Quarterly Report on the New York ISO Electricity Markets Second Quarter of 2016

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August 2016

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Highlights and Market Summary: Energy Market

- This report summarizes market outcomes in the second quarter of 2016.
- The energy markets performed competitively and variations in wholesale prices were driven primarily by changes in fuel prices, demand, and supply availability.
- Average all-in prices ranged from $23/MWh in the North Zone to $56/MWh in NYC, down 4 to 23 percent in most regions from a year ago. (see slide 9)
  - ✓ Capacity costs fell 9 to 21 percent in SENY zones but rose 8 percent elsewhere, which offset the reduction in LBMPs mentioned below in these regions.
- RT LBMPs fell 3 percent in the Capital Zone, 40 percent in the North Zone, and 8 to 17 percent in other areas.
  - ✓ The primary driver was lower natural gas prices, which fell 31 percent in NYC and 17 percent in Long Island, resulting largely from increasing production from Marcellus and Utica shales. (see slide 12)
  - ✓ Average load fell only 0.5 percent but peak load fell 7 percent. (see slide 11)
  - ✓ Hydro generation (see slide 15) and net imports from neighboring areas (see slide 39) rose by 550 MW combined, contributing to lower LBMPs as well.
  - ✓ However, these factors were partly offset by lower nuclear generation, which fell by over 1 GW because of lengthy maintenance outages. (see slide 15)

Highlights and Market Summary: Congestion Patterns

- DAM congestion revenues totaled $94 million (see slides 45-53), up 30 percent from the second quarter of 2015.
  - ✓ Lower natural gas prices and reduced load levels resulted in decreased congestion levels in most areas during the second quarter of 2016.
  - ✓ However, transmission outages reduced transfer capability and led to increased congestion in the following areas:
    - Across the Central-East interface in most of April and May;
    - On the 230 kV system in the West Zone in April;
    - On the transmission paths from North to Central in April and May; and
    - On the transmission paths in LHV in May.
  - ✓ Lower nuclear generation in LHV and higher net exports to ISO-NE also contributed to increased congestion across the Central-East interface.
- Congestion-price differentials increased because of changes in the treatment of transmission shortages following implementation of the Graduated Transmission Demand Curve ("GTDC") project (see slides 65-69).
- In the second quarter of 2016, West Zone constraints accounted for the largest share of DA and RT congestion among all areas.

Highlights and Market Summary: West Zone Congestion

- The pattern of West Zone congestion affected by many significant market changes, including (but not limited to): (see slides 57-70)
  - ✓ (a) the implementation of GTDC in February 2016; (b) the retirements of coal units in December 2015 and in March 2016; (c) the implementation of a composite shift factor at Niagara plant in May 2016; (d) transmission upgrades in May 2016; and (e) the S. Ripley-Dunkirk 230 kV line and Warren-Falconer 115 kV line being taken OOS during most of 2016-Q2.
  - ✓ In addition, volatile loop flows continued to exacerbate congestion.
- These challenges increase the importance of efficient congestion management.
  - ✓ On 6/28, NYISO implemented enhanced loop flow assumptions that are designed to schedule resources more efficiently given uncertainty about loop flows.
  - ✓ Ultimately, efficient congestion management can reduce the need for transmission infrastructure investments. However, we continue to observe:
    - Under-utilization of 115kV circuits that are parallel to congested facilities,
    - Inefficiently-high generation from units that exacerbate 230kV congestion,
    - Under-commitment of West Zone units that relieve 115kV & 230kV congestion,
    - Shadow prices are not well correlated with the severity of congestion during transmission shortages, which undermines scheduling incentives for importers and other non-dispatchable resources.

Highlights and Market Summary: Capacity Market

- UCAP spot prices fell in the zones in SENY but rose elsewhere from the second quarter of 2015. UCAP prices: (see slides 91-93)
  - ✓ In New York City fell 22 percent to an average of \$10.12/kW-month;
  - ✓ In the G-J Locality fell 11 percent to an average of \$7.22/kW-month;
  - ✓ On Long Island fell 19 percent to an average of \$3.92/kW-month;
  - ✓ In Rest of State rose 11 percent to an average of \$3.58/kW-month.
- Average capacity spot prices fell in SENY primarily because:
  - ✓ The ICAP requirement fell 467 MW (4.7 percent) in NYC, 117 MW (2.0 percent) in Long Island, and 109 MW (0.7 percent) in the G-J Locality, because of:
    - (a) Lower LCRs due partly to the TOTS projects that increased import capability into SENY; and (b) lower peak load forecast.
  - ✓ An increase of roughly 300 MW of internal ICAP supply in the G-J Locality.
- Average capacity spot prices rose in the ROS primarily because of lower spot prices in May 2015 (which resulted from high sales from NE in this month).
  - ✓ However, spot prices were similar in April and June between 2015 and 2016.
    - The slightly lower ICAP requirement in 2016 Q2 (reflecting the combined effects of lower peak load forecast and a higher IRM) was offset by a similar decrease in total internal ICAP supply.

Highlights and Market Summary: Uplift and Revenue Shortfalls

- Guarantee payments were $11M, down 34% from 2015-Q2. (see slides 79-82)
  - ✓ Lower natural gas prices decreased the commitment costs of gas-fired units; and
  - ✓ Supplemental commitments and OOM dispatches fell, attributable to lower load levels, transmission upgrades in Western NY, and NYC generation being more economic (relative to the rest of Eastern NY because of gas market conditions).
- DAM congestion shortfalls were $25M, up $19M from 2015-Q2. (see slides 48,52)
  - ✓ Transmission outages were the primary driver – over $17M of shortfalls were assigned to the responsible transmission owners.
  - ✓ The remaining shortfalls accrued primarily on the West Zone constraints, resulting largely from assumptions related to loop flows.
- Balancing congestion shortfalls were $8M, down $6M from 2015-Q2. (see 49,53)
  - ✓ Changes to the modeling of the 901/903 lines in late-April reduced shortfalls from RT congestion in the Valley Stream load pocket (relative to previous years).
  - ✓ The majority of shortfalls ($7M) accrued on the West Zone 230 kV facilities.
    - – $3M was attributable to the differences between DA assumptions and RT outcomes in: (a) the operation of Ramapo, ABC, & JK PARs ($1.6M); and (b) the distribution of output between 115 and 230 kV units at the Niagara plant ($1.3M).
    - – $4M resulted largely from assumptions related to loop flows.

Energy Market Outcomes

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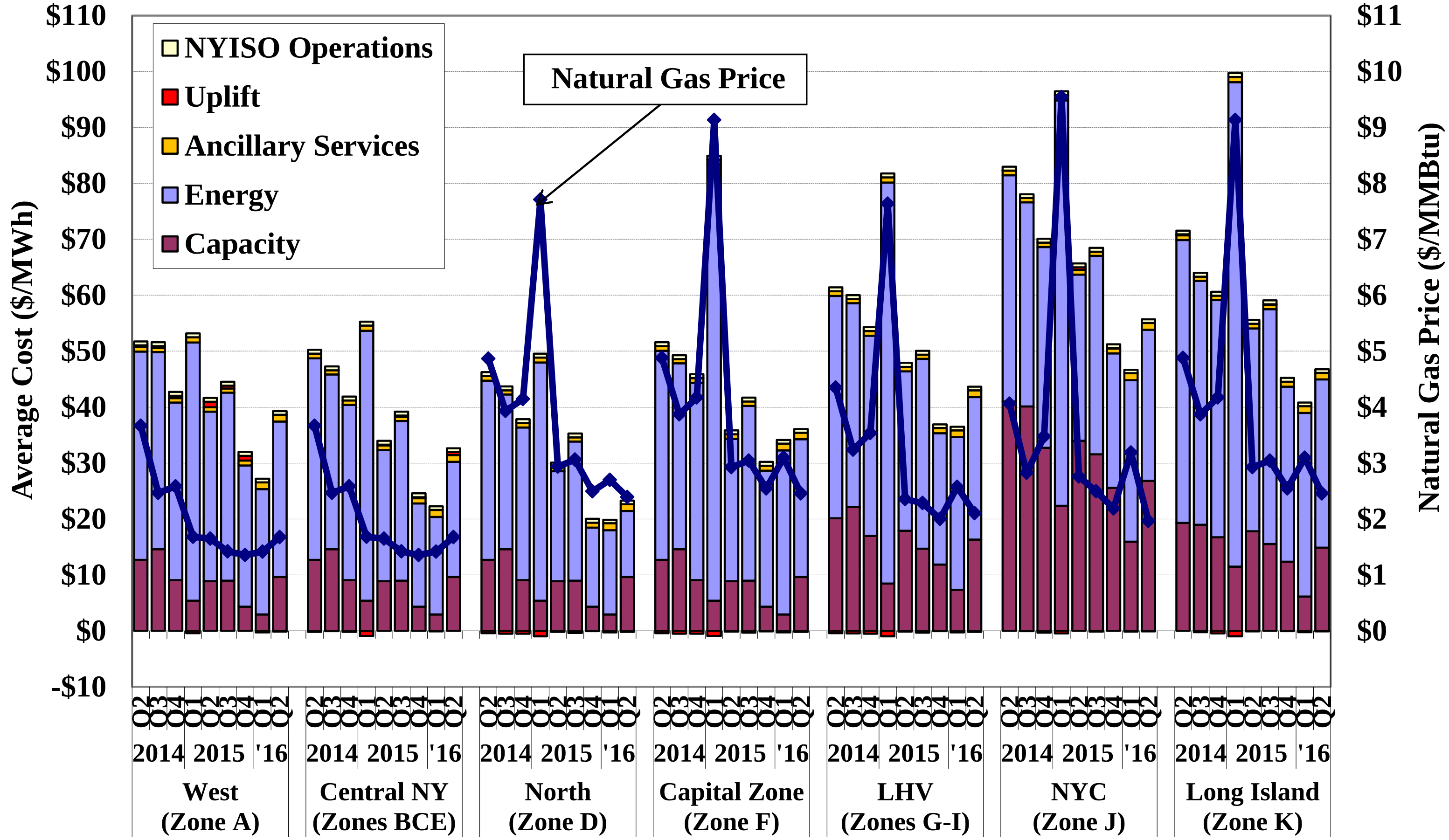
All-In Prices

- 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 roughly $23/MWh in the North Zone to $56/MWh in New York City this quarter, down significantly from a year ago in most regions.
  - ✓ LBMPs fell 3 percent in the Capital Zone, 40 percent in the North Zone, and 8 to 17 percent in other areas.
    - The reductions were due primarily to lower natural gas prices (see slide 12), which were, however, offset by significantly lower nuclear production (see slide 15).
    - LBMPs did not fall significantly in the Capital Zone because of increased congestion across the Central-East interface (see slide 51).
    - LBMPs fell most in the North Zone primarily because of extreme congestion for a total of 7 hours spread across 9 days in April and May (see slide 51).
  - ✓ Capacity costs fell 9 to 21% in SENY zones. (see slides 91-93)
    - In SENY, the reductions were driven primarily by lower ICAP requirements.
    - Increased internal ICAP supply was also a contributor for the G-J Locality.

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 Zone and Central NY, the Iroquois Waddington index for North Zone, the Iroquois Zone 2 index for Capital Zone and LI, the average of Texas Eastern M3 and Iroquois Zone 2 for LHV, the Transco Zone 6 (NY) index for NYC. A 6.9 percent tax rate is also included NYC.

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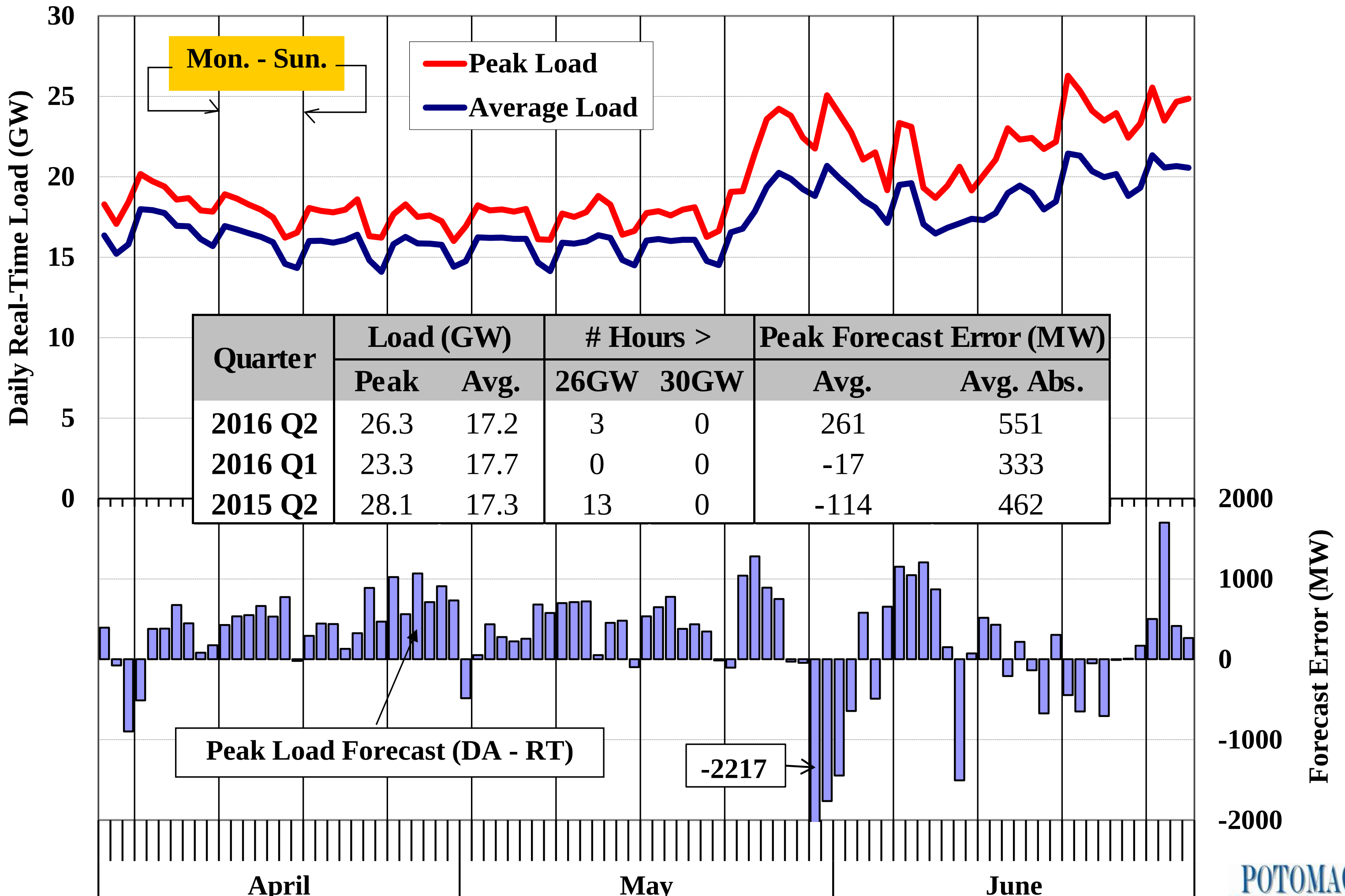
Load Levels and Fuel Prices

- 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.
- Average load (17.2 GW) for the quarter fell slightly (~0.5 percent) from a year ago.
  - ✓ However, average load rose 2 percent in June, offsetting the reductions in April (1 percent) and May (3 percent).
  - ✓ The peak load level was 7 percent lower than last year, which had hotter weather on several days in the month of June.
- Average natural gas prices fell notably from a year ago in most of East NY (e.g., 31 percent in NYC and 17 percent in Long Island) but were little changed in other regions. Compared to the second quarter of 2015:
  - ✓ Average gas spreads between New England and East NY increased, which contributed to higher exports to New England. (see slide 39)
  - ✓ Average gas spreads between East NY and West NY fell, which led to lower re-dispatch costs to manage congestion across the Central-East interface.
  - ✓ Although average coal prices (not including transportation charges) fell 19 percent, coal-fired generation was still uneconomic during most of the period.

Load Forecast and Actual Load



Quarter	Load (GW)		# Hours >		Peak Forecast Error (MW)	
	Peak	Avg.	26GW	30GW	Avg.	Avg. Abs.
2016 Q2	26.3	17.2	3	0	261	551
2016 Q1	23.3	17.7	0	0	-17	333
2015 Q2	28.1	17.3	13	0	-114	462

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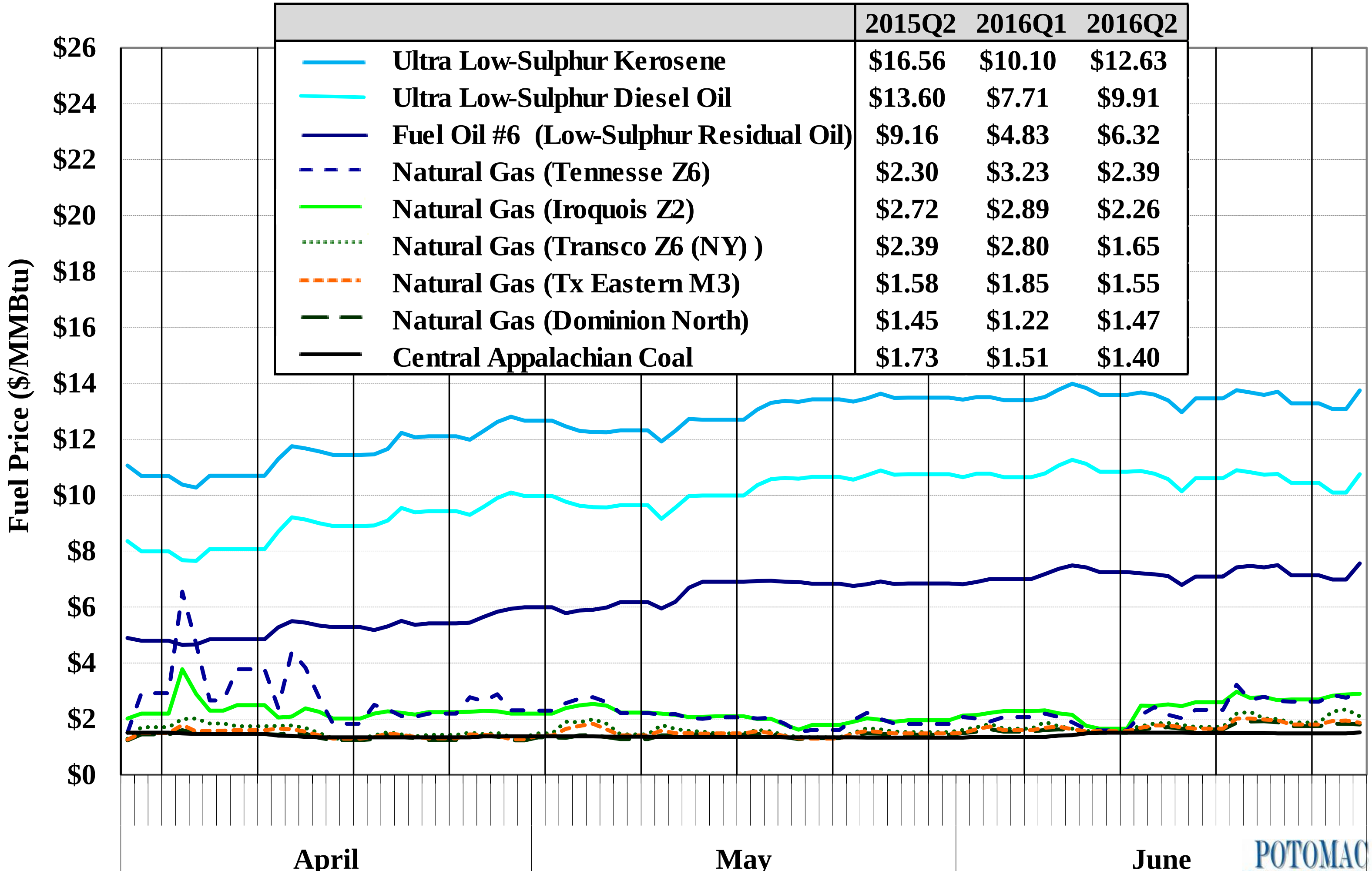
Coal, Natural Gas, and Fuel Oil Prices



	2015Q2	2016Q1	2016Q2
Ultra Low-Sulphur Kerosene	$16.56	$10.10	$12.63
Ultra Low-Sulphur Diesel Oil	$13.60	$7.71	$9.91
Fuel Oil #6 (Low-Sulphur Residual Oil)	$9.16	$4.83	$6.32
Natural Gas (Tennesse Z6)	$2.30	$3.23	$2.39
Natural Gas (Iroquois Z2)	$2.72	$2.89	$2.26
Natural Gas (Transco Z6 (NY))	$2.39	$2.80	$1.65
Natural Gas (Tx Eastern M3)	$1.58	$1.85	$1.55
Natural Gas (Dominion North)	$1.45	$1.22	$1.47
Central Appalachian Coal	$1.73	$1.51	$1.40

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Real-Time Generation by Fuel Type

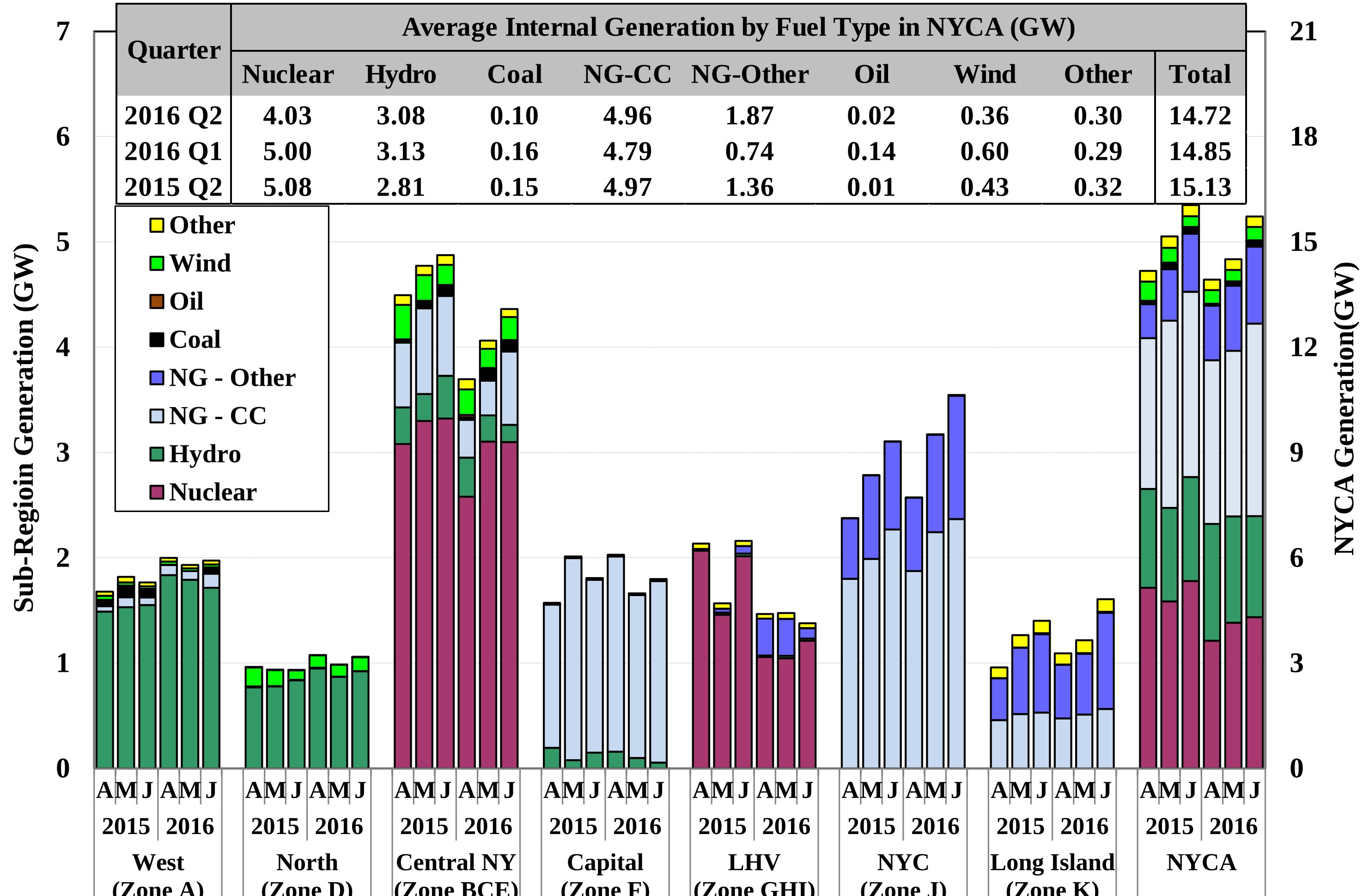
- The following two figures summarize fuel usage by generators in NYCA and their impact on LBMPs in the second quarter of 2016.
- The first figure shows the quantities of real-time generation by fuel type in the NYCA and in each region of New York.
- The second figure summarizes how frequently each fuel 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 (46 percent), nuclear (27 percent), and hydro (21 percent) generation accounted for most of the internal generation in the second quarter of 2016.
  - ✓ Average nuclear generation fell by more than 1 GW from the second quarter of 2015 because of more generation outages.
    - Two units in the Central Zone and Lower Hudson Valley were out of service for months-long maintenance during the quarter.
  - ✓ Average hydro generation rose 270 MW (primarily in the West Zone) from a year ago, partly offsetting the reduction in nuclear generation.
  - ✓ Coal generation continued to fall, reflecting the retirements of several coal units in the West Zone since the second quarter of 2015.
  - ✓ Gas-fired generation rose in East NY (largely in response to reductions in nuclear production), mostly in Lower Hudson Valley and NYC where gas prices were lower than in other eastern regions.
- Gas-fired and hydro resources were on the margin the vast majority of time in the second quarter of 2016.
  - ✓ Most hydro units on the margin have storage capacity and offer based on the opportunity cost of foregone sales in other hours (i.e., when gas is marginal).
  - ✓ However, hydro units in the West Zone were on the margin less frequently in June, due partly to less frequent congestion on the 230 kV facilities.

