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

David B. Patton, Ph.D.
Pallas LeeVanSchaick, Ph.D.
Jie Chen, Ph.D.

Potomac Economics
Market Monitoring Unit

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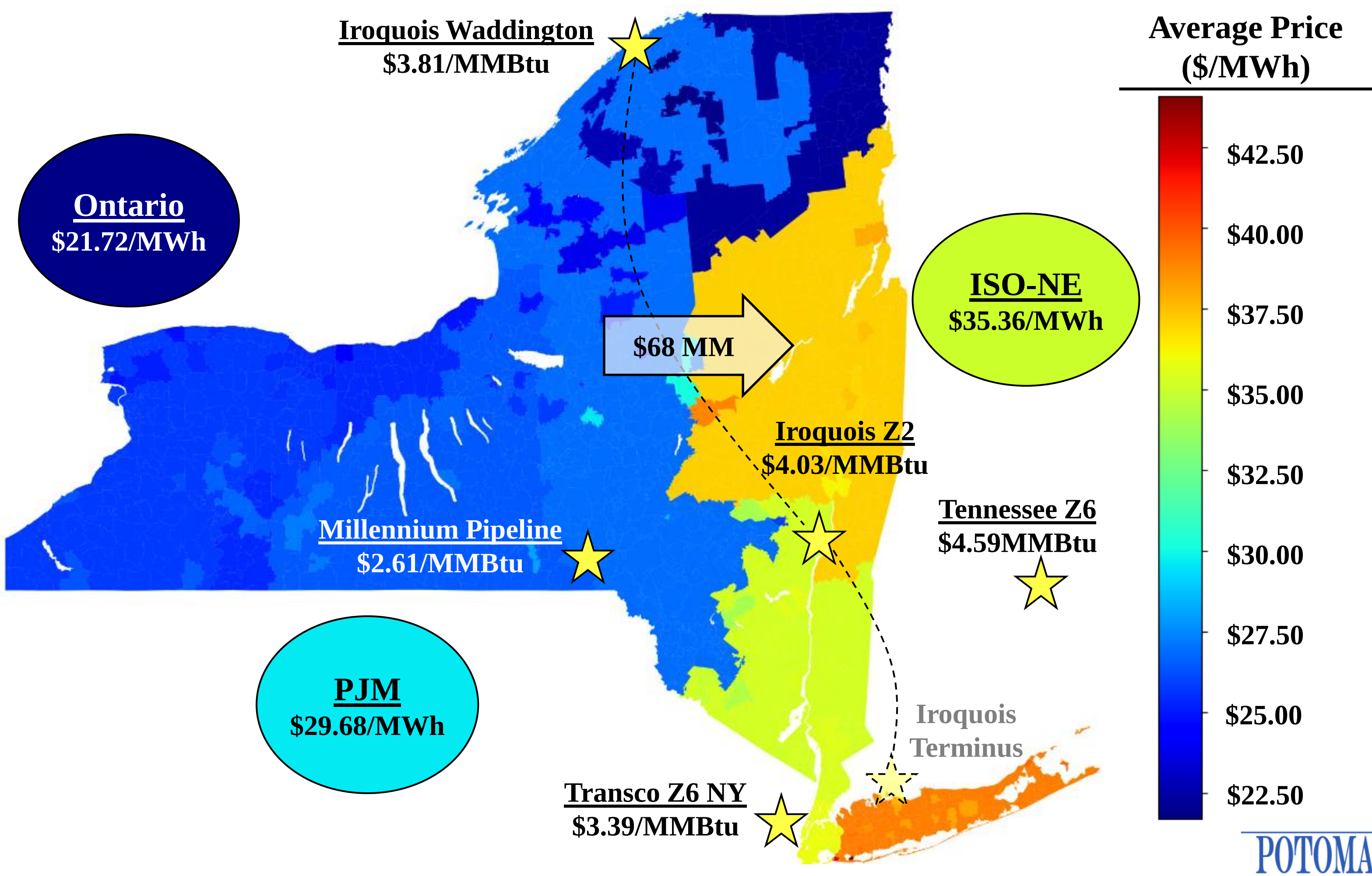
Highlights and Market Summary:
Energy Market Outcomes and Congestion

- This report summarizes market outcomes in 2017-Q1.
- The energy markets performed competitively and variations in wholesale prices were driven primarily by changes in fuel prices, demand, and supply availability.
  - ✓ However, we discuss concerns with performance of the reserve market. (see slide 5)
- The first quarter was characterized by mild winter weather conditions.
  - ✓ Average load levels was near the lowest levels in the last ten winters. (see slide 12)
  - ✓ Natural gas prices rarely increased to the level of oil prices due to scarcity.
- All-in prices averaged from $24/MWh in the North Zone to $46/MWh in NYC.
  - ✓ The range was due mainly to Central East congestion and capacity price differences.
  - ✓ Zone-level LBMPs rose from the previous year by 10 to 48 percent because of:
    - Higher gas prices, which rose 20-40 percent in East NY and 100+ percent in West NY. (see slide 13)
    - Nuclear generation fell ~460 MW because of more deratings & outages. (see slide 16)
    - However, these were offset by higher net imports (over 600 MW). (see slide 41)
  - ✓ Capacity costs fell 39 to 64 percent outside the Hudson Valley. (see slide 84)

Highlights and Market Summary: Energy Market Outcomes and Congestion



Highlights and Market Summary:
Energy Market Outcomes and Congestion

- DA congestion revenue totaled $81M, down 35% from 2016-Q1. (see slides 52-54)
  - ✓ Congestion across the Central-East interface (accounting for ~85% of congestion in 2017-Q1) fell ~10 percent from 2016-Q1.
    - – Lower gas spreads between West NY and East NY (see slide 13) reduced re-dispatch costs to manage congestion across the Central-East interface.
    - – Lower Ontario imports and higher PJM imports contributed to less frequent congestion across the Central-East interface as well. (see slide 41)
  - ✓ West Zone 230 kV constraints were rarely binding, which was attributable to:
    - – Transmission upgrades in early 2016, which reduce congestion on 230 kV facilities;
    - – More frequent congestion on 115 kV facilities, since actions to manage congestion on the 115 kV system often help reduce flows on the 230 kV system. (see slides 59-61)
      - Managing 115 kV congestion using the DA and RT market systems would result in more efficient congestion scheduling and pricing.
- 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.

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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 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 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-Q1 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)
- 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.

Highlights and Market Summary:
Uplift and Revenue Shortfalls

- Guarantee payments were $8.6M, up 21% from 2016-Q1 (see slides 70-73) due to:
  - ✓ Higher gas prices that increased the commitment costs of gas-fired units; and
  - ✓ Increased supplemental commitment for reliability in NYC, due partly to more transmission outages. (see slides 65-68)
- Congestion shortfalls were $17M in the DAM and *negative* $5M (i.e., surpluses) in the RTM. Both were lower than in 2016-Q1. (see slides 54-55)
  - ✓ ~90% of DA shortfalls accrued on the Central-East interface as multiple transmission outages and other factors (including nuclear outages, unit commitments, and the status of capacitors and SVCs) reduced the interface limit.
  - ✓ Nearly all of RT surpluses were associated with the Central-East interface as well.
    - – The RT PAR operation (including Ramapo, ABC, JK, and St. Lawrence PARs) collectively accounted fo a large portion of surpluses.

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Highlights and Market Summary:
Capacity Market

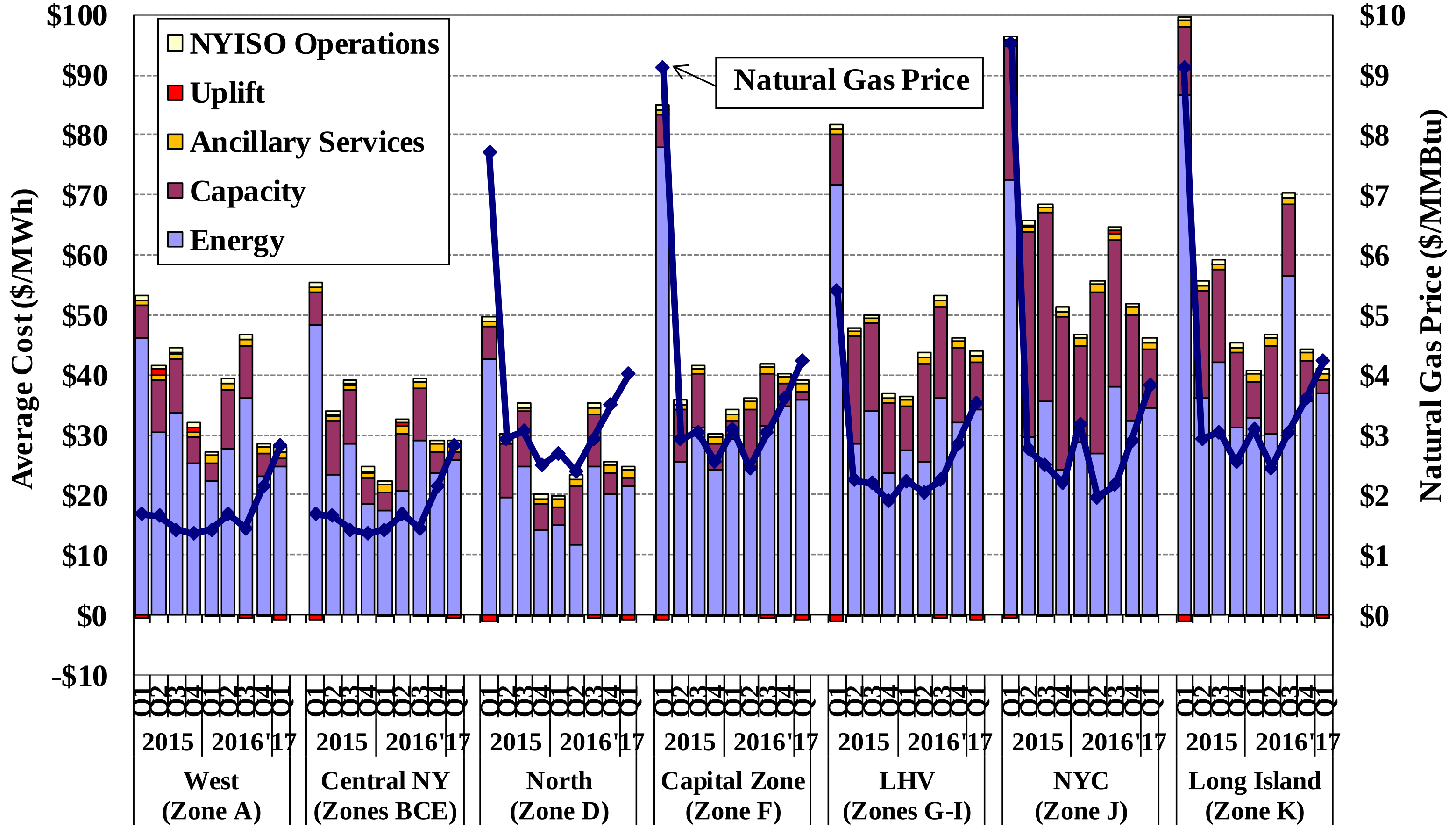
- In 2017-Q1, spot prices averaged \$0.52/kW-month in Long Island and ROS, and \$3.43/kW-month in NYC and the G-J Locality. (see slides 82-84)
  - ✓ The UCAP requirements in Long Island and NYC were not binding, leading Long Island and NYC prices to be same as ROS and G-J prices, respectively.
- Compared to 2016-Q1, average spot prices fell 41-66 percent in all regions except the G-J Locality, where average prices rose 9 precent instead.
  - ✓ The large reductions in most regions were due primarily to lower ICAP requirements that resulted from lower peak load forecast and lower LCRs.
    - – However, the IRM rose, partly offsetting the reduction in the NYCA load forecast.
  - ✓ Internal supply fell as a result of the Huntley retirement in March 2016 and mothballing of multiple Astoria and Ravenswood GTs in NYC after 2016-Q1.
    - – However, this was offset by a net increase of over 400 MW in average imports.
- Changes in LCRs continue to be a key driver of the most significant year-over-year capacity price changes.
  - ✓ Under the current methodology, variations in LCRs for local capacity zones are inefficient and create significant market uncertainty. It is important to establish LCRs that will procure capacity in a cost efficient manner.

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 \$24/MWh in the North Zone to \$46/MWh in NYC in the first quarter of 2017. Compared to 2016-Q1:
  - ✓ All-in prices did not change significantly in NYC, Long Island, and the West Zone, but they rose 13 to 29 percent in other regions.
  - ✓ LBMPs rose 10 to 48 percent.
    - – The increases were driven primarily by higher gas prices. (see slide 13)
    - – The West Zone and Long Island exhibited the smallest LBMP increases because of reduced congestion in the two regions. (see slide 53).
  - ✓ Capacity costs fell 39 to 64 percent outside the Lower Hudson Valley, where capacity prices rose 6 percent.
    - – Capacity prices fell in most areas primarily because of lower ICAP requirements. (see slides 81-84)

All-In Prices by Region

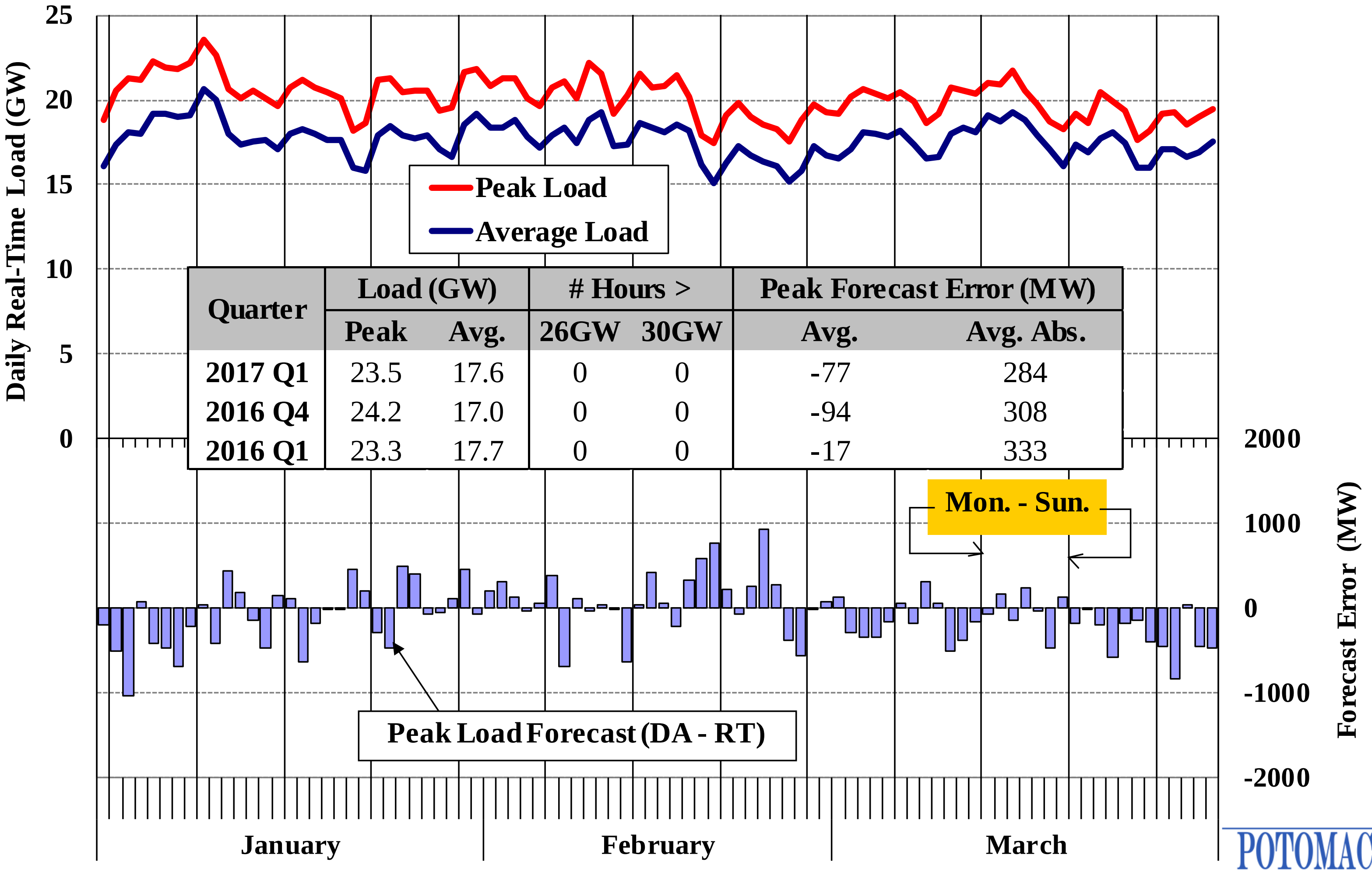


Note: Natural Gas Price is based on the following gas indices (plus a transportation charge of $0.20/MMbtu): the Dominion North index for West Zone and Central NY, the Iroquois Waddington index for North Zone, the Iroquois Zone 2 index for Capital Zone and LI, the average of Millennium East and Iroquois Zone 2 for LHV, the Transco Zone 6 (NY) index for NYC. A 6.9 percent tax rate is also included NYC.

Load Levels and Fuel Prices

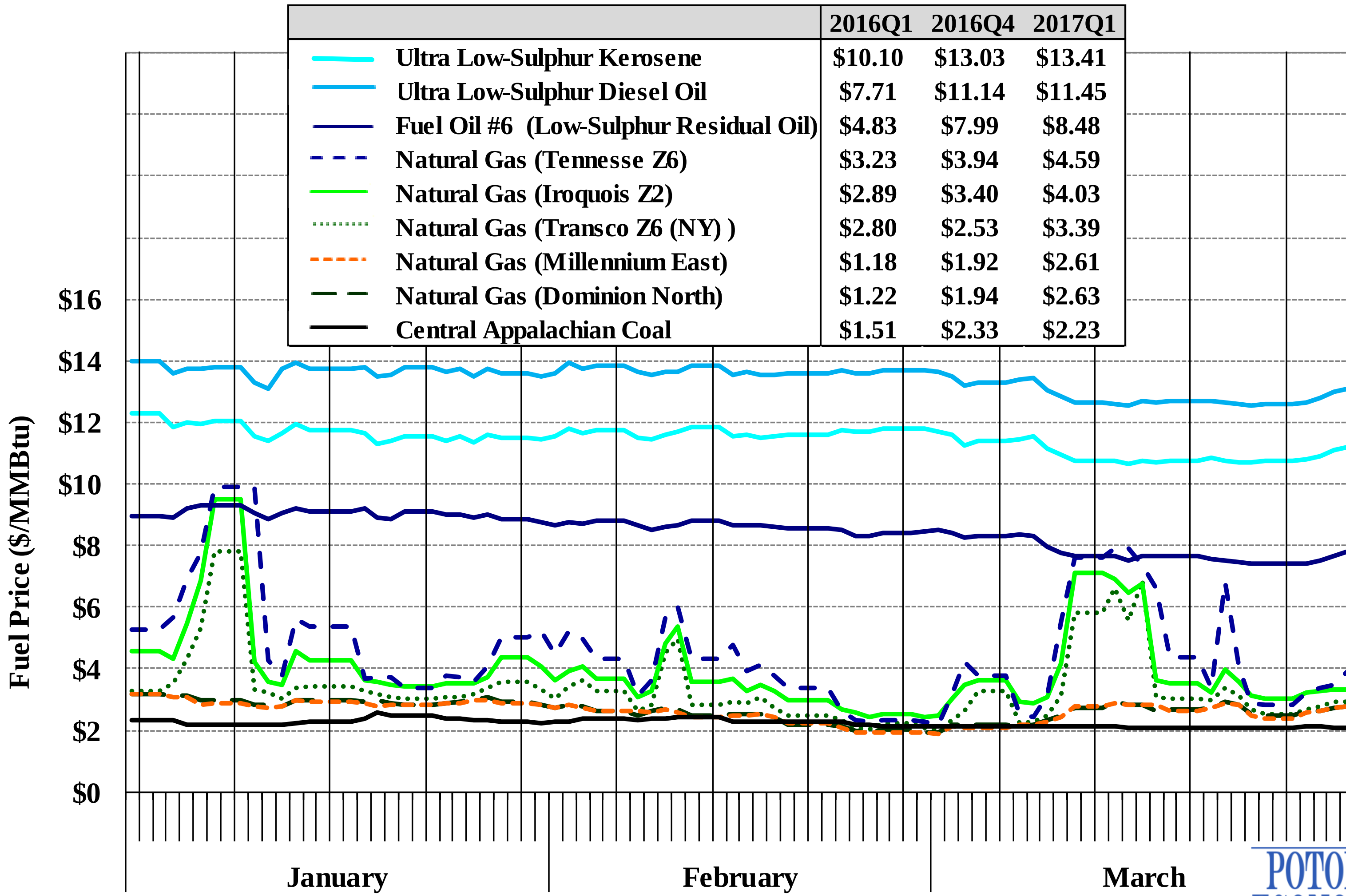
- The next two figures show two primary drivers of electricity prices in the quarter.
  - ✓ The first figure shows the average load, the peak load, and the day-ahead peak load forecast error on each day of the quarter.
  - ✓ The second figure shows daily coal, natural gas, and fuel oil prices.
- Although peak load (23.5 GW) rose nearly 1 percent from the first quarter of 2016, average load (17.6 GW) fell 0.3 percent.
  - ✓ Nonetheless, both values were near the lowest levels seen over the last ten winters, reflecting the mild weather conditions.
- All reported fuel prices rose substantially from 2016-Q1 to 2017-Q1.
  - ✓ Natural gas prices rose 20 to 40 percent in East NY and as much as 120 percent in West NY.
    - These increases reflected lower storage levels in the region.
    - However, gas spreads between East NY and West NY fell from the first quarter of 2016, which reduced congestion across the Central-East interface (see slide 53).
  - ✓ Despite the increase in natural gas prices, gas-fired generation continues to be more economic than coal-fired and oil-fired generation.

