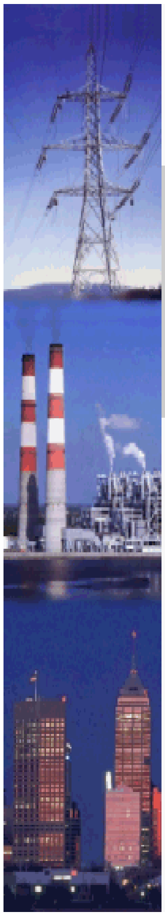


Summer 2004 Review of the New York Electricity Markets

Presented to:

NYISO Board of Directors
and Management Committee

David B. Patton, Ph.D.
Independent Market Advisor

November 15, 2004

Summary and Conclusions

- Electricity prices were generally lower in 2004 than in 2003 due to unusually mild weather in 2004.
- There were no shortages during summer 2004 so shortage pricing did not occur.
- These outcomes have caused the net revenue available to a new entrant in the New York market to be slightly lower than in 2003.
  - Net revenue levels are still substantially less than the costs of entry for most new resources.

Summary and Conclusions

- Market performance improved in a number of areas this summer relative to previous years:
  - ✓ Price convergence between the day-ahead and real-time markets remained at satisfactory levels, which is attributable in part to active virtual trading.
  - ✓ Out of merit dispatch was at a level comparable to levels last year, which has been an improvement since changes in pricing rules and operating procedures were implemented during 2002.
  - ✓ No substantial patterns of withholding or other market abuses were detected during the summer.
  - ✓ The performance of the markets should improve substantially when RTS is implemented.

Summary and Conclusions

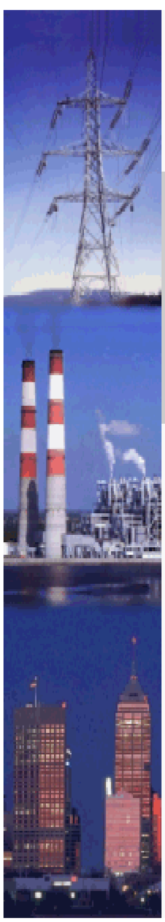
This report identifies some of the potential improvements in the NYISO markets:

- Supplemental commitments through the local reliability pass of SCUC and the SRE process are often required to meet NOx requirements in New York City, which increases uplift on units in the City.
  - ✓ In the longer-run, the ISO should improve the modeling of local reliability rules and NOx constraints to include them in the initial SCUC commitment.
  - ✓ These changes will likely involve significant software changes.
  - ✓ In the short-run, therefore, the ISO should consider the feasibility of allowing operators to pre-commit certain units that are known to be needed.
- Congestion has occurred in real time that appears to be caused by inconsistent transmission limits and loss modeling between the real time and day ahead markets.
  - ✓ RTS will improve the consistency of the transmission limits and other assumptions due to similarity of the RTS and SCUC models.
  - ✓ These changes will reduce uplift costs and improve the consistency of day-ahead and real-time prices in constrained areas.

Summary and Conclusions

Additional improvements and recommendations:

- We recommend that the NYISO implement intra-hour transaction scheduling to improve the utilization of the NYISO’s external interfaces.
- Once RTS is implemented, if price convergence within NYC does not improve, we recommend virtual trading be expanded to load pockets or individual nodes.
- In addition, the NYISO should consider the feasibility of providing more flexibility for the TCCs by:
  - ✓ Selling TCC options;
  - ✓ Increasing the TCC products offered (e.g., peak hour TCCs), and
  - ✓ Considering additional means for participants to more easily and flexibly reconfigure TCCs.

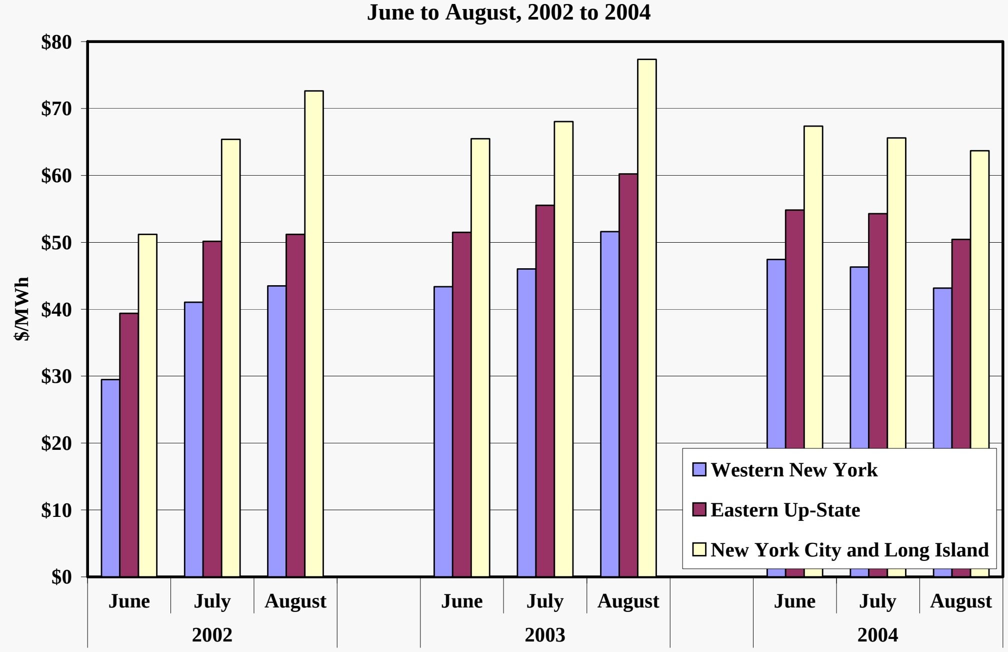


Market Prices and Outcomes

Energy Prices in the Day-Ahead Market

- The following figure shows average energy prices in three regions of New York during the summers of 2002 to 2004.
- Price differences between the three geographic regions are primarily due to:
  - ✓ The Central-East transmission constraint between western and eastern New York. In the summer of 2004, this price difference averaged more than $7/MWh.
  - ✓ Transmission constraints into New York City and the internal load pockets, resulting in price differences into the City averaging more than $11/MWh.
- Despite higher fuel prices, energy prices were slightly lower in 2004 compared to 2003 due to milder weather in 2004.
- The electricity prices decreased from June to August in 2004 due to the decreasing trend in fuel prices in these months.

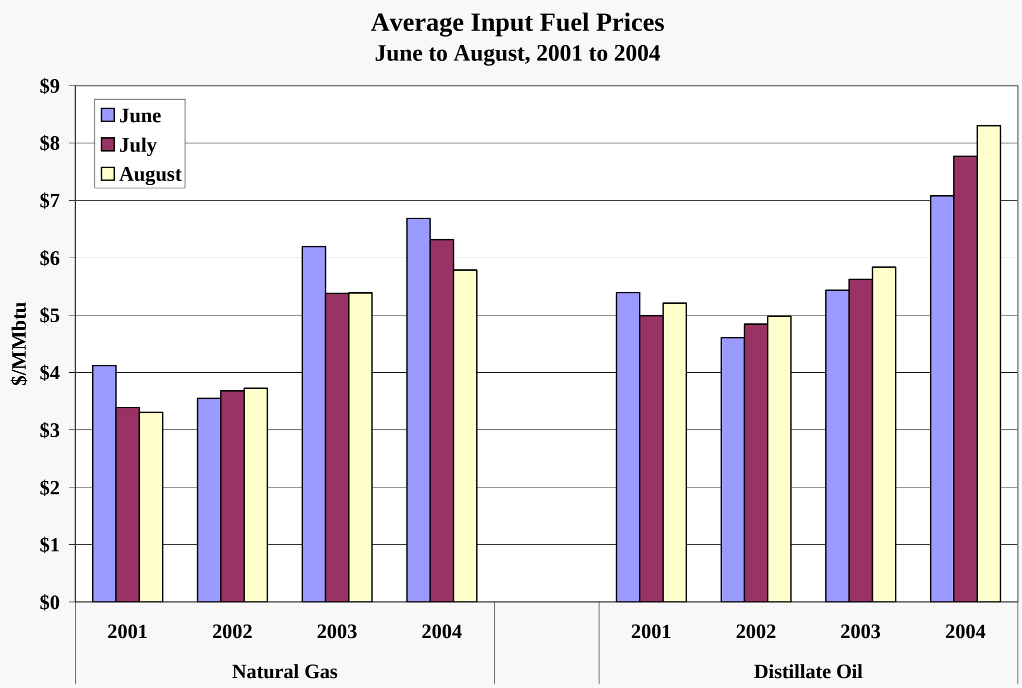
Average Day-Ahead Energy Prices
June to August, 2002 to 2004



Note: August 2003 blackout hours excluded.

