Quarterly Report on the New York ISO Electricity Markets Second Quarter of 2017

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Highlights and Market Summary:
Energy Market Outcomes and Congestion

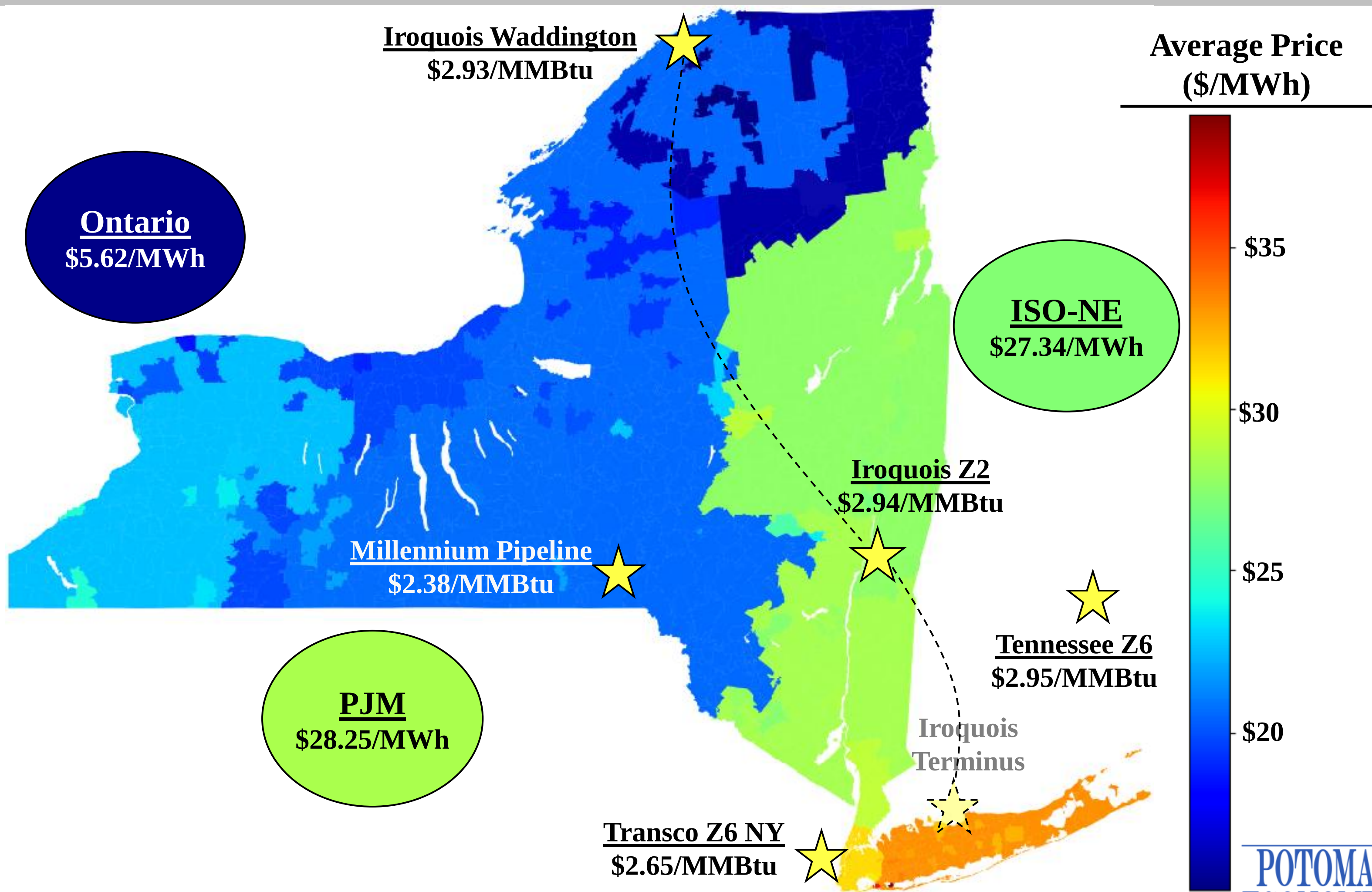
- This report summarizes market outcomes in the second quarter of 2017.
- The energy markets performed competitively and variations in wholesale prices were driven primarily by changes in fuel prices, demand, and supply availability.
- All-in prices averaged from \$21/MWh in the North Zone to \$57/MWh in NYC.
  - ✓ The range was primarily due to congestion on power flowing from the North Zone to central New York, Central East congestion, and capacity price differences.
  - ✓ Zone-level LBMPs rose in most regions by 7 to 25 percent because of:
    - Higher gas prices, which rose 20 to 60 percent in East NY and 65 percent in Western NY. (see slide 12)
    - However, higher output from nuclear, internal hydro, and Canadian imports (~950 MW total) offset much of the gas price impact on LBMPs. (see slides 16, 41)
  - ✓ Capacity costs were impacted by changes in Net CONE from the recent Demand Curve Reset process. (see slide 91)
- Congestion costs from on priced and un-priced constraints rose from 2016.
  - ✓ DA congestion revenue was \$117M, up 24 percent from 2016-Q2. (see slide 54)
  - ✓ Congestion increased into NYC, across the Central East interface, and along paths from western and northern NY.

Highlights and Market Summary:
Energy Market Outcomes and Congestion

- ✓ In western and northern NY, priced congestion declined, while un-priced congestion became more prevalent because of:
  - Improved hydro conditions in NY and low prices in the adjacent Canadian markets;
  - Transmission upgrades completed in May 2016, which reduced priced congestion on 230 kV facilities in the West, but shifted more flows onto parallel 115 kV circuits.
- ✓ We find that actions used to manage 115kV congestion in western and northern New York led to import limitations from Ontario and Quebec as well as congestion on the 200+kV system in other parts of the state. (see slides 64-67)
  - This congestion management could be performed more efficiently through the DA and RT market systems.

- RT congestion costs for the Valley Stream load pocket on Long Island fell from a year ago because of improved modeling of lines between NYC and Long Island.
- The M2M PAR coordination process expanded in May after the 1,000 MW ConEd-PSEG Wheel expired. (see slides 57-63)
  - ✓ Congestion increased through Millwood and into New York City.
  - ✓ The A/B/C and J/K lines were operated more efficiently. (see slides 52, 56)
  - ✓ However, we observe that these PARs were often not utilized to help manage congestion, being adjusted only 2 to 5 times per day on average.

Highlights and Market Summary:
Energy Market Outcomes and Congestion



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Highlights and Market Summary:
Reserve Market Performance

- DA 30-minute reserve prices have been substantially elevated since the market rule change in November 2015, driven primarily by:
  - ✓ The new limitation on scheduling reserves on Long Island (down 250-300 MW);
  - ✓ Increased 30-minute reserve requirement (up 655 MW); and
  - ✓ Higher reserve offer prices from some units (partly reflecting energy limitations).
- We have reviewed DA reserve offers and found many units that offer above the standard competitive benchmark (i.e., estimated marginal cost).
  - ✓ This is partly because it is difficult to accurately estimate the marginal cost of providing operating reserves.
  - ✓ DA offer prices may fall as suppliers gain more experience.
    - – This was evident in 2017-Q2 as a large amount of reserve capacity reduced its offer prices from previous years. (see slides 31-33)
    - – This has helped reduce average DA 30-minute reserve prices. (see slide 30)
- However, we will continue to monitor DA reserve offer patterns and consider potential rule changes including whether to modify the existing $5/MWh "safe harbor" for reserve offers in the market power mitigation measures.

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Highlights and Market Summary:
Uplift and Revenue Shortfalls

- Guarantee payments were $11.2M which was comparable to 2016-Q2. (see slides 76-79)
- Guarantee payments rose in New York City and fell in Western NY due to:
  - ✓ Higher gas prices that increased the commitment costs of gas-fired units in-city;
  - ✓ Increased supplemental commitment for reliability in New York City; and
  - ✓ Decreased OOM dispatch and commitment of the Milliken units. (see slides 73-75)
- Congestion shortfalls were $21M in the DAM and $11M in the RTM. DAM levels were higher and RTM levels lower than in 2016-Q2. (see slides 55-56)
  - ✓ Transmission outages accounted for the majority of DAM shortfalls (roughly 80 percent) in the second quarter of 2017.
    - $17 million was allocated to the responsible TO.
  - ✓ Nearly all of RTM shortfalls were associated with the North Zone lines, the West Zone lines, and the Capital to Hudson Valley lines.
    - North Zone RTM shortfalls were accrued almost in their entirety due to transmission outages on two days in early April (totaling $4.6 million in RTM shortfalls).

Highlights and Market Summary:
Capacity Market

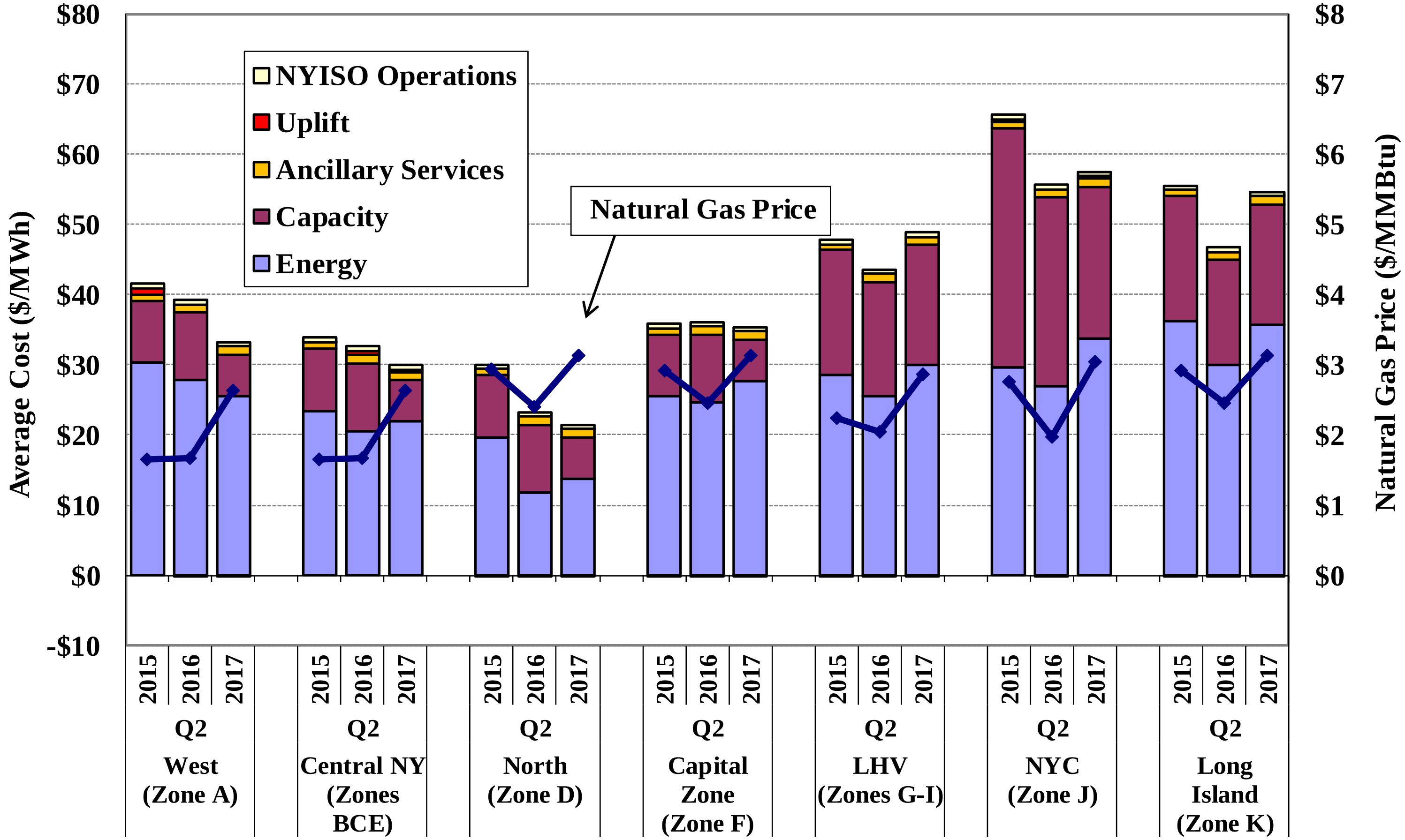
- In 2017-Q2, spot prices ranged from $1.99/kW-month in ROS $8.02/kW-month in NYC. (see slides 88-91)
  - ✓ Average spot price for the second quarter include one month of winter pricing (April) and two months of summer pricing (May and June).
- Compared to 2016-Q2, average spot prices fell 21 to 45 percent in NYC and NYCA and rose 9 to 17 percent in the G-J Locality and Long Island.
  - ✓ Price changes in all regions were driven largely by changes to the IRM and Net CONE of the proxy unit from the Demand Curve Reset process.
    - Net CONE values rose substantially in both G-J Locality and in Long Island while falling in NYC and NYCA which impact capacity prices in directionally the same way. (see slide 91)
  - ✓ Internal supply fell predominantly due to DMNC testing and increased exports, but this was partly offset by the return of Greenidge 4.
    - Additionally, import levels averaged 430 MW higher this quarter compared to 2016-Q2 with noticeably more imports from PJM more than offsetting reduced imports from ISO-NE.

Energy Market Outcomes

All-In Prices

- The first figure summarizes the total cost per MWh of load served in the New York markets by showing the "all-in" price that includes:
  - ✓ An energy component that is a load-weighted average real-time energy price.
  - ✓ A capacity component based on spot prices multiplied by capacity obligations.
  - ✓ The NYISO cost of operations and uplift from other Rate Schedule 1 charges.
- Average all-in prices ranged from roughly $21/MWh in the North Zone to $57.50/MWh in NYC in the second quarter of 2017. Compared to 2016-Q2:
  - ✓ All-in prices generally rose in the SENY regions including NYC, Long Island, and the Hudson Valley, but fell in the rest of the state.
  - ✓ LBMPs rose 7 to 25 percent everywhere but the West Zone which fell 8 percent.
    - – The increases were driven primarily by higher gas prices. (see slide 13)
    - – West Zone LBMPs are less dependent on gas prices and fell mainly because of reduced congestion in the region. (see slide 54).
  - ✓ Capacity prices rose by 5 and 15 percent in the Hudson Valley and Long Island, respectively, but fell by 20 to 40 percent elsewhere.
    - – The variation in capacity prices changes are reflective of changes to such factors as LCR, IRM, Net CONE, and installed capacity changes. (see slides 88-91)

All-In Prices by Region



Note: Natural Gas Price is based on the following 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 Millennium East 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.
- Although peak load (29.1 GW) rose nearly 11 percent from the second quarter of 2016, average load (16.8 GW) fell 2 percent.
  - ✓ This reflects weather patterns that were generally milder but for a number of hot days in both the middle of May and of June.
- All reported fuel prices rose substantially from 2016-Q2 to 2017-Q2.
  - ✓ Gas prices rose 20 to 30 percent in East NY and over 60 percent in West NY.
    - These increases reflected lower storage levels in the region and pipeline expansion projects that open new markets to northeastern natural gas production.
    - Gas spreads between East NY and West NY fell from the second quarter of 2016.
      - While higher gas prices tend to increase congestion, reduced east-west spreads helped offset this increase.
  - ✓ Despite the increase in natural gas prices, gas-fired generation continues to be more economic than coal-fired and oil-fired generation.

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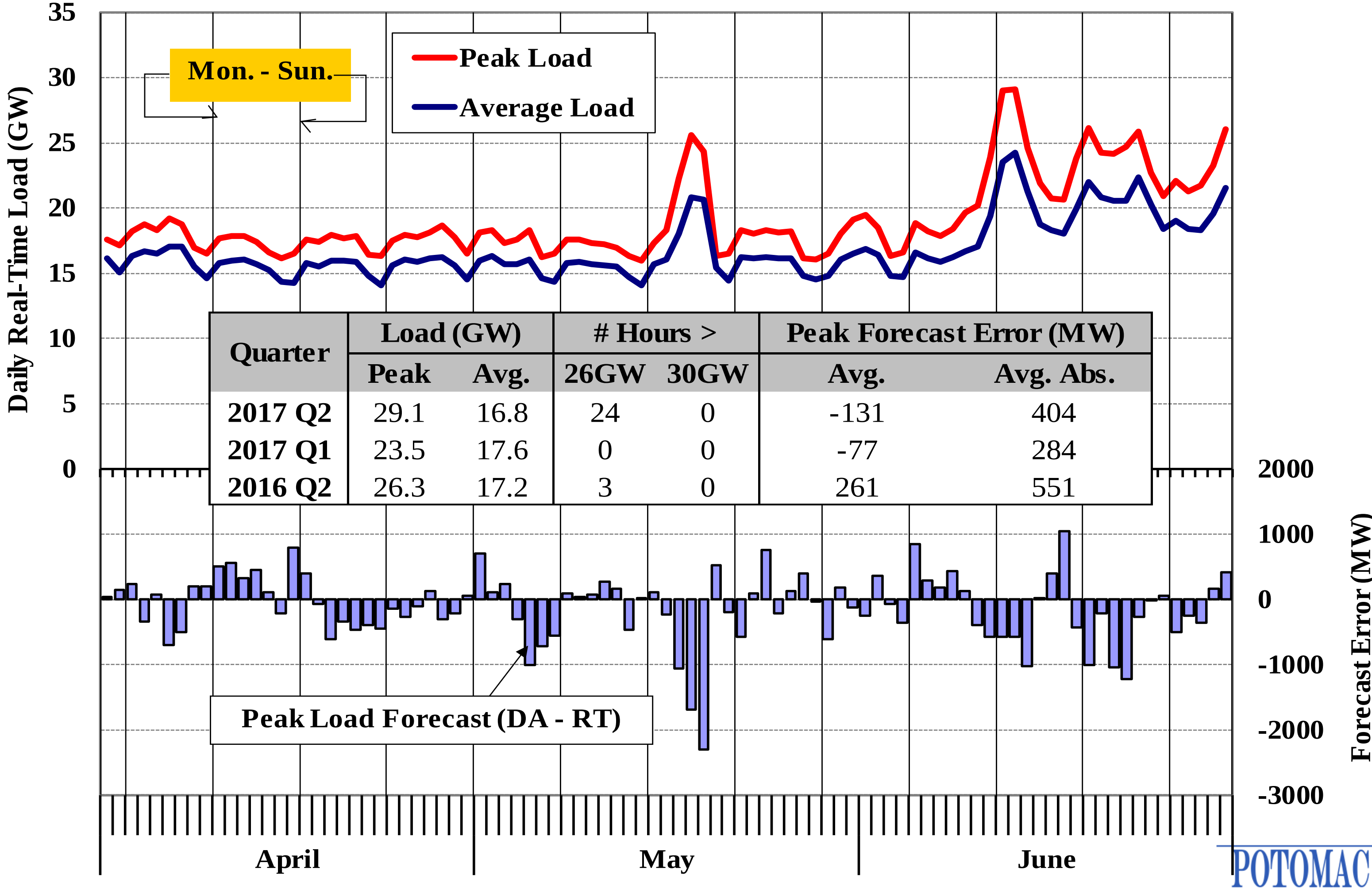
Load Forecast and Actual Load



Quarter	Load (GW)		# Hours >		Peak Forecast Error (MW)	
	Peak	Avg.	26GW	30GW	Avg.	Avg. Abs.
2017 Q2	29.1	16.8	24	0	-131	404
2017 Q1	23.5	17.6	0	0	-77	284
2016 Q2	26.3	17.2	3	0	261	551

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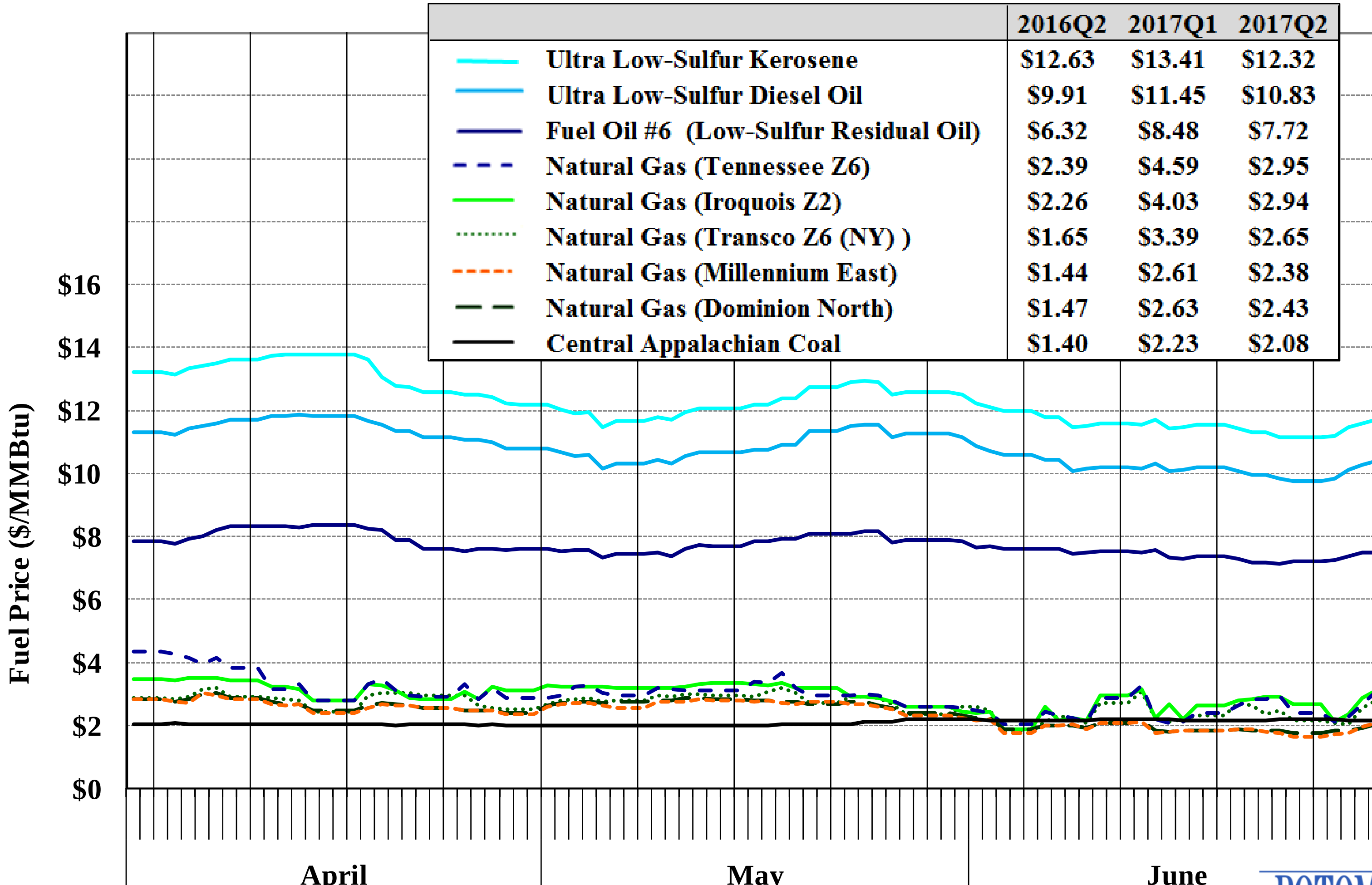
Coal, Natural Gas, and Fuel Oil Prices



	2016Q2	2017Q1	2017Q2
Ultra Low-Sulfur Kerosene	$12.63	$13.41	$12.32
Ultra Low-Sulfur Diesel Oil	$9.91	$11.45	$10.83
Fuel Oil #6 (Low-Sulfur Residual Oil)	$6.32	$8.48	$7.72
Natural Gas (Tennessee Z6)	$2.39	$4.59	$2.95
Natural Gas (Iroquois Z2)	$2.26	$4.03	$2.94
Natural Gas (Transco Z6 (NY))	$1.65	$3.39	$2.65
Natural Gas (Millennium East)	$1.44	$2.61	$2.38
Natural Gas (Dominion North)	$1.47	$2.63	$2.43
Central Appalachian Coal	$1.40	$2.23	$2.08

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RT Generation and Marginal Units by Fuel Type:
Chart Descriptions

- The following two figures summarize fuel usage by generators in NYCA and their impact on LBMPs in the second quarter of 2017.
- 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 was 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.

