# New York Market Advisor
# Annual Report on
# The New York Electric Markets

## for

## Calendar Year 2000

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Capital Economics

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## EXECUTIVE SUMMARY

Calendar year 2000 was the first full year of New York ISO operation, which has included the most ambitious implementation of competitive electricity markets attempted to date. In late 1999, the NYISO simultaneously implemented competitive day-ahead and hourly energy markets, operating reserves markets (30-minute, 10-minute spinning, and 10-minute non-synchronous reserves), a regulation market, an installed capability market, and a TCC market. The energy and reserves markets are implemented with three independent market models: one to operate the day-ahead market, one to perform hourly scheduling of external transactions and certain generating units, and one to dispatch resources in real-time. Although a number of operational issues have arisen in the implementation of these markets, the transition to competitive electric markets has been remarkably smooth given the unprecedented scope of this effort.

However, recent experience in California has shown that the costs of implementing deregulated markets that do not operate efficiently can be enormous – resulting not only in substantial economic costs for consumers, but also in real reductions in the reliability of electric supply. As some have noted, there are a number of similarities between conditions in the electric markets in California and New York:

- Both states have generation siting processes that have resulted in very few new generators entering the market over the past five years.
- Each has experienced steady load growth that has significantly outpaced the growth in new supply.
- The regulators in both states pursued an aggressive program of generation divestiture, resulting in a much larger portion of the power being sold through the market at market-based prices.

The fundamental designs of the two markets, however, are quite different. The centrally dispatched locational marginal pricing design employed in New York should provide a more stable foundation for the New York power markets. Nonetheless, as market conditions become increasingly tight, it is particularly important to closely monitor the performance of the markets to identify and address potential concerns as early as possible. The report thoroughly examines how the markets have performed during 2000 and identifies significant issues that need to be addressed going forward. This includes not only an assessment of the market outcomes and operations, as well as the conduct of market participants.

The markets in New York are designed to produce the most theoretically efficient outcomes by minimizing the bid production costs of meeting demand while setting economically efficient prices at each location to send proper signals to suppliers. However, the efficiency of these markets depends in large part on suppliers being subject to sufficient competitive discipline to compel them to offer their resources at bid prices close to their marginal production costs. Absent market power, this conduct will maximize the suppliers' profits and facilitate the efficient market outcomes described above.

Likewise, the efficiency of the markets will be compromised if load-serving entities or transmission owners bid or take other actions that influence prices or other market outcomes. Therefore, this report includes an assessment of the market participant conduct to determine whether their conduct is consistent with workable competition.

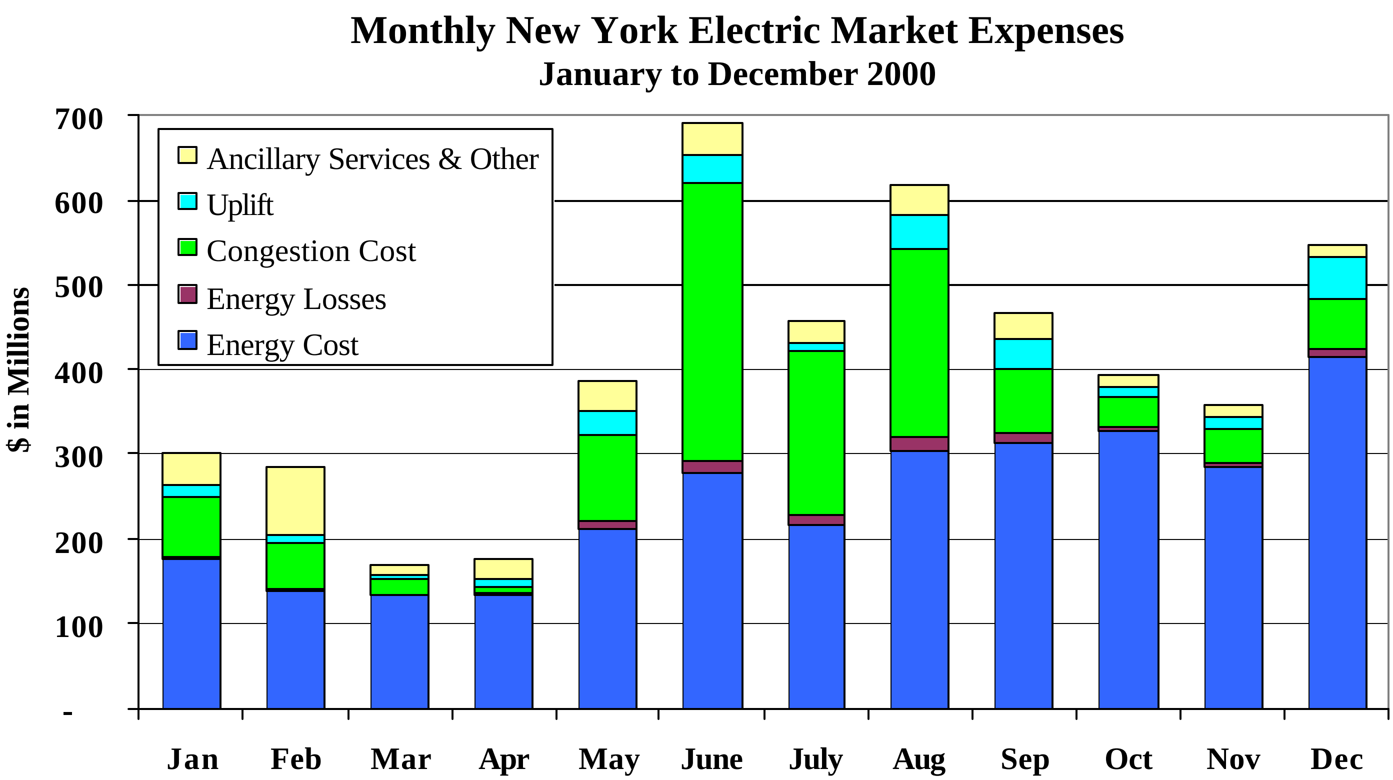
The conclusions drawn in this report include:

- The first priority for ensuring the competitiveness of the New York markets must be to facilitate the entry of new generation and investment in transmission:
  - → The inability of investors to site significant amounts of new generation in the face of growing loads will make the markets increasingly vulnerable to large price fluctuations, even without strategic withholding by suppliers;
  - → I have forecasted that summer electricity prices are likely to rise by close to 50 percent over the next four years if new generation is not built;
  - → The lack of new construction will also increase the vulnerability of the market to abuses of market power as transmission constraints and tight supply cause withholding to have a larger effect on prices;
  - → The process for quantifying and awarding new transmission rights to those investing in new transmission should be completed to provide improved incentives to upgrade the network and relieve congestion.

- The electric markets in New York have been competitive under most conditions experienced to date:
    - → Except for several isolated instances, the analysis reveals that suppliers bid in a manner consistent with workable competition.
    - → These instances can be effectively remedied under the current mitigation measures, and the automated mitigation procedure ("AMP") should effectively address the one day lag in the implementation of mitigation.
    - → Lower conduct thresholds for identifying economic withholding do not appear necessary at this point, but further assessments will be made.
- The competitive markets implemented by the New York ISO have caused suppliers to offer 5 to 10 percent more output from existing generating unit in comparison to the prior regulated system. This additional supply is among the real benefits resulting from the competitive markets and is especially important under the prevailing tight market conditions.
- Prices were not been unreasonably high during 2000 given the dramatic increase in fuel prices over the year and large unit outages – prices during 2000 would have averaged very close to 1999 levels without these factors.
- The poor performance of the transmission interface between New York and New England also contributed to the higher prices in 2000;
    - → Work to resolve seams issues with neighboring markets should continue as rapidly as possible -- interim improvements should be implemented prior to summer.
- Withholding in the 10-minute non-synchronous reserve market ("10-minute NSR") resulted in non-competitive prices in that market, and in the 10-minute spinning reserves and regulation markets during the spring of 2000.
    - → The bidding requirements and pricing provision implemented to remedy this issue has effectively addressed this issue;
    - → Software changes made to increase the amount of reserves that can be provided from existing facilities have improved the competitiveness of the reserves markets;
    - → Further modifications to pricing and other provisions in the reserves and regulation markets may facilitate an increase in the supplies offered in these markets. The additional supplies would improve the competitiveness of these markets, as well as provide benefits to the energy market by loosening capacity conditions when demand peaks.
- Facilitating significant demand-side response to wholesale prices will improve both the competitiveness and reliability in the New York markets during peak demand conditions.

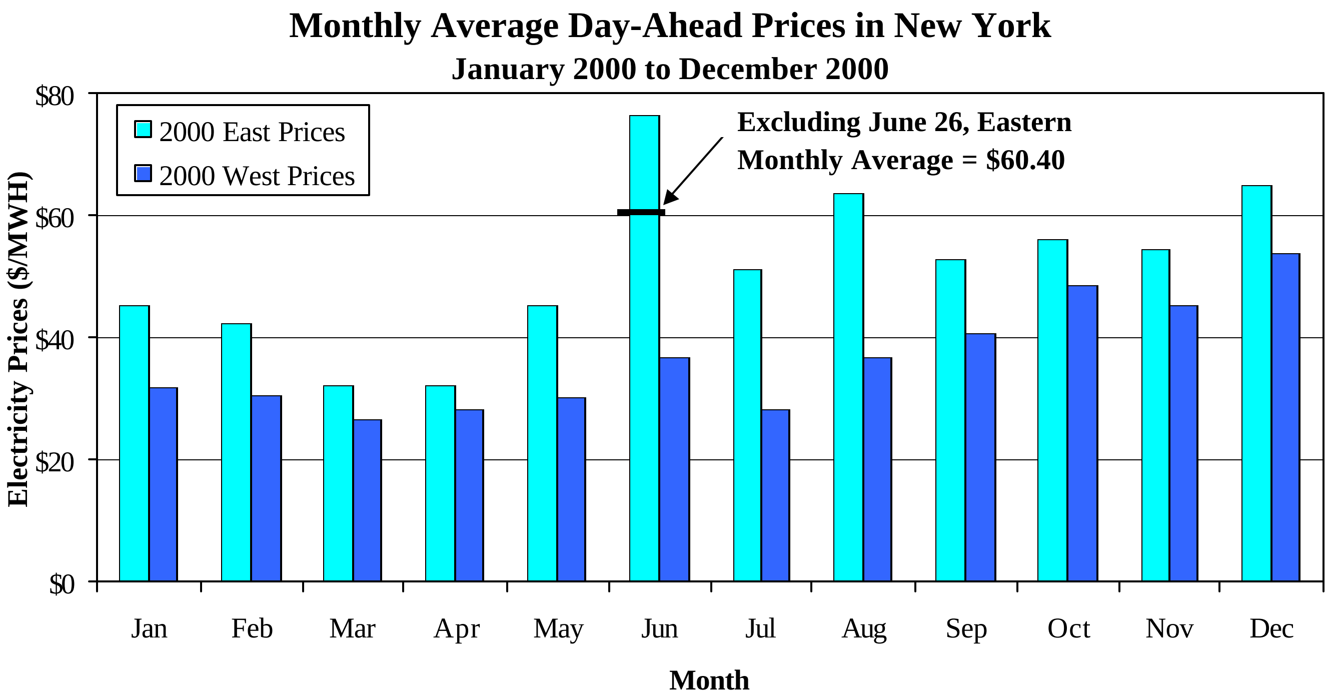
**Market Costs and Prices in 2000**

During the first full year of market operations, almost $5 billion in energy and ancillary services settled through the NYISO markets. The following figure shows the total costs by month generated in both the day-ahead and real-time markets. The total expenses associated with energy include not only the energy costs shown in the figure, but also the energy losses and congestion costs.




Congestion costs are those resulting from the differences in prices between various locations on the New York system. The congestion costs totaled more than $1.2 billion for the year, peaking during the summer when transfers from lower cost resources in Western New York to the load in Eastern New York and New York City were most valuable. This chart also shows that ancillary services costs were a much larger share of total costs during the spring of 2000 than later in the year, which is explained below.

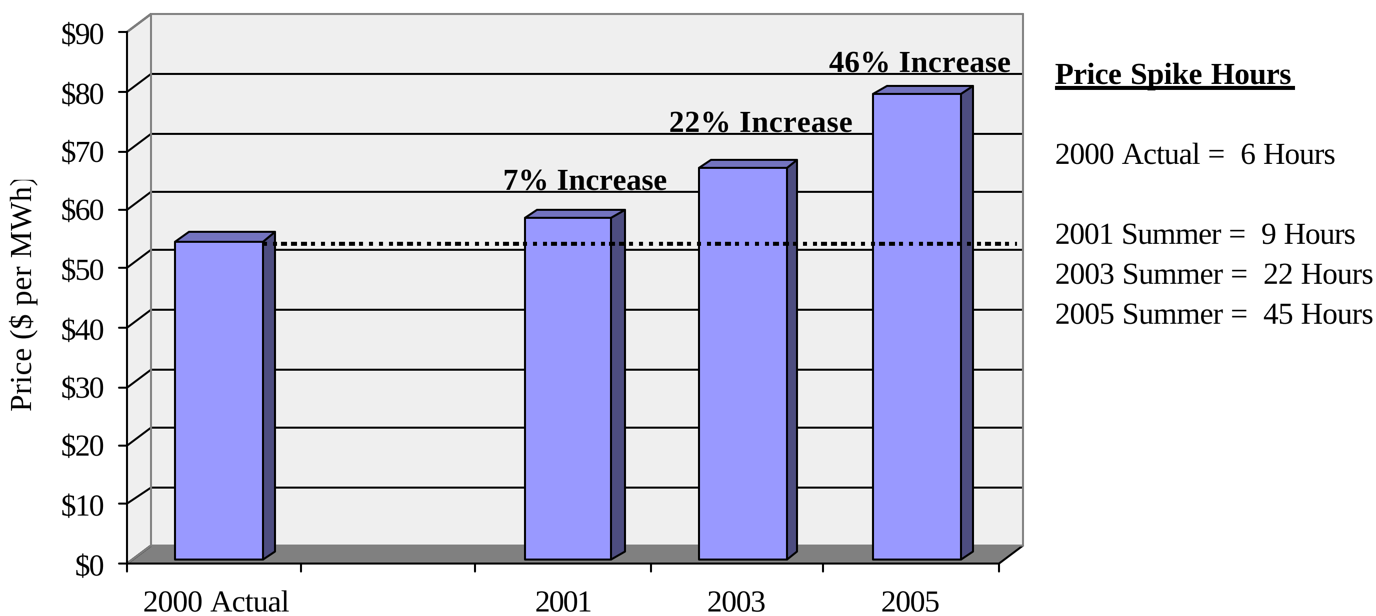
The most significant transmission constraint in the State is the Central-East Interface that limits the power that may flow from Western New York, PJM and Canada to Eastern New York and New England. This single interface is responsible for the majority of the congestion costs produced in the New York market and is likely the most economically significant transmission interface in the Northeast.




The prices in Eastern New York were significantly higher than prices in Western New York as a result of the congestion on the New York system. Day-ahead prices in Eastern New York included two episodes of very high prices (termed "price spikes" by many), occurring on June 26 and August 9. Although these episodes were short-lived, they had a considerable effect on the average prices in the two months. The figure shows that without the price spike that occurred on June 26 when hourly prices exceeded $1200, the average price for June would have been 22 percent lower. Likewise, day-ahead energy costs for June would have been $120 million lower without the June 26 price spike.

These types of pricing episodes can be the legitimate result of the tight market conditions that occur when load peaks and supplies become scarce, or caused by physical and economic withholding of supplies. It is critical in monitoring the market to have the ability to differentiate these two causes. The daily monitoring process screens the markets to detect and remedy various types of withholding. This process effectively addresses the latter potential cause of price spikes, but not the former. As demands continue to grow without significant new generating resources being added in constrained areas of the network, the frequency of price spikes is likely to increase.

**Forecast of Average Summer Prices in New York**
**June to August -- All Hours**




This figure shows a forecast of average summer energy prices over the next four years, assuming no new resources are available. As the load grows, the number of high price episodes in this analysis increases in Eastern New York from 6 hours in 2000 to 45 hours by 2005, resulting in average prices that are almost 50 percent higher than last summer. These price forecasts assume that the competitive bidding patterns observed over the past year continue in the future.

However, as market conditions become increasingly tight, the incentive for suppliers controlling a substantial amount of generation to withhold a portion of its resources will increase and the markets will be vulnerable to additional price increases. For both of these reasons, it is essential for policymakers in

New York to address the current barriers to the construction of new generating facilities. Likewise, barriers to significant transmission upgrades need to be removed as they would not only lower congestion costs, but also allow the markets in Eastern New York to be contested to a greater extent by suppliers in Western New York and adjacent RTOs.

**Analysis of Bidding Patterns**

In addition, until sufficient new generation is added to the system and additional transmission capability is available, mitigation measures will continue to be a very important tool to allow the NYISO to address strategic withholding and ensure the integrity of the competitive market. Mitigation was employed in isolated cases to address bidding that qualified as economic withholding under the Market Mitigation Measures ("MMM"), including June 26.

I consult with the NYISO in their daily monitoring of the markets for behavior that is inconsistent with competitive conduct. This report also provides analyses of longer-term trends to assess the competitive performance of the markets. These analyses are generally intended to determine whether the structure and design of the markets are providing incentives sufficient to compel participants to behave competitively. These analyses have produced a number of results that together demonstrate that performance of the markets has generally been consistent with workable competition.

First, the accepted bids from suppliers on a unit-by-unit basis generally reflected the variable fuel costs of the generating units. Since fuel costs constitute the largest share of a generator's marginal cost in the normal operating range, this analysis shows that generators have been bidding their supplies in a competitive manner. It also suggests that the reference prices (computed based on past accepted bids) used by the NYISO to monitor these bids are appropriate.

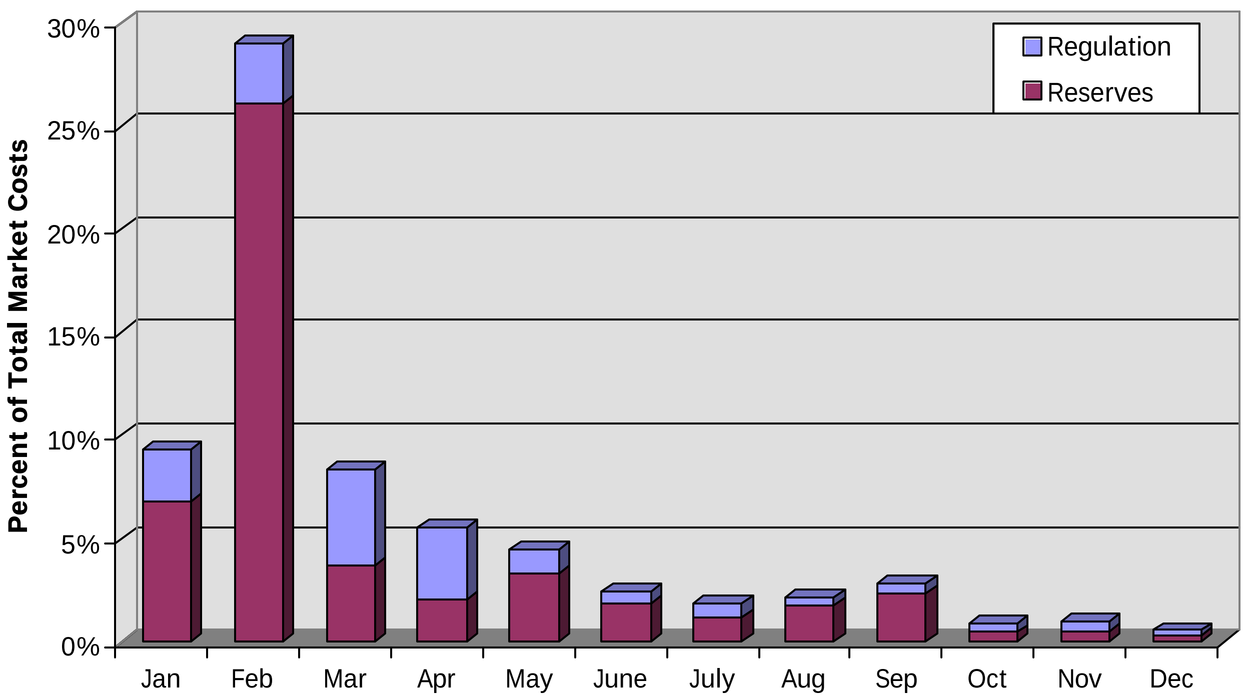
Second, bids that have exceeded the market monitoring thresholds for economic withholding and total deratings (some of which may constitute physical withholding) have both fallen in quantity as loads rose in 2000. These results support a conclusion that the markets have been workably competitive since the incentive to withhold in a non-competitive market should rise significantly as load rises and supply conditions become tight. In a competitive market, suppliers will attempt to maximize the supply offered as load rises to profitably sell as much output as possible. In addition, the quantities potentially qualifying as economic or physical withholding were no higher for large generation owners than small owners. This also supports the conclusion that the markets are not subject to substantial market power.

Third, the load bid by load serving entities ("LSEs") was generally close to their actual load. During the summer, the LSEs bid more load into the day-ahead market than their actual load on average. The market power concern that was raised related to load serving entities was that they may deliberately under-bid day-ahead to cause artificially low day-ahead prices. However, the analysis of load bidding does not reveal that this has been a concern. The over-bidding during the summer is consistent with a rational attempt to hedge the load against the excess volatility in the real-time energy market.

Lastly, the report analyzed the changes in the quantities of energy that were offered under the prior regulated system versus the amounts offered in the NYISO's competitive wholesale markets. This analysis showed that the increased amounts of energy offered into the NYISO energy markets totaled 1000 MW to 3500 MW under various measures of the increase. This supply increase of 5 to 10 percent from existing generating units (excluding the effects of outages, new unit additions, etc.) is a result of the superior incentives provided by competitive wholesale markets. These benefits are particularly important under current conditions with supply conditions becoming increasingly tight.

While bidding patterns in the energy markets were generally consistent with workable competition, withholding in one of the reserves markets during the spring of 2000 caused ancillary services costs to be substantially higher during late January through March of 2000. The key reserve market was the 10-minute NSR market. The amount of 10-minute NSR capability offered decreased substantially, while much of the capability that was offered was bid at levels substantially higher than previous levels (and higher than reasonable variable, opportunity, or other marginal costs). One of the principal factors contributing to this issue was the fact that the 10-minute NSR capability is principally held by only three suppliers, resulting in a highly concentrated market.

**Reserves and Regulation Costs**




The effect of this conduct is apparent in this figure, which includes substantially higher prices for all 10-minute reserves and for regulation. Regulation prices are affected by conduct in the reserves markets because the same resources that can provide regulation can also usually provide 10-minute spinning reserves. Therefore, artificial tightness in the 10-minute reserve market will cause some of the resources that would otherwise have provided regulation to be scheduled to provide 10-minute reserves instead. The total effect of this conduct was estimated at roughly $70 million and, regrettably, occurred prior to FERC's approval of the mitigation measures that would have allowed the NYISO to address the conduct more quickly.[1] The conduct was ultimately remedied by imposing bidding requirements that preclude both economic and physical withholding. Since these measures were implemented, the reserves markets have been relatively stable and additional 10-minute reserve capability has been facilitated by NYISO software changes. These additional supplies should substantially increase the competitiveness of this market and ultimately allow the removal of the bid restrictions.

### Other Factors Affecting Prices in 2000

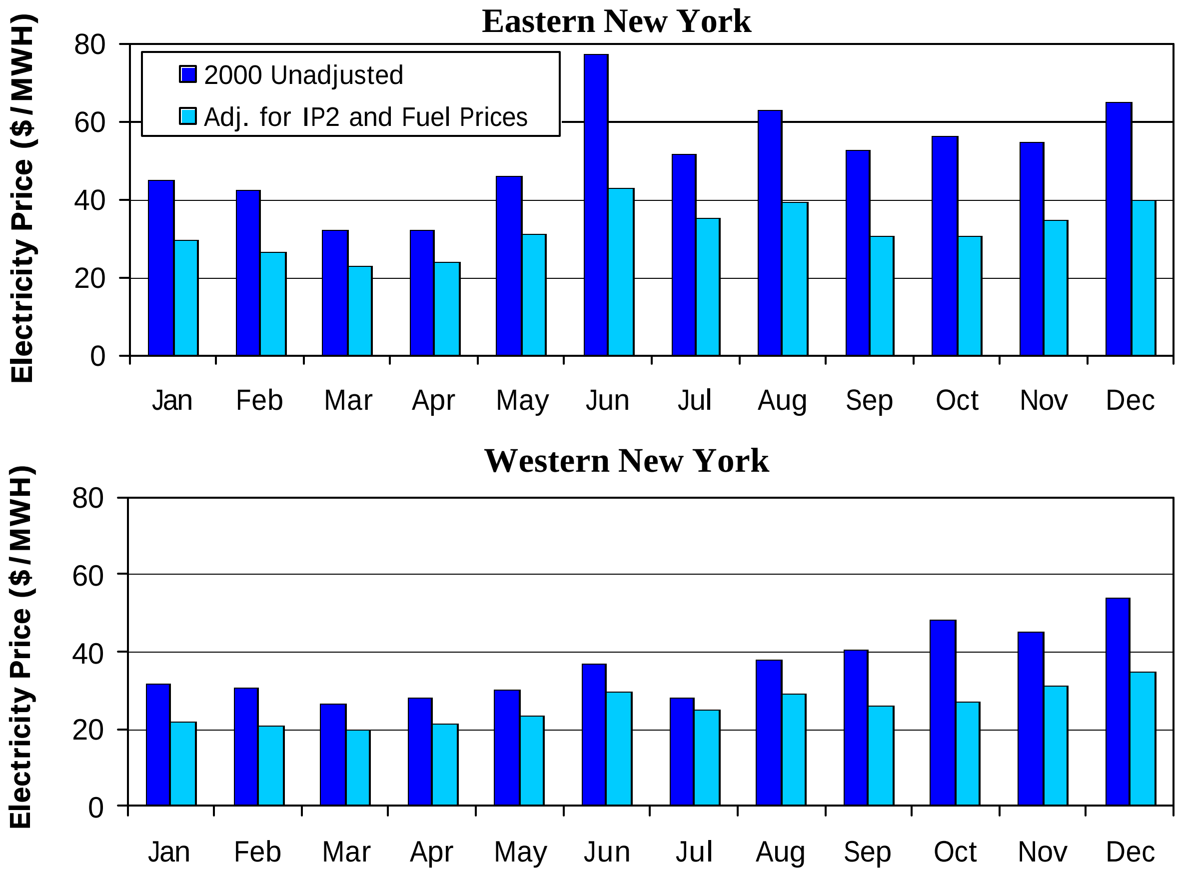
The energy prices shown above for Eastern and Western New York were higher than historical levels prior to the implementation of the NYISO markets. However, the analysis of bidding patterns shows that suppliers have generally bid their output into the market in a competitive manner and, therefore, have not been the cause of the higher prices.

The analysis in this report reveals that the primary causes of the higher prices are real factors that would have caused prices or costs to rise under any type of market. The first factor was the dramatic rise in natural gas and oil prices. Oil and natural gas are on the margin in most hours in Eastern New York. From September 1999 before the introduction of the NYISO markets, the average monthly price of fuel oil rose by as much as 70 percent during 2000, while the average monthly price of natural gas rose by more than 400 percent during the year.

The second factor the report analyzed was the outage of the Indian Point 2 nuclear unit ("IP2") that reduced the supply of energy in Eastern New York by approximately 1000 MW. This had the largest effect during the summer when the reduced supply in Eastern New York contributed to the price spikes in June and August. The report analyzes these two factors by estimating what prices during 2000 would have been absent the fuel price increase and the Indian Point 2 outage. The figure below shows the results of this analysis. This figure shows that these two factors resulted in price increases on a monthly average basis ranging from 11 percent to 84 percent. Absent these factors, average prices would have been at levels equivalent to prices during 1999 prior to the implementation of the NYISO markets.

Unusually cool weather during July and, to a lesser extent August, also affected prices by reducing the peak loads during the summer of 2000. Therefore, the report includes an analysis of the loads that were forecasted to prevail under normal weather conditions, finding that the adjusted prices in Eastern New York would have risen by approximately $7 per MWh. The loads during 2000 in non-summer months were generally higher than historical levels. Therefore, even with this load adjustment to account for cool summer weather, the adjusted prices shown in the figure below to account for fuel prices and the IP2 outage would have only been slightly higher than historical levels.

**DAM Prices Adjusted for IP2 and Fuel Prices**




The report also identifies other factors that affected prices or costs in the NYISO markets during 2000. The most important of these factors was the scheduling of external transactions between New York and neighboring regions. In particular, the failure to fully utilize the New England interface contributed to higher prices in Eastern New York. On June 26 for example, net exports of more than 500 MW were scheduled out of New York when day-ahead prices exceeded $1200 while the clearing prices in New England for the same hours were less than $60. Because exports were scheduled in those hours, the total amount of transmission capability available to schedule additional imports into New York exceeded 2000 MW, which would have substantially mitigated the energy price spike.

The report analyzes the scheduling processes in New York and finds that the market models did schedule transactions economically according to the market rules. However, other considerations have prevented market participants from bidding external transactions to fully utilize the interfaces. These considerations include tariff provisions and conflicting market rules that hinder external transactions. The NYISO issued two emergency corrective actions ("ECAs:") to resolve a pricing problem associated with external transactions that created poor incentives and higher risks for participants.

These issues are being studied through the memorandum of understanding ("MOU") between the NYISO, the other Northeast ISOs, and the Ontario market operator. This process has resulted in some improvements that have already been implemented, or planned to be implemented in the near-term, that should improve the utilization interfaces.

In addition, the day-ahead market study sponsored by the NYISO, New England, and the Ontario IMO has initially identified longer-term alternatives that would improve the arbitrage and coordination between the markets.

Lastly, a number of operational issues have arisen, some of which affected prices or market costs. The report describes these issues and identifies those that have been addressed or will be addressed in the short-term. Operational issues should be expected during the start-up phase of any new market structure, particularly one with as broad a scope as the NYISO markets. Most of these issues are not subject to quantification without extensive modeling or other analysis. However, the report does assess the most important of the operational issues and does not find that they have generated costs as significant as the other factors listed above.

**Conclusions**

Although additional work needs to be done to resolve seams issues with adjacent markets and some of the operational issues that have been identified over the past year, the NYISO's implementation of competitive energy and ancillary services markets in New York has been relatively successful. The markets have not been subject to significant market power abuses as the markets have performed in a workably competitive manner. The existing mitigation measures will allow the NYISO to effectively remedy any market power concerns that may arise in the future without the additional price controls that many have called for in New York. In fact, many of the proposed price controls would likely cause the unintended result of driving some of the current supply into other markets while discouraging entry of supply from outside New York.

The higher prices experienced in New York have been driven primarily by real factors that cannot be eliminated through the application of various types of price controls. These real factors include the reality that supplies can become scarce when demand peaks since barriers to new generation have prevented significant new supply from entering the market. These barriers need to be minimized or eliminated as soon as possible.

Beyond finding solutions that will allow the siting of new generation and transmission facilities, resolving the seams issues with neighboring markets to allow for the emergence of broader power markets over the Northeast region should remain one of the highest priorities. These improvements will increase the stability of the New York markets and reduce the potential for competitive concerns, many of which have already been identified.

The NYISO is also working to implement provisions that facilitate more liquid forward contracting markets. Forward contracting plays a vital role in the emergence of stable and competitive wholesale markets. These changes should be granted a relatively high priority, but implemented in a manner that minimizes the potential for market abuses.

The report identifies several potential changes to the ancillary services markets that would ultimately increase the supply offered in these markets and ensure that they remain competitive. However, these changes would not warrant a priority as high as the other issues described above since the performance of the ancillary services markets, excluding the episode in the spring, was generally very competitive.

Lastly, the NYISO has recently expanded the capability for LSE's to bid their load in the day-ahead market in a price-responsive manner (i.e., shift load from the day-ahead market to the real-time market based on prices in the day-ahead market). In addition, the NYISO is pursuing programs that would compensate loads that can physically reduce their consumption in response to appropriate price signals. These programs are important in the long-term to mitigate the price fluctuations that result when unresponsive load must be served at any cost as supplies become scarce. True demand participation in these markets will improve the competitiveness and stability of the markets, however achieving a meaningful level of participation in these programs will likely take some time.

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# I. INTRODUCTION

The NYISO began the operation of New York's current competitive wholesale power markets in November 1999. The NYISO's auction-based markets that seek to minimize bid production costs of meeting energy and ancillary services demands replaced the centrally dispatched power pool that had operated in New York. The NYISO energy markets set market-clearing prices that reflect transmission conditions by establishing prices at each location equal to the marginal cost of serving the location (i.e., location-based marginal prices or LBMPs).[2] The implementation of these markets was facilitated by the presence of the New York Power Pool infrastructure and systems. Nonetheless, the start-up of the New York ISO markets is perhaps the most ambitious introduction of competitive wholesale markets attempted by a system operator to date.

PJM, for example, initially implemented a real-time energy market when it began operation as an ISO and has added other markets over time, such as a regulation market and a day-ahead energy market. In contrast, the NYISO simultaneously implemented both day-ahead and real-time energy markets, three operating reserves markets (10-minute spinning, 10-minute non-synchronous, and 30-minute), a regulation market, an installed capability market, and firm transmission rights.

Simultaneous implementation of these markets promised to deliver the benefits of full competition to the market more quickly, while recognizing the economic trade-offs between using resources to produce electricity versus ancillary services. However, this approach also increased the chances of encountering significant operational issues during the transition period. This report reviews the performance of the NYISO markets during their initial period of operation in 2000.

Prices in the NYISO energy markets during 2000 were higher than historical levels that prevailed prior to the implementation of the NYISO markets. A number of external factors occurring in 2000 significantly influenced electricity prices, including considerable increases in input fuel prices to electric generators, much lower than average temperatures during the summer, and the outage of a relatively large amount of generating resources. These factors must be accounted for in any assessment of the competitive performance of the NYISO's markets. Therefore, the analysis in this report separately examines the effects of these factors from the effects of the bidding patterns of the market participants and the operations of the NYISO markets.

With regard to longer-term trends, New York loads continued to grow in the face of limited expansions in generating capability, which has led to shrinking reserve margins and increasingly tight market conditions during peak load periods. Although more than 30,000 MW of new proposed generating capability is currently in the queue in New York, a very difficult siting process for new generation has prevented substantial new resources from entering the market in the near-term. These conditions will lead to substantially higher prices as periods of supply scarcity that are generally accompanied by very high prices occur much more frequency.

In addition, the increasingly tight market conditions projected over the next few years (absent substantial new capacity) make it essential to ensure that the New York ISO markets create the proper incentives for suppliers within and outside of New York to offer their resources competitively. Therefore, this report includes an analysis of bidding patterns to assess whether the structure and rules of the New York markets are providing efficient incentives to market participants.