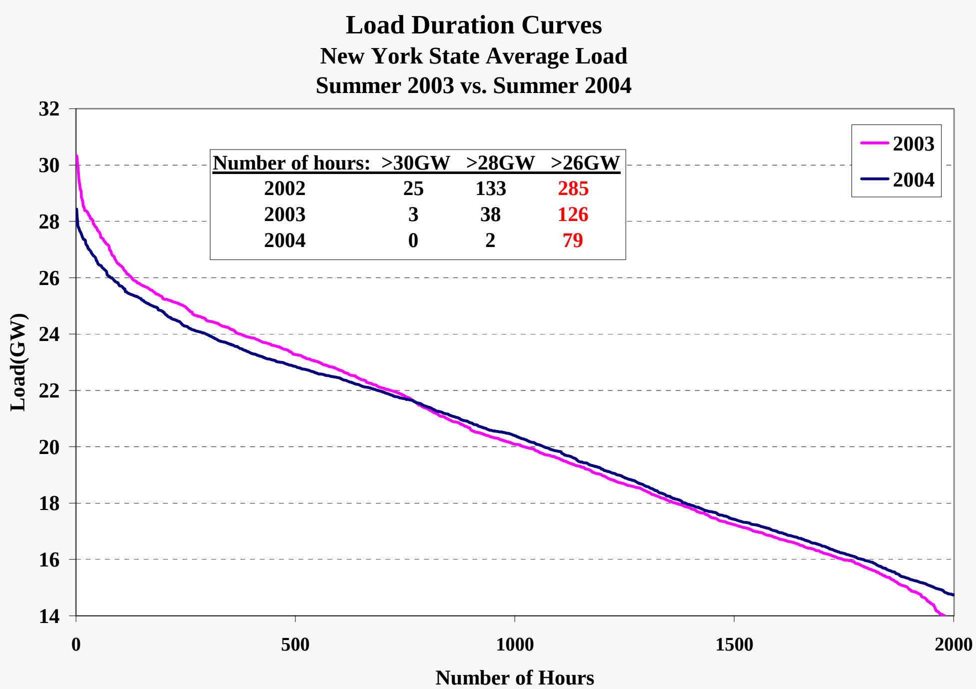
Input Fuel Prices

- The following figure shows average input fuel prices during the summers of 2001 to 2004.
- Natural gas prices increased by more than 50 percent from the summer of 2002 to 2003 and increased another 10% in the summer of 2004.
  - ✓ This translates into approximately $20/MWh of additional fuel costs for a 10,000 btu/kWh combustion turbine.
  - ✓ The summer 2004 average of $6.26/mmbtu is significantly lower than the January 2004 high of more than $11/mmbtu.
- Oil prices increased by approximately 15% from summer 2002 to summer 2003 and increased another 35% from 2003 to 2004.
- While much of the electricity used by New York consumers is generated from hydro, nuclear, and coal-fired generators, natural gas and oil units are on the margin in most hours.



Hourly Load Levels

- The following figure is a load duration curve, which shows hourly load levels sorted in descending order.
  - ✓ The points on this curve indicate (on the x-axis) the number of hours that the load was above designated load level (on the y-axis).
- There were fewer high-demand hours in 2004 than in 2003 primarily due to milder weather in 2004.
  - ✓ In the summer of 2004, there were zero hours with actual loads exceeding 30 GW, compared with 3 hours in 2003 and 25 in 2002.
  - ✓ There were 36 fewer hours with loads above 28 GW in summer 2004 (a 95% decrease from 2003 and a 98% decrease from 2002).
  - ✓ There were 47 fewer hours with loads above 26 GW in summer 2004 (a 37% decrease from 2003 and a 72% decrease from 2002).

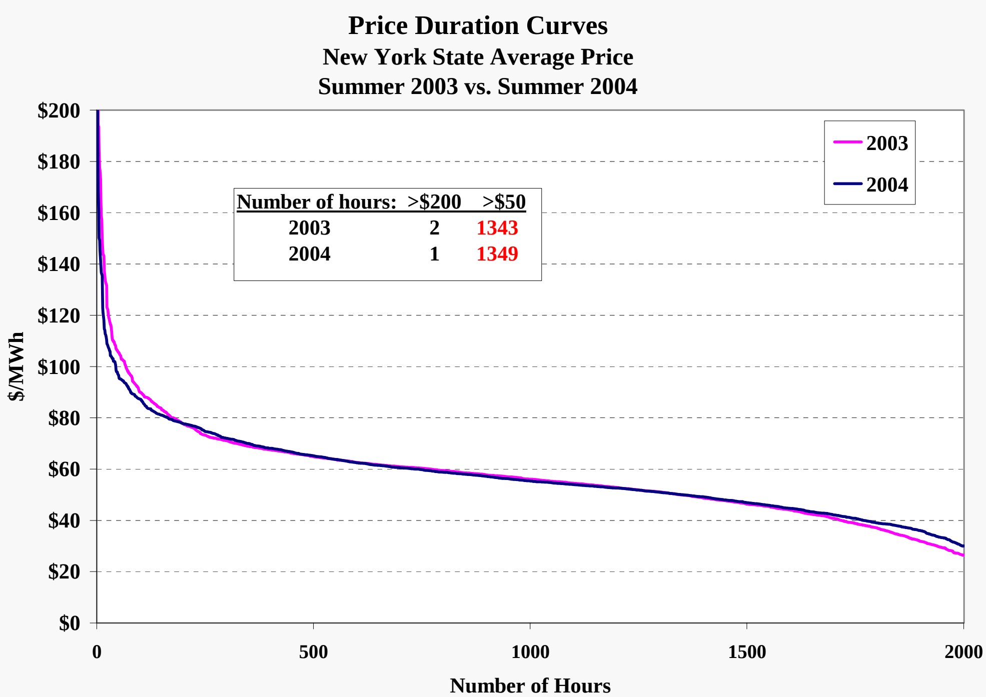


Number of hours:	>30GW	>28GW	>26GW
2002	25	133	285
2003	3	38	126
2004	0	2	79

Note: August 2003 blackout hours excluded.

Load Duration and Price Duration Curves

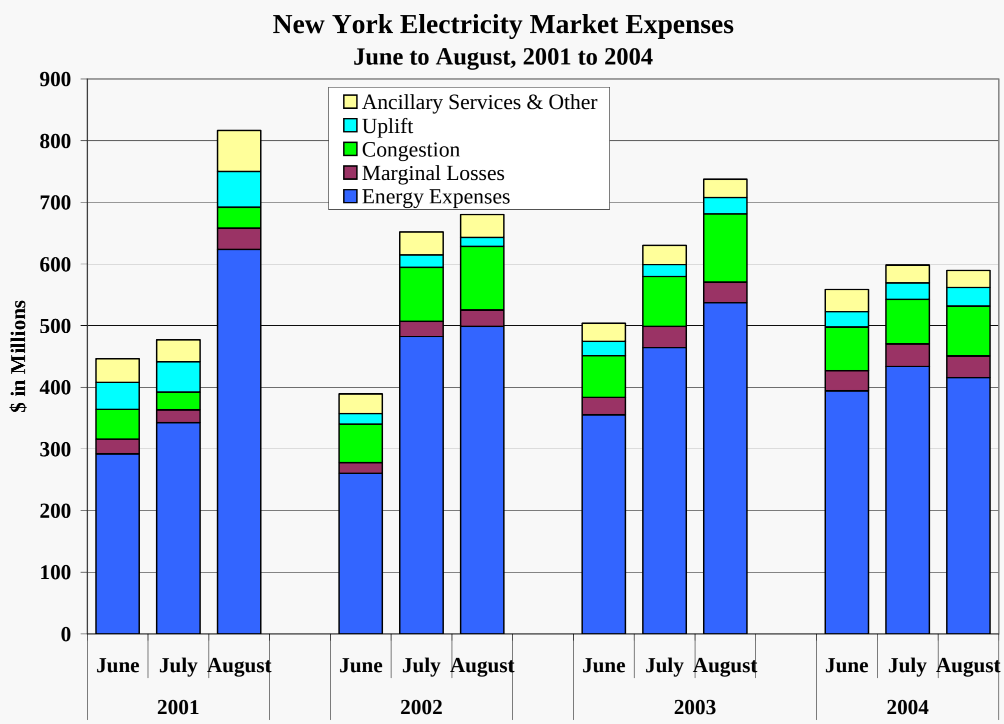
- The next figure is a price duration curve, which shows hourly real-time prices sorted in descending order.
- This curve shows that that there was only one hour with a New York State weighted-average price of greater than $200/MWh.
- This curve shows that there was little difference in the number of hours priced greater than $50/MWh.
  - ✓ The summer of 2003 had 1,343 hours priced above $50/MWh, while the summer of 2004 had 1,349.
  - ✓ The increase in fuel price was offset by milder weather and lower loads.



Note: August 2003 blackout hours excluded.

Total Electricity Costs in the New York Markets

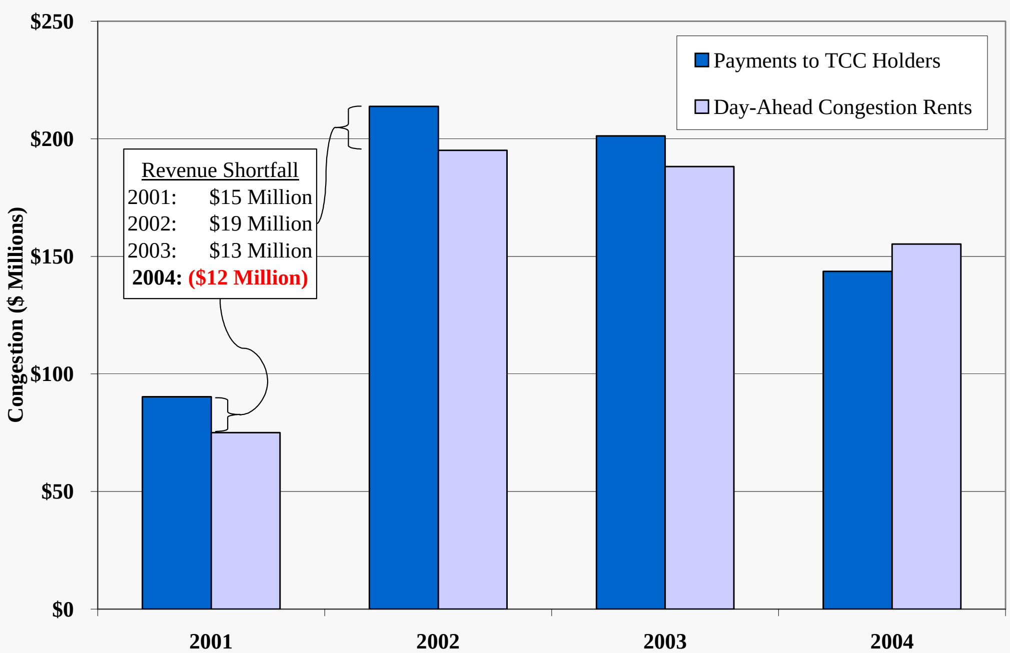
- The following figure shows the total monthly expenses for market participants of the NYISO in the summers of 2001 to 2004.
- Total electricity costs for the summer of 2004 were approximately $1.8 billion – less than total costs in 2003, but slightly more than total costs in the summers of 2001 and 2002.
- Changes in market expenses from the summer of 2003 were caused by:
  - ✓ Lower average energy prices;
  - ✓ Slightly higher levels of physical bilateral schedules (that do not settle the energy with NYISO); and
  - ✓ Lower congestion costs;



Congestion Costs

- The following figure shows day-ahead congestion costs and TCC payments for summer 2001 to summer 2004.
- The increase in congestion costs after 2001 was primarily due to the modeling of load pockets within New York City.
- A shortfall occurs when payments to TCC holders exceed the day-ahead congestion rents.
  - ✓ Congestion shortfalls have generally been related to transmission outages that cause the transmission capability in the day-ahead market to be less than was assumed when the TCCs were sold.
  - ✓ In addition, excess TCCs were sold into NYC and contributed to shortfalls in the summer of 2003 and early summer 2004.
- Changes made during 2004 to reduce the shortfall, together with the resolution of the excess TCCs led to a surplus of $12 million for the summer 2004.

