# 2008 State of the Market Report
# New York ISO Electricity Markets

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POTOMAC ECONOMICS

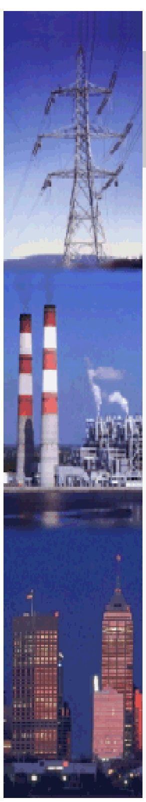
## Executive Summary: Introduction

- This presentation provides the results of our assessment of the performance of the New York electricity markets in 2008.
- The New York ISO ("NYISO") operates the most complete set of electricity markets in the U.S. These markets provide substantial benefits:
  - ✓ Day-ahead and real-time markets jointly optimize energy, operating reserves and regulation. These markets lead to:
    - Prices that reflect the value of energy at each location on the network;
    - The lowest cost resources being started each day to meet demand;
    - Delivery of the lowest cost energy to New York's consumers to the maximum extent allowed by the transmission network; and
    - Efficient prices when the system is in shortage.
  - ✓ Capacity markets that ensure that the NYISO markets produce efficient long-term economic signals to govern decisions to:
    - Invest in new generation, transmission, and demand response; and
    - Maintain existing resources.
  - ✓ The market for transmission rights allows participants to hedge the congestion costs associated with using the transmission network;

# Executive Summary: Unique Aspects of the NYISO Markets

- The performance of the New York markets is enhanced by a number of attributes that are unique to the NYISO:
  - ✓ *A real-time dispatch system that is able to optimize over multiple periods (up to 1 hour)*, which allows the market to anticipate upcoming needs and move resources to efficiently satisfy the needs.
  - ✓ *An optimized real-time commitment system to start gas turbines and schedule external transactions economically* – other RTOs rely on their operators to determine when to start gas turbines.
  - ✓ *A mechanism that allows gas turbines to set energy prices when they are economic* – gas turbines frequently do not set prices in other areas because they are inflexible, which distorts prices.
  - ✓ *A mechanism that allows demand-response resources to set energy prices when they are needed* – this is essential for ensuring that prices signals are efficient during shortages. DR in other RTOs has distorted real-time signals by undermining the shortage pricing.





# Executive Summary

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

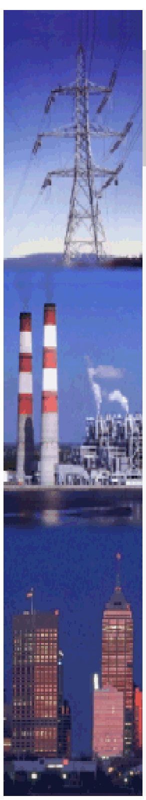
- The energy and ancillary services (operating reserves and regulation) markets performed competitively in 2008.
  - ✓ This report shows no evidence that suppliers have been withholding generation to inflate energy or ancillary services prices.
  - ✓ Despite recent allegations, only one-tenth of one percent of generators' offers were made at very high levels, which reasonably reflect emergency supplies and the offers did not materially affect prices.
  - ✓ There were competitive issues in the capacity market until March 2008. Changes in mitigation rules have been made that address the issue.
- Energy prices increased 12 percent in western New York and 23 percent in eastern New York.
  - ✓ This is primarily due to increased fuel prices in 2008. Natural gas prices rose an average of 19 percent, and fuel oil prices rose an average of 40 percent.
  - ✓ There was a considerable increase in congestion across the Central-East and other interfaces that limit flows from western New York to eastern New York, increasing congestion-related price differences between regions.

# Executive Summary

**Market Performance and Prices (cont.)**

- In January 2008, market participants began to schedule substantial volumes of circuitous transactions around Lake Erie in the counter-clockwise direction. This had several significant effects on market operations:
  - ✓ It increased loop flows (i.e., unscheduled power flows) around Lake Erie in the clockwise direction.
  - ✓ The loop flows used a large portion of the west-to-east transmission capability in New York state.
  - ✓ Transmission capability available to scheduled resources was reduced, increasing congestion-related price differences between western New York and eastern New York.
  - ✓ The effects of loop flows on congestion was the most significant factor contributing to the $166 million increase in balancing congestion uplift from 2007 to 2008.
  - ✓ On July 21, 2008, the NYISO addressed the issue by filing under exigent circumstances to preclude circuitous transaction scheduling.





# Executive Summary

**Market Performance and Prices (cont.)**

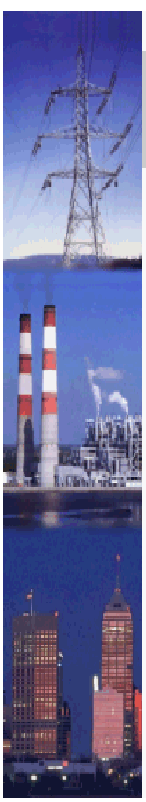
- Convergence between prices in the day-ahead and real-time markets is important because the day-ahead market plays an important role in determining which resources are started-up each day.
  - ✓ Convergence in the energy markets continues to be good in most areas.
  - ✓ However, convergence at specific locations within New York City was not as good as in other areas in the State.
    - – The NYISO implemented an enhancement in February 2009 that should help address this issue by reducing reliability commitments after the day-ahead market.
    - – The NYISO is developing the capability to allow disaggregated virtual trading which is also expected to help address this issue.
  - ✓ Convergence in the reserve market was better in 2008 than in 2007, but still needs improvement.
    - – The NYISO is developing rules to allow certain reserve providers more offer-flexibility in the day-ahead market, which should help address this issue.

# Executive Summary

**Market Performance and Prices (cont.)**

- There was substantial energy price volatility in the real-time market, particularly at the top-of-the-hour during the morning and evening ramp periods.
  - ✓ The report highlights several factors that contribute to price volatility at the top-of-the-hour, including changes in external transaction schedules and changes in the energy schedules of inflexible generation.
  - ✓ Large schedule changes usually occur at the top-of-the-hour rather than being distributed throughout each hour. Such changes can create brief shortages as the NYISO deploys flexible generation to compensate for these changes.
    - – The NYISO has a project to evaluate the causes of price volatility and identify ways to reduce unnecessary price volatility.
- Prices between New York and adjacent markets have not been fully converged.
  - ✓ This is particularly important during peak conditions when adjusting the flow is more likely to have a substantial price impact.
  - ✓ The report includes recommendations to address this issue.





# Executive Summary

**Market Performance during Shortage Conditions**

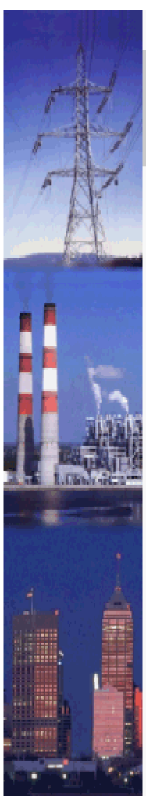
- High prices that occur when resources are insufficient to meet the system's demands contribute to efficient long-term price signals. The report evaluates the market results during three types shortages:
- *Operating reserve shortages*. The market produced reasonable shortage prices during most reserve shortages in 2008.
  - ✓ In virtually all of the instances when the market posted shortage prices, the system was physically in shortage.
  - ✓ However, some of the instances of physical shortages of eastern 10-minute reserves were not accompanied by corresponding shortage prices.
  - ✓ In March 2009, the NYISO implemented an enhancement that should reduce such instances.
- *Unresolved transmission constraints.* When constraints cannot be resolved by the market, prices are now set more efficiently due to the introduction of "Transmission Shortage Pricing" in June 2007.
- *Activation of Emergency Demand Response*. Due to the mild summer weather in 2008, there were no instances when these resources were activated.

# Executive Summary

**Long-Term Economic Signals**

- The report shows that prices in 2008 would not support investment in new peaking generation in most locations. This is consistent with short-term conditions because:
  - ✓ There is a surplus of generation in most areas; and
  - ✓ The summer weather was relatively mild in 2008.
- The report shows that market signals have generally shifted in favor of investment in baseload and intermediate resources. Although such resources are more costly to build, they produce electricity at lower cost.
  - ✓ Over time, the markets provide efficient incentives to invest in a diverse array of generating resources, demand response resources, and transmission.
  - ✓ Currently, market conditions appear more favorable for investment in combined-cycle generation (which have constituted most of the recent entry) than in gas-fired peaking generation.
  - ✓ Depending on the entry costs for a CC, it may be economic to build a CC in some areas under the current market conditions.





# Executive Summary

**Capacity Market**

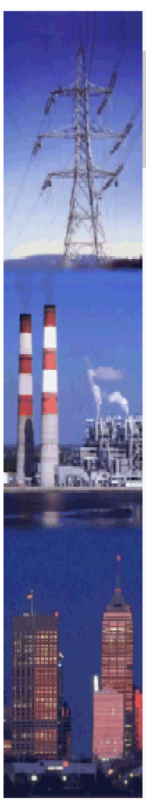
- The capacity market contributes to the signals that govern investment decisions for generation, transmission, and demand response, as well as retirement decisions for supply resources.
- Capacity prices declined substantially in 2008 in NYC and Long Island.
  - ✓ NYC became more competitive in March 2008 as new market power mitigation rules were introduced to ensure the competitiveness of the NYC capacity market.
  - ✓ The reliability benefits from the Neptune cable reduced local capacity requirements, and thus, capacity costs in Long Island.
- Capacity prices are consistent with the findings of the 2009 Reliability Needs Assessment, which concluded that additional resources (beyond what are anticipated) will not likely be needed in New York through 2018.
- Network constraints that limit flows downstate and a new "deliverability" test may cause new resources in western New York and imports that have historically supplied the capacity market to be deemed undeliverable.
  - ✓ If the deliverability test is accurate, the capacity market can only deliver efficient economic signals if the capacity zones are revised to correspond with the constraints.

## Executive Summary

**Schedule 1 Uplift Charges**

- Total Schedule 1 uplift charges increased from $367 million in 2007 to $599 million in 2008. The increase was primarily due to higher guarantee payments to generators and higher balancing congestion residual charges.
- Guarantee payments to generators increased $90 million from 2007 to 2008.
  - ✓ This was primarily due to the increased fuel prices in the first half of 2008.
  - ✓ The majority of these payments are associated with generators that are committed for local reliability.
    - – In February 2009, the NYISO made an enhancement to the DAM software which should reduce the uplift that results from these commitments.
- Balancing congestion residuals increased $166 million from 2007 to 2008. The increase was primarily attributable to:
  - ✓ Increased fuel prices which increased congestion costs generally.
  - ✓ The effects of circuitous transaction scheduling around Lake Erie.
    - – In July 2008, the NYISO filed to preclude these schedules, leading to a dramatic decline in balancing market congestion residuals.





## Executive Summary

**Demand Response Programs**

- Demand response resources participate in the NYISO markets, providing more than 2 GW of supply in the capacity and energy markets.
- Demand response resources set clearing prices when their activation prevents shortages.
  - ✓ This approach is endorsed by FERC Order 719 and is essential for efficient short-term and long-term price signals.
- The NYISO is developing ways to allow participation in the wholesale market by price-responsive loads.
  - ✓ In June 2008, the NYISO began to allow demand resources to provide reserves and regulation, although no resources have qualified under this program yet. Several resources will qualify once the necessary telemetry is installed.
  - ✓ The NYISO is enhancing its IT infrastructure to better enable demand side participation. These enhancements will be deployed in 2009 and 2010.

# Executive Summary

**Demand Response Programs (cont.)**

- The NYISO's Smart Grid initiative will provide real-time wholesale price information to retail customers.
  - ✓ Although retail customers do not pay the wholesale price, this program is likely to increase their awareness of tight operating conditions in the NYISO market.
- The most significant remaining barrier to widespread participation in the energy market is that most retail loads are not exposed to wholesale price fluctuations.
  - ✓ Retail electricity rate reform is one means to give retail loads incentives to be price-responsive.
  - ✓ The NYISO should also consider programs that would better align the incentives of retail customers with the needs of the system if retail rate reform is not anticipated to occur soon.



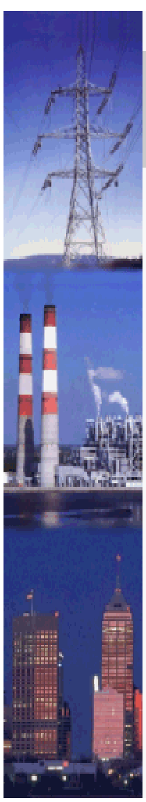
# Executive Summary: Recommendations

1. ***We recommend the NYISO consider defining a new capacity zone or zones in eastern New York. To the extent that capacity is deemed undeliverable from western New York to locations in eastern New York, new zones would:***
   - ✓ Allow consumers in the rest of New York to benefit from lower capacity costs and increased reliability that western resources and capacity imports provide;
   - ✓ Ensure loads in eastern New York only purchase capacity that is deliverable to those locations and provide necessary price signals to invest in new generation, transmission, or demand response resources in those areas when needed.
2. ***We recommend NYISO continue its work with neighboring control areas to better utilize the transfer capability between regions, ideally by directly coordinating the physical interchange and management of congestion.***
3. ***We recommend NYISO evaluate factors that contribute to real-time price volatility, including assumptions used in the real-time commitment model ("RTC") and real-time dispatch model ("RTD"), or other market rules.***
   - ✓ A re-evaluation of the assumptions in RTD and RTC could improve the ramp management and lower price volatility, particularly at the top of the hour.

# Executive Summary: Recommendations

4. ***We recommend the NYISO consider a real-time demand response program to better align the incentives of retail customers with the needs of the system if retail rate reform is not anticipated soon.***
   - ✓ Retail rate reform is one means to give retail loads incentives to respond to prices. However, there are other ways the ISO may provide these incentives.
5. ***We recommend that NYISO revisit the baseline method and testing procedures for SCRs to ensure they have the ability to respond when called in real-time.***
6. ***We recommend NYISO modify two mitigation provisions that may limit competitive Day-Ahead 10-minute reserves offers, which should improve convergence of day-ahead and real-time ancillary services prices.***
7. ***We recommend the offer limit for real-time import and exports be raised from -$1000/MWh to a level more consistent with the avoided costs of curtailment, which would limit balancing congestion shortfalls when they must be curtailed.***
8. ***NYISO has a project underway to enable market participants to schedule virtual trades at a more disaggregated level.***
   - ✓ Currently, virtual trading is allowed at only the zonal level. This change is intended to improve price convergence in the New York City load pockets.





# Executive Summary: Recent Enhancements

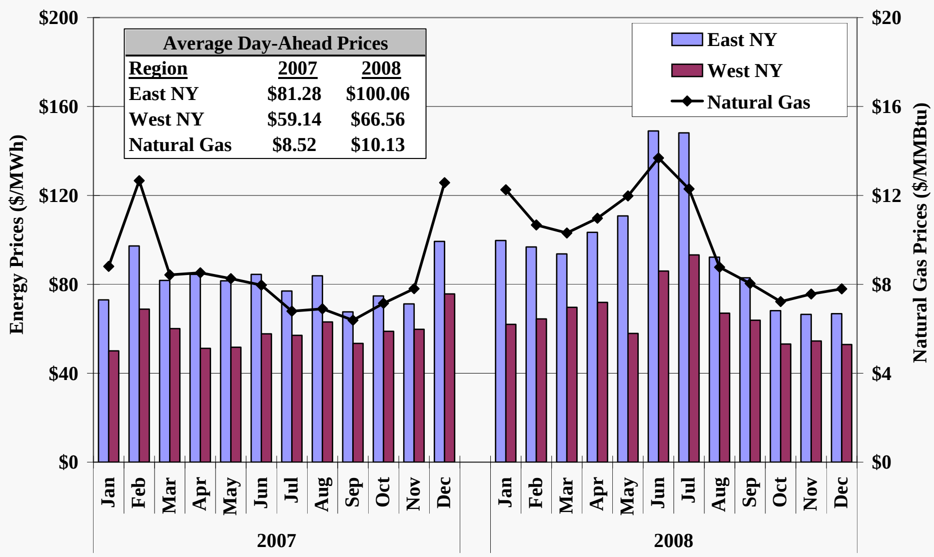
1. ***In February 2009, the NYISO incorporated commitments to satisfy New York City local reliability rules with the economic commitment in the day-ahead market software.***
   - ✓ This is expected to reduce the uplift charges that result from committing generation to satisfy the local reliability rules.
   - ✓ This is also expected to improve convergence between day-ahead and real-time prices in the New York City load pockets.
2. ***In March 2009, the NYISO modified the treatment of ramp limitations in the real-time market's pricing model for units that are not responding to dispatch signals.***
   - ✓ This is expected to improve the consistency of the pricing and physical dispatch passes of RTD, the efficiency of energy and ancillary services prices (particularly during shortages), and reduce uplift.
3. ***The NYISO has refined its procedures to improve the accuracy of the loop flow assumptions in the day-ahead and TCC markets.***

# Market Prices and Outcomes

## Fuel Prices and Energy Prices

- The following figure summarizes energy prices in 2007 and 2008.
- Fuel price fluctuations led to corresponding changes in electricity prices:
  - ✓ Natural gas prices rose an average of 19 percent from 2007 to 2008, while residual oil (#6) and diesel oil (#2) prices each rose an average of 40 percent from 2007 to 2008.
  - ✓ The correlation of electricity prices with natural gas and oil prices is expected. Fuel costs constitute the majority of variable production costs for most generators, and oil and gas units are on the margin in most hours.
- Transmission congestion became more prevalent in the first half of 2008, leading to larger differences between West and East NY prices:
  - ✓ The average price in East NY increased 23 percent from 2007 to 2008, while the average price in West NY increased just 12 percent.
  - ✓ Increased loopflows around Lake Erie reduced the amount of power that could be scheduled into East NY and downstate areas.

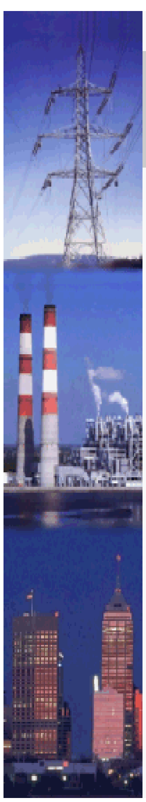
## Day-Ahead Electricity and Natural Gas Prices 2007 – 2008




| Average Day-Ahead Prices | | |
|---|---|---|
| Region | 2007 | 2008 |
| East NY | $81.28 | $100.06 |
| West NY | $59.14 | $66.56 |
| Natural Gas | $8.52 | $10.13 |

Note: The electricity prices are load-weighted averages.

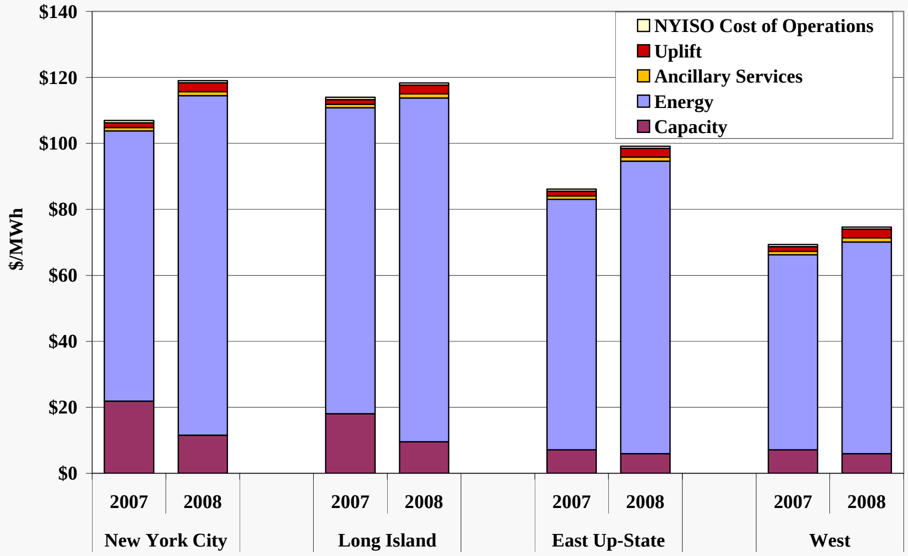




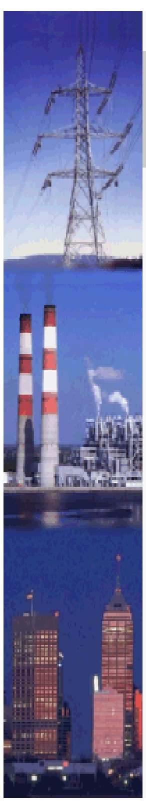
## All-In Energy Prices

- The following figure shows an “all-in” price, which includes the costs of energy, ancillary services, capacity, uplift, and NYISO operating costs.
  - ✓ The capacity component is based on spot capacity prices and load obligations in each area, allocated over energy consumption in the area.
  - ✓ The energy component is a load-weighted average real-time energy price.
- Several factors increased all-in prices from 2007 to 2008.
  - ✓ Higher fuel prices increased energy costs, particularly in east NY.
  - ✓ Balancing residual charges increased, nearly doubling total uplift charges.
- Higher fuel and uplift costs were partially offset by the following factors:
  - ✓ The sale of previously withheld capacity reduced capacity costs in NYC;
  - ✓ The reliability benefits from the Neptune cable reduced local capacity requirements, and thus, capacity costs in Long Island;
  - ✓ Fewer peak load (>28 GW) hours led to fewer real-time shortage events.
- Lake Erie loop flows increased congestion in 2008, raising energy costs in east NY and moderating the effects of higher fuel prices in west NY.

## Average All-In Price by Region
### 2007 – 2008



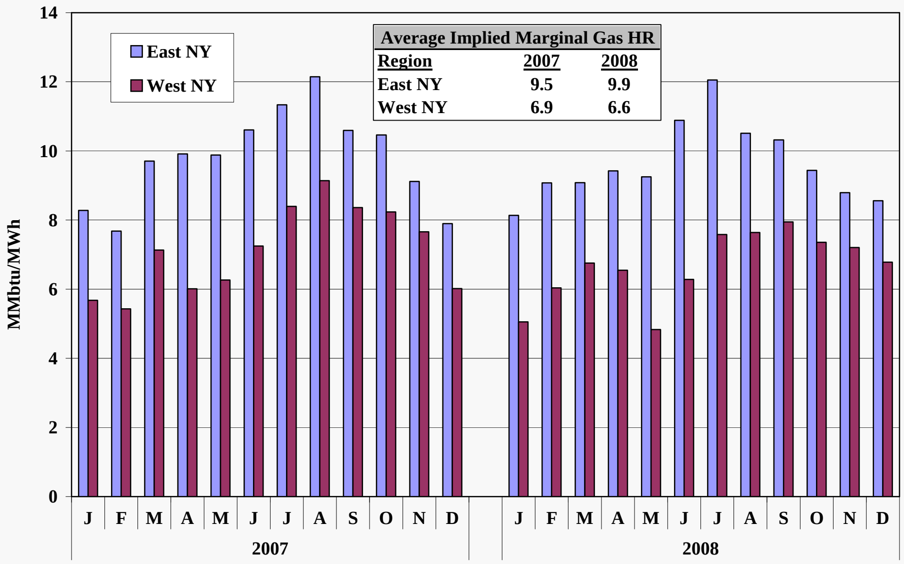


## Fuel Prices and Energy Prices

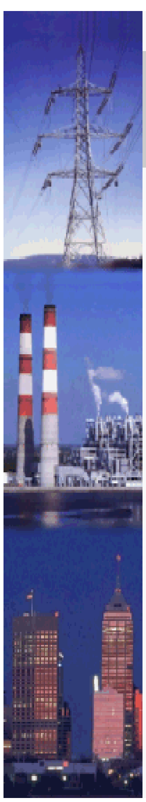
- To identify changes in electricity prices that are not driven by changes in natural gas prices, the following figure shows the marginal heat rate that would be implied if natural gas were always the marginal fuel.
  - ✓ Implied Gas Heat Rate = (Day-Ahead Elec. Price) ÷ (Natural Gas Price)
  - ✓ This metric highlights variations in electricity prices that are due to factors other than fluctuations in natural gas prices.
  - ✓ When this metric drops below the heat rate of a combined cycle unit (~7 MMbtu/MWh), it indicates that lower-cost fuels are frequently marginal (e.g., coal or hydro units in west NY).
- The figure shows that implied heat rates rise in the summer months due to:
  - ✓ Increased demand driven by hotter summer weather; and
  - ✓ Reduced supply resulting from the effects of higher ambient temperatures on the capability of thermal units.
- The figure also shows that the implied heat rates were roughly comparable in 2007 and 2008, although increased congestion led to slightly higher levels in eastern NY and slightly lower levels in west NY in 2008.

# Average Monthly Implied Heat Rate
## 2007 – 2008




Note: Implied heat rate is for a natural gas units and is based on day-ahead prices.

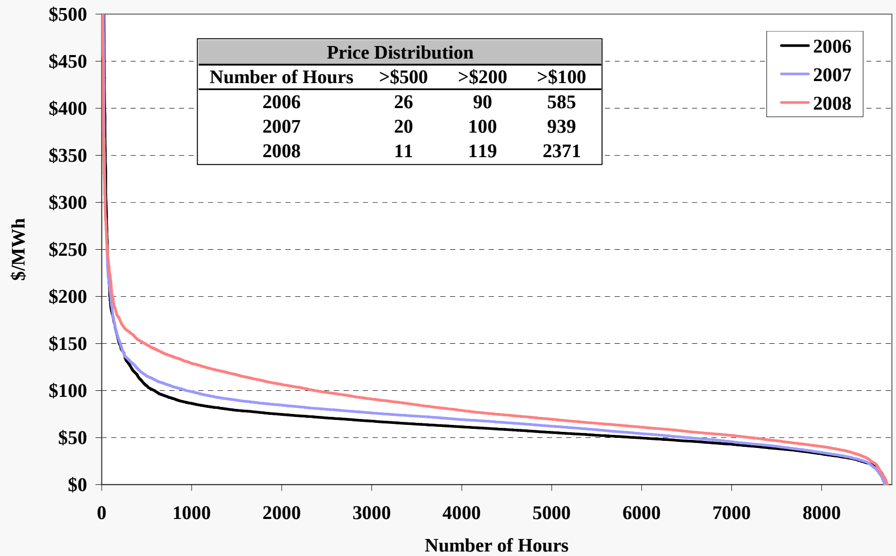




# Energy Prices

- The next figure shows how hourly price levels have changed in the last three years by showing real-time price duration curves from 2006 to 2008.
  - ✓ These curves show the number of hours when the load-weighted, real-time price for NY State was greater than the level shown on the vertical axis.
- This figure shows that electricity prices rose from 2006 to 2008 across a wide range of hours.
  - ✓ This broad increase in prices over many hours is caused by the increase in natural gas and oil prices.
  - ✓ Natural gas prices increased 15 percent from 2006 to 2007 and 19 percent from 2007 to 2008.
- The figure also shows that the number of extremely high-priced hours (e.g., hours when prices exceed $500/MWh) declined from 2006 to 2008.
  - ✓ The reduced number of peak load instances (>28 GW) led to fewer real-time shortage pricing events.

