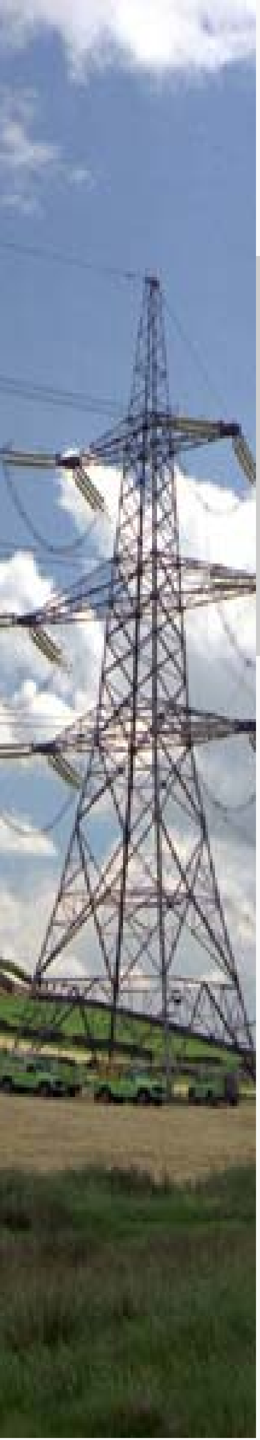


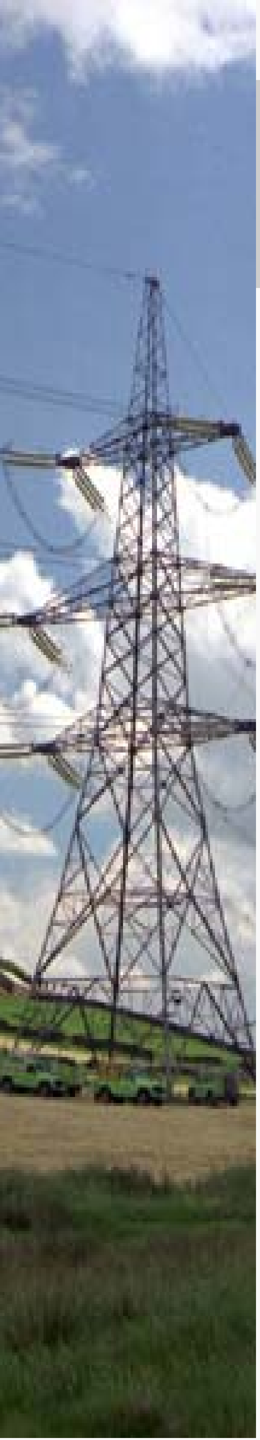
Summer 2003 Review of the New York Electricity Markets

Presented to:

Joint Board of Directors and
Management Committee Meeting

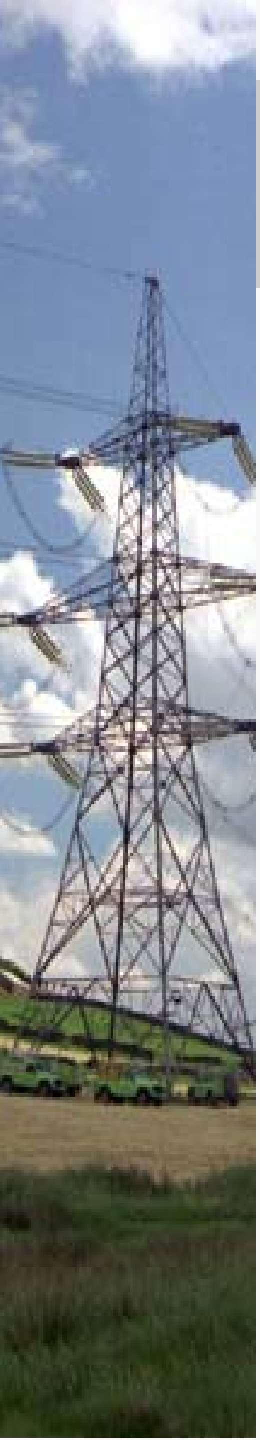
David B. Patton, Ph.D.
Independent Market Advisor

October 21, 2003



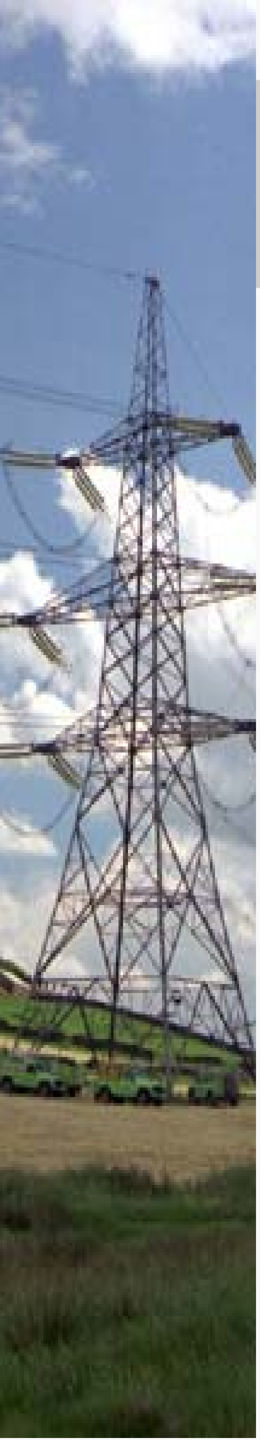
Summary and Conclusions

- Electricity prices generally trended higher with increases in fuel prices during this summer, but not during the highest demand conditions.
  - ✓ Although scarcity pricing provisions were implemented to ensure efficient pricing during shortages, no shortages occurred due to milder peak demand conditions and increased net imports from New England.
  - ✓ These markets outcomes have caused the net revenue available to a new entrant in the New York market to be slightly lower than last year.
- Market performance improved in a number of areas this summer relative to 2001 and 2002:
  - ✓ Price convergence between the day-ahead and real-time markets improved due, in part, to more active virtual trading.
  - ✓ Out of merit dispatch was reduced due to changes in the pricing rules and operating procedures implemented during and after the summer 2002.
  - ✓ No substantial patterns of withholding or other market abuses were detected during the summer.



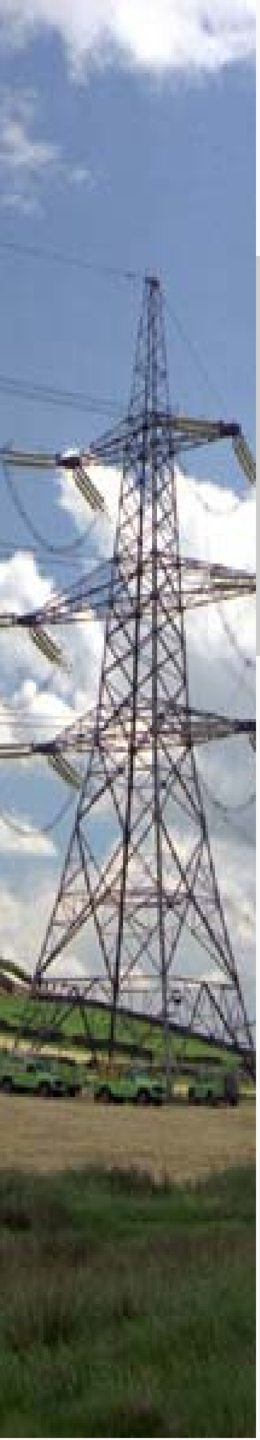
Summary and Conclusions

- This report identifies some areas of potential improvement in the performance of the 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 can result in increased uplift on units in the City.
  - → In the longer-run, the ISO should improve the modeling of local reliability rules:
    1. To address environmental (NOx) constraints; and
    2. To include them in the initial commitment within SCUC.
  - → These changes will likely involve significant software changes.
  - → Hence, the ISO should consider the feasibility and benefits of allowing operators to pre-commit certain units that are known to be needed in the shorter-run.

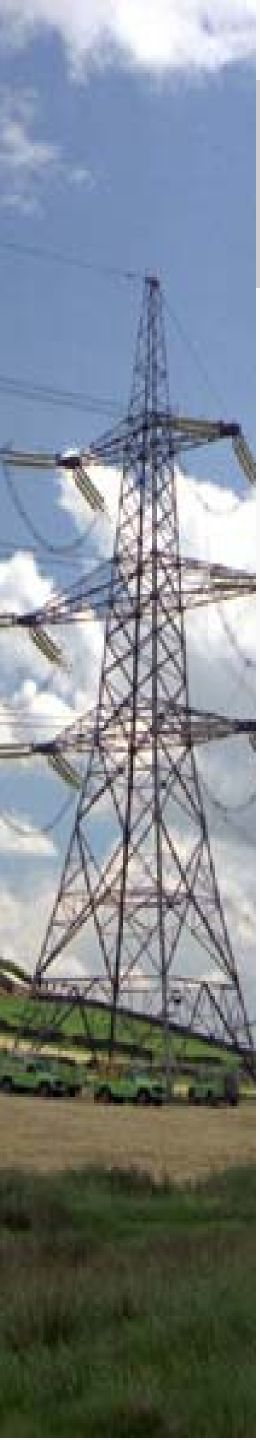


Summary and Conclusions

- Congestion has occurred in real time that appears to be caused by tighter transmission conditions in the real time market than in the day ahead market.
- This has resulted in increased uplift costs associated with reducing flows over key transmission interfaces in the real-time market.
  - → RTS will improve the consistency of the transmission limits and other assumptions due to similarity of the RTS and SCUC models.
  - → I also recommend the ISO review and adjust, as appropriate, the assumptions in the SCUC to improve its consistency with the real-time market.
  - → These changes will reduce uplift costs and improve the consistency of day-ahead and real-time prices in constrained areas.

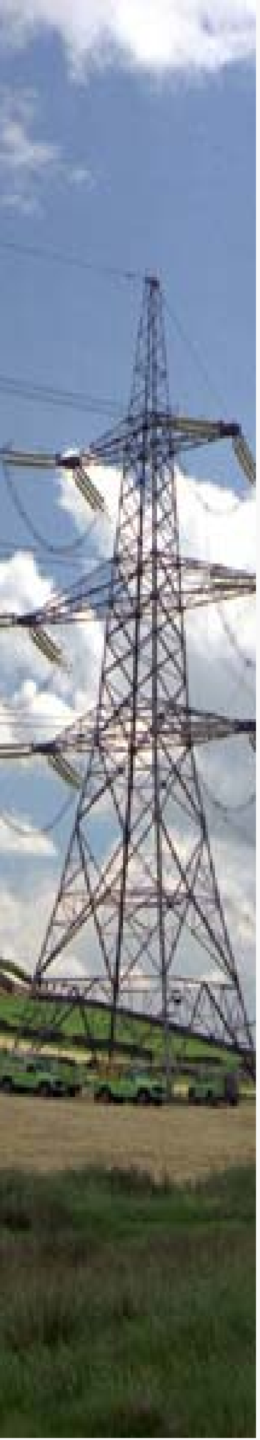


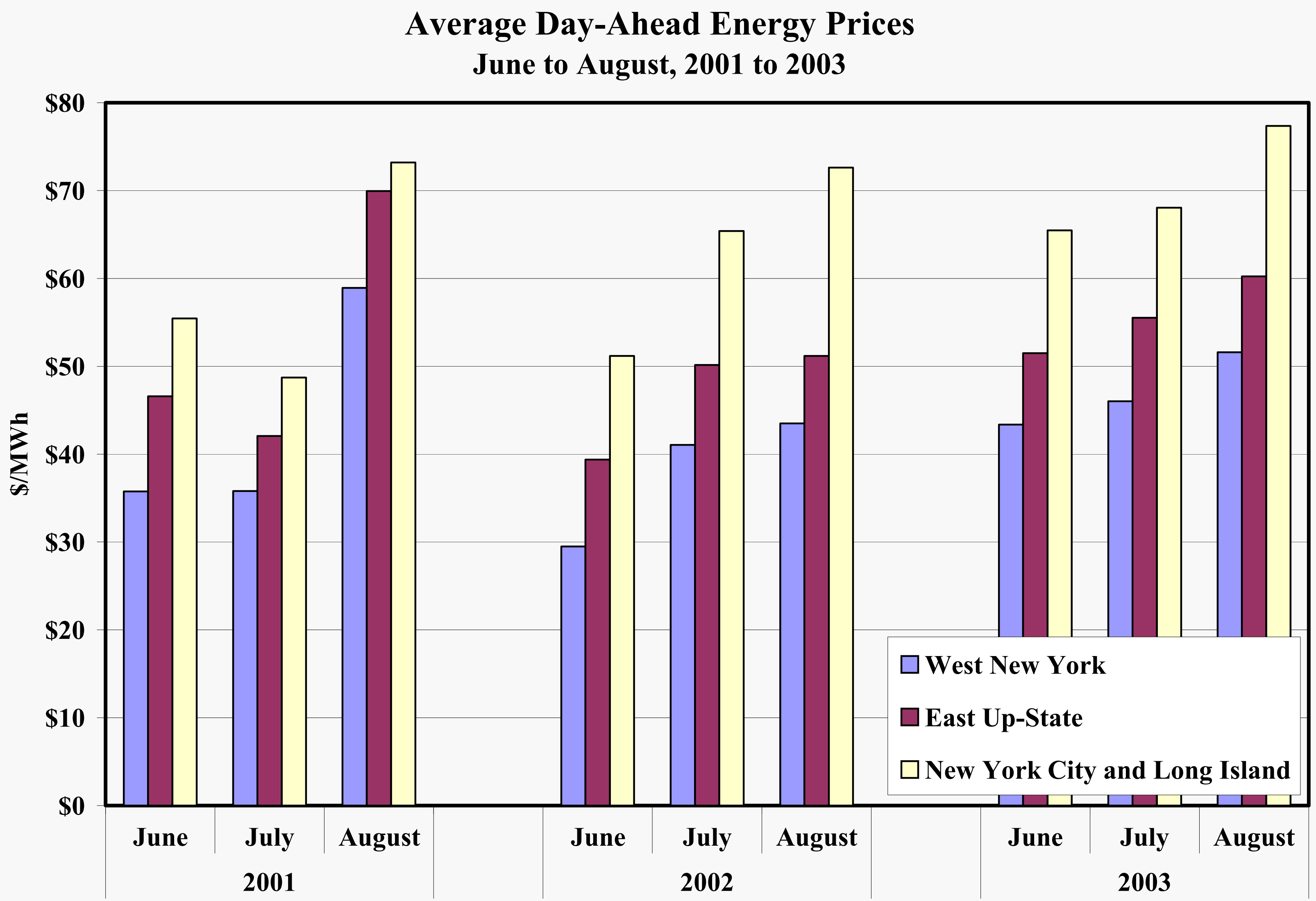
Market Prices and Outcomes



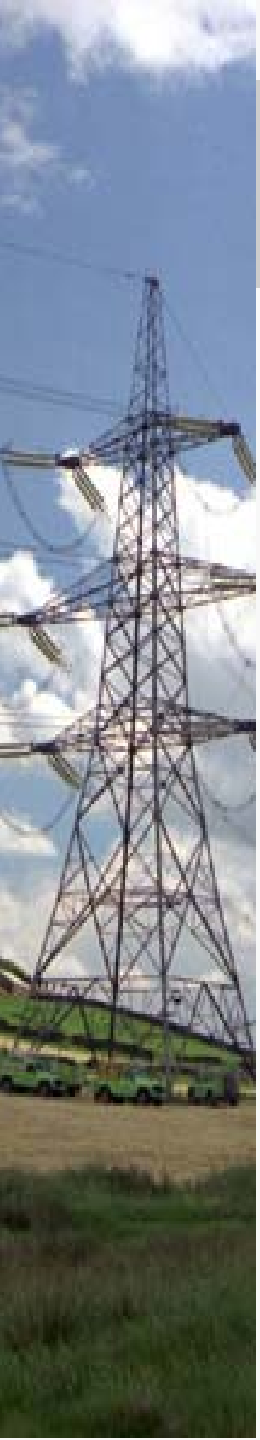
Energy Prices in the Day-Ahead Market

- The following figure shows average energy prices in three regions of New York during the summers of 2001 to 2003. Price differences between the three geographic regions are primarily due to:
  - ✓ The Central-East transmission interface separating western and eastern New York. In 2003, 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 $14/MWh.
- Energy prices were generally higher in 2003 than in the previous two years due to increased fuel prices.
- The increase in prices associated with higher fuel prices was offset by reduced price spikes in summer 2003, due to:
  - ✓ Milder weather in 2003;
  - ✓ Increased net imports from New England;
  - ✓ More active price-responsive load bidding.



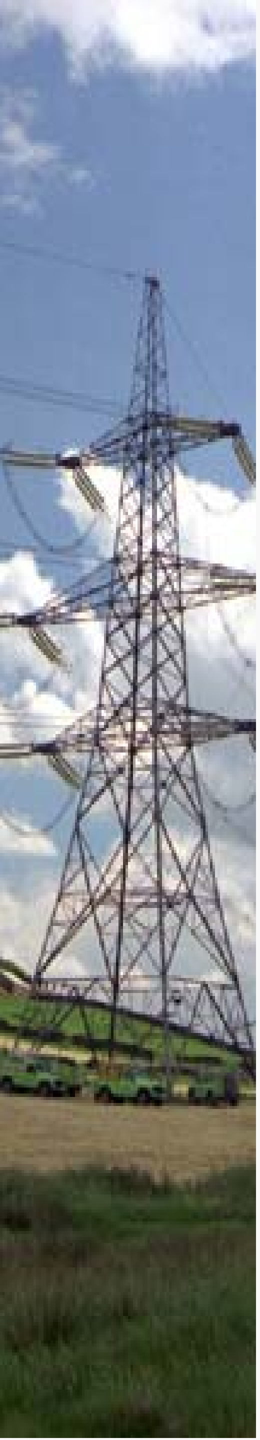


Note: August 2003 blackout hours excluded.

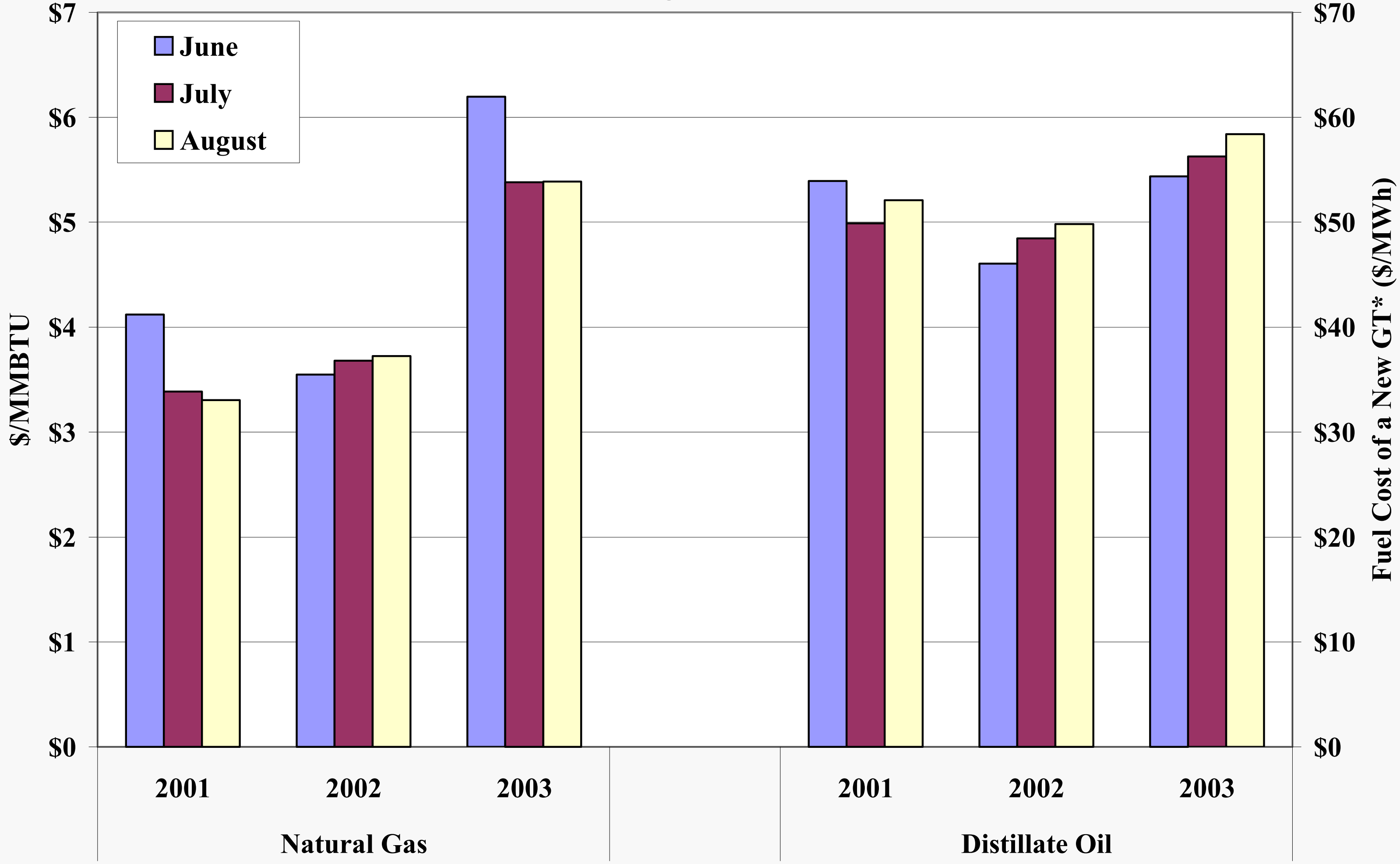


Input Fuel Prices

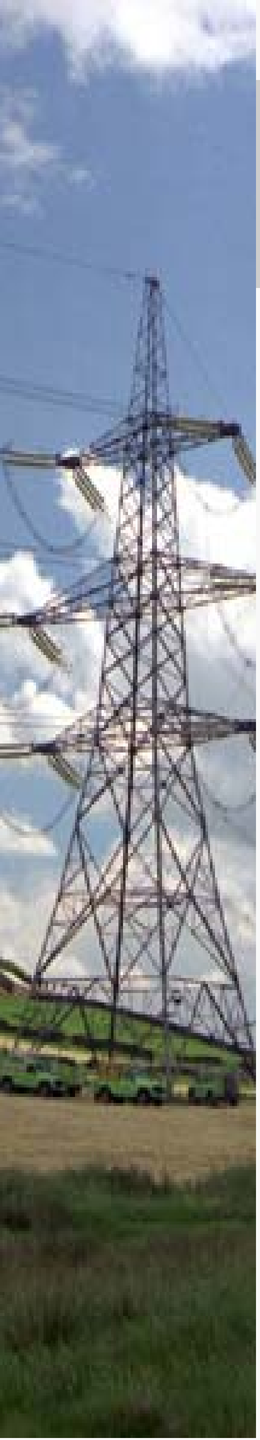
- The following figure shows average input fuel prices during the summers of 2001 to 2003.
- Natural gas prices increased by more than 50 percent from the summer of 2002 to 2003.
  - ✓ This translates into approximately $20/MWh of additional fuel costs for a 10,000 btu/kW combustion turbine.
- Oil prices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



Average Input Fuel Prices
June to August, 2001 to 2003

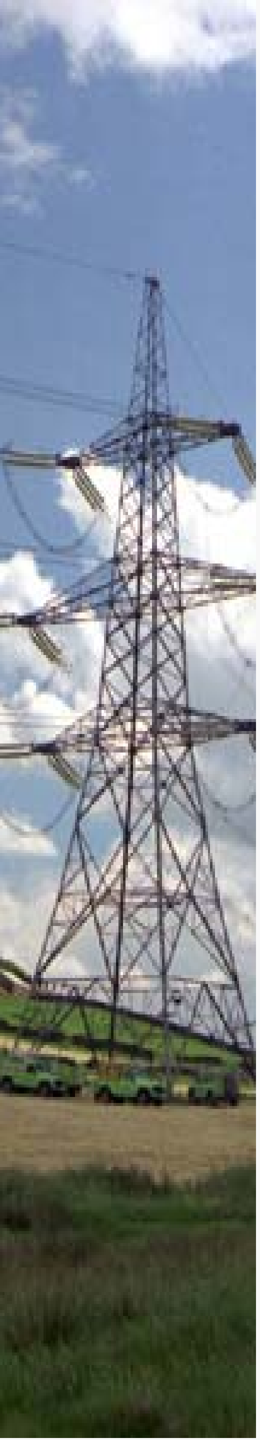


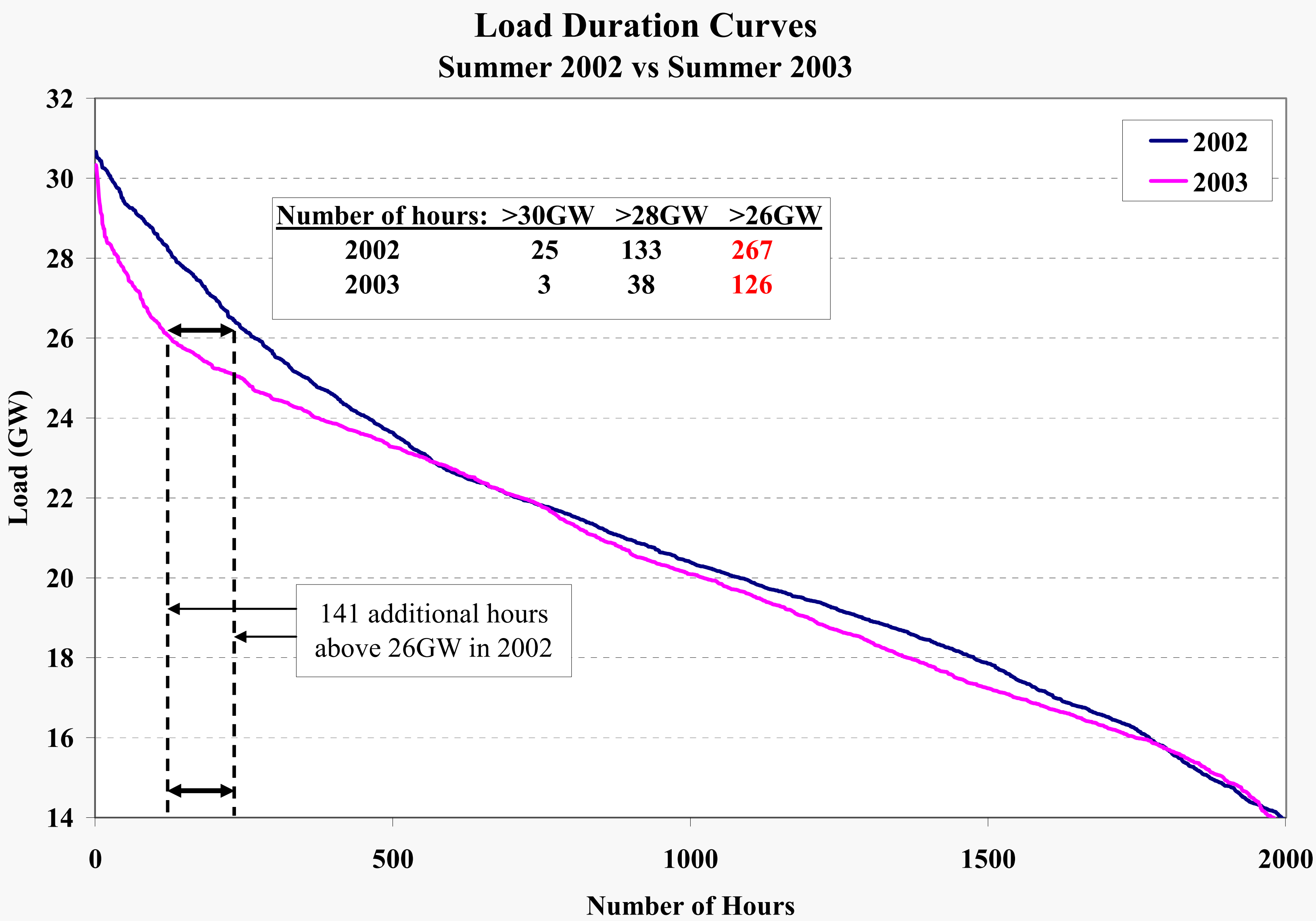
Note: Assumes a heat rate of 10,000 BTU/kwh.



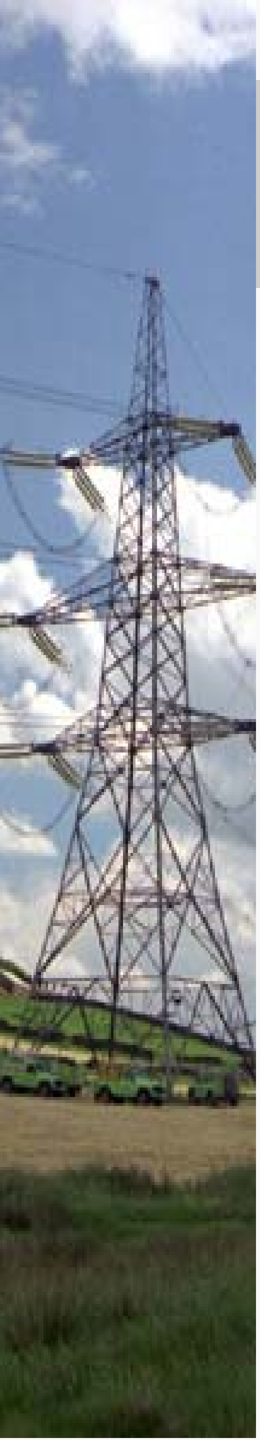
Hourly Load Levels

- The following figure is a load duration curve, which shows the hourly loads 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).
- Load levels in the highest demand periods were higher in 2002 than in 2003 due primarily to milder weather in 2003.
  - ✓ In the summer of 2002, there were 25 hours with actual loads exceeding 30 GW.
  - ✓ In the summer of 2003, there were only three hours with the loads above 30 GW.
  - ✓ There were 95 fewer hours with loads above 28 GW in summer 2003.
  - ✓ There were 141 fewer hours with loads above 26 GW in summer 2003.
- The lower loads under peak demand conditions contributed to the peak prices experienced in 2003.



