



Quarterly Report on the New York ISO Electricity Markets First Quarter of 2019

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Market Highlights



Market Highlights: Executive Summary

- This quarter was characterized by relatively mild winter weather.
 - ✓ There were no prolonged cold periods, and operating conditions were less challenging than last winter. (see slide [8](#))
- All-in prices fell 18 to 37 percent from the first quarter of 2018 due largely to lower LBMPs, which were driven primarily by lower gas prices. (see slide [7](#))
- Modeled congestion fell substantially across the Central-East interface and in NYC because of lower loads, lower gas price spreads between regions, and fewer costly transmission outages. (see slides [9-10](#))
 - ✓ However, West Zone congestion has risen significantly since the NYISO began to model 115 kV constraints there in December 2018.
- Enhanced Niagara modeling (which also began in December 2018) has helped reduce overall congestion management costs in the West Zone.
 - ✓ Optimizing the congestion impacts of individual Niagara units increased the RT congestion value of transmission facilities in the West Zone by 45 percent as compared with assuming a fixed distribution.
 - ✓ However, 49 percent of this benefit was not realized since the plant is not required to follow bus-level optimized schedules. (see slide [12](#))

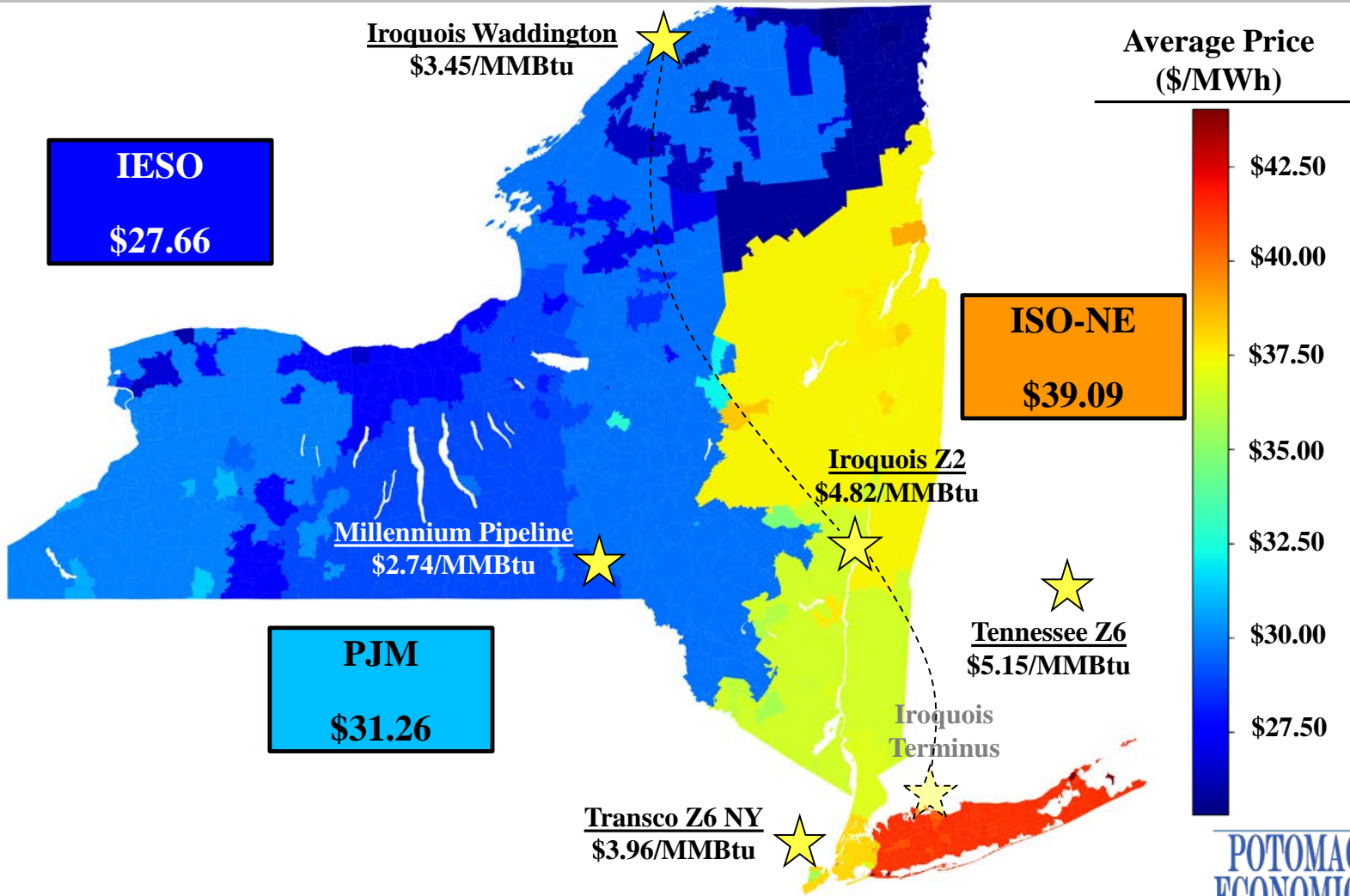



Market Highlights: Executive Summary

- OOM actions were frequently used to manage constraints on 69 kV networks on Long Island (37 days). (see slide [11](#))
 - ✓ We estimate that average LBMPs would have been 18 percent higher in the East of Northport load pocket if these constraints were modeled in the market software.
 - ✓ Better pricing will reduce associated BPCG uplift, better compensate resources that satisfy the needs, and better signal the needs for future investment.
- Large quantities of OOM commitment (520 MW on average) were needed to maintain adequate operating reserves in NYC load pockets. (see slide [13](#))
 - ✓ Reflecting NYC operating reserve requirements in the day-ahead and real-time markets would provide better incentives to suppliers and investors. (NYISO will discuss with stakeholders as part of the “More Granular...” project.)
- OOM actions were used frequently to maintain adequate reserves and secure transmission when the market did not schedule resources to satisfy the needs.
 - ✓ Reflecting these requirements in the day-ahead and real-time markets would lead to more efficient scheduling and better investment signals. (see especially SOM Recommendations #2017-1 and #2018-1)



Market Highlights: System Price Diagram





Market Highlights: Summary of Energy Market Outcomes

- NYISO energy markets performed competitively in the first quarter of 2019.
 - ✓ Variations in regional wholesale prices were driven primarily by changes in fuel prices, demand, and supply availability.
 - ✓ The amount of output gap (slide [55](#)) and unoffered economic capacity (slide [56](#)) remained modest and reasonably consistent with competitive market expectations.
- Average all-in prices fell in all areas and ranged from \$28/MWh in the North Zone to \$47/MWh in Long Island, down 18 to 37 percent from a year ago. (slide [17](#))
 - ✓ Energy prices accounted for the largest component of the decrease, falling by 22 to 37 percent (slides [22-23](#)), driven primarily by lower natural gas prices.
 - Average natural gas prices fell between 32 and 53 percent from a year ago in eastern NY (slide [26](#)), reflecting much milder weather compared to last winter.
 - Load levels fell modestly – average load fell 0.5 percent and peak load fell 1.4 percent (slide [18](#)), contributing to lower prices as well.
 - However, the decrease was partly offset by lower net import levels (slide [35](#)) and lower nuclear generation (slide [27](#)).
 - ✓ Capacity costs rose by 19 percent in Long Island and 163 percent in the ROS areas but fell 46 percent in the G-J region for the reasons discussed in slide [15](#).



Market Highlights: Summary of Winter Operations

- Market operations were less challenging this winter than last winter because of milder weather.
 - ✓ There were two noteworthy cold periods this winter: (a) January 19 to 22 and (b) January 30 to February 2.
 - Although temperatures fell to single digits during both periods, they were higher than in last winter’s lengthier cold spell.
 - Load peaked at 24.7 GW on January 21, which was 1.4 percent lower than last winter.
 - Natural gas prices briefly reached the \$20/MMbtu level in Eastern NY (slide [19](#)), which was much lower than the \$141/MMbtu seen last winter.
 - ✓ There were no significant supplemental commitments or other out-of-market operator actions to address statewide or eastern NY needs during these two periods.
 - ✓ The NYISO’s fuel survey indicated that MPs maintained sufficient oil inventory throughout the winter.
 - The amount of oil production totaled roughly 322 GWh this winter, which was much lower than 1,262 GWh from last winter. (slide [25](#))



Market Highlights: Congestion Patterns, Revenues and Shortfalls

- Day-ahead congestion revenues totaled \$108 million, down 43 percent from the first quarter of 2019, primarily because of lower gas prices. (slide [38](#))
 - ✓ Most of the decrease occurred on the Central-East interface and transmission constraints into and within New York City. (slide [39](#))
- The Central-East interface accounted for the largest share (nearly 60 percent) of day-ahead congestion revenues in the first quarter of 2019. (slide [39](#))
 - ✓ This is typical during the winter season when gas spreads between Western NY and Eastern NY are largest.
 - ✓ However, these DA congestion revenues fell 37 percent from a year ago as the average gas spreads between Western NY and Eastern NY fell by more than 60 percent. (slide [19](#))
 - ✓ In spite of lower load levels, the frequency of congestion across the Central-East interface rose modestly from a year ago, due partly to:
 - Lower nuclear generation in Eastern NY because of more outages and deratings (slide [20](#)); and
 - Higher exports to New England (slide [35](#)) because of fewer transmission outages. Transmission outages accounted for only \$2 million of DA congestion shortfalls this quarter (slide [40](#)), compared to \$11 million from a year ago.



Market Highlights: Congestion Patterns, Revenues, and Shortfalls (cont.)

- Congestion on New York City constraints declined substantially from a year ago.
 - ✓ DA congestion values fell 72 percent and RT congestion values fell 79 percent (slide [39](#)) because of:
 - Fewer costly transmission outages, which led to \$2.7M of DA congestion shortfalls this quarter (slide [40](#)), compared to \$16M in the first quarter of 2018; and
 - Lower natural gas prices relative to other areas in Eastern NY (slide [19](#)), which led NYC generation to become more economic.
 - Lower load levels contributed to less frequent congestion as well.
- Unlike other regions, congestion that was priced in the DA and RT markets rose notably in the West Zone. (slide [39](#))
 - ✓ The increase occurred primarily on the 115 kV constraints, which accounted for nearly all of DA and RT priced-congestion in the West Zone this quarter.
 - ✓ 115 kV constraints were previously managed via proxy transmission constraints and OOM actions. These were incorporated into the DA and RT markets in December 2018.
 - Accordingly, OOM actions to manage West Zone congestion fell. (slide [44](#))
 - This has improved scheduling efficiency and reduced overall costs to manage congestion in this area.



Market Highlights: Congestion Patterns, Revenues, and Shortfalls (cont.)

- Nonetheless, OOM actions to manage lower-voltage (115 kV and below) network congestion were still frequent in other regions. (slide [44](#))
 - ✓ OOM actions were most frequent in Long Island (37 days), the Capital Zone (32 days), and Northern NY (27 days).
- On Long Island, OOM actions to manage 69 kV constraints were most frequent in the East of Northport load pocket this quarter. (slide [45](#))
 - ✓ This not only incurred significant BPCG uplift (slide [52](#)), but it also suppressed energy prices in the load pocket.
 - Our estimates show that, in the first quarter of 2019, average LBMPs would have risen \$7/MWh in the East of Northport load pocket if these 69 kV constraints were modeled in the market software. (slide [44](#))
 - ✓ Therefore, we have recommended that the NYISO model Long Island transmission constraints that are currently managed with OOM actions in the day-ahead and real-time markets. (see Recommendation #2018-1 in our 2018 SOM report)
 - This would greatly reduce associated BPCG uplift, better compensate resources that satisfy the needs, and better signal the needs for future investment.



Market Highlights: Niagara Modeling Enhancement

- The NYISO implemented a modeling enhancement for the Niagara plant in December 2018, which better recognizes the different congestion impacts of 115 kV and 230 kV units at the plant.
 - ✓ This has helped lower the overall costs to manage congestion in the West Zone in the first quarter of 2019.
 - ✓ Optimizing the congestion impacts of individual Niagara units increases the RT congestion value of transmission facilities in the West Zone by 45 percent as compared with assuming a fixed distribution. (slides [40-41](#))
- However, Niagara is not required to follow the unit-specific schedules.
 - ✓ The NYISO still made frequent OOM requests (in more than 500 hours in the first quarter of 2019) for specific Niagara output at the bus level;
 - ✓ Actual flow impact on some constraints deviated significantly from modeled flow impact, affecting overall scheduling efficiency. (slide [42](#))
 - This raised congestion management costs and reduced the congestion management value of Niagara modeling by 49 percent. (slide [41](#))
- It would be beneficial for Niagara to follow the bus-level model-optimized schedules more closely.



Market Highlights: Reliability Commitments, OOM Dispatch, and BPCG

- BPCG payments totaled \$15 million, down 23 percent from the first quarter of 2018 (slides [51-52](#)), driven primarily by lower gas prices and reduced reliability commitments in New York City.
- Nearly \$9 million (or 60 percent) of BPCG payments accrued in NYC. (slide [52](#))
 - ✓ Over \$7 million were paid to units that were committed for local reliability needs.
 - ✓ Reliability commitments in NYC accounted for roughly 80 percent of all reliability commitments this quarter and fell 9 percent from a year ago. (slide [48](#))
 - The decrease reflected reduced reliability needs resulted from lower load levels and fewer generation outages.
 - NYC units that were often needed for reliability were committed economically more frequently this quarter because of lower gas prices (relative to the rest of eastern NY).
 - ✓ We have recommended that the NYISO satisfy the reliability needs that drive these out-of-market costs with local reserve requirements in the DA & RT markets.
- Long Island BPCG payments were about \$3 million this quarter, up 81 percent from a year ago. (slide [52](#))
 - ✓ Most of this uplift was incurred to manage reliability and congestion on the 69 kV network. (slides [45](#), [50](#))



Market Highlights: Use of Operating Reserves to Manage NYC Congestion

- Transmission facilities in New York City can be operated above their Long-Term Emergency (“LTE”) rating if post-contingency actions (e.g., deployment of operating reserves) are available to quickly reduce flows to LTE.
 - ✓ The availability of post-contingency actions is important because they allow the NYISO to increase flows into load centers in NYC and reduce congestion costs.
- In 2019-Q1, 85 percent of the RT congestion in NYC occurred on N-1 constraints that would have been loaded above LTE after a single contingency. (slide [46](#))
 - ✓ The additional capability above LTE averaged from about 25 to 65 MW for the 138 kV constraints in the Greenwood load pocket to roughly 160 to 430 MW for 345 kV facilities in other NYC load pockets.
 - These increases were largely due to operating reserve providers in NYC, but they are not compensated for this service.
 - This reduces their incentives to be available in the short term and to invest in flexible resources in the long term.
 - In addition, when the market dispatches this reserve capacity, it can reduce the transfer capability in NYC.
- We have recommended that the NYISO efficiently schedule and compensate operating reserve units that can help satisfy transmission security criteria. (see Recommendation #2016-1 in our 2018 SOM report)



Market Highlights: Capacity Market

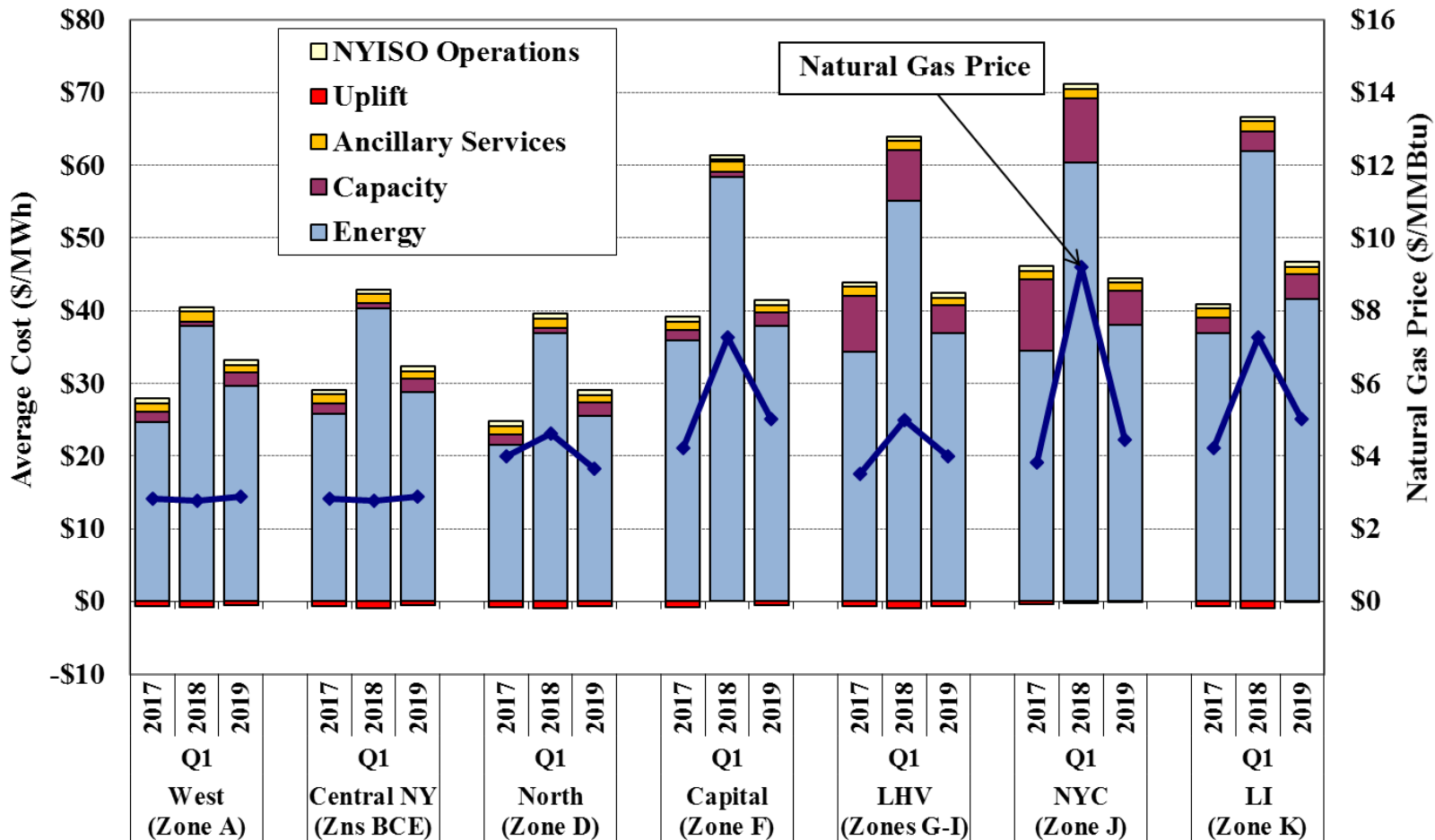
- Average spot capacity prices ranged from \$0.69/kW-month in ROS to \$1.52/kW-month in New York City in the first quarter of 2019. (slide [58-59](#))
- Compared to a year ago, average spot prices fell 53 percent in NYC and the G-J Locality but rose elsewhere, driven largely by changes in supply and demand.
 - ✓ On the demand side:
 - ICAP requirements were lower in all regions but the G-J Locality.
 - Although load forecasts were lower in all regions, the increase in the G-J Locality was due to a 3 percent increase in the LCR.
 - ✓ On the supply side:
 - Cleared import capacity rose by an average of over 300 MW.
 - Several units have been in an IIFO (“ICAP Ineligible Forced Outage”), including Lyonsdale, Gilboa 1, Milliken 2, and several Ravenswood GTs, which collectively reduced the internal supply by roughly 740 MW.
 - The CPV Valley plant and two Bayonne units entered the market, adding roughly 880 MW of supply and offsetting the reduction from IIFO units.
 - The net increase in supply was significant in the G-J Locality, leading to lower spot capacity prices there.



