Quarterly Report on the New York ISO Electricity Markets Second Quarter 2012

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Highlights and Market Summary: Energy Market

- This report summarizes market outcomes in the second quarter of 2012.
- The energy markets performed competitively and variations in wholesale prices were driven primarily by changes in demand, fuel prices, and supply availability.
- Real-time energy prices averaged roughly $36/MWh statewide, down 26 percent from the same quarter in 2011. The following factors contributed to this reduction:
  - ✓ Natural gas prices fell nearly 50 percent from a year ago; and
  - ✓ Over 1 GW of new generating capacity entered in New York City.
  - ✓ However, these factors were partly offset by the loss of imports across the Neptune line and higher energy prices during more frequent peak load conditions in 2012.
- Consistency between day-ahead and real-time energy prices was relatively good, although there were several high load days when unexpected real-time conditions led to poor convergence.
- Day-ahead congestion revenue fell 40 percent from last year to $61 million as: a) lower natural gas prices reduced re-dispatch costs and b) new generation and transmission were built in New York City.
  - ✓ However, congestion across the external interfaces rose significantly in the second quarter of 2012, primarily because the primary HQ interface was fully scheduled much more frequently in May and June.

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Highlights and Market Summary: Activation of Demand Response on High Load Days

- NYISO activated demand response on four days when load exceeded 28 GW.
  - ✓ On May 29 & June 21, DR was activated in all zones for forecasted statewide reserve shortages, transmission security, and voltage support.
  - ✓ On June 20 & 22, DR was activated in Southeast NY for transmission security.
  - ✓ The quantity of activated DR exceeded the amount of available capacity (i.e., capacity not needed for energy or ancillary services) for most of the time on the afternoons when DR was activated.
  - ✓ LBMPs were below the marginal cost of maintaining reliability during many of the hours when DR was activated, and well below the marginal cost of activating DR resources (typically $500/MWh).
- The NYISO plans to enhance the real-time software to allow DR resources to set LBMPs in the five-minute dispatch and to consider DR when optimizing the schedules of other non-dispatchable resources.
- Nonetheless, moderating the quantity of DR that is activated would help ensure that LBMPs reflect the cost of maintaining reliability and that uplift is minimized.
  - ✓ Market design changes that enable DR to be scheduled more flexibly and efforts to stagger the timing of DR activations would be beneficial in this regard.

Highlights and Market Summary: Capacity Market

- UCAP spot prices rose in the second quarter of 2012 relative to the previous year.
  - ✓ In New York City, spot prices averaged $11.10/kW-month, up from $9.02/kW-month in the second quarter of 2011.
  - ✓ Outside New York City, spot prices averaged $1.65/kW-month, up from $0.45/kW-month in the second quarter of 2011.
- The following factors contributed to the increases in UCAP spot prices inside and outside New York City.
  - ✓ Local Capacity Requirement in NYC rose from 81 percent to 83 percent;
  - ✓ The NYCA ICAP requirement rose 840 MW from the 2011/12 capability year to 2012/2013 capability year:
    - – The summer peak load forecast for NYCA increased nearly 600 MW; and
    - – The installed capacity requirement rose from 115.5 percent to 116 percent.
  - ✓ Sales of internal capacity fell as over 600 MW of capacity (primarily in New York City) was retired or mothballed.
  - ✓ However, these factors were offset by increased sales of internal capacity in New York City following the entry of a 550 MW facility in July 2011 and a 510 MW facility in June 2012.

Highlights and Market Summary: Uplift and Revenue Shortfalls

- Lower natural gas prices was a primary driver of reductions for all categories of uplift in the second quarter of 2012.
- The uplift from guarantee payments fell to a total of $22 million, down 39 percent from the second quarter of 2011.
  - ✓ The largest reductions resulted from less frequent commitment for reliability in New York City and Long Island, and lower costs from satisfying minimum oil burn reliability criteria in New York City.
- Day-ahead congestion shortfalls were $1 million, down 95 percent from the second quarter of 2011.
  - ✓ The reduction from a year ago reflects less overall congestion, TCC auction modeling improvements implemented in May 2011, and fewer significant transmission outages in New York City and into Southeast New York.
- Balancing congestion shortfalls were $6 million, up $3 million from the previous quarter and down $7 million from the same quarter last year.
  - ✓ The increase from the prior quarter was primarily due to the seasonal increase in TSAs, while the decrease from a year ago was largely driven by the overall reduction in congestion.

Energy and Ancillary Services Markets

All-In Price

- To summarize costs in the New York markets, the following figure shows the "all-in" price that represents the total cost of serving load, including:
  - ✓ An energy component that is a load-weighted average real-time energy price.
  - ✓ A capacity component based on spot prices times capacity obligations.
  - ✓ The NYISO cost of operations and uplift from other Schedule 1 charges.
- Average all-in prices ranged from \$35/MWh in West NY to \$65/MWh in NYC, down 15 to 20 percent from the second quarter last year.
  - ✓ Energy prices fell 25 to 30 percent primarily because:
    - – Natural gas prices fell 41 to 47 percent;
    - – Over 1000 MW of new generating capacity entered in NYC; but
    - – These factors were partly offset by the loss of imports across the Neptune line and higher energy prices during more frequent peak load conditions in 2012.
  - ✓ However, the capacity component rose 30 to 260 percent because:
    - – The ICAP requirement rose 2 percent in NYC due an increase in the NYCA requirement caused by an higher load forecast;
    - – 600 MW of capacity retired or mothballed in NYC in the past year; but
    - – These factors were partially offset by the entry of over 1 GW of new capacity in NYC since the second quarter of 2011.

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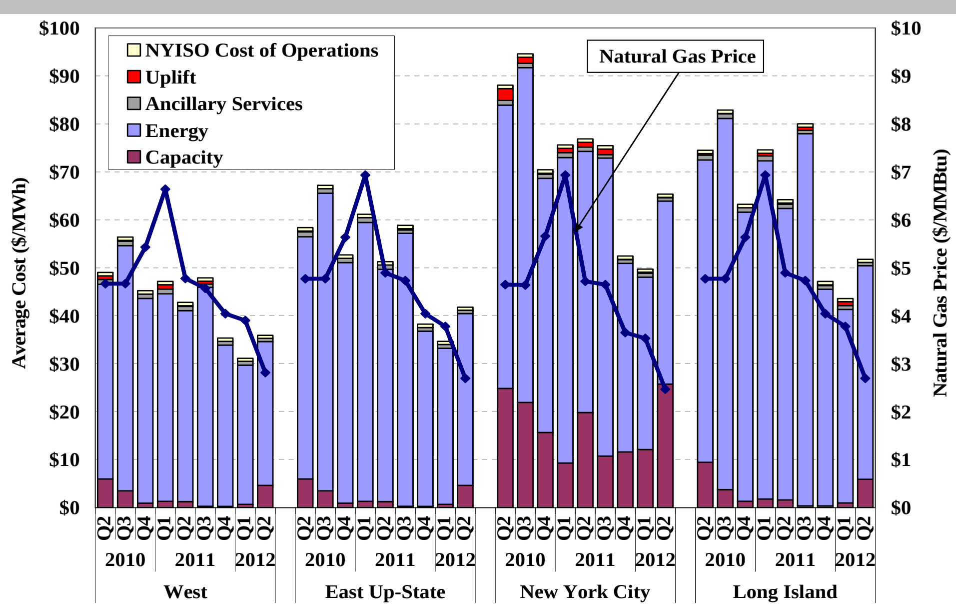
All-In Energy Price by Region



Note: Natural Gas Price based on: Tennessee Zone 6 index for West NY, Iroquois Zone 2 index for East Up-State & Long Island, and Transco Zone 6 index for New York City.

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Implied Heat Rate

- To identify changes in electricity prices that are not driven by changes in natural gas prices, the following figure shows the marginal heat rate that would be implied if natural gas were always the marginal fuel.
  - ✓ Implied Gas Heat Rate = (Day-Ahead Electricity Price) ÷ (Natural Gas Price)
- Prices are higher in East New York than in West New York due to transmission losses and congestion into Southeast New York, New York City load pockets, and Long Island.
- The average implied heat rate rose 39 and 30 percent in western NY and eastern NY from the second quarter of 2011, primarily because:
  - ✓ Some generation costs (e.g., variable O&M) are not related to fuel prices, leading the implied heat rate to rise when gas prices fall.
  - ✓ The differential between gas prices and oil prices widened, increasing the effect of periods when oil-fired capacity is on the margin.
  - ✓ Peak load conditions occurred more frequently due to very hot weather.
  - ✓ The Neptune cable was out of service from the end of May through the end of June, contributing to higher implied heat rates, particularly in eastern NY.

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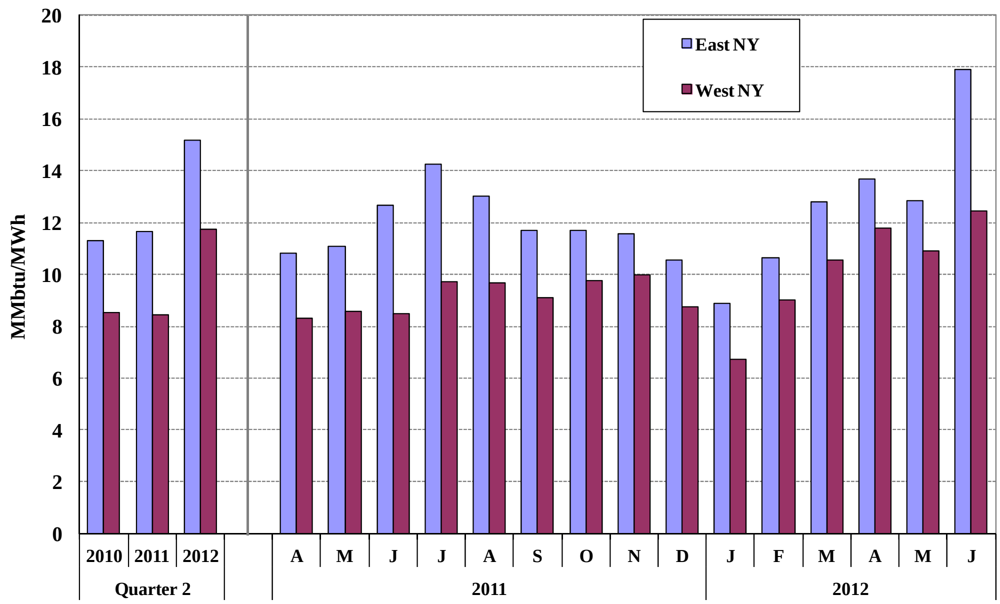
Implied Heat Rate by Region



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Load Forecast and Actual Load

- The following figure shows the average load, the peak load, and the day-ahead peak load forecast error on each day of the first quarter.
  - ✓ The table compares key statistics for the second quarter of 2012 to the previous quarter and the second quarter of 2011.
- Average load was consistent with prior quarters, while peak load levels increased significantly in the second quarter of 2012.
  - ✓ Peak load conditions occurred more frequently due to very hot weather.
    - – Load peaked on June 21st at 32.1 GW, up 4 percent from a year ago.
    - – Load exceeded 30 GW in 16 hours in the second quarter of 2012, compared to 8 such hours in the second quarter of 2011.
- Peak load forecasting was generally good during the quarter, although the magnitude of forecast errors increased during the high load conditions from the end of May through June.
  - ✓ The daily peak load forecast error exceeded 1 GW on six days and 2 GW on one day (May 29).
  - ✓ On average, actual loads ran over the peak forecast by 53 MW, less than in prior quarters.

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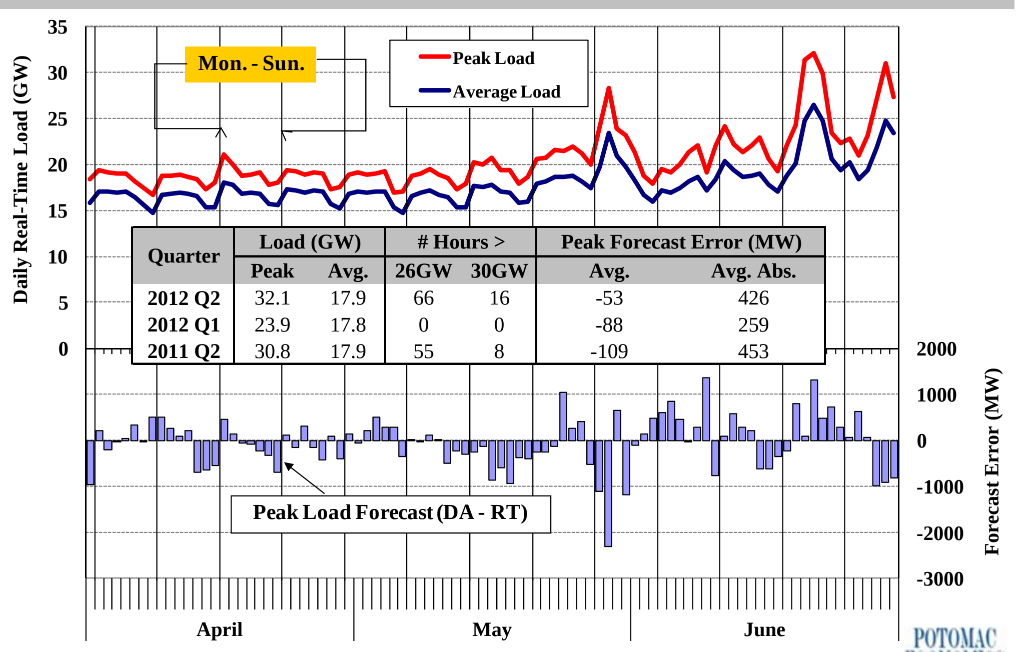
Load Forecast and Actual Load



Quarter	Load (GW)		# Hours >		Peak Forecast Error (MW)	
	Peak	Avg.	26GW	30GW	Avg.	Avg. Abs.
2012 Q2	32.1	17.9	66	16	-53	426
2012 Q1	23.9	17.8	0	0	-88	259
2011 Q2	30.8	17.9	55	8	-109	453

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Natural Gas and Oil Prices

- The following figure shows daily natural gas and fuel oil prices, which are key determinants of electricity prices.
- Natural gas prices averaged roughly $2.50/MMbtu in NYC and $2.70/MMbtu in upstate NY, down nearly 30 percent from the previous quarter and down nearly 50 percent from the second quarter of 2011.
  - ✓ Gas prices exhibited their lowest quarterly average since 2002.
  - ✓ Gas prices ranged from $2 to $3/MMbtu during most of the quarter, but spiked modestly on several days due to hot weather.
- Fuel oil prices fell steadily throughout the second quarter of 2012.
  - ✓ Prices fell 8 percent for both #2 oil and #6 oil from the first quarter, and 5 percent and 3 percent from the second quarter of 2011, respectively.
- Natural gas was much less expensive than fuel oil, but some generators still burn oil due to:
  - ✓ Reliability reasons;
  - ✓ Difficulties obtaining natural gas; or
  - ✓ Unavailability of pipeline capacity.

