for capacity resources in the New England market led to a reduction in external resources coming into New York and additional increases in capacity exported from New York. These suppliers have been attracted by $3.05 per kW-month fixed capacity payments, which are part of New England's transition to its new Forward Capacity Market. December 2006 saw an 1,100 MW reduction in net imports of UCAP from New England and Quebec to New York. In January 2007, there was a 600 MW increase in exported capacity.

Figure 56: UCAP Sales – New York City

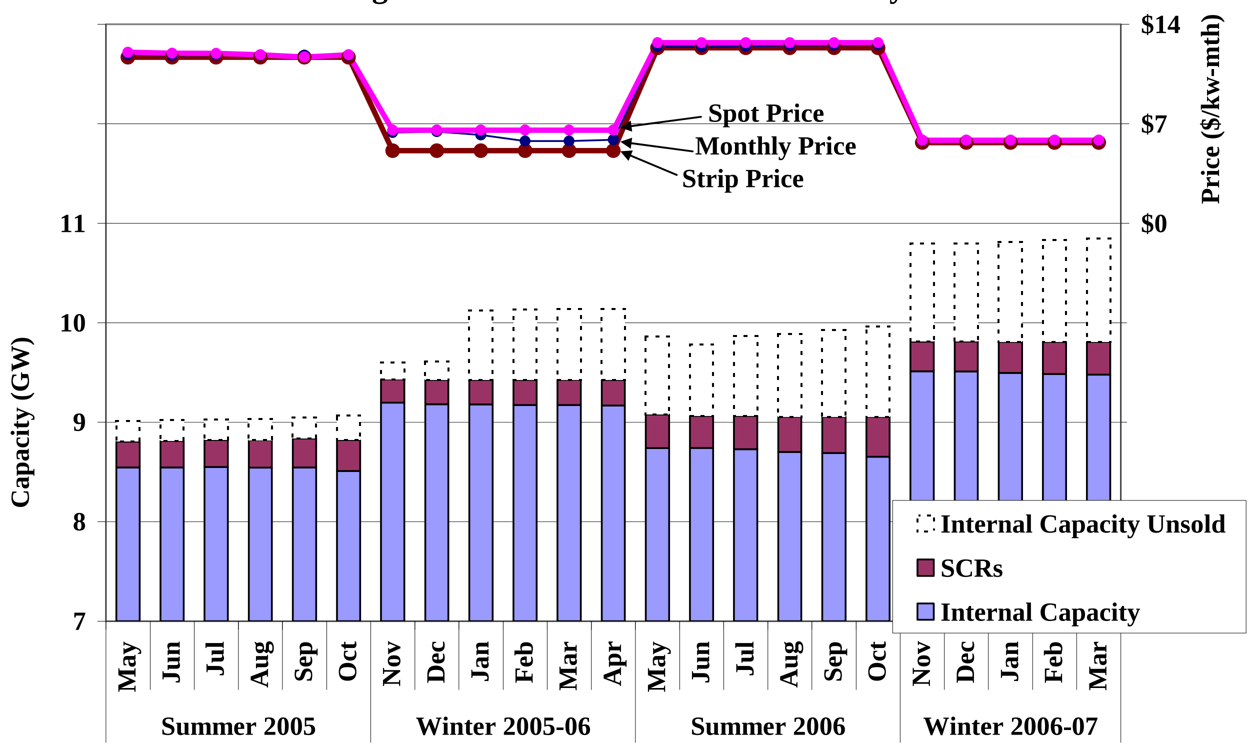


Figure 56 shows that capacity purchases in New York City over the last two years have risen modestly, consistent with the rise in peak load requirements in the City. In addition, new supply has became available in New York City during this period. Approximately 500 MW came into service in January 2006, and another 500 MW came online in May 2006. Demand response resources in New York City have increased by approximately 130 MW over the 23 months shown. Clearing prices in New York City have been consistently close to $7 per kW-month during the winter capability periods and near $12 per kW-month during the summer capability periods. The New York City prices correspond to the price cap on the Divested Generation Owners ("DGOs") that purchased the capacity from ConEd when it was required to divest most of its generation in 1998.