Load Forecast and Actual Load



Quarter	Load (GW)		# Hours >		Peak Forecast Error (MW)	
	Peak	Avg.	26GW	30GW	Avg.	Avg. Abs.
2017 Q1	23.5	17.6	0	0	-77	284
2016 Q4	24.2	17.0	0	0	-94	308
2016 Q1	23.3	17.7	0	0	-17	333

Coal, Natural Gas, and Fuel Oil Prices



	2016Q1	2016Q4	2017Q1
Ultra Low-Sulphur Kerosene	$10.10	$13.03	$13.41
Ultra Low-Sulphur Diesel Oil	$7.71	$11.14	$11.45
Fuel Oil #6 (Low-Sulphur Residual Oil)	$4.83	$7.99	$8.48
Natural Gas (Tennesse Z6)	$3.23	$3.94	$4.59
Natural Gas (Iroquois Z2)	$2.89	$3.40	$4.03
Natural Gas (Transco Z6 (NY))	$2.80	$2.53	$3.39
Natural Gas (Millennium East)	$1.18	$1.92	$2.61
Natural Gas (Dominion North)	$1.22	$1.94	$2.63
Central Appalachian Coal	$1.51	$2.33	$2.23

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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 first 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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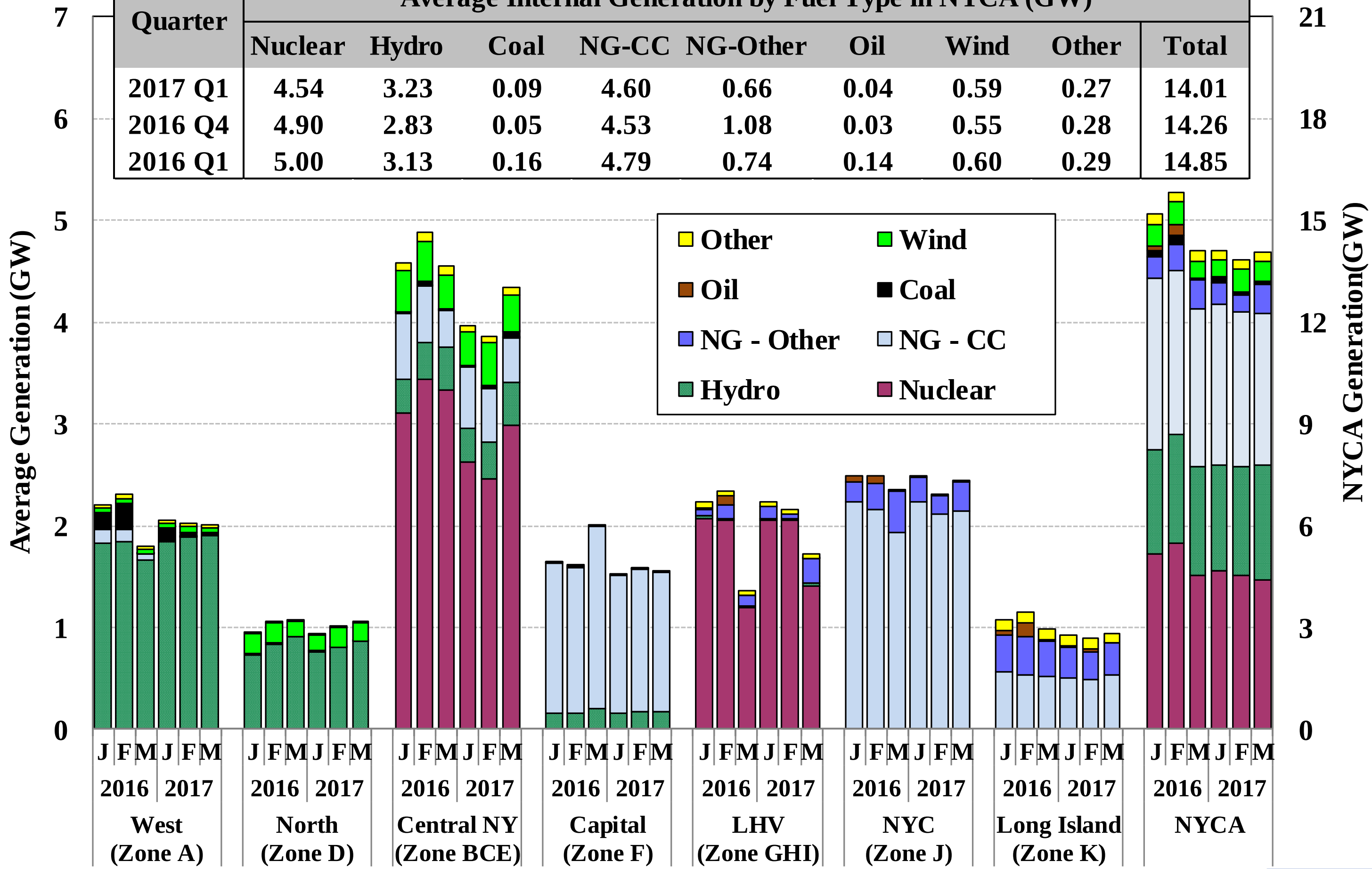
RT Generation and Marginal Units by Fuel Type: Market Results

- Gas-fired (38 percent), nuclear (32 percent), and hydro (23 percent) generation accounted for most of the internal generation in the first quarter of 2017.
  - ✓ Average nuclear generation fell 460 MW from the first quarter of 2016 because of more deratings and outages in Central NY.
  - ✓ Average coal and oil-fired generation fell by a total of 180 MW from 2016.
    - – Coal-fired production fell due primarily to the retirement of Huntley units.
    - – Oil-fired production fell because gas prices rarely increased to the level of oil prices.
  - ✓ These reductions were offset by increases in:
    - – Hydro generation, which rose 100 MW because of higher output from the Niagara facility; and
    - – Net imports, which rose more than 600 MW from 2016-Q1. (see slide 41)
- Gas-fired and hydro resources were on the margin the vast majority of time.
  - ✓ Hydro units in the West Zone were on the margin less frequently than in the first quarter of 2016, reflecting changes in congestion patterns in the West Zone.

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 Q1	4.54	3.23	0.09	4.60	0.66	0.04	0.59	0.27	14.01
2016 Q4	4.90	2.83	0.05	4.53	1.08	0.03	0.55	0.28	14.26
2016 Q1	5.00	3.13	0.16	4.79	0.74	0.14	0.60	0.29	14.85



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

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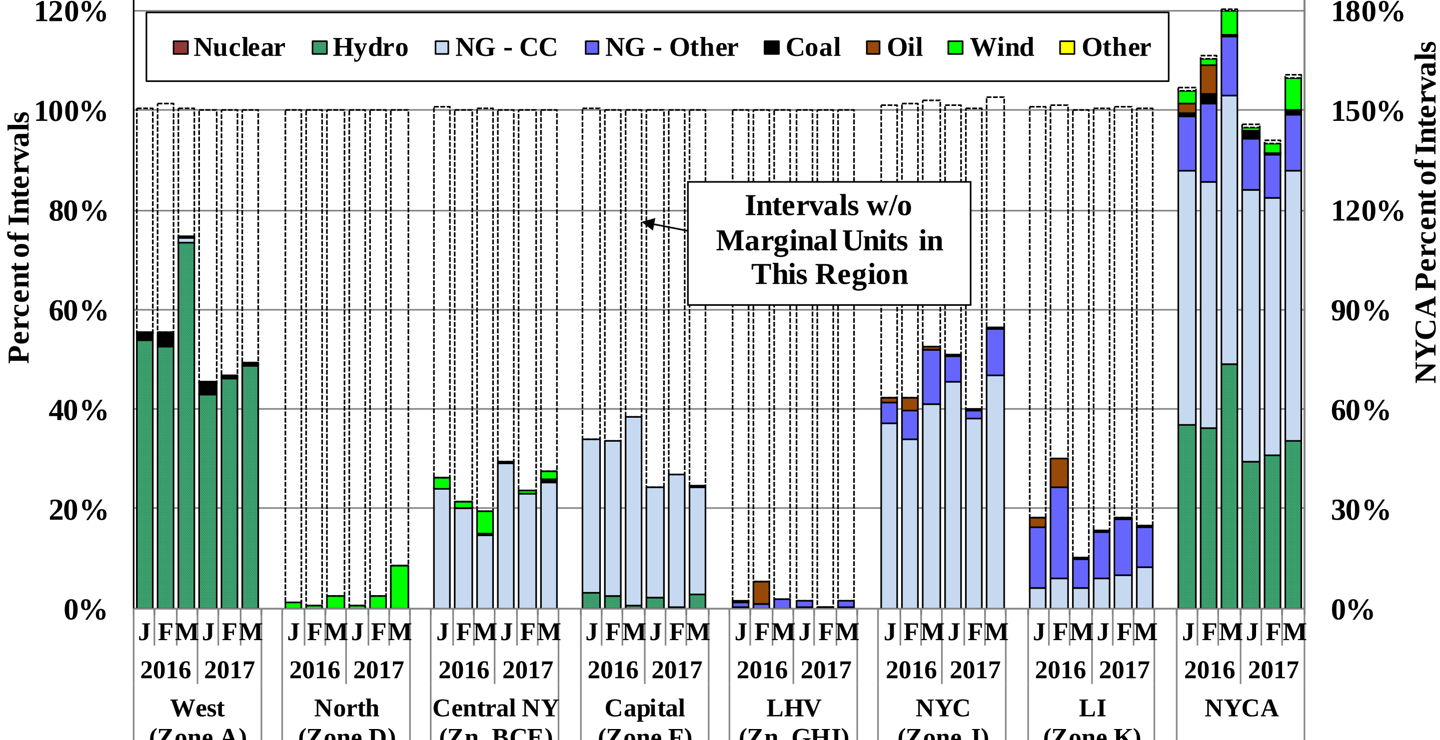
Fuel Type of Marginal Units in the RTM

Quarter	Marginal Fuel Types in NYCA							
	Nuclear	Hydro	Coal	NG-CC	NG-Other	Oil	Wind	Other
2017 Q1	0%	47%	1%	80%	15%	0%	5%	0%
2016 Q4	0%	47%	0%	70%	23%	1%	4%	0%
2016 Q1	0%	61%	1%	77%	19%	4%	4%	0%



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

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 first quarter of 2017.
- Average day-ahead prices ranged from $23/MWh in the North Zone to $41/MWh on Long Island, up 22 to 50 percent from the first quarter of 2016.
  - ✓ The increases were driven primarily by higher natural gas prices. (see slide 13)
  - ✓ Lower nuclear production also contributed to higher LBMPs. (see slide 16)
  - ✓ However, these were partly offset by higher net imports. (see slide 41)
- Western NY (except the West Zone) exhibited a larger increase in LBMPs than Eastern NY from 2016-Q1 to 2017-Q1, because:
  - ✓ The Central-East interface was binding less frequently (see slide 53), indicating that Eastern NY generation set LBMPs for Western NY more often in 2017-Q1; and
  - ✓ Natural gas prices had a larger increase in Western NY.
  - ✓ However, the West Zone exhibited a small LBMP increase because of greatly reduced congestion in 2017-Q1. (see slide 53)

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.
  - ✓ This was typical on winter days with tight gas supply. For example:
    - – Both DA and RT prices were high and volatile during the weekend of January 7th & 8th because multiple pipelines issued hourly Operation Flow Orders ("OFO") that greatly limited gas availability in East NY.
- 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 higher than RT prices in all areas in the first quarter of 2017, with an average DA premium of 7 to 10 percent.
    - – The DA premium was higher than usually seen, which can occur if transient spikes are less frequent than expected.

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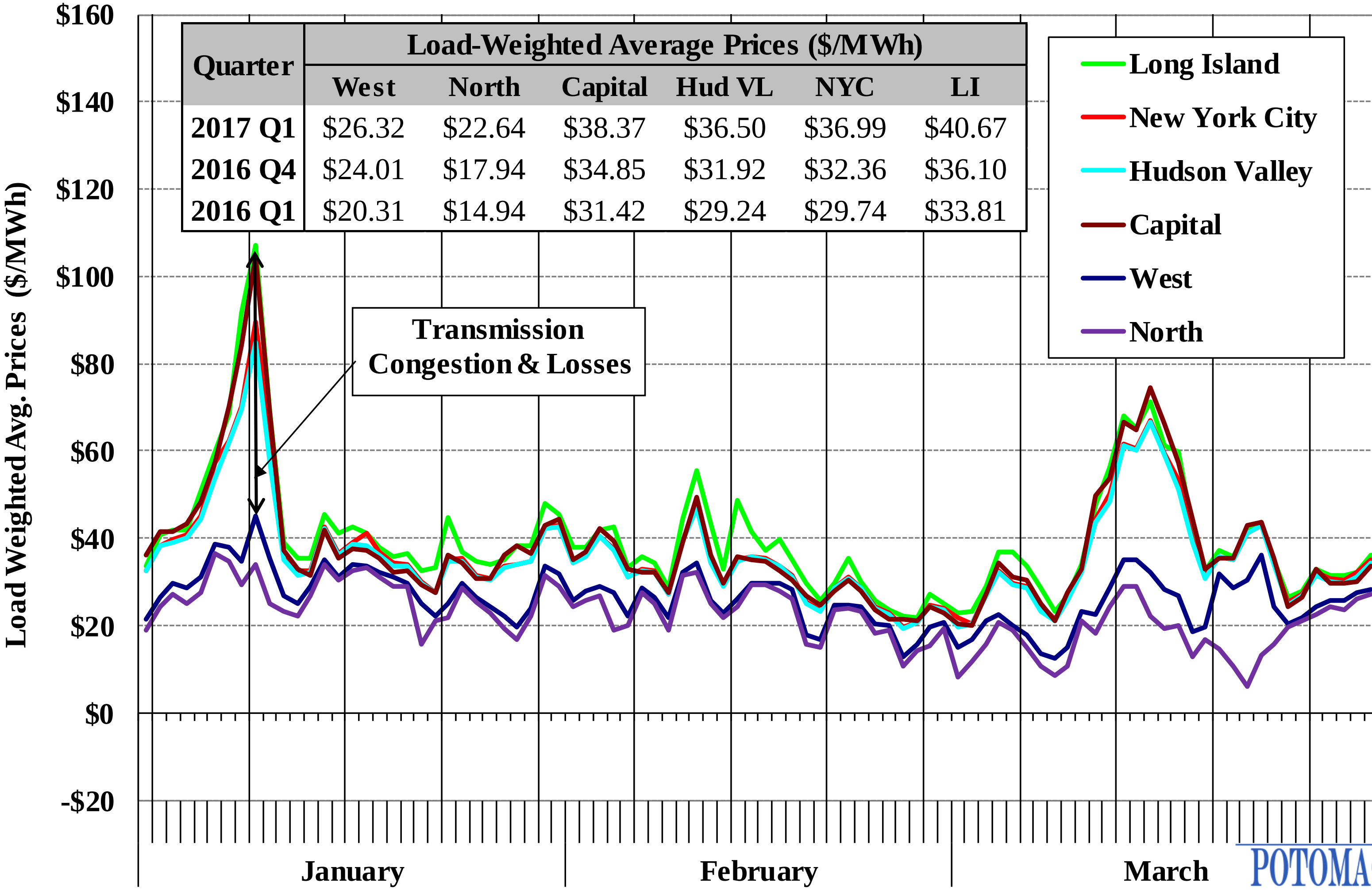
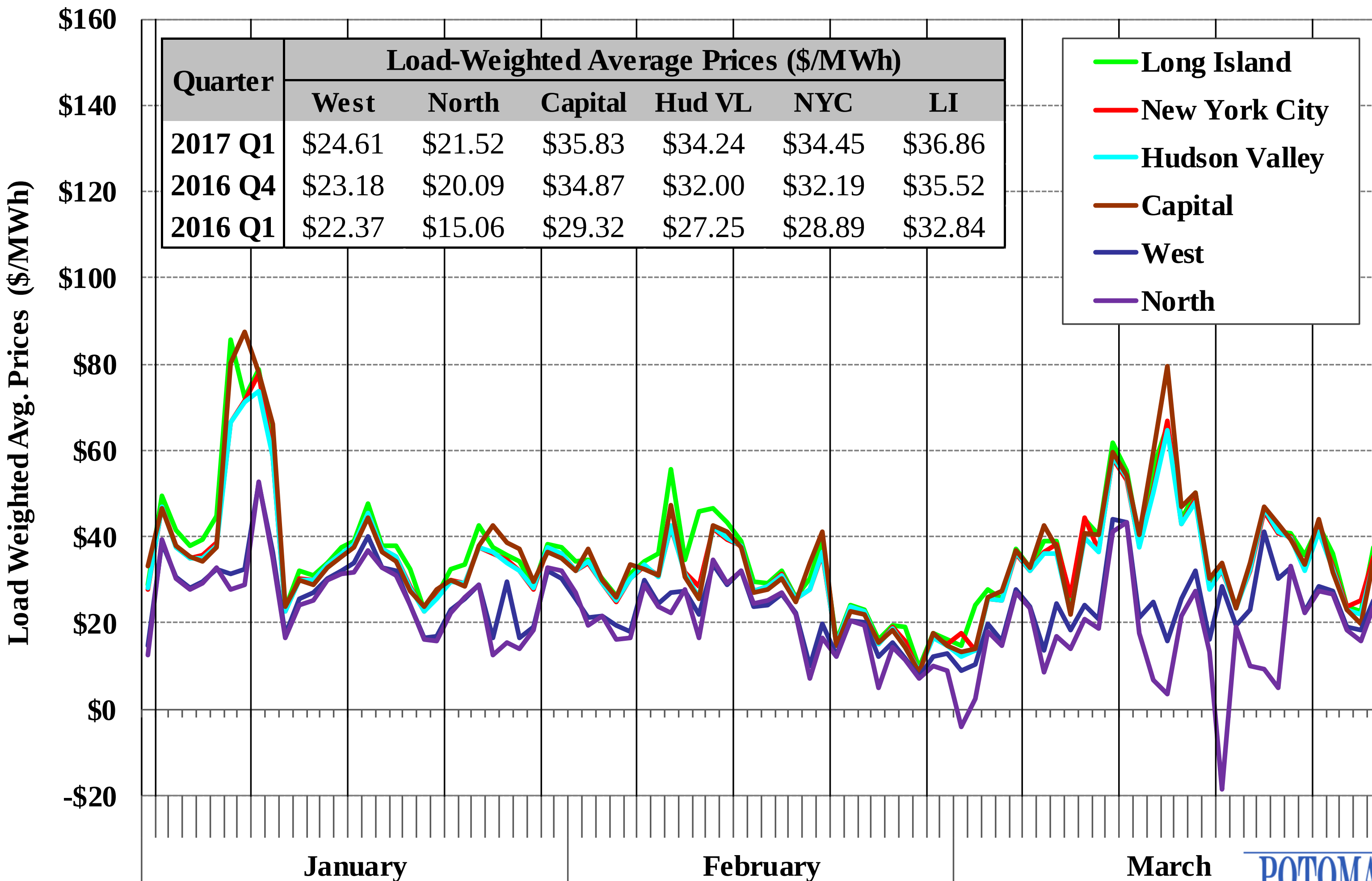
Day-Ahead Electricity Prices by Zone



