Quarterly Report on the New York ISO Electricity Markets Second Quarter of 2018

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August 2018

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Market Highlights

Market Highlights:
Executive Summary

- Weather conditions were mild, leading to moderate gas prices and load levels.
- All-in prices rose 1 to 16 percent across the state from the second quarter of the previous year, reflecting modest increases in capacity prices and LBMPs.
- Central East interface congestion fell 60 percent due to fewer costly transmission outages and changes in the patterns of nuclear generation, imports, & exports.
- The majority of modeled congestion occurred in the West Zone (26 percent) or from Northern to Central NY (28 percent).
  - ✓ Unmodeled congestion in the West Zone was also significant as out-of-market actions were used to manage 115 kV constraints on 59 days during the quarter.
    - – The NYISO plans to incorporate these into the market software by the end of 2018.
  - ✓ Congestion from Northern to Central NY was exacerbated by transmission outages and excessive Constraint Reliability Margin ("CRM") values.
    - – We support the NYISO's efforts to modify the tariff to address the CRM issue.
- Although the NYISO-PJM M2M congestion management process has provided benefits, the PAR actions to manage congestion were still limited.
- Large amounts of reliability commitment occurred in NYC, which would be more efficiently managed and priced with explicit reserve requirements.

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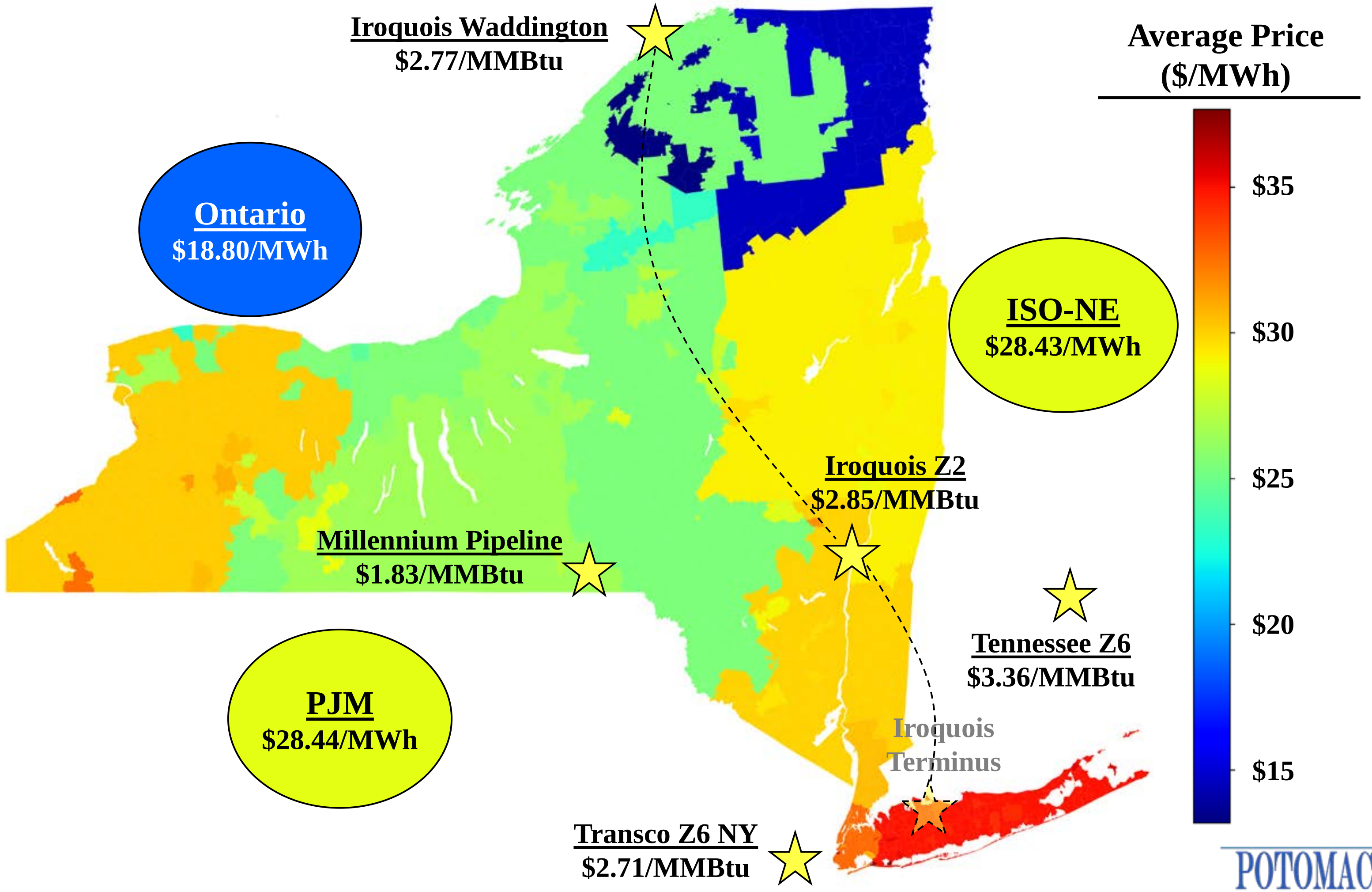
Market Highlights:
System Price Diagram



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Market Highlights:
Summary of Energy Market Outcomes

- NYISO energy markets performed competitively in the second quarter of 2018.
  - ✓ Variations in regional wholesale prices were driven primarily by changes in fuel prices, demand, and supply availability.
  - ✓ The amount of output gap (slide 51) and unoffered economic capacity (slide 52) remained modest and reasonably consistent with competitive market expectations.
- The month of April was colder than usual while June was milder than a year ago.
  - ✓ This contributed to a 1.5 percent increase in quarterly average load. (slide 17)
  - ✓ Natural gas prices rose notably at several locations in East NY on ten days in April, but were otherwise comparable to the second quarter of 2017. (slide 18)
- Average all-in prices ranged from roughly $23/MWh in the North Zone to $60/MWh in NYC, up 1 to 16 percent from a year ago. (slide 16)
  - ✓ Capacity costs rose 5 percent in Long Island and 14 to 16 percent elsewhere. (slide 55)
  - ✓ Energy prices fell slightly (by 1 to 3 percent on average) in New York City and Long Island, but increased 2 to 18 percent elsewhere. (slides 21-22)

Market Highlights:
Congestion Patterns, Revenues and Shortfalls

- Day-ahead congestion revenues totaled $84 million, down 28 percent from the second quarter of 2017. (slide 37)
- The decrease was driven by less congestion across the Central-East interface (down 60 percent) and transmission paths into SENY (down 92 percent) largely because:
  - ✓ Fewer significant transmission outages affected these facilities.
    - – Day-ahead congestion shortfalls (an indicator of the impact of outages) related to these facilities fell from $12 million in 2017 to $2 million in this quarter. (slide 38)
  - ✓ Changes in nuclear generation patterns reduced flows on these paths.
    - – Average nuclear generation rose 470 MW in East NY but fell 280 MW in West NY. These changes caused by variations in generator maintenance outages. (slide 19)
  - ✓ Imports and exports changed in ways that reduced flows on these paths. (slide 33)
    - – Imports from Ontario fell because of higher prices on the Ontario side. (The Ontario HOEP averaged $19/MWh in 2018-Q2 vs. $6/MWh in 2017-Q2.)
    - – Exports to New England fell because the limit was reduced to 400-500 MW (from 1400 MW normally) in April to early May because of transmission outages.
    - – Imports from PJM rose due partly to fewer transmission outages on the Neptune and HTP interfaces.

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

- North Zone to central NY power flows accounted for the largest share (28 percent) of day-ahead congestion revenues for the first time in this quarter. (slide 37)
  - ✓ The NYISO began modeling the Browns Falls-Taylorville 115 kV transmission constraints in May 2018. However, these facilities were overly constrained because the current rules limit the ISO's ability to adjust CRM values. (slide 11)
  - ✓ This congestion was driven by significant transmission outages in May (at the Marcy 765 and 345 kV buses) and in June (on the Browns Falls-Taylorville lines).
    - These transmission outages accounted for most of the $13 million day-ahead congestion shortfalls accrued on North Zone lines. (slide 38)
  - ✓ Frequent congestion on these facilities often led to negative price spikes in the North Zone. (slide 22)
- West Zone lines accounted for the second largest share (26 percent) of day-ahead congestion revenues. (slide 37)
  - ✓ Congestion became severe during key transmission outages. (slide 38)
  - ✓ Nearly 45 percent (or $10 million) of day-ahead congestion revenues and over 70 percent (or $7 million) of day-ahead congestion shortfalls occurred during the outage of Niagara-Robinson Rd 230 line from 5/29 to 6/1.

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

- Congestion across the primary NY/NE interface was high this quarter.
  - ✓ The interface limit was greatly reduced (to 400~500 MW) when the Long Mountain-Pleasant Valley 345 kV line was out of service from April to early May.
  - ✓ This outage accounted for $4 million of day-ahead congestion shortfalls. (slide 38)
- Balancing congestion shortfalls totaled $13 million this quarter.
  - ✓ Balancing congestion shortfalls were small on most days, while unexpected real-time events (slide 39) on several days accounted for the vast majority.
- Out-of-market actions to manage lower-voltage (115 kV and below) network congestion were frequent. (slide 41)
  - ✓ OOM actions were most frequent in Western NY (59 days), the Capital Zone (24 days), Central NY (20 days), and Long Island (14 days).
  - ✓ The costs of this congestion could be reduced by modeling the 115kV constraints in the day-ahead and real-time market systems.
  - ✓ The NYISO plans to model 115 kV constraints in Western NY by the end of 2018.
    - – However, this is awaiting an initiative to improve the modeling of the Niagara plant, which is expected to help coordinate the management of 115 kV and 230 kV congestion in the West Zone.

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.
- Most (77 percent) of the RT congestion in NYC occurred on N-1 constraints that would have been loaded above LTE after a single contingency. (slide 42)
  - ✓ The additional capability above LTE averaged from over 20 MW for the 138 kV constraints in the Greenwood load pocket to over 200 MW for 345 kV facilities.
    - – 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.

Market Highlights:
Use of CRM in Congestion Management

- A Constraint Reliability Margin ("CRM") reduces the available transfer limit in the market software to account for loop flows and other un-modeled factors.
- The default CRM value of 20 MW is used for most facilities. On average, this was:
  - ✓ 1 to 2 percent of the transfer capability of the 345 kV constrained facilities;
  - ✓ 4 to 5 percent of the transfer capability of the 230 kV constrained facilities;
  - ✓ 8 to 11 percent of the transfer capability of the 138 kV constrained facilities; and
  - ✓ 15 percent of the transfer capability of the 115 kV constrained facilities. (slide 43)
  - ✓ Loop flows and other un-modeled factors do not rise in this pattern at low voltages.
- The 20 MW CRM is overly conservative for lower-voltage constraints, which leads to unnecessarily high congestion costs in these areas.
  - ✓ The average amount of shortages on the 115 kV constraints were less than 5 MW.
  - ✓ Over-constraining these small facilities has large effects on inter-regional flows.
    - For example, a 10-MW reduction in flows across a Browns falls-Taylorville 115 kV line can reduce overall transfers from Northern NY to Central NY by 100 MW.
- The NYISO recognizes this issue and is working on Tariff changes that would allow smaller CRMs to be used on lower-voltage constraints.
  - ✓ We support this effort.

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Market Highlights:

Use of CRM in Congestion Management (cont.)

- Higher CRMs are used for a small set of facilities to account for more uncertain loop flows and other un-modeled factors.
  - ✓ For example, a 50 MW CRM is used for the Dunwoodie-Shore Rd 345 kV line (from upstate to Long Island) and the Packard-Sawyer 230 kV lines (near the Ontario border in Western NY).
  - ✓ These lines accounted for most congestion in their areas. In the second quarter:
    - The Dunwoodie-Shore Rd line accounted for 70 percent of day-ahead congestion revenues in Long Island; and
    - The Packard-Sawyer line accounted for 85 percent of day-ahead congestion in the West Zone.
  - ✓ However, actual flows were frequently well below their operational limits (because of the high CRM) during periods of modeled congestion.
    - The average shortage quantity was only 10 MW on the Packard-Sawyer constraint and 15 MW on the Dunwoodie-Shore Rd constraint. (slide 43)
- Since the CRM values have a significant impact on the costs of congestion management, it is important to reassess the appropriateness of the CRM values on an on-going basis.

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Market Highlights:
Reliability Commitments, OOM Dispatch, and BPCG

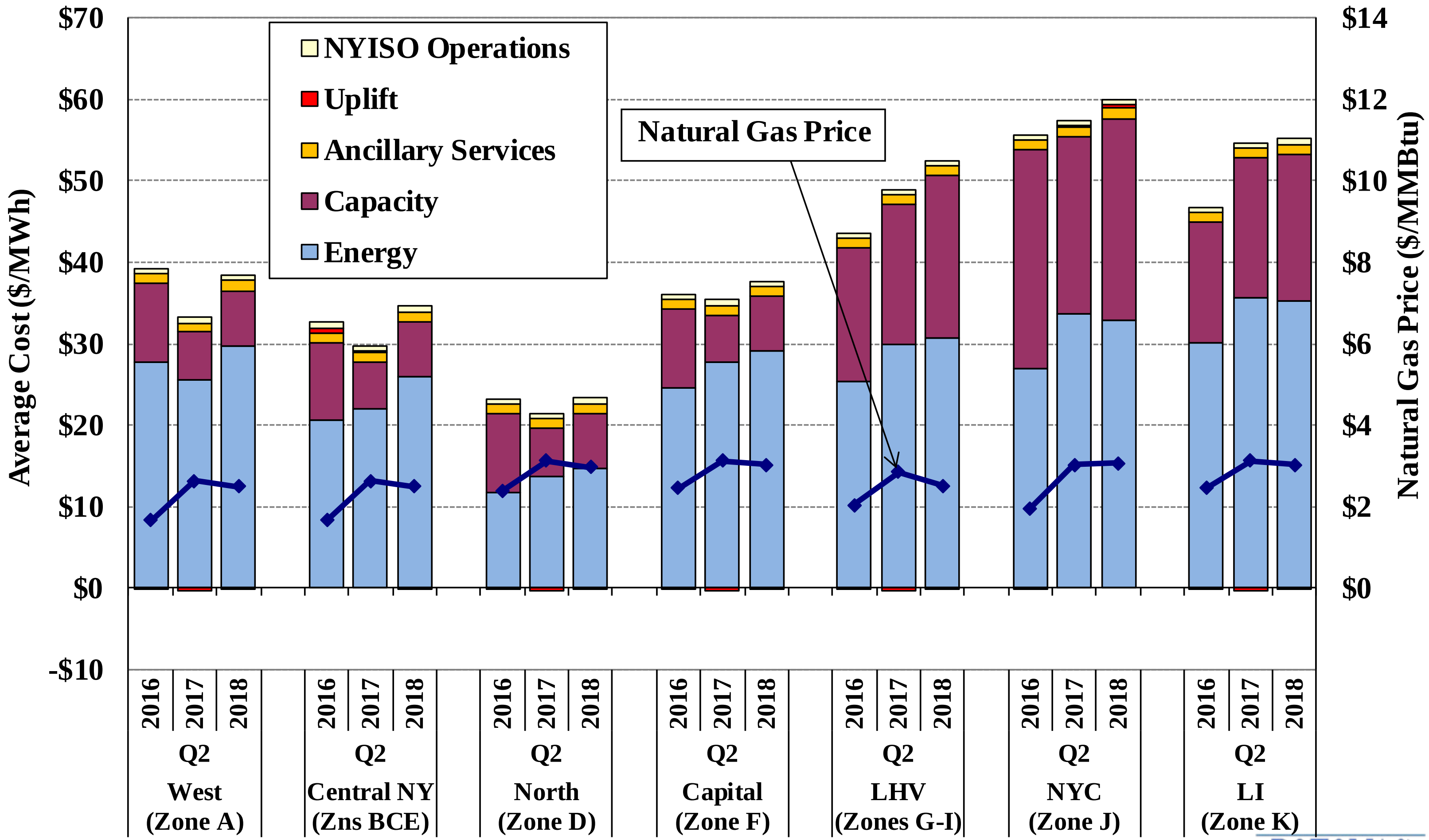
- BPCG payments were $11 million, slightly lower than a year ago. (slides 48-49)
- Nearly $7 million (or 66 percent) of BPCG was paid to NYC generators, up 46 percent from the second quarter of 2017. (slide 49)
  - ✓ Reliability commitment in NYC averaged 630 MW, accounting for 98 percent of all reliability commitments this quarter and up 13 percent from last year. (slide 45)
  - ✓ NYC units were committed more frequently for reliability in May and June after they became less economic because gas prices for NYC units rose relative to other eastern NY units. (see Transco Z6 (NY) vs Iroquois Z2 price difference on slide 18)
  - ✓ We recommend that the NYISO satisfy the reliability needs that drive these out-of-market commitments with local reserve requirements in the DA & RT markets.
- The increase in NYC was largely offset by the decrease in West NY, which saw a 61 percent reduction in BPCG uplift from a year ago. (slide 49)
  - ✓ The Milliken units are no longer needed following transmission upgrades completed in July 2017, which contributed to this reduction.
- Bethlehem units in the Capital Zone accounted for the largest share (42 percent) of OOM station-hours to secure the Albany-Greenbush 115 kV lines. (slide 47)

Market Highlights:
Capacity Market

- Average spot capacity prices ranged from \$2.43/kW-month in ROS to \$8.94/kW-month in New York City in the second quarter of 2018. (slide 55-56)
- Spot capacity prices rose from a year ago in all regions, ranging from 4 percent in Long Island to 22 percent in ROS.
  - ✓ These increases reflected higher reference point prices on the UCAP Demand Curves (up 9 to 15 percent because of annual adjustments).
  - ✓ However, this was offset by a lower load forecast, which resulted in lower ICAP requirements in all regions but the G-J Locality.
    - The ICAP requirement rose 346 MW in the G-J Locality as a result of a higher LCR (increased from 91.5 to 94.5 percent).
  - ✓ Changes in ICAP supply were also a key driver of these price changes.
    - Cleared import capacity fell by an average of 455 MW.
    - Several Ravenswood GTs in NYC have been in an IIFO (“ICAP Ineligible Forced Outage”) since April 2018, lowering ICAP supply by a total of 214 MW.
    - These reductions were partly offset by the new entry of the CPV Valley units. These units added 528 MW of ICAP supply as of June 2018 although they produced limited amounts of energy in the second quarter.

Charts:
Market Outcomes

All-In Prices by Region



Notes: For chart description, see slide 58.