Real-Time Generation Output by Fuel Type

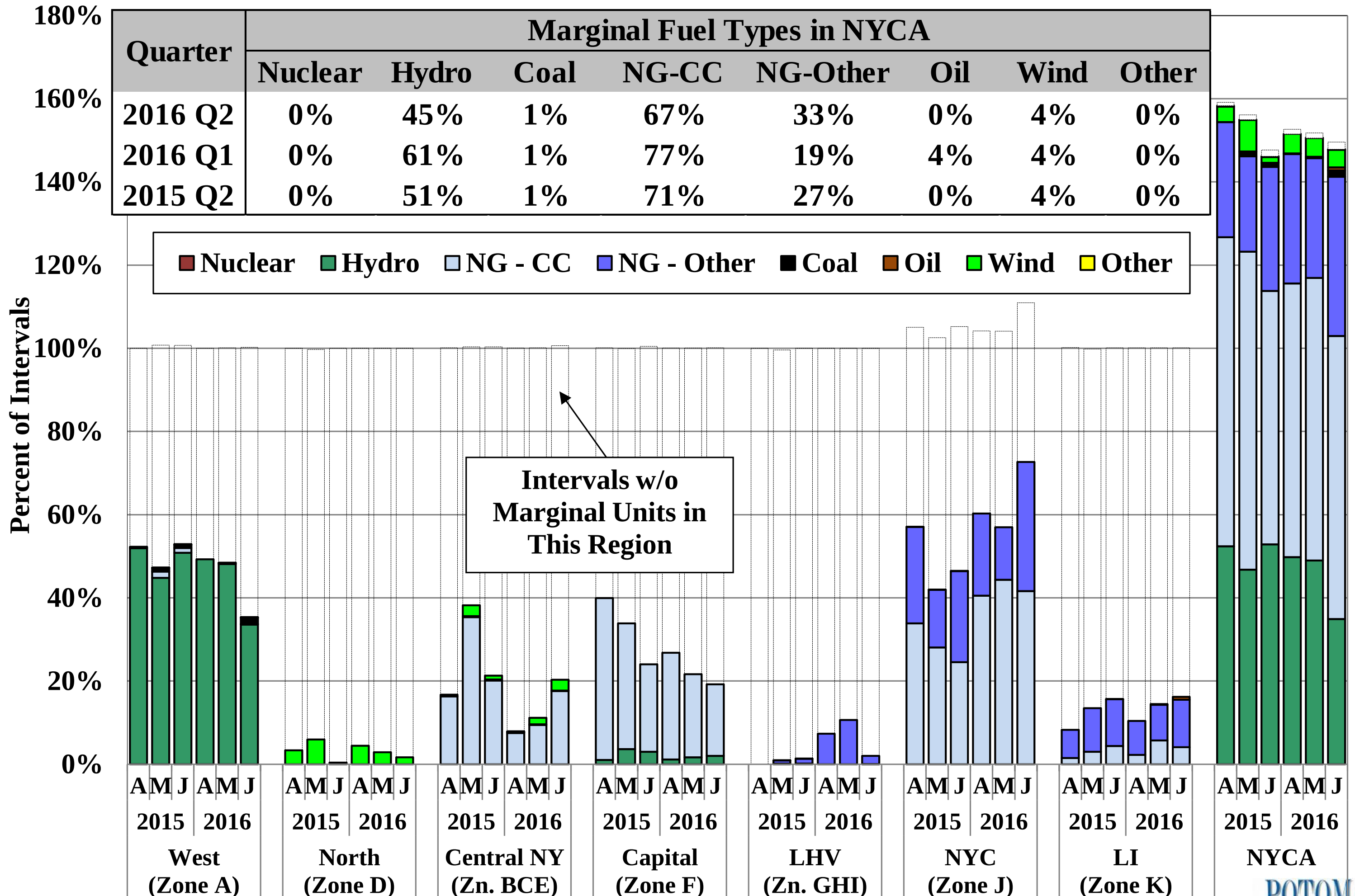
Quarter	Average Internal Generation by Fuel Type in NYCA (GW)								
	Nuclear	Hydro	Coal	NG-CC	NG-Other	Oil	Wind	Other	Total
2016 Q2	4.03	3.08	0.10	4.96	1.87	0.02	0.36	0.30	14.72
2016 Q1	5.00	3.13	0.16	4.79	0.74	0.14	0.60	0.29	14.85
2015 Q2	5.08	2.81	0.15	4.97	1.36	0.01	0.43	0.32	15.13



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

Fuel Types of Marginal Units in the Real-Time Market

Quarter	Marginal Fuel Types in NYCA							
	Nuclear	Hydro	Coal	NG-CC	NG-Other	Oil	Wind	Other
2016 Q2	0%	45%	1%	67%	33%	0%	4%	0%
2016 Q1	0%	61%	1%	77%	19%	4%	4%	0%
2015 Q2	0%	51%	1%	71%	27%	0%	4%	0%



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

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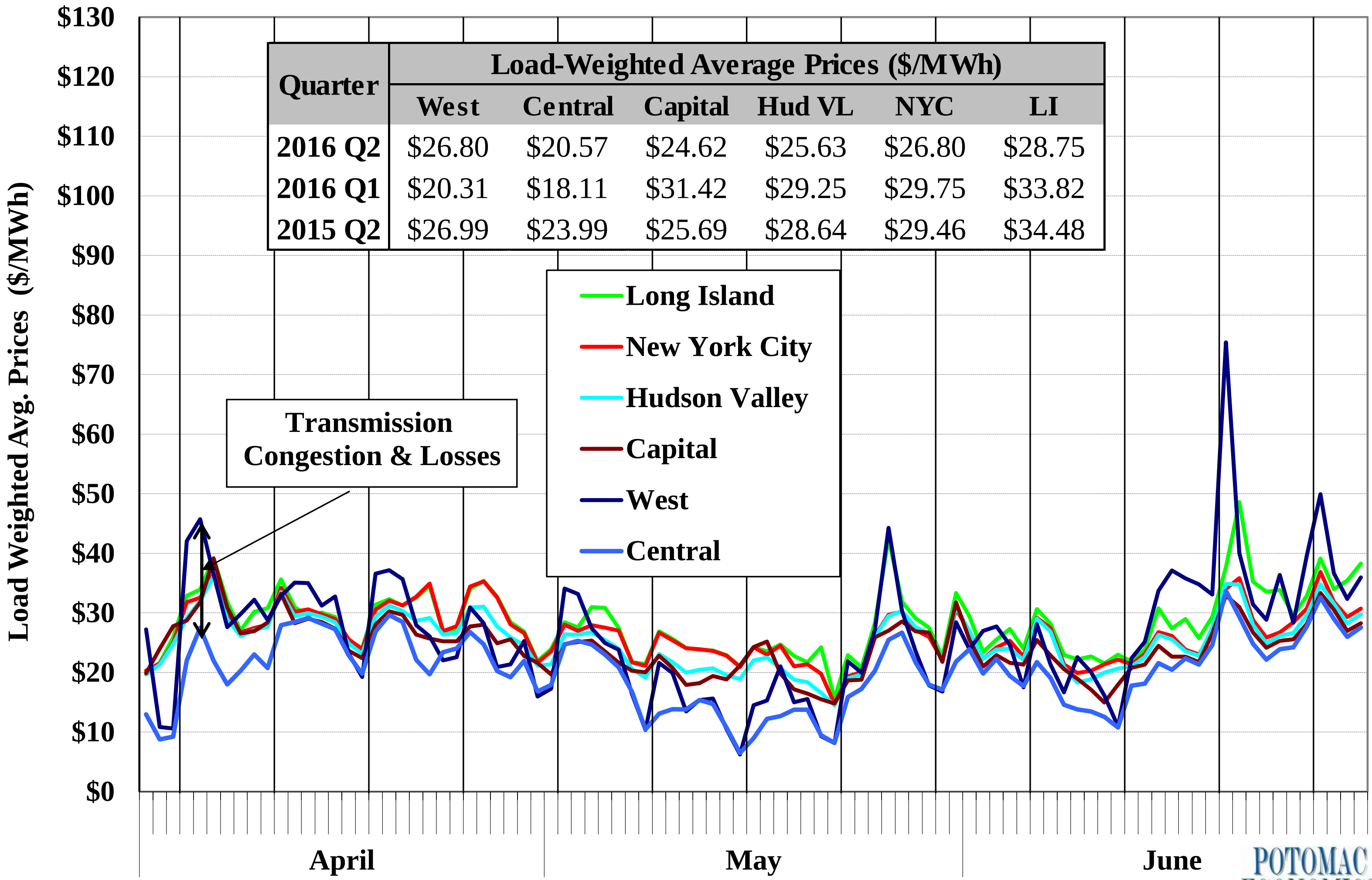
Day-Ahead and Real-Time Electricity Prices

- 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 six zones on a daily basis in the second quarter of 2016.
- Average day-ahead prices ranged from roughly $21/MWh in the Central Zone to $29/MWh on Long Island, down 1 to 17 percent from the second quarter of 2015.
  - ✓ The decreases were driven primarily by lower natural gas prices (see slide 12).
    - – Lower load levels for most of the quarter were also a contributor (see slide 11).
    - – However, the reductions were partly offset by significantly lower nuclear generation due to lengthy maintenance outages (see slide 15).
  - ✓ Long Island exhibited the largest (17 percent) reduction.
    - – In addition to lower loads and higher Neptune imports (see slide 39), changes to the modeling of the 901/903 lines in late-April also reduced the severity and volatility of RT congestion in the Valley Stream load pocket.
  - ✓ Unlike in other areas, LBMPs fell only modestly in the West Zone (1 percent) and the Capital Zone (4 percent).
    - – Congestion across the Central-East interface was more frequent, resulting in higher LBMPs in the Capital Zone during congested hours. (see slide 51)
    - – LBMPs in the West Zone were affected by congestion through the West Zone (which is discussed in more detail in slides 57-70).

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.
  - ✓ For example, from 5/30 to 6/2, LBMPs were elevated in real-time largely because actual load was higher than forecast by an average of 1.5GW due to unexpected hot weather on these days.
    - – Load was under-scheduled in the DAM (90 percent of RT load on average).
- Random and otherwise unforeseen 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 DA prices were generally within 1 to 2 percent of average RT prices in most areas this quarter.
    - – Although a small average DA premium was generally desirable in a competitive market, small RT premiums occurred in some areas because large RT spikes on a few days (due to unexpected RT events) outweighed small DA premiums on other days.
    - – The West Zone exhibited persistent RT premiums, although these have been reduced compared to previous quarters.

Day-Ahead Electricity Prices by Zone



Quarter	Load-Weighted Average Prices ($/MWh)					
	West	Central	Capital	Hud VL	NYC	LI
2016 Q2	$26.80	$20.57	$24.62	$25.63	$26.80	$28.75
2016 Q1	$20.31	$18.11	$31.42	$29.25	$29.75	$33.82
2015 Q2	$26.99	$23.99	$25.69	$28.64	$29.46	$34.48

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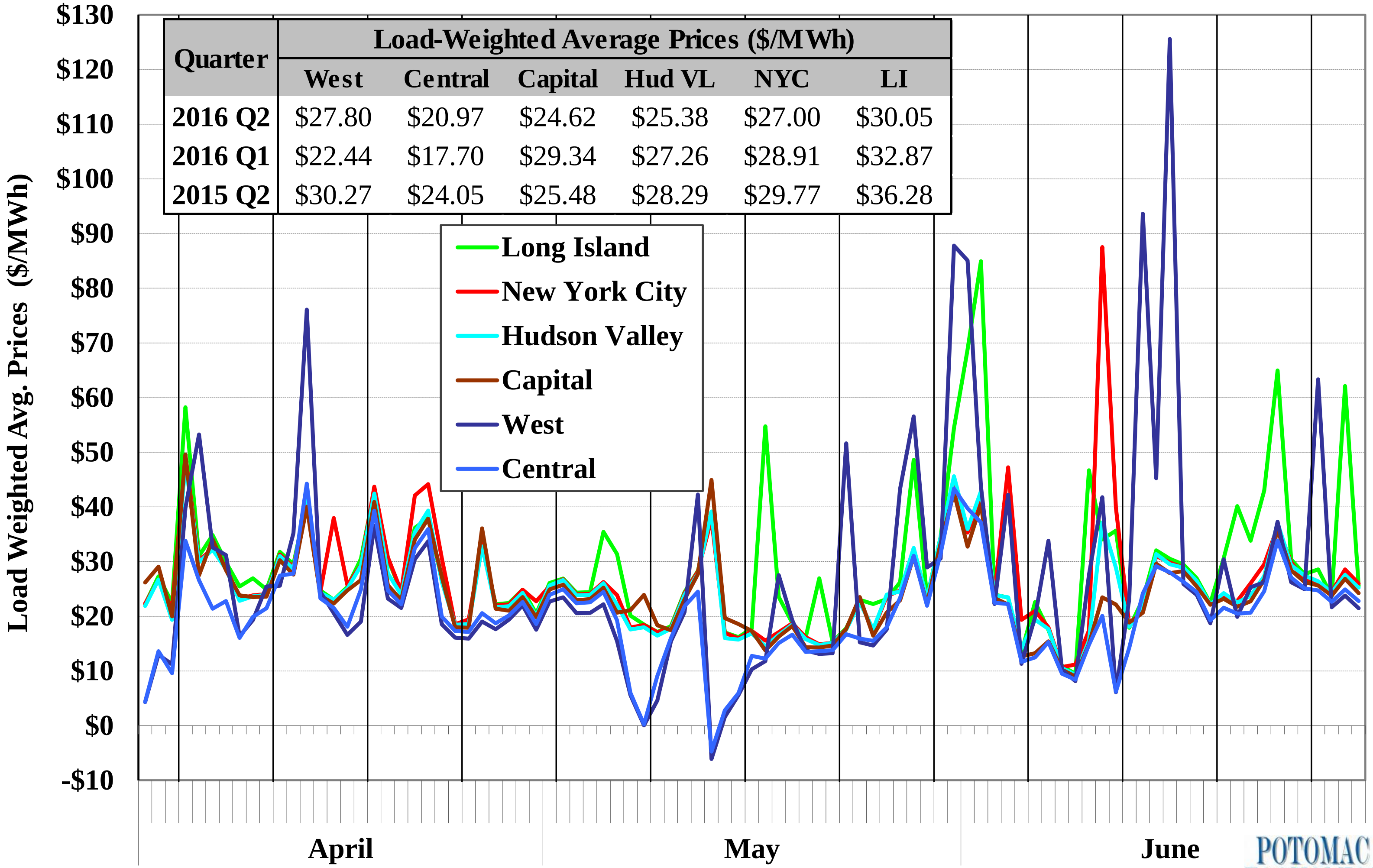
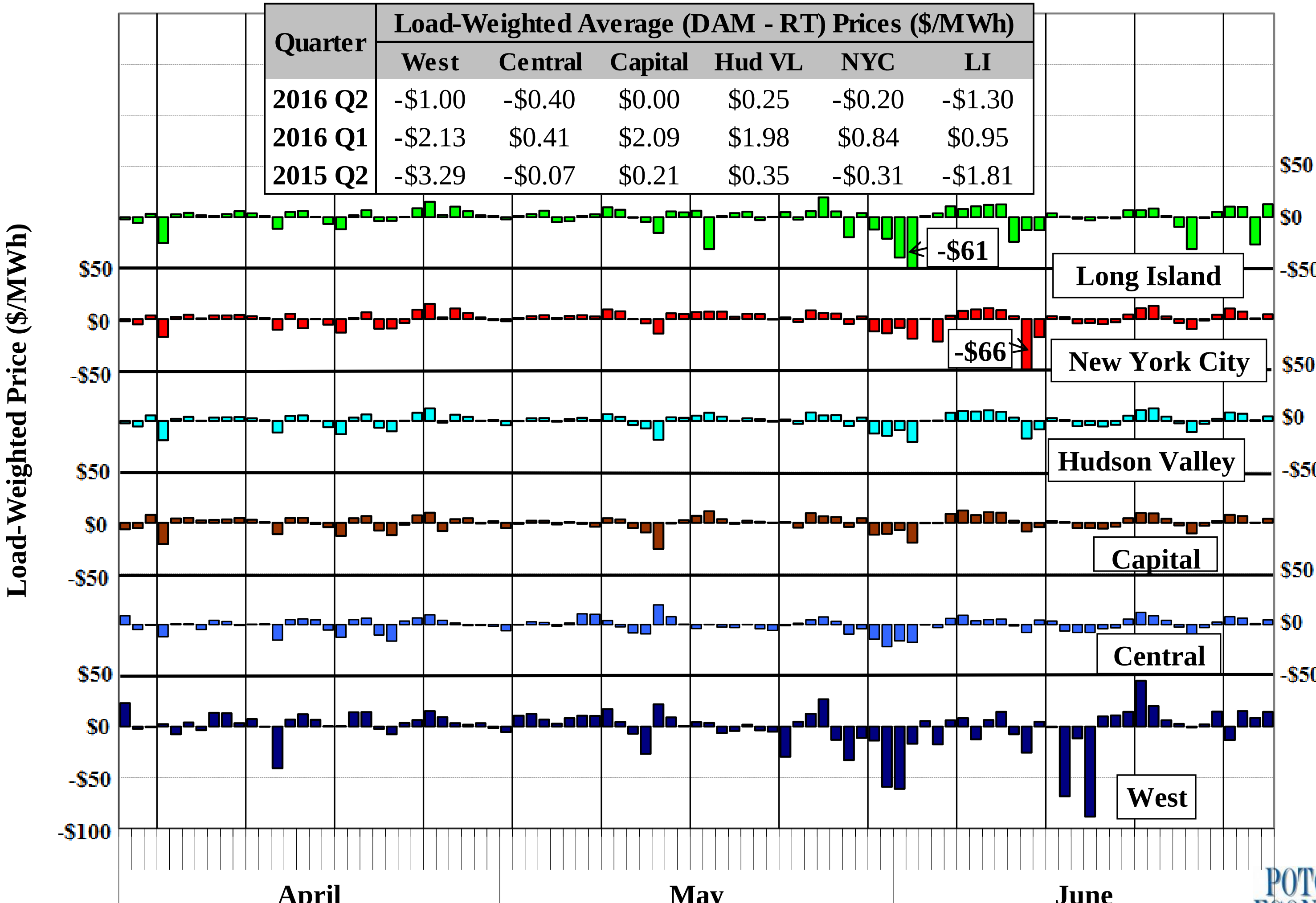
Real-Time Electricity Prices by Zone

Quarter	Load-Weighted Average Prices ($/MWh)					
	West	Central	Capital	Hud VL	NYC	LI
2016 Q2	$27.80	$20.97	$24.62	$25.38	$27.00	$30.05
2016 Q1	$22.44	$17.70	$29.34	$27.26	$28.91	$32.87
2015 Q2	$30.27	$24.05	$25.48	$28.29	$29.77	$36.28



Convergence Between Day-Ahead and Real-Time Prices

Quarter	Load-Weighted Average (DAM - RT) Prices ($/MWh)					
	West	Central	Capital	Hud VL	NYC	LI
2016 Q2	-$1.00	-$0.40	$0.00	$0.25	-$0.20	-$1.30
2016 Q1	-$2.13	$0.41	$2.09	$1.98	$0.84	$0.95
2015 Q2	-$3.29	-$0.07	$0.21	$0.35	-$0.31	-$1.81



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Ancillary Services Market

Ancillary Services Prices

- The following three figures summarize DA and RT prices for six ancillary services products during the quarter:
  - ✓ 10-min spinning reserve prices in eastern NY;
  - ✓ 10-min non-spinning reserve prices in eastern NY;
  - ✓ 10-min spinning reserve prices in western NY;
  - ✓ Regulation prices, which reflect the cost procuring regulation, and the cost from moving regulation units up and down.
    - – Resources were scheduled assuming a Regulation Movement Multiplier of 13 MW per MW of capability, but they are compensated according to actual movement.
  - ✓ 30-min operating reserve prices in western NY; and
  - ✓ 30-min operating reserve prices in SENY.
- The figures also show the number of shortage intervals in real-time for each ancillary service product.
  - ✓ A shortage occurs when a requirement cannot be satisfied at a marginal cost less than its "demand curve".
  - ✓ The highest demand curve values are currently set at $775/MW.

