2006 State of the Market Report
New York Electricity Markets

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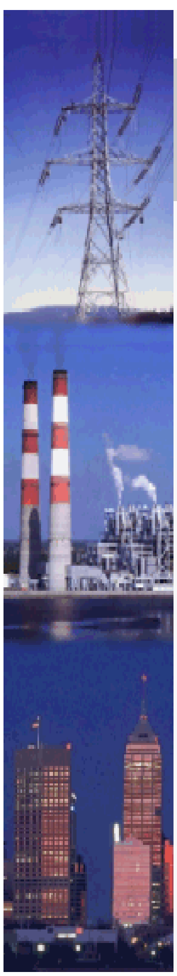
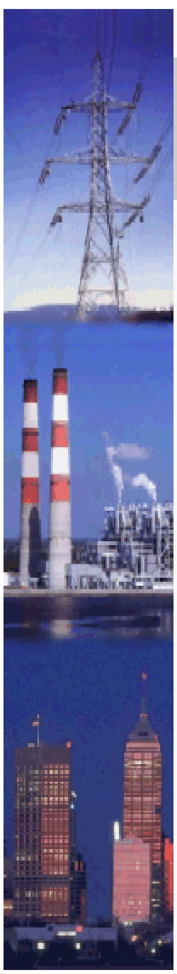


Executive Summary: Introduction

- This presentation provides results of our assessment of the performance of the New York electricity markets in 2006.
- With the implementation of the new real-time spot markets on February 1, 2005, the New York ISO ("NYISO") now operates the most complete and efficient set of electricity markets in the U.S. The NYISO has:
  - ✓ Day-ahead and real-time energy markets that reflect the true value of energy at each location on the network;
  - ✓ Day-ahead and real-time operating reserves and regulation markets;
    - – Some of the requirements for these markets vary by location to reflect the true reliability needs of the system.
    - – These markets are jointly-optimized with its energy markets;
  - ✓ Capacity market with requirements that vary by location and season, which include a monthly spot and short-term forward markets;
  - ✓ A market for transmission rights that allow participants to hedge the congestion costs associated with using the transmission network;
  - ✓ A commitment model that runs each 15 minutes to optimize the use of peaking resources and scheduling of imports and exports.

Executive Summary: Introduction

- The NYISO markets continue to deliver substantial benefits to the States' consumers by meeting its demands at the lowest cost.
  - ✓ The day-ahead market causes the lowest-cost units to be started each day.
  - ✓ The real-time market delivers the lowest cost energy to New York's consumers, to the maximum extent allowed by the transmission network.
  - ✓ Perhaps the most substantial benefits are that transparent, efficient market signals are available to guide decisions to:
    - Invest in new resources,
    - Maintain existing resources; and
    - Develop the capability for demand to voluntarily reduce its consumption under tight conditions.
- Regarding the last benefit, relying on private investment that is made in response to competitive price signals shifts the risks and costs of poor decisions and project management from New York's consumers to the investors.
- Indeed, moving away from costly regulated investment was the primary impetus for the move to competitive electricity markets.



Executive Summary

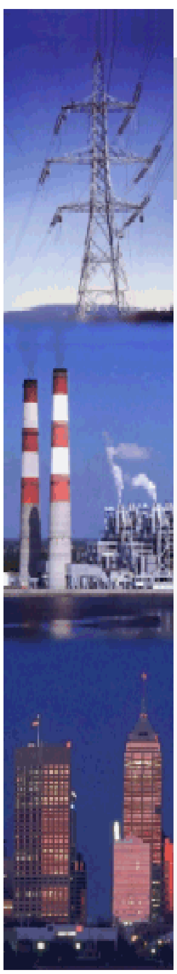
<u>Overall Market Performance and Prices</u>

- The energy and ancillary services (operating reserves and regulation) markets were very competitive in 2006.
  - ✓ The report shows that suppliers have not been withholding generation to inflate energy or ancillary services prices.
  - ✓ However, work is underway to address competitive issues in the NYISO capacity market.
- Prices fell by 20 to 30 percent in most areas in New York. These reductions were primarily due to:
  - ✓ Substantially lower natural gas prices in 2006.
    - Fuel costs constitute the vast majority of most generators' variable costs of producing electricity.
    - In a competitive market, therefore, lower fuel costs will translate to lower offer prices and lower electricity prices.
  - ✓ Substantial new generation added in New York City in 2006. Close to 1000 MW of new capacity was added in the City, which reduced the power flows and congestion into the City.

Executive Summary

Market Performance and Prices (cont.)

- Convergence between prices in the day-ahead and real-time markets is important because the day-ahead market plays an important role in determining which resources are started each day.
  - ✓ Convergence in the energy markets improved markedly in 2006 as participants gained experience with the new real-time markets deployed early in 2005.
  - ✓ However, convergence in the energy markets at specific locations within New York City was not as good as at most locations in the State.
  - ✓ Convergence in the operating reserve market in eastern New York was also relatively poor during the summer when reserve shortages in the real-time market caused the real-time prices to be much higher than day-ahead prices.
  - ✓ The report recommends potential changes for the NYISO to consider that may improve the liquidity of the market in these areas and improve convergence.
- Convergence between the NYISO and adjacent markets is also important --the report shows that prices between New York and adjacent markets during unconstrained periods continue to not be well-arbitraged during peak periods.
  - ✓ This indicates that the transmission interfaces with adjacent areas are not fully utilized, which can have a large impact on prices during peak conditions.
  - ✓ The report includes a recommendation to address this issue.



Executive Summary

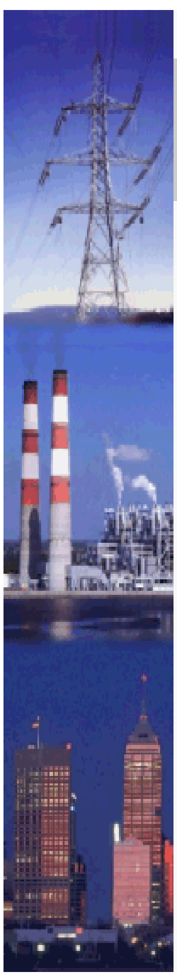
Market Performance during Shortage Conditions

- Prices that occur under shortage conditions are an important contributor to efficient long-term price signals.
- The markets produced relatively accurate shortage pricing in 2006 – i.e., shortage pricing occurred when resources were insufficient to meet both the energy and operating reserves needs of the system.
  - ✓ In 2005, there were a significant number of intervals when eastern New York was physically short of 10-minute reserves, but shortage pricing did not occur.
    - – If this issue had not been addressed, the long-term economic signals provided by the New York markets would be compromised.
  - ✓ In May 2006, the NYISO addressed the largest cause if this issue, which led to a substantial reduction in the instances physical shortages of operating reserves were not accompanied by corresponding shortage prices.
- A significant portion of the shortages in eastern New York were caused by reliability procedures invoked when a thunderstorm occurs (the NYISO calls a “Thunderstorm Alert” or “TSA”).
  - ✓ TSAs result in the NYISO redispatching downstate generation to reduce the southbound power flows on the network into New York City.

Executive Summary

Long-Term Economic Signals

- Regarding long-run price signals, the report shows that prices in 2006 would not support investment in new generation in most locations.
  - ✓ These signals are correct in the short-term because there is a surplus of generation in most areas and prices are very competitive.
  - ✓ However, investors should expect these signals to improve over the next few years as the surplus dissipates.
- This analysis also shows that market signals have tended to shift in favor of investment in baseload and intermediate resources that, while more costly to build, are lower cost to run and produce more electricity.
  - ✓ Over time, the markets provide efficient incentives to invest in a diverse array of generating resources, demand response resources, and transmission.
  - ✓ Any investments that receive regulatory support should be consistent with these signals, except to the extent that they provide benefits not reflected in market prices (e.g., environmental benefits).



Executive Summary

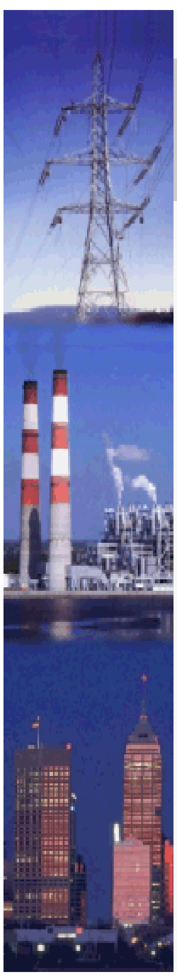
Capacity Market

- The capacity market plays an important role in contributing to the long-term economic signals that govern new investment and retirement decisions for generation, transmission, and demand response resources.
- The capacity market results in New York City were not highly competitive in 2006.
  - ✓ After the addition of approximately 1000 MW of new capacity in 2006, the capacity market clearing prices were virtually unchanged.
  - ✓ A significant amount of existing capacity did not clear in the UCAP market due to the capacity offer prices.
  - ✓ This issue and other issues related to the New York City capacity market is currently the subject of a litigated proceeding at the Federal Energy Regulatory Commission.
- Based on the results of our evaluation of the markets' long-term economic signals and the fact that resources are needed relatively soon in downstate areas, the report recommends that NYISO consider whether additional capacity zones are needed outside of New York City and Long Island.

Executive Summary

Uplift Costs

- Uplift costs decreased by close to 20 percent, or $53 million, from 2005 to 2006.
  - ✓ These costs are associated with Bid Production Cost Guarantee Payments (“BPCG”) made to generators when they are dispatched, but do not recoup their as-bid costs from NYISO markets.
  - ✓ The reduction in these costs is primarily due to more efficient use of peaking resources, which can be attributed to the improved real-time market software implemented in early 2005.
    - – We estimate that this software saved participants approximately $32 million in 2006.
  - ✓ Other factors that contributed to the reduction in uplift expenses include:
    - – Lower natural gas prices in 2006; and
    - – More detailed network modeling of the New York City system in the real-time market, which was implemented by the NYISO in May 2006.



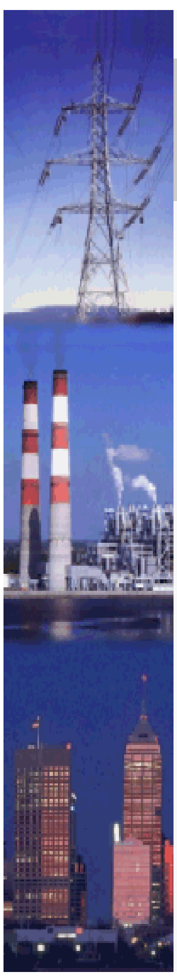
Executive Summary

Transmission Congestion

- Total congestion costs decreased by more than $200 million in 2006.
  - ✓ Day-ahead and real-time congestion costs totaled more than $770 million in 2006 compared to $990 million in 2005.
  - ✓ These reductions were due to:
    - – Lower fuel costs (primarily natural gas), which reduce the redispatch costs incurred to manage network congestion;
    - – The addition of close to 1000 MW of generating capacity in New York City, which has reduced congestion into and within the City.
  - ✓ These total congestion costs do not reflect the efficiency benefits or savings that consumers could expect from investing in new transmission.
    - – Efficiency benefits of transmission are generally much lower than these total congestion costs.
    - – Transmission investment should occur when the efficiency benefits are larger than the investment costs.

Executive Summary: Recommendations

1. ***Evaluate the feasibility of introducing virtual trading of ancillary services.***
   - ✓ Virtual trading would address poor convergence between day-ahead and real-time ancillary services prices.
   - ✓ This change could promote convergence of ancillary services prices and reduce physical suppliers' incentive to raise their offer prices.
   - ✓ However, it would need to be carefully studied to ensure it will not have unintended consequences on day-ahead commitment.
2. ***Consider allowing virtual trading at a more disaggregated level or identify other means of improving convergence in the load pockets.***
   - ✓ Price convergence has improved in NYC load pockets due, in part, to the introduction of modeling individual transmission lines and contingencies in NYC (rather than simplified interfaces) in the real-time market.
   - ✓ However, some NYC load pocket prices still do not converge well.
3. ***Evaluate several areas of potential improvements the report suggests for the real-time commitment model ("RTC").***
   - RTC, which was deployed in 2005, has resulted in significant improvements to the efficiency of commitment and scheduling during real time.
   - However the report identifies some inconsistencies between RTC and the real-time market that can affect the commitments and schedules from RTC.



Executive Summary: Recommendations

4. ***Consider re-calibrating the dispatch levels in the real-time market's pricing model for units that are not responding to dispatch signals.***
   - ✓ Further improvements to the consistency of the pricing and physical dispatch passes of RTD could improve the efficiency of NYISO's energy and ancillary services pricing (particularly during shortages) and reduce uplift.
   - ✓ We recommend the NYISO consider re-calibrating the dispatch levels in the pricing pass for units that are not responding to dispatch signals.
5. ***Implement the proposed "transmission demand curve" that would limit the marginal re-dispatch costs to a maximum of $4,000/MWh.***
   - ✓ Transmission constraint shadow prices can reach extremely high levels for brief periods when redispatch options are unavailable or relatively ineffective.
   - ✓ This may result in re-dispatch that provides little reliability benefit, and in some cases may actually make the system less reliable.
   - ✓ To reduce the incidence of these situations, the NYISO has proposed to limit the marginal re-dispatch costs to a maximum of $4,000/MWh.
   - ✓ We will continue to evaluate congestion management under the new methodology including the appropriateness of the $4,000/MWh limit.

Executive Summary: Recommendations

6. ***Improve the modeling of local reliability rules and NOx constraints in New York City to include them in the initial day-ahead commitment.***
   - ✓ Commitments by the local reliability pass of the day-ahead market and by ISO operators after the day ahead are often required to meet local requirements in NYC, which increases uplift throughout the state.
   - ✓ In the short-run, we continue to recommend that the ISO allow operators to pre-commit certain units that are known to be needed prior to the day-ahead market.
   - ✓ Both of these changes require that the NYISO first work with participants to revise the cost-allocation methodology for uplift associated with the local reliability requirements.
7. ***Continue the work with ISO-New England to develop and implement ITS (Intra-hour Transaction Scheduling) to better utilize the transfer capability between regions.***
8. ***Consider whether additional capacity zones are needed outside of New York City and Long Island.***
   - ✓ This may be necessary to allow the markets' economic signals to be consistent with the fact that resources are needed relatively soon in downstate areas.

Market Prices and Outcomes

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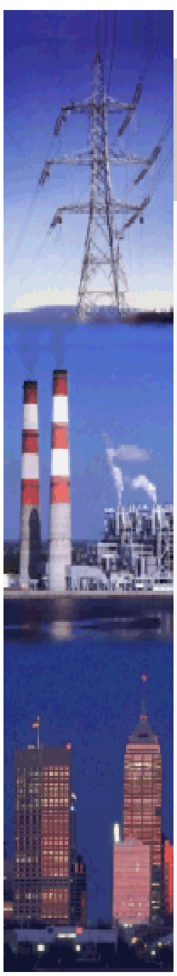
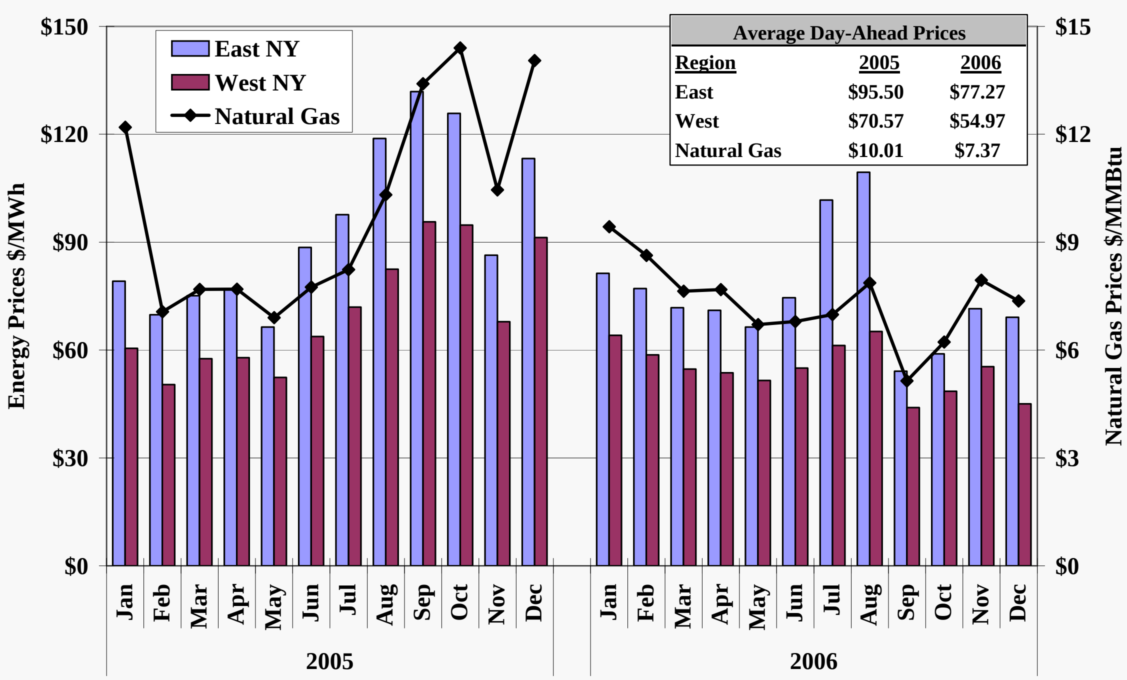
Fuel Prices and Electricity Prices

- The following figure shows monthly energy prices in 2005 and 2006.
- Movements in fuel prices led to corresponding changes in electricity prices in 2006:
  - ✓ Natural gas prices were 27 percent lower in 2006 than in 2005.
  - ✓ 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.
- Substantial price differences continued between West NY and East NY:
  - ✓ Average prices in East NY were about $22/MWh higher than in West.
  - ✓ This is due primarily to congestion on flows from West NY to East NY as well as within East NY.
  - ✓ Transmission losses are also significant on flows from the West to East.



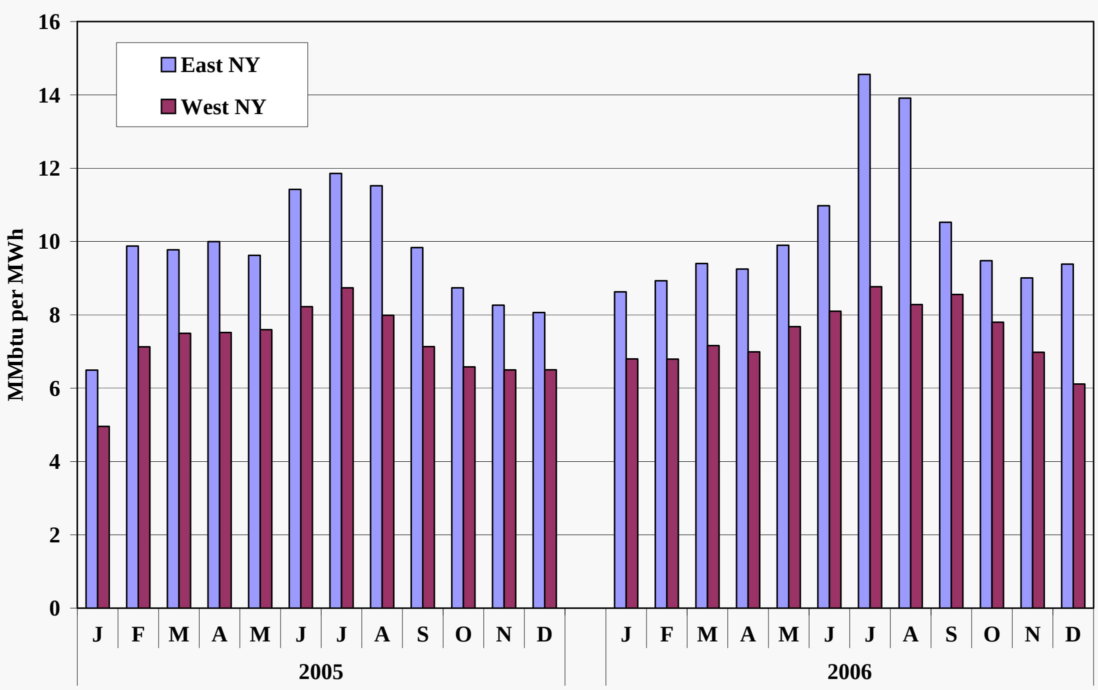
Day-Ahead Electricity and Natural Gas Prices 2005 – 2006



Fuel Prices and Energy Prices

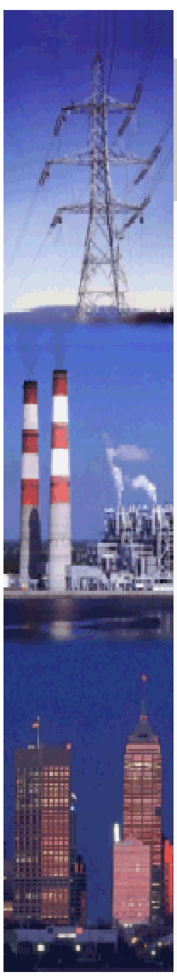
- To identify changes in electricity prices that are not driven by changes in natural gas prices, the following figure shows the marginal heat rate that would be implied if natural gas were always the marginal fuel.
  - ✓ Implied Heat Rate = (Day-Ahead Elec. Price) ÷ (Natural Gas Price)
  - ✓ This metric highlights variations in electricity prices that are due to factors other than fluctuations in natural gas prices.
- The following figure shows:
  - ✓ During July and August, implied heat rates in East New York were significantly higher in 2006 than in 2005 due to improved shortage pricing in 2006;
  - ✓ In West New York an in other months in East New York, average implied heat rates were approximately equal in 2005 and 2006.

Average Implied Marginal Heat Rate
Based on Day-Ahead Electricity and Natural Gas Prices
2005 – 2006

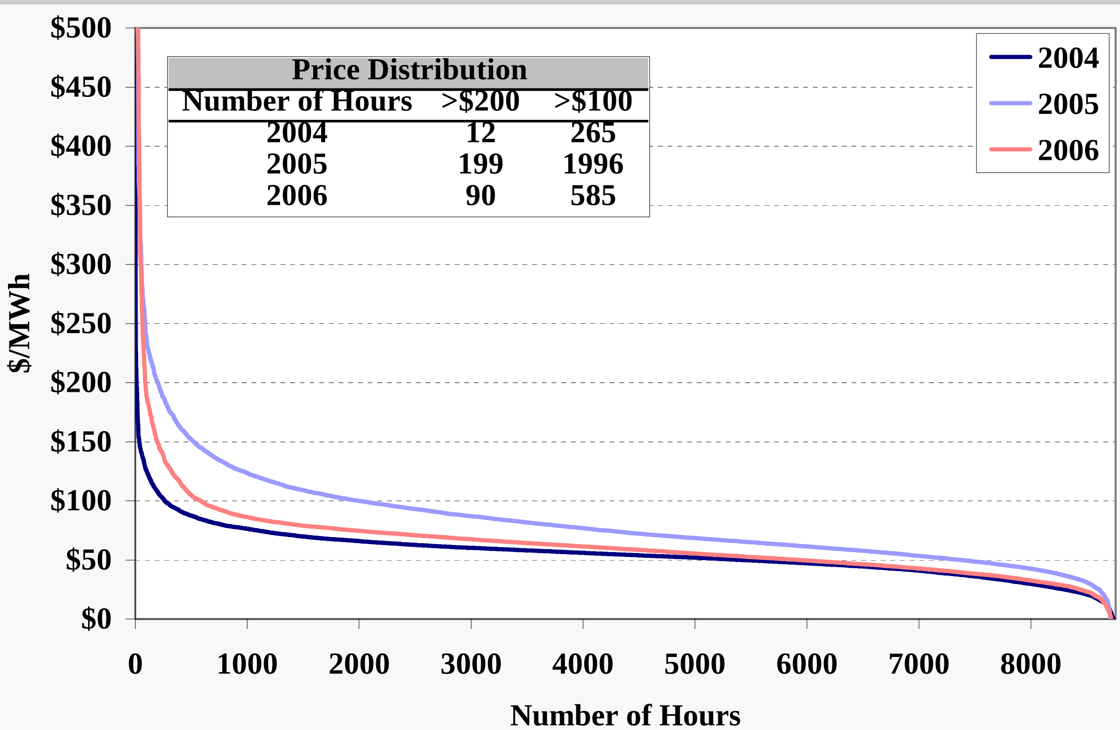


Energy Prices

- The next two figures show how prices have changed in the last three years on an hourly basis.
- The first figures show real-time price duration curves for 2004, 2005, and 2006.
  - ✓ These curves show the number of hours when the load-weighted price for New York State was greater than the level shown on the vertical axis.
- In 2006, prices were lower than in the previous year in most hours due to lower fuel prices and more moderate demand:
  - ✓ In 2006, there were 585 hours with prices above $100, compared to 1996 such hours in 2005.
  - ✓ In 2006, there were 90 hours with prices above $200, compared to 199 such hours in 2005.
  - ✓ At the highest price levels, in 2006 there were 25 hours of prices above $500, but only 21 such hours in 2005.
- The lower prices in most hours is generally attributable to lower fuel prices.
- However, there are a few more hours of very high prices (>$500 MWh) during the highest peak load days due to improvements in the shortage pricing.

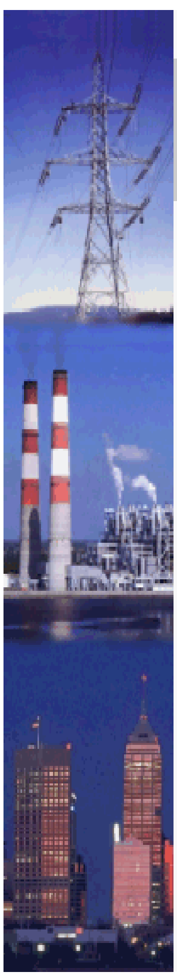


Price Duration Curves
State-wide Average Real-Time Price, 2004 – 2006

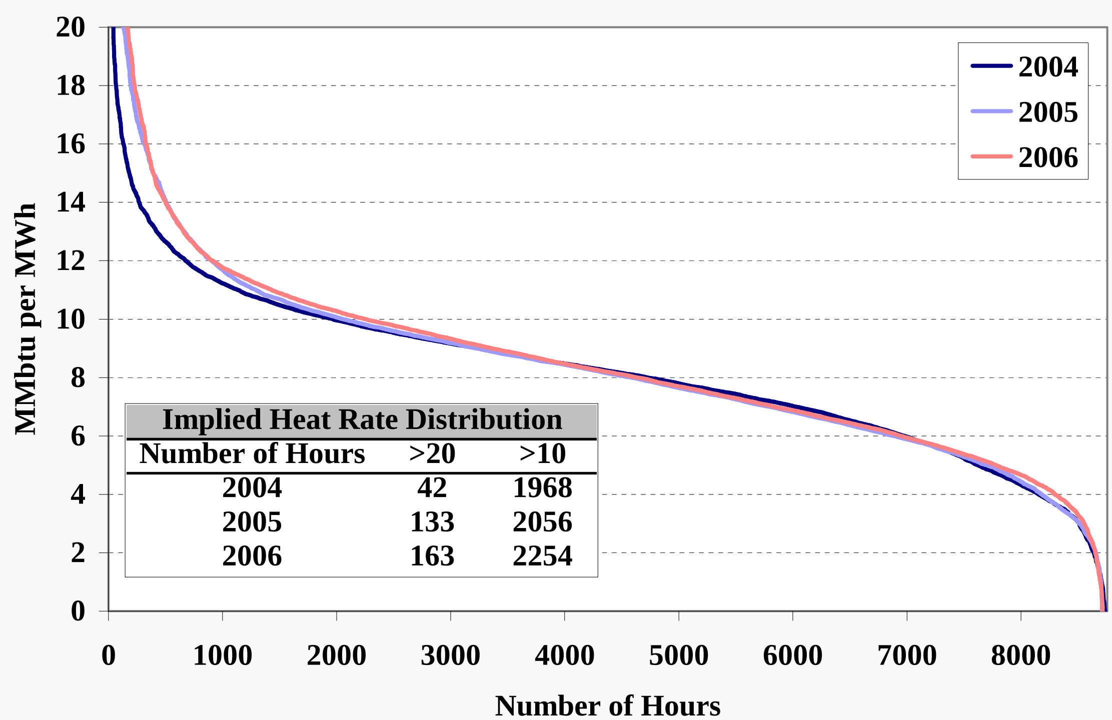


Energy Prices

- To help isolate the price effects that are not caused by changing fuel prices, the second figure shows duration curves for implied marginal heat rates during the same period.
- In general, implied marginal heat rates have been consistent over the past three years.
  - ✓ The past three years experienced comparable numbers of hours when the implied marginal heat rate was greater than 10 MMbtu per MWh.
- However, the number of high-priced hours (i.e. hours with implied marginal heat rates > 20 MMbtu per MWh) has increased substantially since 2004.
  - ✓ Hotter weather contributed to higher peak load in many hours, especially in 2005.
  - ✓ The shortage pricing provisions in SMD 2.0 led to more than 20 hours of shortage prices corresponding to reserve shortages in both 2005 and 2006.
  - ✓ Shortage pricing did not occur in 2004.



Implied Marginal Heat Rate Duration Curves Based on State-wide Average Real-Time Price, 2004 – 2006

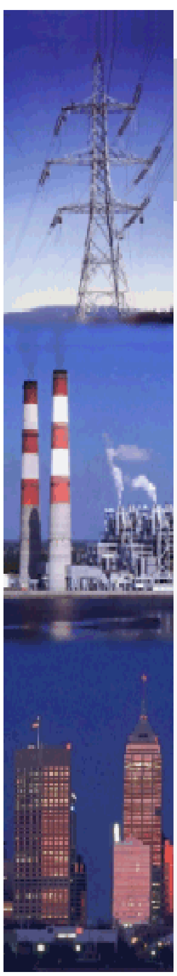


Implied Heat Rate Distribution

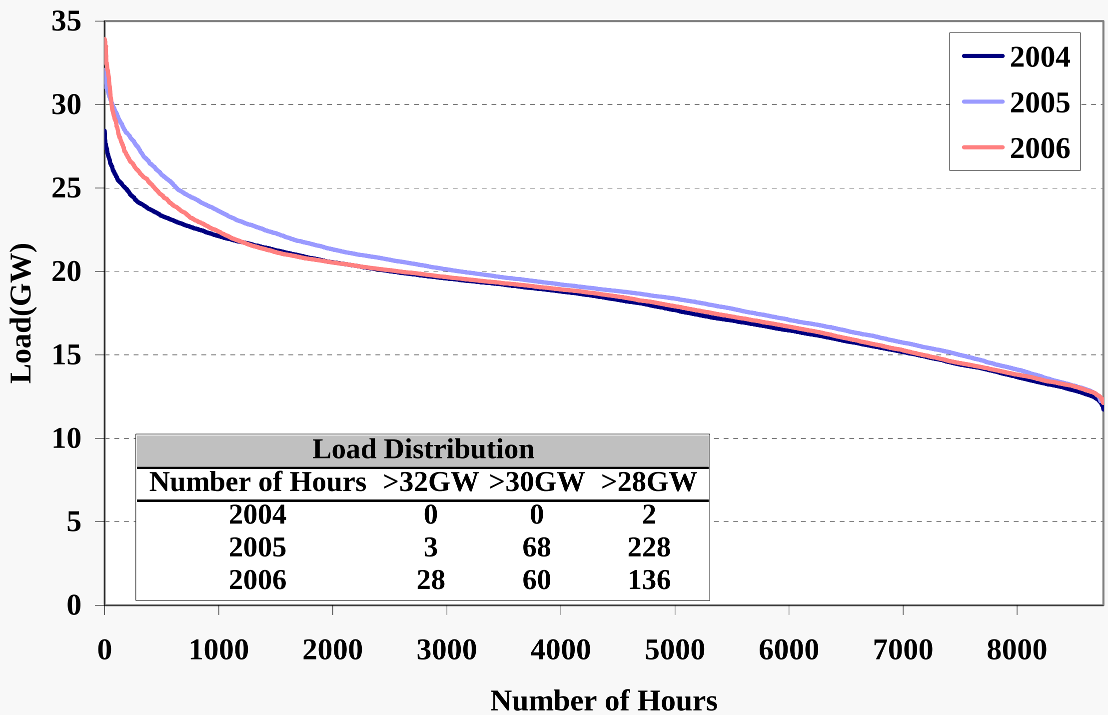
Number of Hours	>20	>10
2004	42	1968
2005	133	2056
2006	163	2254

Load Profile

- Additional insight into market conditions in 2006 can be gained from examining load levels. The next figure shows load duration curves for 2004, 2005, and 2006.
  - ✓ These curves show the number of hours in which the load is greater than the level indicated on the vertical axis.
- Mild summer weather in 2004 lead to moderate load conditions.
- In 2005, there were far more hours with extreme demand levels.
  - ✓ In 2005, there were 68 hours when loads exceeded 30 GW, but no such hours in 2004.
- In 2006, aside from a few days with record load levels, loads were generally lower than in 2005.
  - ✓ In 2006, there were 60 hours when loads exceeded 30 GW.
  - ✓ But 2006 also experienced 28 hours with loads over 32 GW, compared to just 3 such hours in 2005.