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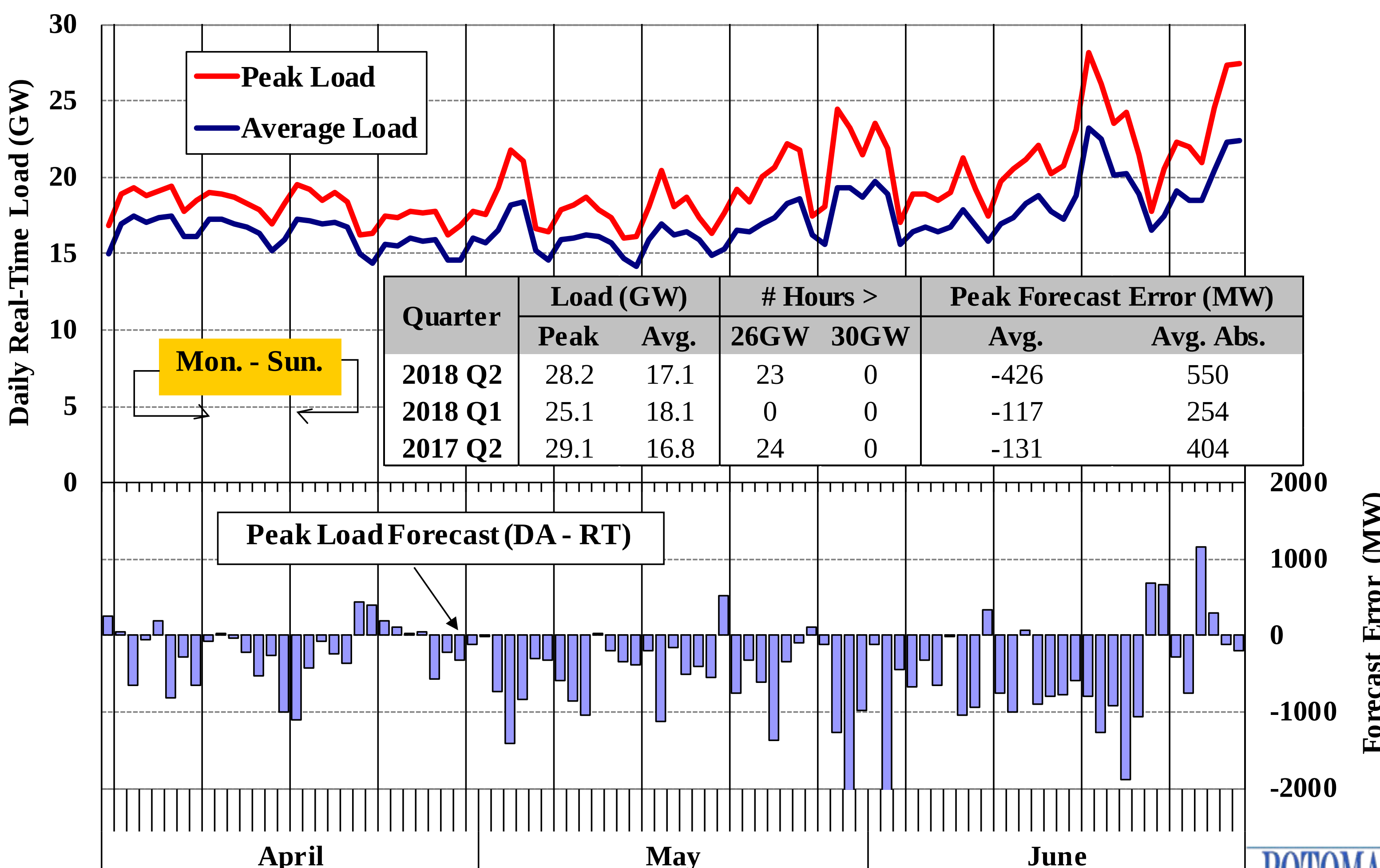
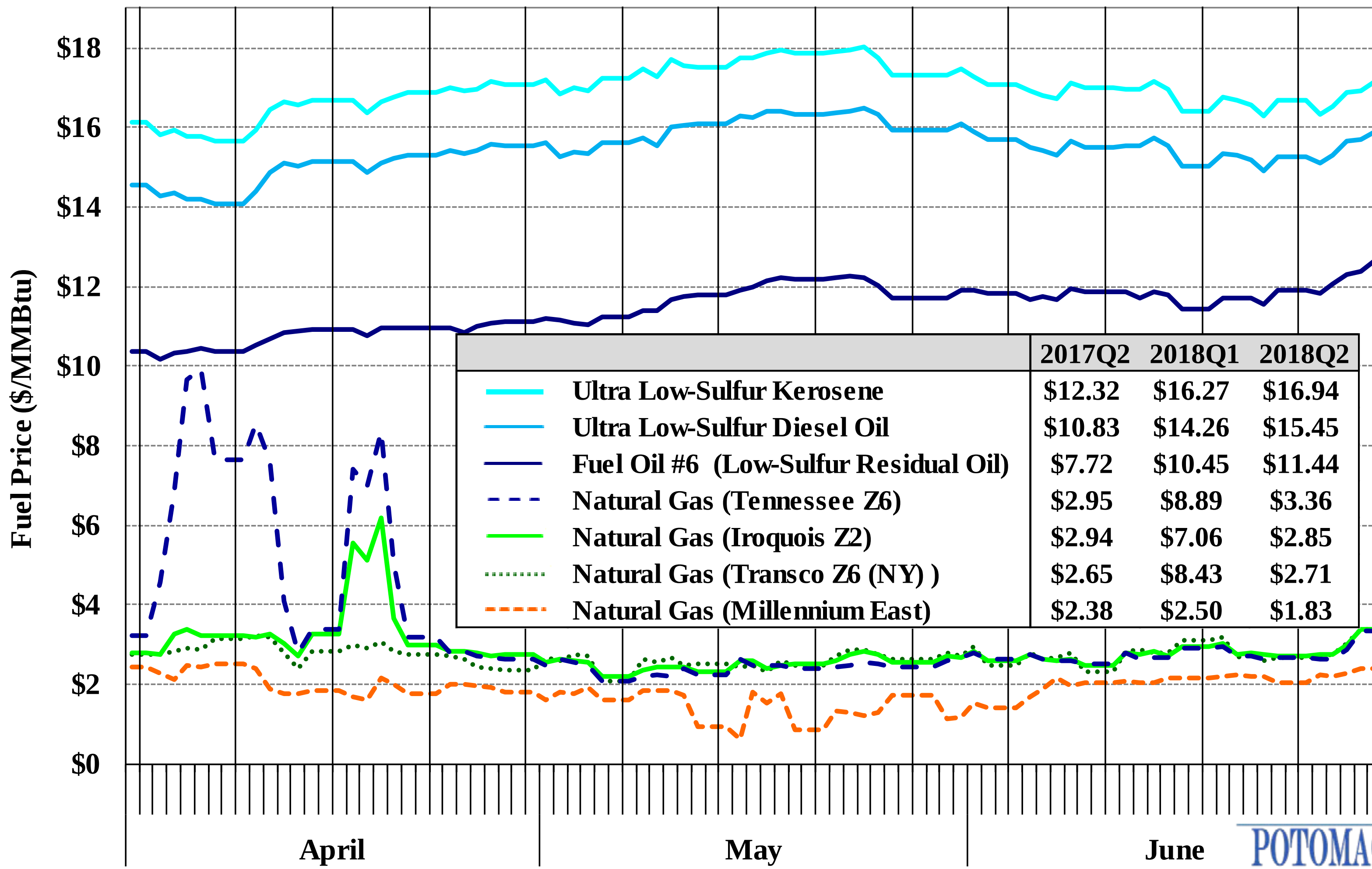
Load Forecast and Actual Load



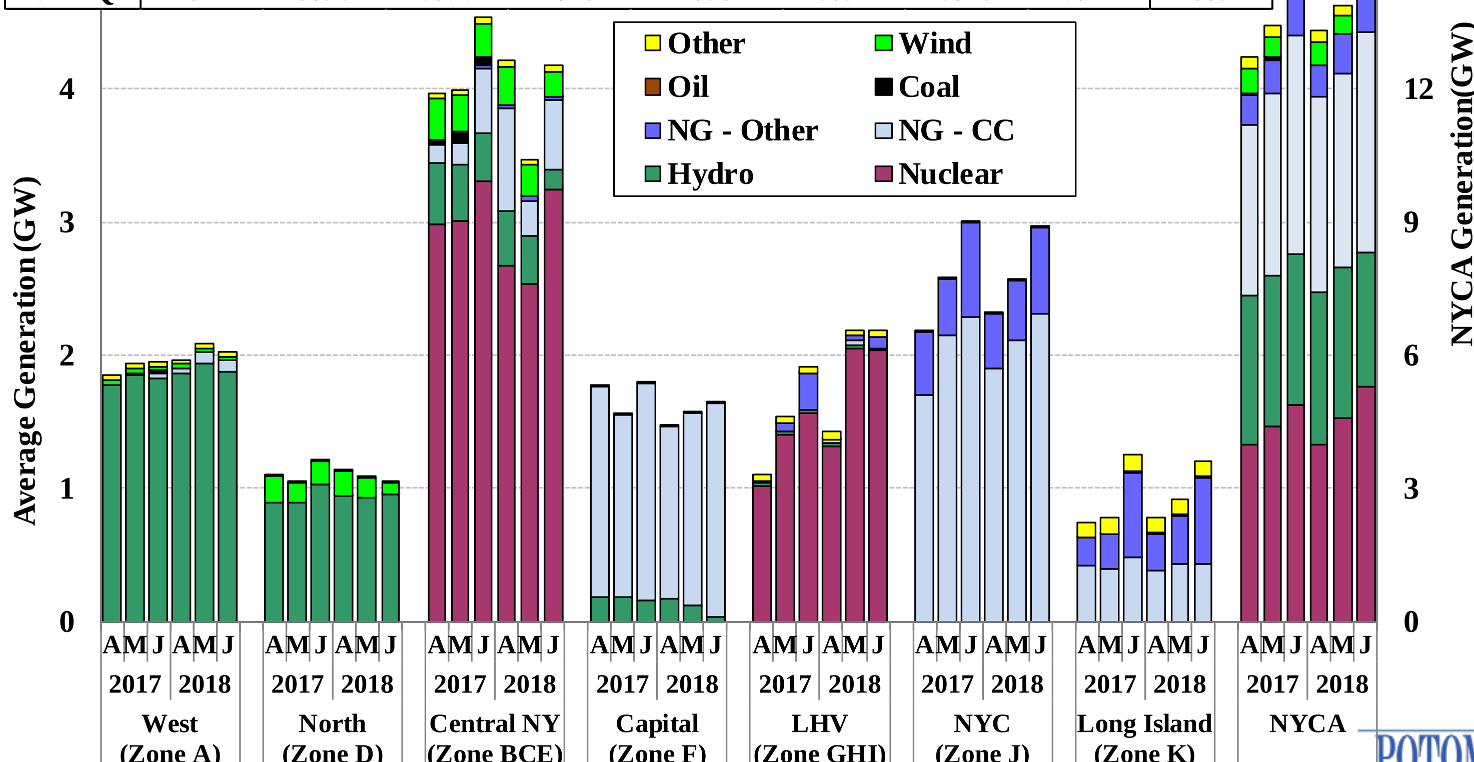
Quarter	Load (GW) Peak	Load (GW) Avg.	# Hours > 26GW	# Hours > 30GW	Peak Forecast Error (MW) Avg.	Peak Forecast Error (MW) Avg. Abs.
2018 Q2	28.2	17.1	23	0	-426	550
2018 Q1	25.1	18.1	0	0	-117	254
2017 Q2	29.1	16.8	24	0	-131	404

Natural Gas and Fuel Oil Prices



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
2018 Q2	4.62	3.28	0.01	4.57	1.00	0.01	0.40	0.26	14.16
2018 Q1	5.06	3.28	0.17	4.01	0.76	0.61	0.60	0.25	14.74
2017 Q2	4.42	3.38	0.06	4.28	1.03	0.02	0.48	0.27	13.94



Notes: For chart description, see slide 59.

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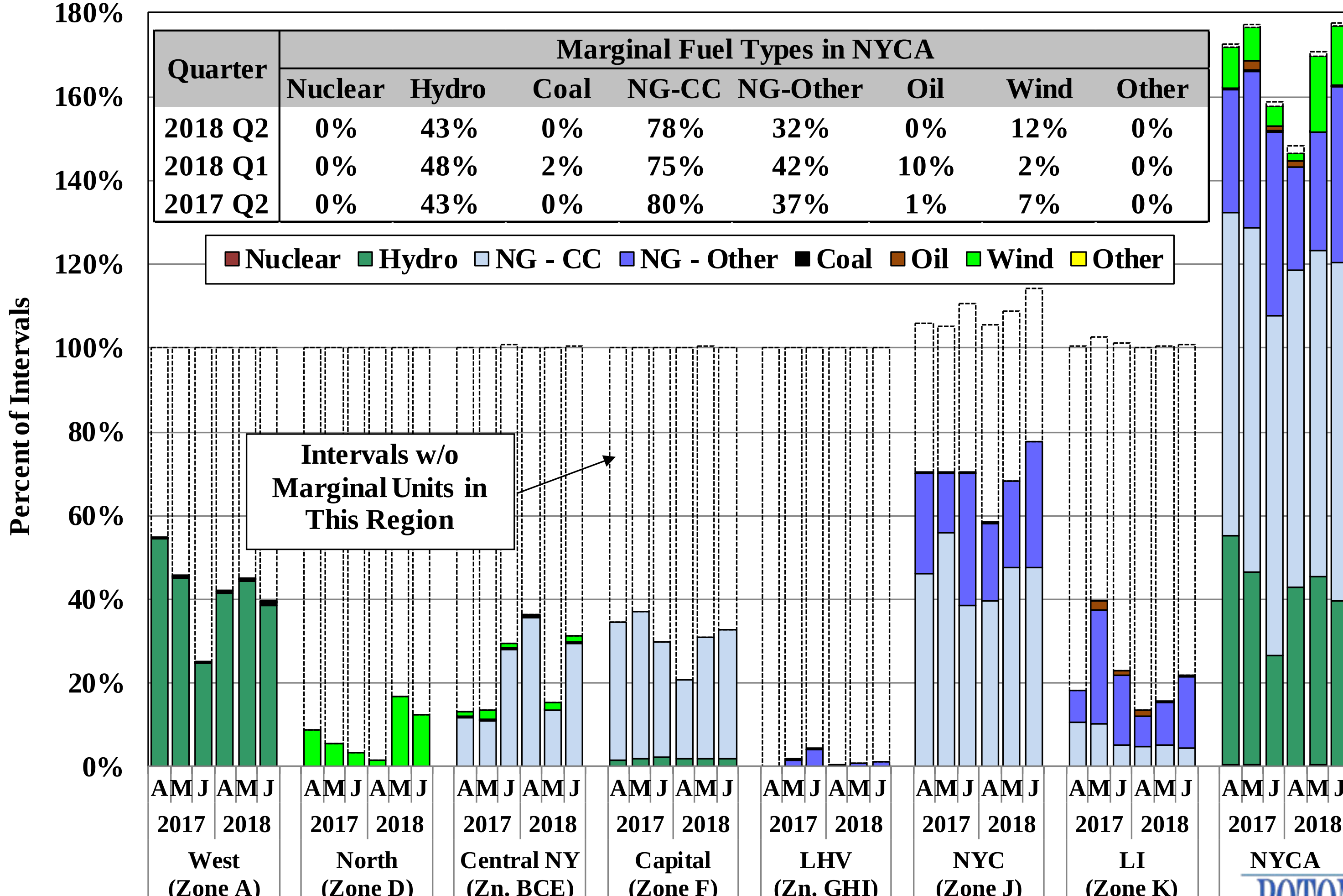
Fuel Type of Marginal Units in the Real-Time Market



Quarter	Marginal Fuel Types in NYCA							
	Nuclear	Hydro	Coal	NG-CC	NG-Other	Oil	Wind	Other
2018 Q2	0%	43%	0%	78%	32%	0%	12%	0%
2018 Q1	0%	48%	2%	75%	42%	10%	2%	0%
2017 Q2	0%	43%	0%	80%	37%	1%	7%	0%

Notes: For chart description, see slide 59.

