Quarterly Report on the New York ISO Electricity Markets First Quarter of 2020

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

Potomac Economics
Market Monitoring Unit

June 2020

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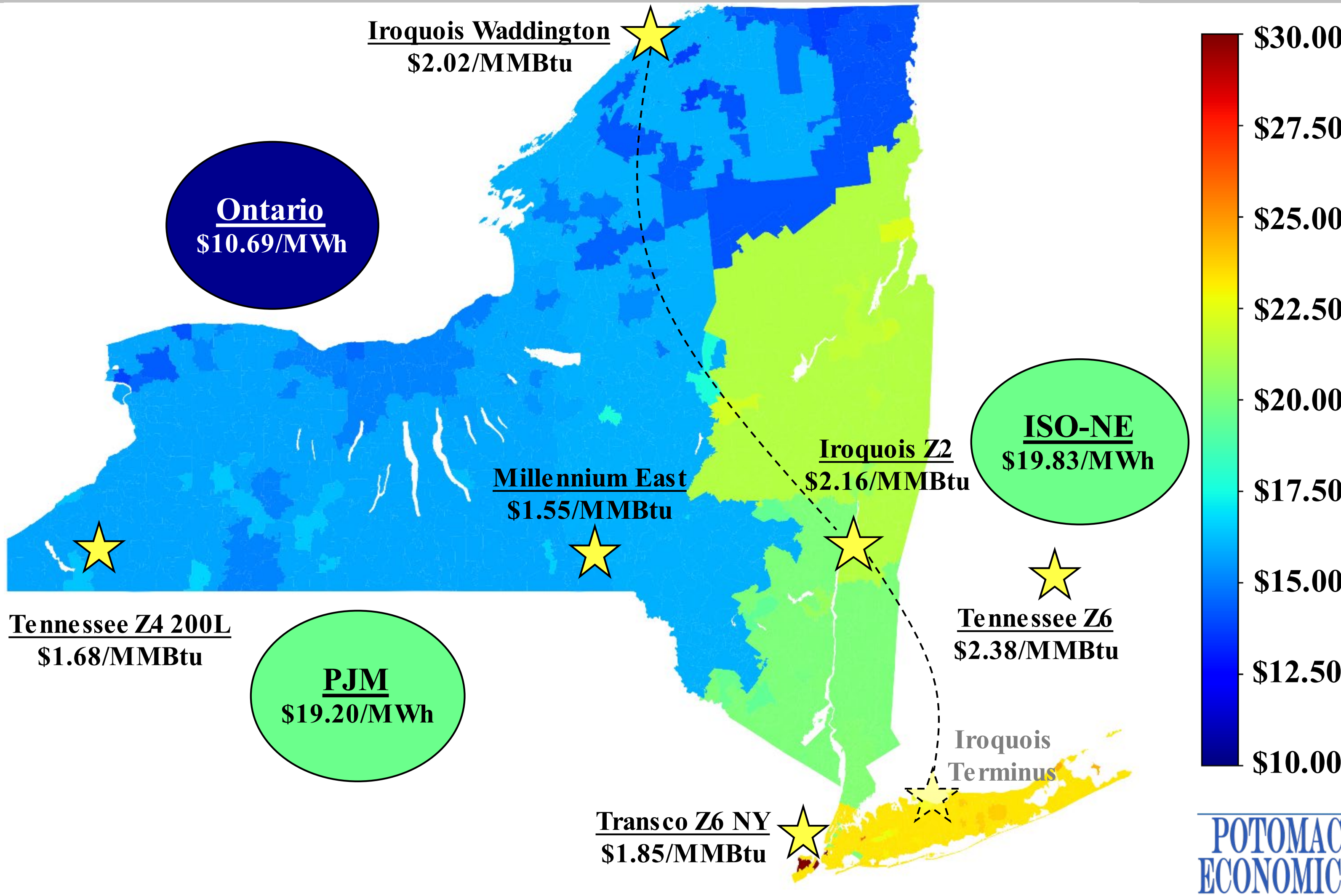
Market Highlights

Market Highlights:
Executive Summary

- NYISO energy markets performed competitively in the first quarter of 2020.
- All-in prices ranged from $15 to $35/MWh, the lowest quarterly average levels in more than a decade. (see slide 6)
  - ✓ Capacity prices have fallen to very low levels reflecting large surpluses.
  - ✓ Natural gas prices in Eastern NY fell to the lowest quarterly average levels since 2009 regardless of season.
  - ✓ Load also fell to the lowest first-quarter level in more than a decade, which was attributable to the combined effects of:
    - Mild winter weather conditions,
    - Energy efficiency and behind-the-meter solar generation, and
    - Covid-19 pandemic, which has reduced load by 8 to 9 percent since mid-March.
- Lower load levels and natural gas prices led to reduced:
  - ✓ Transmission congestion (see slides 7-8),
  - ✓ Supplemental commitment for reliability (see slide 47), and
  - ✓ Imports from PJM (see slide 35).

Market Highlights:
System Price Diagram



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Market Highlights:
Summary of Energy Market Outcomes

- NYISO energy markets performed competitively in the first quarter of 2020.
  - ✓ 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 sharply in all areas and ranged from $15/MWh in the North Zone to $35/MWh in NYC, down 21 to 49 percent from last year. (slide 15)
  - ✓ Energy prices accounted for the largest component of the decrease, falling by 39 to 47 percent (slides 20-21), driven primarily by lower natural gas prices.
    - – Average natural gas prices fell between 53 and 55 percent from a year ago in Eastern NY (slide 23), reflecting much milder weather compared to last winter.
      - The average gas prices in Eastern NY were at the lowest quarterly level since at least 2009 regardless of season.
    - – Load levels also fell substantially – average load fell 6 percent and peak load fell 11 percent (slide 16), contributing to lower prices as well.
      - These were the lowest first-quarter levels in more than a decade.
    - – However, the decrease was partly offset by lower net imports from PJM (slide 35).
  - ✓ Capacity costs fell by 94 to 97 percent in all regions except the NYC where it rose by 109 percent for the reasons discussed in slide 13.

Market Highlights:
Congestion Patterns, Revenues and Shortfalls

- Day-ahead congestion revenues totaled $56 million, down 49 percent from the first quarter of 2019, primarily because of lower gas prices and load. (slide 37)
  - ✓ Day-ahead congestion fell throughout the state with most of the decrease occurring on the Central-East interface. (slide 38)
- The Central-East interface accounted for the largest share (nearly 60 percent) of day-ahead congestion revenues in the first quarter of 2020. (slide 38)
  - ✓ This is typical during the winter season when gas spreads between Western NY and Eastern NY are the largest.
  - ✓ However, these DA congestion revenues fell 50 percent from a year ago as the average gas spreads between Western NY and Eastern NY fell. (slide 16)
    - The 32 percent spread between West NY and NYC gas prices in 2019-Q1 fell to just 11 percent this quarter, which is more typical of summer spreads.
  - ✓ The frequency of congestion across the Central-East interface also fell from a year ago, which was attributable to:
    - Higher nuclear generation in Eastern NY because of fewer outages and deratings. (slide 17)

