Quarterly Report on the New York ISO Electricity Markets First Quarter 2015

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Highlights and Market Summary: Energy Market

- This report summarizes market outcomes in the first quarter of 2015.
- 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 this winter were the primary driver of variations in NYISO market outcomes from last winter.
  - ✓ RT energy prices averaged $66/MWh statewide, down 45 percent from the first quarter of 2014 primarily because natural gas prices fell 44 to 68 percent across the system. (see slide 9) Other important drivers were:
    - – Less frequent extreme load conditions—peak load fell 4 percent from a year ago even though average load was similar; (see slide 11)
    - – Net imports rose nearly 700 MW from the first quarter of 2014. (see slide 41)
      - In particular, net imports from Ontario and Quebec rose roughly 1 GW, which had significant effects on operations and LBMPs in West NY.
  - ✓ Production from oil-fired units fell just 20 percent from a year ago despite the large reduction in natural gas prices. (see slide 15)
    - – Fuel oil prices fell to multi-year lows in the first quarter of 2015, which helped limit the severity of natural gas price spikes during periods when natural gas was in tight supply. (see slide 12)

Highlights and Market Summary: Congestion Patterns and DA-RT Price Convergence

- DAM congestion revenue fell 34 percent from a year ago to $281 million because of lower gas prices and gas spreads between East NY and West NY. (see slide 55)
  - ✓ The Central-East Interface accounted for 70 percent of day-ahead congestion.
  - ✓ West-to-east congestion was more frequent than in the first quarter of 2014, which was attributable to higher import levels from Ontario and Quebec.
    - – Consequently, average real-time energy prices in West NY fell more (51 percent) than in East NY (42 to 46 percent).
- Convergence between day-ahead and real-time energy prices was comparable to the first quarter of 2014 in most areas.
  - ✓ Average DA prices were 2 percent higher than RT prices in the West Zone and were 4 to 6 percent higher than RT prices in other areas. (see slides 19-21)
  - ✓ Congestion was much more severe in RT than in the DA in the West Zone.
    - – The West to Central path exhibited $38 million in RT congestion compared to just $4 million in the DAM. (see slides 55-56)
    - – This pattern resulted from: a) volatile RT Lake Erie loop flows; b) increased Ontario imports and renewable outputs in West NY from DAM to RT; and c) additional flows on the West Zone constraints caused by the operation of the ABC, JK, and Ramapo PARs (to relieve Central-East congestion).

Highlights and Market Summary: Energy Market in Winter Peak Conditions

- Cold weather led natural gas prices to rise above $15/MMbtu on 22 days in East NY in the first quarter of 2015. (see slide 26)
  - ✓ Nonetheless, natural gas prices fell more than 40 percent from a year ago despite colder weather conditions this quarter.
  - ✓ This reflected higher gas production in the Marcellus region and more LNG imports to the region in this quarter.
- Oil-fired generation in East NY totaled roughly 1.5 million MWh this quarter, down 20 percent from a year ago.
  - ✓ The NYISO markets help coordinate fuel consumption decisions across the market, which helps conserve the available supply of fuel under tight conditions.
  - ✓ However, for many units, actual production from oil was significantly lower than would have been optimal based on gas prices and LBMPs because of planned and forced outages, permit limitations, and low oil inventories.
- We also find that energy and reserve prices may be understated in some hours on OFO days when generators are subject to fuel limitations. (see slide 27)
  - ✓ This reduces the incentives for generators to incur costs necessary to provide reserves (and energy) more reliably during tight winter conditions.
  - ✓ However, this occurred much less frequently than in the previous winter.

Highlights and Market Summary: Capacity Market

- UCAP spot prices fell notably from the first quarter of 2014. UCAP prices:
  - ✓ In New York City fell 13 percent to an average of $8.34/kW-month;
  - ✓ In the G-J Locality fell 7 percent (compared to ROS) to $3.63/kW-month;
  - ✓ On Long Island fell 20 percent to an average of $3.14/kW-month;
  - ✓ In Rest of State fell 45 percent to an average of $2.16/kW-month.
- Capacity spot prices fell across the system because: (see slides 82-85)
  - ✓ UCAP demand curves were reduced from the prior Capability Year by 4 percent in NYCA, 8 percent in NYC, and 22 percent in Long Island.
  - ✓ The return-to-service of multiple units, new wind capacity additions, and changes in DMNC test results increased internal capacity supply by 480 MW in Hudson Valley, 325 MW in NYC, and more than 100 MW in West NY.
  - ✓ In addition, average sales from external resources rose roughly 450 MW.
  - ✓ However, these factors were offset by higher capacity requirements, which rose 453 MW (1 percent) in NYCA, 138 MW (1.4 percent) in NYC, 90 MW (1.6 percent) in Long Island.
    - – The modeling of the G-J Locality as a separate capacity zone starting in May 2014 also offset the reduction in spot prices.

Highlights and Market Summary: Uplift and Revenue Shortfalls

- The uplift from guarantee payments totaled $21 million, down 79 percent from the first quarter of 2014. The reduction was consistent with: (see slides 71-74)
  - ✓ Lower gas prices, which decreased the commitment costs of gas-fired units.
  - ✓ Decreased supplemental commitments in NYC and Long Island.(see slides 68-69)
    - – Supplemental commitments fell 58 percent in NYC from a year ago because of fewer transmission outages that require running a generator for local reliability.
    - – DARU commitments became less frequent in Long Island after the installation of the West Bus DRSS and Wildwood DRSS in early 2014. These reduce the need to commit generation to manage voltage constraints and/or protect Long Island from a sudden loss of gas.
- Day-ahead congestion shortfalls were *negative* $7 million (i.e., a surplus), down $42 million from a year ago. (see slides 52, 54, 57)
  - ✓ Transmission outages accounted for less than $5 million of shortfalls this quarter, down more than $35 million from a year ago.
- Balancing congestion shortfalls totaled *negative* $10 million (i.e., a surplus), comparable to the first quarter of 2014. (see slides 53, 54, 58)
  - ✓ The surplus resulted primarily from changes in generation patterns after the DAM and Ramapo Coordination.

Energy Market Outcomes

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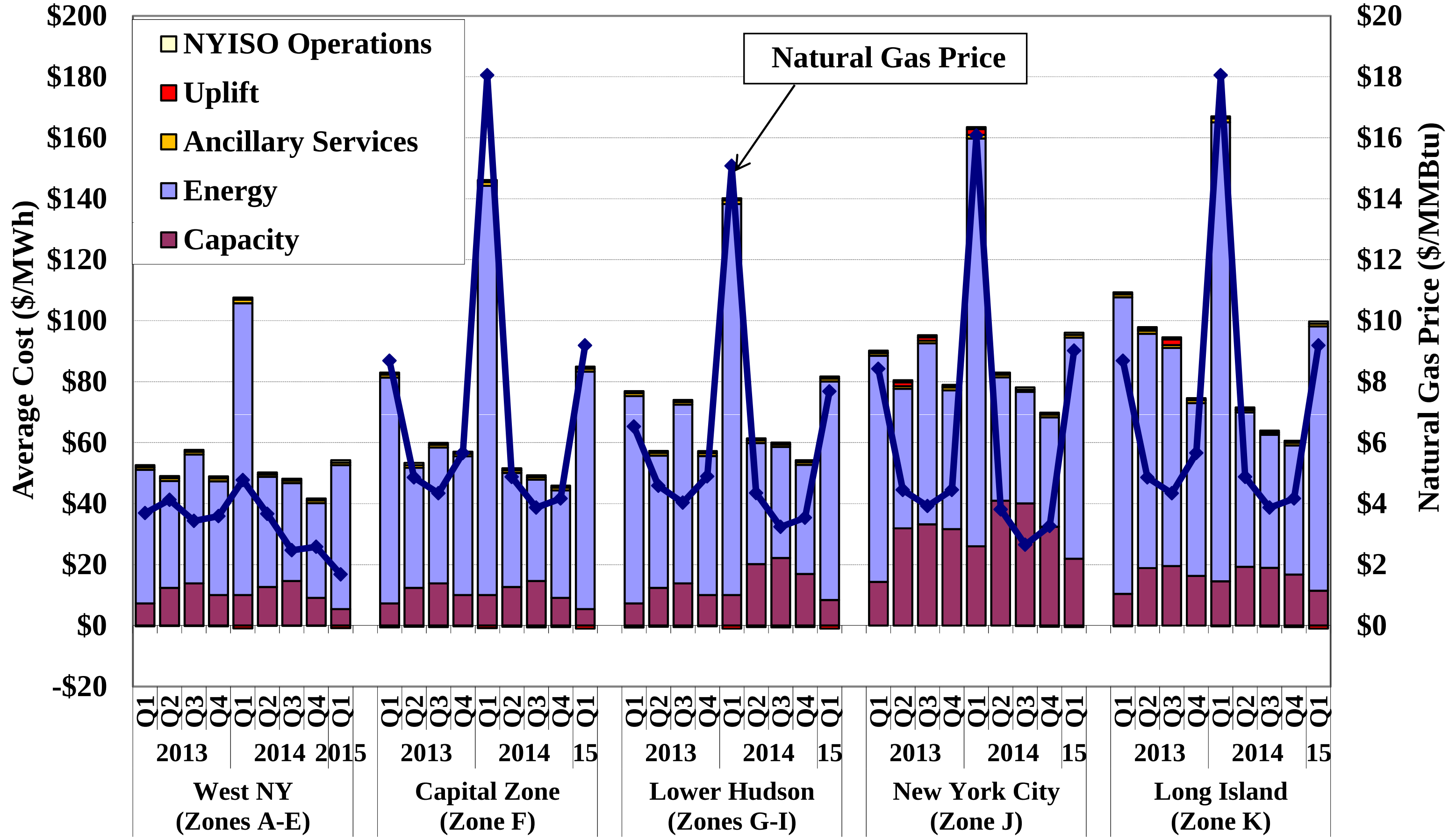
All-In Prices

- 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 \$53/MWh in West NY to \$99/MWh in Long Island, down 41 to 50 percent from the first quarter of 2014.
  - ✓ Energy prices fell 42 percent (Capital Zone) to 51 percent (West NY).
    - – Lower energy prices were due primarily to lower natural gas prices (see slide 12) and decreased peaking conditions (see slide 11).
    - – Higher imports (see slide 41) also contributed to the reduction in LBMPs.
      - In particular, net imports from Ontario and HQ rose nearly 1 GW during afternoon peak hours, resulting in further reduction in LBMPs in West NY.
  - ✓ Capacity costs fell 16 percent (NYC) to 46 percent (West NY).
    - – Capacity spot prices fell across the system because of: (a) reduced UCAP demand curves; (b) increased capacity supply in NYC, the Hudson Valley, and West NY; and (c) increased sales from external resources (see slides 82-85).
    - – However, these were partly offset by increased capacity requirements.

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 Iroquois Zone 2 index 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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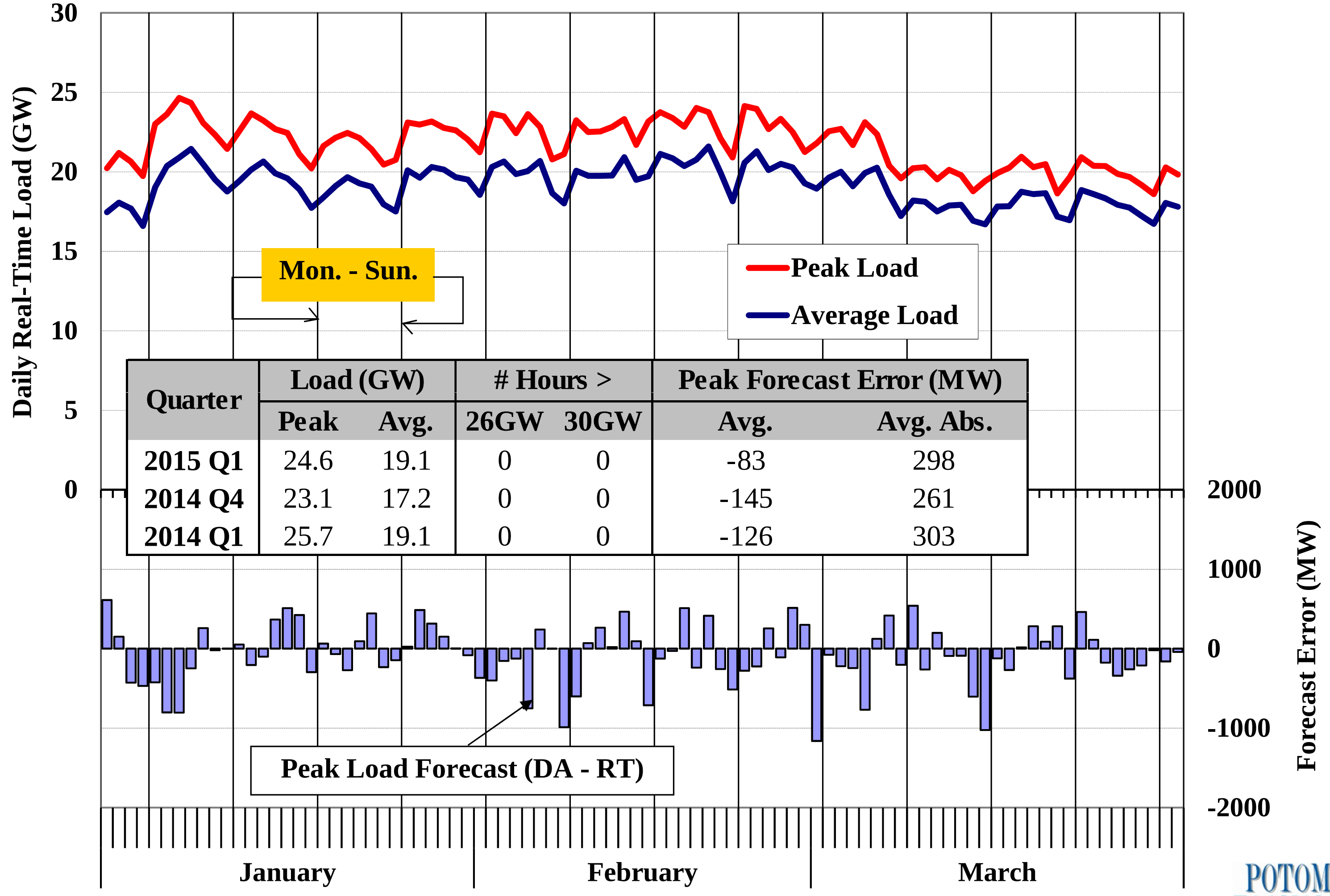
Load Levels and Fuel Prices

- 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.
- Although average load (19.1 GW) did not change from the first quarter of 2014, peak load level and weather patterns were quite different.
  - ✓ Peak load (24.6 GW) fell 4% from the all-time high winter peak set a year ago.
  - ✓ Weather was milder in January and March than from a year ago, while February was the coldest month in recent history.
    - – Average load in February 2015 exceeded average load in January 2014.
- Average natural gas prices fell significantly in all locations from a year ago (68 percent in West NY, 50 percent in Long Island, and 44 percent in NYC).
  - ✓ Fuel oil prices fell to multi-year lows in the first quarter of 2015.
    - – Lower oil prices helped limit the severity of natural gas price spikes during periods when natural gas was in tight supply.
  - ✓ Persistent and large gas price spreads between West NY and East NY led to frequent congestion across the Central-East interface.

Load Forecast and Actual Load



Quarter	Load (GW)		# Hours >		Peak Forecast Error (MW)	
	Peak	Avg.	26GW	30GW	Avg.	Avg. Abs.
2015 Q1	24.6	19.1	0	0	-83	298
2014 Q4	23.1	17.2	0	0	-145	261
2014 Q1	25.7	19.1	0	0	-126	303

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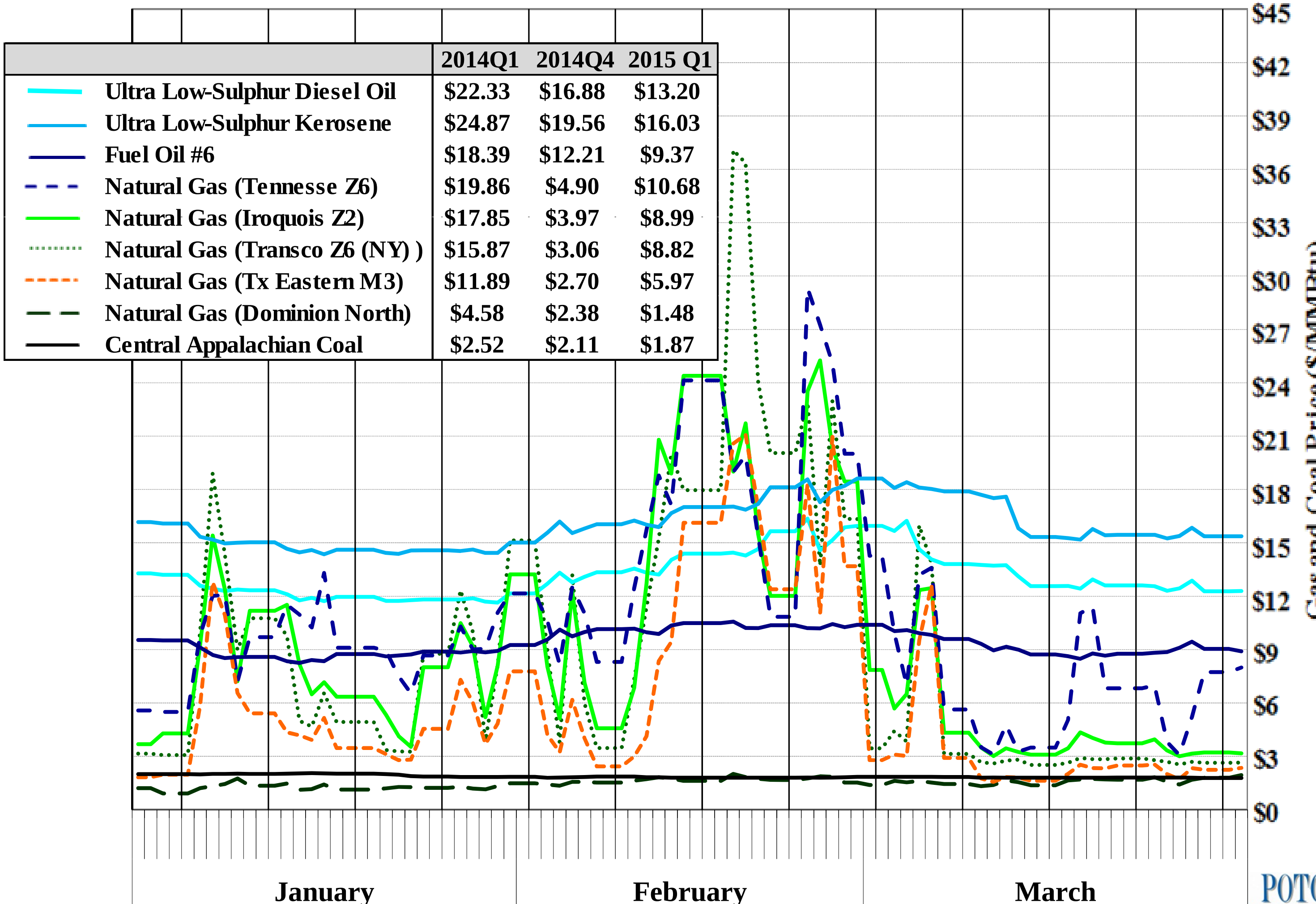
Coal, Natural Gas, and Fuel Oil Prices