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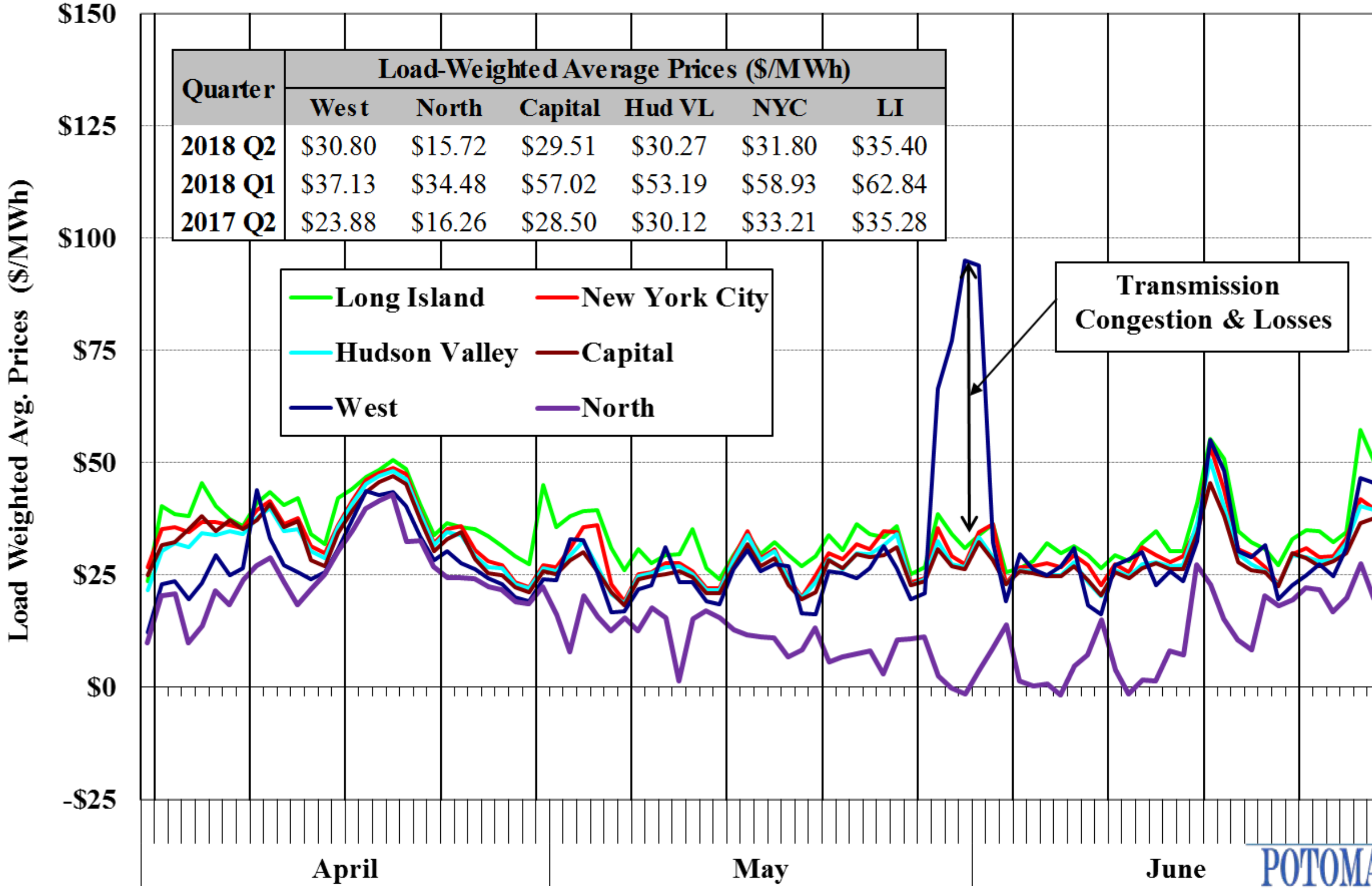
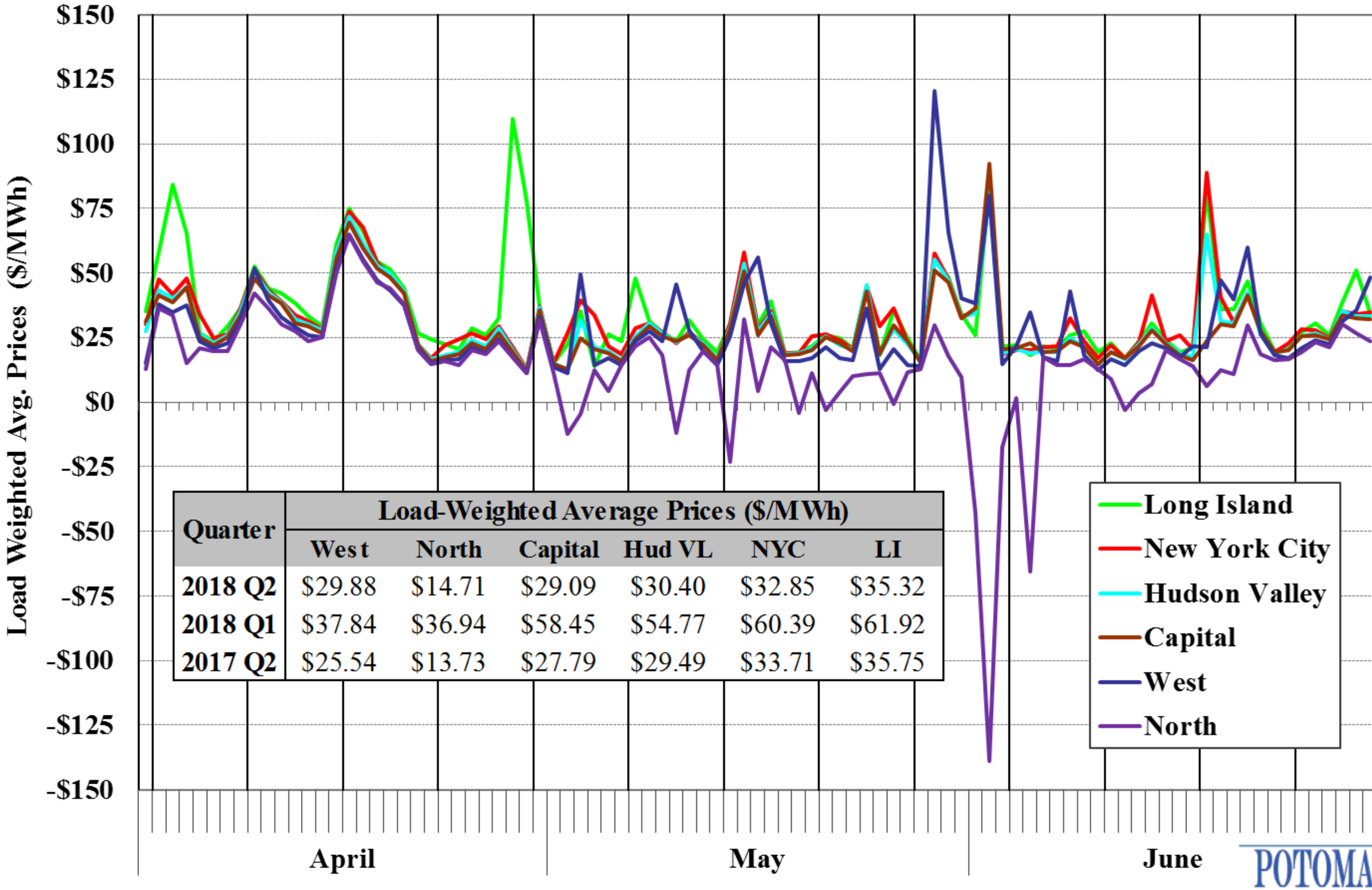
Day-Ahead Electricity Prices by Zone



Quarter	Load-Weighted Average Prices ($/MWh)					
	West	North	Capital	Hud VL	NYC	LI
2018 Q2	$30.80	$15.72	$29.51	$30.27	$31.80	$35.40
2018 Q1	$37.13	$34.48	$57.02	$53.19	$58.93	$62.84
2017 Q2	$23.88	$16.26	$28.50	$30.12	$33.21	$35.28

Real-Time Electricity Prices by Zone



Quarter	Load-Weighted Average Prices ($/MWh)					
	West	North	Capital	Hud VL	NYC	LI
2018 Q2	$29.88	$14.71	$29.09	$30.40	$32.85	$35.32
2018 Q1	$37.84	$36.94	$58.45	$54.77	$60.39	$61.92
2017 Q2	$25.54	$13.73	$27.79	$29.49	$33.71	$35.75

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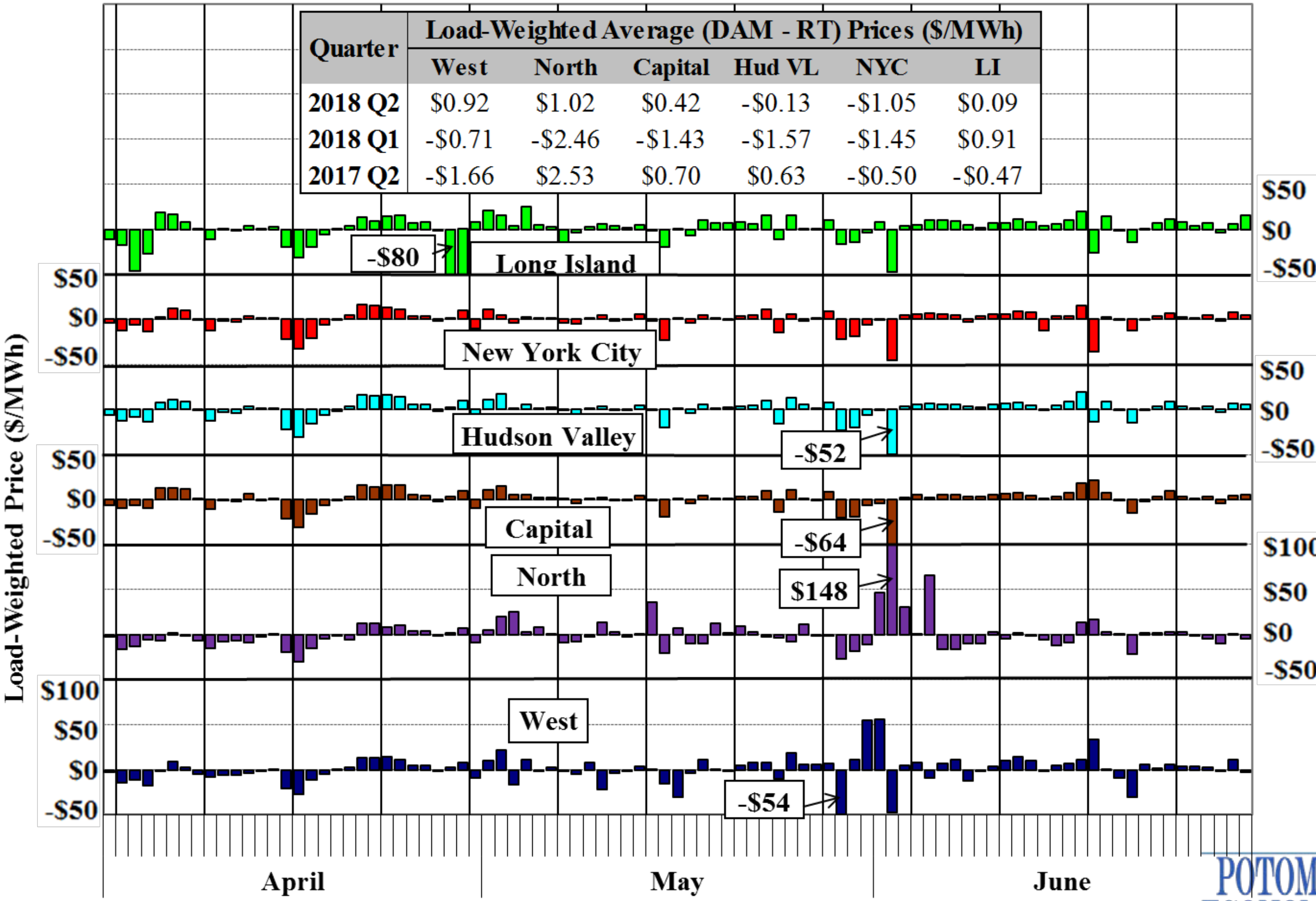
Convergence Between Day-Ahead and Real-Time Prices



Quarter	Load-Weighted Average (DAM - RT) Prices ($/MWh)					
	West	North	Capital	Hud VL	NYC	LI
2018 Q2	$0.92	$1.02	$0.42	-$0.13	-$1.05	$0.09
2018 Q1	-$0.71	-$2.46	-$1.43	-$1.57	-$1.45	$0.91
2017 Q2	-$1.66	$2.53	$0.70	$0.63	-$0.50	-$0.47

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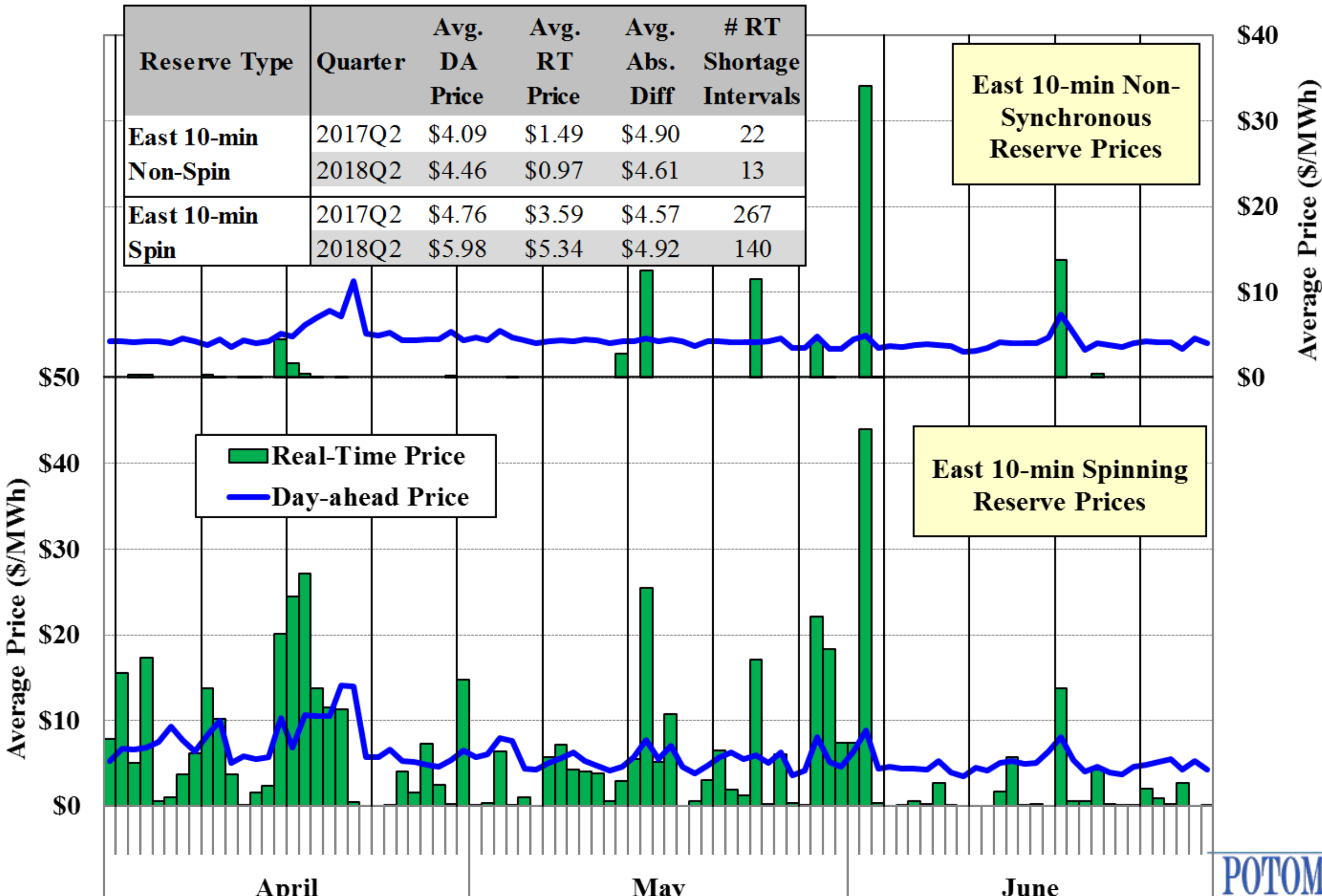
Charts:

Ancillary Services Market

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

Reserve Type	Quarter	Avg. DA Price	Avg. RT Price	Avg. Abs. Diff	# RT Shortage Intervals
East 10-min Non-Spin	2017Q2	$4.09	$1.49	$4.90	22
	2018Q2	$4.46	$0.97	$4.61	13
East 10-min Spin	2017Q2	$4.76	$3.59	$4.57	267
	2018Q2	$5.98	$5.34	$4.92	140



Notes: For chart description, see slide 60.

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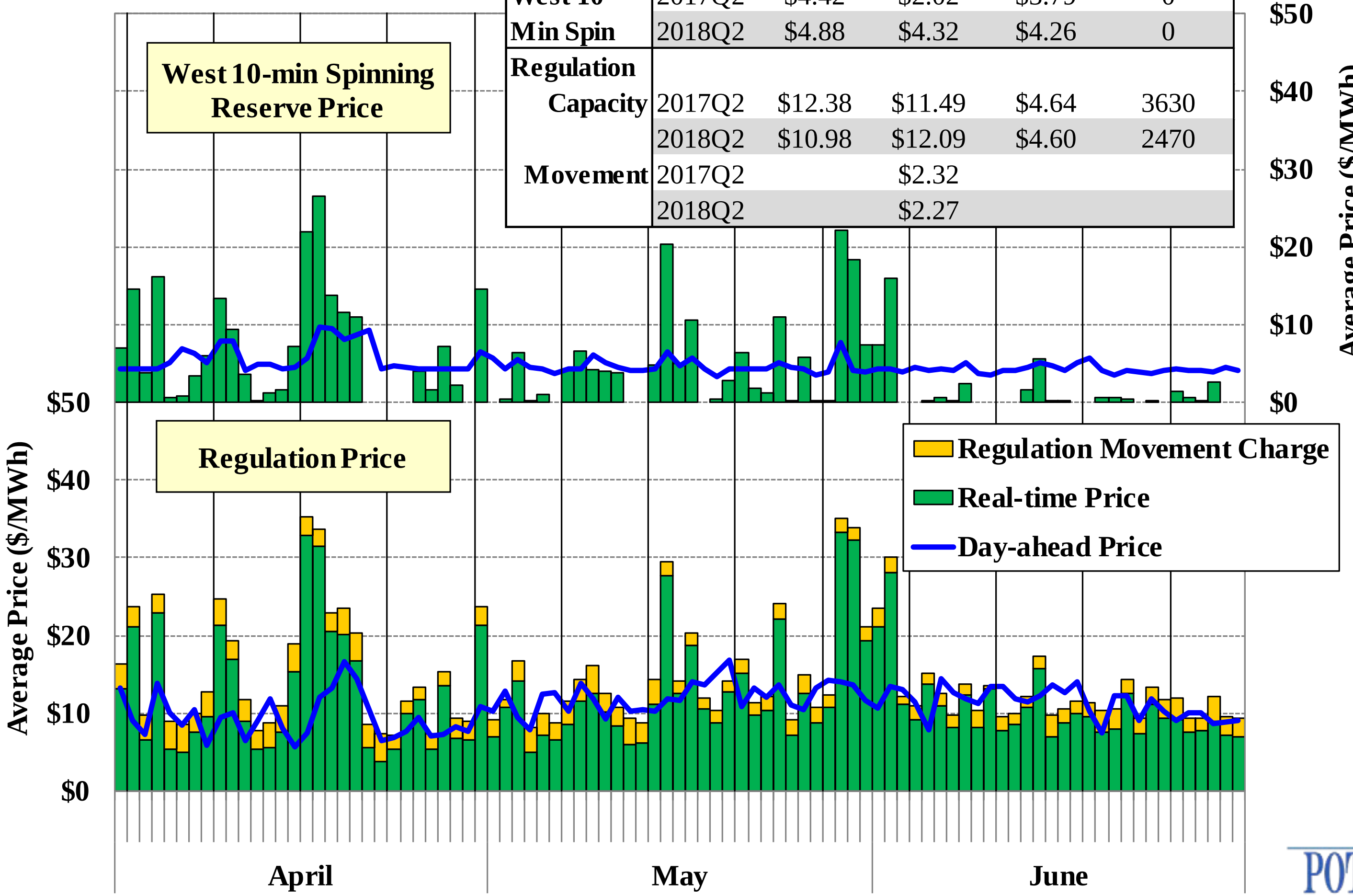
Day-Ahead and Real-Time Ancillary Services Prices
Western 10-Minute Spinning Reserves and Regulation

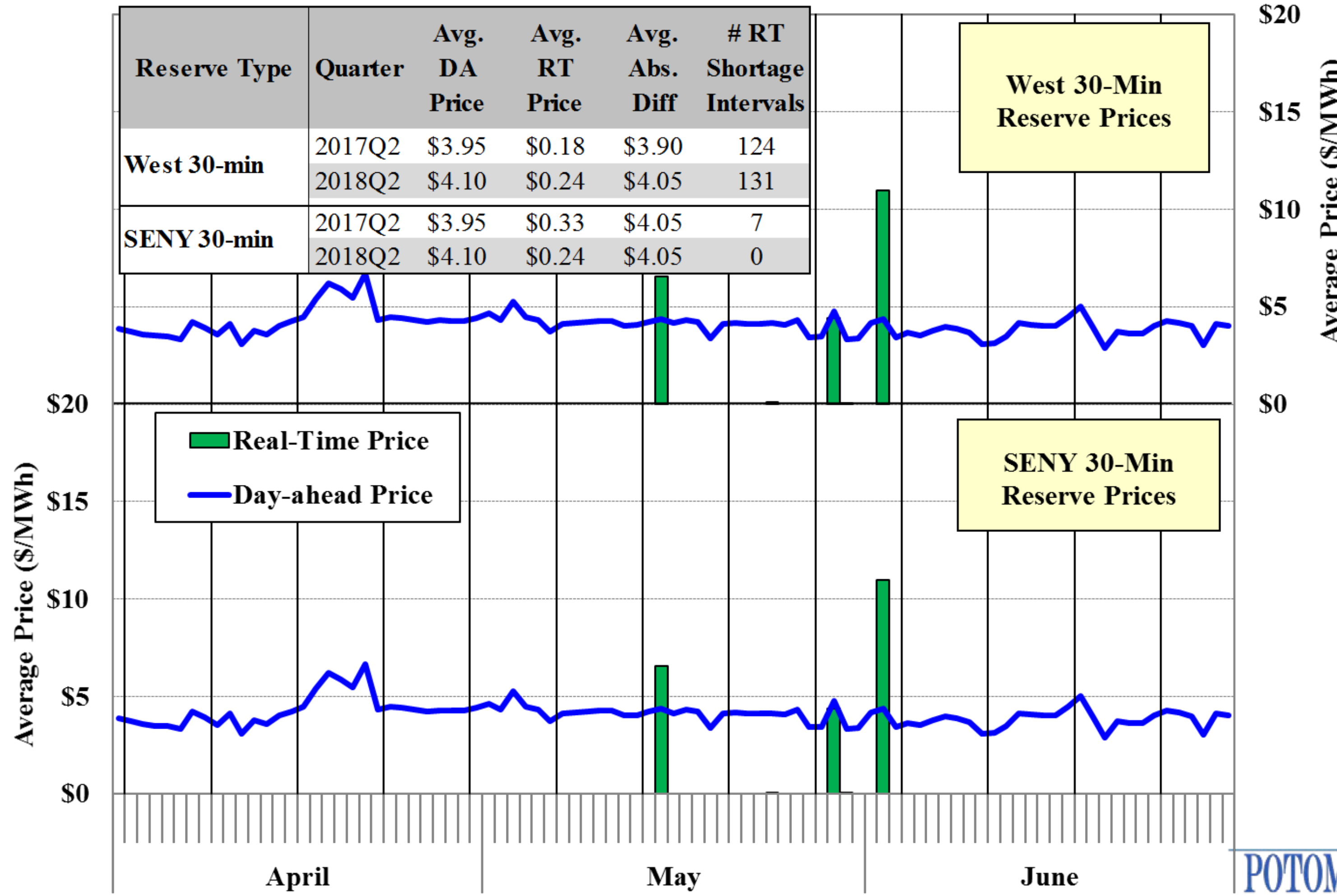
Reserve	Quarter	Avg. DA	Avg. RT	Avg.Abs.	# RT
West 10-Min Spin	2017Q2	$4.42	$2.02	$3.79	0
	2018Q2	$4.88	$4.32	$4.26	0
Regulation Capacity	2017Q2	$12.38	$11.49	$4.64	3630
	2018Q2	$10.98	$12.09	$4.60	2470
Movement	2017Q2		$2.32		
	2018Q2		$2.27		



Notes: For chart description, see slide 60.