Day-Ahead Congestion Rents and TCC Revenues
June to August, 2001 to 2004



Note: August 2003 blackout hours excluded.

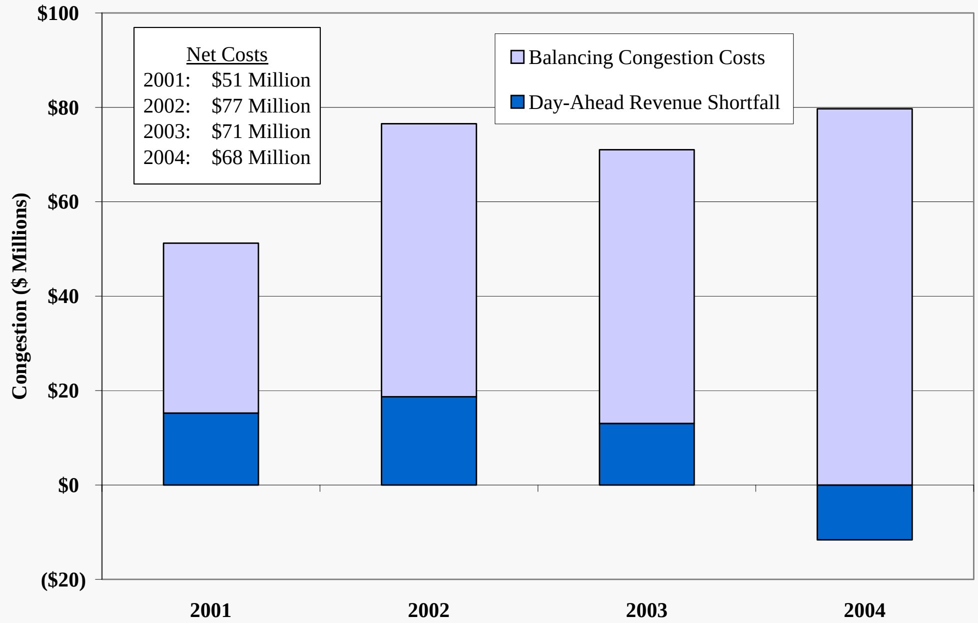
Congestion-Related Uplift Costs

- The following chart shows the day-ahead revenue shortfalls together with balancing congestion costs.
  - ✓ Both of these costs result in uplift charges, although they are allocated slightly differently.
- Summer 2004 had a day-ahead congestion surplus (thus, shortfall is shown as negative).
- However, the balancing congestion costs increased in 2004 to approximately $80 million.
  - ✓ This is an increase of approximately one-third from the levels realized in the summers of 2002 and 2003.
  - ✓ The implications of the balancing energy costs are discussed below.

Congestion-Related Uplift Costs

- The real-time spot market can result in congestion payments from the NYISO or to the NYISO (balancing congestion costs).
  - ✓ The primary cause of positive balancing congestion costs is the reductions in transmission limits between the day-ahead and real-time markets, although changes in loop flows can also cause balancing congestion.
  - ✓ The analysis of the results in 2003 showed that real-time limits appeared to be consistently modeled at lower levels than in the day-ahead market.
- The RTS will improve the consistency of the transmission limits and other assumptions because both the RTS and SCUC models operate on a common software platform.

Day-Ahead Shortfalls and Real-Time Congestion Costs
June to August, 2001 to 2004



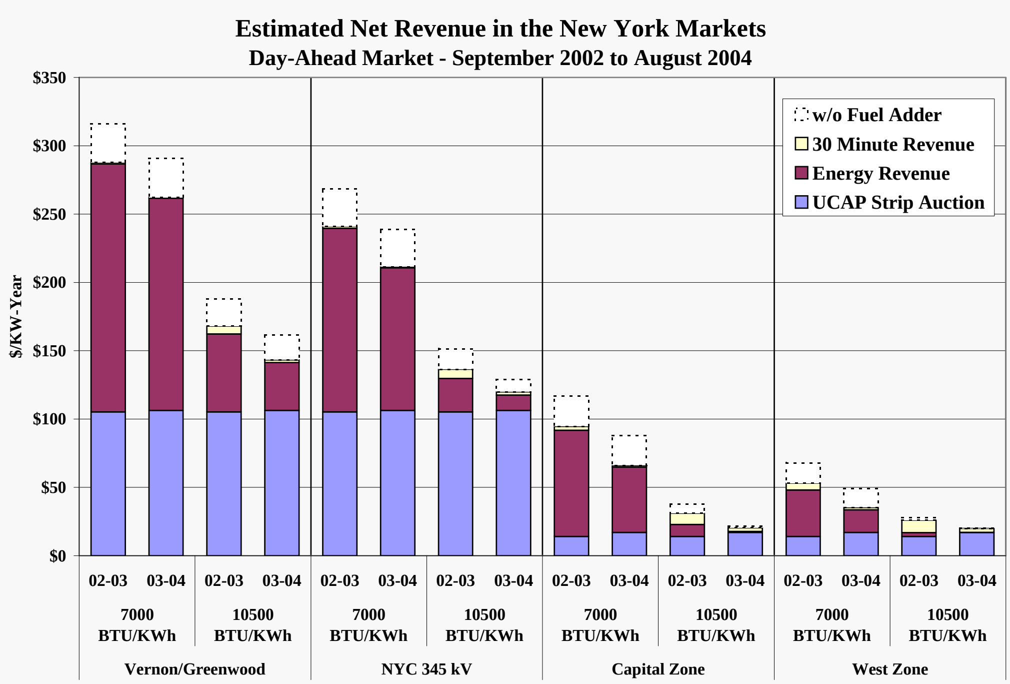
Note: August 2003 blackout hours excluded.

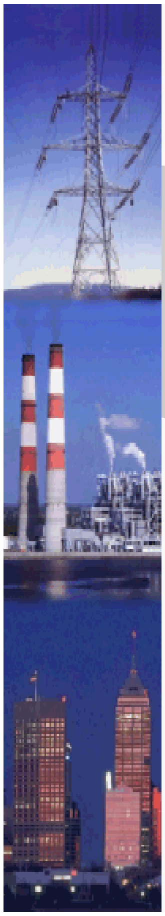
Economic Incentives for New Investment

- The following analysis addresses the long-term economic signals produced by the markets.
  - ✓ The markets govern the entry of new generation and retirement of existing generation.
  - ✓ In long-run equilibrium, the market revenue should be sufficient to cover the entry costs of a new unit and the going-forward costs of existing units.
- Net revenue is the market revenue, net of operating costs, the markets would provide to a generator.
  - ✓ Net revenue will vary with a generator’s heat rate, availability and location.
  - ✓ Net revenue has three main components – capacity payments, net revenue from the sale of energy, and reserve payments.
- The following figure shows the net revenue for generating units with different heat rates in different locations, comparing the 12-month periods ending on August 31, 2003 and 2004.

Economic Incentives for New Investment

- These figures show:
  - ✓ Net revenue levels for each location decreased in the 2003 – 2004 time period compared to the 2002-2003 time period.
  - ✓ This was the case for both relatively efficient generators (low heat rates) and inefficient generators (high heat rates).
- Net revenue was affected by lower energy prices and lower 30-minute reserves revenue.
- The analysis shows that for 2003-04 a new GT would not be economic within or outside of New York City, assuming:
  - ✓ Annual entry costs for a new GT of approximately $87 per kW-Year outside of NYC and $176 per kW-Year inside of NYC.
  - ✓ The primary contributing factor was that neither year exhibited significant shortage pricing.