	2014Q1	2014Q4	2015 Q1
Ultra Low-Sulphur Diesel Oil	$22.33	$16.88	$13.20
Ultra Low-Sulphur Kerosene	$24.87	$19.56	$16.03
Fuel Oil #6	$18.39	$12.21	$9.37
Natural Gas (Tennesse Z6)	$19.86	$4.90	$10.68
Natural Gas (Iroquois Z2)	$17.85	$3.97	$8.99
Natural Gas (Transco Z6 (NY))	$15.87	$3.06	$8.82
Natural Gas (Tx Eastern M3)	$11.89	$2.70	$5.97
Natural Gas (Dominion North)	$4.58	$2.38	$1.48
Central Appalachian Coal	$2.52	$2.11	$1.87

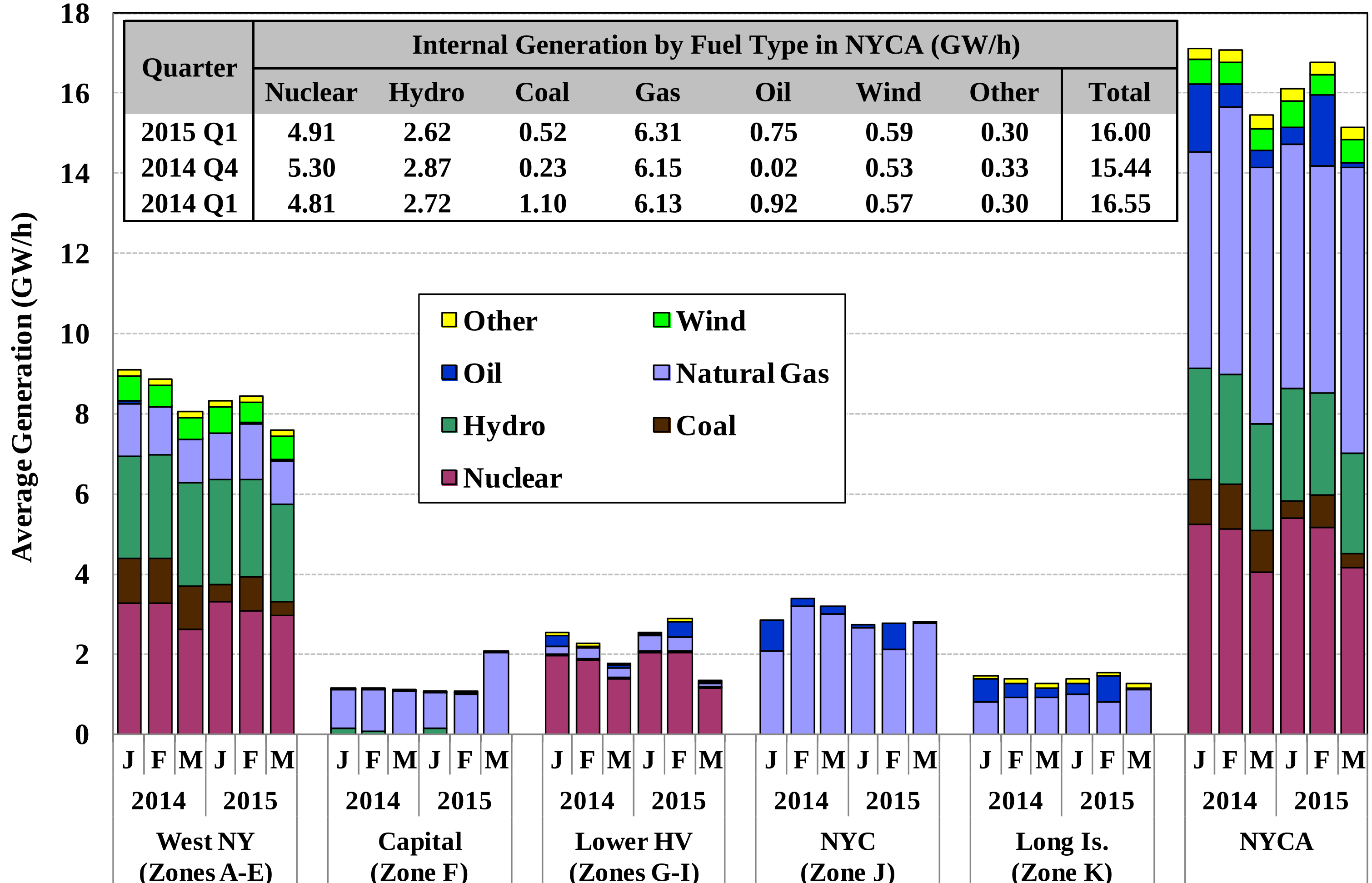
Real-Time Generation by Fuel Type

- The following two figures summarize fuel usage by generators in NYCA and their impact on LBMPs in the first quarter of 2015.
- 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 (40 percent), nuclear (31 percent), and hydro (16 percent) generation accounted for most of internal generation in the first quarter of 2015.
  - ✓ Generation from nuclear and hydro units was similar to the first quarter of 2014.
  - ✓ Coal-fired generation fell 580 MW from the first quarter of 2014.
    - Coal units were less economic because of lower natural gas prices in West NY and higher net imports from Ontario and HQ.
  - ✓ Oil-fired generation in East NY rose notably in February as a result of higher natural gas prices (see slide 26 for more daily details).
    - However, total oil-fired generation fell roughly 200 MW (or 20 percent) from the first quarter of 2014, reflecting lower gas prices and higher gas supply.
  - ✓ The overall reduction in coal-fired and oil-fired generation did not result in an equivalent increase in gas-fired generation because of higher net imports.
- 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 is marginal).
  - ✓ Wind units were on the margin much less frequently because of transmission upgrades in the North Zone, which led to fewer curtailments of wind turbines.

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
2015 Q1	4.91	2.62	0.52	6.31	0.75	0.59	0.30	16.00
2014 Q4	5.30	2.87	0.23	6.15	0.02	0.53	0.33	15.44
2014 Q1	4.81	2.72	1.10	6.13	0.92	0.57	0.30	16.55

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

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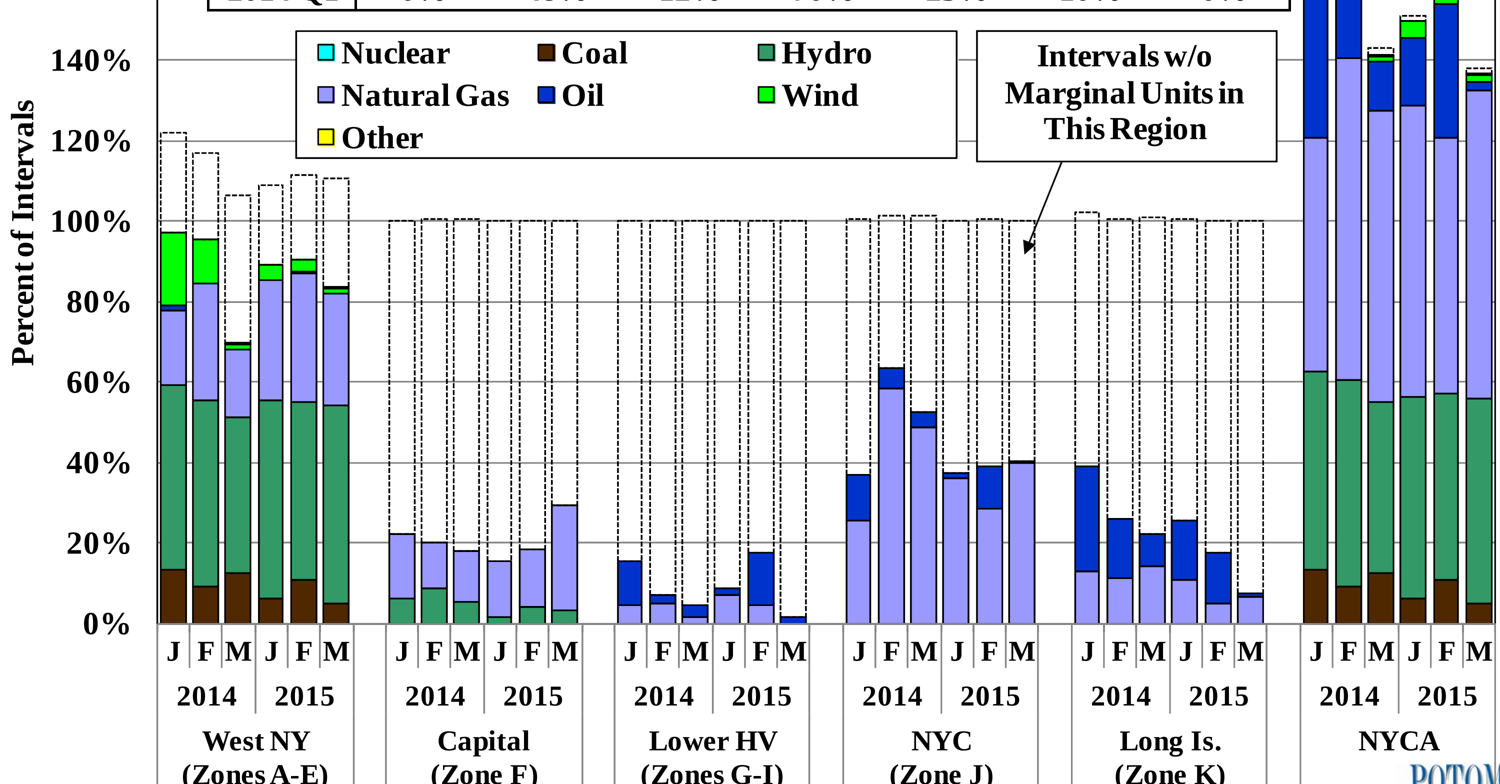
Fuel Types of Marginal Units in the Real-Time Market

Quarter	Marginal Fuel Types in NYCA						
	Nuclear	Hydro	Coal	Gas	Oil	Wind	Other
2015 Q1	0%	49%	7%	71%	17%	3%	0%
2014 Q4	0%	47%	3%	77%	0%	4%	0%
2014 Q1	0%	48%	12%	70%	23%	10%	0%



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

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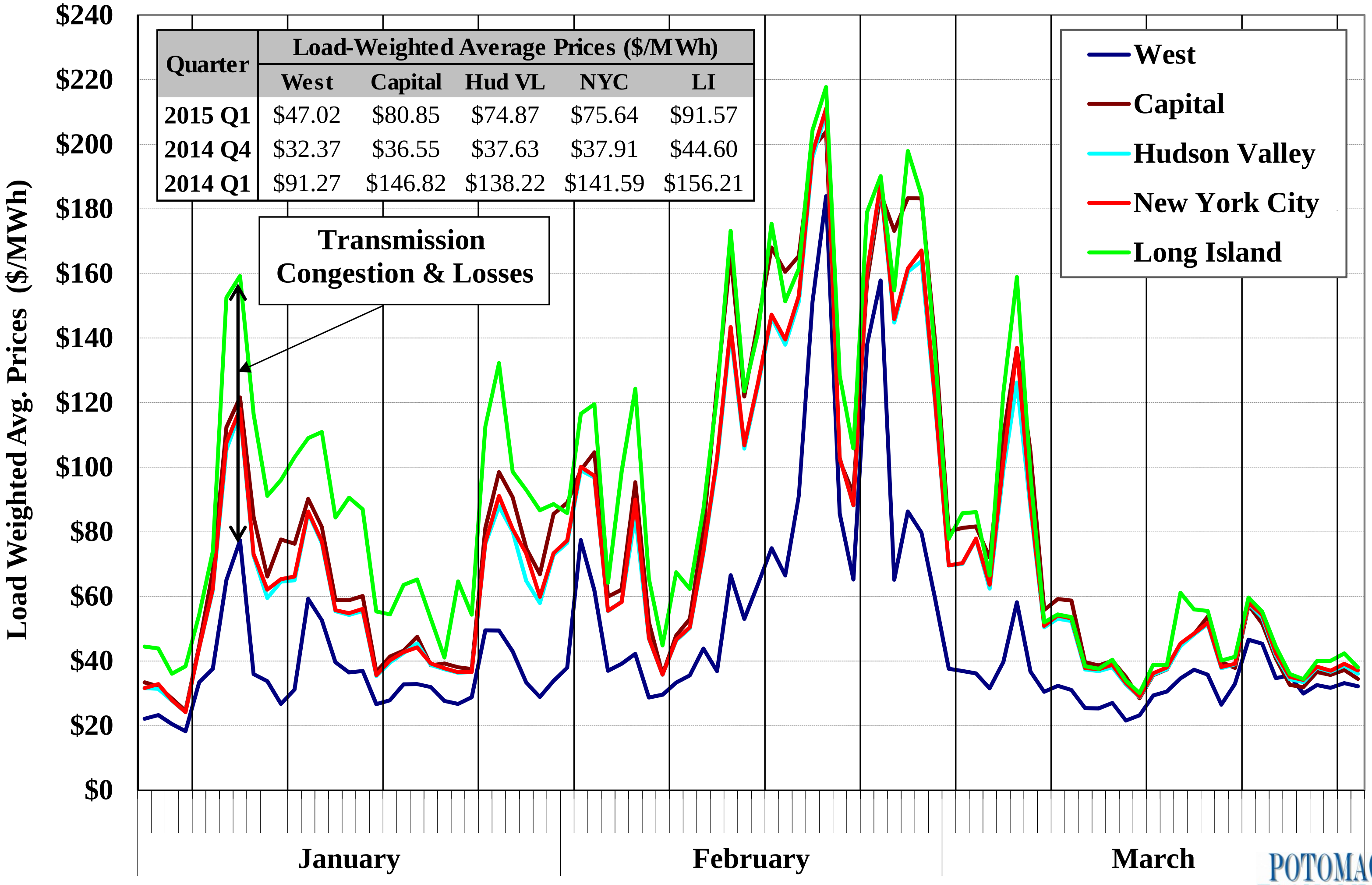
Day-Ahead and Real-Time Electricity Prices

- 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 first quarter of 2015.
- Average day-ahead prices ranged from $47/MWh in the West Zone to $92/MWh on Long Island, down 41 to 48 percent from the first quarter of 2014.
  - ✓ The decreases were driven primarily by:
    - – Lower natural gas prices (see slide 12);
    - – Less severe winter peaking conditions (see slide 11); and
    - – Increased net imports (see slide 41).
  - ✓ The West Zone exhibited the largest reduction in LBMPs (48 percent) because of:
    - – Low natural gas prices in West NY, which averaged less than $1.50/MMBtu and rarely exceeded $2/MMBtu at some trading hubs; and
    - – Higher net imports from Ontario, which increased more than 700 MW from the first quarter of 2014.
  - ✓ Long Island exhibited the smallest reduction in LBMPs (41 percent).
    - – The Cross Sound Cable was out of service from late October 2014 to early February 2015, reducing imports from New England.

Day-Ahead and Real-Time Electricity Prices

- Prices are generally more volatile in the real-time market than in the day-ahead market because of unexpected events. Notable examples include:
  - ✓ On February 16, real-time prices in the West Zone were elevated because of congestion on 230 kV facilities, which was primarily driven by:
    - – Increased clockwise Lake Erie loop flow (up to 600 MW over DAM); and
    - – Reduced imports from PJM (an average of 1.4 GW below DAM) where real-time conditions were very tight.
  - ✓ On February 21, statewide real-time price spikes occurred in early morning and late afternoon hours. During these events:
    - – Imports from PJM were curtailed (870 MWhs over two hours); and
    - – Load was significantly under-scheduled in the DAM (by 1 to 2 GW).
- Random factors can cause large differences between DA and RT prices on individual days, while persistent differences may indicate a systematic issue. The table focuses on persistent differences by averaging over the entire quarter.
  - ✓ Average day-ahead prices were less than 2 percent higher than real-time prices in the West Zone and were roughly 4 to 6 percent higher than real-time prices in other areas this quarter.
  - ✓ Small DA premiums generally facilitate efficient DA commitment.

Day-Ahead Electricity Prices by Zone



Quarter	Load-Weighted Average Prices ($/MWh)				
	West	Capital	Hud VL	NYC	LI
2015 Q1	$47.02	$80.85	$74.87	$75.64	$91.57
2014 Q4	$32.37	$36.55	$37.63	$37.91	$44.60
2014 Q1	$91.27	$146.82	$138.22	$141.59	$156.21

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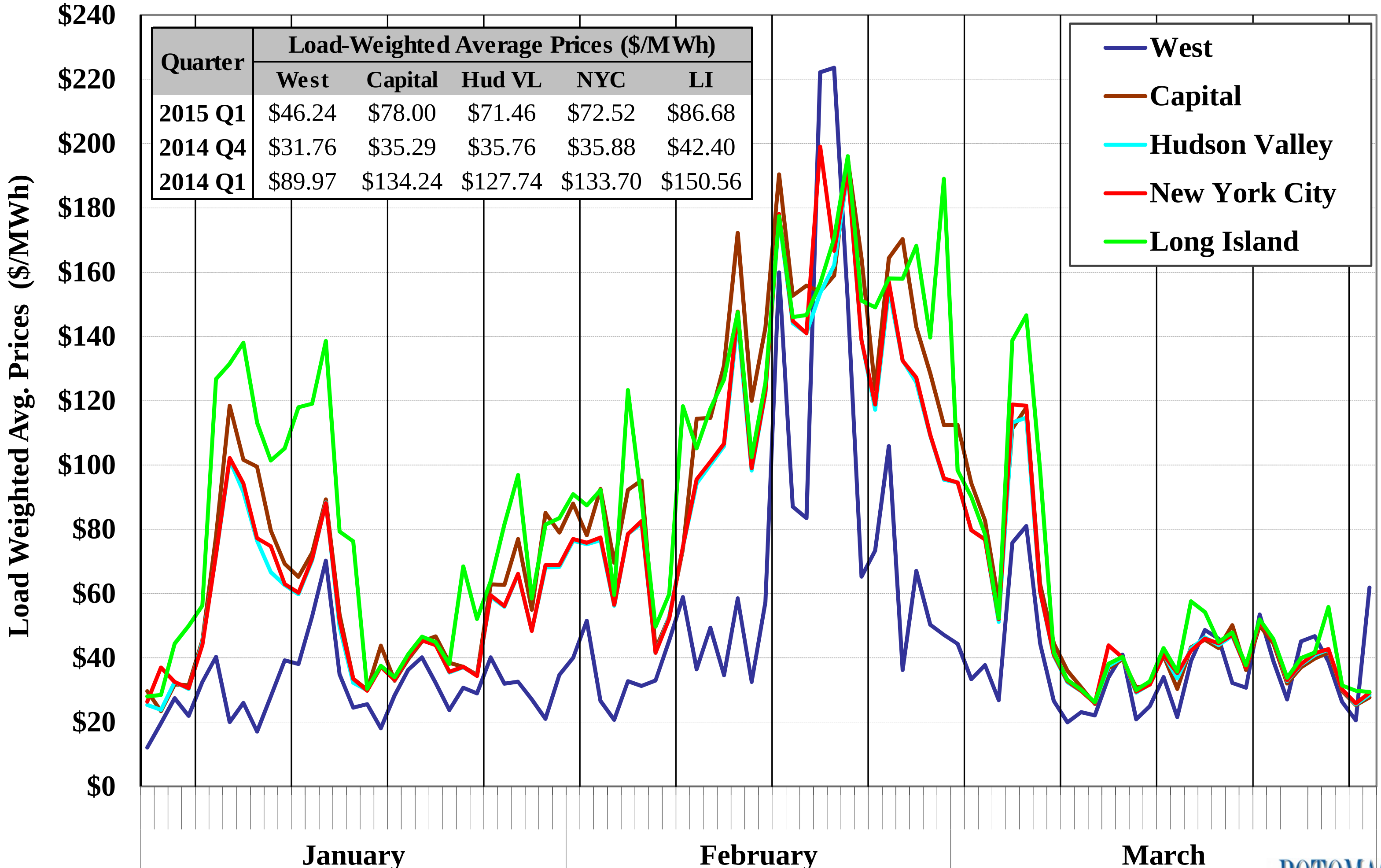
Real-Time Electricity Prices by Zone



