Quarterly Report on the New York ISO Electricity Markets Third Quarter 2014

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Highlights and Market Summary: Energy Market

- This report summarizes market outcomes in the third quarter of 2014.
- The energy markets performed competitively and variations in wholesale prices were driven primarily by changes in fuel prices, demand, and supply availability.
- Lower natural gas prices and load levels contributed to lower LBMPs, congestion, and uplift charges this quarter (compared to the third quarter of 2013).
  - ✓ Average load (19.6 GW) fell 5 percent and peak load (29.8 GW) fell 12 percent primarily because of mild weather. (see slide 10)
    - – Both average and peak load levels were the lowest in the past five years.
  - ✓ Average natural gas prices fell 30 percent in Western NY ($2.27/MMBtu) and 34 percent in NYC ($2.45/MMbtu). (see slide 11)
    - – Gas prices in NY were significantly lower than most of the U.S. (e.g., Henry Hub prices averaged $3.94/MMbtu) because of excess supply in the Marcellus region.
- RT LBMPs averaged $36/MWh statewide, down 34 percent from a year ago.
  - ✓ LBMPs fell most in Southeast NY (39 percent) because a large share of supply relies on natural gas from pipelines offering low-priced natural gas.
  - ✓ LBMPs fell least in the West Zone (20 percent) because of increased congestion on west-to-east flows through the zone, primarily in September.

Highlights and Market Summary: Congestion Patterns

- Day-ahead congestion revenues totaled $46 million, down 64 percent from the third quarter of 2013. (see slides 44–54)
  - ✓ Decreased load levels, less frequent TSAs, and less frequent peaking conditions reduced congestion across the system.
  - ✓ Congestion across the Central-East interface, the UPNY-SENY interface, and in NYC accounted for just $15 million of day-ahead congestion revenues, down 82 percent from the third quarter of 2014.
    - Low natural gas prices reduce congestion in these areas because most of the re-dispatch to manage congestion requires gas-fired generation; and
    - The Ramapo Line was more effective in reducing congestion in eastern NY in 2014 because of enhancements in the M2M process and because the line was partially de-rated for most of 2013.
  - ✓ However, transmission bottlenecks on west-to-east flows through the West Zone became more prevalent the third quarter of 2014 because of:
    - Reduced imports from PJM because of low gas prices in NY.
    - Increased imports from Ontario;
    - Planned and forced outages of generation and transmission in mid to late September.

Highlights and Market Summary: Uplift and Revenue Shortfalls

- Lower gas prices and load levels contributed to lower uplift and revenue shortfalls in the third quarter of 2014 compared with the third quarter of the previous year.
- Guarantee payments totaled $17 million, down 69 percent. (see slides 68–70)
  - ✓ Long Island uplift fell 86 percent, accounting for the largest reduction. Both supplemental commitments and OOM dispatch fell by more than 80 percent because transmission upgrades reduced the need to:
    - Burn oil to protect Long Island from a loss of gas; and
    - Dispatch peaking units to manage voltage constraints.
- Day-ahead congestion shortfalls were $8 million, similar to the third quarter of 2013. (see slide 48)
  - ✓ Transmission outages in the West Zone accounted for 60 percent of the shortfalls.
- Balancing congestion shortfalls totaled $7 million, down 70 percent. (see slide 49)
  - ✓ TSA congestion was still the primary driver of shortfalls in this quarter, but the magnitude of congestion was much lower than in previous years because:
    - TSAs occurred less frequently; and
    - There was much less congestion into SENY because of the low gas prices and load levels.

Highlights and Market Summary: Capacity Market

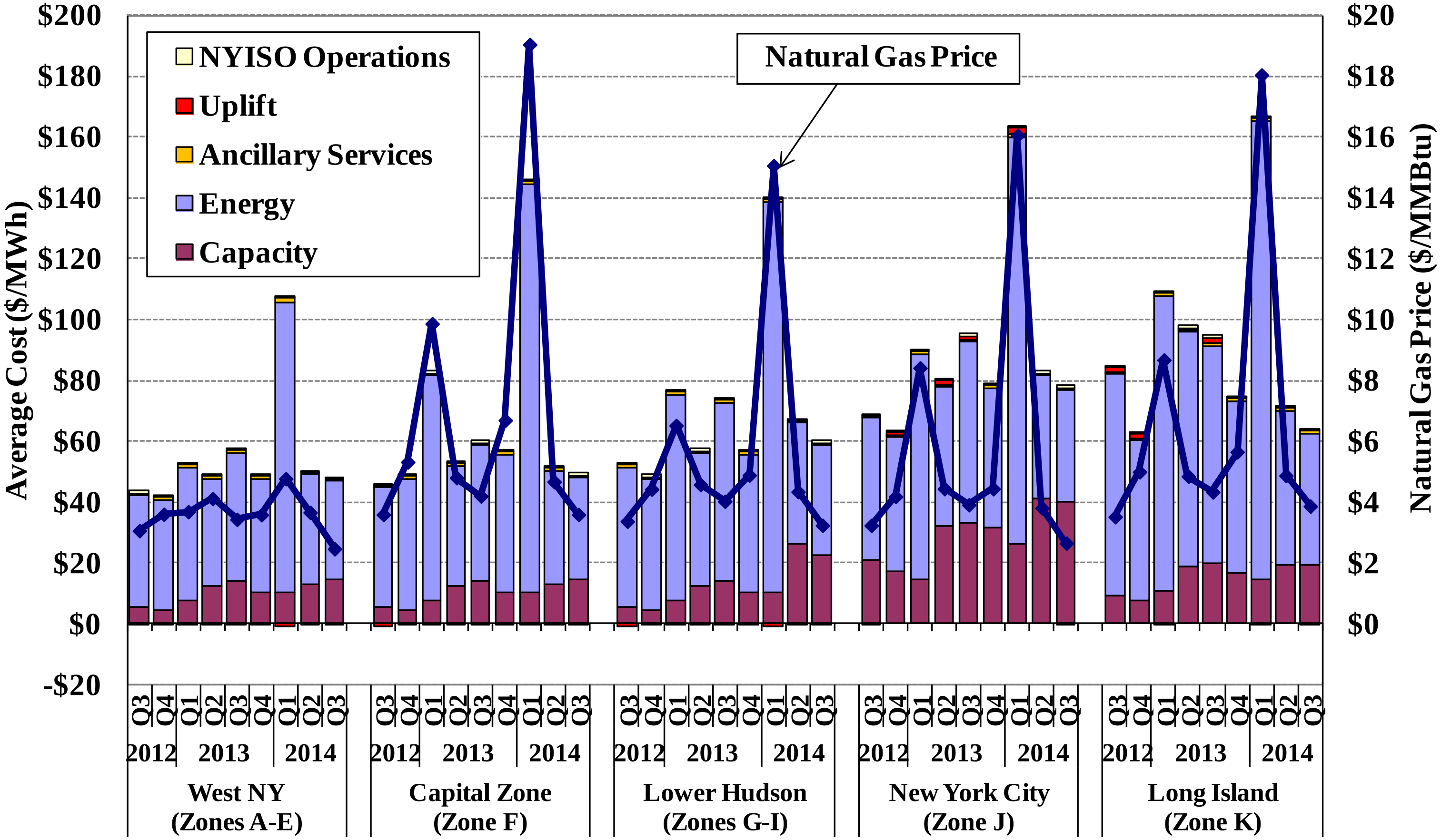
- UCAP spot prices rose in all areas but Long Island in the third quarter of 2014. (see slides 78–80) From the third quarter of 2013, UCAP spot prices:
  - ✓ In New York City, rose 17 percent to an average of \$18.47/kW-month;
  - ✓ In the newly created G-J Locality, averaged \$12.20/kW-month;
  - ✓ On Long Island, fell 9 percent to an average of \$6.47/kW-month; and
  - ✓ In Rest of State, rose 3 percent to an average of \$5.83/kW-month.
- ICAP requirements increased (453 MW in NYCA & 138 MW in NYC) because of an increase in forecasted peak load from the 2013/14 Capability Year, contributing to higher spot prices in those areas.
  - ✓ Long Island spot prices decreased because the UCAP demand curve fell by 20 percent from the previous year.
  - ✓ The new G-J Locality better reflects the reliability need to secure the UPNY-SENY interface and greatly enhances the efficiency of investment signals in this area.
- There was virtually no unsold capacity in the G-J Locality, New York City, and Long Island.

Energy Market Outcomes

All-In Prices

- The first figure summarizes the total cost per MWh of load served in the New York markets by showing the "all-in" price that includes:
  - ✓ An energy component that is a load-weighted average real-time energy price.
  - ✓ A capacity component based on spot prices multiplied by capacity obligations.
  - ✓ The NYISO cost of operations and uplift from other Rate Schedule 1 charges.
- Average all-in prices ranged from $48/MWh in Western NY to $78/MWh in NYC, down 16 to 33 percent from the third quarter of 2013.
  - ✓ Energy prices fell in all areas this quarter, from 24 percent in Western NY to 39 percent in New York City and Long Island.
    - – Lower LBMPs were due primarily to lower gas prices and loads (see slides 9-11).
    - – However, the decreases were offset by reduced nuclear generation (see slide 14) and lower net imports (see slide 40).
  - ✓ The capacity costs rose $7 to $8/MWh in Lower Hudson Valley and NYC and were relatively comparable to a year ago in other regions (see slides 78-80).
    - – Capacity costs rose in NYC due to higher ICAP requirements and reduced capability and increased EFORds for existing resources.
    - – Capacity costs rose in the Lower Hudson Valley after the implementation of the new G-J Locality starting in May 2014.

All-In Energy Price by Region

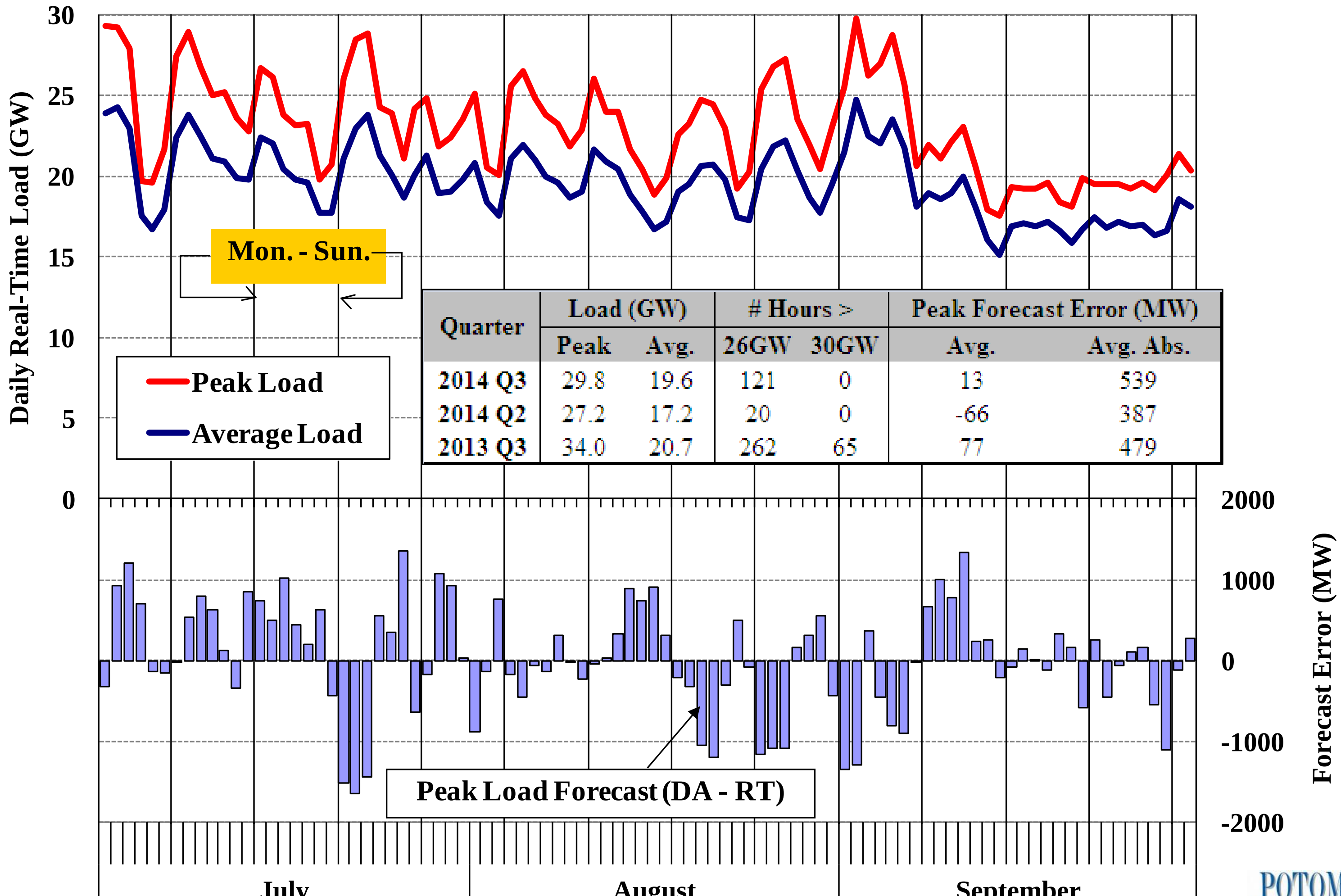


Note: Natural Gas Price is based on the following gas indices (plus a transportation charge of $0.20/MMbtu): the Dominion North index for West NY, the average of Tennessee Zone 6 and Iroquois Zone 2 for the Capital Zone, the average of Texas Eastern M3 and Iroquois Zone 2 for Lower Hudson, the Transco Zone 6 (NY) index for New York City, and the Iroquois Zone 2 index for Long Island.

Load Levels and Fuel Prices

- The next two figures show two primary drivers of electricity prices in the quarter.
  - ✓ The first figure shows the average load, the peak load, and the day-ahead peak load forecast error on each day of the quarter.
  - ✓ The second figure shows daily coal, natural gas, and fuel oil prices.
- Load levels fell notably from prior years, due partly to mild summer weather.
  - ✓ Average load (19.6 GW) and peak load (29.8 GW) fell 5 and 12 percent respectively from last year, and both were the lowest in the past five years.
    - Load peaked in September (rather than in July or August) this quarter.
  - ✓ Daily peak load forecasting was generally good during the quarter, although the magnitude of forecast errors increased at higher load levels.
- Natural gas prices averaged $2.27 at Dominion North (West NY), $2.45 at Transco Zone 6 (NYC), and $3.67 at Iroquois Zone 2 (most other East NY areas).
  - ✓ Average gas prices in most locations fell from the previous year (11 percent on Long Island, 30 percent in West NY, and 34 percent in NYC).
    - Gas prices in NY were lower than in the rest of the country (e.g., Henry Hub averaged $3.94), reducing net imports from PJM by an average of over 500 MW.
    - Decreased gas price spreads between West NY and NYC contributed to the reduction of NYISO market congestion into SENY and NYC.

Load Forecast and Actual Load



Quarter	Load (GW)		# Hours >		Peak Forecast Error (MW)	
	Peak	Avg.	26GW	30GW	Avg.	Avg. Abs.
2014 Q3	29.8	19.6	121	0	13	539
2014 Q2	27.2	17.2	20	0	-66	387
2013 Q3	34.0	20.7	262	65	77	479

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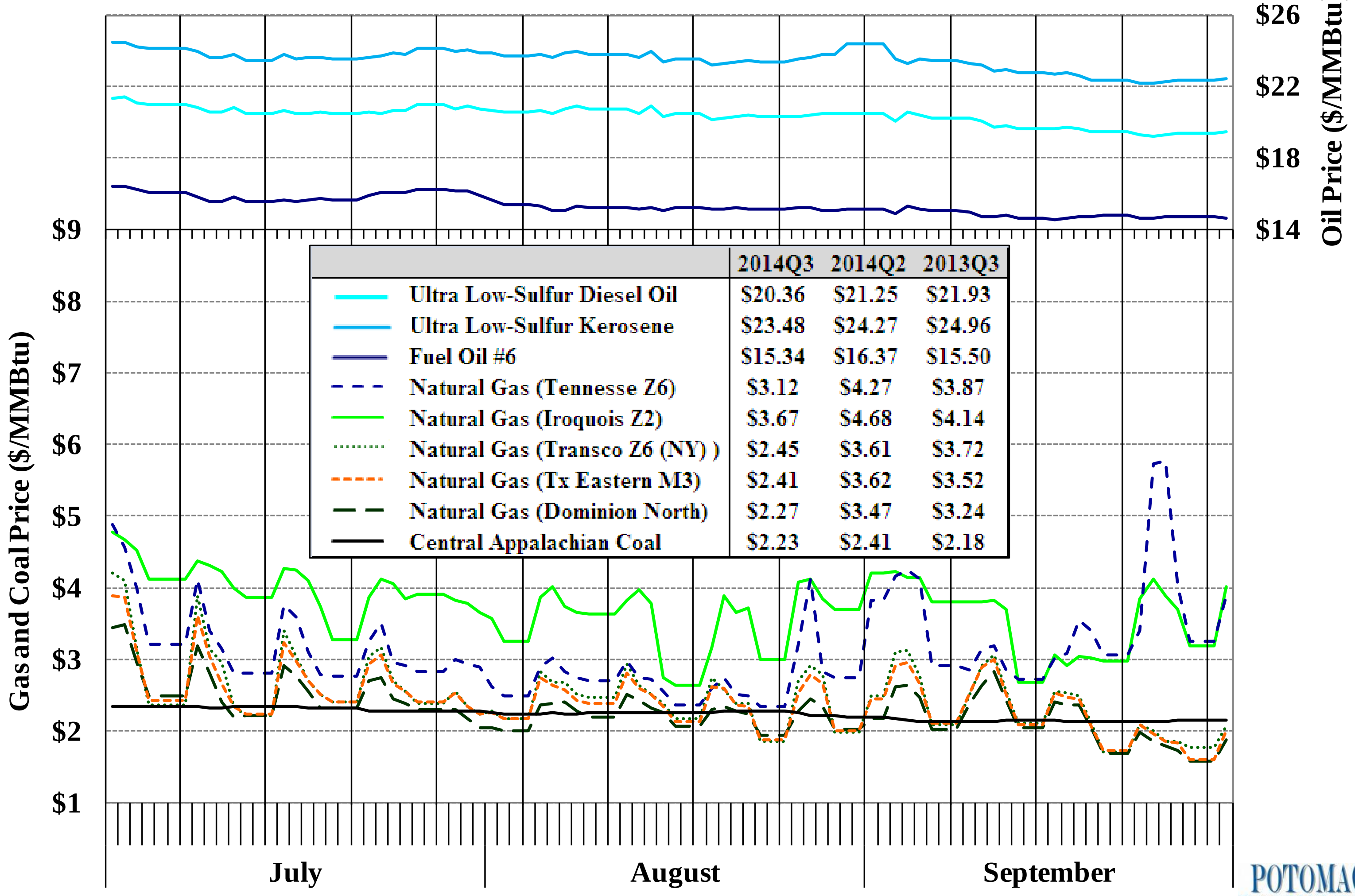
Coal, Natural Gas, and Fuel Oil Prices



	2014Q3	2014Q2	2013Q3
Ultra Low-Sulfur Diesel Oil	$20.36	$21.25	$21.93
Ultra Low-Sulfur Kerosene	$23.48	$24.27	$24.96
Fuel Oil #6	$15.34	$16.37	$15.50
Natural Gas (Tennesse Z6)	$3.12	$4.27	$3.87
Natural Gas (Iroquois Z2)	$3.67	$4.68	$4.14
Natural Gas (Transco Z6 (NY))	$2.45	$3.61	$3.72
Natural Gas (Tx Eastern M3)	$2.41	$3.62	$3.52
Natural Gas (Dominion North)	$2.27	$3.47	$3.24
Central Appalachian Coal	$2.23	$2.41	$2.18