Charts: Market Outcomes

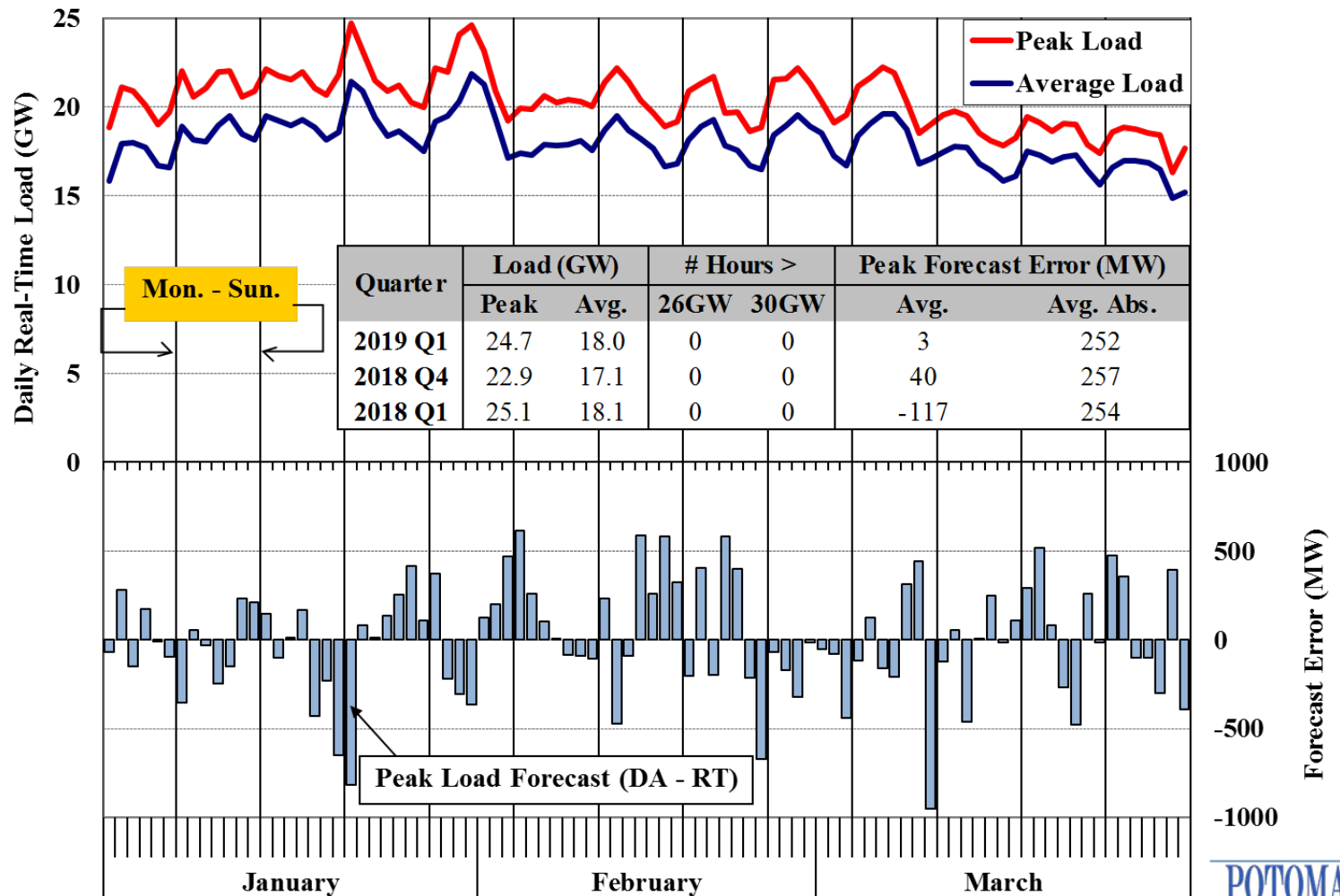


All-In Prices by Region



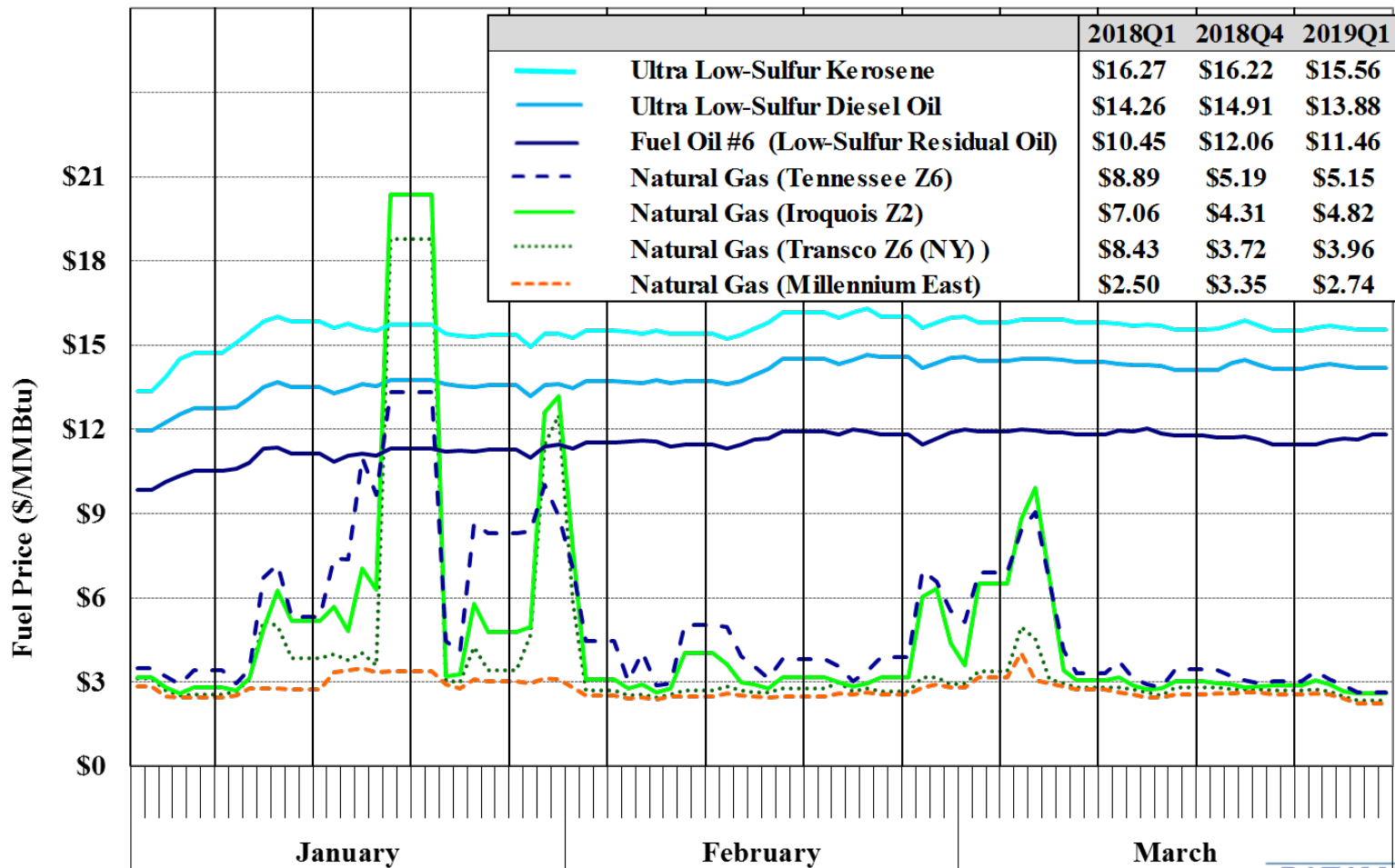


Load Forecast and Actual Load



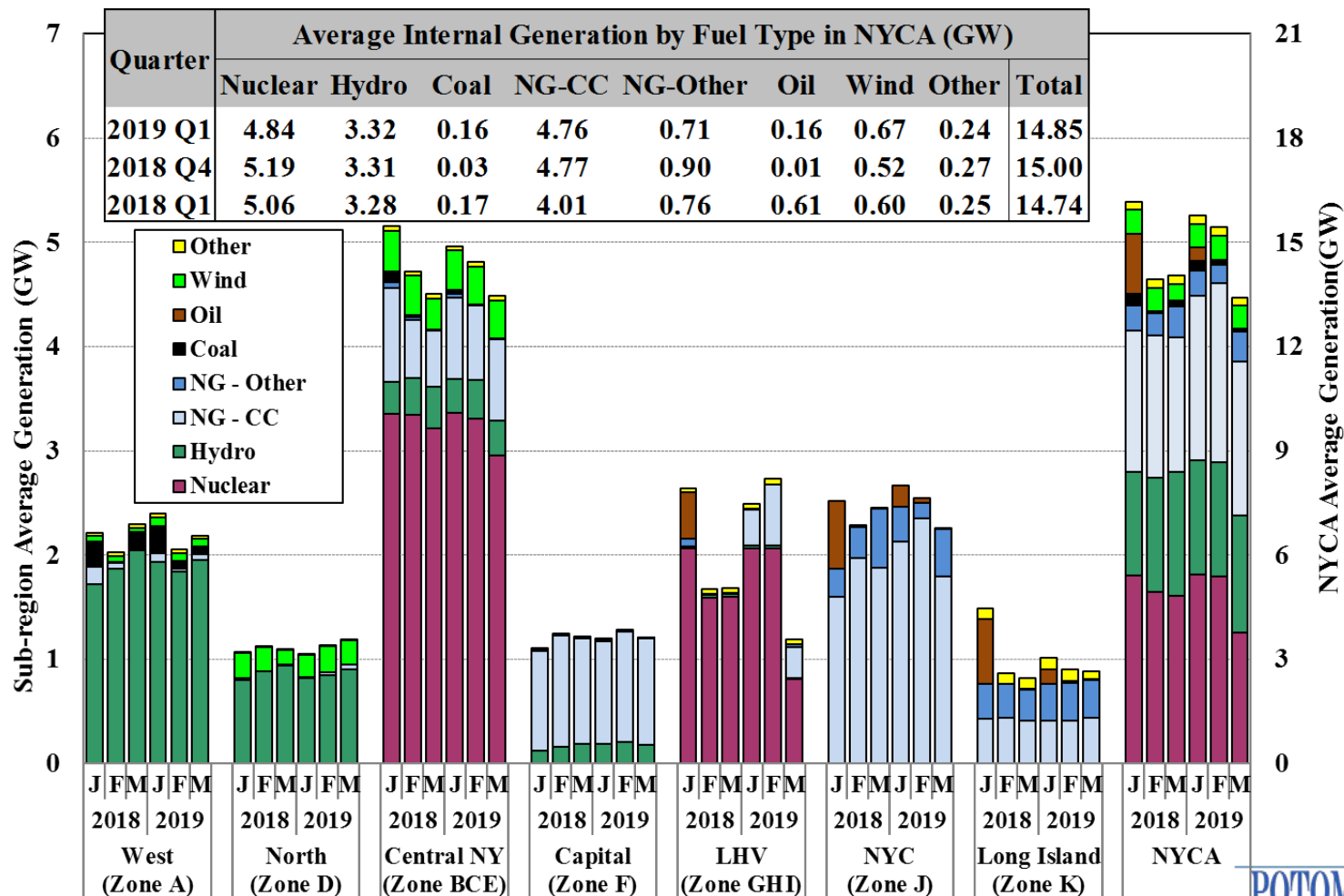


Natural Gas and Fuel Oil Prices



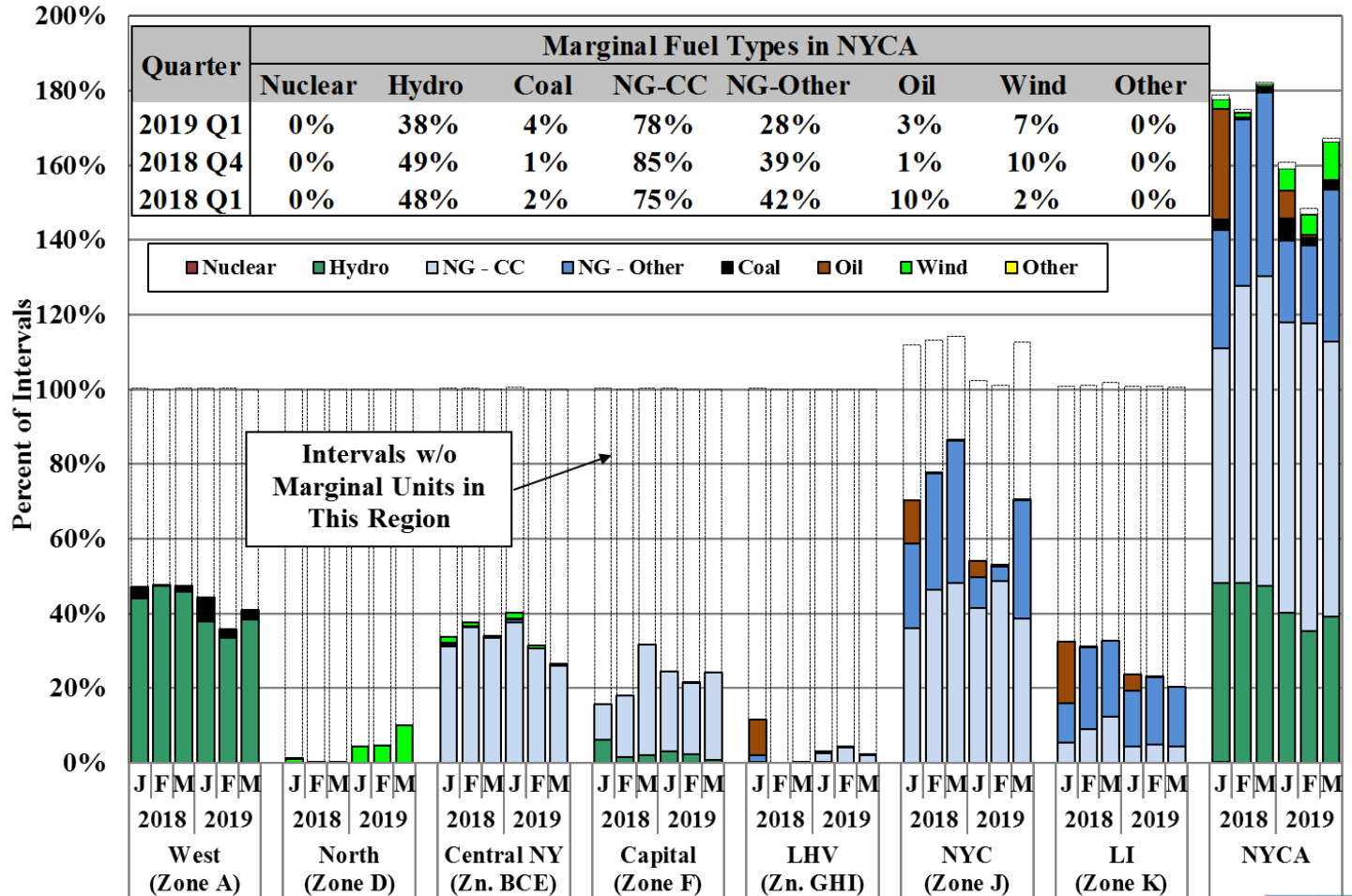


Real-Time Generation Output by Fuel Type

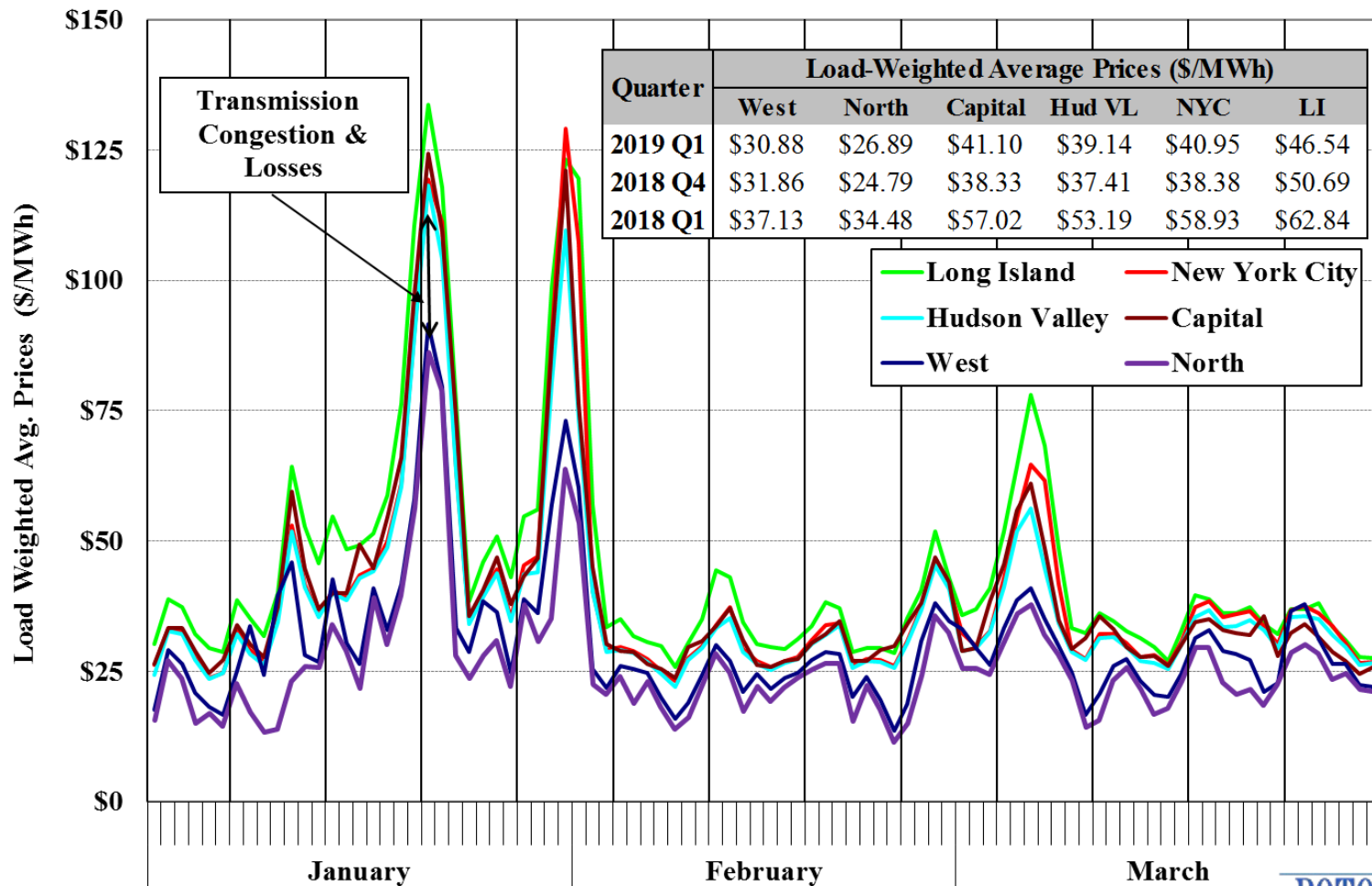




Fuel Type of Marginal Units in the Real-Time Market

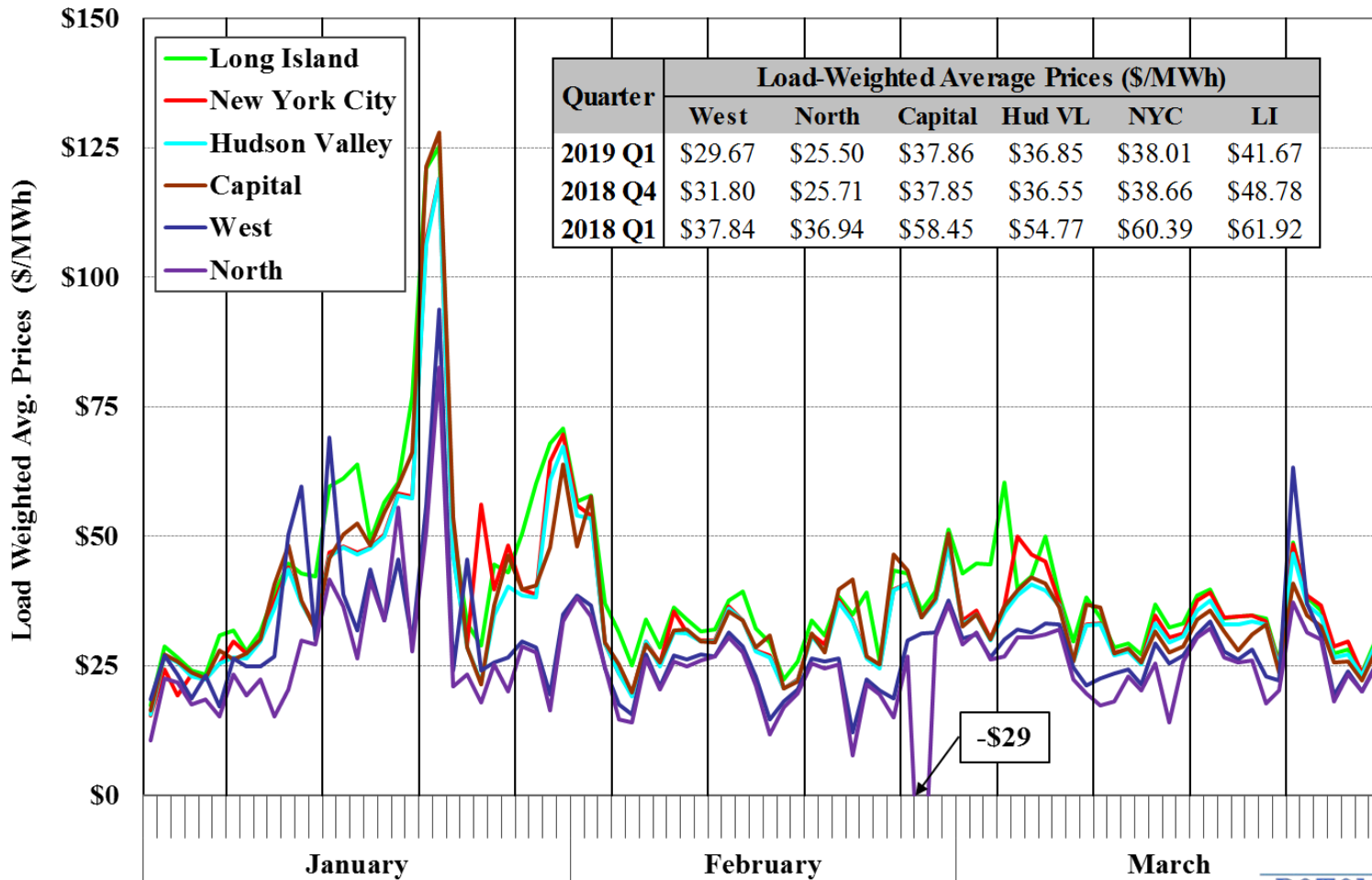


Day-Ahead Electricity Prices by Zone



