2004 State of the Market Report
New York Electricity Markets

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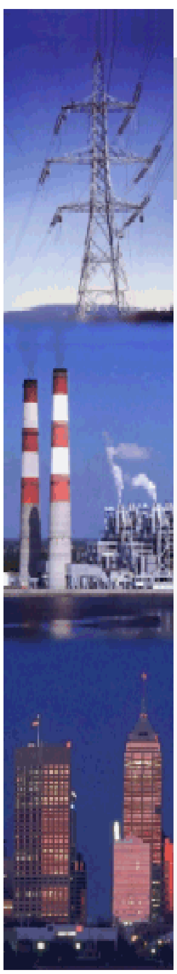
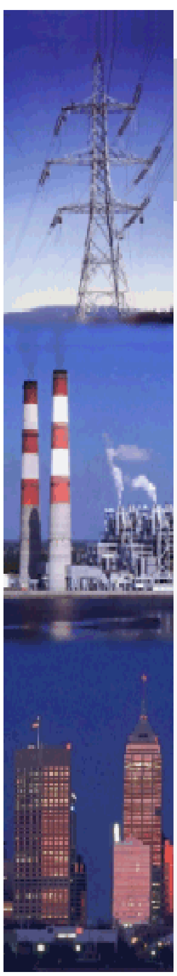


Introduction to the Annual Report

- This presentation provides highlights from the State-of-the-Market Report on the New York electricity markets for 2004.
- The market assessment addresses the following areas:
  - ✓ Energy market prices and outcomes
  - ✓ Market participant bid and offer patterns
  - ✓ External transactions scheduling
  - ✓ Capacity market
  - ✓ Ancillary services
  - ✓ Demand response programs

Summary of Conclusions

- The NYISO markets performed competitively in 2004 with no evidence of significant economic or physical withholding.
- Energy prices were higher in 2003 and 2004 than in to prior years due primarily to higher fuel prices.
- However, 2004 showed no instances of shortages and, but for the higher fuel prices, downward trends in energy prices overall due to:
  - ✓ Mild summer weather conditions that led to low peak loads; and
  - ✓ Surplus capacity conditions in upstate New York and New England;
- These trends caused the net revenue (market revenue – variable costs) available to a new generator in 2004 to continue to be less than the annual entry costs of a new gas turbine throughout New York.
- The capacity demand curve continues to result in stable capacity prices and facilitates price convergence between the various UCAP auctions.

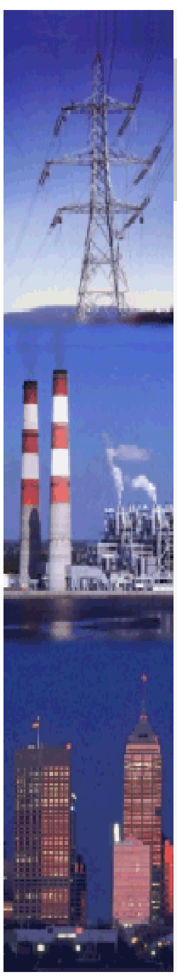


Summary of Conclusions

- Virtual trading volumes continued to increase in 2004, and improved convergence between the day-ahead and real-time prices outside of NYC load pockets.
- During 2004, the NYISO took several steps to eliminate the day-ahead congestion revenue shortfall and improve incentives for transmission owners to schedule maintenance outages efficiently.
- However, balancing congestion shortfalls continued to occur as a result of inconsistent transmission limits and loss modeling between the real time and day ahead markets.
- The NYISO's demand response programs provide a substantial amount of potential real-time load reductions when necessary.
  - ✓ In 2004, these were never called upon due to mild weather conditions.
  - ✓ However, participation by demand response in the capacity markets helped reduce capacity prices.

Summary of Conclusions

- To better address market power in New York City load pockets, the Conduct and Impact Test framework was implemented for these areas in the day-ahead market software.
  - ✓ This replaced the less sophisticated "ConEd" mitigation plan with a more selective framework.
  - ✓ The conduct and impact framework avoids mitigating generators when market power is not a concern.
- An analysis of the value of power transferred over major interfaces indicates that the most valuable transmission is in New York City and Long Island.
  - ✓ The value of constrained interfaces was approximately $400 million for transfers into and within New York City and into Long Island in 2004.
  - ✓ The value of constrained interfaces was approximately $70 million for the Central-East and eastern up-state constraints in 2004.
  - ✓ These amounts reflect the marginal value of transmission, not the benefits of completely relieving the congestion, which has been estimated to be less than $100 million for the state.



Areas of Potential Improvement and Recommendations

- In February 2005, the NYISO implemented enhanced real-time commitment and dispatch software (RTS).
  - ✓ The new real-time software runs on a platform used by the day-ahead market, providing opportunities to make the day-ahead and real-time market models more consistent.
  - ✓ It has the capability of scheduling external transactions and committing generation on a 15-minute rather than hourly basis.
  - ✓ The dispatch software (RTD), co-optimizes energy and ancillary services on a 5-minute basis.
  - ✓ We will be evaluating the performance of the markets under RTS following the summer 2005 and recommend in the meantime that NYISO continue to work to implement the full functionality offered by RTS.
- If price convergence within NYC does not improve with the implementation of RTS, we recommend virtual trading be expanded to load pockets or individual nodes.

Areas of Potential Improvement and Recommendations

- Supplemental commitments through the local reliability pass of SCUC and the SRE process are often required to meet local 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.
  - ✓ In the short-run, we continue to recommend that ISO allow operators to pre-commit certain units that are known to be needed prior to the day-ahead market.
- Real-time prices in adjacent regions continued to not be efficiently arbitraged in 2004.
  - ✓ Implementation of the coordination provisions that are under development with New England will address this issue.
  - ✓ Export fees were eliminated between New York and New England in 2005, which should help improve the interchange between markets.

Market Prices and Outcomes

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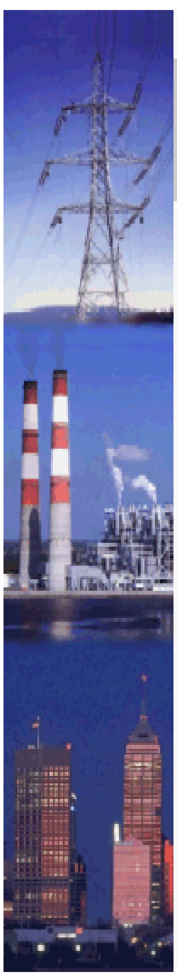
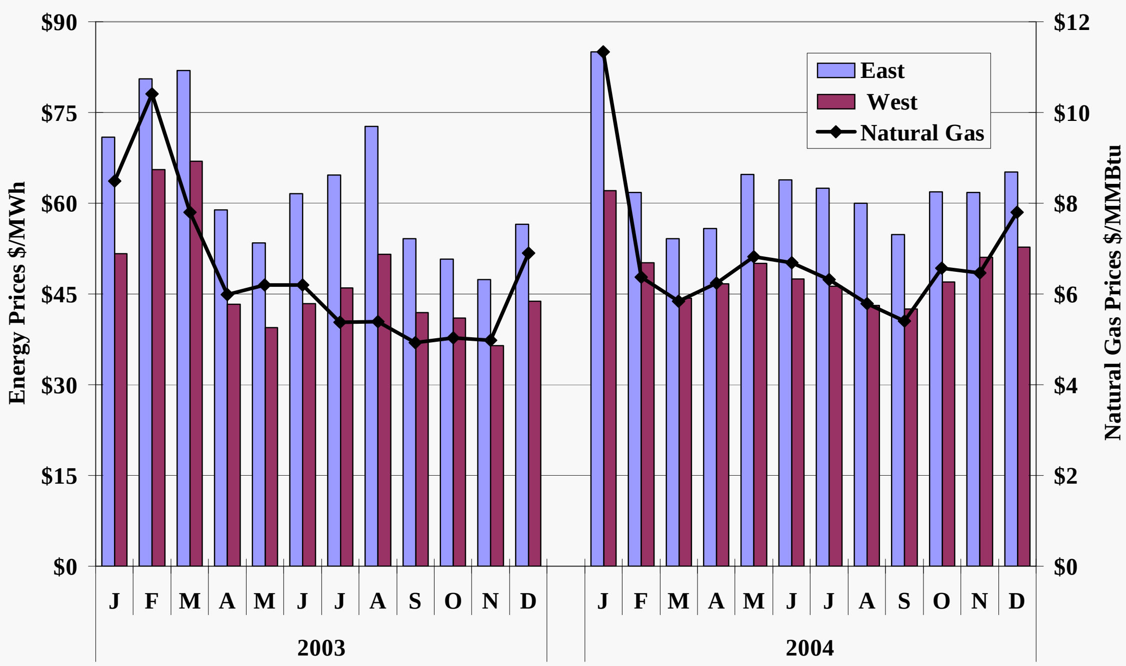
Fuel Prices and Energy Prices

- The following figure shows that monthly energy prices for 2003 to 2004 have been driven by fuel price trends, particularly natural gas prices.
- Electricity prices peaked in the winter months as natural gas prices hit unprecedented levels.
- The difference between East and West prices rises during the summer months as increased summer loads lead to additional congestion and losses.
- Electricity prices in 2004 remained elevated, reflecting continuation of high natural gas and oil prices:.
  - ✓ Natural gas prices rose an additional 5 percent in 2004 after increasing 70 percent in 2003.
  - ✓ The correlation of energy prices with oil and gas prices is expected since a) fuel costs represent the majority of most generators' variable production costs, and b) oil and gas units are on the margin in most hours.

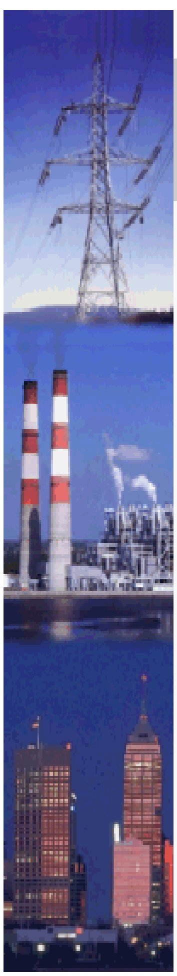


Energy and Natural Gas Prices 2003 – 2004

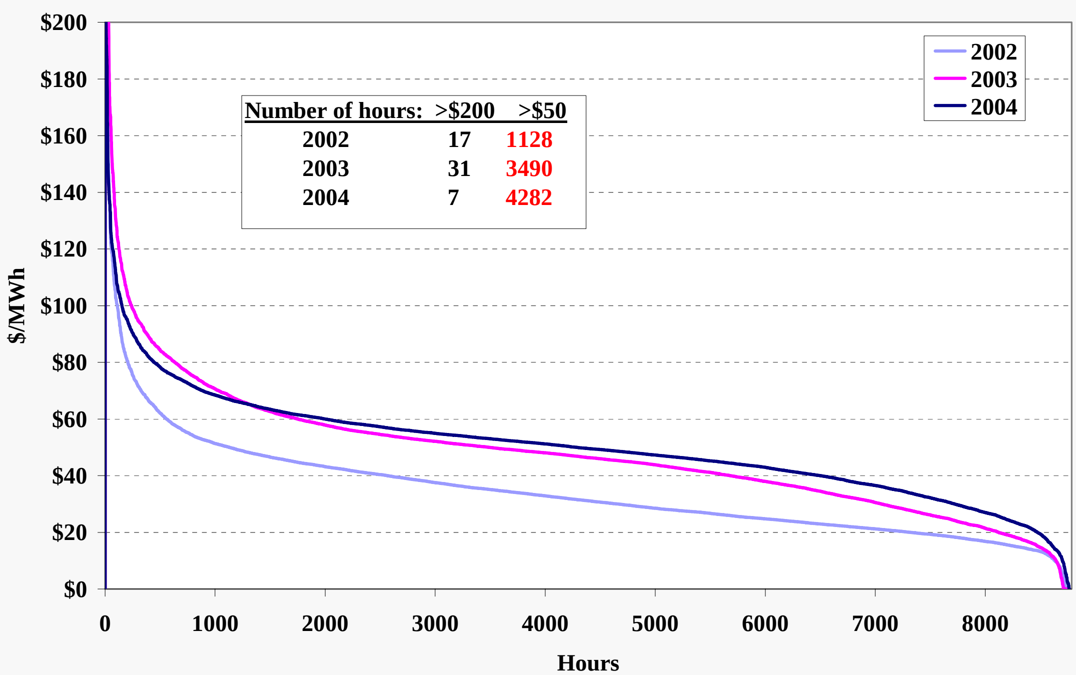


Energy Prices in 2004

- The following figures show real-time price duration curves for 2002 to 2004 in all hours and the highest priced five percent of hours in each year.
  - ✓ These curves show the number of hours when the load-weighted price for New York State is greater than the level shown on the vertical axis.
- In 2004, prices were generally higher than in the previous two years although peak prices were substantially milder:
  - ✓ In 2004, there were more than 4200 hours with prices above $50, compared to about 3400 in 2003, and less than 1100 hours in 2002.
  - ✓ This general rise in prices over the wide array of load conditions is attributable to the higher fuel prices which continued into 2004.
- In 2004, the trend toward fewer and smaller price spikes continued:
  - ✓ In 2004, there were only 7 hours where prices exceeded $200 and 1 hour where the price reached $500.
  - ✓ The lower quantity and magnitude of price spikes was primarily due to mild weather conditions during the summer 2004.

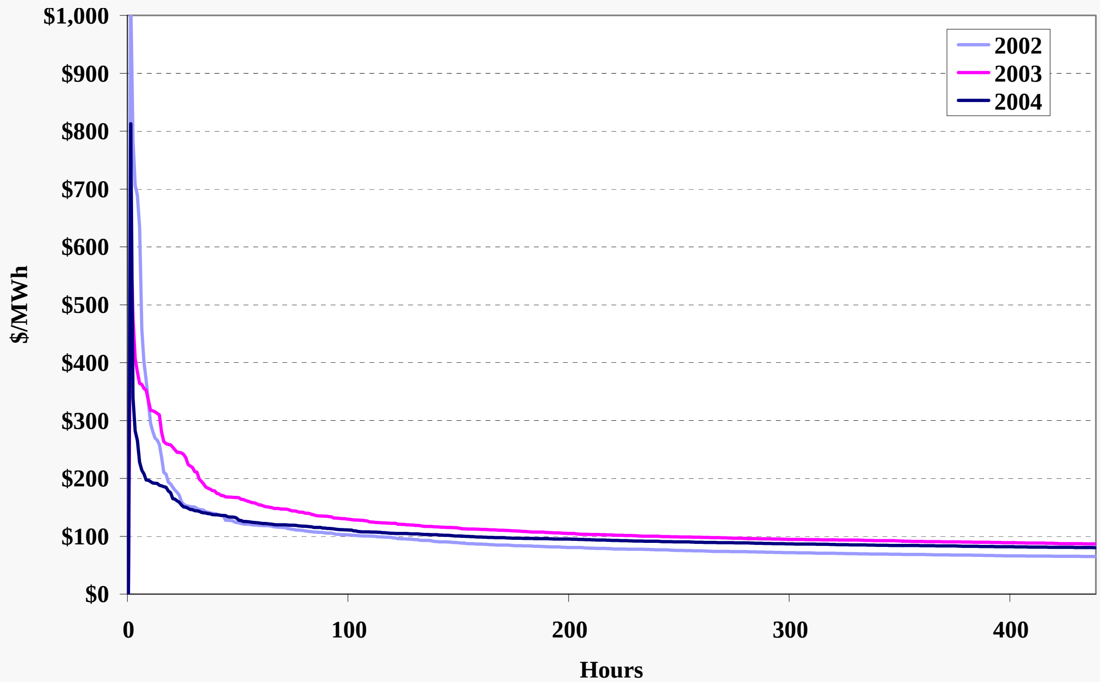


Price Duration Curves 2002 – 2004
New York State Average Real-Time Price



Based on calculations provided by NYISO Market Monitoring and Performance

Price Duration Curves in Highest 5% of Hours
New York State Average Real-Time Price



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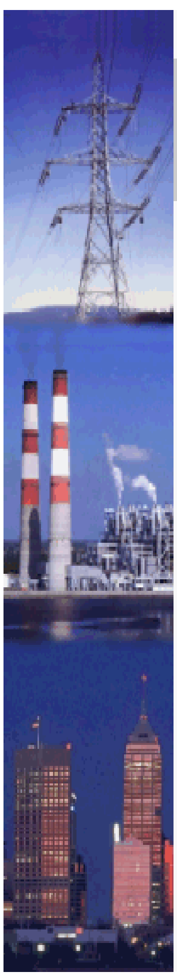
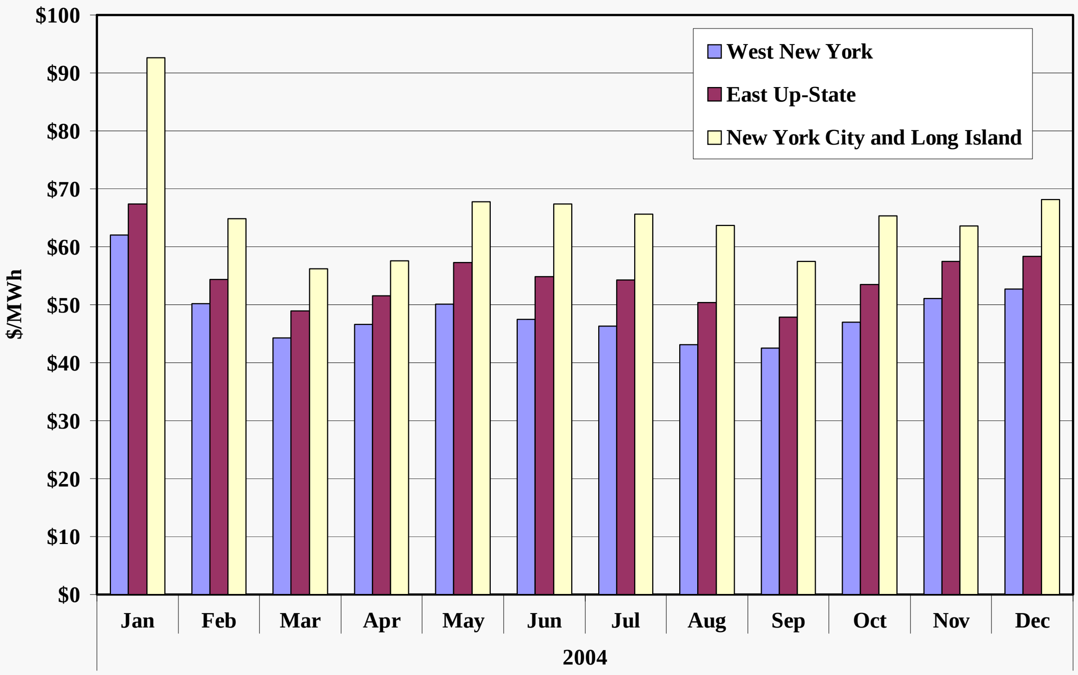
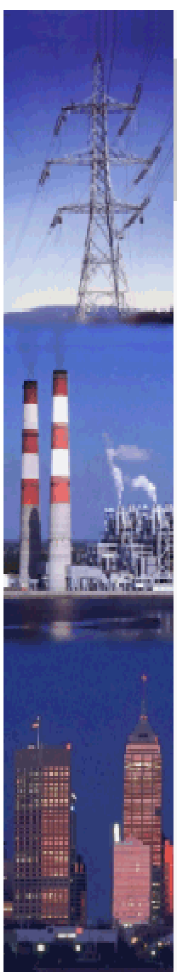


Average Day Ahead Prices

- The next figure presents average day-ahead energy prices by month in west NY, east NY upstate, and NYC/Long Island for 2004.
- Prices in the east exceed prices in the west by an average of $6.06 per MWh due to:
  - ✓ Transmission losses,
  - ✓ Central-East congestion, and
  - ✓ Congestion from the Capital region to areas just outside New York City.
- There are constraints into New York City, as well as local load pockets within the City, which raise average prices inside the constraints.
  - ✓ Price differences between the City and the eastern upstate region averaged $11.18/MWh in 2004.
  - ✓ This price difference peaked in January due to dependence on the margin in NYC on inefficient gas turbine units that caused prices to be disproportionately impacted by the spike in natural gas prices.

Average Day-Ahead Energy Prices - 2004

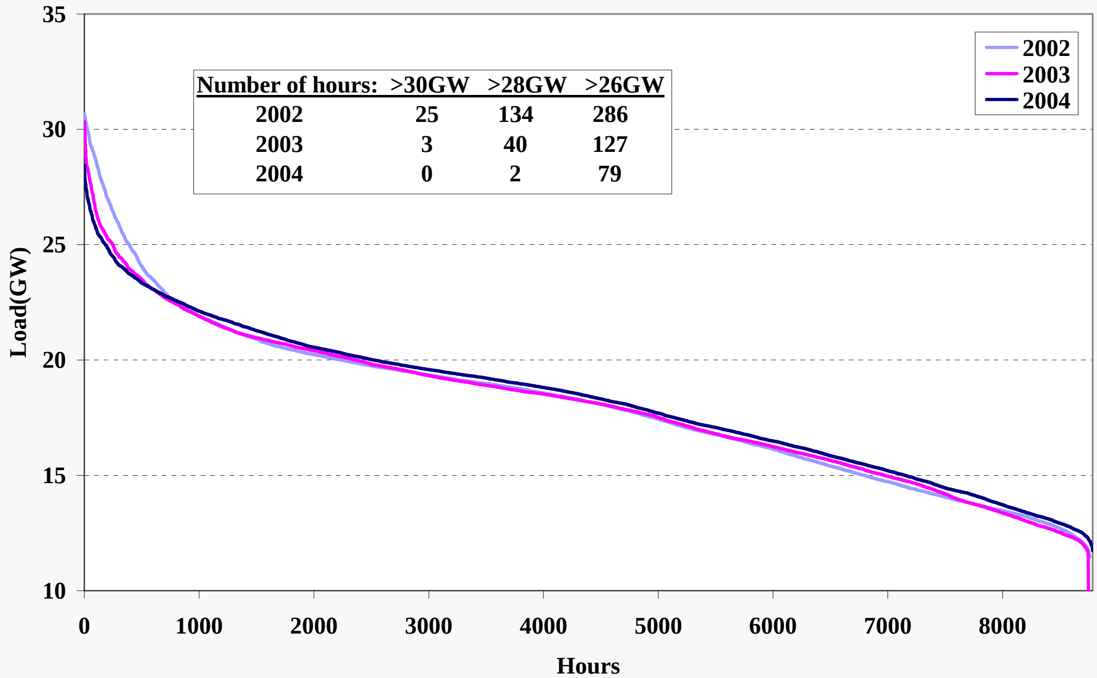




Load Profile

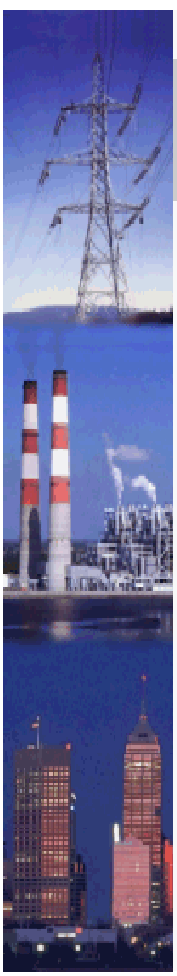
- The next two figures shows annual and summer load duration curves for New York.
  - ✓ These curves show the number of hours in which the load is greater than the level indicated on the vertical axis.
- The absence of severe price spikes was primarily due to mild summer loads in 2003 and particularly in 2004.
  - ✓ There were no hours in 2004 and only 3 hours in 2003 when actual loads exceeded 30 GW, compared to 25 hours in 2002.
  - ✓ In 2004 there were only 2 hours when loads exceeded 28 GW compared to 38 hours in 2003 and 133 hours in 2002.