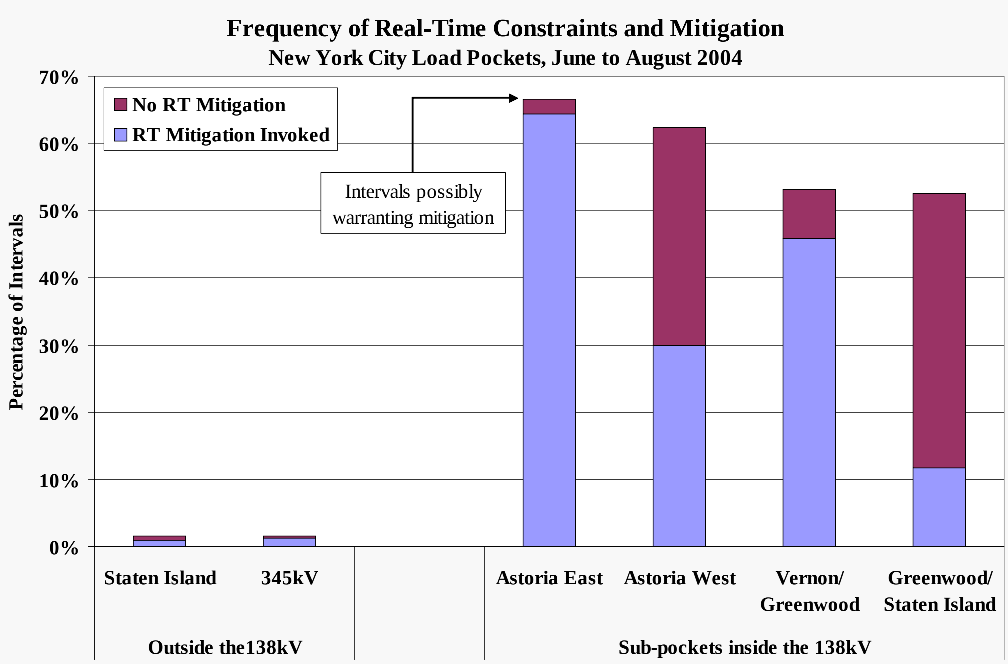
Market Power Mitigation

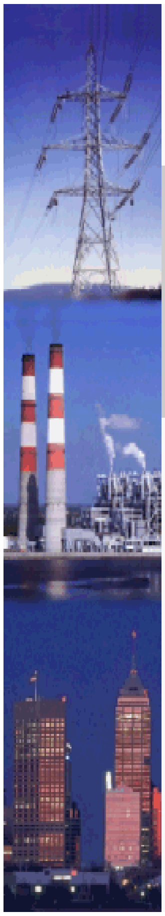
Summary of Day-Ahead Mitigation

- No mitigation occurred under the automated mitigation procedures ("AMP"), although it was triggered to perform the impact test several times.
- The ConEd day-ahead mitigation measures were replaced in 2004 with the conduct impact framework.
  - ✓ During 2003 when the ConEd mitigation was still in effect, some mitigation occurred in every hour during the summer.
  - ✓ In the summer 2004, mitigation occurred much less frequently.

Summary of Real-Time Mitigation

- The following figure summarizes the frequency of constraints into the load pockets and the actual frequency of mitigation.
  - ✓ The constraints shown are those with a positive cumulative shadow price into the load pocket.
  - ✓ When the constraints shown were binding, resources with bids exceeding their reference levels by more than the load pocket's conduct threshold are subject to real-time mitigation.
- This figure shows that outside of the 138 kv system where most of the load pockets are located, mitigation is infrequently imposed due to higher conduct thresholds and more competitive conditions.
- In the narrower load pockets:
  - ✓ Constraints are binding in 50 to 66 percent of the intervals during the summer;
  - ✓ Mitigation is only imposed in from 12 to 48 percent of the intervals in most of the load pockets, and 64 percent of the time in the Astoria East pocket;



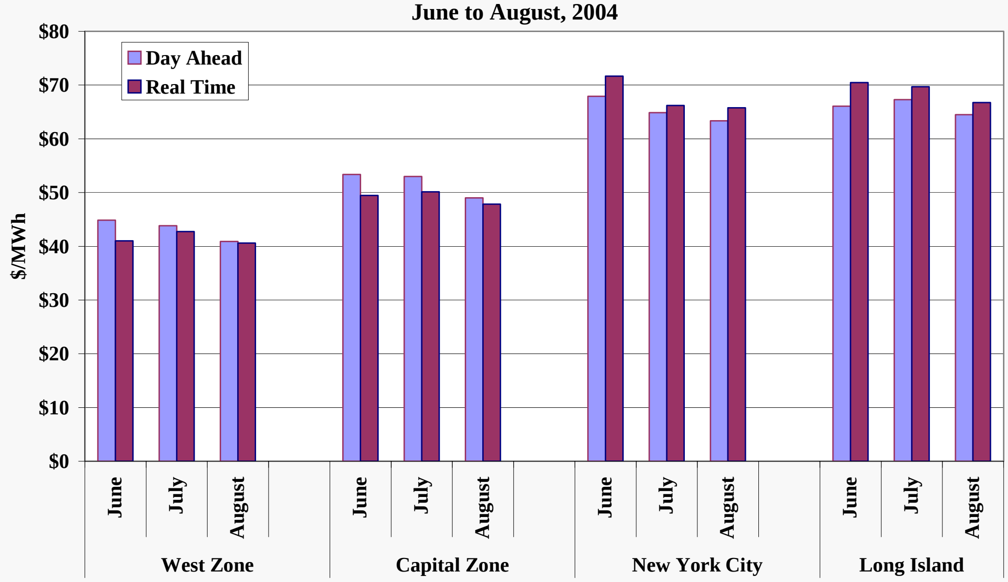


Market Performance

Day-Ahead to Real-Time Price Convergence

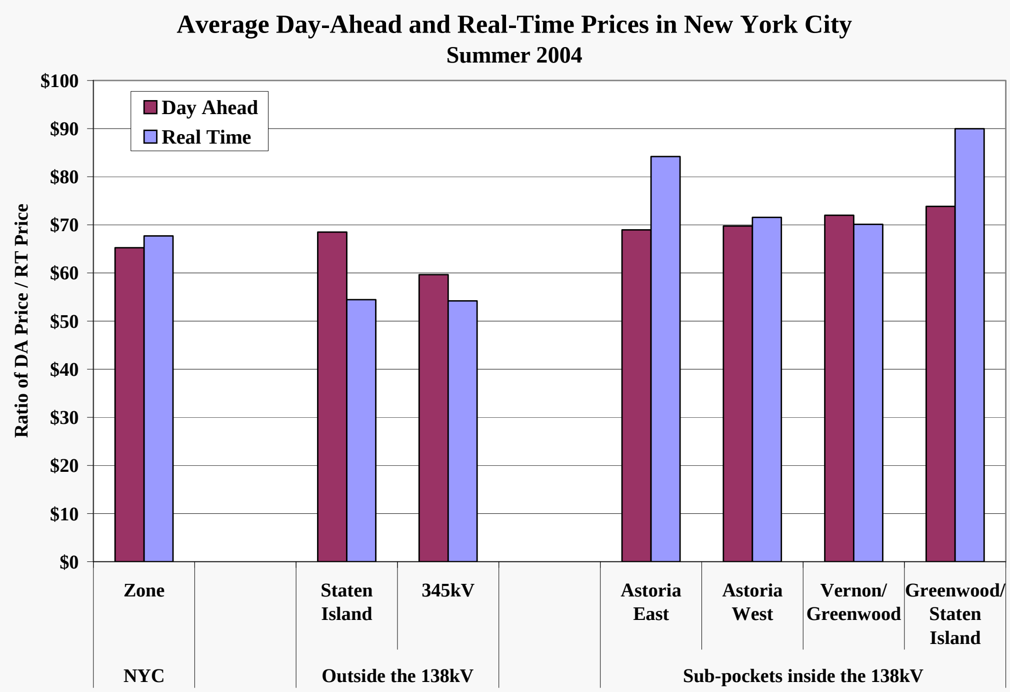
- The following figure shows a monthly comparison of the average day-ahead and real-time energy prices in the West Zone, Capital Zone, New York City, and Long Island.
- The results generally show a slight premium associated with day-ahead prices in the West Zone and Capital Zone, which is consistent with expectations.
  - ✓ Loads should place a premium on the day-ahead market due to the higher volatility in the real-time market and the fact that TCCs settle in the day-ahead market.
  - ✓ Generators selling in the day-ahead market are exposed to some risk associated with committing financially day-ahead;
  - ✓ If participants are risk-averse, these factors will generate a premium in the day-ahead prices.
  - ✓ This is also consistent with the experience from other markets.
- The results do not consistently show a day-ahead premium in New York City and Long Island. In all months, real-time prices are slightly higher than day-ahead prices.

Average Day-Ahead and Real-Time Energy Prices
West, Capital, New York City, and Long Island Zones
June to August, 2004



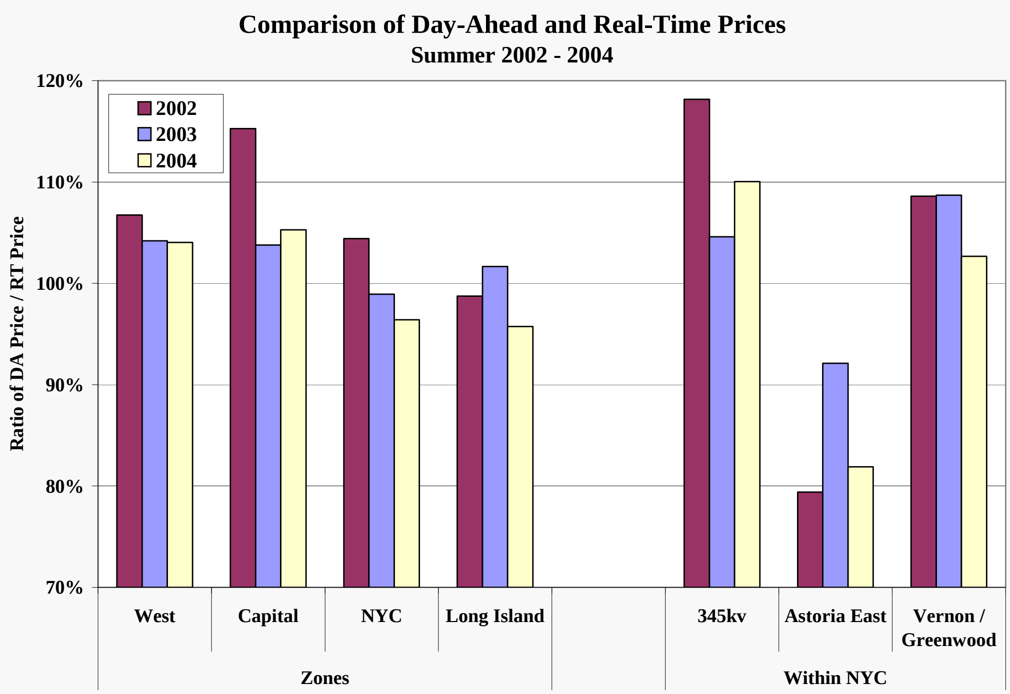
Price Convergence in the NYC Load Pockets

- For the three summer months, the average day-ahead and real-time prices were nearly equal for the NYC zone.
- However, the NYC zone price is a load-weighted average price based on the locational prices in each of the load pockets in the city.
- The following figure shows how well day-ahead and real-time prices converged at various locations within the City.
  - ✓ Convergence varied from location to location.
  - ✓ The Astoria East and Greenwood/Staten Island load pockets showed significant premiums in real time;
  - ✓ Astoria West and Vernon/Greenwood had average prices that were relatively close; and
  - ✓ Staten Island and the 345 kv system generally exhibited modest premiums in the day-ahead market.
- Price convergence in the load pockets could be improved by the introduction of virtual trading within the NYC load pockets.

