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

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Highlights and Market Summary: Energy Market

- This report summarizes market outcomes in the third 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 nearly $60/MWh statewide, down 8 percent from the same quarter in 2011. The following factors contributed to this reduction:
  - ✓ Natural gas prices fell 24 to 35 percent from a year ago;
  - ✓ Over 500 MW of new generating capacity entered in New York City; but
  - ✓ These factors were partly offset by the Neptune outage and multiple retirements.
- Consistency between day-ahead and real-time energy prices improved in most areas in the third quarter of 2012.
  - ✓ However, price volatility rose on Long Island during tight conditions, which were more frequent because of the Neptune outage and multiple retirements.
- Day-ahead congestion revenue rose 8 percent from last year to $130 million.
  - ✓ Congestion increased into Long Island, across the HQ interface, and in West Zone.
  - ✓ However, the increase was offset by: a) lower natural gas prices, which reduced west-to-east congestion and congestion-related re-dispatch costs; and b) new generation and transmission in New York City.

Highlights and Market Summary: Capacity Market

- UCAP spot prices rose significantly in the third quarter of 2012 compared to the same quarter of last year.
  - ✓ In the third quarter of 2012, spot prices averaged \$10.69/kW-month in New York City, \$3.57/kW-month on Long Island, and \$2.09/kW-month in Rest of State.
- The following factors contributed to the increases in spot prices across the state.
  - ✓ Decreased sales of internal capacity that was due to the retirement and mothballing of nearly 1.3 GW of generation, which primarily include:
    - 590 MW in New York City since early 2012;
    - 330 MW on Long Island since July 2012; and
    - 370 MW in the West since September 2012.
  - ✓ The 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 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.
  - ✓ However, these factors were partly offset by increased sales of internal capacity following the entry of a 500 MW facility in New York City in June 2012.

Highlights and Market Summary: Uplift and Revenue Shortfalls

- Lower natural gas prices were a primary driver of reductions for all categories of uplift in the third quarter of 2012.
- The uplift from guarantee payments fell to a total of $35 million, down 42 percent from the third quarter of 2011.
  - ✓ Less commitment for reliability in NYC and Long Island and less OOM dispatch for local reliability on Long Island also contributed to lower guarantee payments.
  - ✓ However, these were partly offset by more frequent reliability commitment in Western New York.
- Day-ahead congestion shortfalls were $5 million, down 74 percent from the third quarter of 2011.
  - ✓ The reduction reflected less west-to-east congestion in Upstate NY and fewer significant transmission outages in NYC and into Southeast NY.
- Balancing congestion shortfalls were $9 million, down 63 percent from the third quarter of 2011.
  - ✓ The decrease was largely driven by the overall reduction in congestion resulting from lower gas prices and good operating performance during TSAs.
  - ✓ The vast majority of the shortfalls in this quarter accrued during TSA operations on several days.

Energy and Ancillary Services Markets

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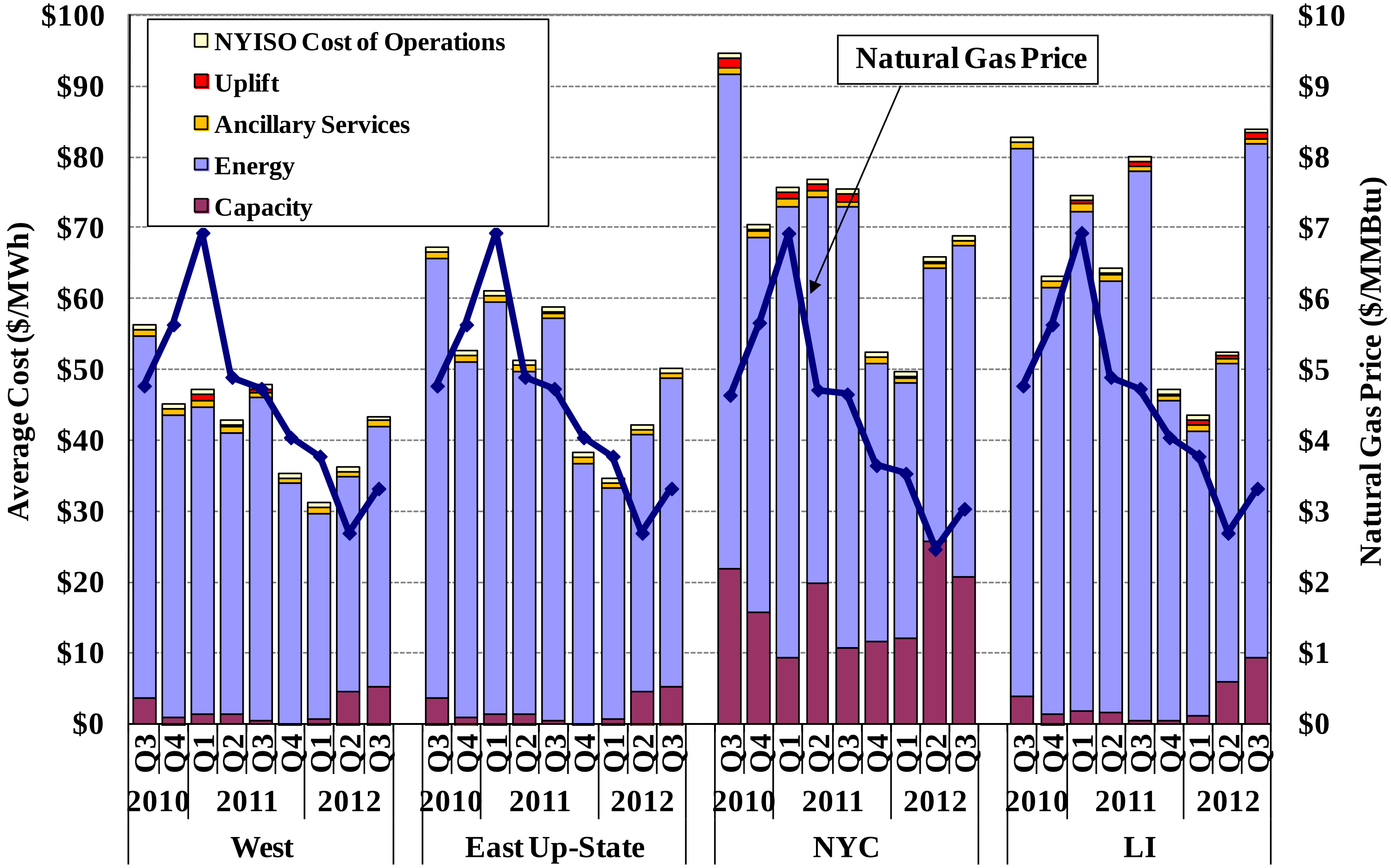
All-In Price

- 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 approximately $43/MWh in West NY to $84/MWh on Long Island, up 5 percent on Long Island and down 9 to 16 percent elsewhere from the third quarter of 2011.
  - ✓ Energy prices fell 7 percent on Long Island and 19 to 25 percent elsewhere due to:
    - – Lower natural gas prices, which fell 24 to 35 percent;
    - – The entry of a 500 MW new peaking facility in NYC;
    - – These were partly offset by the loss of imports across the Neptune line.
  - ✓ However, the capacity component rose significantly in all areas, primarily because:
    - – ICAP requirements increased in NYC (by 220 MW) and NYCA (by 840 MW);
    - – Sales of internal capacity decreased as generation retired and mothballed (590 MW in NYC, 330 MW on LI, and 370 MW in the West); but
    - – These factors were partially offset by a new generator in NYC.

All-In Energy Price by Region



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

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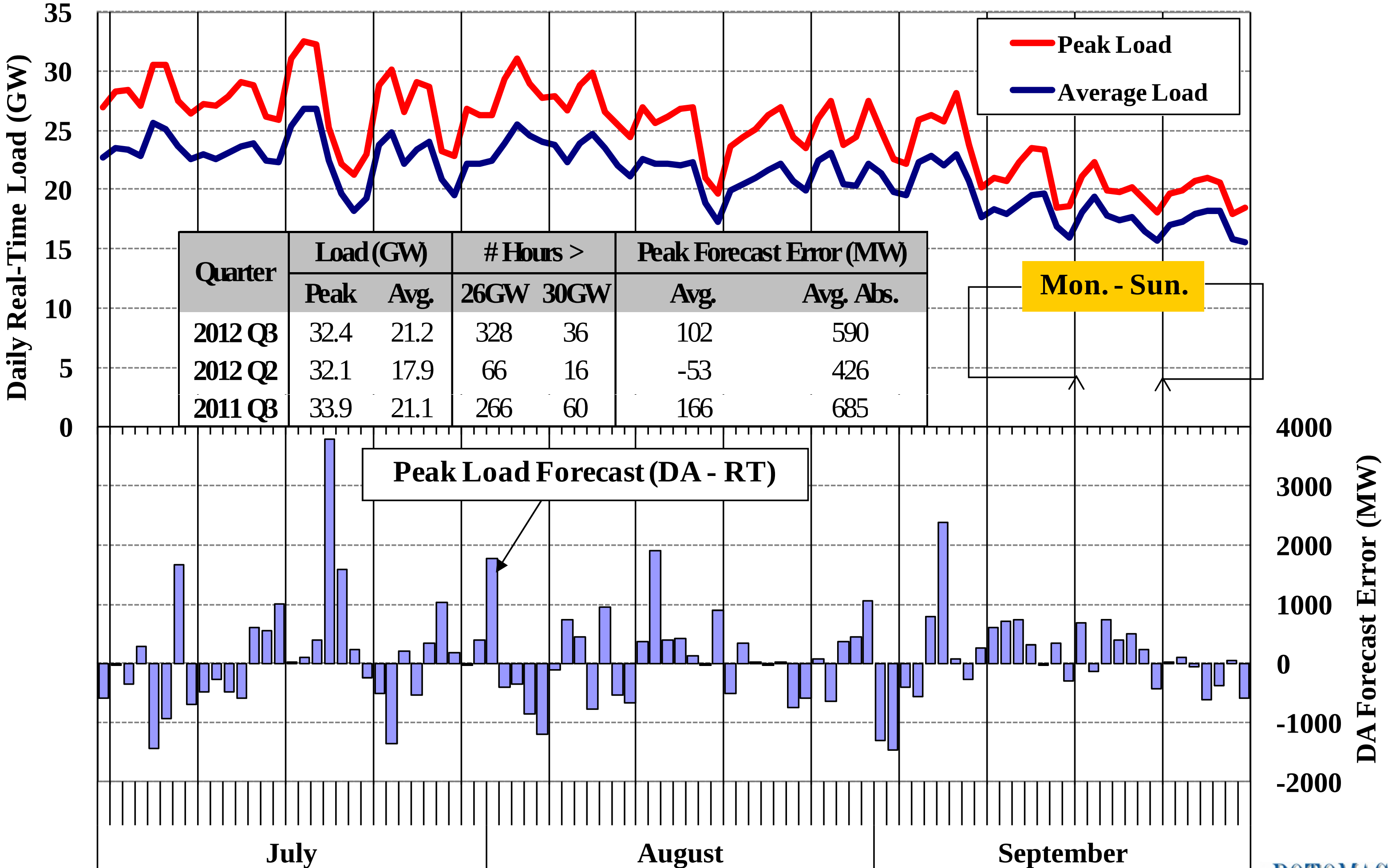
Load Forecast and Actual Load

- The following figure shows the average load, the peak load, and the day-ahead peak load forecast error on each day of the quarter.
  - ✓ The table compares key statistics for the third quarter of 2012 to the previous quarter and the third quarter of 2011.
- Load rose considerably from the previous quarter due to hotter summer weather and was comparable to the same quarter in 2011.
  - ✓ Load averaged 21.2 GW in the third quarter of 2012, up 19 percent from the previous quarter and comparable to the third quarter of 2011.
  - ✓ Load peaked on July17 at 32.4 GW, down 4 percent from a year ago.
  - ✓ Load exceeded 30 GW for 36 hours in the third quarter, compared to 16 hours in the previous quarter and 60 hours from the same quarter of 2011.
- Peak load forecasting was generally good during the quarter, although the magnitude of forecast errors increased from the previous quarter as load levels increased and were more weather-sensitive.
  - ✓ The daily peak load forecast error exceeded 1 GW on 14 days and 2 GW on two days (July 19 & September 6).
  - ✓ On average, actual peak loads ran under the peak forecast by 102 MW, less than in the same quarter of 2011.

Load Forecast and Actual Load



Quarter	Load (GW)		# Hours >		Peak Forecast Error (MW)	
	Peak	Avg.	26GW	30GW	Avg.	Avg. Abs.
2012 Q3	32.4	21.2	328	36	102	590
2012 Q2	32.1	17.9	66	16	-53	426
2011 Q3	33.9	21.1	266	60	166	685

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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 $3.04/MMbtu in NYC and $3.32/MMbtu in upstate NY. These prices are up nearly 25 percent from the previous quarter and down nearly 35 and 30 percent, respectively, from the third quarter of 2011.
  - ✓ Gas prices were relatively stable, ranging between $2.50 and $4.00/MMbtu throughout the third quarter.
- Fuel oil prices increased steadily throughout most of the third quarter of 2012.
  - ✓ Fuel oil #2 prices increased 3 percent from the previous quarter, and was comparable to the third quarter of 2011.
  - ✓ Fuel oil #6 prices fell roughly 2 percent from both the previous quarter and the third quarter of 2011.
- Natural gas was much less expensive than fuel oil, but some generators still burn oil because of:
  - ✓ Reliability reasons;
  - ✓ Difficulties obtaining natural gas; or
  - ✓ Unavailability of pipeline capacity.

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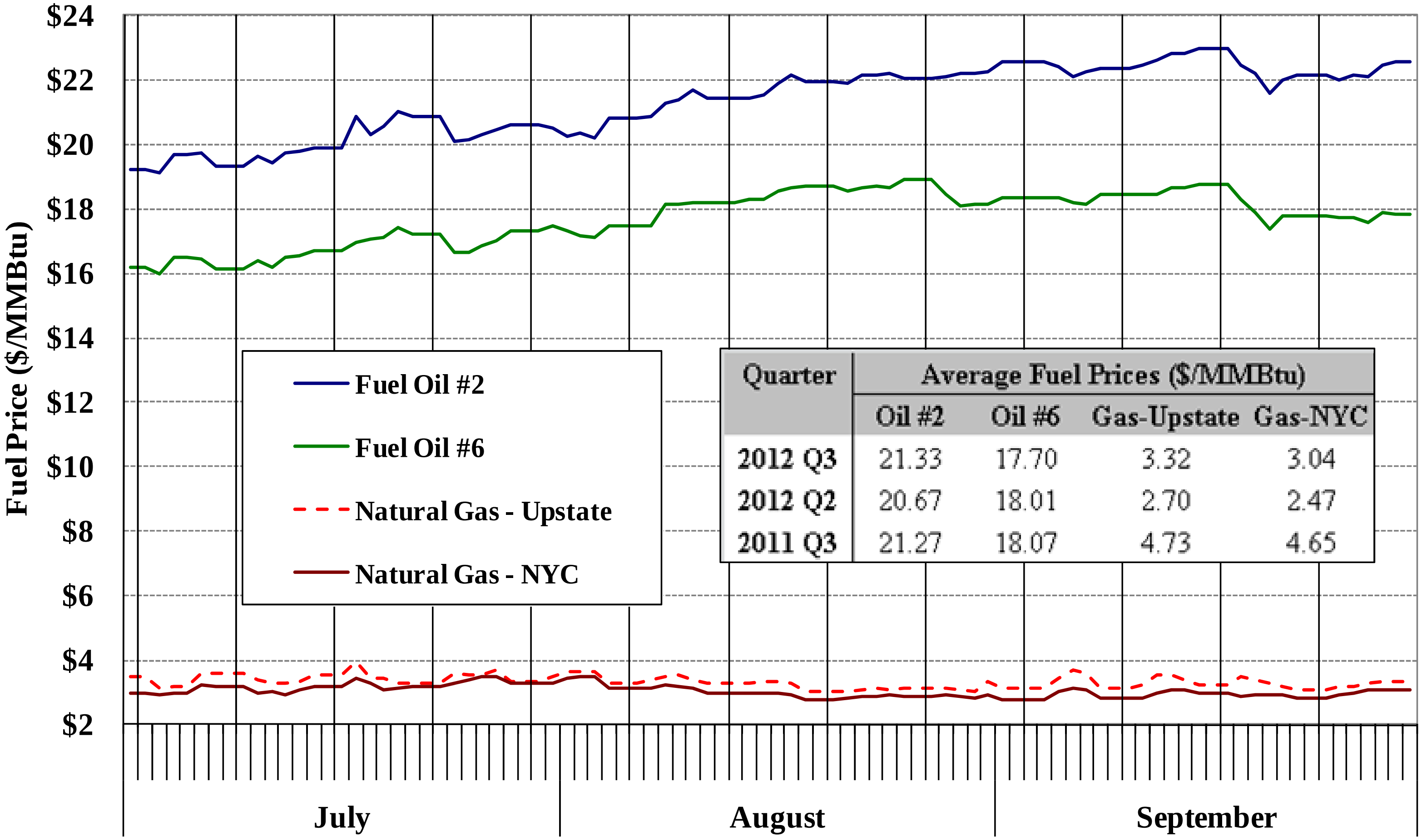
Natural Gas and Oil Prices



Quarter	Average Fuel Prices ($/MMBtu)			
	Oil #2	Oil #6	Gas-Upstate	Gas-NYC
2012 Q3	21.33	17.70	3.32	3.04
2012 Q2	20.67	18.01	2.70	2.47
2011 Q3	21.27	18.07	4.73	4.65

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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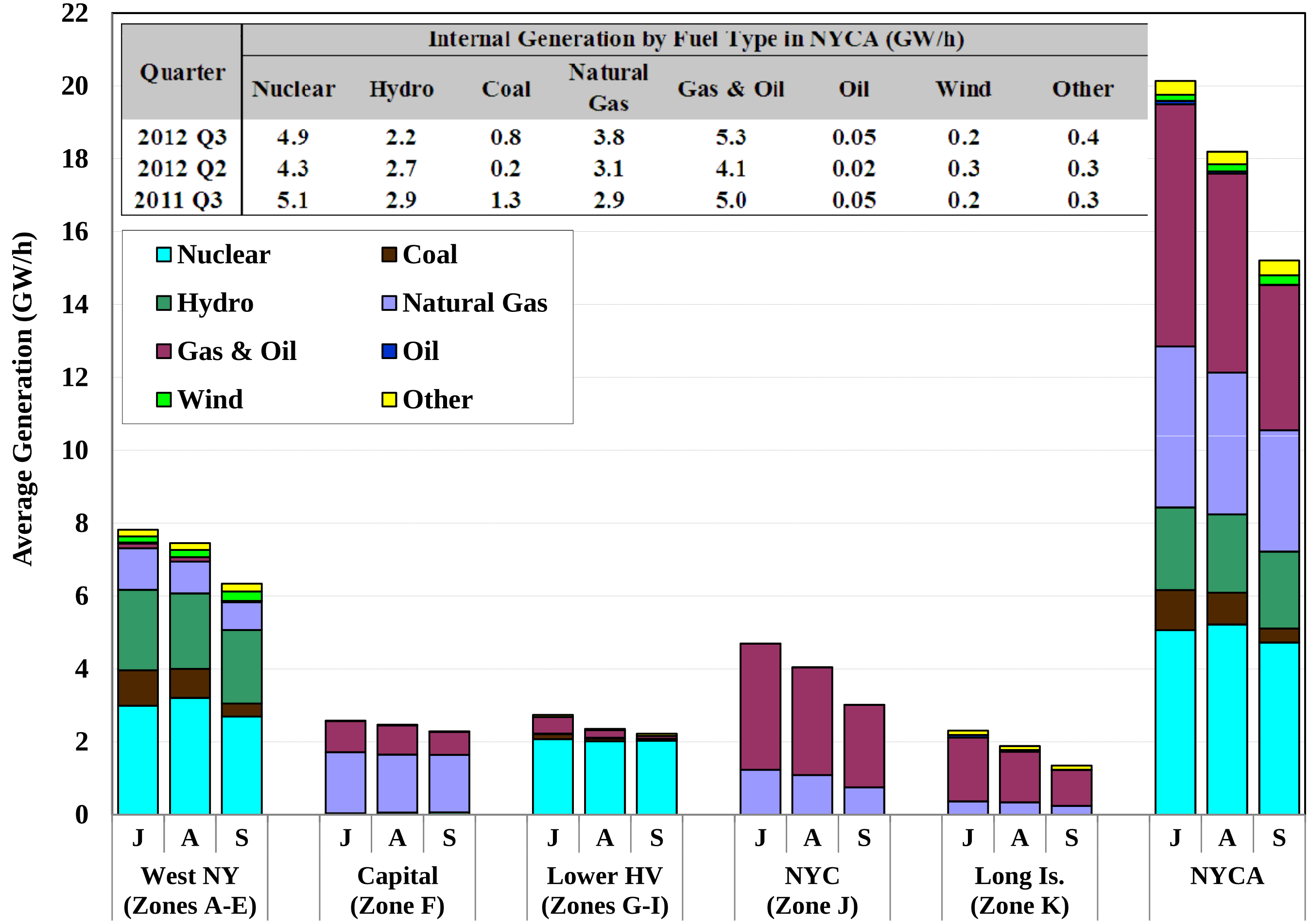
Generation Output by Fuel Type

