2003 STATE OF THE MARKET REPORT
NEW YORK ISO

POTOMAC ECONOMICS, LTD.

Independent Market Advisor
to the New York ISO

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I. EXECUTIVE SUMMARY

Our assessment of the New York ISO wholesale electricity markets in 2003 indicates that the markets continued to perform competitively with no evidence of significant market power or manipulation by market participants. Wholesale electricity prices in 2003 were affected by rising fuel prices, but prices during the highest demand conditions were lower compared to 2002 as a result of milder summer weather and increased imports from New England. Changes to market rules and increased liquidity in day-ahead financial trading have improved the overall market performance. While the overall state of the market in 2003 was positive, there are issues relating to market rules and operations that we recommend be addressed going forward.

In evaluating the NYISO markets in 2003, we address the following areas:

- Energy Market Prices and Outcomes;
- Market Participant Bid and Offer Patterns;
- Market Operations;
- Capacity Market;
- External Transactions Scheduling;
- Ancillary Services; and
- Demand Response Programs

The following subsections provide an overview of the findings of the Report in each of these areas.

A. Energy Market Prices and Outcomes

Summary of Prices Trends in 2003

Energy prices were generally higher in 2003 than in the previous two years due to increased fuel prices. Prices peaked in February and March as natural gas prices rose sharply, and peaked again in August due to summer loads. The increase in fuel prices began in the fall 2002 and continued into 2003. Natural gas prices increased by 70 percent between 2002 and 2003. This translates into approximately $30/MWh of additional fuel costs for a unit with a heat rate of 10,000 BTU/kWh. Likewise, oil prices increased by approximately 24 percent from 2002 to 2003. While much of the electricity used by New York consumers is generated from hydro, nuclear, and coal-fired generators, natural gas and oil units are on the margin (i.e., setting the clearing prices) in most hours. Hence, the higher natural gas and oil prices cause sustained price increases versus 2002 under most load conditions. In 2003, there were more than 4500 hours with prices above $50, while prices exceeded that level for less than 1800 hours in 2001 and 2002.

However, the impact of higher fuel prices on energy prices was partially off-set by a reduced incidence and severity of price spikes. Price spikes were more frequent in 2002 and 2001. For example, real-time weighted prices exceeded $500 for 3 hours, compared to 6 hours in 2002 and 11 hours in 2001. This is despite the fact that scarcity pricing provisions were implemented in summer 2003 that set prices at $1000 during operating reserve shortages. The lower frequency of high-priced hours was primarily due to the lower peak load levels during the summer of 2003. Peak load conditions were much less severe in 2003 due to mild weather conditions. In the summer of 2002, there were 25 hours with actual loads exceeding 30,000 MW, versus only three hours in 2003.

Prices varied at locations throughout the state in 2003 primarily due to transmission congestion over the Central-East transmission interface separating western and eastern New York and due to transmission congestion into load pockets in New York City. In 2003, the day-ahead price difference between western and eastern New York averaged more than $6/MWh and the price difference between eastern New York and New York City averaged more than $12/MWh. The total congestion costs in New York were $310 million in 2001, $525 million in 2002, and $688 million in 2003.[1] The increase in congestion costs is primarily due to the modeling of the load pockets constraints within New York City, which began in June 2002. These changes allowed prices to more accurately reflect the transmission constraints within the City, increasing the apparent congestion and reducing the out-of-merit dispatch costs (i.e., uplift) of managing these constraints.

Total "all-in" prices, which include the costs of energy, ancillary services, capacity, and other costs, increased for all locations in 2003. This increase was primarily caused by higher fuel

1 These values are the total congestion revenues collected from participants. The approach for calculating these values is discussed in Section IV of this report.

costs, as described above and by slightly higher capacity costs. The capacity component of the all-in price increased slightly in 2003 due to the forecasted peak load rising faster than the average load (resulting in a higher obligation) and additional purchases under the demand curve. All-in prices varied from about $50/MWh in western New York to $90 MWh in New York City.

Day-Ahead and Real-Time Price Convergence

A comparison of the average day-ahead and real-time energy prices in the areas outside of New York City and Long Island shows a slight premium in the day-ahead market in these areas. This is consistent with expectations because most loads would place a premium on purchases in the day-ahead market due to a) the higher price volatility in the real-time market and b) the fact that Transmission Congestion Contracts ("TCCs") settle on day-ahead prices and quantities. Additionally, generators selling in the day-ahead market are exposed to some risk associated with day-ahead financial commitments. If participants are risk-averse, these factors will generate a price premium in day-ahead market. This is consistent with the experience from other markets. The results do not consistently show a day-ahead premium in New York City and Long Island. This may be due in part to the operational issues described below affecting the day-ahead market in these areas.

Although price convergence was relatively good in 2003, the absolute differences between the day-ahead and real-time price increased from 2002 to 2003 in most locations. We believe this is attributable to extreme volatility in natural gas prices overwhelming the positive effect of more active virtual trading and reduced price volatility due to milder load conditions. Convergence between the hour-ahead prices (produced by the Balancing Market Evaluation or "BME") and the real-time market prices has continued to be very good, which promotes efficient scheduling of external transactions and off-dispatch generating resources and reduces uplift costs.

Price Corrections

All real-time energy markets are subject to some level of price corrections to account for metering errors and other input data problems or software flaws that cause pricing errors under certain conditions. In New York, the rate of corrections declined steadily until the summer of 2002. The frequency of price corrections increased substantially when the modeling of the New

York City load pockets was introduced in June 2002, before declining again to previous low levels. In 2003, there was a spike in the incidence of price corrections on 14 days in April and 7 days in May. These corrections resulted in slight changes to the New York City zonal prices that had been calculated with incorrect weightings. The weighting problem was resolved and the level of price corrections returned to the historical baseline. Because these corrections did not affect the individual location-based marginal prices ("LBMPs") and did not substantially change the zonal prices, we conclude that they did not compromise the integrity of or otherwise adversely affect the NYISO markets.

Market Power Mitigation

Mitigation did not occur during 2003 under the automated mitigation procedures ("AMP"), although on several occasions the impact test was conducted to evaluate whether mitigation is warranted. The AMP is only applied outside New York City, and the AMP software only runs when energy prices outside the City are greater than $150 per MWh since the probability of the impact test being satisfied at lower pre-mitigation prices is extremely low. The conduct and impact tests in the relatively high-priced hours were not satisfied, so mitigation was not imposed. The mild load conditions during 2003 limited the instances when suppliers would have been pivotal in broader areas within New York and, hence, limited the potential for market power abuses.

However, under the "Con Ed" mitigation inside New York City, mitigation was frequent, occurring in every hour during summer 2003. This frequency is characteristic of the Con Ed mitigation measures because they are not triggered by an attempted abuse of market power, but simply the existence of transmission constraints. Replacing most of the Con Ed measures with measures that employ the conduct and impact mitigation tests will be an improvement over the current mitigation framework.

Mitigation measures to address locational market power in the New York City load pockets were implemented when the modeling changes were made to reflect the constraints into the load pockets. The local market power mitigation measures for New York City are triggered when there are binding constraints into a load pocket. Real-time mitigation was most frequent in the smallest, most congested load pockets that have the lowest mitigation thresholds and the most severe potential market power. Outside of the 138 kV system where most of the load pockets are located, mitigation is infrequently imposed due to higher conduct thresholds and more competitive conditions.

Net Revenue in 2003

The net revenue metric, which measures the total revenue that a hypothetical new generator would have earned in the New York markets less it variable production costs, evaluates the economic signals provided by the market. In long-run equilibrium, the market should support the entry of new generation by providing sufficient net revenues to finance new entry on average. This may not be the case in every year since there are random factors that can cause the net revenue to be higher or lower than the equilibrium value (e.g., weather conditions, generator availability, etc.).

The net revenue results for 2003 indicate that a new gas turbine in New York City would have earned only 60 to 75 percent of its required net revenue, while it would have earned only 33 to 42 percent of its required net revenue outside of New York City. Hence, the market results in 2003 alone would not have supported investment in a new gas turbine. The results for a new natural gas combined-cycle unit are much less clear. The results in eastern upstate New York suggest that the net revenue was close to the required level (although start-up costs were not considered in this analysis). Net revenue for a new combined-cycle unit in New York City was much higher, but we cannot conclude whether it is above the required net revenue level for the area because we do not have reliable estimates of investment costs for a combined-cycle unit in New York City.

The fact that the net revenue results indicate that a new gas turbine would not have earned its required net revenue in New York City or upstate New York does not necessarily raise significant long-term concerns for a number of reasons. First, the lack of shortages in 2003 reduced the net revenue substantially from the levels that would be expected under normal conditions. Second, natural gas turbines were not likely the most economic source of new capacity in 2003. Net revenue for combined cycle units and units burning other fuels earned considerably higher net revenue than gas turbines. Third, the Unforced Capacity (“UCAP”) demand curve is being phased-in, which will increase the expected capacity revenue in 2004.

Finally, upstate New York is currently in a capacity surplus, limiting the need for new gas turbines outside of New York City.

B. Analysis of Energy Bids and Offers

In this section of the Report, we analyze the overall patterns of conduct in the New York Market, including those that could indicate attempts to exercise market power.

Generator Availability

The trend in the equivalent forced outage rate from the beginning of the operation of the New York markets demonstrates the efficacy of the incentives provided by competition. The Equivalent Forced Outage Rate ("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. 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 declined again after the change from Installed Capacity ("ICAP") requirements to UCAP requirements in the fall of 2001, which increased the incentive to minimize forced outages since a unit's UCAP amount reflects its forced outage rates.

Potential Physical and Economic Withholding

This analysis evaluates the correlation of quantities of potential withholding to load levels. The analysis is based in part on the expectation that suppliers in a competitive market should increase bid quantities during higher load periods to sell more power at the higher peak prices. Alternatively, suppliers in markets that are not workably competitive will have the greatest incentive to withhold at peak load levels when the market impact is the largest. Hence, examining how participant conduct changes under different market conditions is an effective means for evaluating the competitive performance of the market.

Our first analysis is of potential physical withholding, analyzing total generation deratings, which include planned outages, long-term forced outages, short-term forced outages, and partial deratings. We find no statistically significant relationship between deratings and load levels.

The two days with extremely large quantities derated occurred on the Monday and Tuesday following the August blackout. There were six days where load in Eastern New York exceeded 18,000 MW and short-term deratings exceeded 2,000 MW. Three of these days occurred in the week following the blackout, while the other three occurred in the last week of June during the Indian Point 3 outage.

We conduct a second analysis intended to assess potential economic withholding, employing a measure called an "output gap". The output gap is the quantity of economic capacity that either remains unsold (for energy or reserves) or sets the market clearing price at inflated levels because the supplier's offer price is substantial higher than a competitive reference level. The report shows that the output gap decreases to extremely low levels under the highest load conditions. This is an important result because prices are most vulnerable to market power under peak load conditions. These results indicate that economic withholding was not a significant concern in 2003. Furthermore, there is no statistically significant relationship between these output gap results and the actual load levels. These results are consistent with expectations in a workably competitive market.

Analysis of Load Bidding

We also analyzed load bidding and scheduling patterns. Four categories of load comprise total load scheduled in the day-ahead market:

- *Physical Bilateral Contracts* – These are bilateral transactions that only settle transmission charges through the ISO. Financial bilateral transactions arranged solely between two parties do not appear in this category.
- *Day-ahead Fixed Load* – Non-price sensitive load scheduled by Load Serving Entities.
- *Price-Capped Load* – Price sensitive load scheduled by Load Serving Entities ("LSEs").
- *Net Virtual Purchases* – Whenever virtual load exceeds virtual supply, there is a net increase in load scheduled day-ahead.

The share of load scheduled through price-capped load bids decreased from 14 percent statewide to 8 percent in 2003. This is a concern because price-capped load bids protect loads against uneconomic purchases and mitigate market power in the day-ahead market. The share of the actual load supplied through physical bilateral contracts has been relatively constant at slightly less than 50 percent. This does not mean that the remaining 50 percent of the load is incurring the spot prices in the NYISO energy markets. Physical bilateral contracts do not include all bilateral contracts. In particular, financial bilateral contracts such as “contracts for differences” are settled privately and generally would show as day-ahead fixed load.

In order to further evaluate the pattern of load bidding, we calculated day-ahead hourly load schedules (including virtual load bids) as a percentage of real-time load for peak hours during 2003. New York City and Long Island tend to over-schedule load day-ahead. In each of the last two summers, substantially more load was scheduled in New York City and Long Island as a percentage of real-time load than other locations. In 2003, 107 percent of real-time load was scheduled day-ahead in New York City and Long Island compared to less than 95 percent in the rest of the state. These results are consistent with the differences between the day-ahead and real-time transmission limits (particularly into and within New York City) that are discussed in the next section.

Virtual Bidding was introduced in November 2001 to allow participation in the day-ahead market by entities other than LSEs and generators. The report shows that scheduled virtual load and supply both increased substantially in 2003, contributing to the relatively good price convergence. Additionally, most of the virtual bids and offers submitted in 2003 were price sensitive, which indicates that manipulation of day-ahead prices through virtual trading practices was not generally a significant concern.

Reference Prices

Reference prices serve as a competitive benchmark used in the monitoring and mitigation processes in New York. This analysis focused on the references prices that are based on the accepted offers into the New York market. To assess how well the reference prices are reflecting marginal costs, we compare the reference prices for different types of units to estimated variable production costs over the normal dispatchable output range. Overall, we found that reference prices statewide, on a weighted average basis, were 3.0 percent below weighted-average variable costs.

We also performed econometric analyses to investigate whether suppliers attempt to change their offers to influence their reference levels. A positive correlation between market prices and offer prices would indicate potential concerns that suppliers were attempting to raise their average accepted offer prices. With few exceptions, these tests showed little correlation between offer prices and market prices. This is not unexpected given the costs and benefits of this strategy.

C. Market Operations

TCC Payments and Congestion Revenue

We analyze congestion and find that payments to holders of TCCs often exceed the revenue from congestion in the day-ahead market, resulting in a TCC revenue shortfall that must be collected through uplift. The shortfall in 2003 was $126 million. In general, this indicates that the transmission limits are higher in the TCC auction models than in the day-ahead market. This is primarily caused by transmission outages modeled in the day-ahead market that were not recognized in the TCC auctions.

The Federal Energy Regulatory Commission ("FERC") has approved two changes that should improve incentives and result in lower shortfall amounts. First, cost-causation principles will be used to assign responsibility for TCC revenue shortfalls and surpluses to transmission owners ("TOs"). Second, TOs will be able to reserve a limited amount of TCC capacity, which would not be available in the TCC auctions and help ensure greater consistency between the transmission capacity sold in the TCC auctions versus capacity in the day-ahead market.

Real-Time Congestion Costs

The report indicates that there were significant congestion costs generated in the real-time market. The primary causes of positive real-time congestion costs are reduced real-time transmission limits or increased real-time loop flows relative to the assumptions in the day-ahead markets. If transmission outages (and returns to service) are random, the magnitude and direction of these congestion payments should be distributed randomly and should sum to zero over time.

In an attempt to identify the source of the persistence of the real-time congestion costs, we analyzed the flows over the primary transmission interfaces into New York. Our analysis indicates that the real-time flows over key interfaces when the interface constraints were binding were generally significantly less than the day-ahead flow scheduled over the same interface. This result indicates inconsistencies between the day-ahead and real-time market models. These inconsistencies should be substantially addressed through the implementation of the Real-Time Scheduling ("RTS") system, which will replace the current hour-ahead and real-time market models. The RTS should improve the consistency of the transmission limits and other assumptions because the RTS is built on the same modeling framework as the day-ahead Security-Constrained Unit Commitment ("SCUC") model. In the short-term, we also recommend that the ISO review and adjust, as appropriate, the current limits and assumptions in the SCUC model to improve its consistency with the real-time market.

Uplift Costs

Our analysis indicates that that uplift costs have fallen sharply. Total uplift expenses fell from $376 million in 2001 to $213 million in 2002 and to $203 million in 2003. The bulk of this reduction was in the area of real-time local reliability uplift expenses, which decreased almost 60 percent between 2001 and 2002 and by a similar amount in 2003. These reductions are primarily the result of load-pocket modeling in New York City. The costs of generation redispatch to manage congestion in the New York City load pockets are now reflected in the spot market prices.

Most of the remaining uplift costs are directly or indirectly related to units committed for local reliability in New York City or units committed after the day-ahead market through the supplemental resource evaluation ("SRE") process. These issues are discussed below.

Out-of-Merit Commitment and Dispatch

Out-of-merit ("OOM") commitment occurs when units are committed to satisfy reliability requirements that were not committed economically through the day-ahead market. This includes SRE actions and local reliability commitments made by the SCUC model. Minimizing OOM commitments is important because they can inefficiently depress energy prices and mask congestion.

Improvements in day-ahead modeling and commitment have reduced the quantity of SRE actions outside of New York City since 2001. However, the average quantity of capacity committed through SRE actions in New York City more than doubled in 2003 relative to 2002. A major reason for the SRE actions is the nitrous oxides ("NOx") emission limits that require certain base load units to be committed to allow gas turbines to operate. Likewise, virtually all of the local reliability commitments made by SCUC involved two units in New York City. These commitments are important because they tend to inefficiently reduce prices and dampen the congestion into constrained areas.

In the long-run, it would be superior to include local reliability and NOx constraints into the initial economic commitment pass of SCUC. In the short-run, we recommend that the ISO consider allowing operators to pre-commit units needed for NOx compliance. This should be feasible because the bulk of the local reliability commitments and SRE commitments in New York City involve only 3 to 4 units. This would reduce both local reliability and non-local reliability uplift.

OOM dispatch occurs when a unit is providing energy at a level where its bid exceeds the LBMP at it is logged by the NYISO as OOM (generally manually dispatched). The load pocket modeling in New York City has reduced OOM dispatch by 80 percent. Hence, OOM quantities fell substantially in 2003.

Market Operations in Shortage Conditions

Two market reforms were implemented prior to the summer of 2003 to improve the efficiency of the energy pricing during shortage conditions. First, Reserve Shortage Pricing ("scarcity pricing") became effective in June 2003. When the system is in shortage (that is, when available capacity is not sufficient to meet both energy and reserve requirements), the ISO meet the system's energy demands by foregoing a portion of its required reserves. Because the ISO will pay a supplier up to the bid cap of $1000 for energy in order to hold 10-minute reserves, the scarcity pricing provisions set the LBMP at $1000/MWh in New York City when a 10-minute reserve shortage occurs.

Second, the pricing provisions were modified to allow demand response resources to set energy prices. The NYISO can call on demand-side resources -- Special Case Resources ("SCRs") and Emergency Demand-Response Program ("EDRP") – to reduce their consumption and pay up to $500 for these load reductions. When these reductions are needed to avoid a shortage, they will set the energy price. Due to the relatively mild weather in the summer of 2003 and increased imports from New England, there were no shortages in 2003. Hence, these pricing provisions were not triggered.

The scarcity pricing provisions are being replaced by reserve demand curves being implemented as part of RTS, which more fully and efficiently reflect the allocation of resources between production of energy and reserves that occur under shortage conditions. The reserve demand curves have been designed to reflect the current operating requirements and reflect the implicit value of the operating reserves based largely on the $1000 bid cap. The reserve demand curves will be included in both the day-ahead and real-time market models, ensuring that the day-ahead commitment, hour-ahead scheduling, and real-time dispatch are all consistent.

D. Capacity Market

The capacity market is intended to provide efficient economic signals for capital investment and retirement decisions for generating capacity. To improve the performance of the capacity market, a demand curve was implemented in May 2003. Analysis of prices before and after implementation of the capacity demand curve show that the capacity demand curve has stabilized capacity prices and substantially improved the consistency of prices in the strip, monthly, and deficiency auctions both in New York City and in the rest of New York State. Implementation also caused a larger share of the capacity to be sold in the deficiency auction, where thin volumes had contributed to erratic prices.

In upstate New York, the capacity demand curve contributed to higher purchase volumes because excess supplies in that region meant that the market equilibrium was reached at a higher target quantity and lower price than the outcome in the traditional deficiency auction. Significantly more exports were purchased in the rest of New York, as higher and more consistent prices encouraged out-of-state resources to participate in the market. In New York

City, where prices were much higher, the increase in UCAP purchases was primarily due to increased requirements in the City rather than the demand curve.

E. External Transactions

We analyzed transfers between New York and adjacent markets by examining the relationship between the hourly difference in prices between New York and neighboring markets and net exports during hours when transmission constraints are not binding. If transactions were scheduled efficiently between regions, there should be little or no price difference between New York and the adjacent regions in the absence of a physical transmission constraint. The data shows that there are significant and persistent prices differences. Additionally, net power flows are frequently inconsistent with the relative prices (i.e., power is flowing from the higher-priced market to the lower-priced market).

These results reinforce the importance of addressing seams issues that remain. One change that will improve the arbitrage with the adjacent markets is to eliminate the export fees on external transactions. We also continue to encourage New York and New England to develop and implement virtual regional dispatch process (“VRD”). VRD is a process where the ISOs would adjust the physical interchange in small increments every 5 to 15 minutes based on the prices at the interface between the two markets. These adjustments would ensure that the interchange levels are efficient, eliminating the price distortions and other inefficiencies caused by poor market arbitrage. In principle, this process is comparable to the ISOs’ determination of the flows over internal interfaces based on generator and load bids. VRD will reduce volatility of the New York to New England prices and achieve significant efficiencies.

F. Ancillary Services

Ancillary Services Costs

Ancillary services costs include costs for regulation, voltage support, and various operating reserves. These costs increased by $20 million in 2003, reflecting the impact of higher fuel prices and the increased costs of regulation. However, because other market costs increased at a faster rate than the ancillary services costs, ancillary services costs decreased slightly as a percentage of total market costs.

Offer Patterns

A substantial portion of the capability that is available to provide reserves in the day-ahead market is not offered, particularly for 30-minute reserves and regulation. However, ancillary services markets are generally not tight because the total offers generally exceed the ancillary services demand:

- For 30-minute reserves, offers typically exceed approximate demand by 230 percent.
- For total 10-minute reserves (spinning and non-spinning) east of the Central-East interface, offers typically exceed approximate demand by 160 percent.
- For regulation and 10-minute spinning reserves, offers typically exceed approximate demand by 100-170 percent – ignoring the fact that some 10-minute spinning reserves can be purchased in the West.

Since these markets are jointly optimized and the same resources are offered in multiple markets, ancillary services markets can become relatively tight when resources are allocated to supply energy or other ancillary services. Hence, maximizing the offer quantities from resources capable of providing each ancillary service is important.

This report includes an analysis of trends in the regulation market in 2003, which exhibited significantly higher prices. Since regulation capacity far exceeds the demand and is controlled by a diverse set of suppliers, market power is not a significant concern. Our analysis indicates that the price increases are primarily attributable to modeling changes and increases in regulation offer prices in 2003.

Changes in Reserve Markets

We had recommended in prior market reports that the NYISO modify the pricing for ancillary services to: a) set the price for each at its marginal cost to the NYISO, including both opportunity costs and availability offers; and b) implement multi-settlement markets for reserves and regulation. These changes are part of the NYISO's RTS to be implemented in fall 2004. In addition, the RTS includes operating reserve demand curves that will substantially improve the pricing of both reserves and energy when the system is in shortage. These changes are very important and should generate considerable benefits over the short-run and long-run. Hence, we recommend that the NYISO allocate its available resources to implementing RTS rather than making any interim changes to the current ancillary services markets.

G. Demand Response

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. The first two are the EDRP and SCR. EDRP loads that curtail in real time on two hours notice the higher of $500/MWh or the real-time clearing price. While response is voluntary for the EDRP resources, SCRs are loads that *must* curtail within two hours, after having been notified day-ahead. The SCRs may sell capacity in the ICAP market as supply resources in exchange for accepting this curtailment obligation.

The SCR and EDRP are two of them most effective demand response programs in the country, together achieving more than one gigawatt of curtailments when called in the past. They are called when operators forecast a reserve deficiency. Due to the mild summer conditions discussed above, the EDRP and SCRs were not called in 2003 due to reserve shortages. They were utilized only during the two-day period after the blackout to assist in the restoration process. On August 15, 800 MW of curtailments were received over a 14 hour period while an average of 470 MW were realized on August 16 for an 8 hour period.

The Day-Ahead Demand Response Program ("DADRP") schedules physical demand reductions for the following day, allowing resources to offer into the day-ahead market as a supply resource and are paid the day-ahead clearing price. The quantities participating in this program are very low. Day-ahead demand response bids were submitted only 3983 hours. The average bid quantity was less than 4 MW per hour and cleared in the day-ahead market in only 25 hours. The low participation is likely due to the alternatives available for demand to bid in the day-ahead market (virtual trading and price-capped load bidding).

II. ENERGY MARKET PRICES AND OUTCOMES

In anticipation of significant changes with the adoption of the new RTS software and a number of complementary new market rules, replacing the NYISO's existing Real-Time Market systems, modifications to the markets in 2003 were limited to improvements that could not be reasonably postponed. While the NYISO continued to make minor refinements to its market rules and procedures over the last year, including the adoption of scarcity pricing provisions, there were no changes to the basic structure of the multi-settlement energy markets that are the central feature of the New York electricity markets.

The multi-settlement system consists of a financially-binding day-ahead market and a real-time market. Through these markets, the NYISO commits generating resources, dispatches generation, procures ancillary services, schedules external transactions, and sets market-clearing prices based on supply offers and demand bids. The day-ahead and real-time markets are augmented with the hour-ahead BME scheduling process that updates the day-ahead commitment of resources based on forecast load for the next hour. The main functions of the BME model is to commit 30-minute gas turbines, establish dispatch levels for units that only receive hourly dispatch signals (i.e., off-dispatch units), and schedule external transactions. Prices are established for energy and ancillary services in both the day-ahead and real-time markets based on supply offers and load bids.

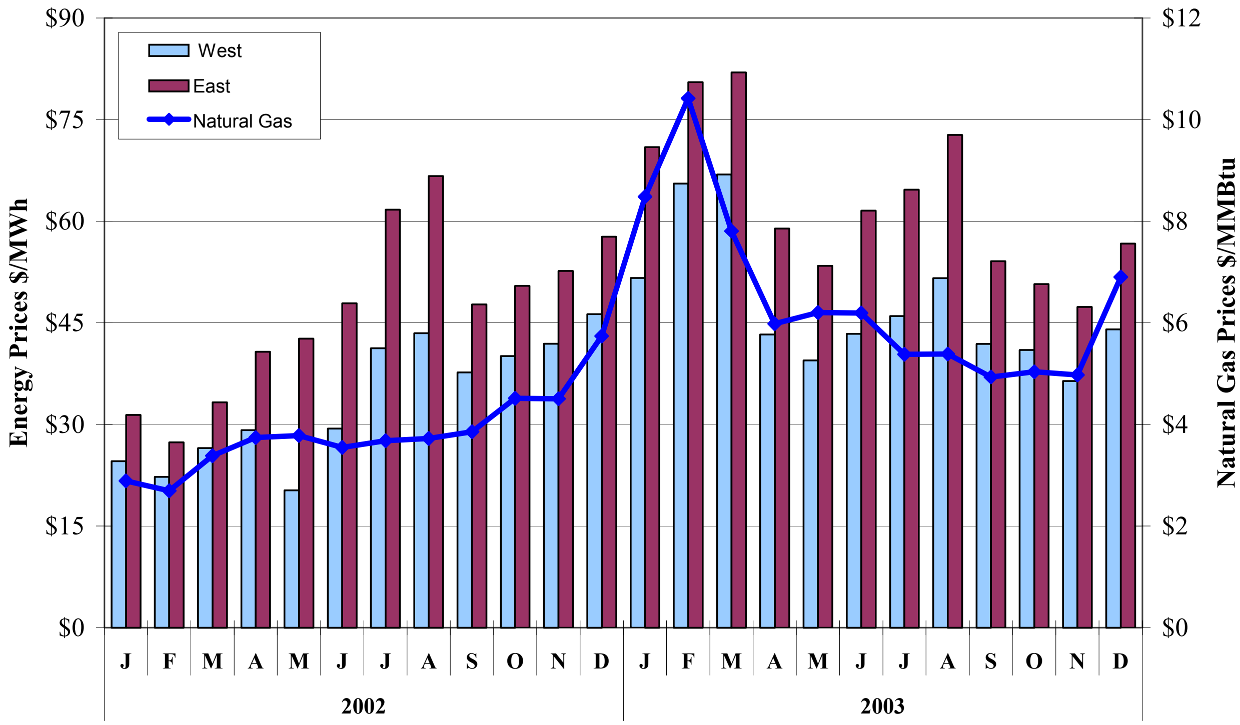
A. Summary of 2003 Prices and Costs

This section of the Report evaluates the performance of these markets with respect to prices and market outcomes. We evaluate the energy price trends over 2003, the overall market expenses, and the trends in individual market cost components. We also evaluate the incentives for new investment given the level of market prices.

1. Energy Prices

Energy prices were generally higher in 2003 than in the previous two years due to increased fuel prices. Changes in fuel prices are the primary driver of trends in energy prices over extended periods. The increase in fuel prices began in 2002, and continued into 2003. An analysis of fuel prices indicates that these prices were significantly higher in 2003 than in 2002. 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 which set prices in the market, especially during peak hours. Therefore, changes in the prices of these fuels will directly impact market prices. Figure 1 shows the relationship between natural gas prices and energy prices.

Figure 1: Energy and Natural Gas Prices
2002 - 2003



The average natural gas price in 2003 was 70 percent higher than in 2002. This translates to approximately $30/MWh of additional fuel costs for a unit with a 10,000 BTU/kWh heat rate. Distillate oil prices were far less volatile with average prices increasing only 24 percent from 2002. Natural gas prices peaked at very high prices, exceeding $10/MCF in February, when cold weather and limited inventories combined to create tight conditions in the natural gas markets.

The impact of higher fuel prices on energy prices was partially off-set by a reduced incidence and severity of price spikes. The lower number of price spikes was the result of three main factors. First, milder weather prevailed during the summer of 2003, reducing loads on the hottest days compared to the hottest days in 2002. Second, improved interchange with New England increased net imports, aiding in meeting loads at peak times. Third, there was more active price-responsive load bidding that reduced the amount of energy purchased in the day-ahead market during hours with high prices.

Figure 2: Price Duration Curve – All Hours
Average Real-Time Price 2001- 2003

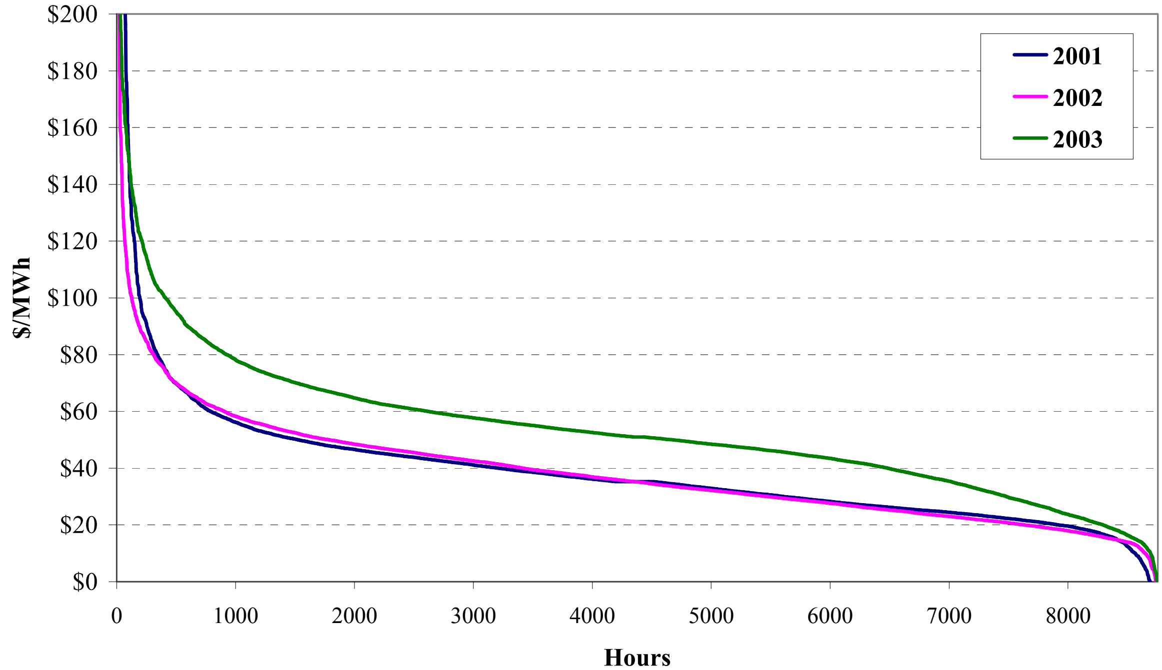


Figure 2 presents a price duration curve, which shows the number of hours in which the market settled at or above a given price level. Figure 3 is also a price duration curve that focuses attention on the highest priced hours, which account for a disproportionate share of the economic signals in any electricity market. While sharp hourly price increases ("price spikes") were more frequent in 2002 (six hours over $500 compared to only one hour in 2003), there were more hours with moderately high prices in 2003 due to the increase in fuel prices. In 2003, prices exceeded $100 for 410 hours in 2003 versus only 127 hours the previous year.