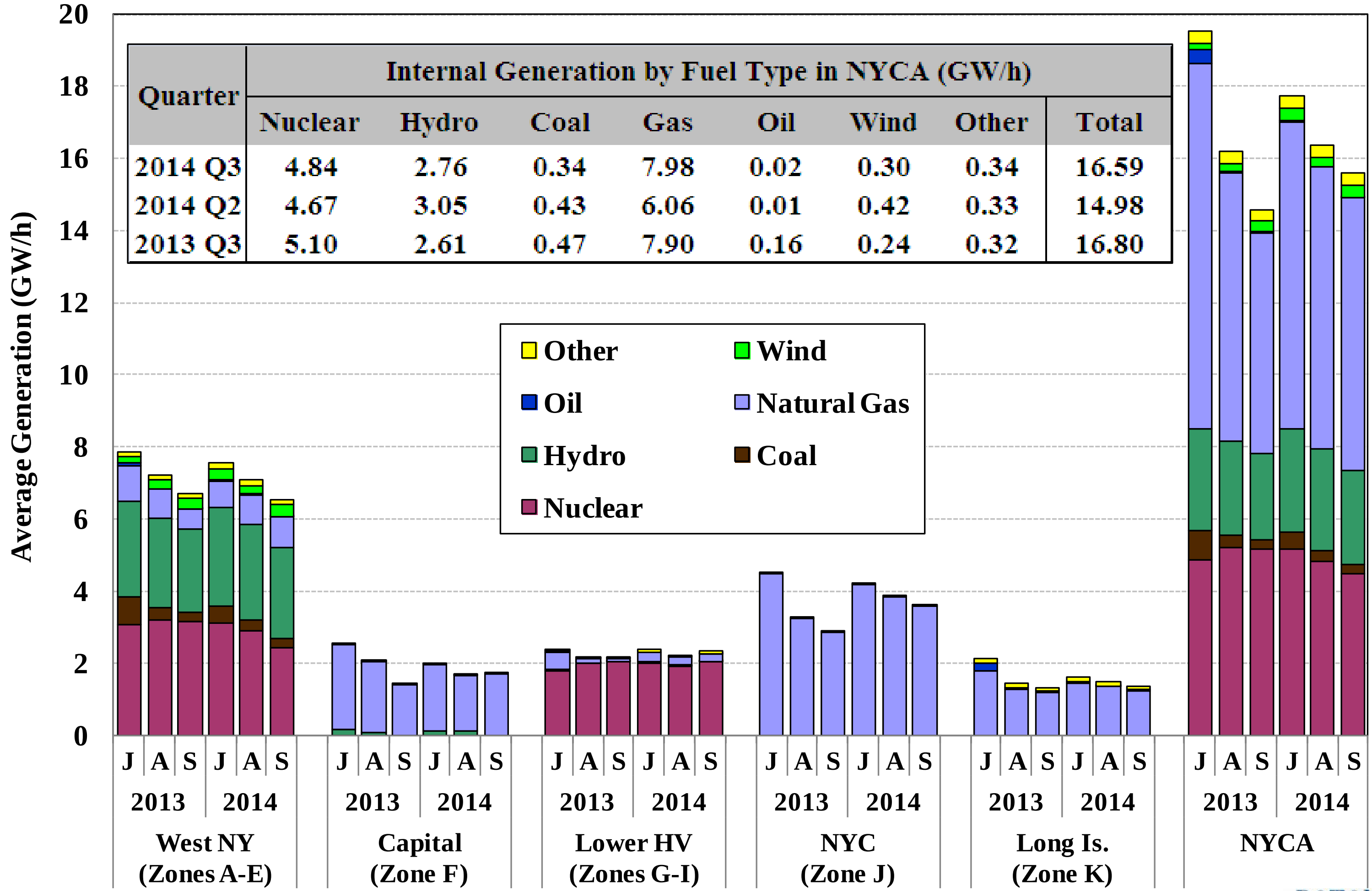
Real-Time Generation by Fuel Type

- The following two figures summarize fuel usage by generators in NYCA and their impact on LBMPs in the third quarter of 2014.
- The first figure shows the quantities of real-time generation by fuel type in the NYCA and in each region of New York.
- The second figure summarizes how frequently each fuel type is on the margin and setting real-time LBMPs in these regions.
  - ✓ More than one type of generator may be on the margin in an interval, particularly when a transmission constraint is binding. Accordingly, 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.
  - ✓ When no generator is on the margin in a particular region, the LBMPs in that region are set by:
    - – Generators in other regions in the vast majority of intervals; or
    - – Shortage pricing of ancillary services, transmission constraints, and/or energy in a small share of intervals.
- The fuel type for each generator is based on its actual fuel consumption reported to the EPA and the EIA.

Real-Time Generation and Marginal Units by Fuel Type

- Gas-fired (48 percent), nuclear (29 percent), and hydro (17 percent) generation accounted for most of internal generation in the third quarter of 2014.
  - ✓ Average nuclear generation fell 260 MW from the third quarter of 2013 due primarily to increased deratings and outages.
  - ✓ Average hydro generation rose 150 MW from the third quarter of 2013.
  - ✓ The overall amount of gas-fired generation was consistent with a year ago. However, gas-fired generation rose in NYC and fell in the rest of Eastern NY, reflecting increased spreads in natural gas prices between the two areas.
  - ✓ Oil-fired generation fell primarily because of transmission upgrades in Long Island (see slide 61).
- Gas-fired and hydro resources were on the margin most of time in New York.
  - ✓ Most hydro units on the margin have storage capacity, leading them to offer based on the opportunity cost of foregone sales in other hours (when gas units are marginal).
  - ✓ Oil, coal, and wind units were on the margin less often than the previous year.
    - Transmission upgrades in the North Zone led to fewer curtailments of wind;
    - Coal units were less economic due to lower natural gas prices; and
    - Lower load levels and transmission upgrades in Long Island reduced the use of oil units.

Real-Time Generation Output by Fuel Type

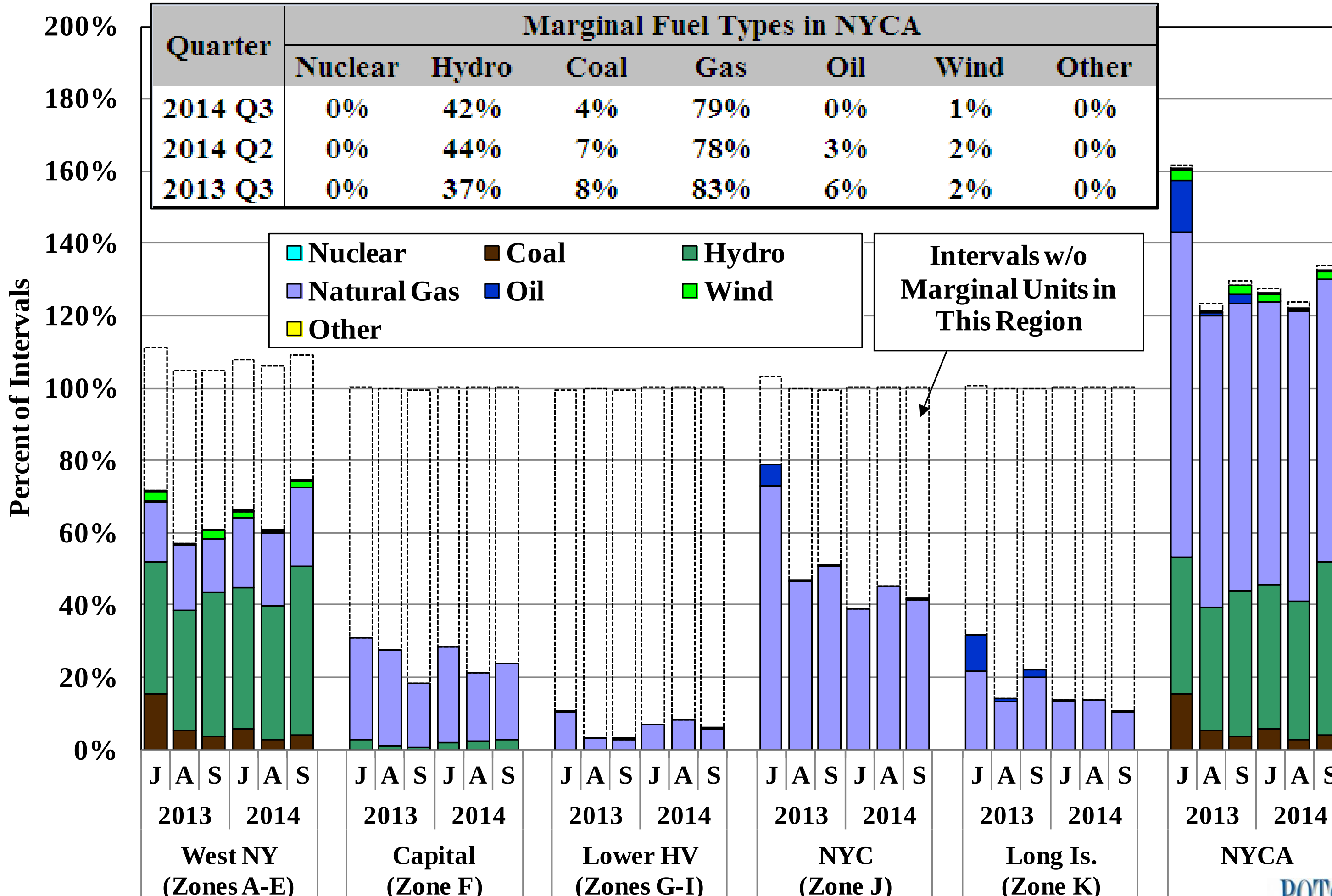


Quarter	Internal Generation by Fuel Type in NYCA (GW/h)							
	Nuclear	Hydro	Coal	Gas	Oil	Wind	Other	Total
2014 Q3	4.84	2.76	0.34	7.98	0.02	0.30	0.34	16.59
2014 Q2	4.67	3.05	0.43	6.06	0.01	0.42	0.33	14.98
2013 Q3	5.10	2.61	0.47	7.90	0.16	0.24	0.32	16.80

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

Quarter	Marginal Fuel Types in NYCA						
	Nuclear	Hydro	Coal	Gas	Oil	Wind	Other
2014 Q3	0%	42%	4%	79%	0%	1%	0%
2014 Q2	0%	44%	7%	78%	3%	2%	0%
2013 Q3	0%	37%	8%	83%	6%	2%	0%



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

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Day-Ahead and Real-Time Electricity Prices

- The following three figures show: 1) load-weighted average DA energy prices; 2) load-weighted average RT energy prices; and 3) convergence between DA and RT prices for five zones on a daily basis in the third quarter of 2014.
- Average day-ahead prices ranged roughly from \$34/MWh in the West Zone to \$45/MWh on Long Island, down 15 to 31 percent from the third quarter of 2013.
  - ✓ Lower LBMPs were driven primarily by lower loads and decreased gas prices.
    - However, these reductions were partly offset by decreased net imports (810 MW) and lower nuclear generation (260 MW).
  - ✓ Long Island exhibited the largest reduction in LBMPs among all areas.
    - More efficient utilization of some generating capacity contributed to lower LBMPs compared to the previous year.
  - ✓ The West Zone exhibited the smallest reduction in LBMP because of increased congestion in this area (particularly in mid-September) as a result of:
    - Multiple planned transmission outages that reduced transfer capability from Niagara-to-Packard and from Packard-to-Sawyer;
    - Several planned outages of generation that relieves this congestion; and
    - Increased hydro production in western NY and imports from Ontario.

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Day-Ahead and Real-Time Electricity Prices

- Prices are generally more volatile in the real-time market than in the day-ahead market due to unexpected events. Notable examples include:
  - ✓ TSAs were called on 11 days (July 2, 3, 8, 14, 15, 23, 28; August 1, 21, 31; and Sept. 6) during which transfer capability into SENY was greatly reduced, leading to very high LBMPs in SENY on several days (e.g., Sept. 6).
    - Fewer TSAs were called compared to the third quarter of 2013 (when there were 18 days), contributing to the reduction in RT price volatility in SENY this quarter.
  - ✓ Actual load was unexpectedly high and ran over day-ahead forecast by over 1 GW on several days, contributing to RT price spikes across the system (e.g., July 22).
  - ✓ West Zone LBMPs rose in September when RT congestion became more volatile partly because of volatile clockwise loop flows around Lake Erie. (See slide 42)
- 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.
  - ✓ Average day-ahead prices were 2 to 4 percent higher than real-time prices in most areas this quarter but were 5 percent lower in the West Zone.
    - The vast majority of the real-time premiums in the West Zone accrued in September because of more frequent RT spikes.

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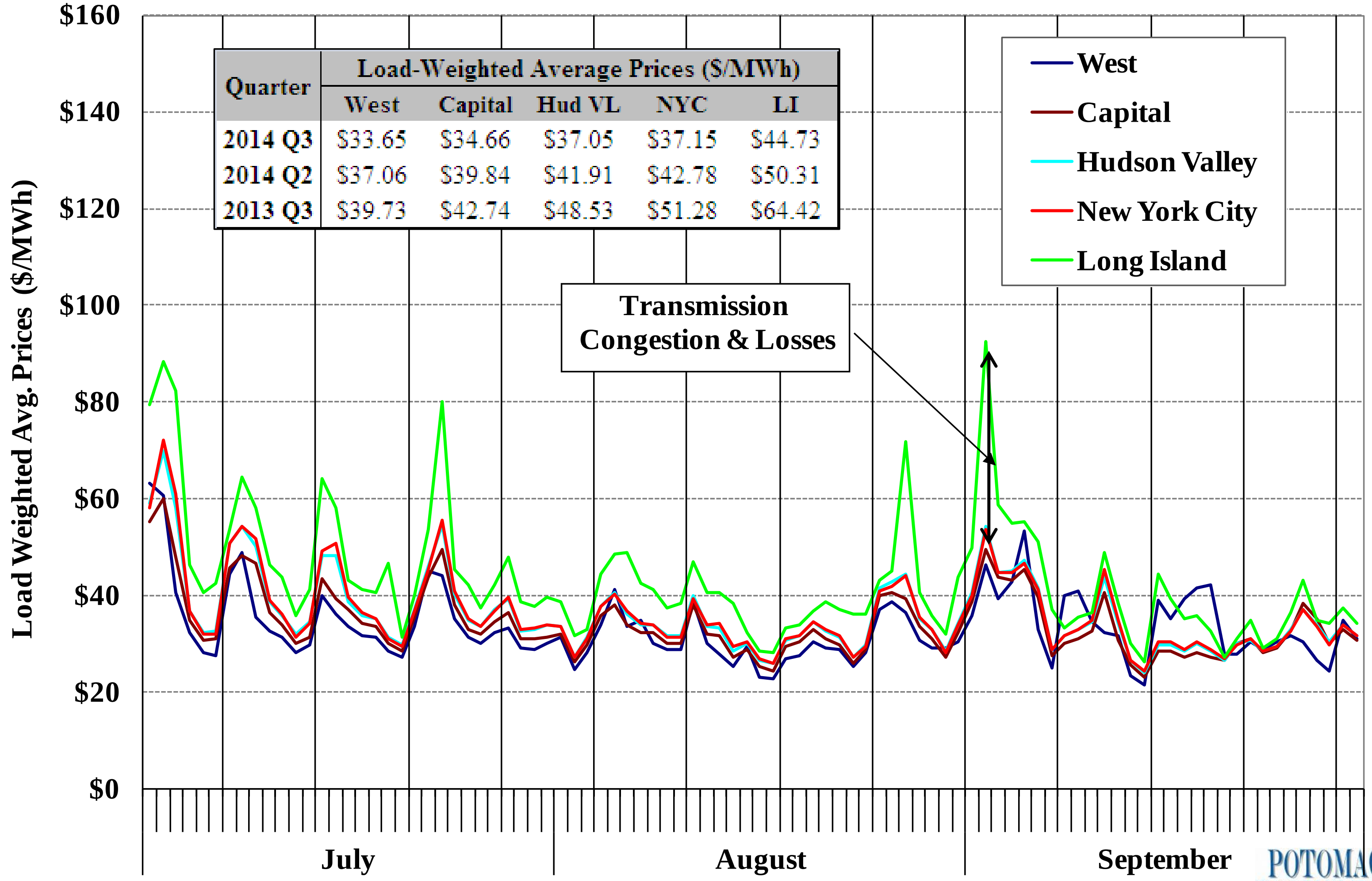
Day-Ahead Electricity Prices by Zone



Quarter	Load-Weighted Average Prices ($/MWh)				
	West	Capital	Hud VL	NYC	LI
2014 Q3	$33.65	$34.66	$37.05	$37.15	$44.73
2014 Q2	$37.06	$39.84	$41.91	$42.78	$50.31
2013 Q3	$39.73	$42.74	$48.53	$51.28	$64.42

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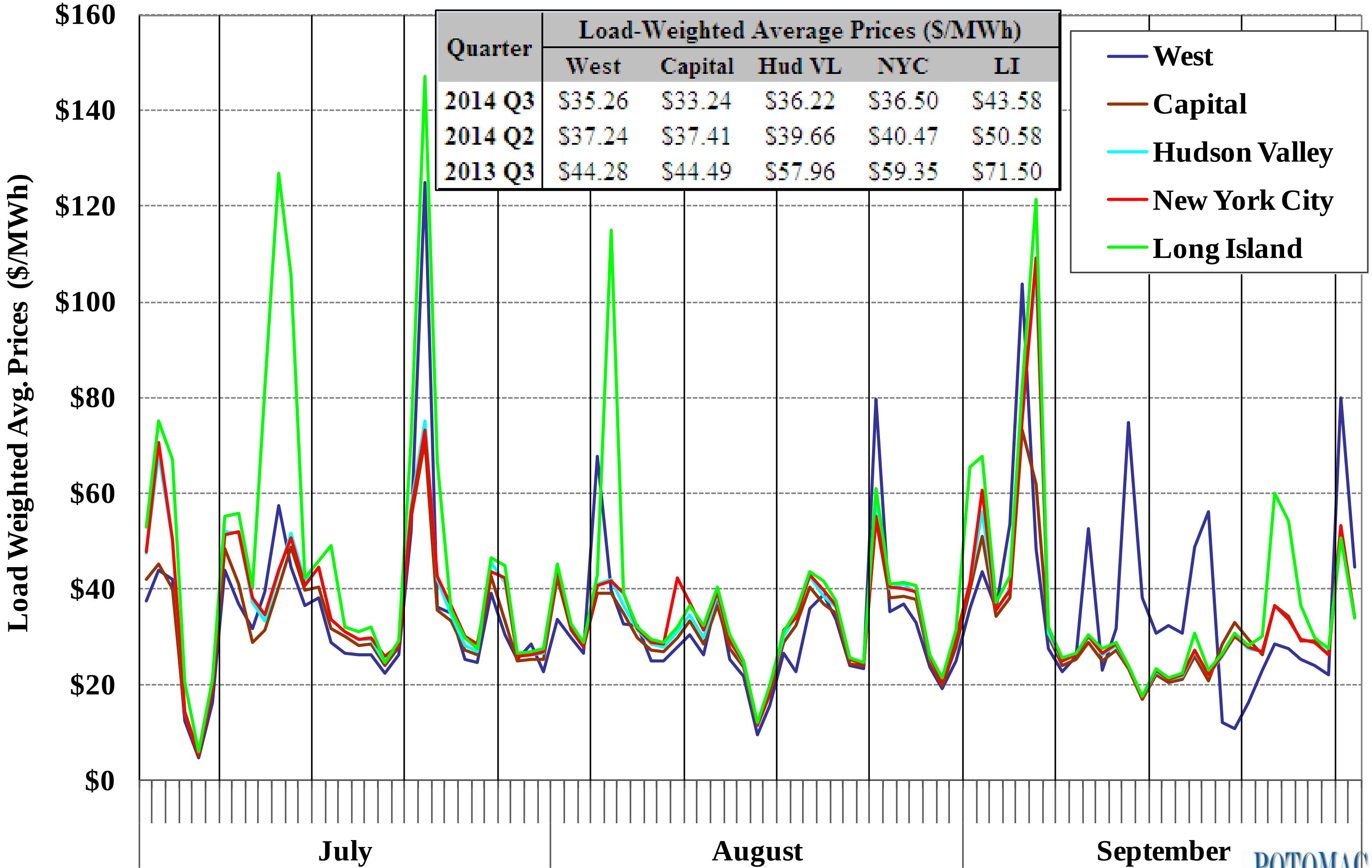
Real-Time Electricity Prices by Zone



Quarter	Load-Weighted Average Prices ($/MWh)				
	West	Capital	Hud VL	NYC	LI
2014 Q3	$35.26	$33.24	$36.22	$36.50	$43.58
2014 Q2	$37.24	$37.41	$39.66	$40.47	$50.58
2013 Q3	$44.28	$44.49	$57.96	$59.35	$71.50