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

- New York City constraints accounted for the second largest share of congestion in the first quarter of 2020.
  - ✓ While congestion fell by more than 40 percent in other regions, congestion in NYC fell just 16 percent in day-ahead and rose 135 percent in real-time. (slide 38)
    - – One Gowanus-Greenwood 138 kV line was OOS in most of January and February, which reduced transfer capability into the Greenwood load pocket. (slide 45)
    - – This pocket also accounted for the vast majority of $3 million of day-ahead congestion shortfalls and $1 million of balancing congestion shortfalls that accrued on the NYC facilities. (slides 40 – 41)
    - – The higher levels of congestion in real-time arose from periods when RTC under-committed generation, leading to brief transmission shortage pricing events.
- Congestion fell by roughly 50 percent in the West Zone. (slide 38)
  - ✓ Roughly 70 percent of congestion occurred on the 115 kV constraints.
  - ✓ 115 kV constraints were incorporated into the M2M process with PJM starting in November 2019, which has helped reduce congestion on these facilities.
    - – Previously, the M2M PARs (i.e., Ramapo, A, J, & K) generally increased congestion and balancing congestion shortfalls on West Zone facilities. (slide 41)

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Market Highlights: Out of Market Actions to Manage Congestion

- The NYISO has greatly reduced the use of OOM actions over the last two years to manage low-voltage transmission constraints by modeling most 115kV constraints in the DA and RT market models.
- OOM actions to manage lower-voltage network congestion were most frequent in Long Island (18 days) and the North Zone (15 days) this quarter. (slide 43)
  - ✓ On Long Island, the frequency of OOM actions was reduced by low load levels.
    - – Oil-fired peaking resources were OOMed on just two days to manage 69 kV constraints in the East of Northport pocket. (slide 44)
  - ✓ In the North Zone, the Saranac generator was committed to relieve congestion on unmodeled transmission constraints.

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Market Highlights:
Reliability Commitments, OOM Dispatch, and BPCG

- BPCG payments totaled $4.2 million, down 72 percent from the first quarter of 2019 (slides 51-52).
  - ✓ The reduction was driven primarily by lower gas prices, lower load levels, and reduced reliability commitments in New York City.
  - ✓ This was the lowest quarterly BPCG uplift ever for the NYISO.
- Roughly $2 million (or 48 percent) of BPCG payments accrued in NYC. (slide 52)
  - ✓ $1.4 million was paid to units that were committed for local reliability needs.
  - ✓ Reliability commitments in NYC accounted for roughly 78 percent of all reliability commitments this quarter and fell 54 percent from a year ago. (slide 47) These fell as a result of:
    - – Lower load levels,
    - – Fewer outages of combined-cycle units, and
    - – Procedural changes that have reduced supplemental commitments at the Arthur Kill plant are not needed to satisfy reliability requirements when applicable quick start resources are available.

Market Highlights:
LRR Commitments in NYC

- Reliability commitments in NYC often occur because a generator is needed only during the highest load hours of the day.
  - ✓ The actual amount of capacity needed in each load pocket varies by hour based on load and network conditions.
  - ✓ However, the DAM software currently uses a single daily capacity requirement for most load pockets, which is applied to all hours.
  - ✓ This can lead to over-commitment, especially in off-peak hours, raising production costs and depressing market clearing prices.
- We estimated the amount of LRR commitments that would not have occurred if the DAM software used hourly capacity requirements. (slide 50)
  - ✓ If hourly capacity requirements were used, we estimate that LRR Commitments in 207 hours across 43 days would have been avoided (total LRR commitments occurred in 606 hours on 60 days in these load pockets).
    - – This accounted for 30 percent of total LRR-committed MWh in these load pockets.
  - ✓ The avoidable commitments mostly occurred in off-peak hours (e.g., HB 0-5, 22-23).

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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 2020-Q1, 81 percent of the RT congestion in NYC occurred on N-1 constraints that would have been loaded above LTE after a single contingency. (slide 45)
  - ✓ The additional capability above LTE averaged from about 30 to 65 MW for the 138 kV constraints in the Greenwood load pocket to roughly 180 to 240 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 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 2019 SOM report)

Market Highlights: Capacity Market

- Average spot capacity prices ranged from $0.04/kW-month in ROS, G-J Locality and LI to $3.71/kW-month in New York City for this quarter. (slide 58-59)
- Compared to a year ago, average spot prices rose substantially in NYC but fell markedly elsewhere, driven largely by changes to administrative parameters.
  - ✓ The IRM and LCRs for all localities changed:
    - The NYCA IRM fell 1.2 percent from 118.2 to 117 percent.
    - The NYC LCR rose 2.3 percent from 80.5 to 82.8 percent. On the other hand, the G-J Locality LCR fell 2.2 percent from 94.5 to 92.3 percent.
    - In Long Island, the LCR rose by 0.6 percent from 103.5 to 104.1 percent.
  - ✓ The ICAP Requirements in all zones except for NYC fell on account of lower load forecasts.
  - ✓ On the supply side:
    - Cleared import capacity fell by an average of over 750 MW.
    - Changes to the internal capacity supply from the prior year were driven mostly by units entering and exiting ICAP Ineligible Forced Outages (IIFO) states during the 2019/20 Capability Year.

Charts:

Market Outcomes

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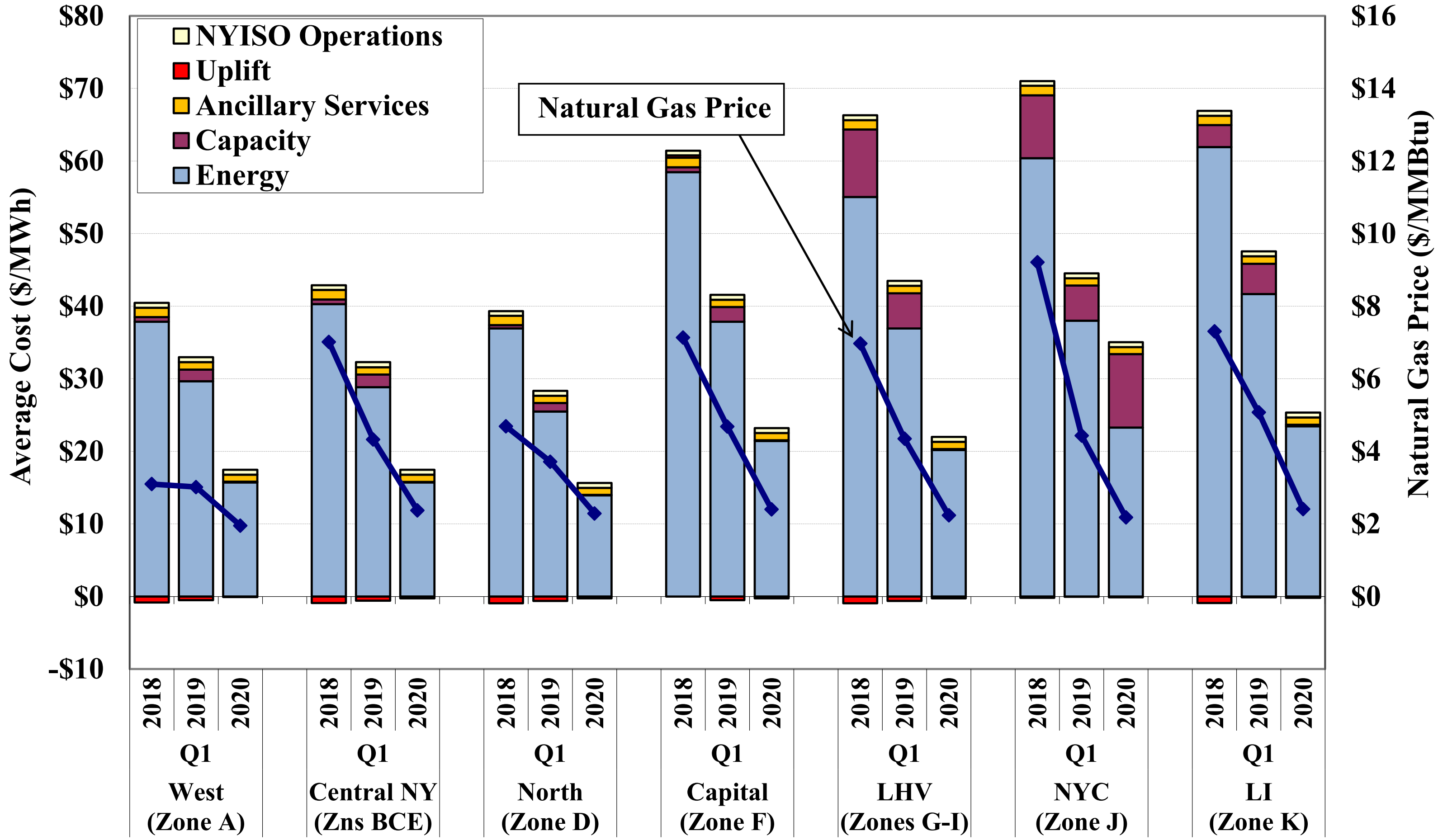
All-In Prices by Region