- 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 third quarter of 2012.
  - ✓ Units that are able to burn gas and oil are categorized "Gas & Oil" and other units are categorized by their primary fuel type.
- 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 28 percent of output in the third quarter of 2012.
- Production from gas-only and gas & oil units rose considerably from a year ago (from 44 percent to 52 percent) as production from coal units fell from 7 percent to 4 percent over the same period. Natural gas usage has been increased by:
  - ✓ The reduction in natural gas prices relative to coal prices; and
  - ✓ The entry of new gas-fired capacity in New York City.
- Hydro resources in West NY and the Capital Zone accounted for 12 percent of output in the third quarter, down from 16 percent in the previous year.
- Wind units and other renewable resources produced about 3 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 Q3	4.9	2.2	0.8	3.8	5.3	0.05	0.2	0.4
2012 Q2	4.3	2.7	0.2	3.1	4.1	0.02	0.3	0.3
2011 Q3	5.1	2.9	1.3	2.9	5.0	0.05	0.2	0.3

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

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Fuel Types of Marginal Units in the Real-Time Market

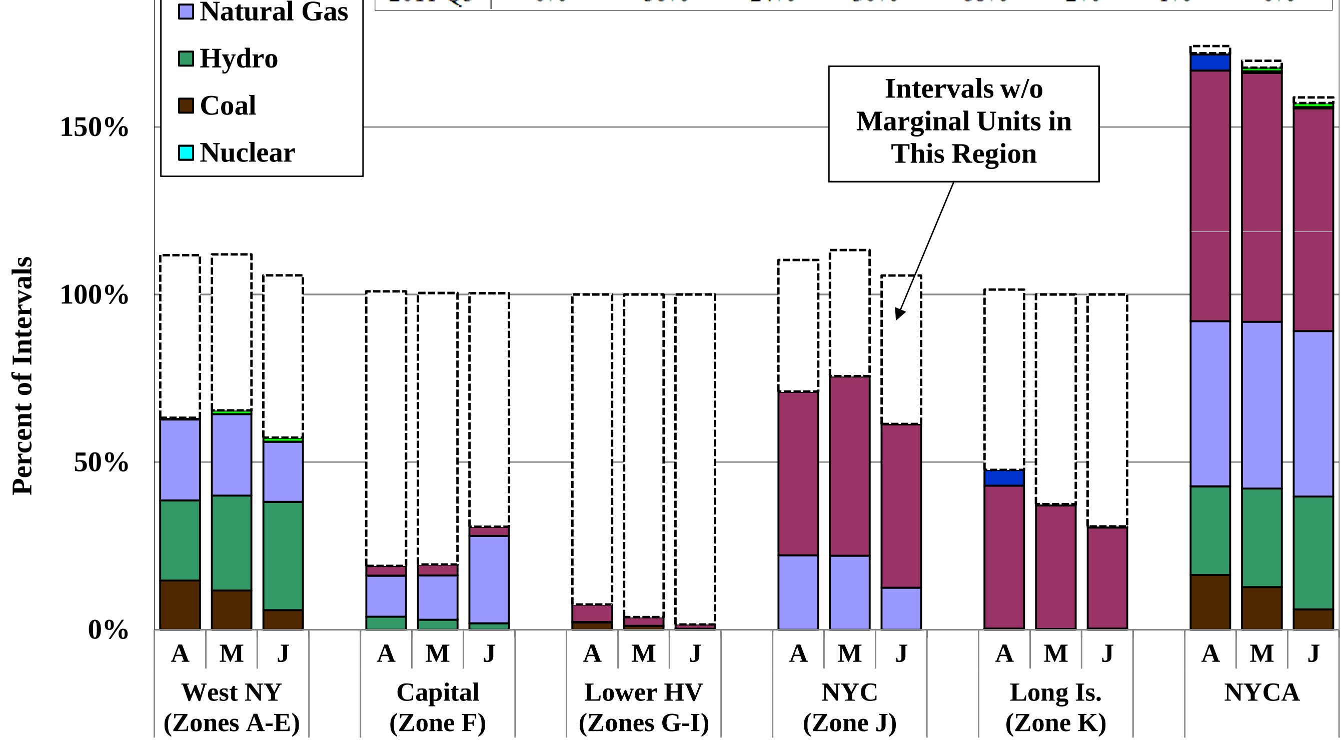
- The following figure summarizes how frequently each fuel type is on the margin and setting real-time energy prices.
- The fuel type for each generator is based on information from the Gold Book:
  - ✓ Generators listed in the Gold Book as using natural gas and fuel oil as their primary and secondary 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 third quarter of 2012.
  - ✓ Gas & oil resources were on the margin in 72 percent of the intervals, up from the previous year. These units are located primarily in NYC and Long Island.
  - ✓ Hydro resources (primarily in Western NY) set the prices in 30 percent of the intervals, down from prior periods. Some hydro resources have storage capability, allowing them to offer price-sensitively based on opportunity costs.
  - ✓ Gas-only resources were marginal in 49 percent of the intervals, sharply up from prior periods. These are primarily in Western NY and the Capital Zone.
    - The increase was due primarily to lower natural gas prices, which have led them to displace coal-fired resources, which are on the margin less frequently.
- Although other fuel types account for 18 percent of the generation capacity in NYCA, they were rarely on the margin in the third 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 occasionally 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 Q3	0%	30%	12%	49%	72%	2%	1%	0%
2012 Q2	0%	42%	1%	36%	64%	1%	1%	0%
2011 Q3	0%	36%	24%	30%	68%	2%	1%	0%



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

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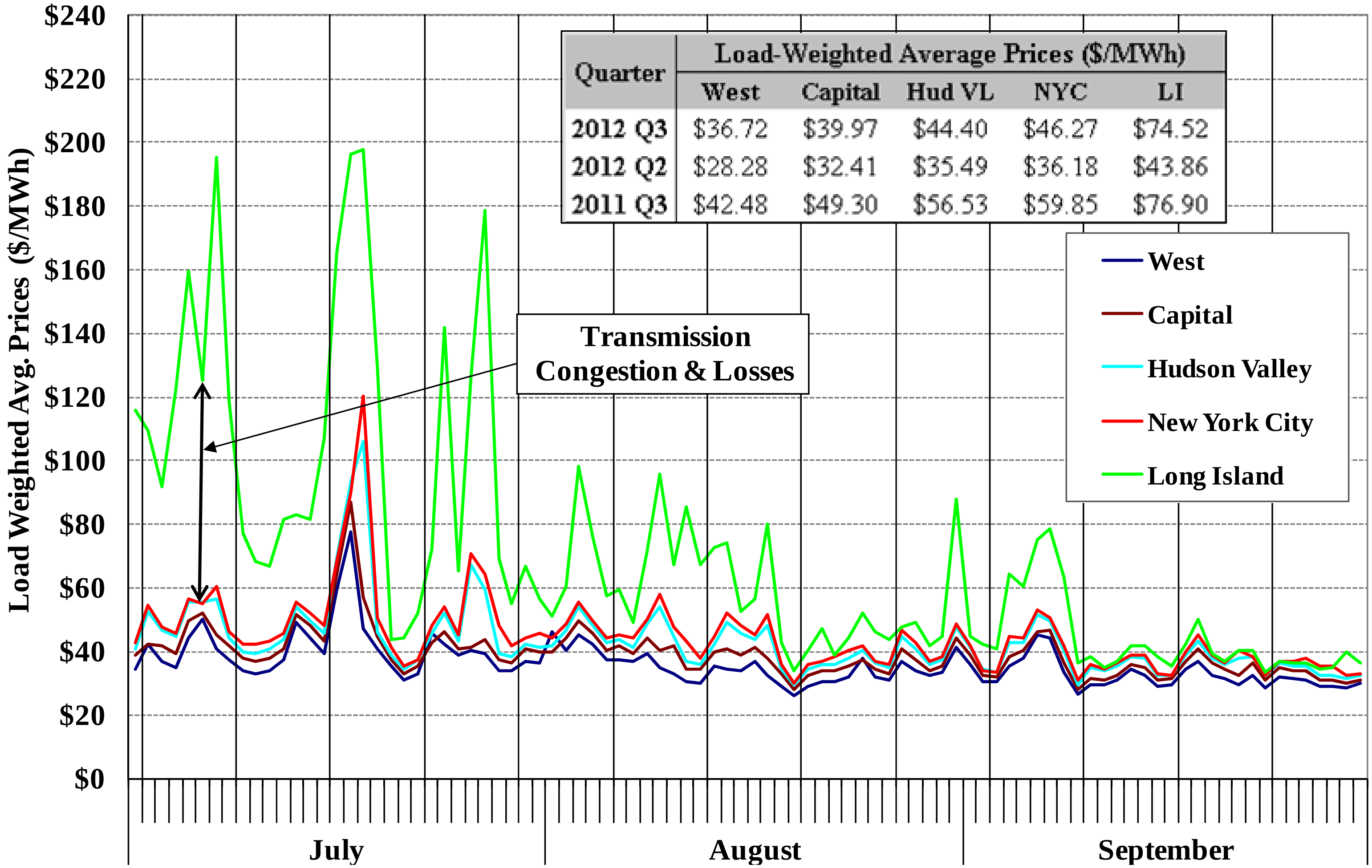
Day-Ahead and Real-Time Electricity Prices by Zone

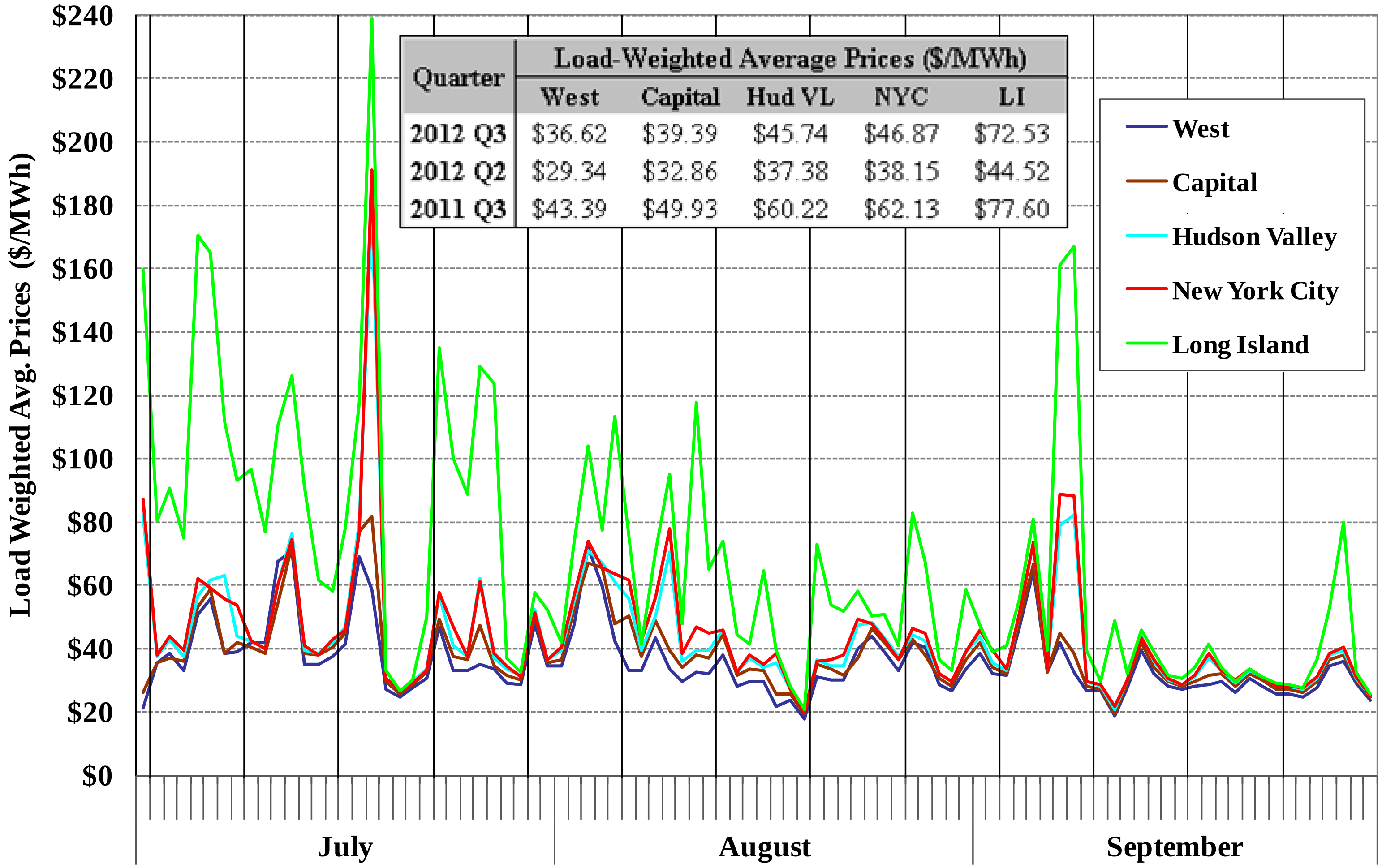
- The following two figures show load-weighted average day-ahead and real-time energy prices for five zones on each day in the third quarter of 2012.
  - ✓ DA prices should reflect probability-weighted expectations of real-time conditions.
- Average day-ahead prices ranged from \$37/MWh in the West Zone to \$75/MWh on Long Island, down 3 percent from the third quarter of 2011 on Long Island and 14 to 23 percent elsewhere.
  - ✓ The reduction from last year was consistent with the decrease in natural gas prices.
  - ✓ During the third quarter of 2012, average day-ahead prices trended downward from July to September, consistent with the falling load levels.
  - ✓ Long Island LBMPs were elevated on many days, especially in July, due largely to the outage affecting the Neptune line and several generator retirements.
- Prices are more volatile in the real-time market than in the day-ahead market. Unexpected events often lead to significant price spikes in real-time. For example,
  - ✓ TSAs occurred on 19 days, leading to elevated prices in Southeast NY, most notably on July 1 & 18, August 7 & 11, and September 7 & 8.
  - ✓ Prices across the state were significantly elevated on July 5 & 6 due partly to unexpectedly high loads and on July 11 & 12 when a large nuclear unit was forced out of service.

Day-Ahead Electricity Prices by Zone



Quarter	Load-Weighted Average Prices ($/MWh)				
	West	Capital	Hud VL	NYC	LI
2012 Q3	$36.72	$39.97	$44.40	$46.27	$74.52
2012 Q2	$28.28	$32.41	$35.49	$36.18	$43.86
2011 Q3	$42.48	$49.30	$56.53	$59.85	$76.90

Real-Time Electricity Prices by Zone



Quarter	Load-Weighted Average Prices ($/MWh)				
	West	Capital	Hud VL	NYC	LI
2012 Q3	$36.62	$39.39	$45.74	$46.87	$72.53
2012 Q2	$29.34	$32.86	$37.38	$38.15	$44.52
2011 Q3	$43.39	$49.93	$60.22	$62.13	$77.60

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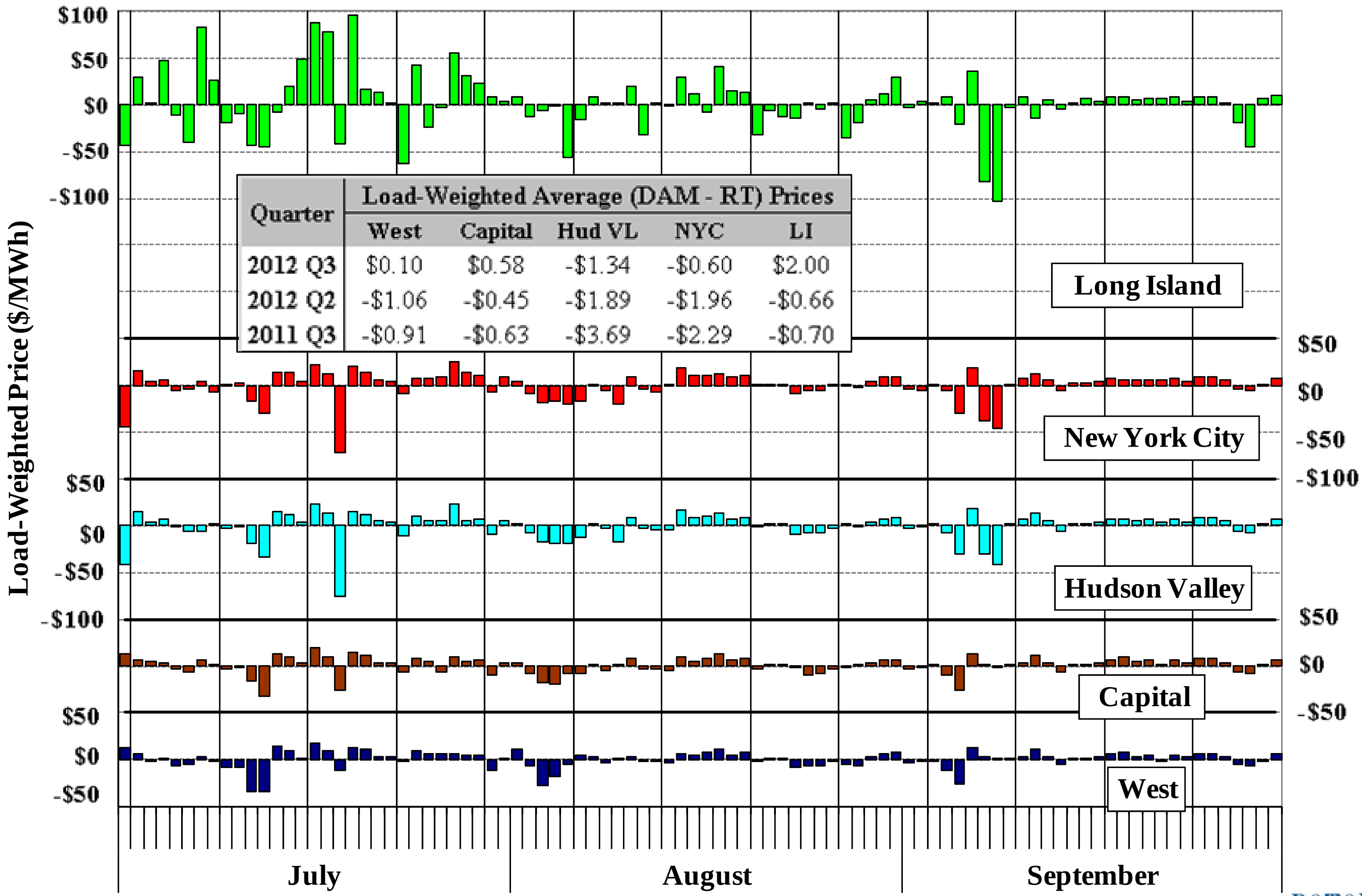
Convergence Between Day-Ahead and Real-Time Prices

- 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 third quarter of 2012.
  - ✓ Convergence should be measured over longer timeframes since random factors can cause large differences in prices on individual days – hence, the table shows the average price convergence over the entire quarter.
- Day-ahead and real-time prices were reasonably consistent on most days in the third quarter of 2012.
- Convergence improved from previous summers in all areas except Long Island.
  - ✓ Average day-ahead prices were within 3 percent of average real-time prices in all areas in the third quarter of 2012.
    - – The largest price differences occurred on July 18 and September 7 & 8 in Southeast New York, primarily because of TSAs called during the afternoons.
  - ✓ Price volatility increased on Long Island as supply was tighter on high load days as a result of the Neptune outage and several retirements.