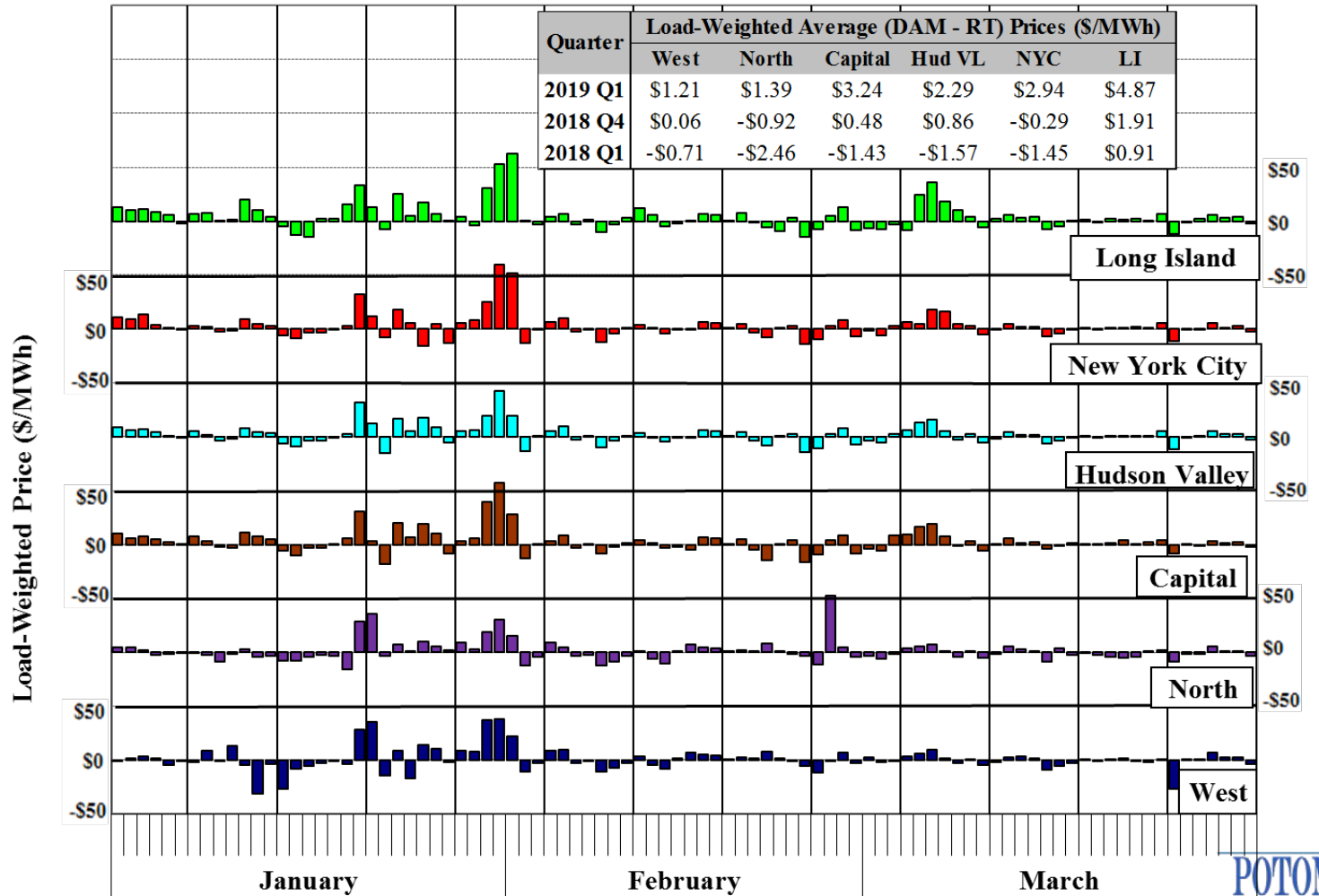


Real-Time Electricity Prices by Zone



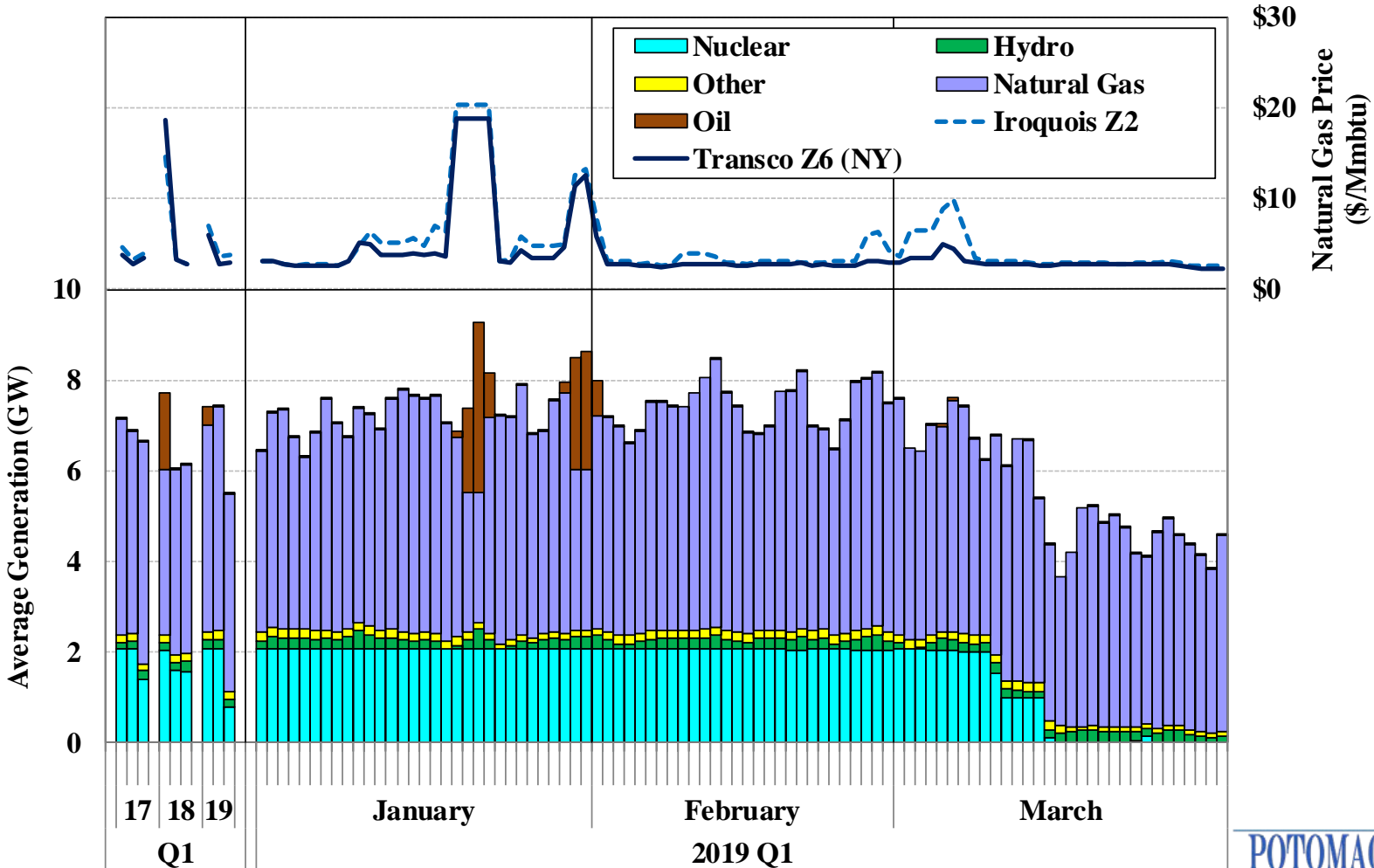


Convergence Between Day-Ahead and Real-Time Prices





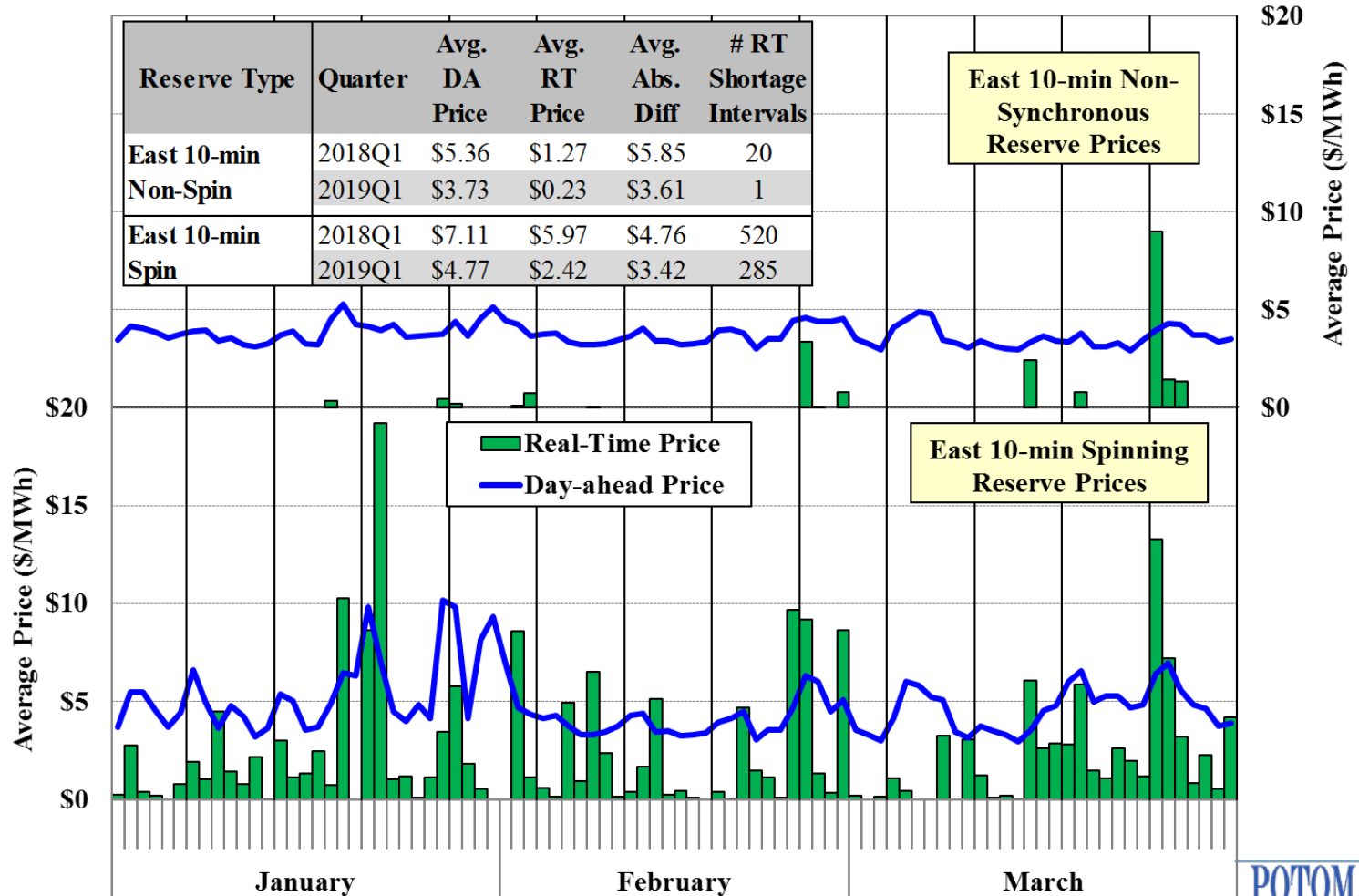
Winter Fuel Usage Eastern New York



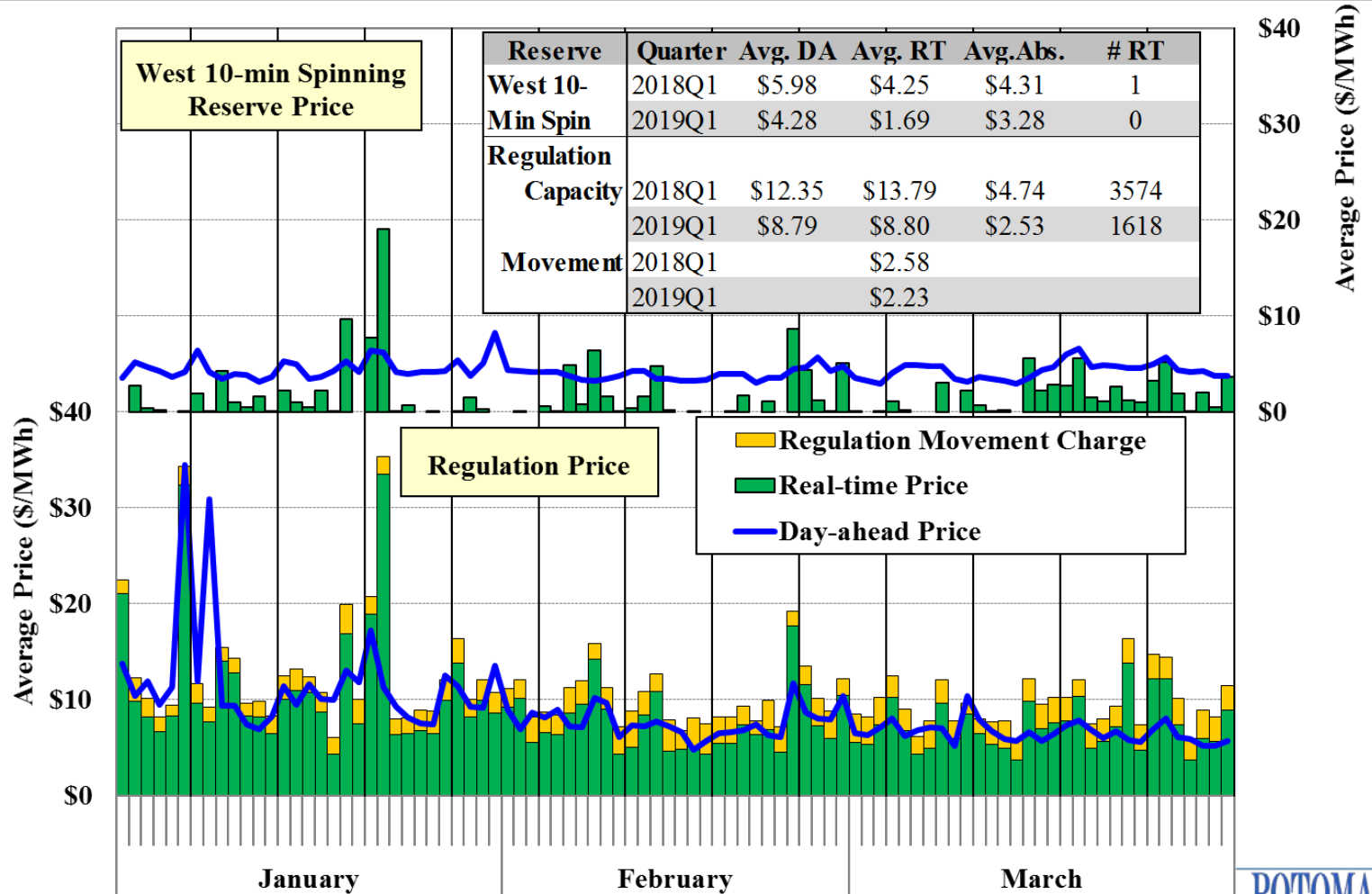


Charts: Ancillary Services Market

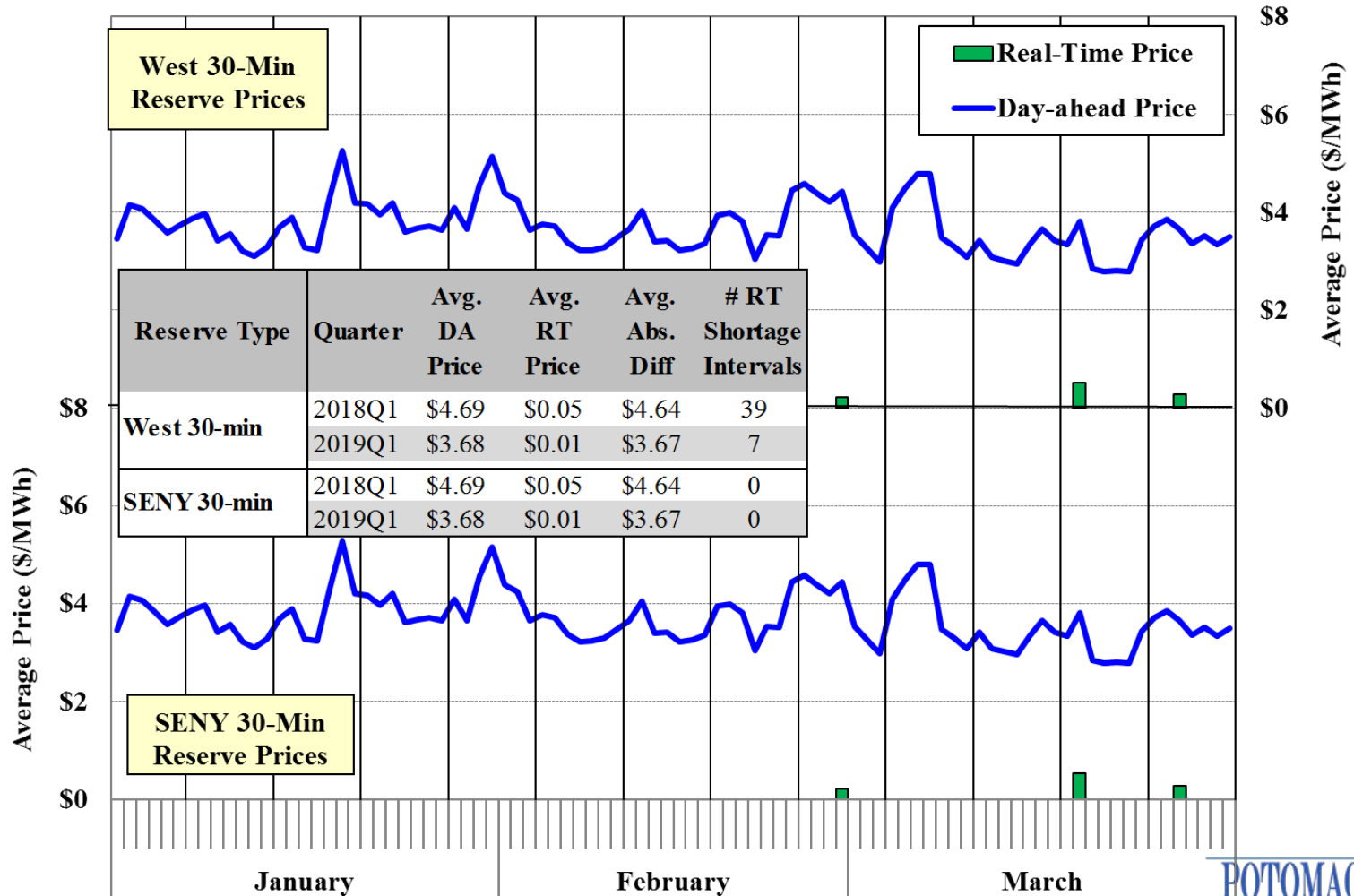
Day-Ahead and Real-Time Ancillary Services Prices Eastern 10-Minute Spinning and Non-Spinning Reserves