Load Duration Curves
New York State Hourly Average Load

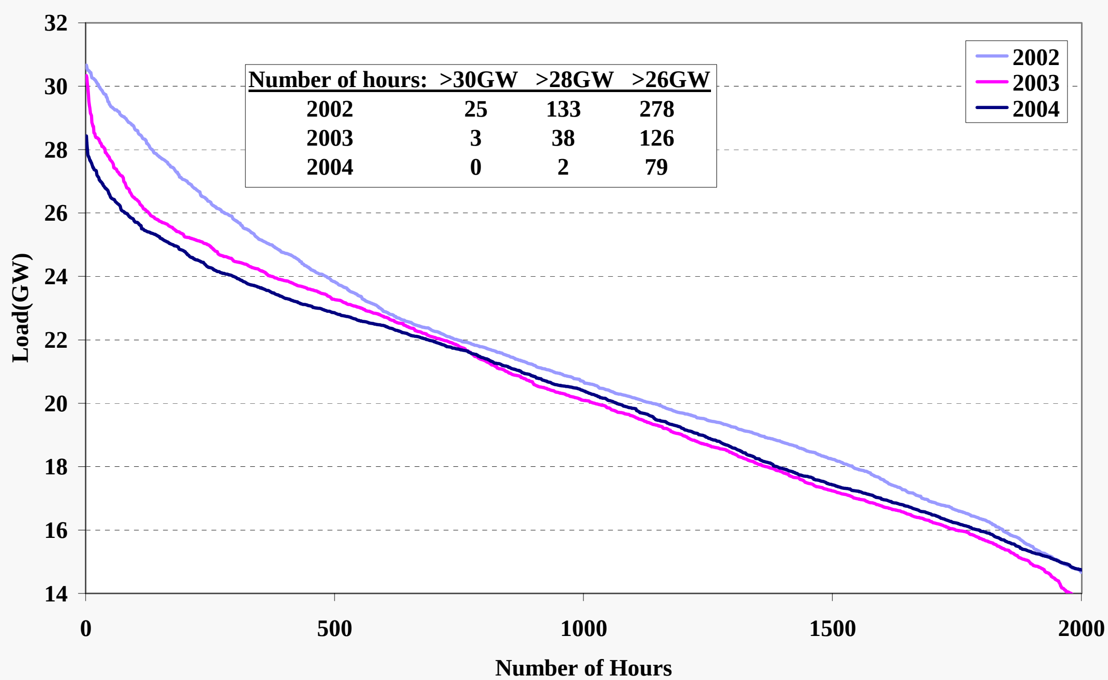


Number of hours:	>30GW	>28GW	>26GW
2002	25	134	286
2003	3	40	127
2004	0	2	79

Based on calculations provided by NYISO Market Monitoring and Performance



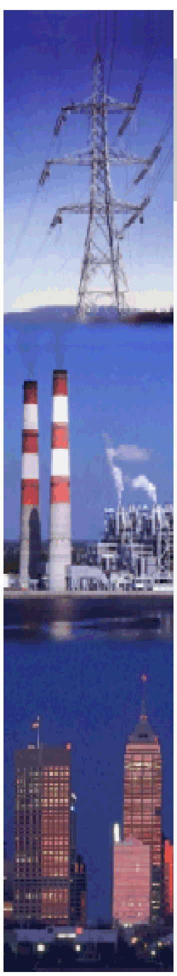
Load Duration Curves for New York
Summer 2002 through Summer 2004



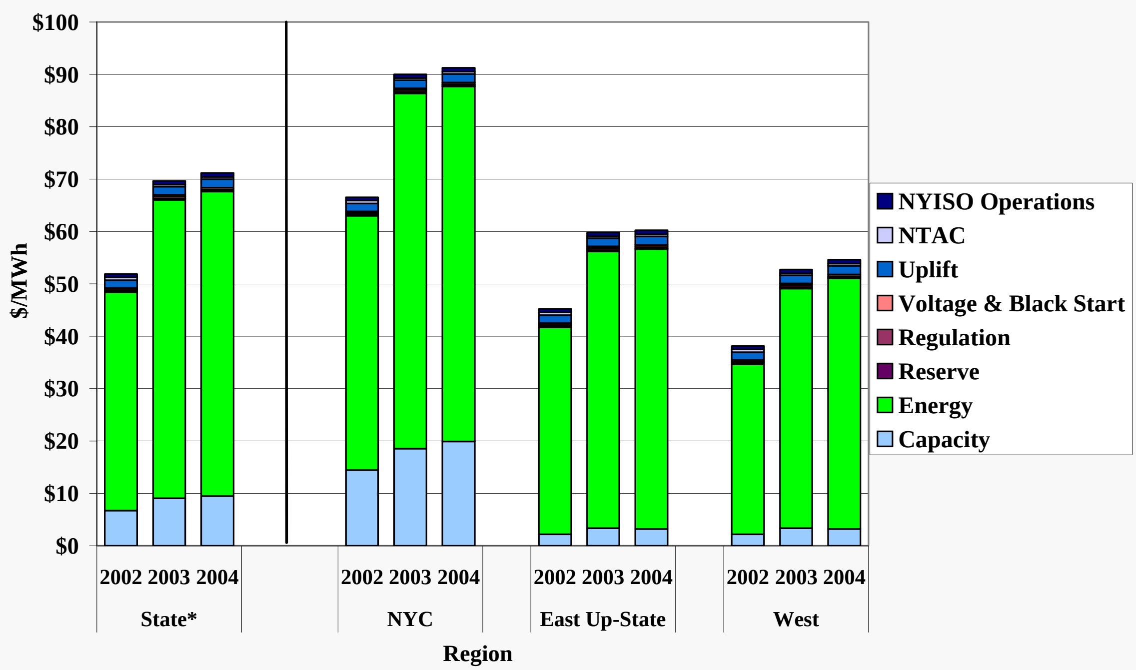
Number of hours:	>30GW	>28GW	>26GW
2002	25	133	278
2003	3	38	126
2004	0	2	79

All-In Energy Prices

- The following figure calculates an "all-in" price that includes the costs of energy, ancillary services, capacity, and other costs.
  - ✓ The all-in price is calculated for various locations within New York since both capacity and energy prices vary substantially by location.
  - ✓ The capacity component is calculated by multiplying the average capacity price by the load obligations in each area, and dividing by total energy consumption.
  - ✓ Real-time energy prices are used for this metric.
- This figure shows that the all-in price rose considerably in 2003 for all locations and remained relatively constant in 2004.
  - ✓ This increase is primarily caused by higher energy prices in 2003, which rose 36 percent in 2003 due to higher fuel prices.
  - ✓ Fuel prices increased an additional 5 percent in 2004, but the impact was mitigated by mild summer weather.
  - ✓ The capacity component also rose in 2003 due primarily to: a) rising forecasted peak load resulting in a higher obligations, and b) additional purchases under the demand curve.



Average All-In Price
Costs per MWh of Load, 2002 - 2004



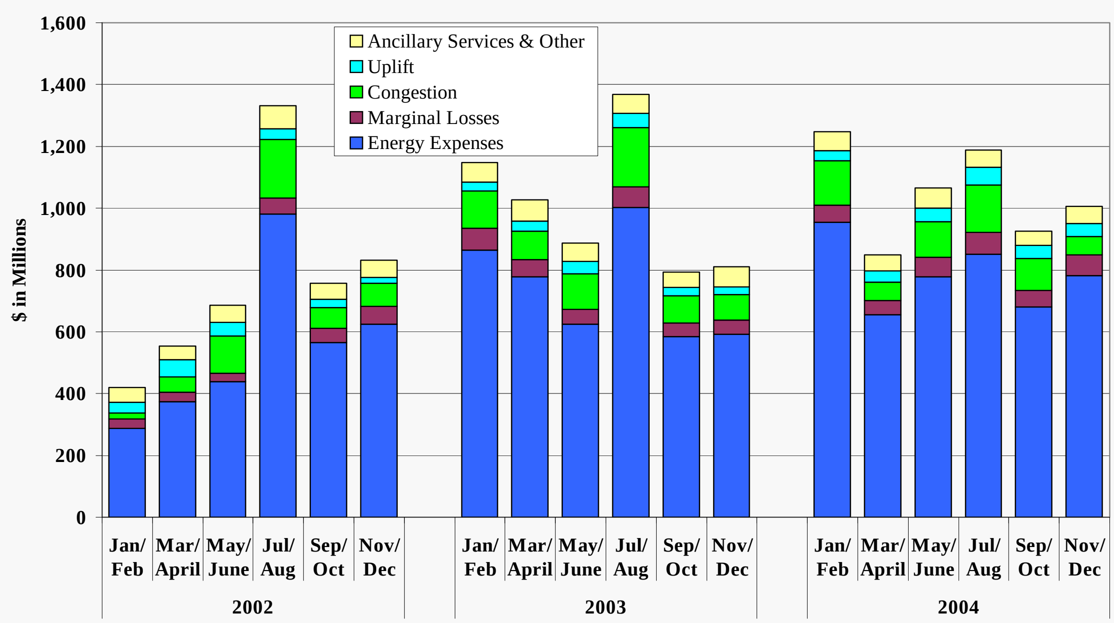
*Capacity portion of state price excludes Long Island.

Based on calculations provided by NYISO Market Monitoring and Performance

Total Electricity Costs in the New York Markets

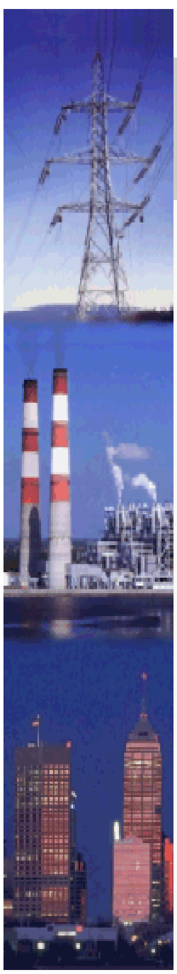
- The following figure shows the total expenses for market participants through the NYISO from 2002 to 2004. This excludes energy costs for the 45 percent of load scheduled through physical bilateral transactions.
- The total expenses in 2004 were approximately \$6.3 billion – an increase of about five percent over 2003 and more than one-third over 2001 and 2002.
- The primary reasons for the increase in total expenses were:
  - ✓ Continuing escalation of fuel costs in 2004, which lead to higher energy prices.
  - ✓ Reduced scheduling of physical bilateral transactions, which increases share of energy in New York settled through the NYISO markets.
    - – As an aside, this does not mean that loads are more exposed to the NYISO market prices since they can execute forward financial contracts that are not reflected in the NYISO settlements.

New York Electricity Market Expenses 2002 - 2004

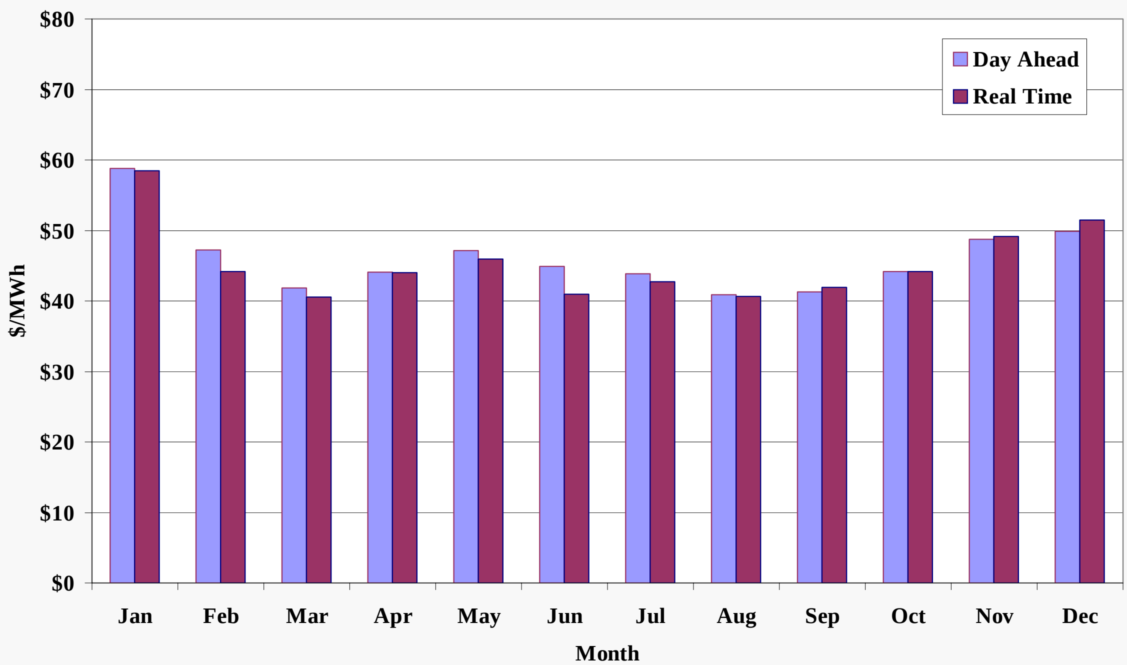


Day-Ahead and Real-Time Energy Prices

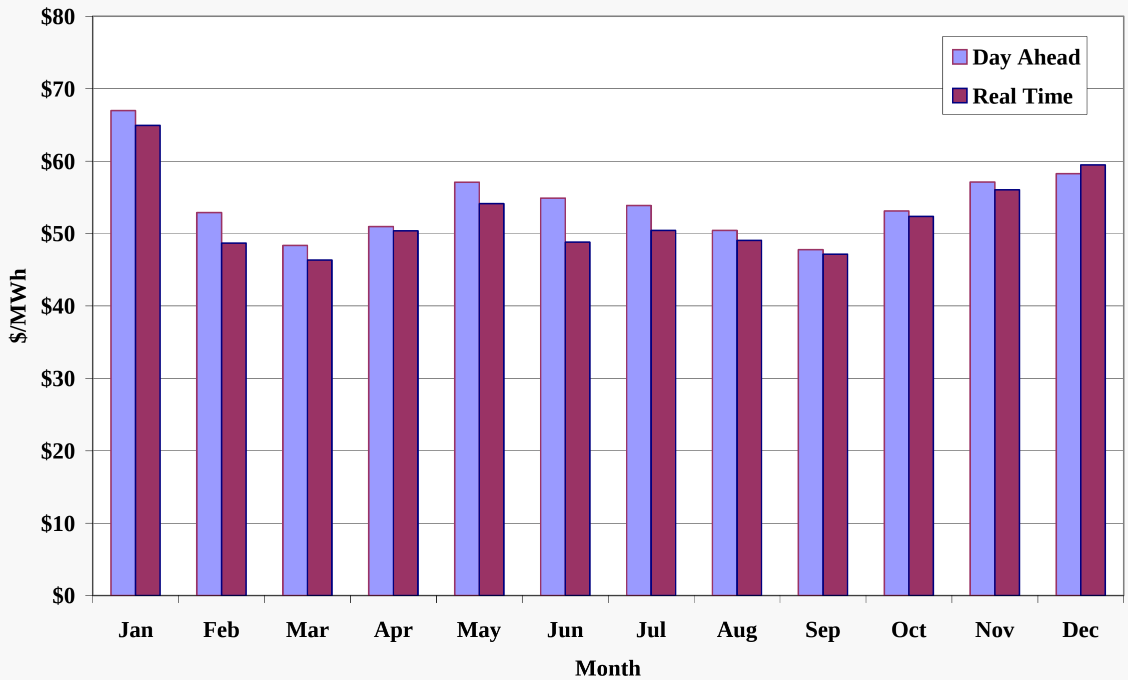
- The following three figures show monthly average day-ahead and real-time energy prices in the West zone, Hudson Valley, and New York City.
- The results show that:
  - ✓ A premium remains in the day-ahead market in the areas of up-state NY, particularly the Hudson Valley (4%),
  - ✓ In New York City, there is a slight premium in the real-time market (3%). A similar premium was experienced on Long Island.
  - ✓ This pattern has led to net virtual supply in up-state New York and net virtual load in New York City and Long Island.
- The absolute value of the positive hourly divergence between day-ahead and real-time prices decreased in upstate markets from 2003 to 2004.
  - ✓ This is an expected result due to more active virtual trading and reduced price volatility associated with the milder peak load conditions.

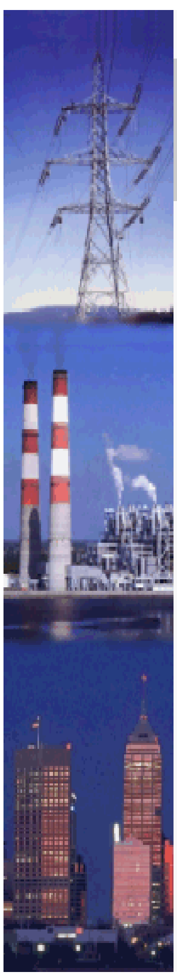


Average Monthly Day-Ahead and Real-Time Energy Prices West Zone 2004

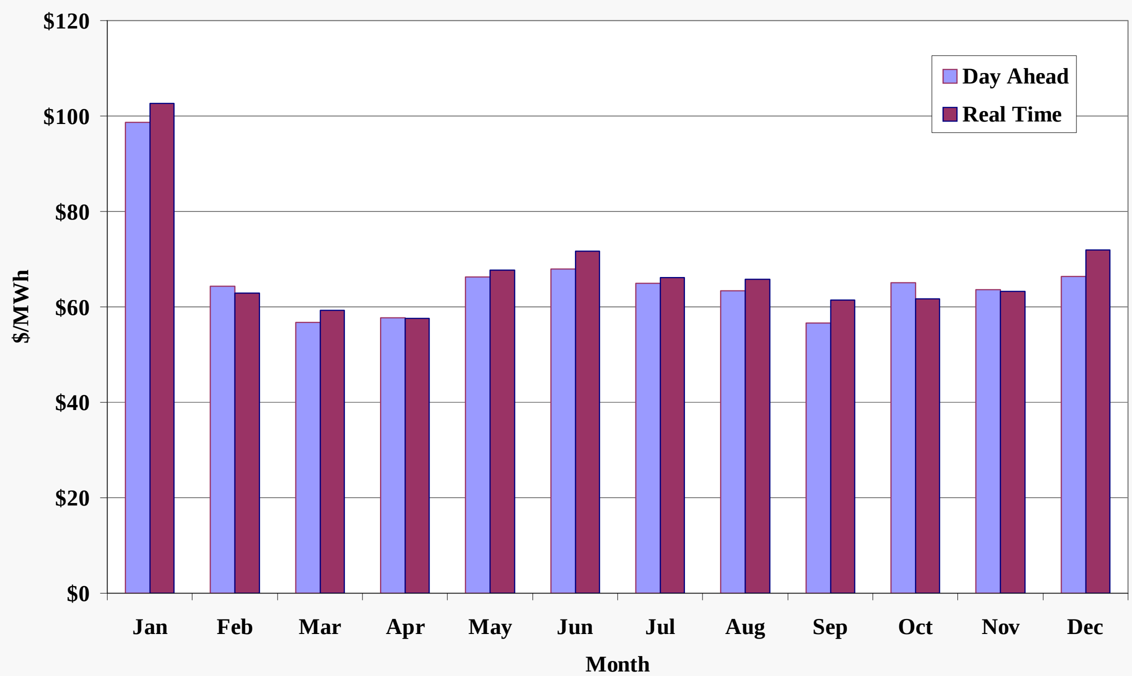


Average Monthly Day-Ahead and Real-Time Energy Prices
Hudson Valley 2004



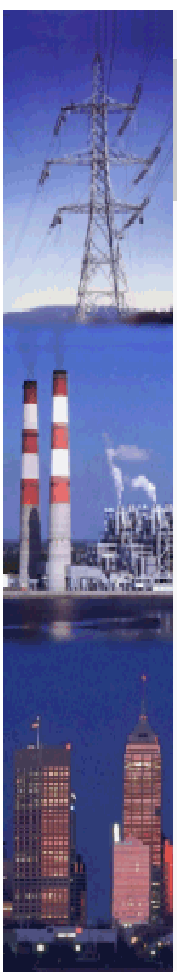


Average Monthly Day-Ahead and Real-Time Energy Prices
New York City 2004



Price Convergence in the Load Pockets

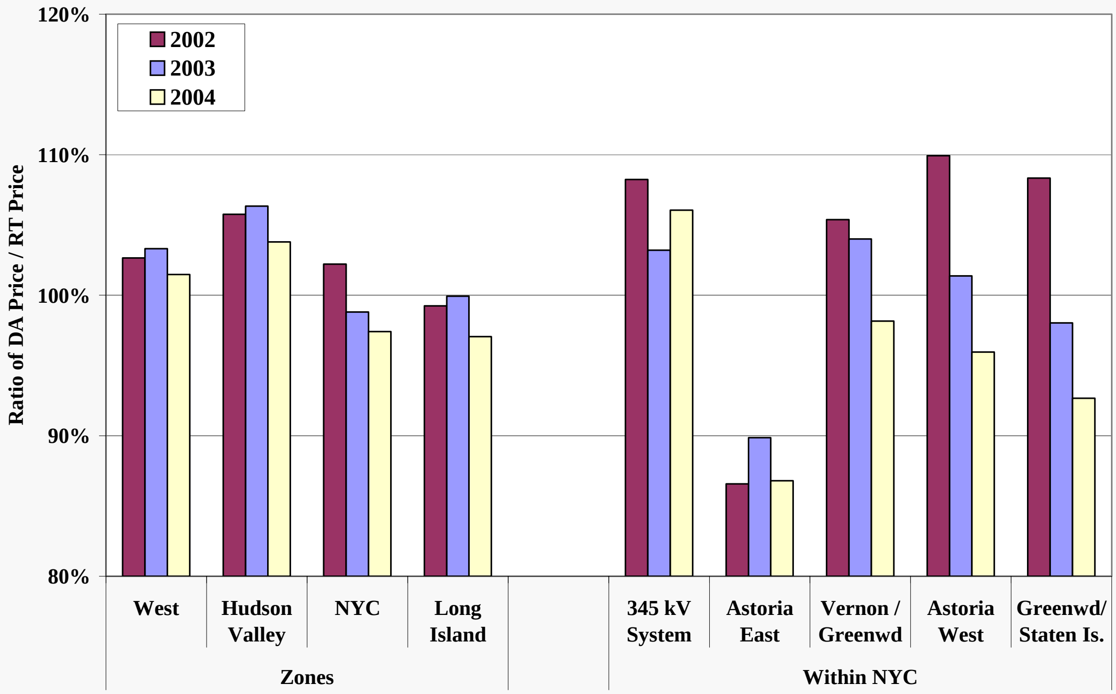
- Modeling of the load pockets within NYC, which was implemented in June 2002, has resulted in:
  - ✓ More accurate locational energy prices as the prices now reflect the load pocket constraints;
  - ✓ Increases in the congestion expenses in the energy market; and
  - ✓ Decreases in uplift that had been paid to generators redispatched to resolve the load pocket constraints.
- A simplified representation of the intra-NYC constraints is used in real time while a more detailed representation is used in the day ahead.
  - ✓ This difference can contribute to divergence between the day-ahead and real-time prices within NYC.