Convergence Between Day-Ahead and Real-Time Prices



Quarter	Load-Weighted Average (DAM - RT) Prices				
	West	Capital	Hud VL	NYC	LI
2012 Q3	$0.10	$0.58	-$1.34	-$0.60	$2.00
2012 Q2	-$1.06	-$0.45	-$1.89	-$1.96	-$0.66
2011 Q3	-$0.91	-$0.63	-$3.69	-$2.29	-$0.70

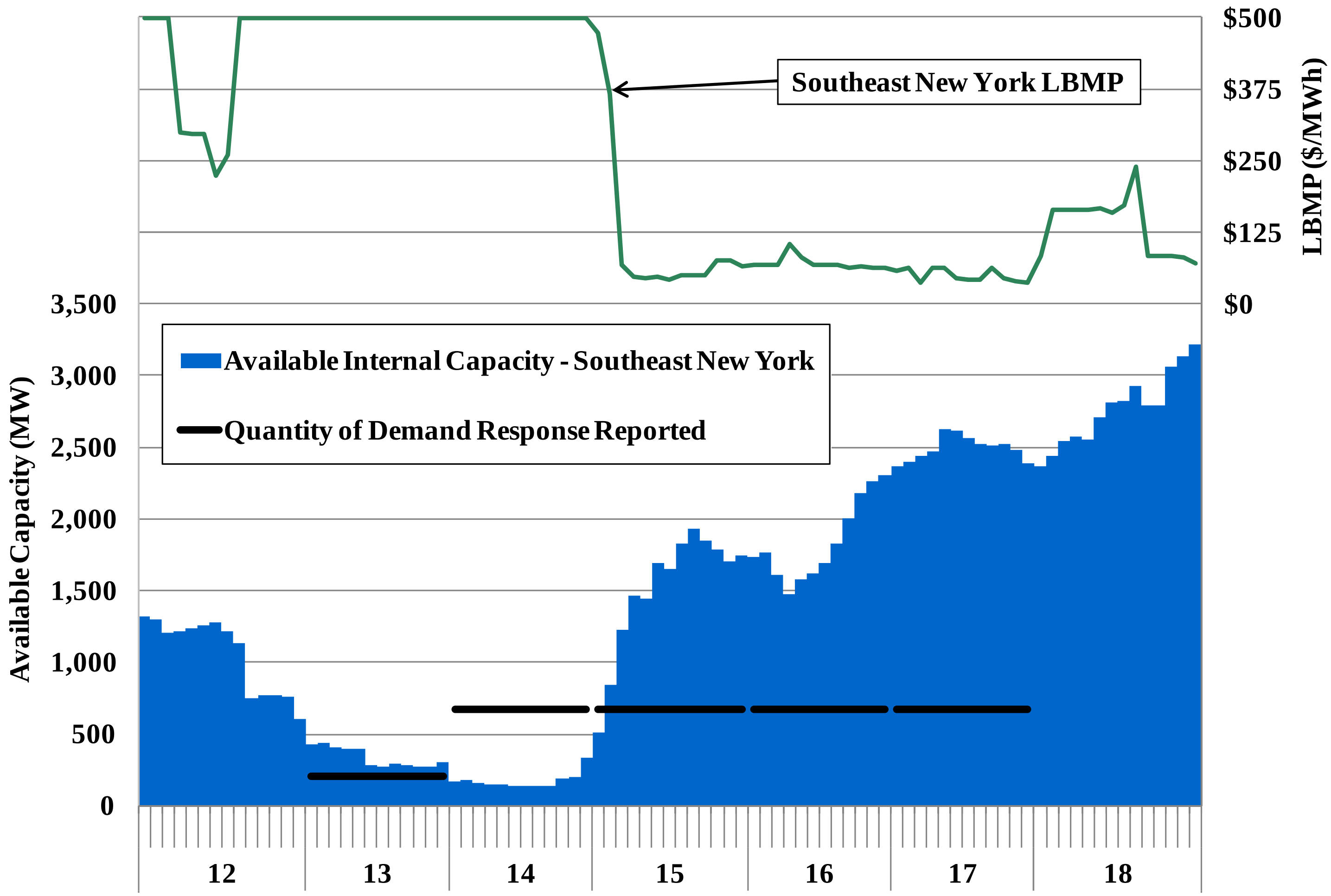
Emergency Demand Response Activations

- NYISO activated demand response on both days when load exceeded 32 GW.
  - ✓ On July 17, load peaked at 32.4 GW and 87 MW of DR was activated.
    - EDRP/SCRs were activated in zone B from HB 14 to 17 for forecasted reserve shortages to reduce Rochester 345/115 kV transformer loadings.
  - ✓ On July 18, load peaked at 32.2 GW and 676 MW of DR was activated.
    - EDRP/SCRs were activated in Zone J from HB 13 to 17 and in Zones G, H, I, K from HB 14 to 17 for forecasted reserve shortages and SENY transmission security.
    - A TSA was in effect from 12:30 to 19:10 on this day.
- 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.
- Hence, the inflexibility of DR resources can lead NYISO to activate an amount of DR that results in substantial excess capacity during a portion of the event.
  - ✓ An excess that is larger than the quantity of DR activated for an entire event may indicate that the activation was not needed in retrospect.

Emergency Demand Response Activations

- The following figure evaluates two aspects of market outcomes on July 18 when DR was activated for SENY transmission security.
  - ✓ First, the amount of DR activation (as reported by RIPs) is compared to the amount of internal capacity ultimately available in each real-time interval during the event.
    - – Available capacity includes unloaded capacity of online units and the capacity of offline peaking units up to the unit's Upper Operating Limit ("UOL").
  - ✓ Second, LBMPs in SENY (the Millwood Zone LBMP is representative) is shown compared with the cost of curtailing DR resources (typically $500/MWh).
- In the initial phase of the TSA (HB 13 & 14), the activation of DR allowed the NYISO to maintain sufficient resources in SENY – available capacity was less than the DR called and LBMPs exceeded $500/MWh throughout both hours.
- From HB 15 to 17, the amount of available capacity in SENY rose considerably, resulting in LBMPs that were well below the marginal cost of the DR (most DR resources are paid $500/MWh to curtail).
  - ✓ The available internal capacity in SENY exceeded the amount of DR by more than 1 GW during most of the three hours.
  - ✓ The causes of the excess available internal capacity are evaluated in the next figure.

RT Prices and Available Capacity – Southeast NY During July 18 DR Activation



Note: LBMPs exceeding $500/MWh are shown at $500/MWh in the figure.

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Variations in Supply and Demand in SENY
During July 18 DR Activation

- The next figure shows factors that contributed to the surplus capacity on July 18.
- In the real time, most generators respond to 5-minute dispatch instructions, while other supply and demand factors are not dispatchable (e.g., load, net imports, etc.).
  - ✓ Large variations in the 5-minute RT LBMPs are usually driven by large changes in load and other inflexible factors.
- The figure summarizes the changes in supply and demand and most (excluding dispatch) that contributed to price variations on July 18.
  - ✓ The figure shows the cumulative impact of these supply and demand variations in each interval relative to start of the examined period at 12:00 pm (noon).
    - *Positive* MW values indicate increases in demand or decreases in supply, which tend to contribute to *higher* LBMPs.
    - *Negative* MW values indicate decreases in demand or increases in supply, which tend to contribute to *lower* LBMPs.
  - ✓ The figure does not show the effect of the TSA, which began at 12:30 and which reduced flows into SENY from the rest of Upstate New York.
- The figure summarizes real-time variations in the following factors:
  - ✓ Load in Southeast New York – including effects of DR activation.

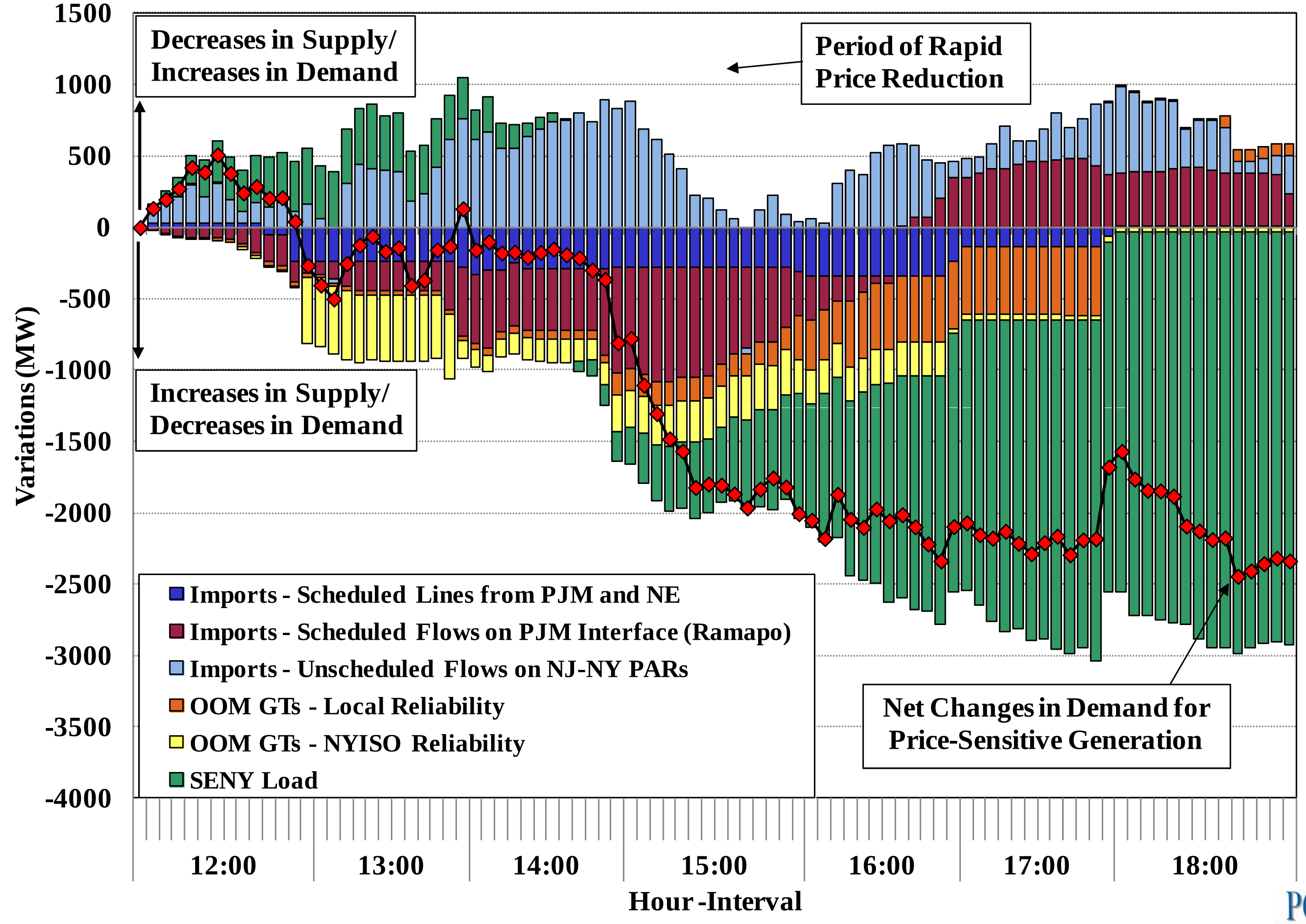
(list continued on next slide)

Variations in Supply and Demand in SENY
During July 18 DR Activation

- ✓ Net imports across the Scheduled Lines from PJM and ISO-NE – including net imports across the 1385 line, the Cross Sound Cable, and the Linden VFT.
- ✓ Scheduled flows across the primary PJM interface into SENY – including the portion of net imports expected to flow into SENY across the Ramapo line.
- ✓ Unscheduled flows on the PAR-controlled lines between NJ and NY – The total difference between actual and expected flows into SENY on ABC, JK, & Ramapo.
- ✓ GTs committed OOM for local reliability & GTs OOM for NYISO reliability.

- The figure shows that net demand fell by 200 MW between noon and 14:50, but then fell by a total of almost 2000 MW by 15:30, which explains the increase in available capacity shown on the prior figure.
- The following factors changed most significantly between 14:50 and 15:30, contributing to the substantial reduction in net demand and LBMPs:
  - ✓ Load fell approximately 420 MW due to a sudden change in weather patterns;
  - ✓ Scheduled imports across the primary interface with PJM expected to flow into SENY (i.e., expected Ramapo flows) rose approximately 245 MW;
  - ✓ Unscheduled flows from NY across the PAR-controlled lines into New Jersey fell approximately 620 MW;
  - ✓ 240 MW of GTs were kept online OOM after the decline in LBMPs.

Variations in Supply and Demand in SENY
During July 18 DR Activation



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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 reserves prices in eastern NY, which reflect the cost of requiring:
    - 330 MW of 10-minute spinning reserves in eastern NY;
    - 655 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 655 MW of 10-minute spinning reserves statewide.
  - ✓ Regulation prices, which reflect the cost of requiring up to 275 MW of regulation, depending upon season and time of day.
- 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

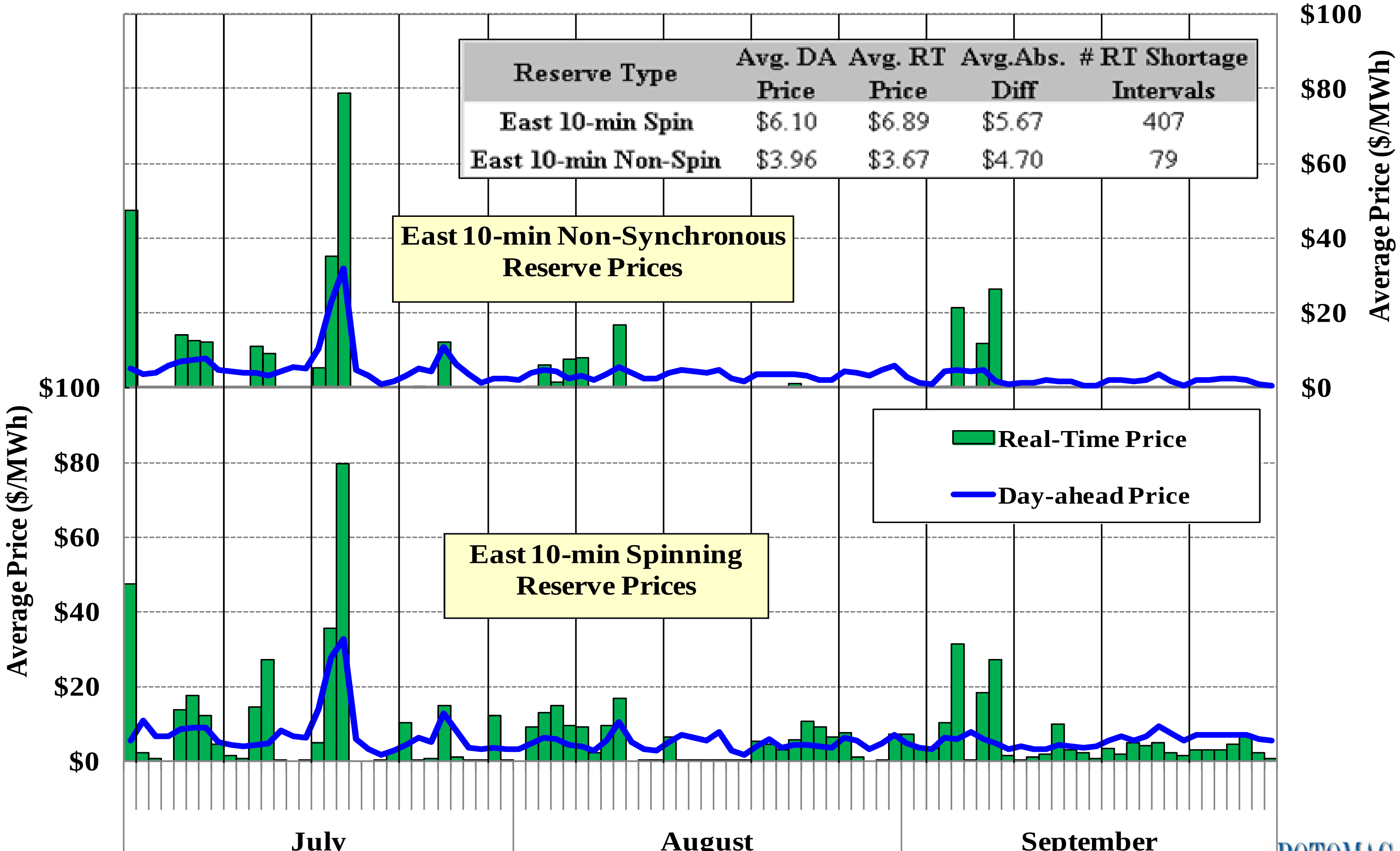
- Reserve prices are relatively consistent in the day-ahead market, but are much more volatile in the real-time market.
  - ✓ DAM reserves prices are based on suppliers' offers, which depend on expectations of real-time prices and the risks associated with selling reserves in the DAM.
  - ✓ Real-time 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 can rise sharply during periods of tight supply and high energy demand, which can be difficult for the day-ahead market to predict.
- Average day-ahead prices were consistent with average real-time prices in eastern NY for 10-minute spinning and non-spinning reserves in the third quarter of 2012.
  - ✓ Day-ahead and real-time prices were more consistent than in previous years.
    - – Changes in day-ahead operating practices improved the consistency of energy and reserves schedules between the day-ahead and real-time for some units.
  - ✓ However, average real-time prices are still far higher than average day-ahead prices during high demand periods.
    - – For example, on afternoons when forecast load exceeded 27 GW, average RT prices were 88 percent higher than average DAM prices for 10-minute spinning reserve.
- In the third quarter, average day-ahead prices were higher than average real-time prices for 10-minute spinning reserves in western NY 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 328 intervals ($25 demand curve);
  - ✓ Eastern 10-minute total reserves in 79 intervals ($500 demand curve);
  - ✓ Statewide 10-minute spinning reserves in 0 intervals ($500 demand curve); and
  - ✓ Regulation in 359 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 407 intervals of shortage pricing: 328 of eastern 10-minute spin, 79 of eastern 10-minute total reserves, and 0 of state-wide 10-minute spin.
- Eastern 10-minute total reserve shortages occurred on nine days in the third quarter of 2012.
  - ✓ Two days (July 1 & 18) accounted for nearly 60 percent of the shortages.
    - – Unexpectedly high loads and TSA events resulted in very tight operating conditions on these days.