Figure 3: Price Duration Curves – Highest 5 Percent of Hours New York State Average Real-Time Price

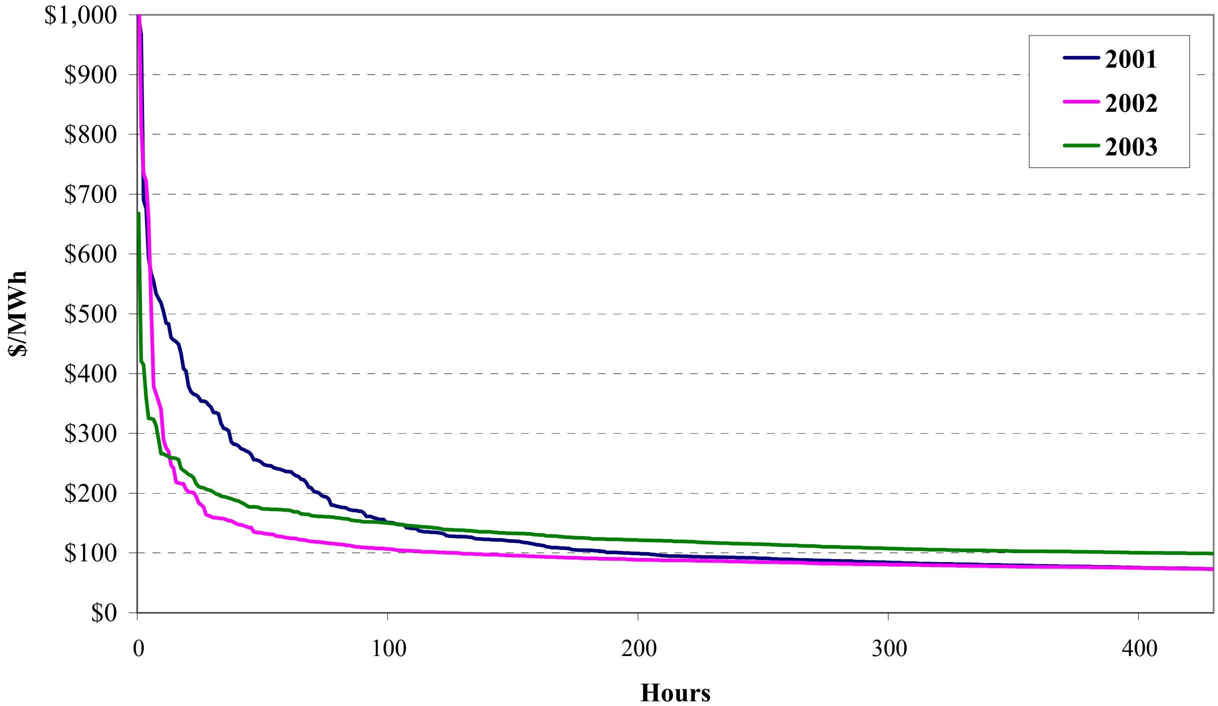
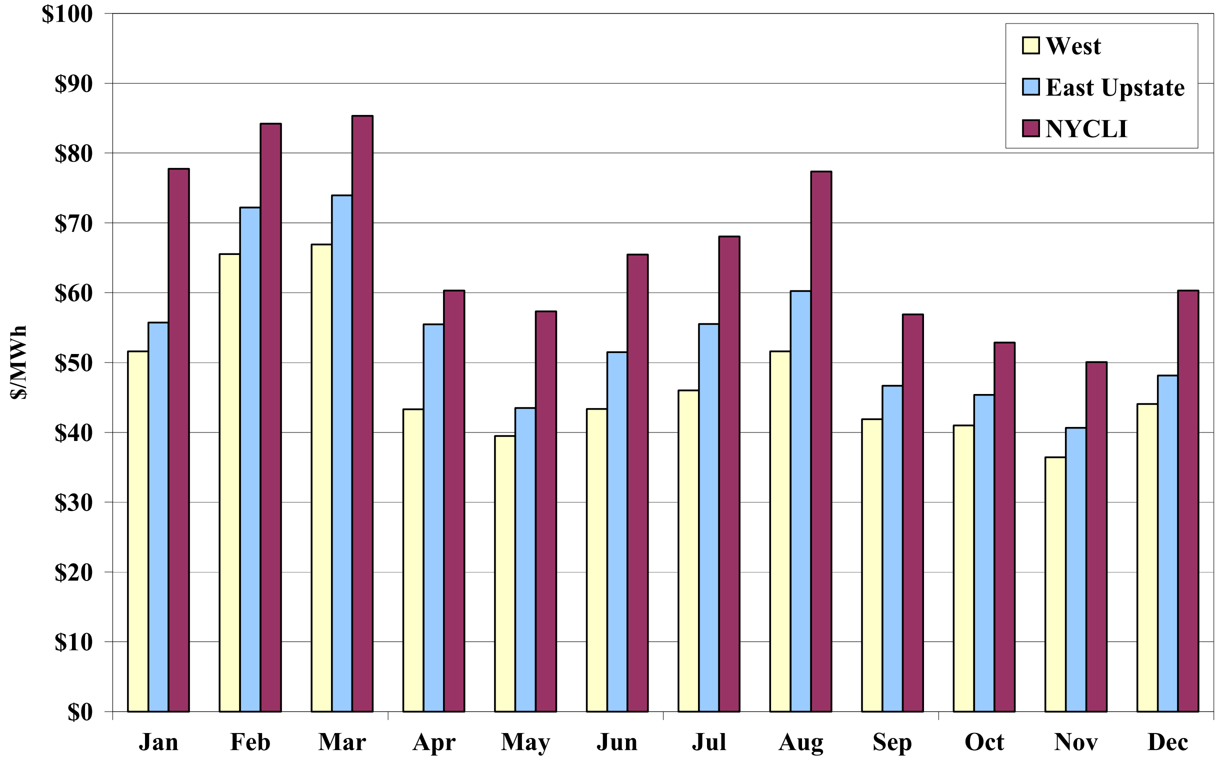


Figure 4 presents the monthly day-ahead energy prices at three separate locations for 2003. The prices are different in these locations as a result of transmission congestion. The Central-East transmission interface separating western and eastern New York is often constrained and causes higher prices east of the constraint. In 2003, this price difference averaged $6.48/MWh, a decrease from the 2002 price difference of $7.41/MWh. Within the area east of the Central-East interface, there are constraints into New York City, as well as local load pockets within the City which resulted in price differences into the City from the eastern upstate region averaging more than $12.62/MWh, a substantial increase from the comparable 2002 value of $8.41/MWh.

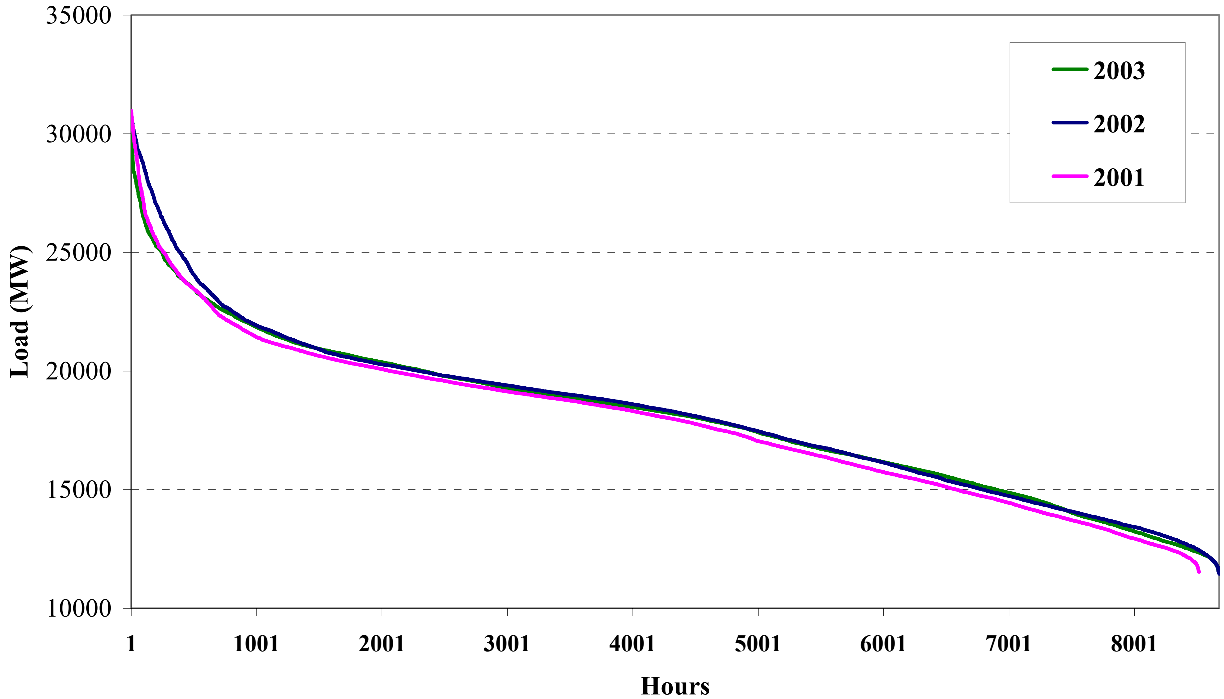
Figure 4: Day-Ahead Energy Prices in 2003



The difference in prices between New York City (and Long Island) and the rest of the eastern region increased in 2003 due to changes in locational pricing and dispatch which cause local prices to more accurately reflect the cost of supplying these constrained areas. A January breaker outage on the Con-Ed interface, which substantially decreased transmission capacity into New York City, contributed to the increase in the price difference on the New York City side of the constraint.

The other factor that generally has a major impact on changes in energy prices in the New York markets is the duration and timing of electricity demand. High prices resulting from a few days of extreme load conditions can raise the average price significantly for the entire year. During peak demand conditions, the relatively high prices are assessed to a larger volume of electricity purchases. Therefore, it is the hours when load peaks that result in both high prices and a substantial portion of all revenues received by energy suppliers, and thus a significant portion of costs experienced by customers.

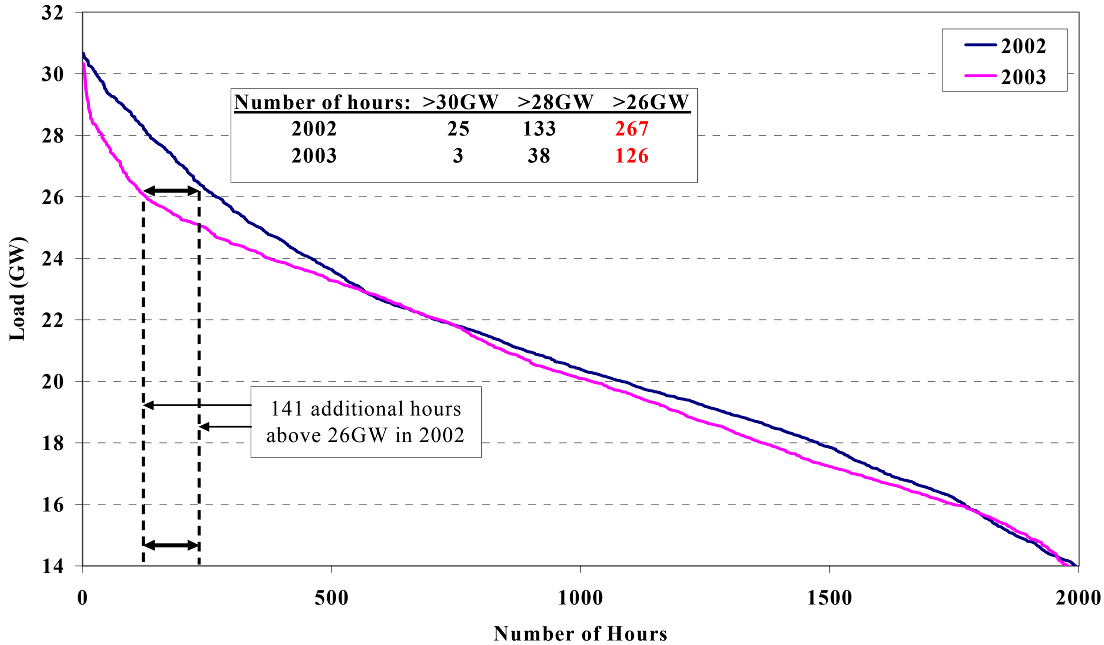
Figure 5: Load Duration Curves
New York State Hourly Average Load



* Hours during the August 2003 blackout period are excluded.

Mild conditions during summer 2003 significantly reduced the frequency of extreme peak demand conditions. As shown on the price duration curve in Figure 5, the highest load levels occurred in a larger number of hours in 2002 than in 2003. This is presented more clearly in Figure 6, which focuses on the summer months. At the highest load levels, the load duration curve for summer 2002 lies above the load duration curve for summer 2003. While there were twenty-five hours in the summer of 2002 when actual loads exceeded 30,000 MW, there were only three hours in the summer of 2003. Likewise, there were 133 hours when loads exceeded 28,000 MW in the summer of 2002 versus 38 hours in the summer 2003.

Figure 6: Load Duration Curves - Summer 2002 vs. Summer 2003



* Hours during the August 2003 blackout period are excluded.

An increase in imports from New England helped to mitigate price increases during peak demand periods since it provided an additional source of supply at relatively low costs, reducing the hours during which higher-cost generators had to be deployed. Price responsive load bidding also reduced prices in the day-ahead market, because load would be reduced as prices rose in that market, smoothing out dramatic price spikes. If demand in real time exceeded levels purchased in the day-ahead market, LSEs that are short would have to purchase supplies at high real-time prices. However, the majority of load would have supply already locked up at more moderate prices, ameliorating the overall impact of peak load periods on average prices paid for electricity.

Figure 7 presents an average monthly all-in price of electricity, which includes the costs of energy, uplift, capacity, ancillary services, congestion, losses, operating expenses, transmission, and other components of wholesale energy costs. 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 prices are a weighted average of the capacity sold in each UCAP auction (6-month strip, monthly, deficiency auctions). The ancillary services component shown in the figure includes the ISO's operating expenses. For the purposes of this metric, uplift and ancillary services costs are distributed evenly for all locations.

Figure 7: Average All-In Price in 2002 and 2003

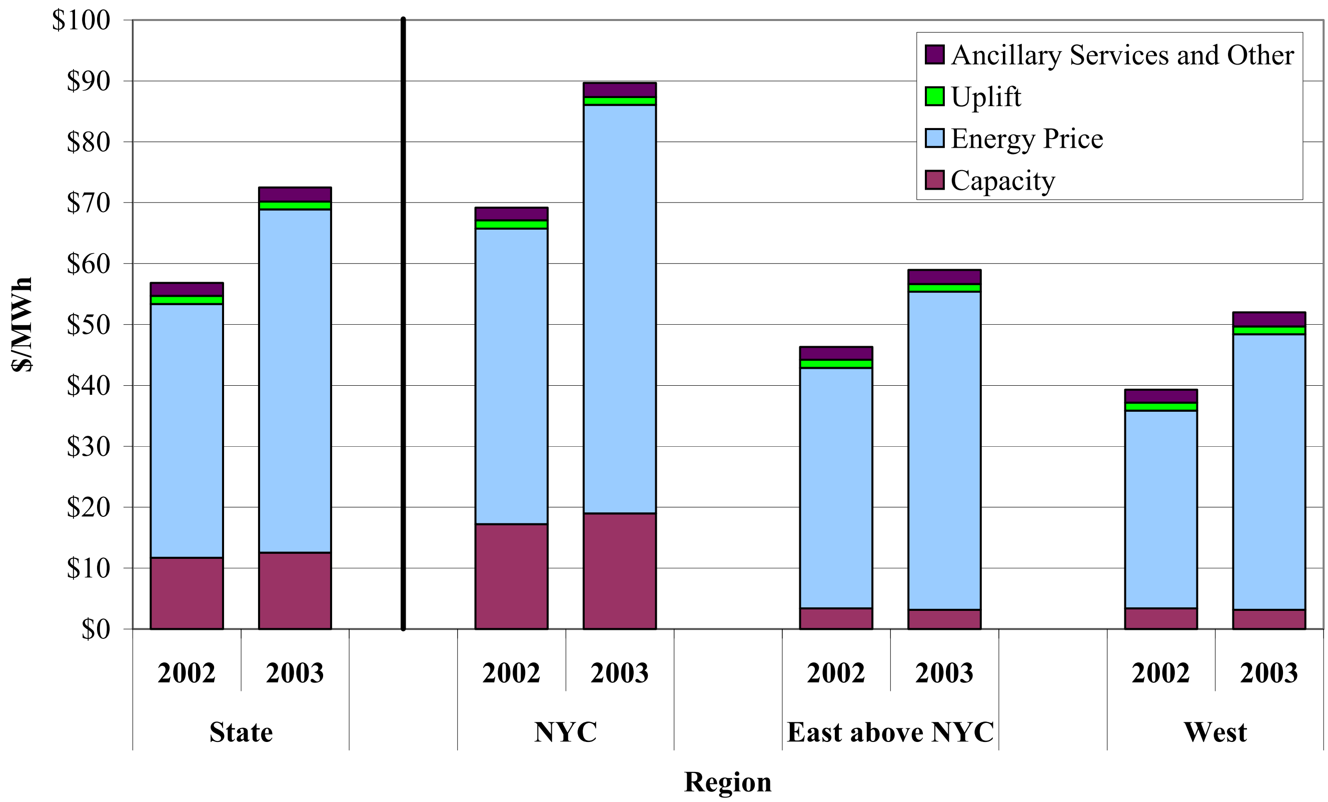
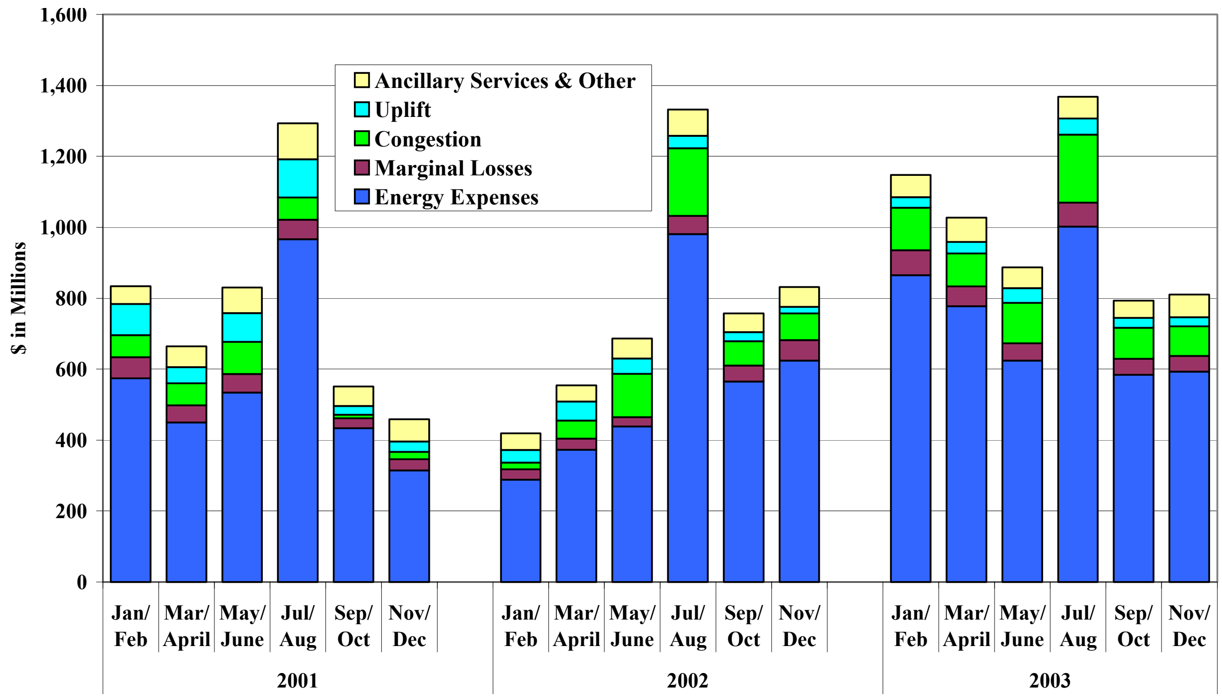


Figure 7 shows that the all-in price increased for all locations in 2003. This increase is primarily caused by higher energy prices in 2003, which rose 36 percent from 2002 due to higher fuel costs. The capacity component of all-in prices also rose in 2003 due primarily to the forecasted peak load rising faster than the average load (resulting in a higher obligation) and additional purchases under the demand curve above the target level.

2. Total Market Expenses

Total market expenses include energy, ancillary services, congestion, losses, and uplift. The market expenses reflect settlements by the participants through the ISO markets and will, therefore, not include all costs of serving load. For example, physical bilateral schedules do not settle the energy component of the schedule through the NYISO, only the congestion and losses. Almost half of the load is scheduled in this manner. Figure 8 shows the total expenses for market participants of the NYISO for 2001 to 2003.

Figure 8: New York Electricity Market Expenses 2001 - 2003



Total electricity costs for 2003 were approximately $6 billion – a substantial increase from the $4.6 billion in total costs in 2001 and 2002. Changes in market expenses from 2002 to 2003 were caused primarily by higher average energy prices due to higher fuel prices. A six percent decrease in the scheduling of physical bilateral contracts in 2003 increased the amount of load settled through the NYISO markets and increased the market expenses. The decrease in physical bilateral schedules does not mean forward contracting has decreased. Finally, lower peak loads due to mild weather reduced total energy costs in 2003 below the level that might have otherwise prevailed.

B. Prices and Price Convergence

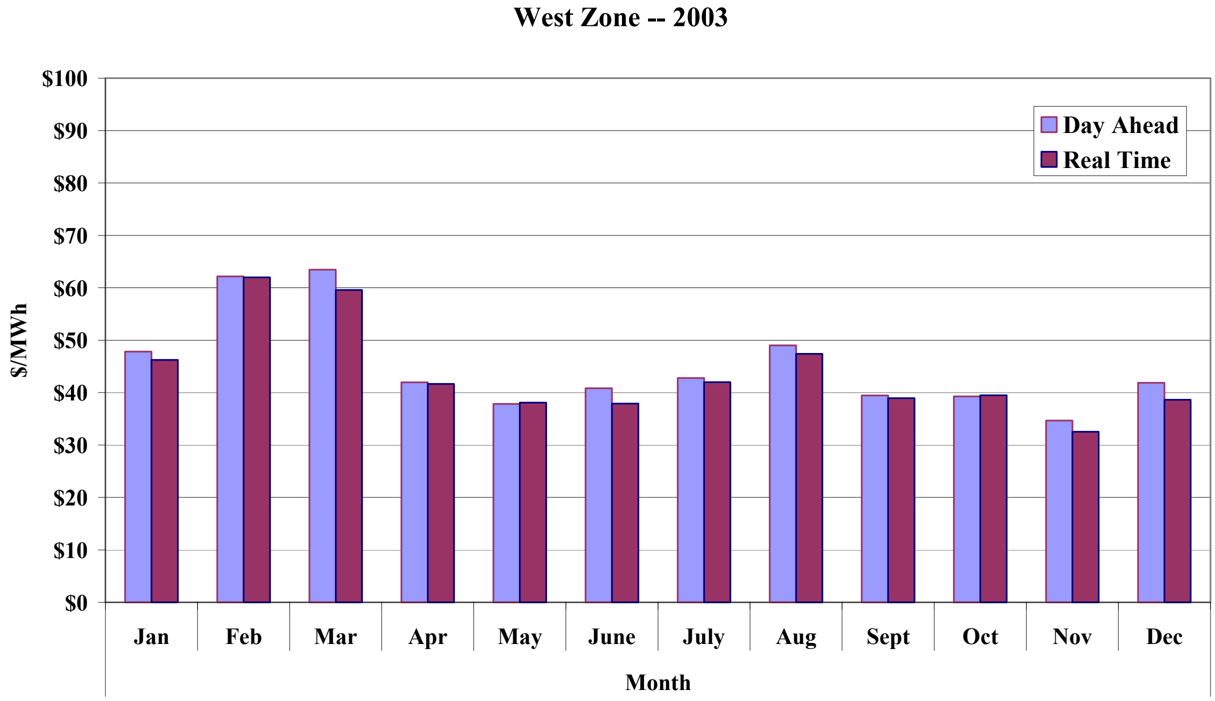
In this section, we evaluate the convergence of prices between day-ahead and real-time markets, and the convergence of hour-ahead prices and real-time prices. Price convergence is an important measure of market performance because it indicates whether the market is efficiently arbitraging intertemporal prices, something that is desirable because it promotes the efficient commitment of generating resources and scheduling of external transactions.

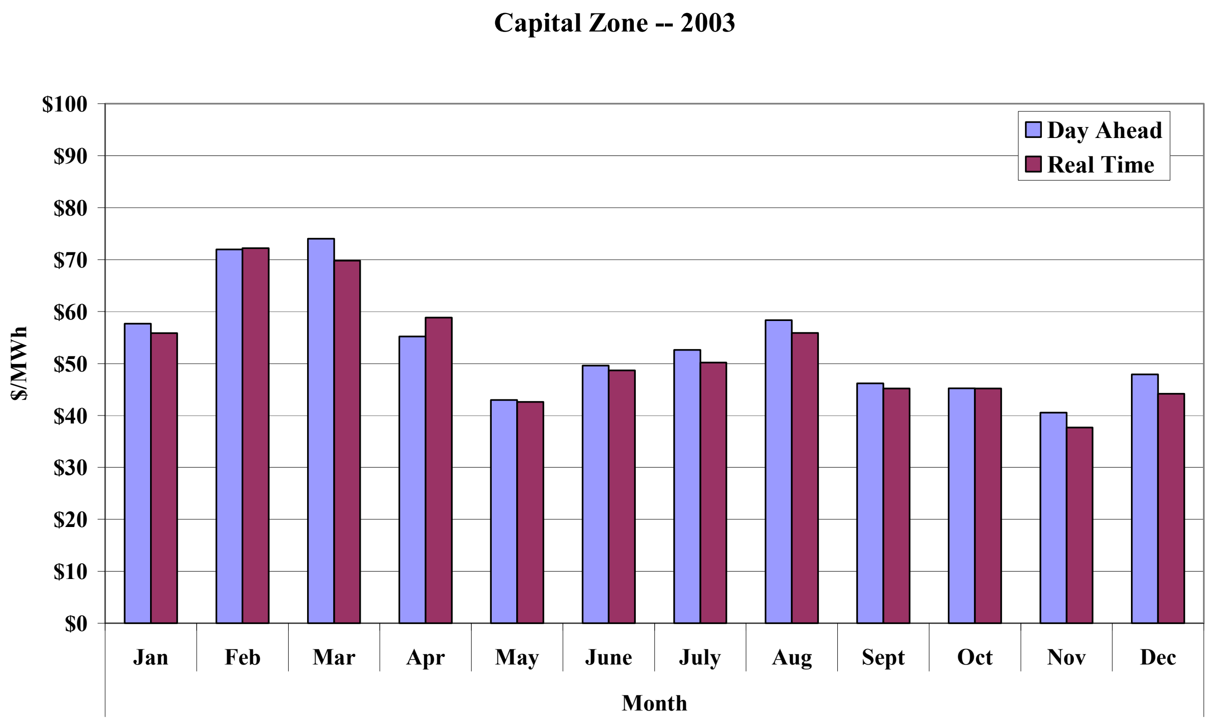
1. Day-Ahead and Real-Time Price Convergence

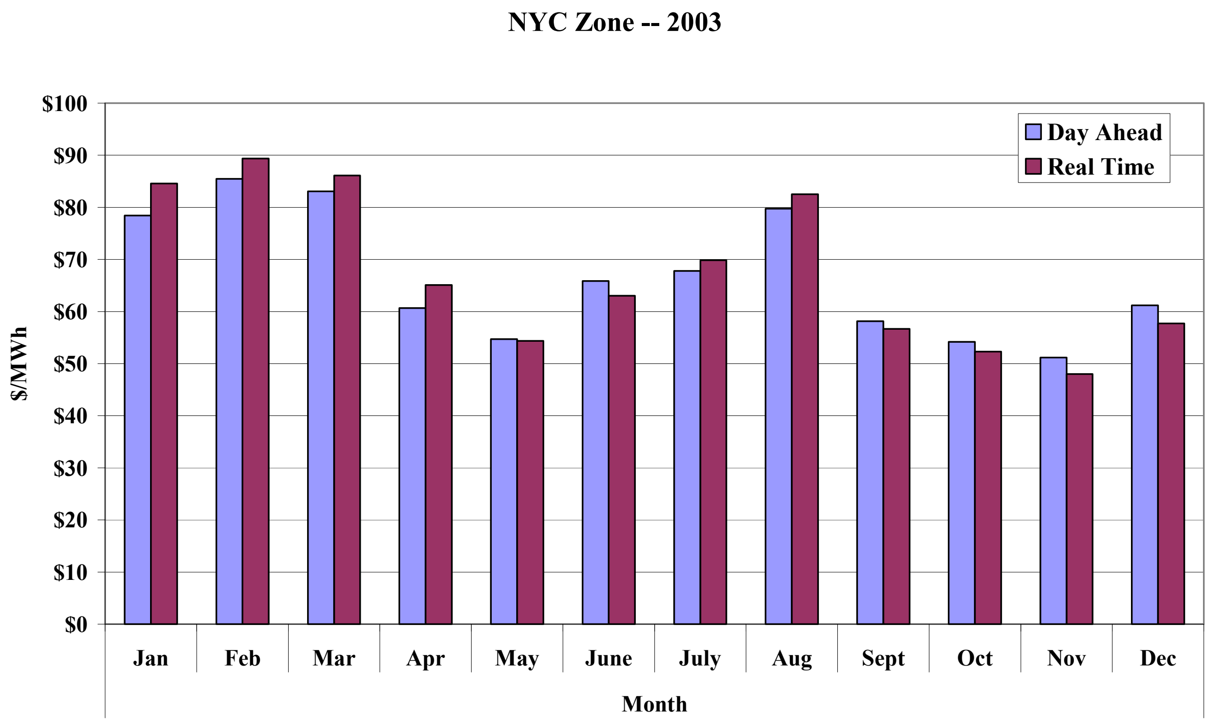
The day-ahead market allows participants to make forward purchases and sales of power for delivery in the real-time. This is a valuable financial mechanism that allows participants to hedge their portfolios and manage risk. Loads can insure against volatility in the real-time market by purchasing in the day-ahead market and use TCCs in the day-ahead market to hedge against congestion. Generators selling in the day-ahead market are exposed to some risk associated with committing financially day-ahead. This is 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.

If participants are risk-averse, these factors will induce a premium in the day-ahead prices. This is also consistent with the experience from other markets. However, day-ahead and real-time prices should not diverge to a significant degree. Figure 9 shows a comparison of the average day-ahead and real-time energy prices in the West zone, Capital zone, and New York City for 2002 and 2003. The results generally show a slight premium associated day-ahead prices in the West zone and Capital zone, which is consistent with expectations. However, the results do not consistently show a day-ahead premium in New York City. In some months, real-time prices are slightly higher than day-ahead prices. A more detailed evaluation of price convergence within New York City is provided in subsection C below.