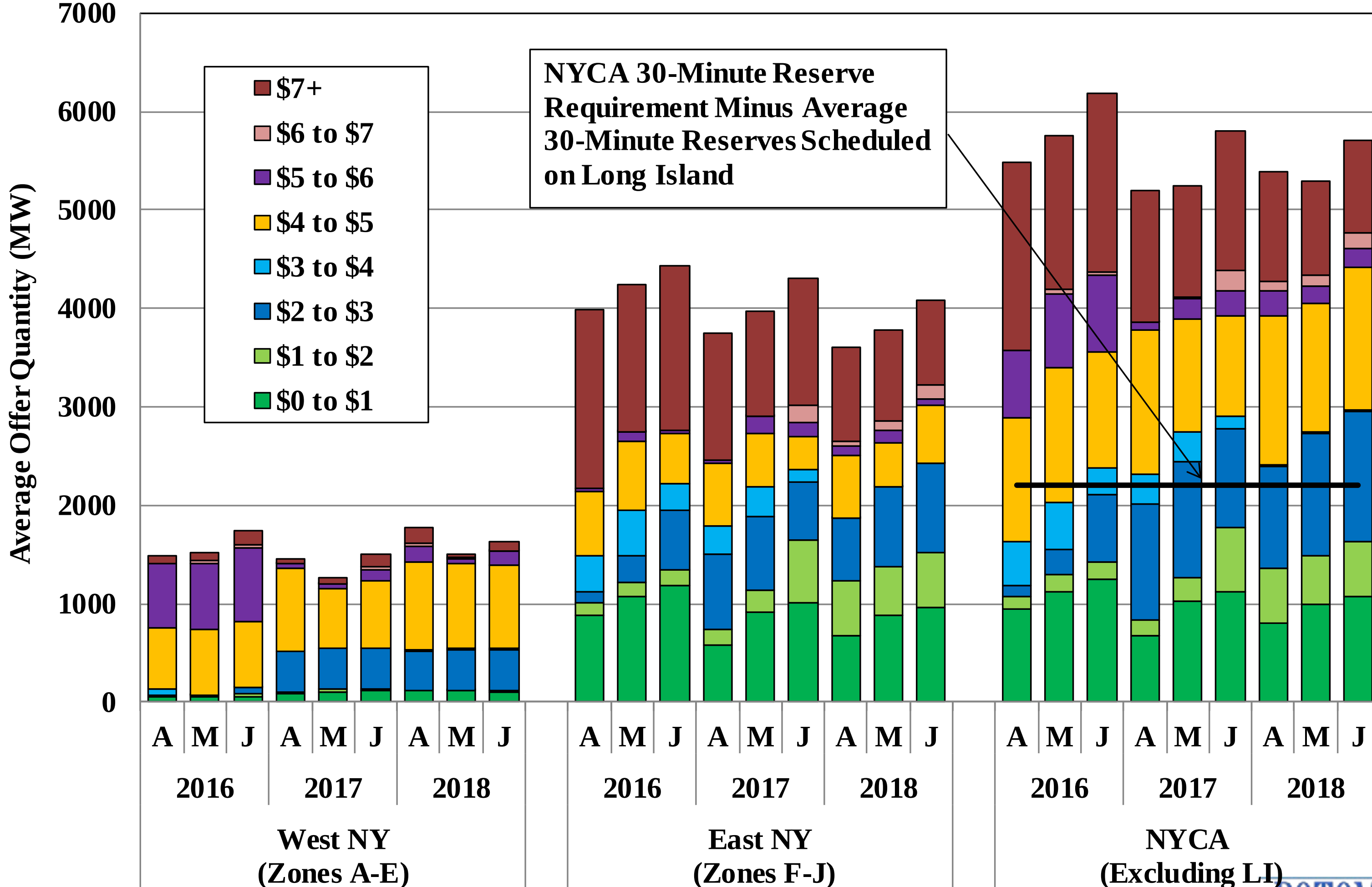
Day-Ahead and Real-Time Ancillary Services Prices
Western and SENY 30-Minute Reserves

Reserve Type	Quarter	Avg. DA Price	Avg. RT Price	Avg. Abs. Diff	# RT Shortage Intervals
West 30-min	2017Q2	$3.95	$0.18	$3.90	124
	2018Q2	$4.10	$0.24	$4.05	131
SENY 30-min	2017Q2	$3.95	$0.33	$4.05	7
	2018Q2	$4.10	$0.24	$4.05	0



Notes: For chart description, see slide 60.

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



Notes: For chart description, see slide 61.

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Charts:
Energy Market Scheduling

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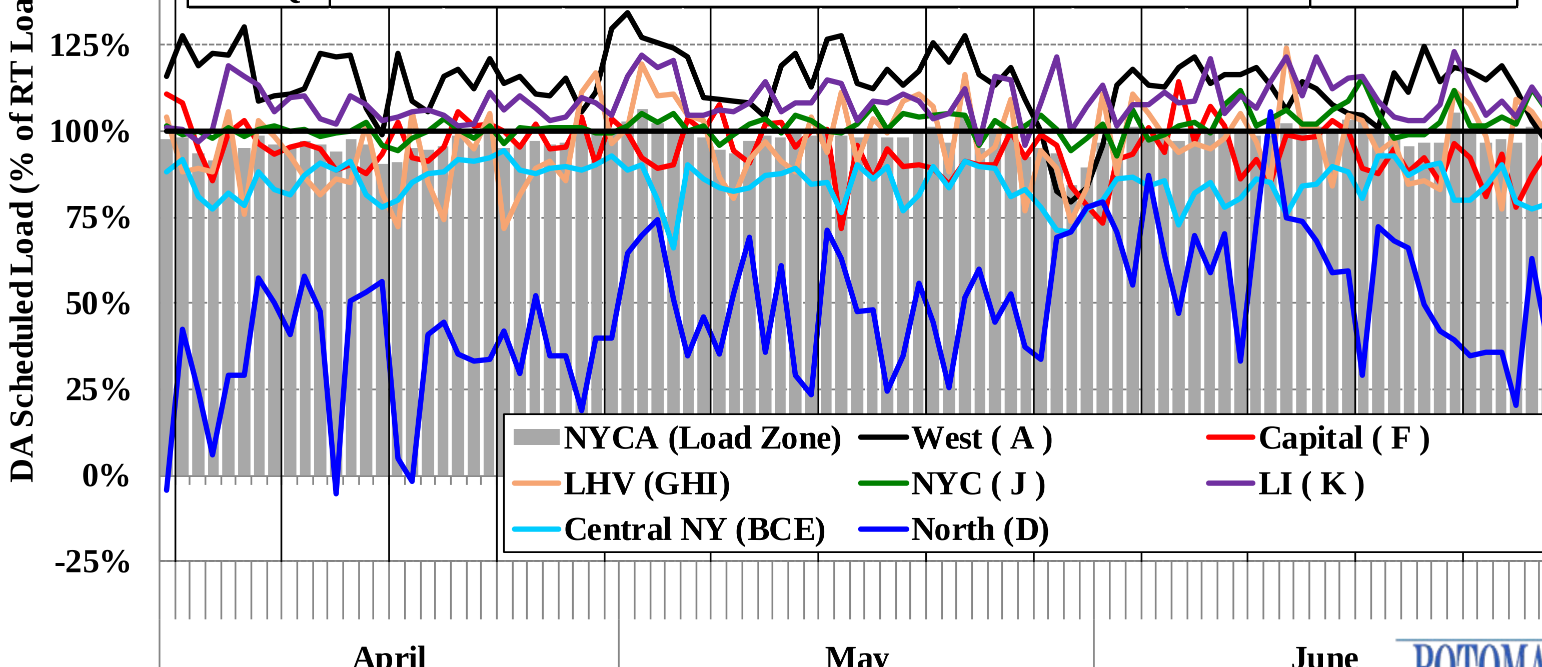
Day-ahead Scheduled Load and Actual Load
Daily Peak Load Hour

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)								
2018 Q2	113%	84%	47%	94%	96%	102%	109%	98%	96%
2018 Q1	110%	89%	44%	97%	92%	99%	103%	96%	94%
2017 Q2	120%	87%	34%	81%	87%	101%	106%	96%	94%



Notes: For chart description, see slide 62.

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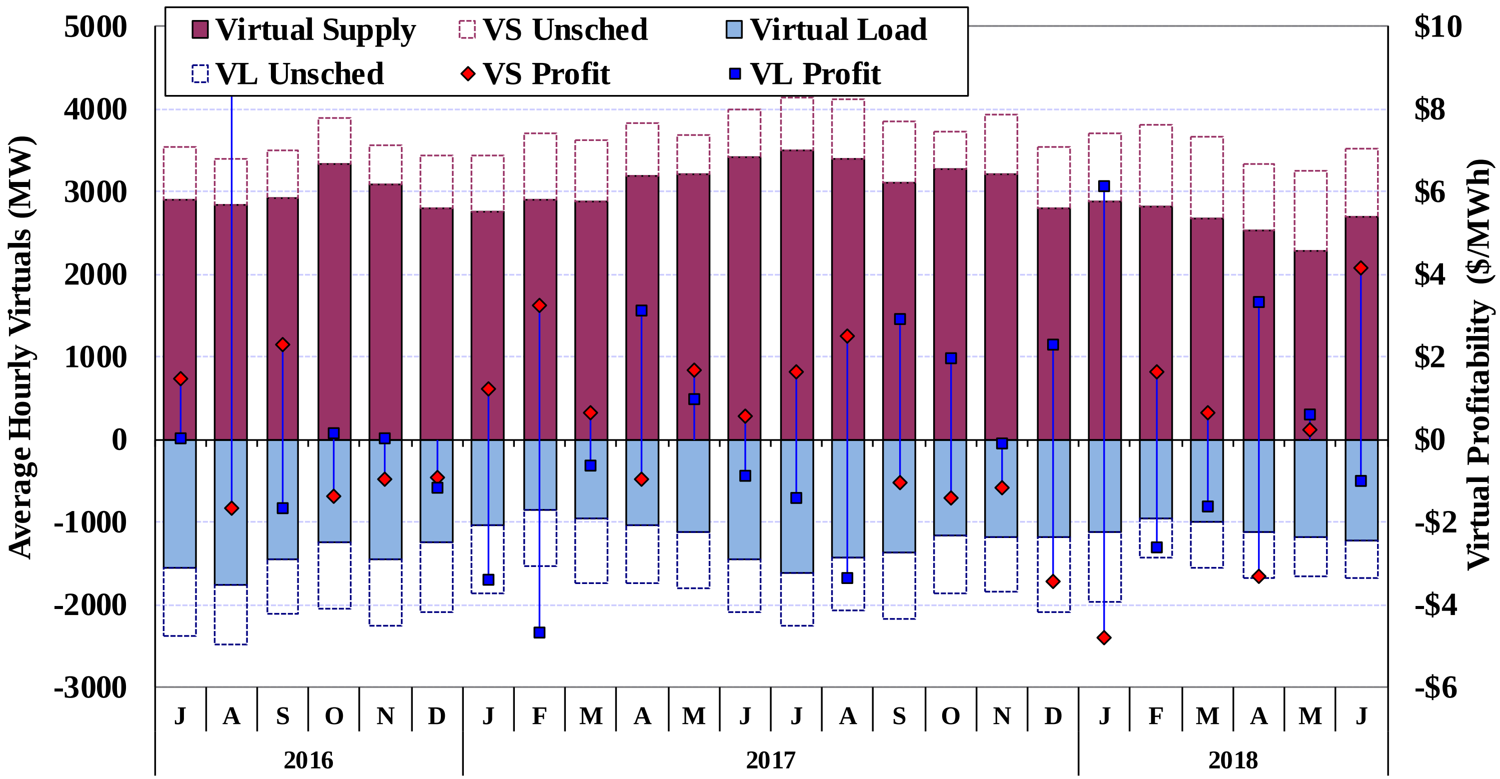
Virtual Trading Activity
by Month



		J	A	S	O	N	D	J	F	M	A	M	J	J	A	S	O	N	D	J	F	M	A	M	J
Profit > 50% of Avg. Zone Price	MW	596	398	360	281	261	490	243	507	585	449	645	502	593	439	257	271	320	396	373	450	419	376	475	620
	%	13%	9%	8%	6%	6%	12%	6%	13%	15%	11%	15%	10%	12%	9%	6%	6%	7%	10%	9%	12%	11%	10%	14%	16%
Loss > 50% of Avg. Zone Price	MW	517	413	411	419	345	587	284	336	514	454	553	542	568	466	418	399	412	478	442	342	401	466	537	531
	%	12%	9%	9%	9%	8%	14%	7%	9%	13%	11%	13%	11%	11%	10%	9%	9%	9%	12%	11%	9%	11%	13%	16%	14%

Notes: For chart description, see slide 62.

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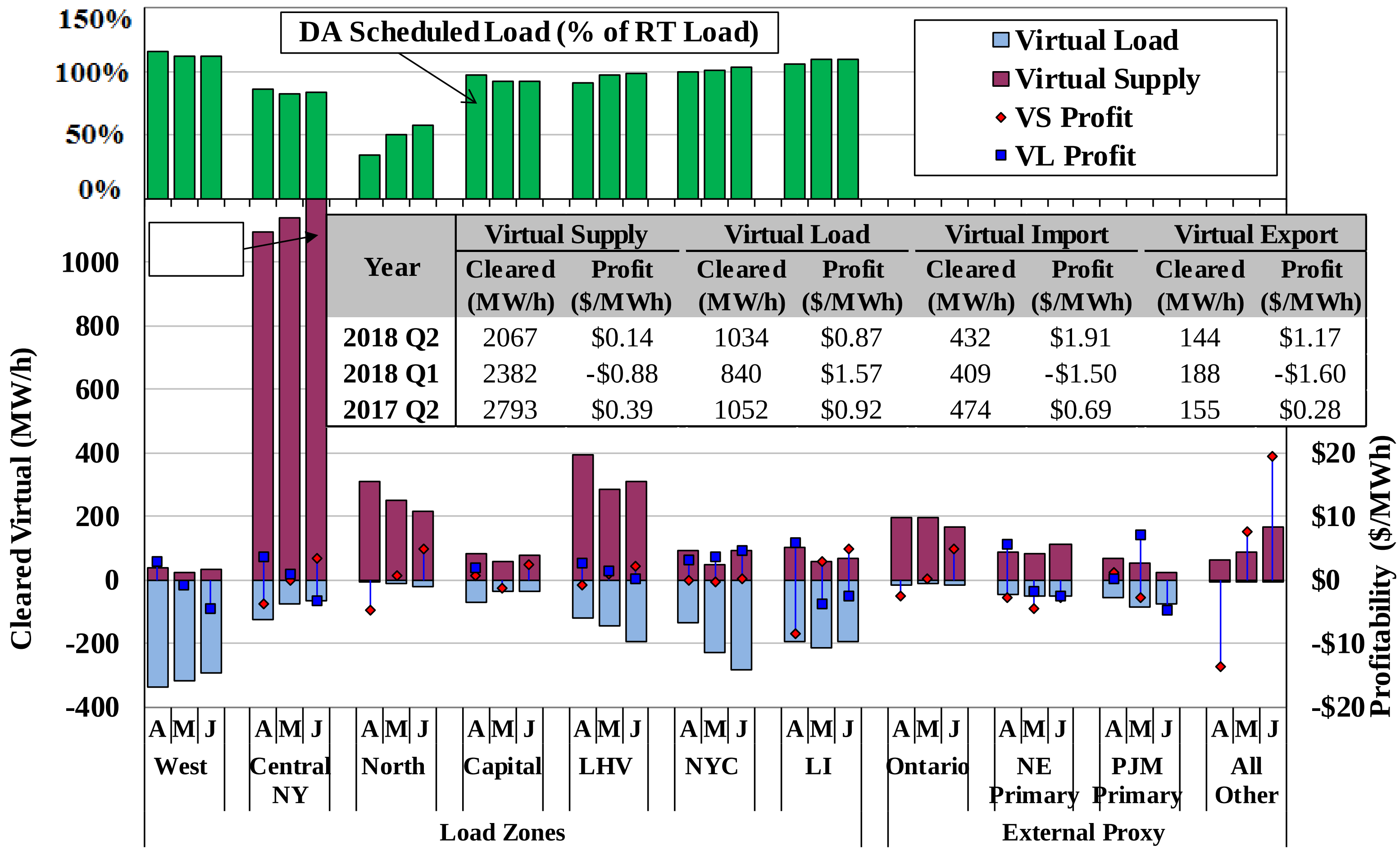
Virtual Trading Activity
by Location