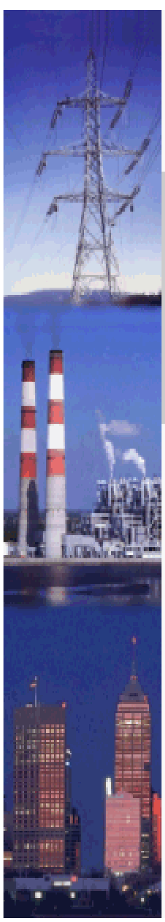


Day-Ahead to Real-Time Price Convergence

- The following figure shows price convergence at various locations in New York in the summer of 2004 compared to summer 2003 and 2002.
- The figure shows the ratio of the average day-ahead price to the average real-time price (values greater than 100% indicate a day-ahead premium).
- This figure shows that compared to 2003, the ratio fell in most locations.
  - ✓ This could reflect a reduced expectation day-ahead of potential real-time price spikes due to shortages.
  - ✓ Despite the reductions, day-ahead premiums outside NYC continued.
- Price convergence was not as good in NYC and Long Island as in 2003, but remained superior to the results in 2002. Convergence in these areas are affected by:
  - ✓ The inability to trade virtually in the load pockets; and
  - ✓ The apparently reduced transfer limits into these areas. The difference in prices and congestion due to this was not arbitraged as completely in 2004;



Note: August 2003 blackout hours excluded.



Analysis of Bidding Patterns

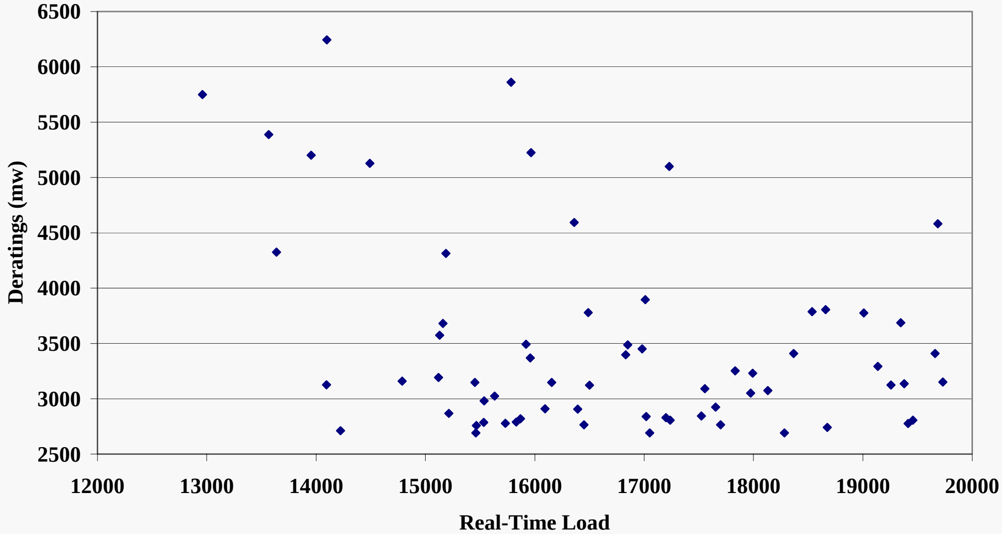
Analysis of Supplier Offers – Deratings

- This section of the report analyzes the patterns of conduct that could indicate physical or economic withholding.
- This analysis evaluates the correlation of quantities of potential withholding to load levels.
  - ✓ Suppliers in a competitive market should increase bid quantities during higher load periods to sell more power at the higher peak prices;
  - ✓ Suppliers in markets that are not workably competitive will have the greatest incentive to withhold at peak load levels when the market impact is the largest.
- The first analysis is of potential physical withholding, which focuses on generator deratings.
- Deratings include planned outages, long-term forced outages, short-term forced outages, and partial deratings.

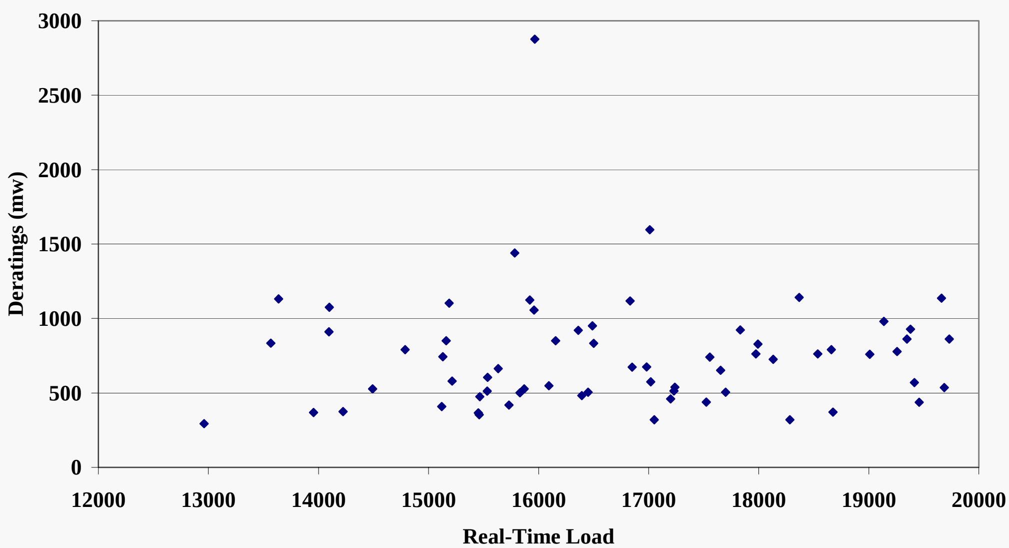
Analysis of Supplier Offers – Deratings

- The following figures show deratings versus actual load in eastern New York in the 3:00 PM hour of the summer of 2004.
- The second figure focuses on short-term outages since these are most likely to reflect attempts to physically withhold.
- The figures show no statistically significant relationship between deratings and load levels.
  - ✓ There was only one day when short-term deratings exceeded 2500 MW. This occurred on July 5th.
  - ✓ There were only eleven days when the short-term deratings exceeded 1000 MW, and this occurred only twice when load was greater than 18,000 MW.
- Under an hypothesis of physical withholding, deratings would be positively correlate with load, which is not the case in the data.

Relationship of Deratings to Actual Load
Day-Ahead Market -- Eastern New York
June to August 2004 -- Weekdays 3pm Hour



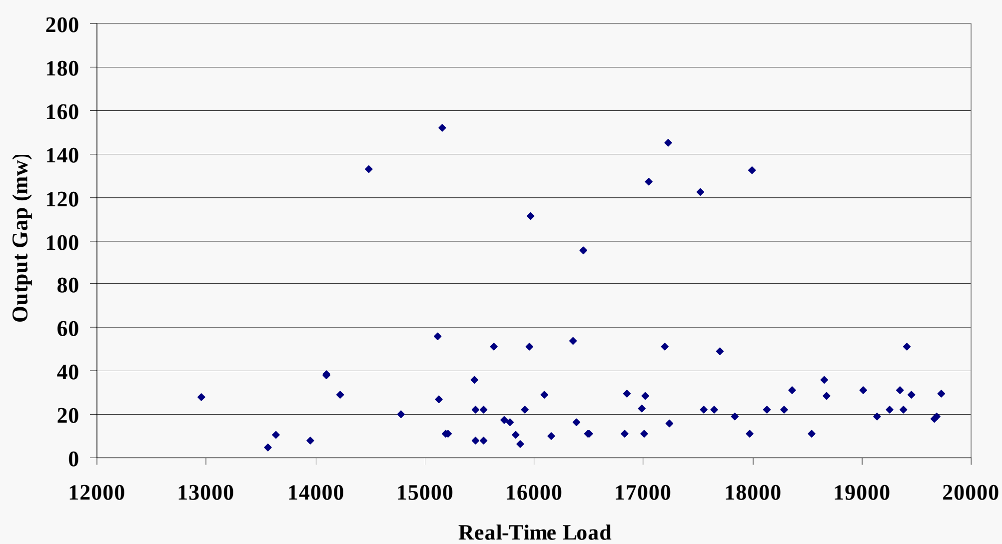
Relationship of Short-Term Deratings to Actual Load
Day-Ahead Market -- Eastern New York
June to August 2004 -- Weekdays 3pm Hour