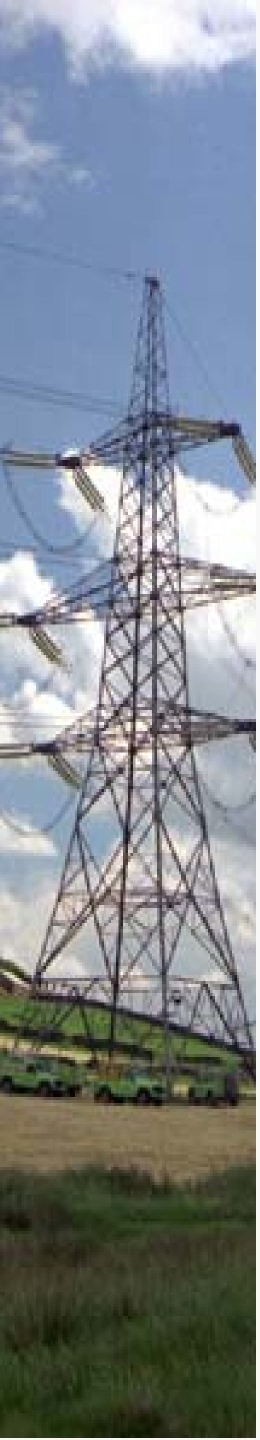


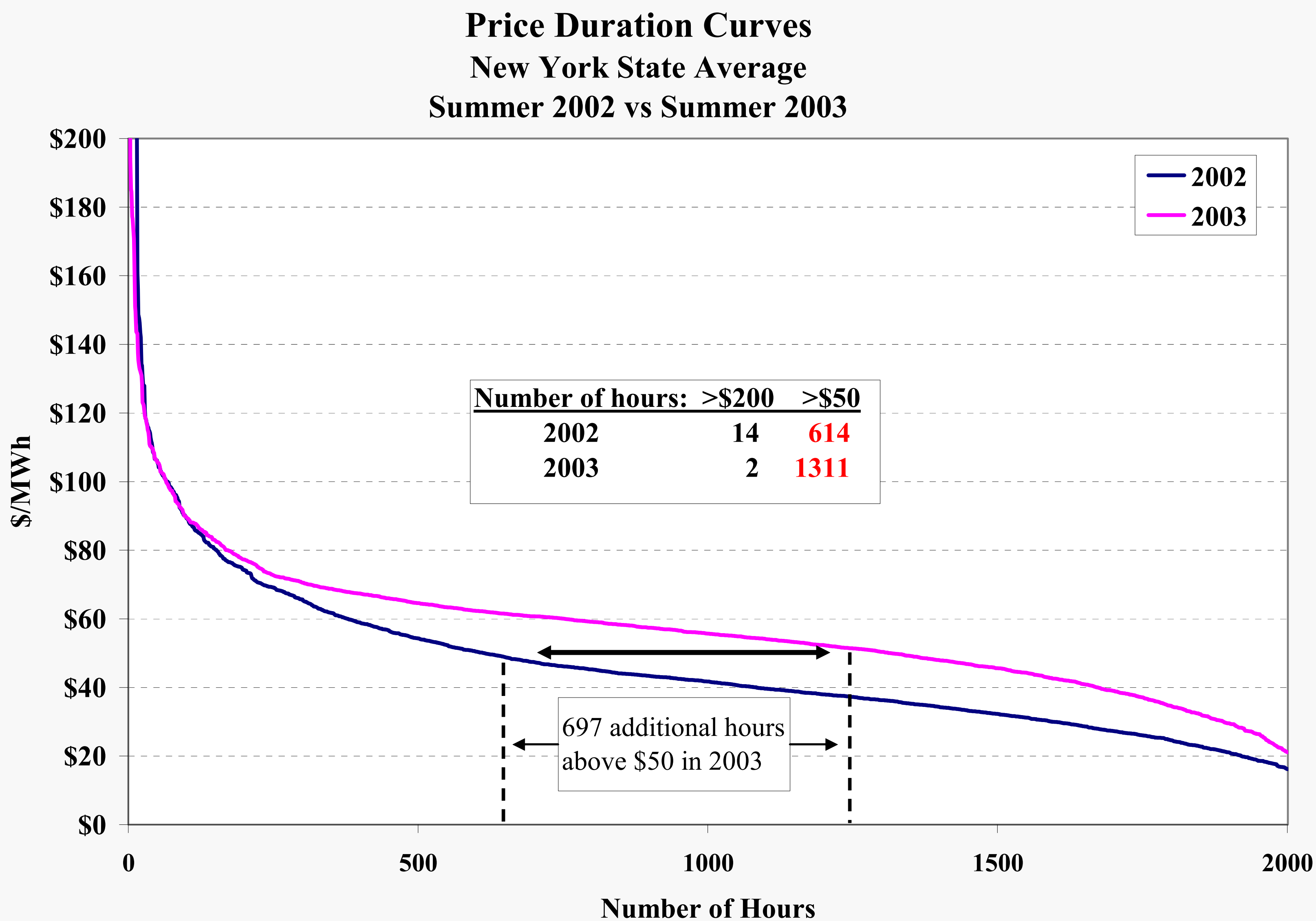
Note: August 2003 blackout hours excluded.



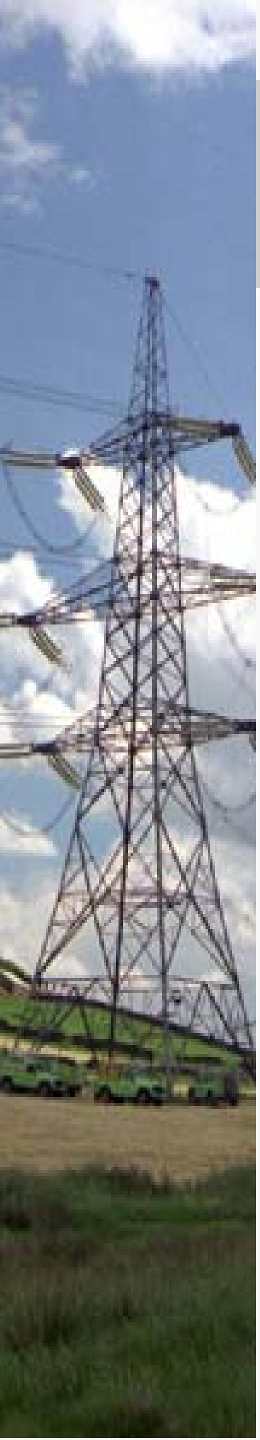
Load Duration and Price Duration Curves

- The next figure is a price duration curve. Like the load duration curve, it shows hourly real-time prices sorted in descending order.
- This curve shows that there were more hours with fewer weighted-average prices (>$200) in New York State in summer 2003 than in summer 2002.
  - ✓ This is despite the fact that scarcity pricing provisions were implemented in summer 2003.
  - ✓ The reduced number of high-priced hours is due to the lower loads shown in the prior figures and higher net imports from New England.
- Under normal load conditions prices were substantially higher in the summer of 2003.
  - ✓ The summer of 2003 had 1,311 hours priced above $50/MWh, while the summer of 2002 had less than half that amount (614 hours).
  - ✓ These price increases are primarily attributable to higher gas and oil prices.



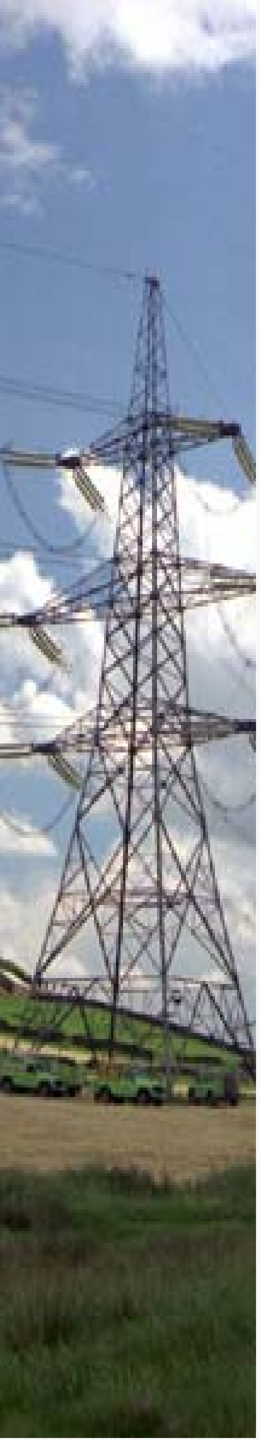


Note: August 2003 blackout hours excluded.



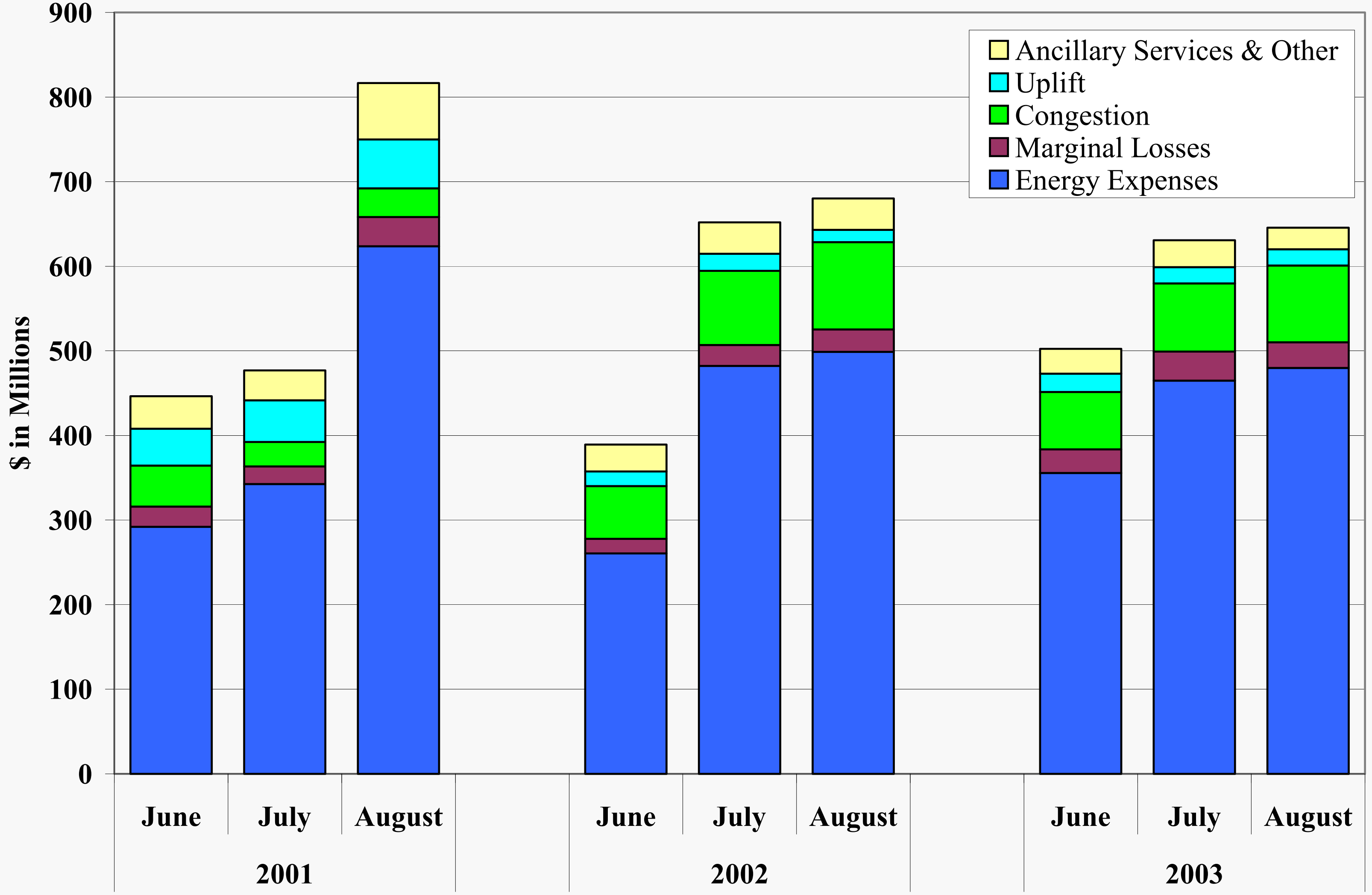
Total Electricity Costs in the New York Markets

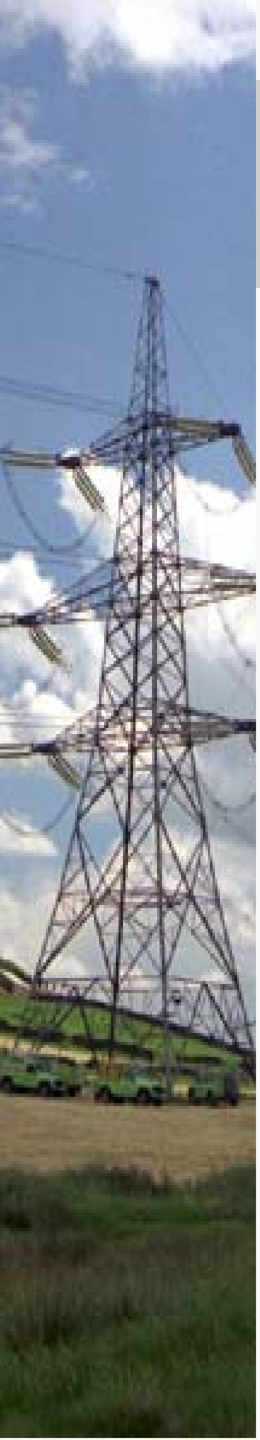
- The following figure shows the total monthly expenses for market participants of the NYISO in the summers of 2001 to 2003.
- Total electricity costs for the summer of 2003 were approximately $1.8 billion – slightly more than total costs in the summers of 2001 and 2002.
- Changes in market expenses from the summer of 2002 were caused by:
  - ✓ Slightly lower scheduling of physical bilaterals, so a higher percentage of the actual load was settled through the NYISO markets;
  - ✓ Higher average energy prices due to higher fuel prices;
  - ✓ Lower peak energy prices; and
  - ✓ Slightly lower ancillary services costs;
- The figure shows that congestion costs continued to be significantly higher than during the summer of 2001. This attributable to modeling the load pockets in NYC, which allows prices to more accurately reflect the transmission constraints within the City.



New York Electricity Market Expenses

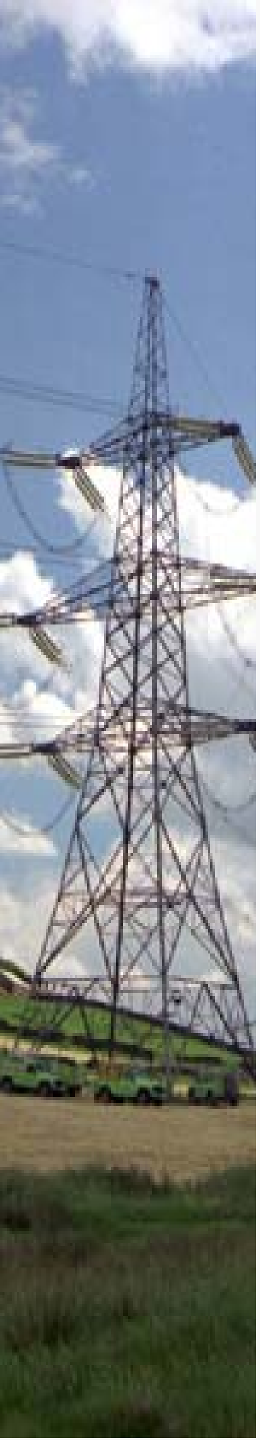
June to August, 2001 to 2003

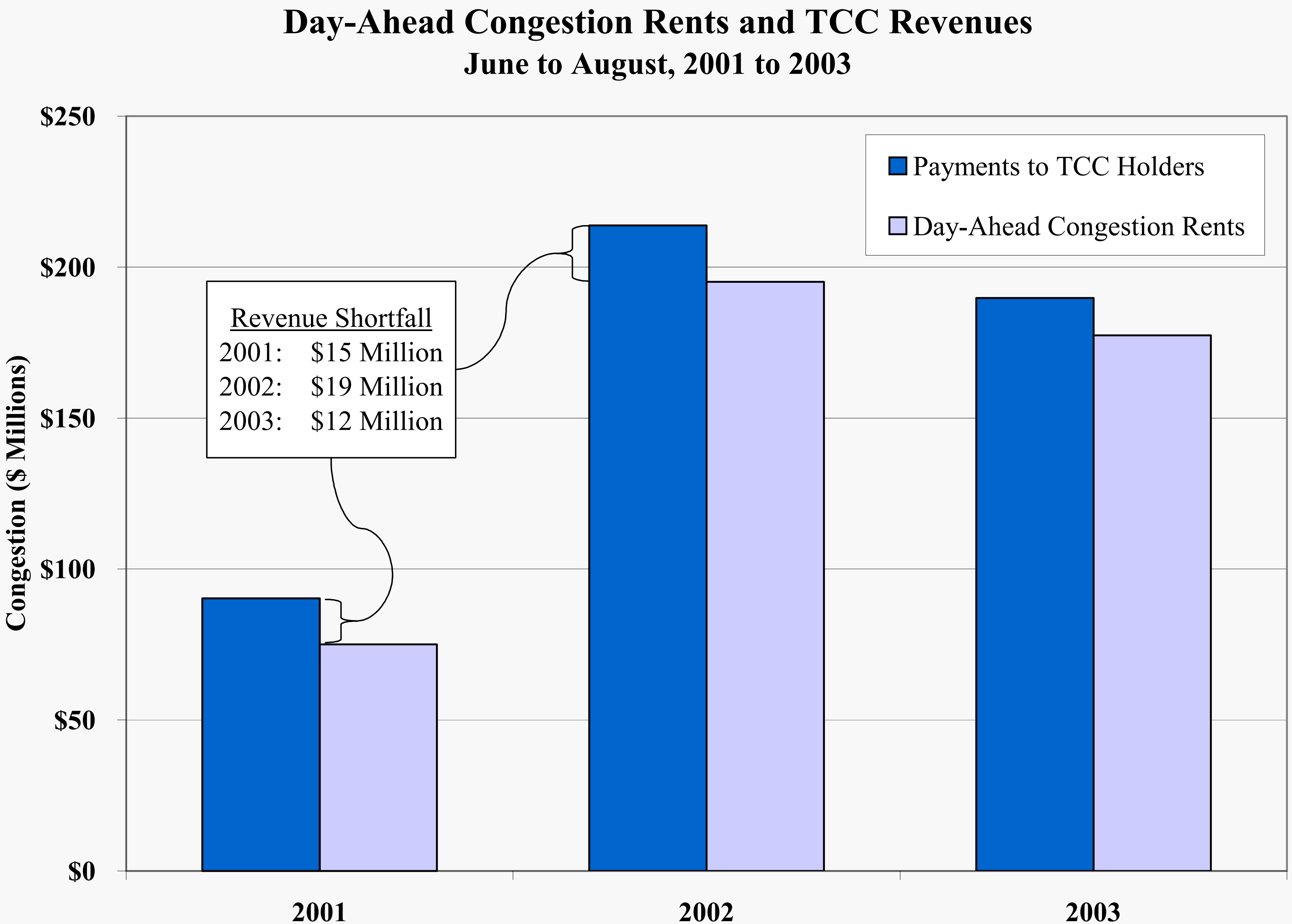




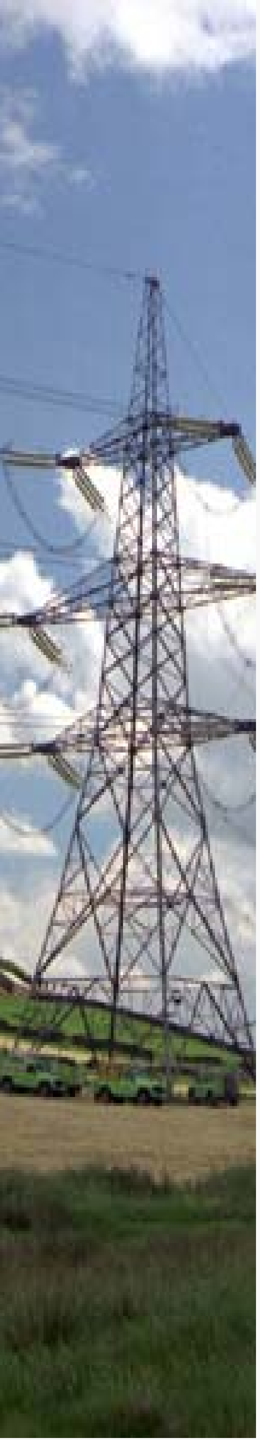
Congestion Costs

- The following figure shows day-ahead congestion costs and TCC payments for summer 2001 to summer 2003.
- The increase in congestion costs after 2001 was primarily due to the modeling of load pockets within New York City.
- The figure shows shortfalls occur when TCC obligations exceed the revenue from congestion in the day-ahead market.
  - ✓ 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.
  - ✓ Revenue shortfalls must recovered from the transmission owners (TOs).
  - ✓ The cost to TOs of revenue shortfalls are generally diminished to the extent that TOs receive the TCC auction revenues or are owners of the TCCs.
- The changes underway to change the allocation of the shortfall should improve incentives and result in lower shortfall amounts.



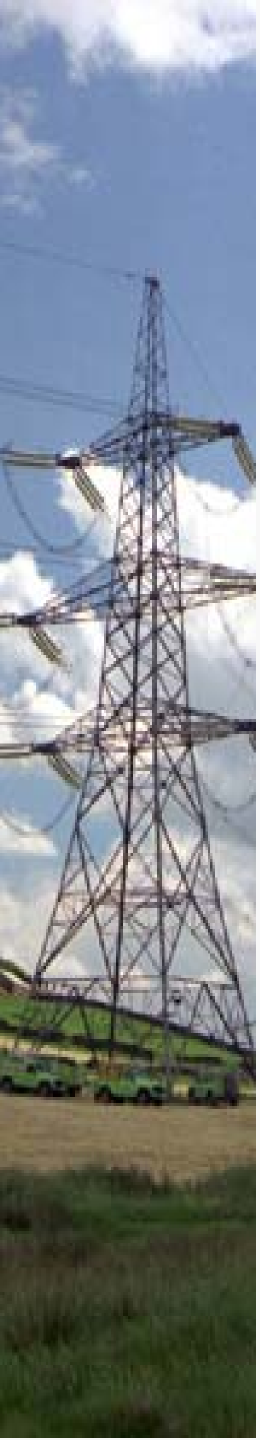


Note: August 2003 blackout hours excluded.

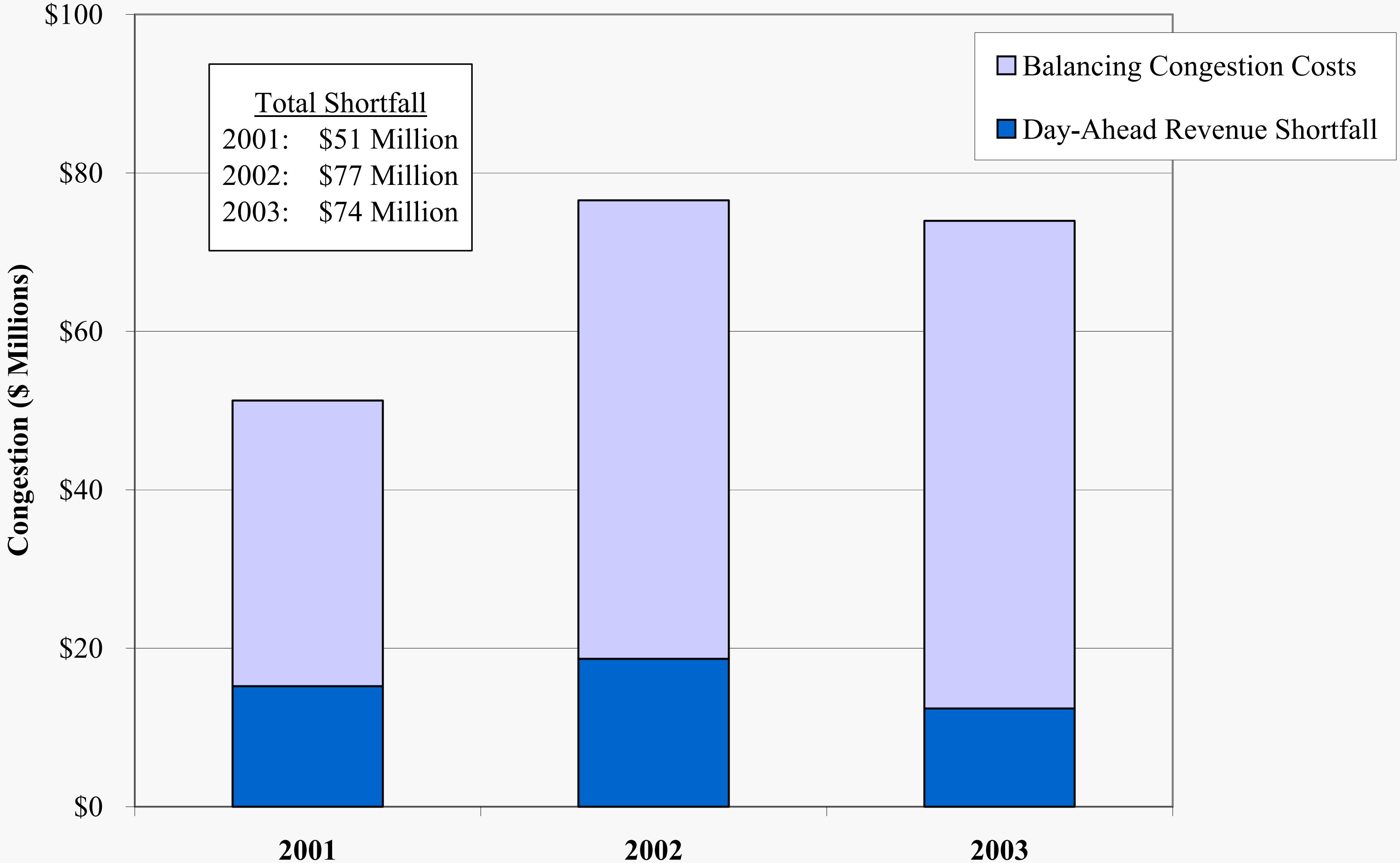


Congestion-Related Uplift Costs

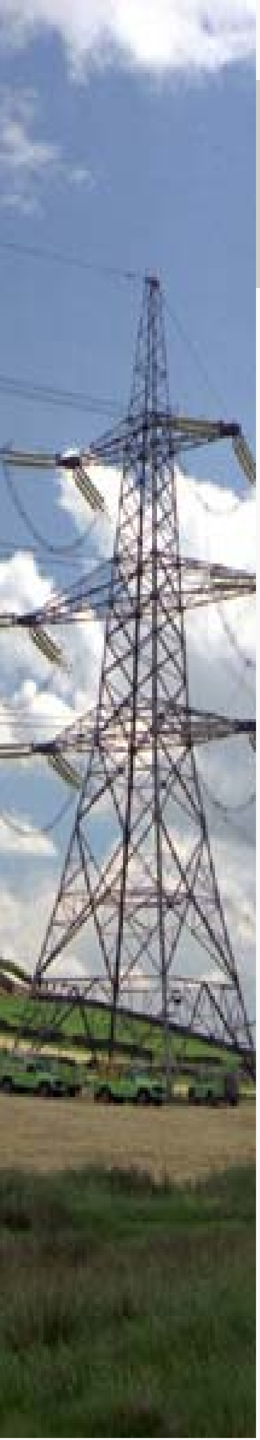
- The following chart shows the day-ahead shortfalls with additional balancing congestion costs.
  - ✓ Both of these classes of costs result in uplift charges, although they are allocated slightly differently.
- Excluding the blackout days, summer 2003 had the following results:
  - ✓ 65 out of 88 summer days had a TCC shortfall. Days with no shortfall tended to be days with higher load.
  - ✓ 87 out of 88 (non-blackout days) in the summer of 2003 had a balancing shortfall because balancing congestion costs were positive.
- The changes underway to change the allocation of the TCC shortfall should improve incentives and result in lower the TCC shortfall amounts.



Day-Ahead and Real-Time Revenue Shortfalls From Congestion
June to August, 2001 to 2003

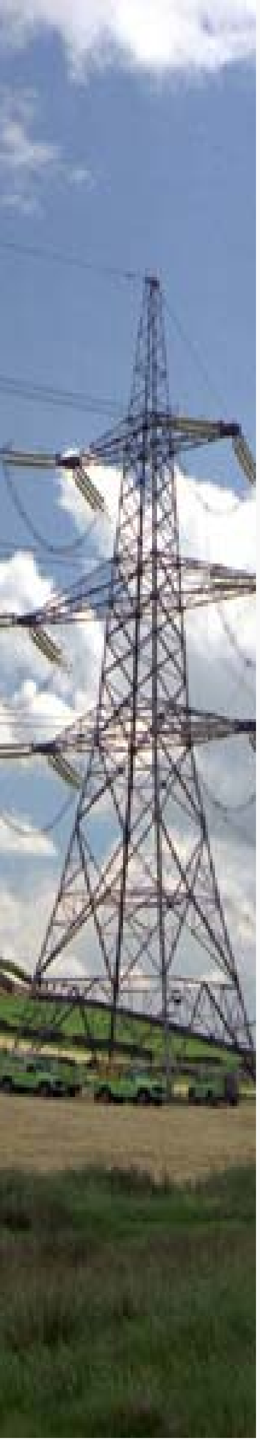


Note: August 2003 blackout hours excluded.

