2010 State of the Market Report
New York ISO Electricity Markets

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April 2011

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Executive Summary: Introduction

- This presentation provides the results of our assessment of the performance of the New York electricity markets in 2010.
- The New York ISO ("NYISO") operates a comprehensive and efficient set of electricity markets, including:
  - ✓ Day-ahead and real-time markets that simultaneously 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.
  - ✓ A market for transmission rights that 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 that starts gas turbines, flexible hydro-electric generators, and some combined cycles and schedules external transactions economically* – most other RTOs rely on their operators to determine when to start gas turbines and other generators with short start-up times.
  - ✓ *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 price signals are efficient during shortages. DR in other RTOs has distorted real-time signals by undermining the shortage pricing.

Executive Summary

Market Performance and Prices

- The energy, capacity, operating reserves, and regulation markets performed competitively in 2010.
  - ✓ Our evaluation of suppliers' conduct in the energy, capacity, and ancillary services markets raised very few competitive concerns.
- Energy prices rose 20 percent in both western and eastern New York from 2009 to 2010. These increases were primarily due to:
  - ✓ Higher fuel prices in 2010 – Natural gas prices rose an average of 11 percent, while residual fuel oil prices rose 30 percent, diesel oil prices rose 29 percent, and eastern coal prices rose 29 percent.
  - ✓ Higher load levels in 2010, particularly during the summer months, due to improved economic conditions and hotter weather.
- Transmission congestion revenue collections increased by 11 percent.
  - ✓ Higher fuel prices and load levels increased congestion into eastern New York.
  - ✓ However, these effects were partly offset by reduced imports to western New York and lower production from hydro and nuclear generation. These factors reduced excess supply in western New York.

Executive Summary

<u>Market Performance and Prices (cont.)</u>

- Convergence between day-ahead and real-time prices is important because the day-ahead market determines which resources are committed each day.
  - ✓ Convergence in the energy markets continues to be good in most areas, although large differences sometimes occur on individual days.
    - – Virtual trading activity helped align day-ahead prices with real-time prices.
    - – Virtual trading is particularly beneficial when modeling and other differences between the day-ahead and real-time markets would otherwise lead to inconsistent prices.
  - ✓ At the nodal level, convergence is not as good in some locations in New York City and Long Island:
    - – We recommend allowing virtual trading (which is currently allowed only at the zone level) at a more disaggregated level to further improve convergence.
  - ✓ Convergence generally improved for operating reserves, although day-ahead prices are still lower than would be expected during peak load periods.
    - – We recommend changes in the mitigation provisions in this report that should improve this convergence.

Executive Summary

Long-Term Economic Signals

- The report shows that prices in 2010 would not support investment in new peaking generation in New York.
  - ✓ This is expected because there is surplus generating capacity in New York.
  - ✓ However, the report shows that prices in 2010 might support investment in new combined cycle generation in New York City.
- Currently, market conditions appear more favorable for investment in combined cycle generation (which has constituted most of the recent entry) than in gas-fired peaking generation.
  - ✓ Hence, the use of a new peaking unit in the demand curve reset process is likely to result in a demand curve that is set higher than the level necessary to satisfy New York state's planning reserve margin criteria.
  - ✓ Therefore, we recommend that the NYISO consider modifying its rules to select the most economic generating technology to establish the demand curves in the next demand curve reset process.

Executive Summary

<u>Market Operations – Price Volatility</u>

- Some price volatility is attributable to large schedule changes that occur at the top-of-the-hour rather than being distributed throughout the hour.
  - ✓ These include: (i) changes in inflexible generation self-schedules; (ii) commitments and decommitments of generation; and (iii) external transaction schedule changes, including TLRs and other curtailments.
  - ✓ Such changes can create either brief shortages or over-generation conditions as the NYISO dispatch rapidly adjusts the output of flexible generation to compensate for these changes.
- Additionally, transient price spikes can arise when transmission constraints emerge due to unforeseen conditions. Contributing factors include:
  - ✓ Large changes in external interchange schedules; and
  - ✓ The assumptions regarding the flows across certain PAR-controlled lines.
- The NYISO is in the process of implementing several market enhancements that we support, which should help reduce the frequency of excess price spikes.
- We recommend the NYISO evaluate the causes of and identify potential solutions for unnecessary real-time price volatility, with particular attention to the RTC and RTD intervals near the top of each hour.

Executive Summary

Market Operations – Shortage Conditions

We evaluated market operations during three types of shortage conditions:

- Operating reserve and regulation shortages – These occurred in a small share of intervals but had significant real-time price effects, including 5 percent of the annual average real-time price in Long Island and 4 percent in NYC.
- Transmission shortages – These were also infrequent but made significant contributions to real-time prices, including 7 percent of the annual average real-time price in Long Island and 5 percent in New York City.
  - ✓ A significant number of peak congestion events occurred when an offline GT set the real-time LBMP but was not actually started, suggesting that real-time prices were set higher than necessary to maintain reliability during a brief shortage.
  - ✓ We recommend the NYISO evaluate the use of a graduated Transmission Shortage Cost so that real-time prices better reflect system conditions.
- Emergency demand response activations – These were activated on two days in NYC and likely prevented transmission shortages in Southeast NY in six hours.
  - ✓ We recommend NYISO consider how the costs of activating demand response can be better reflected in clearing prices when their activation prevents a shortage.

Executive Summary

Schedule 1 Uplift Charges

- Net Schedule 1 uplift charges decreased 21 percent from $287 million in 2009 to $228 million in 2010.
- Uplift from payments to generators (i.e., BPCG, DAMAP, etc), which make up the majority of Schedule 1 Uplift Charges, fell from $249 million in 2009 to $205 million in 2010 for several reasons that are discussed in the report.
  - ✓ The most significant factor was a reduction in supplemental commitment for reliability in New York City.
- Balancing congestion residuals fell from $66 million in 2009 to $46 million in 2010 due to:
  - ✓ Improved operations during Thunderstorm Alerts;
  - ✓ Better consistency between day-ahead and real-time constraint modeling in New York City; and
  - ✓ NYISO procedures to promptly evaluate the causes of balancing congestion residuals and to adjust market operations accordingly.

Executive Summary

<u>External Transaction Scheduling</u>

- Prices between New York and adjacent markets do not fully converge, which results in market inefficiencies and excess consumer costs.
- Loop flows caused by dispatch and scheduling by entities outside of New York sometimes contribute to congestion in New York.
  - ✓ Clockwise loop flows around Lake Erie, which exacerbate congestion, fell 65 percent on average from 2009 to 2010 due to changes in scheduling patterns between Ontario, MISO, and PJM.
  - ✓ When clockwise loop flows increase, the NYISO uses TLR procedures to ameliorate their effect on congestion management costs in New York.
- NYISO is working with neighbors on a series of market enhancements, including:
  - ✓ Coordinated interchange scheduling with New England;
  - ✓ More frequent scheduling of the interfaces with PJM and Quebec; and
  - ✓ Coordinated congestion management with PJM and New England.
  - ✓ We recommend that the NYISO continue to place a high priority on these initiatives, particularly the interface utilization initiative because it offers the highest efficiency benefits.

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.
- Spot prices rose 93 percent in NYC from 2009 to $9.22/kW-month in 2010, while they remained more constant in ROS averaging $1.47/kW-month in 2010.
  - ✓ NYC spot prices rose primarily due to the retirement of the Poletti unit in NYC.
- The NYISO recently filed proposed criteria for defining new capacity zones, which we did not support because they would likely fail to define new capacity zones that are needed to efficiently satisfy the planning requirements of the system.
  - ✓ Hence, we recommend one of two alternative approaches for defining new capacity zones, which are discussed later in the report.
- Capacity demand curves based on a peaking resource. This has some advantages, but they may not be the most economic investment in the short run. In NYC, the default peaking unit has a net CONE 84 percent higher than a combined cycle unit.
  - ✓ To avoid incentives to invest inefficiently, we recommend that the NYISO consider modifying its rules to select the most economic generating technology to establish the demand curves in the next demand curve reset process.

Executive Summary: High Priority Recommendations

1. **We recommend the NYISO adopt one of the following two processes for defining new capacity zone(s) efficiently .**
   - ✓ Use criteria for creating a new zone that is consistent with the Deliverability Test so a new zone is created whenever deliverability constraints on Highway facilities are binding, and streamline implementation of new zones; or
   - ✓ Pre-define a full set of capacity zones that address potential deliverability issues. This would allow price separation between areas when necessary, but would allow areas to clear at the same price when Highway facilities do not restrict sales.
2. **We recommend the NYISO continue working with its neighbors to better utilize the transfer capability between regions, ideally by coordinating the physical interchange and congestion management.**
   - ✓ The NYISO is working with neighboring control areas on several proposals to improve the efficient use of the interfaces, which should be the highest priority initiatives because they promise the largest economic benefits.
   - ✓ We also support other proposals being developed under the Broader Regional Market initiatives, although they promise smaller economic benefits.

Executive Summary:
High Priority Recommendations

3. **We recommend that the NYISO consider modifying its rules to select the most economic generating technology to establish the demand curves in the next demand curve reset process.**
   - ✓ The use of a new peaking unit in the demand curve reset process is likely to result in a demand curve that is set higher than the level necessary to satisfy New York state's planning criteria in the short run.
   - ✓ This change will assure than the NYISO markets do not produce incentives to invest inefficiently in excess capacity and produce higher costs for loads.

Executive Summary: Other Recommendations

4. **We recommend addressing factors that contribute to excess real-time price volatility.**
   - ✓ In May 2011, the NYISO will make market enhancements that will reduce unnecessary real-time price volatility: Reserves and Regulation Demand Curve changes, and 15-Minute Scheduling of the Hydro Quebec interface.
   - ✓ The NYISO is working on several market enhancements with neighboring areas that will further reduce real-time price volatility: Coordination of the interchange with New England, 15-minute scheduling with PJM, and 5-minute scheduling with Hydro Quebec.
   - ✓ However, additional work will likely be needed to eliminate unnecessary volatility.
     - – We recommend the NYISO conduct an evaluation to determine the causes of and potential solutions for unnecessary real-time price volatility.
     - – In particular, we recommend the NYISO consider whether additional look ahead assessments in RTC and RTD at intervals-ending :55 and :05 minutes past the hour would lead to more efficient dispatch at the top of each hour.

Executive Summary: Other Recommendations

5. **We recommend NYISO modify two mitigation provisions that may limit competitive 10-minute reserves offers in the day-ahead market.**
   - ✓ The mitigation provisions:
     - – Limit GTs to a 10-minute non-spinning reserve reference of $2.52/MWh.
     - – Require New York City steam units to offer 10-minute spinning reserves at $0/MWh.
   - ✓ This should improve convergence of day-ahead and real-time reserve prices in peak load hours.
6. **We recommend the NYISO consider the feasibility and potential impacts on reliability and system security from using a graduated Transmission Shortage Cost.**
   - ✓ RTD uses a “Transmission Shortage Cost” that limits the re-dispatch costs that may be incurred to $4,000/MWh when managing congestion.
   - ✓ However, our analysis suggests that this level may be higher than necessary to maintain reliability during some brief shortages.

Executive Summary: Other Recommendations

7. We recommend the NYISO evaluate how the costs of activating demand response might be better reflected in clearing prices when their activation prevents a shortage.

- ✓ Emergency demand response was only activated in NYC on two days, but these activations may be more common in the future if supply margins fall.
- ✓ Hence, efficient price-setting when demand response resources are needed to satisfy reliability needs market-wide or in a local area will be increasingly important.

8. We recommend NYISO enable market participants to schedule virtual trades at a more disaggregated level.

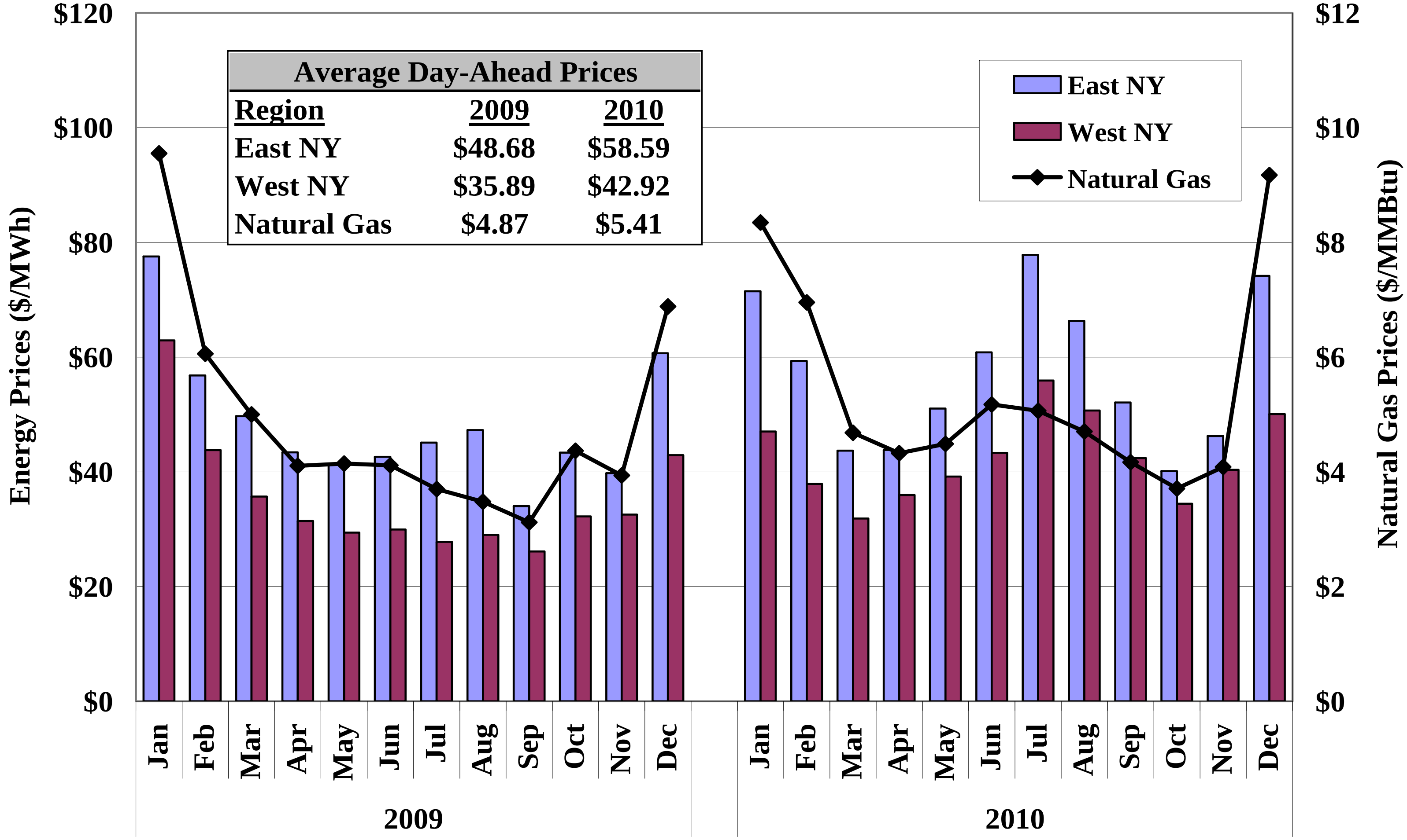
- ✓ Virtual trading improves convergence between day-ahead and real-time prices, particularly when modeling inconsistencies and other differences between the day-ahead and real-time markets would otherwise lead to inconsistent prices.
- ✓ However, virtual trading is currently allowed at only the zonal level.
- ✓ NYISO has a project to expand the locations where virtual trading is allowed.

Market Prices and Outcomes:
Summary of Prices and Loads

Fuel Prices and Energy Prices

- The following figure summarizes day-ahead energy prices in 2009 and 2010.
- Energy prices rose 20 percent on average from 2009 to 2010, due primarily to the increases in fuel prices and load levels.
  - ✓ Natural gas prices rose by an average of 11 percent, residual oil (#6) prices rose by 30 percent and diesel oil (#2) prices rose by 29 percent.
    - – The correlation of energy 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.
  - ✓ Average load increased by more than 3 percent from 2009 and peak load rose 9 percent from 2009.
- The differences between West and East NY prices in 2010 were comparable to the prior year, indicating similar west-to-east congestion costs in both years.
  - ✓ The average price in East NY was 37 percent higher than the average price in West NY in 2010, up slightly from the 36 percent in 2009.
    - – West-to-east congestion became less frequent partly due to reduced clockwise loop flows around Lake Erie and decreased imports to West NY from neighboring areas.
    - – This was offset by the increase in natural gas prices, which raised the congestion price differences between West NY and East NY.

Day-Ahead Electricity and Natural Gas Prices
2009 – 2010



Average Day-Ahead Prices		
Region	**2009**	**2010**
East NY	$48.68	$58.59
West NY	$35.89	$42.92
Natural Gas	$4.87	$5.41

Note: The electricity prices are load-weighted averages.

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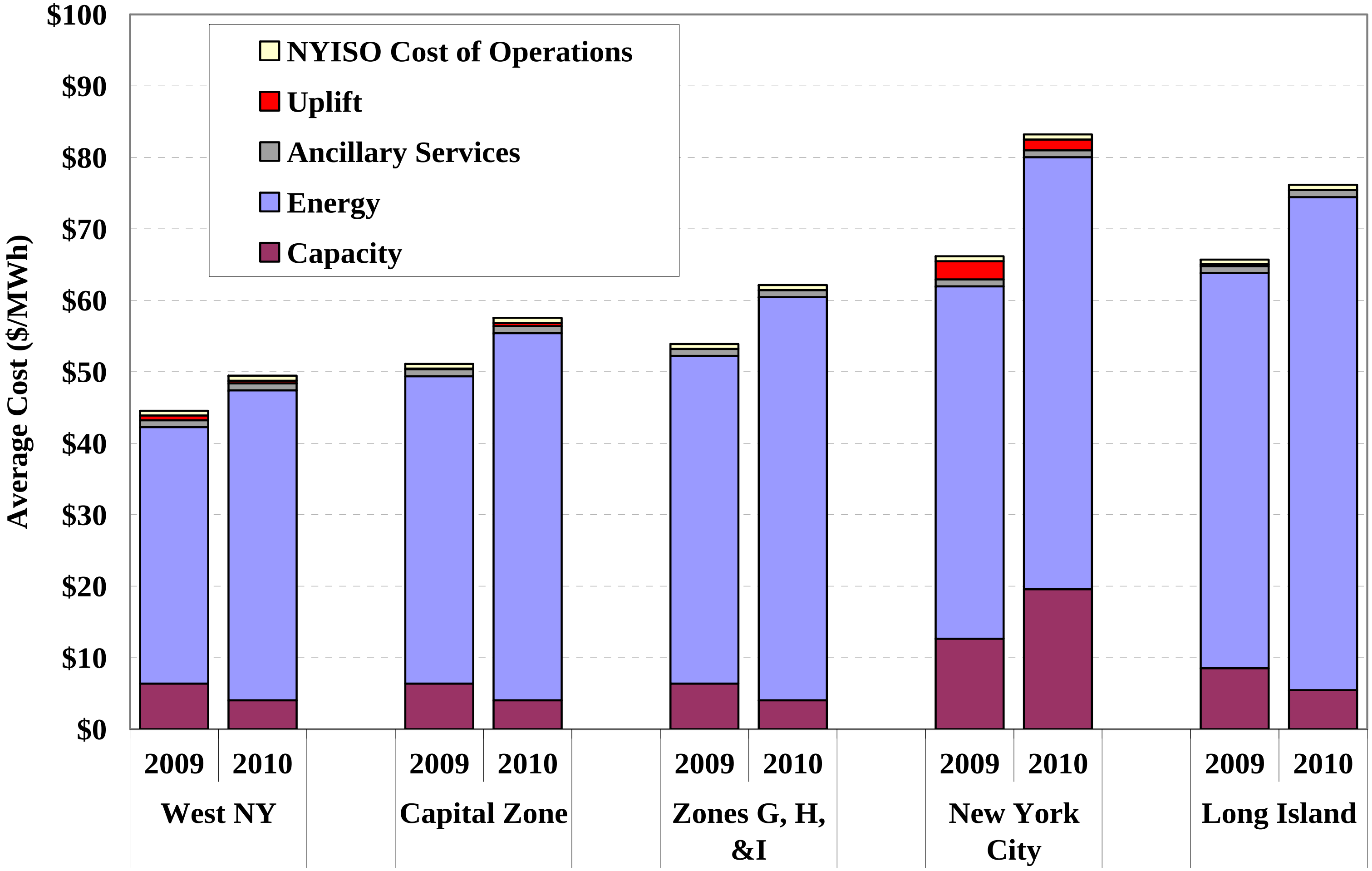
All-In Energy Prices

- To summarize overall price trends in the New York markets, the following figure shows an "all-in" price metric.
  - ✓ This includes energy, ancillary services, capacity, uplift, and NYISO costs.
  - ✓ The energy component is a load-weighted average real-time energy price.
  - ✓ The capacity component is based on spot capacity prices and capacity obligations in each area, allocated over the energy consumption in the area.
  - ✓ The NYISO cost of operations and uplift from other Schedule 1 charges are averaged across all consumption in the relevant area.
- All-in prices rose from 2009 to 2010 with increases ranging from 11 percent in the West to 25 percent in New York City.
  - ✓ The increases were primarily driven by increased energy prices, which were driven by higher fuel prices and increased load levels.
  - ✓ In New York City, capacity prices increased primarily due to the retirement of the Poletti unit.
  - ✓ Outside New York City, capacity prices fell in spite of the Poletti retirement as a result of several capacity additions and a reduction in the statewide capacity requirement (which fell due to a reduction in the peak summer load forecast.)

Average All-In Price by Region
2009 – 2010



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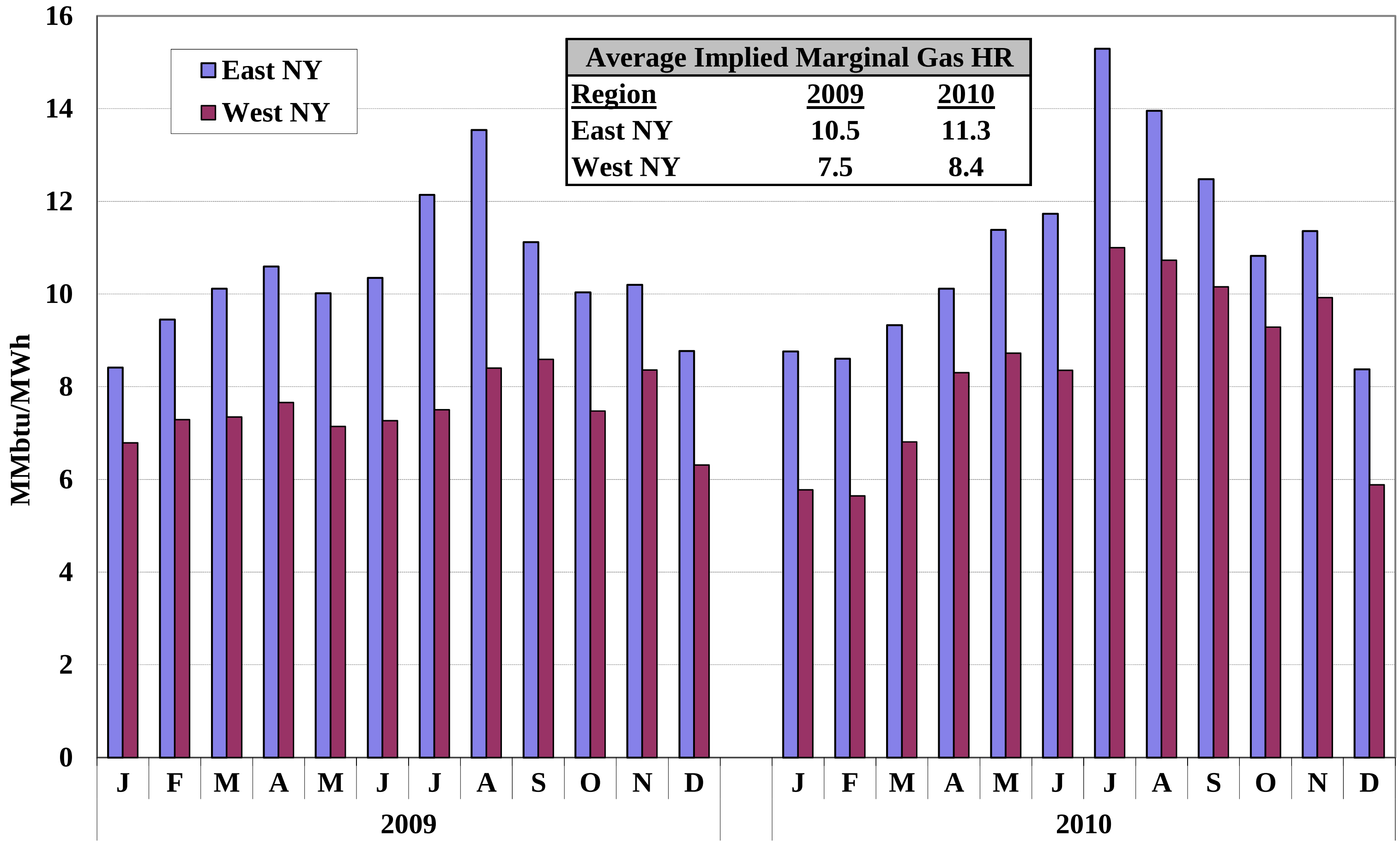
Fuel Prices and Energy Prices

- To identify changes in energy 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)
- The figure shows that implied heat rates rise in the summer months due to:
  - ✓ Increased demand driven by higher temperatures in the summer; and
  - ✓ Reduced supply resulting from the effects of higher ambient temperatures on the capability of thermal units.
- The implied heat rate rose 8 percent in East NY and 12 percent in West NY from 2009, due to factors that include:
  - ✓ Load levels were substantially higher in 2010, particularly in the summer months, resulting in more frequent dispatch of high-cost generation and shortages.
  - ✓ The retirement of the Poletti unit reduced supply in New York City, resulting in more frequent use of peaking units during high load conditions.
  - ✓ Net imports from Hydro Quebec fell 23 percent, contributing to the higher implied heat rates, particularly in West NY.
  - ✓ Production from hydro and nuclear generation also fell by an average of 310 MW, contributing to the higher implied heat rates, particularly in West NY.

Average Monthly Implied Heat Rate
2009 - 2010



Note: Implied heat rates are load-weighted averages based on day-ahead energy prices and natural gas prices.

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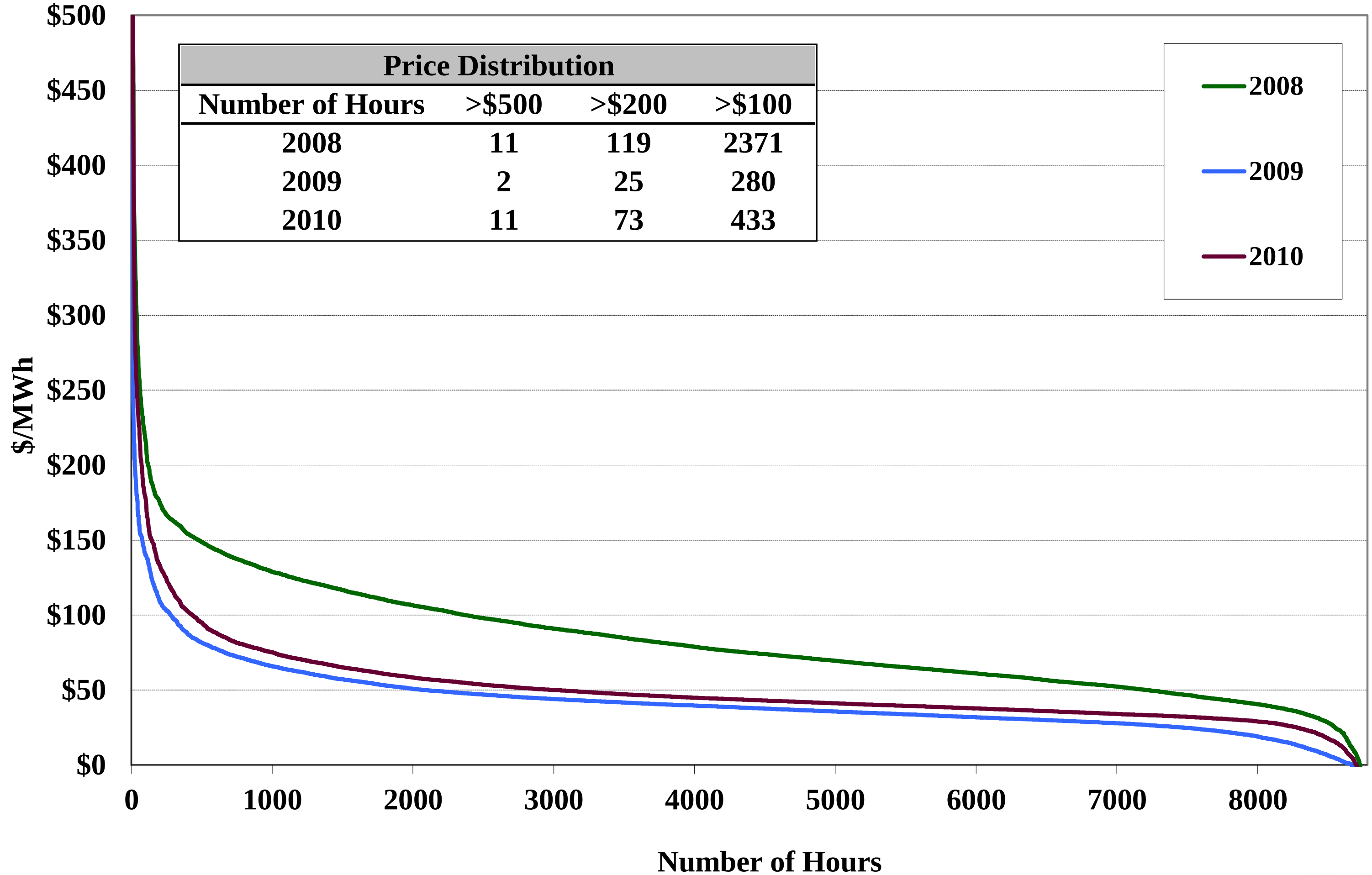
Energy Prices

- The next figure shows how hourly price levels have changed in the last three years by showing real-time price duration curves from 2008 to 2010.
  - ✓ 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 fell substantially from 2008 to 2009 and then rose in 2010 across a wide range of hours.
  - ✓ The broad changes in prices over many hours are primarily caused by the increases in natural gas and oil prices.
  - ✓ Natural gas prices decreased 52 percent from 2008 to 2009, and then increased 11 percent from 2009 to 2010.
- The figure also shows that the number of very high-priced hours (with prices exceeding $500/MWh mainly during shortages) declined from 2008 to 2009, and then increased in 2010.
  - ✓ The change in the number of peak load hours (>30 GW) contributed to the sharp changes in real-time shortage pricing events.

Price Duration Curves

2008 – 2010



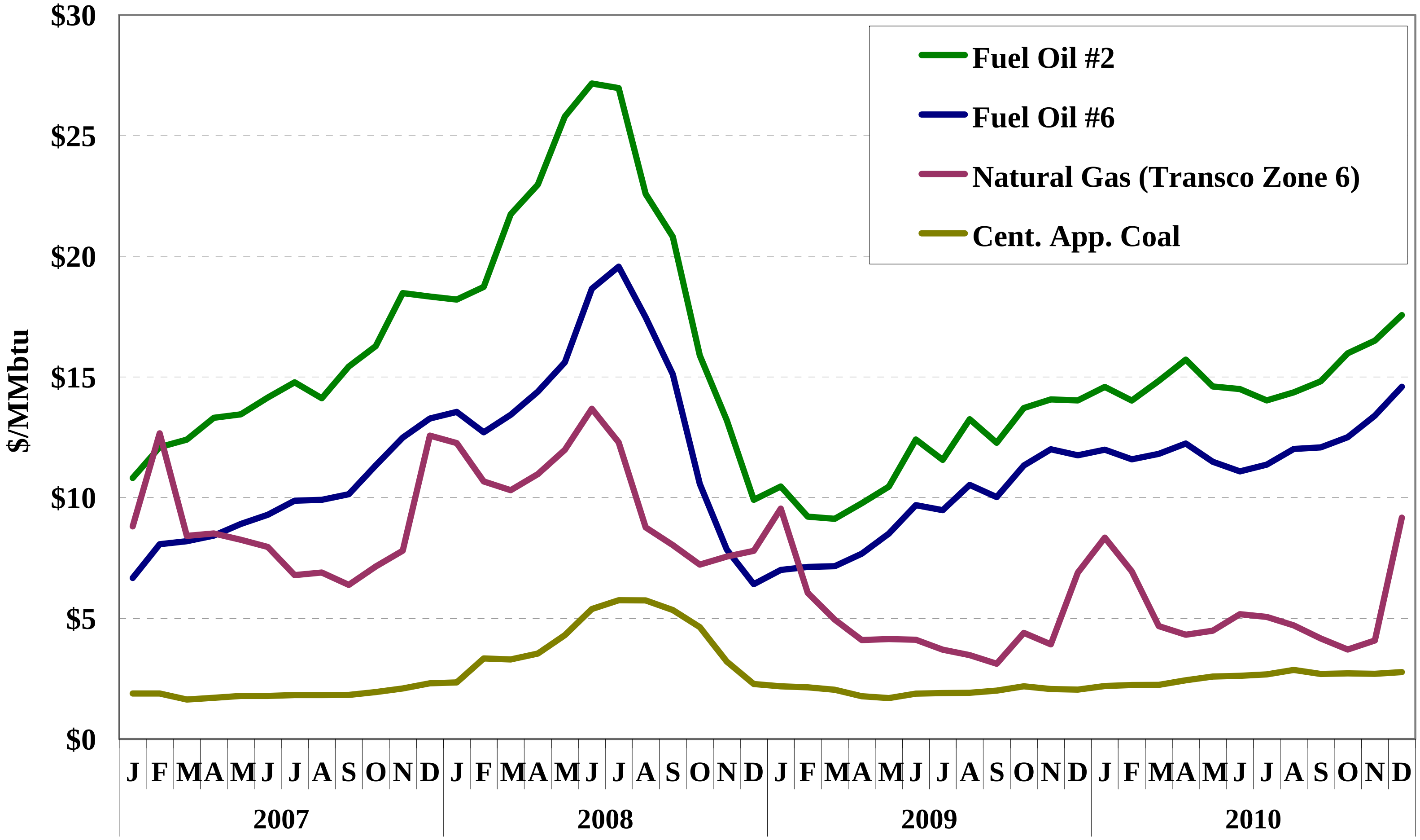
Price Distribution			
Number of Hours	>$500	>$200	>$100
2008	11	119	2371
2009	2	25	280
2010	11	73	433

Note: The prices are load-weighted state-wide average real-time prices.

Fuel Prices

- Fuel prices are a key determinant of electricity prices, so the next figure shows monthly average natural gas, fuel oil, and coal prices from 2007 to 2010.
- Fuel prices rose significantly in 2010 as economic activity increased.
  - ✓ Natural gas prices averaged $5.41/MMBtu in 2010, up 11 percent from 2009.
  - ✓ Fuel oil #2 prices averaged $15.13/MMBtu in 2010, up 29 percent from 2009.
  - ✓ Fuel oil #6 prices averaged $12.18/MMBtu in 2010, up 30 percent from 2009.
  - ✓ Coal prices averaged $2.56/MMBtu in 2010, up 29 percent from 2009.
- Although oil is usually more expensive than gas, oil-use is significant because:
  - ✓ Reliability rules require some units in New York City and Long Island to burn oil to limit exposure to natural gas supply contingencies during high load conditions.
  - ✓ Some units are not connected to the gas pipeline system, primarily in Long Island.
  - ✓ Gas prices sometimes rise above oil prices for short periods, primarily in winter.
- The use of coal has been reduced by several retirements and the decline in natural gas prices relative to coal prices since 2009.
  - ✓ When natural gas is close to the price of coal (e.g., April to November 2010), gas-fired combined cycles are more competitive with coal-fired steam units.

Monthly Average Fuel Prices
2007 – 2010



Note: These are index prices that do not include transportation charges.

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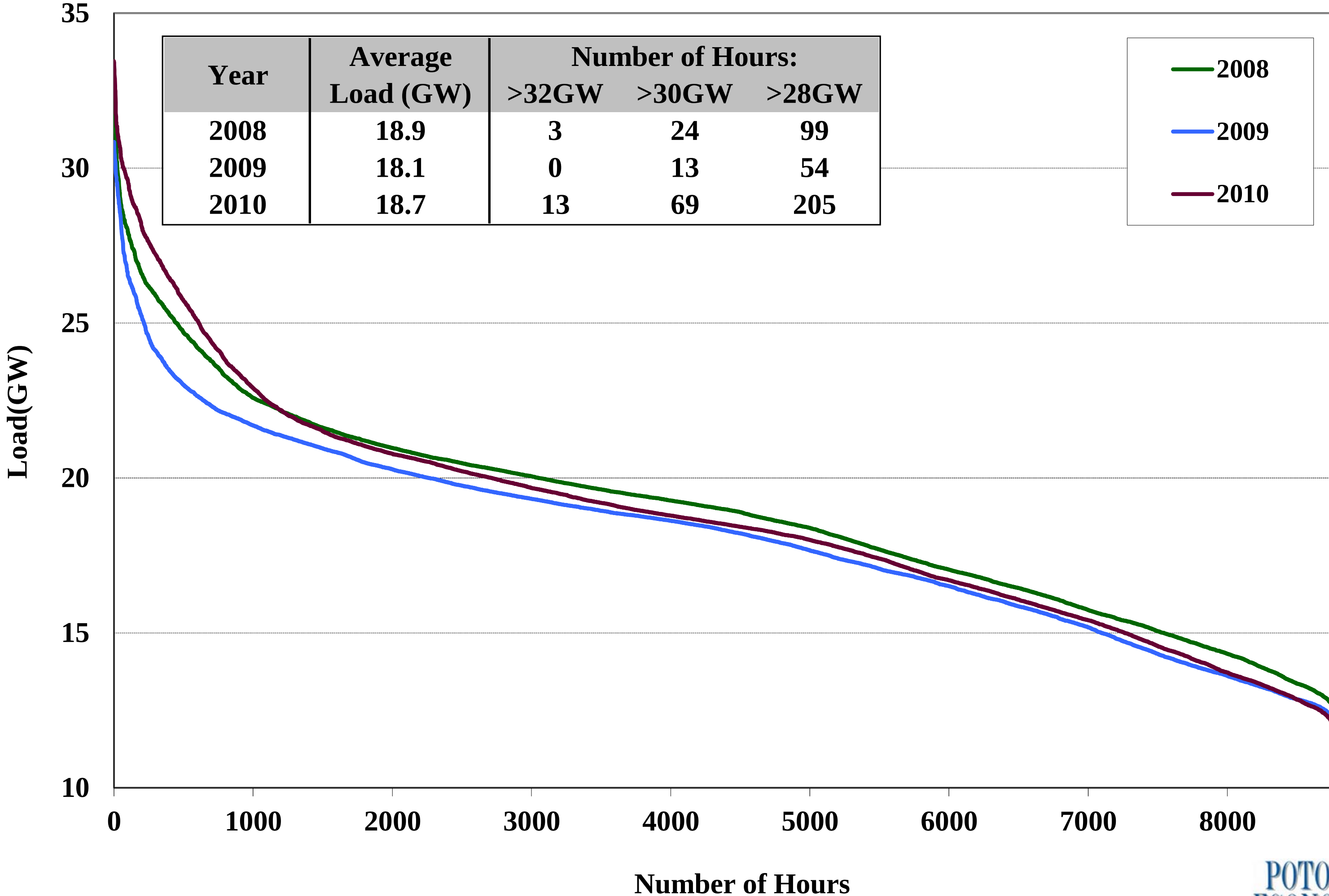
Load Profile

- Load levels are a fundamental determinant of market conditions. The next figure shows load duration curves for 2008 to 2010.
  - ✓ These curves show the number of hours in which the load is greater than the level indicated on the vertical axis.
- Average load decreased considerably (4 percent) from 2008 to 2009 and increased substantially (3 percent) from 2009 to 2010.
- The number of peak load hours rose significantly in 2010, resulting in more frequent shortage conditions and associated price spikes.
  - ✓ Load exceeded 28 GW during 205 hours in 2010 compared to 54 hours in 2009.
  - ✓ Load peaked at 33.5 GW on July 6th, which was:
    - 1 percent lower than the all-time peak (33.9 GW on August 2nd, 2006),
    - 1 percent higher than the 2010 peak load forecast (33.0 GW), and
    - 9 percent higher than the 2009 peak.
- The majority of the increase in load levels from 2009 to 2010 was due to hotter summer weather, although the improvement in economic conditions likely also contributed.

Load Duration Curves for New York State
2008 – 2010

Year	Average Load (GW)	Number of Hours: >32GW	Number of Hours: >30GW	Number of Hours: >28GW
2008	18.9	3	24	99
2009	18.1	0	13	54
2010	18.7	13	69	205



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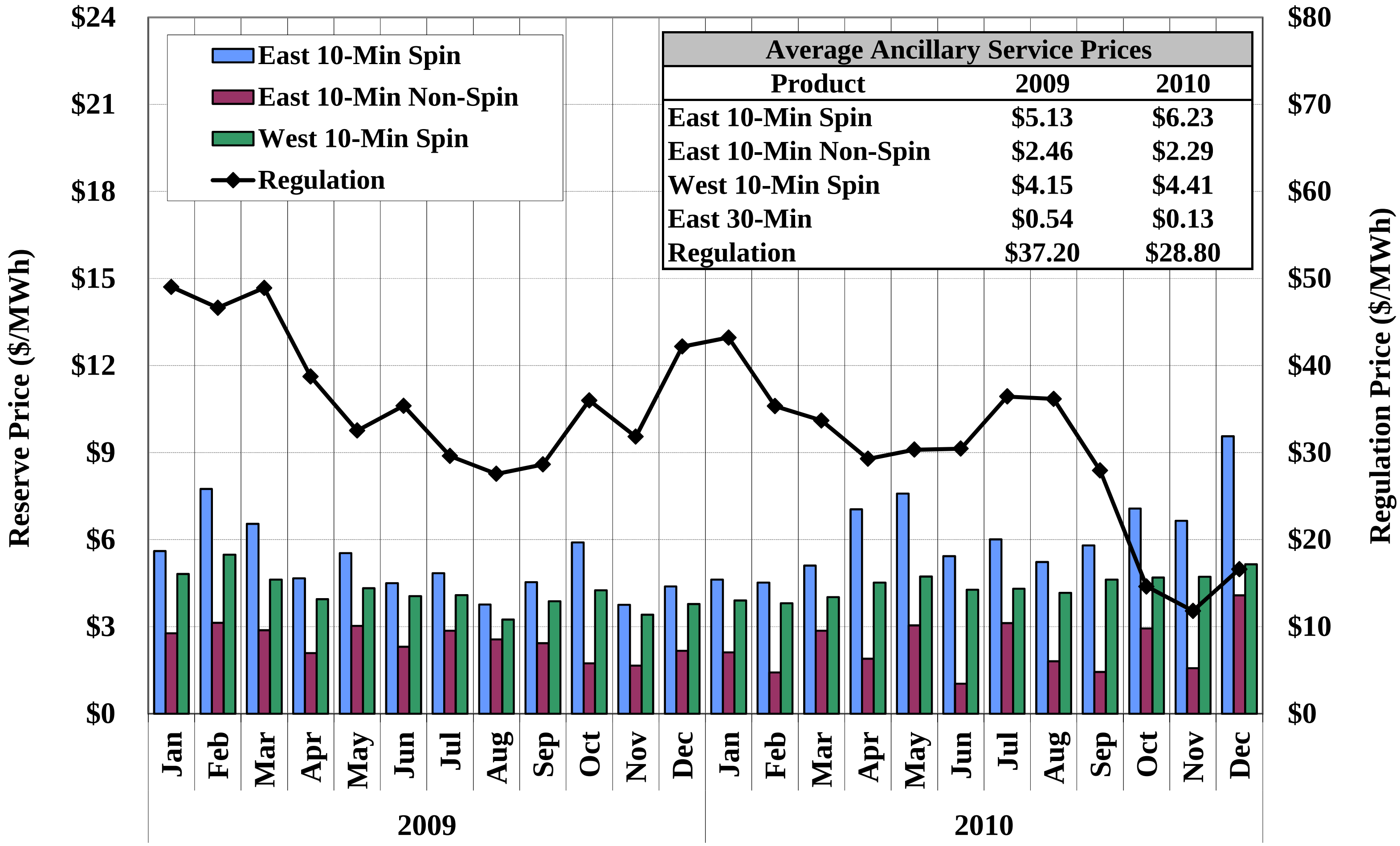
Ancillary Services Prices

- The following figure summarizes the prices of several key ancillary services products in the day-ahead market in 2009 and 2010.
  - ✓ The NYISO has four ancillary services products: (i) 10-minute spinning reserves, (ii) 10-minute total reserves, (iii) 30-minute reserves, and (iv) 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 resources that would otherwise be economic to produce energy, changes in energy prices lead to corresponding changes in the cost of providing ancillary services.
  - ✓ For example, eastern 10-minute spinning reserves prices increased 21 percent from 2009 to 2010, consistent with the 20 percent increase in energy prices.
- Regulation prices have decreased since September 2010 due to the new entry of regulation-capable capacity and reduced offer prices from existing suppliers.
- Eastern 10-minute spinning and non-spinning reserves prices rose in December 2010 following the increase in the eastern 10-minute reserve requirement from 1,000 MW to 1,200 MW.
  - ✓ The increased requirement resulted from the expiration of the *Reserve Sharing Agreement* that previously existed with ISO New England.