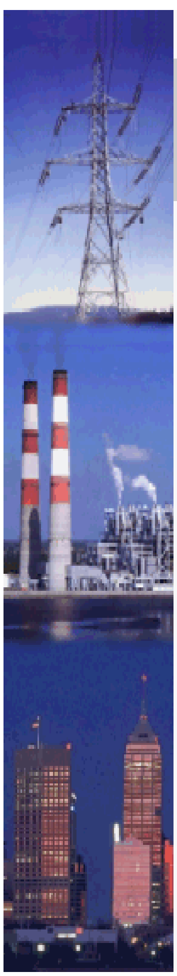


Price Convergence in the Load Pockets

- The following figure shows the ratio of day-ahead and real-time prices in several zones as well as the load pockets in NYC. It shows:
  - ✓ A shift toward larger real-time premiums in the NYC load pockets, particularly Astoria East.
  - ✓ An increase in the day-ahead premium in NYC outside the load pockets (i.e., the 345kv system).
  - ✓ Modest day-ahead premiums in the zones outside NYC and Long Island.
- Limiting price-capped load bidding and virtual trading to the zonal level in NYC limits the ability of participants to arbitrage large price differences in specific pockets.
- We will be evaluating the performance of the post-RTS market after the Summer 2005. If price convergence issues persist in New York City, we will recommend allowing virtual trading at a more disaggregated level.

Ratio of Day-Ahead to Real Time Prices 2002-2004

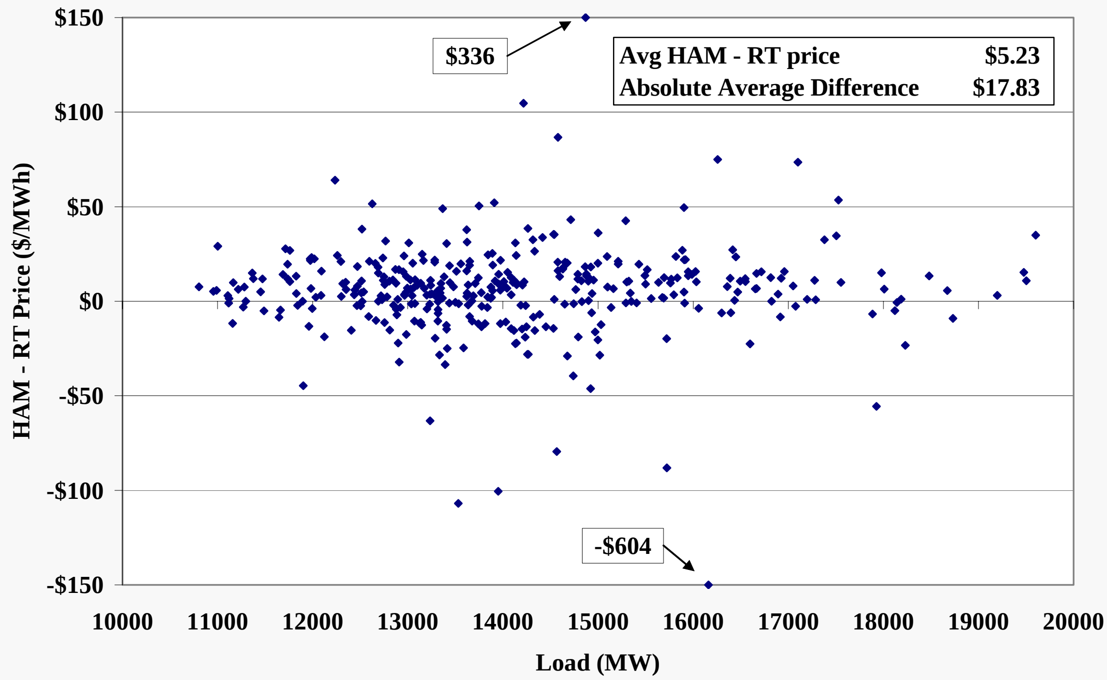


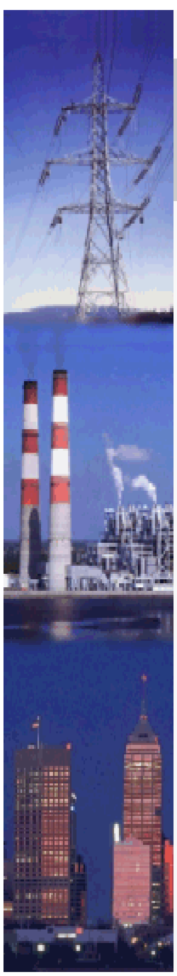


Hour-Ahead and Real-Time Prices

- Lack of convergence between hour-ahead and real-time prices can be a substantial concern because large price differences can result in:
  - ✓ External transactions and off-dispatch generation being scheduled inefficiently; and
  - ✓ Increased uplift costs and inefficient real-time prices.
- Convergence tends to be the worst in the highest demand hours when prices are most volatile.
- While significant improvements were made to BME model in 2002 that drastically reduced these price differences, substantial differences remain. To address this, the BME has been replaced under SMD:
  - ✓ The new scheduling model, RTC, will eventually schedule externals and off-dispatch generation, and commit resources every 15 minutes rather than hourly.
  - ✓ The 5-minute dispatch model, RTD, co-optimizes reserves like RTC which should improve consistency between the models.

Average Hour-Ahead and Real-Time Energy Prices
East New York – Daily Peak Load Hours – 2004

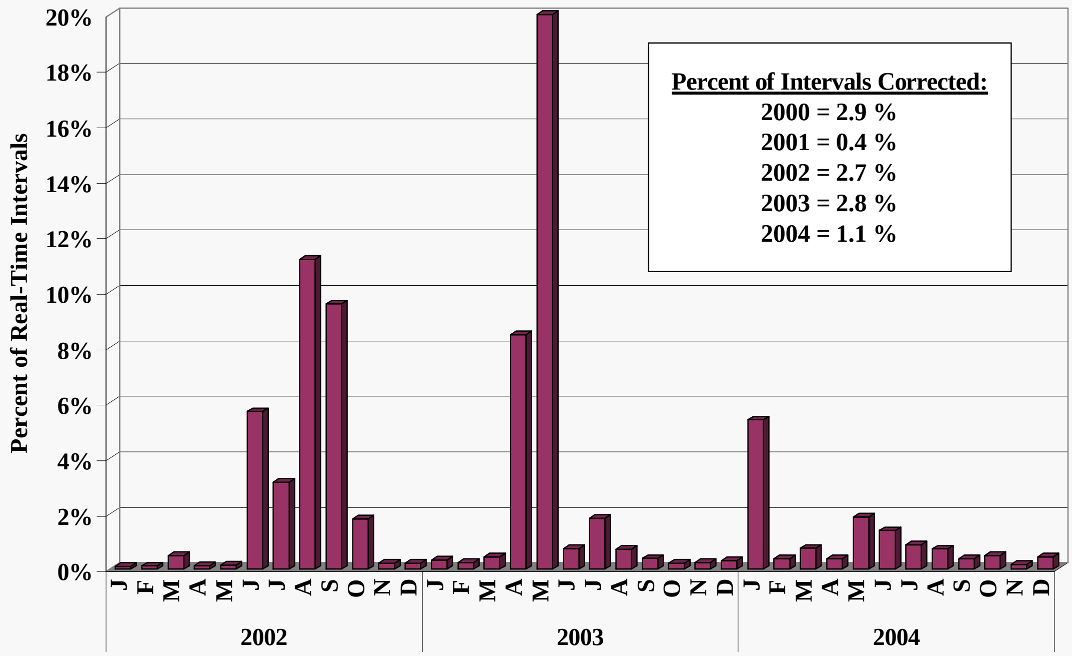




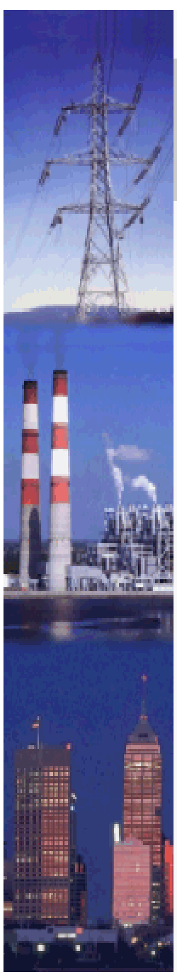
Energy Price Corrections

- All real-time energy markets are subject to some level of price corrections to account for:
  - ✓ Metering errors and other input data problems; or
  - ✓ Software flaws that cause pricing errors under certain conditions.
- The following figure summarizes the frequency of price corrections in the real-time energy market in 2002-2004.
  - ✓ The rate of corrections spiked during the summer of 2002 due to the implementation of modeling New York City load pockets.
  - ✓ There was a weighting error which was corrected in the summer of 2003.
  - ✓ During 2004, corrections occurred at a relatively low level. These results can be attributed in part to the fact that no major enhancements were made to the market software in 2004.

Percentage of Real-Time Prices Corrected
2002- 2004



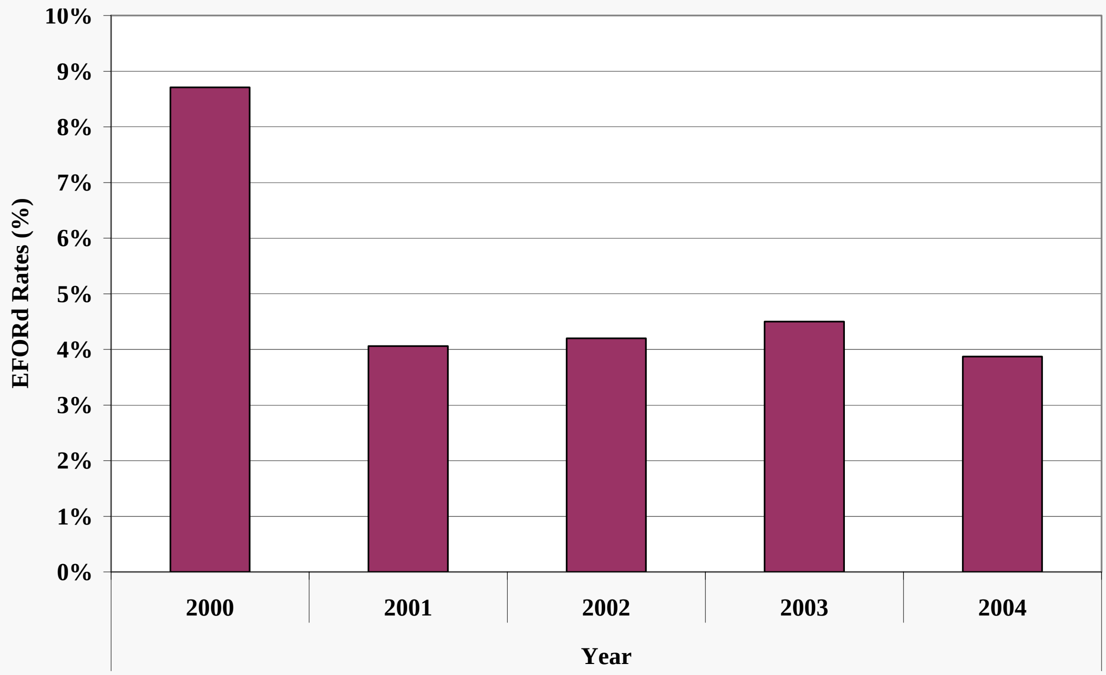
Based on calculations provided by NYISO Market Monitoring and Performance



Forced Outages in 2004

- The next figure shows the trend in the equivalent forced outage rate from just after the beginning of the operation of the New York markets.
  - ✓ The Equivalent Demand Forced Outage Rate (EFORd) is the portion of time a unit is unavailable due to forced outages, expressed as equivalent hours of full forced outage at its maximum net dependable capability.
- EFORd was relatively high in 2000 due to the outage of an Indian Point nuclear unit.
- After the Indian Point outage, the EFORd has been consistently close to 4 percent – much lower than the outage rates that prevailed prior to the implementation of the NYISO markets.
- The potential physical withholding issues associated with these outages are evaluated in the next section.

Equivalent Demand Forced Outage Rates (EFORd) 2000 to 2004

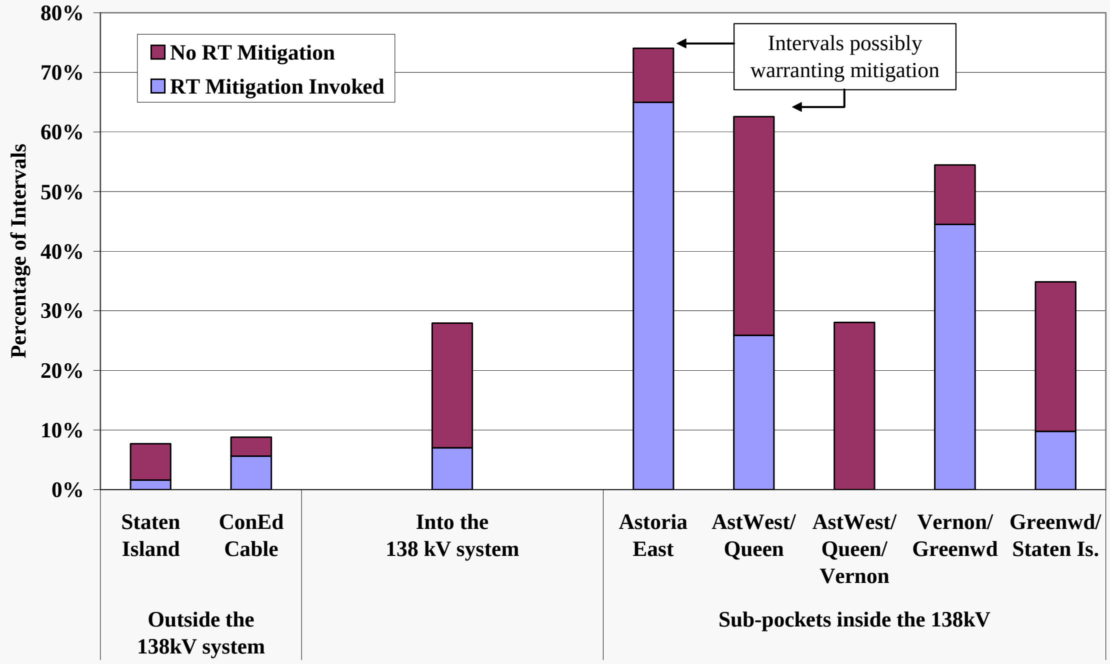


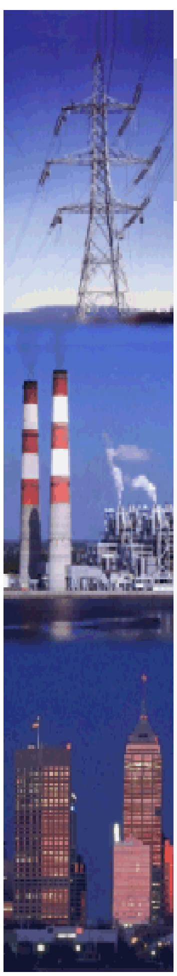
Based on calculations provided by NYISO Market Monitoring and Performance

Summary of Real-Time Mitigation in 2004

- Local market power mitigation measures are triggered when constraints are binding into a load pocket to address market power in these load pockets within NYC.
- The following figure summarizes the frequency of constraints into the load pockets and the actual frequency of mitigation.
  - ✓ The columns in the figure show the percent of intervals with a constraint binding such that mitigation could be warranting.
  - ✓ Of those intervals, the lower portion of the columns shows portion of the intervals in which one or more units in the given load pockets were mitigated.
- Mitigation was most frequent in the smallest, most congested load pockets that have the most severe potential market power.
- In more competitive areas outside of the load pockets, mitigation was much less frequent.

Frequency of Real-Time Constraints and Mitigation New York City Load Pockets in 2004



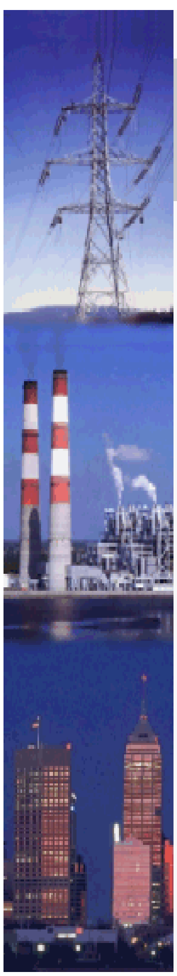


Summary of Day-Ahead Mitigation in 2004

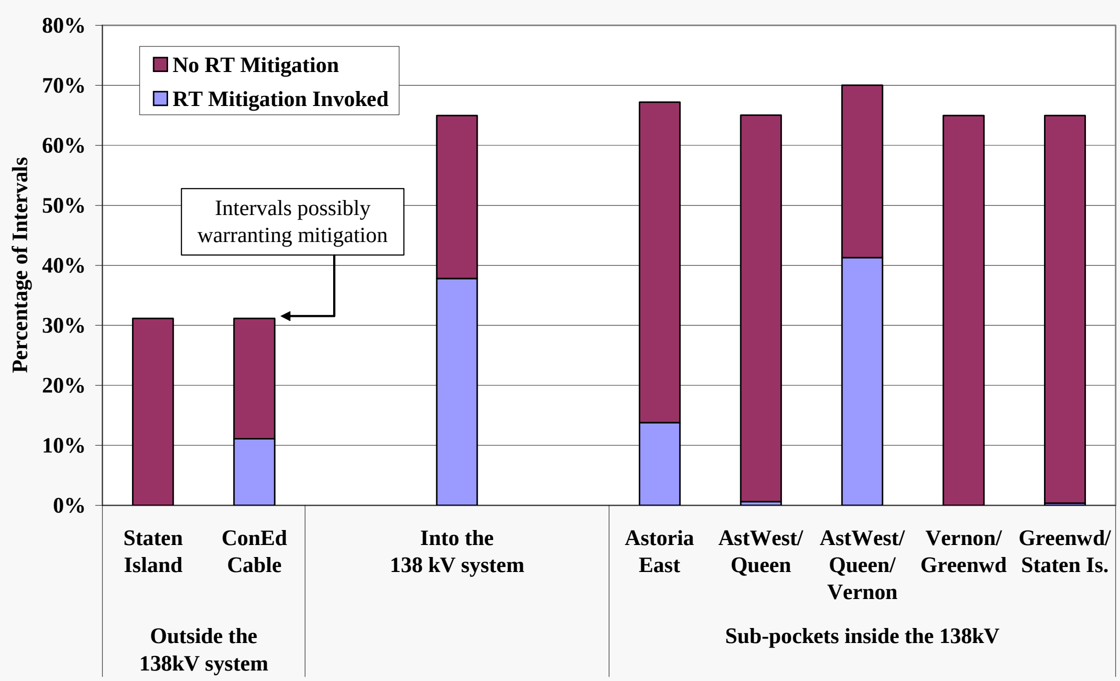
- The conduct and impact mitigation framework ensure that mitigation will occur only when market power is exercised to increase prices.
- This framework is applied with automated mitigation procedures ("AMP") in the day-ahead market to avoid delay in the application of mitigation.
- Outside New York City, mitigation through the AMP is rarely applied.
  - ✓ The AMP software only runs when energy prices outside the City are greater than $150 per MWh when market power is more likely.
  - ✓ Virtual trading, price-sensitive load bids and other factors limit potential market power in the day-ahead market outside the City.
- Inside New York City, the conduct and impact framework with tighter mitigation thresholds replaced the "ConEd" measures on May 1, 2004.
  - ✓ The cost-based ConEd measures were triggered by the presence of congestion, which resulted in mitigation in almost all hours.

Summary of Day-Ahead Mitigation in 2004

- The conduct and impact framework focus more effectively on potential market power in the NYC load pockets than the ConEd measures.
  - ✓ This prevents mitigation from occurring when it is not necessary to address market power.
  - ✓ Allows high prices to occur during legitimate periods of shortage.
- The following figure shows that mitigation has become much less frequent under the conduct and impact framework in NYC.
  - ✓ Like the prior figure, the total column shows the percent of the hours in which constraints are binding while the lower portion of the column shows the percent of hours when mitigation was actually imposed.
  - ✓ Outside of the load pockets in NYC, congestion in 31 percent of hours while mitigation occurred in just 11 percent of hours.
  - ✓ Within the load pockets, mitigation was most common associated with the constraint into the 138 kV system and into the Astoria West/ Queensbridge/Vernon load pocket.

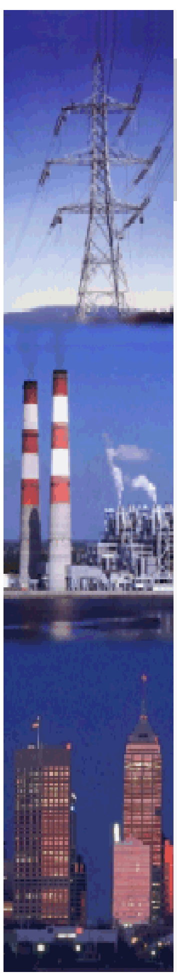


Frequency of Day-ahead Constraints and Mitigation New York City Load Pockets, June to December 2004

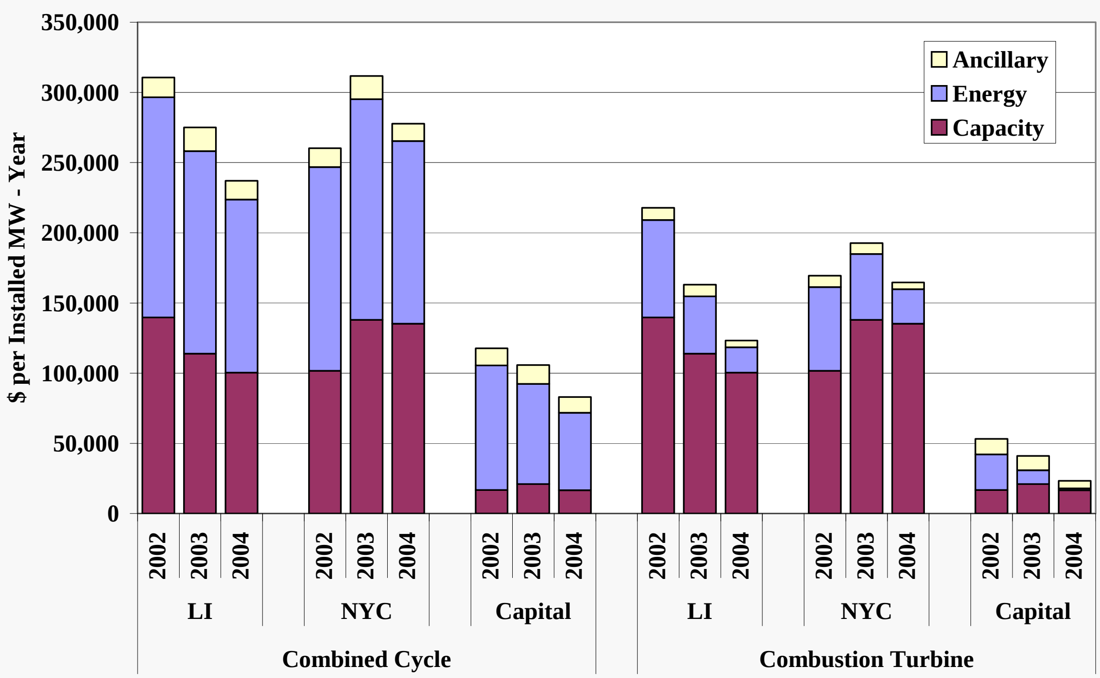


Economic Incentives for New Investment

- In long-run equilibrium, the market should support the entry of new generation by providing sufficient net revenues (revenue in excess of production costs) to finance new entry.
- The following figure shows the net revenue the markets would have provided for two types of units for the Capital zone, New York City zone, and Long Island zone in 2004. The types of units are:
  - ✓ Gas combined-cycle: heat rate assumed of 7000 BTU/KWh.
  - ✓ Gas combustion turbine: heat rate assumed of 10500 BTU/KWh.
- Mild summer weather conditions resulted in lower peak prices in 2004, which resulted in less net revenue. Lower UCAP prices also contributed to less net revenue in 2004.