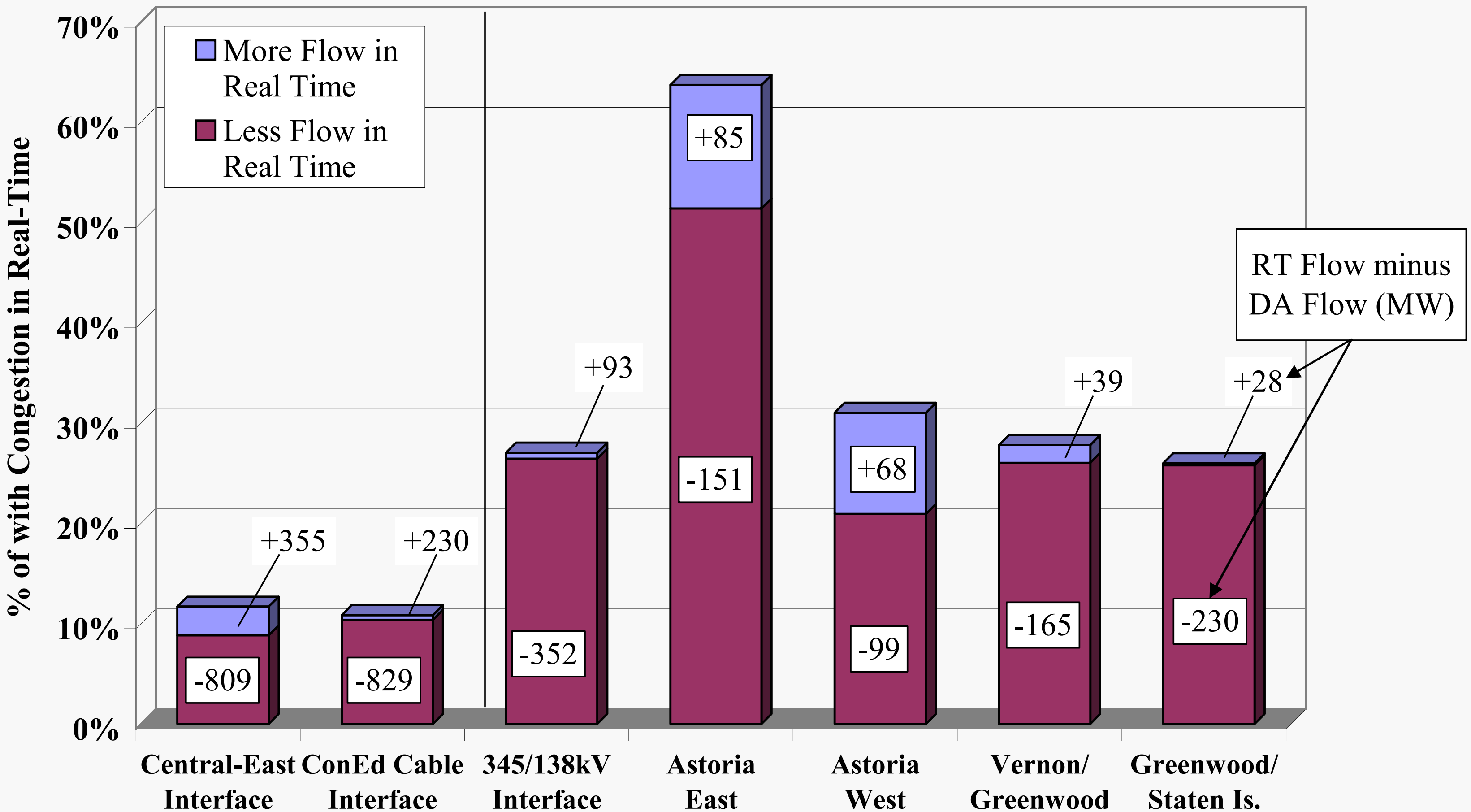


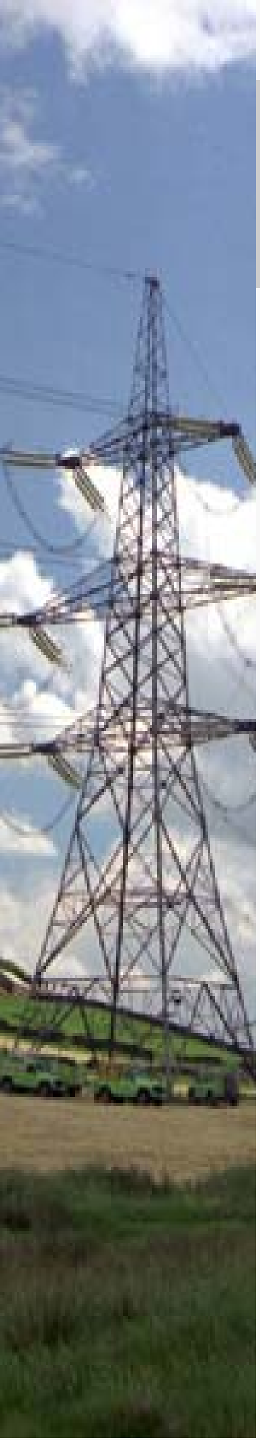
Real-Time Congestion and Interface Flows

- We analyzed the flows over the primary transmission interfaces in an attempt to identify the source of the balancing congestion costs.
- For various interfaces, the following figure shows the portion of the hours congested in real time and the change in flows from day ahead to real time.
- These results show that the flow generally decreases in the real time.
  - ✓ These reductions generally range from 5 to 15 percent of the load served on the constrained side of the interface.
  - ✓ This could be caused by: assumed phase angle regulator settings, thunderstorm alerts, loop flow assumptions, tighter limits in real time, changes in the assumed wheel into NYC, or other factors.
  - ✓ These factors have typically caused the ISO to "buy-back" energy scheduled over the interfaces day ahead, resulting in the uplift shown on the prior figure.
- RTS will improve the consistency of the transmission limits and other assumptions due to similarity of the RTS and SCUC models.



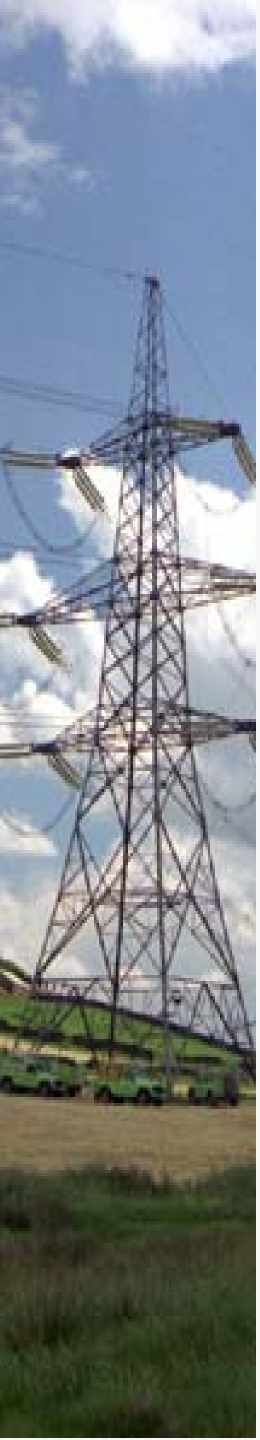
Real-Time Congestion and Interface Flows
Summer 2003

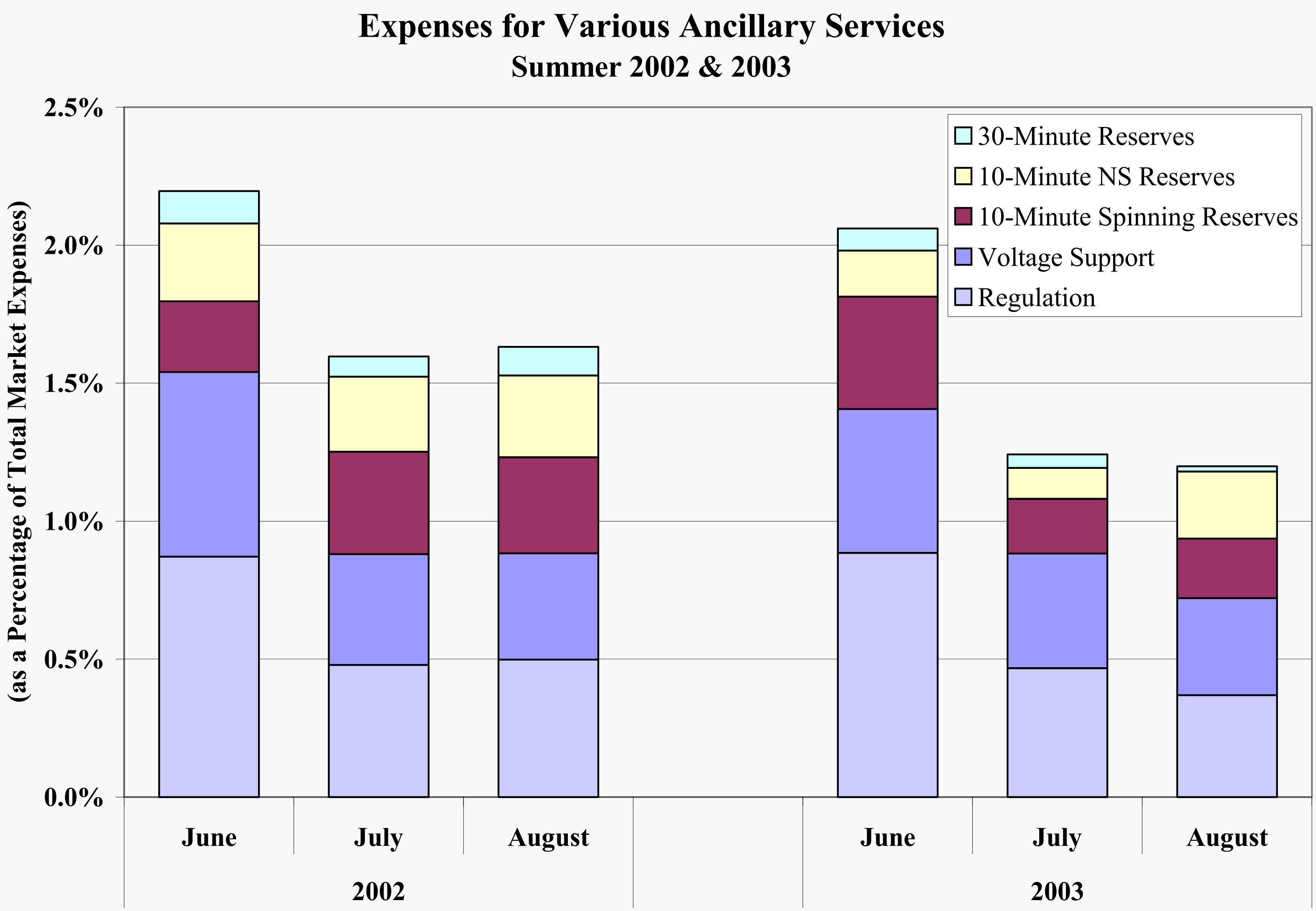


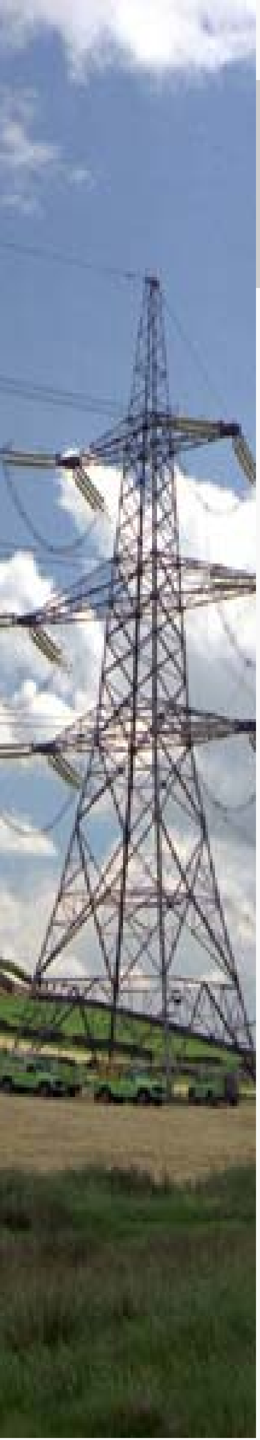


Ancillary Services Costs

- The following figure shows the costs of ancillary services, which includes regulation, voltage support and multiple classes of operating reserves.
- These costs tend to be smaller as a percent of total market expenses in the summer than in other seasons because of the relatively high energy prices during the summer.
- Ancillary services costs declined slightly from 2002 to 2003 as a percentage of total market expenses.
  - ✓ The costs of each of the operating reserves declined in 2003.
  - ✓ Prices of 10-minute non-synchronous reserves declined even after the removal of the $2.52 bid cap.

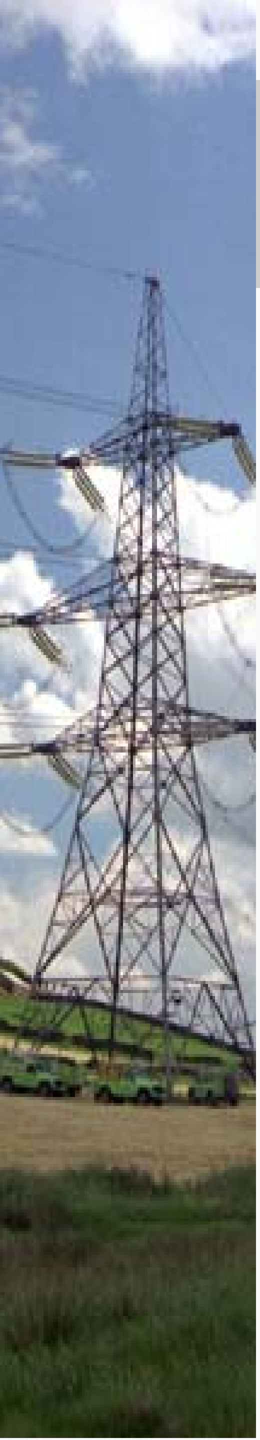



Expenses for Various Ancillary Services
Summer 2002 & 2003
(as a Percentage of Total Market Expenses)
2.5%
2.0%
1.5%
1.0%
0.5%
0.0%
30-Minute Reserves
10-Minute NS Reserves
10-Minute Spinning Reserves
Voltage Support
Regulation
June
July
August
2002
June
July
August
2003



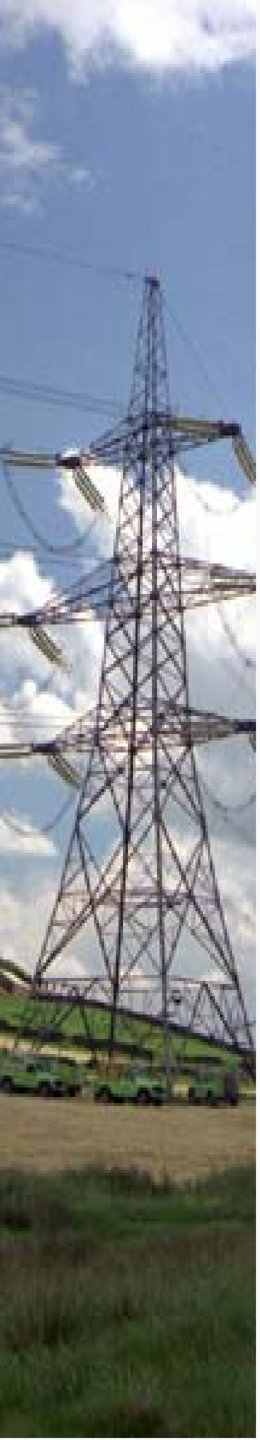
Economic Incentives for New Investment

- 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 figures show the net revenue for generating units with different heat rates in different locations, comparing the 12-month periods ending on August 31, 2002 and 2003.



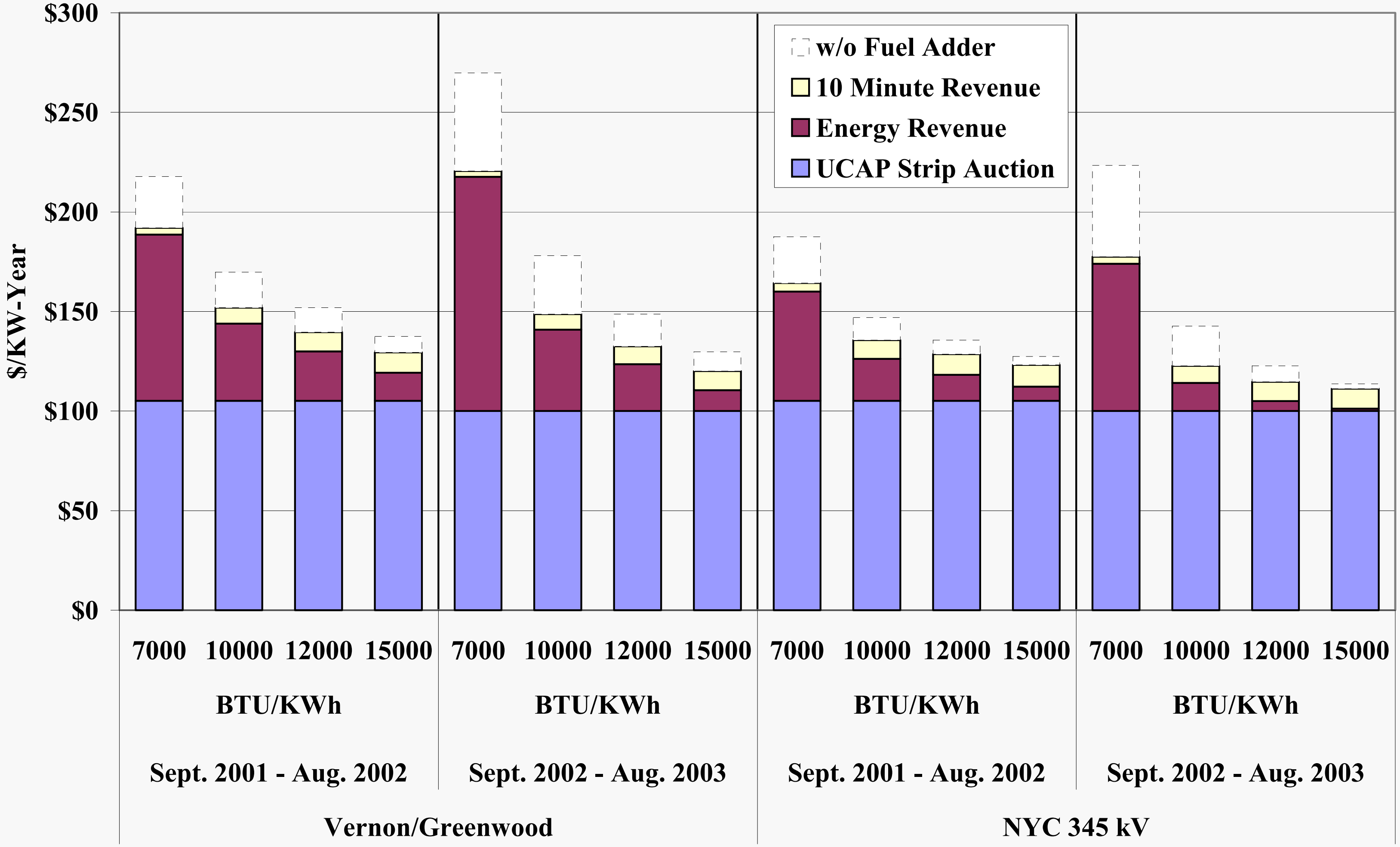
Economic Incentives for New Investment

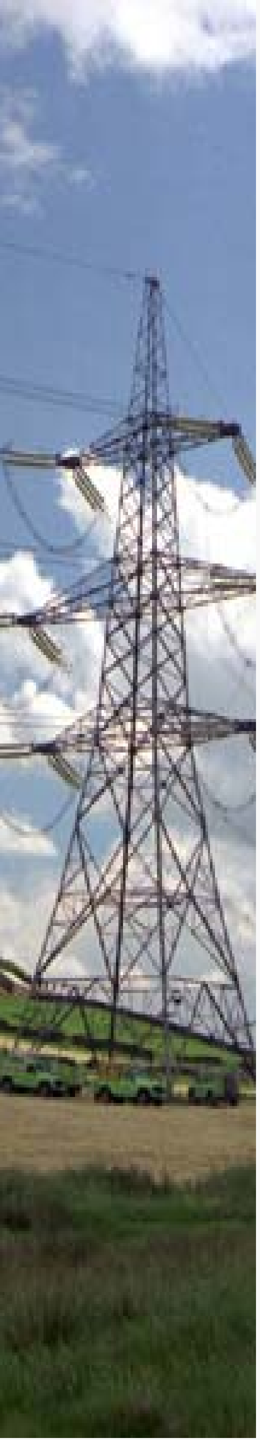
- These figures show:
  - ✓ Net revenue levels for each location changed only slightly from 2002 to 2003.
  - ✓ The net revenue for efficient generators (low heat rates) increased slightly in 2003.
  - ✓ The net revenue for inefficient generators decreased slightly in 2003.
- Net revenue was affected by higher fuel prices and lower peak prices in 2003
  - ✓ Higher fuel prices raise electricity prices and tend to benefit efficient units that are infra-marginal (the market prices rise more than their operating costs).
  - ✓ Inefficient generators will not benefit substantially from higher fuel prices since their operating costs are closely correlated to the market prices.
  - ✓ Capacity revenue also declined slightly in 2003 in each location.
- The analysis shows that a new GT would not be economic within or outside of New York City, assuming:
  - ✓ Assuming annual entry costs for a new GT of approximately $80 per MW-Year outside of NYC and $240 per MW-Year in NYC.



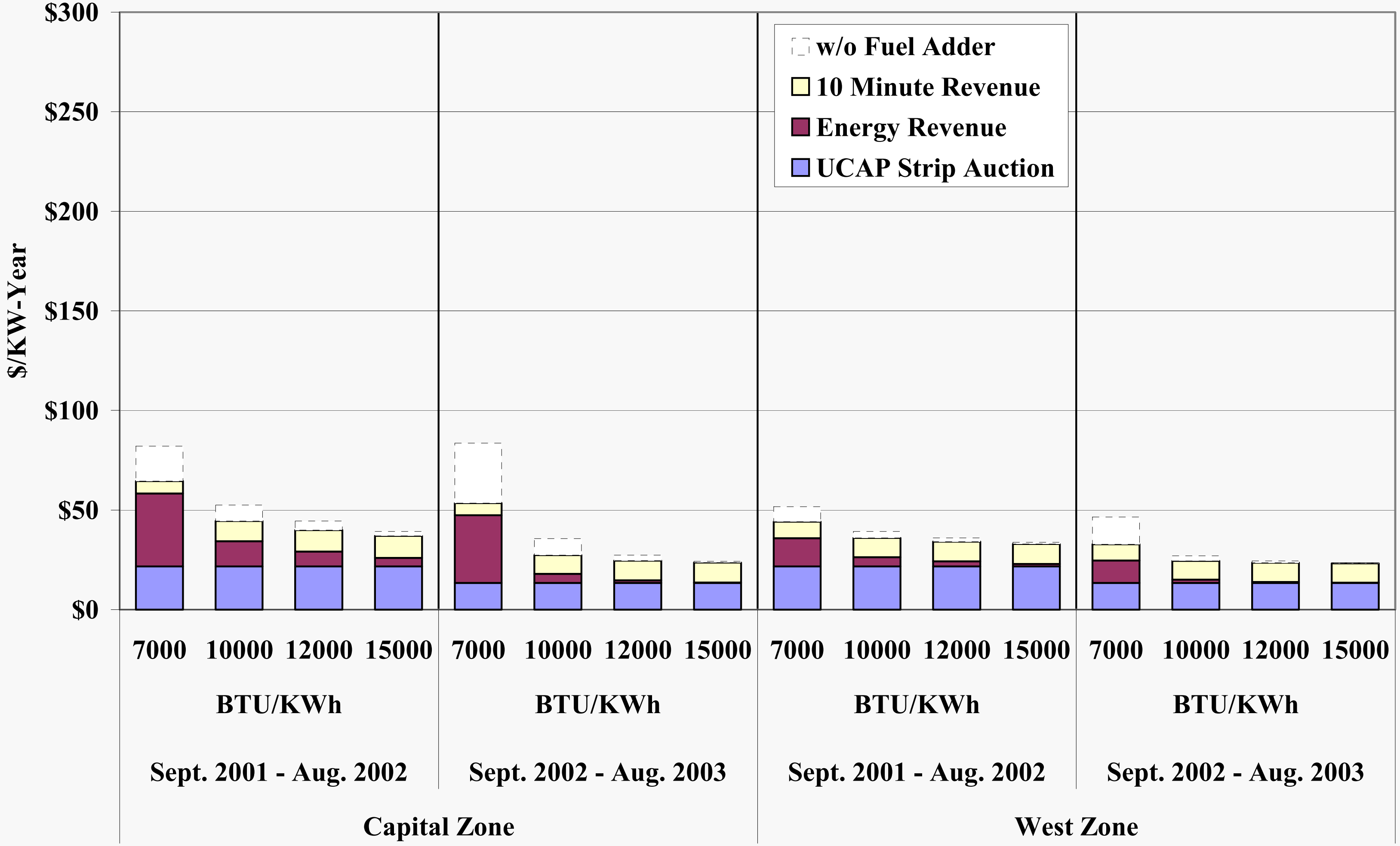
Estimated Net Revenue in the New York Markets

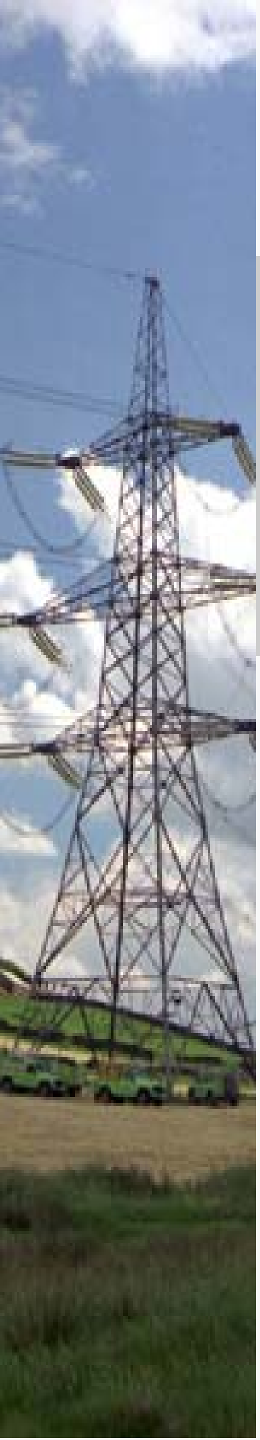
Day-Ahead Market - September 2001 to August 2003



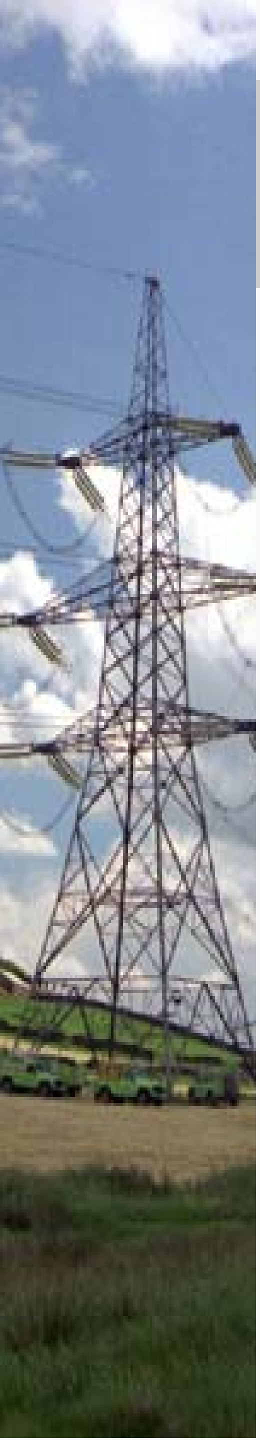


Estimated Net Revenue in the New York Markets
Day-Ahead Market - September 2001 to August 2003



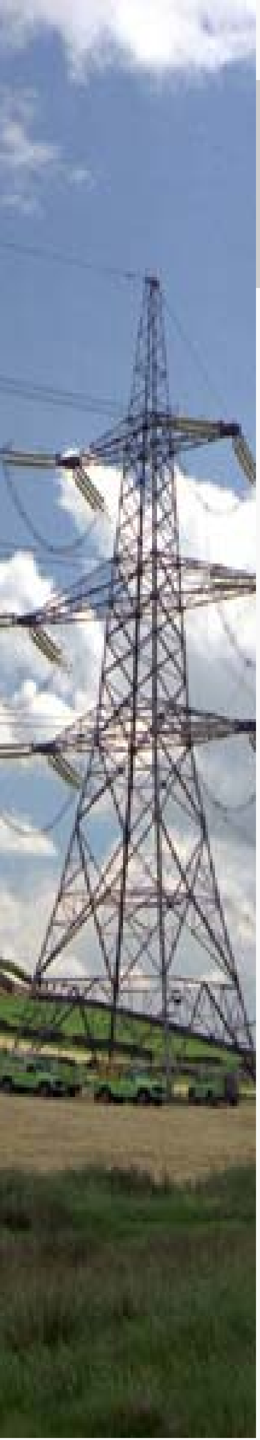


Market Power Mitigation



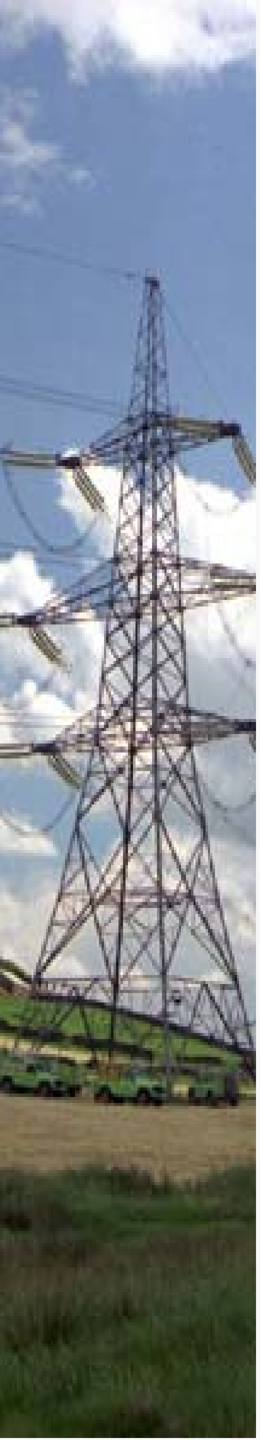
Summary of Day-Ahead Mitigation

- No mitigation occurred under the automated mitigation procedures ("AMP"), although it was triggered to perform the impact test several times.
- Day-ahead mitigation only occurred in NYC during the summer of 2003 under the ConEd mitigation measures.
  - ✓ Inside NYC, some mitigation occurred in every hour during summer 2003.
  - ✓ Mitigated bids in the day-ahead market are carried forward into the real-time market up to the day-ahead scheduled amount.
- These results are indicative the ConEd mitigation measures, which are not triggered by an attempted abuse of market power.
- Replacing most of the ConEd measures with measures that employ the conduct and impact mitigation tests will be a significant improvement.