Analysis of Supplier Offers – Output Gap

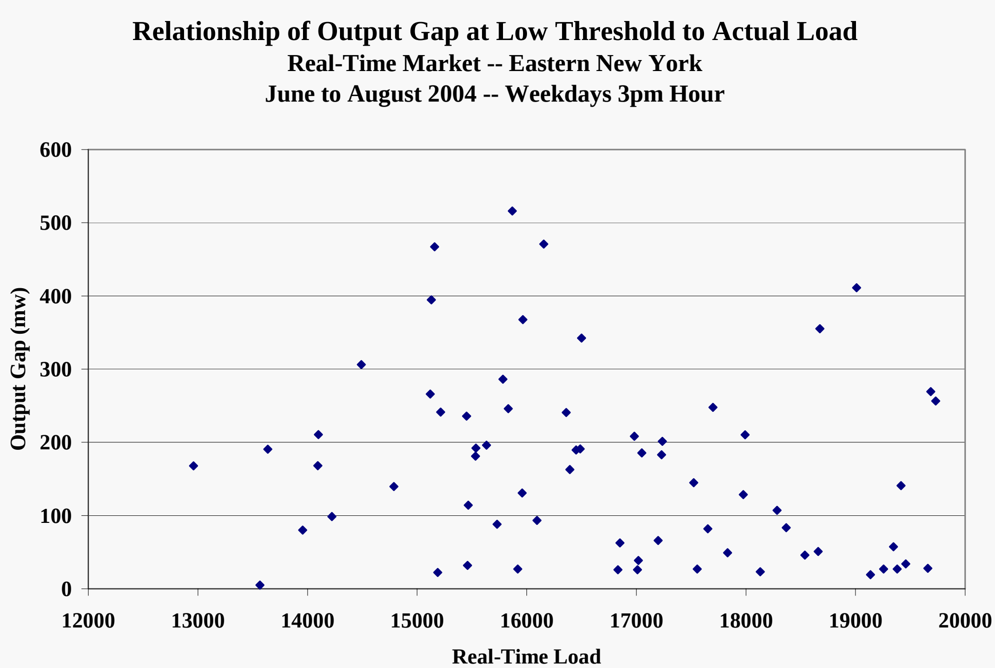
- The second analysis is intended to assess potential economic withholding, employing a measure called an “output gap”.
- The output gap is the quantity of economic capacity that is not sold in the day-ahead or real-time markets for energy or ancillary services because a supplier submits an offer price well above a unit’s reference level.
- The output gap:
  - ✓ Addresses all components of a supplier’s offer, including start-up, minimum generation, and incremental energy offers.
  - ✓ Includes units that “set the price” while bidding well above reference levels.
- The following figure shows the total output gap in eastern New York during the 3 pm hour on weekdays, which is generally the highest load hour.
- The output gap in this figure is computed assuming the conduct thresholds in the mitigation plan ($100/MWh or 300%, whichever is lower).
- The figure indicates a lack of correlation between load and output gap, which is inconsistent with a hypothesis of economic withholding.

Relationship of Output Gap at High Threshold to Actual Load
Real-Time Market -- Eastern New York
June to August 2004 -- Weekdays 3pm Hour



Analysis of Supplier Offers – Output Gap

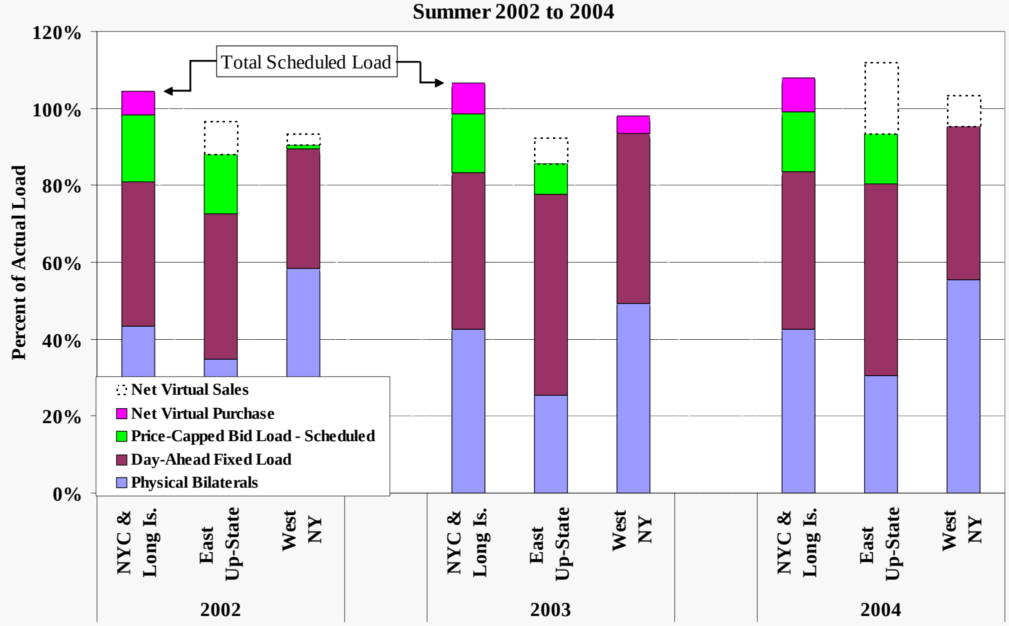
- The previous figure shows that the output gap is very low on all days during the summer of 2004 using the standard mitigation thresholds.
- To test the robustness of this result, we also conducted the analysis using lower threshold values.
- The output gap in the following figure is computed assuming thresholds of $50/MWh or 100% (whichever is lower).
  - ✓ This figure shows the output gap was less than 300 MW on the nine days where load exceeded 19,000 MW.
  - ✓ There is no statistically significant relationship between these output gap results and the actual load levels, which is consistent with expectations in a workably competitive market.



Analysis of Load-Bid Patterns

- The following figure shows the day-ahead load bidding and virtual trading for the summer 2002 -2004; There are five categories of Schedules:
  - ✓ *Physical Bilaterals* – These are bilateral transactions which settle transmission charges through the ISO, however, transactions arranged solely between two parties do not appear in this category.
  - ✓ *Day-ahead Fixed Load* – Non-price sensitive load scheduled by Load Serving Entities.
  - ✓ *Price-Capped Bid Load-Scheduled* – Price sensitive load scheduled by Load Serving Entities.
  - ✓ *Net Virtual Purchases* – Whenever virtual load exceeds virtual supply, there is a net increase in load scheduled day-ahead.
  - ✓ *Net Virtual Sales* – Whenever virtual supply exceeds virtual load, this is equivalent to decreasing the total quantity of load purchased day-ahead (shown as empty boxes).
- Proportionately more load was scheduled in NYC and Long Island.
  - ✓ In 2004, 107 percent of real-time load was scheduled day-ahead in NYC and Long Island compared less than 95 percent in the rest of the state.

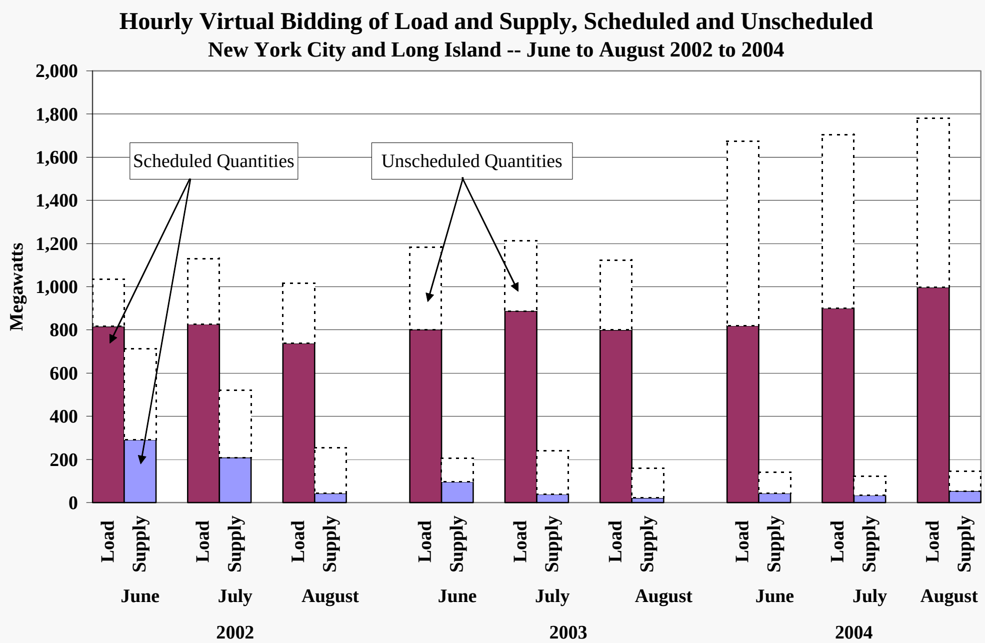
Composition of Day-Ahead Load Schedules as a Proportion of Actual Load
Summer 2002 to 2004



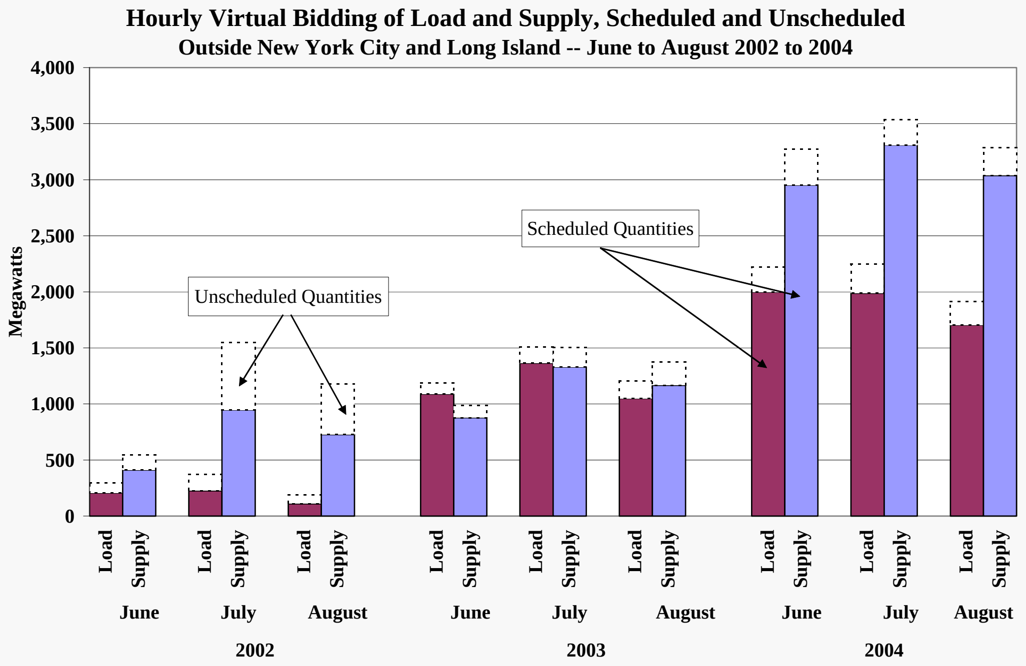
Note: August 2003 blackout hours excluded.