Figure 9: Day-Ahead and Real-Time Price Convergence at Various Locations







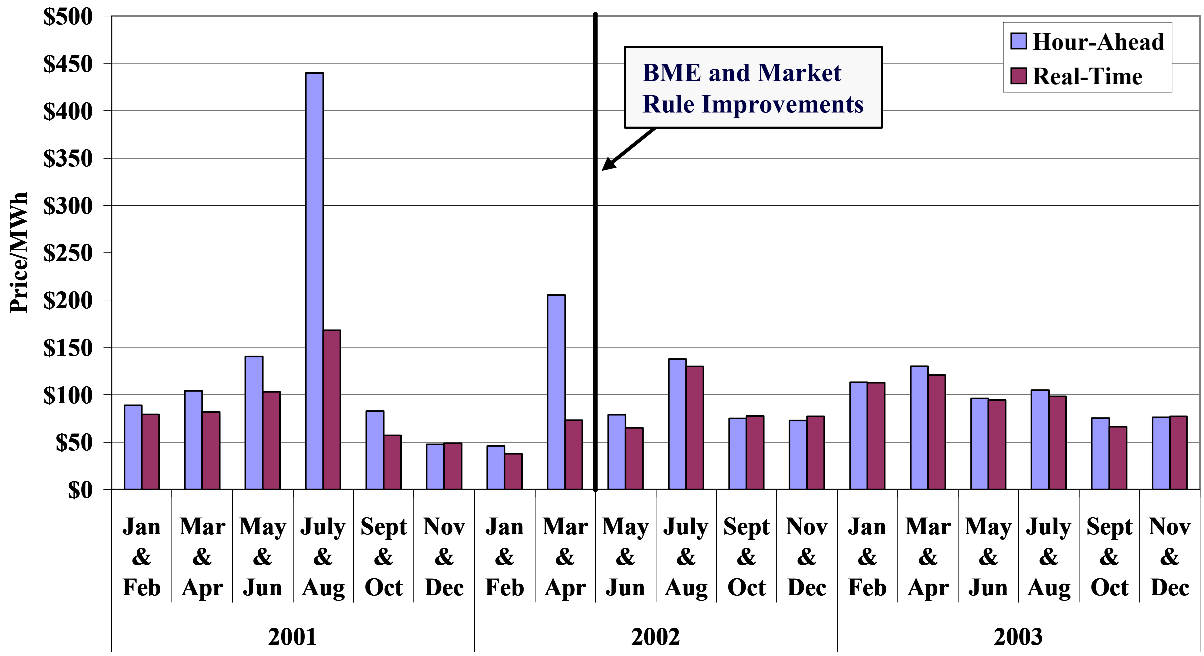
Differences between day-ahead and real-time prices increased at nearly all of the locations from 2002 and 2003, as measured by the absolute value of the hourly divergence of day-ahead and real-time prices. This is an unexpected result, since more active virtual trading and reduced price volatility due to milder load conditions would be expected to have the opposite impact. However, this could be explained by the large fluctuations in natural gas prices during the year, which increased the overall price levels and volatility in the New York energy markets.

2. Hour-Ahead and Real-Time Price Convergence

Until 2002, there was a lack of convergence between hour-ahead and real-time prices in New York. The large price differences that arise in the absence of price convergence can distort market mechanisms, primarily by scheduling external transactions and off-dispatch generation when they are not needed or not scheduling them when they are needed. The result is that external transactions and off-dispatch generation are scheduled inefficiently, resulting in increased uplift costs and inefficient real-time prices. Convergence tends to be the worst in the highest demand hours when prices are most volatile.

Changes to the market software and rules in 2002 dramatically improved price convergence between the hour ahead and real time. The following figure shows that convergence in 2003 continued to be very good, largely due to improvements made to the market rules and the BME model prior to the summer of 2002.[2] Figure 10 shows the average hour-ahead and real-time prices for high-load hours in Eastern New York from 2001 to 2003. As the figure shows, prior to mid-2002, convergence was poor, with hour-ahead BME prices significantly exceeding real-time prices. The data for 2002 and 2003 indicates that this divergence has been ameliorated.

Figure 10: Average Hour-Ahead and Real-Time Energy Prices
Eastern New York – Highest Peak Load Hours



C. Price Convergence in Load Pockets

Prior to June 2002, the NYISO market software did not recognize the load pockets that existed inside New York City. This often resulted in inefficient commitment and dispatch decisions. Modeling of the load pockets within New York City, which was implemented in June 2002, has resulted in more accurate locational energy prices as prices now reflect the load pocket constraints. This change has increased congestion expenses incurred in the energy market while

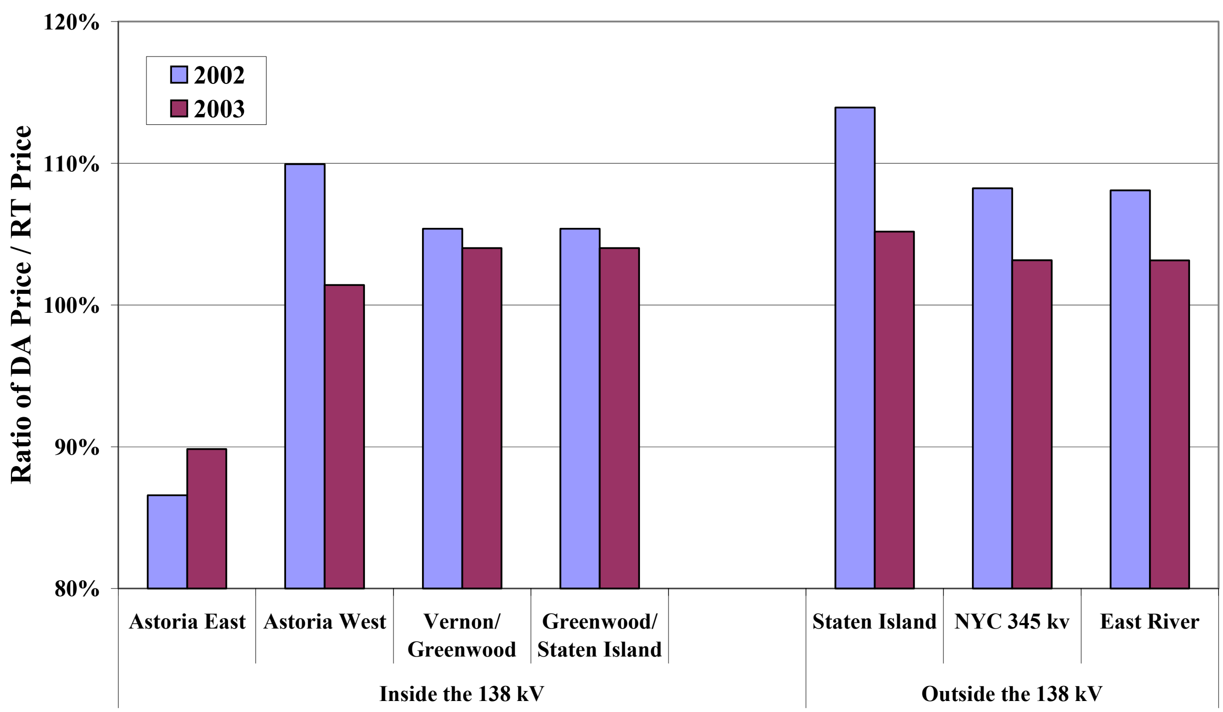
2 These changes included (1) enabling the BME to recognize curtailable export transactions as 30-minute reserves when the cost of maintaining 30-minute reserves on the system rises to certain levels; (2) changing the market software to recognize undispatched portions of on-dispatch units that offer into the energy market as "latent" reserves, helping to free-up other units for meeting energy demand.

decreasing the amount of uplift paid to generators redispatched to resolve the load pocket constraints.

Due to limitations of the Security-Constrained Dispatch ("SCD") model, a simplified representation of the intra-New York City constraints is used in real time while a more detailed representation is used in the day ahead. This difference can contribute to divergence between the day-ahead and real-time prices within New York City. Implementation of RTS, which will utilize the same platform as the day-ahead market software, should address these inconsistencies.

Day-ahead and real-time prices were nearly identical on average for the New York City zone. However, the New York City zone price is a load-weighted average price based on the locational prices in each of the load pockets in the City. Therefore some locations may experience significant divergence in day-ahead and real-time prices that are off-set by divergences in the opposite direction at other locations. Hence, we conducted a further analysis of day-ahead and real-time prices at different locations throughout New York City. These results are shown in Figure 11

Figure 11: Day-Ahead and Real-Time Prices in New York City 2002 and 2003



This figure shows that day-ahead to real-time price convergence varied substantially by load pocket within the City during 2003. The Astoria East load pocket showed significant price premiums in real time. The other load pockets and the 345 kV system (outside the load pockets) generally exhibited modest premiums in the day-ahead market. However, the figure shows that the price convergence improved at each location compared to 2002.

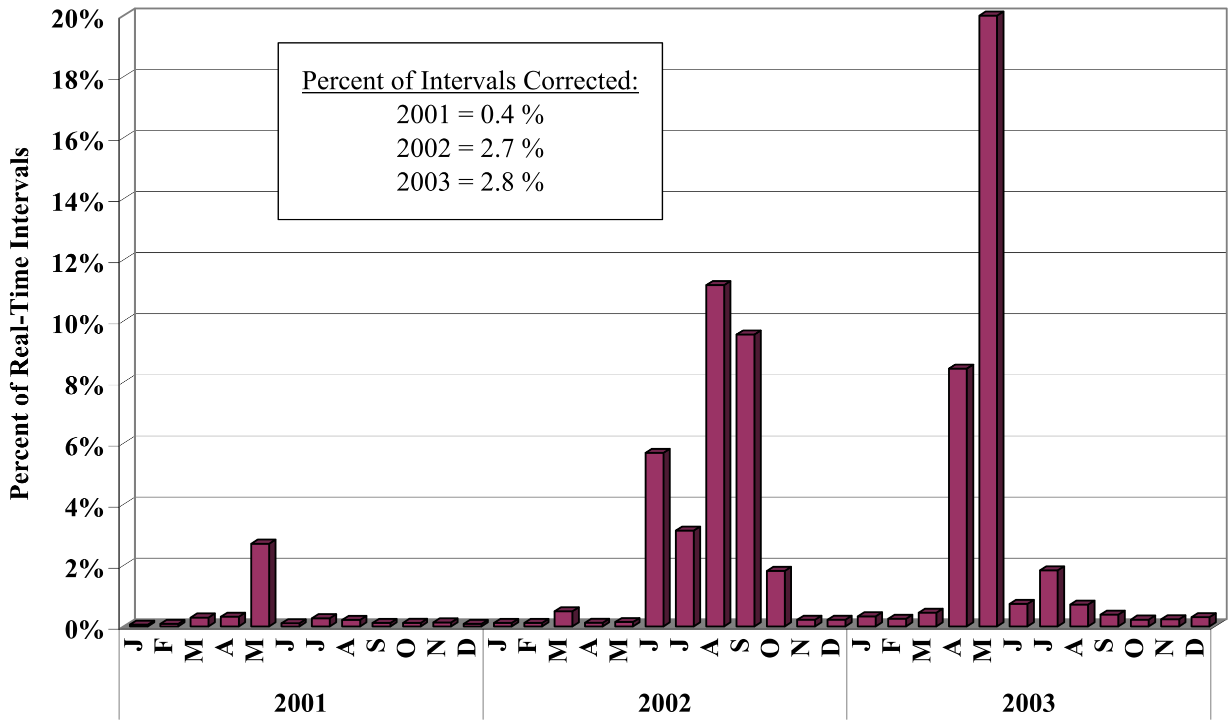
Price convergence in the load pockets could be improved by the introduction of virtual trading within the New York City load pockets. Limiting price-capped load bidding and virtual trading to the zonal level in New York City limits the ability of participants to arbitrage large price differences in specific pockets. Therefore, if price convergence issues persist in New York City after the implementation of RTS, we recommend the NYISO consider allowing virtual trading at a more disaggregated level in the City.

D. 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 participants that have to make continual buy and sell decisions. Therefore, the incidence of these problems should be minimized. Price corrections are required when flaws in the market software or flaws in operator procedures cause prices to be posted erroneously. It is important to resolve these errors as quickly as possible to maximize price certainty.

Figure 12 summarizes the frequency of price corrections in the real-time energy market from 2001 to 2003. The frequency of price corrections was relatively high in 2000, but then decreased steadily until the summer of 2002. The frequency of price corrections increased substantially in June, 2002 as a result of the introduction of changes to the modeling of New York City load pockets. Once the modeling issues related to the introduction of load pocket modeling were addressed, the level of corrections returned to the low frequency that was experienced prior to the summer of 2002.

Figure 12: Percentage of Real-Time Prices Corrected



In 2003, there was a spike in the frequency of real-time price corrections in April and May before the frequency of price corrections returned to the historical norm. These price corrections occurred for most hours on fourteen days in April and seven days in May, resulting in slight changes to the New York City zonal prices that had been calculated with incorrect weightings. Because these corrections did not affect the individual LBMPs and did not substantially change the zonal prices, we conclude that they did not compromise the integrity of or otherwise adversely affect the NYISO markets.

E. Market Power Mitigation

1. Background

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 impact 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 sufficient impact on the energy price. The NYISO may mitigate offers in either the day-ahead or the real-time market.

In the day-ahead market, the market software employs AMP, which evaluates the impact of conduct that exceeds the thresholds and subsequently mitigates the bid parameters if their price impact is significant (according to pre-defined impact thresholds). This automated process is not used in the real-time market, although there are some automated processes for mitigation in New York City load-pockets, as explained below.

In both the day-ahead market and the real-time market, there are special mitigation procedures in New York City, where congestion is a frequent problem. When there is no congestion on the interfaces into New York City or on interfaces on the 138 kV system in New York City, the same AMP conduct and impact thresholds will apply to in-city offers as to offers in the rest of the state. In the day-ahead market, when the dispatch model detects congestion into New York City that exceeds certain thresholds,[3] units inside New York City are mitigated to a reference level based on variable production expenses. These mitigation procedures are referred to as the Consolidated Edison or "Con Ed" mitigation procedures as they were developed by Con Ed when it divested its generation.[4] Offers mitigated in the day-ahead market in accordance with the Con Ed procedures are carried forward to the BME model and the real-time market up to the day-ahead mitigated quantity.

Mitigation may also be applied in the real-time market for units in certain load pockets within New York City using the NYISO's conduct and impact approach (rather than the Con Ed approach applied in the day-ahead market). The in-city load pocket conduct and impact thresholds are set using a formula that is based on the proportion of congested to non-congested hours experienced over the preceding twelve month period.[5] An in-city bid will be mitigated if it exceeds the reference level by this threshold. This approach permits the in-city conduct thresholds to increase as the number of congested hours decreases, whether due to additional generation or increases in transmission capability. Because the process to detect which units

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3 The threshold for in-city mitigation is when bids exceed 107 percent of the price at Indian Point 2 bus.

4 However, NYISO Reference Levels are used in lieu of the default bids specified in the ConEd mitigation measures.

5 $$\text{Threshold} = \frac{2\% * \text{Avg. Price} * 8760}{\text{Constrained Hours}}$$

should be mitigated and when is straightforward, this mitigation has been automated beginning in December 2003.

In the RTS filing, the NYISO proposed replacing most of the Con Ed measures with measures that employ the conduct and impact mitigation tests. The proposed changes will replace the Indian Point mitigation threshold with in-city conduct and impact mitigation tests, and apply mitigation only to the hours in which offers exceed the mitigation thresholds. This approach should significantly reduce the frequency of mitigation by making it more focused.

The NYISO is also developing the capability to apply automated procedures in real-time markets. Real-time AMP was to be initially applied only in New York City, though it was proposed that a generator outside the city that submits a bid which violates both the conduct and impact tests could be subject to real-time AMP. FERC accepted the automated application of the conduct and impact mitigation tests for real-time in-city mitigation, but rejected the use of automated mitigation procedures for generators located outside New York City.[6]

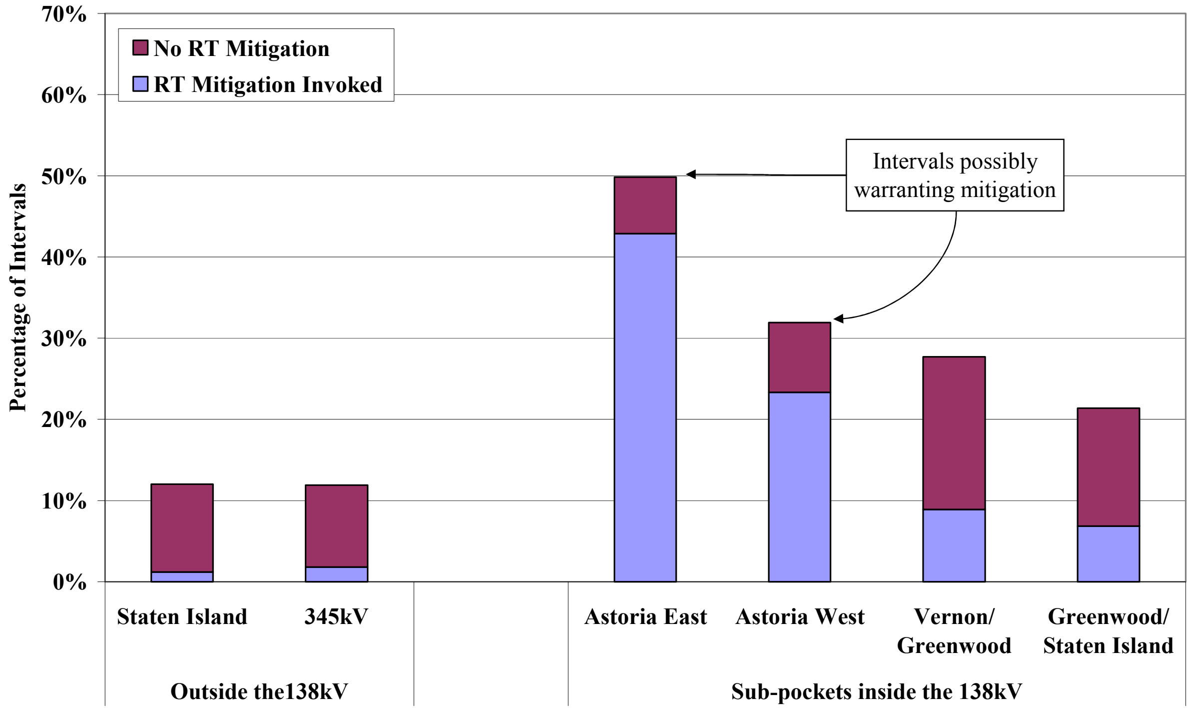
2. Mitigation in 2003

No day-ahead mitigation occurred under the AMP in 2003. Day-ahead mitigation occurred only in New York City during 2003 under the Con Ed mitigation measures. Indeed, in New York City, some mitigation occurred in every hour during 2003. This indicates that the Con Ed congestion thresholds were exceeded in at least one hour of each day in 2003, but does not necessarily indicate that there were attempts to exercise market power in these hours.

A profile of New York City load pocket mitigation is shown in Figure 13. This figure summarizes the frequency of constraints into the load pockets and the actual frequency of mitigation. The constraints shown are those with a positive cumulative shadow price into the load pocket. When the constraints shown are binding, resources with offers exceeding their reference levels by more than the load pocket's conduct threshold are subject to real-mitigation.

[6] *New York Independent System Operator, Inc.*, 106 FERC ¶ 61,111 at P 28-30 (2004).

Figure 13: Frequency of Real-Time Constraints and Mitigation New York City Load Pockets, 2003



This figure shows that outside of the 138 kV system where most of the load pockets are located, mitigation is infrequently imposed due to higher conduct thresholds and more competitive conditions. When the constraints shown were binding, resources with offers exceeding their reference levels by more than the load pocket's conduct threshold are subject to real-time mitigation. In the narrower load pockets, constraints are binding in 21percent to 50 percent of the intervals while mitigation is only imposed in 7 percent to 43 percent of the intervals. In general, the more frequently constrained load pockets are mitigated in a higher portion of the hours when constraints are binding.

F. Net Revenues 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 will depend on the expected net revenues that 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.

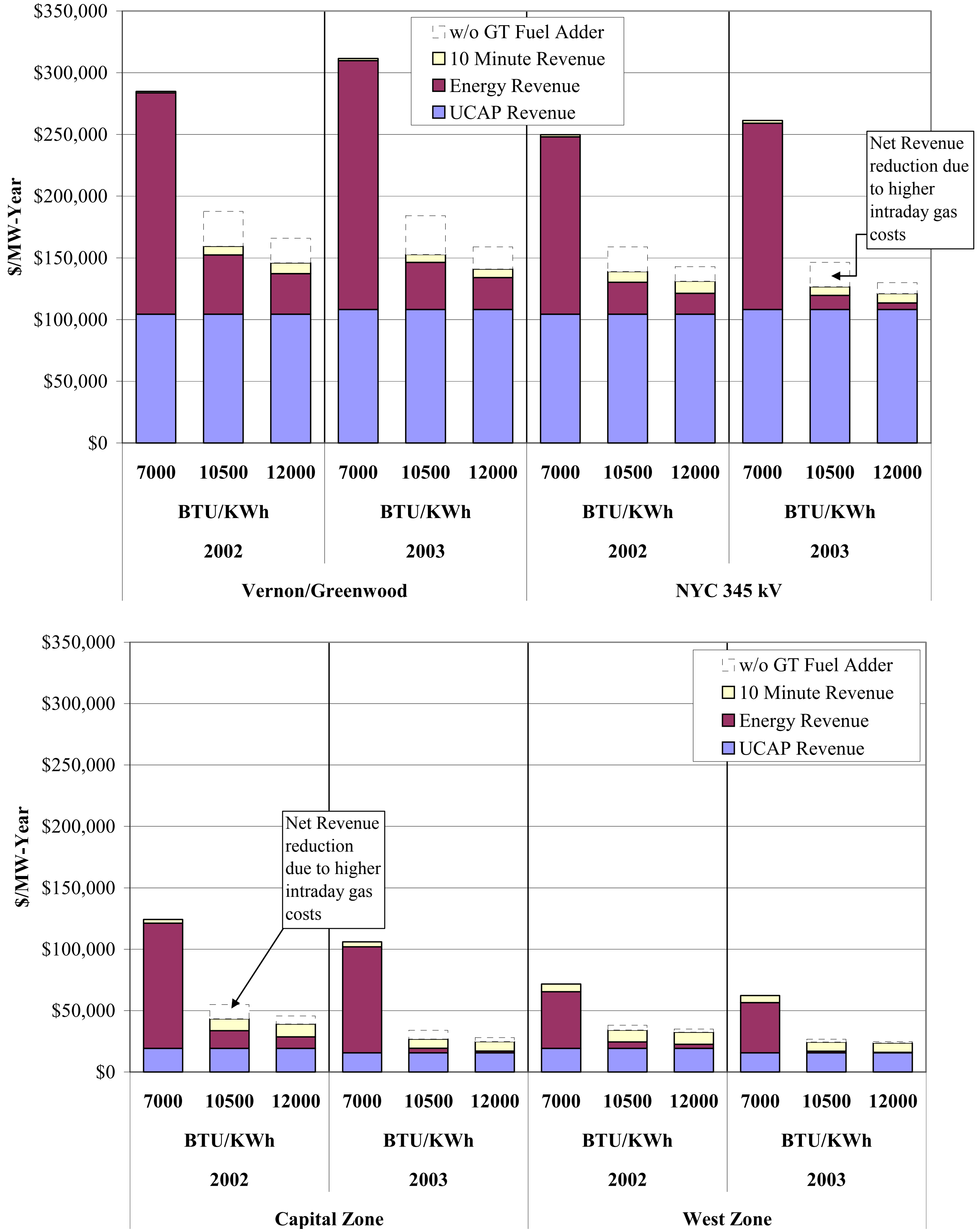
If there is not sufficient net revenue in the short-run from these markets to justify entry, then one or more of the following conditions may be present: (i) new capacity is not needed because there is sufficient generation already available; (ii) load conditions, due to mild weather and/or a reduction in demand, and thus energy prices, are below long-run expected values; or (iii) market rules are causing revenues to be reduced inefficiently. Likewise, the opposite would be true if prices provide excessive revenues in the short-run. If a revenue shortfall persists for an extended period, without an excess of capacity, this is a strong signal that markets need modifications.

In this section we analyze the net revenues that would have been received in 2003 by various types of generators at different locations in New York. We analyzed three zones within New York City and two zones outside of New York City. We calculated the net revenue the markets would have provided to different types of units at various locations in 2003. The types of units are:

- Gas combined-cycle: heat rate assumed of 7000 BTU/KWh.
- New gas turbine: heat rate assumed of 10500 BTU/KWh.
- Older existing gas turbine: heat rate assumed of 12000 BTU/KWh.

We examined two New York City Zones, the New York City 345 kV zone and the Vernon/Greenwood zone. Figure 14 shows the analysis. In the figure, the shadow box indicates the additional revenue earned by avoiding payment of natural gas purchase premium – i.e., gas purchased day ahead is cheaper than that purchased in real-time.

Figure 14: Estimated Net Revenue in the Day-Ahead Market 2002 - 2003



As the figure indicates, a new gas turbine (with a heat rate of 10,500 BTU/kWh) would earn revenue in New York City in the range of $150,000 to $175,000 per-MW. This would recover approximately 60 percent to 75 percent of the net revenue required to support such an investment. The results for the combined-cycle unit are less clear. While a new combined-cycle plant would earn from $250,000 to $300,000 per MW-year, we were unable to obtain data on the costs of investing in a new combined-cycle plant inside New York City.

Outside of New York City, we examined the Capital zone and the West zone. A new gas turbine would earn about $25,000 to $30,000 per mw-year, assuming no natural gas purchase premium. This level of revenue would recover about 33 percent to 42 percent of the revenue needed to support new investment. A new gas turbine would recover about 60 percent to 95 percent of the revenue requirement.

It is apparent that entry is not likely to be profitable anywhere in New York State at present. However, this does not necessarily translate to long-term concerns. First, the lack of shortages in 2003 substantially reduced the net revenue available to peaking facilities. Second, because of natural gas prices, natural gas units were not likely to be the most economic sources of new capacity in 2003. Third, the UCAP demand curve is being phased-in, increasing the expected capacity revenue in 2004. Last, upstate New York has a capacity surplus, limiting the need for new gas turbines outside New York City.

III. 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 in this section.

A. Analysis of Supply Offers

Wholesale electricity production is attributable primarily to base-load and intermediate-load generating resources. Relatively high-cost resources are used to meet peak load and comprise 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 exert market power in electricity markets by withholding resources and increasing the market clearing price. This can be accomplished through physical withholding or economic withholding. 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. Demand must be high enough that withholding a resource has the potential to significantly impact market price. When the market clears along the flat portion of the supply curve, prices will be relatively insensitive to withholding.

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 should increase their offer quantities during the highest load periods to sell more power at the higher peak prices and maximize their profits. 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 non-planned-outage deratings, eliminating 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.[7] The remaining deratings data would then include only long-term and short-term deratings. We first analyze both long-term and short-term deratings together. In our second analysis, we focus on short-term deratings because short-term deratings are likely to be the most effective at exercising market power.

We focused on the hours with higher demand because, under a hypothesis of market power, we would expect to find that withholding increases as demand increases. We also limited ourselves

7 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, that would be the spring and autumn months. Since weather forecasters are currently incapable of predicting unusual weather events, like record setting heat waves in May, the fact that a planned outage results in higher prices in those circumstances is not evidence of the exercise of market power. Thus, only outages which occur during periods where the supplier can anticipate a benefit from withholding are relevant to the market power analysis.

to the locations east of the Central-East interface, as the constraint into Eastern New York would make it most likely that market power would be observed there. We found that no (statistically) significant relationship existed between deratings and load level in 2003, which would lead us to reject the hypothesis that market power was systematically exercised through physical withholding. Focusing only on short-term deratings, we found the same results.

Figure 15 and Figure 16 are scatter-plot diagrams that illustrate this analysis for all deratings in eastern New York and short-term deratings in eastern New York, respectively.