## Price Duration Curves
## State-wide Average Real-Time Price, 2006 – 2008




Price Distribution

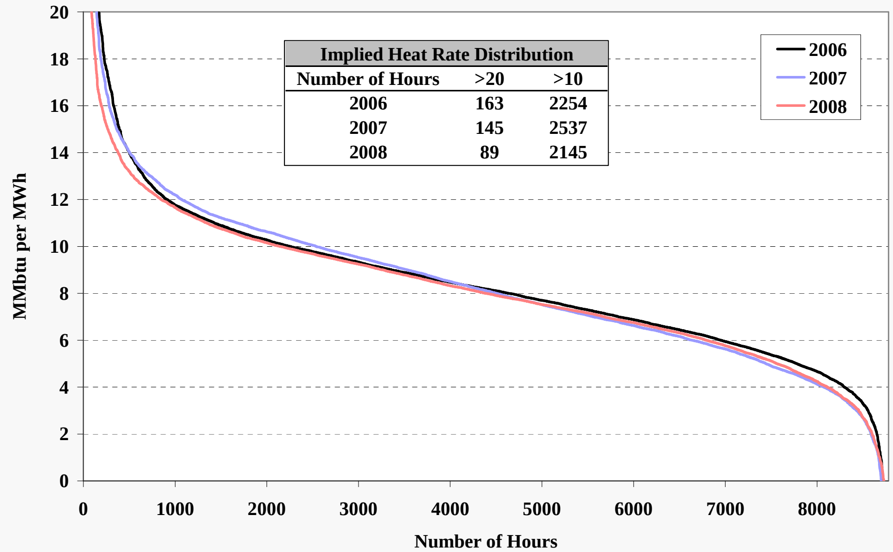
| Number of Hours | >$500 | >$200 | >$100 |
|---|---|---|---|
| 2006 | 26 | 90 | 585 |
| 2007 | 20 | 100 | 939 |
| 2008 | 11 | 119 | 2371 |



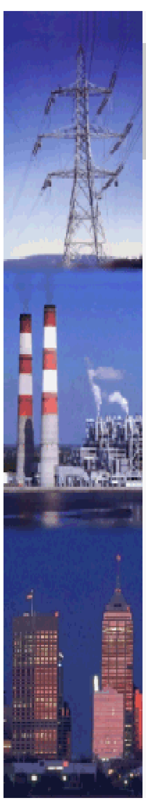
## Energy Prices

- The next figure shows duration curves for implied marginal gas heat rates during the same period.
  - ✓ These isolate real-time price changes that are not caused by changing natural gas prices.
  - ✓ The similarity of duration curves from 2006, 2007, and 2008 highlights the consistency of electricity prices once they are normalized for changes in natural gas prices.
- The figure also confirms the substantial decline in the number of very high-cost hours (e.g., when the implied marginal gas heat rate exceeded 20 MMbtu/MWh) from 2006 to 2008.
  - ✓ Mild summer weather contributed to fewer shortage pricing instances in 2008.
  - ✓ Additionally, there has been no evidence of artificial shortages caused by withholding, since the New York market has been competitive.

# Implied Marginal Gas Heat Rate Duration Curves
## Based on State-wide Average Real-Time Price, 2006 – 2008



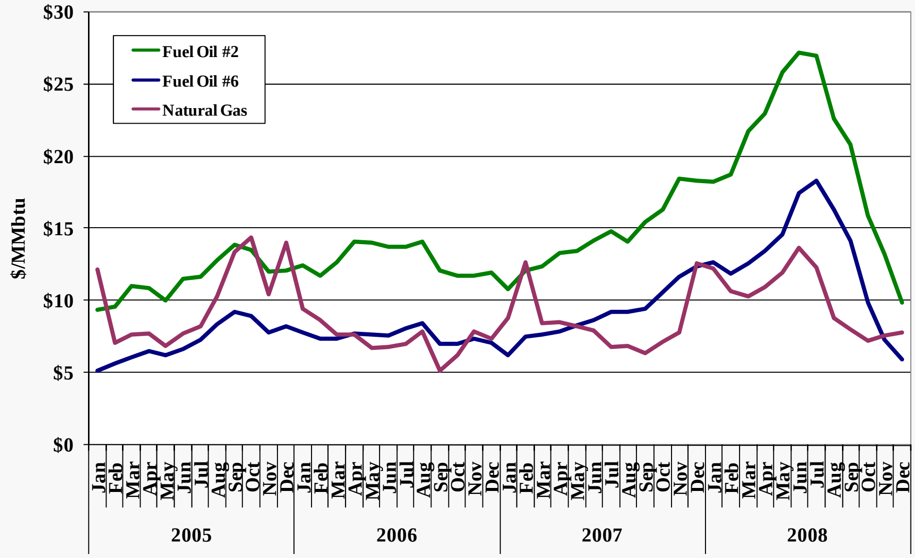


# Prices of Natural Gas and Fuel Oil

- Because fuel prices are a key determinant of electricity prices, the next figure shows monthly average natural gas and fuel prices from 2005 to 2008.
- Many units in New York have dual fuel capability, allowing them to burn either oil or natural gas.
  - ✓ Many steam units can burn fuel oil #6 or natural gas. Natural gas was priced lower than fuel oil #6 on 84 percent of the days in 2008.
  - ✓ Many gas turbines can burn fuel oil #2 or natural gas. Natural gas was priced lower than fuel oil #2 on 98 percent of the days in 2008.
- The rise in oil prices relative to natural gas prices decreased the use of oil for electricity production in recent years. However, the availability of oil still mitigates the electricity price effects transitory spikes in natural gas prices.
- Oil use is increased by the minimum oil burn requirements, which require some units in NYC to burn oil to limit exposure to natural gas supply contingencies.
  - ✓ Such units receive out-of-market payments that are not reflected in prices.
  - ✓ Despite oil price increases, the costs of these payments fell from $21 million in 2007 to $18 million in 2008, partly due to changes in the local reliability rule.

## Monthly Average Natural Gas and Oil Prices 2005 – 2008

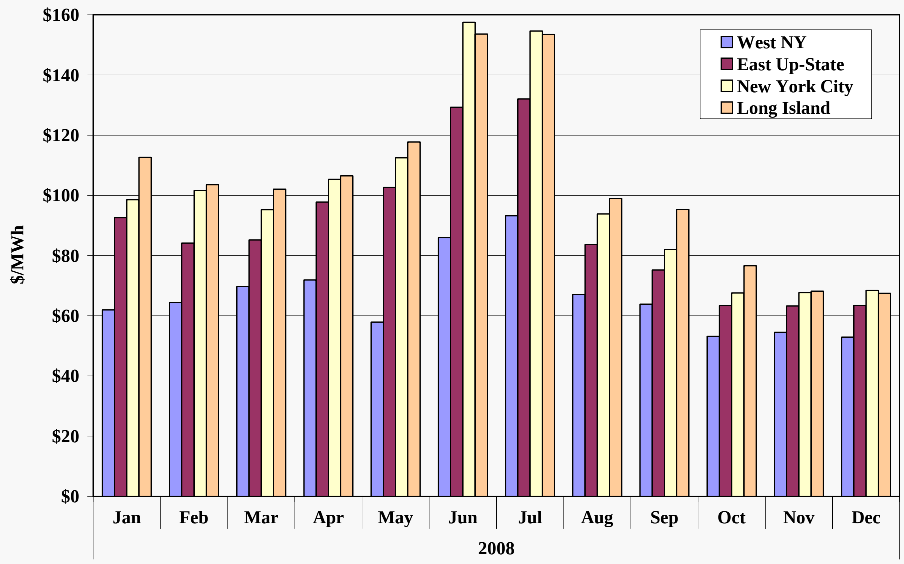





## Day-Ahead Energy Prices

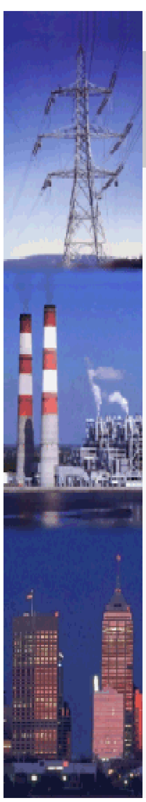
- The next figure presents monthly average day-ahead energy prices in west NY, east upstate NY, NYC, and Long Island for 2008.
- Between east upstate and downstate areas, the price differences are primarily due to transmission losses and congestion on flows from west-to-east and along the Hudson Valley.
  - ✓ The difference was particularly large in May, June, and July when Lake Erie loop flows peaked, which use capability on several key interfaces.
- Prices are elevated in NYC and Long Island due to transmission constraints into and within these zones.
  - ✓ The difference between East Upstate NY and Long Island prices declined from an average of 22 percent in 2007 to 17 percent in 2008.
  - ✓ The difference between East Upstate NY and NYC prices rose from an average of 8 percent in 2007 to 12 percent in 2008, reflecting more frequent congestion into load pockets in the 138kV portion of NYC.

## Day-Ahead Energy Prices by Region 2008




Note: The prices are load-weighted averages.

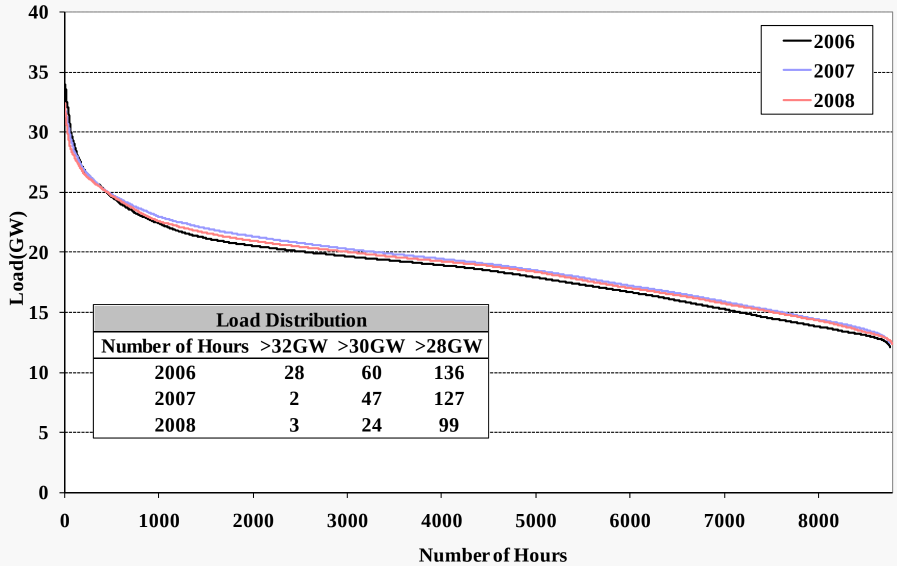




## Load Profile

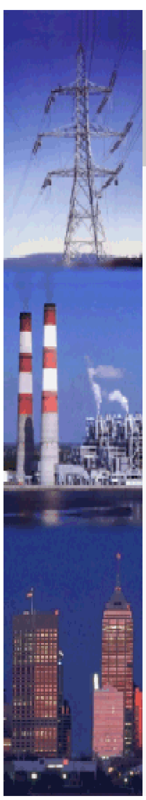
- Additional insight into market conditions is gained from examining load levels. The next figure shows load duration curves for 2006 to 2008.
  - ✓ These curves show the number of hours in which the load is greater than the level indicated on the vertical axis.
- In the majority of hours, load increased substantially from 2006 to 2007 and declined slightly from 2007 to 2008.
- In the peak demand hours, load declined from 2006 to 2008, resulting in less frequently shortage conditions and associated price spikes.
  - ✓ Load exceeded 30 GW during just 24 hours in 2008 compared to 47 hours in 2007 and 60 hours in 2006.
  - ✓ Load exceeded 32 GW during just 3 hours in 2008 compared to 2 hours in 2007 and 28 hours in 2006.

# Load Duration Curves
## New York State Load, 2006 – 2008




| Load Distribution | | | |
|---|---|---|---|
| Number of Hours | >32GW | >30GW | >28GW |
| 2006 | 28 | 60 | 136 |
| 2007 | 2 | 47 | 127 |
| 2008 | 3 | 24 | 99 |

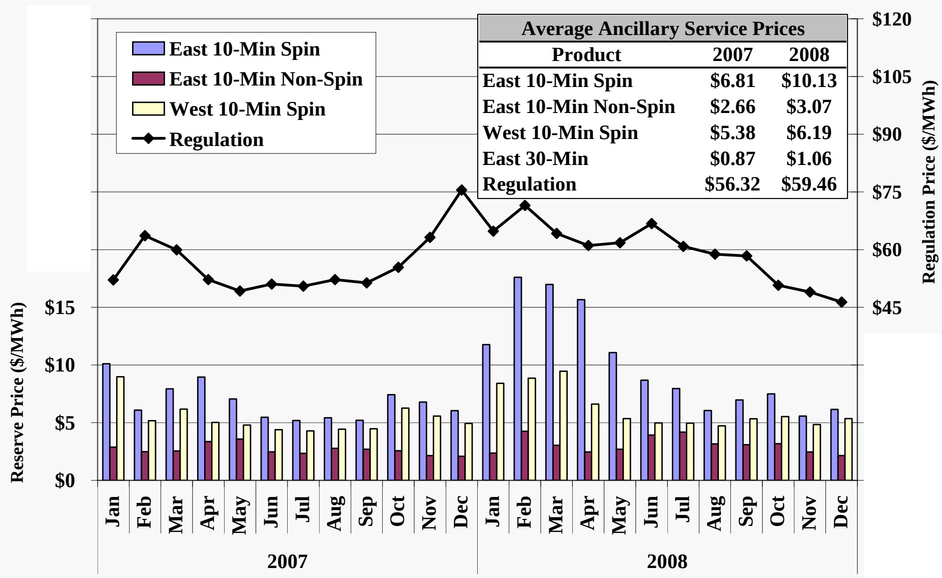




# Ancillary Services Prices

- The following figure summarizes the prices of several key ancillary services products in the day-ahead market in 2007 and 2008.
  - ✓ The NYISO has four ancillary services products: 10-minute spinning reserves, 10-minute total reserves, 30-minute reserves, and regulation.
  - ✓ The NYISO has locational reserve requirements, which result in differences between eastern and western reserve prices.
- To the extent that ancillary services are scheduled on capacity that would otherwise be economic to produce energy, energy price increases push up the cost of providing ancillary services.
  - ✓ Regulation prices and 10-minute spinning reserve prices increased in the first half of 2008, consistent with the general rise in electricity prices during the same period.
  - ✓ Differences between eastern and western 10-minute reserves prices increased in the first half of 2008, which is generally consistent with the increased congestion from west to east during the same period.

## Day-Ahead Ancillary Services Prices
## 2007 – 2008



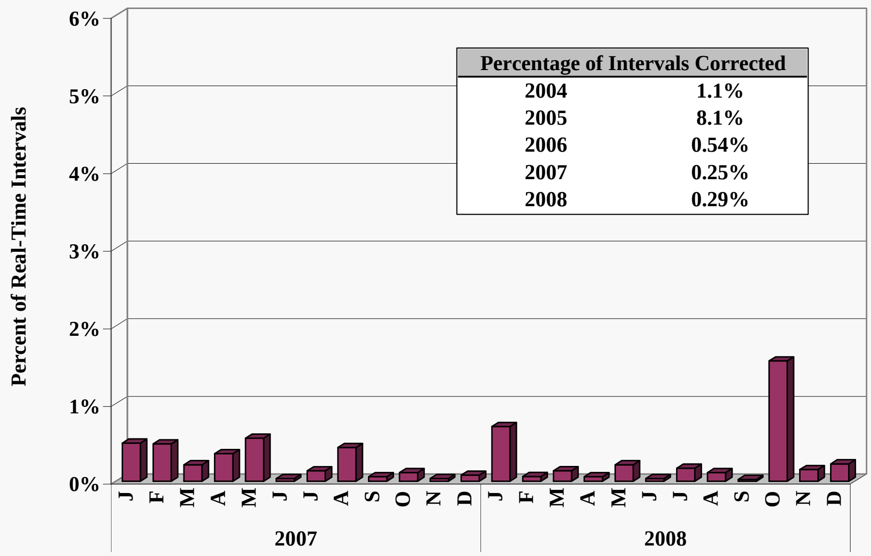

| Product | 2007 | 2008 |
|---|---|---|
| East 10-Min Spin | $6.81 | $10.13 |
| East 10-Min Non-Spin | $2.66 | $3.07 |
| West 10-Min Spin | $5.38 | $6.19 |
| East 30-Min | $0.87 | $1.06 |
| Regulation | $56.32 | $59.46 |



## Price Corrections

- The following figure summarizes the frequency of price corrections in the real-time energy market in 2007 and 2008.
- Price corrections occur in all real-time energy markets due to:
  - ✓ Metering errors and other input data problems; or
  - ✓ Software flaws that cause pricing errors under certain conditions.
- Fewer price corrections reduce administrative burdens and uncertainty for market participants.
- In June 2007, the frequency of price corrections declined as a result of improved modeling when transmission constraints are not resolved.
  - ✓ Reliable and efficient pricing during periods of extreme scarcity improves investment signals.
- The frequency of price corrections was elevated in January 2008 due to a metering error that affected several hours.
- The frequency of price corrections was elevated in October 2008 due to an issue that only affected one proxy generator bus.

## Frequency of Real-Time Price Corrections 2007 – 2008





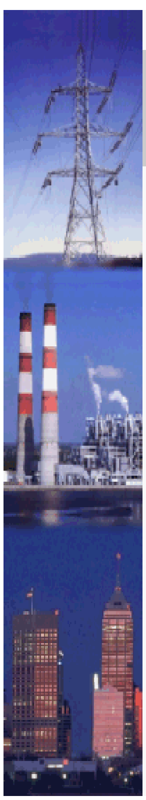

## Long-Term Market Signals – Net Revenue Methodology

- The following two figures show the estimated Net Revenue provided by the NYISO markets over the past five years at several locations.
  - ✓ Net Revenue is the energy, ancillary services, and capacity revenue that a new generator would earn above its variable production costs.
  - ✓ Net Revenue is calculated for a hypothetical gas turbine unit and a hypothetical combined cycle unit using two methods: the Standard Method and the Enhanced Method.
- The Standard Method assumes the units sell at the day-ahead market prices considering variable O&M costs, forced outage rates, and fuel costs with heat rates of:
  - ✓ 7,000 BTU/KWh for the combined cycle and
  - ✓ 10,500 BTU/KWh for the combustion turbine.
- The Enhanced Method also considers start-up costs, minimum run-times, other physical limits, and the two-settlement system (day-ahead & real-time markets).

## Long-Term Market Signals – Net Revenue Methodology

- The enhanced method assumes:
  - ✓ Units are committed based on day-ahead prices, considering start-up costs, and minimum run times and down-times (one hour for CTs).
  - ✓ CCs may sell energy, 10-minute and 30-minute spinning reserves; CTs may sell energy and 30 minute reserves.
  - ✓ Online units respond to real-time prices while offline CTs may be committed based on RTC (or BME prior to Feb. 2005) prices.
- The following figures summarize the results of the enhanced analysis, with a marker showing the standard net revenue analysis results for comparison. The differences in the results for the two methods are due to:
  - ✓ Reductions in net revenue due to start-up costs and minimum runtime restrictions; and
  - ✓ Gains in net revenue for online units that respond to real-time prices;
  - ✓ Gains in net revenue for offline CTs that are economically committed after the day-ahead by RTC (or BME in earlier periods).





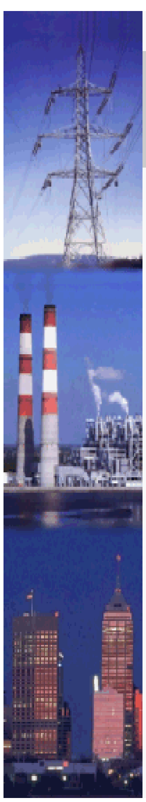
## Long-Term Market Signals – Net Revenue Analysis

- Net revenues rose significantly from 2004 to 2005 due to higher load, more frequent shortages and better shortage pricing under SMD 2.0.
- Net revenues declined significantly in 2006 in NYC due to the installation of 1 GW of new generating capacity in the 138kV system.
- From 2006 to 2008, net revenue levels rose moderately in the Hudson Valley and Capital zones due to:
  - ✓ Additional congestion across the Central-East interface.
  - ✓ Increased capacity prices, resulting partly from the introduction of a new capacity market in New England in December 2006, which attracted some capacity that was previously sold into the NYISO market.
- The introduction of new supply from New Jersey across the Neptune line in July 2007 substantially reduced net revenues from energy for generators in Long Island.

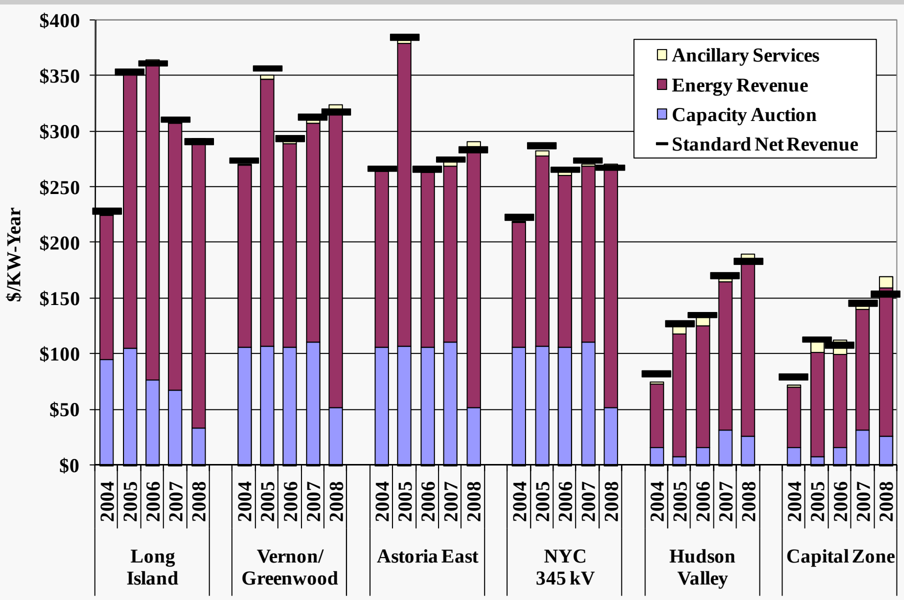
# Long-Term Market Signals – Net Revenue Analysis

- Elevated fuel prices contributed to increased energy net revenues in 2008:
  - ✓ Throughout New York state, energy net revenues rose partly because fuel price increases lead to increases in the spreads between the wholesale prices and the costs of online generation.
  - ✓ In New York City in particular, energy net revenues for natural gas generators were driven higher in periods when LBMPs were set by oil-fired peaking generation.
- Capacity net revenues declined throughout New York state in 2008:
  - ✓ In New York City, previously unsold capacity began to be scheduled in March 2008, leading to a large decline in capacity prices.
  - ✓ In Long Island, the addition of the Neptune line led to a decline in local capacity prices.
  - ✓ In upstate areas, capacity prices were reduced by increased capacity sales in New York City because sales in local capacity zones also count toward the state-wide capacity requirement.



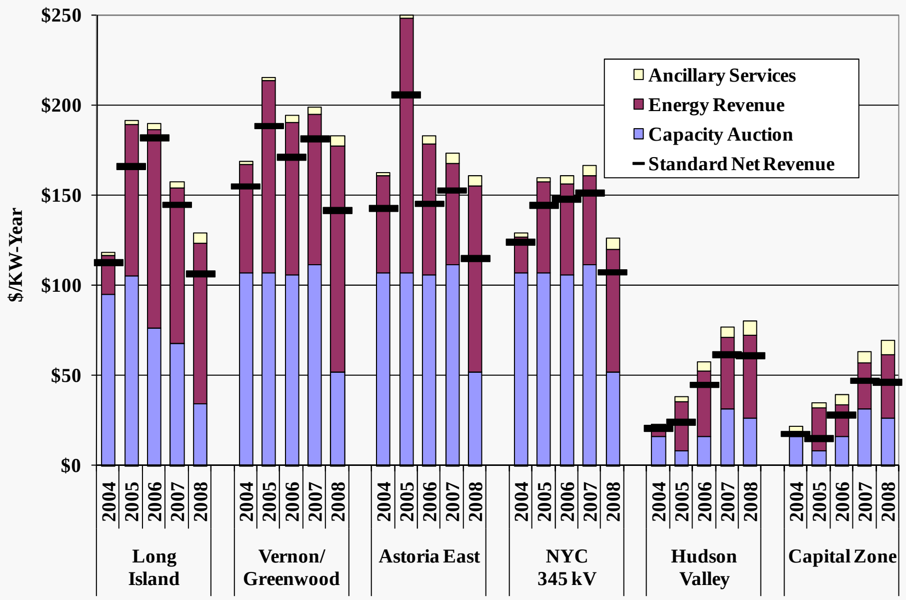


# Enhanced Net Revenue Analysis
## Gas Combined-Cycle Unit, 2004 – 2008

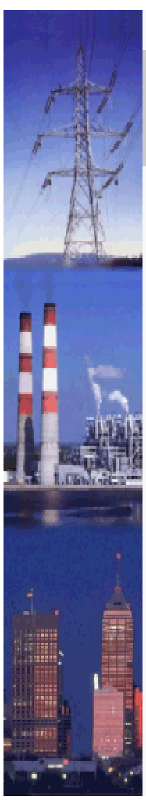


# Enhanced Net Revenue Analysis

## Gas Combustion Turbine, 2004 – 2008





# Long-Term Market Signals – Conclusions

- Based on the net revenue levels in 2008 and Cost of New Entry ("CONE") estimates used to determine the NYISO's Capacity Demand Curves:
  - ✓ Vernon/Greenwood is the only area of NYC where new CT investment might have been profitable in 2008. (The estimated CONE for a new CT in NYC was $188/kW-year for the 2008/09 Capability Period).
  - ✓ This is not surprising because a surplus of capacity exists in both New York City and in the rest of the state.
- The estimated net revenues are substantially higher for a new CC than a new CT.
  - ✓ In up-state areas, the estimated net revenues for a new CC were more than double those for a new CT in 2008.
  - ✓ In New York City, the estimated net revenues for a new CC were more than $100 per KW-month higher than those for a new CT in 2008.
- We do not have reliable estimates of the entry costs for a CC, but it is possible that a CC could be built economically in some areas under the current market conditions.

# External Interface Scheduling

POTOMAC ECONOMICS



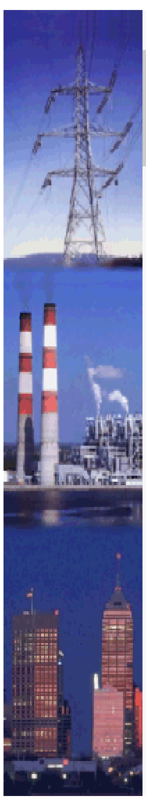
# External Interface Scheduling – Introduction

- Wholesale markets facilitate the efficient use of both internal resources and transmission interfaces between control areas.
- Efficient use of transmission interfaces between regions is beneficial in at least two ways:
  - ✓ By promoting competition in the same way as efficient use of transmission resources within each control area: it allows customers to be served by external resources that are lower-cost than available native resources.
  - ✓ By contributing to reliability in each control area.
- This section examines five areas related to scheduling between regions:
  - ✓ Scheduling patterns between New York and neighboring control areas.
  - ✓ The pattern of transaction scheduling around Lake Erie in 2008.
  - ✓ Convergence of prices between New York and neighboring control areas.
  - ✓ Benefits of external interface scheduling by market participants.
  - ✓ Benefits of ISO-coordinated interchange between control areas.
- Additionally, the section on Market Operations evaluates the efficiency of external transaction scheduling by RTC.

## External Interface Summary

- The following three figures summarize the interchange with neighboring control areas during the past two years.
  - ✓ For each interface, average net imports are shown by month for peak (i.e., 6 am to 10 pm, Monday through Friday) and off-peak hours.
- The three figures show the average net imports across:
  1) The primary interfaces with the Ontario and PJM;
  2) The primary interfaces with Quebec and New England;
  3) Interfaces that directly connect Long Island to PJM and New England.
- From Ontario, the average net imports in peak hours declined from 640 MW in 2007 to 210 MW in the first six months of 2008, and then increased to 700 MW in the last six months of 2008.
  - ✓ The decline in early 2008 was partly due to the large volume of circuitous transactions scheduled from New York counter-clockwise around Lake Erie via Ontario. These transactions were not permitted after July 2008.