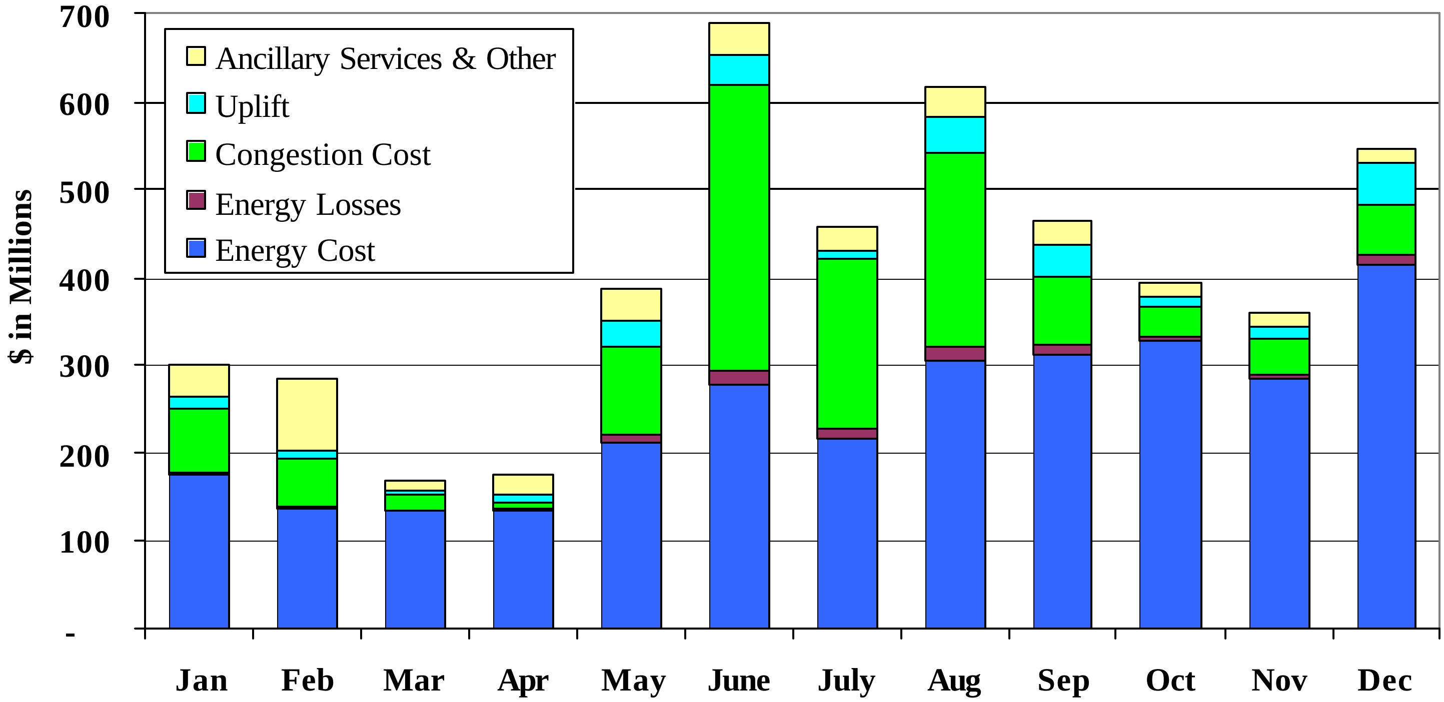
During 2000, almost $5 billion of energy and ancillary services were settled through the NYISO electric markets. This does not include the value of power traded through forward energy markets or any other transactions that are settled outside of the NYISO.

Figure 1 provides a summary of the total market expenses that were incurred during in each month during the year. The costs in this figure include market costs settled through both the day-ahead and real-time energy and ancillary services markets. The figure does not include costs associated with the sale of TCCs or installed capability (ICAP). The total market expenses associated with energy include not only the energy costs shown in the figure, but also the energy losses and congestion costs.

**Figure 1**

**Monthly New York Electric Market Expenses**

**January to December 2000**




This figure shows that energy and associated congestion costs accounted for the majority of the costs cleared through the NYISO markets, although ancillary services expenses and uplift also represent a significant portion of the costs. Each of these areas are reviewed and analyzed in the following four sections of this report.

Section II reviews the energy market outcomes and includes an analysis of a number of external factors that have influenced energy prices in 2000.[3] These factors include the outage of a large nuclear unit in Eastern New York and a substantial increase in natural gas and oil prices that are primary inputs to electric generators in that area. This section of the report also includes a forecast of summer energy prices through 2005 to examine the implications of current barriers that have hindered the development of new generating resources. Lastly, this section thoroughly examines the scheduling of external transactions to determine whether the interfaces with neighboring markets have been fully utilized.

Section III provides the results of my analysis of the conduct of wholesale market participants in the NYISO day-ahead and real-time energy markets. In particular, I analyze the supply and demand bids that underlay the competitive performance of the energy market. The analysis in this section allows conclusions to be drawn regarding whether the markets have performed in a workably competitive manner.

Section IV reviews offer patterns and prices in each of the ancillary services markets to provide an assessment of the competitive performance of these markets. Each market must be assessed in the context of the energy and other ancillary service markets since the markets are jointly dispatched and optimized. These interactions are identified and analyzed in this section, which shows that substantial excess bids are usually submitted for most of the ancillary services although tight conditions in one market or in one location can cause prices to rise significantly throughout the State in multiple markets. For example, withholding of non-synchronous reserves early in the year inflated prices for all 10-minute reserves throughout the State.

# II. Energy Markets in 2000

## A. Summary of Results in 2000

The NYISO operates day-ahead and real-time energy markets, each of which set market clearing prices at each point on the New York electric system and establishes schedules that minimize costs based on supply and demand bids. The day-ahead market commits generation to meet demand and reserve requirements, and establishes energy schedules for each generator. These schedules are essentially one-day forward contracts, while the physical dispatch is determined in the real-time market.

The NYISO has implemented a locational marginal pricing system that appropriately prices energy at the marginal system cost of serving load at each location in the market area. When transmission constraints prevent generation from lower cost areas from being transmitted to other areas so that higher cost resources are needed in those areas to serve load, the energy prices in the two areas will diverge.[4] For example, the most prevalent transmission constraint in the entire Northeast is the Central-East Interface that often limits the amount of power that can be physically transmitted from Western New York to Eastern New York, which results in higher prices in the East that are shown in Figure 2.

**Figure 2**
**Monthly Average Day-Ahead Prices in New York**
**January 2000 to December 2000**

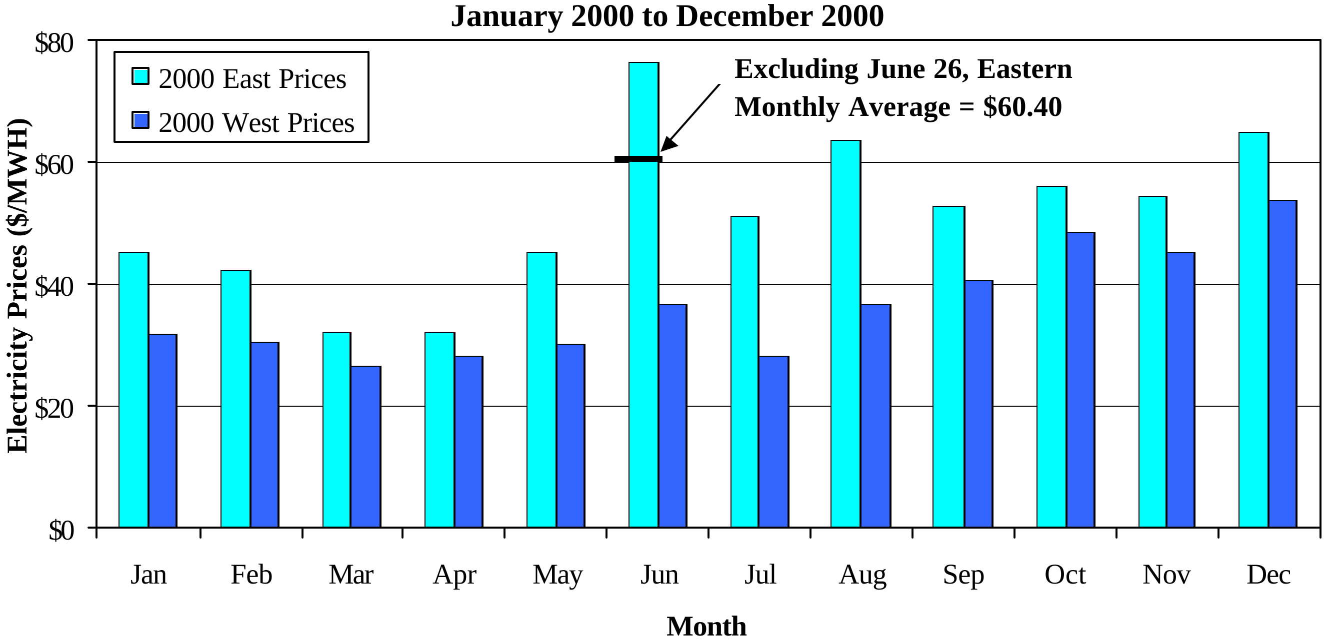
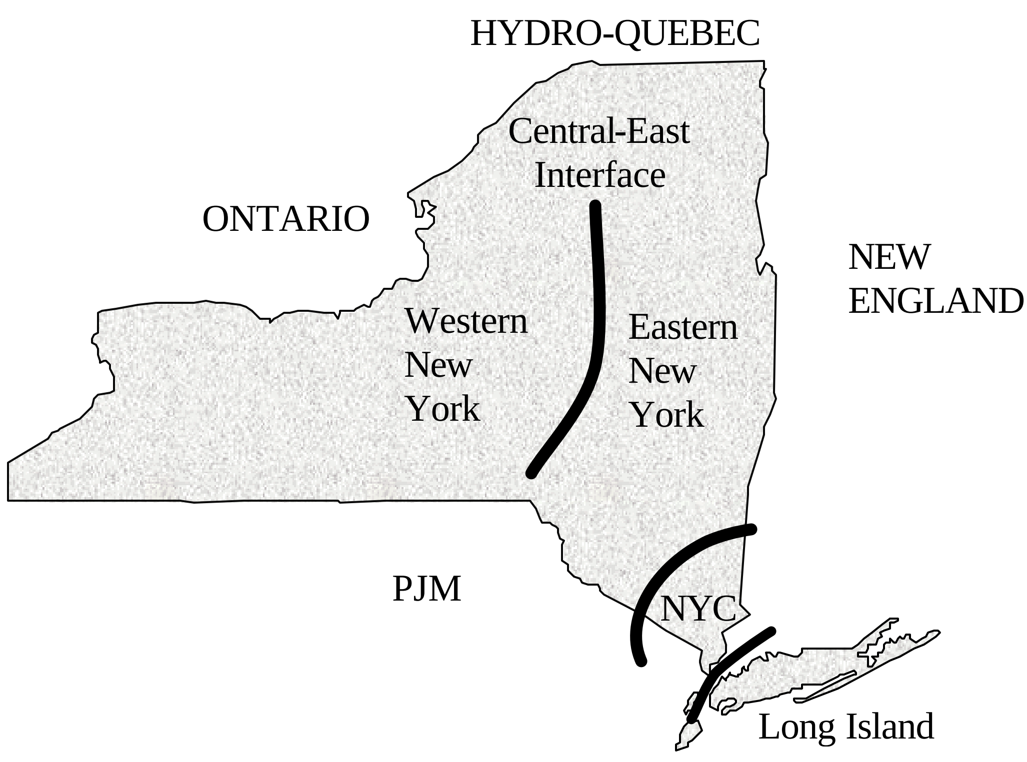


Figure 2 shows the average day-ahead energy prices in Western New York and Eastern New York during 2000. This figure shows that the load-weighted average of prices in Eastern New York was $52.35 for the year while prices in Western New York averaged $36.52. This difference is primarily the result of the Central-East transmission constraint, which contributed to congestion costs for the year of more than $1 billion. Real-time prices exhibited the same pattern averaging $53.72 and $32.00 in Eastern New York and Western New York, respectively. Together the cost of congestion in both markets exceeded $1.2 billion, or more than 20 percent of the total market costs during 2000.

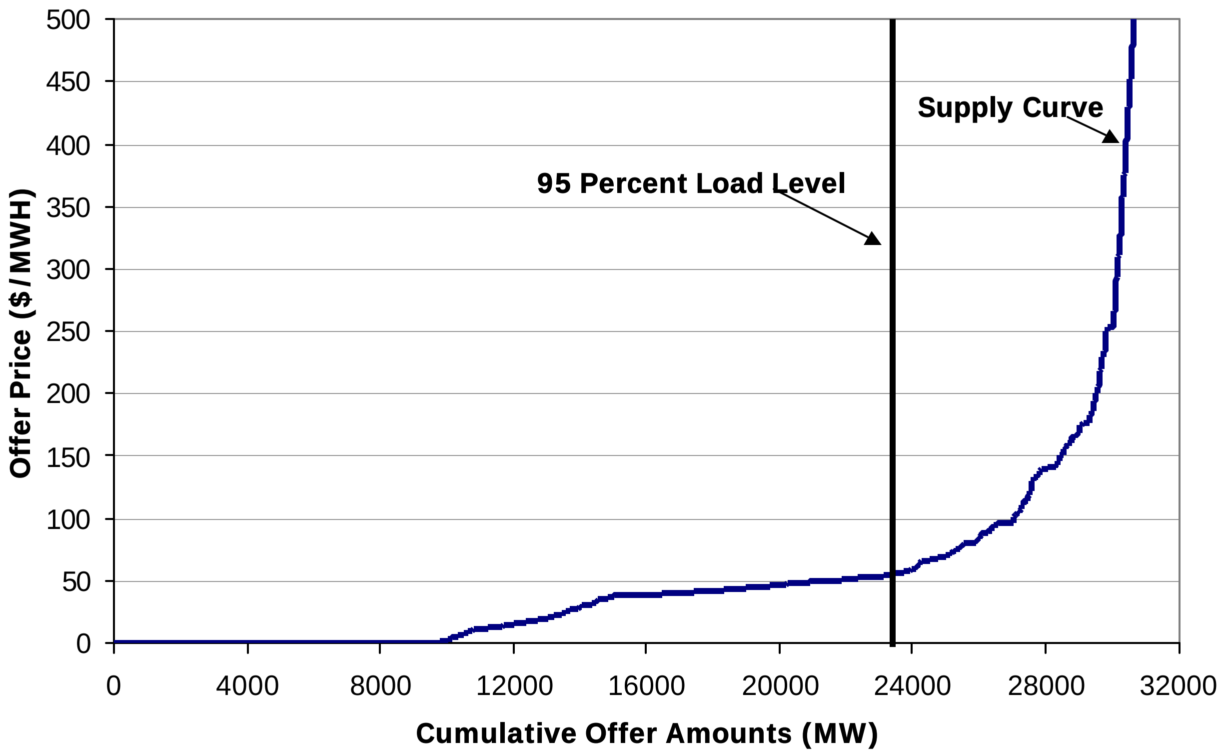
Figure 3 shows both the Central-East Interface and the transmission interfaces into New York City and on to Long Island that sometime cause prices in New York City or Long Island to be higher than other locations in Eastern New York. These transmission constraints can temporarily isolate the New York City market, in which few suppliers compete. The threat of market power in the City led to the adoption of "In-City" mitigation that restrict the ability of the purchasers of Consolidated Edison's ("ConEd") generation assets to raise their bids above cost-based levels when constraints are binding.

**Figure 3**



In addition to showing the effect of congestion on prices, Figure 2 also shows the importance of price spikes in raising average electricity prices. The highest day-ahead prices occurred on June 26 with several hours exceeding $1000 in Eastern New York. The figure shows that the average price for the entire month would have been 22 percent lower without the June 26 peak prices, which resulted in additional day-ahead costs of approximately $120 million. To understand why price spikes occur, one must appreciate the nature of the supply in this market as shown in Figure 4.

**Figure 4**
**Supply Curve for Day-Ahead Energy**
**August 15, 2000 -- Hour 14**




The supply curve shown in Figure 4 shows that a substantial amount of supply is available at very similar bid prices under most load conditions (i.e., the supply curve is flat). The practical implication of this is that, absent transmission constraints, prices will be relatively insensitive to changes in loads or supply, including physical and economic withholding. However, under peak conditions the bid price of resources capable of meeting these peak demands rises very quickly due to the relatively small amount of resources contained in this portion of the supply curve. Hence, the supply curve is steep in this range and prices will be much more responsive to the withholding of resources or additional load.

Given the nature of the supply curve, relatively high prices should only occur when market conditions are tight due to high demand, low supply, and/or binding transmission constraints. These factors can be measured jointly by a single metric – excess capacity. Excess capacity is the amount of additional resources that are available after the demand for energy and ancillary services has been satisfied. It is computed by subtracting the total scheduled energy and ancillary services in an area from the total resources offered in the given market area (i.e., resources offered in the energy and ancillary services markets simultaneously are not double-counted).

An additional adjustment is made to account for economic withholding – resources that are bid at very high levels to indicate an unwillingness to run under normal conditions. This conduct may sometimes indicate a strategic attempt to exercise market power, while other times it may reflect operating concerns or other real factors. Because this value can vary significantly day-to-day, I reduce the excess capacity statistic to account for bids at prices greater than $500 for purposes of the analysis below. Computed in this manner, excess capacity will fall as demand rises or the availability of resources decreases. When excess capacity in a region is close to zero, the market will dispatch the most expensive resources, resulting in the highest clearing prices. Figure 5 shows that this has been the case.

**Figure 5**

**Relationship of Excess Capacity to Prices**
**Day-Ahead Market -- East New York**
**January 1 to December 31, 2000 -- Hour 14**

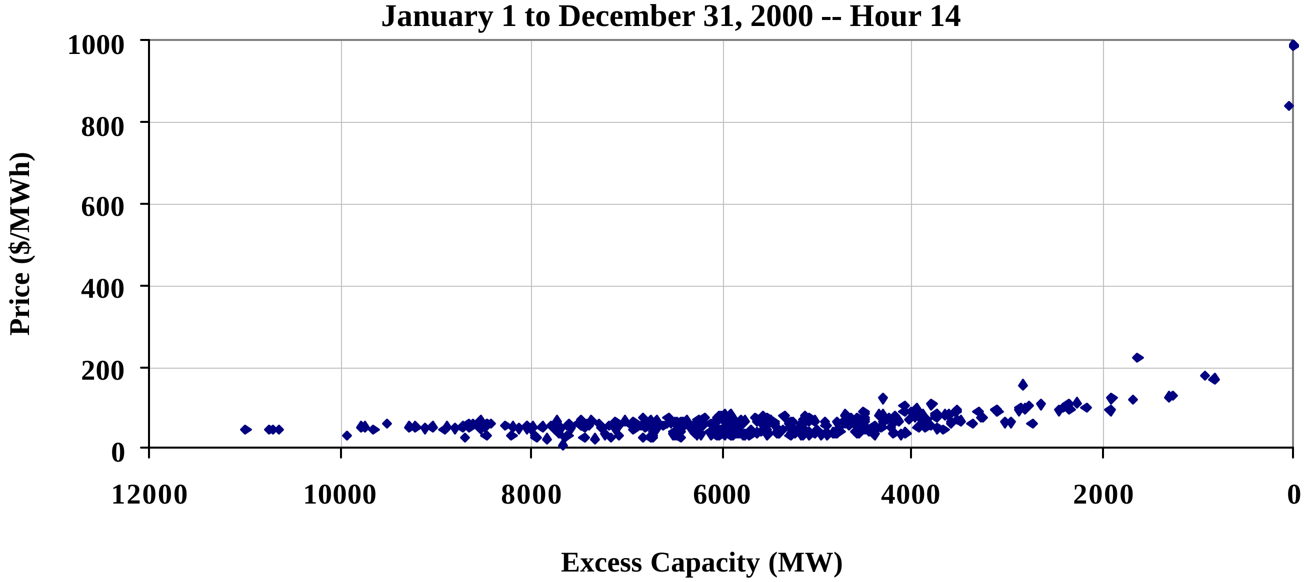


Figure 5 shows the prices in Eastern New York since this region is often isolated from Western New York by binding transmission constraints. It also only shows data for a single hour (2:00 pm to 3:00 pm) to eliminate any potential pricing disparities due to peak/off-peak differences (e.g., start-up hours or high-ramp hours).

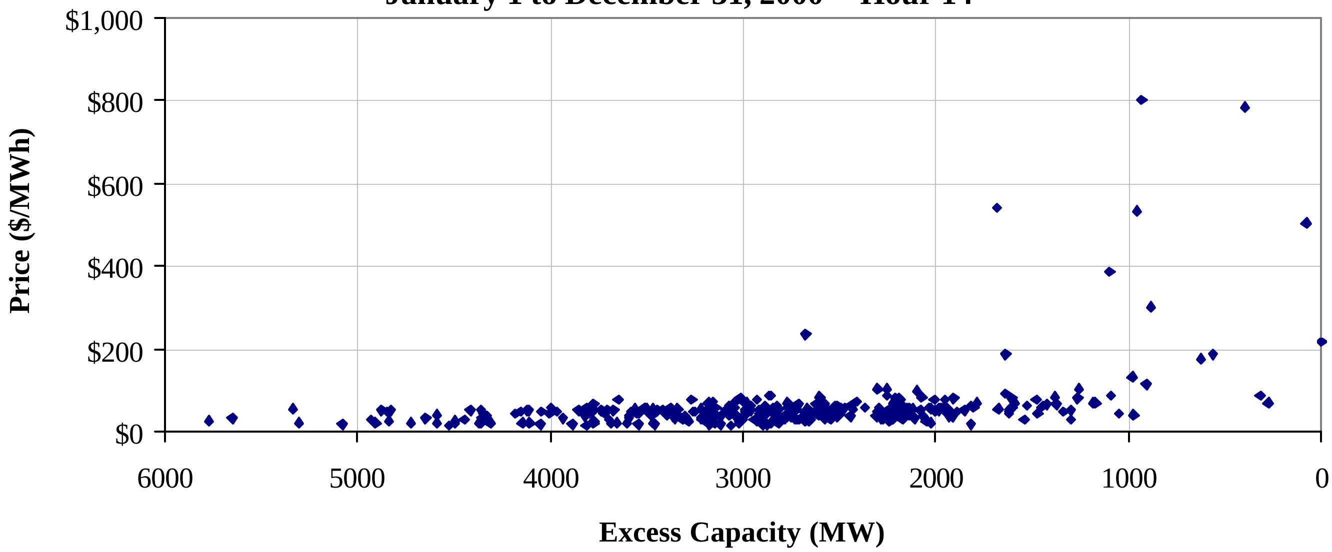
Due to the limited amount of demand side response, the prices emerging as the quantity demanded rises and falls should exhibit a relationship very similar to that described by the energy supply curve. Likewise, changes in excess supply should also exhibit this relationship since, all else equal, an increase in quantity demanded should result in a one-for-one reduction in excess capacity and vice versa. Figure 5 does show that day-ahead pricing during 2000 did reflect the supply curve relationship shown in Figure 4.

During the vast majority of the hours, prices have remained relatively flat and insensitive to changes in excess capacity levels. However, when excess capacity has approached zero in Eastern New York, prices have risen dramatically consistent with the steep portion of the supply curve. This does not imply these prices are solely the result of workable competition under scarcity since both economic and physical withholding would reduce the measure of excess capacity I calculate. These issues will be addressed later in this report.

The figure also reveals that prices have varied noticeably at each given excess capacity level. This variation is caused by the fact that the data is not sorted chronologically so that the points shown with a 10,000 MW excess capacity may have occurred during different seasons or under significantly different fuel prices. In addition, since the figure plots the entire Eastern New York region, transmission constraints that were binding within the region that cause prices in New York City or Long Island to exceed the prices in the rest of the East will cause somewhat higher average prices to be shown for the region at a given excess capacity level.

In the real-time market, higher levels of price volatility contribute to a less predictable relationship between excess capacity and prices in Eastern New York, which is shown below in Figure 6.

**Figure 6**
**Relationship of Excess Capacity to Prices**
**Real-Time Market -- East New York**
**January 1 to December 31, 2000 -- Hour 14**




The high prices in this case are related to a number of constraints that must be resolved with limited available resources to shift in real-time, particularly when excess capacity is low. The SCD solves approximately every 5 minutes. When constraints arise that must be resolved by SCD, it sometimes requires resources that can ramp quickly, some of which are relatively expensive (e.g., 10-minute gas turbines), since the model cannot take actions farther in advance in anticipation of the constraint. This often occurs when a Thunderstorm Alert is called by the NYISO that causes the interfaces into New York City to be derated very quickly and generally requires quick-start resources to produce additional output in the City.

Despite these factors that sometimes cause higher prices to occur when a substantial amount of excess capacity is available (from slower responding resources that are not available to the SCD), the prices in Figure 6 for Eastern New York in the real-time market are generally consistent with the character of the supply curve shown in Figure 4.[5]

## B. External Factors Affecting Prices in 2000

Wholesale energy prices in 2000 under the first year of NYISO operation were significantly higher than historical levels, prompting some to argue that the market is not operating competitively. The analysis below examines the extent to which this increase is attributable to external factors that would have resulted in cost increases, even under the historical system of cost-of-service regulation.

The increase in electric prices have been primarily attributable to severe increases in natural gas and oil prices and the outage of one gigawatt of nuclear capacity in Eastern New York, Indian Point 2.[6] The most significant factor is the increase in fuel prices since gas or oil capacity is on the margin a large portion of the time in Eastern New York. The effects of these types of factors on electric prices relates to how they affect electric supply. Figures 7 and 8 show illustratively how the supply curve originally shown above in Figure 4 would shift in response to fuel price changes versus a change in the availability of a large baseload unit.

**Figure7**
**Supply Curve for Day-Ahead Energy**
**Adjusted for Lower Fuel Prices**
**August 15, 2000 -- Hour 14**

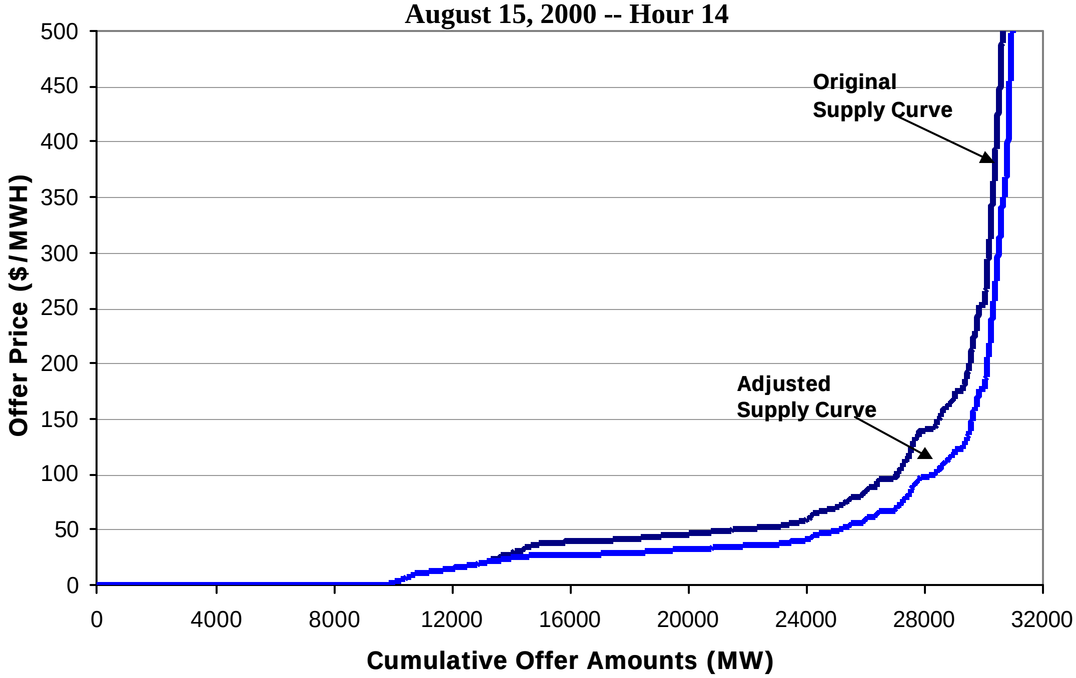


Figure 7 shows the effects of a 30 percent reduction in the variable costs of all units with bid prices greater than $30 per MWh (generally oil and gas-fired units). In this case, the supply curve shifts downward, resulting in reduced supply costs at both peak and off-peak load levels. Therefore, lower fuel prices should reduce electricity prices over a broad range of market conditions, most of which occur in the flat portion of the supply curve below 24,000 MW of load. Alternatively, Figure 8 shows that an expansion in capability of 1000 MW shifts the supply curve to the right, resulting in relatively small supply cost reductions at lower load levels and larger reductions at peak load levels. Hence, the single most significant effect of a capacity expansion under tight supply conditions is that it will substantially reduce the price volatility under peak conditions.

**Figure 8**
**Supply Curve for Day-Ahead Energy**
**Adjusted for 1000 MW Increase**
**August 15, 2000 -- Hour 14**

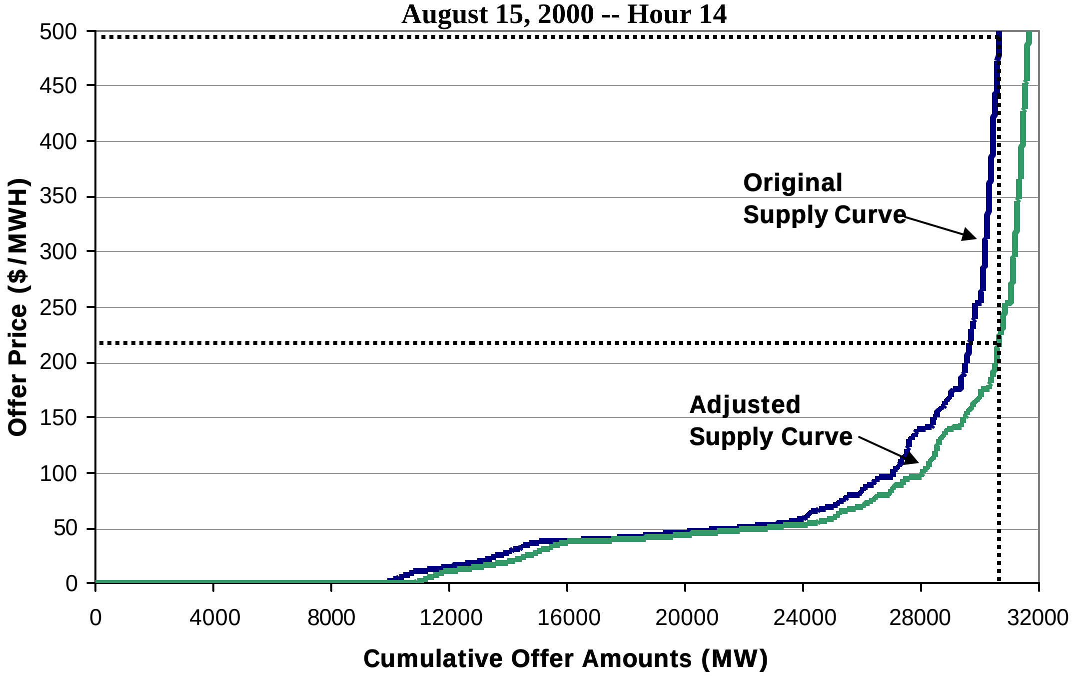
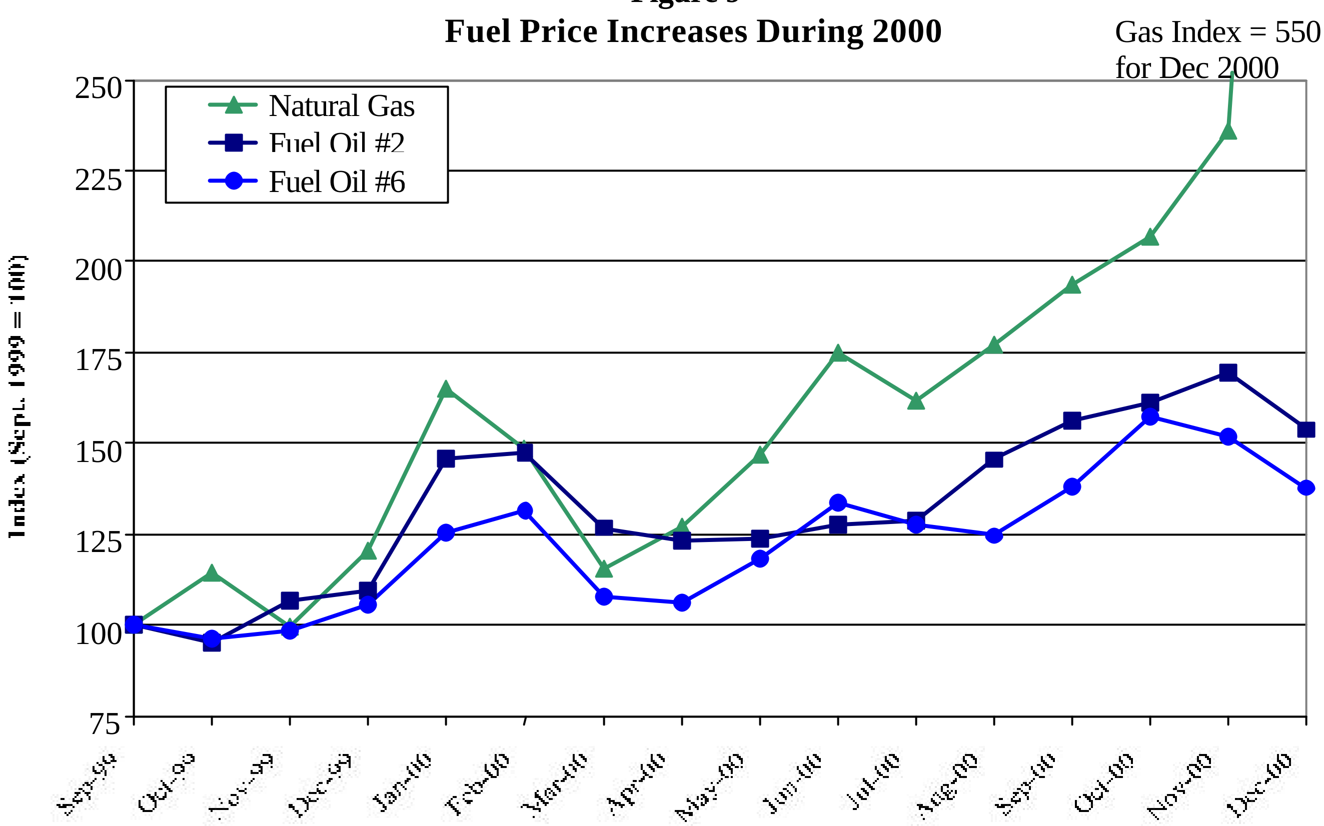



Figure 8 illustrates this effect by showing the effect of the 1000 MW expansion when the original clearing price would be $500 per MWh absent congestion, occurring at a demand level of approximately 30,700 MW. The new supply curve, adjusted for the expansion in capability, would result in a clearing price of approximately $225 per MWh to serve the same load. However, the price reduction caused by the supply expansion at a 22,000 MW load level would be less than five percent.