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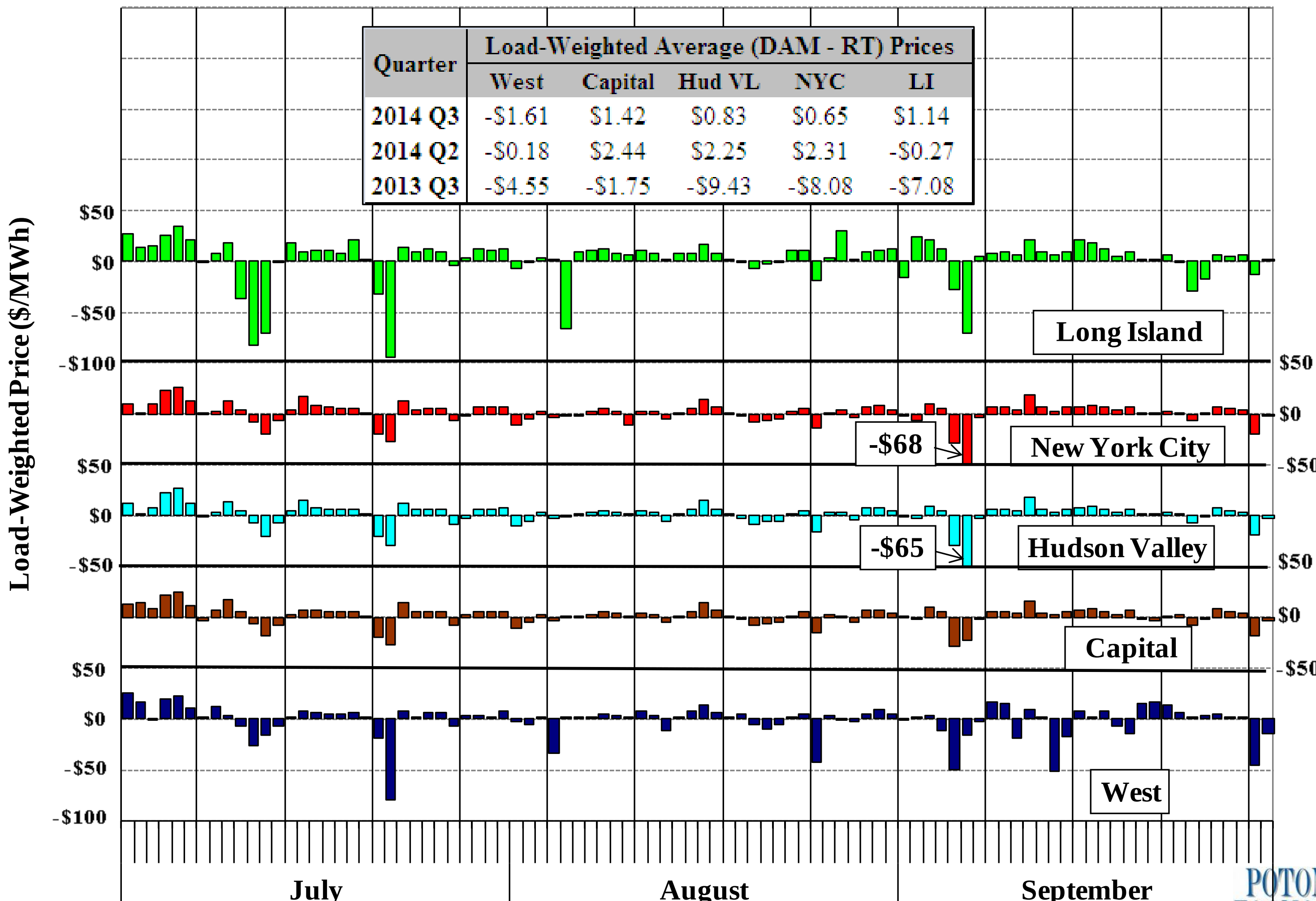
Convergence Between Day-Ahead and Real-Time Prices



Quarter	Load-Weighted Average (DAM - RT) Prices				
	West	Capital	Hud VL	NYC	LI
2014 Q3	-$1.61	$1.42	$0.83	$0.65	$1.14
2014 Q2	-$0.18	$2.44	$2.25	$2.31	-$0.27
2013 Q3	-$4.55	-$1.75	-$9.43	-$8.08	-$7.08

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Energy Offer Patterns over the Gas Day

- Generators' fuel costs are affected by the natural gas scheduling rules.
  - ✓ The gas day runs from 10:00 am to 10:00 am on the following calendar day.
  - ✓ The last intraday nomination deadline is 6:00 pm for many pipelines—this is 16 hours before the end of the gas day.
  - ✓ Generators that consume more or less than their scheduled nominations may incur gas balancing charges.
  - ✓ Hence, gas balancing charges affect offer prices for some generators in the late afternoon, evening, and morning hours.
- The following figure summarizes RT offers from gas-only and dual-fueled thermal peaking units that are connected to local distribution pipelines in NYC and Long Island by time of day for the third quarter of 2013 and 2014. The figure shows:
  - ✓ Amounts of capacity offered in five price range categories relative to the DA offer price (e.g., if DA offer = \$50 and RT offer = \$65, then category is "\$10 to \$25");
  - ✓ The average RT LBMPs for NYC, Long Island, and the reference bus; and
  - ✓ A load profile for New York State.
- The figure excludes offers from peaking units on individual gas days if the unit had a maintenance outage or gas service outage for one or more hours.

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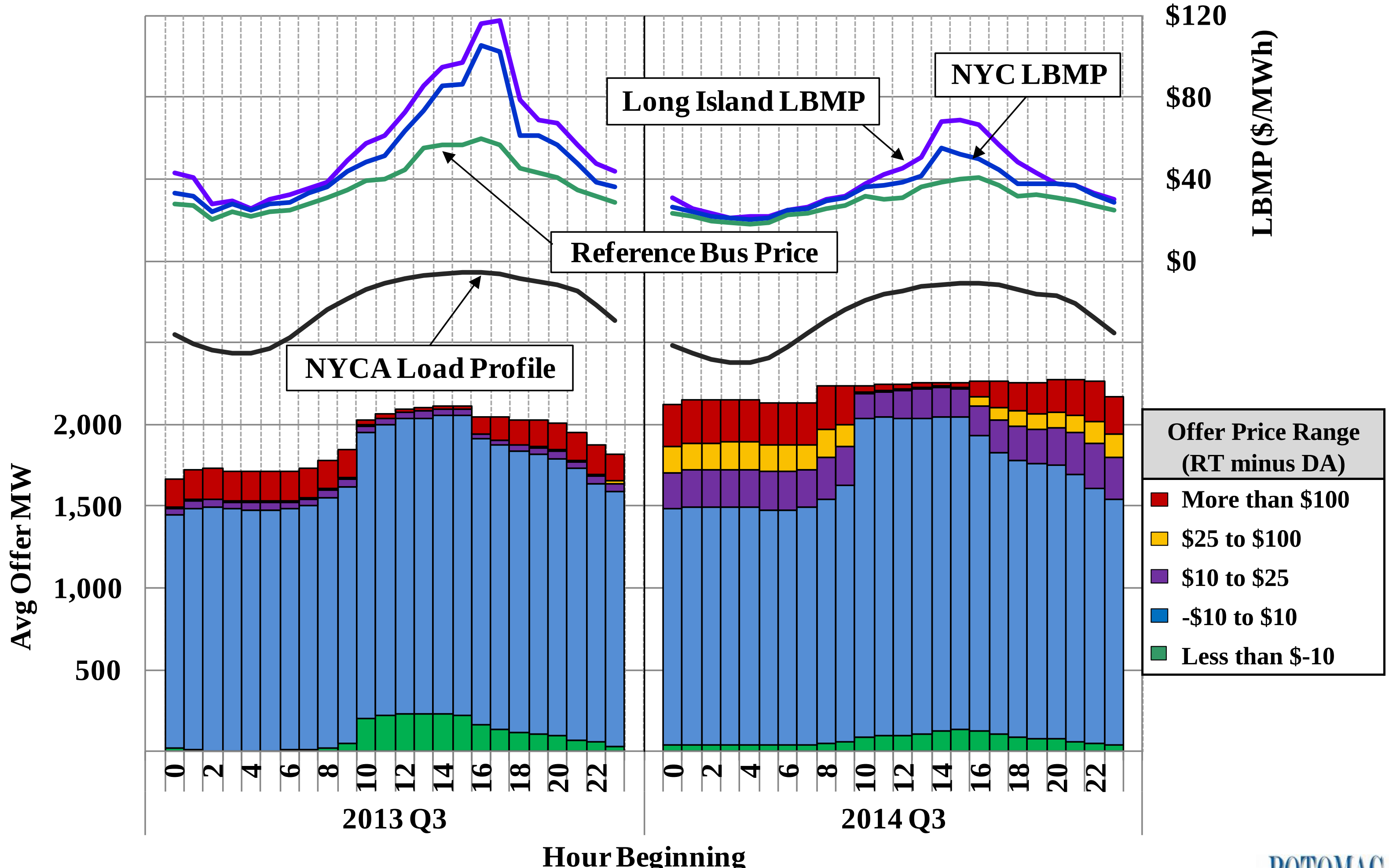
Energy Offer Patterns over the Gas Day

- From hour 10 to 15 (i.e., from 10:00 am to 4:00 pm), RT offer prices were relatively consistent with DA offer prices and nearly all capacity was offered.
  - ✓ Many of the offer price adjustments from the DA to the RT (i.e., after the DA) were in the downward direction in these hours.
    - After receiving a DA energy schedule, some suppliers adjust their offer prices down so that their RT operation will be consistent with their DA schedules.
    - However, this sometimes leads generators to burn scheduled gas before the time of day that would be most efficient.
- In other hours, some generators raise their RT offer prices or do not offer because of concerns about gas scheduling procedures and gas balancing charges.
  - ✓ The share of capacity that was not offered after the DAM was:
    - 12 percent in the third quarter of 2013; and
    - 2 percent in the third quarter of 2014.
  - ✓ Hence, LDC-connected gas-fired peaking units provided more flexibility in RT in the third quarter of 2014 than in the previous year. Overall, this has led to:
    - More efficient utilization of generation in downstate areas; and
    - Fewer RT price spikes during the late afternoon and evening hours.

Energy Offers from LDC-Connected Peaking Units by Time of Day, New York City & Long Island



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Ancillary Services Market

Ancillary Services Prices and Offer Patterns

- This part of the report evaluates the outcomes of the ancillary services markets.
- Two figures summarize DA and RT prices for four ancillary services products:
  - ✓ 10-min 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-min 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-min 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 procuring up to 300 MW of regulation, and the cost and uplift charges from moving regulation units up and down.
- The figures show the number of shortage intervals -- when a requirement cannot be satisfied at a marginal cost less than its "demand curve", which are:
  - ✓ $25 for eastern 10-minute spinning reserves;
  - ✓ $500 for eastern 10-minute total reserves;
  - ✓ $500 for statewide 10-minute spinning reserves; and
  - ✓ $80 to $400 for regulation.

Ancillary Services Prices and Offer Patterns

- The last two figures examine price convergence and offer patterns associated with two reserve products in more detail.
- The NYISO implemented a process to modify two DA ancillary services mitigation provisions in phases. Accordingly, the figure separates:
  - ✓ July to Sept. 2012 – Prior to any modification
  - ✓ July to Sept. 2013 – Phase 1: 10-min Spin offer cap for NYC units was raised from $0 to $5 and 10-min Non-Spin reference level cap was raised from $2.52 to $5.
  - ✓ July to Sept. 2014 – Phase 2: Both caps were raised to $10.
- We evaluate the market effects of these changes. Accordingly, the figures show:
  - ✓ The pattern of DAM reserve offers and DA-RT price convergence in the 10-minute non-spinning reserve market in eastern NY; and
  - ✓ The pattern of DAM 10-minute spinning reserve offers in NYC and DA-RT price convergence of the eastern 10-minute spinning reserves.
  - ✓ The figures show average DA and RT prices for each reserve category in the upper portion and average offer quantities based on offer price level in the lower portion.
    - – Quantities are shown by daily peak load level and by time of day.

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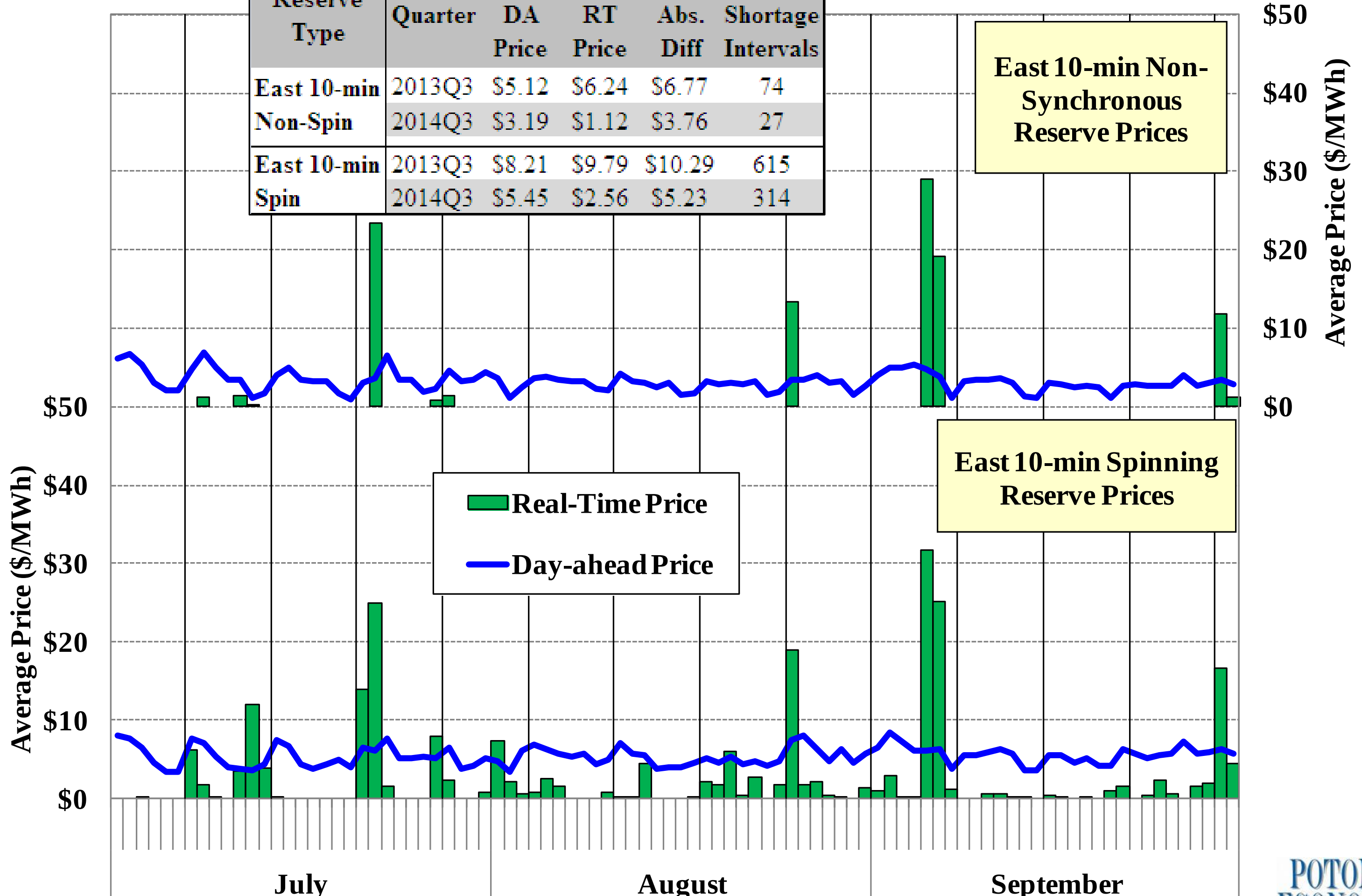
Ancillary Services Prices and Offer Patterns

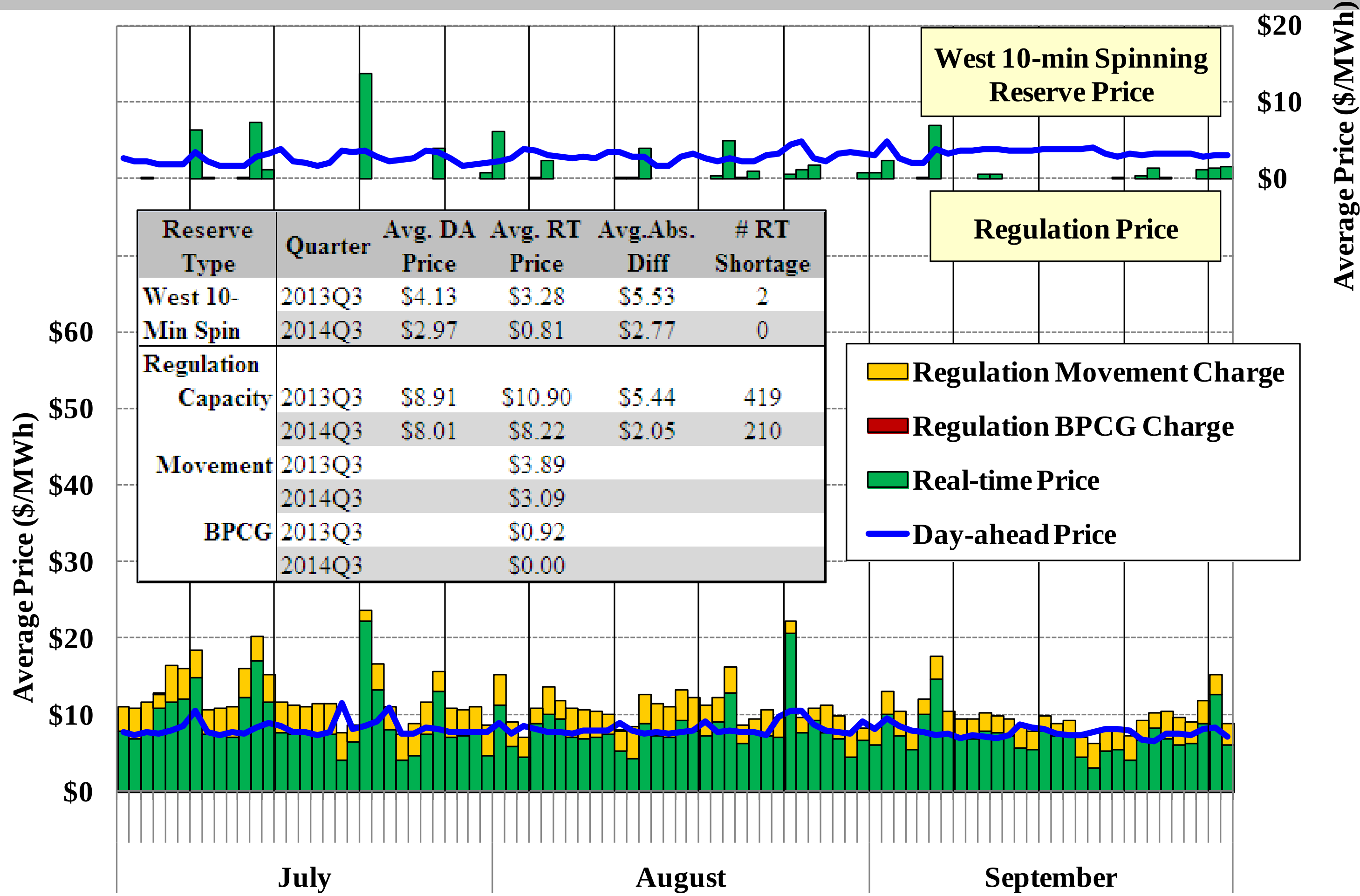
- Average day-ahead and real-time prices for all ancillary services products fell from the third quarter of 2013, consistent with the lower load levels and energy prices.
- Average DA prices were higher than average RT prices for most reserve products.
  - ✓ DAM price premiums are expected in competitive markets with no virtual trading.
  - ✓ There have been fewer RT events resulting in high RT price spikes compared with previous years. This is partly attributable to:
    - Fewer TSA events;
    - Lower load levels; and
    - Less need to OOM dispatch 10-minute GTs for Long Island voltage constraints following transmission upgrades (see slide 63).
- In our evaluation of the 10-min spin and non-spin reserves markets, we have not found offer patterns that raise significant withholding concerns.
  - ✓ Many suppliers have increased their offer prices consistent with expectations, particularly when RT prices are more likely to reach very high levels (e.g., hours 12-17 and when Eastern NY peak load > 19 GW).
    - Such increases are consistent with competitive behavior when the RT clearing price is expected to be higher than the DA clearing price.