Virtual Trading Patterns

- Virtual Bidding was introduced in November 2001 to allow participation in the day-ahead market by entities other than LSEs and generators.
- The following figures show the quantities of virtual load and supply quantities that have been offered and scheduled during the past three summers on a monthly basis.
- The charts show the following:
  - ✓ Virtual load scheduled in New York City and Long Island increased slightly in 2004, although the amount offered rose substantially.
  - ✓ Virtual supply scheduled in New York City and Long Island decreased in 2003 and has stayed at low levels through 2004.
  - ✓ Virtual load scheduled in the rest of the state increased substantially from 2002 to 2003 and again in 2004 to close to 2000 MW.
  - ✓ Virtual supply scheduled also increased sharply over the three years to more than 3000 MW, exceeding the scheduled virtual load for the first time and contributing to the reduction in the day-ahead price premium.



Note: August 2003 blackout hours excluded.

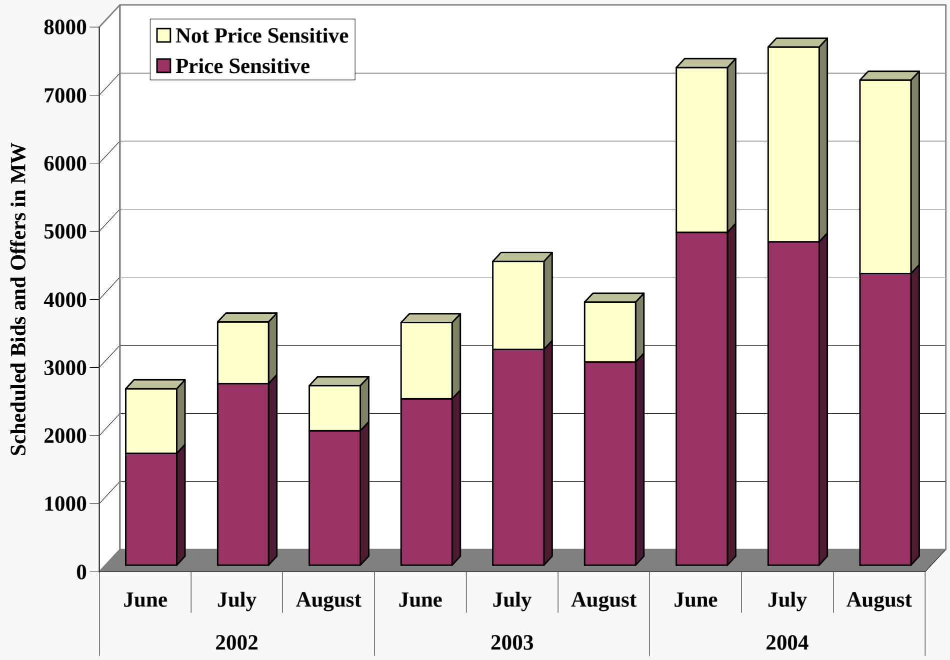


Note: August 2003 blackout hours excluded.

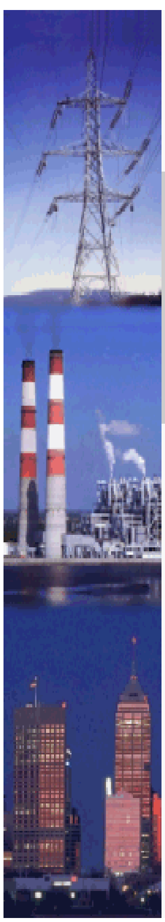
Virtual Trading Patterns

- We monitor the extent to which virtual bids are price sensitive for a number of reasons:
  - ✓ Price sensitive virtual bids and offers make supply and demand more price elastic in the day-ahead market, making the market more resistant to the exercise of market power and attempts to manipulate day-ahead prices.
  - ✓ Attempts to manipulate day-ahead prices with virtual transactions would generally utilize non-price sensitive bids that cause day-ahead and real-time prices to diverge.
- The following figure shows the portion of the virtual bids and offers that are price sensitive versus those with bid prices less than 33% and greater than 300% of the actual price.
  - ✓ The majority of the virtual bids and offers remain price sensitive.
  - ✓ Although the quantity of price insensitive bids increased in 2004, the figure shows that the virtual bids and offer quantities have increased over the past three summers, rising from about 2500 MW in 2002 to over 7000 MW in 2004.

Price Sensitivity of Scheduled Virtual Load Bids and Supply Offers
New York State - Summer 2002 to 2004



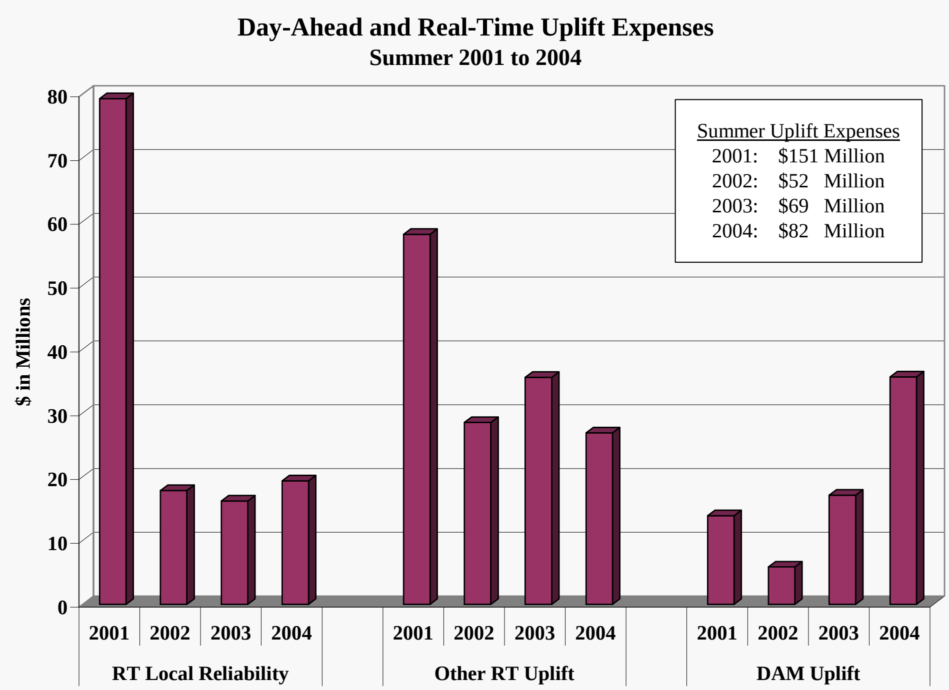
Note: August 2003 blackout hours excluded.



Out-of-Merit Commitment and Dispatch

Uplift Expenses

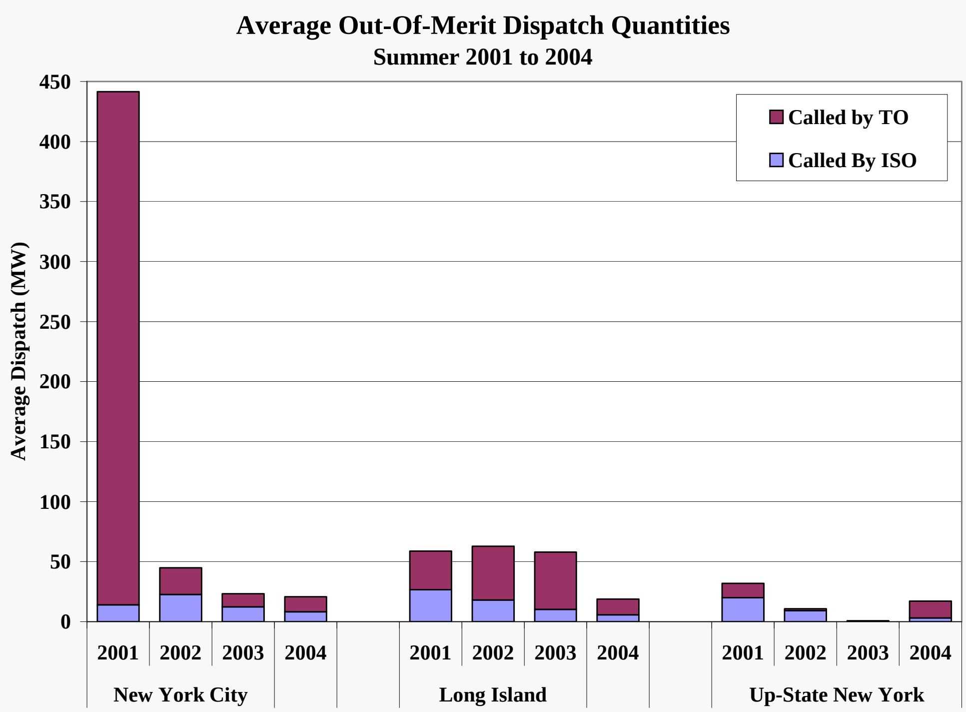
- The following figure shows that uplift costs fell sharply after 2001 (as the result of load-pocket modeling in NYC) and have remained at the lower levels.
- Real-time non-local reliability uplift also fell after 2001.
  - ✓ Out-of-merit (OOM) dispatch and supplemental resource evaluation actions (SREs) that are not specifically logged as a local reliability action are included in this category – even when called by the transmission owner.
- Day-ahead uplift increased in 2004.
  - ✓ Day-ahead uplift is generally caused by units committed primarily to meeting operating reserve requirements or in the local reliability pass of the SCUC.
  - ✓ Units that were committed in the initial commitment receive the majority of the guarantee payments that result in uplift.
  - ✓ These guarantee payments increase when supplemental commitments for local reliability cause day-ahead prices to decrease.



Note: August 2003 blackout hours excluded.