The effects illustrated in these figures show the different nature of these supply effects on electricity prices, both of which occurred during 2000 in New York.

The first factor affecting electric prices during 2000 was the sharp increase in natural gas and oil prices, which are key inputs to electric generation in Eastern New York. Figure 9 shows the increase in key fuel prices during 2000. Using September 1999 as the starting point, the figure shows that the monthly average of fuel oil prices had risen 25 to 50 percent by the summer of 2000 while gas prices had risen as much as 75 percent in the same timeframe. Trends in kerosene prices were substantially similar to those shown above for fuel oil. By the end of the year, natural gas had risen to more than five times its September 1999 level while fuel oil prices continued to rise.

**Figure 9**
**Fuel Price Increases During 2000**




Although a substantial amount of the power produced in New York is supplied from hydroelectric, nuclear, or coal-fired generating resources that were not subject to comparable input cost increases, these resources are generally base-loaded and are not on the margin setting prices in Eastern New York in most hours.

To assess the extent to which increases in fuel prices have affected electric prices in 2000, I have conducted an analysis that estimates the price levels that would have prevailed had fuel prices remained at historical levels. To do this, I identified the marginal generator for each hour in each market area, which are defined by the presence of transmission constraints on the network. When a transmission constraint is binding, different generators will be marginal in each area. For example, when the Central-East constraint is binding, the marginal generating unit in Western New York will generally be a lower cost unit than the marginal unit in Eastern New York, resulting in the price differentials frequently seen between the two areas.

Once the marginal generator was identified, the revised prices in that area were then estimated by subtracting the following price adjustment from each price. The price adjustment is computed using two different methods with the smaller of the two adjustments utilized to estimate the adjusted hourly price in each zone.

$$\text{Price Adjustment} = \text{Minimum of } [\text{Price} * 0.9 * (1 - \text{Index}_1)] \text{ or } [14000 * \text{Index}_2]$$

where: $\text{Index}_1 = [(\text{Fuel Price}_{\text{day n,1998}} + \text{Fuel Price}_{\text{day n,1999}})/2] / \text{Fuel Price}_{\text{day n,2000}}$ and

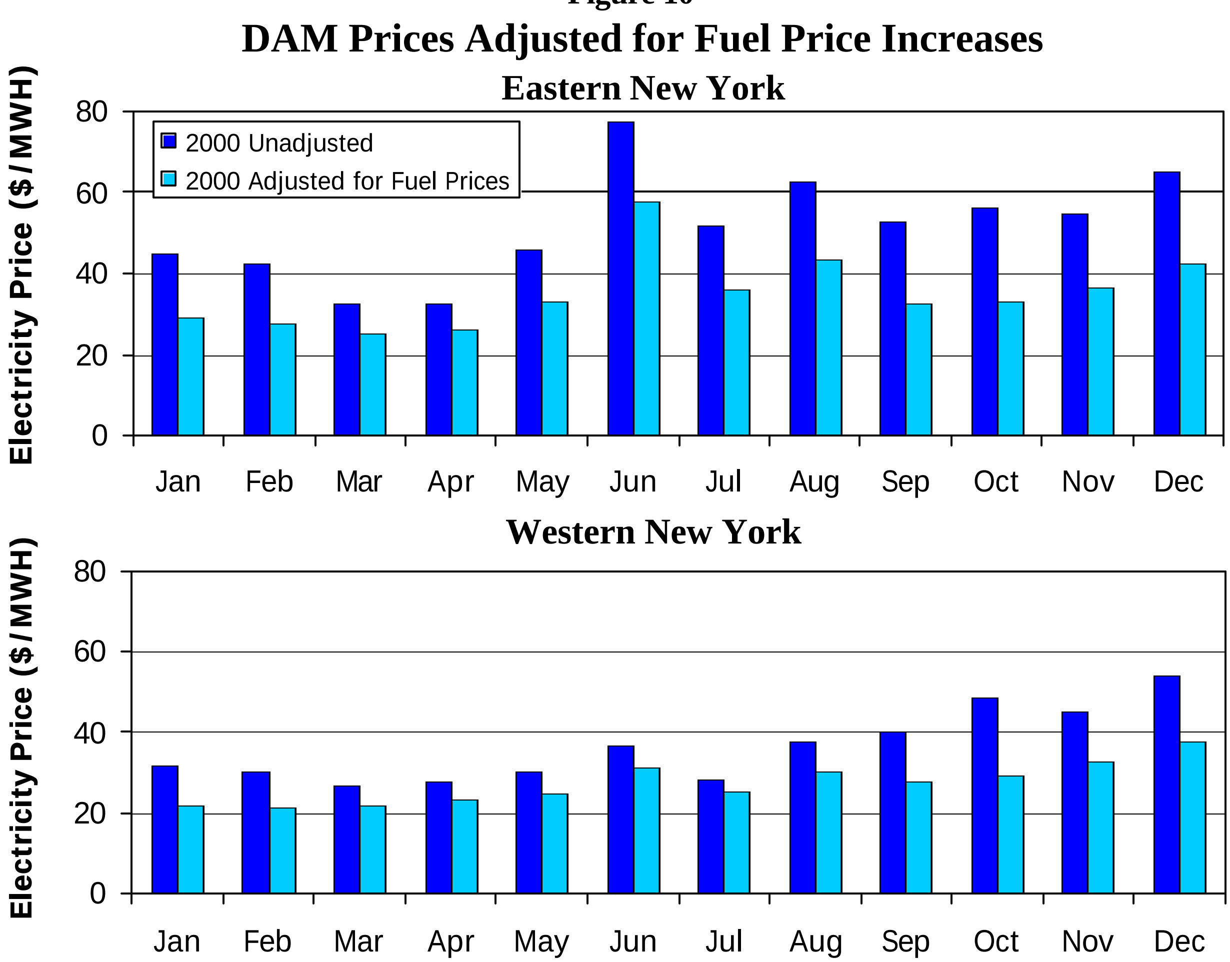
$\text{Index}_2 = [(\text{Fuel Price}_{\text{day n,1998}} + \text{Fuel Price}_{\text{day n,1999}})/2] - \text{Fuel Price}_{\text{day n,2000}}$

This adjustment assumes that 10 percent of a unit's bid is related to marginal costs other than fuel costs and utilizes an index that adjusts fuel prices in 2000 to be equal to the average of the fuel price in 1998 and 1999 during the same day. Fuel prices are a much smaller component of the marginal cost of certain resource blocks, such as the emergency output ranges of fossil steam units. The marginal cost of these resource blocks may reflect the effect of dispatching these resource blocks on the efficiency of the balance of the unit's output, the O&M of the unit, or the forced outage probability of the unit. To prevent $\text{Index}_1$ from over-adjusting prices when these types resources are likely to be on the margin, an alternative adjustment is computed by multiplying the absolute difference in fuel prices ($\text{Index}_2$) by a 14,000 BTU/KWh heat rate.

In addition, the analysis constrains the revised electric prices in any area to be no lower than the price of the next lower priced area. For example, if only the Central-East constraint were binding so the two relevant areas were Eastern New York and Western New York, the fuel price adjustment would not allow the price in Eastern New York to fall below the revised price in Western New York. This provision accounts for the fact that if the transmission constraint is relieved between the areas, the units in the constrained area may no longer be the marginal units and, therefore, prevents the analysis from estimating unrealistically low prices in this case.

Figure 10 shows both the actual day-ahead market ("DAM") prices during the year in Western New York and Eastern New York as well as the comparable fuel price-adjusted prices. The prices shown are the monthly average prices for all hours weighted on the load bid into the day-ahead market in each area, including bilateral contracts.

**Figure 10**



The figure shows that the fuel price adjustment is the largest late in the year, which is consistent with Figure 9 that showed the highest fuel prices occurring late in the year. The increase in natural gas prices, in particular, was extraordinary in December 2000. However, this analysis may underestimate the fuel price impact during December since it does not account for fuel switching. Natural gas units during December were likely not on the margin very frequently due to the high fuel price and lower load conditions. Were it possible to run the SCUC market model over again for the year with modified fuel prices, it would likely show that natural gas units would have been on the margin more frequently in December at lower prices than the adjusted price shown in Figure 10.

Nevertheless, these monthly averages reveal a 25 to 70 percent increase in average energy prices in Eastern New York and a 20 to 67 percent increase in Western New York. Clearly, fuel prices were the single largest factor explaining the increase in electricity prices from historical levels. Unfortunately, with the tight supply and higher prices in natural gas markets this winter, the natural gas prices are likely to remain higher next summer than they were in 2000 and contribute to higher electric prices in 2001.

The second critical factor affecting prices in New York during 2000 was the outage of the Indian Point 2 nuclear unit ("IP2"), which is located in Eastern New York and has a capability of almost one gigawatt (i.e., 1000 MW). I conducted an econometric analysis to assess the impact that the IP2 outage had on prices during the year. This analysis included a regression of excess capacity and natural gas prices on electricity prices in market areas defined by transmission constraints.[7]

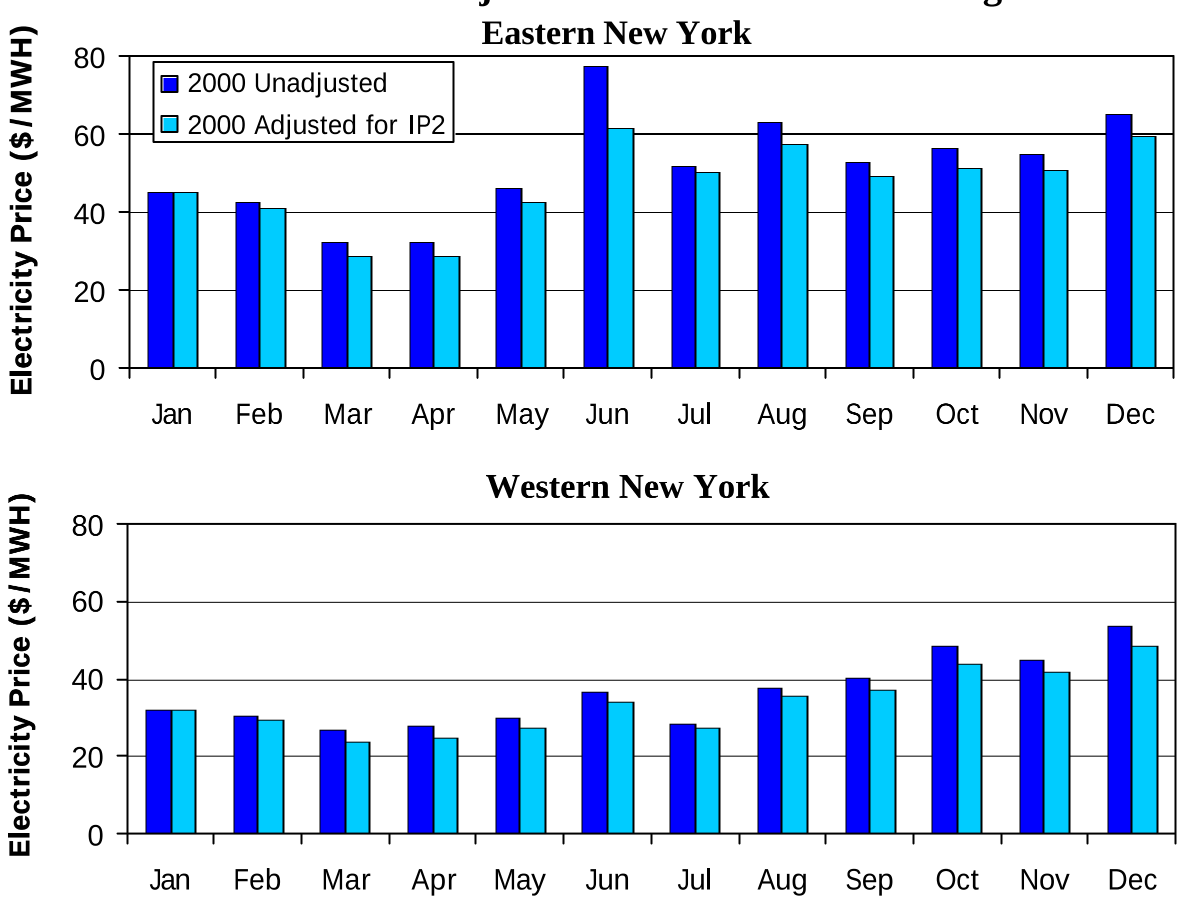
The market areas are defined by the presence of binding transmission constraints. For example, one of the market areas is Eastern New York, which is the relevant area only when the Central-East Interface is binding and no other transmission constraints in the East are binding. For these areas then, the excess capacity quantity is defined as the difference between the total capacity bid into the market from each unit and the quantities scheduled to provide energy, reserves, or economically withheld:

$$\text{Excess Capacity} = \sum_{i=1\,to\,n} [\text{Energy Bid}_i - (\text{Energy Schedule}_i + \text{Reserve Schedule}_i + \text{Econ Withheld}_i)]$$

for all i units in the market area

This excess capacity measure was then used to estimate the relationship described above between excess capacity, natural gas prices, and electricity prices in each market area. With these results, one may compute the price effects of having an additional gigawatt of capacity available in the market areas where the IP2 unit is located. Since IP2 is located in Eastern New York outside of New York City, it will have the largest effect on Eastern prices. It will only affect prices in Western New York when the Central-East Interface is not binding, which explains the modest impact on prices in Western New York during the summer season. Likewise, it will only affect prices in New York City when the constraints into New York City are not binding. Figure 11 shows the results of this analysis in Eastern and Western New York.

**Figure 11**
**DAM Prices Adjusted for Indian Point 2 Outage**

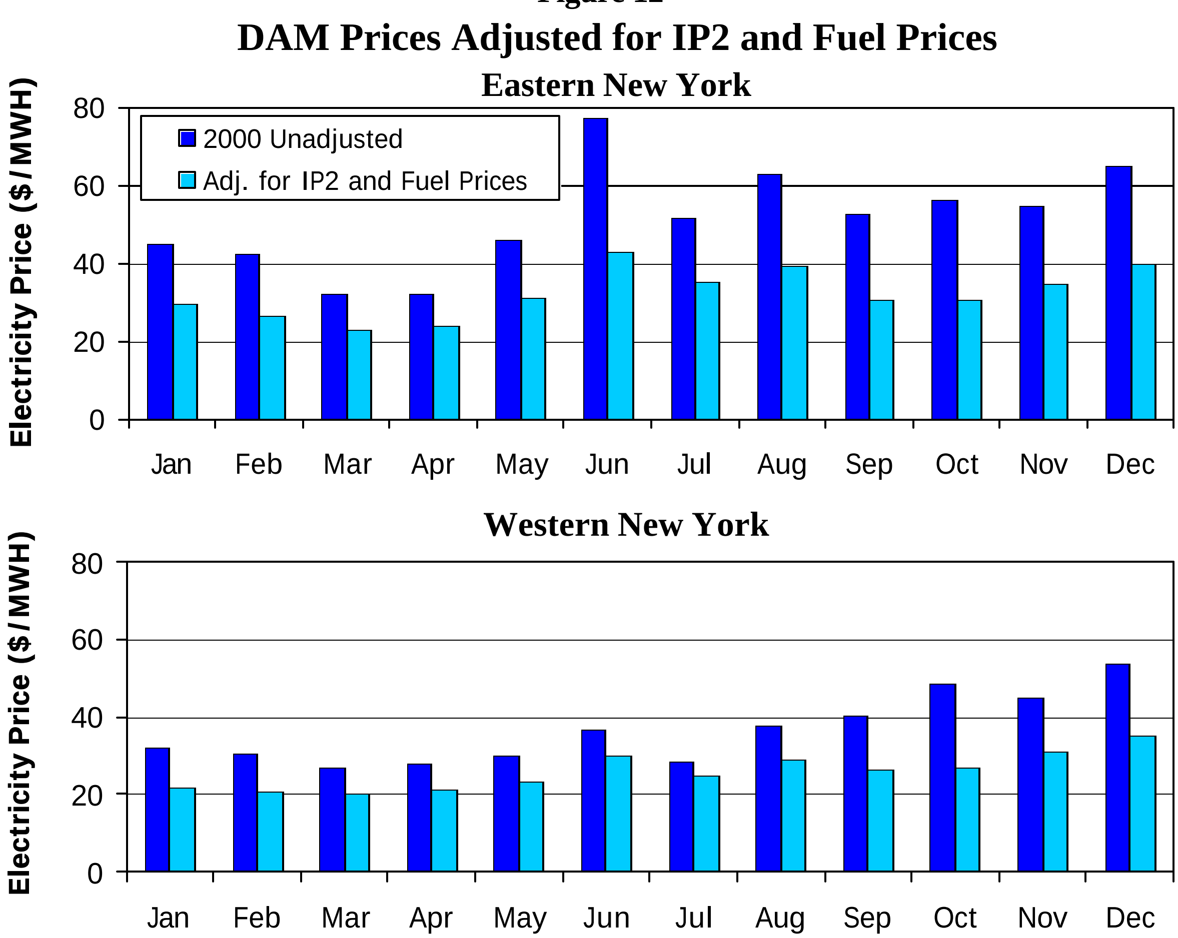



This figure shows that the effect of this outage was relatively modest in all months in Western New York and in the off-peak months in Eastern New York, ranging from an increase of 3 to 13 percent.

However, the price increase due to the outage in June and August in Eastern New York was as high as 30 percent. This larger effect is due to the fact that IP2 would have substantially relieved the tight supply conditions that precipitated the price spikes that occurred on June 26 and August 9. These effects are consistent with the nature of the shift in supply caused by the IP2 outage that was discussed above regarding Figure 8 – at lower demand levels where the market will clear in the flat portion of the supply curve, capacity shifts will result in much smaller price effects than shifts occurring under tight conditions involving the steep portion of the supply curve.

Lastly, I estimated the effects of these two factors together and the results are shown below in Figure 12. These results are not simply the sum of the effects of each of the factors. Rather, the impact of the factors must be estimated jointly since their effects are not additive.

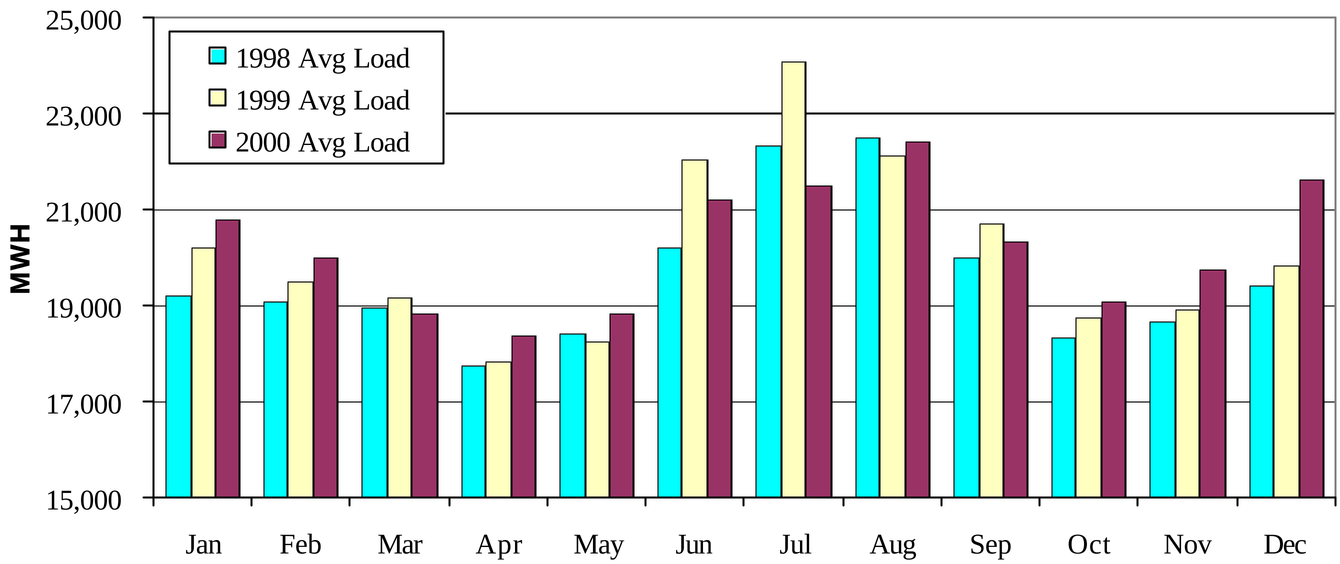
**Figure 12**



The figure shows that together the two factors in question resulted in price increases on a monthly average basis ranging from 11 percent to 84 percent. Consistent with the IP2 results, the largest effects in the East are in June and August due to the contribution of the IP2 outage to the price spikes that occurred in those months.

These results reveal that the adjusted prices are generally consistent with the historical prices prevailing prior to the introduction of the NYISO markets and help explain why the prices during 2000 were higher than some had expected.[8] However, it is important to note that this analysis only addresses these two important factors. It does not assess the effects of a number of other factors influencing prices during the year. For example, it does not account for the fact that loads during the summer were substantially less than average due to mild weather, especially during July. Figure 13 shows the average load during peak hours from 1998 to 2000, revealing the extent to which loads during the year deviated from prior years.

**Figure 13**
**Average Peak Hour Load in New York State**
**1998 to 2000**

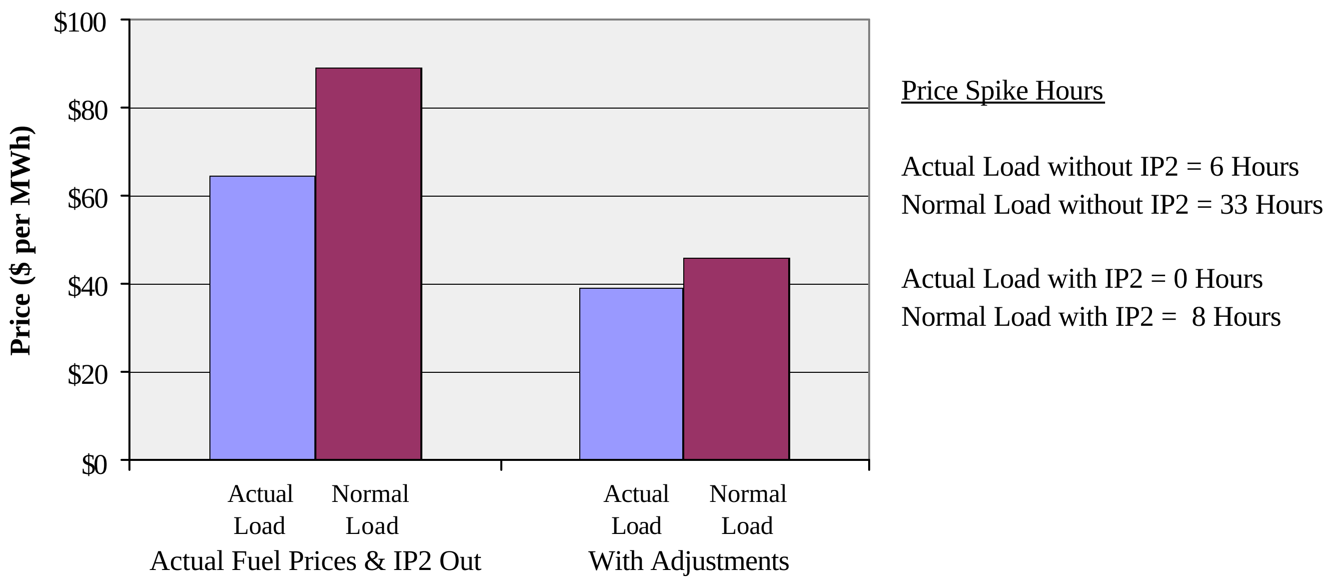



Although loads rose in most months from 1999 to 2000 as would be expected, this chart shows that the load in July 2000 was significantly less than it had been in 1999. While the weather in 2000 was abnormally cool during much of the summer, record warm weather occurred in 1999 resulting in the considerable increases in loads during June and July from 1998 to 1999. Taking longer-term trends into account, peak loads in June 2000 were close to the forecasted levels while peak loads in July 2000 and August 2000 were approximately 2000 MW and 1000 MW below the forecasted levels, respectively. Accurately assessing the effects of load increases is more difficult than changes in generating capability at a single point since the load adjustments result in changes everywhere on the system, leading to less predictable changes in congestion patterns. Nevertheless, I estimated the effects of the higher loads on the adjusted prices shown in Figure 12 by increasing the load in the relevant areas in New York.[9]

To exclude the effects of the cool weather, I adjusted the excess capacity in the relevant market areas defined by the binding transmission constraints in each hour to reflect the increase in load in those hours. Figure 14 below shows the results of this analysis.

**Figure 14**

**Effects of Normal Weather on the Day-Ahead Energy Prices Summer 2000 in Eastern New York**




This figure shows that the adjusted prices I presented earlier in Figure 12 for the summer of 2000 would have been almost $7 per MWh higher excluding the effects of the cool summer temperatures. This increase in average price is due primarily to the fact that the higher loads in Eastern New York cause tight supply conditions sufficient to generate price spikes in 8 hours versus no price spikes in the adjusted prices for 2000. With IP2 in service, therefore, the effect of the higher load due to warmer weather is less important than the substantial increase in fuel prices. Figure 14 also shows the unadjusted prices reflecting the 2000 actual fuel prices and IP2 out of service. In this case, the increase in load due to the warmer weather generates an increase in average prices in Eastern New York of $25 per MWh or almost 40 percent. Again, this increase largely results from the increase in the number of hours with very little excess capacity, resulting in price spikes. As the figure shows, these hours rise from 6 hours to 33 hours. Therefore, given tight supply conditions in the east contributed to by the outage of IP2, the cool weather shielded the market from market prices that could have been considerably higher.

In addition to the effects of the cool weather on prices in New York, other factors affected prices that were not included in the analysis described above. Unlike the weather effects, these other factors generally contributed to higher prices in 2000. First, the outage of phase angle regulators (PARs) in New Jersey led to a derating of the PJM import capability into New York by 500 MW. The effect of this derating is smaller than the IP2 outage, not only because it is a smaller amount but also because PJM imports electrically serve Western New York and must utilize the Central-East Interface (due to loop flow) to deliver power to Eastern New York or New York City.

Second, the New England Interface has not been fully utilized to import power into New York when the value of power in Eastern New York is substantially higher than its value in New England. Power was often exported to New England in these cases, leaving more than the total transfer capability (approximately 1600 MW) available for scheduling power transfers into New York. Since New England can supply Eastern New York, it would mitigate the tight supply conditions in that region that caused relatively high prices in 2000. This issue is described in more detail later in this section.

In conclusion, the outage of IP2 and the considerable increases in fuel prices were the primary causes for prices in 2000 that were higher than historical levels while the relatively cool summer weather prevented the markets from experiencing additional price spikes. The market will remain vulnerable to these types of price increases until substantial new capacity is added in the State, the seams issues with neighboring markets are resolved, or substantial demand-side participation in the market is introduced.

## C. Longer-Term Trends in Energy Prices

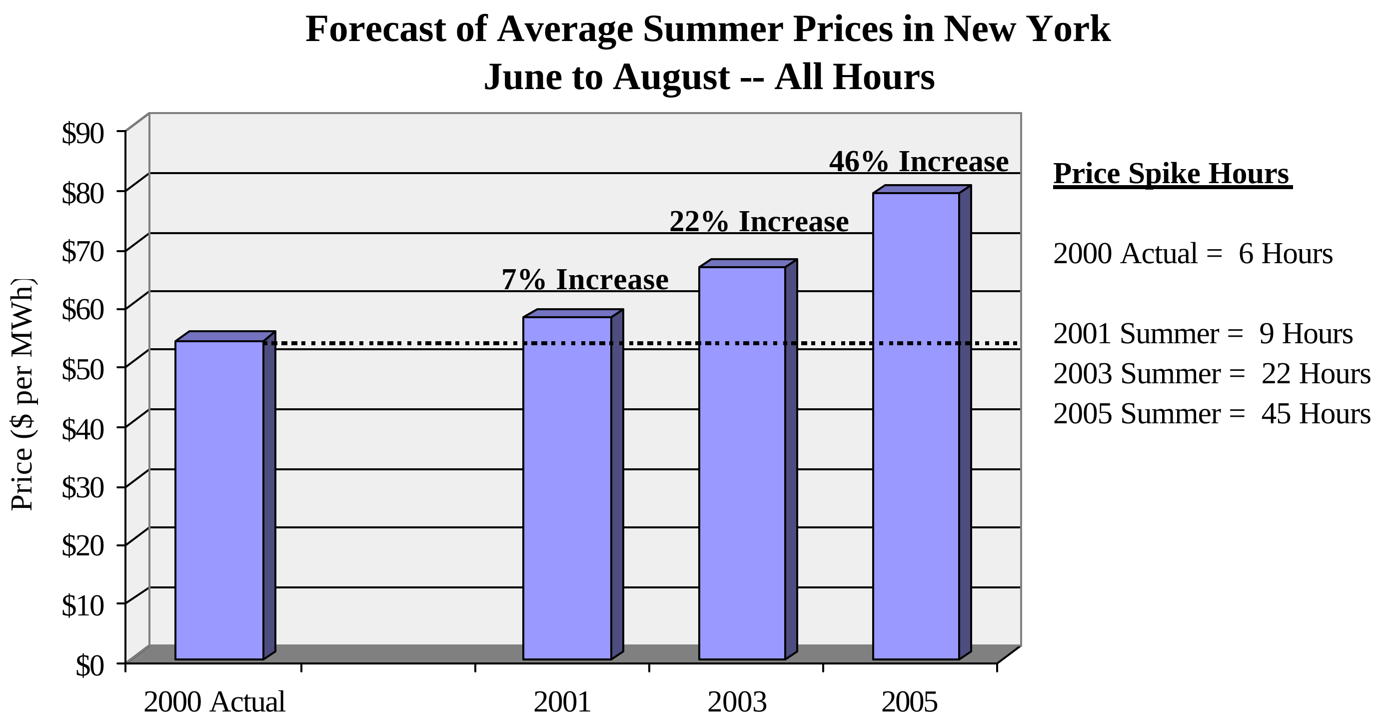
The prior section shows the potentially large price fluctuations that are generated under tight conditions that occur when generator outages or relatively high load cause excess supply to be diminished. These fluctuations generally reflect supply scarcity as long as suppliers are not unjustifiably withholding resources and provide important economic signals to new entrants. The fluctuations are exacerbated by the lack of meaningful demand participation in the market.

Over the longer term, the failure of new generation and transmission investment to keep pace with load growth will increase the vulnerability of the market to more frequent price spikes, increase the market's exposure to market power or other forms of strategic behavior, and increase the costs associated with any market design flaws. Although a number of regulatory and other factors have contributed to the dire market problems experienced recently in California, barriers to the construction of new generation that resulted in rapidly shrinking reserve margins have played a central role in precipitating the problems.

In that regard, New York is facing comparable market risks as barriers have prevented significant quantities of new generation from being installed in New York over the past five years. In a recent report by the NYISO identifying this concern, the NYISO showed that the continued load growth has caused reserve margins in the State to drop from more than 25 percent to approximately 16 percent.[10] Additional reductions in reserve margins are projected in the absence of new generation. The report projects annual electricity cost increases of approximately 20 percent versus the past year if new generation is not available to meet the growing load in the State.

I have also assessed the longer-term need for new generating and transmission capacity in New York using the econometric analysis described above for the analysis of the IP2 outage and the price effects of the cool weather during the summer of 2000. Using this approach, I forecasted the average summer electricity prices for the entire State in 2001, 2003 and 2005 assuming load continues to grow at the levels forecasted by the NYISO in its report. The results of this analysis are shown in Figure 15.

**Figure 15**




This analysis assumes that more than 1500 MW of generation will be on-line by the summer of 2001 that was not available in 2000, consisting of 980 MW from Indian Point 2, 170 MW from the re-powered Astoria unit in New York City, and the addition of several gas turbines in New York City and on Long Island. The addition of this new capacity nearly offsets the increase in load from actual 2000 to forecasted levels in 2001. However, as load grows through 2005, the average price is projected to rise to 46 percent above 2000 levels.

As in the prior analysis, a large share of this price increase is attributable to the increased frequency of price spikes that occur under tight supply conditions. Of course, these prices would substantially underestimate the prices that could prevail if temperatures are much warmer than forecasted as they were in 1999. This underscores the urgency to resolve the regulatory and other issues that have precluded a meaningful expansion in New York's generating resources over the decade. No threat to the market's stability and competitiveness is more pressing than the apparent barriers that currently exist to new investment in generation and transmission facilities.

## D. Market Operations in 2000

The analysis in the prior sections showed that the relationship of energy prices to excess capacity have been consistent with the economic characteristics of the supply available to the New York markets, although these prices were significantly affected by higher fuel prices and other external factors. Nonetheless, a number of design flaws or potential improvements to the market rules were identified over the first full year of market operation. Many of these issues can only be addressed adequately with significant software modifications, some of which have been completed and others that are scheduled over the next year. Others have also been addressed on an interim or permanent basis by modifications in market rules and procedures. Modifications and improvements completed by the NYISO for the energy market include:

- Working with owners of quick-start GTs bidding as a group to allow each unit to be bid separately. With the reduced flexibility associated with the grouped bidding, the NYISO was sometimes compelled to dispatch the GTs substantially less efficiently;
- Modifying its SCD software to prevent the miscalculation of real-time prices when large amounts of uneconomic block energy was running, sometimes occurring due to minimum run time requirements;
- Implementing software changes to give external transactions scheduled in the day-ahead market priority over other transactions reviewed by BME;
- Extending bid production cost guarantee payments to external energy suppliers;
- Improving the information on load and resources used by the BME to more accurately reflect the prevailing real-time conditions. This improvement has allowed the BME prices to better forecast real-time prices; and
- Modifying the NYISO software to prevent erroneous export curtailments.

In addition, a number of other modifications are currently underway to improve the performance of the energy markets, with some of the items scheduled to be completed prior to the summer 2001. These modifications include:

- Implementing an automated procedure for imposing a market power mitigation measure when economic withholding results in substantial price effects consistent with the current Market Mitigation Plan;
- Modifying the inputs to the BME to more accurately reflect generation scheduled out-of-merit, and off-dispatch schedule changes by PURPA and intermittent units;
- Making software changes necessary to allow the SCD model to secure the same constraints related to the Consolidated Edison transmission system as the BME and SCUC models;
- Expanding the capability for load-serving entities to bid their load into the day-ahead market in a price-responsive manner; and
- Implementing an emergency demand-side response program and a day-ahead price responsive load program.

