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

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Highlights and Market Summary: Energy Market

- This report summarizes market outcomes in the second 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.
- Low natural gas prices and load levels resulted in low energy prices, congestion, and uplift charges in the second quarter of 2014.
  - ✓ Average load (17.2 GW) fell 3 percent and peak load (27.2 GW) fell 10 percent from the second quarter of the previous year primarily because of mild weather.
    - Both average and peak load levels were the lowest in the past five years.
  - ✓ Average natural gas prices fell 11 percent in Western NY ($3.47/MMBtu) and 15 percent in NYC ($3.61) from the second quarter of the previous year.
    - Gas prices in these areas were significantly lower than in most areas of the country (e.g., Henry Hub prices averaged $4.58/MMbtu this quarter).
- RT LBMPs averaged $40/MWh statewide, down 13 percent from a year ago.
  - ✓ LBMPs fell most on Long Island (30 percent) because fewer transmission outages resulted in increased imports across the Neptune line and from upstate New York.
  - ✓ However, LBMPs rose modestly in the West Zone because of more transmission constraints on west-to-east flows through the zone.

Highlights and Market Summary: Congestion Patterns

- Day-ahead congestion revenues totaled $50 million, down 44 percent from the second quarter of 2013.
  - ✓ Congestion across the Central-East interface, the UPNY-SENY interface, and in New York City accounted for just $18 million of day-ahead congestion revenue.
    - – Low natural gas prices tends to reduce congestion in these areas because most of the redispatch to manage congestion involves gas-fired generation; and
    - – The full return to operation of the Ramapo line reduced congestion into SENY.
  - ✓ Congestion into Long Island was reduced from the second quarter of 2013 when transmission outages significantly reduced flows across the Neptune Cable and the 345 kV connections from upstate New York.
  - ✓ However, transmission bottlenecks on west-to-east flows through the West Zone became more prevalent in the second quarter of 2014 because of:
    - – Increased production from hydro resources that increase west-to-east flows;
    - – Planned and forced outages of generation and transmission in late-May and June;
    - – Increased exports to PJM in May and June because of low gas prices in NY; and
    - – The retirement of one Dunkirk unit in June 2013.

Highlights and Market Summary: Uplift and Revenue Shortfalls

- Guarantee payments totaled $18 million, down 53 percent from the previous year.
  - ✓ Supplemental commitments in NYC fell 39 percent from a year ago, reflecting:
    - – Fewer transmission and generation outages in the Astoria West and Freshkills load pockets; and
    - – Updates in the NOx bubble modeling in the LRR pass that have reduced the need to commit steam turbine capacity.
  - ✓ OOM dispatch in Long Island fell dramatically after transmission improvements.
- Day-ahead congestion shortfalls were $12 million, down 33 percent from last year.
  - ✓ Transmission outages in NYC and the West Zone accounted for the majority.
  - ✓ Shortfalls on Long Island fell $10 million from a year ago due to fewer transmission outages on 345 kV lines into Long Island.
- Balancing congestion shortfalls totaled $6 million, down slightly from a year ago.
  - ✓ Long Island and West Zone congestion accounted for the majority of shortfalls.
  - ✓ TSAs usually account for most balancing congestion shortfalls in the summer, but TSA operation accounted for just $0.2 million of shortfalls this quarter because:
    - – TSAs occurred less frequently; and
    - – There was less congestion into SENY in general.

Highlights and Market Summary: Capacity Market

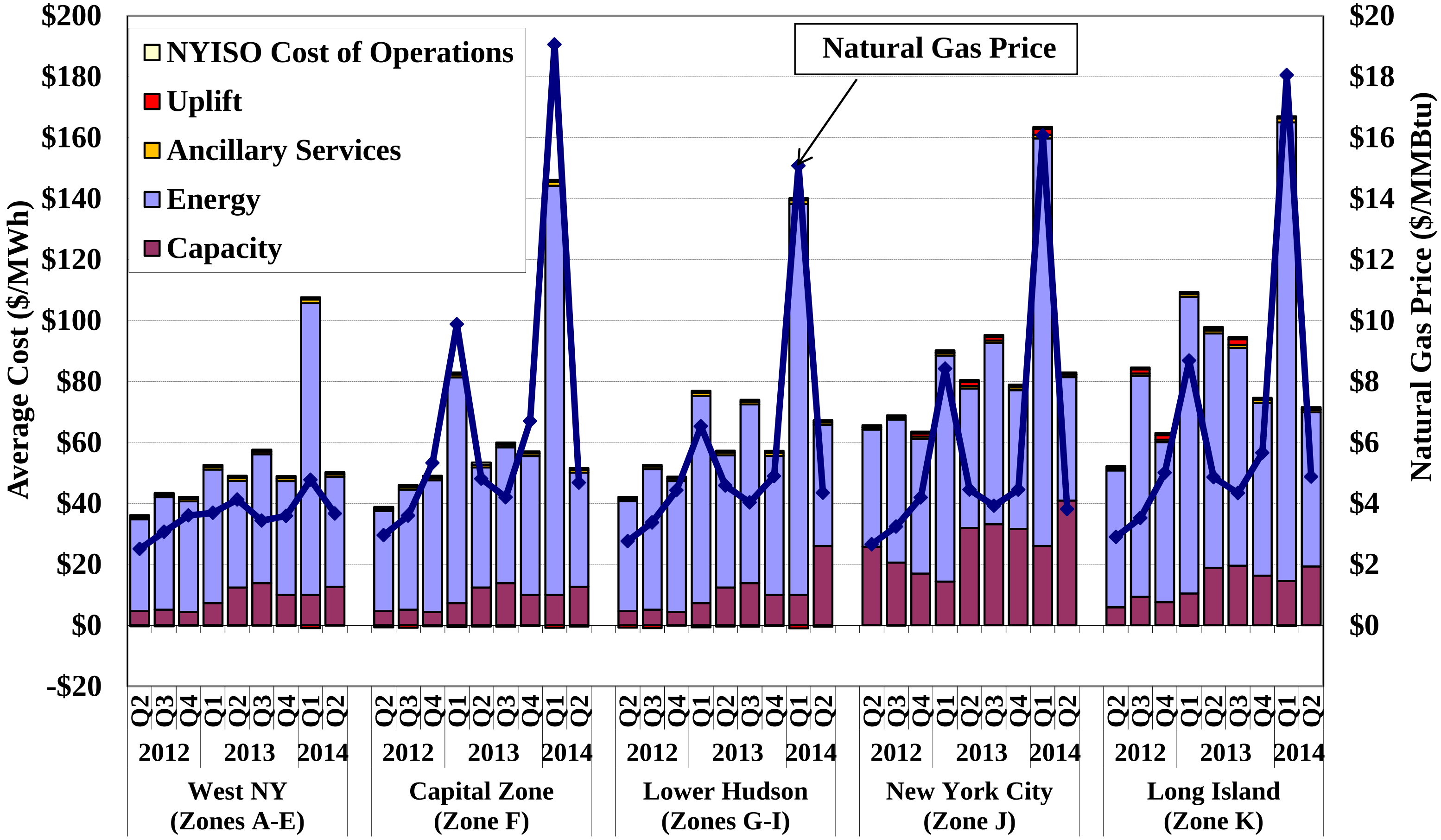
- UCAP spot prices rose in all areas but Long Island in the second quarter of 2014.
  - ✓ In New York City, UCAP spot prices averaged $15.81/kW-month, up 26 percent from the second quarter of 2013.
  - ✓ In the G-J Locality, UCAP spot prices averaged $12.37/kW-month for May and June 2014, significantly higher than the ROS spot prices.
  - ✓ On Long Island, UCAP spot prices averaged $5.22/kW-month, down 1.5 percent from the second quarter of 2013.
  - ✓ In Rest of State, UCAP spot prices averaged $4.88/kW-month, up 10 percent from the second quarter of 2013.
- Higher UCAP prices were primarily driven by increased ICAP requirements, which rose 453 MW in Rest of State and 138 MW in NYC because of increases in forecasted peak load from the 2013/14 Capability Year.
  - ✓ LI spot prices decreased because the UCAP demand curve fell by over 20 percent.
- 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 during the May and June UCAP auctions.

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 \$50/MWh in West NY to \$83/MWh in NYC. Compared to the second quarter of the previous year:
  - ✓ All-in prices changed most in Long Island (falling 27 percent), and in Lower Hudson Valley (rising 18 percent).
  - ✓ Energy prices fell 5 to 34 percent in East NY but rose 3 percent in West NY.
    - In East NY, lower LBMPs were driven by decreased gas prices and load levels.
      - Long Island LBMPs fell primarily because of increased imports across Neptune and fewer outages of generation and transmission.
    - In West NY, LBMPs rose due to the offsetting effects of less frequent west-to-east congestion, lower nuclear generation, and higher West Zone congestion.
  - ✓ Capacity costs rose \$14/MWh in Lower Hudson Valley primarily because of the implementation of the new G-J Locality starting in May 2014.
  - ✓ Capacity costs rose \$9/MWh in NYC because of the increased ICAP requirements and reduced supply (as discussed in slide 76).

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.

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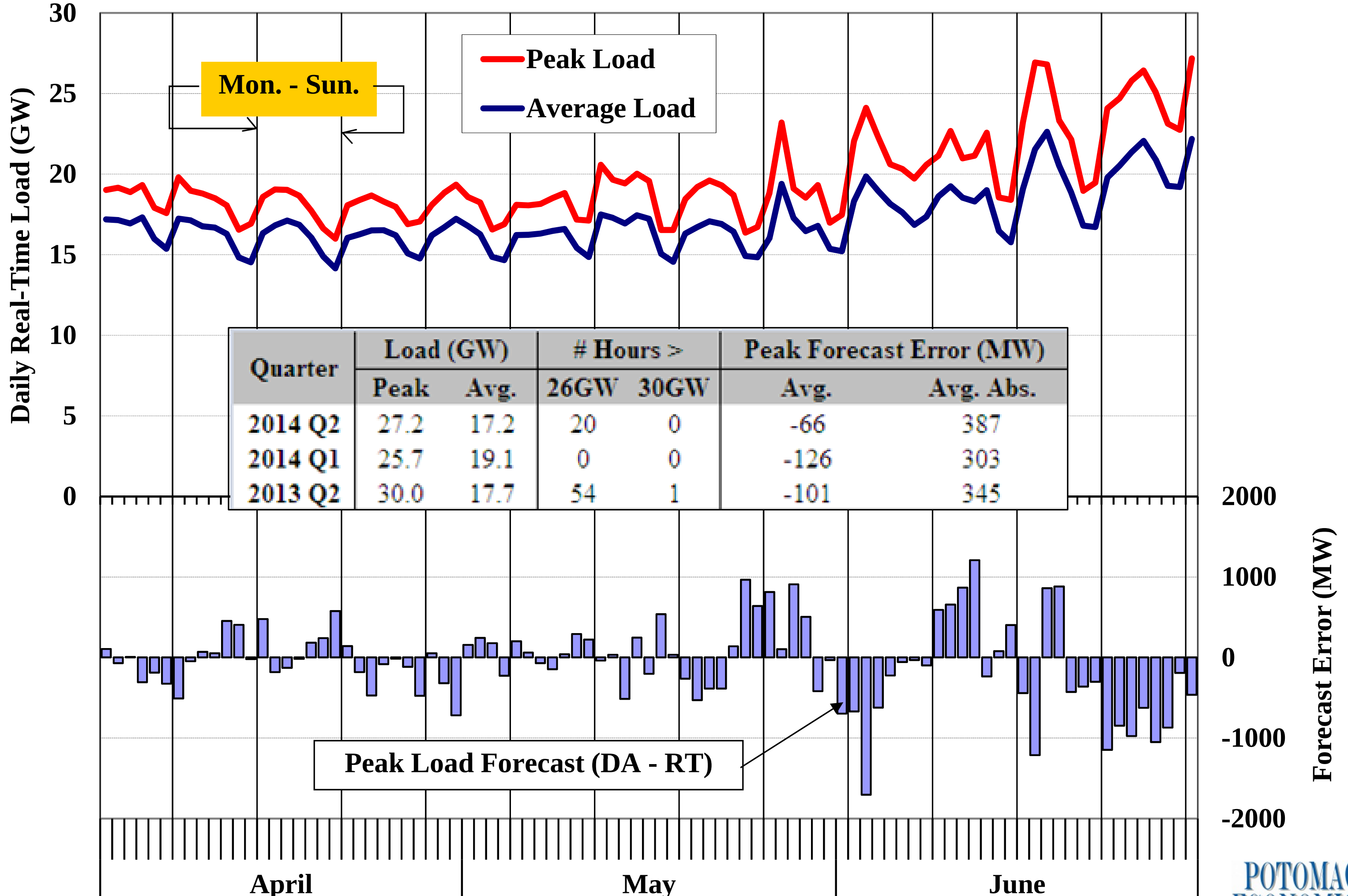
Load Levels and Fuel Prices

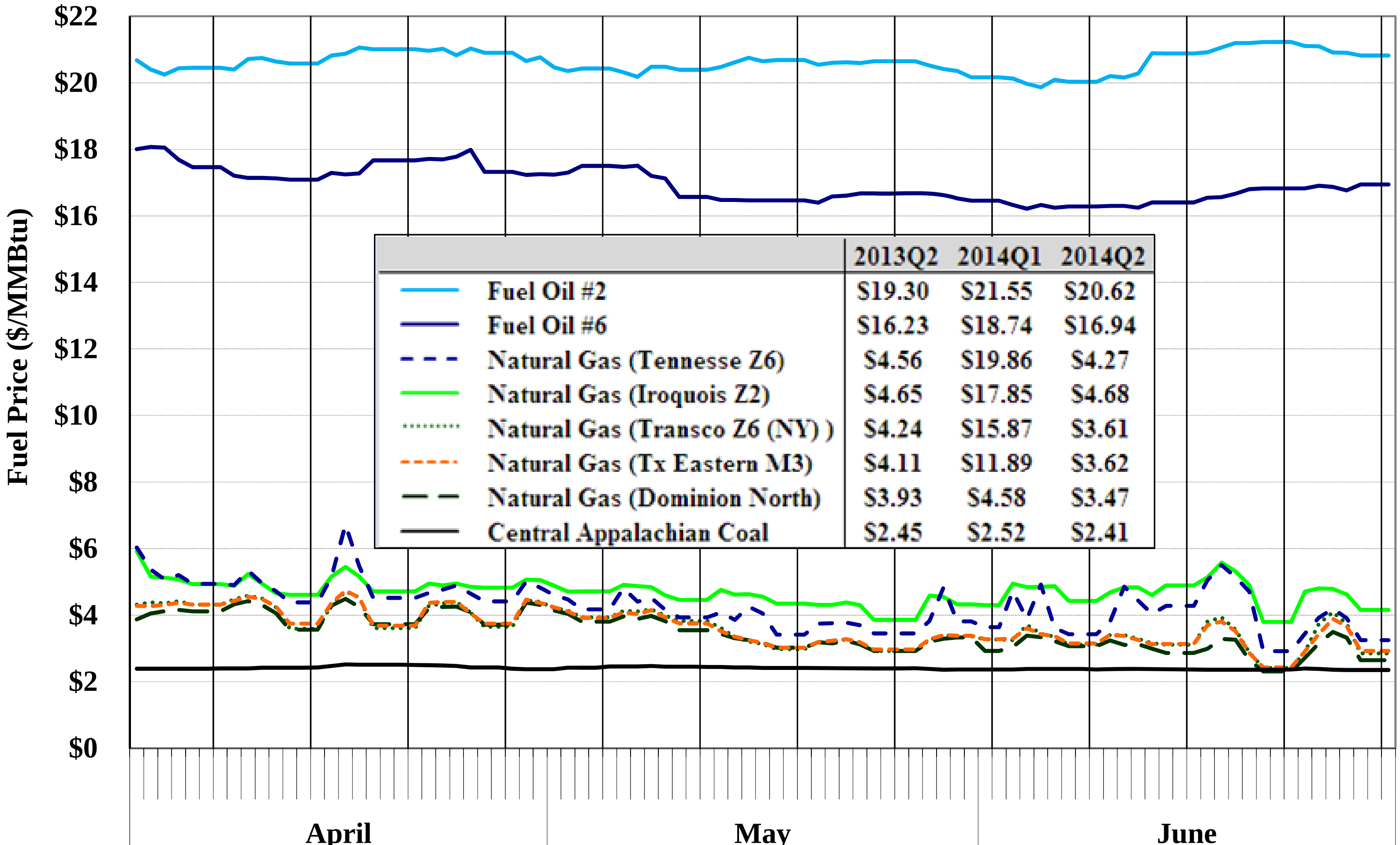
- The next two figures show two primary drivers of electricity prices in the quarter.
  - ✓ The first figure shows the average load, the peak load, and the day-ahead peak load forecast error on each day of the quarter.
  - ✓ The second figure shows daily coal, natural gas, and fuel oil prices.
- Load levels fell notably from prior years, due partly to mild weather conditions.
  - ✓ Average load (17.2 GW) and peak load (27.2 GW) fell 3 and 10 percent respectively from last year, and both were the lowest in the past five years.
  - ✓ 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 $3.47 at Dominion North (West NY), $3.61 at Transco Zone 6 (NYC), and $4.68 at Iroquois Zone 2 (most other East NY).
  - ✓ For Iroquois Zone 2, average gas prices were consistent with the previous year.
  - ✓ On other pipelines, average gas prices fell from the previous year (11 percent in West NY and 15 percent in NYC).
    - – Gas prices in these areas were significantly lower than in the rest of the country (e.g., Henry Hub prices averaged $4.58 this quarter). This contributed to lower net imports (see slide 37) excluding Neptune.
    - – Decreased gas price spreads between West NY and NYC reduced NYISO market congestion into Southeast New York and New York City.