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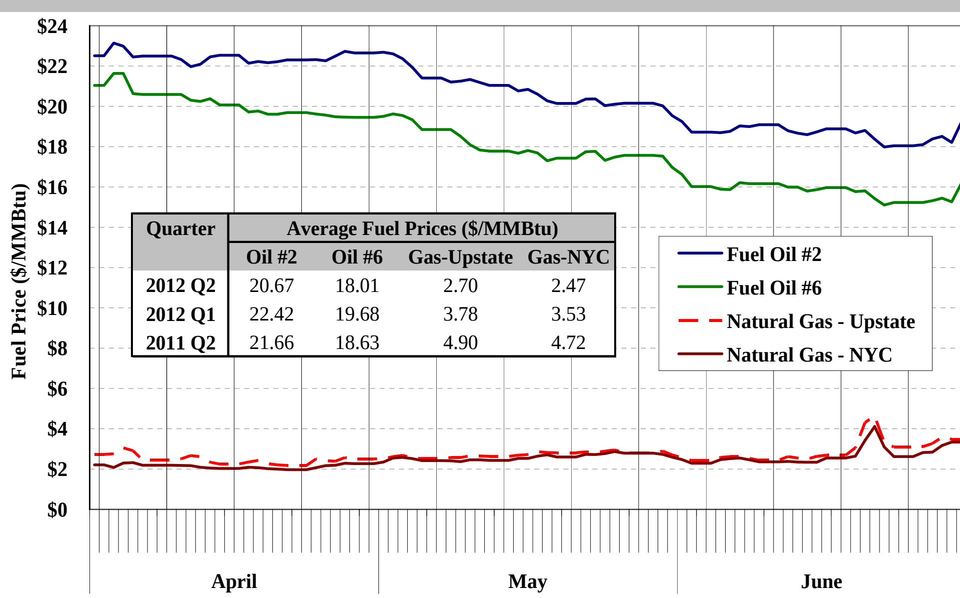
Natural Gas and Oil Prices



Quarter	Average Fuel Prices ($/MMBtu)			
	Oil #2	Oil #6	Gas-Upstate	Gas-NYC
2012 Q2	20.67	18.01	2.70	2.47
2012 Q1	22.42	19.68	3.78	3.53
2011 Q2	21.66	18.63	4.90	4.72

Note: Natural Gas Price based on: Iroquois Zone 2 index for Upstate and Transco Zone 6 index for New York City.

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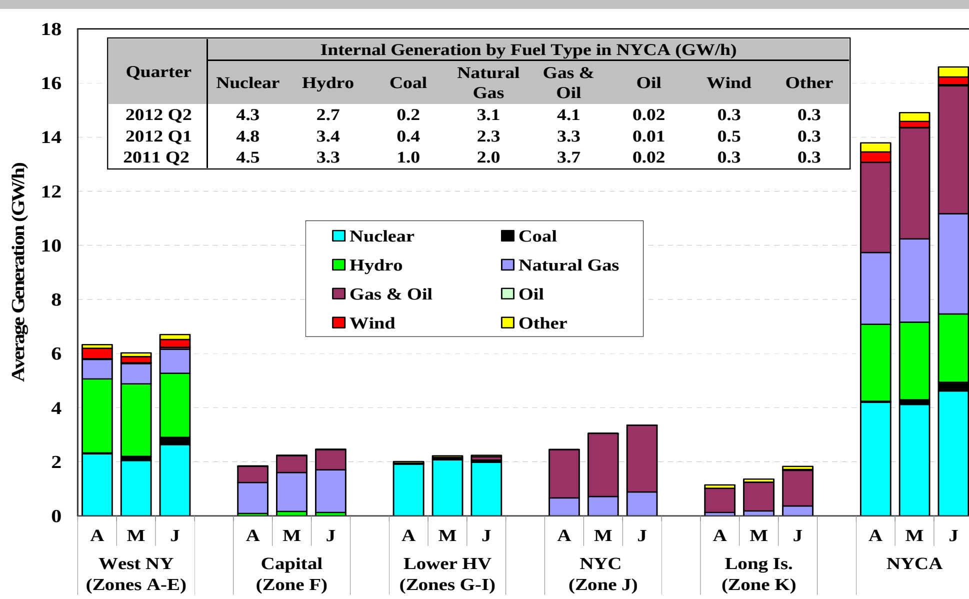
Generation Output by Fuel Type

- The following figure shows the quantities of generation by fuel type (as listed in the Gold Book) in each region of New York in the second quarter of 2012.
- Nuclear units in West NY and Lower Hudson Valley are usually base-loaded.
  - ✓ Although they account for 14 percent of installed capacity, they produced approximately 30 percent of output in the second quarter of 2012.
- Production from gas units rose considerably from a year ago (from 13 percent to 21 percent) as production from coal units fell from 7 percent to 1 percent over the same period.
  - ✓ The reduction in gas prices has reduced the competitiveness of coal units.
- Resources with dual-fuel capability (i.e., gas & oil, primarily in NYC and Long Island) accounted for 27 percent of output in the second quarter, up modestly from the previous year.
- Hydro resources in West NY and the Capital Zone accounted for 18 percent of output in the second quarter, down modestly from the previous year.
- Wind units and other renewable resources typically produce 4 to 5 percent of output in New York.

Generation Output by Fuel Type



Quarter	Internal Generation by Fuel Type in NYCA (GW/h)							
	Nuclear	Hydro	Coal	Natural Gas	Gas & Oil	Oil	Wind	Other
2012 Q2	4.3	2.7	0.2	3.1	4.1	0.02	0.3	0.3
2012 Q1	4.8	3.4	0.4	2.3	3.3	0.01	0.5	0.3
2011 Q2	4.5	3.3	1.0	2.0	3.7	0.02	0.3	0.3

Notes: Pumped-storage resources in pumping mode are treated as negative generation. “Other” includes Methane, Refuse, Solar & Wood.

Fuel Types of Marginal Units in the Real-Time Market

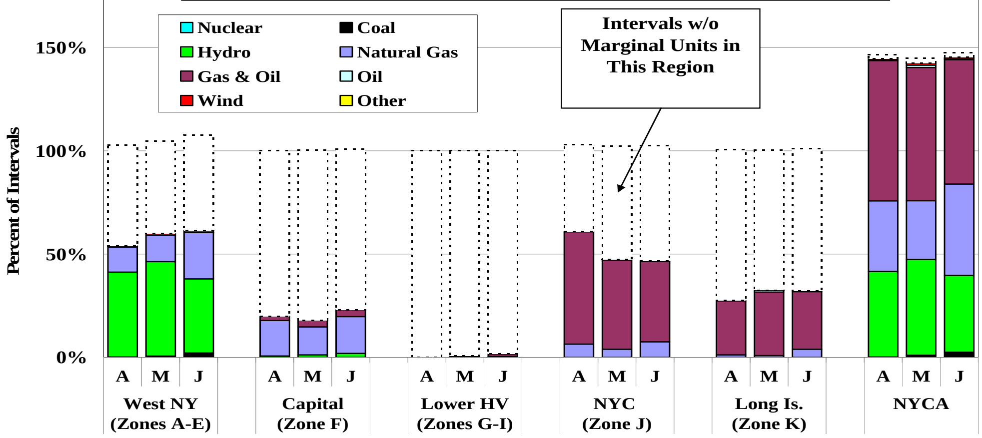
- The following figure summarizes how frequently each fuel type is on the margin and setting real-time energy prices.
  - ✓ The fuel type for each generator is based on information from the Gold Book:
    - Generators listed in the Gold Book as using natural gas and fuel oil as their primary and secondary fuel types are shown in the “Gas & Oil” category.
    - Other generators are shown based on their primary fuel type.
  - ✓ More than one type of generator may be on the margin in an interval, particularly when a transmission constraint is binding.
    - Hence, the total for all fuel types may be greater than 100 percent.
    - For example, if hydro units and gas units were both on the margin in every interval, the total frequency shown in the figure would be 200 percent.
  - ✓ The figure shows how frequently each fuel type is on the margin in NYCA and in each region of the state.
    - When no unit is on the margin in a particular region, the LBMPs in the region are set by generators in other regions.

Fuel Types of Marginal Units in the Real-Time Market

- Hydro, natural gas, and “Gas & Oil” resources set prices in large shares of the intervals in the second quarter of 2012.
  - ✓ Gas & Oil resources, which are located primarily in NYC and Long Island, were on the margin in 64 percent of the intervals, up from the previous year.
  - ✓ Hydro resources, primarily in West NY, set the prices in 42 percent of the intervals, consistent with prior periods. Some hydro resources have storage capability, allowing them to offer price-sensitively based on opportunity costs.
  - ✓ Gas-only resources, primarily in West New York and the Capital Zone, were marginal in 36 percent of the intervals, up significantly from a year ago.
    - The increase was due primarily to lower natural gas prices, which have led coal-fired resources to be on the margin much less frequently.
- Although other fuel types accounted for 18 percent of the generation capacity in NYCA, they were rarely on the margin in the second quarter of 2012.
  - ✓ Nuclear units and wind units were usually base-loaded, although wind units occasionally set price in late evening or early morning hours.
  - ✓ Oil-only units sometimes set price during high-load periods, particularly in NYC and Long Island.

Fuel Types of Marginal Units in the Real-Time Market

Quarter	Marginal Fuel Types in NYCA							
	Nuclear	Hydro	Coal	Natural Gas	Gas & Oil	Oil	Wind	Other
2012 Q2	0%	42%	1%	36%	64%	1%	1%	0%
2012 Q1	0%	47%	10%	31%	61%	1%	1%	0%
2011 Q2	0%	42%	24%	22%	58%	1%	1%	0%

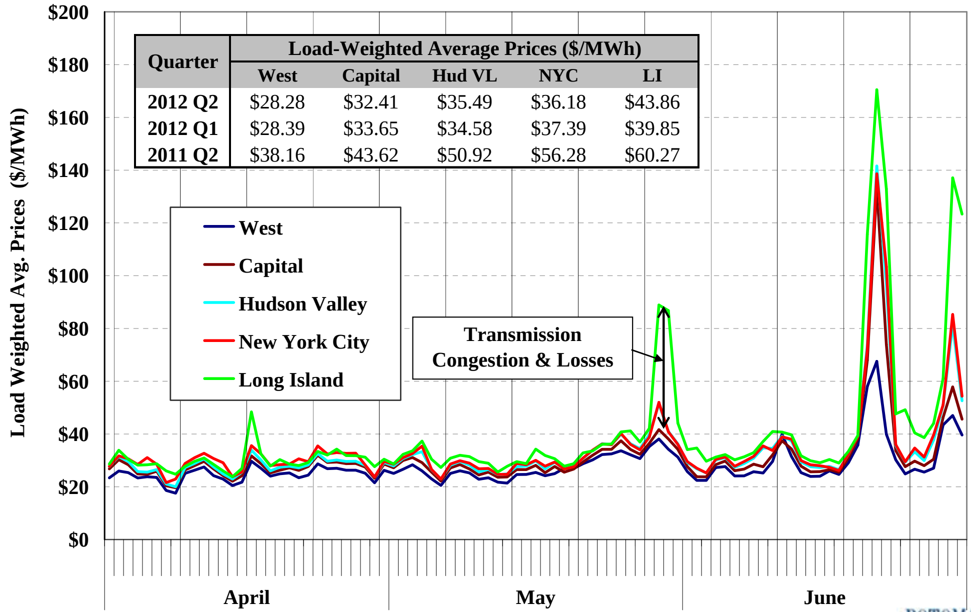


Notes: "Other" includes Methane, Refuse, Solar & Wood.

Day-Ahead Electricity Prices by Zone

- The following figure shows load-weighted average day-ahead energy prices for five zones on each day in the second quarter of 2012.
  - ✓ Prices in the day-ahead market should reflect probability-weighted expectations of real-time market conditions.
- Average day-ahead prices ranged from roughly $28/MWh in the West Zone to $44/MWh in Long Island in the second quarter of 2012.
  - ✓ Average day-ahead prices trended upward from April to June, consistent with the increases in load and natural gas prices over the quarter.
  - ✓ Day-ahead prices rose significantly on days with high forecasted loads in May and June.
  - ✓ The Neptune Cable was out of service from the end of May through the end of June, contributing to elevated prices on Long Island during this period.
- Low gas prices contributed to lower congestion levels in 2012 since capacity is more reliant on gas in eastern NY than in western NY.
  - ✓ However, there were 4 days that exhibited sharp increases in congestion into Southeast NY, NYC, and Long Island when high forecasted load levels led to the scheduling of higher-cost generation in the day-ahead market.

Day-Ahead Electricity Prices by Zone

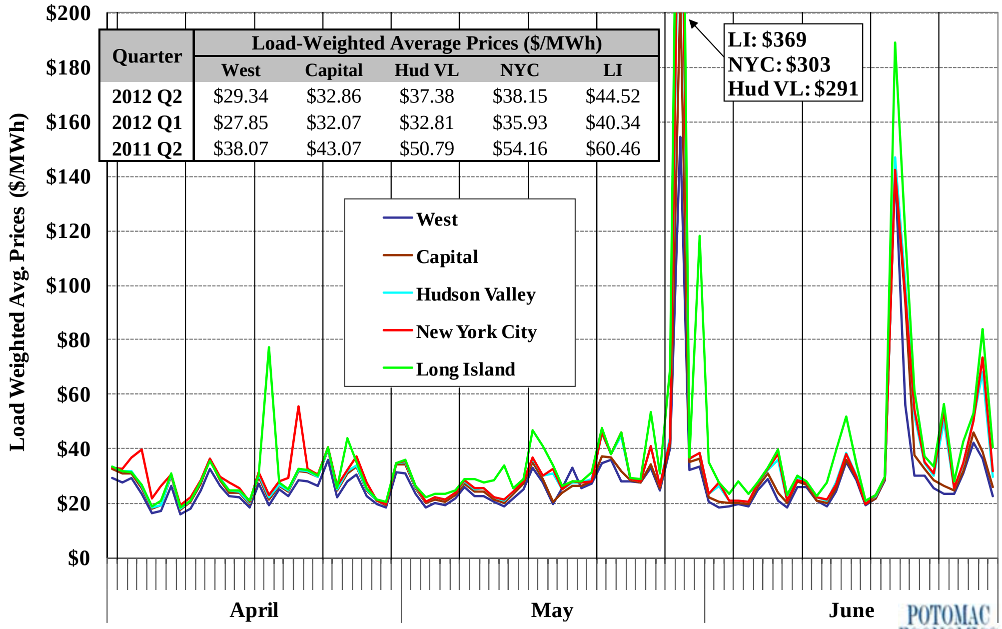


Quarter	Load-Weighted Average Prices ($/MWh)				
	West	Capital	Hud VL	NYC	LI
2012 Q2	$28.28	$32.41	$35.49	$36.18	$43.86
2012 Q1	$28.39	$33.65	$34.58	$37.39	$39.85
2011 Q2	$38.16	$43.62	$50.92	$56.28	$60.27

Real-Time Electricity Prices by Zone

- The following figure shows load-weighted average real-time energy prices for five zones on each day in the second quarter of 2012.
  - ✓ Prices are more volatile in the real-time market than in the day-ahead market.
- Real-time prices decreased significantly from the second quarter of 2011, which was largely due to lower natural gas prices.
- Significant real-time prices spikes occurred on several days:
  - ✓ On May 29, real-time loads were unexpectedly high, leading to very tight conditions, extended operating reserve shortages, and statewide price spikes.
    - Actual loads ran over the day-ahead forecast by 3.2 GW in the peak hour; and
    - Load was under-scheduled day-ahead by 3.5 GW in the peak hour.
    - A TSA led to additional price spikes in Southeast New York in the afternoon.
  - ✓ On June 20 & 21, high statewide prices resulted primarily from high load levels and several unplanned outages of generation and transmission.
  - ✓ On June 29, high prices in Southeast New York resulted primarily from high load levels and a TSA, which reduces transmission capability into Southeast New York.