Day-Ahead and Real-Time Ancillary Services Prices

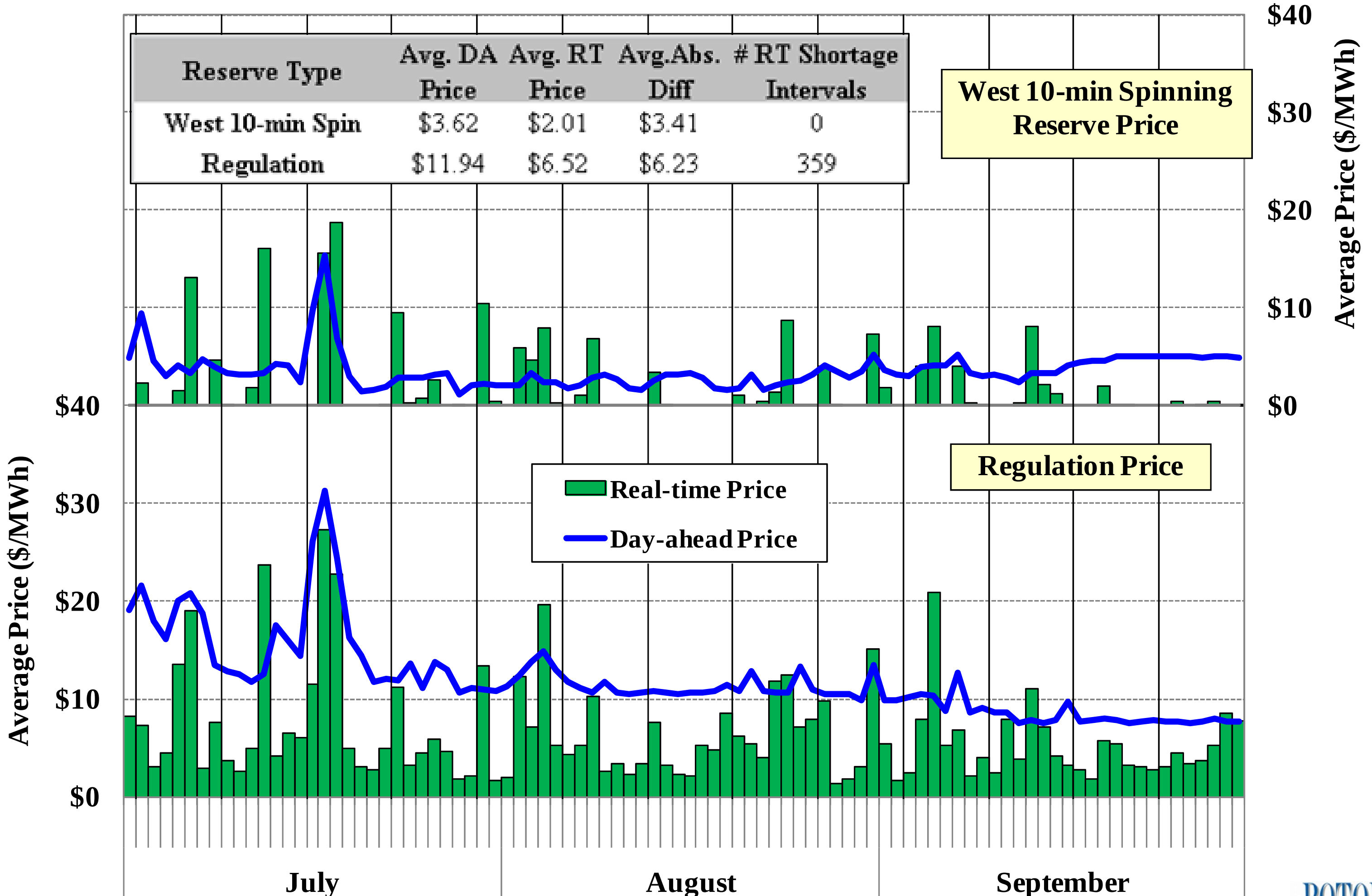
Eastern 10-Minute Spinning and Non-Spinning Reserves



Reserve Type	Avg. DA Price	Avg. RT Price	Avg.Abs. Diff	# RT Shortage Intervals
East 10-min Spin	$6.10	$6.89	$5.67	407
East 10-min Non-Spin	$3.96	$3.67	$4.70	79

Day-Ahead and Real-Time Ancillary Services Prices

Western 10-Minute Spinning Reserves and Regulation



Reserve Type	Avg. DA Price	Avg. RT Price	Avg.Abs. Diff	# RT Shortage Intervals
West 10-min Spin	$3.62	$2.01	$3.41	0
Regulation	$11.94	$6.52	$6.23	359

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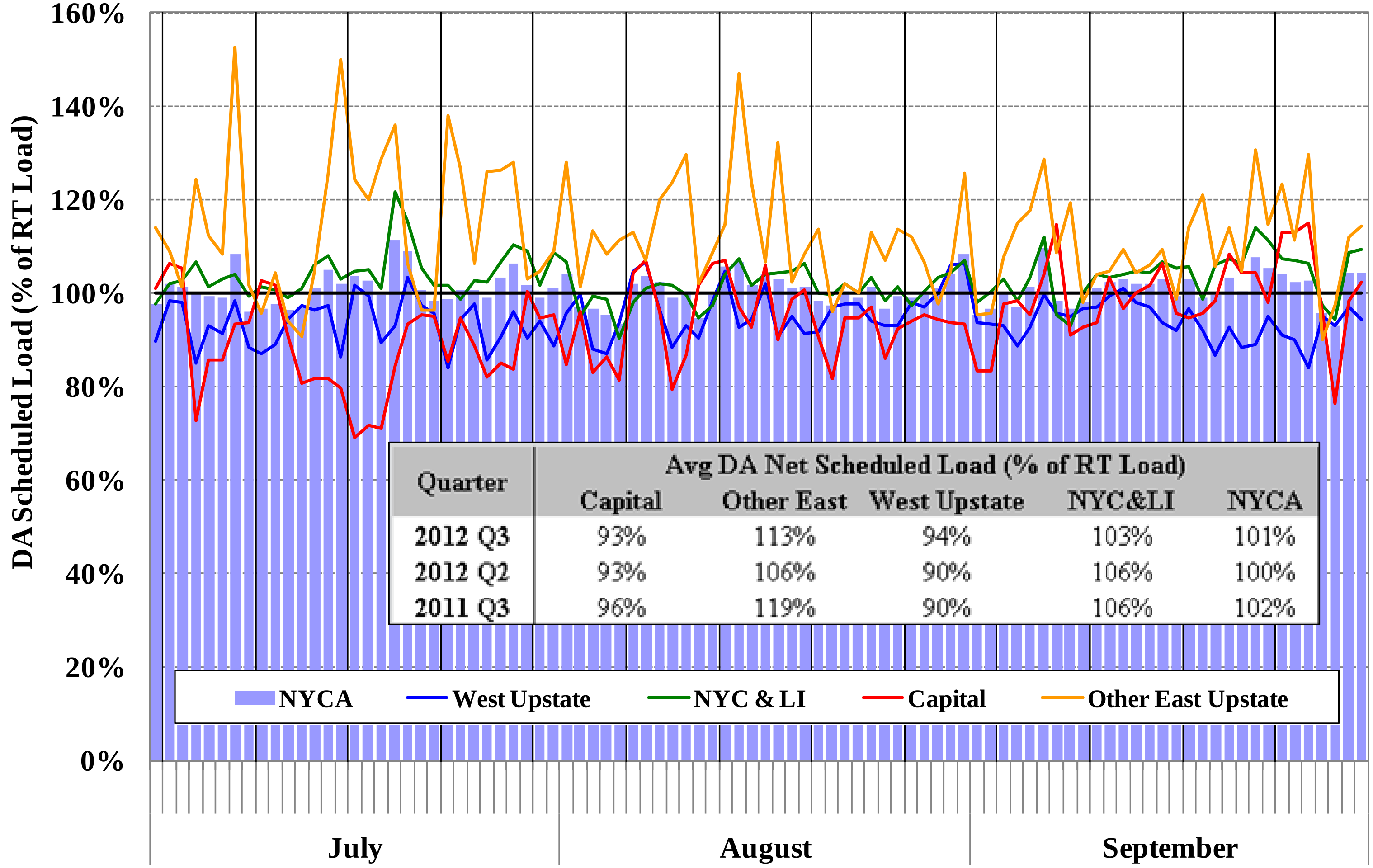
Day-ahead Scheduled Load and Actual Load

- 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 101 percent of actual load in NYCA in the third quarter, modestly higher than the previous quarter.
  - ✓ 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.
  - ✓ Over-scheduling is also balanced by differences between the volume of day-ahead and real-time imports, particularly from New England where day-ahead imports exceeded real-time imports by nearly 400 MW during peak hours.
- Load scheduling is more variable regionally -- load continued to generally be under-scheduled outside Southeast NY and over-scheduled in Southeast NY.
  - ✓ 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.

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 Q3	93%	113%	94%	103%	101%
2012 Q2	93%	106%	90%	106%	100%
2011 Q3	96%	119%	90%	106%	102%

POTOMAC ECONOMICS

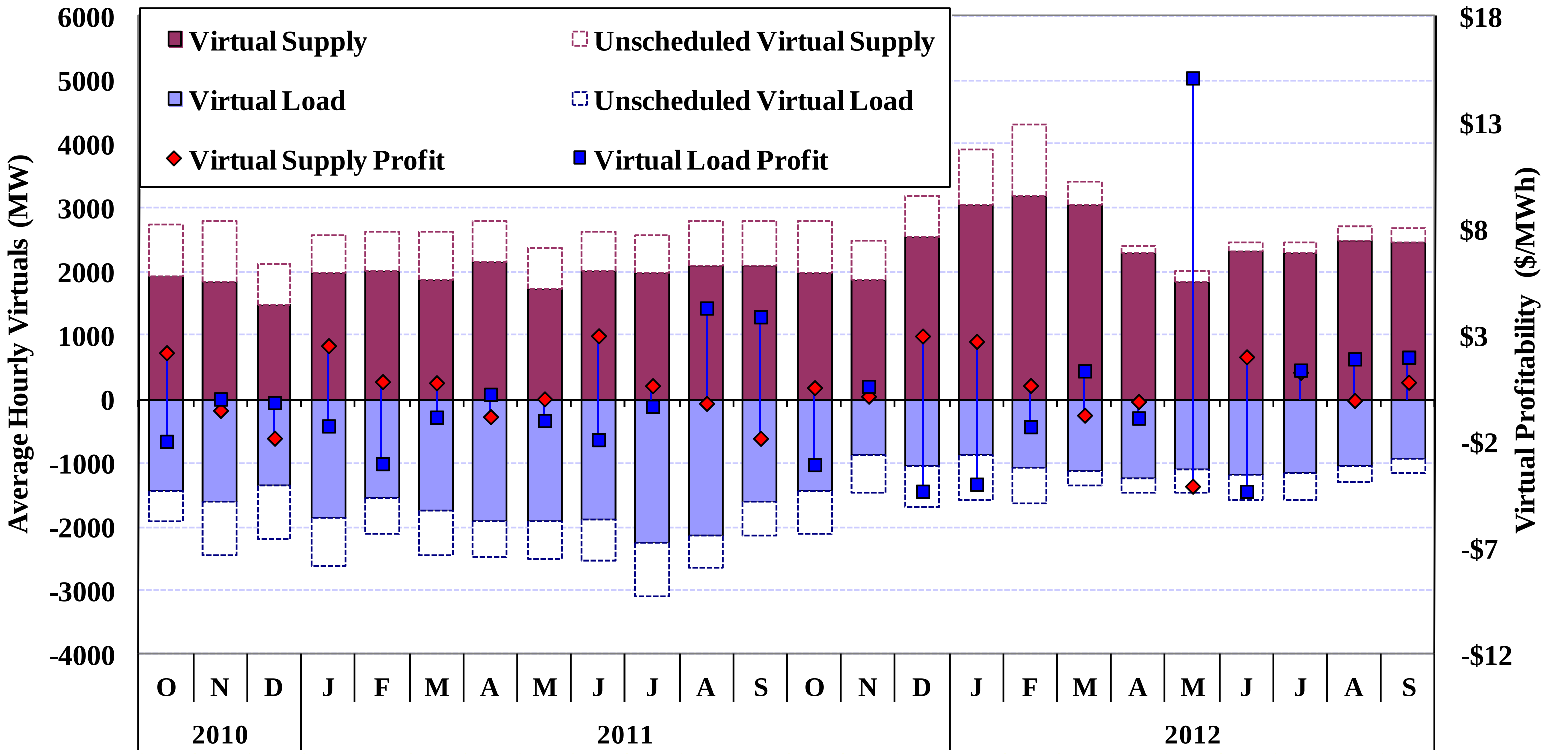
Virtual Trading Activity

- 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 third quarter of 2012 was low.
  - ✓ The transactions with notable profits or losses were primarily associated with real-time price volatility, which do not raise manipulation concerns.

POTOMAC ECONOMICS

Virtual Trading Volumes and Profitability

October 2010 to September 2012

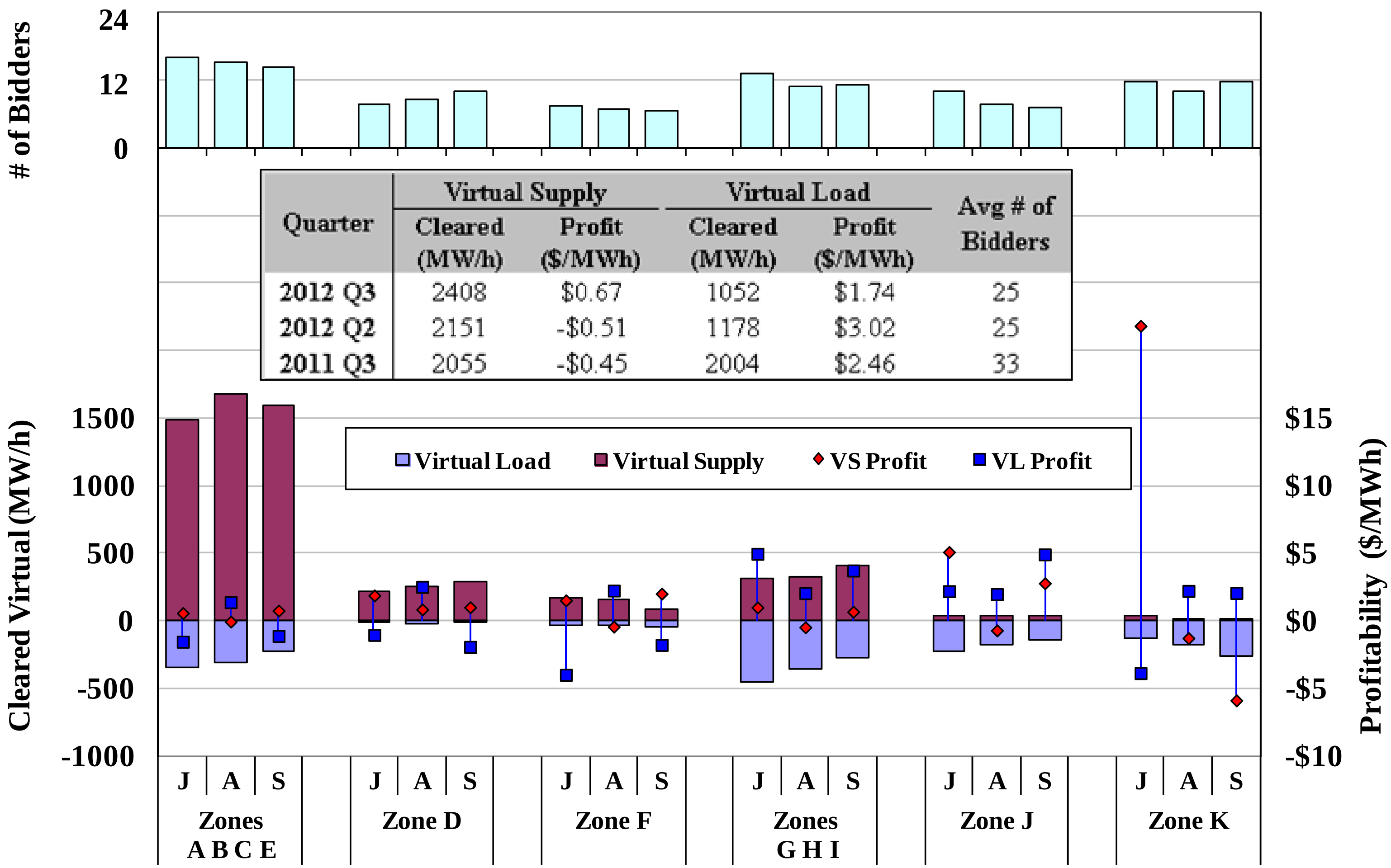


		2010 O	2010 N	2010 D	2011 J	2011 F	2011 M	2011 A	2011 M	2011 J	2011 J	2011 A	2011 S	2011 O	2011 N	2011 D	2012 J	2012 F	2012 M	2012 A	2012 M	2012 J	2012 J	2012 A	2012 S
Profit > 50% of Avg. Zone Price	MW	117	135	221	446	193	161	122	233	350	376	337	186	98	100	208	275	96	224	220	128	345	300	208	158
	%	3%	4%	8%	12%	5%	4%	3%	6%	9%	9%	8%	5%	3%	4%	6%	7%	2%	5%	6%	4%	10%	9%	6%	5%
Loss > 50% of Avg. Zone Price	MW	95	131	273	401	244	133	120	277	381	434	334	122	133	120	193	177	125	283	261	132	377	337	220	129
	%	3%	4%	10%	11%	7%	4%	3%	8%	10%	10%	8%	3%	4%	4%	5%	5%	3%	7%	7%	4%	11%	10%	6%	4%

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 third quarter of 2012, consistent with prior periods.
  - ✓ Virtual supply netted a $3.6 million profit in the third quarter while virtual load netted a $4.0 million profit.