Figure 15: Relationship of Deratings to Actual Load
Day-Ahead Market - East New York

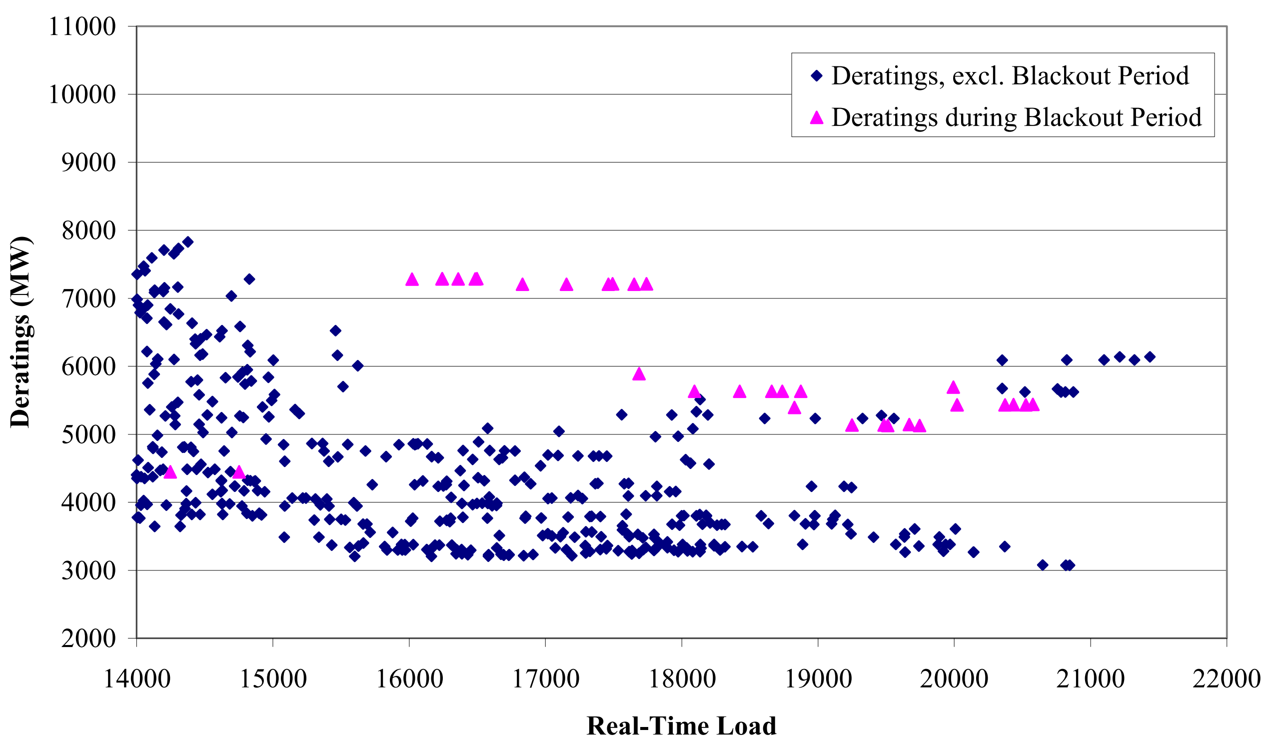
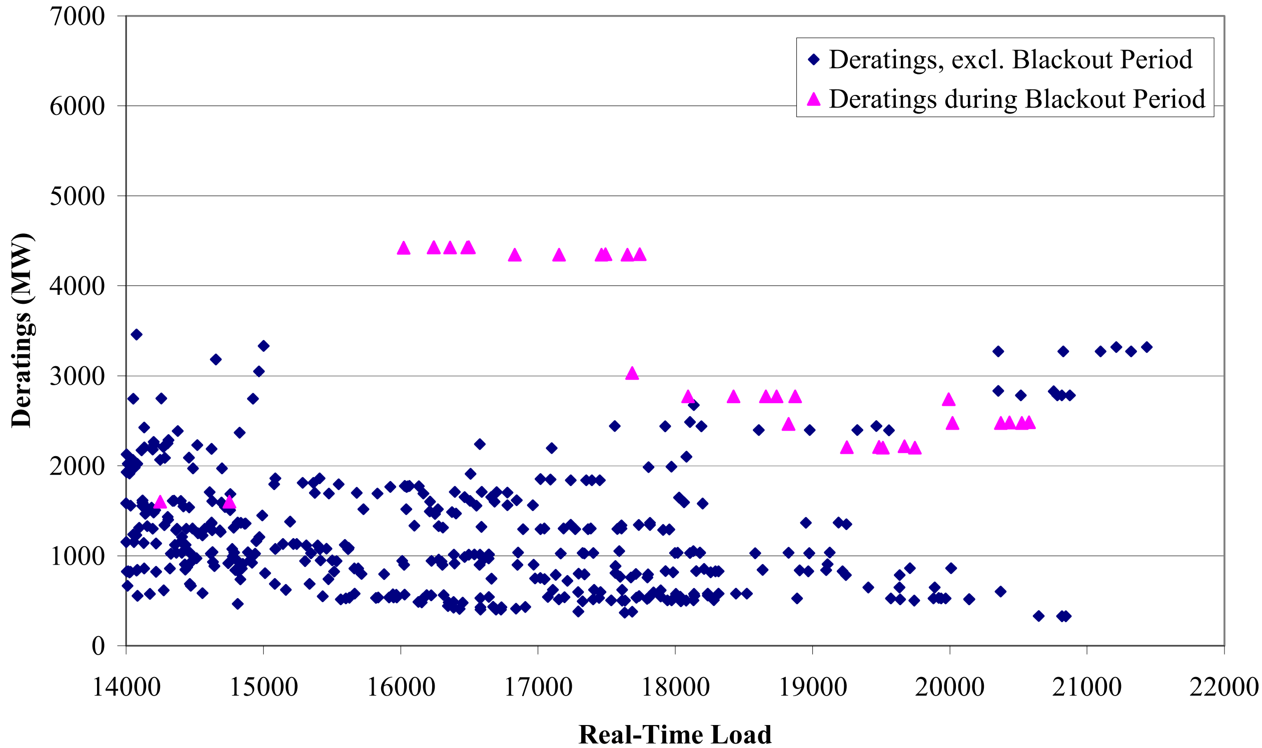


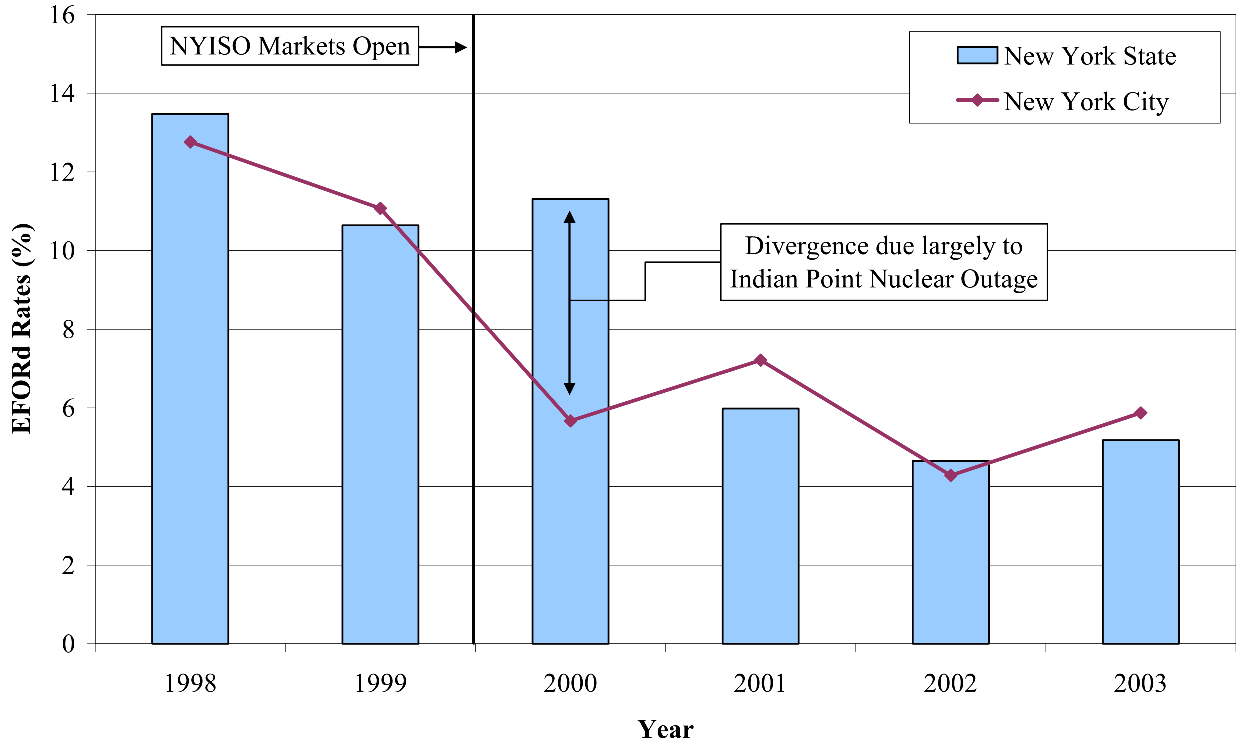
**Figure 16: Relationship of Short-Term Deratings to Actual Load
Day-Ahead Market – East New York**



In our analysis we found that there were two days following the August Blackout when deratings were extremely high. The purple triangles identify those hours. We attribute this to the anomalous conditions of that event. We also found that there were six days when demand exceeded 18,000 MW in eastern New York and the short-term deratings exceeded 2,000 MW, indicating a correlation between deratings and high load. We analyzed these six days more closely and found that three of these days coincided with the post-blackout period and three coincided with the outage at Indian Point. Therefore, we conclude that these were not strategic deratings. However, there were a few specific additional instances of high deratings at relatively high load levels.

We also examined the trend in forced outages since the opening of the New York markets to ascertain if generators are responding to economic incentives to increase reliability of their units. Figure 17 shows the Equivalent Forced Outage Rate, 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 17: Equivalent Forced Outage Rates 1998 - 2003



As Figure 17 shows, 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 declined again with the change from ICAP to UCAP in the fall of 2001, which increased the incentive to minimize forced outages since a unit's UCAP amount reflects its forced outage rates.

2. 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. 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 use reference values based on the past offers of the participant during competitive periods. A supplier will normally offer at levels near marginal cost, because during periods when market power is unlikely to be exercised, excessive offers will cause the unit not to be dispatched and cost the owner lost profits. We allow considerable tolerance in our threshold. An offer parameter is indicated as above competitive levels if it exceeds the reference values by a given threshold. We conduct the analysis with thresholds matching the mitigation thresholds ($100/MWh or 300 percent, whichever is lower) and a lower threshold ($50/MWh or 100 percent, whichever is lower).

Like our analysis of deratings, we would expect to verify a hypothesis of withholding if the output gap increases as load increases. We focus our analysis on Eastern New York where market power is most likely. Figure 18 shows the output gap results using the lower threshold. We found no correlation between load and the output gap and, therefore, we have concluded that economic withholding was not a significant issue in New York in 2003.

Figure 18: Relationship of Output Gap at Low Threshold to Actual Load Real Time Market – East New York

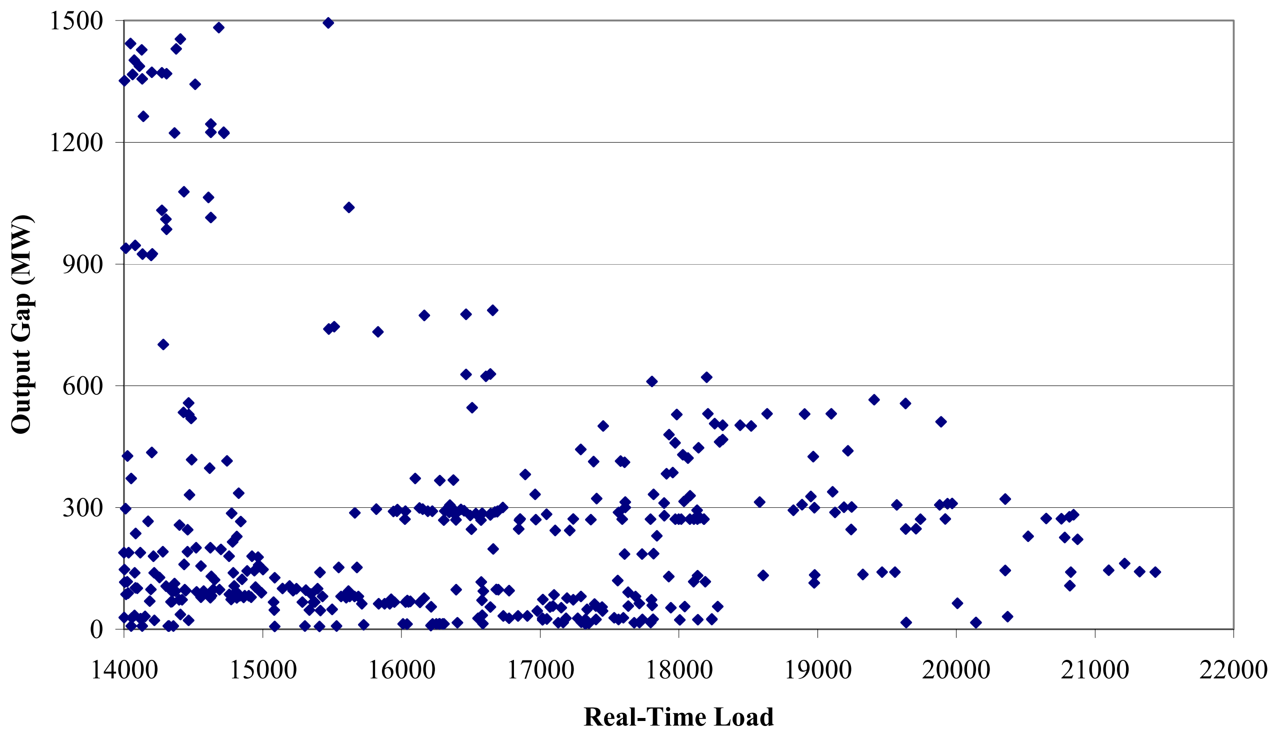
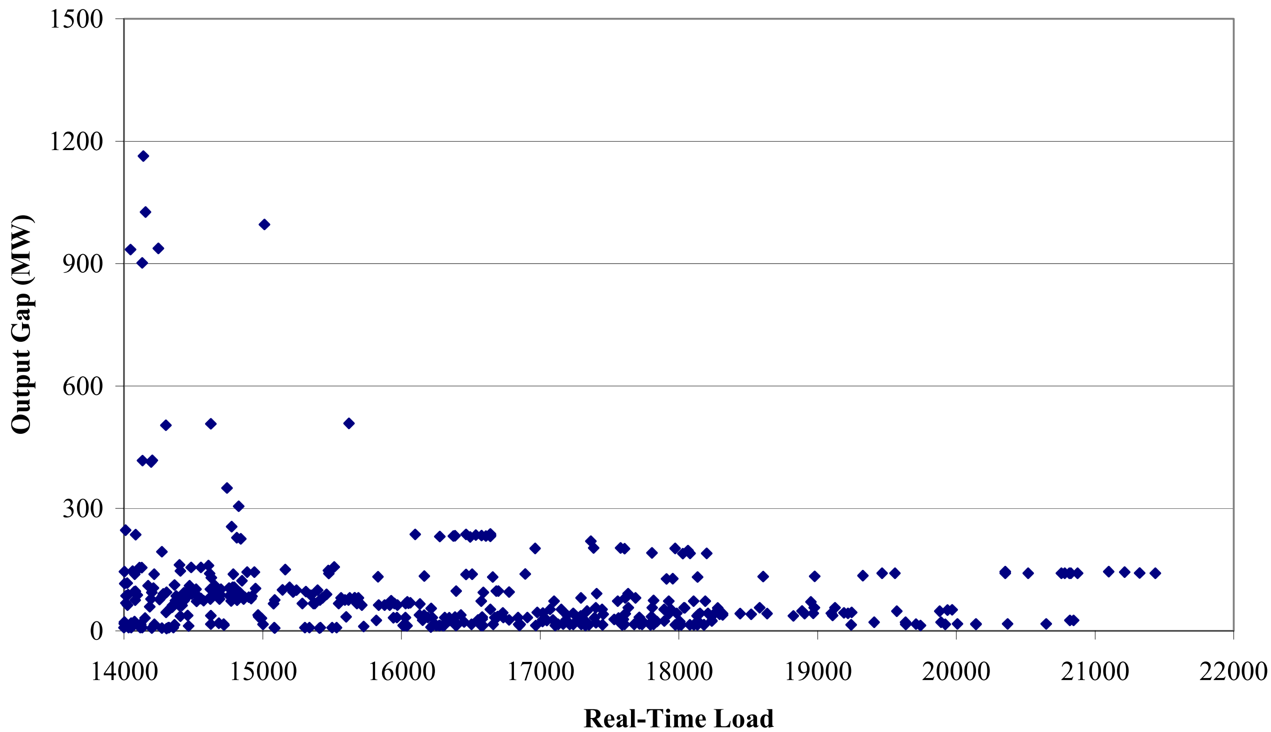


Figure 19 shows the output gap using the applicable mitigation thresholds. These results reinforce conclusions regarding the correlation of the output gap with load.

Figure 19: Relationship of Output Gap at Mitigation Threshold to Actual Load
Real Time Market – East New York



3. Analysis of Load Bidding

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 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.

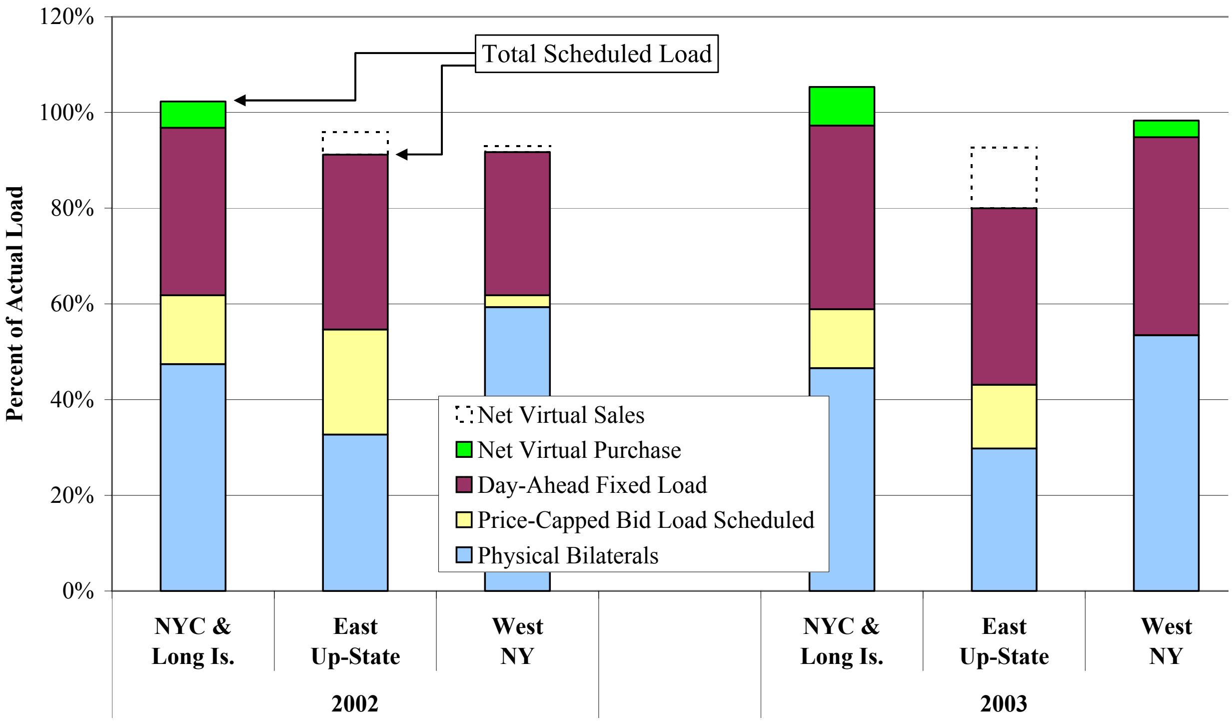
Day-Ahead Fixed Load. This represents load scheduled in the day-ahead market for receipt at a specific bus regardless of the day-ahead price. It is the equivalent of a load bid with an infinite bid price, which is difficult to rationalize from an economic perspective.

Price-Capped Load Bidding. This represents load bid into the day-ahead market with a bid price indicating the maximum amount the 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.

Net Virtual Purchases. This quantity is equal to the virtual load purchases minus the virtual supply sales. Virtual trading was introduced in the NYISO markets in November 2001, and so this report compares virtual trading in 2003 with the first full cycle in which market participants had been able to buy and sell without physical assets.

Figure 20 shows the load that was scheduled in each of these categories. This figure shows that in both 2002 and 2003, substantially more load was scheduled in New York City and Long Island as a percentage of real-time load than other geographic areas. In 2003, 107 percent of real-time load was scheduled day-ahead in New York City and Long Island, compared to less than 95 percent in the rest of the state.

Figure 20: Composition of Day-Ahead Load Schedules as a Proportion of Actual Load 2002 v 2003

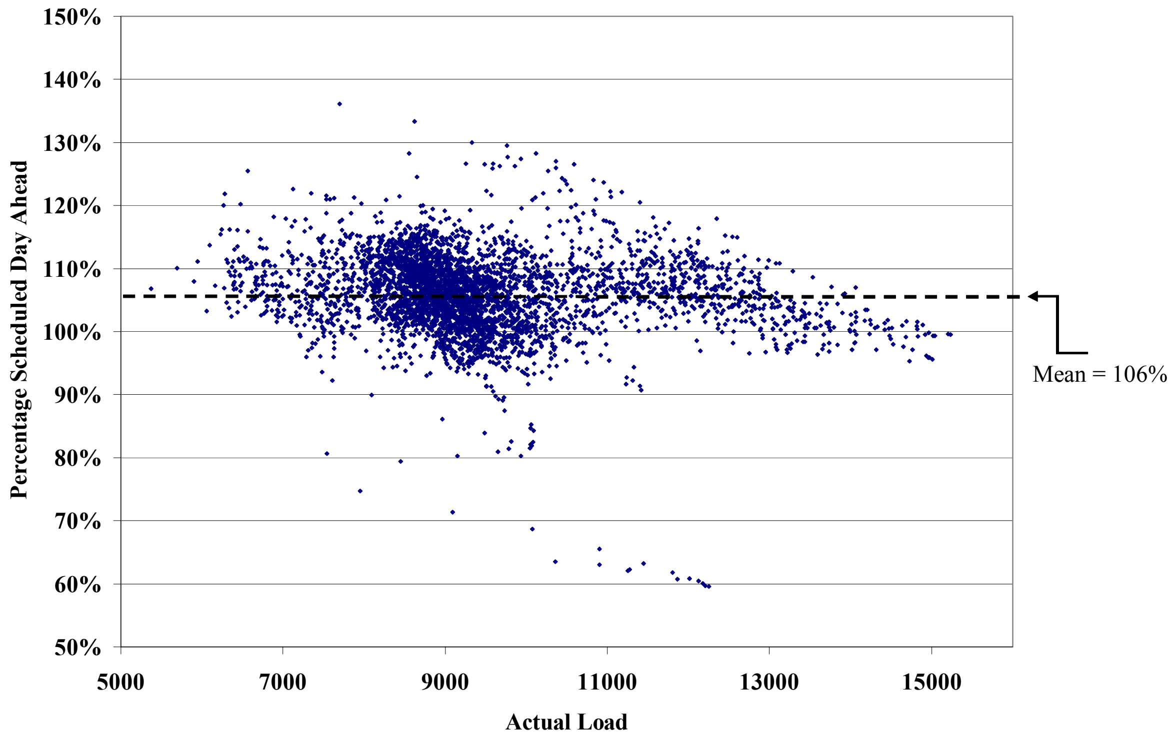


This figure also shows that the share of load scheduled through price-capped load bids decreased from 14 percent statewide to 8 percent in 2003. This is a concern because price-capped load bidding protects loads against uneconomic purchases and mitigates market power in the day-ahead market.

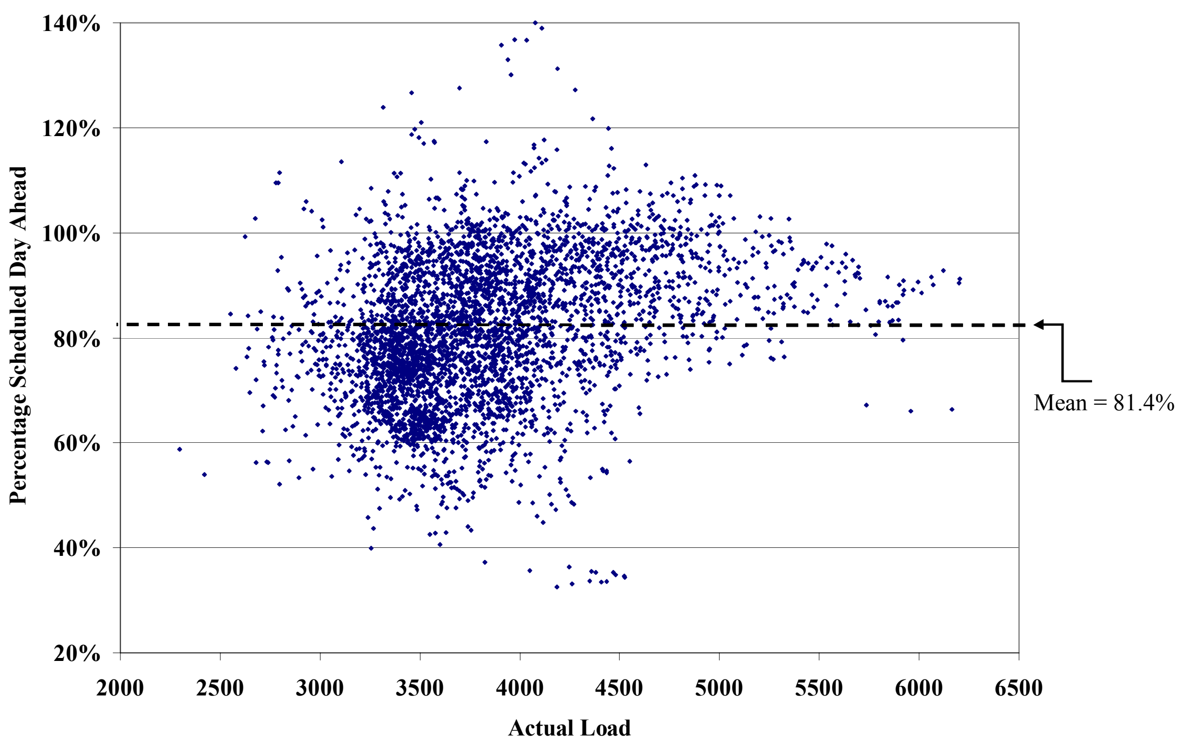
The share of the actual load supplied through physical bilateral contracts has been relatively constant at slightly less than 50 percent. This does not mean that over 50 percent of the load is incurring the spot prices in the NYISO energy markets. As noted above, CFDs corresponding to bilateral contracts and settled financially would not appear as physical bilateral contracts.

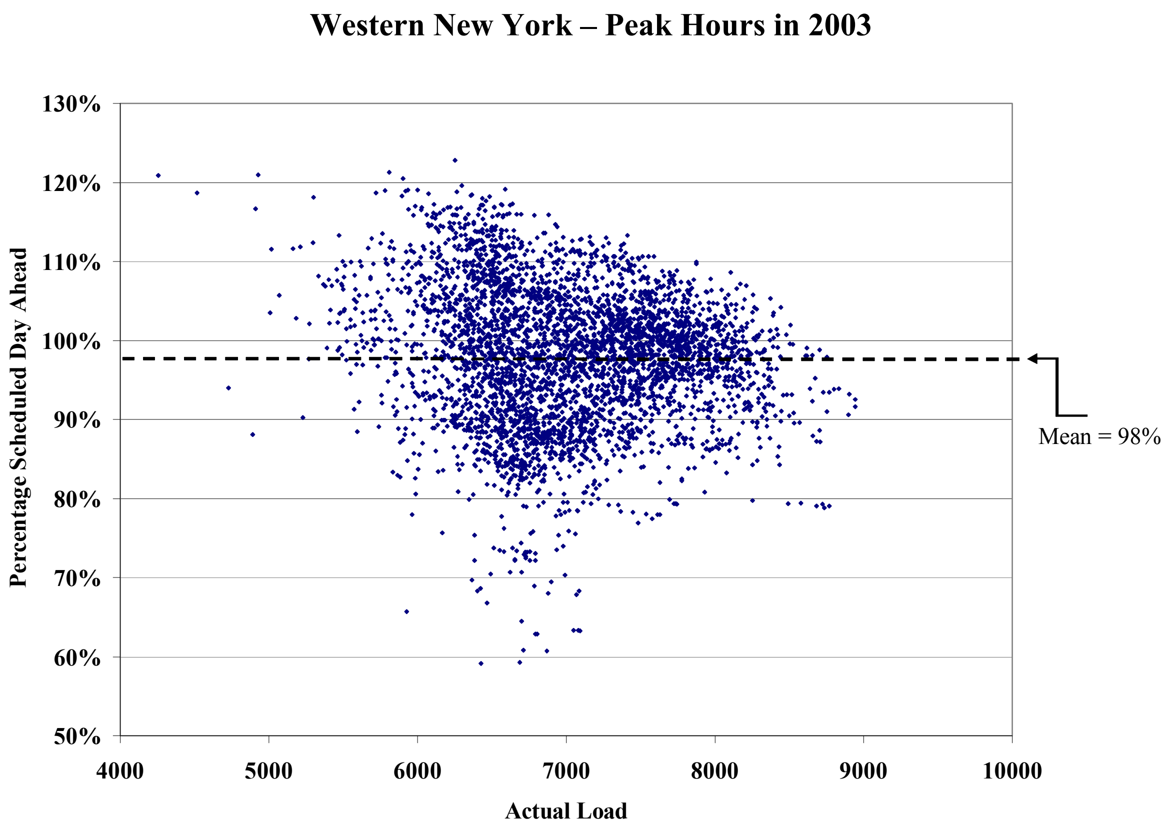
In order to further evaluate the pattern of load bidding, we calculated day-ahead hourly load schedules (including virtual load bids) as a percentage of real-time load for all peak hours during 2003. This analysis is shown in Figure 21, which includes scatter-plot diagrams for New York City, eastern New York upstate of New York City, and western New York.

Figure 21: Load Scheduled Day-Ahead versus Real-Time Load
New York City and Long Island – Peak Hours in 2003



Eastern Upstate New York – Peak Hours in 2003





Our analysis indicates New York City and Long Island tend to over-schedule load day-ahead. However, this pattern diminishes slightly in the highest load hours. Load scheduled day-ahead in eastern up-state New York is more variable and is usually substantially under-scheduled. This under-scheduling decreases with increases in load. In Western New York, the data reveals that day-ahead load is under-scheduled on average, and that this under scheduling becomes more acute as load rises.

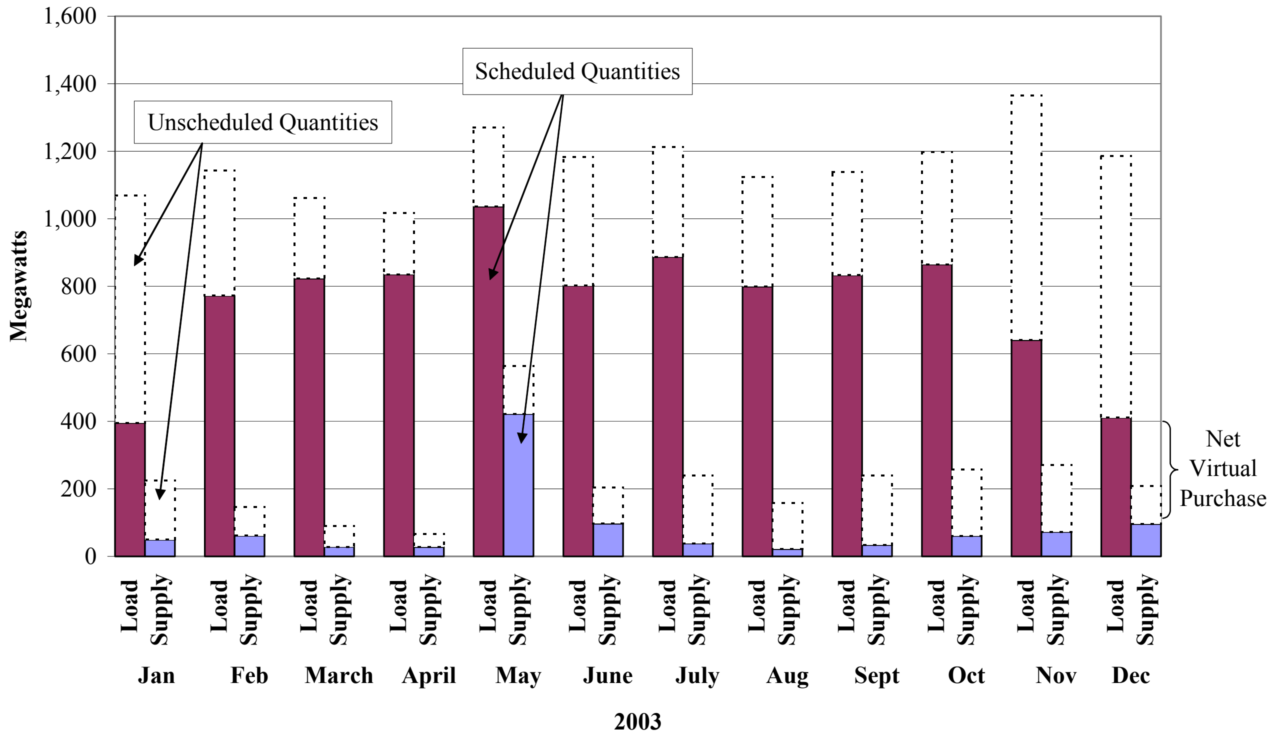
These results are consistent with the differences between the day-ahead and real-time transmission limits (particularly into and within New York City) that are discussed in the next section. The market will respond to the types of inconsistencies that we have detected between the day-ahead and real-time models by adjusting the purchases and sales in the day-ahead market until price convergence is achieved. In this case, that arbitrage results in over-scheduling within New York City and under-scheduling outside of New York City.

4. 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. Figure 22 and Figure 23 show the pattern of virtual bidding in New York City and elsewhere in the State in 2003.