These modifications will resolve a number of market issues and should improve the overall performance of the market. Some of the design flaws necessitating these changes undoubtedly had some effect on market prices in the first year of operation, however these effects are very difficult to accurately estimate without extensive modeling. In addition, these issues generally did not result in large systematic effects on prices, with the exception of the seams issues that are analyzed later in this section. Rather, most of the issues have resulted in only intermittent price effects or other costs. Therefore, rather than analyzing the individual effects of each of these issues, this section will assess the overall performance of the markets and focus on those operational issues that remain to be addressed in the future.

Table 1 provides summary statistics pertaining to the day-ahead and real-time energy markets in New York during 2000. The statistics are shown for New York City and two of the other ten zones in the State. The Capital zone is in northern New York and is east of the Central-East Interface while the West zone is west of Central-East.

**Table 1**
**Day-Ahead and Real-Time Pricing Statistics for Selected Zones**
**January to December 2000**

| | *New York City* | | *Capital Zone* | | *West Zone* | |
|---|---|---|---|---|---|---|
| | Day-Ahead | Real-Time | Day-Ahead | Real-Time | Day-Ahead | Real-Time |
| Mean | 48.83 | 50.34 | 44.82 | 42.05 | 34.46 | 29.88 |
| Std. Deviation | 36.60 | 82.71 | 38.95 | 42.44 | 15.73 | 31.50 |
| Variance | 1,339 | 6,842 | 1,517 | 1,801 | 248 | 992 |
| Minimum | 0.01 | (903.02) | (0.14) | (862.81) | 0.01 | (864.73) |
| Maximum | 1,012.05 | 1,862.41 | 1,296.93 | 1,017.22 | 169.13 | 907.74 |

As discussed earlier, the Central-East Interface is the most binding transmission constraint in the Northeast, which can create significantly different price dynamics in Western and Eastern New York. This table shows that for the two zones in Eastern New York, the means of the day-ahead and real-time energy prices are nearly indistinguishable. This has not been the case in the Western zones, where the mean of the day-ahead price has exceeded the mean in the real-time market by more than 15 percent.

In each of the zones, however, the variance of the real-time energy prices has substantially exceeded the variance of the day-ahead prices, indicating that the prices in the spot market are more volatile. The relatively high volatility in the real-time market is consistent with pricing in other commodities. In general, price volatility is inversely related to the contract duration. Therefore, longer-term forward contract prices will be subject to less volatility than short-term forward contract prices (including day-ahead prices), which will in turn be less volatile than real-time spot markets. The higher volatility in energy prices in the real-time spot market is due primarily to the fact that the SCD model, which solves for the real-time dispatch and prices, has a much smaller set of available actions that may be taken to clear the market and resolve any relevant constraints. For example, the SCUC model for the day-ahead market may utilize all bid-in resources to minimize production costs while resolving all constraints. The real-time market may use only those resources that are currently online or those that may be brought online within a few minutes.

Therefore, much larger price fluctuations in the real-time market should be expected as the SCD model uses online resources to clear the market in the face of loads that may differ substantially from those that had been bid-in or forecasted the prior day, as generating resources may experience outages in-day that create tight supply conditions, or as transmission outages require high-priced generating resources to resolve the resulting transmission congestion. The higher variance in real-time energy markets is, therefore, consistent with expectations and with experience in deregulated electricity markets in other regions. Loads may protect themselves from the higher volatility in the real-time energy markets by signing forward contracts for energy or by purchasing power in the day-ahead market. This issue and others are discussed in the next section that assesses price convergence in the day-ahead and real-time markets.

### *1. Day-ahead and Real-time Market Convergence*

In the summary of energy prices earlier in this section, I reviewed average prices that prevailed in Eastern and Western New York in the day-ahead market where the majority of the settlements through the NYISO markets take place. The analysis in this section will examine the degree to which prices in the day-ahead and real-time energy markets have converged to assess whether the multi-settlement system has allowed effective arbitrage between the markets. To assess this aspect of the market's performance, one must first form an expectation regarding convergence. Some have argued that the markets should converge completely. This could only be the case over the long-term because short-term fluctuations in both the day-ahead and real-time energy prices can cause one to substantially exceed the other over shorter timeframes.

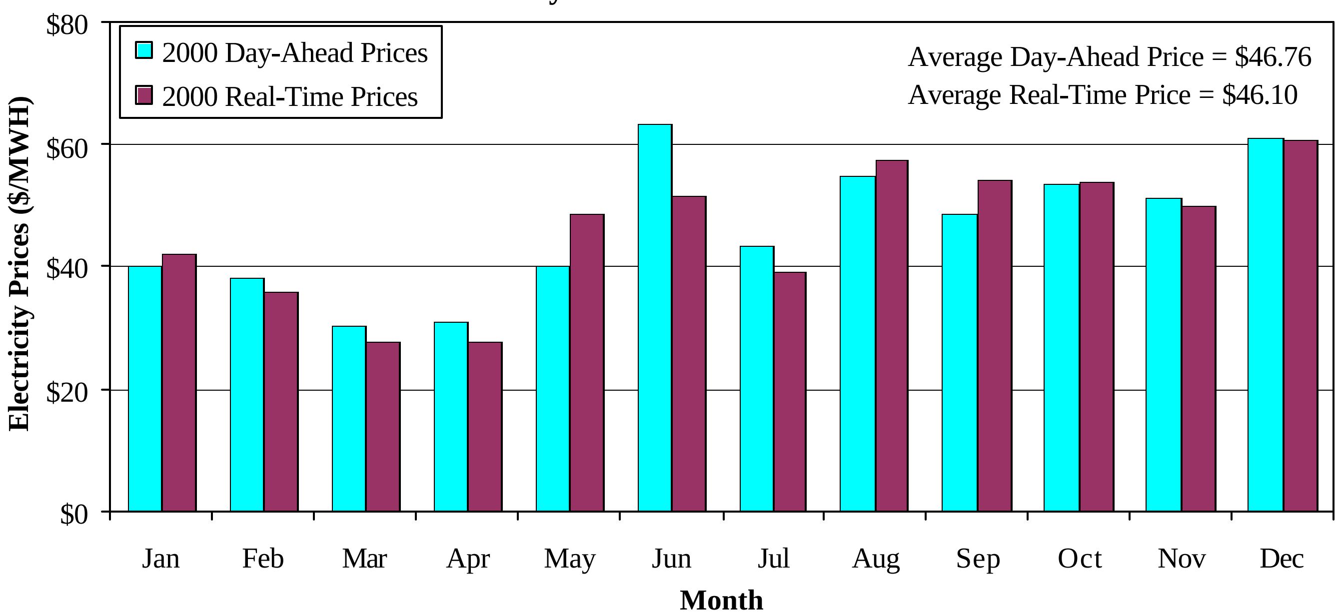
However, the expectation of complete convergence between the two markets may not be justified. Prices in the real-time market are more volatile than in the day-ahead market, caused by the factors described above. This higher variance raises the risk for LSEs to make purchases in the real-time market rather than in the day-ahead market or longer-term forward markets. Since purchases in the day-ahead market carry lower risk, it is rational for LSEs that are risk-averse to be willing to pay a premium to purchase in the day-ahead market.[11] Likewise, sales by generators in the day-ahead market may be accompanied by additional risk since up to 43 hours of financial commitments could have to be repurchased in the real-time market if the generator experiences an outage.

These differences in the underlying risk of buying or selling in the day-ahead market versus the real-time market will be reflected in higher day-ahead prices that cannot be arbitraged as long as the participants in the market are risk-averse. Arbitrage by participants that own generation or serve load can be accomplished by submitting bids that shift the supply and demand in each market to allow efficient convergence. For example, if the day-ahead market were persistently less expensive than the real-time market, one would expect that LSEs would increase their purchases in that market, leading to higher day-ahead prices and lower real-time prices (since the resources are optimally committed to supply the additional demand) and improved convergence.

Arbitrage by other entities, such as energy marketers, is currently limited by the market rules at locations other than the proxy buses with neighboring markets. At the proxy buses, marketers or others are not restricted in their ability to make purchases in the day-ahead market without a load to serve that may subsequently be sold into the real-time spot market (this has been termed "virtual bidding"). Likewise, there are no restrictions that would prevent entities from making sales at the proxy buses in the day-ahead market without a source of supply and then repurchasing the energy in the real-time market. Virtual bidding can help the day-ahead and real-time markets achieve an equilibrium level of convergence. However, this capability is limited at points internal to the New York market.

If these other entities are less risk-averse than the existing generators and LSEs, it is possible that expanding the virtual bidding capability for these entities to buy and sell between the two markets at points internal to New York would improve the arbitrage between the markets. However, the analysis below shows that the markets have tended toward a high level of convergence. Figure 16 shows the monthly average prices throughout the State in the real-time and day-ahead energy markets. These prices are generally higher than those shown in Table 1 above because they are load-weighted (i.e., the relatively high summer prices are weighted more heavily in the averages).

**Figure 16**
**Monthly Average Energy Prices in New York State**
**January 2000 to December 2000**

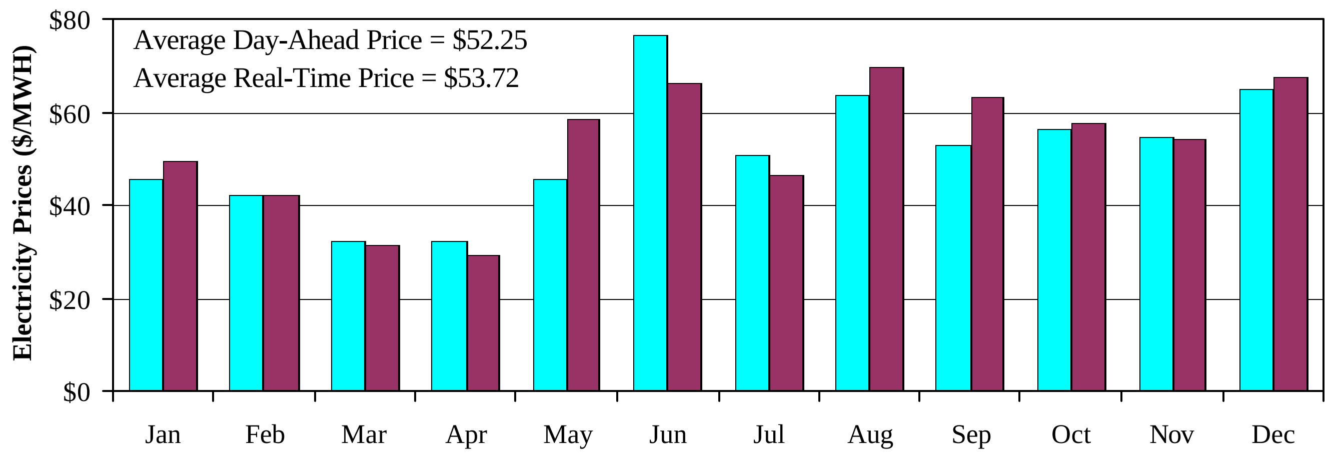


This figure shows that the average prices in the day-ahead and real-time energy markets were very close in nearly every month, especially in the last quarter of 2000. The largest divergences occurred in May and June, both of which were influenced by significant price fluctuations. In May, the real-time market experienced very high prices on May 8 and 9, exceeding $1000 per MWh on both days. The prices in these hours substantially increased the average real-time price for the month. Likewise, the high prices that occurred in Eastern New York on June 26 increased the average day-ahead price for that month significantly. These two fluctuations alone account for most of the price divergence between the day-ahead and real-time markets in both months. Figure 17 shows comparable data for Eastern New York and Western New York.

**Figure 17**

**Monthly Average Prices in the Day-Ahead and Real-Time Markets**

**Eastern New York**




**Western New York**

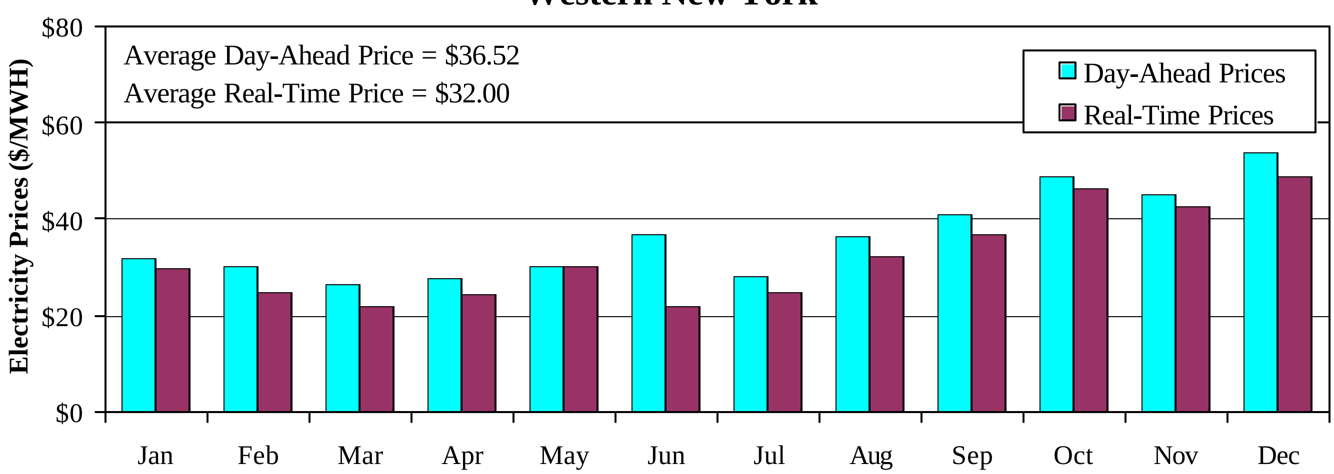
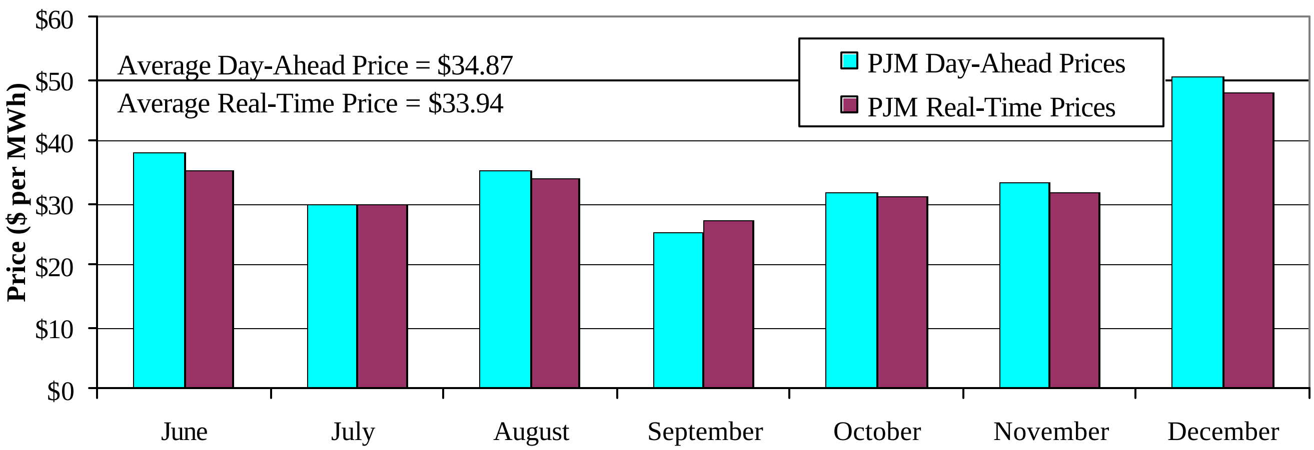


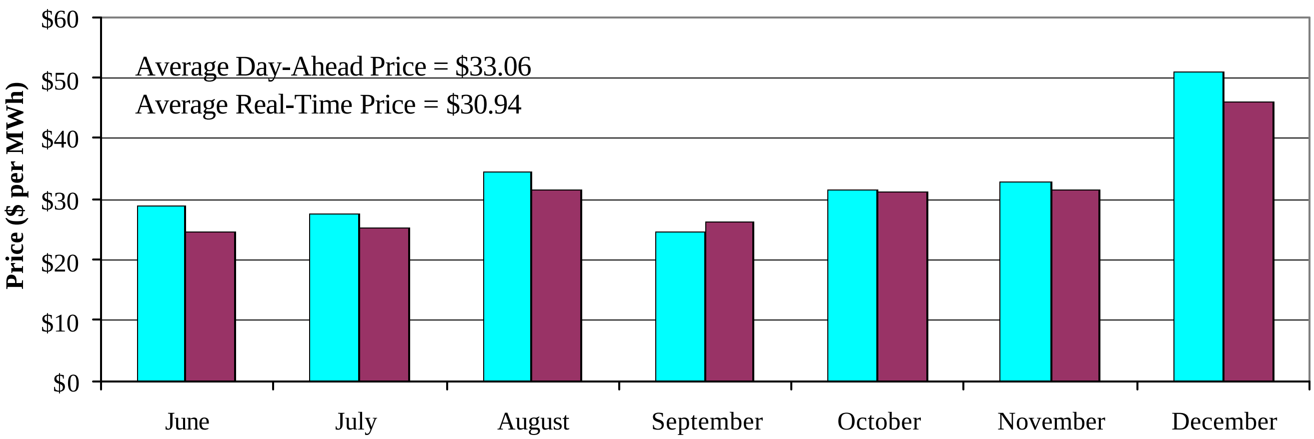
Figure 17 shows that the price relationship in Western New York has been more consistent, with the average day-ahead prices slightly exceeding the average real-time prices. The stability of this relationship is likely due in large part to the lower price volatility in that area. Alternatively, prices in Eastern New York, which has been subject to much larger price fluctuations, were 3 percent lower on average in the day-ahead market than in the real-time market.

For purposes of comparing the price convergence in the New York market to the performance of other markets, I have also plotted the monthly average day-ahead and real-time prices for the PJM market, which is shown in Figure 18.

**Figure 18**
**Monthly Average Prices in the Day-Ahead and Real-Time Markets**
**Eastern PJM**




**Western PJM**



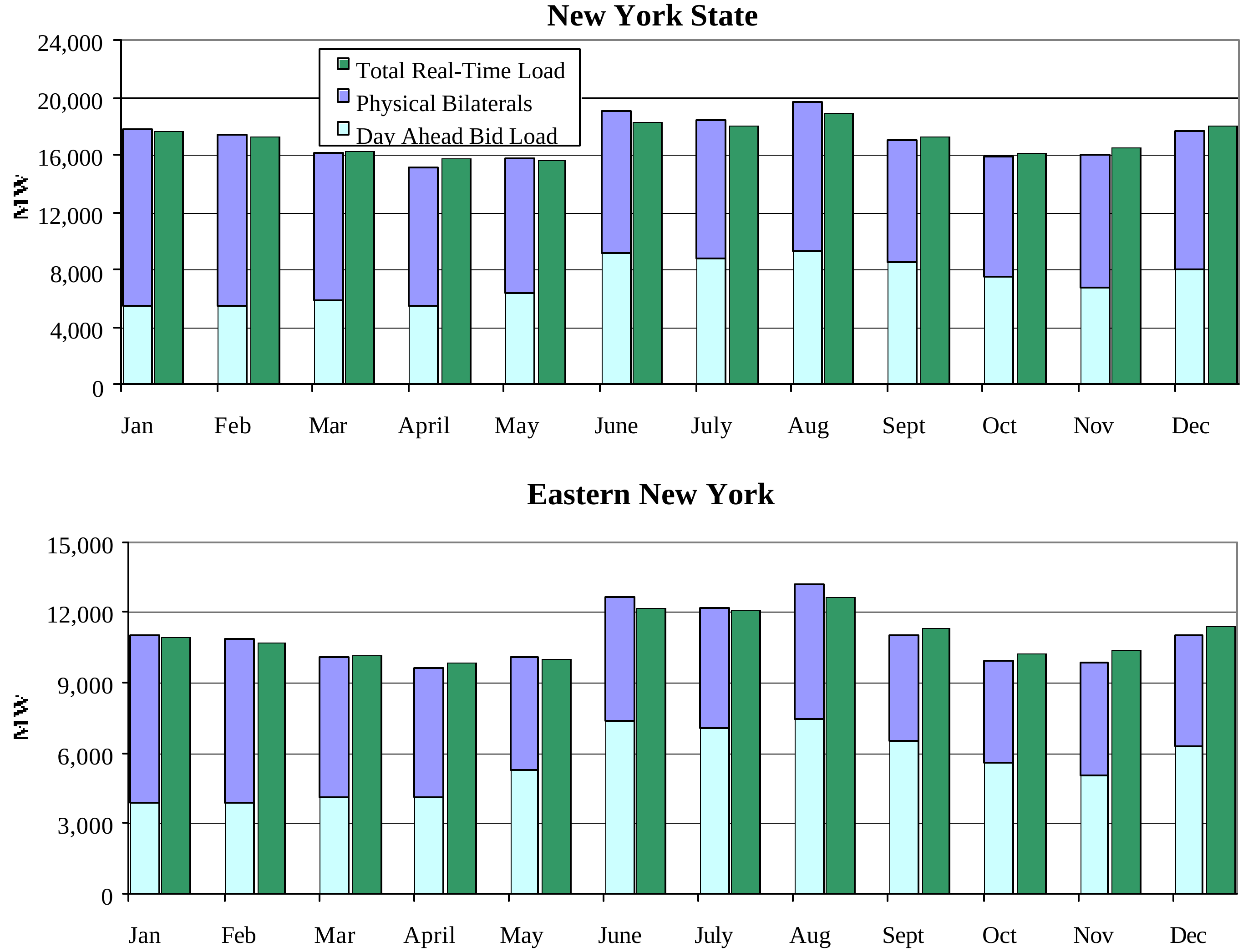
This figure shows that convergence between day-ahead and real-time energy prices in PJM has been similar to the price convergence in New York, with the day-ahead prices exceeding real-time prices as theory would predict. The figure shows June to December of 2000 because PJM implemented its day-ahead market in June. PJM's market rules allow virtual bidding at any point within PJM, which should improve the degree of convergence between the two markets absent gaming. The analysis above shows that price convergence in PJM has been slightly tighter than the convergence in New York. In addition to the potential contribution of virtual bidding, this performance is also probably the result of the lower price volatility in PJM. In general, Eastern New York has been subject to much larger price fluctuations in 2000 than PJM -- price spikes generally result in poorer price convergence between the markets unless they can be foreseen by participants.

### *2. Load Bidding and Forward Contracting*

This section reviews the load bidding in the New York energy markets during 2000. Figure 19 on the following page shows a comparison of the monthly average of the day-ahead loads with the actual loads. The total day-ahead load is composed of the day-ahead bid load with the scheduled physical bilateral transactions. Despite the name, the physical bilateral transactions are not physical schedules of power – they are simply those scheduled transactions that settle the energy transaction outside of the NYISO settlement process.

This figure shows the load bidding and actual loads in New York State, as well as east of Central-East. In both areas, the total load bid into the day-ahead market (including physical bilaterals) exceeded actual load during the summer months, but was slightly less than actual load in the off-peak months. This bidding pattern during the summer likely contributed to the higher prices realized in the day-ahead market during June and July. Some had initially expressed a concern that large LSEs may deliberately under-bid their load in the day-ahead market in an attempt to artificially reduce the day-ahead clearing prices. This has not been the case, but the MMP will continue to monitor for this conduct.

**Figure 19**
**Comparison of Day-Ahead and Actual Loads in 2000**




In addition to the comparison of the total bid load and actual load, the figure shows the shares of the bid-in load that are composed by physical bilateral transactions. Many of these transactions correspond to the purchase contracts associated with the generation divested by the New York utilities.

At the beginning of the year, the chart shows that almost 75 percent of the day-ahead market was accounted for by physical bilateral contracts statewide. By the end of the year, this level had fallen to less than 60 percent. In Eastern New York, the figure shows that by summer of 2000 the share of energy schedules made under physical bilateral contracts had fallen to less than 50 percent.

On its face, this could indicate that a higher portion of the purchases are being made through the day-ahead market rather than through longer-term forward contracts, which would raise the volatility of the load's purchase power costs. However, this data is not sufficient to draw that conclusion because it does not reveal the financial contracts that may be in place to hedge the market's price volatility. A "contract-for-differences" ("CFD") and a transmission congestion contract ("TCC") may be combined to create a fully hedged forward energy purchase. When a CFD is in place, the generator will settle with the NYISO at the generator point and the load will settle with the NYISO at the load's zone as if they have no contract. Subsequently, the parties settle the difference between the LBMP and the strike price if the contract between themselves without the involvement of the NYISO. Power traded under these financial contracts would show as "day-ahead bid load" in Figure 18, which would be misleading since the parties are not, in reality, paying or receiving the day-ahead price.

Nevertheless, it should remain a high priority of the NYISO to facilitate the forward contracting market. One of the important lessons learned in California over the past year is that the lack of a healthy and liquid forward energy market can reduce the stability of the spot market, expose consumers to extremely volatile power costs, and reduce the incentive for suppliers to bid competitively into the NYISO energy markets. Therefore, I will be gathering additional data on the forward contract market and working with participants and the NYISO to remove any barriers to the development of a more robust forward contract market.

### *3. Uplift*

This section reviews the market costs embodied in the uplift charges in New York. These costs are incurred in the process of satisfying the demand for energy, but are not reflected in the energy market prices. Uplift is generally caused by one of three circumstances. First, uplift will result when a generator must be dispatched out of economic merit order to satisfy a local reliability requirement. These requirements are not modeled by the NYISO and are, therefore, not reflected in the NYISO schedules and prices. Although they are not explicitly modeled, some of these requirements are accommodated in the unit commitment passes of SCUC.

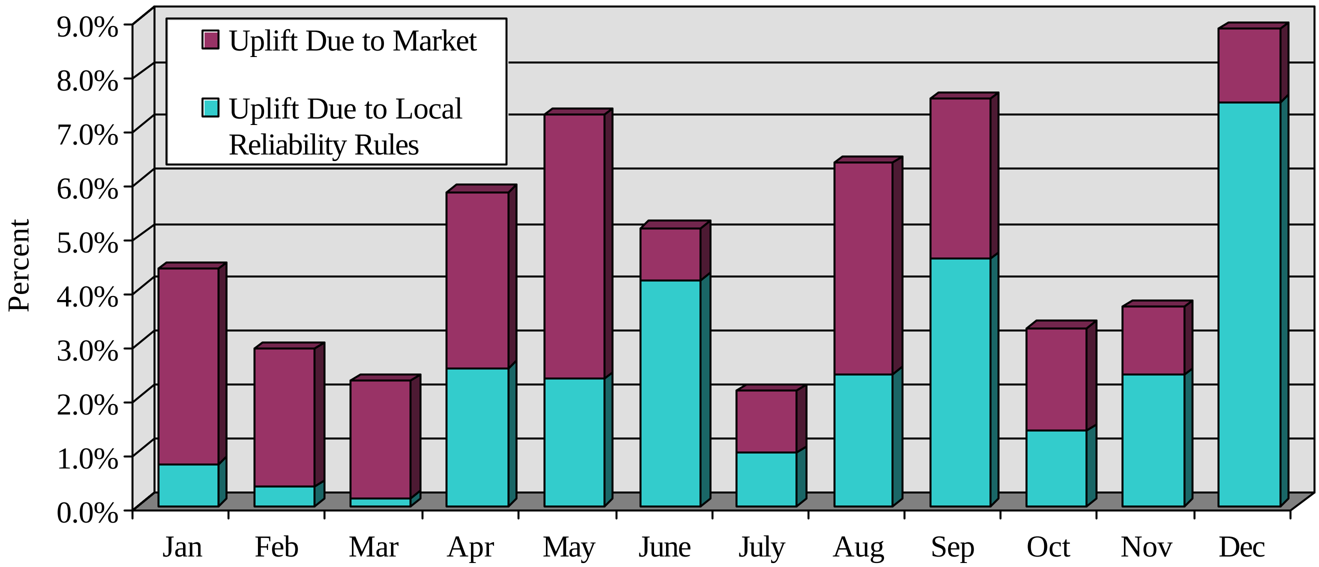
In other cases, transmission owners are responsible for monitoring the system and calling for generators to be dispatched as necessary to accommodate the requirements. The NYISO, in turn, will seek a bid from the generator if necessary through a supplemental resource evaluation ("SRE") and dispatch the generator. Because generators selected through this process are not eligible to set the LBMP, an additional payment will be made to the generator to the extent that its bid exceeds the revenue received at the LBMP. This process can result in uplift charges to recover the costs of this payment, and can also result in lower LBMPs if the generator committed through the SRE process displaces the marginal generator causing the market to clear at a lower level.

Second, uplift in the day-ahead market will result when the total revenue recovered by a generating unit from the NYISO's markets in a day does not exceed the generator's bid production costs. The New York market rules provide for a bid production cost guarantee payment to be made to the unit to ensure that its total revenue covers its bid production cost for the day. In the day-ahead market, generating units are committed to meet the forecasted load for the following day. When the forecast substantially exceeds the bid-in load, uplift costs may be incurred to cover the start-up and minimum load costs of the additional committed units.

Third, uplift can be generated in the real-time market when the real-time price is not sufficient to cover the costs of supplies scheduled in-day. One way this can occur is through the hour-ahead BME process, which schedules external transactions and generating units that are not on dispatch (i.e., cannot receive dispatch instructions from the SCD every 5 minutes). Significant differences between the BME prices and the real-time price can cause transactions to be scheduled that are not economic at the real-time price. Because all transactions are settled at the real-time price[12], a production cost guarantee payment is required to ensure that the external supplier receives revenue equal to at least the level of its bid.

Figure 20 shows the uplift incurred in the New York market as a percent of the total market costs, separately identifying the uplift due to local reliability requirements versus those generated through bid production cost guarantees resulting from the NYISO's market process.

**Figure 20**
**Total Uplift as a Percentage of Market Expenses**
**January to December 2000**




This figure shows that a substantial portion of the market cost during certain months were recovered through uplift charges – close to 9 percent in December. A large portion of these costs were related to local reliability requirements, which increased in magnitude over the year. As described above, uplift related to local reliability requirements is caused by the fact that the initial schedules and prices do not reflect these requirements. The goal of the locational pricing system employed in New York is to reflect transmission system constraints in the energy prices and dispatch to the maximum extent possible. Therefore, the rising levels of these costs raise three potential concerns that should be investigated further.

First, are there any local reliability requirements that reflect transmission constraints that should be modeled explicitly by the NYISO? Second, since generator commitments under local reliability rules can reduce prices, is there any evidence that units have been strategically committed under local reliability requirements. The NYISO has made modeling improvements in SCD to improve its representation of the New York City system and will further investigate uplift issues this year. By modeling the full set of bulk power transmission system constraints that are modeled in SCUC, the

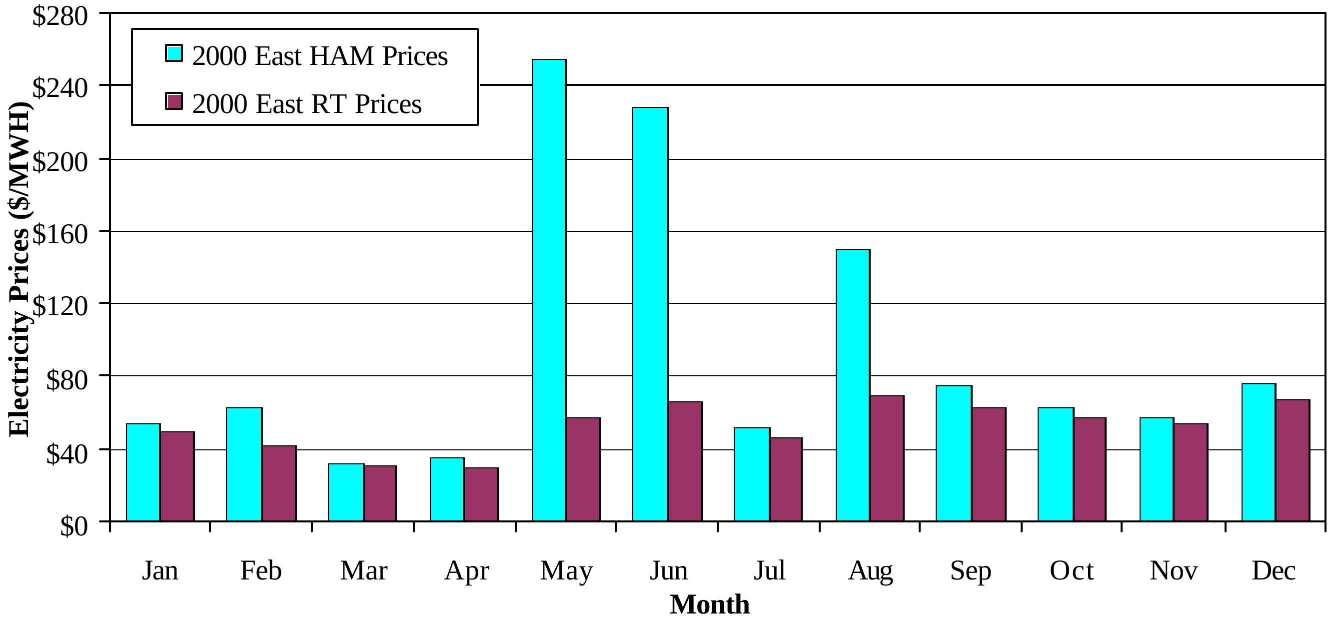
NYISO has significantly reduced the need for Consolidated Edison to call for generation under local reliability rules to resolve these constraints. This change has also improved the correlation of the BME market results and SCD results for the real-time market.

Third, the increasing local reliability costs could be related to must-run conditions caused by the requirements. If a local reliability requirement can only be resolved through the commitment of the resources of a single supplier, the supplier may have the ability and incentive to raise its bid prices when the NYISO seeks a bid from a unit under the SRE process. This conduct would likely be eligible for mitigation under the market mitigation measures ("MMM"). To address this potential issue, the NYISO has implemented a procedure to screen the bids submitted in the SRE process for any conduct that qualifies under the Mitigation Measures as economic withholding and an attempt to exercise market power associated with a temporary must-run circumstance.

In addition to the uplift issues associated with the local reliability requirements, I have reviewed the performance of the BME prices versus real-time to assess the degree to which poor correlation may have contributed to higher real-time uplift. First, a statistical analysis of the BME prices and real-time prices for the same locations suggest that the prices have not been well correlated although the performance has improved over the year. In particular, the BME produced prices in 38 hours that were well over $1000 per MWh, with the highest exceeding $50,000, while the real-time price in these hours were typically less than $500. Some of these BME prices may not be valid since they are not subject to the same validation procedures as the day-ahead and real-time prices. Nonetheless, they are the prices that are used to schedule external transactions and produce hourly dispatch levels for units that are not on dispatch.