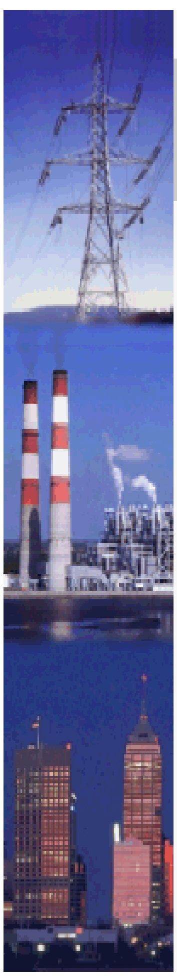
Estimated Net Revenue in the New York Market 2002 to 2004



Based on calculations provided by NYISO Market Monitoring and Performance

Economic Incentives for New Investment

- These results indicate that the market in 2004 did not produce sufficient net revenue to support investment in a new combustion turbine in NYC.
  - ✓ A new gas turbine in NYC would have recovered approximately 50 to 65 percent of the net revenue required annually to support the investment.
- The results for a new combined-cycle unit are less clear.
  - ✓ Net revenue for a new CC in NYC ranged from $250,000 to $300,000 per MW-year during the last three years.
  - ✓ The required net revenue for a new CC in NYC is unknown.
- These results indicate that the market in 2004 did not produce sufficient net revenue to support investment in a new CT or CC in the Capital zone.
  - ✓ A new gas turbine in the Capital zone would have recovered approximately 20 percent of the net revenue require annually to support the investment.
  - ✓ A new gas CC in the Capital zone would have recovered approximately 75 percent of the net revenue require annually to support the investment.



Economic Incentives for New Investment

- The net revenue results for NYC and upstate NY do not raise significant long-term concerns because:
  - ✓ The mild summer conditions and lack of shortages in 2004 reduced the net revenue substantially; and
  - ✓ Upstate NY has a capacity surplus, limiting the need for new gas turbines outside NYC.
  - ✓ These factors should result in net revenue less than need to support investment in new peaking resources outside of NYC.
- Despite these results, new investment is continuing in New York in response to solicitations or based on future expectations.

Analysis of Bid and Offer Patterns

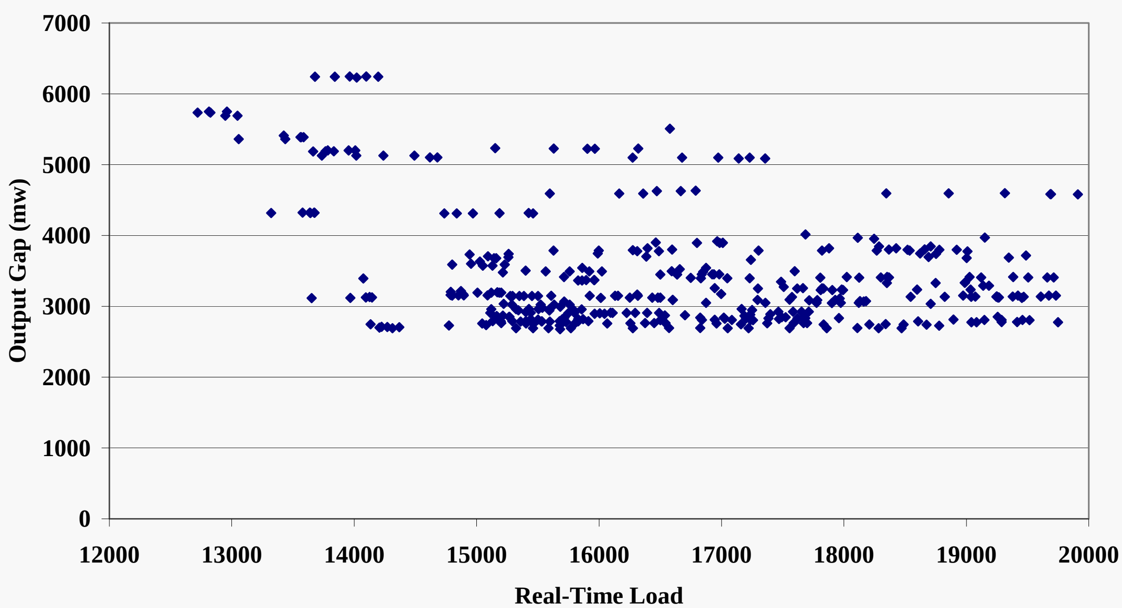
Analysis of Offer Patterns

- 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 offer 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.
  - ✓ Hence, this analysis allows one to discern these quantities reflect attempts to withhold resources to raise prices.
- The first analysis is of potential physical withholding, analyzing total generation deratings (including planned forced outages, and partial deratings).

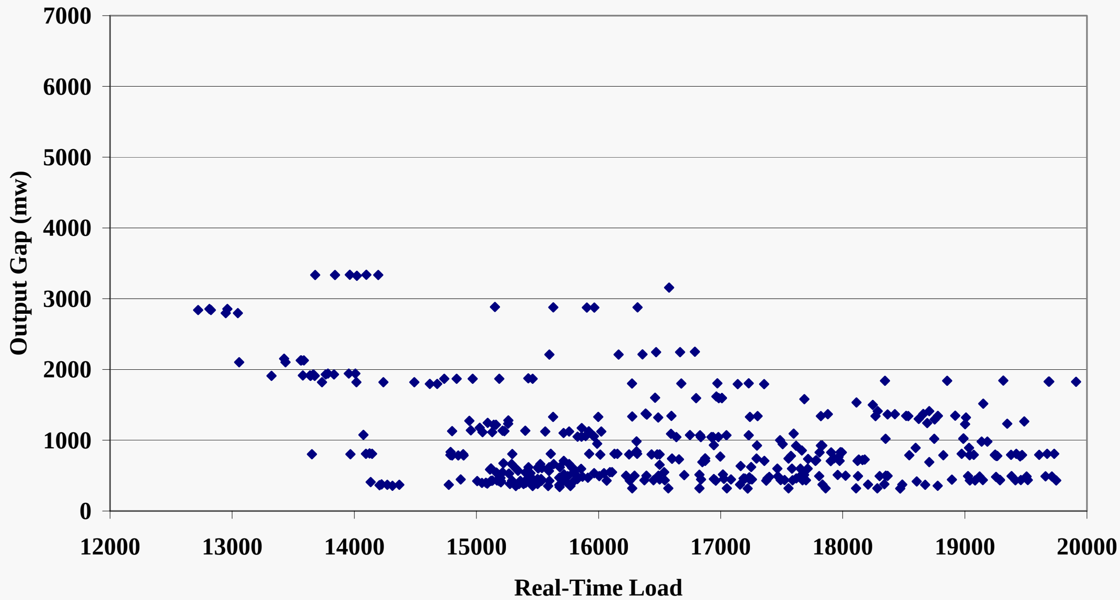
Analysis of Offer Patterns – Deratings

- The following two figures plot the total deratings and short-term deratings versus actual load in eastern NY during peak hours in the summer.
  - ✓ The figures focus on eastern NY because this area, which includes two-thirds of the State's load, has limited import capability and is more vulnerable to the exercise of market power.
  - ✓ We focus this analysis on the summer to exclude the effects of planned outages that typically occur during off-peak seasons, and because market power is most likely during the higher load conditions in the summer.
  - ✓ The short-term deratings shown in the second figure are more likely to reflect attempts to physically withhold since it is more costly to withhold via long-term deratings or outages.
- These figures show that deratings are least frequent when load reaches high levels, which is consistent with workable competition.

Relationship of Deratings to Actual Load
Day-Ahead Market – East New York
Weekdays, Noon to 6 PM, Summer 2004



Relationship of Short-Term Deratings to Actual Load
Day-Ahead Market – East New York
Weekdays, Noon to 6 PM, Summer 2004



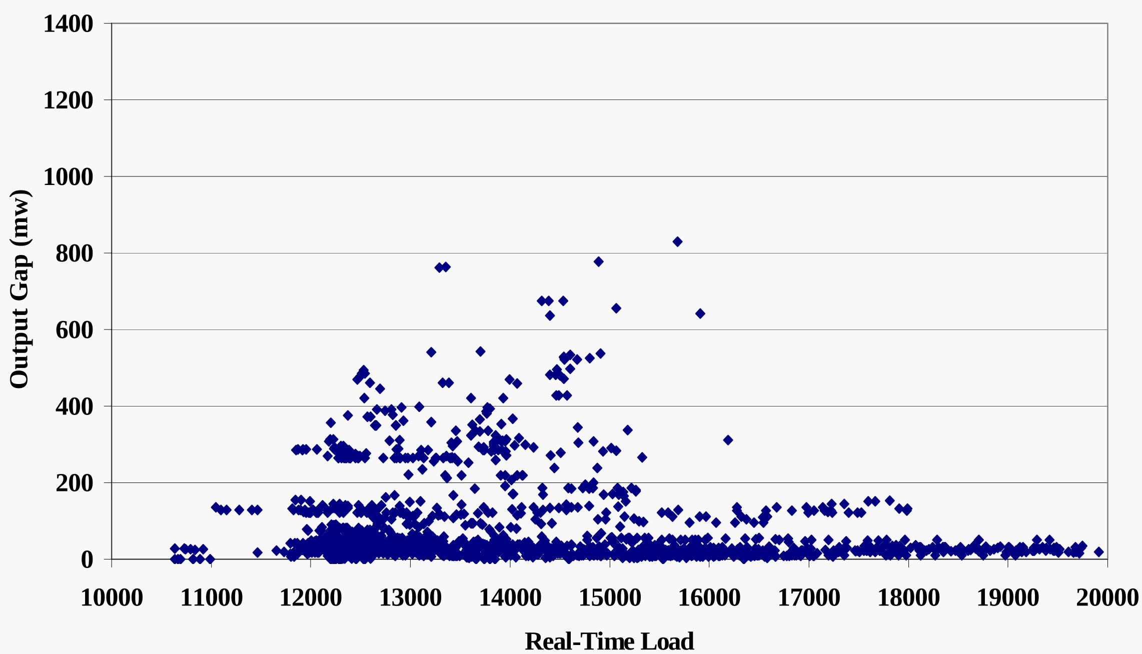
Analysis of Offer Patterns – Output Gap

- 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 does not produce 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”.
  - ✓ Excludes capacity scheduled to provide ancillary services.

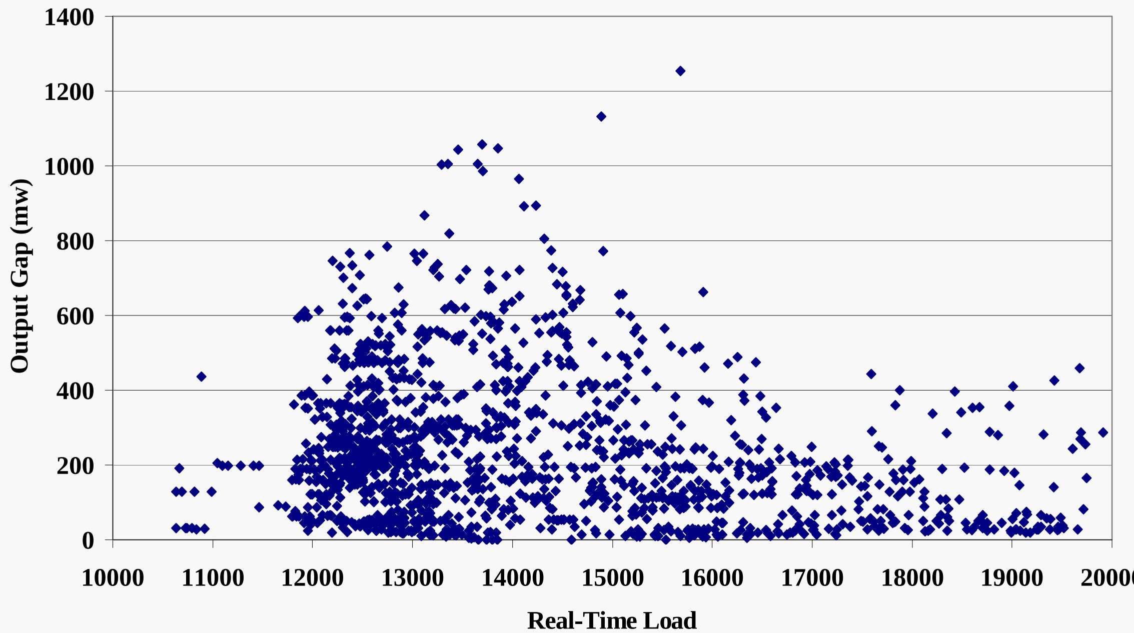
Analysis of Offer Patterns – Output Gap

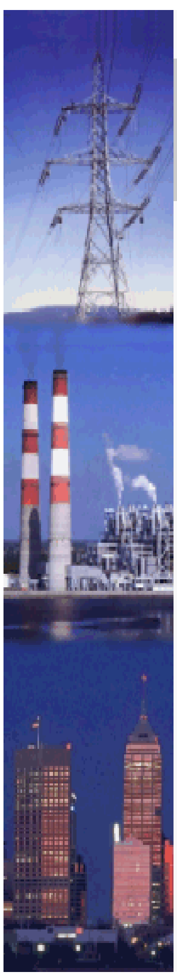
- The following figures shows the real-time output gap in eastern New York during peak hours using:
  - ✓ Low thresholds, \$50/MWh or 100% (whichever is lower), and
  - ✓ Standard conduct thresholds of \$100/MWh or 300% (whichever is lower).
- These figures both show that output gap decreases to extremely low levels under the highest load conditions.
  - ✓ This is an important result because prices are most vulnerable to market power under peak load conditions.
  - ✓ These results indicate that economic withholding was not a significant concern in 2004.

Output Gap at Mitigation Threshold vs. Actual Load
Real-Time Market – East New York
Weekdays, Noon to 6 PM



Output Gap at Low Threshold vs. Actual Load
Real-Time Market – East New York
Weekdays, Noon to 6 PM

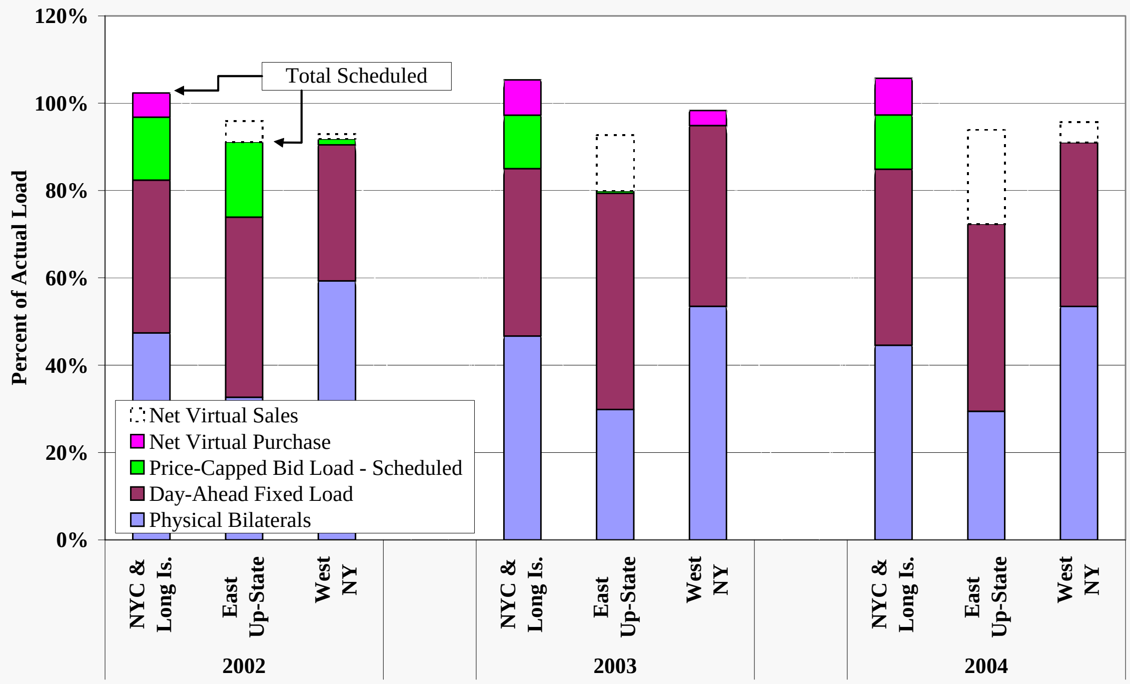




Analysis of Load Bidding Patterns

- The following figure shows the load bidding patterns during 2002 through 2004 at various locations in New York.
- Convergence between day-ahead scheduled load and actual load has declined from 2002 to 2004.
  - ✓ The ratio of day-ahead scheduling to actual load decreased in East Up-state New York from 91 percent in 2002 to just 72 percent in 2004. This is consistent with the persistent day-ahead price premium in that region.
  - ✓ The higher day-ahead purchases in NYC is consistent with the day-ahead premium that has prevailed in that area.
- The share of the actual load supplied through physical bilaterals has been relatively constant at slightly less than 50 percent.
  - ✓ This does not mean that over 50 percent of the load is incurring the spot prices in the NYISO energy markets.
  - ✓ Physical bilaterals do not include all bilaterals. In particular, financial bilaterals such as “contracts for differences” are settled privately and generally would show as day-ahead fixed load.

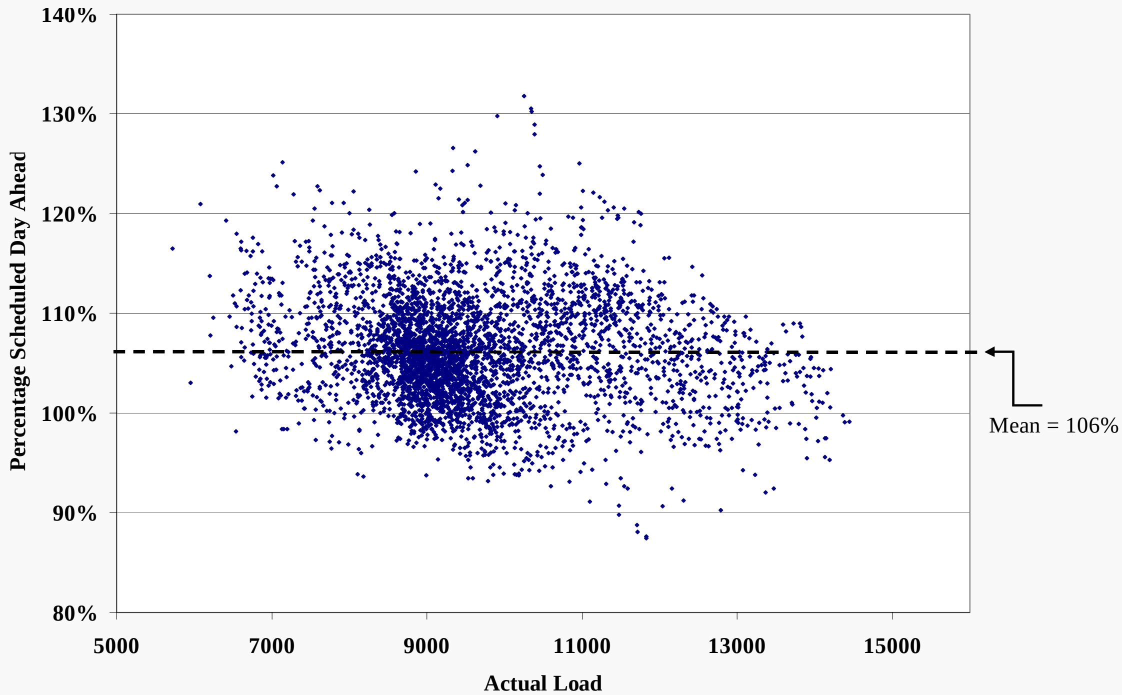
Composition of Day Ahead Load Schedules as Proportion of Actual Load - 2002-2004



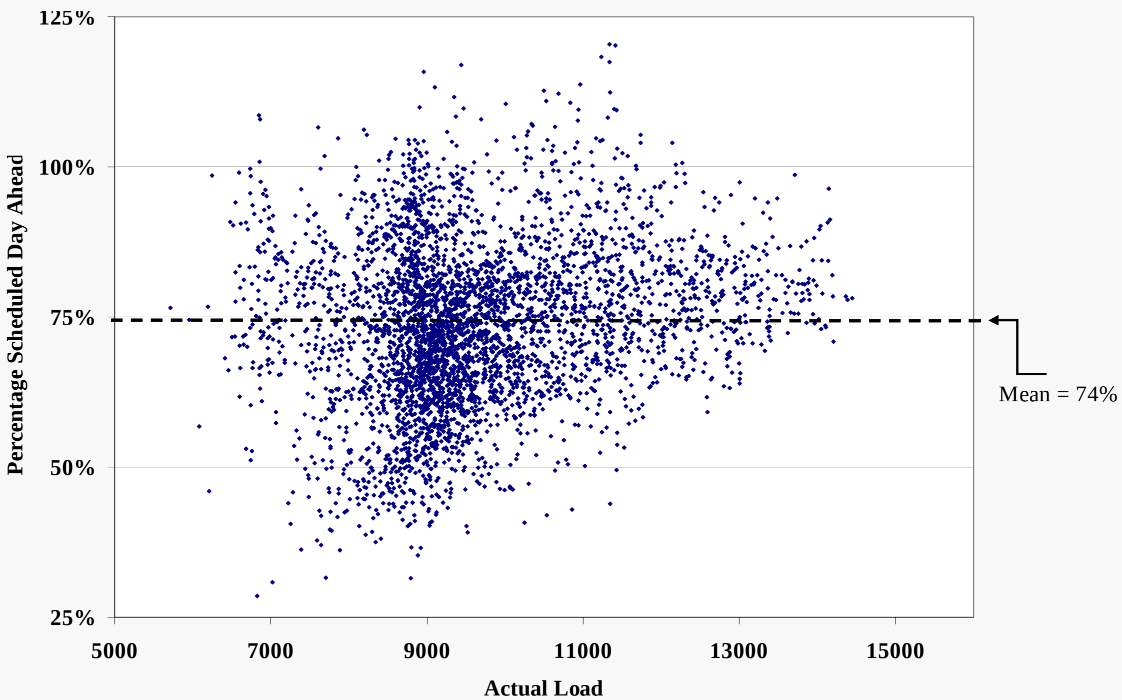
Day-Ahead Load Scheduling

- In order to further evaluate the pattern of load bidding, we analyzed day-ahead hourly load schedules (including virtual load bids) as a percentage of real-time load for peaks hours during 2004.
  - ✓ New York City and Long Island tend to over-schedule load day-ahead. However, this pattern tends to diminish in the highest load hours.
  - ✓ Load scheduled day-ahead in Eastern up-state New York is more variable and is usually substantially under-scheduled. This under scheduling decreases as load increases.
  - ✓ In Western New York, the data reveals that day-ahead load is under-scheduled on average, particularly at the highest load conditions.
- These results are consistent with:
  - ✓ The apparent differences in limits and loss modeling between the day-ahead and real-time markets analyzed in the next section; and
  - ✓ The price differences between the day-ahead and real-time markets in these areas.