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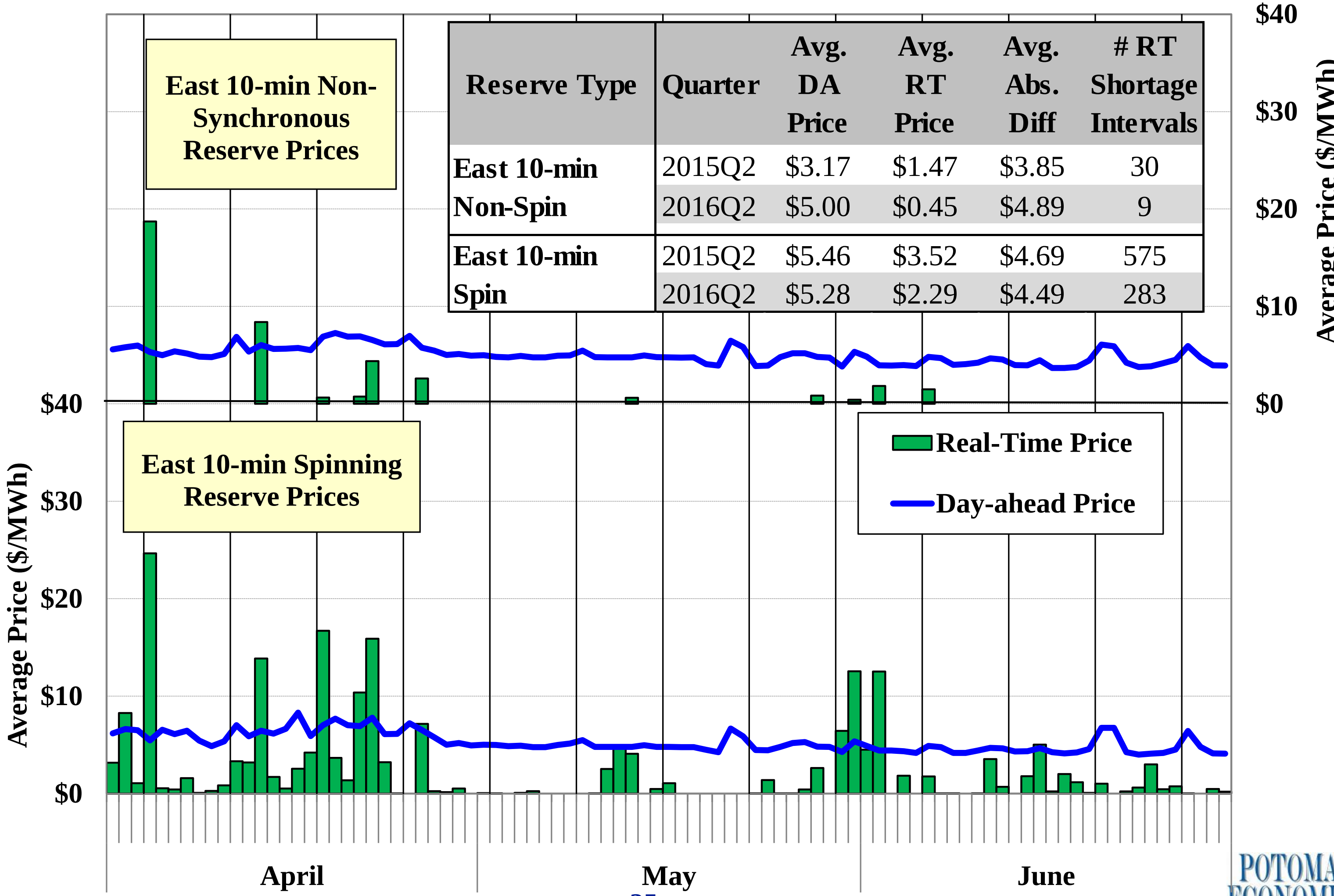
Ancillary Services Prices

- The differences in day-ahead prices between different reserve products became much smaller following the rule changes (Comprehensive Shortage Pricing Project) made in November 2015. In the second quarter of 2016,
  - ✓ The largest average differential was only \$0.43/MWh (between eastern 10-min spinning prices and western 30-min total prices), down from \$4.52/MWh last year.
    - – This is because the statewide 30-minute requirement accounted for most of the operating reserve scheduling costs in the DAM.
  - ✓ Day-ahead western 30-minute reserve prices, rose from \$0.94/MWh in the second quarter of 2015 to \$4.85/MWh in this quarter despite lower natural gas prices and load levels.
    - – The primary driver was rule changes that were implemented as part of the Comprehensive Shortage Pricing project. (see slides 28-30 for a detailed discussion)
- The number of regulation shortages in real-time rose significantly from a year ago.
  - ✓ The increase was also due to the rule changes in November 2015, which reduced the lowest demand curve value from \$80 to \$25/MWh.
  - ✓ However, the average RT regulation prices fell by 10 percent, consistent with lower natural gas prices and load levels this quarter.

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	2015Q2	$3.17	$1.47	$3.85	30
	2016Q2	$5.00	$0.45	$4.89	9
East 10-min Spin	2015Q2	$5.46	$3.52	$4.69	575
	2016Q2	$5.28	$2.29	$4.49	283



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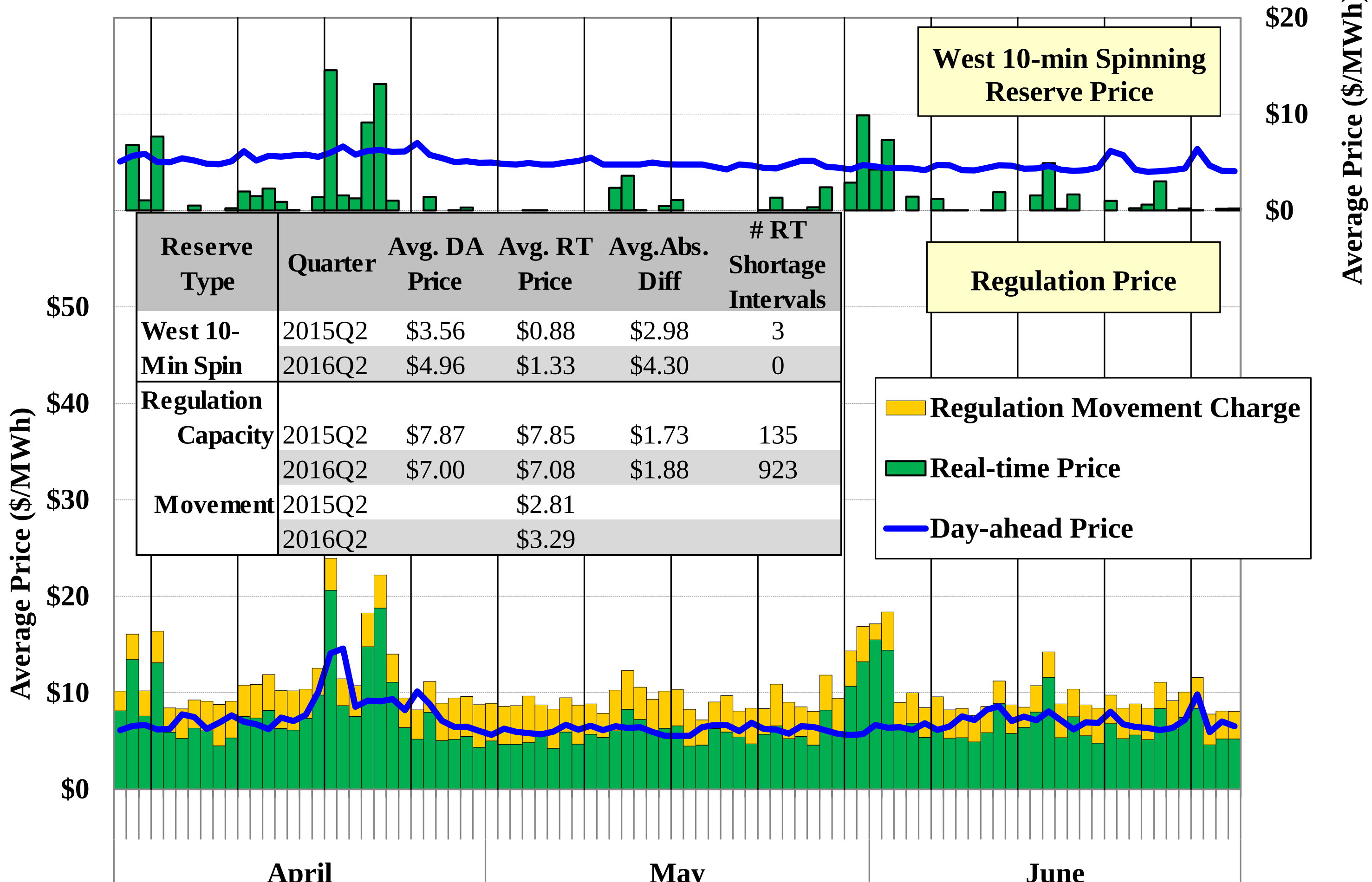
Day-Ahead and Real-Time Ancillary Services Prices

Western 10-Minute Spinning Reserves and Regulation



Reserve Type	Quarter	Avg. DA Price	Avg. RT Price	Avg.Abs. Diff	# RT Shortage Intervals
West 10-Min Spin	2015Q2	$3.56	$0.88	$2.98	3
	2016Q2	$4.96	$1.33	$4.30	0
Regulation Capacity	2015Q2	$7.87	$7.85	$1.73	135
	2016Q2	$7.00	$7.08	$1.88	923
Movement	2015Q2		$2.81		
	2016Q2		$3.29		

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

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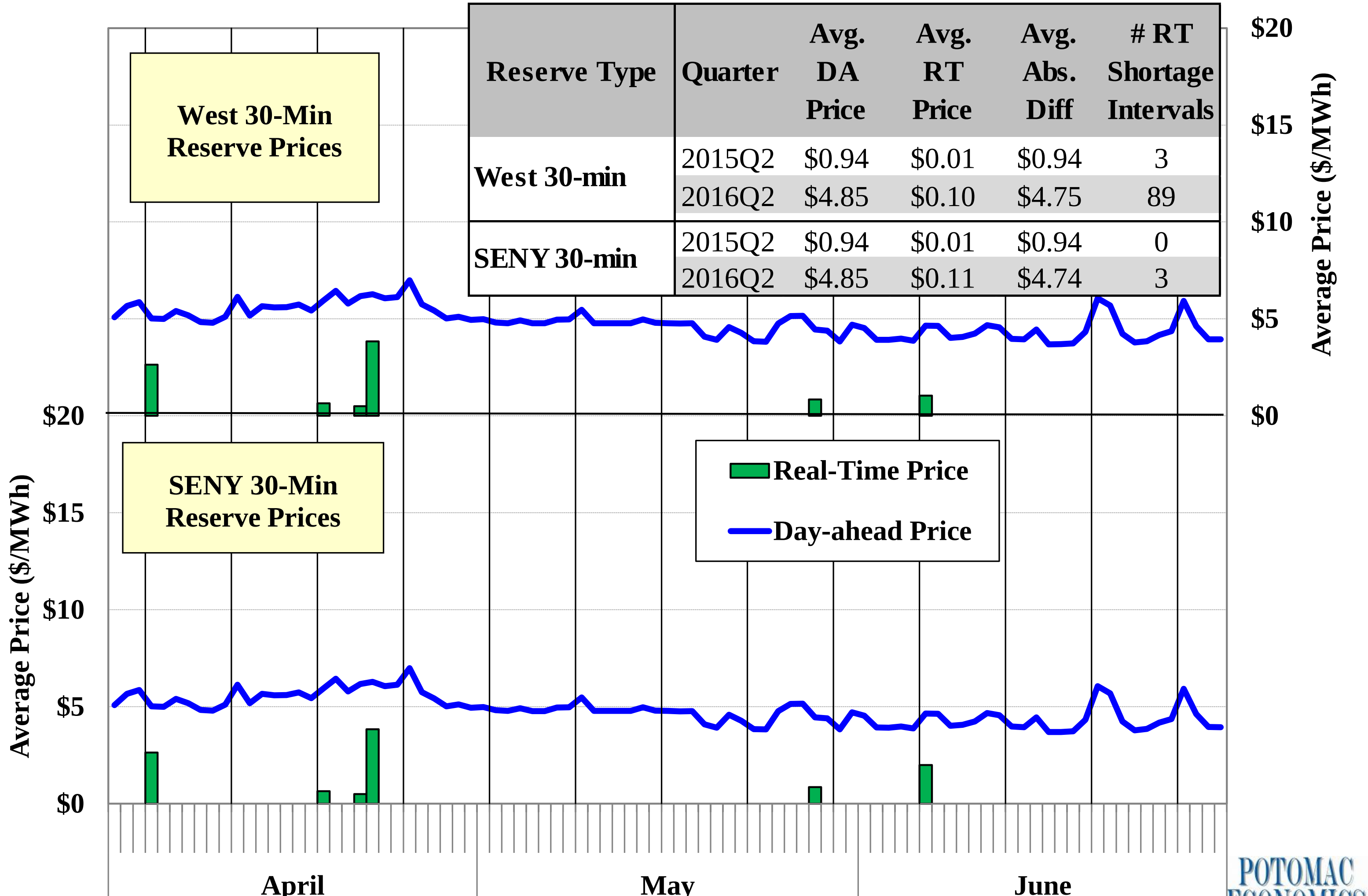
Day-Ahead and Real-Time Ancillary Services Prices

Western and SENY 30-Minute Reserves

Reserve Type	Quarter	Avg. DA Price	Avg. RT Price	Avg. Abs. Diff	# RT Shortage Intervals
West 30-min	2015Q2	$0.94	$0.01	$0.94	3
	2016Q2	$4.85	$0.10	$4.75	89
SENY 30-min	2015Q2	$0.94	$0.01	$0.94	0
	2016Q2	$4.85	$0.11	$4.74	3



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NYCA 30-Minute Reserve Offers in the DAM

- The next figure evaluates the drivers of increased 30-minute reserve prices by summarizing day-ahead reserve offers that can satisfy the statewide 30-minute reserve requirement.
  - ✓ These quantities include both 10-minute and 30-minute and both spinning and non-spin reserve offers. (However, they are not shown separately in the figure)
  - ✓ Only offers from day-ahead committed (i.e., online) resources and available offline quick-start resources are included in this evaluation, since other resources do not directly affect the reserve prices.
  - ✓ The stacked bars show the amount of reserve offers in selected price ranges for West NY (Zones A to E), East NY (Zones F to J), and NYCA (excluding Zone K).
    - – Long Island is excluded because the current rules limit its reserve contribution to the broader areas (i.e., SENY, East, NYCA) to its 30-minute reserve requirement.
    - – As a result, Long Island reserve offers have little impact on NYCA reserve prices.
  - ✓ The two black lines represent the equivalent average 30-minute reserve requirements for areas outside Long Island in the second quarter of 2015 and 2016.
    - – The equivalent 30-minute reserve requirement is calculated as NYCA 30-minute reserve requirement *minus* 30-minute reserves scheduled on Long Island.
    - – Where the lines intersect the bars provides a rough indication of reserve prices (however, opportunity costs are not reflected here).

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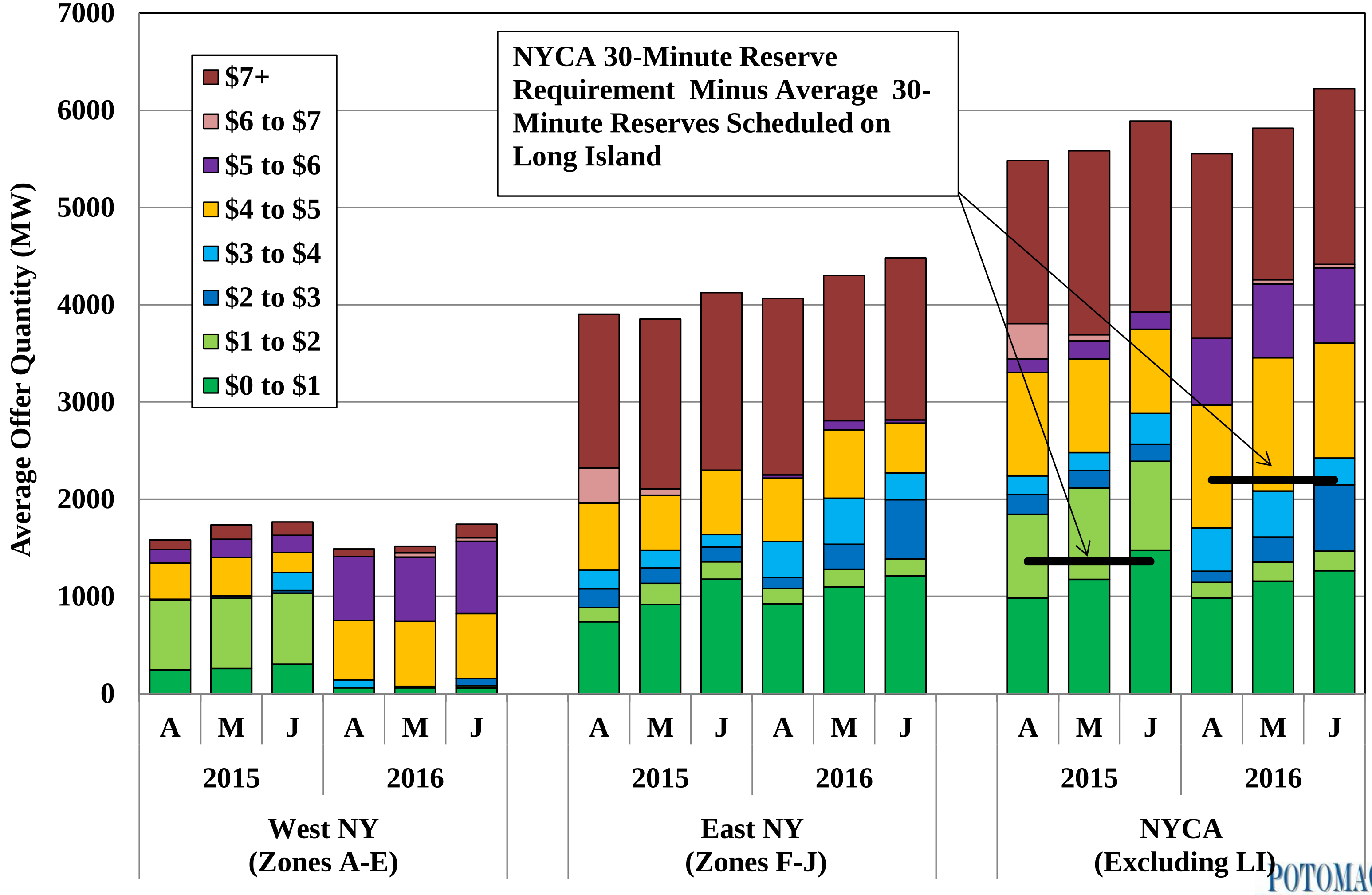
NYCA 30-Minute Reserve Offers in the DAM

- The increase in 30-minute reserve prices from a year ago was primarily driven by the implementation of the Comprehensive Shortage Pricing project.
  - ✓ The increase of the NYCA 30-minute reserve requirement from 1,965 MW to 2,620 MW; and
  - ✓ The limitation on scheduling reserves from Long Island resources.
    - – An average of 423 MW of 30-minute reserves was scheduled on Long Island in the second quarter of 2016, down 183 MW from the second quarter of 2015.
  - ✓ Taken together, these two factors increased the need for 30-minute reserves outside Long Island by 840 MW (compared to a year ago).
- Increased offer prices in West NY was a contributing (yet less significant) factor.
  - ✓ Most reserve offers were priced between $4 and $6/MWh in the second quarter of 2016, while most were between $0 and $2/MWh in the same period of 2015.
  - ✓ We reviewed this offer change and found no significant competitive concerns.
- The amount of low-price offers rose modestly in East NY this quarter, helping to offset the other factors.
- RT 30-minute reserve prices are much lower than DA prices because units that are dispatchable must have availability bids of $0 in RT.

Day-Ahead NYCA 30-Minute Operating Reserve Offers
From Committed and Available Offline Quick-Start Resources



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Energy Market Scheduling

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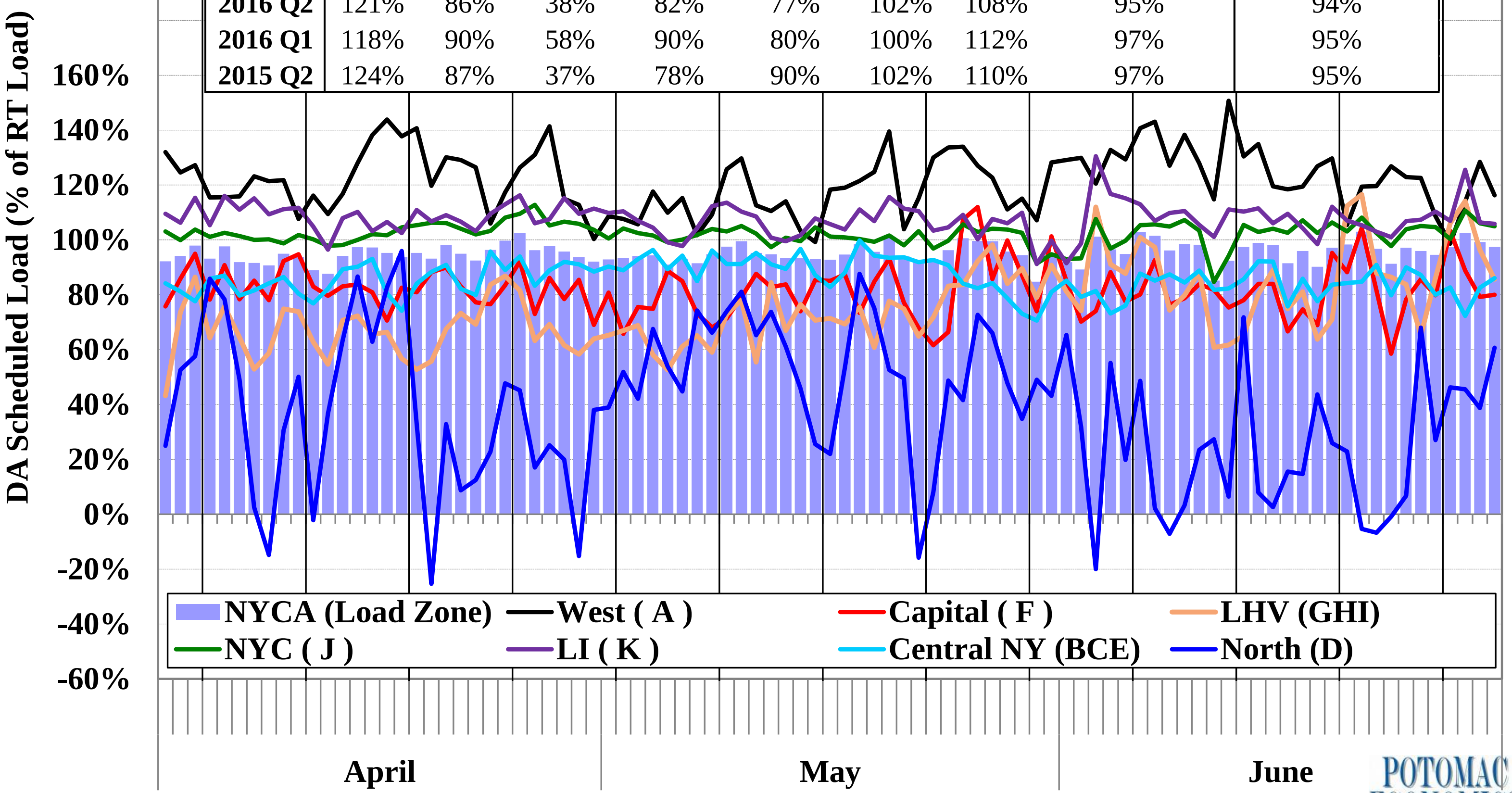
Day-ahead Load Scheduling

- The following figure summarizes the quantity of DA load scheduled as a percentage of RT load in each of seven 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, 94 percent of actual load was scheduled in the DAM (including virtual imports/exports) during peak load hours in 2016-Q2, slightly lower than 2015-Q2.
  - ✓ DA load scheduling in each sub-region was generally consistent with prior periods.
- Average net load scheduling tends to be higher in locations where volatile real-time congestion is more common.
  - ✓ Net load scheduling was generally higher in NYC and Long Island because they were downstream of most congested interfaces.
  - ✓ Net load scheduling was highest in the West Zone partly because of volatile RT congestion on the West Zone 230kV system.
- Load was typically under-scheduled in the North Zone by a large margin primarily in response to the scheduling patterns of wind resources and imports from Canada.
  - ✓ In 2016-Q2, large negative RT LBMPs, which were hard to predict in the DAM, occurred in the North Zone on several days, reflecting transmission outages and the implementation of GTDC (see slides 65-69).