Quarter	Load-Weighted Average Prices ($/MWh)				
	West	Capital	Hud VL	NYC	LI
2015 Q1	$46.24	$78.00	$71.46	$72.52	$86.68
2014 Q4	$31.76	$35.29	$35.76	$35.88	$42.40
2014 Q1	$89.97	$134.24	$127.74	$133.70	$150.56

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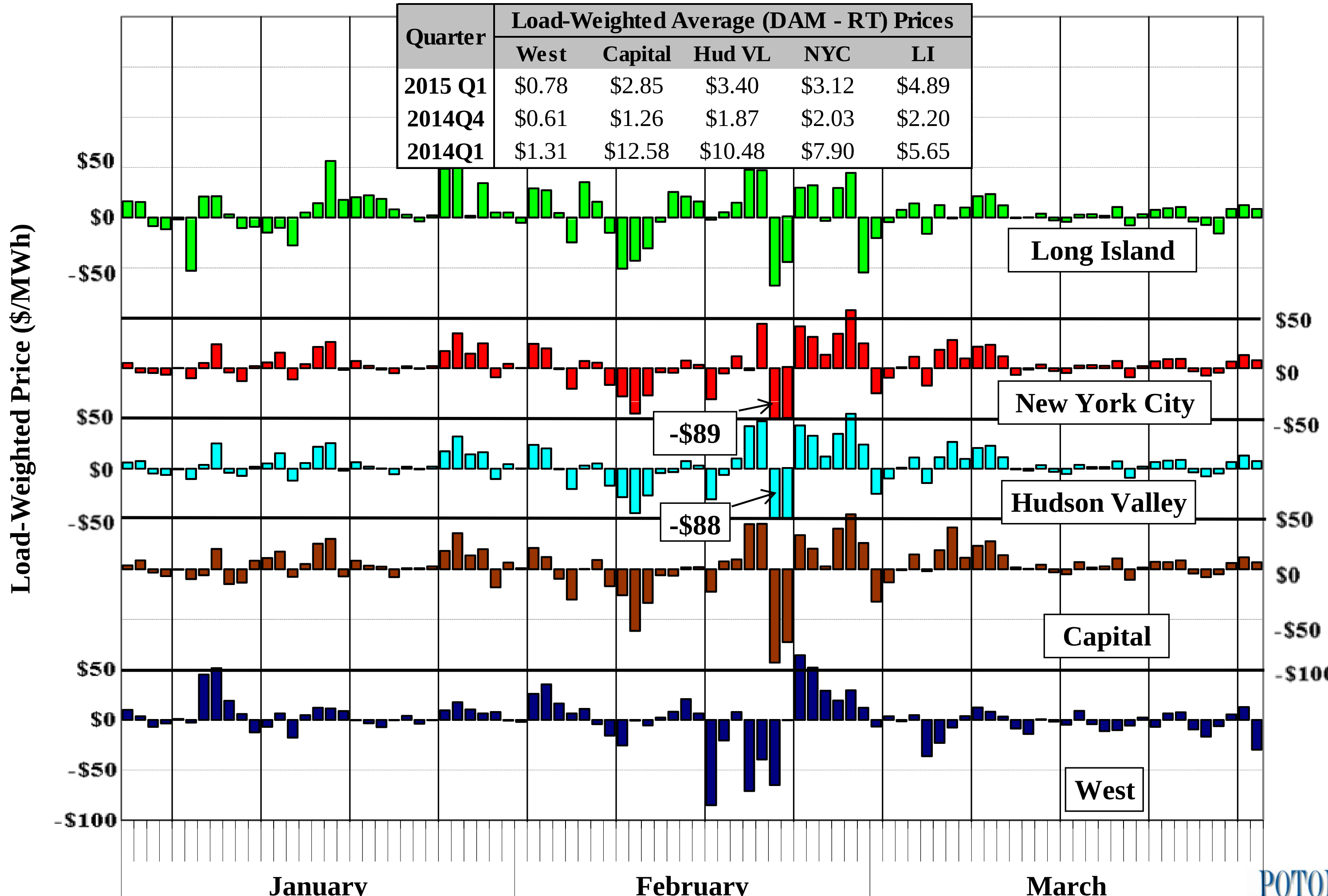
Convergence Between Day-Ahead and Real-Time Prices



Quarter	Load-Weighted Average (DAM - RT) Prices				
	West	Capital	Hud VL	NYC	LI
2015 Q1	$0.78	$2.85	$3.40	$3.12	$4.89
2014Q4	$0.61	$1.26	$1.87	$2.03	$2.20
2014Q1	$1.31	$12.58	$10.48	$7.90	$5.65

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Market Performance Under Tight Gas Supply Conditions

- The first figure in this section evaluates the efficiency of fuel usage in Eastern New York in the first quarter of 2015, showing daily averages for:
  - ✓ Internal generation by actual fuel consumed; and
  - ✓ Day-ahead natural gas price index for Iroquois Zone 2 and Transco Zone 6 (NY).
  - ✓ These quantities are also shown by month for the first quarter of 2014 and 2015.
- The second figure in this section evaluates the availability of 10-minute reserves in East NY on select hourly-OFO days, showing hourly averages in hours 7-20 for:
  - ✓ Eastern 10-minute reserve prices; and
  - ✓ Available 10-minute reserves in East NY in the following categories:
    - – Hydro and oil-capable reserves (including oil-only and dual-fueled units);
    - – Unused import capability on the Central-East interface;
    - – Gas-only reserves (including dual-fueled units that would utilize gas); and
    - – Undeliverable reserves in Long Island (i.e., reserves in excess of flows from upstate NY).
  - ✓ The black marker represents total deliverable reserves from hydro and oil-capable resources and unused Central East capability, indicating the level of reserve capacity that is not dependent on the availability of gas.

Market Performance under Tight Gas Supply Conditions Eastern New York

- Cold weather led natural gas prices (the higher of Transco Z6 NY and Iroquois Z2) to rise above $15/MMbtu on 22 days in East NY in the first quarter of 2015.
  - ✓ Oil-fired generation rose sharply on these days, averaging over 2.2 GW.
  - ✓ Gas prices exceeded $15/MMbtu on 17 consecutive days from mid to late February because of extreme cold weather conditions.
    - This 17-day period accounted for 68 percent of oil-fired generation in the quarter.
    - The large amount of oil use in a single period illustrates the difficulty in predicting (before the winter) how much oil will be needed over the entire winter season.
- Oil-fired generation in East NY totaled roughly 1.5 million MWh in the first quarter of 2015, down from 1.9 million MWh in the first quarter of 2014.
  - ✓ Patterns of weather and oil consumption were different between the two quarters.
    - In the first quarter of 2014, January was the coldest month, accounting for 62 percent of all quarterly oil production.
    - January 2014 and January 2015 exhibited similar average temperatures, but January 2014 had more extreme temperatures.
    - February 2015 was the coldest month in the last ten years, accounting for 75 percent of all oil production in the first quarter of 2015.

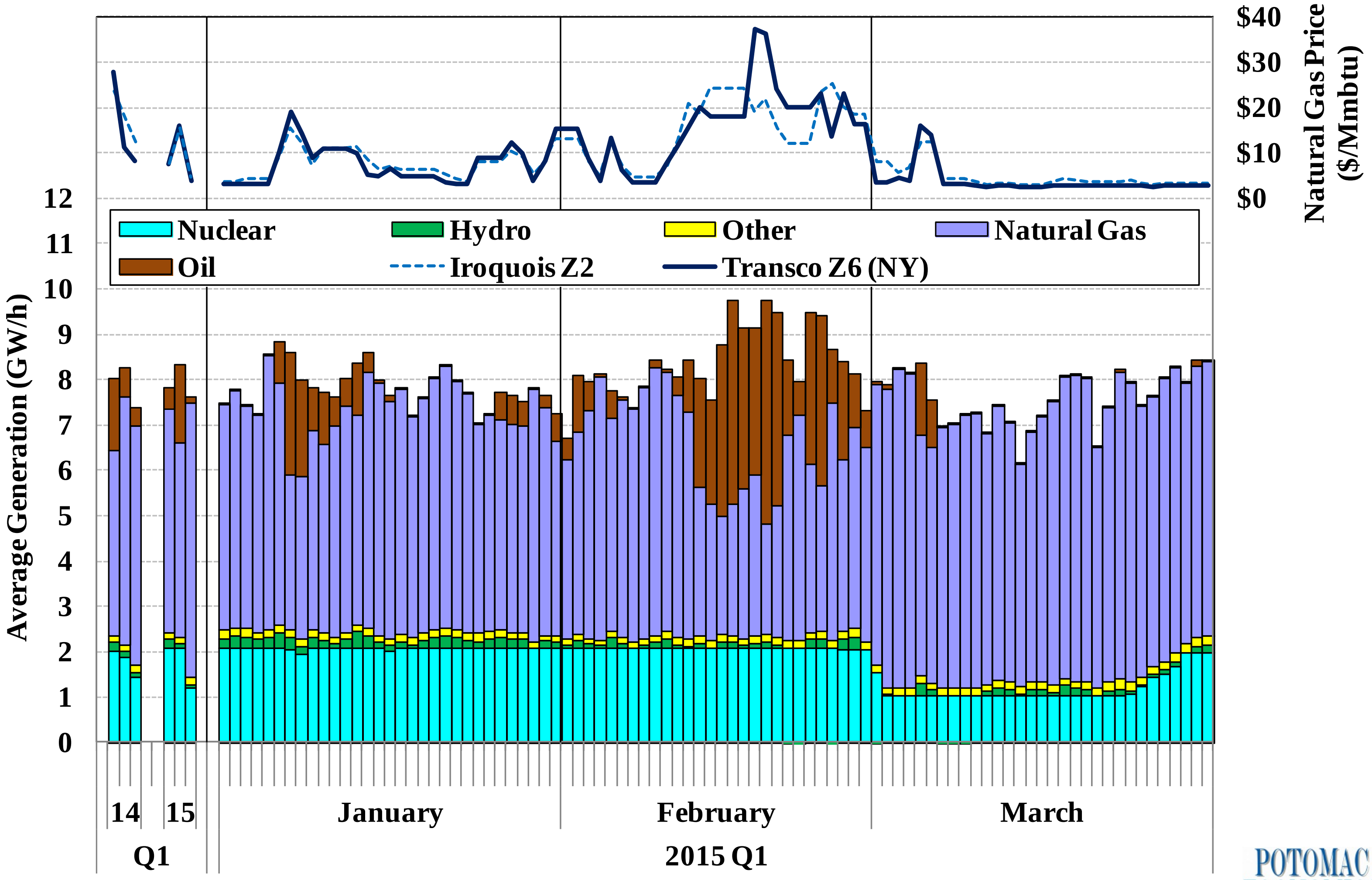
Market Performance under Tight Gas Supply Conditions Eastern New York

- ✓ Natural gas prices and fuel oil prices were significantly lower than a year ago.
  - – Natural gas prices fell 41 to 48 percent despite colder weather conditions this quarter, reflecting:
    - Higher gas production in the Marcellus region; and
    - More LNG imports to the region (from mid-Atlantic up to New Brunswick).
  - – Oil prices fell substantially from a year ago, which also limited the increase in gas prices during the periods of gas pipeline constraints.
- The day-ahead and real-time markets have performed well in helping conserve the available supply of natural gas under tight gas supply conditions.
  - ✓ The NYISO's DAM generally helped coordinate decisions by generators about whether to operate on natural gas, oil, or a blend.
  - ✓ Nonetheless, for many units, actual production from oil is significantly lower than would have been optimal based on gas prices and LBMPs because of:
    - – Planned and forced outages;
    - – Non-maintenance of permits and/or equipment for burning oil;
    - – Low oil inventories; and
    - – Air permit limitations.

Market Performance under Tight Gas Supply Conditions East 10-Minute Reserves on Hourly-OFO Days

- Real-time reserve clearing prices (and LBMPs) are under-stated when the availability of operating reserves is over-estimated by the real-time market model.
  - ✓ Hence, we evaluate whether there were periods when reserve capability was scheduled but may not have been available because of gas pipeline limitations.
- There were 8 hours on hourly-OFO days when the NYISO relied on some gas-only capacity to satisfy the Eastern 10-minute reserve requirement.
  - ✓ However, Eastern 10-minute reserve prices averaged just \$8/MWh in these hours.
  - ✓ This is down from the first quarter of 2014 when we identified 72 such hours, during which Eastern 10-minute reserve prices cleared at \$0/MWh in 53 hours and averaged \$190/MWh in the other 19 hours (see our 2014 SOM report).
  - ✓ SRE commitments occurred on three of these days for Eastern reserve needs, but Eastern 10-minute reserve prices were \$0/MWh on these three days.
- These results suggest that prices may be understated in some hours on OFO days when generators are subject to fuel limitations.
  - ✓ This reduces the incentives for generators to incur costs necessary to provide reserves (and energy) more reliably during tight winter conditions.

Fuel Usage and Natural Gas Price
Eastern New York



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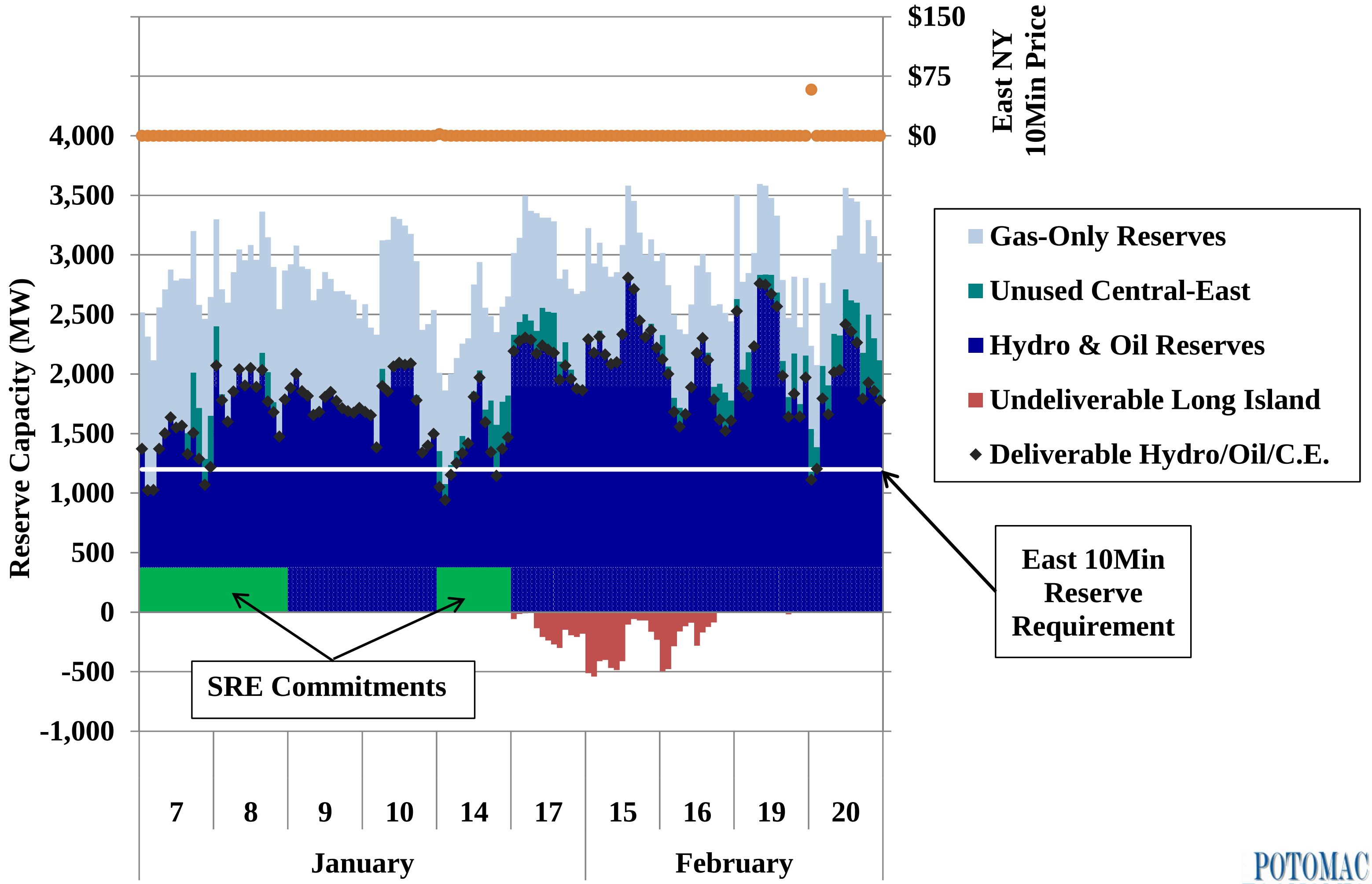
10-Minute Reserve Capacity in Eastern New York On Cold Days with Hourly OFOs
the First Quarter of 2015