Notes: For chart description, see slide 61.

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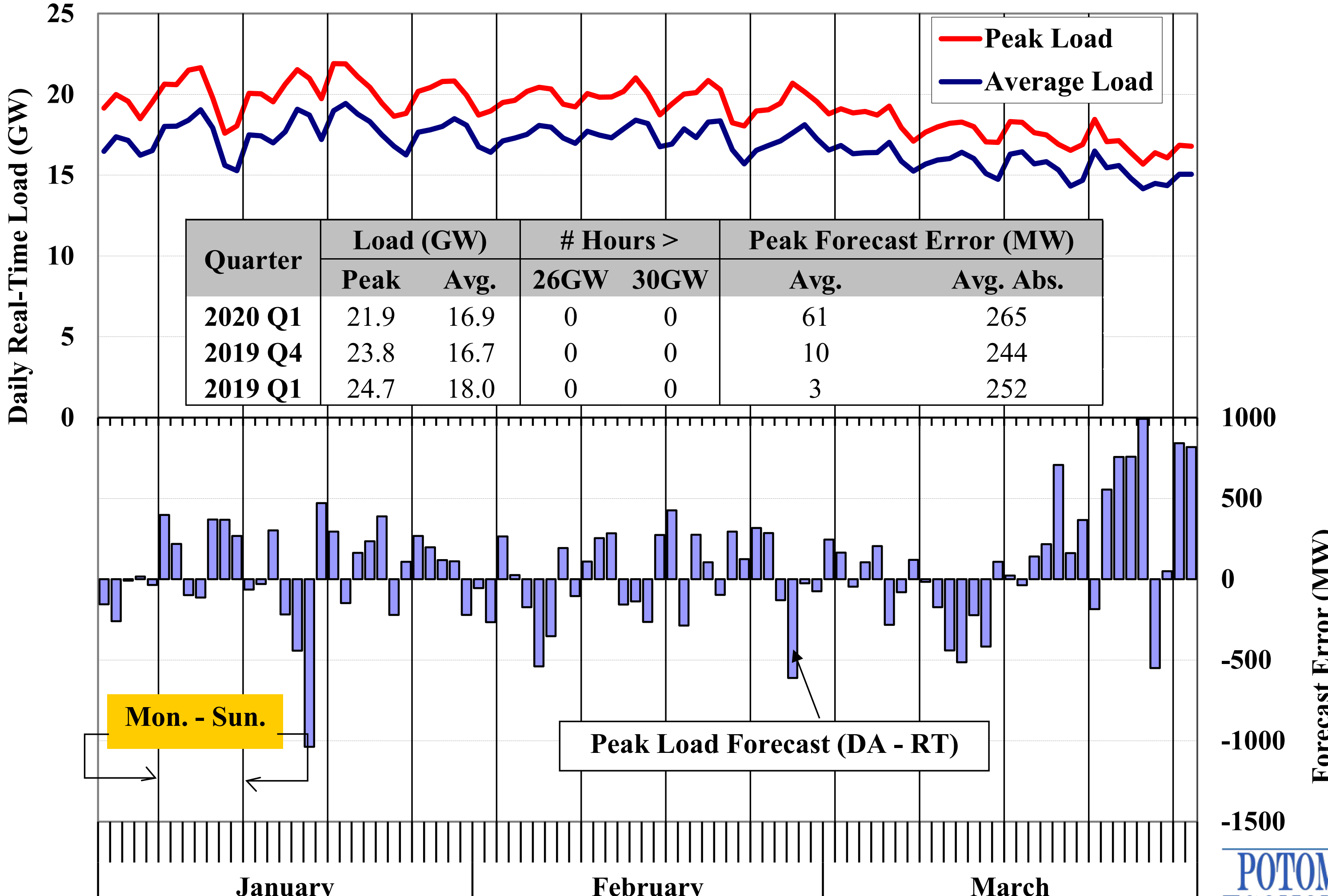
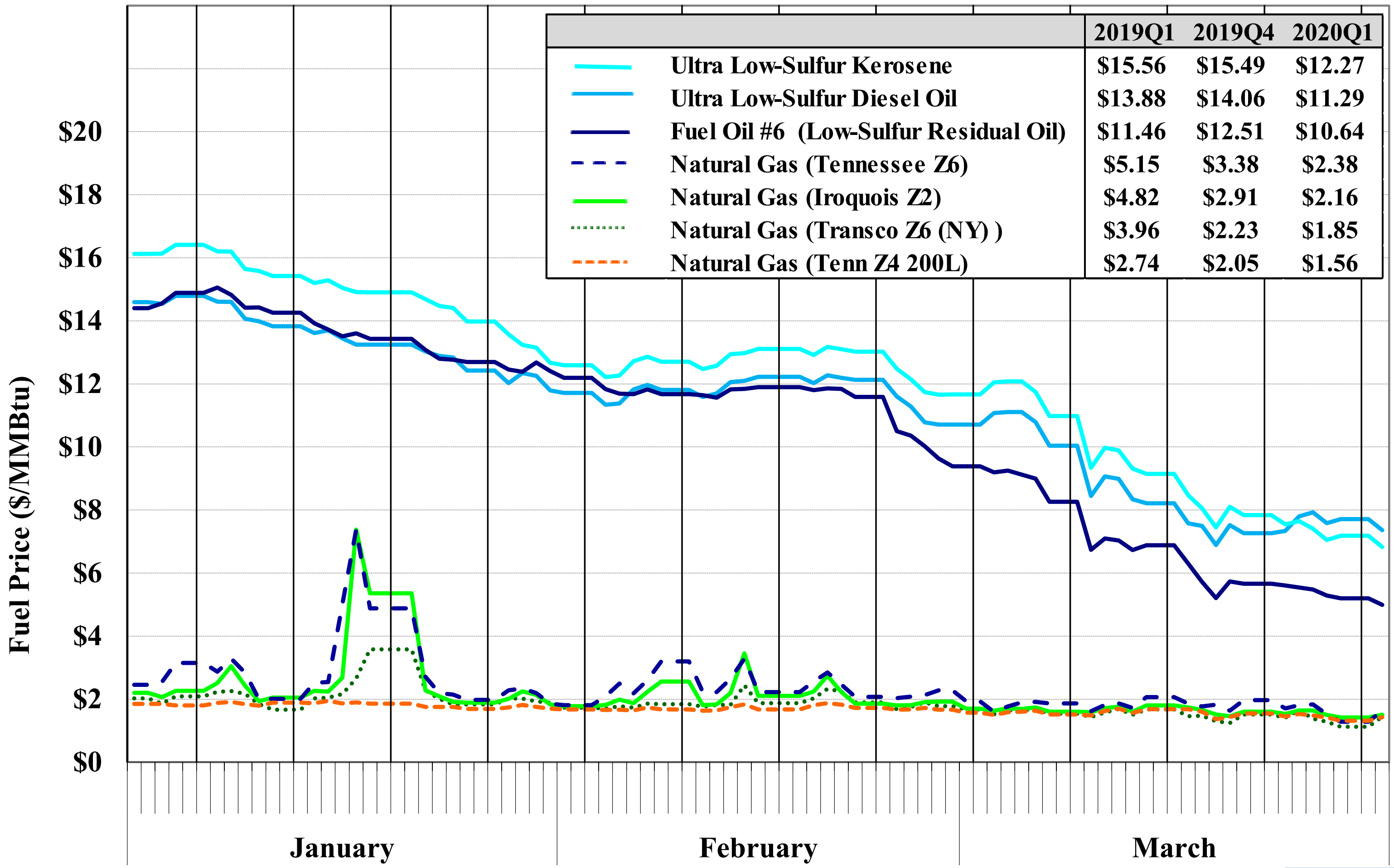
Load Forecast and Actual Load