Day-ahead Scheduled Load and Actual Load

Daily Peak Load Hour

Quarter	Avg DA Net Scheduled Load (% of RT Load)								
	West Zone (A)	Central NY (BCE)	North Zone (D)	Capital (F)	LHV (GHI)	NYC (J)	LI (K)	NYCA (Load Zones)	NYCA (Load Zones + External)
2016 Q2	121%	86%	38%	82%	77%	102%	108%	95%	94%
2016 Q1	118%	90%	58%	90%	80%	100%	112%	97%	95%
2015 Q2	124%	87%	37%	78%	90%	102%	110%	97%	95%



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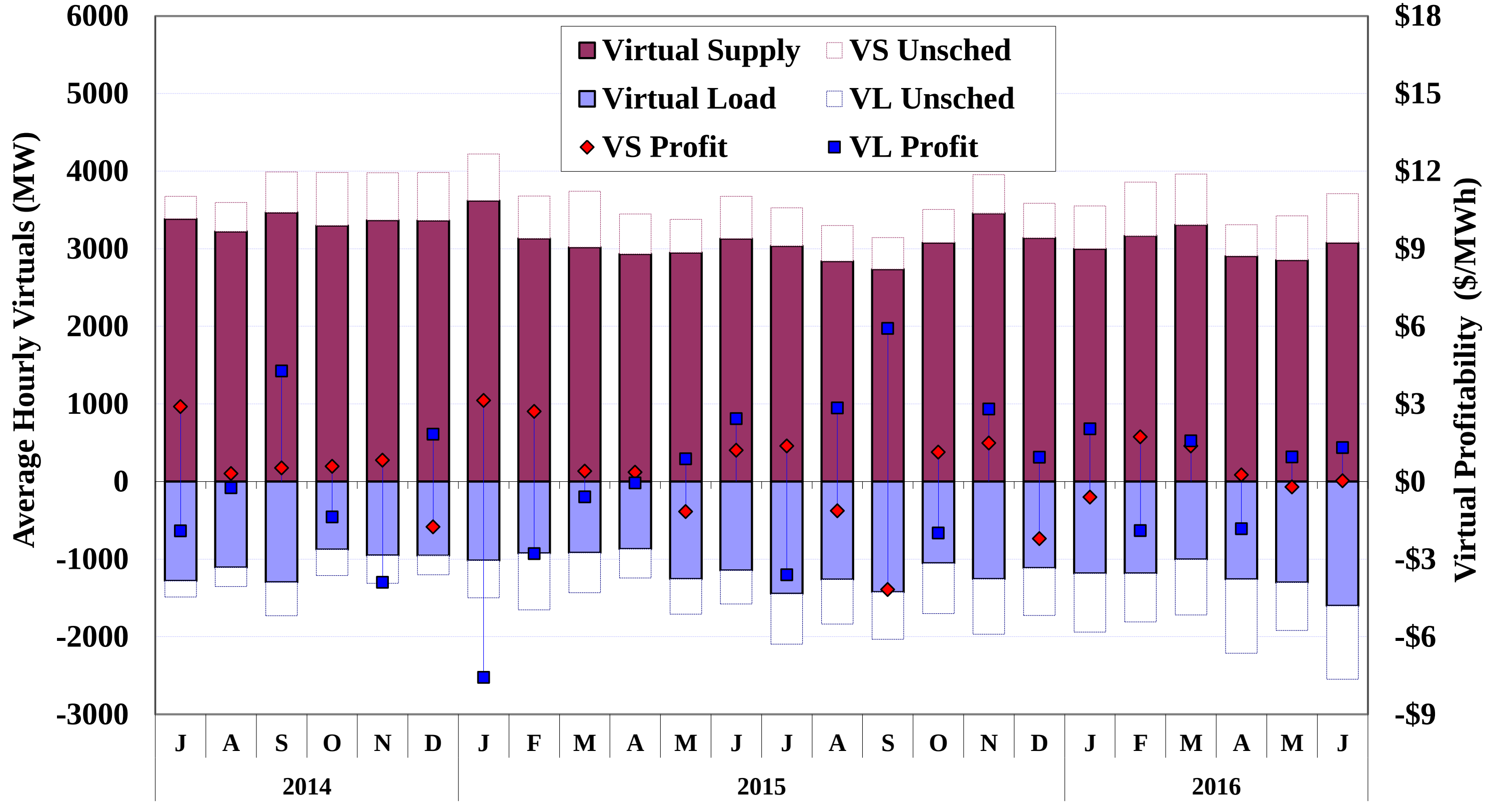
Virtual Trading Activity

- 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 seven regions based on typical congestion patterns.
  - ✓ 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).
  - ✓ The top portion of the chart also shows average day-ahead scheduled load (as a percent of real-time load) at each geographic region.

Virtual Trading Activity

- The volume of virtual trading did not change significantly in the second quarter of 2016, generally consistent with prior periods.
  - ✓ The pattern of virtual scheduling was similar as well.
    - – Virtual traders generally scheduled more virtual load in the West Zone and downstate areas (i.e., NYC and LI) and more virtual supply in other regions.
    - – This was consistent with typical DA load scheduling patterns discussed earlier for similar reasons.
- Overall, virtual traders netted a profit of $0.9 million in the second quarter of 2016.
  - ✓ Virtual transactions were profitable, suggesting 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 varied widely by time and location, reflecting the difficulty of predicting volatile RT prices.
- The quantities of virtual transactions that generated substantial profits or losses were generally consistent with prior periods.
  - ✓ These trades 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



		J	A	S	O	N	D	J	F	M	A	M	J	J	A	S	O	N	D	J	F	M	A	M	J
Profit > 50% of Avg. Zone Price	MW	528	161	337	589	435	380	539	566	316	299	566	782	479	290	241	378	1090	643	692	638	1003	354	431	460
	%	11%	4%	7%	14%	10%	9%	12%	14%	8%	8%	13%	18%	11%	7%	6%	9%	23%	15%	17%	15%	23%	8%	10%	10%
Loss > 50% of Avg. Zone Price	MW	408	214	337	510	456	372	461	453	383	338	671	697	499	300	341	375	715	763	553	547	680	682	550	528
	%	9%	5%	7%	12%	11%	9%	10%	11%	10%	9%	16%	16%	11%	7%	8%	9%	15%	18%	13%	13%	16%	16%	13%	11%

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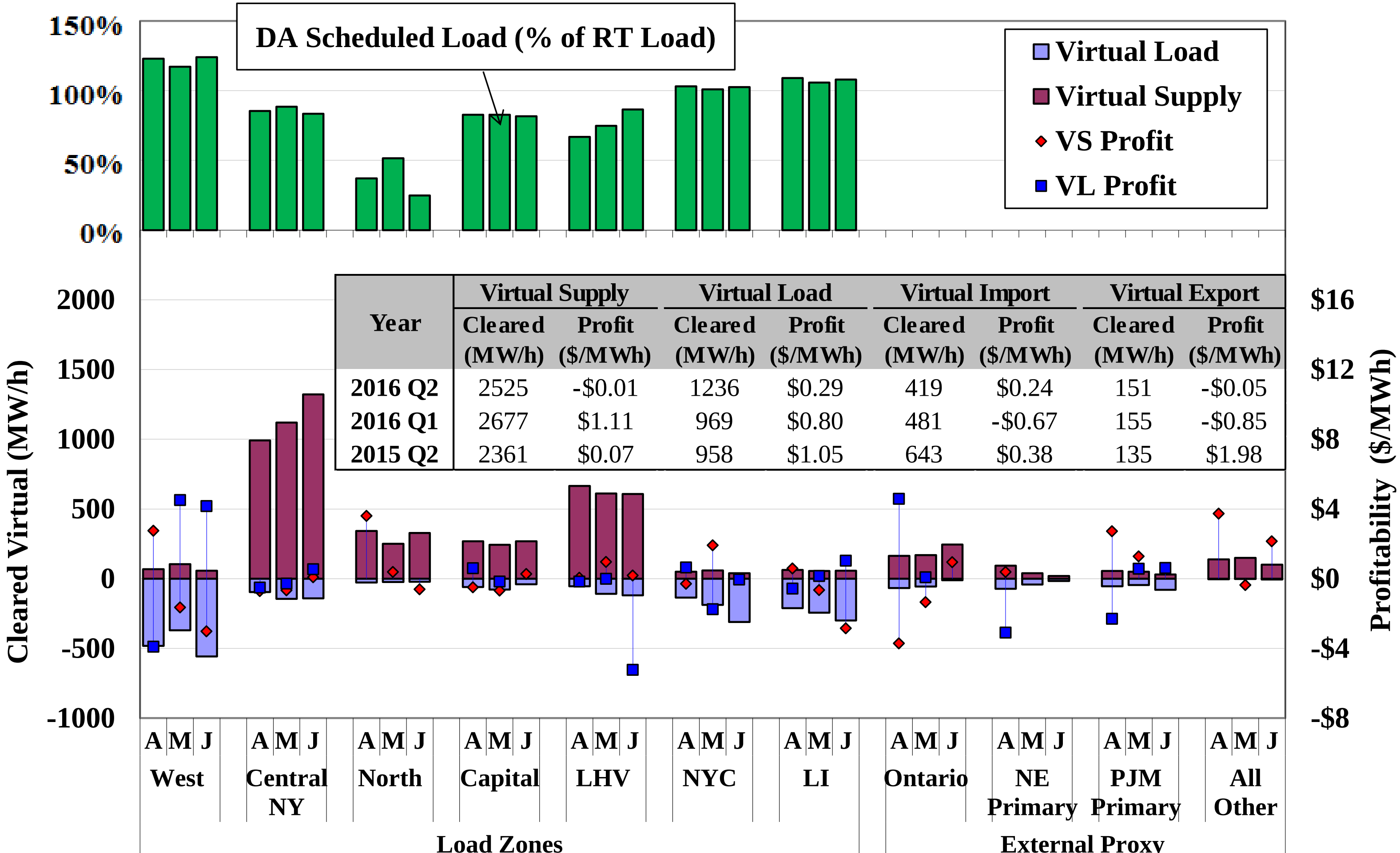
Virtual Trading Activity at Load Zones & Proxy Buses by Location



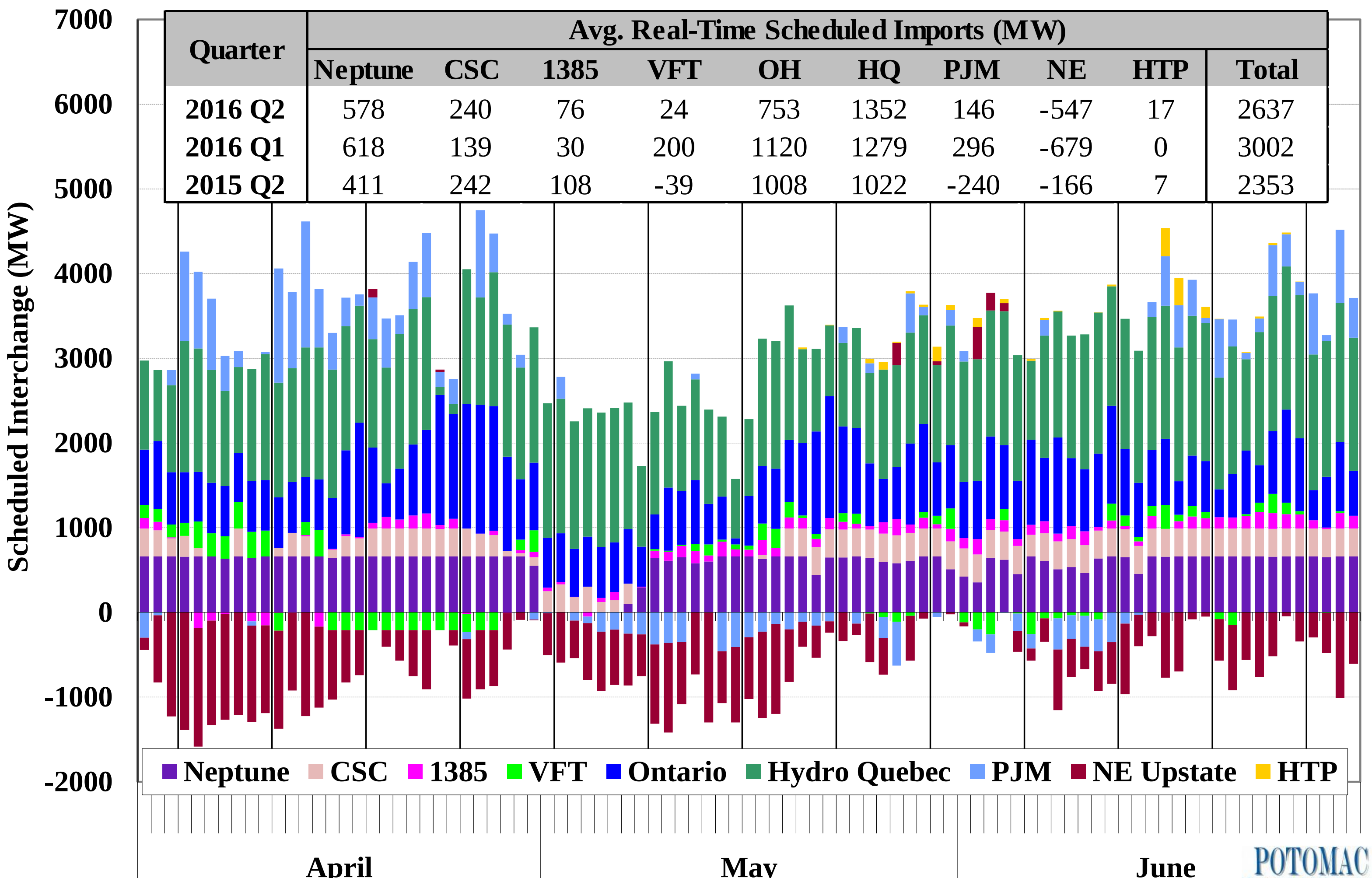
Year	Virtual Supply		Virtual Load		Virtual Import		Virtual Export	
	Cleared (MW/h)	Profit ($/MWh)	Cleared (MW/h)	Profit ($/MWh)	Cleared (MW/h)	Profit ($/MWh)	Cleared (MW/h)	Profit ($/MWh)
2016 Q2	2525	-$0.01	1236	$0.29	419	$0.24	151	-$0.05
2016 Q1	2677	$1.11	969	$0.80	481	-$0.67	155	-$0.85
2015 Q2	2361	$0.07	958	$1.05	643	$0.38	135	$1.98

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

Net Imports Scheduled Across External Interfaces

- The next figure shows average RT net imports to NYCA across ten external interfaces (two HQ interfaces are combined) in peak hours (1-9 pm).
- Overall, net imports averaged roughly 2.6 GW (serving nearly 15 percent of the load) during peak hours, up nearly 300 MW from the second quarter of 2015.
- Imports from Hydro Quebec and Ontario averaged roughly 2,100 MW during peak hours, accounting for 80 percent of total imports this quarter.
  - ✓ Imports from HQ rose 330 MW from 2015 Q2 due to fewer transmission outages.
  - ✓ Imports from Ontario fell notably from previous quarters because of IESO-NYISO interface limits and West Zone congestion, which were exacerbated by transmission outages. (see slides 46-48 for more discussion)
- Net imports from PJM and net exports to New England across their primary interfaces rose from a year ago.
  - ✓ These changes were generally consistent with variations in natural gas price spreads between the three markets.
  - ✓ Net imports from PJM and net exports to New England were highest in April when spreads were also highest (NE > NY > PJM) during the quarter.
    - – For similar reasons, average imports to Long Island across the Neptune line rose roughly 170 MW from a year ago.

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
2016 Q2	578	240	76	24	753	1352	146	-547	17	2637
2016 Q1	618	139	30	200	1120	1279	296	-679	0	3002
2015 Q2	411	242	108	-39	1008	1022	-240	-166	7	2353

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

- The next table evaluates the performance of CTS with PJM and NE at their primary interfaces during the second quarter of 2016. The table shows:
  - ✓ The percent of quarter-hour intervals during which the interface flows were adjusted by CTS (relative to the estimated hourly schedule).
  - ✓ The average flow adjustment from the estimated hourly schedule.
  - ✓ The production cost savings that resulted from CTS, including:
    - Projected savings at scheduling time, which is the expected production cost savings at the time when RTC determines the interchange schedule.
    - Net over-projected savings, which is the portion of savings that was inaccurately projected because of PJM, NYISO, and ISO-NE price forecast errors.
    - Unrealized savings, which are not realized due to: a) real-time curtailment ; b) interface ramping; and c) price curve approximation (which applies only to the NY/NE CTS as NYISO transfers the 7-point supply curve forecasted by ISO-NE into a step-function curve for use in the CTS process).
    - Actual savings (= Projected – Over-projected - Unrealized).
  - ✓ Interface prices, which are forecasted prices at the time of RTC scheduling and actual real-time prices.
  - ✓ Price forecast errors, which show the average difference and the average absolute difference between actual and forecasted prices across the interfaces.

Efficiency of CTS Scheduling with PJM and NE

- The interchange schedules were adjusted during 87 percent of all quarter-hour intervals (from our estimated hourly schedule) at the NE/NY interface, higher than the 58 percent at the PJM/NY interface.
  - ✓ This was partly attributable to the fact that the amount of low-price CTS bids was substantially higher at the NE/NY interface than at the PJM/NY interface.
- Our analyses show that $0.8 million and $0.6 million of production cost savings were projected at the time of scheduling at the NE/NY and PJM/NY interfaces.
  - ✓ However, only an estimated of $0.4 million of savings were realized at the NE/NY interface and $0.2 million were realized at the PJM/NY interface largely because of price forecast errors.
    - – It is important to note that our evaluation may under-estimate both projected and actual savings, because the estimated hourly schedules (by using actual CTS bids) may include some of the efficiencies that result from the CTS process.
    - – Nonetheless, the results of our analysis are still useful for identifying some of the sources of inefficiency in the CTS process.
- Projected savings were relatively consistent with actual savings when the forecast errors were moderate (e.g., less than $20/MWh), while the CTS process produced much more inefficient results when forecast errors were larger.
  - ✓ Therefore, improvements in the CTS process should focus on identifying sources of forecast errors.

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Efficiency of Intra-Hour Scheduling Under CTS
Primary PJM and NE Interfaces

	Average/Total During Intervals w/ Adjustment					
	CTS - NY/NE			CTS - NY/PJM		
	Both Forecast Errors <= $20	Any Forecast Error > $20	Total	Both Forecast Errors <= $20	Any Forecast Error > $20	Total
% of All Intervals w/ Adjustment	80%	7%	**87%**	52%	6%	**58%**
Average Flow Adjustment (MW)	7 (Net) / 71 (Gross)	0.5 (Net) / 98 (Gross)	**7 (Net) / 73 (Gross)**	10 (Net) / 58 (Gross)	11 (Net) / 125 (Gross)	**10 (Net) / 65 (Gross)**
Production Cost Savings ($ Million): Projected at Scheduling Time	$0.5	$0.3	**$0.8**	$0.2	$0.4	**$0.6**
Production Cost Savings ($ Million): Net Over-Projection by: NY Market	$0.03	$0.0	**$0.0**	$0.0	-$0.2	**-$0.2**
Production Cost Savings ($ Million): Net Over-Projection by: Neighbor Market	-$0.05	$0.0	**-$0.1**	-$0.010	-$0.1	**-$0.2**
Production Cost Savings ($ Million): Unrealized Savings Due to: Ramping	-$0.03	$0.0	**-$0.1**	-$0.01	-$0.02	**-$0.03**
Production Cost Savings ($ Million): Unrealized Savings Due to: Curtailment	$0.00	$0.00	**$0.00**	-$0.003	$0.0	**$0.0**
Production Cost Savings ($ Million): Unrealized Savings Due to: Price Curve	$0.0	-$0.1	**-$0.2**	N/A	N/A	**N/A**
Production Cost Savings ($ Million): Actual Savings	$0.4	$0.0	**$0.4**	$0.2	$0.1	**$0.2**
Interface Prices ($/MWh): NY Market: Actual	$21.72	$46.59	**$23.64**	$20.22	$51.71	**$23.52**
Interface Prices ($/MWh): NY Market: Forecast	$21.71	$30.02	**$22.35**	$20.02	$40.76	**$22.10**
Interface Prices ($/MWh): Neighbor Market: Actual	$22.27	$24.90	**$22.47**	$21.25	$48.31	**$24.07**
Interface Prices ($/MWh): Neighbor Market: Forecast	$22.50	$19.39	**$22.26**	$21.84	$44.45	**$24.12**
Price Forecast Errors ($/MWh): NY Market: Fcst. - Act.	-$0.01	-$16.57	**-$1.29**	-$0.21	-$12.71	**-$1.51**
Price Forecast Errors ($/MWh): NY Market: Abs. Val.	$3.13	$33.70	**$5.49**	$3.07	$41.75	**$7.11**
Price Forecast Errors ($/MWh): Neighbor Market: Fcst. - Act.	$0.22	-$5.51	**-$0.22**	$0.59	-$5.73	**-$0.07**
Price Forecast Errors ($/MWh): Neighbor Market: Abs. Val.	$3.63	$47.51	**$7.01**	$2.70	$38.76	**$6.47**

Day-Ahead and Real-Time Transmission Congestion

Congestion Patterns, Revenues, and Shortfalls

- The next four 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 net day-ahead congestion revenues collected by the NYISO are less than the payments to TCC holders.
    - – Shortfalls (or surpluses) arise when the TCCs on a path exceed (or is below) the transfer capability of the path modeled in the DA market in 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 figure examines in detail the value and frequency of day-ahead and real-time congestion along major transmission paths by quarter.
  - ✓ 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 third and fourth figures show the day-ahead and balancing congestion revenue shortfalls by transmission facility on a daily basis.
  - ✓ Negative values indicate day-ahead and balancing congestion surpluses.
- Congestion is evaluated along major transmission paths that include:
  - ✓ West Zone Lines: Primarily 230 kV transmission constraints in the West Zone.
  - ✓ West to Central: Including transmission constraints in the Central 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.

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Day-Ahead and Real-Time Congestion

(cont. from prior slide)

- ✓ NYC Lines: Including lines into and within the NYC 345 kV system, lines leading into and within NYC load pockets, and 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 $94 million this quarter, up 30 percent from the second quarter of 2015 despite lower natural gas prices and load levels.
  - ✓ Transmission outages were a significant driver, which reduced transfer capability and caused increased congestion in the following areas:
    - Across the Central-East interface in most of April and May;
    - On the 230 kV system in the West Zone in April;
    - On the transmission paths from North to Central in April and May; and
    - On the transmission paths from Hudson Valley to Dunwoodie in May.
  - ✓ Average nuclear generation fell by 750 MW in LHV (see slide 15) and average net exports to ISO-NE rose by 380 MW (see slide 39), which also contributed to increased congestion across the Central-East interface.