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RT Generation and Marginal Units by Fuel Type: Market Results

- Gas-fired (38 percent), nuclear (32 percent), and hydro (24 percent) generation accounted for most of the internal generation in the second quarter of 2017.
  - ✓ Natural gas-fired generation fell markedly by more than 1,400 MW from Q2 of 2016 due to higher gas prices, lower load, and higher output from lower cost resources as outlined below:
    - Average nuclear generation rose 420 MW from the second quarter of 2016 because of less deratings and outages.
    - Average wind generation rose 130 MW due to stronger wind patterns and more than 70 MW of new capacity added upstate.
    - Hydro generation rose 340 MW primarily due to higher output from upstate resources that had been impacted by drought conditions a year ago; and
    - Net imports also rose 200 MW from 2016-Q2 across all hours (see slide 41).
- Gas-fired and hydro resources continue to be marginal the vast majority of time.
  - ✓ Hydro units in the West Zone were on the margin less frequently than in the second quarter of 2016, reflecting changes in congestion patterns in the West Zone.
  - ✓ Wind units in the North Zone were on the margin more frequently because of the effects of increased generation and more significant transmission outages.

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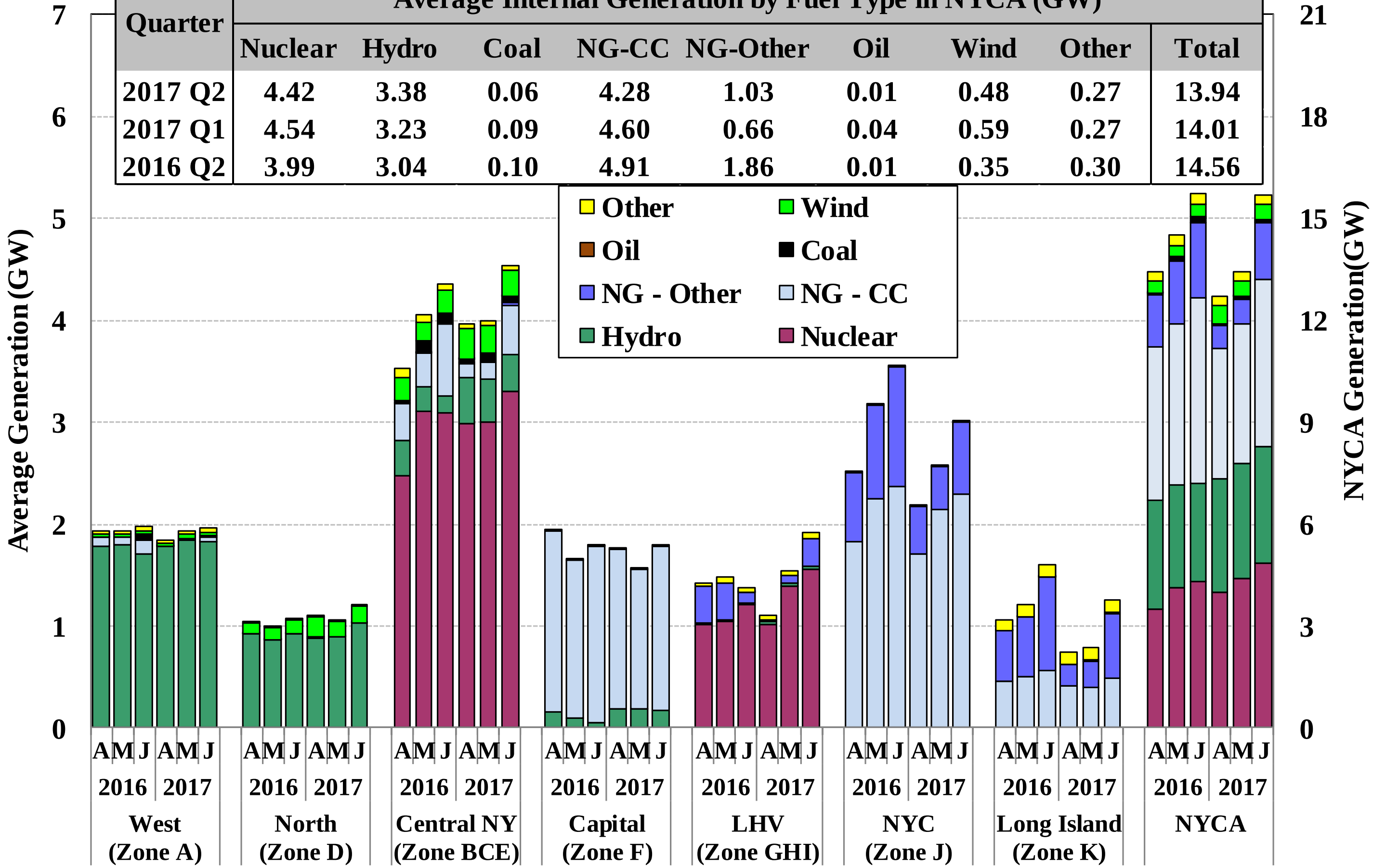
Real-Time Generation Output by Fuel Type

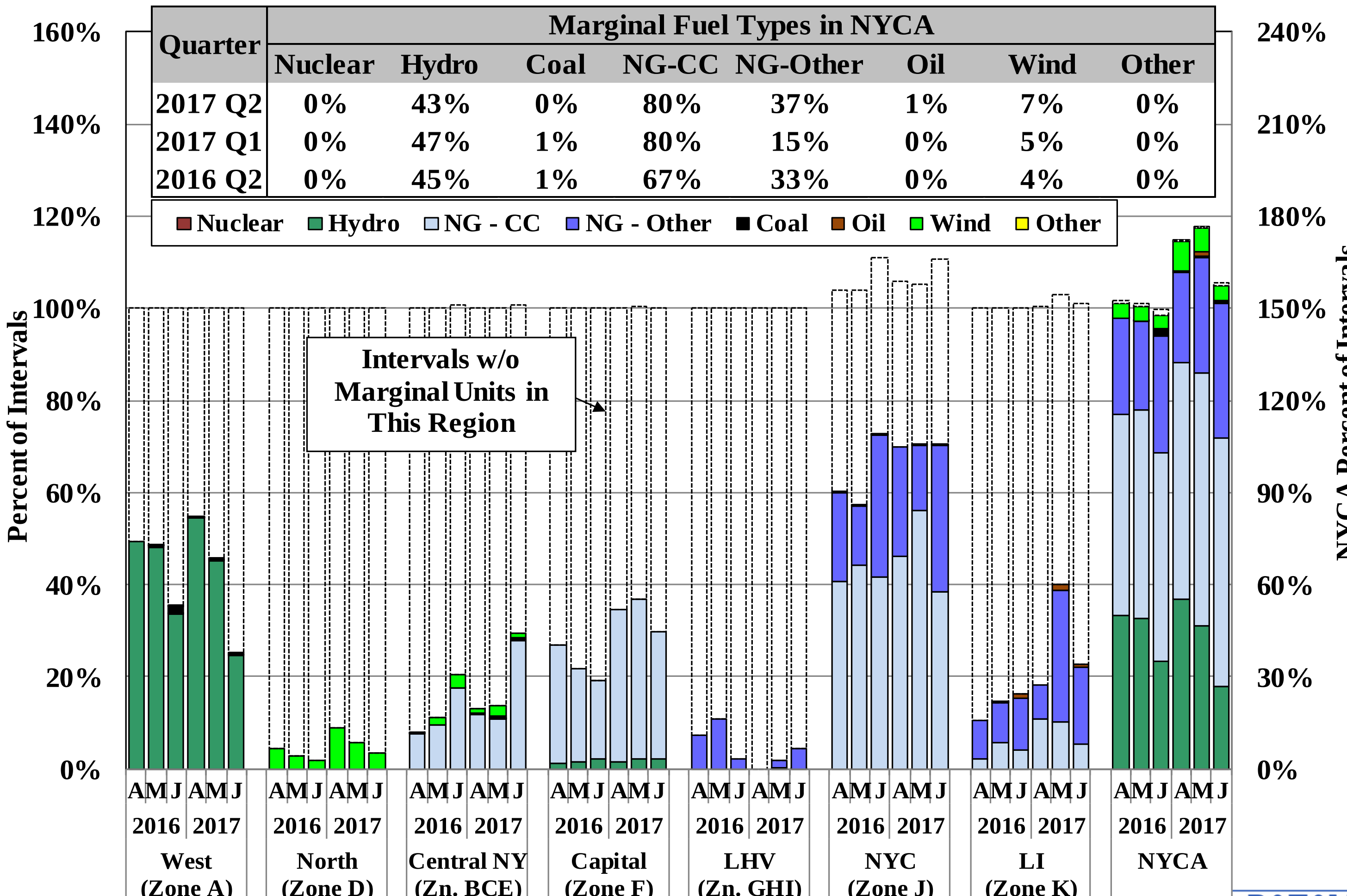
Quarter	Average Internal Generation by Fuel Type in NYCA (GW)								
	Nuclear	Hydro	Coal	NG-CC	NG-Other	Oil	Wind	Other	Total
2017 Q2	4.42	3.38	0.06	4.28	1.03	0.01	0.48	0.27	13.94
2017 Q1	4.54	3.23	0.09	4.60	0.66	0.04	0.59	0.27	14.01
2016 Q2	3.99	3.04	0.10	4.91	1.86	0.01	0.35	0.30	14.56



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

Fuel Type of Marginal Units in the RTM

Quarter	Marginal Fuel Types in NYCA							
	Nuclear	Hydro	Coal	NG-CC	NG-Other	Oil	Wind	Other
2017 Q2	0%	43%	0%	80%	37%	1%	7%	0%
2017 Q1	0%	47%	1%	80%	15%	0%	5%	0%
2016 Q2	0%	45%	1%	67%	33%	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 2017.
- Average day-ahead prices ranged from $16/MWh in the North Zone to $35/MWh on Long Island, up 13 to 24 percent from the second quarter of 2016 in all zones but for the West.
  - ✓ The increases were driven primarily by higher natural gas prices. (see slide 13)
  - ✓ Transmission outages, primarily in the eastern regions, contributed to this increase as well.
- The West Zone experienced a decrease in LBMPs from 2016-Q2 to 2017-Q2,which differed from all other regions because:
  - ✓ Supply to western NY is driven more by renewables and nuclear than by natural gas.
  - ✓ Imports from Ontario increased from the second quarter of 2016 (see slide 41).
  - ✓ Central/East congestion increased which helped reduce prices in the west (see slide 54).

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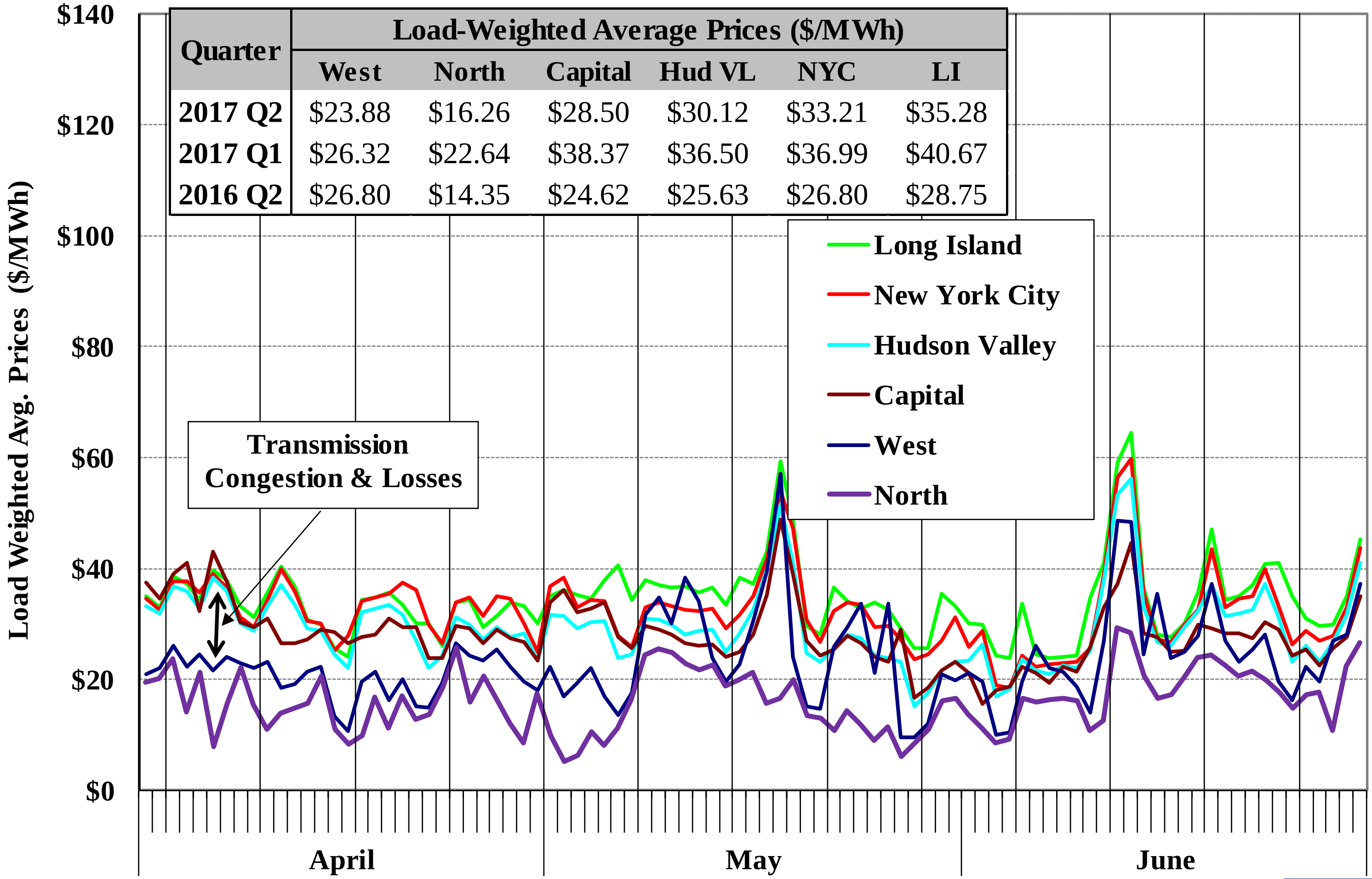
Day-Ahead and Real-Time Electricity Prices

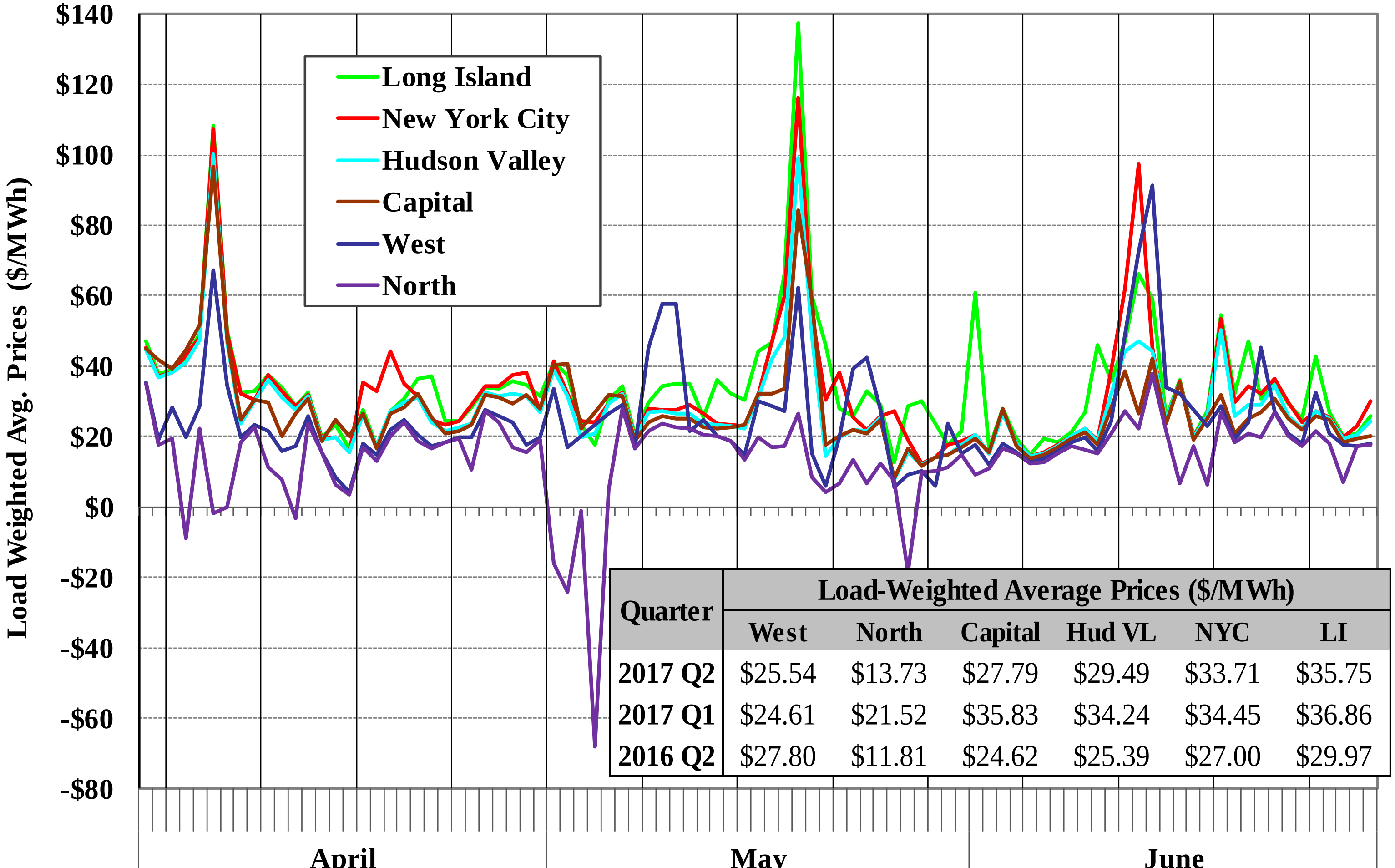
- Prices are generally more volatile in the real-time market than in the day-ahead market because of unexpected events.
  - ✓ Real time load variation from day ahead forecasted levels can contribute to these events. For example:
    - – Prices in NYC averaged nearly $40 per MWh higher in RT than in DA on June 13 due to persistent under forecast of load which was exacerbated by a TSA event later in the day.
- 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 DA prices were 2-3 percent higher than RT prices in areas considered "less-congested" like the North Zone, Capital Zone, and Hudson Valley.
    - – A small average DA premium is generally desirable in a competitive market.
  - ✓ Average RT prices were about 1 percent higher in NYC and Long Island, and 6.5 percent higher in the West Zone in the second quarter of 2017.
    - – Unanticipated transmission outages and loop flows can drive higher real time prices in these more congested regions.

Day-Ahead Electricity Prices by Zone

Quarter	Load-Weighted Average Prices ($/MWh)					
	West	North	Capital	Hud VL	NYC	LI
2017 Q2	$23.88	$16.26	$28.50	$30.12	$33.21	$35.28
2017 Q1	$26.32	$22.64	$38.37	$36.50	$36.99	$40.67
2016 Q2	$26.80	$14.35	$24.62	$25.63	$26.80	$28.75



Real-Time Electricity Prices by Zone



Quarter	Load-Weighted Average Prices ($/MWh)					
	West	North	Capital	Hud VL	NYC	LI
2017 Q2	$25.54	$13.73	$27.79	$29.49	$33.71	$35.75
2017 Q1	$24.61	$21.52	$35.83	$34.24	$34.45	$36.86
2016 Q2	$27.80	$11.81	$24.62	$25.39	$27.00	$29.97

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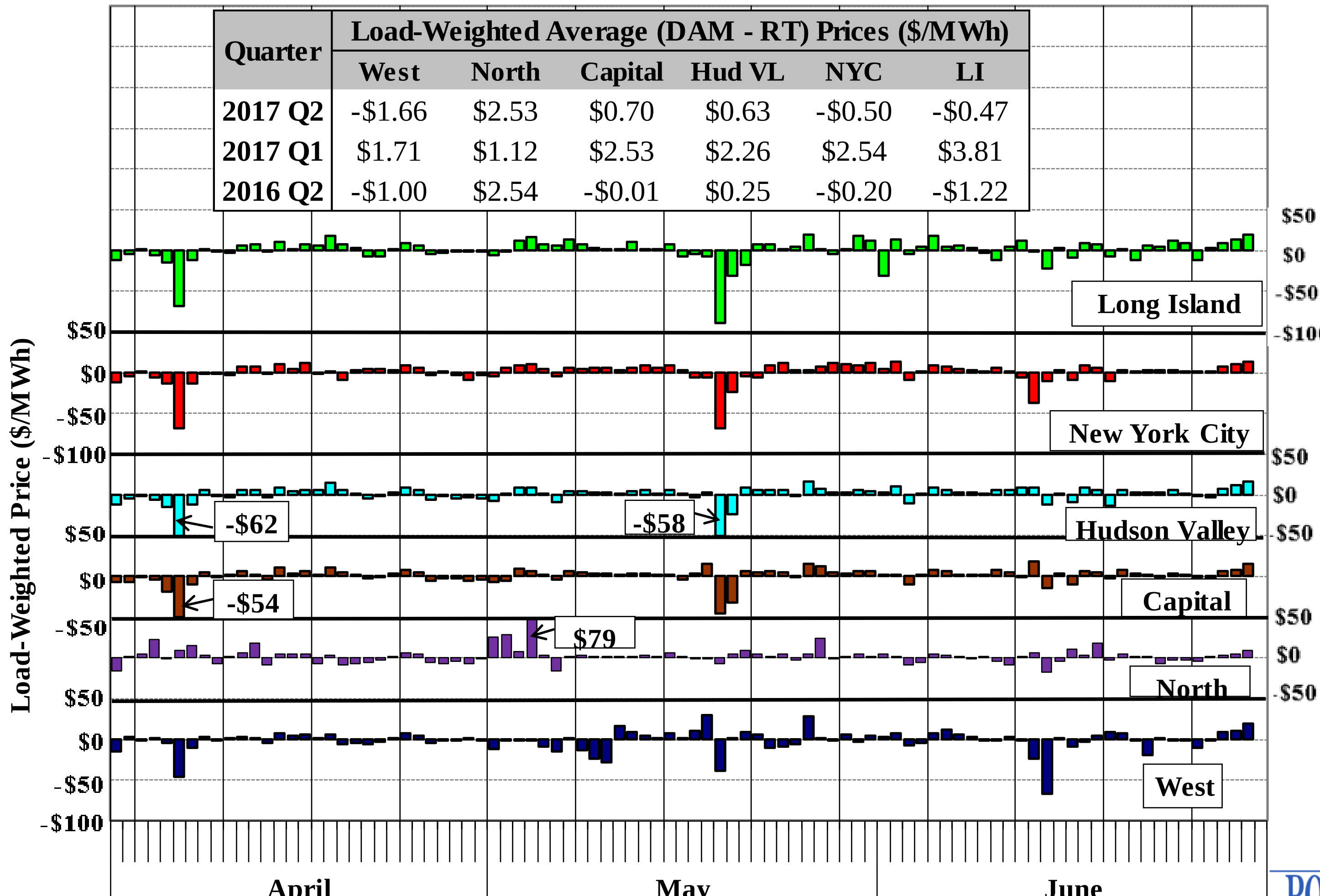
Convergence Between DA and RT Prices