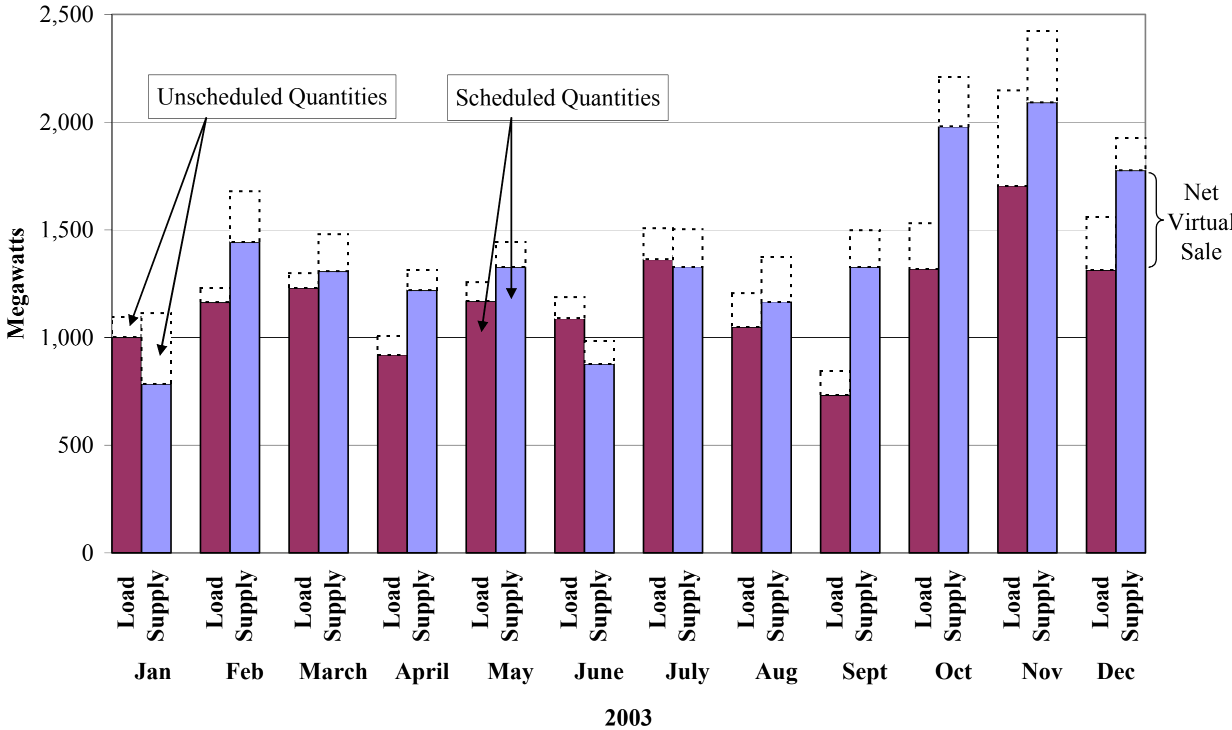
Figure 22: Hourly Virtual Load and Supply New York City and Long Island 2003



Both scheduled virtual load and supply increased by more than 100 percent in 2003 from 2002 levels. Virtual supply scheduled has grown substantially since May 2002, doubling the second half of that year, and continued to increase by more than 750 MW per hour on average in 2003 compared to the previous year. Growth in virtual demand bidding was also substantial, increasing by an average of 1000 MW per hour in 2003 over the second half of 2002. Most of the growth in virtual bidding has occurred outside the New York City area.

Figure 22 shows that virtual load scheduled in New York City and Long Island averages 1,160 MW per hour while virtual supply averages little more than 200 MW per hour. This results in a sizable net virtual purchase on average. This is not consistent with the scheduling patterns outside of New York City and Long Island shown in Figure 23.

Figure 23: Hourly Virtual Load and Supply Outside New York City and Long Island 2003

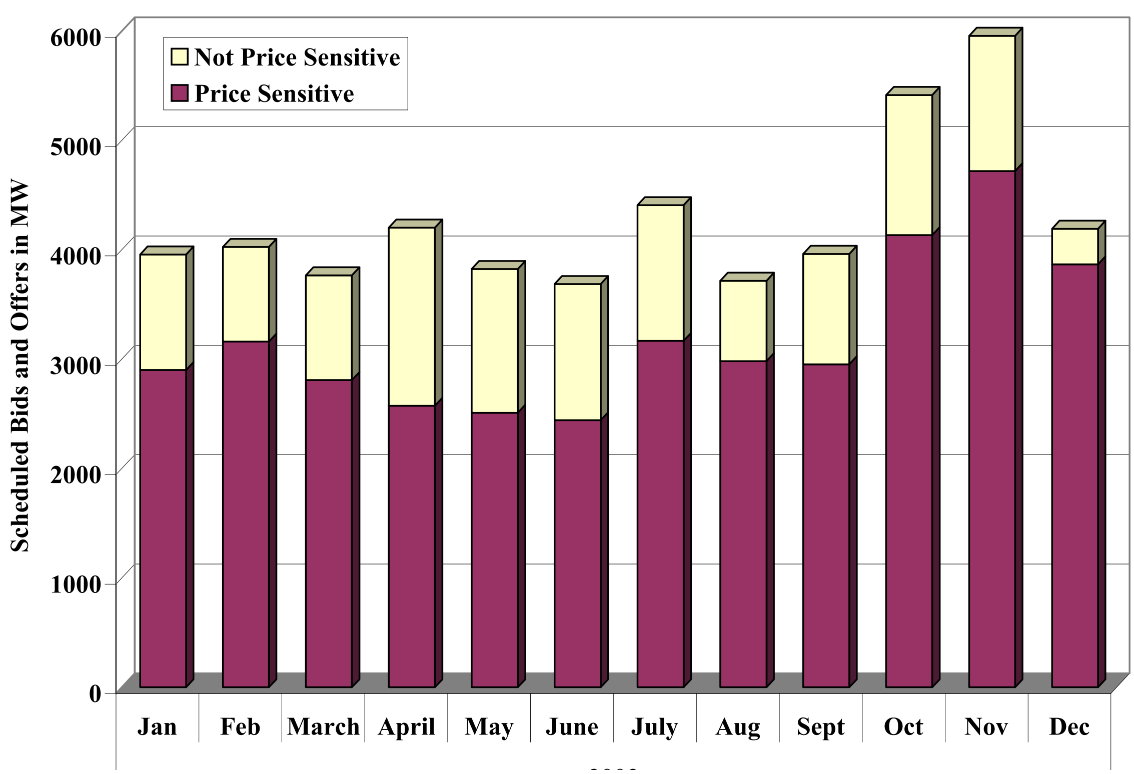


This figure shows that virtual sales are generally larger than virtual purchases, with both averaging more than 1000 MW per hour. The net virtual purchases in New York City and net virtual sales upstate of New York City contribute to the overall over-scheduling in the City and under-scheduling upstate discussed in the prior section. We find that these scheduling patterns are consistent with the transmission modeling issues discussed in the next section. Importantly, these virtual trading patterns contributed to improved convergence between the day-ahead and real-time prices.

A possible concern with virtual trading is that virtual traders might schedule uneconomic transactions in order to manipulate day-ahead prices. However, price manipulation strategies should be undermined by other participants responding to arbitrage opportunities. We monitor the responsiveness of virtual trading to market signals by determining the share of the virtual bids and offers that are price sensitive, which would be consistent with such arbitrage. Price sensitive virtual bids and offers make supply and demand more price elastic in the day-ahead market, thereby making the market more resistant to the exercise of market power and attempts to manipulate day-ahead prices.

Attempts to manipulate day-ahead prices with virtual transactions would generally utilize non-price sensitive bids that cause day-ahead and real-time prices to diverge. Price insensitive bids and offers are not a problem as long as a sizable majority of bids and offers are price sensitive. Bids and offers are considered price-sensitive for this analysis if they have a price within 30 percent to 300 percent of the actual day-ahead price. Figure 24 shows the quantities of the virtual bids and offers that are price sensitive versus those that are non-price sensitive.

Figure 24: Price Sensitivity of Scheduled Virtual Bids and Offers
New York State - 2003



This figure shows that the average quantity of price sensitive bids and offers nearly doubled between January and December 2002, and continued to increase in 2003. Average virtual bids and offer quantities increased by more than 1,000 MW in 2003, and the majority remained price sensitive, though the percentage of price sensitive bids declined from 84 percent in 2002 to 75 percent in 2003.

We also evaluated the relationship of virtual trading to day-ahead and real-time price convergence. When the day-ahead price premium is high, participants will have incentives to schedule additional virtual supply, while participants will have incentives to schedule virtual load when the premium is low or negative. The results have been consistent with the intuition -- net virtual purchases have been made in New York City and Long Island (virtual load schedules have exceeded virtual supply schedules) when the day-ahead premium has been negative. Similarly, outside New York City, net virtual sales have been made when the day-ahead premium has been positive.

B. Analysis of Reference Prices

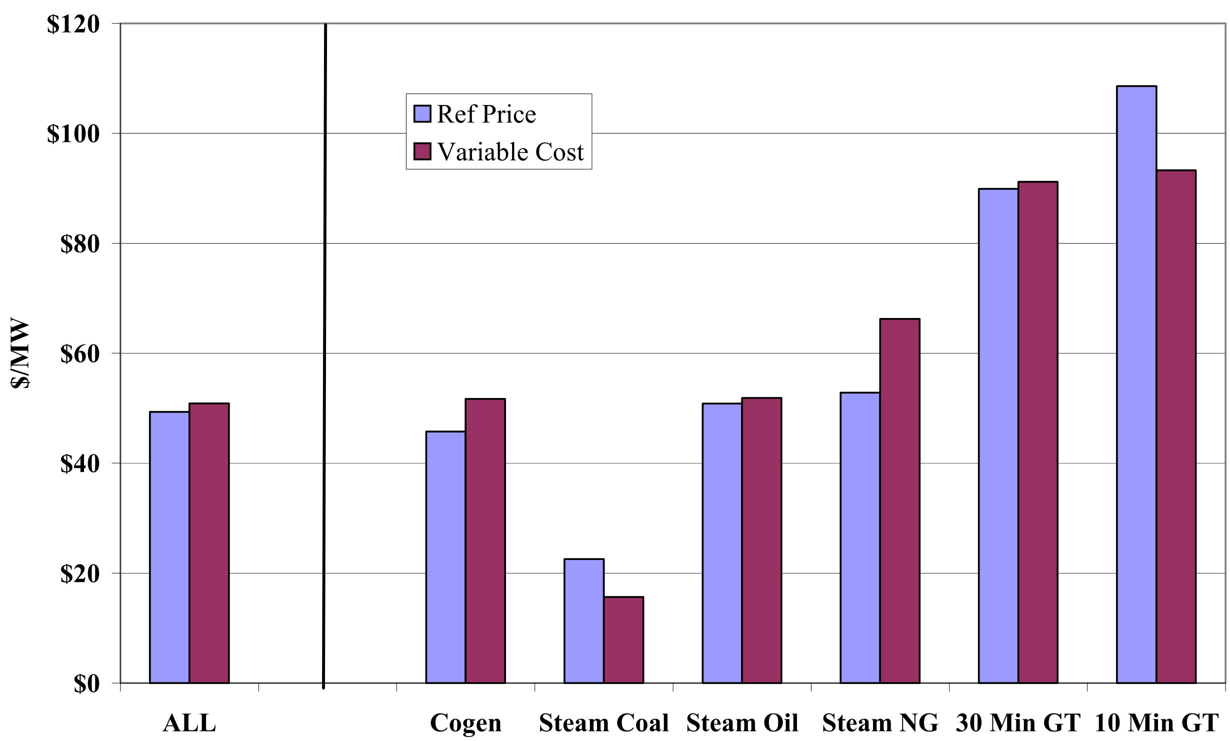
The final analysis in this section evaluates the reference prices that are the basis for the market mitigation in New York. The monitoring plan calls for the calculation of a unit's reference prices based on the unit's accepted offers over the previous 90 days during comparable periods, adjusted for changes in fuel prices. The rationale for using these reference prices to monitor and mitigate market power is that suppliers would be compelled by competitive forces to offer their resources at prices close to marginal costs during most hours when the market is workably competitive. The choice of the lower of the median or average of accepted offers was designed to reduce the incentive to inflate reference prices.

Therefore, reference prices should serve as an effective proxy for actual marginal costs, without the need to estimate marginal costs for every block of output in the State. To assess whether offer patterns have, in fact, been consistent with the assumption that generators should offer their resources at offer prices close to marginal costs, we have compared the reference prices for different types of fossil-fired units to estimated variable production costs. We focus on fossil-fired units because the marginal costs for their normal output range should be close to their variable production costs.

Reference prices are computed for each 10 MW output segment over the output range of each unit in the New York market. The marginal costs of producing the output from a unit near its maximum capability can far exceed the fuel costs for that small segment of output due to increased O&M expenses, increased forced outage probability, and reduced unit efficiency. Because many steam units can have rapidly increasing marginal costs near their maximum capacity, we limited the examination to the range between minimum generation and 90 percent of maximum capacity. We used publicly available data, including heat rates and variable O&M information, to estimate variable production costs in the dispatchable output range of the units.

We calculated an average variable production cost for each unit and compared it to the average reference price per MW. The comparison of per-MW averages, while not as definitive, provides a general guide as to whether and how reference prices have diverged from estimated variable operating costs. Figure 25 shows the relationship between offer-based reference prices and estimated variable production cost for various types of units.

Figure 25: Comparison of Reference Prices and Variable Costs
Average of Monthly Results in 2003



The analysis in this figure compares the average offer-based reference prices from the real-time market over the normal output range of each unit to the average estimated variable costs over the same range. The comparison was conducted for one day in each month during 2003. Overall, we found that reference prices statewide were 3.0 percent below average variable cost on a weighted-average basis. When cogeneration units were eliminated from the analysis, reference prices were 1.2 percent below average variable cost. Further breakdown of the data provide additional insight.

The two types of units for which reference prices exceeded variable costs were coal fired steam units and 10-minute gas turbines ("GTs"). However, coal-fired steam units, because they have low variable costs and long-run times, are poor candidates for strategic bidding. Hence, reference values slightly higher than estimated variable cost for coal units are unlikely to be the result of attempts to raise reference levels.

10-minute GTs incur substantial opportunity costs due to the risk of catastrophic failure every time they start up. Furthermore, because they are not allowed to offer start-up costs, and because their incremental heat rates rapidly decline, they want to offer high enough to ensure that costs of operating at less than full capacity are fully compensated. Therefore, the variable cost estimates will not reflect these incremental costs even though they are likely to be reflected in offers and the resulting reference levels. Hence, the fact that reference values for GTs exceed their estimated variable costs does not present a serious concern.

The thresholds in the mitigation plan for identifying offers that may constitute economic withholding allow for a considerable amount of latitude for suppliers to alter their offer prices. The thresholds allow an increase in the current offer to a level 300 percent or $100 above the reference price, whichever is less. These thresholds are intended to address strategies to remove resources from the market or substantially raise the price of the marginal generating unit, while reducing the potential for unwarranted intrusion in the market by the NYISO.

It has been argued that by raising offers as prices increase during the summer months, suppliers can increase their reference prices and, thus, increase their ability to economically withhold resources. This would permit actions by suppliers to raise energy prices materially without the possibility of immediate mitigation. A supplier that wanted to raise a unit's reference price would make higher offers during periods of higher expected prices, since only accepted offers are used to set the reference prices and the supplier would not want to risk overbidding, losing potential revenues while failing to impact reference prices. Therefore, if suppliers are attempting to raise their reference prices, we would expect offer prices to be positively correlated with expected market prices. A positive relation between offers and market prices may indicate attempts to strategically manipulate reference prices, although it may also reflect generation limitations due to emission limits or other factors.

We performed econometric analyses to investigate whether suppliers attempt to change their offers to influence their reference levels. The offer behavior of a group of 93 generating units in the real-time market outside New York City was examined. We chose units outside New York City because a large share of the in-City units have cost-based reference prices rather than offer-based reference prices. This occurs because hours with congestion into or within New York City are not defined as "competitive periods" and, thus, not included in the reference price calculations. We used Ordinary Least Squares regression analysis to test the hypothesis that generation offers were correlated with market prices. The model hypothesizes generation offers to be directly related to market prices and a fuel price index. The fuel price index is included to account for the effects of fuel prices on offer prices.

These tests generally showed little correlation between offer prices and market prices, which rejects the hypothesis of reference price manipulation. This is not unexpected given the costs and benefits of this strategy. There were some instances of correlation between offer prices and market prices. The vast majority of units showing a positive relationship between offers and prices are owned by a single supplier. Upon further investigation, we have concluded that this supplier's bidding pattern may have been strongly influenced by other constraints on their unit's operation, which result in higher offers that coincide with periods of highest prices. Only two of the units which exhibited a positive relationship between offers and prices were located in Western New York, and both were cogeneration units. Units in Eastern New York that had questionable offer behavior included two cogenerators, four small gas turbines, and two large steam units. Since the owner of the steam units owns only a small proportion of Eastern New York capacity, it is unlikely that any effects on the units' reference prices would allow the supplier to exercise significant market power.

IV. MARKET OPERATIONS

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

- Dispatching generation out-of-merit order;
- Committing supplemental resources not selected by the day-ahead market;
- Dispatching reserves under peak load conditions; and
- Making real-time load curtailments and emergency out-of-market purchases.

Reliability requires that operators have the ability to take these actions, but they should be taken as infrequently as possible and the market rules should minimize adverse effects on prices. This section evaluates these operating actions and examines more broadly the patterns of congestion costs and uplift that occurred in 2003.

A. Transmission Congestion

Congestion can arise in both the day-ahead and real-time markets when transmission capability is not sufficient to accommodate a least-cost dispatch of generation resources. When congestion arises, both the day-ahead and real-time market software establish spot prices based on the cost of meeting load at each location, which reflects the fact that higher-cost generation may be required at locations where transmission constraints prevent the free flow of available resources. This will result in higher spot prices at these "constrained locations" than would occur in the absence of congestion.

The day-ahead market is a forward market, facilitating financial transactions among participants that are binding in real-time. The NYISO applies congestion charges to these transactions, which are both bilateral transactions and spot transactions, by modeling anticipated congestion. Bilateral transactions are charged based on the difference between day-ahead spot prices at the two locations (the price at the sink less the price at the source). Buyers and sellers pay congestion charges implicitly equal to the difference in prices between the locations where power is injected and withdrawn from the transmission network.

Congestion charges may be hedged in the day-ahead market by owning TCCs, which entitle the holder of the TCC to payments corresponding to the congestion charge between two locations. A TCC consists of a directional pair of points (locations or zones) and a MW 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 price at zone B less the price at location A. 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.

In the real-time market, participants with day-ahead contracts do not pay real-time congestion charges. Only transactions that are 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.

Figure 26 shows the monthly congestion costs that occurred in the day-ahead and real-time markets from 2001 to 2003. These values are the total congestion revenues collected from participants, which include: a) the difference between the total payments by loads and the payments to generators and net imports (excluding losses), and b) the congestion costs collected from physical bilateral schedules. In an LMP system, this revenue will be equal to the marginal value of the transmission capacity (i.e., the shadow price of the transmission constraint[8]) times the amount of power flowing across the constrained interface.[9]

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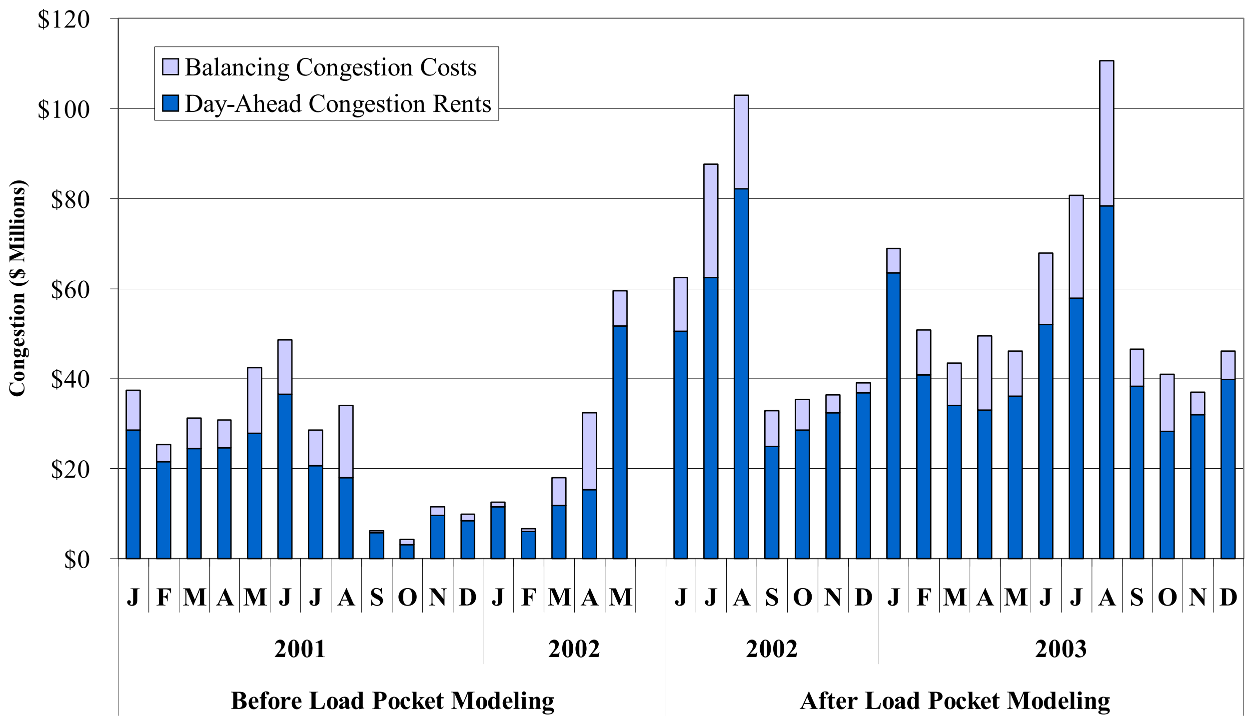
8 A shadow price is the value to the system of increasing the constraint by a very small amount (e.g., 1 MW). In this case, it would be equal to the reduction in system production costs that could be achieved by substituting lower cost resources on the unconstrained side of the interface for higher-cost resources on the constrained side of the interface.

9 These amounts should not be expected to resemble the historical congestion values that have been calculated with methods approved by the NYISO Operating Committee in January 2004. These methods utilize a model to calculate various types of cost differences between the current system and a completely unconstrained system.

Figure 26: Monthly Congestion Expenses
2001 -2003



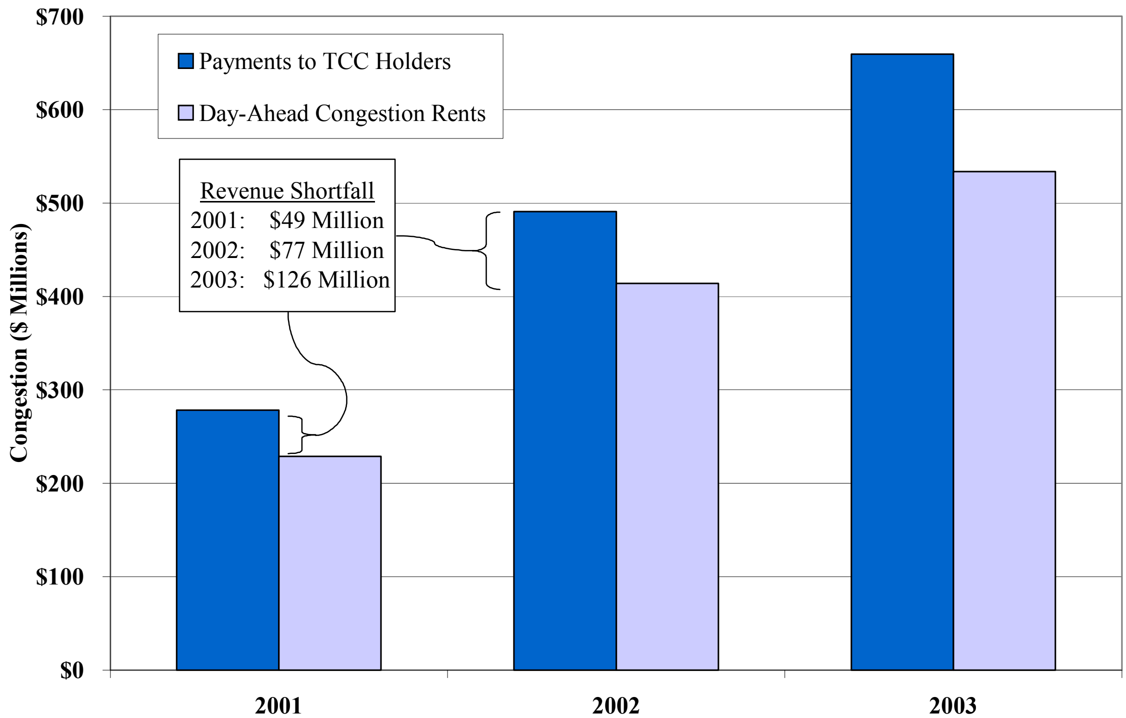
This figure shows that overall congestion costs increased substantially after 2001, from $310 million to $525 million in 2002 and $688 million in 2003. This was primarily due to the modeling of load pockets within New York City, which began in June 2002 and was one of the most substantial modeling changes that have occurred in New York since the market began. This modeling improvement substantially increased the apparent congestion (because LBMPs began reflecting these constraints) and reduced uplift costs. Prior to this change, resources were redispatched out-of-merit and the costs were recovered through uplift charges.

The vast majority of congestion costs occur in the day-ahead market, as expected, but there is a substantial amount of congestion expenses that occur in the real-time spot market (i.e. balancing congestion costs). The fact that balancing congestion costs are significant and sustained is unexpected and raises issues that are investigated below. To evaluate the functionality of the NYISO congestion framework we analyzed several metrics. First, we compared the day-ahead congestion costs paid by market participants to the TCC payments made to market participants. In a well-functioning system, these values should be roughly equal.

In order to determine the quantity of TCCs that can be sold in a TCC Auction,[10] the transmission system must be modeled to ensure that the rights are 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 simultaneously 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 all TCCs.

If transmission outages occur that were not modeled in the TCC auction, then the TCCs may not be feasible and, thus, the congestion rents may be insufficient to meet the TCC obligations. To fully fund TCCs under these conditions, TOs are charged a Congestion Rent Shortfall, which is passed through to final customers through the TOs' service charge. Because these charges are "socialized," they did not provide efficient incentives to minimize the congestion effects of transmission outages. To evaluate the shortfall amounts over the past three years, Figure 27 shows day-ahead congestion costs and TCC payments for 2001 to 2003.

Figure 27: Day-Ahead Congestion Costs and TCC Payments 2001-2003



10 The NYISO administers both longer-term forward TCC Auctions, in which 6-month and 1-year TCCs are sold, and monthly Reconfiguration Auctions to allow participants to buy and sell shorter duration TCCs.

The figure also shows that congestion costs were lower in all three years than the payments to TCC holders, resulting in increasing shortfall levels. These shortfalls are largely due to transmission outages that are reflected in the day-ahead market, but are not included in the TCC auction. The NYISO made two sets of changes to the allocation of the shortfall that should improve incentives and result in lower shortfall amounts.

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 will be charged for the reduction in revenues stemming from a transmission facility outage in the day-ahead market or a facility being modeled as unavailable in the TCC Auctions. Conversely, if a TO can make a facility available which was modeled as unavailable, the TO receives a payment corresponding to the additional auction revenues or congestion rents stemming from the return to service of this facility.

NYISO also proposed two mechanisms to reduce congestion rent shortfalls by allowing TOs to reserve a specified amount of capacity, which would not be available in TCC Auctions. The first mechanism would permit TOs that hold Existing Transmission Capacity for Native Load ("ETCNL")[11] to reserve a limited amount of this capacity. Under the second mechanism, all TOs would be permitted to reserve a limited portion of the residual transmission capacity[12] between contiguous pairs of load zones. In each case, TOs reserve transmission capacity by converting up to 5 percent of transmission capacity into six-month TCCs. Congestion payments for the reserved TCCs will help to offset the TOs' share of a Congestion Rent Shortfall. The FERC approved these measures, subject to minor changes, effective February 2, 2004.

We also examined the amount of congestion revenue shortfall incurred in the day-ahead market and the additional congestion costs incurred in the balancing market (real-time congestion costs). These amounts are shown in Figure 28 for 2001 to 2003.

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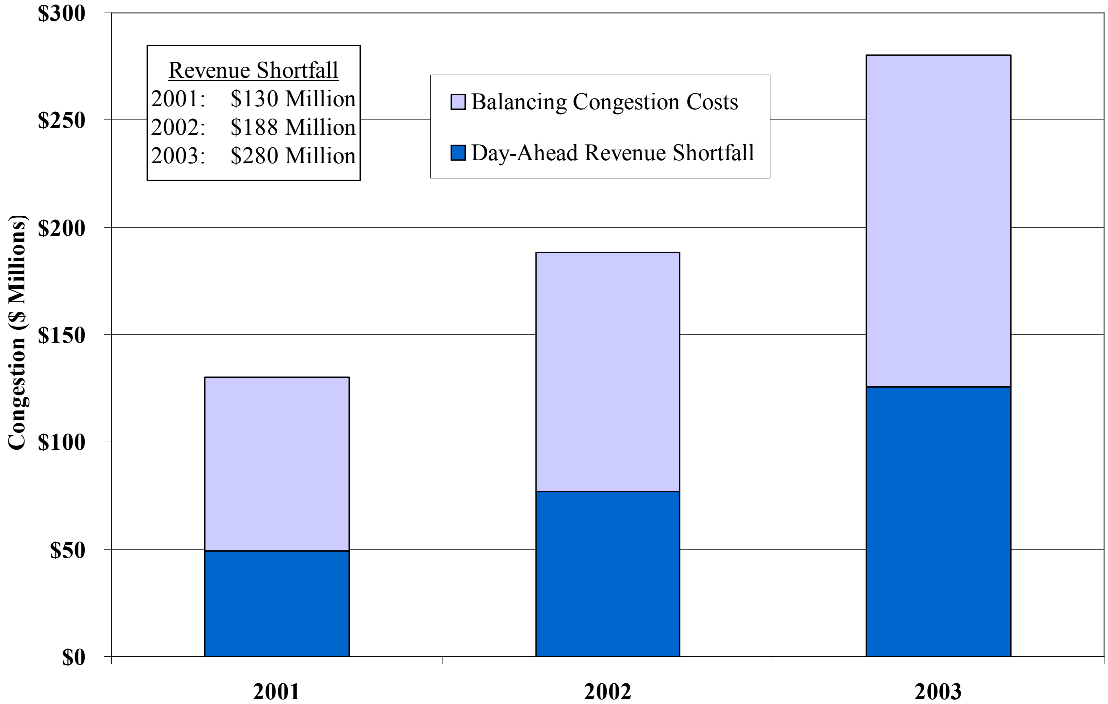
11 TOs were allocated ETCNLs to facilitate the transition to locational marginal pricing.

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

Figure 28: Day-Ahead Congestion Revenue Shortfalls and Real Time Congestion 2001 - 2003



As Figure 28 shows, the real-time congestion costs have been positive and increasing over time. The primary cause of real-time congestion costs are changes in transmission limits between the day-ahead and real-time markets, or changes in loop flows that cause the day-ahead schedule to be infeasible. In this case, the ISO must purchase additional generation in the constrained area and sell back generation in the unconstrained area (i.e., purchase counter-flow to offset the day-ahead schedule). The cost of this redispatch is collected from loads through uplift charges. If transmission outages and other factors affecting capability are generally known day ahead, these congestion costs should be relatively small.[13] The fact that the real-time congestion costs are substantial indicates the need for further investigation regarding the consistency of the transmission limits in the day-ahead and real-time markets.

To examine the consistency of the transmission limits in the two markets, Figure 29 shows the portion of the hours congested over the primary transmission interfaces in real time and the change in flows from day ahead to real time. The height of each bar indicates the percentage of

13 Some factors cannot be known or modeled day ahead, such as thunderstorm alert procedures that are only implemented in real time.

hours in which real-time congestion existed. These bars are divided to show the portion of hours in which the real-time flows were greater or less than day-ahead flows. For each portion, the values that are shown for each bar indicate the average change in real-time versus day-ahead flows. The upper portion of each bar indicates the amount by which real-time flows exceeded day-ahead flows in hours when real-time flows were greater than day-ahead flows. The lower portion of each bar contains a negative number, indicating a reduction in real-time flows compared to day-ahead flows in hours when day-ahead flows exceeded real-time flows. These negative values indicate lower transmission limits in real-time than in the day-ahead.