Real-Time Electricity Prices by Zone



Quarter	Load-Weighted Average Prices ($/MWh)				
	West	Capital	Hud VL	NYC	LI
2012 Q2	$29.34	$32.86	$37.38	$38.15	$44.52
2012 Q1	$27.85	$32.07	$32.81	$35.93	$40.34
2011 Q2	$38.07	$43.07	$50.79	$54.16	$60.46

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Convergence Between Day-Ahead and Real-Time Prices

- The next analysis evaluates day-ahead and real-time price convergence.
  - ✓ Convergence is important because the day-ahead market facilitates the daily commitment of generation and scheduling of natural gas, determines the obligations to TCC holders, and accounts for most energy settlements.
- The figure shows the difference between average day-ahead prices and the average real-time prices on each day in the second quarter of 2012.
  - ✓ This is shown separately for five zones to account for changes in the pattern of congestion from the day-ahead to the real-time.
  - ✓ Convergence should be measured over longer timeframes since random factors can cause large differences in prices on individual days -- the table shows the average price convergence over the entire quarter.
- On average, real-time prices were higher than day-ahead prices (by 1 to 5 percent) in all areas in the second quarter of 2012.
  - ✓ Day-ahead and real-time prices were relatively consistent on most days, but large differences appeared on several days due to unexpected real-time events.
  - ✓ On May 29, real-time prices exceeded day-ahead prices by an average of $100/MWh to $300/MWh due to unexpected real-time conditions. Excluding May 29, day-ahead prices were actually higher on average than real-time prices.

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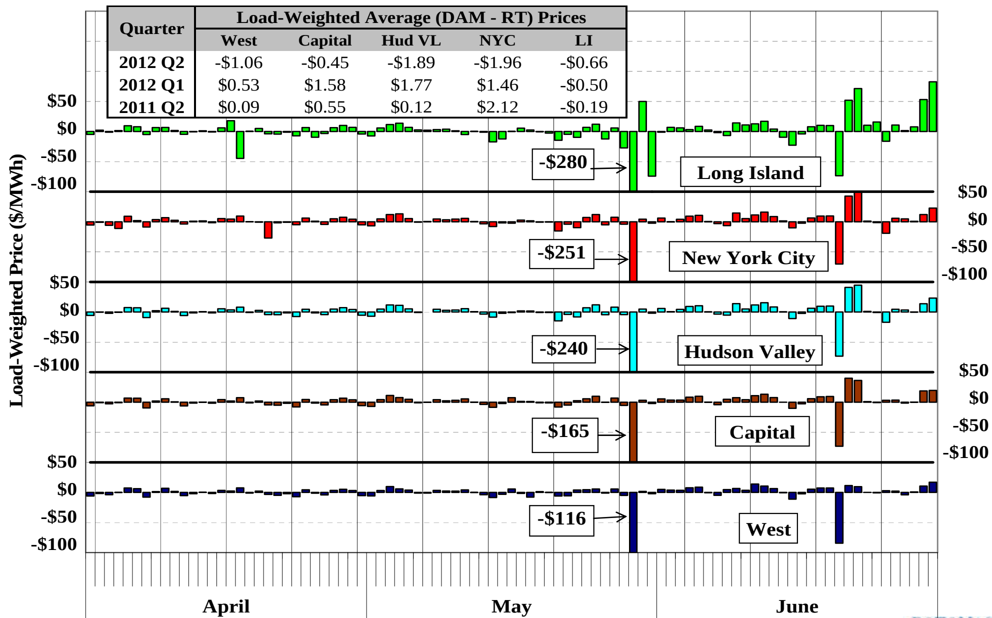
Convergence Between Day-Ahead and Real-Time Prices

Quarter	Load-Weighted Average (DAM - RT) Prices				
	West	Capital	Hud VL	NYC	LI
2012 Q2	-$1.06	-$0.45	-$1.89	-$1.96	-$0.66
2012 Q1	$0.53	$1.58	$1.77	$1.46	-$0.50
2011 Q2	$0.09	$0.55	$0.12	$2.12	-$0.19



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Emergency Demand Response Activations

- Load exceeded 28 GW on five days (May 29, June 20-22, & 29).
- NYISO activated demand response (EDRP/SCRs) on four of the five days, which we evaluate in this section of the report.
  - ✓ On May 29, load peaked at 28.2 GW and 1.8 GW of DR was activated.
    - Response was not mandatory on this day, so 1.1 GW was reported.
    - EDRP/SCRs were activated in all zones from HB 13 through HB 17 for forecasted reserve shortages.
  - ✓ On June 20, load peaked at 31.3 GW and 0.7 GW of DR was activated.
    - EDRP/SCRs were activated from HB 14 through HB 17 in zones G through J for SENY transmission security and in zone C for voltage support.
  - ✓ On June 21, load peaked at 32.1 GW and 1.9 GW of DR was activated.
    - EDRP/SCRs were activated in: a) zones G through K for transmission security, and b) zones A through F for Rochester transformer loadings (zone B), voltage support (zone C), and statewide capacity requirements.
  - ✓ On June 22, load peaked at 29.9 GW and 0.7 GW of DR was activated.
    - EDRP/SCRs were activated in zones G through K from HB 13 through HB 17 for transmission security.

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Emergency Demand Response Activations

- The following figures evaluate two aspects of market outcomes on the four days when DR was activated.
- First, the figures evaluate the amount of DR that was activated compared with the amount of resources that were ultimately available in each real-time interval during the event.
  - ✓ The use of DR program resources is limited by scheduling lead times and other inflexibilities, which has two significant implications:
    - – The NYISO must determine how much DR to activate when there is still considerable uncertainty about the needs of the system; and
    - – The DR may not be needed for the entire duration of the DR activation period.
  - ✓ These factors can cause NYISO to activate an amount of DR that results in substantial excess capacity during a portion of the event.
    - – An excess that larger than the quantity of DR activated for an entire event may indicate that the activation was not needed in retrospect.
- Second, the figures evaluate the consistency of LBMPs with the costs of curtailing DR resources (typically $500/MWh).

Emergency Demand Response Activations

- The two figures report the following quantities in each interval for selected regions that the DR resources were activated to address:
  - ✓ The Quantity of Demand Response Resources that were Reported by RIPs;
  - ✓ The Available Internal Capacity in real-time;
    - – This includes unloaded capacity of online units and the capacity of offline peaking units up to the unit's Upper Operating Limit ("UOL");
    - – This excludes capacity required for ancillary services in the NYCA (i.e., statewide) figure.
  - ✓ The recallable External ICAP Energy sales, which is the amount of scheduled exports that are considered as available reserves in the current Scarcity Pricing software.
  - ✓ The LBMP of the least import-constrained zone in the region that was secured by the DR activation. (The West Zone for the statewide activations and the Millwood Zone for the SENY activations.)
  - ✓ Whether the interval was affected by the Scarcity Pricing Rules, which are applied when the DR activation prevents a statewide or eastern reserve shortage (based on the criteria in Section 17.1.2 of the MST).

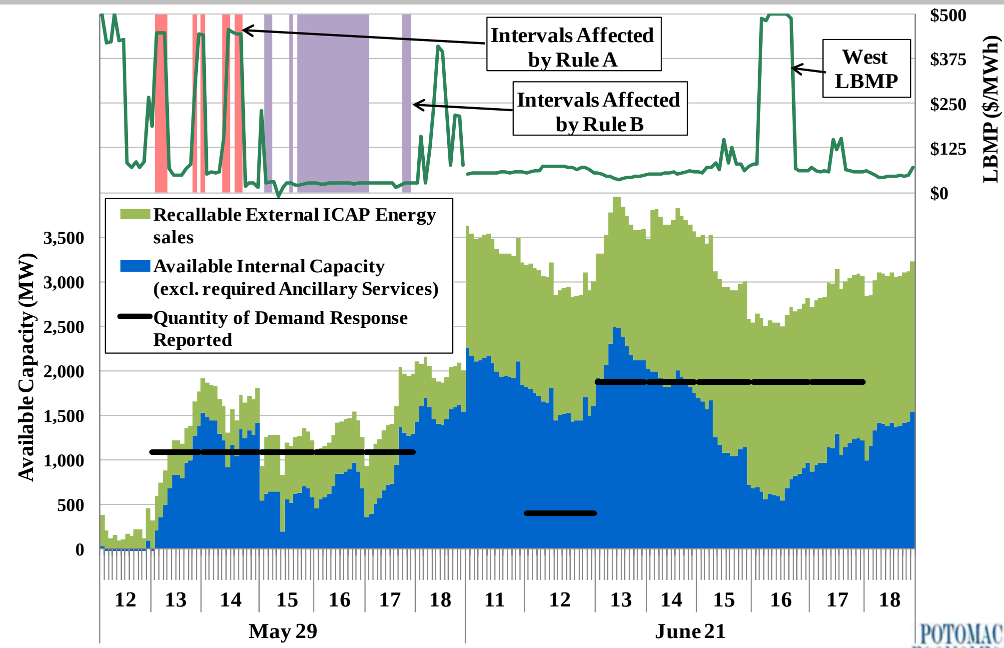
Emergency Demand Response Activations

- On May 29 and June 21, DR was activated statewide.
  - ✓ Immediately after the activation of demand response, the amount of available internal capacity rose and LBMPs fell substantially.
  - ✓ The amount of DR activated exceeded the available internal capacity in nearly all intervals. However, statewide Scarcity Pricing (i.e., Rule A) was not invoked in most of these intervals partly due to the large contribution of "recallable External ICAP Energy sales" on these days.
- On June 20 and 22, DR was activated for SENY transmission security.
  - ✓ The available internal capacity in SENY exceeded the amount of DR by more than 1 GW all afternoon on both days, resulting in relatively low LBMPs in most intervals.
  - ✓ On June 20, the large margin of available capacity was primarily due to the requirement for NYISO to commit sufficient resources to secure SENY based on N-1-1 (i.e., two contingency) criteria, while less stringent N-1 criteria was required in the real-time dispatch.
  - ✓ On June 22, the large margin of available capacity was primarily due to an unexpected reduction in load after a change in the weather pattern.

Emergency Demand Response Activations

- LBMPs were relatively low (less than $100/MWh) during most hours when DR was activated, well below the marginal cost of maintaining reliability since most DR resources are paid $500/MWh to curtail.
- The NYISO plans to enhance the real-time software to:
  - ✓ Allow DR resources to be considered in five-minute dispatch and determination of LBMPs; and
  - ✓ Consider the amount of DR resources in the real-time commitment logic when optimizing the schedules of other resources that are scheduled on an hourly or 15-minute basis.
- Nonetheless, moderating the quantities of DR that are activated would help ensure that LBMPs better reflect the cost of maintaining reliability and that uplift charges are minimized. This might be possible by:
  - ✓ Market design changes that enable some DR resources to be scheduled more flexibly; and
  - ✓ Staggering the timing of the activation of DR resources (to the extent possible).

RT Prices and Available Capacity – Statewide DR Activations



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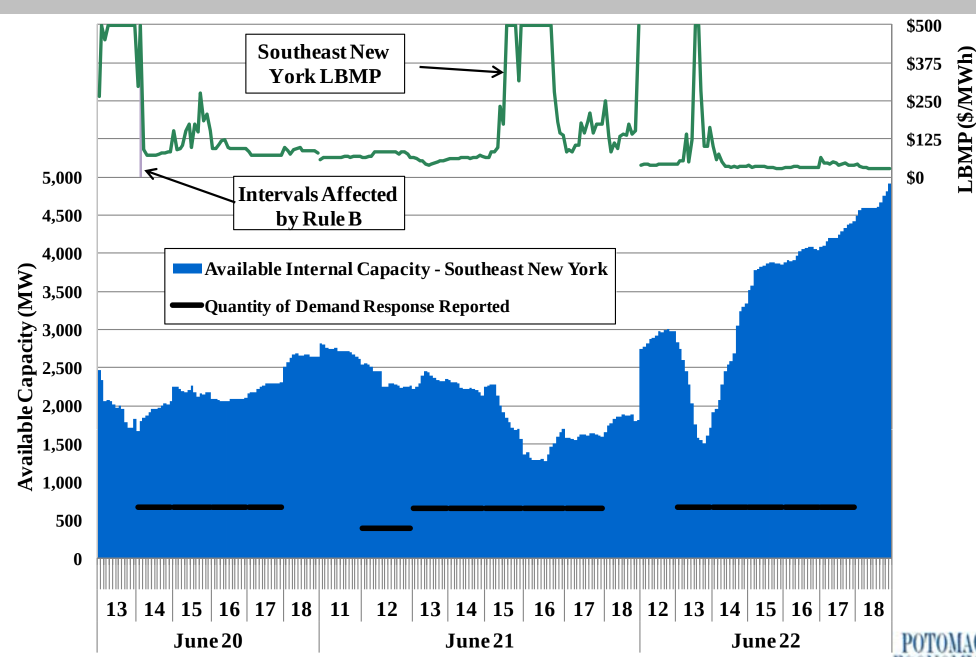
RT Prices and Available Capacity – Southeast New York during DR Activations



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Day-Ahead and Real-Time Ancillary Services Prices

- The following two figures summarize average day-ahead and real-time clearing prices on a daily basis for four key ancillary services products:
  - ✓ 10-minute spinning reserve prices in eastern NY, which reflect the cost of requiring:
    - 300 MW of 10-minute spinning reserves in eastern NY;
    - 600 MW of 10-minute spinning reserves state-wide; and
    - 1,200 MW of 10-minute total reserves (spin and non-spin) in eastern NY.
  - ✓ 10-minute non-spinning reserves prices in eastern NY, which reflect the cost of requiring 1,200 MW of 10-minute total reserves in eastern NY.
  - ✓ 10-minute spinning reserves prices in western NY, which reflect the cost of requiring 600 MW of 10-minute spinning reserves state-wide.
  - ✓ Regulation prices, which reflect the cost of requiring up to 275 MW of regulation, depending upon season and time of day.
- On June 27, several reserve requirements increased following an increase in the NYCA system's largest single contingency from 1,200 MW to 1,310 MW.
- The table in each figure shows the number of intervals when the real-time reserve price of the product was affected by a shortage of reserves.
  - ✓ During shortages, the prices of products that can satisfy the given requirement will include the "demand curve" value of the requirement.

Day-Ahead and Real-Time Ancillary Services Prices

- Reserve prices are relatively consistent from day-to-day in the day-ahead, while reserve prices are much more volatile in the real-time market.
  - ✓ Day-ahead reserves prices are based on suppliers' offers, which depend on expectations of real-time prices and the risks associated with selling reserves in the day-ahead market.
  - ✓ Real-time reserves prices are normally close to $0 because of the excess available reserves from online and quick-start units in most hours.
  - ✓ Real-time prices spike during periods of tight supply and high energy demand, which can be difficult for the day-ahead market to predict.
- Day-ahead prices were lower on average than real-time prices in eastern NY for 10-minute spinning and non-spinning reserves in the second quarter of 2012.
  - ✓ Real-time prices in eastern NY spiked on May 29 due to unexpectedly high loads, TSA conditions, and generation and transmission outages.
  - ✓ Otherwise, day-ahead and real-time prices were more closely correlated for eastern 10-minute spinning and non-spinning reserve prices than in previous years.
    - Changes in day-ahead operating practices have improved the consistency of energy and reserves schedules between the day-ahead and real-time for some units.
- Average day-ahead prices were higher than average real-time prices for 10-minute spinning reserves in western New York and for regulation.