Virtual Trading Activity
By Region By Month



Quarter	Virtual Supply Cleared (MW/h)	Virtual Supply Profit ($/MWh)	Virtual Load Cleared (MW/h)	Virtual Load Profit ($/MWh)	Avg # of Bidders
2012 Q3	2408	$0.67	1052	$1.74	25
2012 Q2	2151	-$0.51	1178	$3.02	25
2011 Q3	2055	-$0.45	2004	$2.46	33

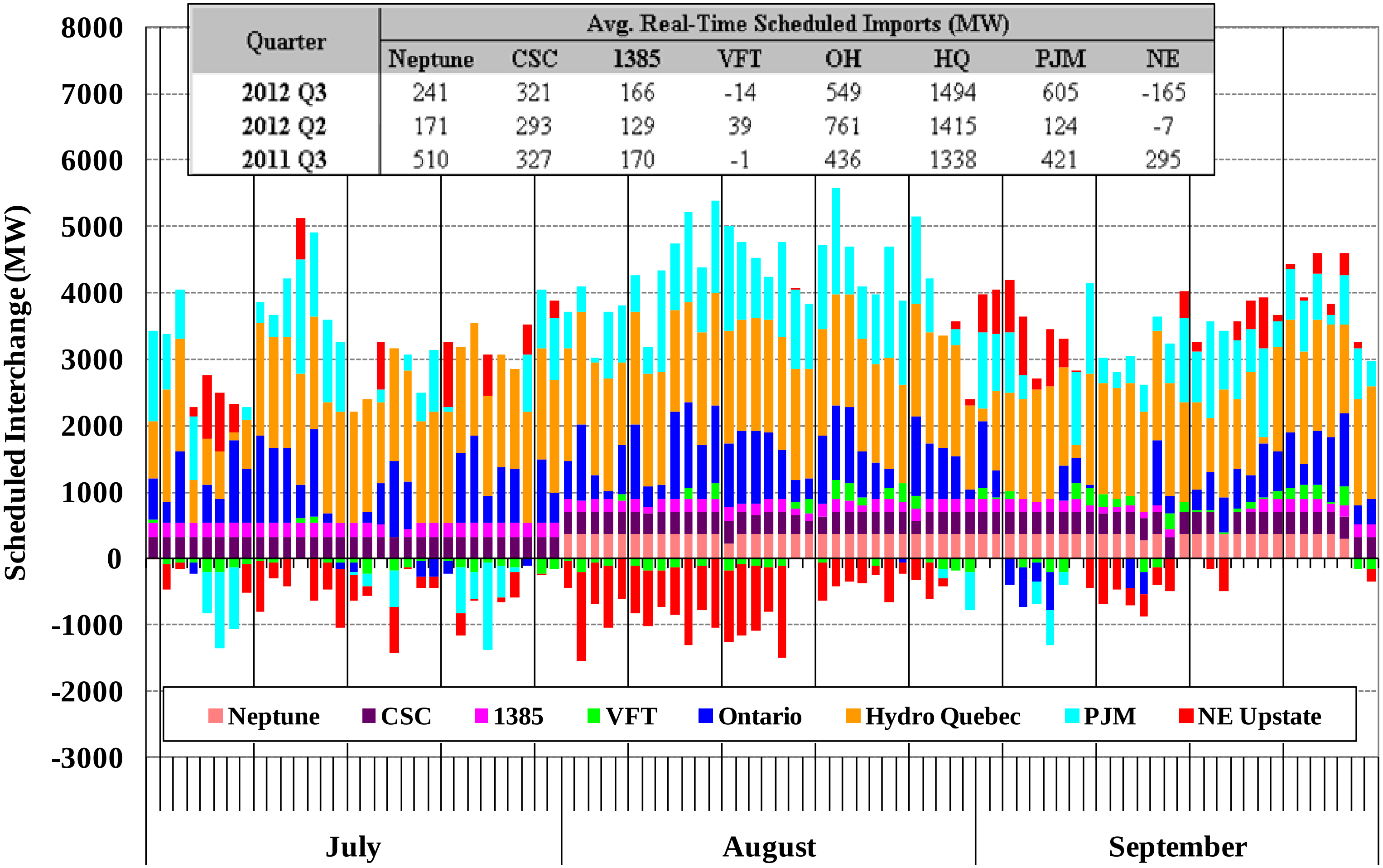
POTOMAC ECONOMICS

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 third quarter of 2012.
- Net imports averaged roughly 3.2 GW in daily peak load hours, up 9 percent from the previous quarter and down 9 percent from the third quarter of 2011.
  - ✓ Net imports across the Neptune line increased 70 MW from the previous quarter and fell 270 MW from the prior year.
    - – The Neptune Cable was completely out of service from May 27 through July 31 and partly returned to service (up to 375 MW) in August and September.
  - ✓ Net imports from Ontario fell 210 MW from the previous quarter and rose about 110 MW from the prior year.
  - ✓ Net imports across the primary PJM interface increased 480 MW from the prior quarter and 180 MW from a year ago.
- On average, imports satisfied 13 percent of the load during daily peak hours in the third quarter of 2012, down moderately from the third quarter of 2011.
  - ✓ However, in peak load hour, imports fell to just 6 percent of the peak load.
- The 2012 State of the Market Report will evaluate the effects of several market developments, including 15-minute scheduling of the PJM-NYISO interface (since June 27) and changes in the calculation of PJM and Ontario proxy prices.

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 Q3	241	321	166	-14	549	1494	605	-165
2012 Q2	171	293	129	39	761	1415	124	-7
2011 Q3	510	327	170	-1	436	1338	421	295

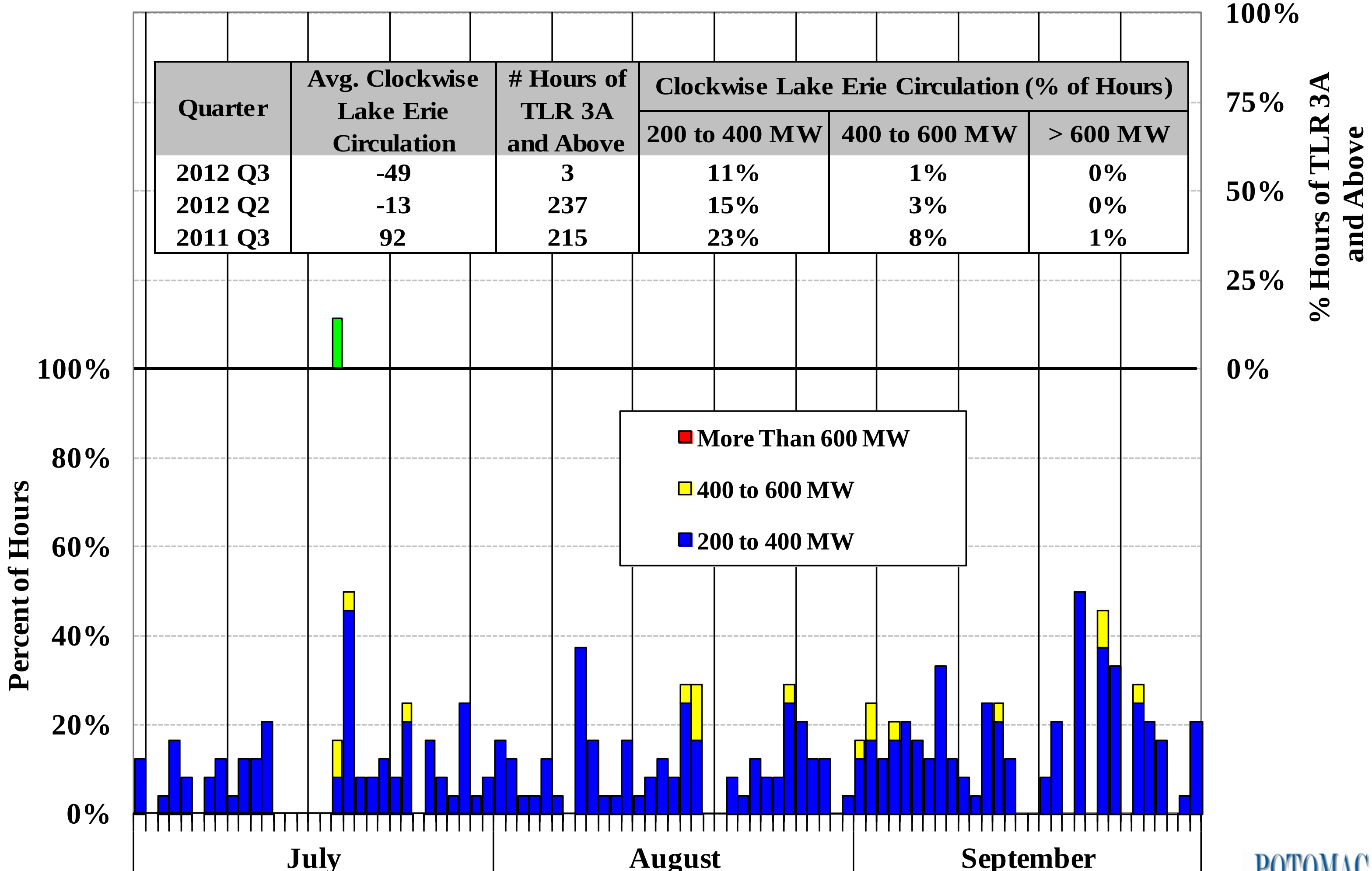


POTOMAC ECONOMICS

External Interface Scheduling and Lake Erie Circulation

- Loop flows occur when physical power flows are not consistent with the scheduled path of a 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 summarizes the frequency of clockwise Lake Erie Circulation and the frequency of TLRs (level 3A) called by the NYISO on each day of the quarter.
- Average clockwise circulation was *negative* 49 MW, down 36 MW from the previous quarter and 141 MW from the third quarter of 2011.
  - ✓ Low natural gas prices have helped reduce west-to-east flows in the eastern U.S., thereby contributing to lower clockwise circulation.
- TLRs were called much less frequently than in previous quarters largely because:
  - ✓ Clockwise circulation remained under 200 MW much more frequently; and
  - ✓ West-to-east congestion in upstate NY occurred much less frequently.

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 Q3	-49	3	11%	1%	0%
2012 Q2	-13	237	15%	3%	0%
2011 Q3	92	215	23%	8%	1%

POTOMAC ECONOMICS

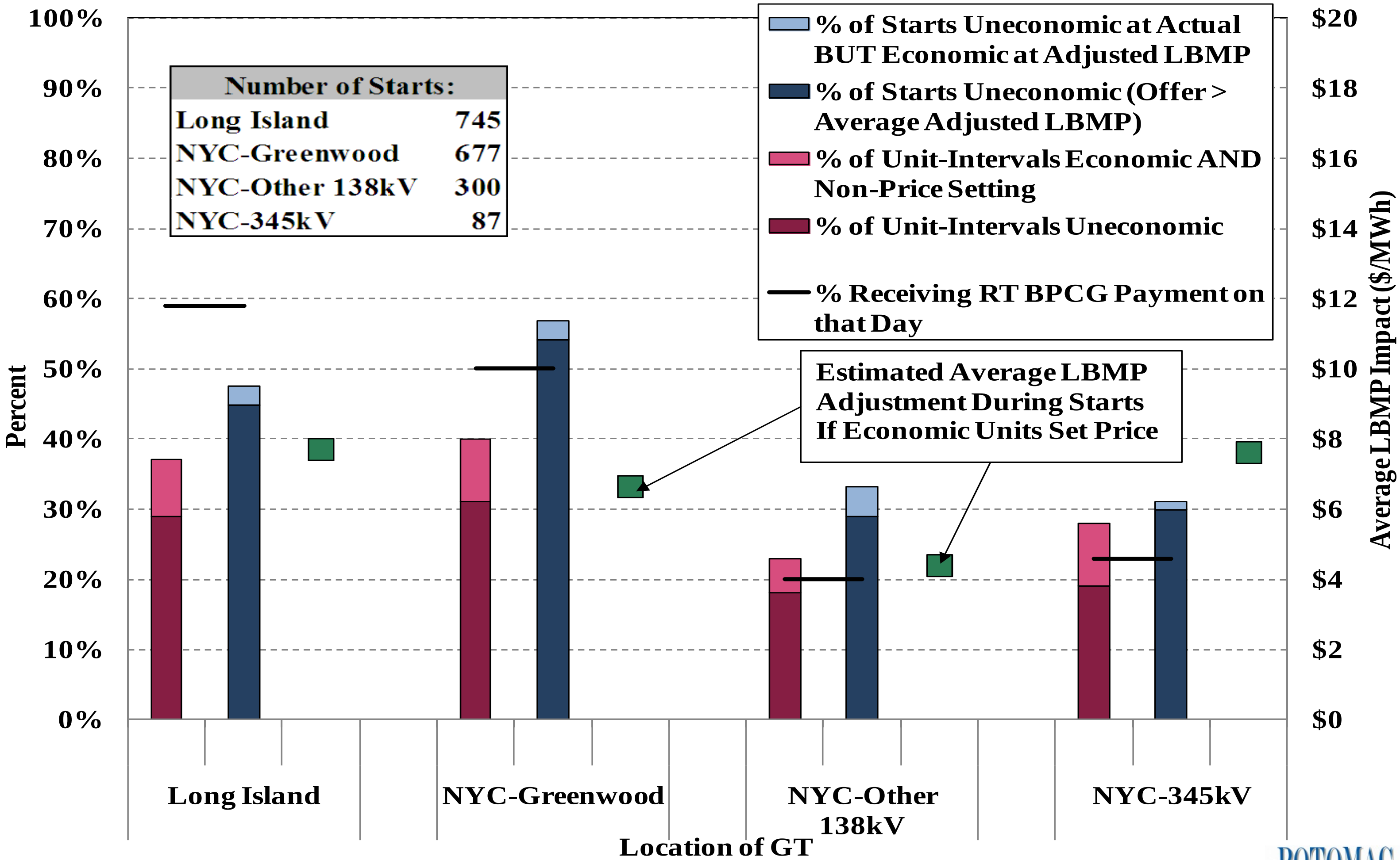
Efficiency of Gas Turbine Commitment and Price Setting

- The next figure evaluates the efficiency of GT commitments and of RT LBMPs during the initial one-hour commitment period in the third quarter of 2012.
- The figure reports the seven quantities for four areas of NYC and Long Island:
  - ✓ *Number of Starts* – Excludes self-scheduled 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.
  - ✓ *Estimated Average LBMP Adjustment During Starts* – Average upward adjustment in LBMPs during starts if economic GTs always set the RT LBMP.
  - ✓ *Percent of Starts Uneconomic (Offer > Average Adjusted LBMP)* – Share of starts when GT's offer was greater than the average "Adjusted LBMP" over the initial commitment period. (The "Adjusted LBMP" is the price that would have been set if economic GTs at the same market location always set the RT LBMP).
  - ✓ *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 average Adjusted LBMP over the initial commitment period.

Efficiency of Gas Turbine Commitment and Price Setting

- The figure shows that between 60 and 75 percent of the unit-intervals are economic and are either setting the price or are inframarginal. This is partly due to the effects of NYISO's Hybrid Pricing methodology in the real-time market.
- Nonetheless, the figure also shows that 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 figure under-estimates the effects of allowing GTs to set the RT LBMP in intervals when they are economic because it:
  - ✓ Assumes that the RT LBMP impact is limited to nodes in the same area (out of the four areas shown in the figure) that have the same LBMP congestion component. The actual LBMPs over a wider area can be effected, depending on congestion.
  - ✓ 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.

Efficiency of Gas Turbine Commitment and Price Setting



POTOMAC ECONOMICS

Day-Ahead and Real-Time Transmission Congestion

POTOMAC ECONOMICS

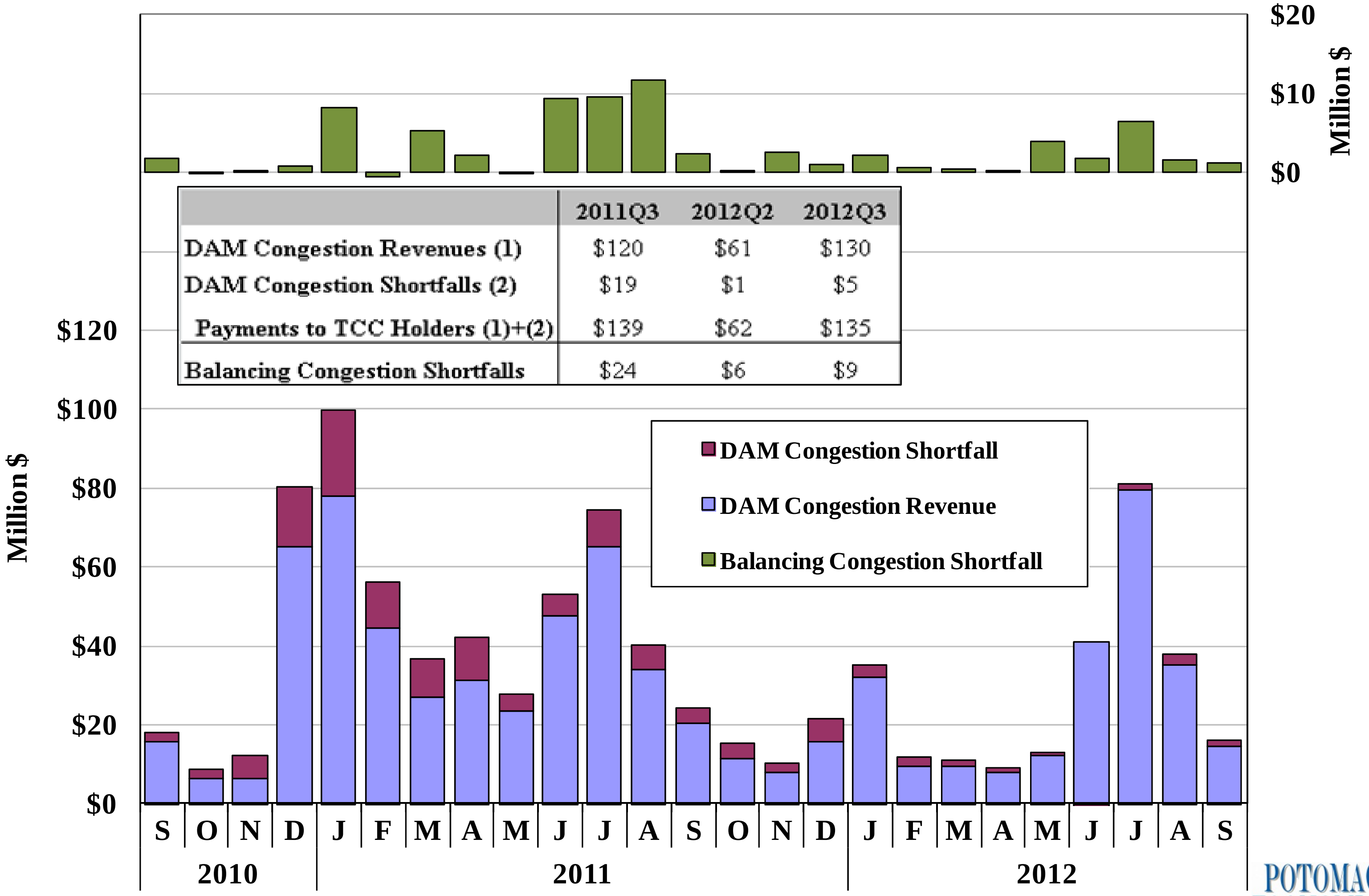
Congestion Revenue and Shortfalls

- 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 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 $130 million in the third quarter.
  - ✓ This was up 113 percent from the prior quarter as a result of higher load levels.
  - ✓ This was up 8 percent from the same quarter last year due to increased congestion into Long Island, across the primary HQ-NY interface, and in the West Zone.
    - – However, the increase was offset by 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.
- Day-ahead congestion shortfalls totaled $5 million, up $4 and down $14 million from the previous quarter and the previous year, respectively.
  - ✓ Outages and deratings of the lines into Long Island accounted for most shortfalls.
  - ✓ The reduction from the previous year reflected less congestion outside Long Island and fewer significant transmission outages in NYC and into SENY.
- Balancing congestion shortfalls were $9 million in the third quarter of 2012, up $3 million from the previous quarter and down from $15 million from a year ago.
  - ✓ The vast majority of shortfalls accrued during TSAs on several days.