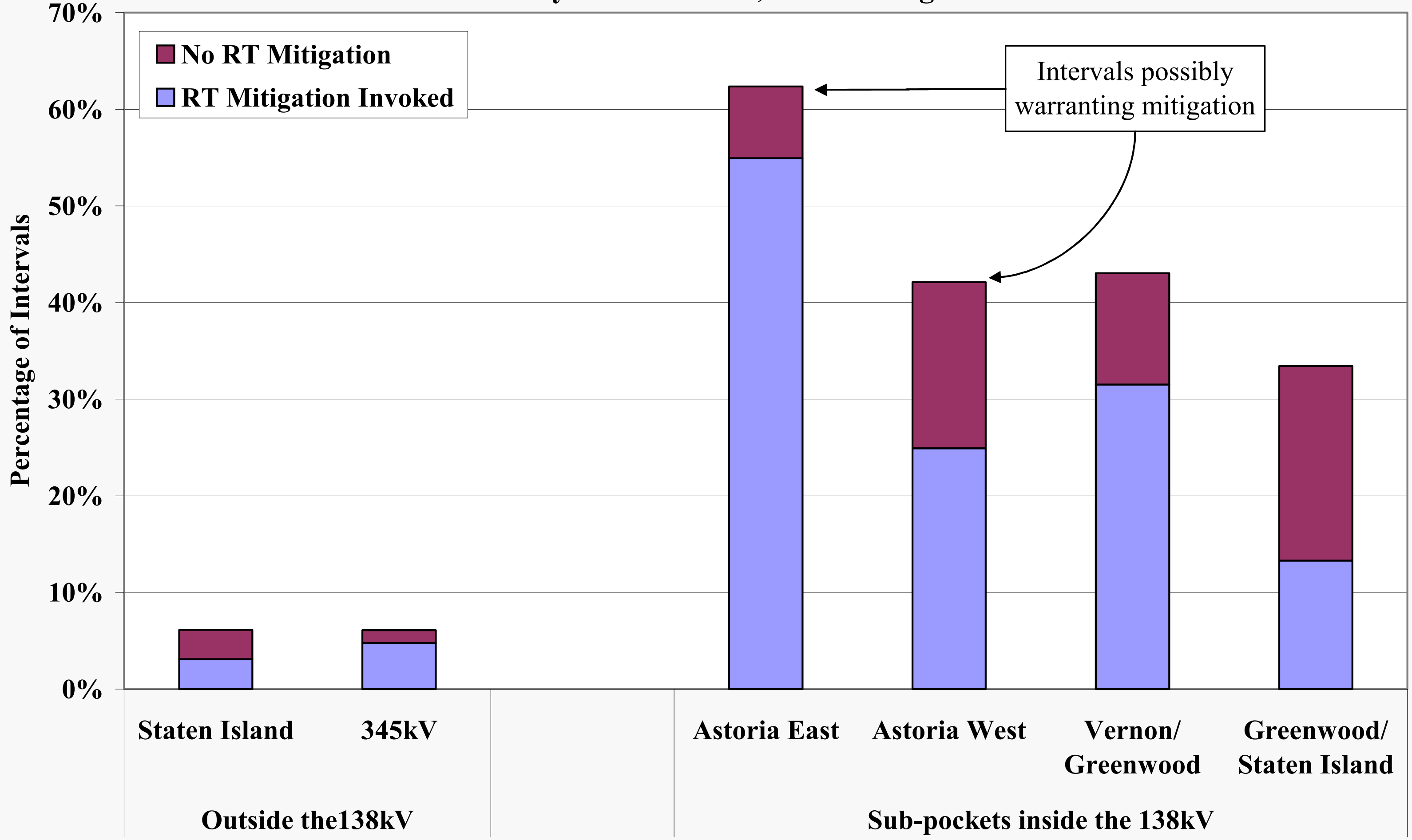


Summary of Real-Time Mitigation

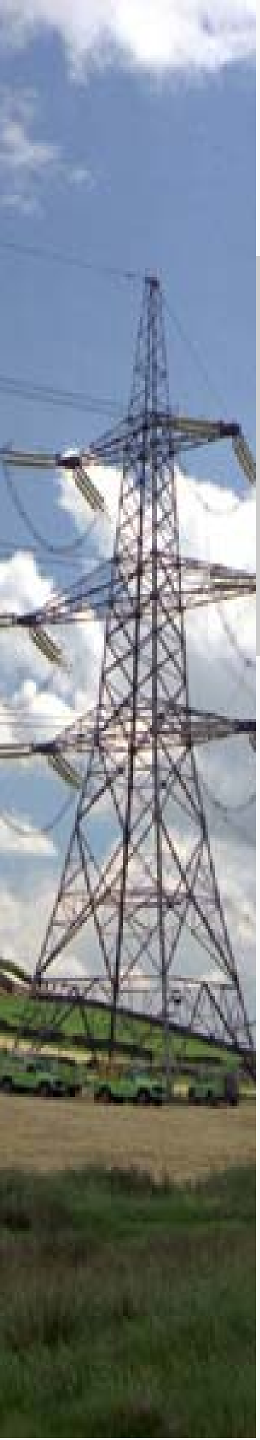
- The following figure summarizes the frequency of constraints into the load pockets and the actual frequency of mitigation.
  - ✓ The constraints shown are those with a positive cumulative shadow price into the load pocket.
  - ✓ When the constraints shown were binding, resources with bids exceeding 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 30 to 60 percent of the intervals during the summer;
  - ✓ Mitigation is only imposed in 14 to 55 percent of the intervals;
  - ✓ In general, the more frequently constrained pockets are mitigated in a higher portion of the hours when constraints are binding.



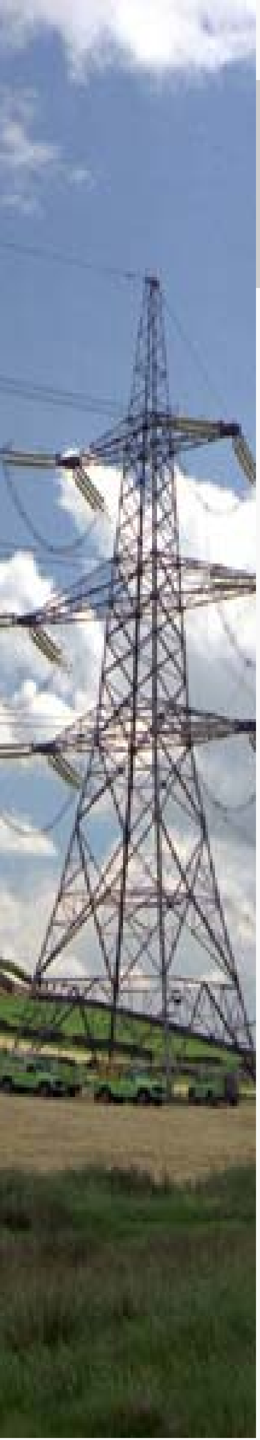
Frequency of Real-Time Constraints and Mitigation
New York City Load Pockets, June to August 2003



Note: August 2003 blackout hours excluded.

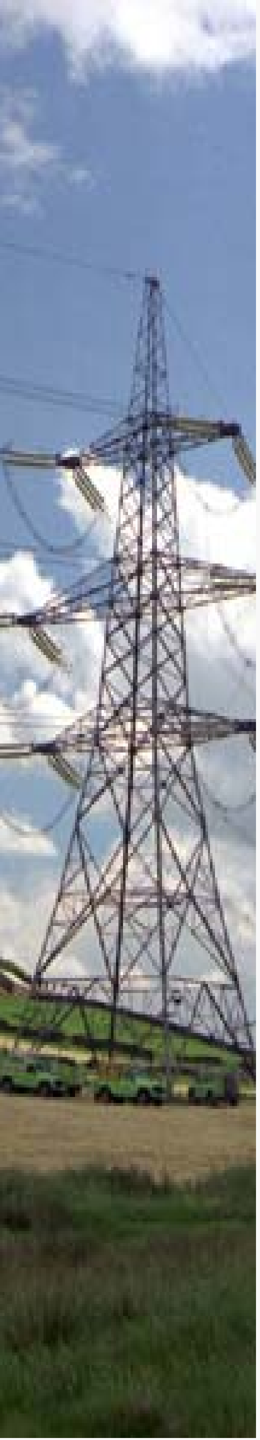


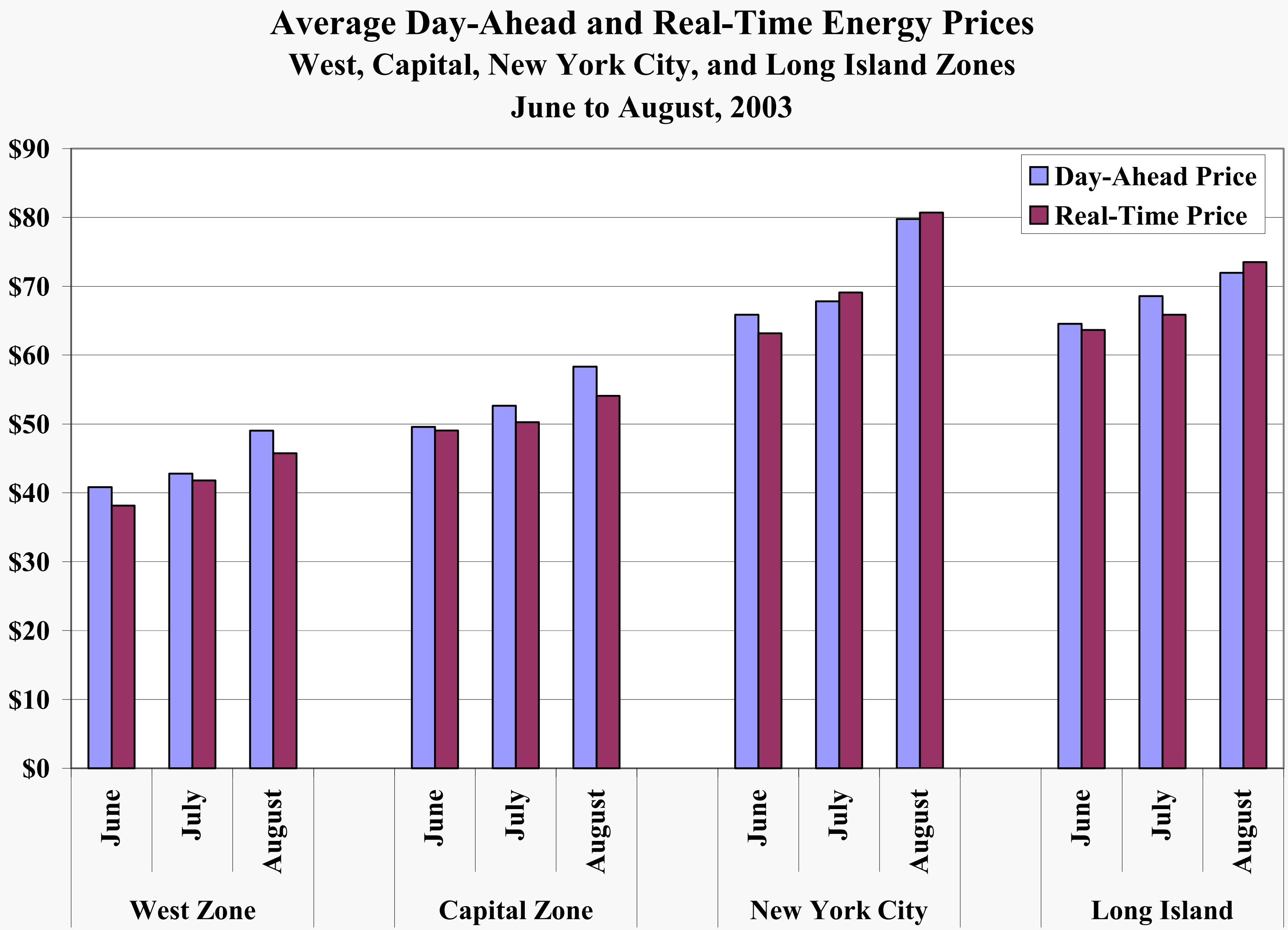
Market Performance



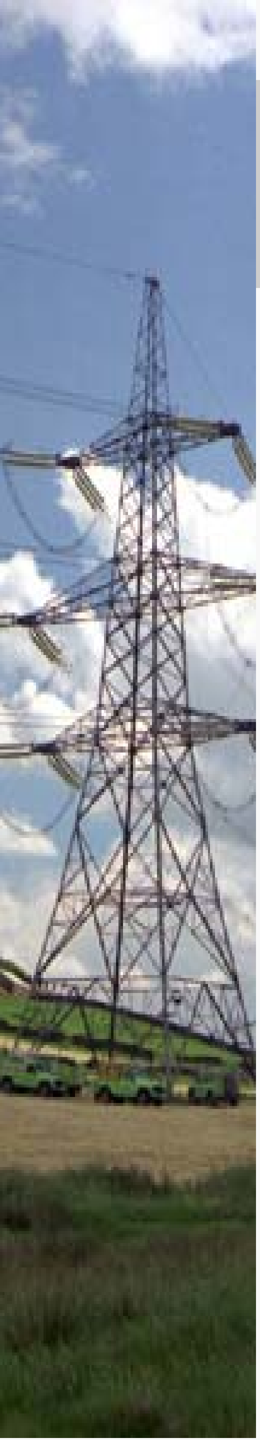
Day-Ahead to Real-Time Price Convergence

- 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 day-ahead prices in the West zone and Capital zone, which is consistent with expectations.
  - ✓ Loads should place a premium on the day-ahead due to the higher volatility in the real-time market and the fact that TCCs settle in the day-ahead.
  - ✓ 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 some months, real-time prices are slightly higher than day-ahead prices.



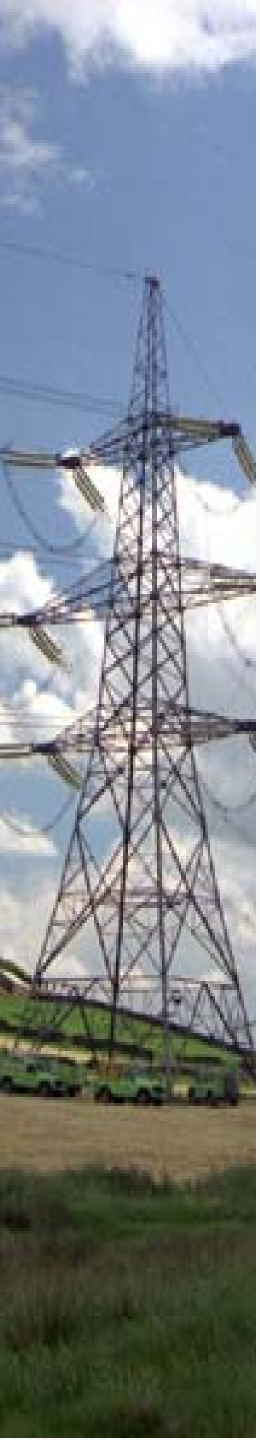


Note: August 2003 blackout hours excluded.



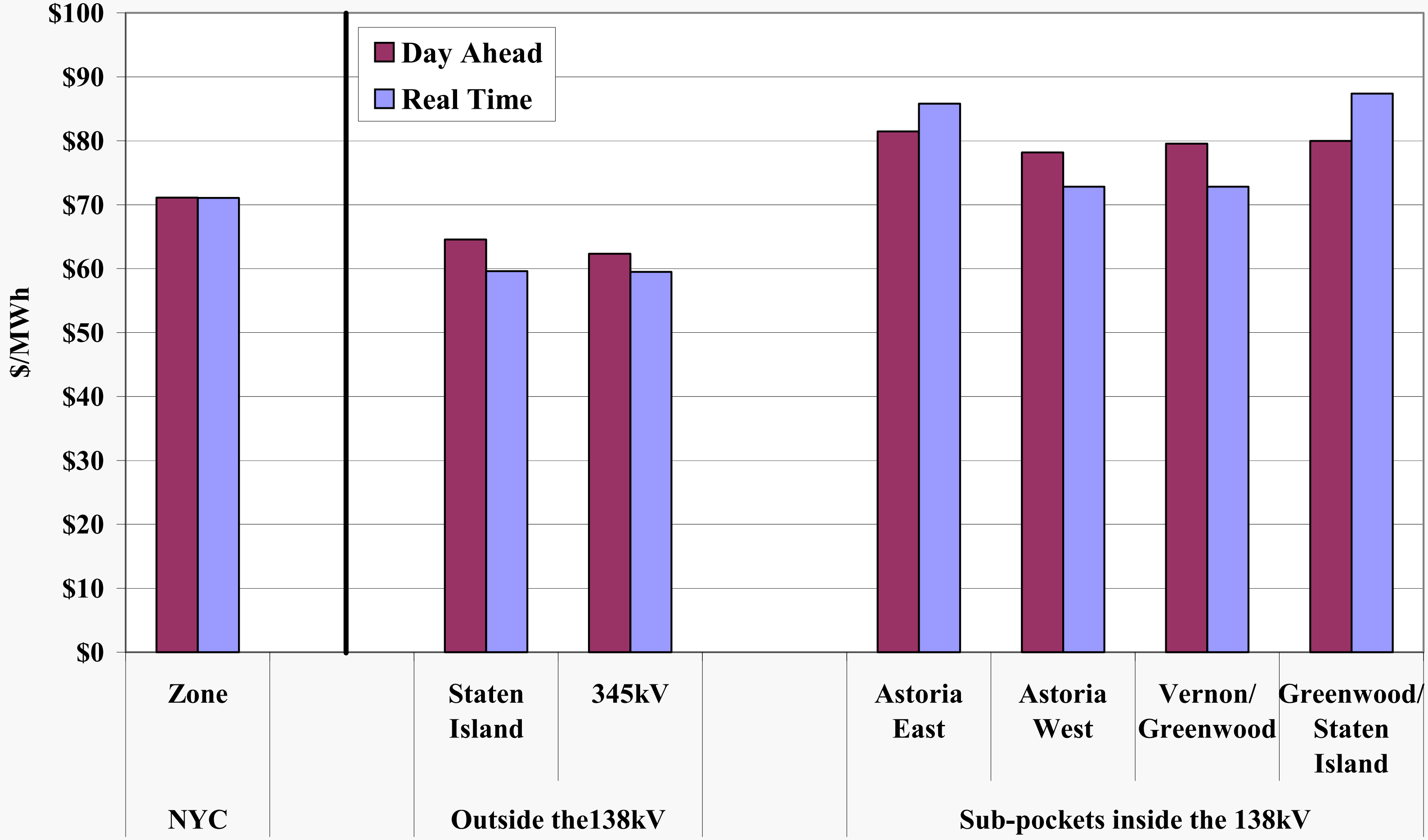
Price Convergence in the NYC Load Pockets

- For the three summer months, day-ahead and real-time prices were nearly identical on average 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;
  - ✓ The other load pockets and the 345 kv system (outside the load pockets) 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.

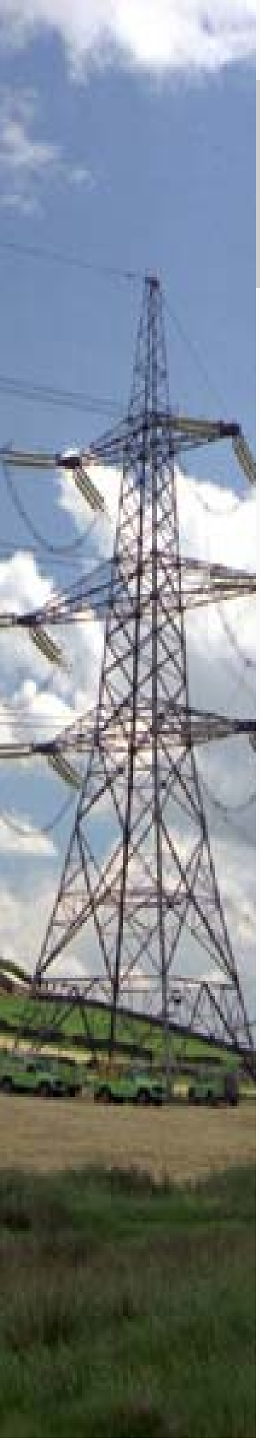


Average Day-Ahead and Real-Time Prices in New York City

Summer 2003



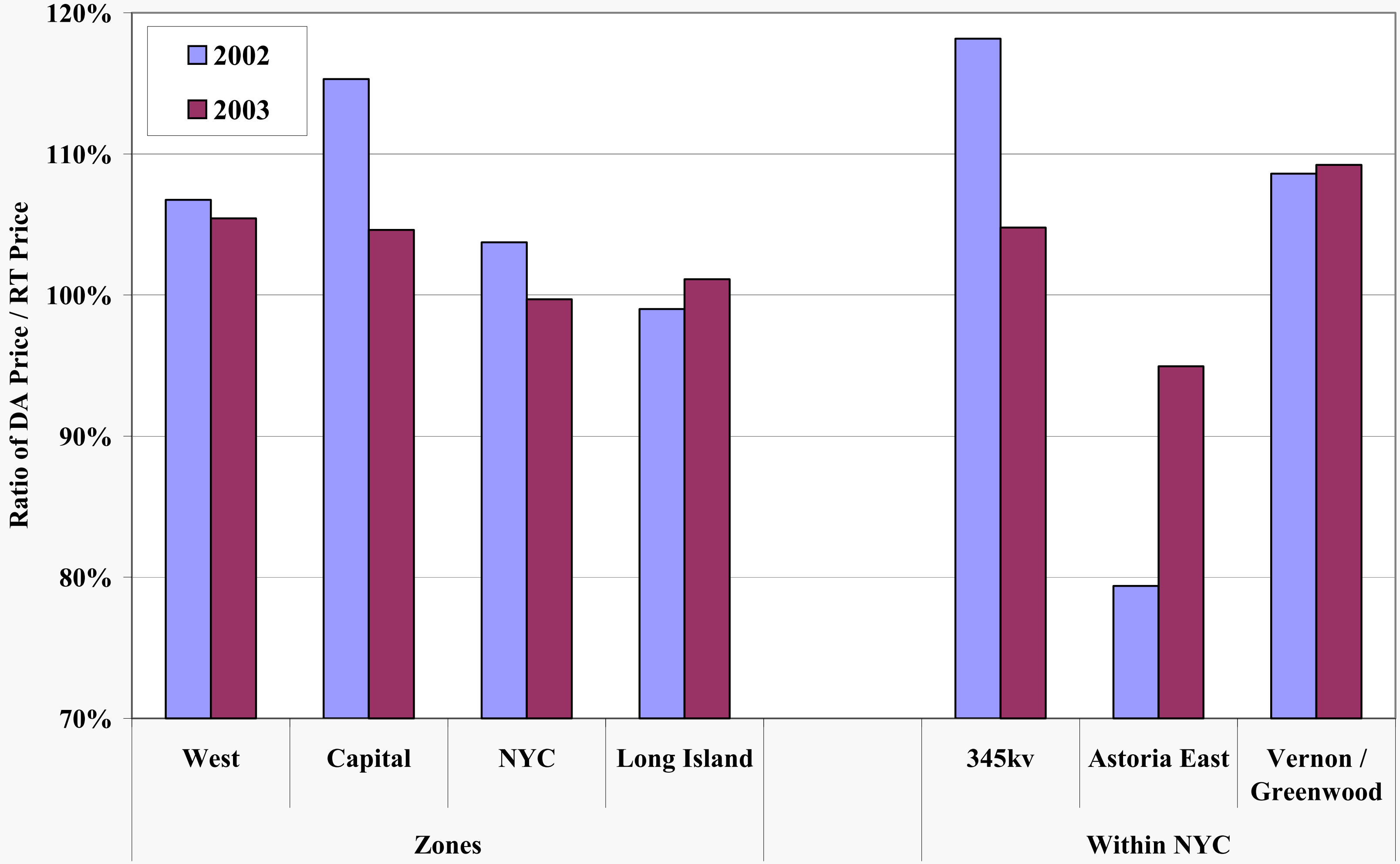
Note: August 2003 blackout hours excluded.



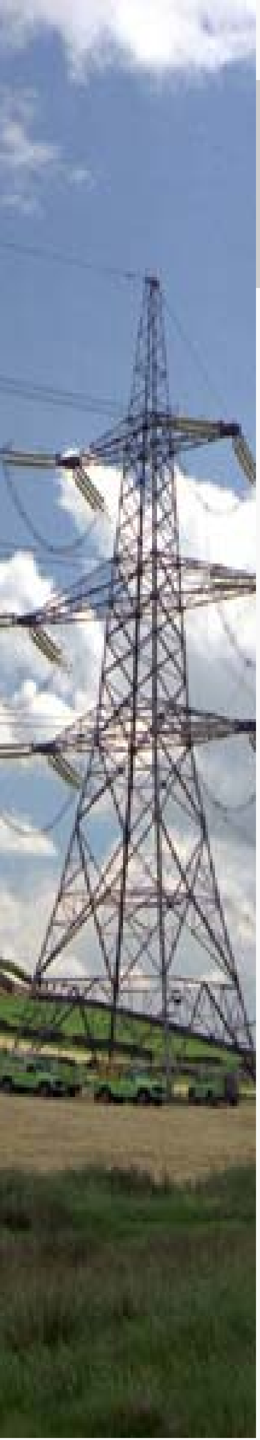
Day-Ahead to Real-Time Price Convergence

- The following figure shows how price convergence at various locations in New York in the summer of 2003 compares with summer 2002.
- The figure shows the ratio of the average day-ahead price to the average real-time price (a result of 110% indicates a 10% day-ahead premium).
- This figure shows that the convergence at nearly all of the locations improved from summer 2002 to summer 2003, which is likely attributable to:
  - ✓ More active virtual trading;
  - ✓ Reduced price volatility due to milder load conditions;

Comparison of Day-Ahead and Real-Time Prices
Summer 2002 and 2003

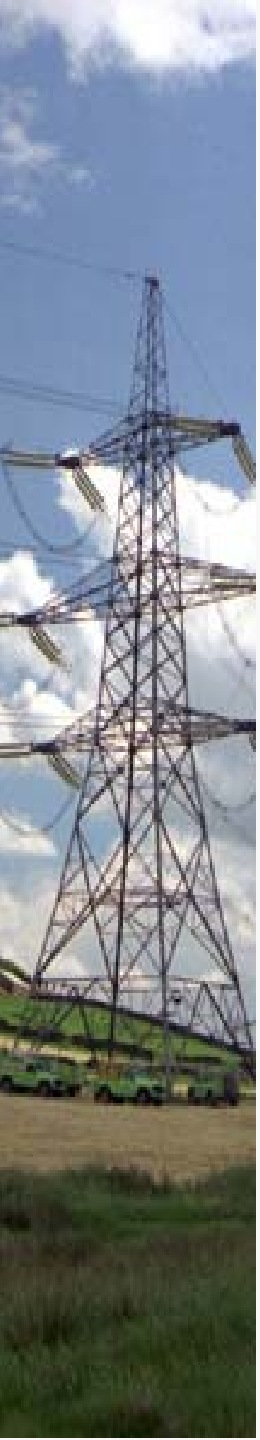


Note: August 2003 blackout hours excluded.