Day-Ahead and Real-Time Ancillary Services Prices

- A shortage occurs when a reserve requirement cannot be satisfied at a marginal cost less than its "demand curve". Shortages occurred in real-time for:
  - ✓ Eastern 10-minute spinning reserves in 220 intervals ($25 demand curve);
  - ✓ Eastern 10-minute total reserves in 72 intervals ($500 demand curve);
  - ✓ State-wide 10-minute spinning reserves in 5 intervals ($500 demand curve); and
  - ✓ Regulation in 361 intervals ($80 to $400 demand curve).
- Prices for a product include the demand curve value for all requirements that the product can satisfy.
  - ✓ For example, the 10-minute spinning reserve prices in eastern NY reflect 297 intervals of shortage pricing: 225 of eastern 10-minute spin, 72 of eastern 10-minute total reserves, and 5 of state-wide 10-minute spin.
- Eastern 10-minute reserve shortages occurred more frequently in the second quarter of 2012 than in prior quarters.
  - ✓ Four days (May 29, June 20, 21, & 29) accounted for nearly all of the shortages.
  - ✓ High loads and unexpected real-time events resulted in very tight operating conditions on these days.

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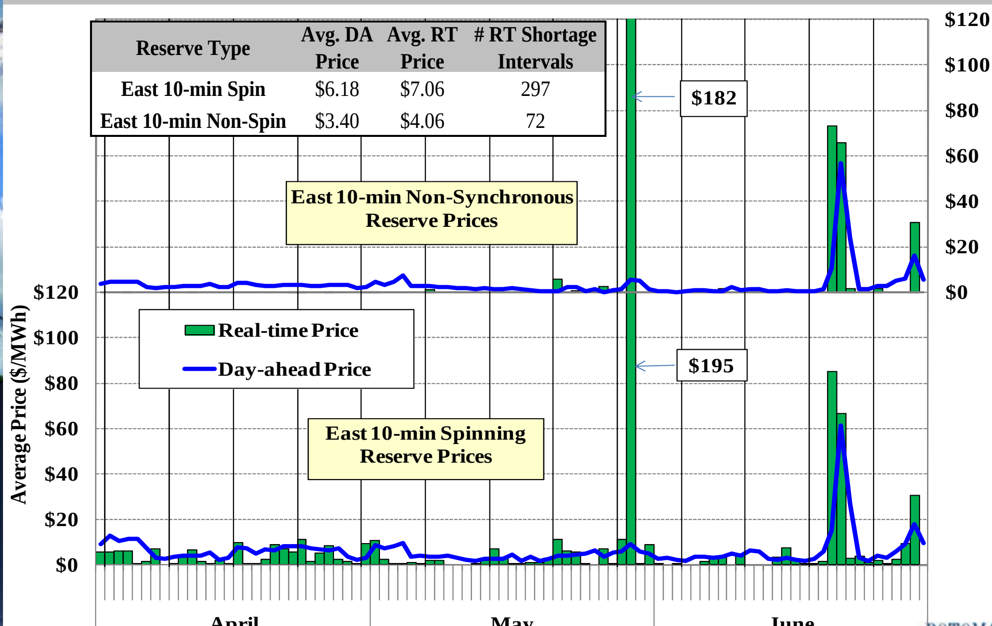
Day-Ahead and Real-Time Ancillary Services Prices
Eastern 10-Minute Spinning and Non-Spinning Reserves



Reserve Type	Avg. DA Price	Avg. RT Price	# RT Shortage Intervals
East 10-min Spin	$6.18	$7.06	297
East 10-min Non-Spin	$3.40	$4.06	72

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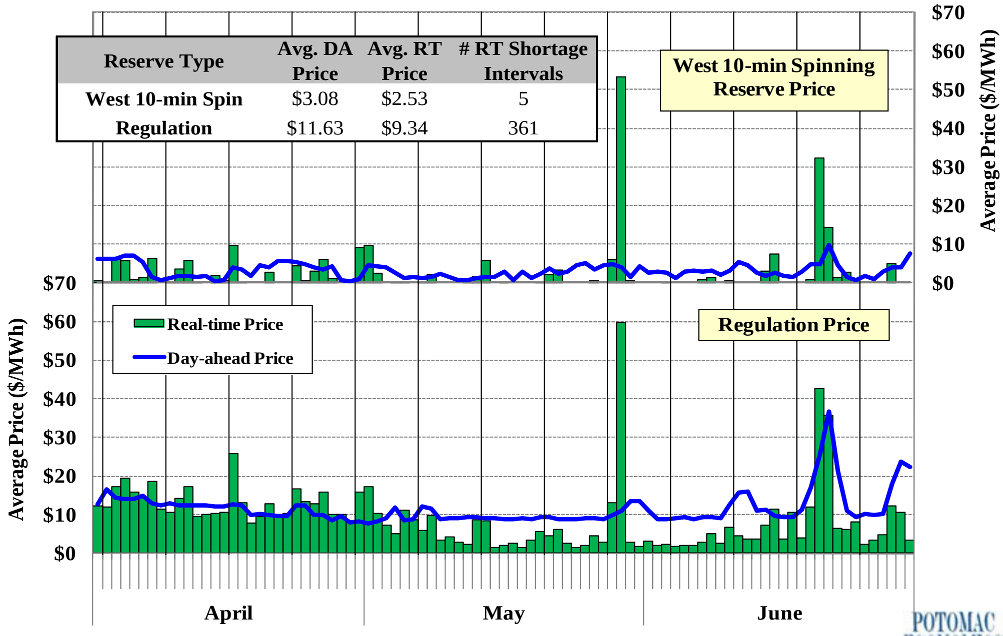
Day-Ahead and Real-Time Ancillary Services Prices
Western 10-Minute Spinning Reserves and Regulation



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Day-ahead Scheduled Load and Actual Load

- The following figure summarizes the quantity of day-ahead load scheduled as a percent of real-time load in each of four regions and state-wide.
  - ✓ Net scheduled load = Physical Bilaterals + Fixed Load + Price-Capped Load + Virtual Load – Virtual Supply
- Overall, load in the day-ahead market was scheduled at 100 percent of actual load in NYCA in the second quarter, comparable to the previous quarters.
  - ✓ However, substantial over-scheduling or under-scheduling of load in the day-ahead market on individual days can cause significant divergence between the day-ahead and real-time markets.
  - ✓ On May 29, day-ahead load was scheduled only at 87 percent of actual load when load rose to unexpectedly high levels, resulting in sharply elevated prices in real-time.
- Load was generally under-scheduled outside Southeast New York (i.e., West Upstate and Capital Zone) and over-scheduled in Southeast New York (i.e., Other East Upstate, New York City and Long Island) in the second quarter.
  - ✓ This pattern is typical, and it is likely a natural market response to real-time congestion on paths into Southeast NY, and into NYC and Long Island.

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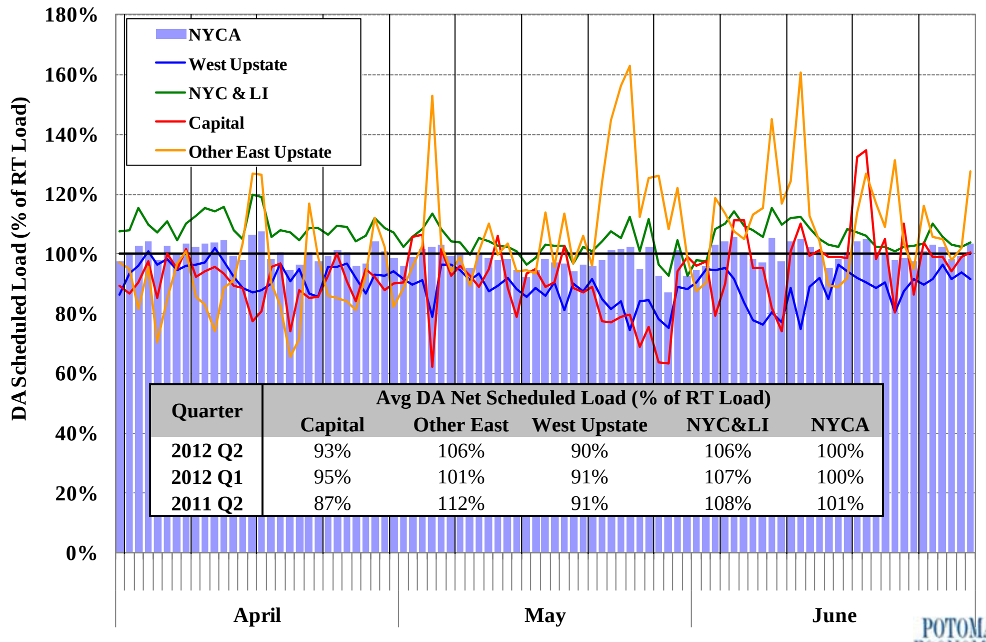
Day-ahead Scheduled Load and Actual Load

Daily Peak Load Hour



Quarter	Avg DA Net Scheduled Load (% of RT Load)				
	Capital	Other East	West Upstate	NYC&LI	NYCA
2012 Q2	93%	106%	90%	106%	100%
2012 Q1	95%	101%	91%	107%	100%
2011 Q2	87%	112%	91%	108%	101%

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Virtual Trading Activity

- The following two figures summarize virtual trading activity in New York.
- The first figure shows monthly average bids/offers and scheduled quantities, and profitability for virtual transactions in each month over the past two years.
  - ✓ In each of the past 24 months, 0.8 to 2.2 GW of virtual load and 1.5 to 3.2 GW of virtual supply have been consistently scheduled in the day-ahead market.
  - ✓ In aggregate, virtual load and supply have generally been profitable over the period, indicating that they typically 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.
- The table below the figure shows a screen for relatively large profits (which may indicate modeling inconsistencies) or losses (which may indicate potential manipulation of the day-ahead market).
  - ✓ The table shows that the quantity of transactions generating substantial profits or losses in the second quarter of 2012 was low.
  - ✓ The transactions with notable profits or losses were primarily associated with real-time price volatility and do not raise manipulation concerns.

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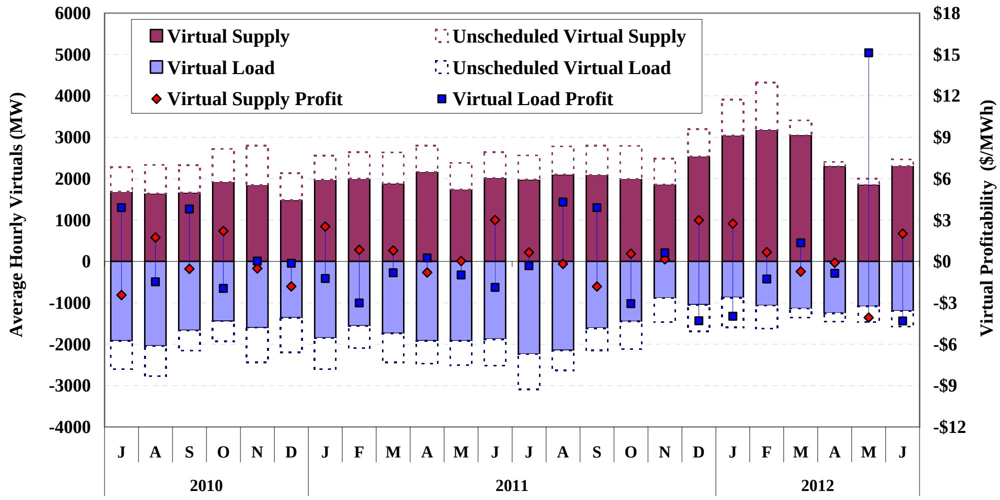
Virtual Trading Volumes and Profitability

July 2010 to June 2012



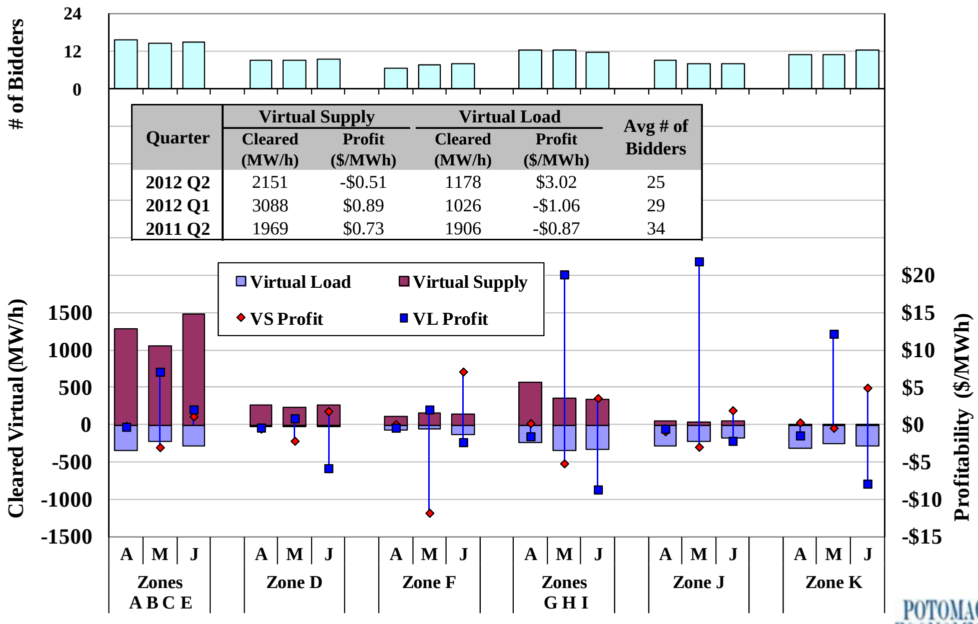
Profit > 50% of Avg. Zone Price	MW	205	176	162	117	135	221	446	193	161	122	233	350	376	337	186	98	100	208	275	96	224	220	128	345
	%	6%	5%	5%	3%	4%	8%	12%	5%	4%	3%	6%	9%	9%	8%	5%	3%	4%	6%	7%	2%	5%	6%	4%	10%
Loss > 50% of Avg. Zone Price	MW	300	205	115	95	131	273	401	244	133	120	277	381	434	334	122	133	120	193	177	125	283	261	132	377
	%	8%	6%	3%	3%	4%	10%	11%	7%	4%	3%	8%	10%	10%	8%	3%	4%	4%	5%	5%	3%	7%	7%	4%	11%

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 transmission constraints frequently affect the value of power in Zone D.
  - ✓ 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, although the number has fallen since the implementation of new credit requirements in October 2011.
  - ✓ On average, seven or more participants submitted virtual trades in each region and 25 participants submitted virtual trades throughout the state.
- There were substantial net virtual load purchases downstate and net virtual supply sales upstate in the second quarter of 2012, consistent with prior periods.
  - ✓ Virtual supply netted a $2 million loss in the second quarter while virtual load netted an $8 million profit due to the prevailing real-time price premiums.
  - ✓ The real-time spikes on May 29 accounted for the majority of profits.