Quarter	Load (GW)		# Hours >		Peak Forecast Error (MW)	
	Peak	Avg.	26GW	30GW	Avg.	Avg. Abs.
2020 Q1	21.9	16.9	0	0	61	265
2019 Q4	23.8	16.7	0	0	10	244
2019 Q1	24.7	18.0	0	0	3	252

Natural Gas and Fuel Oil Prices



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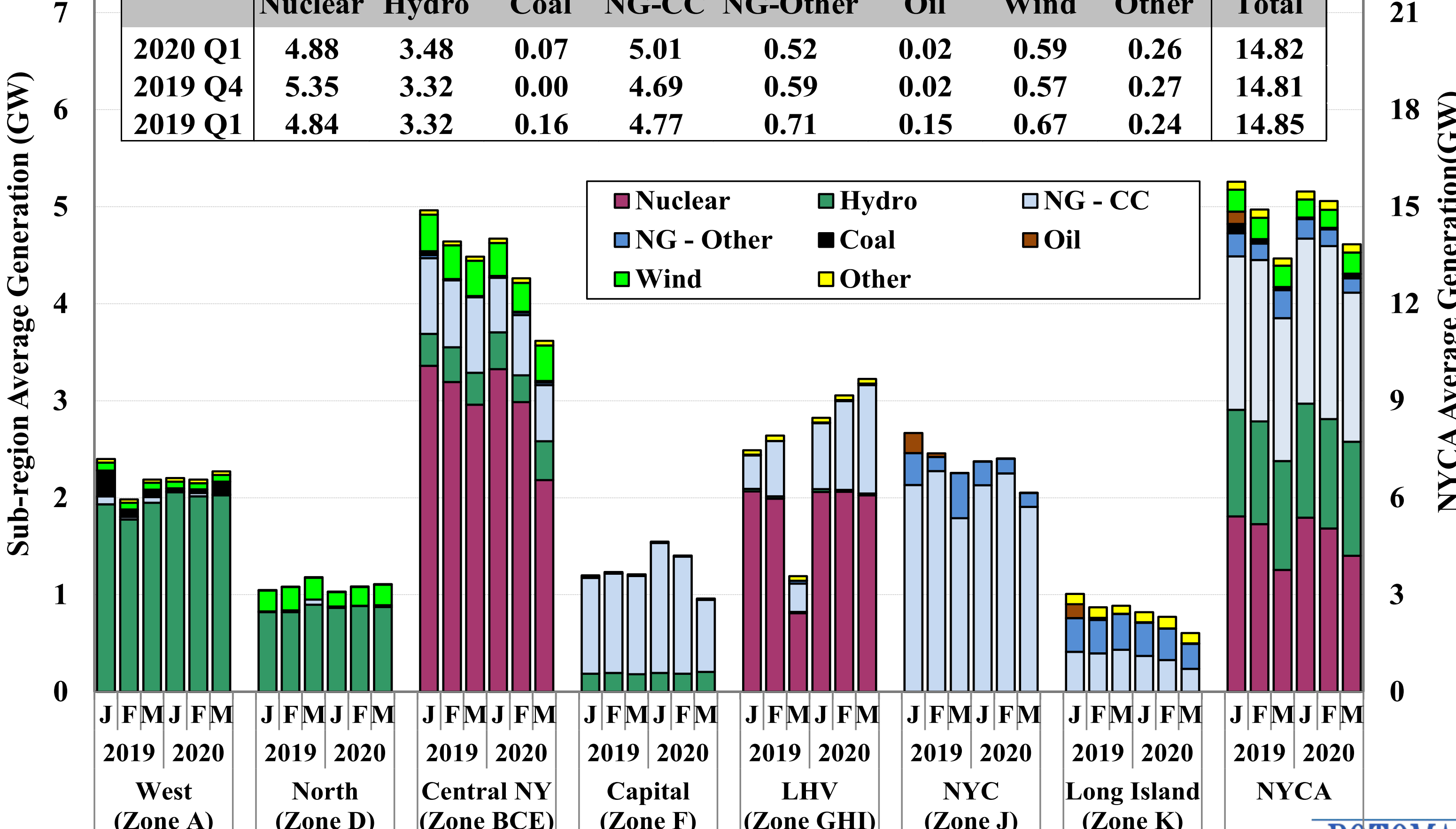
Real-Time Generation Output by Fuel Type