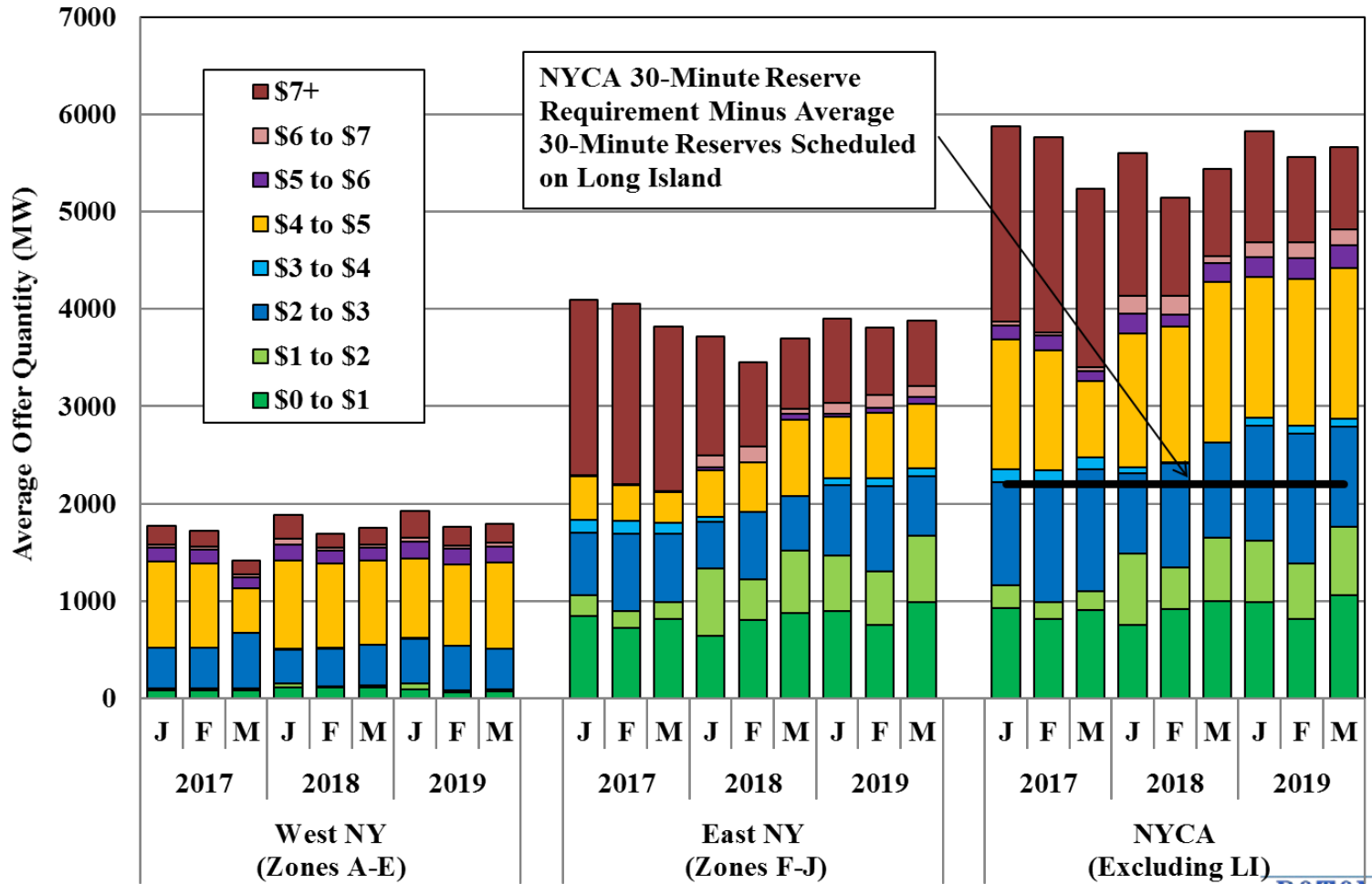
Day-Ahead and Real-Time Ancillary Services Prices Western 10-Minute Spinning Reserves and Regulation



Day-Ahead and Real-Time Ancillary Services Prices Western and SENY 30-Minute Reserves



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

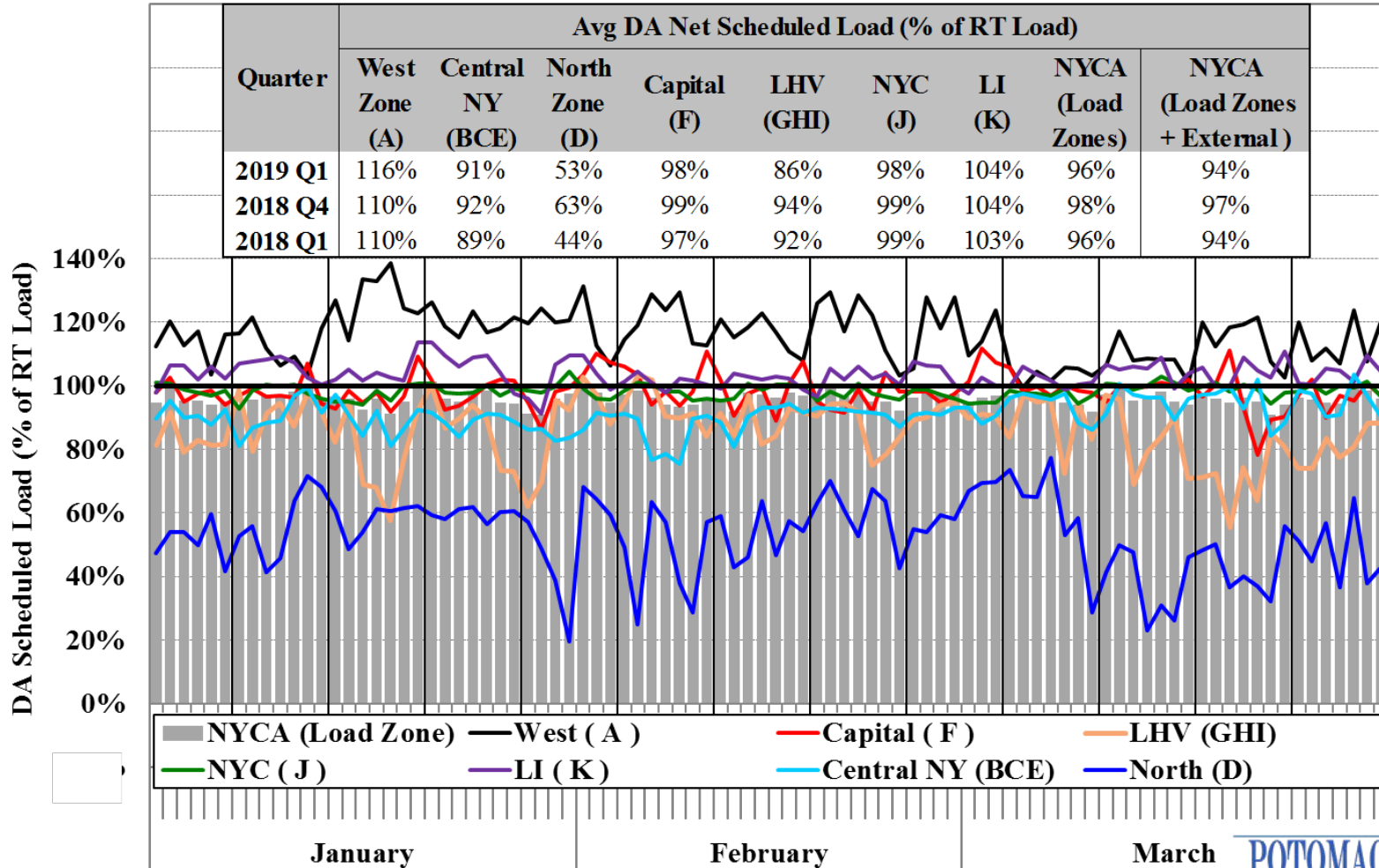




Charts: Energy Market Scheduling

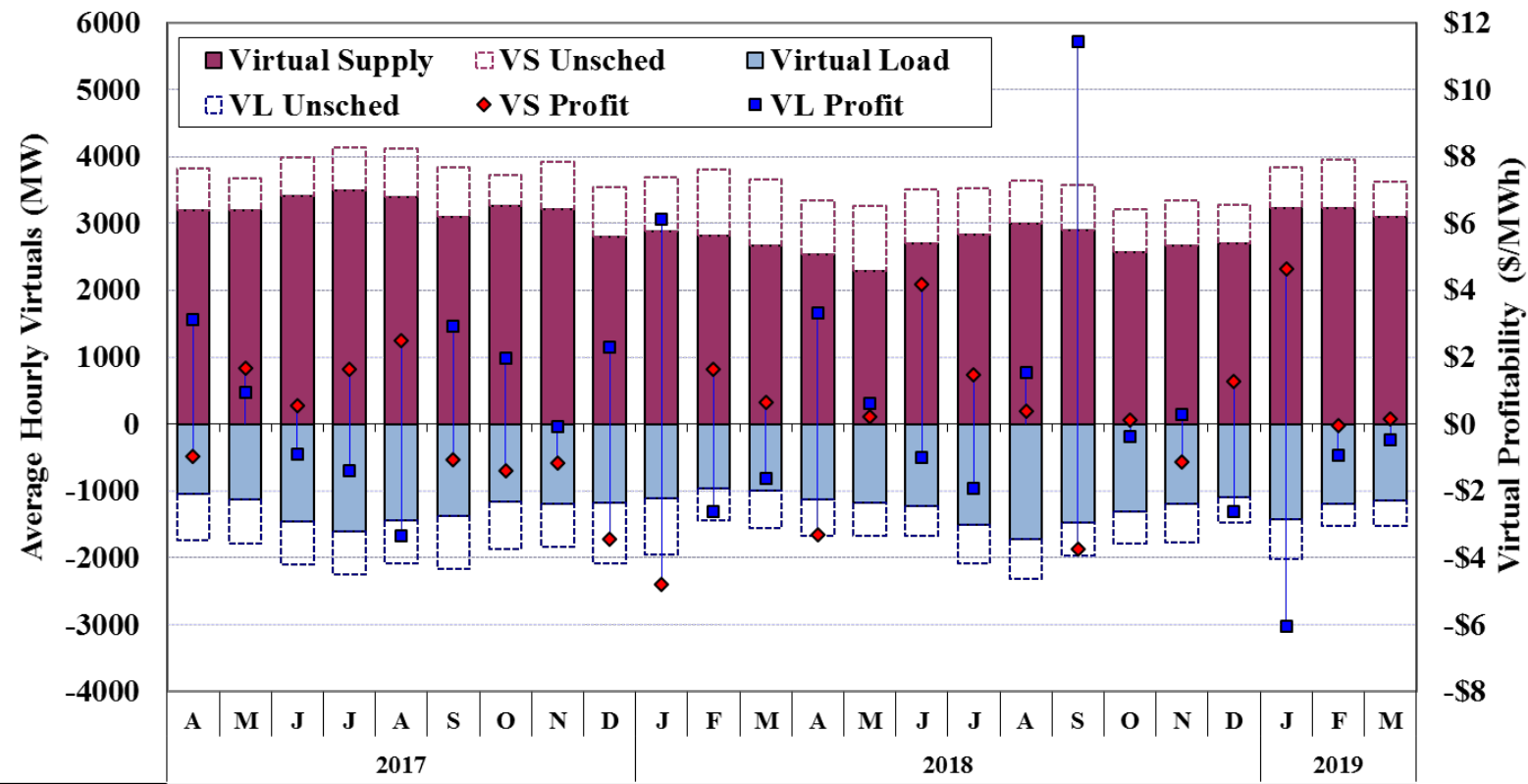


Day-ahead Scheduled Load and Actual Load Daily Peak Load Hour





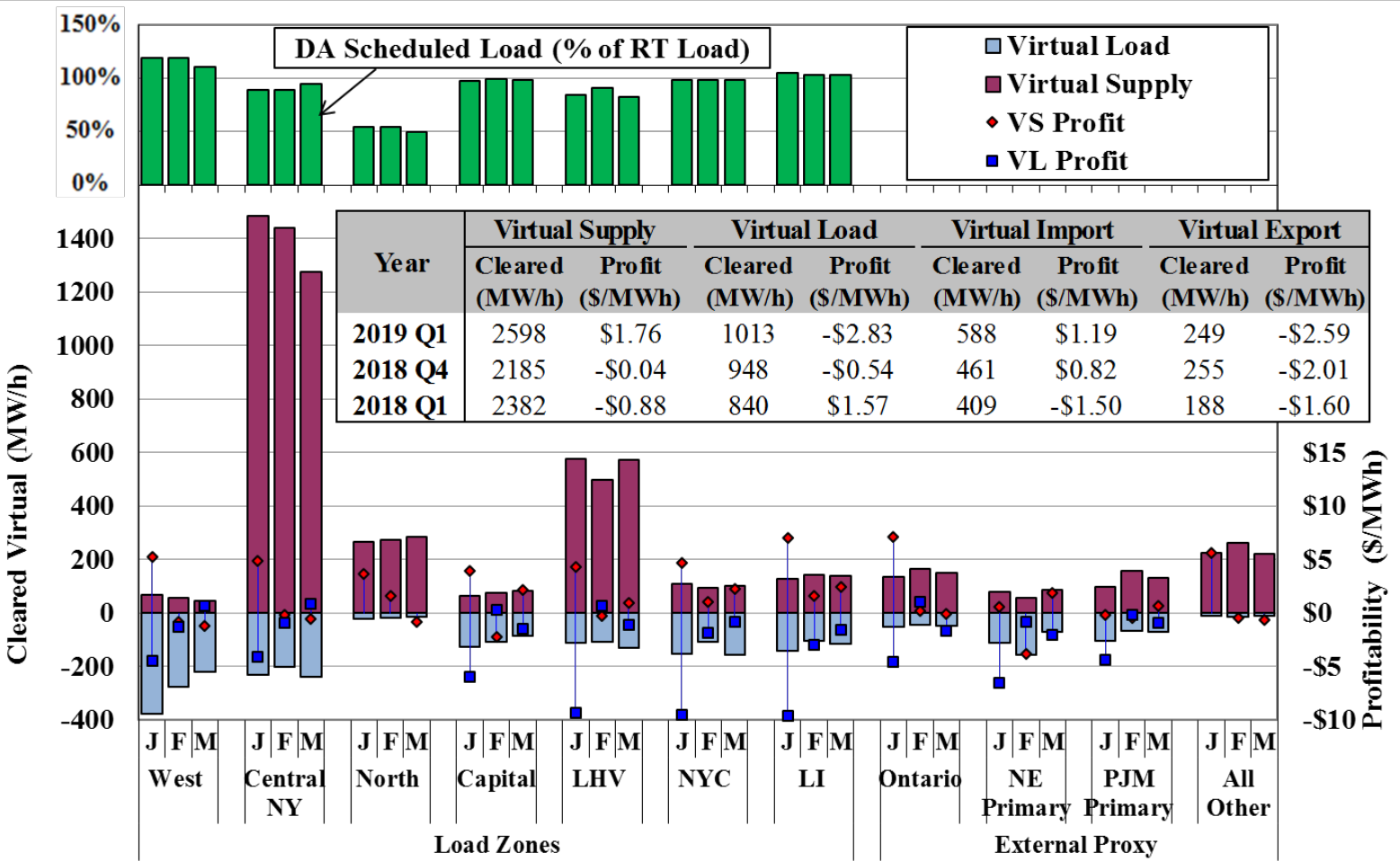
Virtual Trading Activity by Month



		2017												2018												2019		
		A	M	J	J	A	S	O	N	D	J	F	M	A	M	J	J	A	S	O	N	D	J	F	M			
Profit > 50% of Avg. Zone Price	MW	449	645	502	593	439	257	271	320	396	373	450	419	376	475	620	320	299	437	366	312	326	612	279	167			
	%	11%	15%	10%	12%	9%	6%	6%	7%	10%	9%	12%	11%	10%	14%	16%	7%	6%	10%	9%	8%	9%	13%	6%	4%			
Loss > 50% of Avg. Zone Price	MW	454	553	542	568	466	418	399	412	478	442	342	401	466	537	531	329	328	428	430	345	317	439	331	178			
	%	11%	13%	11%	11%	10%	9%	9%	9%	12%	11%	9%	11%	13%	16%	14%	8%	7%	10%	11%	9%	8%	9%	7%	4%			

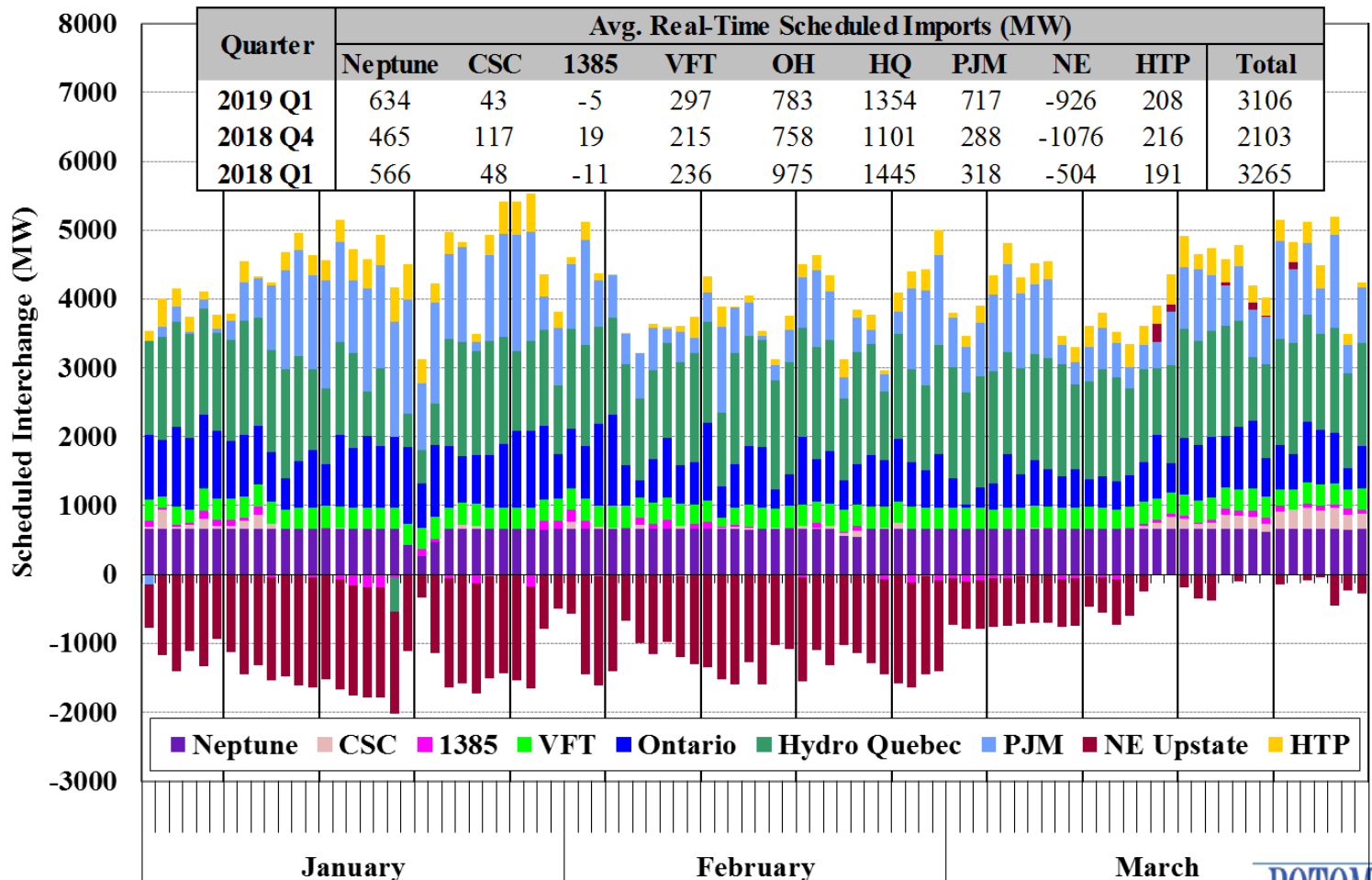


Virtual Trading Activity by Location



Notes: 1. Virtual profit is not shown for a category if the average scheduled quantity is less than 50 MW.
 2. For chart description, see slide [66](#).