Day-Ahead Ancillary Services Prices
2009 – 2010



Average Ancillary Service Prices		
Product	2009	2010
East 10-Min Spin	$5.13	$6.23
East 10-Min Non-Spin	$2.46	$2.29
West 10-Min Spin	$4.15	$4.41
East 30-Min	$0.54	$0.13
Regulation	$37.20	$28.80

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Price Corrections

- The following figure summarizes the frequency of price corrections in the real-time energy market in 2009 and 2010.
- Price corrections occur in the 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.
- The frequency of price corrections has declined sharply in recent years, and it was particularly low in 2010 at less than 0.1 percent of intervals corrected.
  - ✓ Furthermore, the number of pricing locations affected has also decreased.
- Only one month exhibited relatively higher (while still lower than the historical average) price corrections in 2010.
  - ✓ Corrections in June 2010 were mostly due to a software issue that only affected proxy buses.

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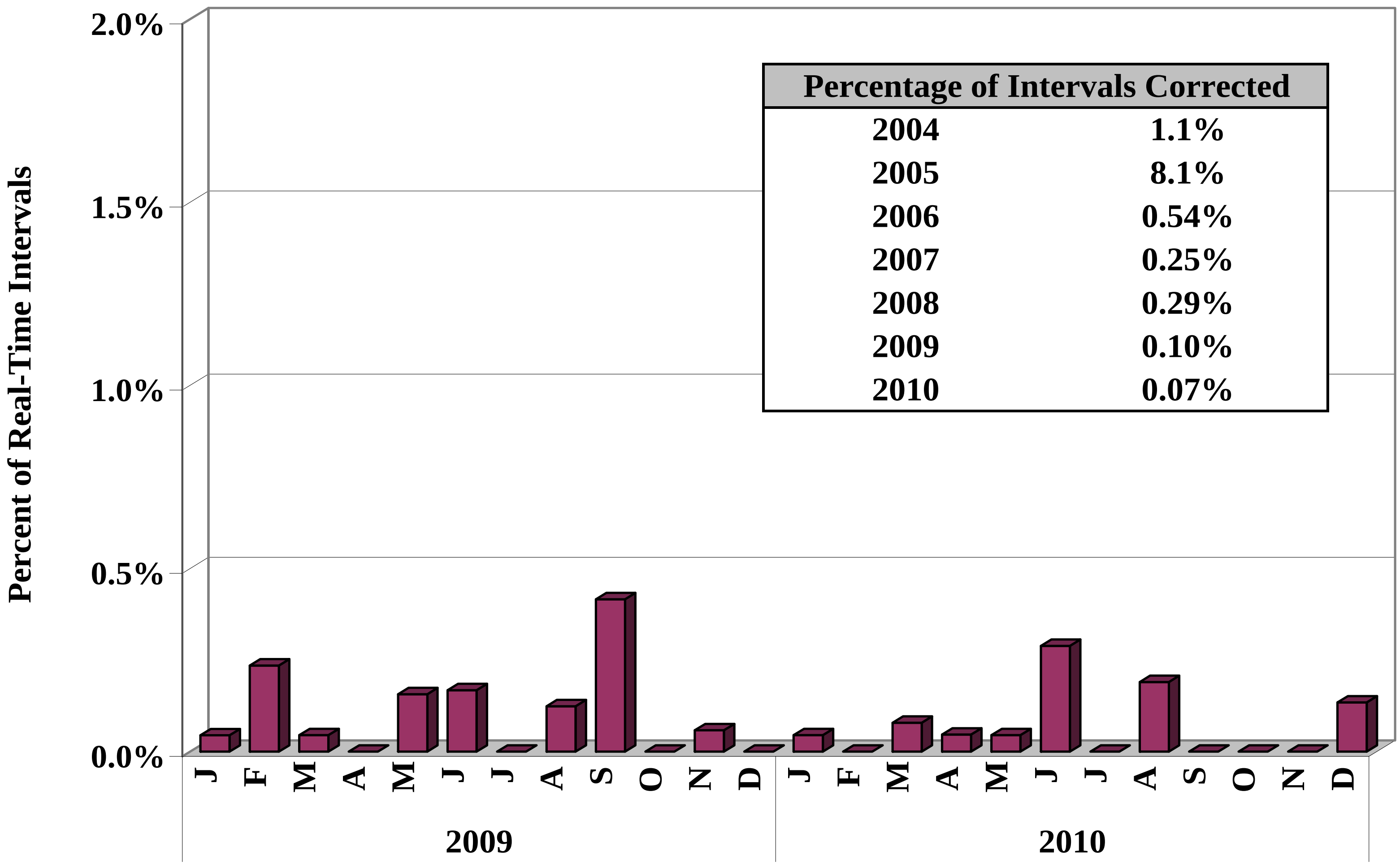
Frequency of Real-Time Price Corrections
2009 – 2010



Percentage of Intervals Corrected	
2004	1.1%
2005	8.1%
2006	0.54%
2007	0.25%
2008	0.29%
2009	0.10%
2010	0.07%

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Market Prices and Outcomes:
Long-Term Market Signals

Long-Term Market Signals – Net Revenue Methodology

- The following two figures show the estimated Net Revenue provided by the NYISO markets over the past four 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 uses assumptions developed by FERC and the market monitors of the various markets to provide a basis for comparison of net revenues between markets.
  - ✓ It assumes that the units sell only at the day-ahead market prices;
  - ✓ It takes into account 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.
  - ✓ It assumes net revenues are earned whenever the assumed cost of the unit is less than the market clearing price at its location, regardless of the unit's physical parameters.

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Long-Term Market Signals –
Enhanced Net Revenue Assumptions

- The Enhanced Method uses the following assumptions:
  - ✓ Units are committed based on day-ahead prices, considering commitment costs, minimum run times, minimum generation levels and other physical limitations;
  - ✓ Combined cycles may sell energy, 10-minute and 30-minute spinning reserves; while combustion turbines may sell energy and 30 minute reserves;
  - ✓ Units are dispatched in real-time and settle on the deviation from their day-ahead schedules, and they may have their run-time extended based on RTC prices;
  - ✓ Offline combustion turbines may be started based on RTC prices;
  - ✓ Fuel costs assume charges of $0.27/MMbtu on top of the Transco Zone 6 day-ahead index price and a 6.9 percent tax for New York City units;
  - ✓ RGGI compliance costs are considered beginning January 2009; and
  - ✓ The following operating and cost assumptions are used:

Characteristics	CC	Upstate CT	Downstate CT
Size	500 MW	165 MW	100 MW
Startup Cost (Dollars)	$8,000	$11,000	$0
Startup Cost (MMBTUs)	5,000	360	215
Heat Rate (HHV)	8,100 to 7,200	10,700	9,100
Min Run Time / Min Down Time	5 hours	1 hour	1 hour
Variable O+M	$1 / MWh	$1 / MWh	$5 / MWh

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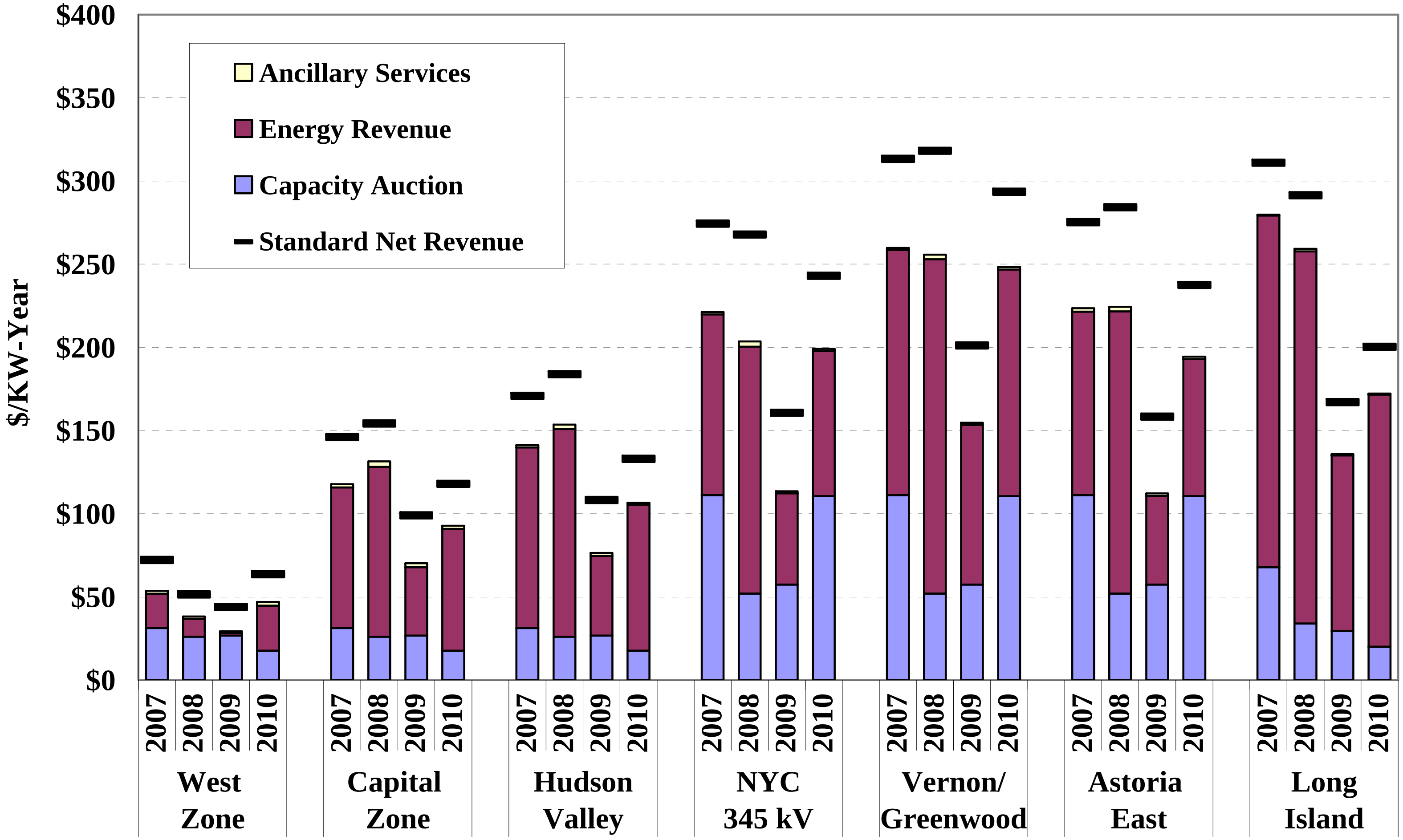
Long-Term Market Signals –
Net Revenue Methodology

- The following figures summarize the results of the enhanced analysis.
  - ✓ A marker shows the standard net revenue analysis results for comparison.
- The results of the enhanced analysis differ from the standard analysis for the following reasons:
  - ✓ Start-up costs and minimum runtime restrictions reduce net revenues in the enhanced analysis;
  - ✓ Online units responding to real-time price signals increases net revenues in the enhanced analysis;
  - ✓ Economic commitment of offline combustion turbines after the day-ahead market by RTC increases net revenues in the enhanced analysis;
  - ✓ Higher fuel costs reduce net revenues in the enhanced analysis, particularly for New York City units.
  - ✓ Higher heat rate assumptions for combined cycles reduce net revenues in the enhanced analysis; and
  - ✓ Higher heat rate assumptions for combustion turbines outside Southeast New York reduce net revenues in the enhanced analysis, while lower heat rates for combustion turbines in Southeast New York increase net revenues.

Long-Term Market Signals –
Net Revenue Analysis

- Fluctuations in shortages fuel prices were the primary drivers of variations in energy net revenues throughout New York state from 2007 to 2010.
  - ✓ Energy net revenues and fuel prices are correlated because higher fuel prices increase the spreads between energy prices and most generators' production costs.
  - ✓ Accordingly, net energy revenues fell sharply in 2009 and increased again in 2010, consistent with the changes in fuel prices and frequency of shortages.
- Capacity net revenues fell outside New York City from 2007 to 2010 primarily due to several capacity additions around the state.
- However, in New York City, capacity net revenues declined from 2007 to 2008 and then rose from 2009 to 2010.
  - ✓ The decrease in 2008 was due to the sale of capacity that was previously withheld.
  - ✓ The increase in 2010 was largely due to the retirement of the Poletti unit.
- Other factors have affected the net revenues:
  - ✓ Notable reductions in load contributed to lower net revenues in 2009.
  - ✓ Higher energy prices in the West in 2010 led to higher net revenues for combined cycles. These resulted from reduced: (i) net imports, (ii) output from hydro and nuclear units, and (iii) clockwise loop flows around Lake Erie.

Net Revenue for Combined-Cycle Unit
2007 – 2010



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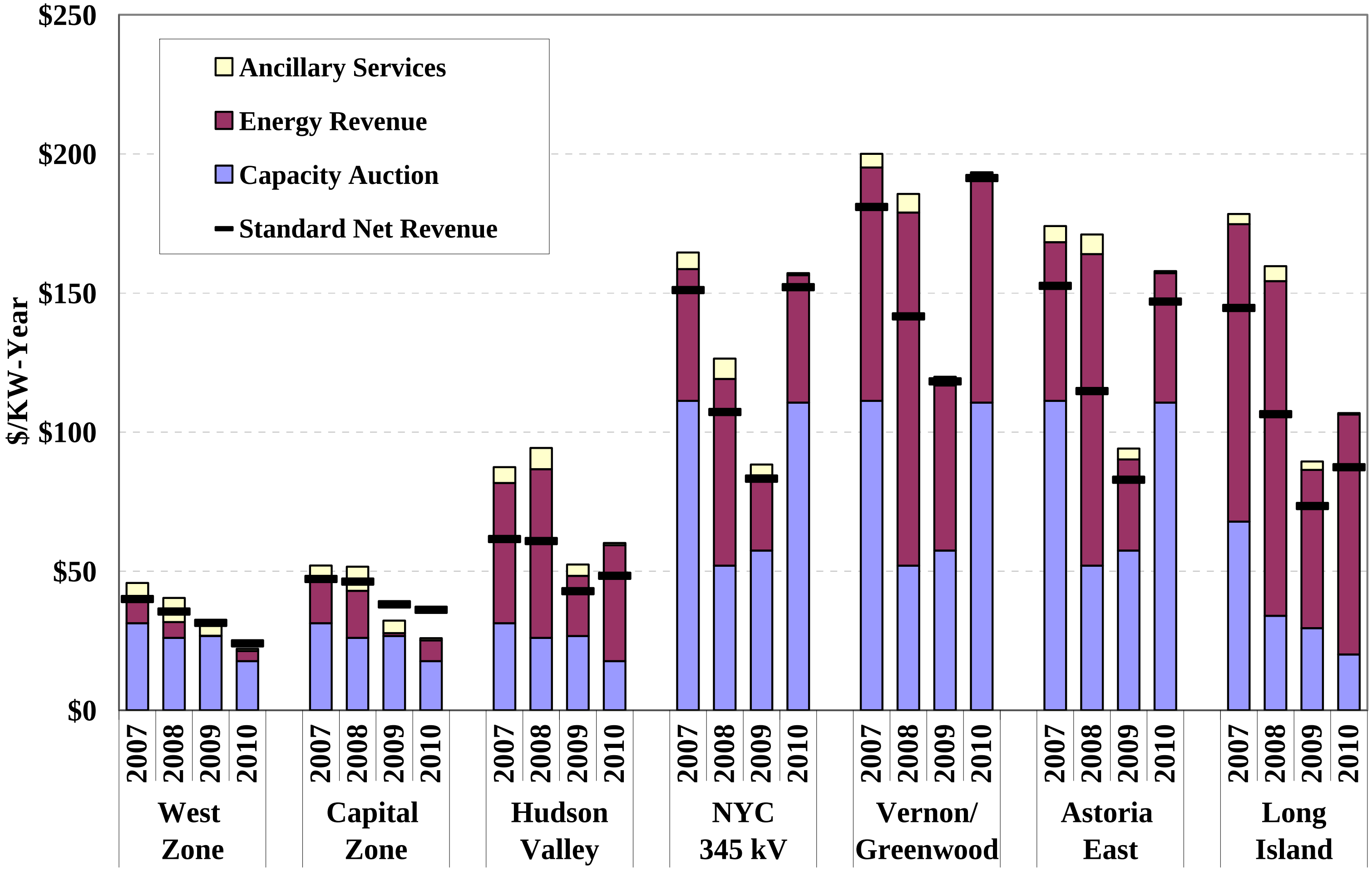
Net Revenue for Combustion Turbine
2007 – 2010



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Long-Term Market Signals – Conclusions

- Estimated net revenues for a new combined cycle unit increased in 2010 by roughly 61 percent in the West Zone, 55 percent in New York City, and 22 to 29 percent in other areas primarily due to higher energy prices and higher New York City capacity prices.
- Estimated net revenues for a new combustion turbine rose for the same reasons, but by smaller margins (and they actually fell in the West and Capital Zones).
- Based on the net revenue levels in 2010 for combustion turbines, we find that there are no areas where a new combustion turbine investment would likely have been profitable.
  - ✓ The Cost of New Entry ("CONE") estimates for a new CT that were used to determine the NYISO Capacity Demand Curves in the 2010/11 Capability Period were (on a levelized annualized basis):
    - $219/kW-year in New York City;
    - $194/kW-year in Long Island; and
    - $107/kW-year in the Capital Zone,
  - ✓ This is not surprising because surplus capacity existed in New York City, in Long Island, and in the rest of the state.

Long-Term Market Signals – Conclusions

- Under current market conditions, investment in a new combined cycle unit is more likely to be profitable than investment in a new peaking unit.
  - ✓ The NYISO recently filed estimates of net CONE (i.e., the capacity market revenues needed to make new investment profitable) for a new combined cycle unit and a new peaking unit in New York City.
  - ✓ The estimates indicated that the net CONE for a new combined cycle unit is 46 percent lower than the net CONE for a new combustion turbine unit.
  - ✓ This suggests that investment in a new combined cycle unit is far more likely to be profitable than investment in a new peaking unit.
- Net revenue and CONE estimates together indicate that a new combined cycle is far more economical than a new combustion turbine under current conditions.
  - ✓ The use of a new peaking unit for the demand curves may lead to more investment in new capacity than is necessary to meet the NYISO's planning requirements.
  - ✓ Hence, we recommend that the NYISO consider modifying the generator technology used to establish the demand curves. (See the Capacity Section.)

Market Prices and Outcomes
Convergence of Day-Ahead and Real-Time Prices

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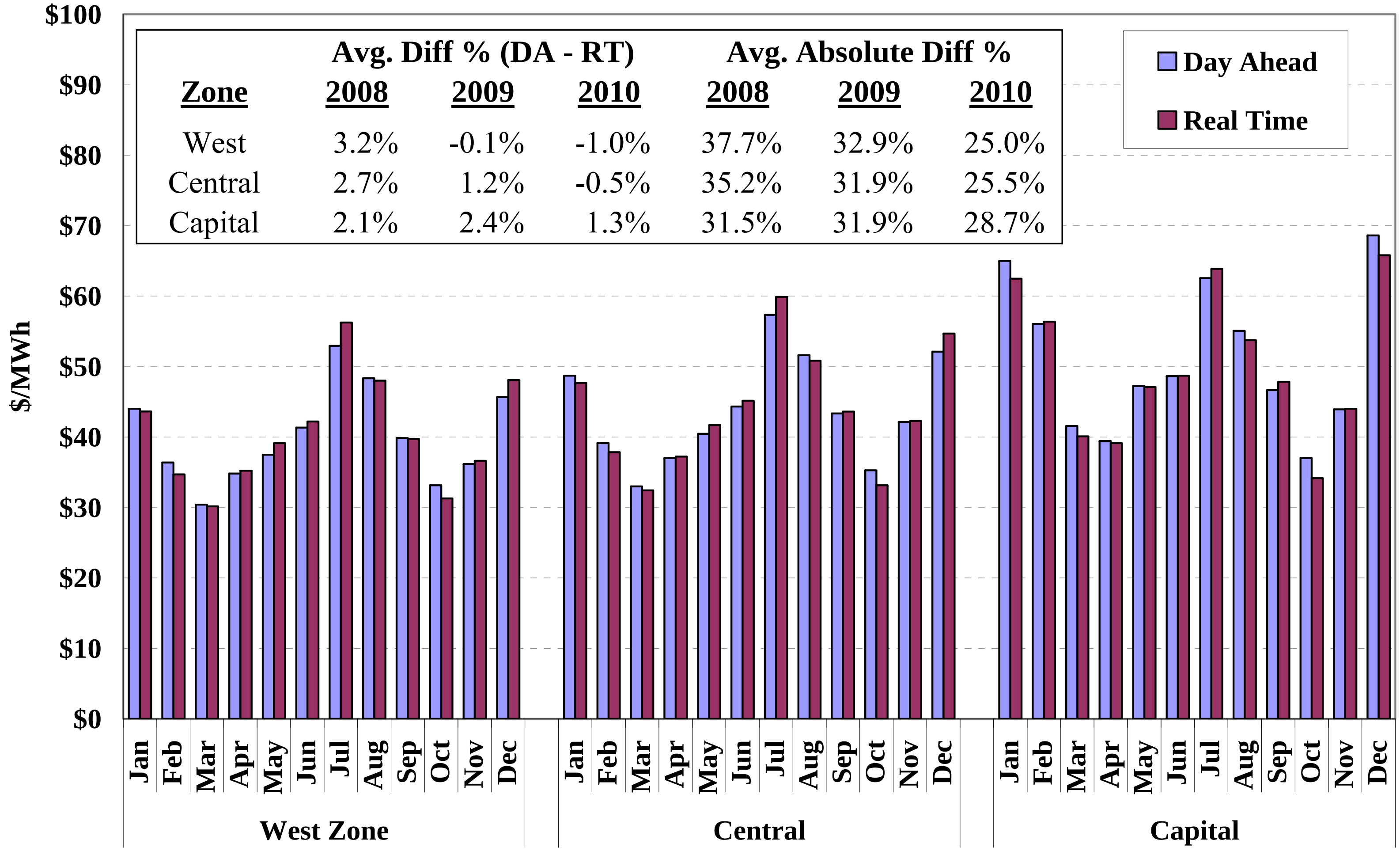
Day-Ahead and Real-Time Prices

- The next set of analyses examine the convergence between day-ahead and real-time prices.
  - ✓ Price convergence is important because most generation is committed in the day-ahead market, so 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. Systematic differences between day-ahead and real-time prices undermine incentives of generators to offer at marginal cost in the day-ahead market.
- 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 2010.
- Substantial day-ahead or real-time price premiums in individual months can occur randomly when real-time prices fluctuate unexpectedly.
  - ✓ Large real-time premiums can arise when real-time scarcity is not fully anticipated in the day-ahead market (e.g., unforeseen congestion due to a TSA event).
  - ✓ Large day-ahead premiums can arise when the day-ahead market anticipates more real-time scarcity than actually occurs (e.g., see prices in October 2010).
- Price convergence outside Southeast New York ("SENY") (i.e., West Zone to Capital Zone) improved from 2009 to 2010 due to fewer extreme negative price events, while the convergence in SENY remained relatively poor.
  - ✓ The difference in average prices between the day-ahead and real-time markets was around 1 percent outside SENY, and ranged from 2 to 6 percent in SENY.
  - ✓ The average absolute difference between day-ahead and real-time prices ranged from 25 to 29 percent outside SENY and from 30 to 36 percent in SENY.
  - ✓ This reflects that real-time energy prices were highly volatile, particularly in SENY during the summer when unexpected TSAs occurred frequently.

Average Day-Ahead and Real-Time Energy Prices
West, Central, and Capital Zones - 2010



	Avg. Diff % (DA - RT)			Avg. Absolute Diff %		
Zone	**2008**	**2009**	**2010**	**2008**	**2009**	**2010**
West	3.2%	-0.1%	-1.0%	37.7%	32.9%	25.0%
Central	2.7%	1.2%	-0.5%	35.2%	31.9%	25.5%
Capital	2.1%	2.4%	1.3%	31.5%	31.9%	28.7%

Note: The prices are load-weighted averages.

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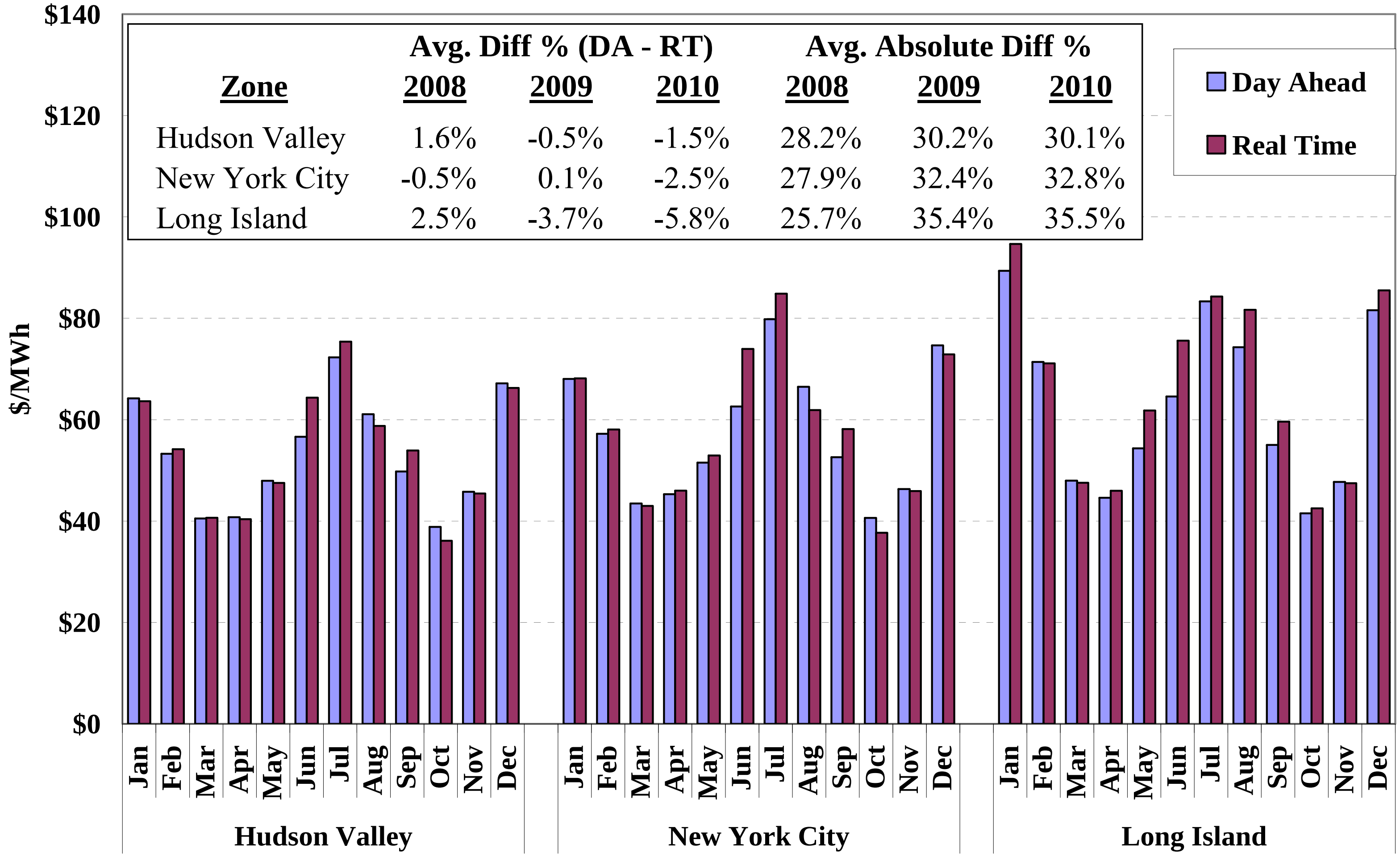
Average Day-Ahead and Real-Time Energy Prices
Hudson Valley, New York City, and Long Island - 2010



	Avg. Diff % (DA - RT)			Avg. Absolute Diff %		
Zone	**2008**	**2009**	**2010**	**2008**	**2009**	**2010**
Hudson Valley	1.6%	-0.5%	-1.5%	28.2%	30.2%	30.1%
New York City	-0.5%	0.1%	-2.5%	27.9%	32.4%	32.8%
Long Island	2.5%	-3.7%	-5.8%	25.7%	35.4%	35.5%

Note: The prices are load-weighted averages.

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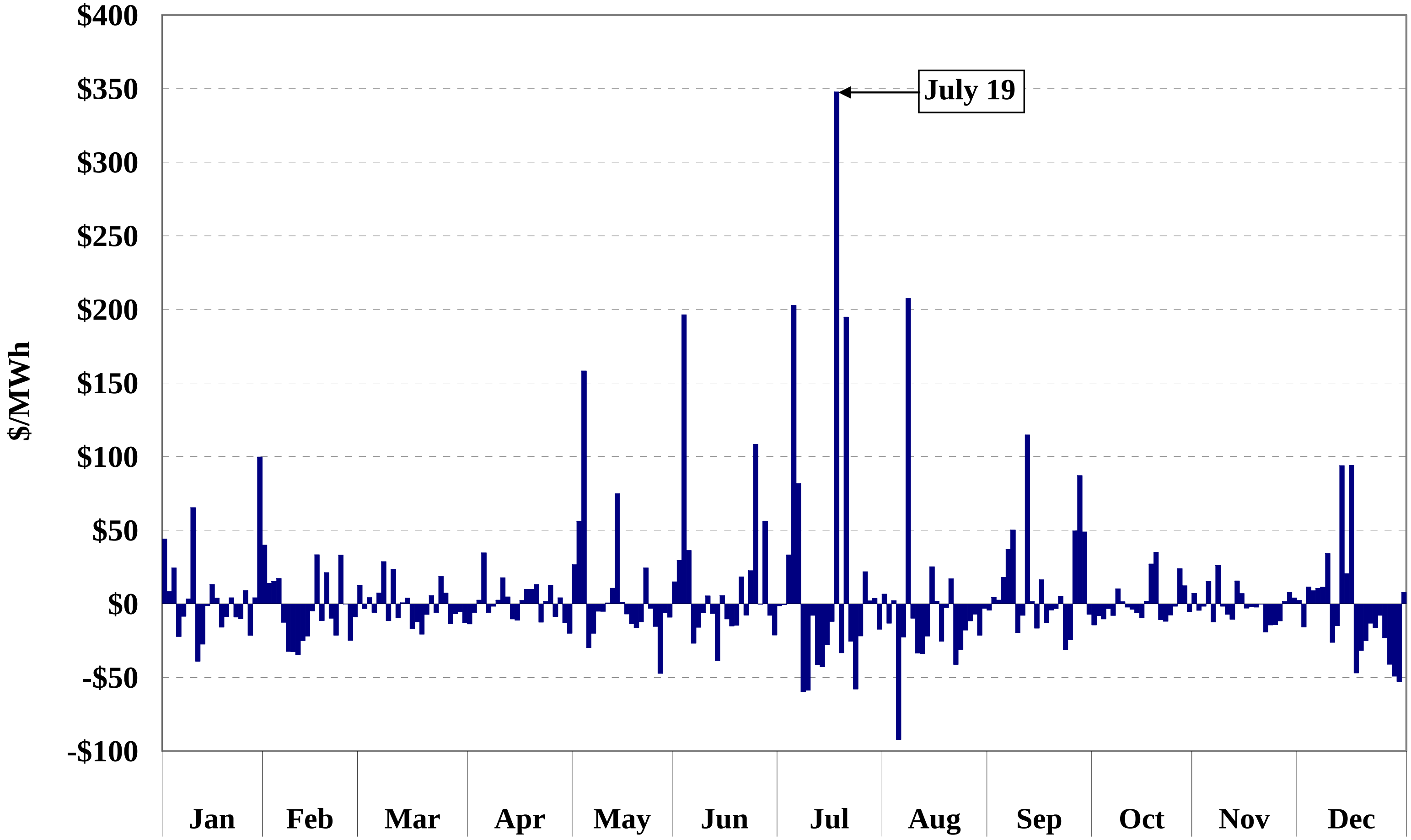
Day-Ahead and Real-Time Energy Prices

- 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.
  - ✓ Operators may commit additional generation for reliability after the day-ahead market, increasing the supply available to the real-time market.
- 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 58 percent of afternoons in New York City and 53 percent of afternoons in Long Island.
- However, high-price events are more frequent in the real-time market:
  - ✓ The day-ahead price premium did not exceed $100 per MWh in any of the afternoons in New York City and Long Island.
  - ✓ The real-time price premium exceeded $100 per MWh in 18 afternoons in New York City and 26 afternoons in Long Island.
- In New York City, the largest real-time price premium occurred on the afternoon of July 19 when the Leeds-to-Pleasant Valley line was severely congested for three hours during a TSA and the average shadow price exceeded $2,000/MWh.
- In Long Island, the largest real-time price premium occurred on the afternoon of July 6 when load rose to 5.7 GW (and statewide load reached the annual peak at 33.5 GW).

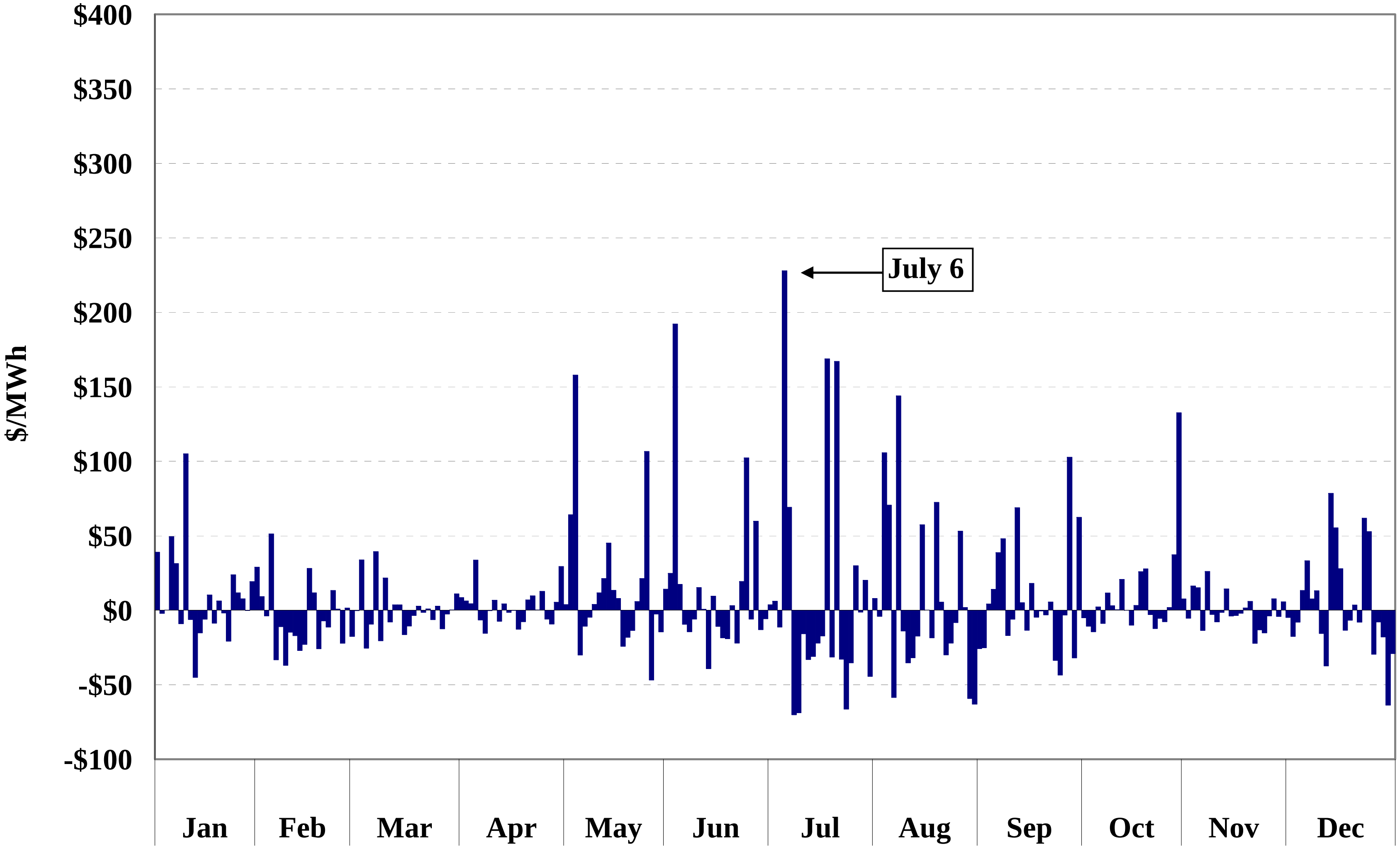
Average Daily Real-Time Price Premium
New York City, 1 p.m. to 7 p.m. Weekdays, 2010



Note: The prices are load-weighted averages.

POTOMAC ECONOMICS

Average Daily Real-Time Price Premium
Long Island, 1 p.m. to 7 p.m. Weekdays, 2010



Note: The prices are load-weighted averages.

POTOMAC ECONOMICS

Day-Ahead and Real-Time Nodal Prices

- When real-time price premiums vary substantially across locations, 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 increase their offers. This is common during periods of fuel price volatility or when gas is more easily procured day-ahead.
  - ✓ Constraints that are sensitive to the load levels may become more or less acute after the day-ahead market due to differences between expected load and 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.
- The following figure shows the average day-ahead LBMP and average real-time price premium at several nodes in NYC, Long Island, and Upstate NY in 2010.
  - ✓ These are shown separately for the summer months (e.g., June to August) and other months because the congestion patterns can vary by season.

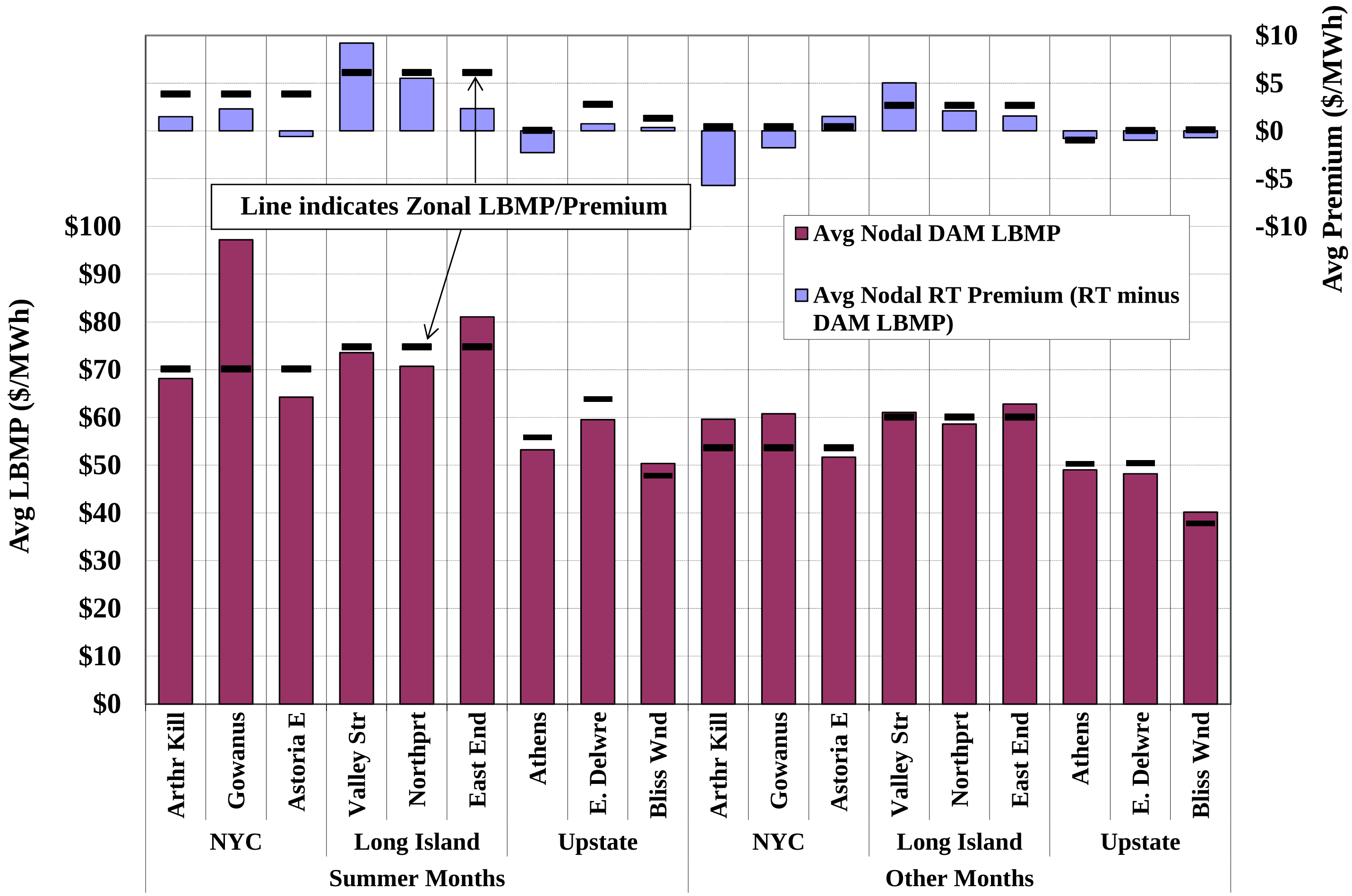
Day-Ahead and Real-Time Nodal Prices

- The figure includes nodes in each region that generally exhibited less consistency between average day-ahead and average real-time prices than other nodes.
- The lower portion of the figure shows the average day-ahead LBMPs at the node compared to the zone in which it is located.
  - ✓ For example, Astoria East is sometimes export-constrained, so its average day-ahead LBMP was $5.85/MWh lower than for the NYC zone in the summer.
- The upper portion of the figure shows the average real-time price premium at the node compared to the zone in which it is located.
  - ✓ For example, Astoria East exhibited a real-time price premium that was $4.43/MWh lower than for the NYC zone in the summer. This implies that the price effects of export-constraints from Astoria East were larger in the real-time market than in the day-ahead market.
- The east end of Long Island was import-constrained relative to other areas in Long Island in the day-ahead market but not in the real-time market.
- The three nodes shown in Upstate areas exhibit better consistency between the day-ahead and real-time prices than the nodes in NYC and Long Island.