Load Duration Curves
New York State Load, 2004 – 2006

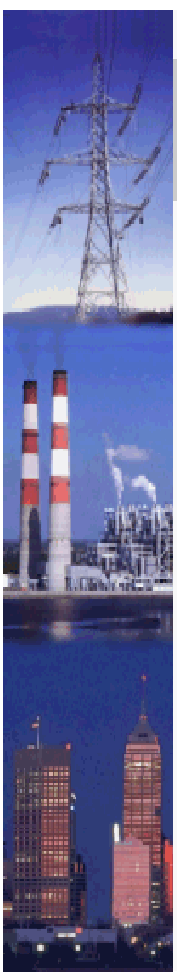


Load Distribution

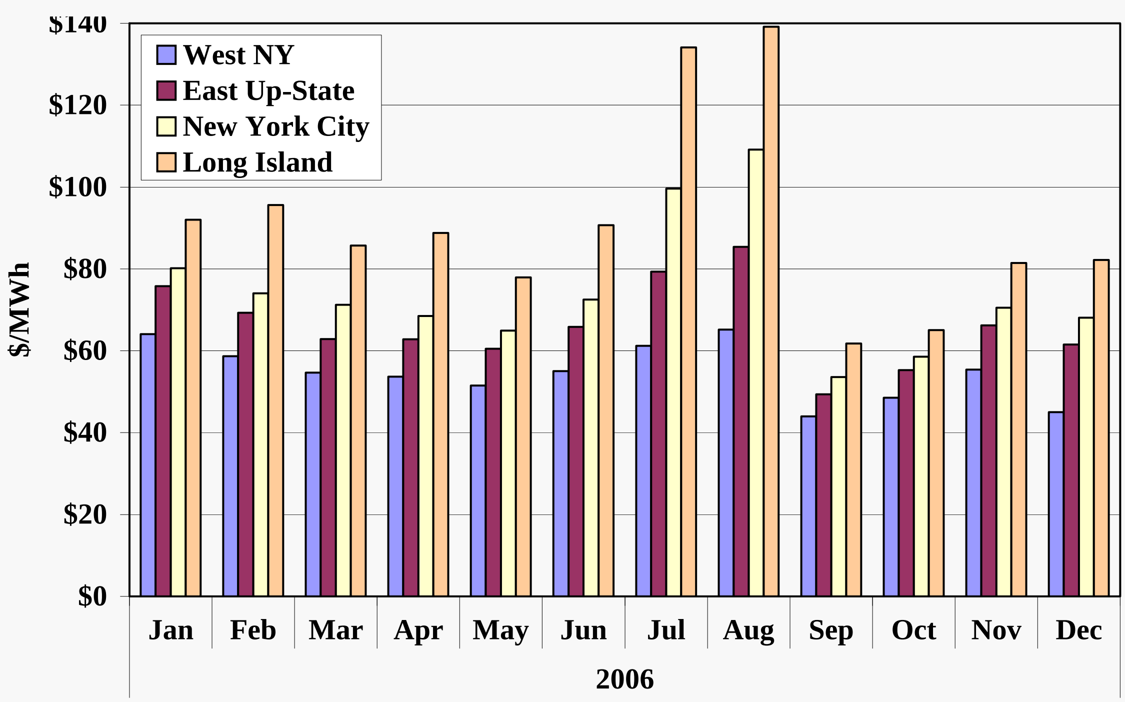
Number of Hours	>32GW	>30GW	>28GW
2004	0	0	2
2005	3	68	228
2006	28	60	136

Day-Ahead Energy Prices

- The next figure presents monthly average day-ahead energy prices in western NY, eastern upstate NY, NYC, and Long Island for 2006.
- Prices in east up-state exceed prices in the west by an average of $12 per MWh due to:
  - ✓ The marginal cost of transmission losses,
  - ✓ Central-East congestion, and
  - ✓ Congestion within eastern upstate NY that constrains flows from the Capital region toward NYC and Long Island.
- Constraints into New York City and Long Island, and local load pockets within these areas, further raise average prices in these zones.
  - ✓ Price differences between New York City and the eastern upstate region averaged $9 per MWh in 2006. This reduction from $16 the difference in 2005 was primarily due to new capacity in New York City.
  - ✓ Price differences between Long Island and the eastern upstate region averaged over $27 per MWh in 2006, up from a $22 difference in 2005.



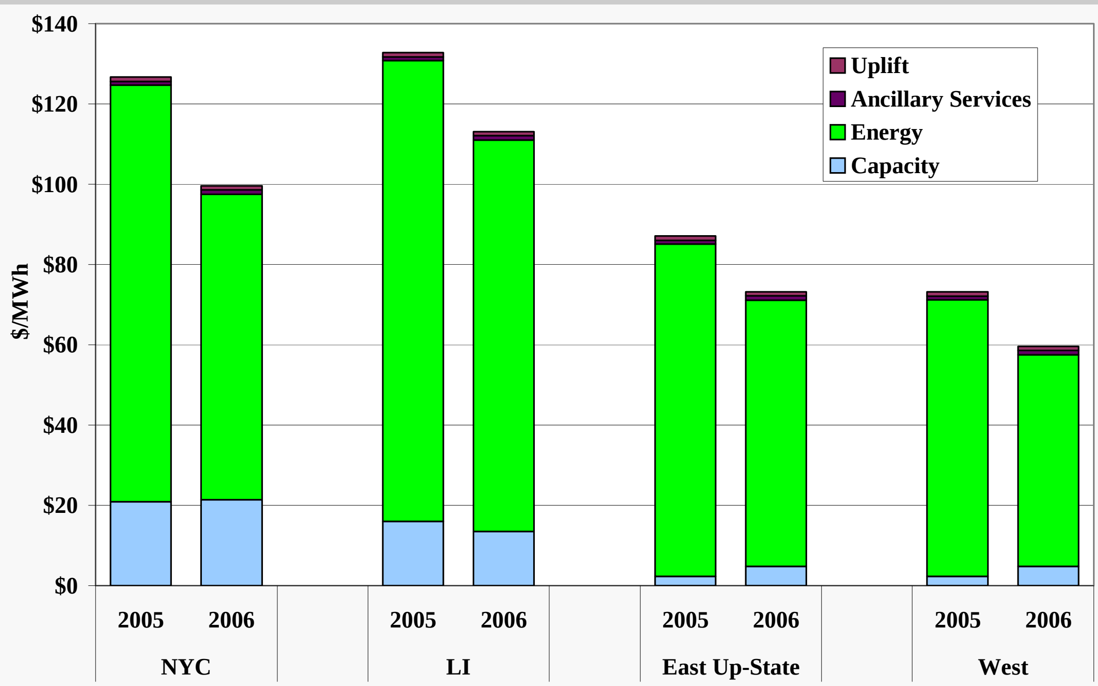
Day-Ahead Energy Prices
2006



All-In Energy Prices

- The following figure shows an “all-in” price that includes the costs of energy, ancillary services, capacity, and uplift.
  - ✓ 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 fell substantially from 2005 to 2006.
  - ✓ Lower fuel costs and generally lower load levels contributed to the reduction in average energy prices.
  - ✓ Energy prices fell more in New York City than elsewhere in the state, reflecting the addition of substantial new capacity.
  - ✓ However, capacity prices in New York City did not fall due to offer patterns in the capacity market, which is discussed later in this report.

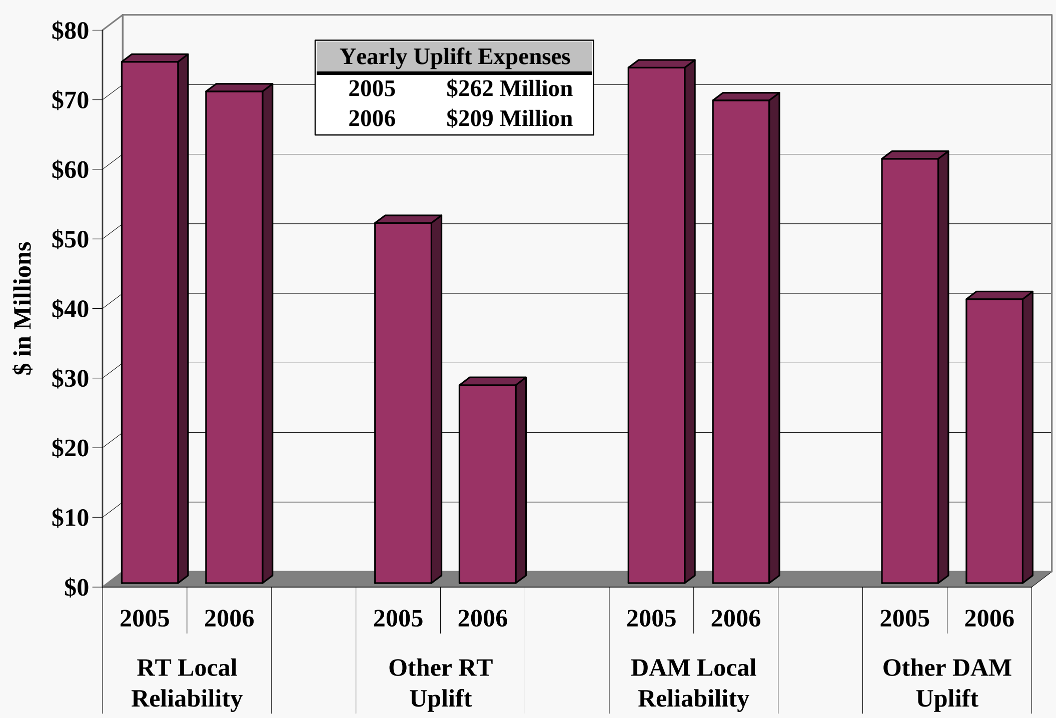
Average All-In Price
2005 – 2006



Uplift Charges from BPCG Payments

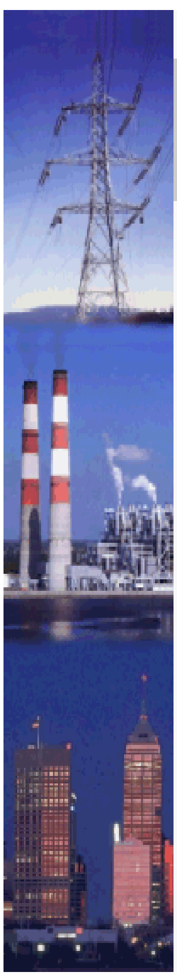
- The following figure summarizes uplift charges resulting from Bid Production Cost Guarantee (“BPCG”) payments during 2005 and 2006.
  - ✓ BPCG payments arise when a generator is committed or dispatched but does not recoup its as-bid costs from energy and ancillary services market revenue.
- Non-local reliability uplift is allocated to all load in NYCA, whereas local reliability uplift is allocated to the local TO.
- Total yearly uplift expenses declined to $209 million in 2006 from $262 million in 2005.
  - ✓ Non-local reliability uplift decreased substantially due to lower fuel costs and improvements to the efficiency of gas turbine commitment by the real-time market software.
  - ✓ Local reliability uplift expenses stayed relatively constant as the benefits of lower fuel costs were partially offset by more frequent commitment for local reliability.

Summary of Uplift Expenses from BPCG Payments 2005 – 2006

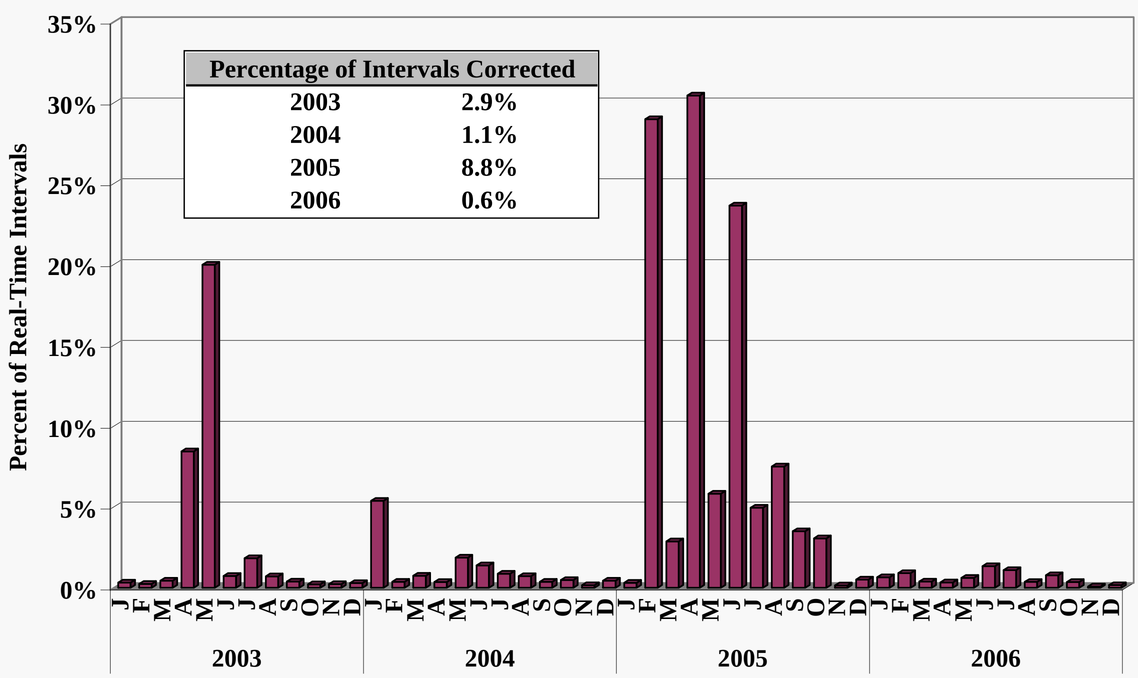


Price Corrections

- 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.
- Reducing the number of price corrections improves the market.
- The following figure summarizes the frequency of price corrections in the real-time energy market in 2003-2006.
  - ✓ The rate of corrections spiked in 2005 after the implementation of SMD 2.0 due to software issues.
  - ✓ Nine major software issues under SMD 2.0 accounted for the majority of price corrections.
- Once these software issues were addressed by NYISO, the frequency of price corrections fell below the levels prior to SMD 2.0.
- In 2006, NYISO had a very low rate of price corrections.

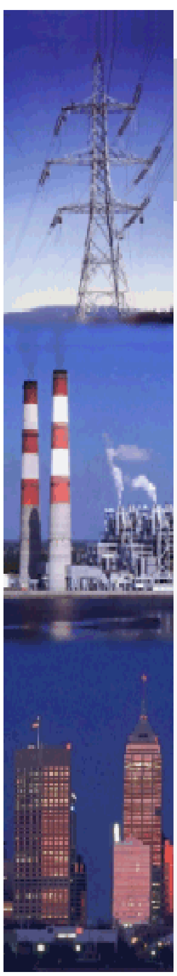


Price Corrections
2003 - 2006



Long-Term Market Signals

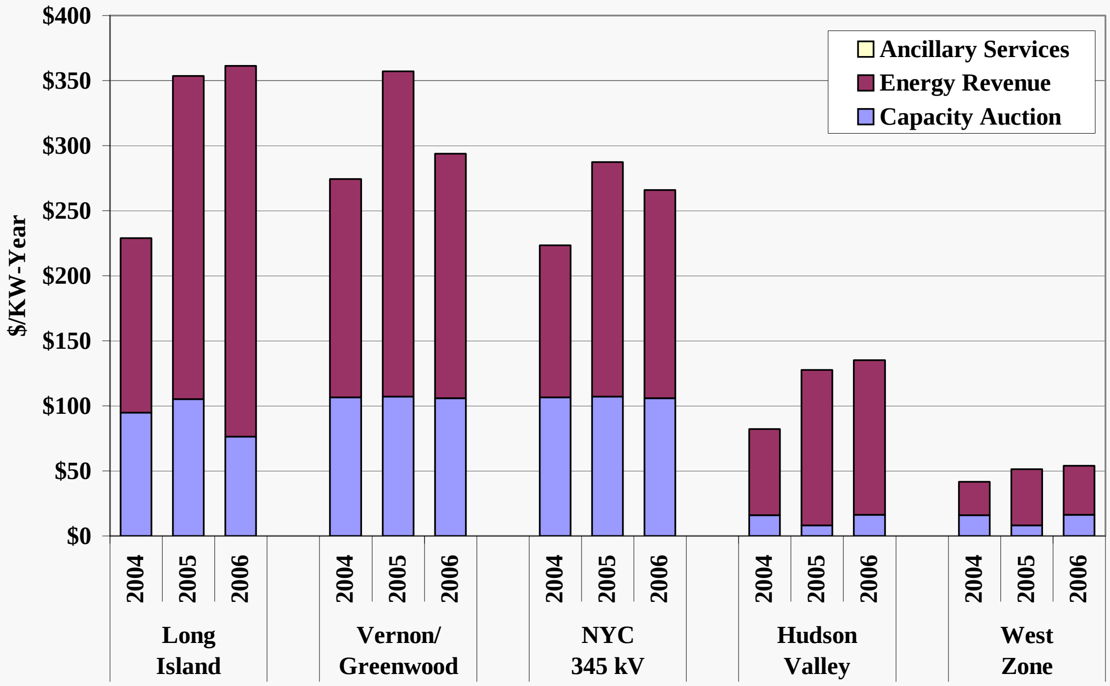
- The following two figures show the Net Revenue provided by the NYISO markets over the past three years at several locations.
  - ✓ Net Revenue is the day-ahead market revenue and capacity market revenue that a new generator would earn above its variable production costs.
  - ✓ The first slide shows net revenue for a hypothetical gas combined-cycle unit with an assumed heat rate of 7000 BTU/KWh.
  - ✓ The second slide shows the same information for a hypothetical gas combustion turbine with an assumed heat rate of 10500 BTU/KWh.
- In calculating Energy Net Revenue, FERC's standardized assumptions account for variable O&M costs, fuel costs, and forced outages.
  - ✓ For the combustion turbine, the analysis includes estimated revenues from 30-minute reserves.
  - ✓ However, it does not include start-up costs, minimum run-times, and other physical limitations.
  - ✓ Capacity Net Revenue is based on Strip Auction prices for New York City and up-state areas and Spot Auction prices for Long Island.

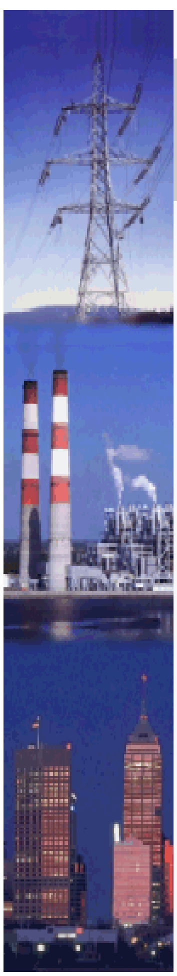


Long-Term Market Signals

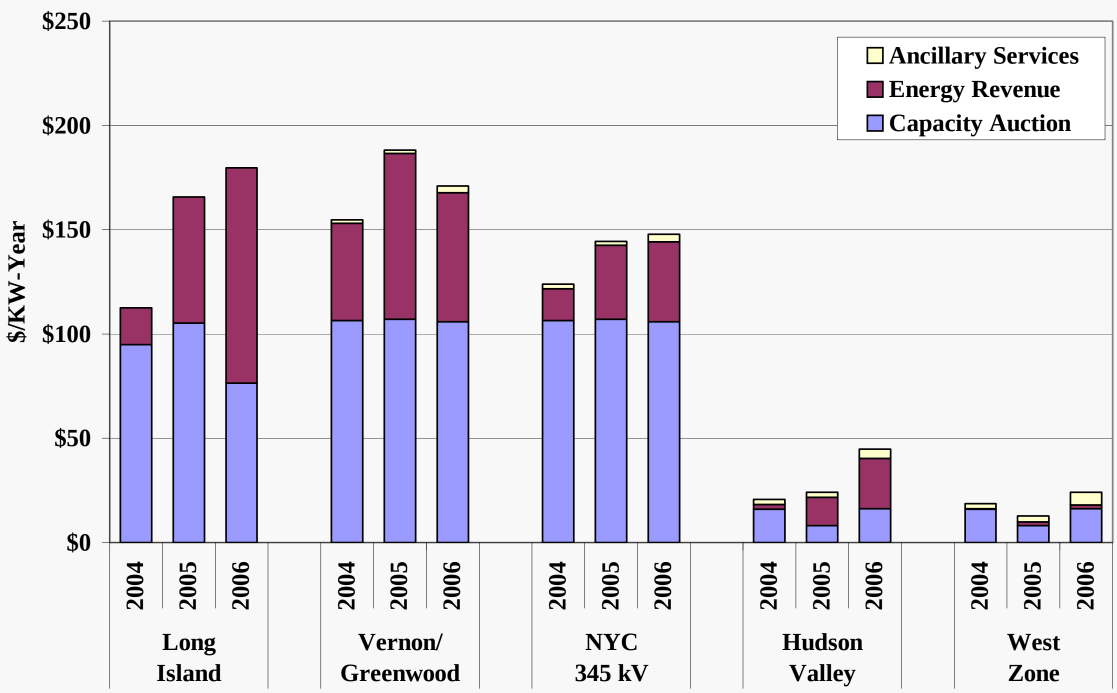
- The net revenue levels rose significantly from 2004 to 2005 due to:
  - ✓ Higher load and more frequent shortage conditions in 2005;
  - ✓ In 2005, shortages resulted in very high energy prices due to the shortage pricing provisions implemented under SMD 2.0.
- Two factors contributed to a modest increase in net revenues in most areas from 2005 to 2006.
  - ✓ In 2005, day-ahead prices were lower on average than real-time prices, while price convergence was better in 2006. Because the calculation is made using day-ahead prices, the 2006 result shows higher net revenue.
  - ✓ While there were fewer shortage intervals in 2006, shortage pricing occurred during a larger share of shortages due to improvements in the real-time software.
- The introduction of new capacity in New York City substantially reduced net revenues from energy for generators in New York City, particularly the 138 kV areas (such as Vernon/Greenwood).

Estimated Net Revenue
Gas Combined-Cycle Unit, 2004 – 2006



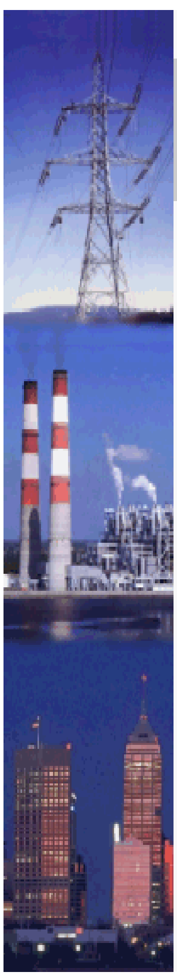


Estimated Net Revenue
Gas Combustion Turbine, 2004 – 2006



Enhanced Net Revenue Analysis

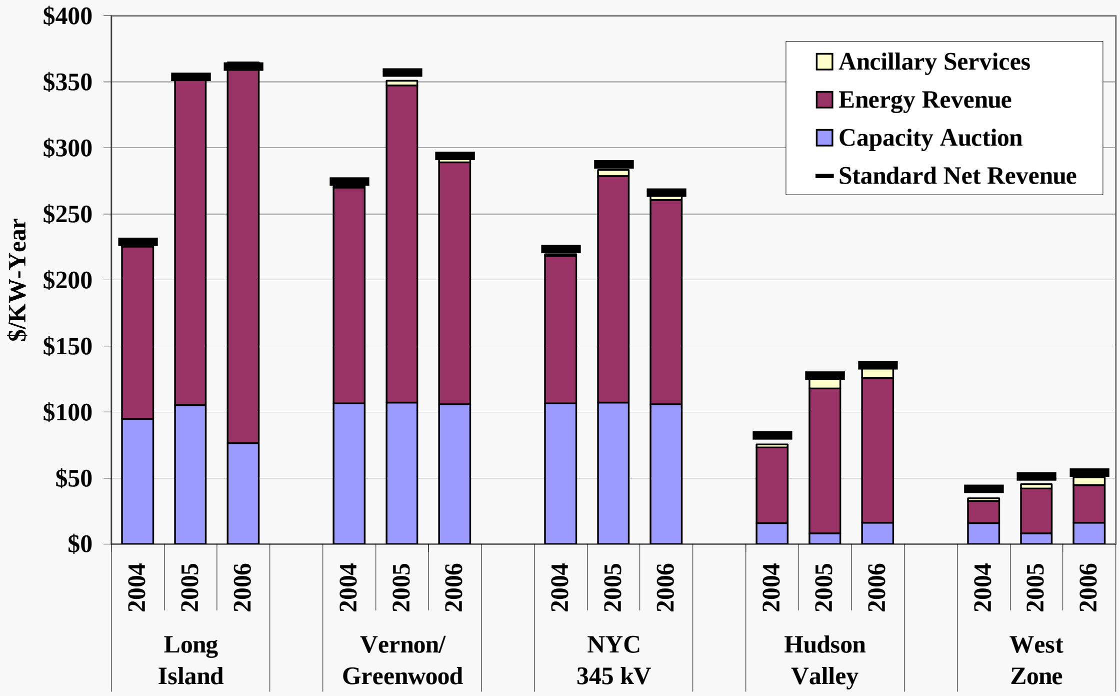
- To address limitations in the standard net revenue analysis, we conducted a second, more sophisticated net revenue assessment as well.
- For CC technology, the analysis assumes the unit is committed based on prices in the day-ahead market. This analysis:
  - ✓ Considers start-up costs, minimum run times, and a limited dispatchable range with 10-minute spinning reserve and 30-minute reserve capability.
  - ✓ Assumes online generators are able to arbitrage differences between day-ahead prices and hourly average real-time prices.
- For CT technology, the analysis assumes the unit is initially committed and scheduled based on prices in the day-ahead market. This analysis:
  - ✓ Considers start-up costs, a one hour minimum run time, a one hour minimum downtime, and 30-minute reserve capability.
  - ✓ Assumes the CT may be committed for additional hours based on RTC (or BME) prices, but is paid the hourly average real-time price.

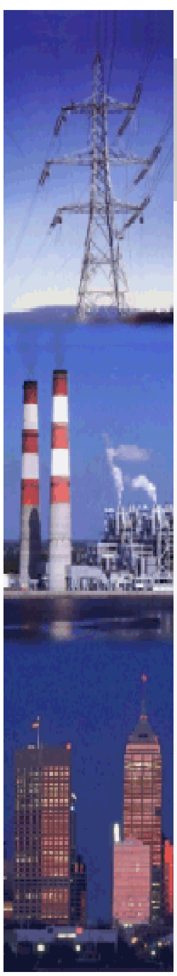


Enhanced Net Revenue Analysis

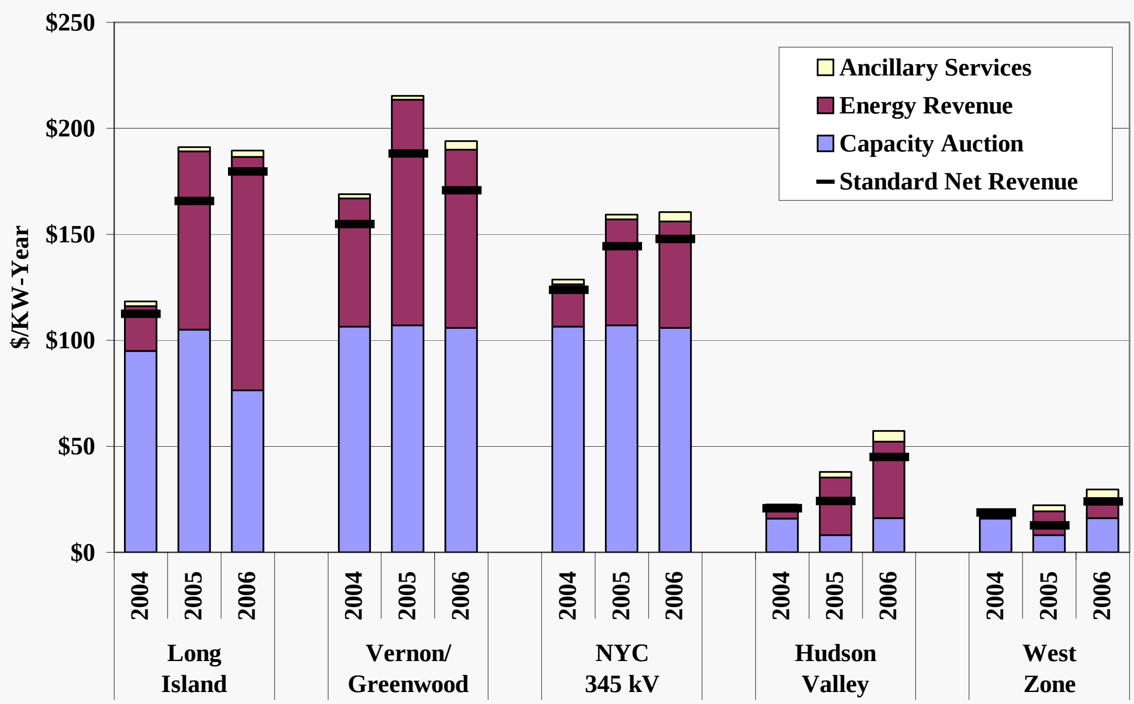
- The following figures summarize the results of the enhanced analysis.
  - ✓ For comparison purposes, a marker is included in the chart showing the results of the standard net revenue analysis.
- The estimates for a Gas Combined-Cycle Unit are slightly lower than under the standard analysis. The differences are primarily from:
  - ✓ Reductions in net revenue due to start-up costs and minimum runtime restrictions; and
  - ✓ Gains in net revenue from arbitrage of differences between day-ahead and real-time prices (i.e., the ability to reduce output when prices are lower in the real-time market or vice versa).
- The estimates for a Gas Combustion Turbine are higher than in the standard analysis for most locations. The differences are primarily from:
  - ✓ Reductions in net revenue due to start-up costs.
  - ✓ Gains in net revenue from hours when the generator is economically committed after the day-ahead market by RTC or BME.