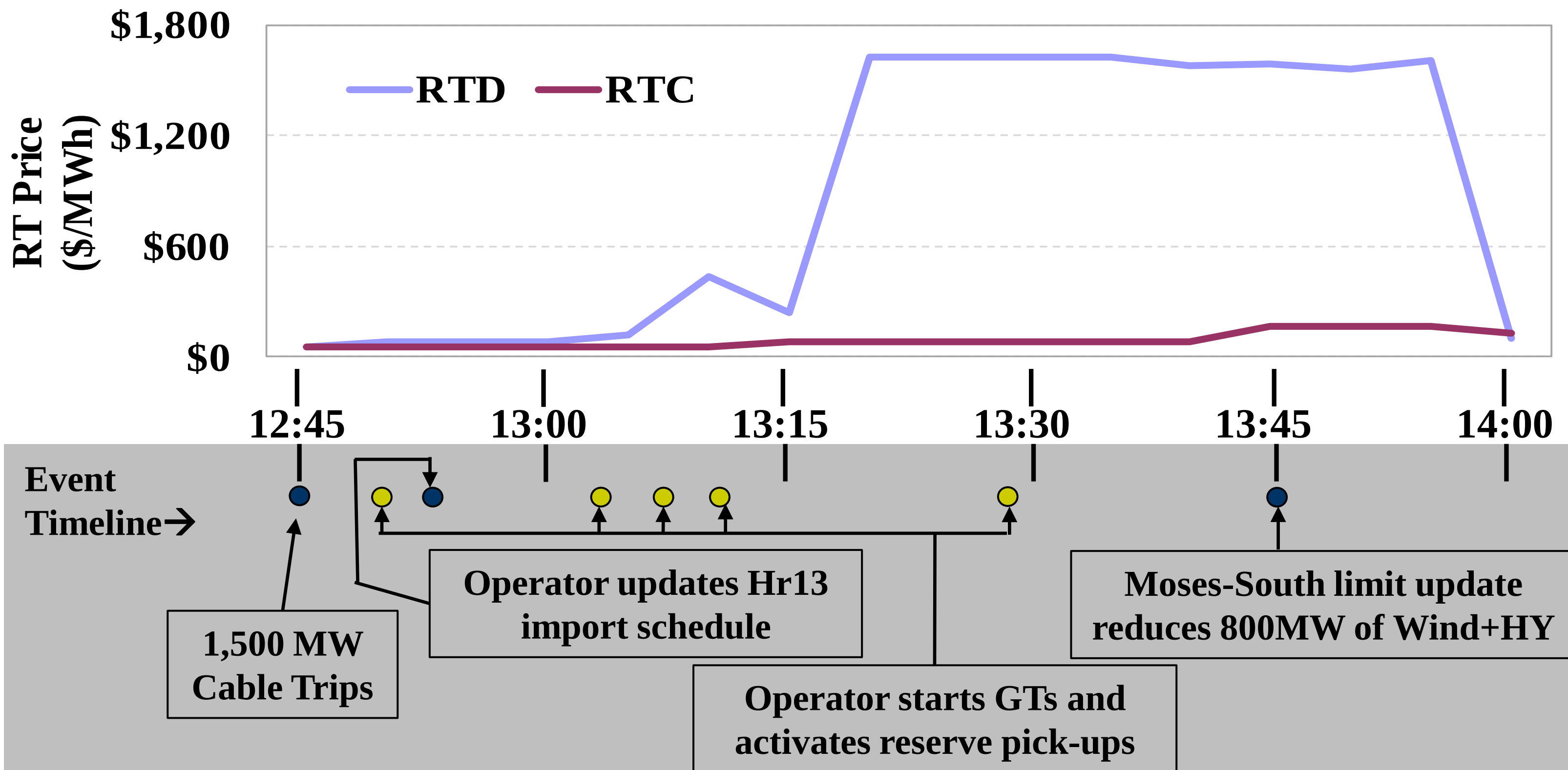
Quarter	Load-Weighted Average (DAM - RT) Prices ($/MWh)					
	West	North	Capital	Hud VL	NYC	LI
2017 Q2	-$1.66	$2.53	$0.70	$0.63	-$0.50	-$0.47
2017 Q1	$1.71	$1.12	$2.53	$2.26	$2.54	$3.81
2016 Q2	-$1.00	$2.54	-$0.01	$0.25	-$0.20	-$1.22



April 6 Real-Time Pricing Event

- Despite moderate demand conditions, unexpected reserve shortage conditions occurred in the afternoon on April 6, leading to high real-time shortage pricing.
  - ✓ While such events are infrequent, it is important to consider how efficiently the real-time market performed in bringing up imports and reserve capacity.
- The following slide outlines the sequence of events on this afternoon, including factors that led to large differences between RTC and RTD results.
  - ✓ The figure shows the RTC and the RTD price paths over a 75 minute period from 12:45 to 14:00 after the loss of 1,500 MW of imports from Quebec.
  - ✓ The event timeline lists a series of actions taken in response to the contingency.
    - – Operators started a series of quick start units between 12:50 and 13:30.
    - – The Moses South transmission constraint limit was reduced at following the contingency, leading significant amounts of hydro and wind to be scheduled down.
  - ✓ The RTC timeline illustrates why RTC did not schedule more imports from PJM and ISO-NE during the event.
    - – RTC schedules resources based on information available ahead of real-time.
- RTD prices spiked during this event due to transmission outages at the HQ interface, while RTC prices were moderate.

April 6 Real-Time Pricing Event: RTC & RTD Modeling Results



RTC Timeline→

RTC 13:15	RTC 13:30	RTC 13:45
Assumes incorrect HQ import MW	DNI ramp limited at +300MW	Assumes excess Wind+HY

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Ancillary Services Market

Ancillary Services Prices:
Chart Descriptions

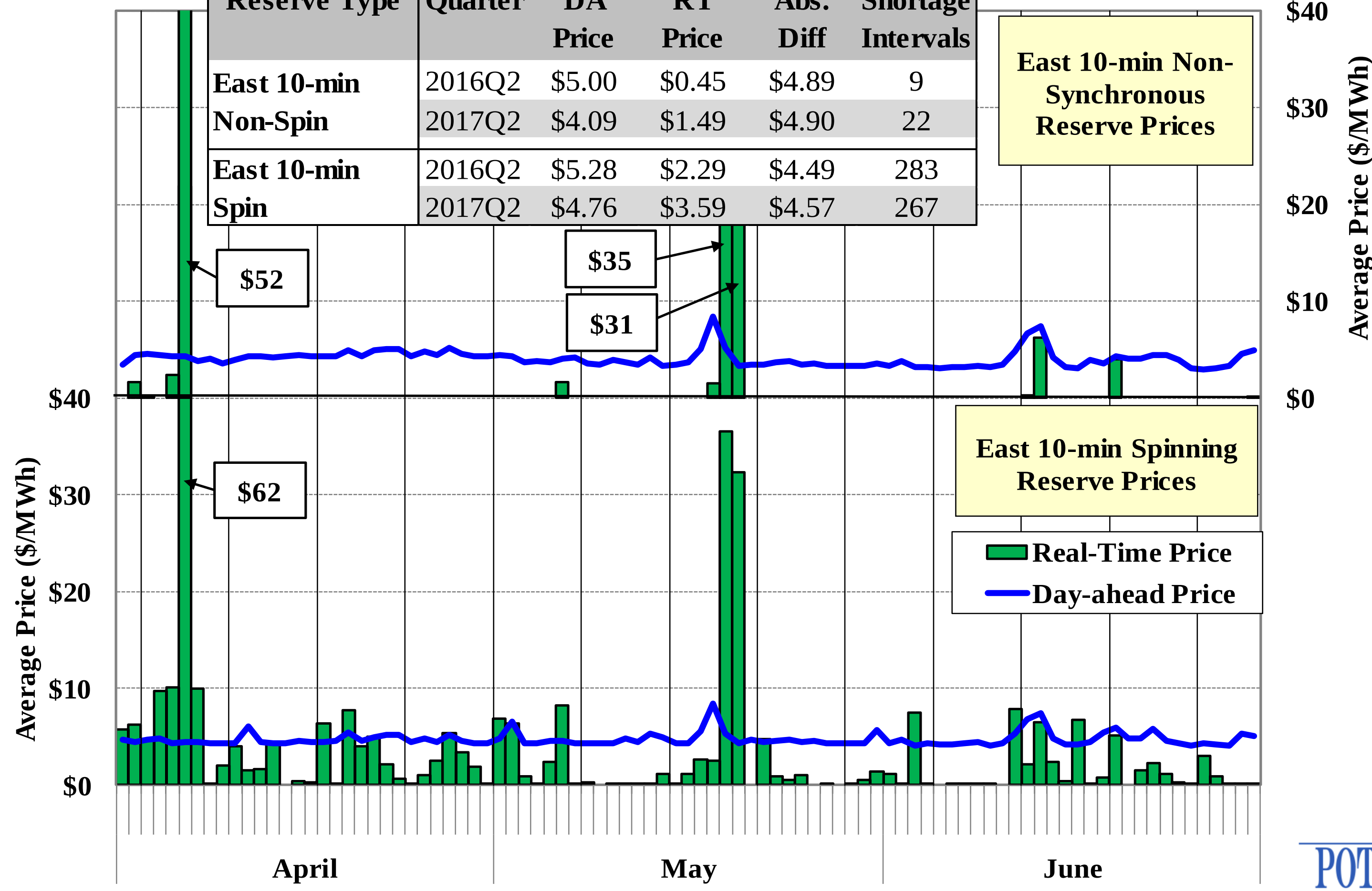
- The following three figures summarize DA and RT prices for six ancillary services products during the quarter:
  - ✓ 10-min spinning reserve prices in eastern NY;
  - ✓ 10-min non-spinning reserve prices in eastern NY;
  - ✓ 10-min spinning reserve prices in western NY;
  - ✓ Regulation prices, which reflect the cost of procurement, and the cost of moving generation of regulating 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.

Ancillary Services Prices:
Market Results

- The differences in DA prices between various reserve products have been small since rule changes in November 2015 (Comprehensive Shortage Pricing Project).
  - ✓ The spreads between eastern reserve prices and western reserve prices have fallen considerably since the rule changes were implemented.
  - ✓ This is because all reserve requirements except the statewide 30-minute requirement have been rarely binding since the rule change.
- Average DA reserve prices were generally stable, but they rose during a few periods, mostly in May and June.
  - ✓ Higher reserve prices occurred because of increases in the opportunity costs (of not providing energy based on offers) for certain reserve providers rather than higher offer prices.
  - ✓ However, average DA reserve prices fell 10 to 19 percent from the second quarter of 2016 despite higher natural gas prices and LBMPs, because of a general decline in DA reserve offer prices from the previous year.
- RT regulation prices rose notably on June 2 because of reduced regulation capability that resulted from OOM actions to manage 115 kV constraints.

DA and RT 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	2016Q2	$5.00	$0.45	$4.89	9
	2017Q2	$4.09	$1.49	$4.90	22
East 10-min Spin	2016Q2	$5.28	$2.29	$4.49	283
	2017Q2	$4.76	$3.59	$4.57	267



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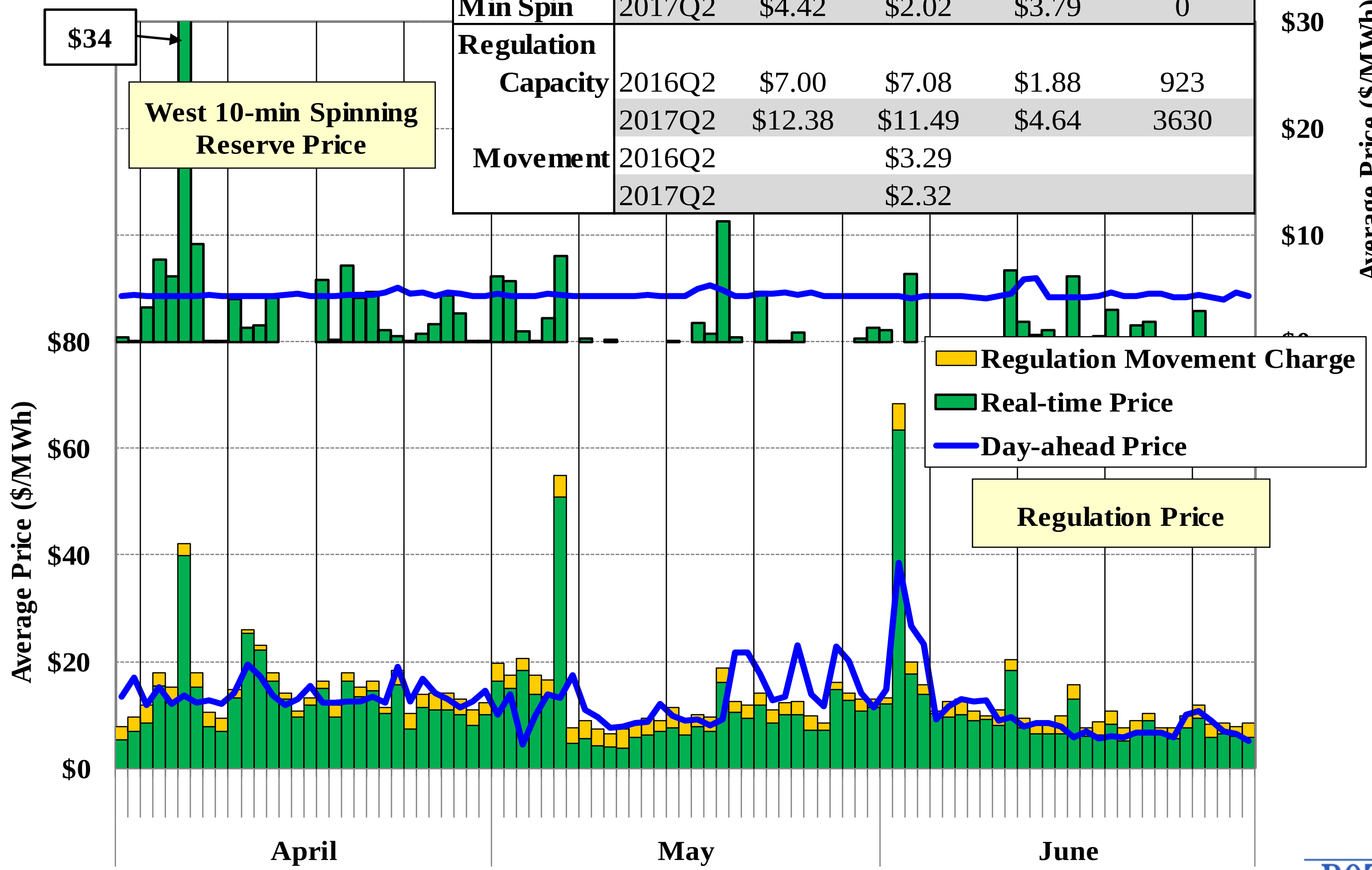
DA and RT Ancillary Services Prices
Western 10-Minute Spinning Reserves and Regulation

Reserve	Quarter	Avg. DA	Avg. RT	Avg.Abs.	# RT
West 10-Min Spin	2016Q2	$4.96	$1.33	$4.30	0
	2017Q2	$4.42	$2.02	$3.79	0
Regulation Capacity	2016Q2	$7.00	$7.08	$1.88	923
	2017Q2	$12.38	$11.49	$4.64	3630
Movement	2016Q2		$3.29		
	2017Q2		$2.32		



Note: RT Regulation Movement Charges are shown as averaged per MWh of RT Scheduled Regulation Capacity.

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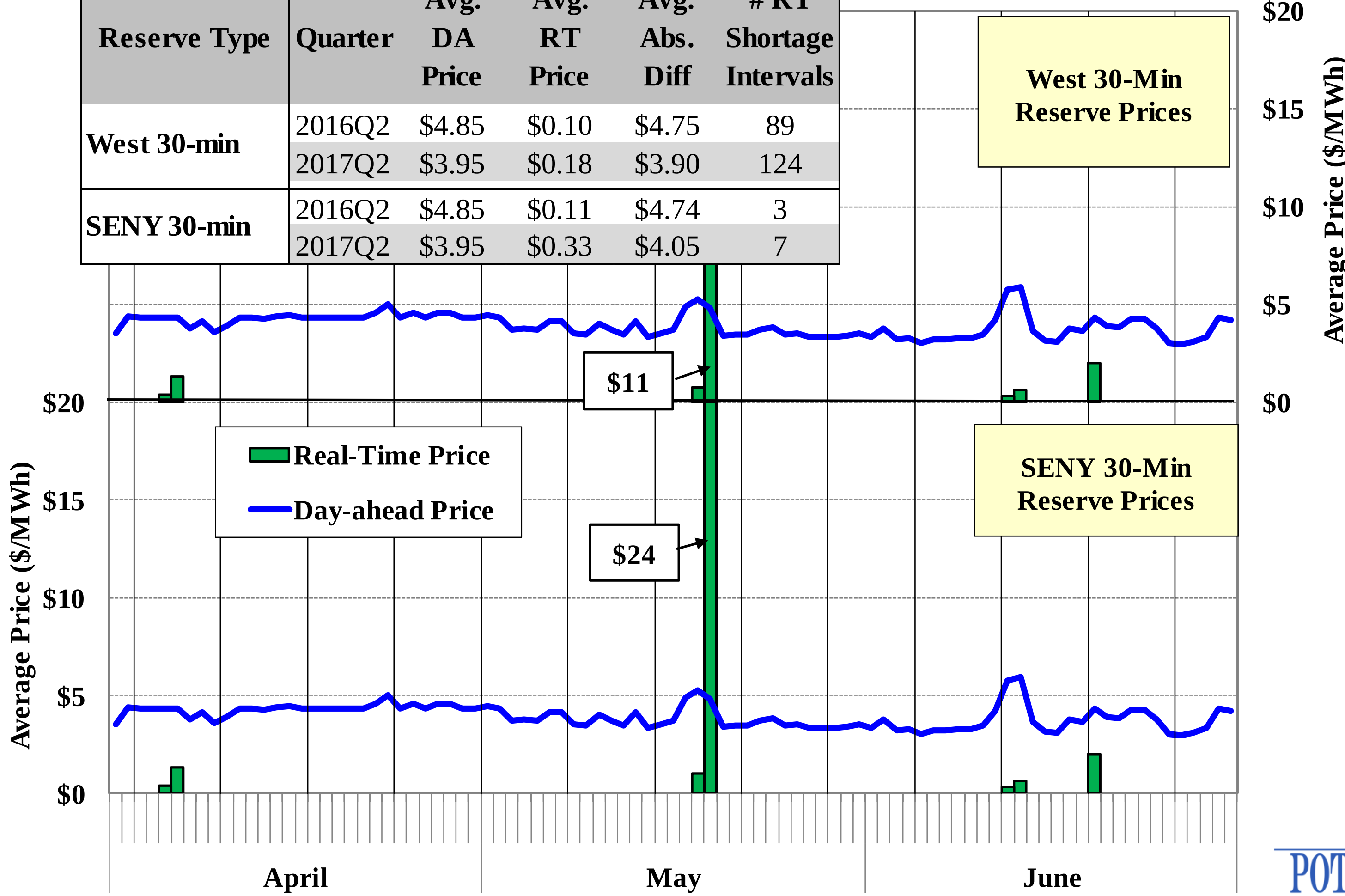
DA and RT Ancillary Services Prices
Western and SENY 30-Minute Reserves

Reserve Type	Quarter	Avg. DA Price	Avg. RT Price	Avg. Abs. Diff	# RT Shortage Intervals
West 30-min	2016Q2	$4.85	$0.10	$4.75	89
	2017Q2	$3.95	$0.18	$3.90	124
SENY 30-min	2016Q2	$4.85	$0.11	$4.74	3
	2017Q2	$3.95	$0.33	$4.05	7



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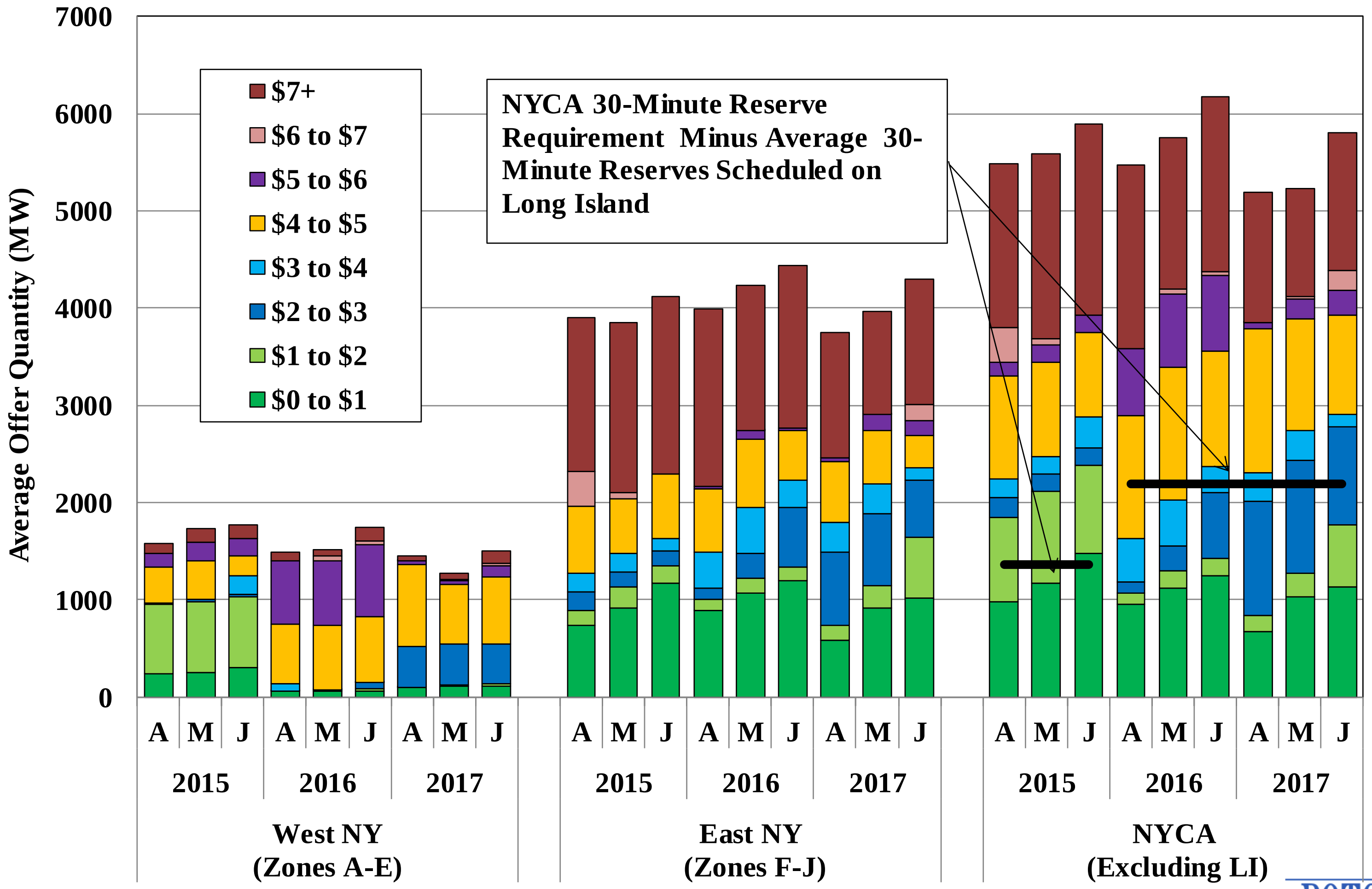
NYCA 30-Minute Reserve Offers in the DAM:
Chart Descriptions

- The next figure summarizes the amount of reserve offers in the day-ahead market 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, since they directly affect the reserve prices.
  - ✓ The stacked bars show the amount of reserve offers in each select price range 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) in the 30-minute reserve requirement.
    - – Thus, Long Island reserve offer prices have little impact on NYCA reserve prices.
  - ✓ The black line represents the equivalent average 30-minute reserve requirements for areas outside Long Island.
    - – 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).