Congestion Revenue and Shortfalls



	2011Q3	2012Q2	2012Q3
DAM Congestion Revenues (1)	$120	$61	$130
DAM Congestion Shortfalls (2)	$19	$1	$5
Payments to TCC Holders (1)+(2)	$139	$62	$135
Balancing Congestion Shortfalls	$24	$6	$9

POTOMAC ECONOMICS

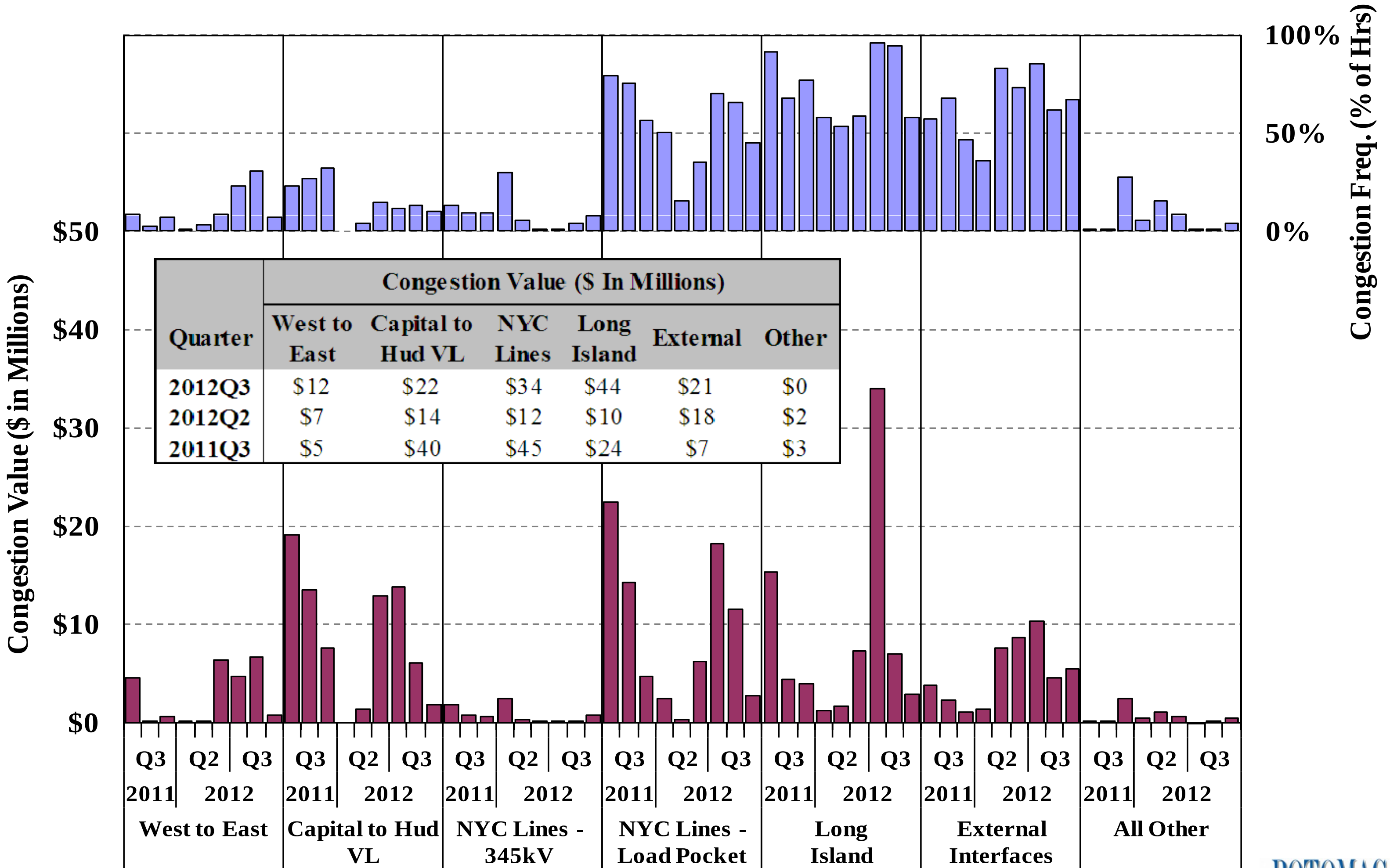
Congestion by Transmission Path

- The following two figures examine the value and frequency of congestion along major transmission paths in the day-ahead and real-time markets.
  - ✓ 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 transmission path.
  - ✓ 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 into the following transmission paths:
  - ✓ West to East: including lines in western NY and 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.

Congestion by Transmission Path

- 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.
- Congestion patterns were consistent in the day-ahead and the real-time markets in the third quarter. Most congestion occurred in the following areas:
  - ✓ Long Island (33% DAM, 31% RTM) – Congestion into Long Island rose from prior periods, due largely to the outage affecting Neptune and several retirements.
  - ✓ New York City lines (25% DAM, 20% RTM) – The vast majority of this congestion occurred in the Greenwood load pocket.
  - ✓ Capital to Hudson Valley lines (16% DAM, 26% RTM) – The majority of this congestion occurred during high load periods and TSAs.
  - ✓ External Interfaces (16% DAM, 9% RTM) – The primary HQ interface was fully scheduled more often than in previous years, leading to increased congestion.
    - – This pattern is consistent with the increased real-time congestion across the interface in recent summers during TSA operations.
  - ✓ West to East (9% DAM, 13% RTM) – Two lines (i.e., Scriba-Volney 345 kV and Niagara-Packard 230 kV) accounted for the majority of this congestion.

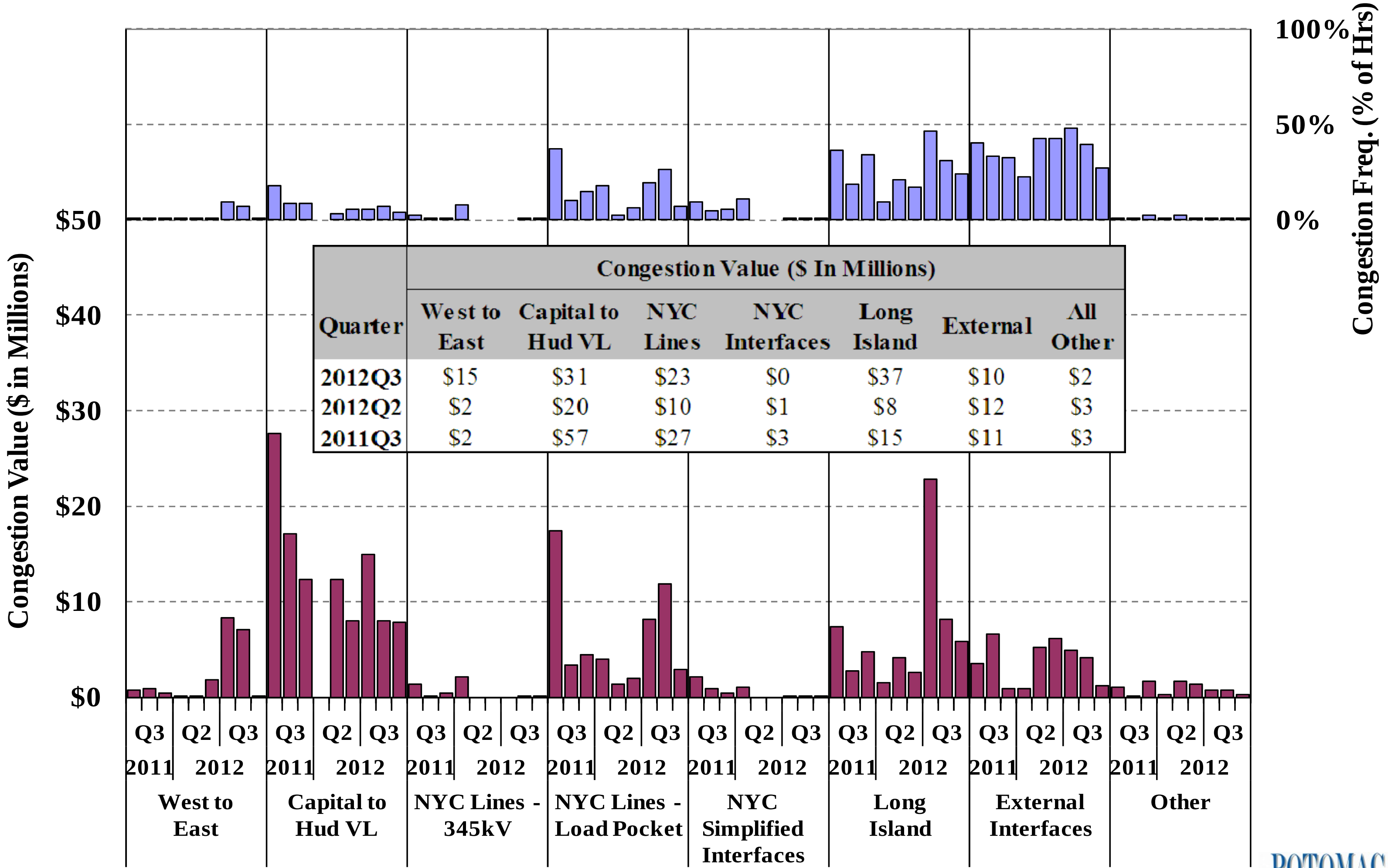
Day-Ahead Congestion by Transmission Path



Quarter	Congestion Value ($ In Millions)					
	West to East	Capital to Hud VL	NYC Lines	Long Island	External	Other
2012Q3	$12	$22	$34	$44	$21	$0
2012Q2	$7	$14	$12	$10	$18	$2
2011Q3	$5	$40	$45	$24	$7	$3

POTOMAC ECONOMICS

Real-Time Congestion by Transmission Path



Quarter	Congestion Value ($ In Millions)						
	West to East	Capital to Hud VL	NYC Lines	NYC Interfaces	Long Island	External	All Other
2012Q3	$15	$31	$23	$0	$37	$10	$2
2012Q2	$2	$20	$10	$1	$8	$12	$3
2011Q3	$2	$57	$27	$3	$15	$11	$3

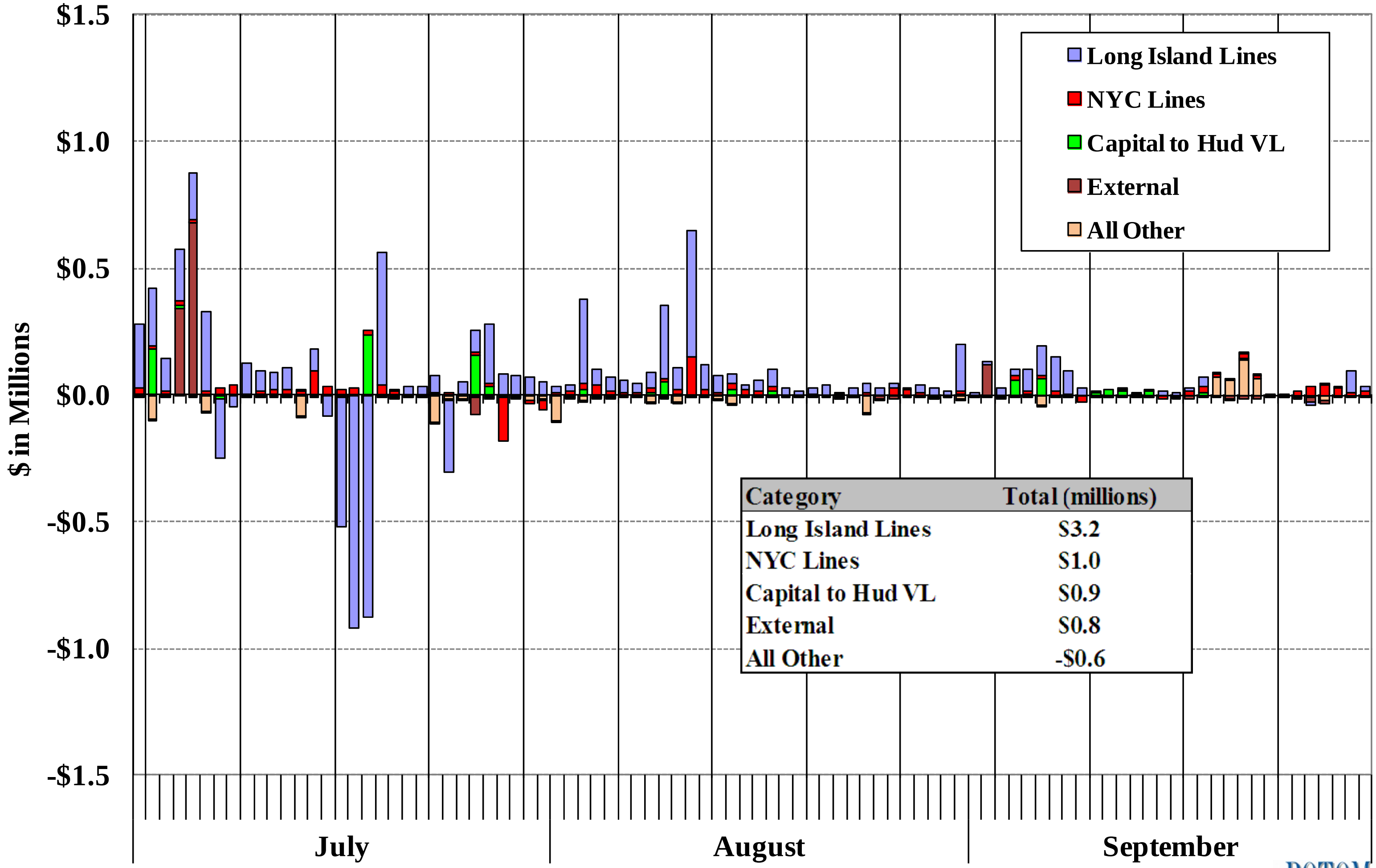
POTOMAC ECONOMICS

Day-Ahead Congestion Revenue Shortfalls

- The following figure shows the daily day-ahead congestion revenue shortfalls by transmission path or facility in the third 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.
- Long Island facilities accounted for $3 million of shortfalls in the third quarter.
  - ✓ The 345kV lines into Long Island were derated frequently due to higher-than-normal utilization during the quarter, resulting partly from the reduction in imports across the Neptune line.
  - ✓ A surplus of $2 million accrued on three days (July 16 to 18) on 138kV lines in Long Island because of changes in the pattern of flows from the TCC auctions. These surpluses partly offset the shortfalls on other days.
- External interfaces accounted for nearly $1 million of shortfalls in this quarter.
  - ✓ The vast majority accrued on the primary HQ interface on two days (July 4 to 5) when the interface was derated to 600 MW.

POTOMAC ECONOMICS

Day-Ahead Congestion Revenue Shortfalls



Category	Total (millions)
Long Island Lines	$3.2
NYC Lines	$1.0
Capital to Hud VL	$0.9
External	$0.8
All Other	-$0.6

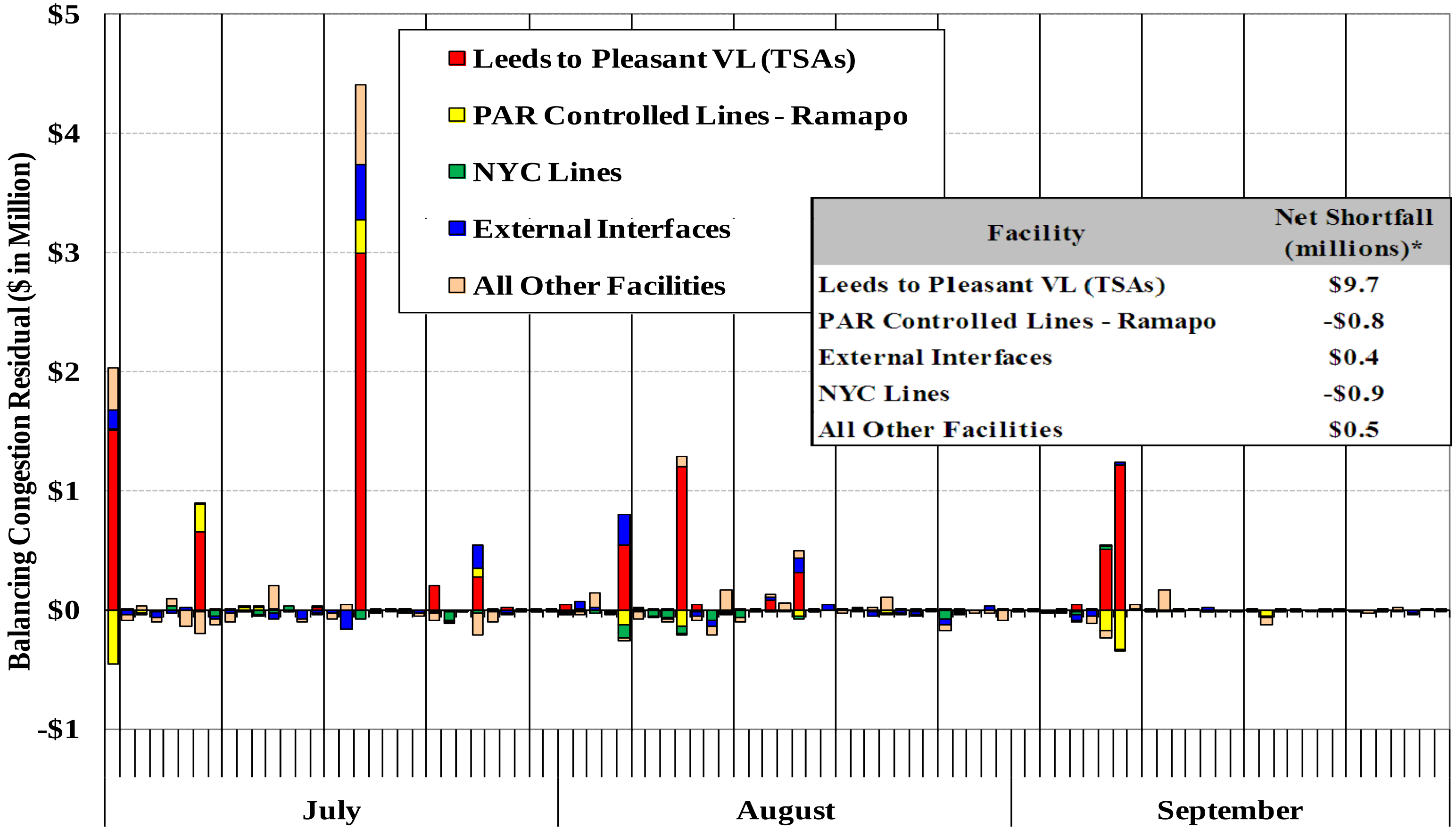
Balancing Congestion Shortfalls

- The following figure shows daily balancing congestion revenue shortfalls by transmission path or facility in the third 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 when unexpected real-time events occurred.
- TSAs events accounted for the vast majority of the balancing congestion shortfalls in the third quarter.
  - ✓ TSA events occurred on 19 days in this quarter, during which the transfer capability into Southeast New York was greatly reduced in real-time.
  - ✓ High balancing shortfalls accrued on 10 of the 19 days, particularly on July 18 when the quarterly peak demand occurred.
- The Ramapo PAR-controlled line accounted for $0.8 million of surpluses.
  - ✓ These generally occurred during TSAs, reflecting that the line was frequently used to manage congestion into Southeast New York during TSA operations.
- External interfaces accounted for $0.4 million of shortfalls in the third quarter.
  - ✓ The shortfalls often arise when import capability is reduced below the day-ahead scheduled level in order to manage internal congestion.
  - ✓ The majority of these shortfalls accrued on four days with TSA operations because imports are often limited in order to manage congestion on the LPV line.

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).