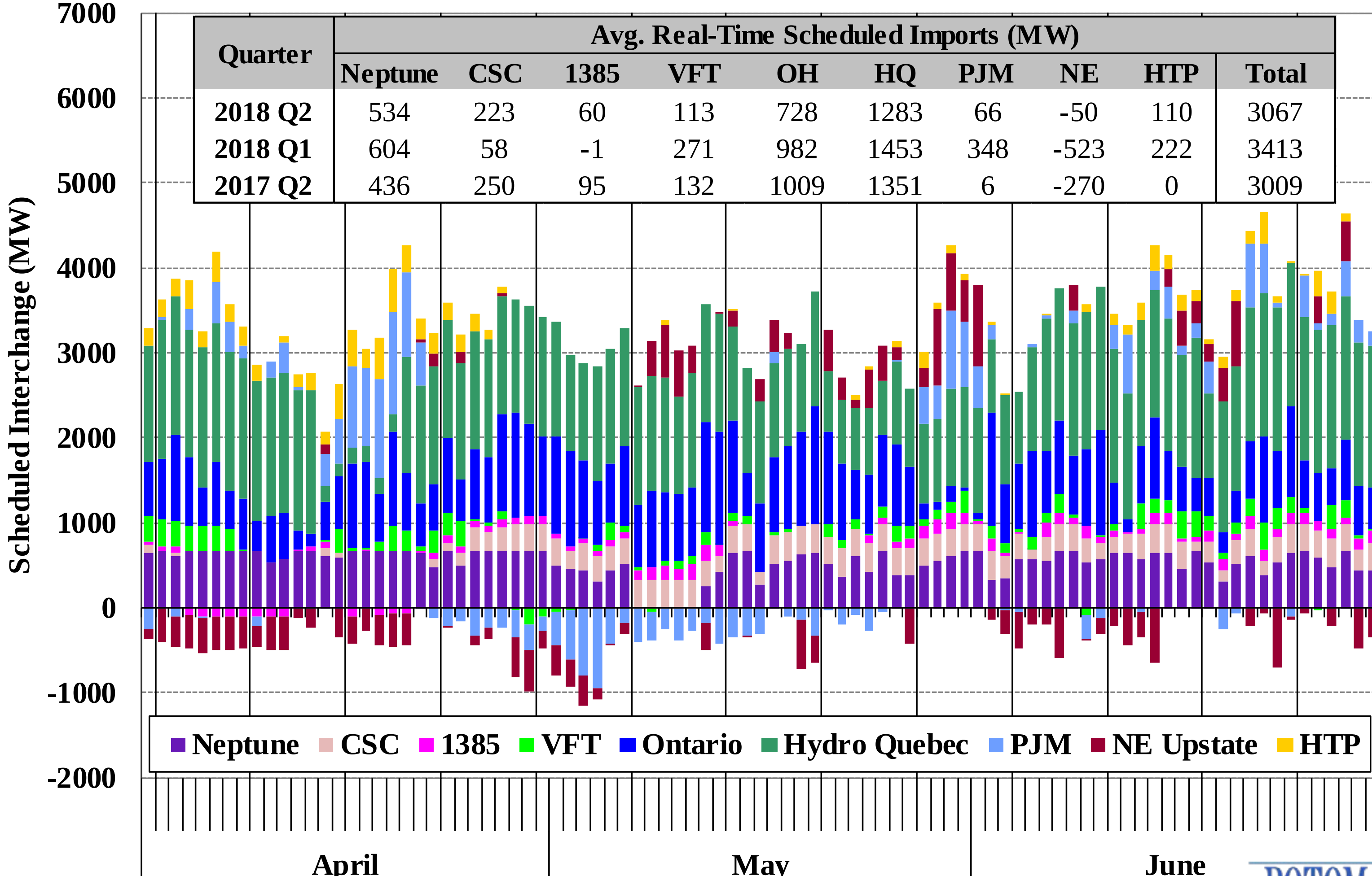


Year	Virtual Supply		Virtual Load		Virtual Import		Virtual Export	
	Cleared (MW/h)	Profit ($/MWh)	Cleared (MW/h)	Profit ($/MWh)	Cleared (MW/h)	Profit ($/MWh)	Cleared (MW/h)	Profit ($/MWh)
2018 Q2	2067	$0.14	1034	$0.87	432	$1.91	144	$1.17
2018 Q1	2382	-$0.88	840	$1.57	409	-$1.50	188	-$1.60
2017 Q2	2793	$0.39	1052	$0.92	474	$0.69	155	$0.28

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 62.

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
2018 Q2	534	223	60	113	728	1283	66	-50	110	3067
2018 Q1	604	58	-1	271	982	1453	348	-523	222	3413
2017 Q2	436	250	95	132	1009	1351	6	-270	0	3009



Notes: Two HQ interfaces are combined into one.

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

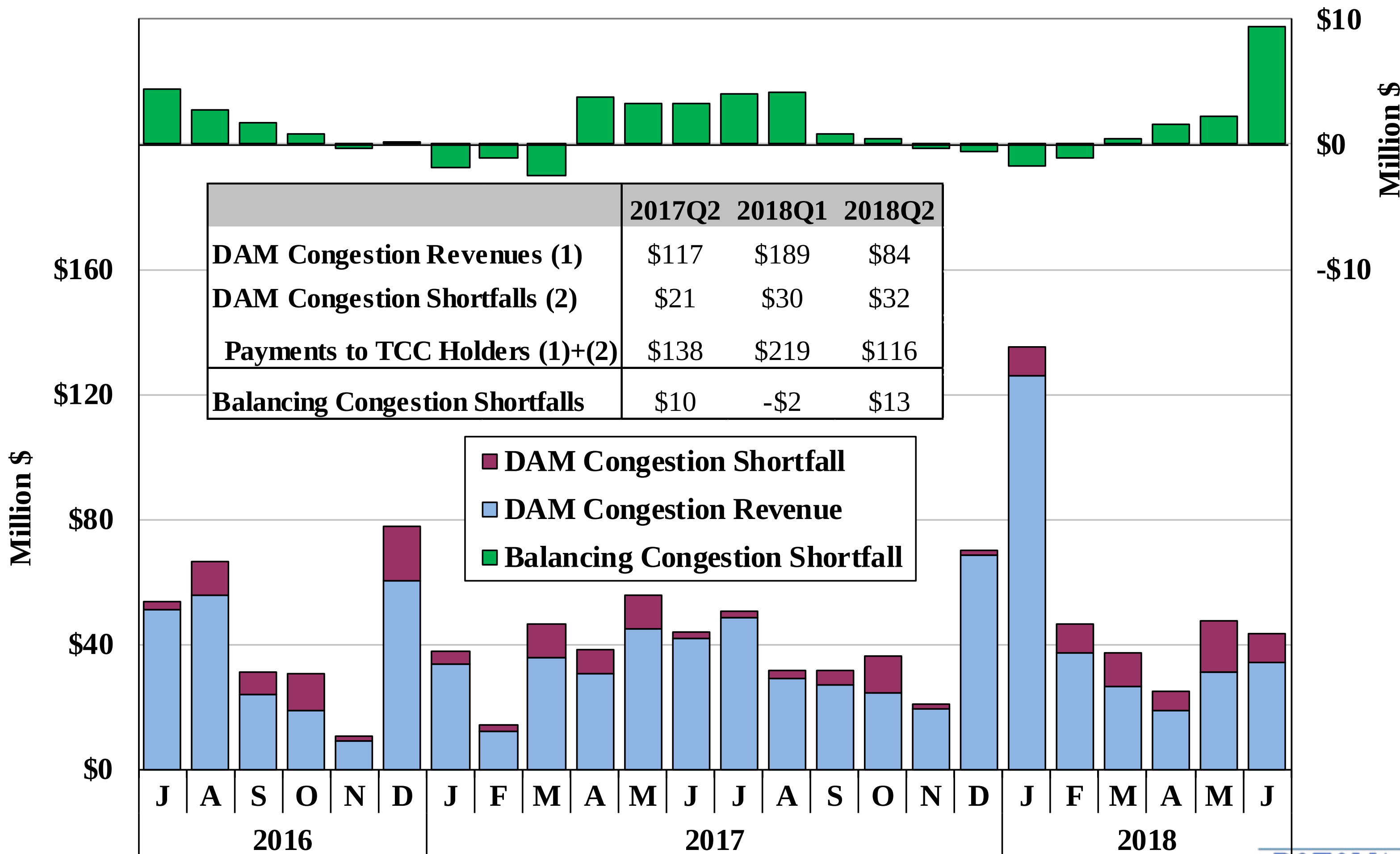
			Average/Total During Intervals w/ Adjustment					
			CTS - NY/NE			CTS - NY/PJM		
			Both Forecast Errors <= $20	Any Forecast Error > $20	Total	Both Forecast Errors <= $20	Any Forecast Error > $20	Total
% of All Intervals w/ Adjustment			71%	9%	**80%**	56%	10%	**66%**
Average Flow Adjustment (MW)	Net Imports		22	16	**22**	8	7	**8**
	Gross		92	122	**95**	58	88	**63**
Production Cost Savings ($ Million)	Projected at Scheduling Time		$0.7	$0.6	**$1.3**	$0.3	$0.5	**$0.8**
	Net Over-Projection by:	NY	-$0.1	$0.2	**$0.1**	-$0.05	-$0.2	**-$0.2**
		NE or PJM	$0.01	-$0.2	**-$0.2**	-$0.1	-$0.3	**-$0.4**
	Other Unrealized Savings		-$0.04	-$0.1	**-$0.1**	-$0.03	-$0.1	**-$0.1**
	Actual Savings		$0.6	$0.5	**$1.2**	$0.1	-$0.1	**$0.1**
Interface Prices ($/MWh)	NY	Actual	$23.17	$56.08	**$26.85**	$22.23	$57.98	**$27.84**
		Forecast	$24.25	$34.52	**$25.40**	$23.14	$42.61	**$26.19**
	NE or PJM	Actual	$24.87	$37.01	**$26.23**	$24.85	$55.01	**$29.59**
		Forecast	$24.60	$36.78	**$25.96**	$26.32	$50.11	**$30.06**
Price Forecast Errors ($/MWh)	NY	Fcst. - Act.	$1.08	-$21.56	**-$1.45**	$0.91	-$15.37	**-$1.65**
		Abs. Val.	$3.49	$37.56	**$7.30**	$3.32	$37.14	**$8.63**
	NE or PJM	Fcst. - Act.	-$0.27	-$0.23	**-$0.27**	$1.47	-$4.91	**$0.47**
		Abs. Val.	$4.41	$30.72	**$7.35**	$4.62	$43.41	**$10.71**

Notes: For chart description, see slide 63.

POTOMAC ECONOMICS

Charts:
Transmission Congestion Revenues and Shortfalls

Congestion Revenues and Shortfalls by Month

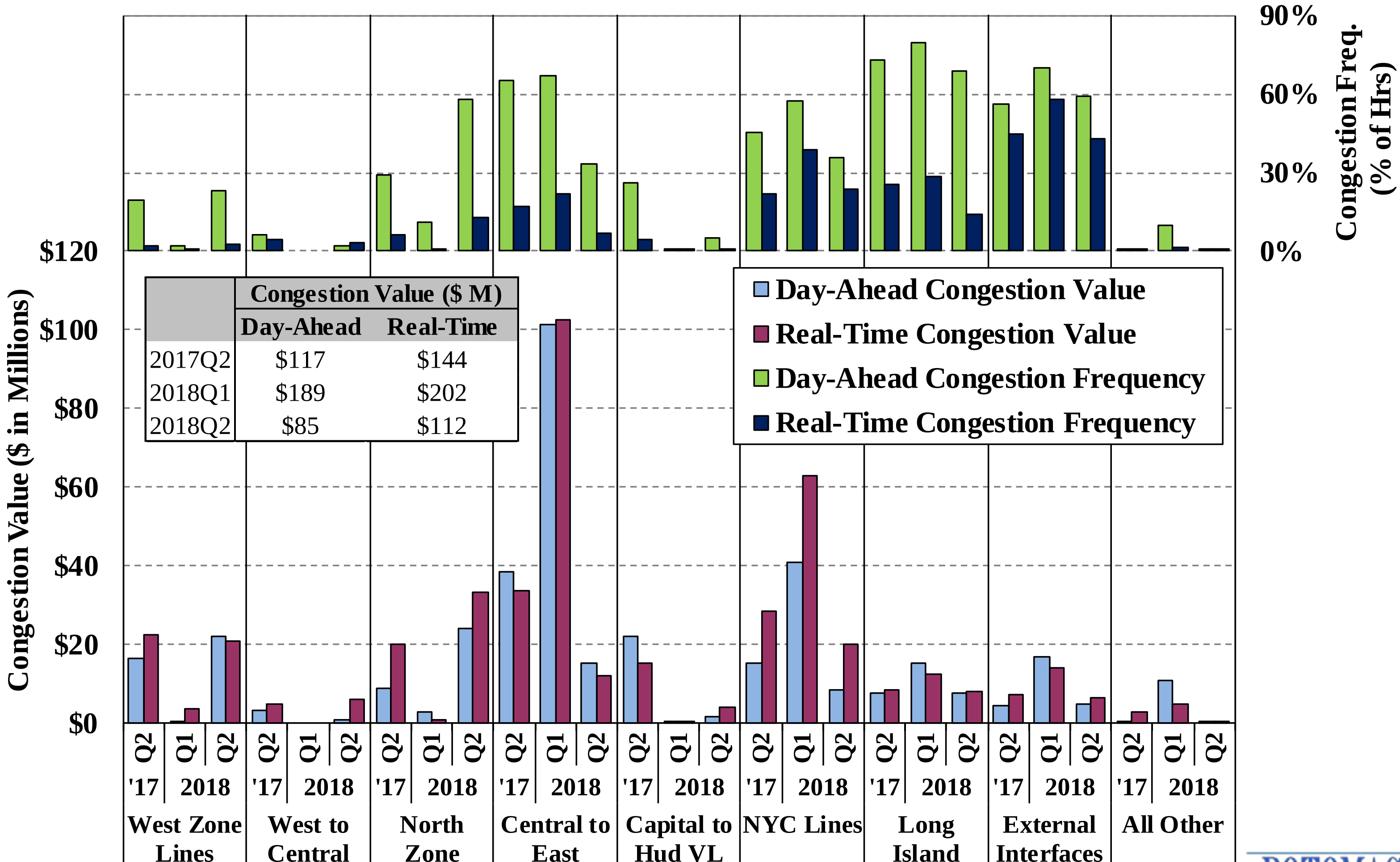


	2017Q2	2018Q1	2018Q2
DAM Congestion Revenues (1)	$117	$189	$84
DAM Congestion Shortfalls (2)	$21	$30	$32
Payments to TCC Holders (1)+(2)	$138	$219	$116
Balancing Congestion Shortfalls	$10	-$2	$13

Notes: For chart description, see slides 64 and 65.

POTOMAC ECONOMICS

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

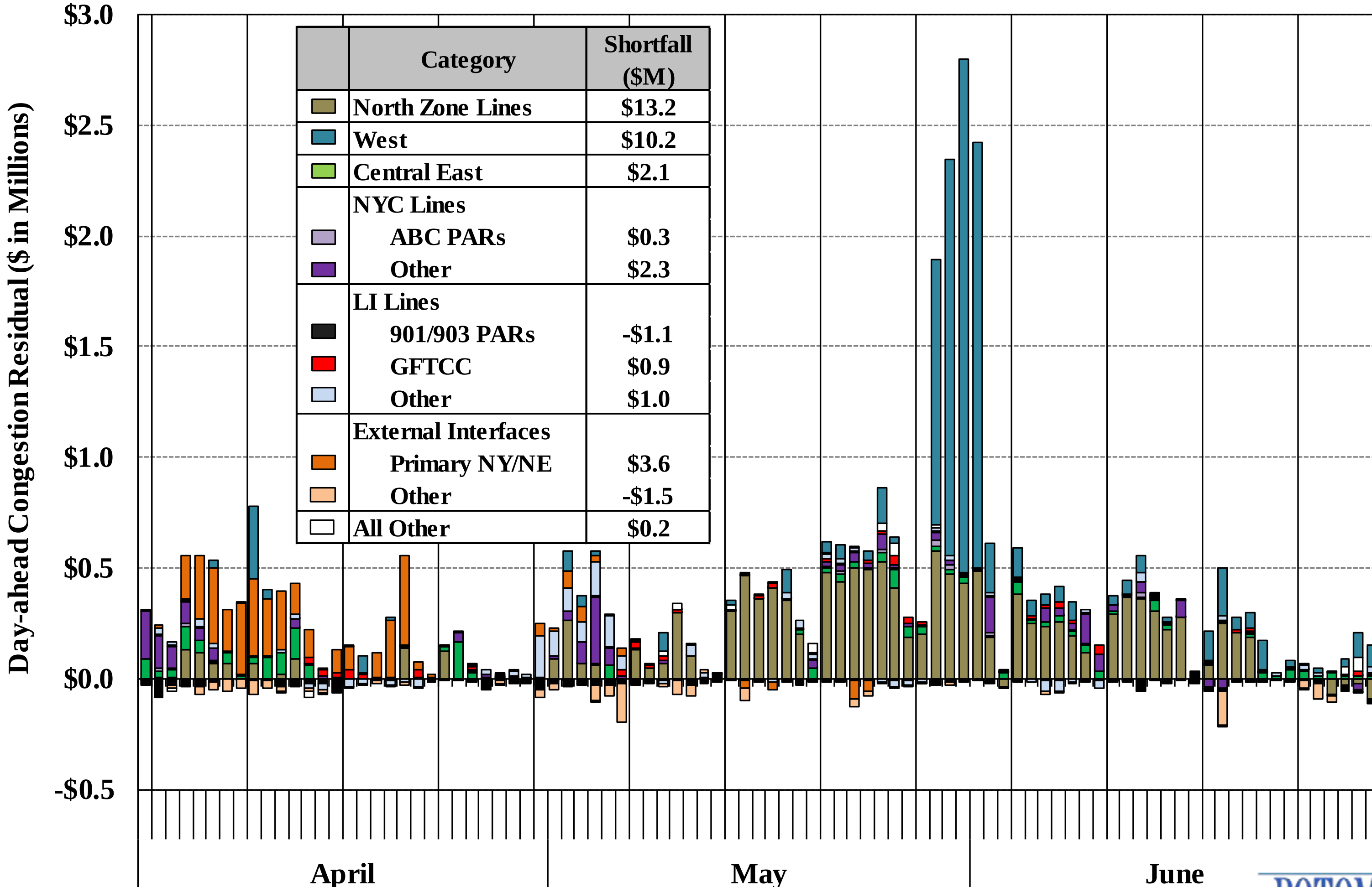


	Congestion Value ($ M)	
	Day-Ahead	Real-Time
2017Q2	$117	$144
2018Q1	$189	$202
2018Q2	$85	$112

Notes: For chart description, see slides 64, 65, and 66.