Enhanced Net Revenue Analysis
Gas Combined-Cycle Unit, 2004 – 2006





Enhanced Net Revenue Analysis
Gas Combustion Turbine, 2004 – 2006



Long-Term Market Signals: Conclusions

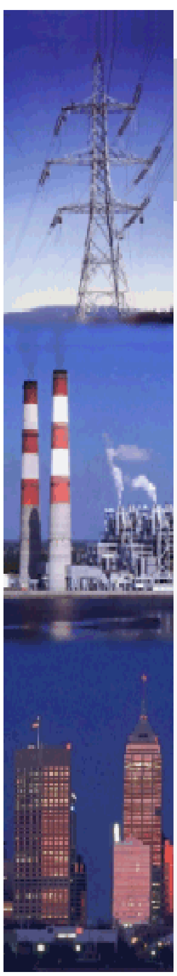
- The effect of new capacity on capacity market prices in New York City was moderated by offer patterns in the capacity market that caused less capacity to be sold from the existing resources.
- This analysis shows that net revenues levels in 2006 might support:
  - ✓ New CT investment in Long Island.
  - ✓ New CC investment in Long Island, NYC, and the Hudson Valley.
- The following factors will likely lead to significant changes in net revenue in the near future:
  - ✓ The Neptune line, which is scheduled to come into service in 2007, will increase import capability into Long Island by 660 MW.
  - ✓ If the amount of existing NYC capacity that is sold into the capacity market increases, capacity revenue will decrease substantially.
- Prospective investors must consider the effects of these factors and other factors, such as expected demand growth and participation by price-responsive demand before making capacity investments.

Day-Ahead to Real-Time Convergence

POTOMAC ECONOMICS

Day-Ahead and Real-Time Prices

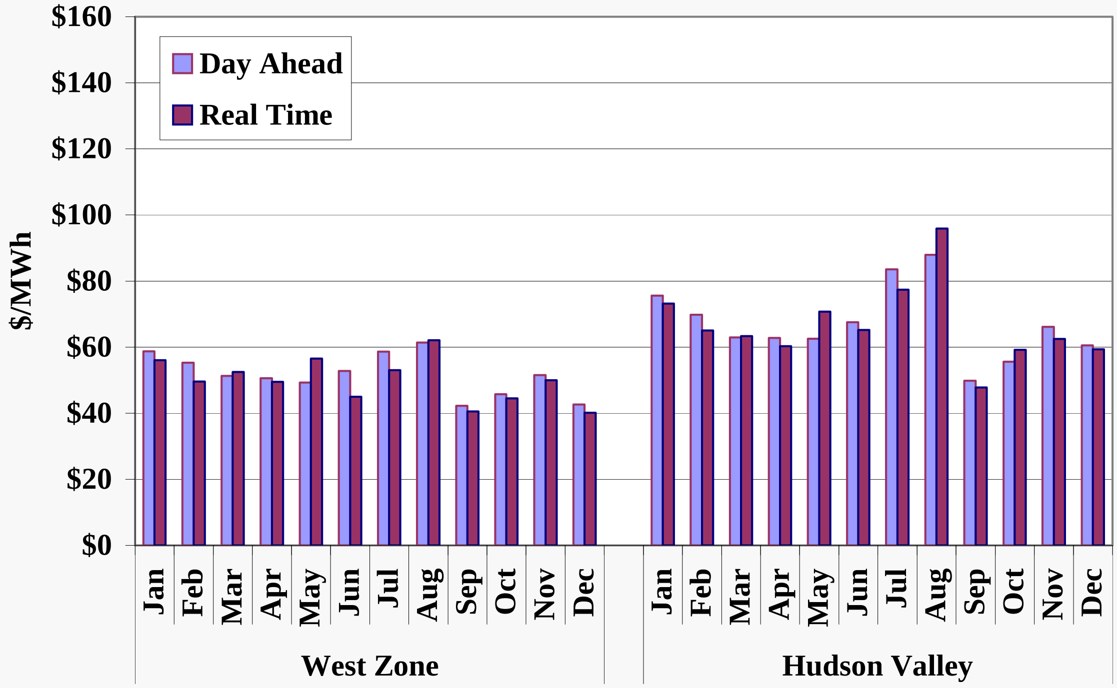
- This section of the report examines the degree of consistency between day-ahead and real-time prices, which is very important for the overall efficiency of the market. There are two kinds of inconsistency:
  - ✓ Random variations between day-ahead and real-time prices, which should be minimized; and
  - ✓ Systematic differences between the average level of day-ahead prices and the average level of real-time prices.
- One reason why convergence between day-ahead and real-time prices is important is because most generation is committed in the Day-Ahead Market -- good convergence leads to the most economic commitment for the actual conditions in real time.
- Good convergence is also compatible with efficient incentives for generators. Persistent differences between day-ahead and real-time prices undermine the incentives of generators to offer at marginal cost.



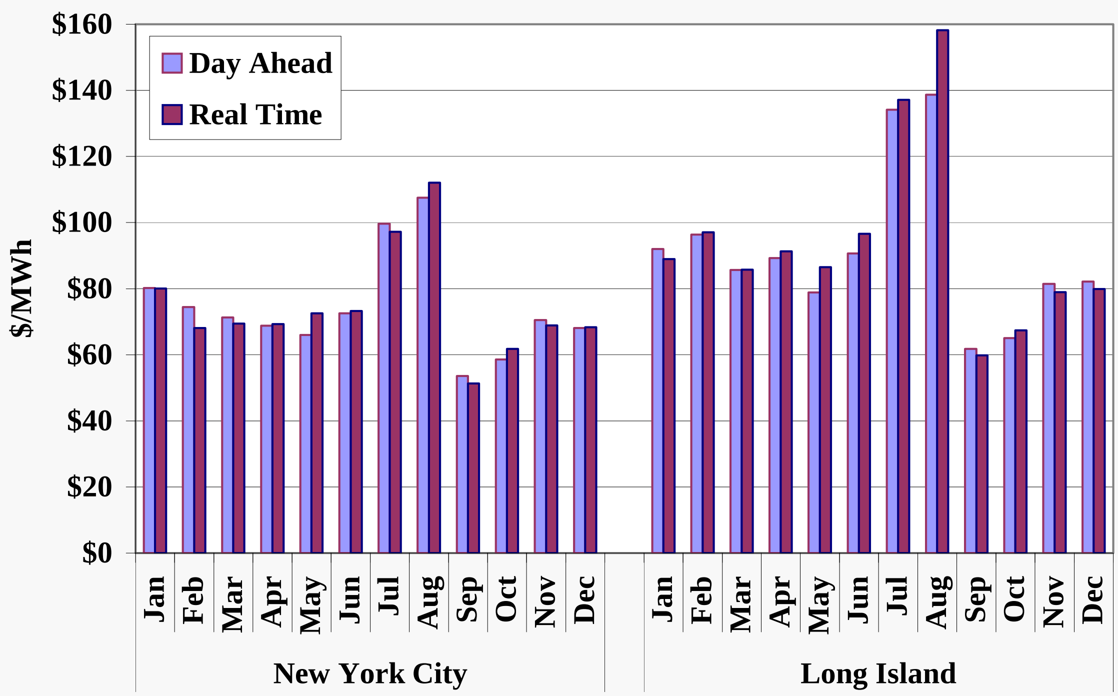
Day-Ahead and Real-Time Energy Prices

- The following two figures show monthly average day-ahead (“DA”) and real-time (“RT”) energy prices in several zones in 2006.
- Price convergence was better in 2006 than in 2005, as reflected by smaller differences between average DA and average RT energy prices.
  - ✓ West NY prices are the exception, showing a larger DA price premium in 2006 (4.3%) than in 2005 (2.4%).
- Average price differences are heavily affected by large spikes in RT price premiums associated with high load conditions and more frequent Thunder Storm Alerts (“TSAs”).
  - ✓ New York City exhibited a slight RT price premium on average during the summer months, but a slight DA premium in other months.
  - ✓ Long Island had an average $9.44 RT price premium in the summer and a $3.10 RT price premium in other months.
  - ✓ In Eastern New York, days with TSAs had an average RT price premium of over $50; days without TSAs had a slight *DA* price premium.

Average Monthly Day-Ahead and Real-Time Energy Prices
West Zone and Hudson Valley, 2006

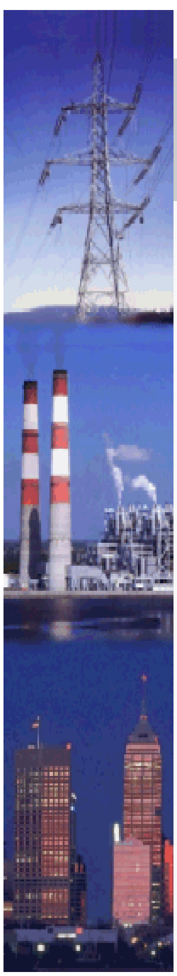


Average Monthly Day-Ahead and Real-Time Energy Prices
New York City and Long Island, 2006



Day-Ahead and Real-Time Energy Prices

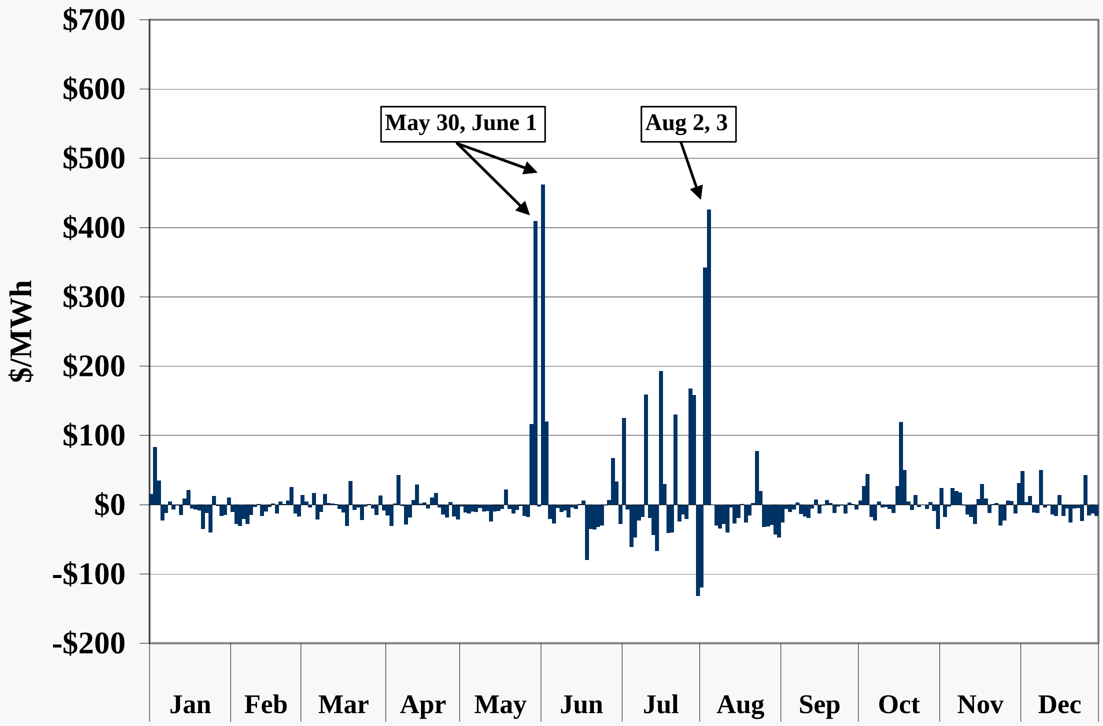
- DA and RT prices tended to be more consistent on a monthly average basis in 2006, but still reflect substantial differences at the daily level.
- Market participants buy and sell in the Day-Ahead Market based in part on their expectations of Real-Time Market outcomes. Day ahead decisions naturally involve several uncertainties:
  - ✓ Demand can be difficult to forecast with precision; the capability of supply resources may change due to forced outages or numerous other factors.
  - ✓ Special operating conditions, such as TSAs, may alter the capability of the transmission system in ways difficult to arbitrage in Day Ahead markets.
- In general, DA prices reflect the probability-weighted expectation of infrequent high-priced events in the Real-Time Market.
- Convergence between DA and RT prices has improved as market participants have gained more experience with shortage pricing under SMD 2.0.

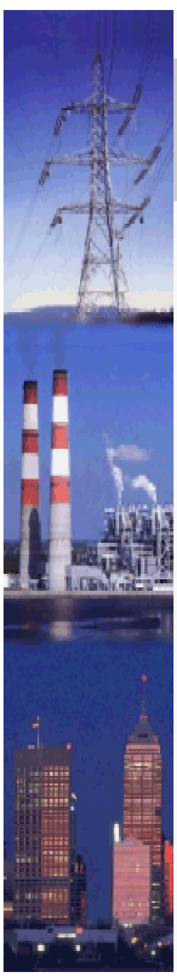


Day-Ahead and Real-Time Energy Prices

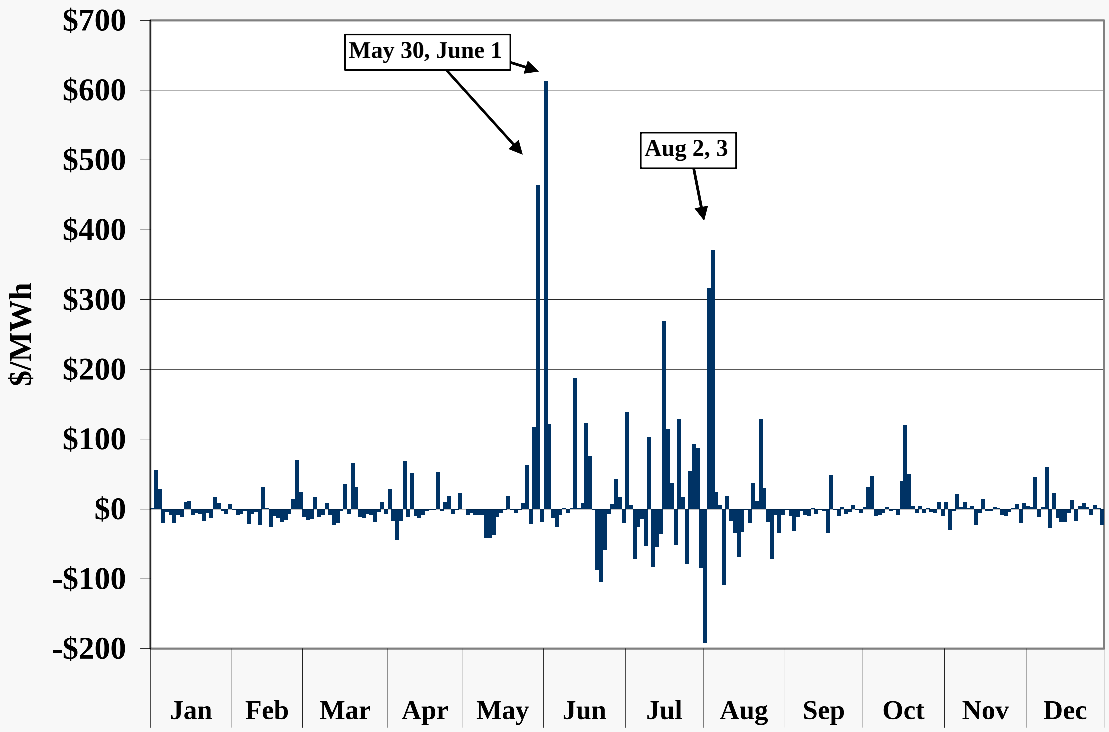
- The following figures show average daily RT price premiums for afternoon hours for New York City and Long Island.
- Average DA prices are higher than average RT prices on the majority of afternoons shown in the following figures:
  - ✓ In NYC, DA prices were higher almost 70 percent of the afternoons; and
  - ✓ In Long Island, DA prices were higher on just over half of the afternoons.
- However, high-price events are more frequent in the Real-Time Market. On afternoons when the difference between average DA and RT prices exceeded $100 per MWh:
  - ✓ In NYC, the RT price was higher on 10 out of 12 afternoons.
  - ✓ In Long Island, the RT price was higher on 12 out of 15 afternoons.
- A large number of price spikes were caused by TSAs, which require double contingency operation of the ConEd overhead transmission system in real-time but not in the day-ahead market.

Average Daily Real-Time Price Premium
New York City, 1 p.m. to 7 p.m. Weekdays, 2006





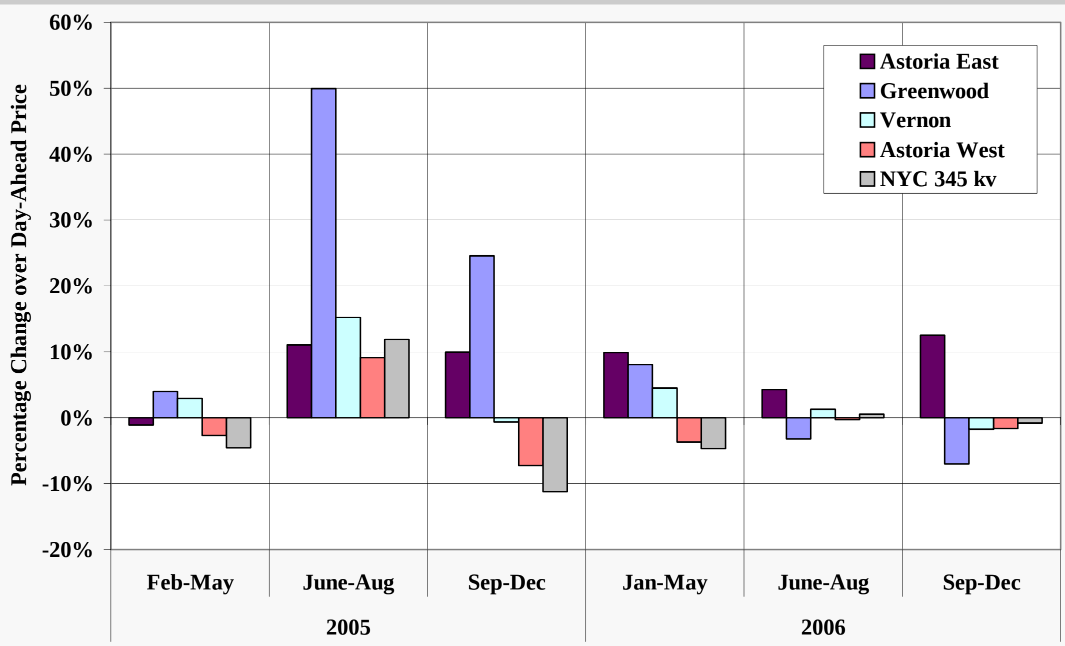
Average Daily Real-Time Price Premium
Long Island, 1 p.m. to 7 p.m. Weekdays, 2006



Day-Ahead and Real-Time Load Pocket Prices

- The following figure shows the average real-time price premium at several locations in NYC on a seasonal basis during 2005 and 2006. Four locations are sub-load pockets in the 138kV system, while one point is in the 345kV system.
- When the RT premium varies significantly across locations within New York City, it reflects that DA congestion patterns are different from RT patterns.
- Systematic differences between DA and RT prices were generally smaller in 2006. Several factors helped improve convergence:
  - ✓ New capacity was installed in Astoria West in January 2006 and in Astoria East in May 2006. This has substantially reduced congestion within New York City.
  - ✓ In May 2006, the NYISO began to use a more detailed network model for real-time scheduling that was already being used in the Day-Ahead Market. This has improved the consistency of congestion patterns between the day-ahead and real-time.
- Price-capped load bidding and virtual trading is limited to the zonal level,
  - ✓ This limits the ability of market participants to arbitrage large price differences within the zone.
  - ✓ Improved convergence may be achieved within NYC by allowing virtual trading at a more detailed level.

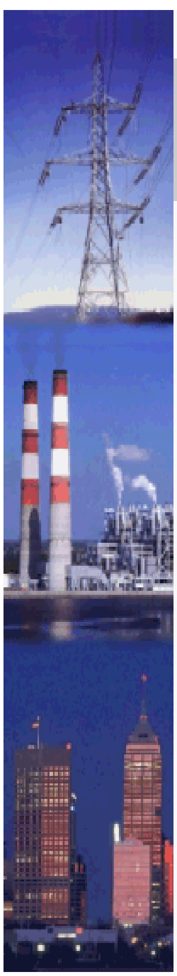
Average Real-Time Price Premium in NYC Load Pockets 2005 – 2006



Note: Individual generator buses were used to represent the areas listed in the figure: Astoria GT 10 for Astoria East, Gowanus GT 1/1 for Greenwood, Ravenswood 1 for Vernon, Astoria GT 2/1 for Astoria West, and Poletti for the New York City 345kV area.

Real-Time Transmission Price Spikes

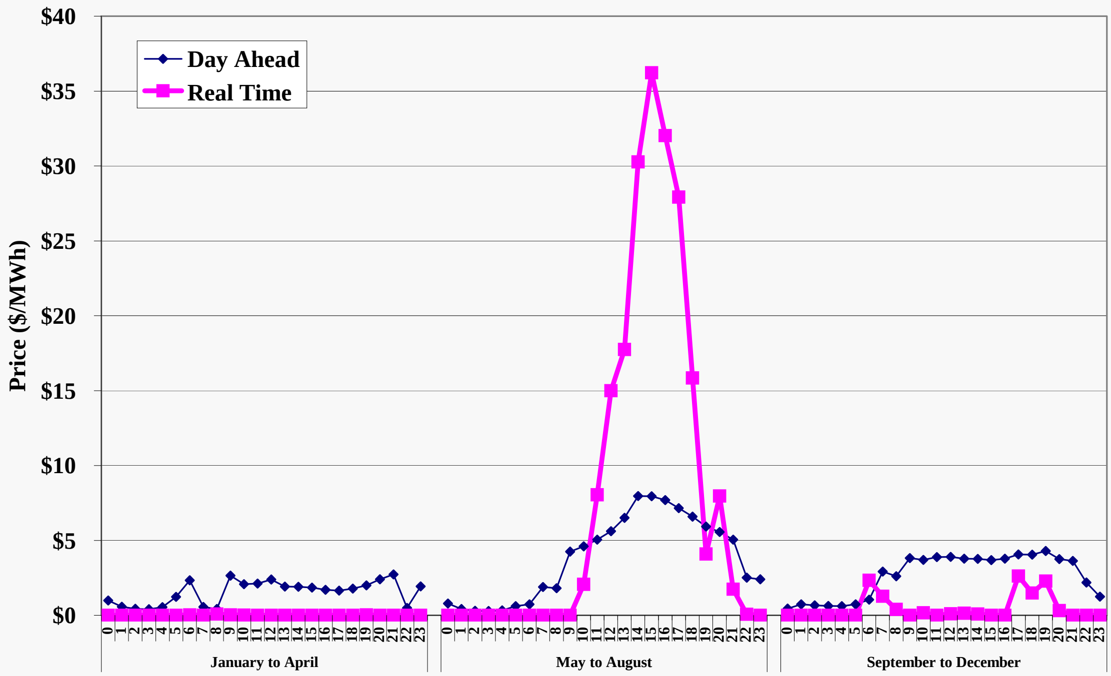
- Real-time transmission price spikes occur when the re-dispatch costs necessary to resolve a transmission constraint reach extremely high levels.
  - ✓ During 2006, there were 1314 intervals when marginal re-dispatch costs exceeded $1,000/MWh on one or more constraints and 214 intervals when they exceeded $4,000/MWh.
  - ✓ These contribute significantly to the severity of real-time energy price spikes.
- These spikes typically occur for brief periods when there is not sufficient ramp capability within a constrained area.
  - ✓ This may result in re-dispatch that provides little reliability benefit, and in some cases may actually make the system less reliable.
- To reduce the incidence of these situations, the NYISO has proposed to limit the marginal re-dispatch costs to a maximum of $4,000/MWh.
  - ✓ We support this change, which the NYISO proposes to implement before the summer of 2007.
  - ✓ We will continue to evaluate congestion management under the new methodology including the appropriateness of the $4,000/MWh limit.



Ancillary Services Price Convergence – Eastern 10-Minute Reserves

- The following chart shows day-ahead and real-time eastern 10-minute reserves prices by hour of the day for several periods in 2006.
- The NYISO requires 1,000 MW of 10-minute reserves east of the Central-East Interface.
  - ✓ The market models include an economic demand curve value of $500/MWh on meeting this requirement.
- From May to August, prices were significantly higher than other times of year:
  - ✓ A small number of days with real-time price spikes account for a large share of the average real-time price in afternoon hours.
  - ✓ While day-ahead prices are higher than real-time price on most days, the difference is much larger on days when the real-time price is higher.
- In the spring and fall, day-ahead prices tend to be above real-time prices.
- The factors contributing to this poor convergence are discussed in the evaluation of ancillary service offer patterns in the next section.

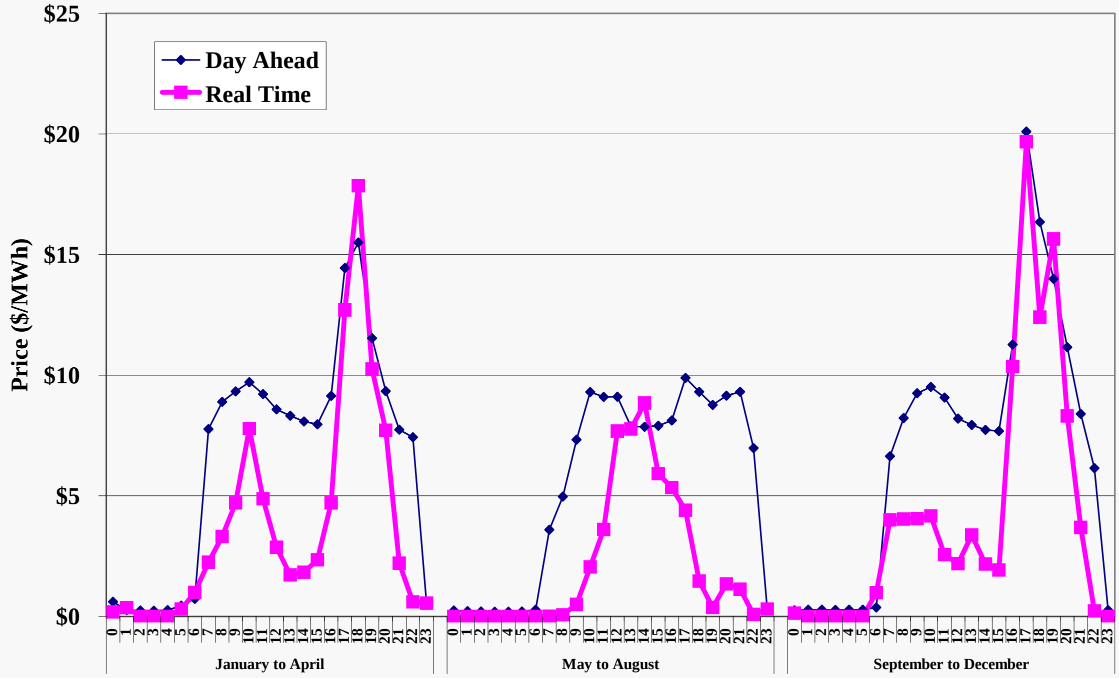
10-Minute Total Reserve Prices in East NY
by Hour of Day, 2006



Ancillary Services Price Convergence – 10-Minute Spinning Reserves in West NY

- Day-ahead spinning reserves prices are based on the offers of individual generators as well as the opportunity costs of providing reserves rather than energy.
- The following figure shows day-ahead and real-time 10-minute synchronous reserves prices in western NY, which depend primarily on the state-wide 10-minute synchronous reserves requirement of 600 MW.
  - ✓ Currently, the economic value of this requirement is set at $500/MWh.
- Several observations can be made from the following figure:
  - ✓ In the Spring and Fall, day-ahead prices tend to exceed real-time prices during morning and afternoon hours, but track real-time prices closely during evening hours.
  - ✓ During the Summer, day-ahead prices generally exceeded real-time prices except at mid-afternoon when prices were about equal on average.
  - ✓ Western 10-minute synchronous reserves prices fall during the summer when more frequent dispatch of quick start GTs for energy increases the use of steamers to meet the eastern 10-minute reserve requirement.

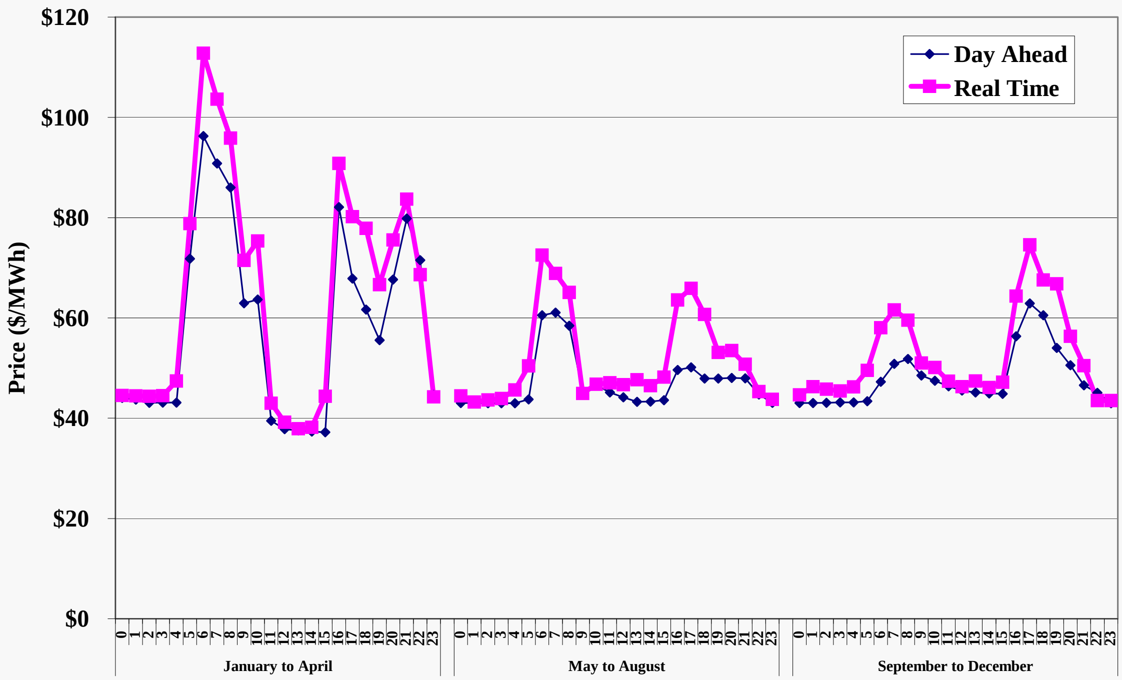
10-Minute Spinning Reserve Prices in West NY by Hour of Day, 2006



Ancillary Services Price Convergence – Regulation Market

- The following figure summarizes convergence between day-ahead and real-time prices for regulation by time of day.
- New York has a state-wide regulation requirement that ranges from 275 MW during ramping hours down to as low as 150 MW during other hours.
  - ✓ When the system is short of regulation, the value of the requirement is set at $250/MW for the first 25 MW of shortage and $300/MW thereafter.
  - ✓ Day-ahead and real-time regulation prices are closely correlated across the day, but real-time prices are $2 to $14/MWh higher on average.
- Regulation clearing prices decreased after the spring of 2006.
  - ✓ Starting in June 2006, additional capability was offered into the market, which helped lower clearing prices during ramping hours.
  - ✓ Regulation offer patterns are discussed in more detail in the next section.

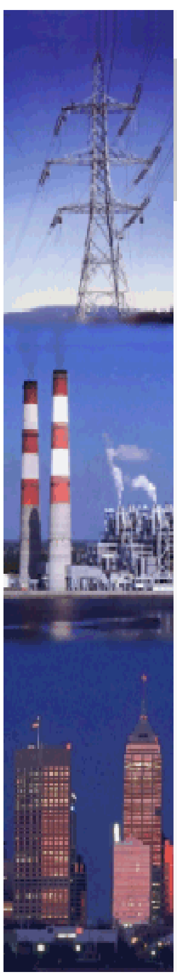
Regulation Prices
by Hour of Day, 2006



Ancillary Services Price Convergence Conclusions

- Price convergence between day-ahead and real-time improved for 10-minute spinning reserves compared with 2005 but remained poor for Eastern 10-minute total reserves.
- Price spikes related to reserves shortages occur more frequently in the real-time than in the day-ahead market.
  - ✓ Because sufficient capacity is offered into the day-ahead market, reserves shortages never occur in the day-ahead market.
  - ✓ Unforeseen conditions such as forced outages, short term ramp limits, and transmission constraints can occur resulting in real-time reserves shortages.
  - ✓ Under-forecasted demand in the day ahead can lead to under-commitment that can lead to real-time reserves shortages.
- Pervasive real-time price premiums for reserves give generators an incentive to raise their day-ahead reserves offer prices, which can reduce the efficiency of the day-ahead commitment.
  - ✓ The following section reports on our analysis of generators' offer patterns.