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



Notes: Two HQ interfaces are combined into one.
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Efficiency of Intra-Hour Scheduling Under CTS

Primary PJM and NE Interfaces

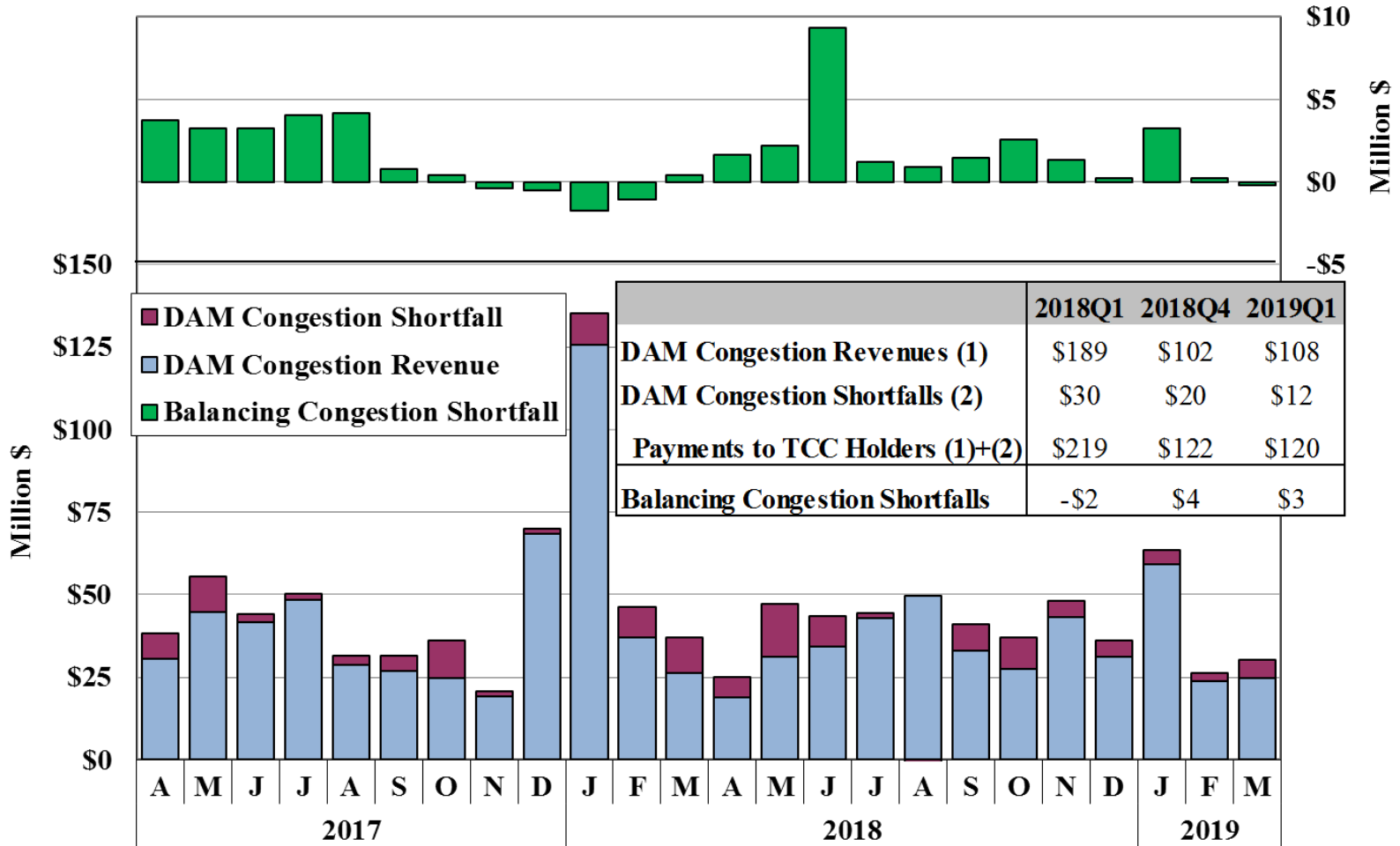
			Average/Total During Intervals w/ Adjustment					
			CTS - NY/NE			CTS - NY/PJM		
			Both Forecast Errors <= \$20	Any Forecast Error > \$20	Total	Both Forecast Errors <= \$20	Any Forecast Error > \$20	Total
% of All Intervals w/ Adjustment			65%	11%	75%	63%	11%	74%
Average Flow Adjustment (MW)	Net Imports		4	-6	3	19	-16	14
	Gross		100	124	103	86	118	91
Production Cost Savings (\$ Million)	Projected at Scheduling Time		\$1.0	\$0.5	\$1.5	\$0.5	\$1.0	\$1.4
	Net Over-Projection by:	NY	-\$0.02	-\$0.1	-\$0.1	-\$0.1	-\$0.1	-\$0.2
		NE or PJM	\$0.05	\$0.04	\$0.1	-\$0.1	-\$1.2	-\$1.2
	Other Unrealized Savings		-\$0.02	-\$0.04	-\$0.1	-\$0.03	-\$0.1	-\$0.1
Actual Savings		\$1.0	\$0.4	\$1.4	\$0.3	-\$0.4	-\$0.1	
Interface Prices (\$/MWh)	NY	Actual	\$30.75	\$66.64	\$35.78	\$27.54	\$54.93	\$31.51
		Forecast	\$31.87	\$58.52	\$35.61	\$28.65	\$50.28	\$31.79
	NE or PJM	Actual	\$31.43	\$83.13	\$38.67	\$25.96	\$59.84	\$30.87
		Forecast	\$30.26	\$53.04	\$33.45	\$27.17	\$71.99	\$33.66
Price Forecast Errors (\$/MWh)	NY	Fcst. - Act.	\$1.13	-\$8.11	-\$0.17	\$1.11	-\$4.65	\$0.27
		Abs. Val.	\$3.78	\$35.21	\$8.18	\$3.35	\$25.20	\$6.52
	NE or PJM	Fcst. - Act.	-\$1.18	-\$30.08	-\$5.23	\$1.21	\$12.15	\$2.79
		Abs. Val.	\$4.05	\$39.20	\$8.98	\$2.93	\$68.53	\$12.44



Charts: Transmission Congestion Revenues and Shortfalls

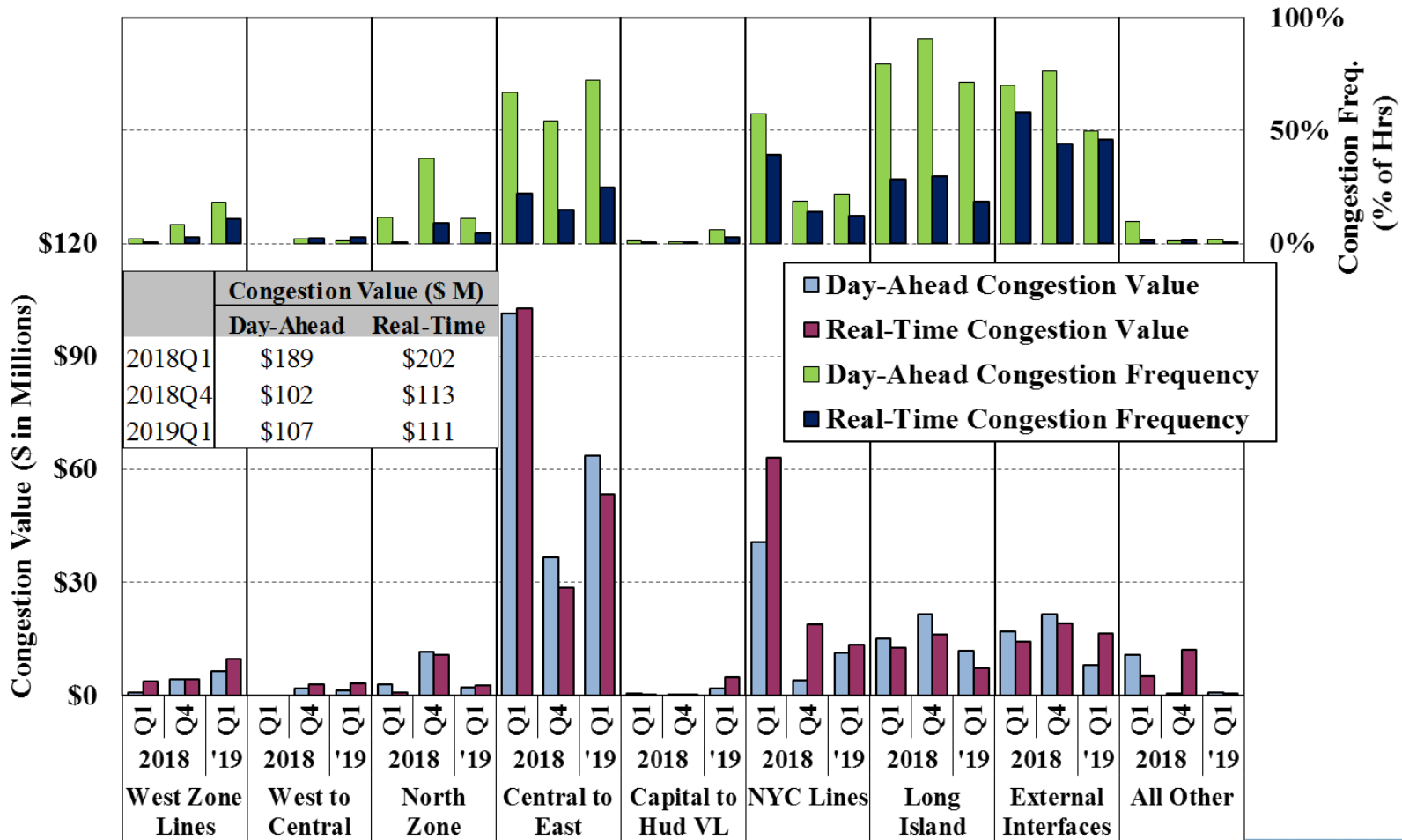


Congestion Revenues and Shortfalls by Month



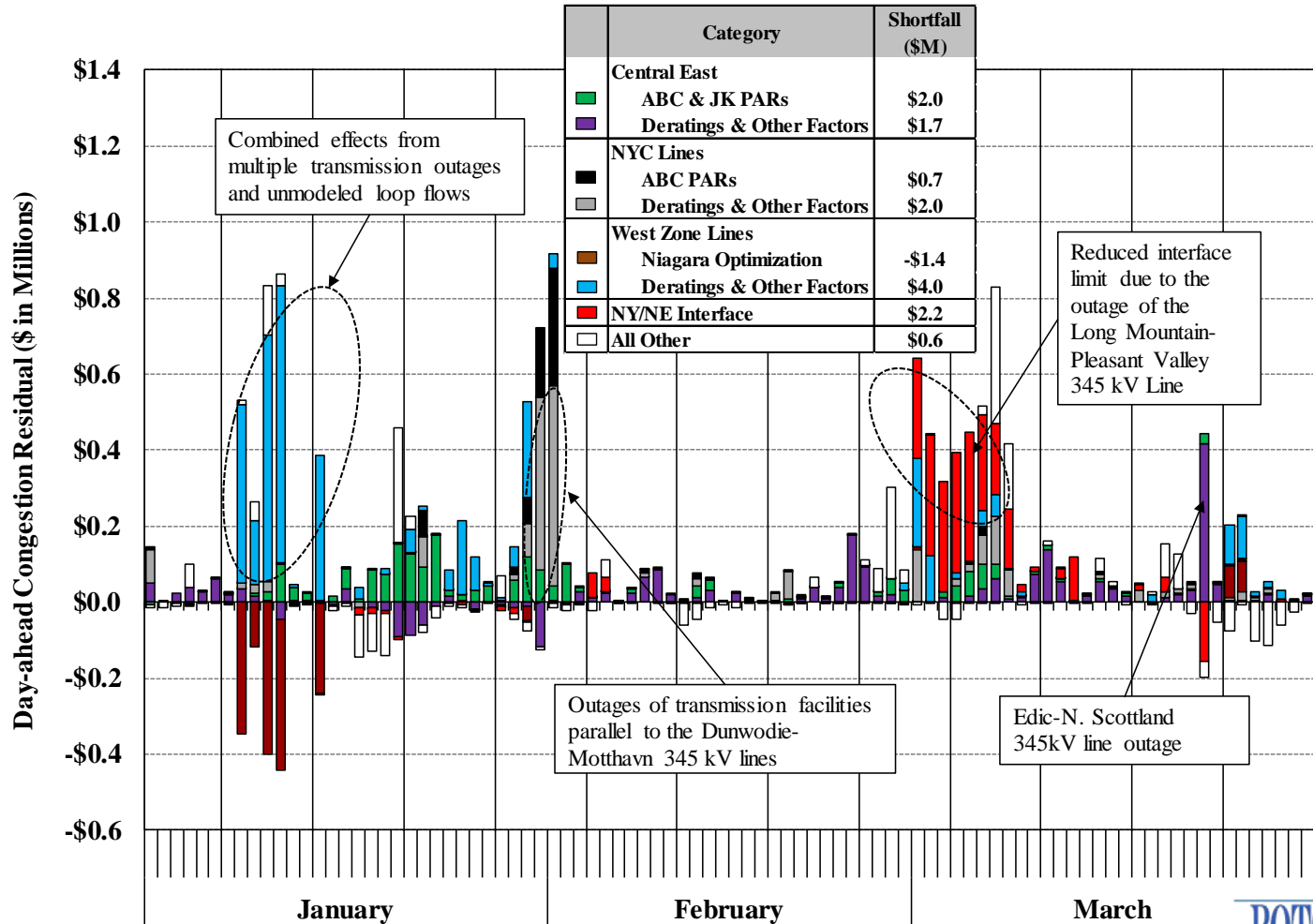


Day-Ahead and Real-Time Congestion Value by Transmission Path



Notes: For chart description, see slides [68](#), [69](#), and [70](#).

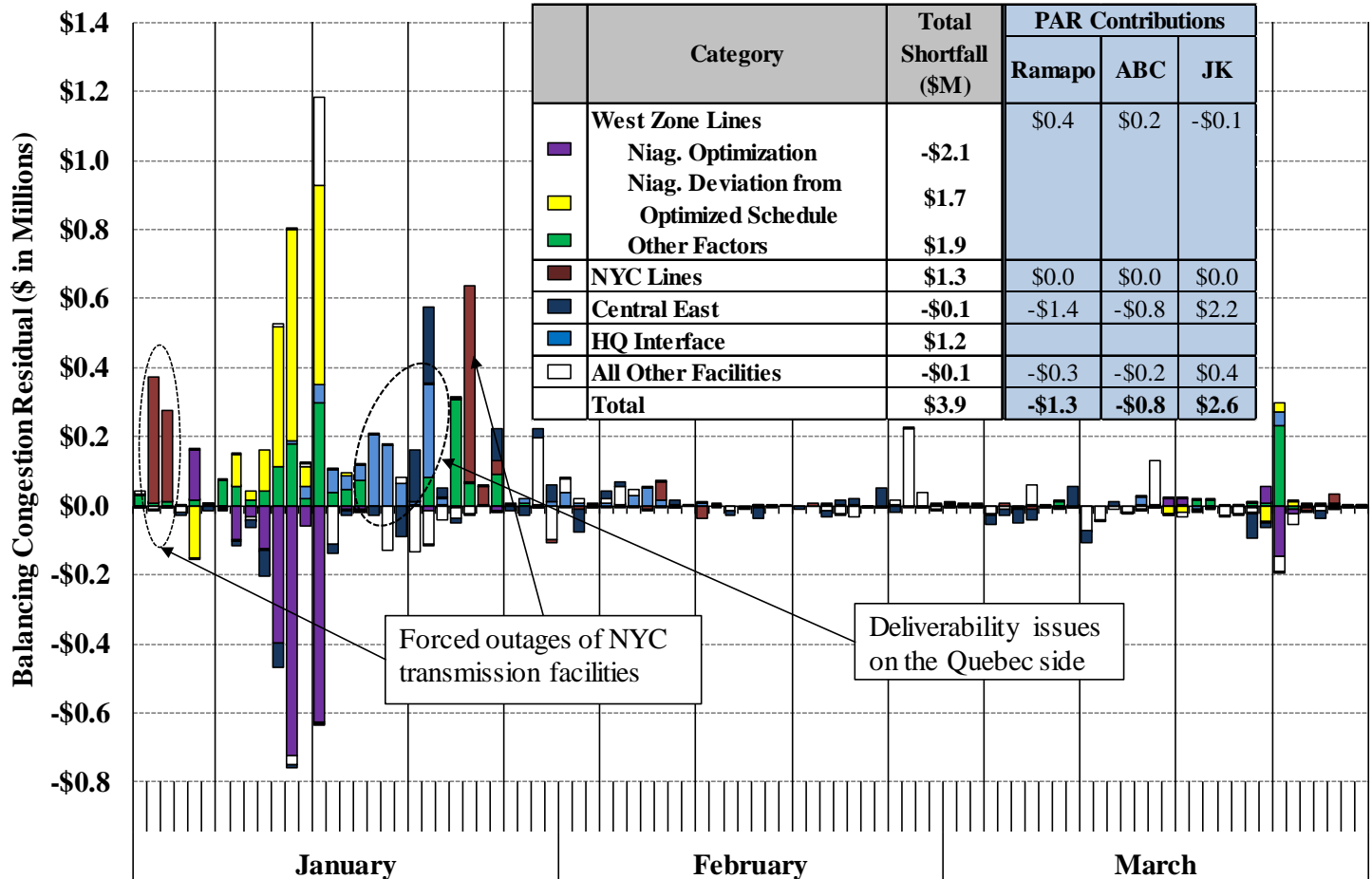
Day-Ahead Congestion Revenue Shortfalls by Transmission Facility



Notes: For chart description, see slides [68](#), [69](#), and [70](#).

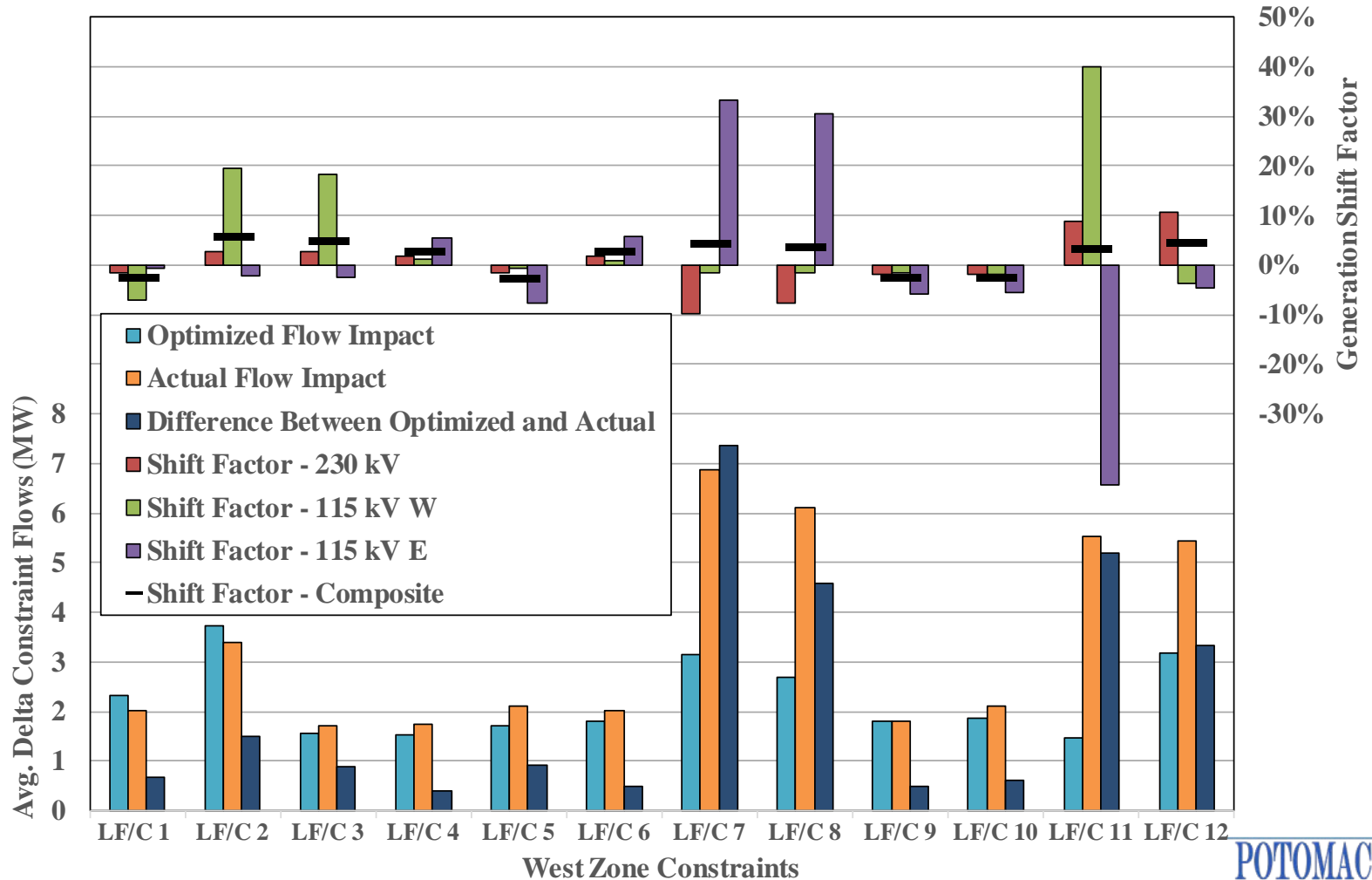


Balancing Congestion Shortfalls by Transmission Facility



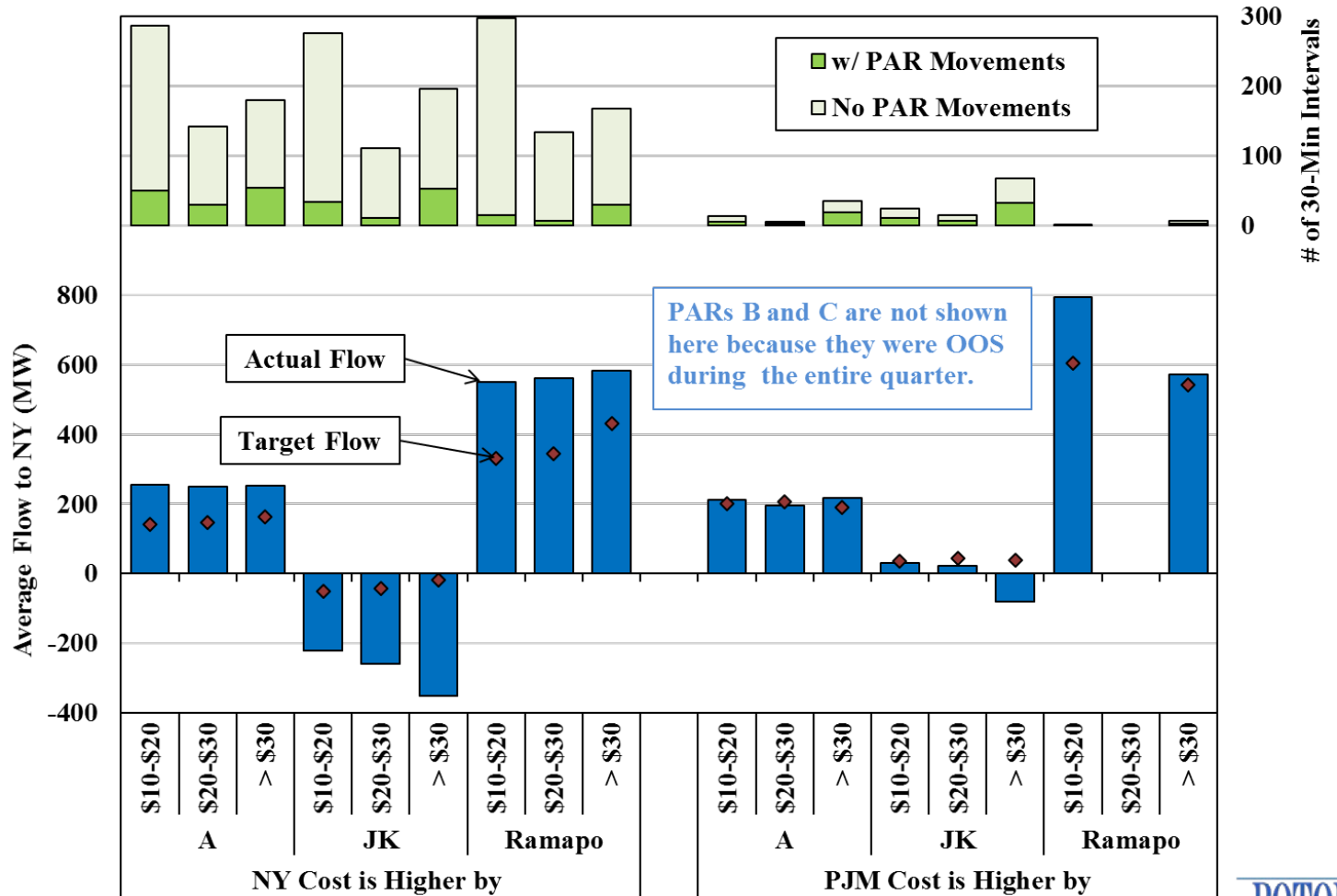
Notes: 1. The BMCR estimated above may differ from actual BMCR because the figure is partly based on real-time schedules rather than metered values. 2. For chart description, see slides [68](#), [69](#), and [70](#).