Figure 21 shows the monthly load-weighted averages in Eastern New York of the hour-ahead and real-time prices. For purposes of computing the hour-ahead prices, I set all prices greater than $1000 to $1000 and prices less than $-1000 to $-1000 to avoid allowing the extraordinary HAM prices in relatively few hours from overwhelming the averages.

**Figure 21**
**Hour-Ahead and Real-Time Prices in Eastern New York**
**January 2000 to December 2000**



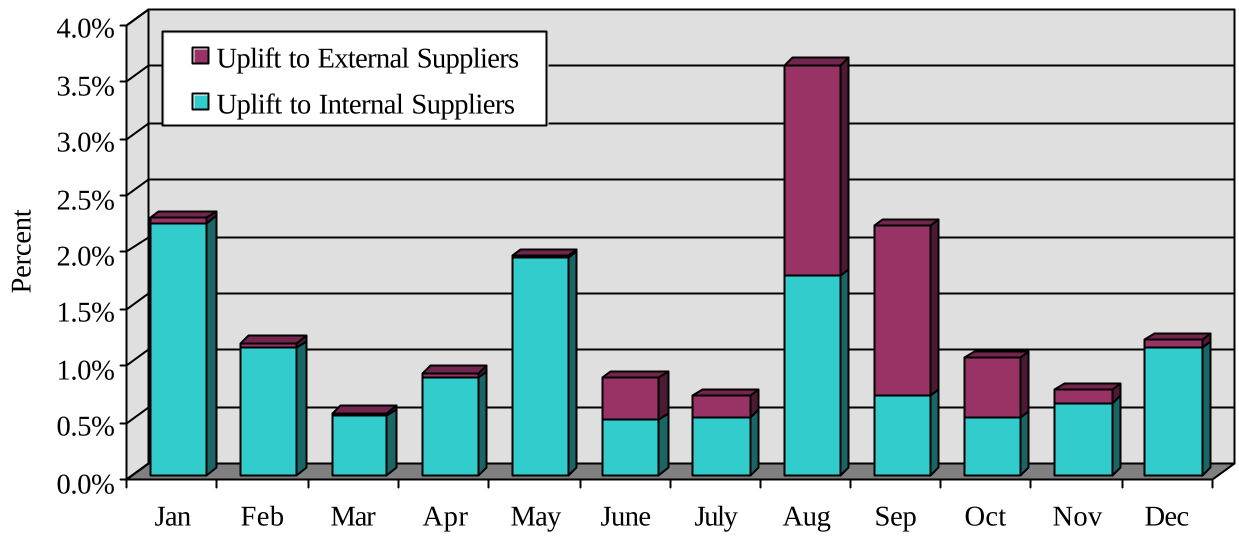

The NYISO published its *Initial Report On Price Differentials Between Balance Market Evaluation And Real-Time* in May 2000, which assessed the reasons for the real-time volatility and the poor convergence of the BME and real-time prices.

This report identified four primary causes:

- Differences in the generation resources available in real-time versus those assumed in the execution of the BME;
- Differences in the load in real-time versus the load assumed by the BME;
- Differences in the constraints that are modeled in the BME versus those secured by the SCD in real-time; and
- Changes in the transmission network that can occur unexpectedly in real-time.

As indicated above, a number of changes have been made to improve the quality of the input data for the BME model. These changes contributed to the improvement in the convergence of the BME and real-time prices that occurred in the fourth quarter of the year. However, to evaluate the potential costs reflected in uplift charges of these periods when the BME results did not accurately forecast real-time market conditions, I have examined the real-time bid-production cost guarantee payments made to internal and external generators. Figure 22 shows these results.

**Figure 22**
**Real-Time Uplift as a Percentage of Market Expenses***
**January to December 2000**




* Does not include uplift paid resulting from local reliability considerations.

This figure shows that the uplift costs due to bid production cost guarantee payments to external suppliers in the real-time market has been very small with the exception of August and September. As noted above, the anomalously high prices produced by the BME model occurred in May, June and August. Further, less than 10 percent of the uplift shown in Figure 22 for August was incurred on the days during the month that experienced the anomalously high hour-ahead prices produced by the BME. Therefore, external transactions scheduled by the BME that were ultimately uneconomic at real-time prices did not produce a substantial uplift obligation for consumers in New York.

Nonetheless, the NYISO has taken a number of steps described above so the BME more accurately reflects real-time market conditions. In addition, other changes in the operation of the BME and SCD models suggested in the pricing report issued by the New York Department of Public Service are being evaluated.

Lastly, an inefficient pricing provision related to external transactions contributed to the relatively large external uplift costs shown in the figure for August and September. This pricing issue was addressed with two Extraordinary Corrective Actions ("ECA") issued by the NYISO in October 2000, which are discussed in the following section.

## E. External Transactions

One of the most significant issues in any energy market is the extent to which power can be efficiently traded to allow for efficient arbitrage of market prices at different locations. Within New York, the NYISO market models (SCUC and SCD) accomplish this arbitrage by producing an economic dispatch and the associated locational prices based on the supplier and load bids. However, arbitrage between the New York market and the neighboring markets in New England, PJM and Canada must be accomplished by participants that schedule transactions to take advantage of price differences.

Therefore, this section analyzes the extent to which this arbitrage has occurred by analyzing the price differences between the markets and the utilization of the interfaces. The analysis reveals significant seams issues that are preventing full use of the interfaces between New York and neighboring markets. In addition, I analyze the results of the NYISO's import and export scheduling process to determine whether the NYISO models or market design have been an impediment to trading. Lastly, I review the processes currently underway to address the seams issues prior to next summer and in the longer-run.

Absent transmission constraints, trading should occur between the markets to cause the prices in the neighboring markets to converge. In other words, when prices are higher in New England than New York, exports should continue until the interface is fully scheduled or until prices have converged and no incentive remains to increase exports. The scatter plots shown below show the relative differences in prices between New York and neighboring markets as well as the flow of power between the markets. The vertical axis shows the hour difference between the price in New York and the price in the adjacent market. The top two quadrants, therefore, are hours where the price in New York was higher than the price in the neighboring market. The horizontal axis shows available import capability into New York from the adjacent market and computed in the following manner:

*Available Import Capability = Total Transfer Capability - Net Scheduled Import*

Therefore, when the NYISO is exporting (net scheduled import is 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 dashed line is shown at the approximate total transfer capability level for each interface so the two right quadrants represent net exports while the two left quadrants generally show net imports.

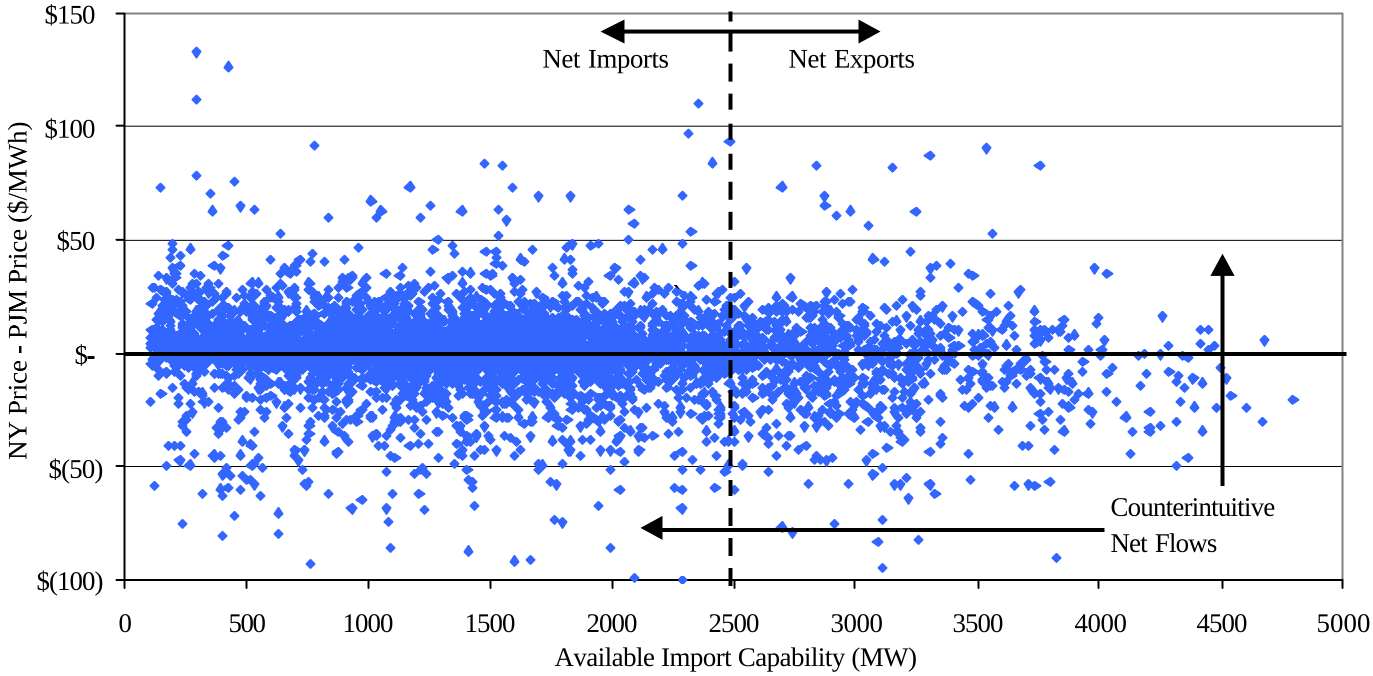
If transactions were scheduled efficiently between the ISOs, one would expect that the points in each of the charts would be relatively closely clustered around the horizontal line showing no price difference between New York and the adjacent market in the absence of a physical transmission constraint. One would not expect net exports to occur when the New York price substantially exceeds the price in the neighboring market – likewise, one would not expect net imports to occur when prices in New York are less than prices in the neighboring market. These two are situations are shown in the upper right and lower left quadrants in the charts and are labeled as "counterintuitive".

Figure 23 shows the hour-ahead results for PJM and New York in the real-time market during 2000 in unconstrained hours. I did not have data indicating when constraints are binding in the real-time market across the external interfaces. Therefore, as a proxy I excluded hours when the NYISO either reported an ATC value of zero or the computed ATC (TTC – net schedule) was less than 100 MW. In addition, transactions can be constrained by limits in the total change in net interchange from hour to hour (i.e., the net imports and exports over all of the external interfaces). This limit is a constraint on the desired net interchange ("DNI") and is currently set at 700 MW.

When the DNI constraint is binding, the price at all of the proxy buses will reflect the shadow price of the DNI constraint. Therefore, I filtered the hours for those where each of the proxy bus prices are

**Figure 23**

**Difference Between New York and PJM Price During Unconstrained Hours**
**Hour Ahead Market -- January 1, 2000 to December 31, 2000**




similarly constrained to exclude the hours where the DNI constraint may have prevented full arbitrage. Using these measures to identify the hours when the these transmission constraints are binding indicates that the PJM interface was fully scheduled in roughly only one quarter of the hours during 2000.

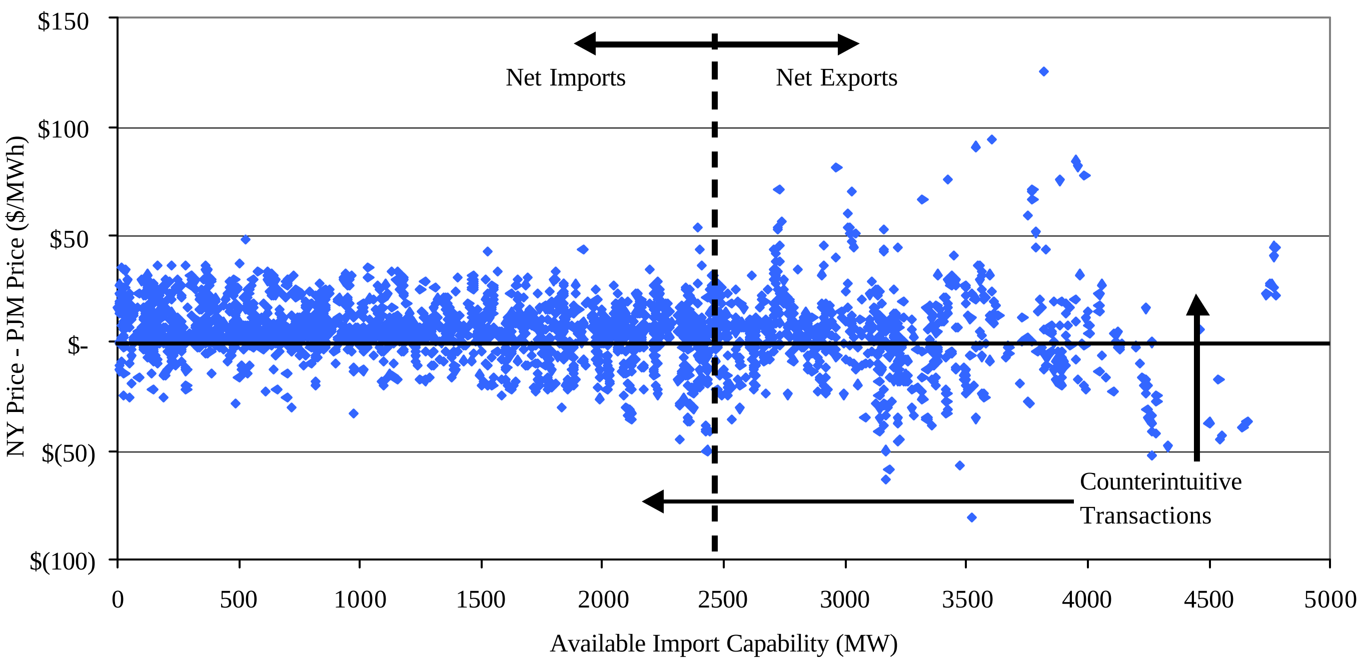
The price difference shown in Figure 23 is the difference between the Western New York and PJM West prices since PJM is electrically located west of the Total-East Interface. The mean of the difference between these prices in New York and PJM shown in this figure is relatively close to zero at -$0.11 per MWh, and the standard deviation of these hourly differences is $34. Although the figure shows that more than 40 percent of the points are located in the "counterintuitive" quadrants, only 16 percent of all the points also show a price difference greater than $10 per MWh.

Several factors prevent the markets from being fully arbitraged. First, market participants do not operate with perfect foreknowledge of market conditions in each market so that without explicit coordination between the markets by the ISOs, complete arbitrage will not be possible. Second, differences in scheduling procedures and timing can serve as a barrier to full arbitrage of the markets.

Lastly, risks associated with curtailment and congestion will reduce participants' incentives to engage in external transactions as the difference in prices diminishes. Given these factors, arbitrage between the PJM and New York hourly market has been reasonable efficient.

Since the implementation of the PJM's day-ahead market, the arbitrage of the day-ahead prices in PJM and New York have been more effective than the hour ahead prices as might be expected since the resources needed to support the transactions are generally easier to arrange. Figure 24 shows the results for the day-ahead market. Instead of the proxy used for the hour-ahead analysis to identify constrained hours, I was able to use data from the day-ahead market to identify when a constraint is binding on the PJM interface or when the DNI constraint is binding.

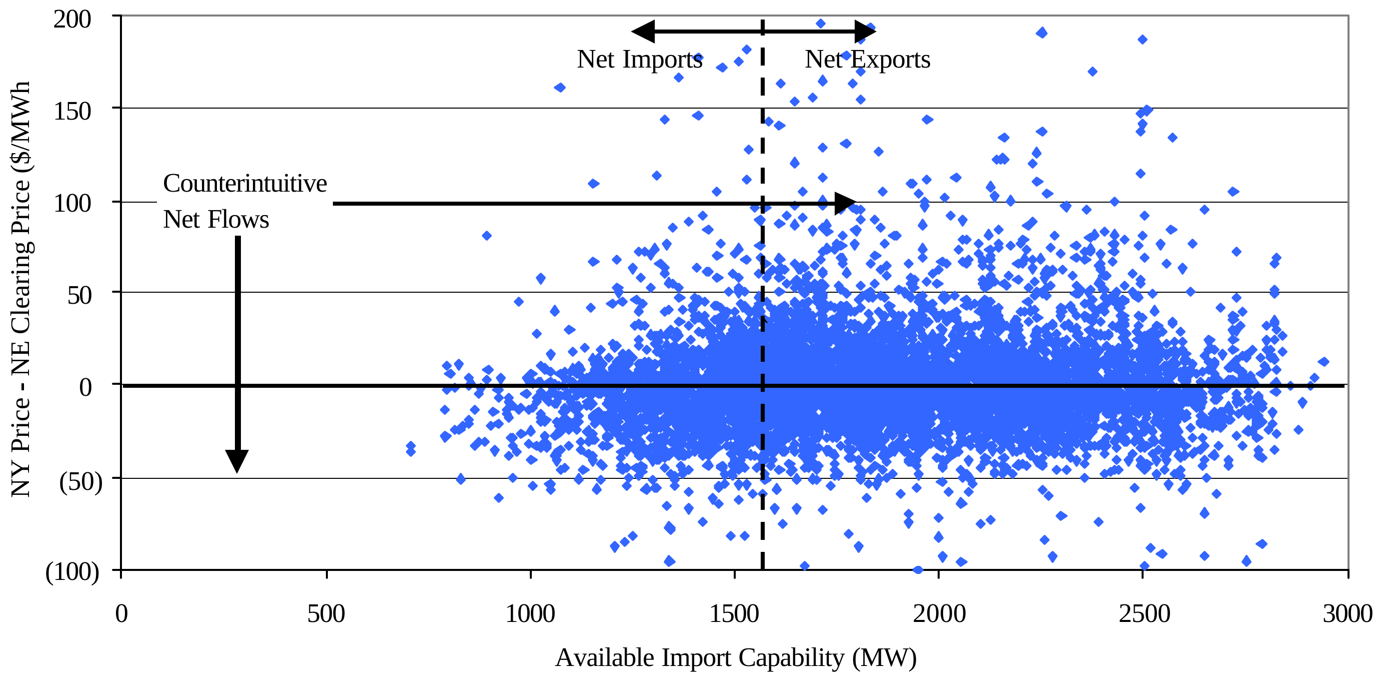
**Figure 24**
**Difference Between New York and PJM Price During Unconstrained Hours**
**Day Ahead Market -- June 1, 2000 to December 31, 2000**




In this case, the mean of the difference in price between the two markets was $5.40 per MWh while the standard deviation was less than half of the hour-ahead value at $15.30. In addition to the tighter convergence of the prices, the percent of unconstrained hours where the difference was greater than $10 and the net flow was in the counter-intuitive direction was only 12.5 percent. These results for the

PJM interface indicate that while benefits could be achieved through better coordination between the ISOs regarding the scheduling of external transactions, the markets have been relatively well arbitraged, particularly later in the year after the implementation of ECA A and B. However, the New England interface has not been as well utilized as the PJM interface, which is shown in Figure 25.

**Figure 25**
**Difference Between New York and New England Price in Unconstrained Hours**
**Hour Ahead Market -- January 1, 2000 to December 31, 2000**




This figure shows that in most hours New York was exporting power on net to New England, even when prices in New York were substantially higher than the prices in New England. More than 50 percent of the points in the figure are in the counter-intuitive quadrants, and roughly one third of all the points are both counter-intuitive with price differences greater than $10 per MWh. The mean of the price difference between the two markets was $-1.30 per MWh while the standard deviation was $146. Together, these statistics demonstrate that arbitrage has not been effective on the New England interface to cause prices to converge between the markets.

The fact that the prices in Eastern New York and New England have not been well arbitraged is critical since it is the markets in Eastern New York that have been subject to capacity shortages and energy price spikes. The New England interface offers up to 1600 MW of physical capability to import power into New York. Further, when substantial exports are scheduled associated with longer-term transactions, incremental imports of 2000 to 3000 MW may be scheduled since imports may be counter-scheduled against the scheduled exports. When the markets in Eastern New York become tight, the ability to schedule imports from New England can be critical in avoiding inefficient price spikes and allowing the markets to remain competitive. For example, on June 26 when prices exceeded $1200 per MWh in Eastern New York, net exports were scheduled in every high priced hour in the day-ahead market, while the price in New England's energy market ultimately ranged from $38 to $58 per MWh. Table 2 shows these results for the day-ahead price spikes on both June 26 and August 9.

**Table 2**
**External Transactions with New England During High Priced Periods**
**June 26, 2000**

| | Day Ahead Market | | | Real-Time Market | | |
|---|---|---|---|---|---|---|
| Hour | New England Proxy Price | Net Scheduled Import | Available Import Capability | Net Scheduled Import | New England Proxy Price | New England Price |
| 9:00 AM | $558 | -1086 | 2586 | -941 | $183 | $38 |
| 10:00 AM | $739 | -896 | 2396 | -450 | $196 | $48 |
| 11:00 AM | $723 | -541 | 2041 | -363 | $189 | $55 |
| 12:00 PM | $526 | -235 | 1735 | -180 | $164 | $68 |
| 1:00 PM | $1,208 | -545 | 2045 | -77 | $122 | $55 |
| 2:00 PM | $1,206 | -546 | 2046 | -80 | $122 | $52 |
| 3:00 PM | $926 | -300 | 1800 | -176 | $159 | $53 |
| 4:00 PM | $606 | -100 | 1600 | -60 | $138 | $52 |
| 5:00 PM | $983 | -100 | 1600 | 121 | $98 | $54 |
| 6:00 PM | $739 | -546 | 2046 | -16 | $154 | $55 |

**August 9, 2000**

| | Day Ahead Market | | | Real-Time Market | | |
|---|---|---|---|---|---|---|
| Hour | New England Proxy Price | Net Scheduled Import | Available Import Capability | Net Scheduled Import | New England Proxy Price | New England Price |
| 12:00 PM | $283 | 247 | 1353 | 96 | $40 | $43 |
| 1:00 PM | $964 | 304 | 1296 | -26 | $41 | $37 |
| 2:00 PM | $1,000 | 304 | 1296 | 76 | $20 | $33 |
| 3:00 PM | $125 | 244 | 1356 | 40 | $12 | $31 |

One June 26, the table shows that prices in both the day-ahead and real-time markets in New York exceeded the energy prices in New England, while relatively large net exports into New England were scheduled in nearly every hour. The price shown in the table labeled as the "New England Proxy" is the price published by the NYISO for the point on the New York system where imports and exports are assumed to pass between New York and New England. Clearly, the exports shown in the table were in retrospect uneconomic and contributed to the price spikes on the two days shown above.

In addition to the inability of market participants to reduce exports in these hours or increase imports, virtual bidding at the proxy buses failed to ensure that the markets were well arbitraged. Participants have the ability to engage in virtual bidding at the proxy buses and then settle the imbalance at the real-time price when the transaction is not scheduled in real-time.

On June 26, for example, a participant could have bid an import into the day-ahead market from New England at close to $1000 and been scheduled. Having been scheduled and received the high day-ahead price, the participant could repurchase its import obligation at the real-time price of $150, thereby receiving a net profit of the difference between the day-ahead and real-time price. Not only would the participant have earned a considerable profit, but it would have assisted the markets to converge and mitigated the day-ahead price spike.

At this point, it is useful to discuss the market design flaw that had a significant effect on external transactions in the real-time market. The BME schedules transactions based on the hour-ahead forecasted prices that the BME model produces. However, the BME prices are only forecasts and transactions were actual settled at real-time prices. This misalignment in prices between the scheduling determination and the settlement process created substantial risks for market participants that ultimately affected their behavior.

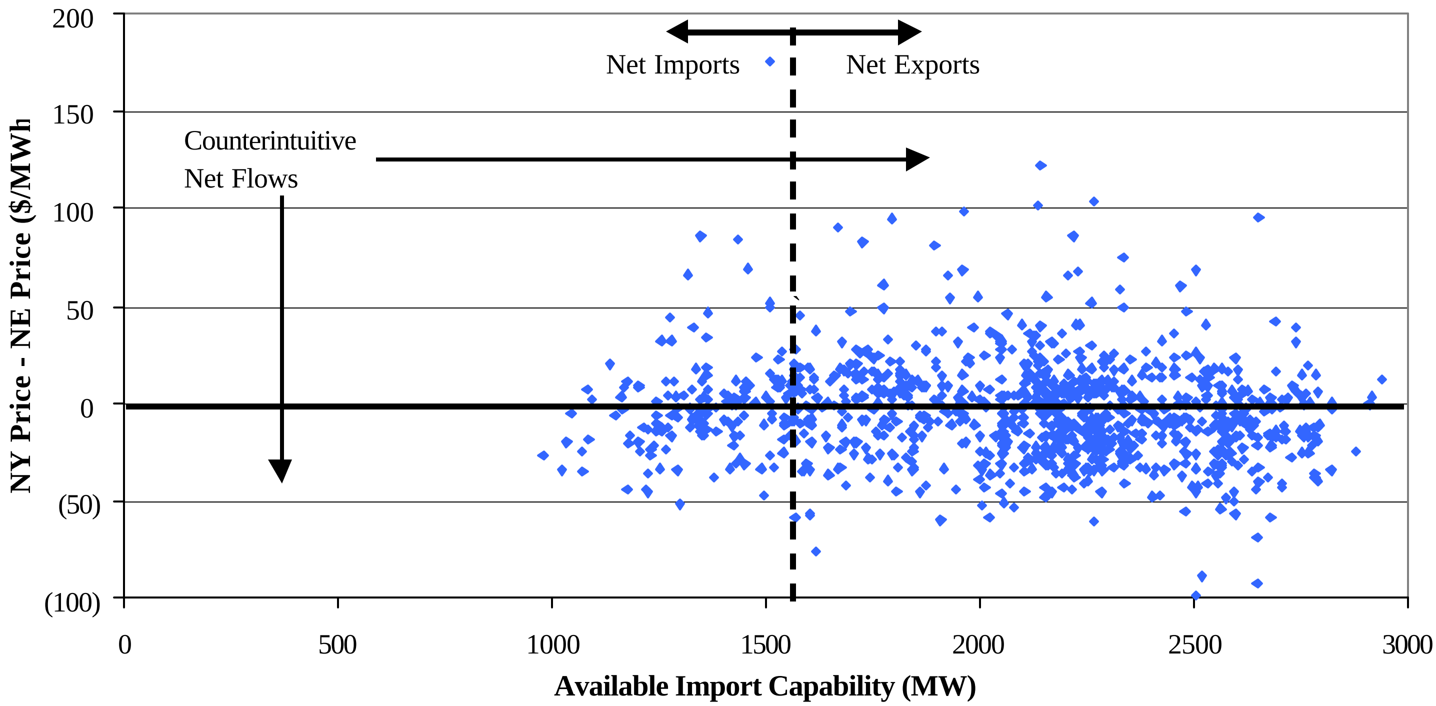
For example, assume a participant had a day-ahead import that was scheduled at $100 per MWh while the marginal cost of supplying the import is $20 per MWh. One might expect that the market participant would bid $20 per MWh in the real-time market so that if the price is lower than its own marginal cost of supply, that it would satisfy its obligation by purchasing the lower cost power from the pool. However, if the participant bids $20 per MWh into BME, it would not schedule the transaction if its forecasted price were $10 per MWh. If the real-time market subsequently cleared at $40, the participant would be faced with buying back its obligation at $40 per MWh and incurring a $20 loss versus supplying the power itself at $20 per MWh. This risk caused some participants to enter very large negatively priced bids for their transactions into the BME to ensure that their transaction would be scheduled, resulting periodically in inefficient pricing at the proxy buses and external transactions scheduled in hours where they were not economic.

These issues were addressed by the external transaction Emergency Corrective Actions ("ECA"), which have improved the scheduling of external transactions significantly.[13] These ECAs are commonly referred to as ECA A and ECA B and are currently in the committee process to be translated into permanent tariff amendments. ECA A causes a participant with a transaction that was accepted in the BME and subsequently fails checkout due to the participant's action (or inaction) to settle with the NYISO at the difference between its hour-ahead bid and the real-time price. Effectively, the transaction is settled at the participant's bid and then bought back at the real-time price. This provision compels the participant to bear the financial consequences of its aberrant bidding or scheduling in the hour-ahead process, thus eliminating the incentive to engage in "phantom" transactions.

ECA B causes transactions to be settled at the hour-ahead price when constraints bind in the BME at the interfaces. This substantially reduces the risk that participants were facing that accepted day-ahead transactions would be cut by BME at one price and that the participant would have to settle the imbalance resulting from the cut at a much different price in SCD. In doing so, it has reduced participants' incentives to bid extreme values in the hour-ahead process to force BME to schedule the transaction. In addition, it also has created a much better incentive for counter-flow transactions that can allow more transactions to be accepted in the direction of the prevailing flow.

These ECAs were implemented on October 11, 2000. I have produced a revised version of the figure shown above corresponding to the timeframe after the ECAs' implementation. Figure 26 shows these results for the New England interface.

**Figure 26**
**Difference Between New York and New England Price in Unconstrained Hours**
**Hour-Ahead Market -- October 11, 2000 to December 31, 2000**




This figure shows a similar pattern to the prior figure for New England, although the convergence around the zero price difference level is improved. The mean of the price difference in this case is $-3.65 and the standard deviation is reduced by approximately 60 percent to $57. In addition, the portion of the hours with counter-intuitive net flows when the price difference is greater than $10 fell from one third for the year to one quarter for the post-ECA timeframe.

These results are undoubtedly due in part to the fact that prices were generally less volatile in the fall than they were in the summer. Although the improved bidding incentives provided by the ECAs have likely contributed to the improvement, significant seams issues with New England remain that must be addressed to ensure the continued development of a competitive and efficient power market in the Northeast.

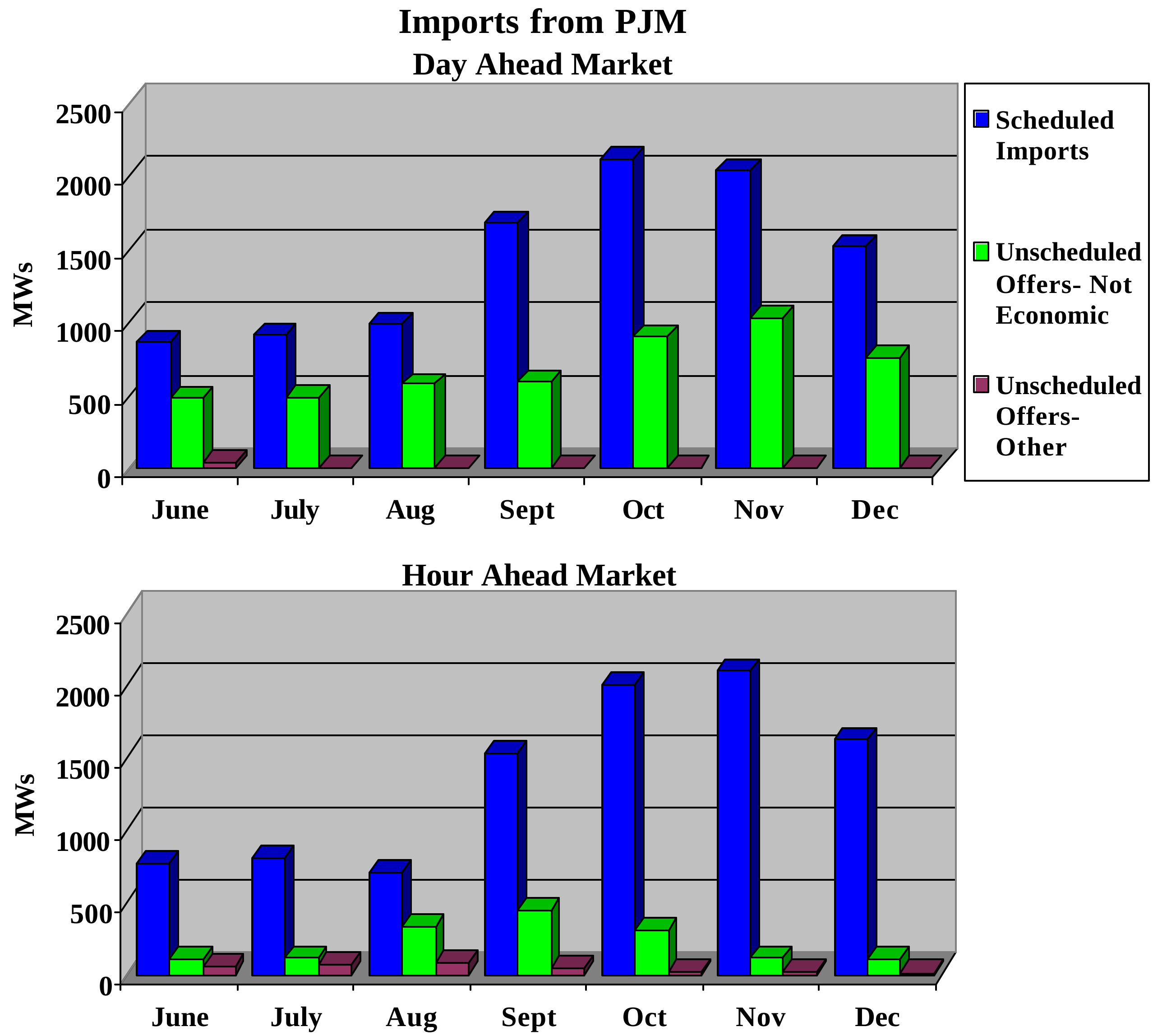
One possible source of the seams issues that may be hindering full arbitrage of the Northeast markets is the inconsistencies between the physical rights used to schedule external transactions in PJM and ISO New England and the economic scheduling process in New York that requires the participants to bid to import or export power. The analysis presented below provides an assessment of the results of the NYISO's scheduling process to determine whether the NYISO failed to accept transactions that were economic, given prices in New York and the participants' bids.

To do this, I have examined the hourly data on transaction bids and schedules for each of the interfaces into New York. Using this data and the price data for each of the proxy buses, I was able to categorize transactions into those that were scheduled, those that were not scheduled for economic reasons (e.g., the bid price for an import is higher than the proxy bus price rendering it uneconomic), or not scheduled for other reasons. The last category includes transactions that appear to be economic, but were not scheduled by the NYISO. If the NYISO scheduling process was not operating correctly, one should find substantial quantities of external transactions that failed to be scheduled although they were economic.

However, the other explanation for these types of schedules in the real-time market is that the transaction failed the check-out process whereby the NYISO compares its accepted transactions against those of PJM and ISO New England to ensure that they have scheduled the same transactions. Any transaction not scheduled in the neighboring market is then rejected, whether or not it appears to be economic.

Figure 27 shows the results of this analysis for imports into PJM in the day-ahead and hourly market. These figures show that substantially all of the transactions that were unscheduled in the day-ahead market were not scheduled because they were uneconomic. Economic transactions that were not scheduled for other reasons in the day-ahead market were virtually non-existent.