POTOMAC ECONOMICS

Uplift Costs and Supplemental Commitments

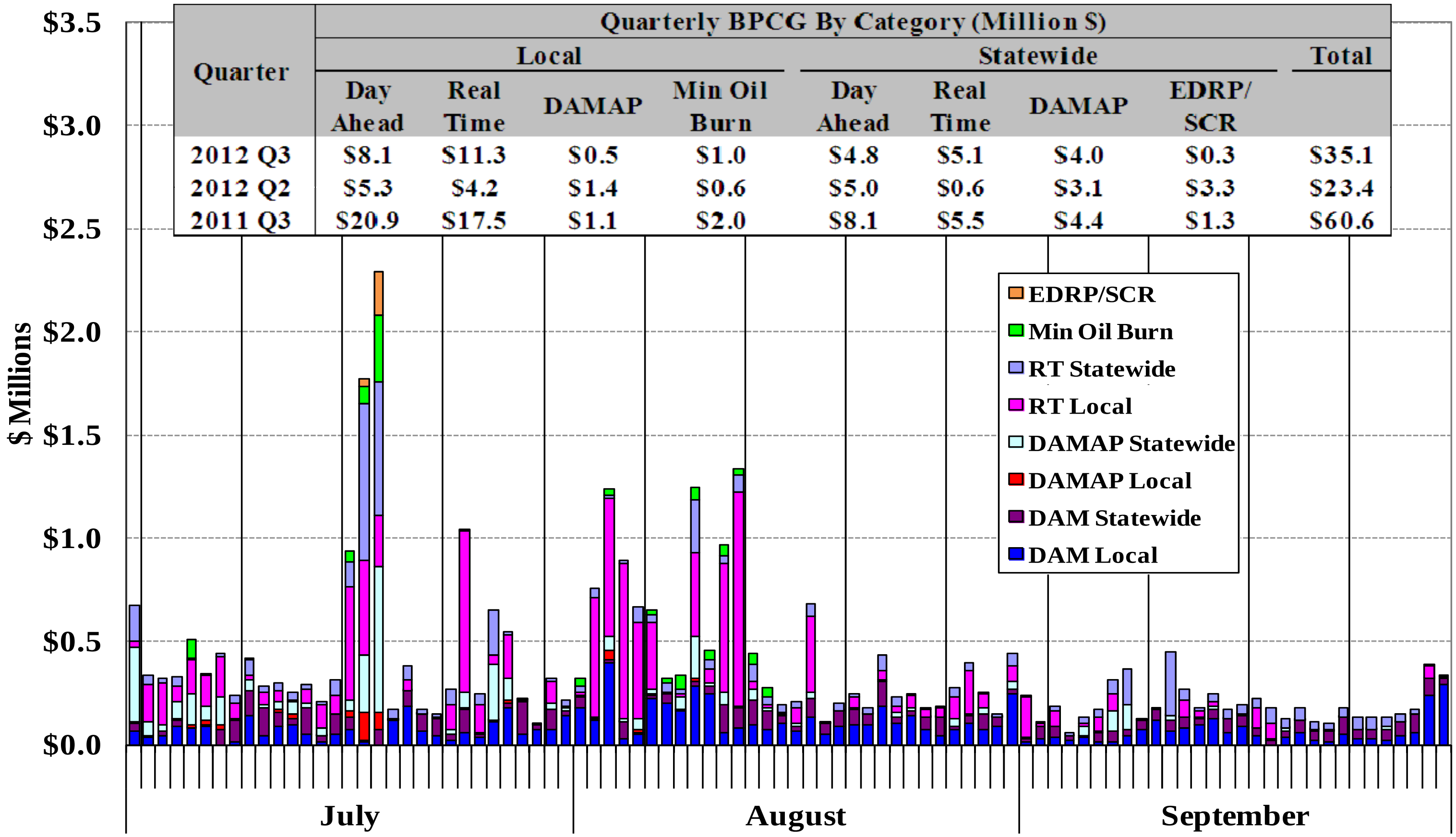
Uplift Costs from Guarantee Payments

- 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: For units committed in the day-ahead market (usually economically) whose day-ahead market revenues do not cover their as-offered costs.
  - ✓ Real Time: For external transactions and gas turbines that are scheduled economically, or units committed or dispatched OOM for bulk system reliability whose real-time market revenues do not cover their as-offered costs.
  - ✓ Day Ahead Margin Assurance Payment (“DAMAP”): For generators that incur losses because they are 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 eight categories of uplift charges on a daily basis in the third quarter of 2012.
- Guarantee payment uplift was $35 million in the third quarter of 2012, up 50 percent from the previous quarter.
  - ✓ The increase was largely associated with the increase in local real-time guarantee payments, most of which were related to OOM dispatch by the local TO to manage transmission security on the East End of Long Island.
  - ✓ Higher natural gas prices and load levels also contributed to the increase.
- Guarantee payment uplift fell 42 percent from the third quarter of 2011, due to:
  - ✓ A 30 percent reduction in natural gas prices;
  - ✓ A 20 percent reduction in OOM dispatch for reliability on Long Island; and
  - ✓ A 54 percent reduction in reliability commitment in NYC and Long Island.
- RT local uplift was elevated from mid-July to mid-August because high loads require frequent OOM dispatch on the East End of Long Island.
  - ✓ On the two days when load exceeded 32 GW (July 17 & 18), guarantee payment uplift was high as supplemental commitments of oil-fired units increased for local reliability.

Uplift Costs from Guarantee Payments
Local and Non-Local by Category



Quarter	Quarterly BPCG By Category (Million $)								
	Local				Statewide				Total
	Day Ahead	Real Time	DAMAP	Min Oil Burn	Day Ahead	Real Time	DAMAP	EDRP/ SCR	
2012 Q3	$8.1	$11.3	$0.5	$1.0	$4.8	$5.1	$4.0	$0.3	$35.1
2012 Q2	$5.3	$4.2	$1.4	$0.6	$5.0	$0.6	$3.1	$3.3	$23.4
2011 Q3	$20.9	$17.5	$1.1	$2.0	$8.1	$5.5	$4.4	$1.3	$60.6

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.

POTOMAC ECONOMICS

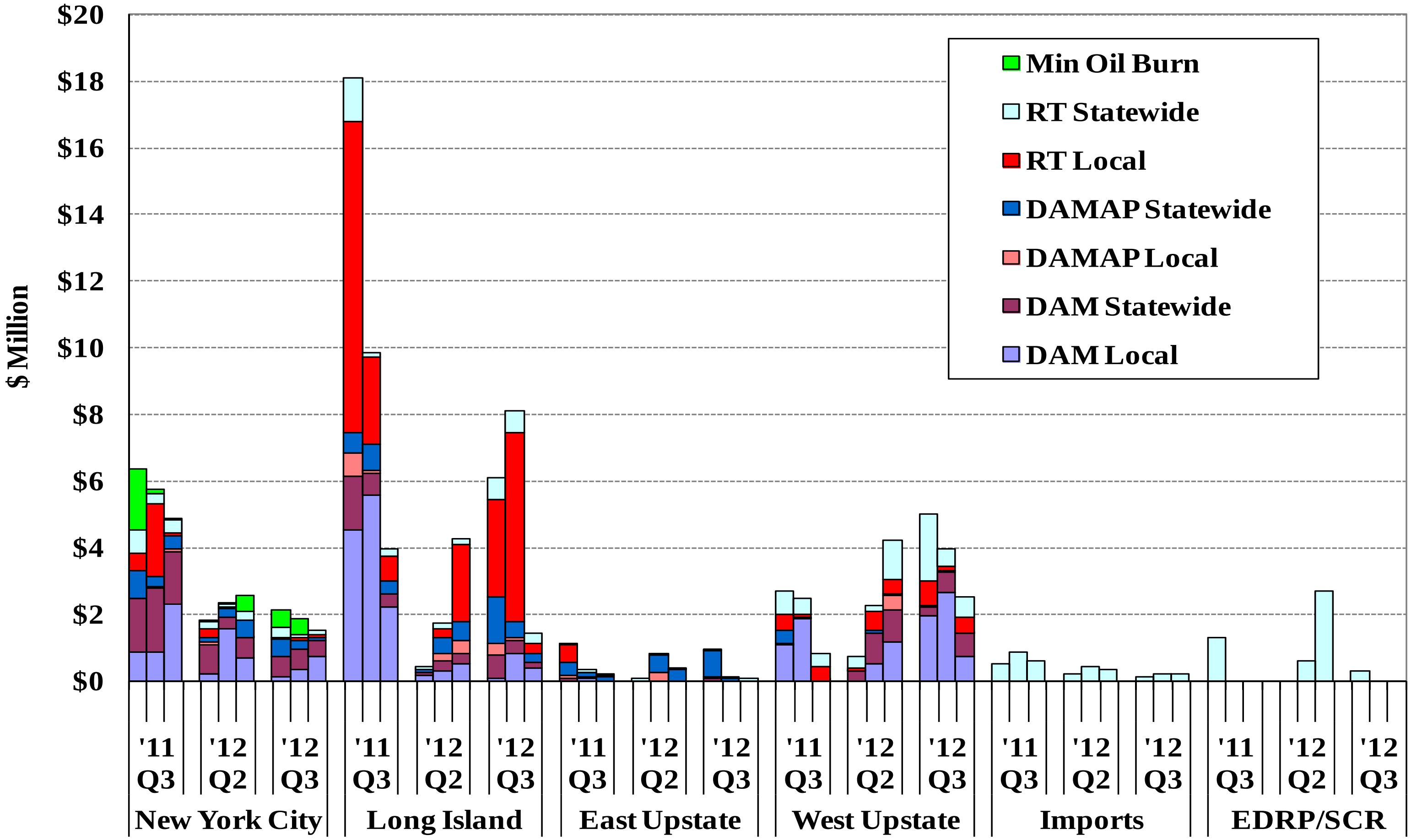
Uplift Costs from Guarantee Payments by Region

- The next figure shows eight categories of uplift on a monthly basis by region.
- Day-ahead local reliability uplift in the third quarter of 2012:
  - ✓ Western New York accounted for nearly 70 percent, resulting primarily from DARU commitments for local transmission security.
- Day-ahead statewide uplift in the third quarter of 2012:
  - ✓ A significant share of these costs (64 percent) were paid to generators in New York City (36 percent) and Long Island (28 percent).
  - ✓ Another 32 percent were paid to generators in the West Zone that were committed to ensure sufficient capacity would be available to manage transmission security.
    - – Uplift is allocated statewide when the facility being secured is 230kV or higher.
- Real-time local reliability uplift in the third quarter of 2012:
  - ✓ Long Island accounted for nearly 80 percent, primarily to manage local reliability on the East End where many units operate on fuel oil rather than natural gas.
- Real-time statewide uplift in the third quarter of 2012:
  - ✓ The majority of this was for SRE commitments for security of 230kV facilities in Western NY (57 percent) and for GTs dispatched for reliability that did not set the clearing price for their entire run (30 percent).

Uplift Costs from Guarantee Payments by Region

- Guarantee payment uplift fell 42 percent (or roughly $25 million) from the third quarter of 2011 partly due to the 30 percent decrease in natural gas prices.
- Long Island accounted for the largest share of the reduction ($16 million) in uplift from the third quarter of 2011.
  - ✓ The outage limiting imports across the Neptune line and multiple unit retirements led to higher LBMPs during the third quarter. Consequently,
    - – Oil-fired peaking units that are dispatched for East End local reliability received smaller guarantee payments; and
    - – Generators needed for local reliability were more often committed economically.
- NYC accounted for an $11 million reduction from the third quarter of 2011.
  - ✓ Day-ahead uplift fell by more than $6 million and real-time uplift fell by more than $3 million as a result of fewer DARU and SRE commitments.
    - – DARU and SRE commitments fell because units needed for reliability on the 138kV system were more often committed economically, while units were less often needed for reliability on the 345kV system.
- In Western NY, day-ahead uplift increased by $4 million from the third quarter of 2011, primarily because more DARU commitments were made 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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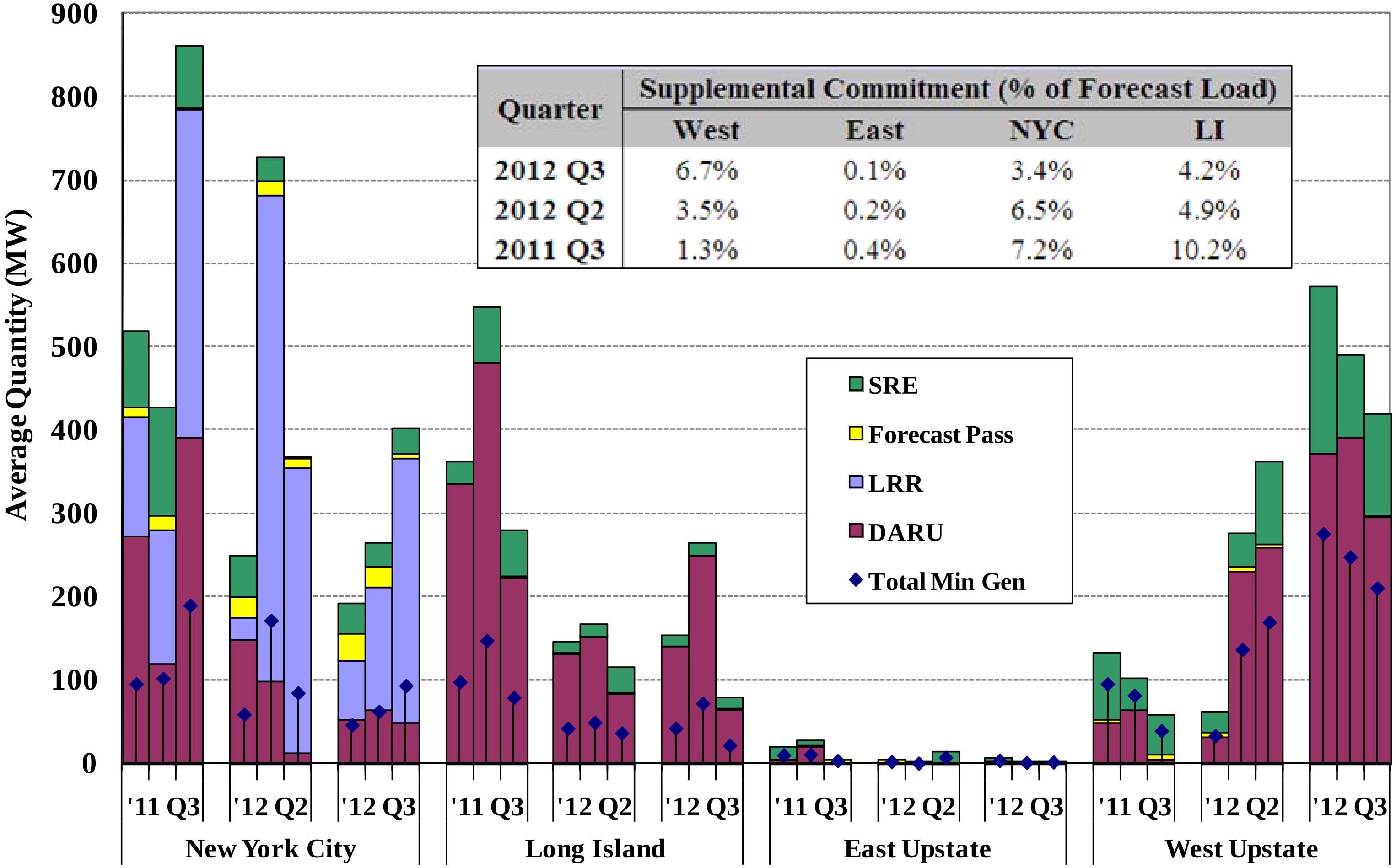
Supplemental Commitment for Reliability

- The following figure shows the monthly quantities of capacity committed for reliability by type of commitment and region.
- In Western NY, reliability commitment averaged 490 MW in the third quarter, up from 100 MW in the third quarter of 2011.
  - ✓ Several coal units that are frequently needed for reliability were economically committed less often, partly because of lower natural gas prices.
- On Long Island, reliability commitment averaged 165 MW in the third quarter, down 58 percent from the third quarter of 2011.
  - ✓ Units that are frequently needed for local reliability were committed economically because of the higher LBMPs after the Neptune outage and several retirements.
- In NYC, reliability commitment averaged 285 MW in this quarter, down 52 percent from the third quarter of 2011.
  - ✓ This reflects large reductions in DARU and SRE commitments, which are discussed in greater detail later in this section.
  - ✓ Slow-start units continue to be committed in the Forecast Load Pass when off-line fast-start units are available, although these commitments produce little uplift.
    - – The NYISO is preparing a modeling enhancement to help reduce unnecessary commitment of slow-start units.

Supplemental Commitment for Reliability
by Category and Region



Quarter	Supplemental Commitment (% of Forecast Load)			
	West	East	NYC	LI
2012 Q3	6.7%	0.1%	3.4%	4.2%
2012 Q2	3.5%	0.2%	6.5%	4.9%
2011 Q3	1.3%	0.4%	7.2%	10.2%

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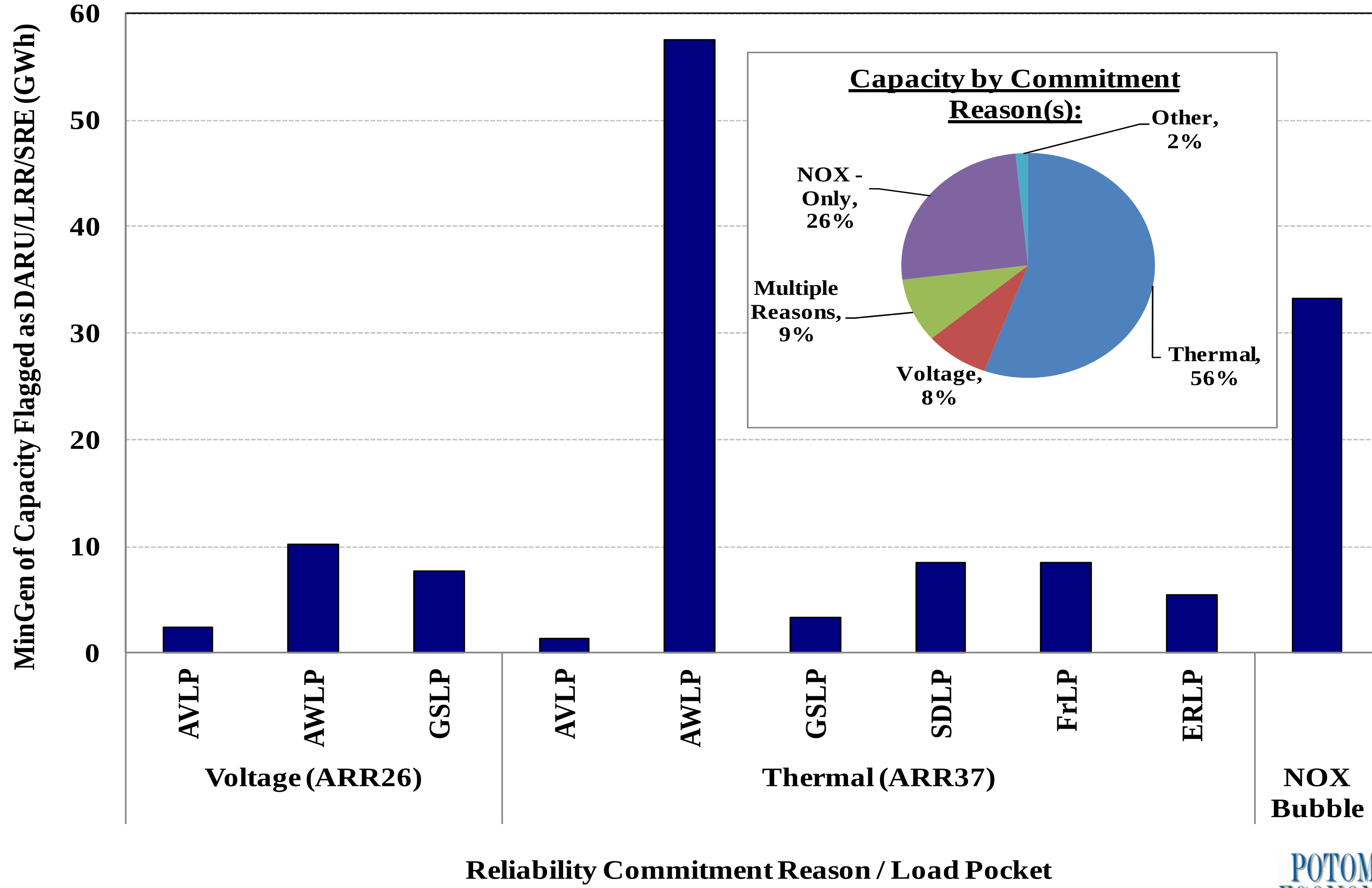
Supplemental Commitment for Reliability in NYC

- The following figure evaluates the reasons for reliability commitments in the third quarter of 2012 in New York City where most occurred.
- 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/Corona/Jamaica, AWLP = Ast West/Queensbridge, AVLP = Ast West/Queensbridge/Vernon, ERLP = East River, FRLP = Freshkills, GSLP = Greenwood/Staten Island, & SDLP = Sprainbrook/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 following requirements accounted for most of reliability commitment:
  - ✓ Astoria West/Queensbridge thermal and voltage requirements – Ensure facilities into the pocket will not be overloaded if the largest two contingencies occur.
  - ✓ NOX bubble requirements – Require operation of a steam turbine to reduce the overall NOX emission rate from a portfolio containing higher-emitting GTs.
    - – These requirements are in effect from May to September each year.
    - – On moderate load days, these can require large amounts of reliability commitment.
      - The output from these steam turbines frequently displaced output from newer, lower-emitting generation in the city and from imports to the city.
    - – On high load days, these requirements are frequently satisfied by economically committed units.
- Reliability commitments fell substantially from the third quarter of 2011 for:
  - ✓ Sprainbrook/Dunwoodie thermal and voltage requirements (85 percent), reflecting that less capacity was needed for reliability on the 345kV system following the entry of a 500 MW generating unit and new transmission facilities; and
  - ✓ NOX Bubble requirements (40 percent), reflecting more frequent economic commitment of resources needed to satisfy these requirements that was partly due to changes in offer patterns.