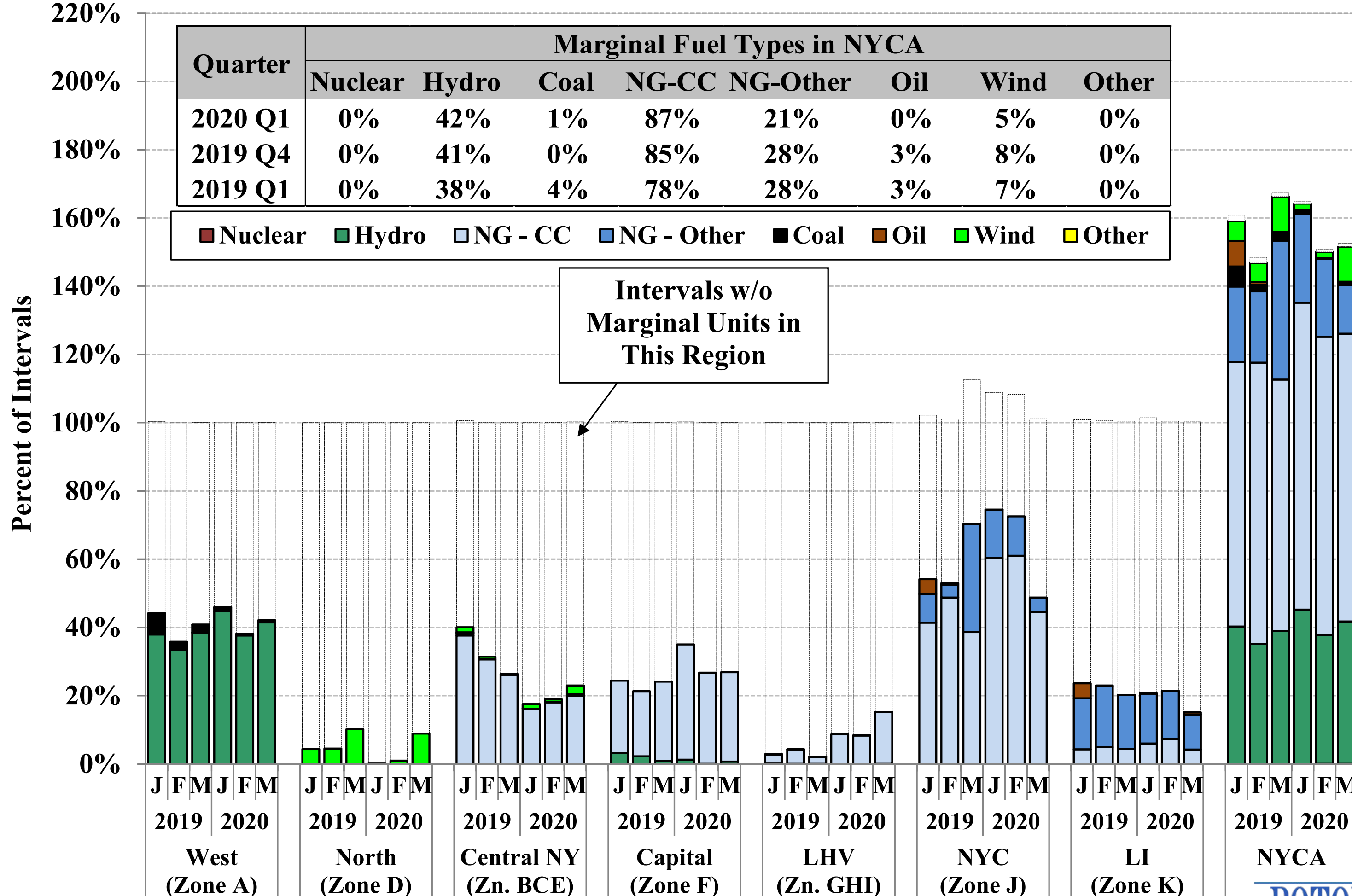
Quarter	Average Internal Generation by Fuel Type in NYCA (GW)								
	Nuclear	Hydro	Coal	NG-CC	NG-Other	Oil	Wind	Other	Total
2020 Q1	4.88	3.48	0.07	5.01	0.52	0.02	0.59	0.26	14.82
2019 Q4	5.35	3.32	0.00	4.69	0.59	0.02	0.57	0.27	14.81
2019 Q1	4.84	3.32	0.16	4.77	0.71	0.15	0.67	0.24	14.85



Notes: For chart description, see slide 62.

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
2020 Q1	0%	42%	1%	87%	21%	0%	5%	0%
2019 Q4	0%	41%	0%	85%	28%	3%	8%	0%
2019 Q1	0%	38%	4%	78%	28%	3%	7%	0%



  Notes: For chart description, see slide 62.

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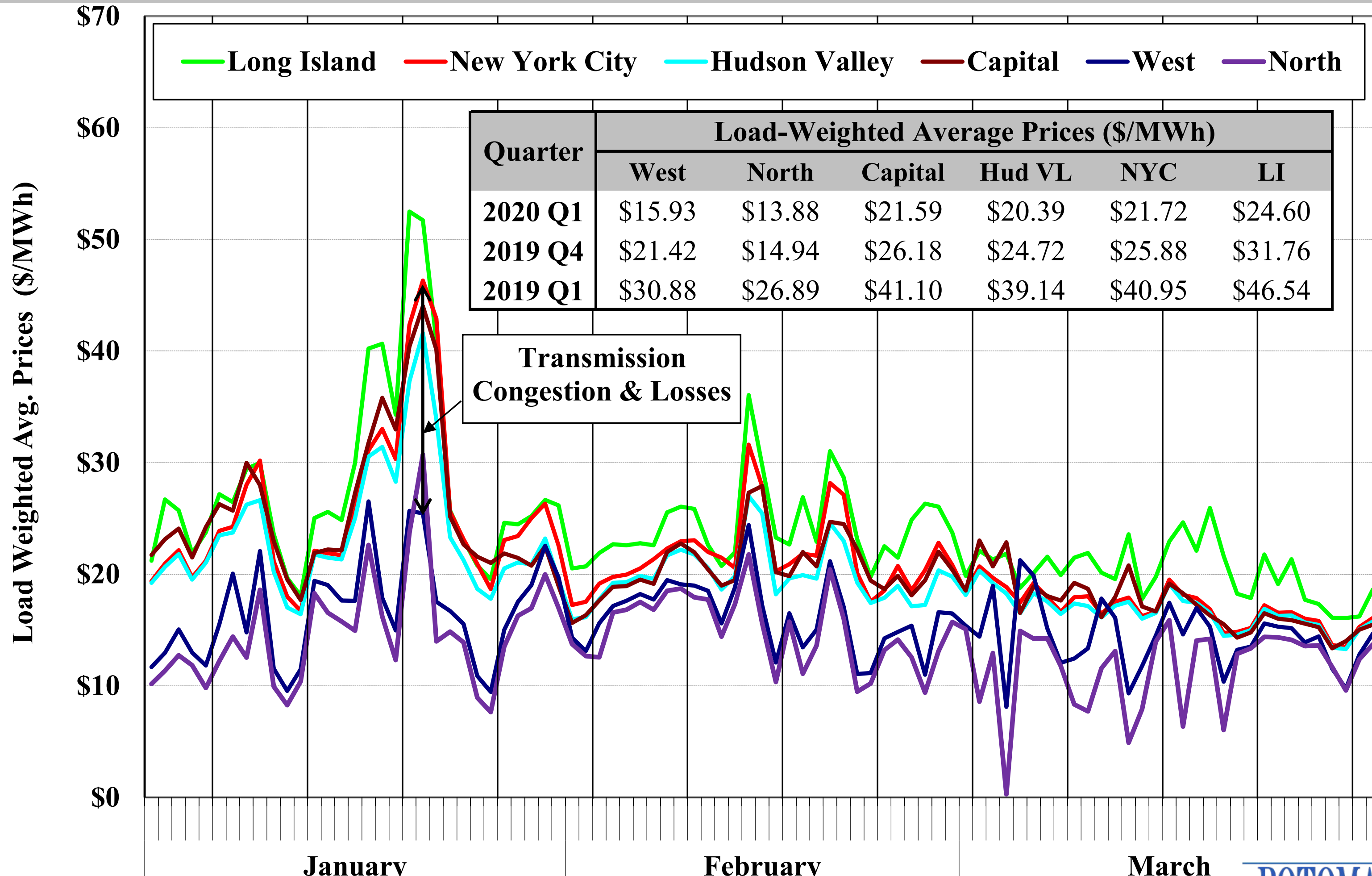
Day-Ahead Electricity Prices by Zone