Prior to January 2006, virtually all of the capacity in New York City was sold. However, after the addition of new capacity in January and May 2006, there has been virtually no increase in the amount of scheduled capacity and, thus, no reduction in clearing prices from the In-City suppliers' price cap. After examining the data on capacity and energy outcomes, we found that the unsold capacity participated in the energy market. The results shown in Figure 56 therefore raise competitive concerns regarding the highly concentrated New York City capacity market. Currently, a proceeding at FERC is addressing these concerns and other issues related to the capacity market in New York City.

Most of the capacity in New York City is owned by several Divested Generation Owners ("DGOs") that purchased the capacity from ConEd when it was required to divest itself of most of its generation in 1998. Regulators foresaw the potential for market power and imposed market power mitigation measures at that time. These measures primarily consisted of caps on the revenue that DGOs could earn from the capacity market, and a requirement to offer the capacity in the NYISO's market at a price no higher than the cap. Although this provision was intended to mitigate the DGO's market power, it allows the DGOs to raise prices substantially above competitive level under conditions when NYC has surplus capacity. It is also important to recognize that the price that the DGOs paid for the in-city units were likely substantially higher than they would have been if more effective market power mitigation measures had been required. Hence, modifying the mitigation measures to more effectively mitigate the market power in NYC would raise significant equity considerations.

The NYISO is conducting a review and update of its capacity demand curves. This update occurs every three years and is intended to allow changes in the costs of building new capacity at various locations in the state to be reflected in the market. One location where long-term reliability concerns have arisen is in the lower Hudson Valley. The past two Reliability Needs Assessments have identified this area as requiring new capacity in the relatively short-term horizon. It is likely more costly to build new generation in this area than further upstate or in western New York. Our analysis of the long-term price signals suggests that the markets are likely not providing economic signals that would cause an investor to build generation in the Hudson Valley.

A similar issue is addressed in New York City and Long Island by the definition of local capacity requirements. In contrast, Hudson Valley is in the "rest-of-state" area with no local capacity requirements. Hence, we recommend that the NYISO initiate an assessment to determine whether a new capacity zone with local requirements is warranted to address the Hudson Valley reliability requirements.

VIII. External Transactions

This section evaluates the extent to which prices have been efficiently arbitraged between New York and adjacent regions by analyzing the price differences between the markets and the use of the interfaces. Although several market design improvements have been made in recent years to improve the efficiency of flows between adjacent markets, the interfaces are still not fully utilized. There are additional changes that should be made to improve the efficient price convergence at these "seams" between New York and the adjacent markets.

In particular, we encourage the NYISO to continue working with ISO New England to develop external scheduling provisions to enable the two markets to realize many of the benefits of better coordination between the regions. Since April 2005, PJM and the Midwest ISO have coordinated congestion management in the two markets under the framework of the Joint Operating Agreement ("JOA"). Under the JOA, the dispatch software of each market incorporates transmission constraint information from the other market in real-time, allowing for more efficient congestion management and pricing in the two markets. In the long-term, experience gained from operation under the JOA should inform the development of ideas to coordinate between New York and adjacent markets. However, in the near term, it is reasonable for New York to focus on implementing external scheduling provisions with New England to improve the price convergence between the markets.

Price convergence occurs when the energy prices at the border are equal in the absence of transmission congestion. In real-time, it has proven difficult for the adjacent markets to achieve price convergence by relying on transactions scheduled by market participants. Uncertainty, imperfect information, and offer submittal lead times limit the ability of participants to capitalize on real-time arbitrage opportunities. This failure of real-time arbitrage gives rise to market inefficiencies that could be remedied if the ISOs were to coordinate interchange to reduce or eliminate the price differences.