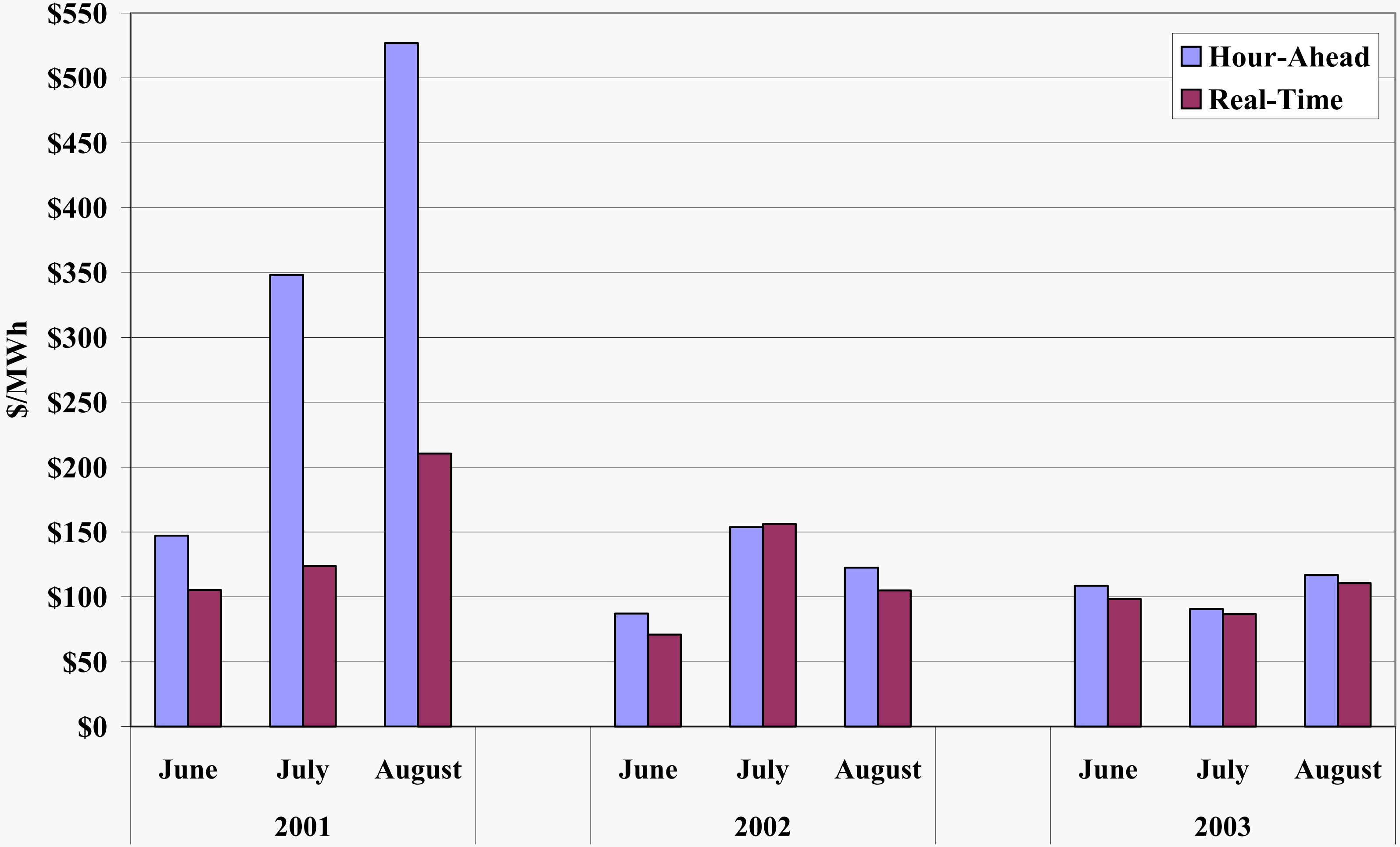


Hour-Ahead and Real-Time Prices

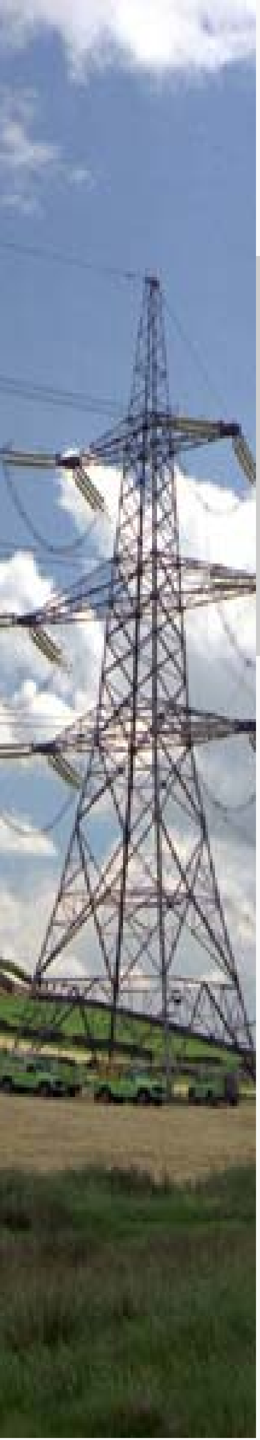
- Lack of convergence between hour-ahead and real-time prices prior to 2002 was a concern because large price differences can:
  - ✓ Cause external transactions and off-dispatch generation to be scheduled inefficiently;
  - ✓ Result in substantial uplift costs; and
  - ✓ Inefficiently affect real-time prices.
- Several changes to market rules and the BME model were made to improve the price convergence prior to the summer of 2002.
  - ✓ Counting exports as 30-minute reserves at specific shadow price levels.
  - ✓ Crediting latent 30-minute reserves in real time.
- The following figure shows that the convergence of hour-ahead and real-time prices in 2003 in the highest demand hours continued to be much better than the convergence prior to these market rule changes.



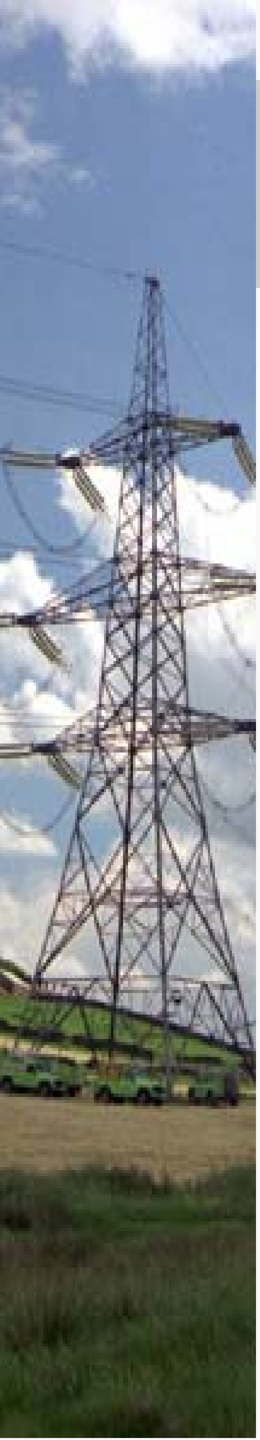
Average Hour-Ahead and Real-Time Energy Prices
East New York -- June to August 2001 to 2003
Hours with Highest 10% of Real-Time Load



Note: August 2003 blackout hours excluded.

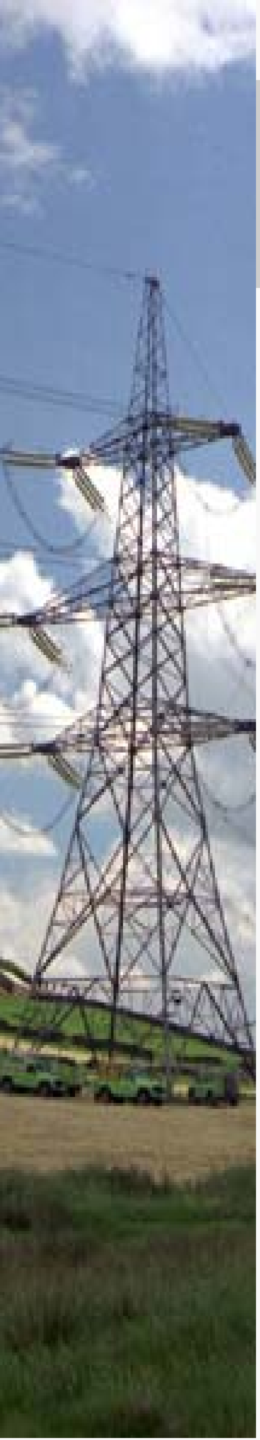


Analysis of Bidding Patterns



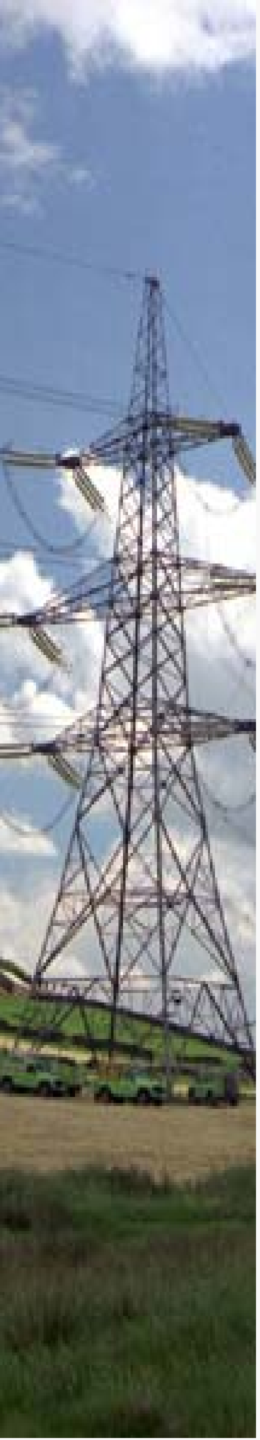
Analysis of Supplier Offers – Deratings

- 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, analyzing generator deratings.
- Deratings include planned outages, long-term forced outages, short-term forced outages, and partial deratings.

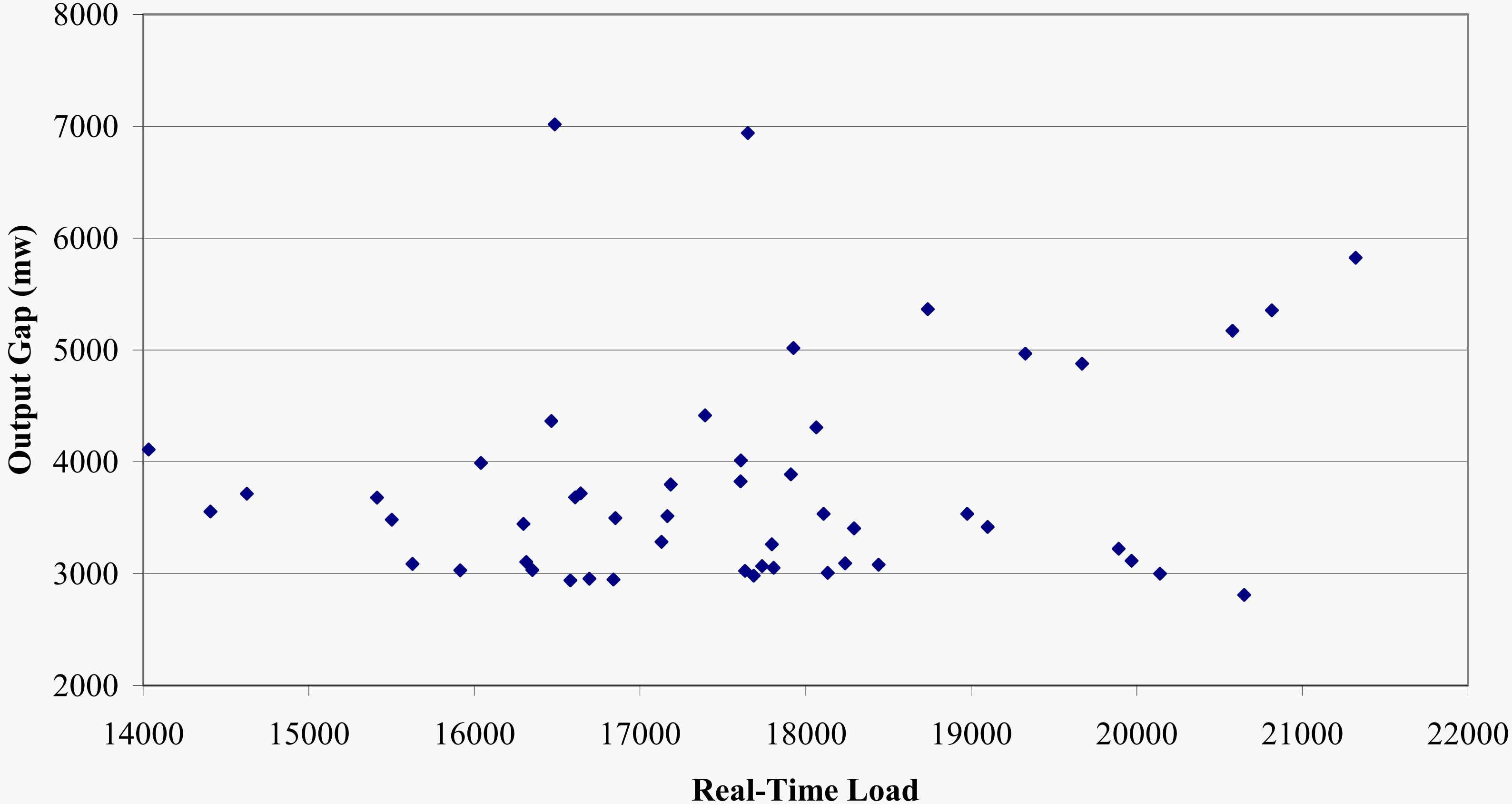


Analysis of Supplier Offers – Deratings

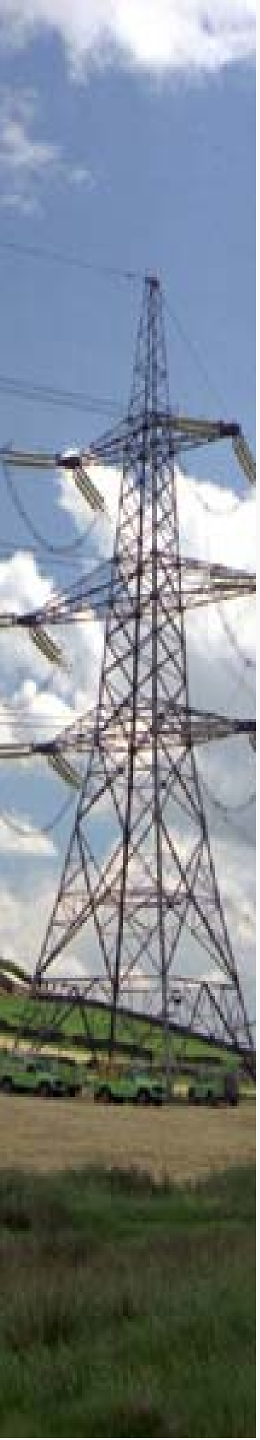
- The following figures show deratings during the summer 2003 versus actual load in eastern New York.
- The second figure focuses on short-term outages since these are most likely to reflect attempts to physically withhold.
- The figures show no statistically significant relationship between deratings and load levels.
  - ✓ The two days with extremely large quantities derated occurred on the Monday and Tuesday following the August blackout.
  - ✓ There were six days where load in the east exceeded 18 gigawatts and short-term deratings exceeded 2 gigawatts. Three occurred in the week following the blackout, while the other three occurred in the last week of June during the Indian Point 3 outage.



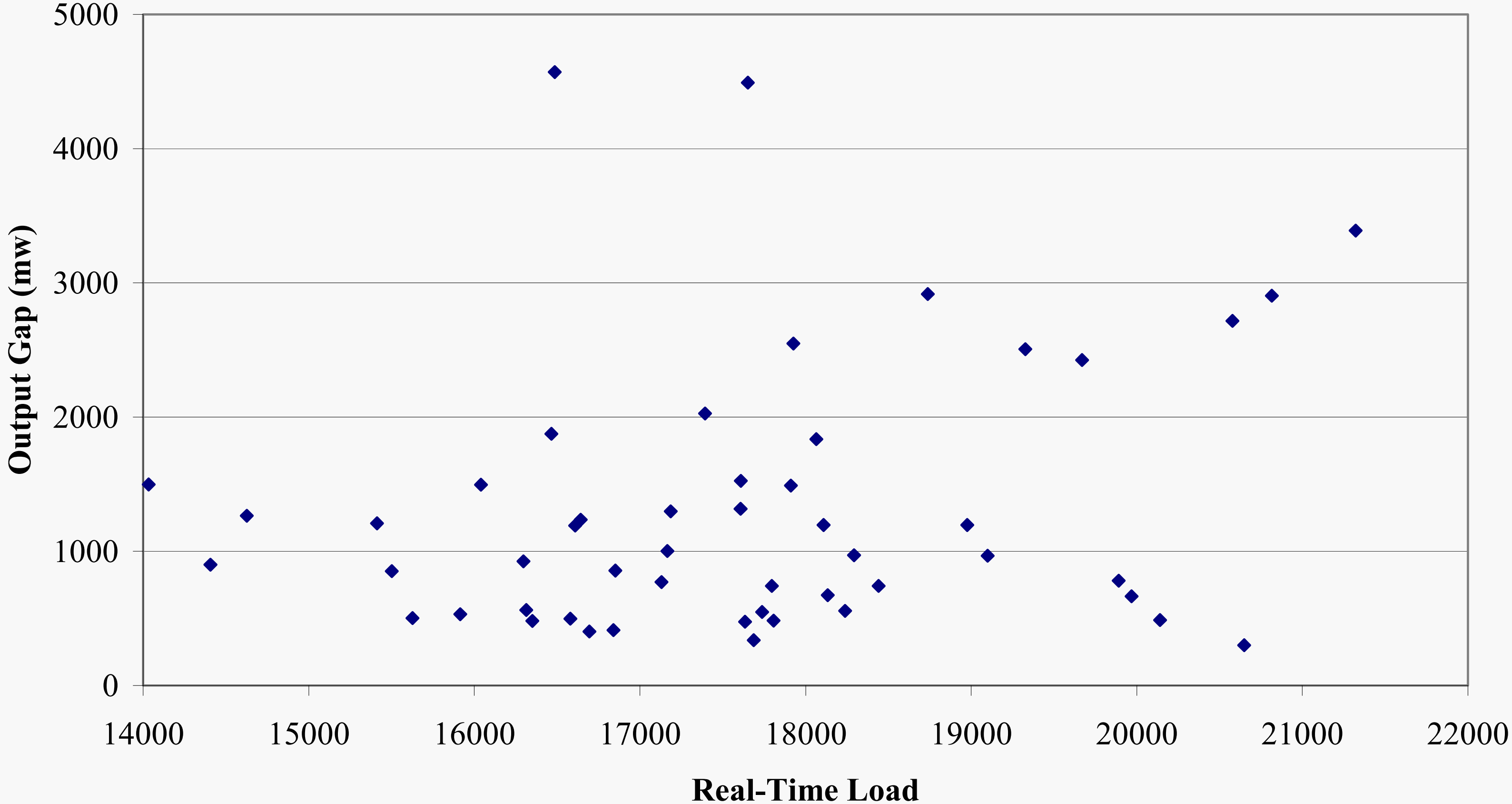
Relationship of Deratings to Actual Load
Day-Ahead Market -- East New York
June to August 2003 -- Weekdays 3pm Hour



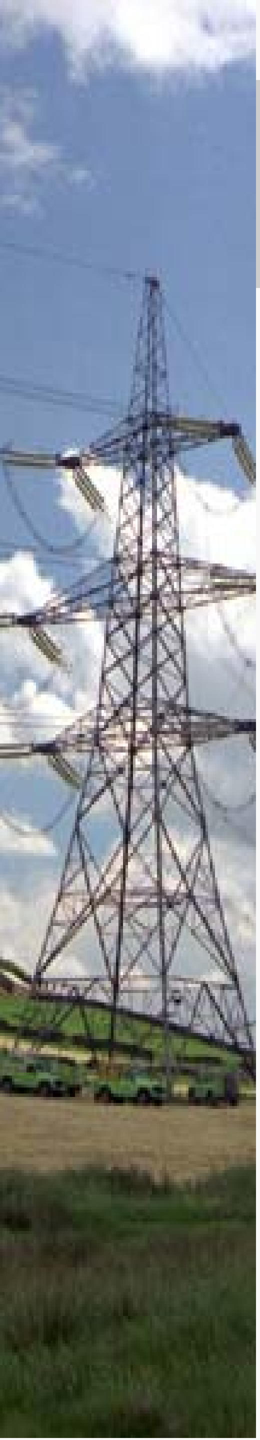
Note: August 2003 blackout hours excluded.



Relationship of Short-Term Deratings to Actual Load
Day-Ahead Market -- East New York
June to August 2003 -- Weekdays 3pm Hour

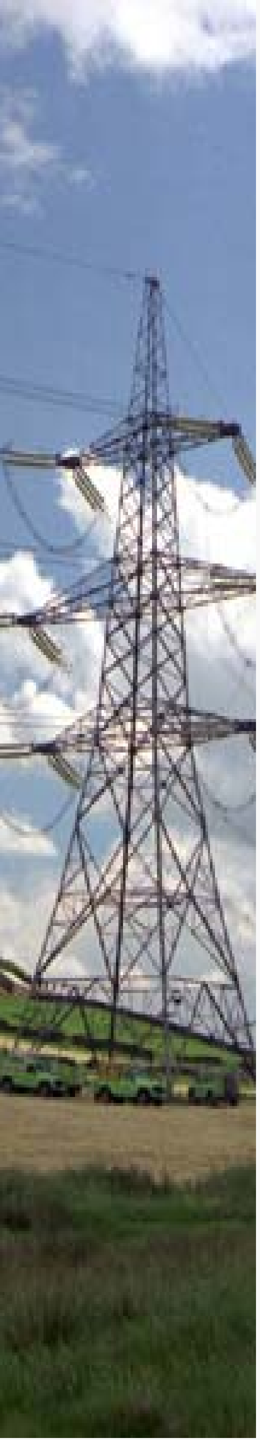


Note: August 2003 blackout hours excluded.

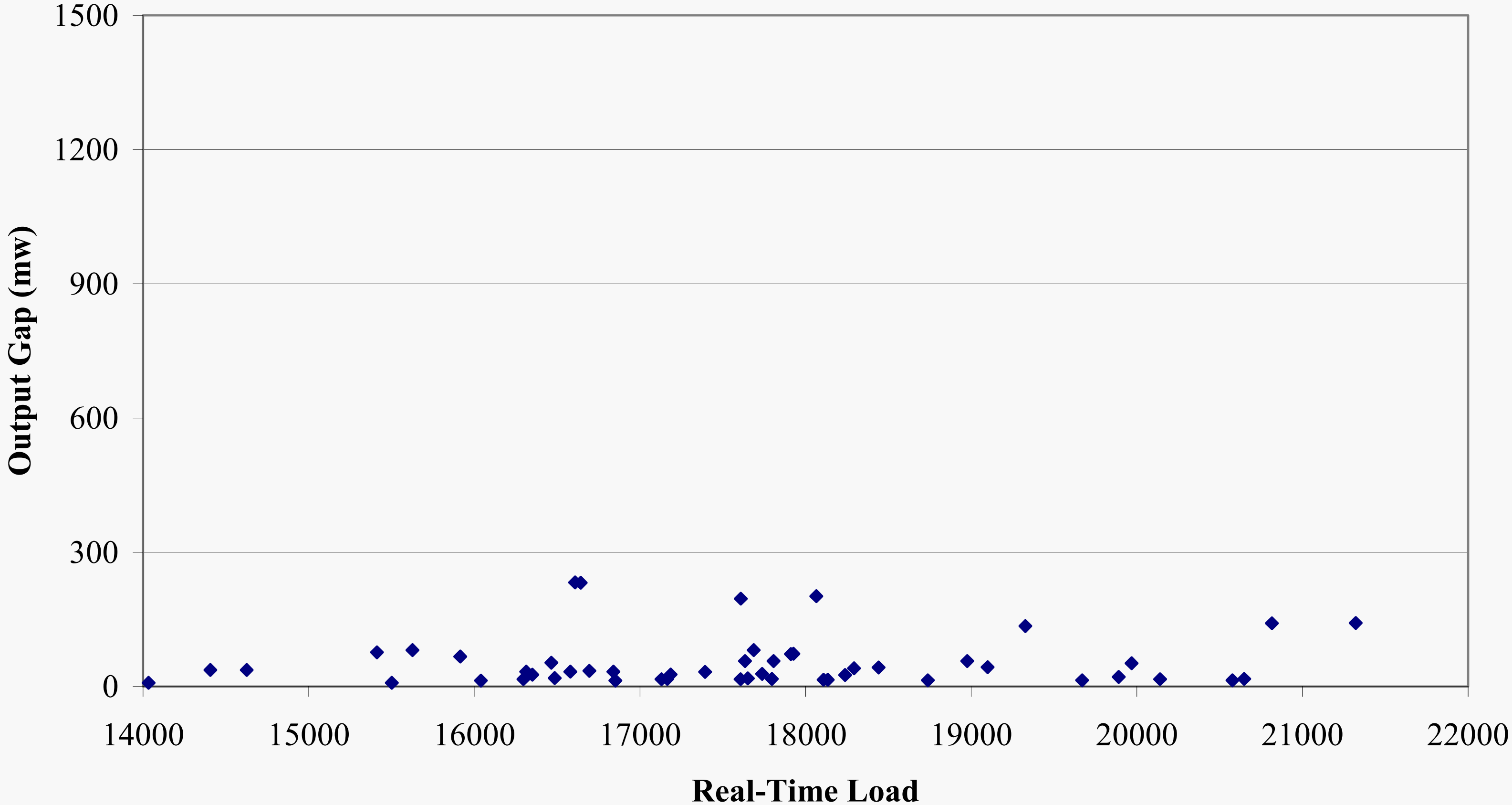


Analysis of Supplier Offers – Output Gap

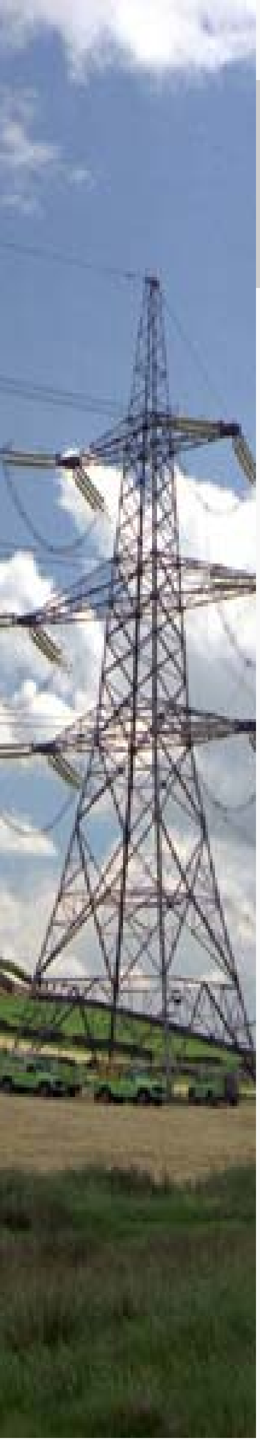
- The second analysis is intended to assess potential economic withholding, employing a measure called an "output gap".
- The output gap is the quantity of economic capacity that is not sold in the day-ahead or real-time markets for energy or ancillary services because a supplier submits an offer price 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).



Relationship of Output Gap at High Threshold to Actual Load
Real-Time Market -- East New York
June to August 2003 -- Weekdays 3pm Hour

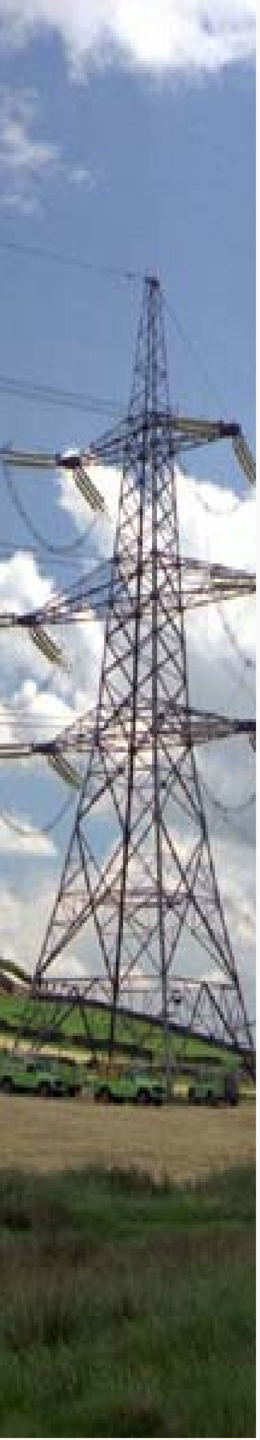


Note: August 2003 blackout hours excluded.