Load Forecast and Actual Load



Quarter	Load (GW)		# Hours >		Peak Forecast Error (MW)	
	Peak	Avg.	26GW	30GW	Avg.	Avg. Abs.
2014 Q2	27.2	17.2	20	0	-66	387
2014 Q1	25.7	19.1	0	0	-126	303
2013 Q2	30.0	17.7	54	1	-101	345

Coal, Natural Gas, and Fuel Oil Prices



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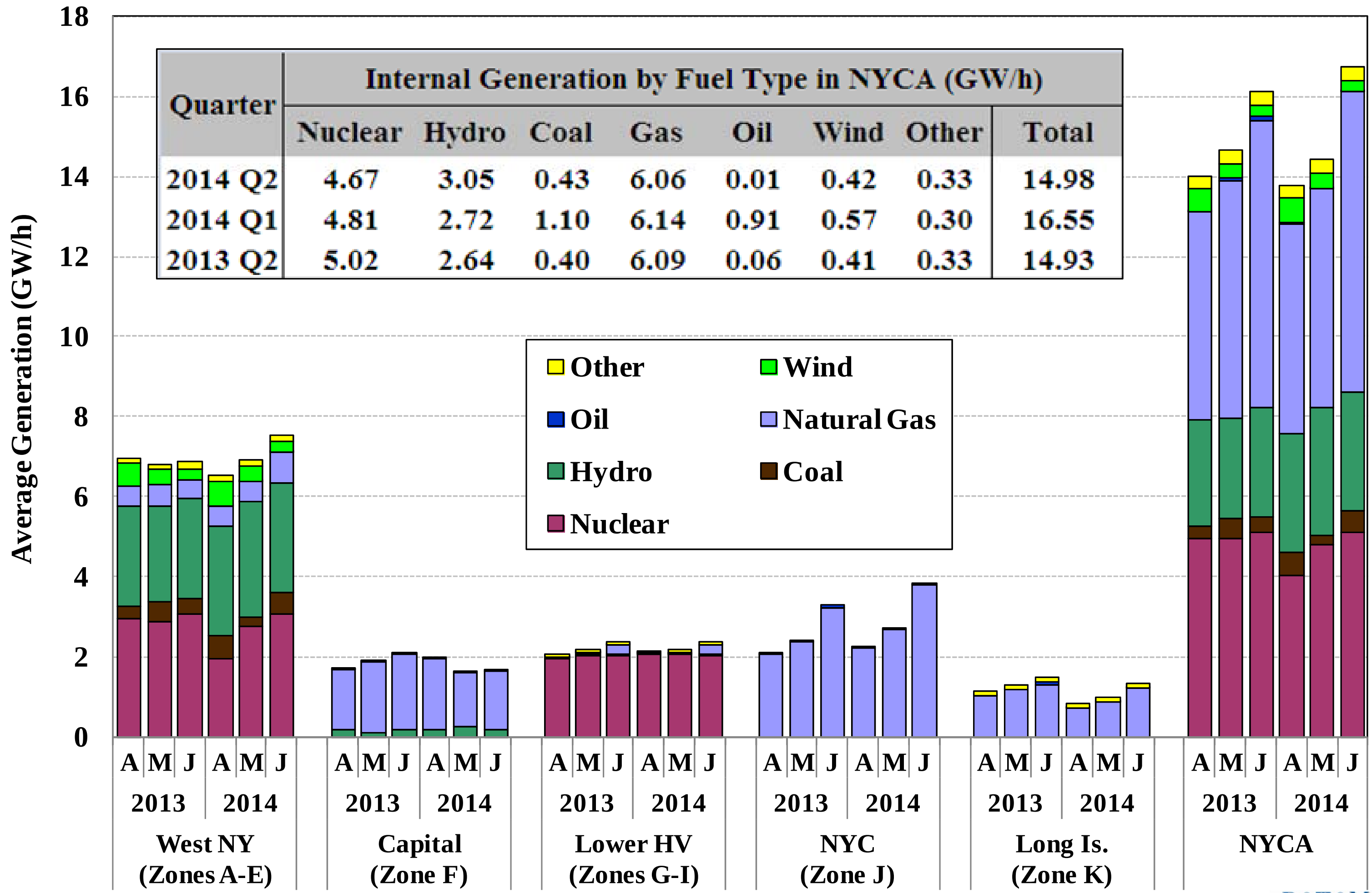
Real-Time Generation by Fuel Type

- The following two figures summarize fuel usage by generators in NYCA and their impact on LBMPs in the second 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 (41 percent), nuclear (31 percent), and hydro (20 percent) generation accounted for most of internal generation in the second quarter of 2014.
  - ✓ Average nuclear generation fell 345 MW from the second quarter of 2013 due primarily to maintenance outages of two units in Western NY in April and May.
  - ✓ Average hydro generation rose 410 MW (primarily in Western NY) from the second quarter of 2013, offsetting the decrease in nuclear generation.
  - ✓ 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.
  - ✓ Generation from other resources (i.e., coal, oil, wind, and other renewables) was comparable to the second quarter of 2013.
- Gas-fired and hydro resources were on the margin most of time in New York.
  - ✓ Most hydro units have storage capacity, leading them to offer based on the opportunity cost of foregoing sales in another hour (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 because of lower natural gas prices; and
    - – Transmission upgrades in Long Island reduced the need for 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 Q2	4.67	3.05	0.43	6.06	0.01	0.42	0.33	14.98
2014 Q1	4.81	2.72	1.10	6.14	0.91	0.57	0.30	16.55
2013 Q2	5.02	2.64	0.40	6.09	0.06	0.41	0.33	14.93

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

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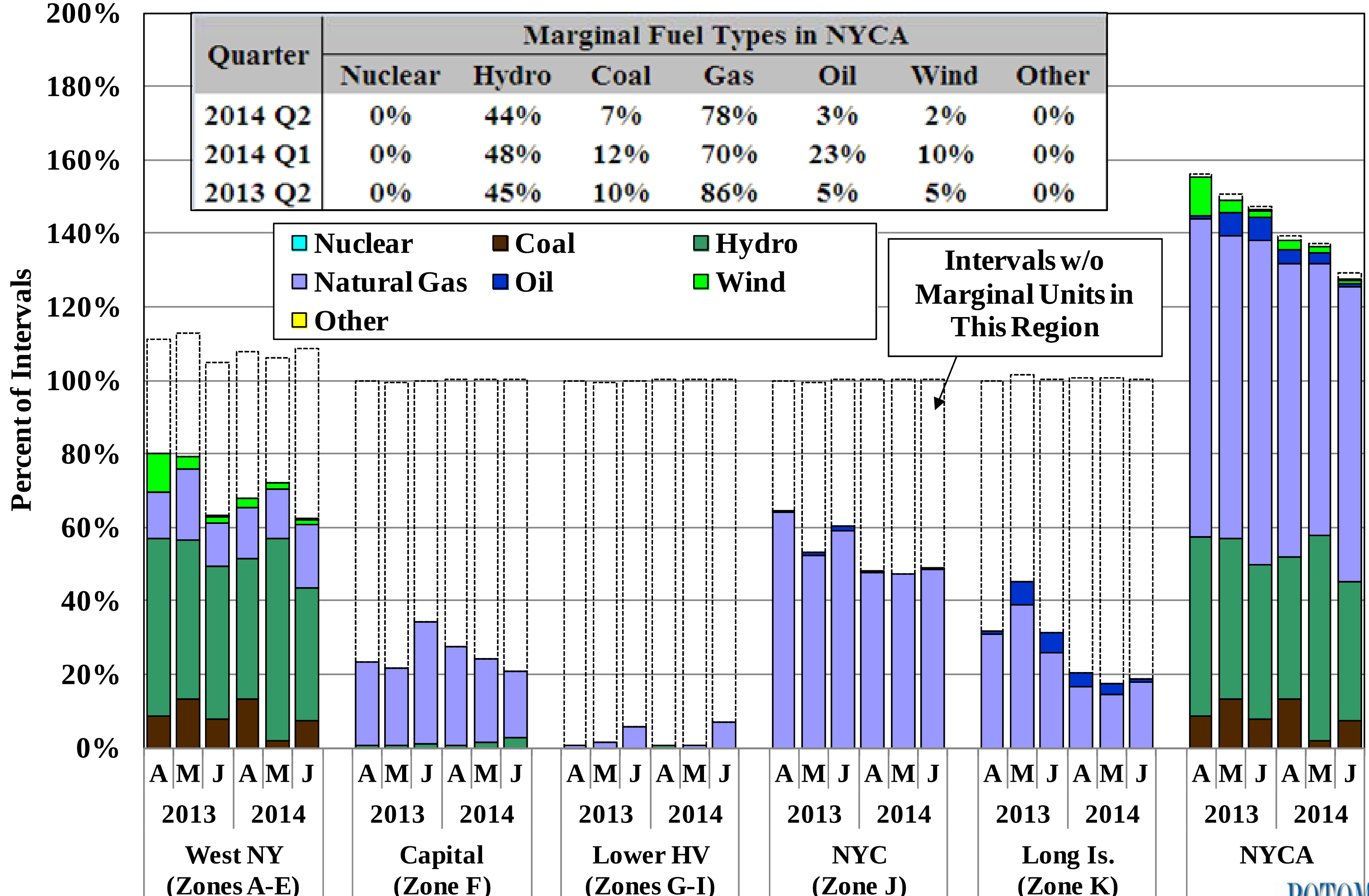
Fuel Types of Marginal Units in the Real-Time Market

Quarter	Marginal Fuel Types in NYCA						
	Nuclear	Hydro	Coal	Gas	Oil	Wind	Other
2014 Q2	0%	44%	7%	78%	3%	2%	0%
2014 Q1	0%	48%	12%	70%	23%	10%	0%
2013 Q2	0%	45%	10%	86%	5%	5%	0%



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

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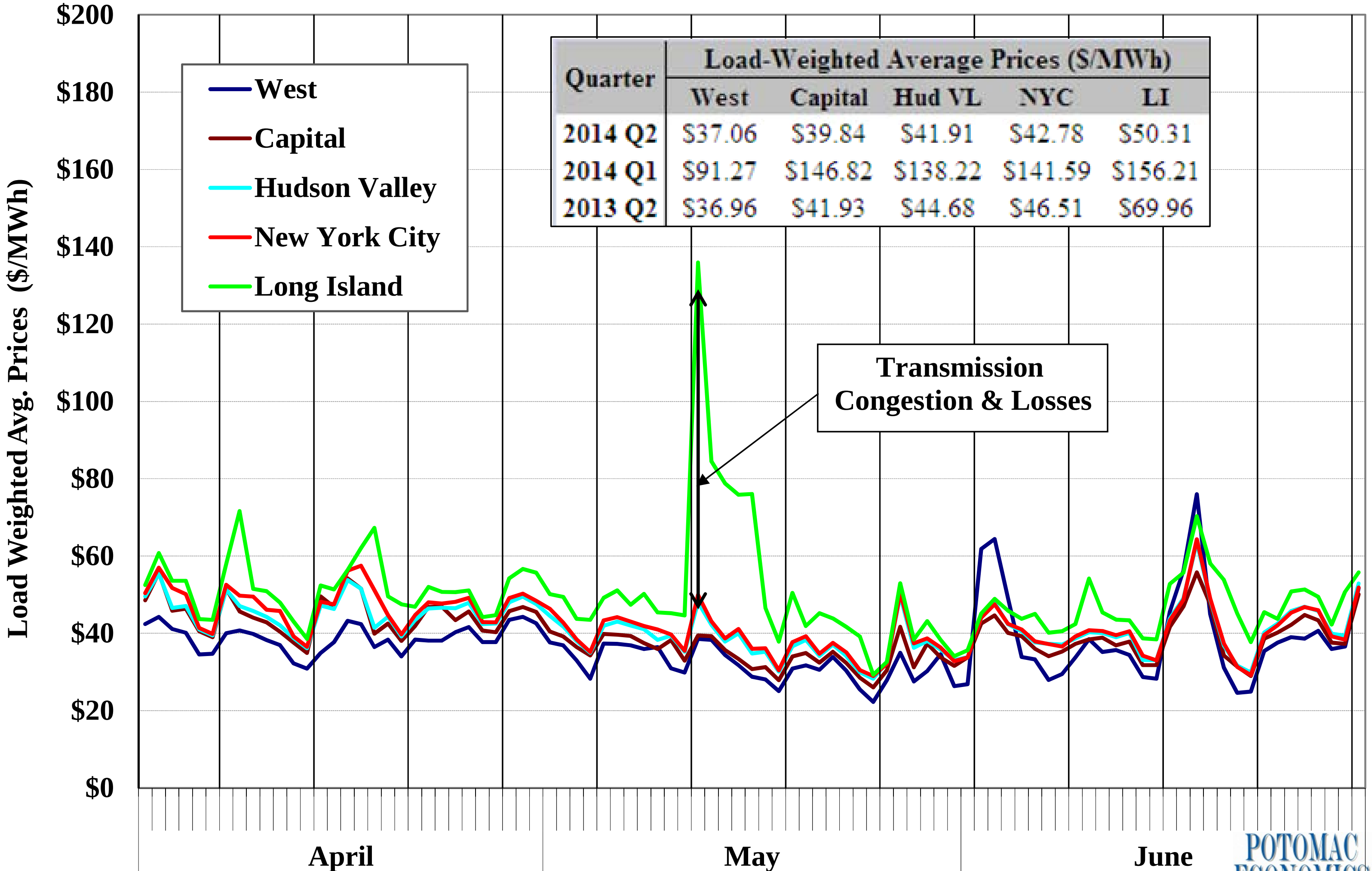
Day-Ahead and Real-Time Electricity Prices

- 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 second quarter of 2014.
- Average day-ahead prices fell from the second quarter of 2013 in most areas, ranging roughly from $37/MWh in the West Zone to $50/MWh on Long Island.
  - ✓ Lower LBMPs were due primarily to lower natural gas prices and decreased load levels, which were offset by decreased nuclear generation and lower imports.
  - ✓ Long Island exhibited the largest decrease (28%) among these regions, due to:
    - – Increased Neptune imports (since it fully returned after July 2013); and
    - – Increased Upstate imports (one of the two 345 kV lines from upstate was out of service in April and May in 2013, while both lines were in service this quarter).
    - – However, LI LBMPs rose notably in one week in mid-may when acute congestion occurred in the Valley Stream load pocket due to maintenance outages.
      - Oil-fired units were dispatched for 59 hours because of: (a) maintenance outages and (b) an on-going requirement to export power to New York City.
  - ✓ West Zone LBMPs rose from a year ago because of more transmission constraints on west-to-east flows through the zone. The following were key contributors:
    - – The retirement of one Dunkirk unit in June 2013 and several PJM units;
    - – Multiple transmission outages in late-May and June; and
    - – Increased production from hydro resources.

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. Some notable examples were:
  - ✓ On May 1, RT prices spiked in LI when load was under-scheduled in the DAM (see slide 31) and Neptune imports were reduced in most hours (see slide 37).
  - ✓ On June 17, RT prices rose considerably across the state when actual load ran over day-ahead forecast by 1.2 GW.
- 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 DA prices were roughly 6 percent higher than RT prices in most areas except Long Island and the West Zone which exhibited a small RT premium.
    - – Price convergence on Long Island improved notably from prior quarters, reflecting lower load levels and increased imports from upstate and PJM.
  - ✓ Although price convergence at the zonal level was fair this quarter, price differences were less consistent at the nodal level. For example:
    - – On Long Island, the Barrett station had a $13 RT premium while the Northport station had a $3 DA premium (compared to a $0.29 zonal RT premium).
    - – In the West Zone, the Huntley station had a $1 RT premium while the Niagara station had a $3 DA premium (compare to a $0.19 zonal RT premium).

Day-Ahead Electricity Prices by Zone



Quarter	Load-Weighted Average Prices ($/MWh)				
	West	Capital	Hud VL	NYC	LI
2014 Q2	$37.06	$39.84	$41.91	$42.78	$50.31
2014 Q1	$91.27	$146.82	$138.22	$141.59	$156.21
2013 Q2	$36.96	$41.93	$44.68	$46.51	$69.96

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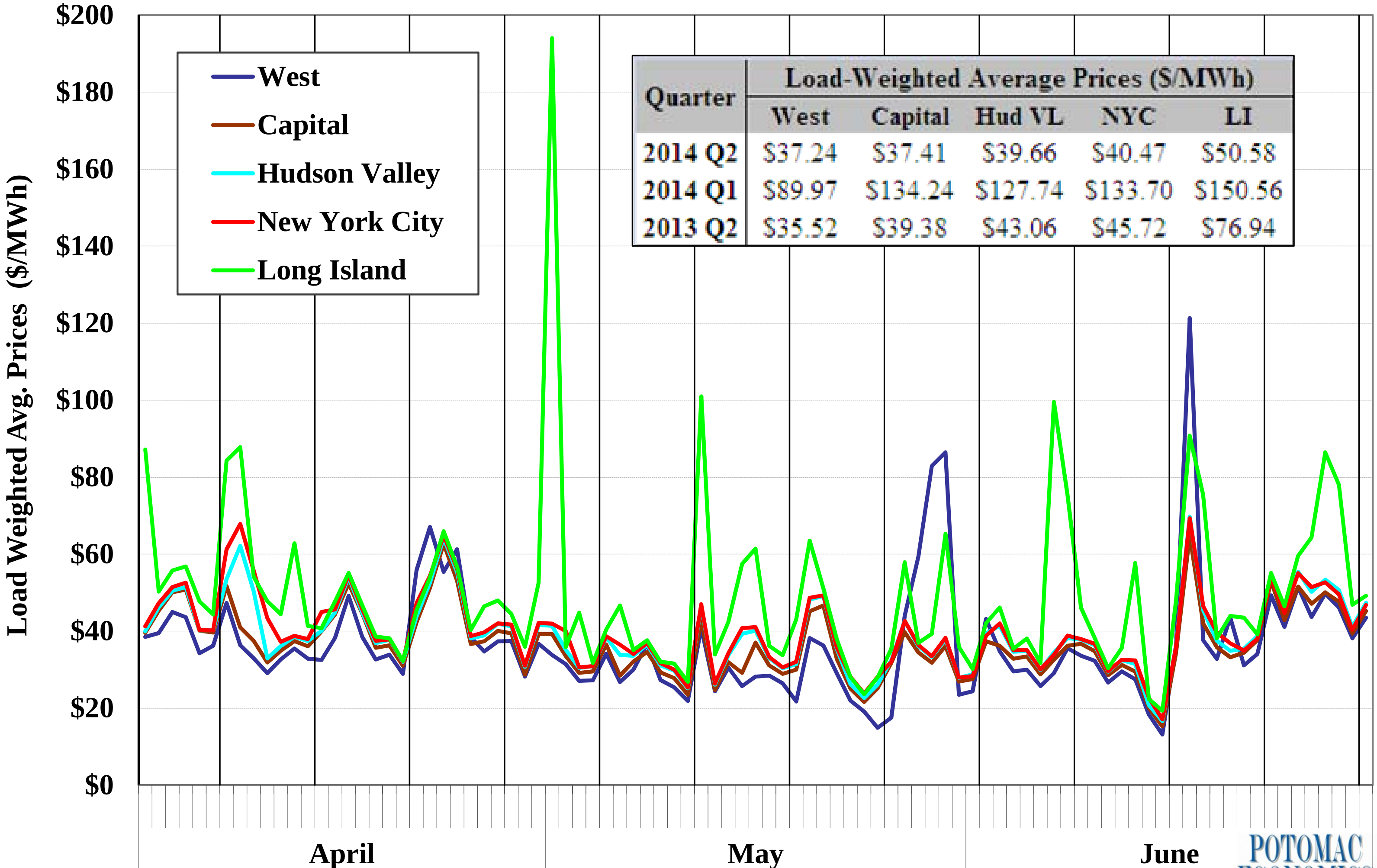
Real-Time Electricity Prices by Zone