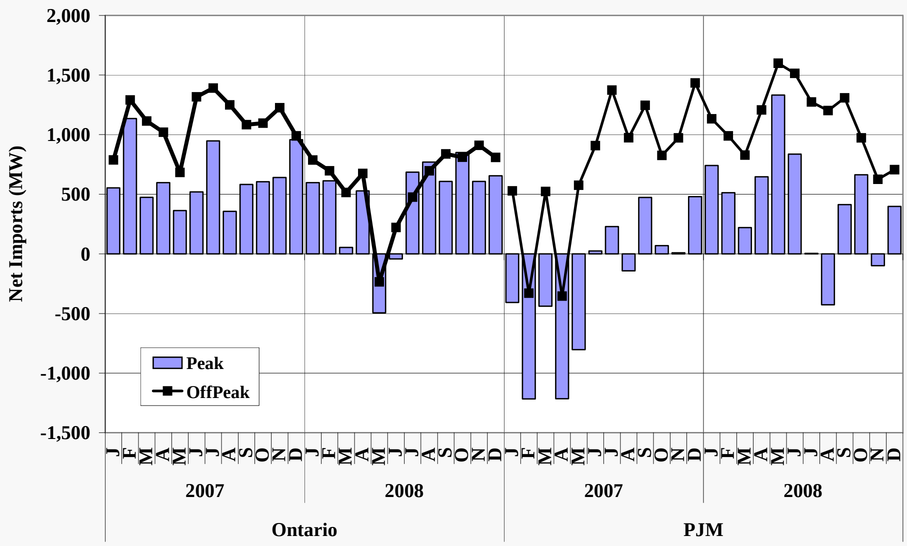




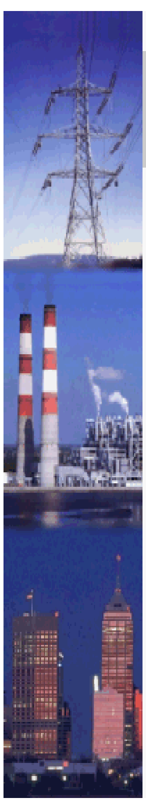
## External Interface Summary

- From PJM, the average net imports in peak hours rose from -680 MW in the first six months of 2007 to 190 MW in the last six months of 2007, and then increased to 720 MW in the first six months of 2008.
  - ✓ In June 2007, the NYISO's prices for the PJM interface began considering congestion in eastern New York (see Tech Bulletin 152).
  - ✓ This led to higher LBMPs at the PJM proxy bus, attracting higher levels of imports from PJM.
- Significant quantities of imports come across the primary interfaces with Hydro Quebec and New England during peak hours.
- A substantial share of the imports to New York state come directly to Long Island via the Cross Sound Cable and the Neptune Cable.
  - ✓ The Cross Sound Cable ("CSC") connects Long Island to Connecticut with a transfer capability of 330 MW.
  - ✓ The Neptune Cable, which began normal operation in July 2007, connects Long Island to New Jersey with a transfer capability of 660 MW.

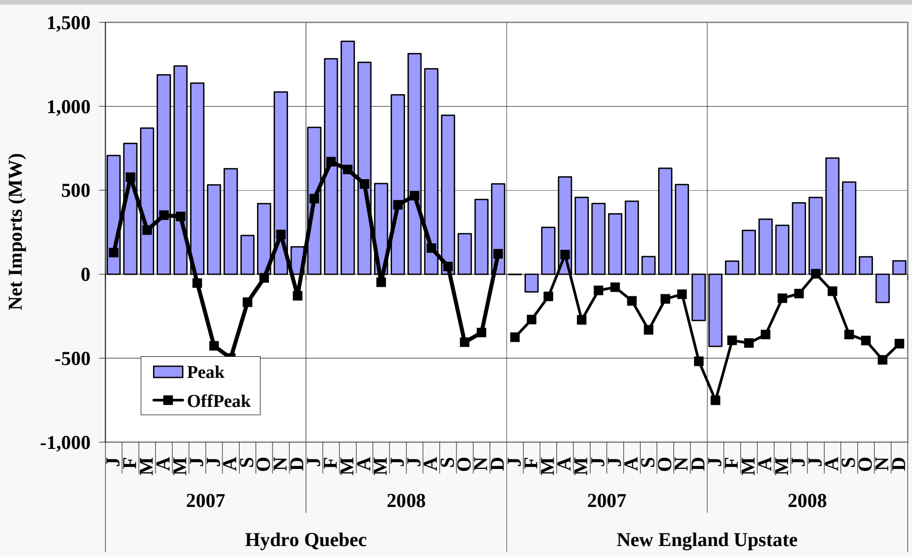
## Imports Across Primary Interfaces with Ontario & PJM 2007 – 2008



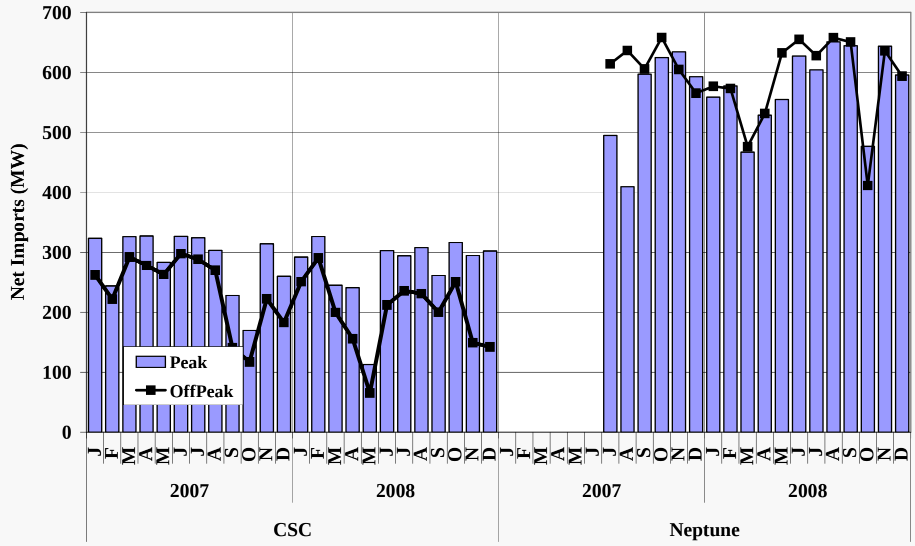


## Imports Over Primary Interfaces with Quebec & New England 2007 – 2008



## Imports Across Cross Sound Cable & Neptune Cable 2007 – 2008

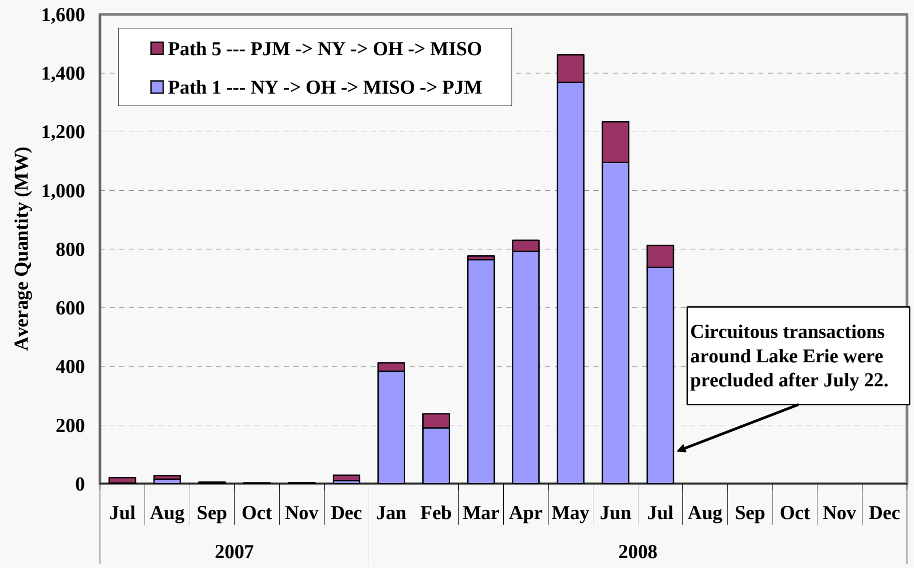





## Circuitous Transaction Scheduling

- The following figure summarizes circuitous transaction scheduling involving the four control areas ("CAs") around Lake Erie.
  - ✓ Path 1 transactions source in the NYCA, wheel through Ontario and the MISO, and sink in PJM.
  - ✓ Path 5 transactions source in the PJM, wheel through the NYCA and Ontario, and sink in the MISO.
- Scheduling a transaction indirectly does not alter the physical flow of the power. The extent to which the physical flows differ from scheduled flows are known as "loop flows".
  - ✓ Path 1 and Path 5 transactions contributed to large amounts of clockwise loop flows (i.e., unscheduled power flows in from Ontario and out to PJM).
  - ✓ Clockwise loop flows use west-to-east transfer capability without bearing the cost of congestion or losses.
- The circuitous transactions increased gradually in early 2008 before rising sharply in May. The vast majority of these were Path 1 schedules.
- On July 21, 2008, the NYISO filed under exigent circumstances to preclude scheduling of Path 1, Path 5, and other circuitous transactions.

## Circuitous Transaction Scheduling Around Lake Erie
## July 2007 – December 2008





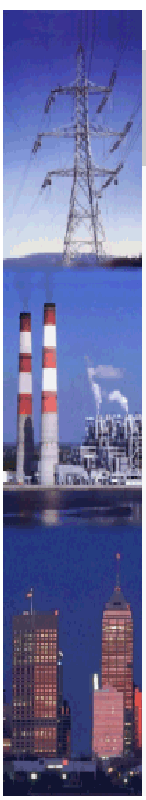

## Uplift Charges Related to External Transactions

- The circuitous transactions contributed to an increase in uplift charges in the first half of 2008.
- The following figure shows actual congestion and loss charges that were avoided by circuitous transactions in each month of 2008.
  - ✓ Path 1 transactions were charged to export at the Ontario interface, although power flowed as if it were exported at the PJM interface.
  - ✓ Path 5 transactions were paid to wheel power through New YOrk from the PJM interface to the Ontario interface, but most of the power did not flow through New York.
  - ✓ These transactions avoided congestion and loss charges that can be calculated based on difference between the LBMPs at the Ontario proxy bus and the PJM proxy bus.
  - ✓ Since these charges are not borne by the circuitous transactions, these schedules lead to increased congestion and loss residuals that are uplifted to the market.

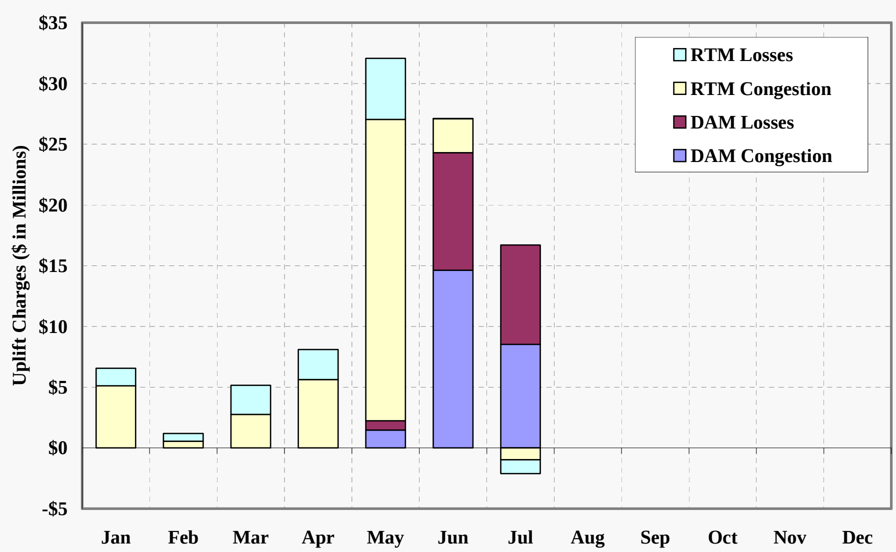
## Uplift Charges Related to External Transactions

- In May 2008, in response to the loop flows caused by the increase in the circuitous transactions, the NYISO began adjusting its loop flow assumptions in the day-ahead market more frequently.
  - ✓ As a result, most costs associated with the circuitous transactions shifted from the real-time market to the day-ahead market in June and July.
- We estimate that the charges not borne by circuitous transactions were:
  - ✓ $25 million of congestion and $19 million of losses in the day-ahead market.
  - ✓ $41 million of congestion and $11 million of losses in the real-time market.
- The Transmission Congestion section provides further analysis of the effects of the circuitous transaction scheduling on balancing market congestion residuals that are uplifted to the market.
  - ✓ The analysis shows that balancing market congestion residuals declined dramatically after the NYISO precluded scheduling of Path 1, Path 5, and other circuitous transactions around Lake Erie.





## Charges Not Borne by Circuitous Transactions
## January to December 2008

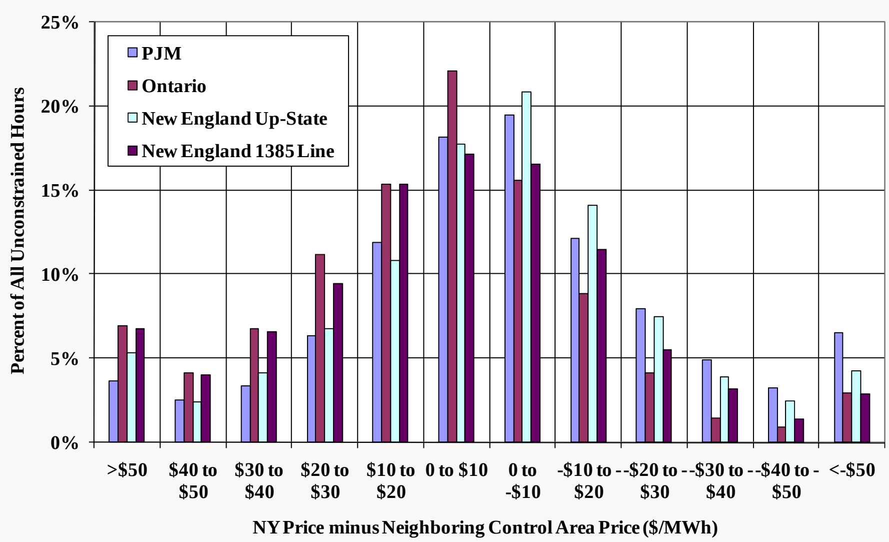


## External Interface Scheduling – Price Convergence Between Control Areas

- When interfaces are used efficiently, prices in adjacent markets and New York should converge unless transmission constraints limit scheduling between regions.
- The following figure summarizes price differences between New York and neighboring markets during unconstrained hours.
  - ✓ The price differences are substantial for every interface.
  - ✓ For example, the price difference exceeded $20/MWh in 37 to 40 percent of the unconstrained hours across each of the interfaces.
- This reinforces the importance of efforts to improve real-time interchange between New York and adjacent markets.
  - ✓ Efficient scheduling is particularly important during reserve shortages when flows between regions have the largest economic and reliability consequences.
  - ✓ Efficient scheduling can also alleviate over-generation conditions that can otherwise lead to negative price spikes.



## Price Convergence Between NY and Adjacent ISO Markets Unconstrained Hours in Real-Time Market, 2008

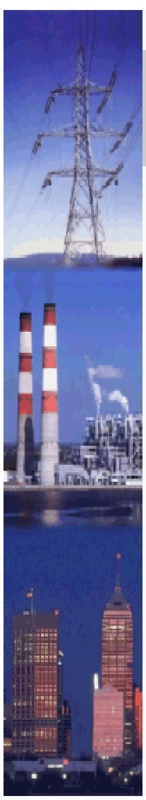



Note: The Neptune and Cross Sound Cable proxy busses are omitted because a separate system is used to allocate transmission reservations on them.

## External Interface Scheduling – Market Participant Scheduling

- It has proven difficult to achieve real-time price convergence with adjacent markets through the transaction scheduling of market participants.
  - ✓ Uncertainty, imperfect information, and required offer lead times limit the ability of participants to capitalize on real-time arbitrage opportunities.
  - ✓ Furthermore, transaction costs from uplift allocations and export fees reduce or eliminate the expected profits from arbitrage.
- The following two figures assist in evaluating the efficiency of scheduling by market participants between markets.
  - ✓ The first figure contains two scatter plots showing scheduled flows versus price differences between New England and up-state NY.
  - ✓ The second figure illustrates the consistency of real-time price differences between NY and New England in the two hours leading up to each real-time five-minute interval.

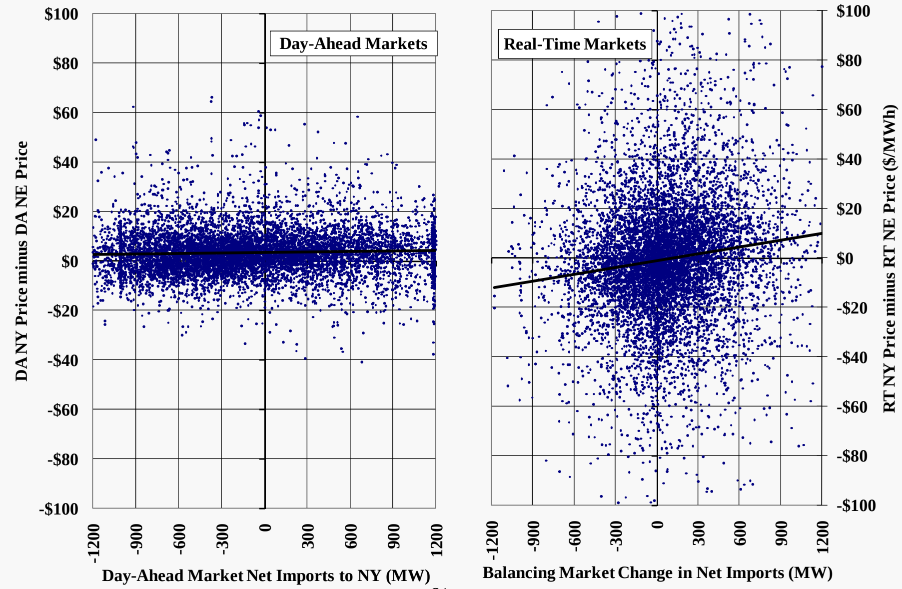




## External Interface Scheduling – Market Participant Scheduling

- The following figure shows scheduled flows versus price differences between New England and up-state NY on an hourly basis.
  - ✓ The left side shows day-ahead scheduling and pricing.
  - ✓ The right side shows scheduling and pricing of incremental changes that occur in the real-time market (relative to the day-ahead schedules).
- The trend line in the left panel does not show a clear positive or negative correlation.
- The trend line in the right panel shows a statistically significant positive relationship between the price differences and schedules in the real-time.
  - ✓ This indicates that participants tend to increase their schedules toward the higher price region, which improves efficiency.
  - ✓ However, the fact that points are so widely dispersed (with 44 percent of the transactions scheduled *from* the high-priced market *to* the low-priced market) suggests there is significant potential for improved efficiency.
  - ✓ If the NYISO and other control areas remove barriers to scheduling, it should enable MPs to schedule transactions more efficiently.

## Efficiency of Scheduling in the Day-Ahead and Real-Time Interface Between Up-state NY and New England, 2008

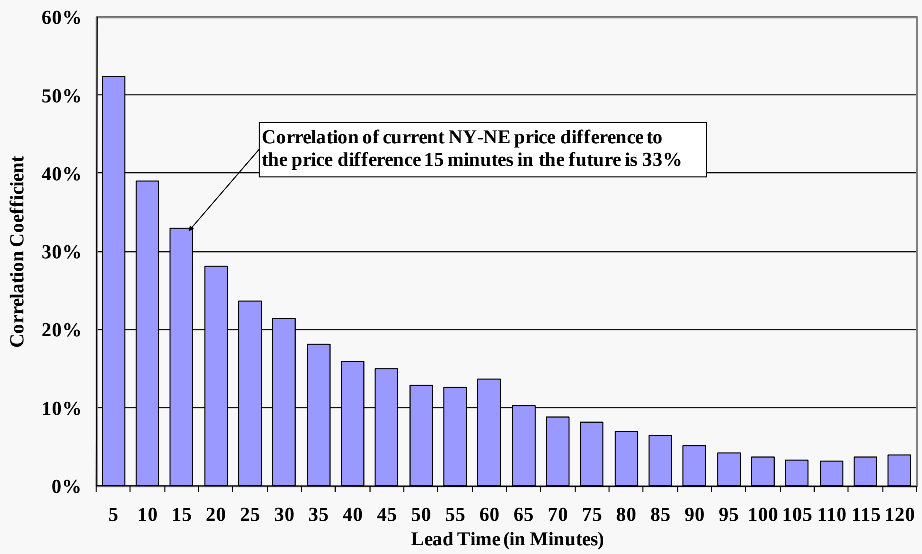





## External Interface Scheduling – Market Participant Scheduling

- The following figure shows how the current five-minute price difference between NY and New England is useful for predicting the price difference over the subsequent 120 minutes.
- The correlation coefficient increases as the lead time is reduced below 120 minutes. However, this under-estimates the predictability of price differences between control areas because:
  - ✓ Market participants can use more sophisticated techniques for forecasting; and
  - ✓ RTC's advisory prices help market participants schedule transactions more efficiently. (The consistency of RTC's advisory prices with real-time prices is evaluated in the Market Operations section of this report.)
- Currently, market participants submit transactions 75 minutes before the start of an hour, which is 75 to 135 minutes before the power flows.
- This analysis suggests that the relatively long lead times likely contribute to inefficient bidding by market participants.

## Correlation of Price Differences and Lead Time New York–New England Interface, 2008





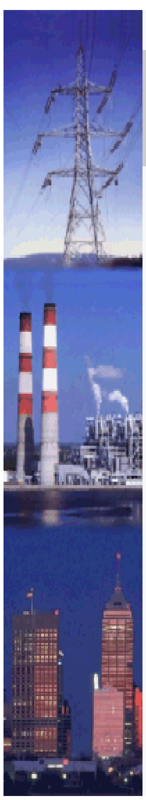

## External Interface Scheduling – Coordination of Interchange by the ISOs

- Although shortening the scheduling lead time would be beneficial, coordination of flows between New England and up-state New York would generate larger benefits for both markets.
- We have performed simulations to estimate the benefits of optimal hourly scheduling of the interface. The results of our estimates based on 2006 and 2007 are summarized in following table.
  - ✓ Production cost savings average $19 million annually.
  - ✓ Net consumer savings average $159 million annually.
- The net consumer savings are concentrated on a small share of the total hours when changes in flows would have had large consequences.
  - ✓ The 99 hours with reserve shortages of at least two intervals account for 28 percent of the net consumer savings.
- Another source of benefits that are not shown in the table below relate to costs savings associated with generator commitments.
  - ✓ To the extent that coordination would improve interface use, commitments the ISO makes to support participant transactions would be reduced.
  - ✓ We have not quantified this source of benefits, but they could be substantial.

## Estimated Benefits of Coordinated Interface Scheduling Up-state Interface with ISO-New England, 2006 – 2007

| | 2006 | 2007 |
|---|---|---|
| **Estimated Production Cost Net Savings (in Millions)** | **$17** | **$21** |
| **Estimated Consumer Net Savings (in Millions):** | | |
| **New York Customers** | **$59** | **$177** |
| **New England Customers** | **$61** | **$22** |
| **Total for New York and New England Customers** | **$120** | **$199** |
| **During Reserve Shortage Hours** | **$16** | **$75** |





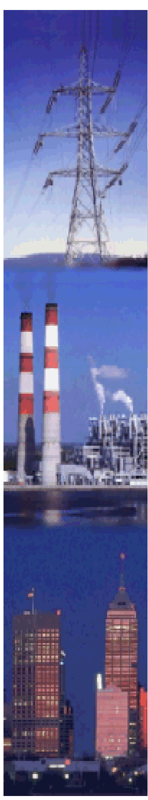
## External Interface Scheduling – Coordination of Interchange by the ISOs

- Prices between New York and adjacent markets continue to not be arbitraged fully during unconstrained periods.
- Reducing barriers will help, but coordination by the ISOs is needed for full price convergence.
- We continue to recommend the ISOs develop a process of adjusting flows to converge real-time price differences.
  - ✓ Even a solution that is used under limited conditions, such as reserve shortages, is likely to result in substantial consumer savings.
- We support efforts to coordinate congestion management with PJM.
  - ✓ Currently, the NYISO and PJM schedule internal resources that affect flows across constrained interfaces in one other's systems. Such effects are not reflected in the nodal prices of the internal resources.
  - ✓ Coordination would reduce the cost of congestion management for both control areas, leading to more efficient nodal prices and congestion charges.

## External Interface Scheduling – Conclusions

- Steps have been taken to reduce barriers to arbitrage between markets:
  - ✓ Export fees were eliminated by the NYISO and ISO-NE on transactions between New York and New England in 2005.
- However, significant barriers still exist:
  - ✓ Uplift for supplemental commitment is allocated to transactions between New York and adjacent markets.
  - ✓ Export fees are allocated to transactions with PJM and Ontario.
  - ✓ Substantial lead times are necessary for scheduling transactions, increasing the difficulty for market participants to predict how to schedule efficiently between markets.
- Reducing these barriers would likely improve efficiency, but it will not likely result in full convergence.
  - ✓ Scheduling transactions on a 15-minute basis would effectively reduce scheduling lead times.
- Full convergence requires coordination by the ISOs using information that is unavailable to participants to optimize the interchange between markets.



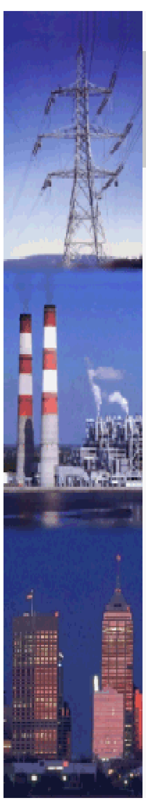


# Convergence of Day-Ahead and Real-Time Prices

## Day-Ahead and Real-Time Prices

- This section of the report examines the degree of consistency between day-ahead and real-time prices.
  - ✓ Price convergence is important because most generation is committed in the day-ahead market -- good price convergence leads to the most economic commitment of resources to serve load in real-time.
  - ✓ Good convergence also helps maintain efficient incentives for generators. Persistent systematic differences between day-ahead and real-time prices undermine incentives of generators to offer at marginal cost.
- There are two kinds of inconsistency between day-ahead and real-time prices:
  - ✓ Random variations between day-ahead and real-time prices due to unanticipated changes in energy supply and load; and
  - ✓ Persistent systematic differences between the average level of day-ahead prices and the average level of real-time prices.
- The analyses in this section of the report look for evidence of persistent systematic differences between day-ahead and real-time prices.