Quarter	Load-Weighted Average Prices ($/MWh)					
	West	North	Capital	Hud VL	NYC	LI
2020 Q1	$15.93	$13.88	$21.59	$20.39	$21.72	$24.60
2019 Q4	$21.42	$14.94	$26.18	$24.72	$25.88	$31.76
2019 Q1	$30.88	$26.89	$41.10	$39.14	$40.95	$46.54

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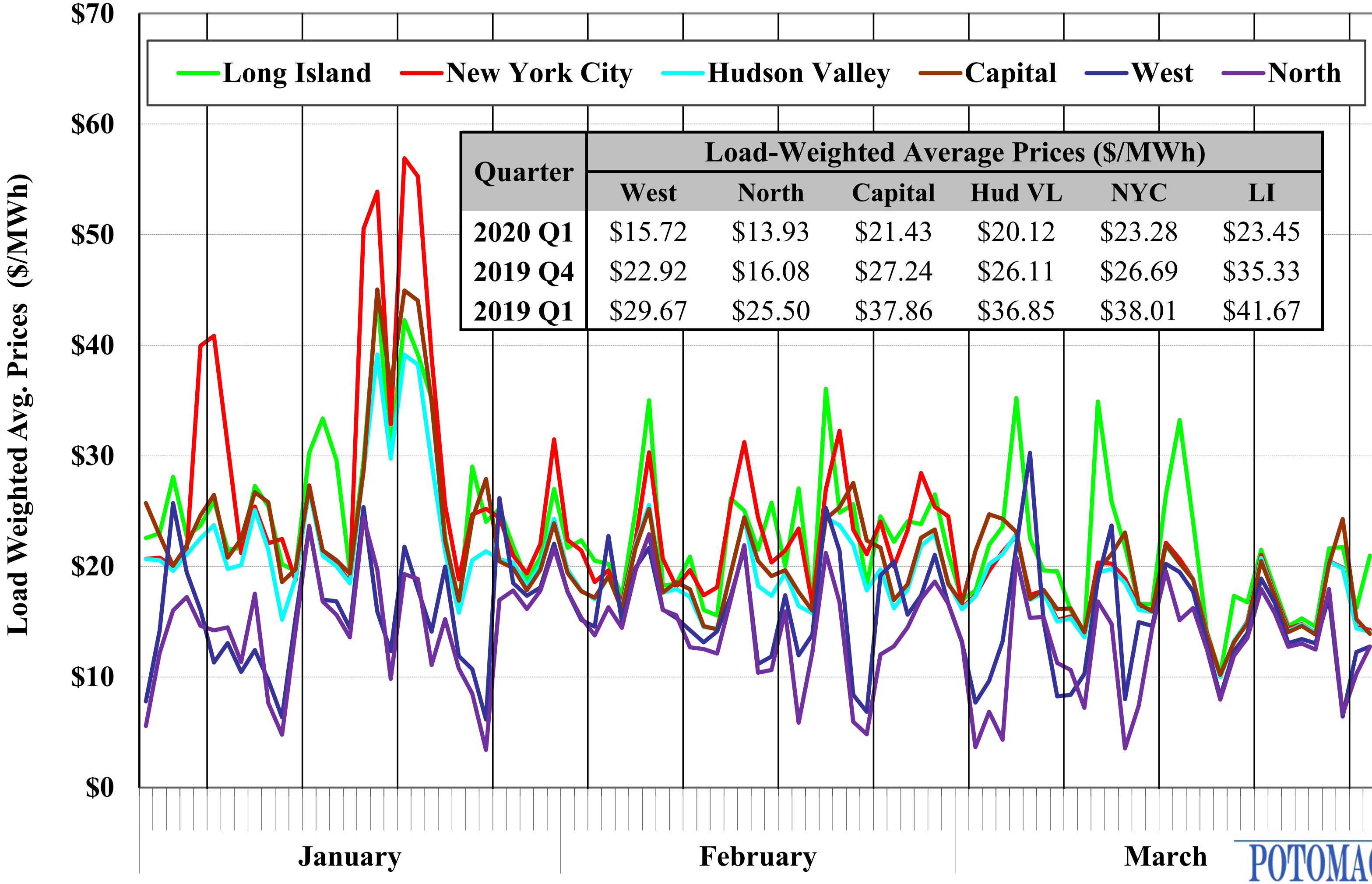
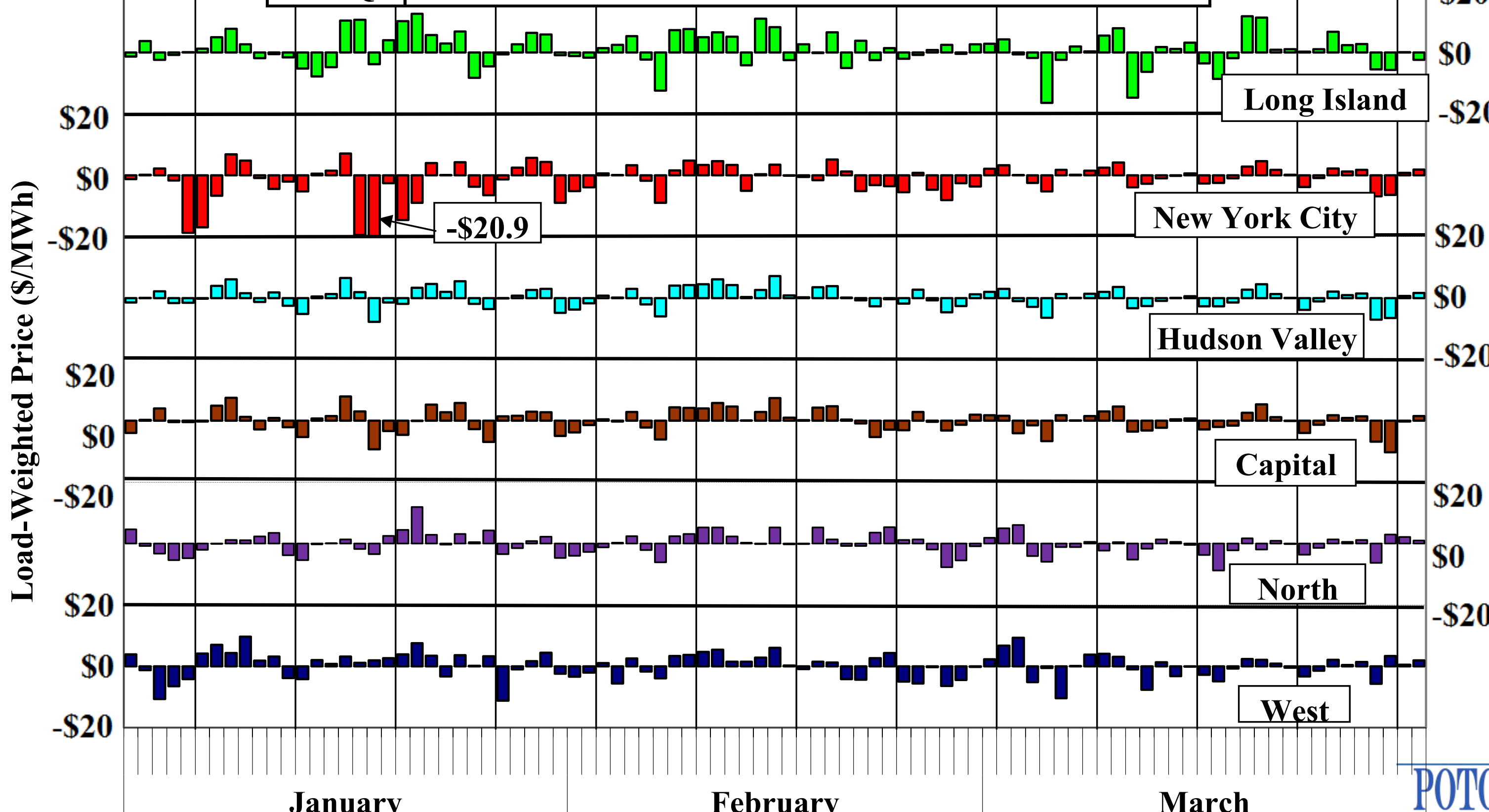
Real-Time Electricity Prices by Zone