NYCA 30-Minute Reserve Offers in the DAM: Market Results

- DA 30-minute reserve prices became much higher than RT prices following the market rule change in November 2015, which was driven primarily by:
  - ✓ The increased 30-minute reserve requirement (up 655 MW);
  - ✓ The limit on scheduled reserves on Long Island (down 250-300 MW); and
  - ✓ The increased reserve offers from some capacity.
- We have reviewed DA reserve offers and found many units that offer above the standard competitive benchmark (i.e., estimated marginal cost).
  - ✓ This is partly due to the difficulty of accurately estimating the marginal cost of providing reserves.
  - ✓ Thus, DA offer prices may fall as suppliers gain more experience. Compared to the second quarter of the previous year:
    - – The amount offered below \$3/MWh increased by an average of 800 MW; and
    - – The amount offered below \$5/MWh increased by an average of 585 MW.
- We will continue to monitor DA reserve offer patterns and consider potential rule changes including whether to modify the existing \$5/MWh “safe harbor” for reserve offers in the market power mitigation measures.

DAM NYCA 30-Minute Operating Reserve Offers
Committed and Available Offline Quick-Start Resources



Energy Market Scheduling

DA Load Scheduling and Virtual Trading:
Chart Descriptions

- The next three figures summarize DA load scheduling and virtual trading activities.
  - ✓ The first figure summarizes the quantity of DA load scheduled as a percentage of RT load in each of seven regions and state-wide by day.
    - Net scheduled load = Physical Bilaterals + Fixed Load + Price-Capped Load + Virtual Load – Virtual Supply
  - ✓ The second figure shows monthly average scheduled and unscheduled quantities, and gross profitability for virtual trades 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 third figure summarizes virtual trading by region.
    - The top portion of the chart also shows average DA scheduled load (as a percent of real-time load) at each geographic region.
  - ✓ Virtual imports/exports are included as they have similar effects on scheduling.
    - A transaction is deemed virtual if its DA schedule is greater than its RT schedule. So, a portion of these virtuals result from forced outages or curtailments by NYISO or another control area (rather than the intent of the participant).

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DA Load Scheduling and Virtual Trading:
Market Results

- For NYCA, 94 percent of actual load was scheduled in the DAM (including virtual imports/exports) in peak load hours, comparable to prior quarters.
  - ✓ The scheduling pattern in each sub-region was also consistent with prior quarters.
  - ✓ In the second quarter of 2017, net load scheduling rose in the Hudson Valley, consistent with increase congestion between it and the Capital zone (see slide 54).
- Net load scheduling and net virtual load tend to be higher in locations where volatile RT congestion is more common (e.g., NYC, LI, and the West Zone).
- Load was typically under-scheduled in the North Zone by a large margin because a large quantity of virtual supply is often scheduled in the zone.
  - ✓ This is an efficient response to the scheduling patterns of wind generators in the zone and imports from Canada, which typically increase in RT (over the DA).
- Virtual traders netted a $5.3 million profit in the second quarter of 2017. Profitable virtual trades generally improve convergence between DA and RT prices.
- The quantities of virtual trades with 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.

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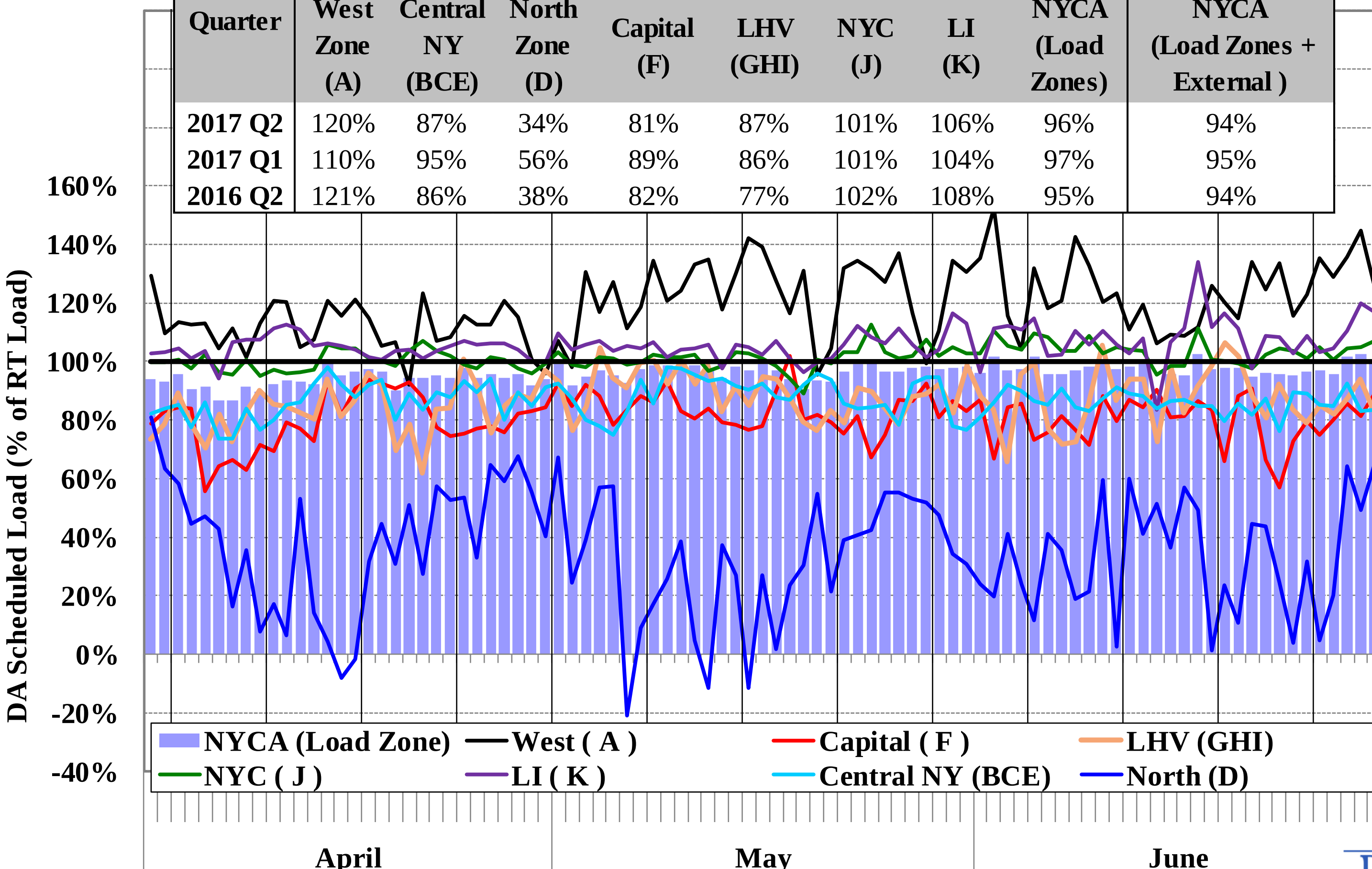
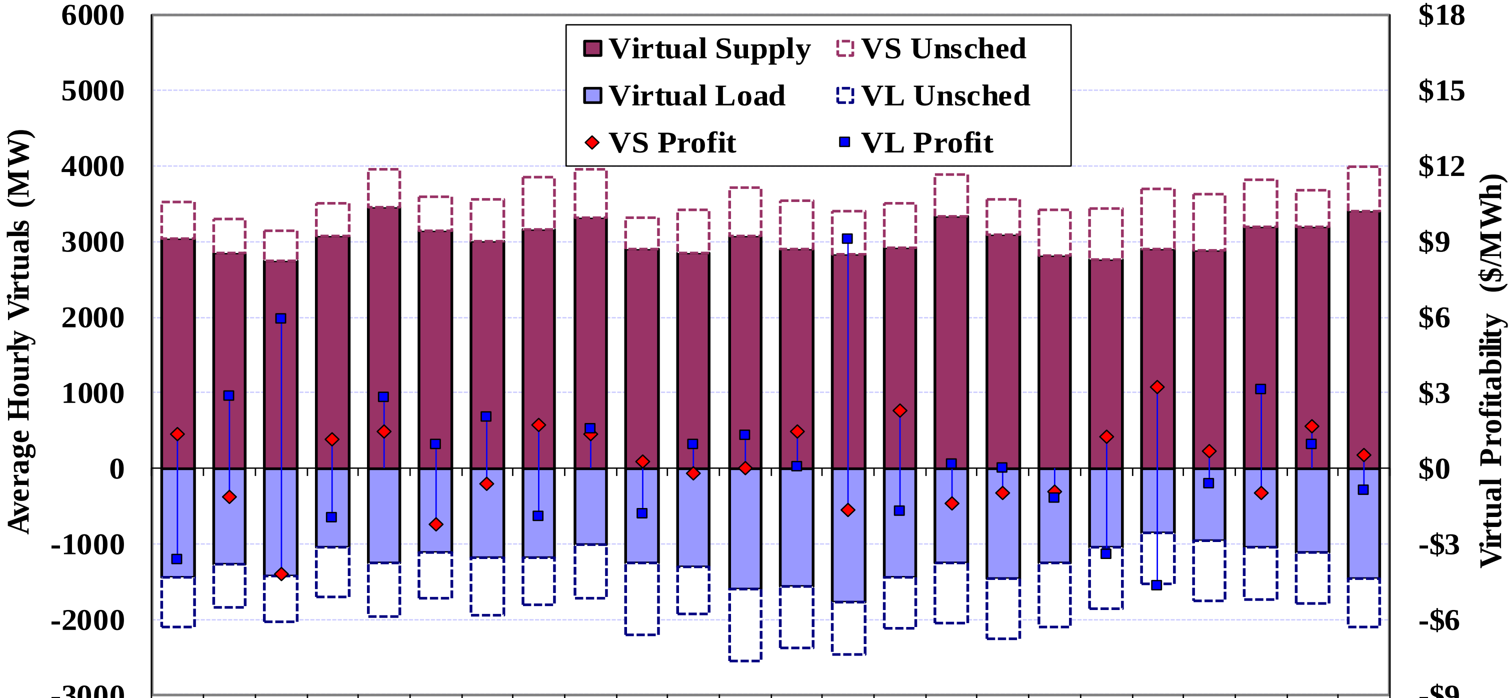
Day-ahead Scheduled Load and Actual Load
Daily Peak Load Hour

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)
2017 Q2	120%	87%	34%	81%	87%	101%	106%	96%	94%
2017 Q1	110%	95%	56%	89%	86%	101%	104%	97%	95%
2016 Q2	121%	86%	38%	82%	77%	102%	108%	95%	94%



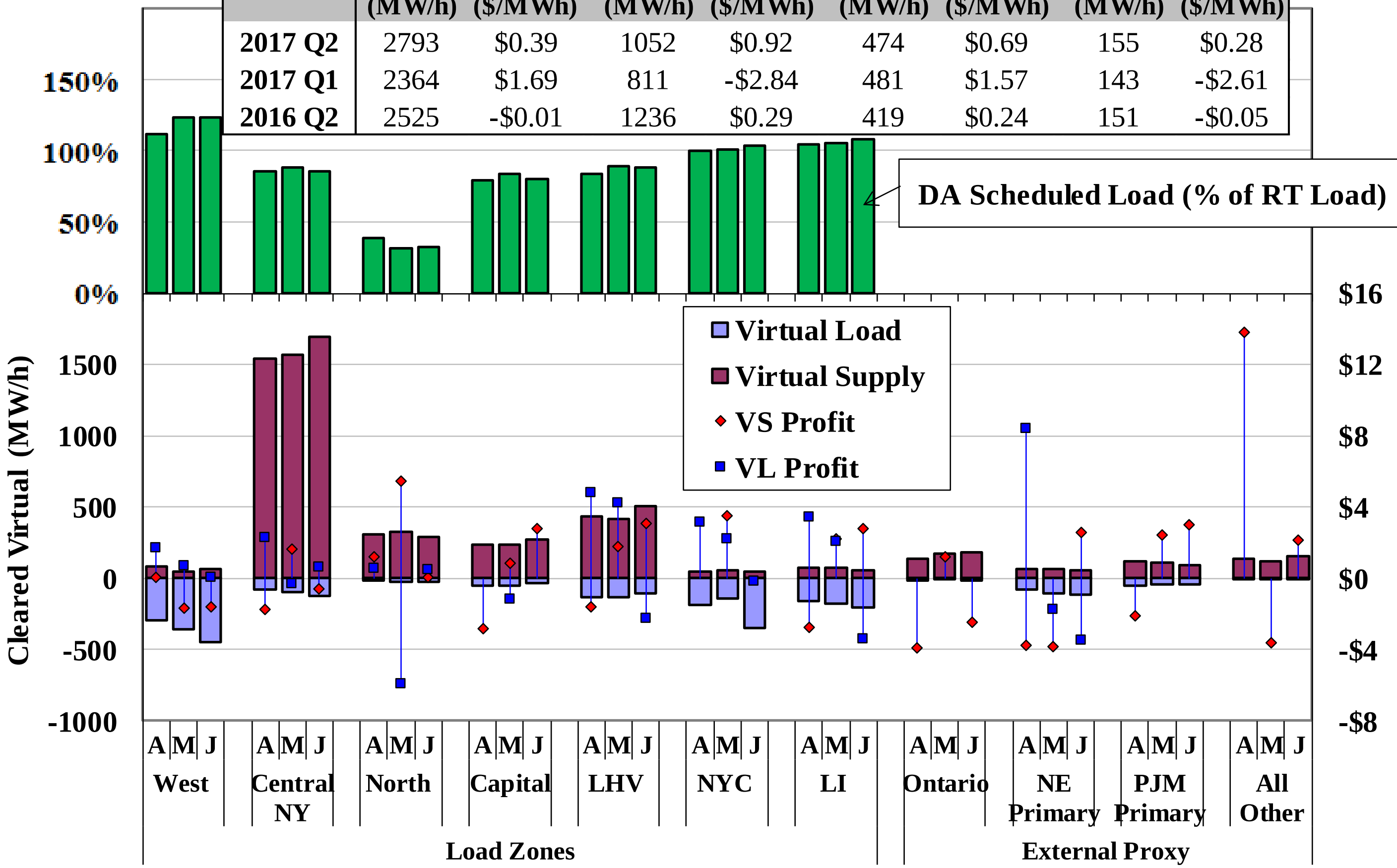
Virtual Trading Activity
by Month



		2015 J	A	S	O	N	D	2016 J	F	M	A	M	J	J	A	S	O	N	D	2017 J	F	M	A	M	J
Profit > 50% of Avg. Zone Price	MW	479	290	241	378	1090	643	692	638	1003	354	431	460	596	398	360	281	261	490	243	507	585	449	645	502
	%	11%	7%	6%	9%	23%	15%	17%	15%	23%	8%	10%	10%	13%	9%	8%	6%	6%	12%	6%	13%	15%	11%	15%	10%
Loss > 50% of Avg. Zone Price	MW	499	300	341	375	715	763	553	547	680	682	550	528	517	413	411	419	345	587	284	336	514	454	553	542
	%	11%	7%	8%	9%	15%	18%	13%	13%	16%	16%	13%	11%	12%	9%	9%	9%	8%	14%	7%	9%	13%	11%	13%	11%

Virtual Trading Activity 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)
2017 Q2	2793	$0.39	1052	$0.92	474	$0.69	155	$0.28
2017 Q1	2364	$1.69	811	-$2.84	481	$1.57	143	-$2.61
2016 Q2	2525	-$0.01	1236	$0.29	419	$0.24	151	-$0.05



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

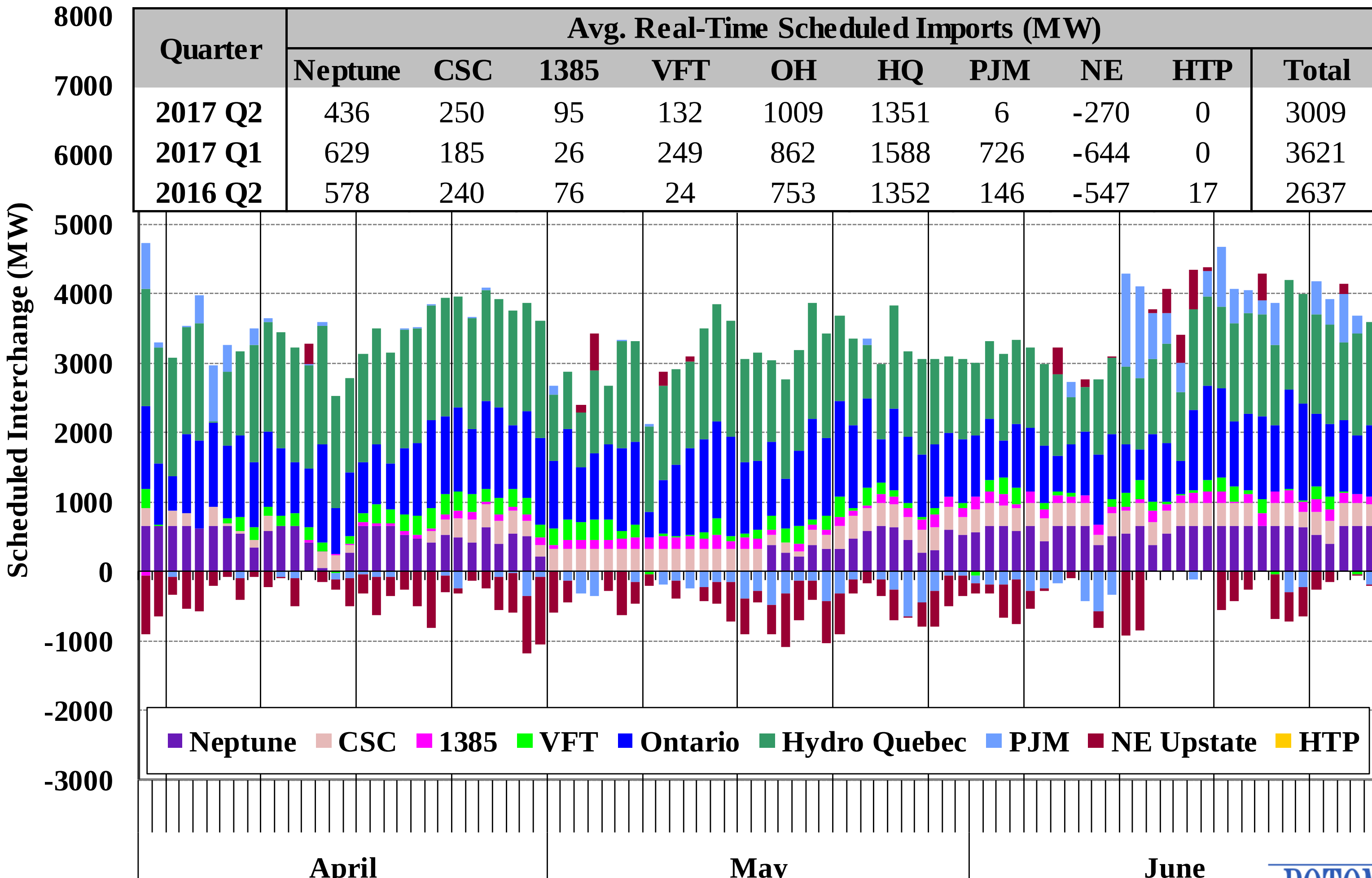
Net Imports Scheduled Across External Interfaces

- 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).
- Total net imports averaged roughly 3 GW (serving ~18 percent of all load) during peak hours in the second quarter of 2017, up 370 MW from the previous year.
- Imports from Hydro Quebec and Ontario averaged nearly 2.4 GW during peak hours, accounting for 78 percent of total net imports.
  - ✓ Imports from Quebec were consistent with the previous year.
  - ✓ However, imports from Ontario rose by 250 MW partly due to the increased price spread between markets and less-restrictive import transfer limits from Ontario.
- New York normally exported power to New England across their primary interfaces in the second quarter while the net direction of flow with PJM varied more by day.
  - ✓ This pattern was generally consistent with the spreads in natural gas prices between these markets in the winter (i.e., NE > NY > PJM).
  - ✓ The convergence of gas prices between NY and PJM contributed to the reduced amount of net imports relative to this period in 2016.

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
2017 Q2	436	250	95	132	1009	1351	6	-270	0	3009
2017 Q1	629	185	26	249	862	1588	726	-644	0	3621
2016 Q2	578	240	76	24	753	1352	146	-547	17	2637



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Efficiency of CTS Scheduling with PJM and NE:
Chart Descriptions

- The next table evaluates the performance of CTS with PJM and NE at their primary interfaces in the second quarter of 2017. 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.
    - Other Unrealized savings, which are not realized due to: a) real-time curtailment; and b) interface ramping.
    - Actual savings (= Projected – Over-projected – Other 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: Market Results

- The interchange was adjusted in 92 percent of intervals (from our estimated hourly schedule) at the ISO-NE interface compared to 71 percent at the PJM interface.
  - ✓ This was partly attributable to the larger amount of low-price CTS bids at the ISO-NE interface (compared to the PJM interface).
- Our analyses show that \$1.5 million and \$1.1 million of production cost savings were projected at the time of scheduling at the ISO-NE and PJM interfaces.
  - ✓ However, an estimated \$1.6 million and only \$0.3 million of savings were realized, the latter largely by 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) likely 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 large.
  - ✓ 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 > $20	Total
% of All Intervals w/ Adjustment			82%	10%	**92%**	63%	8%	**71%**
Average Flow Adjustment (MW)	Net Imports		17	-14	**14**	12	65	**18**
	Gross		100	125	**103**	78	162	**87**
Production Cost Savings ($ Million)	Projected at Scheduling Time		$0.9	$0.6	**$1.5**	$0.3	$0.8	**$1.1**
	Net Over-Projection by:	NY	-$0.02	$0.3	**$0.3**	-$0.05	-$0.4	**-$0.5**
		NE or PJM	$0.01	-$0.2	**-$0.1**	-$0.1	-$0.2	**-$0.3**
	Other Unrealized Savings		-$0.05	$0.02	**-$0.03**	-$0.02	-$0.01	**-$0.04**
	Actual Savings		$0.9	$0.7	**$1.6**	$0.1	$0.1	**$0.3**
Interface Prices ($/MWh)	NY	Actual	$23.39	$58.59	**$27.32**	$20.44	$51.09	**$23.90**
		Forecast	$23.85	$37.71	**$25.40**	$21.09	$46.97	**$24.01**
	NE or PJM	Actual	$25.18	$41.16	**$26.96**	$24.77	$47.82	**$27.37**
		Forecast	$25.52	$54.86	**$28.80**	$25.72	$49.77	**$28.44**
Price Forecast Errors ($/MWh)	NY	Fcst. - Act.	$0.46	-$20.87	**-$1.92**	$0.65	-$4.11	**$0.11**
		Abs. Val.	$3.73	$39.32	**$7.71**	$3.70	$48.57	**$8.77**
	NE or PJM	Fcst. - Act.	$0.35	$13.70	**$1.84**	$0.95	$1.95	**$1.06**
		Abs. Val.	$3.65	$33.43	**$6.98**	$3.23	$27.65	**$5.99**

POTOMAC ECONOMICS

Day-Ahead and Real-Time Transmission Congestion

Transmission Congestion:
Chart Descriptions

- The next four figures evaluate the congestion patterns in the DAM and RTM 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 DAM, which is the primary funding source for TCC payments.
  - ✓ Day-Ahead Congestion Shortfalls occur when the net DA congestion revenues are less than the payments to TCC holders.
    - – Shortfalls (or surpluses) arise when the TCCs on a path exceed (or is below) its DAM transfer capability in periods of congestion.
    - – These typically result from modeling differences between the TCC auction and the DAM, including assumptions related to PAR schedules, loop flows, and transmission outages.
  - ✓ Balancing Congestion Shortfalls arise when DAM scheduled flows over a constraint exceed what can flow over the constraint in the RTM.
    - – 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).