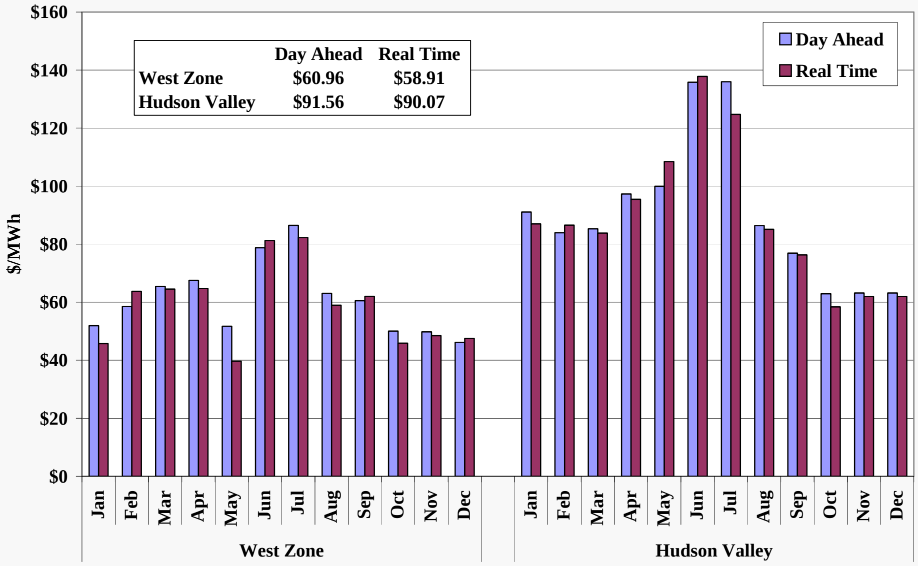




## Day-Ahead and Real-Time Energy Prices

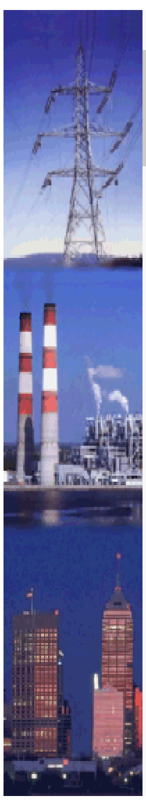
- The following two figures show monthly average day-ahead and real-time energy prices in several zones in 2008. The figures show that:
  - ✓ Some months exhibit material day-ahead to real-time price differences, some of which occur throughout New York and others in specific areas.
- Substantial day-ahead or real-time price premiums in individual months can occur randomly when real-time conditions differ from expectations.
  - ✓ Large real-time premiums can arise when real-time scarcity is not anticipated in the day-ahead.
    - For example, extreme real-time congestion occurred over the Leeds-to-Pleasant Valley line on May 27;
    - This led real-time LBMPs to be much higher than day-ahead LBMPs in Southeast NY and much lower than day-ahead LBMPs in upstate areas.
  - ✓ Day-ahead premiums (e.g., July 2008) can arise when the day-ahead market anticipates more real-time scarcity than actually occurs.
  - ✓ Random or otherwise unpredictable events can lead to intermittent day-ahead or real-time price premiums in individual months.

## Average Monthly Day-Ahead and Real-Time Energy Prices West Zone and Hudson Valley, 2008

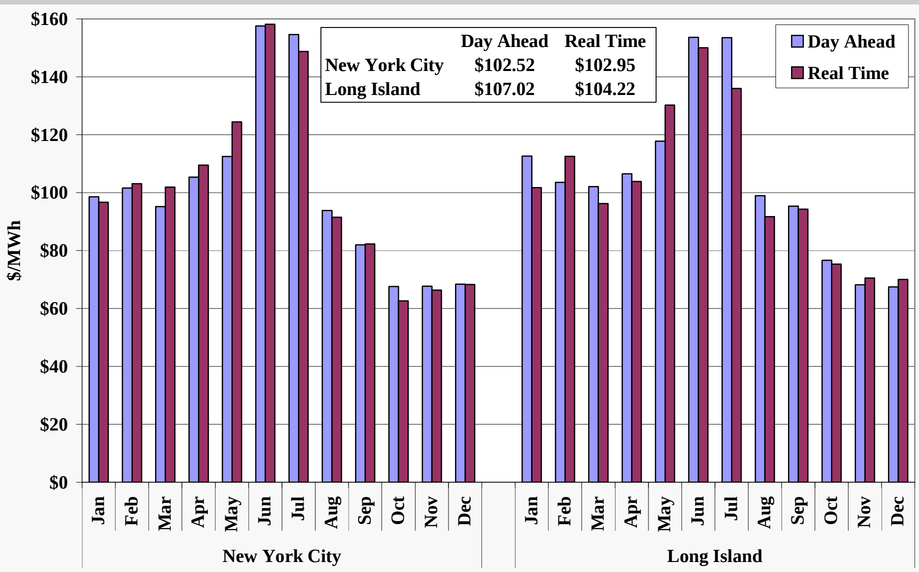



Note: The prices are load-weighted averages.





## Average Monthly Day-Ahead and Real-Time Energy Prices New York City and Long Island, 2008

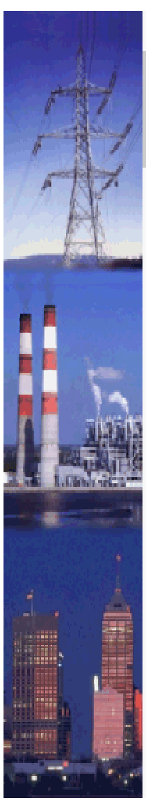



Note: The prices are load-weighted averages.

## Day-Ahead and Real-Time Energy Prices

- The following two figures show average daily real-time price premiums for weekday afternoon hours for New York City and Long Island.
- Even when average day-ahead and real-time prices are consistent in a month, the figures show substantial differences on individual days.
- Market participants buy and sell in the day-ahead market based in part on their expectations of real-time market outcomes. Day-ahead decisions are influenced by several uncertainties:
  - ✓ Demand can be difficult to forecast with precision; the availability of supply 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, day-ahead prices reflect the probability-weighted expectation of infrequent high-priced events in the real-time market.

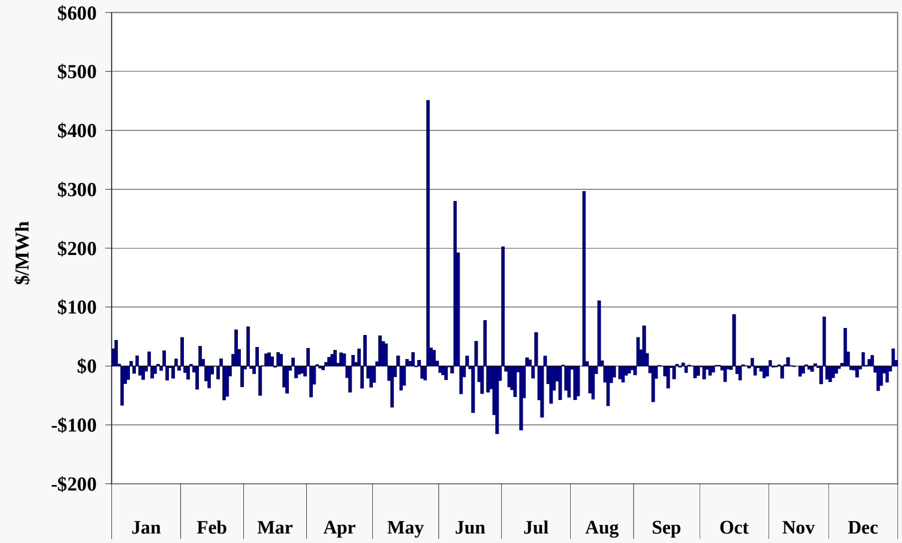




## Day-Ahead and Real-Time Energy Prices

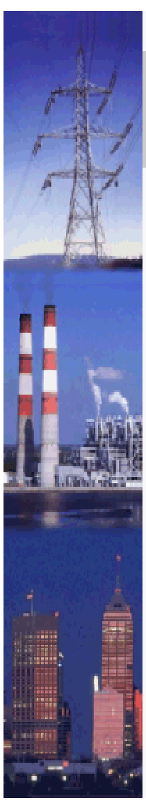
- Average day-ahead prices are higher than average real-time prices on the majority of afternoons shown in the following figures:
  - ✓ Day-ahead prices were higher than real-time prices on almost 63 percent of afternoons in New York City and on almost 68 percent of afternoons in Long Island.
- However, high-price events are more frequent in the real-time market:
  - ✓ The day-ahead price premium exceed $100 per MWh on 2 afternoons in New York City and 2 afternoons in Long Island.
  - ✓ The real-time price premium exceeded $100 per MWh on 6 afternoons in New York City and 3 afternoons in Long Island.
- The day with the largest real-time price premium was May 27.
  - ✓ The real-time price premium on May 27 reflects 5 hours of high real-time congestion through Hudson Valley associated with a Thunder Storm Alert.

## Average Daily Real-Time Price Premium
## New York City, 1 p.m. to 7 p.m. Weekdays, 2008

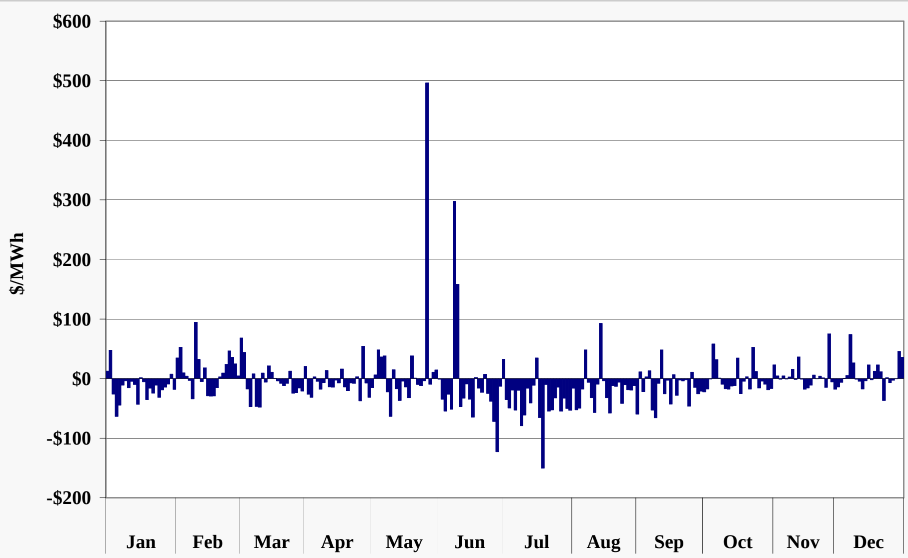



Note: The prices are load-weighted averages.





## Average Daily Real-Time Price Premium
## Long Island, 1 p.m. to 7 p.m. Weekdays, 2008

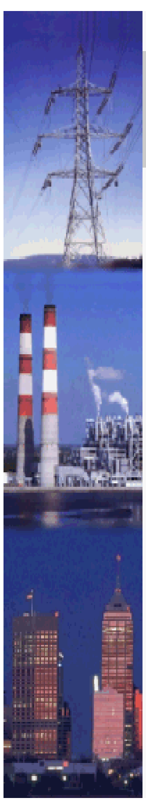



Note: The prices are load-weighted averages.

## Day-Ahead and Real-Time Nodal Prices

- When real-time premiums vary substantially across locations in a particular time period, it indicates that day-ahead congestion patterns are different from real-time patterns.
- Congestion patterns may differ between the day-ahead and real-time for many reasons, including the following:
  - ✓ Differences between constraint limits used in the two markets.
  - ✓ Generators that are not scheduled day-ahead may change their offers. This is common during periods of fuel price volatility or when gas is more easily procured day-ahead.
  - ✓ Transmission constraints that are sensitive to the level of demand may become more or less acute after the day-ahead market due to differences between expected load and actual load.
  - ✓ Transmission forced outages may occur and transmission maintenance schedules may change unexpectedly.
  - ✓ Generators may be committed or decommitted after the day-ahead market, which changes transmission flows.





## Day-Ahead and Real-Time Nodal Prices

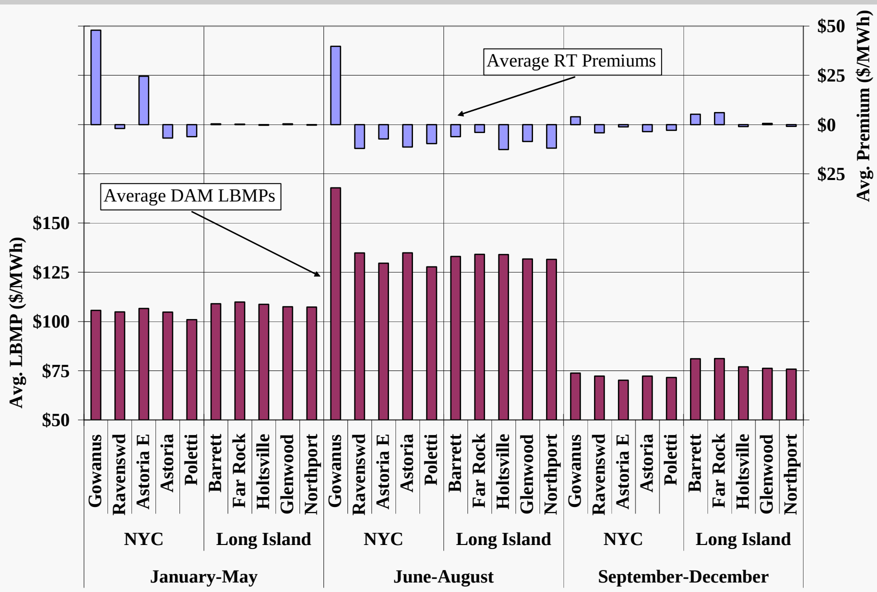
- The following figure shows the average day-ahead LBMP and the average real-time price premium at several nodes in New York City and Long Island in 2008.
  - ✓ The New York City and Long Island zones are shown because they have exhibited the highest levels of intra-zonal congestion historically.
  - ✓ A review of similar data indicates relatively good day-ahead to real-time convergence at the nodal level in up-state areas.
- The figure shows substantial real-time congestion into certain areas that was not fully reflected in the day-ahead market.
  - ✓ From June to August for example, the difference between the average LBMP at the Gowanus plant and other areas of New York City was approximately $30/MWh in the day-ahead and $80/MWh in real-time.
- The large difference between oil and natural gas prices likely contributed to inconsistencies between day-ahead and real-time congestion patterns.
  - ✓ Some generators have difficulty obtaining gas intra-day and must rely on oil.

# Day-Ahead and Real-Time Nodal Prices

- In New York City, two additional factors likely contributed to inconsistencies between day-ahead and real-time congestion patterns:
  - ✓ SRE commitments were made after the DAM on most days.
    - SRE commitments accounted for an average 250 MW of energy production and additional available online capacity in NYC in 2008.
    - In February 2009, the NYISO developed the capability to integrate SRE commitments in the day-ahead market. We expect this improvement to reduce inconsistencies between day-ahead and real-time.
  - ✓ Load pocket interface constraints were sometimes used in real-time, while more detailed network constraints were always used in the DAM.
    - For instance, 64 percent of the real-time binding constraints in New York City were interface constraints. (A real-time constraint was binding in New York City in 32 percent of intervals in 2008.)
- Currently, virtual trading is allowed at only the zonal level, but the NYISO is developing a plan to allow virtual trading at a more disaggregated level.
  - ✓ This may improve convergence in NYC load pockets by allowing market participants to arbitrage day-ahead to real-time prices at the nodal level.



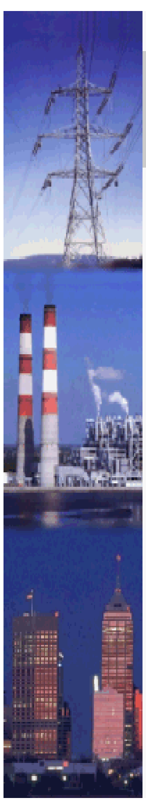
# Average Real-Time Price Premium at Selected Nodes 2008



## Day-Ahead and Real-Time Ancillary Services Prices

- The following figures summarize day-ahead and real-time clearing prices for the two most important reserve products in NY state.
  - ✓ The first figure shows 10-minute non-spinning reserve prices in eastern New York, which are primarily based on the requirement to hold 1,000 MW of 10-minute reserves east of the Central-East Interface.
  - ✓ The second figure shows 10-minute spinning reserve prices in western New York, which are primarily based on the requirement to hold 600 MW of 10-minute spinning reserves in New York state.
  - ✓ Average prices are shown by season and by hour of day.
- The market models use “demand curves” that place an economic value of $500/MWh on meeting each of these requirements.
- Both figures show that average day-ahead prices are systematically higher or lower than real-time prices under various circumstances.
  - ✓ Average real-time prices tend to be higher during the afternoon peak, and average day-ahead prices tend to be higher at other times.

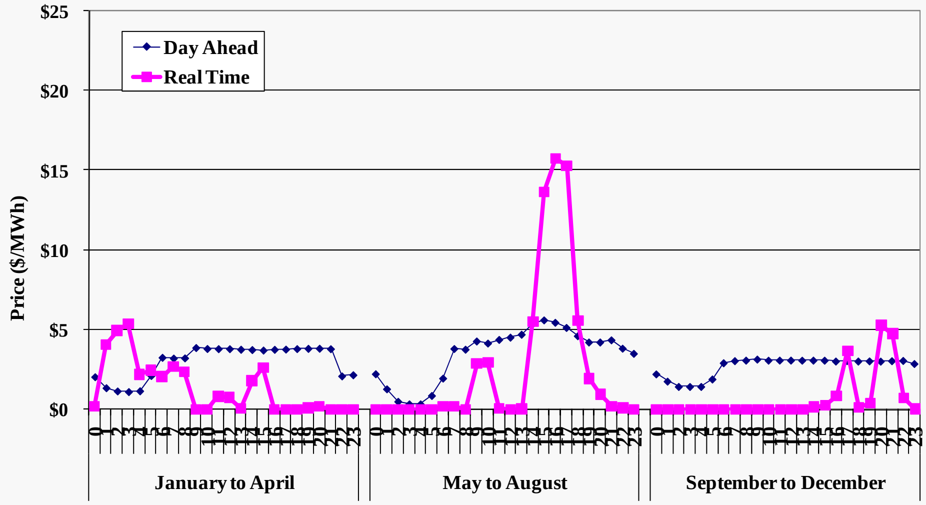




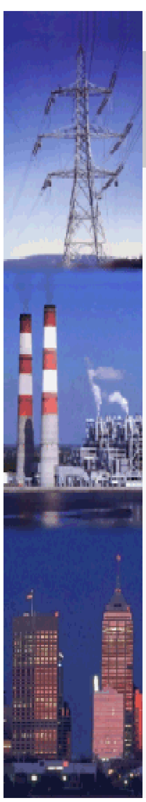
## Day-Ahead and Real-Time Ancillary Services Prices

- Real-time reserve prices are generally volatile, making them difficult for the day-ahead market to predict.
  - ✓ Eastern real-time 10-minute non-spinning reserves prices are normally close to $0, reflecting the excess available reserves from off-line quick-start GTs.
    - – However, real-time prices can spike during periods of tight supply and high energy demand.
  - ✓ 10-minute spinning reserves prices are less volatile, but still prone to unexpected spikes.
- Day-ahead reserve prices tend to fluctuate based on the expected likelihood of a real-time price spike.
- Convergence between day-ahead and real-time ancillary services prices has gradually improved since the introduction of the SMD 2.0 markets in 2005.
  - ✓ However, convergence may be inhibited by day-ahead offer limitations, which are discussed in the next section.

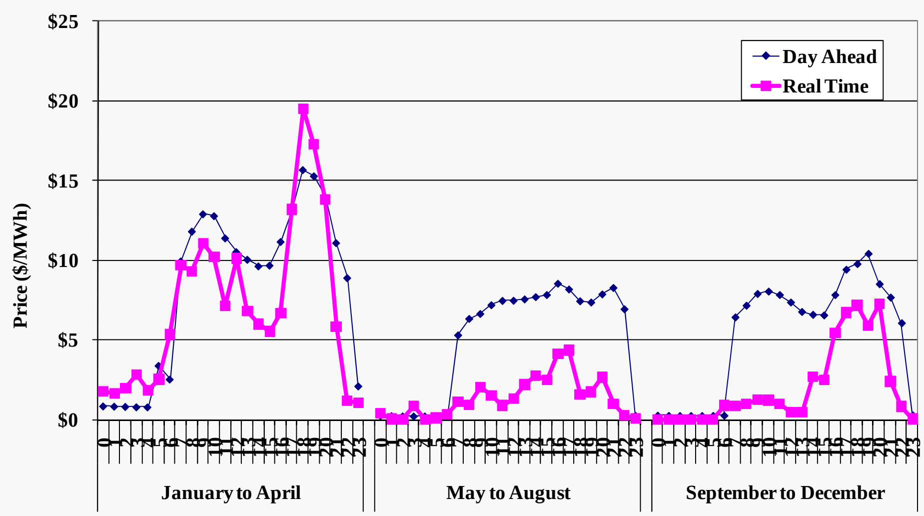
## 10-Minute Non-Spinning Reserve Prices in East NY by Season and Hour of Day, 2008





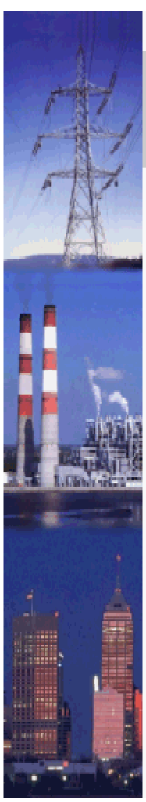



## 10-Minute Spinning Reserve Prices in West NY by Season and Hour of Day, 2008



# Analysis of Bids and Offers – Energy Offer Patterns





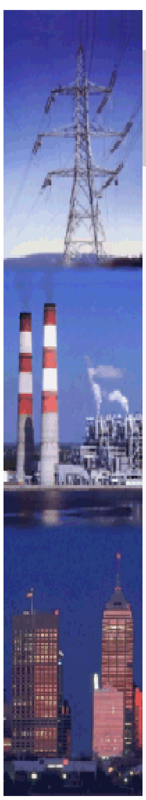
## Analysis of Energy Offer Patterns

- This section of the report analyzes 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).

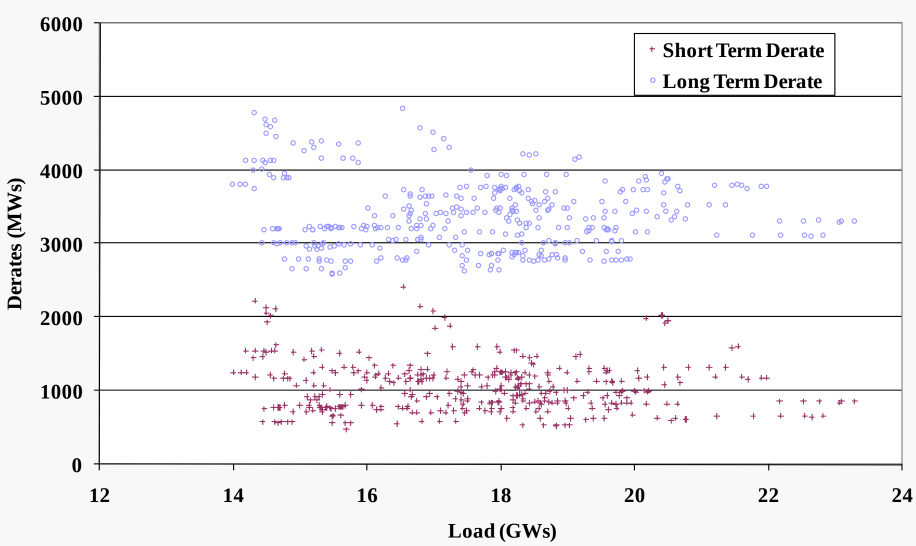
# Analysis of Offer Patterns – Deratings

- The following figure plots long-term deratings and short-term deratings versus actual load in eastern NY during peak hours in the summer.
  - ✓ The figures focus on east NY because this area includes two-thirds of the State's load and is more vulnerable to the exercise of market power due to the limited import capability into the area.
  - ✓ The analysis focuses 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.
  - ✓ Long-term deratings are measured relative to the most recent DMNC test value. Short-term deratings exclude quantities lasting more than 30 days.
  - ✓ The short-term deratings are more likely to reflect attempted physical withholding since it is more costly to withhold via long-term deratings or outages.
- The figure shows that long-term deratings and short-term deratings decline during the highest load conditions, which is consistent with expectations for a competitive market.





# Deratings versus Actual Load in Eastern New York
## Day-Ahead Market, Peak Hours*, Summer 2008

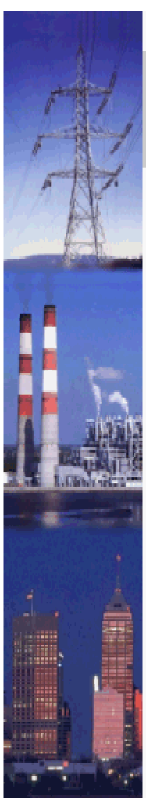



* Peak hours are defined as weekdays from 12 PM to 6 PM for purposes of this analysis.

## Analysis of Offer Patterns – Output Gap

- The second analysis examines potential economic withholding, employing the “output gap” metric.
- The output gap is the quantity of economic capacity that does not produce energy 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.
  - ✓ Excludes capacity that is more economic to provide ancillary services.
- Like the prior analysis of deratings, output gap levels that rise with load indicates potential competitive concerns, while output gap that declines with load is an indication of competitiveness.

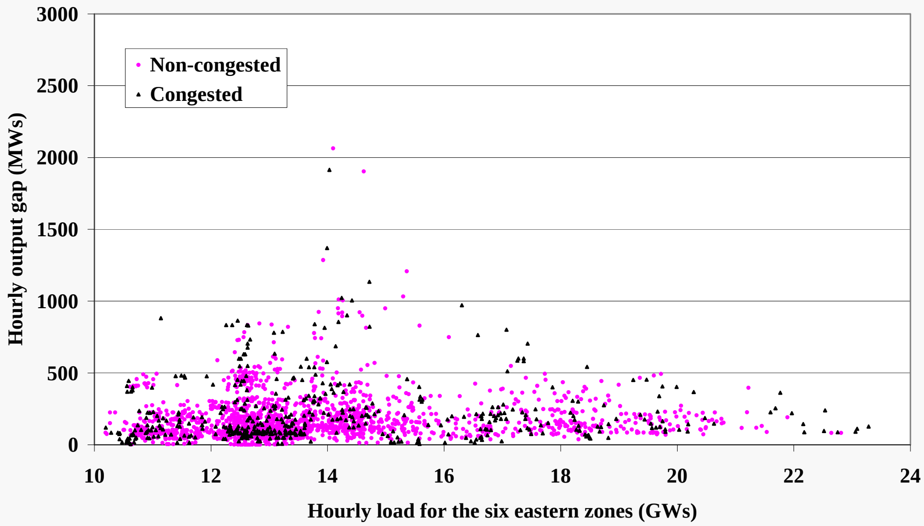




## Analysis of Offer Patterns – Output Gap

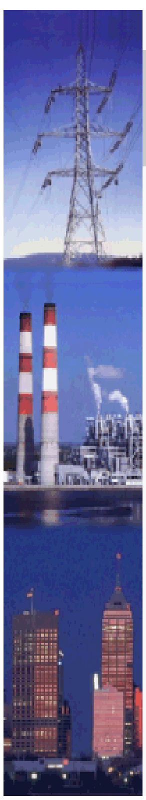
- The following two figures show the real-time output gap in eastern New York during peak hours:
  - ✓ The first chart uses the standard conduct threshold used for mitigation outside New York City, which is the lower of $100/MWh or 300 percent.
  - ✓ The second chart uses a lower conduct threshold of $50/MWh or 100 percent (whichever is lower).
- Congested hours and non-congested hours are indicated separately to show whether the output gap increases during periods of congestion.
  - ✓ These figures indicate that the output gap decreases under the highest load conditions. This is important because prices are most vulnerable to market power under peak load conditions.
  - ✓ These results are consistent with the expectations for a competitive market.
  - ✓ These results are particularly notable for the lower threshold because this conduct is not subject to mitigation.

# Output Gap at Mitigation Threshold in East New York Real-Time Market, Peak Hours*, 2008

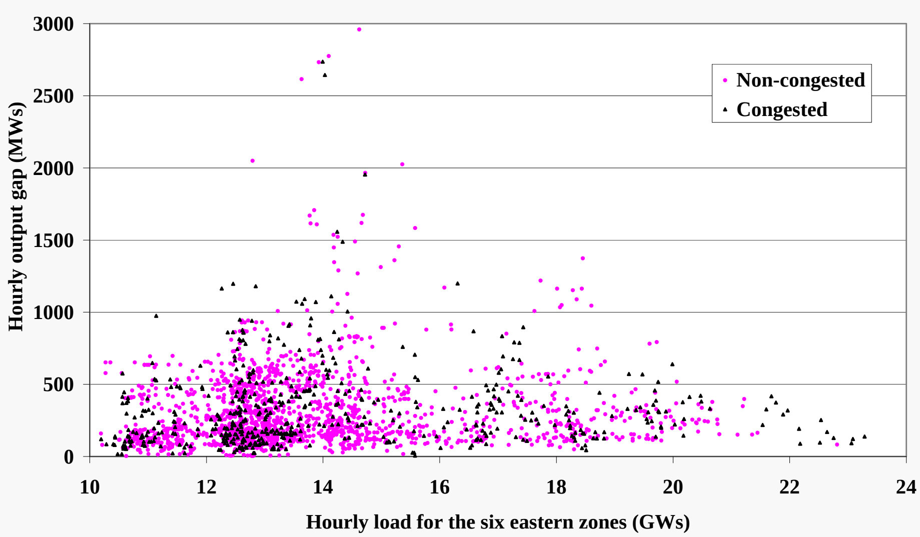



* Peak hours are defined as weekdays from 12 PM to 6 PM for purposes of this analysis.