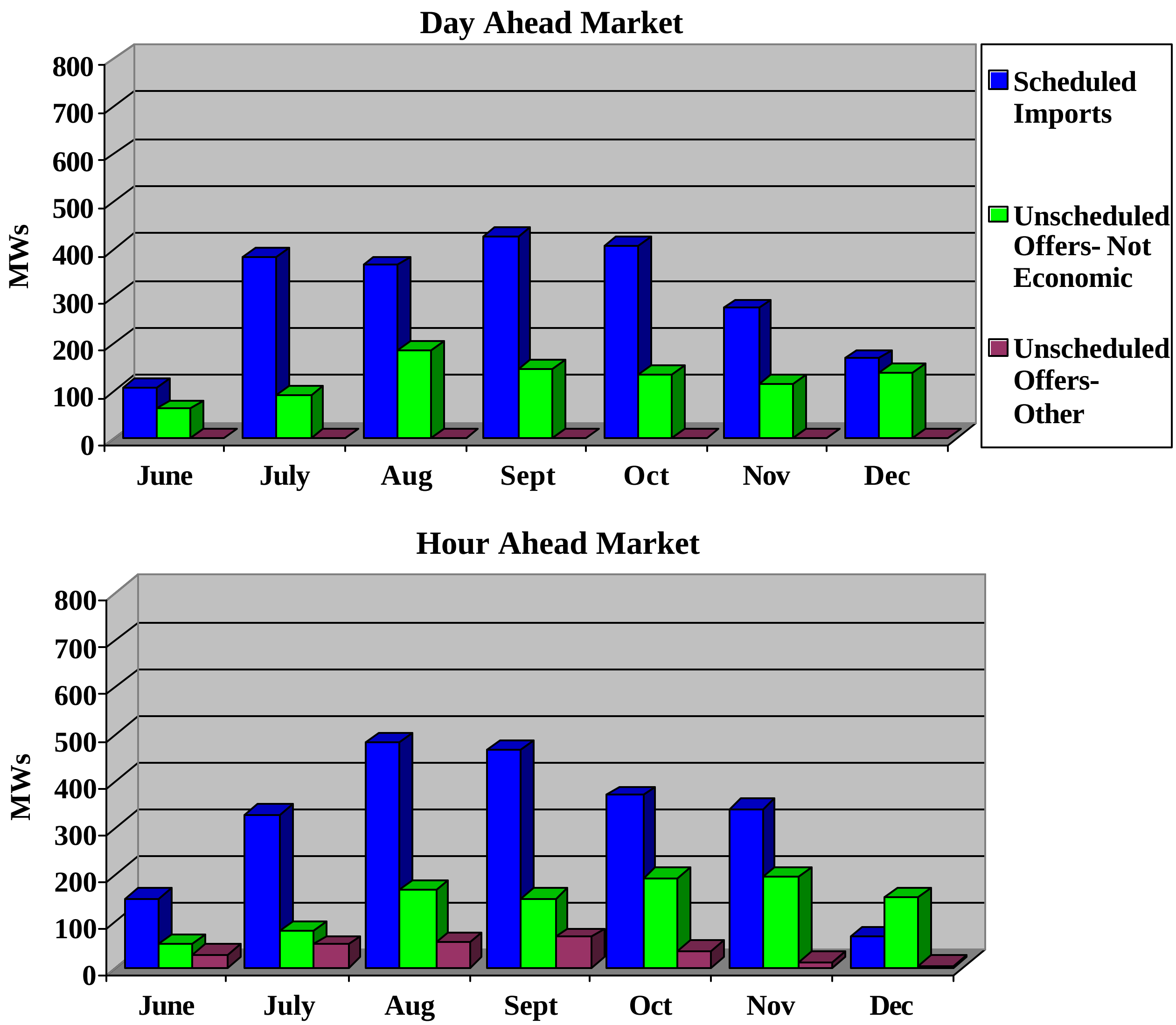
Figure 27




The figure also shows the utilization of the import capability increased significantly after September. The total import capability from PJM was established at close to 2000 MW for a large portion of the year after the outage of a phase angle regulator in New Jersey.

Consistent with the figure, import constraints were binding in 80 percent of the hours from October through December. The data for the hour-ahead market shows a modest quantity of transactions that were unscheduled for other reasons. These transactions were generally not scheduled because they failed the checkout process. Spot checking of the transaction logs have not revealed that any of these transactions should have been scheduled. These logs generally show that the transactions were not scheduled in the neighboring market, or that the participant withdrew or reduced the quantity of the transaction. Figure 28 shows comparable scheduling data for the New England interface.

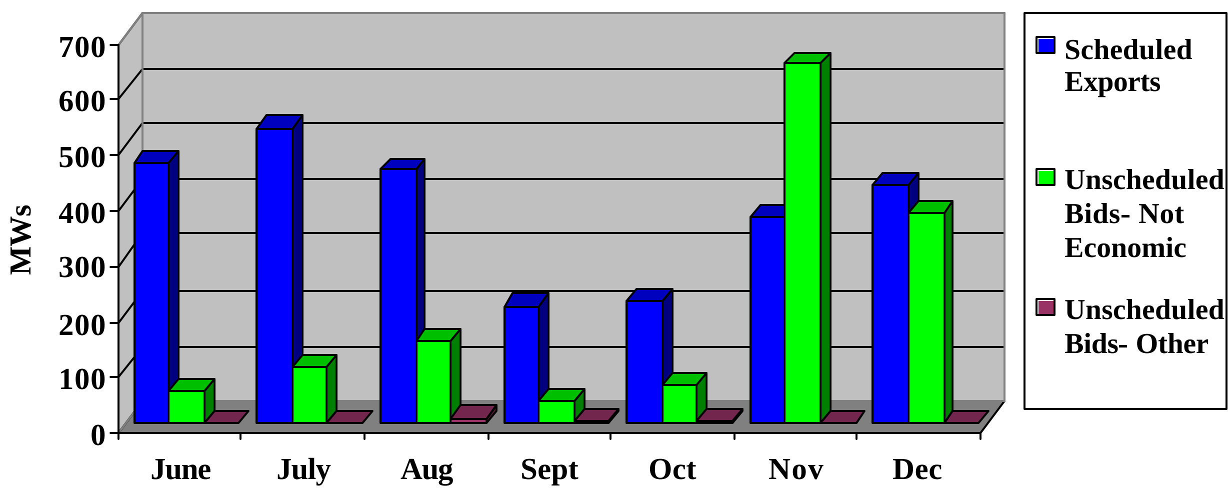
**Figure 28**
**Imports from New England**




This figure shows a similar pattern in that the day-ahead market with virtually no economic transactions unscheduled for other reasons while the amount of such transactions unscheduled in the hour-ahead market was more than 50 MW on average. In the case of both PJM and New England, the amount of "other" transactions that were not scheduled because they failed the checkout process decreased to a very low level after the ECAs were issued in October 2000. As I described above, ECA A causes participants to bear the financial burden of deliberately failing the checkout process, which effectively addressed the issue of participants submitting "phantom" transactions in the hour-ahead auction.

The export analysis confirms these results and shows one additional change in the scheduling of external transactions that occurred after the ECAs were issued. Figure 29 shows the monthly average scheduling results for exports to PJM during 2000, indicating that the total amount of bids to counter-schedule power flows into PJM from New York increased significantly following the implementation of the ECAs.

**Figure 29**
**Hour-Ahead Exports to PJM**




In particular, participants more frequently provided bids to counter-schedule that were generally not economic (i.e., with a very low bid price), but can occasionally be valuable as they allow the NYISO to accept the export in lieu of refusing to schedule additional imports. These counter-schedules not only allow higher levels of imports to be scheduled into New York, but also can be very profitable for the participant offering the counter-schedule. This opportunity became more attractive after ECA B was issued, which ensured that settlement for the counter-schedules would occur based on the BME prices under which these transactions are scheduled.

In sum, this analysis suggests that the NYISO's systems did schedule external transactions as intended via its economic evaluation, and that the reason for the incomplete utilization of the external interfaces was a lack of adequate bids from market participants. In evaluating the results of this analysis, it is important to remember that participants cannot always accurately predict which market will be the most profitable, particularly since the real-time markets are subject to random events (e.g., line outages) that can cause significant price movements. Nevertheless, these results likely reflect in part the inefficient incentives that were addressed by the ECAs, as well as a number of potential seams issues that are currently being evaluated.

The seams issues have been the most severe on the interface between New York and New England for the following reasons. First, some of the ISO New England's market rules have limited economic exports from New England into New York. As noted earlier, New England employs a physical rights system governing the scheduling of transactions into or out of New England. Because all external transactions must be accompanied by a physical right, if the holders of the rights do not schedule a transaction or sell the right to others then the interface will not be fully utilized as those that want to schedule transactions may not be able acquire the rights. FERC approved some changes to improve the ISO New England physical transmission right system, but additional changes will likely be needed to allow full utilization of the interface.[14] Even when participants are able to acquire rights, the scheduling of short-notice transactions are hindered by a market rule that will not allow any transactions to be scheduled that would cause New England's energy clearing price to rise above the bid price of any uncommitted resource in New England.[15] This rule is a barrier to arbitrage between the two markets.

Second, the timing of the New York and New England auctions can hinder external transactions. Participants must submit schedules to both ISOs 90 minutes before the hour, making it impossible to know in advance whether the transaction will be accepted in none, one, or both of the markets. Sequential timing may improve the scheduling process by removing the uncertainty facing participants scheduling across the markets.

Third, when transactions fail the check-out process because the transaction was not scheduled in one of the two ISOs, there is not currently a process for allowing the resulting available transfer capability to be scheduled.

Lastly, the ISOs lack a coordinated instrument to manage the risk of congestion across the seam. For example, the ISOs could possibly coordinate with each other to create a firm transmission right across the seam that would allow participants to better hedge the congestion risk associated with external transactions. In addition, changes to the NYISO rules to allow participants to bid external transactions in 16 hour (peak hours) blocks may allow for transactions that accommodate the commercial needs of the market. The NYISO with the participants are currently evaluating this change.

These ISOs have been working together through the Northeast ISO MOU process to address some of these issues to improve the utilization of the interfaces. I have recommended that the NYISO place the highest priority on any solutions that are identified through this process to improve the use of the interfaces this summer. As load grows in New York in the face limited new generation east of Central-East, it will be critical that the interface with New England is fully utilized.

To identify opportunities over the longer-run, ISO New England, the Ontario IMO, and the NYISO have participated in a study to investigate the feasibility of increasing the direct coordination of the day-ahead markets. Economic efficiency currently requires participants to actively transact between the markets to fully arbitrage prices. This study has identified several alternatives that may be feasible to increase the direct coordination among the ISOs. This coordination would potentially facilitate more efficient congestion management, day-ahead unit commitment, and procurement of reserves.

Identifying these opportunities to improve the coordination of the markets and eliminate the seams will be key to ensuring that the markets remain competitive and the supply remains reliable. However, these improvements are longer-term solutions and it will continue to be essential in the shorter-term to identify meaningful interim measures to be adopted until the longer-term improvements can be implemented.

# III. Analysis of Bidding Patterns

A necessary prerequisite to achieve the benefits that deregulation promises is that the market structure and rules must provide strong incentives for suppliers and loads to bid competitively. Competitive markets that send efficient price signals should cause suppliers to aggressively seek to sell their output under high priced market conditions rather than withholding the output to cause prices to rise further. The prior section showed that market prices were significantly influenced by a number of external factors. However this section will assess the conduct of suppliers and LSEs to determine whether this conduct has been consistent with workable competition.

The market monitoring plan establishes thresholds for identifying economic or physical withholding that may warrant mitigation. However, the conduct thresholds are not sufficient to establish that the identified conduct is an attempt to exercise market power. This conduct is often responsive to other considerations that are consistent with the incentives provided by the market rules under workably competitive conditions.

## A. Assessment of Trends in Supplier Conduct

The Market Monitoring Plan identifies two primary types of conduct that may be inconsistent with workable competition:

"(1) Physical withholding of an Electric Facility, that is, not offering to sell or schedule the output of or services provided by an Electric Facility capable of serving a New York Electric Market. Such withholding may include, but not be limited to, (i) falsely declaring that an Electric Facility has been forced out of service or otherwise become unavailable, (ii) refusing to offer bids or schedules for an Electric Facility when it would be in the economic interest, absent market power, of the withholding entity to do so, or (iii) operating a generating unit in real-time to produce an output level that is less than the NYISO's dispatch instruction.

(2) Economic withholding of an Electric Facility, that is, submitting bids for an Electric Facility that are unjustifiably high so that (i) the Electric Facility is not or will not be dispatched or scheduled, or (ii) the bids will set a market clearing price."[16]

On a daily basis, the NYISO assesses this conduct to determine whether the conduct may warrant mitigation. Conduct that may warrant economic withholding are identified by comparing the current bid prices for a generating resource to a reference price equal to the average of its accepted bid prices over the past 90 days during comparable periods. When temporary conditions arise in which a supplier may have market power, its accepted bids under other workably competitive periods serve as a standard against which its current bid may be evaluated. If the current bid is substantially above its reference price, further investigation is warranted to determine whether the bid may warrant mitigation as an attempt to exercise market power or, rather, a competitive response to changes in costs or other real factors. Thresholds of $100 or 300 percent above the reference price are currently used to identify conduct that warrant further investigation and potentially mitigation.

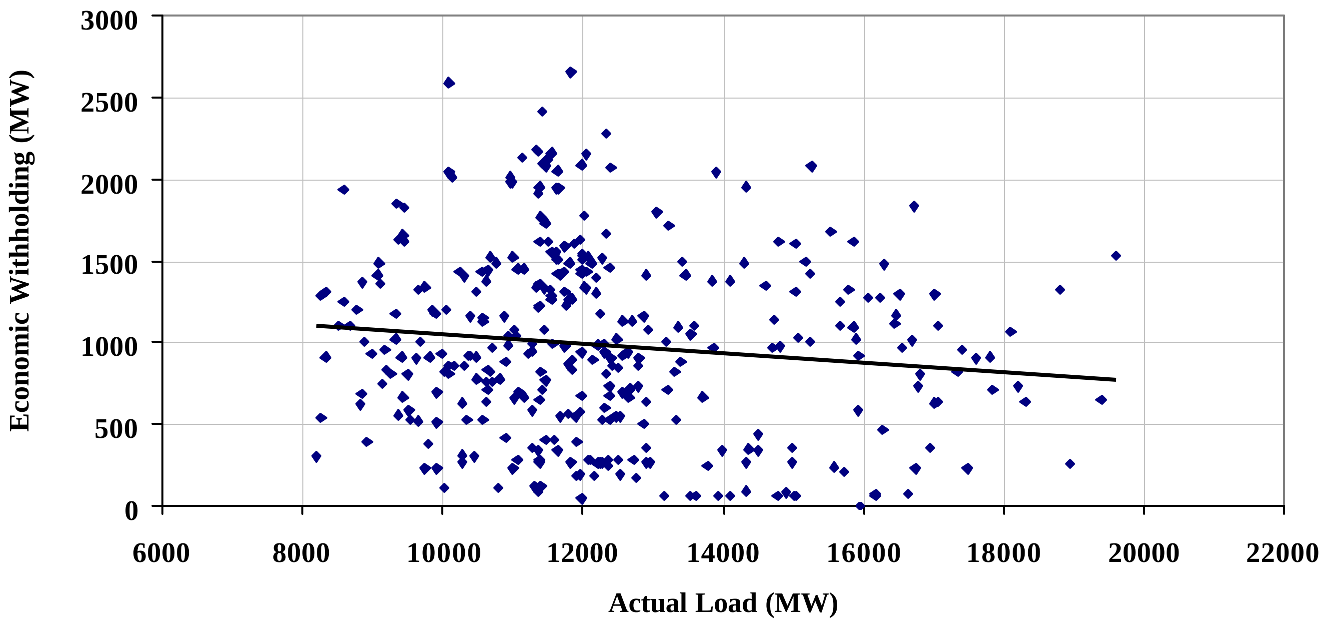
One key test to determine whether the conduct exceeding these thresholds may warrant mitigation is a test to evaluate its effect on market prices. Due to the nature of the supply shown in Figure 4, withholding under most load conditions will not significantly affect market prices, absent binding transmission constraints. When the conduct does not materially raise prices, one may conclude that it does not constitute an exercise of market power. There are many other reasons why a supplier may increase its bid price for all or a portion of a unit. Therefore, the fact that a bid exceeds the economic withholding thresholds established in the Market Mitigation Plan is not sufficient to conclude that the bid constitutes an attempt to exercise market.

Over the longer-term, trends in bidding patterns can be analyzed to determine whether they are consistent with workable competition or whether they indicate significant market power concerns. As discussed in prior sections, withholding is more likely to have a significant price effect when market conditions become tight due to high loads or transmission constraints. Hence, withholding should increase as load increases if participants have, or believe they have market power. However, periods of high load are also the periods when prices will naturally rise as higher cost resources are needed to meet load and suppliers without market power will have an incentive to sell as much power as possible. Therefore, one method to assess the competitiveness of the market is to examine whether the total hourly quantity of bids exceeding the physical or economic withholding thresholds increases as the market load increases.

The following charts show these results by plotting the amount of physical derating (includes outages) and the amount of economic withholding against the actual load. The most significant price fluctuations have occurred in Eastern New York when the Central-East Interface is binding. Withholding in the Western New York is much less likely to result in a material price increase. Therefore, the charts focus on the withholding and loads in Eastern New York. In addition, the charts focus only on a peak hour when loads are the highest to make the withholding patterns easier to discern. Figure 30 shows the economic withholding in the day-ahead energy market in Eastern New York at 2:00 pm (hour 14).

**Figure 30**

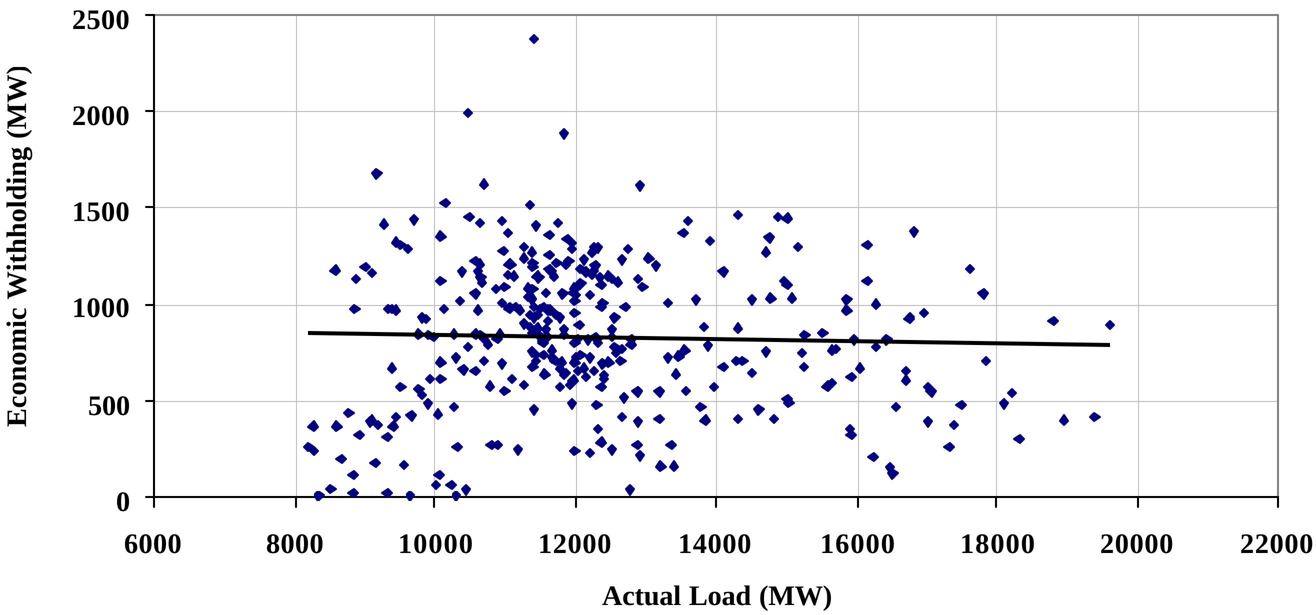
**Relationship of Economic Withholding to Actual Load**
**Day-Ahead Market -- East New York**
**January 1 to December 31, 2000 -- Hour 14**




This figure shows that the quantity of bids exceeding the economic withholding has generally decreased as load increased consistent with the competitive incentives. Figure 31 likewise does not indicate that economic withholding in the real-time market has been positively correlated with load. The figures confirm the conclusion reached based on the daily analysis of bid prices that the bidding in the New York market has been well disciplined by competitive forces.

**Figure 31**

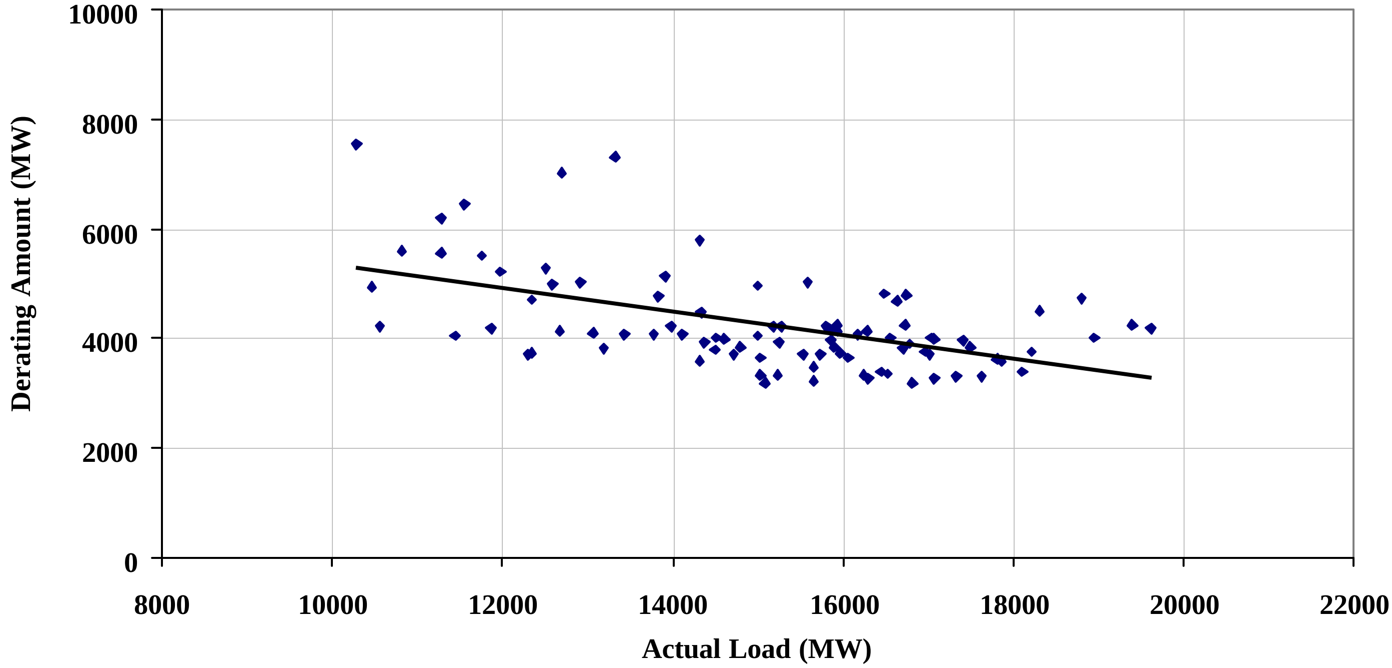
**Relationship of Economic Withholding to Actual Load**
**Real-Time Market -- East New York**
**January 1 to December 31, 2000 -- Hour 14**




A similar analysis of deratings is necessary to determine whether there is evidence that suppliers have physically withheld resources under high load conditions in an attempt to raise energy prices. Maintenance outages will cause deratings to increase during off-peak periods in the spring and fall when loads are considerably lower. Including these periods in the analysis would bias the analysis by introducing a negative correlation between deratings and load consistent with the maintenance outages. Therefore, I have excluded off-peak periods from this analysis by examining the relationship of deratings to actual load only during the summer for a peak hour.

Figure 32 shows the results of this examination for Eastern New York. Like the analysis of bids exceeding the economic withholding thresholds, the deratings in Eastern New York during the summer have tended to fall as load has increased. The same relationship exists for the State. Therefore, the evidence is consistent with workable competition and suggests that physical withholding has not been a significant market power concern.

Figure 32
Relationship of Deratings to Actual Load
Day-Ahead Market -- East New York
June 1 to August 31, 2000 -- Hour 14




Despite the fact that our analyses have not indicated that physical withholding was a problem during 2000, I have recommended that the NYISO increase its capability to detect physical withholding by: 1) requiring real-time explanations of deratings and forced outages, and 2) acquiring the additional resources to identify and investigate those deratings or forced outages that appear questionable. These improvements will help ensure that physical withholding does not become a problem in the future under tighter market conditions.

I conducted one last analysis to evaluate the offer patterns of suppliers under the NYISO. One of the benefits of moving to deregulated electric markets is that they provide strong incentives to maximize the amount of output that can be profitably provided from each generating unit. Therefore, I tested whether the amount of electricity offered from existing units has increased or decreased in comparison to the former regulated system. To do this, I selected five days from 2000 with two being days from the summers exhibiting large price fluctuations, two from the fall, and one from the winter.

For each of the five days, I compared the amount of energy offered on a unit-by-unit basis under the NYISO markets to the unit ratings from 1999 on comparable days used to dispatch generation under the New York Power Pool ("NYPP") operations, the predecessor organization to the NYISO. The NYPP ratings include a maximum output level that can be achieved under emergency operations (i.e., maximum rating) and a maximum output level that can be achieved under normal operations (i.e., normal rating). In making the unit level comparisons, I included only those units that were in service on the days selected for 2000 and the comparable days in 1999.[17] Therefore, the analysis is not influenced by outages, units that were not committed on the relevant days, or new units.

Table 3 shows the results of this analysis. The average amount of energy bid by the unit over each day into the NYISO day-ahead market is referred to in the Table as the NYISO rating.

**Table 3**

## Comparison of NYISO Ratings to NYPP Ratings for Selected Dates

| Date | NYISO Ratings - Max. NYPP Rating | NYISO Ratings - Normal NYPP Rating | Bids Below $500 - Max. NYPP Rating | Bids Below $500 - Normal NYPP Rating |
|---|---|---|---|---|
| June 26, 2000 | 1411 | 2889 | 340 | 1740 |
| August 9, 2000 | 2249 | 5064 | 1475 | 4290 |
| September 1, 2000 | 2174 | 5090 | 1746 | 4662 |
| October 20, 2000 | 513 | 1999 | 32 | 1576 |
| December 15, 2000 | 2054 | 3071 | 1566 | 2588 |
| **Average** | **1680** | **3623** | **1032** | **2971** |

The first two columns show the difference between the NYISO energy offers (i.e., NYISO rating) and the maximum and normal ratings of the same units under the New York Power Pool. On average over the five days, this analysis shows an increase in energy offered under the competitive markets of 1700 MW versus the maximum NYPP rating and 3600 versus the normal rating. This represents an increase of more than 5 percent and 12 percent, respectively.

Some may argue that some of this increase is a result of the fact that suppliers seeking to maximize their ICAP payments may bid a higher amount of energy in the day-ahead market than can be physically achieved. Under this theory, the generator would likely offer the over-stated portion of its capacity at very high prices to avoid it being scheduled in the day-ahead market. Although this is possible, it is also true that steam units can often produce output above their normal operating range by taking actions with considerable associated incremental costs. Therefore, the high bids would be a valid representation of the units' marginal costs in this range. Nonetheless, to determine whether the first concern (i.e., that capacity is offered that is not physically available) would undermine the results of this analysis, I excluded all bid segments with bid prices greater than $500.

These results are also shown in Table 3, where the right two columns compare all capacity with bids below $500 with the maximum and normal NYPP ratings. Like the prior results, the average increase versus the maximum NYPP rating is greater than 1000 MW or 3.5 percent of the average available capacity in New York. The increase compared to the normal NYPP rating averages 3000 MW – more than 10 percent of the average available capacity in the State.

Table 4 shows the same analysis by type of generating unit. This table produces an average by unit type for each of the five days analyzed, showing that the increases in offers occur over all types of generating units. These results confirm that the competitive markets are providing substantially near-term supply benefits by creating accurate price signals and improving the incentives facing suppliers.

**Table 4**

## Comparison of NYISO Ratings to NYPP Ratings By Type of Unit

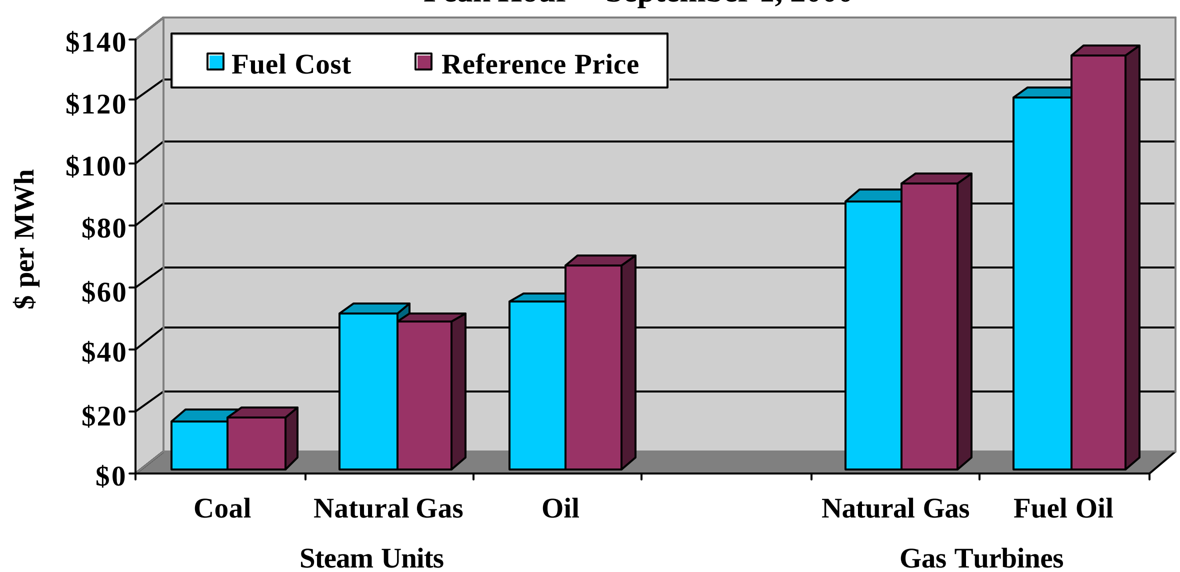
| Fuel Type | NYISO Ratings - Max. NYPP Rating | NYISO Ratings - Normal NYPP Rating | Bids Below $500 - Max. NYPP Rating | Bids Below $500 - Normal NYPP Rating |
|---|---|---|---|---|
| **Steam Units** | | | | |
| Natural Gas | 240 | 445 | 176 | 381 |
| Oil | 771 | 1000 | 576 | 806 |
| Coal | 340 | 361 | 228 | 250 |
| Other | -8 | -8 | -13 | -13 |
| **Nuclear** | 27 | 29 | -49 | -47 |
| **Hydro** | 226 | 996 | 176 | 946 |
| **Gas Turbines** | | | | |
| Natural Gas | -189 | 159 | -197 | 151 |
| Oil | 151 | 565 | 141 | 539 |
| **PURPA/Cogen** | 148 | 105 | 121 | 91 |

## B. Analysis of References Prices

Another useful analysis of the competitiveness of the suppliers' bid patterns is an examination of the references prices that have resulted from the accepted bids in the New York markets. The monitoring plan calls for the calculation of reference prices corresponding to the output curve of each unit that would be primarily based on the accepted bids from the units over the previous 90 days during comparable periods, adjusted for changes in fuel prices. The rationale for using this form of reference price to monitor and mitigate market power is that suppliers should be compelled by competitive forces to bid their resources at prices close to marginal costs during most hours when the market is workably competitive.

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 bidding has, in fact, been consistent with the assumption that generators should offer their resources at bid prices close to marginal costs, I have compared the reference prices for different types of fossil-fired units to the fuel costs of producing electricity. Fuel costs account for the majority of the marginal costs in the normal output range for these units. Figure 33 shows the average fuel prices and reference prices by fuel type, as of September 1, 2000.

**Figure 33**
**Comparison of Average Fuel Costs to Reference Prices by Type of Unit**
**Peak Hour -- September 1, 2000**

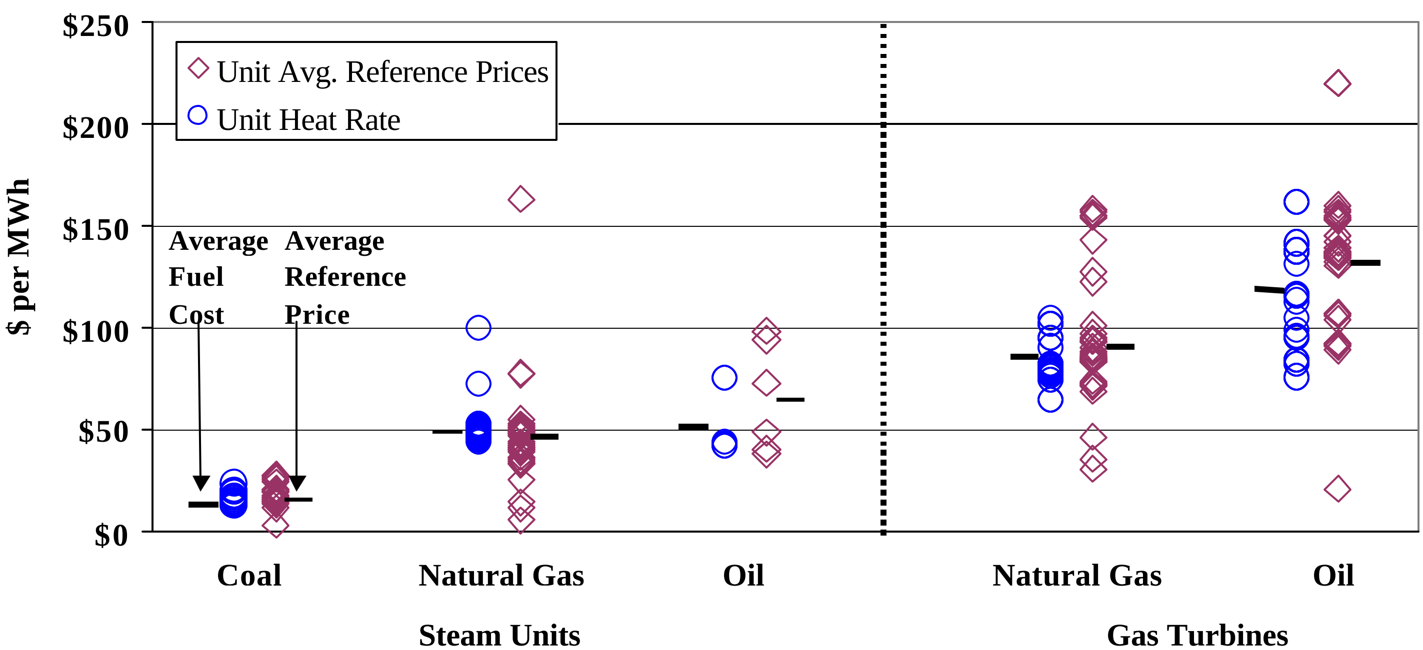


Reference prices are computed for each 10 MW output segment over the output range of each unit in the New York market. The marginal costs of increasing the output from a unit to its maximum capability can far exceed the fuel costs for that small segment of output due to increased O&M expenses, increased forced outage probability, and reduced unit efficiency. To account for this, I have excluded a very small amount output with reference prices exceeding $500 per MWh in the computation of the average reference prices. Fuel costs are computed using heat rate data compiled during New York Power Pool operation prior to the implementation of the NYISO markets.