Transmission Congestion:
Chart Descriptions

- 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.
  - ✓ North Zone: The Moses-South interface and other lines in the North Zone and leading into Southern New York.

Transmission Congestion:
Chart Descriptions

(cont. from prior slide)

- ✓ 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 SENY (e.g., the New Scotland-Leeds line, the Leeds-Pleasant Valley line, etc.)
- ✓ 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 and Real-Time Congestion

- Day-ahead congestion revenue totaled $117 million in the second quarter of 2017, up 24 percent from the second quarter of 2016.
  - ✓ The increase was consistent with higher natural gas prices (see slide 13), which increased the redispatch cost to manage congestion.
  - ✓ However, this was partly offset by lower average load levels. (see slide 12)
- Congestion rose notably from a year ago on transmission paths from Central to East, from Capital to Hudson Valley, and into NYC.
  - ✓ More transmission outages in these areas were a key driver as well (see slides 50-52 for details).
- However, congestion in the West Zone and the North Zone fell from a year ago, offsetting the overall increase.
  - ✓ Reduced congestion in the West Zone was attributable to transmission upgrades completed in May 2016, which have helped relieve congestion on the 230 kV system.
  - ✓ Reduced congestion from the North Zone was due to fewer transmission outages on the high voltage network, although 115kV congestion coming down from the North Zone became more frequent.

Day-Ahead Congestion Shortfalls

- Transmission outages accounted for most shortfalls in the second quarter of 2017.
  - ✓ Roughly $17 million (out of $21.5 million) was allocated to the responsible TO.
- $9.4 million of shortfalls accrued on the transmission paths from Central NY to East NY (primarily the Central-East interface).
  - ✓ Most of these shortfalls were attributable to the following transmission outages:
    - – The Fraser-Gilboa 345 line was OOS in early April;
    - – The Fraser-Coopers 345 line was OOS in mid-April;
    - – The Marcy-New Scotland 345 line was OOS in early May and at the end of May;
    - – The EDIC-Fraser 345 line was OOS in early June;
    - – The EDIC-New Scotland 345 line was OOS in mid-June
  - ✓ The remaining resulted from other factors that include nuclear outages changes after the day-ahead market in the commitment status of key units and the status of capacitors and SVCs.
    - – These affect the voltage limit on the Central-East interface and the resulting shortfalls are currently allocated to statewide.

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Day-Ahead Congestion Shortfalls

- $5.5 million of shortfalls accrued on New York City lines.
  - ✓ Most of these shortfalls were attributable to the outage of one Dunwoodie-Motthaven 345 line from mid-April to the end of May.
  - ✓ The two PAR-controlled lines between NJ and NYC (i.e., B & C lines) were OOS in April, contributing to shortfalls as well.
- $3.4 million of shortfalls accrued on the North Zone lines, mostly attributable to the following transmission outages:
  - ✓ The Moses-Adirondack 230 line was OOS during most of April;
  - ✓ A Marcy 765/345 transformer was OOS on several days in late-May and late-June.
- $2.2 million of shortfalls accrued on the transmission paths from Capital to Hudson Valley, due mostly to outages of the Leeds-Pleasant Valley 345 line and the Leeds-New Scotland 345 line on several days in April and June.
- $1.5 million of shortfalls accrued on the 230 kV lines in the West Zone.
  - ✓ A large portion of shortfalls was attributable to different loop flow assumptions between the TCC auction and the DAM.
  - ✓ Differences between the TCC and the DAM in the assumed distribution of Niagara generation (230 vs 115 kV) accounted for $0.6 million of surplus.

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Balancing Congestion Shortfalls

- North Zone lines accounted for $4.6 million of shortfalls in the second quarter of 2017, most of which accrued on two days (4/6 and 4/7).
  - ✓ The primary HQ interface was forced out on 4/6 and returned on 4/7.
  - ✓ During this period, the Moses-South interface was operated with greatly reduced limits for system reliability. (see slide 24)
- The West Zone 230 kV lines accounted for $4 million of shortfalls.
  - ✓ Unexpected changes in loop flows were a key driver.
  - ✓ Line deratings on several days in May and June were also a contributor.
- $1.7 million of shortfalls accrued on paths from Capital to Hudson Valley, driven largely by TSA events that substantially reduced the transfer capability into SENY.
- The PAR operations had a mixed effect on RT congestion management.
  - ✓ Ramapo PAR contributed $3.5 million of surpluses on the Central-East interface and Leeds-Pleasant Valley line, but $0.4 million of shortfalls on West Zone lines.
  - ✓ The PAR-controlled JK lines accrued more shortfalls than the ABC PARs, reflecting that the ABC PARs are operated more actively to reduce congestion.
  - ✓ St. Lawrence PARs were often used to relieve West Zone congestion, but caused shortfalls on constraints as well.

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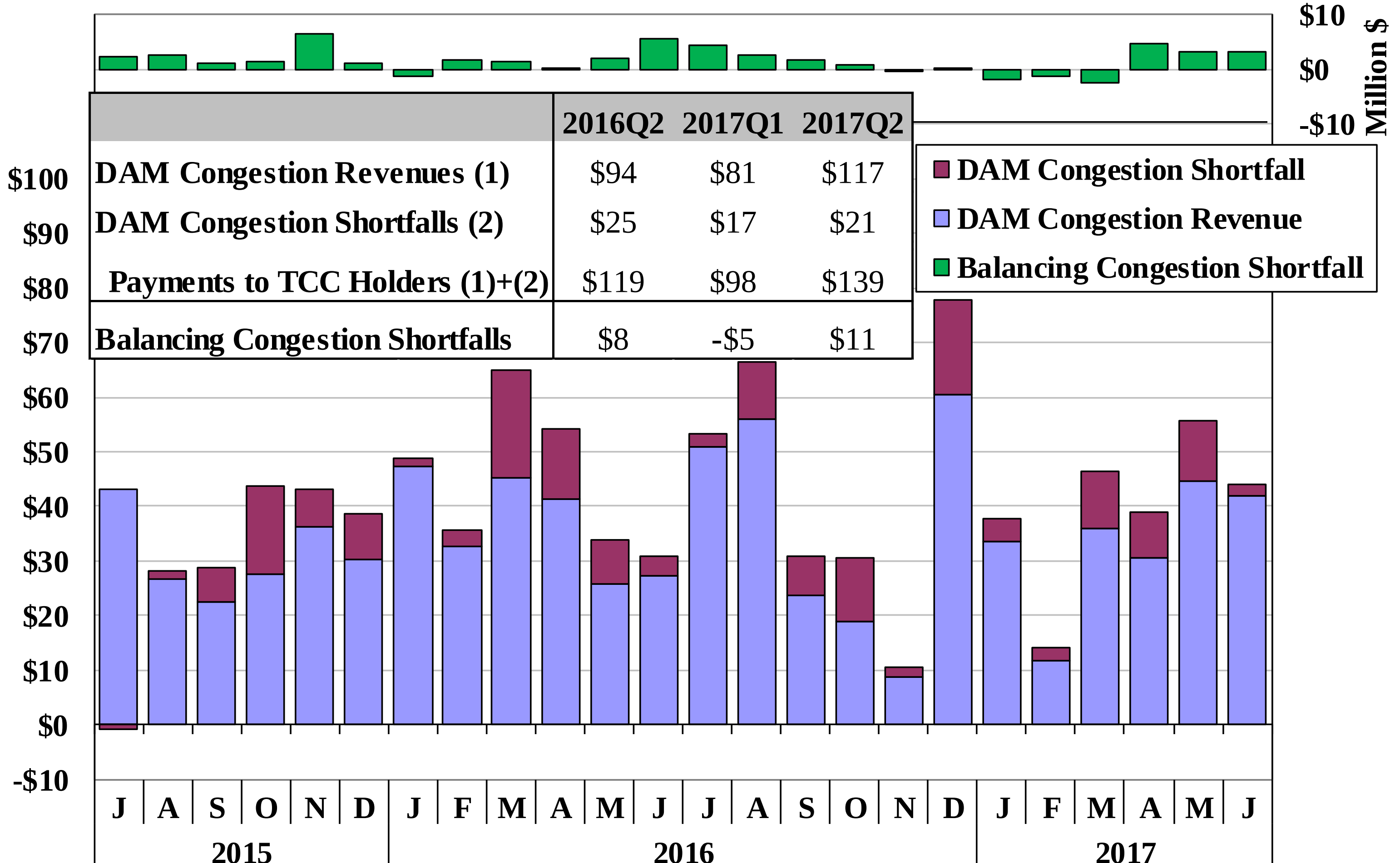
Congestion Revenues and Shortfalls by Month



	2016Q2	2017Q1	2017Q2
DAM Congestion Revenues (1)	$94	$81	$117
DAM Congestion Shortfalls (2)	$25	$17	$21
Payments to TCC Holders (1)+(2)	$119	$98	$139
Balancing Congestion Shortfalls	$8	-$5	$11

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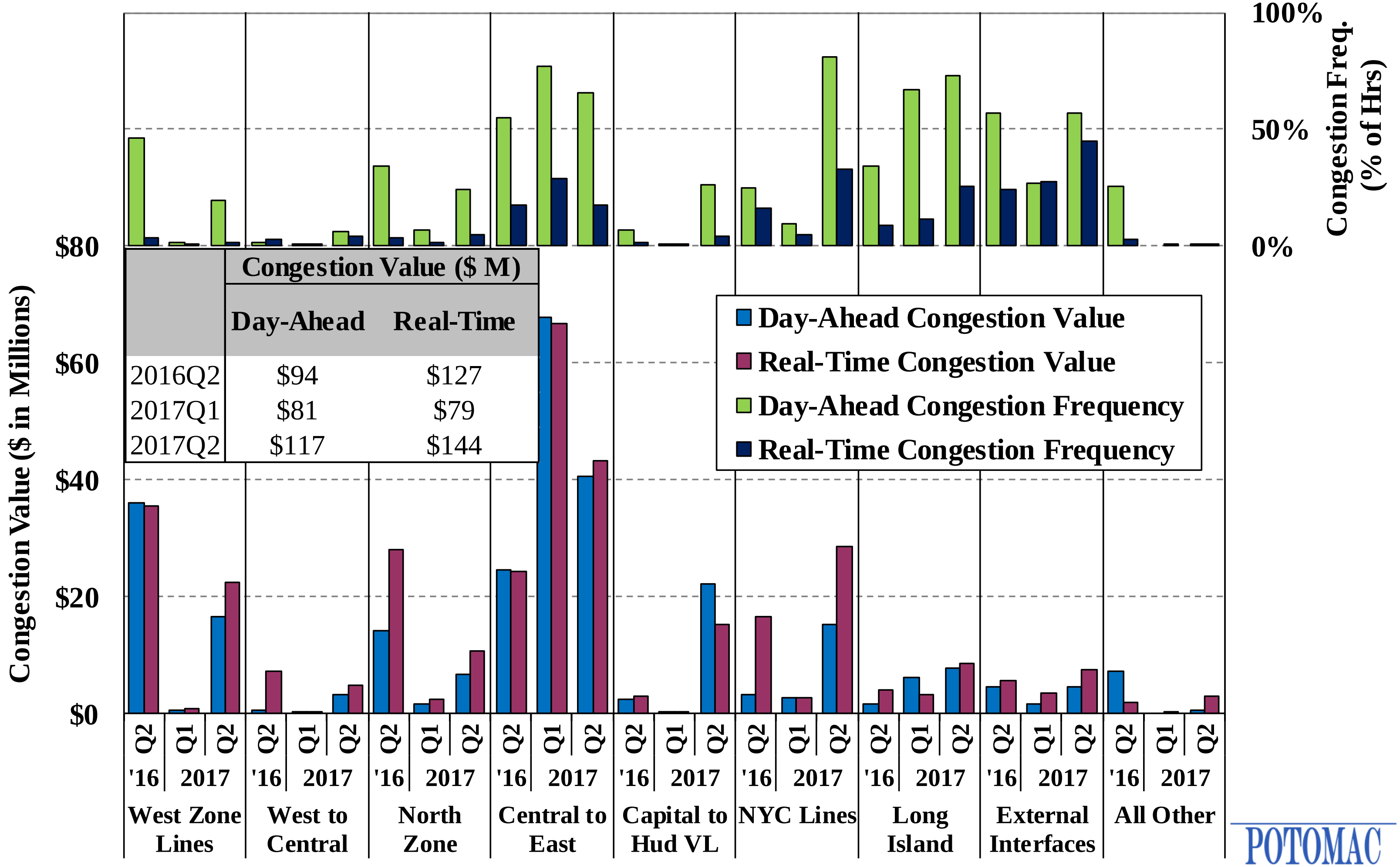
DA and RT Congestion Value and Frequency by Transmission Path



	Congestion Value ($ M)	
	Day-Ahead	Real-Time
2016Q2	$94	$127
2017Q1	$81	$79
2017Q2	$117	$144

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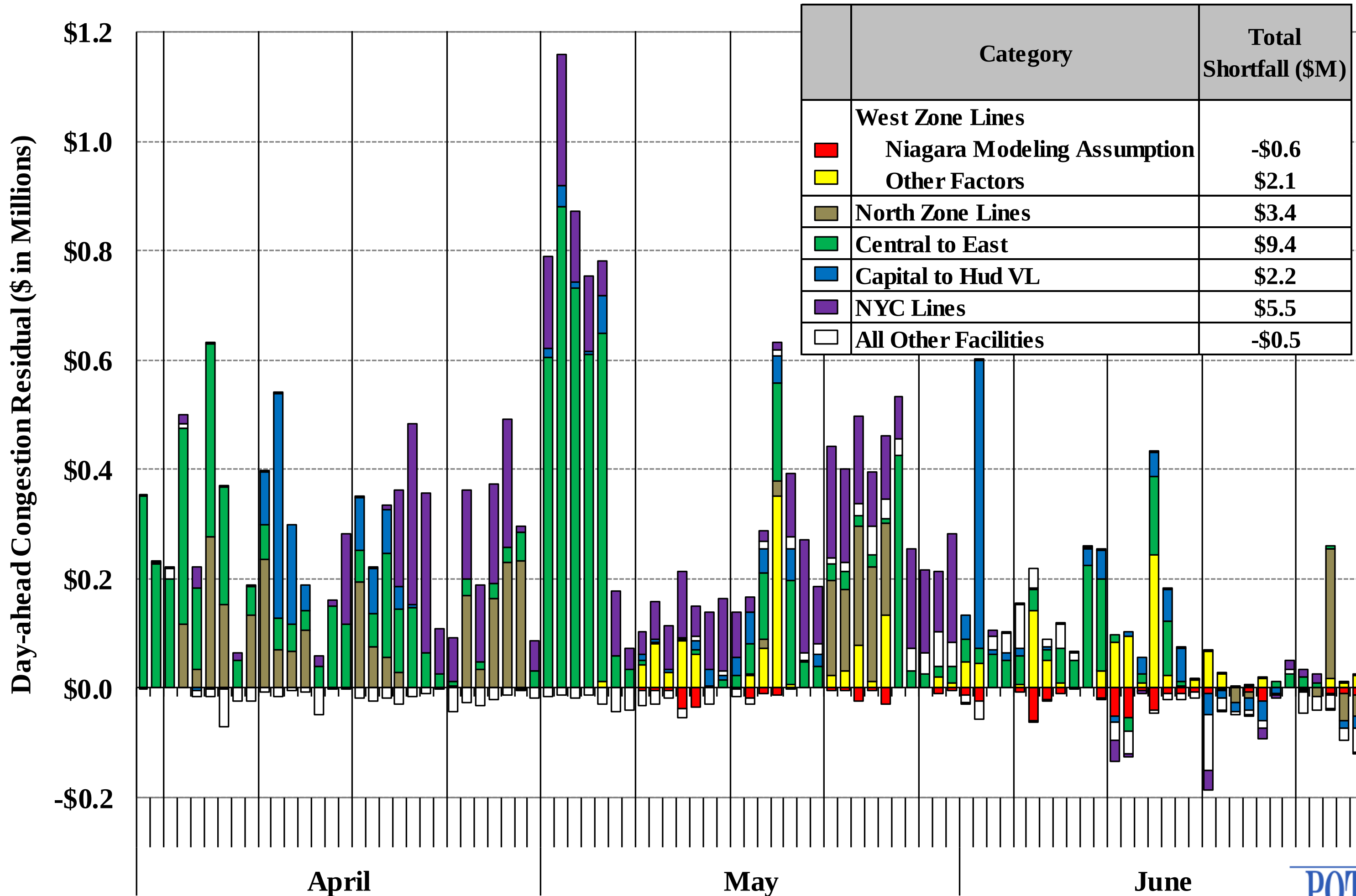
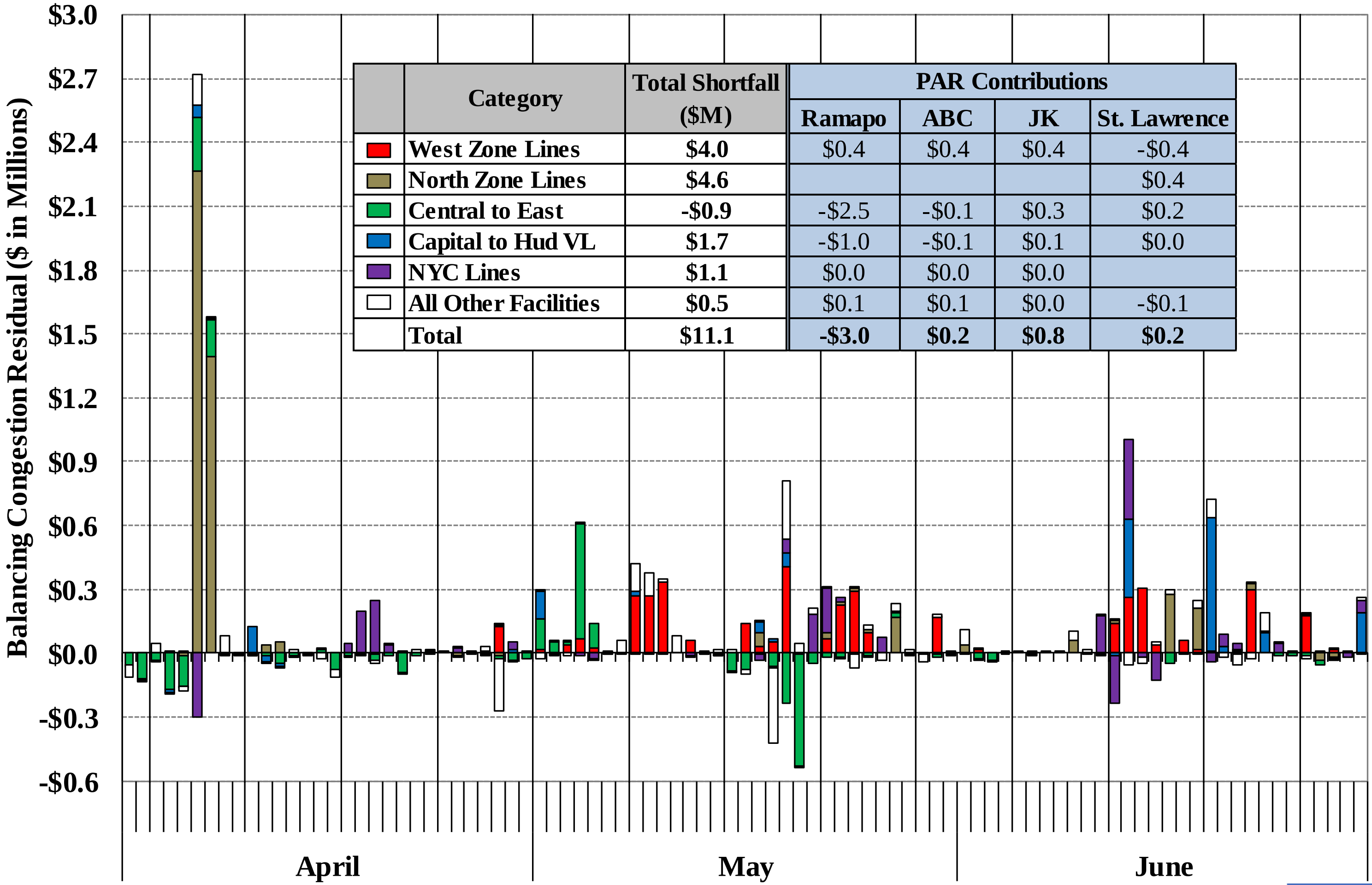
Day-Ahead Congestion Revenue Shortfalls
by Transmission Facility



Balancing Congestion Shortfalls by Transmission Facility



	Category	Total Shortfall ($M)	PAR Contributions			
			Ramapo	ABC	JK	St. Lawrence
	West Zone Lines	$4.0	$0.4	$0.4	$0.4	-$0.4
	North Zone Lines	$4.6				$0.4
	Central to East	-$0.9	-$2.5	-$0.1	$0.3	$0.2
	Capital to Hud VL	$1.7	-$1.0	-$0.1	$0.1	$0.0
	NYC Lines	$1.1	$0.0	$0.0	$0.0	
	All Other Facilities	$0.5	$0.1	$0.1	$0.0	-$0.1
	Total	**$11.1**	**-$3.0**	**$0.2**	**$0.8**	**$0.2**

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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PAR Operations under M2M with PJM: Chart Descriptions

- The following figures evaluate the PAR operations under M2M with PJM for four PAR groups:
  - ✓ Goethals PAR (i.e., A PAR);
  - ✓ Farragut PARs (i.e., B & C PARs)
  - ✓ Waldwick PARs (i.e., E, F, and O PARs); and
  - ✓ Ramapo PARs.
- Each figure shows the following quantities on a daily basis:
  - ✓ The upper portion shows the total number of PAR tap movements (counted as total tap position changes. e.g., if one tap adjustment requires to move two taps, the figure shows two movements rather than one for that adjustment).
  - ✓ The middle portion shows two stacked bars, which indicate the number of 30-minute intervals when average: a) NY costs on relevant M2M constraints exceed PJM costs by $10, or b) PJM costs exceed NY costs by $10.
  - ✓ The bottom portion shows average actual PAR flows (blue bar), compared with their average M2M targets (red diamond).
  - ✓ The inset table shows daily average tap movements for each PAR in the group.