# Output Gap at Lower Threshold in East NY Real-Time Market, Peak Hours*, 2008



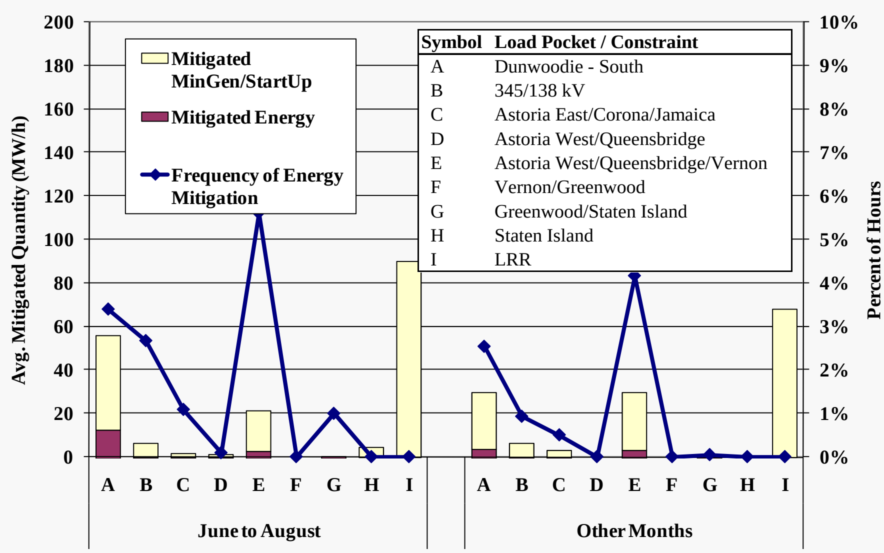

* Peak hours are defined as weekdays from 12 PM to 6 PM for purposes of this analysis.

# Summary of Mitigation

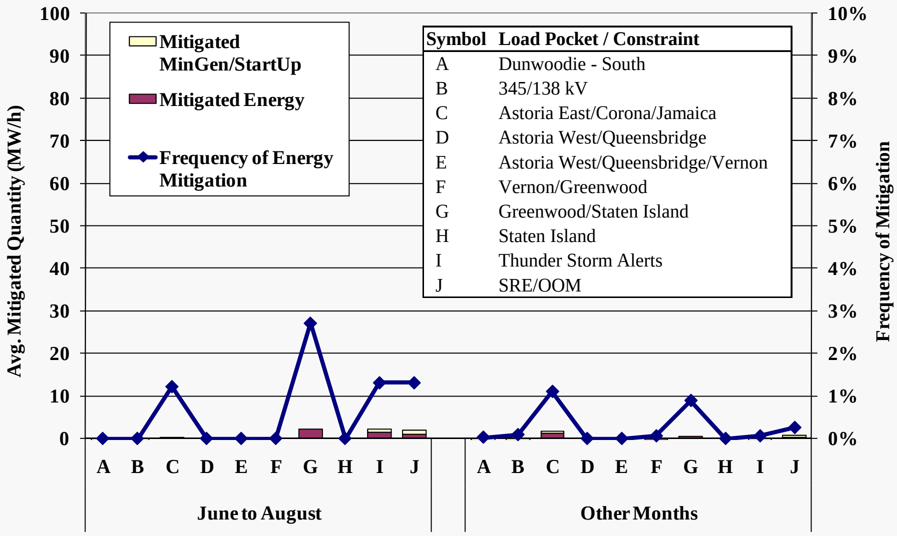
- The market power mitigation measures are based on the conduct and impact framework, which is triggered when constraints bind into NYC load pockets.
  - ✓ This framework prevents mitigation when it is not necessary to address market power and allows high prices during legitimate periods of shortage.
- The following two figures summarize the amount of mitigation that occurs in NYC in the day-ahead market and in the real-time market.
  - ✓ 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).
  - ✓ The bars show the average amount of capacity mitigated by location in hours when mitigation was imposed.
  - ✓ The lines show the percent of hours when energy mitigation was imposed.
- In the day-ahead market, the majority of mitigation is of units committed to satisfy Local Reliability Requirements ("LRR"), which are mitigated by rule whenever their start-up or mingen offers exceed the reference level.
- The majority of day-ahead energy mitigation occurs when constraints bind into the Dunwoodie-South or the Astoria West/Queensbridge/Vernon load pockets.
- Mitigation was very infrequent in the real-time market, despite frequent congestion and high levels of market concentration in the load pockets.



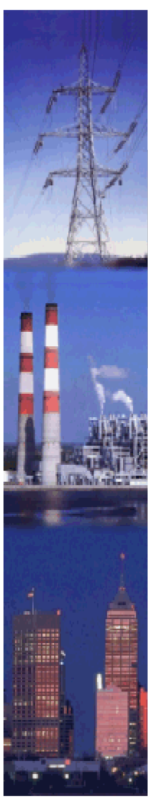
# Summary of Day-Ahead Mitigation
## New York City, 2008



# Summary of Real-Time Mitigation
## New York City, 2008





# Analysis of Bids and Offers – Ancillary Services Offer Patterns

POTOMAC ECONOMICS

## Day-Ahead Ancillary Services Offers

- The following figure evaluates day-ahead offers to provide ancillary services in each month of 2008.
  - ✓ The quantities offered are shown for the following categories:
    - 10-minute spinning reserves in western New York;
    - 10-minute spinning reserves in eastern New York;
    - 10-minute non-spinning reserves in eastern New York; and
    - Regulation.
  - ✓ Offer quantities are shown according to offer price level for each category.
- Regarding 10-minute spinning reserve capacity:
  - ✓ Offer quantities decline in the shoulder months when more capacity is out-of-service.
  - ✓ Offer prices are substantially lower in the east than in the west because New York City generators are required to offer 10-minute spinning reserves at $0/MWh.

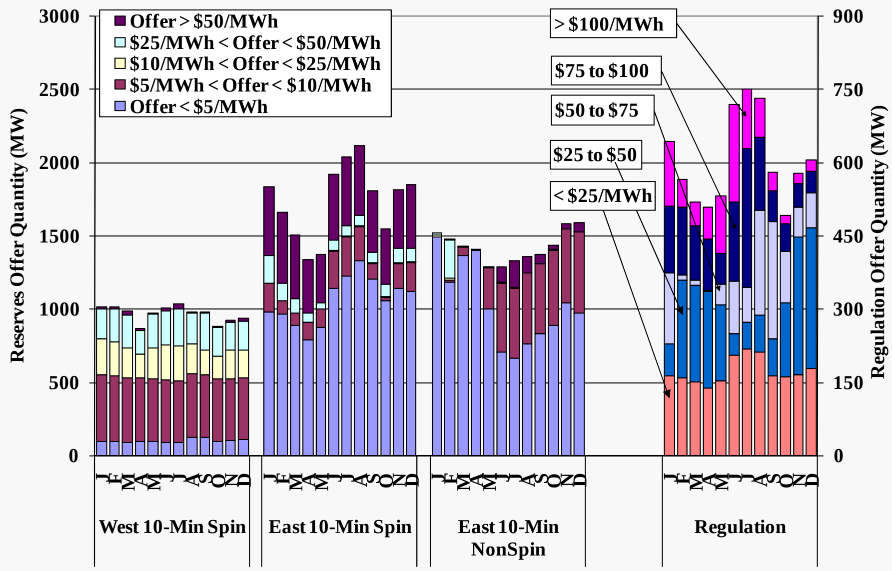


## Day-Ahead Ancillary Services Offers

- Regarding 10-minute non-spinning reserve capacity:
  - ✓ It is rational for suppliers to avoid being scheduled in the day-ahead market in periods when day-ahead prices are systematically lower than real-time prices.
  - ✓ Hence, the rise in offer prices in May and June was a rational market response to the pattern prices (there was a substantial real-time premium for the May-to-August period). However, this response is limited because:
    - Offer price increases are limited by the mitigation rules, which cap the reference levels of 10-minute non-spinning reserve units to $2.52/MWh.
    - Decreases in offer quantities are limited by the ICAP rules, which require non-PURPA ICAP units that have 10-minute non-spinning reserve capability to offer it in the day-ahead market.
- Regarding regulation offer patterns:
  - ✓ There was a substantial increase in the quantity offered during the summer months.

# Summary of Ancillary Services Offers

## Day-Ahead Market, 2008




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



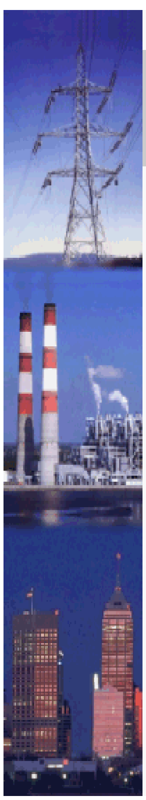
# Ancillary Services Offers – Conclusions and Recommendations

- Convergence between day-ahead and real-time prices has improved, but is still not always good for certain reserve products.
  - ✓ Average day-ahead prices are systematically higher or lower than real-time prices under certain circumstances.
  - ✓ Systematically low day-ahead prices increase the opportunity cost of selling reserves in the day-ahead market.
  - ✓ Adjustments in offer prices by reserve suppliers are likely to improve convergence between day-ahead and real-time.
- We recommend reconsideration of two provisions in the mitigation measures that may limit competitive offers in the day-ahead market:
  - ✓ Limit on gas turbines to a 10-minute non-spinning reserve reference level of $2.52/MWh.
  - ✓ Requirement for steam units in New York City to offer 10-minute spinning reserves at $0/MWh.

# Analysis of Bids and Offers – Load Bidding and Virtual Trading

POTOMAC ECONOMICS

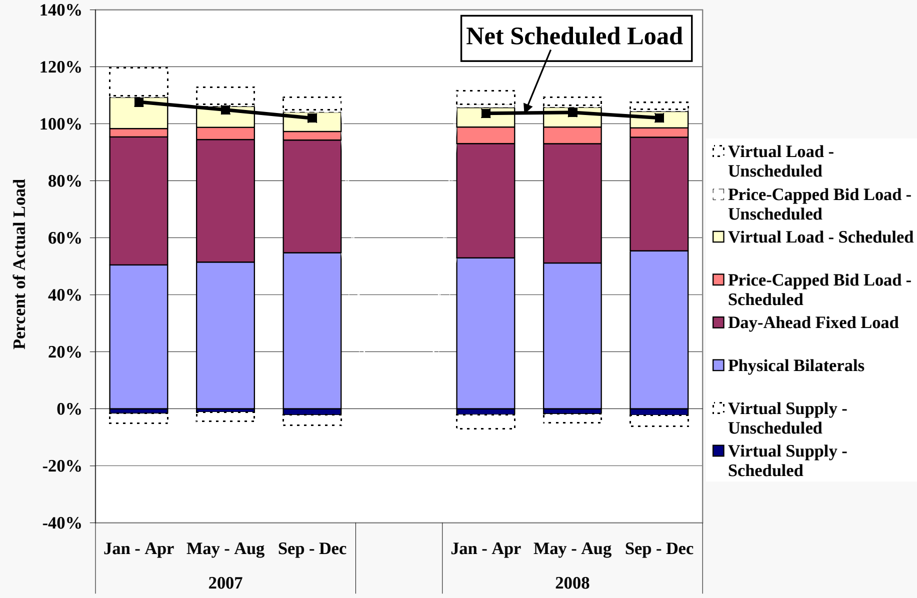




## Load Bidding Patterns in the Day-Ahead Market

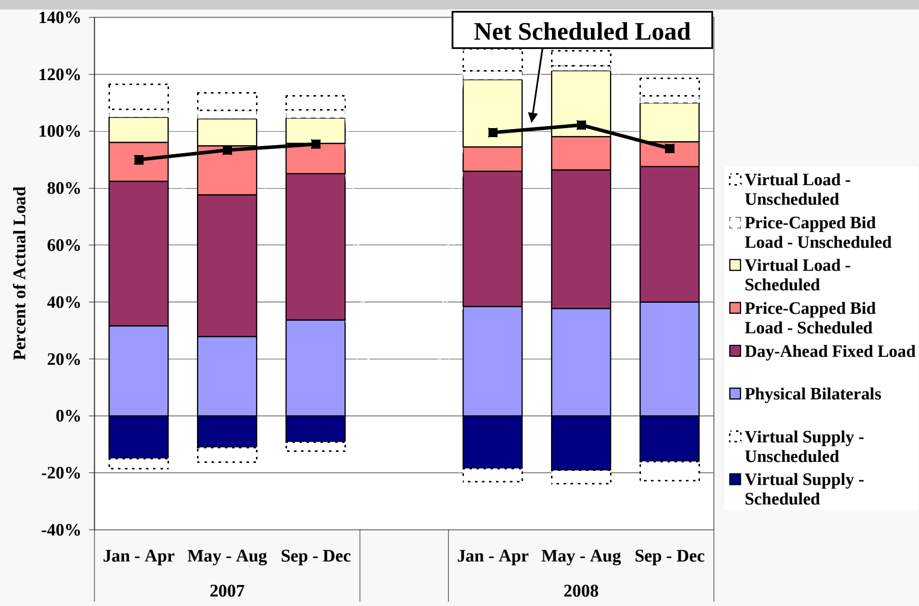
- The following three figures summarize the quantity of day-ahead load scheduled as a percent of real-time load in 2007 and 2008 in three regions of NY state.
  - ✓ Virtual supply nets out an equivalent amount of scheduled load, so it is shown as a negative quantity.
  - ✓ Net scheduled load = Physical Bilaterals + Fixed Load + Price-Capped Load + Virtual Load – Virtual Supply
- On a state-wide basis, the average amount of load scheduled in the day-ahead market is consistent with the average amount of real-time load.
  - ✓ Consistency between the day-ahead scheduled load and real-time load is a positive sign for market efficiency.
- For years, load has generally been over-scheduled in NYC and Long Island and under-scheduled in up-state NY.
  - ✓ This implies that, on average, the day-ahead market schedules more imports into NYC and Long Island than the real-time market.
  - ✓ In 2008, the average amounts of over-scheduling in down-state areas and under-scheduling in up-state areas declined considerably.

# Composition of Day-Ahead Load Schedules versus Actual Load
## New York City and Long Island, 2007 – 2008

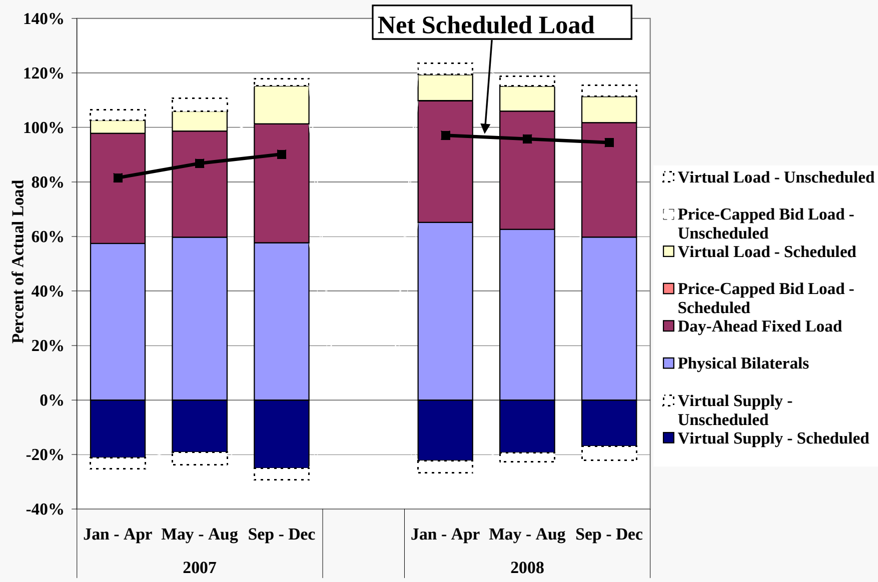





# Composition of Day-Ahead Load Schedules versus Actual Load
## East Up-State New York, 2007 – 2008



## Composition of Day Ahead Load Schedules versus Actual Load West Up-State New York, 2007 – 2008

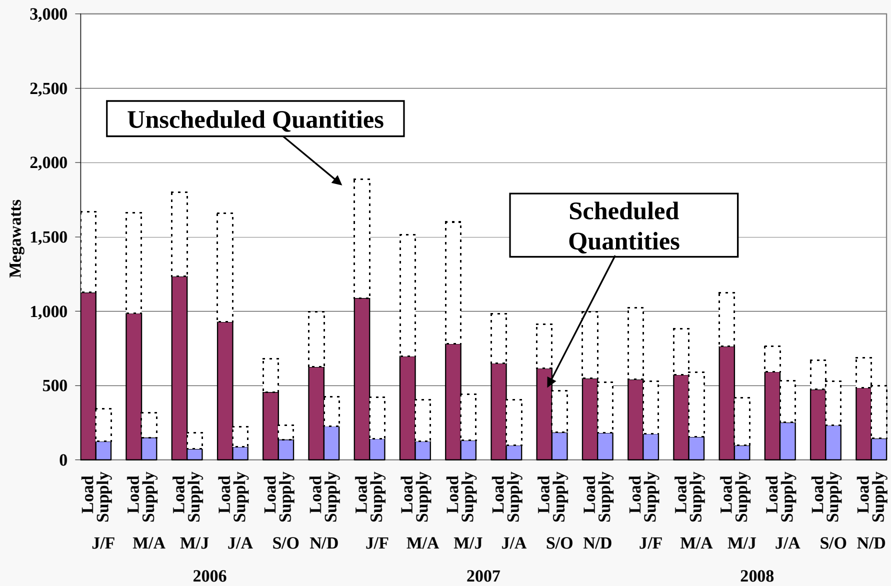




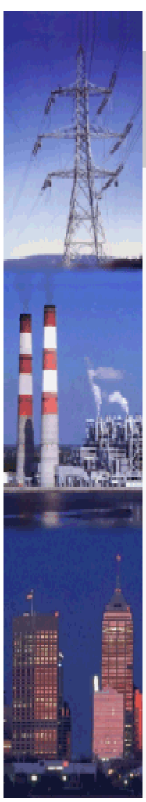

## Virtual Trading Patterns

- Virtual trading allows participation in the day-ahead market by entities other than LSE's and generators.
- The following figures show the virtual bids and offers that have been offered and scheduled on a bi-monthly basis in upstate and downstate areas from 2006 to 2008.
- There have been substantial net virtual sales upstate and virtual purchases downstate during the past three years.
  - ✓ This is consistent with the pattern of imports into downstate areas being higher in the day-ahead market than in the real-time market.
  - ✓ The average net sales upstate and average net purchases downstate have diminished over the past three years.
    - – The average net virtual sale upstate declined from 1230 MW in 2006 to 545 MW in 2008.
    - – The average net virtual purchase downstate declined from 759 MW in 2006 to 396 MW in 2008.

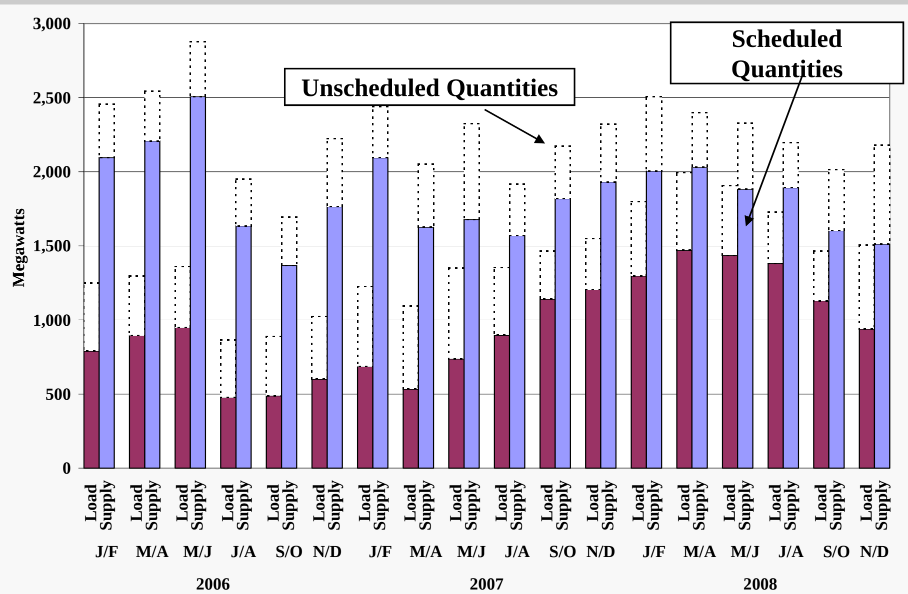
## Hourly Virtual Bidding of Load and Supply
## New York City and Long Island, 2006 – 2008





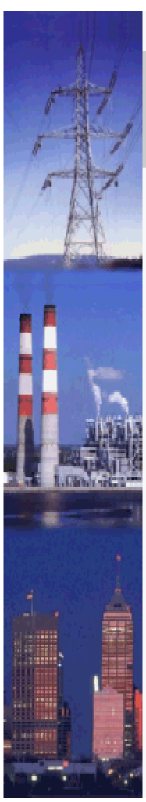



## Hourly Virtual Bidding of Load and Supply
## Outside New York City and Long Island, 2006 – 2008



# Transmission Congestion

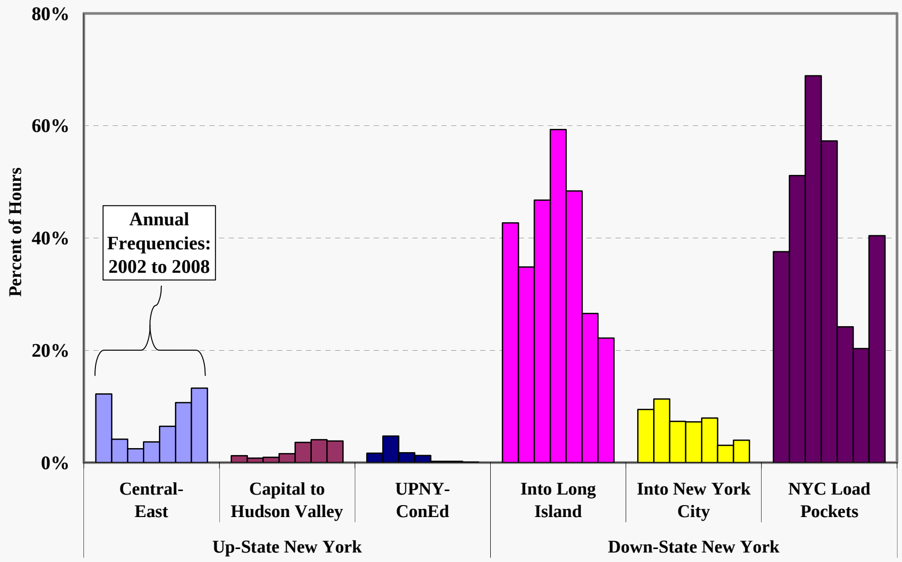




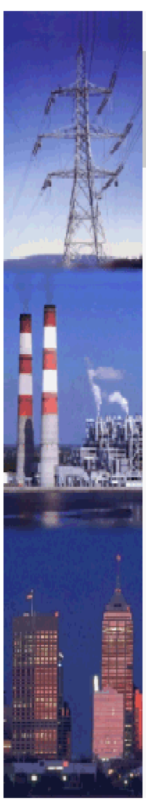
# Real-Time Congestion on Major Interfaces

- The following figures summarize the extent of transmission congestion on select interfaces in up-state and down-state NY.
  - ✓ The first figure shows the frequency of congestion.
  - ✓ The second figure summarizes the value of transfers across congested interfaces, which is based on the volume of flows across the interface and the real-time price differences between regions.
- The Central-East Interface exhibited more frequent constraints in 2008, due to:
  - ✓ Higher net imports from Hydro Quebec; and
  - ✓ Increased clockwise loop flows around Lake Erie.
- The value of congestion in NYC load pockets increased in 2008 due to:
  - ✓ More frequent congestion into the Astoria East and Greenwood areas; and
  - ✓ Increased fuel prices which increased the costs of congestion management, particularly in hours when oil-fired peaking generation was required.
- The value of congestion into Long Island did not change significantly from 2007 to 2008 as the effects of increased fuel prices were offset by the mild summer weather and the supply available through the Neptune Cable.

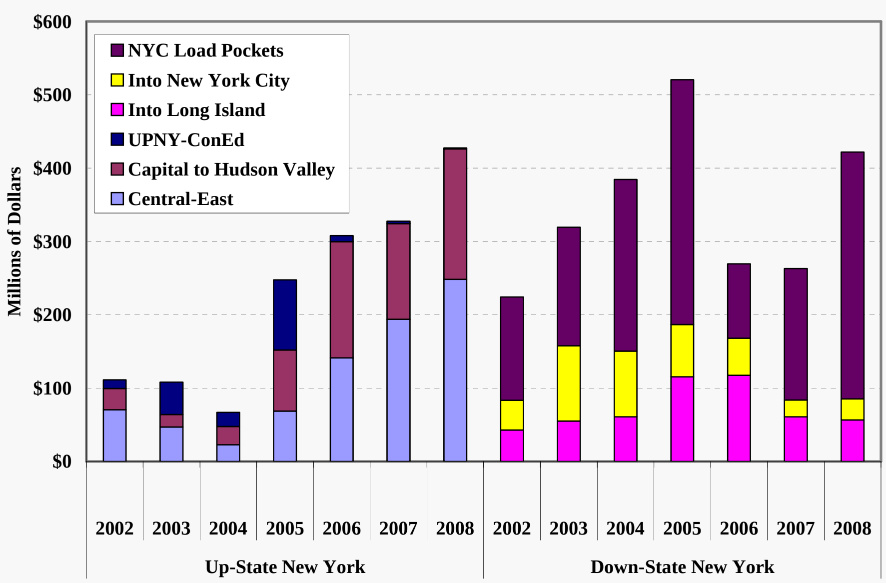
# Frequency of Real-Time Congestion on Major Interfaces 2002 – 2008





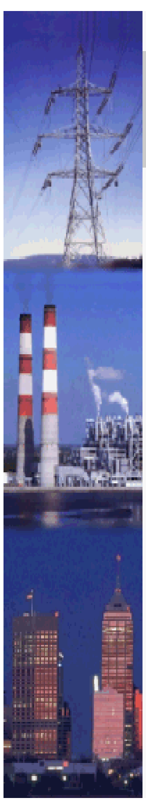
# Value of Real-Time Congestion on Major Interfaces 2002 – 2008



# TCC Prices and Day-Ahead Congestion

- The next two analyses evaluate the TCC market. A TCC entitles the holder to the day-ahead congestion price difference between two points.
  - ✓ Hence, TCC prices reflect expectations of congestion in the DAM.
- There are two types of TCC Auctions:
  - ✓ *Capability Period Auctions*: 1-year and 6-month TCC products are offered.
    - Typically, 33 percent of transmission capability is auctioned in the form of 1-year TCC products, and 67 percent of transmission capability is auctioned in the form of 6-month TCC products.
    - The 1-year and 6-month product auctions consist of a series of rounds. In each round, a portion of the transmission capability is offered, resulting in a set of TCC awards and clearing prices.
  - ✓ *Reconfiguration Auctions:* 1-month TCC products are auctioned following the Capability Period Auctions.
- Auctions occurring closer to the contract start date generally reflect DAM congestion prices more closely than auctions occurring further in advance of the contract start date.