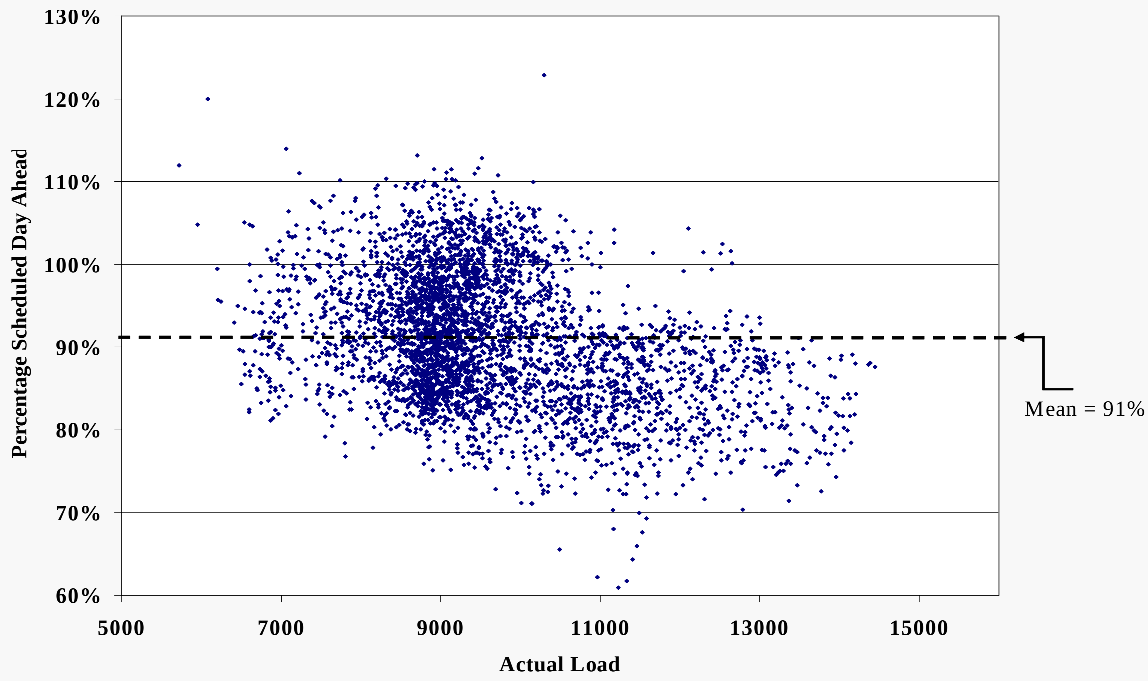
Load Scheduled Day-Ahead v. Real-Time Load
NYC and Long Island – Peak Hours in 2004



Load Scheduled Day-Ahead v. Real-Time Load
East Up-State New York – Peak Hours in 2004



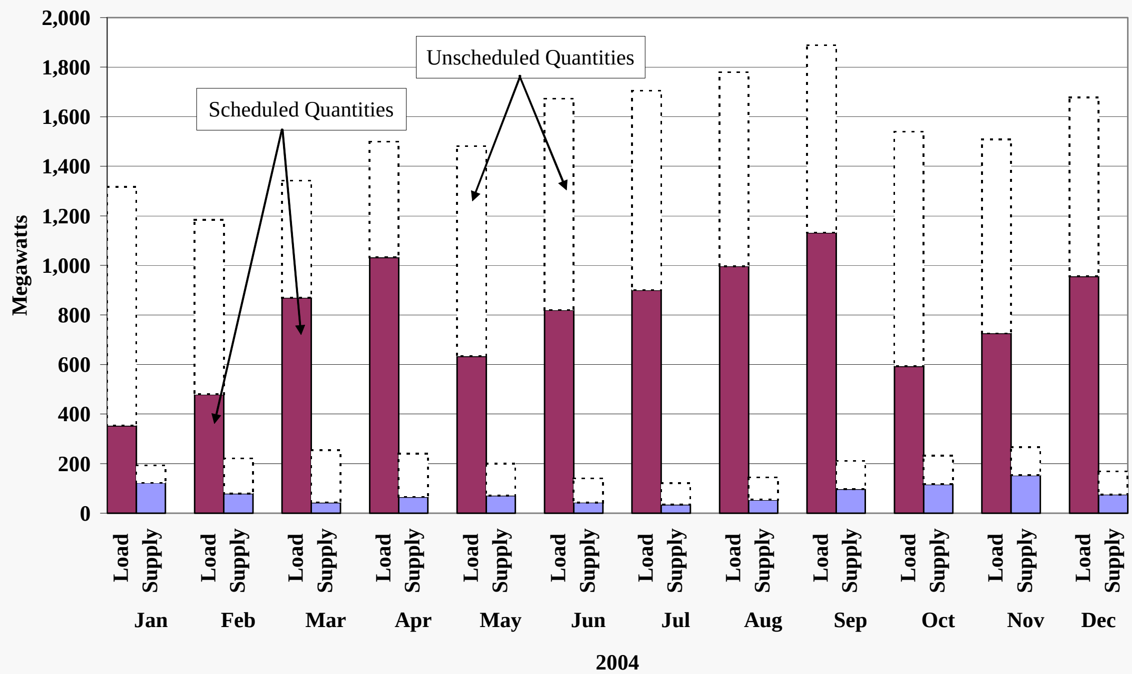
Load Scheduled Day-Ahead v. Real-Time Load West New York – Peak Hours in 2004

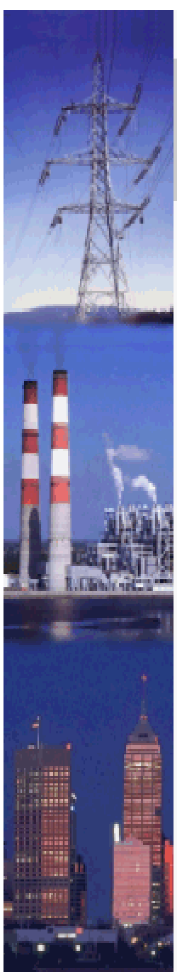


Virtual Trading Patterns

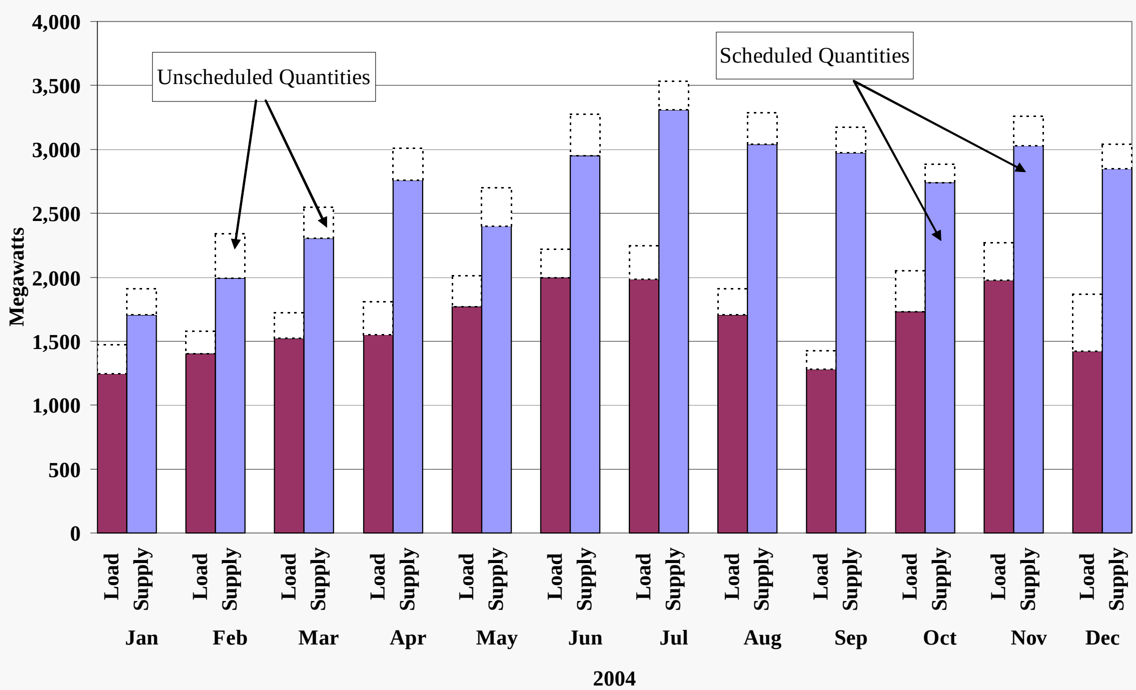
- Virtual trading was introduced in November 2001 to allow participation in the day-ahead market by entities other than LSE's and generators.
- The following figures show the quantities of virtual load and supply that have been offered and scheduled on a monthly basis in New York City and Long Island as well as areas of up-state New York.
- These figures shows the following:
  - ✓ Virtual trading activity tends to be highest during the summer when real-time load is highest and prices are most volatile.
  - ✓ Virtual trading increased trended upward during 2004.
  - ✓ 50 percent of virtual bids and offers in New York City and Long Island were scheduled.
  - ✓ 90 percent of virtual bids and offers in up-state New York were scheduled.

Hourly Virtual Load and Supply
New York City and Long Island - 2004

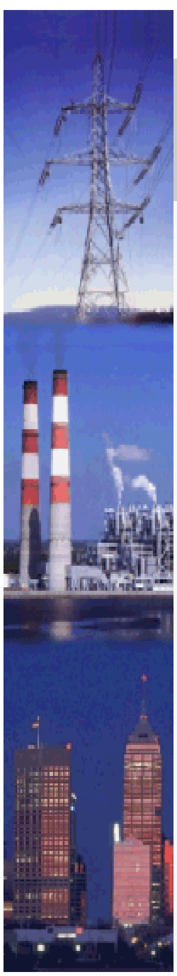




Hourly Virtual Load and Supply
Outside New York City and Long Island - 2004



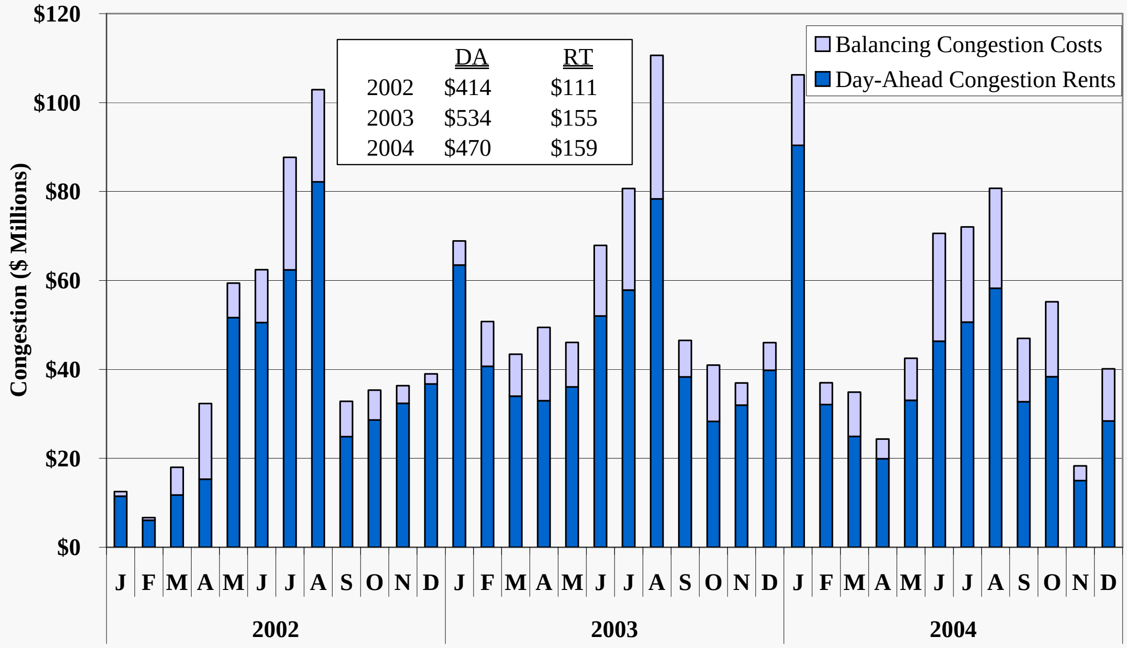
Market Operations

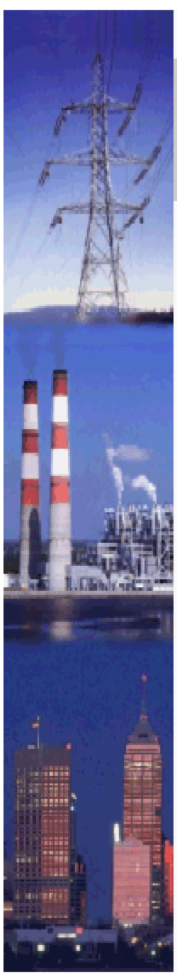


Congestion Costs

- The following figure shows monthly congestion costs collected in the day-ahead market and the real-time market (i.e., balancing congestion costs).
  - ✓ These costs are the marginal value of congestion (i.e., the price differences times the flows between areas), which is much higher than the total benefit of eliminating all congestion, estimated to be less than $100 million.
- This figure shows that congestion costs rose in 2003 to $688 million, but decreased slightly in 2004 to $629 million.
- The increase in congestion costs from 2002 to 2003 is largely due to higher fuel prices and the implementation of New York City load pocket modeling.
- Mild summer load in 2004 contributed to the decrease in congestion from 2003 to 2004.

Monthly Congestion Expenses 2002 – 2004

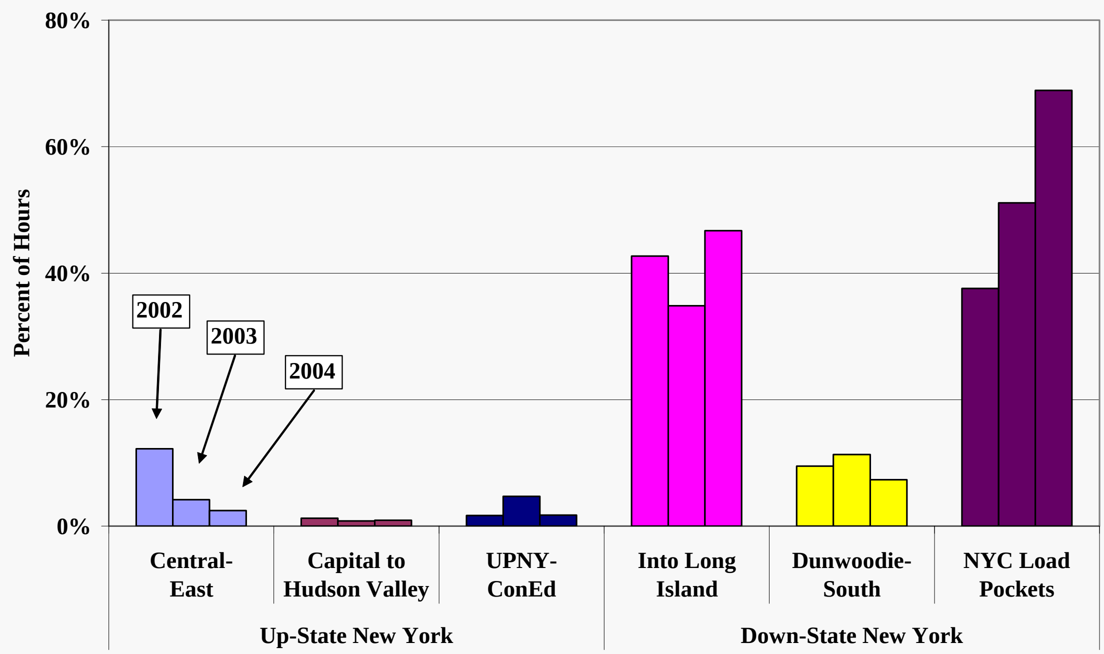




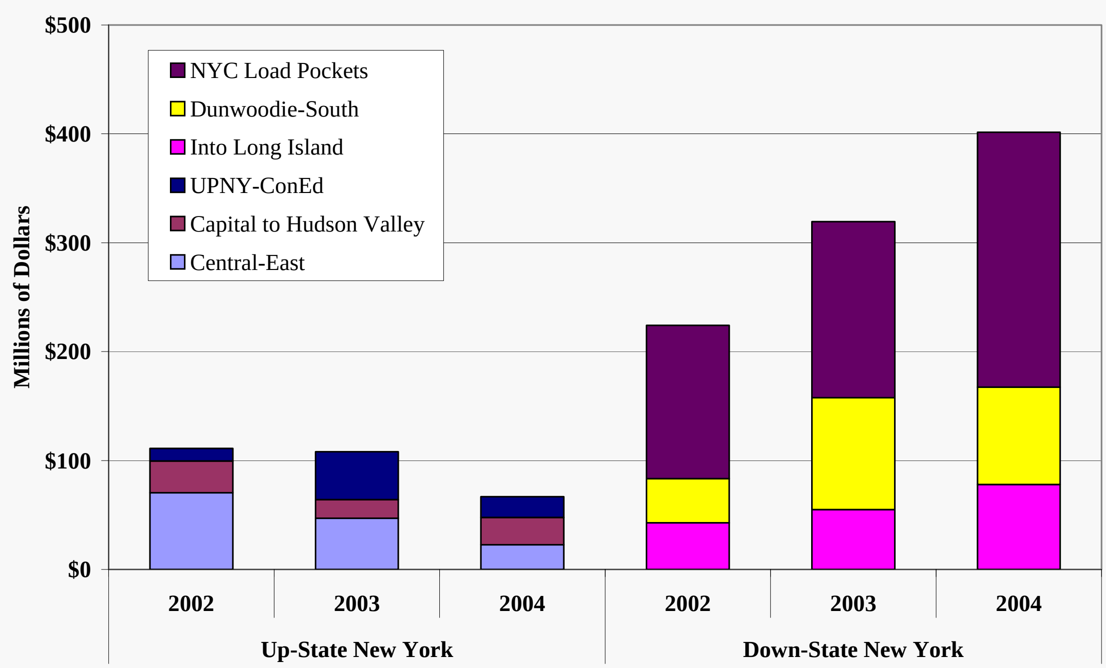
Major Transmission Interfaces

- The following two figures summarize the extent of transmission congestion on select interfaces in up-state and down-state New York. The first figure shows the frequency of congestion.
  - ✓ While the Central-East has decreased in frequency since 2002, the congestion over other upstate interfaces have not increased significantly.
  - ✓ Congestion is most frequent into the New York City load pockets and the frequency increased from 2002 to 2004.
- The second figure measures the approximate value of congestion in real-time annually for each of the interfaces.
  - ✓ Constrained interfaces in up-state New York have generally decreased in value, while the value of transmission interfaces shown for New York City and Long Island have increased substantially.
  - ✓ The value of the up-state transmission interfaces was approximately $70 million, while the value of the down-state interfaces totaled $400 million.

Frequency of Real-Time Congestion on Major Interfaces 2002 – 2004



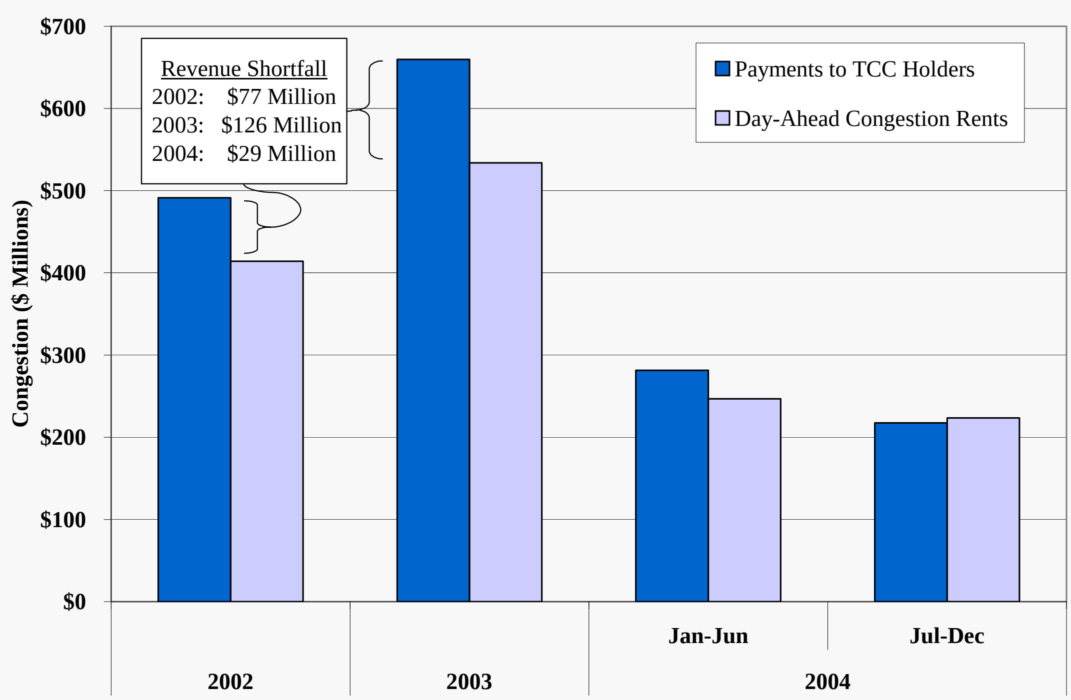
Value of Real-Time Congestion on Major Interfaces 2002 – 2004



Congestion Revenue and TCC Obligations

- To evaluate the NYISO congestion costs and transmission congestion contracts ("TCCs"), we performed several analyses.
- First, we compared the day-ahead congestion costs collected by the NYISO to the TCC payments made to market participants.
  - ✓ In a well-functioning system, these values should be roughly equal.
  - ✓ Congestion revenues were lower than payments to TCC holders until mid-way through 2004, which occur when the transmission capability assumed in the TCC auction exceeds what is available in the day-ahead market.
  - ✓ A large share of the shortfall was due to excess TCCs sold into New York City. These excess TCCs were repurchased in July 2004.
  - ✓ The NYISO also made the following changes to reduce the shortfalls:
    - – Allow up to a 5% reduction in the quantity of TCCs offered in the auction by each transmission owner;
    - – Assess shortfall costs resulting from maintenance to individual transmission owners.