PAR Operations under M2M with PJM: Market Outcomes

- In May, the ABC and JK lines were incorporated into the M2M process following the expiration of the ConEd-PSEG wheel agreement.
  - ✓ New coordinated flow gates were added mostly in NYC and West Zone.
- For all PARs, actual flows typically exceeded their M2M targets towards NY, resulting in a small amount of M2M payments from PJM to NYISO in the second quarter.
- We have observed instances with efficient M2M coordination as PARs were moved in the correct direction to reduce overall congestion costs in a relatively timely manner.
  - ✓ However, there were many instances when PAR adjustments may have been available and would have reduced congestion but no adjustments were made.
  - ✓ PAR adjustments were not taken in some cases because of:
    - Difficulty predicting the effects of PAR movements under uncertain conditions;
    - The adjustment would have pushed actual flows or post-contingent flows close to the limit;
    - The transient nature of congestion; and
    - Mechanical failures (e.g., stuck PARs).

PAR Operations under M2M with PJM: Market Outcomes

- The Ramapo PARs have provided significant benefits to the NYISO in managing congestion on coordinated flow gates.
  - ✓ Balancing congestion surpluses have resulted from relief of transmission paths from Central to East and into SENY (see slide 56), indicating that it reduced production costs and congestion.
  - ✓ Nonetheless, comparable benefits have not been observed from the operation of ABC and JK PARs in the second quarter of 2017.
- We observed potential opportunities for increased utilization of M2M PARs.
  - ✓ The normal limit for each PAR-controlled line was over 500 MW, but flows were generally well below this level. However, these lines sometimes limited by their post-contingency limits versus flows, which are not shown.
  - ✓ On average, each PAR was adjusted 2 to 5 times per day.
    - – This was well below the operational limits of 20 taps/day and 400 taps/month.
    - – This was also below the average five to six 30-minute blocks of time per day when the congestion differential between PJM and NYISO exceeded $10/MWh across these PAR-controlled lines.
- We will continue to monitor the performance of the M2M process.

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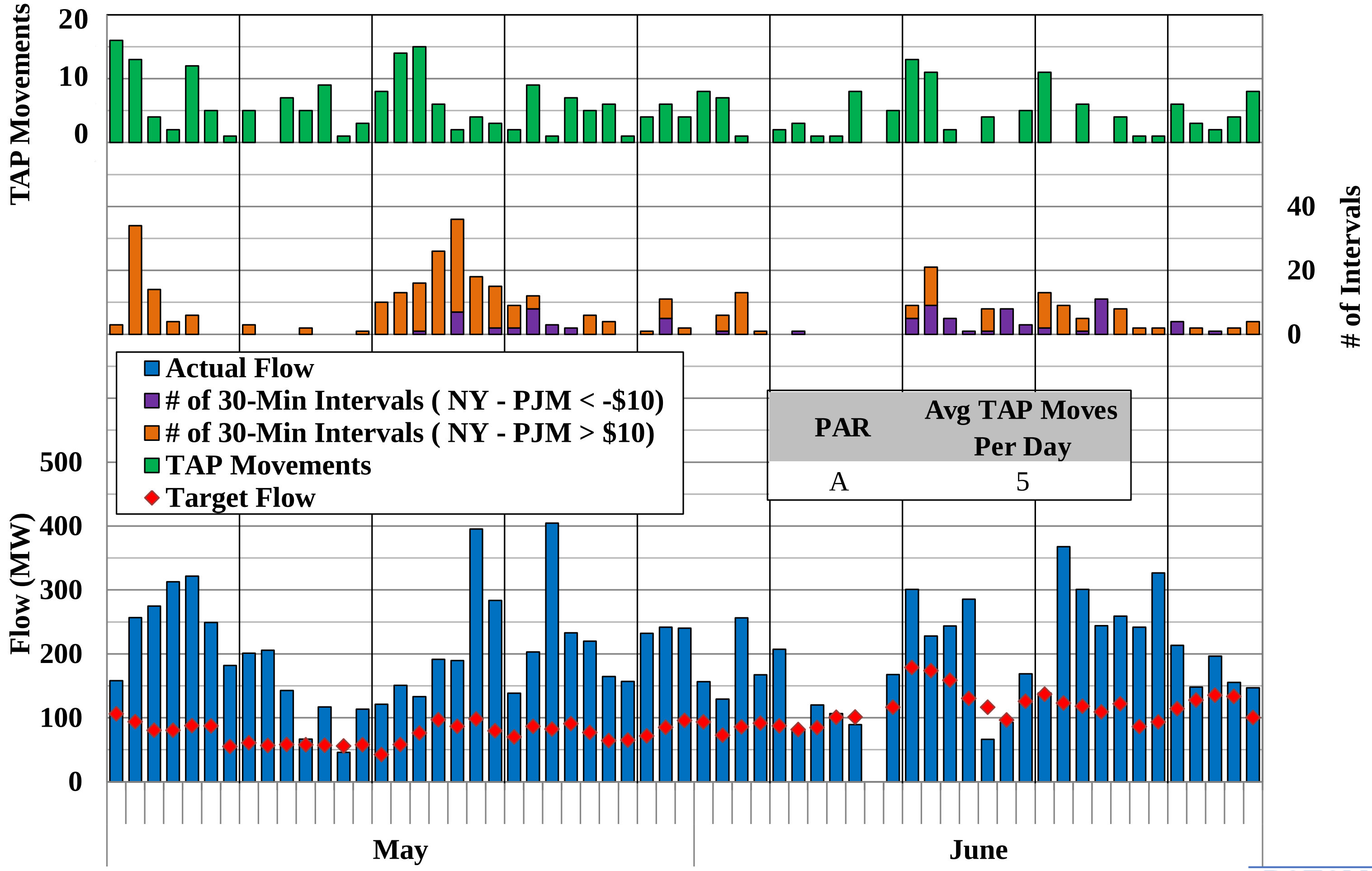
PAR Operation under M2M with PJM: A PAR



A PAR

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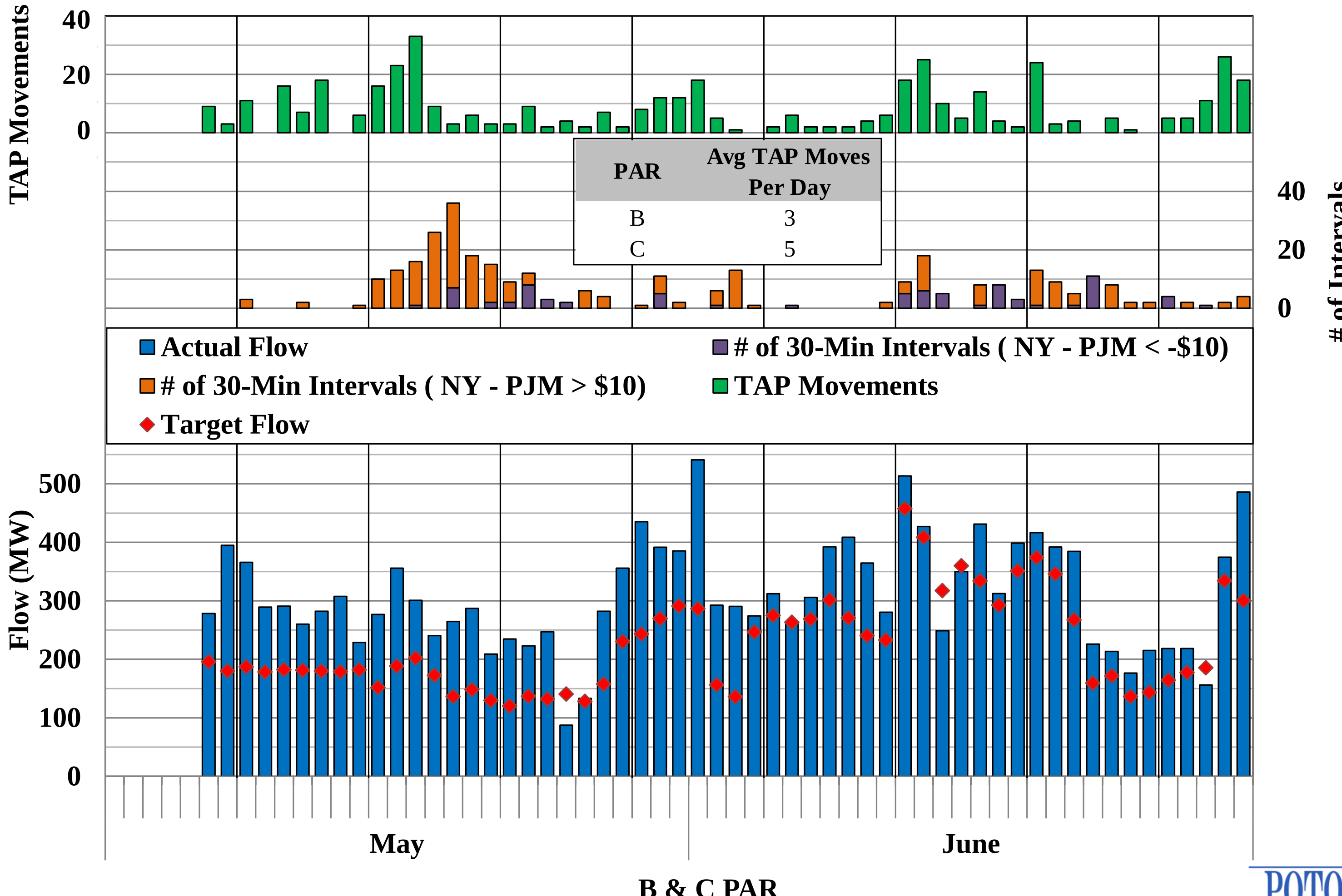
PAR Operation under M2M with PJM:
B & C PAR



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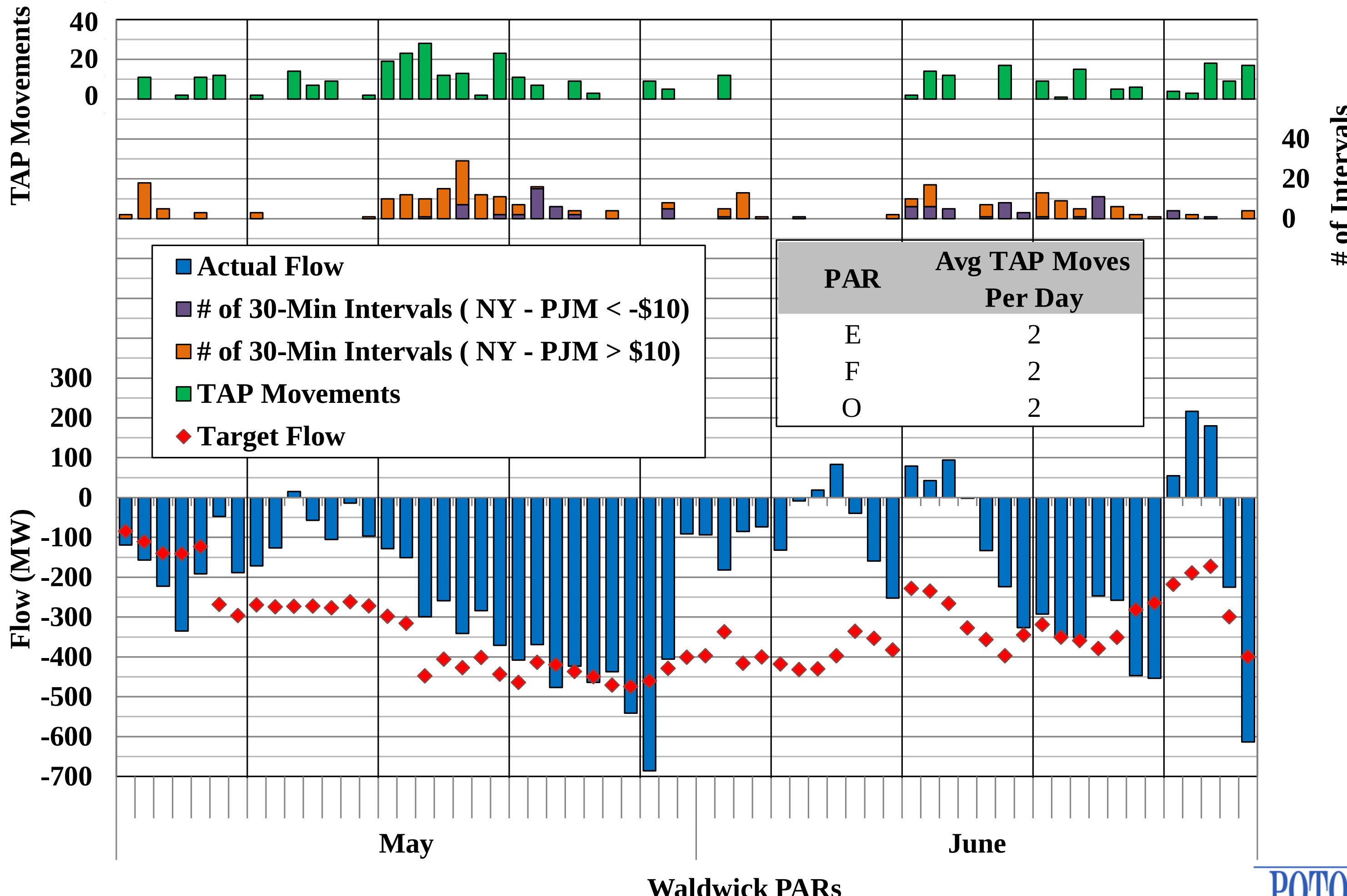
PAR Operation under M2M with PJM:
Waldwick PARs



PAR	Avg TAP Moves Per Day
E	2
F	2
O	2

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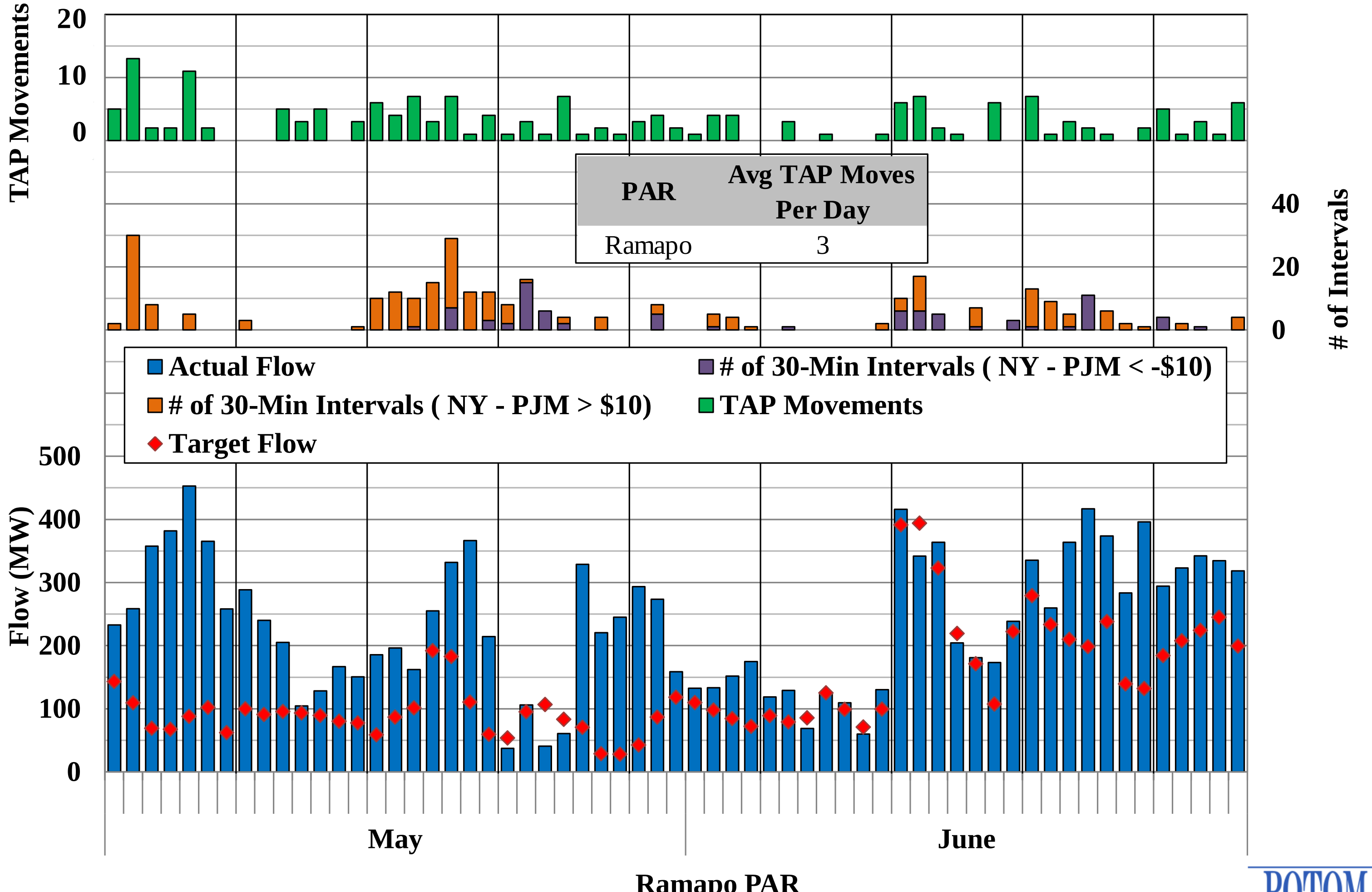
PAR Operation under M2M with PJM:
Ramapo PARs



Constraints on the Low Voltage Network Upstate

- In upstate New York, constraints on 230 and 345 kV facilities is generally managed through the DA and RT market systems. This provides several benefits:
  - ✓ Efficient dispatch and scheduling decisions; and
  - ✓ Transparent prices that provide efficient signals for longer lead time decisions such as fuel procurement, external transaction scheduling, and investment.
- However, 69 and 115 kV constraints are resolved in other ways, including:
  - ✓ Out of merit dispatch and supplemental commitment;
  - ✓ External interface transfer limits;
  - ✓ Use of an internal interface limit as a proxy for the facility; and
  - ✓ Adjusting PAR-controlled lines.
- The first figure shows the number of days in the second quarter of 2017 when various resources were used to manage constraints in five areas of upstate NY.
  - ✓ West Zone: Mostly Niagara-to-Gardenville and Gardenville-to-Dunkirk circuits;
  - ✓ Central Zone: Mostly constraints around the State Street 115kV bus;
  - ✓ Cent-Hudson: Mostly constraints on the 69kV system in the Hudson Valley;
  - ✓ Capital Zone: Mostly Albany-to-Greenbush 115kV constraints; and

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Congestion on the Low Voltage Network Upstate

- ✓ North Zone: Mostly 115kV constraints coming south from the North Zone between the Colton 115kV and Taylorville 115kV buses.
- The West Zone contains the most frequently constrained 115kV facilities.
  - ✓ Generation and Ontario imports were constrained on many days, while PARs in Northern NY and Southeast NY were also used on some days.
  - ✓ West Zone constraint management affected other areas of New York by:
    - Reducing low-cost imports from Ontario, which raised LBMPs in other areas; and
    - Using PARs to relieve West Zone constraints tends to exacerbate constraints going south from the North Zone, across the Central East interface, and into NYC.
    - Thus, the actions should be done in a manner that balances the benefits of relieving constraints in one area against the cost of exacerbating congestion in another.
      - This can be done more effectively if low-voltage constraints were managed using the DA and RT market systems.
    - The second figure illustrates these interactions for an example day (April 3).
  - ✓ Although the PJM export limit bound on just 9 days, PJM imports are generally helpful for managing 115kV congestion in the West Zone and Central Zone.
    - Modeling 115kV constraints in the market systems would provide incentives for PJM imports to relieve congestion in NY.

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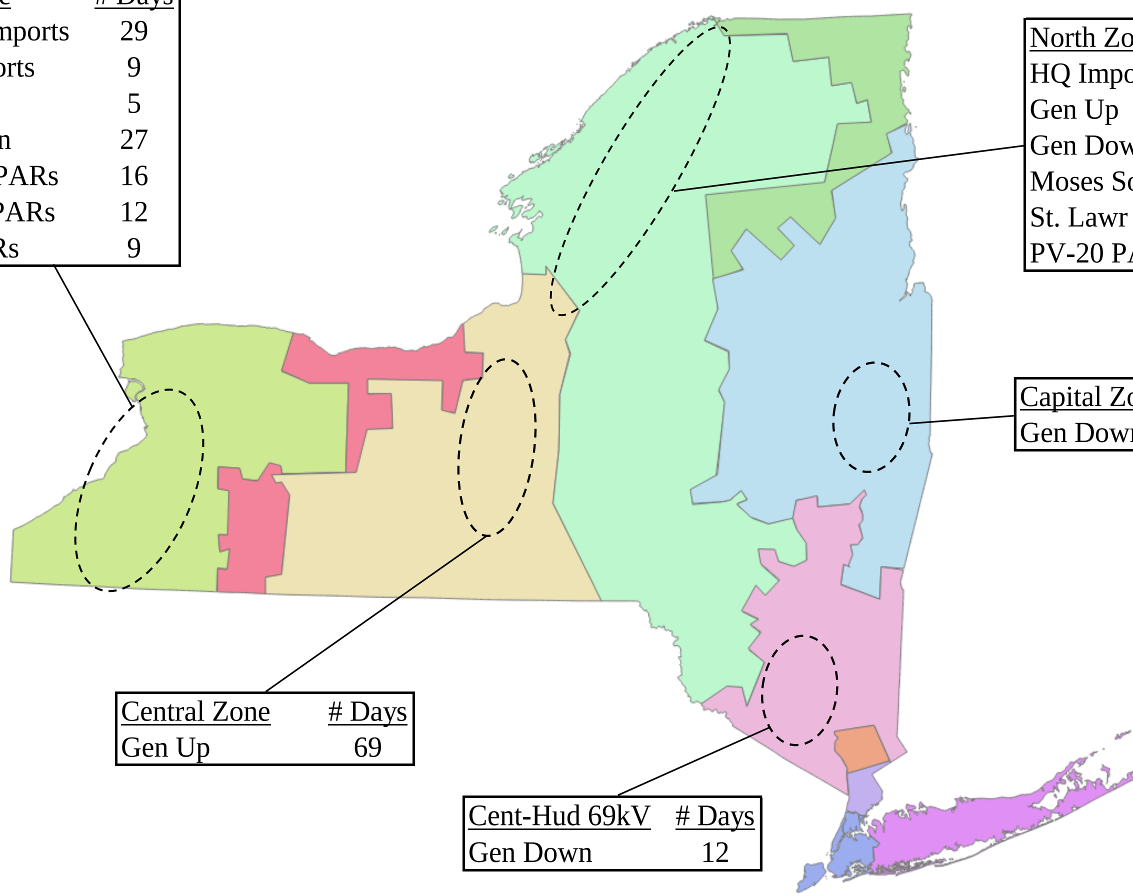
Constraints on the Low Voltage Network Upstate:
Summary of Resources Used to Manage Congestion



West Zone	# Days
Ontario Imports	29
PJM Exports	9
Gen Up	5
Gen Down	27
St. Lawr PARs	16
Ramapo PARs	12
ABC PARs	9

North Zone	# Days
HQ Imports	21
Gen Up	1
Gen Down	30
Moses South	3
St. Lawr PARs	20
PV-20 PAR	5