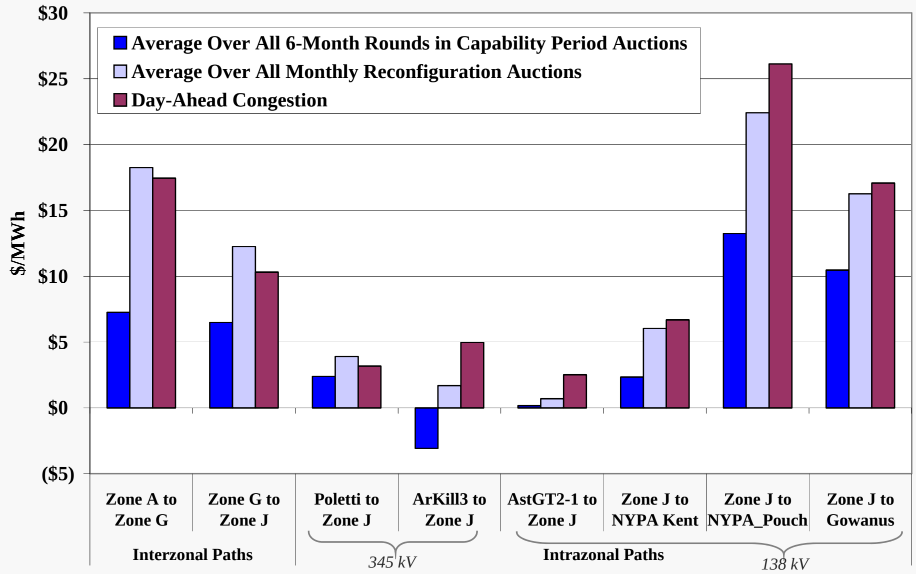




# TCC Prices and Day-Ahead Congestion – Summer 2008 Capability Period

- The next figure compares TCC prices for the 2008 Summer Capability Period to DAM congestion. The TCC prices are shown averaged over:
  - ✓ The five rounds in the 6-month capability auction; and
  - ✓ The six 1-month reconfiguration auctions.
- Prices are shown (i) between three zones commonly used for bilateral trading: Zone A (West), Zone G (Hudson Valley), and Zone J (New York City), and (ii) paths between Zone J and selected nodes inside Zone J.
- The monthly reconfiguration auction prices were more consistent with DAM congestion than the average 6-month capability period auction prices.
  - ✓ Although the monthly reconfiguration auctions substantially under or over-valued DAM congestion in individual months.
- Two factors led to more DAM congestion than anticipated in the TCC auctions:
  - ✓ High west-to-east loopflows due to the high volume of circuitous transactions scheduled around Lake Erie, increasing congestion from Zone A to Zone G.
  - ✓ Within NYC, intrazonal congestion increased from 2007 to 2008.
- These factors were partly offset by mild August weather, which reduced congestion.

# TCC Prices and Day-Ahead Congestion
# Summer 2008 Capability Period





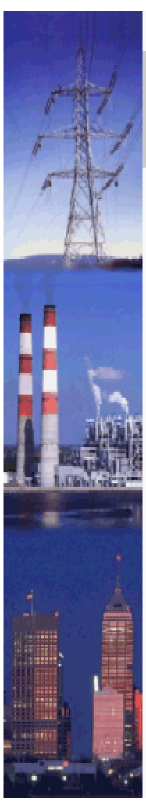

# Day-Ahead Congestion Revenue and TCC Payments

- The next figure shows payments to TCC holders and DAM congestion revenue shortfalls in each month in 2007 and 2008.
  - ✓ Payments to TCC holders are based on the contract-quantities and DAM prices.
  - ✓ DAM congestion revenues are collected by the NYISO when power is scheduled across constrained interfaces in the DAM. The amount collected is based on the quantity scheduled across the interface and DAM prices.
  - ✓ DAM congestion shortfalls arise when TCC payments are greater than DAM congestion revenues. This occurs when contract-quantities are higher than DAM scheduled quantities.
- The rise in congestion value in the DAM from 2007 to 2008 led to a $566 million increase in payments to TCC holders, which exceeded the $480 million increase in DAM congestion revenue.
  - ✓ Accordingly, DAM congestion revenue shortfall rose $86 million in 2008.

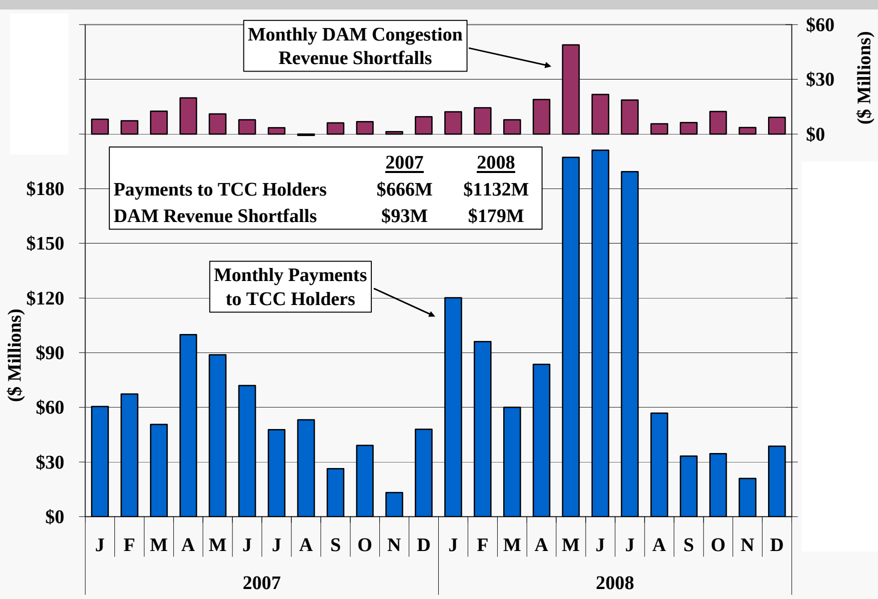
# Day-Ahead Congestion Revenue and TCC Payments

- Outages reduce the transfer capability of the NYISO grid. When outages are not reflected in the TCC auction assumptions, it may lead to an over-sale of TCCs, contributing to DAM congestion revenue shortfalls.
  - ✓ The NYISO has a process for allocating DAM congestion revenue shortfalls to specific outages, which are attributable to specific TOs.
  - ✓ In this manner, 43 percent of the shortfalls in 2008 were charged to specific TOs for equipment outages and derates.
  - ✓ TOs can avoid allocations of DAM congestion revenue from specific outages by electing to incorporate them in the TCC auction assumptions.
  - ✓ Although many of the outages were scheduled before the TCC auctions, none of the TOs elected to incorporate them in the TCC auctions in 2008.
- The 57 percent of DAM congestion revenue shortfalls not associated with specific outages are charged to all TOs.
- Modeling assumption differences between the TCC auction and the DAM, including PAR schedules and unscheduled loop flows, can lead to congestion surpluses or shortfalls.





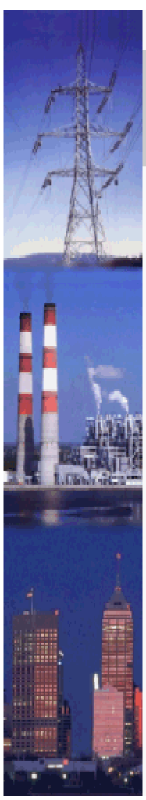
# Payments to TCC Holders and DAM Congestion Shortfalls 2007 – 2008



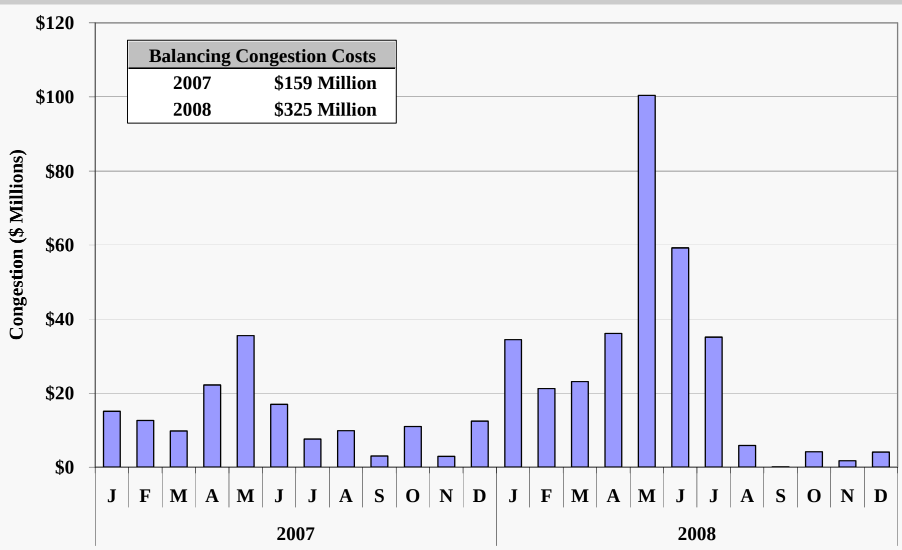
## Balancing Congestion Revenue Shortfalls

- The following figure shows the congestion revenue shortfalls that were incurred in the balancing market in each month of 2007 and 2008.
- Balancing congestion shortfalls generally result from decreases in transmission capability between the day-ahead and real-time markets .
  - ✓ When day-ahead scheduled flows exceed real-time transmission capability, the NYISO must incur additional re-dispatch costs in the real-time market.
- In June 2007, improvements to real-time pricing and dispatch during periods of transmission scarcity reduced revenue shortfalls during such periods.
- Balancing congestion shortfalls rose 104 percent from 2007 to 2008.
- In 2008, 95 percent of the total shortfall was incurred between January and July. The shortfalls have been very low since August 2008.
  - ✓ The rise in shortfalls coincided with the increase in circuitous transaction scheduling around Lake Erie, and the general rise in fuel prices that contributed to larger congestion-related price differences between regions.
  - ✓ The next figure is followed by a more detailed evaluation of the factors that contributed to the variation in shortfalls in 2008.





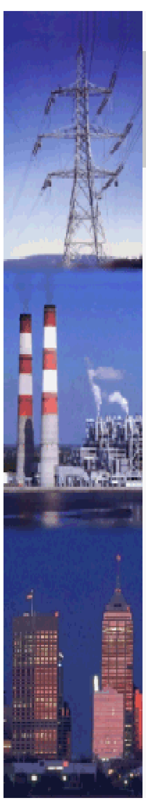
## Balancing Congestion Revenue Shortfalls 2007 – 2008



## Balancing Congestion Revenue Shortfalls – Evaluation of Contributing Factors

- Balancing congestion revenue shortfalls can occur when the transfer capability of a particular interface changes between day-ahead and real-time due to:
  - ✓ Deratings and outages of the lines that make up the constrained interface;
  - ✓ Unexpected or forced transmission outages of facilities that reduce the transfer capability of other constrained facilities;
  - ✓ Unscheduled loop flows across constrained interfaces;
  - ✓ Unutilized transfer capability that can arise from Hybrid Pricing, which treats physically inflexible GTs as flexible in the pricing logic; and
  - ✓ Differences between DA assumptions and RT operations regarding the flows across PAR-controlled lines, which can affect transfer capability of multiple interfaces.
- The following two figures provide additional monthly detail on significant categories of balancing congestion shortfalls in 2008.
  - ✓ The first figure shows the balancing congestion shortfalls related to Transfer Capability Changes between DA and RT for specific interfaces.
  - ✓ The second figure shows the balancing congestion shortfalls related to changes between DA and RT that affected multiple interfaces.





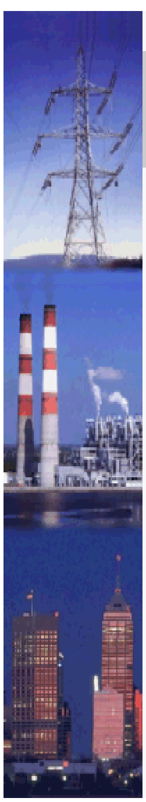
## Balancing Congestion Revenue Shortfalls – Shortfall Categories

- The first figure shows balancing congestion shortfalls associated with transfer capability changes between DA and RT for the following interfaces:
  - ✓ Leeds-to-PleasantValley line during TSA operations;
  - ✓ Simplified NYC load pocket interfaces;
  - ✓ Dysinger-East, West-Central, and Central-East interfaces;
  - ✓ Other internal interfaces and line constraints; and
  - ✓ External interfaces.
- The second figure shows balancing congestion shortfalls associated with the following changes from DA to RT that directly affected multiple interfaces:
  - ✓ The loop flows around Lake Erie; and
  - ✓ The flows across the following PAR-controlled lines:
    - – Waldwick PARs and Branchburg-Ramapo PARs, which both affect flows between New Jersey and upstate NY;
    - – Farragut and Linden PARs, which affect flows between New Jersey and NYC;
    - – Other PARs.

## Balancing Congestion Revenue Shortfalls – Circuitous Transaction Scheduling

- Circuitous transaction scheduling around Lake Erie increased clockwise loop flows around Lake Erie. The loop flows had substantial direct and indirect effects on operations that increased balancing congestion revenue shortfalls.
  - ✓ Most directly, differences between day-ahead assumptions and real-time operations related to the amount of loop flows around Lake Erie directly led to a shortfall of $29 million.
- Large differences between scheduled real-time transactions and actual real-time flows between NYISO and PJM led to material differences between day-ahead assumptions and real-time operations regarding the Branchburg-Ramapo PARs.
  - ✓ Hence, a large portion of the $44 million shortfall associated with the Branchburg-Ramapo PARs resulted indirectly from the circuitous transactions.
- Congestion from west-to-east across the Dysinger-East, West-Central, and Central-East interfaces substantially increased due to the Lake Erie loop flows and the real-time operation of the Branchburg-Ramapo PARs.
  - ✓ Hence, a large portion of the $39 million shortfall associated with these interfaces resulted indirectly from circuitous transaction scheduling.





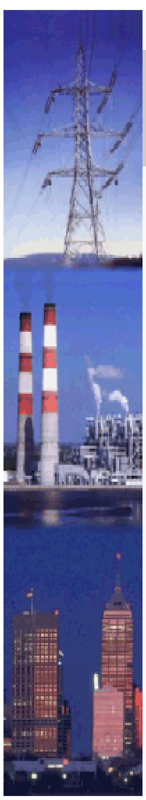
## Balancing Congestion Revenue Shortfalls – Circuitous Transaction Scheduling

- In late May 2008, the NYISO implemented a more timely update of the Lake Erie loop flow assumption used in the day-ahead.
  - ✓ Although this did not eliminate the loop flows around Lake Erie, it helped reduce shortfalls related to the factors listed above.
- In late July 2008, the NYISO precluded the circuitous transactions, which reduced Lake Erie loop flows and associated shortfalls, particularly those related to the Branchburg-Ramapo PAR flows.
- Additional shortfalls can occur when the external interface flows are limited in real-time below the day-ahead scheduled level. Such constraints became more frequent during the period of increased loop flows around Lake Erie as a result of TLR events that were called by PJM and IESO.
  - ✓ During TLR events, the primary PJM interface and the Ontario interface accounted for over 90 percent of this category of shortfalls.
  - ✓ Hence, a large portion of the $48 million shortfall associated with the external interfaces resulted indirectly from circuitous transaction scheduling.
  - ✓ The NYISO implemented improved operating procedures that helped reduce shortfalls related to the PJM and Ontario interfaces when neighboring control areas declare TLRs.

## Balancing Congestion Revenue Shortfalls – Other Factors

- TSAs require double contingency protection of the Leeds-to-Pleasant Valley line, effectively reducing the transfer capability of the system from the day-ahead to the real-time.
  - ✓ The associated shortfall of $53 million occurred primarily during the summer months when TSAs are most frequent.
- Simplified interface constraints were frequently used to manage congestion into New York City load pockets in 2008. Using interface constraints in the real-time market (rather than the detailed modeling used in the day-ahead market) results in less transfer capability in New York City in the real-time market.
  - ✓ Most of the associated shortfall of $67 million was related to congestion across the Astoria East and Greenwood/Staten Island interface constraints.
- Incorrect inputs were used in the day-ahead market to represent the expected flows across the Waldwick PARs for 12 days in January, leading the day-ahead market to over-schedule flows across the Central-East interface.
  - ✓ Approximately 55 percent of the $19 million shortfall associated with the Waldwick PARs is attributable to this issue.

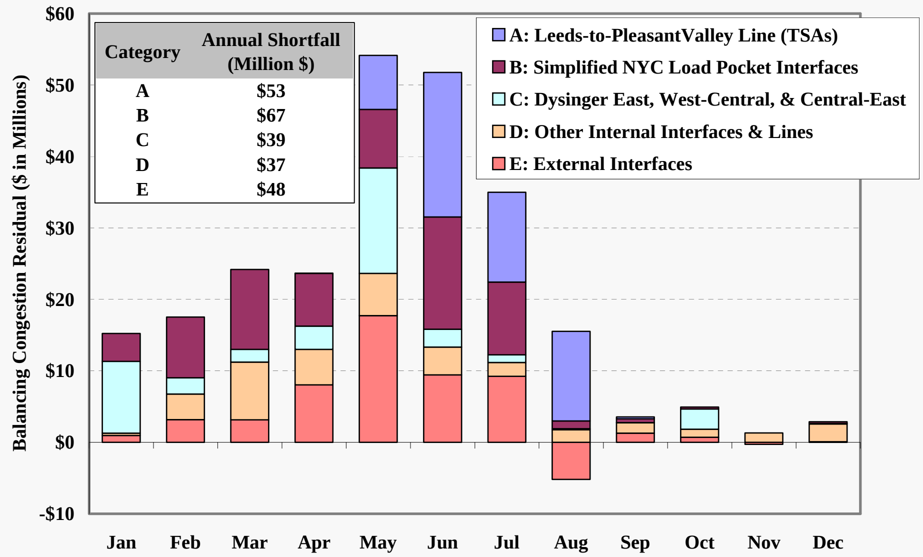




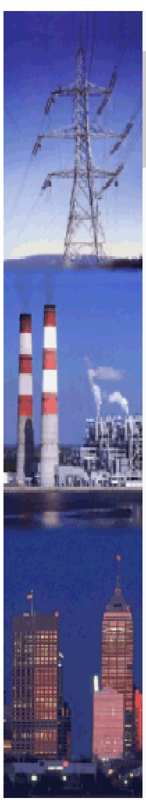
## Balancing Congestion Revenue Shortfalls – Other Factors

- The Waldwick, Farragut, and Linden PARs are set to support the wheel of up to 1 GW of power from upstate New York through New Jersey to New York City.
  - ✓ The amount of flow in real-time may be reduced under certain circumstances, although the NYISO normally expects 1 GW will flow in the day-ahead market.
  - ✓ Hence, curtailments of the wheel in RT leads to balancing congestion shortfalls.
- The following two figures shows the balancing congestion shortfalls that are caused by the various factors discussed above.
- The actual balancing congestion shortfalls were $30 million higher than those shown in the because they exclude effects the following items (some of which generated balancing congestion surpluses in 2008):
  - ✓ Differences between the generators’ basepoints (used in this analysis) and their actual output levels (that determine financial settlements) during each interval,
  - ✓ Differences between the amount of load scheduled by RTD (used in this analysis) and the amount of actual metered load (which determine financial settlements) during each interval,
  - ✓ Balancing congestion revenue surpluses for certain interfaces that had unused transfer capability in the day-ahead market.

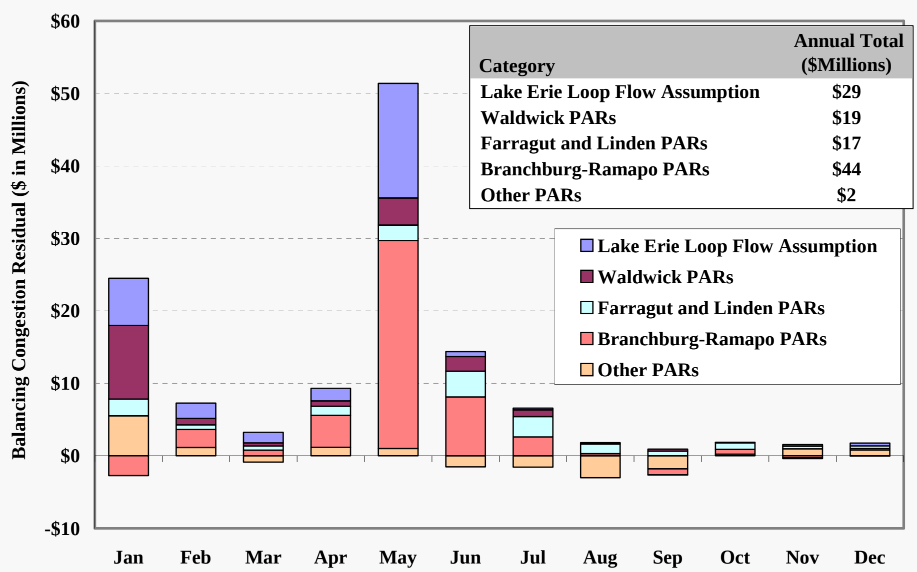
# Balancing Congestion Revenue Shortfall by Category
## Transfer Capability Changes, 2008





# Balancing Congestion Revenue Shortfall by Category
## Other Categories, 2008



## Balancing Congestion Revenue Shortfalls – Conclusions

- All shortfall categories declined significantly in the last five months of 2008.
  - ✓ Shortfalls were reduced by smaller day-ahead to real-time transfer capability differences, lower fuel prices, and less frequent congestion.
  - ✓ The NYISO improved operating procedures that helped reduce balancing congestion shortfalls related to the PJM and Ontario interfaces when neighboring control areas declare TLRs.
  - ✓ In May 2008, the NYISO began making more timely updates of the day-ahead loop flow assumptions, which reduced the shortfalls resulting from the loop flows.
  - ✓ In July 2008, the NYISO precluded the scheduling of circuitous transactions, which eliminated the shortfalls resulting from the high volume of loop flows.
- Balancing congestion shortfalls result when external interface capability is reduced in real-time below the day-ahead scheduled level.
  - ✓ In such hours, the resulting shortfalls are increased when the proxy bus LBMP is set by a negative offer price (e.g. the offer price limit is -$999.70/MWh). The benefits of allowing participants to submit extremely low offer prices are limited.
  - ✓ Hence, we recommend that the current offer limit for real-time import transactions be adjusted from -$999.70/MWh a level more consistent with the avoided costs of curtailing the import. This should also improve the performance of the market during over-generation conditions.



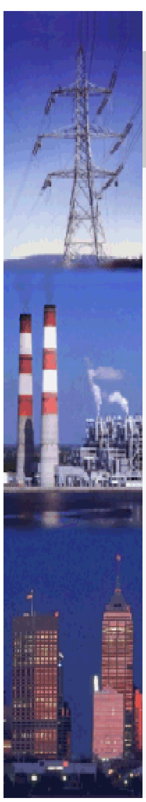
## Market Operations – Real Time Commitment and Scheduling

POTOMAC ECONOMICS

## Market Operations – Real-Time Commitment

- The Real-Time Commitment model (“RTC”) commits generators with short lead times such as GTs and schedules external transactions.
  - ✓ It re-evaluates just ahead of the real-time market every 15 minutes, which is a significant improvement over its predecessor, the BME model.
- Convergence between RTC and actual real-time dispatch is important because a lack of convergence can result in:
  - ✓ Uneconomic commitment of generation, primarily GTs; 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

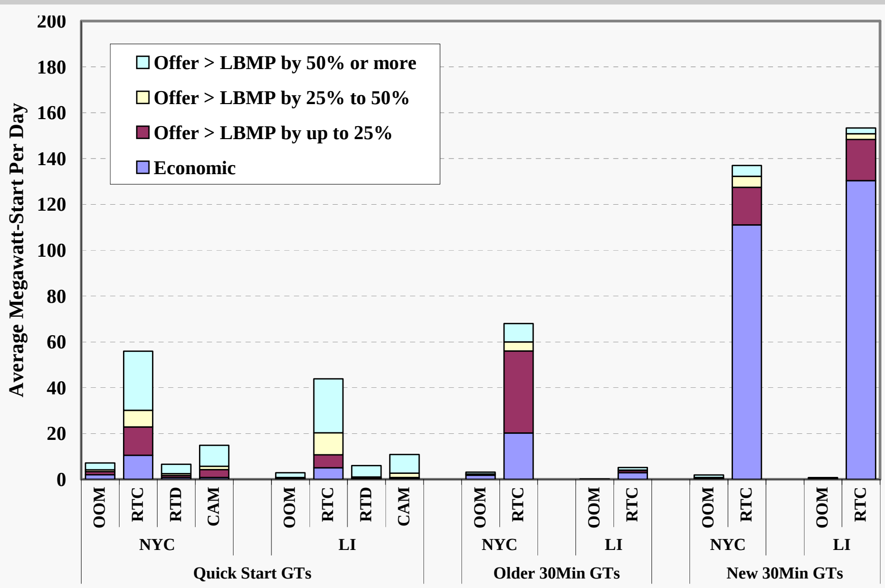
- The next figure measures the efficiency of GT commitment by comparing the offer price to the real-time LBMP.  The figure shows the average volume of GTs started whose energy plus start-up costs (amortized over the commitment period) are:
  - (a) < LBMP (clearly economic);
  - (b) > LBMP by up to 25 percent;
  - (c) > LBMP by 25 to 50 percent; or
  - (d) > LBMP by more than 50 percent.
- Starts are shown separately for quick start GTs, older 30-minute GTs, and new 30-minute GTs; whether they occurred in NYC or Long Island; and whether they were started by RTC, RTD, RTD-CAM, or by an OOM instruction.
- Some GTs with offers greater than the LBMP are also economic.
  - ✓ GTs that are started efficiently and set the LBMP at their location do not earn additional revenues needed to recover their start-up offer.
  - ✓ GTs that are started efficiently to address a transient shortage (e.g. transmission constraint violation) may lower LBMPs substantially, and as a consequence, appear uneconomic over the commitment period.

# Efficiency of Gas Turbine Commitment

- Although new 30-minute GTs account for just 28 percent of the GT capacity in New York, they account for approximately 57 percent of the GT capacity started in 2008.
  - ✓ Newer GTs (those installed since 2000) run more frequently since they are far more fuel efficient than older GTs.
- One factor that tends to reduce the efficiency of GT commitment is the use of simplified interface constraints in NYC load pockets rather than the more detailed model of transmission capability.
  - ✓ To commit GTs efficiently, RTD and RTC must forecast congestion patterns in future intervals. The detailed model allows them to forecast congestion more accurately.
  - ✓ In 2008, 64 percent of the binding constraints in NYC were simplified interface constraints rather than detailed model constraints.
- The volume of starts shown in the figure is significantly lower than in the 2007 report which inadvertently included self scheduled GTs.



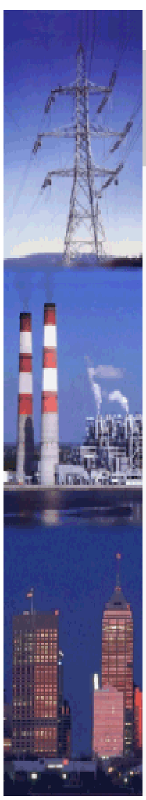
# Efficiency of Gas Turbine Commitment
# 2008



## Efficiency of External Transaction Scheduling

- The following figure summarizes the efficiency of external transaction scheduling by RTC across the primary interface between New York and New England from 2005 to 2008.
  - ✓ It includes transactions that are price-sensitive in real-time (specifically, it excludes transactions with DAM priority, exports bid above $300/MWh, and imports offered above $300/MWh).
- Transactions are shown according to whether they were:
  - ✓ *Scheduled* or *not scheduled*
  - ✓ *Consistent* or *not consistent* – consistent refers to whether the transaction was scheduled in accordance with real-time prices
    - – For example, if an export is scheduled but the bid is less than the real-time price, it would be considered "not consistent" since exports are scheduled when the bid is greater than or equal to the RTC price.
  - ✓ *Profitable* or *not profitable* – profitable refers to whether the transaction would be profitable if scheduled based on the real-time proxy bus prices on either side of the border.
    - – Transactions that RTC schedules consistent with real-time prices are not always profitable.