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

Reserve Type	Quarter	Avg. DA Price	Avg. RT Price	Avg. Abs. Diff	# RT Shortage Intervals
East 10-min Non-Spin	2013Q3	$5.12	$6.24	$6.77	74
	2014Q3	$3.19	$1.12	$3.76	27
East 10-min Spin	2013Q3	$8.21	$9.79	$10.29	615
	2014Q3	$5.45	$2.56	$5.23	314



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

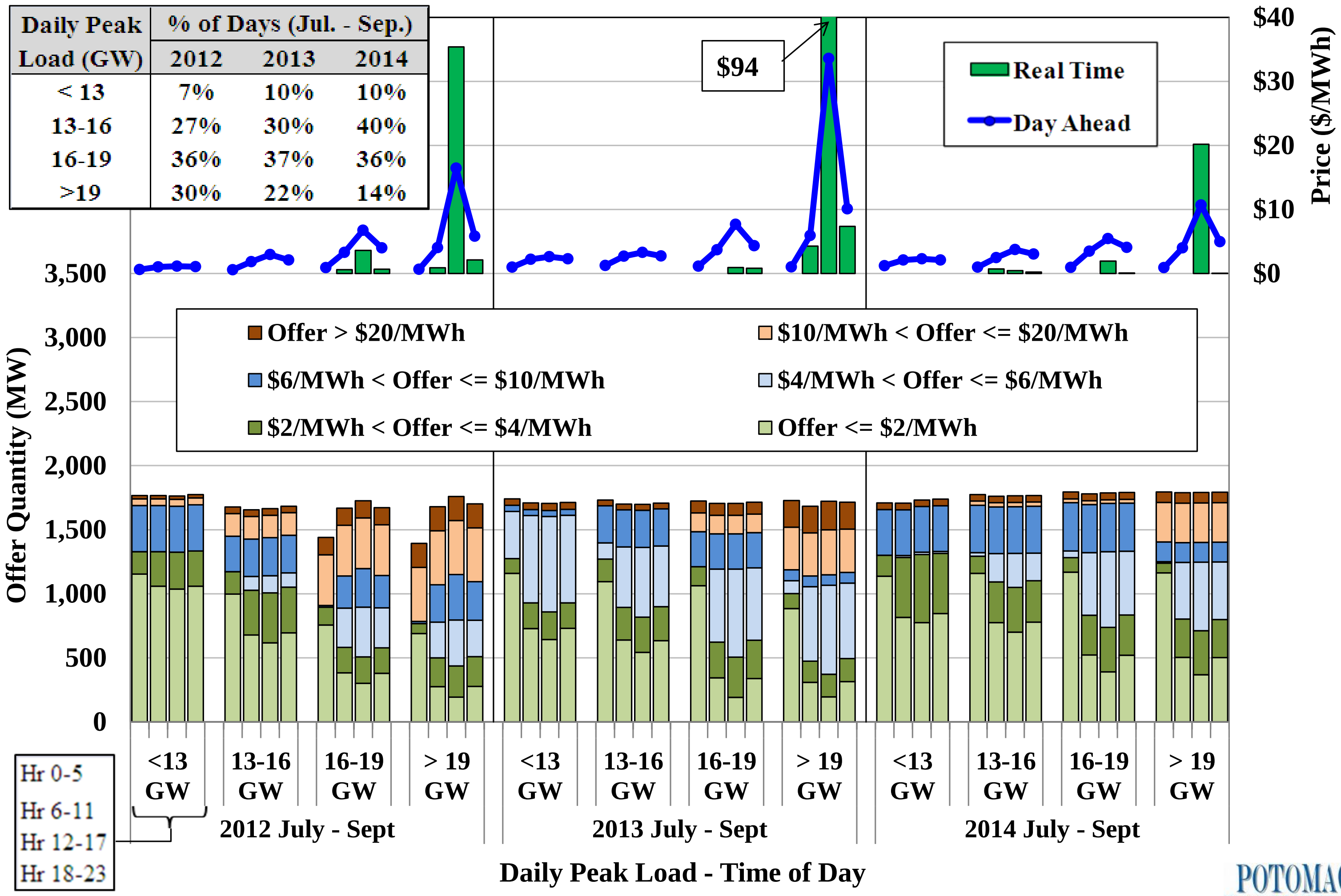


Reserve Type	Quarter	Avg. DA Price	Avg. RT Price	Avg.Abs. Diff	# RT Shortage
West 10-Min Spin	2013Q3	$4.13	$3.28	$5.53	2
	2014Q3	$2.97	$0.81	$2.77	0
Regulation					
Capacity	2013Q3	$8.91	$10.90	$5.44	419
	2014Q3	$8.01	$8.22	$2.05	210
Movement	2013Q3		$3.89		
	2014Q3		$3.09		
BPCG	2013Q3		$0.92		
	2014Q3		$0.00		

Note: Regulation Movement Charges and BPCG charges from regulating in real-time are shown in the figure averaged per MWh of RT Scheduled Regulation Capacity.

Day-Ahead Reserve Offers and Price Convergence
Eastern 10-Minute Non-Spinning Reserves

Daily Peak Load (GW)	% of Days (Jul. - Sep.) 2012	2013	2014
< 13	7%	10%	10%
13-16	27%	30%	40%
16-19	36%	37%	36%
>19	30%	22%	14%



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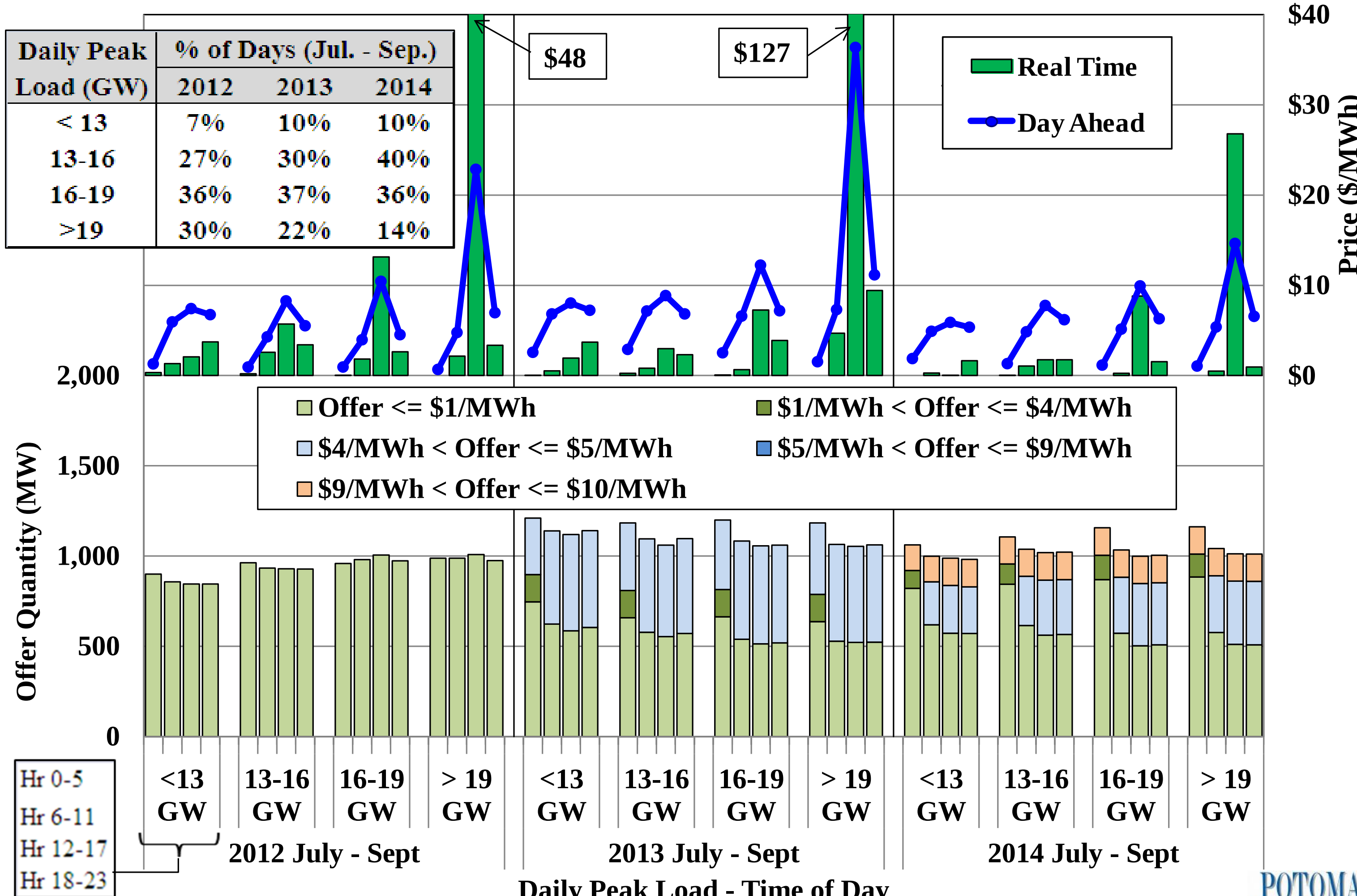
Day-Ahead Reserve Offers and Price Convergence
Eastern 10-Minute Spinning Reserves from NYC Units



Daily Peak Load (GW)	% of Days (Jul. - Sep.) 2012	2013	2014
< 13	7%	10%	10%
13-16	27%	30%	40%
16-19	36%	37%	36%
>19	30%	22%	14%

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Energy Market Scheduling

Day-ahead Load Scheduling

- The following figure summarizes the quantity of DA load scheduled as a percentage of RT load in each of five regions and state-wide.
  - ✓ Net scheduled load = Physical Bilaterals + Fixed Load + Price-Capped Load + Virtual Load – Virtual Supply
  - ✓ The table also summarizes a system-wide net scheduled load that includes virtual imports and virtual exports at the proxy buses.
- For NYCA, 96 percent of actual load was scheduled in the DAM (including virtual imports/exports) in the third quarter of 2014, similar to prior quarters.
- The percentage of load scheduled in the DAM was generally higher in SENY.
  - ✓ DAM scheduling was generally highest on Long Island where the most frequent periods of acute RT congestion occurred.
  - ✓ DAM scheduling in SENY (particularly in Other East Upstate) rose notably on days in July when TSAs were anticipated (see slide 17 for the TSA dates).
  - ✓ DAM scheduling in New York City has fallen in recent periods because of historically low natural gas prices in NYC that led to increased generation and decreased congestion in this area.
- Under-scheduling continued to be prevalent outside SENY, consistent with the tendency for hydro and wind units to increase RT output above DA schedules.

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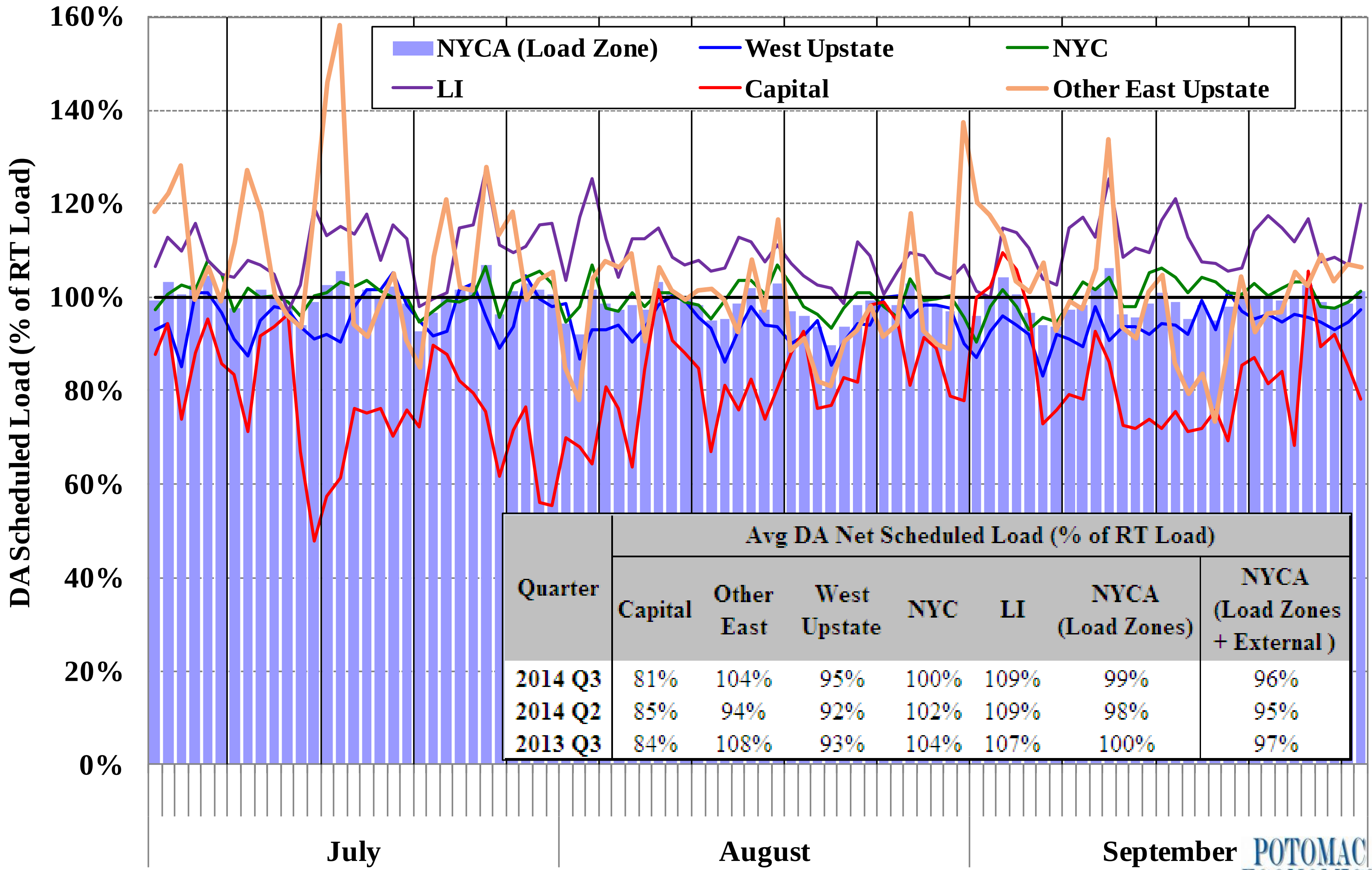
Day-ahead Scheduled Load and Actual Load
Daily Peak Load Hour



Quarter	Avg DA Net Scheduled Load (% of RT Load)						
	Capital	Other East	West Upstate	NYC	LI	NYCA (Load Zones)	NYCA (Load Zones + External)
2014 Q3	81%	104%	95%	100%	109%	99%	96%
2014 Q2	85%	94%	92%	102%	109%	98%	95%
2013 Q3	84%	108%	93%	104%	107%	100%	97%

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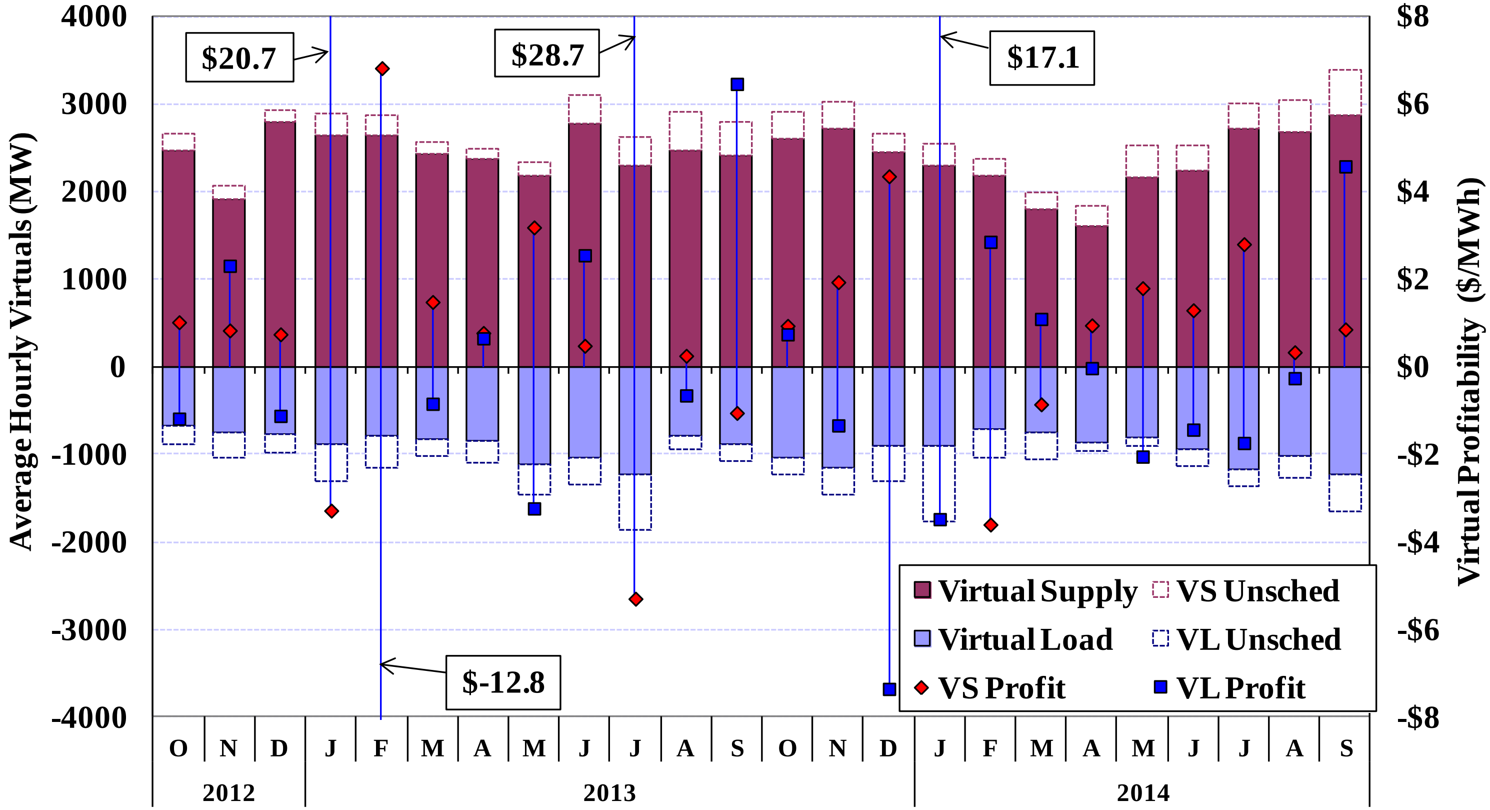
Virtual Trading Activity

- The following two charts summarize recent virtual trading activity in New York.
- The first figure shows monthly average scheduled and unscheduled quantities, and gross profitability for virtual transactions at the load zones in the past 24 months.
  - ✓ The table shows a screen for relatively large profits or losses, which identifies virtual trades with profits or losses larger than 50% of the average zone LBMP.
    - – Large profits may indicate modeling inconsistencies between DA and RT markets, and large losses may indicate manipulation of the day-ahead market.
- The second figure summarizes virtual trading by geographic region.
  - ✓ The load zones are broken into six regions based on typical congestion patterns.
    - – The North Zone is shown separately because transmission constraints frequently affect the value of power in that area.
    - – The Capital Zone is shown separately because it is constrained from West NY by the Central-East Interface and from SENY by constraints in the Hudson Valley.
    - – NYC and Long Island are shown separately because congestion frequently leads to price separation between them and other areas.
  - ✓ Virtual imports and exports are shown as they have similar effects on scheduling.
    - – A transaction is deemed virtual if the DA schedule is greater than the RT schedule, so a portion of these transactions result from forced outages or curtailments by NYISO or another control area (rather than the intent of the participant).

Virtual Trading Activity

- Virtual traders generally scheduled more virtual load in downstate areas and more virtual supply in upstate regions.
  - ✓ This was consistent with prior periods and typical load scheduling patterns.
- The amount of scheduled virtual supply increased from a year ago, reflecting prevailing day-ahead premiums in most regions this quarter (compared to an average real-time premium in the third quarter of 2013).
  - ✓ However, virtual load increased in the West Zone in response to high and volatile RT prices, which resulted from west-to-east congestion in the West Zone.
- In aggregate, virtual traders netted a gross profit of roughly $10 million at the load zones and over $1 million at the proxy buses in the third quarter of 2014.
  - ✓ Virtual transactions have been profitable over the period, indicating that they have generally improved convergence between DA and RT prices.
  - ✓ However, the profits and losses of virtual trades have varied widely by time and location, reflecting the difficulty of predicting volatile RT prices.
- Only small quantities of virtual transactions generated substantial profits or losses, consistent with similar periods in prior years.
  - ✓ These were primarily associated with high price volatility that resulted from unexpected events, which do not raise significant concerns.