A. Price Convergence between New York and Other Markets

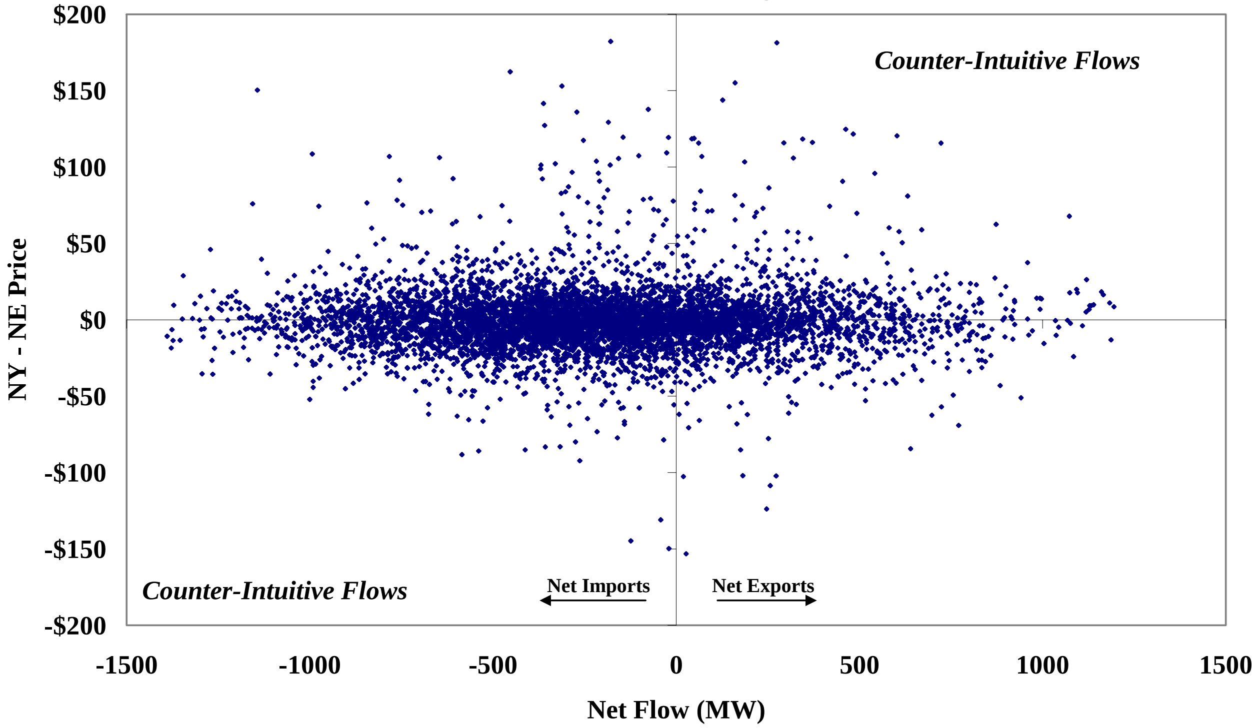
The performance of wholesale electricity markets depends not only on the efficient use of internal resources, but also the efficient use of transmission interfaces between New York and other areas. Absent transmission constraints, trading between neighboring markets should cause prices to converge. When the interfaces are efficiently used, one would expect that prices in adjacent areas would not differ greatly except when the interface constraint is binding. In other words, when prices are higher in New England than in New York, exports to New England should continue until the interface is fully scheduled or until prices have converged and no economically-viable exports remain.

The series of scatter plots/charts in Figure 57 show the hourly difference in real-time prices between New York and neighboring markets relative to net exports during hours when transmission constraints are not binding:

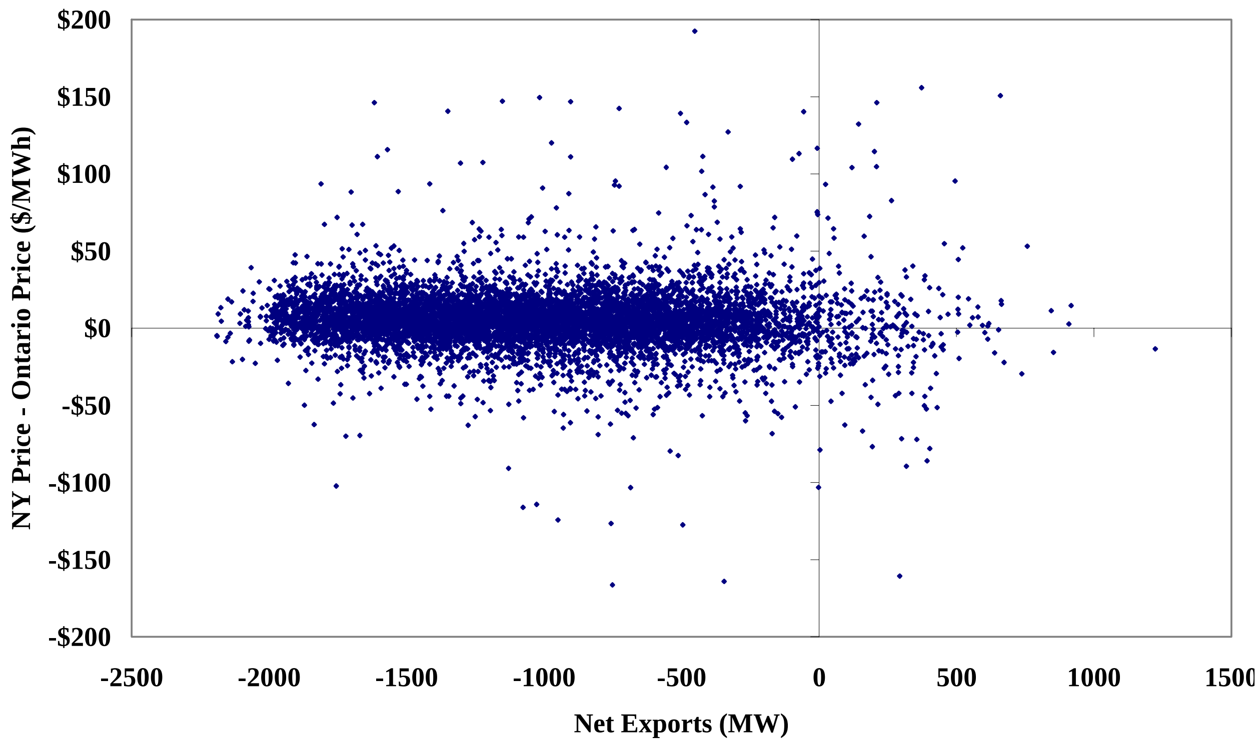
- The price differences plotted against the left axis are always computed by subtracting the external price from the New York price (i.e., positive price differences mean prices are higher inside New York). The top half of each scatter diagram, therefore, reflects hours when the price in New York was higher than the price in the neighboring region.
- The net exports are shown on the x-axis with positive values reflecting net exports from New York and negative values representing net imports.
- Two "counter-intuitive" quadrants are shown where power is scheduled from the higher priced market to the lower priced market.

If transactions were scheduled efficiently between regions, it is expected that the points in each of the charts would be relatively closely clustered around the horizontal line at $0 – indicating little or no price difference between New York and the adjacent region in the absence of a physical transmission constraint (quantities of imports or exports can vary widely, but without transmission constraints power flows should continue in one direction or another until prices differences were arbitraged away). Moreover, one would not expect net exports to occur when the New York price substantially exceeds the price in the neighboring region. Likewise, one would not expect net imports to occur when the New York price is substantially less than the price in a neighboring region.