Ancillary Services Markets

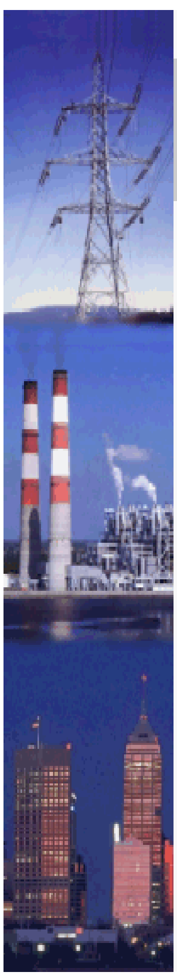


Ancillary Services Markets – Background

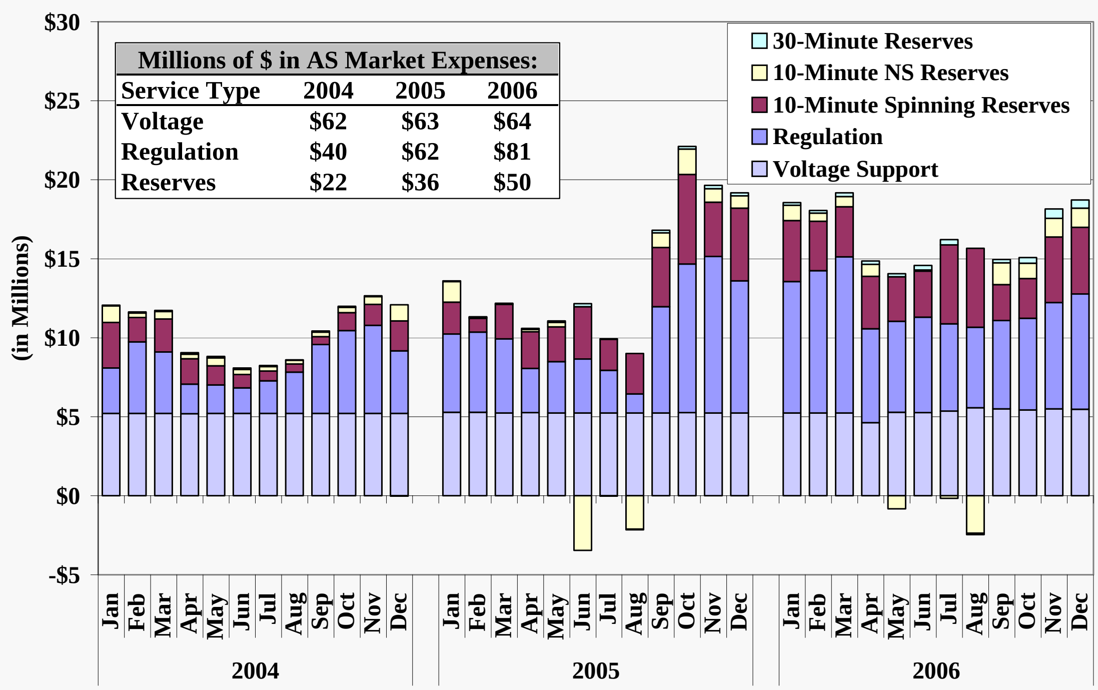
- This section of the report summarizes trends in the ancillary services markets and makes one recommendation to address several areas of the concern.
- The design of the ancillary services markets changed substantially with the implementation of SMD 2.0, which included the following key elements:
  - ✓ Co-optimization of regulation and reserves with energy in both the day-ahead and real-time markets.
  - ✓ Use of demand curves for ancillary services to better reflect the value of ancillary services and energy in prices under shortage conditions.
  - ✓ AS prices are now based on the marginal cost to the system of providing the service. This is equal to the sum of the marginal AS provider's availability offer price and the opportunity cost of not providing another product, such as energy.
  - ✓ In real-time, all dispatchable generators must offer to provide reserves with a \$0/MWh availability offer.
  - ✓ A two-settlement system for ancillary services, whereby day-ahead schedules must either be provided in real-time or purchased back from the ISO's real-time market.

Ancillary Services Expenses

- The following figure summarizes expenses for ancillary services, which have risen substantially in each of the last two years.
- Under SMD 2.0, clearing prices more fully reflect the costs to the system of diverting resources to provide ancillary services that would otherwise provide energy. This has contributed to increased expenses for regulation and operating reserves.
- At least two factors contributed to other increases.
  - ✓ Higher fuel prices, particularly from September 2005 to January 2006, increased the opportunity costs of low-cost units providing ancillary services rather than energy.
  - ✓ Regulation offer prices rose substantially in September 2005.
- Poor convergence between day-ahead and real-time eastern reserve prices has reduced expenses for 10-minute non-spinning reserves.
  - ✓ The ISO purchases the required quantity of reserves in the day-ahead, and day-ahead prices have been considerably lower than real-time prices.
  - ✓ Expenses for operating reserves increased due to better convergence in 2006.
- Net expenses were negative for 10-minute non-spin reserves in several months.
  - ✓ This occurred when generators sold reserves at low day-ahead prices and bought back their obligations in real-time at higher prices during reserves shortages when they produced energy.



Ancillary Services Expenses
2004 – 2006

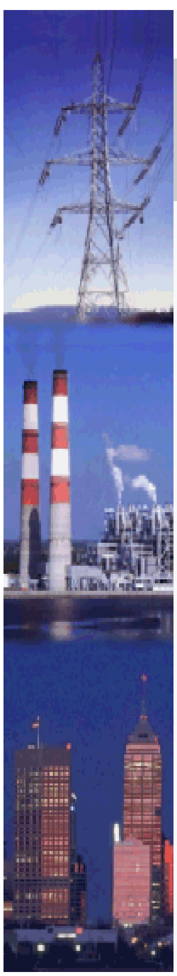


Millions of $ in AS Market Expenses:

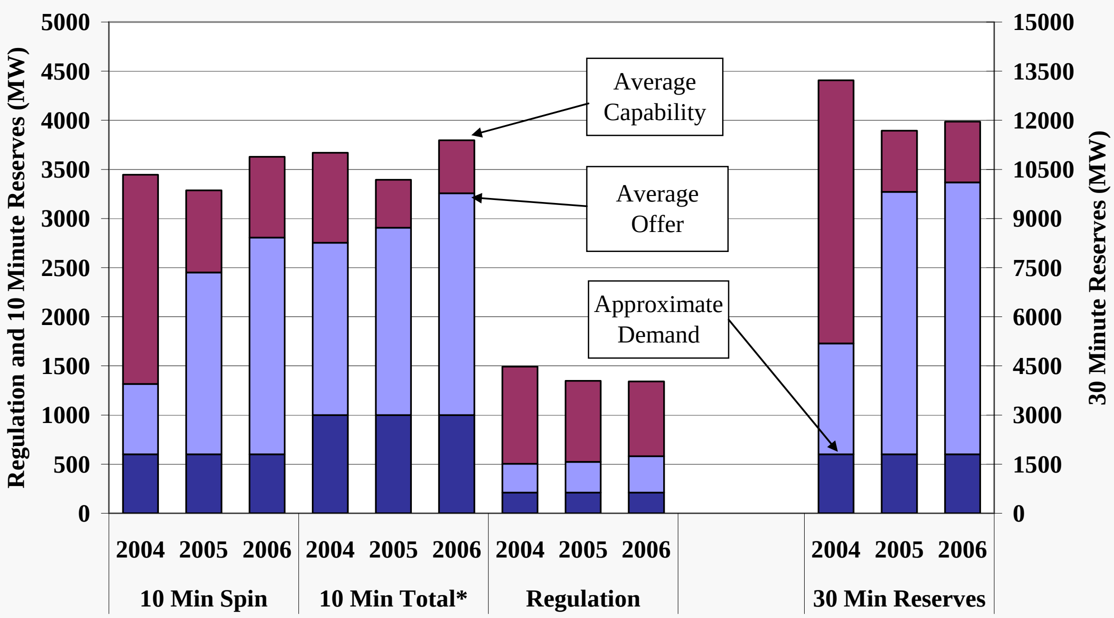
Service Type	2004	2005	2006
Voltage	$62	$63	$64
Regulation	$40	$62	$81
Reserves	$22	$36	$50

Day-Ahead Capacity and Offers

- The following figure summarizes supply and demand for several ancillary services market requirements: (i) 10-minute spinning reserves, (ii) 10-minute total reserves in eastern New York, (iii) regulation, and (iv) 30-minute reserves.
  - ✓ Capability to provide each service is based on customer registration data.
- Improved incentives under SMD 2.0 led to a substantial rise in 10-minute spinning reserves and 30-minute reserve offer quantities in early 2005.
  - ✓ Prior to SMD 2.0, generators ran the risk of selling reserves in the day-ahead market when it would have been more profitable to sell energy.
  - ✓ Under SMD 2.0, generators are selected to provide whichever is more profitable (based on the offer they submit).
- Most regulation-capable capacity is not offered to the market.
  - ✓ Many generators incur costs to provide regulation or face non-economic barriers, and may therefore rationally choose not to provide regulation.
- In 2006, the introduction of new combined cycle capacity in NYC led to increased offers and capability of 10-minute spinning reserves and eastern 10-minute reserves.



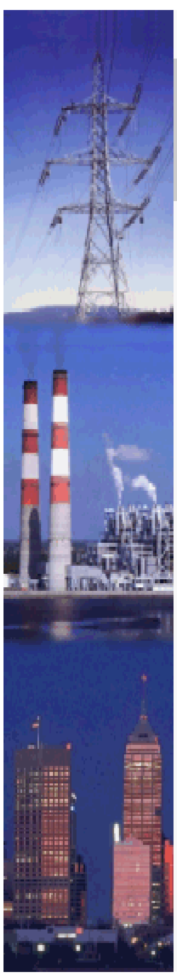
Ancillary Services Capability and Offers
Day-ahead Market, 2004-2006



*Eastern side of the Central-East Interface only

Day-Ahead Ancillary Services Offers Under SMD 2.0

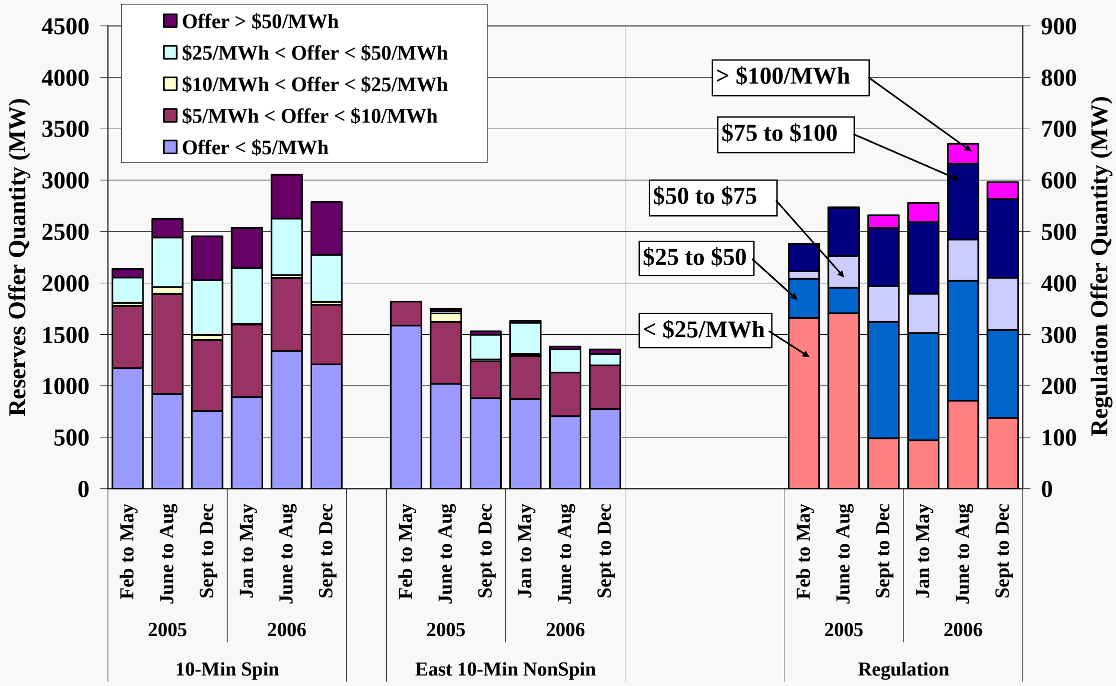
- The following figure summarizes day-ahead offers to supply three categories of ancillary services during the past two years.
  - ✓ Offer quantities are shown according to offer price level.
- Statewide 10-Minute Spinning Reserves Offer Patterns:
  - ✓ In 2005, the quantity of 10-minute spinning reserves offered at $5/MW or less trended down as many market participants raised their offer prices.
  - ✓ In 2006, the quantity of inexpensive offers rose due to the installation of new combined cycle capacity in New York City.
    - NYC units are required to offer 10-minute spinning reserves at $0/MW.
- Eastern 10-Minute Non-Spinning Reserves Offer Patterns:
  - ✓ Since the start of SMD 2.0, offer quantities have gradually decreased and offer prices have increased.
  - ✓ Most of the quantity is units with ICAP obligations that have to offer 10-minute non-spinning reserves in the day-ahead market. Mitigation may restrict their ability to raise their offers.



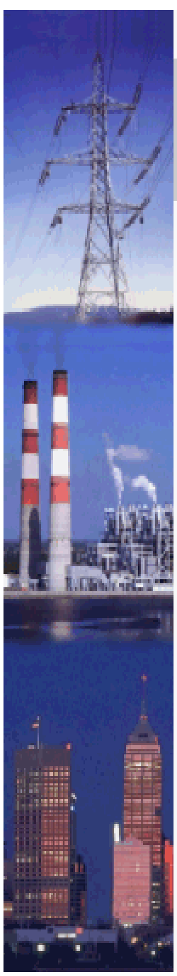
Day-Ahead Ancillary Services Offers Under SMD 2.0

- Regulation Offer Patterns:
  - ✓ Higher offer prices, beginning in September 2005 and continuing in 2006, contributed to a significant rise in regulation clearing prices and expenses.
  - ✓ The rise in offers was not sufficient to warrant mitigation of regulation offers under the NYISO Tariff.
  - ✓ The effects of higher offer prices were partially offset by the entry in June 2006 of approximately 100 MW of low-priced offers from generators that did not previously offer regulation.
- Due to limited participation by regulation-capable generators, the ownership of resources that participate in the regulation market is relatively concentrated.

Summary of Ancillary Services Offers Under SMD 2.0 Day-Ahead Market, 2005-2006



Note: Spinning and non-spinning offers are an average of 1pm to 7pm, while regulation includes all hours.

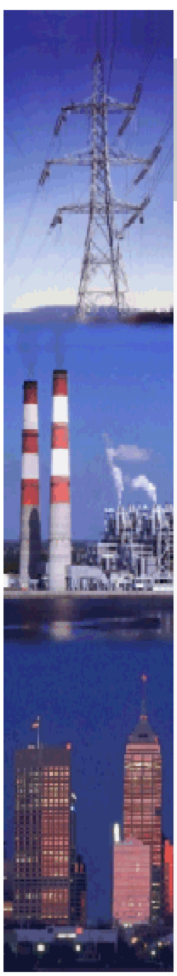


Ancillary Services Markets – Conclusions and Recommendations

- The introduction of SMD 2.0 substantially improved the incentives to participate in the ancillary services markets.
- Poor price convergence for 10-minute reserves prices in eastern New York (real-time prices higher than day-ahead prices) increase the opportunity cost of selling reserves in the day-ahead market.
  - ✓ Given the increased opportunity costs, the wide-spread rise in 10-minute reserve offer prices is consistent with expectations of a competitive market.
  - ✓ The rise in 10-minute reserve offer prices has helped improve convergence between day-ahead and real-time prices.
  - ✓ However, the higher reserve offer prices can undermine the efficiency of day-ahead commitment.
- To address the lack of price convergence and resulting inefficiencies, we recommend that the ISO evaluate the feasibility of virtual trading of ancillary services.
  - ✓ This could correct the systematic differences between day-ahead and real-time prices by enabling day-ahead market participants to buy more than the required amount of reserves.

Analysis of Energy Bids and Offers

POTOMAC ECONOMICS



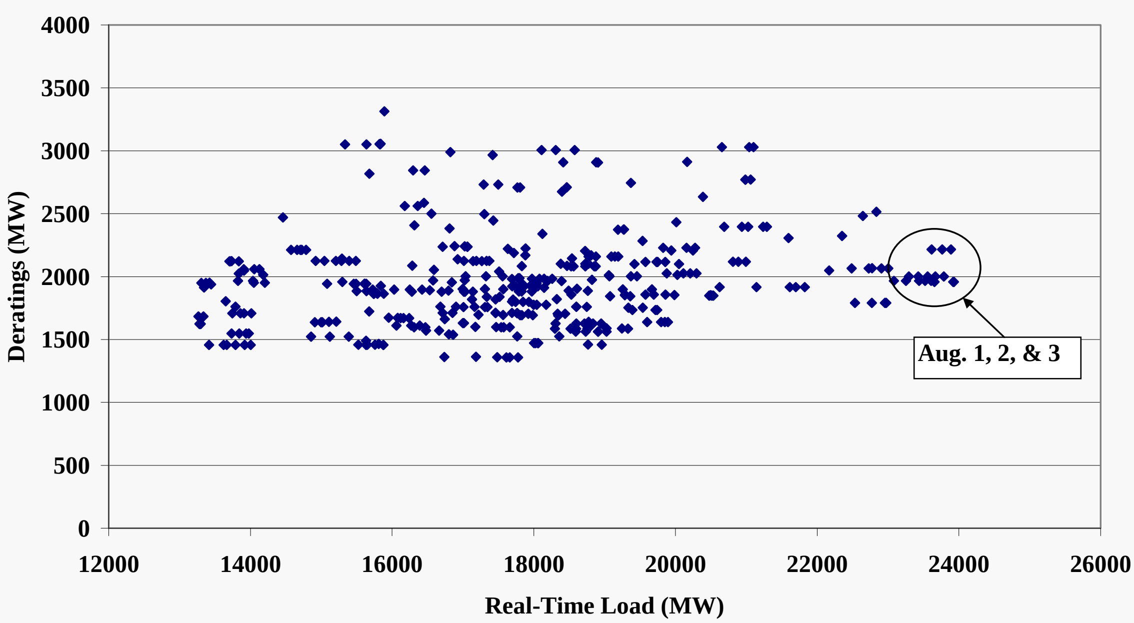
Analysis of Energy Offer Patterns

- 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 highlights market participant behavior that may reflect attempts to withhold resources to raise prices.
- The first analysis examines potential physical withholding, which includes total generation deratings (including planned outages, forced outages, and partial deratings).

Analysis of Offer Patterns – Deratings

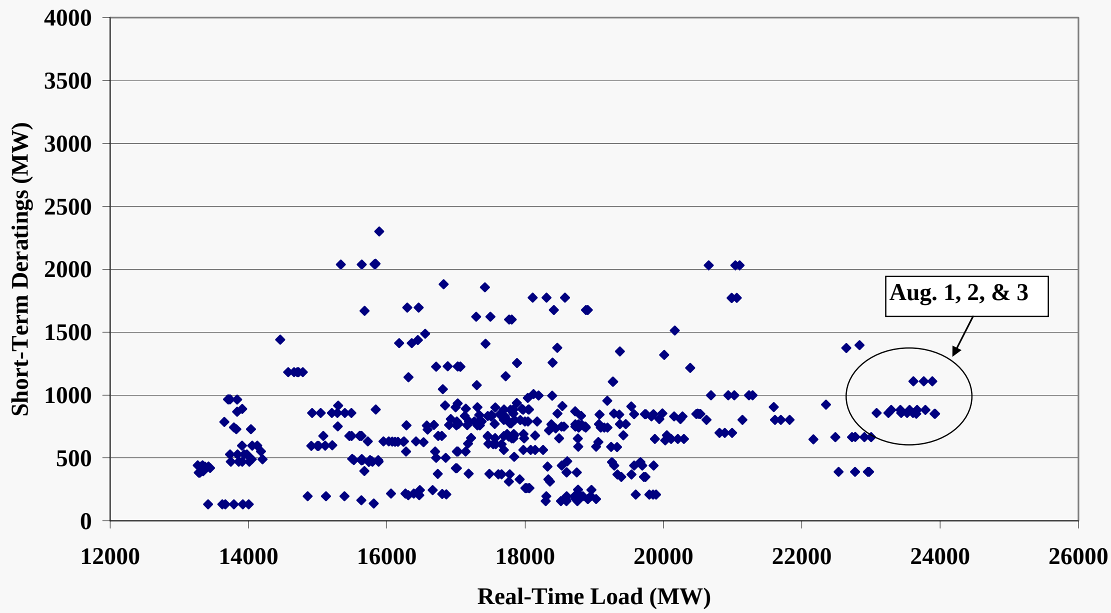
- The following two figures plot the total deratings and short-term deratings versus actual load in eastern NY during peak hours in the summer.
  - ✓ The figures focus on eastern NY because this area, which includes two-thirds of the State's load, has limited import capability and is more vulnerable 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.
  - ✓ Deratings in the first figure are measured relative to the most recent DMNC test value, while short-term derating in the second figure exclude quantities that are derated for 30 days or more.
  - ✓ The short-term deratings are more likely to reflect attempts to physically withhold since it is more costly to withhold via long-term deratings or outages.
- While deratings and short-term deratings do not clearly rise during the highest load conditions, the quantities shown in the following figures are not insignificant.
  - ✓ Since this can be an indication of physical withholding, we conducted additional analysis of the underlying data and found no cause for significant competitive concerns.

Deratings versus Actual Load in Eastern New York Day-Ahead Market, Peak Hours*, Summer 2006



* Peak hours are defined as weekdays from 12 PM to 6 PM for purposes of this analysis.

Short-Term Deratings versus Actual Load in Eastern NY
Day-Ahead Market, Peak Hours*, Summer 2006

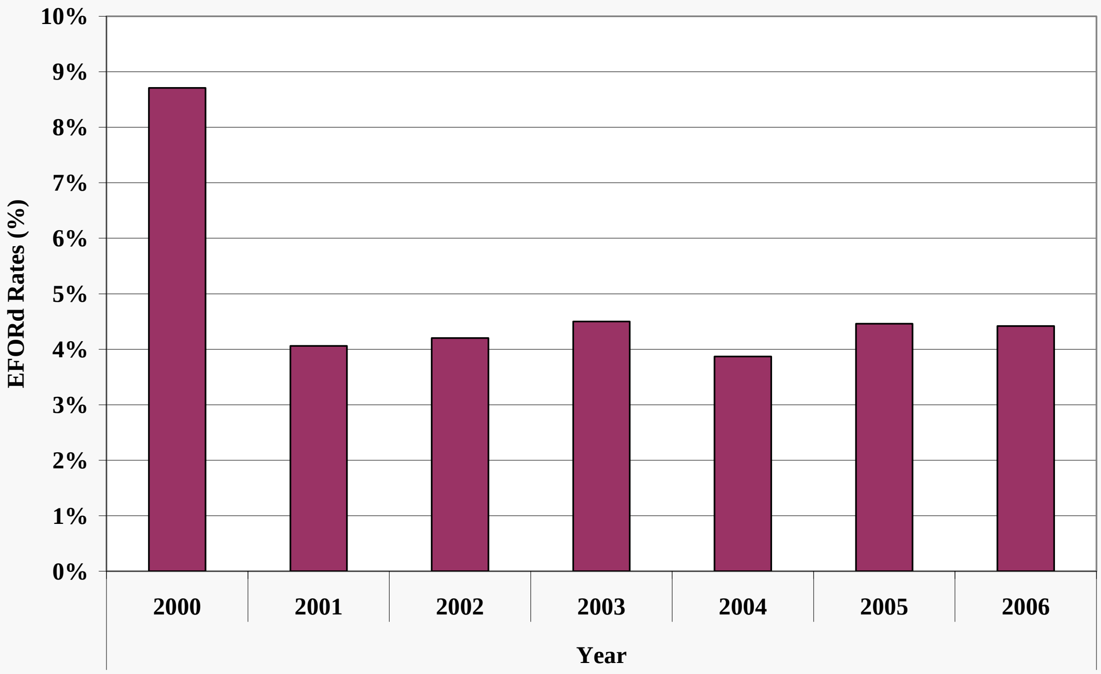


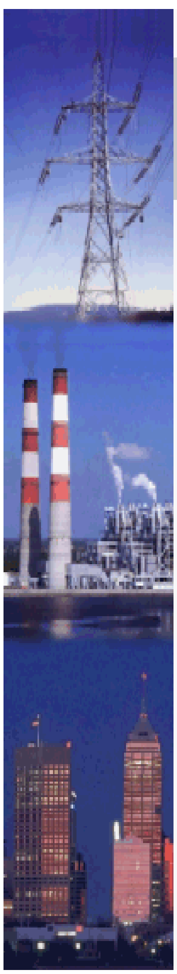
* Peak hours are defined as weekdays from 12 PM to 6 PM for purposes of this analysis.

Forced Outages

- 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.

Equivalent Forced Outage Rates
2000 - 2006



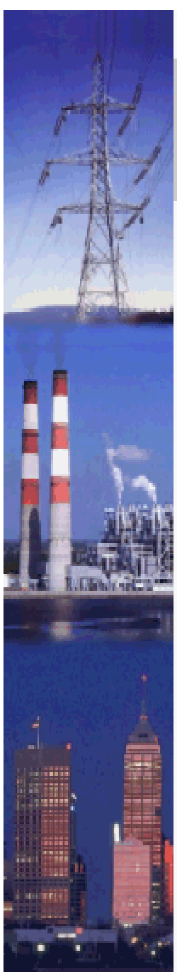


Analysis of Offer Patterns – Output Gap

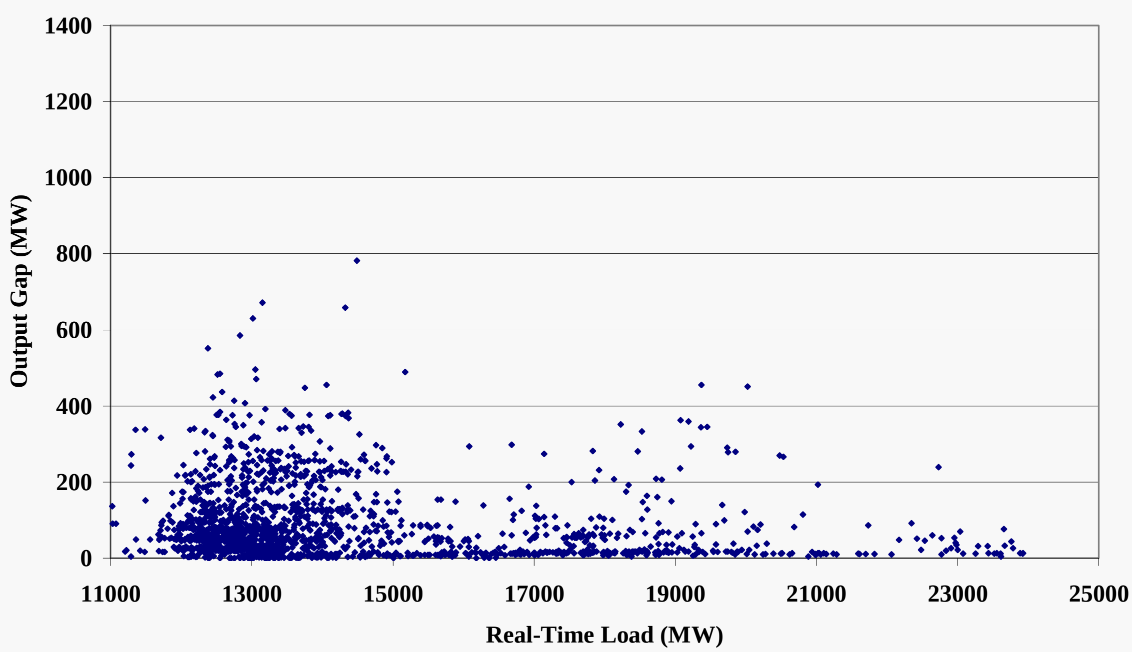
- The second analysis examines potential economic withholding, employing a measure called an "output gap".
- The output gap is the quantity of economic capacity that does not produce energy or ancillary services because a supplier submits an offer price well above a unit's reference level.
- The output 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.
- It is particularly notable that the output gap measured at the lower threshold declines and is very low during high load periods, because this conduct is not subject to mitigation.

Analysis of Offer Patterns – Output Gap

- The following figures show the real-time output gap in eastern New York during peak hours using:
  - ✓ The standard conduct threshold used for mitigation outside New York City, which is the lower of $100/MWh or 300 percent; and
  - ✓ A lower conduct threshold of $50/MWh or 100 percent (whichever is lower).
- These figures indicate that the output gap decreases substantially 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 2006.

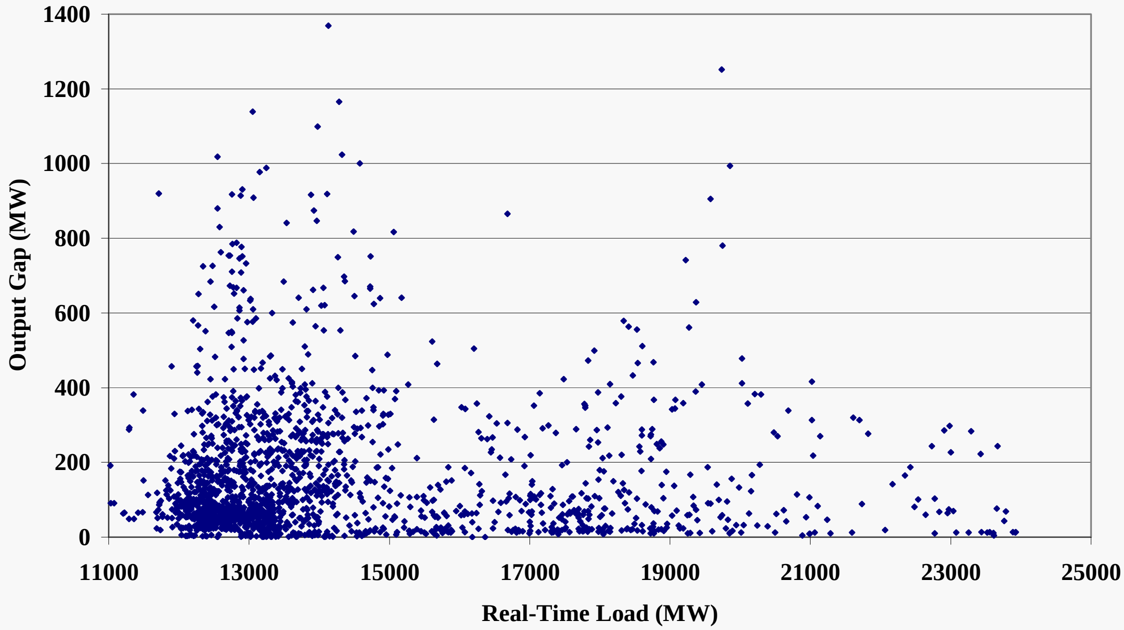


Output Gap at Mitigation Threshold vs. Actual Load in East NY Real-Time Market, Peak Hours*, 2006

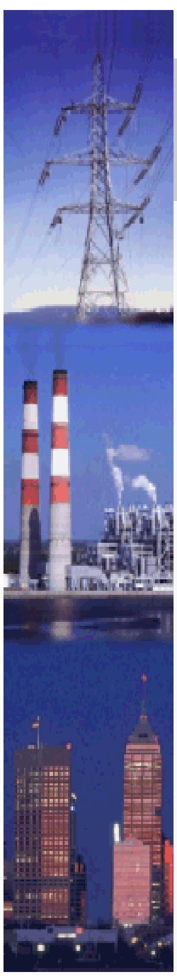


* Peak hours are defined as weekdays from 12 PM to 6 PM for purposes of this analysis.