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Ancillary Services Market

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Ancillary Services Prices

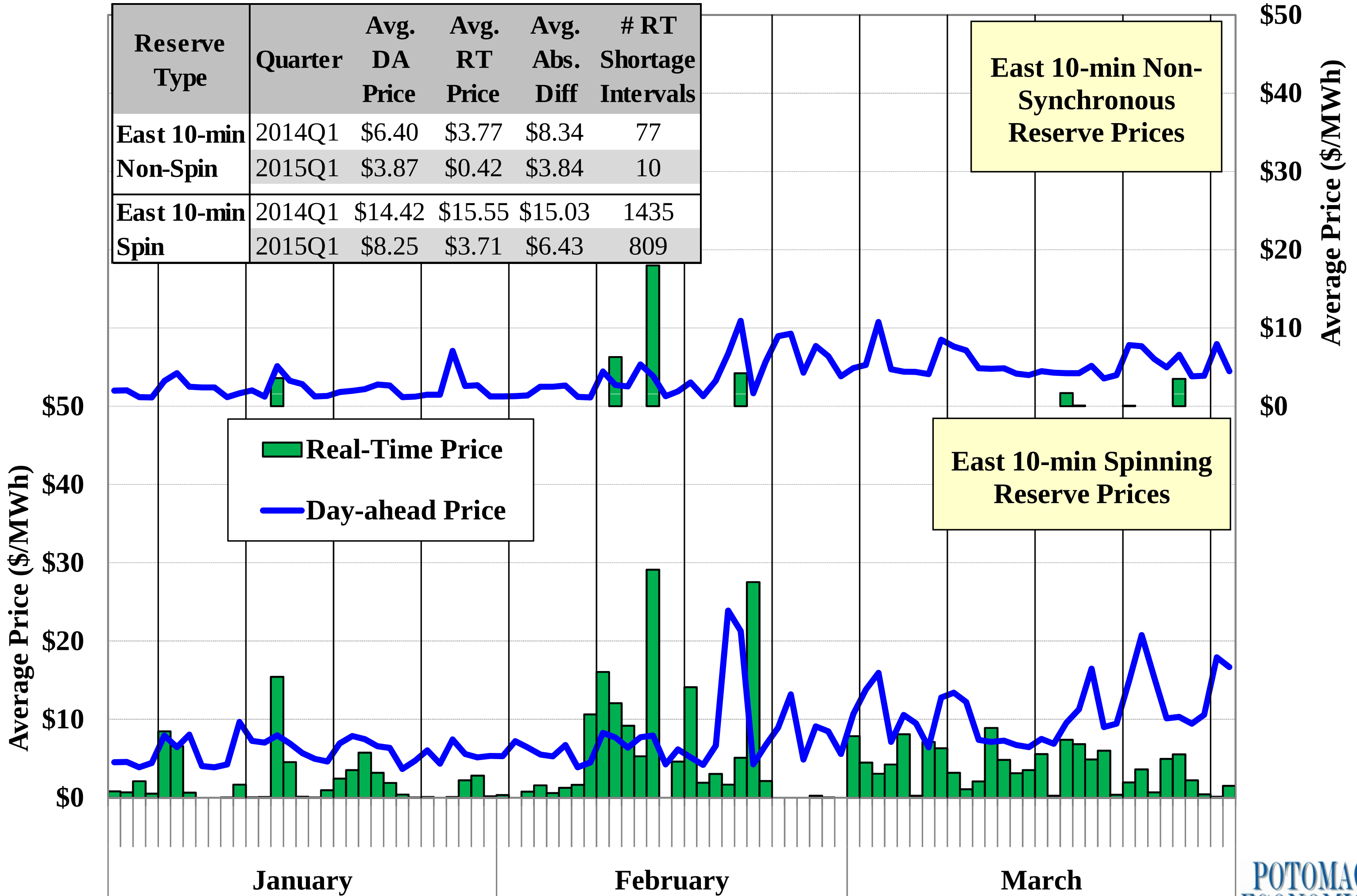
- Two figures summarize DA and RT prices for four ancillary services products:
  - ✓ 10-min spinning reserve prices in eastern NY, which reflect the cost of requiring:
    - 330 MW of 10-minute spinning reserves in eastern NY;
    - 655 MW of 10-minute spinning reserves state-wide; and
    - 1,200 MW of 10-minute total reserves (spin and non-spin) in eastern NY.
  - ✓ 10-min non-spinning reserve prices in eastern NY, which reflect the cost of requiring 1,200 MW of 10-minute total reserves in eastern NY.
  - ✓ 10-min spinning reserve 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.
    - Resources were scheduled assuming a Regulation Movement Multiplier of 10 MW per MW of capability, but they are compensated according to actual movement.
- 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 all ancillary services products fell from the first quarter of 2014, consistent with lower opportunity costs from lower energy prices.
- Average DA prices were higher than average RT prices for all reserve products.
  - ✓ This is expected in competitive markets with no virtual trading.
- DA spinning and non-spinning reserve prices in East NY rose during the quarter.
  - ✓ Several low-cost spinning reserve units were on planned outages during March.
  - ✓ Some offline gas turbines increased their offer prices in late February and March.
- RT price spikes were less frequent in the first quarter of 2015 because of:
  - ✓ Lower and less volatile natural gas prices;
  - ✓ Less frequent peaking (i.e., load > 24 GW) conditions; and
  - ✓ Higher net imports from Ontario and HQ (see slide 41).
  - ✓ These factors contributed to fewer shortages of ancillary services products, which fell 44 to 87 percent from the first quarter of 2014.
    - – In the first quarter of 2014, regulation shortages were particularly high because of elevated opportunity costs to provide the service.
    - – The model "chose" to be short of regulation when the cost to provide regulation exceeded the lowest demand curve value of $80.

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	2014Q1	$6.40	$3.77	$8.34	77
Non-Spin	2015Q1	$3.87	$0.42	$3.84	10
East 10-min	2014Q1	$14.42	$15.55	$15.03	1435
Spin	2015Q1	$8.25	$3.71	$6.43	809



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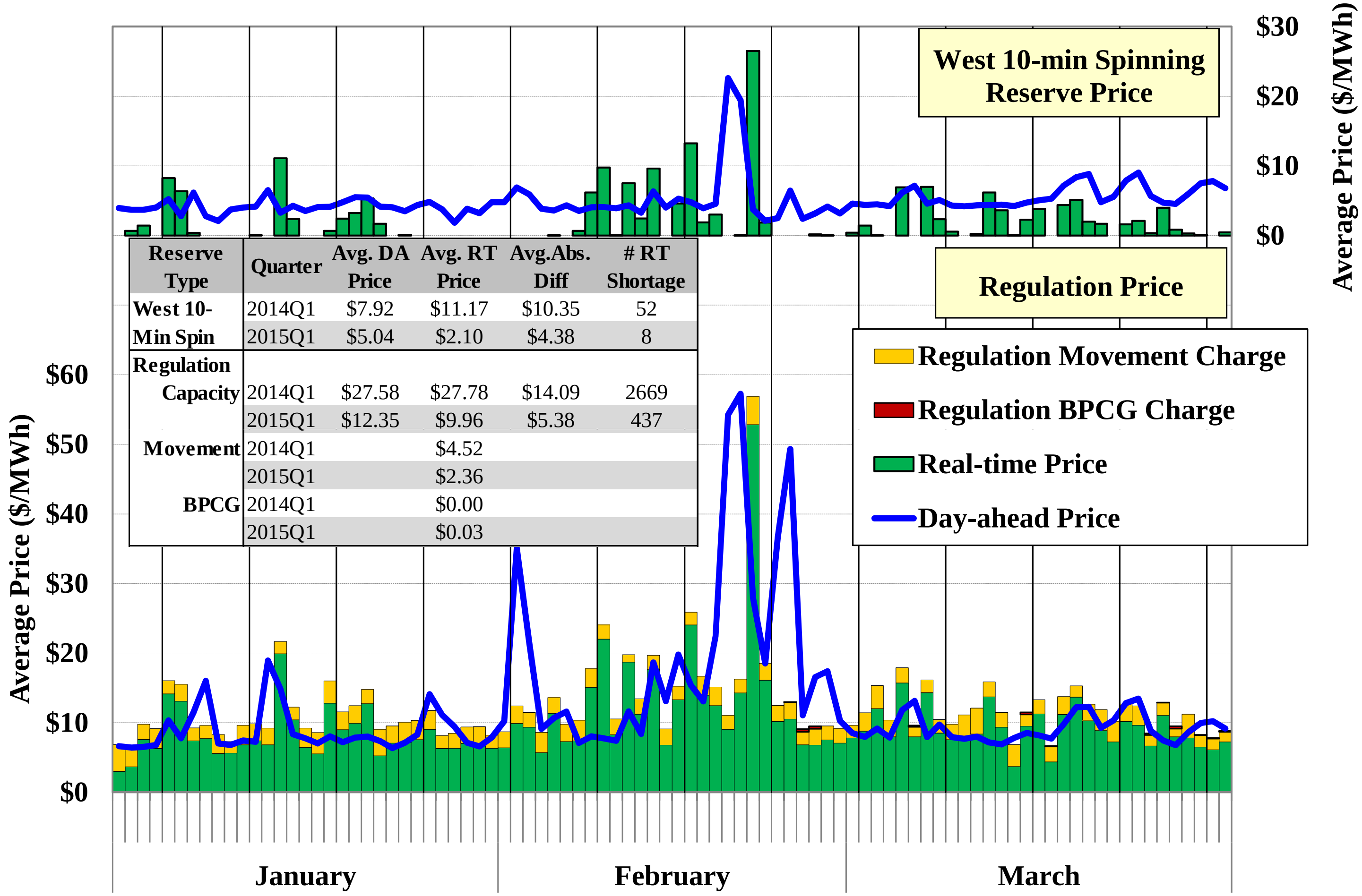
Day-Ahead and Real-Time Ancillary Services Prices
Western 10-Minute Spinning Reserves and Regulation



Reserve Type	Quarter	Avg. DA Price	Avg. RT Price	Avg.Abs. Diff	# RT Shortage
West 10-Min Spin	2014Q1	$7.92	$11.17	$10.35	52
	2015Q1	$5.04	$2.10	$4.38	8
Regulation Capacity	2014Q1	$27.58	$27.78	$14.09	2669
	2015Q1	$12.35	$9.96	$5.38	437
Movement	2014Q1		$4.52		
	2015Q1		$2.36		
BPCG	2014Q1		$0.00		
	2015Q1		$0.03		

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

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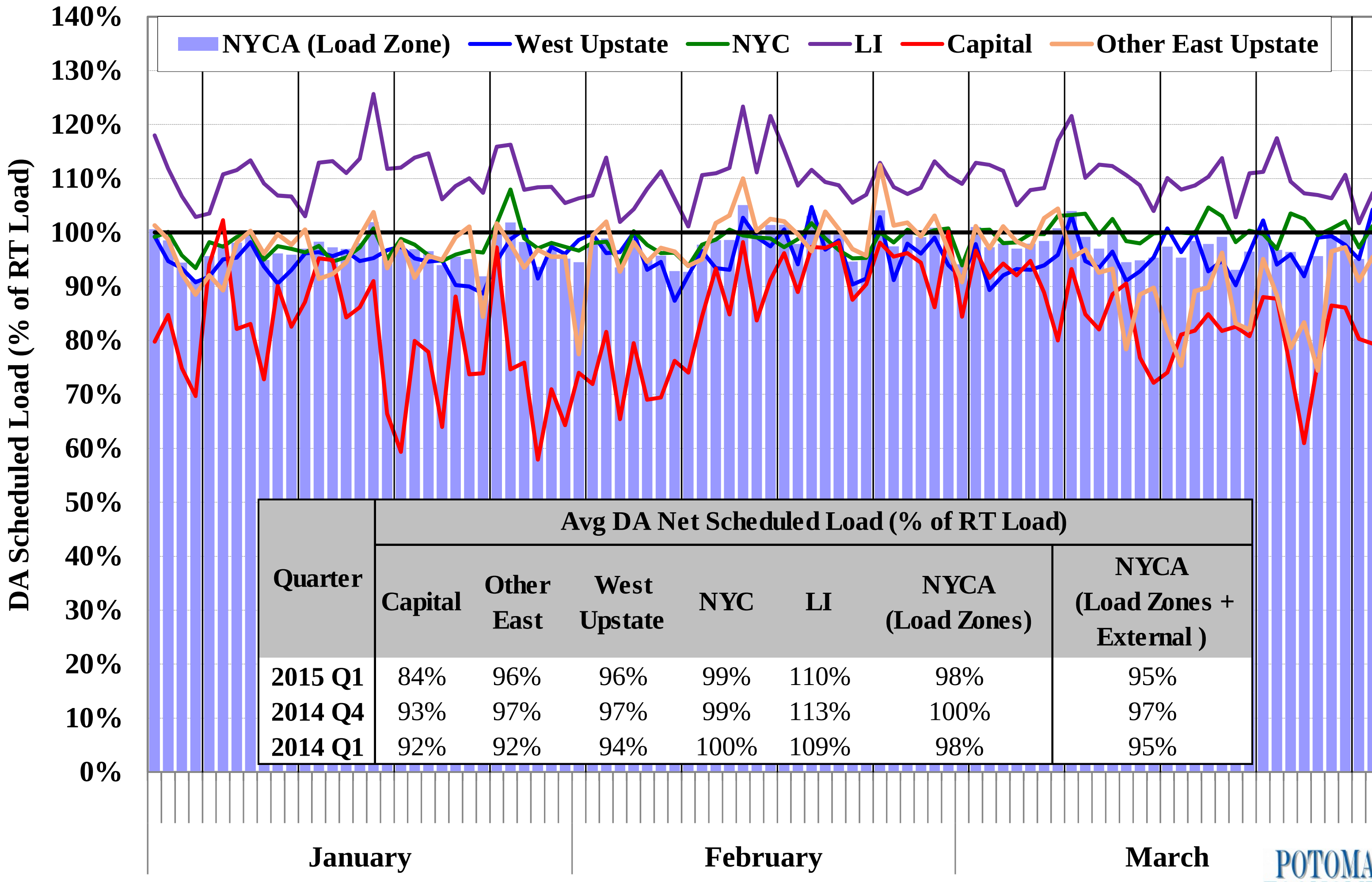
Day-ahead Load Scheduling

- 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 first quarter of 2015, similar to the prior year.
- Load scheduling tends to be higher in locations at times when acute real-time congestion is more likely. For example:
  - ✓ Load scheduling in the Capital Zone was higher in February than in the other two months of the quarter due to higher congestion across the Central-East interface.
  - ✓ Load was consistently over-scheduled in Long Island because it is usually the most import-constrained area.
- In the first quarter of 2015, under-scheduling in most areas helped improve convergence between DA and RT prices given prevailing DA premiums.

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)
2015 Q1	84%	96%	96%	99%	110%	98%	95%
2014 Q4	93%	97%	97%	99%	113%	100%	97%
2014 Q1	92%	92%	94%	100%	109%	98%	95%

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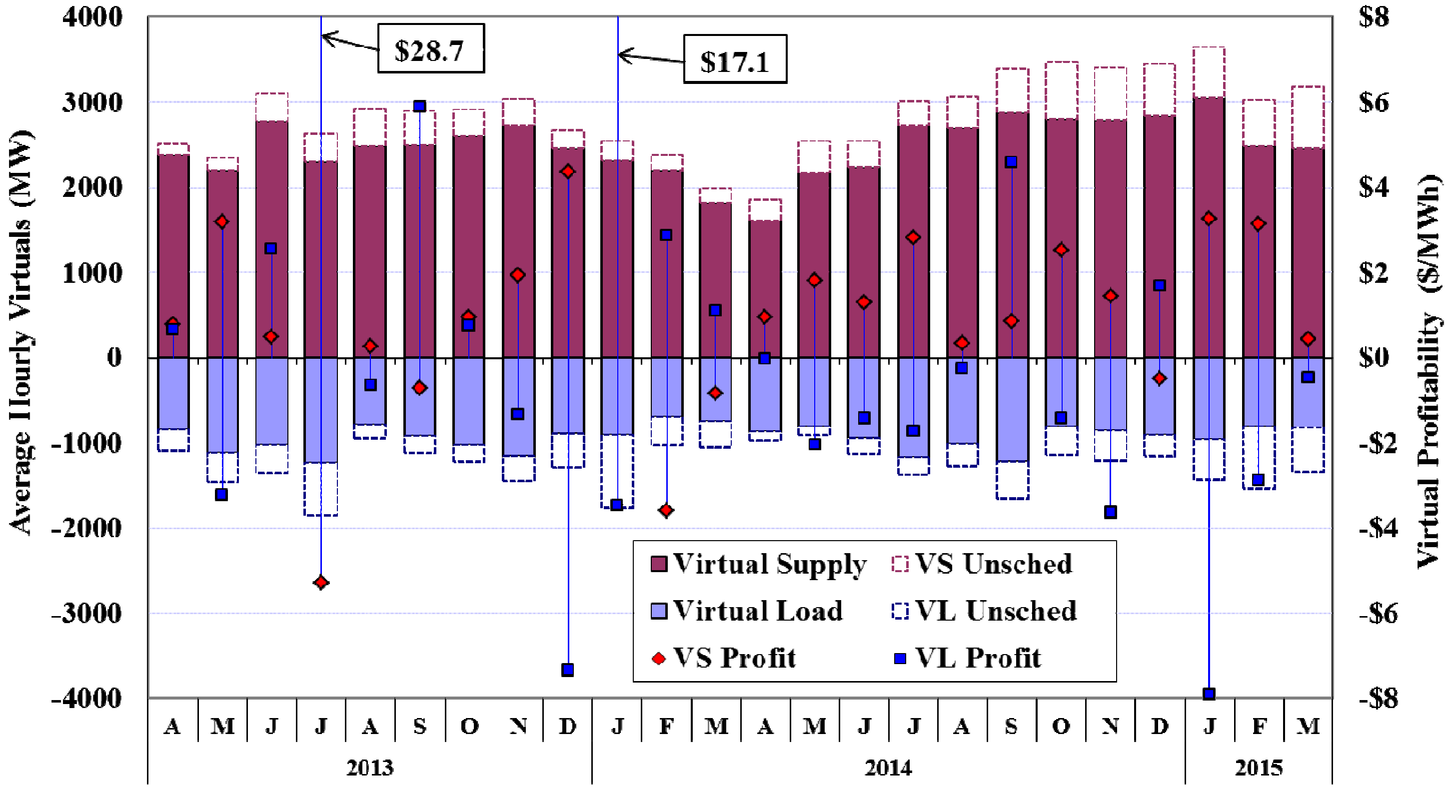
Virtual Trading Activity

- 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

- The trading volume of virtual supply rose modestly in recent months, consistent with prevailing day-ahead premiums in these periods.
- 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.
- In aggregate, virtual traders netted a gross profit of roughly $6 million at the load zones and over $1 million at the proxy buses in the first quarter of 2015.
  - ✓ Virtual transactions were profitable, indicating that they have generally improved convergence between DA and RT prices. (For example, profitable virtual supply tends to reduce the DA price, bringing it closer to the RT price.)
  - ✓ However, the profits and losses of virtual trades have varied widely by time and location, reflecting the difficulty of predicting volatile RT prices.
    - – For example, virtual supply netted a loss of over $3 million on February 21 because of unexpected system-wide RT price spikes (see slides 19-21).
- 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	187	328	253	345	156	206	230	438	319	590	260	250	83	169	160	421	136	289	522	387	313	460	453	270
	%	6%	10%	7%	10%	5%	6%	6%	11%	10%	18%	9%	10%	3%	6%	5%	11%	4%	7%	15%	11%	8%	11%	14%	8%
Loss > 50% of Avg. Zone Price	MW	149	275	166	252	176	182	201	369	258	395	333	256	70	196	199	346	185	289	428	371	306	412	359	316
	%	5%	8%	4%	7%	5%	5%	6%	10%	8%	12%	12%	10%	3%	7%	6%	9%	5%	7%	12%	10%	8%	10%	11%	10%

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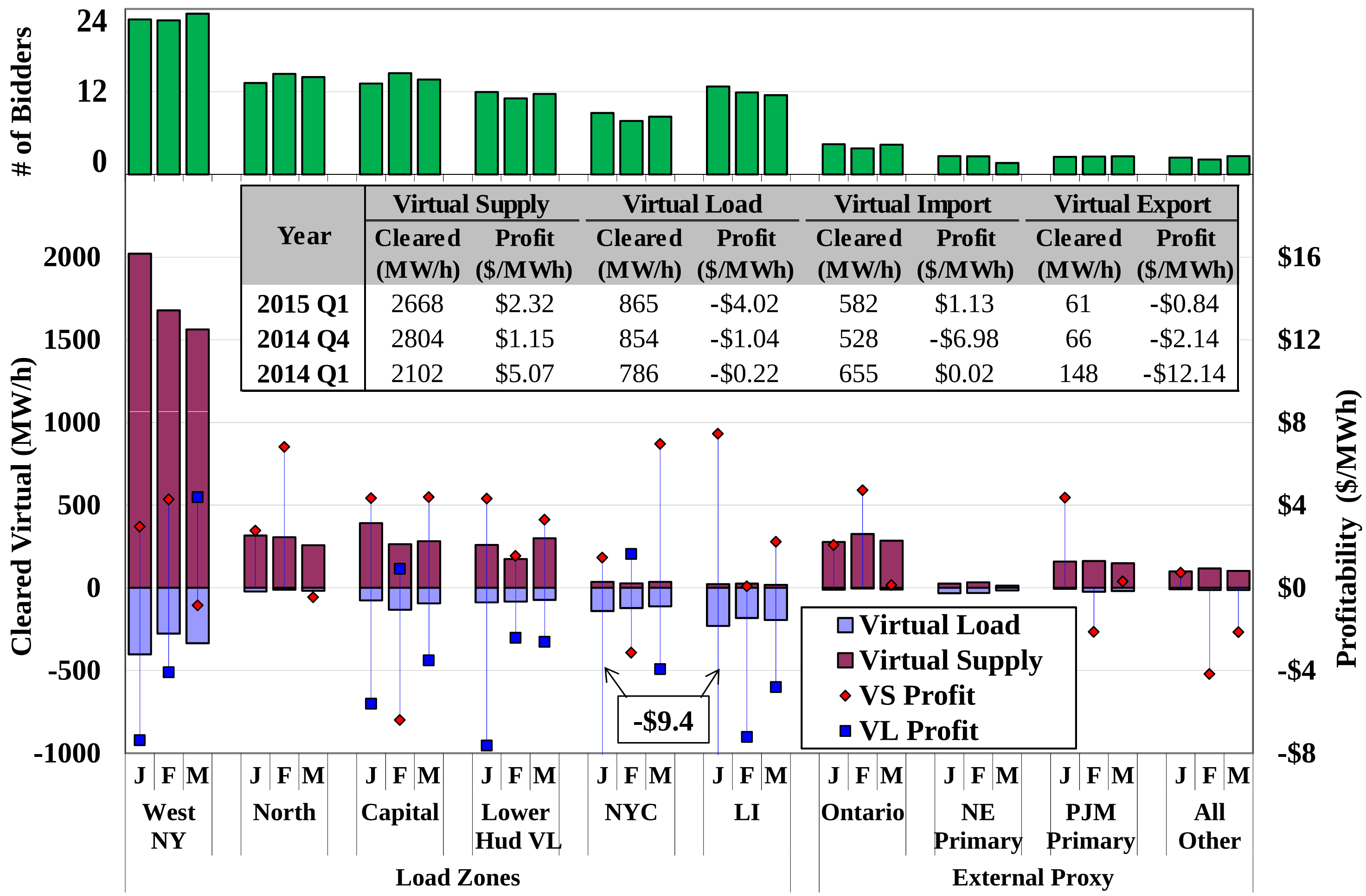
Virtual Trading Activity at Load Zones & Proxy Buses by Location