Figure 33 shows that on average, reference prices have been relatively close to the average fuel prices. One should expect that the true marginal costs would be slightly higher than the fuel cost to account for other costs including environmental costs and variable operations and maintenance expenses. Complementing the averages shown in the previous figure, Figure 34 shows a scatter plot of the reference prices and fuel costs for each of the individual units, organized by type of unit.

**Figure 34**

**Unit Reference Prices and Fuel Costs By Type**
**Peak Hour - September 1, 2000**



These figures both show that the reference prices have served as an effective proxy for fossil-fired units' marginal costs, consistent with the economic incentives provided by the competition prevailing in New York's electric markets. In addition to providing an indication that the electric markets remain workably competitive, these results provide additional assurance that the current market monitoring and mitigation plan will continue to be effective in identifying and remedying market power.

## C. Monitoring and Mitigation Thresholds

The thresholds in the mitigation plan for identifying bids that may constitute economic withholding allow for a considerable amount of latitude for suppliers to alter their bid prices. The thresholds allow an increase in the current bid 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.

Some have argued that these thresholds for identifying economic withholding and considering mitigation are too generous and allow for actions by suppliers to raise energy prices materially without the possibility of immediate mitigation. Although, the NYISO retains the right to make a 205 filing with FERC to seek a remedy for conduct below the current thresholds, it is difficult to adequately address market abuses retroactively. Therefore, I have periodically assessed whether lower conduct thresholds would identify conduct that may warrant mitigation.

To make this assessment, I identified the amount of additional resources that would have exceeded the thresholds at lower levels. For this analysis, I used thresholds equal to a 100 percent or $50 over reference prices, whichever is less. Having identified these additional resources, three conditions must be met for the bids of these resources to potentially affect. First, the reference price for the resource must be lower than the LBMP at the generator's point; otherwise the resource would not be economic even if it bid its reference price. Second, the current bid should be close to or above the LBMP, otherwise the resource is inframarginal and will be scheduled whether its current bid were reduced to the reference price or not. Lastly, I excluded bids below $60 since bids in this range are highly unlikely to have a significant effect on prices given the nature of the market's supply in that price range. As described in prior sections, the supply at lower price levels is inelastic due to the large quantity of generating resources with similar marginal cost profiles.

Employing these three conditions, I identified the bids that would exceed the lower thresholds that could potentially have had some effect on the energy market prices. The results of this analysis are shown in Table 5.

**Table 5**

**Analysis of Economic Witholding at Lower Screening Thresholds**
**$50 per MWh or 100% Increase Over Reference Price**

| Date | Amt. Exceeding Threshold | # of Bidding Organizations | Average LBMP | Average Bid | Average Reference |
|---|---|---|---|---|---|
| June 26 | 107 | 6 | $112.26 | $119.59 | $49.07 |
| August 09 | 94 | 6 | $96.68 | $115.57 | $54.37 |
| October 20 | 0 | N/A | N/A | N/A | N/A |
| December 15 | 160 | 11 | $91.11 | $119.40 | $63.54 |

Two of the days chosen for this analysis were days with considerable price fluctuations – June 26 and August 9. The other two days were average weekdays chosen at random from the fall and winter. This table shows that a very small quantity of resources met the criteria described above for "low-level" economic withholding that could potentially have had some effect on prices. Given these quantities and the size of the bid price increase, one may conclude that the conduct identified had no substantive effect on prices. Further, the table shows that this small quantity of identified resources were generally held by 6 or more suppliers, making it highly unlikely that the withholding of any one supplier was a strategic attempt to influence prices.

Given the results of the analyses for these selected days, there is little evidence that lowering the conduct thresholds would significantly improve the efficacy of the monitoring and mitigation plan. In fact, to the extent that the lower thresholds would falsely identify conduct that is not a strategy to economically withhold output to raise prices, the reduced thresholds would reduce the effectiveness of the monitoring and mitigation plans.

Because this analysis only examines conduct on the four days shown above, these conclusions may not be apply to all of the market conditions during 2000. To make a more thorough assessment of the threshold levels, I have recommended that the MMP monitor bids continually at the lower threshold levels. This analysis will allow 1) the identification of conduct that may warrant a 205 filing with the FERC to impose a remedy, 2) a full assessment of the threshold levels in the mitigation plan that are currently used to determine when mitigation may be appropriate.

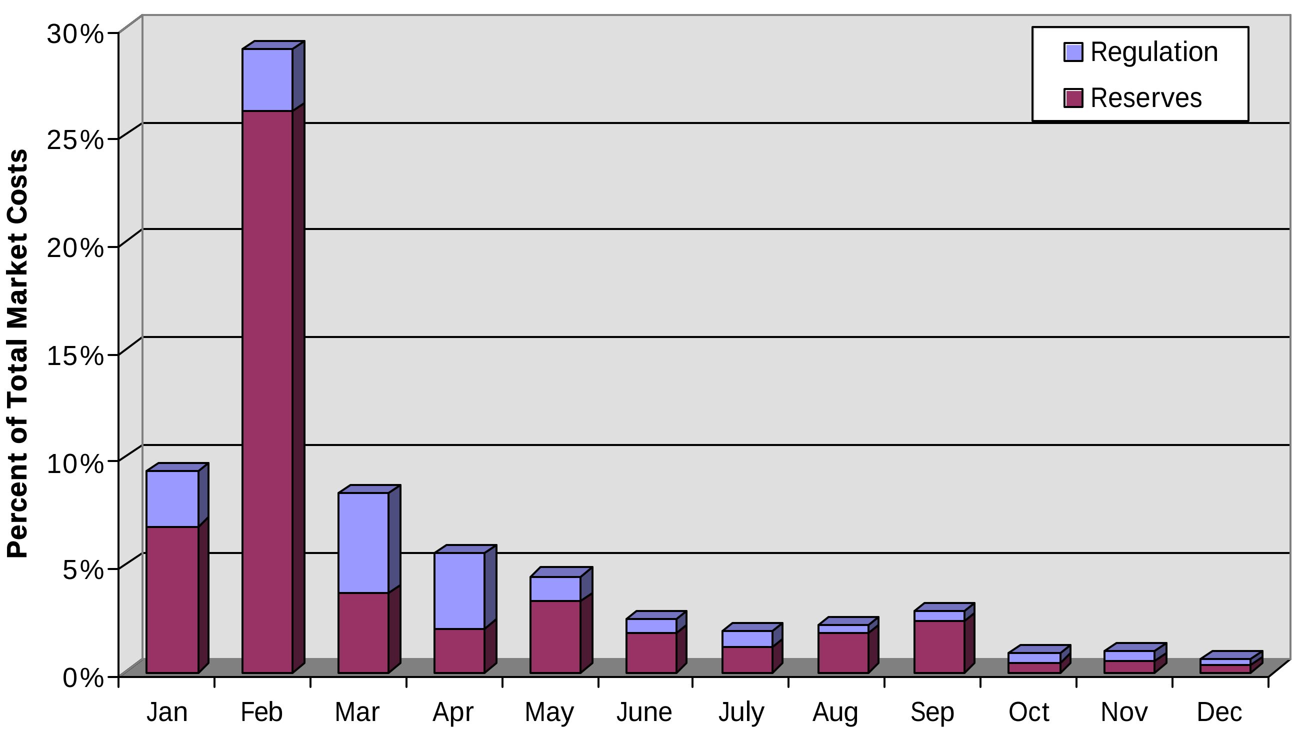
# IV. ANCILLARY SERVICES MARKETS

## A. Introduction

The New York ISO ("NYISO") began operation in 1999 by implementing three reserves markets and a regulation market along with the energy markets. This report will review the competitive performance of these markets and the issues that have arisen during the first year. In addition, this section will summarize the modifications that have been made or are underway to address the issues and recommends future improvements to further enhance the performance of the markets.

Figure 35 shows that during the latter months of 2000, reserves and regulation expenses were reasonable as a percentage of the total market costs -- ranging from one to three percent on a monthly basis. Earlier in the year, however, these costs far exceeded this expected range due to withholding in one of the reserve markets.

**Figure 35**
**Reserves and Regulation Costs**



However, before describing these events and assessing the competitive performance of the ancillary services markets, I will briefly describe how they are structured and operate. New York procures three types of operating reserves: 10-minute spinning reserves, 10-minute total reserves (can be spinning or non-synchronous reserves ("NSR")), and 30-minute reserves. 10-minute spinning reserves are those that are on-line and can provide additional output within 10 minutes. 10-minute NSR resources are resources that are not on-line but may be turned on and providing their output within 10 minutes, which are typically gas turbines. 30-minute reserves may be on-line or off-line resources that can be producing a given output within 30 minutes. The NYISO receives availability bids from each generator that indicates the minimum price they are willing to accept to provide the reserve.

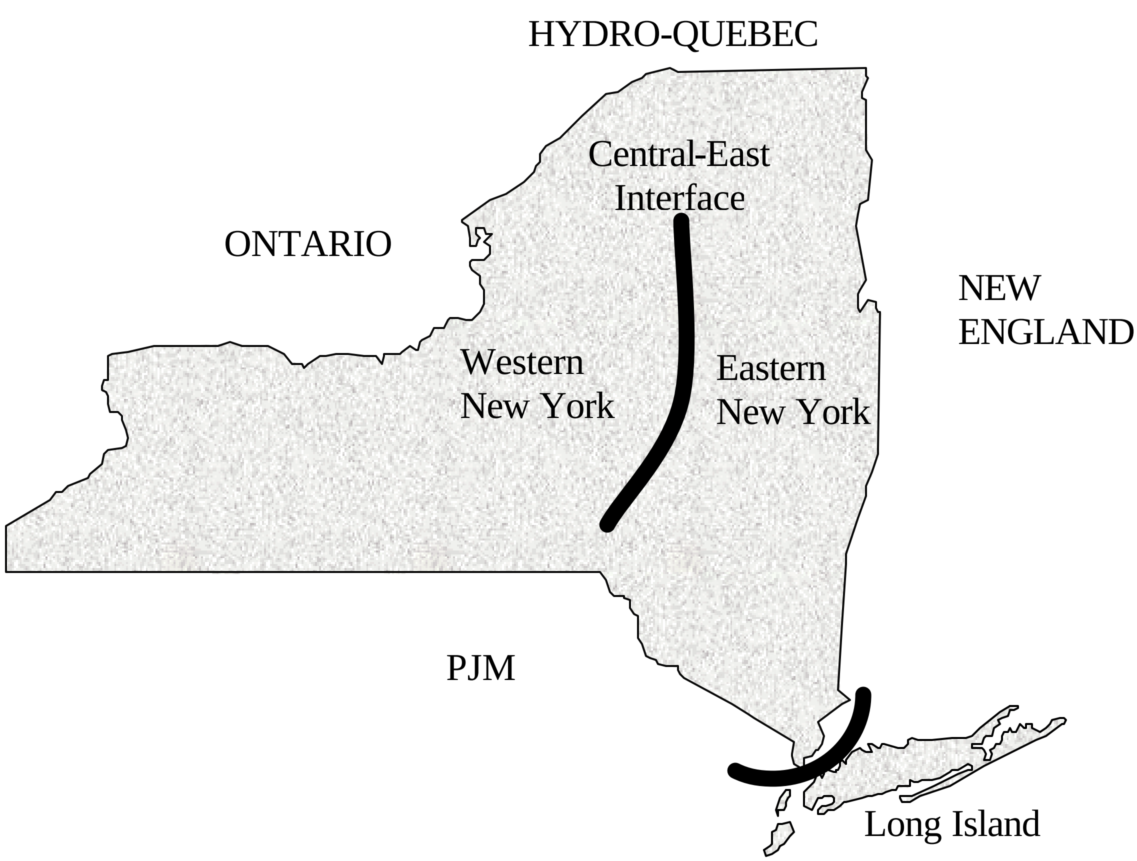
In total, 1800 MW of operating reserves must be purchased in the New York Control Area ("NYCA"), of which 1200 MW must be 10-minute total reserves (spinning or NSR). Therefore, the NYISO may purchase up to 600 MW of 30-minute reserves. Of the 1200 MW of 10-minute total reserves, at least 600 MW must be spinning reserves and the balance may be NSR resources. Therefore, there is a limit on how much NSR resources can be used to meet the statewide 1200 MW requirement for 10-minute reserves. There is no such limit on spinning reserve purchases – i.e., all 1200 MW 10-minute total reserve purchases by the NYISO could be spinning reserves. Likewise, 30-minute reserves cannot be substituted for 10-minute reserves, but 10-minute reserves could be purchased to meet the entire 1800 MW operating reserve requirement.

Therefore, 10-minute spinning reserves are the highest value reserve while 30-minute reserves are the lowest value reserves. The reserves markets are simultaneously cleared together with the energy market to minimize total bid production costs. In this process, the price for lower value reserves often clears below the price for higher value reserves. For example, the 10-minute NSR prices generally clear below the price of 10-minute spinning reserve prices because the ISO must purchase reserves from more expensive spinning reserve units to meet the 600 MW spinning reserve requirement.

However, when higher value reserves are substituted for lower value reserves because the lower value reserves are more expensive, then the price of both types of reserves will be set at the marginal cost of the higher value reserve. For example, when 10-minute NSR resources were withheld in the spring of 2000, 10-minute spinning reserves were often substituted for 10-minute NSR resources to satisfy the 10-minute total reserves requirement and the price in both markets were set at the same level – i.e., the bid of the marginal 10-minute spinning reserve.

In addition to the NYCA requirements described above, the procurement of reserves are also subject to locational requirements to ensure that they will be fully available to respond to possible system contingencies and maintain reliability. The transmission interfaces that can become constrained and contribute to the locational requirements are shown in Figure 36.

**Figure 36**




The most significant interface in New York, and perhaps the entire Northeast, is the Central-East Interface that limits economic transfers from Western New York, PJM, Ontario, and Hydro Quebec to Eastern New York and New England. 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. These requirements include the following.

First, 1200 MW of total 10-minute reserves (spinning and NSR) must be purchased east of the Central-East constraint. This does not mean that all of the 600 MW of 10-minute spinning reserves required within the NYCA will necessarily be purchased in Eastern New York. When 10-minute NSR resources are relatively inexpensive, more than 600 MW may be purchased in the east (e.g., 800 MW) with the balance of the eastern requirement supplied from 10-minute spinning resources (400 MW) and the rest of the 600 MW 10-minute spinning requirement purchased in Western New York (200 MW). This example shows that some 10-minute spinning reserves may be procured in Western New York despite the locational requirement for Eastern New York. Nevertheless, the eastern requirement does limit quantity of 10-minute reserves that may be purchased in Western New York where roughly half of the State's spinning reserve capability is located.

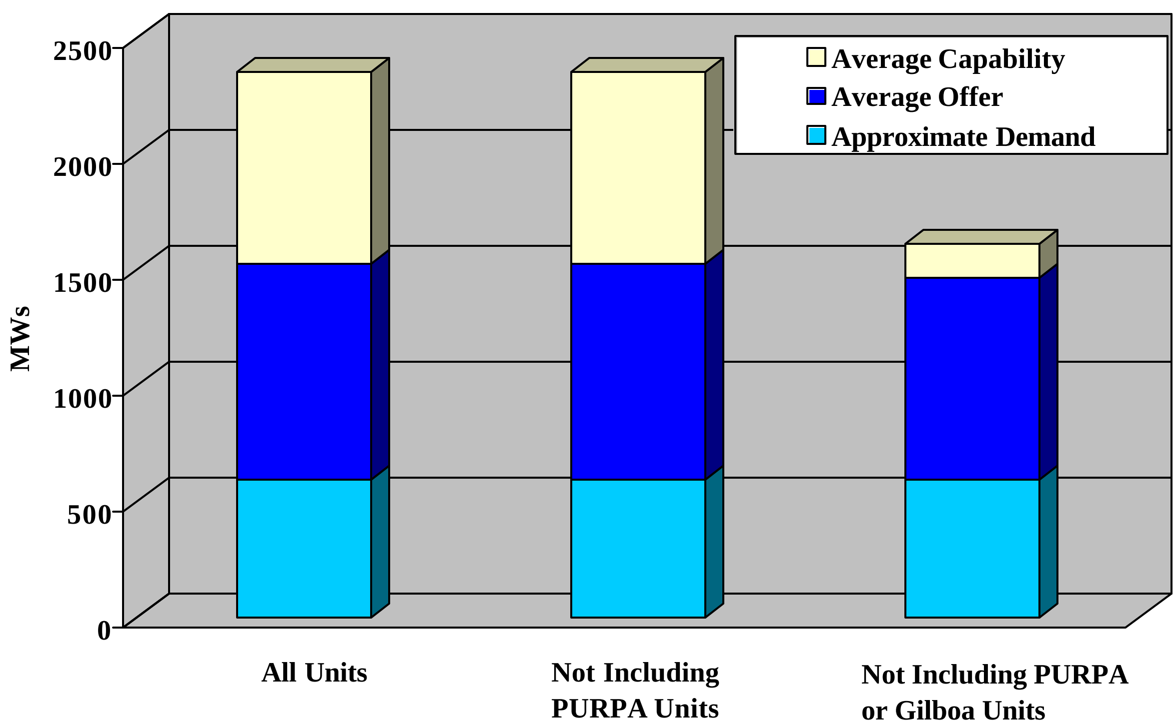
Second, prior to November 1, 2000 locational reserve requirements for Long Island required that 380 MW of 10-minute reserves (spinning and NSR) and 540 MW of total reserves (10-minute and 30-minute) be purchased on Long Island. After November 1, the 10-minute reserve requirements for Long Island were reduced to 60 MW of 10-minute spinning and 120 MW of total 10-minute reserves while the requirement for total operating reserves remained at 540 MW. Because prices in each reserve market are set by the bid of the marginal resource, if an expensive resource is needed to meet the Long Island requirements, it will establish the clearing price for the entire State. The NYISO has proposed modifying this provision to allow spatially differentiated prices to reflect the effects of the locational reserve requirements in the same way that locational energy prices reflect transmission system limits.

There are no locational requirements for the procurement of regulation service, which may be purchased throughout the NYCA. The NYISO purchases a greater amount of regulation during high ramp hours than during low ramp hours. 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. When a regulating unit is off of its dispatch point on the low side by a significant amount, it may be subject to significant penalties, while a unit producing more than its dispatch point (i.e., over-generating) is not paid for its excess energy. The following sections will describe the performance of each of the ancillary services markets and provide recommendations short-term and longer-term modifications.

## B. 10-Minute Non-Synchronous Reserves

Withholding of 10-minute NSR resources was primarily responsible for the inflated reserve costs in early 2000. Therefore, the results in the 10-minute spinning reserve market will be better understood after first reviewing the offers and results in the 10-minute NSR market. I will describe the withholding later that led to the imposition of the mandatory bidding requirement and bid cap. First, the average capability available to the market is shown in Figure 37 for the period during 2000 with the bidding requirements in place.

**Figure 37**
**10 - Minute Non - Sync. Reserves in Eastern New York**
**April 1, 2000 - December 31, 2000**



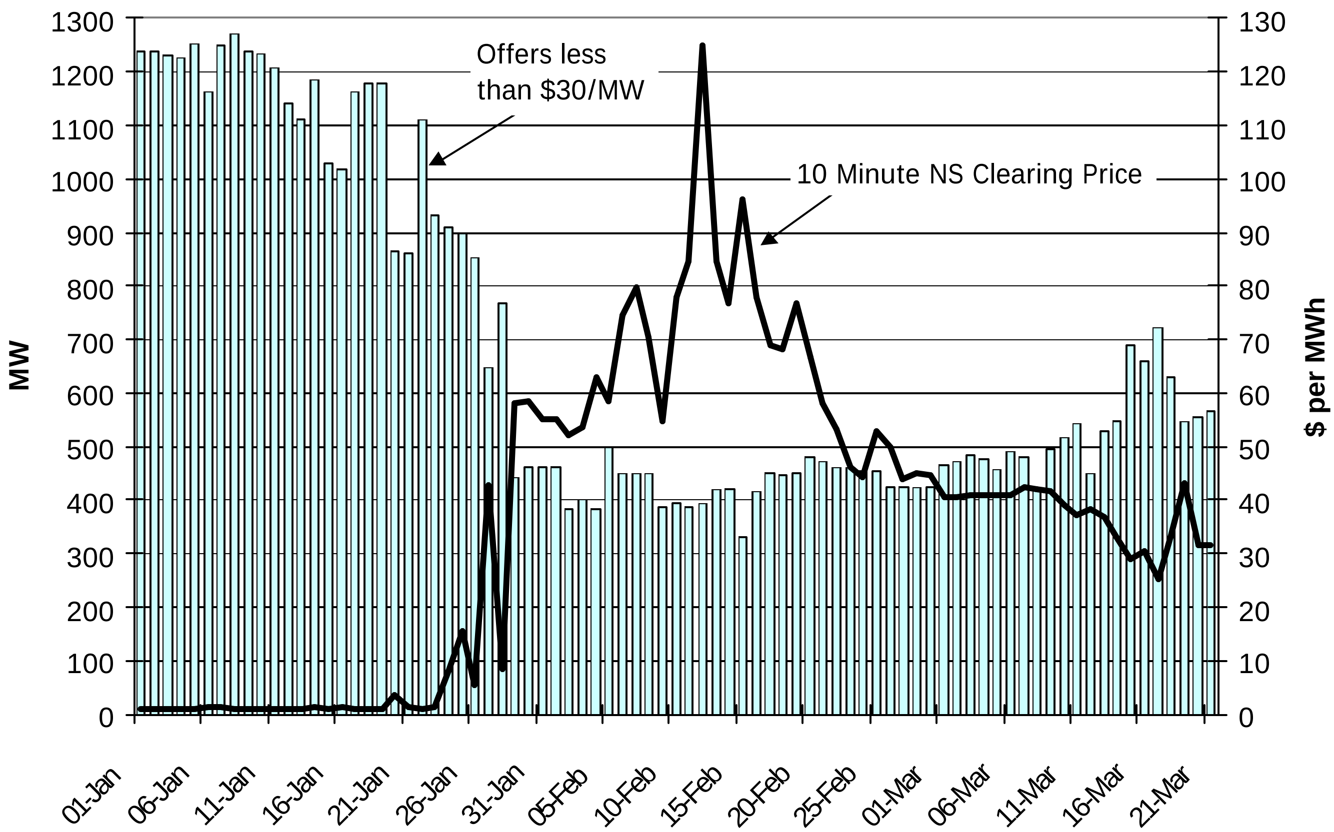

The first two bars in Figure 37 show the capability located in Eastern New York with and without PURPA units included. PURPA units generally do not offer capacity into the reserves markets due to contractual limitations or concerns regarding qualifying facility status. The last bar removes the capability and offers of the Blenheim-Gilboa Pumped Storage Project ("Gilboa"). Although the average capability from Gilboa shown in the figure approaches 1000 MW, the initial modeling of the project under the "B-G Scheduling Agreement with NYISO Operation" limited the amount of Gilboa's capability that could provide reserves by modeling Gilboa as a single unit. In reality, Gilboa is comprised of four 250 MW units that can pump water into storage ("pumping mode"), or release the water to generate electricity ("generating mode").

Each unit can switch very quickly from pumping to generating mode or start-up from stand-still. By modeling Gilboa as a single unit in the generating or standstill mode, it could only be scheduled to generate in a given hour if none of the units are in pumping mode. This prevented the NYISO from taking full advantage of Gilboa's flexibility as a supplier of reserves. However, the necessary software changes were completed last fall to allow Gilboa to bid as 10-minute spinning and 10-minute NSR to the extent that its capabilities allow. In theory then, Gilboa could now bid all 1000 MW into the 10-minute reserve markets although the NYISO has limited its purchases of reserves from Gilboa to 560 MW for reliability reasons (i.e., so as not to hold an excessive portion of the State's reserves at one location). Even without Gilboa, however, Figure 37 shows that the NYISO receives more than double the amount of offers than the typical demand for 10-minute NSR, all of which are subject to the $2.52 per MW bid cap. This was not always the case.

During the spring of 2000 after more than two months of relatively competitive conduct on the part of 10-minute NSR suppliers, a significant amount of physical and economic withholding began. The 10-minute NSR market had been clearing below the $2.52 level because the amount of capability offered substantially exceeded the typical demand. However, this capability is held principally by only three suppliers, with the capability of one of the three entities bid by an affiliate of another one of the three entities bid under an agency agreement. The largest supplier of 10-minute NSR holds 58 percent of the capability, while the capability of the two entities bid by the affiliates total more than three quarters of the total 10-minute NSR capability.

Figure 38 shows the changes in bidding patterns for the 10-minute NSR suppliers from the beginning of January 2000 through the third week in March.

**Figure 38**
**10 Minute Non-Synch Clearing Prices and Offers less than $30 per MW**
**Daily Averages for January 1 to March 21**

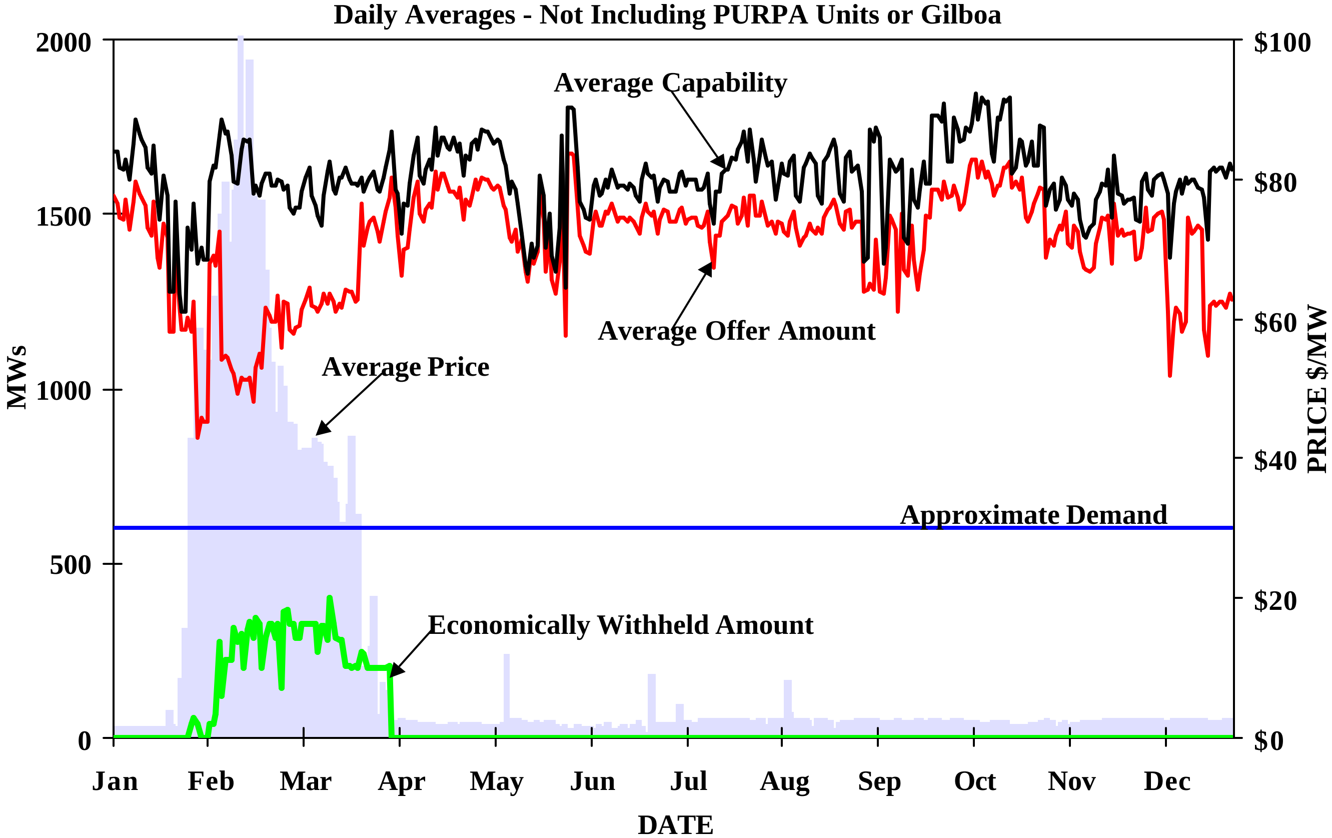



The $30 per MW level was selected for this figure because it should substantially exceed the expected lost opportunity costs facing most suppliers during this period. The figure shows the considerable reduction in economic bids for 10-minute NSR resources that occurred at the end of January 2000, falling from well over 1000 MW to close to 400 MW. Both physical and economic withholding contributed to this reduction. The decline in economic bids caused 10-minute spinning reserves to be substituted for 10-minute NSR resources, resulting in a single clearing price for all 10-minute reserves at substantially elevated levels.

I estimated the cost of this conduct at close to $70 million by calculating the likely clearing prices in the 10-minute reserve markets assuming the 10-minute NSR suppliers continued to offer their resources as they had prior to January 29. One of the justifications the 10-minute suppliers cited for the substantial increases in 10-minute NSR bid prices was that the units sometimes face the lost opportunity to profitably sell their output in the energy market. This cost should rationally be incorporated in the suppliers' availability bids.

Therefore, when the $2.52 bid cap and mandatory bidding requirement was imposed to address this conduct, a lost opportunity cost provision was also implemented to ensure that suppliers receive the full value of their resources in either the reserves or energy market. These provisions have effectively protected the reserves markets from any further consequences from withholding of 10-minute NSR capability as Figure 39 shows.

**Figure 39**
**10 - Minute Non - Sync. - Eastern New York**
**Daily Averages - Not Including PURPA Units or Gilboa**



The figure shows that prices after March 2000 were relatively flat due to the bid cap with the exception of the isolated price increases due to the 30-minute reserve market. In each of these cases, tight reserve conditions on Long Island caused relatively high priced 30-minute reserves to clear the market to meet the Long Island locational reserve requirement. As discussed above, the price of lower value reserves can set the price for all higher value reserves when the marginal cost of supplying the lower value reserve is higher. Because reserve prices are not locational (i.e., the highest accepted bid needed to meet all reserve requirements for a given type of reserve sets the price statewide), the high 30-minute clearing price needed to satisfy the Long Island constraint set high prices statewide for all reserves. A proposal to set reserves prices by location is described below that would address this issue.

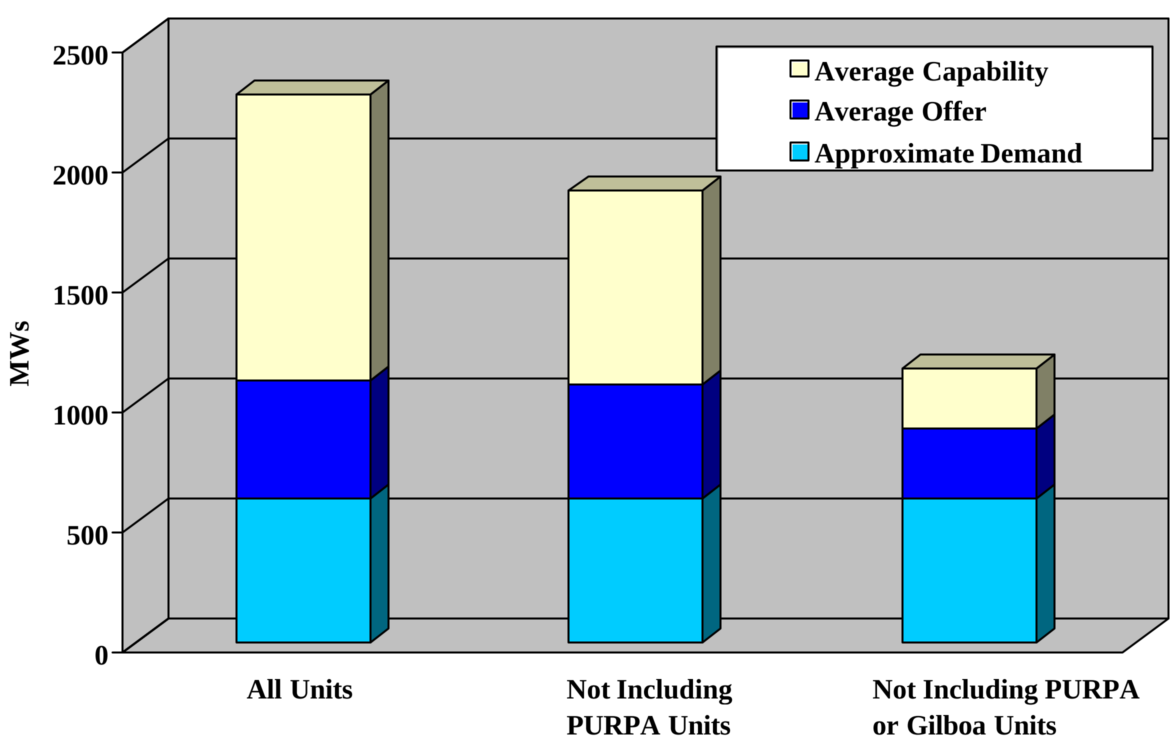
Additional supply of 10-minute NSR resources will help ensure that the market remains competitive once the bid cap is removed by decreasing the ability of suppliers to withhold and raise the price. Therefore, the enhancements to the modeling of Gilboa should clearly be beneficial. In addition, gas turbines that require longer than 10 minutes to reach full output can currently only supply 30-minute reserves. The NYISO is investigating modifications that would allow such units to supply 10-minute NSR for the portion of its output that would be available within 10 minutes, thereby increasing the 10-minute NSR supply. Several measures to increase the supply of 10-minute spinning reserves are outlined in the next section that will impose additional competitive discipline on the 10-minute NSR suppliers since spinning reserves may be freely substituted for NSR resources to meet the total 10-minute reserve requirement.