Quarter	Load-Weighted Average Prices ($/MWh)					
	West	North	Capital	Hud VL	NYC	LI
2017 Q1	$26.32	$22.64	$38.37	$36.50	$36.99	$40.67
2016 Q4	$24.01	$17.94	$34.85	$31.92	$32.36	$36.10
2016 Q1	$20.31	$14.94	$31.42	$29.24	$29.74	$33.81

Real-Time Electricity Prices by Zone

Quarter	Load-Weighted Average Prices ($/MWh)					
	West	North	Capital	Hud VL	NYC	LI
2017 Q1	$24.61	$21.52	$35.83	$34.24	$34.45	$36.86
2016 Q4	$23.18	$20.09	$34.87	$32.00	$32.19	$35.52
2016 Q1	$22.37	$15.06	$29.32	$27.25	$28.89	$32.84



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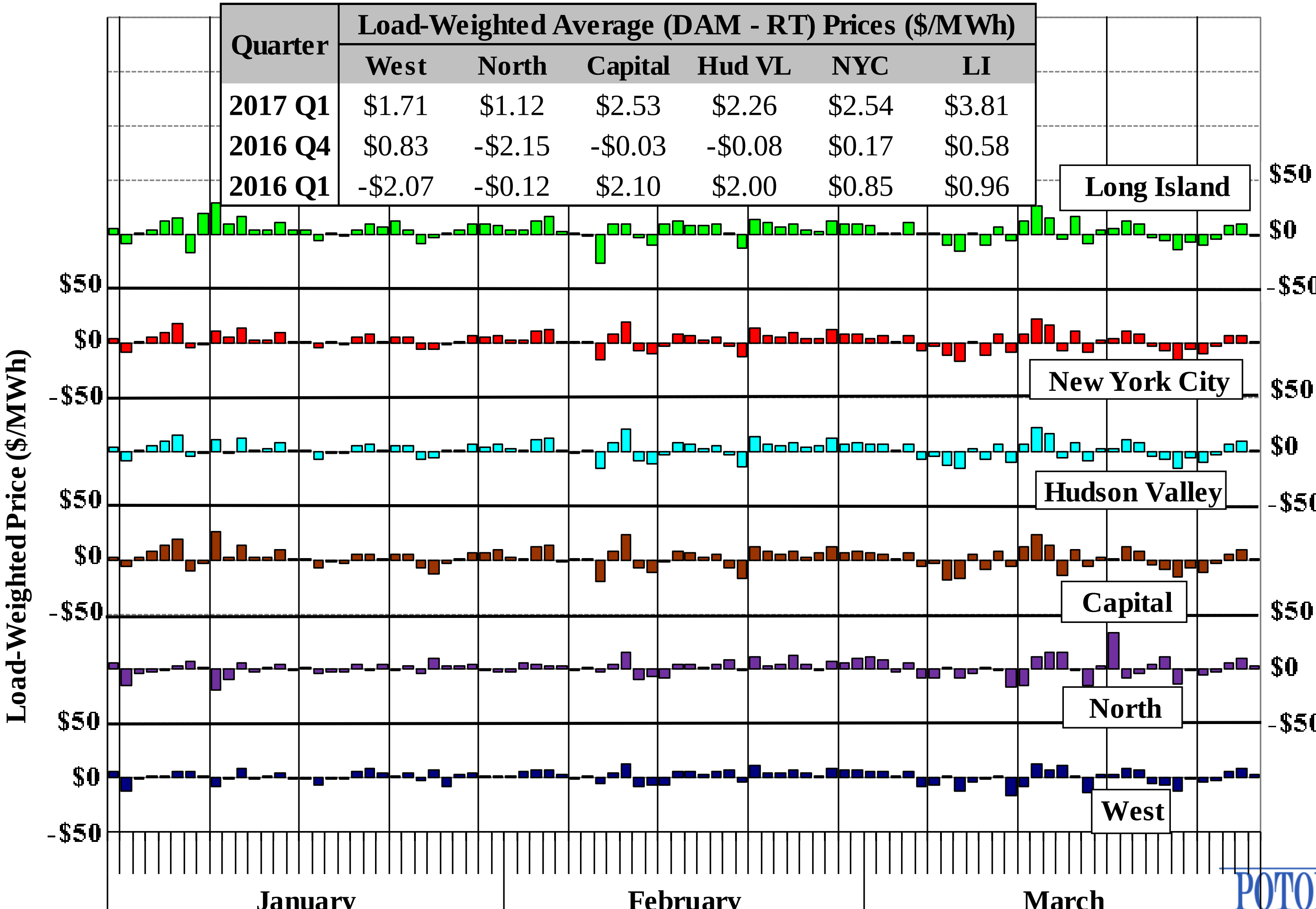
Convergence Between DA and RT Prices

Quarter	Load-Weighted Average (DAM - RT) Prices ($/MWh)					
	West	North	Capital	Hud VL	NYC	LI
2017 Q1	$1.71	$1.12	$2.53	$2.26	$2.54	$3.81
2016 Q4	$0.83	-$2.15	-$0.03	-$0.08	$0.17	$0.58
2016 Q1	-$2.07	-$0.12	$2.10	$2.00	$0.85	$0.96



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Fuel Usage in the Winter
Eastern New York

- The following figure evaluates the efficiency of fuel usage in Eastern New York in 2017-Q1, showing daily averages for:
  - ✓ Internal generation by actual fuel consumed; and
  - ✓ Day-ahead natural gas price index for Iroquois Zone 2 and Transco Zone 6 (NY).
  - ✓ These quantities are also shown by month for the first quarters of 2015 to 2017.
- Oil-fired generation in East NY has been relatively low over the last two winters. It was just 0.06 million MWh in 2017-Q1 and 0.3 million MWh in 2016-Q1, down dramatically from the 1.6 million MWh in 2015-Q1.
  - ✓ Mild weather conditions in the past two winters were a key driver.
  - ✓ Gas supply constraints were much less frequent and severe, particularly in 2017-Q1.
    - – As a result, natural gas prices in Eastern NY never exceeded \$10/MMbtu in 2017-Q1 (while gas prices exceeded \$15/MMbtu on 22 days in 2015-Q1).
  - ✓ Although natural gas prices rose from 2016-Q1 to 2017-Q1, the increase in oil prices was more significant over the same period.

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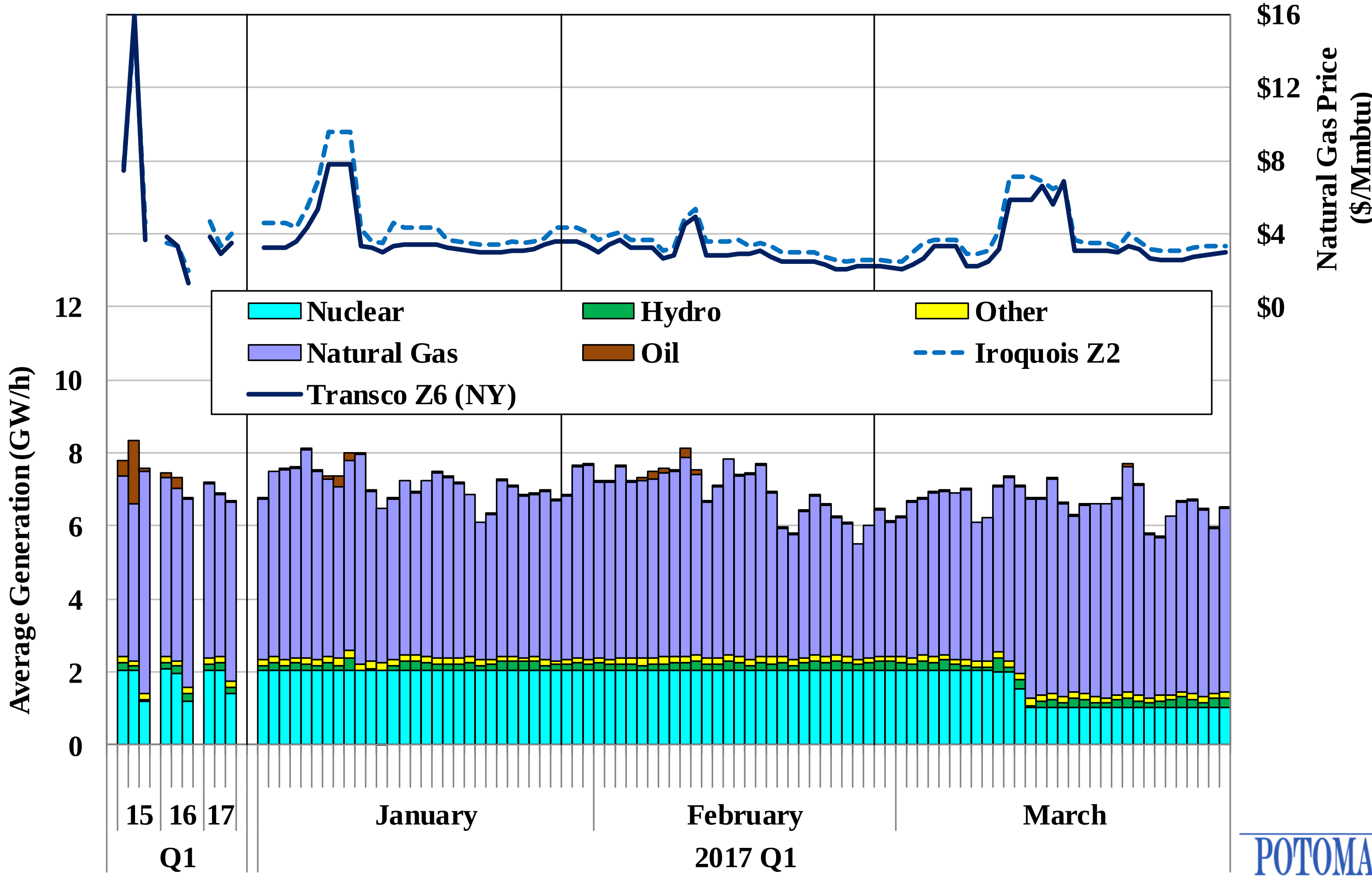
Fuel Usage and Natural Gas Price
Eastern New York



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Ancillary Services Market

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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.

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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 several periods, especially in March.
  - ✓ 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.
  - ✓ Nonetheless, average DA reserve prices fell 9 to 13 percent from the first quarter of 2016 despite higher natural gas prices and LBMPs.
- RT regulation prices rose notably on March 8 because of reduced regulation capability that resulted from OOM actions on units in Western NY, which was driven by multiple transmission outages resulting from high winds.

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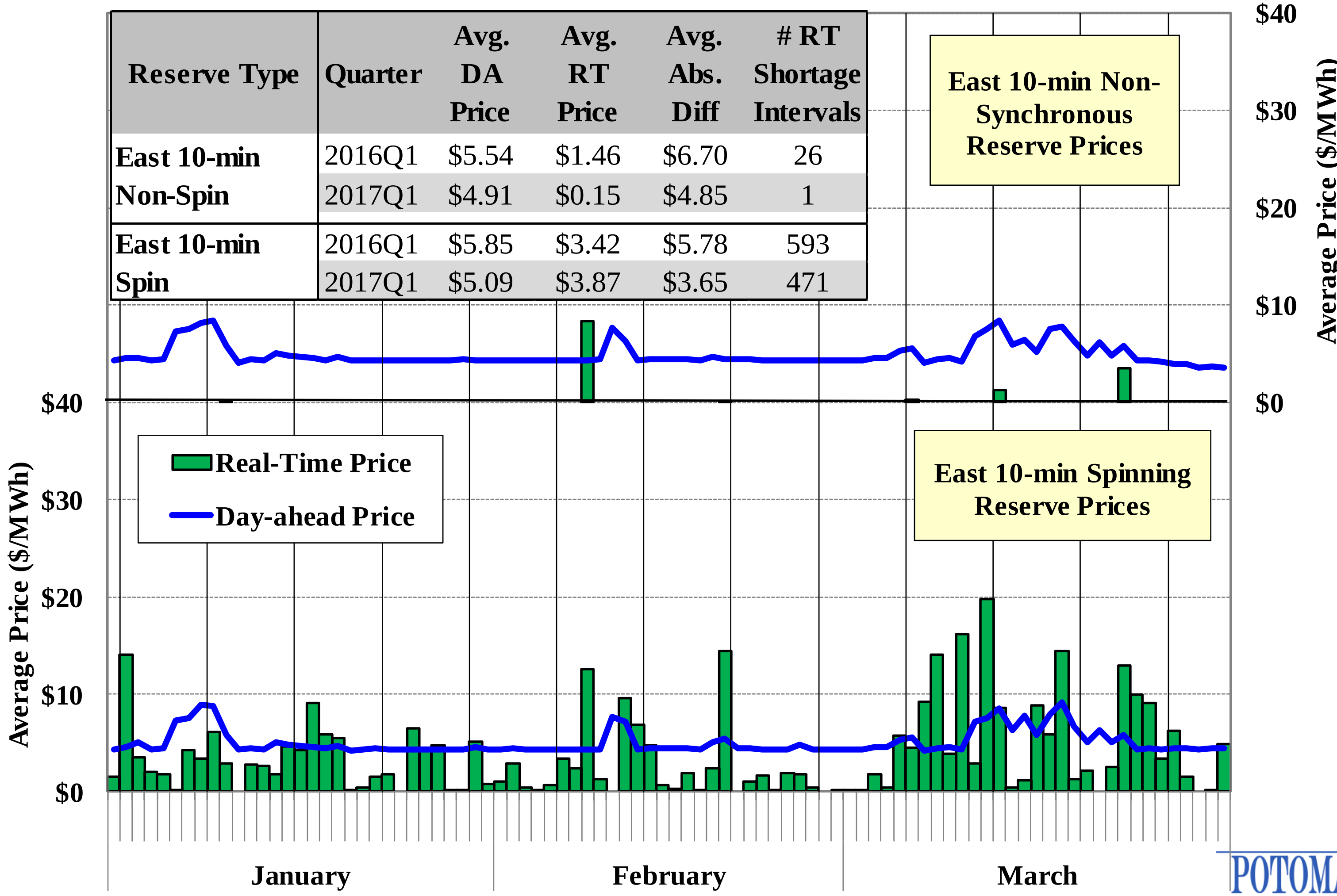
DA and RT Ancillary Services Prices
Eastern 10-Minute Spinning and Non-Spinning Reserves

Reserve Type	Quarter	Avg. DA Price	Avg. RT Price	Avg. Abs. Diff	# RT Shortage Intervals
East 10-min Non-Spin	2016Q1	$5.54	$1.46	$6.70	26
	2017Q1	$4.91	$0.15	$4.85	1
East 10-min Spin	2016Q1	$5.85	$3.42	$5.78	593
	2017Q1	$5.09	$3.87	$3.65	471



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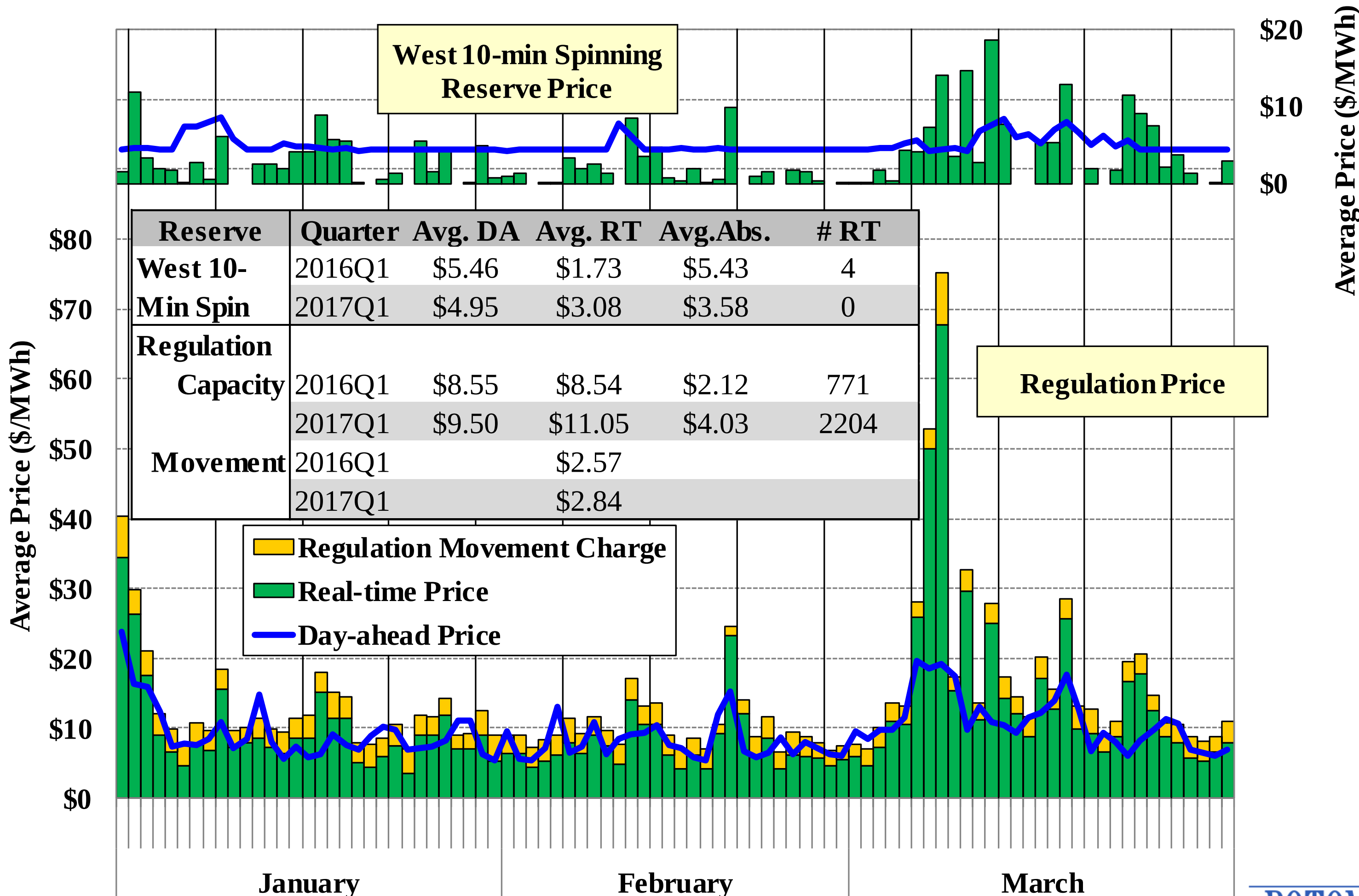
DA and RT Ancillary Services Prices
Western 10-Minute Spinning Reserves and Regulation