Year	Virtual Supply		Virtual Load		Virtual Import		Virtual Export	
	Cleared (MW/h)	Profit ($/MWh)	Cleared (MW/h)	Profit ($/MWh)	Cleared (MW/h)	Profit ($/MWh)	Cleared (MW/h)	Profit ($/MWh)
2015 Q1	2668	$2.32	865	-$4.02	582	$1.13	61	-$0.84
2014 Q4	2804	$1.15	854	-$1.04	528	-$6.98	66	-$2.14
2014 Q1	2102	$5.07	786	-$0.22	655	$0.02	148	-$12.14

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

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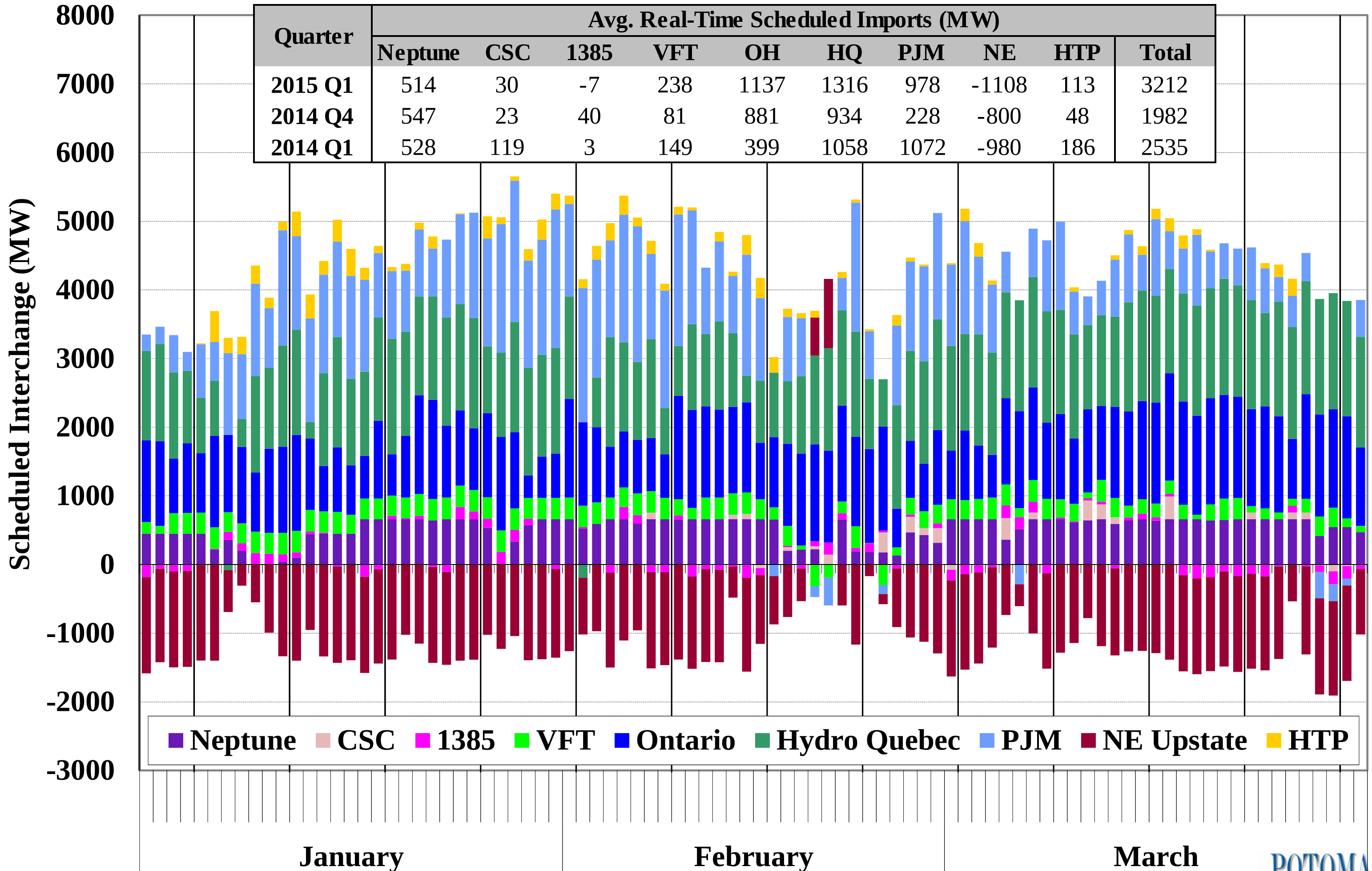
Net Imports Scheduled Across External Interfaces

- 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 roughly 3,200 MW (serving nearly 16 percent of the load) during peak hours, up 680 MW from the first quarter of 2014.
- Average net imports from Ontario and HQ rose by roughly 1 GW from the first quarter of 2014, accounting for the vast majority of the overall increase.
  - ✓ Average net imports from Ontario rose 740 MW, reflecting less frequent peaking conditions and lower natural gas prices in Ontario this winter.
  - ✓ Average net imports from HQ rose 260 MW, attributable to less frequent winter peaking conditions in Quebec as well.
  - ✓ These increases had significant effects on operations and LBMPs in the West NY.
- Net imports to Long Island fell by 110 MW during peak hours from the prior year, partly due to the lengthy outage of the CSC.
- New York normally imported power from PJM and exported power to New England across their primary interfaces in the winter season.
  - ✓ This pattern was consistent with the spreads in natural gas prices between these markets in the winter (i.e., NE > NY > PJM).

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
2015 Q1	514	30	-7	238	1137	1316	978	-1108	113	3212
2014 Q4	547	23	40	81	881	934	228	-800	48	1982
2014 Q1	528	119	3	149	399	1058	1072	-980	186	2535



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Intra-Hour Scheduling with PJM
Coordinated Transaction Scheduling ("CTS")

- The next table evaluates the performance of CTS with PJM at its primary interface for each month of the first quarter of 2015 (see Table A-8 in our 2014 SOM report for more detailed description). The table shows:
  - ✓ The percent of quarter-hour intervals during which the interface flows were adjusted (relative to the base schedule) in the scheduling RTC interval.
  - ✓ The average flow adjustment from the base schedule.
  - ✓ The production cost savings that resulted from the CTS, including:
    - – Projected savings at scheduling time, which is the expected production cost savings at the time when RTC determines the interchange schedule.
    - – Unrealized savings, which are not realized due to: a) New York forecast error; b) PJM forecast error; and c) other factors.
    - – Actual savings (= Projected – Unrealized).
  - ✓ Interface prices on both NY and PJM sides that include actual prices (i.e., RTD prices and PJM RT prices) and forecasted prices at the time of RTC scheduling (i.e., RTC prices and PJM IT SCED prices).
  - ✓ Price forecast errors, which show the average difference and the average absolute difference between the actual and forecasted prices on both sides.

Intra-Hour Scheduling with PJM
Coordinated Transaction Scheduling ("CTS")

- Interchange between NY and PJM was adjusted evenly under CTS in both the import and export directions. In the first quarter of 2015:
  - ✓ On average, 119 MW of flows were adjusted in the export direction to PJM in 40 percent of intervals, while 122 MW of flows were adjusted in the import direction to NY in 44 percent of intervals.
- Sizable benefits (measured by production cost savings) were projected at the time of scheduling, but a relatively small portion was realized primarily because of price forecast errors in both markets. In the first quarter of 2015:
  - ✓ A total of $6.5 million in production cost savings was estimated at the time when RTC determined final schedules. However,
    - – NY price forecast errors accounted for a reduction of $0.9 million in savings; and
    - – PJM price forecast errors accounted for an additional reduction of $4.4 million.
- Average forecast errors were generally smaller on the New York side than on the PJM side. In the first quarter of 2015:
  - ✓ Average RTC forecast prices were persistently lower than average RTD prices ($4.40 lower when export-adjusted and $1.20/MWh lower when import-adjusted).
  - ✓ Average PJM IT SCED forecast prices deviated more widely from average real-time prices in both directions ($5.70/MWh higher when export-adjusted and $12.90/MWh lower when import-adjusted).

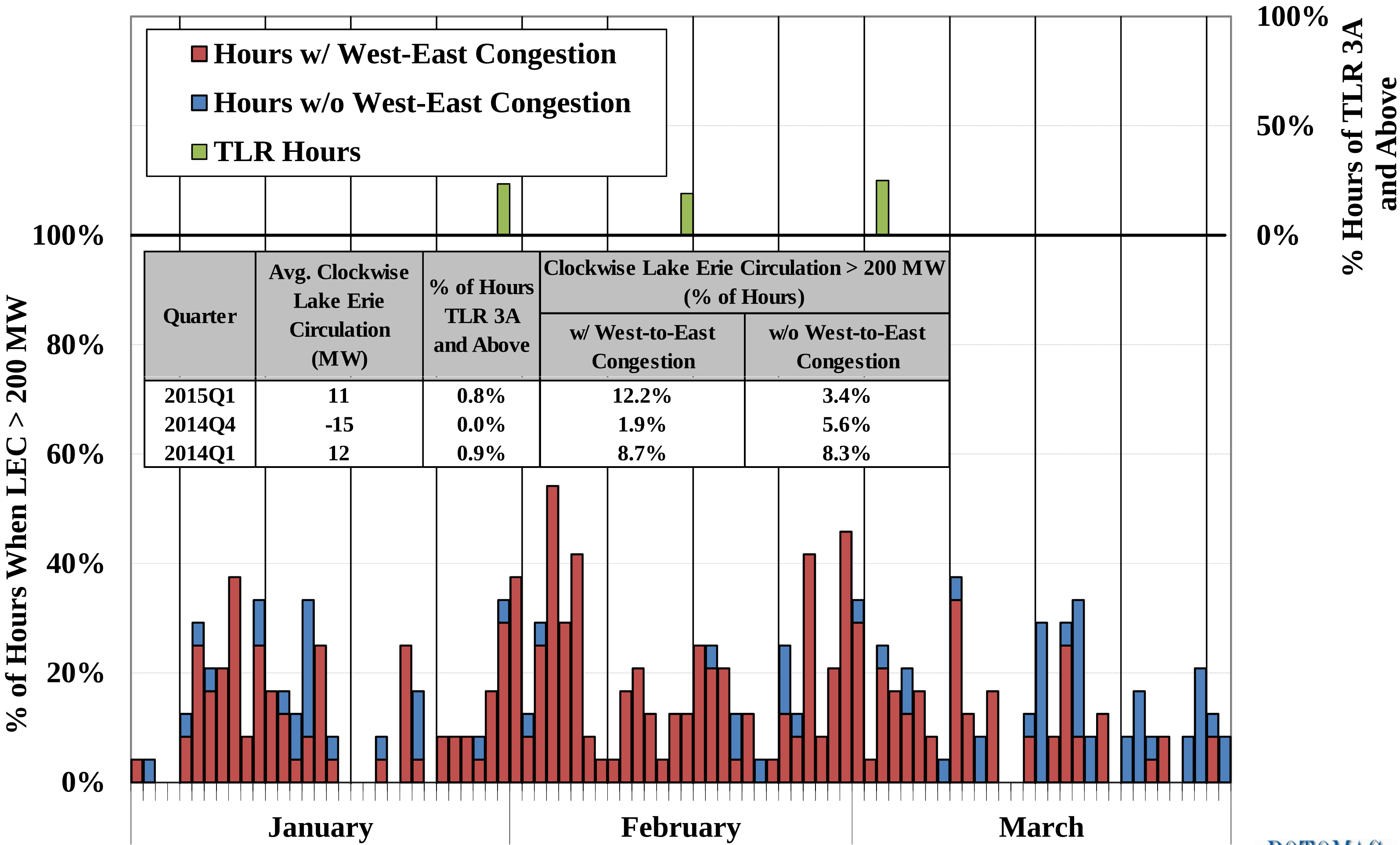
Efficiency of Intra-Hour Scheduling Under CTS
Primary PJM Interface

			Export (NY to PJM)			Import (PJM to NY)			Average/ Total
			Jan-15	Feb-15	Mar-15	Jan-15	Feb-15	Mar-15	
% of All Intervals			39%	41%	39%	43%	46%	43%	**84%**
Average Flow Adjustment (MW)			-90	-150	-114	90	170	106	**8 (Net) / 121 (Gross)**
Production Cost Savings ($ Million)	Projected at Scheduling Time		$0.84	$2.47	$1.37	$0.17	$1.05	$0.56	**$6.5**
	Unrealized Savings Due to:	NY Fcst. Err.	-$0.06	-$0.42	-$0.15	-$0.02	$0.01	-$0.17	**-$0.8**
		PJM Fcst. Err.	-$0.51	-$1.17	-$0.56	-$0.22	-$1.07	-$0.96	**-$4.5**
		Other	-$0.04	-$0.27	-$0.03	-$0.06	-$0.11	$0.02	**-$0.5**
	Actual		$0.23	$0.61	$0.62	-$0.13	-$0.12	-$0.55	**$0.7**
Interface Prices ($/MWh)	NY	Actual	$43.27	$96.48	$45.86	$44.54	$93.61	$43.52	**$61.73**
		Forecast	$41.09	$88.42	$43.11	$42.97	$92.06	$43.01	**$59.01**
	PJM	Actual	$47.78	$101.88	$55.73	$48.27	$103.65	$55.18	**$69.32**
		Forecast	$52.42	$114.43	$55.71	$41.65	$87.94	$38.74	**$65.29**
Price Forecast Errors ($/MWh)	NY	Fcst. - Act.	-$2.18	-$8.06	-$2.75	-$1.57	-$1.55	-$0.51	**-$2.72**
		Abs. Val.	$9.28	$24.78	$12.54	$10.46	$23.19	$13.02	**$15.68**
	PJM	Fcst. - Act.	$4.64	$12.55	-$0.02	-$6.62	-$15.71	-$16.44	**-$4.03**
		Abs. Val.	$19.44	$51.49	$29.44	$14.42	$41.28	$23.78	**$30.08**

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 first quarter of 2015.
- Clockwise LEC was relatively high (> 200 MW) during 16 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 80 percent of these hours.
    - – In particular, large variations in LEC are a leading contributor of volatile West Zone congestion (see our 2014 SOM report for more details).
- The frequency of TLRs called by the NYISO has been relatively low for the last three years due to changes in the TLR process.
  - ✓ The NYISO called TLRs for the Central-East interface for 16 hours this 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
2015Q1	11	0.8%	12.2%	3.4%
2014Q4	-15	0.0%	1.9%	5.6%
2014Q1	12	0.9%	8.7%	8.3%

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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).

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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: Including transmission constraints in the West Zone and interfaces from West to Central.
  - ✓ 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).

Day-Ahead and Real-Time Congestion

(cont. from prior slide)

- ✓ NYC Lines – 345kV: Lines into and within the NYC 345 kV system.
- ✓ 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 $281 million this quarter, down 34 percent from the first quarter of 2014. The key contributors were:
  - ✓ Less frequent winter peaking conditions, which generally resulted in less frequent severe congestion across the system;
  - ✓ Lower natural gas prices, which led to lower re-dispatch costs to manage congestion; and
  - ✓ Lower gas spreads between West NY and East NY, which led to less severe congestion across Central-East and into the Hudson Valley and NYC.

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:
  - ✓ Central to East (70% DAM, 59% RTM) – Most occurred in February as a result of higher natural gas prices and higher gas spreads between regions.
    - Although congestion values (in $s) decreased from the first quarter of 2014, the frequency of congestion across the Central-East interface increased.
    - Average net imports from Ontario and HQ rose roughly 1 GW from the first quarter of 2014, contributing to more frequent west-to-east congestion.
  - ✓ External Interfaces (13% DAM, 13% RTM) – More than 75 percent was associated with the primary interface with NE, which was fully utilized to export throughout most of the quarter when natural gas prices were higher in NE than in NY.
  - ✓ West to Central (2% DAM, 11% RTM) – Congestion was much more severe in RT than in the DA this quarter, partly because:
    - Lake Erie loop flow is volatile, and changes in the clockwise direction contribute to congestion price spikes on these facilities;
    - Imports from Ontario and output from renewable generation in West NY usually increase from the DAM to the RT (increasing flow across these facilities); and
    - Operation of the ABC, JK, and Ramapo PARs (to relieve Central-East congestion) increases flows across the most frequent constraints in the West Zone.

Day-Ahead Congestion Shortfalls

- Day-ahead congestion shortfalls totaled *negative* $7 million (i.e., a $7 million net surplus) this quarter, down notably from a year ago ($35 million).
  - ✓ The reduction was primarily due to fewer costly transmission outages this quarter.
    - – In this quarter, outages accounted for less than $5 million of shortfalls (roughly $2 million on facilities from upstate to Long Island in January and less than $3 million on the Dysinger-East interface in early March).
    - – In the first quarter of 2014, outages of the Ramapo PARs, NYC facilities, and Long Island facilities accounted for more than $40 million of shortfalls.
  - ✓ A portion of day-ahead shortfalls resulted from grandfathered TCCs that exceed the transfer capability of the system from Dunwoodie (Zone I) to Long Island.
    - – This resulted in more than $2 million of shortfalls in the first quarter of 2015.
- The shortfalls were offset by surpluses accrued on the following facilities:
  - ✓ The Central-East interface accounted for $3 million of surpluses, most of which accrued on several extreme cold days in late February because changes in the commitment pattern led to increased voltage transfer limits for the interface.
  - ✓ External interfaces accounted for another $6 million of surpluses because imports on most interfaces increased in the DAM from the TCC auction in many hours.
  - ✓ The PAR-controlled lines between NYC and LI (i.e., 901/903 lines) generated surpluses in hours when the lines were scheduled to flow less than the contractual amount assumed in the TCC auction, resulting in $4 million of surpluses.