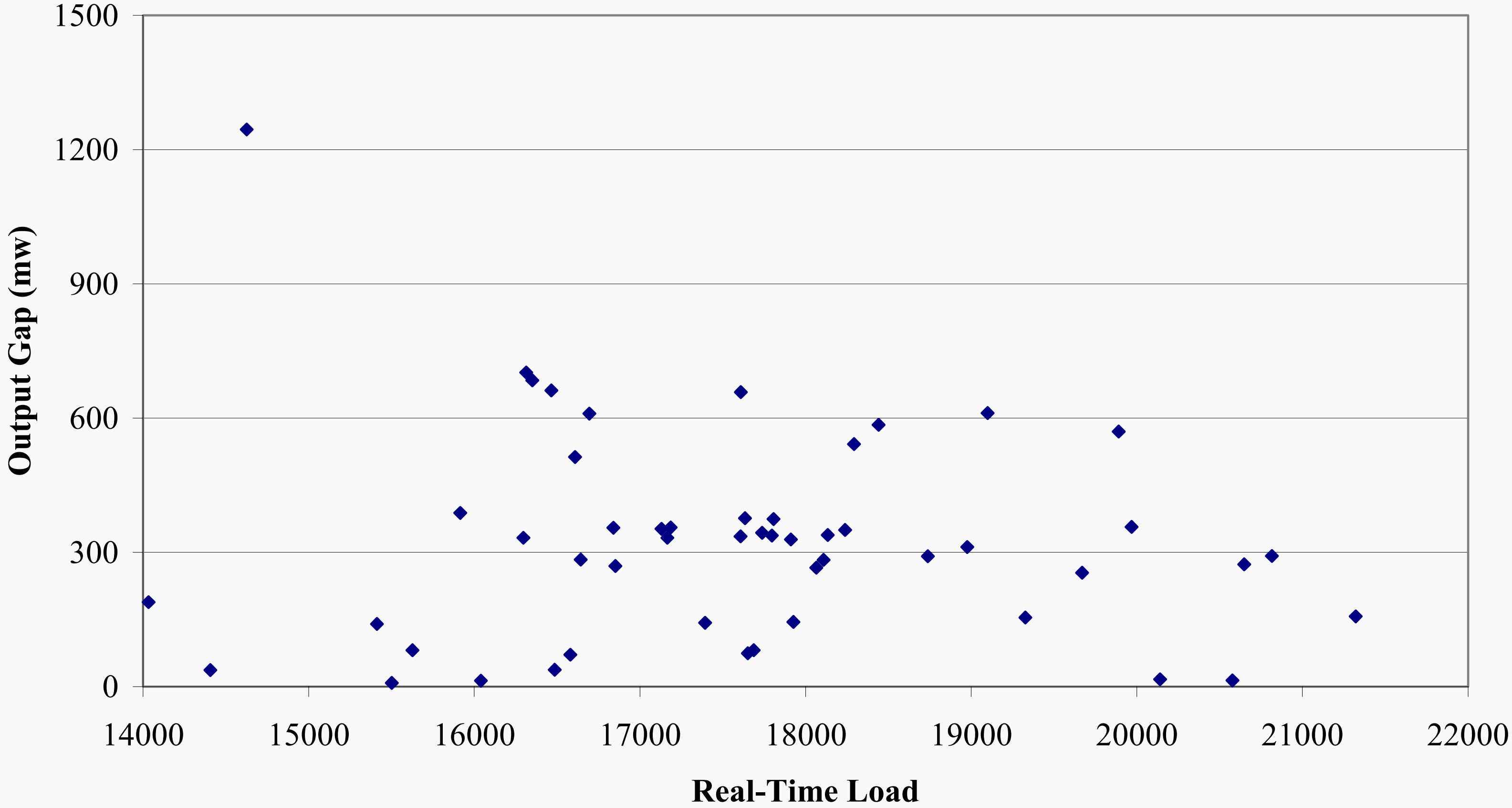


Analysis of Supplier Offers – Output Gap

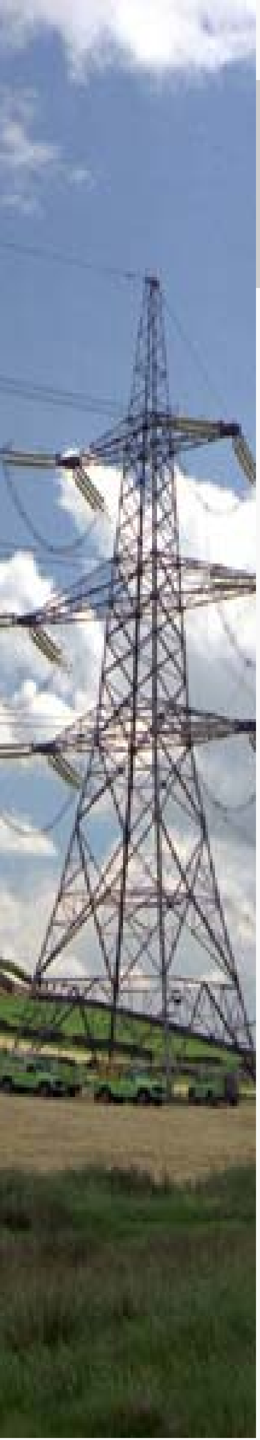
- The previous figure shows that the output gap is very low on all days during the summer of 2003 using the standard mitigation thresholds.
- To test the robustness of this result, we also conducted the analysis using lower threshold values.
- The output gap in the following figure is computed assuming thresholds of $50/MWh or 100% (whichever is lower).
  - ✓ This figure shows the output gap was less than 300 megawatts on the five days where load exceeded 20 gigawatts.
  - ✓ There is no statistically significant relationship between these output gap results and the actual load levels.
- These results are consistent with expectations in a workably competitive market.



Relationship of Output Gap at Low Threshold to Actual Load
Real-Time Market -- East New York
June to August 2003 -- Weekdays 3pm Hour

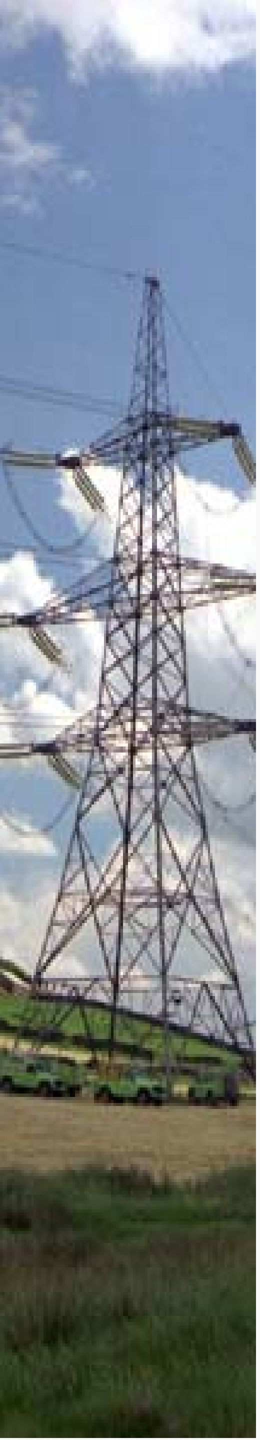


Note: August 2003 blackout hours excluded.

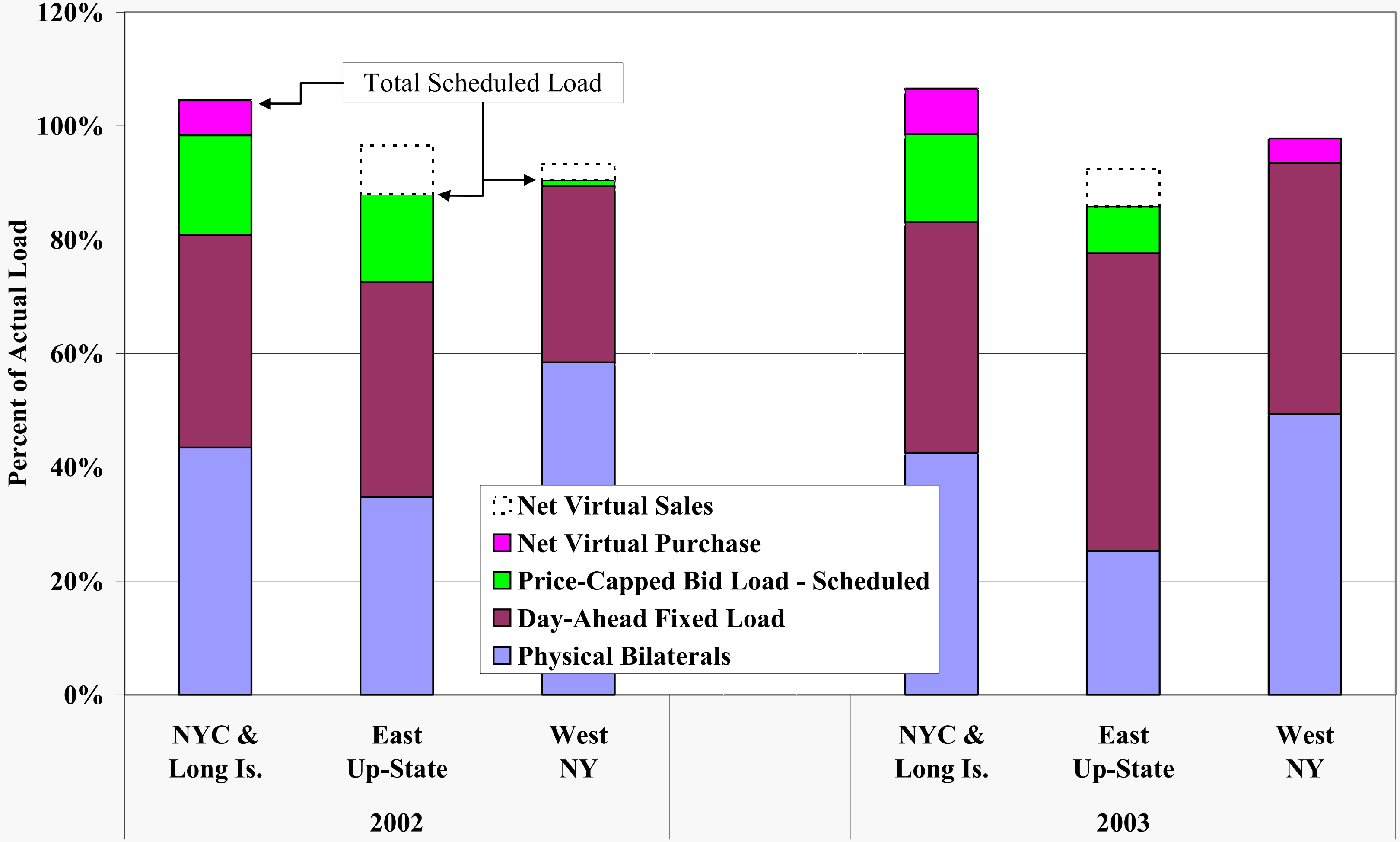


Analysis of Load-Bid Patterns

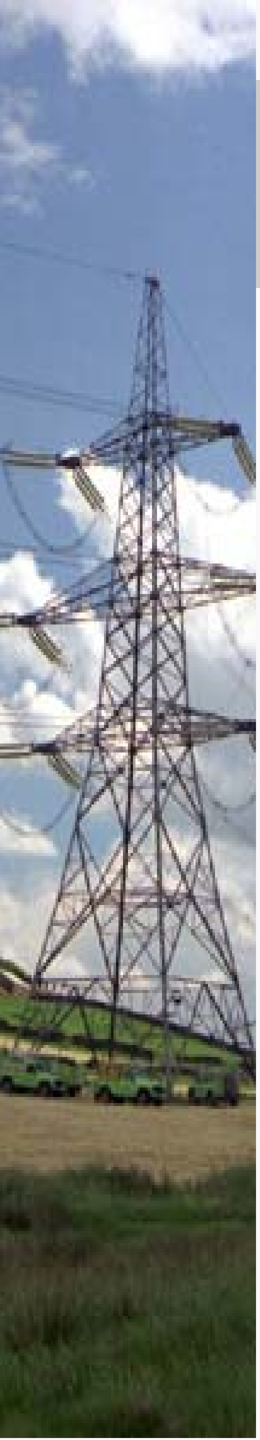
- The following figure shows the load bidding and virtual trading patterns during the summers of 2002 and 2003. Five categories comprise day-ahead total scheduled load:
  - ✓ *Physical Bilaterals* – These are bilateral transactions which settle transmission charges through the ISO, however, transactions 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. These are shown as empty boxes because they net out other categories of day-ahead load.
- In each of the last two summers, substantially more load was scheduled in NYC and Long Island as a percentage of real-time load than other geographic areas.
  - ✓ In 2003, 107 percent of real-time load was scheduled day-ahead in 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 2003

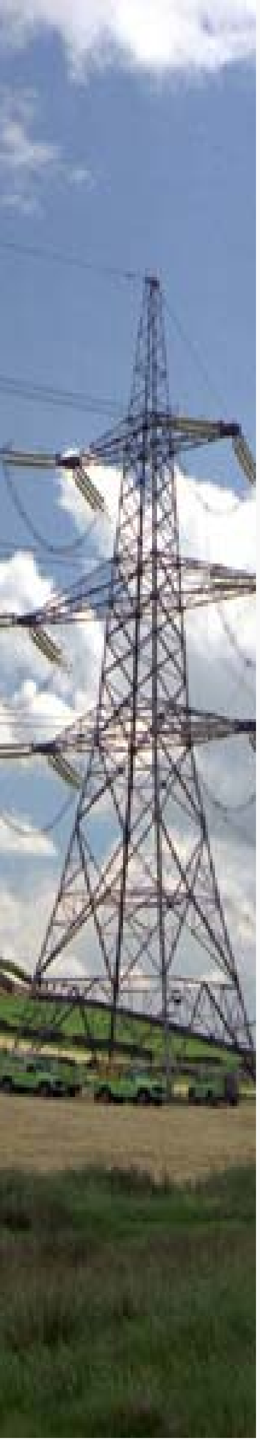


Note: August 2003 blackout hours excluded.

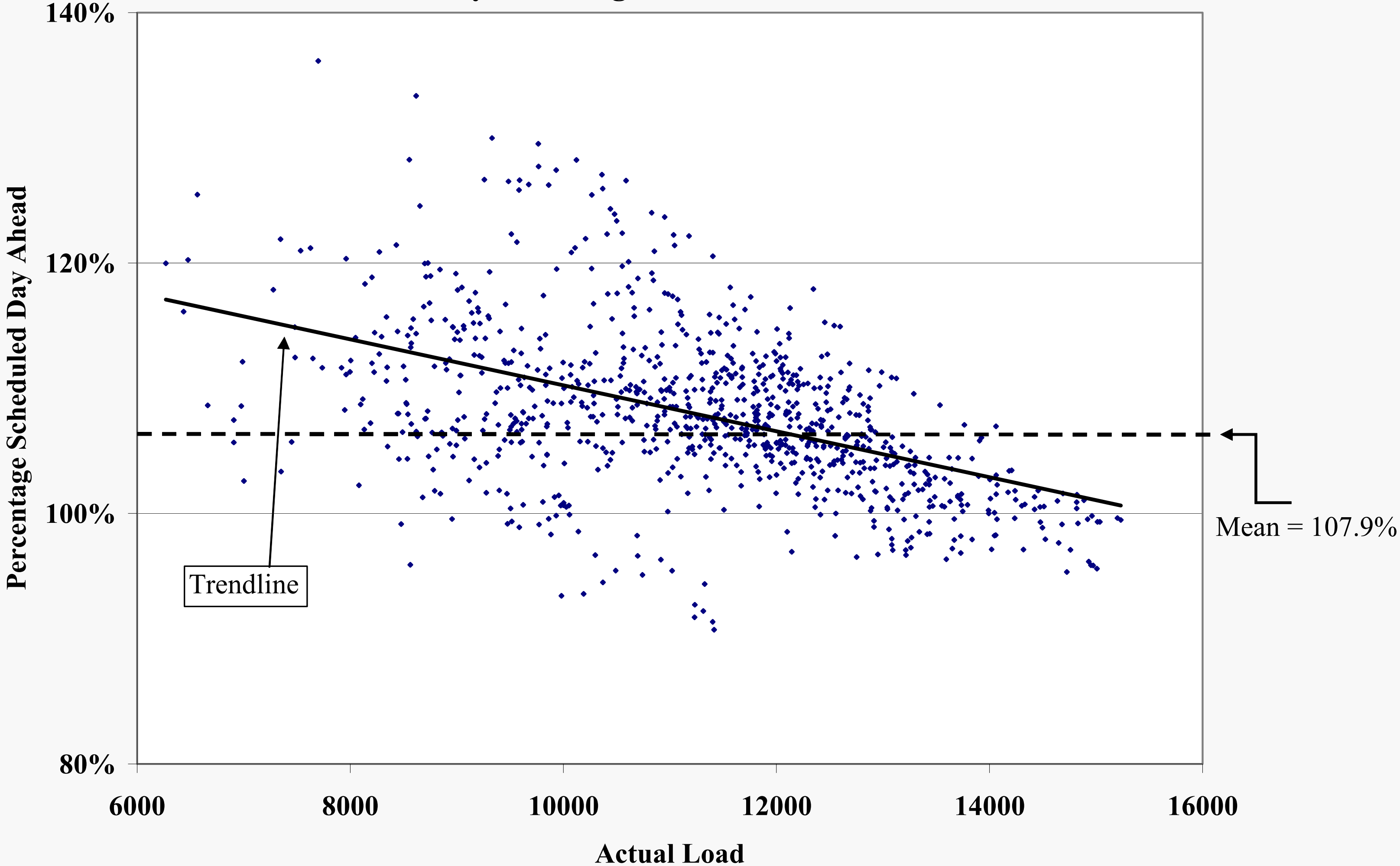


Analysis of Load-Bid Patterns

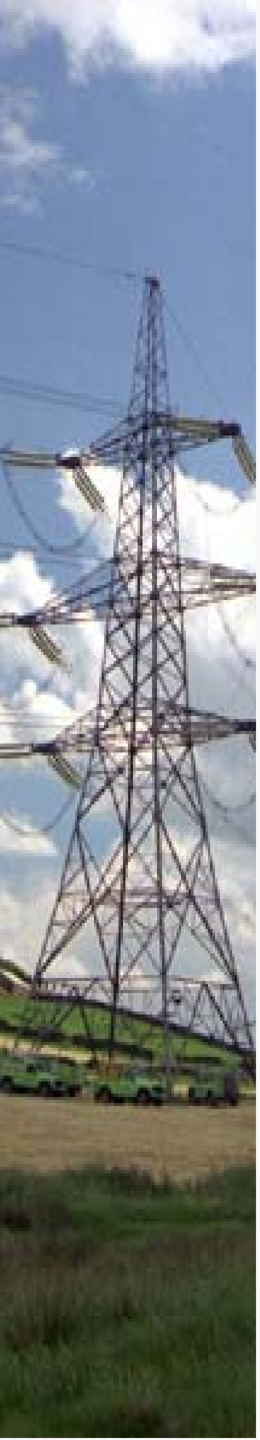
- The following figures show day-ahead hourly scheduled load (including virtual trades) as a percentage of real-time load during summer of 2003.
  - ✓ The first figure depicts New York City and Long Island which tend to over-schedule load day-ahead. However, the trend line shows that this pattern diminishes in the highest load hours.
  - ✓ The second figure shows that the load scheduled day-ahead in east up-state New York which is more random -- although load is usually under-scheduled, there is no statistically significant relationship with the actual load level.
  - ✓ The third scatter figure shows that day-ahead load in west New York is under-scheduled on average, and that the percentage purchased day-ahead tends to decrease with actual load.
- The causes of these patterns are evaluated later in this report.



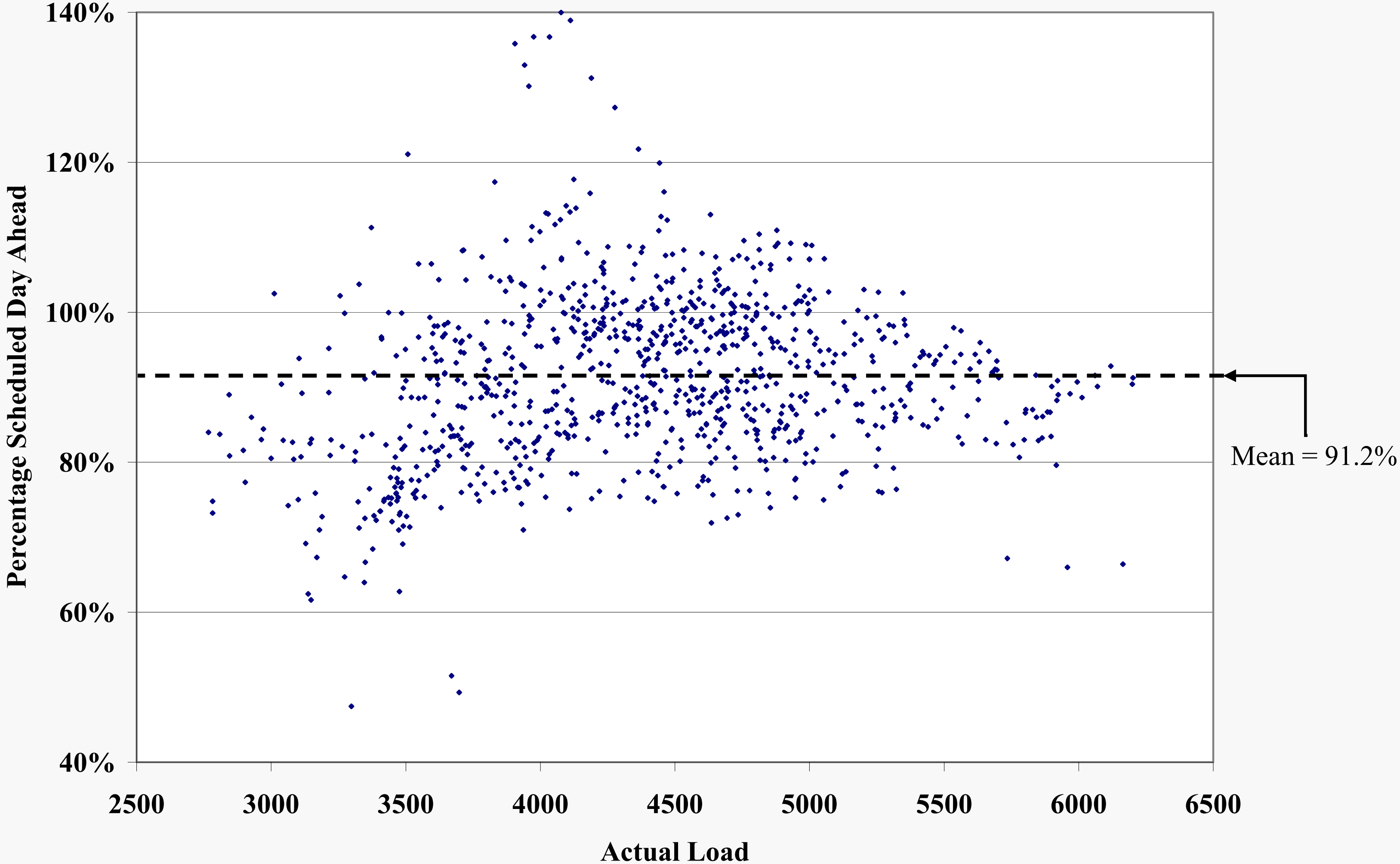
Percentage of Load Scheduled Day-Ahead versus Real-Time Load
New York City and Long Island -- Summer 2003, Peak Hours



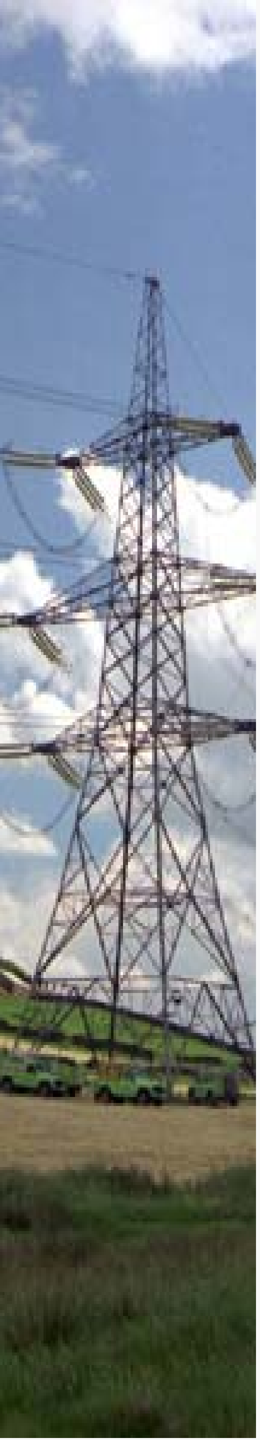
Note: August 2003 blackout hours excluded.



Percentage of Load Scheduled Day-Ahead versus Real-Time Load
East Up-State New York -- Summer 2003, Peak Hours

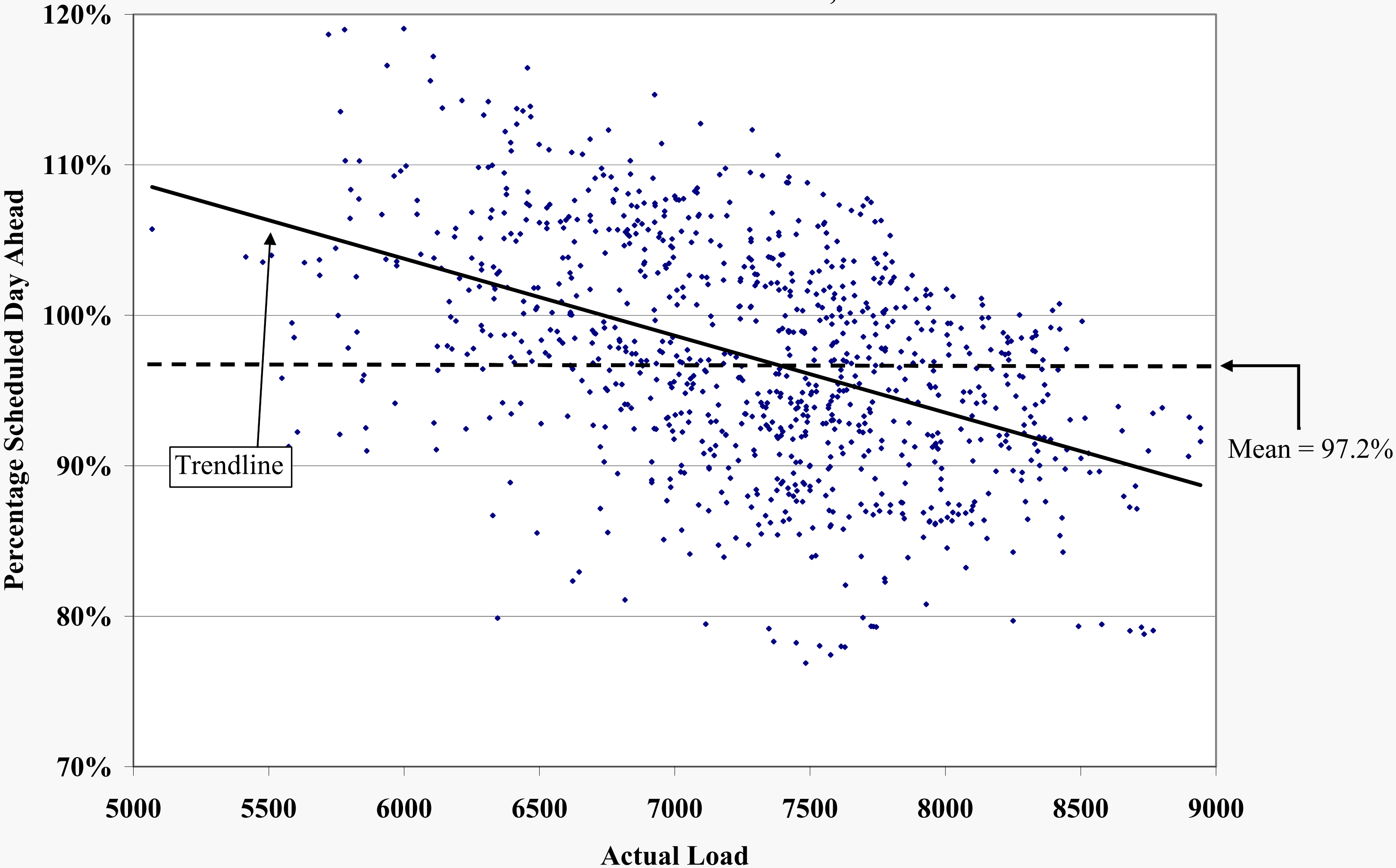


Note: August 2003 blackout hours excluded.

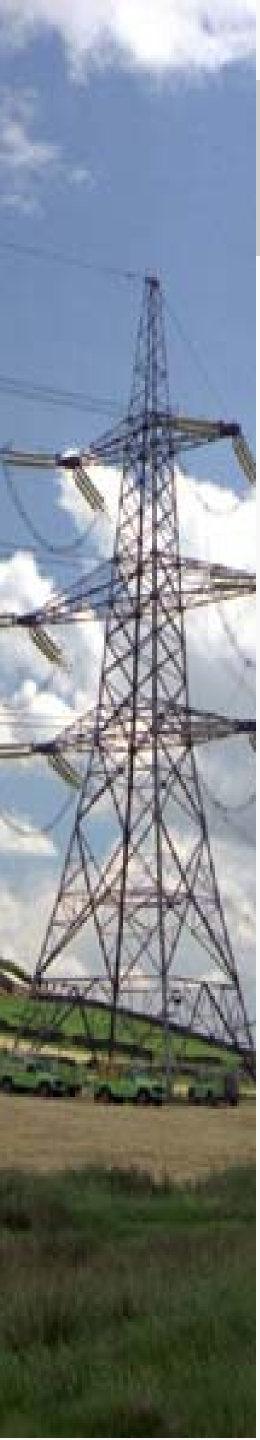


Percentage of Load Scheduled Day-Ahead versus Real-Time Load

West New York -- Summer 2003, Peak Hours

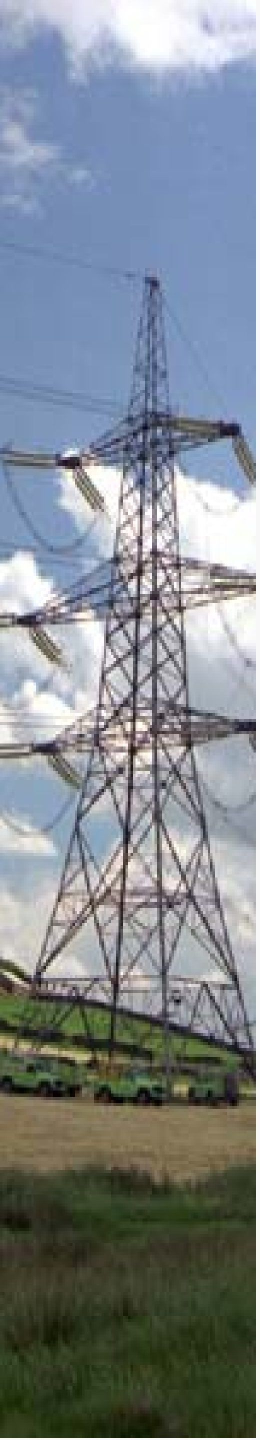


Note: August 2003 blackout hours excluded.