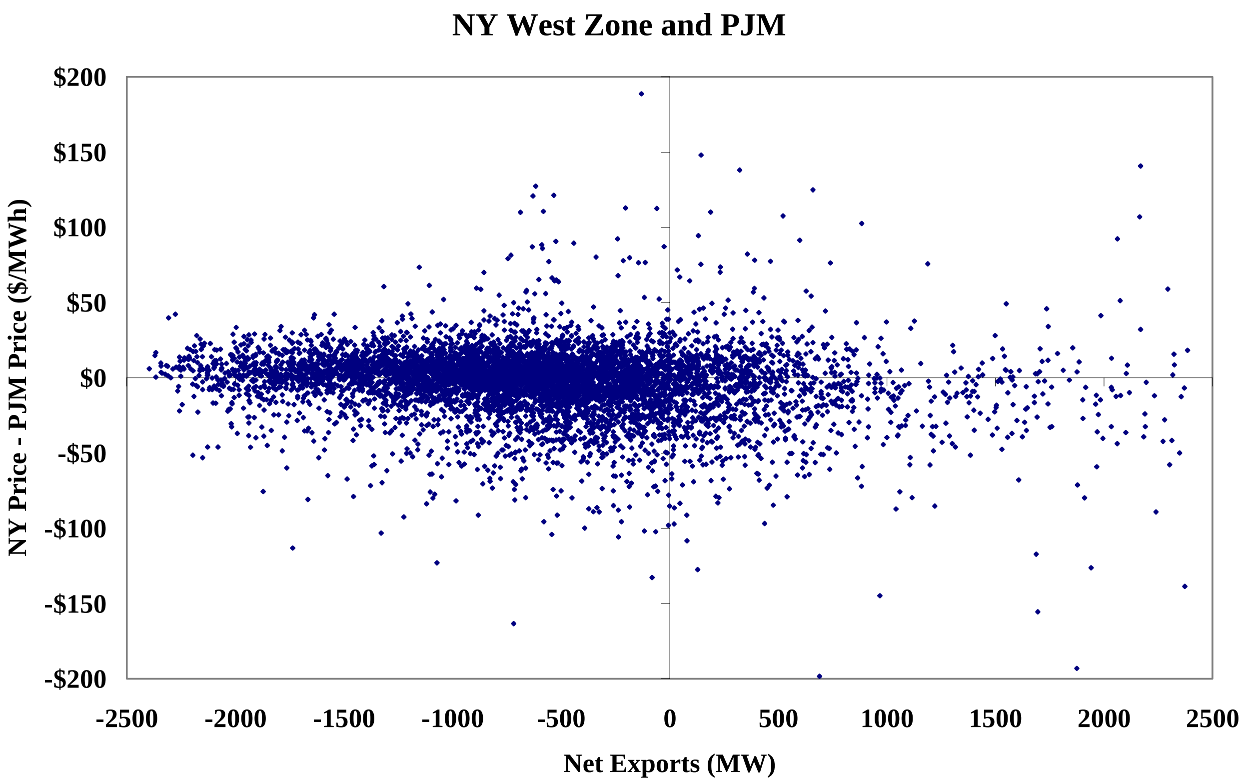
Figure 57: Real Time Prices and Interface Schedules
Eastern NY and New England



West NY and Ontario*



* Price difference measured in US dollars



These figures show the real-time markets are not arbitraged efficiently by participants. The dispersion in prices during unconstrained hours is shown to be considerable. In a significant number of hours for each interface, power is scheduled from the high-priced market to the lower-priced market. These results are similar to results presented in prior years.