Day-Ahead and Real-Time Nodal Prices

- Overall, convergence between day-ahead and real-time prices at the nodal level has not changed much from 2009 to 2010, although several factors helped improve convergence:
  - ✓ SRE commitments (which increase commitment after day-ahead market) were less frequent in 2010 in New York City.
  - ✓ Simplified interface constraints in New York City load pockets were used less frequently in real-time to manage congestion.
    - – The share of binding constraints in New York City that were simplified interface constraints (rather than line constraints) fell from 43 percent in 2009 to 30 percent in 2010. (Simplified interface constraints are never used in the day-ahead market.)
  - ✓ However, these effects were offset by increased price volatility in real-time associated with higher load levels, higher fuel costs, and more frequent TSAs.
- Currently, virtual trading is allowed at only the zonal level.
  - ✓ We have recommended that NYISO allow virtual trading at a more disaggregated level in prior reports and the NYISO has developed an approach.
  - ✓ This would likely improve convergence at individual nodes by allowing market participants to arbitrage day-ahead to real-time prices at the nodal level.

Average Real-Time Price Premium at Select Nodes
2010



Note: In NYC, *Arthur Kill* is the Arthur Kill 2 bus and *Astoria East* is the Astoria GT 2 bus. In Long Island, *Valley Stream* is the Barrett 1 bus and *East End* is the Global Greenport GT 1 bus. In Upstate , *Athens* is in Capital Zone, *E. Delwre* is the East Delaware bus in Hudson Valley, and *Bliss Wind* is in West Zone.

POTOMAC ECONOMICS

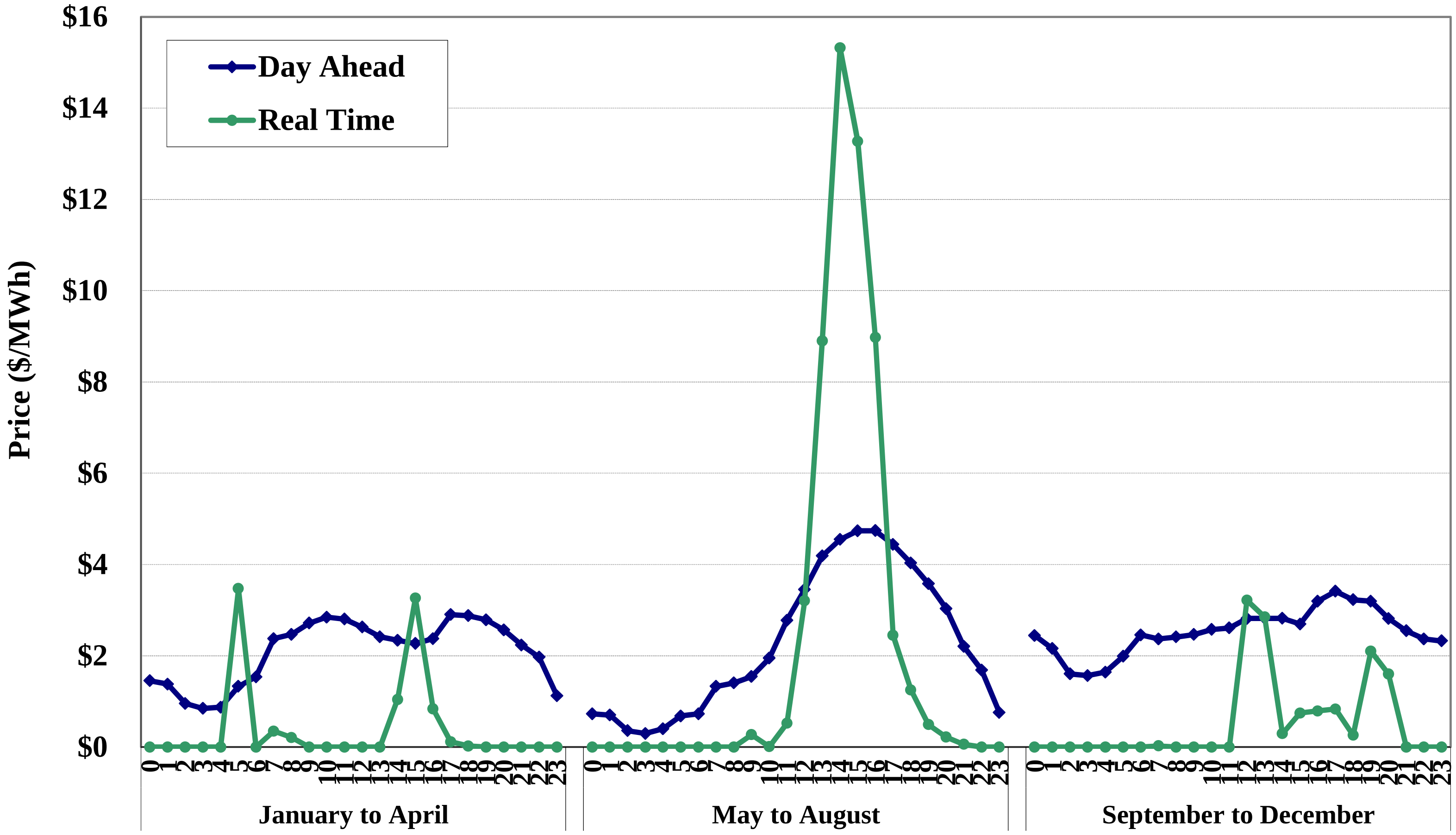
Day-Ahead and Real-Time Ancillary Services Prices

- The following figures summarize day-ahead and real-time clearing prices for the two most important reserve products in New York State.
  - ✓ The first figure shows 10-minute non-spinning reserve prices in eastern New York, based primarily on the requirement to hold 1,000 MW (1,200 MW beginning Dec. 1, 2010) of 10-minute reserves east of the Central-East Interface.
  - ✓ The second figure shows 10-minute spinning reserve prices in western New York, based primarily 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 on meeting each of these requirements.
- Average day-ahead prices are substantially higher than average real-time prices in most hours.
  - ✓ However, average real-time prices are substantially higher during several afternoon hours, particularly during the summer.

Day-Ahead and Real-Time Ancillary Services Prices

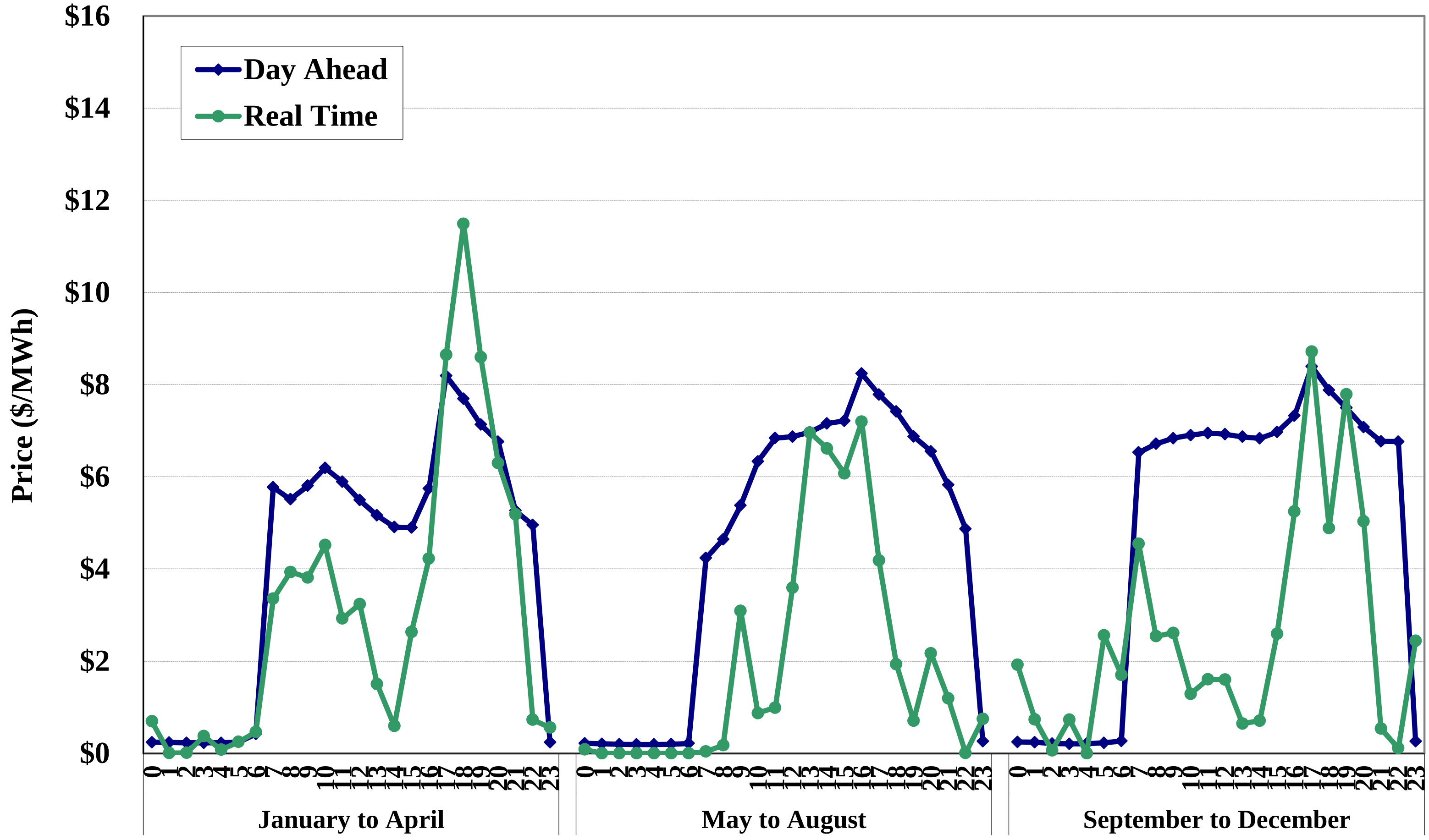
- Real-time reserve prices are generally volatile, making them difficult for market participants to predict in the day-ahead market.
  - ✓ Eastern real-time 10-minute non-spinning reserves prices are normally close to $0, reflecting the excess available reserves from off-line GTs.
    - – However, real-time prices can spike during periods of tight supply.
    - – It can be risky to sell reserves in the day-ahead market. If the real-time price spikes, the supplier can incur substantial losses or foregone profits.
  - ✓ 10-minute spinning reserves prices are less volatile, but still prone to spikes.
- Day-ahead reserve prices tend to fluctuate based on the expected likelihood of a real-time price spike.
  - ✓ The fact that day-ahead prices were consistently higher than real-time prices in certain periods when real-time price spikes are particularly unlikely suggests that suppliers may have over-estimated the frequency of real-time price spikes.
- Average day-ahead reserve prices were lower than real-time prices in certain periods, partly due to day-ahead reserve offer limitations that we discuss in the next section.

10-Minute Non-Spinning Reserve Prices in East NY
by Season and Hour of Day, 2010



POTOMAC ECONOMICS

10-Minute Spinning Reserve Prices in West NY
by Season and Hour of Day, 2010



POTOMAC ECONOMICS

Analysis of Bids and Offers:
Energy Offer Patterns

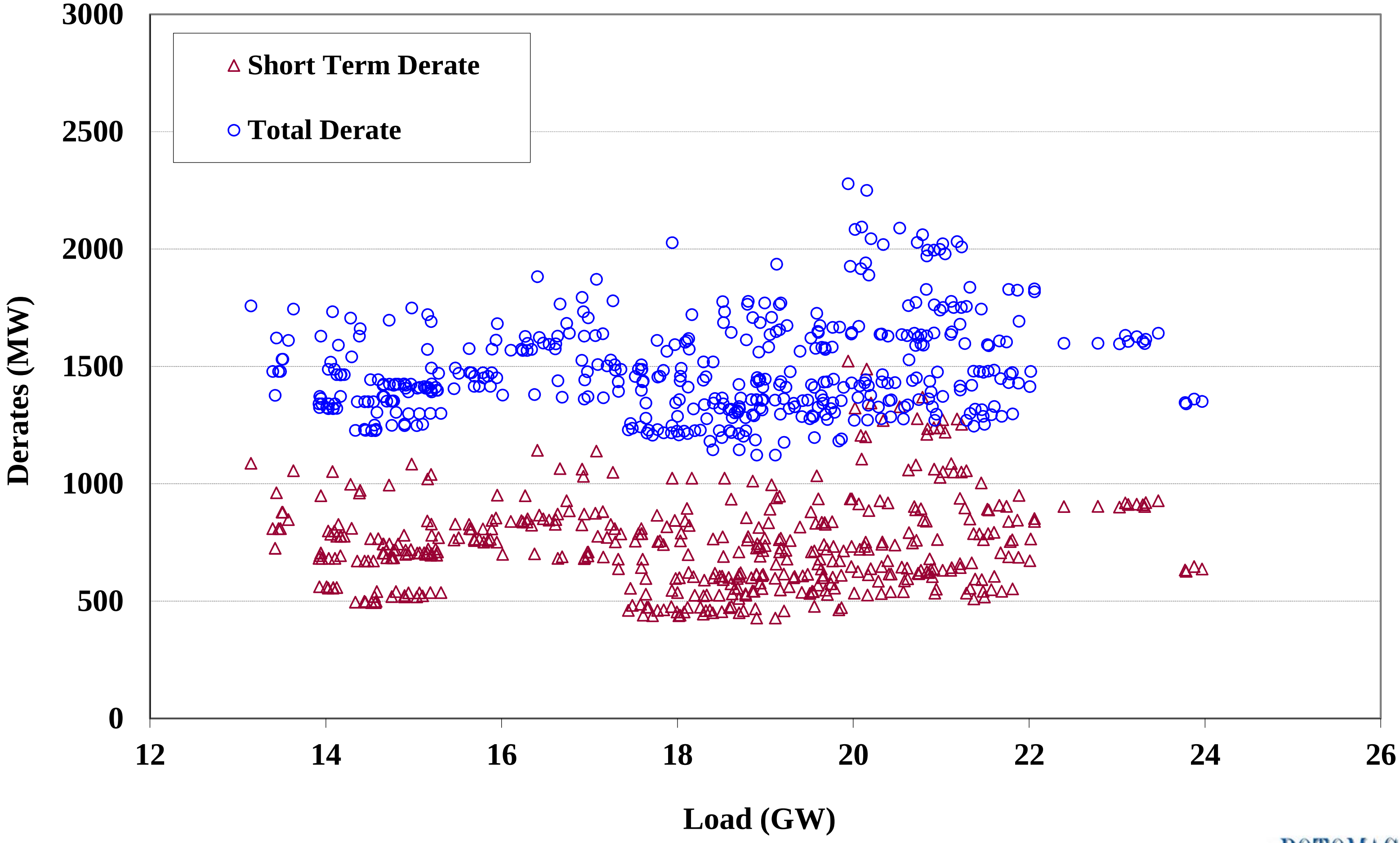
Analysis of Energy Offer Patterns

- This section of the report analyzes offer patterns that could indicate potential anticompetitive or manipulative conduct, including physical or economic withholding.
- These analyses evaluate the overall quantities of potential withholding, as well as the correlation of potential withholding to load levels.
  - ✓ Because each of the withholding metrics will include legitimate, competitive conduct, examining their correlation with load levels can help identify anticompetitive conduct.
  - ✓ 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 tends to be 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 New York during peak hours in the summer.
  - ✓ The figures focus on East New York 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 values. Short-term deratings exclude quantities lasting more than 30 days.
  - ✓ The short-term deratings are more likely to reflect physical withholding since it is more costly to withhold via long-term deratings or outages.
- The figure shows that neither long-term deratings nor short-term deratings increased during the highest load conditions, which is consistent with expectations for a competitive market.
  - ✓ As MMU, we review deratings with significant market effects, which raised no significant competitive concerns in 2010.

Deratings versus Actual Load in East New York
Peak Hours* in Summer 2010



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

POTOMAC ECONOMICS

Analysis of Offer Patterns – Output Gap

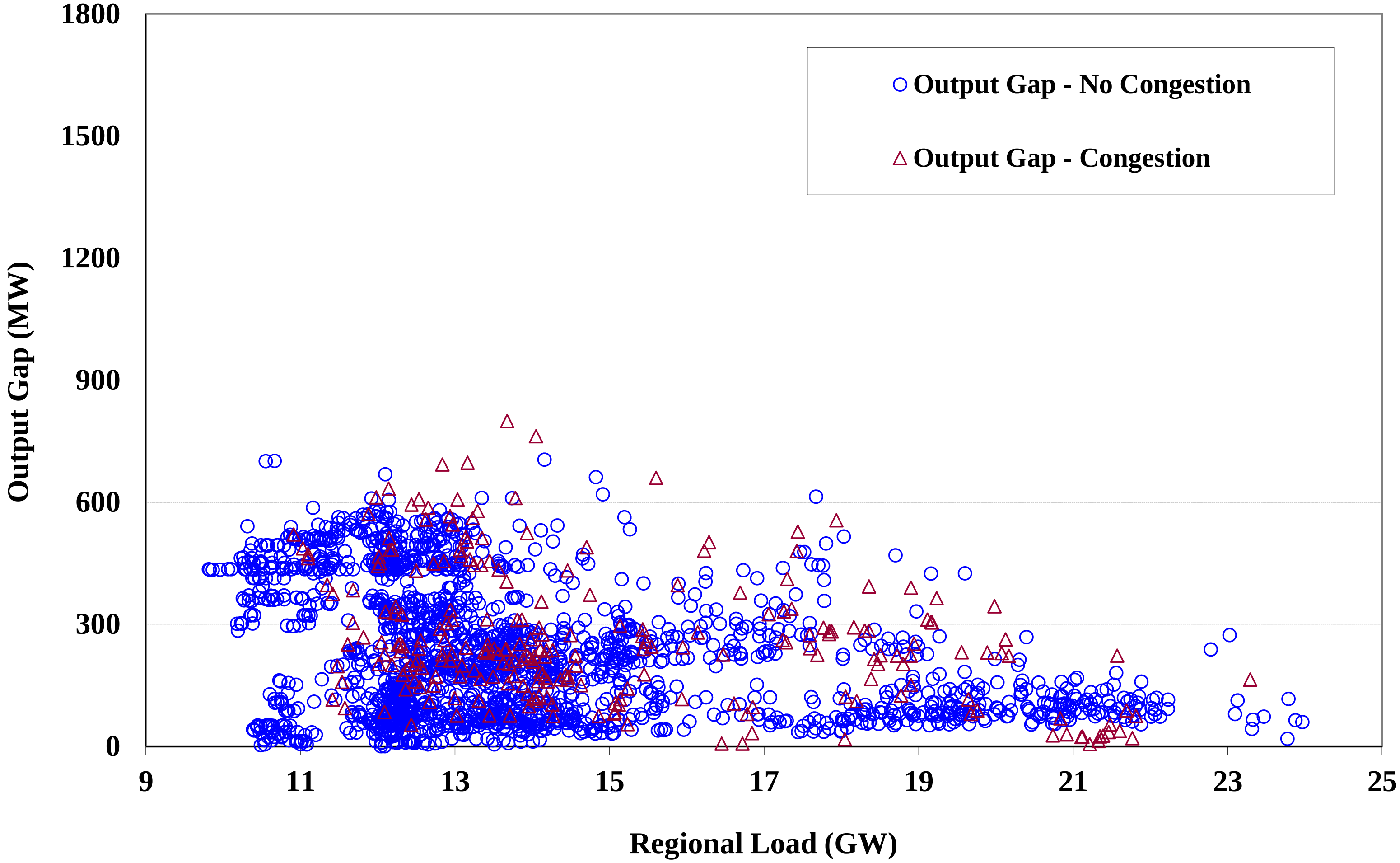
- The second analysis examines potential economic withholding, employing the "output gap" metric.
- The output gap is the quantity of economic capacity that does not produce energy or reserves because a supplier submits an offer price well above a unit's competitive offer price.
  - ✓ The analysis assumes that the unit's competitive offer price is equal to its 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 economic to provide ancillary services.
- Like the prior analysis of deratings, output gap levels that are relatively large or that rise with load would indicate potential competitive concerns, particularly if this were to occur during periods of congestion.

POTOMAC ECONOMICS

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 average levels of output gap are similar across high and low load conditions for congested and uncongested hours.
  - ✓ 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.
- As MMU, we continually review significant instances of output gap to determine whether they may be an indication of potential withholding.
  - ✓ These reviews have not indicated that these isolated instances raise significant competitive concerns.

Real-Time Output Gap at Mitigation Threshold
East New York - Peak Hours* in 2010



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

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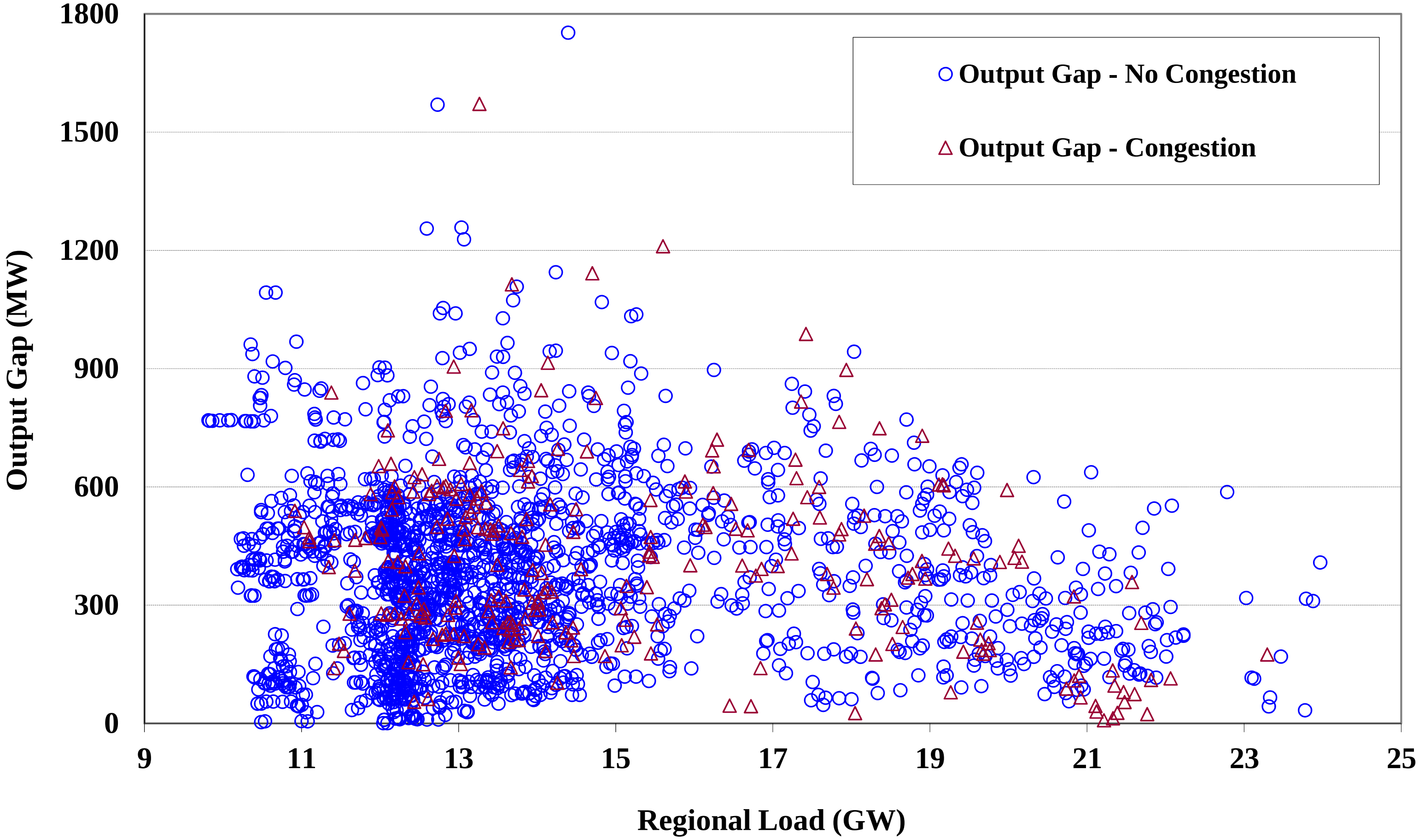
Real-Time Output Gap at Lower Threshold
East New York - Peak Hours* of 2010



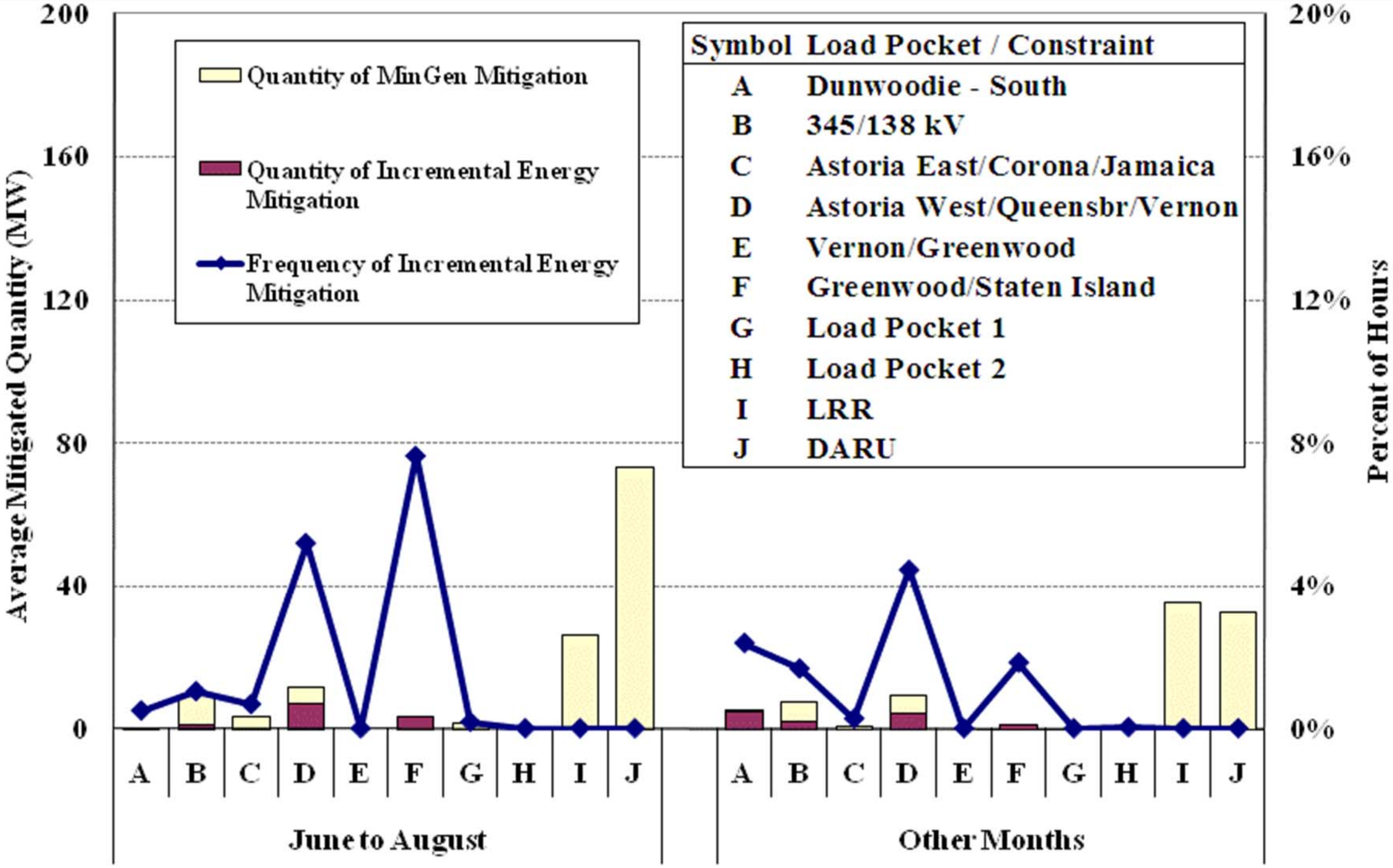
* Peak hours are defined as weekdays from 12 PM to 6 PM for purposes of this analysis.

POTOMAC ECONOMICS

Summary of Mitigation

- The market power mitigation measures are based on the conduct and impact framework, and are triggered when constraints bind into New York City load pockets.
  - ✓ This framework prevents mitigation when it is not necessary to address market power, while allowing high prices during legitimate periods of shortage.
- The following two figures summarize the amount of mitigation that occurred in New York City in the day-ahead market and in the real-time market (but not guarantee payment mitigation that occurs in settlements).
  - ✓ In the day-ahead market, mitigated quantities are shown separately for (i) the flexible output ranges of units (i.e. incremental energy) and (ii) the non-flexible portions (i.e., MinGen).
  - ✓ In the real-time market, mitigated quantities are shown separately for: (i) incremental energy and (ii) the capacity of GTs that is mitigated for start-up.
  - ✓ The bars show the average amount of capacity mitigated in each location across all hours.
  - ✓ The lines show the percent of hours when incremental energy mitigation was imposed.

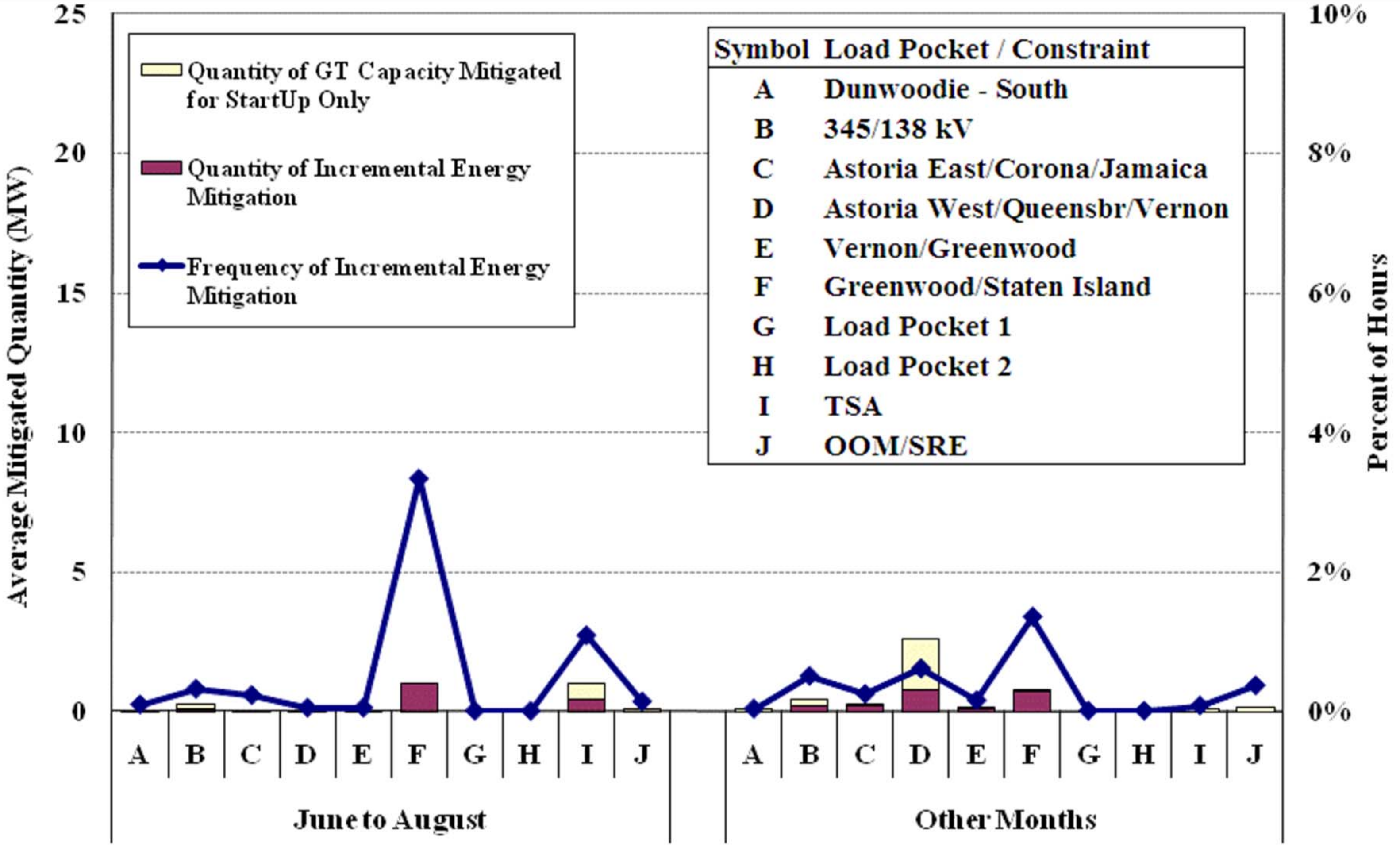
Summary of Day-Ahead Mitigation
New York City, 2010



Note: To avoid providing confidential information, the Astoria West/Queensbridge and Staten Island load pockets are labeled Load Pocket 1 and Load Pocket 2.

POTOMAC ECONOMICS

Summary of Real-Time Mitigation
New York City, 2010



Note: To avoid providing confidential information, the Astoria West/Queensbridge and Staten Island load pockets are labeled Load Pocket 1 and Load Pocket 2.

POTOMAC ECONOMICS

Summary of Mitigation

- In the day-ahead market, the majority of mitigation (75 percent) occurred on units that were committed for local reliability (i.e., “LRR” and “DARU”).
  - ✓ These units are mitigated whenever their start-up or MinGen offers exceed the reference level.
- Most of the incremental energy offer mitigation in the day-ahead market was associated with constraints that bind into the Astoria West/Queensbridge/Vernon (40 percent), the Dunwoodie South (29 percent) and the Greenwood/Staten Island (15 percent) load pockets.
- Real-time mitigation occurred infrequently, most of which was associated with constraints that bind into Greenwood/Staten Island load pockets
- Overall, the majority of energy offer mitigation occurred in the day-ahead market rather than the real-time market due to:
  - ✓ The use of tighter conduct and impact thresholds in the day-ahead market; and
  - ✓ Most energy is initially scheduled in the day-ahead market, and offers scheduled in the day-ahead market could not be increased in real time for most of the year. (This prohibition was removed in October 2010.)

Analysis of Bids and Offers:
Ancillary Services Offer Patterns

Day-Ahead Ancillary Services Offers

- The following figure evaluates day-ahead offers to provide ancillary services in each month of 2010.
  - ✓ 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.

<u>10-minute spinning reserve capacity:</u>

- Offer prices are substantially lower in the East than in the West because New York City generators are required to offer at $0/MWh.
- Offer quantities generally decline in the shoulder months when more capacity is out-of-service for planned maintenance.
- Offer quantities in the East NY increased beginning September 2010 due to new entry.

Day-Ahead Ancillary Services Offers

<u>10-minute spinning reserve capacity (Cont.):</u>

- Offer prices in both West NY and East NY increased notably during 2010.
  - ✓ The average quantity offered below $10/MWh fell by 28 percent and 36 percent from January to December in East NY and West NY, respectively.
  - ✓ The increased offer prices may reflect changes in suppliers' expectations regarding the level of real-time reserve prices relative to day-ahead reserve prices.
  - ✓ Rising fuel prices also likely contributed to the higher offer prices because they raise many units' opportunity costs.

<u>10-minute non-spinning reserves:</u>

- Offer quantities decline in the summer due to the reduced capability of GTs (primarily due to higher ambient temperatures) ,which provide the majority of non-spinning reserves in Eastern New York.
- Suppliers may avoid being scheduled in the day-ahead market by raising their offer prices in periods when:
  - ✓ Day-ahead prices tend to be lower than expected real-time prices; or
  - ✓ There is risk that a real-time price spike will coincide with the supplier failing to start, leading the supplier to incur losses in the balancing market.

Day-Ahead Ancillary Services Offers

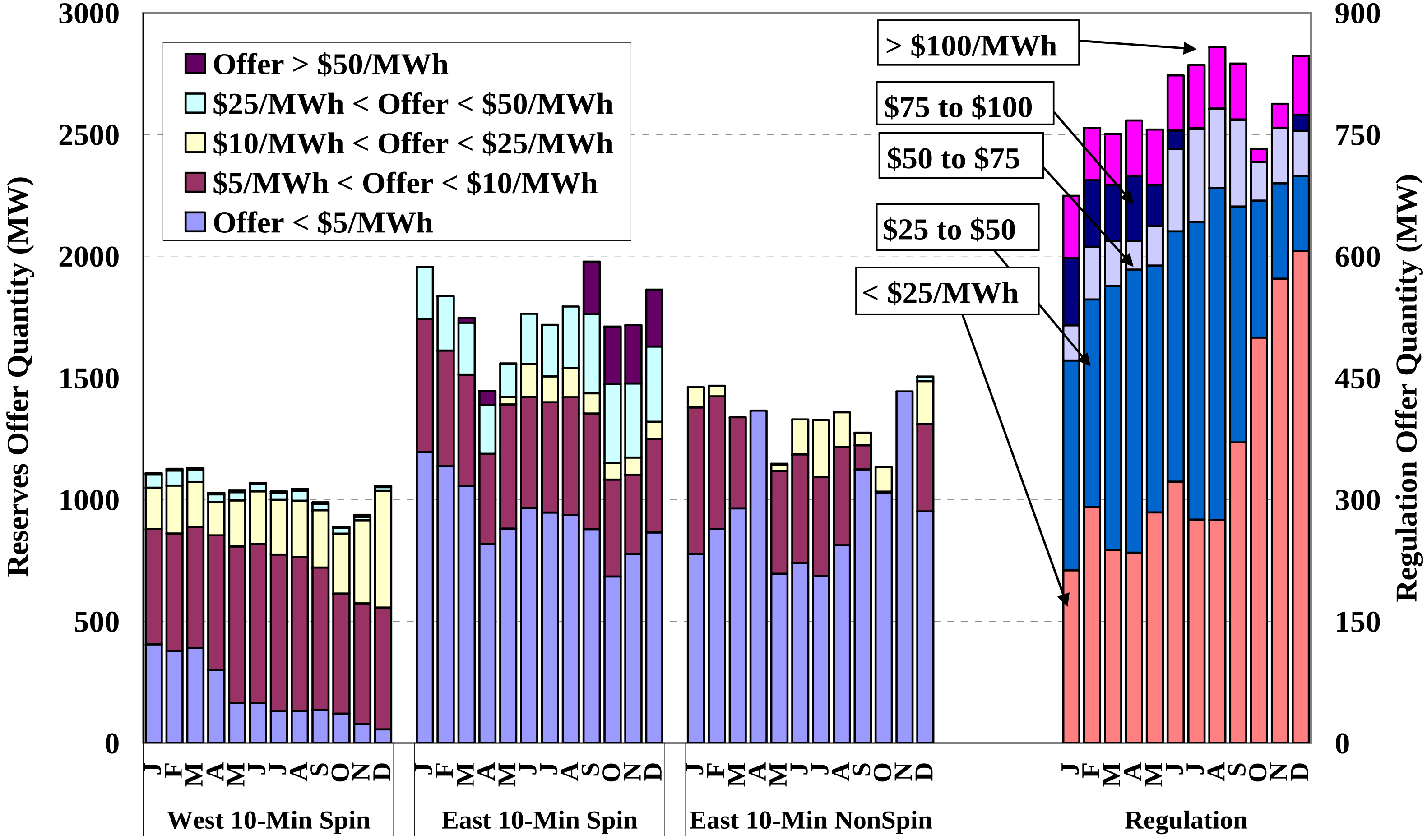
<u>10-minute non-spinning reserves (Cont.):</u>

- However, offer price increases are limited by the mitigation rules, which cap the reference levels of 10-minute non-spinning reserve units at $2.52/MWh.
- Suppliers are likely to continue offering even when the expected cost exceeds their offer price, since non-PURPA ICAP units that have 10-minute non-spinning reserve capability are required to offer it in the day-ahead market.

<u>Regulation:</u>

- Regulation offer quantities increased during the summer months when fewer units are on outage and many steam units offer more frequently.
- Low-cost offers increased throughout the year, particularly in the fall due to new entry and reduced offer prices from existing suppliers.
  - ✓ Regulation prices fell from an average of approximately $34/MWh in the first eight months to an average of $18/MWh in the last four months of 2010.

Summary of Ancillary Services Offers
Day-Ahead Market in 2010



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

POTOMAC ECONOMICS

Ancillary Services Offers – Conclusions and Recommendations

- Average day-ahead reserves prices are systematically higher than real-time prices in the majority hours.
  - ✓ This is consistent with the risks suppliers may incur by selling reserves in the day-ahead market.
  - ✓ However, it may also be that some suppliers over-estimate the likelihood of a real-time price spike.
- Average real-time prices are frequently much higher than average day-ahead prices during afternoon hours under high-load conditions.
  - ✓ Systematically low day-ahead prices in these hours increase the opportunity cost of selling reserves in the day-ahead market.
  - ✓ Adjustments in day-ahead offer prices by reserve suppliers are likely to improve convergence between day-ahead and real-time.
- We recommend the NYISO reconsider two provisions in the mitigation measures that may limit competitive offers in the day-ahead market:
  - ✓ Limiting GTs to a 10-minute non-spinning reserve reference of $2.52/MWh.
  - ✓ Requiring New York City steam units 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

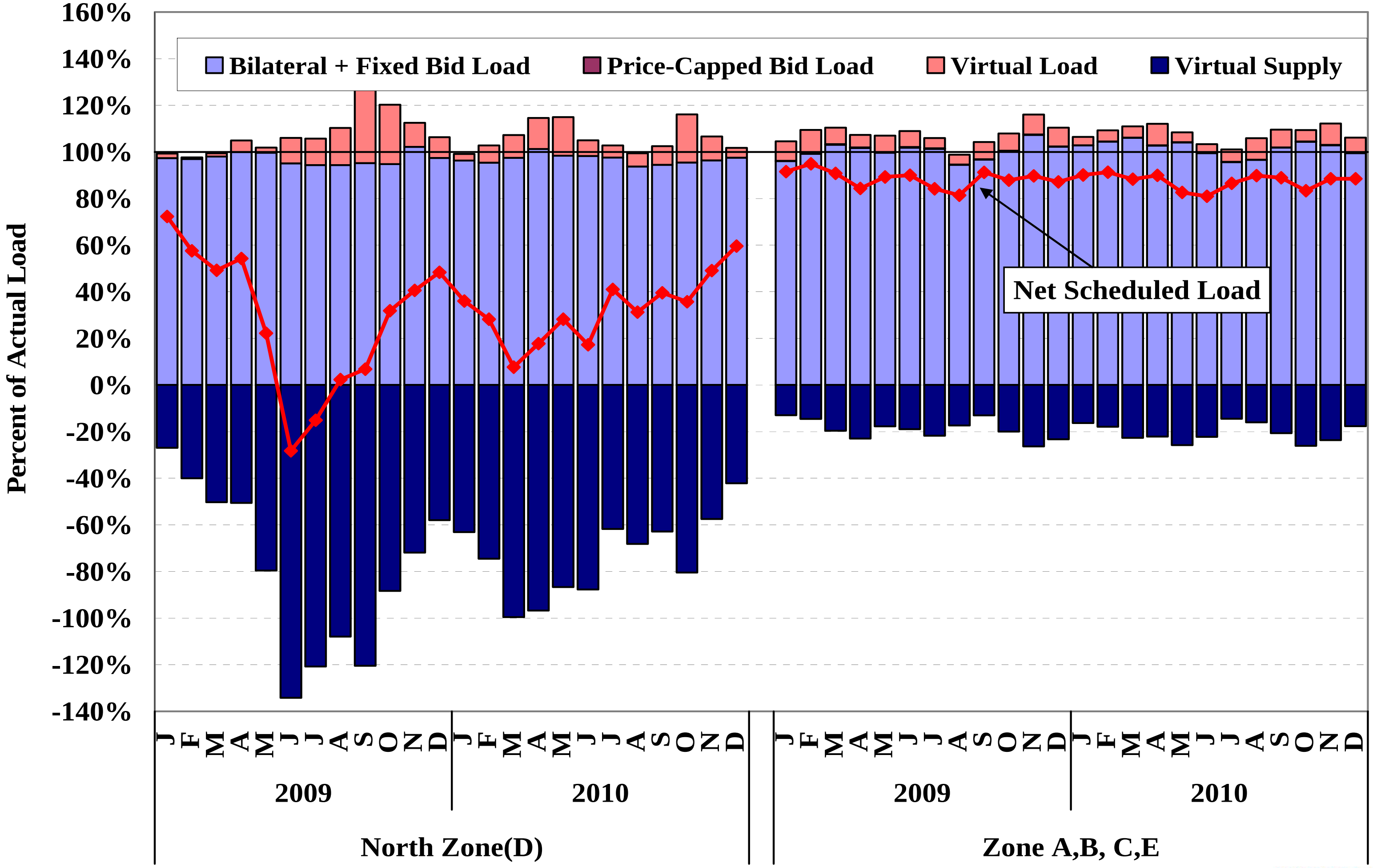
- The following three figures summarize the quantity of day-ahead load scheduled as a percent of real-time load in 2009 and 2010 in six regions.
  - ✓ Virtual supply nets out an equivalent amount of scheduled load, so it is shown as a negative quantity.
  - ✓ Net scheduled load = Physical Bilaterals + Fixed Load + Price-Capped Load + Virtual Load – Virtual Supply
- The figures show that the market generally responds rationally to differences between congestion patterns in the day-ahead and real-time markets.
- On a state-wide basis, the average amount of load scheduled in the day-ahead market is slightly lower than the average amount of real-time load.
  - ✓ The ratio of average net load scheduled in the day-ahead market to average real-time load was 96 percent in 2010, comparable to prior years.
  - ✓ The under-scheduling likely reflects the additional supply that is sometimes committed after the day-ahead market.
- Load is usually over-scheduled in New York City and Long Island and under-scheduled in up-state New York.
  - ✓ This implies that, on average, the day-ahead market schedules more imports into New York City and Long Island than the real-time market.