Real-Time Out-of-Merit Dispatch

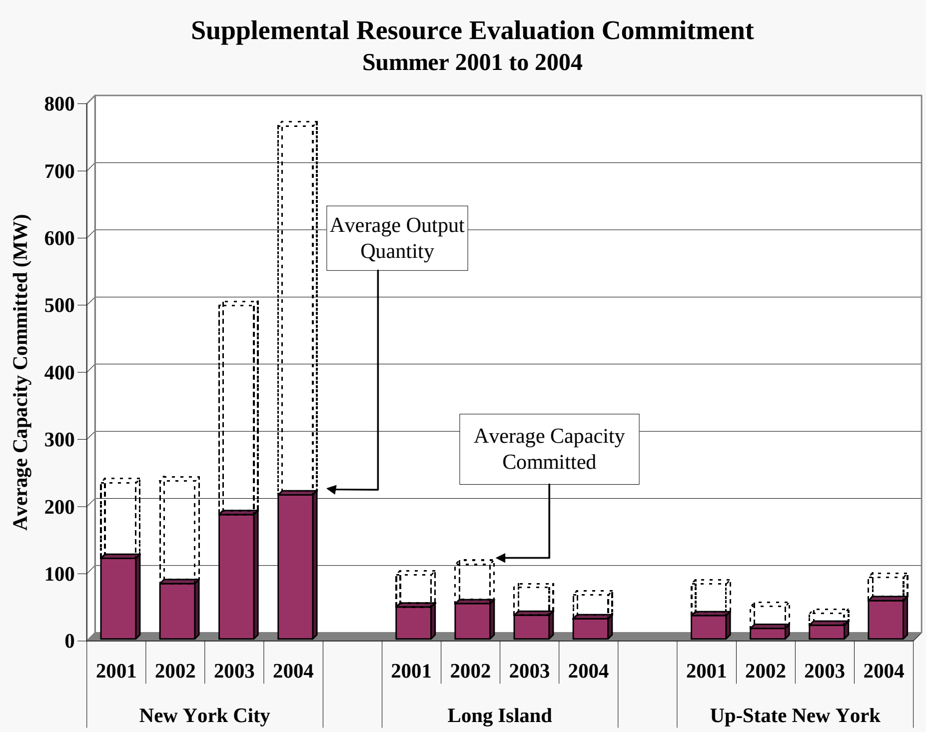
- Prior to load pocket modeling, OOM dispatch in New York City accounted for approximately 80% of resources dispatched OOM.
  - ✓ Uplift paid to OOM units is only considered local reliability uplift if the dispatch of the unit is specifically logged as local reliability.
- Since 2002, Long Island units have accounted for two-thirds of OOM dispatches.
- The following figure shows the average quantity of OOM resources in different locations in New York from 2001-2004. This figure shows:
  - ✓ OOM quantities have fallen substantially since 2001.
  - ✓ Changes in price-setting rules and operating procedures have caused the ISO-called OOM dispatch to fall by more than two-thirds.
  - ✓ During the summer of 2004, the average quantity of OOM generation dispatched was less than 50 megawatts.



Note: August 2003 blackout hours excluded.

Supplemental Resource Evaluation

- The average quantity of capacity committed through SRE increased in 2004.
- A major reason for the SREs are nitrous oxides (NOx) emission limits that require certain base load units to be committed to order to allow gas turbines to operate.
  - ✓ SREs were required for NOx due to lower day-ahead commitments arising from lower summer load.
- In addition, supplemental commitments were made during the republican convention.

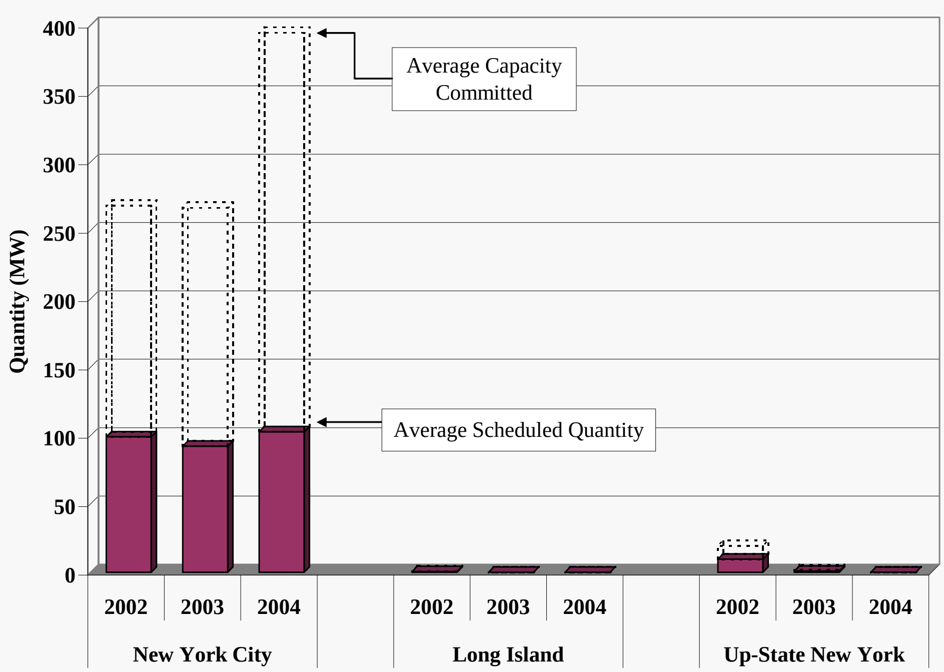


Note: August 2003 blackout hours excluded.

Day-Ahead Local Reliability

- The following figure shows the average quantity of commitments made by the SCUC for local reliability day-ahead.
  - ✓ The average capacity committed for local reliability increased substantially in 2004, while the average scheduled quantity remained at about the same level as in 2003 and 2002.
  - ✓ Virtually all of the local reliability commitments made by SCUC involved two units in New York City.
- These commitments are important because they tend to:
  - ✓ Reduce prices from levels that would result from a purely economic dispatch; and
  - ✓ Can increase uplift – a portion of the uplift resulting from these commitments is incurred to make guarantee payments to other generators that will not cover their as-bid costs at the reduced price levels.

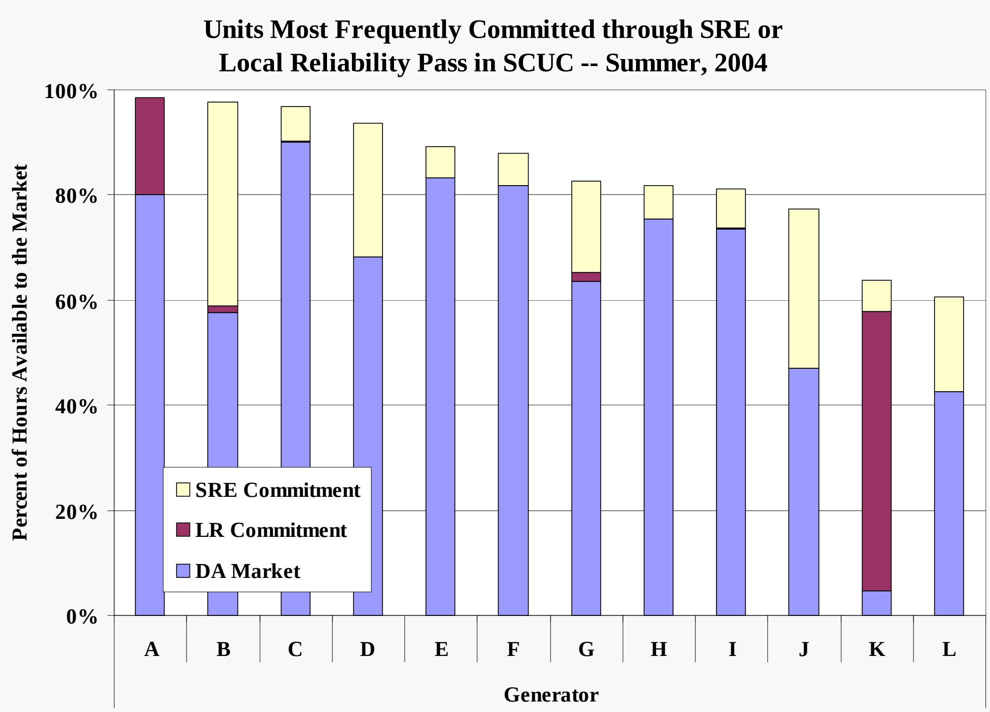
SCUC Local Reliability Pass Commitment
Summer 2002 to 2004



Note: August 2003 blackout hours excluded.

Units Committed for Local Reliability

- We have also evaluated supplemental commitment at the individual unit level. The following figure shows the 12 units with the highest commitment rates that are frequently committed for local reliability.
  - ✓ The values shown are the hours that each unit is committed as a percent of the hours that the unit is available (i.e., not on outage).
  - ✓ Eight of these units are in NYC, two are on Long Island, and two are located up-state.
- Four of the units analyzed appeared to be needed almost every day.
  - ✓ The top four units were each committed more than 90% of the time.
  - ✓ When these units were not committed economically in SCUC they were generally committed in the local reliability pass of SCUC or through an SRE.
- One of the units analyzed was committed in the local reliability pass in 53% of available hours.



Supplemental Commitment Conclusions

- Supplemental commitments have a number of significant market effects:
  - ✓ Inefficiently reducing prices in both the day-ahead market and real-time market;
  - ✓ When it occurs in a constrained area, it will inefficiently dampen the apparent congestion into the area; and
  - ✓ Increasing uplift as units committed economically will be less likely to recover their full bid production costs;
- In the long-run, it would be superior to include local reliability constraints into the initial economic commitment pass of SCUC.
- In the short-run, I continue to recommend that the ISO consider the feasibility and benefits of allowing operators to pre-commit units needed for NOx compliance.
  - ✓ This would only affect 3 to 4 units;
  - ✓ This would reduce local reliability and non-local reliability uplift payments;
  - ✓ Any guarantee payments payable to the pre-committed units could be directly assigned as local reliability uplift.