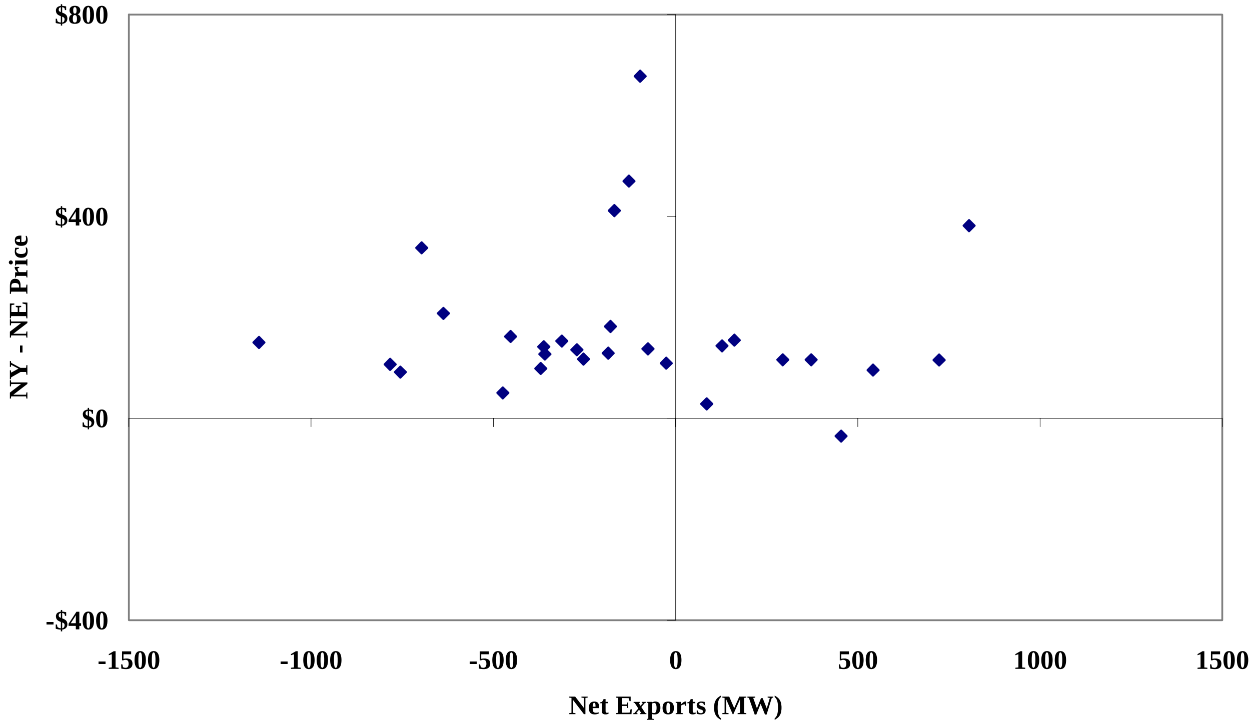
Several factors prevent real-time prices from being fully arbitraged between New York and adjacent regions. First, market participants do not operate with perfect foresight of future market conditions at the time that transaction bids must be submitted. Without explicit coordination between the markets 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 would not be expected to schedule additional power between regions unless they expect a price difference greater than these costs. Last, risks associated with curtailment and congestion will reduce participants' incentives to engage in external transactions at small price differences.

Uncertainty, imperfect information, and required offer lead times limit the ability of participants to capitalize on real-time arbitrage opportunities. These results reinforce the importance of provisions that are being developed to coordinate the real-time interchange between New York and New England. This is particularly important during shortages – when optimizing the flow between areas has larger economic and reliability consequences.

Fees assessed to transactions between control areas tend to inhibit convergence. In 2005, export fees between New York and New England were eliminated, facilitating arbitrage of the adjacent markets. However, several other charges are still imposed on transactions between New York and New England. Exports from New York and New England scheduled after the day-ahead market continue to be allocated charges for certain ISO/RTO operating costs. Prior to the fall of 2005, the ISO-NE allocated these charges based on the largest transaction scheduled during a month. This method resulted in very large charges (on a per MWh basis) for some market participants. In the fall of 2005, the ISO-NE addressed this problem by allowing market participants to choose an alternative method which allocates on a per MWh basis. Transactions from New York to New England scheduled after the day-ahead market continue to be allocated uplift for certain types of supplemental commitment by both ISOs. However, neither ISO assesses these charges to transactions that flow from New England to New York.

During peak demand conditions, it is especially important to efficiently schedule flows between control areas. The following chart, Figure 58, examines the difference between New York and New England real-time border prices in unconstrained hours when the Capital Zone price exceeded $200/MWh.