Load Bidding Patterns in the Day-Ahead Market

- TSAs become frequent in the summer, resulting in transmission limits from the Capital Zone to the Hudson Valley that are tighter in the real-time market than in the day-ahead. This provides incentives to:
  - ✓ Schedule virtual load in Southeast New York (Zones G – K) in anticipation of higher real-time prices; and
  - ✓ Schedule virtual supply outside Southeast New York in anticipation of lower real-time prices.
  - ✓ Accordingly, the ratio of average net scheduled load to average real-time load in 2010 was:
    - – 108 percent in the summer vs. 101 percent in other months in Zones G – I; and
    - – 81 percent in the summer vs. 94 percent in other months in the Capital Zone.
- In Zone D, where the day-ahead energy schedules of wind and thermal units are typically lower than the real-time energy schedules, market participants have incentives to schedule large quantities of virtual supply.
- The over- and under-scheduling patterns generally improve convergence between day-ahead and real-time prices in most areas.

Day Ahead Load Schedules versus Actual Load

West Up-State New York, 2009 – 2010



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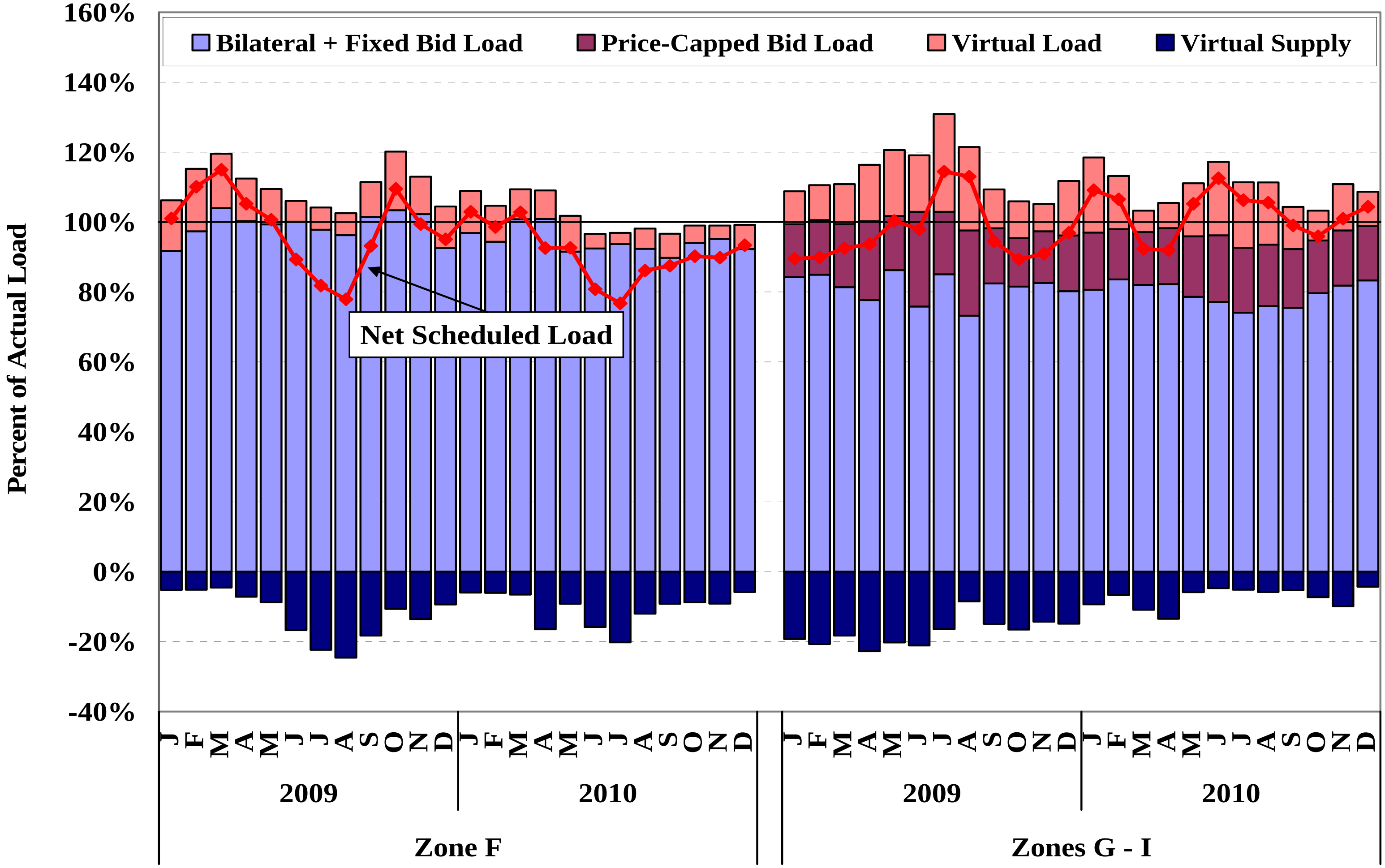
Day-Ahead Load Schedules versus Actual Load

East Up-State New York, 2009 – 2010



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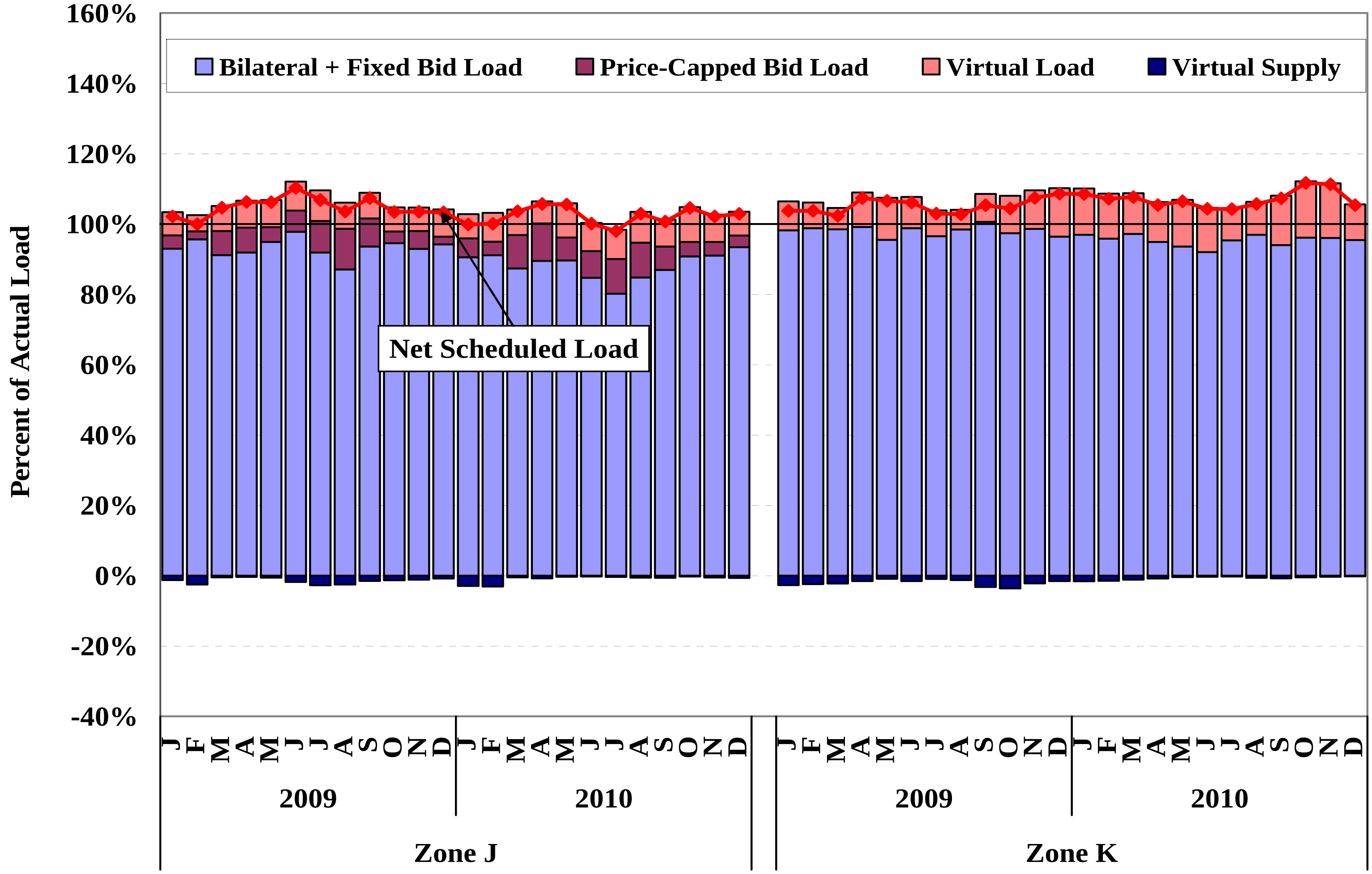
Day-Ahead Load Schedules versus Actual Load

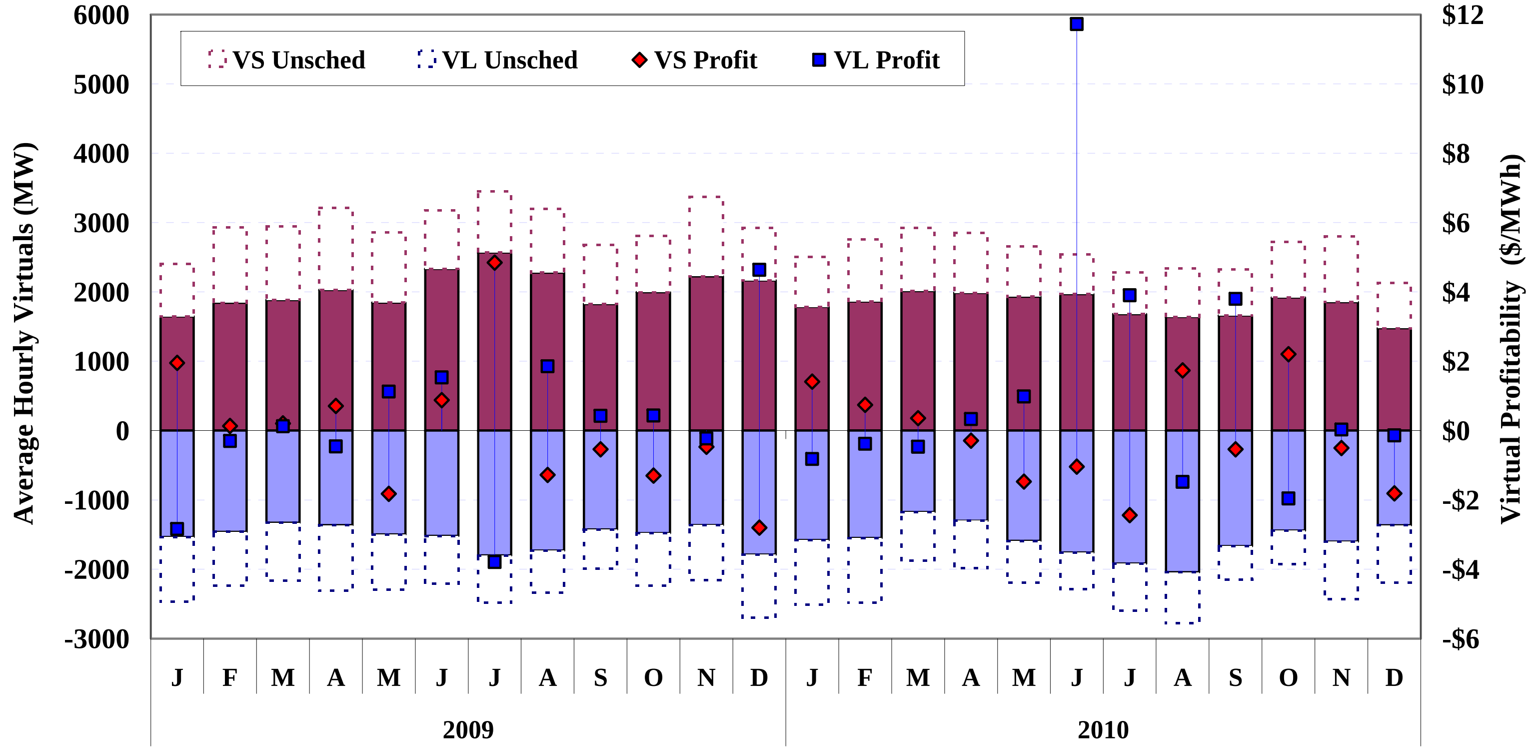
New York City and Long Island, 2009 – 2010



Virtual Trading Activity

- The following two figures summarize virtual trading activity in New York.
- The first figure shows monthly average scheduled quantities, unscheduled quantities, and profitability for virtual transactions in 2009 and 2010.
  - ✓ In each of the 24 months, 1.2 to 2.0 GW of virtual load and 1.5 to 2.5 GW of virtual supply have been consistently scheduled in the day-ahead market.
  - ✓ In aggregate, virtual load and supply have been profitable over the period, indicating that they have generally improved convergence between day-ahead and real-time prices.
  - ✓ However, the profits and losses of virtual load and supply have varied widely from month-to-month, reflecting the difficulty of predicting volatile real-time prices.
    - – For example, virtual loads scheduled in Southeast New York earned large profits in June 2010 due to poor price convergence, but they incurred losses in August 2010 due to a reversal in the price differences in New York City.
- The table below the figure shows a screen for relatively large profits or losses.
  - ✓ Large profits may be an indicator of a modeling inconsistency, and large losses may be an indicator of potential manipulation of the day-ahead market.
  - ✓ These levels were modest in 2010, and our monitoring of these indicators have not raised potential manipulation concerns.

Virtual Trading Volumes and Profitability
January 2009 to December 2010

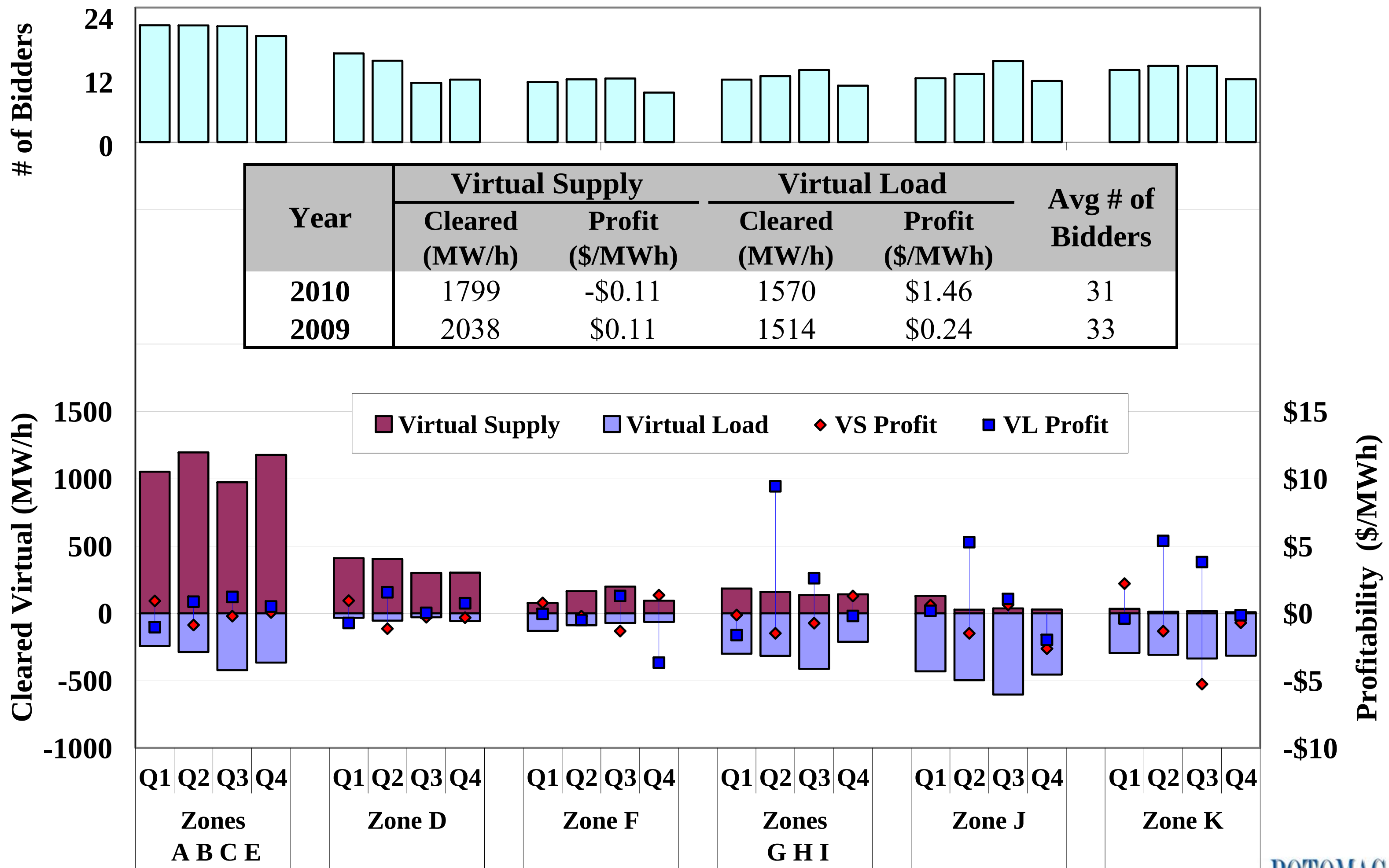


Profit > 50% of Avg. Zone Price	MW	97	105	225	270	271	420	514	293	235	315	239	573	380	324	240	122	181	285	205	176	162	117	135	221
	%	3%	3%	7%	8%	8%	11%	12%	7%	7%	9%	7%	14%	11%	10%	8%	4%	5%	8%	6%	5%	5%	3%	4%	8%
Loss > 50% of Avg. Zone Price	MW	108	102	192	249	281	384	611	441	244	369	253	578	347	284	201	112	211	241	300	205	115	95	131	273
	%	3%	3%	6%	7%	8%	10%	14%	11%	7%	11%	7%	15%	10%	8%	6%	3%	6%	6%	8%	6%	3%	3%	4%	10%

Virtual Trading Activity

- The second figure summarizes virtual trading by geographic region. The eleven zones are broken into six geographic regions based on typical congestion patterns.
  - ✓ Zone D (the North Zone) is shown separately because generation in that zone exacerbates transmission congestion on several interfaces, particularly the Central-East interface.
  - ✓ Zone F (the Capital Zone) is shown separately because it is constrained from Western New York by the Central-East Interface and from Southeast New York by constraints in the Hudson Valley.
  - ✓ Zones J (New York City) and K (Long Island) are shown separately because congestion frequently leads to price separation between them and other areas.
- A large number of market participants regularly submit virtual bids and offers.
  - ✓ On average, 10 or more participants submitted virtual trades in each region and 31 participants submitted virtual trades somewhere in the state.
- There were substantial net virtual load purchases in downstate areas and net virtual supply sales in upstate areas in 2010, consistent with prior years.
  - ✓ Virtual load scheduling in downstate areas in the second and third quarters accounted for 73 percent of total virtual trading profits in 2010.
  - ✓ This is not surprising because real-time congestion was not fully reflected in day-ahead prices during these two quarters.

Virtual Trading Activity
by Region by Quarter, 2010



Year	Virtual Supply Cleared (MW/h)	Virtual Supply Profit ($/MWh)	Virtual Load Cleared (MW/h)	Virtual Load Profit ($/MWh)	Avg # of Bidders
2010	1799	-$0.11	1570	$1.46	31
2009	2038	$0.11	1514	$0.24	33

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Transmission Congestion

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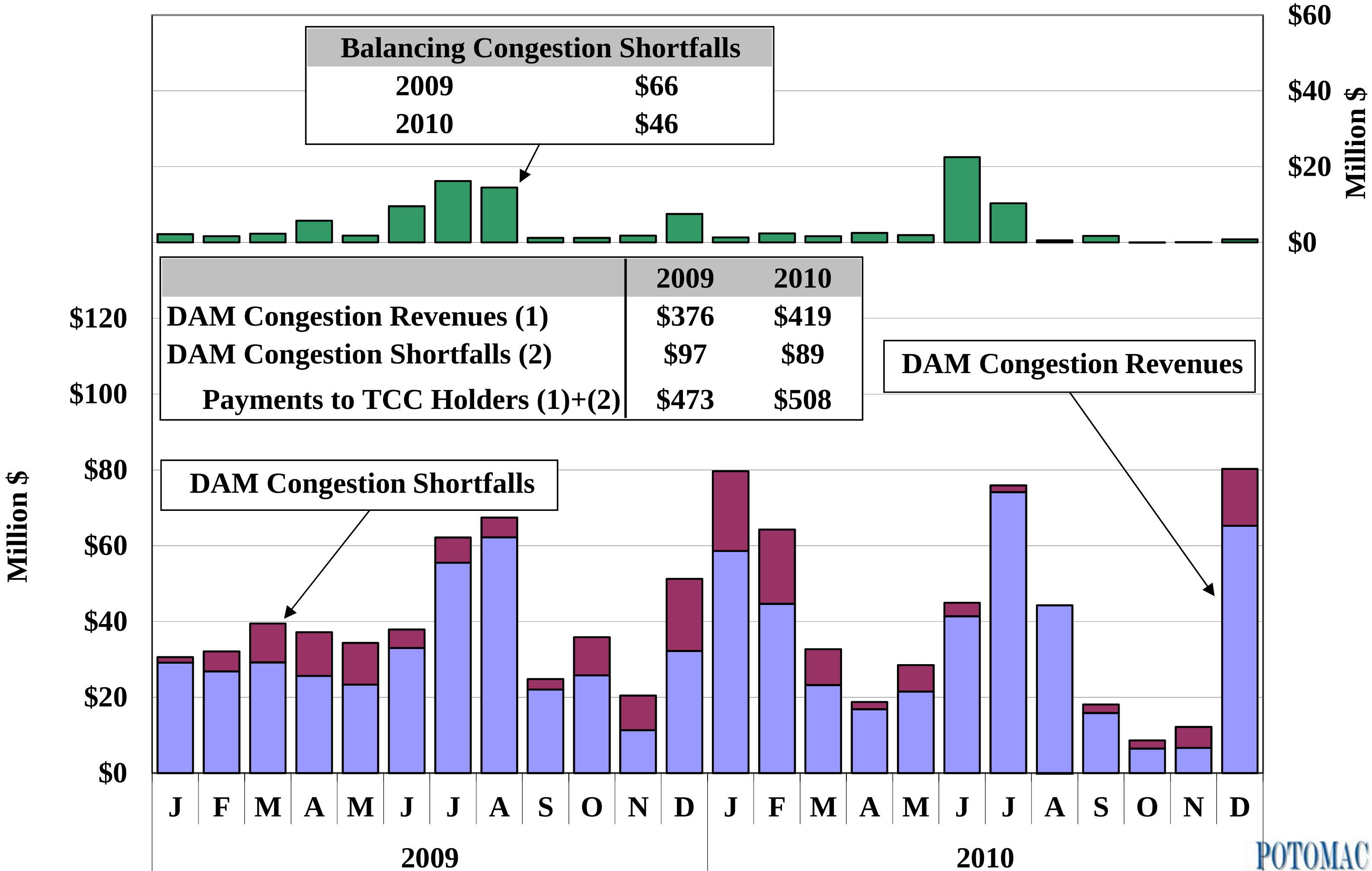
Congestion Revenue Collections and Shortfalls

- This section of the report summarizes and evaluates the congestion patterns in 2010 and quantifies the following categories of congestion costs:
  - ✓ *Day-Ahead Congestion Revenues* are collected by the NYISO when power is scheduled to flow across congested interfaces in the day-ahead market.
  - ✓ *Day-Ahead Congestion Shortfalls* occur when the day-ahead congestion revenues collected by the NYISO are less than the payments to TCC holders.
    - Shortfalls generally arise when the quantity of TCCs on a path exceeds the transfer capability of the path modeled in the day-ahead market during periods of congestion.
    - Payments to TCC holders are equal to the sum of day-ahead congestion revenues and day-ahead congestion shortfalls.
    - These shortfalls are partly offset by the revenues from selling excess TCCs.
  - ✓ *Balancing Congestion Shortfalls* arise when day-ahead scheduled flows over a constraint exceed what can flow over the constraint in the real-time market.
    - This requires the ISO to re-dispatch generation on each side of the constraint in the real-time market, buying additional energy in the high-priced area and selling back energy (that was purchased day-ahead) in the low-priced area.
    - This re-dispatch results in balancing congestion shortfalls which are recovered through uplift.

Congestion Revenue Collections and Shortfalls

- The following figure summarizes day-ahead congestion revenue and shortfalls, and balancing congestion shortfalls in 2009 and 2010.
- Day-ahead congestion revenue collections were $419 million in 2010, up 11 percent from 2009. The increase was mostly attributable to:
  - ✓ Increased fuel costs, which increased congestion price differences; and
  - ✓ Higher load levels, which increased flows into constrained areas.
- Day-ahead congestion revenues and balancing congestion shortfalls rose during the summer months, which is normal due to higher loads and more frequent Thunderstorm Alerts ("TSAs").
- Day-ahead congestion shortfalls were typically lowest in the summer because transmission outages (that are reflected in the day-ahead market but not necessarily in the TCC auctions) are less frequent in summer months.
  - ✓ Only 5 percent of the total day-ahead congestion shortfall in 2010 accrued in the summer months (i.e., June to August).
- Balancing congestion shortfalls fell 30 percent from $66 million in 2009 to $46 million in 2010.
  - ✓ The decrease was largely due to improved operations during TSA events and less frequent use of simplified interface constraints in New York City.

Congestion Revenue Collections and Shortfalls
2009 – 2010



Balancing Congestion Shortfalls	
2009	$66
2010	$46

	2009	2010
DAM Congestion Revenues (1)	$376	$419
DAM Congestion Shortfalls (2)	$97	$89
Payments to TCC Holders (1)+(2)	$473	$508

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Congestion by Transmission Path

- The following two figures examine the value and frequency of congestion along major transmission paths in the day-ahead and real-time market.
  - ✓ The value of real-time congestion equals the marginal cost of relieving the constraint (i.e., shadow price) multiplied by the scheduled flow across the interface.
  - ✓ In the day-ahead market, the value of congestion equals the congestion revenue collected by the NYISO, which is the primary funding source for TCC payments.
- The two figures group congestion along the following transmission paths:
  - ✓ West to Central: Primarily Dysinger East, West-Central, and West Export interfaces.
  - ✓ Central to East: Primarily the Central-East interface.
  - ✓ Capital to Hudson Valley: Primarily the Leeds-to-Pleasant Valley line.
  - ✓ NYC Lines – 345 kV system: Lines leading into and within the NYC 345kV system.
  - ✓ NYC Lines – Load Pockets: Lines leading into and within NYC load pockets.
  - ✓ NYC Simplified Interface Constraints: Groups of lines to NYC load pockets that are modeled as interface constraints.
  - ✓ Long Island: Lines leading into and within Long Island.
  - ✓ External Interface: Congestion related to the total transmission limits or ramp limits of the nine external interfaces.

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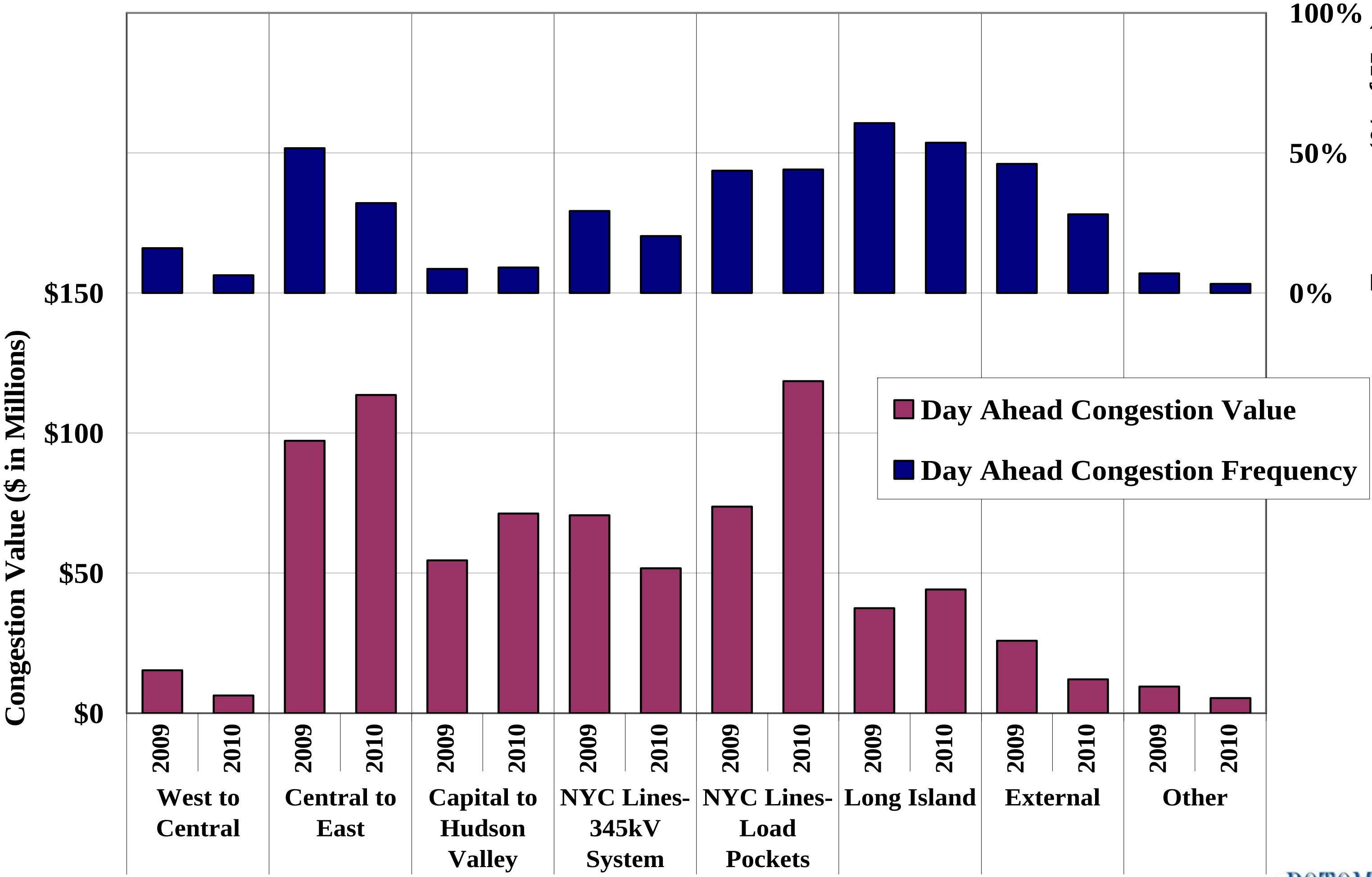
Day-Ahead Congestion by Transmission Path

- The next figure summarizes the frequency of congestion and congestion revenue collected by transmission path in the day-ahead market in 2009 and 2010.
- Day-ahead congestion patterns are determined by the market participants’ bids and offers, which reflect their expectations of real-time congestion.
  - ✓ Congestion is more frequent in the day-ahead market than in real-time, but shadow prices of constrained interfaces are generally higher in real-time.
- The majority of day-ahead congestion revenue in 2010 occurred over lines into and within New York City (40 percent), paths from Central to East (27 percent), and lines from Capital to Hudson Valley (17 percent).
- Compared to 2009, the congestion occurred less frequently in 2010. The decrease was mostly attributable to:
  - ✓ Less clockwise circulation around Lake Erie for most of the year;
  - ✓ Reduced imports from Ontario and HQ into western New York; and
  - ✓ Increased imports from PJM to New York City via the Linden VFT interface.
- However, the overall congestion cost rose in 2010, due primarily to the increases in fuel prices and load levels.

Day-Ahead Congestion by Transmission Path
2009 – 2010



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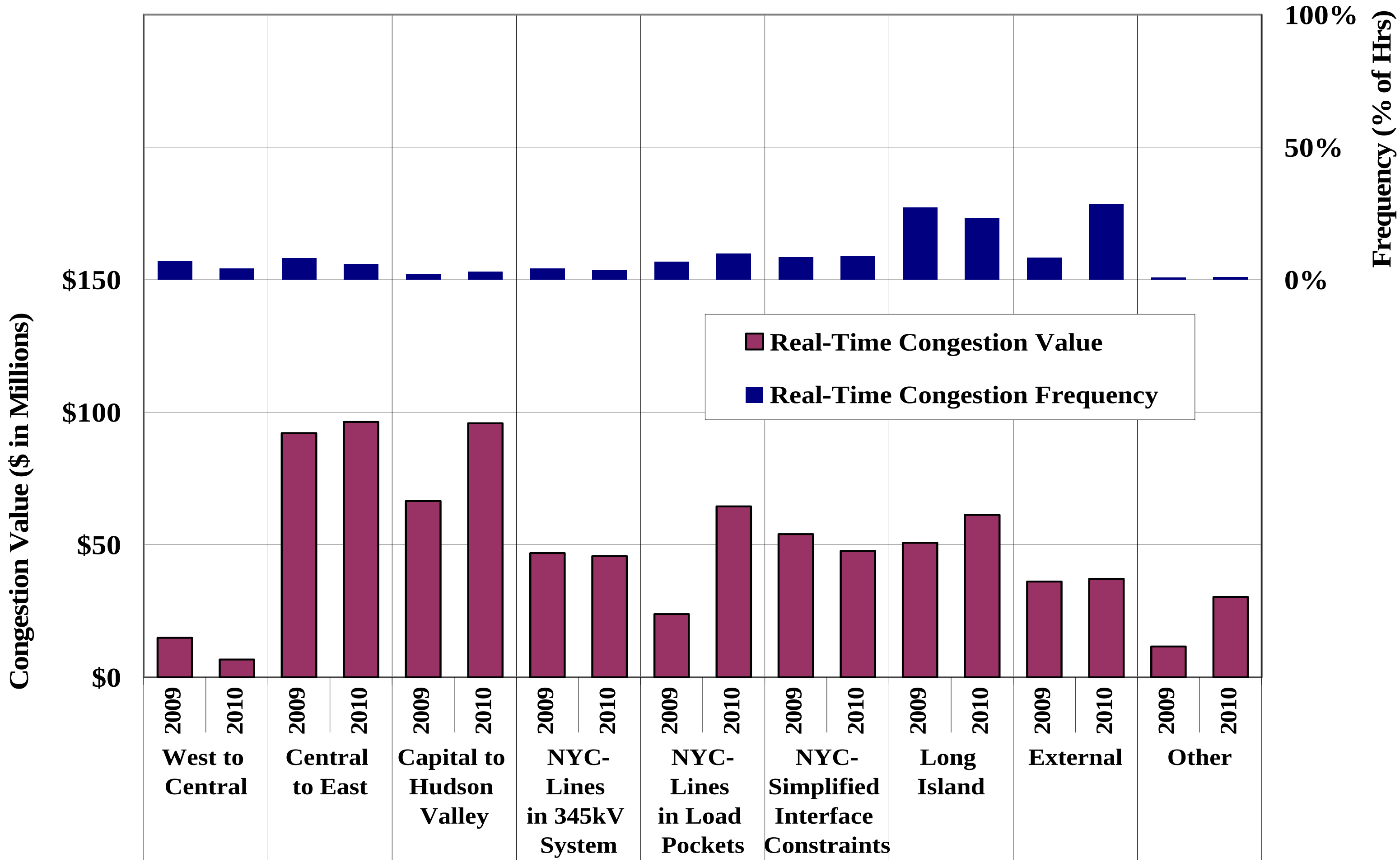
Real-Time Congestion by Transmission Path

- The following figure summarizes the value and frequency of congestion by transmission path in the real-time market for 2009 and 2010.
- Real-time congestion occurred mostly in the following areas in 2010:
  - ✓ *NYC lines and simplified interface constraints*: 32 percent – The use of simplified interface constraints decreased from 2009 to 2010, which reduced the share of the real-time congestion value associated with simplified interface constraints.
  - ✓ *Central to East*: 20 percent.
  - ✓ *Capital to Hudson Valley*: 20 percent – Of this, 59 percent occurred during TSA events in the summer.
- Real-time congestion occurred mostly in the summer (39 percent) and winter (36 percent) in 2010.
  - ✓ Congestion in the summer (June to August) was mostly associated with the Greenwood load pocket in New York City and lines from Capital to Hudson Valley, primarily due to high loads and TSAs.
  - ✓ Nearly half of congestion in the winter (January, February, and December) was related to the Central-East Interface.

Real-Time Congestion by Transmission Path
2009 – 2010



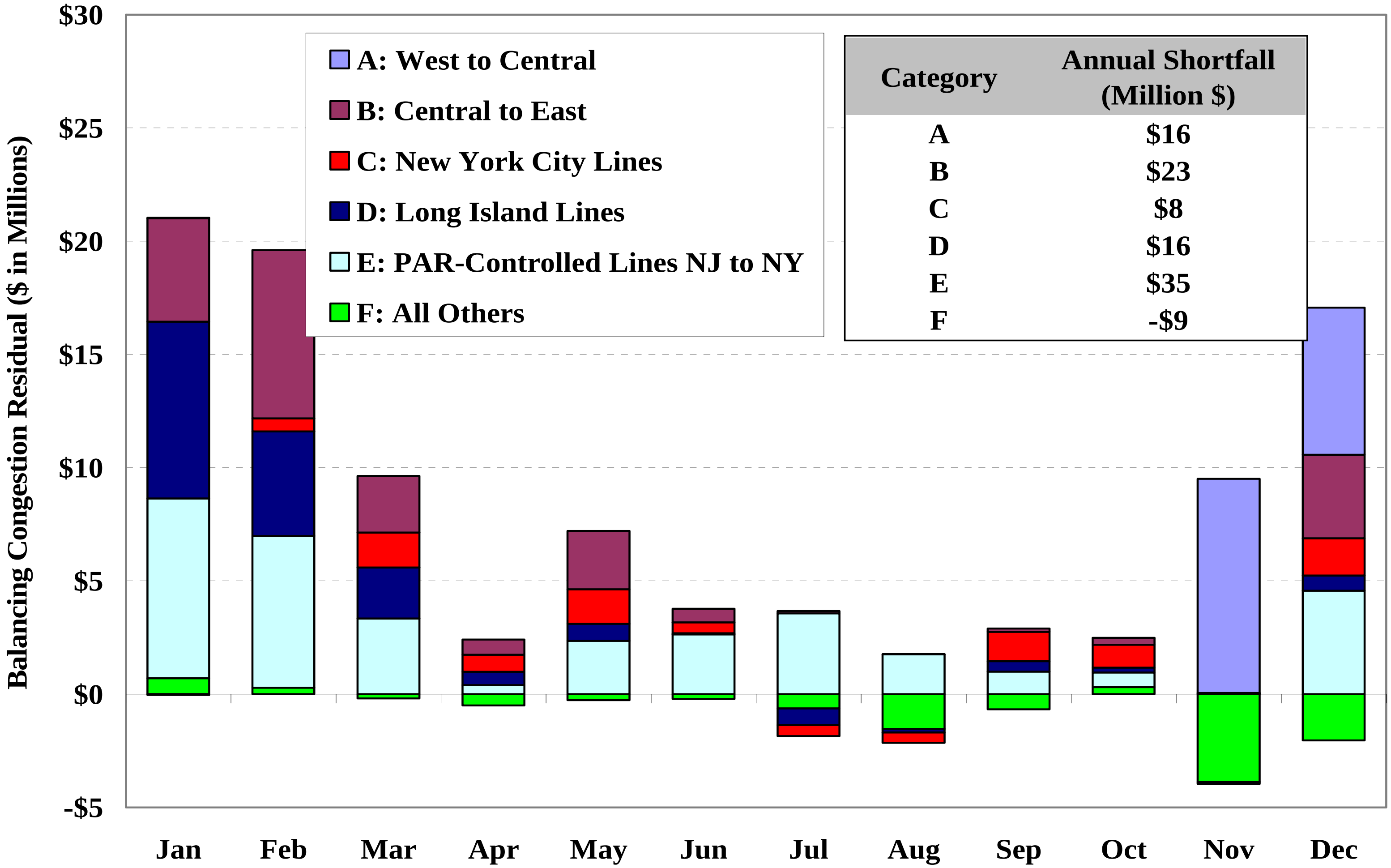
Day-Ahead Congestion Revenue Shortfalls

- Day-ahead congestion revenue shortfalls can result from:
  - ✓ Modeling assumption differences between the TCC auction and the day-ahead market, including assumptions related to PAR schedules and loop flows; and
  - ✓ Transmission outages that are assumed in the day-ahead market but not in the TCC auctions.
- The following figure shows the monthly day-ahead congestion revenue shortfalls by transmission path or facility in 2010. Negative values indicate congestion revenue surpluses.
- The West to Central and Central to East paths accounted for 55 percent of the total day-ahead congestion revenue shortfalls in 2010. The transfer capability of these paths in the day-ahead market was consistently lower than the amount of TCCs sold in some months, partly due to:
  - ✓ Outages on the interface between Ontario and New York contributed to large shortfalls in November and December (see West to Central).
  - ✓ Differences between the commitment pattern assumed in the TCC auction and generators scheduled in the day-ahead market contributed to shortfalls from January to March, since the voltage transfer limit of the Central East Interface is affected by the commitment of generation in the Central Zone.

Day-Ahead Congestion Revenue Shortfalls

- PAR-controlled lines between New Jersey and New York (i.e., Waldwick, Ramapo, Farragut, and Linden) accounted for 39 percent of the total shortfalls.
  - ✓ Different modeling assumptions between the TCC auction and the day-ahead market led to sustained day-ahead congestion shortfalls. These differences were corrected prior to the Spring 2011 TCC auctions.
- Long Island lines accounted for 18 percent of the total shortfalls.
  - ✓ The outage of one 345kV line from Upstate to Long Island accounted for most of the shortfalls in January and February.
- The NYISO has a process for allocating day-ahead congestion revenue shortfalls to outages that are attributable to specific TOs.
  - ✓ The portion of day-ahead congestion revenue shortfalls that were charged to specific TOs for equipment outages and derates was 43 percent in 2008, 34 percent in 2009, and 37 percent in 2010.
  - ✓ TOs can avoid allocations of day-ahead congestion revenue shortfalls from specific outages by electing to incorporate them in the TCC auction assumptions.
  - ✓ Many planned outages last for part of a capability period, so there might be benefit in selling a portion of the transmission capability in TCC auctions for more granular periods than six months (e.g., one month).