Output Gap at Lower Threshold vs. Actual Load in East NY Real-Time Market, Peak Hours*, 2006



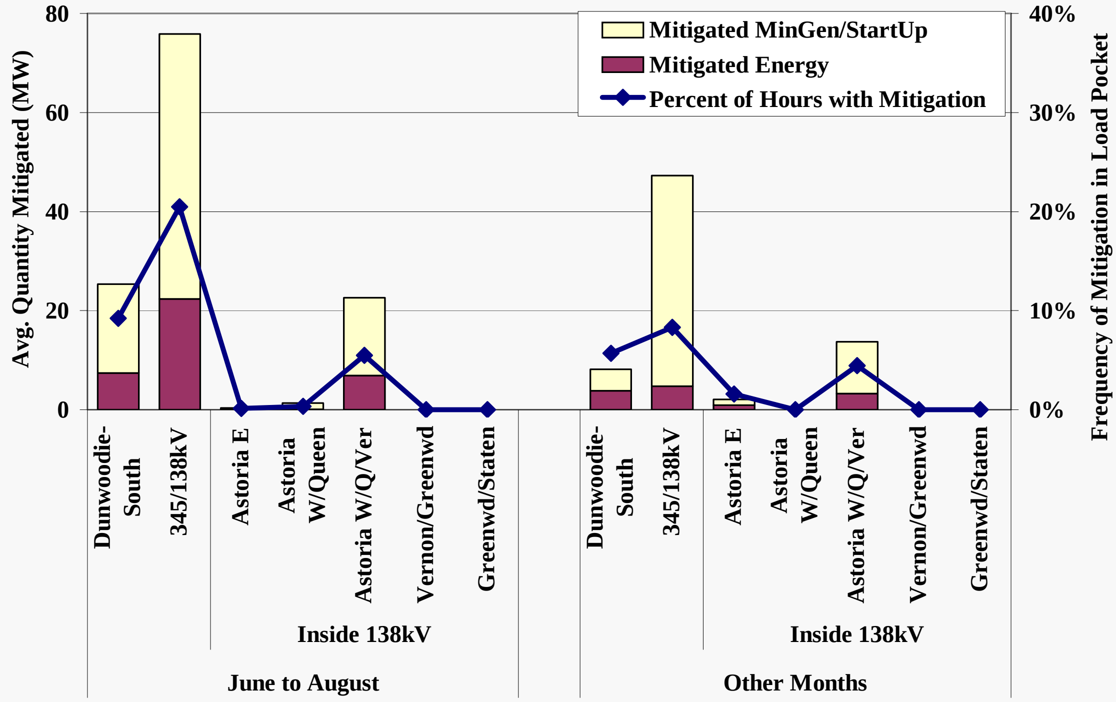
* Peak hours are defined as weekdays from 12 PM to 6 PM for purposes of this analysis.



Summary of Day-Ahead Mitigation

- The market power mitigation measures, which are based on the conduct and impact framework, are triggered when constraints are binding into NYC load pockets.
- The conduct and impact framework focuses mitigation more effectively on potential market power in NYC load pockets than the ConEd measures that were used until May 2004.
  - ✓ This approach prevents mitigation from occurring when it is not necessary to address market power, and allows high prices to occur during legitimate periods of shortage.
- The following figure summarizes the frequency of mitigation in NYC.
  - ✓ The line shows the percent of hours when mitigation was imposed on one or more units for each load pocket constraint.
  - ✓ The bars indicate the average amount of capacity mitigated in hours when mitigation occurred.
  - ✓ Mitigated quantities are shown separately for the flexible output ranges of units (i.e. Energy) and the non-flexible portions (i.e. Mingen/Start-Up).
- As in 2005, mitigation was most commonly associated with the constraints into New York City (i.e. Dunwoodie-South) and the 138 kV system.

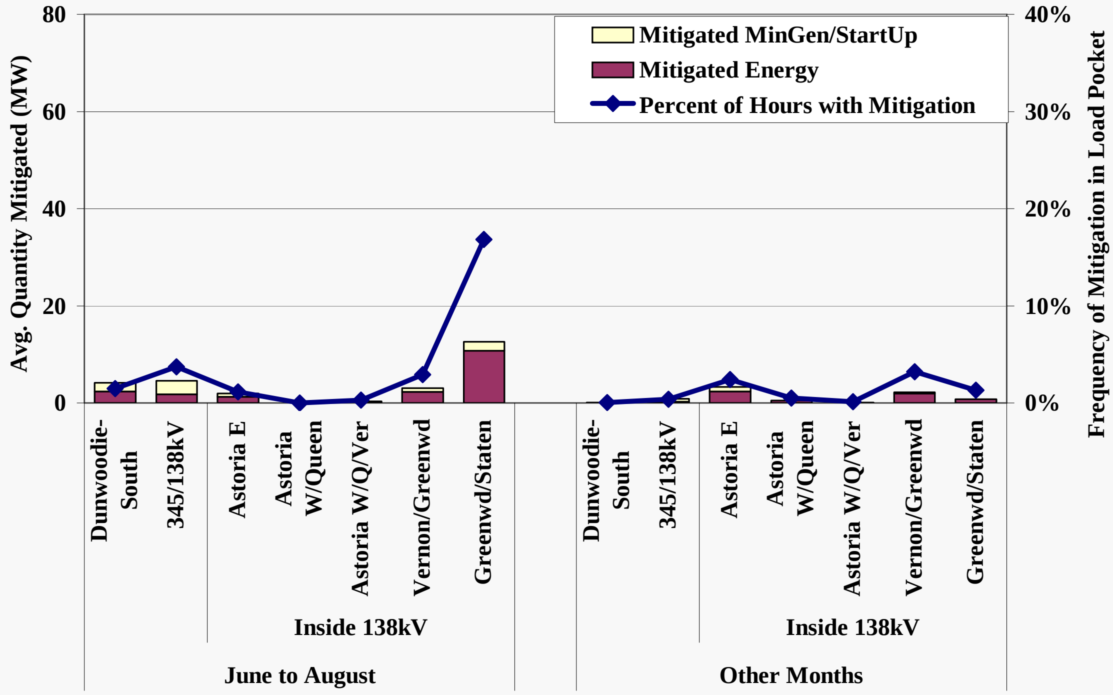
Summary of Day-Ahead Mitigation
New York City -- 2006

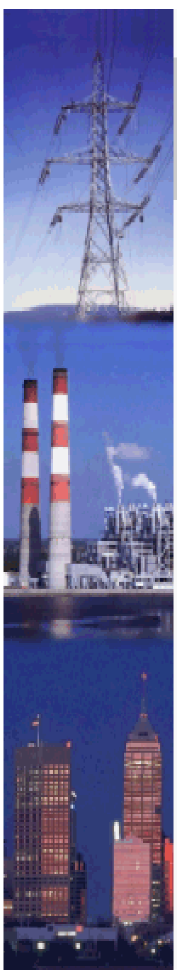


Summary of Real-Time Mitigation

- While the previous figure summarizes mitigation in the day-ahead market in New York City, the following figure summarizes real-time mitigation.
- Most real-time mitigation occurred for constraints into the Greenwood/Staten Island sub-load pocket, which is located in the 138 kV load pocket, while day-ahead mitigation was generally done for the larger load pockets.
  - ✓ The real-time market experienced more congestion into the sub-load pockets inside the 138kV load pocket of New York City than the day-ahead market.
  - ✓ Higher levels of congestion give rise to more frequent conditions when mitigation is warranted.
- In 2006, real-time mitigation was much less frequent than in 2005, except within the Greenwood/Staten load pocket.
  - ✓ The installation of new capacity has significantly reduced congestion into the sub-load pocket areas inside the 138 kV system, thereby reducing the need for real-time mitigation.
  - ✓ The introduction of detailed line modeling has improved use of transmission into the load pockets and tends to reduce the effect of generators' offer prices on LBMPs in the load pockets.

Summary of Real-Time Mitigation
New York City -- 2006

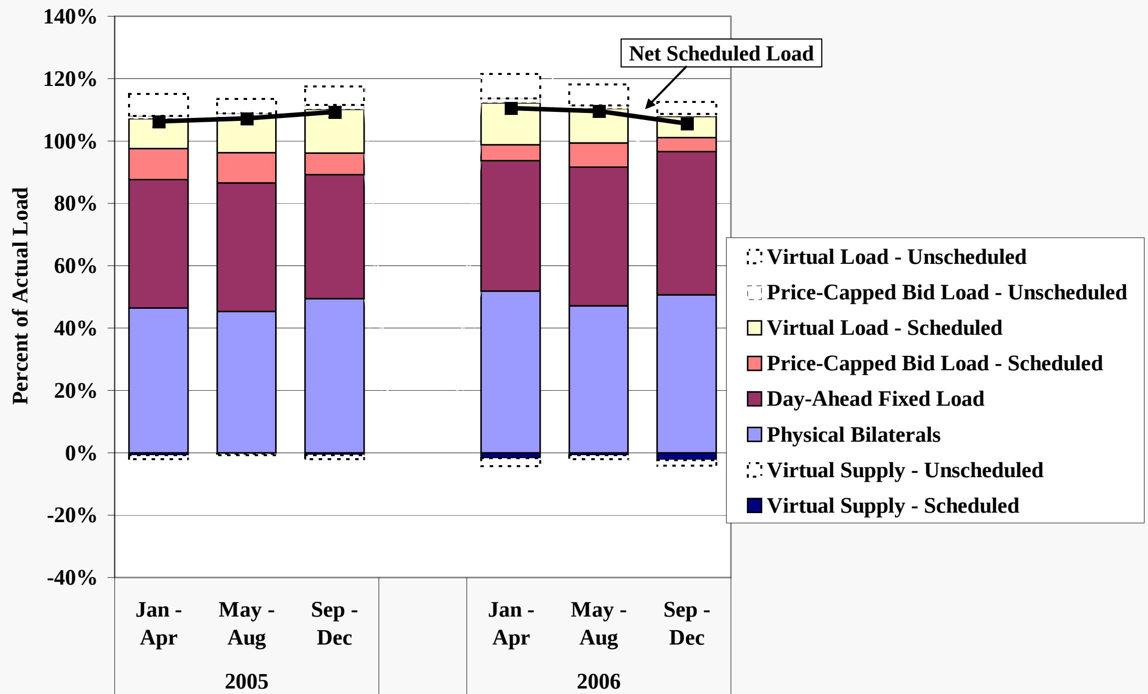




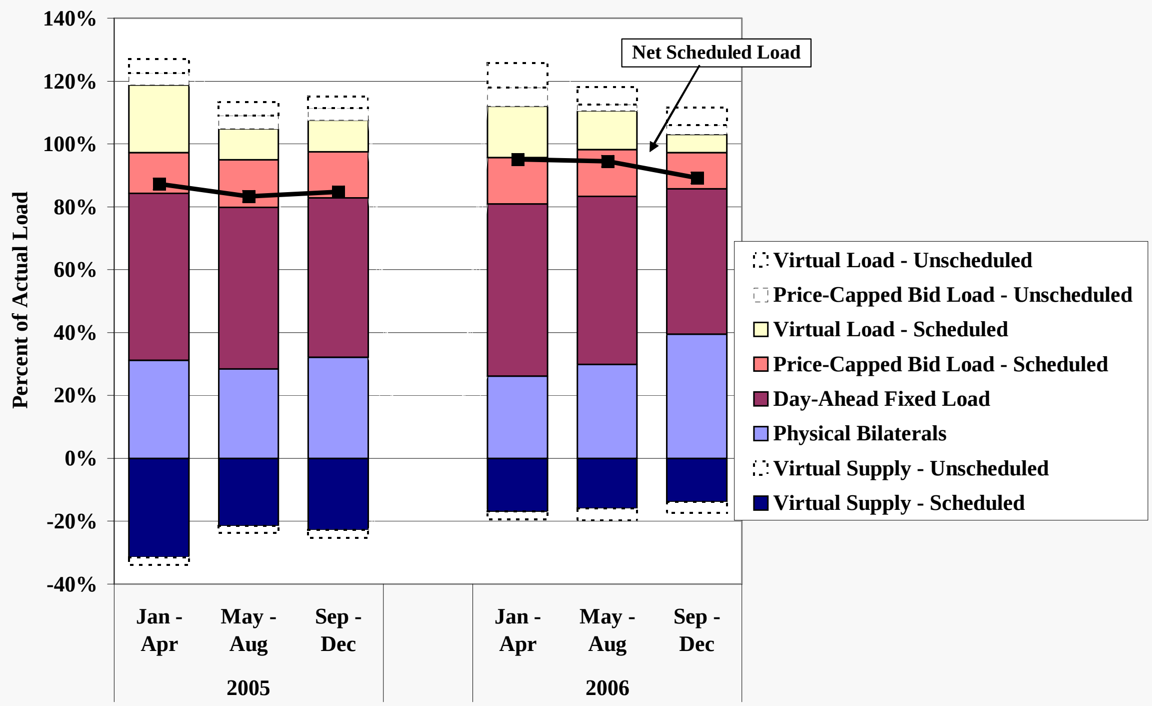
Analysis of Load Bidding Patterns

- The following figures show day-ahead load schedules and offers as a fraction of real-time load during 2005 and 2006 at various locations in New York.
  - ✓ Virtual supply nets out an equivalent amount of scheduled load, so it is shown as a negative quantity.
  - ✓ Net scheduled load = Physical Bilaterals + Fixed Load + Price-Capped Load + Virtual Load – Virtual Supply
- Load is generally over-scheduled in New York City and Long Island and under-scheduled in up-state New York.
  - ✓ This implies that, on average, the day-ahead market schedules more imports into New York City and Long Island than the real-time market.
  - ✓ This pattern of load scheduling is consistent with the pattern of day-ahead prices being greater than real-time prices in the majority of hours.
  - ✓ Prior to the summer of 2006, the real-time market began to use the same detailed model of the NYC transmission system that was previously used by the day-ahead market, and this has led to a decline in the amount of over-scheduling.
- For New York State as a whole, load was under-scheduled in the day-ahead market by an average of 4 percent in 2006.

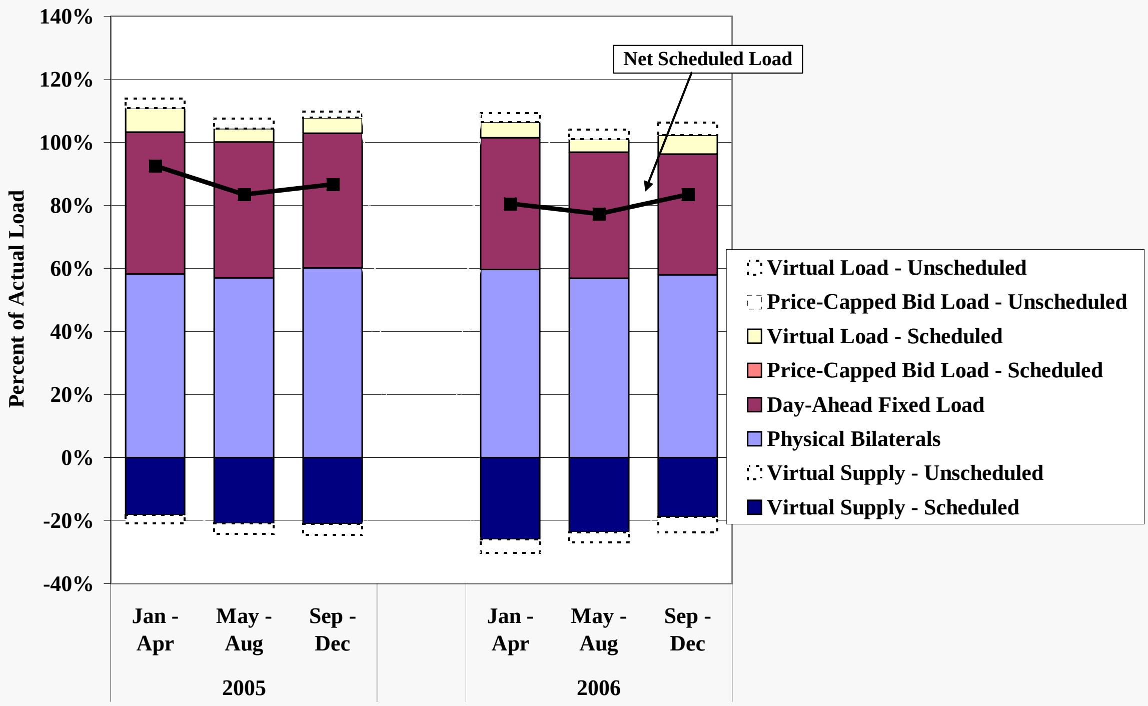
Composition of Day-Ahead Load Schedules versus Actual Load
New York City and Long Island, 2005 - 2006



Composition of Day-Ahead Load Schedules versus Actual Load
East Up-State New York, 2005 - 2006



Composition of Day Ahead Load Schedules versus Actual Load West Up-State New York, 2005 - 2006



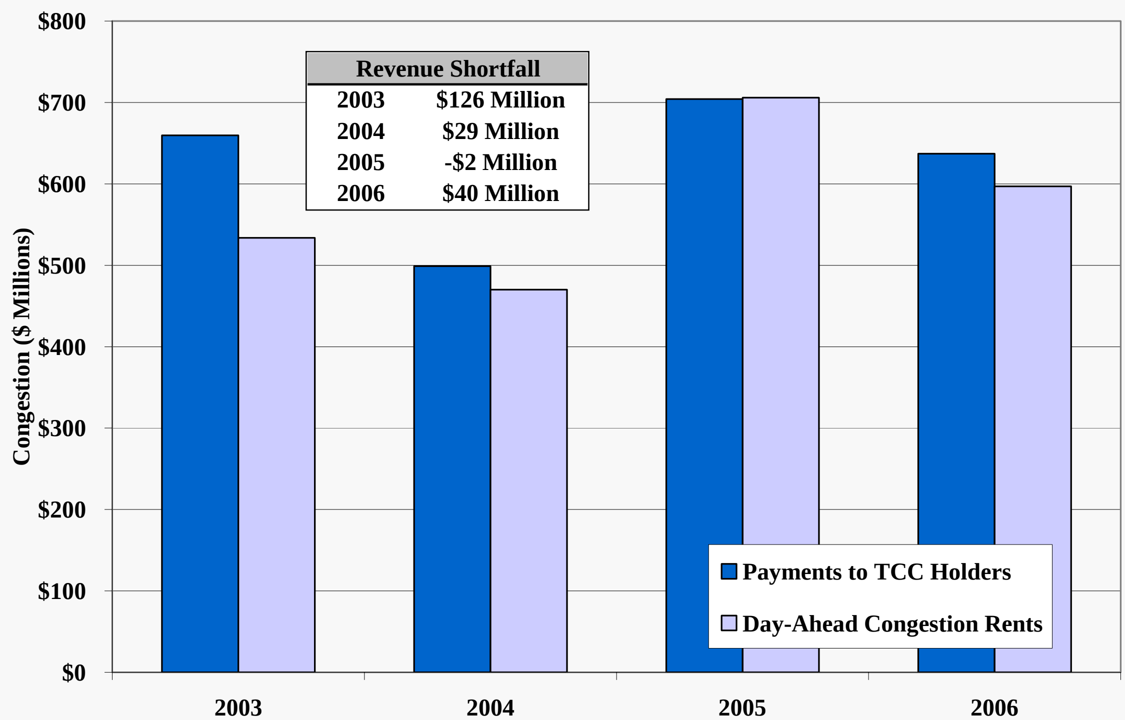
Transmission Congestion

POTOMAC ECONOMICS

Day-Ahead Congestion Revenue and TCC Payments

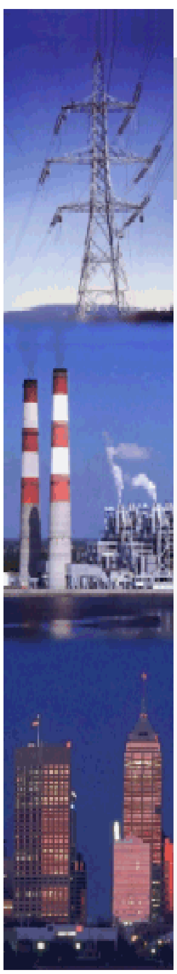
- The following figure shows the day-ahead congestion rents and payments to TCC holders, whose totals should be close if the TCCs are consistent with the capability of the system.
- Day-ahead congestion rents fell by more than $100 million in 2006, from over $700 million in 2005 to close to $600 million in 2006.
  - ✓ Lower levels of congestion in the Day-Ahead Market resulted from reduced fuel costs, modestly lower loads, and the introduction of new capacity in NYC.
  - ✓ Congestion rents fell more than payments to TCC holders, resulting in a $40 million TCC revenue shortfall.
  - ✓ Revenue shortfalls can arise when transmission outages are not reflected in the TCC auctions.
- Until 2004, payments to TCC holders generally exceeded congestion rents by a substantial margin, because the transmission capability assumed in the TCC auction exceeded the transmission capability available in the day-ahead market. The NYISO tooks several steps to reduce shortfalls:
  - ✓ Excess TCCs sold into NYC were re-purchased in July 2004.
  - ✓ The NYISO began to assign the costs of outages to the responsible TO.

Day-Ahead Congestion Revenue and TCC Payments 2003 - 2006

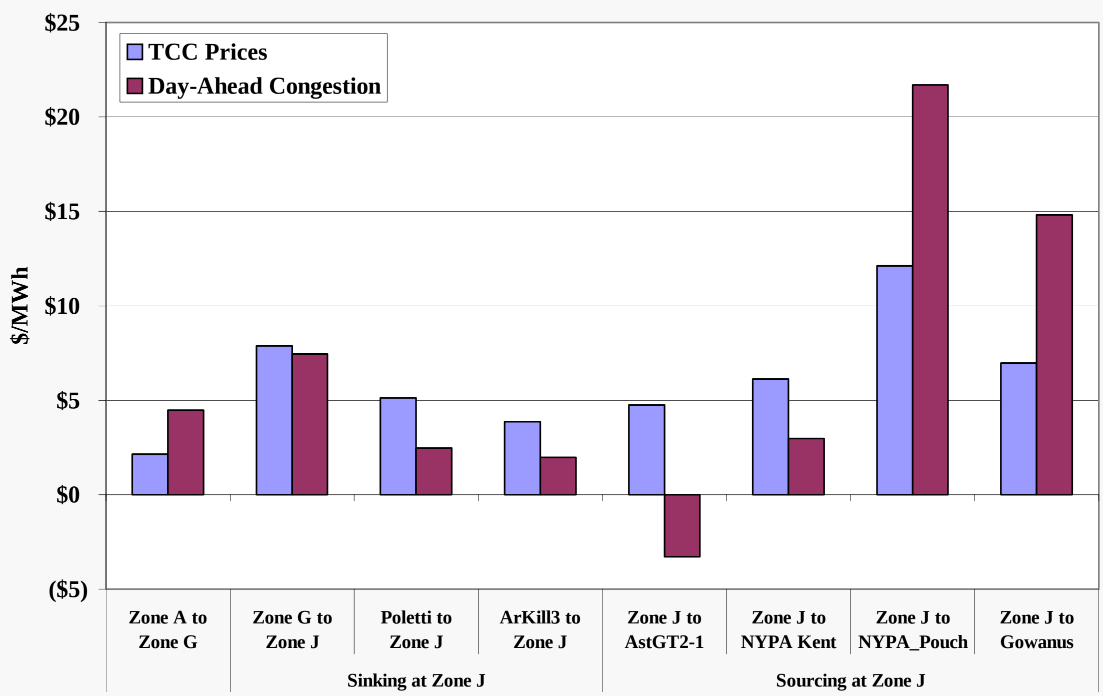


TCC Prices and Day-Ahead Congestion

- TCCs entitle the holder to the day-ahead congestion between two points.
  - ✓ The prices of TCCs should reflect expectations of day-ahead congestion.
- To evaluate this, the next figure compares the TCC auction prices from the 2006 Summer Capability Period to the actual day-ahead congestion that occurred during the period. A comparison of prices is shown:
  - ✓ Between three locations commonly used for bilateral trading: Zone A (the West Zone), Zone G (Hudson Valley), and Zone J (New York City).
  - ✓ For TCCs to Zone J from points on the 345kV system in Zone J.
  - ✓ For TCCs from Zone J that terminate in load pockets on the 138kV system in Zone J.
- The results of this analysis show:
  - ✓ West to east congestion, as shown by the Zone A to Zone G product, was under-valued, while TCCs sourcing in the 345kV area of NYC and sinking at Zone J were generally over-valued.
  - ✓ The TCCs from Zone J into Astoria East (Astoria GT2/1) and Vernon/Greenwood (NYPA_Kent) were over-valued, while congestion into Greenwood/Staten Island (NYPA Pouch and Gowanus) was greatly underestimated.



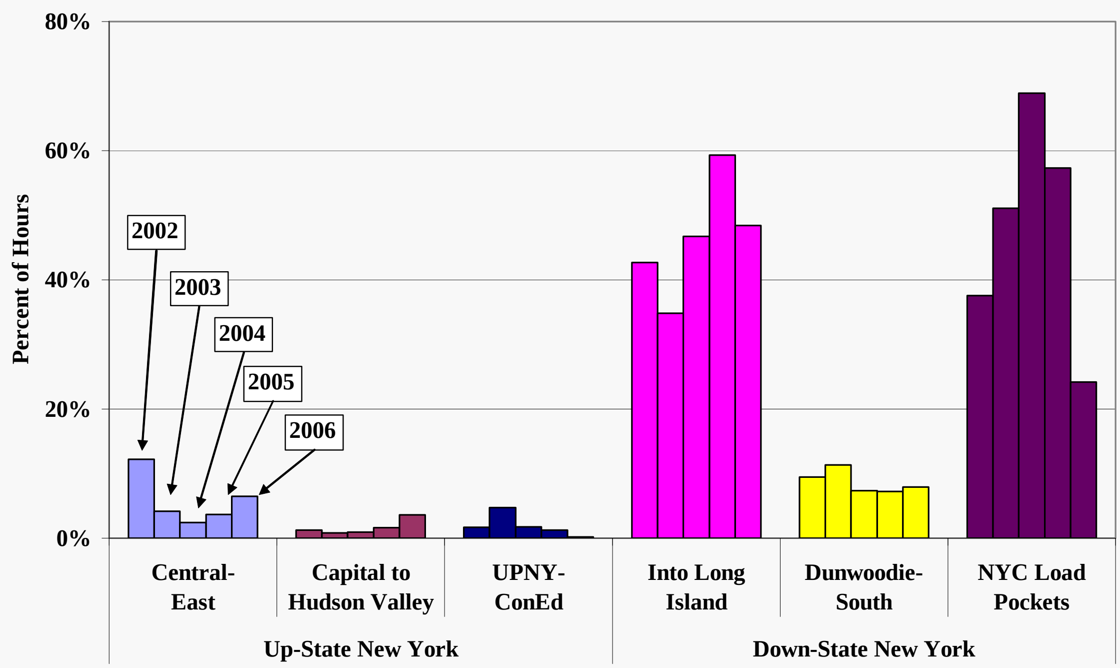
TCC Prices and Day-Ahead Congestion
May to October 2006



Real-Time Congestion on Major 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.
- The frequency of congestion decreased dramatically for the load pocket areas within New York City. This is due to:
  - ✓ The installation of one gigawatt of new combined cycle capacity in New York City; and
  - ✓ The use of a more detailed network model for real-time dispatch, which allows fuller utilization of the transmission system into New York City load pockets.
- In 2006, the frequency of congestion increased across the Central-East interface and from Capital to Hudson Valley.
  - ✓ Nearly half of the congestion across the Central-East interface occurred in December.
  - ✓ Congestion from Capital to Hudson Valley is still relatively infrequent, but is occurring during more non-TSA hours.
- Congestion continues to be very frequent into Long Island.

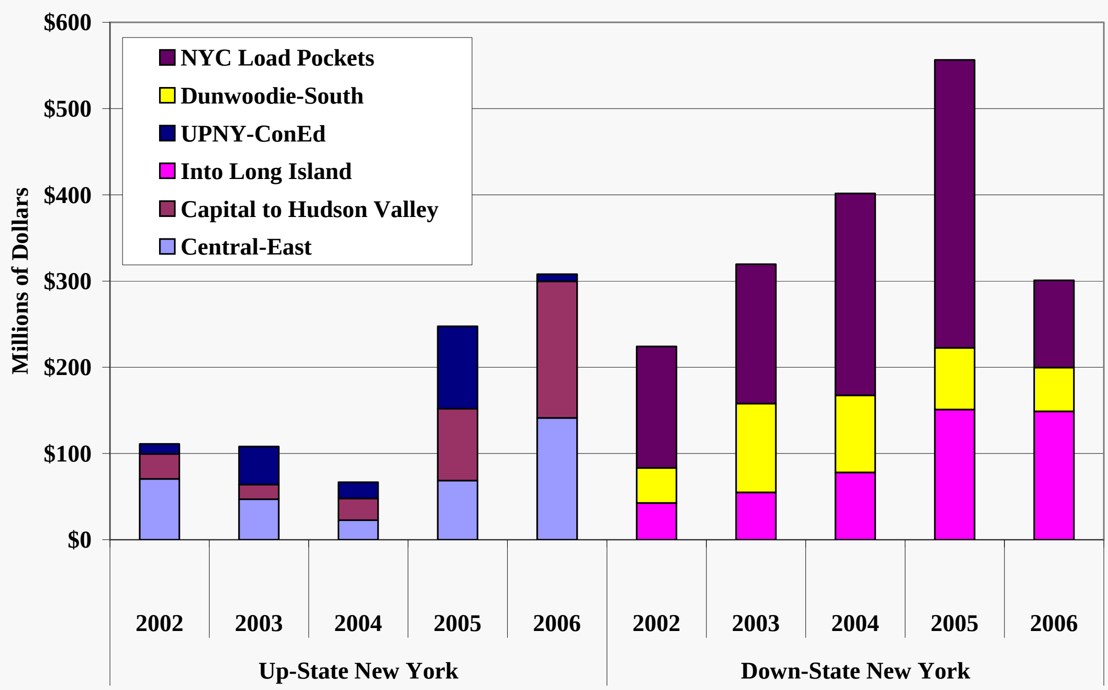
Frequency of Real-Time Congestion on Major Interfaces 2002 – 2006



Real-Time Congestion on Major Interfaces

- The second figure measures the approximate value of congestion in real-time annually for each of the interfaces.
  - ✓ The reduced fuel prices contributed to lower overall congestion costs.
  - ✓ The value of New York City load pocket congestion decreased dramatically due to the installation of new capacity in the 138kV system.
  - ✓ The use of a more detailed network for modeling in-City constraints has also helped reduce the value of congestion.
- TSAs and 10-minute reserve shortages are infrequent, but they have a significant impact on the value of constrained interfaces.
  - ✓ Intervals with TSAs accounted for $60 million of the value of up-state congestion in 2005 and $80 million in 2006.
  - ✓ Shortage intervals (without TSAs) accounted for an additional $12 million in 2005 and $40 million in 2006.
  - ✓ These events primarily affected the congestion costs on lines from the Capital area through Hudson Valley.
- Since the installation of new capacity and improved real-time modeling in New York City, the economic signals for transmission investment have shifted to other areas.