Quarter	Load-Weighted Average Prices ($/MWh)				
	West	Capital	Hud VL	NYC	LI
2014 Q2	$37.24	$37.41	$39.66	$40.47	$50.58
2014 Q1	$89.97	$134.24	$127.74	$133.70	$150.56
2013 Q2	$35.52	$39.38	$43.06	$45.72	$76.94

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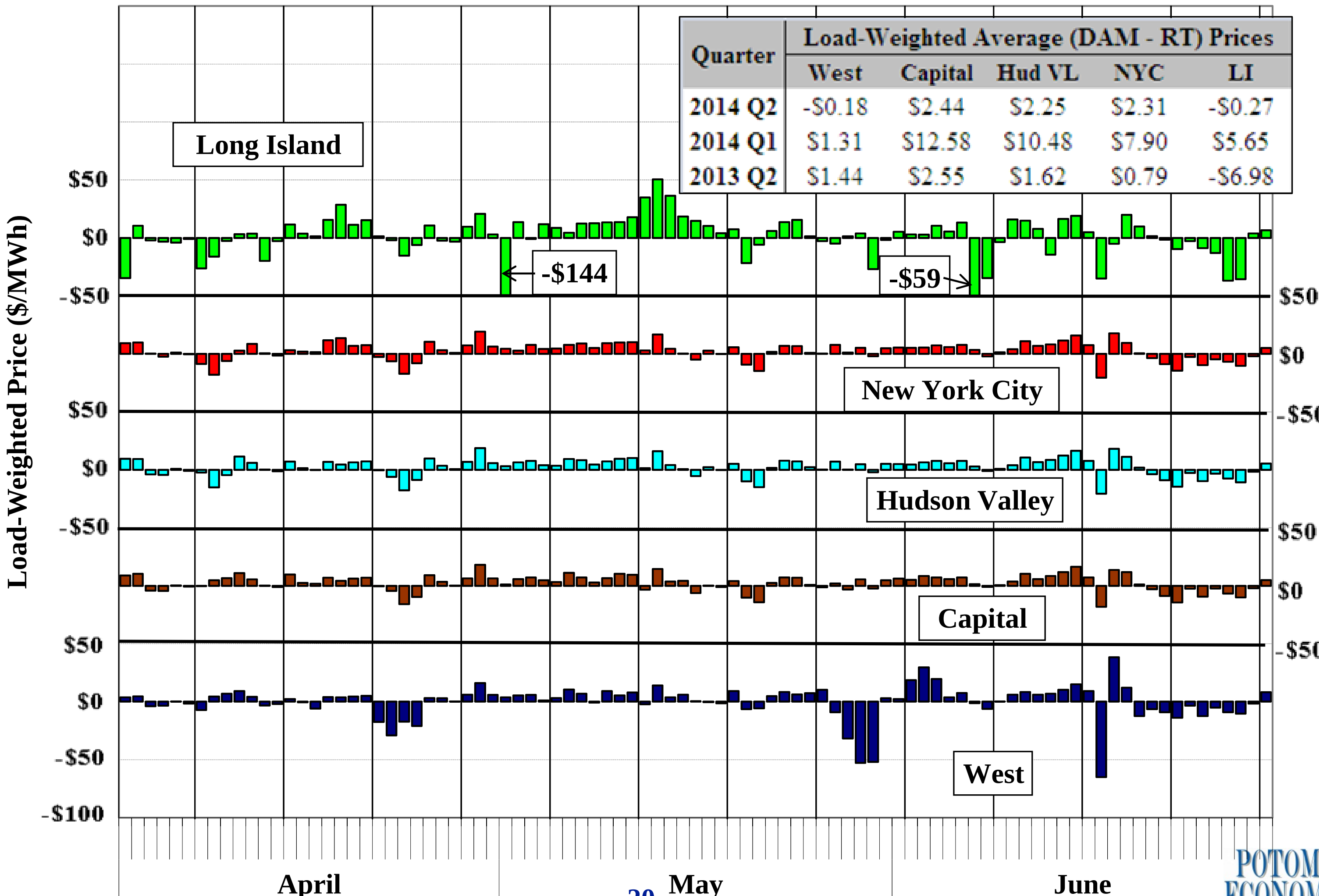
Convergence Between Day-Ahead and Real-Time Prices



Quarter	Load-Weighted Average (DAM - RT) Prices				
	West	Capital	Hud VL	NYC	LI
2014 Q2	-$0.18	$2.44	$2.25	$2.31	-$0.27
2014 Q1	$1.31	$12.58	$10.48	$7.90	$5.65
2013 Q2	$1.44	$2.55	$1.62	$0.79	-$6.98

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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 evaluates RT offers submitted by thermal peaking units that are connected to local distribution pipelines in NYC and Long Island by time of day. The figure shows:
  - ✓ The amounts of capacity offered in six price range categories;
  - ✓ The average RT LBMPs for NYC, Long Island, and the reference bus; and
  - ✓ A load profile for New York State.
- The evaluation excludes offers from peaking units on individual gas days if the unit had a maintenance outage or an outage of gas service for one or more hours.

Energy Offer Patterns over the Gas Day

- Offer prices are lowest and the amounts of capacity offered are highest from hour 10 to 15 (i.e., from 10:00 am to 4:00 pm).
  - ✓ The total amount of capacity offered was 10 percent lower in other hours.
  - ✓ Capacity offered under $100/MWh was 30 percent lower in other hours.
  - ✓ Hours 10 to 15 generally do not coincide with the peak demand hours.
    - – Average demand for electricity peaks in the late afternoon (hour 17).
- Average real-time LBMPs peak in hours 17 and 20 when congestion is highest.
  - ✓ Real-time LBMPs rise on some days as generators raise their offer prices and/or stop offering altogether after hour 15.
  - ✓ Gas scheduling procedures and gas balancing charges have significant impacts on LBMPs and congestion patterns, even when there is little or no congestion on the gas pipeline system.
- Many of the offer price increases and decisions not to offer are justified by gas balancing charges and natural gas system limitations.
  - ✓ However, the market power mitigation measures have been invoked in some instances when offer prices and non-offers were not justified.

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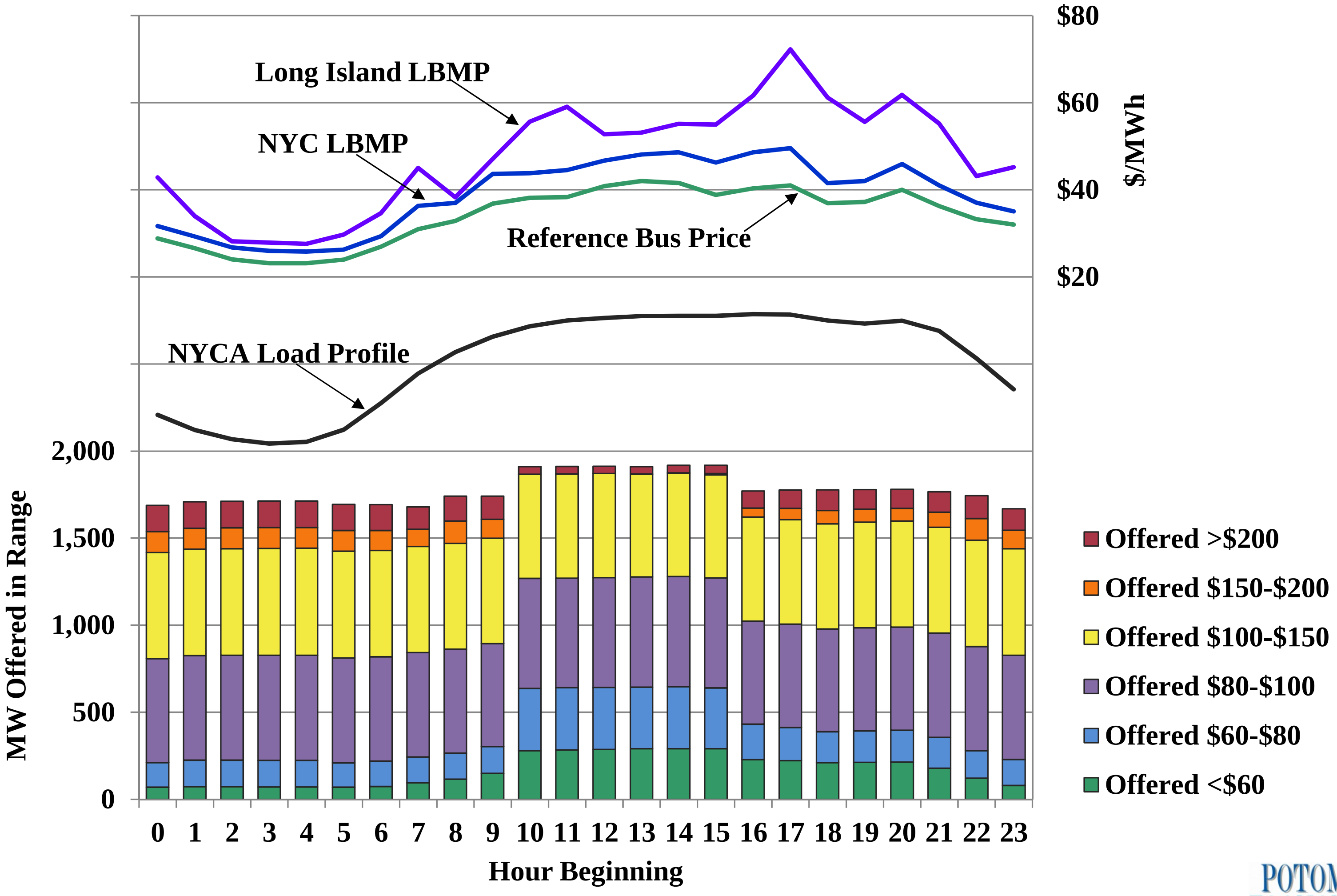
Energy Offers from Gas Peaking Units by Time of Day
New York City & Long Island



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Ancillary Services Market

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Ancillary Services Prices

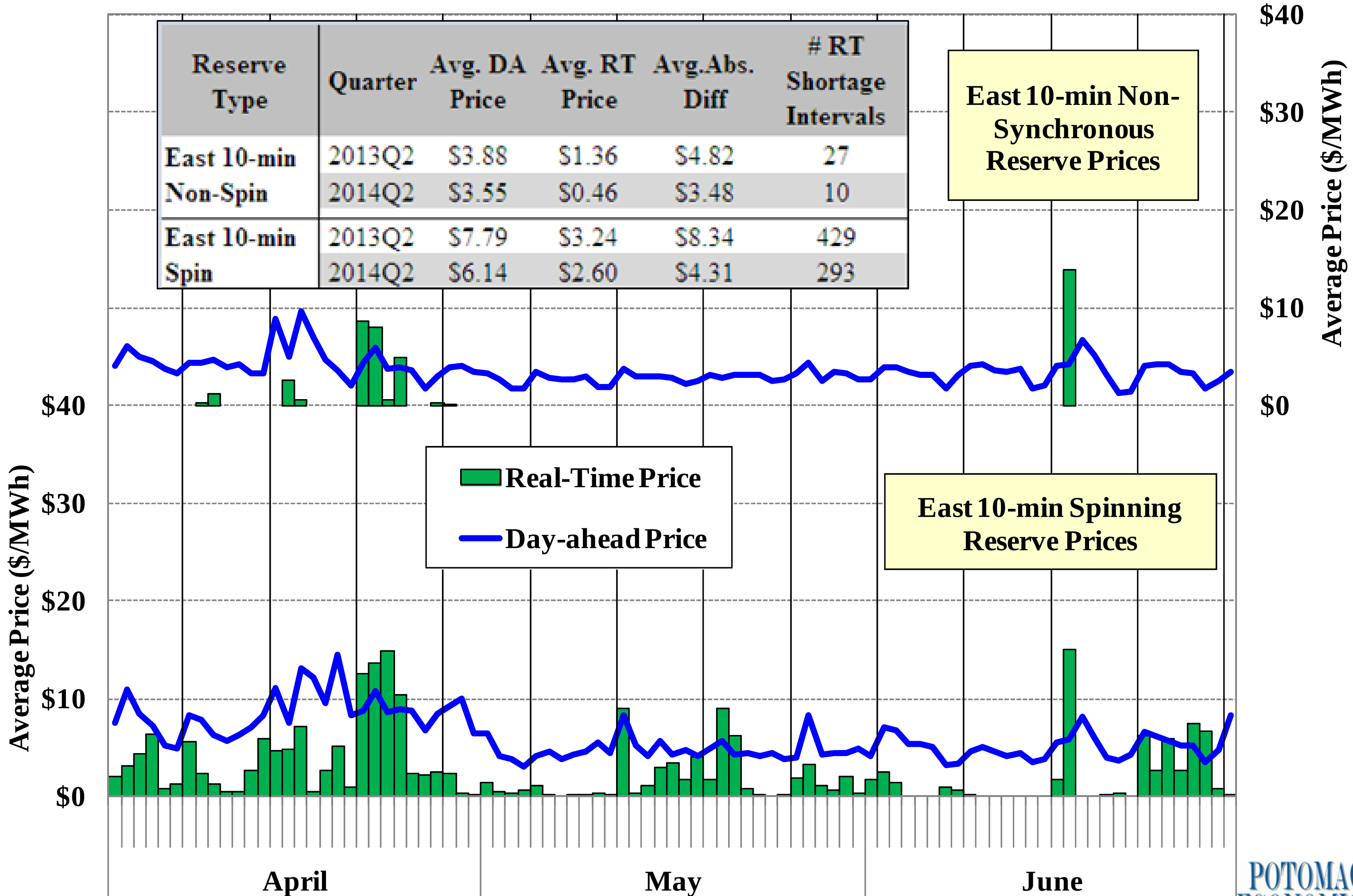
- This part of the report evaluates the outcomes of the ancillary services markets.
- Two figures summarize DA and RT prices for four ancillary services products:
  - ✓ 10-min spinning reserves prices in eastern NY, which reflect the cost of requiring:
    - 330 MW of 10-minute spinning reserves in eastern 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

- Average DA and RT prices for most ancillary services products fell from the second quarter of 2013, consistent with the decreases in load levels and LBMPs.
- 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 few RT events resulting in high RT prices compared with previous years.
- Average hourly absolute differentials between DA and RT clearing prices fell as a share of average DA prices for all four products.
  - ✓ For example, this fell from 124 to 98 percent for Eastern 10-minute non-spin reserves and from 107 to 70 percent for Eastern 10-minute spinning reserves.
  - ✓ Several factors contributed to the improvement:
    - Lower load levels led to fewer shortages and less volatile RT prices.
    - DA and RT reserve prices became more consistent by load level and time of day.
    - DA regulation capacity prices were generally more consistent with RT capacity prices following the implementation of the new regulation market in June 2013, which allows participants to offer regulation movement costs separately from regulation capacity costs.