POTOMAC ECONOMICS

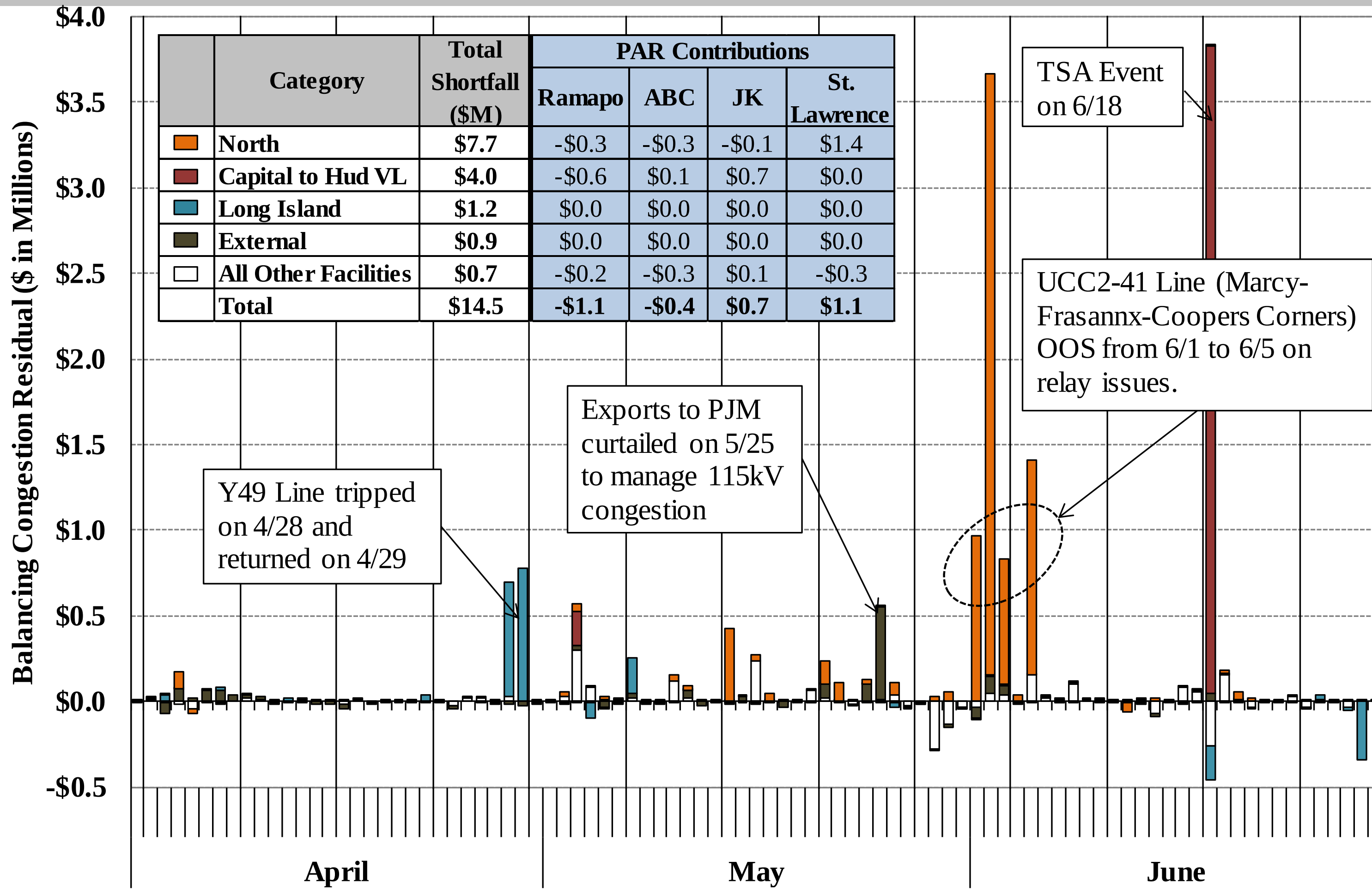
Day-Ahead Congestion Revenue Shortfalls by Transmission Facility



Notes: For chart description, see slides 64, 65, and 66.

POTOMAC ECONOMICS

Balancing Congestion Shortfalls by Transmission Facility

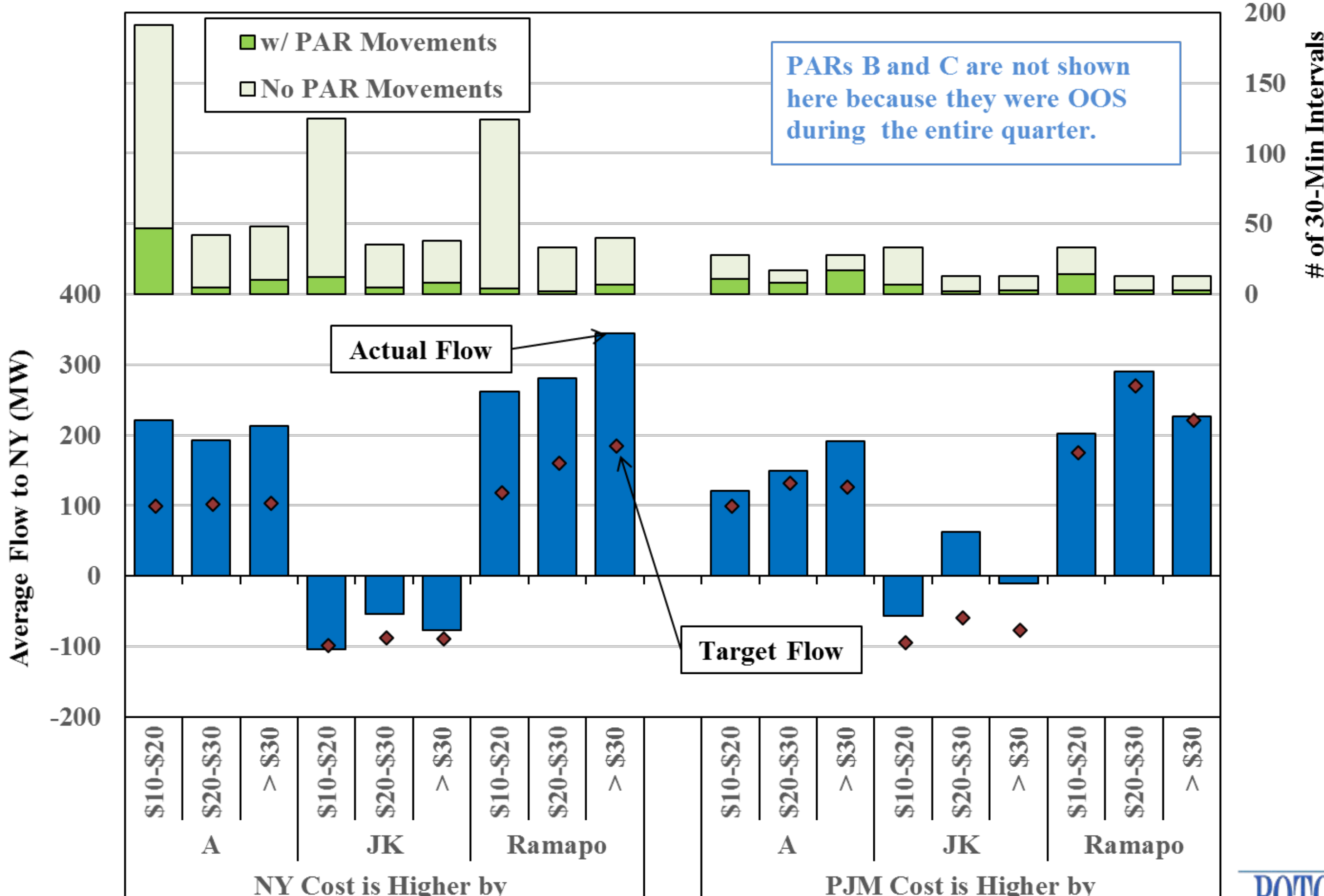


	Category	Total Shortfall ($M)	PAR Contributions			
			Ramapo	ABC	JK	St. Lawrence
■	North	$7.7	-$0.3	-$0.3	-$0.1	$1.4
■	Capital to Hud VL	$4.0	-$0.6	$0.1	$0.7	$0.0
■	Long Island	$1.2	$0.0	$0.0	$0.0	$0.0
■	External	$0.9	$0.0	$0.0	$0.0	$0.0
□	All Other Facilities	$0.7	-$0.2	-$0.3	$0.1	-$0.3
	Total	**$14.5**	**-$1.1**	**-$0.4**	**$0.7**	**$1.1**

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 64, 65, and 66.

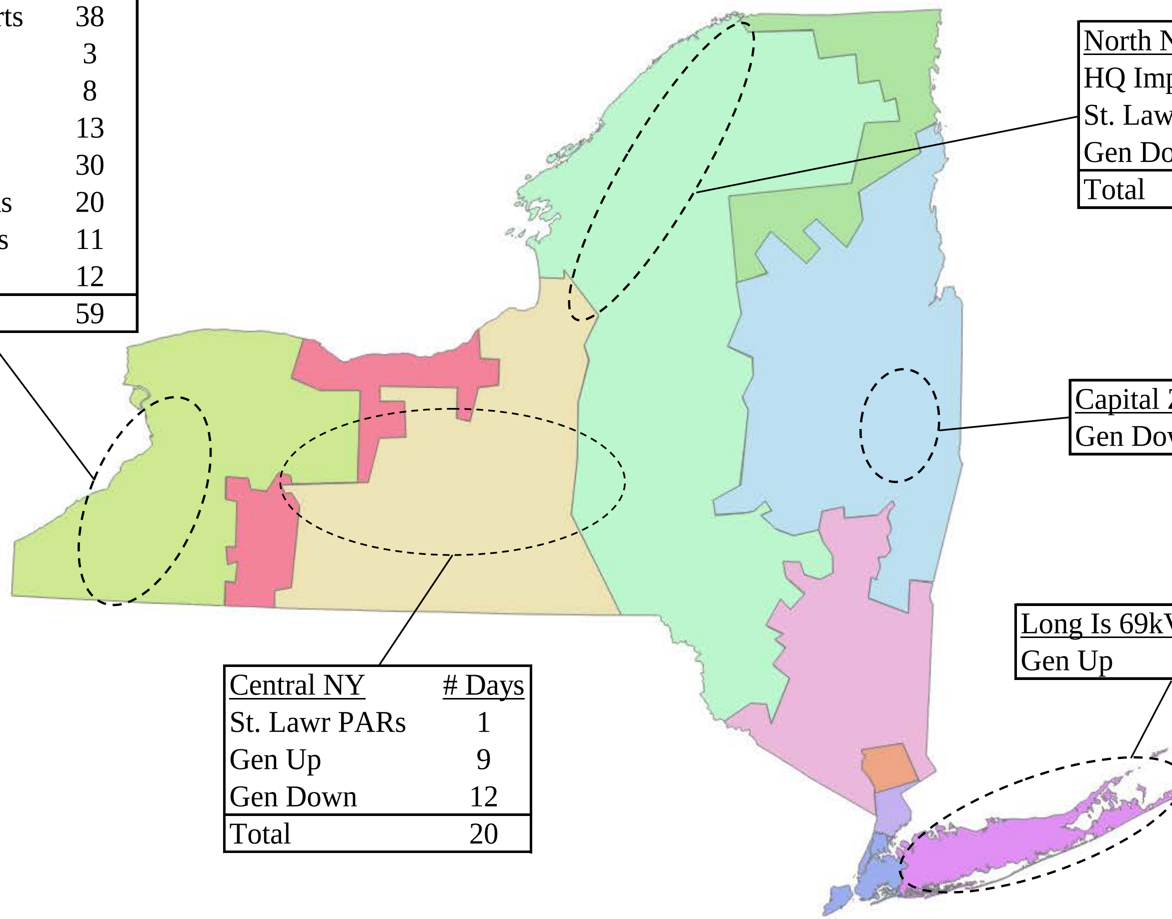
POTOMAC ECONOMICS

PAR Operation under M2M with PJM
2018 Q2



  Notes: For chart description, see slide 67.

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



West NY	# Days
Ontario Imports	38
PJM Exports	3
Dysinger East	8
Gen Up	13
Gen Down	30
St. Lawr PARs	20
Ramapo PARs	11
ABC PARs	12
Total	59

North NY	# Days
HQ Imports	7
St. Lawr PARs	1
Gen Down	1
Total	9

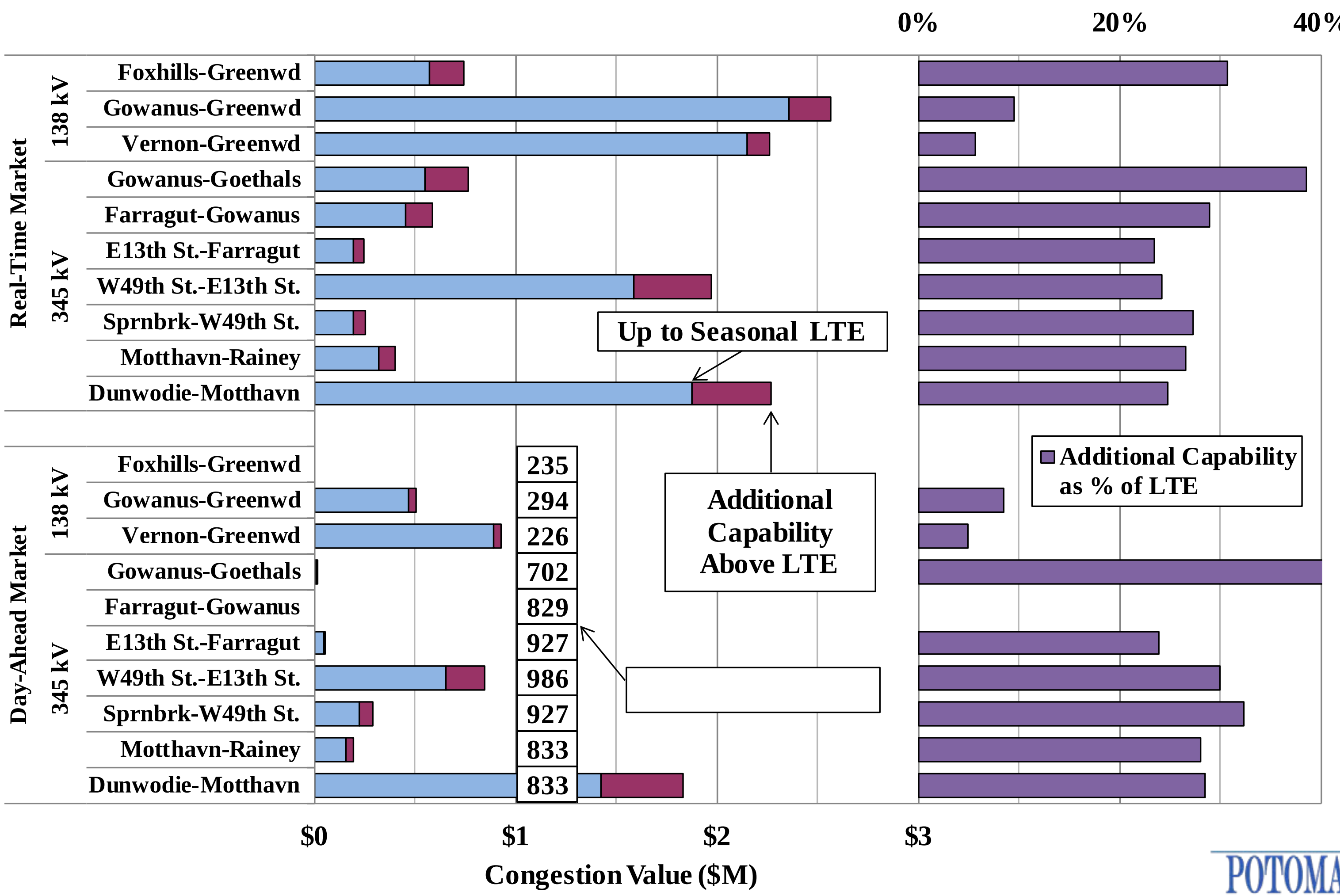
Capital Zone	# Days
Gen Down	24

Central NY	# Days
St. Lawr PARs	1
Gen Up	9
Gen Down	12
Total	20

Long Is 69kV	# Days
Gen Up	14

Notes: For chart description, see slide 68.

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



Notes: For chart description, see slide 69.

POTOMAC ECONOMICS

Constraint Limit and CRM in New York
During Real-Time Transmission Shortage Intervals

Constraint Voltage Class	Constraint Location	# of Constraint-Shortage Intervals	Avg Constraint Limit (MW)	Avg CRM (MW)	Avg Shortage MW		CRM as % of Limit
					Recognized in Model	Excluding Offline GT	
115 kV	**North**	465	137	20	4	4	15%
138 kV	**New York City**	561	194	20	6	6	11%
	Long Island	219	260	20	7	11	8%
230 kV	**West**	555	688	43	10	10	6%
	North	62	374	20	7	7	5%
	All Others	10	479	20	9	9	4%
345 kV	**New York City**	162	909	20	3	9	2%
	North	133	1588	50	50	56	3%
	Long Island	247	779	50	0.5	15	6%
	All Others	37	1533	21	6	20	1%

Notes: 1. In this analysis, a transmission shortage is measured excluding the congestion-relief effects from offline GTs.
2. For chart description, see slide 70.

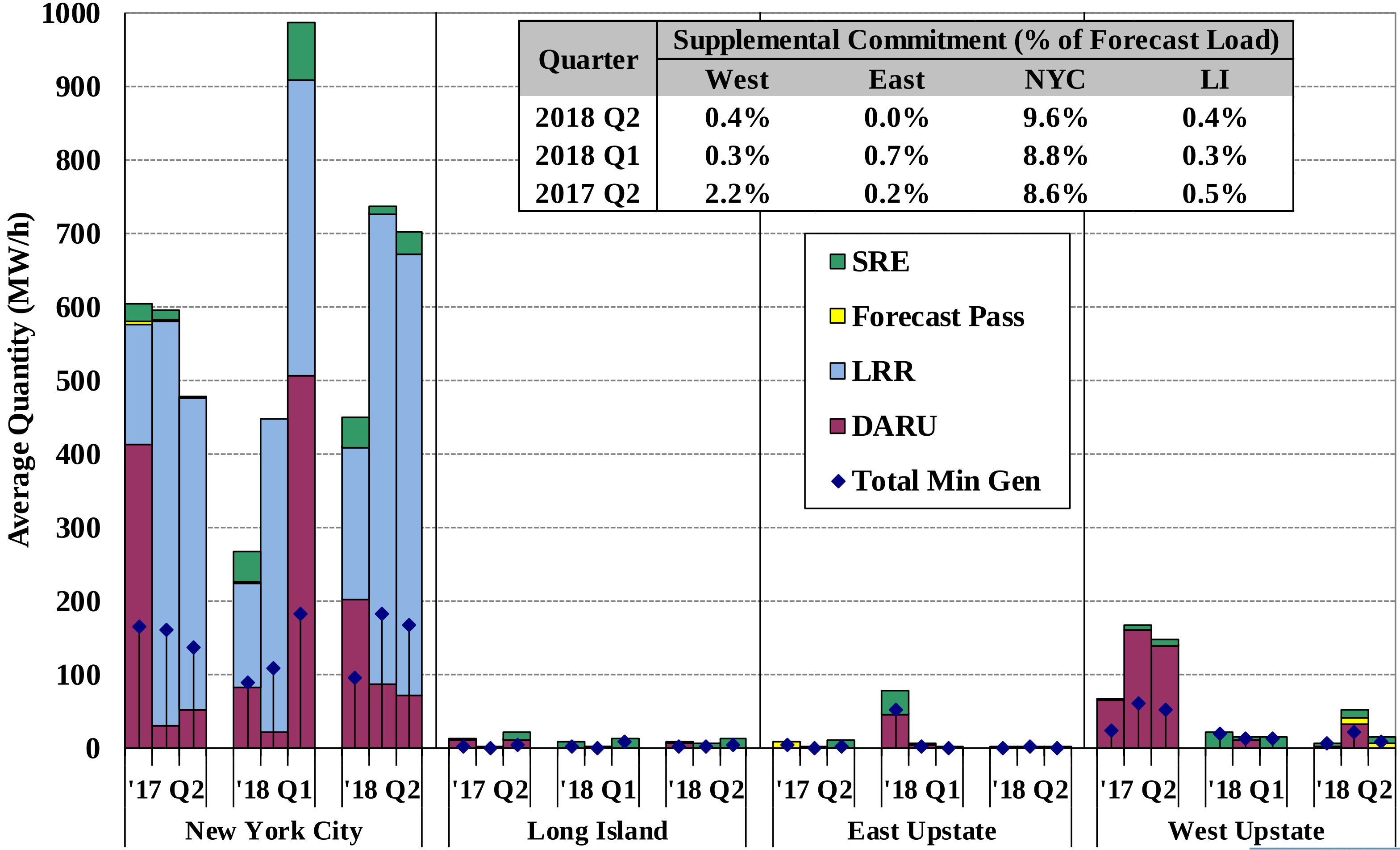
POTOMAC ECONOMICS

Charts:

Supplemental Commitment, OOM Dispatch, and BPCG Uplift

POTOMAC ECONOMICS

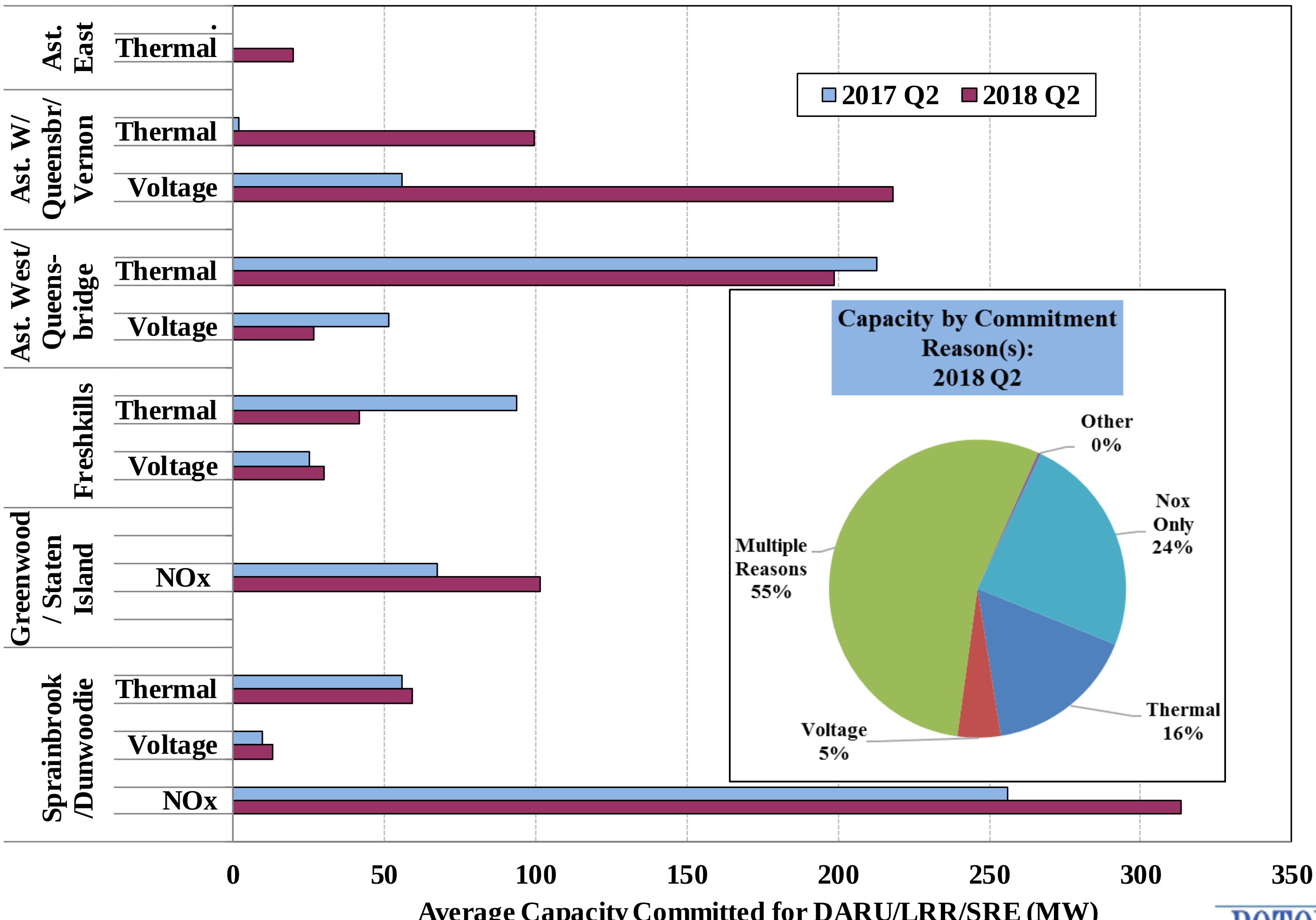
Supplemental Commitment for Reliability
by Category and Region



Quarter	Supplemental Commitment (% of Forecast Load)			
	West	East	NYC	LI
2018 Q2	0.4%	0.0%	9.6%	0.4%
2018 Q1	0.3%	0.7%	8.8%	0.3%
2017 Q2	2.2%	0.2%	8.6%	0.5%

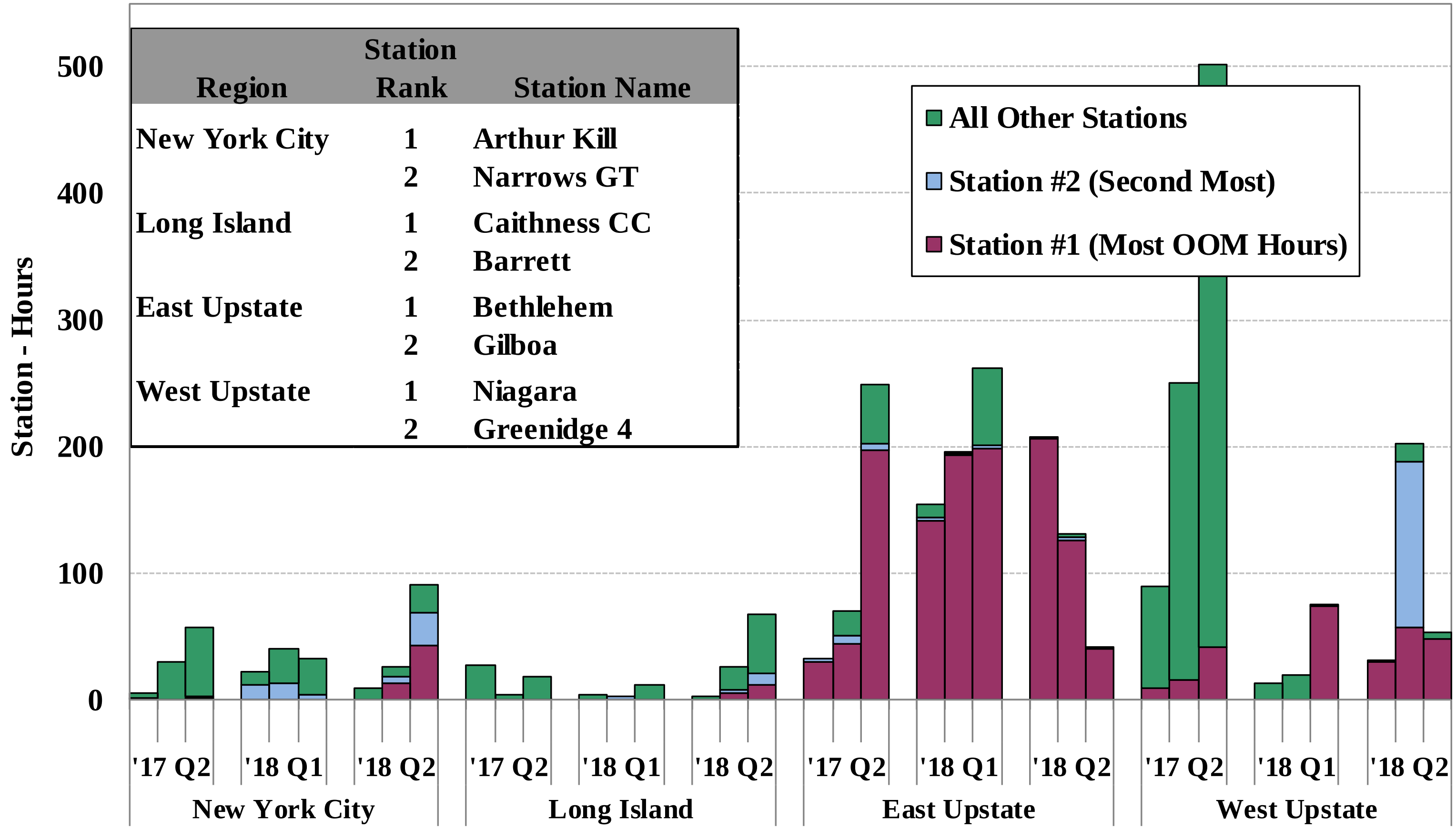
Notes: For chart description, see slides 71 and 72.

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



Notes: For chart description, see slides 71 and 72.

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

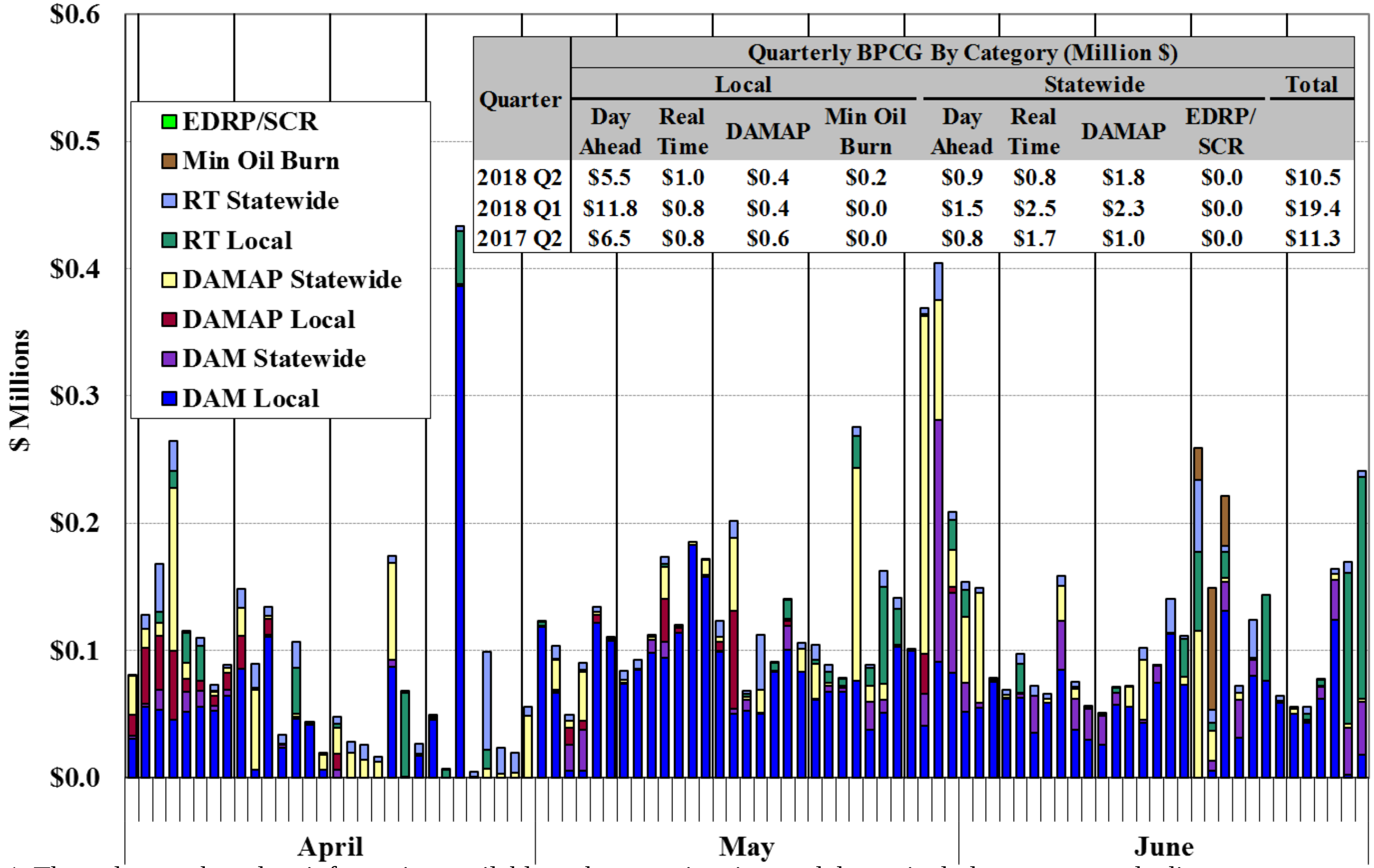


Region	Station Rank	Station Name
New York City	1	Arthur Kill
	2	Narrows GT
Long Island	1	Caithness CC
	2	Barrett
East Upstate	1	Bethlehem
	2	Gilboa
West Upstate	1	Niagara
	2	Greenidge 4

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 289 hours in 2017-Q2, 247 hours in 2018-Q1, and 382 hours in 2018-Q2. However, these were not classified as Out-of-Merit in hours when the NYISO did not adjust the UOL or LOL of the Resource.
2. For chart description, see slides 71 and 72.

POTOMAC ECONOMICS

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

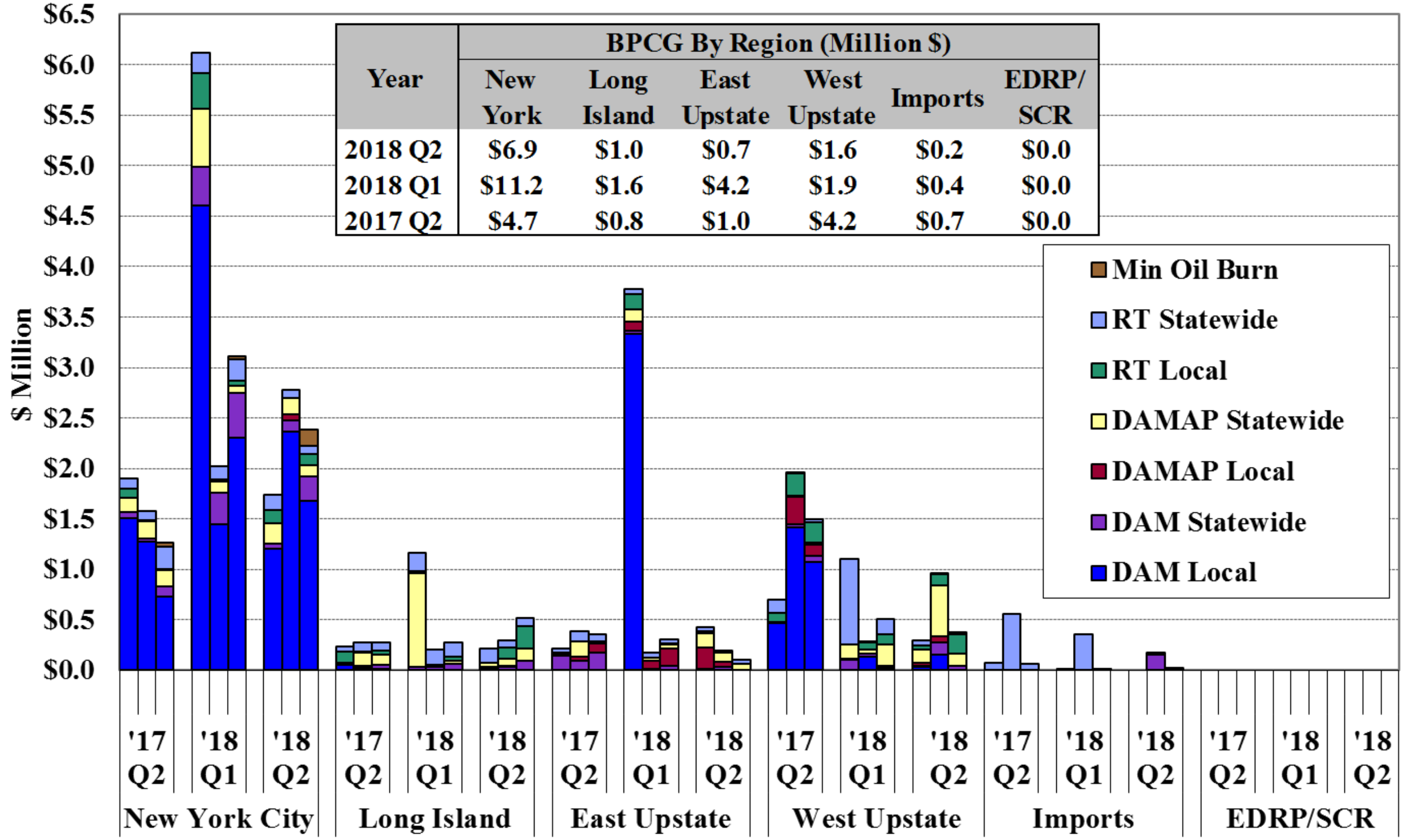


Quarter	Quarterly BPCG By Category (Million $)								
	Local				Statewide				Total
	Day Ahead	Real Time	DAMAP	Min Oil Burn	Day Ahead	Real Time	DAMAP	EDRP/ SCR	
2018 Q2	$5.5	$1.0	$0.4	$0.2	$0.9	$0.8	$1.8	$0.0	$10.5
2018 Q1	$11.8	$0.8	$0.4	$0.0	$1.5	$2.5	$2.3	$0.0	$19.4
2017 Q2	$6.5	$0.8	$0.6	$0.0	$0.8	$1.7	$1.0	$0.0	$11.3

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 73.

POTOMAC ECONOMICS

Uplift Costs from Guarantee Payments
By Category and Region



Year	BPCG By Region (Million $)					
	New York	Long Island	East Upstate	West Upstate	Imports	EDRP/ SCR
2018 Q2	$6.9	$1.0	$0.7	$1.6	$0.2	$0.0
2018 Q1	$11.2	$1.6	$4.2	$1.9	$0.4	$0.0
2017 Q2	$4.7	$0.8	$1.0	$4.2	$0.7	$0.0

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 73.