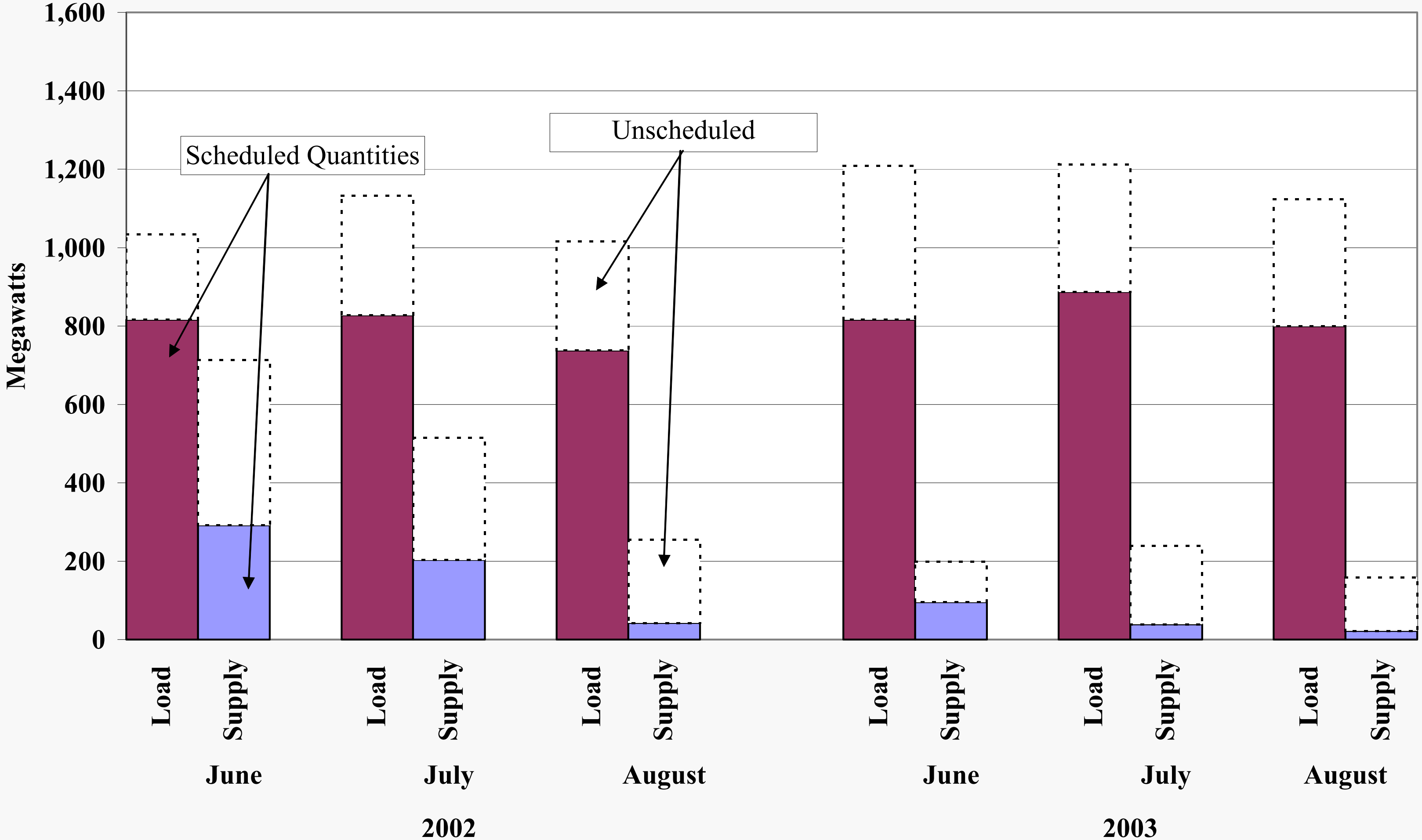
Virtual Trading Patterns

- 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 two summers on a monthly basis.
- The charts show the following:
  - ✓ Virtual load scheduled in New York City and Long Island has remained relatively constant at 800 megawatts on average.
  - ✓ Virtual supply scheduled in New York City and Long Island has decreased from already low levels to less than 100 megawatts on average.
  - ✓ Virtual load scheduled in the rest of the state has grown six-fold to approximately 1100 megawatts on average.
  - ✓ Virtual supply scheduled in the rest of the state has increased from substantial levels to approximately 1100 megawatts on average.

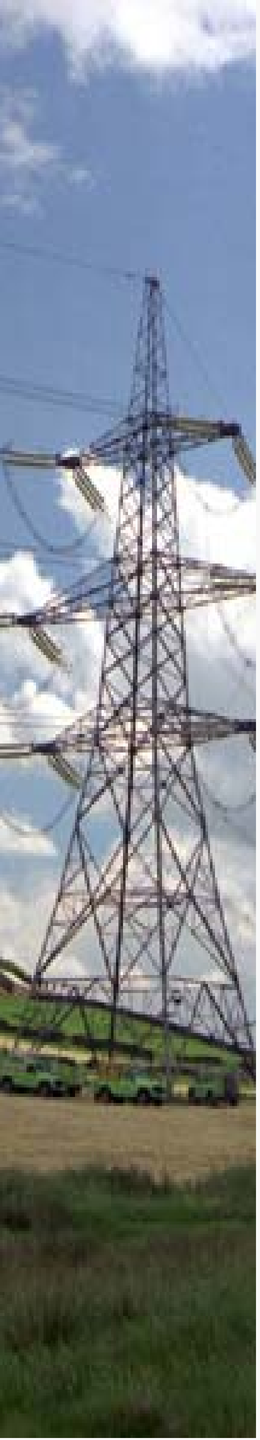


Hourly Virtual Bidding of Load and Supply, Scheduled and Unscheduled

New York City and Long Island -- June to August 2002 to 2003

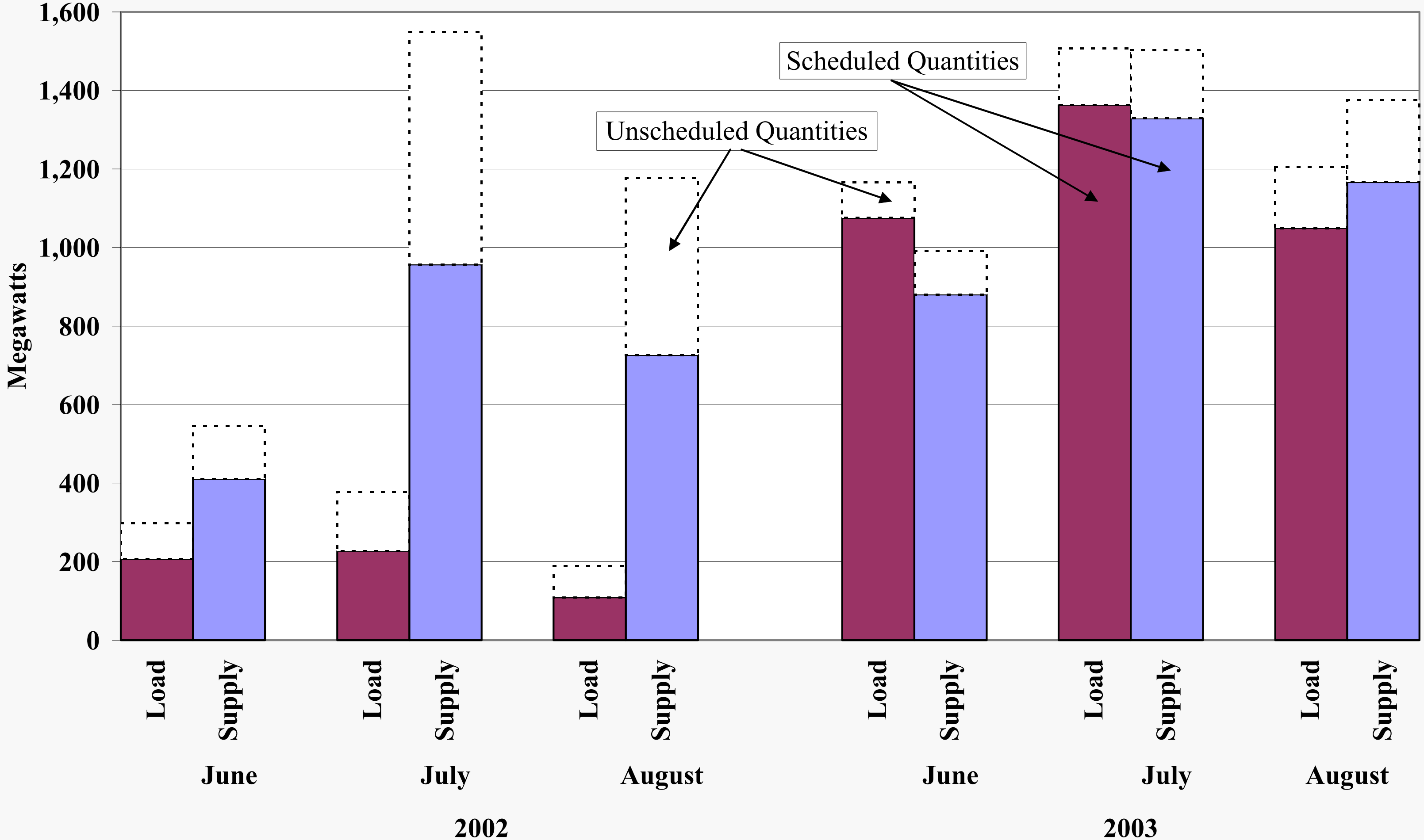


Note: August 2003 blackout hours excluded.

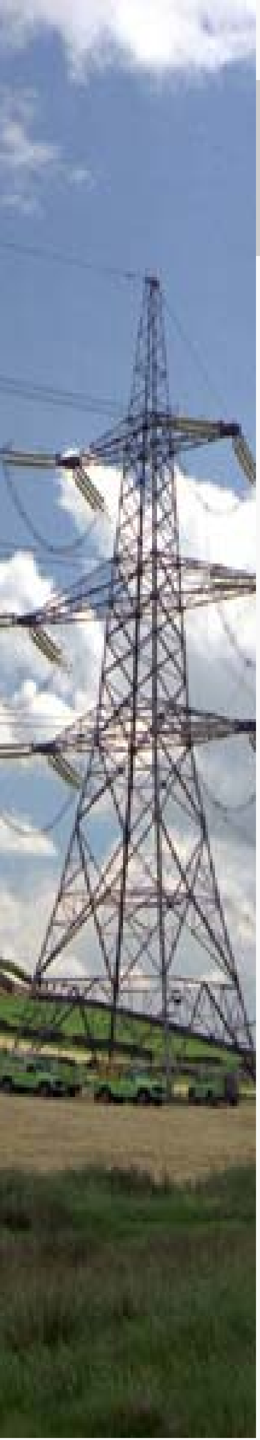


Hourly Virtual Bidding of Load and Supply, Scheduled and Unscheduled

Outside New York City and Long Island -- June to August 2002 to 2003

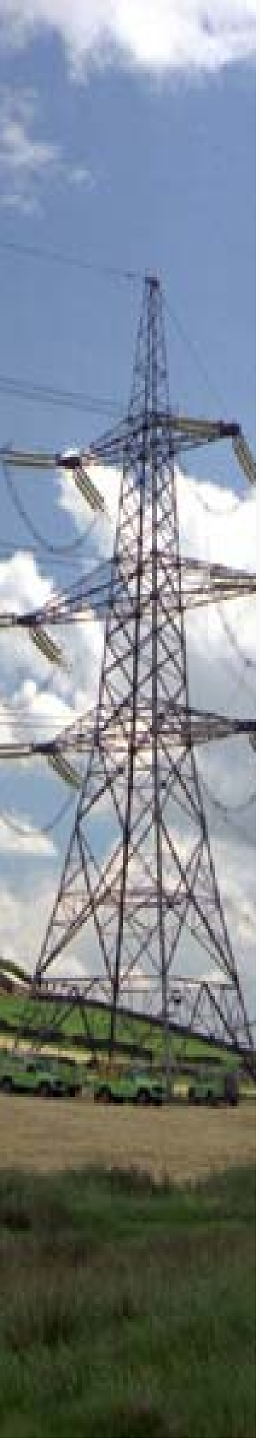


Note: August 2003 blackout hours excluded.



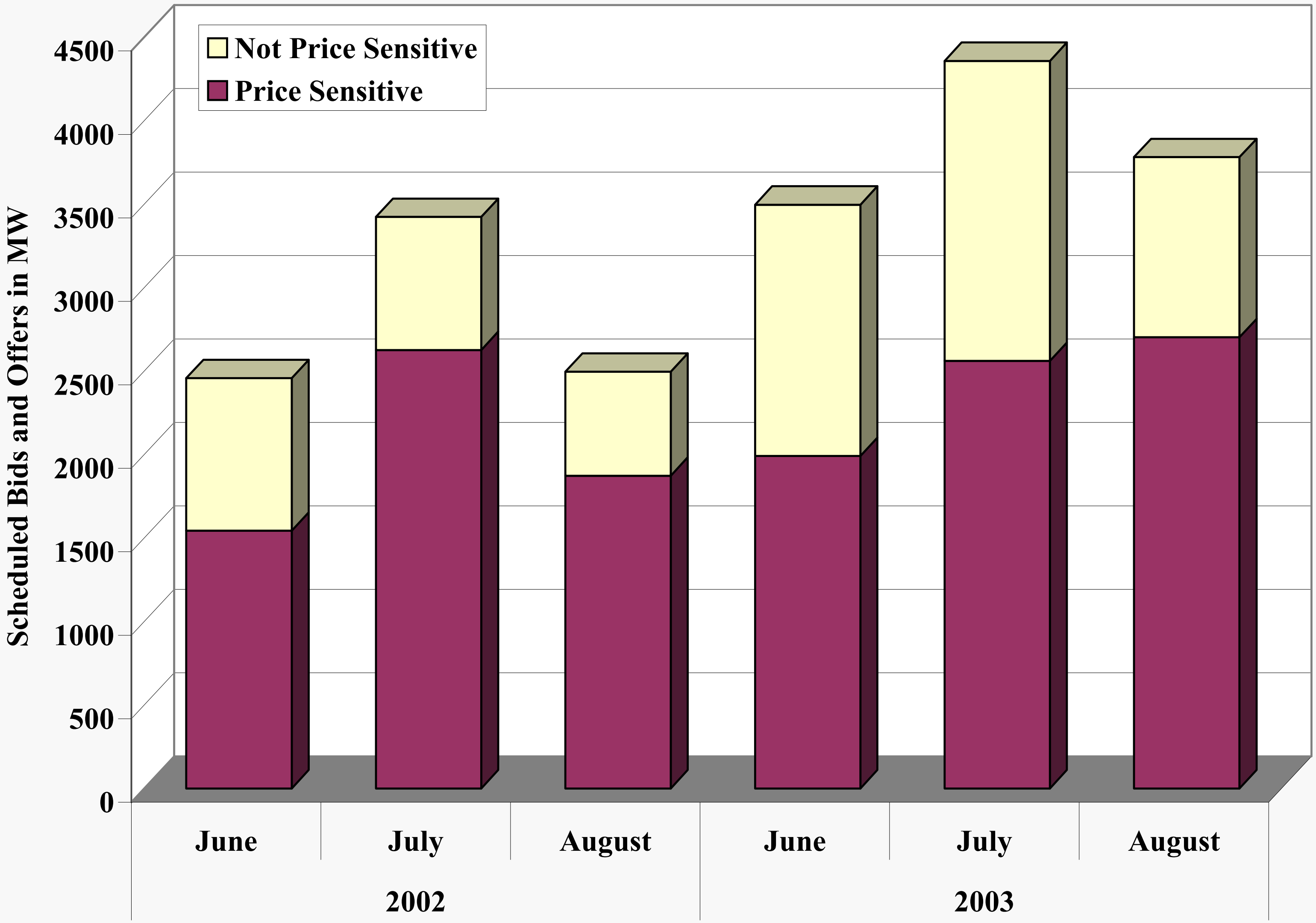
Virtual Trading Patterns

- 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 that are non-price sensitive.
  - ✓ Non-price sensitive bids and offers are those with bid prices less than 33% and greater than 300% of the actual price.
- The figure shows that average virtual bids and offer quantities increased by more than 1,000 MW in 2003, and that the majority remain price sensitive.

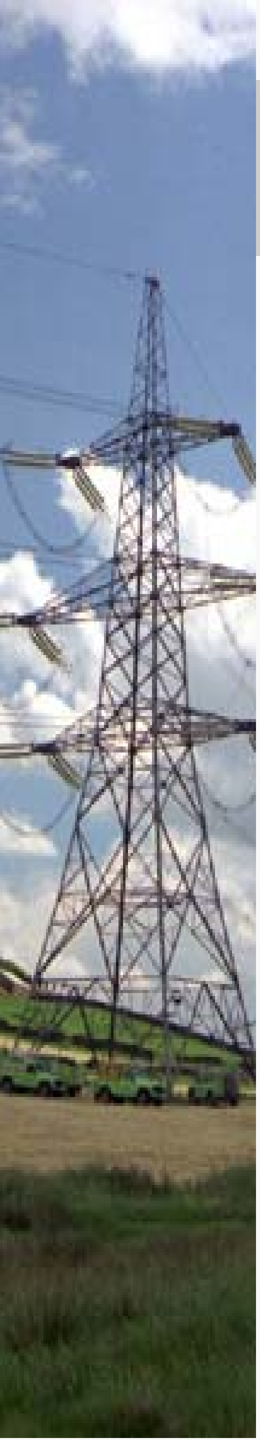


Price Sensitivity of Scheduled Virtual Load Bids and Supply Offers

New York State - Summer 2002 to 2003

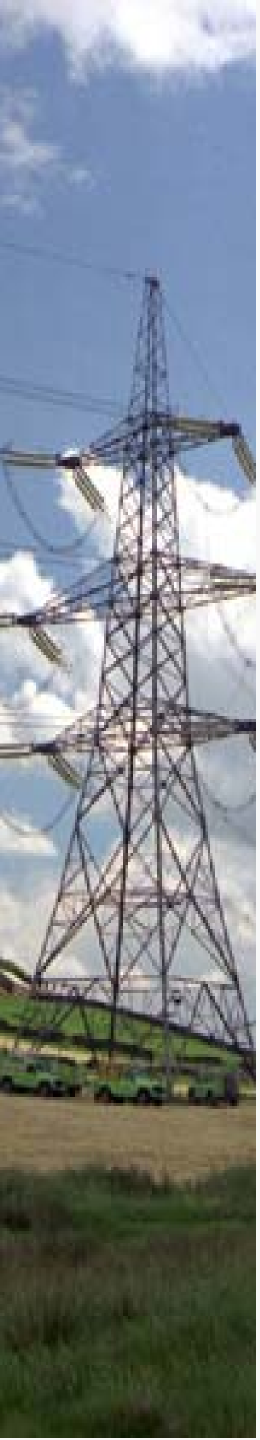


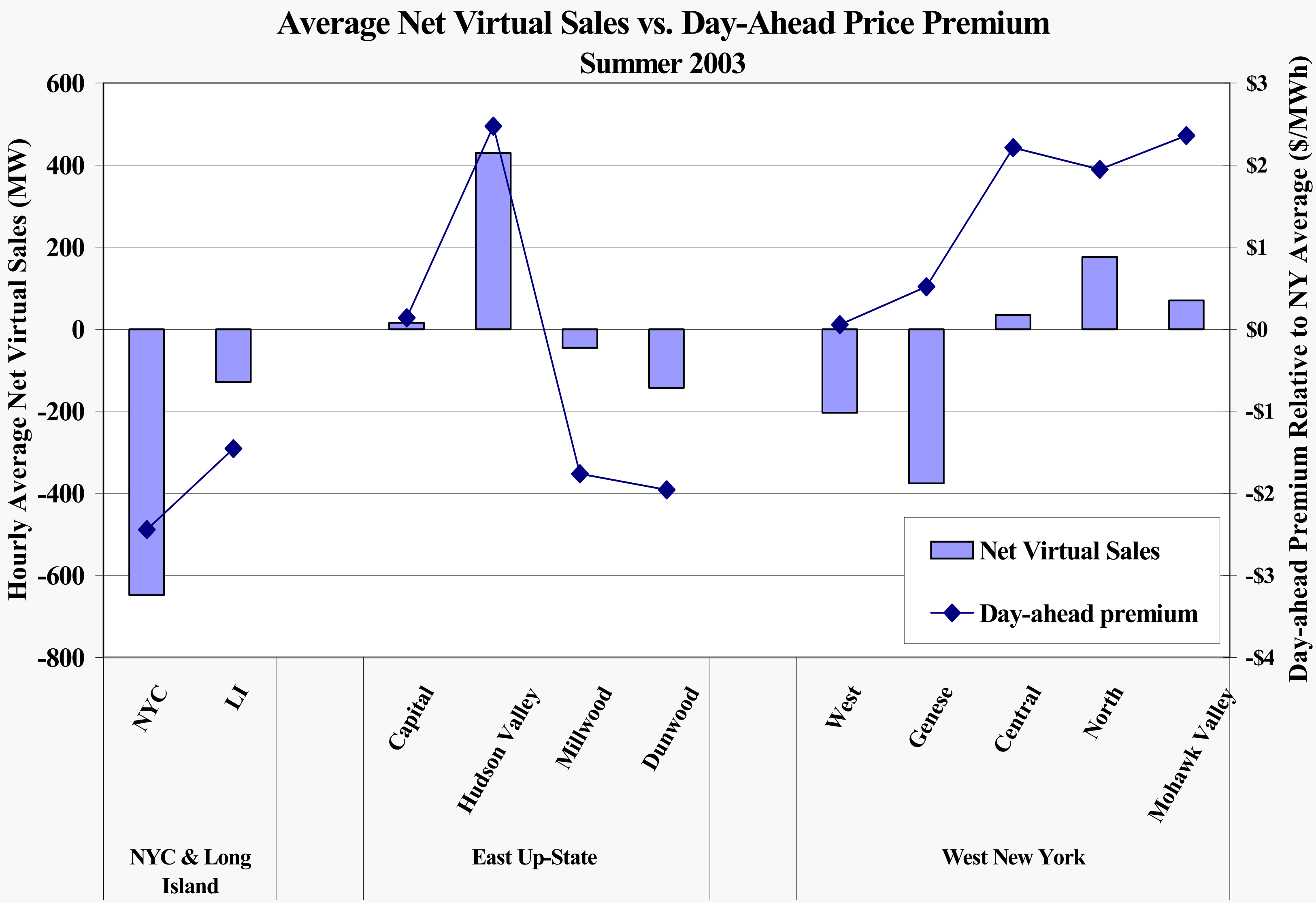
Note: August 2003 blackout hours excluded.



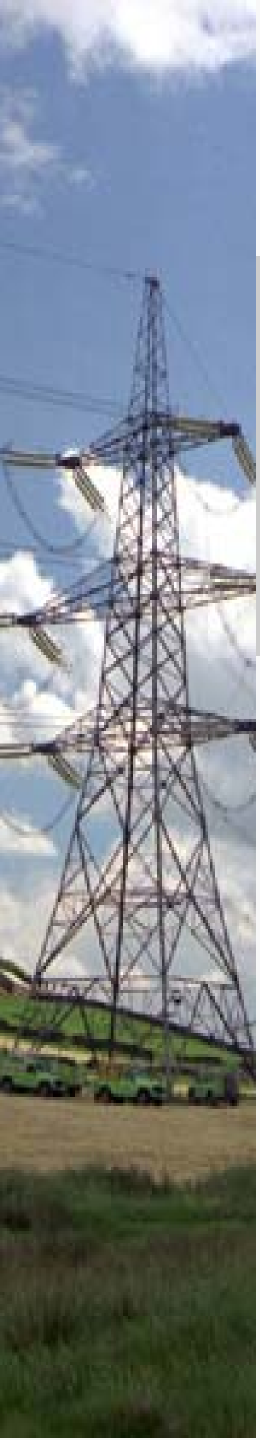
Virtual Trading Patterns

- The following figure examines the relationship of virtual trading to day-ahead to real-time price convergence by zone during the summer of 2003:
  - ✓ The bars show the average net virtual sales. Positive values indicate that virtual supply scheduled exceed virtual load scheduled, such as in Hudson Valley.
  - ✓ The line shows the day-ahead price premium in each zone relative to the state-wide average (equal to $2.22 during summer 2003).
- When the day-ahead price premium is high, participants will have incentives to schedule additional virtual supply, while participants will have incentives to schedule virtual load when the premium is low or negative.
- The results have been consistent with these incentives:
  - ✓ Net virtual purchases have been made in NYC and Long Island (virtual load schedules have exceed virtual supply schedules) where the day-ahead premium has been negative).
  - ✓ Net virtual sales have been made outside NYC and Long Island (virtual supply schedules have exceed virtual load schedules) particularly in the Hudson Valley.

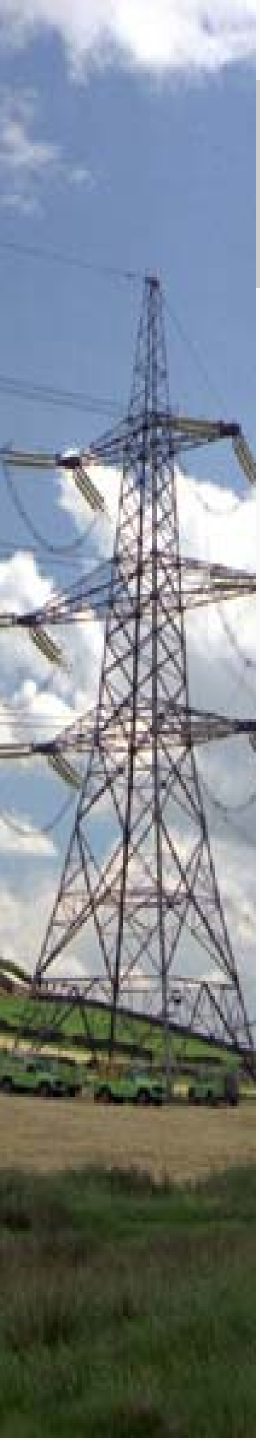




Note: August 2003 blackout hours excluded.



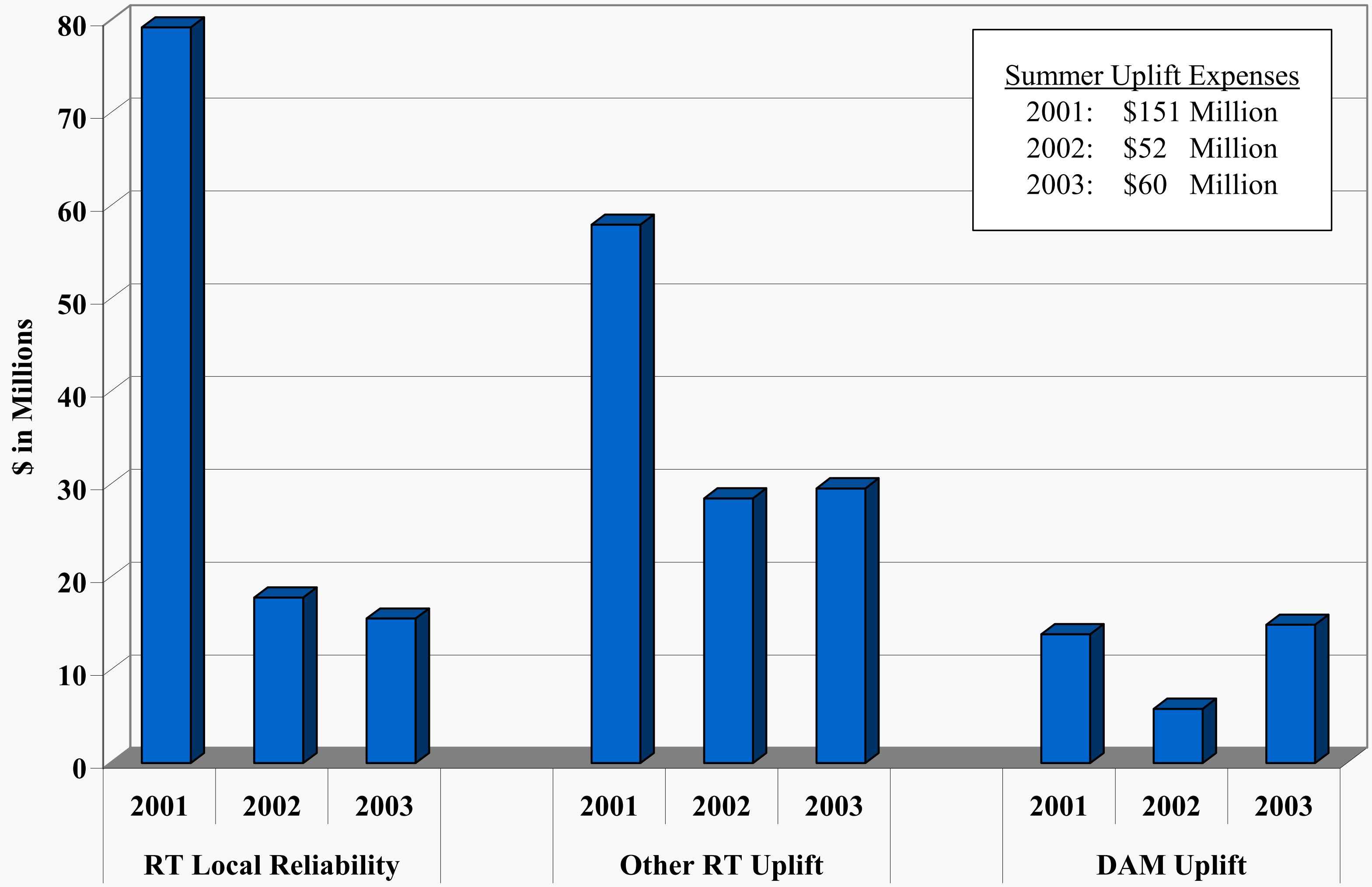
Out-of-Merit Commitment and Dispatch



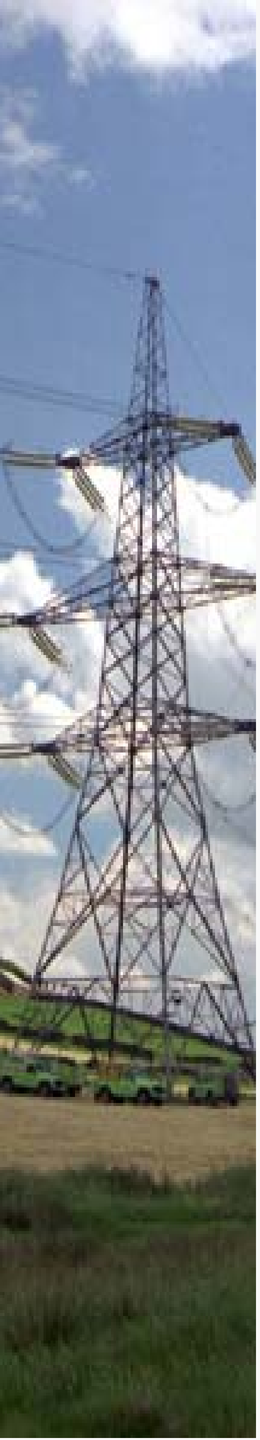
Uplift Expenses

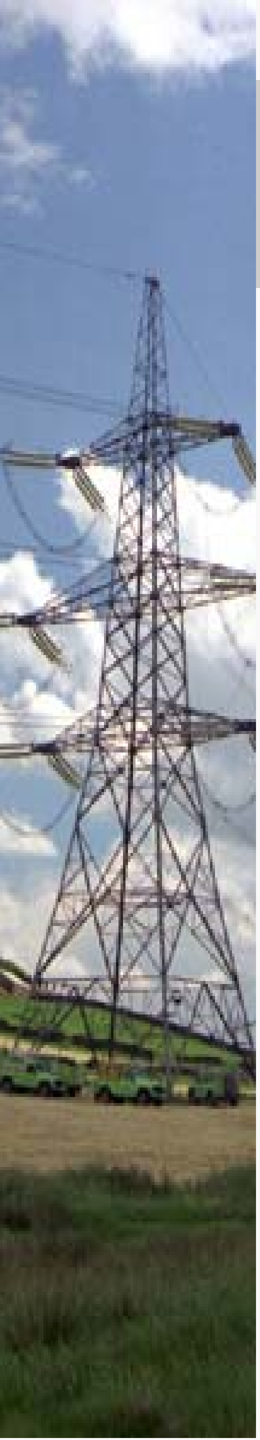
- The following figure shows that uplift costs have fallen sharply.
- Real-time local reliability uplift decreased 80% between 2001 and 2002 and slightly more in 2003, primarily the result of load-pocket modeling in NYC.
- Real-time non-local reliability uplift was reduced by half in 2002.
  - ✓ Out-of-merit (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 fell in 2002, but increased to previous levels in 2003.
  - ✓ 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.