Virtual Trading Activity at Load Zones by Month



		O	N	D	J	F	M	A	M	J	J	A	S	O	N	D	J	F	M	A	M	J	J	A	S
Profit > 50% of Avg. Zone Price	MW	143	238	202	418	426	191	187	328	253	345	156	193	230	438	319	590	260	250	83	169	160	421	136	289
	%	5%	9%	6%	12%	12%	6%	6%	10%	7%	10%	5%	6%	6%	11%	10%	18%	9%	10%	3%	6%	5%	11%	4%	7%
Loss > 50% of Avg. Zone Price	MW	93	182	195	354	347	125	149	275	166	252	176	177	201	369	258	395	333	256	70	196	199	346	185	289
	%	3%	7%	5%	10%	10%	4%	5%	8%	4%	7%	5%	5%	6%	10%	8%	12%	12%	10%	3%	7%	6%	9%	5%	7%

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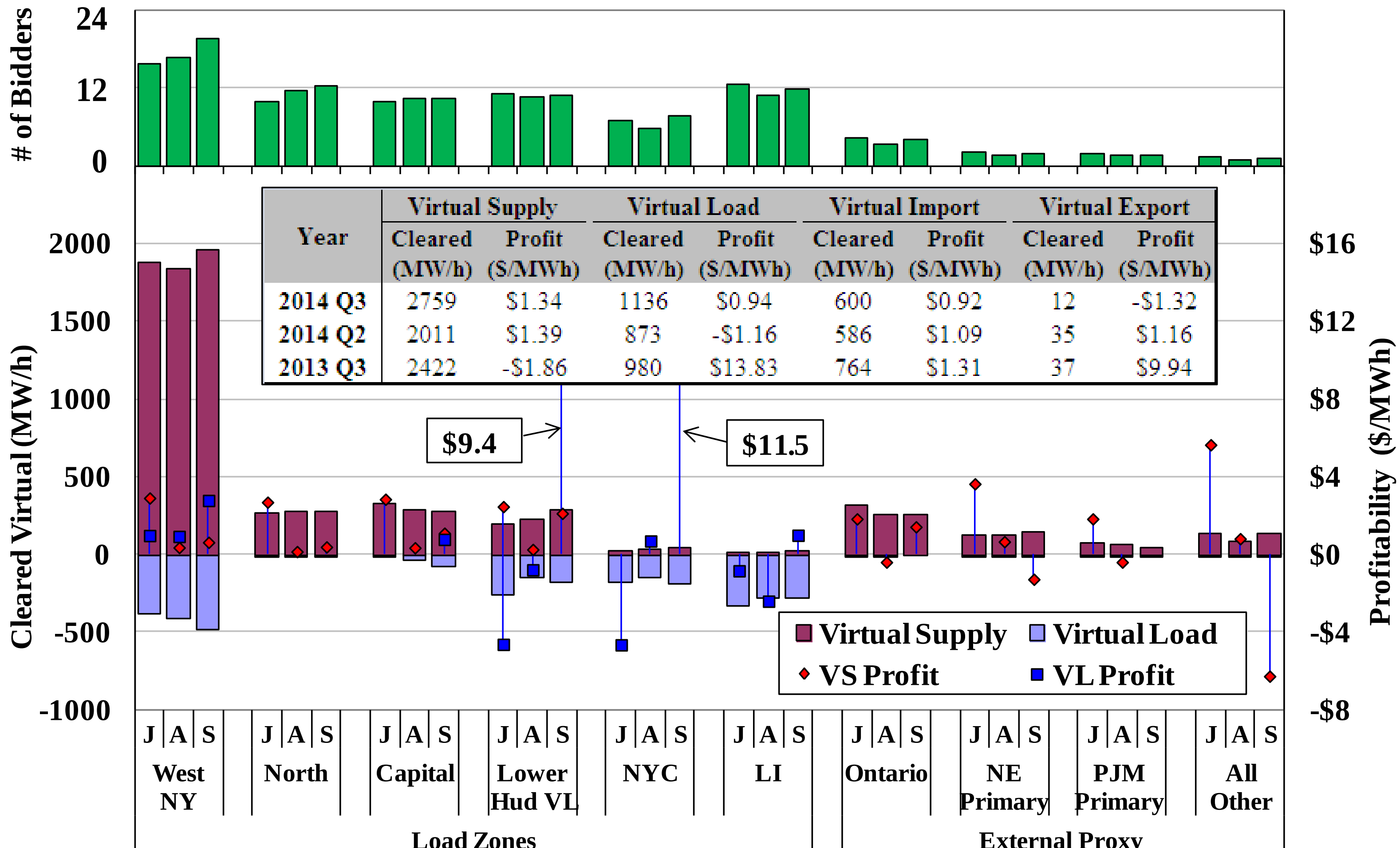
Virtual Trading Activity at Load Zones & Proxy Buses by Location



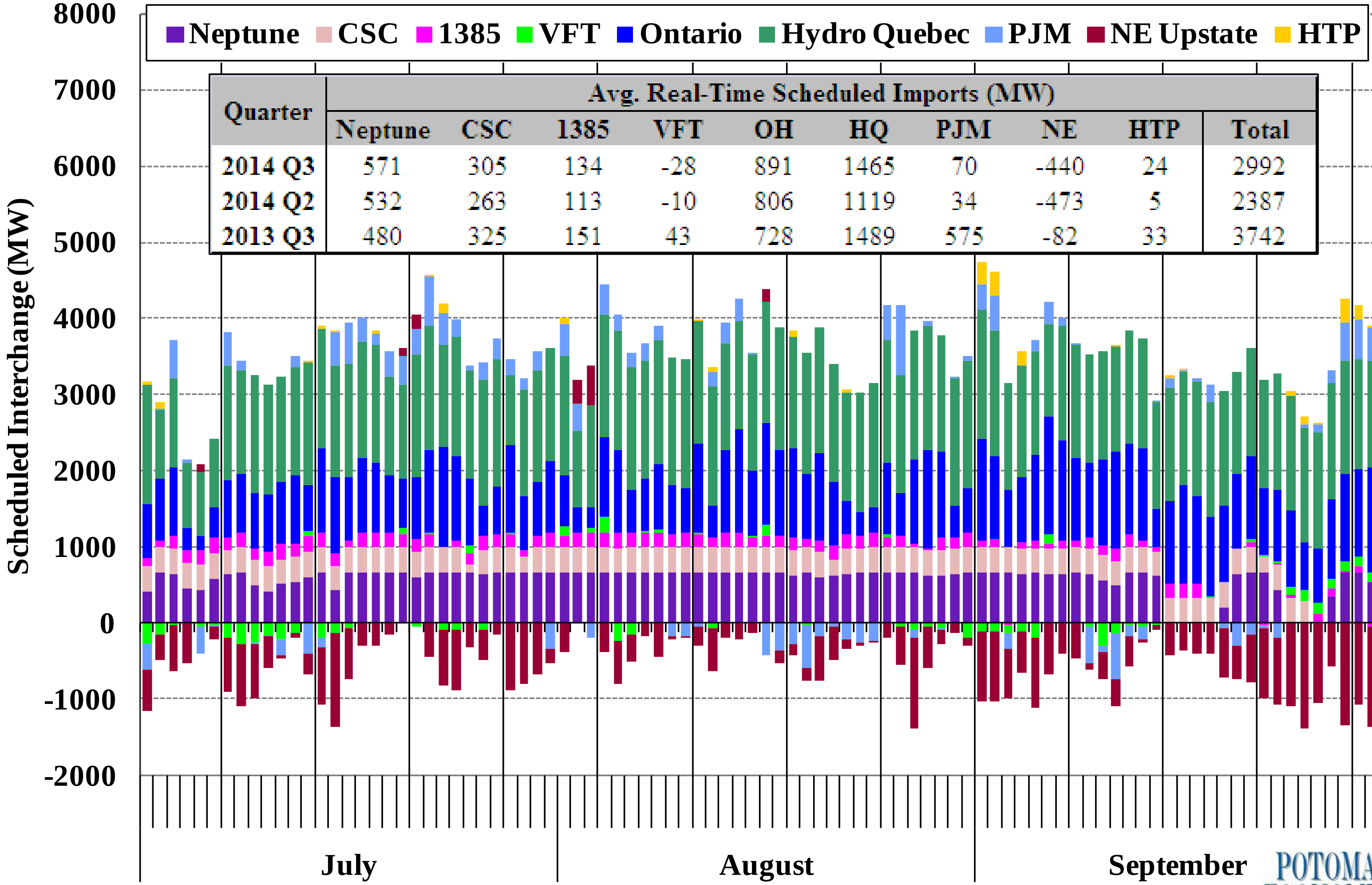
Year	Virtual Supply Cleared (MW/h)	Virtual Supply Profit ($/MWh)	Virtual Load Cleared (MW/h)	Virtual Load Profit ($/MWh)	Virtual Import Cleared (MW/h)	Virtual Import Profit ($/MWh)	Virtual Export Cleared (MW/h)	Virtual Export Profit ($/MWh)
2014 Q3	2759	$1.34	1136	$0.94	600	$0.92	12	-$1.32
2014 Q2	2011	$1.39	873	-$1.16	586	$1.09	35	$1.16
2013 Q3	2422	-$1.86	980	$13.83	764	$1.31	37	$9.94

Note: Virtual profit is not shown for a category if the average scheduled quantity is less than 50 MW.

Net Imports Scheduled Across External Interfaces

- The next figure shows average RT scheduled net imports to NYCA across ten external interfaces (two HQ interfaces are combined) in the peak hours (1-9 pm).
- Overall, net imports averaged 2,992 MW (serving roughly 15 percent of the load) during peak hours, down approximately 750 MW from the third quarter of 2013.
  - ✓ The reduction was primarily driven by lower net imports from NE and PJM.
- Net exports to NE across its primary interface averaged 440 MW during peak hours, up nearly 360 MW from last year.
  - ✓ This was consistent with increased spreads in natural gas prices between New York and New England over the period, particularly in September.
- Net imports from PJM (including VFT, HTP, and the primary interface) fell roughly 585 MW from the third quarter of 2013.
  - ✓ Natural gas prices in New York were low this quarter compared to the rest of the country, reducing incentives to import from other regions.
  - ✓ However, Neptune imports increased from the third quarter of 2013.

Net Imports Scheduled Across External Interfaces
Daily Peak Hours (1-9pm)



Quarter	Avg. Real-Time Scheduled Imports (MW)									
	Neptune	CSC	1385	VFT	OH	HQ	PJM	NE	HTP	Total
2014 Q3	571	305	134	-28	891	1465	70	-440	24	2992
2014 Q2	532	263	113	-10	806	1119	34	-473	5	2387
2013 Q3	480	325	151	43	728	1489	575	-82	33	3742

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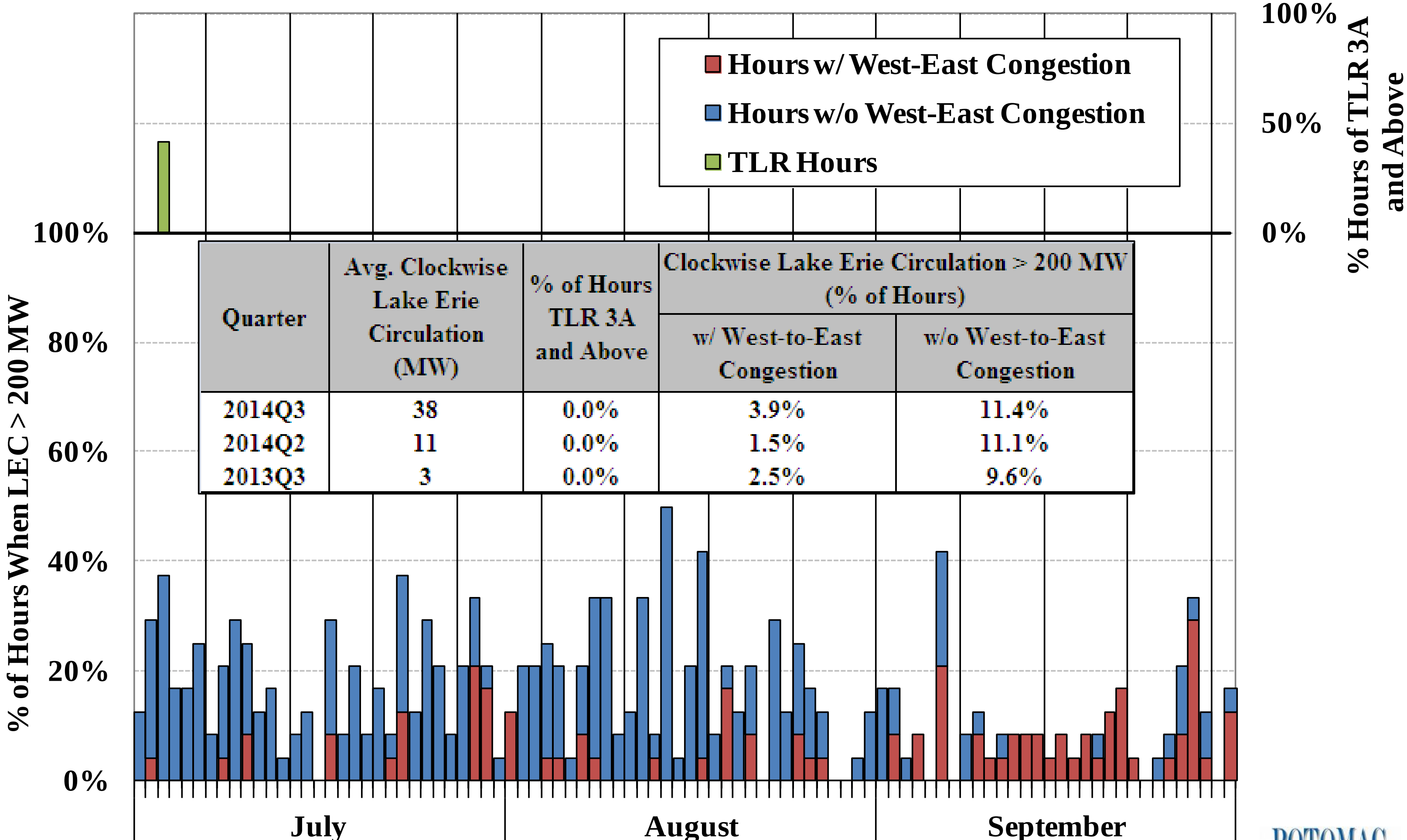
Lake Erie Circulation

- Loop flows occur when physical flows are not consistent with the scheduled path of a transaction between control areas or within a control area (from a generator to a load), so loop flow patterns are affected by many factors.
  - ✓ Clockwise Lake Erie Circulation ("LEC") use west-to-east transmission in upstate NY, reducing capacity available for scheduling internal generation to satisfy internal load and increasing congestion (e.g., on the Central-East interface).
- The figure summarizes the frequency of clockwise LEC and the frequency of TLRs (level 3A and above) called by the NYISO in the third quarter of 2014.
- Clockwise LEC was relatively high (> 200 MW) during 15 percent of all hours.
  - ✓ West-to-east congestion (including congestion in the West Zone, from West-to-Central, and from Central-to-East) occurred in roughly 26 percent of these hours.
    - – Severe congestion in the West Zone in mid-September was exacerbated by sporadic clockwise LEC in some hours.
- The frequency of TLRs called by the NYISO has been low for the last two years – there was only one TLR call during the third quarter.
  - ✓ The NYISO is unable to use TLRs to manage congestion resulting from loop flows when the IESO-Michigan PARs are deemed in "regulate" mode.

Clockwise Lake Erie Circulation and TLR Calls



Quarter	Avg. Clockwise Lake Erie Circulation (MW)	% of Hours TLR 3A and Above	Clockwise Lake Erie Circulation > 200 MW (% of Hours)	
			w/ West-to-East Congestion	w/o West-to-East Congestion
2014Q3	38	0.0%	3.9%	11.4%
2014Q2	11	0.0%	1.5%	11.1%
2013Q3	3	0.0%	2.5%	9.6%

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Day-Ahead and Real-Time Transmission Congestion

Congestion Patterns, Revenues, and Shortfalls

- The next five figures evaluate the congestion patterns in the day-ahead and real-time markets and examine the following categories of resulting 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, which is the primary funding source for TCC payments.
  - ✓ Day-Ahead Congestion Shortfalls occur when the day-ahead congestion revenues collected by the NYISO are less than the payments to TCC holders.
    - Shortfalls (or surpluses) generally arise when the TCCs on a path exceeds (or is below) the transfer capability of the path modeled in the day-ahead market during periods of congestion.
    - These typically result from modeling assumption differences between the TCC auction and the DA market, including assumptions related to PAR schedules, loop flows, and transmission outages.
  - ✓ Balancing Congestion Shortfalls arise when day-ahead scheduled flows over a constraint exceed what can flow over the constraint in the real-time market.
    - The transfer capability of a constraint falls (or rises) from DA to RT for the similar reasons (e.g., deratings and outages of transmission facilities, inconsistent assumptions regarding PAR schedules and loop flows, etc.).
    - In addition, payments between the NYISO and PJM related to the M2M process also contribute to shortfalls (or surpluses).

Congestion Patterns, Revenues, and Shortfalls

- The first figure summarizes day-ahead congestion revenue and shortfalls, and balancing congestion shortfalls over the past two years on a monthly basis.
- The second and third figures examine in detail the value and frequency of day-ahead and real-time congestion along major transmission paths by month.
  - ✓ 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.
- The fourth and fifth figures show the day-ahead and balancing congestion revenue shortfalls by transmission facility on a daily basis.
  - ✓ Negative values indicate day-ahead and balancing congestion surpluses.
- Congestion is evaluated along major transmission paths that include:
  - ✓ West Zone Lines: Transmission constraints in the West Zone.
  - ✓ Central to East: The Central-East interface and other lines transferring power from the Central Zone to Eastern New York.
  - ✓ Capital to Hudson Valley: Primarily lines leading into Southeast New York (e.g., the Leeds-Pleasant Valley Line, the New Scotland-Leeds Line).
  - ✓ NYC Lines – 345kV: Lines into and within the NYC 345 kV system.

Day-Ahead and Real-Time Congestion

(cont. from prior slide)

- ✓ NYC Lines – Load Pockets: Lines leading into and within NYC load pockets.
- ✓ NYC Simplified Interfaces: Groups of lines into NYC load pockets that are modeled as interface constraints.
- ✓ Long Island: Lines leading into and within Long Island.
- ✓ External Interfaces – Congestion related to the total transmission limits or ramp limits of the external interfaces.
- ✓ All Other – All of other line constraints and interfaces.

- Day-ahead congestion revenue totaled $46 million, down 64 percent from the third quarter of 2013. The key contributors were:
  - ✓ Decreased load levels and less frequent peaking conditions, which generally resulted in less frequent congestion across the system;
  - ✓ Lower natural gas prices, which led to lower re-dispatch costs to manage congestion; and
  - ✓ Lower gas spreads between Western NY and NYC, which led to less frequent congestion across the Central-East interface and into the Hudson Valley and NYC.
  - ✓ However, congestion in the West Zone rose modestly (for the reasons discussed in slide 16).

Day-Ahead and Real-Time Congestion

- Most congestion (measured as a share of total DA/RT congestion value) occurred in the following areas in the third quarter of 2014:
  - ✓ West Zone (40% DAM, 44% RTM) – West-to-east flows across 230kV facilities in the West Zone accounted for a large share of congestion.
    - – Most of occurred from mid- to late-September (for reasons discussed in slide 16).
    - – Congestion was more severe in RT than in DA partly because:
      - Volatile Lake Erie loop flows use a portion of these transmission facilities;
      - Re-dispatch options were limited by parallel constraints on the 115kV system, which are managed with OOM dispatch instructions (see slide 63).
  - ✓ Long Island (18% DAM, 11% RTM) – Primarily from upstate NY to Long Island.
    - – This was partly because Long Island had the highest natural gas prices in the state.
    - – However, congestion was alleviated by Long Island generating capacity that was utilized more efficiently than in the previous year.
- RT congestion into SENY was reduced partly because TSAs were declared 30 percent less often than the previous summer because of milder weather conditions.
  - ✓ The impact of TSAs was also reduced by lower load levels, lower gas prices, the return to full capacity of the Ramapo line, and enhancements in the M2M process that now allow the Ramapo line to relieve TSA congestion (see slide 56).

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Day-Ahead Congestion Shortfalls

- DA shortfalls totaled $8 million in the third quarter of 2014, down modestly from the third quarter of 2013.
- The majority of DA shortfalls are from transmission outages and allocated to the responsible TOs.
  - ✓ Multiple transmission facilities in the West Zone were out of service from mid to late September, which resulted in bottlenecks on 230kV lines in the West Zone, accounting for nearly $5 million (58 percent) of shortfalls.
  - ✓ One of the circuit breakers on the 345 kV transmission lines from upstate to Long Island was out of service during most of August, which limited import capability, accounting for $1 million of shortfalls.
  - ✓ The Central-East interface accounted for $1 million of shortfalls in late September.
    - – The voltage limit was reduced from the TCC auction when DAM commitment patterns changed and multiple capacitors were out of service during off-peak hours.
- A portion of DA shortfalls result from grandfathered TCCs that exceed the transfer capability of the system from Dunwoodie to Long Island.
  - ✓ This resulted in $2 million of shortfalls this quarter and $3 million in the third quarter of 2013 (previously reported in the "Long Island" category).