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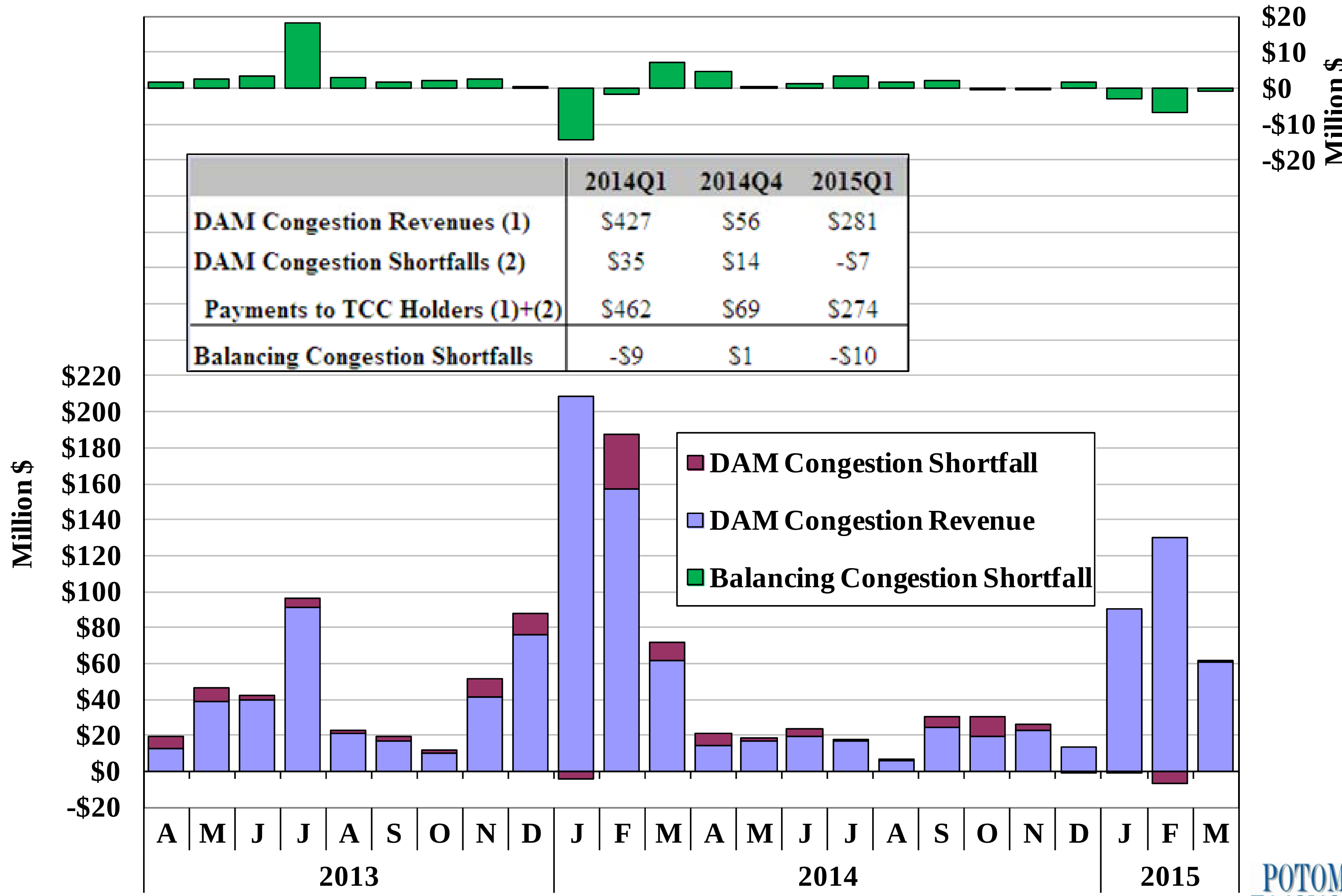
Balancing Congestion Shortfalls

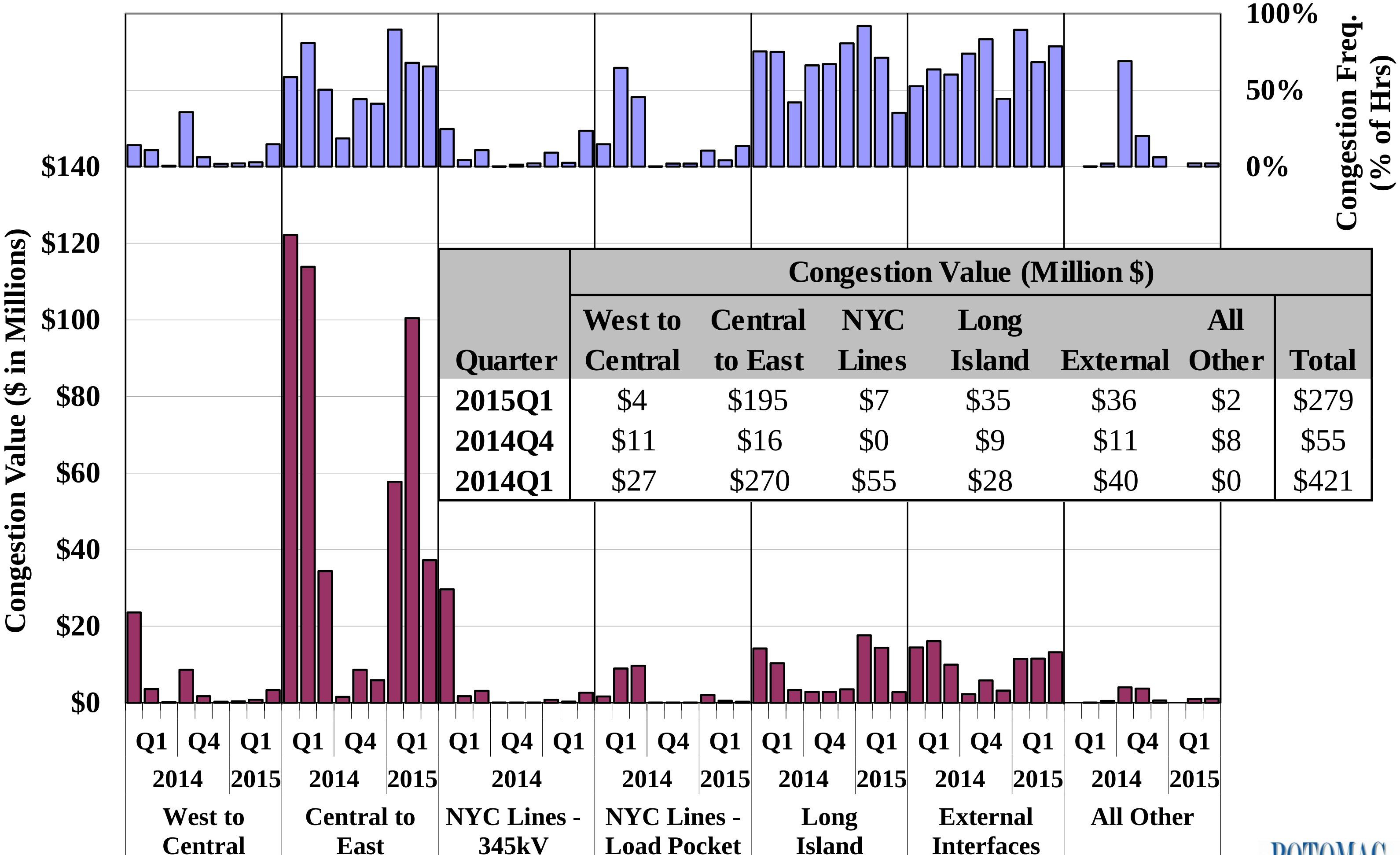
- Balancing congestion shortfalls totaled *negative* $10 million (i.e., a $10 million surplus) in this quarter, comparable to the first quarter of 2014.
  - ✓ When the transmission system is modeled consistently in the DA and RT markets, balancing congestion surpluses are to be expected as a result of changes in generation and load patterns between the DA and RT markets.
- The Central-East interface accounted for nearly a $3 million surplus, the majority of which accrued on several peak days in January and February, driven by:
  - ✓ Changes in generation patterns after the DAM because of changing weather patterns, natural gas prices, and SRE commitments.
- Operation of the Ramapo PARs under M2M with PJM provides significant benefit to NY in managing congestion and reducing balancing congestion shortfalls.
  - ✓ Combined with M2M settlements between PJM and the NYISO, this reduced shortfalls by $5 million in the first quarter of 2015.
- The two PAR-controlled lines between NYC and LI (i.e., 901/903 lines) consistently contributed to shortfalls because of volatile RT flows.
  - ✓ RT flow increases (out of LI) coincide with high congestion costs on LI facilities.
  - ✓ This contributed to a $2.5 million shortfalls in the first quarter of 2015.

Congestion Revenues and Shortfalls by Month



	2014Q1	2014Q4	2015Q1
DAM Congestion Revenues (1)	$427	$56	$281
DAM Congestion Shortfalls (2)	$35	$14	-$7
Payments to TCC Holders (1)+(2)	$462	$69	$274
Balancing Congestion Shortfalls	-$9	$1	-$10

Day-Ahead Congestion Value and Frequency by Transmission Path



Quarter	Congestion Value (Million $)						
	West to Central	Central to East	NYC Lines	Long Island	External	All Other	Total
2015Q1	$4	$195	$7	$35	$36	$2	$279
2014Q4	$11	$16	$0	$9	$11	$8	$55
2014Q1	$27	$270	$55	$28	$40	$0	$421

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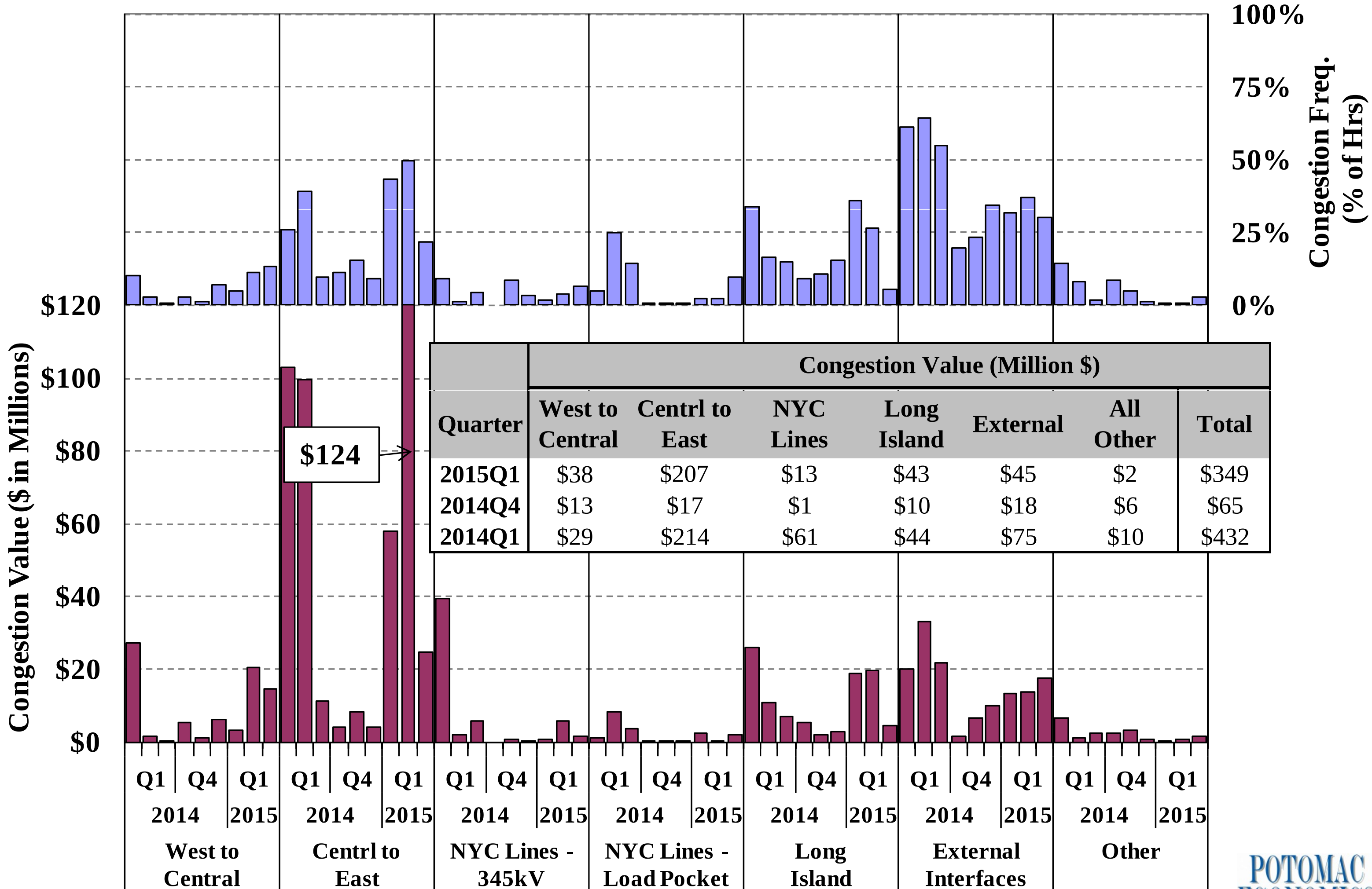
Real-Time Congestion Value and Frequency by Transmission Path



	Congestion Value (Million $)						
Quarter	West to Central	Centrl to East	NYC Lines	Long Island	External	All Other	Total
2015Q1	$38	$207	$13	$43	$45	$2	$349
2014Q4	$13	$17	$1	$10	$18	$6	$65
2014Q1	$29	$214	$61	$44	$75	$10	$432

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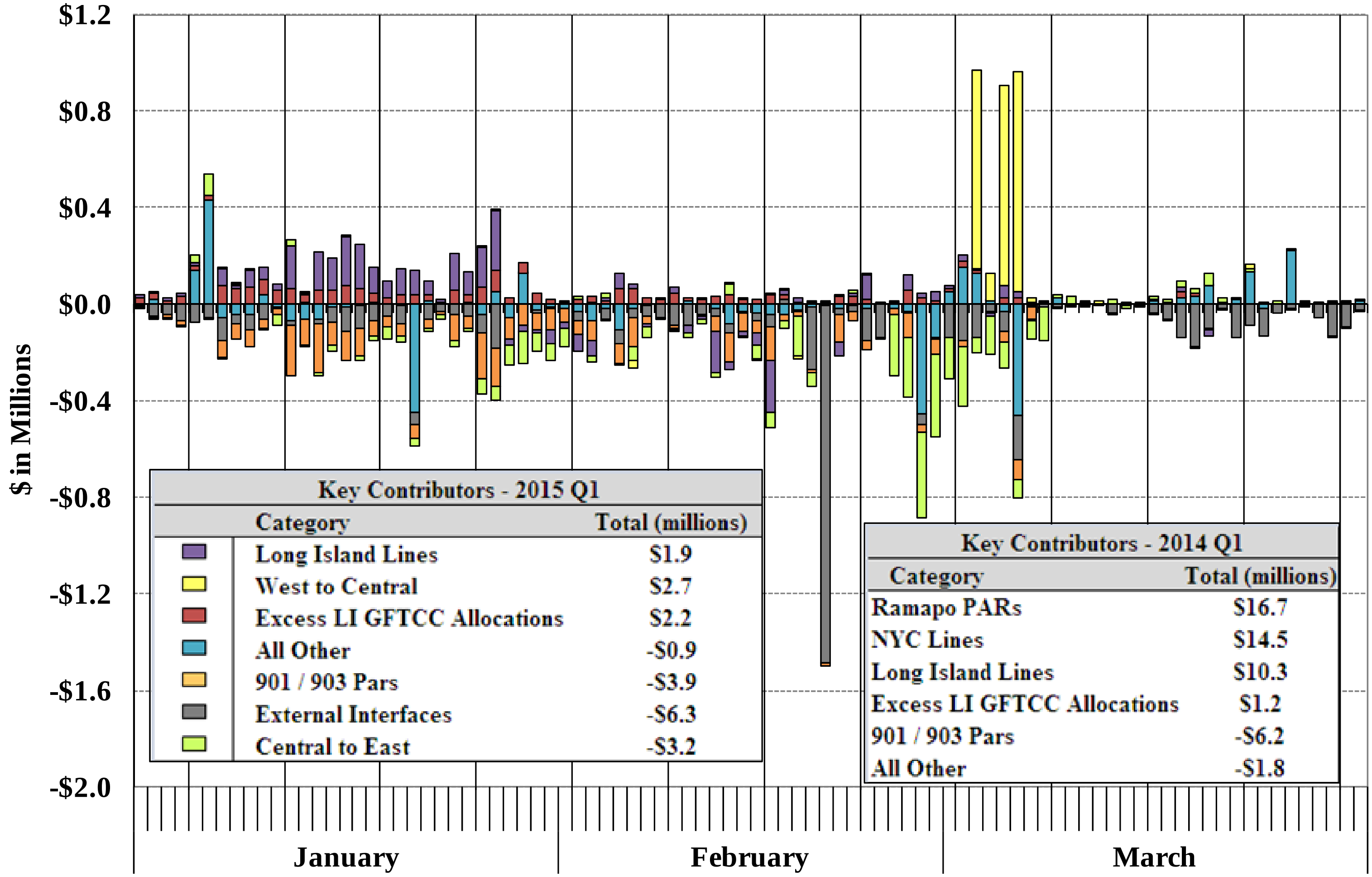
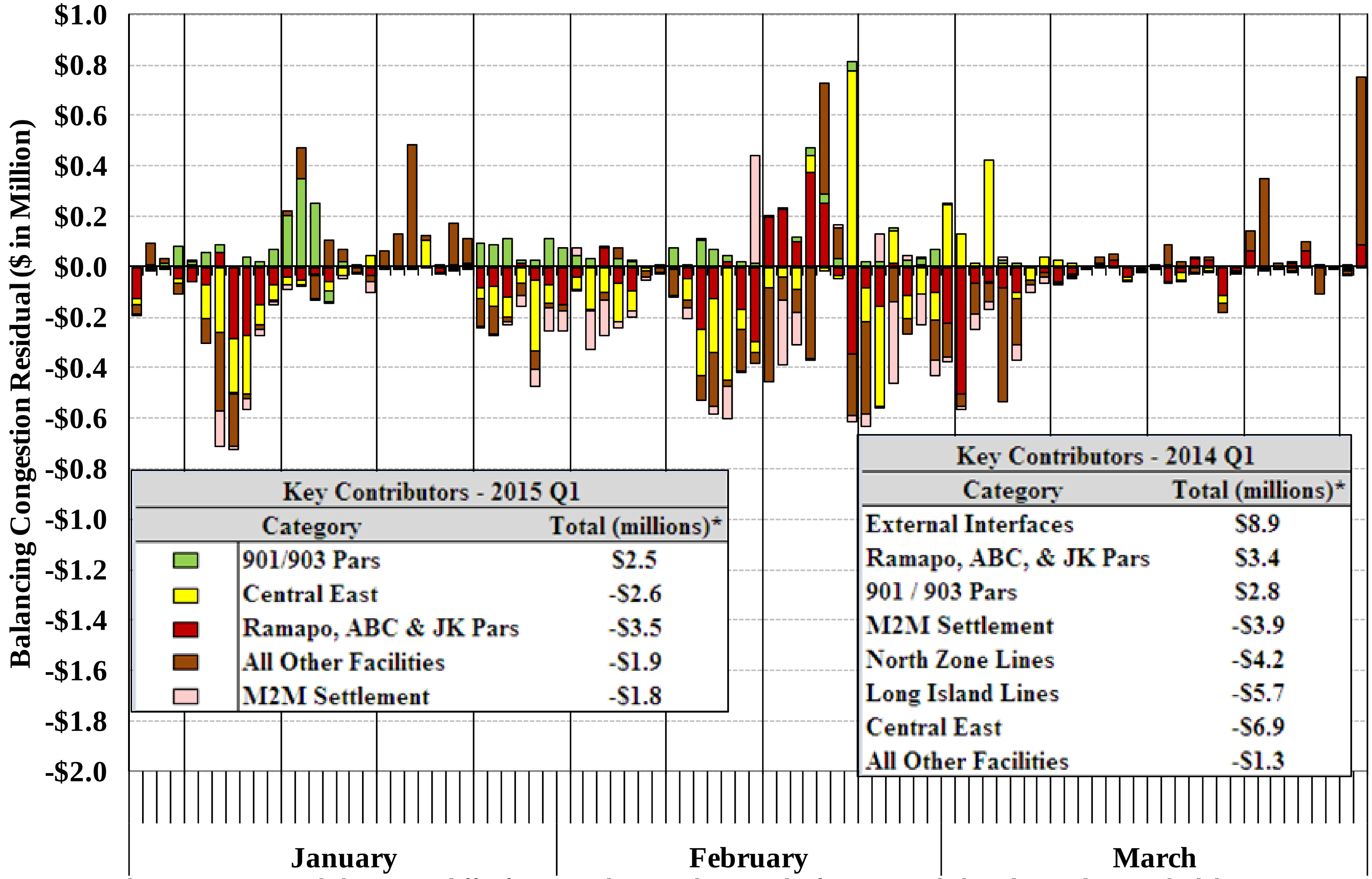
Day-Ahead Congestion Revenue Shortfalls by Transmission Facility