Reserve	Quarter	Avg. DA	Avg. RT	Avg.Abs.	# RT
West 10-Min Spin	2016Q1	$5.46	$1.73	$5.43	4
	2017Q1	$4.95	$3.08	$3.58	0
Regulation					
Capacity	2016Q1	$8.55	$8.54	$2.12	771
	2017Q1	$9.50	$11.05	$4.03	2204
Movement	2016Q1		$2.57		
	2017Q1		$2.84		

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

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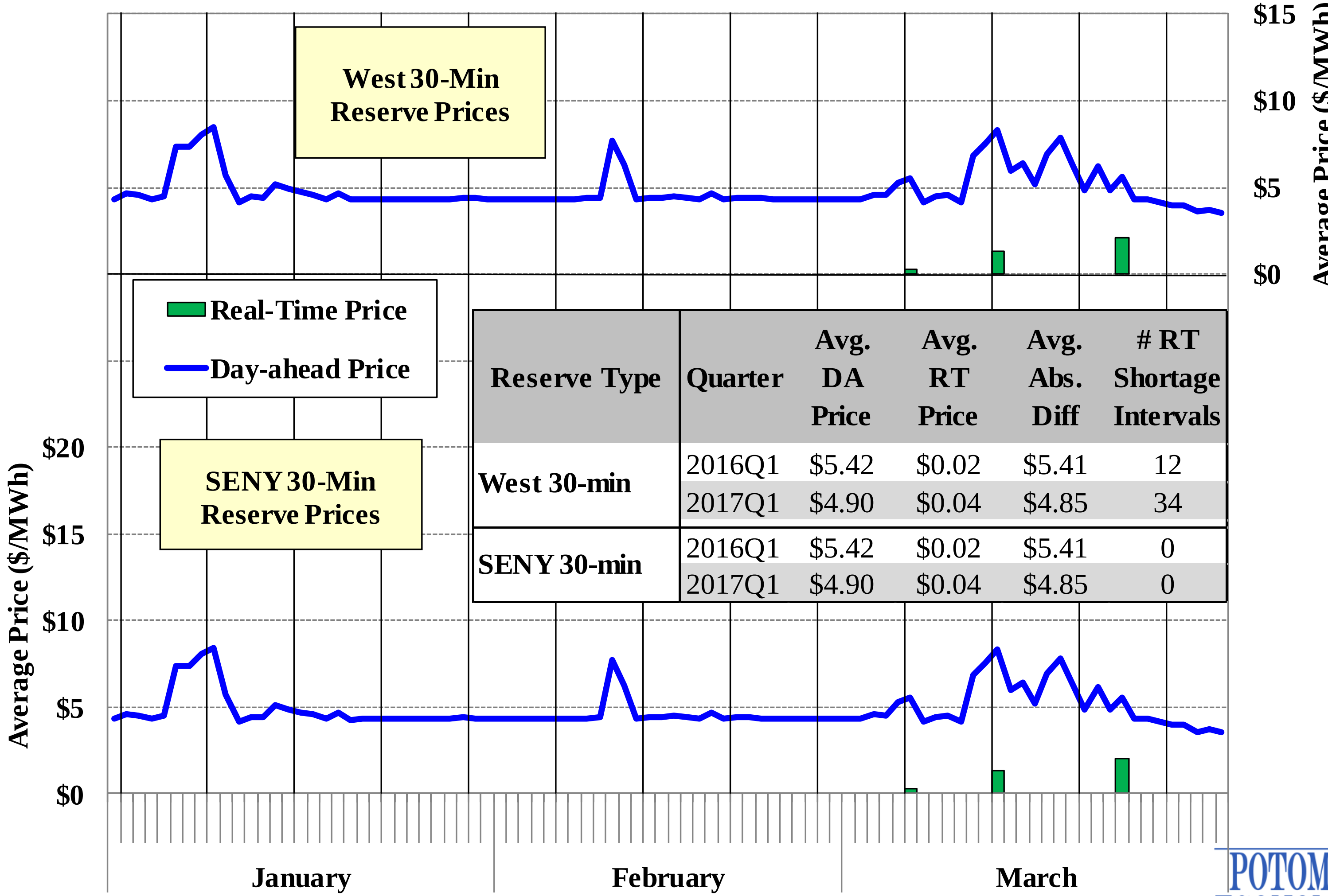
DA and RT Ancillary Services Prices
Western and SENY 30-Minute Reserves



Reserve Type	Quarter	Avg. DA Price	Avg. RT Price	Avg. Abs. Diff	# RT Shortage Intervals
West 30-min	2016Q1	$5.42	$0.02	$5.41	12
	2017Q1	$4.90	$0.04	$4.85	34
SENY 30-min	2016Q1	$5.42	$0.02	$5.41	0
	2017Q1	$4.90	$0.04	$4.85	0

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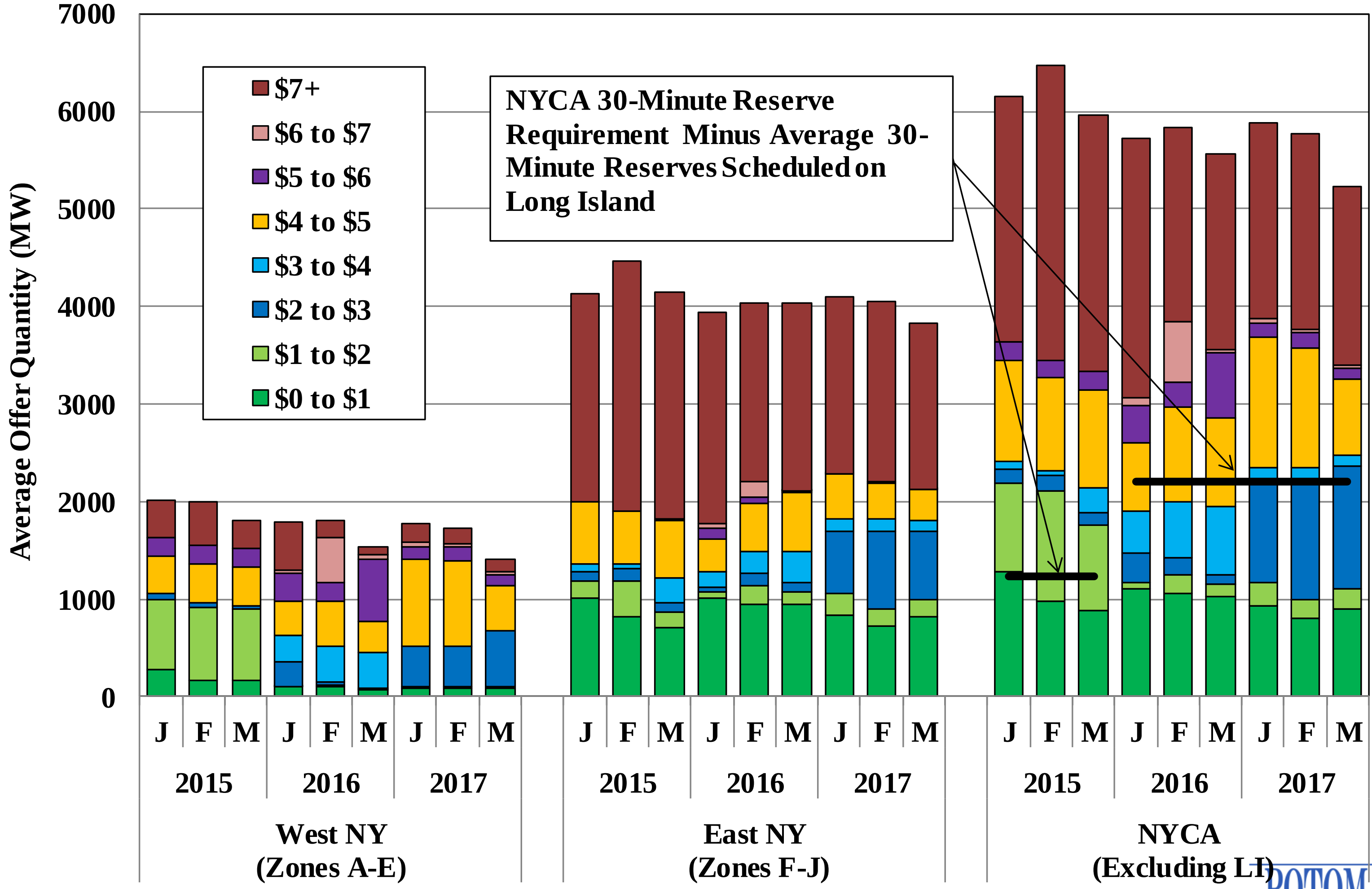
NYCA 30-Minute Reserve Offers in the DAM:
Chart Descriptions

- 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 first quarter of the previous year:
    - – The amount offered below \$3/MWh increased by an average of 880 MW; and
    - – The amount offered below \$5/MWh increased by an average of 700 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



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Energy Market Scheduling

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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).

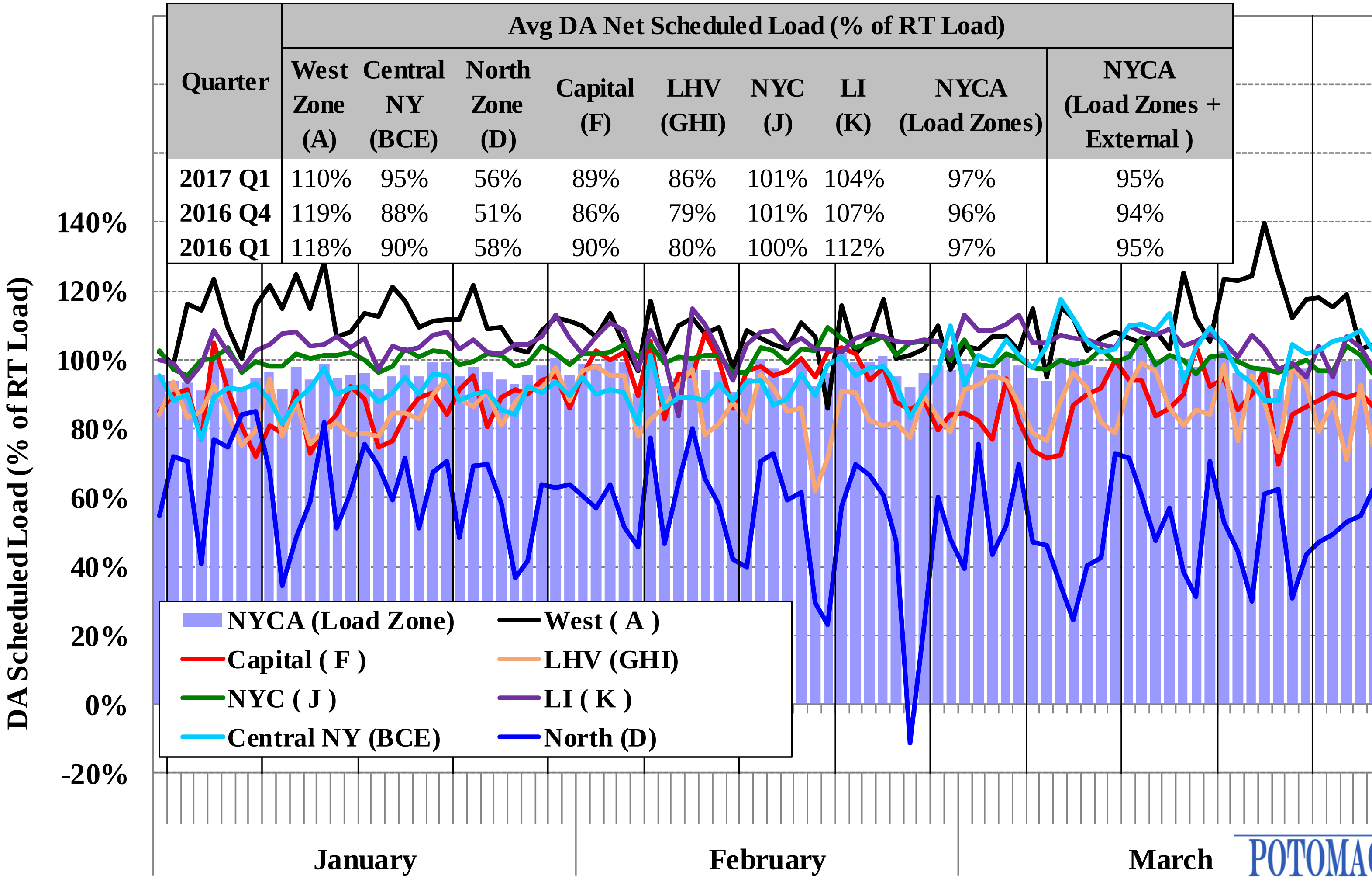
DA Load Scheduling and Virtual Trading:
Market Results

- For NYCA, 95 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.
- 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).
  - ✓ In the first quarter of 2017, net load scheduling fell in the West Zone and Long Island, consistent with reduced congestion in these areas (see slide 53).
- 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 profit of $4.5 million in the first 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.

POTOMAC ECONOMICS

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

Quarter	West Zone (A)	Central NY (BCE)	North Zone (D)	Capital (F)	LHV (GHI)	NYC (J)	LI (K)	NYCA (Load Zones)	NYCA (Load Zones + External)
	Avg DA Net Scheduled Load (% of RT Load)								
2017 Q1	110%	95%	56%	89%	86%	101%	104%	97%	95%
2016 Q4	119%	88%	51%	86%	79%	101%	107%	96%	94%
2016 Q1	118%	90%	58%	90%	80%	100%	112%	97%	95%



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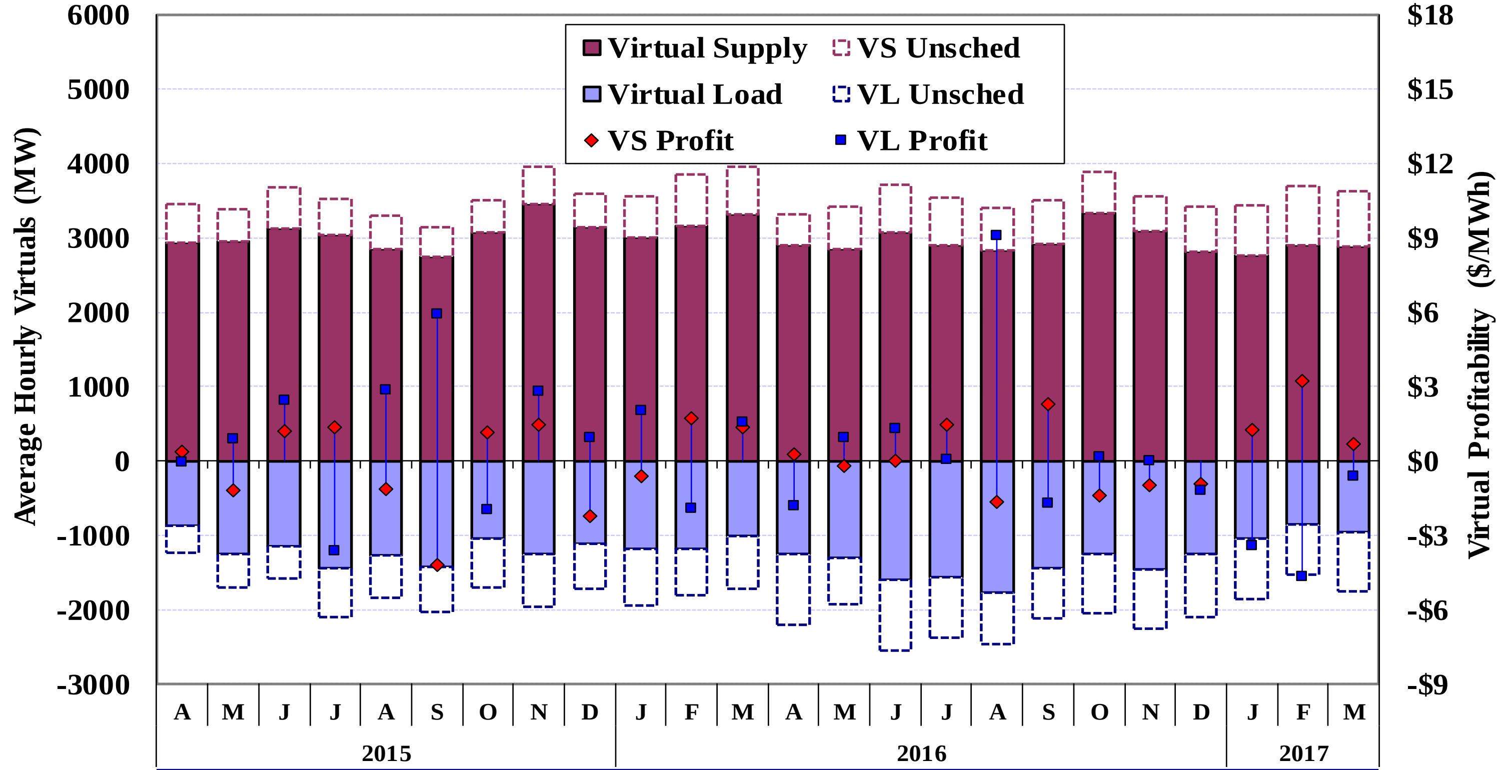
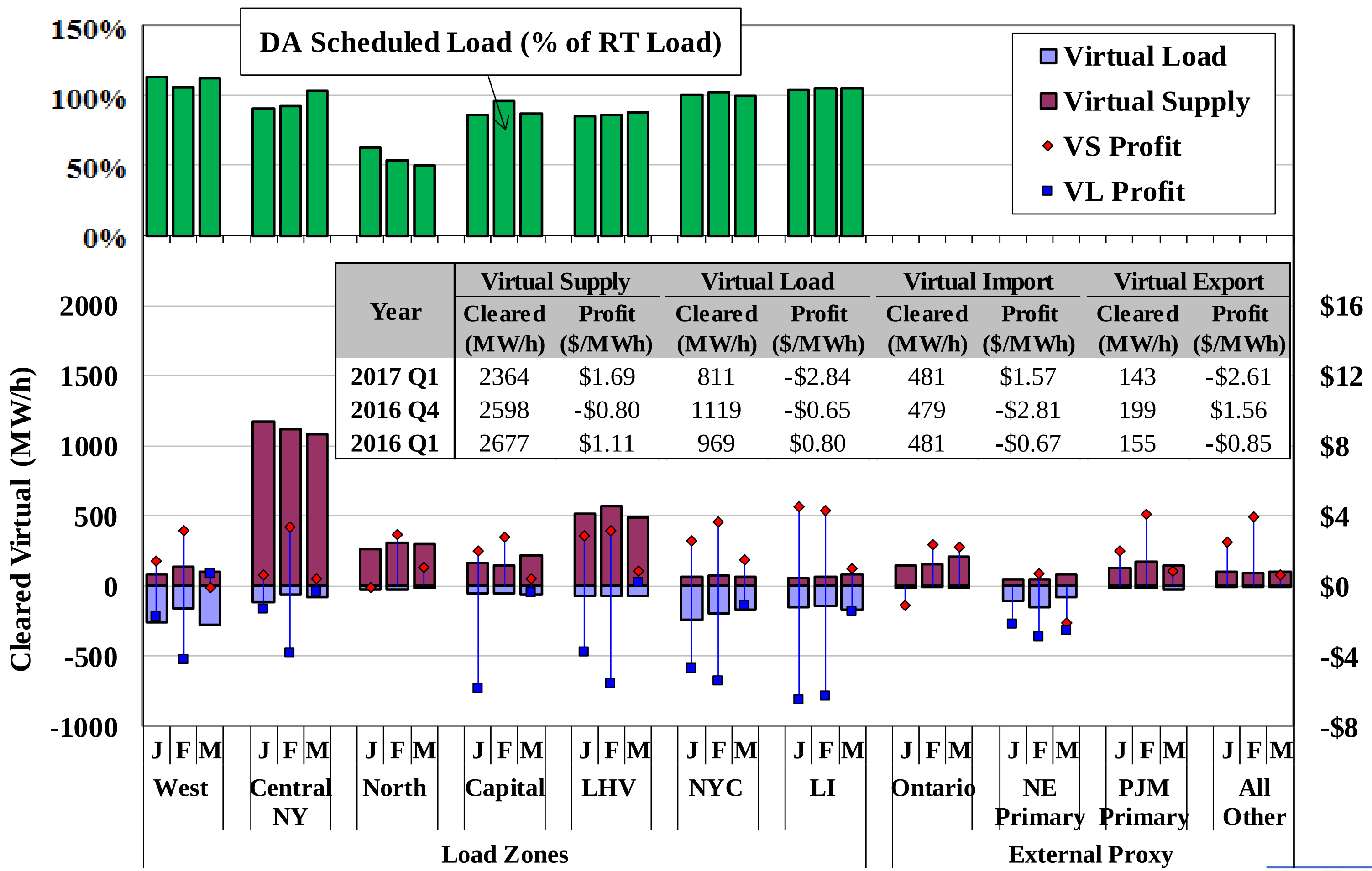
Virtual Trading Activity
by Month