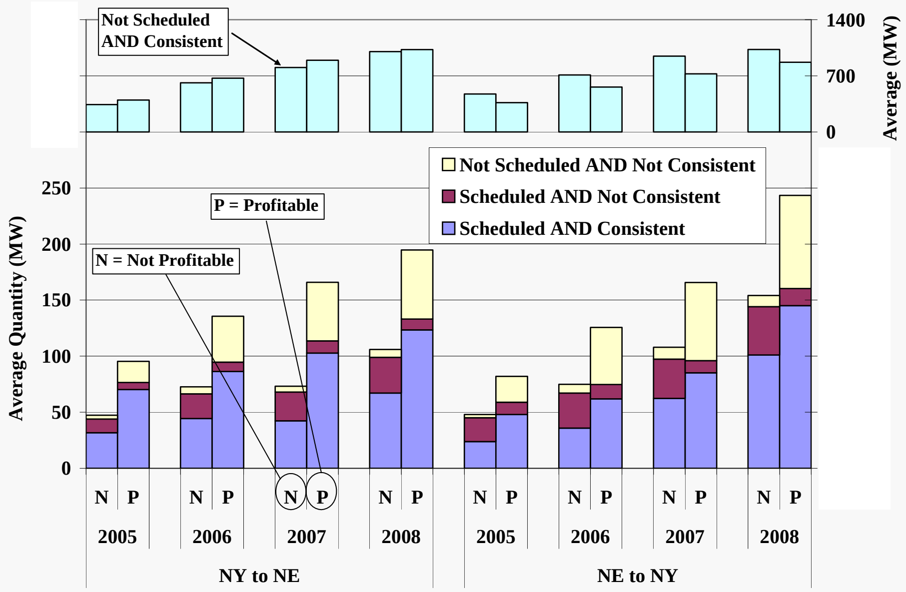




## Efficiency of External Transaction Scheduling

- The volume of price-sensitive offers to transact over the primary interface between NY and New England increased 150 percent from 2005 to 2008.
  - ✓ Just 12 percent of price-sensitive offers were scheduled in 2008.
- The share of offers that were "consistent" has not changed much since 2005.
  - ✓ 81 percent of scheduled offers were "consistent" in 2008.
  - ✓ 96 percent of offers not scheduled were "consistent" in 2008.
- The figure shows that "consistent" scheduling is not the same as efficient scheduling.
  - ✓ *Scheduled and consistent* – 61 percent of these transactions were profitable (i.e., efficient) in 2008.
  - ✓ *Scheduled and not consistent* – 25 percent of these transactions were still profitable (i.e., efficient) in 2008.
  - ✓ *Not scheduled and not consistent* – 90 percent of these transactions would have been profitable if scheduled (i.e., 10% of these outcomes were efficient) in 2008.
- The efficiency of transaction scheduling depends on both the consistency of RTC with RTD and the predictability (to market participants) of real-time price differences between New York and adjacent markets.

# Efficiency of External Transaction Scheduling
# Primary Interface with New England, 2005 – 2008






# Efficiency of External Transaction Scheduling – Conclusions

- The volume of price-sensitive transaction bidding in the real-time market at the primary interface with New England grew significantly from 2005 to 2008, suggesting that market participants have increasingly relied on RTC to determine when it will be economic to schedule between adjacent control areas.
- The efficiency of transaction scheduling depends on both the consistency of RTC with RTD and the predictability of real-time price differences between New York and adjacent markets.
- Hence, there are several potential ways to improve the efficiency of external transaction scheduling. These include:
  - ✓ Improving the assumptions used in RTC to be more consistent with RTD.
  - ✓ Reducing unnecessary volatility in RTD prices. RTD price volatility (which is evaluated later in this section) reduces the efficiency of external transaction scheduling by RTC, while inefficient transaction scheduling may, in turn, contribute to RTD price volatility.
  - ✓ Increasing the predictability of prices in New York and adjacent control areas. One way to do this is to reduce the lead time for scheduling external transactions.

## Comparison of RTC and RTD Inputs

- The following analysis evaluates the consistency of 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 analysis compares RTC prices with the RTD 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. However, there are periods when RTC prices are consistently higher or lower than RTD prices.
- Inconsistent RTC and RTD prices are a concern because they can lead to uneconomic commitment of generation and inefficient scheduling of external transactions.
  - ✓ Excess commitment and scheduling results in increased uplift costs and depressed real-time prices;
  - ✓ Failing to commit economic resources leads to unnecessary transient price spikes.



## Comparison of RTC and RTD Inputs

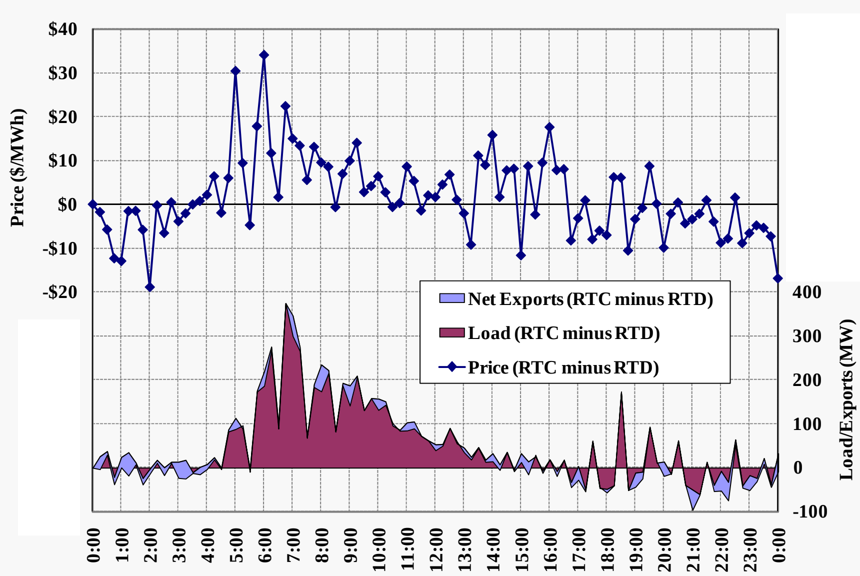
- The following figure shows the differences between RTC and RTD in scheduled loads, net scheduled exports, and prices at 15-minute intervals during the day in the Summer.
- Scheduled loads and net exports are inputs that jointly determine the quantity of internal resources that must be scheduled by RTC and RTD.
  - ✓ 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+5 minutes*, and *t+10 minutes*.
  - ✓ As a result, RTC load is approximately ten minutes ahead of the load forecast during the morning ramp period.

## Comparison of RTC and RTD Inputs

- The figure indicates that the assumptions that RTC and RTD use about net exports are relatively consistent.
  - ✓ This suggests that the assumptions related to net exports are not a significant source of inconsistency between RTC and RTD prices.
  - ✓ In January 2008, the assumptions used by RTC relating to net exports were revised to make them more consistent with RTD. This has likely contributed to improved convergence between RTC and RTD.
- The analysis suggests that differences between RTC load and RTD load contribute to average RTC prices being higher than average RTD prices during the morning ramp hours.
  - ✓ Predictable differences can lead to uneconomic commitments or uneconomic scheduling of external transactions.
  - ✓ However, RTC is responsible for committing sufficient resources to satisfy demand in throughout each 15 minute period. Any changes to eliminate predictable differences between RTC load and RTD load must still allow RTC to ensure sufficient resources are be available.



## Consistency of Prices, Load, and Net Exports in RTC and RTD by Time of Day, Summer 2008



# Market Operations – Real-Time Price Volatility



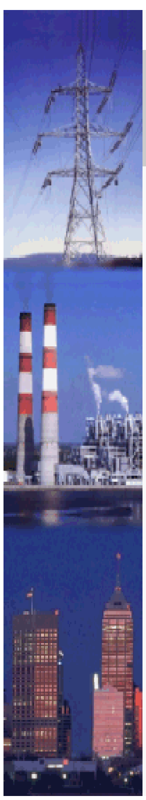
## Real-Time Price Volatility

- The NYISO runs a real-time power auction usually every five minutes, resulting in a new set of LBMPs every five minutes.
- Changes in LBMPs from one interval to the next depend on how flexible generators (i.e., generators that can be dispatched by RTD according to their offer) respond to fluctuations in the following factors:
  - ✓ Electricity demand;
  - ✓ Net export schedules (which are determined prior to RTD); and
  - ✓ Generation schedules of self scheduled and other non-flexible generation.
- Generally, LBMPs increase as a result of increased load, increased net exports, or decreased non-flexible generation.
  - ✓ Hence, large changes in the LBMP from one interval to the next are an indication of substantial fluctuations in at least one of these factors.
- The two figures in this section evaluate factors that contributed to price volatility in real-time in the summer of 2008.

# Real-Time Price Volatility

- The first figure shows the average prices in each five minute interval of the day in the summer of 2008.
  - ✓ The figure shows the loaded-weighted average price for New York state.
- The second figure shows how the following categories of inflexible supply change from one interval to the next on average:
  - ✓ Net Imports – Net imports ramp at a constant rate from five minutes prior to the top of the hour (:55) to five minutes after the top of the hour (:05).
  - ✓ Switches Between Pumping and Generating – This is when pump storage units switch between consuming electricity and producing electricity.
  - ✓ Fixed Schedule Changes for Online STs – Many generators are not dispatchable by the ISO and produce according to their fixed generation schedule.
  - ✓ Start-up and shutdown of Self Scheduled GTs – These GTs are not dispatchable by the ISO, starting-up and shutting-down according to their fixed schedule.
  - ✓ Start-up and shutdown of STs – These non-GTs are not dispatchable during their start-up and shut-down phases of operation.

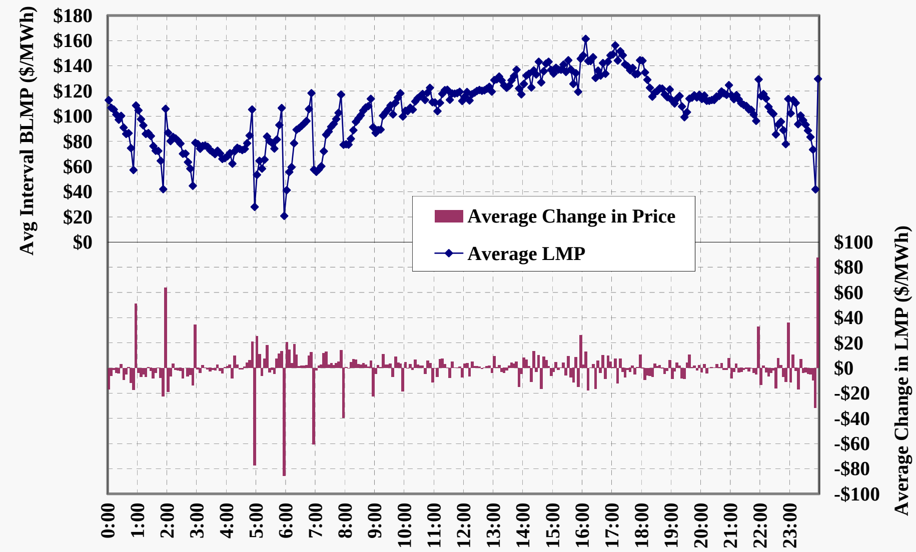




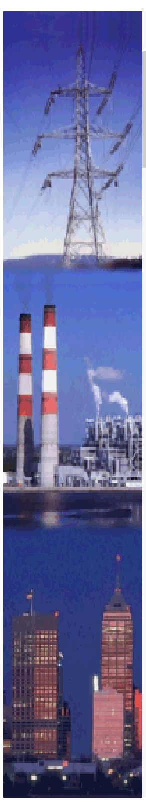
# Real-Time Price Volatility

- The first figure shows that prices are generally more volatile at the top of the hour during ramp up and ramp down hours.
  - ✓ The upward and downward price spikes in these hours reflect relatively frequent ramp rate constraints.
  - ✓ In the last interval of the hour, clearing prices drop substantially in ramp-up hours, and clearing prices rise substantially in ramp-down hours.
  - ✓ In the first interval of the ramp-up and ramp-down hours, the clearing prices swing in the opposite direction.
- The second figure shows the average net changes for five categories of inflexible supply.
  - ✓ Adjustments in net imports, pumped storage units switching between pumping and generating, and adjustments in fixed generation schedules account for the most significant changes from hour-to-hour.
  - ✓ For example, from 5:55 am to 6:00 am, the average net increase in inflexible supply from imports, pumped storage units, and fixed scheduled units was 357 MW, coinciding with an $86/MWh decrease in real-time LBMP.

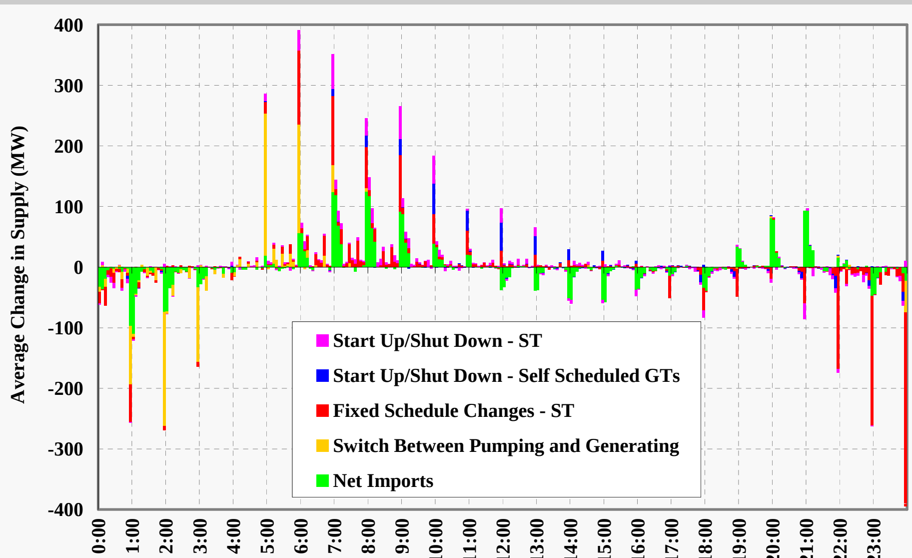
## Five Minute Pricing by Time of Day
### Load-Weighted System Average LBMP, June to August 2008





## Factors Contributing to Real-Time Price Volatility
### June to August 2008



## Real-Time Price Volatility – Conclusions

- The figure indicates that high price volatility during the morning and evening ramp periods is likely exacerbated by large changes in inflexible supply around the top of each hour.
- If inflexible supply changes were distributed more evenly throughout the hours, it is likely that price volatility would be diminished.
- Market participants who change their fixed schedules or switch from pumping to generating at the top of the hour would benefit from making such changes mid-hour.
  - ✓ For instance, units starting at 6:00 am sold their output at prices between $20/MWh and $60/MWh in the first 15 minutes of operation.
  - ✓ For many units, it would have been more profitable to wait until 6:15 am to start or increase output.
- We recommend the ISO perform an evaluation of factors that contribute to real-time price volatility, and determine whether it can be reduced by modifying the real-time scheduling software or by other improvements.



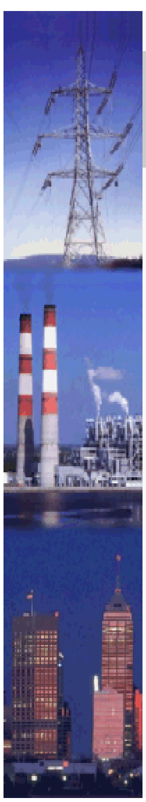
## Market Operations – Pricing and Shortage Conditions

POTOMAC ECONOMICS

## Reserve Shortages and Shortage Pricing

- RTD co-optimizes procurement of energy and ancillary services. This is beneficial in several ways:
  - ✓ 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.
  - ✓ 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 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 requirement to meet during high demand conditions.





## Reserve Shortages and Shortage Pricing

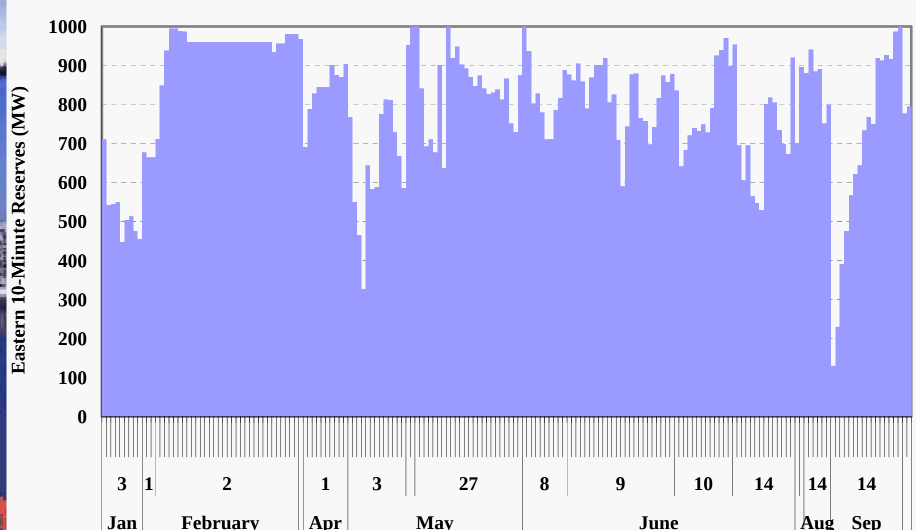
- Co-optimization of energy and reserves is integrated with the Hybrid Pricing approach in the market software. The Hybrid Pricing approach allows GTs to set clearing prices.
  - ✓ The inflexibility of GTs creates challenges for pricing energy efficiently when the GTs are the marginal source of supply.
  - ✓ 28 percent of dispatchable capacity in New York City and 42 percent of the dispatchable capacity in the 138kV load pocket are GTs.
  - ✓ Thus, Hybrid-Pricing is a particularly important element of setting efficient prices in NYC.
- Hybrid Pricing treats GTs as flexible resources for pricing purposes. This results in inconsistencies between the pricing dispatch and the physical dispatch. However, these inconsistencies should be limited such that:
  - ✓ Under physical shortage conditions, prices reflect scarcity; and
  - ✓ Shortage 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 2008.
- Based on the amount of physically available 10-minute reserves, Eastern NY was in a physical shortage in 97 percent of these intervals.
  - ✓ The pricing and physical dispatch passes of RTD have been very consistent during periods when shortage pricing was invoked.
  - ✓ Hence, shortage pricing in Eastern NY has occurred during true shortages.
- Milder load conditions in 2008 contributed to a reduction in the number of shortage pricing intervals.
  - ✓ Overall, the frequency of shortage pricing declined from 219 intervals in 2007 to 181 intervals in 2008.
  - ✓ However, during the summer months, the frequency increased from 63 intervals in 2007 to 69 intervals in 2008.



# Scheduling of 10-Minute Reserves in the East During Shortage Pricing Intervals, 2008

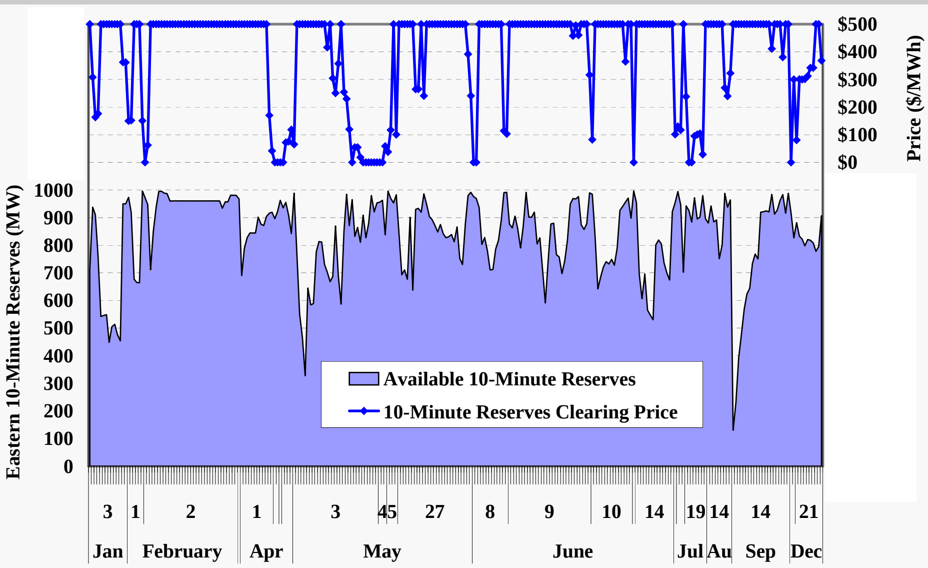


# Reserve Shortages and Shortage Pricing

- The following figure shows the price and quantity of available Eastern 10-minute reserves during physical shortages of Eastern 10-minute reserves.
- 32 percent of the 266 intervals with physical shortages of Eastern 10-minute reserves did not exhibit shortage pricing in 2008.
  - ✓ The Eastern 10-minute reserve price averaged $164/MWh in these intervals.
  - ✓ The shortage was less than 100 MW in 70 percent of these intervals.
- In 2008, the consistency between the pricing dispatch and the physical dispatch passes of RTD during eastern 10-minute reserve shortage periods declined slightly from 2007.
  - ✓ In 2007, 28 percent of intervals with physical reserve shortages had no Eastern 10-minute reserves shortage pricing.
- A significant number of intervals remain when the physical dispatch pass perceives a shortage of reserves while the pricing dispatch pass does not. The following section discusses factors that contribute to these instances.



# Scheduling and Pricing of 10-Minute Reserves in the East During Physical Shortage Intervals, 2008

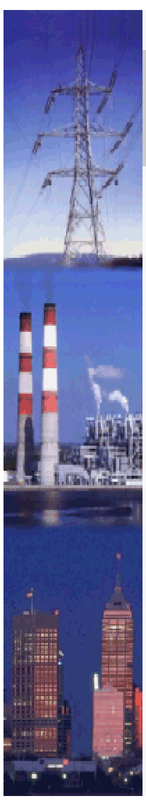



Note: In cases where the East 10-Minute Non-Spin price exceeds $500/MWh, the figure shows $500/MWh.

# Hybrid Pricing

- Hybrid Pricing consists of a Physical Dispatch, which governs the deployment of resources, and a Pricing Dispatch, which determines the prices of energy and ancillary services.
  - ✓ This approach enables the real-time software to calculate efficient prices, especially in areas that are primarily served by GTs.
- The Hybrid Pricing approach works by allowing 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 GTs, but only when they are not economically in-merit, which is generally not the case during reserve shortages.
- However, differences between the Pricing Dispatch and Physical Dispatch can also arise when resources do not follow dispatch instructions. This is discussed on the following slide.





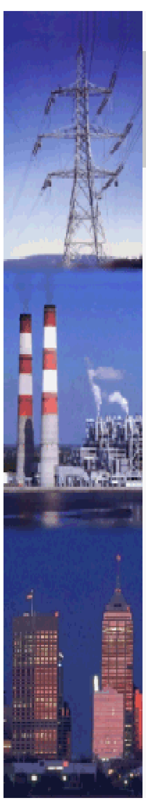
# Hybrid Pricing

- In RTD, physical dispatch instructions are “ramp-constrained” by the expected physical output of the unit plus or minus what can be ramped in one interval. 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.
- In RTC, the Pricing Dispatch, which determines the commitment of 30-minute GTs, is ramp-constrained in the same manner as the Pricing Dispatch of RTD.
  - ✓ Hence, when units persistently under-produce, RTC may not anticipate a physical shortage.
  - ✓ As a result, RTC may under-commit 30-minute GTs.
  - ✓ In many cases, a physical shortage could be prevented by the economic commitment of 30-minute GTs.

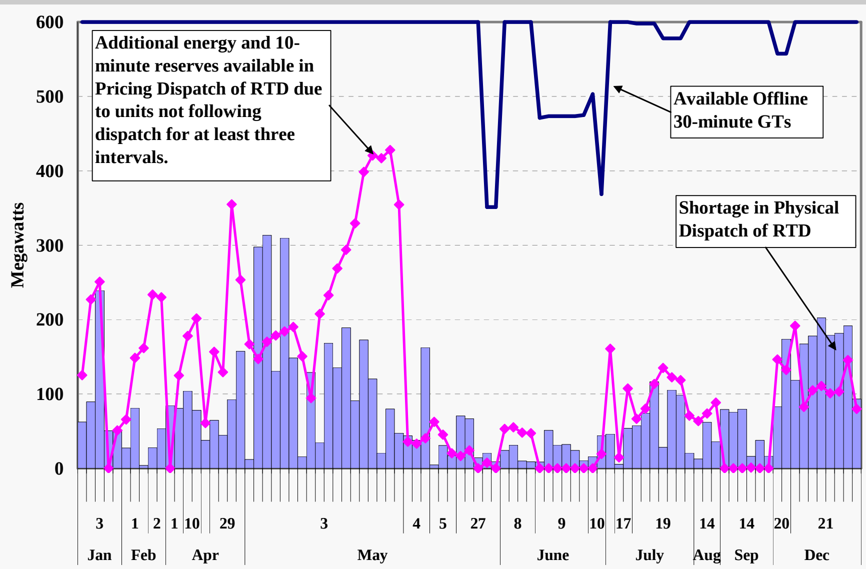
# Hybrid Pricing

- The following figure summarizes the potential effect of units persistently not following dispatch instructions on Eastern 10-minute reserves prices during the intervals when there was a physical shortage and no shortage pricing.
  - ✓ The bars indicate the shortage quantity in the Physical Dispatch of RTD.
  - ✓ The pink line indicates the additional energy and 10-minute reserves available in the Pricing Dispatch due to inconsistencies in the treatment of units not following dispatch instructions.
  - ✓ The blue line indicates the amount of offline 30-minute GT capacity, which would have been able to come online if a shortage had been anticipated by RTC.
- In 58 percent of these intervals, the additional supply available to the Pricing Dispatch was greater than the physical shortage quantity.
- Hence, the inconsistent treatment of units not following dispatch instructions may explain the majority of the instances when the Physical Dispatch perceived a shortage of reserves while the Pricing Dispatch pass did not.
  - ✓ However, if units not following dispatch instructions were treated consistently, some or all of these physical shortages would not have occurred due to the availability of offline 30-minute GT capacity.





# Impact of Units Not Following Dispatch Instructions
## Shortage Intervals without Shortage Pricing, 2008




Note: In cases where the amount of available offline 30-minute GTs exceeds 600 MW, the figure shows 600 MW.

## Hybrid Pricing – Conclusions

- Some differences between the Pricing Dispatch and the Physical Dispatch are necessary for Hybrid Pricing. However, unnecessary differences will generally lead to inaccurate prices and increased uplift.
- Improvements to the consistency of the Pricing Dispatch and the Physical Dispatch of RTD and RTC should lead to:
  - ✓ More efficient pricing of energy and ancillary services (particularly during shortages), thereby reducing uplift; and
  - ✓ Fewer physical shortages because RTC will be more likely to start 30-minute GTs in anticipation of a shortage.
- In March 2009, NYISO made enhancements to reduce divergences between the Physical Dispatch and Pricing Dispatch that are caused by units not following dispatch instructions by re-calibrating the ramp limits for such units.
  - ✓ These enhancements are known as "Real-Time Scheduling & Performance Phase 2".
  - ✓ We plan to evaluate whether these enhancements lead to greater consistency between the occurrence of reserve shortages in the Physical Dispatch and shortage pricing.