Day-Ahead Congestion Shortfalls
2010



Category	Annual Shortfall (Million $)
A	$16
B	$23
C	$8
D	$16
E	$35
F	-$9

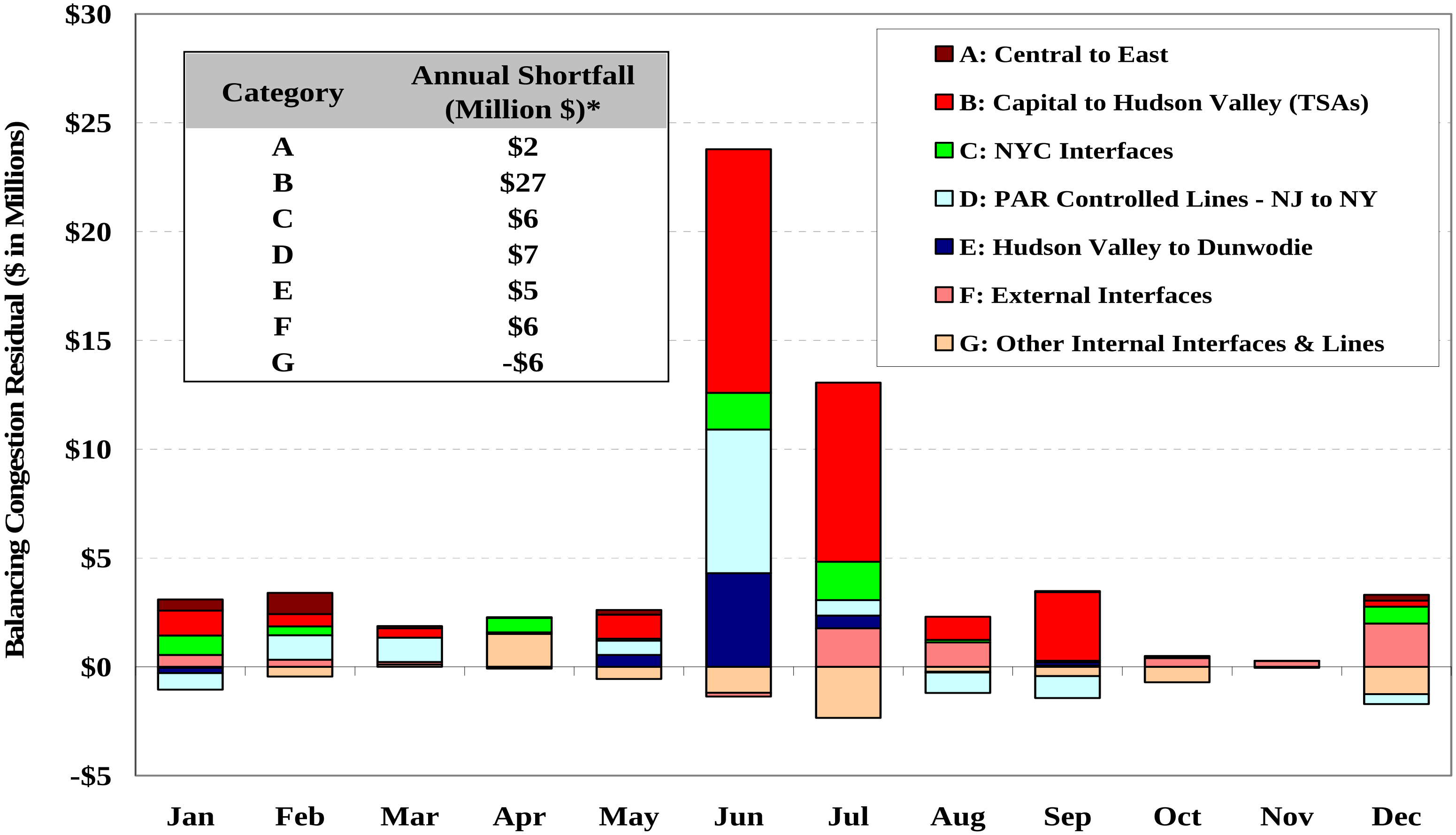
Balancing Congestion Shortfalls

- The following figure shows monthly balancing congestion shortfalls by transmission path or facility in 2010.
  - ✓ Negative values indicate balancing congestion surpluses.
- Balancing congestion 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 outages of facilities that alter the distribution of flows across other constrained facilities; and
  - ✓ Unutilized transfer capability that can arise from Hybrid Pricing, which treats physically inflexible GTs as flexible in the pricing logic.
- Balancing congestion revenue shortfalls can also occur when assumptions used in the market models change from day-ahead to real-time. This includes the direction and magnitude of:
  - ✓ Unscheduled loop flows across constrained interfaces; and
  - ✓ Flows across PAR-controlled lines.

Balancing Congestion Shortfalls

- Capital to Hudson Valley accounted for 56 percent of balancing congestion shortfalls, primarily during TSAs events.
  - ✓ TSAs require double contingency protection of the Leeds-to-Pleasant Valley line, effectively reducing the transfer capability of the path in real time.
- PAR-controlled lines between New Jersey and New York (Ramapo, Farragut, and Linden) accounted for 14 percent of balancing congestion revenue shortfalls, mostly during TSA events. This fell from the previous years, due partly to:
  - ✓ Improved operations to better manage reliability during TSA events, including better recognition of the effects of imports on congestion management in the real-time transaction scheduling process; and
  - ✓ Increased circulation around Lake Erie in the counter-clockwise direction.
- Simplified interface constraints in New York City accounted for 13 percent of congestion revenue shortfalls.
  - ✓ Use of interface constraints in the real-time market (rather than the detailed model used in the day-ahead market) generally reduces transfer capability.
  - ✓ This was lower than in prior years because simplified interface constraints were used less frequently, although NYISO should continue to seek means to minimize the use of these interfaces.

Balancing Congestion Shortfalls
2010



Category	Annual Shortfall (Million $)*
A	$2
B	$27
C	$6
D	$7
E	$5
F	$6
G	-$6

*These slightly over-estimate shortfalls since they are partly based real-time schedules rather than metered values.

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TCC Prices and Day-Ahead Congestion

- 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*: 2-year, 1-year, & 6-month TCC products are offered.
    - These are sold for periods spanning one or more whole six-month capability periods: either winter capability periods, which run from November to the following April, or summer capability periods, which run from May to October.
  - ✓ *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.
- The next two analyses evaluate the TCC market.
  - ✓ The first figure evaluates the consistency of TCC prices among different auctions and day-ahead congestion prices.
  - ✓ The second figure evaluates congestion patterns within individual zones between the TCC auctions and the day-ahead market.

TCC Prices and Day-Ahead Congestion

- The following figures summarizes TCC prices and DAM congestion prices for the Winter 2009/10 and Summer 2010 Capability Periods (i.e., the 12-month period from November 2009 through October 2010).
  - ✓ 1-year TCC prices – These are shown for the four auction rounds where TCCs were sold for the period. These occurred in August and September 2009.
  - ✓ For the Winter 2009/10 and Summer 2010 Capability Periods, the figure shows:
    - 6-month TCC prices – Shows the average price from five auction rounds.
    - Reconfiguration TCC prices – Shows sum of prices from the six monthly auctions.
    - DAM Congestion prices – Shows sum of congestion prices from the period.
- The first figure shows prices for seven zones around New York state.
  - ✓ Each price is shown relative to the reference bus at Marcy, NY.
- The second figure shows prices at six nodes that exhibited relatively poor convergence between the TCC auctions and the DAM at the intra-zonal level.
  - ✓ Each price is shown relative to the load-weighted average price for its load zone. (rather than relative to the reference bus at Marcy, NY).

TCC Prices and Day-Ahead Congestion

- Prices are not shown for Long Island in the one-year and six-month TCC auctions because the NYISO does not sell TCCs that source or sink in Long Island in those auctions.
- Zone-level TCC prices were relatively consistent with DAM congestion prices except for New York City.
  - ✓ The TCC auctions over-estimated congestion to New York City.
    - – However, the TCC prices improved from the one-year auctions to the six-month auctions, and from the six-month auctions to the reconfiguration auctions.
    - – This is consistent with expectations because participants generally have better information by the time the monthly auction occurs.
- TCC prices were less consistent with DAM congestion prices at several locations:
  - ✓ Wethersfield WT – The TCC auctions anticipated more intra-zonal congestion from this new wind site to the grid.
  - ✓ New York City – The TCC auctions predicted less congestion between export-constrained (Astoria East) and import-constrained areas (Greenwood/Pouch).
- The prices in the TCC auctions were reasonably consistent with DAM congestion prices given the difficulty of predicting DAM congestion far in advance.

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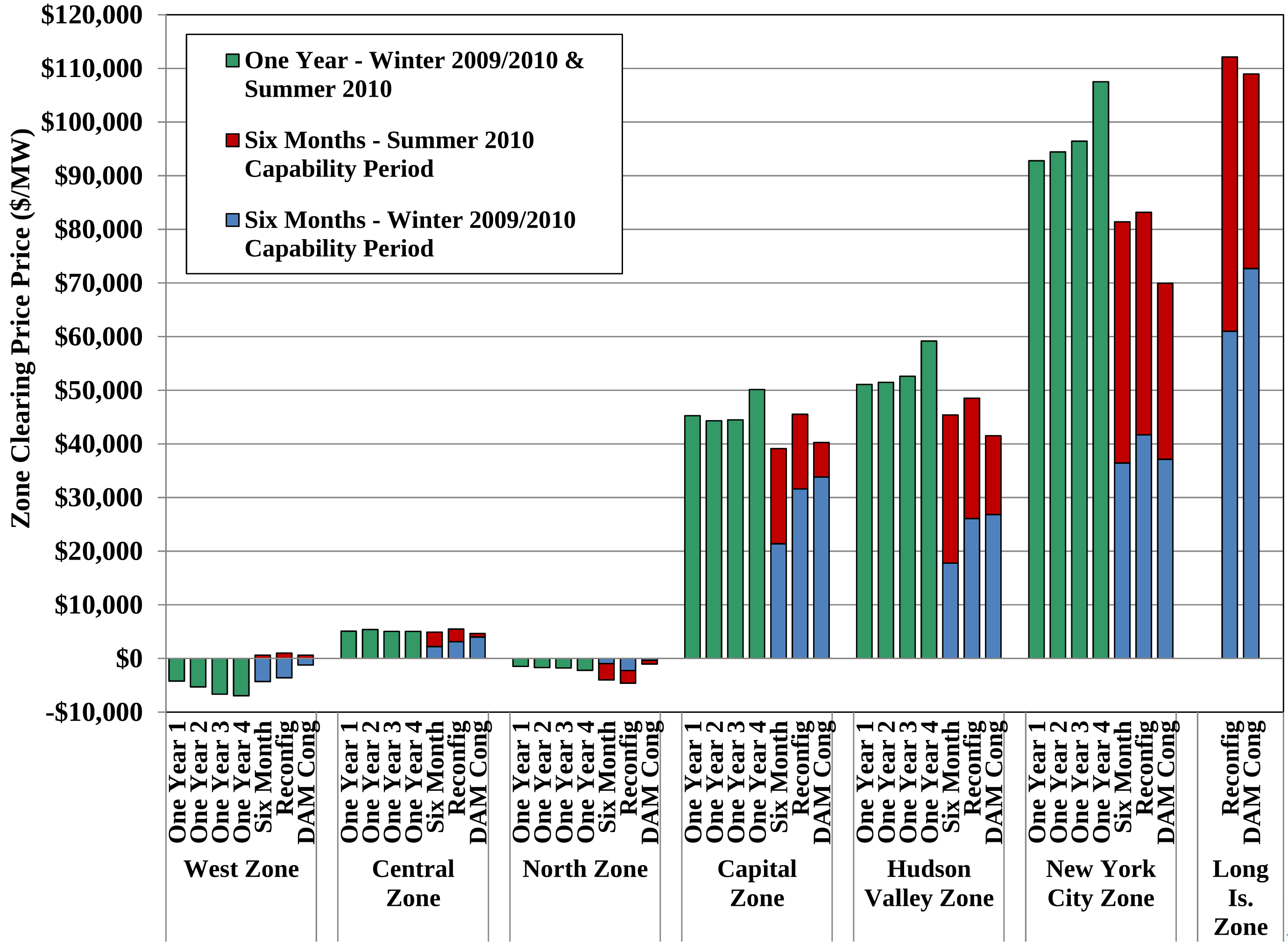
TCC Prices and DAM Congestion by Zone

Winter 2009/10 and Summer 2010 Capability Periods



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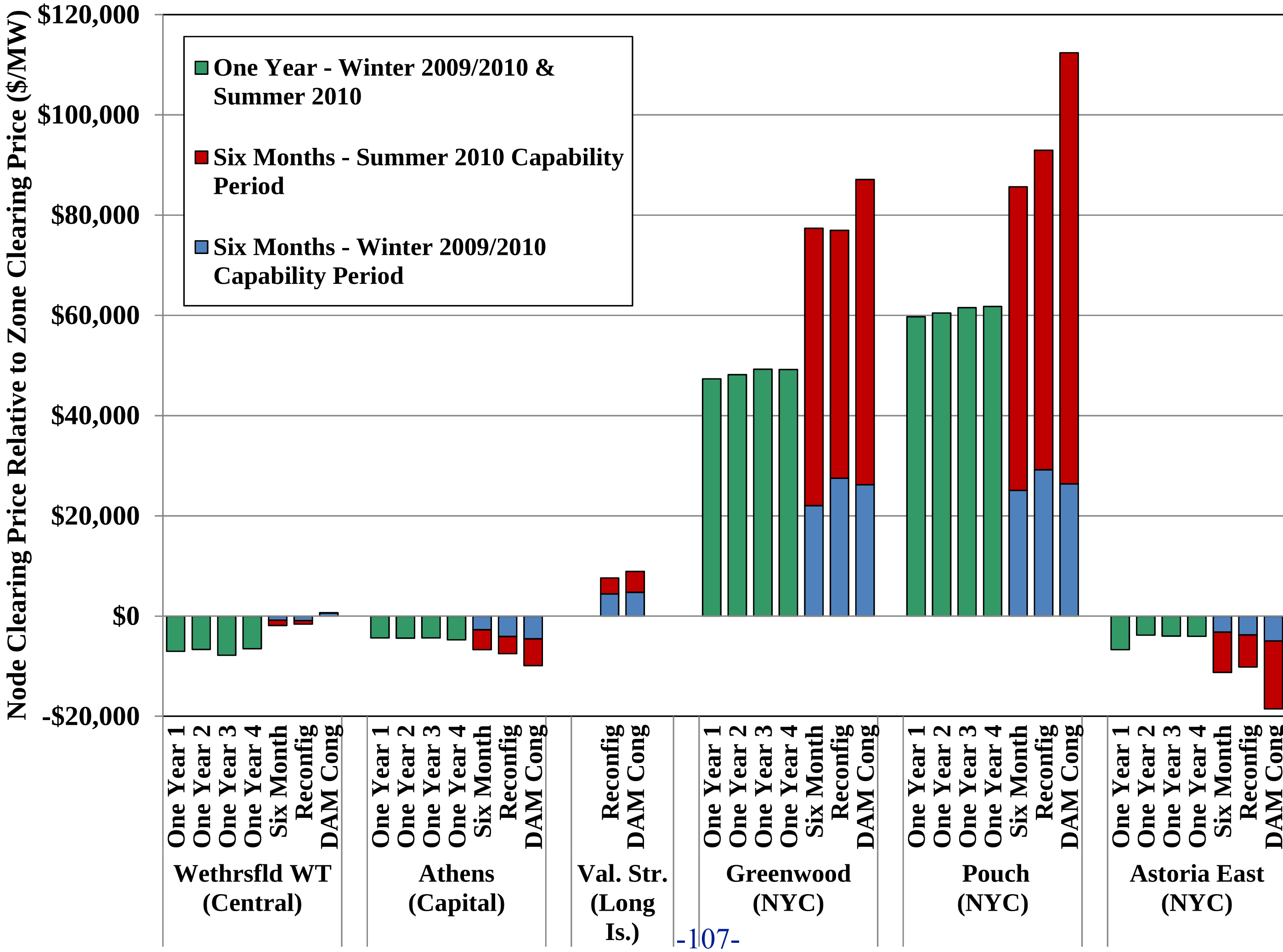
TCC Prices and DAM Congestion at Selected Nodes
Winter 2009/10 and Summer 2010 Capability Periods



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Market Operations

Market Operations – Introduction

- The operation of the real-time market plays a critical role in the efficiency of the market outcomes.
  - ✓ Physical demands and limitations can lead to small changes in operations that have a large effect on the market.
  - ✓ Efficient price signals encourage efficient commitment and dispatch by suppliers, participation by demand response, and investment in new resources and transmission where it is most valuable.
- This section of the report evaluates the following four areas of market operations:
  - ✓ Real-time commitment and external transaction scheduling by the real-time commitment model (“RTC”);
  - ✓ Real-time price volatility;
  - ✓ Prices under real-time shortage conditions; and
  - ✓ Supplemental commitment for reliability and the associated uplift charges.

Market Operations:
Real-Time Commitment and Scheduling

Market Operations – Real-Time Commitment

- The Real-Time Commitment model ("RTC") commits generators with short lead times such as gas turbines and schedules external transactions.
  - ✓ It re-evaluates just ahead of the real-time market every 15 minutes.
- Convergence between RTC and actual real-time dispatch is important because a lack of convergence can result in:
  - ✓ Uneconomic commitment of generation, particularly gas turbines; and
  - ✓ Inefficient scheduling of external transactions.
- When excess resources are committed or scheduled, the results are increased uplift costs and depressed real-time prices. Alternatively, committing insufficient resources leads to unnecessary scarcity and price spikes.
- This section includes two analyses that evaluate the consistency between RTC and actual real-time outcomes. These analyses evaluate:
  - ✓ The efficiency of gas turbine commitments; and
  - ✓ The efficiency of external transaction scheduling.

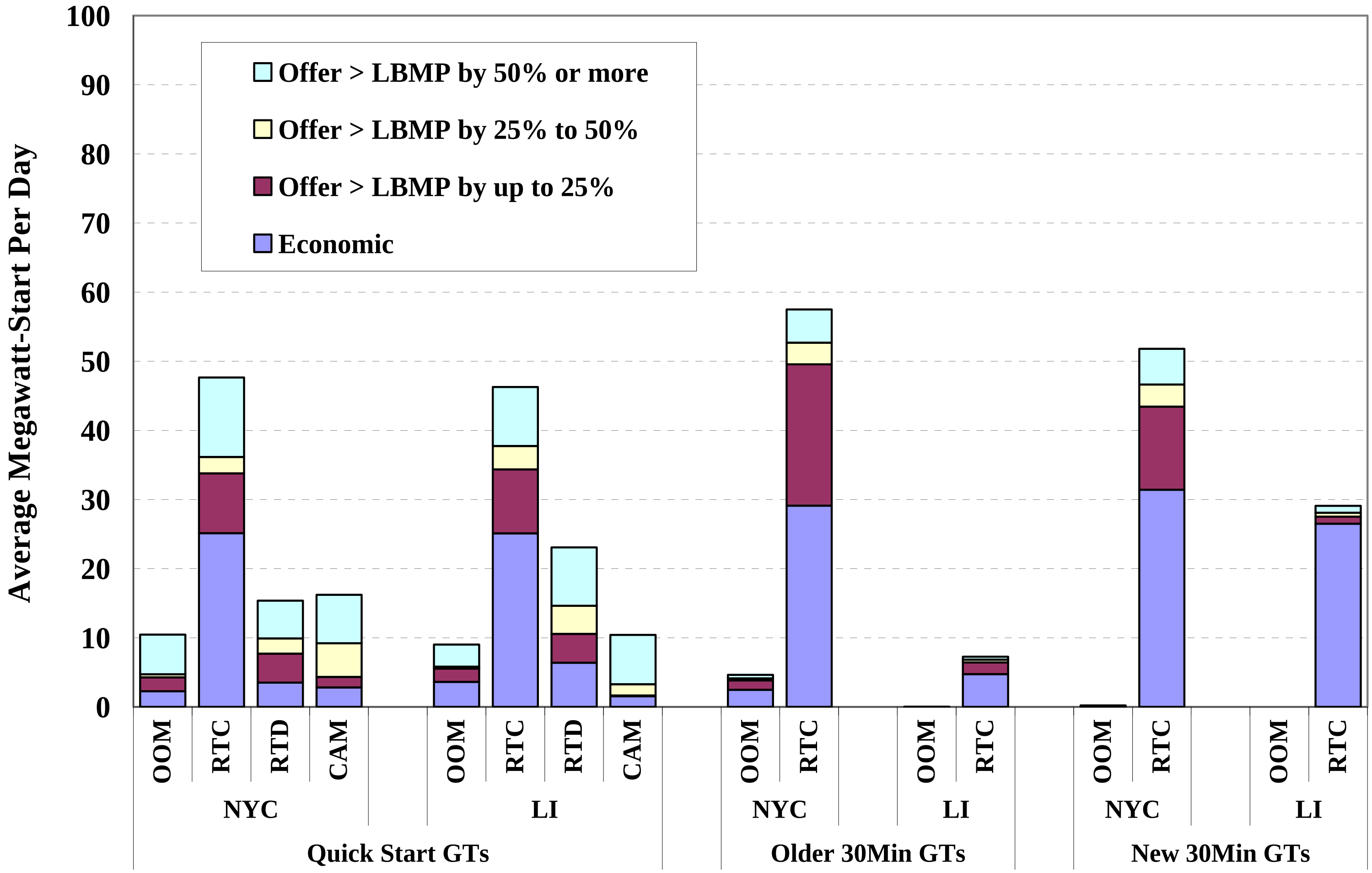
Efficiency of Gas Turbine Commitment

- The next figure measures the efficiency of gas turbine commitment by comparing the offer price to the real-time LBMP.
- The figure shows the average volume of gas turbines 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 by type of unit and location, and whether they were started by RTC, RTD, RTD-CAM, or by an OOM instruction.
- Gas turbines with offers greater than the LBMP can be economic because:
  - ✓ Gas turbines that are started efficiently and set the LBMP at their location do not earn additional revenues needed to recover their start-up offer.
  - ✓ Gas turbines that are started efficiently to address a transient shortage (e.g. a transmission shortage lasting less than one hour) may lower LBMPs and appear uneconomic over the commitment period.

Efficiency of Gas Turbine Commitment

- The efficiency of gas turbine commitment was consistent from 2009 to 2010.
  - ✓ 50 percent of all GT commitments were clearly economic in 2010, similar to 2009.
  - ✓ 71 percent of all GT commitments were cases where the GT offer was within 125 percent of LBMP in 2010, up modestly from the 67 percent in 2009.
- The average amount of gas turbine commitment fell modestly from nearly 370 MW in 2009 to 330 MW in 2010.
  - ✓ The decrease was due to less GT commitment in Long Island, which fell 47 percent from 2009, primarily due to the entry of the Caithness unit in August 2009.
  - ✓ However, the decrease was offset by a 53 percent increase in GT commitment in New York City, primarily due to the retirement of the Poletti unit and higher loads.
- One factor that can reduce the efficiency of gas turbine commitment is the use of simplified interface constraints in New York City load pockets rather than the more detailed model of transmission capability.
  - ✓ To commit gas turbines efficiently, RTD and RTC must forecast congestion patterns in future intervals. The detailed model allows them to forecast congestion more accurately.
  - ✓ The use of simplified interface constraints decreased from 2009 to 2010 as discussed in the transmission congestion section.

Efficiency of Gas Turbine Commitment 2010



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Efficiency of External Transaction Scheduling

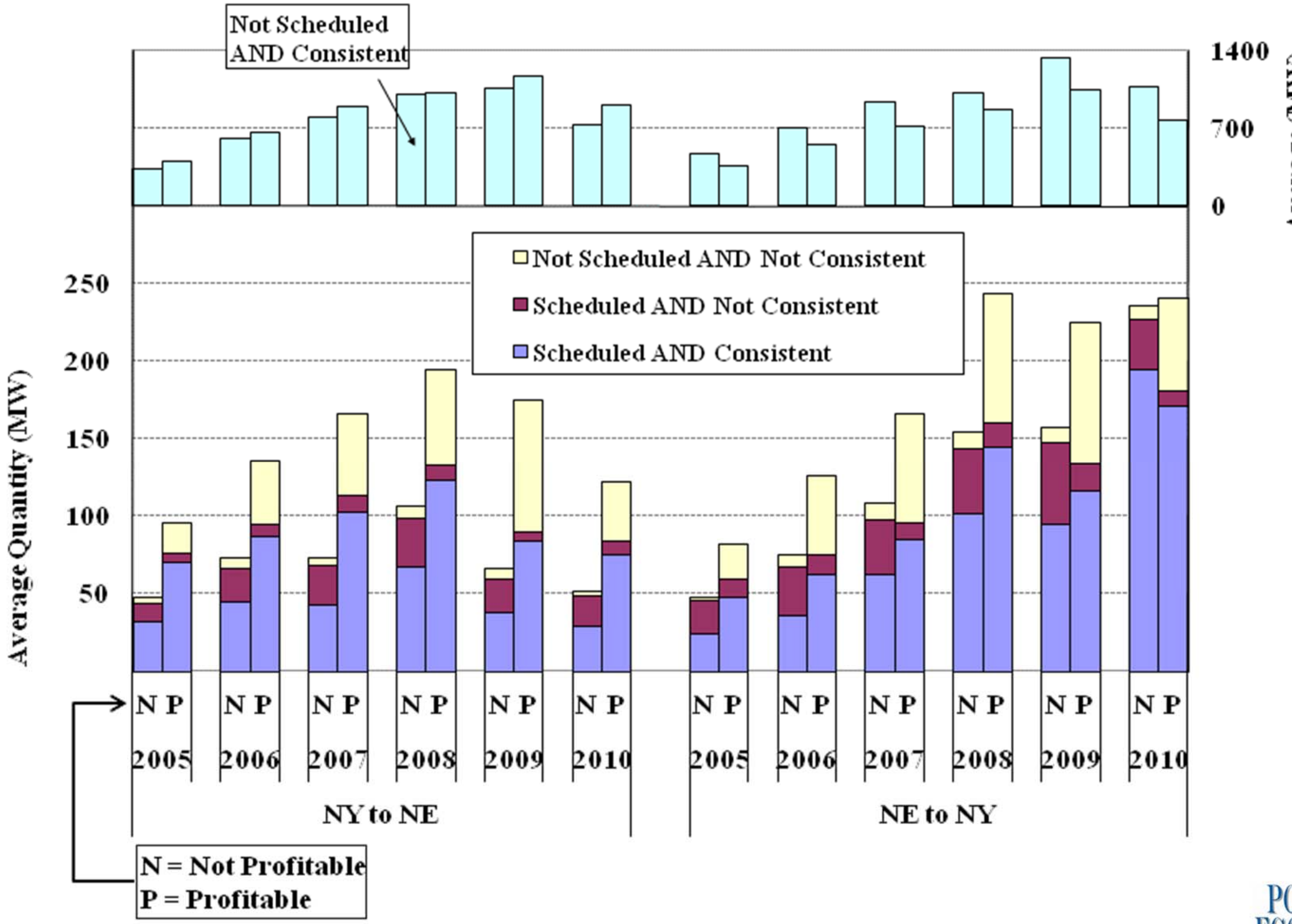
- The next figure evaluates the external transaction scheduling by RTC of the primary interface with New England from 2005 to 2010.
  - ✓ It includes transactions that are price-sensitive in real-time (it excludes transactions with DAM priority, bids above $300/MWh, and offers below −$300/MWh).
  - ✓ We analyze the New England interface due to its importance in serving eastern areas in New York. We would expect similar results for PJM and Ontario.
- 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 RT proxy bus prices on both sides 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 New York and New England increased 123 percent from 2005 to 2010.
  - ✓ However, only 13 percent of price-sensitive offers were scheduled in 2010.
- The share of schedules that were consistent rose from prior years.
  - ✓ 87 percent of scheduled offers were consistent in 2010, up modestly from prior years (ranged from 75 to 81 percent during 2005 to 2009).
  - ✓ 97 percent of offers not scheduled were consistent in 2010, up slightly from the prior years (roughly 96 percent during 2005 to 2009).
- The figure shows that "consistent" scheduling is not the same as efficient scheduling (efficient schedules all profitable). Results for 2010 show:
  - ✓ *Scheduled and consistent* – only 52 percent of these transactions were profitable.
  - ✓ *Scheduled and not consistent* – 26 percent of these were still profitable.
  - ✓ *Not scheduled and not consistent* – 89 percent of these transactions would have been profitable if scheduled (i.e., 11% of these outcomes were efficient).
- 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 – 2010



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Efficiency of Commitment and Scheduling – Conclusions

- The volume of price-sensitive real-time transaction bidding at the New England interface grew significantly from 2005 to 2010.
  - ✓ This indicates that participants have increasingly relied on RTC to determine when it will be economic to schedule between adjacent control areas.
- The consistency of RTC with RTD plays a crucial role in both efficient commitment of gas turbines and efficient external transaction scheduling.
- Although the results in this section do not raise significant concerns, there are several potential ways to improve the consistency of RTC and RTD, including:
  - ✓ Improving the assumptions that are used in RTC to be more consistent with RTD, including those related to load forecasting and to the ramping of generators and transactions.
  - ✓ Ensuring that market participants have incentives to make sure their transactions pass check-out (i.e., flow in real-time) if scheduled by RTC.
  - ✓ Reducing unnecessary volatility in RTD prices, which is evaluated in the next sub-section. Unnecessary price volatility reduces the efficiency of external transaction scheduling and gas turbine commitment by RTC.

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Market Operations:
Real-Time Price Volatility

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Real-Time Price Volatility

- The NYISO runs a real-time dispatch usually every five minutes, resulting in a new set of LBMPs every five minutes.
- Real-time clearing prices can be quite volatile in wholesale electricity markets, even when sufficient supply is online.
  - ✓ Changes in LBMPs from one interval to the next depend on how much dispatch flexibility the system has to respond to fluctuations in the following factors:
    - Electricity demand;
    - Net export schedules (which are determined prior to RTD by RTC or by transaction curtailments);
    - Generation schedules of self scheduled and other non-flexible generation; and
    - Transmission congestion patterns.
  - ✓ 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.
- This section evaluates factors that contribute to price volatility.
  - ✓ Two figures evaluate the volatility of statewide average prices, while
  - ✓ Two figures examine the volatility of the shadow prices of individual transmission constraints.

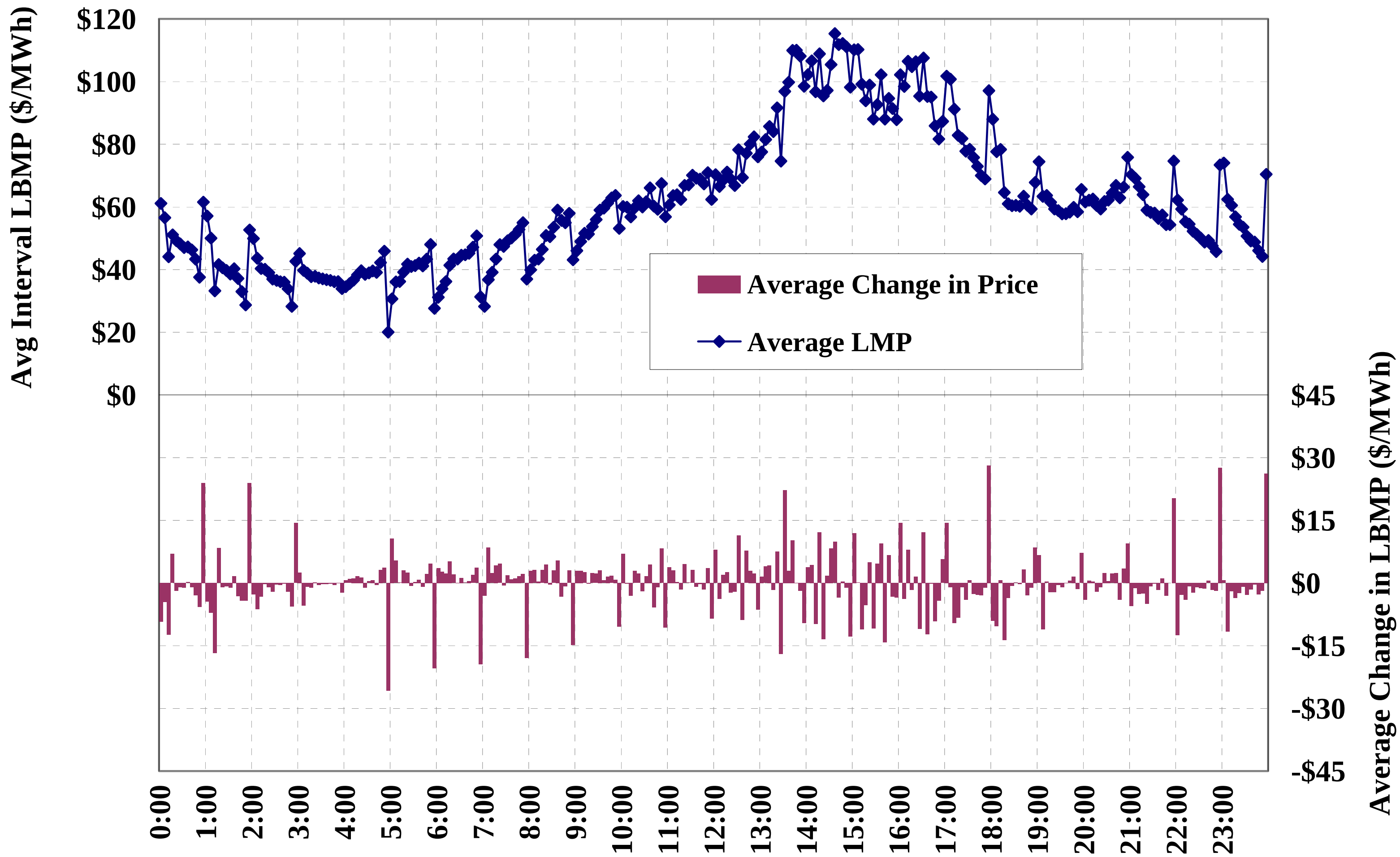
Real-Time Price Volatility – Statewide

- The first figure shows the average prices in each five minute interval of the day in the summer of 2010.
  - ✓ The figure shows the loaded-weighted average prices for the entire New York state, although the results are similar in each individual zone.
- The second figure shows how the following categories of inflexible supply change from one interval to the next on average:
  - ✓ *Net Imports* – Net imports normally 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). They can change unexpectedly due to curtailments and TLRs before or during the hour.
  - ✓ *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 units 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 – Statewide

- 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 first interval of the hour, clearing prices dropped substantially in ramp-up hours, and rose substantially in ramp-down hours.
    - – The upward and downward price spikes at the top of the hour ranged from an average of $20 to $30/MWh during ramping hours, while most other interval-to-interval price changes averaged less than $5/MWh.
- The second figure shows the average net changes for five categories of inflexible supply that contribute to large price changes at the top of the hour.
  - ✓ Adjustments in net imports, pumped storage units switching between pumping and generating, and adjustments in fixed generation schedules are most significant.
  - ✓ For example, from 10:55 pm to 11:00 pm, the average net decrease in inflexible supply from imports and fixed scheduled units was 545 MW, coinciding with an $28/MWh average increase in the real-time LBMP.

Statewide Average Five-Minute Prices by Time of Day
June to August 2010



Note: The prices shown are load-weighted system average prices.

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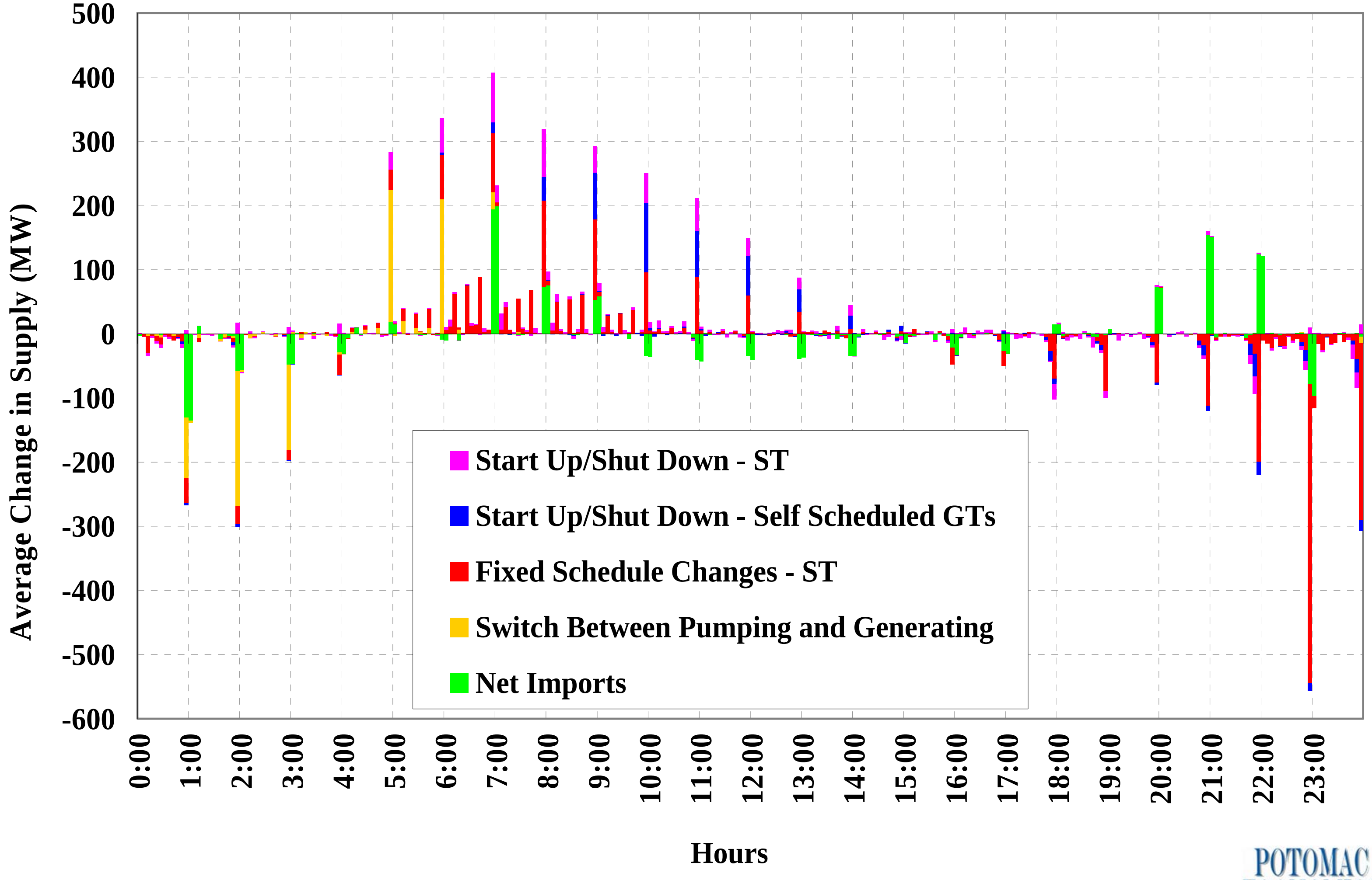
Factors Contributing to Real-Time Price Volatility
June to August 2010



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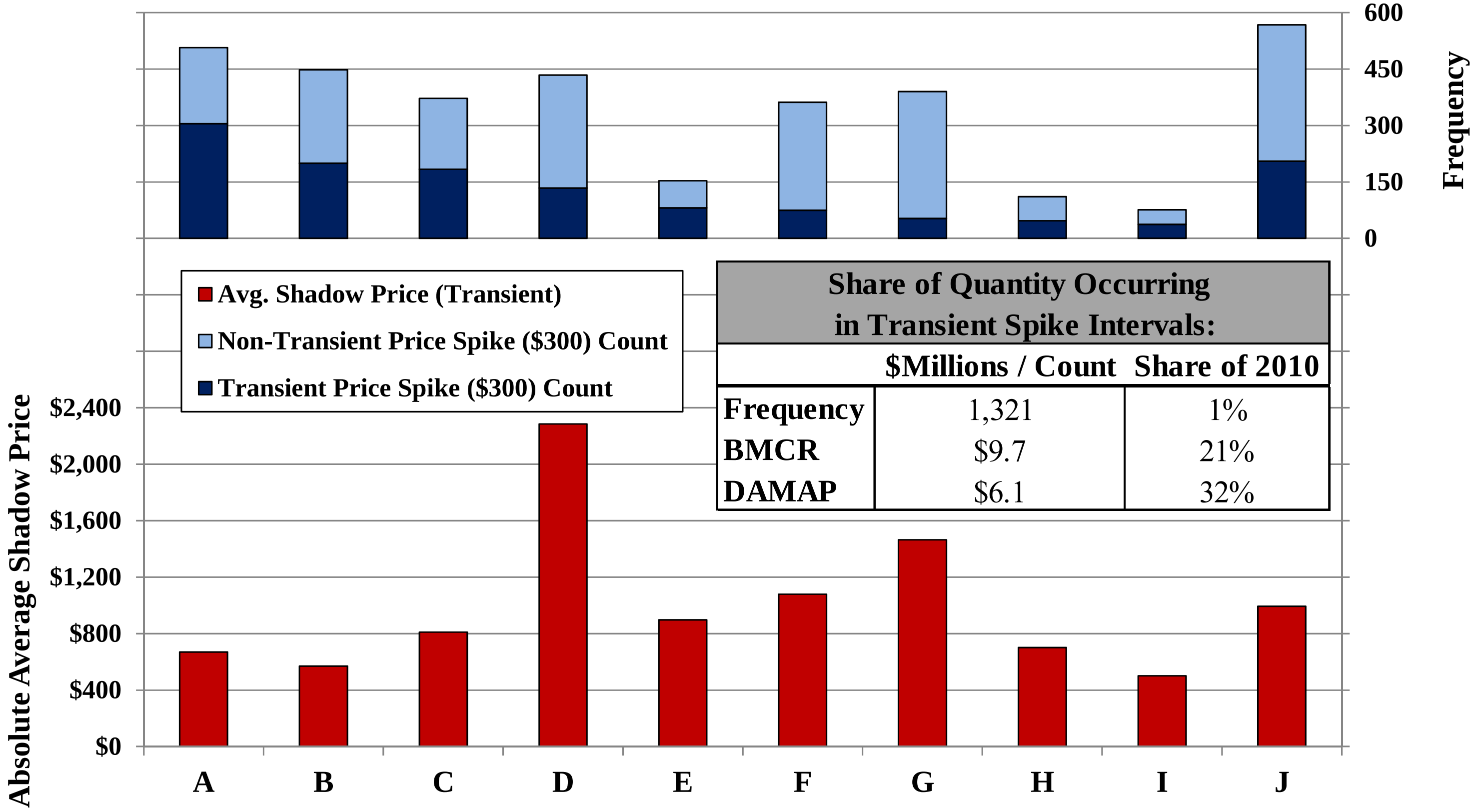
Real-Time Price Volatility – Constrained Areas

- In the following two figures, a spike in the shadow price of a particular transmission constraint is considered *transient* if:
  - ✓ It exceeds $300/MWh;
  - ✓ It increased by at least 400 percent from the previous interval; and
  - ✓ It is at least 400 percent higher than in the most recent RTD "look ahead" interval.
- The first figure summarizes transient shadow price spikes by facility in 2010.
  - ✓ For each transmission facility, it shows the frequency of transient and non-transient spikes and the average shadow price in transient spikes.
  - ✓ The top nine facilities (A through I) are ranked in descending order by the frequency of transient spikes, and all other facilities are grouped in category J.
- Although relatively infrequent, transient shadow price spikes are important, since it may be far more costly to manage congestion that is not fully anticipated.
  - ✓ The table shows that proportionately large quantities of uplift from BMCR and DAMAP arise from intervals when transient spikes occur.
- Transient shadow price spikes accounted for 61 percent of the intervals when shadow prices exceeded $300/MWh.