Virtual Trading Activity

By Region By Month



Quarter	Virtual Supply		Virtual Load		Avg # of Bidders
	Cleared (MW/h)	Profit ($/MWh)	Cleared (MW/h)	Profit ($/MWh)	
2012 Q2	2151	-$0.51	1178	$3.02	25
2012 Q1	3088	$0.89	1026	-$1.06	29
2011 Q2	1969	$0.73	1906	-$0.87	34

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Net Imports Scheduled Across External Interfaces

- The following figure summarizes scheduled net imports to NYCA across eight external interfaces during the daily peak load hour in the second quarter of 2012.
- Net imports averaged roughly 2.9 GW in daily peak load hours, down 16 percent from the previous quarter and 4 percent from the second quarter of 2011.
  - ✓ Net imports across the Neptune line fell 345 MW from the previous quarter and 260 MW from the prior year, which was due to a transmission outage in Long Island from May 27 through June.
  - ✓ Net imports from Ontario were consistent with the previous quarter and rose 380 MW from the prior year.
  - ✓ Net imports across the primary PJM interface fell 400 MW from the prior quarter and 130 MW from a year ago.
    - Imports fell partly due to the effects of lower natural gas prices and of changes in the operation of some PAR-controlled lines between the NYISO and PJM (i.e., the A, B, C, J, & K lines) since May 1, 2012.
- On average, imports satisfied 18 percent of the load during daily peak hours in the second quarter of 2012, comparable to 17 percent in the previous quarter.
  - ✓ During the quarterly peak load hour on June 21, NYCA imported 2.5 GW, satisfying 8 percent of the peak load.

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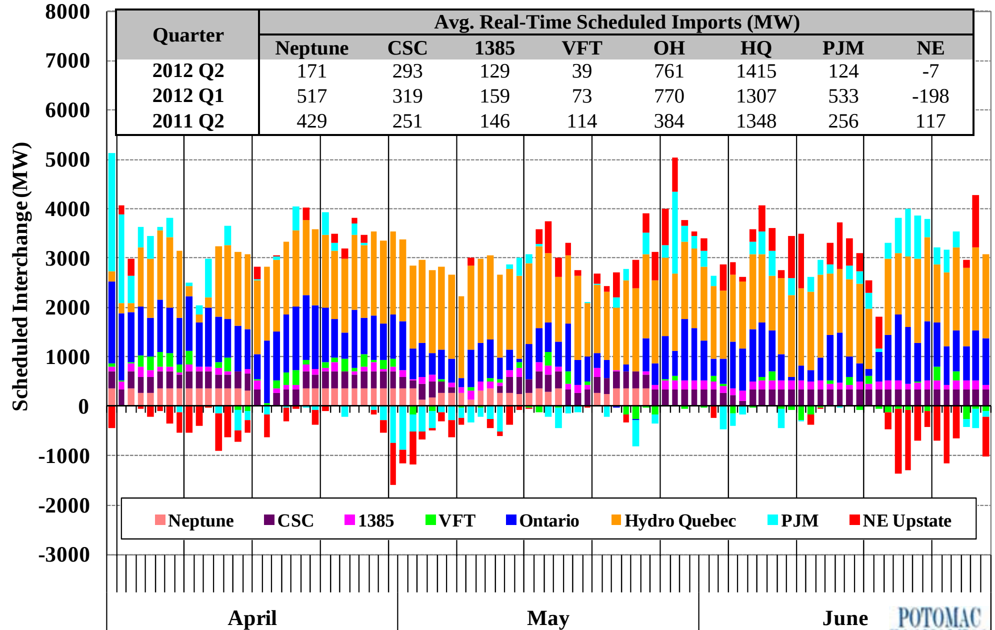
Net Imports Scheduled Across External Interfaces
Daily Peak Load Hour



Quarter	Avg. Real-Time Scheduled Imports (MW)							
	Neptune	CSC	1385	VFT	OH	HQ	PJM	NE
2012 Q2	171	293	129	39	761	1415	124	-7
2012 Q1	517	319	159	73	770	1307	533	-198
2011 Q2	429	251	146	114	384	1348	256	117

POTOMAC ECONOMICS

Change in Scheduled Imports from Day Ahead to Real Time

- The following figure summarizes the change in scheduled net imports between the day-ahead market and the real-time market in the daily peak load hour.
  - ✓ As with virtual transactions, these changes should be consistent with the RT price signals and should improve the convergence of DA and RT prices.
- Average net scheduled imports fell 800 MW from day-ahead to real-time during daily peak load hours in the second quarter of 2012. Net scheduled imports:
  - ✓ Decreased across the PJM interface by an average of 416 MW;
  - ✓ Decreased across the primary interface with NE by an average of 246 MW; and
  - ✓ Decreased across the Ontario interfaces by an average of 95 MW.
- On average, the changes in schedules between the day-ahead and real-time markets were consistent with the differences in prices.
  - ✓ However, power was still scheduled in the inefficient direction (i.e., from the high-priced area to the low-priced area) in a large share of hours.
    - – 15-minute scheduling with PJM was implemented on June 27, which is expected to improve the efficiency of scheduling between PJM and NY.
    - – The NYISO is working on other market enhancements to improve the efficiency of the interchange (e.g., CTS with ISO-NE).

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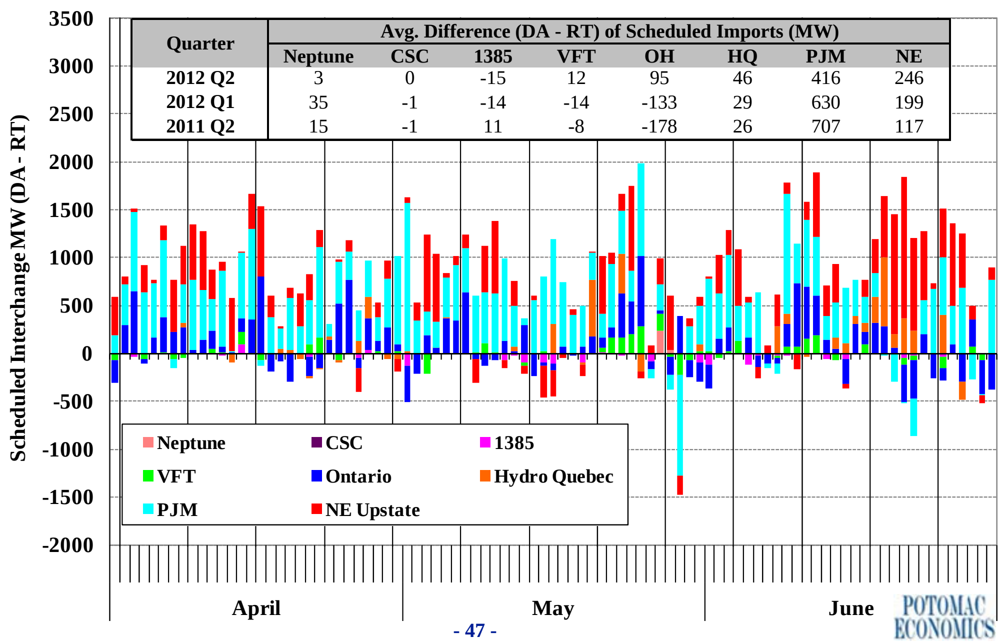
Change in Scheduled Imports from DA to RT
Daily Peak Load Hour



Quarter	Avg. Difference (DA - RT) of Scheduled Imports (MW)							
	Neptune	CSC	1385	VFT	OH	HQ	PJM	NE
2012 Q2	3	0	-15	12	95	46	416	246
2012 Q1	35	-1	-14	-14	-133	29	630	199
2011 Q2	15	-1	11	-8	-178	26	707	117

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External Interface Scheduling and 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.
  - ✓ The Transmission Loading Relief ("TLR") procedure is used by the NYISO when loop flows significantly contribute to congestion on internal flow gates.
  - ✓ In addition, IESO-Michigan PARs began operating in April 2012 and they are capable of controlling up to 600 MW of loop flows around Lake Erie.
- The figure shows the frequency of clockwise Lake Erie Circulation in each given range and the number of hours of TLRs (level 3A) that were called by the NYISO on each day of the quarter.
- Average clockwise circulation was *negative* 13 MW, down 29 MW from the previous quarter and 227 MW from the second quarter of 2011.
  - ✓ In this quarter, clockwise circulation rarely exceeded 600 MW, exceeded 400 MW in 3 percent of hours, and 200 MW in 18 percent of hours.
- TLRs were called much less frequently than in previous quarters primarily due to:
  - ✓ Clockwise circulation remained under 200 MW much more frequently; and
  - ✓ West-to-east congestion in upstate NY occurred much less frequently.

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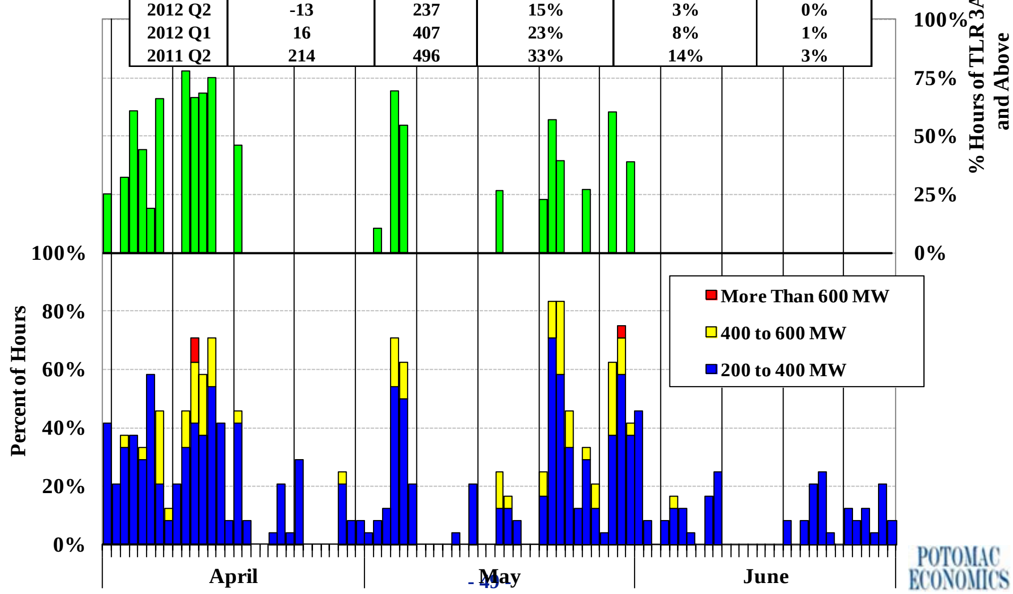
RT Clockwise Lake Erie Circulation and TLR Calls

Quarter	Avg. Clockwise Lake Erie Circulation	# Hours of TLR 3A and Above	Clockwise Lake Erie Circulation (% of Hours)		
			200 to 400 MW	400 to 600 MW	> 600 MW
2012 Q2	-13	237	15%	3%	0%
2012 Q1	16	407	23%	8%	1%
2011 Q2	214	496	33%	14%	3%



Efficiency of Gas Turbine Commitment and Price Setting

- Under the current RT pricing methodology, GTs operating during their one-hour initial commitment may not always set the RT LBMP when they are economic (i.e., when their output is displacing output from more expensive resources).
  - ✓ Allowing these GTs to set the RT LBMP would lead to more efficient and higher LBMPs in some intervals and to a reduction in RT BPCG payments.
- The next figure evaluates the efficiency of GT commitments and of RT LBMPs during the initial one-hour commitment period in the second quarter of 2012. The figure reports the seven quantities for four areas of NYC and Long Island:
  - ✓ *Number of Starts* – Number of GT commitments in each area excluding self-scheduled units and local reliability units.
  - ✓ *Percent Receiving RT BPCG Payment on that Day* – Share of GT commitments that occurred on days when the unit received a RT BPCG payment for the day.
  - ✓ *Percent of Unit-Intervals Uneconomic* – Share of intervals during the initial commitment period when the unit was displacing less expensive capacity.
  - ✓ *Percent of Unit-Intervals Economic AND Non-Price Setting* – Share of intervals during the initial commitment period when the unit was displacing more expensive capacity, but not setting the RT LBMP. *(list continued on next slide)*

Efficiency of Gas Turbine Commitment and Price Setting

- ✓ *Percent of Starts Uneconomic (Offer > Average Adjusted LBMP)* – Share of starts when GT's offer was greater than the "Adjusted LBMP" (i.e., the average LBMP that would have been set if economic GTs at the same wholesale market location always set the RT LBMP) over the initial commitment period.
- ✓ *Percent of Starts Uneconomic at Actual BUT Economic at Adjusted LBMP* – Share of starts when GT's offer was (a) greater than the average actual LBMP but (b) less than the Adjusted LBMP over the initial commitment period.
- ✓ *Estimated Average LBMP Adjustment During Starts* – Average upward adjustment in LBMPs during starts if economic GTs always set the RT LBMP.

- The figure under-estimates the effects of allowing GTs to set the RT LBMP in intervals when they are economic for the following reasons:
  - ✓ The figure assumes that the RT LBMP impact is limited to the wholesale market location where the GT's facility is interconnected. However, the actual RT LBMP impact would often affect a wider area, depending on congestion patterns.
  - ✓ The figure does not include the effects of higher RT LBMPs on GTs after their initial commitment period.
- The figure shows that GTs tend to receive RT BPCG payments on many days when their initial commitment was economic. This can occur when the GT is kept online due to an OOM dispatch instruction after the initial commitment period.

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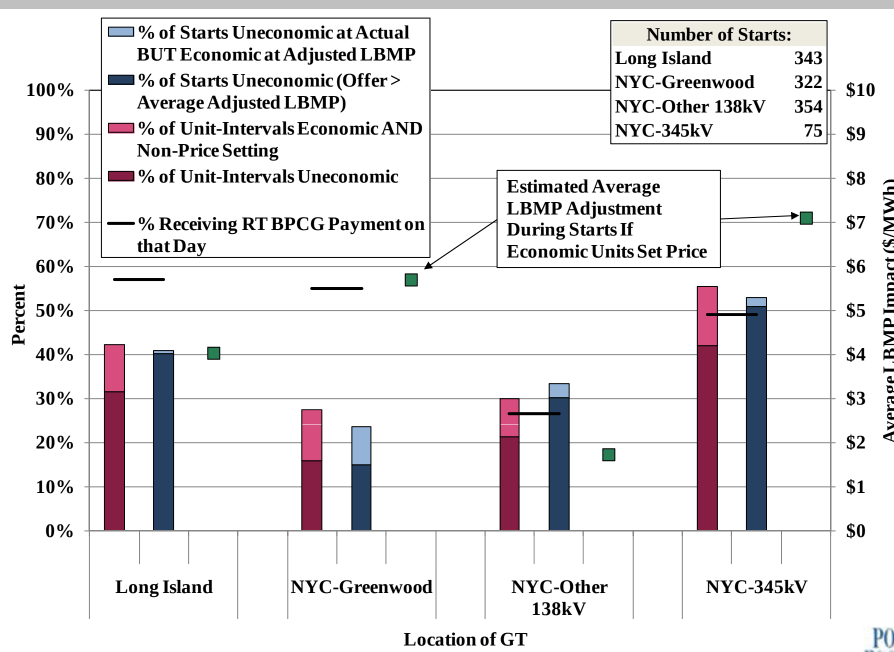
Efficiency of Gas Turbine Commitment and Price Setting



POTOMAC ECONOMICS

Day-Ahead and Real-Time Transmission Congestion

Congestion Revenue and Shortfalls

- This section of the report summarizes and evaluates the congestion patterns in New York 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 and Shortfalls

- The following figure summarizes day-ahead congestion revenue and shortfalls, and balancing congestion shortfalls over the past two years.
- Day-ahead congestion revenue was $61 million in the second quarter, up nearly 20 percent from the previous quarter but down 40 percent from a year ago.
  - ✓ The reduction from a year ago is primarily due to the effects of lower natural gas prices, which reduce flows into eastern NY (where gas is the dominant fuel) and which reduce congestion-related price differences between regions in general.
  - ✓ 1 GW of new generation and a new transmission line in NYC also contributed to the decline in congestion.
- Day-ahead congestion shortfalls totaled $1 million, down $6 and $20 million from the previous quarter and the previous year, respectively.
  - ✓ The reductions were due to the general decline in congestion, TCC auction modeling improvements made in May 2011, and fewer transmission outages.
- Balancing congestion shortfalls were $6 million in the second quarter of 2012, up $3 million from the previous quarter and down from $12 million from a year ago.
  - ✓ The increase from the prior quarter was primarily due to more frequent TSA operations, while the decrease from a year ago was largely driven by the overall reduction in congestion.