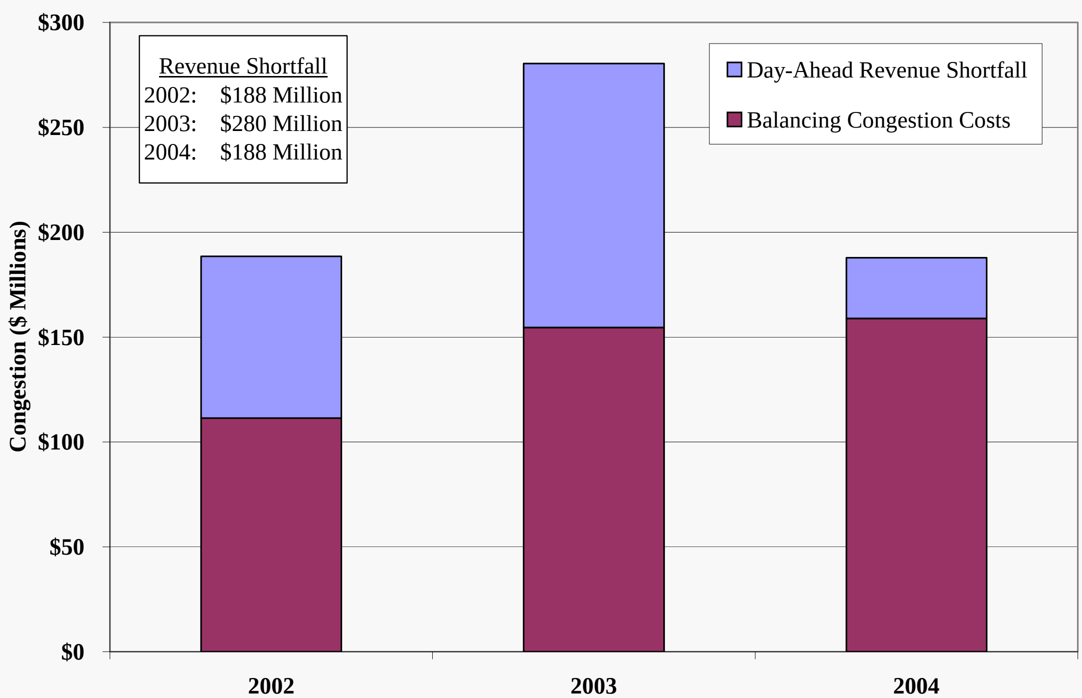
Day-Ahead Congestion Costs and TCC Payments



Congestion Shortfall

- Second, we examined the amount of congestion revenue shortfall incurred in the balancing market.
  - ✓ The primary cause of balancing congestion costs are changes in transmission limits between the day-ahead and real-time markets.
  - ✓ When transmission capability decreases in real-time, the NYISO will have a revenue shortfall that is uplifted to the market.
  - ✓ If transmission outages are random, the magnitude and direction of these congestion payments should be distributed randomly and should sum to zero over time.
- However, as the following figure shows, the balancing congestion costs have been positive and increasing over time, while day-ahead shortfalls were largely addressed in 2004.
- The implementation of RTS should improve the consistency of the day-ahead and real-time market and reduce the balancing congestion costs.

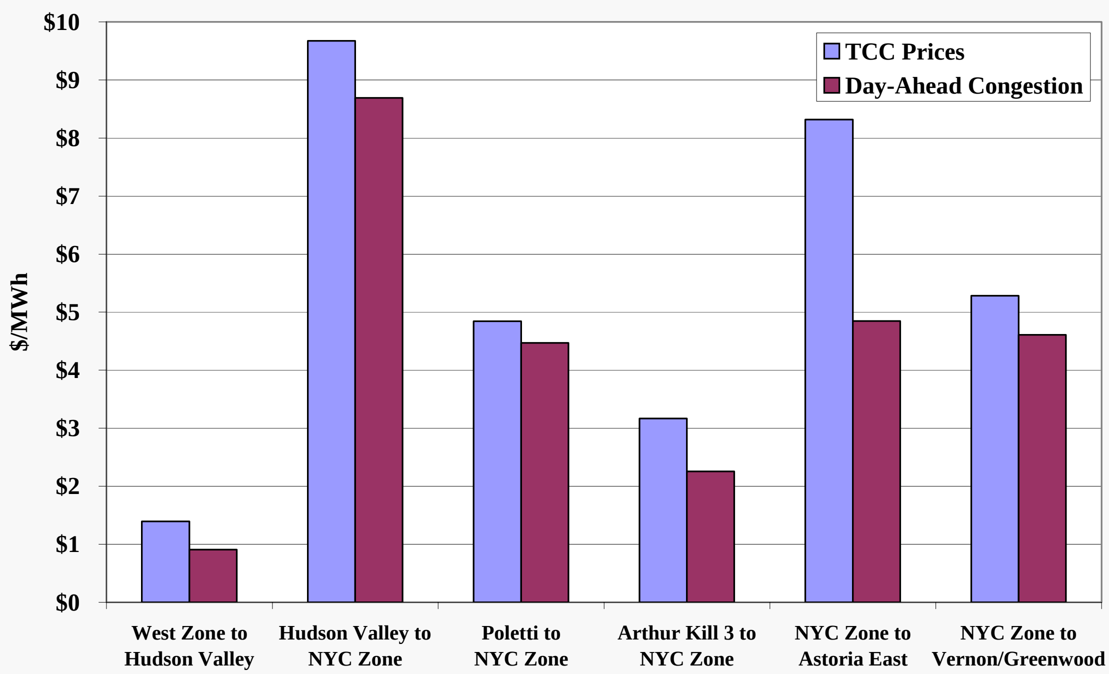
Day-Ahead Shortfalls and Real-Time Congestion
2002 – 2004



TCC Prices and Day-Ahead Congestion

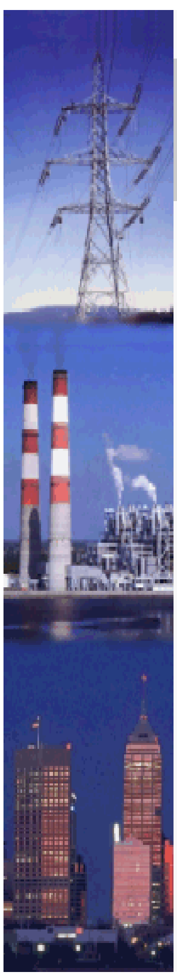
- Our final analysis in this area is designed to evaluate with the TCC prices that have emerged from the NYISO's markets are efficient.
- TCCs provide an entitlement to the holder for the day-ahead congestion between two points.
  - ✓ Hence, in a well-functioning market, the price for the TCC should reflect a reasonable expectation of the day-ahead congestion.
- To evaluate this, the next figure compares the auction prices from the auction of 6-month TCCs during the summer capability period for 2004 to the day-ahead congestion that actually occurred during the period.
- The results of this analysis show:
  - ✓ The TCC prices have reflected the value of the day-ahead congestion relatively accurately, with TCC prices slightly exceeding actual congestion.
  - ✓ Actual congestion was likely lower than expected due to mild conditions.
  - ✓ The worst result was related to the Astoria East load pocket, which also showed the worst convergence between the day-ahead and real-time market.

TCC Prices and Day-Ahead Congestion
May to October 2004

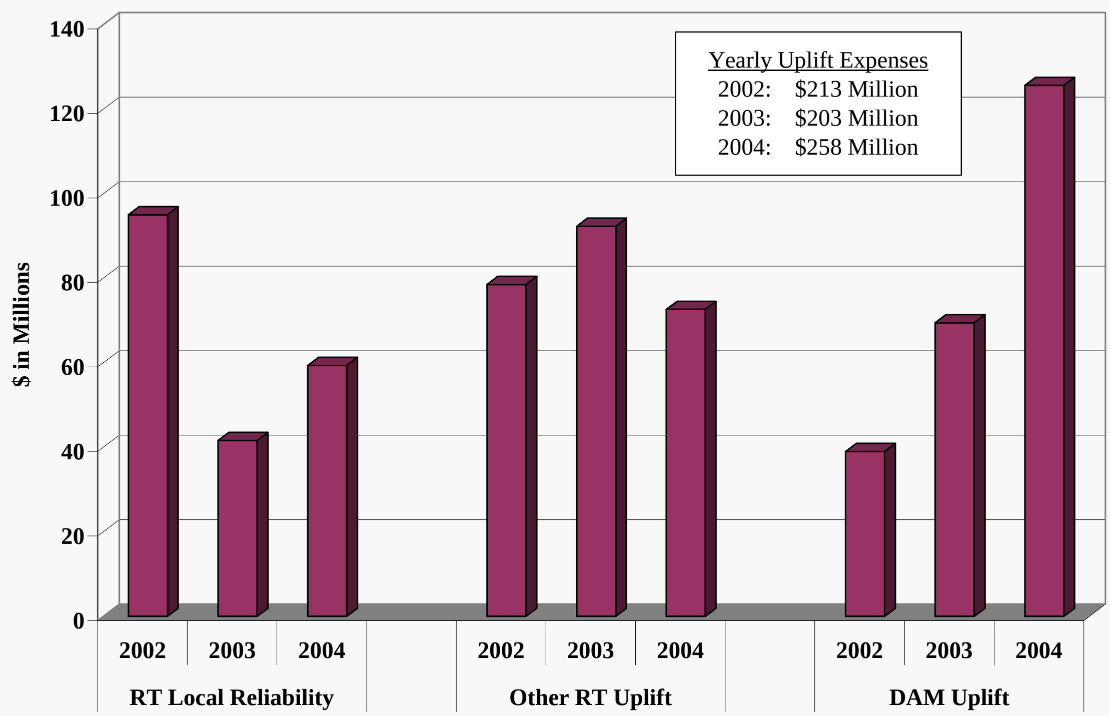


Uplift Expenses

- The next figure shows the uplift costs from different sources from 2002-2004.
- Uplift costs for real-time reliability fell sharply after 2002 due to the introduction of load pocket modeling in June 2002.
  - ✓ Previously, the re-dispatch costs to manage load pocket congestion had been collected through uplift.
- Day ahead market uplift has tripled since 2002. This is uplift paid to units committed by SCUC, mostly in the local reliability pass of SCUC.
- These supplemental commitments by SCUC have a tendency to decrease day-ahead prices.
  - ✓ As a result of lower prices, large amounts of DAM uplift are paid to generators committed before the local reliability pass in the form of Bid Production Cost Guarantees.
  - ✓ Only uplift paid to units committed in the local reliability pass is allocated to the local area, while the majority of DAM uplift is assessed market-wide.



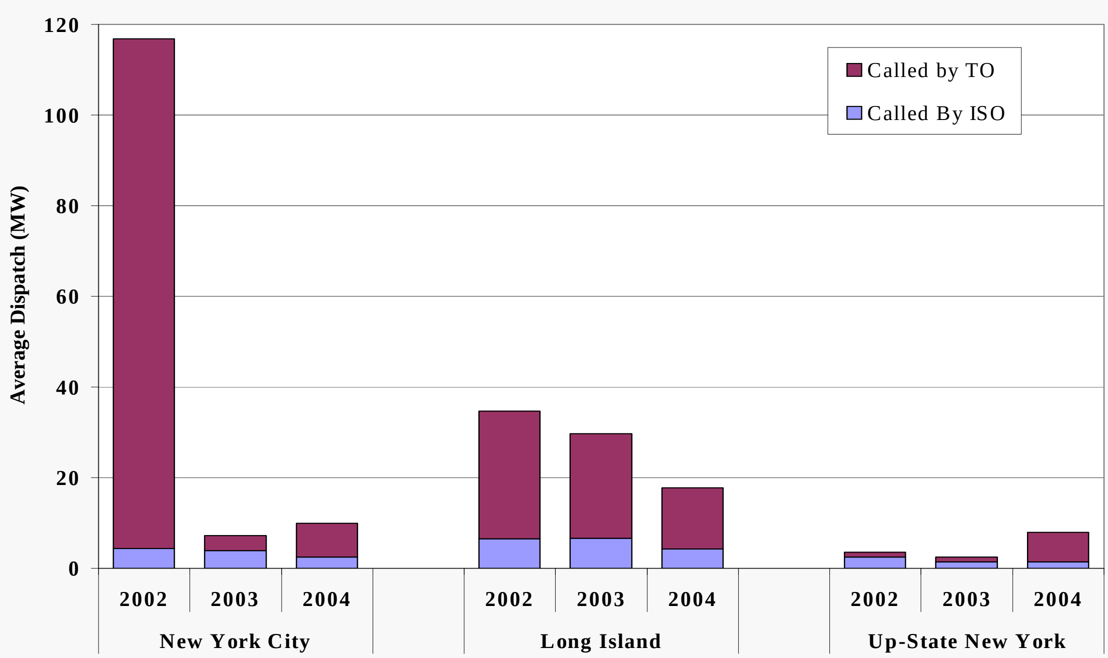
Day-Ahead and Real-Time Uplift Expenses 2002 – 2004



Real-Time Out of Merit Dispatch

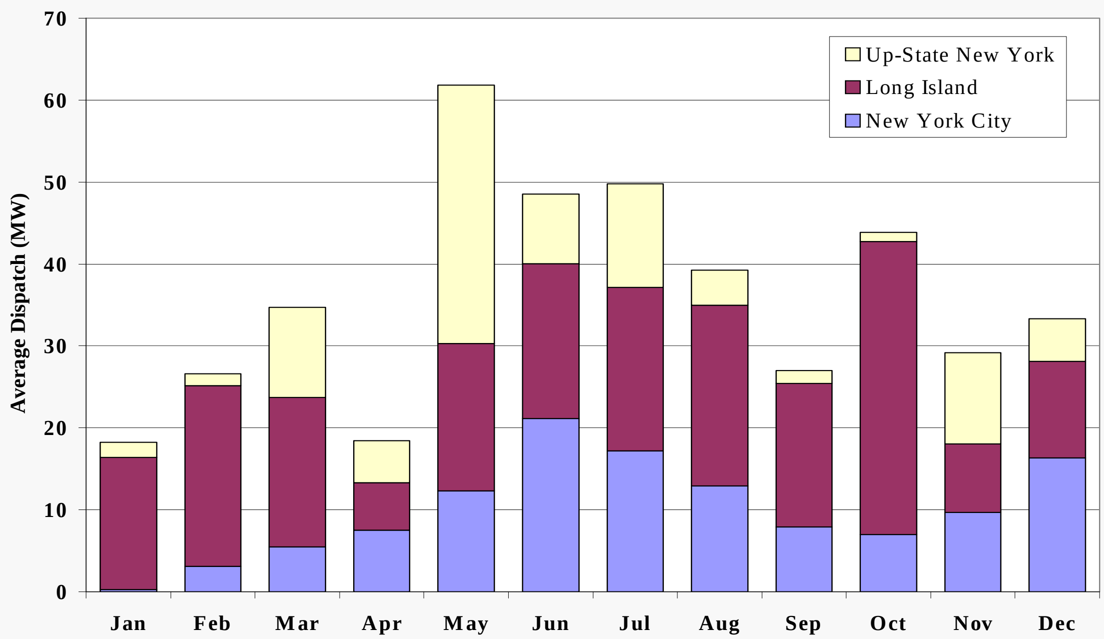
- The next analysis focuses on the dispatch of resources out-of-merit ("OOM"), which is important because it can distort energy prices.
- OOM resources are units logged by the NYISO as OOM (generally manually dispatched), whose offer price is higher than the LMP.
- In 2002, Prior to load pocket modeling, OOM dispatch in New York City accounted for approximately 80% of resources dispatched OOM. Long Island units now account for approximately half of OOM dispatch.
- The following figures show the average quantity of OOM resources in different locations in New York. This figure shows:
  - ✓ OOM dispatch quantities are generally very low.
  - ✓ OOM dispatch in NYC fell substantially after load pocket modeling as expected.
  - ✓ Changes in price-setting rules and operating procedures have caused the ISO-called OOM dispatch to fall by more than two-thirds.

Average Out-of-Merit Dispatch Quantities 2002 – 2004



Note: August 2003 blackout hours excluded.

Average Out-of-Merit Dispatch Quantities 2004

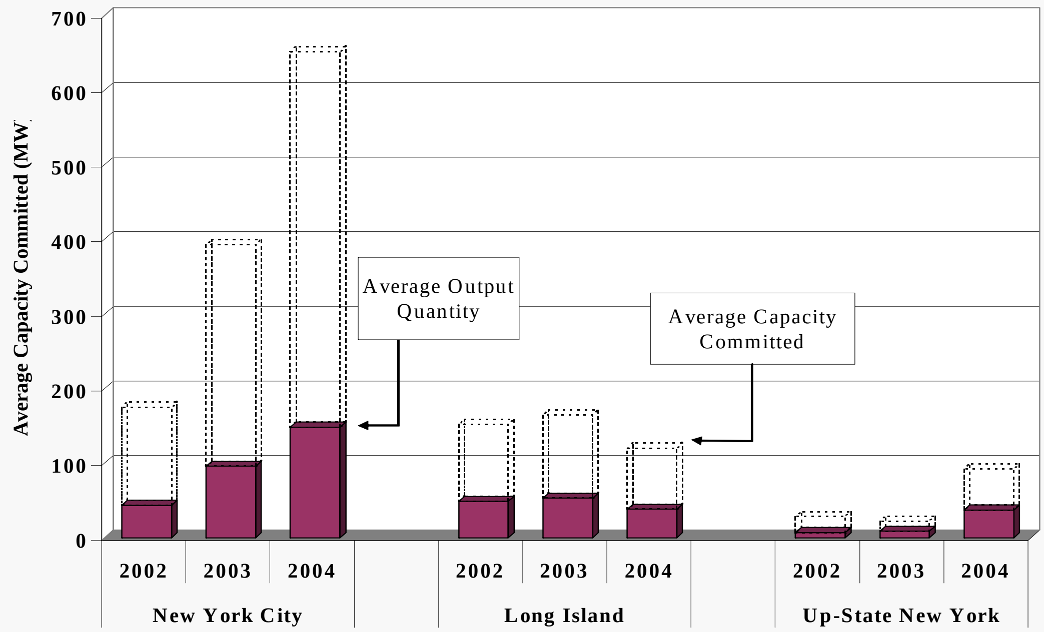


Note: August 2003 blackout hours excluded.

Supplemental Resource Evaluation

- The next analysis evaluates supplemental commitments made by the NYISO after the day-ahead market, which are important because they can influence the real-time market results.
- The average quantity of capacity committed through SRE in New York City has increased three-fold since 2002.
  - ✓ A major reason for the SREs are nitrous oxides (NOx) emission limits that require certain baseload units to operate in order for gas turbines to operate.
  - ✓ Additional SREs were required to meet NOx emission limits due to lower day-ahead market-based commitments.
- Since SREs are ordinarily called by individual transmission operators, the uplift associated with them constitutes a large share of RT Local Reliability Uplift, and is allocated to the local area.

Supplemental Resource Evaluation Commitment 2002 – 2004

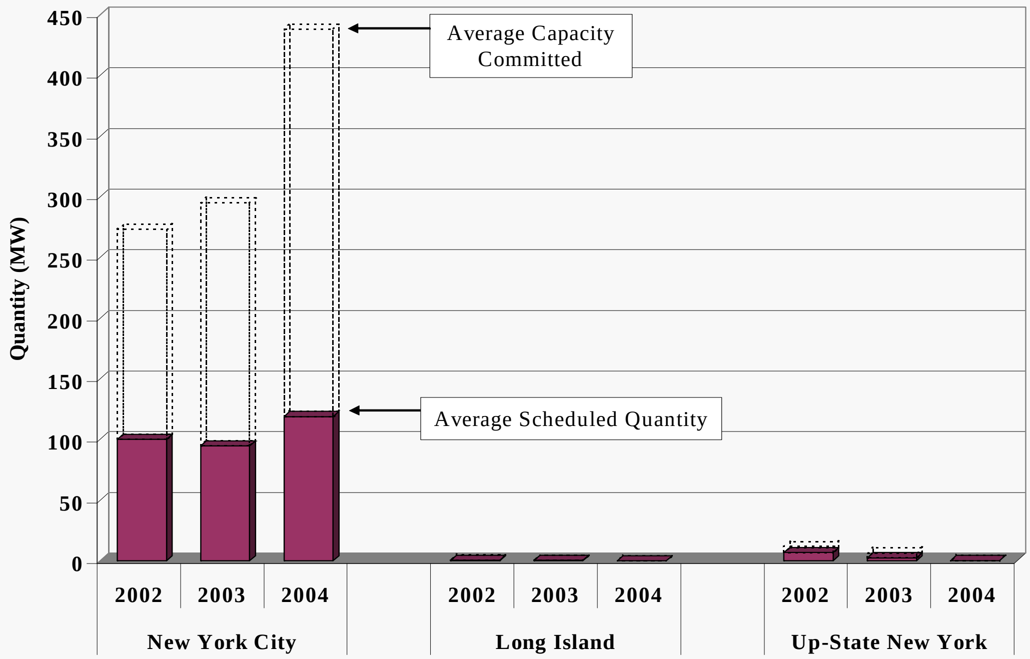


Note: August 2003 blackout hours excluded.

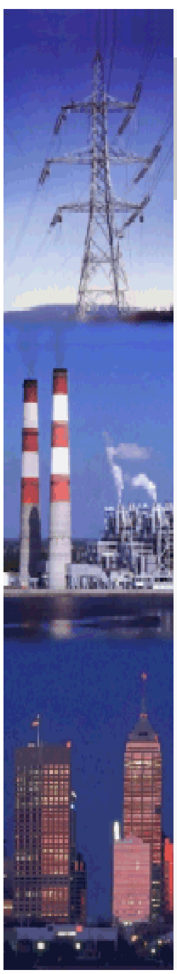
Day-Ahead Local Reliability

- The next analysis focuses on commitments made in the day-ahead market (i.e., by SCUC) to meet local reliability requirements.
- These commitments are not made because they are economic to serve day-ahead load and 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 caused by these commitments is incurred to make guarantee payments to other generators that will not cover their as-bid costs at the reduced price levels.
- The following figure shows the average quantity of these commitments.
  - ✓ The average capacity committed for local reliability was approximately 440 MW in 2004, which is a 50 percent increase from 2003.
  - ✓ These units received average day-ahead schedules of nearly 120 MW, indicating they are generally scheduled at their minimum generation level. This is the quantity of energy that will affect the day-ahead prices.

SCUC Local Reliability Pass Commitment
June 2002 – December 2004



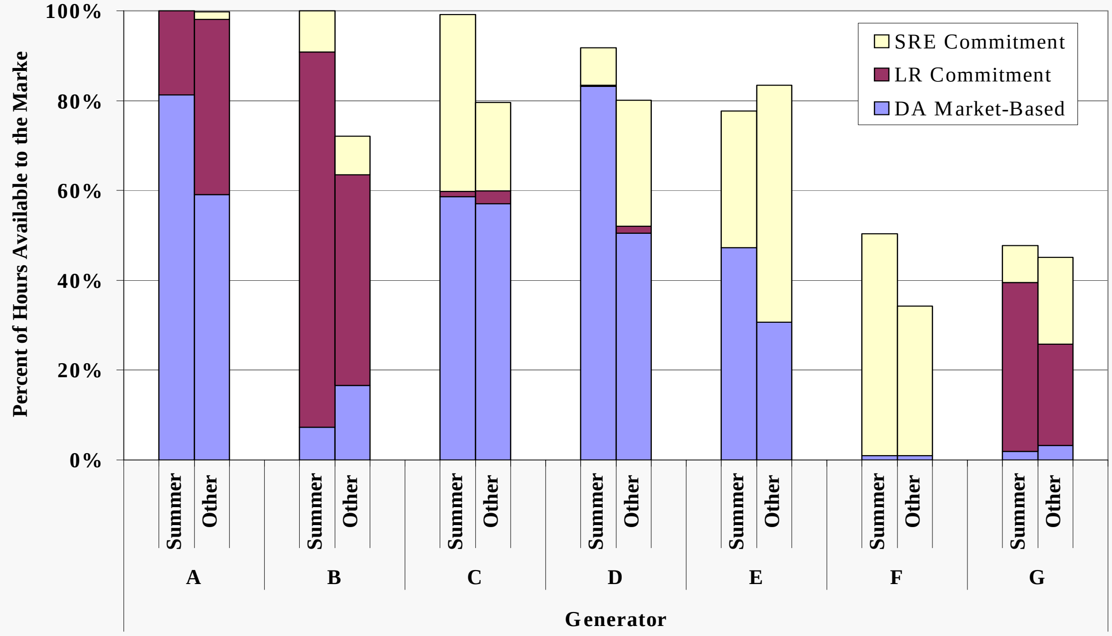
Note: August 2003 blackout hours excluded.