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

Balancing Congestion Shortfalls by Transmission Facility



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 first quarter of 2015).
    - 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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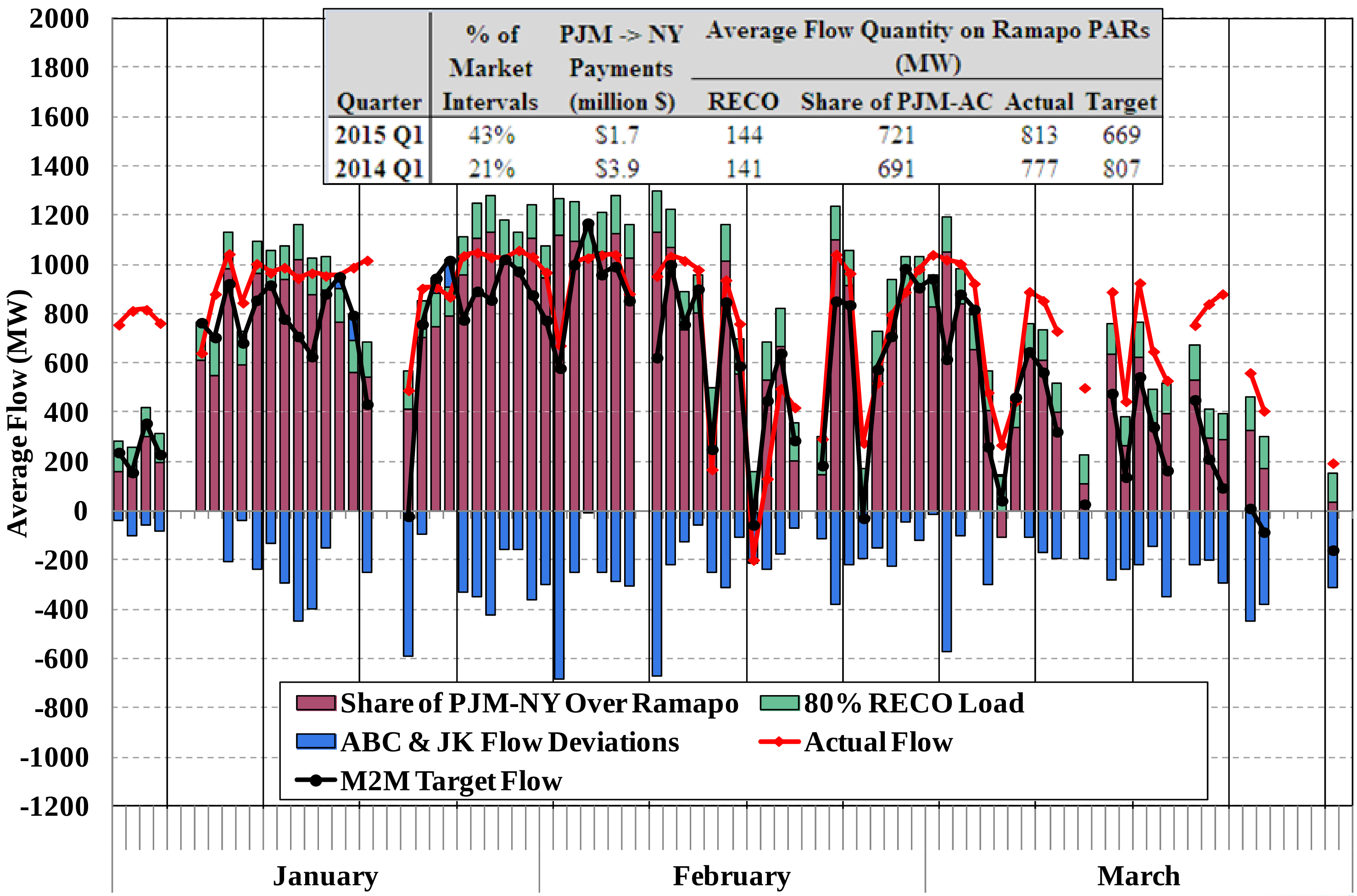
Operations under M2M with PJM

- The use of Re-dispatch Coordination continued to be infrequent.
  - ✓ It was activated for the Central-East interface in a total of 129 hours and the Dysinger East interface for a total of 24 hours.
  - ✓ These resulted in a total payment of roughly $136k from PJM to NY.
- Active Ramapo Coordination (i.e., when M2M constraints were binding) occurred in 43 percent of intervals this quarter, up from 21 percent in the prior year.
  - ✓ Congestion across the Central-East interface was more frequent than a year ago, resulting in more frequent Ramapo Coordination.
  - ✓ Both Ramapo PARs were out of service for more than two weeks in mid-February 2014, contributing to less frequent coordination last year.
- Average actual flows across Ramapo exceeded the M2M Target Flow by more than 140 MW in this quarter (when M2M constraints were binding).
  - ✓ The additional flow above the Target helped the NYISO relieve congestion on M2M Flowgates. They also reduced M2M payments from PJM from $4 million in the first quarter of 2014 to less than $2 million this quarter.
- Although Ramapo PAR Coordination provided congestion relief on key paths from West to East (e.g., the Central-East interface), there were times when additional flows across Ramapo contributed to congestion in the West Zone.

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
2015 Q1	43%	$1.7	144	721	813	669
2014 Q1	21%	$3.9	141	691	777	807

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 455 MW of capacity was committed for reliability in the first quarter of 2015, down 54 percent from the first quarter of 2014.
  - ✓ Of the capacity committed for reliability in the first quarter, 61 percent was in New York City, 38 percent was in Western NY, and only 1 percent was in Long Island.
- Reliability commitments rarely occurred in Long Island this quarter.
  - ✓ DARU commitments became less frequent after the installation of the West Bus DRSS and Wildwood DRSS in early 2014, which reduced the need to:
    - – Commit generation for voltage constraints on Long Island (see ARR 28); and
    - – Burn oil to protect Long Island from a loss of gas (see IR-5).
- Reliability commitments in Western NY averaged 170 MW in this quarter, up 22 percent from the first quarter of 2014.
  - ✓ DARU commitments increased because several coal units that were often needed for local reliability became less economic as a result of lower gas prices.
  - ✓ However, SRE commitments fell from the previous year because of transmission upgrades in the North Zone (which were completed in March 2014) that reduced the need to commit generation to maintain reliability.

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

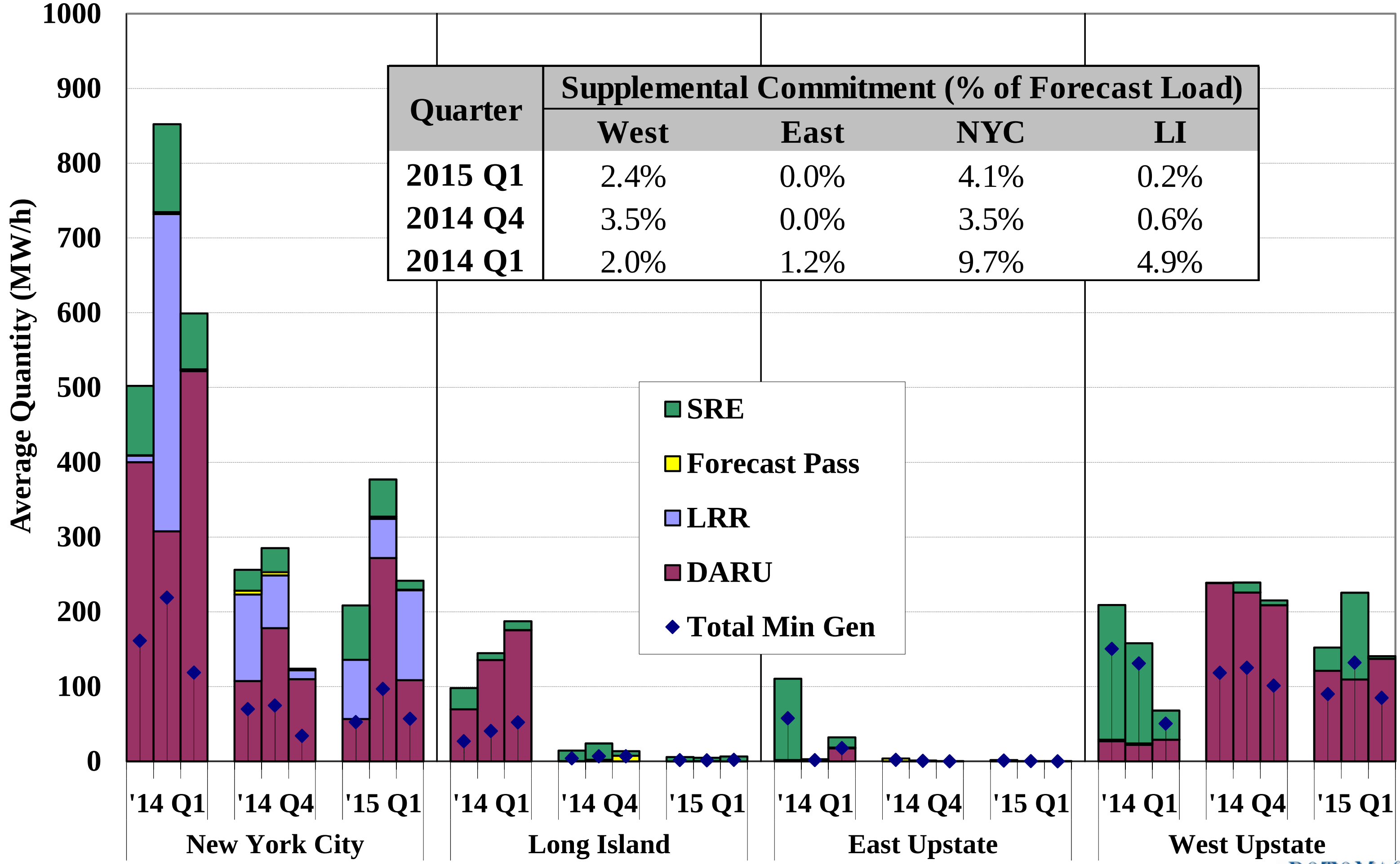
- In New York City, reliability commitment averaged 275 MW in this quarter, down 58 percent from the first quarter of 2014.
  - ✓ Variations in the amount of capacity committed for reliability was primarily driven by transmission and generation outages in NYC.
    - Reliability commitments were elevated in the first quarter of 2014 in the Freshkills load pocket on Staten Island because of multiple transmission outages that were related to transmission work at the Goethals Bus.
    - Fewer transmission outages led to fewer DARU commitments this quarter.
    - Reliability commitment for voltage needs increased modestly from the previous year in the Astoria West/Queensbridge/Vernon load pocket partly because of more generation outages in the first quarter of 2015.
- Supplemental commitment for contingencies associated with a loss of gas in New York City increased in the first quarter of 2015.
  - ✓ February 2015 was the coldest month in recent years.
  - ✓ Several units with dual-fuel capability were committed on several extreme cold days in mid to late February for possible gas interruptions.

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 1,143 station-hours, up 77 percent from the first quarter of 2014.
  - ✓ Of the total OOM station-hours, Western NY accounted for 50 percent, Long Island accounted for 33 percent, and New York City account for 12 percent.
- OOM dispatch in Western NY rose notably from the first quarter of 2014.
  - ✓ The Dunkirk unit was frequently OOMed by the local TO in March to manage congestion on 115 kV facilities—primarily the Gardenville-to-Dunkirk 115kV line.
- OOM dispatch in Long Island rose roughly 43 percent from a year ago.
  - ✓ The Barrett and Far Rockaway stations were OOMed to manage East Garden City-to-Valley Stream 138kV congestion involving a split ring bus contingency (which cannot be modeled accurately with the existing market model).

Supplemental Commitment for Reliability
by Category and Region

Quarter	Supplemental Commitment (% of Forecast Load)			
	West	East	NYC	LI
2015 Q1	2.4%	0.0%	4.1%	0.2%
2014 Q4	3.5%	0.0%	3.5%	0.6%
2014 Q1	2.0%	1.2%	9.7%	4.9%



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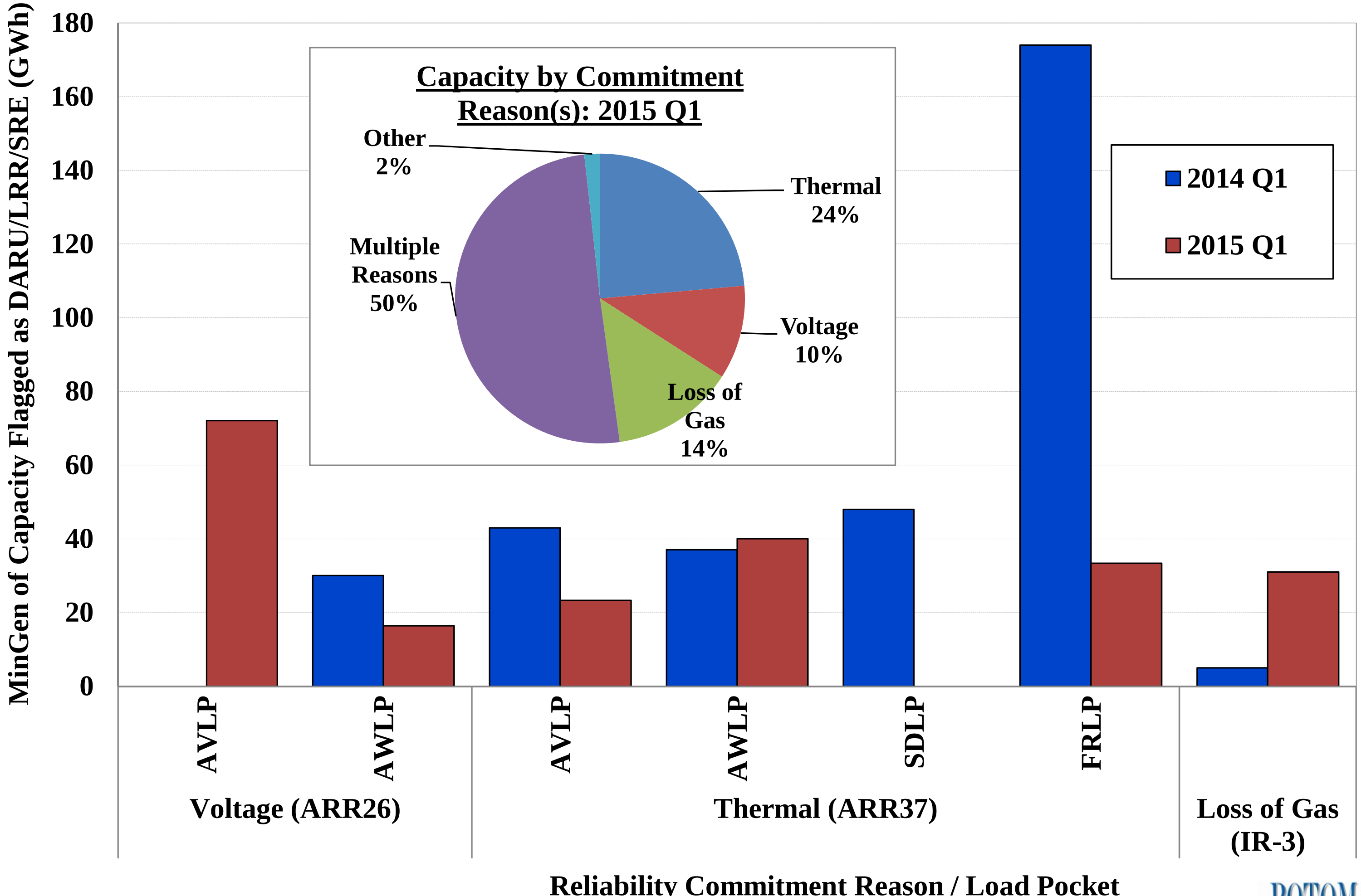
Supplemental Commitment for Reliability in NYC by Reliability Reason and Load Pocket



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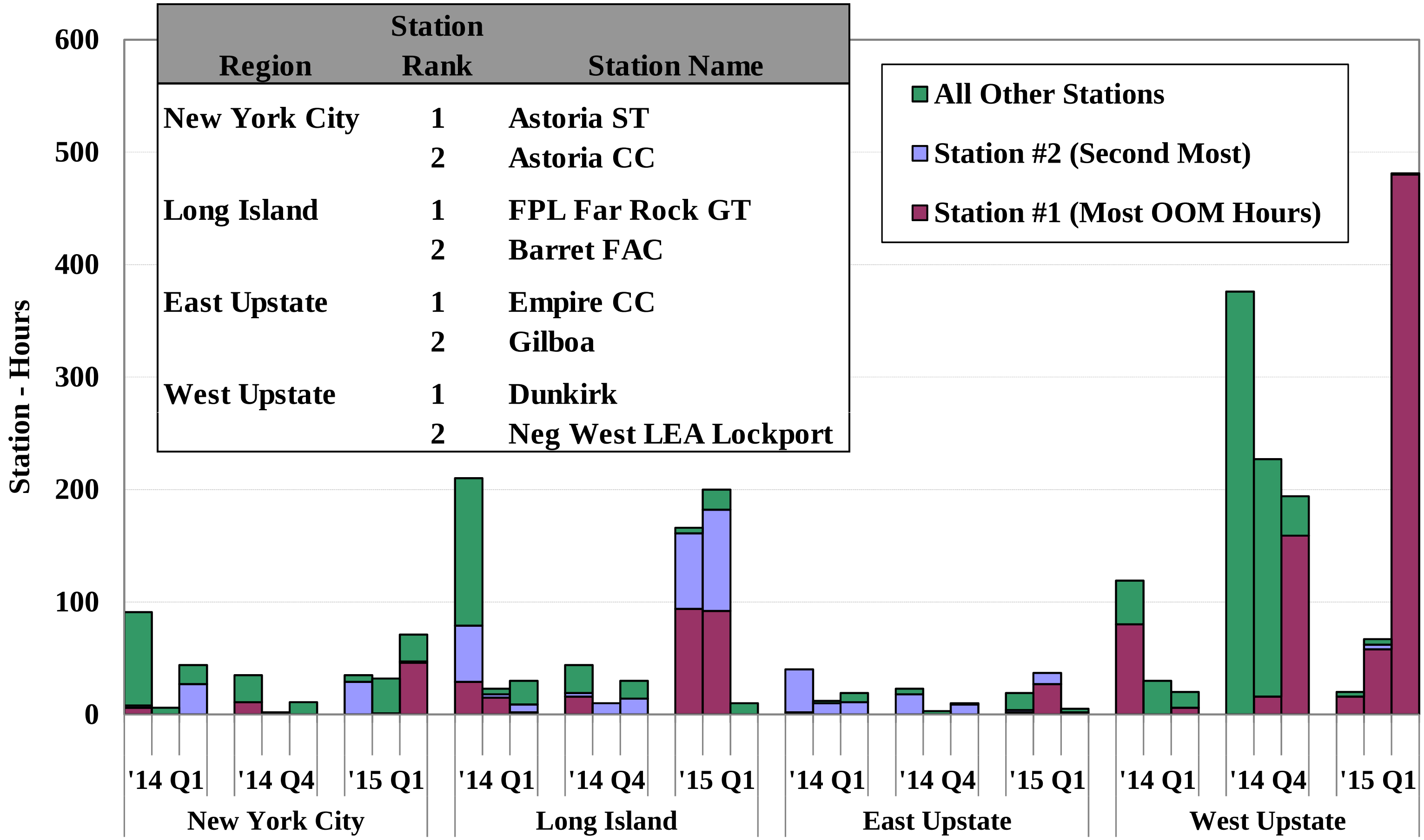
Frequency of Out-of-Merit Dispatch by Region by Month