Day-Ahead and Real-Time Uplift Expenses
Summer 2001 to 2003



Note: August 2003 blackout hours excluded.

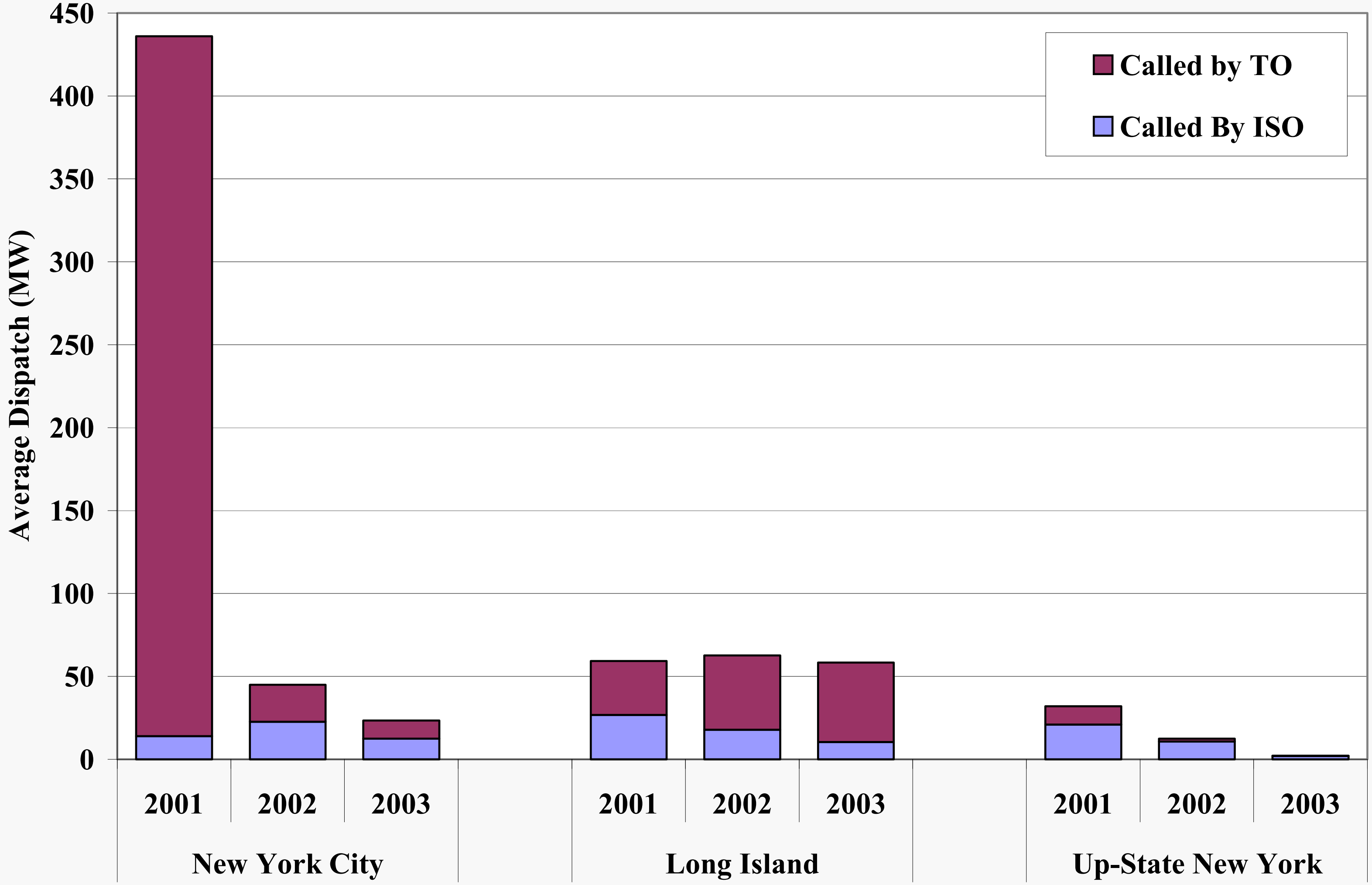




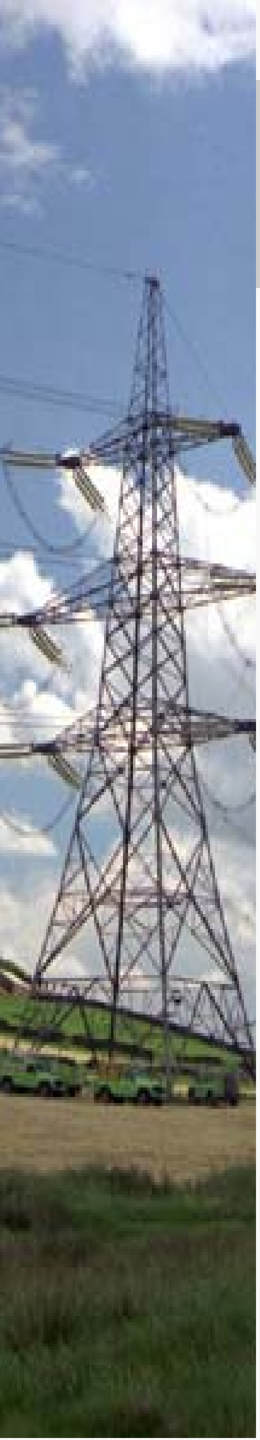
Real-Time Out of Merit Dispatch

- 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.
- Long Island units now account for two-thirds of OOM dispatches.
- The following figure shows the average quantity of OOM resources in different locations in New York. This figure shows:
  - ✓ OOM quantities have fallen substantially in 2003.
  - ✓ 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 2003, the average quantity of OOM dispatched was less than 100 megawatts.

Average Out-Of-Merit Dispatch Quantities
Summer 2001 to 2003

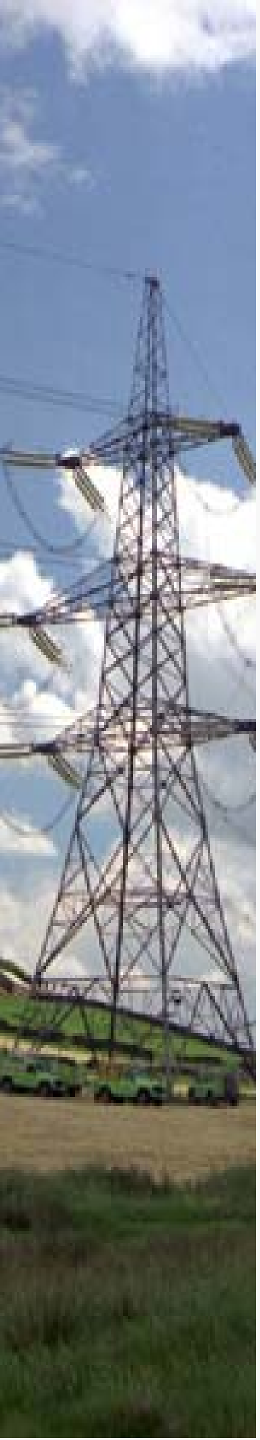


Note: August 2003 blackout hours excluded.

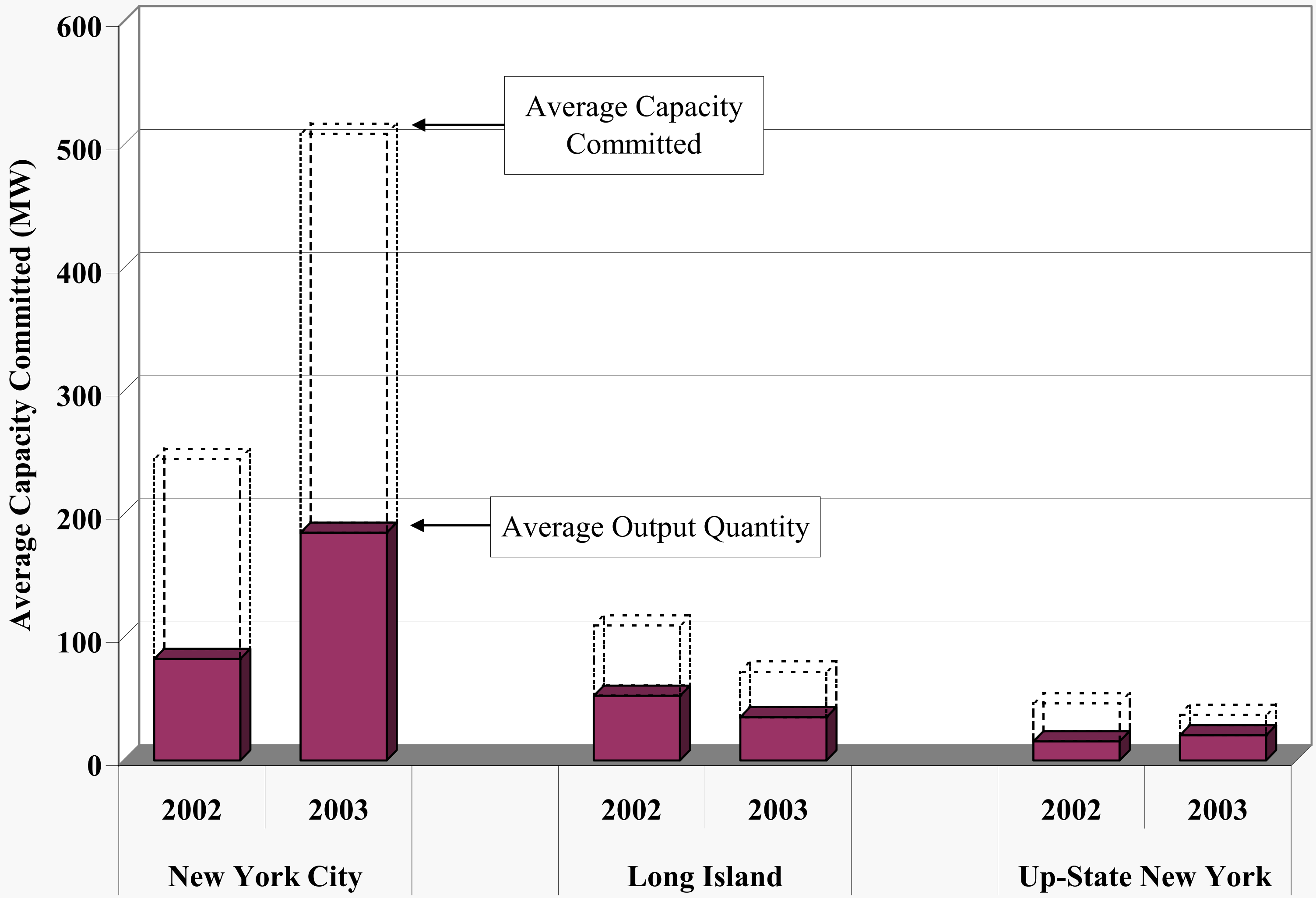


Supplemental Resource Evaluation

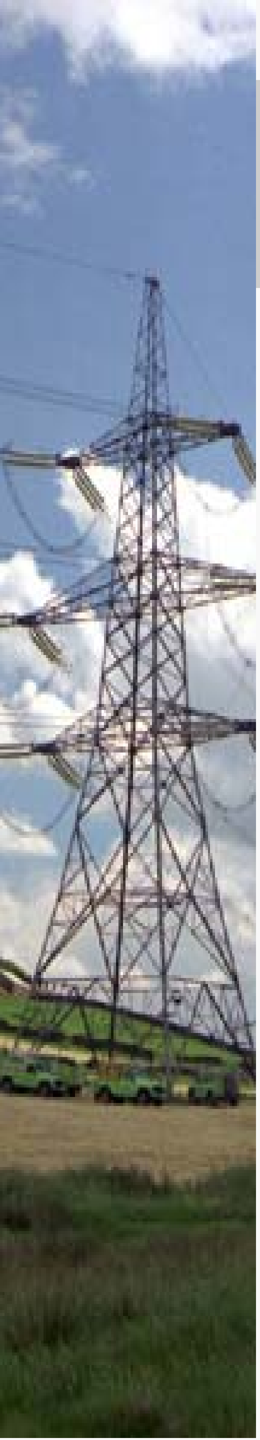
- Improvements in day-ahead modeling and commitment has reduced the quantity of SREs in New York City since 2002.
- However, the average quantity of capacity committed through SRE increased by 60% in 2003 relative to 2002.
  - ✓ A major reason for the SREs are nitrous oxides (NOx) emission limits that require certain baseload units to operate in order to allow gas turbines to operate.
  - ✓ More SREs were required for NOx due to lower DAM commitments to meet second contingency local reliability constraints due to lower summer load.
- We performed an analysis of uplift payments for 14 days in May 2003.
  - ✓ Uplift associated with the SREs called on these days were not accounted for as local reliability uplift.
  - ✓ SRE units accounted for 60% of non-local reliability uplift.



Supplemental Resource Evaluation Commitment
Summer 2002 to 2003

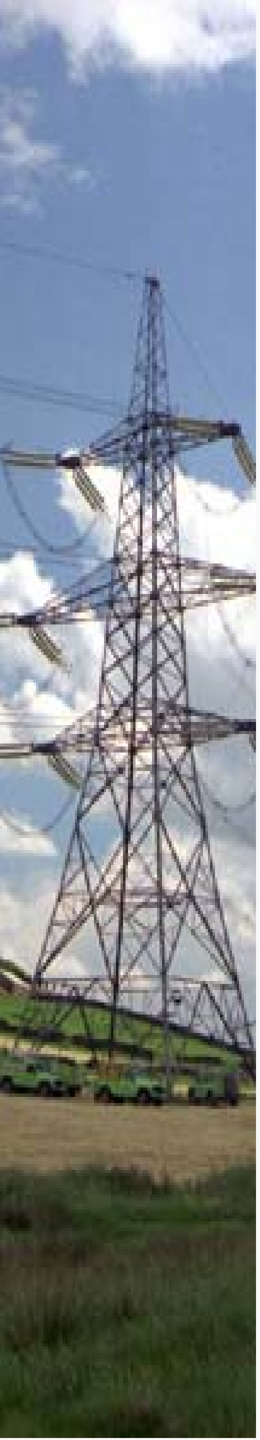


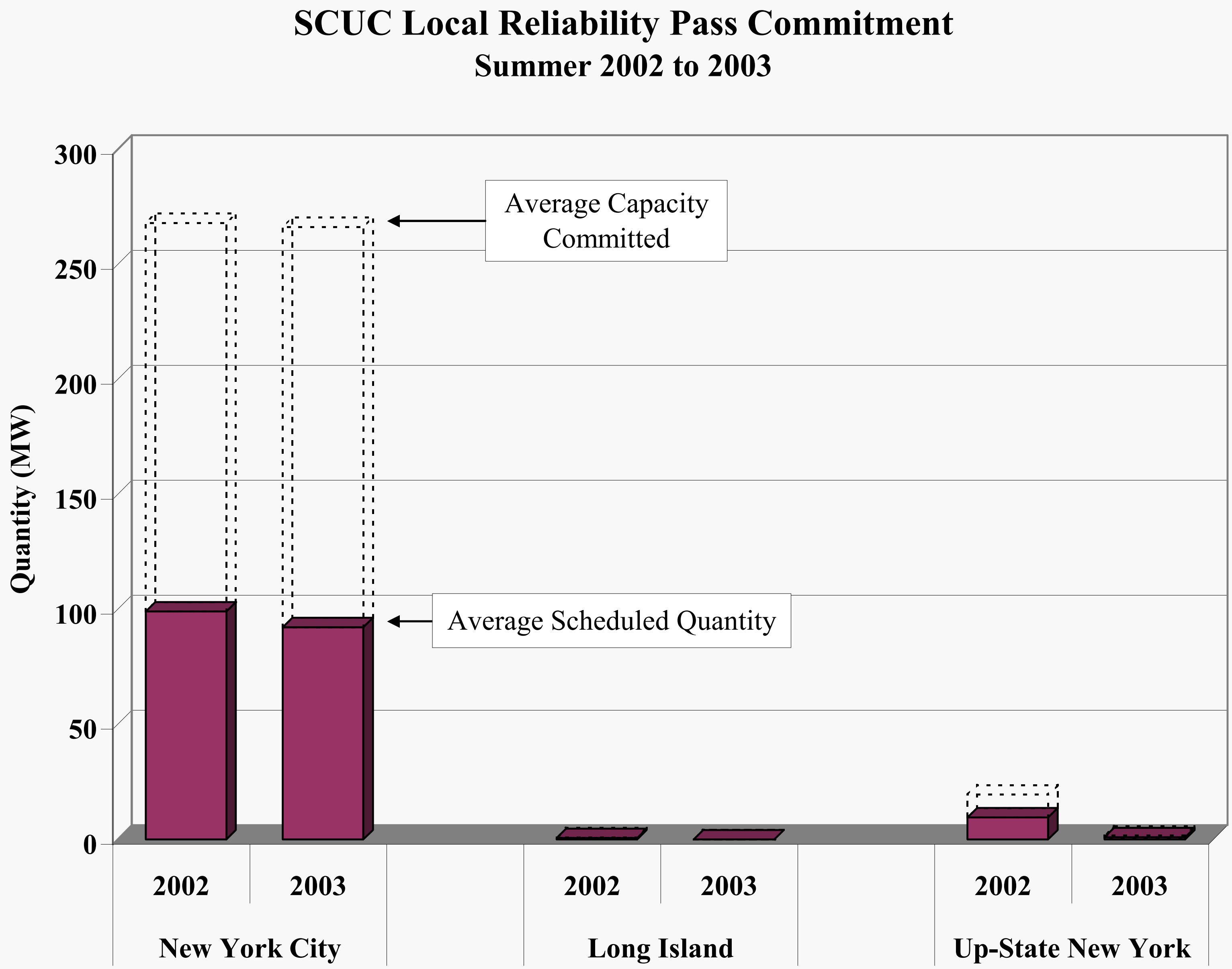
Note: August 2003 blackout hours excluded.



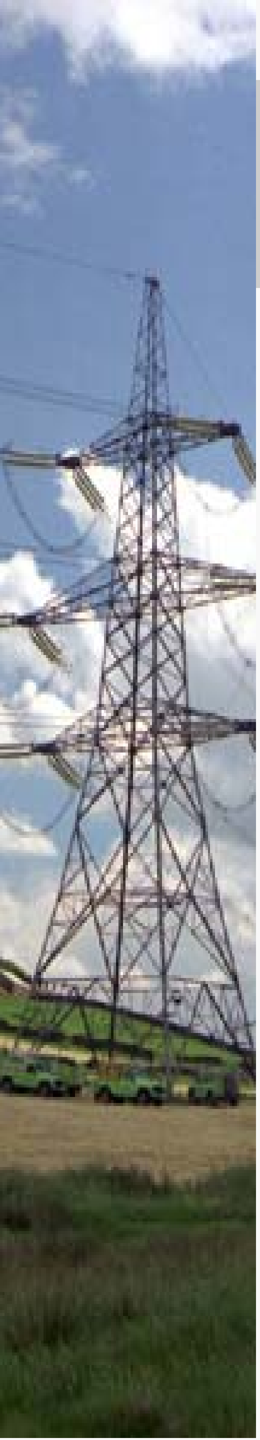
Day-Ahead Local Reliability

- The following figure shows the average quantity of commitments made by the SCUC for local reliability day-ahead.
  - ✓ The average capacity committed local reliability was more than 250 MW in Summer 2003, receiving day-ahead schedules of approximately 100 MW.
  - ✓ Virtually all of the local reliability commitments made by SCUC involved two units in New York City.
- The increase in day-ahead uplift in 2003 is not due to an increase in quantity of supplemental commitments, but primarily to increased fuel prices that raised minimum generation costs.
- 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.



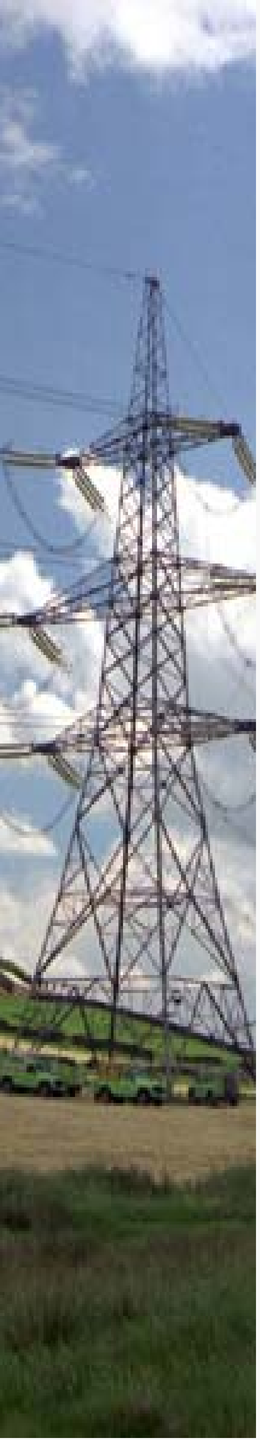


Note: August 2003 blackout hours excluded.

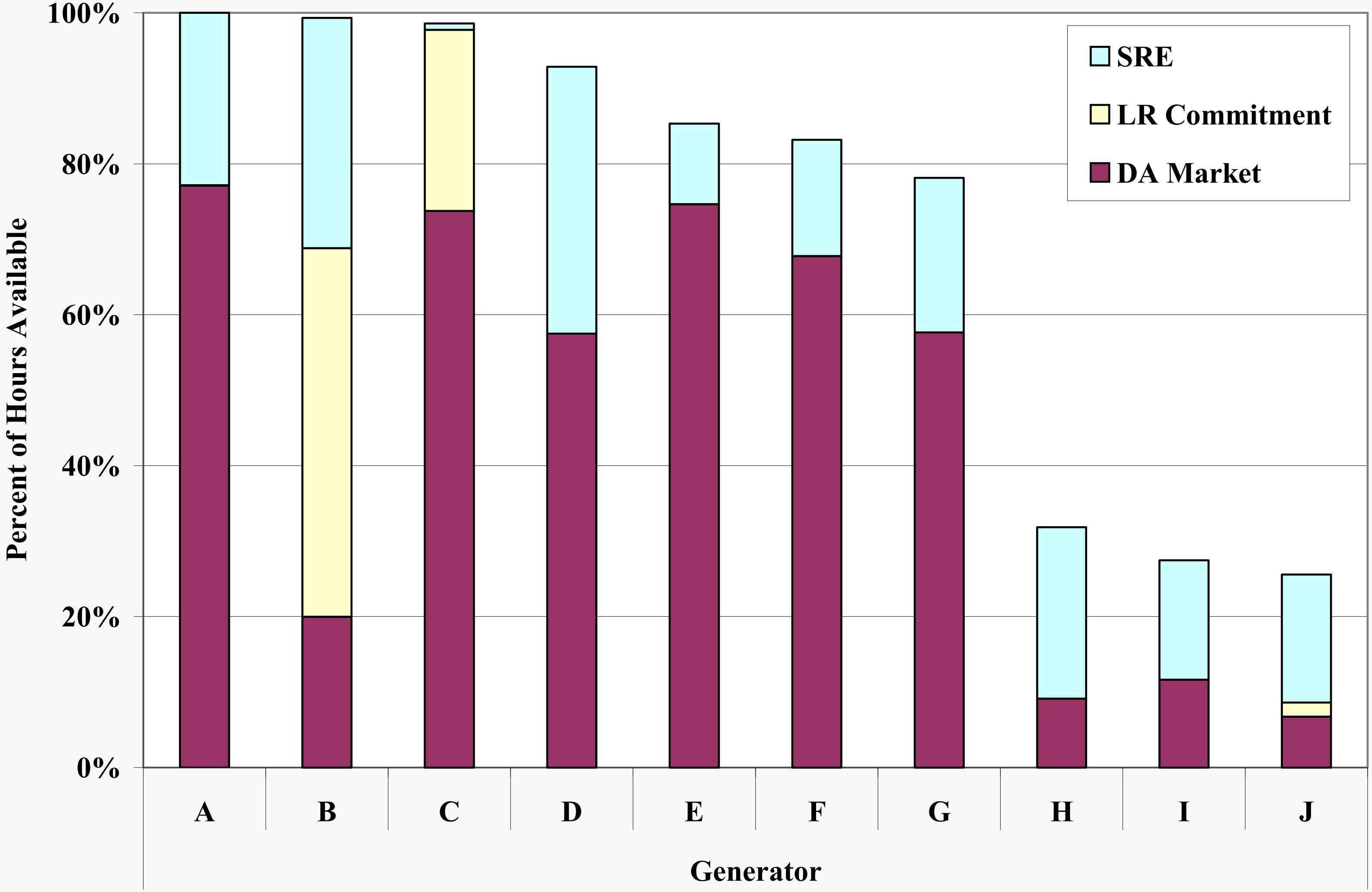


Units Committed for Local Reliability

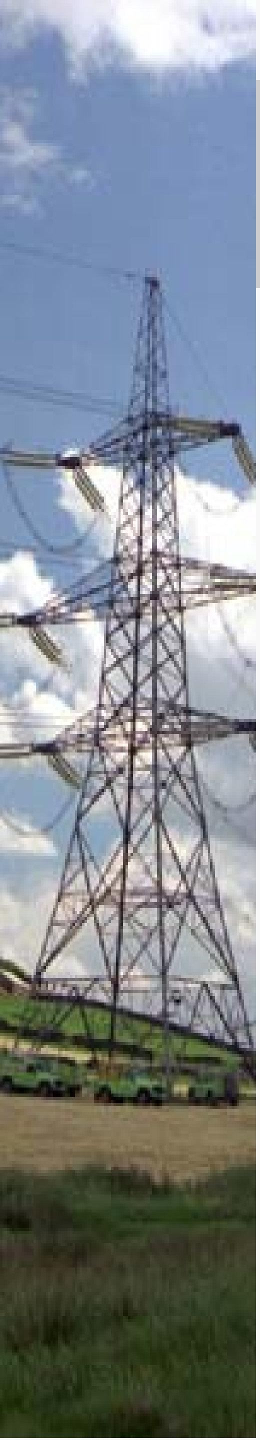
- We have also evaluated supplemental commitment at the individual unit level. The following figure shows the ten units with the highest commitment rates that are frequently for local reliability.
  - ✓ The values shown are the hours that each unit is committed as a percent of the hours that the unit is available (i.e., not on outage).
  - ✓ The units in the figure accounted for more than 80% of the SREs and 99% of local reliability commitment by SCUC.
  - ✓ Six of these units are in NYC, three are on Long Island, and one is located up-state.
- Four of these units analyzed appeared to be needed almost every day.
  - ✓ The top for 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 four units, which was committed in 98 percent of the hours, was committed through SRE or for local reliability in almost 80 percent of the hours.



Units Most Frequently Committed through SRE or Local Reliability Pass in SCUC -- Summer 2003



Note: August 2003 blackout hours excluded.



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 recommend that the ISO consider the feasibility and benefits of allow operators to pre-commit units needed for NOx compliance.
  - ✓ This would only involve affect 3 to 4 units;
  - ✓ This would reduce local reliability and non-local reliability uplift.
  - ✓ Any guarantee payments payable to the pre-committed units could be directly assigned as local reliability uplift.