West Zone Congestion and Niagara Generation Modeling



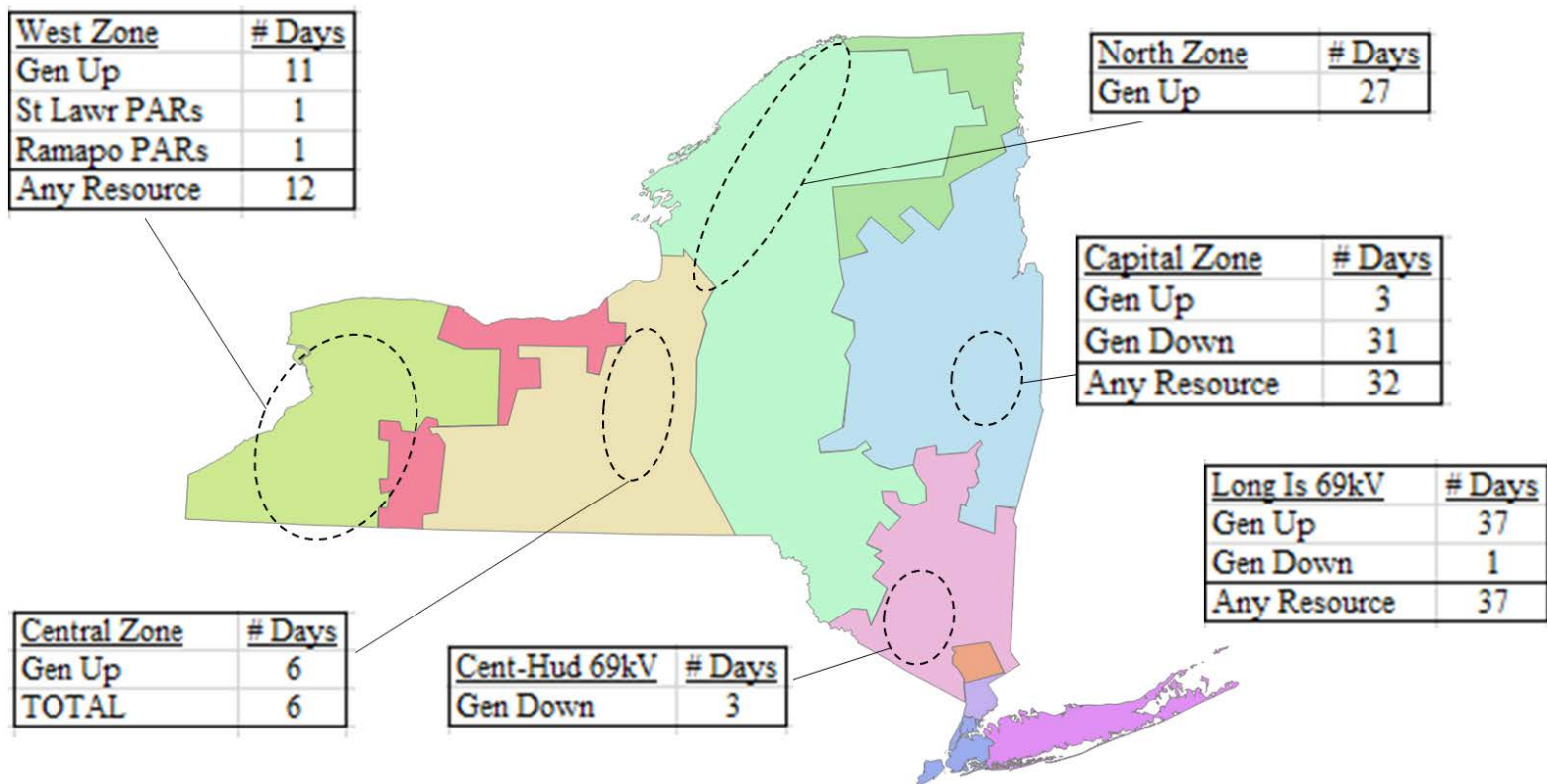


PAR Operation under M2M with PJM 2019 Q1





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

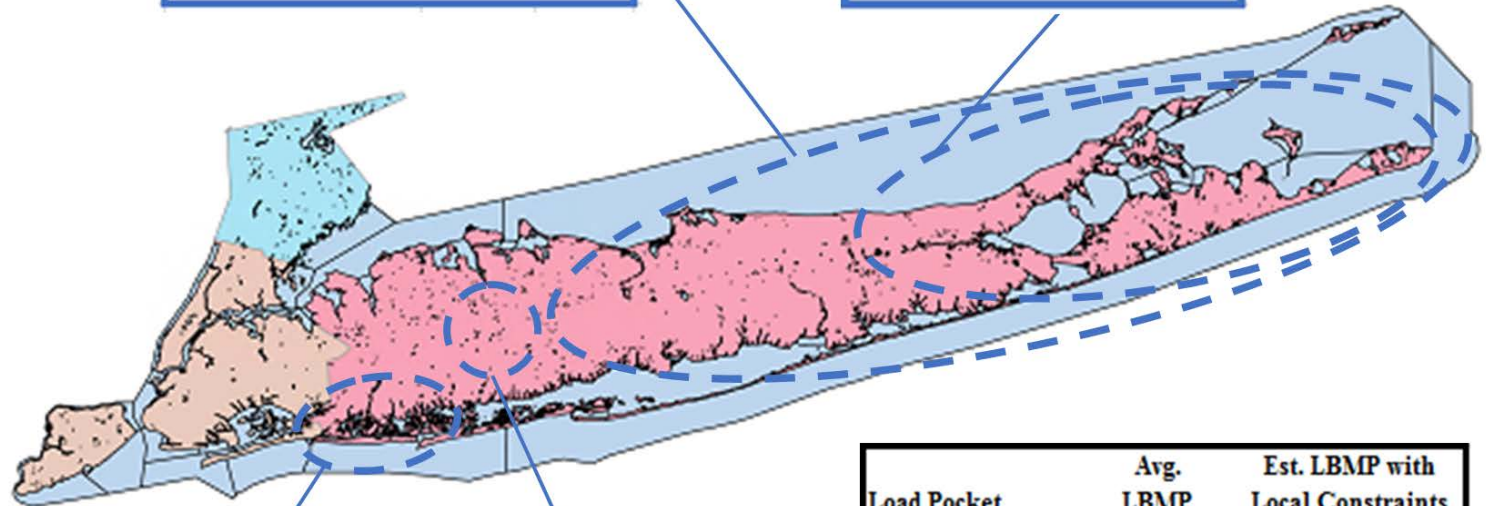


Notes: For chart description, see slides [73-74](#)

Constraints on the Low Voltage Network: Long Island Load Pockets [Note: Recalculating East End]

East of Northport	#Hours	#Days
69kV	599	26
138kV	106	8
TOTAL	705	34

East End	#Hours	#Days
69kV	44	6

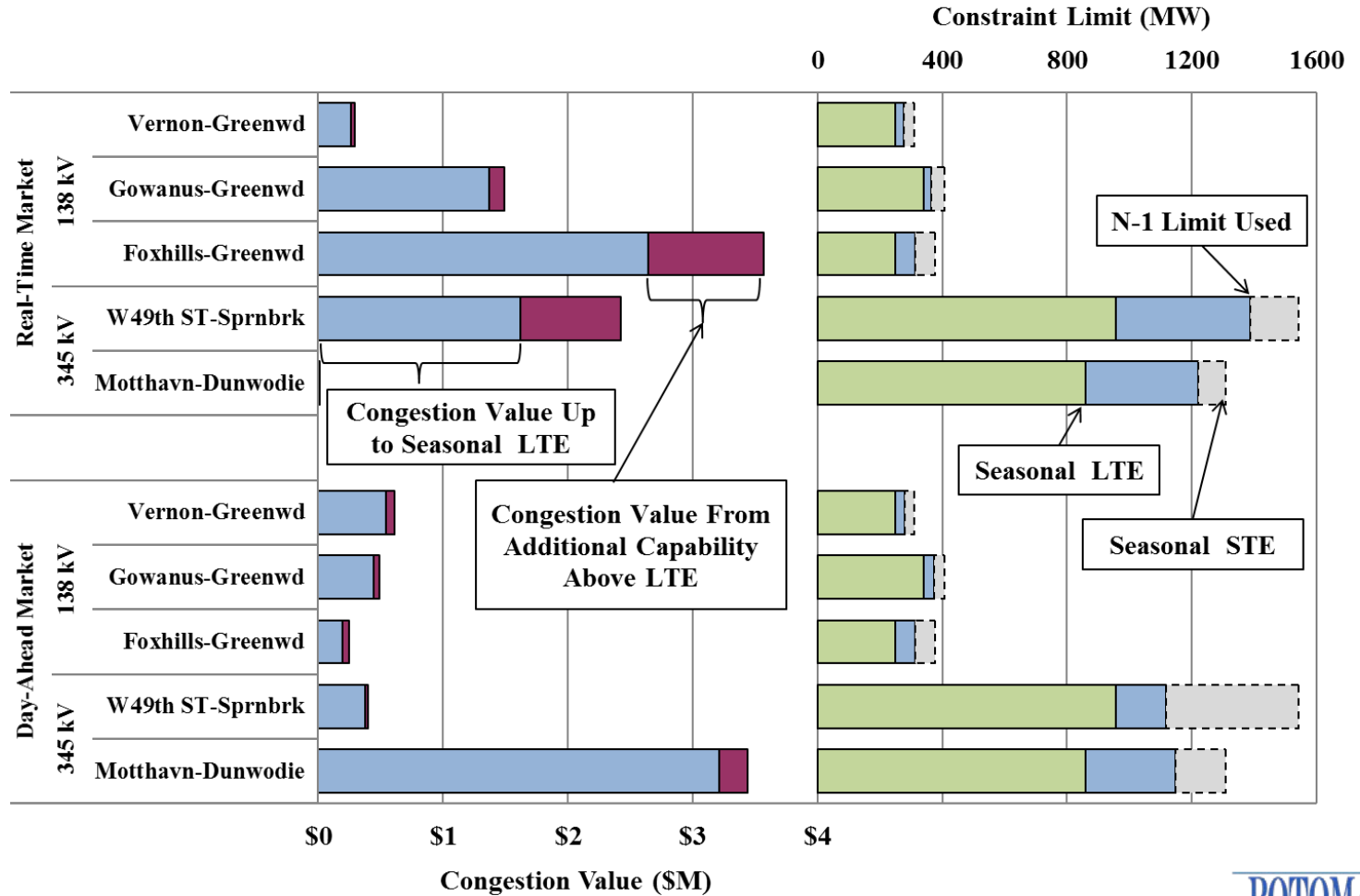


Valley Stream	#Hours	#Days
69kV	178	8
138kV	2087	89
TOTAL	2138	90

Brentwood	#Hours	#Days
69kV	14	1

Load Pocket	Avg. LBMP	Est. LBMP with Local Constraints
Brentwood	\$39.49	\$40.63
East End	\$42.34	\$43.70
East of Northport	\$39.67	\$46.79
Valley Stream	\$42.72	\$42.98

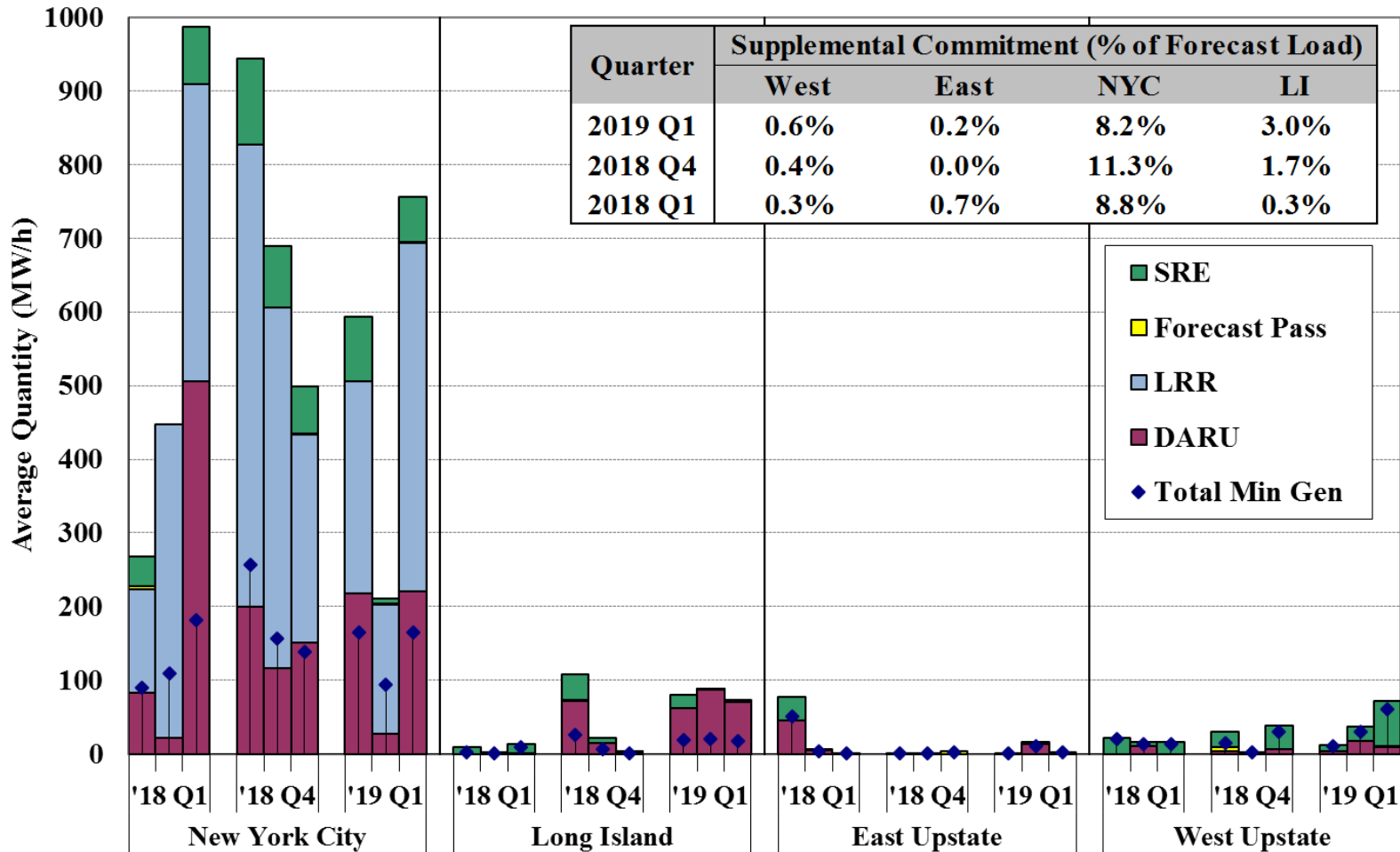
N-1 Constraints in New York City Limits Used vs Seasonal LTE Ratings





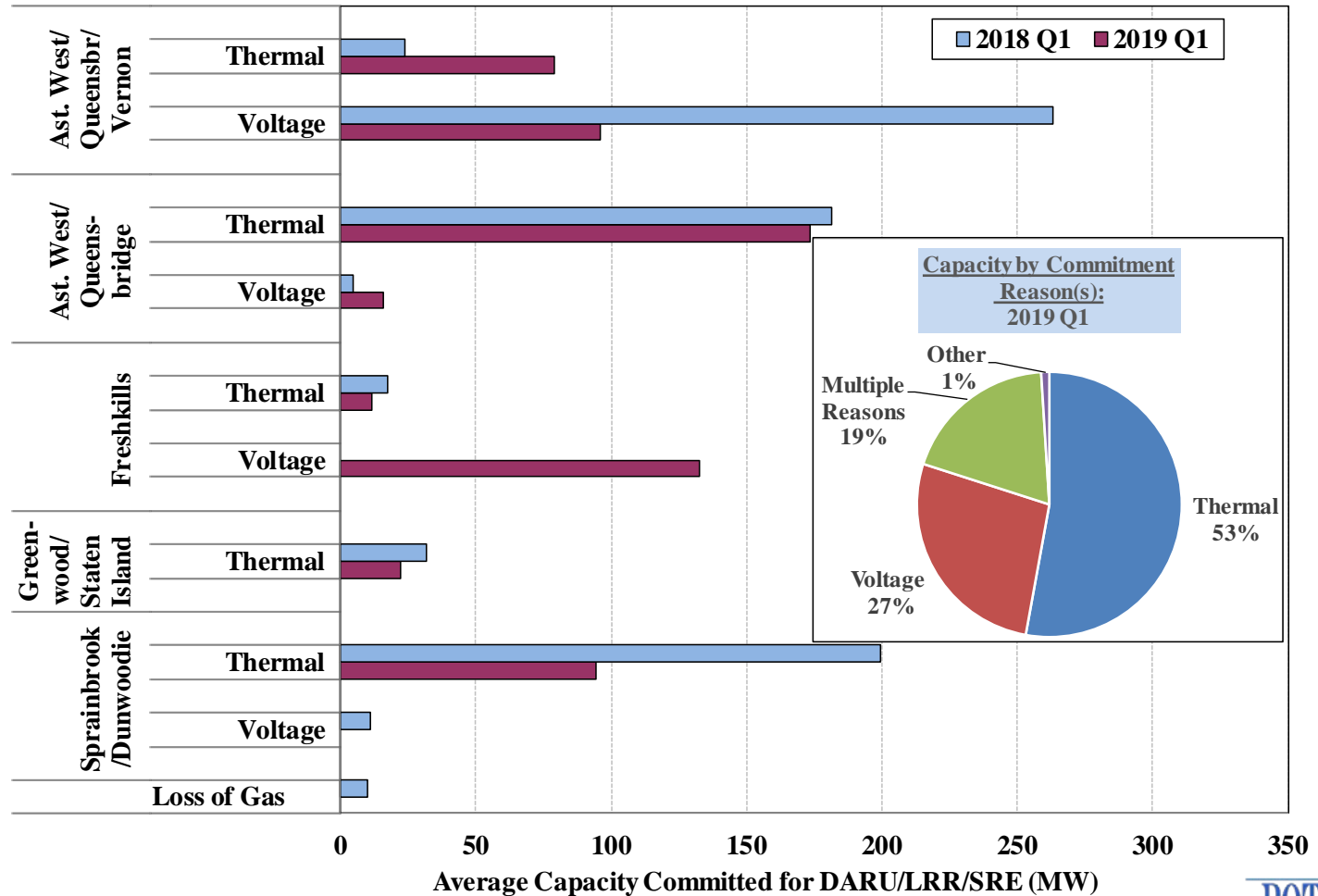
Charts:
**Supplemental Commitment, OOM Dispatch,
and BPCG Uplift**