Region	Station Rank	Station Name
New York City	1	Astoria ST
	2	Astoria CC
Long Island	1	FPL Far Rock GT
	2	Barret FAC
East Upstate	1	Empire CC
	2	Gilboa
West Upstate	1	Dunkirk
	2	Neg West LEA Lockport

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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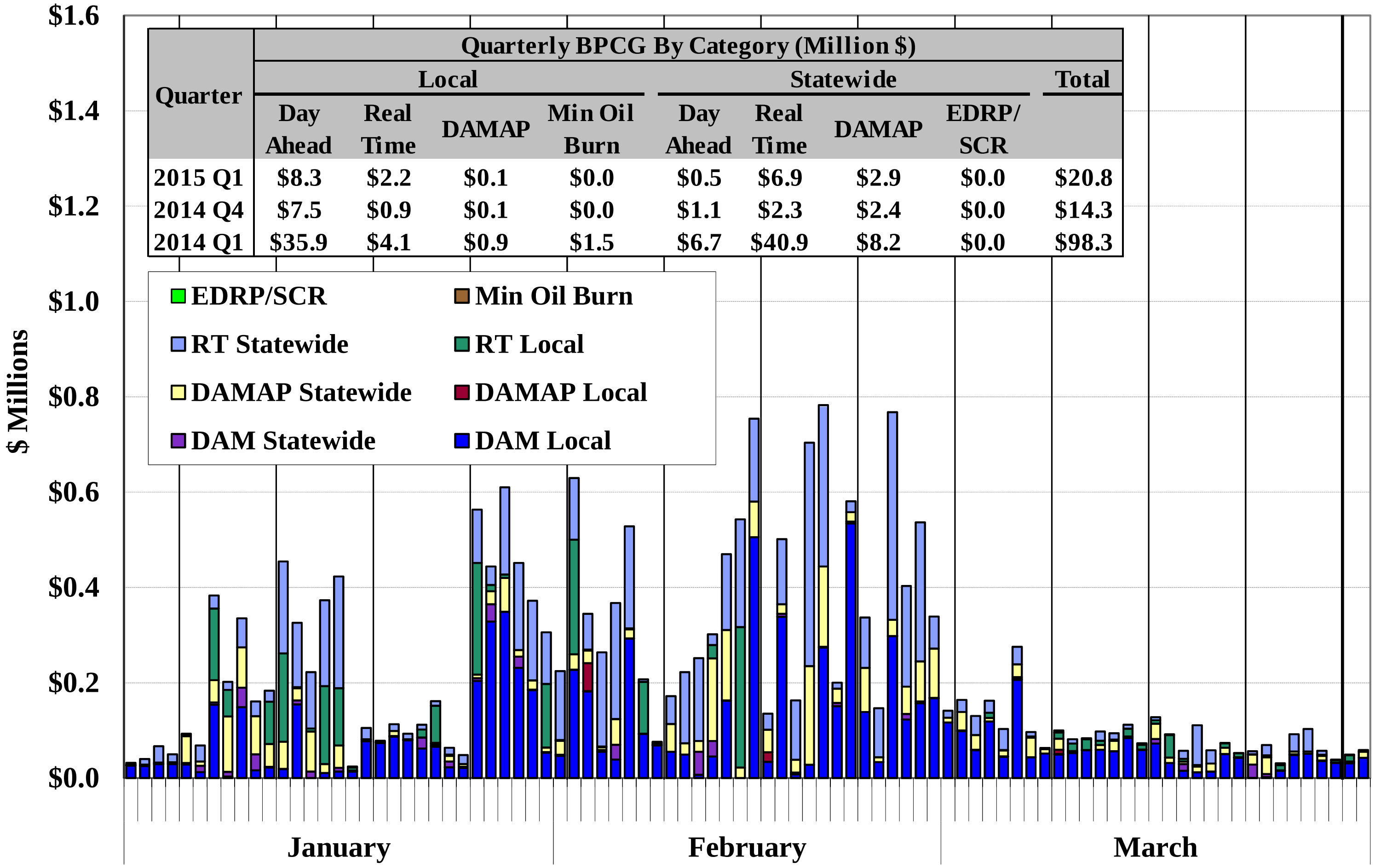
Uplift Costs from Guarantee Payments: Chart Descriptions

- 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 (before April 2014) 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 $21 million this quarter, down 79 percent from the first quarter of 2014. The reduction was consistent with:
  - ✓ Decreased supplemental commitment in NYC and LI (as discussed earlier); and
  - ✓ Lower natural gas prices, which decreased the commitment costs of gas-fired units.
- Of the total guarantee payment uplift in the first quarter of 2015:
  - ✓ Local reliability uplift accounted for 51 percent, and non-local uplift accounted for the remaining 49 percent.
  - ✓ NYC accounted for 38 percent, Western NY accounted for 37 percent, and Long Island accounted 19 percent.
- DAM local uplift fell 77 percent from the first quarter of 2014 primarily because of reduced DARU commitment in Long Island and NYC.
  - ✓ However, this was partly offset by increased local uplift in Western NY from increased DARU commitments.
- RT statewide uplift fell 83 percent from a year ago, primarily because of the transmission upgrades in the North Zone.
- Min Oil Burn uplift was virtually eliminated in the first quarter of 2015 because of increased reliance on auto-switchable CCs rather than steam turbines running on a blend of oil and gas (on days when gas prices were lower than oil prices).

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	
2015 Q1	$8.3	$2.2	$0.1	$0.0	$0.5	$6.9	$2.9	$0.0	$20.8
2014 Q4	$7.5	$0.9	$0.1	$0.0	$1.1	$2.3	$2.4	$0.0	$14.3
2014 Q1	$35.9	$4.1	$0.9	$1.5	$6.7	$40.9	$8.2	$0.0	$98.3

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.

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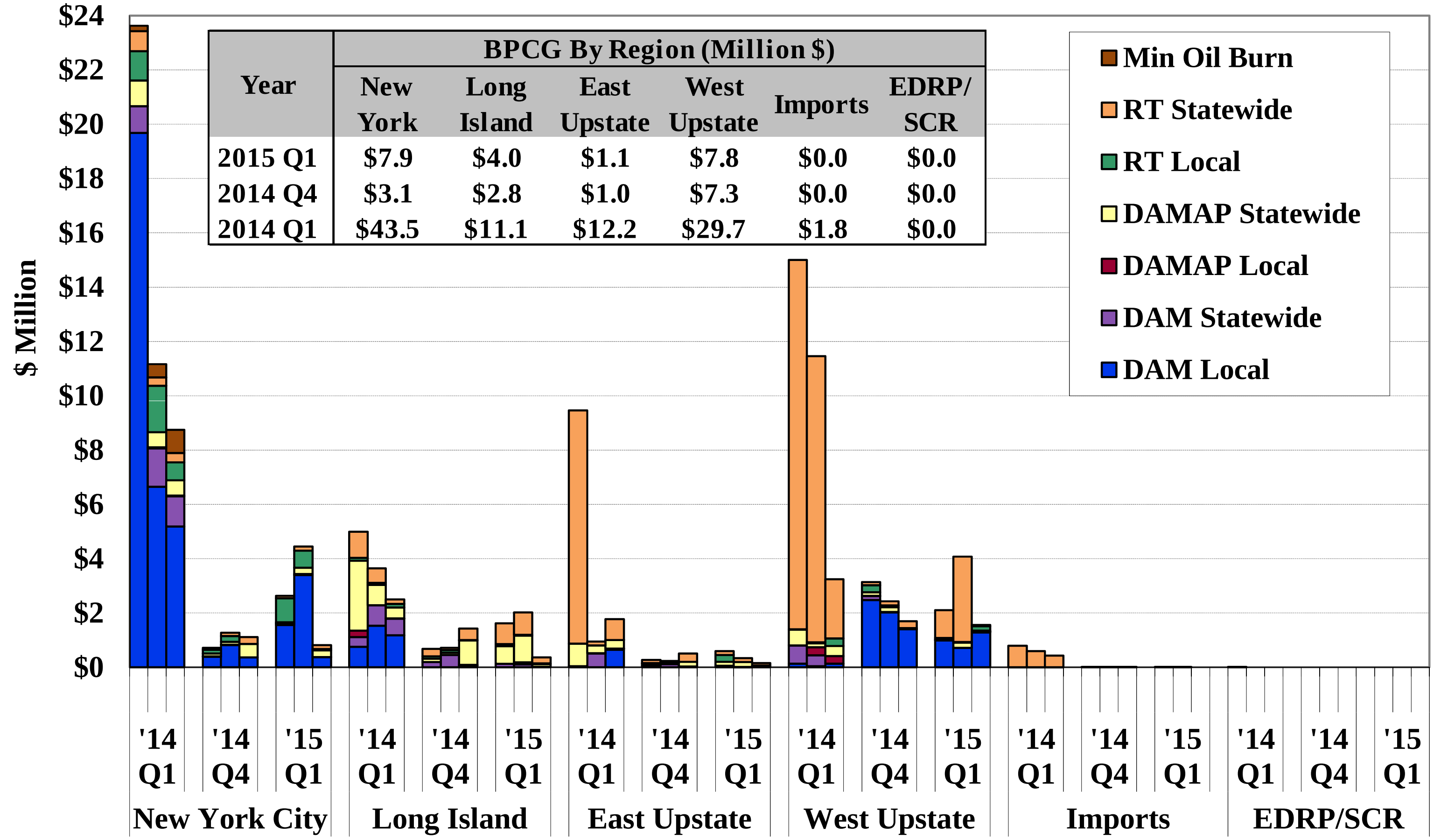
Uplift Costs from Guarantee Payments
By Category and Region



Year	BPCG By Region (Million $)					
	New York	Long Island	East Upstate	West Upstate	Imports	EDRP/ SCR
2015 Q1	$7.9	$4.0	$1.1	$7.8	$0.0	$0.0
2014 Q4	$3.1	$2.8	$1.0	$7.3	$0.0	$0.0
2014 Q1	$43.5	$11.1	$12.2	$29.7	$1.8	$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.

Market Power and Mitigation

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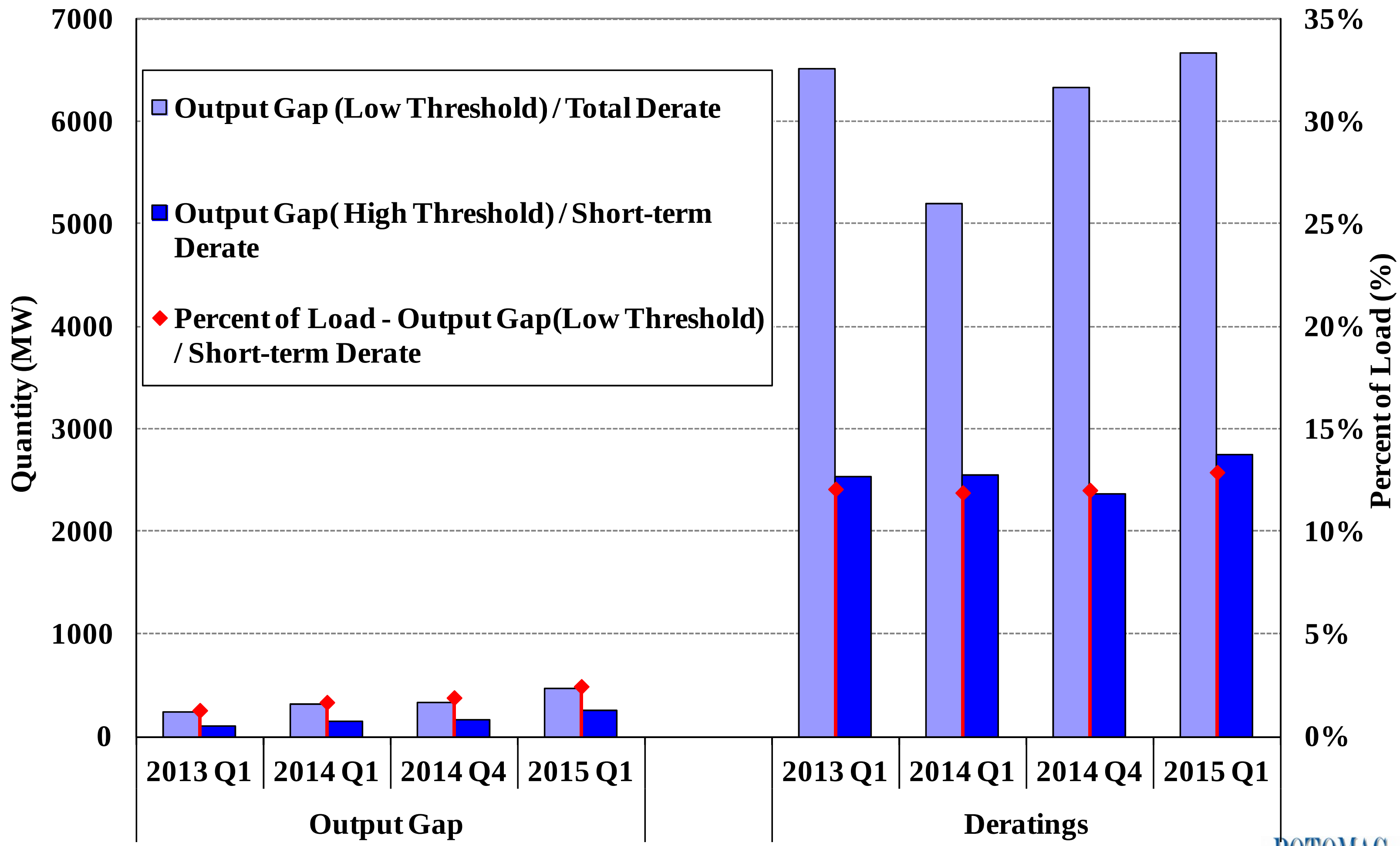
Market Power Screens: Economic Withholding

- 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 this quarter.
  - ✓ The output gap averaged slightly more than 2 percent of load at the low threshold, up modestly from the same quarter in prior years.
  - ✓ However, the output gap did not raise significant market power concerns because most of the output gap occurred on units that are:
    - – Co-generation resources, most of which operate in a relatively inflexible manner because of the need to divert energy production to non-electric uses; and/or
    - – Owned by suppliers with small portfolios, which generally do not have an incentive to withhold supply.

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 were significant, but physical withholding concerns are limited because most deratings are long-term and unlikely to reflect withoholding.
- The amount of deratings rose modestly from the first quarter of 2014.
  - ✓ A large unit in New York City was forced out of service because of equipment issues, accounting for a large portion of the increase in the long-term deratings.
  - ✓ Short-term deratings rose moderately in Long Island and the Capital Zone.
    - – Units at several plants were scheduled for weeks-long maintenance outages during the winter season.
    - – Although such outages are unlikely to reflect withholding, they may still be inefficient. Thus, a generator may be economic for a significant portion of its planned outage.

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 day-ahead market, since that is where most supply is scheduled.
  - ✓ In the first quarter of 2015, 88 percent of mitigation occurred in the day-ahead market primarily for:
    - – Local reliability (i.e., DARU & LRR) units (62 percent); and
    - – The Astoria West Queensbridge/Vernon load pocket (32 percent).
- Both the frequency and quantity of mitigation fell significantly from the first quarter of 2014, due largely to fewer reliability commitments (see slide 68) and less frequent congestion in New York City (see slides 55-56) this quarter.

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Automated Market Mitigation

Quarterly Mitigation Summary

		2013 Q1	2014 Q1	2014 Q4	2015 Q1
Day-Ahead Market	**Average Mitigated MW**	165	197	52	74
	Energy Mitigation Frequency	30%	7%	0.05%	3%
Real-Time Market	**Average Mitigated MW**	44	30	0.1	10
	Energy Mitigation Frequency	8%	4%	0.05%	1%

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.
- In NYC, UCAP spot prices averaged $8.34/kW-month this quarter, down 13 percent from the first quarter of 2014 because:
  - ✓ The demand curve was reduced by 8 percent as the demand curve proxy unit technology was changed from an LMS 100 CT to a Frame 7 (F Class) CT;
  - ✓ Internal capacity supply rose roughly 155 MW in NYC primarily because of a change in the ambient temperature conditions assumed for adjusting the generator DMNC test results; and
  - ✓ An additional 170 MW of capacity supply was added in March 2015 when the Astoria Unit 20 returned to service.
  - ✓ However, these factors were offset by an increase of 138 MW in the ICAP requirement (or 1.4 percent) because of a nearly 300 MW increase in the forecasted peak load (which was partly offset by a decrease in the LCR from 86 percent to 85 percent).

Capacity Market Results

- The Long Island UCAP spot prices averaged $3.14/kW-month this quarter, down 20 percent from the first quarter of 2014.
  - ✓ The UCAP demand curve was reduced by 22 percent as the demand curve proxy unit technology was changed from an LMS 100 CT to a Frame 7 CT.
  - ✓ 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.
- In the G-J Locality, UCAP spot prices averaged $3.63/kW-month this quarter, down 7 percent from the first quarter of 2014 (based on the ROS spot prices).
  - ✓ The supply of internal capacity has risen by 800 MW from a year ago.
    - In the Hudson Valley, internal capacity supply rose by 480 MW as four units at the Danskammer plant were returned to service from October 2014 to January 2015.
    - In NYC, internal capacity supply rose by 155 MW in January and February and by 325 MW in March (due to reasons discussed earlier).
  - ✓ However, the increase in supply was offset by the modeling of the G-J Locality as a separate capacity zone starting in May 2014, which led to higher spot prices than the ROS prices.
- There was virtually no unsold capacity in the G-J Locality, New York City, and Long Island.

Capacity Market Results

- Rest-of-State UCAP spot prices averaged $2.16/kW-month this quarter, down 45 percent from the first quarter of 2014.
  - ✓ The substantial reduction was due largely to the increase in internal capacity supply from a year ago, which rose:
    - 480 MW in the Hudson Valley Zone as four Danskammer units returned to service.
    - 155 to 325 MW in NYC (due to reasons discussed earlier).
    - More than 100 MW in Western NY as a result of the return-to-service of the Binghamton co-gen unit in January 2015 and additions of new wind capacity.
  - ✓ In addition, sales from external resources increased roughly 450 MW on average, primarily from Hydro Quebec.
  - ✓ The demand curve was reduced by 4 percent from a year ago.
  - ✓ However, these were partly offset by an increase in the NYCA ICAP requirement, which rose 453 MW (more than 1 percent) from the 2013/14 Capability Year due to a 387 MW increase in forecasted peak load.

Capacity Market Results: First Quarter 2014 & 2015

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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