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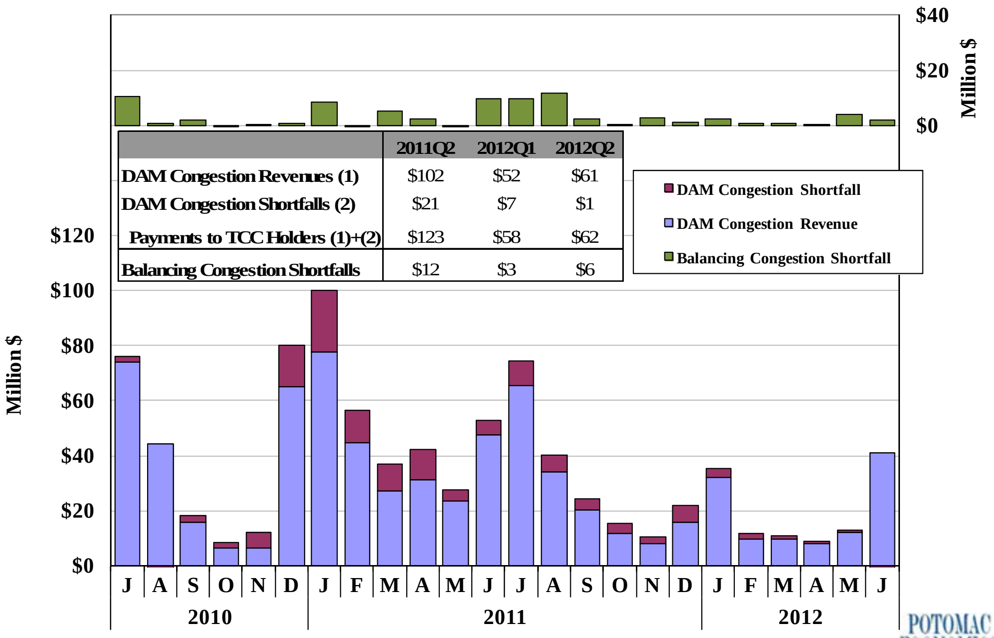
Congestion Revenue and Shortfalls



	2011Q2	2012Q1	2012Q2
DAM Congestion Revenues (1)	$102	$52	$61
DAM Congestion Shortfalls (2)	$21	$7	$1
Payments to TCC Holders (1)+(2)	$123	$58	$62
Balancing Congestion Shortfalls	$12	$3	$6

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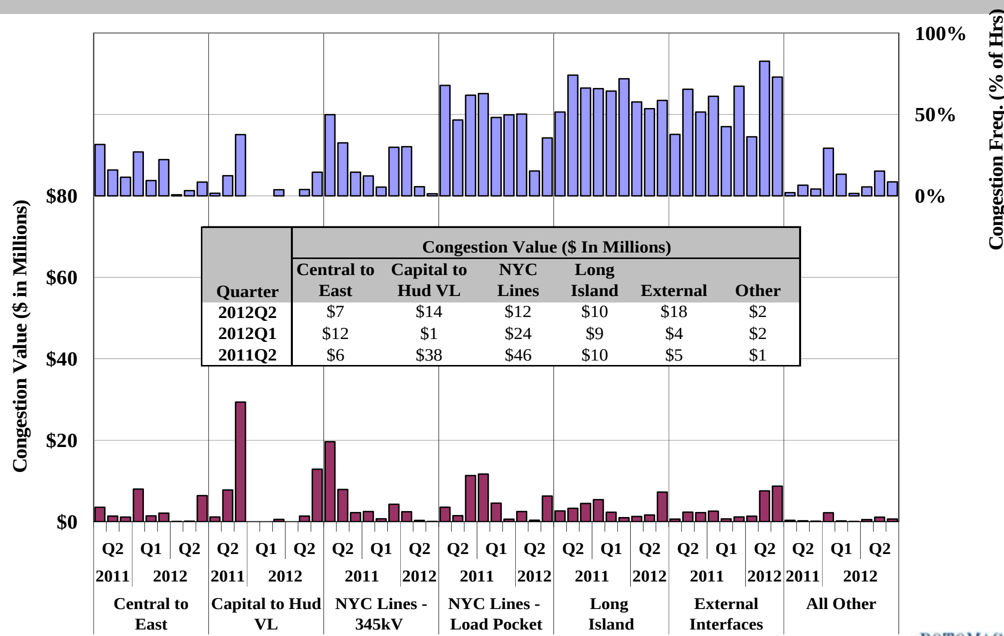
Congestion by Transmission Path

- 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 transfers is equal to 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 is equal to the congestion revenue collected by the NYISO, which is the primary funding source for TCC payments.
- The two figures group congestion into the following transmission paths:
  - ✓ West to Central: Primarily the Dysinger East interface.
  - ✓ Central to East: Primarily the Central-East interface.
  - ✓ Capital to Hudson Valley: Primarily the Leeds-Pleasant Valley Line.
  - ✓ NYC Lines – 345kV: Lines leading into and within the NYC 345 kV system.
  - ✓ NYC Lines – Load Pockets: Lines leading into and within NYC load pockets.
  - ✓ Long Island: Lines leading into and within Long Island.
  - ✓ NYC Simplified Interfaces: Groups of lines to NYC load pockets that are modeled as interface constraints.
  - ✓ External Interfaces – Congestion related to the total transmission limits or ramp limits of the external interfaces.

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.
- 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 the shadow prices of constraints are generally lower in the day-ahead market.
- Most day-ahead congestion revenue in this quarter was collected for:
  - ✓ External Interfaces (28 percent) – The primary HQ interface was fully scheduled much more frequently in May and June, leading to increased congestion.
    - – This pattern is consistent with the increased real-time congestion across the interface in recent summers during TSA operations.
  - ✓ Capital to Hudson Valley lines (23 percent) – Congestion rose from the previous quarter, likely reflecting expectations of more frequent TSA-related congestion.
  - ✓ New York City lines (19 percent) – Congestion fell from prior quarters, reflecting the effects of lower gas prices, new transmission, and generation in the City.
  - ✓ Long Island (16 percent) – Congestion into Long Island rose in June primarily due to the transmission outage affecting the Neptune line.

Day-Ahead Congestion by Transmission Path



Quarter	Congestion Value ($ In Millions) Central to East	Capital to Hud VL	NYC Lines	Long Island	External	Other
2012Q2	$7	$14	$12	$10	$18	$2
2012Q1	$12	$1	$24	$9	$4	$2
2011Q2	$6	$38	$46	$10	$5	$1

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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. However, this analysis does not reflect the effects of price corrections or the Scarcity Pricing Rules.
- The total value of real-time congestion was $56 million.
  - ✓ Real-time congestion value rose 21 percent from the previous quarter, reflecting increased congestion across the external interfaces and on the transmission paths from Capital to Hudson Valley.
  - ✓ Real-time congestion value fell 41 percent from a year ago, due primarily to lower natural gas prices. Also, the additions of generation and transmission in New York City contributed to reduced congestion.
- Real-time congestion occurred mostly in the following areas in the second quarter:
  - ✓ Capital to Hudson Valley lines (36 percent): The majority of this congestion occurred during high load periods and TSAs.
  - ✓ External Interfaces (22 percent): Nearly all of the congestion (94 percent) occurred on the Hydro-Quebec interface, primarily in May and June. The Hydro-Quebec interface frequently becomes congested when NYISO Operations reduces the TTC of the interface to manage reliability during TSA events.

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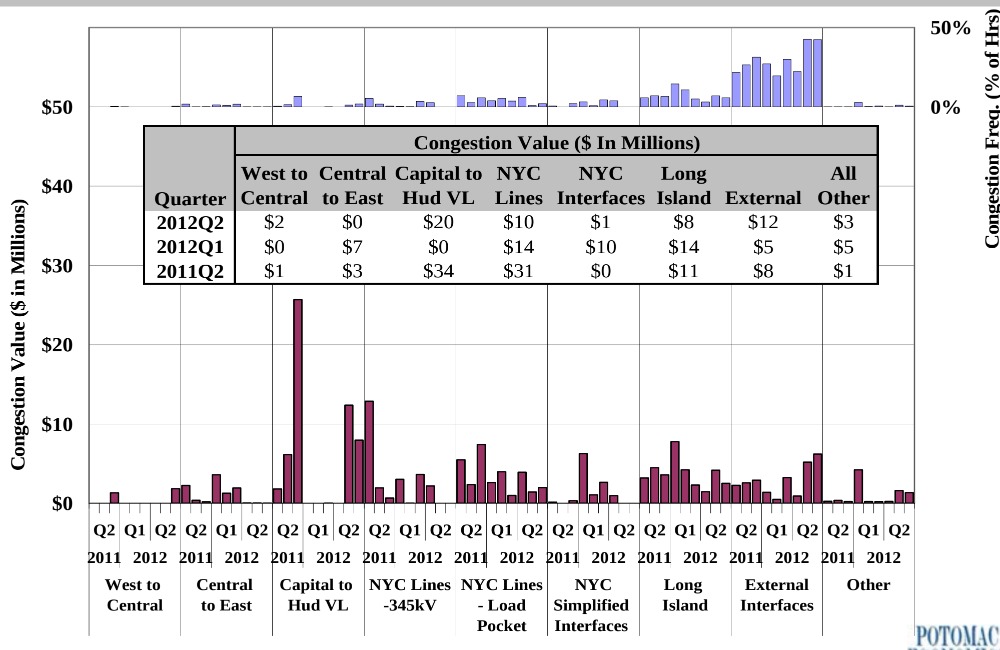
Real-Time Congestion by Transmission Path



	Congestion Value ($ In Millions)							
Quarter	West to Central	Central to East	Capital to Hud VL	NYC Lines	NYC Interfaces	Long Island	External	All Other
2012Q2	$2	$0	$20	$10	$1	$8	$12	$3
2012Q1	$0	$7	$0	$14	$10	$14	$5	$5
2011Q2	$1	$3	$34	$31	$0	$11	$8	$1

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Day-Ahead Congestion Revenue Shortfalls

- The following figure shows the daily day-ahead congestion revenue shortfalls by transmission path or facility in the second quarter of 2012.
  - ✓ Negative values indicating congestion surpluses that arise from higher day-ahead utilization of interfaces than in the TCC auction.
- Day-ahead congestion revenue shortfalls can result from modeling assumption differences between the TCC auction and the day-ahead market.
  - ✓ This includes assumptions related to PAR schedules, loop flows, and transmission outages. (Outage-related shortfalls are allocated to the responsible TO.)
- Day-ahead congestion shortfalls were quite low in the second quarter of 2012, less than $1 million in total. The following issues contributed to shortfalls:
  - ✓ In April, the shortfalls in New York City resulted primarily from planned transmission work.
  - ✓ From the last week of May through June, the majority of shortfalls and surpluses were related to Long Island facilities.
    - – Shortfalls occurred on some days due to de-ratings of the two 345kV lines from up-state New York.
    - – Large surpluses on June 21, resulted from internal congestion on flows out of the Northport generation pocket.

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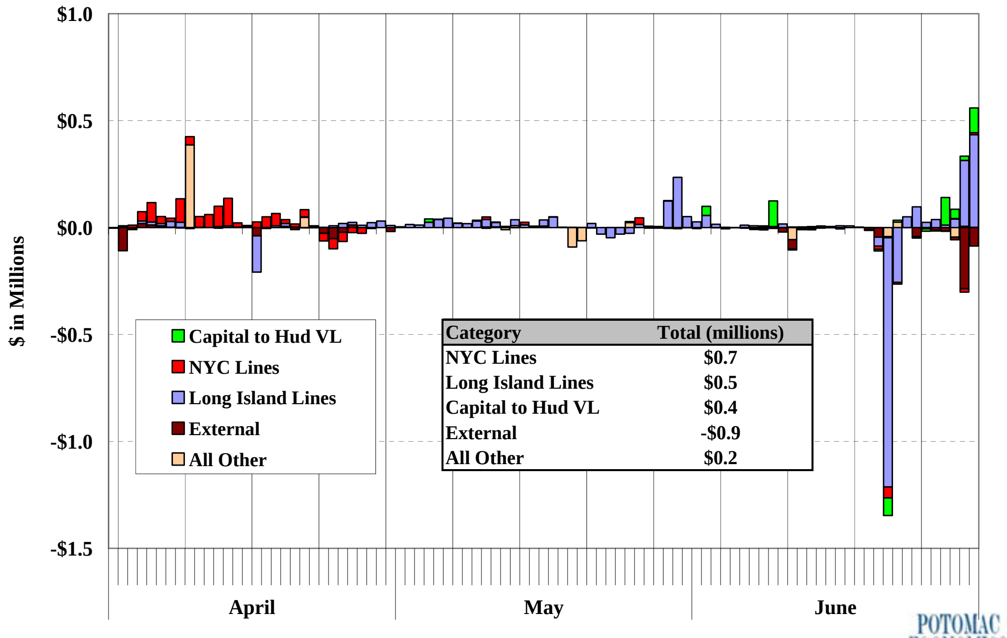
Day-Ahead Congestion Revenue Shortfalls



Balancing Congestion Shortfalls

- The following figure shows daily balancing congestion revenue shortfalls by transmission path or facility in the second quarter of 2012.
  - ✓ Negative values indicate balancing congestion surpluses that arise from increased real-time utilization of an interface from the day-ahead market.
- Balancing congestion revenue shortfalls can occur when the transfers across a congested interface fall from day-ahead to 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 shortfalls can also occur when modeling assumptions in the day-ahead to real-time markets are inconsistent, including assumptions regarding:
  - ✓ Unscheduled loop flows across constrained interfaces; and
  - ✓ Flows across PAR-controlled lines.

Balancing Congestion Shortfalls

- Balancing shortfalls were small on most days in this quarter but rose notably on several days in May and June when unexpected real-time events occurred.
- TSA events accounted for the largest share of the balancing congestion shortfalls.
  - ✓ TSA events occurred on 14 days in May and June, during which the transfer capability into Southeast New York was greatly reduced in real-time.
  - ✓ Notable balancing shortfalls accrued on 8 out of 14 such days, particularly on May 29 when under-forecasting of load and outages exacerbated LPV congestion.
- External Interfaces accounted for most of the remaining shortfalls in this quarter, which accrued primarily in two days where:
  - ✓ The primary HQ interface was forced out of service on both days, reducing day-ahead scheduled imports on both days.
  - ✓ Transactions that were scheduled by RTC were subsequently curtailed in real-time to manage system security issues by neighboring controlling areas.
- Scarcity Pricing produced significant surpluses on May 29, since overall, MPs made significant balancing purchases at the locations where LBMPs were revised.
- Ramapo PAR Controlled Lines accounted for $1.6 million of surpluses.
  - ✓ These generally coincided with TSAs, reflecting that the line was helpful in managing congestion into Southeast New York during TSA operations.