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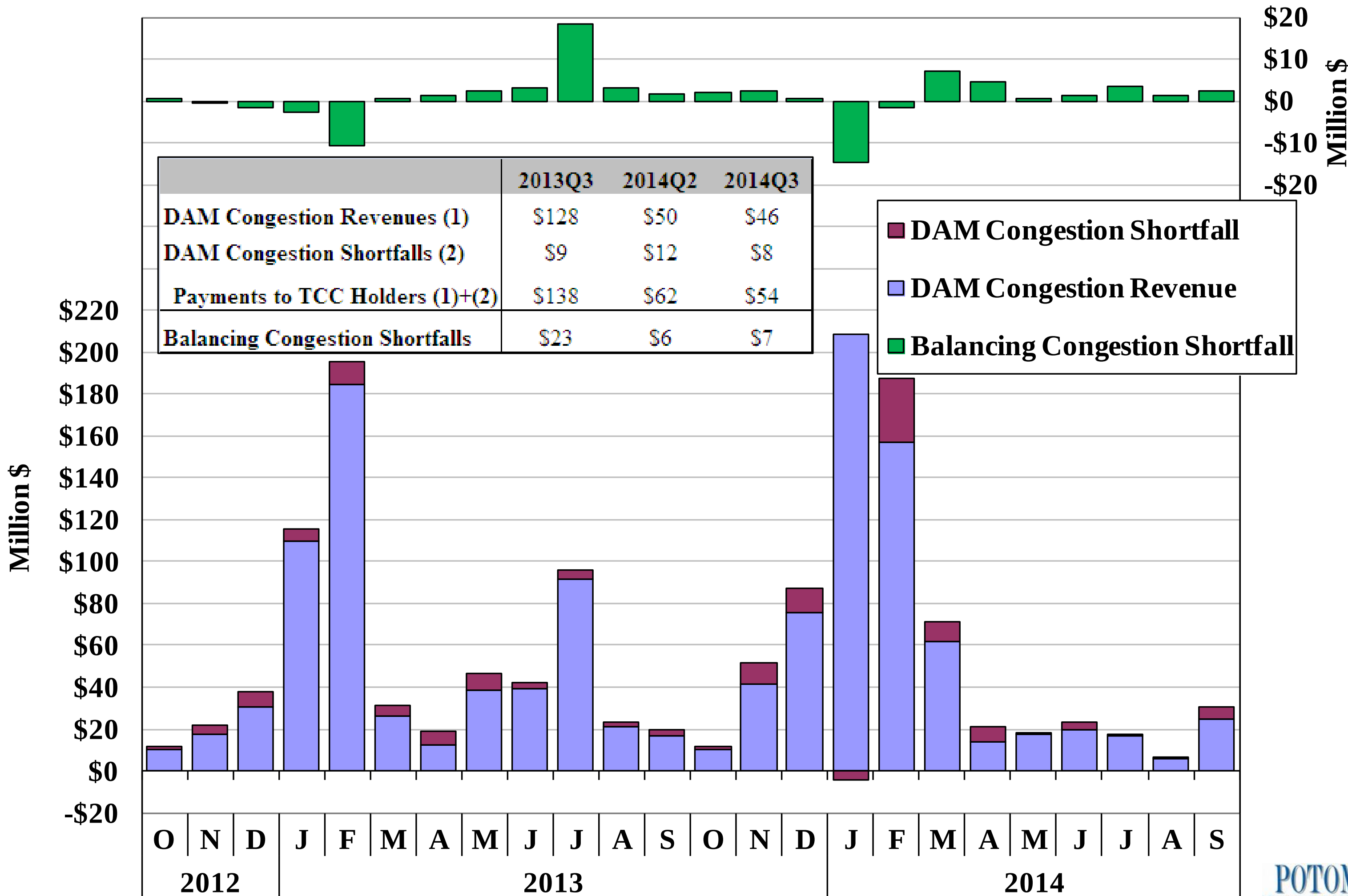
Balancing Congestion Shortfalls

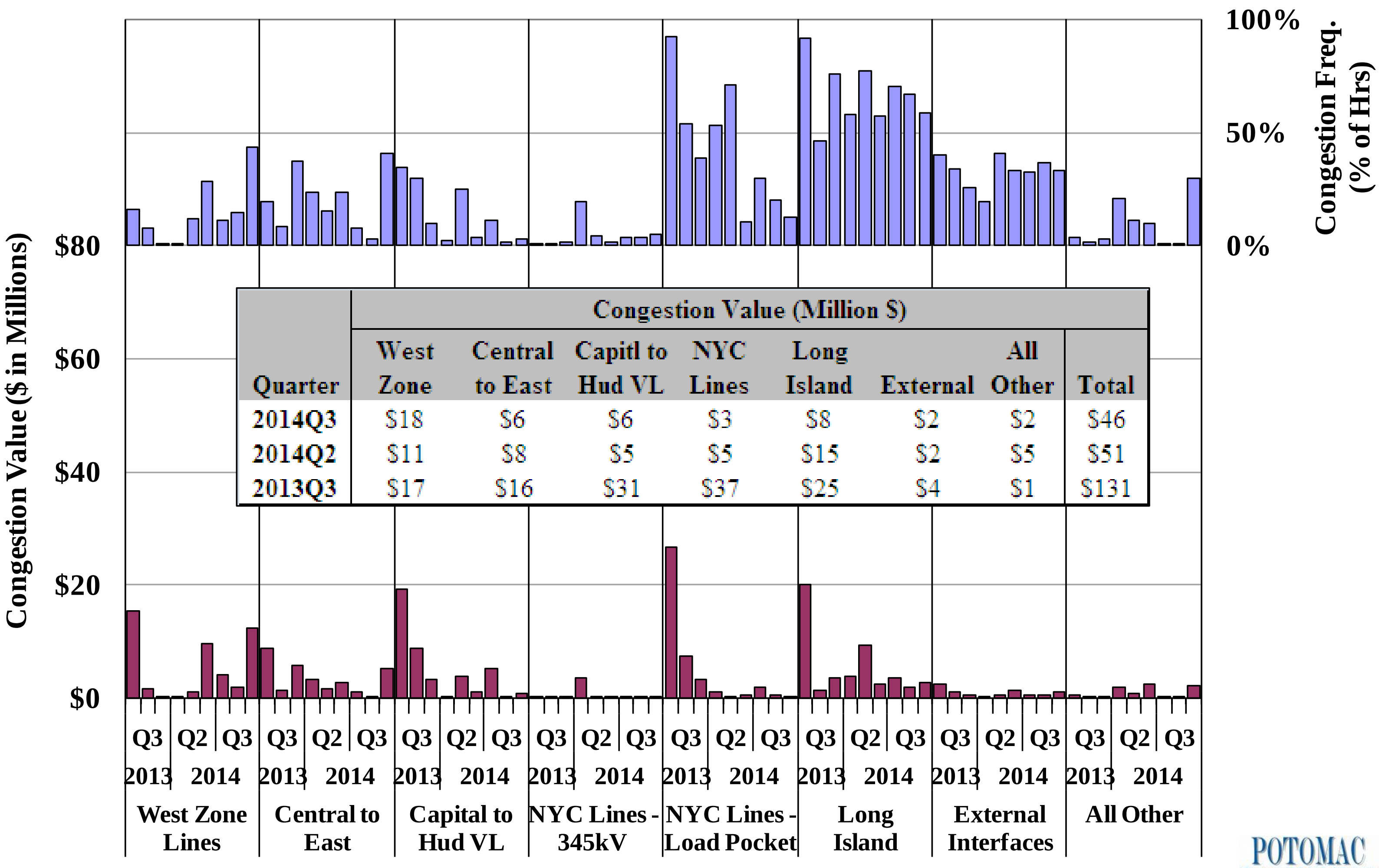
- Balancing congestion shortfalls totaled $7 million this quarter, down significantly from the third quarter of 2013.
  - ✓ The overall reduction in RT congestion contributed to the reduction in shortfalls.
- Balancing shortfalls rose on several days with unexpected real-time events.
  - ✓ TSAs were the primary driver of high balancing shortfalls on these days, since the transfer capability into SENY is greatly reduced during TSAs.
    - This accounted for over $4 million of shortfalls (reflecting re-dispatch due to the reduced transfer limit into SENY, external transaction curtailment, and performance of NY-NJ PAR-controlled lines during the events).
    - This was much lower than the $17 million that occurred in the third quarter of 2013 (for the reasons discussed in slide 47).
  - ✓ Transmission constraints in the West Zone accounted for another $3 million of shortfalls this quarter.
    - High and volatile clockwise Lake Erie loop flows (which reduce the available transfer capability through the West Zone) accounted for some of these shortfalls.
    - The over-delivery into SENY across the Ramapo line also contributed to shortfalls on 230 kV transmission constraints in the West Zone.

Congestion Revenues and Shortfalls by Month



	2013Q3	2014Q2	2014Q3
DAM Congestion Revenues (1)	$128	$50	$46
DAM Congestion Shortfalls (2)	$9	$12	$8
Payments to TCC Holders (1)+(2)	$138	$62	$54
Balancing Congestion Shortfalls	$23	$6	$7

Day-Ahead Congestion Value and Frequency by Transmission Path



Quarter	West Zone	Central to East	Capitl to Hud VL	NYC Lines	Long Island	External	All Other	Total
	Congestion Value (Million $)							
2014Q3	$18	$6	$6	$3	$8	$2	$2	$46
2014Q2	$11	$8	$5	$5	$15	$2	$5	$51
2013Q3	$17	$16	$31	$37	$25	$4	$1	$131

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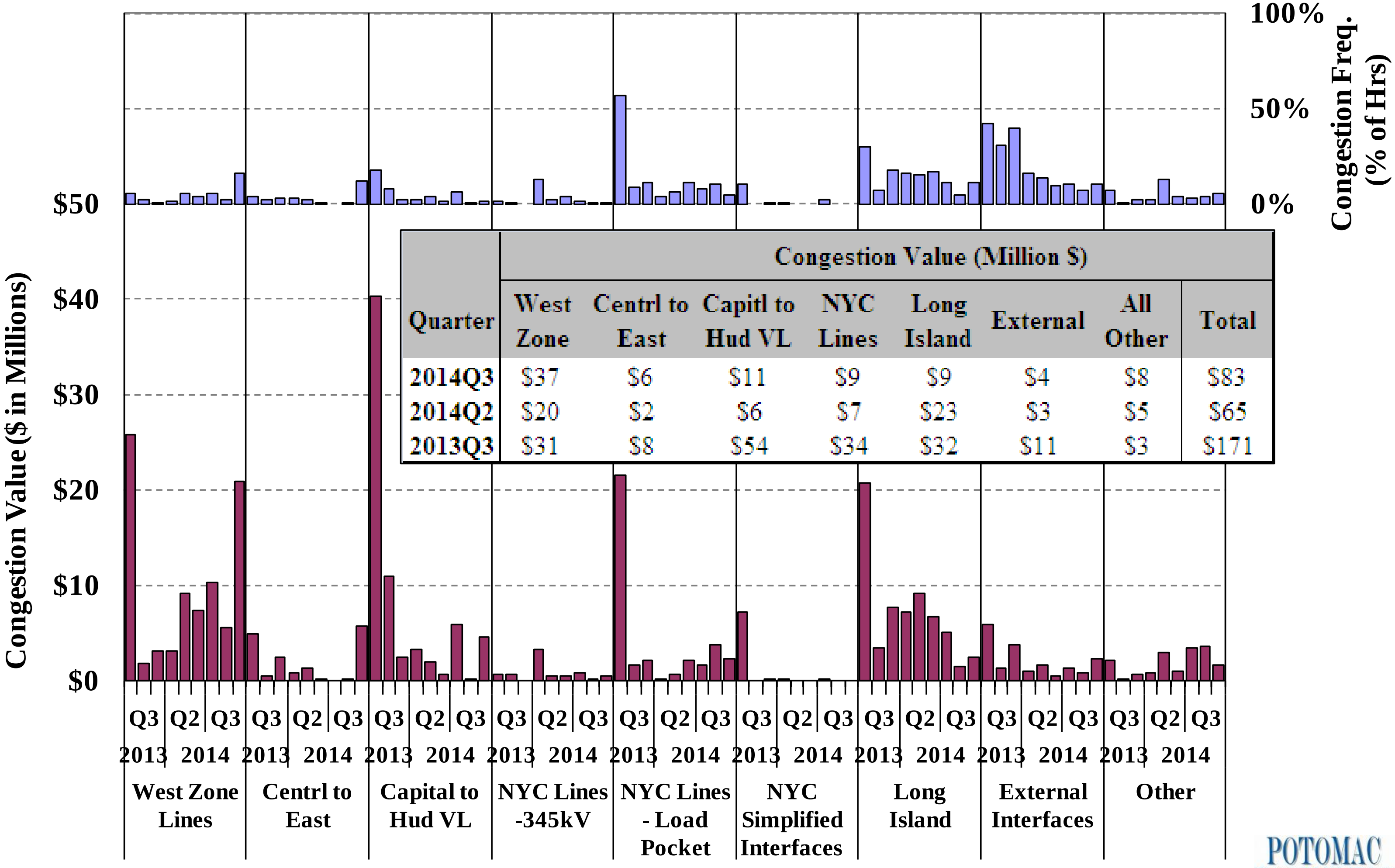
Real-Time Congestion Value and Frequency by Transmission Path



Quarter	Congestion Value (Million $)							
	West Zone	Centrl to East	Capitl to Hud VL	NYC Lines	Long Island	External	All Other	Total
2014Q3	$37	$6	$11	$9	$9	$4	$8	$83
2014Q2	$20	$2	$6	$7	$23	$3	$5	$65
2013Q3	$31	$8	$54	$34	$32	$11	$3	$171

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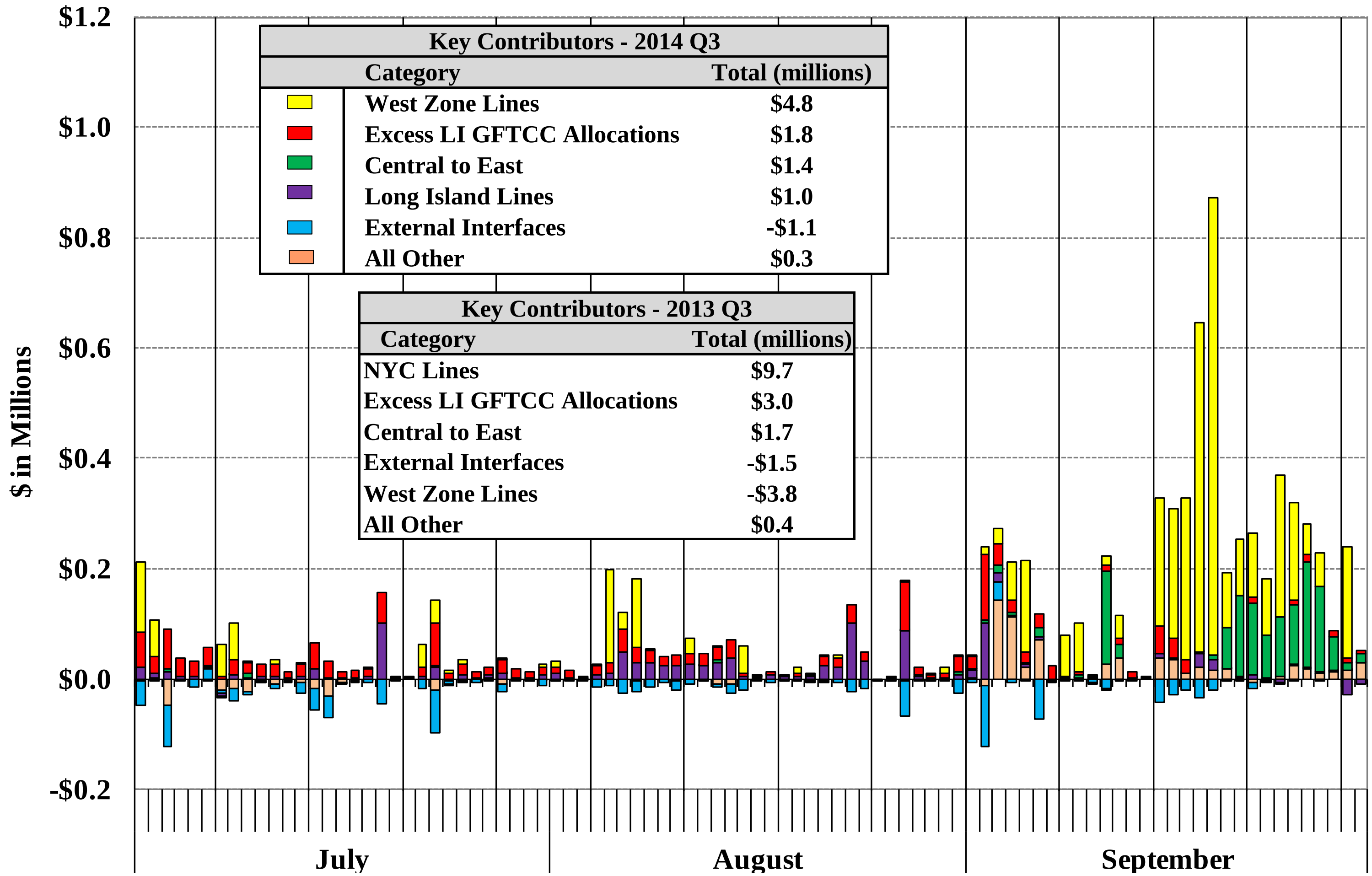
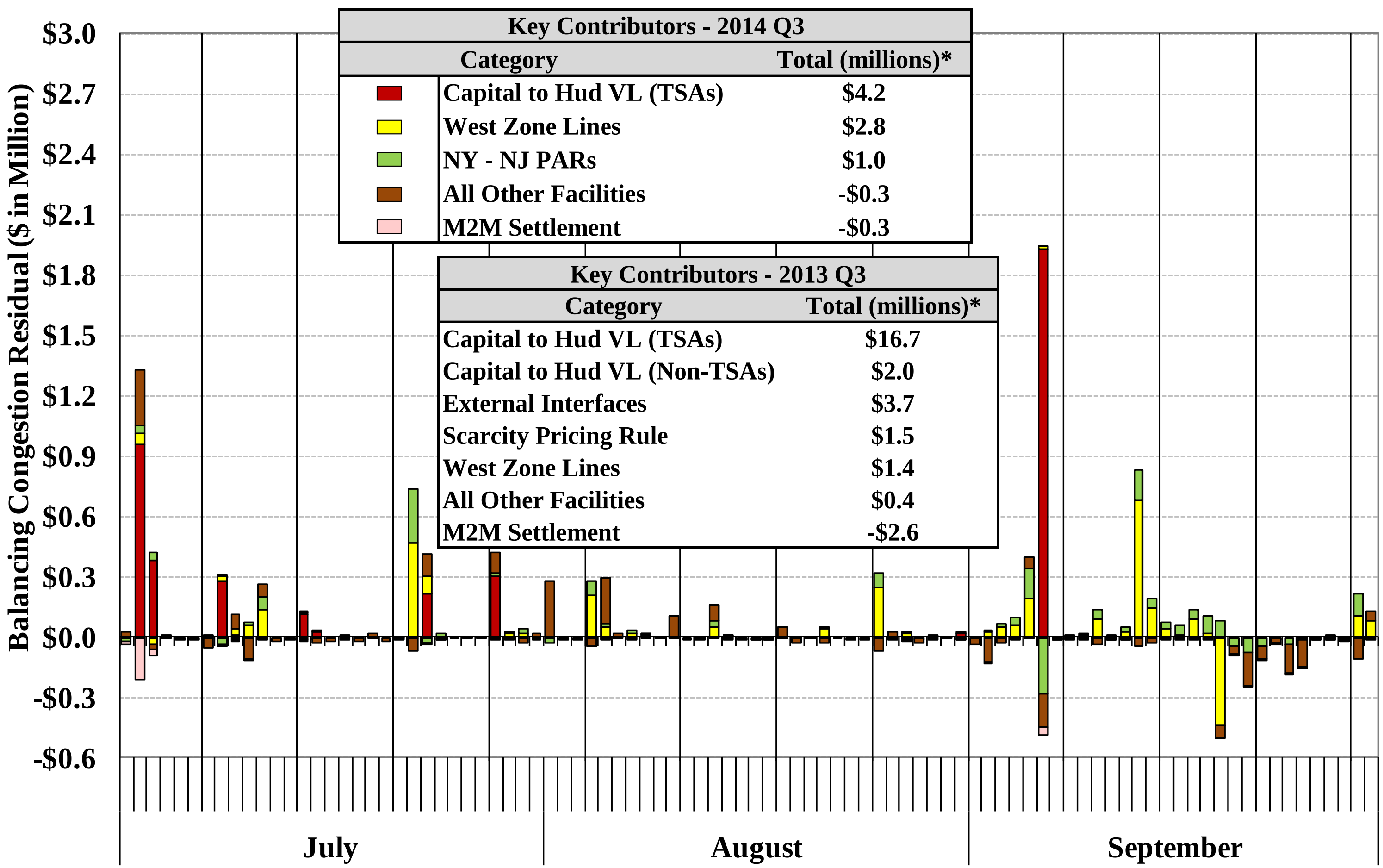
Day-Ahead Congestion Revenue Shortfalls by Transmission Facility



Note: "Excess LI GFTCC Allocations" refers to excess grandfathered TCCs from Dunwoodie (Zone I) to Long Island .

Balancing Congestion Shortfalls by Transmission Facility



Key Contributors - 2014 Q3	
Category	**Total (millions)***
Capital to Hud VL (TSAs)	$4.2
West Zone Lines	$2.8
NY - NJ PARs	$1.0
All Other Facilities	-$0.3
M2M Settlement	-$0.3

Key Contributors - 2013 Q3	
Category	**Total (millions)***
Capital to Hud VL (TSAs)	$16.7
Capital to Hud VL (Non-TSAs)	$2.0
External Interfaces	$3.7
Scarcity Pricing Rule	$1.5
West Zone Lines	$1.4
All Other Facilities	$0.4
M2M Settlement	-$2.6

Note: The BMCR estimated above may differ from actual BMCR because the figure is partly based on real-time schedules rather than metered values.

Operations under M2M with PJM

- Coordinated congestion management between NYISO and PJM (“M2M”) includes two types of coordination:
  - ✓ Re-dispatch Coordination – If one of the pre-defined flowgates becomes congested in the monitoring RTO, the non-monitoring RTO will re-dispatch its generation to help manage congestion when economic.
  - ✓ Ramapo PAR Coordination – If certain pre-defined flowgates become congested in one or both RTOs, the Ramapo PARs are adjusted to reduce overall congestion.
- The following figure evaluates the operation of Ramapo PARs this quarter, which compares the actual flows on Ramapo PARs with their M2M operational targets.
  - ✓ The M2M target flow has the following components:
    - Share of PJM-NY Over Ramapo – Based on the share of PJM-NY flows that were assumed to flow across the Ramapo Line (61% in the third quarter of 2014).
    - 80% RECo Load – 80 percent of telemetered Rockland Electric Company load.
    - ABC & JK Flow Deviations – The total flow deviations on ABC and JK PAR-controlled lines from schedules under the normal wheeling agreement.
  - ✓ The figure shows these average quantities over intervals when M2M constraints for Ramapo Coordination were binding on a daily basis (excluding days with fewer than 12 binding intervals).