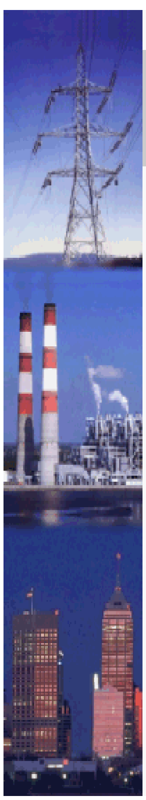
# Market Operations – Uplift and Supplemental Commitment

POTOMAC ECONOMICS

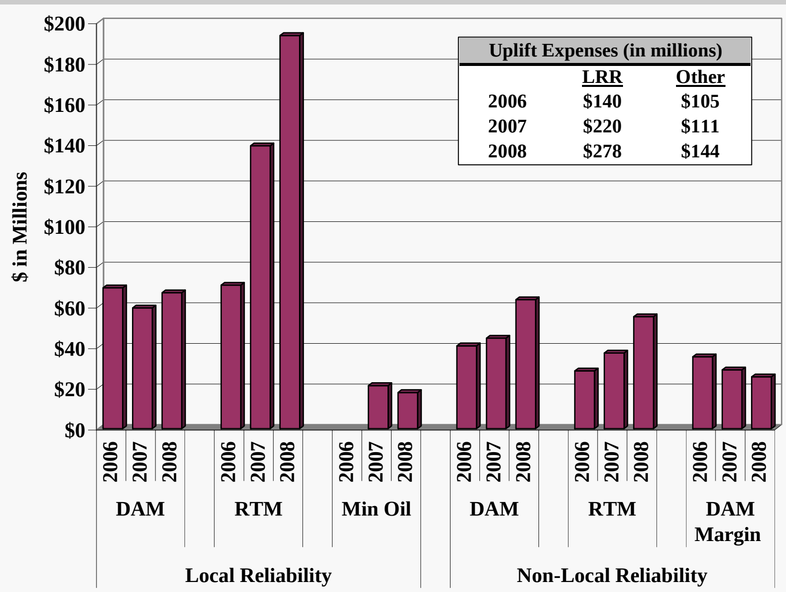
## Uplift Expenses from Guarantee Payments

- The next figure shows uplift costs associated with guarantee payments over the past three years.
- From 2007 to 2008, total uplift rose from $331 million to $422 million, primarily due to increases in fuel prices that affect all categories of guarantee payments.
- From 2006 to 2007, total uplift rose due to an increase in local reliability uplift of $80 million.
  - ✓ $20 million of the increase in 2007 is associated with commitments needed to satisfy minimum oil burn requirements.
  - ✓ The remaining increase is associated with a 75 percent increase in the Supplemental Resource Evaluation ("SRE") commitment from 2006 to 2007.
    - – SREs occur after the day-ahead market to satisfy local reliability requirements.
    - – These SREs are called by the local TO.
    - – The increase in SREs is partly associated with reduced economic commitments of oil-fired generation that are needed for local reliability.





## Uplift Expenses from Guarantee Payments 2006 to 2008

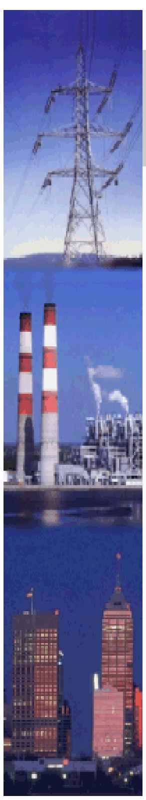



| Uplift Expenses (in millions) | | |
|---|---|---|
| | LRR | Other |
| 2006 | $140 | $105 |
| 2007 | $220 | $111 |
| 2008 | $278 | $144 |

## Supplemental Commitment

- This section evaluates supplemental commitments during 2008.
- 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.
    - – Uplift generated from these units makes up the entirety of day-ahead local reliability uplift.
  - ✓ The Supplemental Resource Evaluation ("SRE") process is used to commit generators after the day-ahead market.
    - – Uplift generated from these units makes up nearly all of the real-time local reliability uplift.

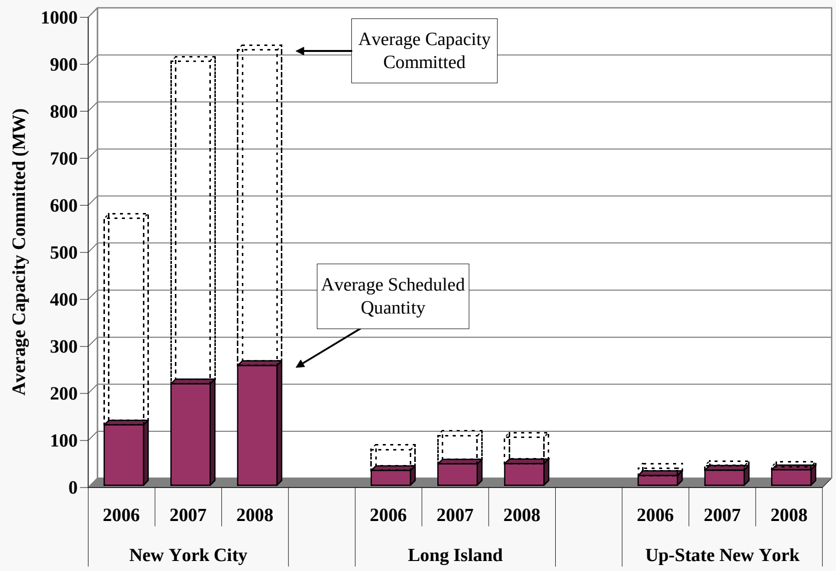




## Supplemental Resource Evaluation

- 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 by reducing LBMPs.
  - ✓ 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 the SRE process in New York City increased by approximately 75 percent in 2007.
  - ✓ The increased need for SREs was partly due to reduced economic commitment of oil-fired generators that are needed for local reliability.
- The average quantity of capacity committed through the SRE process did not change significantly in 2008.
- The market impact of SRE commitments is primarily related to the amount of energy they produce, which averaged 300 MW in 2008. These units also provide large amounts of 10-minute spinning and 30-minute reserves.

## Supplemental Resource Evaluation Commitment 2006 – 2008

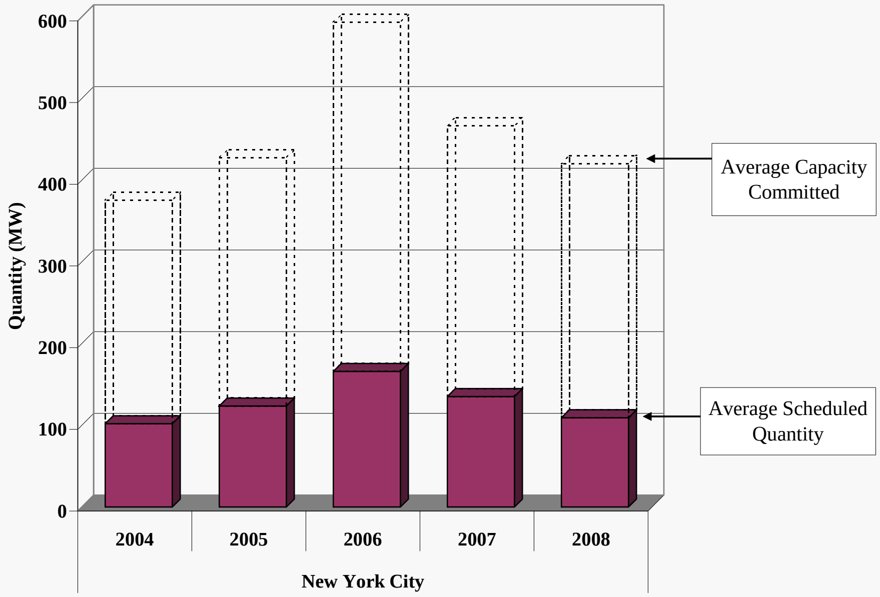




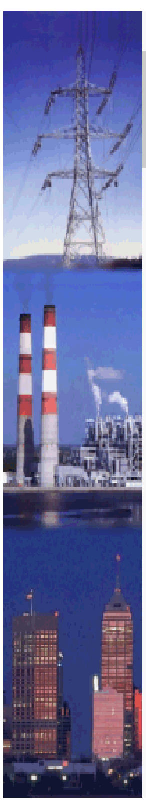

## Day-Ahead Local Reliability Commitment

- The next analysis focuses on commitments made in the day-ahead market (i.e., by SCUC) to meet local reliability requirements.
- These commitments are generally not economic at day-ahead market prices. They affect the market because they:
  - ✓ 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, which increased from 2004 to 2006 and declined in 2006 to 2008.
  - ✓ The market impact of such commitments is primarily determined by the amount of energy they are scheduled to provide, which averaged 100 MW in 2008.

## SCUC Local Reliability Pass Commitment 2004 – 2008





## Supplemental Commitment – Conclusions

- The average amount of capacity committed for local reliability in NYC exceeded 1,300 MW in 2008, but only 350 MW was scheduled for energy.
- Supplemental commitments have significant market effects:
  - ✓ Inefficiently reducing LBMPs in the day-ahead and real-time markets;
  - ✓ When they occur in a constrained area, they inefficiently dampen the apparent congestion into the area; and
  - ✓ Increasing uplift on units committed economically, which are less likely to recover their full offer production costs;
- In February 2009, the NYISO implemented a new process for committing units for local reliability which should substantially reduce the market effects of maintaining local reliability.
  - ✓ SRE and other local reliability requirements have been integrated in the economic pass of the day-ahead market model, thereby improving the efficiency of the economic commitments and reliability commitments.

# Capacity Market

## Capacity Market – Background

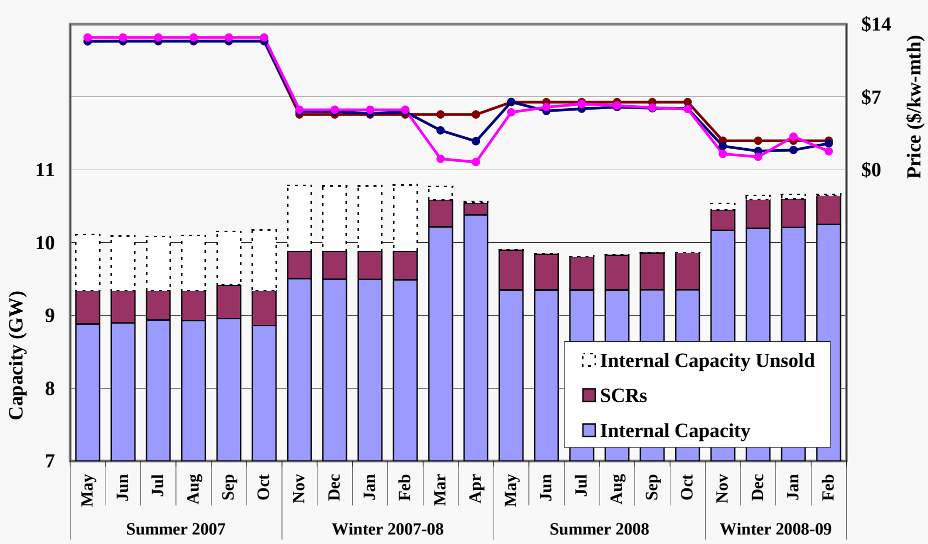
- The capacity market complements the energy and ancillary services markets in providing efficient economic signals for investment and retirement decisions.
- LSEs have several ways to satisfy their capacity obligations. They can:
  - ✓ "Self-schedule" their own generating capacity;
  - ✓ Purchase capacity through bilateral contracts; or
  - ✓ Participate in voluntary ICAP market auctions run by the NYISO.
- Additional capacity is purchased in the monthly UCAP Spot Auction on behalf of LSEs that have remaining obligations.
  - ✓ LSEs that have purchased more than their obligation prior to the Spot Auction, may sell the excess in the Spot Auction.
- To enhance the competitiveness of the capacity markets, a demand curve is used in the monthly UCAP Spot Auction.
  - ✓ Each LSE's capacity obligation is determined by the intersection of supply in the Spot 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, the amounts scheduled, and the UCAP prices in the NYISO auctions for NYC.
- The most significant changes in clearing prices result from the variations in the quantity of capacity supply.
  - ✓ Additional capability is available in the winter capability periods that generally results in lower prices in these months.
  - ✓ Prior reports had identified economic withholding of capacity in NYC that was addressed with new mitigation measures implemented in the 2008.
    - – In March 2008, the amount of unsold capacity was virtually eliminated, which contributed to a substantial decrease in capacity prices.
- SCR sales have increased since 2001, but SCR sales in NYC dipped to 160 MW in April 2008 as the NYC capacity price dropped to $0.7/kW-month.
- Total UCAP available declined from summer 2007 and winter 2007-2008 to summer 2008 and winter 2008-2009 primarily due to an increase in the forced outage rate of one participant.



# UCAP Sales and Prices in New York City
## May 2007 to February 2009

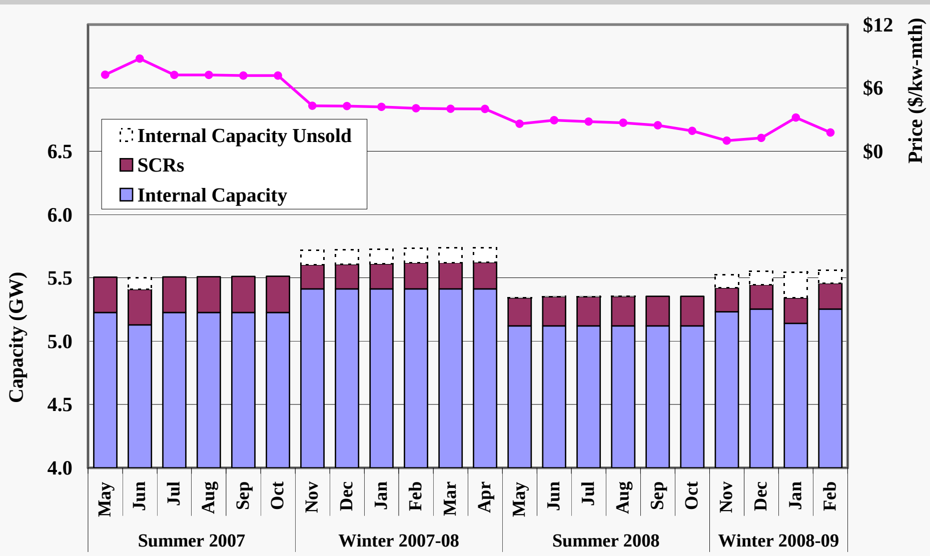


# Capacity Market – Long Island

- The following figure shows the resources available to provide UCAP, the amounts actually scheduled, and the UCAP prices that cleared in the NYISO-run auctions for Long Island.
- The most significant changes in clearing prices result from seasonal variations in the quantity of capacity supply.
- The Local Capacity Requirement ("LCR") in Long Island decreased from 99 percent to 94 percent starting in May 2008 to recognize the reliability benefits from the Neptune HVDC line between eastern PJM and Long Island.
  - ✓ The reduced LCR led to a substantial reduction in the spot clearing price, from \$7.4/kW-month in summer 2007 and \$4.1/kW-month in winter 2007-2008 to \$2.5/kW-month in summer 2008 and \$1.8/kW-month in winter 2008-2009.
- Total UCAP supply in Long Island declined modestly in summer 2008 as a result of a 3 percentage point increase in the average forced outage rate.
  - ✓ Although this reduced UCAP supply, it did not increase the clearing price, because the local installed capacity requirement is also adjusted downward by the forced outage rate to determine the UCAP requirement.



# UCAP Sales and Prices in Long Island
## May 2007 to February 2009



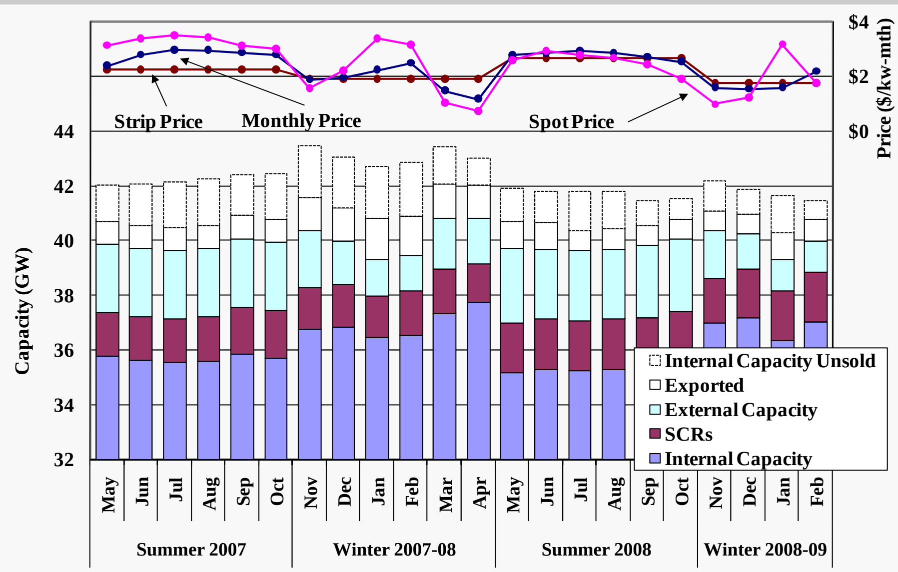

Note: UDRs are included in "Internal Capacity"

# Capacity Market – New York State

- The following figure shows the resources available to provide UCAP to NY State, the amounts actually scheduled, and the prices that cleared for the Rest-Of-State area in the NYISO-run auctions.
- The price for the Rest-Of-State area is affected by sales of capacity in local capacity zones, since capacity sold in local capacity zones also satisfies NY State requirements.
  - ✓ In March 2008, the increased UCAP sales in NYC contributed to the spot price decline from February to March 2008 in Rest-Of-State.
- The Installed Reserve Margin (“IRM”) for NYCA declined from 16.5 percent in the period from May 2007 to April 2008 to 15 percent in the period from May 2008 to April 2009, contributing to lower clearing prices for capacity.
- Most fluctuations in capacity prices in the winter capability periods are related to variations in the quantities of imports and exports.
  - ✓ Net imports ranged from over 1,000 MW in November 2008 to under 200 MW in January 2009, contributing to an increase in spot prices.



# UCAP Sales and Prices in New York State
## May 2007 to February 2009

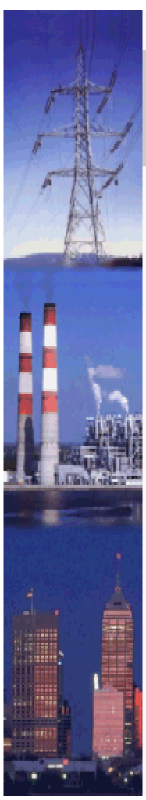



Note: UDRs are included in “Internal Capacity”

## Capacity Market Configuration

- The capacity market provides investment signals to meet planning requirements for New York State. Local capacity prices guide investment to areas where it is most valuable.
  - ✓ The current local capacity regions are: New York City (Zone J), Long Island (Zone K), and Rest-of-State (Zones A to I).
  - ✓ The value of the capacity is reflected in the clearing price of each region.
- Network constraints that limit flows downstate may make capacity more valuable in eastern and downstate areas.
  - ✓ A new "deliverability" test is being implemented that indicates that supplies outside of eastern New York may be deemed undeliverable, including:
    - New resources in western New York; and
    - Imports that have historically supplied the capacity market.
  - ✓ The deliverability test is not designed to represent a realistic case so its results may not be accurate.
  - ✓ The test should be revised over time to correspond to a real potential set of contingencies. This would determine whether incremental capacity can respond to maintain the reliability of the system.



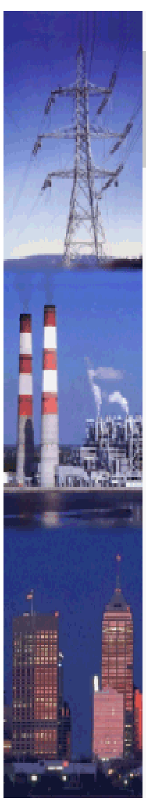


## Capacity Market Configuration

- If the deliverability test determines that new units or imports are not deliverable due to a congested path, the definition of a new capacity zone is likely needed to distinguish between capacity on either side of the path.
- Several problems or inefficiencies occur if a new zone is not created:
  - ✓ The capacity market will not send the signals necessary to build new capacity if it is needed in the congested area. This may be particularly important in Southeast New York because the cost of new entry is higher there than in other areas.
  - ✓ Suppliers up-state and a large share of the potential capacity imports will be foreclosed from the market. This will raise capacity costs for New York consumers and reduce competition.
  - ✓ Suppliers that can provide capacity and reliability benefits to a large portion of the NYCA will not receive any revenue, which results in inefficient investment incentives.
- Given the initial indications that capacity in Zones A to F may not be deliverable to Southeast New York, we recommend the NYISO consider whether one or more new capacity zones are needed in eastern New York.
  - ✓ This would improve investment incentives, reliability in the long-term, and lower costs to New York's consumers.

# Demand Response Programs





## Demand Response Programs – Existing Programs

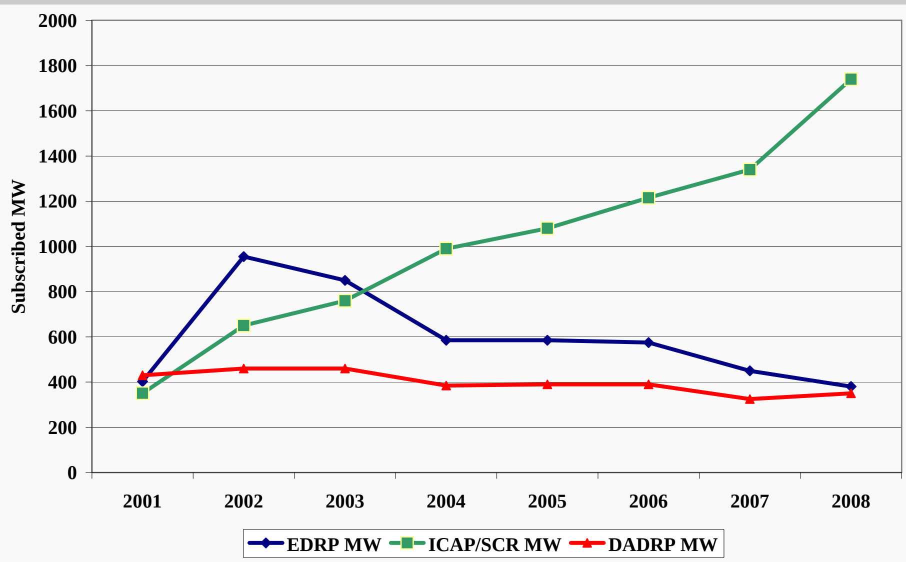
- The NYISO has five programs that allow retail loads to participate in wholesale market operations:
  - ✓ Three programs curtail loads in real-time for reliability reasons:
    - – Emergency Demand Response Program (“EDRP”) resources are paid the higher of $500/MWh or the LBMP when called by the ISO for reliability.
    - – Special Case Resources (“SCRs”) are paid the higher of their strike price (usually $500/MWh) or the LBMP when called by the ISO for reliability.
    - – Targeted Demand Response Program (“TDRP”) deploys EDRP resources and SCRs to curtail when called by the local TO.
  - ✓ Day-Ahead Demand Response Program (“DADRP”) resources offer to curtail in the day-ahead market with a floor price of $75/MWh.
  - ✓ Demand Side Ancillary Services Program (“DSASP”) allows resources to offer regulation and reserves in the day-ahead and real-time markets.
- The cost of EDRP and SCR activation is reflected in clearing prices when it prevents reserve shortages at the state-level or eastern New York.
  - ✓ This mechanism for shortage pricing is one of four approaches suggested in FERC Order 719.

# Demand Response Programs – Existing Programs

- The following figure summarizes the growth in participation in the NYISO's demand response programs from 2001 to 2008.
  - ✓ EDRP resources and SCRs are able to participate in the TDRP program.
- The SCR resources are more valuable than EDRP resources because SCRs are capacity resources that are obligated to curtail when activated.
  - ✓ SCR registration has grown consistently in each year since 2001, providing considerable benefits by reducing the cost of meeting New York's planning reserve margin requirements.
  - ✓ There has been a steady migration of resources from the EDRP program to the SCR program because SCRs receive capacity payments.
- Given the increased reliance on SCRs, it is increasingly important to ensure that the SCRs can perform when called.
  - ✓ The current SCR baseline methodology is based on the monthly peak loads from the prior year. This may allow loads that have shut down their facilities to make sales as SCRs (though they can't respond if called).
  - ✓ We recommend that the NYISO revisit the baseline calculation and testing processes for SCRs to ensure they have the capability to respond when called in real-time.



# Registration in NYISO Demand Response Programs 2001 to 2008

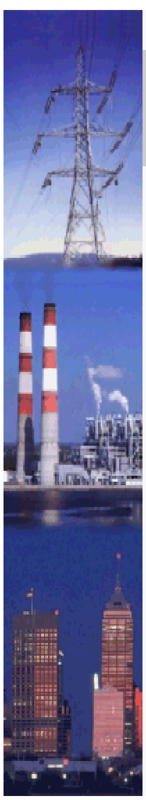



Note: This figure is reproduced from the NYISO's January 15, 2009 Demand Response Compliance Report.

## Demand Response Programs – New Developments

- Demand-Side Ancillary Services Program (“DSASP”) resources – This program, which was introduced in June 2008, allows demand side resources to provide regulation and reserves.
  - ✓ Resources must qualify to provide reserves or regulation or both under the same requirements as generators.
  - ✓ As of January 2009, no resources were qualified as DSASP resources, although several will qualify once the necessary telemetry is installed.
  - ✓ Currently, aggregations of loads are not allowed to participate in this program, but the NYISO plans pilot projects to evaluate their potential.
- Demand Response Information System (“DRIS”) – This IT project will enhance the NYISO’s capability to enable participation by demand resources.
  - ✓ The project will address the following requirements: registration, communication during events, settlements, performance monitoring, meter data management, and other functions that currently require manual effort.
  - ✓ The NYISO plans to deploy some functionality by the end of 2009 and to complete the project in 2010.





## Demand Response Programs – Compliance with Order 719

- FERC Order 719 required ISOs to implement several provisions related to demand resources. The NYISO already satisfies or has made substantial progress toward satisfying the following requirements:
  - ✓ Allowing demand resources to provide ancillary services.
  - ✓ Eliminating deviation charges during system emergencies.
  - ✓ Allowing aggregation of retail customers.
  - ✓ Implementing rules that set efficient prices during reserve shortages.
- The NYISO plans additional work:
  - ✓ Aggregations of retail customers are currently able to participate in the reliability-based programs (EDRP, SCR, TDRP) and the DADRP program. The NYISO is evaluating their potential to provide ancillary services as well.
  - ✓ The DRIS project will enhance the NYISO’s ability to develop additional programs for demand resources to participate in the wholesale market.

# Demand Response Programs – Barriers to Demand Response

- The NYISO is taking steps to enhance opportunities for demand resources to participate in the NYISO energy market.
- However, the most significant barrier to widespread participation is that most retail loads are not exposed to wholesale price fluctuations.
  - ✓ Hence, retail electricity rate reform is one means to give retail loads incentives to be price-responsive.
- If retail rate reform is not anticipated in the short-term, the NYISO should consider developing programs that allow loads to receive payments that would better align their incentives with the needs of the system.
  - ✓ Most retail loads would likely have to participate in the wholesale market through intermediaries (e.g. curtailment service providers).
  - ✓ An efficient payment in such a program is equal to the difference between the wholesale LBMP and the retail customers rate. Paying this amount aligns the loads’ incentives with the value of the energy to the system.
  - ✓ Under such programs, the costs of the payments to responsive retail loads should be allocated to the corresponding load serving entity (who would otherwise receive a windfall when its load curtails when prices are high.
  - ✓ However, such programs would require significant efforts by the ISO to monitor and measure performance of the demand resources.