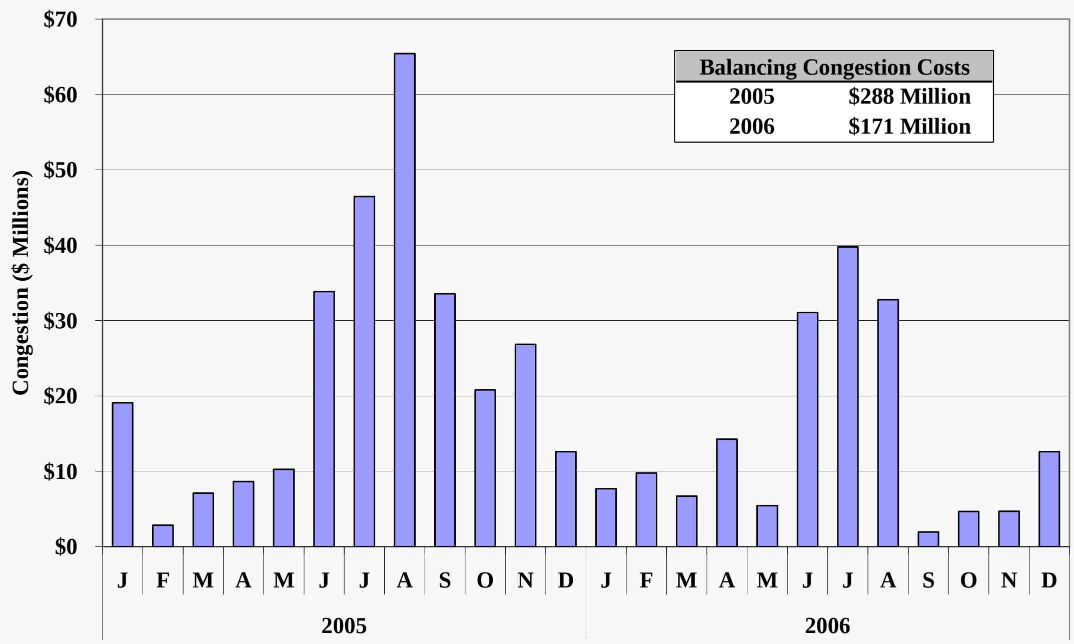
Value of Real-Time Congestion on Major Interfaces 2002 – 2006



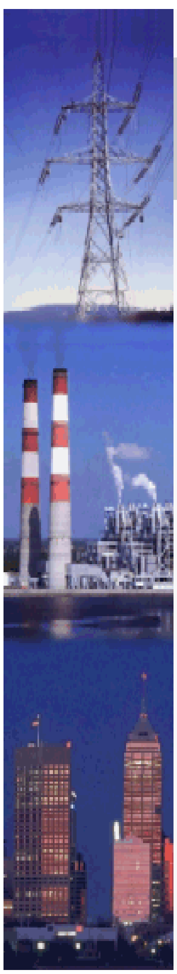
Balancing Congestion Shortfall

- The following figure shows the congestion revenue shortfalls that were incurred in the balancing market.
- The primary cause of balancing congestion shortfalls are changes between the day-ahead and real-time markets in the amount of transfer capability associated with the transmission system.
  - ✓ When day-ahead schedules exceed real-time transmission capability, the NYISO must buy back the excess in real-time.
  - ✓ TSAs led to real-time pricing events under derated transmission limits that significantly contributed to the balancing congestion costs.
- In 2006, balancing congestion costs fell 41 percent from the previous year due to several factors:
  - ✓ Total congestion costs fell due to lower fuel costs, decreased load levels, and capacity additions in New York City.
  - ✓ The introduction of line modeling in New York City in the summer of 2006 also contributed to the reduction in balancing congestion costs.

Balancing Congestion Costs 2005-2006



Market Operations – Real Time Commitment



Market Operations – Real-Time Commitment

- The NYISO upgraded its real-time commitment model as part of the SMD 2.0 implementation:
  - ✓ The RTC model commits gas turbines, and schedules generation, ancillary services, and external transactions. It runs every 15 minutes and is a significant improvement over its predecessor, the hourly BME model.
- Convergence between RTC and actual real-time dispatch is a substantial concern because a lack of convergence can result in:
  - ✓ Uneconomic commitment of generation, primarily gas turbines; and
  - ✓ Inefficient scheduling of external transactions.
- When excess resources are committed or scheduled, the results are increased uplift costs and depressed real-time prices.
  - ✓ Alternatively, committing insufficient resources leads to unnecessary scarcity and price spikes.
- This section includes several analyses that evaluate the consistency between RTC and actual real-time outcomes.

Efficiency of Gas Turbine Commitment

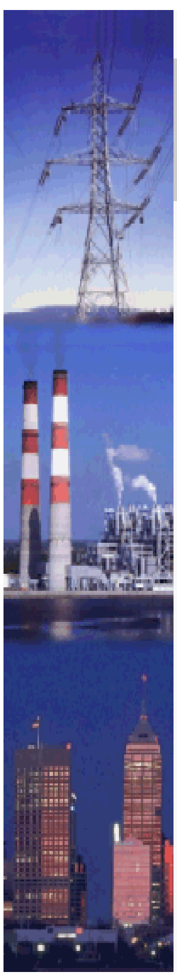
- The following figure measures the efficiency of GT commitment by comparing the offer price (energy plus start-up) to the real-time LBMP over the period of time the unit is initially committed for.
  - ✓ The left panel shows the average volume of gas turbines being started whose energy + start-up costs (amortized over the commitment period) are:
    - (a) < LBMP (clearly economic);
    - (b) > LBMP by up to 25 percent;
    - (c) > LBMP by 25 to 50 percent; and
    - (d) > LBMP by more than 50 percent.
  - ✓ The right panel shows the quantity gas turbines that were likely economic, but not started (i.e. the LBMP > Energy plus start-up offer).
- Some of the GTs with offers greater than the LBMP in the left panel are also economic, because GTs that are started efficiently may sometimes not recover their start-up costs.

Efficiency of Gas Turbine Commitment

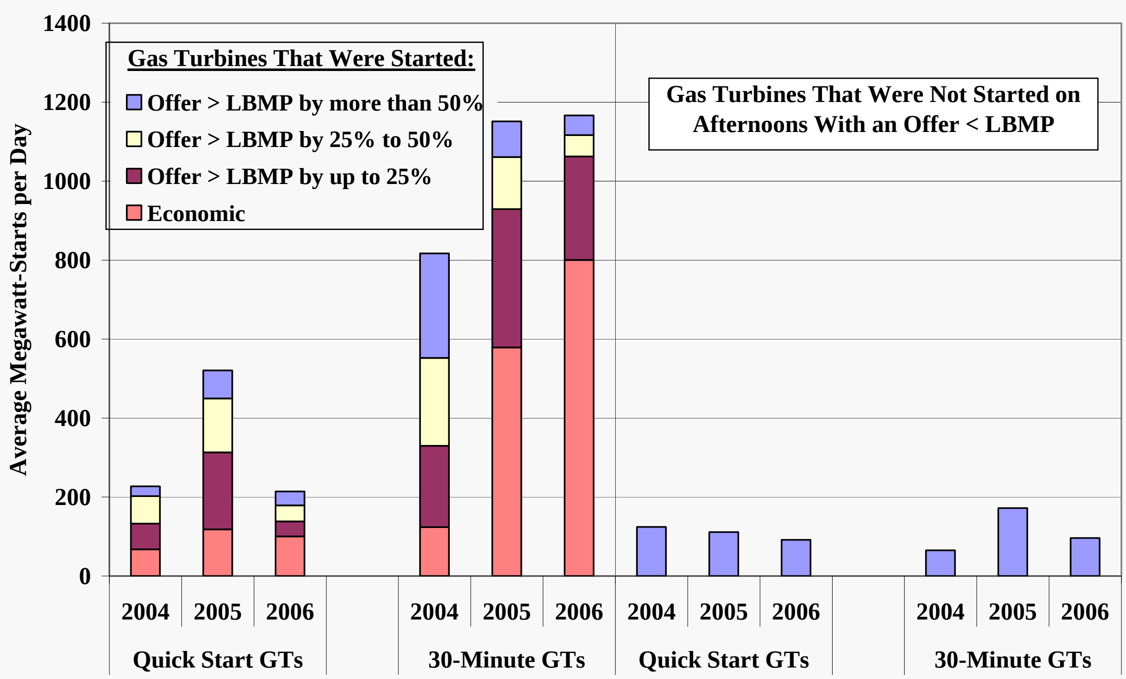
- The figure shows that the efficiency of gas turbine commitment has improved in each of the last two years. The figure indicates that:
  - ✓ A growing share of the GT commitments are economic.
  - ✓ To the extent GT commitments are not economic, they are becoming more consistent with LBMPs.
  - ✓ The amount of uncommitted GTs that would have been economic is generally small and declined from 2005 to 2006 for both quick-start and 30-minute GTs.
  - ✓ The 30-minute GTs exhibit the most substantial improvement since 2004.
- The commitment of quick-start GTs was much less frequent in 2006.
  - ✓ Many of the quick-start GTs are located in the same load pockets as the combined cycle capacity that was installed in 2006.
  - ✓ More efficient commitment of 30-minute GTs reduces the need to start quick-start GTs, which generally more costly to operate.

Efficiency of Gas Turbine Commitment – Improvements Under SMD 2.0

- Improvements to RTC and RTD after the initial implementation of SMD 2.0 have led to more efficient commitment of GT resources.
- In August 2005, RTD was modified to include the ability to start quick start resources.
- In May 2006, RTD and RTC began to model transmission constraints in New York City, replacing the use of simplified interface constraints with a detailed representation of the network of transmission lines.
  - ✓ When constraints are binding, RTD now re-dispatches generators more efficiently.
  - ✓ Frequently RTC must commit generation before constraints are actually binding; the detailed line model of New York City enables RTC to better anticipate congestion, which leads to more efficient commitment.
- Discrepancies between RTC and RTD have likely been reduced by better consistency between the physical and pricing passes of RTD.



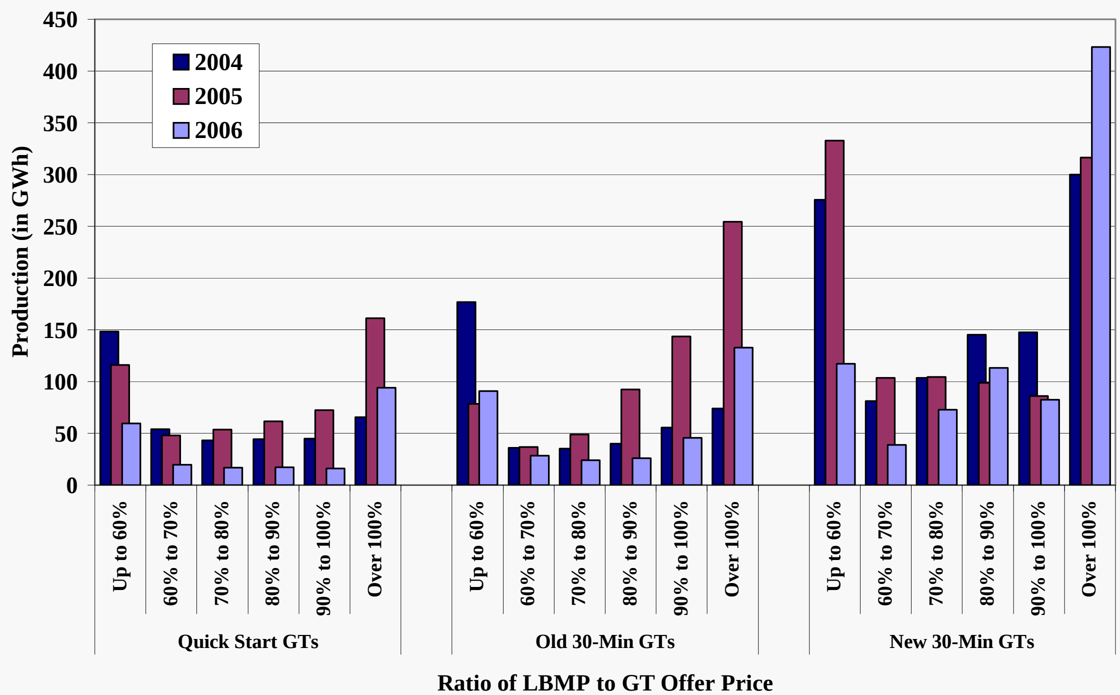
Efficiency of Gas Turbine Commitment
June to December, 2004-2006



Efficiency of Gas Turbine Production

- The next figure summarizes the efficiency of GT production by comparing the offer price (energy plus average start-up) to the average hourly real-time LBMP when GTs are running.
- This assessment differs from the previous analysis in two ways:
  - ✓ It includes all hours when gas turbines are running. The previous analysis evaluates the initial decision to start a gas turbine.
  - ✓ It compares hourly average LBMPs to offer prices, which can be misleading if a GT runs in the highest priced portion of a particular hour.
- The figure shows:
  - ✓ Total production from GTs increased in 2005 due to higher load levels and declined in 2006 due to the installation of new capacity in New York City.
  - ✓ In the two years under SMD 2.0, the figure shows a significant shift toward more of the production being economic at the real-time price for each type of GT.
- Newer gas turbines (i.e. ones installed since 2001) have much lower running costs than older ones.
  - ✓ These account for 13 percent of GT capacity, but 60 percent of the total output from GTs.
  - ✓ In many of the hours showing uneconomic production, these GTs had day-ahead energy schedules and were not exposed to real-time prices (and thus, could not receive real-time BPCG payments).

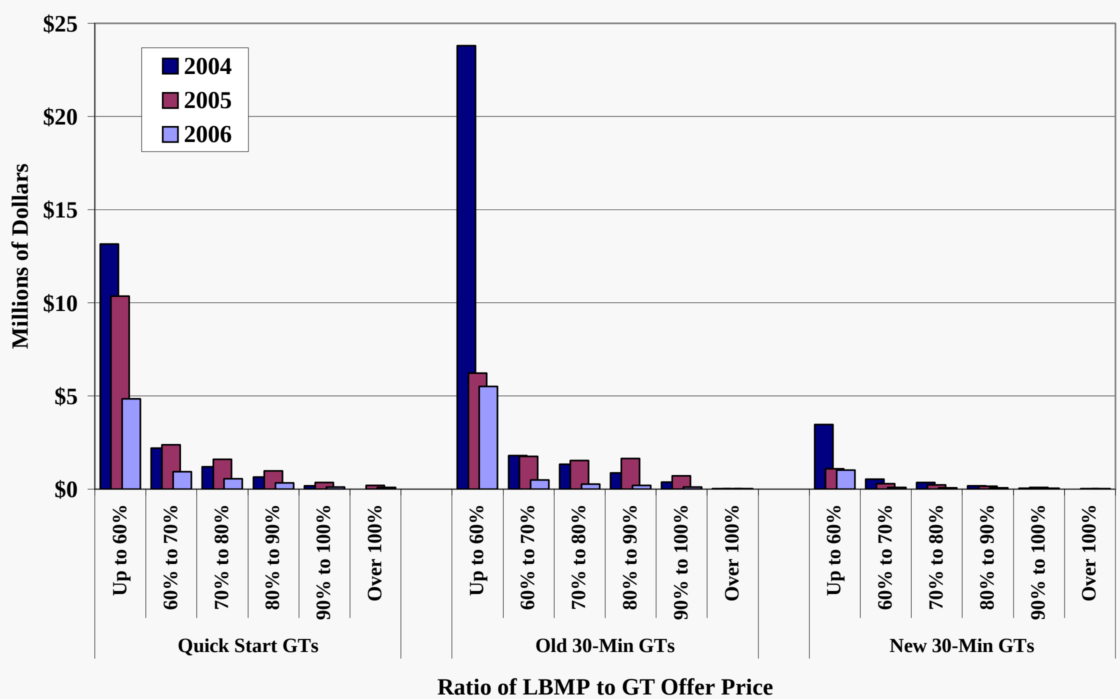
Efficiency of Production by Gas Turbines Based on Comparison of LBMPs and Offer Prices 2004 – 2006



Efficiency of Gas Turbine Production

- Gas turbines that do not earn sufficient revenue to compensate them for as-bid costs receive make whole payments (i.e. BPCG payments).
  - ✓ BPCG payments are paid based on a daily comparison of as-bid costs and revenues earned from the market, but we have estimated these on an hourly basis for the purposes of this analysis.
- The following figure summarizes BPCG payments according to the ratio of the LBMP to the GT's offer price.
- The figure shows:
  - ✓ The majority of BPCG payments come from hours when the LBMP is less than 60 percent of the GT's offer price.
  - ✓ In 2005, there was a dramatic reduction in BPCG payments associated with hours where the LBMP was less than 60 percent of the GT's offer price, particularly for older 30-minute GTs
- An increasing share of GTs energy sales are made in the day-ahead market, which reduces the potential for uplift when they are dispatched.
  - ✓ The percent of GT production sold in the day-ahead market has risen from 35 percent in 2004 to 61 percent in 2006.

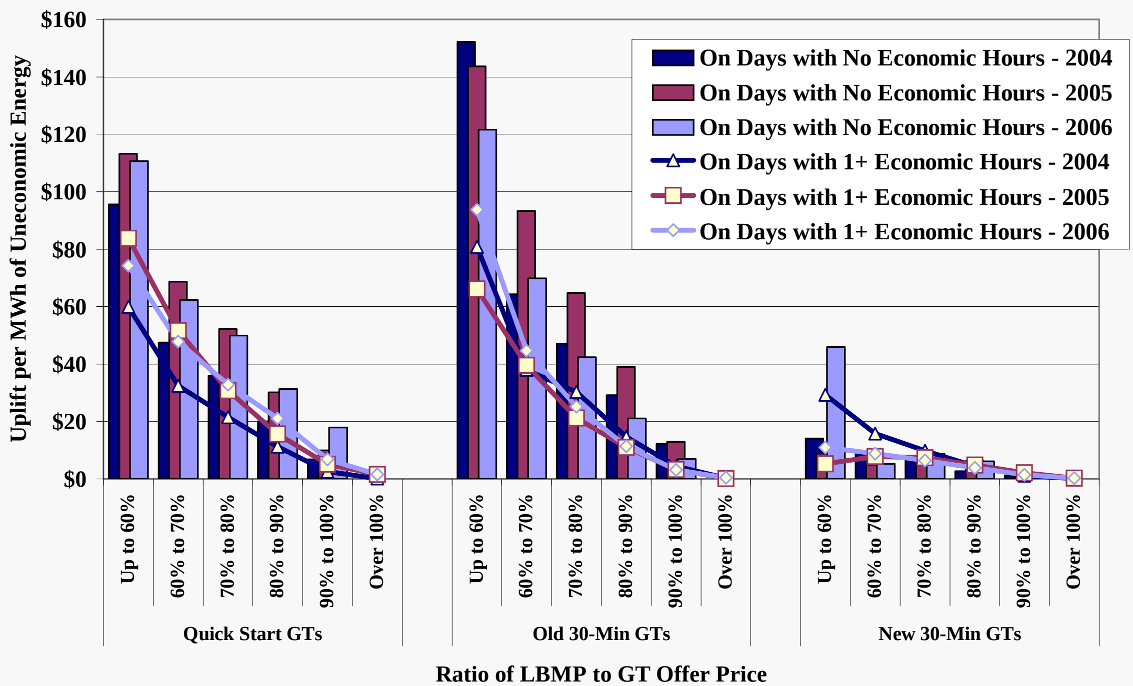
Summary of BPCG Payments to Uneconomic GTs 2004 – 2006



Efficiency of Gas Turbine Production

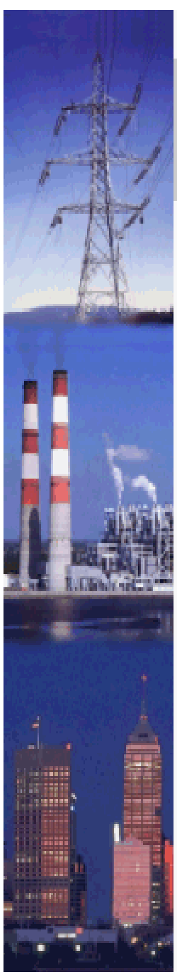
- The following figure shows BPCG payments per megawatt-hour of uneconomic production according to the ratio of the LBMP to the GT's offer price.
- Average BPCG payments are shown separately for hours that occurred on days when at least one other hour was economic.
  - ✓ Since BPCG payments are calculated on a daily basis, gains from high-priced hours go to defray losses from low-priced hours.
- The figure shows:
  - ✓ Due to the rise in fuel prices, in 2005, the payments were generally higher per megawatt-hour of uneconomic production than in 2004.
  - ✓ The decline in fuel prices, in 2006, led to a corresponding decline of the average payment per megawatt-hour.
  - ✓ BPCG payments are significantly lower per megawatt-hour on days when at least some hours were economic.
- In 2005, although BPCG payments were higher per unit of uneconomic production, total costs were lower due to a reduction in the volume of uneconomic production.
- In 2006, BPCG payments declined further due to lower fuel prices, less operation of GTs, and a decline in the share of production that was uneconomic.

BPCG Payments per Unit of Uneconomic GT Production 2004 – 2006



Efficiency of Gas Turbine Production - Conclusions

- The series of analyses comparing gas turbine efficiency from 2004 to 2006 leads to the conclusion that changes made under SMD 2.0 have substantially improved the efficiency of the commitment and dispatch of gas turbines.
  - ✓ The frequency of uneconomic commitment and production decreased, resulting in lower BPCG payments, especially for older gas turbines.
- We estimated the uplift savings from more efficient gas turbine commitment under SMD 2.0 in 2005 and 2006 versus the old market software, taking into account the following factors:
  - ✓ The rate of commitment efficiency in 2004 compared to 2005 and 2006.
  - ✓ In 2005 and 2006, LBMPs were generally higher relative to gas turbine offer prices, which helped push uplift down.
  - ✓ In 2005, higher fuel prices led to higher payments per unit.
  - ✓ In 2005 and 2006, the exposure to uplift from uneconomic commitment was diminished by increased sales from GTs in the day-ahead market.
- Estimated uplift savings were $22 million in 2005 and $32 million in 2006.

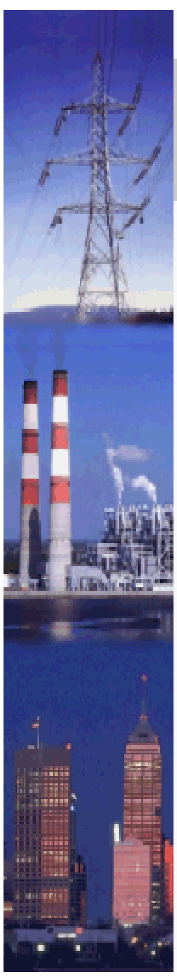


Comparison of RTC and RTD Prices

- The following analyses in this section examine the reasons for differences between RTC and RTD prices.
  - ✓ RTC runs every 15 minutes, and each RTC run produces advisory prices at 15 minute intervals over a 2 hour and 30 minute horizon.
  - ✓ The following analyses compare RTD prices with the RTC prices for the interval that is closest to the time when RTC runs.
- The comparison of RTC and RTD prices provides a general indication of convergence between RTC and RTD. Inflated RTC prices can lead to:
  - ✓ Uneconomic commitment of generation, primarily gas turbines; and
  - ✓ Inefficient scheduling of external transactions.
- Excess commitment and scheduling results in increased uplift costs and depressed real-time prices.
  - ✓ Alternatively, failing to commit economic resources leads to unnecessary scarcity and price spikes.

Comparison of RTC and RTD Inputs

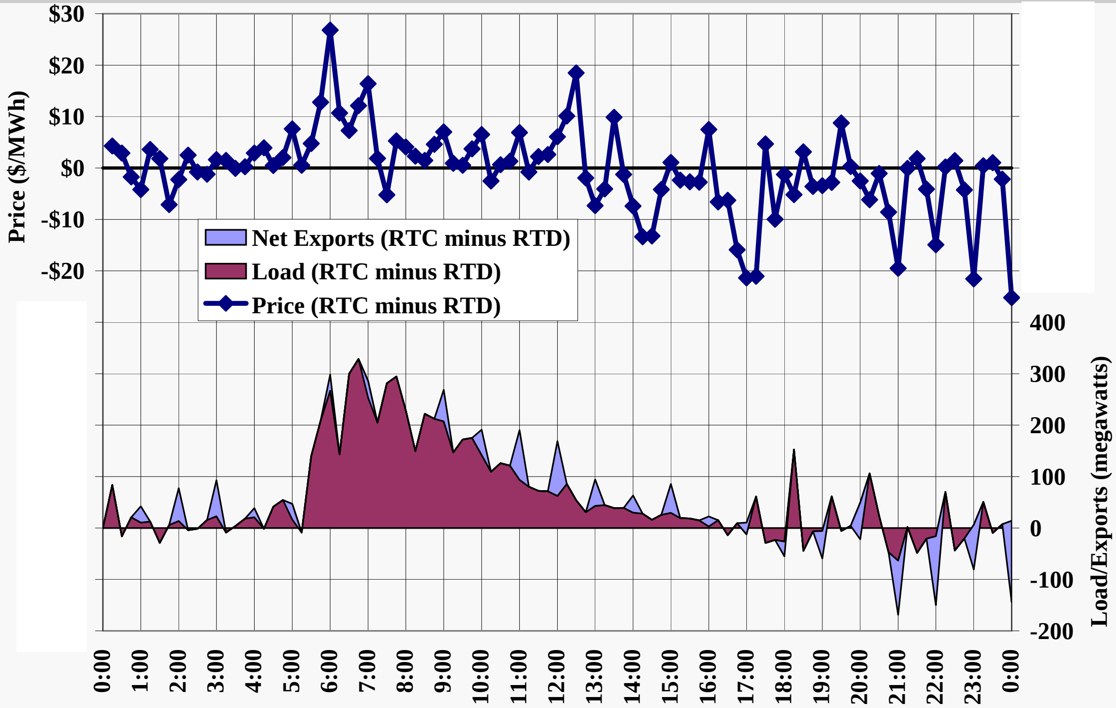
- The following figure shows the differences between RTC and RTD in loads, net exports, and prices at 15-minute intervals during the day.
- Loads and net exports are inputs which jointly determine the quantity of internal resources that must be scheduled by RTC and RTD.
  - ✓ Thus, increasing load and net exports requires additional internal generation, which leads to higher prices.
  - ✓ Net exports and loads are stacked in the figure to show their cumulative effect.
- RTC load is consistently higher than RTD load during the morning ramp period, which leads to correspondingly higher RTC prices.
  - ✓ RTC schedules resources at time *t* using the highest of the load forecasts of time *t*, *t plus five minutes*, and *t plus ten minutes*.
  - ✓ As a result, RTC load is approximately ten minutes ahead of the load forecast during the morning ramp period.
- The difference between RTC and RTD prices briefly spikes high and low at specific times during the day.
  - ✓ RTC prices are *higher* on average by at least $15/MWh at 6:00, 7:00, and 12:30.
  - ✓ RTC prices are *lower* on average by at least $20/MWh at 17:00, 17:15, 21:00, 23:00, and midnight.



Comparison of RTC and RTD Inputs

- Systematic differences between RTC and RTD prices are correlated with differences between RTC and RTD values of load and net exports.
  - ✓ At the top of each hour, RTC and RTD do not expect the same level of exports. RTD assumes that each interface "ramps" at a constant rate from five minutes before the top of the hour to five minutes after, whereas RTC assumes that each interface meets the next hour schedule at the top of the hour.
  - ✓ Reasons for the 15-minute variations in the differences between RTC and RTD load are discussed in the next analysis.
- At specific times of day, systematic differences between RTC and RTD prices seem to be explained by differences between RTC and RTD values of load and exports.
  - ✓ From 5:15 to 11:00, there is a strong correlation;
  - ✓ Likewise, from 20:30 to midnight, there is a strong correlation; and
  - ✓ The afternoon and early evening do not exhibit an obvious correlation. Thus, other factors, such as transmission constraints and locational reserves shortages, become increasingly important.
- The analysis suggests that differences between RTC and RTD values of load and exports play a significant role during ramping hours.

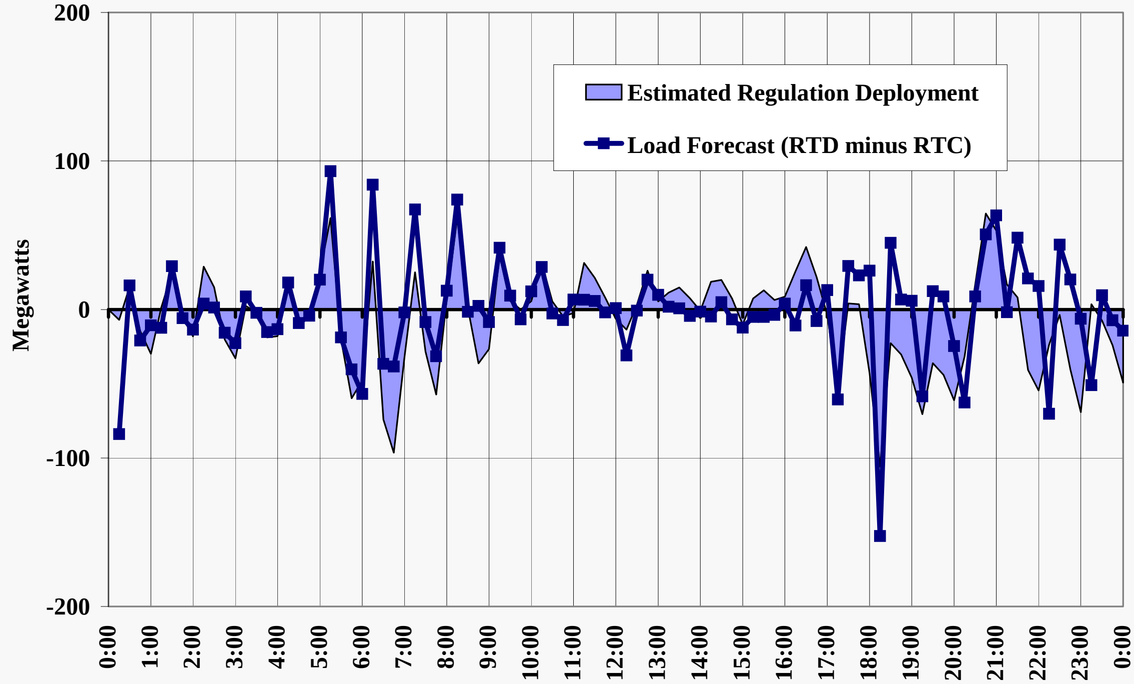
Prices, Loads, and Net Exports in RTC and RTD by Time of Day, Summer 2006



Comparison of RTC and RTD Inputs

- The following analysis compares differences between the load forecasts used by RTC and RTD to the net estimated regulation deployment by time of day.
- There is a strong correlation between variations in regulation deployment and the difference between the load forecasts used by RTD and RTC.
- For example, at 5:15:
  - ✓ Regulating units are usually being instructed to increase output relative to 5:00.
  - ✓ The difference between the RTD load forecast and the RTC load forecast shifts in the positive direction.
  - ✓ The additional load scheduled by RTD reduces the amount of regulation that must ultimately be deployed.
- To minimize regulation deployment, the operators make incremental adjustments to the load forecast, which reduces the need for regulation.
  - ✓ Lower regulation requirements lead to lower regulation procurement costs.
  - ✓ Reduced deployment of regulation results in less economically out-of-merit generation.
- Because RTC looks further into the future than RTD, adjustments to the load forecast are reflected “sooner” in RTD than in RTC.