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Operations under M2M with PJM

- The use of Re-dispatch Coordination continued to be infrequent.
  - ✓ It was activated for the Central-East interface in a total of 7 hours and resulted in a total payment of roughly $400 from PJM to NY.
- The use of Ramapo PAR Coordination was also relatively limited this quarter because low gas prices and load levels led to mild congestion on M2M constraints.
  - ✓ Active Ramapo Coordination occurred in 642 intervals this quarter, down from 829 intervals in the third quarter of 2013.
- Average actual flows across Ramapo exceeded the M2M Target Flow by more than 150 MW this quarter (when M2M constraints were binding).
  - ✓ M2M Target Flow was lower than in the third quarter of 2013 because:
    - RECo deliveries fell as a result of lower load levels; and
    - The share of PJM-NY interchange fell because of decreased net imports from PJM (for reasons discussed in slide 39).
  - ✓ Actual flows into New York were increased this quarter because:
    - Both Ramapo PARs were in service (while one PAR was out of service in the third quarter of 2013), better enabling the line to satisfy the operational targets.
    - M2M process enhancements now allow Ramapo to relieve TSA congestion.
    - M2M constraints in PJM were rarely binding.

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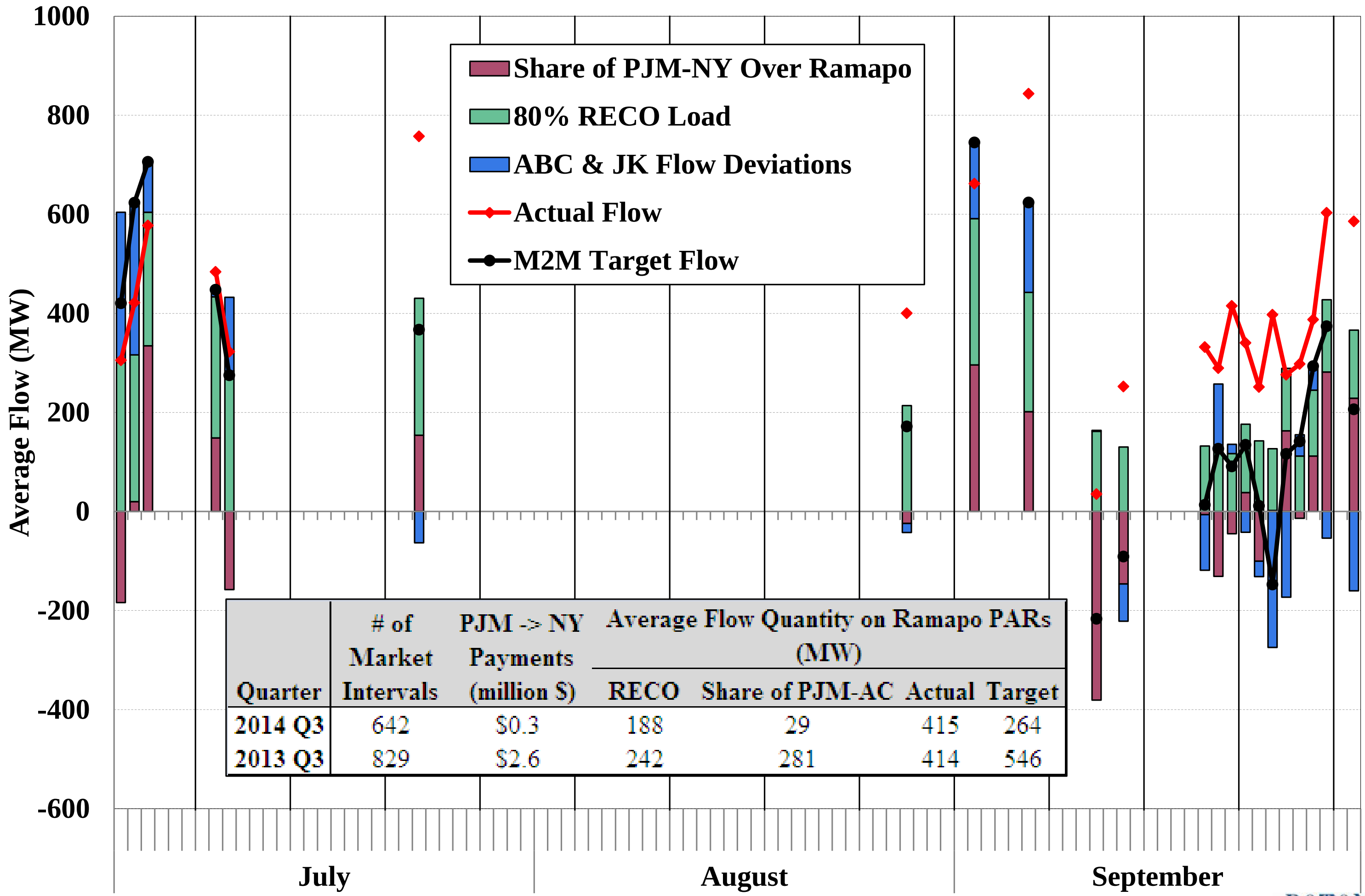
Actual and Target Flows for the Ramapo Line
During the Intervals with Binding M2M Constraints



Quarter	# of Market Intervals	PJM -> NY Payments (million $)	Average Flow Quantity on Ramapo PARs (MW)			
			RECO	Share of PJM-AC	Actual	Target
2014 Q3	642	$0.3	188	29	415	264
2013 Q3	829	$2.6	242	281	414	546

Note: This chart does not show the days during which M2M constraints were binding in less than 12 intervals.

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Supplemental Commitments, OOM Dispatch, and Uplift Charges

Supplemental Commitment and OOM Dispatch: Chart Descriptions

- The next three figures summarize out-of-market commitment and dispatch, which are the primary sources of guarantee payment uplift.
  - ✓ The first figure shows the quantities of reliability commitment by region in the following categories on a monthly basis:
    - Day-Ahead Reliability Units (“DARU”) Commitment – occurs before the economic commitment in the DAM at the request of local TO or for NYISO reliability;
    - Day-Ahead Local Reliability (“LRR”) Commitment – occurs in the economic commitment in the DAM for TO reliability in NYC; and
    - Supplemental Resource Evaluation (“SRE”) Commitment – occurs after the DAM.
    - Forecast Pass Commitment – occurs after the economic commitment in the DAM.
  - ✓ The second figure examines the reasons for reliability commitments in NYC where most reliability commitments occur. (This is described on the following slide.)
  - ✓ The third figure summarizes the frequency (measured by the total station-hours) of Out-of-Merit dispatches by region on a monthly basis.
    - The figure excludes OOMs that prevent a generator from being started, since these usually indicate transmission outages that make the generator unavailable.
    - In each region, the two stations with the highest number of OOM dispatch hours in the current quarter are shown separately.

Supplemental Commitment and OOM Dispatch: Chart Descriptions

- Based on a review of operator logs and LRR constraint information, each New York City commitment (flagged as DARU, LRR, or SRE) was categorized for one of the following reasons:
  - ✓ NOx Only – If needed for NOx bubble requirement and no other reason.
  - ✓ 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.
- A unit is considered to be committed for a LRR constraint if the constraint would be violated without the unit's capacity.
- For voltage and thermal constraints, the capacity is shown by the following load pocket that was secured:
  - ✓ (a) AELP = Astoria East; (b) AWLP = Astoria West/Queensbridge; (c) AVLP = Astoria West/Queensbridge/ Vernon; (d) ERLP = East River; (e) FRLP = Freshkills; (f) GSLP = Greenwood/ Staten Island; and (g) SDLP = Sprainbrook/Dunwoodie.

Supplemental Commitment and OOM Dispatch: Supplemental Commitment Results

- An average of roughly 800 MW of capacity was committed for reliability in the third quarter of 2014, down 25 percent from the third quarter of 2013.
  - ✓ Of this total, 60 percent of reliability commitment was in NYC, 33 percent was in Western NY, and 7 percent was on Long Island.
- On Long Island, reliability commitment averaged roughly 60 MW, down nearly 80 percent from the third quarter of 2013.
  - ✓ The reduction was primarily attributable to the installation of the West Bus DRSS and Wildwood DRSS early this year. These upgrades have reduced the need to:
    - Commit generation for voltage constraints (see ARR 28); and
    - Burn oil to protect Long Island from a loss of gas contingency (IR-5).
- In Western NY, reliability commitment averaged over 260 MW, consistent with the third quarter of 2013.
  - ✓ DARU commitments rose when several coal units that were often needed for local reliability became less economic due to lower load levels and natural gas prices.
  - ✓ SRE commitments were virtually eliminated because transmission upgrades in the North Zone (completed in March 2014) reduced the effects of key transmission contingencies.

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Supplemental Commitment and OOM Dispatch: Supplemental Commitment Results in New York City

- In NYC, reliability commitment averaged approximately 475 MW, down 8 percent from the third quarter of 2013.
  - ✓ Natural gas prices in NYC were lower than the rest of Eastern NY, which made several steam units that were often needed for reliability more economic.
  - ✓ In addition, reliability commitment for NOx bubble constraints fell because of updates in the NOx bubble modeling in the LRR pass.
    - These requirements are in effect from May to September each year, normally accounting for a large share of supplemental commitments during this period.
    - Less steam turbine capacity is now required to satisfy the NOx bubble requirements in the LRR pass (after the modeling change).
- However, one steam turbine in NYC that satisfies the NOx bubble requirements was committed economically less often because of lower DAM LBMPs (relative to fuel prices) at its pricing node.
  - ✓ Hence, this generator was committed for reliability more often, offsetting the overall reduction in reliability commitment (from the factors listed above).
- Reliability commitment also rose modestly in the Astoria West load pocket partly because of more generation outages.

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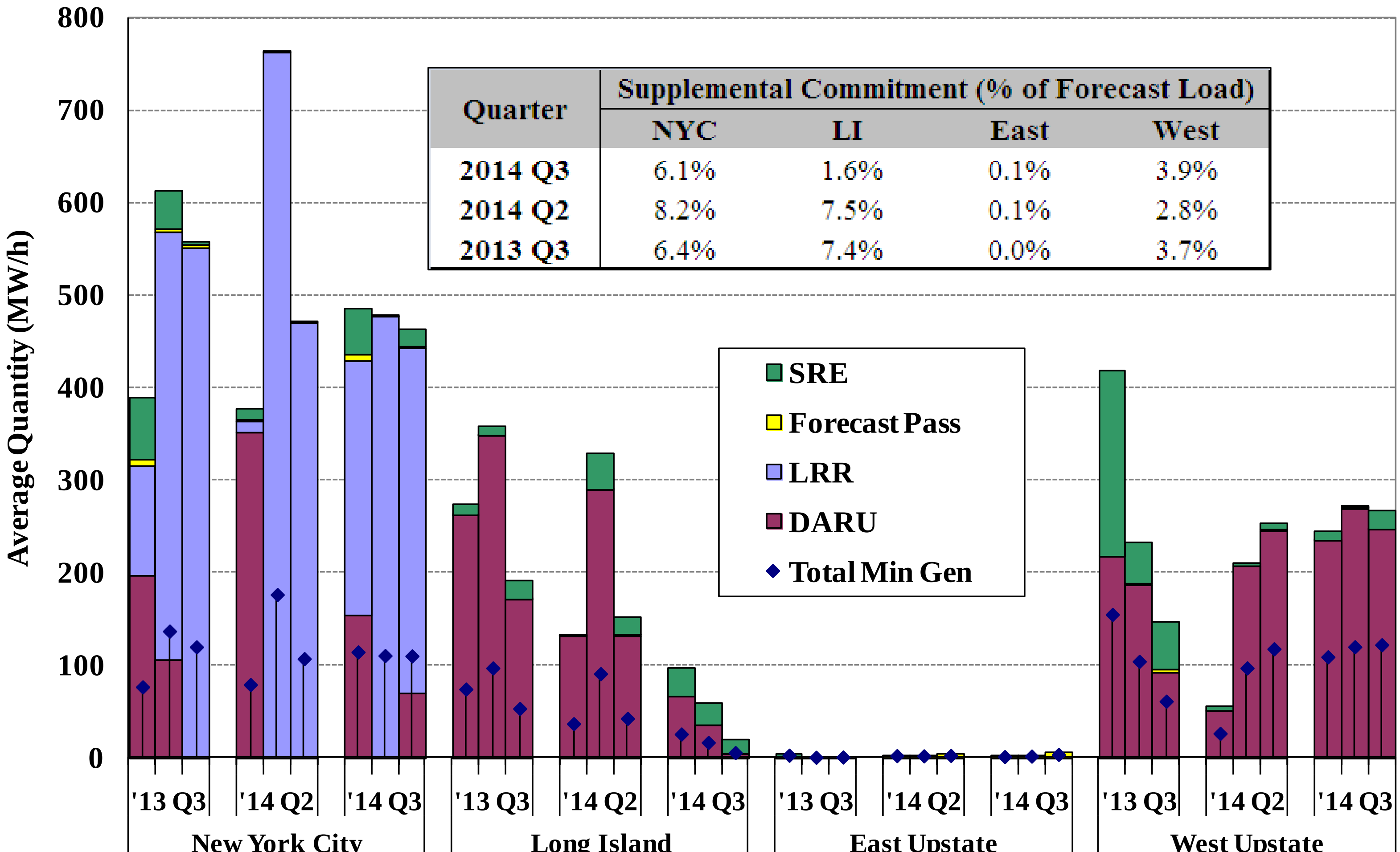
Supplemental Commitment and OOM Dispatch: OOM Dispatch Results

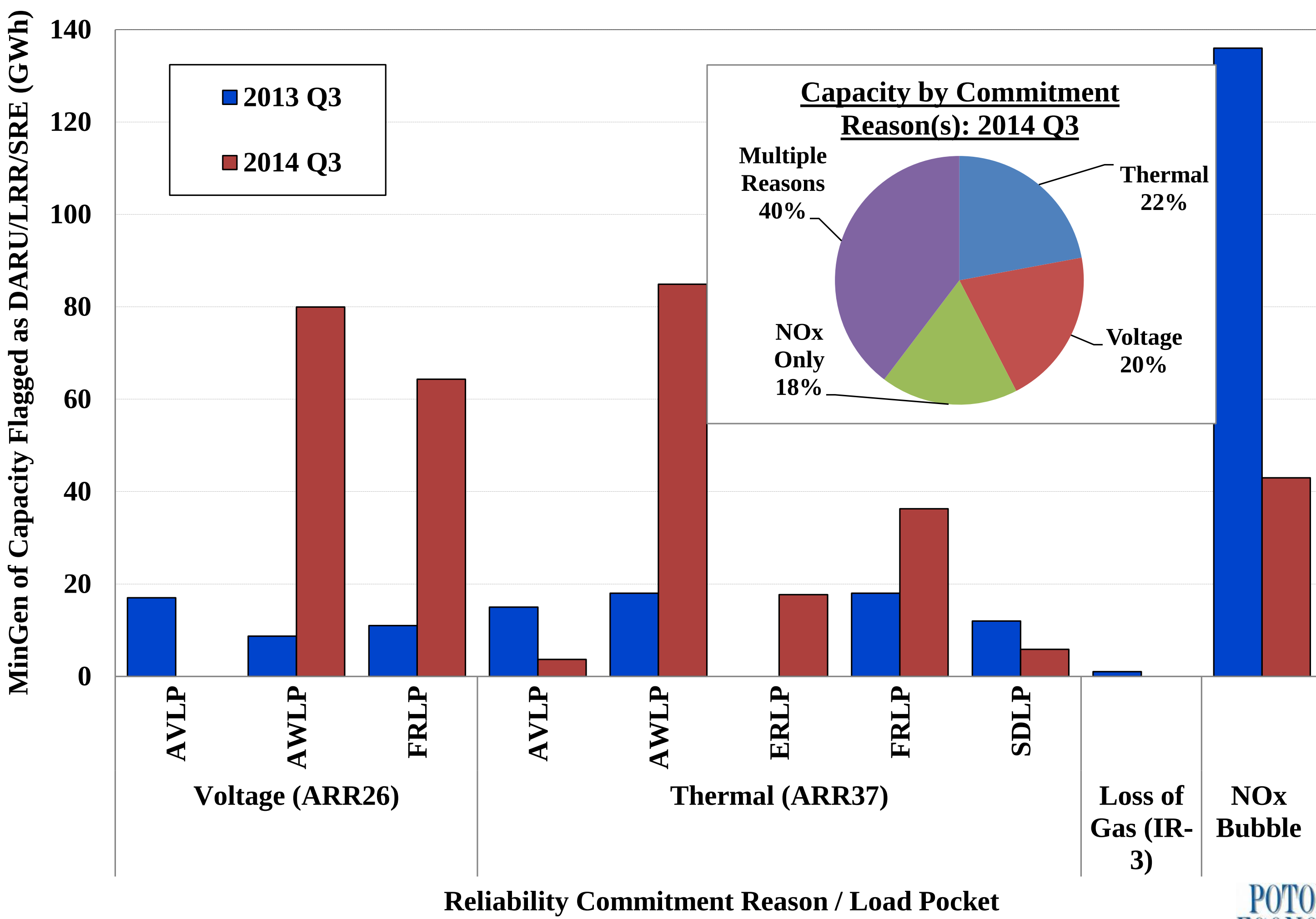
- The NYISO and local TOs sometimes dispatch generators out-of-merit in order to:
  - ✓ Maintain reliability of the lower-voltage transmission and distribution networks; or
  - ✓ Manage constraints of high voltage transmission facilities that are not fully represented in the market model.
- Generators were dispatched Out-of-Merit (“OOM”) for 820 station-hours, down 73 percent (primarily in NYC and Long Island) from the third quarter of 2013.
  - ✓ The reduction in NYC was partly attributable to lower load levels, increased in-city generation because of lower natural gas prices, and fewer transmission outages in the Greenwood area.
  - ✓ The reduction on Long Island was attributable to transmission improvements (see slide 61) that greatly reduced the need to dispatch peaking generators to manage voltage constraints on the East End of Long Island.
- Western NY accounted for 64 percent of OOM station-hours in the third quarter.
  - ✓ OOM dispatch of other generators was primarily used to prevent post-contingency overloading on several 115 kV transmission lines in Western NY.
- The Niagara facility was often manually instructed to shift output to the 115kV system when 230kV constraints were binding. However, in some hours, output was shifted to the 230kV system to relieve 115kV constraints.