Capital Zone	# Days
Gen Down	24

Central Zone	# Days
Gen Up	69

Cent-Hud 69kV	# Days
Gen Down	12

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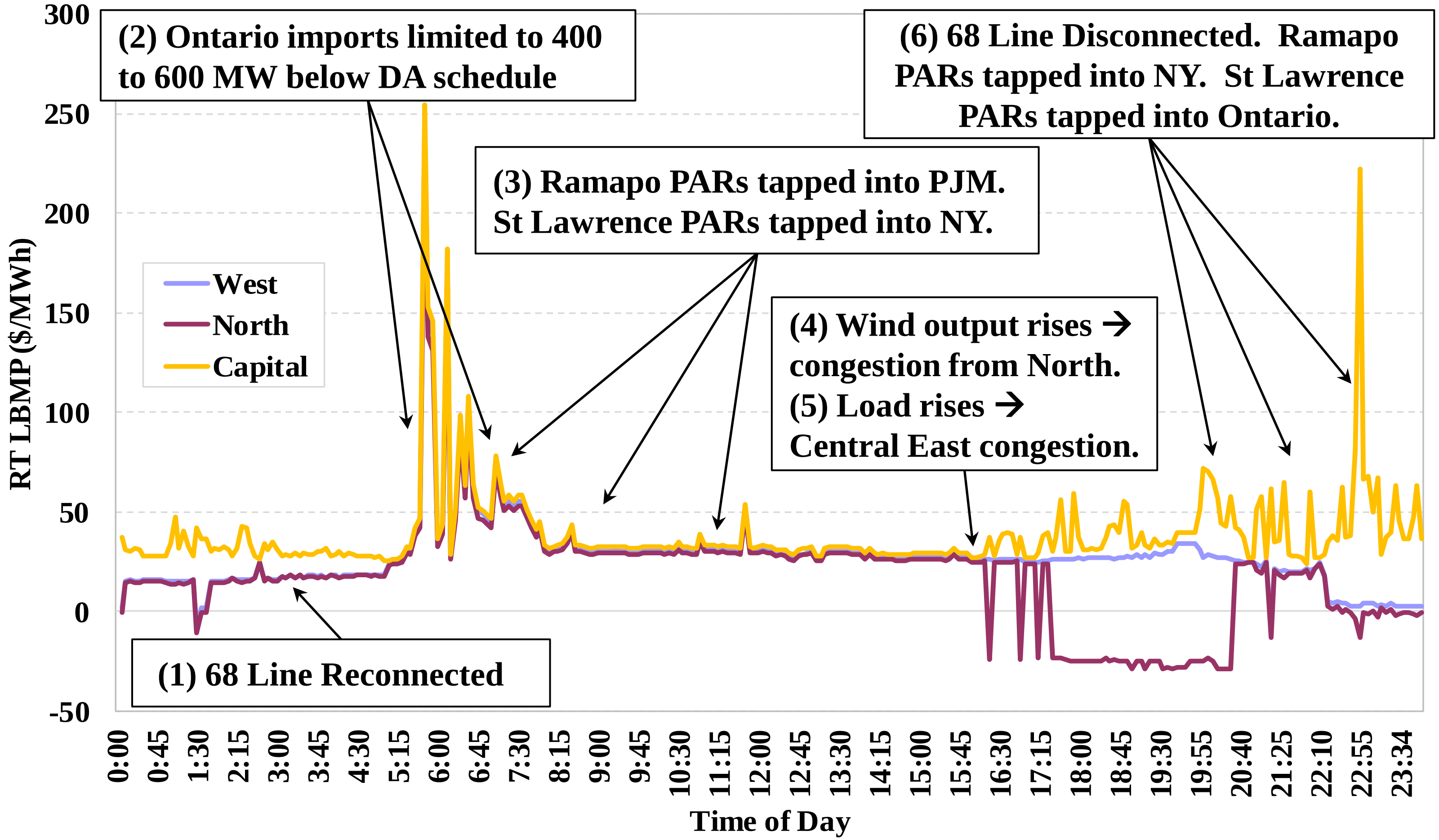
Congestion on the Low Voltage Network Upstate:
Management of 115kV Congestion on April 3



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;
  - ✓ 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.
  - ✓ Based on a review of operator logs and LRR constraint information (where a unit is considered to be committed for a LRR constraint if the constraint would be violated without the unit’s capacity), each NYC commitment (flagged as DARU, LRR, or SRE) was categorized for one of the following reasons:

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Supplemental Commitment and OOM Dispatch: Chart Descriptions

  - 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.*
- ✓ 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.

- 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.

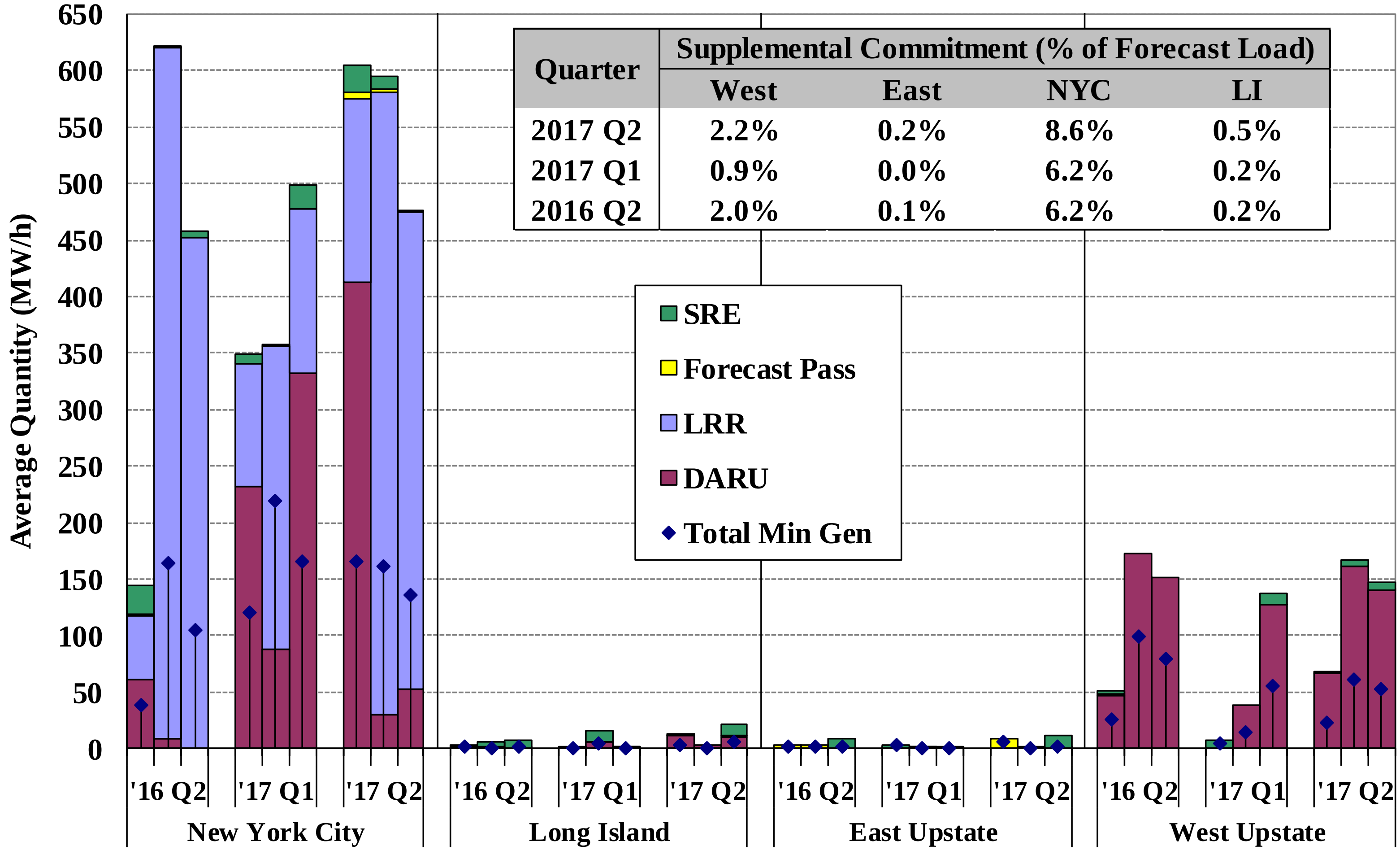
Supplemental Commitment and OOM Dispatch:
Supplemental Commitment Results

- Reliability commitment averaged 705 MW in the second quarter of 2017.
  - ✓ New York City accounted for 80 percent (or 560 MW), which was up 37 percent from the second quarter of 2016.
    - Higher DARU commitments in April resulted from increased local needs because of planned transmission outages that greatly reduced transfer capability into the Freshkills load pocket and the 345 kV system (from upstate).
    - Most LRR commitments in the second quarter of 2017 were made to satisfy the N-1-1 thermal requirements in the Astoria West/Queensbridge load pocket.
  - ✓ Western NY accounted for 18 percent (or 130 MW), which was comparable to the second quarter of 2016.
    - These have fallen notably since recent transmission upgrades.
    - The vast majority of DARU commitments occurred in the Central Zone at the Cayuga (Milliken) plant to manage post-contingency flows on 115kV facilities.
    - DARU commitments are expected to fall following the completion of transmission upgrades that facilitated the expiration of Milliken RSSA on 6/30.
- Reliability commitments were rare in other areas this quarter.

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.
- OOM dispatched occurred for 1336 station-hours in the second quarter of 2017, down 8 percent from a year ago.
- Western NY accounted for the largest share (63 percent) of OOM actions.
  - ✓ OOM dispatch has been less frequent since 2015 because of transmission upgrades, which allowed the retirement of several units that were frequently OOMed in the past for local reliability needs.
  - ✓ Two hydro units were frequently OOMed in May and June due to increased local needs on the 115 kV network because of transmission outages.
- The Niagara facility was often manually instructed to shift output among its units to secure certain 115kV and/or 230 kV transmission constraints (which was not included in the OOM counts in the chart). In the second quarter of 2017,
  - ✓ This manual shift was required in 276 hours to manage 115 kV constraints and in 13 hours to manage 230 or 345 kV constraints.

Supplemental Commitment for Reliability
by Category and Region



Quarter	Supplemental Commitment (% of Forecast Load)			
	West	East	NYC	LI
2017 Q2	2.2%	0.2%	8.6%	0.5%
2017 Q1	0.9%	0.0%	6.2%	0.2%
2016 Q2	2.0%	0.1%	6.2%	0.2%

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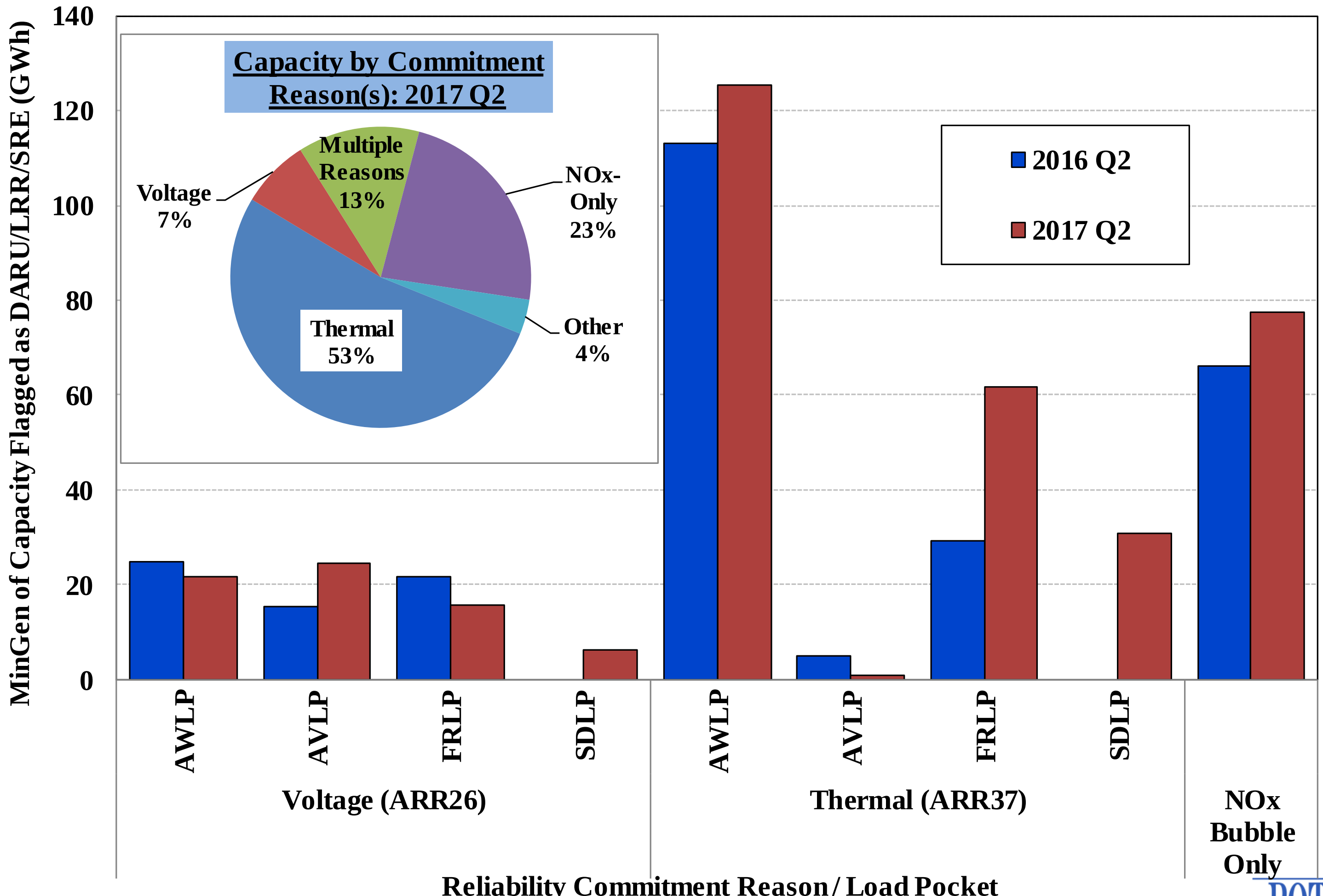
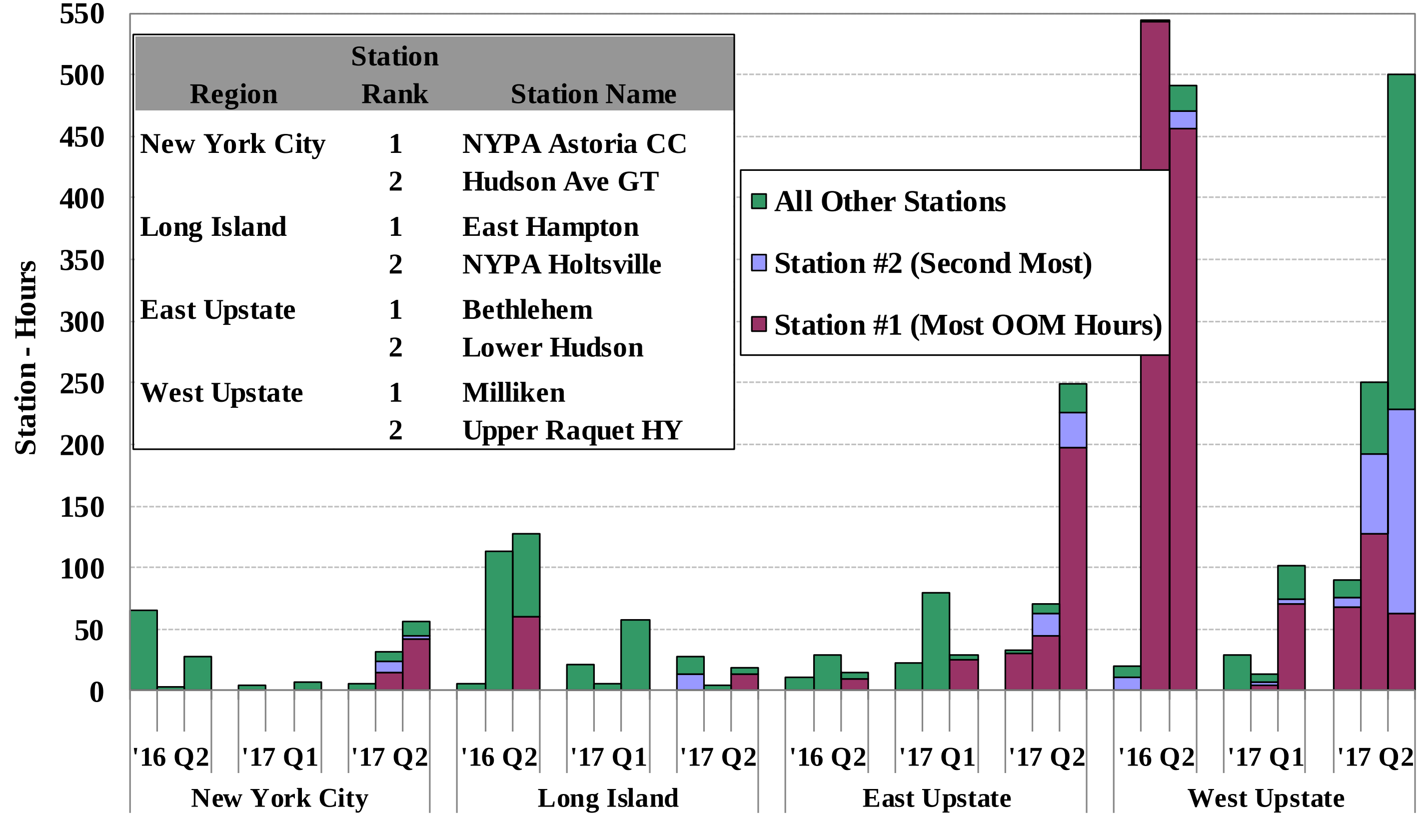
Supplemental Commitment for Reliability in NYC by Reliability Reason and Load Pocket



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



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

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 600 hours in 2016-Q2, 252 hours in 2017-Q1, and 289 hours in 2017-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.

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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 DAM (usually economically) whose day-ahead market revenues do not cover their as-offered costs.
    - Real Time: Typically for quick-start resources 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 DA schedule when the RT LBMP is higher than the DA 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 for local reliability.
    - 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:
Market Results

- Guarantee payments totaled $11.2 million this quarter, comparable to the second quarter of 2016.
- Guarantee payments in New York City rose by $2.5 million, reflecting:
  - ✓ Increased supplemental commitment for reliability (see slides 73-74); and
  - ✓ Higher natural gas prices (see slide 13]), which increased the commitment costs of gas-fired units.
- However, this increase was offset by a decrease in local uplift in Western NY.
  - ✓ Decreased OOM dispatch (see slide 75) and higher LBMPs led to lower guarantee payment to the Milliken units.
- RT uplift for curtailed imports was high on May 24.
  - ✓ The Chateauguay-Massena 7040 line and the Massena-Marcy MSU1 line both tripped.
  - ✓ As a result, transactions scheduled at the primary HQ interface were curtailed to zero for 4 hours.

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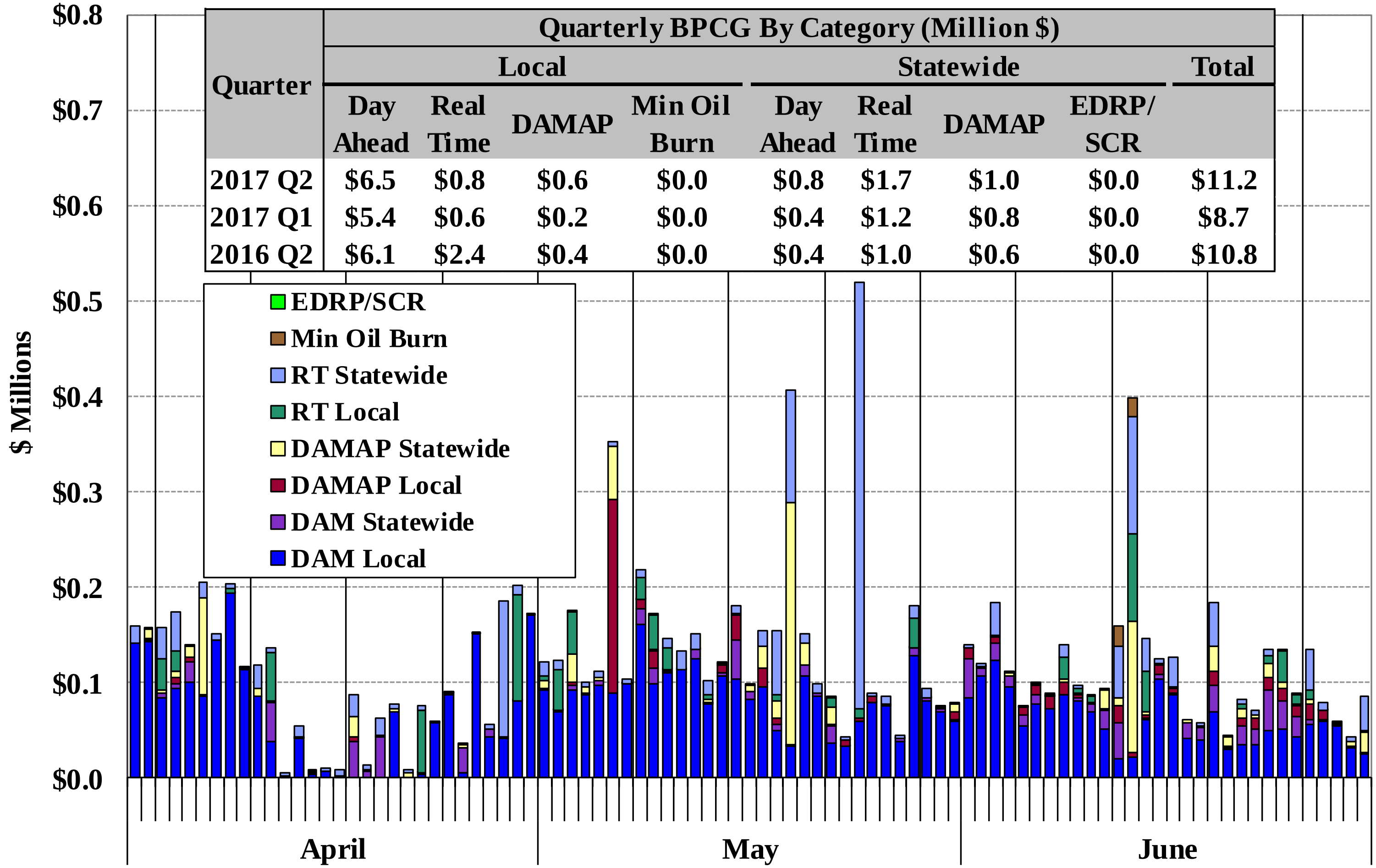
Uplift Costs from Guarantee Payments
Local and Non-Local by Category

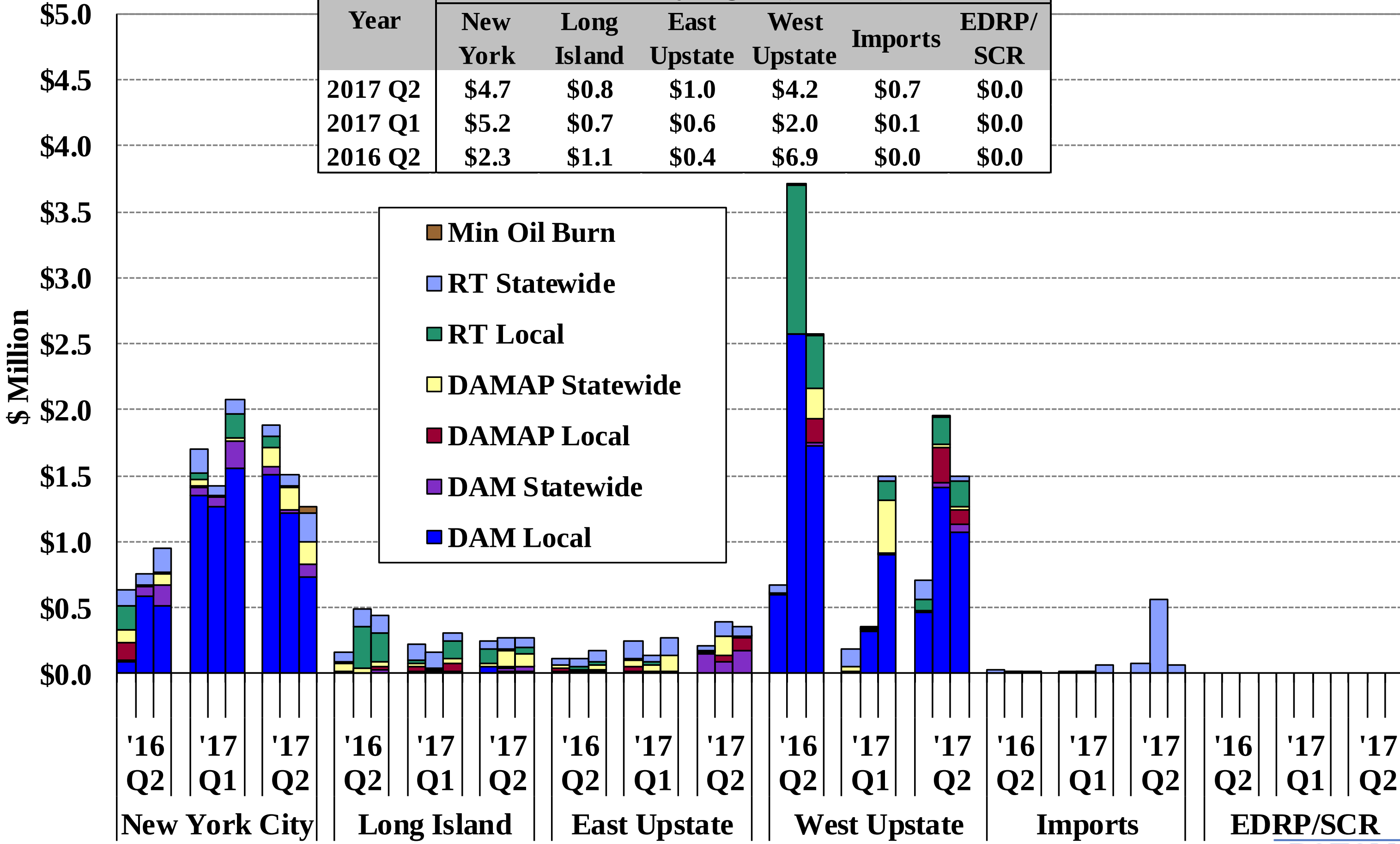


Quarter	Quarterly BPCG By Category (Million $)								
	Local				Statewide				Total
	Day Ahead	Real Time	DAMAP	Min Oil Burn	Day Ahead	Real Time	DAMAP	EDRP/ SCR	
2017 Q2	$6.5	$0.8	$0.6	$0.0	$0.8	$1.7	$1.0	$0.0	$11.2
2017 Q1	$5.4	$0.6	$0.2	$0.0	$0.4	$1.2	$0.8	$0.0	$8.7
2016 Q2	$6.1	$2.4	$0.4	$0.0	$0.4	$1.0	$0.6	$0.0	$10.8

Note: These data are based on information available at the reporting time and do not include some manual adjustments to mitigation, so they can be different from final settlements.