Day-Ahead and Real-Time Congestion

- West Zone constraints accounted for the largest share of congestion (38% DA, 28% RT, measured as a share of DA/RT congestion value) in 2016-Q2.
  - ✓ There were notable changes from a year ago in the pattern of West Zone congestion, driven by various factors, including (but not limited to):
    - – The implementation of GTDC in February 2016. (see slides 65-69)
    - – The retirements of the last Dunkirk unit in December 2015 and two Huntley units in March 2016, which had relieved West Zone congestion (averaging ~20 to 30 MW of flow relief on frequently congested 230 kV lines in 2015-Q2).
    - – The implementation of a composite shift factor at Niagara plant in early May 2016. (see slides 60-64 for more discussion)
    - – The addition of two series reactors on the Packard-Huntley 230 kV #77 and #78 lines in mid-May 2016, which can be used to divert a portion of flows from 230 kV facilities to parallel 345 kV and 115 kV facilities.
    - – The S. Ripley-Dunkirk 230 kV line and Warren-Falconer 115 kV line were taken OOS during most of 2016-Q2 for 115kV transmission security, but these also reduced flows on frequently congested 230 kV lines.
  - ✓ Reductions of the BMS limits of frequently binding constraints averaged 10 MW in 2016-Q2, down from an average of 47 MW in 2015-Q2, which contributed to a substantial reduction in the frequency of RT congestion. (see slides 66, 69)

Day-Ahead Congestion Shortfalls

- Transmission outages accounted for a large share of shortfalls – over $17 million (out of $24.6 million) was allocated to the responsible TO in 2016-Q2.
  - ✓ Roughly $8 million of shortfalls accrued on the 230 kV lines in the West Zone.
    - – Multiple 230 kV lines along the Niagara-Packard-Sawyer-Huntley path were out of service in April, accounting for roughly $3 million of shortfalls.
    - – Inconsistencies between the TCC auctions and the DAM in the assumed distribution of Niagara generation (230 kV vs. 115 kV) accounted for: (a) $1.2 million of shortfalls before the modeling change of Niagara plant on 5/4; and (b) $1.2 million of surplus afterwards.
    - – Of the remaining $5 million of shortfalls, a large portion was attributable to different loop flow assumptions between the TCC auction and the DAM.
  - ✓ Nearly $6 million of shortfalls accrued on the parallel transmission path (categorized as ‘North to Central’) when a Marcy 765/345 kV breaker was OOS from early to mid April and from late May to early June.
  - ✓ Another $5.5 million of shortfalls accrued on the Central-East interface, most of which was attributable to the following transmission outages:
    - – The Edic-Fraser 345 line was OOS from late April to late May.
    - – The Marcy-Coopers 345 line was OOS in most of April.
    - – The Ramapo-Rock Tavern 345 line was OOS in most of April and May.

Balancing Congestion Shortfalls

- Balancing congestion shortfalls totaled nearly $8 million in the second quarter of 2016, down $6 million from a year ago.
- West Zone 230 kV constraints accounted for the majority of shortfalls (~$7 million), most of which occurred in June.
  - ✓ Differences between the assumed distribution of Niagara generation between the 115 kV and 230 kV units in the DAM and the actual distribution contributed $1.3 million of shortfalls.
  - ✓ The operation of Ramapo, ABC and JK PARs contributed another $1.6 million of shortfalls.
    - – However, the operation generated $1.8 million of surpluses on the Central-East interface mostly in April and May, offsetting these shortfalls.
  - ✓ Among the other factors that accounted for an additional $4 million of shortfalls, unexpected changes in loop flows was a key contributor.

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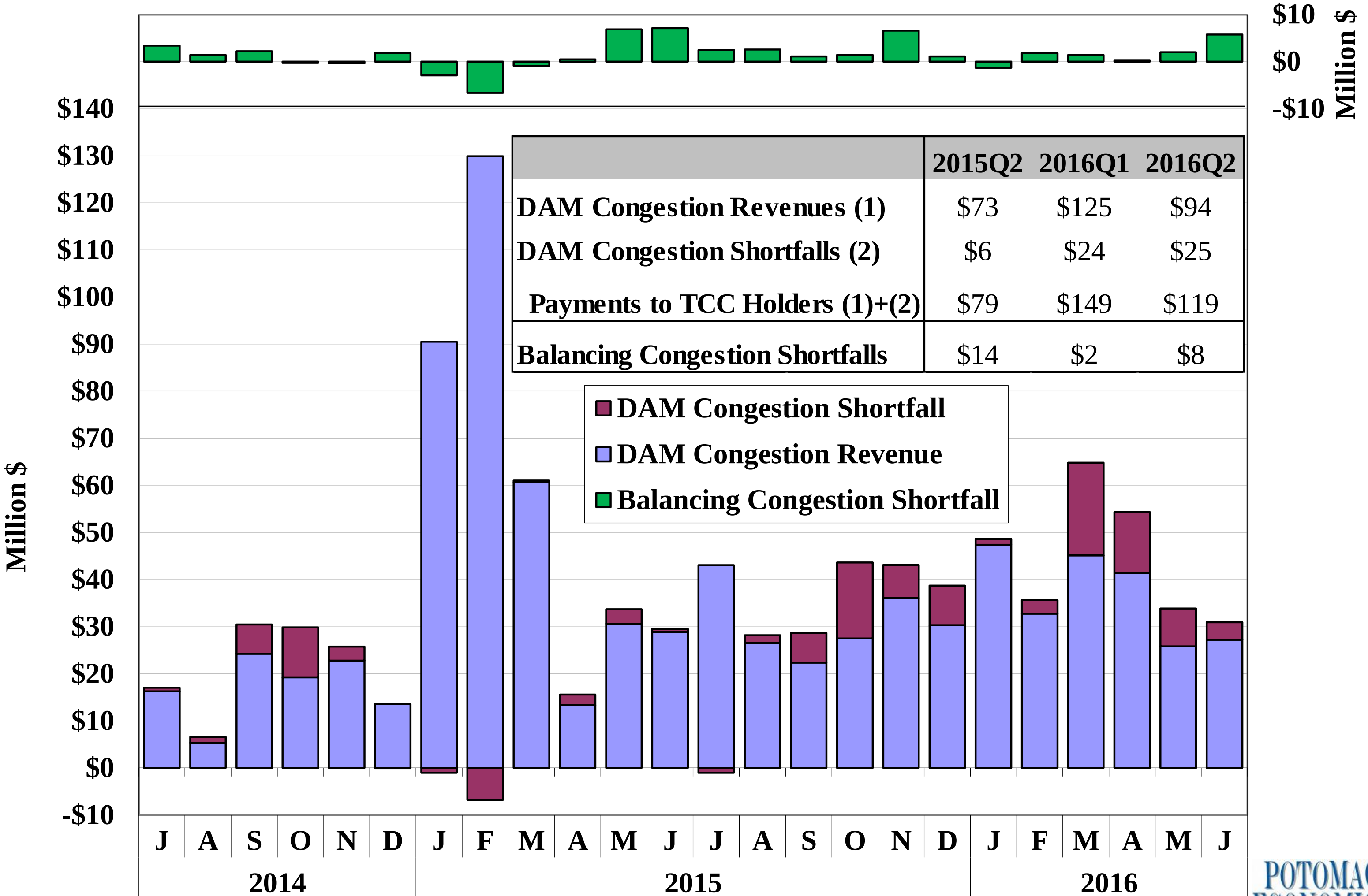
Congestion Revenues and Shortfalls by Month



	2015Q2	2016Q1	2016Q2
DAM Congestion Revenues (1)	$73	$125	$94
DAM Congestion Shortfalls (2)	$6	$24	$25
Payments to TCC Holders (1)+(2)	$79	$149	$119
Balancing Congestion Shortfalls	$14	$2	$8

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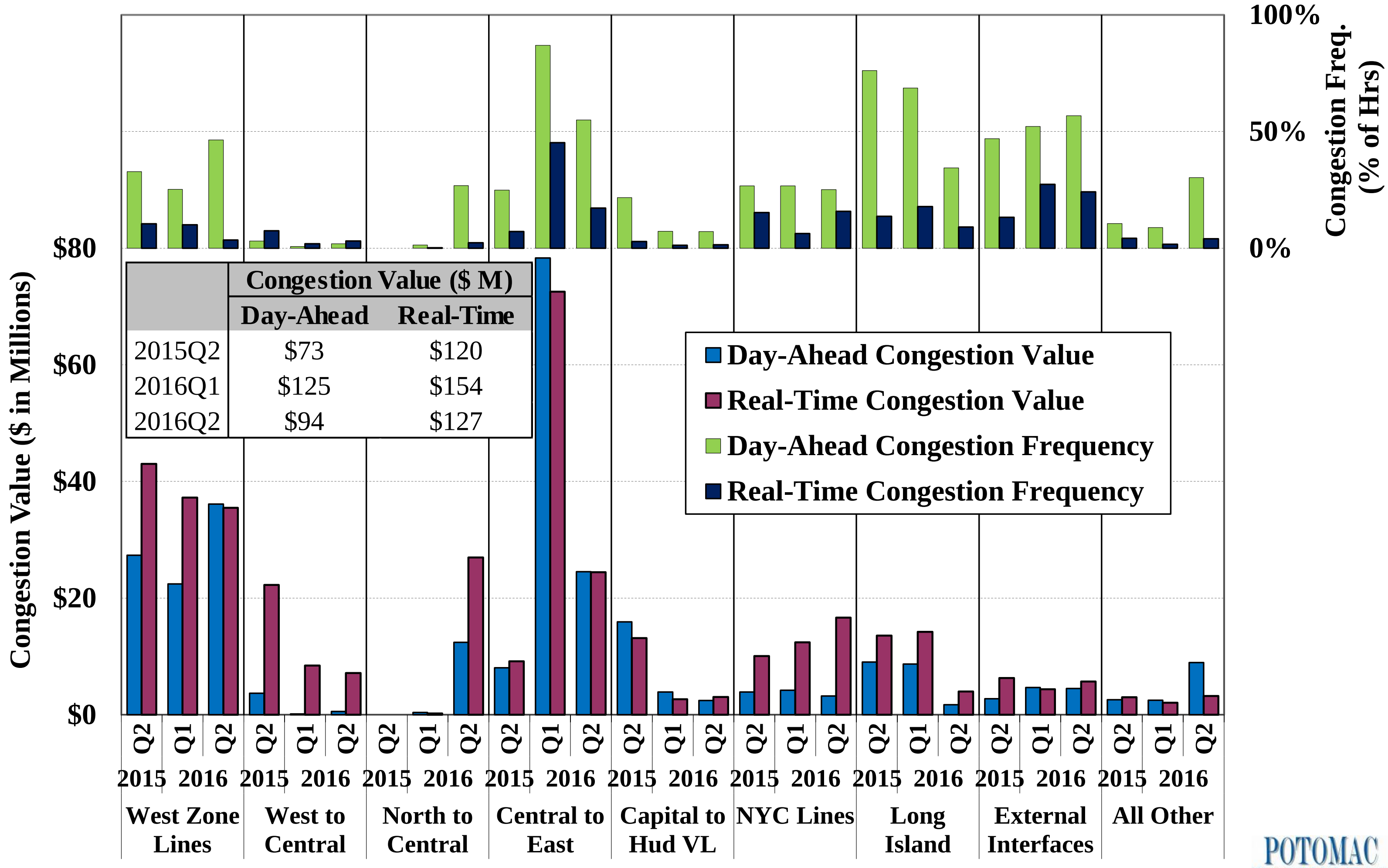
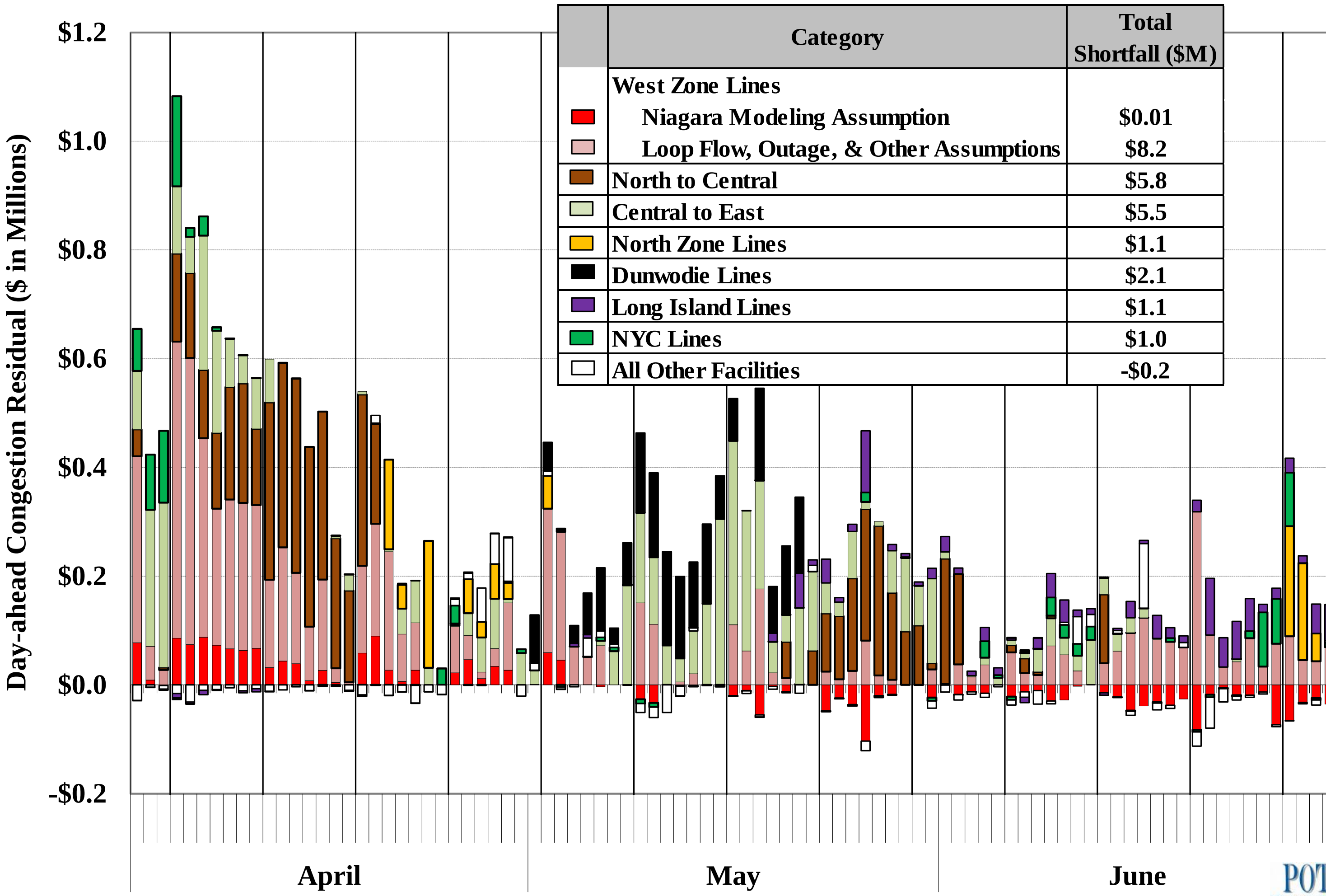
DA and RT Congestion Value and Frequency by Transmission Path



	Congestion Value ($ M)	
	Day-Ahead	Real-Time
2015Q2	$73	$120
2016Q1	$125	$154
2016Q2	$94	$127

Day-Ahead Congestion Revenue Shortfalls by Transmission Facility



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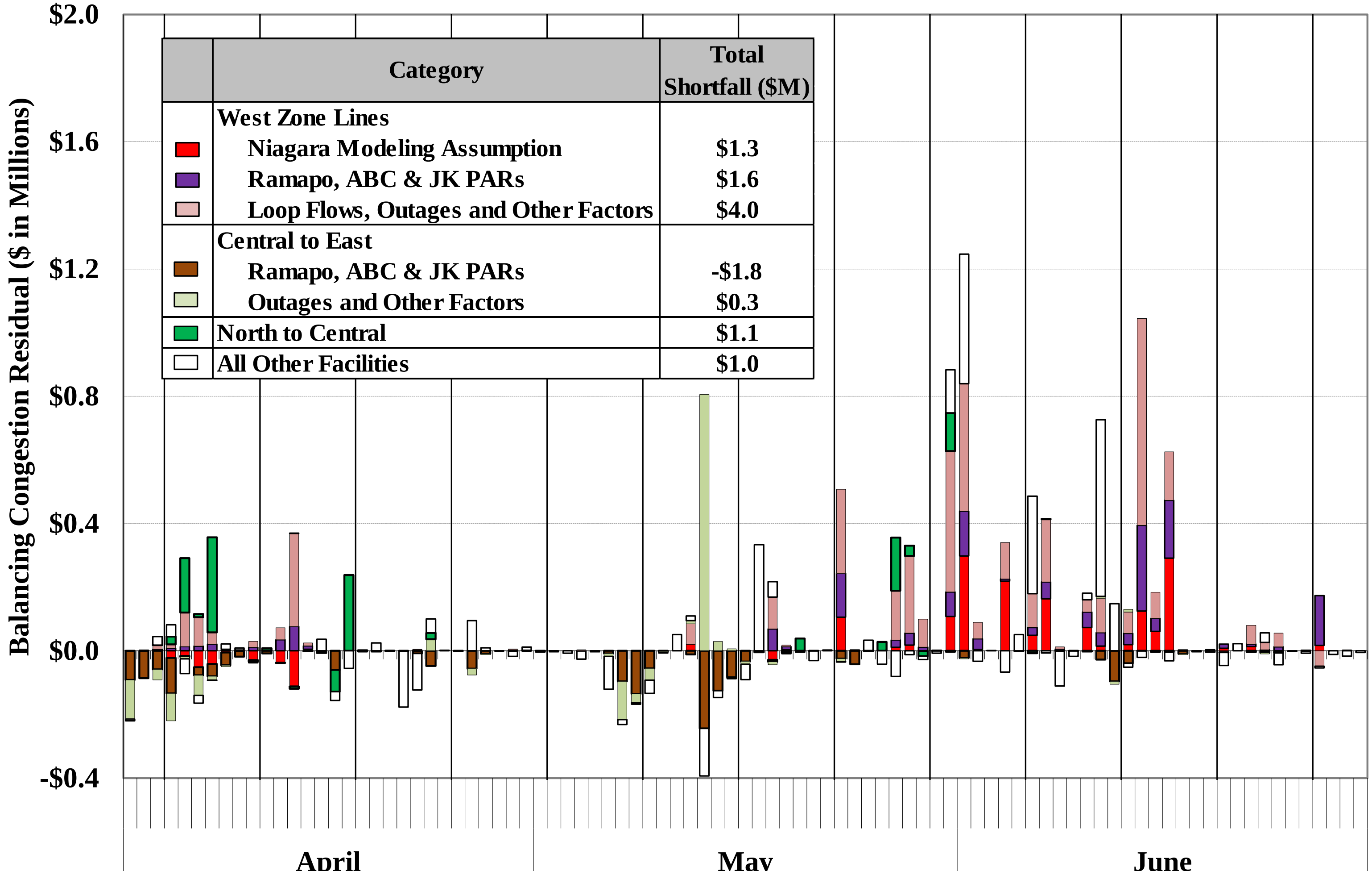
Balancing Congestion Shortfalls by Transmission Facility



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

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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.
    - 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.
    - ABC & JK Auto Correction Factors – These represent “pay-back” MW generated from cumulative deviations on the ABC or JK interface from prior days.
- 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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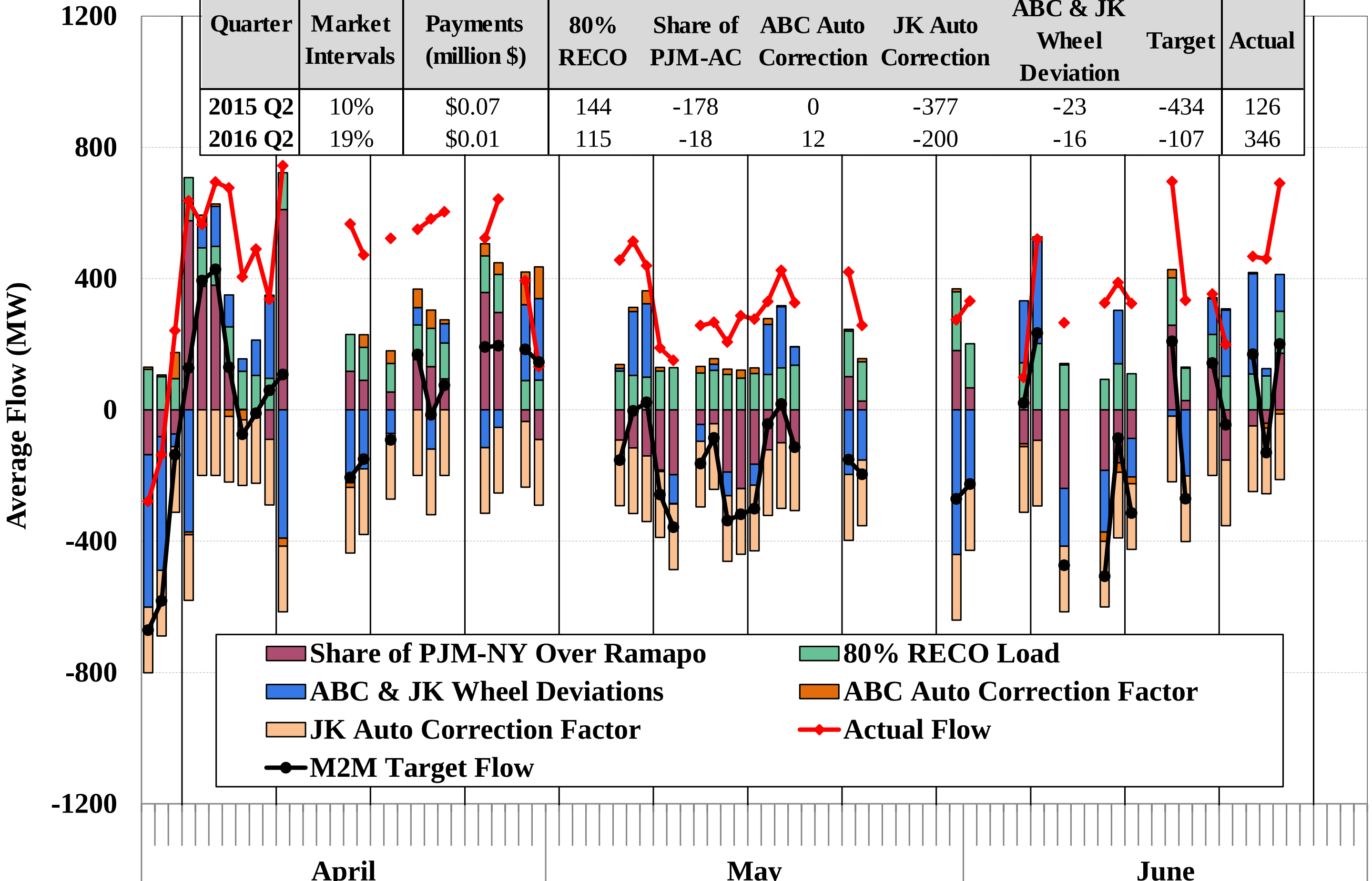
Operations under M2M with PJM

- Active Ramapo Coordination (i.e., when M2M constraints were binding) occurred in 19 percent of intervals, higher than in the second quarter of 2015.
  - ✓ The increase reflected more frequent congestion across the Central-East interface.
  - ✓ Average actual flows exceeded the Target Flow by 450 MW, resulting in a very small amount of M2M payments (~$12K) from PJM to NY this quarter.
    - – The low Target Flow resulted primarily from still large cumulative negative deviations on the JK PARs (represented by JK auto correction).
- The operation of the Ramapo PARs under M2M with PJM has provided significant benefit to the NYISO in managing congestion on coordinated flow gates.
  - ✓ The balancing congestion surpluses resulted from this operation on the Central-East interface indicate that it reduced production costs and congestion.
  - ✓ However, these were partly offset by shortfalls, an indication of PAR operations that increase production costs and congestion on the West Zone lines, which are currently not under the M2M JOA.
    - – The NYISO improved its operating practice in November 2015 to limit the use of Ramapo Coordination process to periods when the NYISO does not expect constraints in Western New York to be active.
    - – Nonetheless, it will be difficult to optimize the operation of the Ramapo line without a model to forecast the impacts of tap adjustments in RT.