RTC and RTD Load Forecasts and Regulation Deployment by Time of Day, Summer 2006



Comparison of RTC and RTD – Conclusions

- Currently, three factors undermine convergence during ramping hours:
  - ✓ RTC schedules resources at time *t* using the highest of the load forecasts at time *t*, *t plus five minutes*, and *t plus ten minutes*. This practice consistently leads RTC prices to be higher than RTD prices during the morning ramp period.
  - ✓ RTC and RTD use different assumptions about the level of expected exports. RTD assumes that each interface "ramps" at a constant rate from five minutes before the top of the hour to five minutes after, whereas RTC assumes that each interface meets the next hour schedule at the top of the hour.
  - ✓ The load forecast is adjusted in real-time to reduce the need for regulation deployment, which results in differences between RTC and RTD load.
- We recommend the NYISO evaluate whether:
  - ✓ There is an alternative to RTC using the highest of three five-minute load forecasts;
  - ✓ The assumptions about external transaction ramp can be made consistent to eliminate differences at the top of each hour; and
  - ✓ Predictable adjustments to the RTD load forecast, which are made to minimize regulation deployment, can be reflected more quickly in the RTC load forecast.

Market Operations – Real Time Scheduling and Shortage Pricing

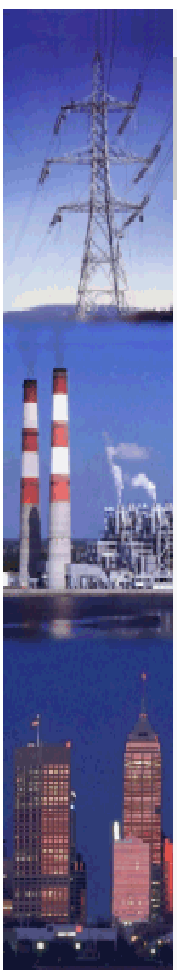
POTOMAC ECONOMICS

Reserve Shortages and Shortage Pricing

- RTD co-optimizes procurement of energy and ancillary services. This has several advantages:
  - ✓ The software efficiently allocates resources to provide energy and ancillary services every five minutes.
  - ✓ This incorporates the costs of maintaining reserves into the price of energy, whereas these costs were not considered prior to SMD 2.0.
  - ✓ Demand curves rationalize the pricing of energy and reserves during shortage periods by setting limits on the costs that can be incurred to maintain reserves.
- This section evaluates the consistency between Eastern 10-minute reserves pricing done by the new software and the actual physical scarcity of Eastern 10-minute reserves.
  - ✓ The real-time software maintains 1000 MW of 10-minute reserves inside Eastern New York up to a cost of $500/MWh.
  - ✓ The Eastern 10-minute reserves requirement has been the most costly to maintain since the introduction of real-time ancillary services markets.

Reserve Shortages and Shortage Pricing

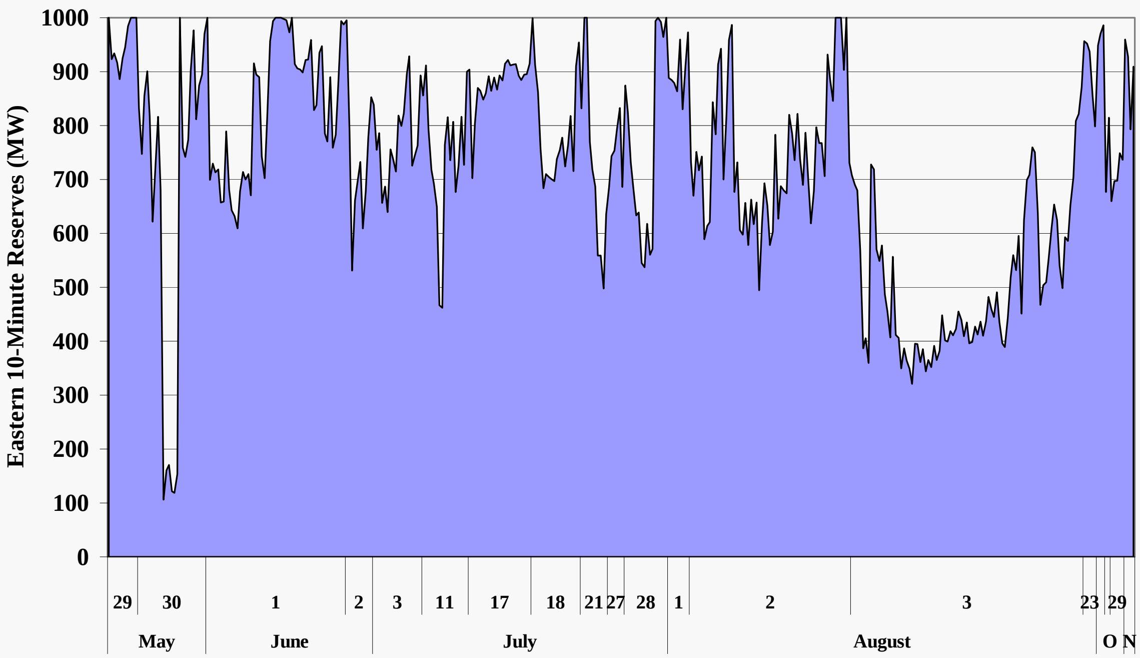
- Under SMD 2.0, co-optimization of energy and reserves is integrated with the Hybrid Pricing approach. Hybrid Pricing of gas turbines has been a key element of the real-time market software since 2002.
  - ✓ The inflexibility of gas turbines creates challenges for pricing energy efficiently when the gas turbines are the marginal source of supply.
  - ✓ 28 percent of dispatchable capacity in New York City and 42 percent of the dispatchable capacity in the 138kV load pocket are gas turbines.
  - ✓ Thus, Hybrid-Pricing is particularly important to setting efficient price signals in NYC.
- Hybrid Pricing treats gas turbines as flexible resources for pricing purposes, which results in certain inconsistencies between the pricing dispatch and the physical dispatch. However, these inconsistencies should be limited such that:
  - ✓ Under physical shortage conditions, prices should reflect scarcity; and
  - ✓ High prices are only set when the system is physically in shortage.

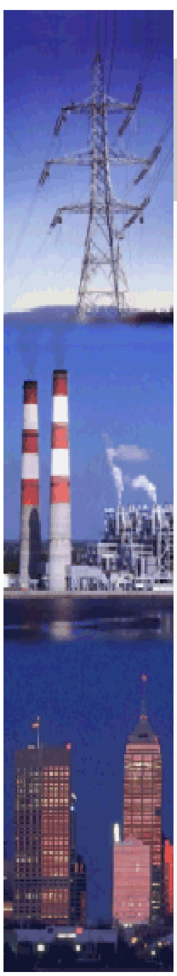


Reserve Shortages and Shortage Pricing

- The following chart shows the amount of Eastern 10-minute reserves that were physically scheduled during shortage pricing intervals in 2006.
  - ✓ The figure shows 376 intervals with shortage pricing of Eastern 10-minute reserves.
  - ✓ Based on the amount of physically available 10-minute reserves, Eastern New York was in a physical shortage in 96 percent of these intervals.
  - ✓ This is an improvement over the previous year when 89 percent of shortage pricing intervals occurred during periods of physical shortage.
- The following figure shows very good consistency between the pricing dispatch and physical dispatch passes of RTD during periods when shortage pricing was invoked.
  - ✓ Thus, shortage pricing in Eastern New York has occurred during true shortages, and these shortages have been accurately reflected in the real-time prices of energy and reserves.

Scheduling of 10-Minute Reserves in the East During Shortage Pricing Intervals – 2006

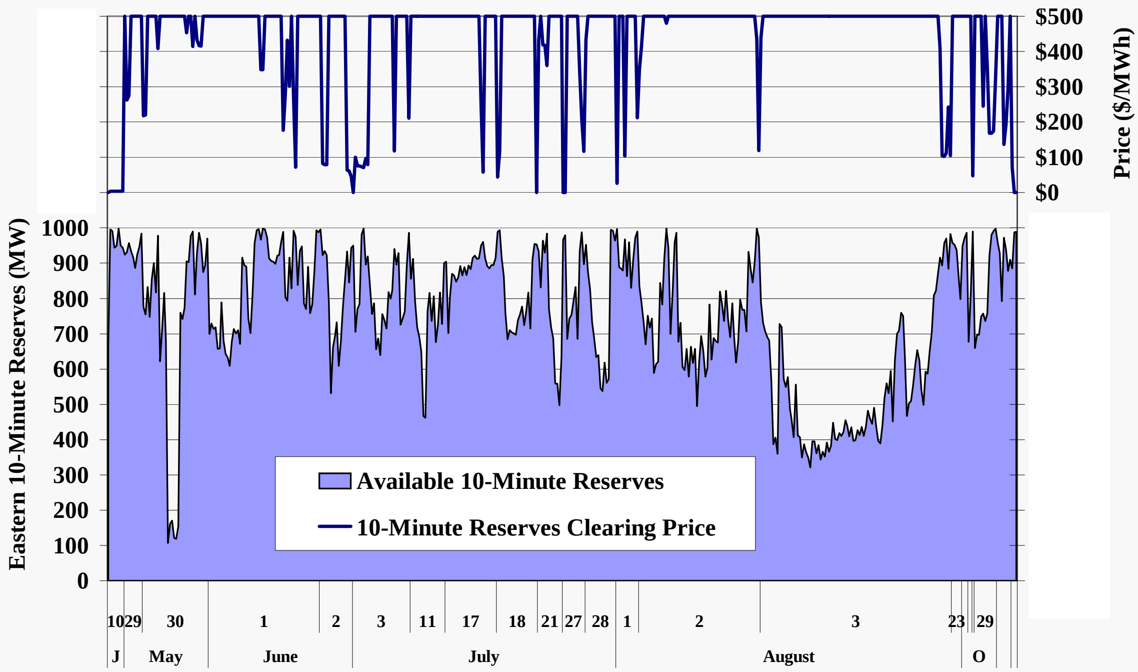




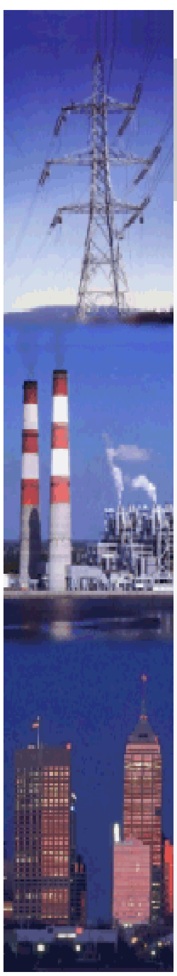
Reserve Shortages and Shortage Pricing

- The following figure shows available reserves during physical shortages of Eastern 10-minute reserves as well as a line indicating intervals with Eastern 10-minute reserves shortage pricing.
- There were 85 intervals with physical reserves shortages but no Eastern 10-minute reserves shortage pricing.
  - ✓ This represents 19 percent of the intervals with physical shortages;
  - ✓ The shortage was less than 100 MW in 67 percent of these intervals;
  - ✓ The average Eastern 10-minute reserves price was $190/MWh during these intervals.
- These results demonstrate a dramatic improvement in consistency between the pricing dispatch and the physical dispatch passes of RTD during periods when the East is short of 10-minute reserves.
  - ✓ During 2005, there were 235 intervals with physical reserves shortages but no Eastern 10-minute reserves shortage pricing, with an average price of $113/MWh.

Scheduling and Pricing of 10-Minute Reserves in the East During Physical Shortage Intervals – 2006



Note: In cases where the East 10-Minute Non-Spin price exceeds $500/MWh, the figure shows $500/MWh.

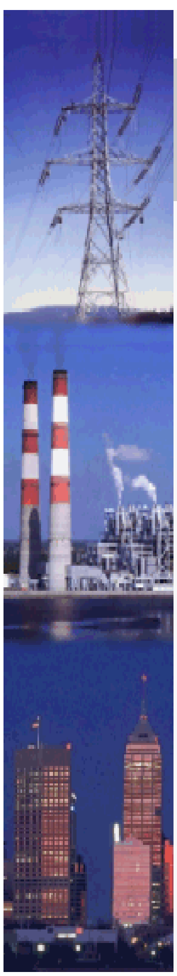


Reserve Shortages and Shortage Pricing Conclusions

- The dispatch software implemented under SMD 2.0 has significantly improved the efficiency of energy and ancillary services pricing.
  - ✓ It replaced software that did not consider how ancillary services affect the cost of energy.
  - ✓ It reduces system costs by re-allocating ancillary services every five minutes.
- During 2005, real-time energy and reserves prices sometimes did not fully reflect that the system was under shortage conditions.
- Prior to the summer of 2006, two software changes were made that better enable the real-time market model to set efficient clearing prices.
  - ✓ In mid-August 2005, enhancements were made to allow off-line quick-start GTs to be co-optimized by RTD for providing energy and reserves.
  - ✓ In May 2006, a change was made to allow the physical and pricing passes of RTD to be more consistent regarding the ratings of gas turbines in high ambient temperature conditions. This is explained below in greater detail.

Hybrid Pricing

- Hybrid Pricing generally enables the real-time software to calculate efficient prices, especially in areas that are primarily served by GTs.
- Hybrid Pricing utilizes a pricing dispatch and a physical dispatch that can differ significantly, which can affect whether the pricing dispatch perceives a shortage in 10-minute reserves.
  - ✓ The Hybrid Pricing approach allows the pricing dispatch to treat on-line GTs as flexible from zero to maximum, while the physical dispatch always includes them at their maximum output level.
  - ✓ Thus, the pricing dispatch may count less energy from these units, but only when it is not economically in-merit, which is generally not the case during reserves shortages.
- Two additional factors that have contributed to differences between the pricing dispatch and physical dispatch are described on following slide.

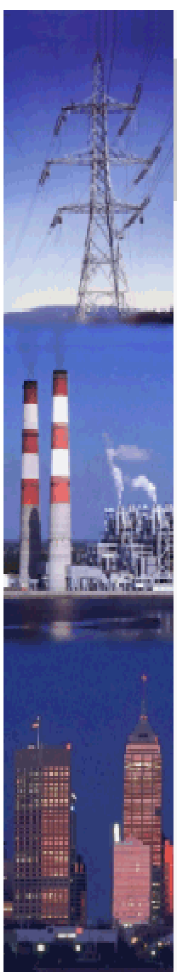


Hybrid Pricing

- *Units Not Following Dispatch*: In general, physical dispatch instructions are "ramp-constrained" by the expected physical output of the unit plus or minus what can be ramped in one interval, while the pricing dispatch level is ramp constrained by the last pricing dispatch level plus or minus the ramp limit.
  - ✓ Thus, the pricing dispatch may count *more* energy from units that persistently *under*-produce.
  - ✓ And, the pricing dispatch may count *less* energy from units that persistently *over*-produce.
- *Inconsistent Output Limits for GTs*: Inconsistencies between the offer amount and the actual production level can arise when high ambient temperatures reduce the maximum output level of GTs.
  - ✓ The physical dispatch uses the actual production level while, until May 2006, the pricing dispatch used the offer quantity.
  - ✓ The physical dispatch and pricing dispatch currently use the same value.
  - ✓ Until this software change, the pricing dispatch generally counted more production from GTs than the physical dispatch.

Hybrid Pricing

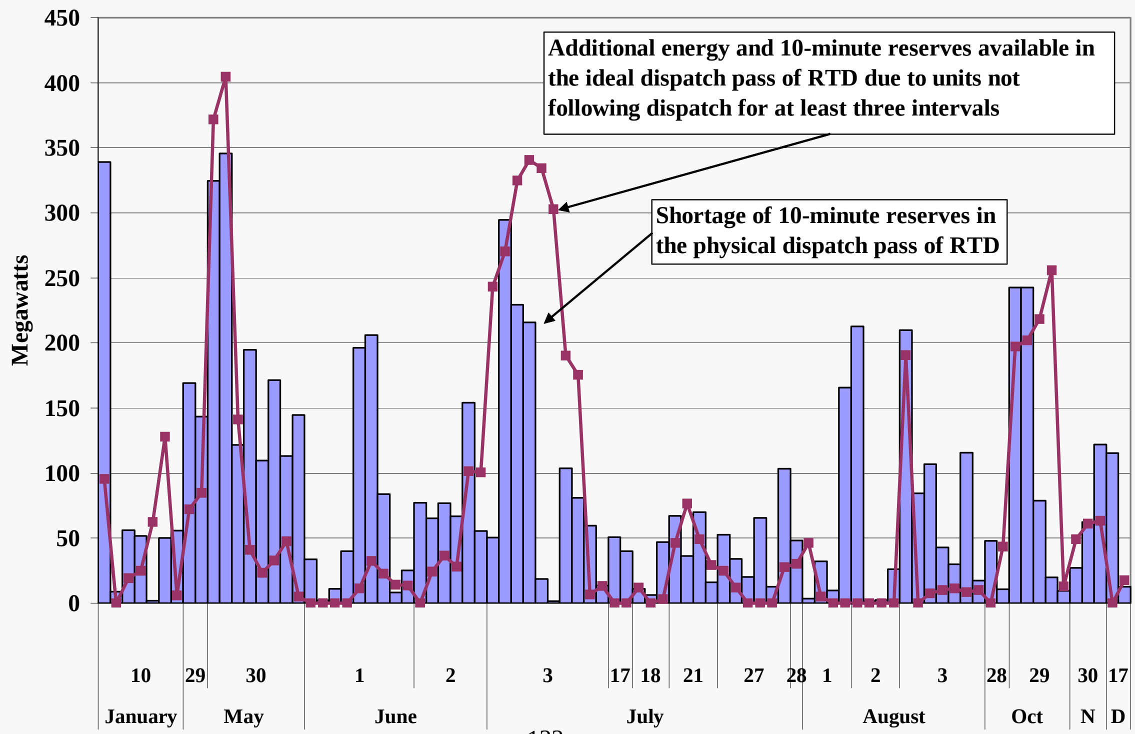
- In May 2006, inconsistencies were eliminated between the pricing and physical dispatches in the output limits of GTs.
  - ✓ GTs that fail to reach their as-bid maximum output level after three intervals are treated as having a derated maximum output level.
  - ✓ Now, the physical dispatch and the pricing dispatch both assume the maximum output level is equal to the telemetered output level.
  - ✓ Once the reduction in capability is recognized by RTD, it is also fed back to RTC, which takes it into account when making commitment decisions.
- Consistent ratings of GTs under high ambient temperatures has greatly improved the efficiency of prices during reserves shortages.
- The following analysis examines the effects of inconsistent treatment of units not following dispatch instructions on Eastern 10-minute reserve prices during intervals when a) there was a physical shortage and b) no shortage pricing.

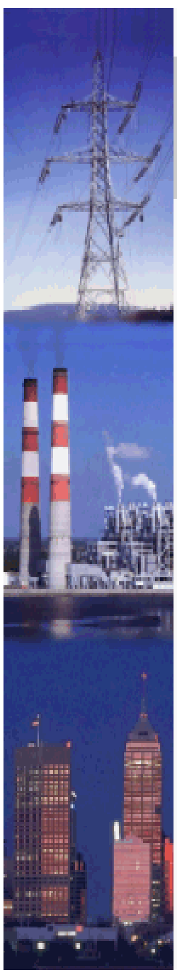


Hybrid Pricing

- The following figure summarizes the effect of units persistently not following dispatch instructions on Eastern 10-minute reserves prices during the 85 intervals when there was a physical shortage and no shortage pricing.
  - ✓ The bars indicate the shortage quantity in the physical dispatch pass of RTD.
  - ✓ The line indicates the additional energy and 10-minute reserves available in the ideal dispatch pass due to inconsistencies in the treatment of units not following dispatch instructions.
- The additional supply available to the ideal dispatch pass was greater than the physical shortage quantity:
  - ✓ in 24 of the 85 intervals shown; and
  - ✓ In 6 of the 28 intervals when the shortage exceeded 100 MW.
- The inconsistent treatment of units not following dispatch instructions explains a modest share of the instances when the physical dispatch pass perceived a shortages of reserves while the pricing dispatch pass did not.

Impact of Units Not Following Dispatch Instructions
Shortage Intervals without Shortage Pricing, 2006





Hybrid Pricing – Conclusions

- Some differences between the pricing and physical dispatches in RTD are necessary to implement the hybrid pricing regime. However, unnecessary differences will generally lead to inaccurate prices and increased uplift.
- The consistent treatment of GTs under ambient temperature restrictions, which was implemented in May 2006, has greatly improved the efficiency of prices during Eastern 10-minute reserves shortages.
- Additional improvements to the consistency of the pricing and physical dispatch passes of RTD should lead to more efficient pricing of energy and ancillary services (particularly during shortages) and reduce uplift.
  - ✓ We recommend the NYISO assess the feasibility of re-calibrating the dispatch levels in the pricing pass for units that are not following dispatch signals.

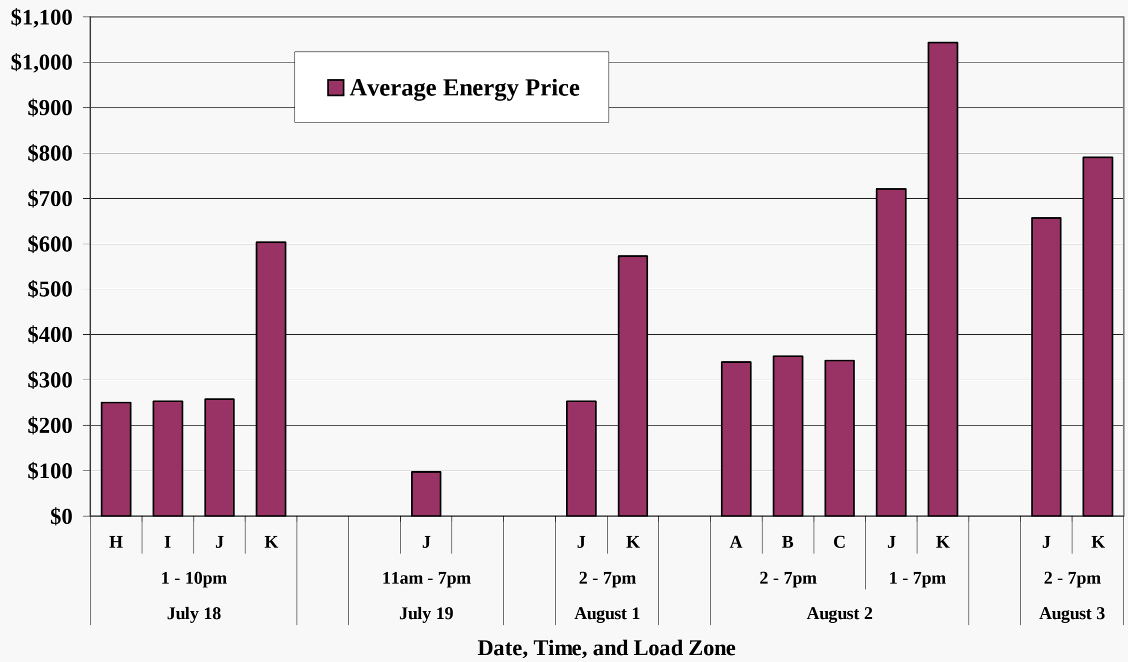
Demand Response and Shortage Pricing

- Operators are able to call upon EDRP and SCR resources to curtail load. They must give advanced notice of at least two hours and if they curtail resources, it must be for no less than four hours.
- When called by the operators:
  - ✓ EDRP resources are paid the higher of $500/MWh or the clearing price.
  - ✓ SCR resources are paid the higher of their strike price, which is typically $500/MWh, or the clearing price.
- EDRP and SCR resources must be called in advance based on projections of operating conditions, and since they are not dispatchable by the real-time model, there is no guarantee that they will be "in-merit."
  - ✓ After EDRP and SCR resources are curtailed, if adequate resources are available to the system in real-time, clearing prices can be well below $500/MWh.
  - ✓ The NYISO has partially addressed this concern by implementing shortage pricing rules that allow EDRP and SCR resources to "set price" when their curtailment enables the ISO to avoid a shortage of eastern or state-wide reserves.

Demand Response and Shortage Pricing

- The following figure shows the average prices in each zone during each EDRP and SCR curtailment in 2006.
  - ✓ There were 35 hours on five days when EDRP and SCRs were curtailed in one or more zones.
  - ✓ In each case, they were curtailed to address a local issue rather than a large-scale shortage of NYCA reserves or eastern reserves.
- The figure indicates that the $500/MWh EDRP and SCR resources were:
  - ✓ Economic in Zone K (Long Island) on all four days curtailed;
  - ✓ Economic in Zone J (NYC) on two of the four days curtailed; and
  - ✓ Uneconomic for the entirety of every day in any of the other zones.
- To minimize the impact of "out of merit" SCR and EDRP resources, the NYISO has proposed to develop the capability to call these resources in blocks smaller than an entire zone.
- We support this proposal and the development of rules to enable these resources to set prices in local areas when they are needed to avoid a local shortage.

Average Real-Time Prices During EDRP/SCR Activation 2006

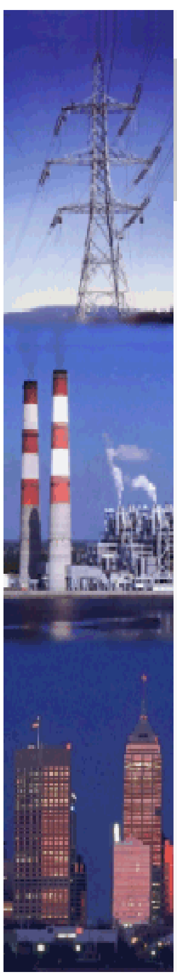


Market Operations – Supplemental Commitment and Out of Merit Dispatch

POTOMAC ECONOMICS

Supplemental Commitment

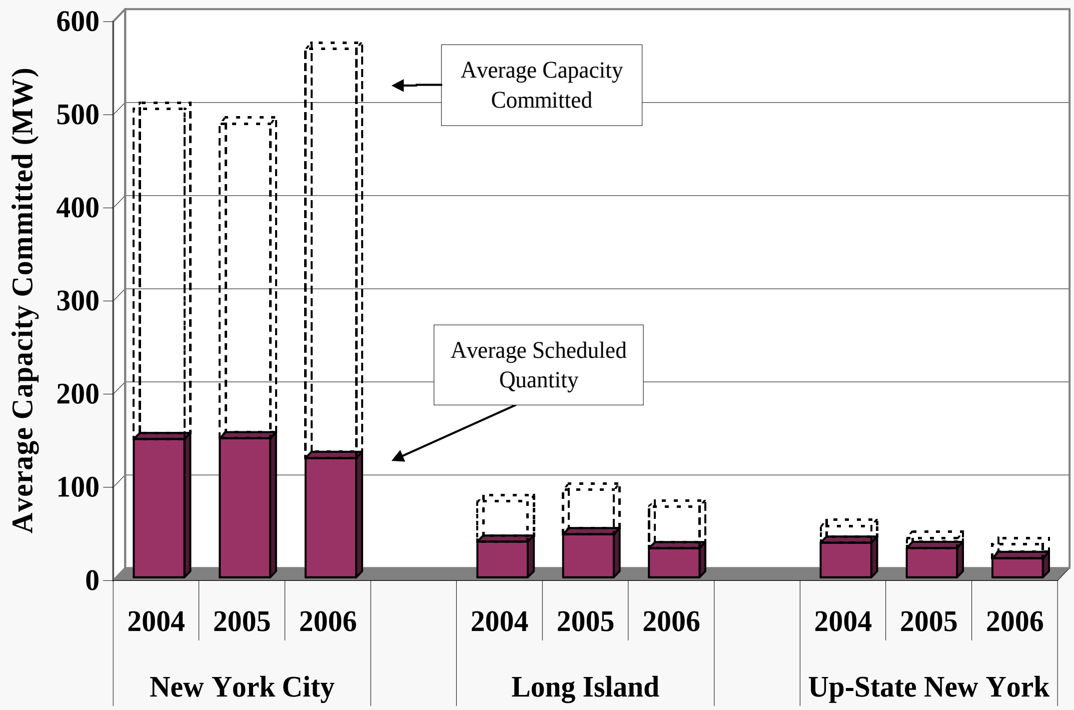
- The last section of this review evaluates supplemental commitments during the summer of 2006.
- Supplemental commitment occurs when a generator is not committed in the economic pass of the day-ahead market but is needed for local reliability. Supplemental commitment primarily occurs in two ways:
  - ✓ The Day-Ahead Local Reliability Pass of SCUC commits generators after the economic commitment but before clearing prices are determined.
  - ✓ The Supplemental Resource Evaluation (“SRE”) process is used to commit generators after the day-ahead market.
- In the first section of this review, we reported increased uplift expenses for both day-ahead and real-time local reliability.
  - ✓ Day-ahead local reliability uplift arises entirely from commitments by the local reliability pass of the day-ahead model.
  - ✓ Real-time local reliability uplift arises primarily from SRE commitments.

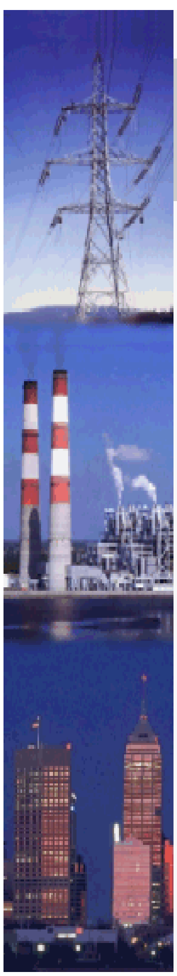


Supplemental Resource Evaluation

- The following figure summarizes supplemental commitments made by the NYISO after the day-ahead market.
  - ✓ They are important because they influence the real-time market results.
  - ✓ To the extent that they are anticipated by the day-ahead market, they will also influence day-ahead market results.
- The average quantity of capacity committed through SRE in New York City increased in 2006.
- SREs are called by individual TOs, so the resulting uplift is allocated to the local area. SREs are the primary source of Real-Time Local Reliability Uplift.
  - ✓ While SREs increased from 2005 to 2006, RT Local Reliability Uplift decreased from $75 million to $70 million.
  - ✓ The decline in fuel prices contributed to the decline in RT Local Reliability Uplift.