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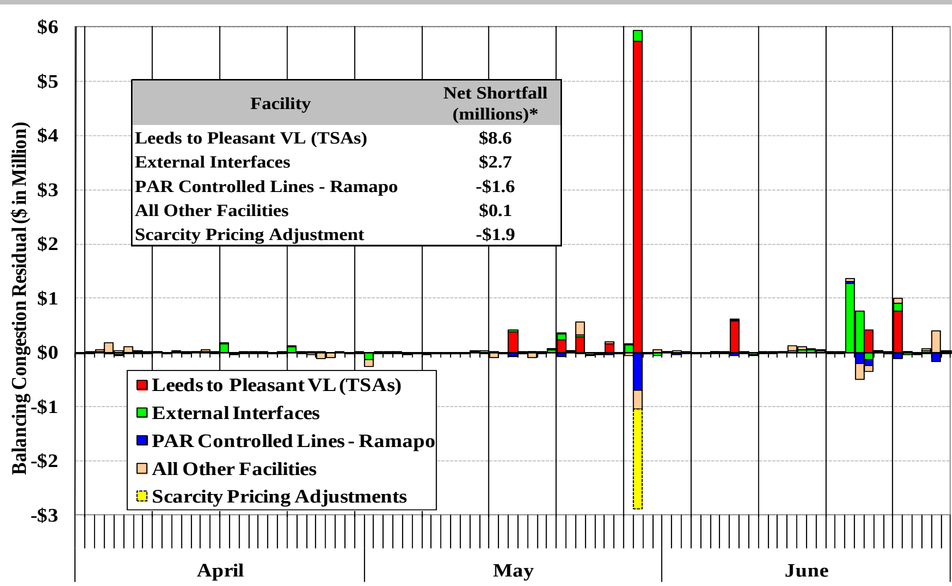
Balancing Congestion Shortfalls



Notes: The BMCR estimated above may differ from actual BMCR because the figure: (a) is partly based on real-time schedules rather than metered values and (b) assumes the energy component of the LBMP is the same at all locations including proxy buses (while the actual LBMPs are not calculated this way under all circumstances).

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Uplift Costs and Supplemental Commitments

Uplift Costs from Guarantee Payments

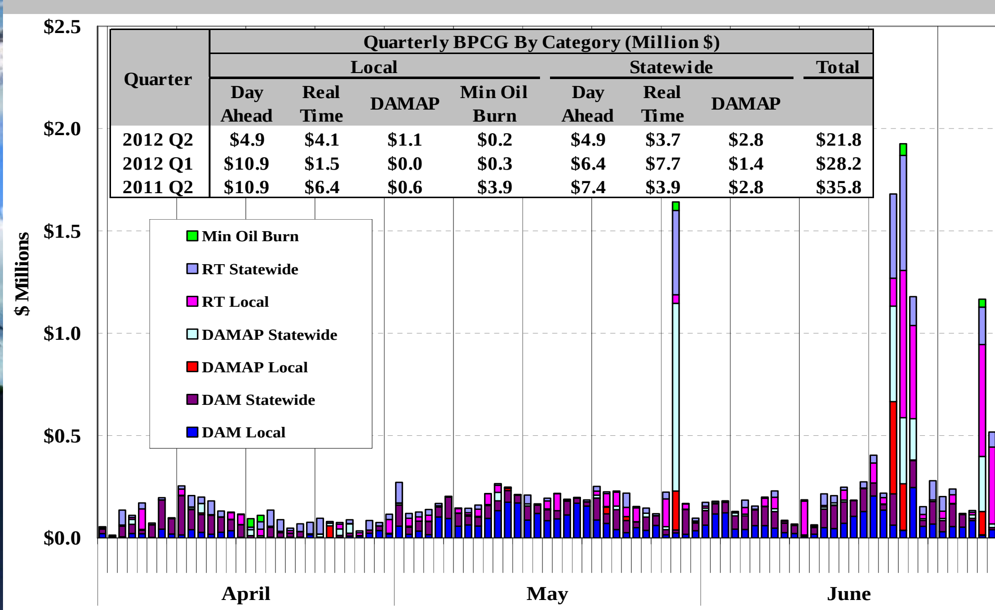
- The next two figures summarize uplift charges resulting from guarantee payments in the following seven categories.
- Three categories of non-local reliability uplift are allocated to all LSEs:
  - ✓ Day Ahead: Primarily for units committed economically that don't recoup their as-offered start-up and min generation costs from LBMPs.
  - ✓ Real Time: For external transactions and gas turbines that are scheduled economically but don't recoup their as-offered costs 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 for generators dispatched 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 Local Reliability Requirements ("LRR") and Day-Ahead Reliability Unit ("DARU") commitments.
  - ✓ Real Time: From Supplemental Resource Evaluation ("SRE") commitments and Out-of-Merit ("OOM") dispatched units.
  - ✓ 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 units that are dispatched OOM for local reliability reasons.

Uplift Costs from Guarantee Payments

- The following figure shows the seven categories of uplift charges on a daily basis in the second quarter of 2012.
- Guarantee payment uplift was $22 million in the second quarter of 2012, down 23 percent from the previous quarter and 39 percent from the second quarter of 2011. The reductions were due to:
  - ✓ Lower natural gas and fuel oil prices;
  - ✓ Decreased reliability commitment in New York City and Long Island;
  - ✓ More accurate generator reference levels; and
  - ✓ Less need for New York City generators to burn fuel oil for IR-3 (i.e., minimum oil burn) requirements.
- Guarantee payments rose significantly on several days in May and June when high loads and unexpected real-time events led to increased commitment of oil-fired units for reliability, particularly in Long Island.
- NYISO's mitigation consultations are on-going for the second quarter, so guarantee payments may increase once these are fully reflected.

Uplift Costs from Guarantee Payments

Local and Non-Local by Category



Quarterly BPCG By Category (Million $)

Quarter	Local				Statewide			Total
	Day Ahead	Real Time	DAMAP	Min Oil Burn	Day Ahead	Real Time	DAMAP	
2012 Q2	$4.9	$4.1	$1.1	$0.2	$4.9	$3.7	$2.8	$21.8
2012 Q1	$10.9	$1.5	$0.0	$0.3	$6.4	$7.7	$1.4	$28.2
2011 Q2	$10.9	$6.4	$0.6	$3.9	$7.4	$3.9	$2.8	$35.8

Note: These data are based on information available at the reporting time and do not include some manual adjustments to mitigation, so they can be different from final settlements.

Uplift Costs from Guarantee Payments by Region

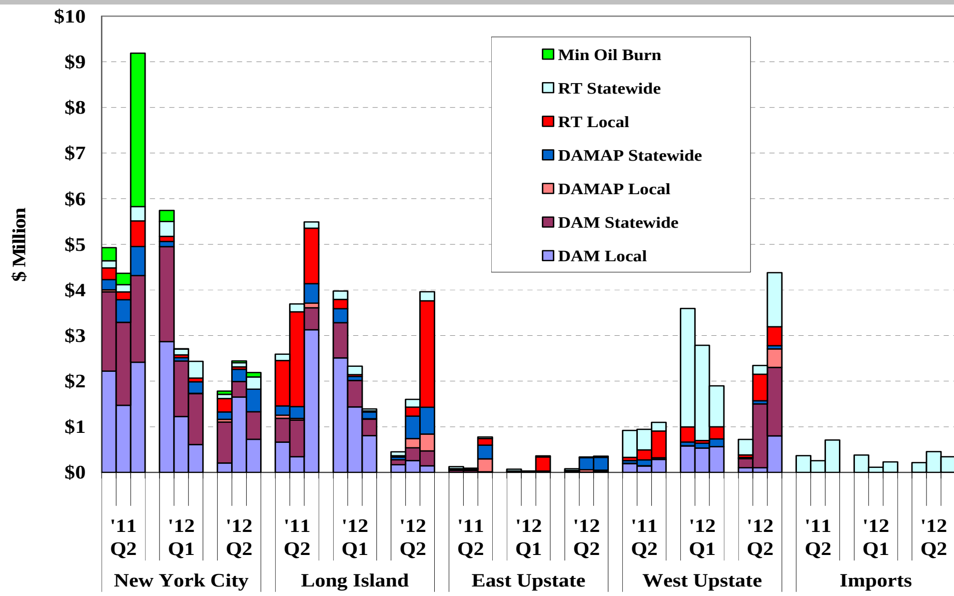
- The next figure shows seven categories of uplift on a monthly basis by region.
- Day-ahead local reliability uplift in the second quarter of 2012:
  - ✓ The majority was for NYC (53 percent), primarily day-ahead commitments for NOX Bubble Requirements and for Astoria West/Queensbridge reliability.
- Day-ahead statewide uplift in the second quarter of 2012:
  - ✓ A significant share of these costs (60 percent) were paid to generators in the West Zone at several plants where one or more units were required to manage transmission congestion.
  - ✓ The resulting guarantee payments are allocated statewide if the facility being secured is monitored by the NYISO (i.e., 230kV or higher).
- Real-time local reliability uplift in the second quarter of 2012:
  - ✓ Long Island accounted for 65 percent, primarily to manage local congestion on the East End where some generators do not have a source of natural gas.
- Real-time statewide uplift in the second quarter of 2012:
  - ✓ The majority was for Western New York (46 percent) associated primarily with SRE commitments and for imports (27 percent).

Uplift Costs from Guarantee Payments by Region

- Guarantee payment uplift decreased 39 percent from the second quarter of 2011.
  - ✓ This was driven partly by reductions in natural gas prices and fuel oil prices.
- New York City accounted for a large share of the reduction in uplift from the second quarter of 2011.
  - ✓ Day-ahead uplift fell by $8 million. This was partly the result of less reliability commitment during June and improved accuracy of generator reference levels.
  - ✓ Minimum Oil Burn uplift fell by over $3 million. This was largely due to the entry of the new Astoria Energy II generator, which has auto-fuel swapping capability, thereby reducing the need for steam units to burn oil in many hours.
- On Long Island, day-ahead and real-time local uplift fell by $5 million from the second quarter of 2011.
  - ✓ The outage limiting imports across the Neptune line led to higher LBMPs from late May through the end of June.
  - ✓ Consequently, generators needed for local reliability were more often committed economically, and oil-fired peaking units that are dispatched for East End local reliability received less guarantee payments.
- In western NY, day-ahead uplift increased by over $3 million from the second quarter of 2011 partly due to more DARU commitment in the West Zone.

Uplift Costs from Guarantee Payments

By Category and Region



Note: These data are based on information available at the reporting time and do not include some manual adjustments to mitigation, so they can be different from final settlements.

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Supplemental Commitment for Reliability

- The following figure shows the monthly quantities of capacity committed for reliability by type of commitment and region.
- Reliability commitment in Western NY rose considerably from a year ago.
  - ✓ Committed capacity averaged 235 MW in the second quarter of 2012, up from 65 MW in the second quarter of 2011.
  - ✓ DARU commitment increased partly because several coal units were frequently needed to manage congestion on 230kV and 115kV lines in the West Zone.
- Reliability commitment on Long Island fell notably from a year ago.
  - ✓ Committed capacity averaged 140 MW, down 42 percent from a year ago.
  - ✓ DARU commitment fell as many of the units that are frequently needed for local reliability were instead committed economically. This was largely due to the higher LBMPs that occurred after the Neptune outage.
- Reliability commitment in New York City fell modestly from a year ago.
  - ✓ Committed capacity averaged 450 MW in this quarter, down from 540 MW in the second quarter of 2011. The reduction occurred primarily on higher load days.
  - ✓ A small number of slow-start units continue to be committed in the Forecast Load Pass when off-line fast-start units were available and unscheduled. Relatively little uplift was generated by these commitments.

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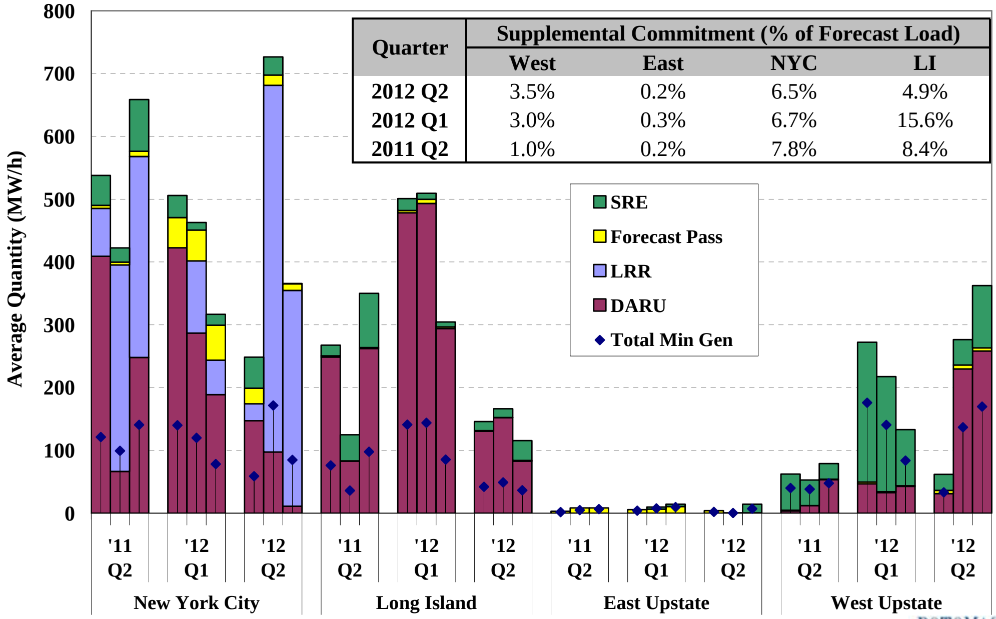
Supplemental Commitment for Reliability
by Category and Region



Quarter	Supplemental Commitment (% of Forecast Load)			
	West	East	NYC	LI
2012 Q2	3.5%	0.2%	6.5%	4.9%
2012 Q1	3.0%	0.3%	6.7%	15.6%
2011 Q2	1.0%	0.2%	7.8%	8.4%

Supplemental Commitment for Reliability in NYC

- The following figure evaluates the reasons for reliability commitments in the second quarter of 2012 in New York City where most occur.
- Based on our review of the reliability commitment logs and LRR constraint information, each hour that was flagged as DARU, LRR, or SRE was categorized according to one of the following reliability reasons:
  - ✓ Voltage – If needed for ARR 26 and no other reason except NOX.
  - ✓ Thermal – If needed for ARR 37 and no other reason except NOX.
  - ✓ Loss of Gas – If needed for IR-3 and no other reason except NOX.
  - ✓ Multiple Reasons – If needed for two or three out of ARR 26, ARR 37, IR-3. The capacity is shown for each separate reason in the bar chart.
- For voltage and thermal constraints, the capacity is shown by the load pocket that was secured (AELP = Ast East, AWLP = Ast West/Queens, AVLP = Ast West/ Queens/Vernon, ERLP = East River, FRLP = Freshkills, GSLP = Greenwd/Staten Is, & SDLP = Sprainbr/Dunwoodie).
- A unit is considered to be committed for an LRR constraint if the constraint would be violated without the unit's capacity.

Supplemental Commitment for Reliability in NYC

- The reliability requirements that accounted for the most MWhs of capacity in the second quarter of 2012 were:
  - ✓ NOX bubble requirements – These require the operation of a steam turbine unit in order to reduce the overall NOX emission rate from a portfolio containing higher-emitting gas turbine units.
    - – These requirements are in effect from May to September each year.
    - – On moderate load days, these requirements accounted for a large number of reliability commitments.
      - The output from these steam turbine units frequently displaced output from newer cleaner generation in the city and imports to the city.
    - – On high load days, these requirements were frequently satisfied by economically committed units.
  - ✓ Astoria West/Queensbridge thermal and voltage requirements – These ensure facilities into this pocket will not be overloaded if the largest two generation or transmission contingencies were to occur.