Supplemental Commitment for Reliability by Category and Region



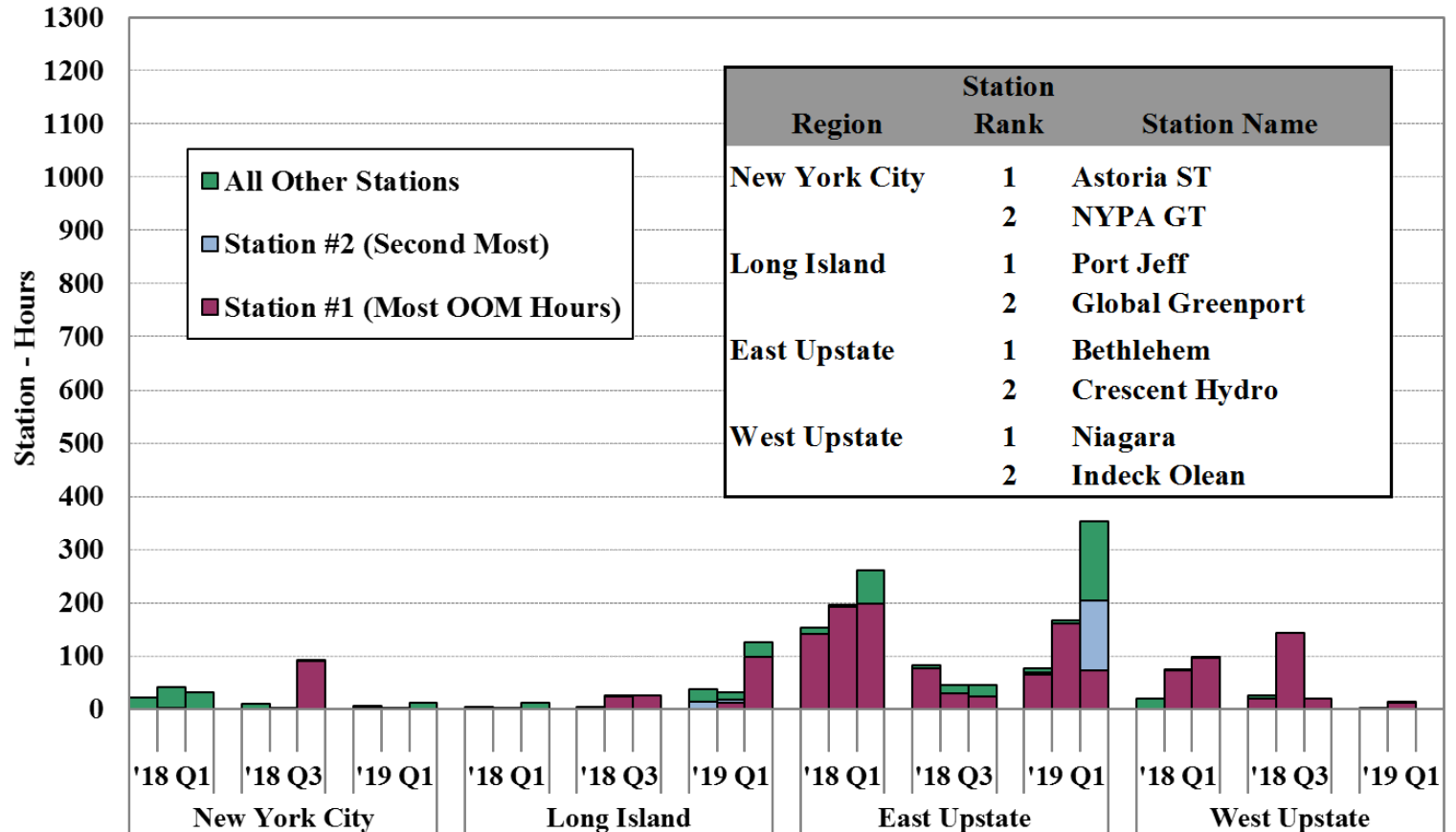
Notes: For chart description, see slides [76](#) and [77](#).

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



Notes: For chart description, see slides [76](#) and [77](#).

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

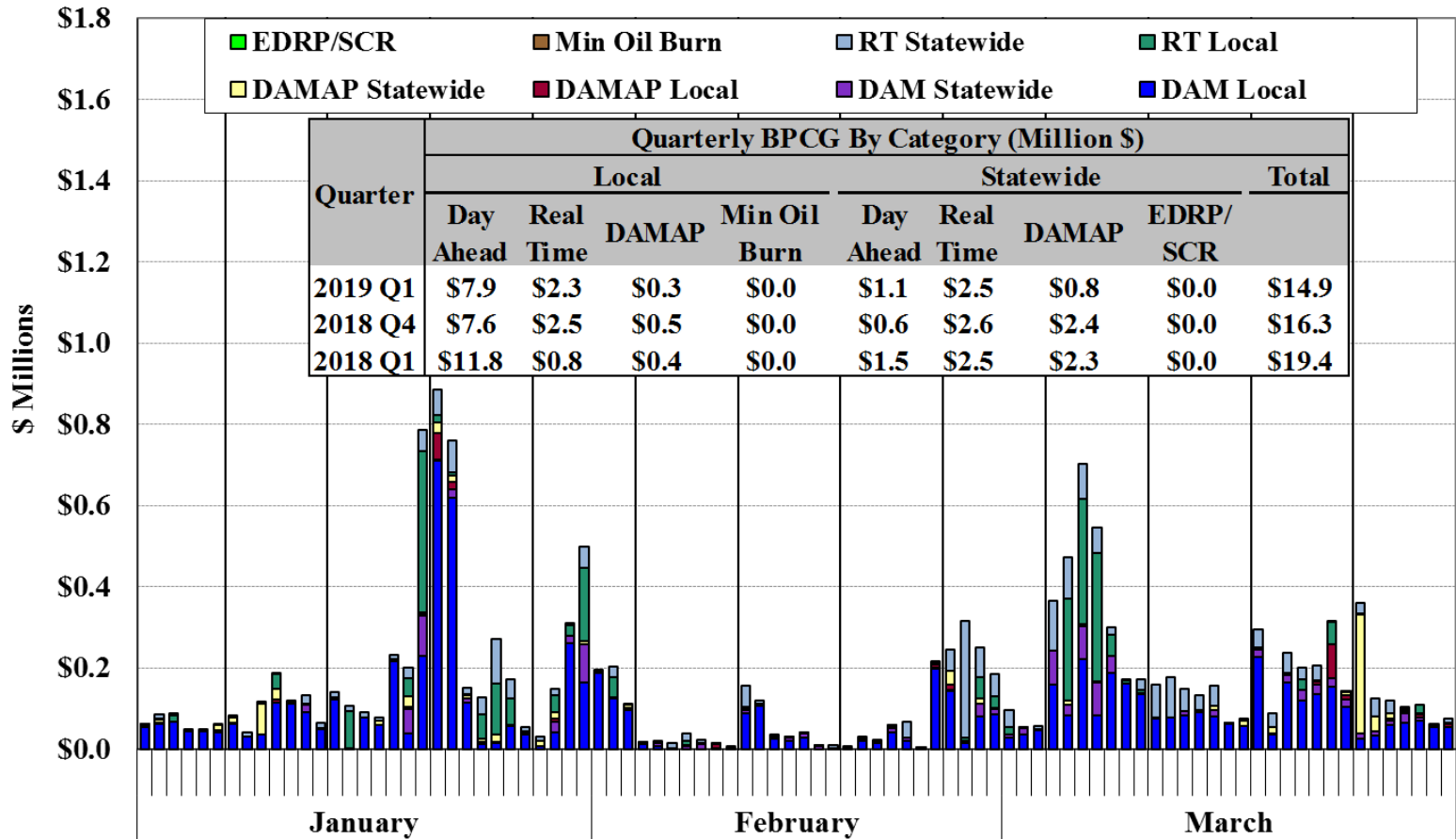


Notes: 1. The NYISO also instructed Niagara to shift output among the generators at the station in order to secure certain 115kV and/or 230kV transmission facilities in 247 hours in 2018-Q1, 496 hours in 2018-Q4, and 517 hours in 2019-Q1. However, these were not classified as Out-of-Merit in hours when the NYISO did not adjust the UOL or LOL of the Resource.

2. For chart description, see slides [76](#) and [77](#).



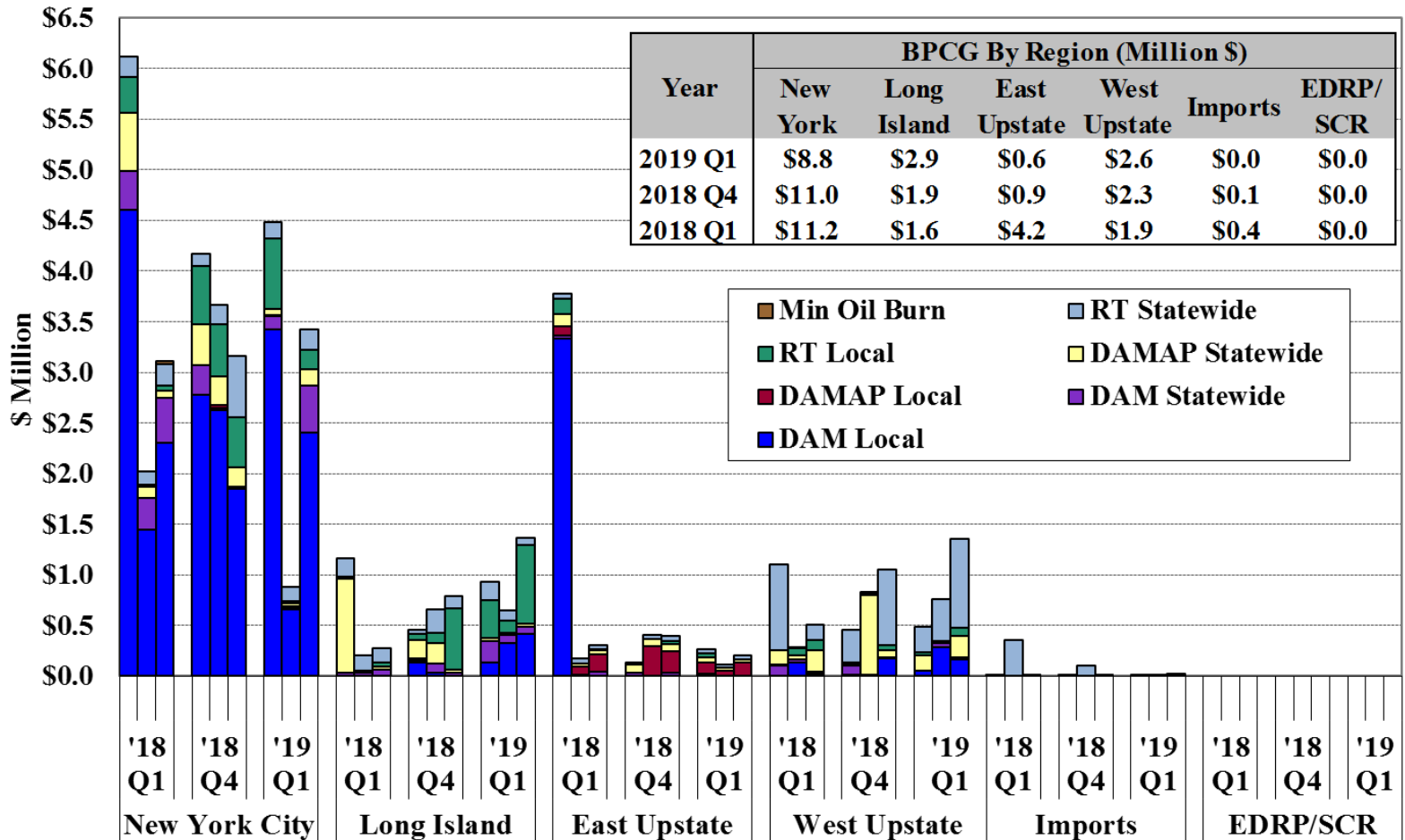
Uplift Costs from Guarantee Payments Local and Non-Local by Category



Notes: 1. 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.

2. For chart description, see slide [78](#).

Uplift Costs from Guarantee Payments By Category and Region



Notes: 1. BPCG data are based on information available at the reporting time that can be different from final settlements.