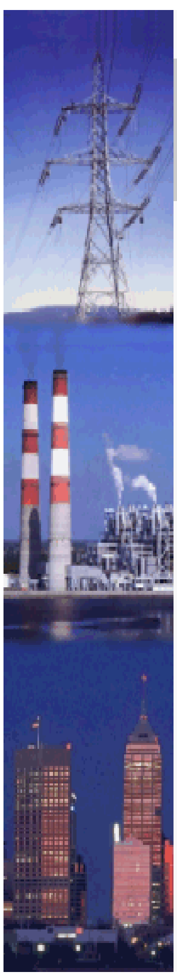
Units Committed for Local Reliability

- To further evaluate both the local reliability and SRE commitments, we analyze them at the individual unit level.
- The following figure shows seven units committed very frequently for local reliability or through the SRE process.
  - ✓ The values shown are the hours that each unit is committed as a percent of the hours that the unit is available (i.e., not on outage) in summer (June to August) and non-summer days.
  - ✓ The units in the figure accounted for more than 52% of the SREs and 93% of local reliability commitments by SCUC.
  - ✓ Five of these units are in NYC and two are on Long Island.
- Three of these units analyzed were needed almost every day in the summer.
  - ✓ When they were not committed economically, they were generally committed in the local reliability pass of SCUC or through SRE.
  - ✓ It would be more efficient for these units to be committed within the economic pass of SCUC because it may cause SCUC to not commit units in other locations, which would reduce uplift and improve energy prices.

Units Frequently Committed in 2004 through SRE or the Local Reliability Pass in SCUC



Note: August 2003 blackout hours excluded.



Supplemental Commitment Conclusions

- Supplemental commitments have a number of significant market effects:
  - ✓ Inefficiently reducing prices in the day-ahead and real-time markets;
  - ✓ When they occur in a constrained area, they will inefficiently dampen the apparent congestion into the area; and
  - ✓ Increasing uplift as units committed economically will be less likely to recover their full offer production costs;
- Local reliability commitments increased in 2004 because the resources needed in the City were economically committed less frequently.
- 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 allow operators to pre-commit units needed for NOx compliance or other local reliability needs.
  - ✓ This would likely only involve 3 to 4 units; pre-committing these units could reduce divergence between day-ahead and real-time prices.

Reserve Shortages and Shortage Pricing

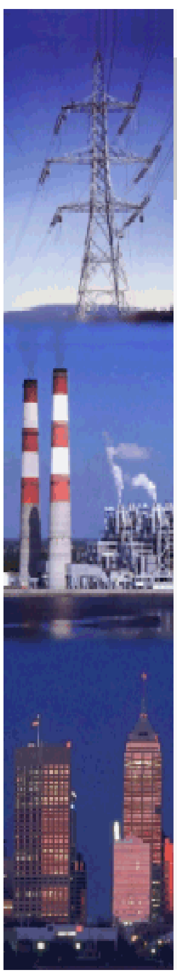
- Reserve Shortage Pricing ("scarcity pricing") became effective in June 2003.
  - ✓ Sets the LBMP at $1000/MWh in 10-minute reserve shortages.
  - ✓ Emergency demand response providers ("EDRP") can be paid up to $500 per MWh for load reductions, which can set the LBMP when they are needed to avoid a reserve shortage.
- Scarcity pricing was never triggered in 2004 due to:
  - ✓ Mild summer weather;
  - ✓ The surplus in generating capability outside of NYC; and
  - ✓ The availability of surplus of generation in New England.
- The lack of shortage conditions is important because they are needed over the long-run to produce the economic signals needed to support investment.
- The factors that have prevented the shortages are fundamental and temporary.
- A more sophisticated approach to shortage pricing utilizing reserve demand curves has been implemented as part of RTS.

Capacity Market

POTOMAC ECONOMICS

Capacity Market – Background

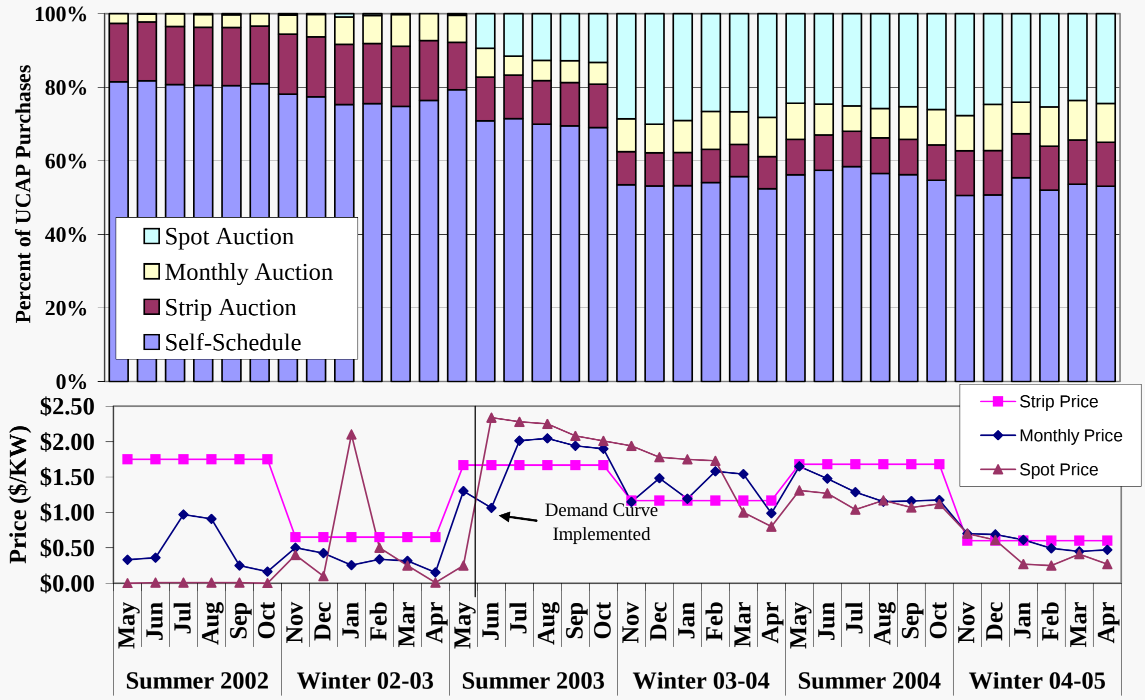
- The capacity market complements the energy and ancillary services markets to provide efficient economic signals for investment and retirement decisions.
- To improve the performance of the capacity markets, a demand curve was implemented in May 2003 in the monthly spot auction (i.e., the deficiency auction).
- All requirements must be satisfied at the conclusion of the spot market. All other auctions are voluntary forward markets.
- Capacity that is “self-scheduled” corresponds to capacity owned by an entity with a capacity obligation or purchased through a bilateral contract.

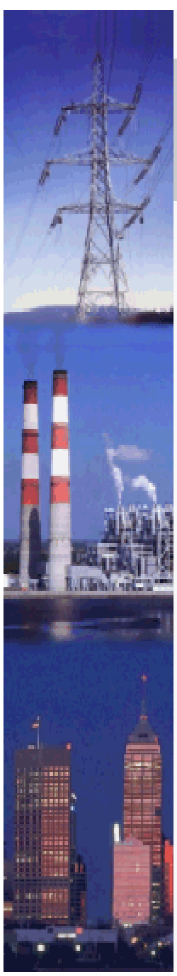


Capacity Market – New York State

- The following figure shows UCAP prices and procurements in the “rest-of-state” area -- does not include the requirements for NYC and Long Island.
- This figure shows that the capacity demand curve:
  - ✓ Stabilized the capacity prices and substantially improved the consistency of prices in the strip, monthly, and spot auctions.
  - ✓ Caused a larger share of the capacity to be sold in the spot auction, whose thin volumes had contributed to erratic prices in this auction.
- The increase in spot procurements corresponds to a reduction in self-schedules.
  - ✓ This is not a concern because it indicates that the spot purchases are largely displacing short-term bilateral purchases.

Unforced Capacity Market – Rest of State

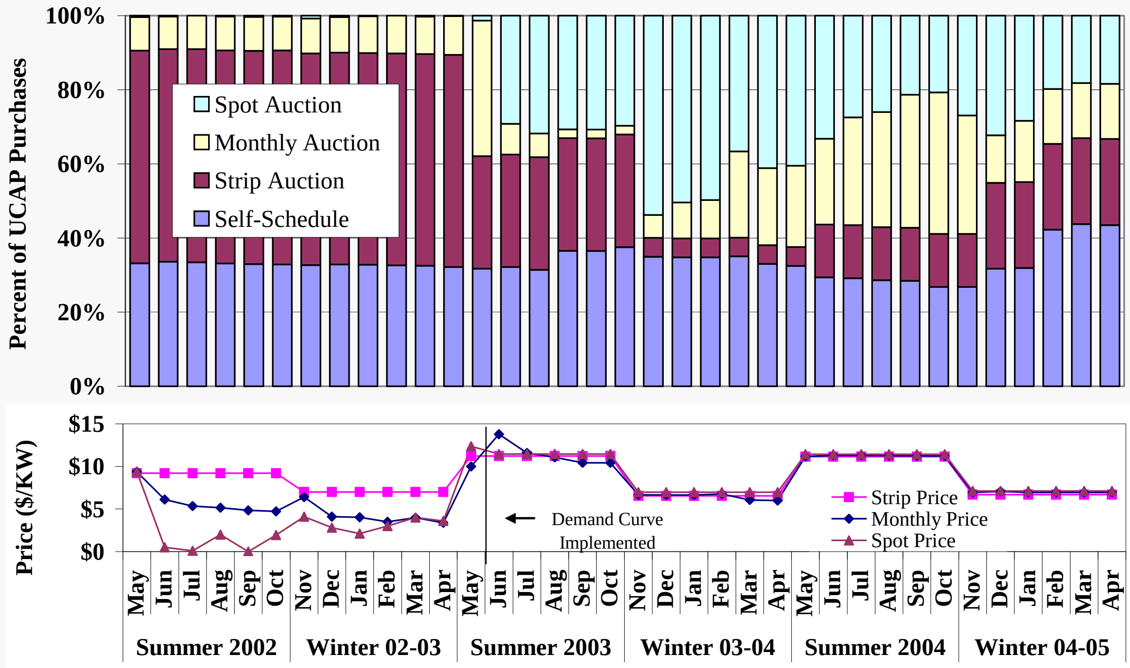


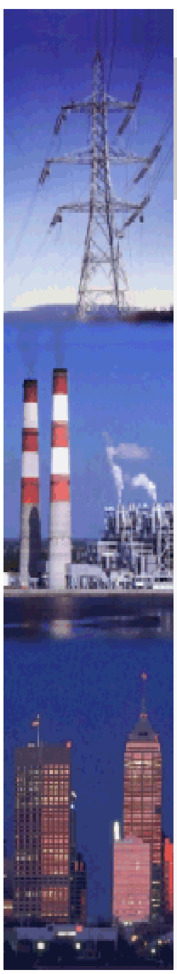


Capacity Market – New York City

- The following figure shows UCAP prices and the proportion of UCAP self-scheduled and purchased in the various UCAP auctions for NYC.
- The figure shows similar results for NYC as for the rest of the state area:
  - ✓ Prices in the three auctions have converged; and
  - ✓ A larger share of purchases were made in the spot auction, with less purchases in the strip and monthly auctions.
- However, there has been a gradual increase in the portions of UCAP self-scheduled, which now exceeds 40 percent.

Unforced Capacity Market – New York City

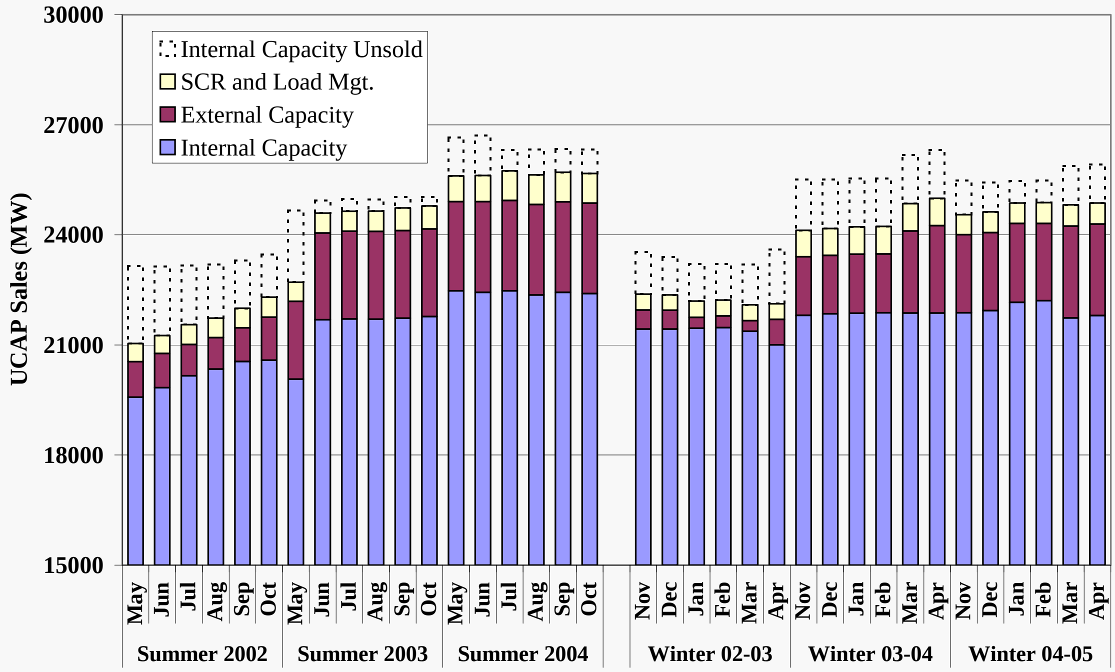


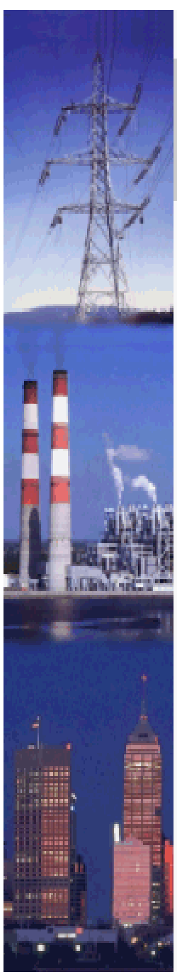


Capacity Market

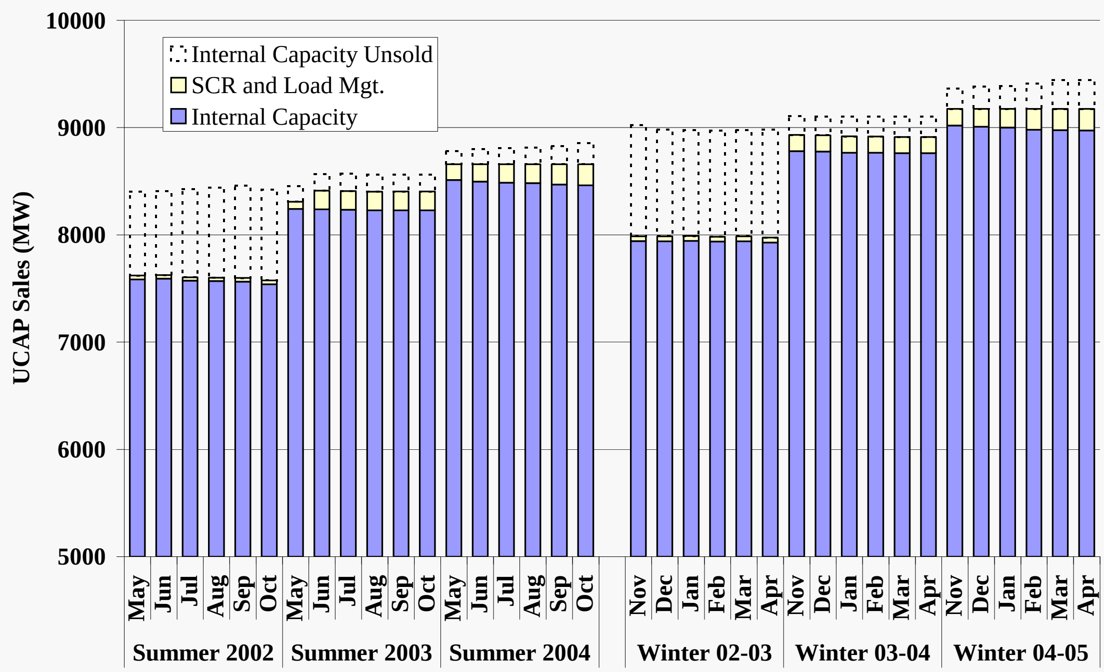
- The prior figures showed where the UCAP is scheduled or purchased.
- The following figures shows the source of UCAP supplies before and after the implementation of the capacity demand curve in NYC and the state.
- In New York State:
  - ✓ The capacity demand curve contributed to higher purchases in the rest-of-state.
  - ✓ A substantial share of the additional UCAP came from external sources.
  - ✓ A large amount of capacity was added with the Athens plant in May 2004.
- In New York City:
  - ✓ The increased UCAP purchases are primarily due to increased requirements in the City rather than the demand curve.
  - ✓ Virtually all of the capacity in the City was sold, i.e., much less capacity was withheld from the capacity market.
  - ✓ A substantial amount of capacity was added at the Ravenswood plant in May 2004.

UCAP Sales – New York State





UCAP Sales – New York City



External Transactions

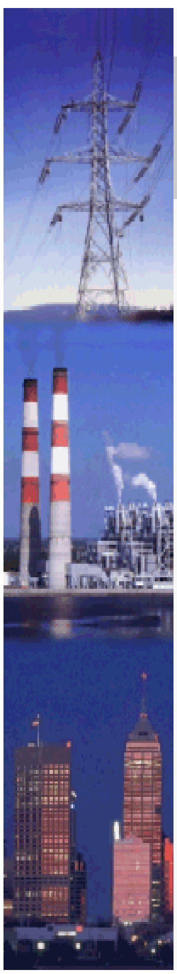
POTOMAC ECONOMICS

Utilization of the Interfaces in All Hours

- The performance of the wholesale electricity markets depends not only on the efficient utilization of the internal resources, but also the efficient utilization of the transmission interfaces between NY and other areas.
- The figures in this section contain our analysis of utilization of these interfaces.
- When the interfaces are efficiently utilized, one would expect that the hourly prices in adjacent areas would not differ greatly except when the interface capability is fully used (the interface constraint is binding).
- The following four figures plot the hourly difference in prices between New York and neighboring markets against net exports during hours when transmission constraints are not binding.

Utilization of the Interfaces in All Hours

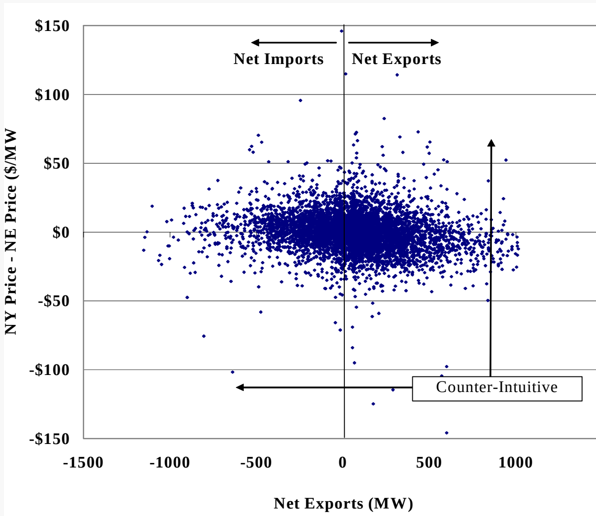
- On the left side of the first four figures:
  - ✓ The price differences plotted against the left axis are always computed by subtracting the external price from the New York price (i.e., positive price differences mean prices are higher inside New York).
  - ✓ The net exports are shown on the x-axis with positive values reflecting net exports from New York and negative values representing net imports.
  - ✓ Two "counter-intuitive" quadrants are shown where power is scheduled *from* the higher priced market *to* the lower priced market.
- On the right side of these four figures, the monthly average price differences between New York and the adjacent market are shown.
- These figures show that the real-time markets continue to not be efficiently arbitraged by participants.
  - ✓ Uncertainty, imperfect information, and required offer lead times limit the ability of participants to capitalize on real-time arbitrage opportunities.

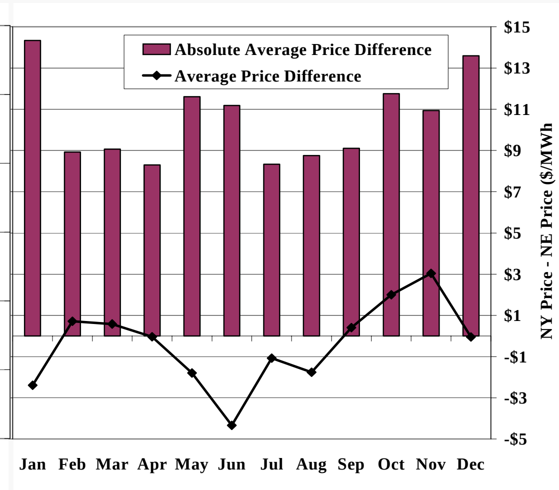


Utilization of the Interfaces in All Hours

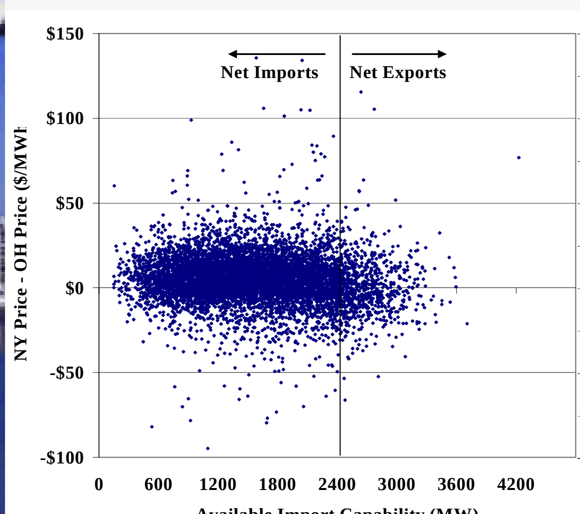
- These results reinforce the importance of the provisions being developed to improve real-time interchange between New York and New England.
- These provisions will be particularly important when the capacity surpluses in the Northeast are eliminated – when optimizing the flow between areas will have larger economic and reliability consequences.
- Fees assessed to transactions between control areas tend to inhibit convergence.
  - ✓ In 2005, export fees between New York and New England were eliminated, which will help improve the arbitrage of the adjacent markets.
  - ✓ However, exports from New England scheduled after the day-ahead market continue to be allocated uplift charges for certain types of supplemental commitment that can be significant.