Frequency and Cost of Transient Congestion Price Spikes 2010



Share of Quantity Occurring in Transient Spike Intervals:		
	$Millions / Count	Share of 2010
Frequency	1,321	1%
BMCR	$9.7	21%
DAMAP	$6.1	32%

Legend			
A	East Garden City - Valley Stream	F	Astoria East (Generation Pocket)
B	Dunwoodie - Shore Road	G	Leeds - Pleasant Valley
C	Central East - VC	H	Astoria East (Load Pocket)
D	Greenwood / Staten Island (Load Pocket)	I	Sprainbrook - East Garden City
E	Dunwoodie - Motthaven	J	All Other Limiting Facilities

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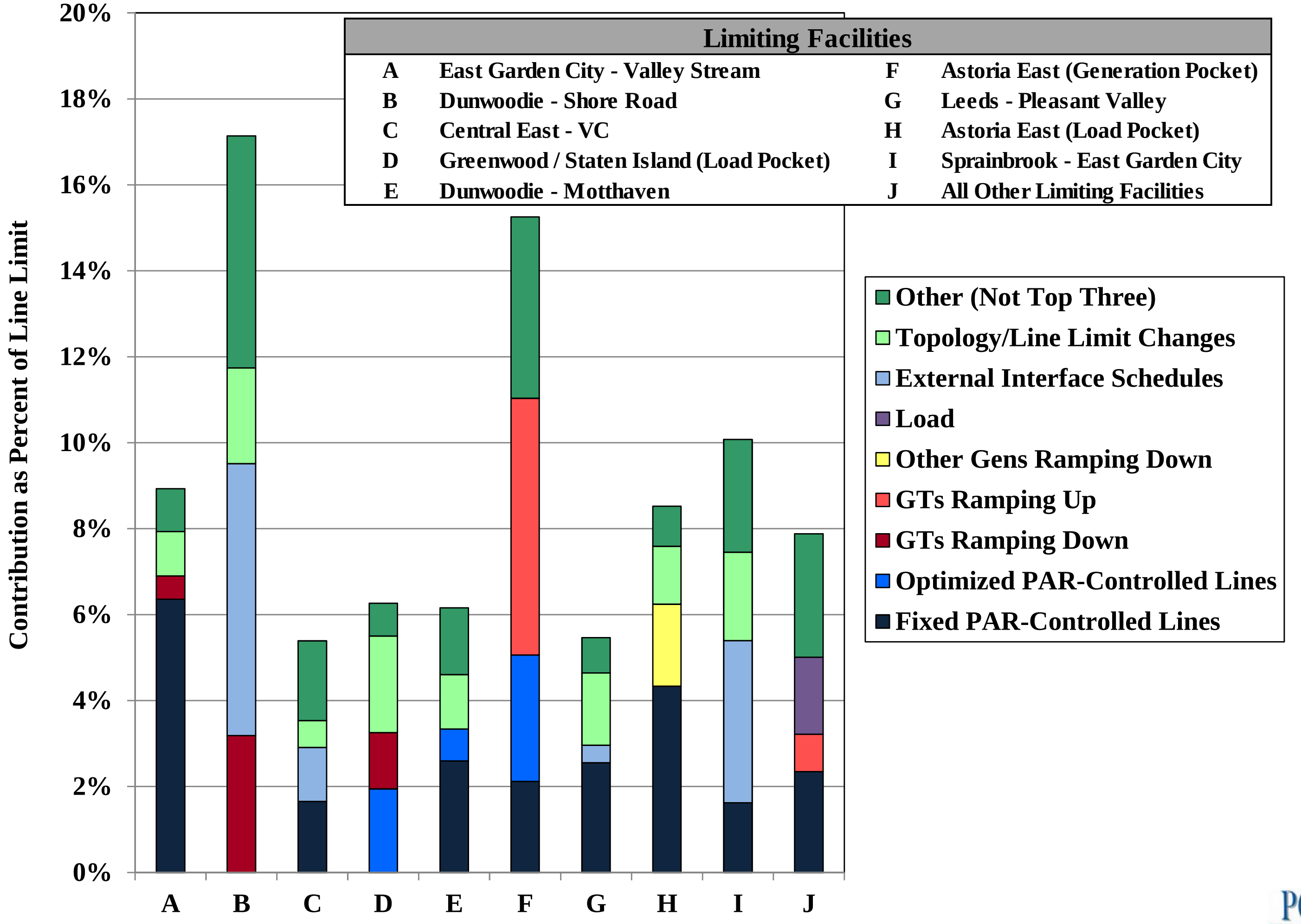
Real-Time Price Volatility – Constrained Areas

- For intervals with transient shadow price spikes, the second figure summarizes factors that changed from the previous five-minute interval, contributing to increased flows across the constrained facility. This includes:
  - ✓ Increases in scheduled flows from the following factors:
    - – *Fixed PAR-Controlled Lines* – The flow across these lines is assumed by RTD and RTC to be fixed at the most recent telemetered value;
    - – *Optimized PAR-Controlled Lines* – The flows across these lines are optimized by RTD and RTC;
    - – *External Interface Schedules* – These are normally determined by RTC in the prior hour, although these may be adjusted closer to real-time due to curtailments;
    - – *GTs Ramping Up or Ramping Down* – Most decisions to start-up and shut-down GTs are made by RTC;
    - – *Other Generators Ramping Up or Ramping Down* – The output of these generators is determined by self schedule, dispatch instruction, and/or dragging; and
    - – *Load*.
  - ✓ *Topology/Line Limits* – This includes the reduction in modeled transfers across a facility due to changes in the limit or changes in topology (i.e., shift factors).
  - ✓ *Other (Excludes Top Three)* – This category includes factors that are not among the three most significant factors for a particular facility.

Real-Time Price Volatility – Constrained Areas

- Fixed PAR-Controlled Line flow changes were the most significant factor contributing to transient shadow price spikes in 2010.
  - ✓ This was the top contributing factor for six of ten facility categories shown: (A) East Garden City to Valley Stream, (C) Central East, (E) Dunwoodie to Motthaven, (G) Leeds to Pleasant Valley, (H) Astoria East (import direction), and (J) all other facilities.
  - ✓ Both RTC and RTD assume that the flows across these PAR-controlled lines will remain fixed at the level of the most recent telemetered value (plus an adjustment for lines that make up the primary interface between PJM and the NYISO).
    - However, the flow across a PAR-controlled line is affected by changes in the setting of the PAR, the settings of other nearby PARs, generation, and load.
    - These factors can lead to significant changes in the flow across a PAR-controlled line that are not predicted by RTC and RTD, which can contribute to transient spikes in the shadow prices of constrained facilities.
- External Interface Schedule changes were the most significant factor contributing to transient price spikes on the two lines flowing into Long Island from Upstate NY: (B) Dunwoodie to Shore Road and (I) Sprainbrook to East Garden City.

Factors Contributing to Transient Congestion Price Spikes 2010



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Real-Time Price Volatility – Conclusions

- The first part of the section evaluates price volatility at the statewide level, finding:
  - ✓ High price volatility during morning and evening ramp periods is largely caused by changes in inflexible supply at the top of each hour.
  - ✓ If inflexible supply changes were distributed more evenly throughout each hour, price volatility would be diminished.
  - ✓ Generators who change fixed schedules or switch from pumping to generating at the top of the hour would benefit from making such changes mid-hour.
- The second part of the section analyzes factors that contribute to the volatility of real-time transmission constraint shadow prices. This found that:
  - ✓ Fixed PAR-Controlled Line flow changes were a significant contributing factor to transient price spikes for most of the transmission facilities analyzed.
    - – RTC and RTD assume the flow across a PAR-controlled line will remain constant, although it is affected by changes in PAR settings, generation, or load.
    - – When changes in these factors lead to significant changes in the flow across a PAR-controlled line that are not predicted by RTC and RTD, it can contribute to transient spikes in the shadow prices of constrained facilities.
  - ✓ External Interface Schedule changes were also a significant contributor to transient price spikes.

Real-Time Price Volatility – Conclusions

- The NYISO will introduce three market enhancements in May 2011 that are expected to help address the causes of unnecessary real-time price volatility:
  - ✓ Regulation Demand Curve modifications that will prevent small brief shortages of regulation from causing large positive or negative statewide price spikes.
  - ✓ 30-Minute Long Island Reserve Demand Curve modifications that will reduce the frequency and severity of transient spikes in the shadow prices of lines from upstate NY to Long Island (i.e., Dunwoodie-Shore Rd & Sprainbk-EastGarCity).
  - ✓ 15-Minute Scheduling of the Hydro Quebec interface rather than hourly scheduling. This will increase the flexibility of supply in west NY, reducing the volume of interchange adjustments that occur at the top of the hour.
    - The NYISO is working to schedule this interface on a 5-minute basis eventually.
- The NYISO is developing two market enhancements with neighboring RTOs that will help reduce real-time price volatility, both statewide and congestion-related:
  - ✓ Coordination of the interchange with New England; and
  - ✓ 15-minute scheduling with PJM.
  - ✓ These enhancements will increase the flexibility of supply in western and eastern New York, including New York City and Long Island, and should reduce the volume of interchange adjustments that occur at the top of the hour.

Real-Time Price Volatility – Conclusions

- The NYISO is working on several initiatives that should help reduce unnecessary real-time price volatility, which leads to inefficient dispatch and increases uplift charges. However, additional work will likely be needed to eliminate unnecessary volatility.
  - ✓ Hence, we recommend that the NYISO conduct an evaluation to determine the causes of and potential solutions for unnecessary real-time price volatility.
- When RTC and RTD accurately forecast that a constraint will bind in a future interval, it is efficient in many cases to start re-dispatching generation before the constraint binds.
  - ✓ So, it is important for RTC and RTD to accurately forecast system conditions.
  - ✓ The look ahead assessments of RTC and RTD forecast conditions at :00, :15, :30, and :45 minutes past each hour, although the most volatile pricing intervals include the intervals-ending at :55 and :05 minutes past the hour.
  - ✓ We recommend the NYISO consider whether additional look ahead assessments in RTC and RTD at intervals-ending :55 and :05 minutes past the hour would lead to more efficient dispatch at the top of each hour.

POTOMAC ECONOMICS

Market Operations:
Prices Under Shortage Conditions

POTOMAC ECONOMICS

Prices During Shortage Conditions – Introduction

- Efficient pricing under shortage conditions is important because it:
  - ✓ Gives suppliers and demand response resources incentives to perform well during real-time shortages, which improves reliability.
  - ✓ Provides market participants in the day-ahead market with incentives to commit sufficient resources to satisfy anticipated system conditions the following day.
  - ✓ Contributes to efficient long-term price signals for investment in new resources.
- However, it is important for shortage pricing to occur only during legitimate shortage conditions (i.e., when resources are insufficient to meet the energy and operating reserves needs of the system while satisfying security constraints).
- In this section of the report, we evaluate the operation of the market and resulting prices during three types of shortage conditions:
  - ✓ Shortages of operating reserves and regulation;
  - ✓ Transmission shortages; and
  - ✓ Emergency demand response activations.

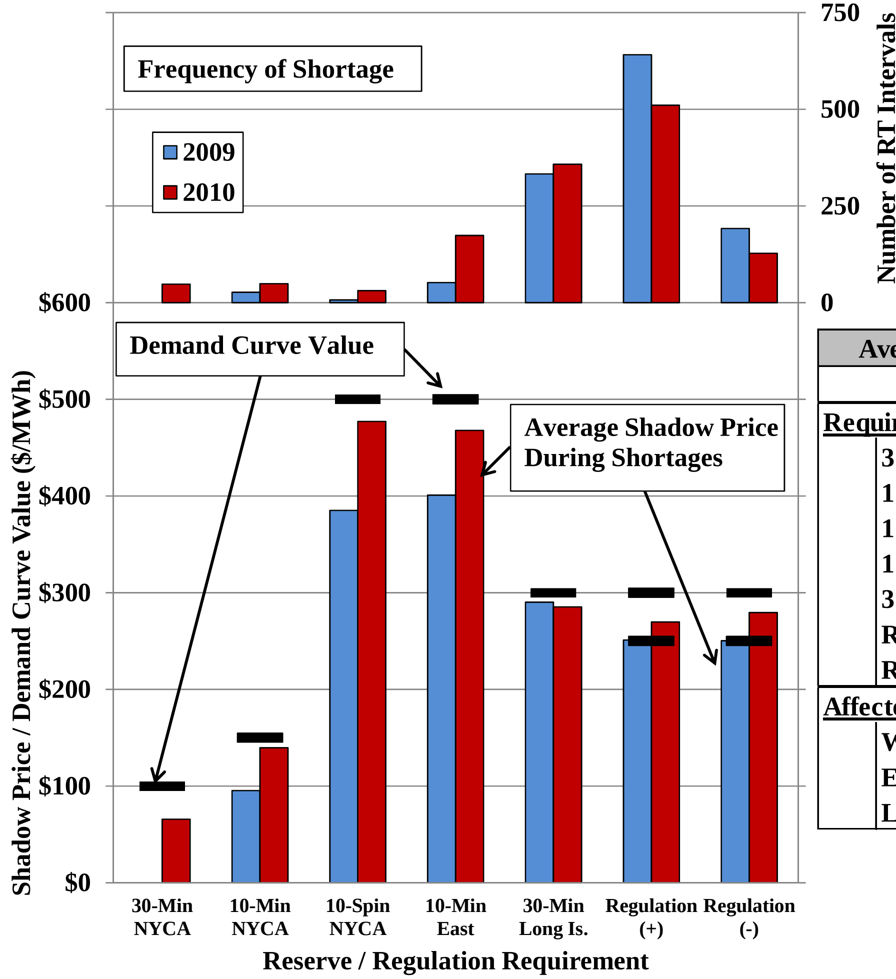
Prices During Shortage Conditions – Reserve and Regulation Shortages

- The figure summarizes ancillary services shortages and their effects on real-time prices in 2009 and 2010.
  - ✓ The top portion of the figure shows the frequency of shortages.
  - ✓ The bottom portion shows the average shadow price during shortage intervals and the demand curve level of the requirement.
  - ✓ The table shows the average shadow price during shortages multiplied by the frequency of shortages, indicating the overall price impact of the shortages by product and in total by region.
- The figure shows that real-time prices reflected system conditions during shortage events relatively well, especially in 2010.
  - ✓ The average shadow price during shortages was close to the demand curve level for each reserve requirement, and became closer from 2009 to 2010.
  - ✓ For example, for the 10-minute eastern reserve requirement, the average shadow price rose from 80 percent of the demand curve level in 2009 to 94 percent in 2010.
  - ✓ This differential (between the shadow price and demand curve level during shortages) likely fell due to the longer average duration of shortages in 2010, since the differential tends to be larger during shorter duration shortages.

Prices During Shortage Conditions – Reserve and Regulation Shortages

- The ancillary services shortages with the largest effects on real-time prices were:
  - ✓ Regulation shortages when supply was limited and could not ramp down sufficiently to provide regulation, leading to *positive* energy price spikes;
  - ✓ Regulation shortages when supply was in excess and could not ramp up to provide regulation, leading to *negative* energy price spikes;
  - ✓ 10-minute eastern reserve shortages; and
  - ✓ 30-minute Long Island reserve shortages, which are not reflected in the Long Island reserve clearing prices (under the NYISO rules).
    - However, they still affect real-time energy prices since units providing energy usually have an opportunity cost equal to the reserve price.
- The table shows the cumulative effect of all ancillary services shortages on average real-time energy clearing prices in:
  - ✓ West New York – This is based on the sum of shadow prices of the NYCA reserve requirements as well as the effects of positive and negative regulation spikes.
  - ✓ East New York – This equals the West New York effect plus the sum of shadow prices of eastern reserve requirements.
  - ✓ Long Island – This equals the East New York effect plus the sum of shadow prices of Long Island reserve requirements.

Real-Time Prices During Ancillary Services Shortages
2009 – 2010



Average Contribution to Energy Price		
	2009	2010
Requirement:		
30-Min NYCA	$0.00	$0.03
10-Min NYCA	$0.02	$0.07
10-Spin NYCA	$0.03	$0.14
10-Min East	$0.20	$0.77
30-Min Long Is.	$0.92	$0.97
Regulation (+)	$1.27	$1.11
Regulation (-)	-$0.32	-$0.28
Affected Region:		
West	$1.00	$1.06
East (excl. Long Island)	$1.20	$1.84
Long Island	$2.12	$2.81

Note: The figure excludes reserve requirements with a demand curve level of $25/MWh.

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Prices During Shortage Conditions – Transmission Shortages

- RTD manages congestion by re-dispatching available capacity, including (i) online units that can be ramped in five minutes and (ii) offline quick-start GTs.
  - ✓ The shadow price of the transmission constraint reflects the marginal re-dispatch cost of managing the constraint.
- However, transmission shortages can occur in the following three ways:
  1) If the available capacity is not sufficient to resolve a transmission constraint, RTD will *relax* the constraint by increasing the limit to a level that can be resolved.
  2) If the marginal re-dispatch cost needed to resolve a constraint exceeds the $4,000 *Transmission Shortage Cost*, RTD foregoes more costly and operationally inefficient re-dispatch options.
  3) If the available capacity from an offline quick-start GT is counted towards resolving a transmission constraint, but the GT is not given a start-up instruction.
     - Offline quick-start GTs are usually the most expensive available capacity due to their commitment costs, so offline GTs are usually not counted towards resolving the constraint unless all available online generation has already been scheduled.
     - When an offline GT is counted towards resolving a constraint but not started, the actual marginal re-dispatch cost is lower than the shadow price set by the GT.
- Due to the unavailability of some data, the following analysis focuses on the third type of transmission shortage, which is most common.

Prices During Shortage Conditions – Transmission Shortages

- The following figure analyzes events when a transmission constraint has a large effect on real-time LBMPs, since this is likely to coincide with a transmission shortage. Specifically, the figure includes intervals when:
  - ✓ A transmission constraint accounted for a $500/MWh differential between two zone LBMPs, and
  - ✓ One or more zone LBMPs is greater than $500/MWh.
- The upper right table shows the share of these intervals when an offline GT was counted by RTD towards resolving the constraint and marginal (i.e., setting the shadow price), but not actually started.
  - ✓ In such cases, the GT is not actually started, so the actual marginal re-dispatch cost is lower than the shadow price.
  - ✓ However, the analysis evaluates each interval separately, so a GT that is not started in one interval might then be started in the next interval.
- The lower right table shows the average shadow price during likely transmission shortages multiplied by the frequency of shortages over the year.
  - ✓ This is an indicator of the economic significance of the shortages.
- The lower right table also shows the overall contribution of all likely transmission shortages to the LBMPs in each zone.

POTOMAC ECONOMICS

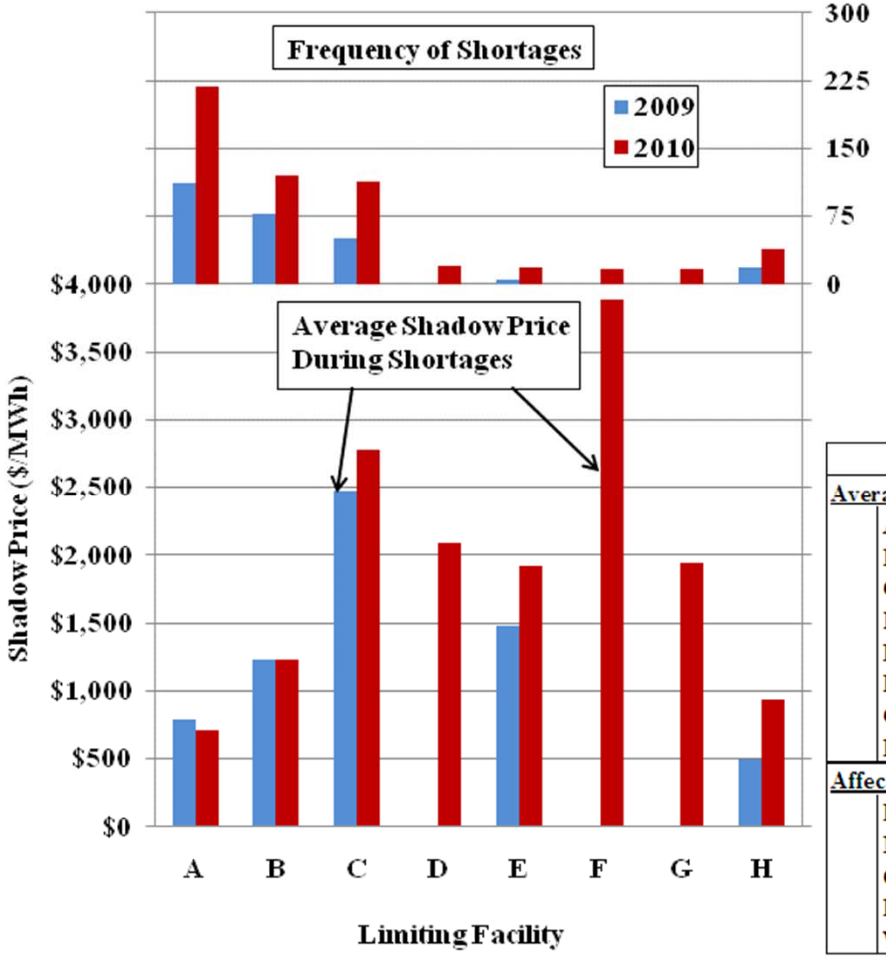
Prices During Shortage Conditions – Transmission Shortages

- The Leeds-Pleasant Valley constraint exhibited the most economically significant transmission shortages in 2010.
  - ✓ In the 113 intervals shown, this constraint contributed an average of $1,067/MWh to the New York City LBMP, which is $1.15/MWh averaged over the year.
  - ✓ This is not surprising because this constraint is the most affected by TSAs, which cause its available transfer capability to be reduced and can lead to a shortage.
- Other facilities that exhibited economically significant shortages in 2010 were:
  - ✓ Central-East Interface – The shadow price averaged $1.40/MWh over the year.
  - ✓ Dunwoodie-Shore Rd. – The shadow price averaged $1.49/MWh over the year.
- The table shows the total contribution from likely transmission shortages to the real-time LBMPs averaged over the year by zone, including:
  - ✓ New York City – The total was $2.47/MWh of which the Central-East Interface accounted for 31 percent, the Leeds-Pleasant Valley line accounted for 46 percent, and the Millwood-Dunwoodie line accounted for 7 percent.
  - ✓ Long Island – The total was $3.78/MWh of which the Central-East Interface accounted for 20 percent, the Leeds-Pleasant Valley line accounted for 30 percent, and the Dunwoodie-Shore Road line accounted for 39 percent.

Prices During Shortage Conditions – Transmission Shortages

- The upper right table shows that an offline GT was counted towards resolving the constraint and was a marginal resource but was not actually started in 83 percent of all likely transmission shortage intervals in 2010.
  - ✓ In these intervals, the offline GT set the shadow price but was not actually started-up to manage congestion in that interval. The table shows that this was particularly common for:
    - New Scotland-Leeds – 100 percent of intervals – An average of 92 MW was scheduled on the marginal offline GT.
    - Dunwoodie-Shore Road – 95 percent of intervals – An average of 45 MW was scheduled on the marginal offline GT.
  - ✓ Also shown is the mean quantity of offline GT capacity that was marginal (i.e., setting price) in RTD's pricing algorithm, but not actually started.
    - This suggests that some degree of small transmission shortages may occur for brief periods without significantly undermining reliability.
- Hence, the decision not to start a GT to resolve congestion is an indication that the shadow price of the constraint is set to a level higher than needed to prevent a small brief shortage.

Real-Time Prices During Transmission Shortages
2009 – 2010



Price Set by Offline GT That Was Not Started in 2010		
	# of Intervals	Pct of Shortages
A	208	95%
B	101	84%
C	64	57%
D	19	95%
E	17	94%
F	10	59%
G	17	100%
H	33	85%

	2009	2010
Average Shadow Price During All Intervals:		
A: Dunwoodie-Shore Road	$0.84	$1.49
B: Central East	$0.90	$1.40
C: Leeds-Pleasant Valley	$1.20	$2.98
D: Millwood-East View	$0.00	$0.40
E: Dunwoodie-Mott Haven	$0.06	$0.33
F: East Garden City-New Bridge	$0.00	$0.63
G: New Scotland-Leeds	$0.00	$0.31
H: Other	$0.09	$0.35
Affected Zone:		
Long Island	$1.90	$3.78
NYC	$1.01	$2.47
Capital	$0.70	$1.08
Hudson Valley	$0.91	$1.91
West	$0.03	$0.00

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Prices During Shortage Conditions – Emergency Demand Response Activation

- Emergency demand response (i.e., SCR and EDRP) resources were activated in New York City on two high load days in 2010 (July 6 & 7).
  - ✓ Resources were activated from 1:00 pm to 7:00 pm on both days.
  - ✓ The NYISO reported to stakeholders that the activations were necessary to maintain proper voltages at Sprainbrook.
  - ✓ Lines into New York City were not constrained, although the voltage issues limited transfers across the UPNY-ConEd interface on both days. (Leeds-Pleasant Valley congestion was also significant on July 7.)
- We evaluated whether real-time energy prices were efficient during the activation, given that most SCR and EDRP resources are paid $500/MWh to curtail their load.
- The following figure summarizes real-time prices and available capacity in several portions of Southeast New York during the activations and the quantities activated.
  - ✓ Prices are shown for (i) the Greenwood load pocket, which was import-constrained for a substantial portion of each day, and (ii) the rest of New York City, excluding export-constrained areas (primarily Astoria East).
  - ✓ Available capacity is shown for generators in: (i) the Greenwood load pocket; (ii) the rest of New York City, excluding export-constrained areas; and (iii) Long Island. No capacity was available in the import-constrained portion of Upstate New York.

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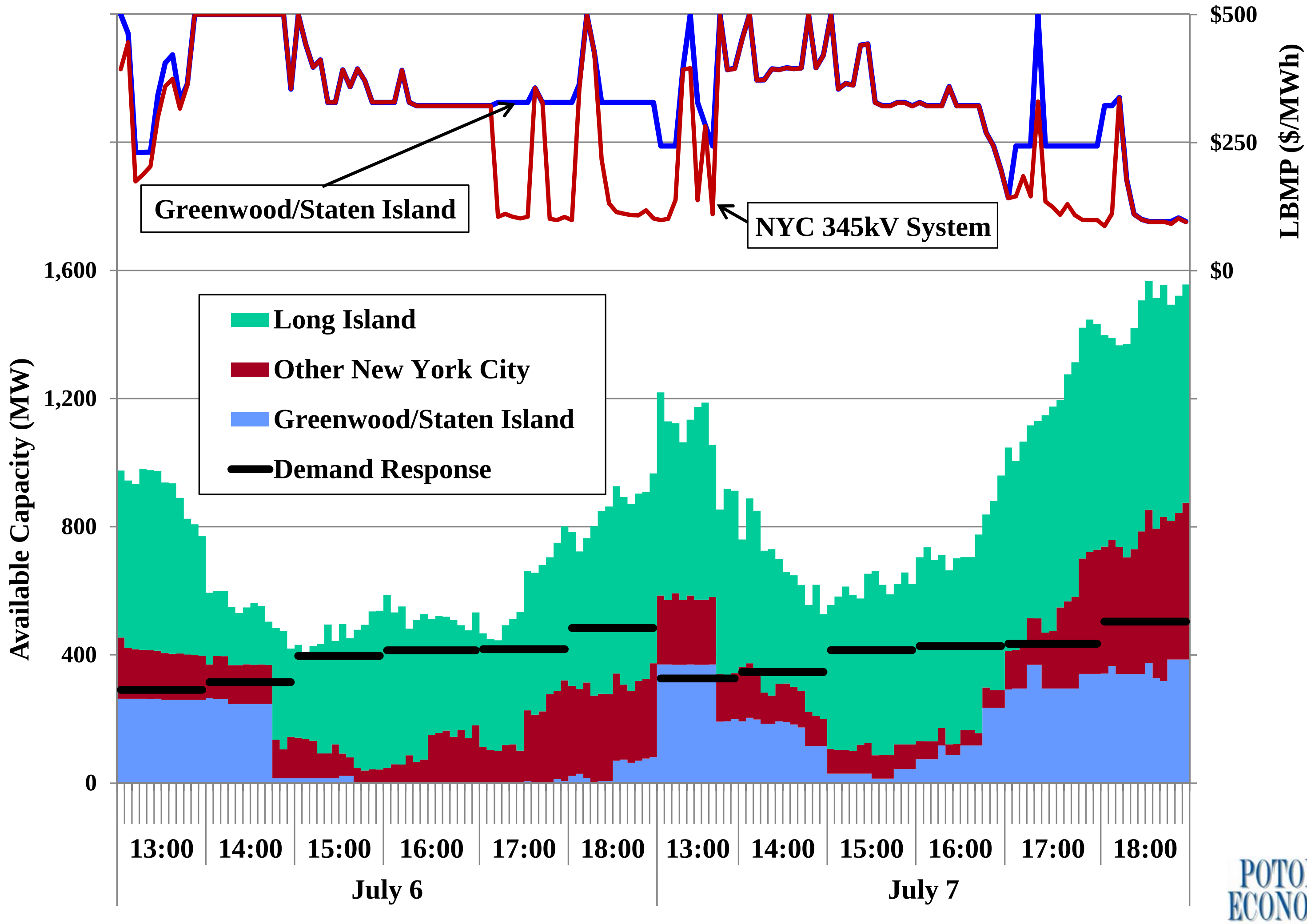
Prices During Shortage Conditions – Emergency Demand Response Activation

- In New York City, available capacity was 100 MW or less for three hours on the 6th and two hours on the 7th.
  - ✓ Although no lines into New York City were constrained, constraints into the City would likely have emerged if there was an additional 400 to 500 MW of demand.
- Any demand response resources activated in Astoria East were most likely not needed for reliability, since generation was export-constrained there.
- The activation of demand response likely had a significant effect on real-time prices in the combined areas shown in the figure.
  - ✓ Available capacity fell under 500 MW in four hours on the 6th and under 700 MW in two hours on the 7th. In these hours, the NYC price averaged $456/MWh.
  - ✓ Most available capacity was on 30-minute reserve units in Long Island, so many of them would be scheduled for energy if the demand response was not activated.
    - – The demand curve value for the Long Island 30-minute reserve requirement is $300/MWh, so Long Island units scheduled for energy would have had an opportunity cost of at least $300/MWh in addition to their offered costs.
  - ✓ Hence, if demand response resources were dispatchable at $500/MWh, they would likely have set real-time prices at $500/MWh in at least six hours.

Real-Time Prices and Available Capacity During Emergency Demand Response Activations



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Prices During Shortage Conditions – Conclusions

- Well-functioning markets provide efficient price signals during shortages. This section indicates the most economically significant:
  - ✓ Ancillary services shortages were for regulation, eastern 10-minute reserves, and Long Island 30-minute reserves; and
  - ✓ Transmission shortages were for the Leeds-Pleasant Valley line, the Central-East Interface, and the Dunwoodie-Shore Road line.
  - ✓ Emergency demand response was only activated in NYC on two days, but these activations may become more significant in the future if supply margins fall.
    - – Hence, the NYISO should consider how the costs of activating demand response might be better reflected in clearing prices when their activation prevents a shortage.
- The area with real-time LBMPs most affected by shortages was Long Island, which received a contribution of \$2.81/MWh from ancillary services shortages and \$3.78/MWh from likely transmission shortages.
  - ✓ The real-time price effect on Long Island from reserve shortages will decrease in May 2011 when the demand curve level for the Long Island 30-minute reserve requirement is reduced from \$300/MWh to \$25/MWh.
  - ✓ The effect from transmission shortages will also fall, since many of the Dunwoodie-Shore Road constraints are made more severe by the high opportunity cost of generators not scheduled for reserves during reserve shortages.

Prices During Shortage Conditions – Conclusions

- Transmission shortages occur when transmission constraints are not fully resolved by RTD.
- We performed an analysis of intervals with likely transmission shortages and found:
  - ✓ An offline quick start GT was on the margin (i.e., setting the clearing price) but not actually started in 83 percent of the intervals. In such cases,
    - – A small transmission shortage occurs since the GT does not actually produce output that reduces flows on the constrained facility; and
    - – Real-time prices are set at a level that exceeds the actual marginal re-dispatch cost incurred.
  - ✓ When it is deemed unnecessary to start a GT to prevent or reduce a transmission shortage, it suggests that there are some instances when the Transmission Shortage Cost of $4,000/MWh is larger than the reliability value of preventing the shortage.
- Therefore, we recommend that the NYISO consider the feasibility and potential impacts on reliability and system security from using a graduated Transmission Shortage Cost.
  - This level could be set according to the severity of the shortage condition.

POTOMAC ECONOMICS

Market Operations –
Uplift and Supplemental Commitment

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Supplemental Commitment for Reliability

- This section evaluates supplemental commitments for reliability and its market effects in 2010.
- Supplemental commitment occurs when a generator would not be committed in the economic pass of the day-ahead market if it were not needed for reliability.
- Supplemental commitment primarily occurs in three ways:
  - ✓ Day-Ahead Reliability Units (“DARU”) are committed by the local Transmission Owner prior to the economic commitment in SCUC.
    - – Uplift generated from these units goes into day-ahead local reliability uplift.
  - ✓ Day-Ahead Local Reliability (“LRR”) constraints cause generators to be committed within the economic commitment in SCUC.
    - – Uplift generated from these units for “non-economic hours” goes into day-ahead local reliability uplift.
  - ✓ The Supplemental Resource Evaluation (“SRE”) process is used to commit generators after the day-ahead market.
    - – Uplift generated from units committed for reliability of the local Transmission Owner’s system makes up nearly all of the real-time local reliability uplift.
    - – Uplift generated from units committed for reliability of the bulk power system goes into real-time non-local reliability uplift.

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Supplemental Commitment for Reliability

- Generators that are committed for reliability are generally not economic at market prices, but they affect the market by reducing prices from levels that would otherwise result.
  - ✓ Hence, it is important to commit these units efficiently.
- In February 2009, the NYISO made enhancements to improve the efficiency of reliability commitments. These enhancements:
  - ✓ Allow local Transmission Owners to commit units prior to economic commitment of SCUC (i.e., DARU), so that SRE commitments are generally not needed unless there is a change in operating conditions after the day-ahead market.
  - ✓ Commit units for New York City LRR constraints within the economic commitment of SCUC, rather than afterward.
- To the extent LRR constraints in SCUC reflect the reliability requirements in New York City, the local Transmission Owner does not need to commit DARU and SRE units.
  - ✓ LRR commitment is more efficient than DARUs and SREs, which are selected without considering factors in the economic evaluation of SCUC.

Supplemental Commitment for Reliability

- The following figure shows the quarterly quantities of capacity (left) and minimum generation (right) committed for reliability by type of commitment and region in 2009 and 2010.
- Local reliability commitment in New York City decreased substantially from 2009 to 2010.
  - ✓ Committed capacity in New York City averaged 810 MW in 2010, down 36 percent from the previous year.
  - ✓ The minimum generation level of these units averaged 180 MW in 2010, down 35 percent from the prior year.
  - ✓ SRE quantities fell notably beginning in March 2009, since most local reliability commitment now occurs in the day-ahead market (i.e., DARU & LRR).
  - ✓ DARU commitment fell in 2010, due primarily to:
    - – The retirement of the Poletti unit in February 2010 that had frequently been committed by DARU; and
    - – Higher LBMP levels relative to the offers of generators frequently committed for reliability. Such generators were flagged as economic more frequently in the day-ahead market, particularly in the third and fourth quarters of 2010.

Supplemental Commitment for Reliability

- Reliability commitment in western New York rose modestly in 2010.
  - ✓ Committed capacity in western New York averaged 310 MW in 2010, up 55 percent from the previous year.
  - ✓ The minimum generation level of these units averaged 180 MW in 2010, up 52 percent from the prior year.
  - ✓ Reliability commitment rose considerably in the first quarter of 2010 from the first quarter of 2009, due largely to the emergence of SRE commitments for bulk power system reliability, which had not been necessary for several years.
  - ✓ DARU commitments increased in the second quarter of 2010 because several coal units were committed more frequently for local reliability due, in part, to lower natural gas prices.
- Reliability commitment in Long Island was comparable to the previous year on average, although the amount varied from quarter to quarter.
  - ✓ Committed capacity in Long Island averaged 80 MW in 2010 and the minimum generation level of these units averaged 20 MW.
  - ✓ The increase of DARU commitment in the fourth quarter of 2010 from the previous year arose partly because generators needed for voltage support were committed economically more often in the previous year.

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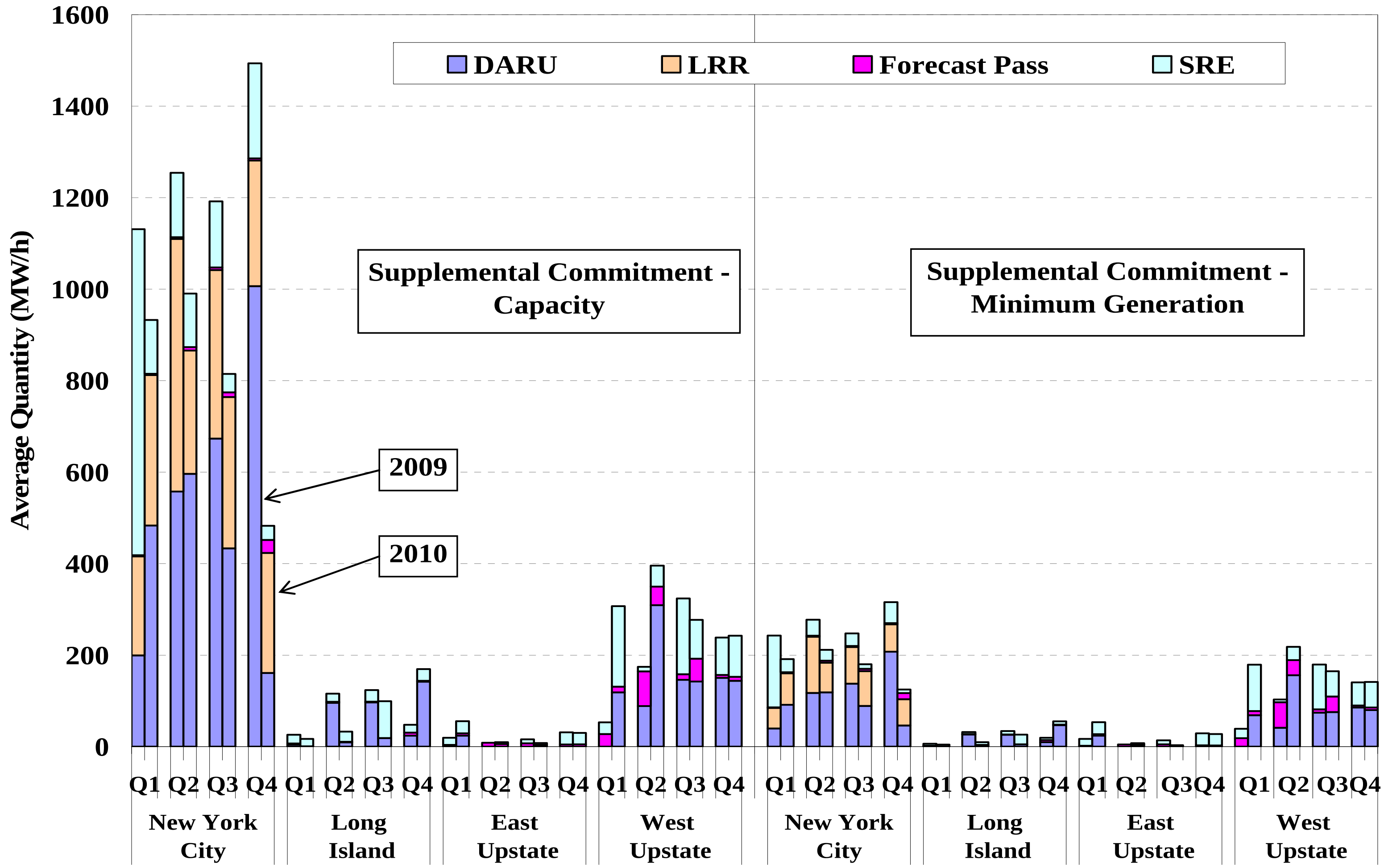
Supplemental Commitment for Reliability
by Category and Region, 2009 - 2010



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Uplift Costs from Guarantee Payments

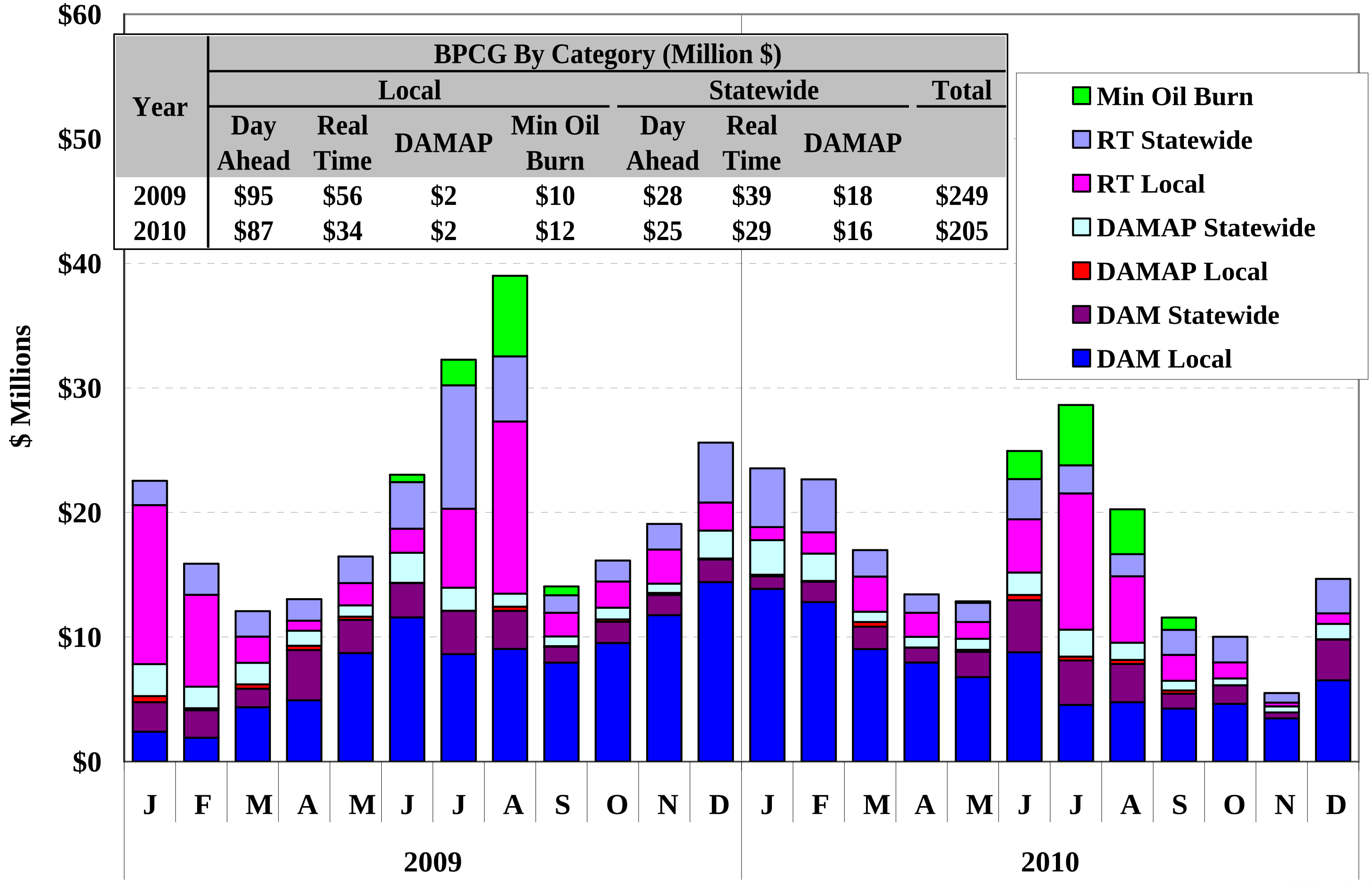
- Three categories of statewide reliability uplift are allocated to all LSEs:
  - ✓ Day Ahead: Primarily for units committed economically that don't recoup their as-offered start-up and minimum generation costs across the day from LBMPs.
  - ✓ Real Time: For import transactions and GTs that are scheduled economically but don't recoup their as-offered costs across the day from LBMPs, for SRE commitments and OOM dispatch that are done for bulk power system reliability.
  - ✓ Day Ahead Margin Assurance Payment ("DAMAP"): For payments to cover losses in margin for generators dispatched by NYISO instruction below their day-ahead schedule when the real-time LBMP is higher than the day-ahead LBMP.
- Four categories of local reliability uplift are allocated to the local TO:
  - ✓ Day Ahead: From New York City Local Reliability Requirements ("LRR") included programmatically in SCUC and Day-Ahead Reliability Unit ("DARU") commitments requested by TOs for local reliability.
  - ✓ Real Time: From Supplemental Resource Evaluation ("SRE") commitments and Out-of-Merit ("OOM") dispatched units requested by TOs for local reliability.
  - ✓ Minimum Oil Burn Program: Covers spread between oil and gas prices when generators burn oil to satisfy NYC gas pipeline contingency reliability criteria.
  - ✓ DAMAP: For payments to cover losses in margin for generators dispatched OOM for local reliability reasons below their day-ahead schedule.