		A	M	J	J	A	S	O	N	D	J	F	M	A	M	J	J	A	S	O	N	D	J	F	M
		2015									2016												2017		
Profit > 50% of Avg. Zone Price	MW	299	566	782	479	290	241	378	1090	643	692	638	1003	354	431	460	596	398	360	281	261	490	243	507	585
	%	8%	13%	18%	11%	7%	6%	9%	23%	15%	17%	15%	23%	8%	10%	10%	13%	9%	8%	6%	6%	12%	6%	13%	15%
Loss > 50% of Avg. Zone Price	MW	338	671	697	499	300	341	375	715	763	553	547	680	682	550	528	517	413	411	419	345	587	284	336	514
	%	9%	16%	16%	11%	7%	8%	9%	15%	18%	13%	13%	16%	16%	13%	11%	12%	9%	9%	9%	8%	14%	7%	9%	13%

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 Q1	2364	$1.69	811	-$2.84	481	$1.57	143	-$2.61
2016 Q4	2598	-$0.80	1119	-$0.65	479	-$2.81	199	$1.56
2016 Q1	2677	$1.11	969	$0.80	481	-$0.67	155	-$0.85

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 3.6 GW (serving about 21 percent of all load) during peak hours in the first quarter of 2017, up 620 MW from the previous year.
- Imports from Hydro Quebec and Ontario averaged nearly 2.5 GW during peak hours, accounting for 68 percent of total net imports.
  - ✓ Imports from Quebec rose from the previous year due partly to higher LBMPs (which resulted from higher natural gas prices) in New York.
  - ✓ However, this was mostly offset by lower imports from Ontario, which were frequently reduced by import transfer limitation of the interface.
- New York normally imported power from PJM and exported power to New England across their primary interfaces in the winter season.
  - ✓ This pattern was generally consistent with the spreads in natural gas prices between these markets in the winter (i.e., NE > NY > PJM).
  - ✓ Increased PJM imports resulted partly from larger natural gas spreads between the two markets in the first quarter of 2017.

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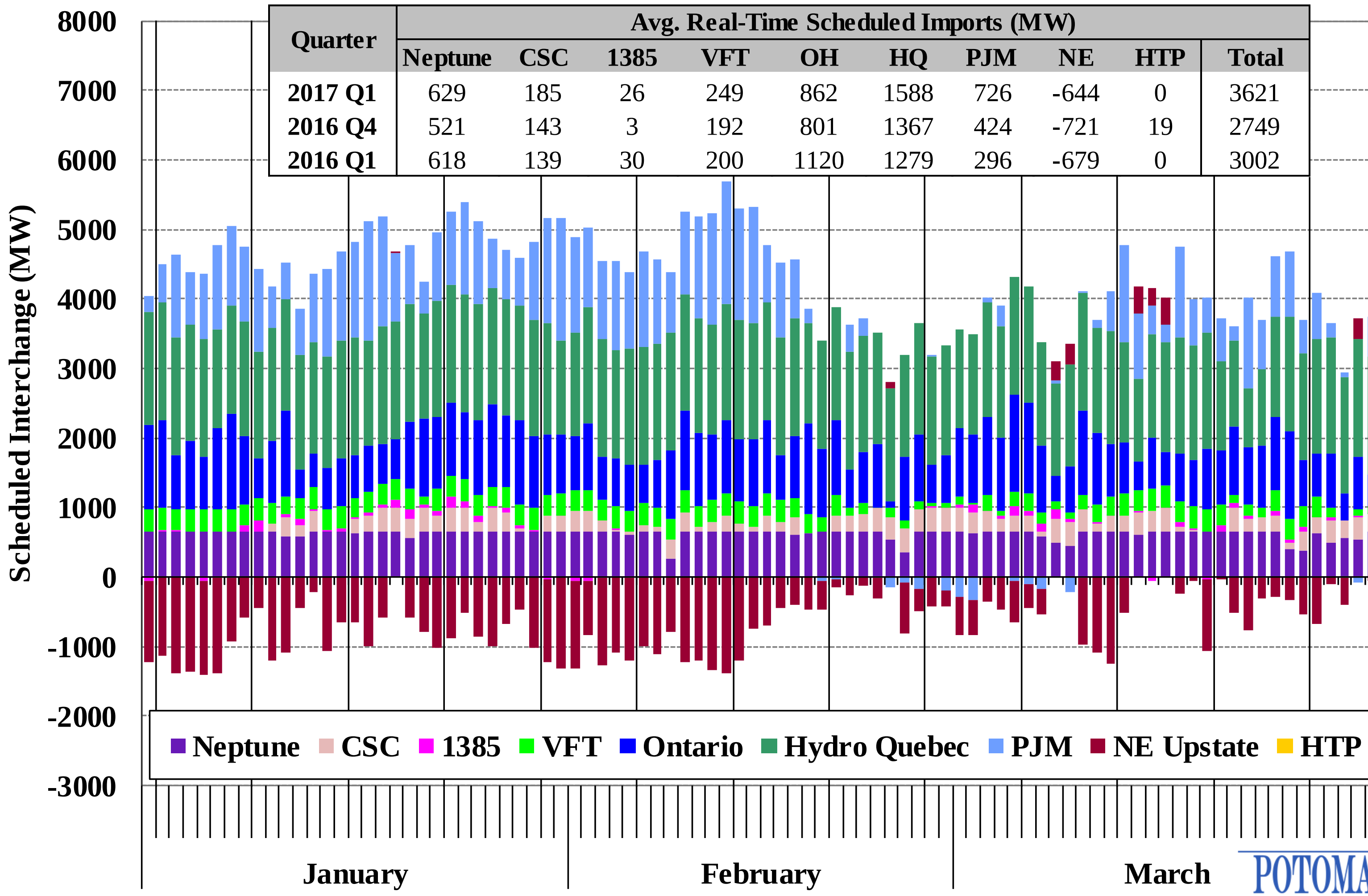
Net Imports Scheduled Across External Interfaces

Daily Peak Hours (1-9pm)

Quarter	Avg. Real-Time Scheduled Imports (MW)									
	Neptune	CSC	1385	VFT	OH	HQ	PJM	NE	HTP	Total
2017 Q1	629	185	26	249	862	1588	726	-644	0	3621
2016 Q4	521	143	3	192	801	1367	424	-721	19	2749
2016 Q1	618	139	30	200	1120	1279	296	-679	0	3002



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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 first 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 94 percent of intervals (from our estimated hourly schedule) at the ISO-NE interface compared to 69 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 $1.2 million and $0.7 million of production cost savings were projected at the time of scheduling at the ISO-NE and PJM interfaces.
  - ✓ However, only an estimated $0.9 million and $0.2 million of savings were realized 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) 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 > $20	Total
% of All Intervals w/ Adjustment			78%	16%	**94%**	61%	8%	**69%**
Average Flow Adjustment (MW)	Net Imports		-3	4	**-2**	16	5	**15**
	Gross		84	100	**87**	70	93	**72**
Production Cost Savings ($ Million)	Projected at Scheduling Time		$0.8	$0.5	**$1.2**	$0.3	$0.4	**$0.7**
	Net Over-Projection by:	NY	$0.00	-$0.1	**-$0.1**	-$0.1	-$0.1	**-$0.2**
		NE or PJM	-$0.01	-$0.1	**-$0.1**	-$0.1	-$0.2	**-$0.3**
	Other Unrealized Savings		-$0.04	-$0.08	**-$0.1**	-$0.02	-$0.04	**-$0.1**
	Actual Savings		$0.7	$0.1	**$0.9**	$0.2	$0.01	**$0.2**
Interface Prices ($/MWh)	NY	Actual	$29.24	$58.63	**$34.16**	$25.31	$61.37	**$29.34**
		Forecast	$29.80	$41.98	**$31.84**	$25.55	$42.70	**$27.47**
	NE or PJM	Actual	$32.10	$41.16	**$33.62**	$27.41	$55.77	**$30.58**
		Forecast	$31.86	$47.33	**$34.45**	$28.08	$51.72	**$30.73**
Price Forecast Errors ($/MWh)	NY	Fcst. - Act.	$0.55	-$16.66	**-$2.33**	$0.24	-$18.67	**-$1.88**
		Abs. Val.	$4.00	$34.99	**$9.19**	$3.60	$41.03	**$7.79**
	NE or PJM	Fcst. - Act.	-$0.24	$6.16	**$0.83**	$0.67	-$4.04	**$0.15**
		Abs. Val.	$4.33	$25.58	**$7.89**	$2.75	$33.29	**$6.17**

Day-Ahead and Real-Time Transmission Congestion

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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).

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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 $81 million in the first quarter of 2017, down 35 percent from the first quarter of 2016.
- West Zone 230 kV facilities accounted for the largest reduction from 2016.
  - ✓ Congestion was increased in March 2016 because of planned transmission outages, which were necessary for transmission upgrades that have helped relieve congestion on the 230 kV system since they were completed in May 2016.
  - ✓ The reduction was also attributable to lower Ontario imports and higher PJM imports.
- The Central-East interface accounted for nearly 85 percent of congestion in the first quarter of 2017. This was down 10 percent from the previous year.
  - ✓ Lower gas spreads between Western NY and Eastern NY reduced re-dispatch costs to manage congestion across the Central-East interface.
  - ✓ Lower Ontario imports and higher PJM imports contributed to less frequent congestion across the Central-East interface as well.
- RT Congestion into the Valley Stream load pocket on Long Island fell notably from the first quarter of 2016 partly because of an improvement to the modeling of the 901 and 903 lines in April 2016.

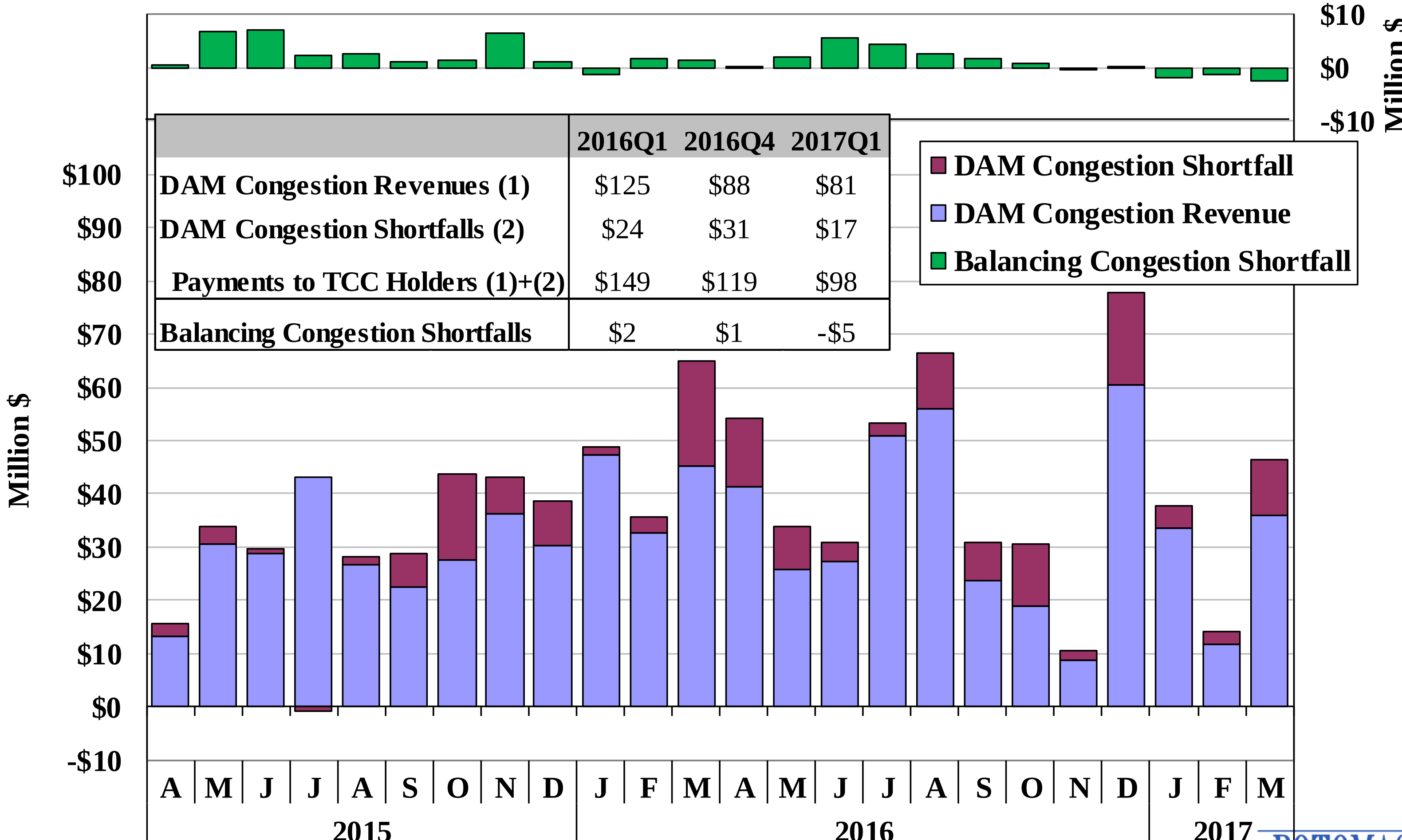
Day-Ahead Congestion Shortfalls

- Transmission outages accounted for most shortfalls in the first quarter of 2017.
  - ✓ Roughly $11.5 million (out of $17 million) was allocated to the responsible TO.
- More than 90 percent 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 Fitzpatrick-EDIC 345 line was OOS from mid-January to mid-February.
    - – The EDIC-Fraser 345 line was OOS from early to mid-March.
    - – The Marcy-Coopers-Rock Tavern 345 lines were OOS for most of March.
    - – One Ramapo PAR were OOS during the entire quarter.
  - ✓ A significant portion of shortfalls (~$5M) resulted from other factors that include nuclear outages, unit commitments, 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.
- Roughly $1 million of shortfalls accrued on the transmission paths following power out of the North Zone because of transmission outages on several days that reduced transfer capability on parallel paths.

Balancing Congestion Shortfalls

- Nearly all of the balancing congestion surpluses in the first quarter of 2017 were associated with the Central-East interface.
  - ✓ The operation of PAR-controlled lines (including the Ramapo, ABC, JK, and St. Lawrence lines) collectively contributed nearly \$3.5 million of surpluses.
  - ✓ Other factors, including the operation of capacitors and SVCs, contributed another \$1 million of surpluses.
  - ✓ In addition, \$0.5 million was paid by PJM under M2M JOA.
- Nearly \$0.8 million of shortfalls accrued on the Ontario interface in a few intervals on March 8, partly offsetting the overall surplus.
  - ✓ The Ontario import limit was reduced to 300 MW because of multiple transmission outages on the 230 and 115 kV networks in the West Zone due to high winds.

Congestion Revenues and Shortfalls by Month



	2016Q1	2016Q4	2017Q1
DAM Congestion Revenues (1)	$125	$88	$81
DAM Congestion Shortfalls (2)	$24	$31	$17
Payments to TCC Holders (1)+(2)	$149	$119	$98
Balancing Congestion Shortfalls	$2	$1	-$5

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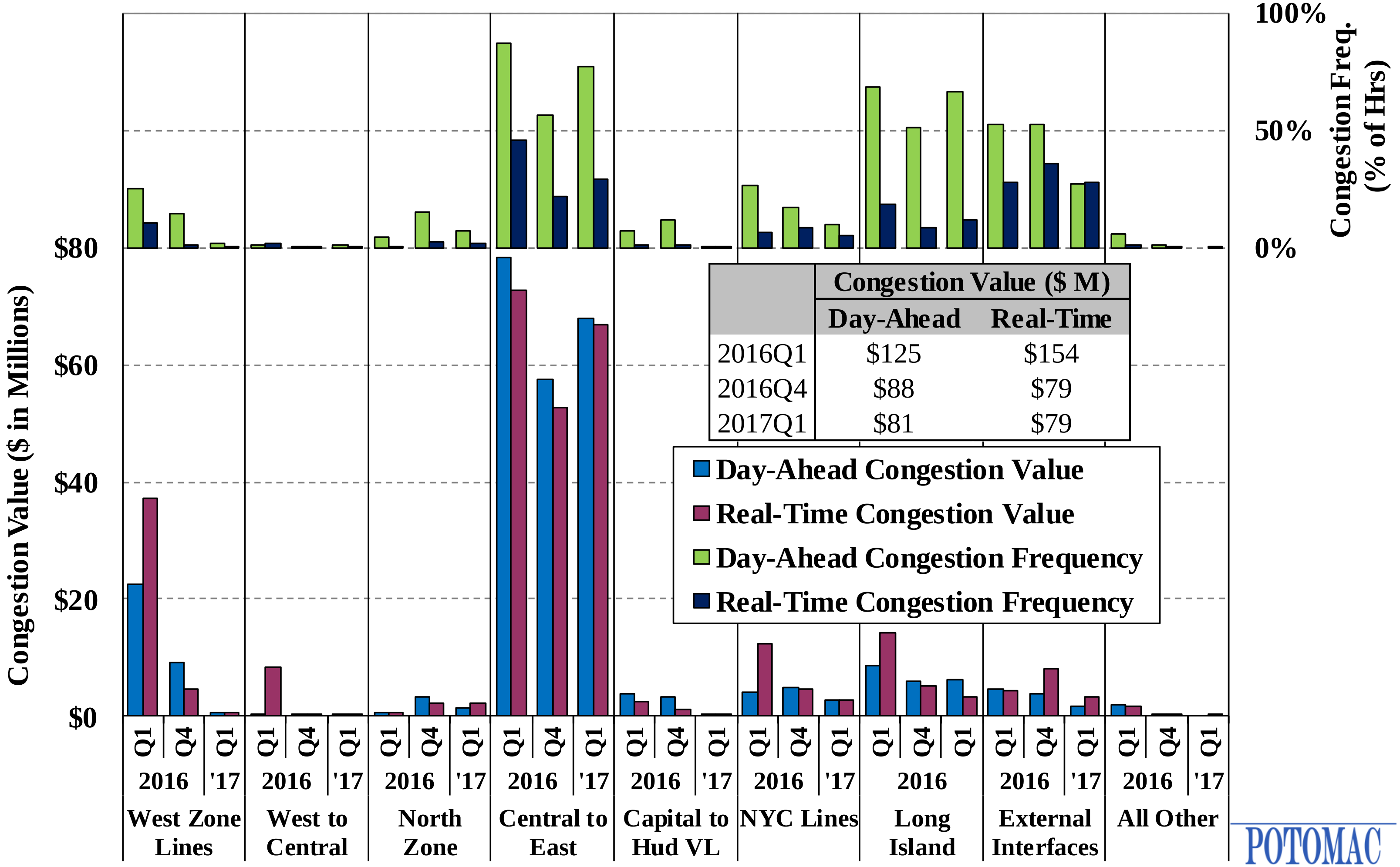
DA and RT Congestion Value and Frequency by Transmission Path