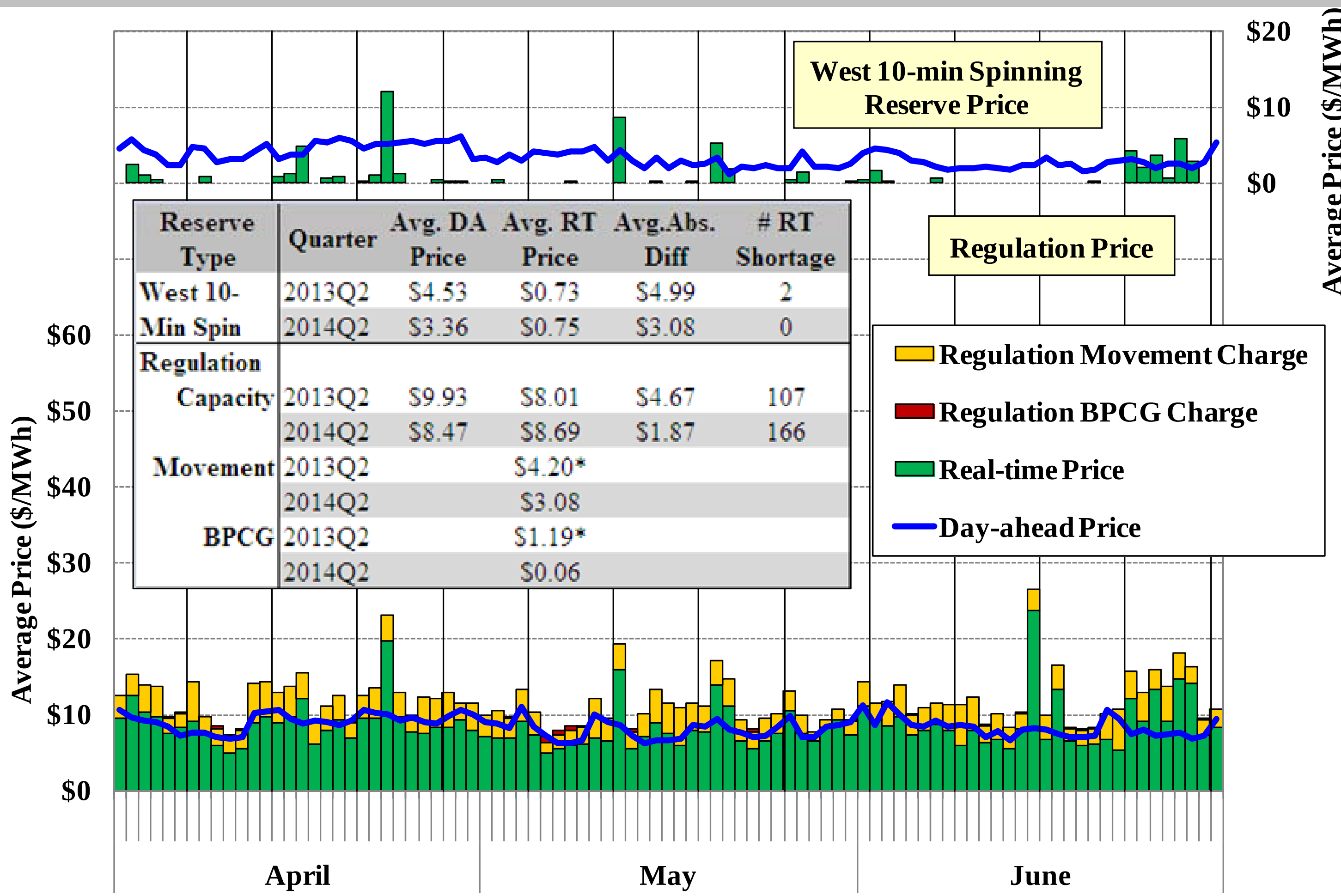
Day-Ahead and Real-Time Ancillary Services Prices

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	2013Q2	$3.88	$1.36	$4.82	27
	2014Q2	$3.55	$0.46	$3.48	10
East 10-min Spin	2013Q2	$7.79	$3.24	$8.34	429
	2014Q2	$6.14	$2.60	$4.31	293

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	2013Q2	$4.53	$0.73	$4.99	2
	2014Q2	$3.36	$0.75	$3.08	0
Regulation					
Capacity	2013Q2	$9.93	$8.01	$4.67	107
	2014Q2	$8.47	$8.69	$1.87	166
Movement	2013Q2		$4.20*		
	2014Q2		$3.08		
BPCG	2013Q2		$1.19*		
	2014Q2		$0.06		

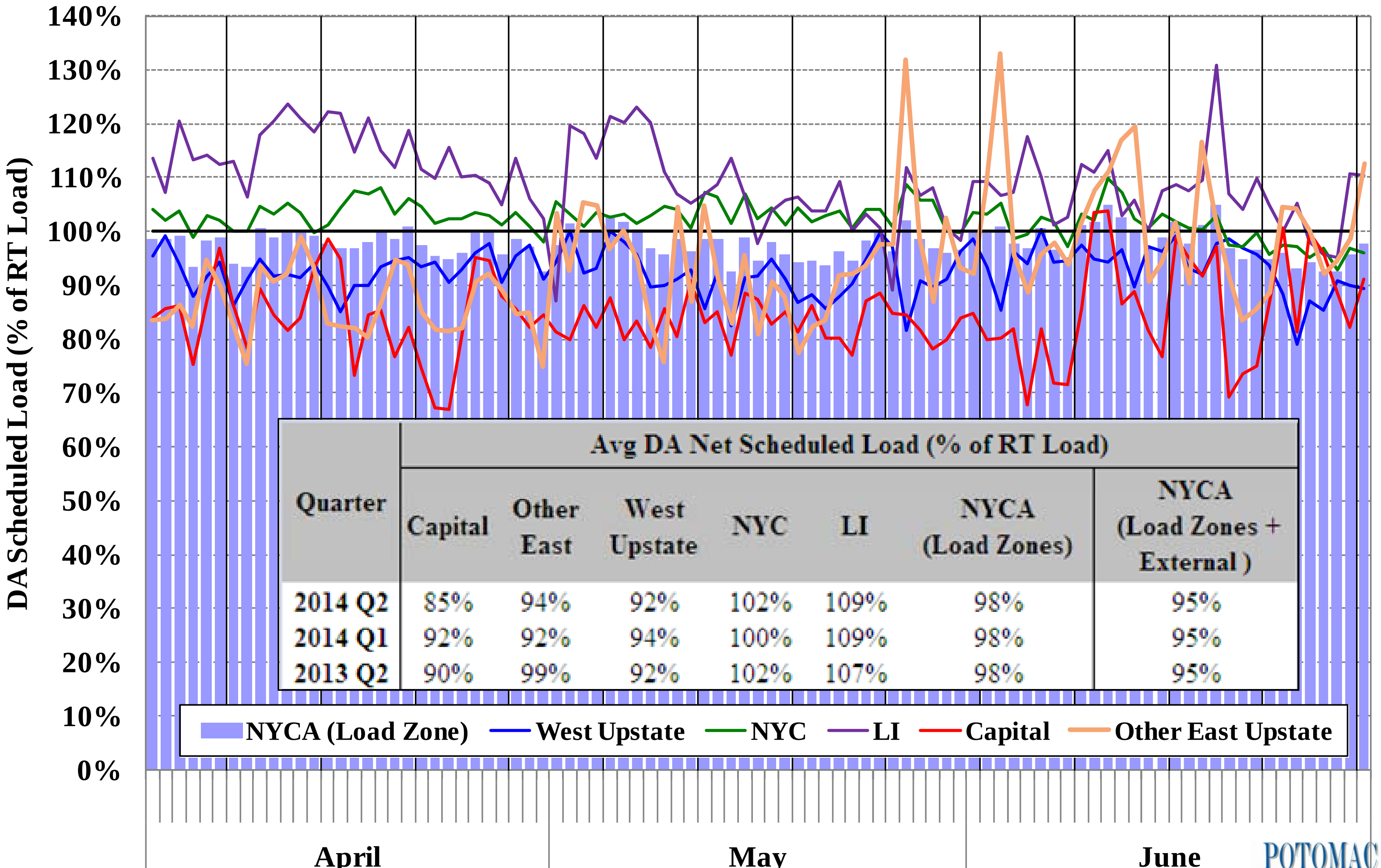
Note: Regulation Movement Charges and BPCG charges from regulating in real-time are shown in the figure averaged per MWh of RT Scheduled Regulation Capacity.

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, 95 percent of actual load was scheduled in the DAM (including virtual imports/exports) in the second quarter of 2014, consistent to prior quarters.
- The percentage of load scheduled in the DAM is generally higher in SENY, particularly Long Island.
  - ✓ DAM scheduling is generally highest in areas that experience more frequent periods of acute RT congestion.
  - ✓ DAM scheduling in SENY (particularly in Other East Upstate) rose notably on several days in late May and June, likely in anticipation of TSAs.
- Under-scheduling continues to be prevalent outside SENY, consistent with the tendency for hydro and wind units to increase RT output above DA schedules.
- These scheduling patterns generally improved convergence between DA and RT prices in most areas during the second quarter.

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 Q2	85%	94%	92%	102%	109%	98%	95%
2014 Q1	92%	92%	94%	100%	109%	98%	95%
2013 Q2	90%	99%	92%	102%	107%	98%	95%

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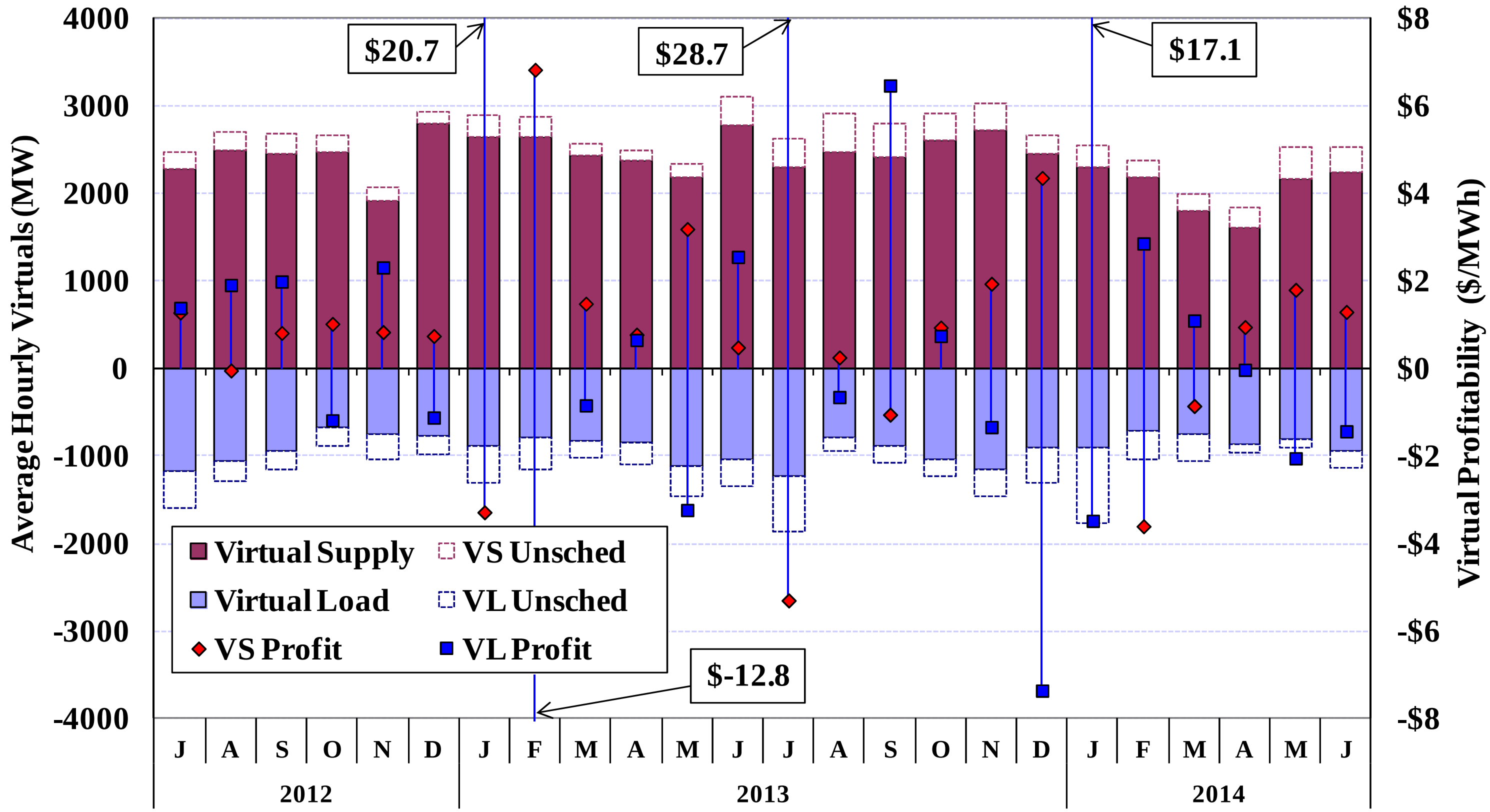
Virtual Trading Activity

- 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.
- Scheduled virtual supply in Western NY fell notably in April.
  - ✓ The decrease coincided with decreased bilateral load scheduling in Western NY during the same period because some firms that made bilateral load purchases used virtual supply to sell energy in the day-ahead market.
- In aggregate, virtual traders netted a gross profit of roughly \$4 million at the load zones and \$1.5 million at the proxy buses in the second 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



Profit > 50% of Avg. Zone Price	MW	300	208	158	143	238	202	418	426	191	187	328	253	345	156	193	230	438	319	590	260	250	83	169	160
	%	9%	6%	5%	5%	9%	6%	12%	12%	6%	6%	10%	7%	10%	5%	6%	6%	11%	10%	18%	9%	10%	3%	6%	5%
Loss > 50% of Avg. Zone Price	MW	337	220	129	93	182	195	354	347	125	149	275	166	252	176	177	201	369	258	395	333	256	70	196	199
	%	10%	6%	4%	3%	7%	5%	10%	10%	4%	5%	8%	4%	7%	5%	5%	6%	10%	8%	12%	12%	10%	3%	7%	6%

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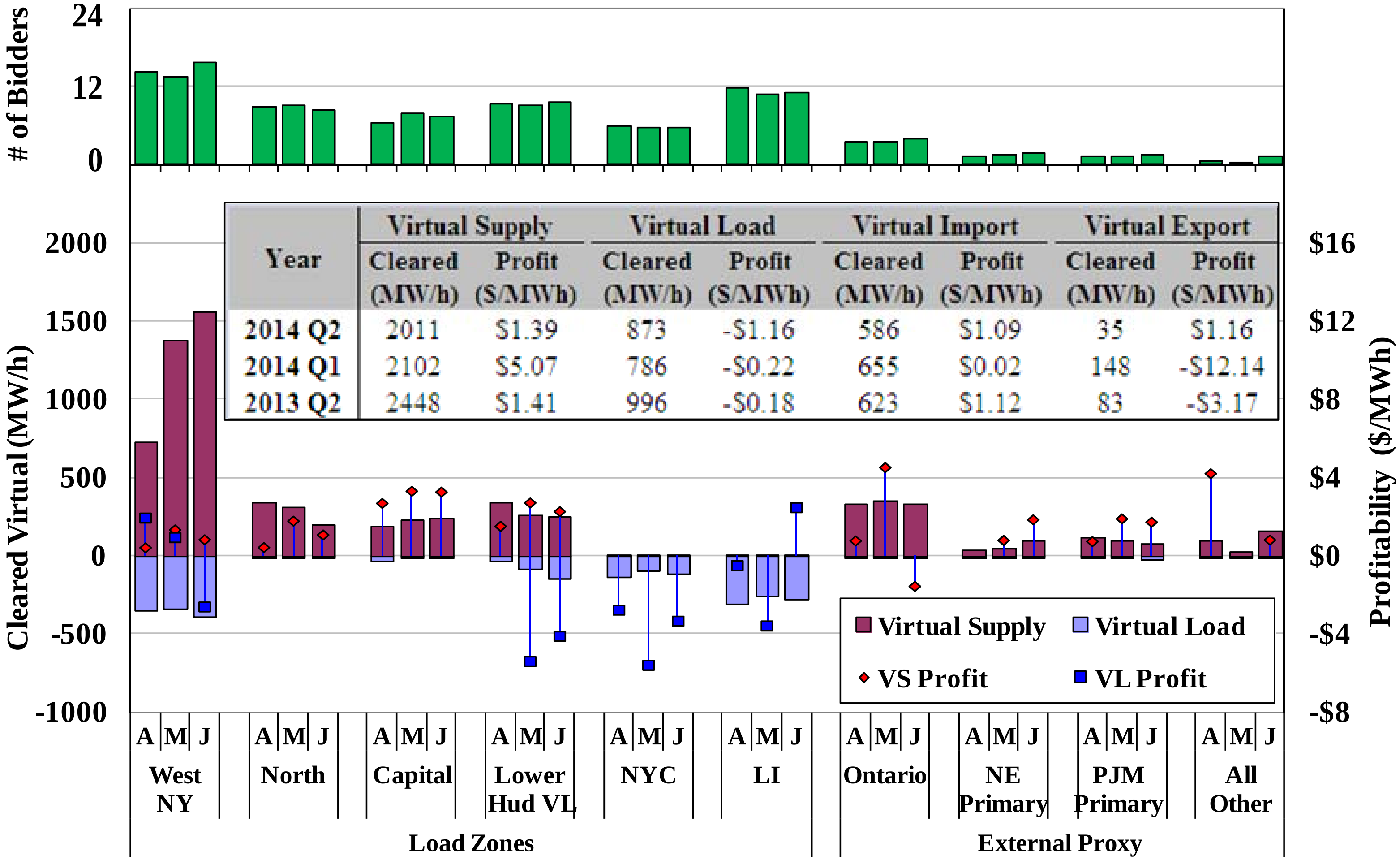
Virtual Trading Activity at Load Zones & Proxy Buses by Location



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 Q2	2011	$1.39	873	-$1.16	586	$1.09	35	$1.16
2014 Q1	2102	$5.07	786	-$0.22	655	$0.02	148	-$12.14
2013 Q2	2448	$1.41	996	-$0.18	623	$1.12	83	-$3.17