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): 80% RECO	Share of PJM-AC	ABC Auto Correction	JK Auto Correction	ABC & JK Wheel Deviation	Target	Actual
2015 Q2	10%	$0.07	144	-178	0	-377	-23	-434	126
2016 Q2	19%	$0.01	115	-18	12	-200	-16	-107	346



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

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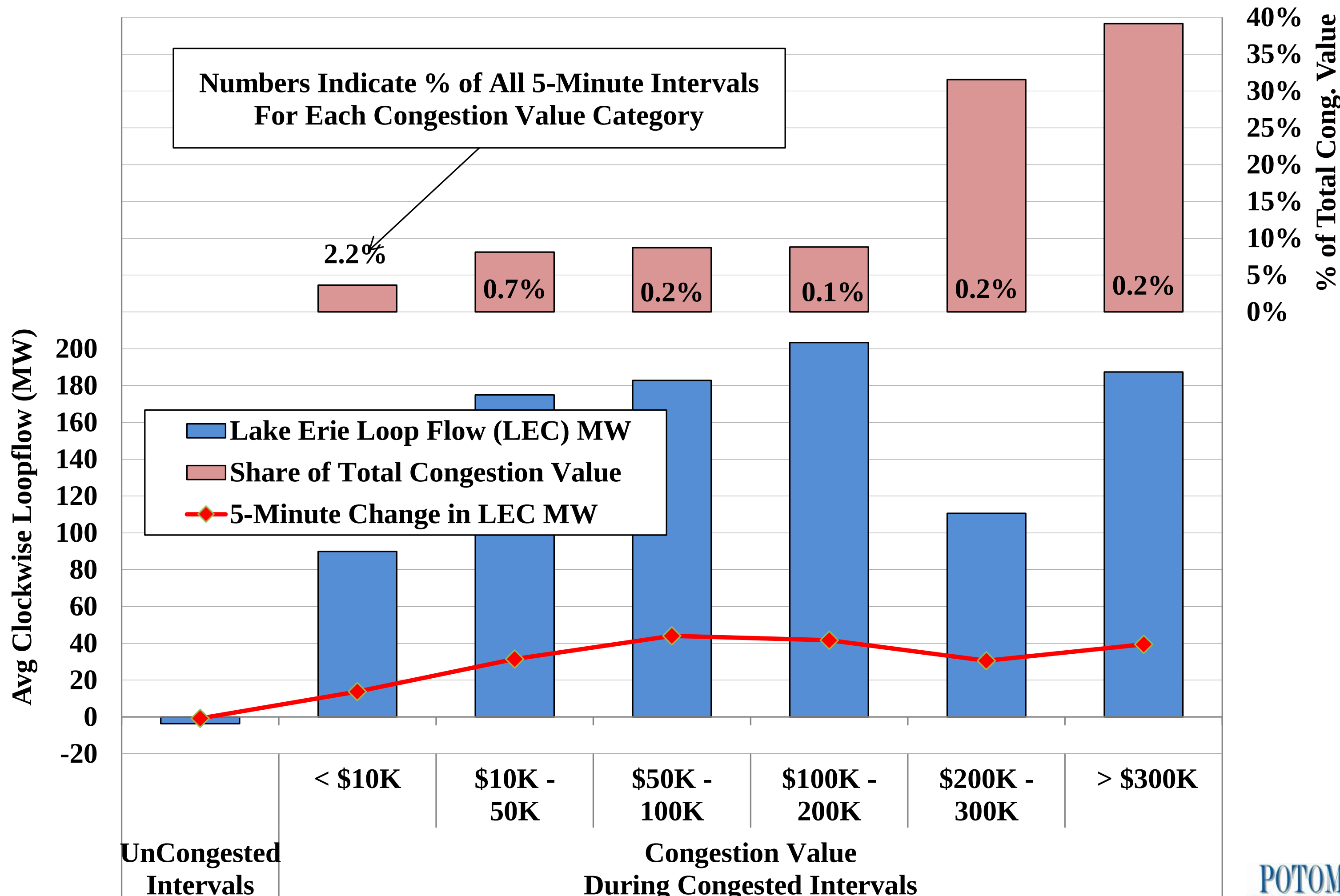
West Zone Congestion and Clockwise Loop Flows

- Clockwise loop flows contribute to congestion on transmission paths in Western New York, particularly in the West Zone.
- The following figure illustrates how and to what extent loop flows affected congestion on West Zone 230 kV constraints in the quarter.
  - ✓ The bottom portion of the chart shows the average amount of:
    - Lake Erie clockwise loop flows (the blue bar); and
    - Changes in loop flows from the prior 5-minute interval (the red line) during congested intervals in real-time. The congested intervals are grouped based on different ranges of congestion values.
    - For comparison, these numbers are also shown for the intervals with no West Zone congestion.
  - ✓ In the top portion of the chart,
    - The bar shows the portion of total congestion values that each congestion value group accounted for during the quarter; and
    - The number in each bar indicates how frequently each congestion value group occurred during the quarter.

West Zone Congestion and Clockwise Loop Flows

- A correlation was apparent between the severity of West Zone congestion (measured by congestion value) and the magnitude of loop flows and the occurrence of sudden changes from the prior interval.
- There was no West Zone congestion in 96.5 percent of intervals in the quarter.
  - ✓ Both the average amount of clockwise loop flows and the average change from the prior interval were low in these intervals.
- However, West Zone congestion was more prevalent when loop flows arose or happened to swing rapidly in the clockwise direction.
  - ✓ The congestion value on the West Zone constraints exceeded $50,000 in just 0.7 percent of all intervals in the second quarter of 2016.
    - However, these intervals accounted for 88 percent of the total congestion value in the West Zone.
    - In previous quarters, a small number of intervals accounted for relatively large share of the total congestion, this has been accentuated by the implementation of the GTDC. (see slides 65-69)
  - ✓ In these intervals, unscheduled clockwise loop flows averaged nearly 165 MW and clockwise changes in unscheduled loop flows averaged nearly 40 MW.

West Zone Congestion and Clockwise Loop Flows During the Second Quarter of 2016



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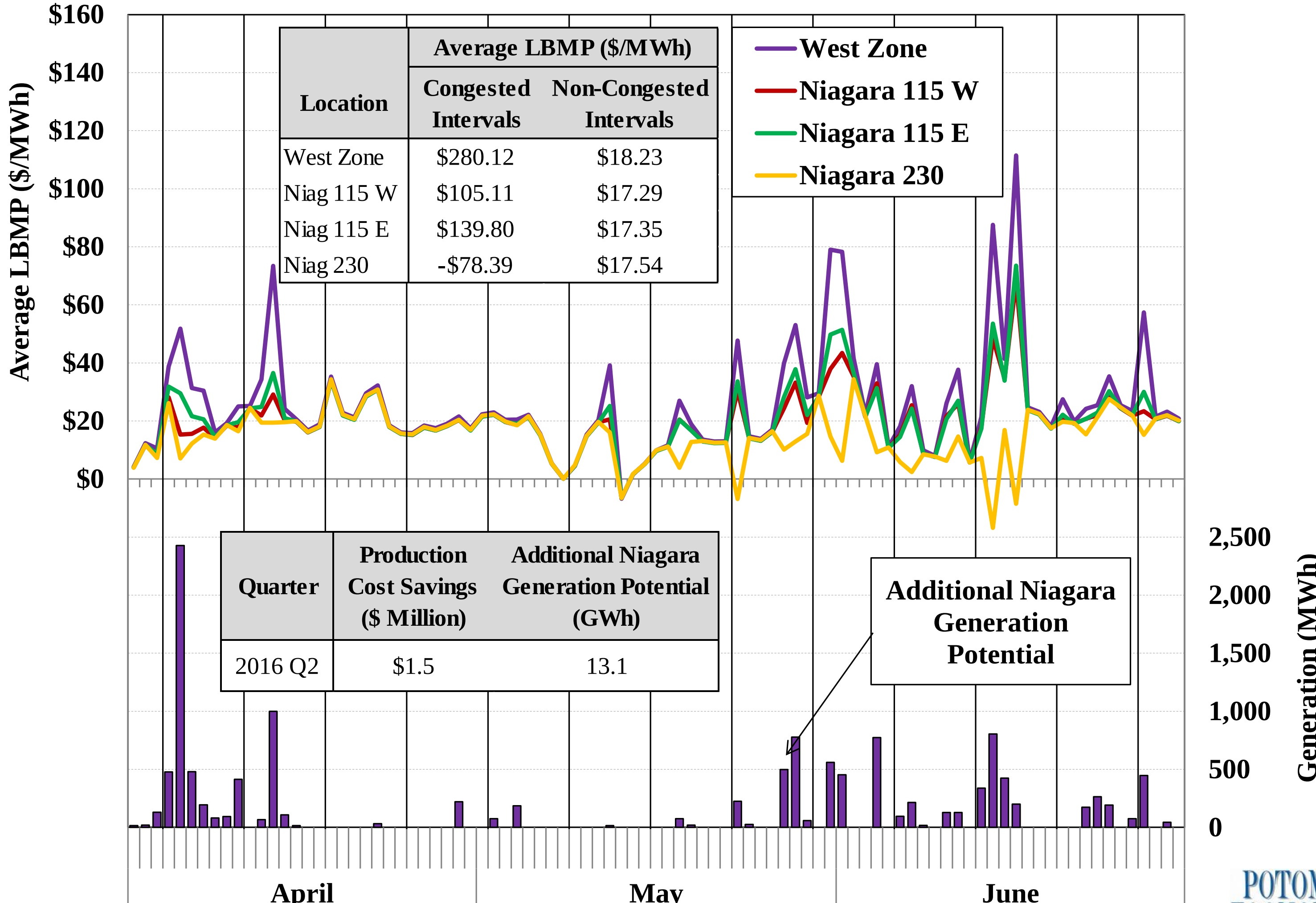
West Zone Congestion and Niagara Generation Modeling

- Transmission constraints on the 230kV network in the West Zone have become more frequent in recent years, limiting the flow of power towards Eastern NY.
  - ✓ Niagara units on the 115kV system tend to relieve these constraints, while ones on the 230kV system exacerbate this congestion.
  - ✓ These impacts are not considered optimally by the optimization engine, which treats Niagara as a single bus for pricing and dispatch.
    - – Assumption before May 4, 2016: Output injected at the 230kV bus.
    - – Assumption since May 4, 2016: Output distributed among 115kV and 230kV buses consistent with last telemetered distribution.
  - ✓ NYISO procedures still use manual instructions to shift generation among the individual units at the Niagara plant to alleviate congestion when appropriate.
- The next two figures evaluate how congestion in Western NY is affected by the modeling of the distribution of output from the Niagara plant.
  - ✓ The first figure illustrates the impact of shifting generation among Niagara units.
    - – The figure shows average estimated LBMPs for the West Zone, Niagara 230 kV Bus, Niagara East 115 kV Bus, and Niagara West 115 kV Bus.
    - – Additional Niagara Generation Potential – Additional generation (in MWhs) that would be deliverable if capability of 115kV circuits was fully utilized.

West Zone Congestion and Niagara Generation Modeling

- Although LBMPs at the Niagara 115 kV and 230 kV buses were very similar when West Zone congestion was not present, LBMP differences were significant during periods of congestion. In the second quarter of 2016:
  - ✓ West Zone 230 kV congestion occurred in 3.5 percent of all intervals; and
  - ✓ On average, LBMPs were $183 to $218 per MWh higher at the Niagara 115 kV Buses than at the Niagara 230 kV Buses during these intervals.
    - Negative LBMPs suggest over-utilization of 230kV units at the Niagara plant.
- If the 115kV circuits were fully utilized by shifting output to the 115kV buses:
  - ✓ Production costs would have been reduced by an additional $1.5 million in the second quarter of 2016 (assuming no changes in the constraint shadow costs). However, this does not consider:
    - Production cost savings: (a) from reducing over-utilization of the 230kV units and (b) from improved turbine efficiency during intervals with no congestion, and
    - The capital upgrade costs required to fully optimize.
  - ✓ An additional 13 GWh (or 170 MW on average) of Niagara generation could have been deliverable during these intervals. This would have had significant LBMP effects outside the west zone, since sudden reductions in Niagara output sometimes require expensive generation to be dispatched in East NY.

West Zone Congestion and Niagara Generation Modeling
LBMPs by Generator & Under-Utilization of 115kV Circuits



Location	Average LBMP ($/MWh)	
	Congested Intervals	Non-Congested Intervals
West Zone	$280.12	$18.23
Niag 115 W	$105.11	$17.29
Niag 115 E	$139.80	$17.35
Niag 230	-$78.39	$17.54

Quarter	Production Cost Savings ($ Million)	Additional Niagara Generation Potential (GWh)
2016 Q2	$1.5	13.1

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West Zone Congestion and Niagara Generation Modeling

- The second figure illustrates how modeling assumptions related to the system impacts of the Niagara plant differ from the actual impacts of the plant.
  - ✓ The scatter plots show the impact on constrained facilities in the West Zone:
    - – The horizontal axis shows the RTD model's assumed impact;
    - – The vertical axis reflects where output was actually increased (or decreased) at the plant (assuming perfect dispatch performance relative to the 5-minute signal).
    - – Hence, a point on the diagonal line indicates consistency between modeled impact and actual impact.
  - ✓ The table summarizes the average absolute value for both quantities as well as the average differential between the modeled impact and the actual impact.
- Consistency between the modeled and actual impacts was poor in both periods, which contributes to transient price volatility.
  - ✓ The average differential between modeled and actual impacts was large relative to the average modeled impact. (2.3 v 2.8 MW in 2016 & 5.4 v 10.3 MW in 2015.)
  - ✓ Under the old modeling approach, RTD generally over-estimated the impacts from re-dispatching Niagara.
  - ✓ Under the new modeling approach, RTD generally under-estimates the impacts from re-dispatching Niagara.

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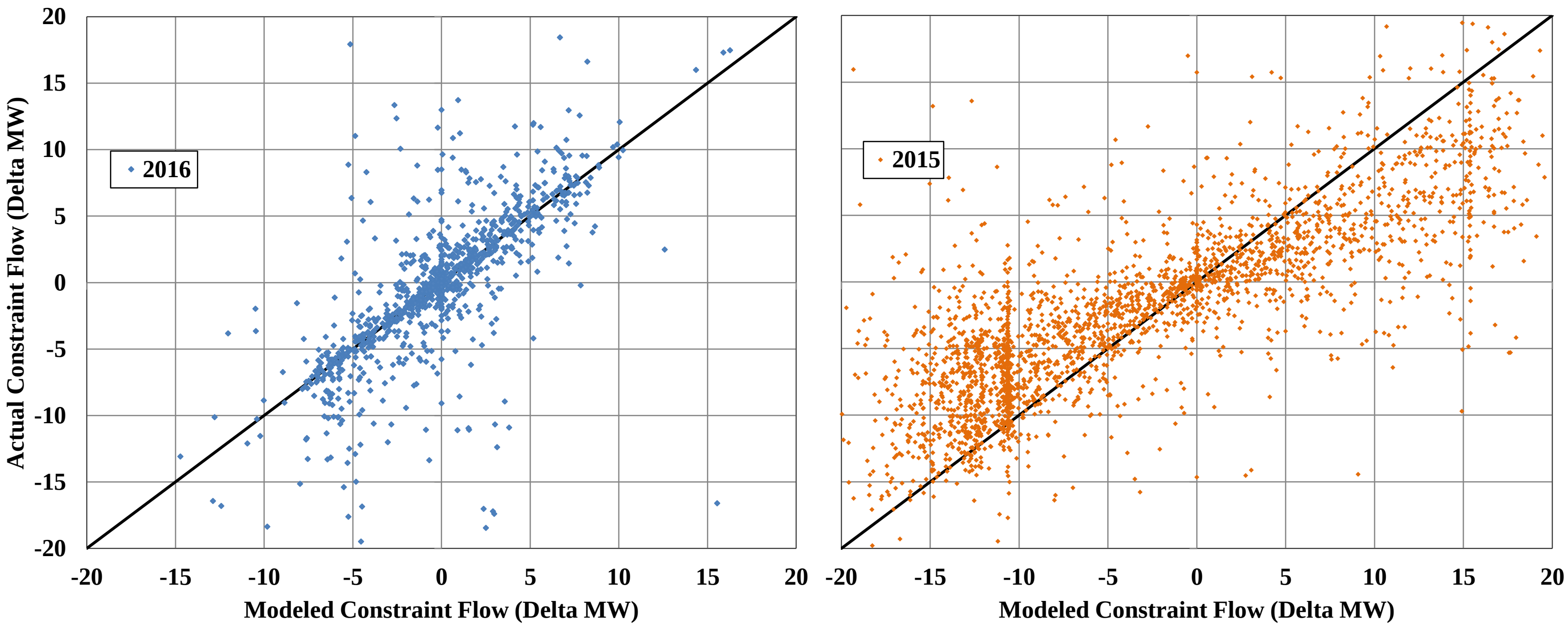
West Zone Congestion and Niagara Generation Modeling
Modeled Impact vs. Actual Impact



Average Constraint Flow Impact (Delta MW)		
Absolute Value of:	**2016-Q2**	**2015-Q2**
Modeled Impact	2.8	10.3
Actual Impact	4.2	6.9
Modeled v Actual	2.3	5.4

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Congestion Management with the GTDC

- The NYISO implemented the Graduated Transmission Demand Curve (“GTDC”) on February 12 to improve market efficiency during transmission shortages.
  - ✓ Efficient shadow prices facilitate efficient operations by providing incentives for market participants to schedule generation and external transactions efficiently.
  - ✓ Ideally, constraint shadow prices would reflect the importance and severity of a transmission constraint when flows exceed the BMS limit in RTD.
    - – The BMS limit is used by RTD to limit flows in each 5-minute interval.
- The GTDC project changed the scheduling and pricing methodology during shortages. (See *2015 SOM Report*, Appendix Section V.H. for details.)
  - ✓ Key changes include: (a) replacing the $4000 penalty with 3-step GTDC, and (b) reducing the constraint relaxation limit adjustment from +8 MW to +0.2 MW.
- The next three figures compare market performance before and after the change.
  - ✓ The first figure summarizes shadow prices, shortage quantities relative the BMS limit (adjusted for the CRM), and RT congestion value by constraint group.
  - ✓ The second figure shows this information for individual 5-minute intervals.
  - ✓ The third figure shows shadow prices and shortage quantities relative to the seasonal limit (adjusted for the CRM) for West Zone constraints.

Congestion Management with the GTDC

- Shadow prices during shortages have increased since the GTDC was implemented.
  - ✓ This is from the reduced limit adjustment (+0.2MW) since most (~70%) shortages are still resolved using the constraint relaxation method (rather than the GTDC).
  - ✓ Constraint relaxation can lead shadow prices to be higher or lower than the GTDC.
    - In NYC & Long Island, shadow prices were generally lower than the GTDC.
    - In the West Zone, the results were mixed (shadow prices averaged $908 v $350 for shortages of <5 MW and $1957 v $2350 for shortages of 5 to 20 MW).
- Transmission shortage quantities have fallen since the GTDC was implemented.
  - ✓ Higher shadow prices provide stronger incentives for external transactions (and other non-dispatchable resources) to avoid schedules that exacerbate congestion.
    - Efficient prices provide incentives that are neither too strong nor too weak.
  - ✓ However, the shortage frequency increased in NYC & Long Island partly because the GTDC makes RTC less likely to start a GT to manage a brief shortage.
- In the West Zone, volatile loop flows and difficulty managing congestion can lead operators to reduce the BMS limit below the seasonal limit.
  - ✓ BMS limits and modeled flows have been much closer to the seasonal limits (i.e., higher) this year in the West Zone partly because the GTDC project has improved the ability of RTS to manage flows.

Congestion Management with the GTDC
Constraint Summary, 2015-Q2 vs. 2016-Q2

Location of Constrained Facility	Transmission Shortage	# of Constraint-Intervals		Average Shortage (MW)		Average Shadow Price ($/MWh)		RT Congestion Value ($M) Original		RT Congestion Value ($M) Adjusted Using GTDC Directly	
		2015	2016	2015	2016	2015	2016	2015	2016	2015	2016
West Zone	N	1928	662	0	0	$148	$107	$12	$3	$12	$3
	Y	924	487	27	8	$679	$1,587	$31	$33	$131	$32
New York City	N	11951	11171	0	0	$26	$37	$8	$10	$8	$10
	Y	238	763	17	12	$356	$484	$2	$7	$18	$32
Long Island	N	7198	3222	0	0	$66	$30	$12	$2	$12	$2
	Y	186	302	18	10	$464	$293	$2	$2	$10	$8
All Other	N	6074	7727	0	0	$74	$30	$44	$36	$44	$36
	Y	156	177	15	24	$488	$1,339	$9	$34	$27	$39