	Congestion Value ($ M)	
	Day-Ahead	Real-Time
2016Q1	$125	$154
2016Q4	$88	$79
2017Q1	$81	$79

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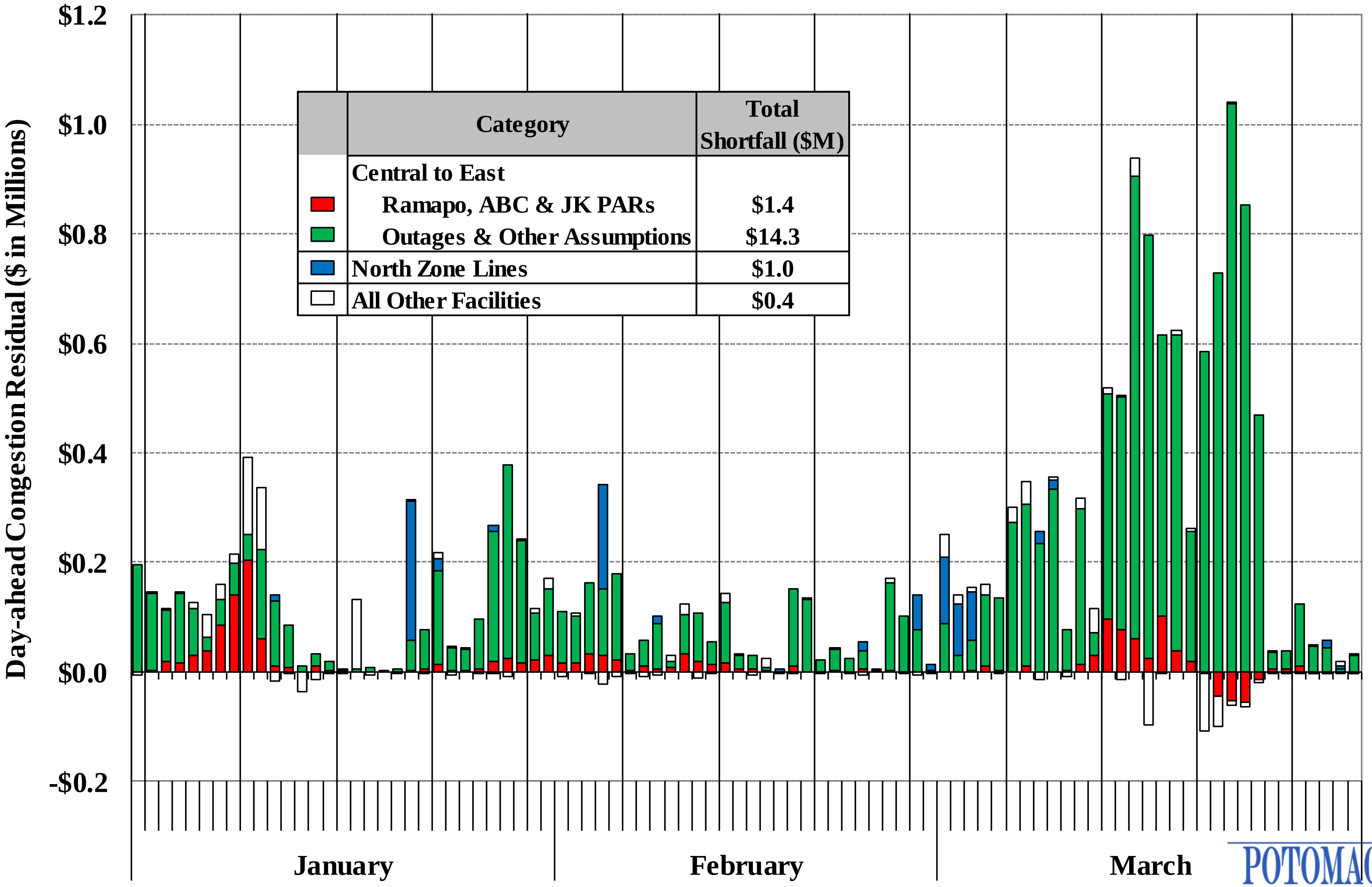
Day-Ahead Congestion Revenue Shortfalls by Transmission Facility



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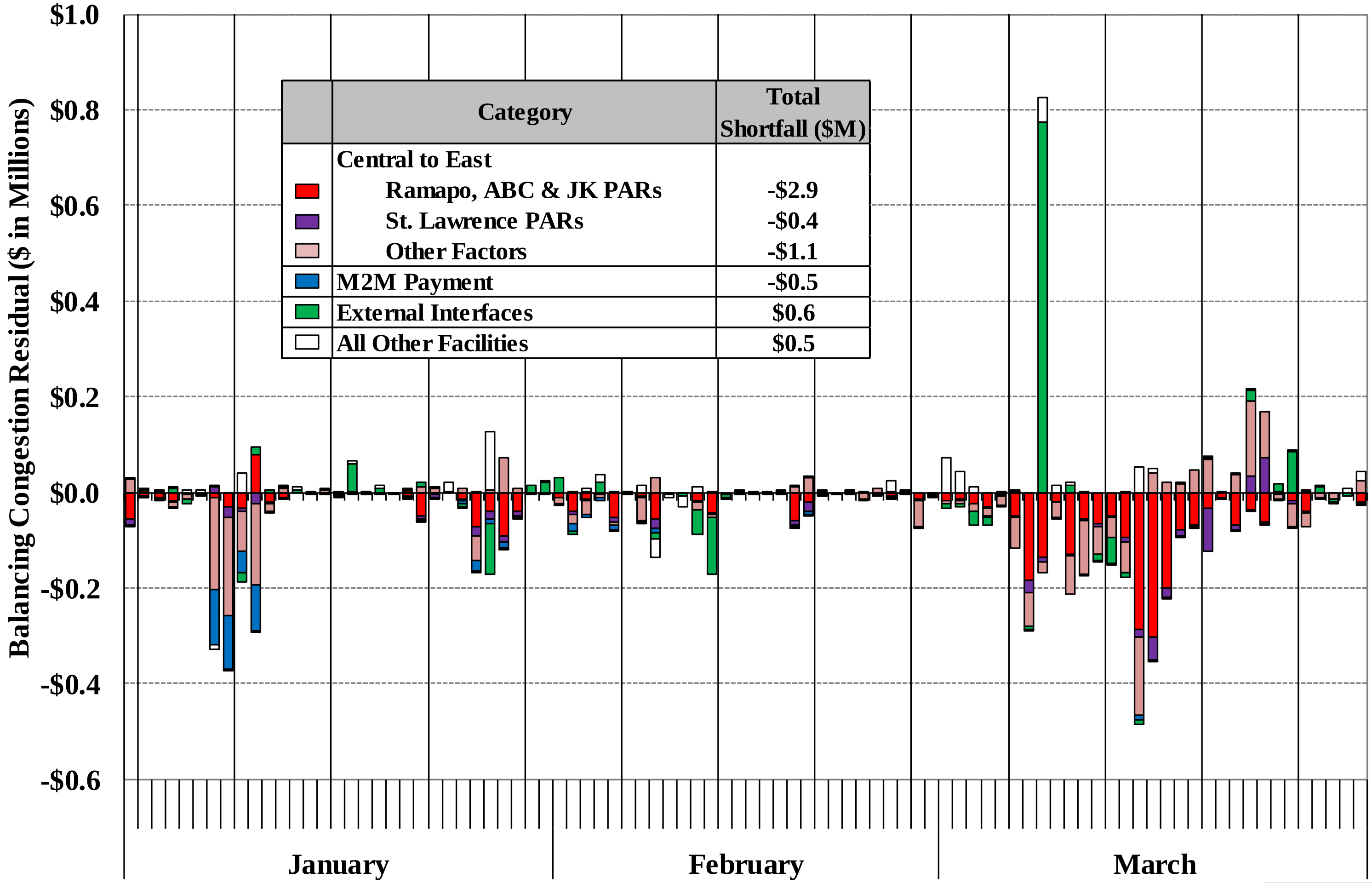
Balancing Congestion Shortfalls by Transmission Facility



	Category	Total Shortfall ($M)
	Central to East	
	Ramapo, ABC & JK PARs	-$2.9
	St. Lawrence PARs	-$0.4
	Other Factors	-$1.1
	M2M Payment	-$0.5
	External Interfaces	$0.6
	All Other Facilities	$0.5

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

Operations under M2M with PJM:
Chart Descriptions

- 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 interfaces 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).

Operations under M2M with PJM:
Market Outcomes

- Active Ramapo Coordination (i.e., when M2M constraints were binding) occurred in 29 percent of intervals, down from the first quarter of 2016 because of less frequent congestion across the Central-East interface.
  - ✓ Average actual flows exceeded the Target Flow by 420 MW, resulting in a small amount of M2M payments (~$90K) from PJM to NY this quarter.
    - The low Target Flow resulted from large negative deviations on the JK lines. This is represented by "JK auto correction" and capped at 200 MW.
- Ramapo Coordination under M2M with PJM has provided significant benefit to the NYISO in managing congestion on coordinated flow gates.
  - ✓ Balancing congestion surpluses have resulted from relief of the Central-East interface, indicating that it reduced production costs and congestion.
- Beginning in May 2017, the ABC and JK lines were incorporated into the M2M process after the expiration of the ConEd-PSEG wheel agreement.
  - ✓ Many new coordinated flow gates (in NYC and West Zone) were added.
  - ✓ We will continue to report on the performance of the M2M process after these changes go into effect.

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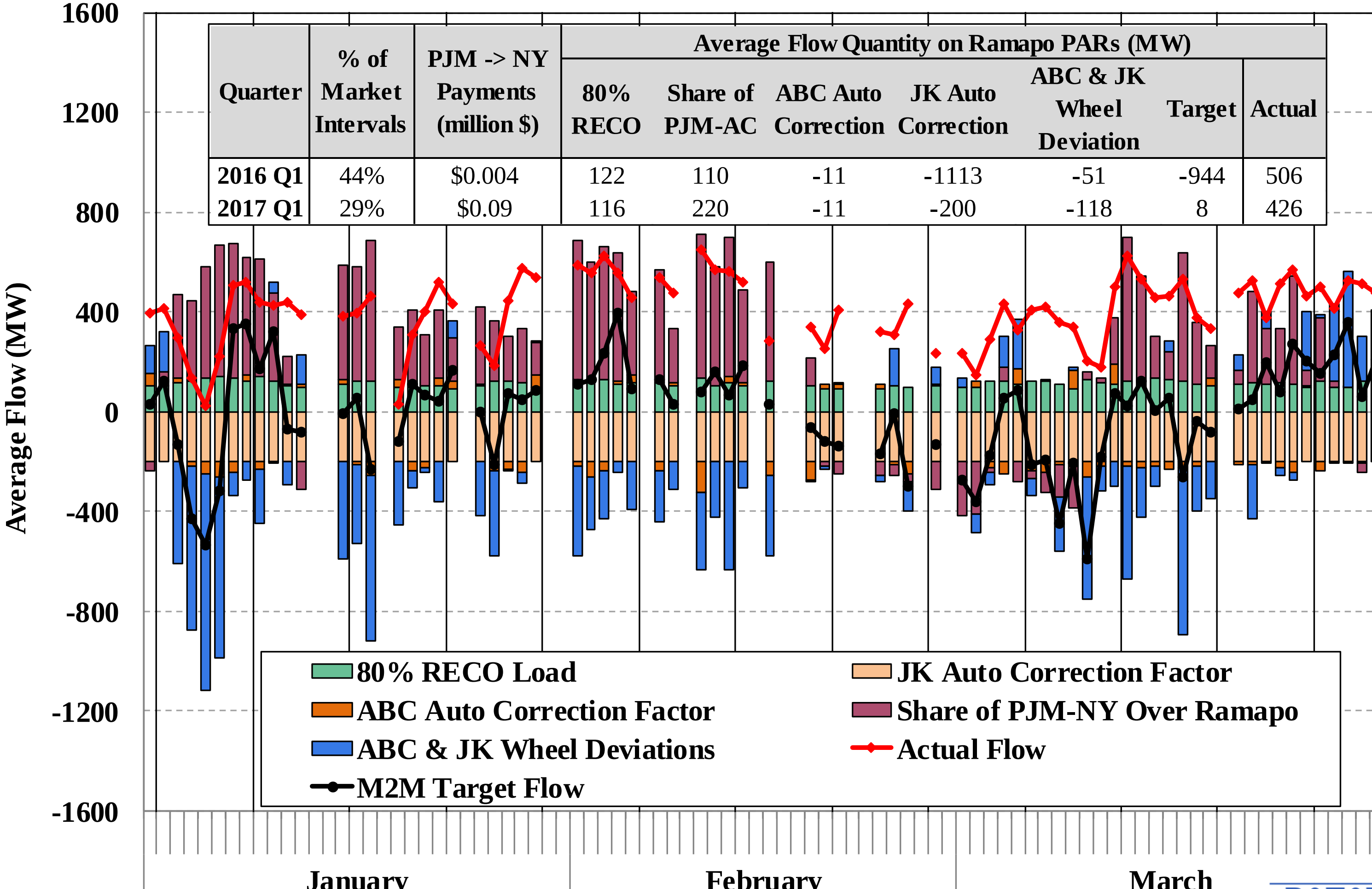
Actual and Target Flows for the Ramapo Line During the Intervals with Binding M2M Constraints

Quarter	% of Market Intervals	PJM -> NY Payments (million $)	Average Flow Quantity on Ramapo PARs (MW)						
			80% RECO	Share of PJM-AC	ABC Auto Correction	JK Auto Correction	ABC & JK Wheel Deviation	Target	Actual
2016 Q1	44%	$0.004	122	110	-11	-1113	-51	-944	506
2017 Q1	29%	$0.09	116	220	-11	-200	-118	8	426



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

Congestion on the Low Voltage Network Upstate

- In upstate New York, congestion 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 congestion is 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 following figure shows the number of days in the first quarter of 2017 when various resources were used to manage congestion in five areas of upstate NY.
  - ✓ West Zone: Mostly Gardenville-to-Dunkirk and Niagara 230/115kV transformers;
  - ✓ Central Zone: Mostly constraints around the State Street 115kV bus;
  - ✓ Cent-Hudson: Mostly constraints on the 69kV system in the Hudson Valley;

(cont'd)

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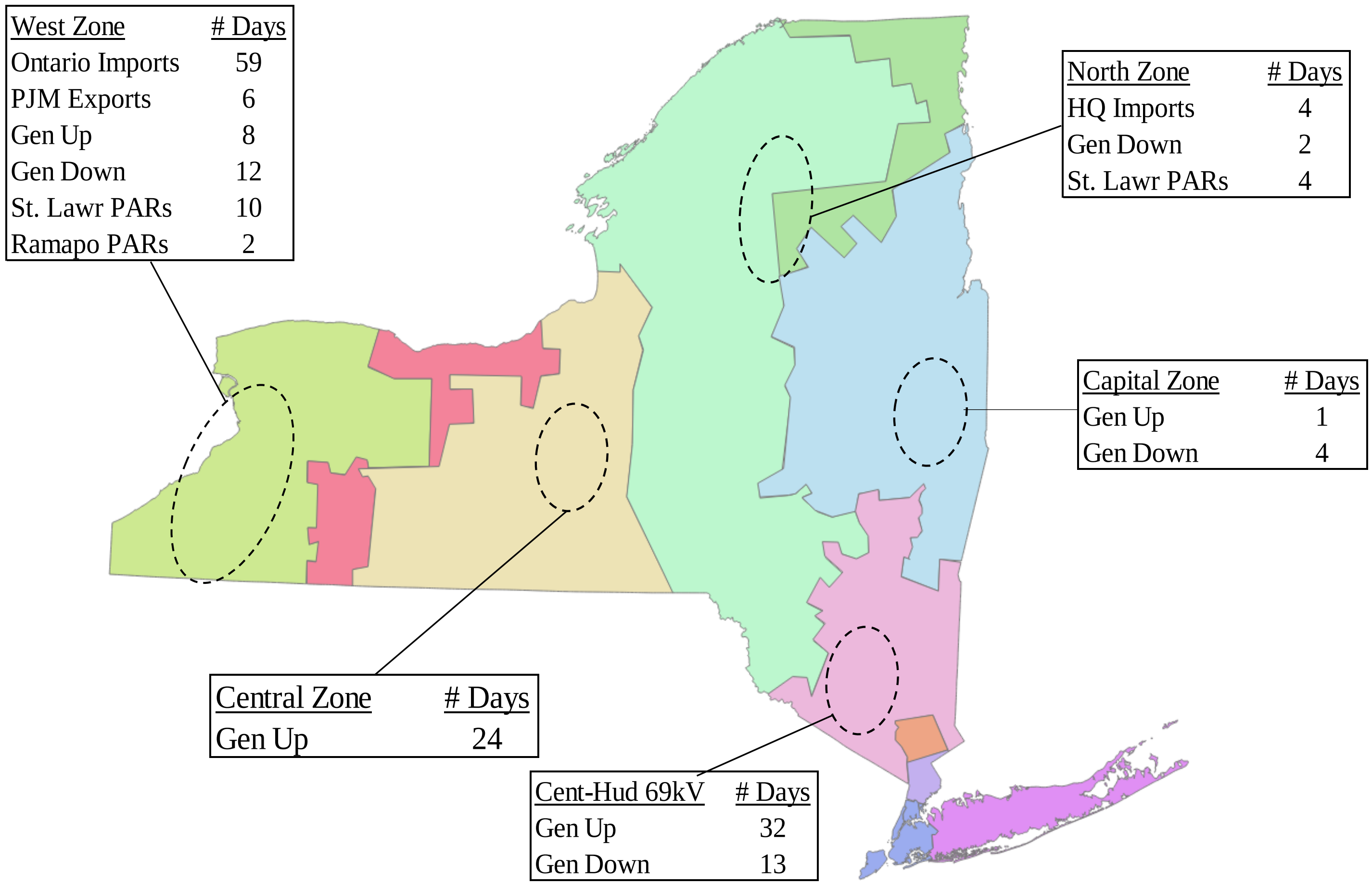
Congestion on the Low Voltage Network Upstate

  - ✓ North Zone: Mostly 115kV constraints coming south from the North Zone between the Colton 115kV and Taylorville 115kV buses; and
  - ✓ Capital Zone: Mostly Albany-to-Greenbush 115kV constraints.
- The West Zone contains the most frequently constrained 115kV facilities.
  - ✓ Ontario imports were limited on most days, while generation redispatch and PAR adjustments were used on a significant number of days.
  - ✓ West Zone congestion management affected other areas of New York by:
    - Reducing low-cost imports from Ontario, which raised LBMPs in other areas; and
    - Using the St. Lawrence PARs to relieve West Zone congestion tends to exacerbate congestion going south from the North Zone and across the Central East interface.
    - Thus, the actions should be done in a manner that balances the benefits of relieving congestion 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.
  - ✓ Although the PJM export limit bound on just 6 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.

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



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;
  - ✓ 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 470 MW in the first quarter of 2017.
  - ✓ New York City accounted for 85 percent (or 400 MW on average), which was up 108 percent from the first quarter of 2016.
    - – Reliability commitments in NYC are frequently driven by transmission and generation outages. More transmission and generation outages led to more reliability commitments in the first quarter of 2017.
    - – Most reliability commitments in the first quarter of 2017 were made to satisfy the N-1-1 thermal requirements in the Astoria West/Queensbridge and Freshkills load pockets.
  - ✓ Western NY accounted for 13 percent (or 60 MW on average), which was comparable to the first 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 for local voltage support and/or managing post-contingency flows on 115kV facilities.
- Reliability commitments were rare in other areas in the first quarter of 2017.