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

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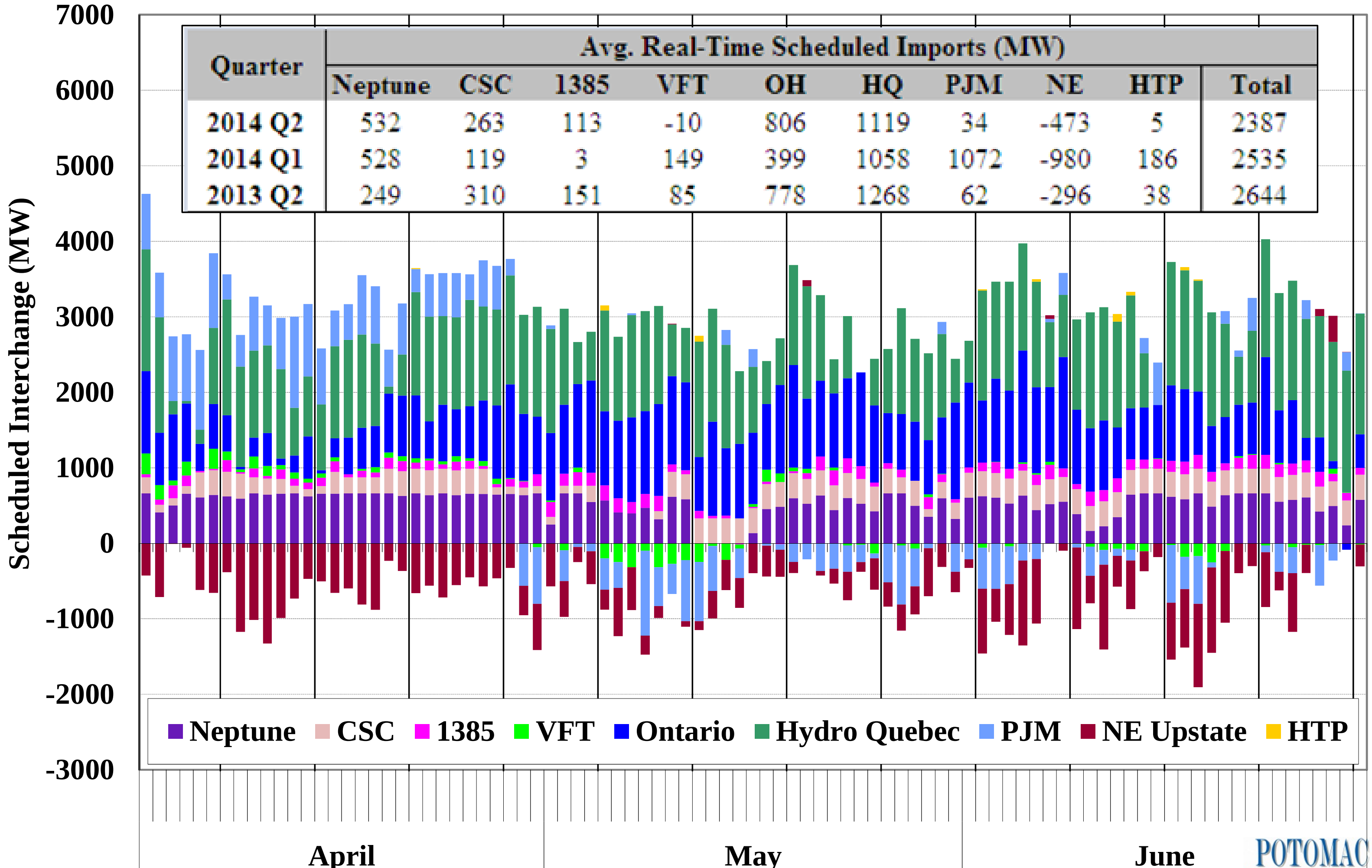
Net Imports Scheduled Across External Interfaces

- 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 2,390 MW (serving roughly 14 percent of the load) during peak hours, down approximately 260 MW from the second quarter of 2013.
- Net exports to NE across its primary interface averaged roughly 475 MW during peak hours, down 510 MW from last quarter and up 180 MW from last year.
  - ✓ These changes are consistent with the variations in natural gas price spreads between NE and NY over the period.
  - ✓ Imports to Long Island across the 1385 Line and CSC varied for similar reasons.
- Net imports to Long Island across the Neptune Line increased roughly 285 MW from the second quarter of 2013.
  - ✓ The Neptune Line was in full operation this quarter but was not fully available in the second quarter of 2013 due to a transmission outage.
- Net imports from PJM (including VFT, HTP, and the primary interface) fell from the prior quarters.
  - ✓ Natural gas prices in Western NY and most of Eastern NY (particularly NYC) were low during most of the quarter compared to the rest of the country, reducing incentives to import to NY.

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

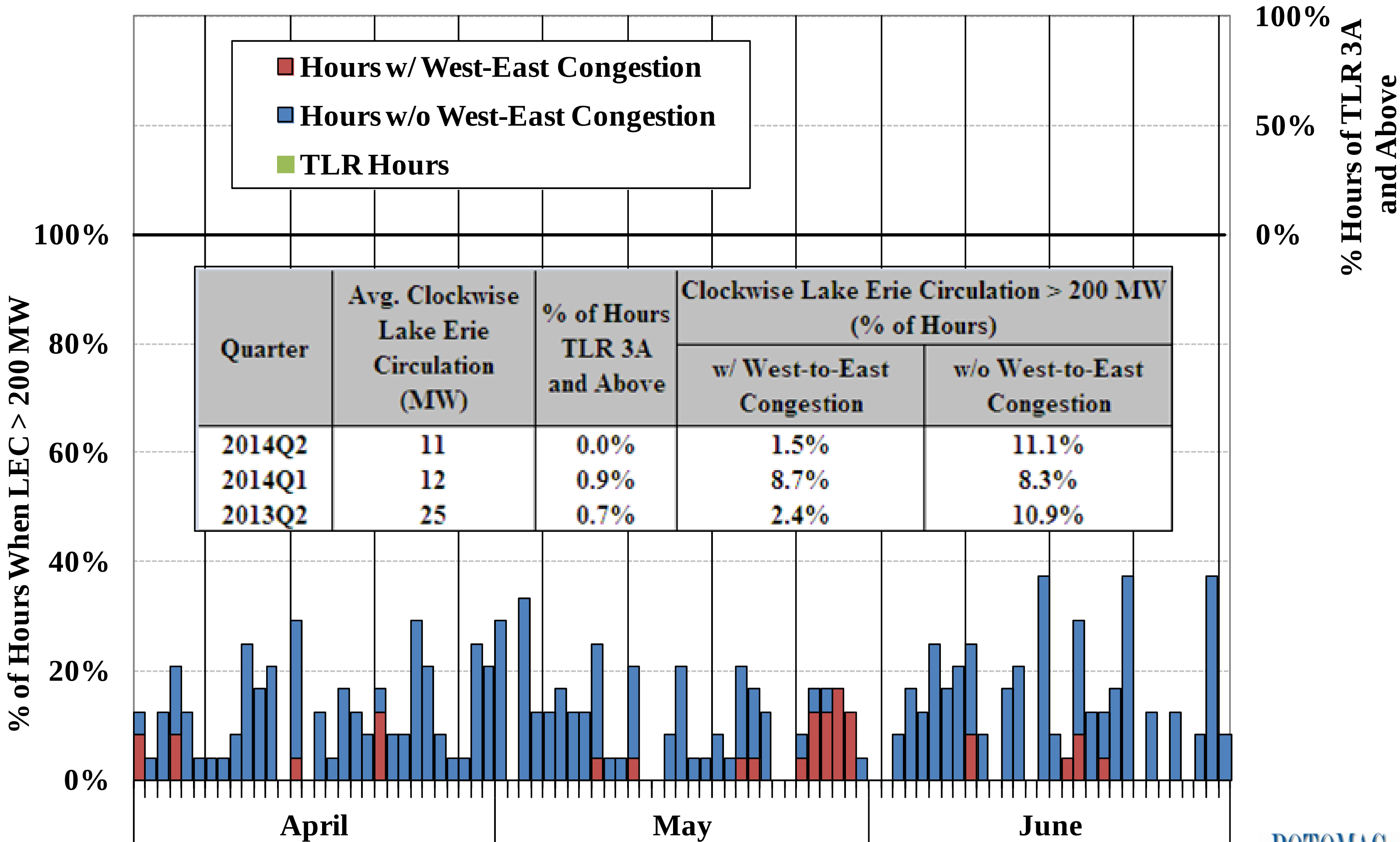


Quarter	Avg. Real-Time Scheduled Imports (MW)									
	Neptune	CSC	1385	VFT	OH	HQ	PJM	NE	HTP	Total
2014 Q2	532	263	113	-10	806	1119	34	-473	5	2387
2014 Q1	528	119	3	149	399	1058	1072	-980	186	2535
2013 Q2	249	310	151	85	778	1268	62	-296	38	2644

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 second quarter of 2014.
- Clockwise LEC was relatively high (> 200 MW) during 13 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 just 12 percent of these hours.
    - – However, severe West Zone congestion in the last week of May was exacerbated by high clockwise LEC in some hours.
- The frequency of TLRs called by the NYISO has been very low for the last two years – there were no TLR calls in the second quarter of 2014.
  - ✓ Loop flows have fallen since the IESO-MI PARs went in service in April 2012.
  - ✓ 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
2014Q2	11	0.0%	1.5%	11.1%
2014Q1	12	0.9%	8.7%	8.3%
2013Q2	25	0.7%	2.4%	10.9%

Day-Ahead and Real-Time Transmission Congestion

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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 to Central: Lines and interfaces in the West Zone through Central 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 $50 million, down 88 percent from the prior quarter and 44 percent from the second quarter of 2013, due to:
  - ✓ Decreased load levels and less frequent peaking conditions, which generally resulted in less frequent congestion across the system;
  - ✓ Lower gas prices, which led to lower re-dispatch costs to manage congestion;
  - ✓ Lower gas price spreads between Western NY and Eastern NY, which led to reduced congestion across the Central-East interface, into SENY and NYC; and
  - ✓ Fewer transmission outages in Long Island, which resulted in increased imports from upstate and PJM into Long Island and less congestion into Long Island.

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 second quarter of 2014 :
  - ✓ Long Island (30% DAM, 36% RTM) – Long Island accounted for the largest share of congestion in NY partly because it had the highest natural gas prices.
    - Valley Stream load pocket accounted for half of the congestion, most of which occurred on several days in mid-May (for reasons discussed in slide 16).
    - Most of the remaining congestion occurred on transmission paths into Long Island.
  - ✓ West to Central (26% DAM, 34% RTM) – West Zone congestion rose from prior periods (for reasons discussed in slide 16).
    - Congestion along the Niagara-Packard and Huntley-Sawyer 230 kV transmission lines accounted for nearly 80 percent of the congestion.
- Congestion across the Central-East interface, into SENY, and into NYC has fallen in the second quarter of 2014 due partly to lower natural gas spreads between West NY and East NY.
  - ✓ In addition, TSAs were declared less frequently due to mild weather and its impact on congestion was greatly reduced.
    - Consequently, TSA constraints were active on 5 days for a total of 93 intervals this quarter, compared to 737 intervals on 13 days in the second quarter of 2013.

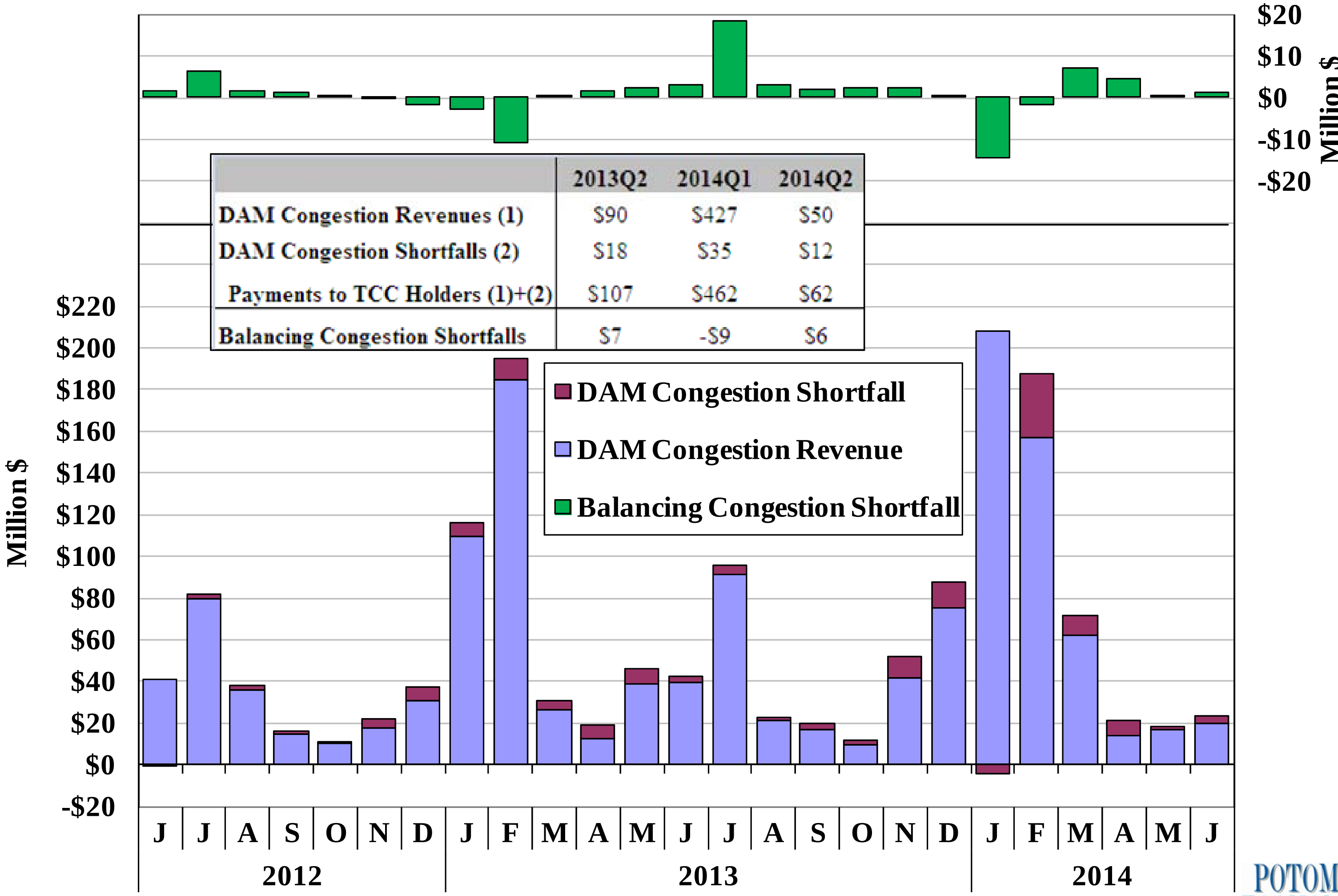
Day-Ahead Congestion Shortfalls

- Day-ahead congestion shortfalls totaled roughly $12 million in the second quarter of 2014, down from $18 million in the second quarter of 2013.
- The majority of shortfalls were driven by transmission outages this quarter, which are allocated to the responsible TOs.
  - ✓ Transmission outages in Gowanus-Goethals area from early April to early May caused reduced transfer capability in the Freshkills load pocket, accounting for $4 million of shortfalls during this period.
  - ✓ Several facilities around the Niagara 115 kV bus were out of service in late-May, early-June, and mid-June, which led to transmission bottlenecks on 230kV lines, accounting for $3 million of shortfalls.
  - ✓ The majority of the shortfalls on Long Island accrued on the transmission lines from upstate into Long Island.
    - One of the two 345 kV lines was out of service on several days in mid-April, mid-May, and mid-June, which reduced transfer capability into Long Island and accounted for nearly $2 million of shortfalls.
    - However, this fell notably from $12 million in the second quarter of 2013 when one of the two 345 kV lines was out of service during most of the quarter.
  - ✓ The Central-East interface accounted for another $2 million of shortfalls, most of which accrued in mid-April when generation and transmission outages reduced the voltage transfer limit of the interface.

Balancing Congestion Shortfalls

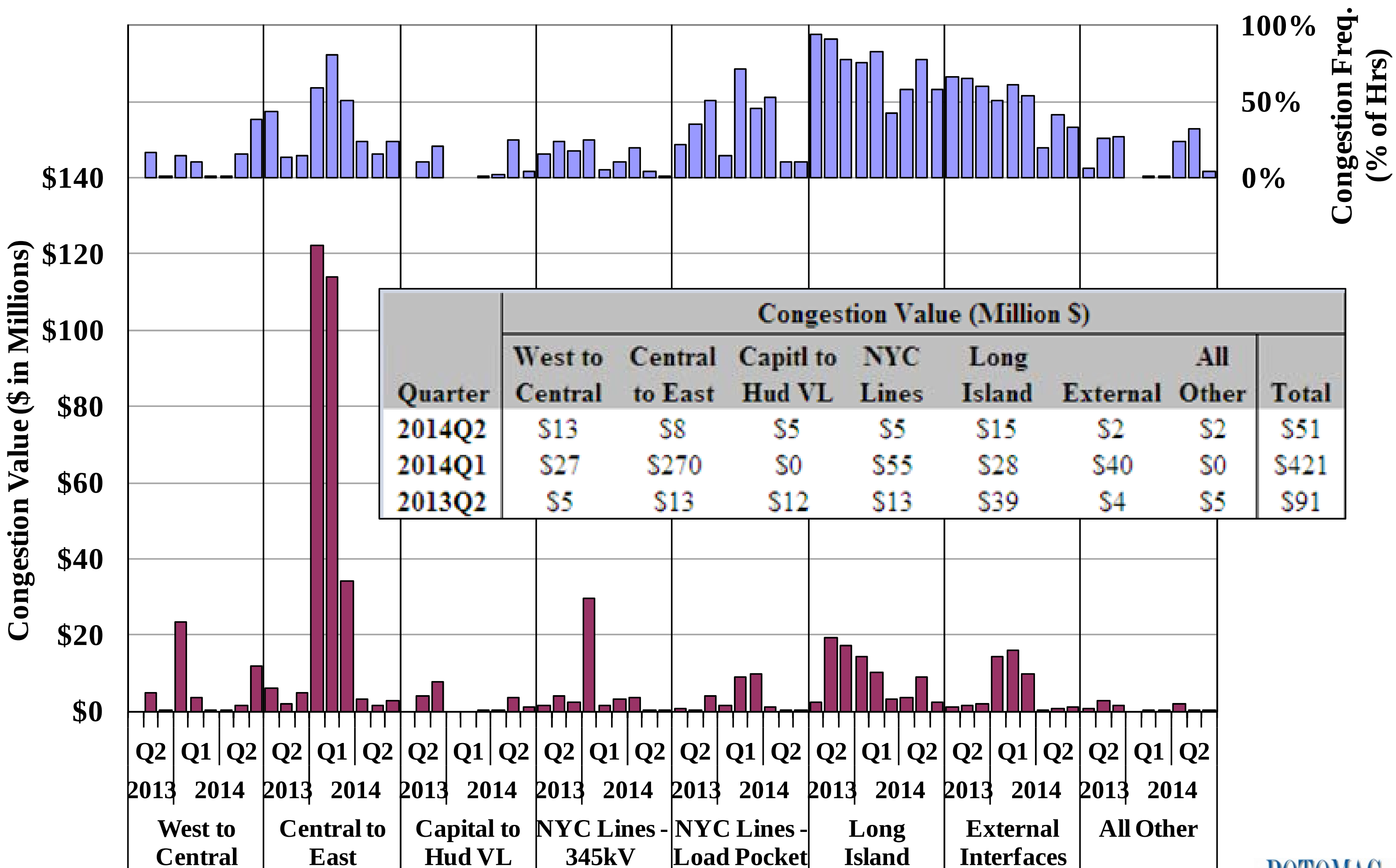
- Balancing congestion shortfalls totaled $6 million this quarter, down modestly from the second quarter of 2013.
  - ✓ Balancing shortfalls were small on most days but rose on several days when unexpected real-time events occurred. For example:
    - On April 7, nearly $1 million of shortfalls accrued on transmission lines into the Valley Stream load pocket on Long Island because DAM modeling of an outage condition led the DAM to under-commit generation in the pocket.
    - Shortfalls in the West Zone rose on several days in late May, partly due to unexpected Niagara 230/115kV transformer outages.
  - ✓ Unlike in the second quarter of 2013, TSAs (which greatly reduce the transfer capability into SENY) were not the dominant driver of balancing shortfalls in the second quarter of 2014.
    - Less than $0.2 million of shortfalls (grouped in the ‘All Other’ Category) accrued this quarter, down substantially from over $6 million from a year ago.
    - The large reduction was attributable to:
      - Less frequent TSA events due to mild weather; and
      - Less congestion into SENY due to: (a) lower load levels; (b) increased NYC generation (because of low NYC gas prices); and (c) full Ramapo capability to relieve congestion.