2. For chart description, see slide [78](#).

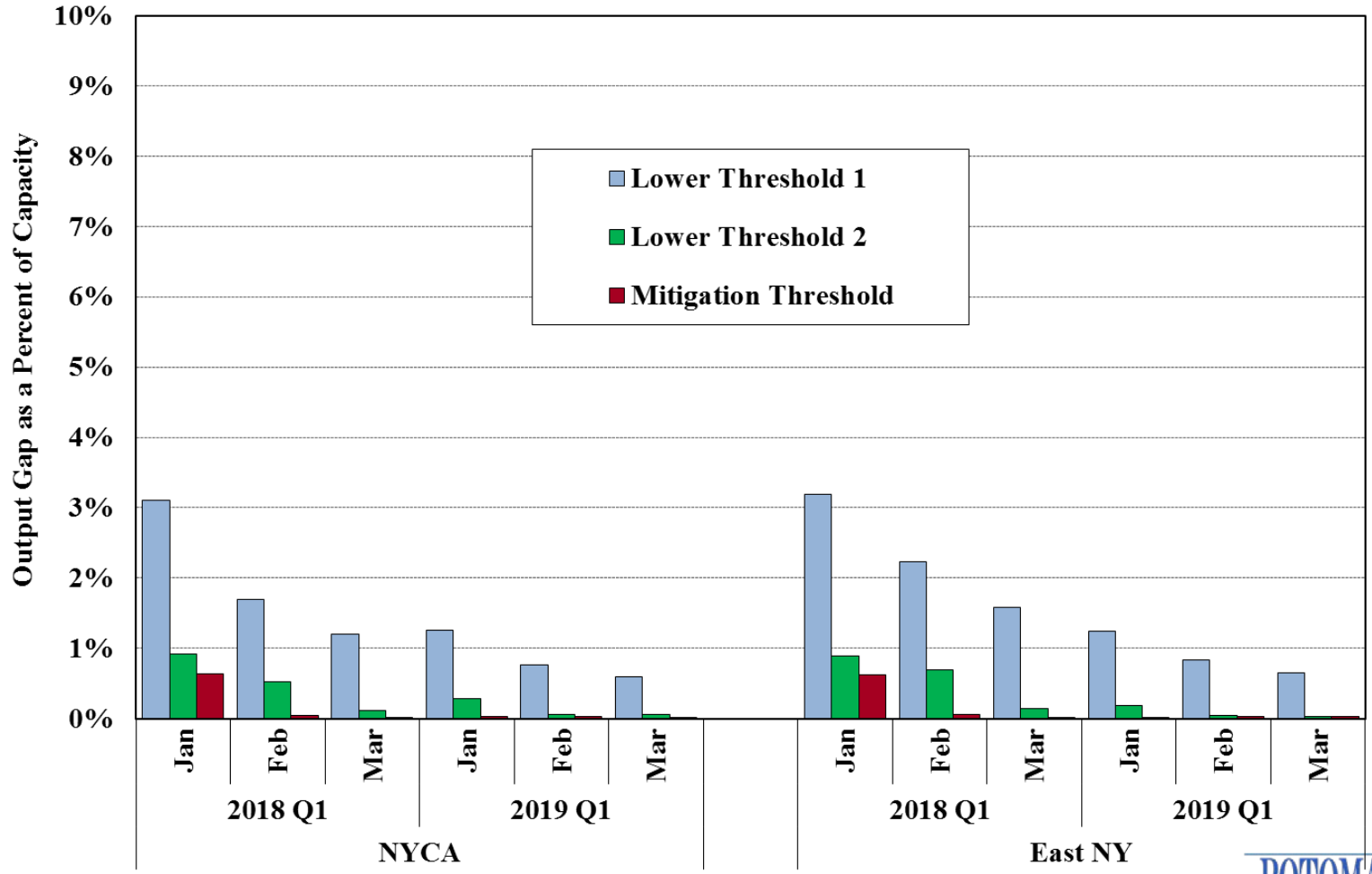


Charts: Market Power and Mitigation



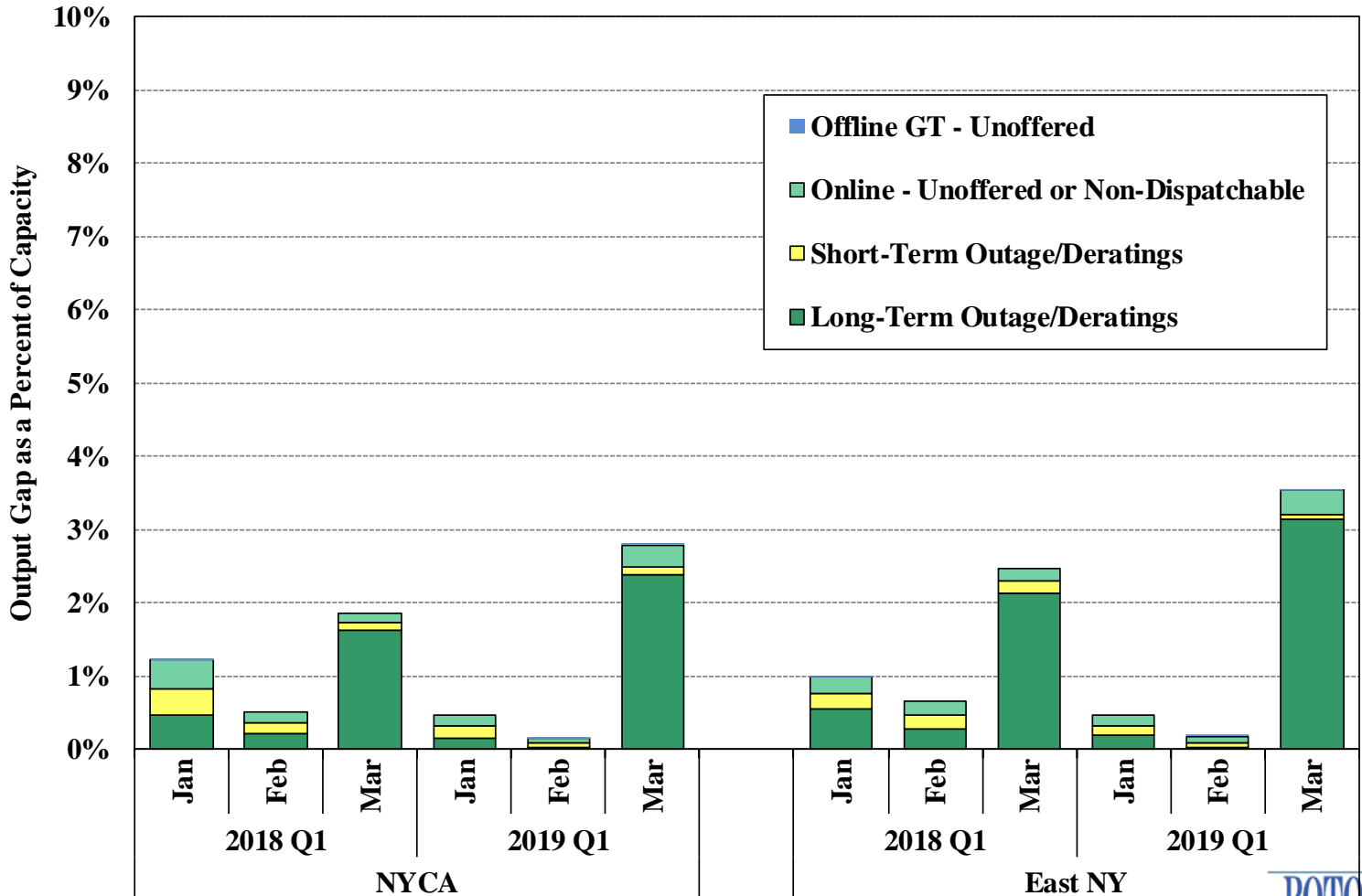
Output Gap by Month

NYCA and East NY

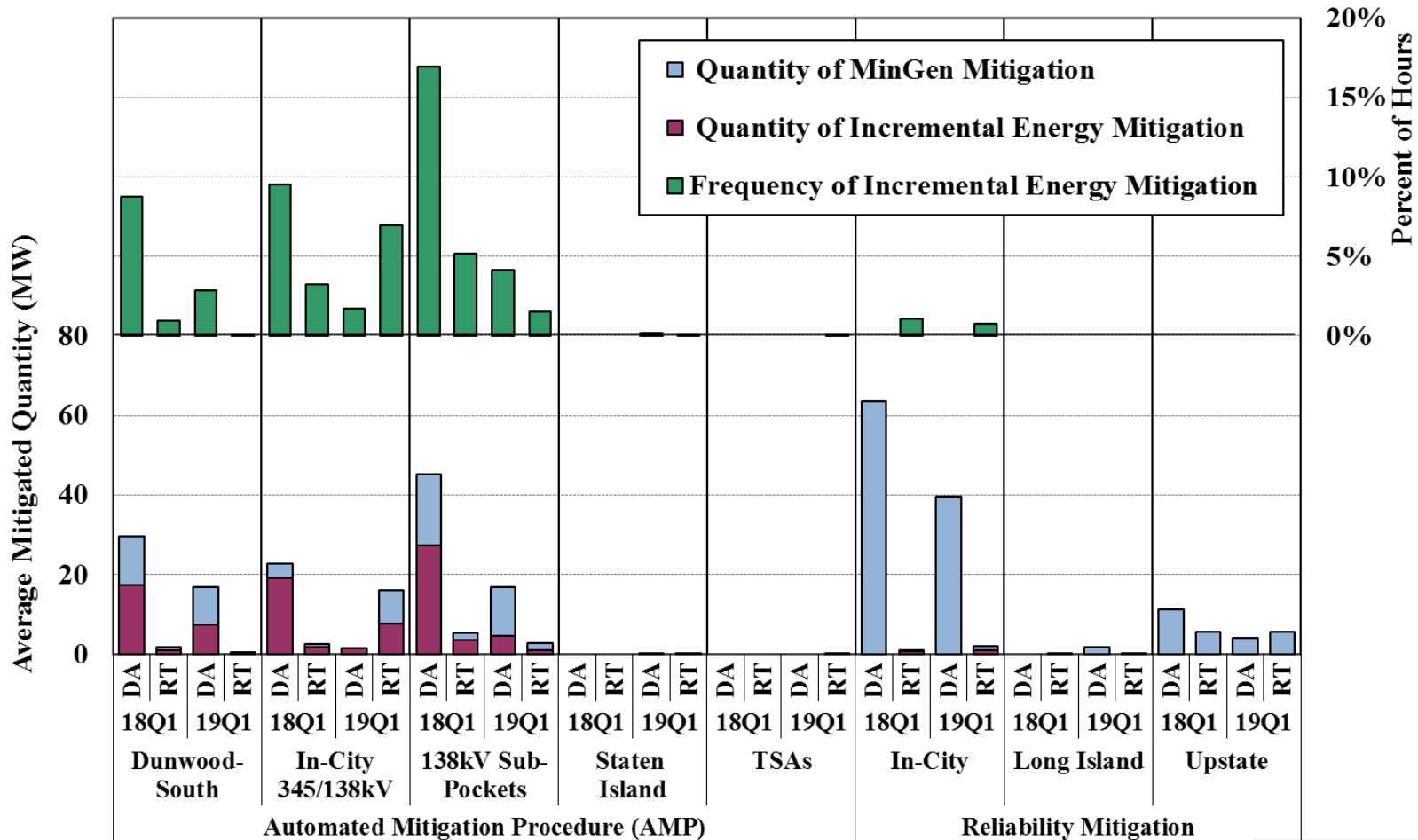


Unoffered Economic Capacity by Month

NYCA and East NY



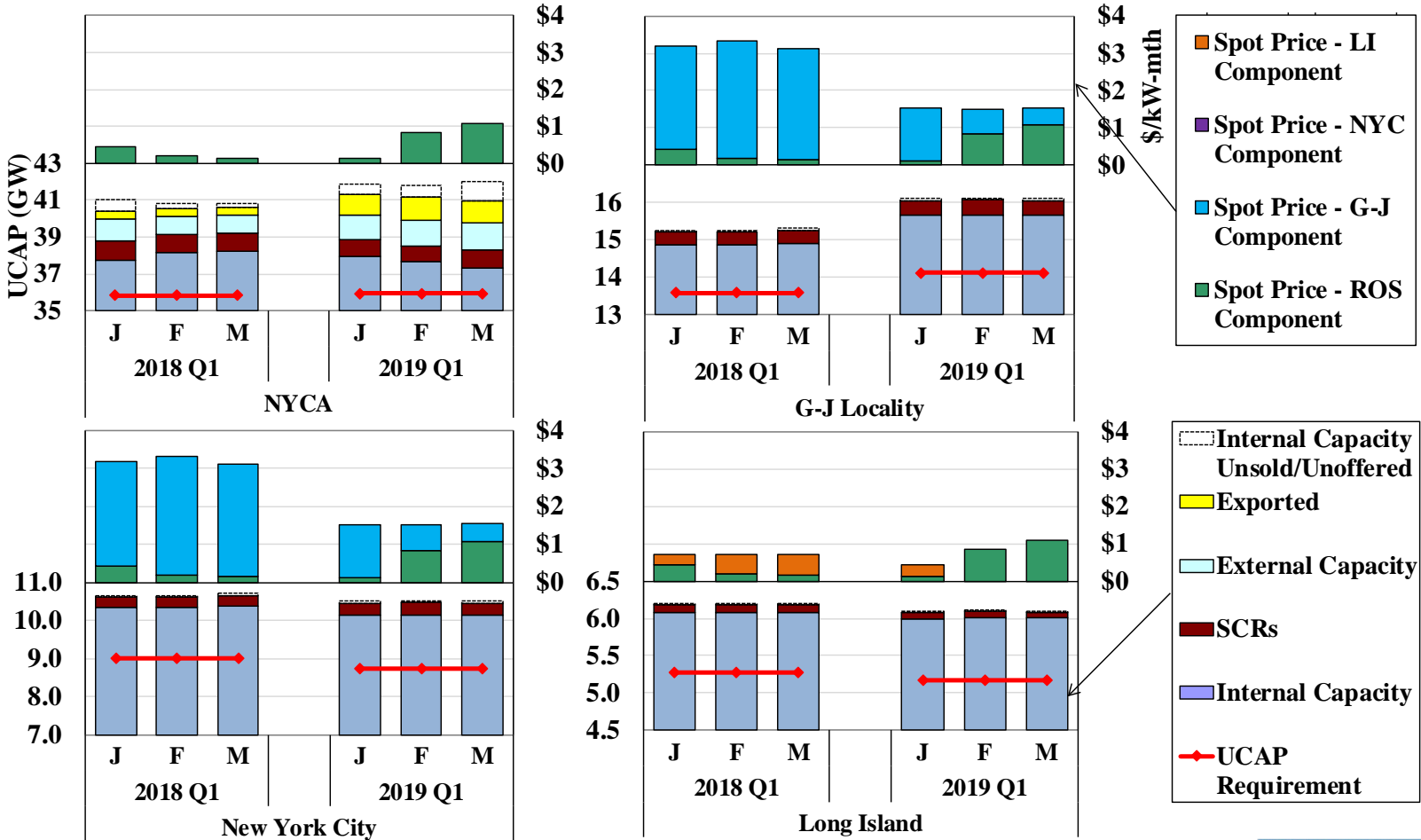
Automated Market Power Mitigation





Charts: Capacity Market

Spot Capacity Market Results 2018-Q1 & 2019-Q1



Key Drivers of Capacity Market Results

	NYCA	NYC	LI	G-J Locality
Avg. Spot Price				
2019 Q1 (\$/kW-Month)	\$0.69	\$1.52	\$0.79	\$1.52
% Change from 2018 Q1	161%	-53%	12%	-53%
Change in Demand				
Load Forecast (MW)	-275	-131	-51	-144
IRMLCR	0.2%	-1.0%	0.0%	3.0%
2018/2019 Winter	118.2%	80.5%	103.5%	94.5%
2017/2018 Winter	118.0%	81.5%	103.5%	91.5%
ICAP Requirement (MW)	-259	-222	-53	346
Key Changes in ICAP Supply (MW)				
<i>Generation</i>	-10	-146	-59	587
<i>Entry</i>	886	131		886
<i>Exit</i>	-742	-284		-284
<i>DMNC</i>	-155	8	-59	-14
<i>Cleared Import⁽¹⁾</i>	314			
Change in Demand Curve				
UCAP Based Reference Price @ 100% Req.				
% Change from 2017/2018 Winter	9%	13%	13%	9%

(1) Based on quarterly average cleared quantity.



Appendix: Chart Descriptions



All-in Price

- Slide [17](#) 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 that is calculated based on clearing prices in the monthly spot capacity auctions and capacity obligations in each area, allocated over the energy consumption in that area.
 - ✓ An uplift component that is based on local and statewide uplift from Schedule 1 charges, allocated over the energy consumed in the area.
 - ✓ An ancillary services component that is based on costs associated with operating reserves, regulation, voltage support, and black start.
 - For the purpose of this metric, these costs are distributed evenly across all locations.
 - ✓ The figure also shows representative natural gas prices for each location that is based on the following indices (plus a transportation charge of \$0.20/MMBtu):
 - a) the Millennium East index for West Zone and Central NY; b) the Iroquois Waddington index for North Zone; c) the Iroquois Zone 2 index for Capital Zone and LI; d) the average of Millennium East and Iroquois Zone 2 for LHV; and e) the Transco Zone 6 (NY) index for NYC. A 6.9 percent tax rate is also included NYC.



Real-Time Output and Marginal Units by Fuel

- Slide [20](#) shows the quantities of real-time generation by fuel type.
 - ✓ Real time generation by fuel type is derived from data reported to the U.S. Environmental Protection Agency (“EPA”) and the U.S. Energy Information Administration (“EIA”).
 - ✓ Pumped-storage resources in pumping mode are treated as negative generation. “Other” includes Methane, Refuse, Solar & Wood.
- Slide [21](#) 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.



Winter Fuel Usage Eastern New York

- Slide [25](#) evaluates the efficiency of fuel usage in Eastern New York in the quarter.
 - ✓ The figure shows the daily averages for:
 - Internal generation by actual fuel consumed in the lower portion; and
 - Day-ahead natural gas price index for Iroquois Zone 2 and Transco Zone 6 (NY) in the upper portion.
 - ✓ For a year-over-year comparison, these quantities are also shown by month for the same quarters in the recent three years.



Ancillary Services Prices

- Slides [27](#), [28](#), and [29](#) summarize day-ahead and real-time 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.
 - Real-time Regulation Movement Charges shown on Slide [28](#) are estimated by dividing total movement charges by real-time scheduled regulation capacity.
 - ✓ 30-min operating reserve prices in western NY; and
 - ✓ 30-min operating reserve prices in SENY.
- The number of shortage intervals in real-time for each ancillary service product are also shown.
 - ✓ 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.



Day-Ahead NYCA 30-Minute Reserve Offers

- Slide [30](#) 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).
 - 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 (less opportunity costs).



Day-Ahead Load Scheduling and Virtual Trading

- Slide [32](#) shows the quantity of day-ahead load scheduled as a percentage of real-time load in each of seven regions and statewide by day.
 - ✓ Net scheduled load = Physical Bilaterals + Fixed Load + Price-Capped Load + Virtual Load – Virtual Supply
- Slide [33](#) shows monthly average scheduled and unscheduled quantities and gross profitability for virtual trades in the past 24 months.
 - ✓ The table identifies virtual trades with relatively large profits or losses that exceed 50 percent of the average zone LBMP.
 - ✓ Large profits may indicate modeling inconsistencies between day-ahead and real-time markets, and large losses may indicate manipulation of the day-ahead market.
- Slide [34](#) summarizes virtual trading by region including average quantities of scheduled virtual supply and load and gross profitability for seven NY regions and four groups of external proxy buses.
 - ✓ The top portion of the chart also shows average day-ahead scheduled load (as a percent of real-time load) by geographic region.
 - ✓ Virtual imports/exports are included as they have similar effects on scheduling.
 - A transaction is deemed-“virtual” if its day-ahead schedule is greater than its real-time schedule.



Efficiency of CTS Scheduling with PJM and NE

- Slide [36](#) evaluates the performance of CTS with PJM and NE at their primary interfaces in the quarter. 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.



Transmission Congestion and Shortfalls

- Slides [38](#), [39](#), [40](#), and [41](#) 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 day-ahead 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 day-ahead to real-time 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 and Shortfalls (cont.)

- Slide [38](#) summarizes day-ahead congestion revenue and shortfalls, and balancing congestion shortfalls over the past two years on a monthly basis.
 - ✓ The upper portion of the figure shows balancing congestion revenue shortfalls, and the lower portion of the figure shows day-ahead congestion revenues collected by the NYISO and day-ahead congestion shortfalls. The sum of these two categories is equal to the total net payments to TCC holders in each month.
- Slide [39](#) 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.
 - ✓ In the real-time market, the value of congestion does not equal the congestion revenue collected by the NYISO, since most real-time power flows settle at day-ahead prices rather than real-time prices.
- Slides [40](#) and [41](#) 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.



Transmission Congestion and Shortfalls (cont.)

- 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.
 - ✓ 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.



West Zone Congestion and Niagara Generation Modeling

- Slide [42](#) illustrates how modeling assumptions related to the system impacts of the Niagara plant differ from the actual impacts of the plant on West Zone constraints.
 - ✓ In the upper portion of the figure,
 - The side-by-side bars indicate average shift factors on each of the constraints for individual units at the 115 kV West, 115 kV East, and 230 kV buses.
 - The black line indicates the composite shift factor for the plant.
 - ✓ In the lower portion of the figure, the side-by-side bars show from left to right:
 - RTD model's optimized impact on the West Zone constraints;
 - Actual impact on the constraints (assuming perfect dispatch performance relative to the 5-minute signal in terms of total plant output level); and
 - The average absolute difference between the modeled impact and the actual impact.
 - ✓ These quantities are shown for select West Zone constraints (i.e., limiting facility/contingency pairs) in the quarter.



NY-NJ PAR Operation Under M2M with PJM

- Slide [43](#) evaluates operations of NY-NJ PARs under M2M with PJM during the following periods of noticeable congestion differential between NY and PJM:
 - ✓ When NY costs on relevant M2M constraints exceed PJM costs by: a) \$10/MWh to \$20/MWh; b) \$20/MWh to \$30/MWh; or c) more than \$30/MWh.
 - ✓ When PJM costs on relevant M2M constraints exceed NY costs by: a) \$10/MWh to \$20/MWh; b) \$20/MWh to \$30/MWh; or c) more than \$30/MWh;
 - ✓ The market cost is measured as the constraint shadow price multiplied by the PAR shift factor, summed over relevant M2M constraints in each 5-minute market interval and then averaged over each half-hour period.
 - ✓ The top portion of the figure shows two stacked bars for each evaluation group, representing the total number of 30-minute intervals with and without any PAR tap movements.
 - ✓ The bottom portion of the figure shows average actual PAR flows (blue bar), compared with their average M2M targets (red diamond).



Constraints on the Low Voltage Network

- Transmission constraints on the 115 kV and lower voltage networks in New York are often resolved in ways that include:
 - ✓ Out of merit dispatch and supplemental commitment of generation;
 - ✓ Curtailment of external transactions and limitations on external interface limits;
 - ✓ Use of an internal interface transfer limit that functions as a proxy for the limiting transmission facility; and
 - ✓ Adjusting PAR-controlled lines on the high voltage network.
- Slide [44](#) shows the number of days in the quarter when various resources were used to manage constraints in five areas of upstate New York:
 - ✓ West Zone: Mostly Niagara-to-Gardenville and Gardenville-to-Dunkirk circuits;
 - ✓ Central Zone: Mostly constraints around the State Street 115kV bus;
 - ✓ Capital Zone: Mostly Albany-to-Greenbush 115kV constraints;
 - ✓ North & Mohawk Valley Zones: Mostly 115kV constraints on facilities that flow power south from the North Zone and through the Mohawk Valley Zone between the Colton 115kV and Taylorville 115kV buses; and
 - ✓ Long Island: Mostly constraints on the 69kV system on Long Island.



Constraints on the Low Voltage Network

- Slide [45](#) shows the number of hours and days in the quarter when various resources were used to manage 69 kV and TVR (“Transient Voltage Recovery”) constraints in four local areas of Long Island:
 - ✓ Valley Stream: Mostly constraints around the Valley Stream bus;
 - ✓ Brentwood: Mostly constraints around the Brentwood bus;
 - ✓ East of Northport: Mostly the C._ISLIP-Hauppaug and the Elwood-Deposit circuits;
 - ✓ East End: Mostly the constraints around the Riverhead bus and the TVR requirement.
 - ✓ For a comparison, the tables also show the frequency of congestion management on the 138 kV constraint via the market model.
- Slide [45](#) also shows our estimated price impacts in each LI load pocket that result from explicitly modeling these 69 kV and TVR constraints in the market software.
 - ✓ The following generator locations are chosen to represent each load pocket:
 - Barrett ST for the Valley Stream pocket;
 - NYPA Brentwood GT for the Brentwood pocket;
 - Holtsville IC for the East of Northport pocket; and
 - Green Port GT for the East End pocket.



N-1 Constraints in New York City

- The NYISO sometimes operates a facility above its Long-Term Emergency (“LTE”) rating if post-contingency actions (e.g., deployment of operating reserves) would be available to quickly reduce flows to LTE.
 - ✓ The use of post-contingency actions is important because it allows the NYISO to increase flows into load centers and reduce congestion costs.
 - ✓ However, the service provided by these actions are not properly compensated.
- Slide [46](#) shows such select N-1 constraints in New York City. In the figure,
 - ✓ The left panel summarizes their DA and RT congestion values in the quarter.
 - The blue bars represent the congestion values measured up to the seasonal LTE ratings of the facilities (i.e., constraint shadow cost*seasonal LTE summed over all intervals); and
 - The red bars represent the congestion values measured for the additional transfer capability above LTE (i.e., constraint shadow cost*(modeled constraint limit – seasonal LTE) summed over all intervals).
 - ✓ The bars in the right panel show the seasonal LTE and STE ratings for these facilities, compared to the average N-1 constraint limits used in the market software.



Supplemental Commitments and OOM Dispatch

- Slides [48](#), [49](#), and [50](#) summarize out-of-market commitment and dispatch, which are the primary sources of guarantee payment uplift.
- Slide [48](#) 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.
- Slide [49](#) 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:



Supplemental Commitments and OOM Dispatch (cont.)

- NO_x Only – If needed for NO_x bubble requirement and no other reason.
 - Voltage – If needed for ARR 26 and no other reason.
 - Thermal – If needed for ARR 37 and no other reason.
 - Loss of Gas – If needed for IR-3, a sudden loss of gas supply in NY, and no other reason except NO_x.
 - Multiple Reasons – If needed for two or three of the following reasons: voltage support, thermal support, NO_x, or loss of gas. The capacity is shown multiple times for each separate reason in the bar chart.
- ✓ For voltage and thermal constraints, the capacity is shown by the load pocket that was secured.
 - Slide [50](#) 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, “Station #1” is the station with the highest number of OOM hours in its region in the current quarter; “Station #2” is the station with the second-highest number of OOM hours; all other stations are grouped together.



Uplift Costs from Guarantee Payments

- Slides [51](#) and [52](#) 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 day-ahead schedule when the real-time LBMP is higher than the day-ahead LBMP.
 - ✓ Four categories of local reliability uplift are allocated to the local TO:
 - Day Ahead: From Local Reliability Requirements (“LRR”) and Day-Ahead Reliability Unit (“DARU”) commitments.
 - Real Time: From Supplemental Resource Evaluation (“SRE”) commitments and Out-of-Merit (“OOM”) dispatched units 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.
 - ✓ Slide [51](#) shows these seven categories on a daily basis during the quarter.
 - ✓ Slide [52](#) summarizes uplift costs by region on a monthly basis.



Potential Economic and Physical Withholding

- Slides [54](#) and [55](#) 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.



Automated Market Power Mitigation

- Slide [56](#) summarizes the automated mitigation that was imposed in the day-ahead and real-time markets (not including BPCG mitigation) in the quarter.
 - ✓ The bars in the upper panel shows the percent of hours when incremental energy offer mitigation was imposed on one or more units in each category.
 - ✓ The bars in the lower panel shows the average mitigated capacity.
 - Mitigated quantities are shown separately for flexible output range of units (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.
 - ✓ The right portion shows the amount of mitigation on the units committed for reliability in New York City, Long Island, and the upstate area.
 - ✓ Mitigation of gas turbine capacity is shown in the Incremental Energy category whenever the incremental energy offer or the startup offer is mitigated.



Spot Capacity Market Results

- Slides [58](#) and [59](#) summarize market results and key drivers in the monthly spot capacity auctions.
 - ✓ Slide [58](#) summarizes available and scheduled Unforced Capacity (“UCAP”), UCAP requirements, and spot prices that occurred in each capacity zone by month.
 - Sales associated with Unforced Deliverability Rights (“UDRs”) are included in “Internal Capacity,” but unsold capacity from resources with UDRs is not shown.
 - ✓ Slide [59](#) compares the year-over-year changes in capacity spot prices by Locality and shows variations in key factors that drove these changes, including:
 - The changes in the UCAP requirements, which are affected by changes in the forecasted peak load, the minimum capacity requirement, and the derating factors;
 - The changes in the UCAP supply, which are affected by changes in new entry, mothballing and retirement, and DMNC test values; and
 - The changes in the demand curves, which are mostly affected by the assumptions used in each demand curve reset process.
 - The most recent reset was done for the Capability Periods from 2017 to 2021.