Figure 29: Real-Time Congestion and Interface Flows
2003

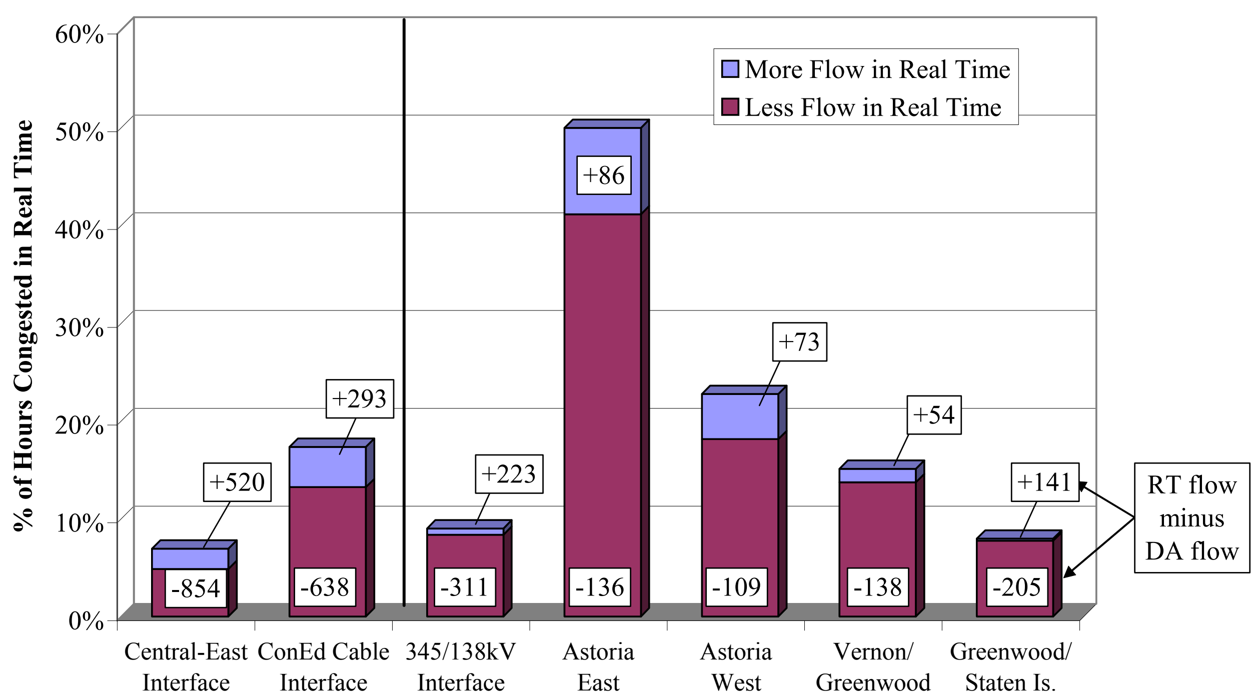


Figure 29 shows that the limits into and within New York City generally decrease in the real-time market by substantial amounts. It is clear from the figure that there is a tendency for flows to decline between the day-ahead market and real-time markets. Reductions generally range from 7 to 22 percent of the load served on the constrained side of the interface. These results are consistent with the real-time congestion costs, as well as the over-scheduled load in New York City and under-scheduled load outside of New York City in the day-ahead market.

The RTS will improve the consistency of the transmission limits and other assumptions because both the RTS and SCUC models will operate on a common software platform. We also recommend the ISO review and adjust, as appropriate, the current limits and assumptions in the SCUC to improve its consistency with real time market.

B. Uplift and Out-of-Merit Commitment/Dispatch

In this section of the report, we evaluate patterns of uplift and out-of-merit actions that occurred in 2003. 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. The first analysis presented in Figure 30 shows the trends in uplift costs over the past three years.

Figure 30: Day-Ahead and Real-Time Uplift Expenses 2001 - 2003

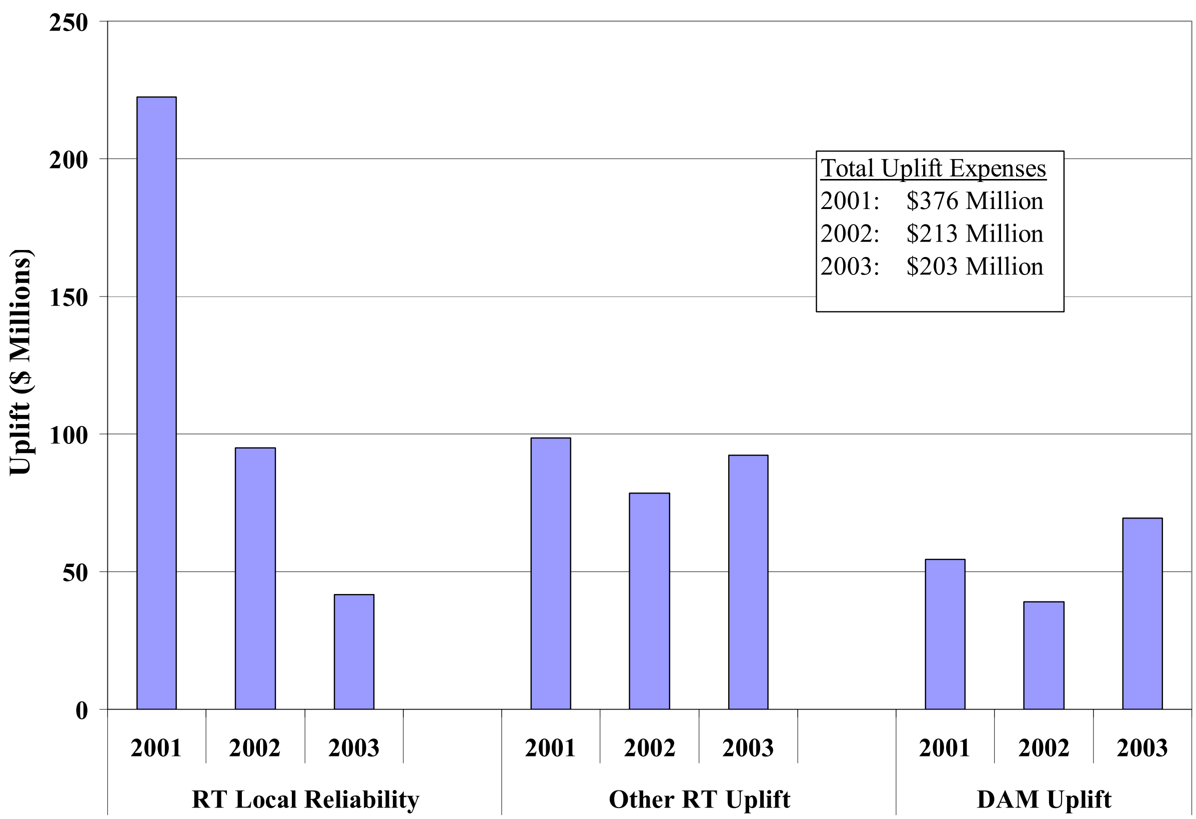


Figure 30 shows that uplift costs have fallen sharply since 2001, although high fuel prices at the end of 2002 and in 2003 reduced the apparent savings relative to 2001. Uplift costs, in large part, depend on the operating cost of generators, which increased as a result of higher fuel costs. Despite these higher fuel costs, total uplift costs declined slightly in 2003 from 2002.

Day-ahead uplift fell in 2002, but rebounded to 27 percent above the 2001 level in 2003. Day-ahead uplift is generally paid to units committed to meet operating reserve requirements or in the local reliability pass of the SCUC. Units that were committed in the initial commitment receive the majority of the guarantee payments that result in uplift. Changes to the BME in 2002 to more accurately schedule units and imports for the real-time market reduced uplift associated with the real-time market, but the effect of these changes was offset by higher fuel costs in 2003. These guarantee payments increase when supplemental commitments for local reliability cause day-ahead prices to decrease.

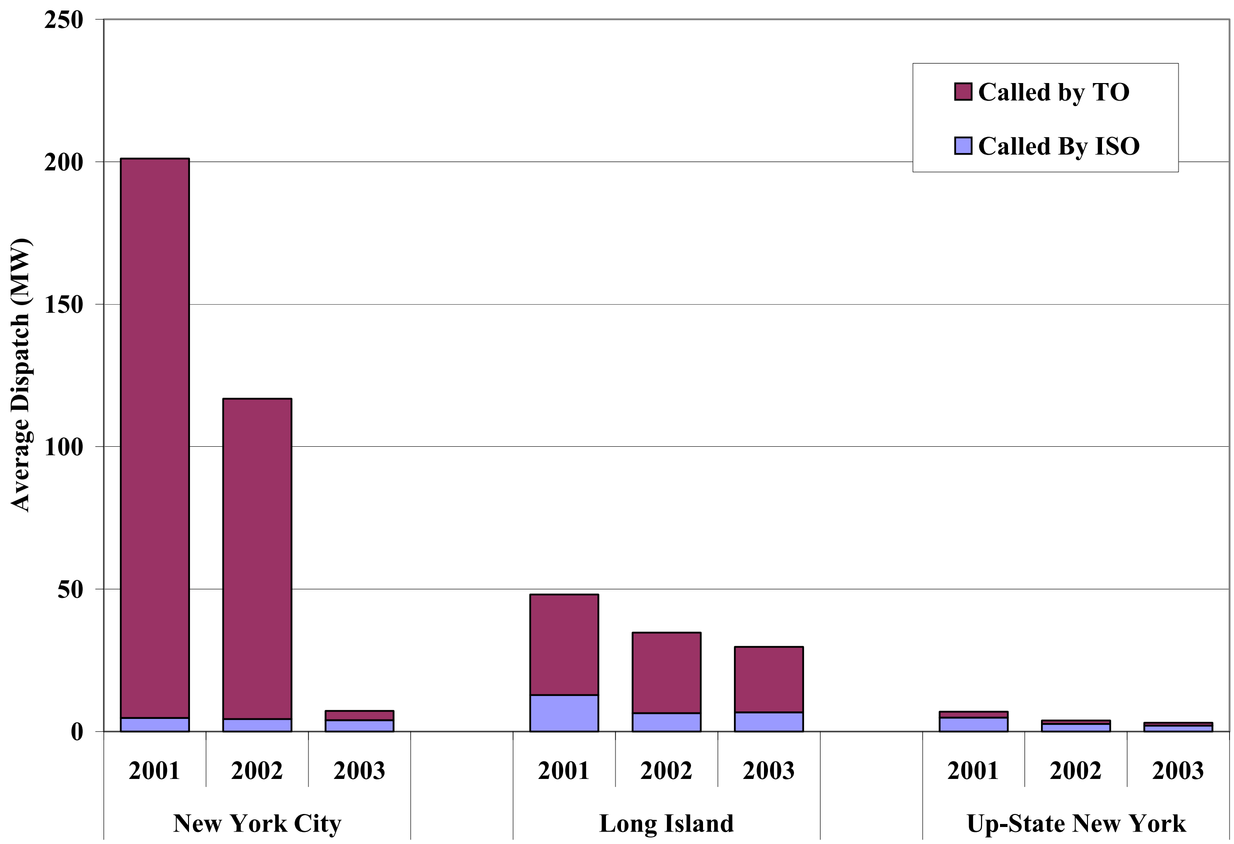
Real-time local reliability uplift decreased almost 60 percent between 2001 and 2002 and by a similar amount in 2003, primarily the result of load-pocket modeling in New York City. Reduced payments for out-of-merit generation to manage congestion in the New York City load pockets are now reflected in the congestion component of the spot market price. Real-time non-local reliability uplift was reduced by about 20 percent in 2002 before rebounding back to close to 2001 levels in 2003. Out-of-merit dispatch and SRE actions that are not specifically logged as a local reliability action are included in this category – even when called by the transmission owner.

1. Real-Time Out-of-Merit Dispatch

A resource is dispatched OOM when it is dispatched by the ISO even though its energy offer exceeds the price at its location. This can be caused by the physical parameters of the unit (e.g., minimum run-time that requires the unit to run after it has become uneconomic) or by operator action. OOM actions are generally taken to ensure reliability and resolve congestion. Actions to ensure reliability in the day-ahead market to ensure enough capacity is committed for the real-time market results in OOM commitment, as discussed in the next subsection. OOM dispatch in real-time can also be used to manage network constraints that are not included in the model.

OOM actions tend to depress spot market prices, particularly during peak demand conditions when prices are most sensitive. This is because OOM units are ineligible to set prices and when they are added to the supply stack, the result is to supplant higher-offer units on the margin and depress prices, causing a divergence between the spot price and the actual marginal cost of meeting load.[14] The use of OOM units to maintain reliability also creates a need to make supplemental payments to the OOM units because the spot price is not sufficient to pay the OOM units' offer costs. The costs of these payments are recovered through uplift charges. Figure 31 shows the average OOM dispatch quantities for 2001-2003.

Figure 31: Average Out-of-Merit Dispatch Quantities
2001 - 2003

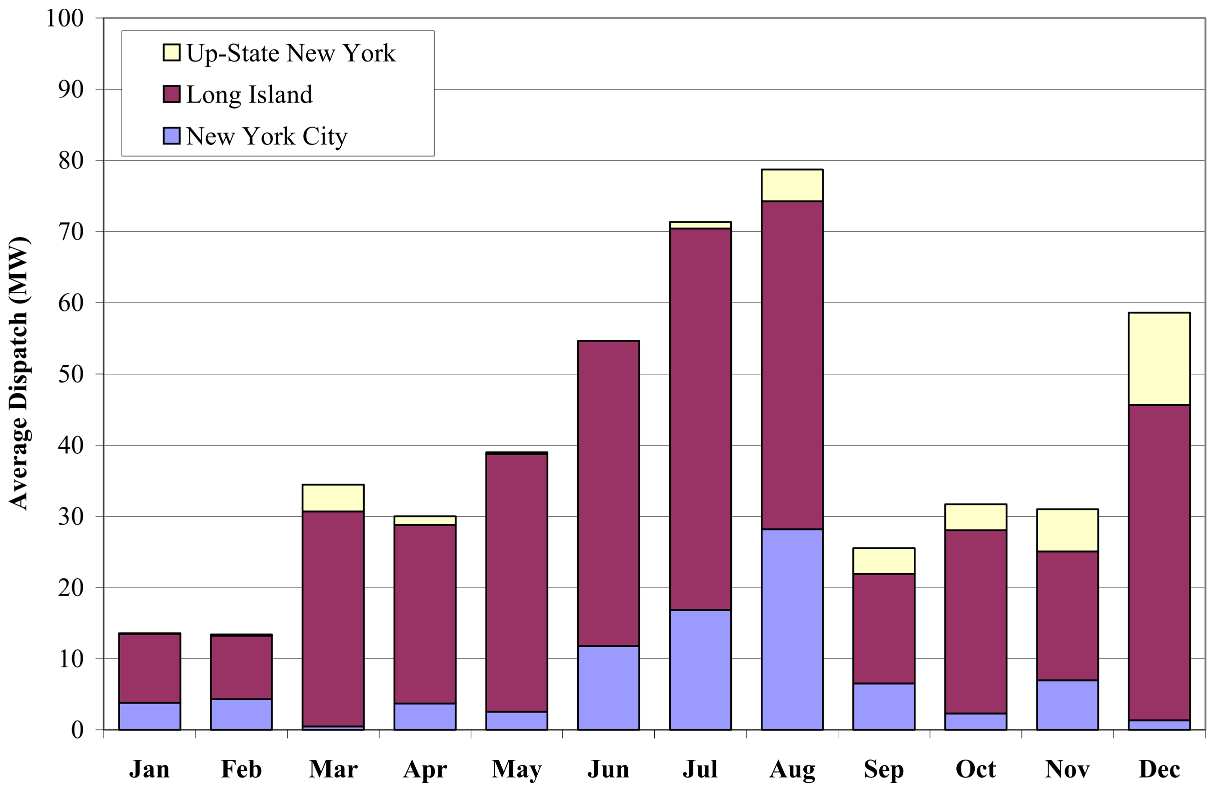


Note: August 2003 blackout hours excluded.

14 While OOM resources are ineligible to set energy prices, in many cases these resources turn out to be economic (i.e., in merit). Only units that are economically OOM will affect prices.

Prior to changes in the modeling load pockets in New York City, OOM dispatch in New York City accounted for approximately 80 percent of all resources dispatched OOM in the real-time market. OOM quantities have fallen by more than two-thirds from 2002 to 2003, primarily due to the introduction of load pocket modeling and improvements in the commitment of gas turbines in the real-time market. Because this demand for OOM dispatch has been substantially eliminated, Long Island units now account for two-thirds of OOM dispatches. To more closely examine OOM patterns in 2003, Figure 32 shows the incidence of OOM dispatch by month for New York City, Long Island and the rest of the state.

Figure 32: Average Out-of-Merit Dispatch Quantities 2003



Note: August 2003 blackout hours excluded.

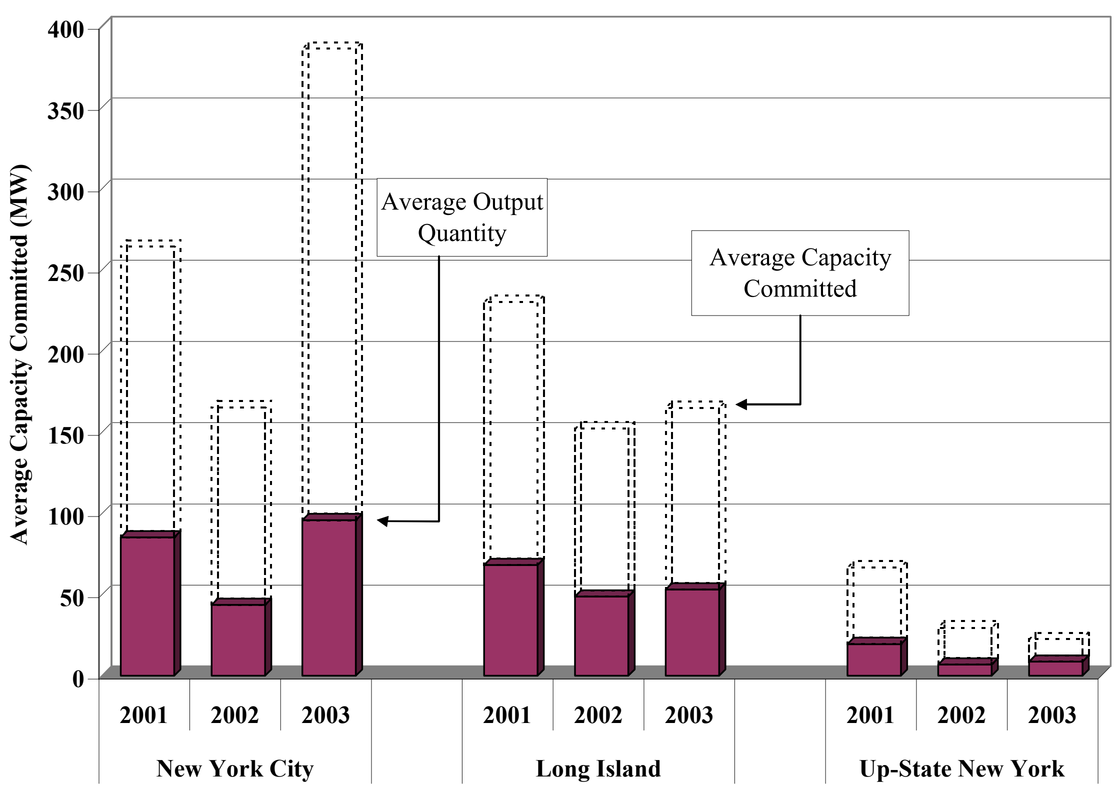
This figure shows that although the OOM dispatch levels were highest during the summer months, the average quantity of OOM dispatched was less than 80 MW. The increase in OOM quantities during the summer primarily occurred in New York City, although they remained less than 30 MW on a monthly average basis.

2. OOM Commitment

There are two types of OOM commitment in the day-ahead: SRE commitment and local reliability commitment. The SRE is a process by which the ISO commits additional resources after the day-ahead market closes in order to meet reliability requirements. This may occur when the day-ahead market assumptions are modified after the market has closed (e.g., operators expect loads to be higher than the day-ahead forecast). When operators assess the SCUC run, they may commit additional resources through the SRE process to be on-line for the next day.

Day-ahead local reliability commitment is a form of out-of-merit commitment that takes place during the day-ahead market process, as opposed to 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 some units that are not committed economically may be committed to meet certain specific reliability requirements. Our first analysis in this section is of the SRE commitments. Figure 33 shows the quantity of SRE commitments made from 2001 to 2003 in New York City, Long Island and upstate.

Figure 33: Supplemental Resource Evaluation 2001- 2003



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 impact.

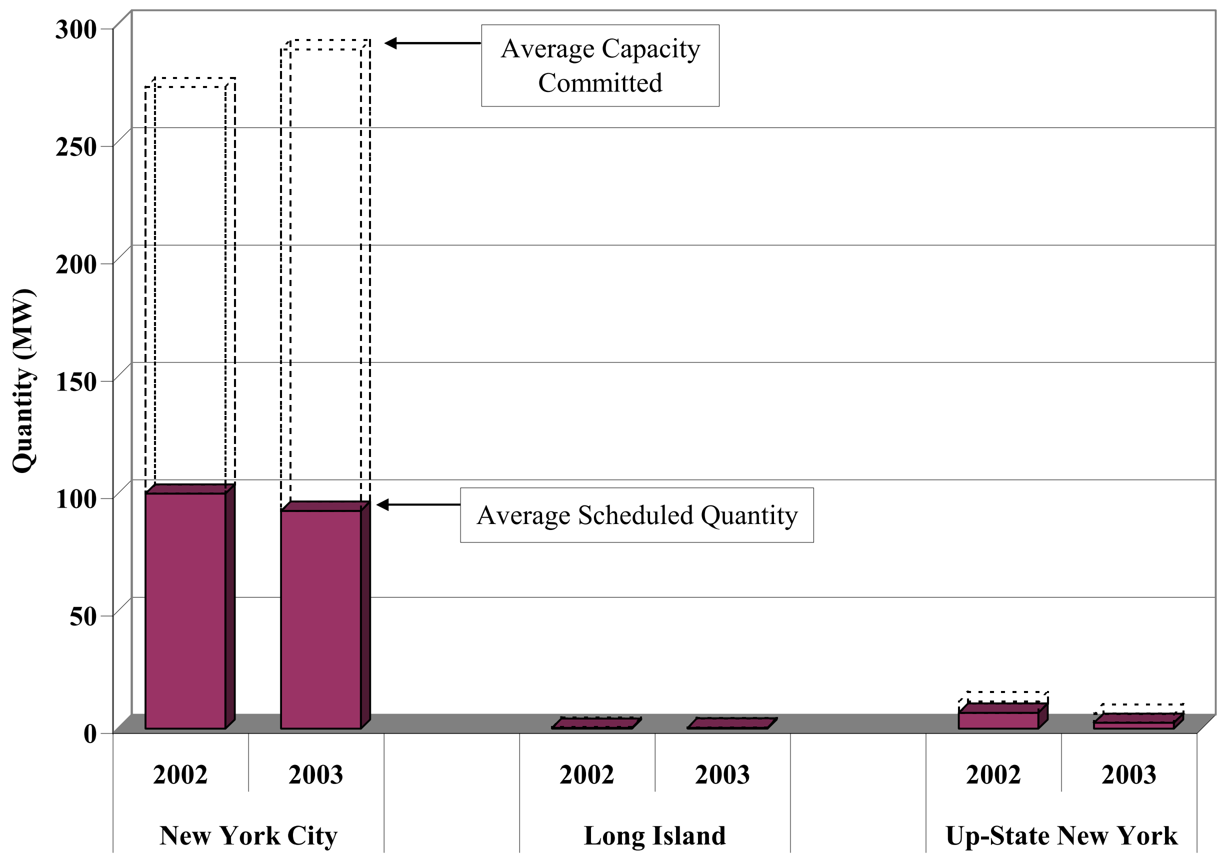
Figure 33 shows that most of the SRE commitments occur in New York City and on Long Island. Improvements in day-ahead modeling and commitment have reduced the quantity of SRE actions outside of New York City and Long Island since 2001. The average quantity of capacity committed through SRE in New York City more than doubled in 2003 relative to 2002.

The SRE commitments in the City are generally made to satisfy the generators' NOx requirements, which restrict the average emissions (per MWh of output) from a generator's portfolio. Because gas turbines emit at a much higher rate, each supplier must have a steam unit committed to provide the capable to dispatch the gas turbines if necessary. Hence, certain steam units in the City are committed through the SRE process when they are not committed by SCUC. Ironically, these environmental regulations likely increase emission substantially in the City by compelling the commitment of steam generators that would not otherwise be running on many days. More frequent SRE actions were required in 2003 to meet the NOx requirements due to lower day-ahead market commitments.

Finally, Figure 33 also shows that most of the units committed through the SRE process are dispatched at close to their minimum generation levels (i.e., 25 to 35 of the maximum capacity). Hence, although almost 400 MW of capacity is committed in the City, only 100 MW of additional energy is produced due to these commitments on average. This limits the effects of these commitments on the NYISO energy markets.

The next analysis shows the local reliability commitments made by SCUC. Figure 34 shows the average capacity committed in the day-ahead market for local reliability and the day-ahead scheduled quantity.

Figure 34: SCUC Local Reliability Pass Commitment June 2002 – December 2003

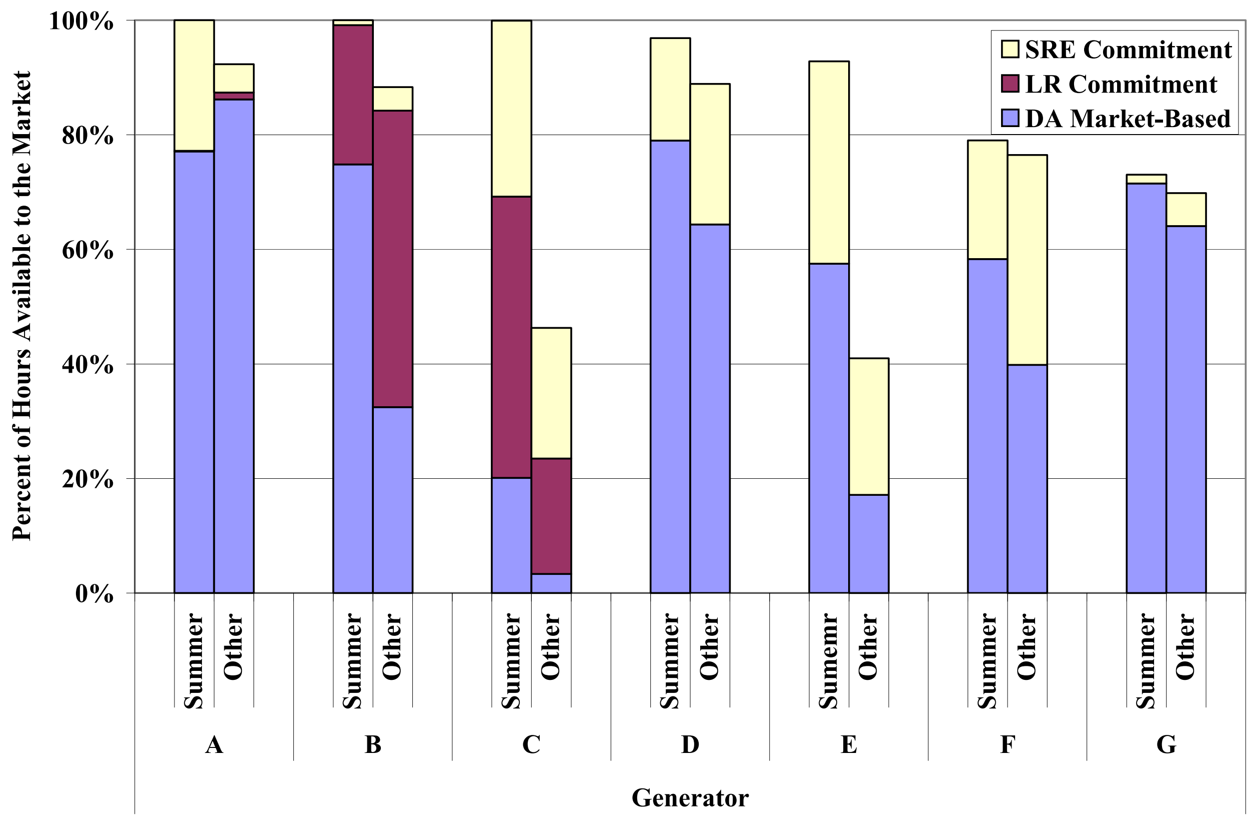


This figure indicates that the average daily commitment in 2003 for local reliability was more than 290 MW. These commitments resulted in average day-ahead schedules of approximately 100 MW, which indicates that the units are generally scheduled at their minimum generation level. Virtually all of the local reliability commitments made by SCUC involved two units in New York City. The increase in day-ahead uplift costs in 2003 was primarily due to increased fuel prices that increased minimum generation costs.

These day-ahead local reliability commitments are important because they tend to reduce prices from levels that would result from a purely economic dispatch and create uplift. A portion of the uplift resulting from these commitments is incurred to make guarantee payments to other generators that will not cover their as-offered costs at the reduced price levels.

In our final analysis of the OOM commitment, we evaluate the frequency of these commitments at the individual unit level. Figure 35 shows the seven units with the highest commitment rates, which are frequently for local reliability. The values shown are the number of hours that each unit is committed as a percent of the hours that the unit is available (i.e., not on outage) for both summer (June – August) and non-summer days.

Figure 35: Units Most Frequently Committed for Local Reliability and SRE 2003



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

The units in this figure accounted for more than 80 percent of the SRE actions and 99 percent of local reliability commitment by SCUC. Four of these units are in New York City and three are on Long Island. Four of these units analyzed appeared to be needed almost every day during the summer. When these units were not committed economically in SCUC they were generally committed in the local reliability pass of SCUC or through an SRE action.

3. Out-of-Merit Dispatch and Commitment -- Conclusions

Out-of-merit dispatch and commitment have significant market effects. Primarily, they inefficiently reduce 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.

SRE commitments are generally made to satisfy certain reliability requirements. To minimize potential price effects from SRE actions, the ISO should continue to adjust SCUC to meet local reliability requirements and thereby minimize the need for SRE commitments. For example, the NYISO should include the commitments needed to satisfy the NOx rules in New York City in the day-ahead market.

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 NOx compliance. This would only involve 3 to 4 units. Pre-committing these units would reduce divergence between day-ahead and real-time prices. Finally, when TOs make SRE commitments, the same economic criteria should be employed as is used for supplemental commitments by the ISO (to minimize start-up and minimum generation costs).

C. Market Operations under Shortage Conditions

When the system is in shortage (that is, when available capacity is not sufficient to meet both energy and reserve requirements), the ISO may take a number of operating actions to satisfy its operating requirements. First, the NYISO also can ask for load reductions from SCR and EDRP resources. EDRP loads that curtail in real time on two hours notice are paid the higher of $500/MWh or the real-time clearing price. While response is voluntary for the EDRP resources, SCRs are loads that *must* curtail within two hours after having been notified day ahead. The SCRs may sell capacity in the ICAP market as supply resources in exchange for accepting this curtailment obligation. When these actions are needed to meet reserve requirements, they will generally set energy prices at $500 per MWh. Second, the ISO may curtail exports from capacity resources or purchase emergency power from neighboring control areas. Unlike the demand response programs, these actions do not contribute to setting energy prices during shortages.

Despite these actions, shortages can occur that require the ISO to relax its reserve requirements so the system can meet energy needs. When reserves are released and dispatched for energy, the reserve market has effectively become the marginal supplier of energy and the energy price should reflect the value of the reserves compromised. The economic value of ten-minute reserves (and hence the energy price during shortages) is implicitly established by the $1000 NYISO bid cap. Under the current market design, the ISO will pay up to $1000 for an incremental energy supplier to provide one MW of energy (allowing the operator to restore one MW of its operating reserves).

Therefore, the NYISO submitted and the FERC accepted, effective as of June 23, 2003, a scarcity pricing proposal, called "Reserve Shortage Pricing", which sets the LBMP at $1000/MWh when a 10-minute reserve shortage persists and a short-term response will not immediately remedy the situation. The Real-Time energy price during scarcity conditions will be the higher of the LBMP set by the SCD, the price set under Reserve Shortage Pricing (if activated), or the price set pursuant to the pricing rules for SCR and EDRP. However, due to the relatively mild weather in the summer of 2003 and increased imports from New England, there were no shortages in 2003 and these pricing provisions were not triggered.

The implementation of reserve demand curves and other changes in RTS will replace the Reserve Shortage Pricing provisions in the fall 2004. The reserve demand curves will be fully integrated with the market software – they will be included in both the day-ahead and real-time market models, ensuring that the commitment decisions made in the day-ahead market, the hourly scheduling of external transactions and off-dispatch generation, and the dispatch of resources in real time will all be consistent. Hence, the reserve demand curves provide a more efficient means to set prices during shortage conditions. The reserve demand curves have been designed to emulate the current operating requirements and reflect the implicit value of the operating reserves based largely on the $1000 bid cap.

V. CAPACITY MARKET

A. Background

This section assesses the design and competitive performance of the 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.