Uplift Costs from Guarantee Payments

- The next figure shows the seven categories of uplift costs associated with guarantee payments on a monthly basis for the past two years.
- Guarantee payment uplift totaled $205 million in 2010, down 18 percent from the previous year.
  - ✓ Real-time local reliability uplift fell 39 percent ($22 million) from 2009, due primarily to the large reductions in SRE commitment in New York City.
  - ✓ Real-time statewide uplift fell 26 percent ($10 million) from 2009 because of:
    - – Lower guarantee payments to import transactions, due mostly to less frequent negative price events in real-time; and
    - – Mitigation measures implemented in the fall of 2009 that reduced the uplift charges from SRE commitments for bulk power system reliability.
  - ✓ Day-ahead local reliability uplift fell 9 percent (or $8 million) from 2009, due primarily to the reduction in DARU commitments in New York City.
    - – Generators that were needed for local reliability were flagged as economic more frequently in 2010 due to higher LBMPs relative to their offers.
  - ✓ However, the overall reduction was partly offset by higher fuel prices in 2010.
- Guarantee payment uplift typically rises in the summer when load increases and in the winter when fuel prices increase.

Uplift Costs from Guarantee Payments
2009 - 2010

Year	BPCG By Category (Million $)							
	Local				Statewide			Total
	Day Ahead	Real Time	DAMAP	Min Oil Burn	Day Ahead	Real Time	DAMAP	
2009	$95	$56	$2	$10	$28	$39	$18	$249
2010	$87	$34	$2	$12	$25	$29	$16	$205



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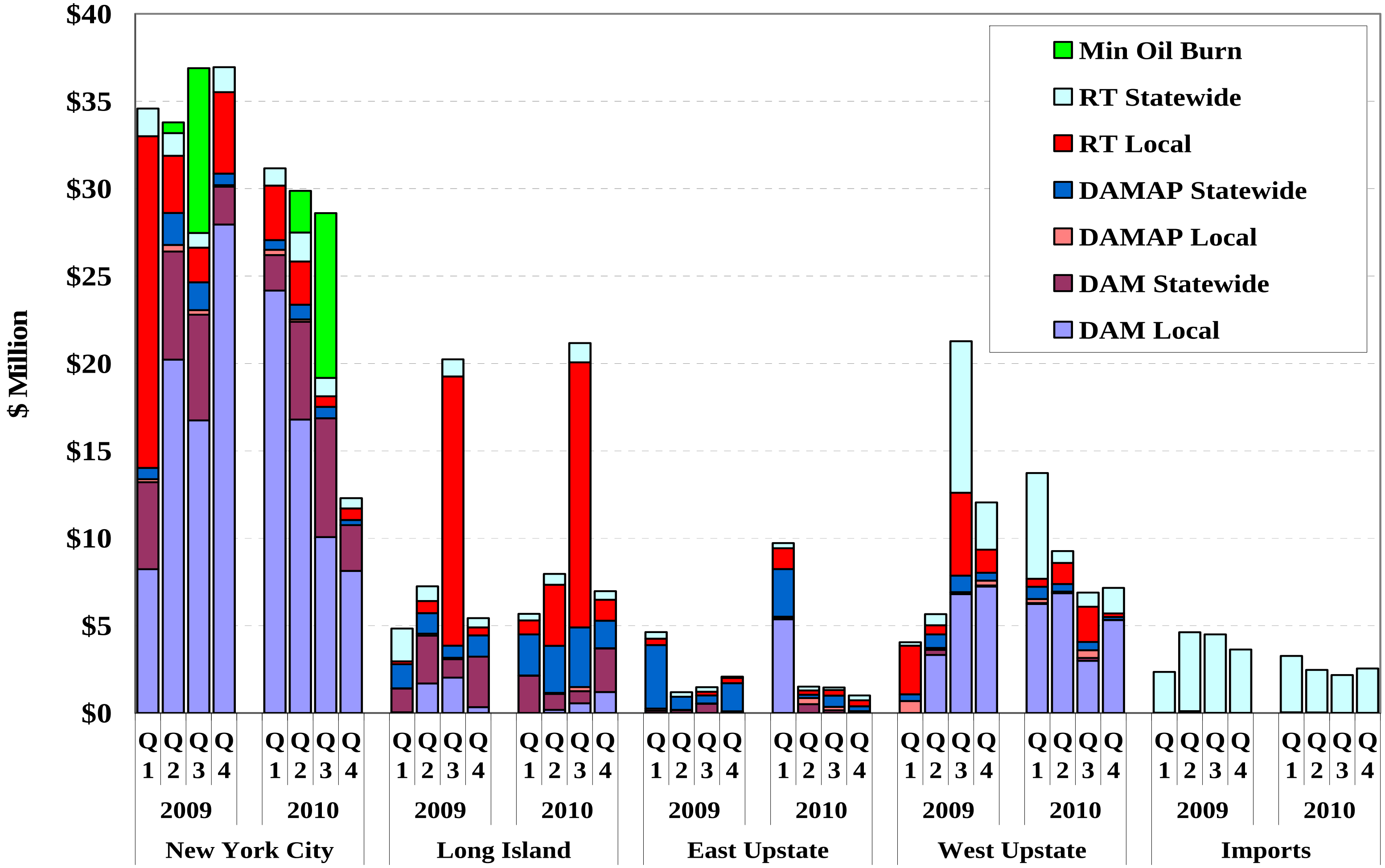
Uplift Costs from Guarantee Payments By Region

- The following figure shows the seven categories of uplift charges on a quarterly basis by region in 2009 and 2010.
- Real-time statewide reliability uplift in 2010:
  - ✓ 36 percent was paid to import transactions that were scheduled by RTC when the real-time LBMP was lower than the offer price.
  - ✓ 21 percent was paid to several generators in western New York in the first quarter when they were committed more frequently due, in part, to transmission outages and changes in commitment patterns.
- DAMAP statewide uplift in 2010:
  - ✓ A large portion of this category was paid to relatively slow-ramping steam units in Southeast New York immediately after the onset of price spikes.
  - ✓ A significant share was paid to generators in Long Island in the summer that were dispatched below their day-ahead schedules when generation was dispatched out-of-merit to manage transmission facilities on the East End.
- The decrease in overall guarantee payment uplift from 2009 to 2010 was also due to mitigation measures instituted in September 2009 to address market power associated with certain reliability commitments outside New York City.

Uplift Costs from Guarantee Payments By Region

- Day-ahead local reliability uplift in 2010:
  - ✓ The majority was for New York City (68 percent) and western New York (25 percent) DARU- and LRR-commitments.
  - ✓ This fell from 2009 primarily due to less DARU commitment in New York City.
- Day-ahead statewide reliability uplift in 2010:
  - ✓ The majority (68 percent) was paid to New York City generators.
    - 81 percent of this was paid in hours when the generator was needed for local reliability but ultimately flagged as economic.
    - If SCUC commits a resource to minimize production costs even when the local reliability rules are removed from the evaluation, it is deemed economic.
  - ✓ 25 percent was paid to Long Island generators.
- Real-time local reliability uplift in 2010:
  - ✓ Payments to Long Island generators accounted for the majority (62 percent).
    - The third quarter alone accounted for 45 percent, primarily to manage transmission facilities on the East End that are secured by OOM dispatch by the TO.
  - ✓ This fell from 2009 due to fewer SRE commitments in New York City.

Uplift Costs from Guarantee Payments
By Category and Region



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External Interface Scheduling

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External Interface Scheduling

- 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 internal resources.
  - ✓ 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 loop flow around Lake Erie.
  - ✓ Convergence of prices between New York and neighboring control areas.
  - ✓ Benefits of external interface scheduling by market participants.
  - ✓ Potential benefits from market enhancements associated with:
    - – Inter-Regional Interchange Scheduling with New England; and
    - – The Broader Regional Markets initiative.

External Interface Summary

- The following two figures summarize the interchange with neighboring control areas during the past two years over the primary interfaces.
  - ✓ 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 two figures show the average net imports across:
  - ✓ The primary interfaces with Ontario and PJM; and
  - ✓ The primary interfaces with Quebec and New England.

<u>Ontario</u>

- The average net imports from Ontario in peak hours declined 25 percent from 2009 to 231 MW in 2010.
  - ✓ Net imports averaged between 300 and 500 MW during most months in 2010.
  - ✓ Average net imports fell in February, March, May, June, and November 2010, due primarily to:
    - – Scheduling was affected by several outages of large transmission lines that are part of the interface with Ontario, particularly in November; and
    - – A significant planned generation outage in Ontario likely affected scheduling in May and June.

External Interface Summary

PJM

- The average net imports from PJM in peak hours rose 10 percent from 606 MW in 2009 to 666 MW in 2010.
  - ✓ The average volume of imports during off-peak hours increased substantially by 53 percent to 1,018 MW in 2010.

Hydro Quebec and New England

- Significant quantities of imports come across the primary interfaces with Hydro Quebec and New England during peak hours.
  - ✓ Imports from these areas generally increase during peak hours and in the summer, while switching to exports during the winter and in off-peak hours.
    - – Quebec's peak load generally occurs in the winter.
    - – New England is more reliant on natural gas generation, which is more uncertain during the winter months.
  - ✓ Average net imports from Hydro Quebec during peak hours fell 9 percent from 2009; while average net imports from New England rose 26 percent from 2009.
    - – Imports from Hydro Quebec greatly reduced from September to November 2010, reflecting higher internal load and reduced reservoir levels in Quebec, and relatively low electricity prices in New York.

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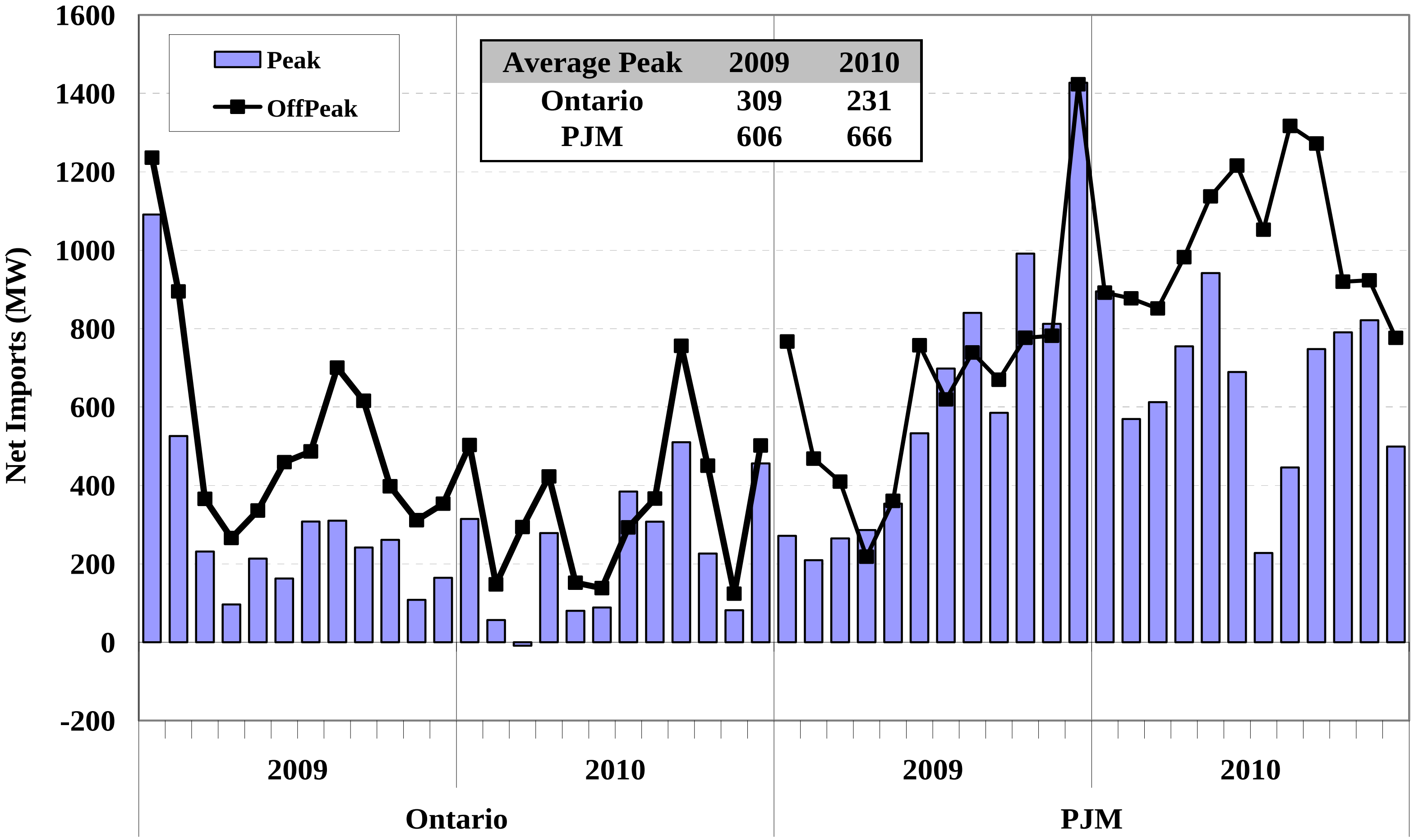
Monthly Average Net Imports from Ontario and PJM
2009 – 2010



Note: Net Imports from PJM include only net imports over the primary interface with PJM. Does not include the Neptune line or Linden VFT shown later.

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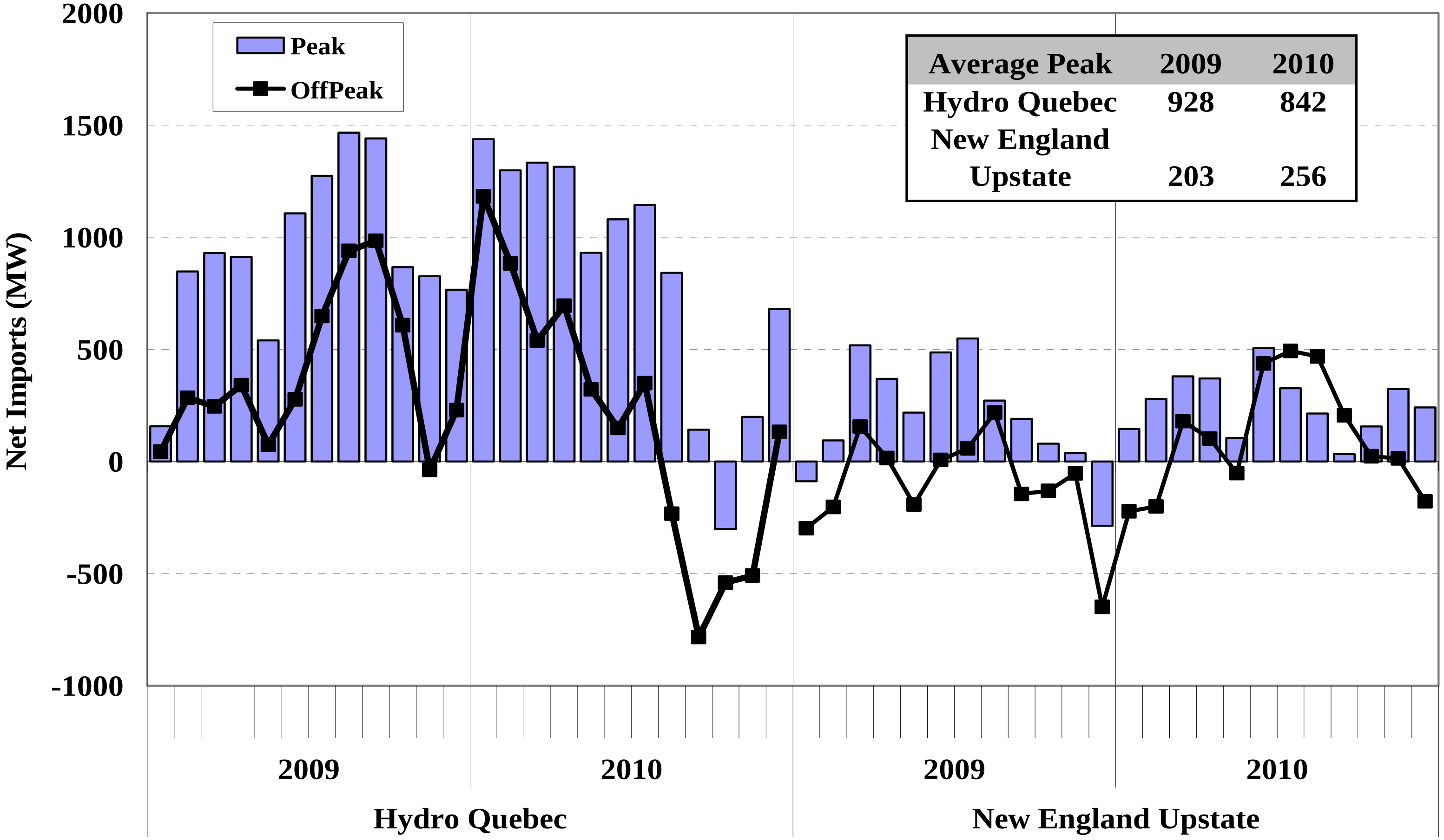
Monthly Avg Net Imports from Quebec and New England 2009 – 2010



Note: Net Imports from New England include only net imports over the primary free-flowing interface. Does not include the Cross-Sound Cable or the Northport-Norwalk line that are shown later.

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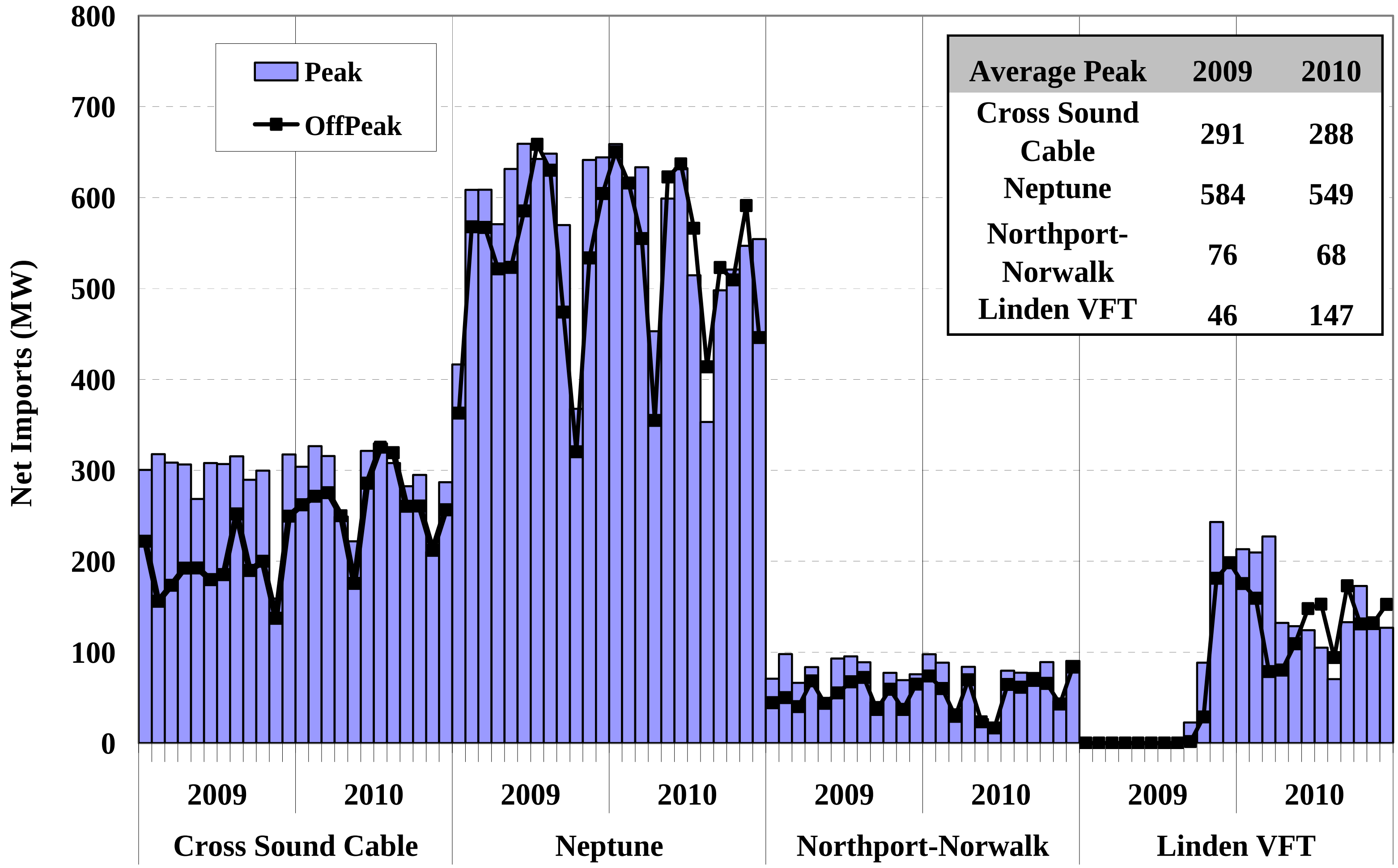
External Interface Summary

- A substantial share of the imports to New York state go directly to New York City and Long Island via the:
  - ✓ The Cross Sound Cable (330 MW) and the Northport-to-Norwalk line (100 MW), which usually import power to Long Island from Connecticut.
  - ✓ The Neptune Cable (660 MW) usually imports to Long Island from New Jersey.
  - ✓ The Linden VFT line (300 MW) usually imports to New York City from New Jersey.
    - – The Linden VFT line began normal operation in November 2009.
- The Cross Sound Cable, the Northport-to-Norwalk line, and the Neptune Cable satisfied approximately 34 percent of the load in Long Island in 2010.
- The next figure shows the interchange in peak and off-peak hours over these interfaces.
  - ✓ The imports across these direct interfaces were slightly more during peak hours than during off-peak hours.
  - ✓ Unlike the primary interfaces, the interchange over these direct interfaces is generally relatively consistent from month to month.

Monthly Avg Imports into New York City and Long Island 2009 – 2010



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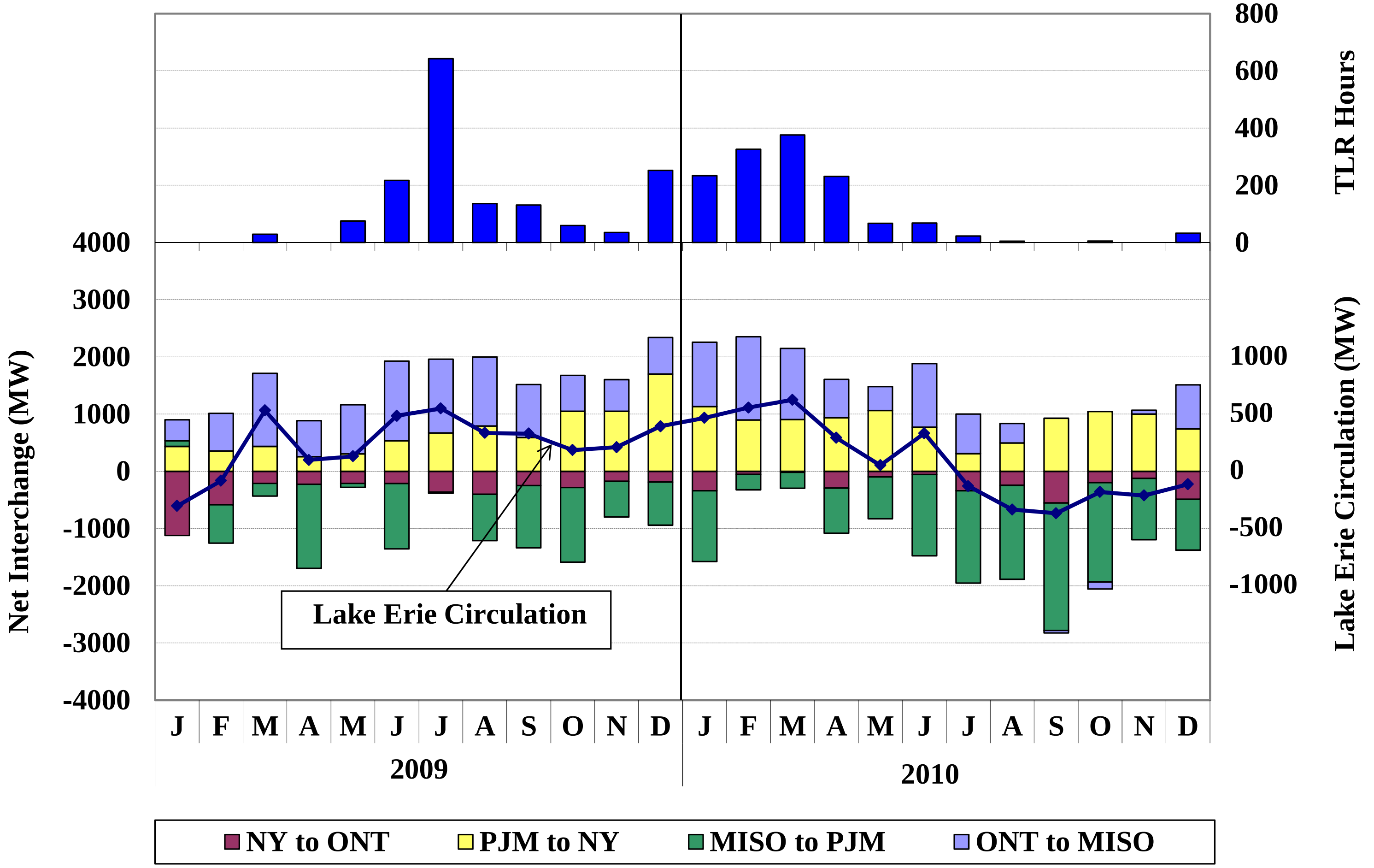
External Interface Scheduling – Lake Erie Circulation

- Loop flows occur when physical power flows are not consistent with the scheduled path of the transaction between control areas.
  - ✓ Clockwise loop flows around Lake Erie use valuable west-to-east transmission capacity through upstate New York, reducing the capacity available for scheduling internal generation to satisfy internal load.
  - ✓ Conversely, counter-clockwise loop flows increase the transmission capacity available for scheduling internal generation.
  - ✓ Transmission Loading Relief ("TLR") procedure is used by the NYISO when loop flows contribute to congestion on internal flowgates.
- The following figure summarizes the pattern of loop flows and the net scheduled interchange between the four control areas around Lake Erie in each month in 2009 and 2010. The figure shows:
  - ✓ The monthly averages of actual real-time loop flow in the clockwise (or counter-clockwise, if negative) direction;
  - ✓ The monthly averages of actual real-time net interchanges between the NYISO, Ontario, PJM, and the MISO; and
  - ✓ The number of hours in each month when TLRs (level 3A and above) were called by NYISO.

External Interface Scheduling – Lake Erie Circulation

- The figure shows that average clockwise circulation around Lake Erie fell from 2009 to 2010.
  - ✓ Clockwise circulation averaged roughly 85 MW in 2010, down 65 percent from the 240 MW in 2009.
  - ✓ Clockwise circulation fell substantially in the second half of 2010.
    - Clockwise circulation averaged 388 MW in the first six months, but fell to *negative* 222 MW (counter clockwise) in the last six months.
  - ✓ The decrease was partly driven by reduced scheduling from Ontario to MISO and by increased scheduling from PJM to MISO.
- TLRs (level 3A and above) were called less frequently in 2010 compared to the previous year, consistent with the reduction in clockwise circulation.
  - ✓ TLRs occurred in approximately 1365 hours in 2010, down 13 percent from 2009.
    - Most of these occurred in the first half of 2010 when circulation around Lake Erie averaged more than 380 MW in the clockwise direction.
- The Broader Regional Market Initiatives developed by the NYISO and other RTOs around Lake Erie will improve the efficiency with which these flows are managed.

Lake Erie Circulation
2009 – 2010



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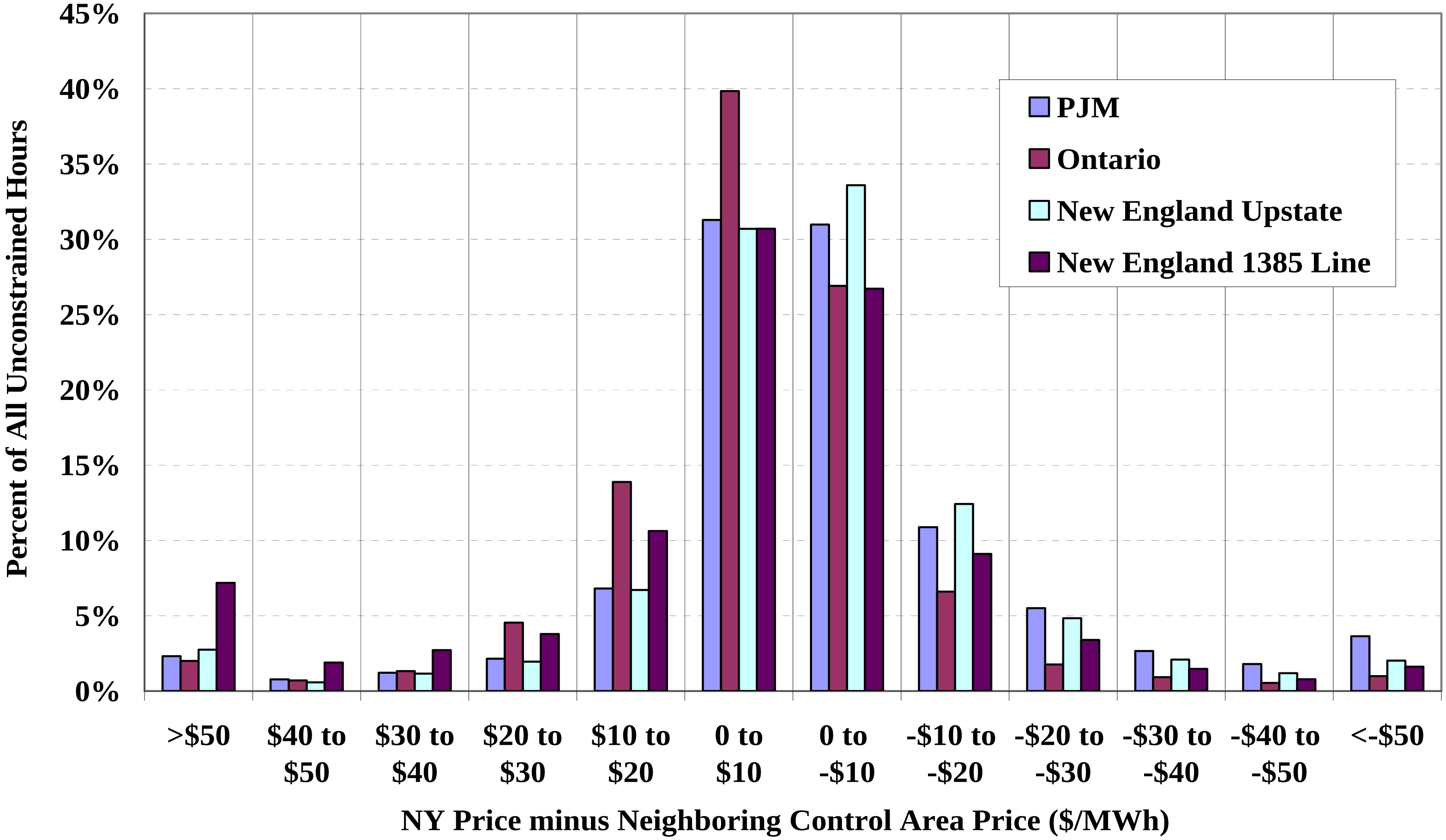
External Interface Scheduling –
Price Convergence Between Control Areas

- When interfaces are used efficiently, prices in adjacent markets and New York should converge unless transmission constraints limit the schedules.
- 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 $10/MWh in 33 to 43 percent of the unconstrained hours across each of the interfaces.
  - ✓ The Ontario results were slightly worse that the other interfaces and the price differences were skewed toward higher prices in New York and lower prices in Ontario.
- This reinforces the importance of efforts to improve real-time interchange between New York and adjacent markets.
  - ✓ Efficient scheduling is particularly important during 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 Markets
Unconstrained Hours in Real-Time Market, 2010



Note: In these hours, there were no NYISO constraints that prevented scheduling. However, in some of these hours, there may have been constraints that prevented the other ISO from scheduling transactions.

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External Interface Scheduling – Market Participant Scheduling

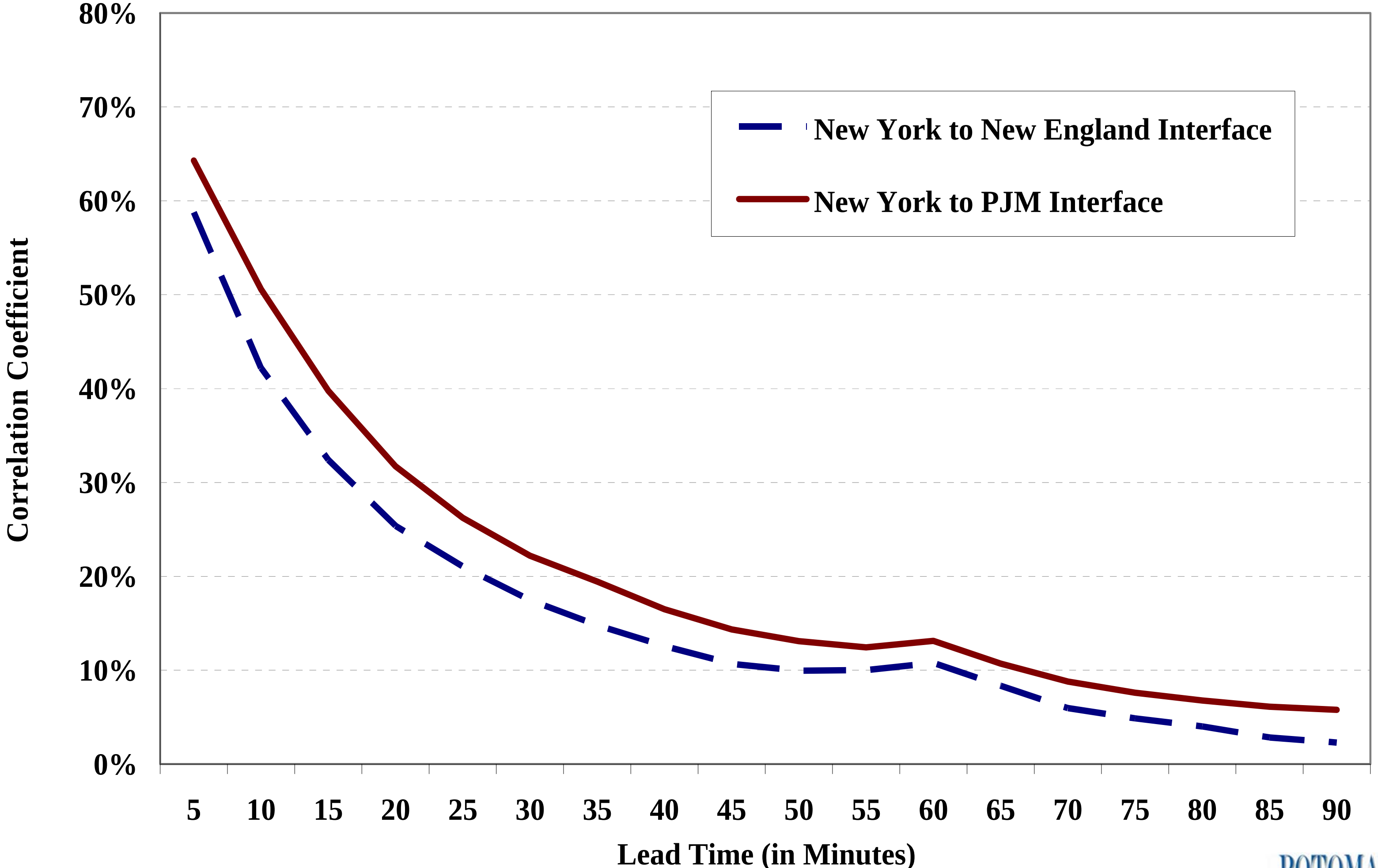
- The prior analyses show that it has proven difficult to achieve real-time price convergence with adjacent markets through the current process of transaction scheduling by market participants.
  - ✓ Uncertainty, imperfect information, and required offer lead times limit the ability of participants to 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 evaluate the efficiency of scheduling by market participants between markets.
  - ✓ The first figure illustrates the consistency of real-time price differences between New York and the two adjacent ISO markets in the 90 minutes leading up to each real-time five-minute interval.
  - ✓ The second figure evaluates the consistency of the direction of external transaction scheduling and price differences between New York and the three adjacent ISO markets.

External Interface Scheduling
Market Participant Scheduling

- Currently, market participants submit transactions 75 minutes before the start of an hour, which is 75 to 135 minutes before the power flows.
- This may contribute to participants' inability to fully arbitrage the difference in prices between adjacent markets.
- To evaluate this, the following figure shows the correlation between the current five-minute price difference between New York and an adjacent market and the actual differences that occurred up to 90 minutes earlier.
  - ✓ The figure shows that the correlation coefficient increases as the lead time is reduced below 90 minutes.
  - ✓ This may under-estimates the predictability of price differences between control areas because participants can use more sophisticated techniques for forecasting and use the RTC's advisory prices.
  - ✓ Nonetheless, the correlation is still less than 25 percent for a 30 minute lead time at New York's primary interfaces with PJM and New England. This is the shortest scheduling time used currently by any of the RTOs.
- This analysis suggests that shortening lead times for scheduling would capture a modest share of the available benefits from utilizing the external interfaces more efficiently.

Correlation of Price Differences and Lead Time

Primary Interfaces with Adjacent Markets – 2010



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External Interface Scheduling –
Market Participant Scheduling

- The following figure summarizes the efficiency of external transaction scheduling across the primary interfaces between New York and New England, PJM, and Ontario.
  - ✓ The left side shows hours when power was scheduled in the export direction.
  - ✓ The right side shows hours when power was scheduled in the import direction.
  - ✓ The top portion of the figure reports the share of these hours when power was scheduled in the profitable direction (i.e., from the lower-price market to the higher-priced market).
    - Hence, if more than 50 percent of the hours are profitable, then the market schedules power to flow in the efficient direction in the majority of hours.
  - ✓ The lower portion of the figure summarizes price differences between markets during these hours.
    - It is efficient for New York to export in hours when the clearing price in New York is lower than in the adjacent area (i.e., the bar is negative), and to import when the clearing price in New York is higher (i.e., the bar is positive).
- This analysis evaluates: (i) day-ahead schedules and clearing prices, and (ii) incremental changes in schedules in the real-time market (relative to the day-ahead schedules).

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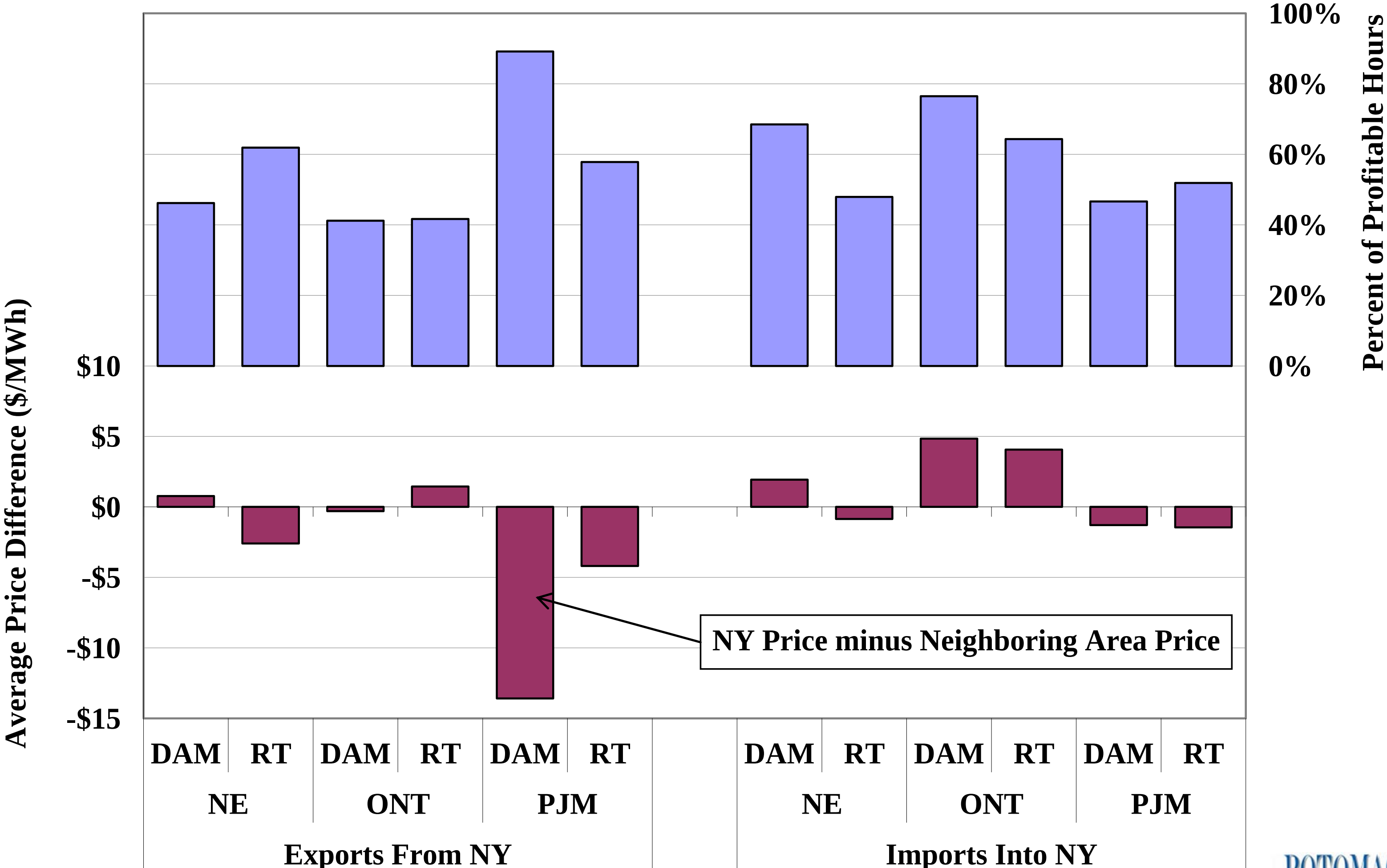
External Interface Scheduling – Market Participant Scheduling

- The figure shows the following:
  - ✓ For most categories of transactions, the average clearing price was lower in New York when exports are scheduled and higher in New York when imports are scheduled.
    - – Hence, scheduling by market participants generally improves the efficiency of power flows between markets.
  - ✓ However, power was scheduled in the *unprofitable* direction in a large share of the hours for most the categories of transactions shown in the figure.
    - – Individual categories of transactions were unprofitable in 11 to 59 percent of hours.
    - – In the real-time, most of the interfaces and directions showed unprofitable transactions on net in 40 to 50 percent of the hours.
    - – Hence, in almost half of the hours the power physically flows from the high-priced market to the low-priced markets, which is inefficient.
  - ✓ These results indicate that substantial improvement is possible in the utilization of New York's external interfaces.
- Hence, we continue to recommend that the NYISO coordinate its interchange with adjacent markets or otherwise allow real-time intra-hour scheduling to achieve better utilization of the interfaces.