Supplemental Commitment for Reliability
by Category and Region



Quarter	Supplemental Commitment (% of Forecast Load)			
	NYC	LI	East	West
2014 Q3	6.1%	1.6%	0.1%	3.9%
2014 Q2	8.2%	7.5%	0.1%	2.8%
2013 Q3	6.4%	7.4%	0.0%	3.7%

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



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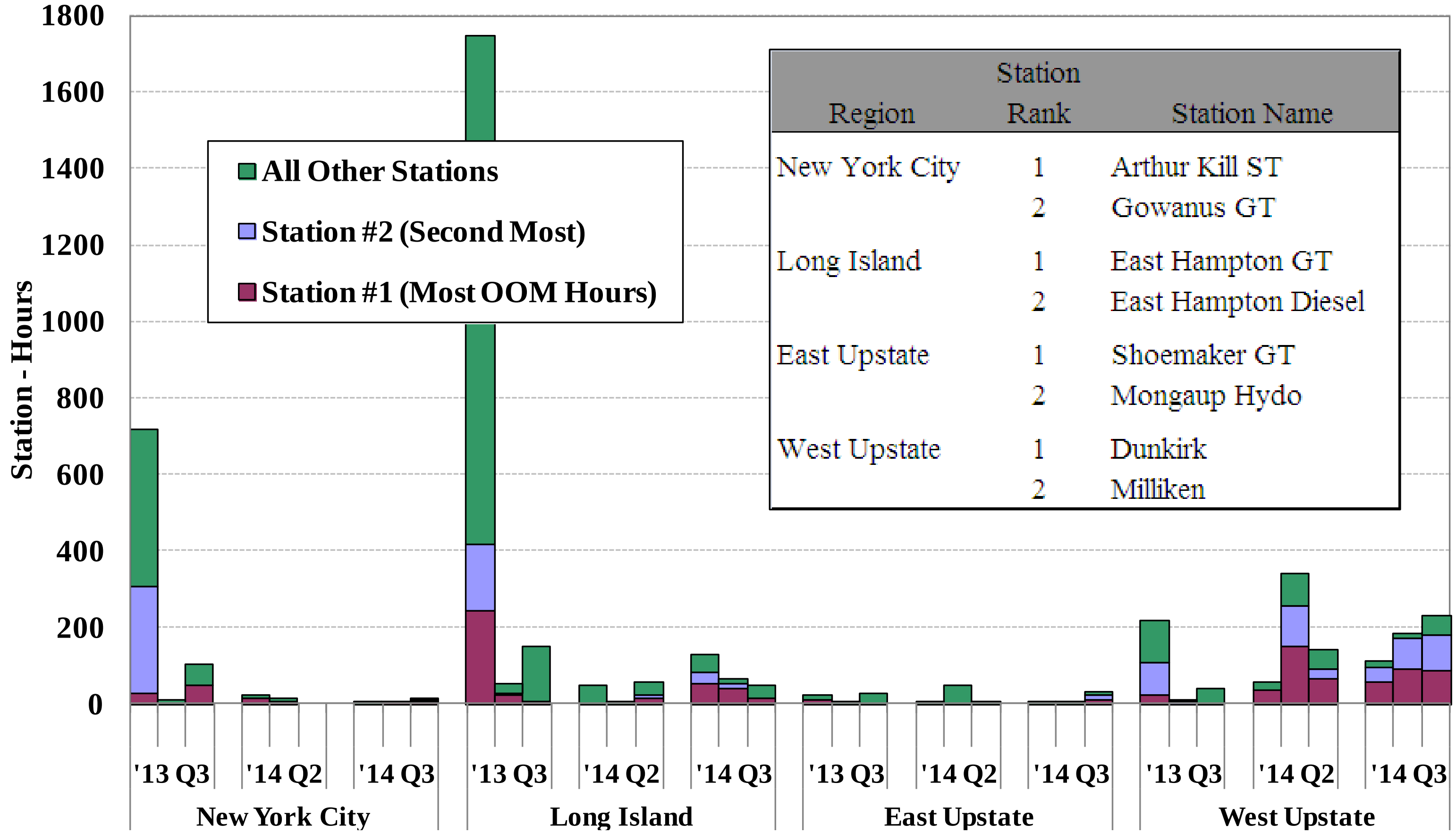
Frequency of Out-of-Merit Dispatch by Region by Month



Region	Station Rank	Station Name
New York City	1	Arthur Kill ST
	2	Gowanus GT
Long Island	1	East Hampton GT
	2	East Hampton Diesel
East Upstate	1	Shoemaker GT
	2	Mongaup Hydo
West Upstate	1	Dunkirk
	2	Milliken

Note: The NYISO also instructed Niagara to shift output among the generators at the station in order to secure certain 115kV and/or 230kV transmission facilities in 423 hours in 2013-Q3, 358 hours in 2014-Q2, and 531 hours in 2014-Q3. However, these were not classified as Out-of-Merit in hours when the NYISO did not adjust the UOL or LOL of the Resource.

Uplift Costs from Guarantee Payments: Chart Descriptions

- The next two figures show uplift charges 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 import 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.
  - ✓ The first figure shows these seven categories on a daily basis during the quarter.
  - ✓ The second figure summarizes uplift costs by region on a monthly basis.

Uplift Costs from Guarantee Payments: Results

- Guarantee payments totaled $17 million, down 69 percent from third quarter 2013.
  - ✓ The reduction was driven by decreased supplemental commitment and OOM dispatch in NYC and Long Island (see slides 64-66).
  - ✓ Lower natural gas prices also decreased the commitment costs of gas-fired units.
- Of the total guarantee payment uplift in the third quarter of 2014:
  - ✓ Local reliability uplift accounted for 74 percent (while non-local was 26 percent).
  - ✓ Western NY accounted for 48 percent, NYC accounted for 26 percent, and Long Island accounted 22 percent.
- Long Island uplift fell 86 percent (the largest among all areas) from a year ago. Transmission upgrades (see slide 61) reduced the need to:
  - ✓ Burn oil to protect Long Island from a loss of gas (reducing DAM uplift); and
  - ✓ Dispatch peaking units to manage voltage constraints (reducing RT uplift).
- NYC uplift fell 71 percent from the third quarter of 2013.
  - ✓ Non-local uplift accounted for nearly 60 percent of total reduction because lower natural gas prices decreased commitment costs.
  - ✓ Lower load levels and increased reliance on auto-switching units also reduced the need to burn oil to protect the NYC system from a loss of gas.

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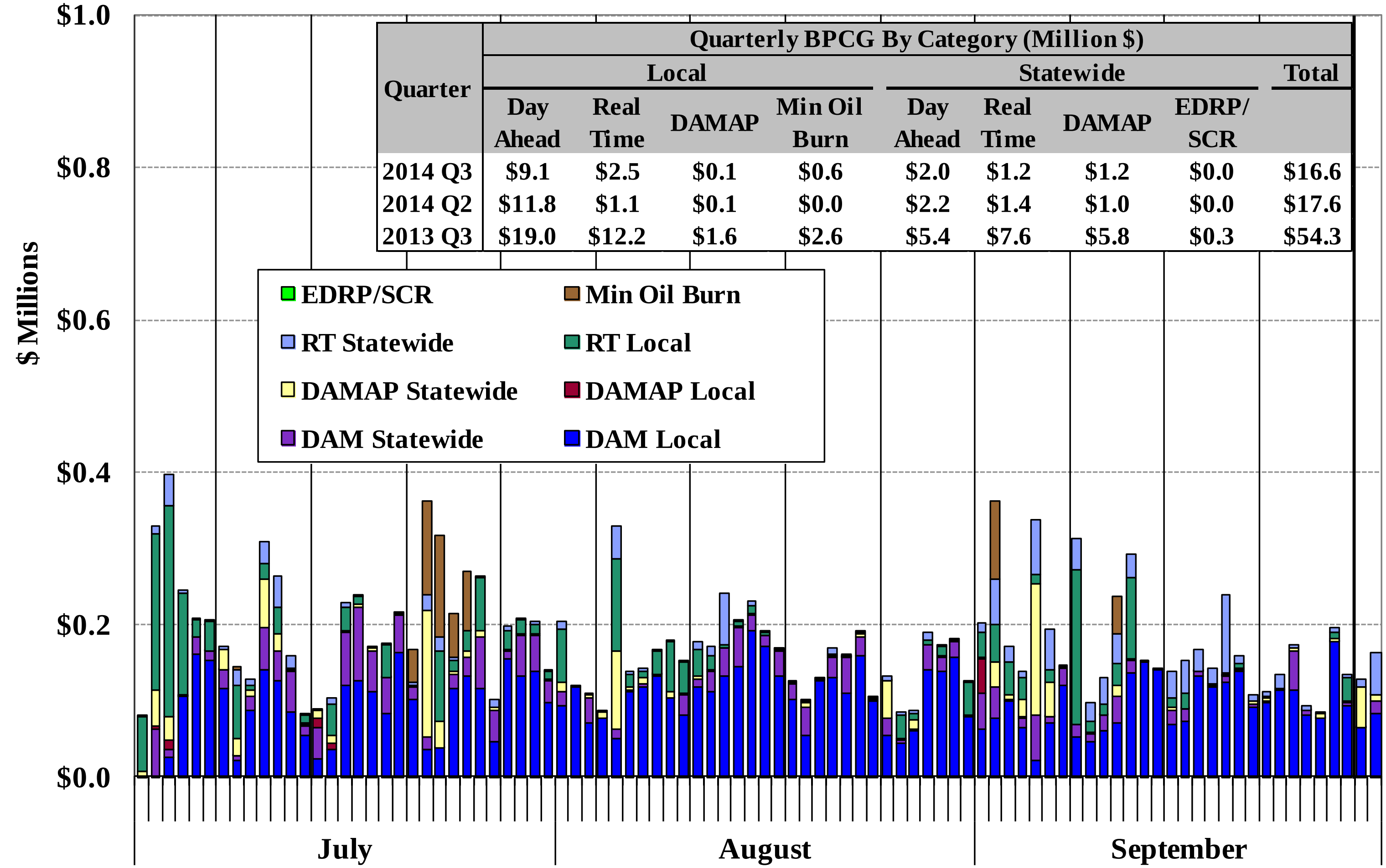
Uplift Costs from Guarantee Payments

Local and Non-Local by Category

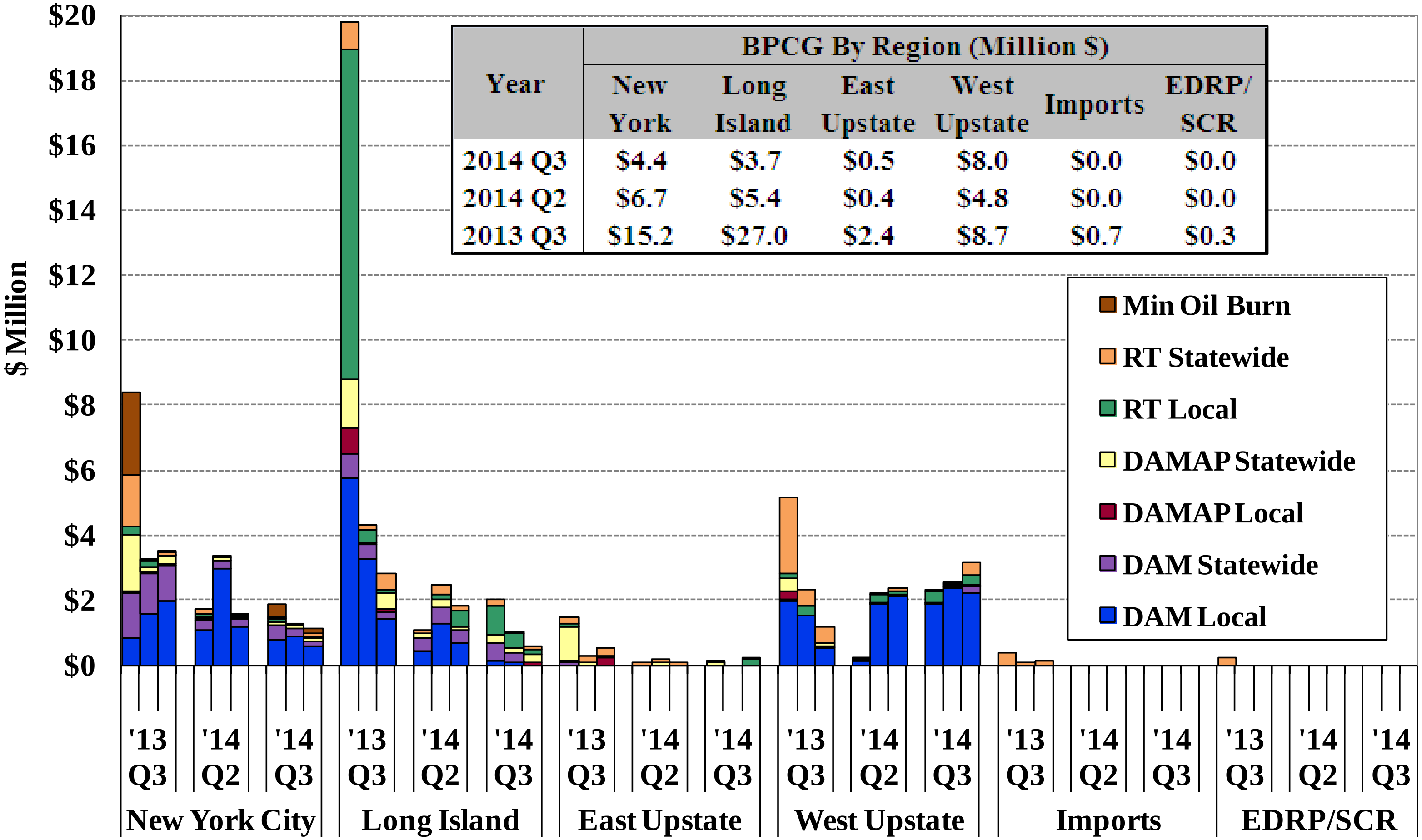


Quarterly BPCG By Category (Million $)

Quarter	Local				Statewide				Total
	Day Ahead	Real Time	DAMAP	Min Oil Burn	Day Ahead	Real Time	DAMAP	EDRP/ SCR	
2014 Q3	$9.1	$2.5	$0.1	$0.6	$2.0	$1.2	$1.2	$0.0	$16.6
2014 Q2	$11.8	$1.1	$0.1	$0.0	$2.2	$1.4	$1.0	$0.0	$17.6
2013 Q3	$19.0	$12.2	$1.6	$2.6	$5.4	$7.6	$5.8	$0.3	$54.3

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 Category and Region



Year	BPCG By Region (Million $)					
	New York	Long Island	East Upstate	West Upstate	Imports	EDRP/ SCR
2014 Q3	$4.4	$3.7	$0.5	$8.0	$0.0	$0.0
2014 Q2	$6.7	$5.4	$0.4	$4.8	$0.0	$0.0
2013 Q3	$15.2	$27.0	$2.4	$8.7	$0.7	$0.3

Note: BPCG 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.

Market Power and Mitigation

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 this quarter.
  - ✓ The output gap averaged 1 percent of load at the low threshold, which rose modestly from the same quarter in prior years.
  - ✓ The output gap did not raise significant market power concerns because:
    - – NYC accounted for 30 percent of all output gap at the low threshold, which occurred primarily during periods when the prices would not be substantially affected (would be AMP-mitigated otherwise).
    - – The Capital Zone accounted for another 45 percent, most of which occurred on several units that are: (a) co-gen resources; and (b) owned by suppliers with small portfolios.

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Market Power Screens: Physical Withholding

- We evaluate generator deratings in the day-ahead market 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 are typically highest in shoulder months when load is lower and lowest in the summer months when load is higher.
  - ✓ Total deratings in the third quarter are normally lower than in the second quarter.
    - Total deratings are significant, but physical withholding concerns are limited because most deratings are long-term and less likely to reflect withholding.
    - However, inefficient outage scheduling (i.e., scheduling an outage when the unit is likely to be economic for a significant portion of the time) may raise concerns.
- The amount of long-term deratings fell modestly from the third quarter of 2013.
  - ✓ More capacity was available in New York City and Long Island this quarter due to less planned outages.
- The amount of short-term deratings was consistent with the third quarter of 2013.

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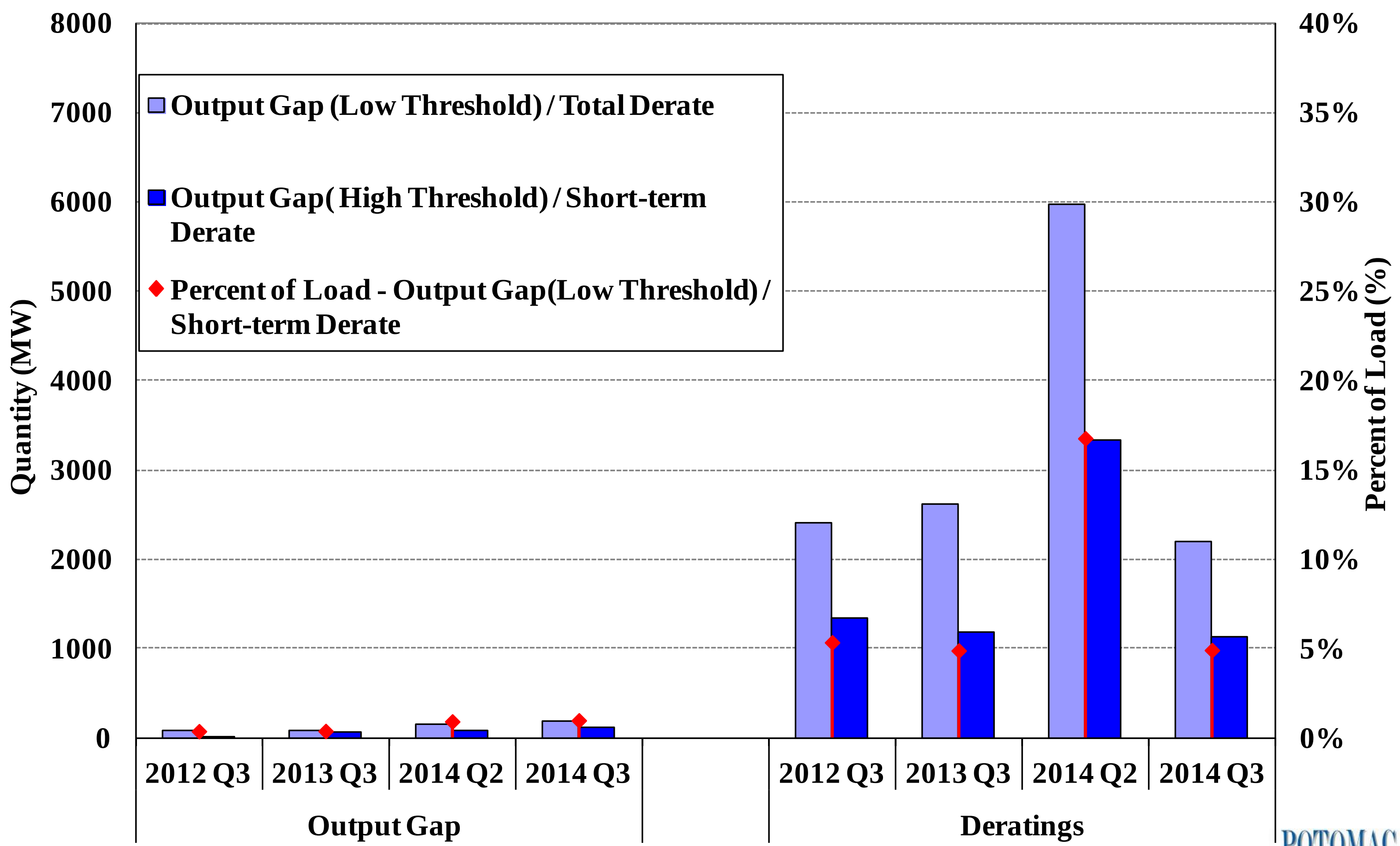
Market Monitoring Screens



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Automated Market Power Mitigation

- The next table summarizes the automated mitigation that was imposed during the quarter (not including BPCG mitigation).
- 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.
- Most mitigation occurs in the DAM (where most supply is scheduled).
  - ✓ 98 percent of AMP mitigation occurred in the DAM this quarter, of which:
    - – Local reliability (i.e., DARU & LRR) units accounted for 85 percent. These mitigations generally affect guarantee payment uplift but not LBMPs.
    - – Units in the Greenwood/Staten Island load pocket accounted for 12 percent.
- The frequency of incremental energy mitigation fell notably from the third quarter of 2013.
  - ✓ Congestion occurred less frequently in the 345kV and 138kV areas of NYC because of low natural gas prices in NYC and decreased load levels.

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Automated Market Mitigation

Quarterly Mitigation Summary					
		2012 Q3	**2013 Q3**	**2014 Q2**	**2014 Q3**
Day-Ahead Market	**Average Mitigated MW**	64	141	121	116
	Energy Mitigation Frequency	12%	41%	5%	15%
Real-Time Market	**Average Mitigated MW**	19	7	1	2
	Energy Mitigation Frequency	7%	3%	0%	1%

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.
- Rest-of-State UCAP spot prices averaged $5.83/kW-month this quarter, up modestly from $5.68/kW-month in the third quarter of 2013.
  - ✓ The increase was mostly attributable to the increase in the NYCA ICAP requirement, which rose 453 MW (roughly 1 percent) from the 2013/14 Capability Year due to an increase in forecasted peak load.
  - ✓ However, the increase was partly offset by:
    - An increase in sales from external resources (roughly 350 MW on average); and
    - A modest decrease in the UCAP demand curve value.
- Long Island UCAP spot prices averaged $6.47/kW-month this quarter, down modestly from $7.10 kW-month in the third quarter of 2013 because:
  - ✓ The UCAP demand curve was reduced from the 2013/14 Capability Year by more than 20 percent.
  - ✓ However, this was offset by a 90 MW increase (1.6 percent) in the Long Island ICAP requirement because the LCR increased from 105 to 107 percent.

Capacity Market Results

- In NYC, UCAP spot prices averaged $18.47/kW-month this quarter, up from $15.85/kW-month in the third quarter of 2013, attributable to:
  - ✓ ICAP supply was reduced by approximately 100 MW from Summer 2013 to Summer 2014. This reduction occurred primarily because some generators have discontinued the practice of performing DMNC tests at a peak firing temperature.
  - ✓ EFORds rose for some units since the start of the Summer 2014 capability period.
  - ✓ The ICAP requirement rose 138 MW (or 1.4 percent) primarily because of a nearly 300 MW increase in the forecasted peak load.
    - – This was partly offset by a decrease in the LCR from 86 percent to 85 percent.
  - ✓ The demand curve was reduced by 7 percent from the 2013/14 Capability Year, partly offsetting the increase in spot prices.
- In the G-J Locality, UCAP spot prices averaged $12.20/kW-month in the third quarter of 2014, significantly higher than the ROS spot prices.
  - ✓ The new capacity zone better reflects the reliability need to secure the UPNY-SENY interface and greatly enhances the efficiency of the market to provide investment signals in this area.
- There was virtually no unsold capacity in the G-J Locality, New York City, and Long Island.

Capacity Market Results: Third Quarter 2013 & 2014

Note: Sales associated with Unforced Deliverability Rights ("UDRs") are included in "Internal Capacity," but unsold capacity from resources with UDRs is not shown.