The NYISO implemented a change to the design of its capacity market at the end of 2001. Since that time, LSEs have been required to purchase UCAP rather than ICAP. The difference is that UCAP is adjusted to reflect forced outages. Thus, an unreliable 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 maintain their units for 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. Likewise, suppliers sell capacity from each of their units on a similarly adjusted basis.

The NYISO filed a proposal to modify the rules governing the requirement for LSEs in New York to procure installed capacity, which was accepted by the FERC to become effective May 21, 2003, absent a supplemental supply fee.[15] The ICAP requirement is no longer fixed at 118 percent of peak load. Instead, it will vary depending on the market price for ICAP, which is determined using an ICAP Demand Curve in the monthly capacity auction. The proposed ICAP Demand Curve replaced a vertical demand curve with a sloped demand curve. In addition, the fixed deficiency charge was replaced with a variable charge equal to the ICAP price that results from the monthly auction. The ICAP Demand Curve was set so that at a capacity of 118 percent

15 *New York Independent System Operator, Inc.*, 103 FERC ¶ 61,201 (2003).

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 for each area.[16] 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 as capacity declined below the target level.

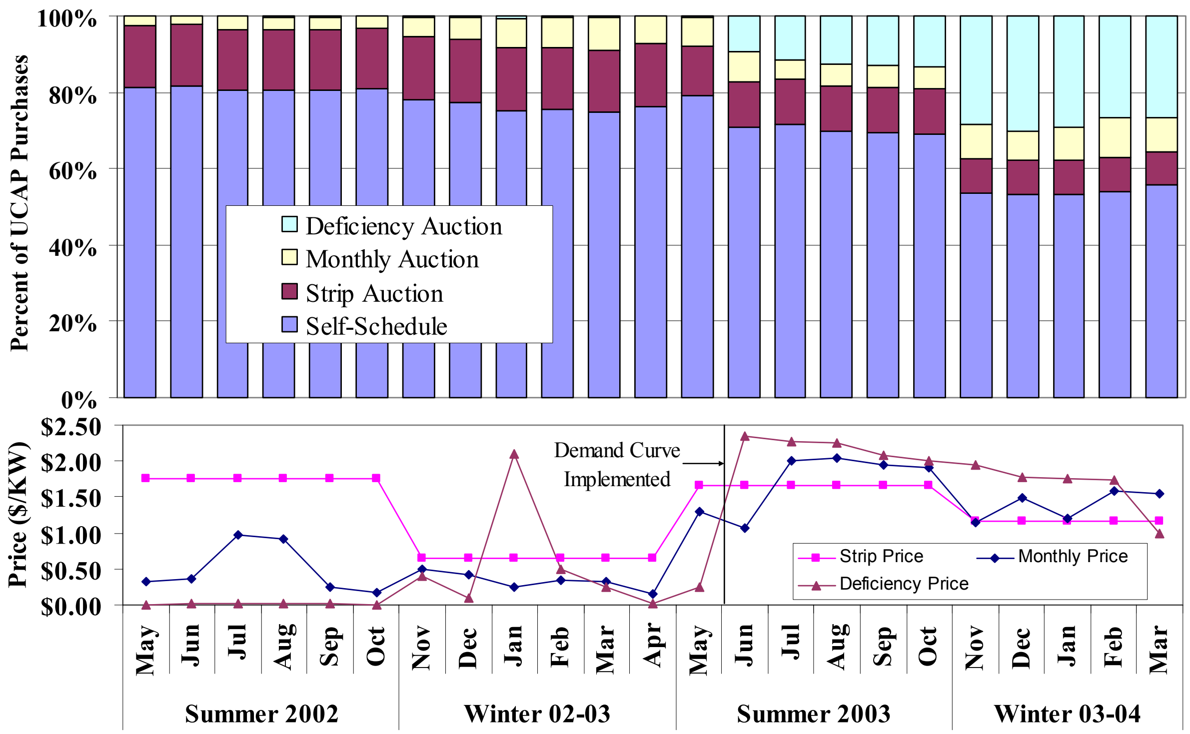
Monthly UCAP spot market auctions replaced LSE bids in deficiency procurement auctions. The ICAP Demand Curve and the results of the monthly UCAP supply (or bid) auction define the amount of Installed Capacity each LSE must obtain for the following month (which can be no less than the 118 percent minimum capacity reserve requirement). The Demand Curve will phase-in over a three year period such that in year one, the Demand Curve reflects a price less than the cost of entry. In years two and three the Demand Curve will pivot up to the point at which price reflects the full cost of a new peaking unit. The aggregate UCAP requirement and the associated UCAP price are established at the point where the supply curve of offers crosses the ICAP Demand Curve. All ICAP 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 in 2003

To evaluate the impact of the ICAP Demand Curve on the capacity market we looked at the two six-month capability periods before the capacity demand curve was implemented and the two capability periods after implementation. Figure 36 shows UCAP prices in the "rest-of-state" area (i.e., the capacity requirements of the state after the local requirements of New York City and Long Island are satisfied). It also shows the proportion of UCAP self-scheduled and purchased in the various UCAP auctions.

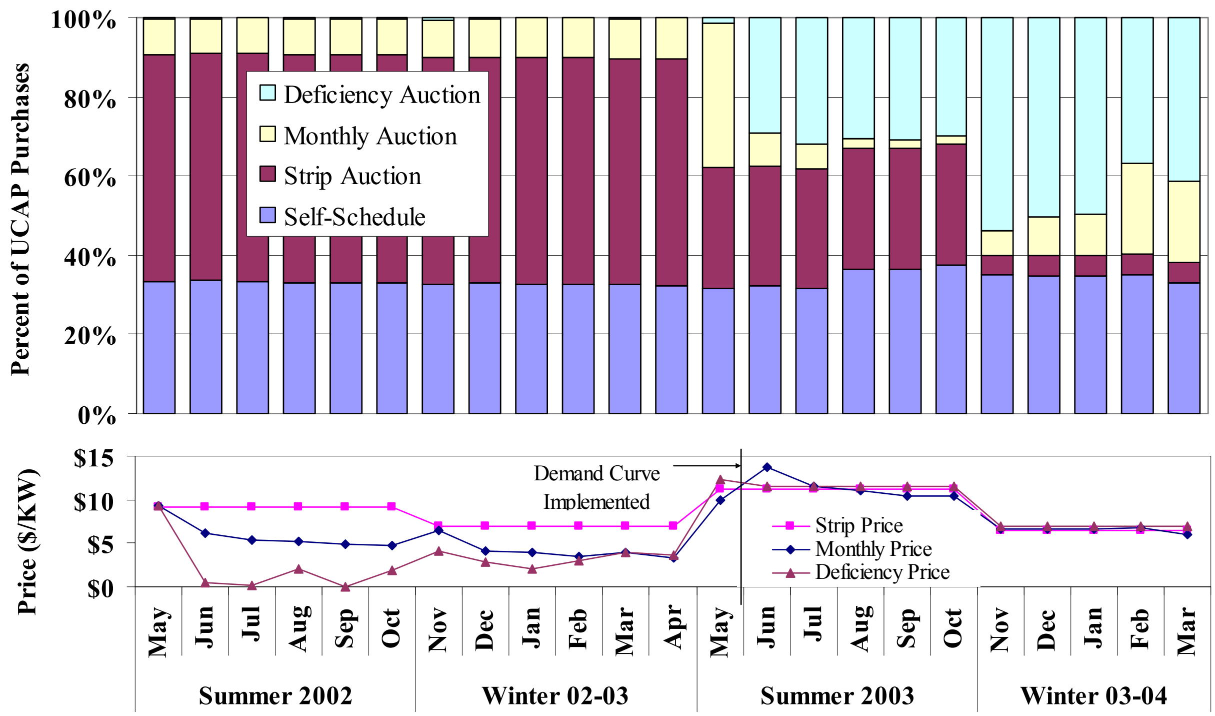
16 There are 3 areas: Long Island, New York City, and the rest of New York State.

Figure 36: Unforced Capacity Market – Rest of State



This figure shows that the capacity demand curve stabilized the capacity prices and substantially improved the consistency of prices in the strip, monthly, and deficiency auctions. The capacity demand curve also caused a larger share of the capacity to be sold in the deficiency auction, where previously the small volumes purchased had contributed to erratic prices in this auction. Overall, the capacity prices were not substantially higher following the implementation of the demand curve. Capacity prices in the strip auction, where most capacity is sold or self-scheduled, decreased slightly in the summer 2003 from the prior year and increased slightly in the winter 2003-2004 from the prior year. Figure 37 provides similar data for New York City.

Figure 37: Unforced Capacity Market – New York City

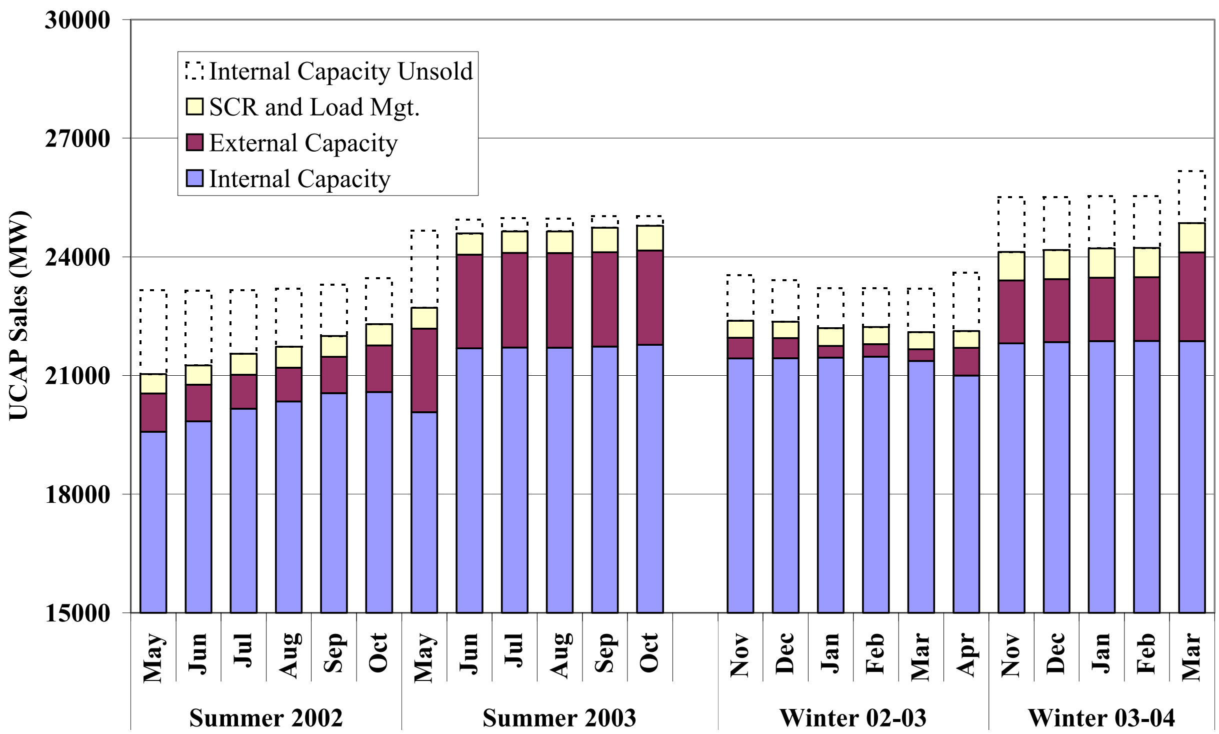


As in the upstate capacity markets, this figure shows that prices in the three auctions converged following the implementation of the demand curves. Prices were higher in summer 2003 as the City's capacity level was at its minimum required level and purchases in the deficiency auction displaced purchases in the strip auction.

One of the reasons for implementation of a capacity demand curve was to minimize the uncertainty surrounding the capacity market. The convergence and stabilization of UCAP prices is an expected and positive development. The economic signals sent by the capacity market will not have the desired effect in guiding new investment if the signals are subject to substantial uncertainty over the longer-run, causing investors to discount the capacity market signals.

The following analyses in Figure 38 and Figure 39 show the results of the capacity market over the past four capability periods (from May 2002 to March 2004). The corresponding capability periods before and after implementation of the ICAP Demand Curve (i.e. summer 2002-2003 and summer 2003-2004) are juxtaposed to provide a direct comparison of the purchases before and after the demand curve. These figures show the source of UCAP supplies before and after the implementation of the capacity demand curve in the rest-of-state and New York City. The amounts shown in this figure include all capacity sold by New York capacity suppliers into the New York capacity market. The hollow portion of each bar represents the in-State capacity not sold in any market.

Figure 38: UCAP Sales – New York State



In New York State, the capacity demand curve contributed to higher purchases in the rest-of-state. The capacity demand curve resulted in additional purchases in the summer 2003 of 2200 to 2500 MW. In the winter, the demand curve resulted in slightly higher purchase ranging from 2500 to 3300. The additional purchases in the winter are due to the higher unit ratings during the winter months that increase available UCAP supplies.

The figure also 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. The share UCAP provided from external sources increased in 2003. The higher and more stable prices due to the capacity demand curve seems to have encouraged exports of UCAP to New York from external sources.

Figure 39: UCAP Sales – New York City

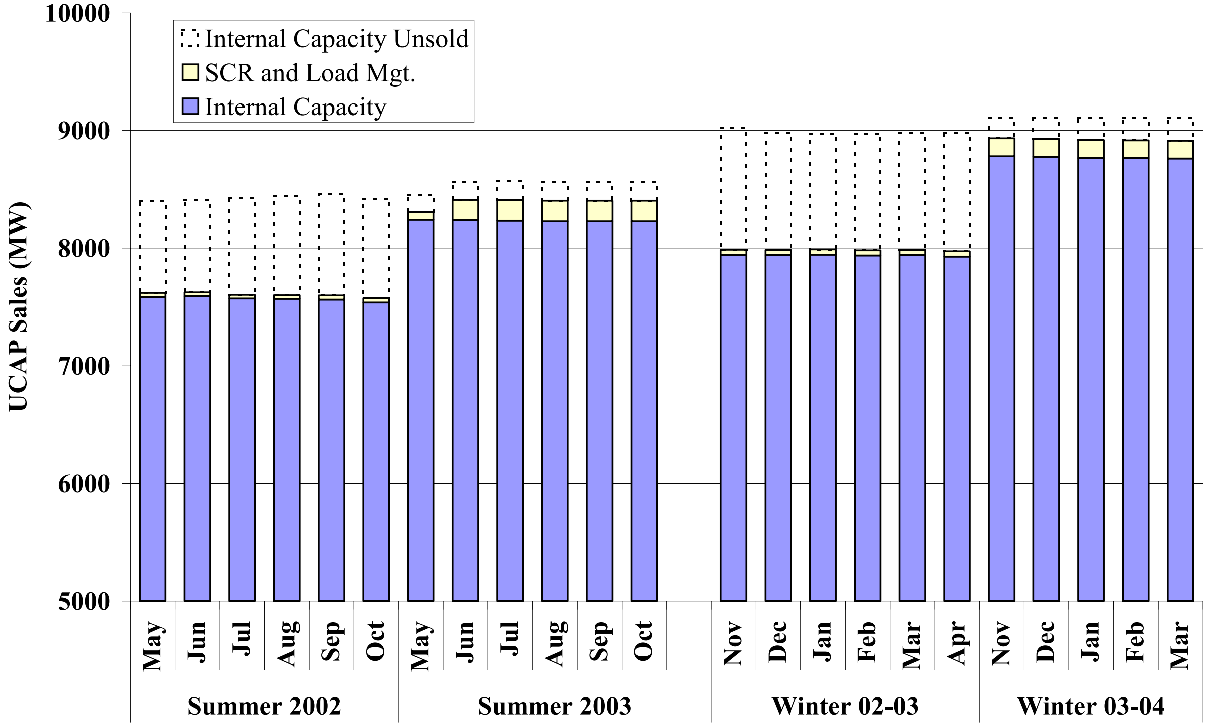


Figure 39 shows that capacity purchase in the City increased significantly. These increases were largely due to increased requirements in the City rather than the demand curve. In the summer 2003, virtually no additional capacity was purchased under the demand curve because the City was close to a capacity deficiency. In the winter 2003-2004, some excess capacity existed because of the increase in unit ratings, which resulted in additional capacity purchases under the demand curve of 570 MW. Virtually all of the internal capacity in the City was sold, in contrast to the prior capability periods.

VI. 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 utilization of the interfaces. While the interfaces are still not fully-utilized, this section shows that trading has improved as a result of several market design changes. Although there have been improvements, further changes should be made that will remedy the lack of efficient price convergence at these "seams" between control areas.

In particular, I encourage the NYISO to continue working with ISO New England to develop the Virtual Regional Dispatch to enable the two markets to realize many of the benefits of a larger control area. PJM is currently working with the Midwest ISO to develop coordination procedures that could serve as a model to implement between PJM and New York. Hence, it is reasonable for New York to focus on the New England interface and work with PJM when it completes its work with the Midwest ISO.

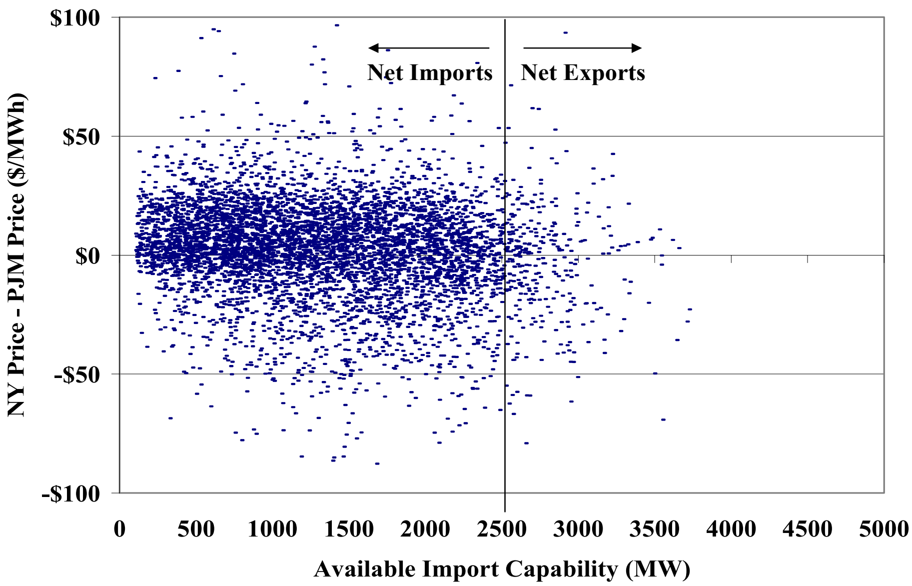
Price convergence occurs when the energy prices at the border are equal in the absence of transmission congestion. In real-time, it has proven difficult for the adjacent markets to achieve price convergence by relying on transactions scheduled by market participants. Uncertainty, imperfect information, 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. Interchange between New York and Other Markets

Absent transmission constraints, trading should occur between neighboring markets to cause prices to converge. 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 in Figure 40 show the relative differences in prices between New York and neighboring markets and the corresponding power flows between the markets.

Figure 40: Difference between NY and Adjacent Markets Real-Time Prices

Difference Between West Zone and PJM Price*
Real-Time Prices vs. Hour-Ahead Schedules
Unconstrained Hours - 2003

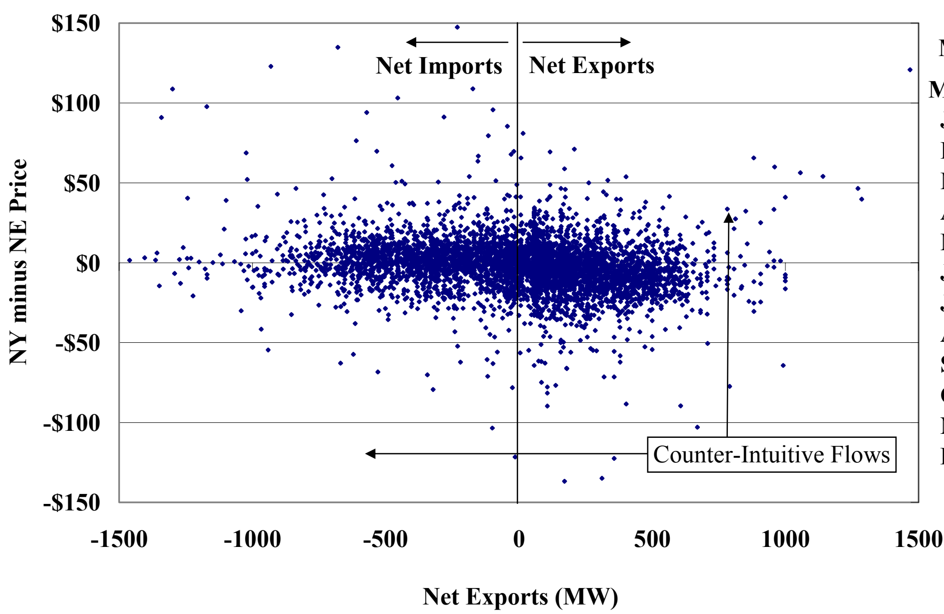


Monthly Price Statistics

Month	Mean	Std Dev
Jan	-$0.14	$22.61
Feb	$8.45	$32.61
Mar	$0.76	$34.75
Apr	$2.19	$28.45
May	$3.80	$15.46
Jun	$4.34	$19.28
Jul	-$4.43	$20.12
Aug	$4.07	$31.30
Sept	$6.41	$14.89
Oct	$9.04	$15.03
Nov	$1.74	$20.42
Dec	$0.10	$18.93

* PJM Western Hub Price

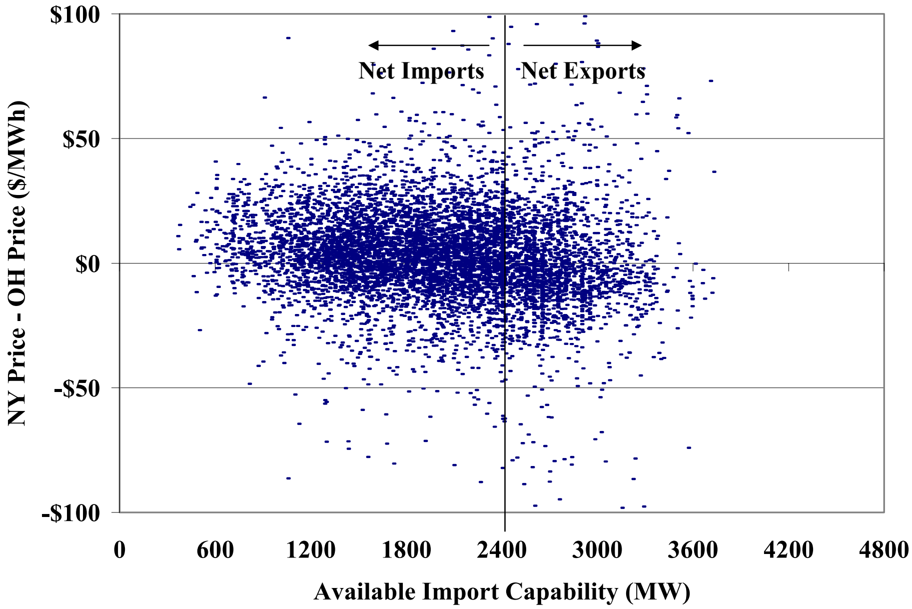
Price Difference Between New England and Eastern New York
Real-Time Prices and Net Export Schedules in Unconstrained Hours
March to December 2003



Monthly Price Statistics

Month	Mean	Std Dev
Jan	N/A	N/A
Feb	N/A	N/A
Mar	-$1.78	$30.53
Apr	$6.21	$28.18
May	-$5.24	$16.49
Jun	-$3.11	$16.93
Jul	$0.77	$11.33
Aug	$4.10	$18.94
Sept	-$0.71	$11.77
Oct	-$0.34	$12.59
Nov	-$7.37	$15.86
Dec	-$7.28	$14.38

Difference Between West Zone and Ontario Price*
Real-Time Prices vs. Hour-Ahead Schedules
Unconstrained Hours - 2003



Monthly Price Statistics

Month	Mean	Std Dev
Jan	$5.15	$21.69
Feb	$1.66	$34.52
Mar	$2.27	$30.89
Apr	$0.53	$28.35
May	$5.06	$17.18
Jun	$6.19	$18.14
Jul	$10.12	$13.13
Aug	$9.27	$29.79
Sept	$1.97	$14.54
Oct	-$4.81	$15.24
Nov	$0.26	$17.98
Dec	$1.89	$16.07

The vertical axis in each figure shows the hourly difference between the price in New York and the price in the adjacent region. The top half of each figure, therefore, reflects hours when the price in New York was higher than the price in the neighboring region. The horizontal axis shows available import capability into New York from the adjacent region. Available import capability is total transfer capability minus net scheduled imports. Therefore, when the NYISO is exporting (net scheduled imports are negative), the available import capability will exceed the total transfer capability. In other words, when power is being exported from New York, the available import capability on an incremental basis is greater than the physical transfer capability because participants may counter-schedule imports against the prevailing exports.

The vertical line intersecting the horizontal axis represents the approximate total transfer capability level for each interface. Hence, the two right quadrants represent net exports while the two left quadrants show net imports. 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. 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.

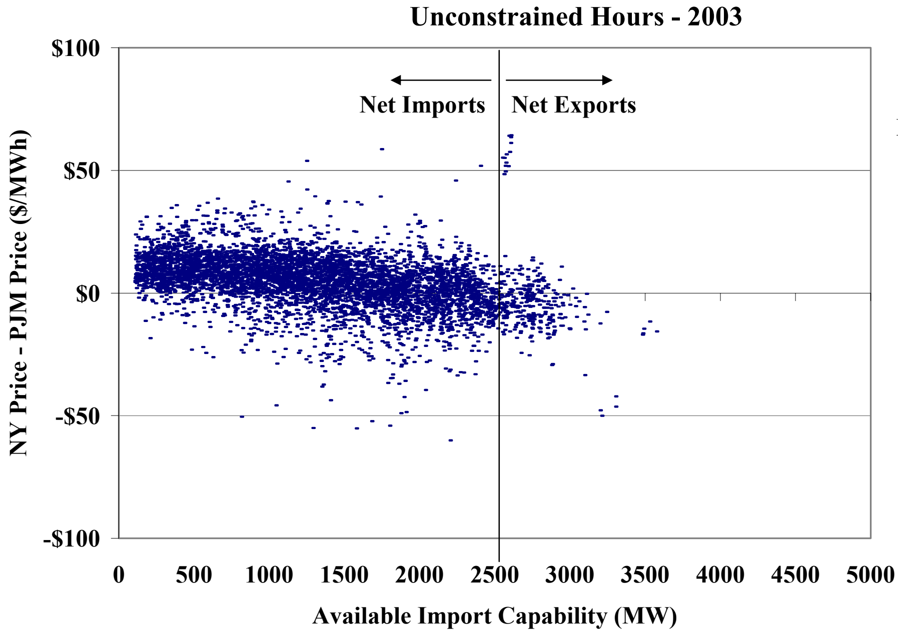
These figures show that the markets are not well arbitraged. The dispersion in prices during unconstrained hours is shown to be considerable. In a significant number of hours for each interface, power is scheduled from the high-priced market to the lower-priced market. These results are similar to results presented in prior years. Some had expected the introduction of the SMD markets in New England in March 2003 to substantially resolve these issues between New York and New England, but this has not been the case. Although SMD is a significant improvement because it establishes accurate locational prices, including prices at the border with New York, it does not address the underlying factors that cause the markets to be poorly arbitraged.

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 substantial transmission fees and other 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. FERC has recently required that the export fees between New England and New York be eliminated, which should address this factor. Last, risks associated with curtailment and congestion will reduce participants' incentives to engage in external transactions at small price differences.

In addition to the real-time price difference shown above, we also examined the price differences between PJM and New York in the day ahead. This analysis is shown in Figure 41.

Figure 41: Difference between West Zone and PJM Day-Ahead Prices



Monthly Price Statistics

Month	Mean	Std Dev
Jan	-$0.49	$11.01
Feb	$10.03	$11.36
Mar	$1.31	$16.37
Apr	$2.59	$9.77
May	$2.56	$7.28
Jun	$3.99	$11.09
Jul	-$0.89	$11.59
Aug	$7.89	$13.56
Sept	$8.61	$5.96
Oct	$11.44	$6.92
Nov	$5.03	$6.27
Dec	$3.72	$8.17

* PJM Western Hub Price

This figure shows that prices are not efficiently arbitraged in the day-ahead, though the reduced volatility in prices in the day-ahead markets contributes to a tighter dispersion of the prices. The monthly standard deviations of the price difference are much lower in the day-ahead market than in the real-time market. Although the day-ahead markets exhibit better convergence, the general trends shown in the figure above are similar to those observed in Figure 40.

B. Scheduled Interchange by Hour of Day

We also examined the temporal pattern of imports and exports to and from the New York markets. Figure 42 and Figure 43 show how real-time imports vary across an average day from different adjacent regions.

Figure 42: Average Net Imports from LMP Markets by Hour of Day
Weekdays 2003

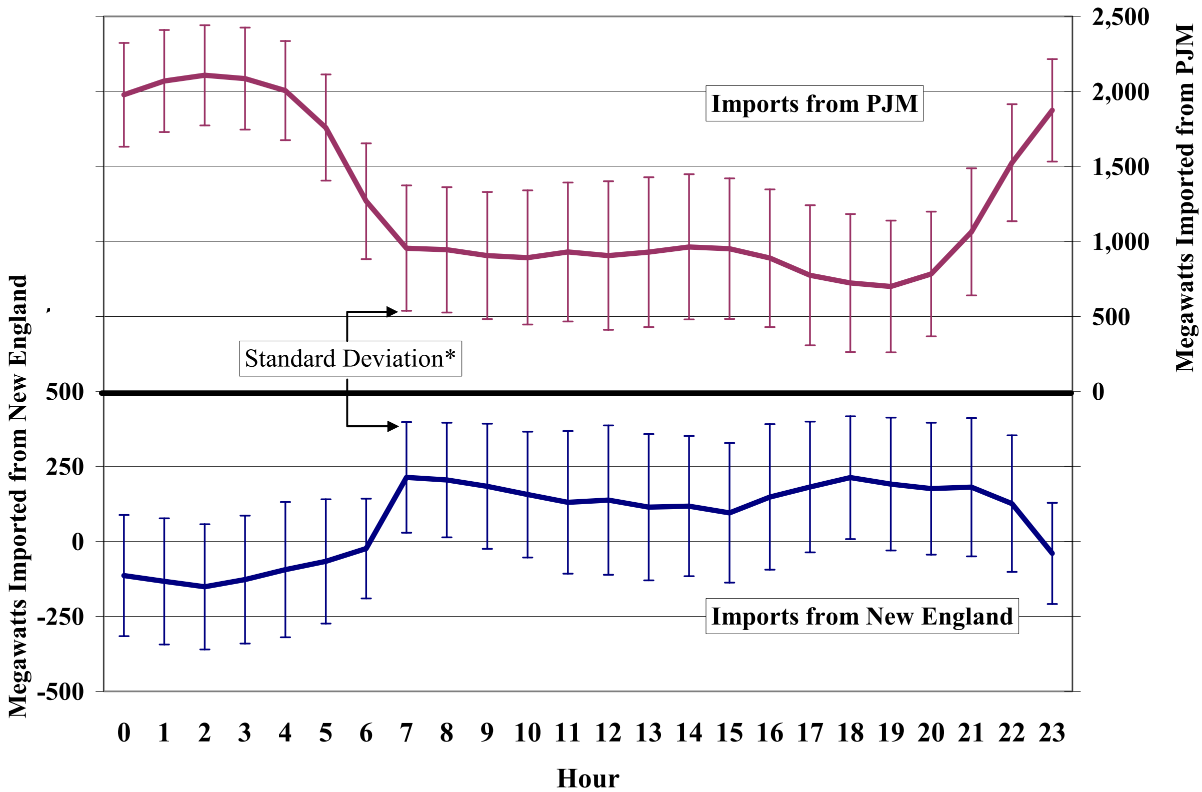


Figure 42 shows that imports from PJM are highest during the night-time hours, while New York is a net exporter to New England during this period. During the day, New York imports from both regions. Though PJM exports a smaller quantity to New York during the day than at night, it is still much larger than supply obtained from New England. Although the interface capability is smaller and trading activity is lower with New England than with PJM, trading with New England is more economically significant because New England exports serve the congested Eastern New York area. However, in the overwhelming majority of instances, only a small portion of the interface capability is being used, even in hours where there are substantial price differences.