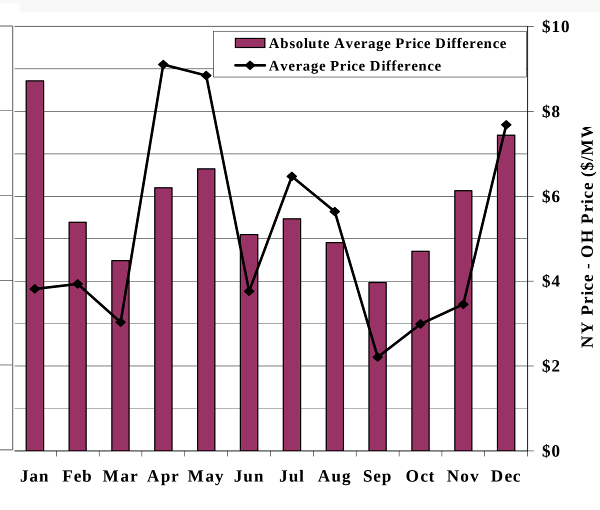
Real-Time Prices and Interface Schedules Eastern NY and New England





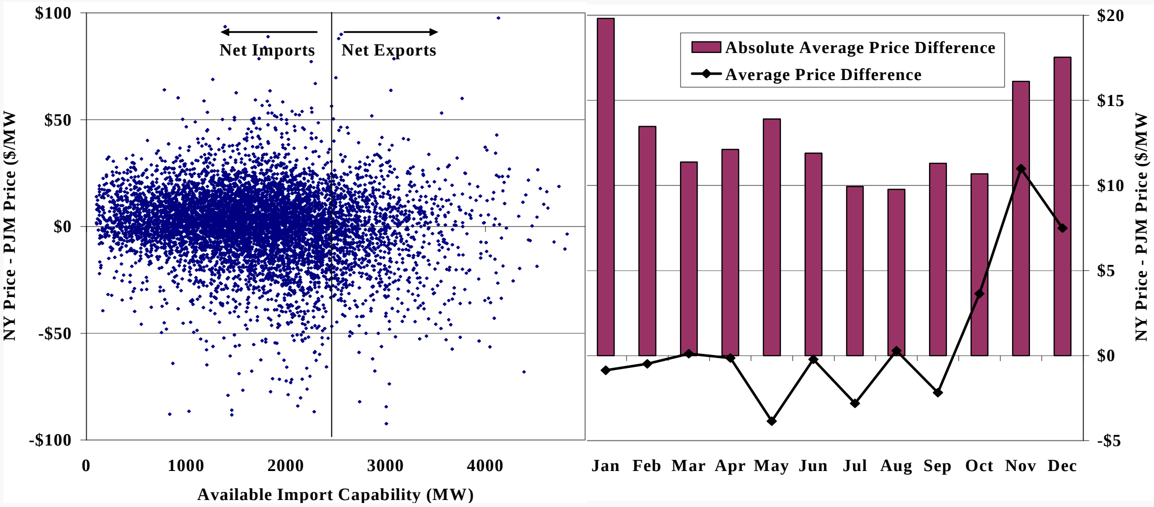
Real-Time Prices and Interface Schedules West NY and Ontario

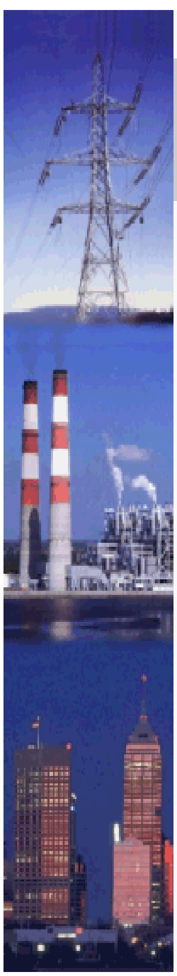




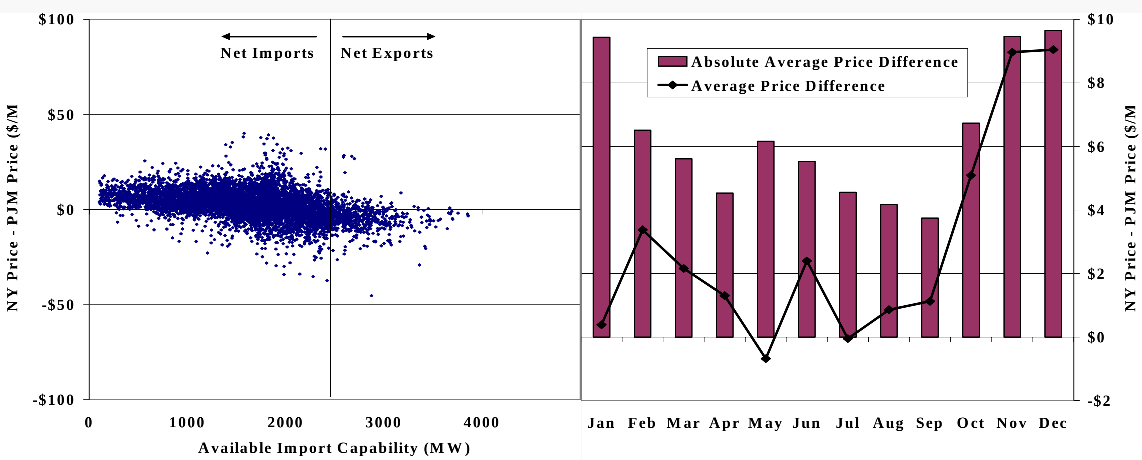
* Price difference measured in US dollars

Real-Time Prices and Interface Schedules NY West Zone and PJM





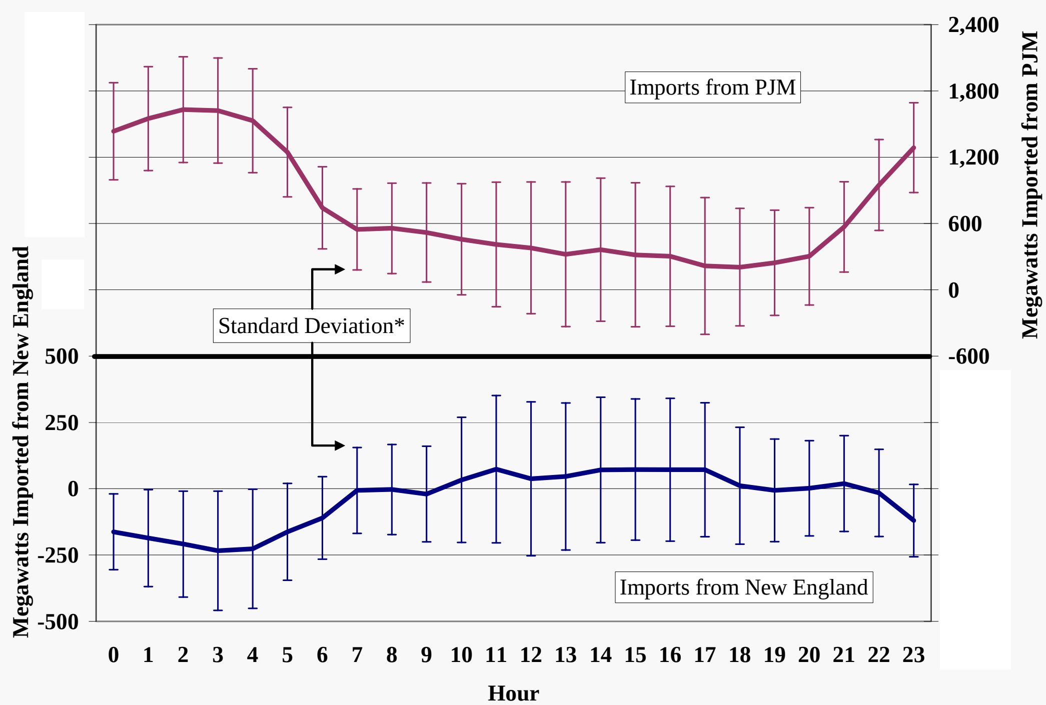
Day-Ahead Prices and Interface Schedules NY West Zone and PJM



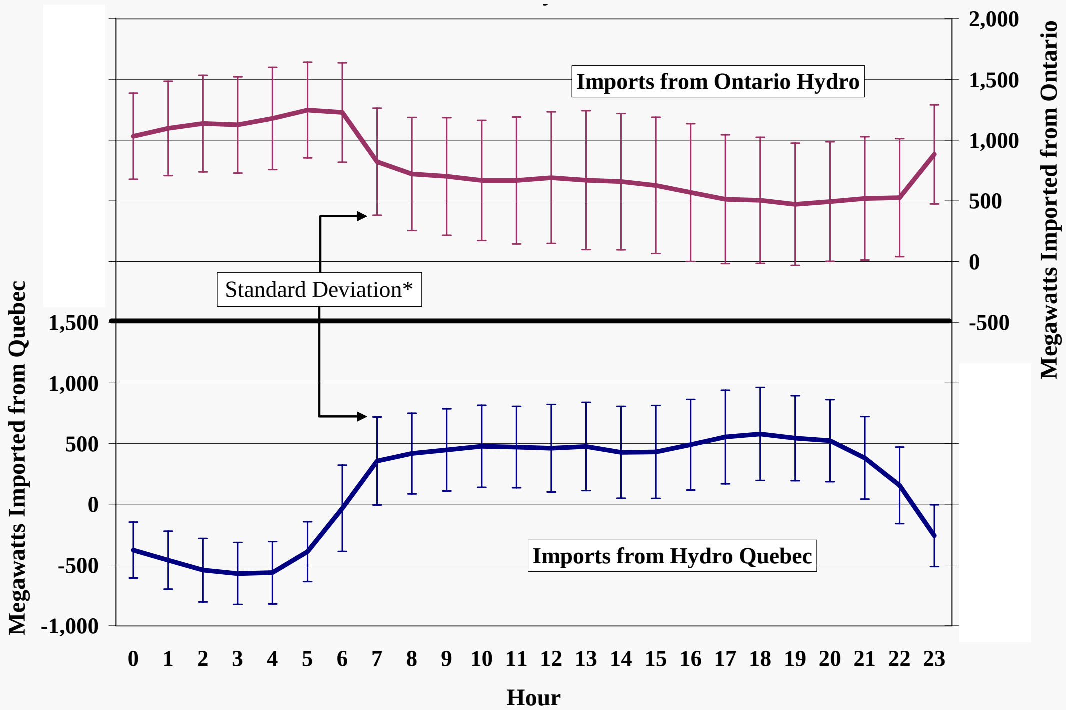
Imports into New York

- The next two figures show how imports vary across an average day from different adjacent regions.
  - ✓ Imports from PJM are highest during the night-time hours, while New York is a net exporter to New England during this period.
  - ✓ During the day, New York imports from both regions. Though PJM exports a smaller quantity to New York during the day than at night, it is still much larger than supply obtained from New England.
  - ✓ Hydro-Quebec is a net importer at night and exporter during the day from New York.
  - ✓ New York typically receives 500 MW of imports from Ontario during the day and nearly 1000 MW at night. This is a significant increase from 2003.
- The change in schedules that occur during the 16 peak hours are consistent with most schedules being made to support longer-term bilateral agreements (rather than arbitrage of hourly prices).

Average Net Imports from LMP Markets by Hour of Day Weekdays, 2004



Average Net Imports from Canada by Hour of Day
Weekdays, 2004

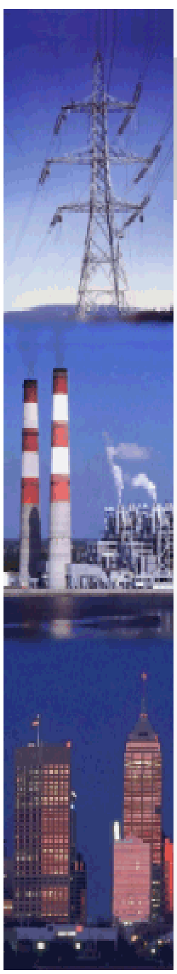


Ancillary Services Markets

POTOMAC ECONOMICS

Ancillary Services

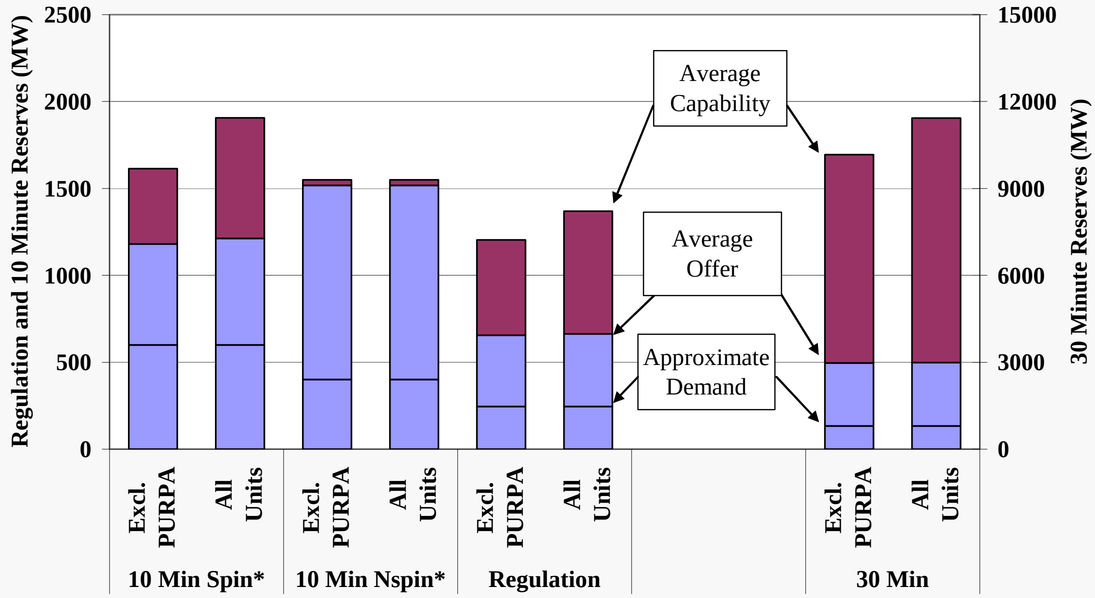
- This section summarizes the conditions and outcomes in the ancillary services markets in New York during 2004.
- The first figure shows the offers and procurements in each of the ancillary services markets. For each ancillary service, this figure shows:
  - ✓ The total capability to supply the service;
  - ✓ The quantity offered by suppliers; and
  - ✓ The average level of demand for each service.
- The next two figures show the costs and prices in the various markets administered by the NYISO.



Ancillary Services

- The first figure shows that with the exception of the 10-minute non-synchronous resources, a substantial portion of the capability all other ancillary services were not offered in the day-ahead markets.
- However, ancillary services markets are generally not tight because offers to supply typically exceed approximate demand:
  - ✓ For 30 minute reserves, offers typically exceed approximate demand by 280 percent.
  - ✓ Offers for total 10-minute reserves, 10-minute spinning reserves, and regulation (spin and non-spin) east of the Central-East interface, offers typically exceed approximate demand by 170 percent.
  - ✓ For regulation and 10-minute spinning reserves, offers typically exceed approximate demand by 100-170 percent – but ignores the fact that some 10-minute spinning reserves can be purchased in the West.
- Prior recommendations to increase the portion of the capability offered have now been implemented as part of the RTS system implemented in February 2005, which we will evaluate following the Summer 2005.

Ancillary Services Capability and Offers

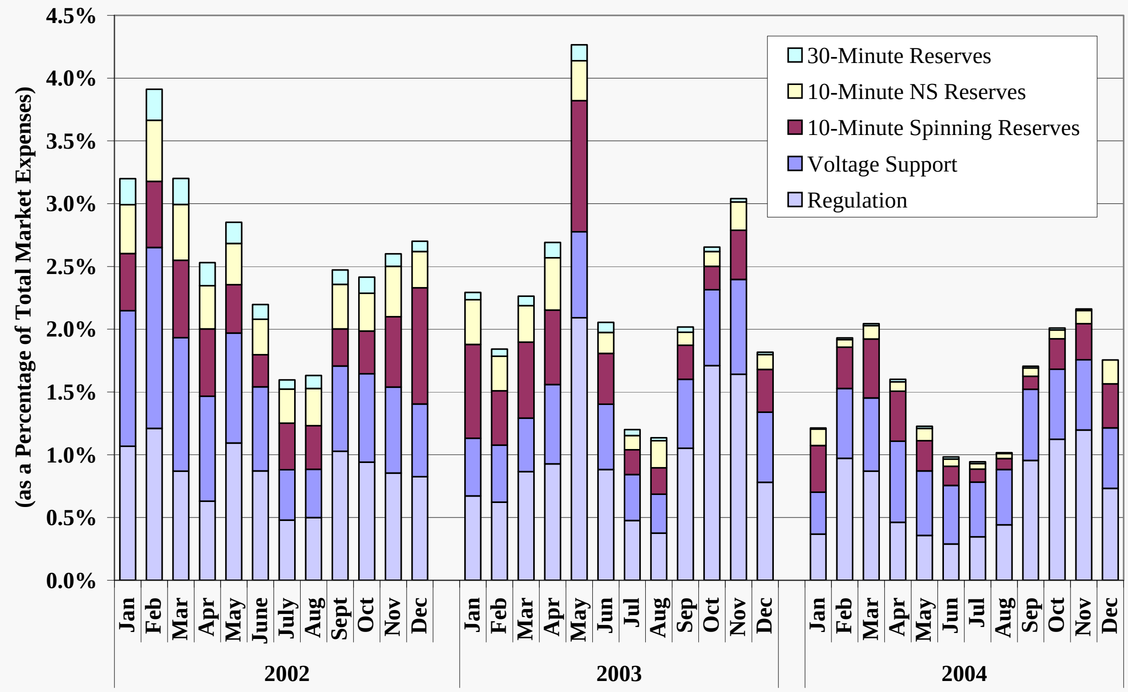


*Eastern side of the Central-East Interface only

Ancillary Services Costs

- The following figure shows the ancillary services expenses, including expenses for regulation, voltage support, and various operating reserves.
- These costs tend to be smaller as a percent of total market expenses in the summer than in other seasons due to higher average energy prices during the summer and relatively low levels planned outages.
- Ancillary services costs declined slightly as a percentage of total market expenses from close to 2.5 percent in 2002 to roughly 1.5 percent in 2004.
  - ✓ Over the same timeframe, total ancillary services expenses decreased by $15 million to a total of approximately $94 million in 2004.
- Decreased expenditures for ancillary services was primarily due to reductions in the cost of 10-minute total and 30-minute reserves.

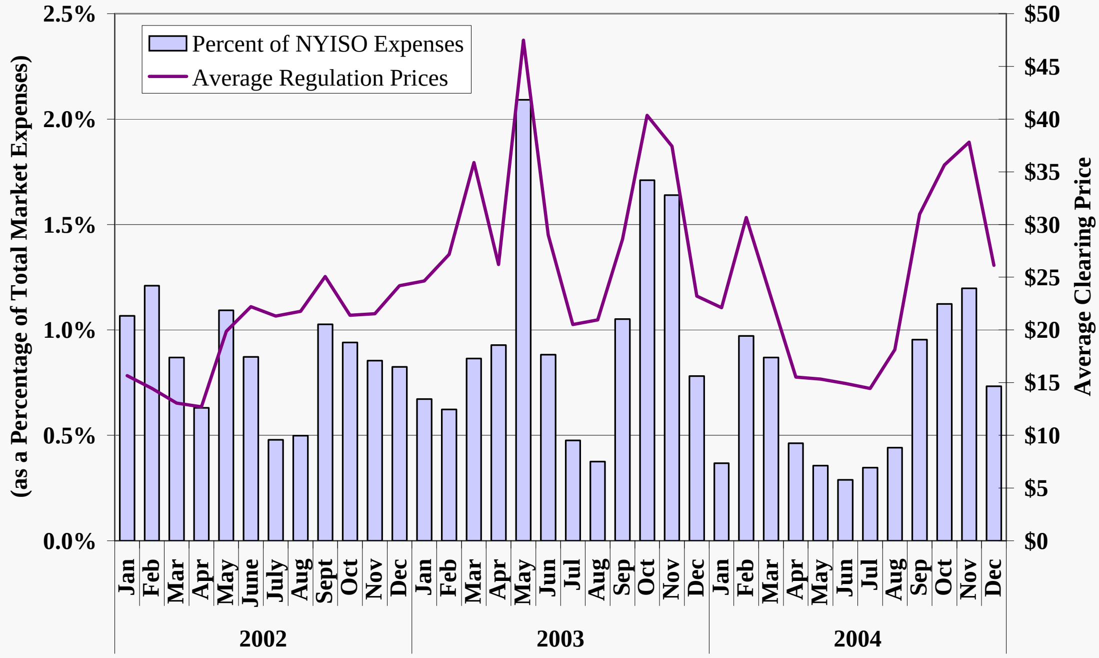
Expenses for Ancillary Services 2002 – 2004



Ancillary Services

- The following figure shows the average price for regulation service from 2002 through 2004, as well as the share of the total market expenses that are accounted for by regulation.
- Regulation prices have increased from 2002 levels. The primary reasons for the increases in regulation prices were:
  - ✓ Modeling changes in SCUC and BME to recognize that units' minimum generation level may limit the range in which a unit can regulate down. This reduced the supply available on some units, particularly off-peak.
  - ✓ Fuel price increases that increase opportunity costs to provide regulation.
- Regulation costs still remain a relatively small part of the total electricity market expenses for the NYISO (little more than 1 percent).

Average Clearing Price and Expenses for Regulation



Demand Response Programs

POTOMAC ECONOMICS

Demand Response Programs

- The New York ISO has some of the most effective demand response programs in the country.
- There are currently three demand response programs in New York:
  - ✓ Day-Ahead Demand Response Program (DADRP) – This program schedules physical demand reductions for the following day, allowing resources to offer into the day ahead market as any supply resource. These resources are paid the day-ahead clearing price.
  - ✓ Special Case Resources (SCR) – These are loads that must curtail within two hours. They are called when operators forecast a reserve deficiency and may sell capacity in the capacity market corresponding to their commitment to curtail load.
  - ✓ Emergency Demand Response Program (EDRP) – The emergency demand response program pays loads that curtail on two hours notice the higher of $500/MWh or the real-time clearing price. SCRs receive this payment as well.

Day-Ahead Demand Response Program

- The day-ahead program that schedules physical reductions in load for the following day is the day-ahead demand response program.
- The quantities participating in this program are very low:
  - ✓ There were 2818 hours with day-ahead demand response bids.
  - ✓ The average quantity bid was approximately 2 MW per hour, and the average quantity scheduled was less than half a megawatt.
  - ✓ There were 222 hours when day-ahead demand response bids amounted to 10 MW or more, with a high of 17 MW, and these bids were accepted in 132 hours.
  - ✓ The hours with these large bids primarily occurred around holidays such as New Year's Day, Thanksgiving, and Christmas week.
- The low participation may be due to the alternatives available for demand to bid in the markets (virtual trading and price-capped load bidding).

Emergency Demand Response

- EDRP and SCRs were not utilized in 2004 due to mild load conditions and good resource availability.
- Special Case Resources are qualified to sell into the capacity market, and by adding to the total supply, help reduce capacity prices.
  - ✓ In 2004, the quantity of SCR/ICAP subscribers that sold capacity were:
    - 175 MW in NYC;
    - 98 MW in Long Island; and
    - 707 MW in upstate New York.
  - ✓ The state total has increased 30 percent from 2003.