Figure 58: Interchange and Price Differences Between New York and New England Unconstrained Price Spike Hours*, 2006



* Includes hours when the real-time Capital Zone price exceeded $200 per MWh

Figure 58 indicates that price convergence between adjacent markets remains poor during peak demand conditions. In 23 of 29 hours – nearly 80 percent of the hours examined – the New York price was higher than the New England price by $100 per MWh or more. While 2005 saw many more hours in which prices were greater than $200 MWh, only in 50 of the 82 hours – just over 60 percent – was the New York price at least $100 per MWh higher than the New England price. In 8 of the hours shown in Figure 58, power was flowing out of New York even though the New York price was higher. Frequently during peak demand conditions, a small amount of additional imports can substantially reduce the magnitude of a price spike. This underscores the potential benefits of real-time coordination of the interchange between control areas, especially during peak demand periods.

B. 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. A detailed estimate of the benefits of complete coordination between the New York and New England markets suggested that in 2004 consumers in New York and New England would have saved as much as $48 million and in 2005 savings in the region would have totaled $155 million.[28] This analysis indicates that optimizing the interchange between markets would bring very significant benefits. As a result of more frequent shortage conditions and higher fuel prices, the estimated benefits are much higher for 2005 than for 2004.

Although we did not perform simulations to estimate the benefits of coordinated dispatch in 2006 we did perform a detailed evaluation of the interchange during shortages. This evaluation revealed that sufficient interface capacity was available to relieve the shortage during many of the shortages. Hence, had the interchange between the markets been optimized, it is likely that New York would not have experienced a shortage in a number of shortage hours, which would result in significant consumer savings.

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.

C. Conclusions and Recommendations

Over the past several years, modeling improvements and rule changes have led to some improved convergence between control areas during non-transmission-constrained hours. While the external transaction scheduling process is functioning properly, significant price differences remain between markets in hours when no congestion is present. The economic consequences of these issues were minimized in 2003 and 2004, because demand was relatively mild and there were no instances of shortage. However, the economic effects of the seams issues were larger in 2005 and 2006 when the market experienced more shortages, some of which could have been avoided if the external interfaces were fully utilized.

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

These results reinforce the importance of addressing remaining seams issues. We continue to encourage New York and New England to develop and implement new procedures to better coordinate flows between control areas. Intra-hour Transaction Scheduling ("ITS") has been proposed to allow the physical interchange to be adjusted within an hour when prices diverge at the interface between the two markets. If ITS could facilitate efficient interchange, it would eliminate the price distortions and other inefficiencies caused by poor market arbitrage. Better arbitrage will lead to less volatility and more predictability in the New York to New England prices. We also recommend that the NYISO work with PJM to eliminate export fees and improve coordination of net interchange.

IX. Demand Response Programs

The New York ISO has some of the most effective demand response programs in the country. There are currently three demand response programs in New York State:

- Day-Ahead Demand Response Program (DADRP) – This program schedules physical demand reductions for the following day, allowing 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 the accepted offers and is paid day-ahead clearing price for each MW of curtailed load.
- Special Case Resources (SCR) – These are loads that must curtail within two hours when the operators forecast a reserve deficiency, and they are paid the higher of their strike price or the real-time clearing price. These resources may sell capacity in the capacity market corresponding to their commitment to curtail load.
- Emergency Demand Response Program (EDRP) – The emergency demand response program pays loads that curtail on two hours notice the higher of $500/MWh or the real-time clearing price.

A. Overview of Market Outcomes

The EDRP and SCR programs have been effective in achieving actual load reductions during peak conditions. The two programs had a total of 2,594 participants enrolled providing nearly 1,800 MW of demand response. The DADRP has been less of a factor in market outcomes and system operations.

In 2006, the NYISO activated EDRP and SCR resources on five occasions for a total of 35 hours. According to the NYISO, on July 18, 19, and August 2, EDRP and SCR performance was notably better than in 2005, and performance on August 1 and 3 was comparable to performance in 2005. Average SCR performance on during a 6 hour event on August 2 was over 73 percent, and reached 90 percent during the NYISO record peak load hour on August 2. In each case in 2006, EDRP and SCR resources were called upon to address local rather than large-scale shortages of reserves.