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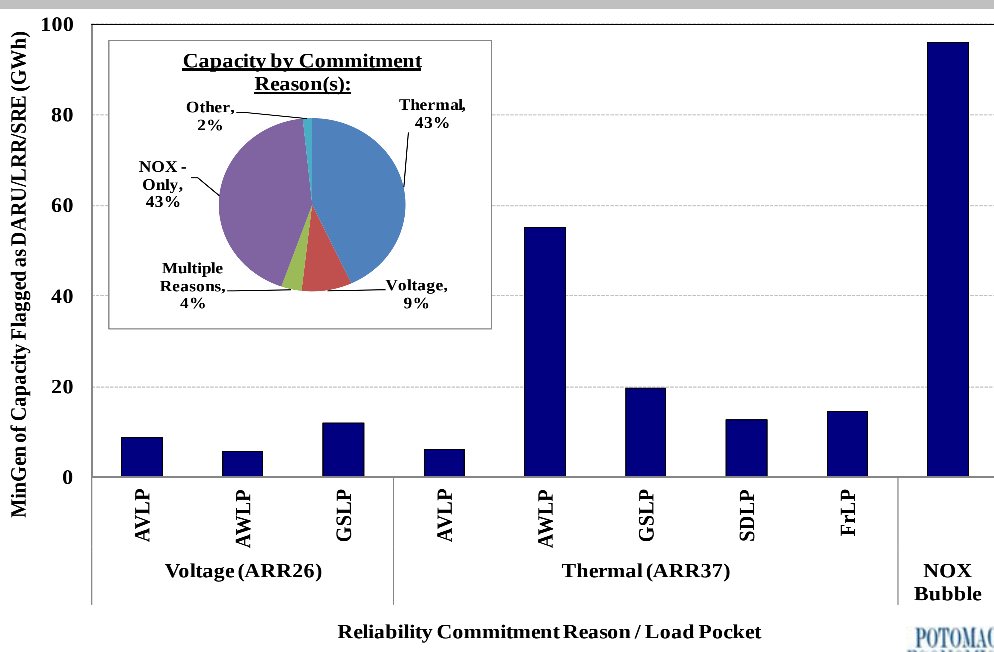
Supplemental Commitment for Reliability in NYC by Reliability Reason and Load Pocket



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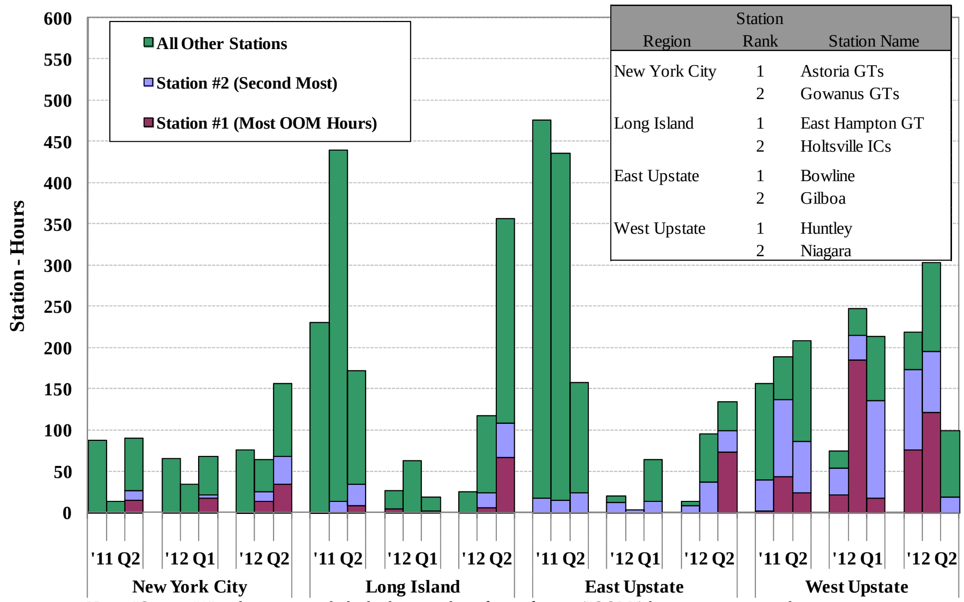
Out-of-Merit Dispatch

- The NYISO and local Transmission Owners sometimes dispatch generators out-of-merit ("OOM") in order to:
  - ✓ Manage constraints of high voltage transmission facilities that are not fully represented in the market model; or
  - ✓ Maintain reliability of the lower voltage transmission system and the distribution system.
- The following figure summarizes the frequency (i.e., the number of total station-hours) of the OOM actions on a monthly basis by region in the second quarter of 2012.
  - ✓ In each region, the two stations with the highest number of OOM dispatch hours in the second quarter of 2012 are shown separately.
  - ✓ The figure excludes OOMs that prevent a generator from being started, since these usually indicate transmission outages that make the generator unavailable.
- Overall, generators were OOMed for over 1,600 station-hours in the second quarter of 2012, up approximately 700 station-hours from the previous quarter.
  - ✓ The increase was generally attributable to higher load levels, which led to more frequent OOMs for local reliability and transmission security.

Out-of-Merit Dispatch

- OOM dispatch in West Upstate accounted for 38 percent of total OOM station-hours in the second quarter of 2012.
  - ✓ Huntley and Niagara units accounted for 62 percent of all OOM station-hours in West Upstate New York.
    - – These units were often OOMed by the NYISO to manage reliability of 230 kV lines in the West Zone.
    - – The NYISO implemented improved constraint modeling of these lines in the day-ahead and real-time markets in mid-May 2012, which:
      - Subsequently reduced OOM dispatch and the related uplift charges; and
      - Should result in market signals that lead to more efficient commitment of generation in the West Zone and more efficient scheduling of imports from Ontario and PJM.
- OOM dispatch on Long Island accounted for 30 percent of total OOM station-hours in the second quarter of 2012, a significant share of which was called by the local TO to manage local reliability on the East End of Long Island.
- OOM dispatch in New York City accounted for 18 percent of total OOM station-hours in the second quarter, primarily called to manage security and reliability on days with high loads and/or TSAs.

Frequency of Out-of-Merit Dispatch by Region by Month



Note: "Station #1" is the station with the highest number of out-of-merit ("OOM") hours in a region in the current quarter.
"Station #2" is that station with the second-highest number of OOM hours in a region in the current quarter.

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Market Monitoring and Mitigation

- The following figure summarizes energy offer mitigation as well as the results of potential withholding screens.
- Energy, minimum generation, and start-up offer mitigation is performed by automated mitigation procedure ("AMP") software in the day-ahead and real-time markets in New York City. The following figure reports:
  - ✓ The frequency of incremental energy offer mitigation; and
  - ✓ The average quantity of mitigated capacity, including capacity below the minimum generation level when the minimum generation offer is mitigated.
- The output gap is the amount of economic capacity that does not produce energy because a supplier submits an offer price above the unit's reference level by a substantial threshold. The following figure shows this using:
  - ✓ A high threshold (the lower of $100/MWh and 300 percent); and
  - ✓ A low threshold (the lower of $50/MWh and 100 percent).
- Generator deratings are reviewed to screen for potential physical withholding. The figure summarizes:
  - ✓ Total deratings, which are measured relative to the DMNC test value; and
  - ✓ Short-term deratings, which exclude deratings lasting more than 30 days.

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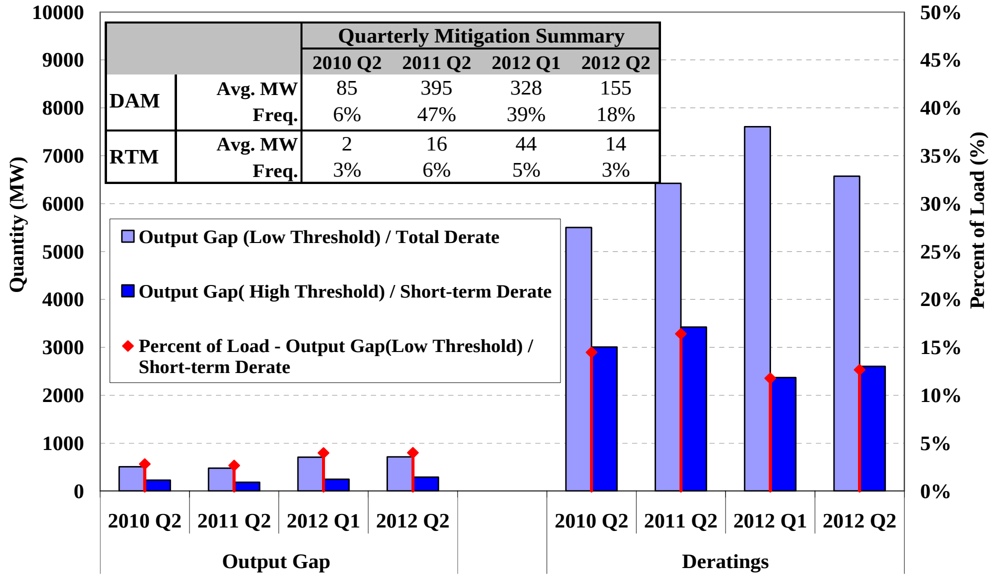
Automated Market Mitigation

- The vast majority of mitigation occurred in the day-ahead market.
  - ✓ In the second quarter of 2012, day-ahead mitigation occurred primarily for:
    - DARU & LRR units (53%),
    - The 345/138kV interface (20%), and
    - The Astoria West/Queens/Vernon load pocket (17%).
  - ✓ Mitigation fell from previous quarters primarily because:
    - Less frequent congestion in the 345kV and 138kV areas of NYC, resulting from new generation, new transmission, and fewer transmission outages.
    - Units frequently mitigated in ROS were DARU-flagged less frequently.
- Mitigation increased substantially in Long Island and in Upstate New York after October 2010 due to the application of the new ROS reliability mitigation rules.
- Mitigation increased substantially in New York City in 2011 and 2012 because of changes in offer patterns by some suppliers and improvements in the accuracy of reference levels for some generators.
- Some mitigation consultations are on-going for the second quarter of 2012, but the amount of un-mitigation is expected to be smaller than in recent quarters.

Market Monitoring of Withholding

- The output gap was relatively low as a share of load in this quarter.
  - ✓ The amount of output gap averaged 290 MW at the high threshold and 710 MW at the low threshold in this quarter (< 4% of load), consistent with the same periods from previous years.
  - ✓ The output gap did not raise significant market power concerns because they occurred primarily during periods when the prices would not be substantially affected.
- Deratings fell modestly from the prior quarter and were consistent with the second quarter of 2011.
  - ✓ Total deratings are significant, but physical withholding concerns are limited because:
    - Deratings are highest in shoulder months when demand is lowest; and
    - Most deratings are long-term and less likely to reflect withholding.
  - ✓ Short-term deratings (< 30 days) decreased modestly compared to the same period of last year.

Market Monitoring Screens and Mitigation



Quarterly Mitigation Summary		2010 Q2	2011 Q2	2012 Q1	2012 Q2
DAM	Avg. MW	85	395	328	155
	Freq.	6%	47%	39%	18%
RTM	Avg. MW	2	16	44	14
	Freq.	3%	6%	5%	3%

Note: Mitigation summaries for 2011-Q2 and 2012-Q1 are revised from the previous report to reflect the results from mitigation consultations.

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Capacity Market

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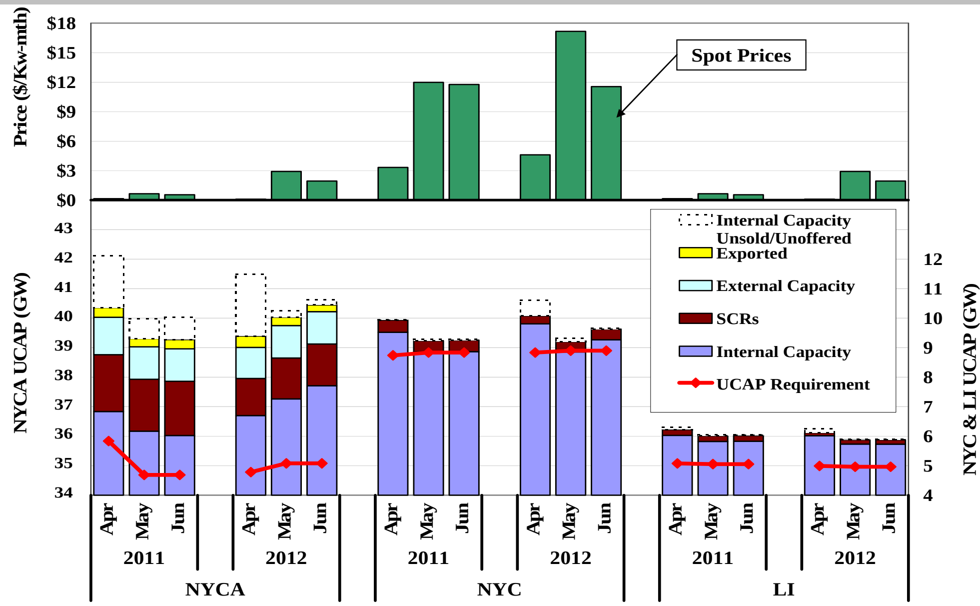
Capacity Market Results

- The following figure summarizes available and scheduled UCAP resources, the UCAP requirement, and the spot clearing prices in each capacity zone.
- Due to seasonal variations, there are higher levels of internal capacity in the Winter Capability Period (e.g., April) than in the Summer (e.g., May and June), leading to lower capacity prices in the Winter Capability Period.
- In New York City, UCAP spot prices rose to an average of $11.10/kW-month in the second quarter of 2012, up 23 percent from the second quarter of 2011.
- The increase in New York City was primarily due to:
  - ✓ The deployment of a higher new demand curve;
  - ✓ An increase in the Local Capacity Requirement from 81 percent to 83 percent in Summer 2012; and
  - ✓ Nearly 600 MW of capacity was retired or mothballed over the same period.
  - ✓ However, the increase was partly offset by new entry of a 550 MW facility in July 2011 and a 510 MW facility in June 2012.

Capacity Market Results

- In Rest of State and Long Island, spot prices averaged $1.65/kW-month in the second quarter, up from $0.45/kW-month in the second quarter of 2011.
  - ✓ Long Island and Rest of State clearing prices were equal during the two quarters, reflecting that Long Island had more capacity than needed to satisfy the local capacity requirement.
- Clearing prices outside New York City rose because of the following factors:
  - ✓ Decreased sales of internal capacity due to the retirement and mothballing of generation of over 600 MW, primarily in New York City.
  - ✓ The NYCA ICAP requirement rose 840 MW from the 2011/12 capability year to 2012/2013 capability year because:
    - – The summer peak load forecast for NYCA increased nearly 600 MW; and the installed capacity requirement rose from 115.5 percent to 116 percent.
  - ✓ A 400 MW decrease from SCRs. (After recent changes in the baseline calculation method, some RIPs failed to report the necessary verification data. A subsequent tariff waiver permitted NYISO to accept late data and recalculate performance factors for enrollment in July 2012 auction.)
  - ✓ However, these factors were offset by increased sales of internal capacity following the entry of new supply in July 2011 and June 2012.

Capacity Market Results



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

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