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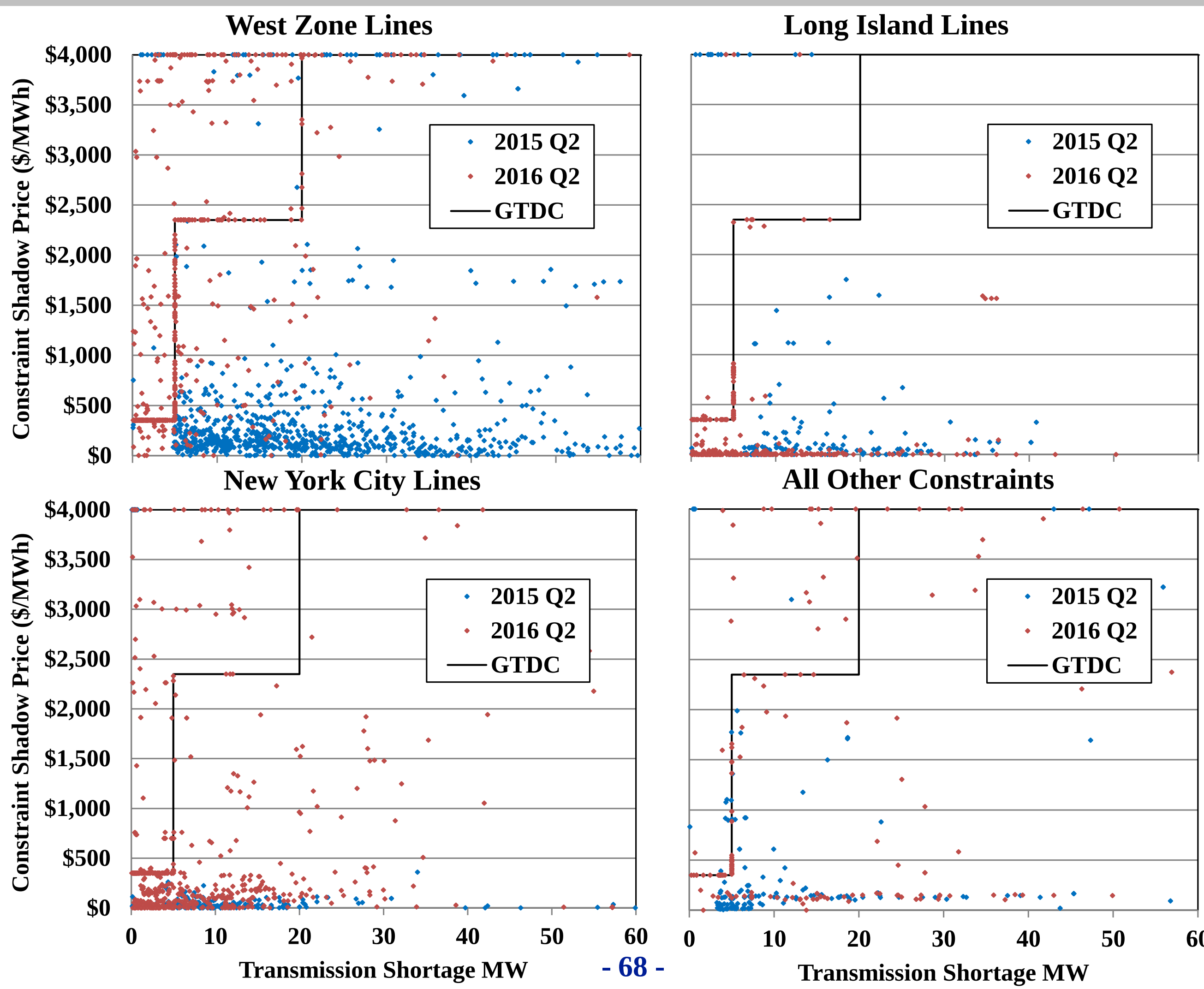
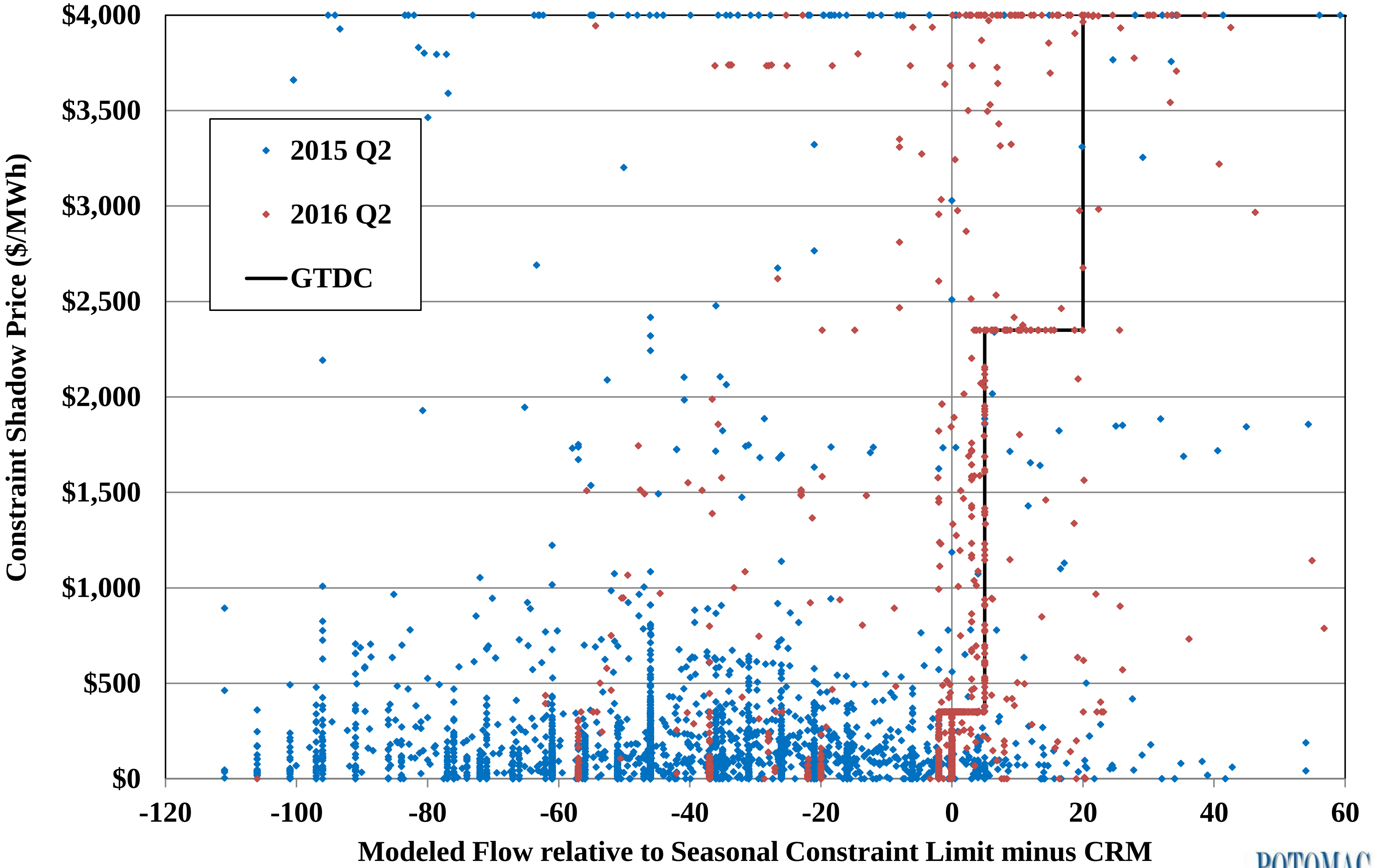
Congestion Management with the GTDC
Transmission Shortage Pricing, 2015-Q2 vs. 2016-Q2



Congestion Management with the GTDC
Limit Adjustments & Shortage Pricing, 2015-Q2 vs. 2016-Q2



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Conclusions Regarding West Zone Congestion

- Transmission constraints in West Zone have become more frequent in recent years, increasing wholesale prices, price volatility, and congestion residual uplift.
  - ✓ These have been driven by many factors including gas market conditions, coal plant retirements, and increased renewables in NY and neighboring regions.
  - ✓ Volatile loop flows continue to exacerbate congestion.
  - ✓ However, recent transmission investments have ameliorated congestion.
  - ✓ (See the NYISO's 8/4 MIWG presentation for a detailed discussion of factors.)
- These challenges increase the importance of efficient congestion management.
  - ✓ On 6/28, NYISO implemented enhanced loop flow assumptions that are designed to schedule resources more efficiently given uncertainty about loop flows.
  - ✓ Ultimately, efficient congestion management can reduce the need for transmission infrastructure investments. However, we continue to observe:
    - – Under-utilization of 115kV circuits that are parallel to congested facilities,
    - – Inefficiently-high generation from units that exacerbate 230kV congestion,
    - – Under-commitment of West Zone units that relieve 115kV & 230kV congestion,
    - – Shadow prices are not well correlated with the severity of congestion during transmission shortages, which undermines scheduling incentives for importers and other non-dispatchable resources.

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Supplemental Commitments, OOM Dispatch, and Uplift Charges

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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.

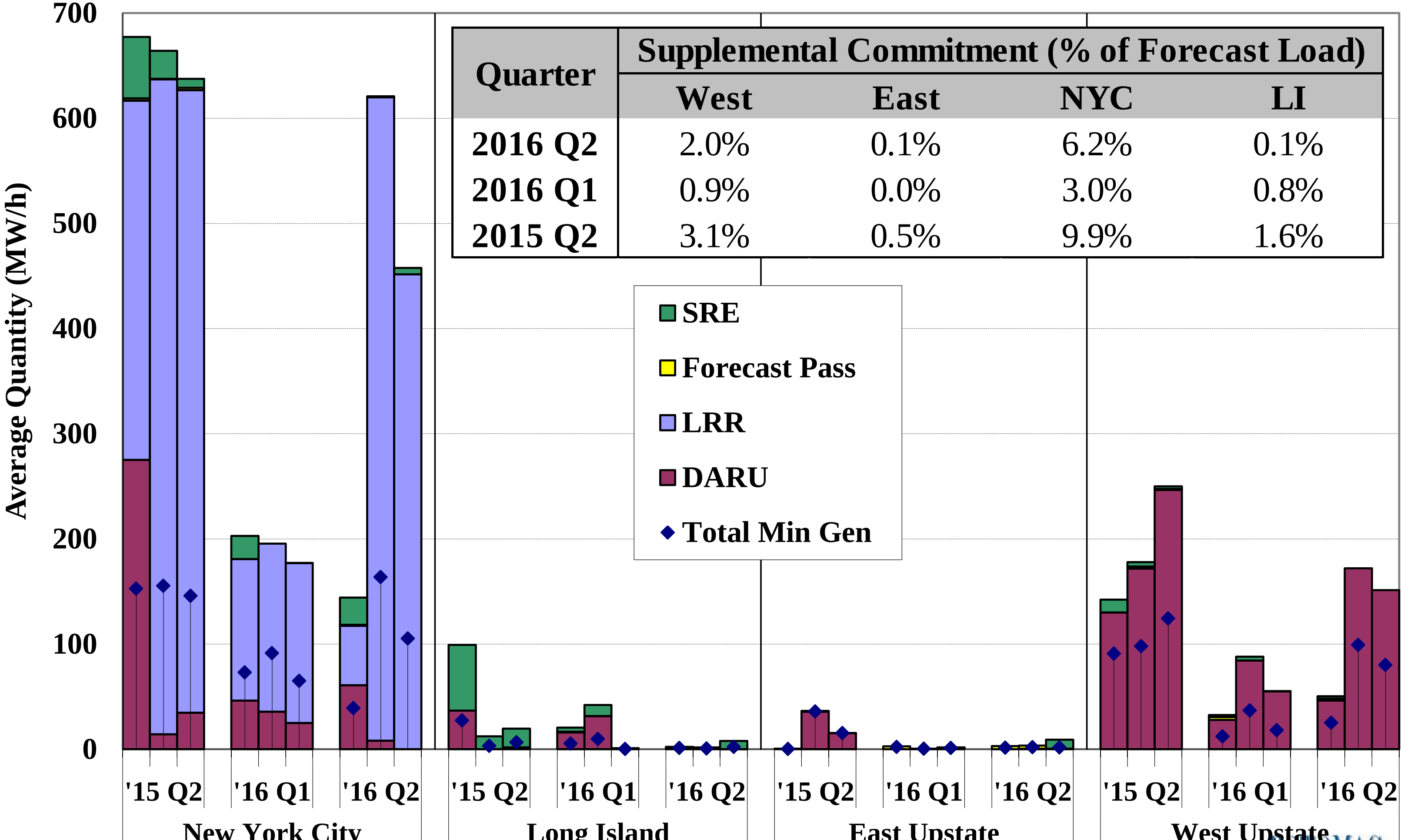
Supplemental Commitment and OOM Dispatch: Supplemental Commitment Results

- An average of 540 MW of capacity was committed for reliability in the second quarter of 2016, down 41 percent from the second quarter of 2015.
  - ✓ NYC (75 percent) and Western NY (23 percent) accounted for nearly all of the capacity committed for reliability in this quarter.
- Reliability commitments in Western NY averaged 125 MW, down 34 percent from a year ago, which was driven partly by reduced local needs because of recent transmission upgrades in Western NY.
  - ✓ With several coal retirements, the vast majority of DARU commitments has recently occurred in the Central Zone at the Cayuga (Milliken) plant.
- Reliability commitments in NYC averaged 410 MW, down 38 percent from the second quarter of 2015 because of:
  - ✓ More frequent economic commitments of NYC generators, reflecting larger gas spreads between NYC and the rest of Eastern NY and lengthy nuclear outages in Lower Hudson Valley; and
  - ✓ Fewer transmission and generation outages, which led to reduced local needs and fewer DARU commitments in April.
    - – In the second quarter of 2016, most reliability commitments were made to satisfy the N-1-1 thermal requirements in the Astoria West/Queensbridge load pocket.

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 1456 station-hours, down 17 percent from the second quarter of 2015.
  - ✓ The reduction occurred primarily in Western NY, which accounted for 72 percent of all OOM actions in this quarter.
  - ✓ OOM levels were low in January to April following the retirement of the last Dunkirk unit (which was frequently OOMed in the past for local reliability needs) at the end of December 2015.
  - ✓ Relatively high OOM levels in May and June were from frequent OOM dispatch of the Milliken unit to manage congestion on the Elbridge-State Street 115kV line.
- The Niagara facility was often manually instructed to shift output among its units to secure certain 115kV and/or 230 kV transmission constraints.
  - ✓ In the second quarter of 2016, this manual shift was required in 97 hours to manage 115 kV constraints and in 503 hours to manage 230 or 345 kV constraints.
  - ✓ This pattern has continued since the Huntley reactors were activated.

Supplemental Commitment for Reliability
by Category and Region



Quarter	Supplemental Commitment (% of Forecast Load)			
	West	East	NYC	LI
2016 Q2	2.0%	0.1%	6.2%	0.1%
2016 Q1	0.9%	0.0%	3.0%	0.8%
2015 Q2	3.1%	0.5%	9.9%	1.6%

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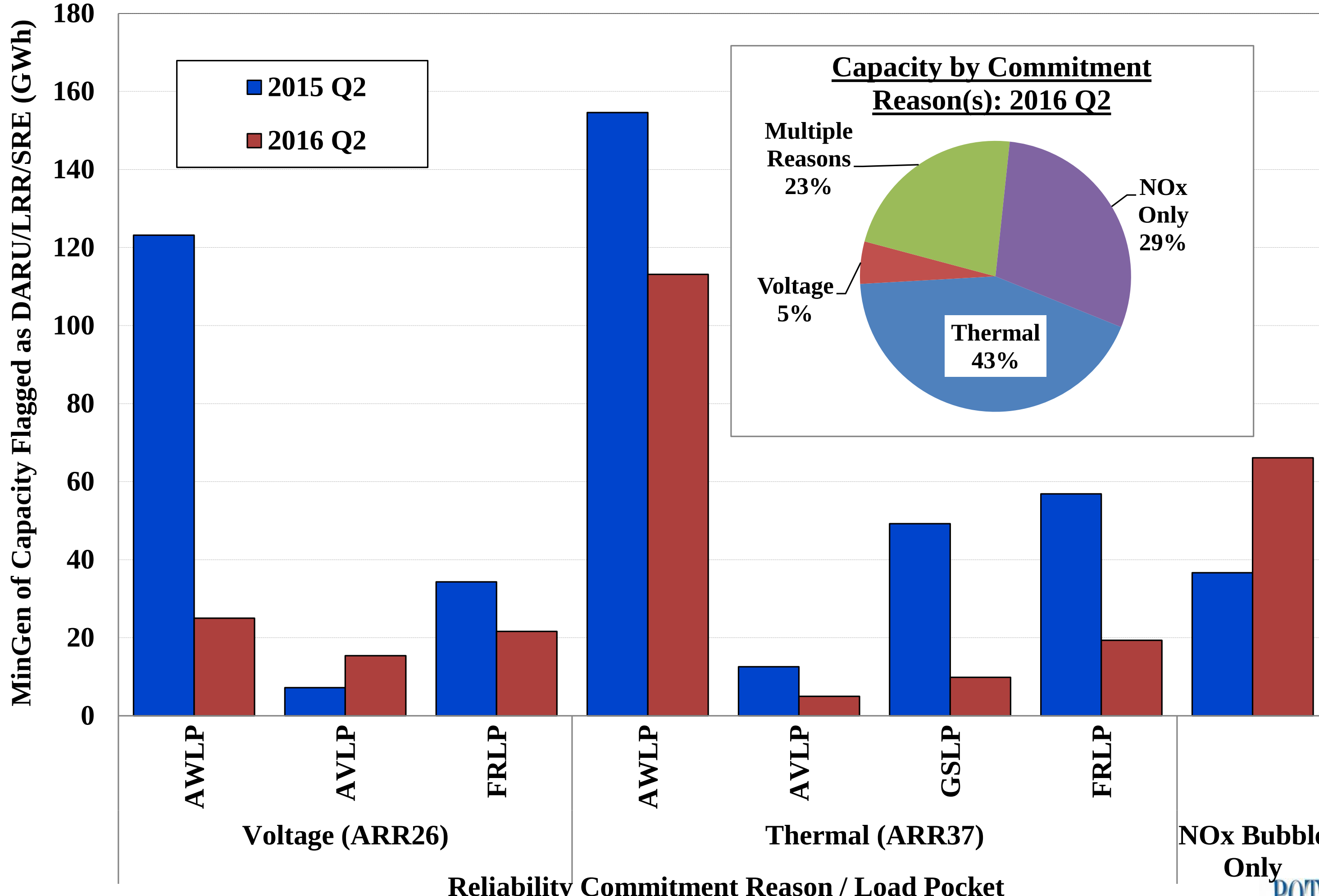
Supplemental Commitment for Reliability in NYC by Reliability Reason and Load Pocket



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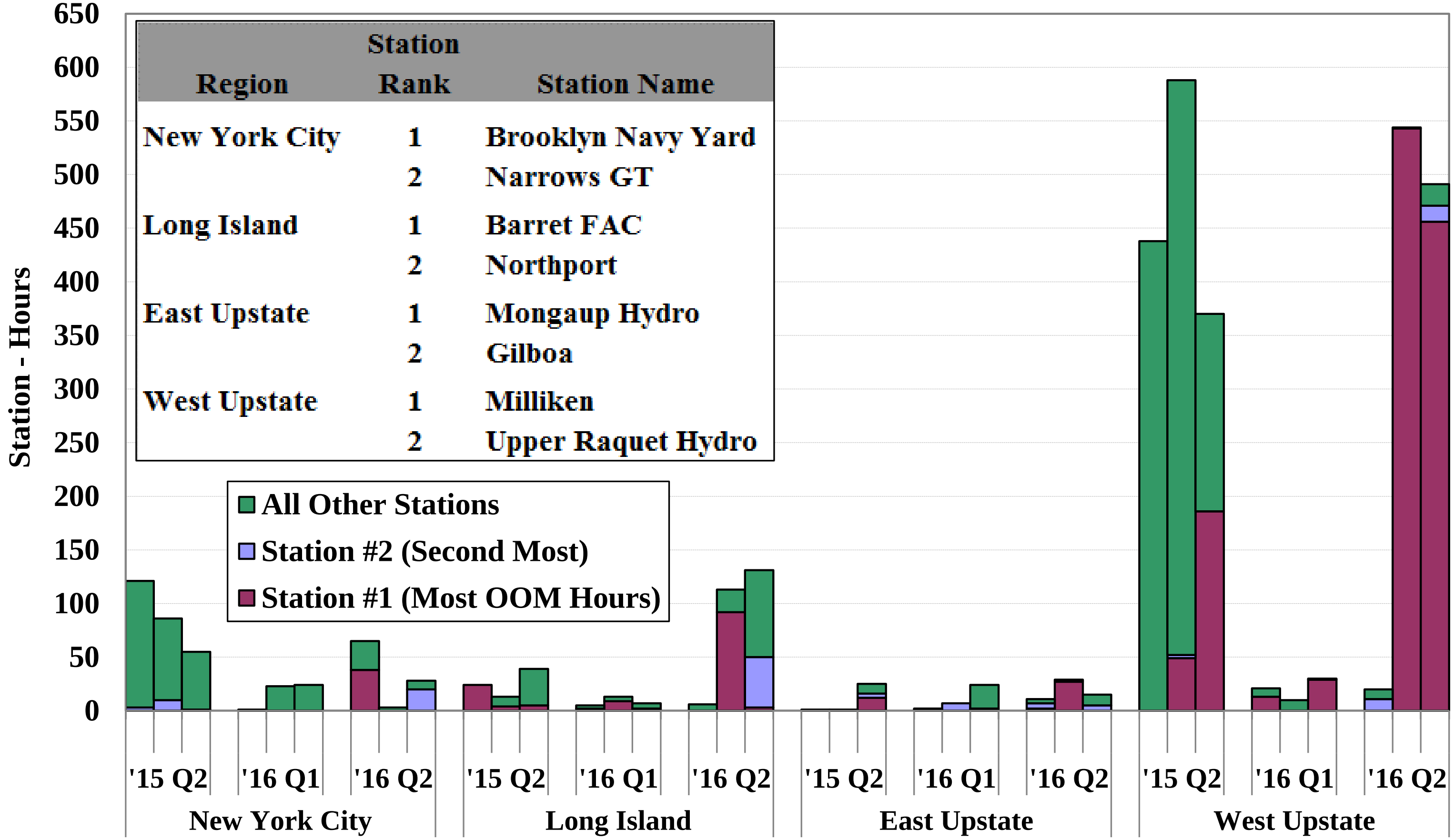
Frequency of Out-of-Merit Dispatch by Region by Month



Region	Station Rank	Station Name
New York City	1	Brooklyn Navy Yard
	2	Narrows GT
Long Island	1	Barret FAC
	2	Northport
East Upstate	1	Mongaup Hydro
	2	Gilboa
West Upstate	1	Milliken
	2	Upper Raquet Hydro

Note: The NYISO also instructed Niagara to shift output among the generators at the station in order to secure certain 115kV and/or 230kV transmission facilities in 797 hours in 2015-Q2, 337 hours in 2016-Q1, and 600 hours in 2016-Q2. However, these were not classified as Out-of-Merit in hours when the NYISO did not adjust the UOL or LOL of the Resource.

Uplift Costs from Guarantee Payments: Chart Descriptions

- The next two figures show uplift charges in the following seven categories.
  - ✓ Three categories of non-local reliability uplift are allocated to all LSEs:
    - Day Ahead: For units committed in the day-ahead market (usually economically) whose day-ahead market revenues do not cover their as-offered costs.
    - Real Time: For 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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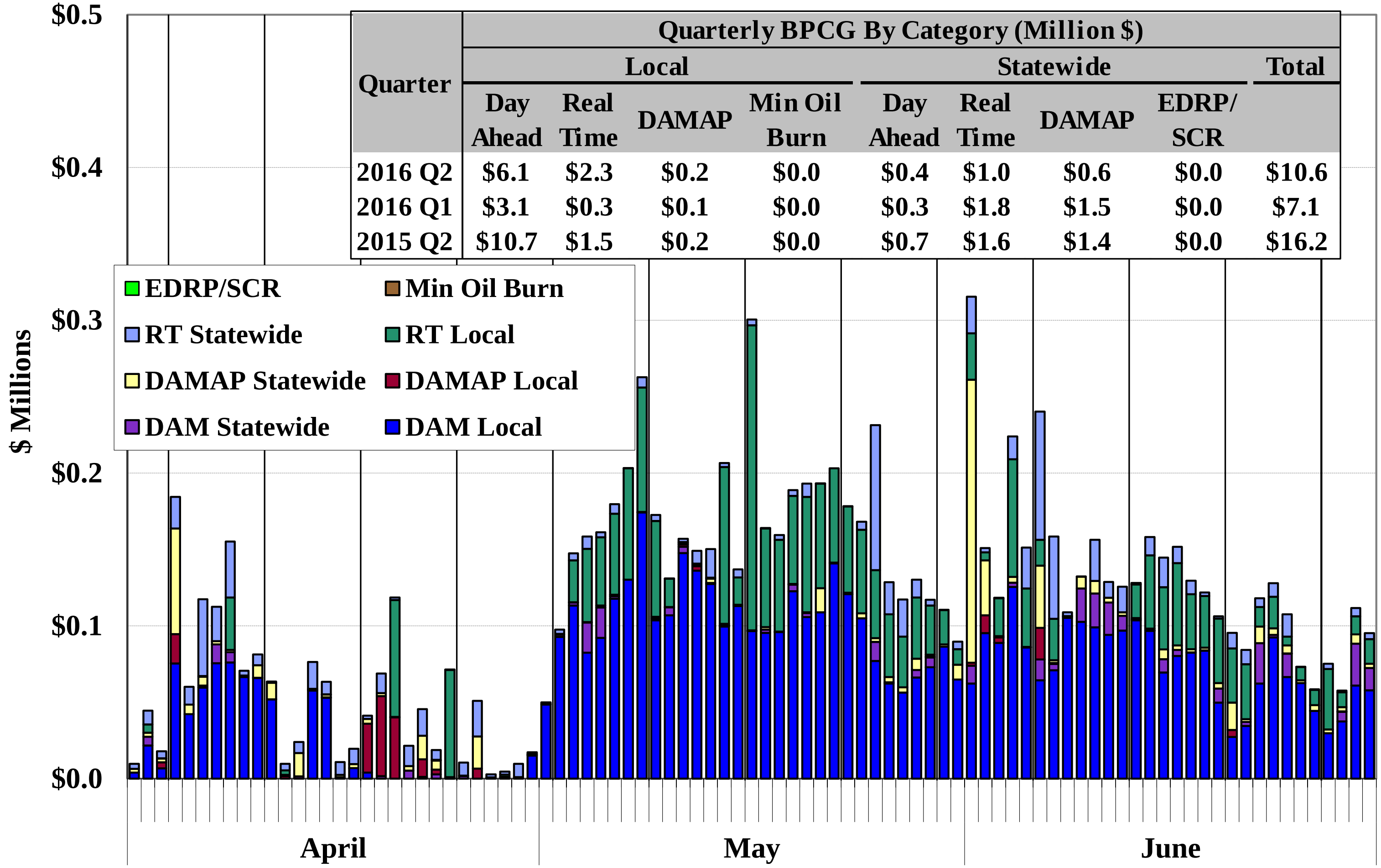
Uplift Costs from Guarantee Payments: Results

- Guarantee payments totaled nearly $10.6 million this quarter, down 34 percent from the second quarter of 2015. The reduction was consistent with:
  - ✓ Decreased supplemental commitment and OOM dispatches (see slides 76-78); and
  - ✓ Lower natural gas prices (see slide 12), which decreased the commitment costs of gas-fired units.
- Of the total guarantee payment uplift in the second quarter of 2016:
  - ✓ 82 percent was allocated locally, while the remainder was allocated statewide.
  - ✓ Western NY accounted for 64 percent, NYC accounted for 22 percent, and Long Island accounted for 10 percent.
- Local uplift in Western NY totaled $6.4 million, accounting for 60 percent of total guarantee uplift this quarter.
  - ✓ Nearly all of this local uplift was paid to units that were committed and/or OOMed to manage congestion on the 115 kV system (see slide 78).