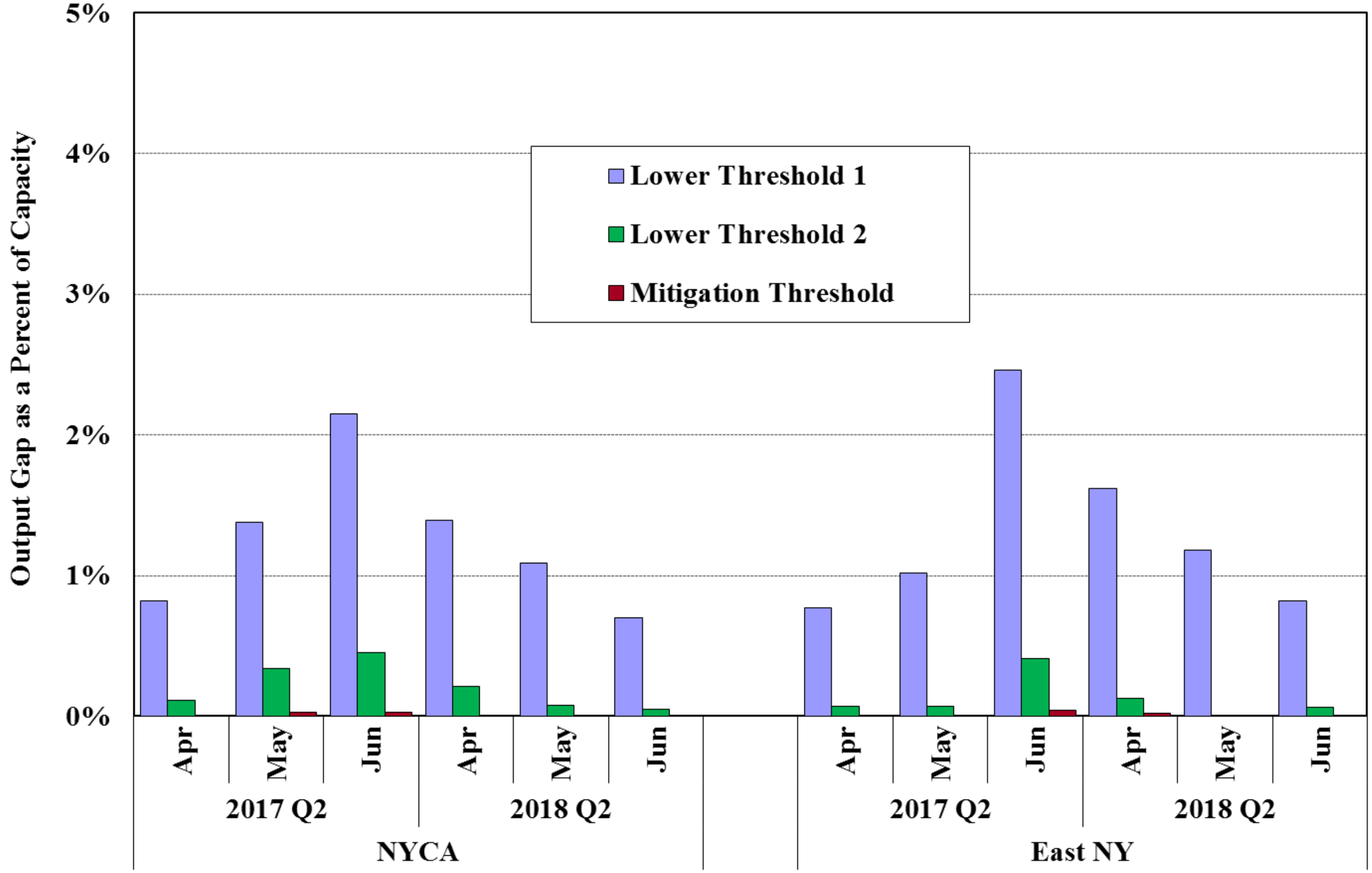
POTOMAC ECONOMICS

Charts:

Market Power and Mitigation

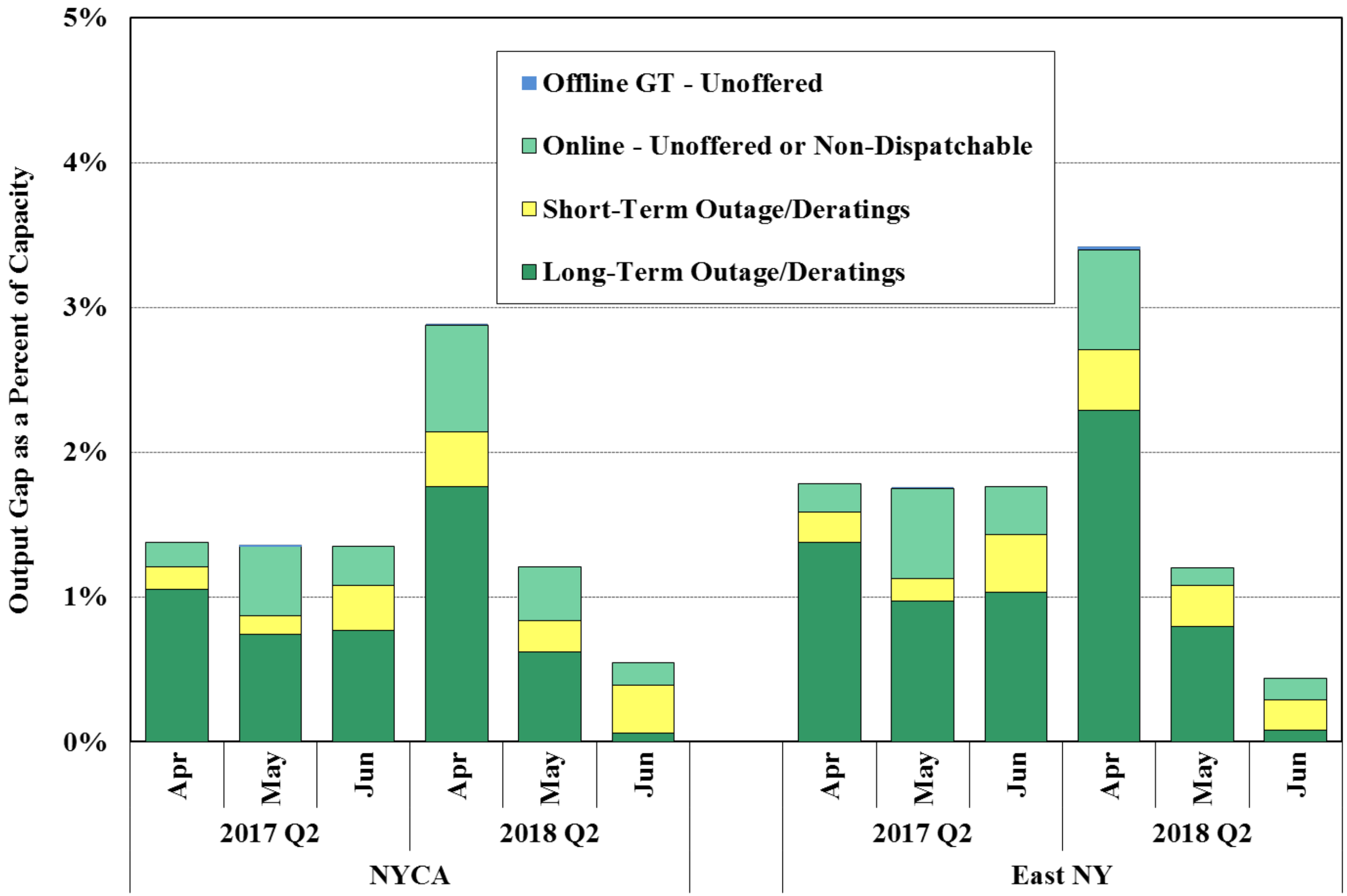
POTOMAC ECONOMICS

Output Gap by Month
NYCA and East NY



Notes: 1. Numbers reported here for historical periods may be slightly different from the ones reported previously because of improved assumptions and methodology for the calculation. 2. For chart description, see slide 74.

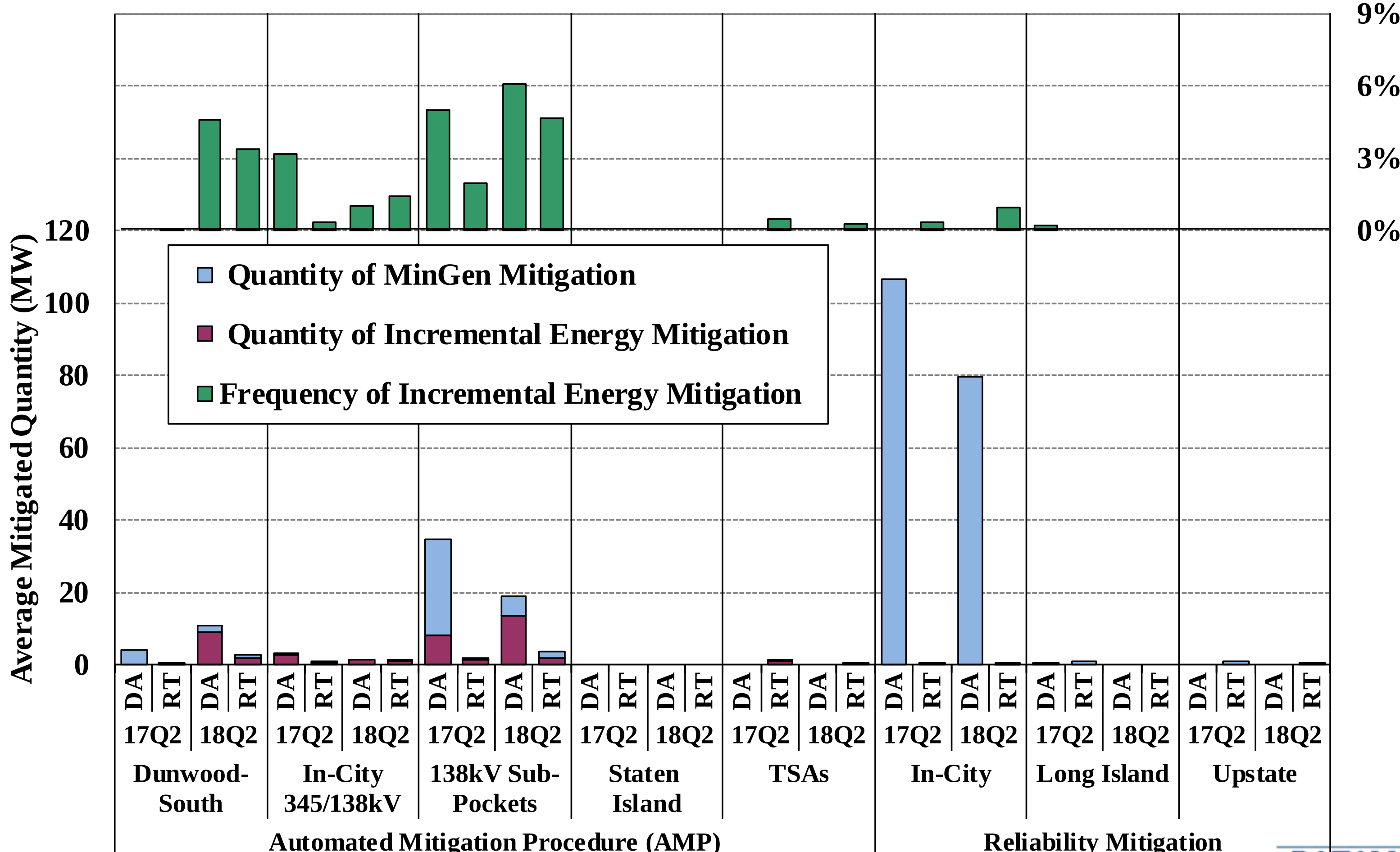
Unoffered Economic Capacity by Month
NYCA and East NY



Notes: 1. Numbers reported here for historical periods may be slightly different from the ones reported previously because of improved assumptions and methodology for the calculation. 2. For chart description, see slide 74.

POTOMAC ECONOMICS

Automated Market Power Mitigation



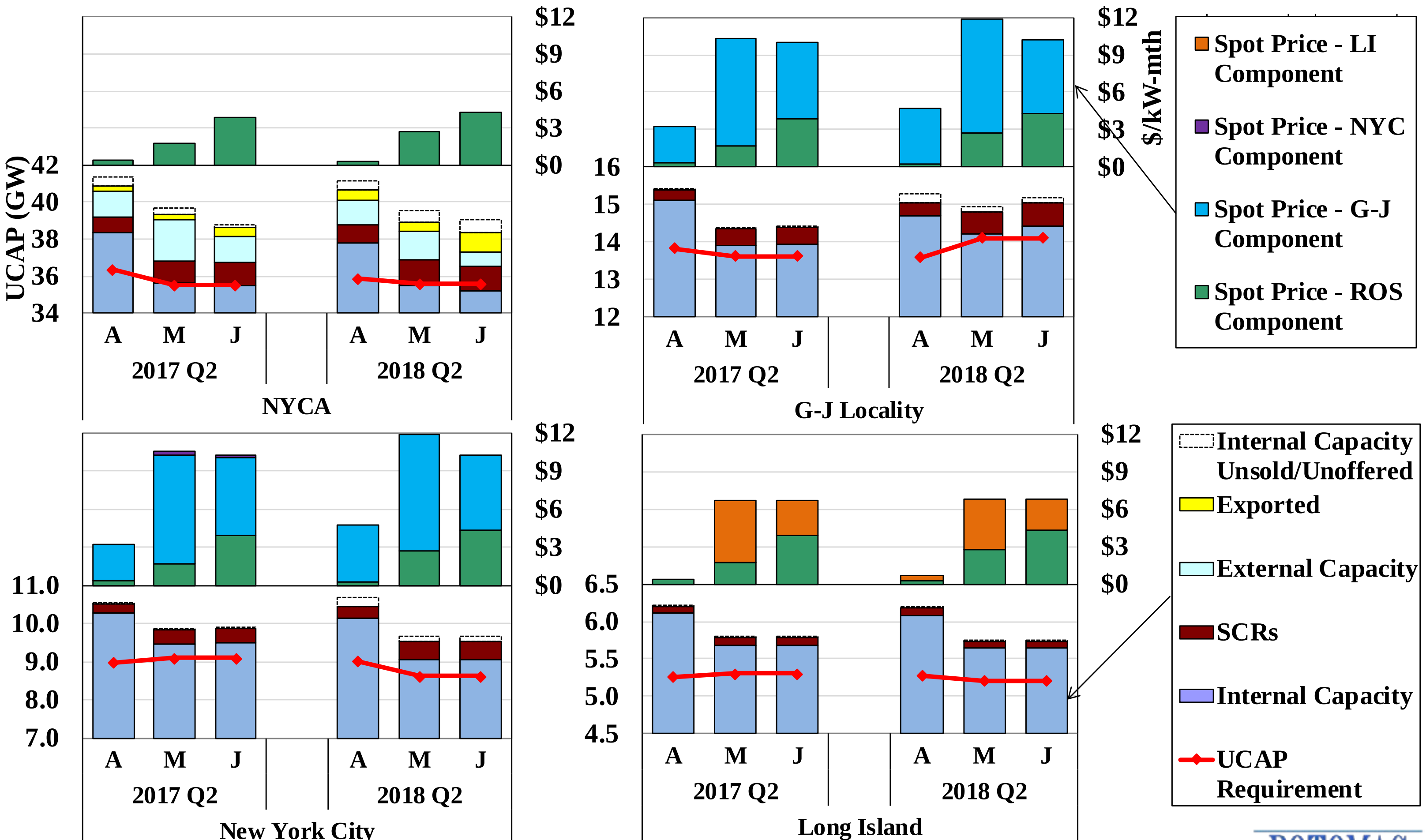
Notes: For chart description, see slide 75.

POTOMAC ECONOMICS



Charts:
Capacity Market

Spot Capacity Market Results
2017-Q2 & 2018-Q2



Notes: For chart description, see slide 76.

Key Drivers of Capacity Market Results

	NYCA	NYC	LI	G-J Locality
Avg. Spot Price				
2018 Q2 ($/kW-Month)	$2.43	$8.94	$4.77	$8.94
% Change from 2017 Q2	**22%**	**11%**	**4%**	**14%**
Change in Demand				
Load Forecast (MW)	-275	-131	-51	-144
IRM/LCR	0.2%	-1.0%	0.0%	3.0%
2018/2019 Summer	*118.2%*	*80.5%*	*103.5%*	*94.5%*
2017/2018 Summer	*118.0%*	*81.5%*	*103.5%*	*91.5%*
ICAP Requirement (MW)	**-259**	**-222**	**-53**	**346**
Key Changes in ICAP Supply (MW)				
(New - May 2018) CPV Valley CC1 & CC2 (1)	**528**			**528**
(IIFO - Apr. 2018) Ravenswood GT 2-1, 2-2, 2-3, 2-4	**-121**	**-121**		**-121**
(IIFO - Apr. 2018) Ravenswood GT 3-1, 3-2, 3-4	**-93**	**-93**		**-93**
(Retire - Oct. 2017) Binghamton Cogen	**-44**			
Cleared Import (2)	**-455**			
Change in Demand Curve				
UCAP Based Reference Price @ 100% Req.				
% Change from 2017/2018 Summer	10%	15%	13%	9%

(1) Only a portion of total ICAP (300 MW) was qualified and sold in May.

(2) Based on quarterly average cleared quantity.

Notes: For chart description, see slide 76.

Appendix: Chart Descriptions

All-in Price

- Slide 16 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 19 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 20 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.

Ancillary Services Prices

- Slides 25, 26, and 27 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 26 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.

POTOMAC ECONOMICS

Day-Ahead NYCA 30-Minute Reserve Offers

- Slide 28 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).

POTOMAC ECONOMICS

Day-Ahead Load Scheduling and Virtual Trading

- Slide 30 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 31 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 32 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 34 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 36, 37, 38, and 39 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).

POTOMAC ECONOMICS

Transmission Congestion and Shortfalls (cont.)

- Slide 36 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 37 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 38 and 39 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.

POTOMAC ECONOMICS

NY-NJ PAR Operation Under M2M with PJM

- Slide 40 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 41 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.

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 42 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 number stacks show the seasonal LTE ratings of these facilities.
  - ✓ The purple bars in the right panel shows the average additional transfer capability above LTE as a percent of LTE for these facilities (i.e., average modeled constraint limit/seasonal LTE – 100%).

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Constraint Limit and CRM in New York

- A Constraint Reliability Margin ("CRM") is a reduction in actual physical limit used in the market software, largely to account for loop flows and other un-modeled factors.
  - ✓ A default CRM value of 20 MW is used for most facilities across the system regardless of their actual physical limits. (Currently, Tariff only allows to use a CRM value of 0 MW or greater than 20 MW on specific constraints)
- Slide 43 summarizes the following quantities for the transmission constraints grouped by facility voltage class and by location:
  - ✓ # of Constraint-Shortage Intervals – the total number of constraint-shortage intervals in each facility group during the quarter.
  - ✓ Avg Constraint Limit – The average transmission limit in each facility group.
  - ✓ Avg CRM – The average CRM MW used in each facility group.
  - ✓ Avg Shortage MW – This includes: a) the average transmission shortage MW that is recognized in the market model; and b) additional shortages when removing the congestion-relief effect from offline GTs.
  - ✓ CRM as % of Limit – The average CRM as a percentage of average limit
  - ✓ These quantities are summarized over real-time transmission shortage intervals and for transmission constraints that have a 20+ MW CRM.

Supplemental Commitments and OOM Dispatch

- Slides 45, 46, and 47 summarize out-of-market commitment and dispatch, which are the primary sources of guarantee payment uplift.
- Slide 45 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 46 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 Commitments and OOM Dispatch (cont.)

- NOx Only – If needed for NOx 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 NOx.
- Multiple Reasons – If needed for two or three of the following reasons: voltage support, thermal support, NOx, 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 47 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 48 and 49 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 48 shows these seven categories on a daily basis during the quarter.
  - ✓ Slide 49 summarizes uplift costs by region on a monthly basis.

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Potential Economic and Physical Withholding

- Slides 51 and 52 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 53 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.

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Spot Capacity Market Results

- Slides55 and 56 summarize market results and key drivers in the monthly spot capacity auctions.
  - ✓ Slide55 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.
  - ✓ Slide56 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.