Supplemental Resource Evaluation Commitment 2004-2006

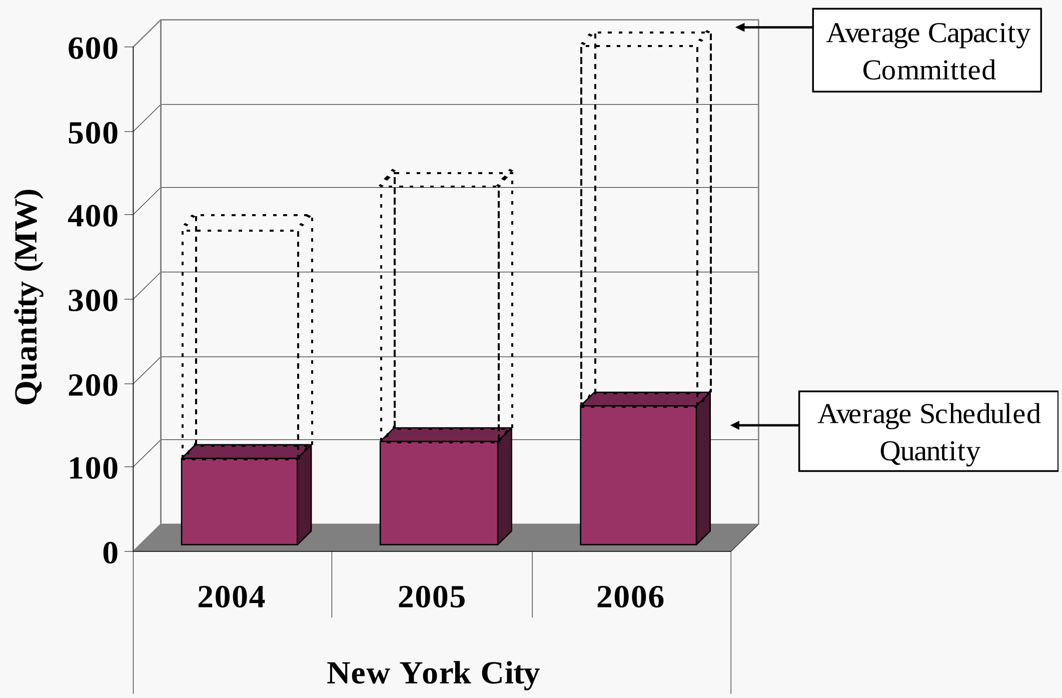


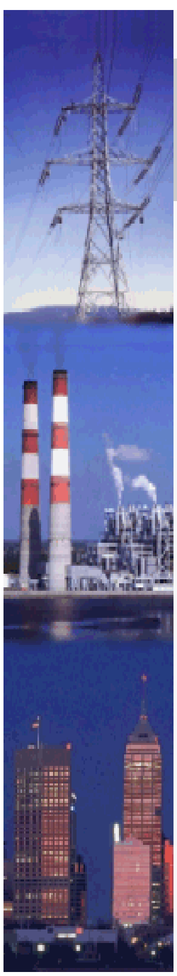


Day-Ahead Local Reliability Commitment

- 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 at day-ahead market prices, but they are important because they tend to:
  - ✓ Reduce prices from levels that would result from a purely economic dispatch; and
  - ✓ Can increase non-local reliability 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, but not scheduled, increased from 304 MW in 2005 to about 427 MW in 2006.
  - ✓ Day-ahead local reliability uplift decreased, partly due to lower fuel prices, from approximately $74 million in 2005 to $69 million in 2006.

SCUC Local Reliability Pass Commitment 2004 – 2006

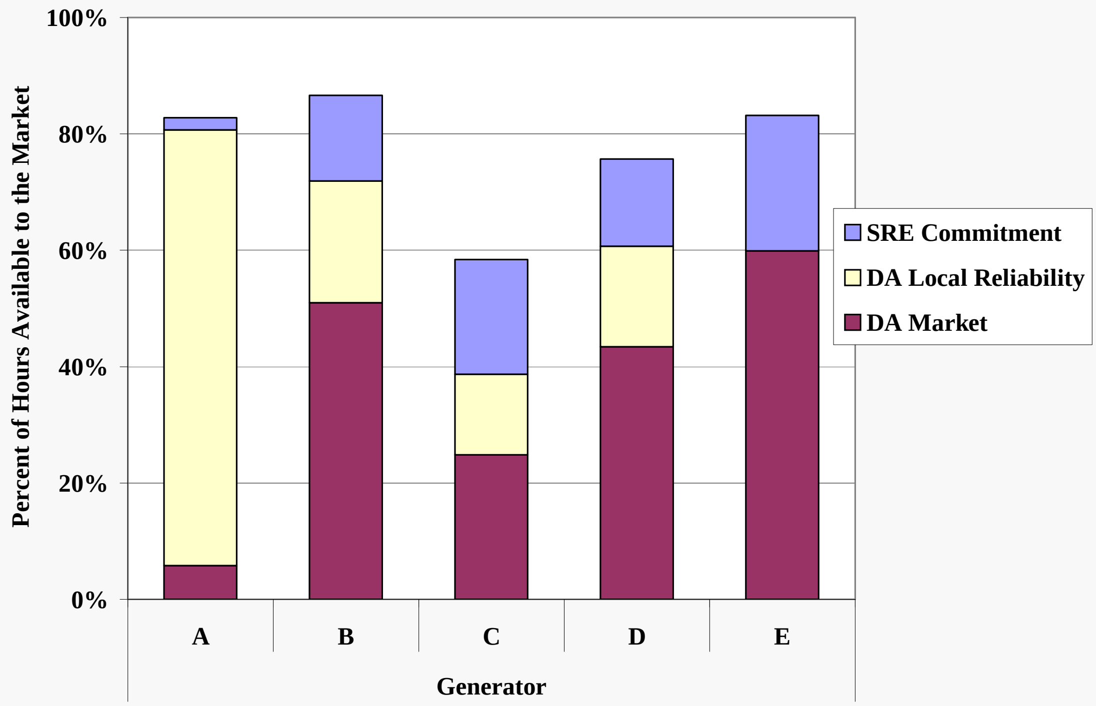


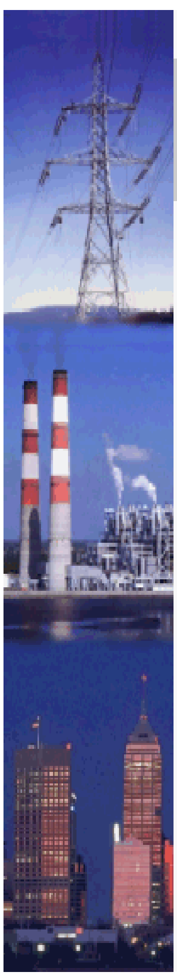


Units Frequently Committed for Local Reliability

- To further evaluate both the day-ahead local reliability and SRE commitments, we analyze them at the individual unit level.
- The following figure shows the five units committed most frequently for day-ahead 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 to the day-ahead market (i.e., not on outage).
  - ✓ All five units are located in New York City.
- When these units were available but not committed economically, they were generally committed in the local reliability pass of SCUC or through SRE at least half the time.
  - ✓ Supplemental commitments can cause other units that were committed in the economic pass to be uneconomic, thereby increasing uplift and depressing energy prices.
  - ✓ It would be more efficient for these units to be committed within the economic pass of SCUC.

Generators Committed Most Frequently for Reliability
Top Five Units, 2006





Supplemental Commitment Conclusions

- Local reliability commitments have been rising for several years.
  - ✓ The average amount of capacity committed for local reliability in New York City exceeded 1100 MW in 2006, although less than 300 MW was scheduled for energy.
- 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;
- To reduce the inefficiency and uplift associated the supplemental commitments we recommend:
  - ✓ In the short-run, that the ISO allow operators to pre-commit units needed for NOx compliance or other local reliability needs; and
  - ✓ In the long-run, that the local reliability and NOx constraints be included in the initial economic commitment pass of SCUC.

Supplemental Commitment Conclusions

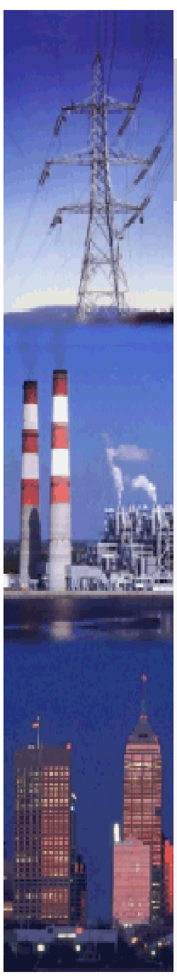
- Both of these recommendations will require the NYISO to work with participants to revise the cost allocation methodology for uplift associated with the local reliability requirements.
- Currently, the uplift costs that are associated with guarantee payments to units committed to meet local reliability requirements are allocated locally.
- Reliability commitments reduce clearing prices, which results in higher guarantee payments to economically committed units. However, the uplift costs from these guarantee payments are allocated throughout NYCA.

Capacity Market

POTOMAC ECONOMICS

Capacity Market – Background

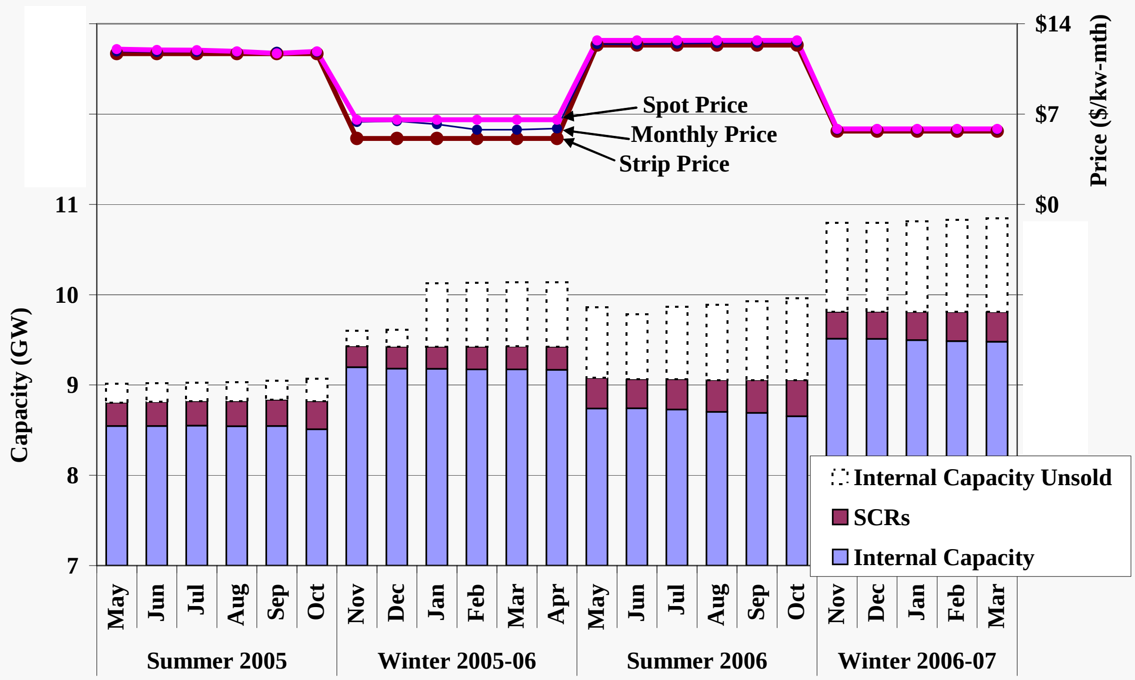
- The capacity market complements the energy and ancillary services markets to provide efficient economic signals for investment and retirement decisions.
- LSEs have several ways to satisfy their capacity obligations. They can:
  - ✓ "Self-schedule" their own generating capacity;
  - ✓ Purchase capacity through bilateral contracts; or
  - ✓ Participate in voluntary ICAP market forward auctions run by the NYISO.
- LSEs must purchase additional capacity in the Monthly ICAP Spot Market Auction if they have remaining obligations.
  - ✓ LSEs that have purchased more than their obligation prior to the Spot Market Auction, may sell the excess in the Spot Market Auction.
- To enhance the competitiveness of the capacity markets, a demand curve is used in the final Monthly ICAP Spot Market Auction.
  - ✓ Each LSE's capacity obligation is determined by the intersection of supply in the Spot Market Auction and the demand curve (adjusted for capacity sales through bilateral contracts and forward auctions).



Capacity Market – New York City

- The following figure shows the resources available to provide UCAP in New York City versus the amounts actually scheduled. The figure also shows UCAP prices that cleared in the NYISO-run auctions.
- Substantial new capacity became available in New York City during this period.
  - ✓ Approximately 500 MW in January 2006 and another 500 MW in May 2006.
  - ✓ Demand response has increased by approximately 130 MW over the 23 months shown.
- After the additions of new capacity in 2006, there was virtually no increase in the amount of scheduled UCAP, and correspondingly, no reduction in clearing prices from the In-City suppliers' price cap.
  - ✓ A significant amount of existing capacity did not clear in the UCAP market due to the units' offer prices.
  - ✓ There is currently a proceeding at FERC that is intended to address this issue.

UCAP Sales – New York City
May 2005 to March 2007



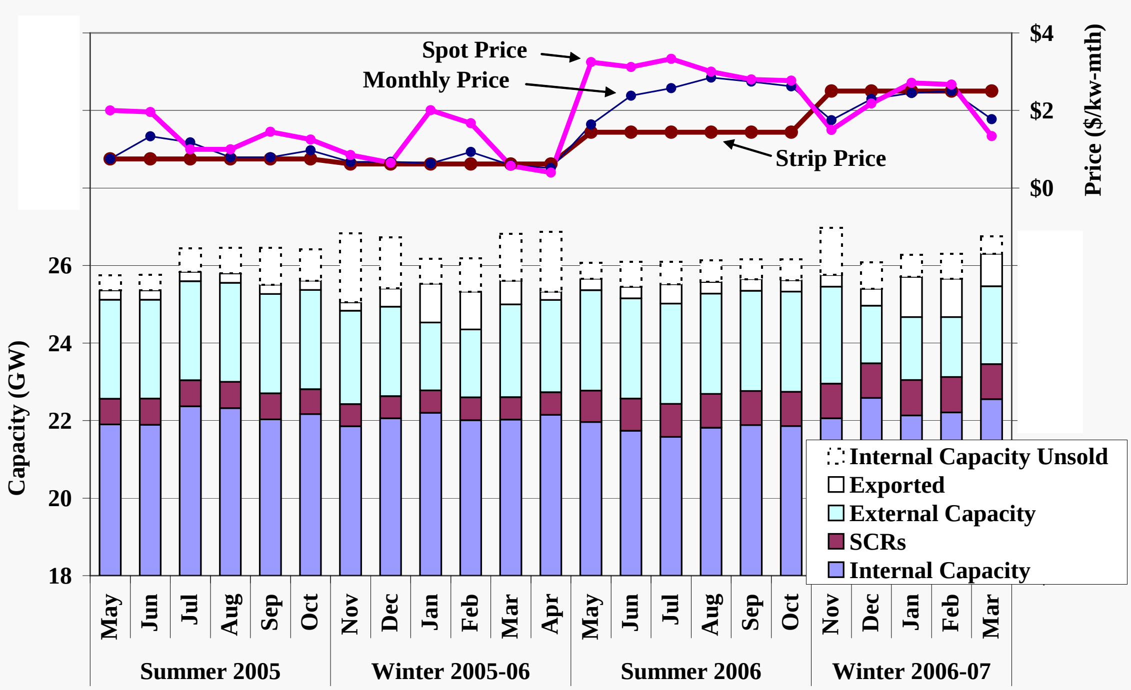
Capacity Market – Rest of New York State

- The following figure shows the available resources to provide UCAP outside New York City and Long Island versus the amounts actually scheduled and the clearing prices in the NYISO-run auctions.
- The UCAP available from resources in up-state New York varies.
  - ✓ The only significant installation of new capacity occurred in July 2005, when the 700 MW Bethlehem Energy Center came online in the Capital Zone, coinciding with a substantial drop in the Spot Auction clearing price.
  - ✓ Several small units have been taken out of service, while demand response has increased modestly over the period.
  - ✓ The UCAP that can be provided from individual resources varies with changes in the Equivalent Demand Forced Outage Rate of the resource.
- The state-wide demand for UCAP rose approximately 1500 MW from the summer of 2005 to the summer of 2006 due to an increase in the peak load forecast.
  - ✓ This contributed to a rise in Spot Auction clearing prices in May 2006.

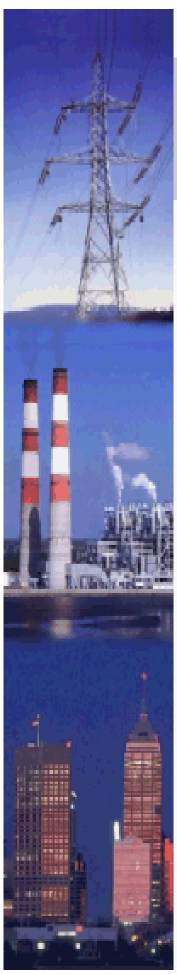
Capacity Market – Rest of New York State

- Market factors in neighboring control areas can have a large impact on UCAP prices for Rest of State.
- UCAP purchases in New York City and Long Island count toward the New York state-wide requirement.
  - ✓ Some market participants expected the installation of new capacity in New York City to reduce clearing prices for Rest of State.
  - ✓ This led to a decreased imports and increased exports in January and February 2006.
  - ✓ However, due to the unsold capacity in New York City, Spot Market Auction clearing prices actually rose in Rest of State.
- Market rule changes in neighboring control areas can affect the UCAP market in New York.
  - ✓ In December 2006, New England began to pay $3.05/kW-mth for UCAP.
  - ✓ This coincided with an 1100 MW reduction in net imports of UCAP to New York State from New England and Quebec, and this was followed by a 600 MW increase in exported capacity.

UCAP Sales – Rest of New York State
May 2005 to March 2007



External Transactions

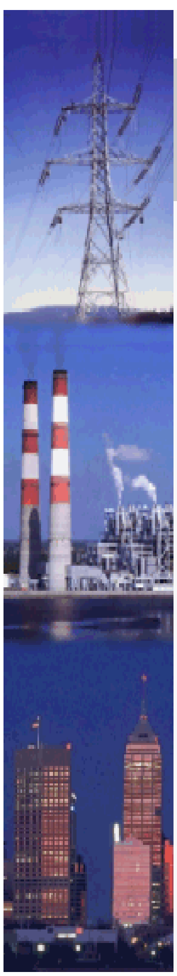


Efficient Utilization of the External Interfaces

- The performance of the wholesale electricity markets depends not only on the efficient use of internal resources, but also the efficient use of transmission interfaces between NY and other areas.
- Efficient use of transmission interfaces between regions promotes competition in the same way that efficient use of transmission resources within a region promotes competition: it allows lower cost generation to reach customers instead of the higher cost resources that would otherwise be used.
- Transmission links between regions also provide other reliability and economic benefits which tend to lower the costs of providing reliable power within regions.
- When interfaces are used efficiently, energy prices in adjacent areas should be consistent except when the interface constraint limits additional flows into the higher priced region.

Efficient Utilization of the External Interfaces

- In real-time, it has proven difficult for the adjacent markets to achieve price convergence by relying on transactions scheduled by market participants.
  - ✓ Uncertainty, imperfect information, and required offer lead times limit the ability of participants to capitalize on real-time arbitrage opportunities.
- These conclusions reinforce the importance of efforts to improve real-time interchange between New York and adjoining regions.
- Efficient interchange is particularly important during reserve shortages when flows between regions have the largest economic and reliability consequences.
- Several actions have been taken to improve coordination between adjacent control areas. The next slide discusses recent efforts to eliminate barriers to efficient scheduling by market participants.



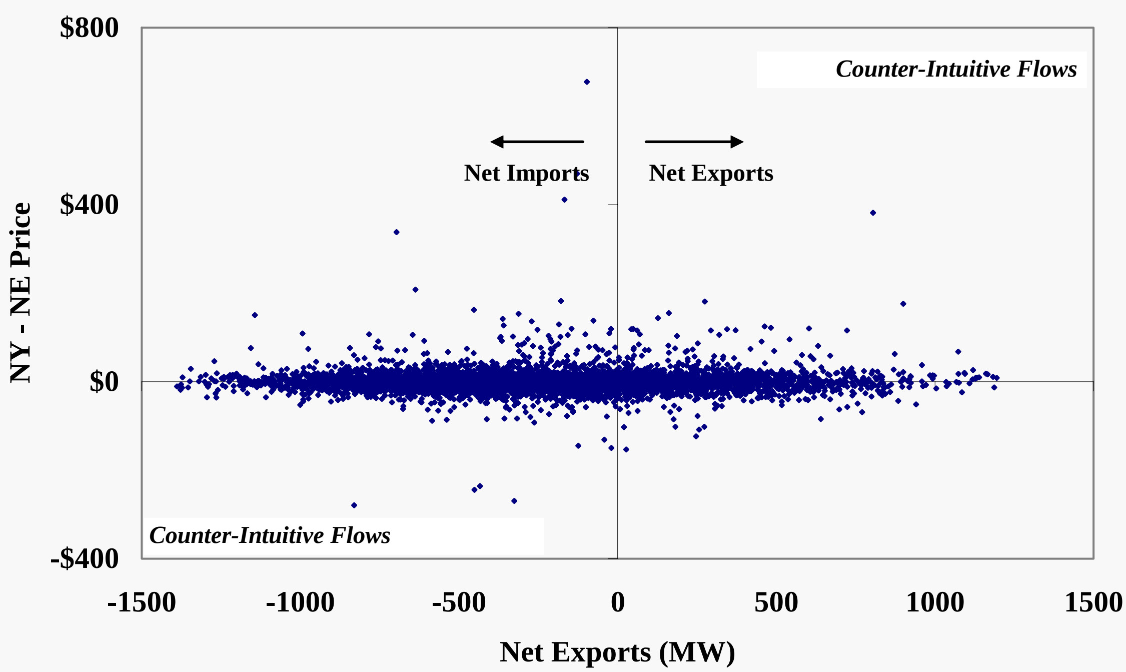
Efficient Utilization of the External Interfaces

- At the beginning of 2005, export fees between New York and New England were eliminated, which should facilitate arbitrage of the adjacent markets.
- Exports from New York and New England scheduled after the day-ahead market continue to be allocated charges for ISO/RTO operating costs.
  - ✓ Prior to the fall of 2005, the method used by the ISO-NE for allocating these charges to exports could result in very large charges (on a per MWh basis) for some market participants.
  - ✓ In the fall of 2005, the ISO-NE addressed this problem by allowing market participants to choose an alternative method which allocates on a per MWh basis.
- Transactions from New York to New England scheduled after the day-ahead market continue to be allocated uplift for certain types of supplemental commitment by both ISOs. However, neither ISO assesses these charges to transactions that flow from New England to New York.

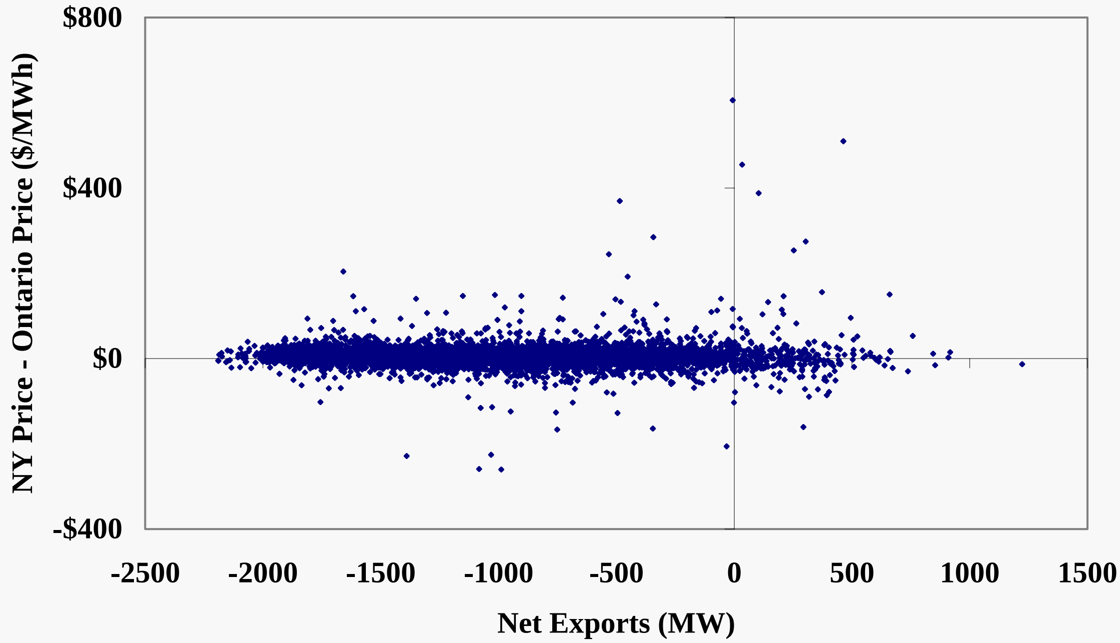
Efficient Utilization of the External Interfaces

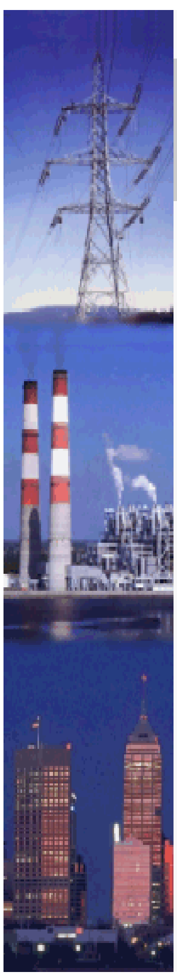
- The following three figures plot the hourly difference in prices between New York and neighboring markets against net exports during hours when transmission constraints are not binding.
  - ✓ Price differences plotted against the vertical axis are always computed by subtracting the external price from the New York price (i.e., positive price differences mean prices are higher inside New York).
  - ✓ Net exports are shown on the horizontal 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.
  - ✓ Efficiency improvements are also possible for the points in the other quadrants, too, whenever price differences between markets exceed the transaction costs of scheduling an export.
- Such interface flow levels are inefficient because they result in higher-cost generation running in place of available lower cost generation.

Real-Time Prices and Interface Schedules
Comparison of NY and NE Border Prices
Unconstrained Hours, 2006

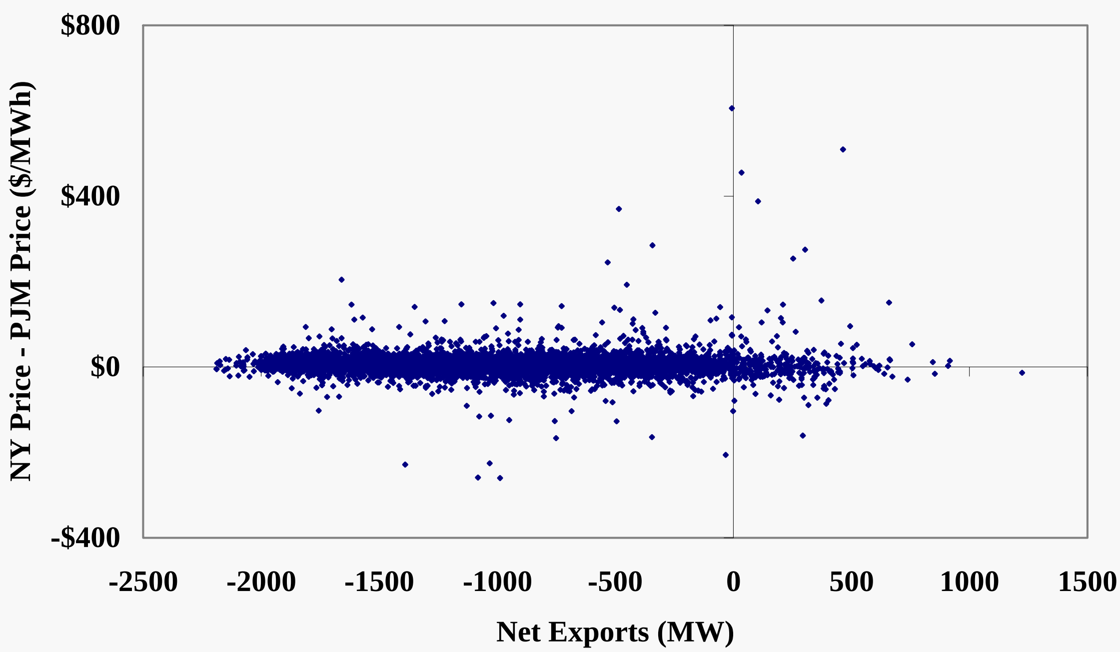


Real-Time Prices and Interface Schedules
Comparison of NY Border and Ontario Prices
Unconstrained Hours, 2006



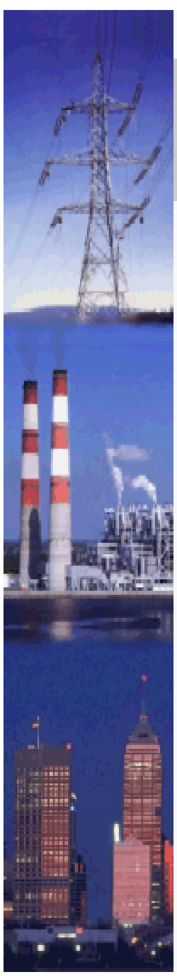


Real-Time Prices and Interface Schedules
Comparison of NY and PJM Border Prices
Unconstrained Hours, 2006

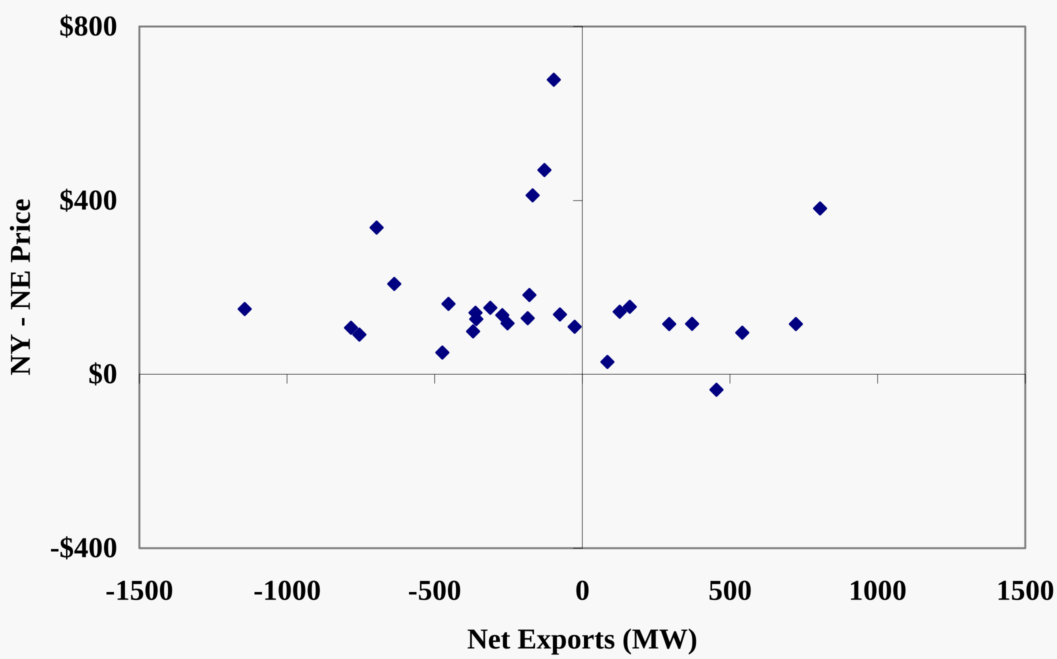


Interface Use During Scarcity Conditions

- During peak demand conditions, it is especially important to efficiently schedule flows between control areas.
- The following chart examines the difference between New York and New England real-time border prices in unconstrained hours where the Capital Zone price exceeded $200/MWh.
- Price convergence has been especially poor during price spikes:
  - ✓ 6 of 29 hours show the NY price is higher by more than $200/MWh.
  - ✓ 23 of 29 hours show the NY price is higher by more than $100/MWh.
  - ✓ In 8 of the hours shown, power was flowing out of NY, even though the NY price was higher.
- Frequently during times prices are spiking, a small amount of additional imports can substantially reduce the magnitude of a price spike. This underscores the potential benefits of ITS (Intra-hour Transaction Scheduling) during peak demand periods.



Interchange and Price Differences Between NY and NE Unconstrained Eastern NY Price Spike Hours*, 2006



* Includes hours when the RT Capital zone price exceeded $200/MWh.

External Scheduling Conclusions

- Prices between New York and adjacent markets during unconstrained periods continue to not be arbitraged effectively.
  - ✓ Efficient scheduling between New York and New England is particularly important during peak pricing events, which were more frequent in 2005 and 2006 than in previous years.
  - ✓ In hours when the Capital Zone price exceeded $200/MWh, prices in New England were generally much lower and substantial transmission capability was unused.
  - ✓ Even small adjustments in flow between markets can have a large impact on prices during peak conditions.
- Real-time prices in adjacent regions continue to not be efficiently arbitraged, particularly during peak pricing conditions.
  - ✓ We recommend that New York and New England continue their work to develop and implement ITS (Intra-hour Transaction Scheduling) to better utilize the transfer capability between regions.