Quarter	Load-Weighted Average Prices ($/MWh)					
	West	North	Capital	Hud VL	NYC	LI
2020 Q1	$15.72	$13.93	$21.43	$20.12	$23.28	$23.45
2019 Q4	$22.92	$16.08	$27.24	$26.11	$26.69	$35.33
2019 Q1	$29.67	$25.50	$37.86	$36.85	$38.01	$41.67

Convergence Between Day-Ahead and Real-Time Prices

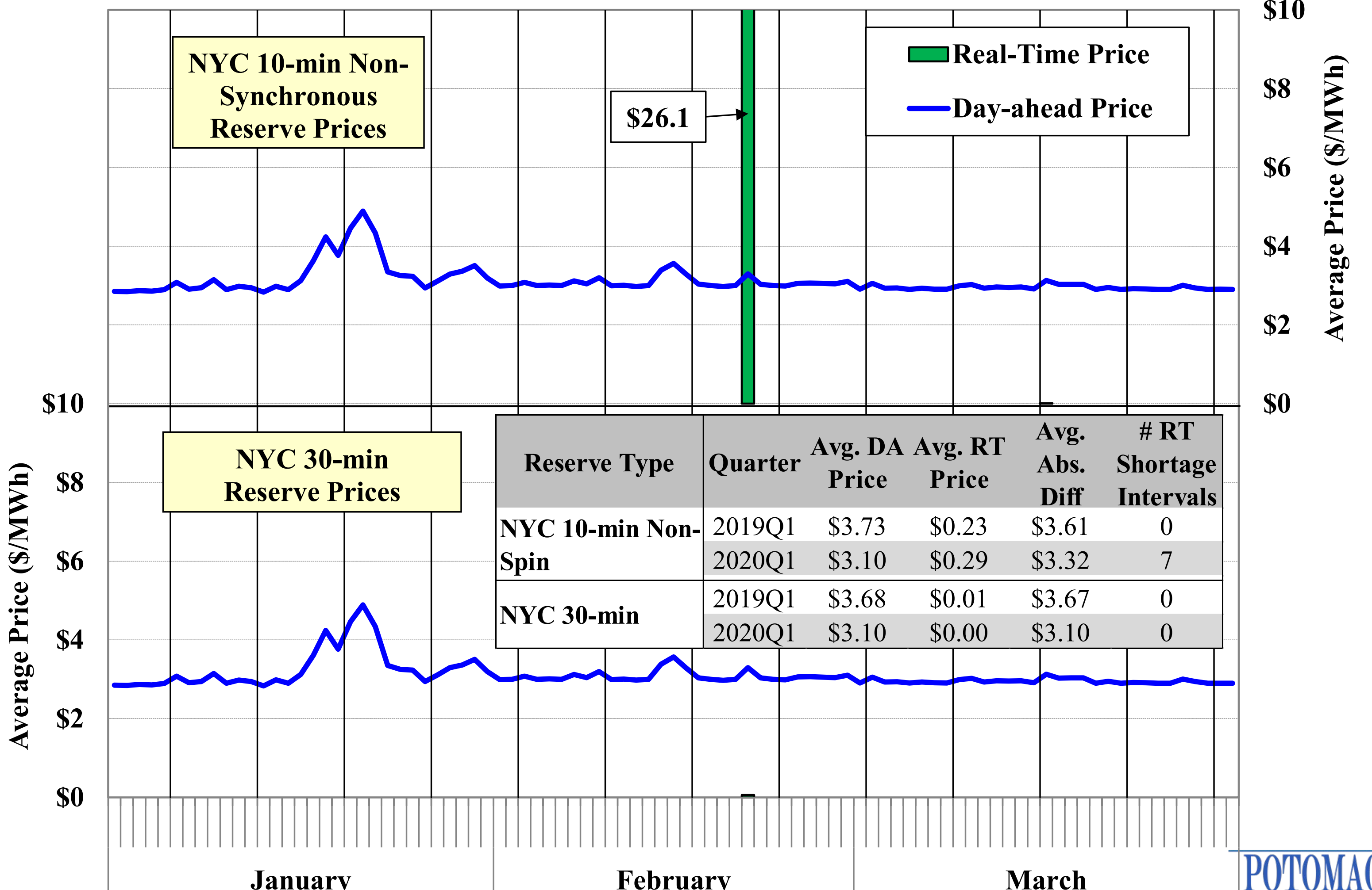
Quarter	Load-Weighted Average (DAM - RT) Prices ($/MWh)					
	West	North	Capital	Hud VL	NYC	LI
2020 Q1	$0.21	-$0.04	$0.16	$0.28	-$1.57	$1.16
2019 Q4	-$1.50	-$1.14	-$1.07	-$1.39	-$0.81	-$3.58
2019 Q1	$1.21	$1.39	$3.24	$2.29	$2.94	$4.87



Charts:

Ancillary Services Market

Day-Ahead and Real-Time Ancillary Services Prices
NYC 10-Minute Non-Spinning and 30-Minute Reserves



Reserve Type	Quarter	Avg. DA Price	Avg. RT Price	Avg. Abs. Diff	# RT Shortage Intervals
NYC 10-min Non-Spin	2019Q1	$3.73	$0.23	$3.61	0
	2020Q1	$3.10	$0.29	$3.32	7
NYC 30-min	2019Q1	$3.68	$0.01	$3.67	0
	2020Q1	$3.10	$0.00	$3.10	0

Notes: For chart description, see slide 63.