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 total station-hours) of OOM actions on a monthly basis by region in the third quarter of 2012.
  - ✓ In each region, the two stations with the highest number of OOM dispatch hours in the third 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.
- Generators were dispatched OOM for roughly 1,750 station-hours in the third quarter of 2012, up approximately 400 station-hours from the previous quarter.
  - ✓ The increase was generally attributable to higher load levels, which led to more frequent OOM dispatch for local reliability and transmission security.

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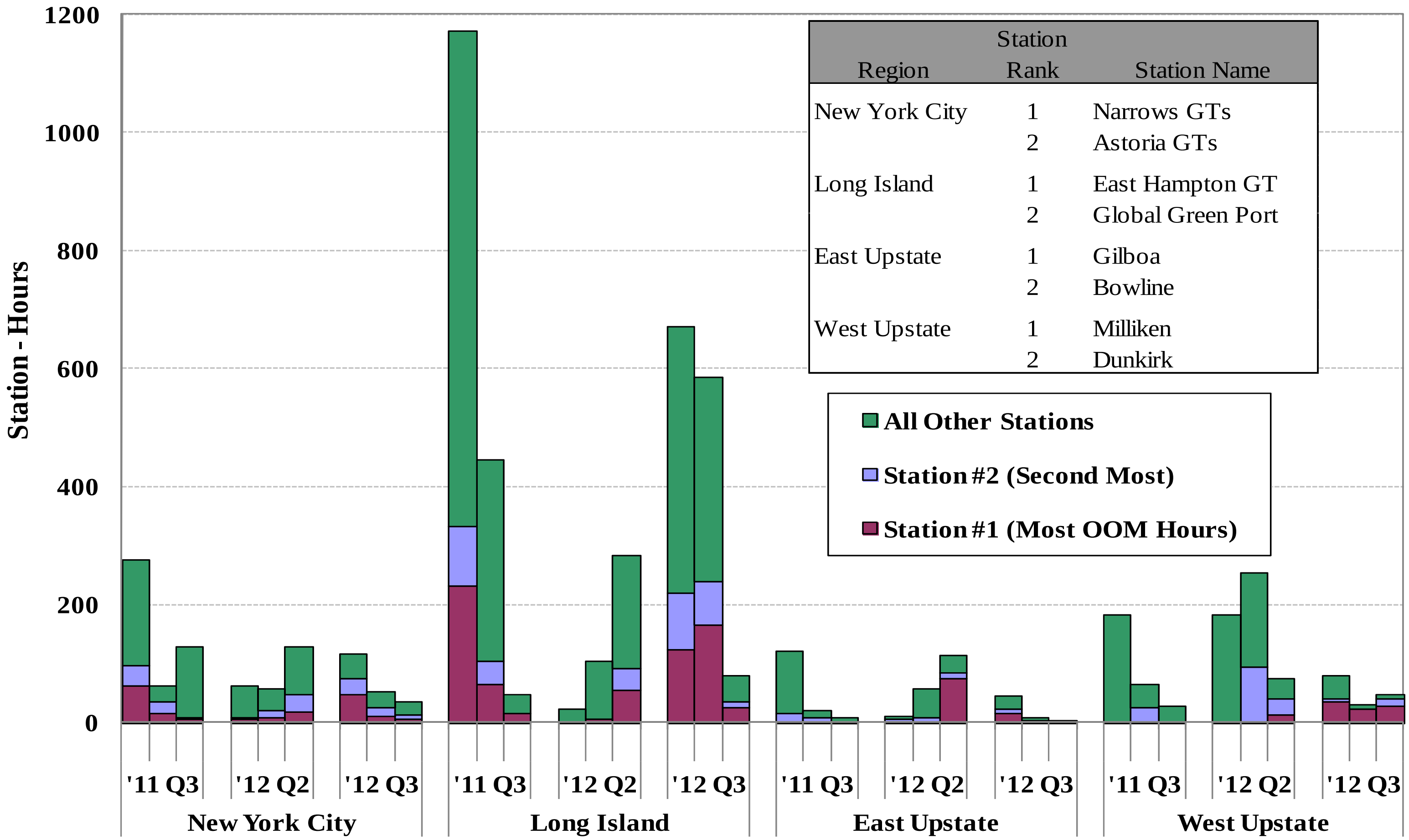
Out-of-Merit Dispatch

- Long Island accounted for 76 percent of OOM station-hours in the third quarter.
  - ✓ Most was called to manage local reliability on the East End of Long Island.
  - ✓ These fell from the third quarter of 2011, since units needed for reliability were more often dispatched economically due to the higher LBMP levels during the Neptune outage.
- NYC accounted for 12 percent of OOM station-hours in the third quarter.
  - ✓ These were primarily to manage NYISO security and reliability on days with high loads and/or during TSA events.
  - ✓ These were less frequent than 2011 partly due to the addition of new transmission facilities in the city.
- Western NY accounted for 9 percent of OOM station-hours in the third quarter.
  - ✓ 55 percent was to dispatch the Milliken units for local transmission security.
  - ✓ These fell from the previous quarters due to transmission constraint modeling improvements made in May 2012 for the West Zone.
- The total number of OOM station-hours in the third quarter fell by nearly 800 from the third quarter of 2011 due to the reductions in the regions described above.

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



Region	Station Rank	Station Name
New York City	1	Narrows GTs
	2	Astoria GTs
Long Island	1	East Hampton GT
	2	Global Green Port
East Upstate	1	Gilboa
	2	Bowline
West Upstate	1	Milliken
	2	Dunkirk

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.

Market Power and Mitigation

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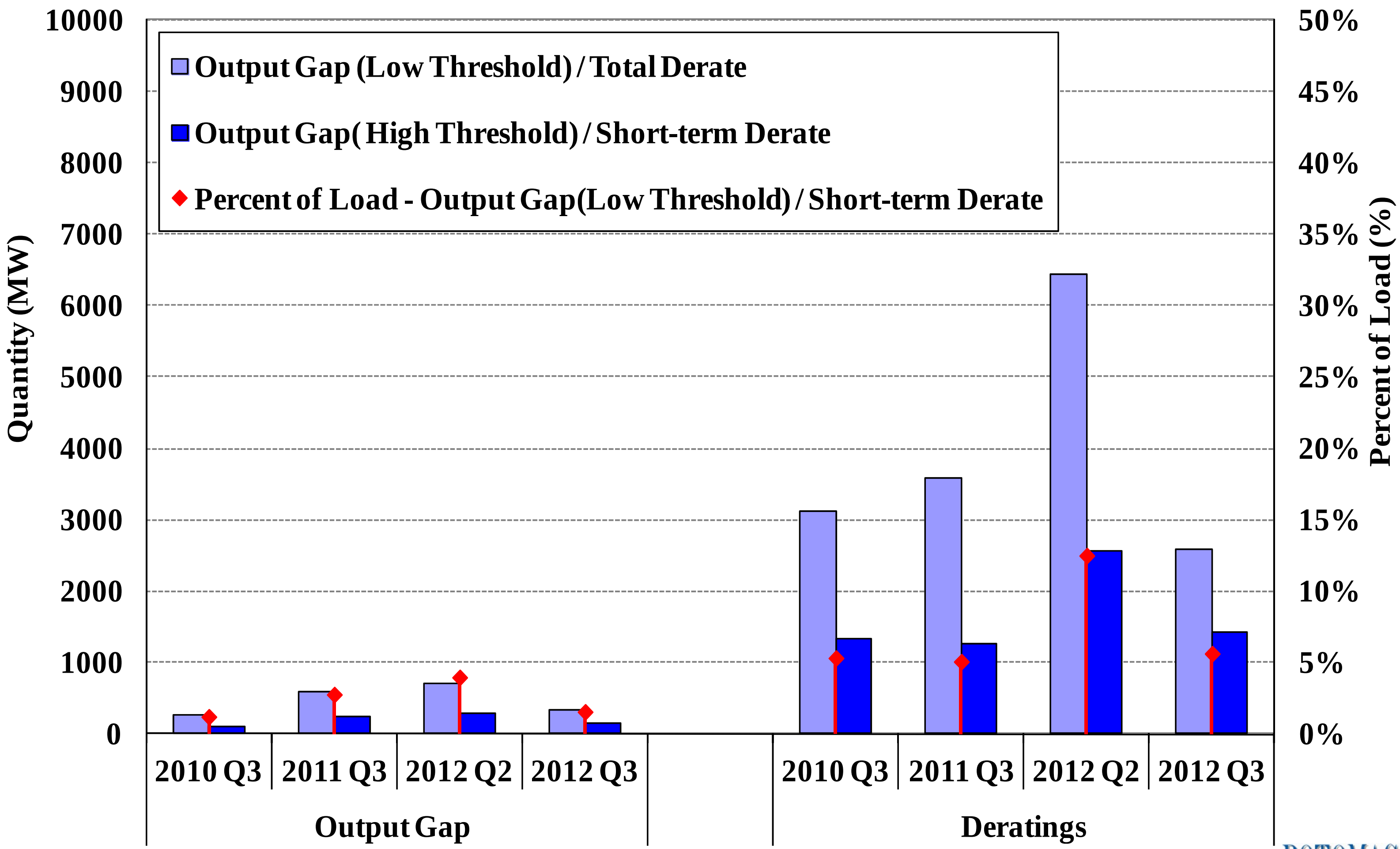
Market Power Screens: Economic Withholding

- The next figure shows the results of our screens for attempts to exercise market power, which may include economic withholding and physical withholding.
- The screen for economic withholding is the "output gap", which 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.
- In the following figure, we show the output gap based on:
  - ✓ A high threshold (the lower of $100/MWh and 300 percent); and
  - ✓ A low threshold (the lower of $50/MWh and 100 percent).
- The output gap was relatively low as a share of load in this quarter.
  - ✓ The output gap averaged less than 2 percent of load based on the low threshold, which is comparable to the same period in prior years.
  - ✓ The output gap did not raise market power concerns because it occurred primarily during periods when the prices would not be substantially affected.

Market Power Screens: Physical Withholding

- We evaluate generator deratings 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.
- Deratings fell notably from the prior quarter, consistent with the seasonal changes.
  - ✓ Deratings are typically highest in shoulder months when load is lower and lowest in the summer months when load is higher.
  - ✓ Total deratings are significant, but physical withholding concerns are limited because most deratings are long-term and not likely to reflect withholding.
    - – Mothballing or retirement of several units (which is excluded from the deratings) contributed to the reduction of total deratings in this quarter versus prior years.
  - ✓ The amount of short-term deratings (< 30 days) was consistent with the third quarter of the last two years.

Market Monitoring Screens



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Market Power Mitigation

- This table summarizes the mitigation that was imposed during the quarter.
- 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.

Quarterly Mitigation Summary

		2010 Q3	2011 Q3	2012 Q2	2012 Q3
Day-Ahead Market	**Average Mitigated MW**	151	417	153	70
	Energy Mitigation Frequency	13%	54%	18%	12%
Real-Time Market	**Average Mitigated MW**	1	48	14	20
	Energy Mitigation Frequency	3%	19%	3%	7%

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

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Automated Market Mitigation

- The vast majority of mitigation occurred in the day-ahead market.
  - ✓ In the third quarter of 2012, day-ahead mitigation occurred primarily for:
    - DARU & LRR units (81 percent),
    - The 345/138kV interface (11 percent), and
    - The Greenwood Staten Island load pocket (6 percent).
  - ✓ 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.
    - DARU commitments fell in New York City and Long Island, leading to reduced mitigation in this category.
- 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 the first half of 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 third quarter of 2012, but the amount of un-mitigation is expected to be smaller than in recent quarters.

Capacity Market

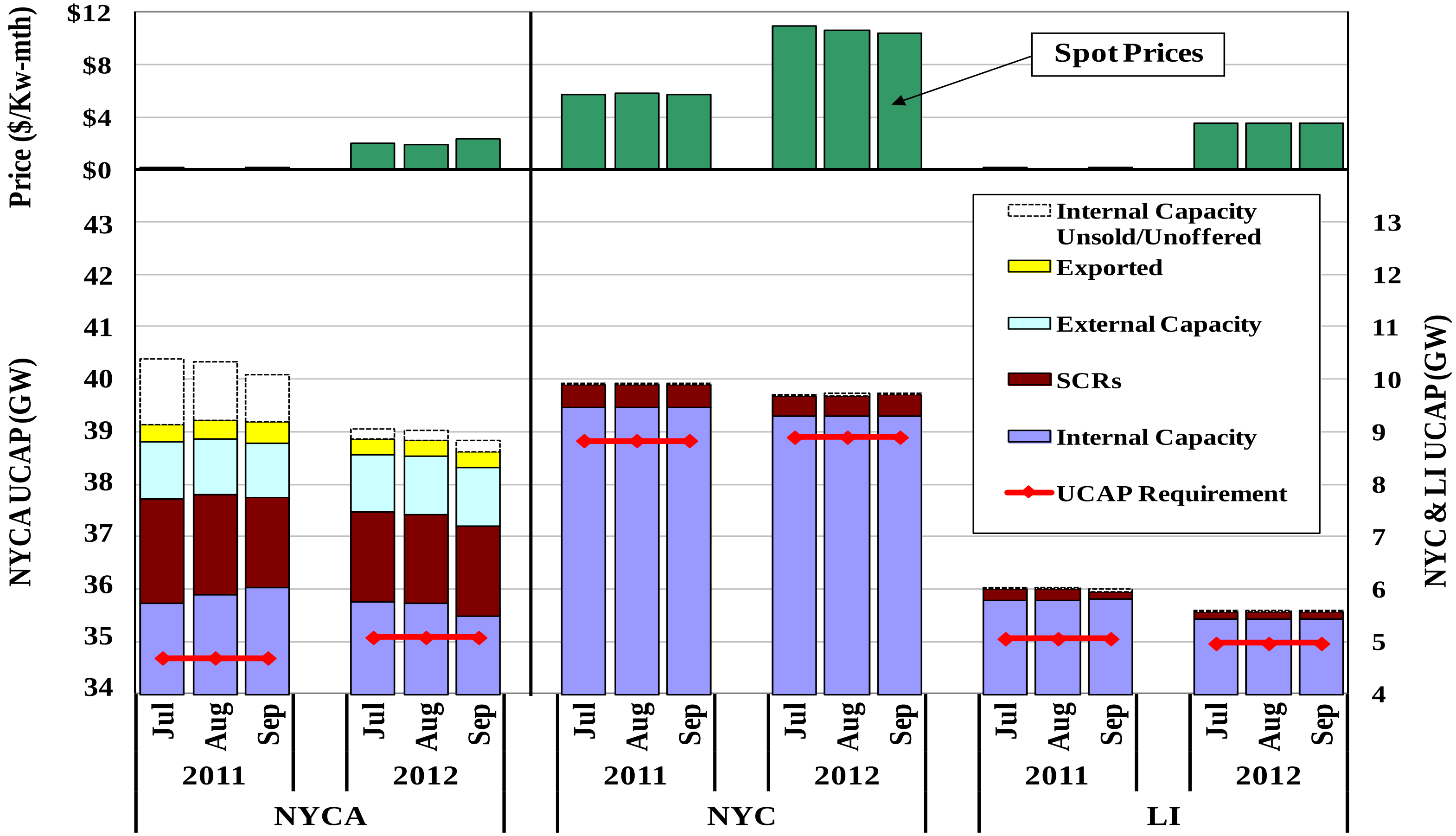
Capacity Market Results

- The following figure summarizes available and scheduled Unforced Capacity ("UCAP"), UCAP requirements, and spot prices in each capacity zone.
  - ✓ UCAP is a measure of installed capacity that accounts for forced outage rates.
- In Rest of State, UCAP spot prices increased to average $2.09/kW-month this quarter (up from $0.13/kW-month in the third quarter of 2011) because:
  - ✓ Sales of internal capacity fell since last year because 1.3 GW of generation retired or mothballed, including: a) 590 MW in New York City; b) 330 MW on Long Island since July 2012; and c) 370 MW in the West since September 2012.
  - ✓ The NYCA UCAP requirement rose nearly 800 MW from the 2011/12 capability year to the 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.
  - ✓ However, these factors were offset by increased sales following the entry of nearly 500 MW of new supply in New York City in June 2012.

Capacity Market Results

- In New York City, UCAP spot prices rose to average of $10.69/kW-month in the third quarter of 2012, up 85 percent from the third quarter of 2011.
- This increase was due primarily to the following factors:
  - ✓ A higher new demand curve was deployed after the third quarter of 2011.
    - – The new demand curve is approximately $4/kW-month (or 24 percent) higher at 100 percent of UCAP requirement than the previous demand curve.
  - ✓ The Local Capacity Requirement rose from 81 percent to 83 percent in Summer 2012, contributing 200 MW to the UCAP requirement.
  - ✓ Several generating units were mothballed or retired, which reduced the available installed capacity by 600 MW.
    - – However, this was offset by the entry of a 500 MW unit in June 2012.
- On Long Island, UCAP spot prices averaged $3.57/kW-month in the third quarter, significantly higher than the Rest of State price.
  - ✓ UCAP sales fell 330 MW due to retirements in July 2012, which increased capacity prices in this quarter.
  - ✓ Previously, Long Island prices were equal to Rest of State prices because of the substantial excess capacity on Long Island.

Capacity Market Results



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

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