The figure also shows that there is a substantial change in the average interchange in hours 6 and 22. This suggests that a significant portion of the interchange is scheduled under bilateral contracts, which are commonly traded for the 16 hour peak period from hours 6 to 22. Many of these schedules tend to be insensitive to real-time prices and contribute to the price divergence.

Figure 43: Average Net Imports from Canada by Hour of Day
Weekdays 2003

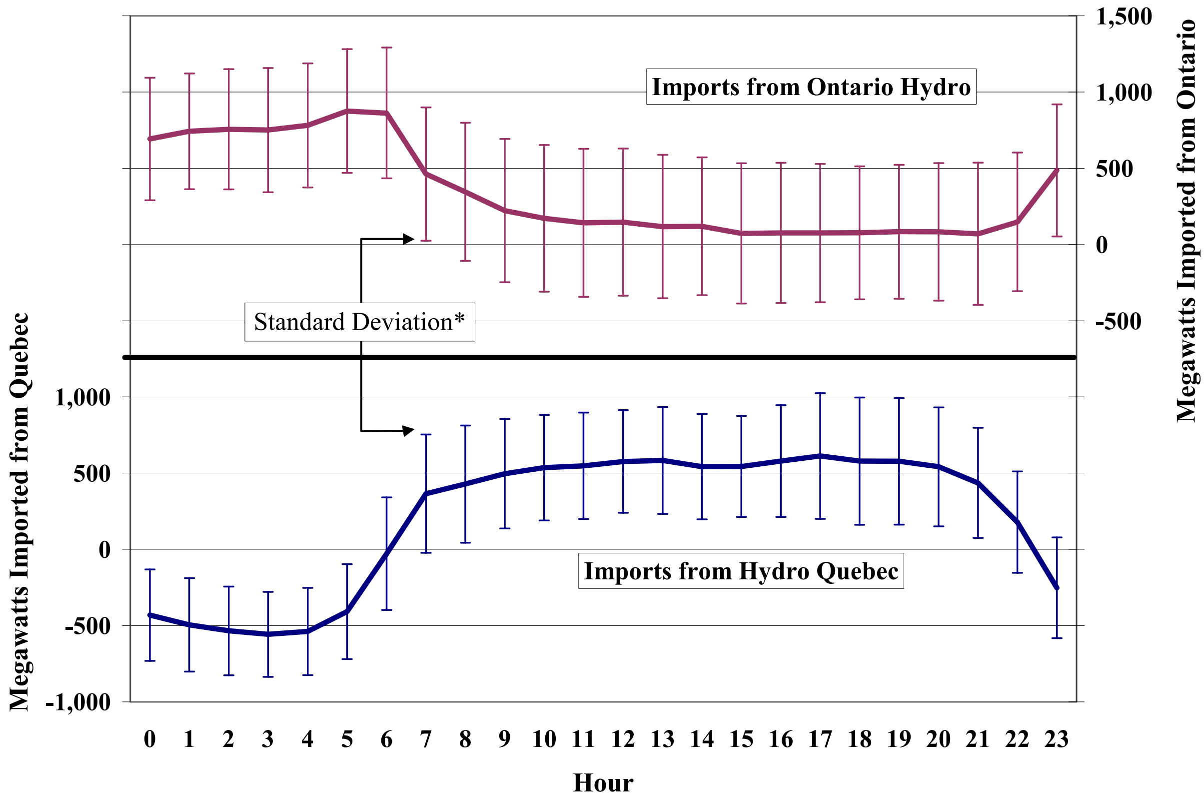


Figure 43 shows that Hydro-Quebec is a net importer at night from New York in quantities that are comparable to net imports into New York from Ontario. During the day Hydro-Quebec exports substantial quantities of power to New York while imports from Ontario fall close to zero. Again, the change in schedules that occurs during the 16 peak hours is consistent with most schedules being made to support longer-term bilateral agreements (rather than arbitrage of hourly prices).

C. Conclusions and Recommendations

Over the past several years, modeling improvements and rule changes have led to substantial declines in price differences between control areas during non-transmission constrained hours. Our analysis indicates that the economic scheduling process is functioning properly. However, significant price differences remain in hours where no congestion is present.

These results reinforce the importance of addressing seams issues that remain. One change that will improve the arbitrage with the adjacent markets is to eliminate the export fees on external transactions. We also continue to encourage New York and New England to develop and implement VRD.

VRD is a process where the ISOs would adjust the physical interchange in small increments every 5 to 15 minutes based on the prices at the interface between the two markets. These adjustments would ensure that the interchange levels are efficient, eliminating the price distortions and other inefficiencies caused by poor market arbitrage. In principle, this process is comparable to the ISOs' determination of the flows over internal interfaces based on generator and load bids. VRD will lead to less volatility and more predictability in the New York to New England prices.

VII. ANCILLARY SERVICES

A. Background

In conjunction with the day-ahead and real-time energy markets, the NYISO also operates ancillary services markets. These include three operating reserve markets and a regulation market. This section reviews the competitive performance of these markets and the issues that have arisen over the past year. This section also summarizes the modifications that have been introduced to improve the performance of these markets, modifications that will be implemented in the future, and recommendations for additional improvements.

New York procures three types of operating reserves: ten-minute spinning reserves, ten-minute total reserves (can be spinning or non-synchronous 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.

New York also purchases regulation services, 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.

The NYISO receives availability offers from each generator that indicate the minimum price they are willing to accept to provide each reserve product. The marginal cost of procuring reserves includes both the availability offers and the opportunity costs in other markets (i.e., holding economic resources out of the energy market is part of the costs of maintaining operating reserves). Both of these costs are considered in the simultaneous optimization of the reserve designation and energy dispatch. However, reserve prices are set in each market by the highest accepted availability offer – while opportunity cost payments are made to the providers of regulation and spinning reserves in the real-time market and to the providers of ten-minute non-spinning reserves in the day-ahead market. Currently, the NYISO operates only a day-ahead market for reserves, although it reallocates the reserves hourly during the operating day.

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). Consequently, the NYISO may purchase up to 600 MW of 30-minute reserves. There is no limit on how much spinning reserves is purchased – all 1200 MW of total ten-minute reserves (indeed, all 1800 MW of the total operating reserves) could be spinning reserves. Hence, ten-minute spinning reserves are the highest-valued reserve while 30-minute reserves are the lowest-valued reserve.

The reserves markets are cleared simultaneously with the energy market to minimize total bid-production costs. In this process, the price for lower-valued reserves often clears below the price for higher-valued reserves. For example, the ten-minute non-spinning reserves price generally clears below the price of ten-minute spinning reserves because the ISO must purchase reserves from more expensive spinning reserve units to meet the 600 MW spinning reserve requirement.

The procurement of reserves is also subject to locational requirements to ensure that they will be fully available to respond to possible system contingencies. The most congested interface in the state is the Central-East Interface. Because of this constraint, maintaining reliability requires that a substantial portion of the reserves be procured in Eastern New York. Likewise, the interface between Long Island and the rest of New York has resulted in a requirement that specified amounts of operating reserves be purchased from generating units on Long Island.

For total ten-minute reserves (spinning and non-spinning) 1000 MW must be purchased east of the Central-East constraint, including at least 300 MW of 10 minute spinning reserves. Prior to 2002, the eastern requirement was 1200 MW. However, it was lowered to 1000 MW after the NYISO and ISO-NE entered into a reserve-sharing agreement. The locational reserve requirements for Long Island oblige the NYISO to designate at least 60 MW of ten-minute spinning, 120 MW of total ten-minute, and 540 MW of total reserves (ten-minute and 30-minute) on Long Island.

The NYISO sets prices for reserves that can vary for Western New York, Eastern New York, and Long Island when the locational reserve requirements are binding. This change allows reserve prices to be set by the marginal reserve supplier to satisfy each of these locational reserve requirements. The primary result of this locational pricing is that higher prices for the ten-minute reserves will emerge in the East when the locational requirements are binding.

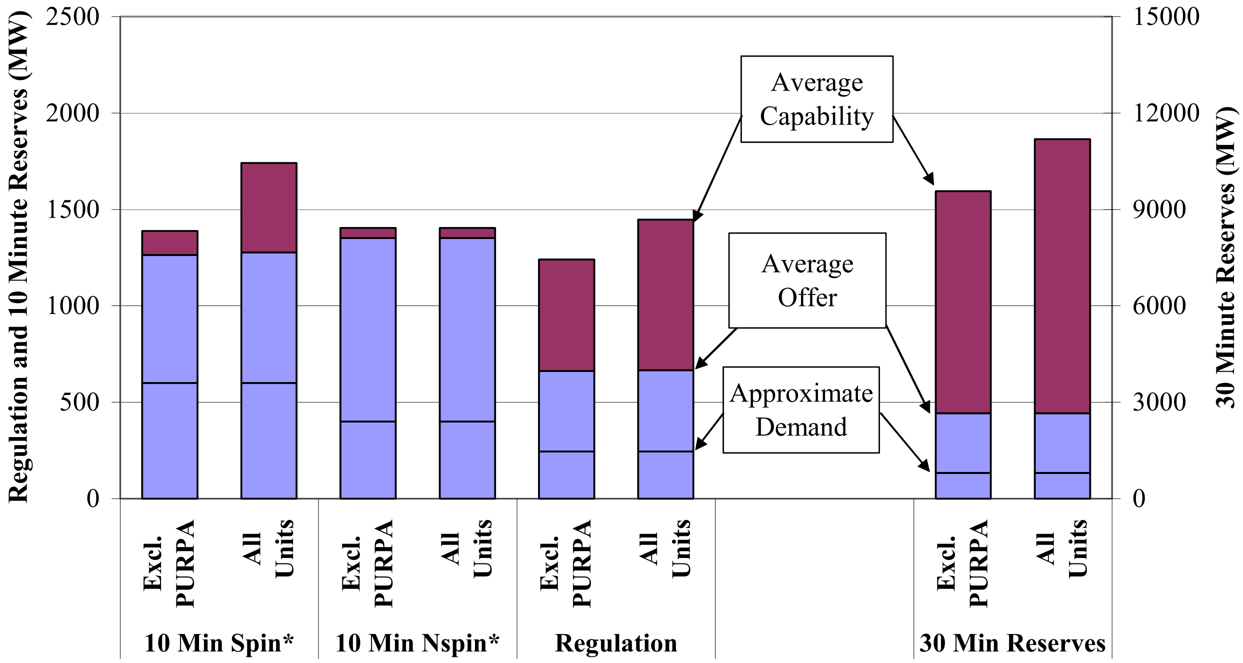
Regulation capability can be purchased from anywhere within the New York Control Area. The NYISO purchased 275 MW of regulation during high-ramp hours and 200 MW during low-ramp hours in 2003. The amount of regulating capability a generating resource may sell is equal to the amount of output it can produce 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 and have the ability to ramp at a rate of 1 percent of the unit's total capability per hour.

B. Offer Patterns

Our findings in previous analyses in New York have indicated that a substantial portion of the capability of certain services is not offered in the day-ahead ancillary services markets, particularly for 30-minute reserves and regulation. Offering into the ancillary services markets is not mandatory, with the exception the ten-minute non-spinning reserves in Eastern New York. This section reassesses the ancillary services offer patterns to determine whether participation in this market has improved.

Figure 44 summarizes the average levels of capacity, offers to supply, and demand for all three day-ahead reserves products as well as demand for the day-ahead regulation service. Because of the nature of the locational requirements, ten-minute reserves are shown only for the region east of the Central-East Interface. In addition, the results of this analysis are shown with and without the PURPA units because a large portion of this capacity may be contractually limited from supplying the reserves markets.

Figure 44: Ancillary Services Capability and Offers



*Eastern side of the Central-East Interface only

Ancillary services markets are generally not tight because offers to supply typically exceed approximate demand. The figure shows that:

- For 30 minute reserves, offers typically exceed approximate demand by 230 percent.
- For total 10-minute reserves (spinning and non-spinning) east of the Central-East interface, offers typically exceed approximate demand by 160 percent.
- For regulation and 10-minute spinning reserves, offers typically exceed approximate demand by 100-170 percent – but this ignores the fact that some 10-minute spinning reserves can be purchased in the West.

However, since these markets are jointly optimized and the same resources are offered in multiple markets, energy and other ancillary services markets can bid resources away from a given service resulting in relatively tight conditions.

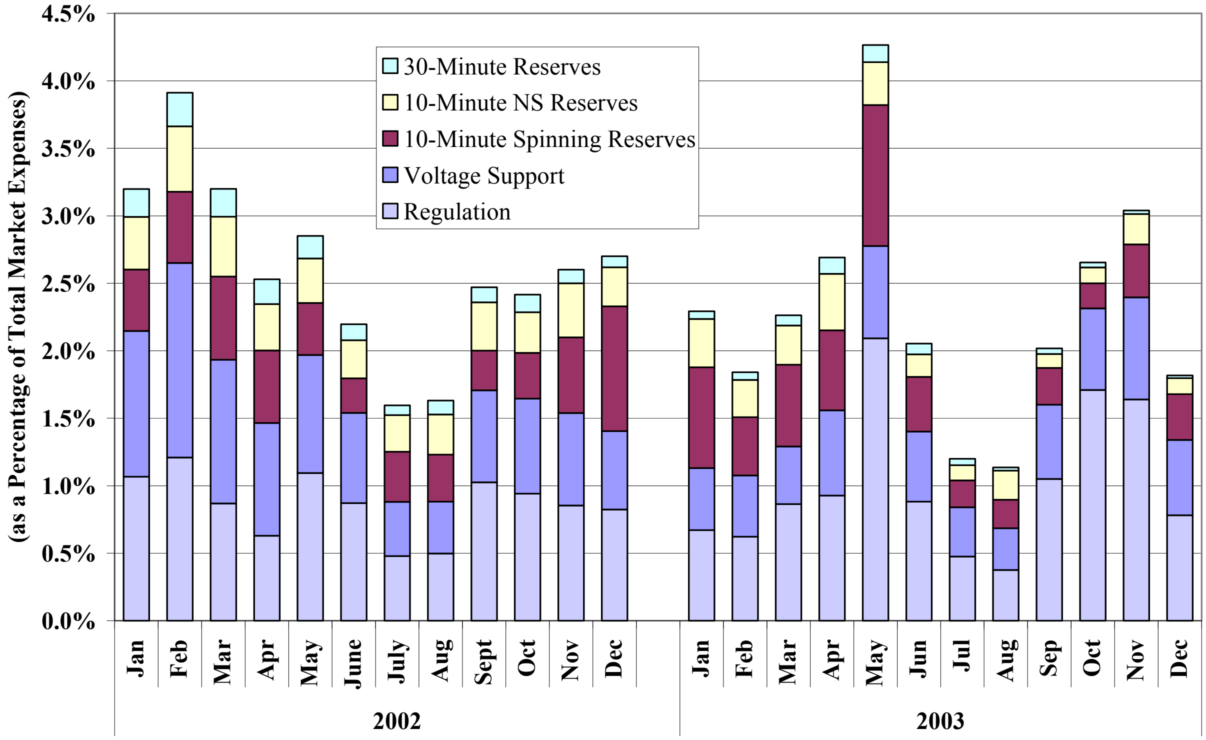
The figure shows good participation in the ten-minute spinning reserves market with nearly all non-PURPA units offering their full ten-minute spinning capability. The offer level in the ten-minute non-spinning reserve market remains the highest of all of the markets due to the offer requirement imposed in 2000 with the $2.52 per MWh offer cap. On July 1, 2003, the FERC accepted the NYISO's proposal to end the $2.52 per MWh offer cap on ten-minute non-spinning reserve. Non-spinning reserve suppliers remain subject to the mandatory offer requirement, which decreases the potential for physical withholding. In addition, the reference levels used for assessing offers are limited to either the lower of the bid-based values or $2.52/MW.

However, participation in the regulation and 30-minute reserves markets remains relatively poor. The average quantity of regulation being offered to the market is approximately one-half of the total capability, and the average quantity of 30-minute operating reserves being offered is approximately one quarter of the total capability. Generally, this is not a significant concern given the excess reserve and regulation capability that is available. However, under peak load conditions, a large amount of capacity is purchased for energy in the day-ahead market and can cause tight conditions in the day-ahead ancillary services markets.

C. Ancillary Services Expenses

Figure 45 shows the ancillary services expenses, which include expenses for regulation, voltage support, and operating reserves. These expenses tend to be smaller as a percent of total market expenses in the summer than in other seasons because of the relatively high energy prices during the summer.

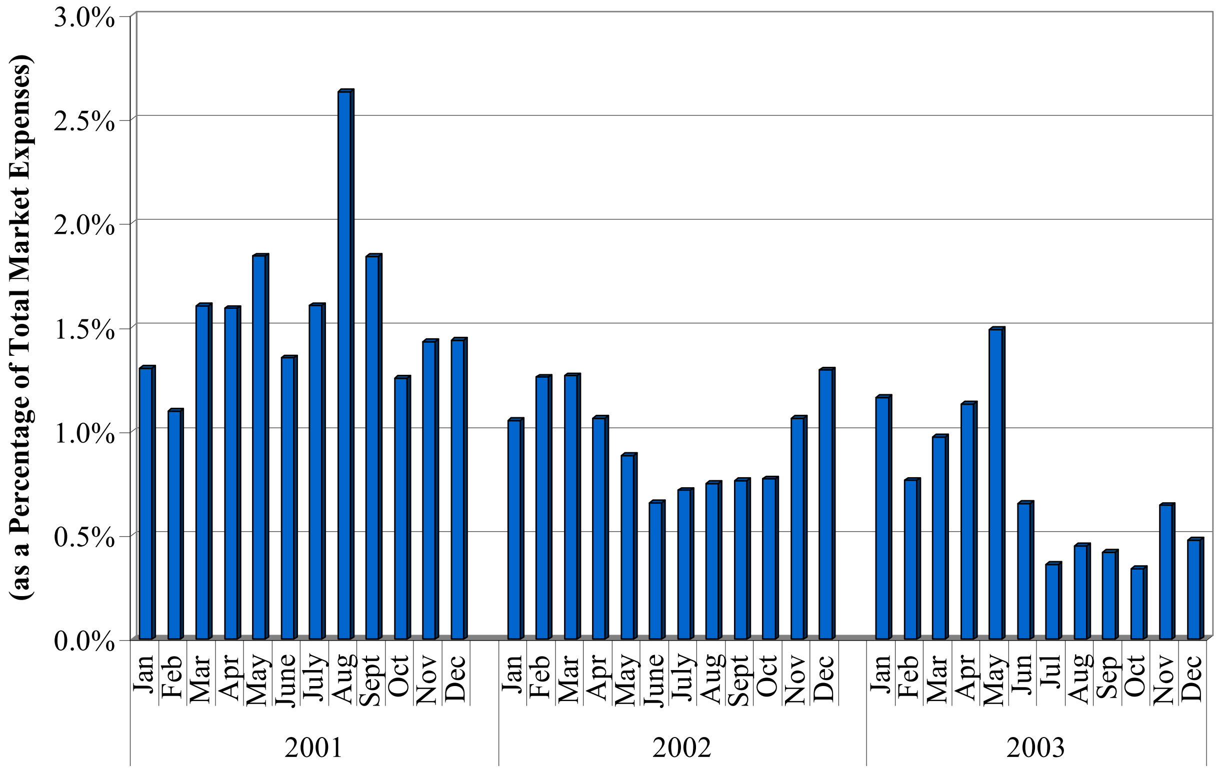
Figure 45: Ancillary Services Costs
2002 - 2003



Overall, ancillary services expenses declined slightly from 2002 to 2003 as a percentage of total market expenses. In absolute terms, however, ancillary services expenses increased by $20 million to a total of almost $130 million. The decrease in expenses as a percentage of total market expenses occurred because increases in fuel prices had a larger effect on the energy market expenses than on the ancillary services expenses. The increased costs of ancillary services was due to the higher prices for regulation and 10-minute spinning reserves, both which were affected by higher fuel costs. Prices of 10-minute non-spinning reserves declined even after the removal of the $2.52 bid cap.

To focus more directly on the costs of operating reserves, Figure 46 shows operating reserves costs as a percentage of total market expenses on a monthly basis in 2001 through 2003.

Figure 46: Expenses for Reserves Procurement 2001 - 2003



This figure shows that expenses for reserves were slightly higher in 2003 than in 2002, but remained lower than in 2001. Reserves costs accounted for 1.7 percent of total market expenses in calendar year 2001, but this dropped to 0.9 percent in 2002 and 1.0 percent of total market expenses in 2003. The actual increase in reserve costs was about $2 million or 4.6 percent of 2002 levels. The cost of 10-minute spinning reserves rose by 27 percent, because of higher natural gas prices, but costs for 10-minute non-spinning reserves fell by 10 percent, and 30-minute reserve costs fell by 40 percent, due to fewer peak periods with high reserve prices.

The decline in reserve costs since 2001 can be attributed to three market design changes. The reserve-sharing agreement with ISO-NE permitted a reduction in the ten-minute reserve requirement for the East (from 1200 MW to 1000 MW), although the state-wide requirement is still 1200 MW. Locational ancillary services prices for Long Island, Eastern New York (excluding Long Island), and Western New York limited the impact of reserve shortages in constrained areas on state-wide reserve prices. Changes in the BME model to recognize latent

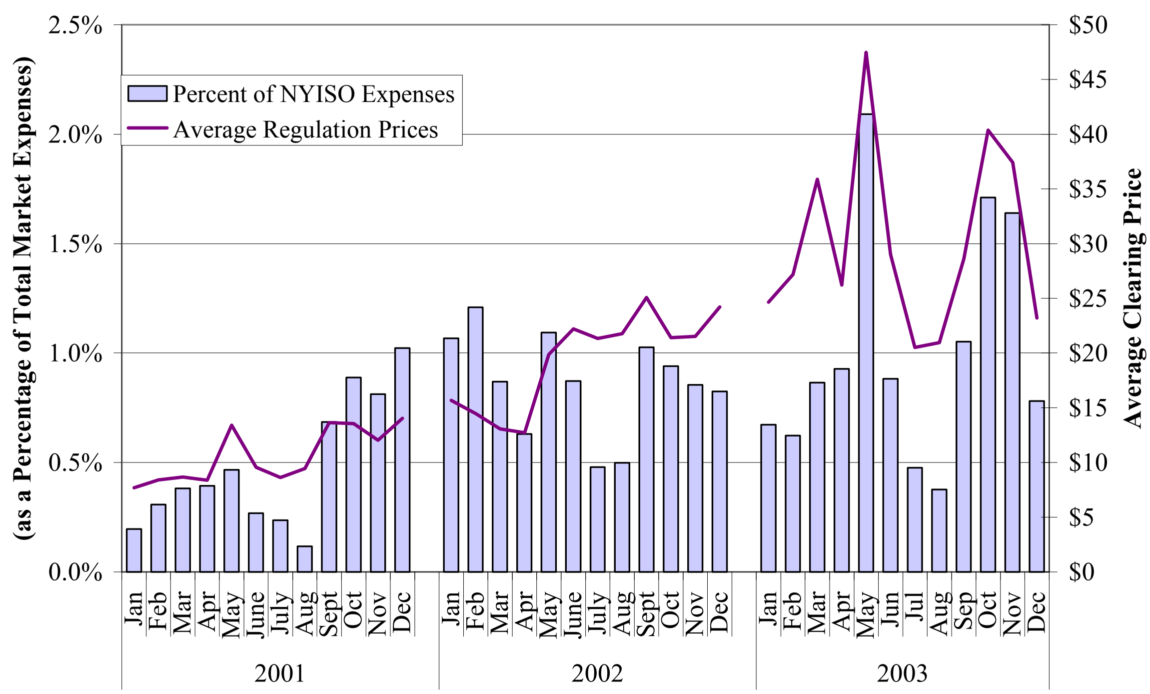
30-minute reserves on un-dispatched portions of on-line resources, resources that are available to the real-time model for energy but did not submit a 30-minute reserves availability bid, prevents the BME model from setting irrationally high prices for reserves when plenty of 30-minute capability is available.

We expect further improvements with the implementation of RTS, as the multi-settlement system for reserve procurement eliminates additional costs incurred in today's market. More efficient pricing of reserves in scarcity conditions will likely increase total reserve costs, despite cost reductions due to other RTS improvements. This is an important feature of the RTS operating reserves markets because it provides the necessary economic signals to attract and retain resources that are primarily needed to meet the NYISO's reserve requirements, such as gas turbines.

D. Regulation Market

This subsection focuses on the regulation market, which is the only market-based ancillary service that is not a type of operating reserve. Figure 47 shows the average price for regulation service from 2001 through 2003, as well as regulation's share of the total market expenses.

Figure 47: Average Clearing Price and Expenses for Regulation Procurement 2001 - 2003



This figure shows that regulation prices have increased considerably over this period. The primary reason for this increase was a change to SCUC and BME in May 2002. This modeling change was made to recognize that units' minimum generation level may limit the range in which a unit can regulate down. This reduced the supply available on some units, particularly in off-peak hours. Previously, units could be scheduled with unequal amounts of up-regulation and down-regulation, whereas now units must be scheduled for equal amounts. For example, a generator with an energy schedule of 100 MW, a minimum generation level of 50 MW, and a maximum capacity of 200 MW, is limited to providing 50 MW of upward regulation (because this is the maximum downward regulation amount) although it is capable of providing 100 MW. This constraint on assigning regulation will not exist after the implementation of RTS. The second factor that contributed to the rise in regulation prices is that regulation offer prices during off-peak hours have increased modestly.

Nonetheless, regulation costs still remain a relatively low portion of the total electricity market expenses for the NYISO (little more than 1 percent). Regulation prices are not highly correlated with energy prices. Hence, the figure shows that when total market expenses rise during the summer, regulation accounts for a smaller share of total market expenses. In addition, the cost of providing regulation is not as directly affected by fuel prices as are energy prices. Higher fuel prices can increase opportunity costs to provide regulation and raise regulation prices, but this effect does not explain a large portion of the higher regulation prices in 2003. The two periods with the highest regulation prices in 2003 (May and in the fall) occurred when fuel prices were not peaking.

E. Changes in Reserve Markets

The implementation of RTS in 2004 will lead to major changes in the markets for reserves and regulation. The multi-settlement system for the reserve and regulation markets will eliminate additional costs due to re-optimization or procurement of replacement services in real time. Under the multi-settlement system, real time ancillary services schedules will be settled against the day-ahead schedules. Since suppliers are liable for the real-time cost of reserves that they schedule day ahead, they will have an incentive to be available in real time and to perform when called.

Reserve market clearing prices will be set in both the day-ahead and real-time markets on a locational basis using the shadow prices of the reserve constraints out of the SCUC and RTS models. Both day-ahead and real-time clearing prices of ancillary services will cover the lost opportunity cost of the marginal supplier (i.e., the supplier with the lowest energy bid and, thus, the highest opportunity cost). This is intended to give price incentives to the lowest cost reserve providers to provide reserves rather than energy, and eliminate the need for separate lost opportunity cost payments currently recovered through uplift charges.

Regulation suppliers will submit availability offers for both the day-ahead and real-time regulation markets. Availability offers for reserves may only be submitted in the day-ahead reserve markets. However, if no reserve offer is submitted, a $0 offer is assumed. Real-Time availability offers for reserves are fixed at $0. Hence, all “On-dispatch” and Self-Committed Flexible resources (including eligible demand side resources), that submit energy offers will be considered for reserve scheduling in real time. The FERC, in its February 11, 2004 order accepting the RTS filing, conditionally accepted the proposed default availability bid of $0 as a reasonable amount for suppliers that submit energy offers in the day-ahead market, subject to the restriction that the default availability bid applies only to ICAP suppliers.

Reserve and regulation market clearing prices under RTS in both the day-ahead and real-time markets are set on an locational basis, equal to the shadow price of each type of reserves and regulation (i.e., the marginal cost of the reserve including generators’ lost opportunity costs). Real-time reserve schedules are settled at each real-time dispatch interval. The multi-settlement system for reserve and regulation services provides an incentive to perform to the schedule, and should contribute to a reduction in uplift costs.

In the RTS design, the current reserve shortage scarcity pricing provisions will be superceded by the reserve demand curve. There will no longer be special energy pricing rules invoked when there is a persistent 10-minute reserve shortage. Instead, the demand curves establish an economic value for reserves that will be reflected in energy prices at times when the energy market must bid scarce resources away from the reserve markets. The total value of a reserve in a location will be 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 will generally include the sum of the demand curve values of the lower quality reserves. 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. A reserve demand curve will be applied to each of the nine reserve constraints in the New York Control Area. The reserve demand curves will be applied consistently in the day-ahead and real-time markets.

VIII. Demand Response Programs

There are currently three demand response programs in New York State -- the Emergency Demand Response Program, the Special Case Resource program, and the Day-Ahead Demand Response Program. The EDRP and the SCR programs can contribute substantial demand-side resources to the market. This success is the result of the pricing incentives that induce a high-level of participation and contribute to efficient pricing in time of shortage. However, the day-ahead demand response program has not resulted in substantial quantities of real-time demand reductions.

A. EDRP and SCR

1. Background

The EDRP and SCR programs are among the most effective of their kind in achieving actual load reductions during peak conditions. The total registered quantity of more than 1700 MW is much larger than comparable programs in other ISOs. EDRP and SCR resources were utilized only during the two-day restoration period after the blackout (August 15 and 16) in order to limit demand as the system was restored to full power. For various reasons that are identified below, the response rates for these resources were relatively low on these days (ranging from 470 MW to 800 MW). Nevertheless, even these quantities are relatively large compared to actual load reductions achieved by similar programs.

The success of these programs is largely due to incentives provided by the programs. EDRP participants are paid the higher of $500/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/MWh) and the LBMP.[17]

[17] 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.

This payment structure satisfies two critical objectives. First, the strategy is likely to result in payments to participants that are close to or exceed $500/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.[18] 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 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.

2. August 15 and 16, 2003

Both EDRP and SCR resources were called following the blackout on August 15 and 16. At that time, there were 954 MW of registered EDRP and 757 MW of registered SCR, for a total of 1,711 MW. All EDRP and all SCR resources were called on August 15 for 14 hours and on August 16 for 8 hours. An average of 800 MW responded on August 15 and an average of 470 MW on August 16. Total costs to the system for the deployment were $5.5 million on August 15 and were $1.8 million on August 16. For August 15, the EDRP resources responded at a rate of 48 percent and the SCR at a rate of 46 percent. On August 16, the EDRP responded at a rate of 19 percent and the SCR at a rate of 39 percent.

It is typical that EDRP resources respond at a rate of about 50 percent and are modeled at such a rate in reliability studies. SCR resources typically respond at slightly more than 90 percent. The low response rates for the period August 15-16 is the result of the post-blackout circumstances. Additionally, the August 16 call occurred on a Saturday when the baseline consumption (i.e., the level against which reductions are measured during prior comparable periods) was substantially lower than a peak weekday period. Hence, the curtailment quantities would naturally be lower.

18 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.

For these two reasons, the response rates during these two days were not representative of curtailments that would be expected under super-peak demand conditions.

B. Day-Ahead Demand Response Program

While the EDRP and SCR programs have contributed to NYISO market efficiency by providing a significant amount of demand response at peak times, the day-ahead program has not been as effective. DADRP allows LSEs with curtailable load to offer such load resources into the day-ahead market in the same manner as other supply resources. If the offer clears in the day-ahead market, the LSE must curtail its load in accordance with the accepted offers and is paid day-ahead clearing price for each MW of curtailed load.

The quantities participating in this program are very low. There were 3,983 hours with day-ahead demand response bids, but the average quantity bid was less than 4 MW per hour. There were 91 hours when day-ahead demand response bids reached at least 10 MW, with a high of 12 MW, and these bids were accepted in 25 hours. The largest bids were by one company, responsible for 82 percent of all day-ahead demand response bids by volume. Participation has likely been low in this program because loads have other means to bid in the day-ahead market, including price-capped load bids and virtual supply offers. The low participation in the program is consistent with a conclusion that this program provides little additional value to participants beyond the price-capped load bidding and virtual supply capability.