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

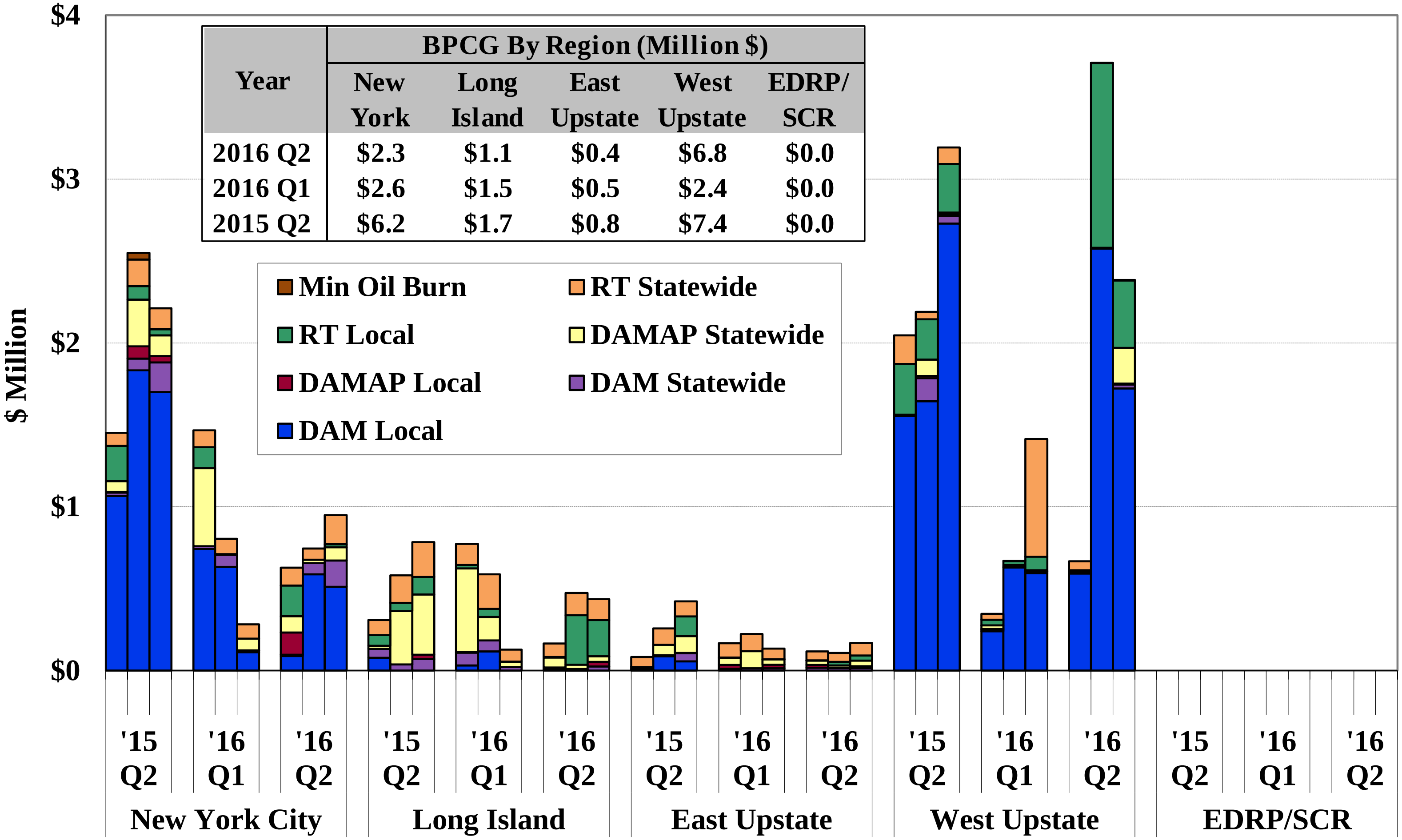


Quarter	Quarterly BPCG By Category (Million $)								
	Local				Statewide				Total
	Day Ahead	Real Time	DAMAP	Min Oil Burn	Day Ahead	Real Time	DAMAP	EDRP/ SCR	
2016 Q2	$6.1	$2.3	$0.2	$0.0	$0.4	$1.0	$0.6	$0.0	$10.6
2016 Q1	$3.1	$0.3	$0.1	$0.0	$0.3	$1.8	$1.5	$0.0	$7.1
2015 Q2	$10.7	$1.5	$0.2	$0.0	$0.7	$1.6	$1.4	$0.0	$16.2

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	EDRP/ SCR
2016 Q2	$2.3	$1.1	$0.4	$6.8	$0.0
2016 Q1	$2.6	$1.5	$0.5	$2.4	$0.0
2015 Q2	$6.2	$1.7	$0.8	$7.4	$0.0

Note: BPCG data are based on information available at the reporting time that can be different from final settlements.

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Market Power and Mitigation

Market Power Screens: Potential Economic and Physical Withholding

- The next two figures show the results of our screens for attempts to exercise market power, which may include economic and physical withholding.
- The screen for potential 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.
  - ✓ We show output gap in NYCA and East NY, based on:
    - The state-wide mitigation threshold (the lower of $100/MWh and 300 percent); and
    - Two other lower thresholds (100 percent and 25 percent).
- The screen for potential physical withholding is the "unoffered economic capacity", which is the amount of economic capacity that is not available to the market because a supplier does not offer, claims a derating, or offers in an inflexible way.
  - ✓ We show the unoffered economic capacity in NYCA and East NY from:
    - Long-term outages/deratings (at least 7 days);
    - Short-term outages/deratings (less than 7 days);
    - Online capacity that is not offered or offered inflexibly; and
    - Offline GT capacity that is not offered in the real-time market.

Market Power Screens: Potential Economic and Physical Withholding

- The amount of output gap was relatively low as a share of capacity.
  - ✓ During the second quarter of 2016, the average amount of output gap averaged:
    - Less than 0.1 percent of total capacity at the mitigation threshold; and
    - Roughly 1 to 2 percent at the lowest threshold evaluated (i.e., 25 percent).
  - ✓ The amount of output gap fell modestly from a year ago.
  - ✓ Overall, the output gap raised no significant market power concerns this quarter.
- The amount of unoffered (including outages/deratings) economic capacity was reasonably consistent with expectations for a competitive market.
  - ✓ Economic capacity on long-term outages/deratings were higher in April and May as suppliers typically scheduled more maintenance during the shoulder months.
    - In some cases, it would have been efficient to postpone the some of these outages because it would have been economic to operate given actual market conditions.
    - However, some generators will likely be economic whenever they take an outage because they have very low operating costs (e.g., nuclear units).
  - ✓ In the second quarter of 2016, two nuclear units had lengthy maintenance outages and frequent short-term deratings, accounting for more than 50 percent of economic capacity on long-term outages/deratings and over 30 percent on short-term outages/deratings.

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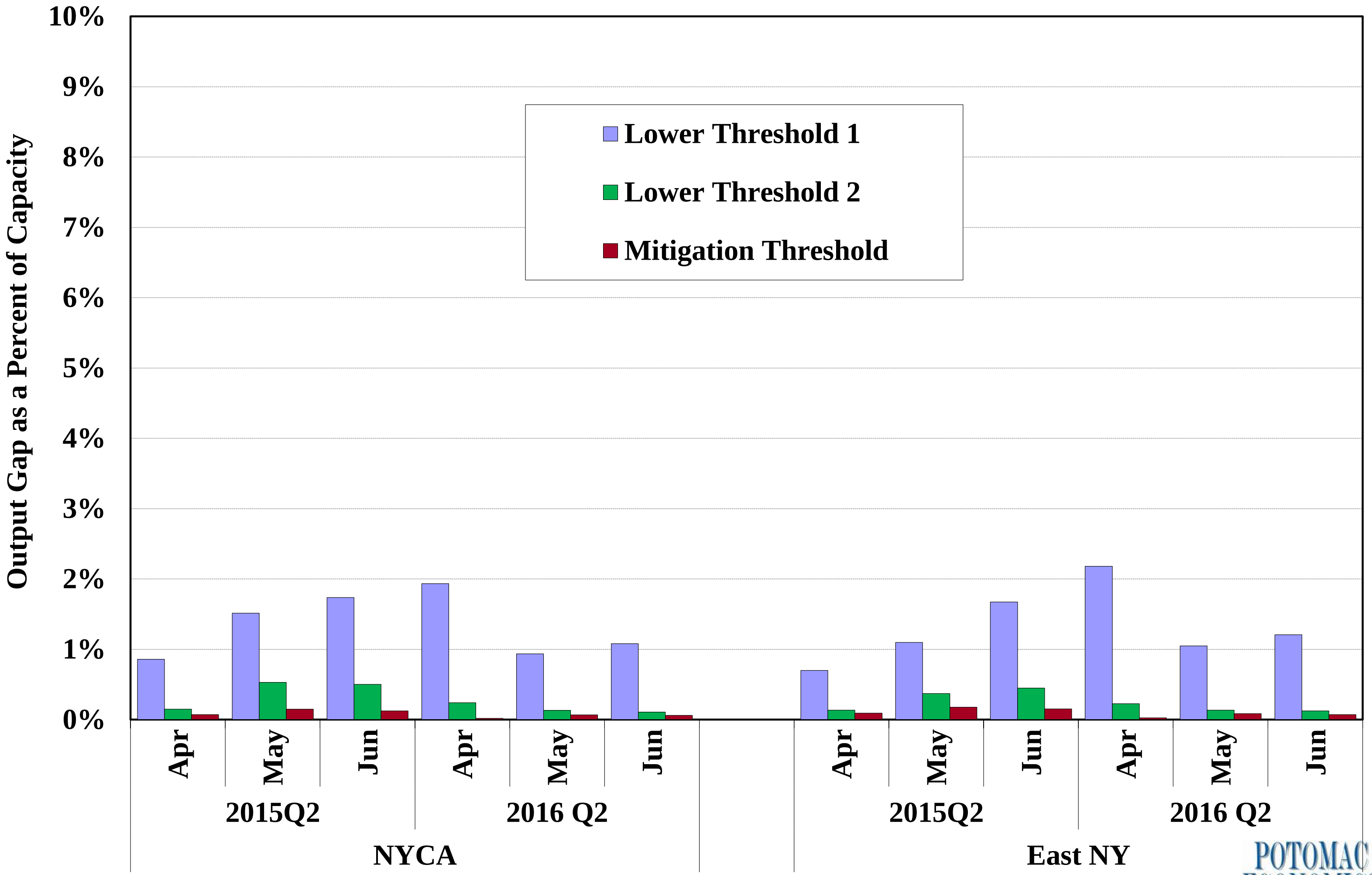
Output Gap in NYCA and East NY



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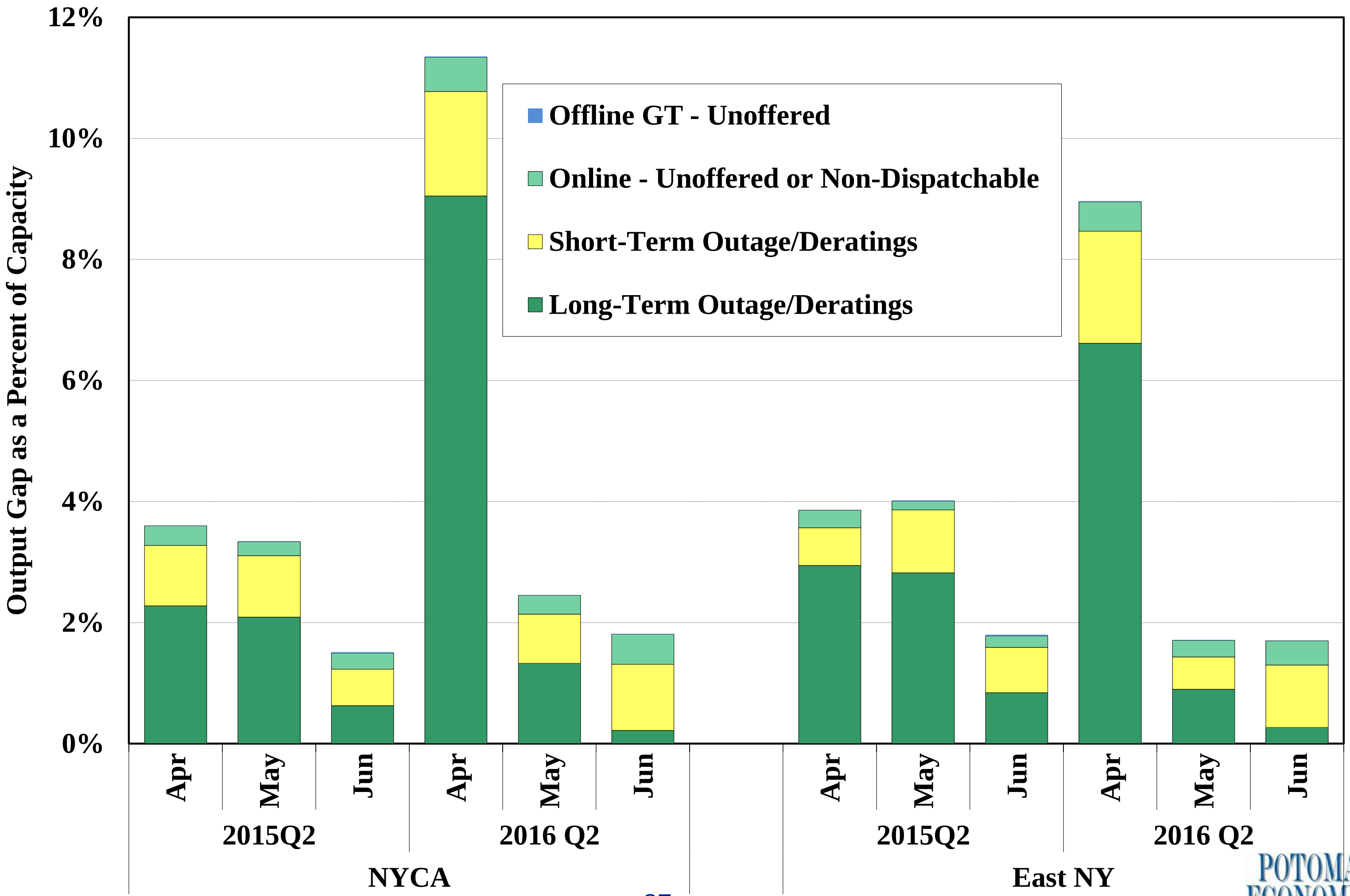
Unoffered Economic Capacity in NYCA and East NY



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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 second quarter of 2016,
  - ✓ Nearly all of mitigation occurred in the day-ahead market, of which:
    - Local reliability (i.e., DARU & LRR) units accounted for 89 percent. These mitigations generally affect guarantee payment uplift but not LBMPs.
    - Units in the Greenwood/Staten Island load pocket accounted for 9 percent.
- The quantity of mitigation declined from the second quarter of 2015 primarily because of reduced DARU and LRR commitments in NYC (see slides 76-77).

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Automated Market Mitigation

Quarterly Mitigation Summary

		2014 Q2	2015 Q2	2016 Q1	2016 Q2
Day-Ahead Market	**Average Mitigated MW**	121	146	52	103
	Energy Mitigation Frequency	5%	3%	1%	8%
Real-Time Market	**Average Mitigated MW**	1	1	0.3	1
	Energy Mitigation Frequency	0.3%	1%	0.0%	0.3%

Capacity Market

Capacity Market Results

- The following two figures summarize capacity market results and key market drivers in the second quarter of 2016.
  - ✓ The first figure summarizes available and scheduled Unforced Capacity ("UCAP"), UCAP requirements, and spot prices that occurred in each capacity zone by month (also compared to those from a year ago).
  - ✓ The next table shows: (a) the year-over-year changes in spot prices by locality; and (b) variations in key factors that drove these changes.
- The average spot prices fell by 11 to 22 percent in the capacity zones in SENY from a year ago, due primarily to:
  - ✓ An increase of roughly 300 MW of internal ICAP supply in the G-J Locality; and
  - ✓ Lower ICAP requirements because of lower peak load forecast and reduced LCRs (due partly to the TOTS projects, which increased import capability into SENY).
- However, the average spot prices rose 11 percent in the ROS.
  - ✓ The ICAP requirement fell slightly from a year ago, reflecting the net effect of lower peak load forecast and a higher IRM.
    - – This was offset by a similar decrease in total internal ICAP supply.
  - ✓ Sales from ISO-NE were higher in May 2015, contributing to a lower average spot price in the second quarter of 2015.

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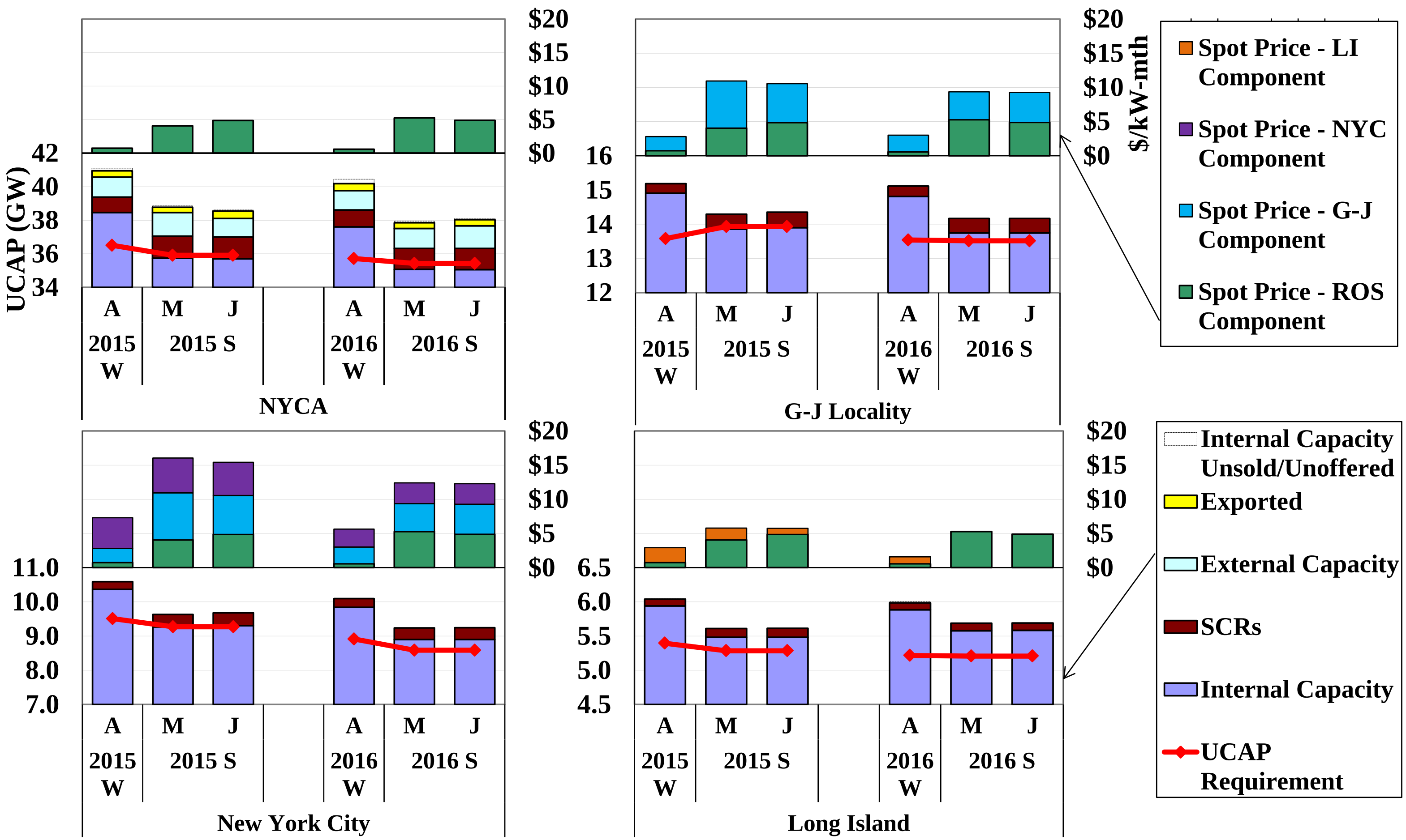
Capacity Market Results:
Second Quarter 2015 & 2016



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

Key Drivers of Capacity Market Results

	NYCA	NYC	LI	G-J Locality
Avg. Spot Price				
2016 Q2 ($/kW-Month)	3.58	10.12	3.92	7.22
% Change from 2015 Q2	11%	-22%	-19%	-11%
Change in Demand				
Load Forecast (MW)	-209	-136	-61	-31
IRM/LCR	0.5%	-3.0%	-1.0%	-0.5%
2016 Summer	*117.5%*	*80.5%*	*102.5%*	*90.0%*
2015 Summer	*117.0%*	*83.5%*	*103.5%*	*90.5%*
ICAP Requirement (MW)	**-77**	**-467**	**-117**	**-109**
Change in ICAP Supply (MW)				
Reductions Due to: Retirement (R), ICAP Inegilible FO (FO), Mothball (M)				
R - Huntley 67 & 68 (Mar-16)	-375			
FO - Astoria GT 05,07,08,12,13 (Jan-16)	-74	-74		-74
R - Dunkirk 2 (Jan-16)	-75			
M - Ravenswood 04,05,06 (May-16)	-49	-49		-49
Additions Due to: Return to Service				
Bowline Unit 2 (Jul-15)	374			374
Changes Due to: DMNC Test	102	73	23	50
Net Changes (MW)	**-97**	**-50**	**23**	**301**

Note: The changes in demand and supply are measured based on the Summer Capability Period.

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