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Supplemental Commitment and OOM Dispatch: OOM Dispatch Results

- The NYISO and local TOs sometimes dispatch generators out-of-merit in order to:
  - ✓ Maintain reliability of the lower-voltage transmission and distribution networks; or
  - ✓ Manage constraints of high voltage transmission facilities that are not fully represented in the market model.
- OOM dispatched occurred for 372 station-hours in the first quarter of 2017.
- Overall, OOM dispatch has been relatively low since 2015.
  - ✓ The largest reduction occurred in Western NY because of transmission upgrades, which allowed the retirement of several units that were frequently OOMed in the past for local reliability needs.
    - – Modestly higher OOM dispatch in March 2017 resulted from increased local needs on the 115 kV network because of transmission outages.
- Nonetheless, the Niagara facility was still 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 first quarter of 2017, this manual shift was required in 236 hours to manage 115 kV constraints and in 16 hours to manage 230 or 345 kV constraints.

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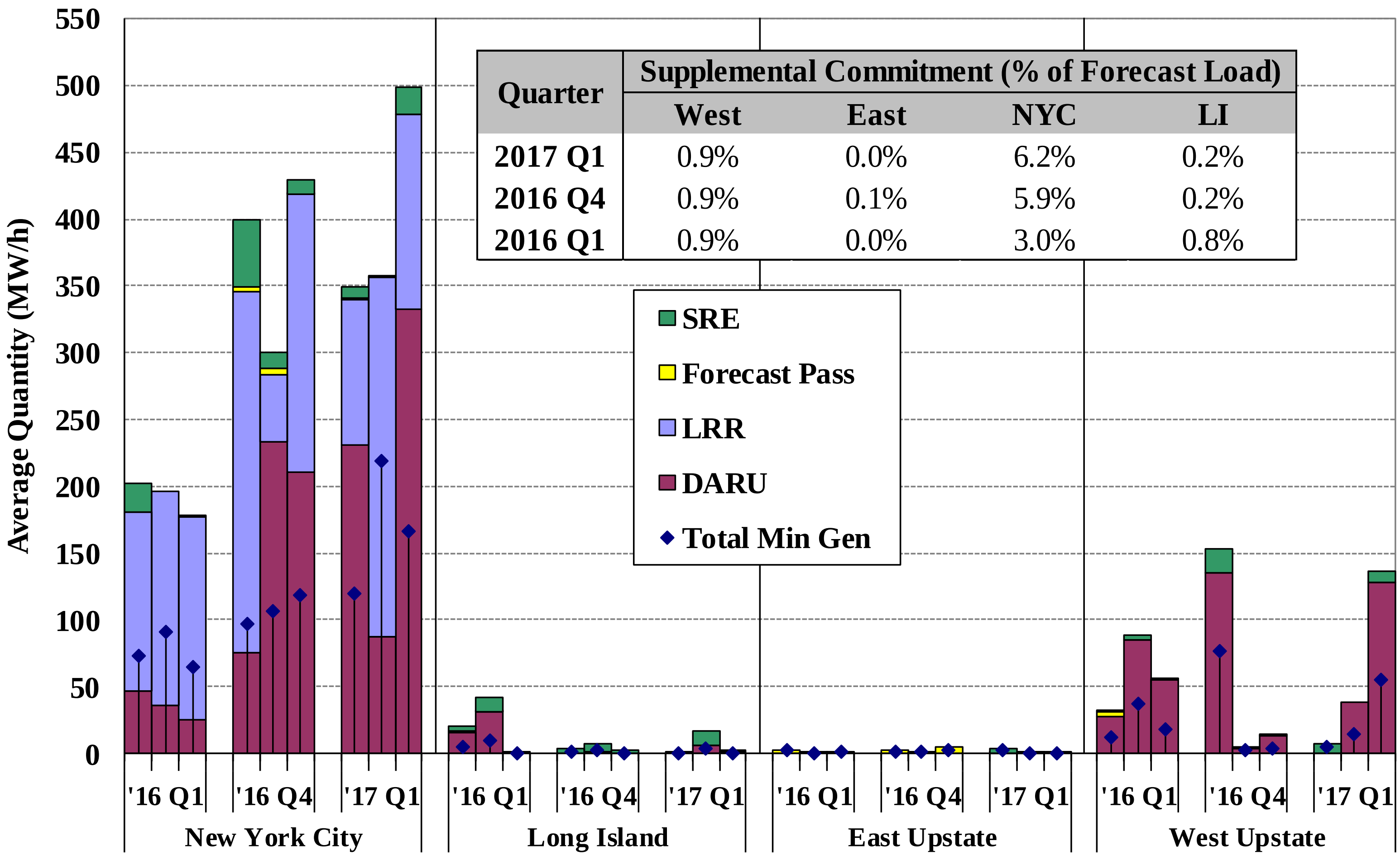
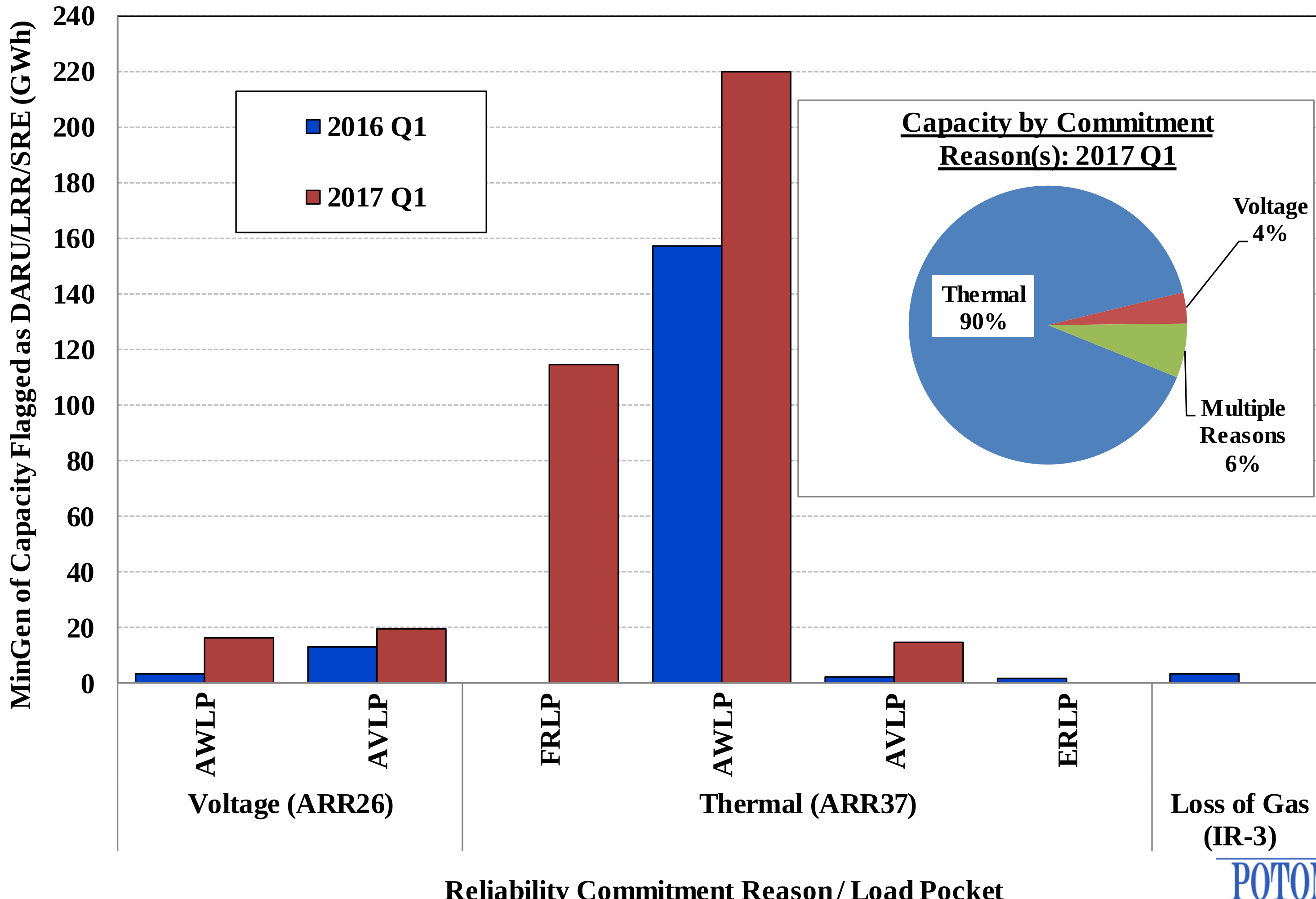
Supplemental Commitment for Reliability
by Category and Region



Quarter	Supplemental Commitment (% of Forecast Load)			
	West	East	NYC	LI
2017 Q1	0.9%	0.0%	6.2%	0.2%
2016 Q4	0.9%	0.1%	5.9%	0.2%
2016 Q1	0.9%	0.0%	3.0%	0.8%

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



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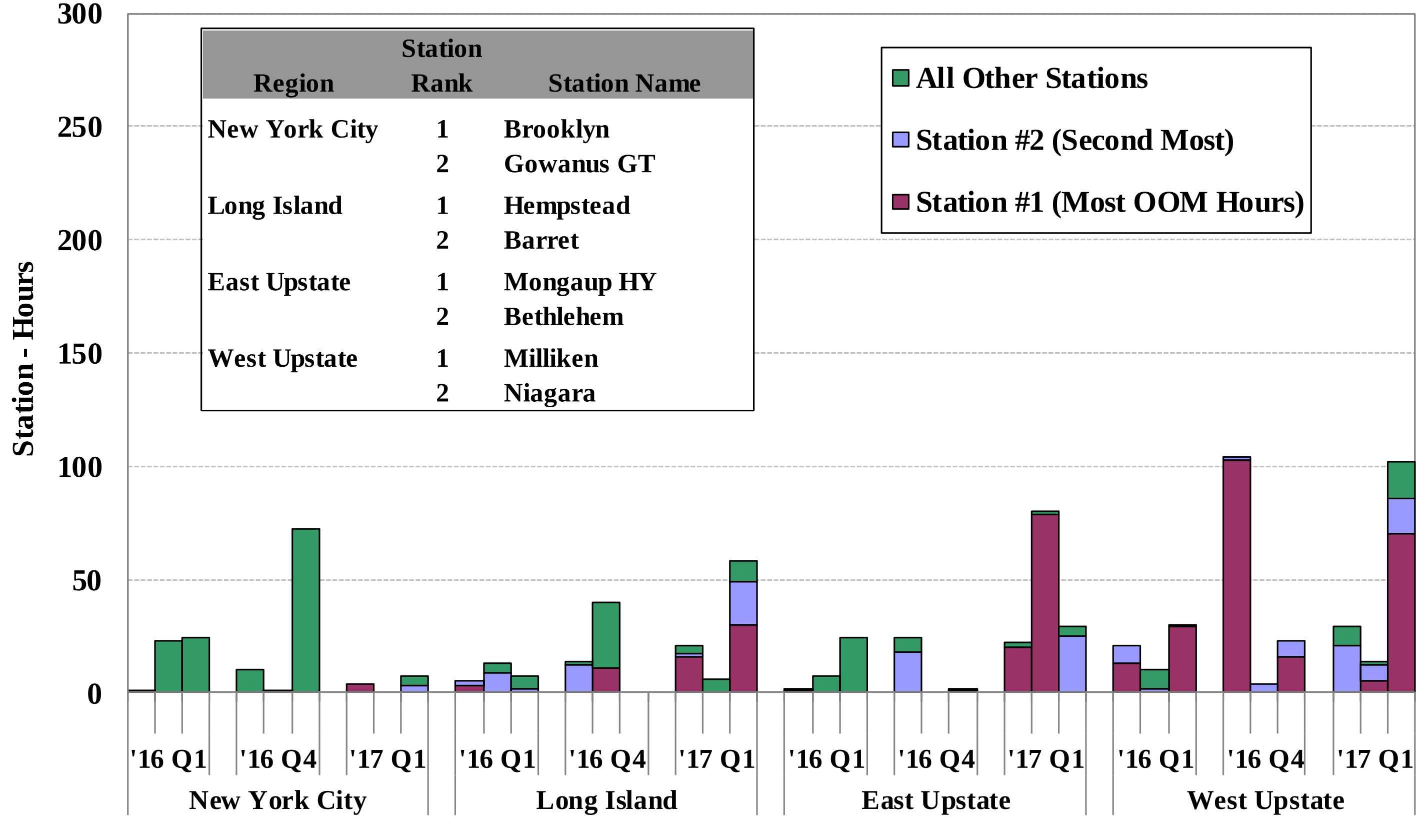
Frequency of Out-of-Merit Dispatch by Region by Month



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

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 461 hours in 2016-Q1, 183 hours in 2016-Q4, and 252 hours in 2017-Q1. 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 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.

Uplift Costs from Guarantee Payments:
Market Results

- Guarantee payments totaled $8.6 million this quarter, up 21 percent from the first quarter of 2016. The increase was consistent with:
  - ✓ Increased supplemental commitment for reliability in NYC (see slide 67); and
  - ✓ Higher natural gas prices (see slide 13), which increased the commitment costs of gas-fired units.
- Local uplift in Western NY totaled $2 million, accounting for 23 percent of total guarantee uplift this quarter.
  - ✓ Nearly all of the local uplift was paid to units that were committed and/or OOMed to manage congestion on the 115 kV system (see slides 67, 69).
- DAMAP uplift was high on March 8.
  - ✓ High winds led to multiple transmission outages during the afternoon on the 230 kV and 115 kV system in Western NY.
  - ✓ A large unit in Western NY was OOMed down to manage overloads on the 230/115 kV facilities and had to buy out its DAM schedules (energy, reserves, and regulation) at high RT prices.

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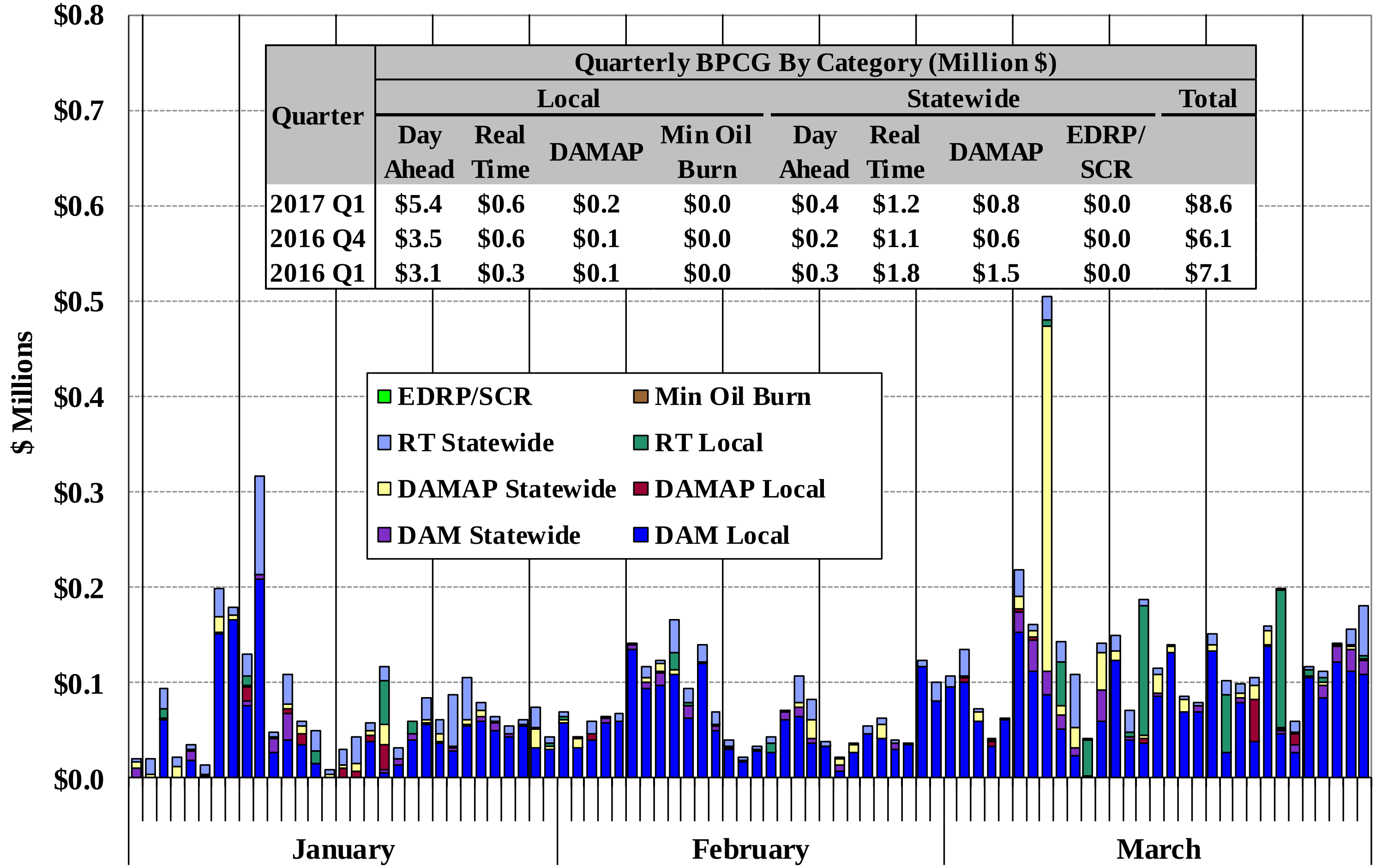
Uplift Costs from Guarantee Payments
Local and Non-Local by Category



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 Q1	$5.4	$0.6	$0.2	$0.0	$0.4	$1.2	$0.8	$0.0	$8.6
2016 Q4	$3.5	$0.6	$0.1	$0.0	$0.2	$1.1	$0.6	$0.0	$6.1
2016 Q1	$3.1	$0.3	$0.1	$0.0	$0.3	$1.8	$1.5	$0.0	$7.1

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

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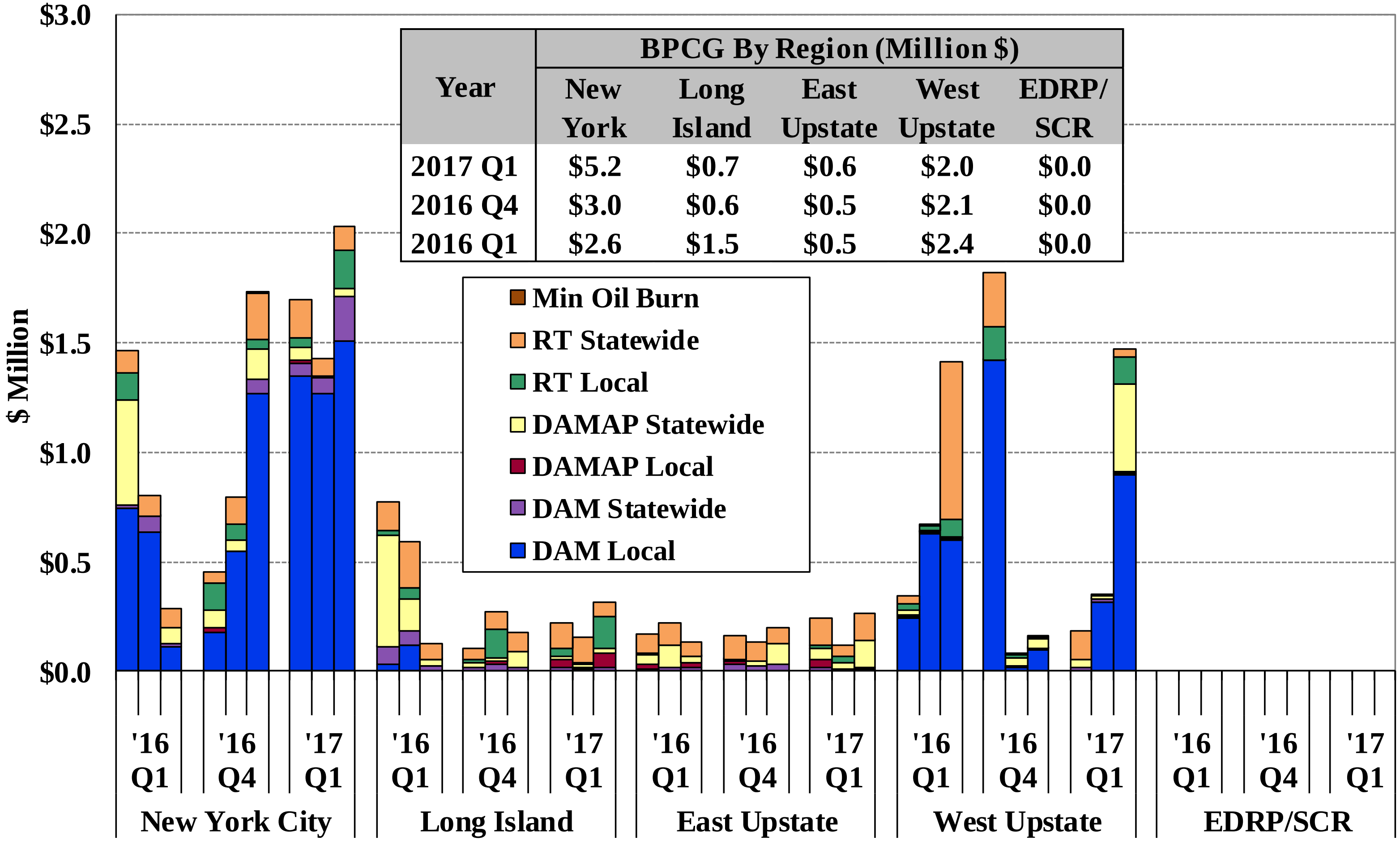
Uplift Costs from Guarantee Payments
By Category and Region