Uplift Costs from Guarantee Payments
By Category and Region

Year	BPCG By Region (Million $)					
	New York	Long Island	East Upstate	West Upstate	Imports	EDRP/ SCR
2017 Q2	$4.7	$0.8	$1.0	$4.2	$0.7	$0.0
2017 Q1	$5.2	$0.7	$0.6	$2.0	$0.1	$0.0
2016 Q2	$2.3	$1.1	$0.4	$6.9	$0.0	$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

Potential Economic and Physical Withholding:
Chart Descriptions

- 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.
  - ✓ Long-term nuclear outages/deratings are excluded from this analysis.

Potential Economic and Physical Withholding:
Market Power Screening Results

- The amount of output gap remained low in the second quarter of 2017 and raised no significant market power concerns.
  - ✓ Output gap averaged < 0.1 percent of total capacity at the mitigation threshold and ~1.5 percent at the lowest threshold evaluated (i.e., 25 percent).
  - ✓ Most of output gap occurred on several units that are owned by small suppliers and located at regions with no significant local congestion.
- 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 typically rose in April and May as suppliers scheduled more maintenance expecting milder conditions.
    - In some cases, it would have been efficient to reschedule some of these outages because it would have been economic to operate given actual market conditions.
  - ✓ Economic capacity on long-term outages/deratings were modestly higher in June 2017 because one nuclear unit was forced out of service for about two weeks.
  - ✓ The year-over-year variation in outage patterns during this period was driven largely by forced outages of different generators.

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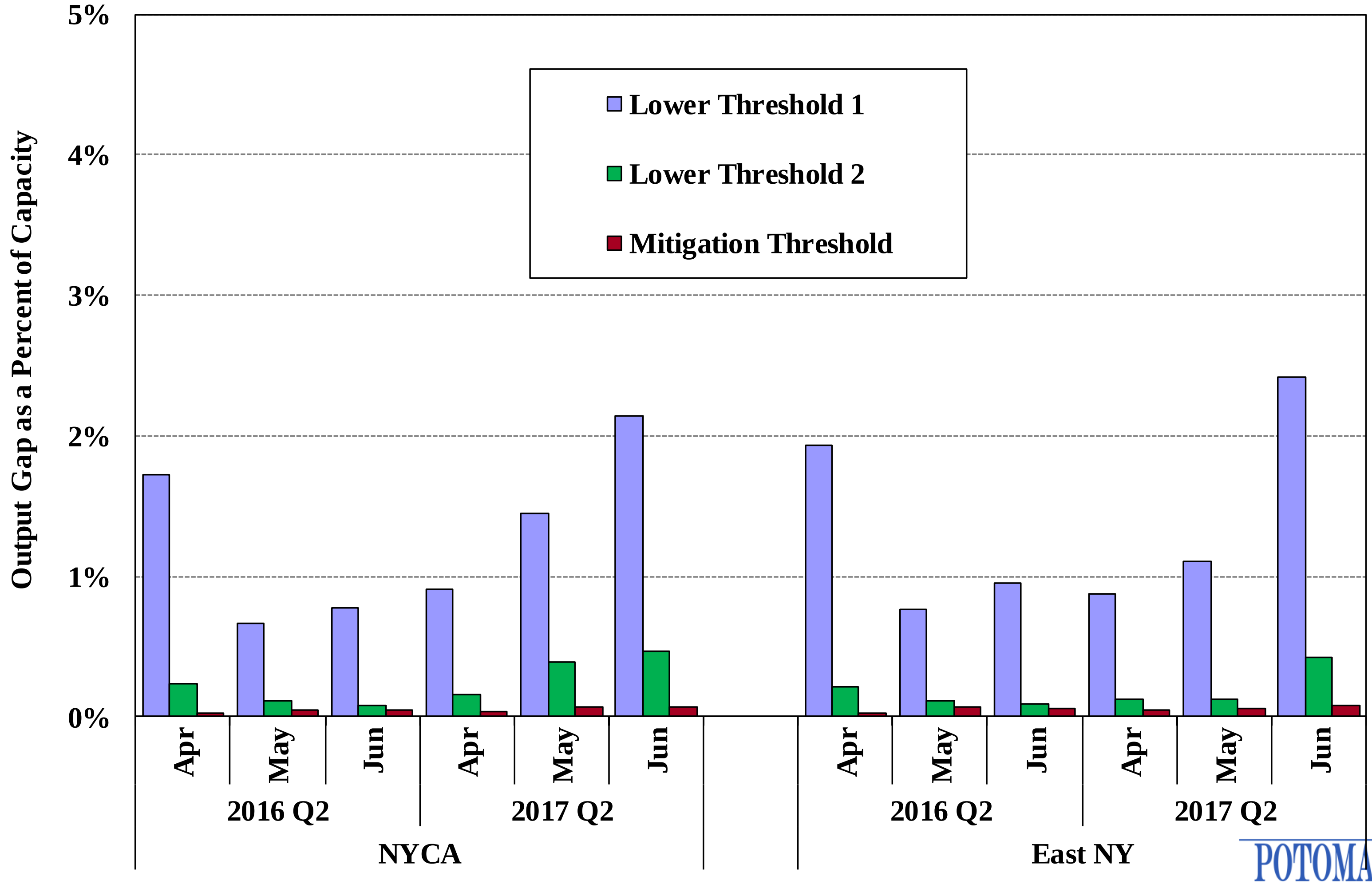
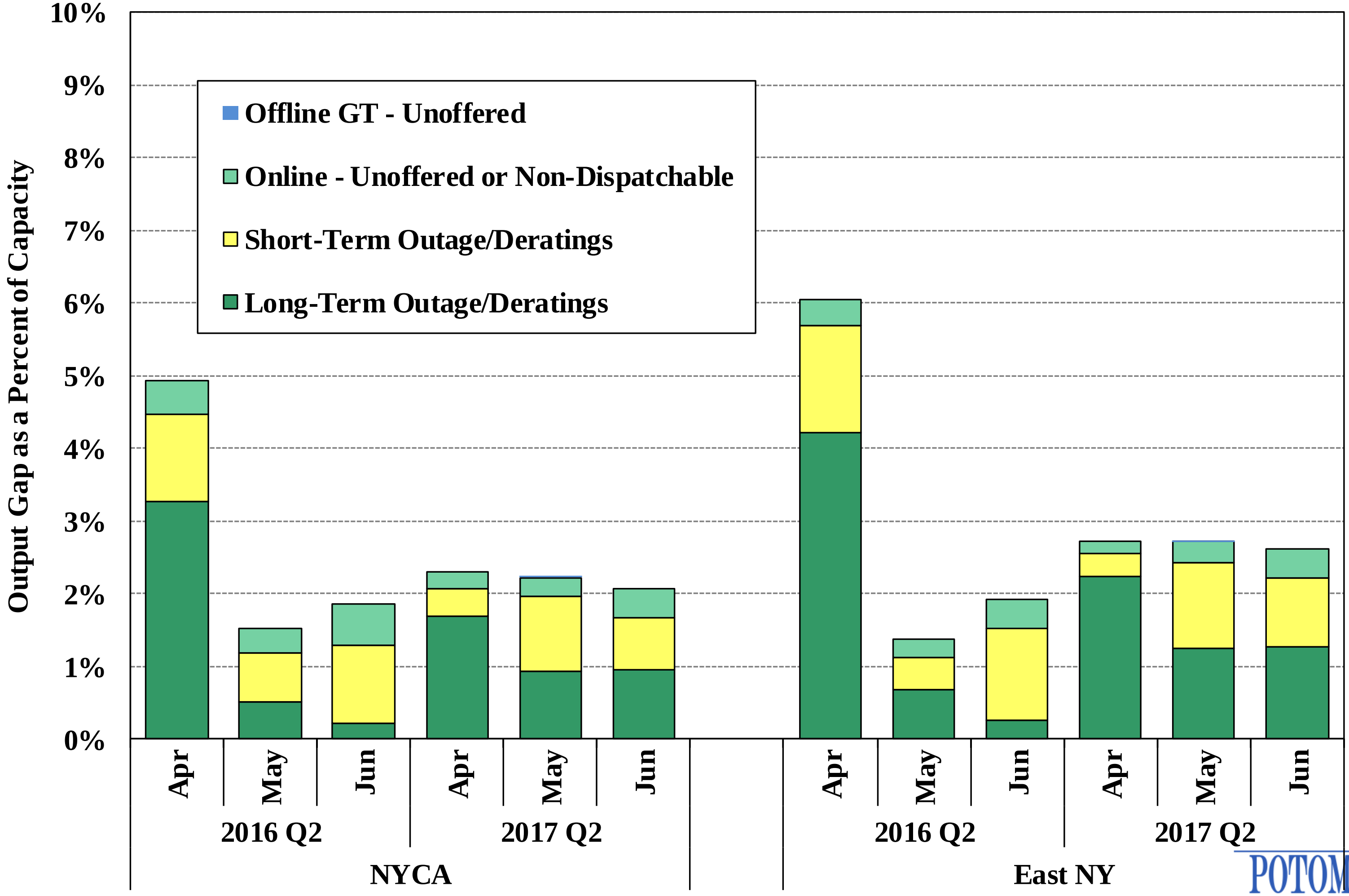
Output Gap by Month
NYCA and East NY



Unoffered Economic Capacity by Month
NYCA and East NY



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Automated Market Power Mitigation

- The next figure summarizes the automated mitigation that was imposed in the DAM and RTM (not including BPCG mitigation).
  - ✓ The upper panel shows the frequency of incremental energy mitigation, and the lower panel shows the average mitigated capacity, including the flexible output range (i.e., Incremental Energy) and the non-flexible portion (i.e., MinGen).
  - ✓ The left portion shows the amount of mitigation by the Automated Mitigation Procedure ("AMP") on economically committed units in NYC load pockets, while the right portion shows for units committed for reliability.
- Most mitigation occurs in the DAM, since that is where most supply is scheduled.
  - ✓ Nearly all of mitigation occurred in the DAM in the second quarter of 2017.
    - – Local reliability (i.e., DARU & LRR) mitigation (which accounted for 72 percent of DAM mitigation) rose modestly from a year ago because of more DARU and LRR commitments in New York City (see slides 73-74).
    - – However, these mitigations generally affect guarantee payment uplift but not LBMPs.
  - ✓ More frequent congestion in the 138 kV load pockets, particularly into the Astoria West load pocket, contributed to more mitigation in these areas.

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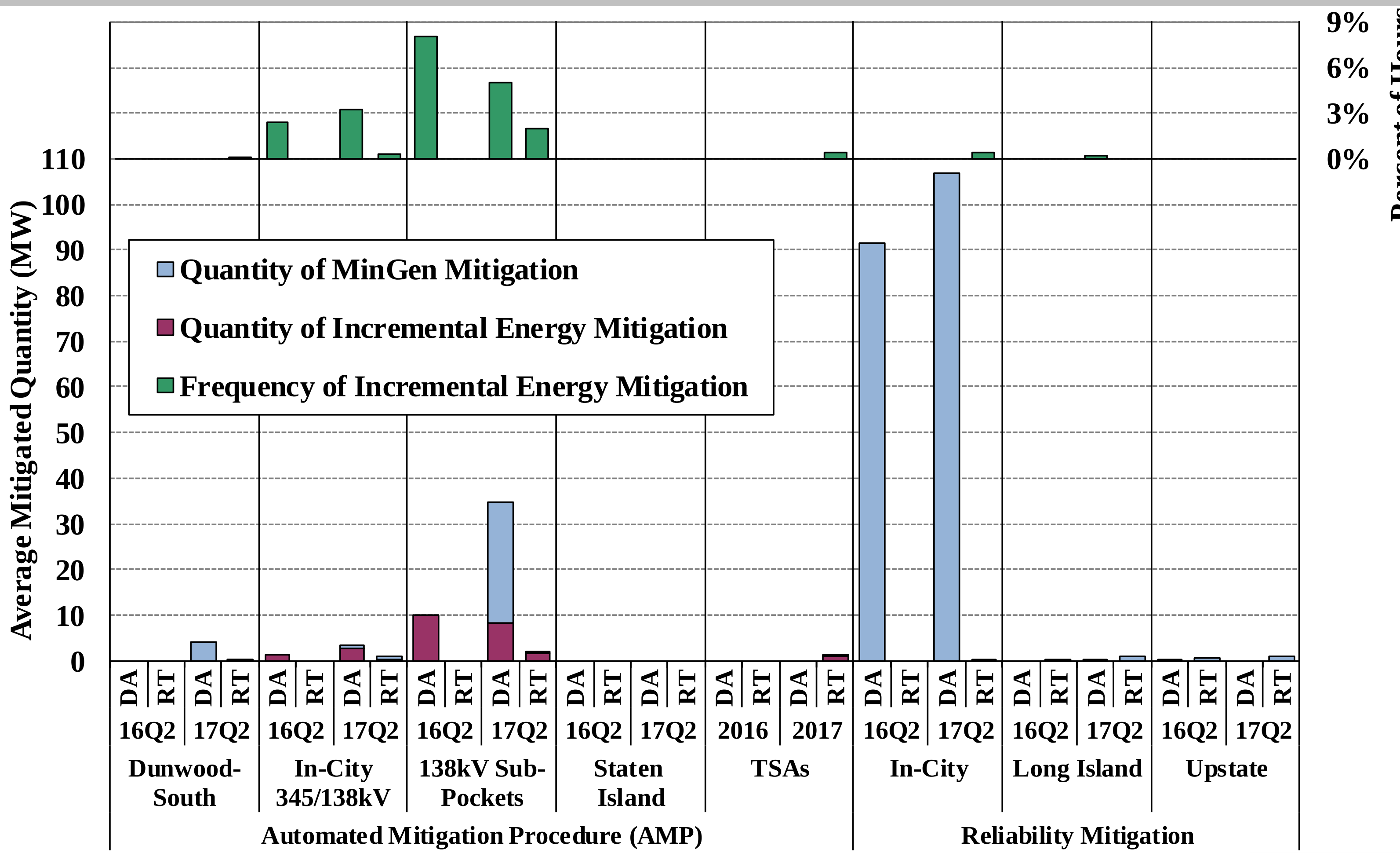
Automated Market Power Mitigation



Capacity Market

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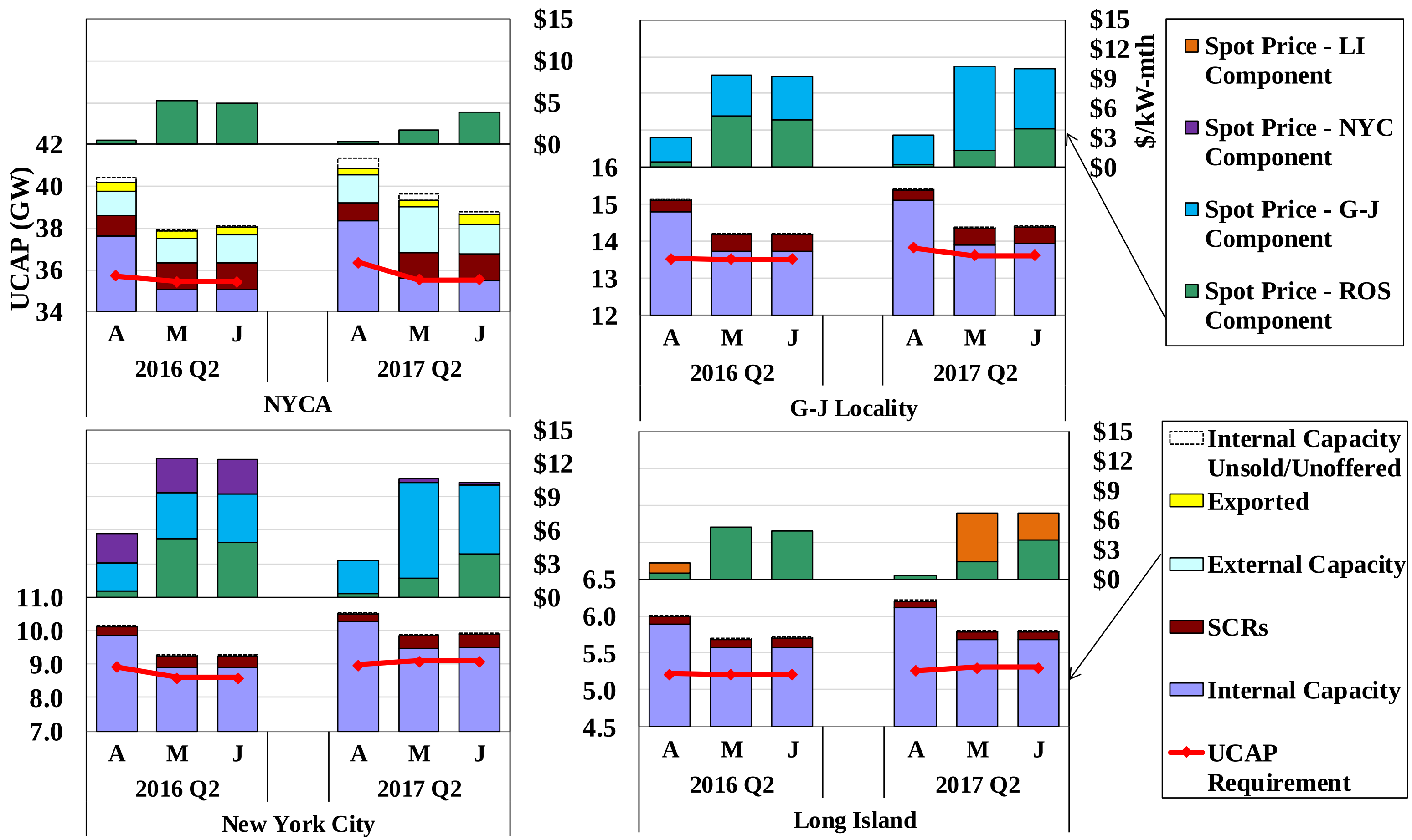
Spot Capacity Market Results

- The following three exhibits summarize capacity market results and key market drivers in 2017-Q2.
  - ✓ 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 first table shows: (a) the year-over-year changes in spot prices by locality; and (b) variations in key factors that drove these changes.
  - ✓ The second table shows changes in the demand curves from the previous year.
- The average spot prices increased or fell depending on the region:
  - ✓ Spot prices decreased by 21 and 45 percent in NYC and NYCA, respectively.
    - – NYC prices decreased primarily due to Net CONE reductions whereas NYCA price reductions were driven by that and higher imports from external control areas.
  - ✓ Spot prices rose by 9 and 17 percent in the G-J Locality and LI, respectively.
    - – These increases were driven primarily by changes to the unit Net CONE assumptions for the proxy unit from the latest Demand Curve Reset process. (see Slide 91)
- LCRs rose across all localities which drives up capacity prices; however, the load forecasts fell across regions offsetting this impact.

Capacity Market Results
2016-Q2 & 2017-Q2



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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Key Drivers of Capacity Market Results

	NYCA	NYC	LI	G-J Locality
Avg. Spot Price				
2017 Q2 ($/kW-Month)	$1.99	$8.02	$4.58	$7.85
% Change from 2016 Q2	-45%	-21%	17%	9%
Change in Demand				
Load Forecast (MW)	-181	-124	-51	-248
IRM/LCR	0.5%	1.0%	1.0%	1.5%
2017 Summer	*118.0%*	*81.5%*	*103.5%*	*91.5%*
2016 Summer	*117.5%*	*80.5%*	*102.5%*	*90.0%*
ICAP Requirement (MW)	**-47**	**17**	**2**	**18**
Change in ICAP Supply (MW) - Quarter Avg				
Generation	-128	-185	27	-173
Import Capacity	431			

2017 Demand Curve Reset: Changes to the Regional UCAP Reference Price

	Reference Price		
Region	**2017 Summer**	**2016 Summer**	**Delta**
NYCA	$ 10.01	$ 10.21	$ (0.20)
G-J Locality	$ 16.01	$ 13.77	$ 2.24
NYC	$ 19.46	$ 21.41	$ (1.95)
LI	$ 13.47	$ 8.95	$ 4.52

- In late-2016, the NYISO completed it's Demand Curve Reset Process ("DCR") that established the guidelines for generating the demand curves for each locality for the next eight capability periods.
  - ✓ This process updated the assumptions used for determining the unit Net CONE for the demand curve proxy generator which ultimately determines the reference prices in each locality.
  - ✓ Changes to the estimated Net CONEs in each region contributed significantly to yearly price differences as outlined in the table above.