Congestion Revenues and Shortfalls by Month



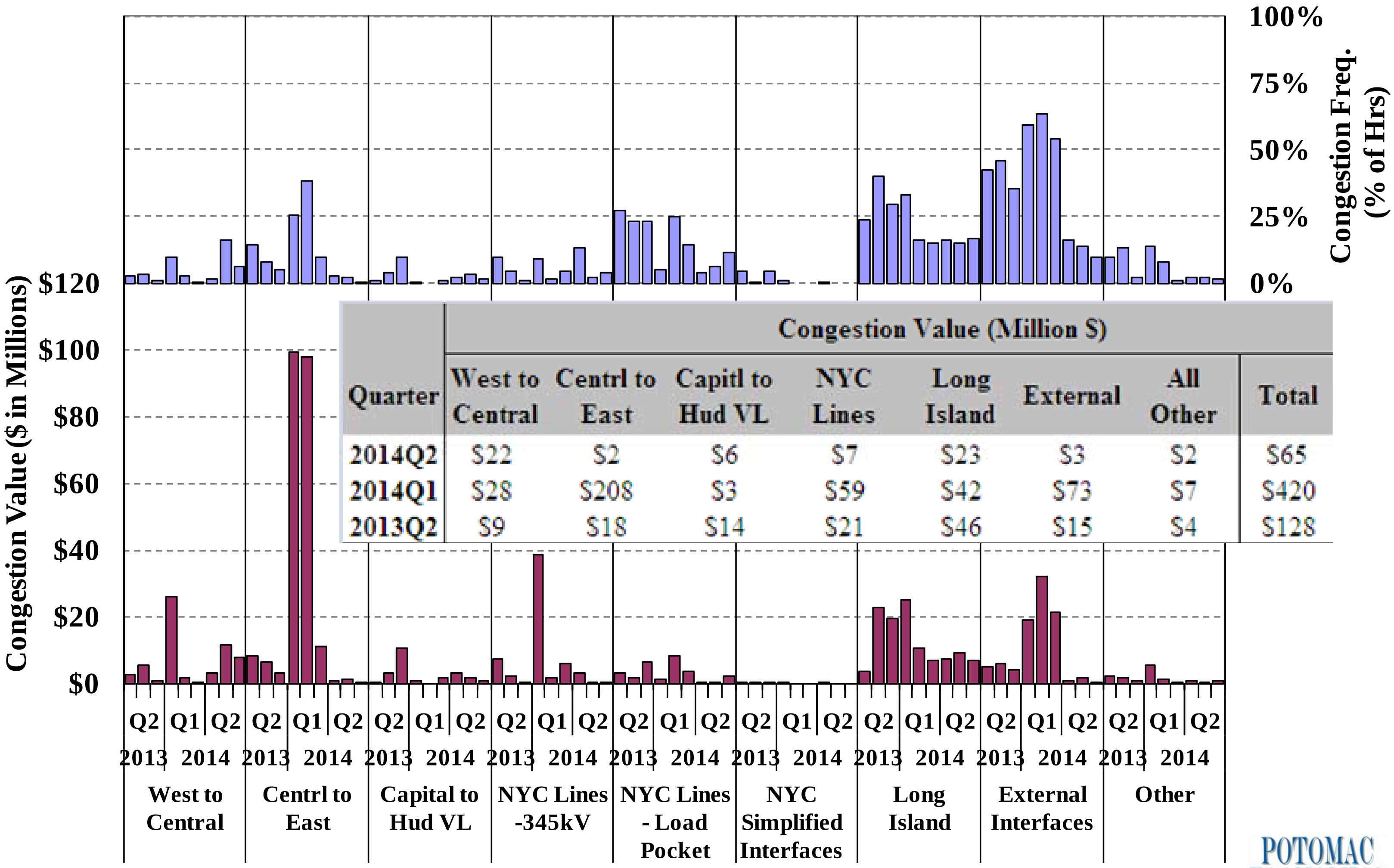
	2013Q2	2014Q1	2014Q2
DAM Congestion Revenues (1)	$90	$427	$50
DAM Congestion Shortfalls (2)	$18	$35	$12
Payments to TCC Holders (1)+(2)	$107	$462	$62
Balancing Congestion Shortfalls	$7	-$9	$6

Day-Ahead Congestion Value and Frequency by Transmission Path



Quarter	Congestion Value (Million $) West to Central	Central to East	Capitl to Hud VL	NYC Lines	Long Island	External	All Other	Total
2014Q2	$13	$8	$5	$5	$15	$2	$2	$51
2014Q1	$27	$270	$0	$55	$28	$40	$0	$421
2013Q2	$5	$13	$12	$13	$39	$4	$5	$91

Real-Time Congestion Value and Frequency by Transmission Path



Quarter	Congestion Value (Million $)							
	West to Central	Centrl to East	Capitl to Hud VL	NYC Lines	Long Island	External	All Other	Total
2014Q2	$22	$2	$6	$7	$23	$3	$2	$65
2014Q1	$28	$208	$3	$59	$42	$73	$7	$420
2013Q2	$9	$18	$14	$21	$46	$15	$4	$128

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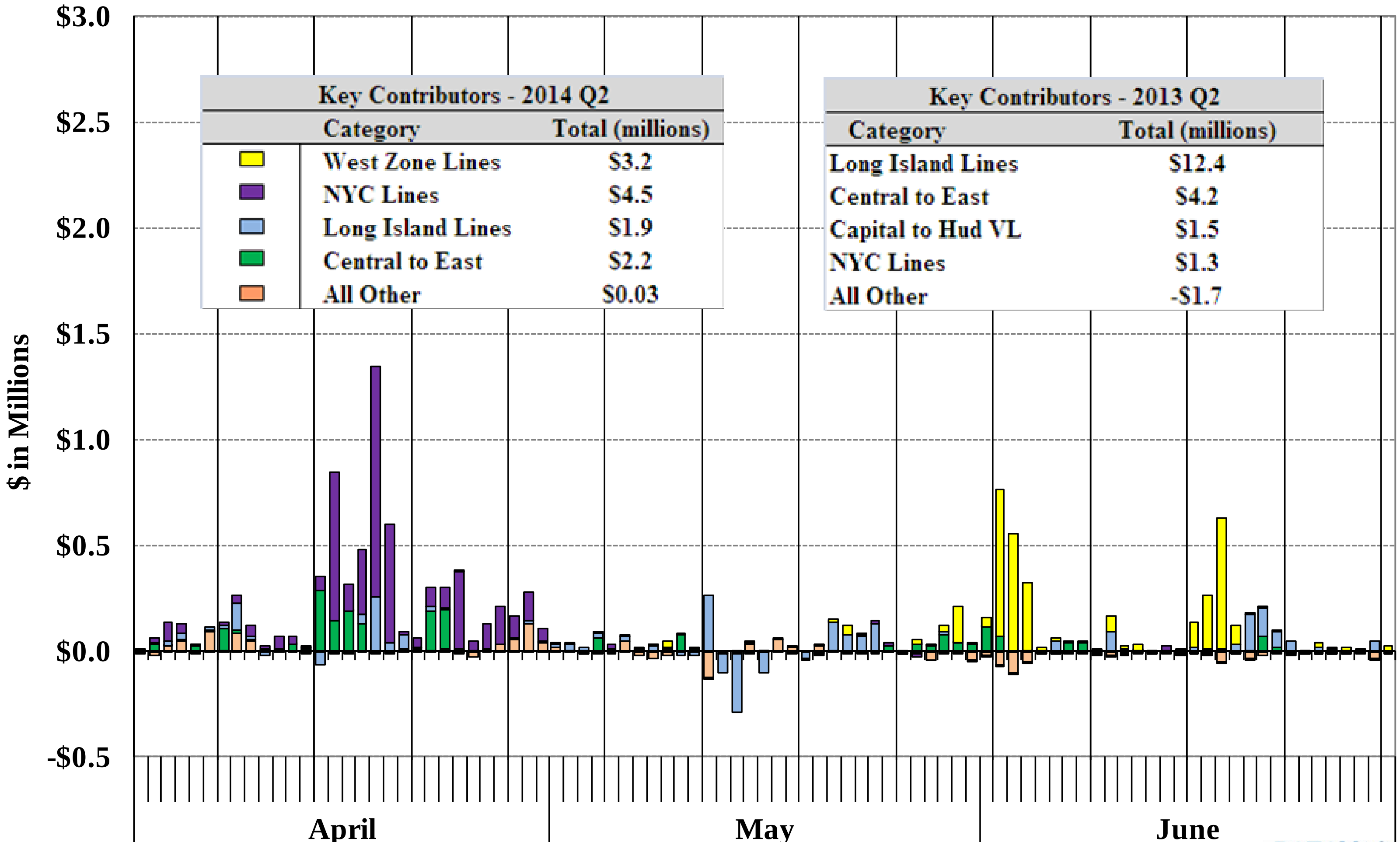
Day-Ahead Congestion Revenue Shortfalls by Transmission Facility



Key Contributors - 2014 Q2		
	Category	Total (millions)
	West Zone Lines	$3.2
	NYC Lines	$4.5
	Long Island Lines	$1.9
	Central to East	$2.2
	All Other	$0.03

Key Contributors - 2013 Q2	
Category	Total (millions)
Long Island Lines	$12.4
Central to East	$4.2
Capital to Hud VL	$1.5
NYC Lines	$1.3
All Other	-$1.7

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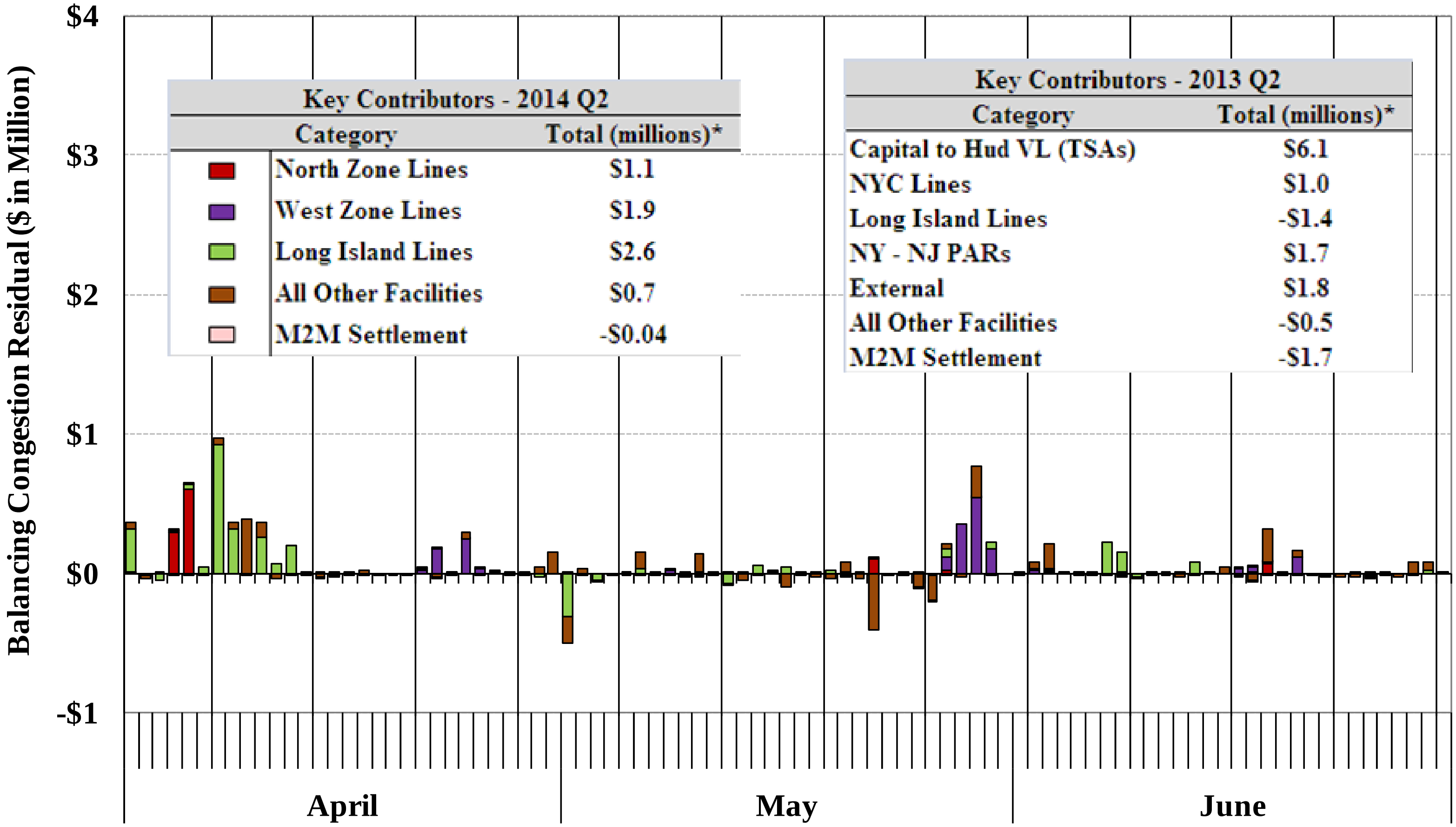
Balancing Congestion Shortfalls by Transmission Facility



Key Contributors - 2014 Q2	
Category	Total (millions)*
North Zone Lines	$1.1
West Zone Lines	$1.9
Long Island Lines	$2.6
All Other Facilities	$0.7
M2M Settlement	-$0.04

Key Contributors - 2013 Q2	
Category	Total (millions)*
Capital to Hud VL (TSAs)	$6.1
NYC Lines	$1.0
Long Island Lines	-$1.4
NY - NJ PARs	$1.7
External	$1.8
All Other Facilities	-$0.5
M2M Settlement	-$1.7

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

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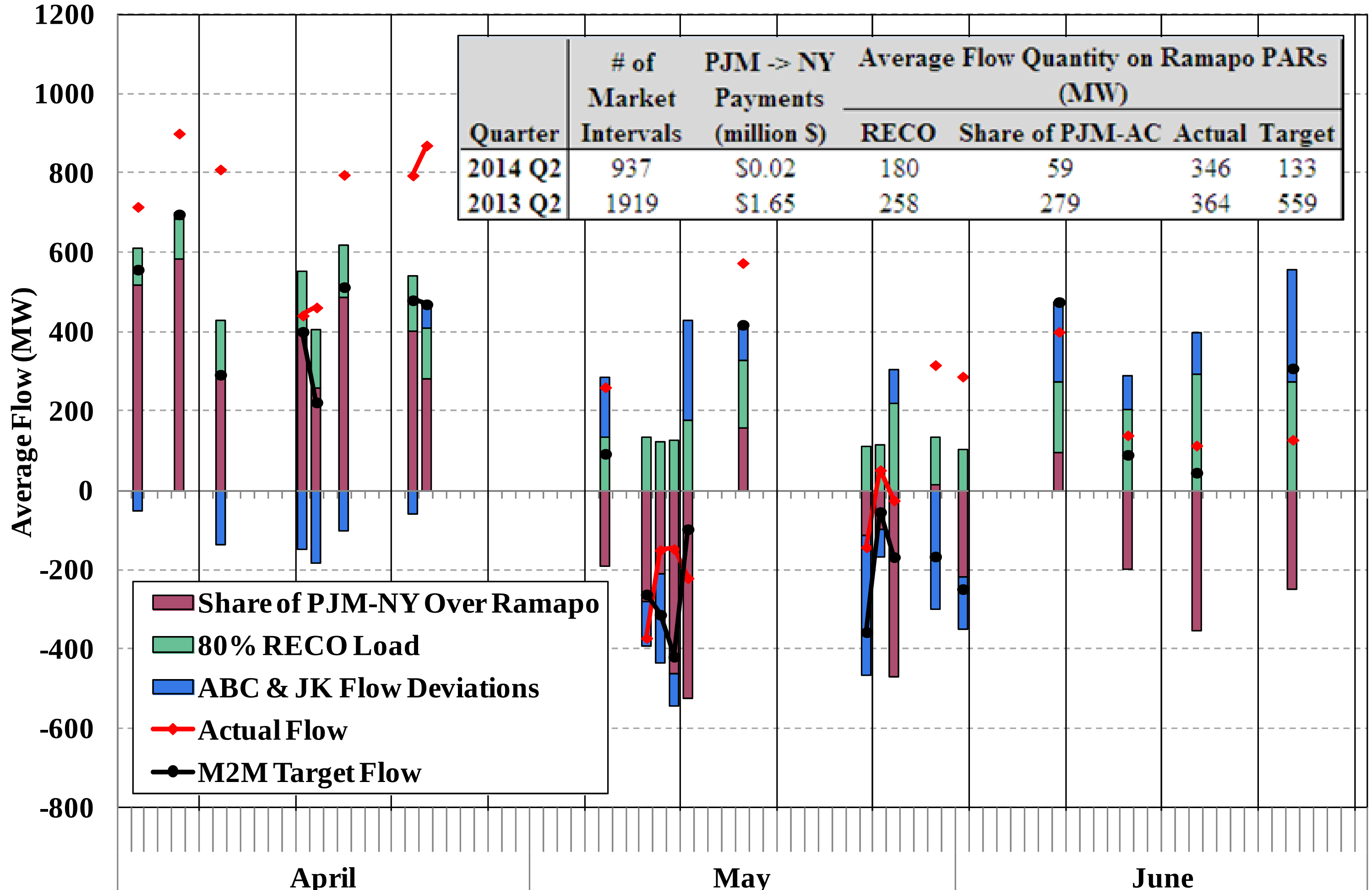
Operations under M2M with PJM

- 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 second 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).