## C. 10-Minute Spinning Reserves

As discussed in the prior section, prices in the 10-minute spinning reserve market were affected by the conduct in the 10-minute NSR market. Apart from that episode, the spinning reserve market has generally exhibited competitive results. The spinning reserve market is significantly less concentrated, as 10 suppliers in the east hold significant shares of the spinning reserve capability, and none with a share higher than 25 percent.

Figure 40 shows the amount of capability on average that is available and has been offered in the 10-minute spinning reserve market in Eastern New York during the year, with and without the PURPA units and Gilboa. Reserves in Eastern New York only are shown due to the locational requirement that 1200 MW of 10-minute reserves be purchased in Eastern New York. This provision limits the value of 10-minute reserves in Western New York.

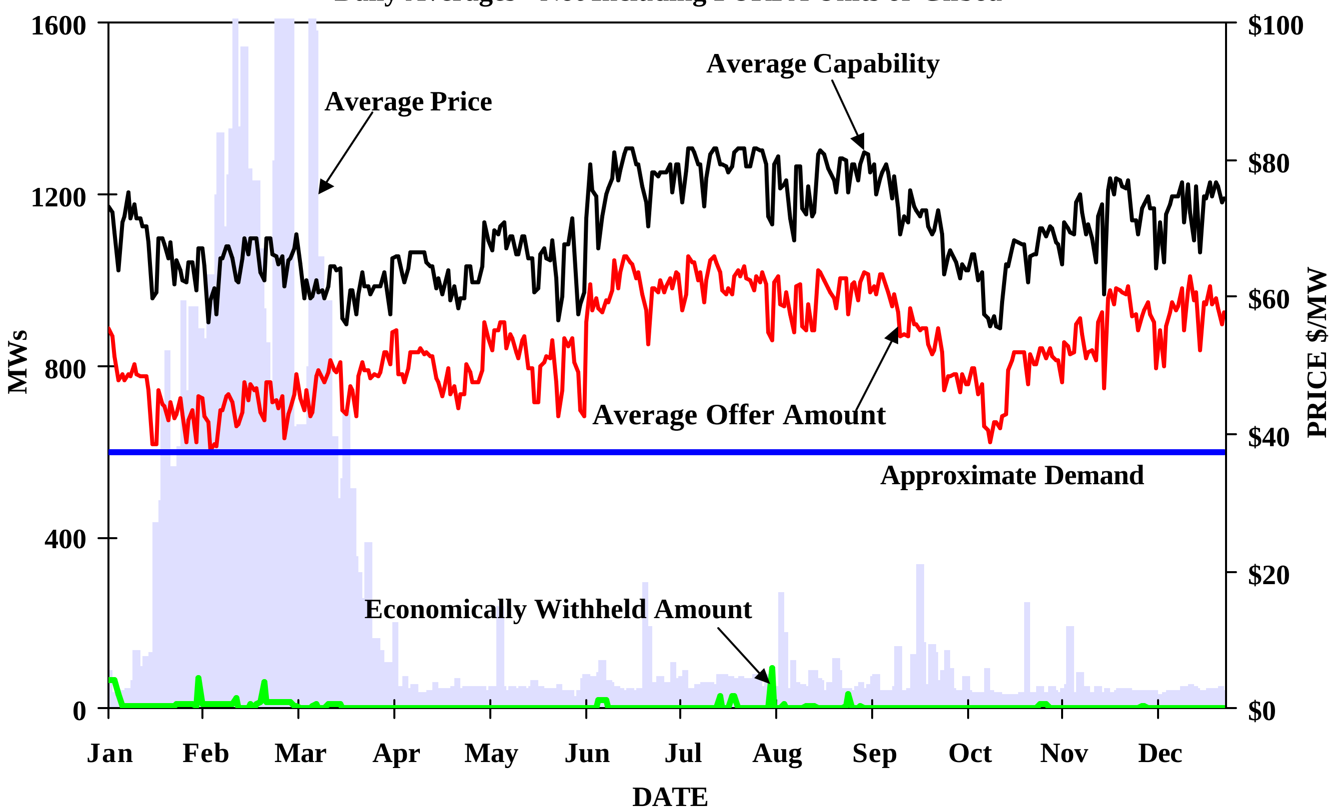
**Figure 40**
**10 - Minute Spinning Reserves in Eastern New York**
**April 1, 2000 - December 31, 2000**



The figure shows that suppliers typically offer 75 percent more 10-minute spinning reserve capability than the approximate demand level of 600 MW. This rough estimate of the excess bids ignores the fact that some spinning reserves in Western New York may be used to meet the 600 MW spinning reserve requirement if additional 10-minute NSR resources are substituted to meet the 10-minute reserve requirement in Eastern New York.

Figure 41 shows the average daily capability, bids, and prices for 10-minute spinning reserves in Eastern New York, showing that adequate capacity generally is offered on a daily basis, even ignoring Gilboa and PURPA units.

**Figure 41**
**10 - Minute Spinning Reserves - Eastern New York**
**Daily Averages - Not Including PURPA Units or Gilboa**




The figure clearly shows that there were substantial effects during the spring on prices in the 10-minute spinning reserve market due primarily to the conduct in the 10-minute NSR market. Some physical withholding did occur that reduced the amount offered to levels close to the approximate demand on some days that contributed to the higher 10-minute reserve prices by limiting the amount of substitution that could occur between the spinning and NSR market. This conduct alone, however, would not have been sufficient to cause the price increases that were experienced during that period. After March of 2000, the amount offered in this market has generally been adequate to achieve competitive results. Nevertheless, the chart clearly shows that a substantial amount of capability is generally not offered in this market. With Gilboa more fully utilized in the reserve markets, this will not cause significant problems under most conditions. However, it is important to remember that the energy, operating reserves, and regulation markets are all simultaneously cleared. All of the spinning reserve resources can provide energy and many also have the capability to provide regulation service.

Hence, under tight market conditions when a large share of the resources bidding in the 10-minute spinning reserve market is also needed to supply energy or regulation, price spikes in all three markets are possible. On June 26, for example, day-ahead energy prices in Eastern New York exceeded $1000 for most of the afternoon. On this day, tight conditions in the reserves markets caused some lower priced energy resources to be selected to provide reserves causing higher priced energy resources to be selected to provide energy (because the higher priced energy resources had not offered to provide reserves). Therefore, increasing the amount of 10-minute spinning reserve offers will likely benefit the energy market and other ancillary services markets when market conditions become tight.

Several enhancements are underway to increase the capability offered in the 10-minute spinning reserve markets beyond the modeling improvements for the Gilboa units that I described in the prior section. First, the NYISO is discussing a reserve sharing agreement with New England that would allow reserves in New England to be available to New York and vice-versa. This would effectively increase the amount of available supply to each region and potentially reduce the overall reserve requirements.

Second, the NYISO is investigating the feasibility of allocating transmission capability on the Central-East Interface to allow Western reserve suppliers to meet Eastern New York reserve requirements. This would be beneficial in cases where the difference in the marginal cost of providing energy in Eastern New York versus Western New York is less than the difference in marginal costs of reserves in Eastern and Western New York. This is sometimes the case under normal conditions when the Central-East Interface constraint is not binding. However, it was frequently true during the episode in spring 2000 and this type of provision could have mitigated the effects of the withholding seen during that period by providing an additional source of potential supply. Therefore, this modification promises some benefits to the market, the change should be investigated thoroughly prior to implementation to ensure that it does not create inefficient effects in the energy market by under-utilizing the transmission system, or otherwise hinder reliability.

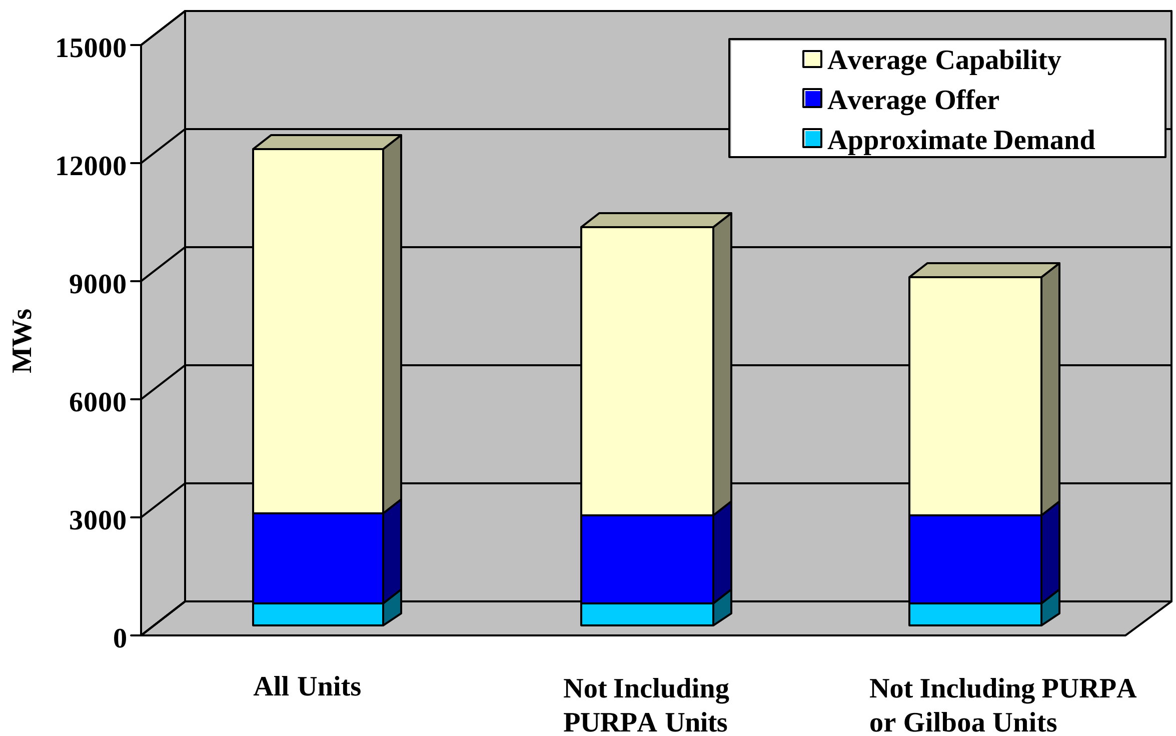
In addition to these measures to increase the total capability of 10-minute spinning reserves available to the New York markets, improvements in the pricing of 10-minute spinning reserves may provide additional incentives for potential suppliers to bid in this market. For example, the NYISO currently compensates a generator for its own lost opportunity costs of providing reserves versus selling energy in the real-time energy market. No lost opportunity costs are available associated with foregone sales in the day-ahead energy market although these costs may be substantially different than real-time lost opportunity costs. Also, because the price is set at the level of the highest accepted availability bid, it may not reflect the true market value of the service in the day-ahead market. The availability bid currently should include an expected lost opportunity cost component, but the uncertainty associated with this expectation will cause the availability bids not to accurately reflect these costs.

Therefore, pricing reforms that would pay each reserve supplier the sum of the availability plus lost opportunity of the marginal reserve supplier would provide a more accurate price signal to potential suppliers. This pricing structure would be appropriate for each of the reserves and regulation markets, which currently receives no lost opportunity cost payment. However, like the previous provision to meet eastern reserve requirements with western supplies, this provision is not critical to the reliable supply of operating reserves for the upcoming summer. For this reason and because it will require tariff modifications and software changes, it should be considered as a potential longer-term improvement.

## D. 30-Minute Reserves

The 30-minute reserve market was not significantly affected by the conduct in the 10-minute NSR market since 30-minute reserves are a lower value resource that cannot be substituted for 10-minute NSR resources. Therefore, the performance of this market throughout the year has been relatively consistent, as sufficient supply has existed in all hours to meet the demand for 30-minute reserves. Figure 42 shows the capability and offers of the 30-minute reserve suppliers during 2000 with and without PURPA units and Gilboa included.

**Figure 42**
**30 - Minute Reserves All New York**
**April 1, 2000 - December 31, 2000**

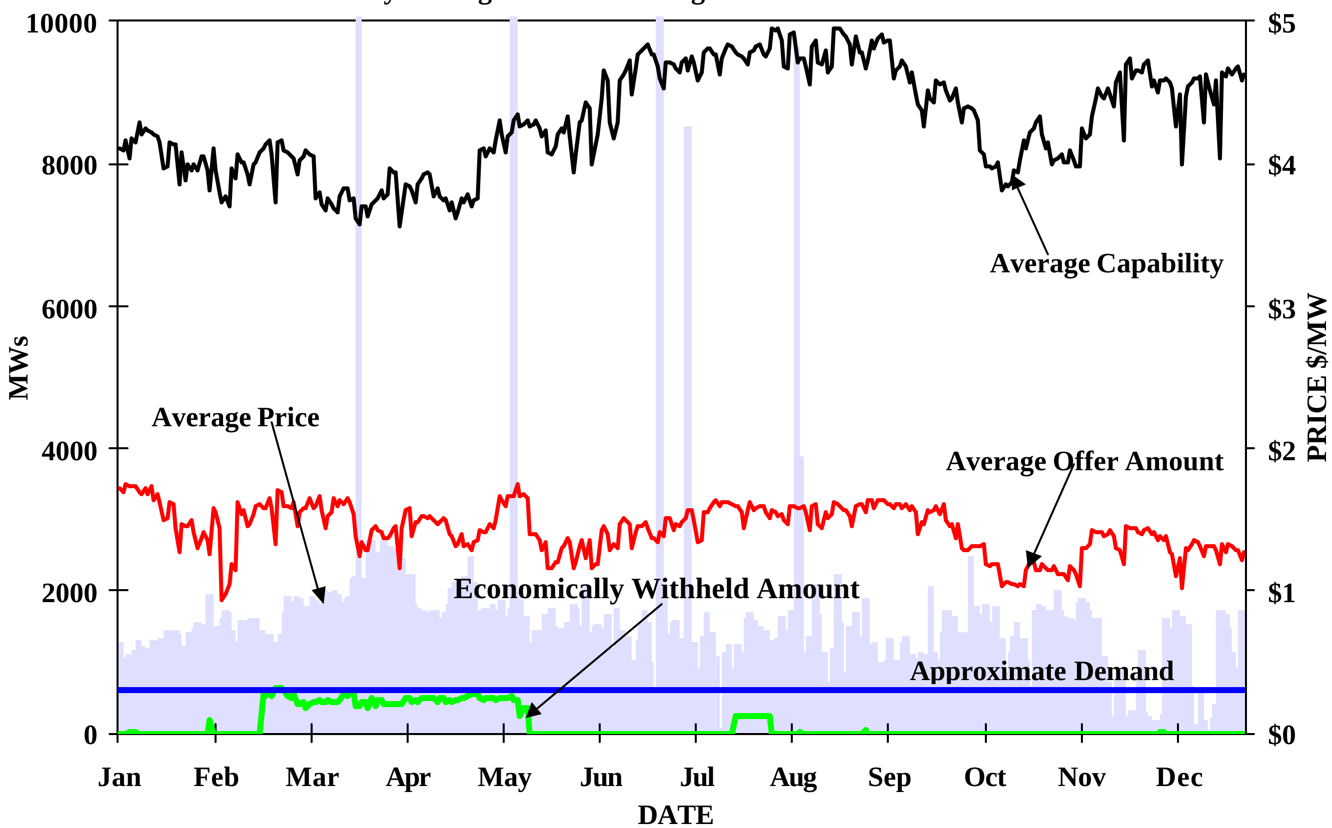



Relative to the other reserves, the 30-minute reserve market had the highest level of excess supply offered. On average, the NYISO received bids totaling almost five times the approximate demand for 30-minute reserves. This excess supply is caused by a number of factors.

First, with the exception of Long Island, there are no locational requirements for 30-minute reserves so they may be provided from anywhere within the NYCA. Second, non-synchronous reserves that cannot be producing at full output within 10 minutes may qualify to provide 30-minute reserves. Third, units that provide spinning reserves can generally provide three times the amount of 30-minute reserves that they could provide of 10-minute reserves since the amount that can be provided is equal to the ramp rate of the unit multiplied by the timeframe (10 minutes vs. 30 minutes) subject to the total capability of the unit.

The daily average capability and prices are shown below in Figure 43, showing that substantial excess supply is available on a daily basis that has led to relatively flat and reasonable prices.

**Figure 43**
**30 - Minute Reserves - All New York**
**Daily Averages - Not Including PURPA Units or Gilboa**



As the figure shows, the price for 30-minute reserves is generally close to $1 per MW and is the lowest price of all of the operating reserves. The figure also shows a number of price increases that have occurred in this market in the presence of the substantial excess supply I have described above. These temporary increases are related to the Long Island locational requirement. When the market for reserves on Long Island is tight or the resources offered are more valuable in the energy market, the marginal cost of meeting the reserve requirements on Long Island can be substantially higher than the typical clearing price level. When this occurs, the marginal cost for 30-minute reserves on Long Island can set the price for all reserves in the State.

Because the Long Island Power Authority ("LIPA") resources are necessary to meet the Long Island reserve requirements, LIPA has the unilateral ability to raise statewide reserves prices to any level it chooses by withholding resources from these markets and thereby causing a shortage of reserves on Long Island. To mitigate this concern, LIPA has agreed to offer sufficient reserves to meet its locational reserve requirements at competitive levels. In addition, the market mitigation measures would apply if withholding of reserve capability were to raise concerns in the future.

In addition, the NYISO has proposed locational reserve pricing that would set reserves prices at the marginal cost of meeting the reserve requirements at that location. Therefore, if the marginal cost of meeting the Long Island reserve requirement were higher than the marginal cost of meeting the reserve requirements for the NYCA, the price paid to the reserve suppliers in each location would vary accordingly. This would eliminate the pricing effects in the rest of the State that occurred during 2000 when reserve conditions on Long Island became tight. Therefore, the relevant pricing zones for all of the operating reserves would be: Western New York, Eastern New York excluding Long Island, and Long Island alone. When a locational reserve requirement is not binding, the price in all three areas would be identical.

Currently, only the price paid to generators is proposed to vary by location. The allocation of the reserves costs would not vary by location, although this would be the logical extension. The reason for this is that some argue that the locational reserve requirements provide reliability benefits to loads located in other areas. In the longer-term, the NYISO should establish a cost-allocation method that is fair, reflects these benefits, and sends appropriate signals for loads choosing to self-supply their reserve obligation.

Given the performance of this market, limited changes appear to be needed in the near-term to ensure adequate and competitive supply of 30-minute reserves. However, some of the improvements described in prior sections will enhance supplies in this market as well. For example, a reserve sharing arrangement with New England would likely include 30-minute reserves and allow for reduced purchases of 30-minute reserves, as the requirements are coordinated.

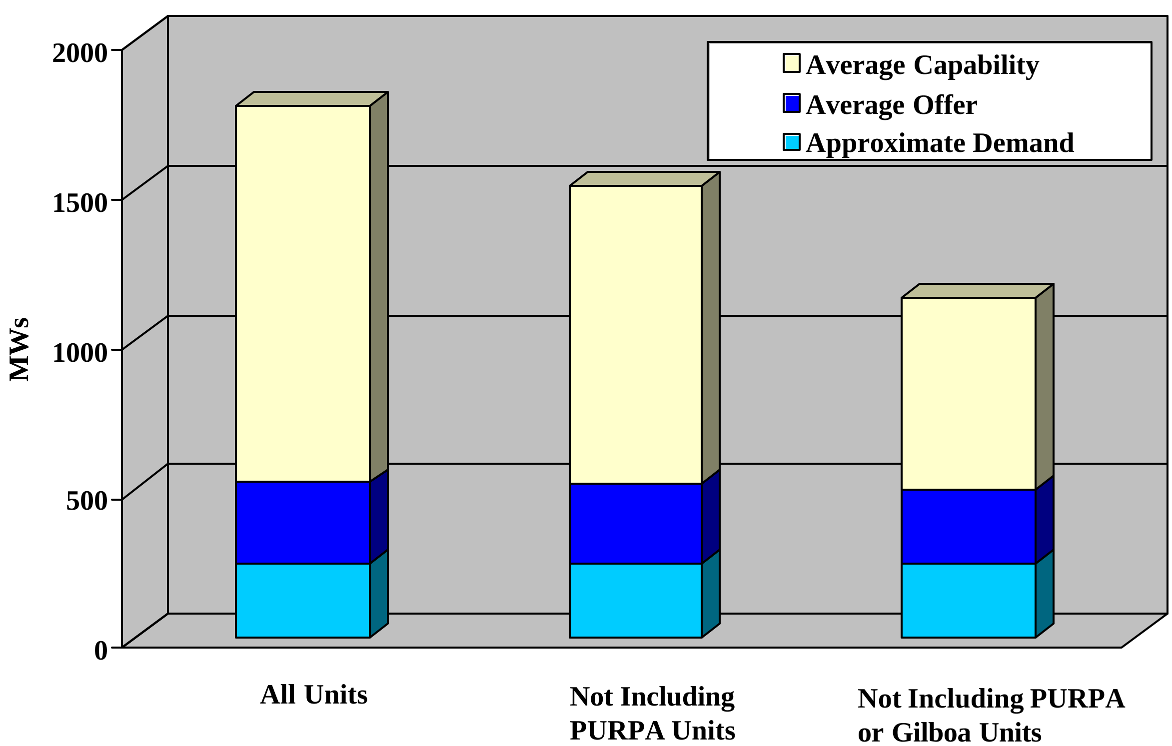
In addition, the pricing reform I described in the previous section would also improve the incentive for certain suppliers to offer their resources in this market by including in the 30-minute reserve price the opportunity cost for suppliers related to sales in the day-ahead energy market. Although this reform is not immediately necessary in this market, consistent pricing across all reserves markets and the regulation market would make the markets easier to understand and participate in, would reduce risks associated with lost opportunity costs, and ultimately make it easier to monitor.

## E. Regulation Market

The last ancillary service market that I review in this report is the regulation market. Units providing regulation service receive a dispatch signal every six seconds, allowing the NYISO to ensure that supply equals demand on a real-time basis. Regulating units must have the ability to move upward or downward from their base point an amount equal to the amount of regulating service they are providing. Like an operating reserve, therefore, a regulating unit cannot be scheduled to provide energy to the upper operating limit of the unit and may incur a lost opportunity cost associated with the undispatched portion of its output.

The amount of regulating service a unit may provide is equal to its ramp rate per minute times five minutes. Therefore, a unit's regulating capability is generally half of its 10-minute spinning reserve capability. Figure 44 shows the average capability and the offers the NYISO received during 2000.

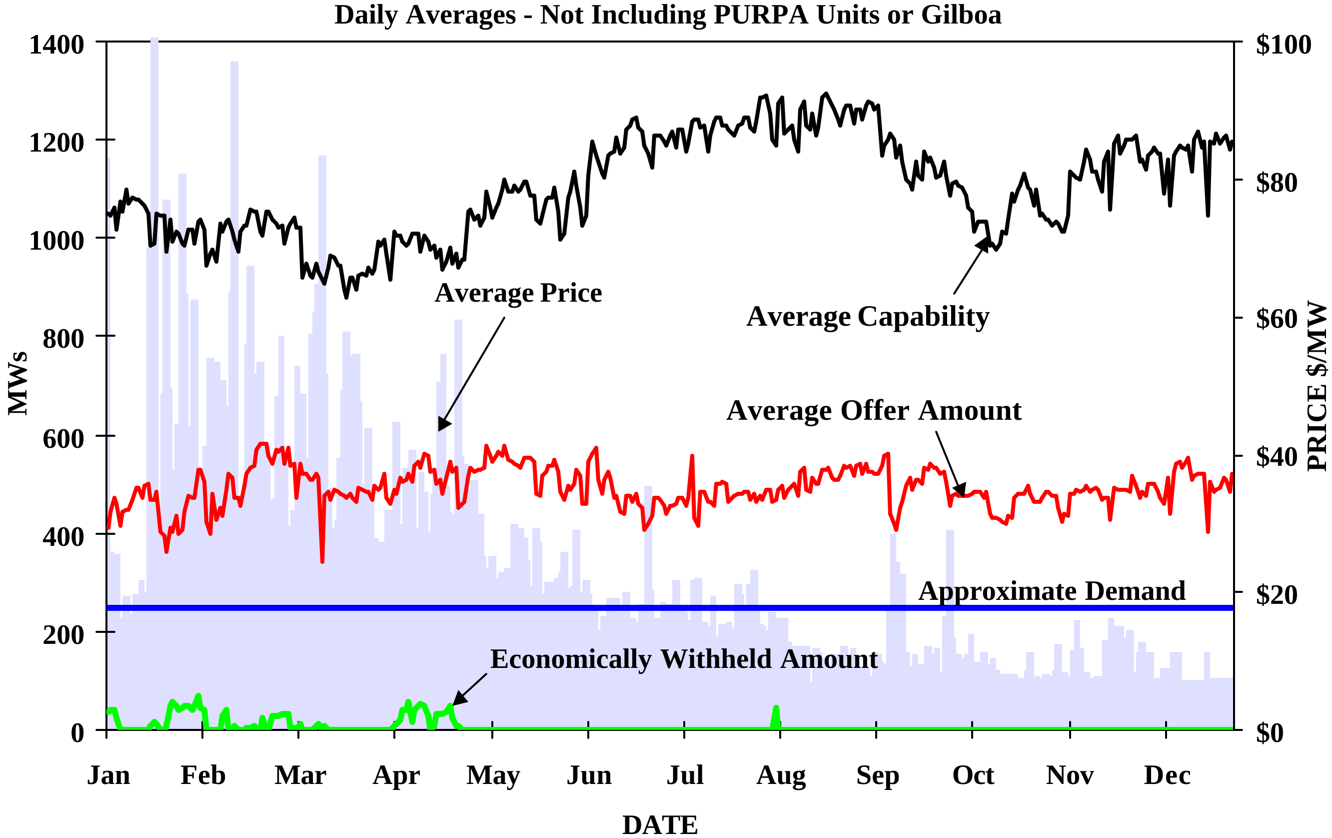
**Figure 44**
**Regulation Market All New York**
**April 1, 2000 - December 31, 2000**



This figure shows that the NYISO typically received approximately 75 percent more bids than the regulation requirement of 275 MW during high-ramp hours (200 MW is required in other hours). This is approximately the same amount of excess as in the 10-minute spinning reserve market. However, the regulation market is arguably tighter than the 10-minute spinning market because some substitution is possible from Western New York into Eastern New York for 10-minute spinning reserves. The 75 percent margin for regulation already includes all of the capability statewide since the regulation requirement is not locational.

When the market first began in late 1999, the NYISO frequently received fewer regulation bids than the total regulation requirement. This shortage was remedied by the beginning of 2000 with additional suppliers offering resources into the regulation market. The average daily offer amount continued to rise on average through the end of February and then remained relatively constant over the rest of the year. These daily offer patterns are shown in Figure 45 below together with the daily average regulation prices.

**Figure 45**
**Regulation Market - All New York**
**Daily Averages - Not Including PURPA Units or Gilboa**



The figure shows that prices for regulation fell consistently over the year, particularly from late January to April 2000. The higher prices that occurred in the spring may be attributable in part to the events in the operating reserve markets during this timeframe. As supplies of 10-minute NSR decreased, increasing amounts of 10-minute spinning reserves were substituted to meet the reserve requirements. Because the resources that provide 10-minute spinning reserves also typically supply regulation, the resources available to meet the regulation requirement were reduced, resulting in higher clearing prices.

Although Figures 44 and 45 both show that the supply has been adequate to meet the regulation requirement, they also show that less than half of the available regulation capability is typically offered in this market. The relatively low participation rate in this market limits the amount of excess supply in this market, making it much more susceptible to significant price increases. This can occur when a large portion of the supply is uncommitted or in the process of starting up. For example the highest regulation prices in recent months has occurred between midnight and 2 a.m. The regulation market will also be vulnerable to price increases when conditions are tight in other markets and a portion of the regulation-capable resources are needed to provide operating reserves or energy. In this case, a higher participation rate would result in more stable prices.

There are a number of factors that may contribute to the participation rates that the NYISO has realized in this market and are currently being investigated. Some participants cite the additional wear on the generating unit that can be caused by frequent output changes required by regulating units. However, this cost could be estimated and incorporated in a unit's bid to provide regulation. The more likely cause of the low participation rates is the market rules that currently apply to regulating and other on-dispatch generators.

Regulating units must meet a number of other requirements in addition to having the ability to receive dispatch signals every six seconds. For example, regulating units must have the ability to change their output by 1 percent of the unit's capability per minute. In addition, regulating units must operate within a relatively tight band around their instructed dispatch level or they can be subject to substantial regulation performance penalties. Units that are above their dispatch level are not compensated for their over-generation, even if it is assisting the NYISO keep the market balanced because other generators are producing below their instructed dispatch level. Together, these rules may preclude some generators from participating in the market, and may reduce the incentive or raise the costs for other generators.

The NYISO has recently conducted a survey of suppliers regarding these issues to determine the extent to which they may be hindering participation and is considering modifying the rules to reduce or eliminate regulation penalties and increase the amount of capacity that would qualify to provide regulation (e.g., by reducing the one percent ramp rate requirement). The results of this survey have informed the NYISO's decision to modify these rules to encourage additional supply to participate in the market. The market participant committees are currently considering a proposal by the NYISO to modify these rules and if action is taken by the committees and ultimately by FERC, these changes could be in place prior to the summer.

## F. Conclusions and Recommendations

The performance of the operating reserves markets and regulation market has been consistent with workable competition during 2000 with the exception of the episode during the spring. Following the imposition of the 10-minute NSR bidding requirement and cap, the bids and prices in each of the other markets remained at competitive levels. However, tight conditions in the ancillary services markets have contributed to the price spikes in the energy market in Eastern New York during the year. Under these conditions, even a modest amount of additional supply can provide substantial benefits to the market.

Therefore, I have recommended that the NYISO proceed most rapidly with those provisions that would expand the total capability or participation rates in the reserves and regulation markets. This includes:

- Allowing 30-minute NSR units to provide 10-minute NSR at the level their generator can produce within 10 minutes, although it may not have the ability to achieve full output in 10 minutes;
- Establishing a reserve sharing agreement with New England to coordinate reserve purchases and utilization, which should result in lower reserve requirements and competitive improvements in the reserves markets; and
- Modifying regulation market rules and penalties to remove disincentives or other barriers to fuller participation in the market by reserve capable generators.

These improvements should be implemented as soon as is feasible as they promise immediate relief for the reserves and regulation market when conditions become tight. Another provision that may increase the supply of reserves in Eastern New York under certain circumstances is the provision to allow reserve suppliers in Western New York to supply reserves in Eastern New York by setting allocating or reserving transmission capability on the Central-East transmission interface for this purpose. However, this modification requires more investigation and planning than the measures listed above. Therefore, I have recommended that this not be attempted in the short-term, until it is thoroughly investigated and tested to ensure that it will not adversely affect the utilization of the transmission system.

In addition to the supply enhancements, a number of pricing enhancements are also being considered.

- Establishing prices that vary by location for suppliers of operating reserve when the locational reserve requirements are binding. This would lower the cost of reserves and send more accurate price signals to reserve suppliers. This provision has been proposed and awaits FERC's approval.

- Implementing a consistent pricing structure for the operating reserves and regulation that would compensate the suppliers in each market with a clearing price equal to the availability bid plus lost opportunity cost of the marginal supplier in that market. This would reduce uncertainty regarding lost opportunity costs, which results in much higher availability bids and may be a significant disincentive for some suppliers offering their resources.

I have recommended that the former be implemented as soon as feasible after FERC approves this modification. Given the process required to implement the latter provision, I have recommend that the NYISO consider this modification over the longer-term.

Finally, additional long-term modifications have been discussed, including implementing a second settlement in the hour-ahead for the ancillary services. The NYISO currently optimizes its reserves purchases in the hour-ahead, but does not settle the differences between the day-ahead schedules and the hour-ahead schedules at an hour-ahead price. A second settlement would provide more accurate price signals for potential reserve suppliers in the real-time market and could lower costs to the market to the extent that a day-ahead reserve supplier is dispatched for energy the following day. Without the second settlement, the day-ahead supplier is not obligated to buy back its reserve schedule in the hour-ahead and would be paid for both the reserve schedule and the energy schedule. However, this remains a longer-term recommendation because it is not resulting in substantial costs to the market.

# END NOTES

1 Although the NYISO has filed for rehearing with FERC on this issue and is attempting to recover the revenues obtained by

2 Generators are paid the LBMP at their location for production while loads pay a zonal average price.

3 The wholesale electricity market includes a number of products, including the electricity commodity itself (termed "energy" in this report), as well as various other system support services and reserves (termed "ancillary services" in this report).

4 To a lesser degree, price differences result from differences in electrical losses caused by the injections or withdrawals of power at different points in the network.

5 These relatively high real-time prices are verified on a daily basis by the NYISO to ensure that they are calculated correctly consistent with the provisions of the tariff. Improperly calculated prices or prices based on data errors have been corrected and the corrected prices are reflected in the figure.

6 Other factors that affected prices that were not analyzed in this analysis include the derating of the transmission interface with PJM due related to the facility outages, the under-utilization of the New England Interface discussed later in the report, and the various operational issues that have resulted in some market inefficiencies.

7 The equation estimated was in logarithmic form, which better reflects the supply conditions in the electric market that are depicted in figures 3, 4, and 5: $\ln(\text{Price}_i) = c + a_1\ln(\text{Excess Cap}_i) + a_2\ln(\text{Gas Price})$ for i market areas defined by binding transmission constraints.

8 Prior to the auction-based markets implemented by the New York ISO, a measure of historical price levels may be gained from the New York Power Pool "split-savings" data, which represents the price at which economy pool transactions were conducted between the members. Alternatively, survey data of short-term bilateral contracts reported in publications such as *Power Markets Weekly* and *Megawatt Daily* provide a measure of wholesale power prices.

9 I assumed no changes in congestion patterns or net imports from 2000 levels.

10 *Power Alert: New York's Energy Crossroads*, New York ISO, March 2001.

11 Risk-aversion means that the entity is not indifferent between two events that have the same expected value. Insurance markets exist because consumers are willing to pay a premium for insurance rather than bearing the brisk of a large loss with a low probability (e.g., a home fire).

12 This excludes the provisions of the ECAs pertaining to external transactions that were filed in the fall of 2000. These ECAs are discussed in the section on external transactions.

13 ECA #20001208a and #20001208b.

14 New England Power Pool, Docket ER00-3577-000 November 22, 2000.

15 See ISO New England Operating Procedures, OP-9 Section I, and section 4.3.3 of the Market Rules & Procedures section 4.3.3.

16 NYISO Market Monitoring Plan, Addendum A.

17 The only exception to this treatment was that the Blenheim-Gilboa pumped storage units were excluded from the analysis. The Gilboa ratings under NYPP operation seemed to substantially understate the true maximum capability of the unit and would have increased results substantially. To be conservative, therefore, Blenheim-Gilboa was excluded.