Efficiency of Inter-Market Scheduling
Over Primary Interfaces – 2010



Benefits of Inter-Regional Interchange Scheduling

- The remainder of this section summarizes our assessment of the benefits of initiatives to improve the efficiency of the interchange between the New York and New England.
- Improved scheduling would more fully utilize the transmission interfaces between the markets and generate significant benefits.
  - ✓ The true efficiency benefits are best measured as reduced production costs.
  - ✓ Production costs are reduced as lower-cost resources in one market displace higher-cost resources in the adjacent market.
  - ✓ The result of this process is improved price convergence between the markets.
  - ✓ In most cases, the short-term consumer savings (resulting from the price-effects of improved scheduling) would be substantially higher than the production cost savings.
- Our previous State of the Market Reports have consistently found that coordination would lead to significant reductions in production costs and consumer costs.
- This assessment expands the analysis to estimate the benefits of specific proposals for coordinating the interchange between New York and New England.

Benefits of Inter-Regional Interchange Scheduling – Alternative Proposals

- Our previous simulations estimated the benefits that would result from optimal scheduling of the interfaces between the markets.
  - ✓ However, the portion of the benefits that are ultimately realized depends on the effectiveness of the market solutions that are implemented by the ISOs.
- The ISOs are currently evaluating the benefits of specific proposals that will improve, but will not perfectly optimize the interchange due to uncertainties.
- The results that are discussed in this presentation compare the benefits from optimal scheduling to the benefits that would result from two specific proposals:
  - ✓ <u>Tie Optimization</u> – The ISOs exchange information 15 minutes in advance and optimize the interchange based on a prediction of market conditions. The interchange would be adjusted every 15 minutes.
  - ✓ <u>Coordinated Transaction Scheduling</u> – Identical to Tie Optimization, except the interchange schedule is only adjusted to the extent that market participants have submitted intra-hour Interface Bids priced below the predicted price difference between markets.

Benefits of Inter-Regional Interchange Scheduling – Modeling Specific Proposals

- To quantify the share of potential benefits that would be captured by each proposal, we performed the simulations using three sets of assumptions:
  - ✓ Ideal Interchange – Assumes the interchange is adjusted to the optimal level based on perfect information. The adjustment in interchange increased toward the higher-priced market until: (i) the interface is fully loaded, (ii) internal constraints prevent additional re-dispatch, or (iii) the adjustment reaches 500 MW.
  - ✓ Tie Optimization – Assumes the interchange is adjusted to the forecasted optimal level. The ISOs' forecast may differ from actual conditions, so the resulting interchange may not be optimal.
    - – For NYISO, we use the advisory price produced by the RTD that precedes the quarter hour RTD case.
    - – For ISO-NE, we use its hour-ahead forecast. The forecast errors are larger than the errors in New York understandably. We reduce the errors by 50 percent to account for the expected increase in accuracy when the timeframe is shortened.
  - ✓ Coordinated Transaction Scheduling – Same as Tie Optimization, except an assumed interface "bid stack" limits re-dispatch when the marginal bid the forecasted price difference.
- Comparing the results of these simulations allows us to evaluate the efficiency of specific proposals compared to ideal interchange scheduling.

Benefits of Inter-Regional Interchange Scheduling – Discussion of Assumptions Used in Simulations

- Use of Interval Data – In past analyses (e.g., in State of the Market Reports), we estimated the optimal interchange using historic hourly-integrated real-time data, while these simulations use real-time data at the interval level.
  - ✓ The use of hourly data resulted in conservative estimates by assumed one interchange value for the hour -- it is usually efficient to adjust the interchange throughout the hour.
  - ✓ This analysis allows adjustments each 15 minutes.
- 500 MW Limit on Adjustments – The latest simulations impose a 500 MW limit on the size of the adjustment in the interchange in any interval (past simulations had no limit).
  - ✓ The simulation model does not "see" internal transmission constraints that would bind due to the interchange adjustment, so this limit reduces tendency to over-estimate potential re-dispatch.
- Consumer Savings – These are calculated as the change in real-time prices times the load affected by the price change.
  - ✓ The load affected is limited by congestion (e.g., binding constraints into SE New York limit the downstate consumer savings).
- Negative-LBMP Intervals – We exclude intervals when the New York border price is negative, since these are likely to become far less prevalent after (i) the HQ interface is scheduled on a 5-minute basis and (ii) the regulation demand curve is modified.

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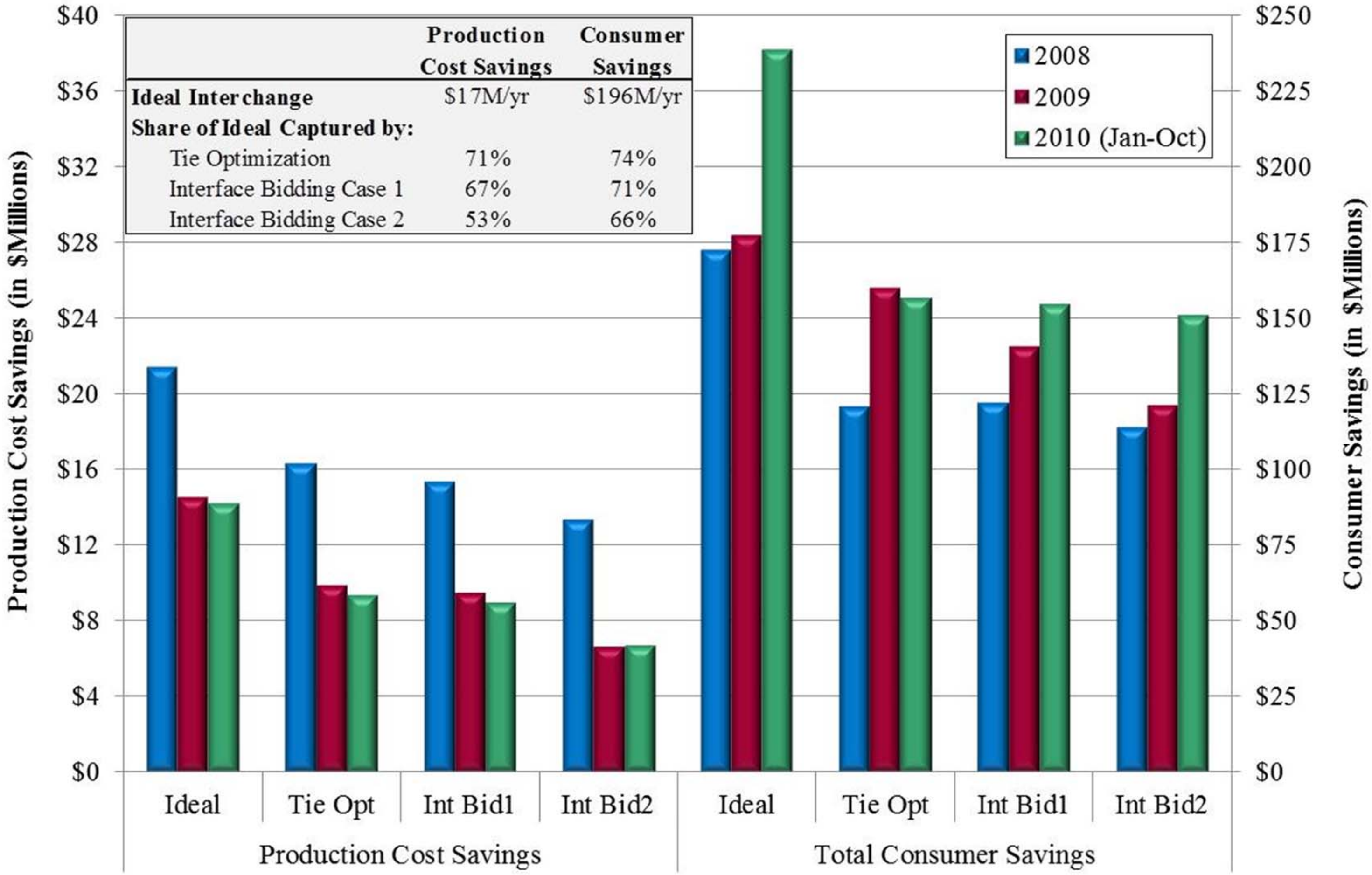
Benefits of Inter-Regional Interchange Scheduling – Discussion of Assumptions Used in Simulations

- Top of the Hour: Our simulations exclude intervals at the top of each hour.
  - ✓ These intervals are frequently affected by ramp constraints and other conditions that lead to transient price spikes that our simulations are not designed to model accurately.
  - ✓ Hence, we conservatively estimate zero benefits from these intervals, although it is likely that the interchange would be improved in these intervals.
- Congestion Assumptions: The simplified network model used in our simulations is based on active constraints, and assumes no re-dispatch after the interchange adjustments.
  - ✓ This is conservative because redispatch may occur that would produce additional savings that we do not capture.
  - ✓ For example, the scope of the consumer savings could be broader than we estimate if optimal redispatch would reduce or eliminate congestion on active constraints.
- Interface Bidding assumption: We assumed a interface bid stack beginning at zero and rising linearly up to $10 at 500 MW in the first case, and rising linearly to $40 at 500 MW in the second case.

Benefits of Inter-Regional Interchange Scheduling – Production Cost Savings and Consumer Savings

- The following figures shows the estimated production cost savings and consumer savings for each of the cases that we analyzed.
- The average production cost savings was roughly $18 million per year, although this is likely conservative as a long-run expectation because:
  - ✓ One quarter of the hour is not included;
  - ✓ The supply and demand conditions in both areas were not as tight as they are likely to be in the long run and shortages were relatively infrequent; and
  - ✓ Fuel prices were relatively lower for much of this period.
- The results show that roughly 70 percent of the efficiency benefits are captured by Tie Optimization and only slightly less by the lower priced interface bids.
  - ✓ The higher-priced interface bids degrades the benefits to 54 percent of the ideal case.
- The figure also shows that consumer savings in the ideal case average almost $200 million per year, which is conservative for the same reasons as listed above.
  - ✓ Nearly three-quarters of the savings are captured by Tie Optimization, which falls only slightly to 71 percent with low-priced interface bids.
- The second figure shows that the consumer savings accrue to both areas, although the relative savings has shifted year-to-year as congestion patterns and supply conditions have changed.

Production Cost Savings and Consumer Savings January 2008 – October 2010



	Production Cost Savings	Consumer Savings
Ideal Interchange	$17M/yr	$196M/yr
Share of Ideal Captured by:		
Tie Optimization	71%	74%
Interface Bidding Case 1	67%	71%
Interface Bidding Case 2	53%	66%

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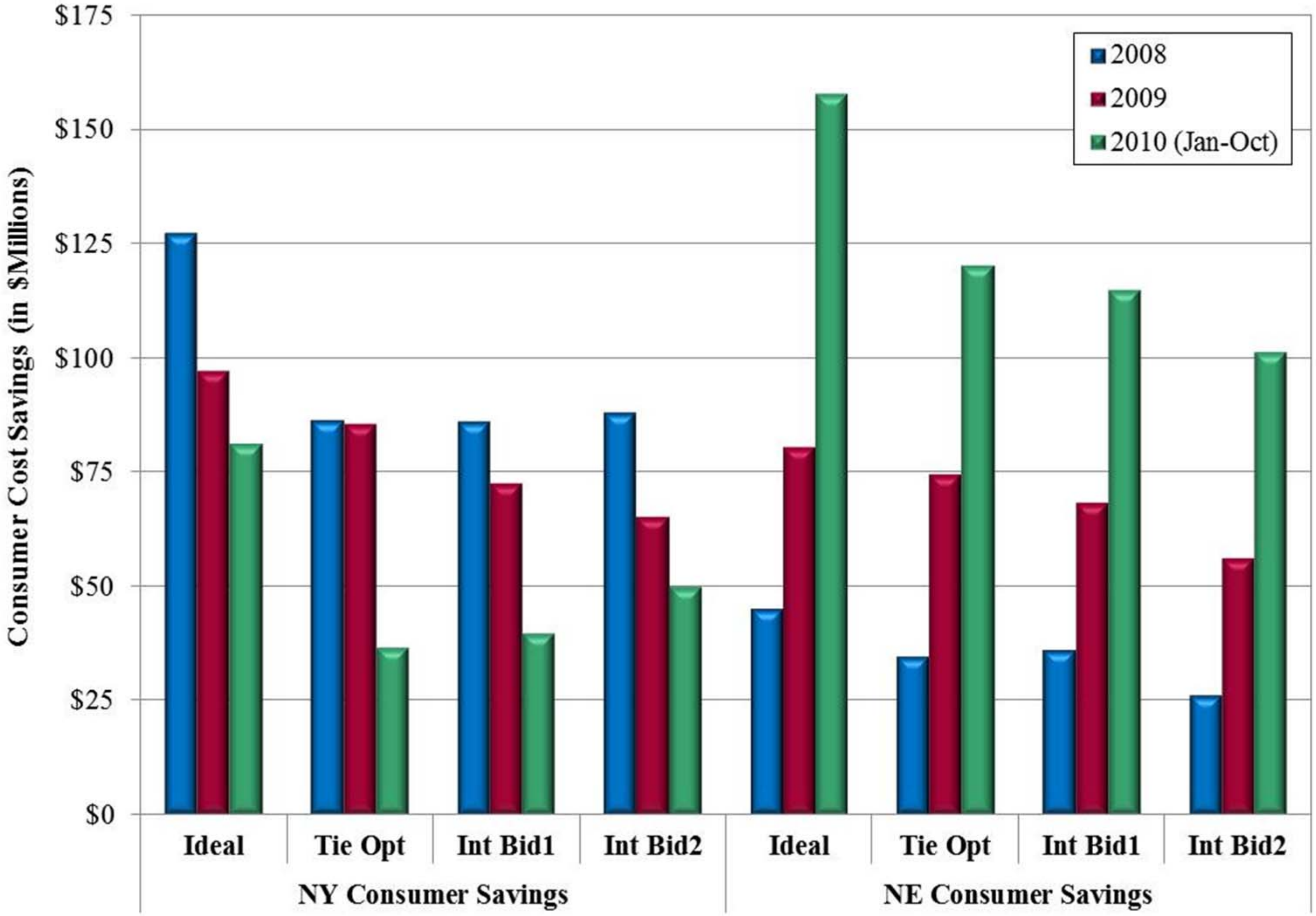
Estimated Consumer Savings by Market
January 2008 – October 2010



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Summary of Simulation Results
January 2008 – October 2010

- The following table provides some additional detail regarding the results of the simulations.
- It shows that in each year, the adjustments occur relatively evenly in both directions, which contributes to consumer savings in both areas each year.

	Ideal Interchang				Tie Opt	Int Bid1	Int Bid2
	2008	**2009**	**2010**	**2008-10**	**2008-10**	**2008-10**	**2008-10**
Flow Adjusted Into NY (% of intervals)	42%	46%	44%	44%	43%	43%	43%
Flow Adjusted Into NE (% of intervals)	41%	44%	45%	43%	42%	42%	42%
When Flow Adjusted Into NY:							
Avg. Adjustment (MW)	266	259	265	264	304	228	143
Avg. System LBMP Change in NY ($/MWh)	-$10.63	-$7.19	-$7.07	-$8.30	-$8.24	-$7.11	-$5.64
Avg. System LMP Change in NE ($/MWh)	$7.00	$2.96	$3.39	$4.45	$4.84	$3.95	$2.75
When Flow Adjusted Into NE:							
Avg. Adjustment (MW)	-226	-220	-237	-228	-145	-88	-24
Avg. System LBMP Change in NY ($/MWh)	$7.96	$4.36	$4.83	$5.72	$6.73	$5.62	$4.14
Avg. System LMP Change in NE ($/MWh)	-$8.21	-$4.93	-$7.43	-$6.86	-$6.88	-$5.87	-$4.39

POTOMAC ECONOMICS

Broader Regional Market Initiatives – Conclusions and Recommendations

- These results show sizable efficiency and consumer savings in all cases analyzed, which supports the ISOs' initiative to pursue improved interface scheduling.
  - ✓ For the reasons we have discussed, these savings are likely to be conservative and would be larger under tighter supply/demand conditions over the long-run.
  - ✓ These savings are larger than the potential savings available from most other initiatives and should, therefore, be a relatively high priority.
- While Tie Optimization is superior to Coordinated Transaction Scheduling, the benefits are very similar if participants submit relatively low-cost interface bids.
- In addition to improving the interface utilization with New England, the Broader Regional Market ("BRM") initiatives include:
  - ✓ More frequent scheduling with PJM and Quebec (every 15 minutes); and
  - ✓ Coordinated congestion management with PJM and with New England.
- We recommend that the NYISO continue to place a high priority on these initiatives, particularly the interface utilization initiative because it offers the highest efficiency benefits.

Capacity Market

Capacity Market – Background

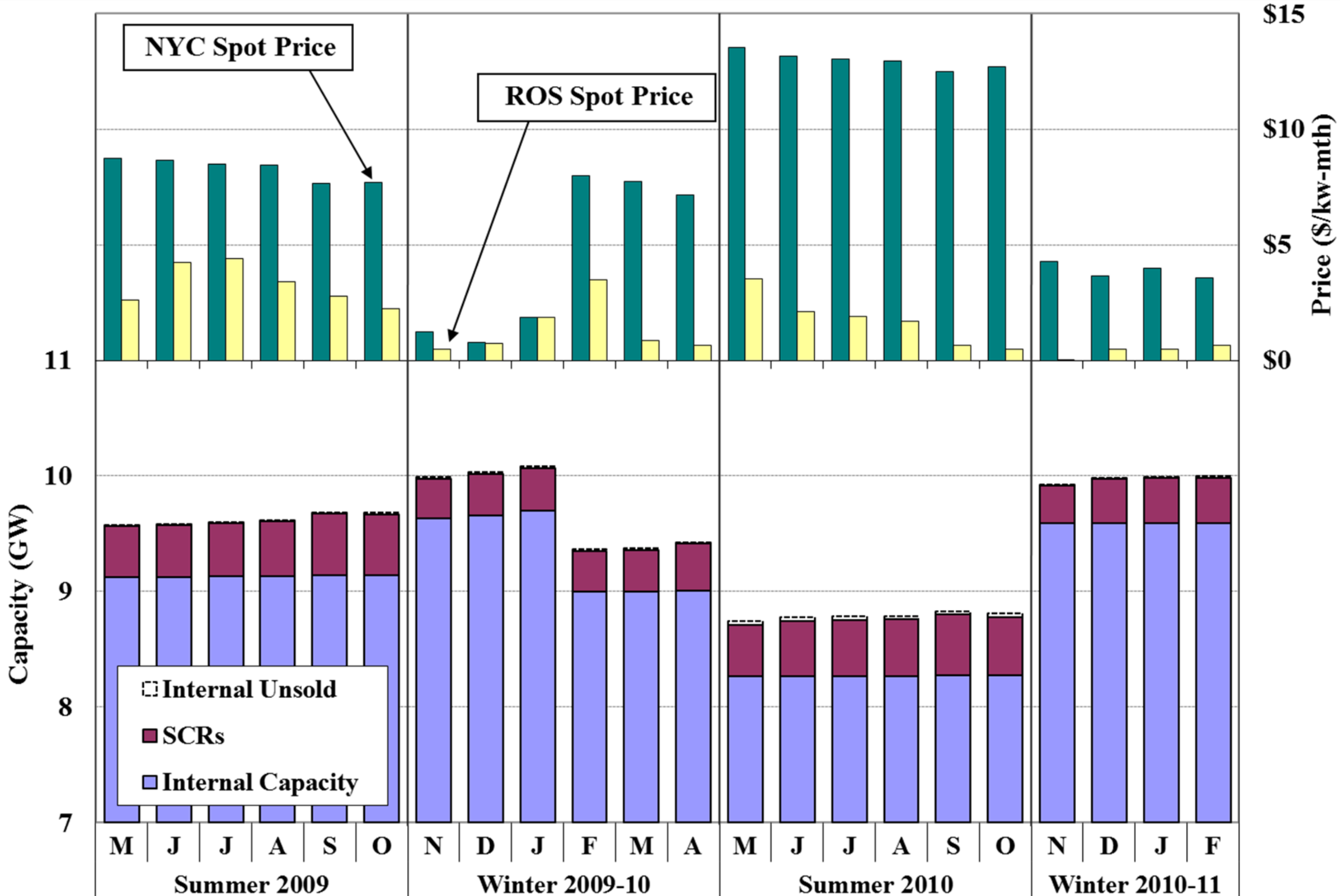
- The capacity market complements the energy and ancillary services markets in providing efficient economic signals for investment and retirement decisions.
- LSEs have several ways to satisfy their capacity obligations. They can:
  - ✓ "Self-schedule" their own generating capacity;
  - ✓ Purchase capacity 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 summarizes available and scheduled UCAP resources and the clearing prices in NYC for the past four Capability Periods.
- The most significant changes in clearing prices result from the seasonal variations in the quantity of capacity supply.
  - ✓ Typically, additional capability is available in the winter capability periods due to lower ambient temperatures, resulting in lower prices in these months.
- NYC clearing prices rose to an average of $12.99/kW-month in the summer 2010, up 57 percent from the summer 2009 due to:
  - ✓ The scheduled escalation of the NYC capacity demand curve; and
  - ✓ The retirement of the Poletti unit, reducing supply by nearly 900 MW since Feb. 2010.
  - ✓ However, these increases were partly offset by a 325 MW reduction in the summer peak load forecast for New York City and capacity sales from new resources.
- UCAP sales rose significantly from the end of the Winter 2009/10 Capability Period to the Winter 2010/11 Capability Period due to an improvement in forced outage rates.
  - ✓ However, this did not significantly reduce prices because an improvement in forced outage rates automatically triggers an increase in the UCAP requirement.
- The figure shows that virtually all internal capacity has been sold in each month so withholding of supply has not been a concern.

UCAP Sales and Prices in New York City

May 2009 to February 2011



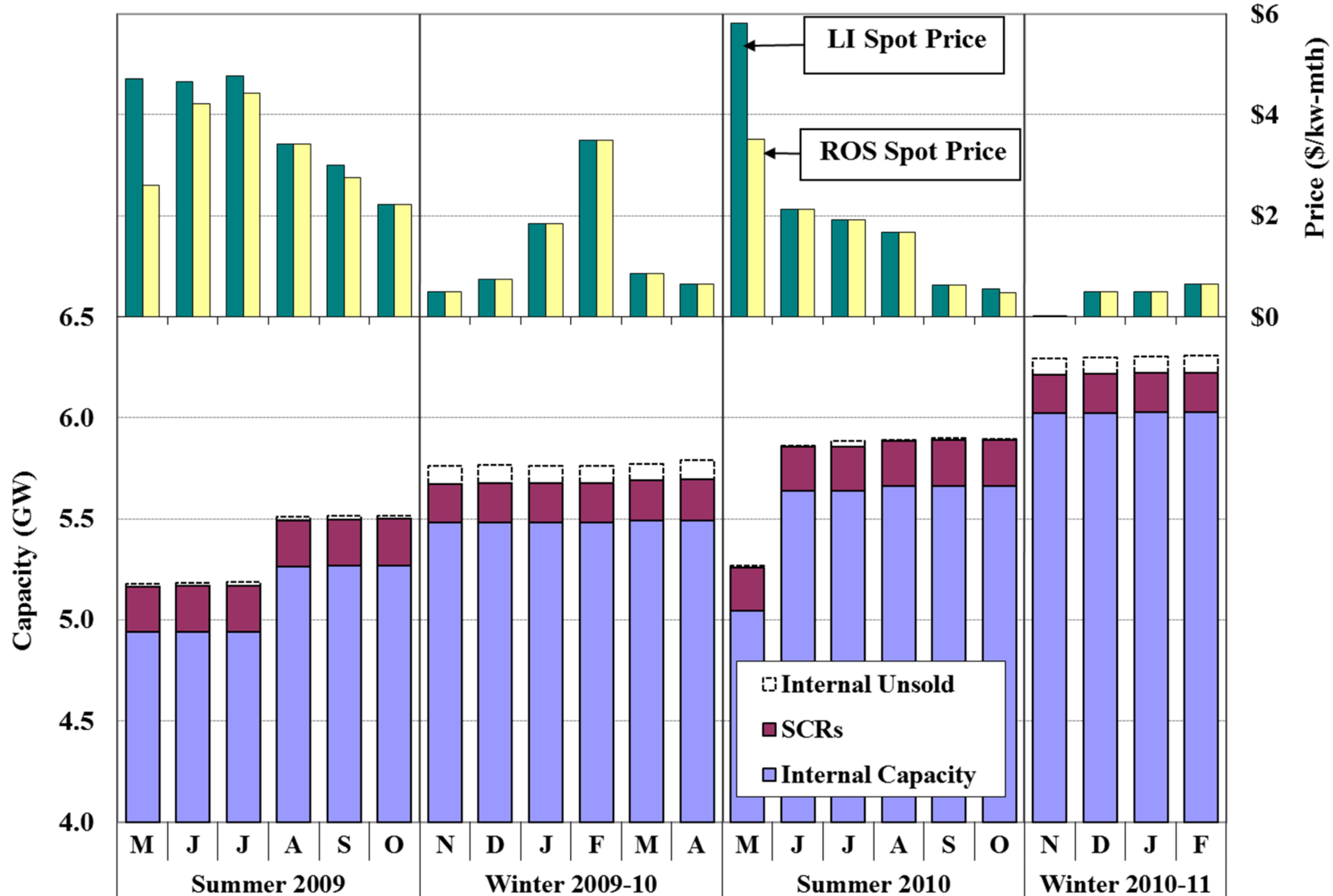
Note: Sales related to Unforced Deliverability Rights ("UDRs") are included in "Internal Capacity".

Capacity Market – Long Island

- The following figure summarizes available and scheduled UCAP resources and the clearing prices in Long Island for the past four Capability Periods.
- In 16 of 22 months shown, the Long Island clearing price was equal to the NYCA clearing price, indicating that the local capacity requirement was not binding.
  - ✓ Long Island has substantial excess capacity—approximately 17 percent more than the amount of capacity needed to satisfy the local summer capacity requirement.
- The capacity surplus in Long Island generally increased during the period.
  - ✓ Capacity levels increased approximately 300 MW in August 2009 due to the start of operation of the Caithness combined cycle generator;
  - ✓ The summer peak load forecast for Long Island fell 106 MW from 2009 to 2010; and
  - ✓ Changes in the sales of "internal" capacity from UDRs occurred during the summer of 2010.
  - ✓ These factors were partly offset by the increase in the Long Island Local Capacity Requirement ("LCR") from 97.5 percent in the summer 2009 to 102 percent in May 2010 and 104.5 percent since June 2010.

UCAP Sales and Prices in Long Island

May 2009 to February 2011



Note: Sales related to Unforced Deliverability Rights ("UDRs") are included in "Internal Capacity".

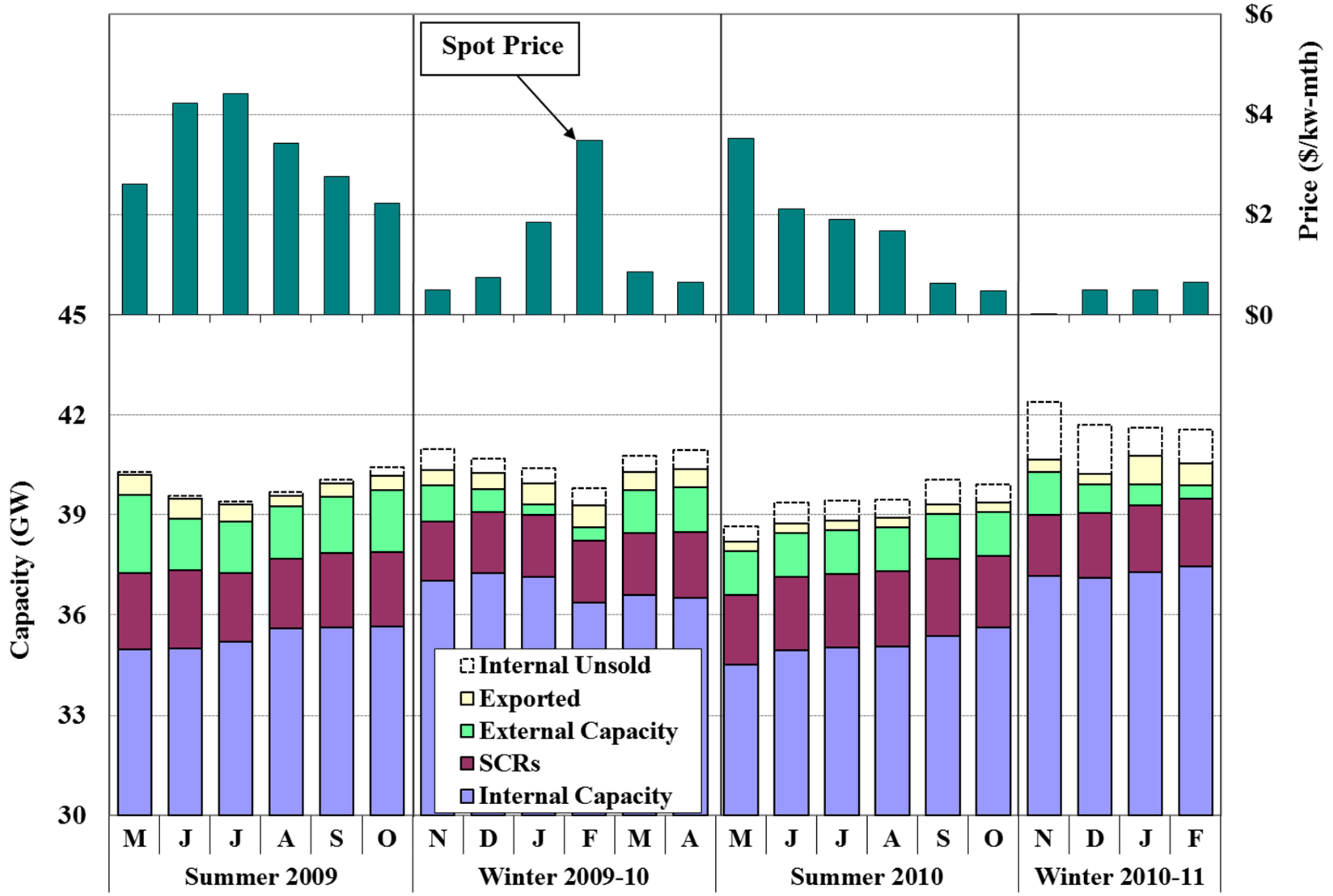
POTOMAC ECONOMICS

Capacity Market – New York State

- The following figure summarizes available and scheduled UCAP resources and the clearing prices in the NYCA area for the past four Capability Periods.
- Seasonal variations in capacity led to higher levels of internal capacity in the winter months and correspondingly lower clearing prices.
- Changes in the amount of available internal supply affected clearing prices in 2010.
  - ✓ Poletti's retirement in February 2010 reduced UCAP supply by nearly 900 MW, contributing to a $1.64/kW-month increase in the clearing price after January.
  - ✓ The sales from UDRs increased in Long Island in June 2010, contributing to $1.40/kW-month decrease in the clearing price after May.
  - ✓ New capacity at Empire increased supply by over 500 MW in September 2010, contributing to a $1.05/kW-month decrease in the clearing price after August.
- Substantial changes in imports and exports in response to capacity prices in New York also affected prices. For example:
  - ✓ Imports rose sharply in March 2010 after prices rose in February when Poletti retired.
  - ✓ Imports fell and exports increased after the market cleared at close to zero in Nov. 2010.
- The capacity requirement fell because the summer peak load forecast for NYCA fell 905 MW from 2009 to 2010, decreasing clearing prices after May 2010.
  - ✓ However, this was partly offset by an increase in the installed capacity requirement from 116.5 percent to 118 percent over the same period.

UCAP Sales and Prices in New York State

May 2009 to February 2011



Note: Sales related to Unforced Deliverability Rights ("UDRs") are included in "Internal Capacity".

POTOMAC ECONOMICS

Capacity Market – Zone Configuration and Deliverability

- The capacity market should provide price signals that are consistent with the state's planning requirements, allowing the market to facilitate investment that will satisfy these requirements.
- Because transmission constraints limit the ability of the system to deliver supplies from upstate New York to New York City and Long Island, these areas have local planning requirements that separate zones in the capacity market.
  - ✓ Local capacity zones allow the clearing prices to reflect the local conditions and to facilitate investment in local generation and transmission when it is needed.
  - ✓ Outside of these areas, there is only one "rest-of-state" zone ("ROS") where the market sets a single capacity price and all resources are deemed fungible.
  - ✓ To address transmission limitations within the ROS zone, the NYISO uses a Deliverability Test to determine whether resources in one location cannot be fully delivered to another location in the same zone.
  - ✓ New resources or imports deemed undeliverable must either upgrade the transmission network so that it can be fully delivered or acquire deliverability rights from another participant to be able to sell capacity in the market.
  - ✓ Resources may be undeliverable because excess supply on the unconstrained side of a constraint cannot all be transferred across the constraint, even if such transfers would not likely occur in reality and the constraint would not likely bind.

Capacity Market – Zone Configuration and Deliverability

- The Deliverability Test was first applied to Class Year 2008 (projects that requested interconnection in 2008).
  - ✓ Resources in Class Year 2008 outside Southeast New York were deemed undeliverable.
  - ✓ To sell capacity, these suppliers must pay to upgrade transmission into the Hudson Valley at a cost of over $170/kW or acquire rights from existing suppliers.
- This raises efficiency and competitive concerns because the deliverability framework:
  - ✓ Does not provide efficient investment incentives for new investment supply resources, demand resources, or transmission facilities, or maintenance or retirement of existing resources;
  - ✓ Creates a substantial barrier to entry for competitive new supplies and imports, reducing the competitiveness of the market;
  - ✓ Does not reflect the marginal reliability value of resources at different locations; and
  - ✓ Will likely raise capacity costs for New York consumers.

Capacity Market – Zone Configuration and Deliverability

- In prior reports, we have shown that these issues can be addressed by defining capacity zones that reflect transmission bottlenecks that affect the planning needs of the system.
  - ✓ This is essential because the market must have a means to produce long-term economic signals that accurately reflect the supply and demand for capacity in different areas, which is not possible under the current deliverability framework.
- The transmission bottleneck that has raised deliverability issues most recently is an interface into Southeast New York.
- Defining a capacity zone in Southeast New York would distinguish the value of capacity in SE New York from the value of capacity in other areas, which would:
  - ✓ Allow the capacity market to signal where new capacity would be most beneficial. This may be particularly important in southeast New York because the cost of new entry is likely higher there than in other areas.
  - ✓ Enable more suppliers to sell capacity outside the new zone(s), thereby lowering capacity costs for New York consumers in those areas.
  - ✓ Since new capacity is not currently needed in southeast New York, creating the new zone(s) would likely lower overall capacity costs in New York.

POTOMAC ECONOMICS

Capacity Market – Zone Configuration and Deliverability

- The NYISO recently filed a proposed criteria with the Commission for defining new capacity zones.
- As MMU, we did not support the NYISO proposed criteria because they would likely fail to define new capacity zones that are needed to satisfy the planning requirements of the system efficiently.
- We recommend one of two approaches for defining new capacity zones:
  - ✓ Define new capacity zones whenever deliverability constraints bind on highway transmission facilities, which will ensure consistency between the capacity zones and the results of the deliverability test.
  - ✓ Pre-define a full set of capacity zones and interzonal limits that address potential deliverability issues.
    - This is the preferred approach because it would establish a stable zonal structure that would not require re-definition of the capacity zones over time.
    - It would allow price separation between areas when necessary, but cause areas to clear at the same price when deliverability constraints do not bind.

Capacity Market – Technology of Hypothetical New Unit

- The capacity demand curves are set to ensure that a sufficient amount of market investment occurs to satisfy the NYISO's planning reserve requirements efficiently.
  - ✓ Such investments must cover their Cost of New Entry ("CONE") from the energy, ancillary services, and capacity markets.
  - ✓ Ideally, these markets efficiently govern investment and retirement decisions such that the NYISO would satisfy planning requirements with a minimum amount of surplus.
- The capacity market is designed to ensure that efficient investments recover necessary revenues that are not recovered through the energy and ancillary services markets.
  - ✓ To do this, demand curves are established that should allow suppliers to recover the Net CONE (i.e., CONE minus net revenues from the energy ancillary services markets) for the investments over the long term.
  - ✓ For this process, a technology must be chosen and the tariff specifies a peaking unit.
  - ✓ In long-run equilibrium, all types of resources (baseload, intermediate, peaking) should be equally economic.
    - – As one type of resource becomes more profitable, increased investment in that type should reduce its profitability and increase the profitability of others by shifting the net revenues in the energy and ancillary services market.
    - – However, this may not be the case in the short-run based on the relative levels of energy, ancillary services, and capacity prices.

POTOMAC ECONOMICS

Capacity Market – Technology of Hypothetical New Unit

- There are advantages to choosing a peaking resource as the default technology because the uncertainties regarding the CONE and net energy and ancillary services are lower than for some other technologies.
- In the short-run, however, the default peaking resource may or may not be the most economic investment.
- When a demand curve is developed to support investment in a unit that is not the most economic type of unit, the capacity market will provide incentives to invest in the lower cost resource type when additional investment is not necessary.
  - ✓ The result of this process is a sustained surplus that will dissipate only when the default peaking resource is among the most economic investments once again.
  - ✓ Until this happens, the capacity market may motivate inefficiently large quantities of investment and raise overall market costs.
  - ✓ Therefore, it would be preferable for the default resource upon which the capacity demand curves are based to always be among the most economic and realistic investment choices, given regulatory and environmental restrictions.

Capacity Market –
Technology of Hypothetical New Unit

- Given the capacity surpluses that are prevailing and are forecasted to continue, and the fact that the most recent investments have not been in the default peaking resources, an examination of the relative economics of alternate technologies is warranted.
- Recent data produced by NERA and Sargent & Lundy suggests that the net CONE (cost of new entry of the net revenues from energy and ancillary services) are substantially higher for peaking resources than for other resources. For example:
  - ✓ The net CONE for the default peaking resource in New York City ($279 per kw-month) is 84 percent higher than the net CONE for a combined cycle unit ($152 per kw-month).
- These estimated cost differences are consistent with the fact that combined cycle units have been the most common supply investment in recent years.
- This type of short-term disequilibrium can result in Demand Curves that lead to inefficient levels of investment and sustained surpluses.
  - ✓ Hence, we recommend the NYISO consider modifying its rules to select the most economic generating technology to establish the demand curves in the next demand curve reset process.

Demand Response Program

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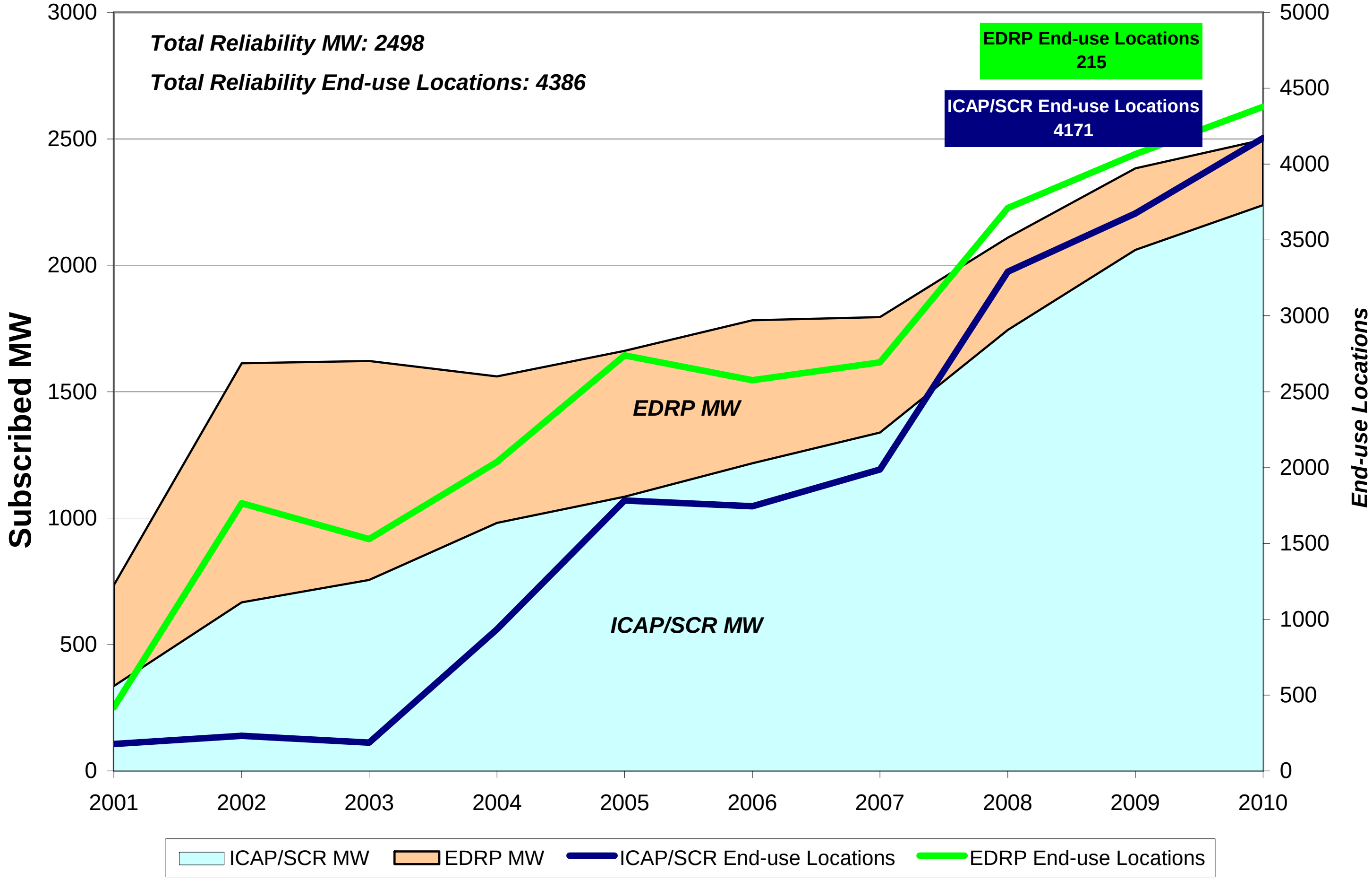
Demand Response Programs – Existing Programs

- 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 activating EDRP and SCR resources is reflected in clearing prices when they prevent reserve shortages at the state-level or eastern New York.
  - ✓ Efficient shortage pricing provides price signals that encourage participation in demand response programs.

Demand Response Programs – Existing Programs

- The following figure summarizes the growth in participation in the NYISO's demand response programs from 2001 to 2010.
  - ✓ EDRP resources and SCRs may be deployed under the TDRP program, although it is voluntary for them to respond.
- 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 partly because many resources have shifted from the EDRP to the SCR program.
    - In 2010, total SCR registration reached 547 MW in New York City, 176 MW in Long Island, and 1,517 MW in Upstate areas.
  - ✓ SCR resources provide considerable benefits by reducing the cost of meeting New York's planning reserve margin requirements.
- Since SCRs are needed to satisfy the NYISO's planning reserve requirements, it is important to ensure that the SCRs' performance is measured accurately.
  - ✓ The NYISO has proposed revisions to the baseline methodology, aggregation performance, and deficiency calculation and is awaiting FERC approval for changes to become effective for the Summer 2011 Capability Period.

Registration in NYISO Demand Response Programs 2001 to 2010



Note: This figure is reproduced from the NYISO's January 25, 2011 filing to FERC related to the Demand Response Compliance Report.

Demand Response Programs – Enhancements and New Developments

- Demand Response Information System ("DRIS") – This project has enhanced the NYISO's capability to administer demand response programs and reduced the costs of participation.
  - ✓ Once complete, DRIS will automate registration, communication during events, settlements, performance monitoring, meter data management, and other functions that have historically required manual effort.
- Demand-Side Ancillary Services Program ("DSASP") – This program allows demand resources to provide regulation and reserves.
  - ✓ However, participation in this program has been hampered by long delays related to setting up communications with the NYISO through the local Transmission Owner.
  - ✓ For this reason, the NYISO is developing the capability to communicate directly with DSASP resources rather than through the local Transmission Owner.
- DSASP Aggregations – The NYISO is developing the processes that would allow smaller DR resources (e.g., Retail Customers) to provide ancillary services as DSASP resources.

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