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 13 hours and resulted in a total payment of roughly $22,000 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 937 intervals this quarter, down from 1,919 intervals from the second quarter of 2013.
    - – This reduction is particular significant given that the Ramapo line was out of service for 38 days in the second quarter last year.
- Average actual flows across Ramapo exceeded the M2M Target Flow by more than 200 MW this quarter (when M2M constraints were binding).
  - ✓ NYISO congestion was substantially reduced by over-delivery across Ramapo.
  - ✓ M2M Target Flow was lower than in the second 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 36).
  - ✓ Both Ramapo PARs were in service the second quarter of 2014, better enabling the line to fully support the operational targets on most days.

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 Q2	937	$0.02	180	59	346	133
2013 Q2	1919	$1.65	258	279	364	559

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

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Supplemental Commitment and OOM Dispatch

- 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 for Reliability in NYC

- Based on our review of reliability recommitment logs and LRR constraint information, each 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 Results

- An average of roughly 920 MW of capacity was committed for reliability in the second quarter of 2014, down 18 percent from the second quarter of 2013.
  - ✓ Of this total, 59 percent of reliability commitment was in NYC, 22 percent was in Long Island, and 19 percent was in Western NY.
- On Long Island, reliability commitment averaged 205 MW, up 137 percent from the second quarter of 2013.
  - ✓ Units frequently needed for local reliability were committed economically less often because of lower LBMP levels (which are discussed in slide 16).
- In Western NY, reliability commitment averaged 175 MW, up 16 percent from the second quarter of 2013.
  - ✓ DARU commitments increased in May and June because higher loads require capacity on the 115kV system in western New York to manage congestion on 115kV facilities.
  - ✓ SRE commitments in Western NY were virtually eliminated because transmission upgrades in the North Zone greatly reduced such needs.
- In NYC, reliability commitment averaged 540 MW, down 39 percent from the second quarter of 2013.

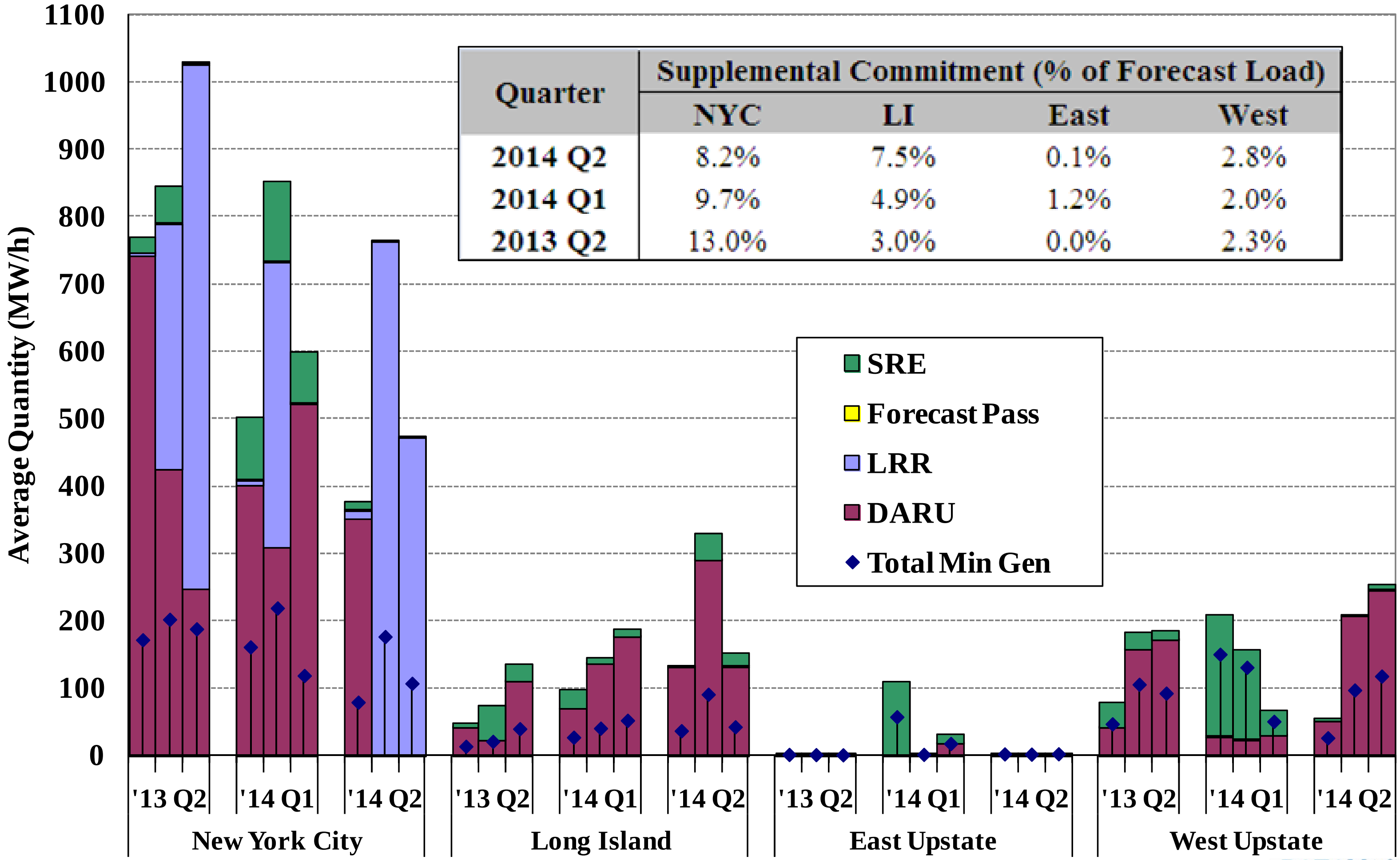
Supplemental Commitment Results in New York City

- NYC supplemental commitment decreased partly because of low NYC gas prices, which led NYC generators to be committed economically more often.
- Other factors that contributed to reduced supplemental commitments include:
  - ✓ Fewer transmission and generation outages in the load pockets.
    - The thermal and voltage requirements in NYC ensure facilities into the load pockets will not be overloaded if the largest two contingencies were to occur.
    - Most DARU commitments were made for Astoria West and Freshkills load pockets following significant transmission outages in these areas.
    - Fewer outages this quarter led to a reduction in DARU commitments.
  - ✓ Updates in the NOx bubble modeling in the LRR pass.
    - These requirements are in effect from May to September each year, normally accounting for the majority of supplemental commitments during this period.
      - In the second quarter of 2014, these requirements accounted for 45 percent of supplemental commitments.
    - Less steam turbine capacity is now required to satisfy the NOx bubble requirements in the LRR pass.

OOM Dispatch Results

- The NYISO and local TOs sometime 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 733 station-hours, down 31 percent from the second quarter of 2013.
  - ✓ Western NY accounted for 73 percent, Long Island accounted for 15 percent, Eastern NY accounted for 7 percent, and New York City accounted for 5 percent.
- In NYC and Long Island, OOM dispatch fell dramatically from the previous year.
  - ✓ Transmission outages at Freshkills (NYC) and near Northport (Long Island) required significant OOM dispatch in the second quarter of 2013; and
  - ✓ The installation of the West Bus DRSS and Wildwood DRSS on Long Island have reduced the need to dispatch peaking generators to manage voltage constraints.
- In Western NY, OOM dispatch of coal-fired units rose from the previous year.
  - ✓ OOM dispatch is used to manage congestion on the 115 kV system in Western NY.
  - ✓ The reduction in natural gas prices made coal-fired generation less economic than in the second quarter of 2013, requiring more OOM dispatch.

Supplemental Commitment for Reliability
by Category and Region



Quarter	Supplemental Commitment (% of Forecast Load)			
	NYC	LI	East	West
2014 Q2	8.2%	7.5%	0.1%	2.8%
2014 Q1	9.7%	4.9%	1.2%	2.0%
2013 Q2	13.0%	3.0%	0.0%	2.3%

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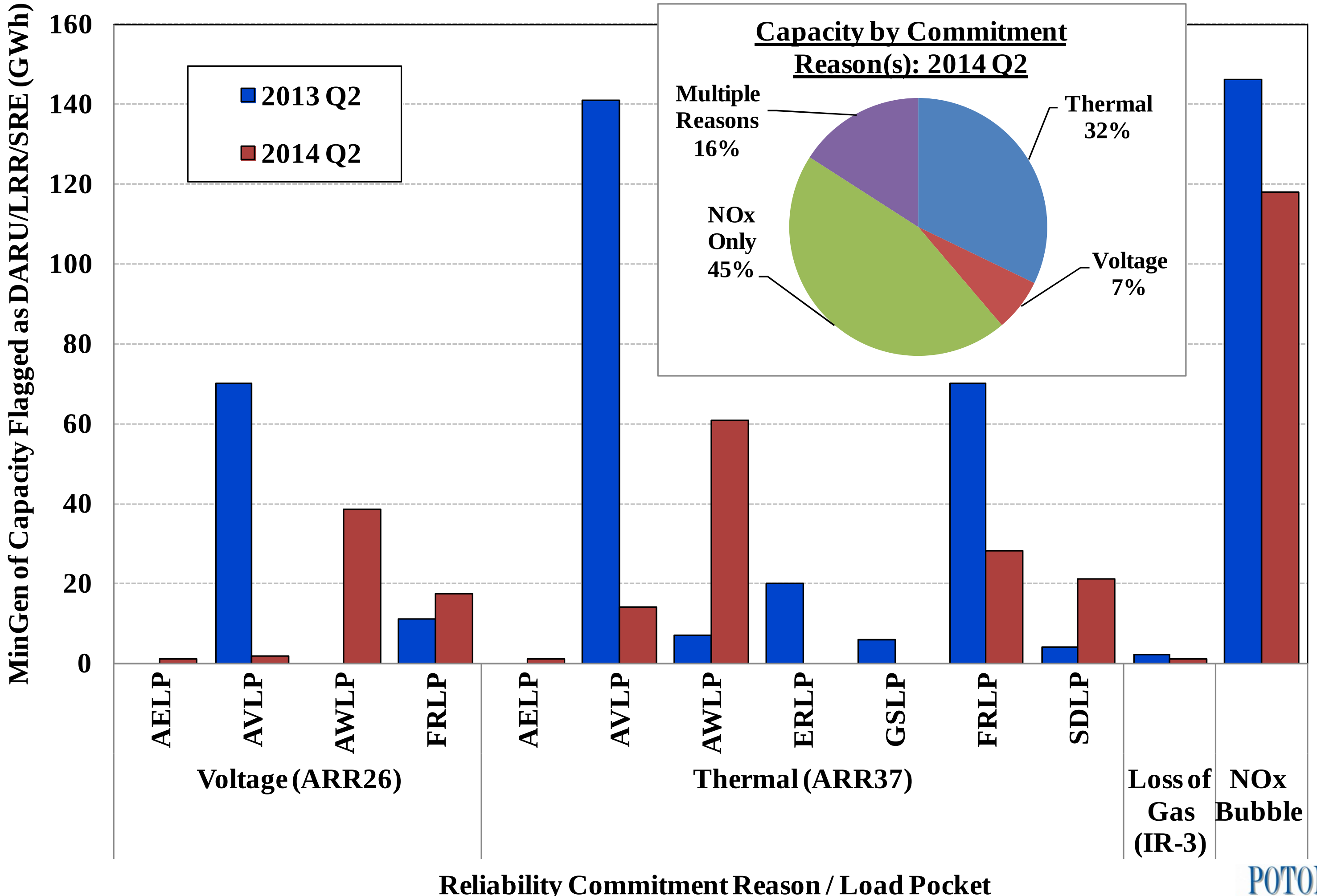
Supplemental Commitment for Reliability in NYC
by Reliability Reason and Load Pocket



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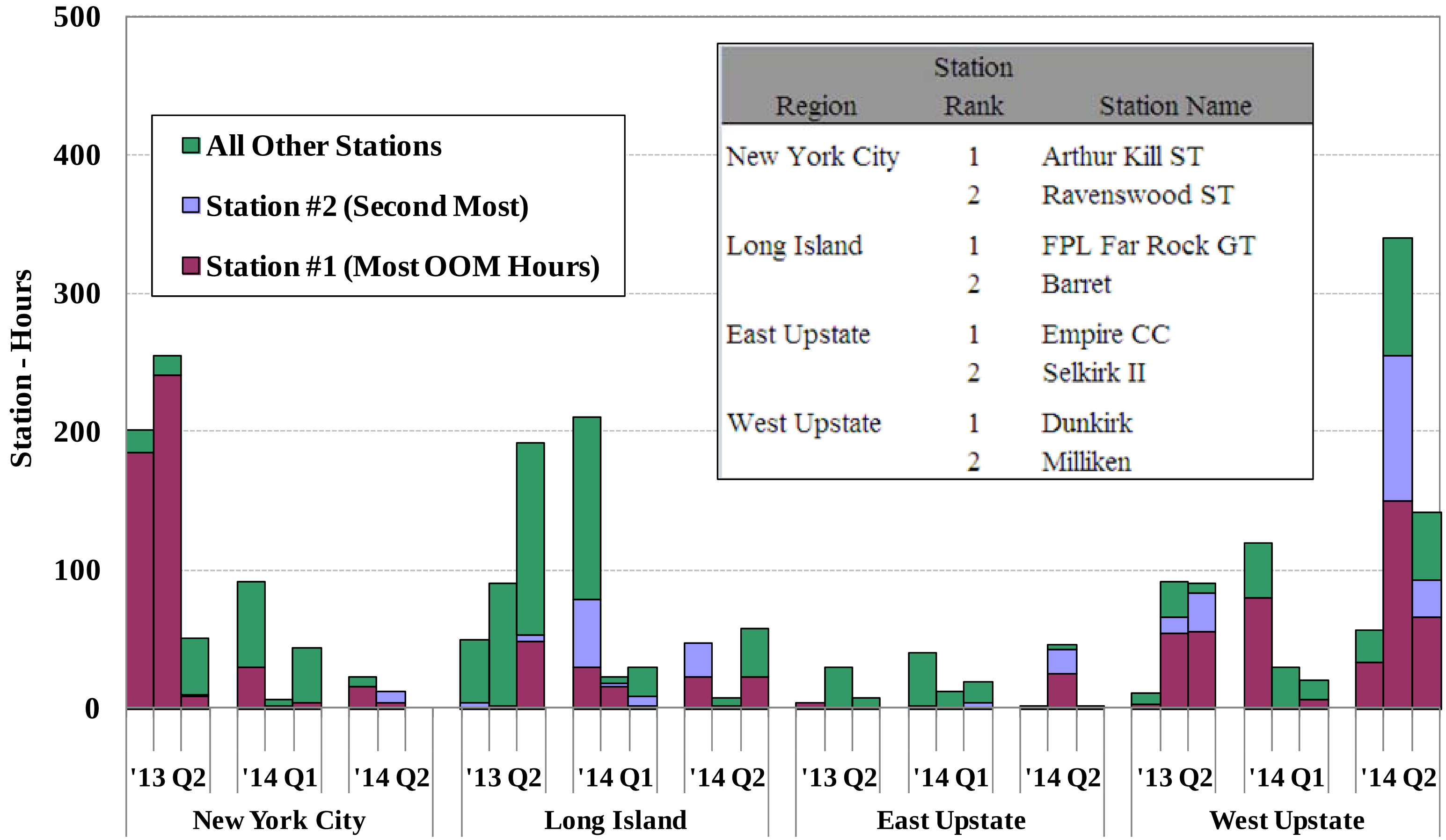
Frequency of Out-of-Merit Dispatch by Region by Month



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

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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.