Year	BPCG By Region (Million $)				
	New York	Long Island	East Upstate	West Upstate	EDRP/ SCR
2017 Q1	$5.2	$0.7	$0.6	$2.0	$0.0
2016 Q4	$3.0	$0.6	$0.5	$2.1	$0.0
2016 Q1	$2.6	$1.5	$0.5	$2.4	$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

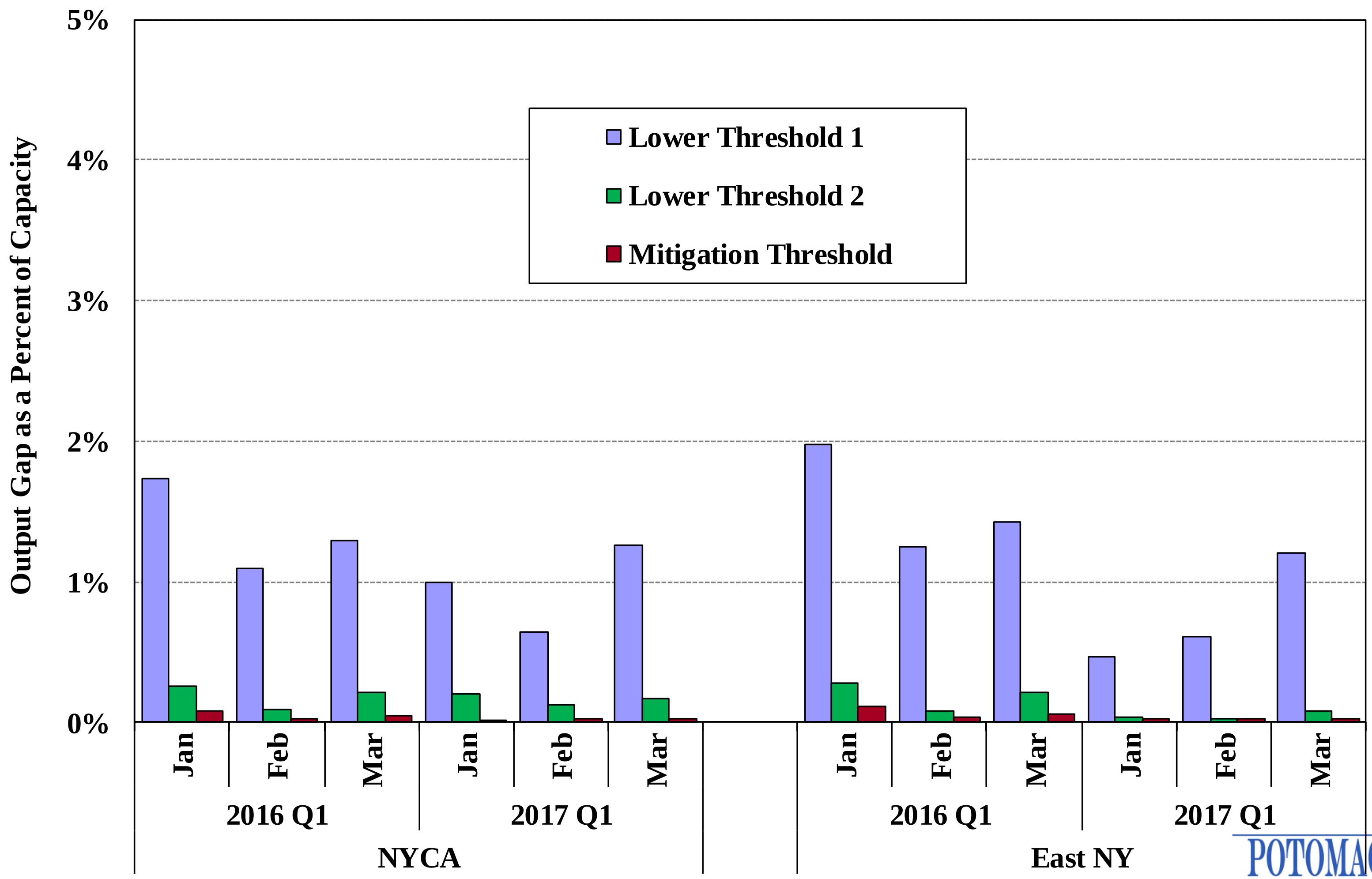
Potential Economic and Physical Withholding:
Chart Descriptions

- 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.

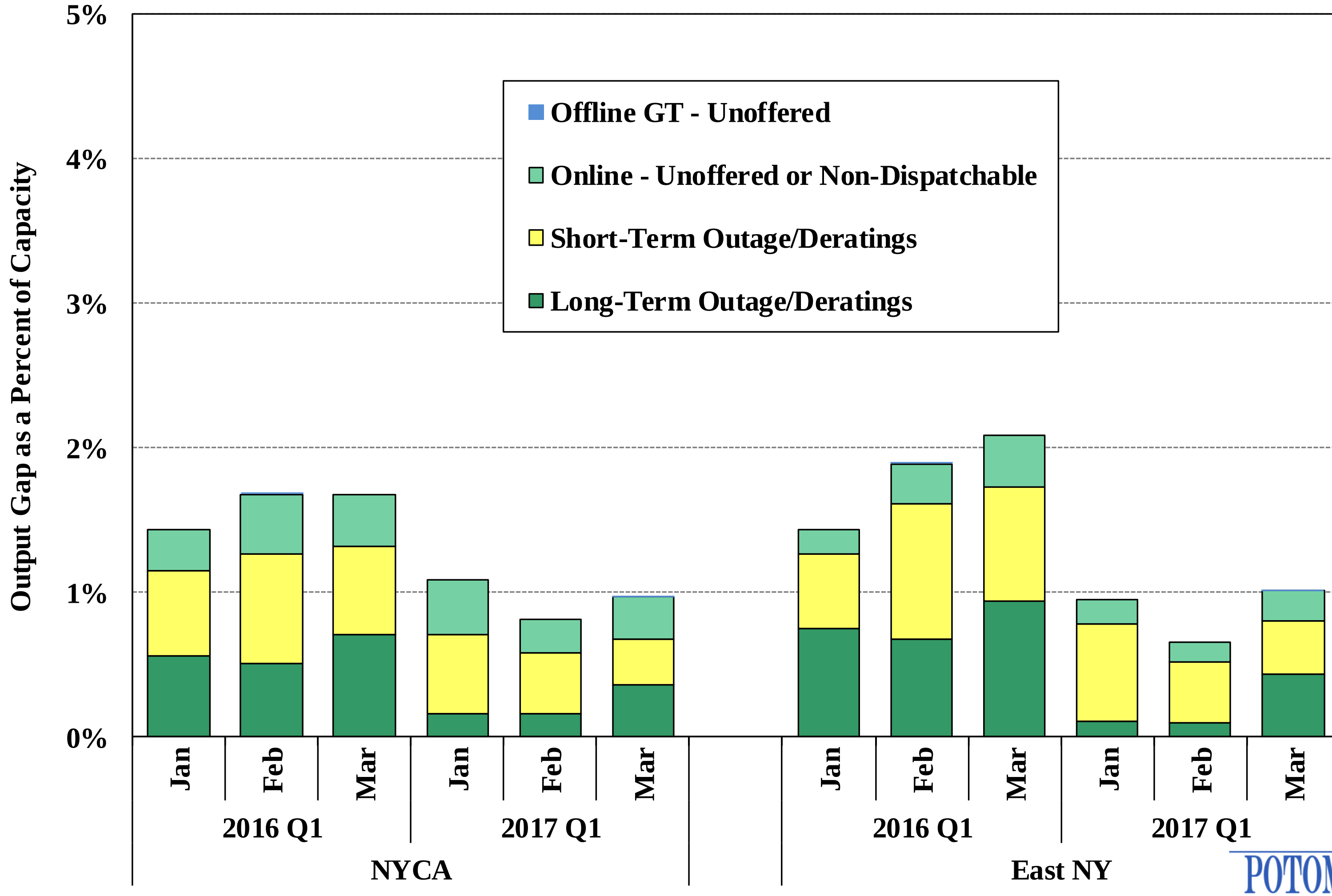
Potential Economic and Physical Withholding:
Market Power Screening Results

- The amount of output gap remained low in the first quarter of 2017 and raised no significant market power concerns.
  - ✓ Output gap averaged less than 0.1 percent of total capacity at the mitigation threshold and 0.7 to 1.3 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 short-term outages/deratings was generally higher in the colder months of the quarter (e.g., February 2016 & January 2017), reflecting that cold temperatures tend to increase outage risks.
  - ✓ Economic capacity on long-term outages/deratings rose in March as suppliers scheduled more maintenance expecting milder conditions.
    - – In some cases, it would have been efficient to postpone 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 the first quarter of 2016 because two combined-cycle units in NYC were partially derated during most of the quarter for transmission line maintenance.

Output Gap by Month
NYCA and East NY



Unoffered Economic Capacity by Month
NYCA and East NY



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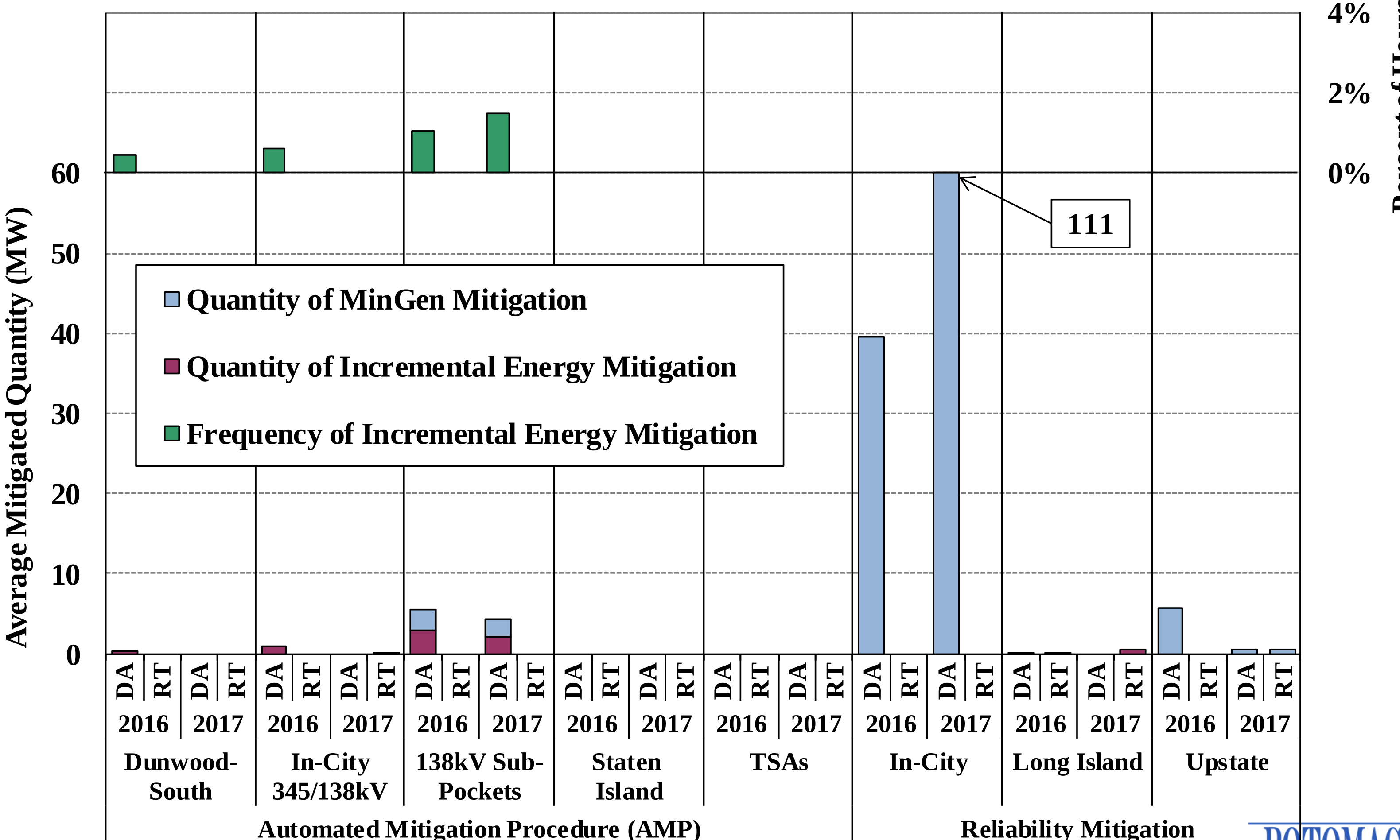
Automated Market Power Mitigation

- 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 first quarter of 2017.
    - – Local reliability (i.e., DARU & LRR) units accounted for 96 percent of DAM mitigation. However, these mitigations generally affect guarantee payment uplift but not LBMPs.
- The quantity of mitigation rose modestly from the first quarter of 2016 primarily because of higher DARU and LRR commitments in New York City.

Automated Market Power Mitigation



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Capacity Market

Spot Capacity Market Results

- The following two figures summarize capacity market results and key market drivers in 2017-Q1.
  - ✓ 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 41 to 66 percent from a year ago in all regions except the G-J Locality, where prices rose modestly instead.
  - ✓ The large reductions in most regions were due primarily to lower ICAP requirements that resulted from lower peak load forecast and lower LCRs.
    - – However, the IRM for NYCA was higher, partially offsetting the reduction in the NYCA ICAP requirement.
  - ✓ Internal supply fell from a year ago as a result of the Huntley retirement in March 2016 and mothballing of multiple Astoria and Ravenswood GTs in NYC after 2016-Q1. This was offset by a net increase of over 400 MW in imports.
- Spot prices in NYC and the G-J Locality were identical in 2017-Q1 as NYC requirement was not binding.

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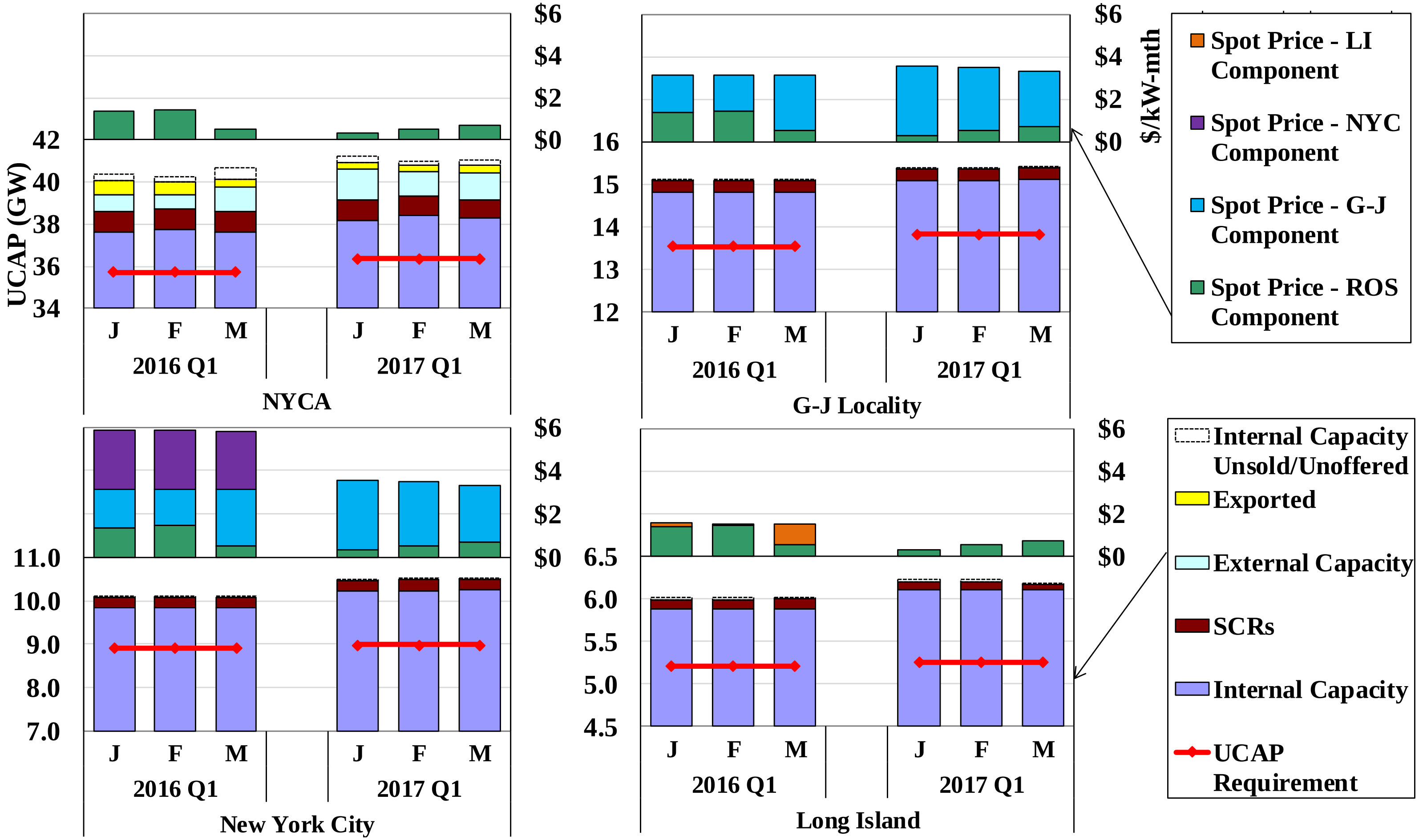
Capacity Market Results
2016-Q1 & 2017-Q1



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				
2017 Q1 ($/kW-Month)	$0.52	$3.43	$0.52	$3.43
% Change from 2016 Q1	-53%	-41%	-66%	9%
Change in Demand				
Load Forecast (MW)	-209	-136	-61	-31
IRM/LCR	0.5%	-3.0%	-1.0%	-0.5%
2017 Winter	*117.5%*	*80.5%*	*102.5%*	*90.0%*
2016 Winter	*117.0%*	*83.5%*	*103.5%*	*90.5%*
ICAP Requirement (MW)	**-77**	**-467**	**-117**	**-109**
Change in ICAP Supply (MW) - Quarter Avg				
Generation	-270	-65	40	-55
Import Capacity	420			