The success of these programs is largely due to incentives provided by the programs. EDRP participants are paid the higher of $500 per MWh or the LBMP for voluntary load reductions (i.e., they have no obligation to respond), which is the only source of revenue for the EDRP resources. SCR resources can sell their curtailable load in the capacity market in exchange for an obligation to respond when called. SCR participants are paid the higher of a strike price that they bid (limited to be less than $500 per MWh) and the LBMP.[29]

This payment structure satisfies two critical objectives. First, it results in payments to participants that are close to or exceed $500 per MWh, which allow them to be paid an amount that covers their marginal value of consumption during peak periods. Hence, it would provide an adequate incentive for loads to respond, even though most are served under regulated or otherwise fixed rates that cause them not to incur the wholesale price of electricity.[30] Second, during times when EDRP and SCR are the marginal sources of supply in the market that allow the system to satisfy its reserve requirements, the LBMP typically will be set at $500/MWh. This price is in a range that is consistent with the marginal value of reserves to the system. Hence, these payments and the associated pricing provisions contribute to efficient pricing during shortage (or near-shortage) conditions.

The EDRP and the SCR programs can contribute substantial demand-side resources to the market. Special Case Resources are qualified to sell into the capacity market, and by adding to the total supply, help reduce capacity prices. In the summer of 2006, SCR/ICAP subscribers sold capacity of approximately 350 MW in New York City, 185 MW in Long Island, and 680 MW in the Rest of State zones. These demand response resources have had a substantial effect on prices in the capacity market. They also help increase the competitiveness of the capacity market in New York City where ownership of generation is relatively concentrated.

Over 3,400 MWh of day-ahead demand response was scheduled in summer 2006, a substantial increase over previous summers. Nonetheless, the day-ahead demand response program has

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29 The NYISO will provide a 24-hour notice if it anticipates a need to make curtailments under the SCR program to meet reserve requirements. These curtailments may or may not ultimately be called. However, there is a two-hour notice given when the NYISO determines that the load should be curtailed. EDRP also provides the NYISO with resources to meet potential reserve shortfalls. These curtailable load resources are given two-hours notice prior to being asked to curtail.

30 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 EDRP and SCR load reductions, load that is interrupted would save only the regulated rate. This rate does not reflect the marginal system cost of serving the load as embodied in the wholesale LBMPs.

provided considerably less valuable demand reduction than the EDRP and SCR programs. DADRP allows retail customers the ability to offer load curtailment capability into the day-ahead spot market in a manner similar to generation supply offers. While almost all DADRP offers into the market were accepted in whole or in part during 2006, relatively few resources participate in the DADRP program, and offers typically are highest around holidays which generally already tend to be lower load days.

B. Demand Response and Shortage Pricing

Since the demand response resources are not dispatchable by the real-time model, EDRP and SCR resources must be called upon in advance of real time based upon projections of operating conditions. Because activations of EDRP and SCR resources are based upon projections, there is no guarantee that they will be deployed in “merit order”; market clearing prices may be above or well below $500 MWh when the resources are used. The NYISO’s shortage pricing rules allow its EDRP and SCR resources to set the market price when their activation enables the ISO to avoid a shortage of reserves in the New York Control Area or in the region east of the Central-East Interface.

- An analysis of the use of EDRP and SCR resources during the five days with activations in one or more zones indicated that the $500/MWh EDRP and SCR resources were only economic part of the time when activated.
- EDRP and SCR resources were economic in Long Island on all four days activated;
- EDRP and SCR resources were economic in New York City on two of five days activated; and
- EDRP and SCR resources outside of Long Island and New York City were not economic on any of the days when they were activated.

The events when EDRP and SCR resources were activated are discussed in greater detail in Section VI.B.

When the operators activated demand response in 2006, it was to manage local rather than regional or state-wide constraints. However, operators were not capable of activating demand response in increments smaller than a zone. To minimize the impact of “out of merit” SCR and EDRP resources, the NYISO implemented the capability to call these resources in blocks smaller than an entire zone prior to the summer of 2007. We support this change and the development of rules to enable these resources to set prices in local areas when they are needed to avoid a local shortage. The proposal should improve reliability in the local areas and improve the efficiency of the price signals.