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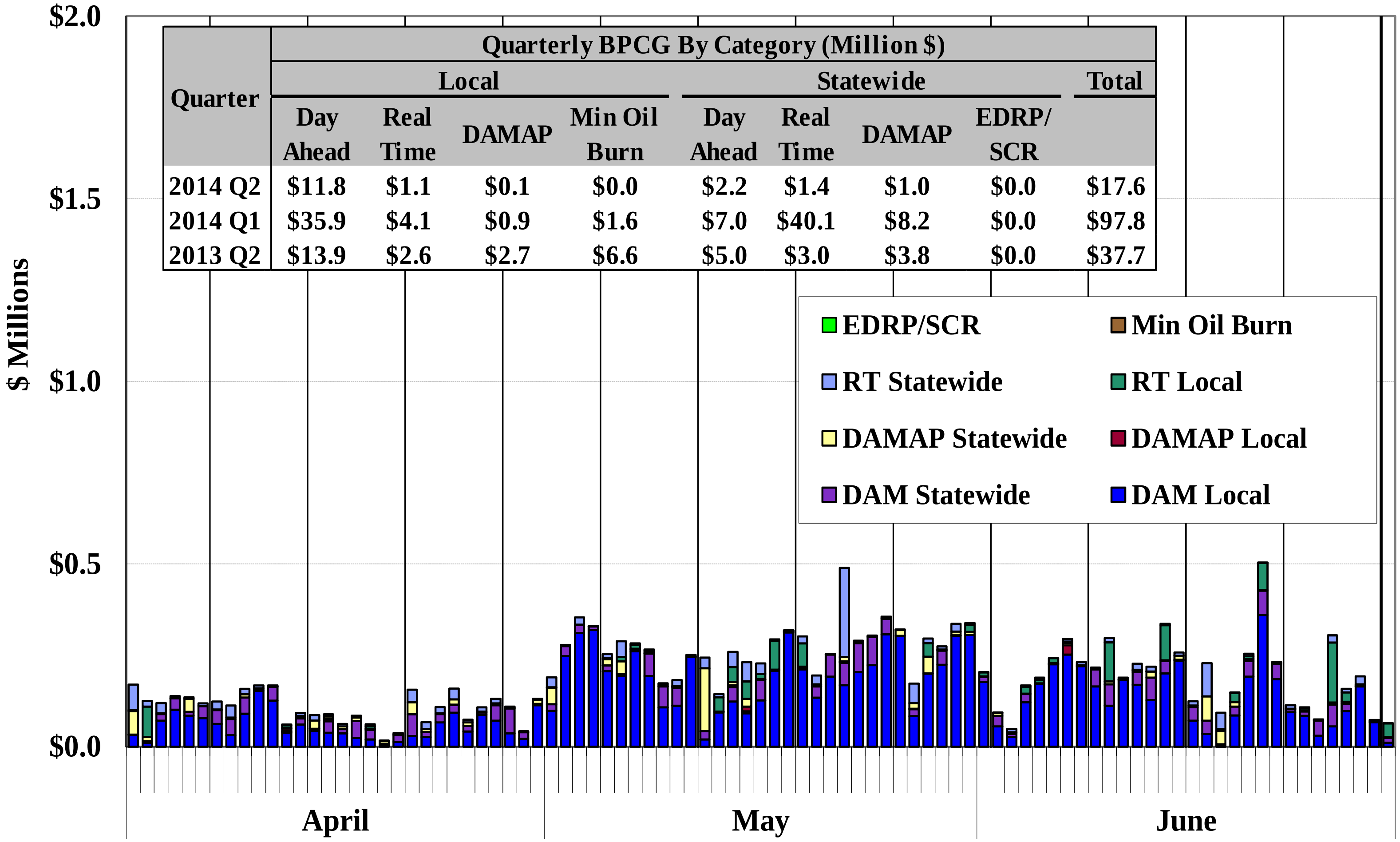
Uplift Costs from Guarantee Payments

- Guarantee payment uplift totaled $17.6 million in the second quarter of 2014, down 53 percent from the second quarter of 2013.
  - ✓ Lower natural gas prices decreased the commitment costs of gas-fired units.
  - ✓ Decreased supplemental commitment and OOM dispatch in NYC and Long Island (see slides 61 to 63) also contributed to the decrease in guarantee payment uplift.
- Of the total guarantee payment uplift in the second quarter of 2014:
  - ✓ Local reliability uplift accounted for 74 percent (while non-local was 26 percent).
  - ✓ NYC accounted for 39 percent, Long Island accounted 31 percent, and Western NY accounted for 28 percent.
- NYC accounted for a large decrease in uplift partly because of less supplemental commitment and OOM dispatch and lower natural gas prices.
  - ✓ Min Oil Burn Compensation program payments fell to $0 from $6.6 million in the second quarter of 2013. Less reliability commitment of steam turbine units reduced the need to burn oil to protect the NYC system from a loss of gas.
- Long Island DAM uplift was also reduced because transmission upgrades (see slide 60) reduced the need to burn oil to protect Long Island from a loss of gas.

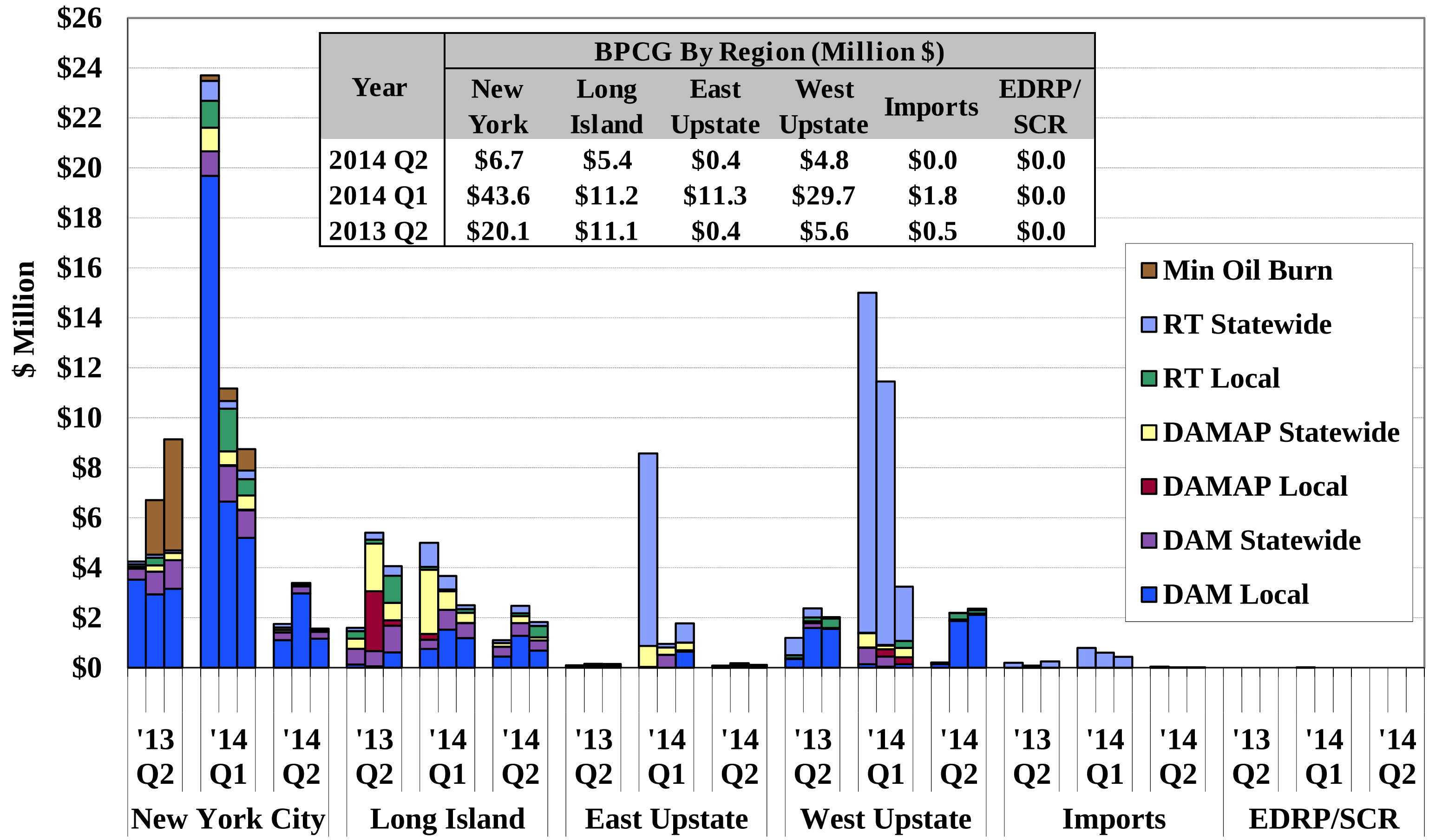
Uplift Costs from Guarantee Payments
Local and Non-Local by Category



Quarter	Quarterly BPCG By Category (Million $)								
	Local				Statewide				Total
	Day Ahead	Real Time	DAMAP	Min Oil Burn	Day Ahead	Real Time	DAMAP	EDRP/ SCR	
2014 Q2	$11.8	$1.1	$0.1	$0.0	$2.2	$1.4	$1.0	$0.0	$17.6
2014 Q1	$35.9	$4.1	$0.9	$1.6	$7.0	$40.1	$8.2	$0.0	$97.8
2013 Q2	$13.9	$2.6	$2.7	$6.6	$5.0	$3.0	$3.8	$0.0	$37.7

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 Q2	$6.7	$5.4	$0.4	$4.8	$0.0	$0.0
2014 Q1	$43.6	$11.2	$11.3	$29.7	$1.8	$0.0
2013 Q2	$20.1	$11.1	$0.4	$5.6	$0.5	$0.0

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.

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Market Power and Mitigation

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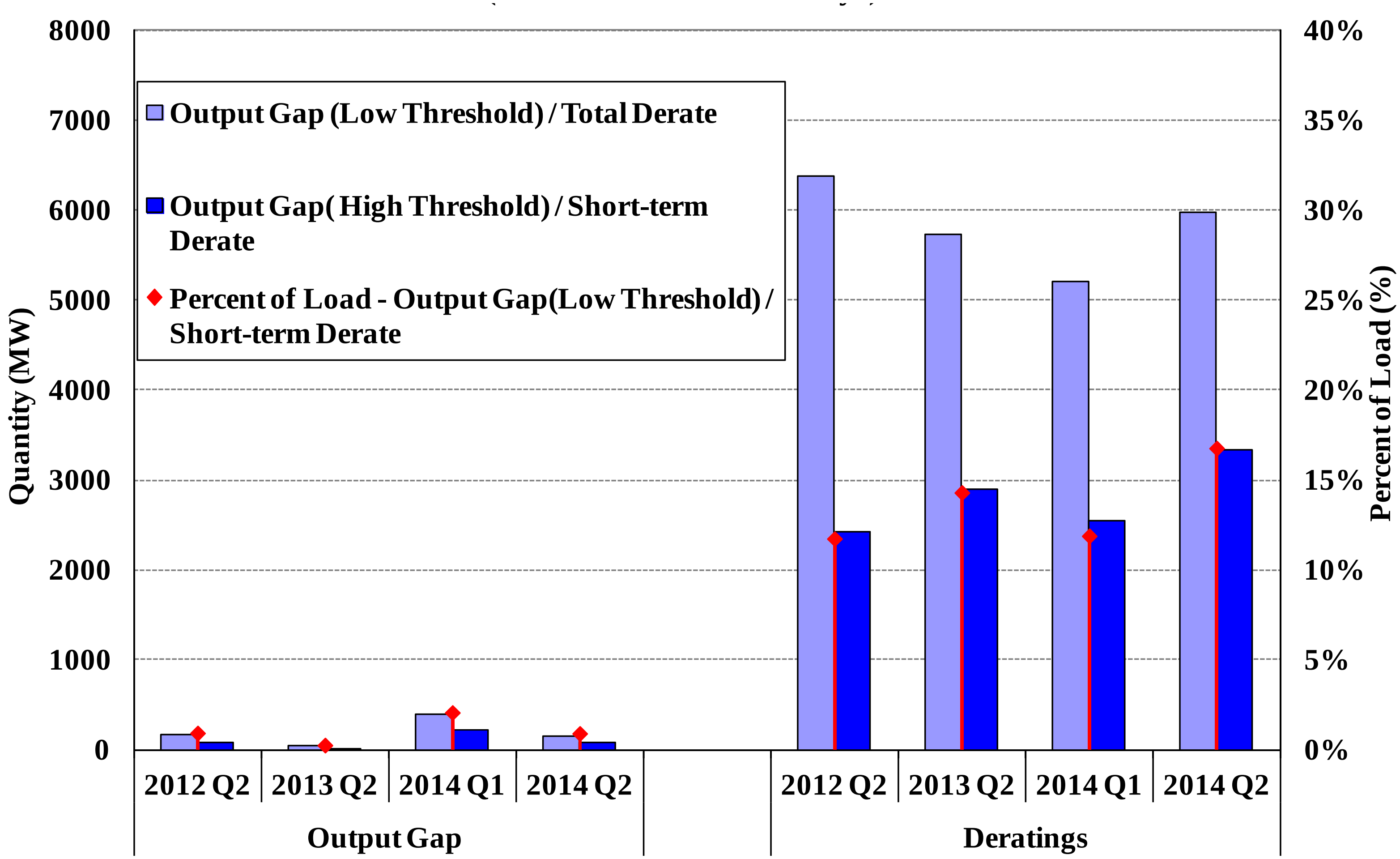
Market Power Screens: Economic Withholding

- 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 1 percent of load at the low threshold, which was consistent with the same quarter in prior years.
  - ✓ The output gap did not raise significant market power concerns because:
    - – NYC accounted for 47 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 Hudson Valley Zone accounted for another 36 percent, most of which occurred: (a) on two units that are owned by suppliers with small portfolios; and (b) during periods with limited congestion in this area.

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 (e.g., total deratings in the second quarter are normally higher than in the first 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 in the second quarter of 2014 was consistent with the same period in the previous years.
  - ✓ The amount of short-term deratings rose modestly but did not raise significant withholding concerns because:
    - – Most of the short-term deratings resulted from maintenance outages (lasting up to 4 weeks) that were scheduled in March, April, and May.
    - – Only roughly 10 percent of all short-term deratings occurred in June.

Market Monitoring Screens



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Market Power Mitigation

- The next 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.
- Most mitigation occurs in the DAM (where most supply is scheduled). In the second quarter of 2014:
  - ✓ 99 percent of AMP mitigation occurred in the DAM.
  - ✓ Local reliability (i.e., DARU & LRR) units accounted for 96 percent of all day-ahead AMP mitigation.
    - – These mitigations generally affect guarantee payment uplift but not LBMPs.
- The frequency of incremental energy mitigation fell notably from prior quarters.
  - ✓ Congestion occurred less frequently in the 345kV and 138kV areas of NYC because of low natural gas prices in NYC in the second quarter.

Automated Market Mitigation

Quarterly Mitigation Summary

		2012 Q2	2013 Q2	2014 Q1	2014 Q2
Day-Ahead Market	**Average Mitigated MW**	153	167	197	122
	Energy Mitigation Frequency	18%	14%	7%	5%
Real-Time Market	**Average Mitigated MW**	14	2	30	1
	Energy Mitigation Frequency	3%	1%	4%	0.3%

Capacity Market

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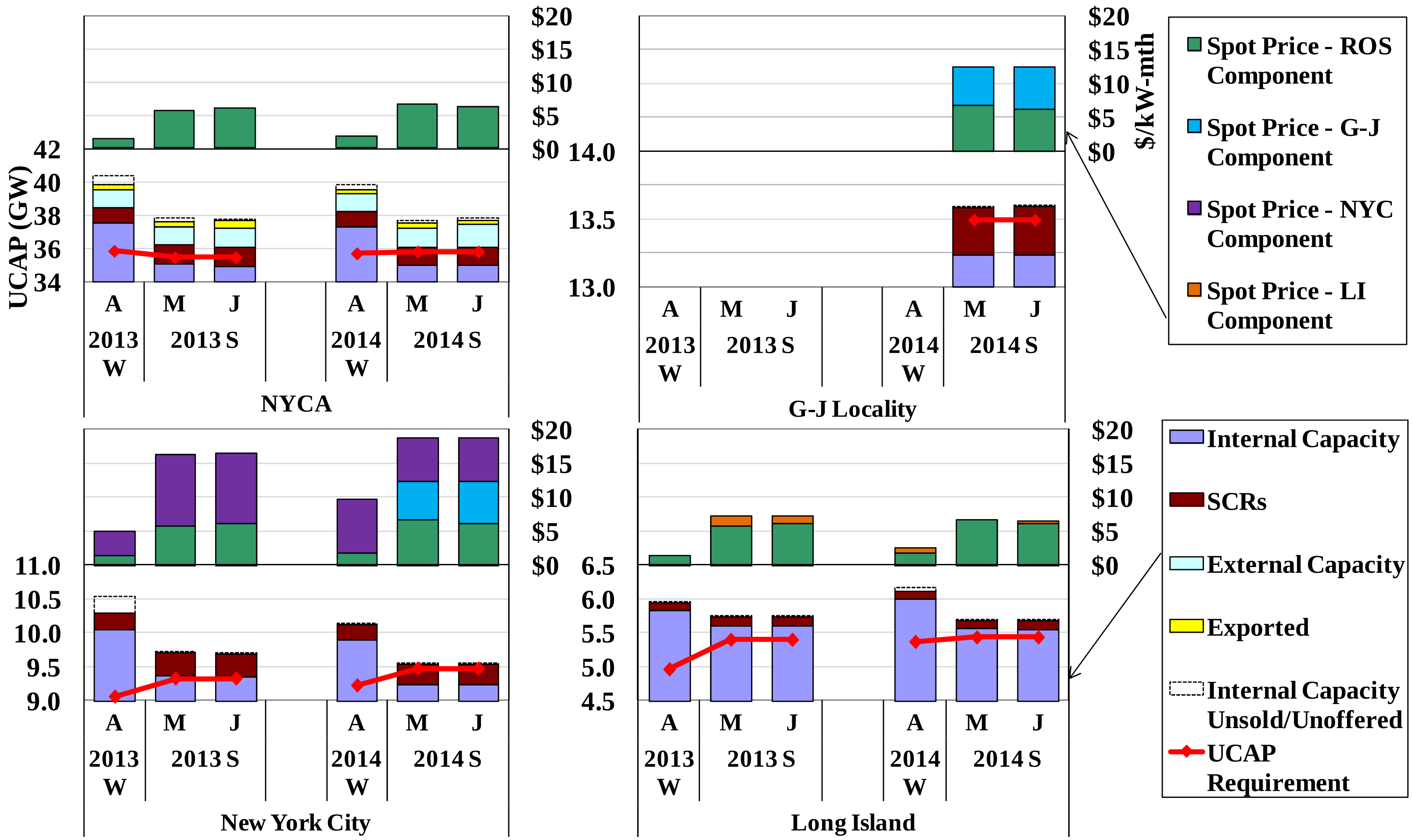
Capacity Market Results

- 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 \$4.88/kW-month this quarter, up modestly from \$4.44/kW-month in the second 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 200 MW on average); and
    - – A modest decrease in the UCAP demand curve value.
- Long Island UCAP spot prices averaged \$5.22/kW-month this quarter, down slightly from \$5.30 kW-month in the second quarter of 2013, because:
  - ✓ The UCAP demand curve was reduced from the 2013/14 Capability Year by more than 20 percent.
  - ✓ This was offset by a 90 MW increase (1.6 percent) in the Long Island ICAP requirement because of an increase in the LCR from 105 percent to 107 percent.

Capacity Market Results

- In NYC, UCAP spot prices averaged $15.81/kW-month this quarter, up from $12.55/kW-month in the second quarter of 2013, attributable to:
  - ✓ ICAP supply was reduced by approximately 100 MW from Summer 2013 to Summer 2014.
  - ✓ The ICAP requirement rose 138 MW (or 1.4 percent), primarily due to an increase of nearly 300 MW 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, offsetting the increase in spot prices.
- In the G-J Locality, UCAP spot prices averaged $12.37/kW-month for May and June 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 investment signals in this area.
  - ✓ There was virtually no unsold capacity in the G-J Locality in the May and June UCAP auctions.

Capacity Market Results
The Second Quarter of 2013 and 2014



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

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