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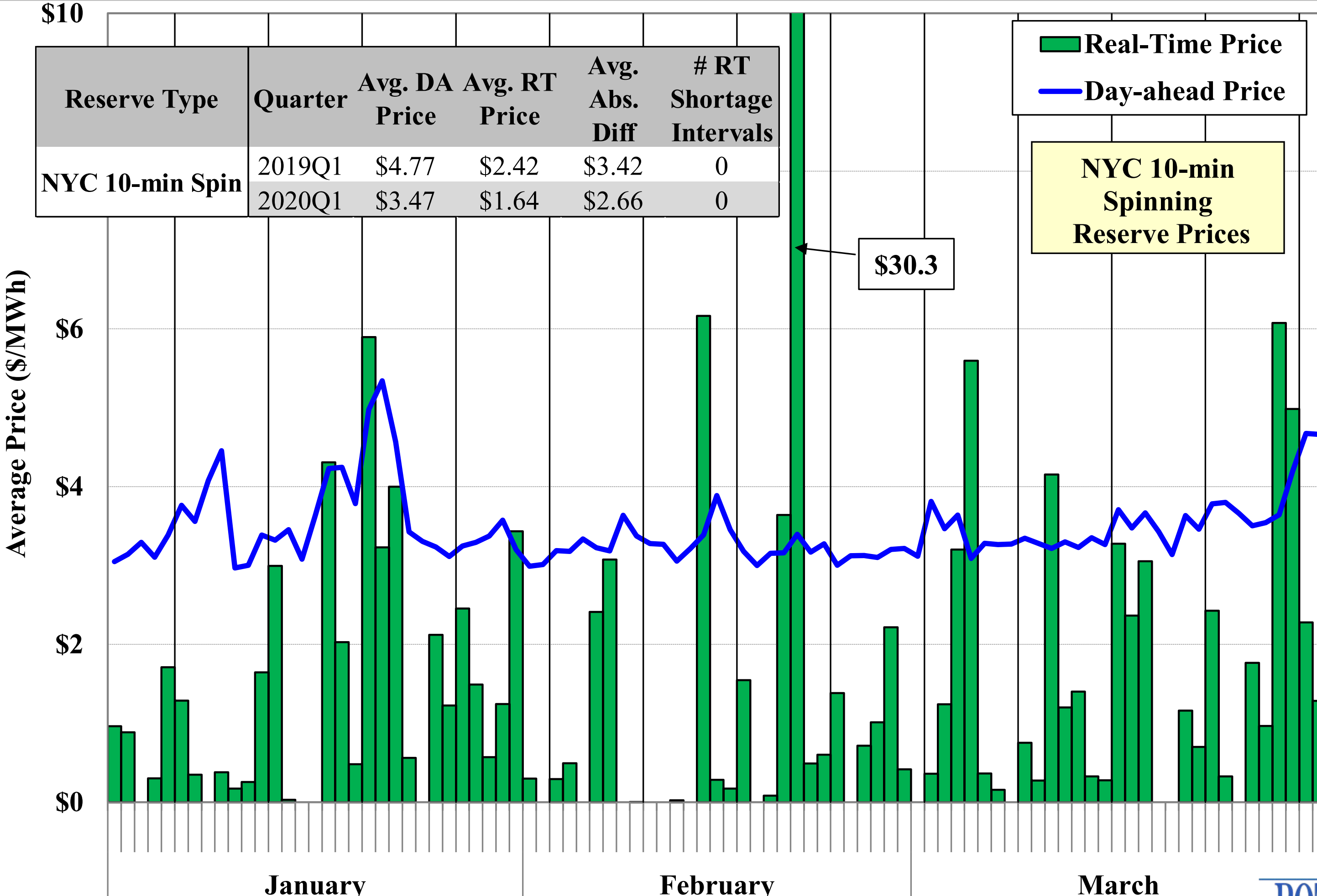
Day-Ahead and Real-Time Ancillary Services Prices
NYC 10-Minute Spinning Reserves

Reserve Type	Quarter	Avg. DA Price	Avg. RT Price	Avg. Abs. Diff	# RT Shortage Intervals
NYC 10-min Spin	2019Q1	$4.77	$2.42	$3.42	0
	2020Q1	$3.47	$1.64	$2.66	0



Notes: For chart description, see slide 63.

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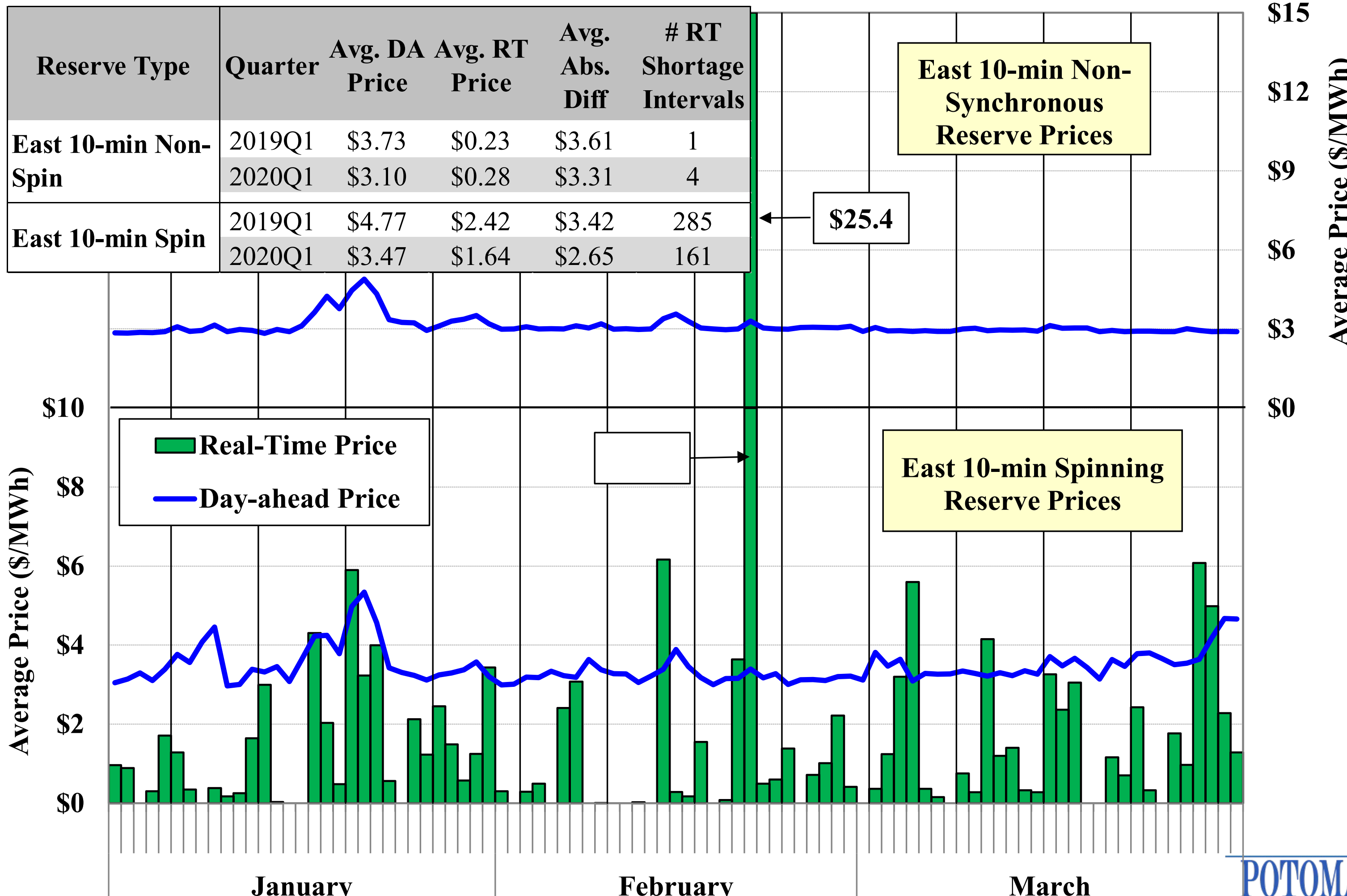
Day-Ahead and Real-Time Ancillary Services Prices
Eastern 10-Minute Spinning and Non-Spinning Reserves

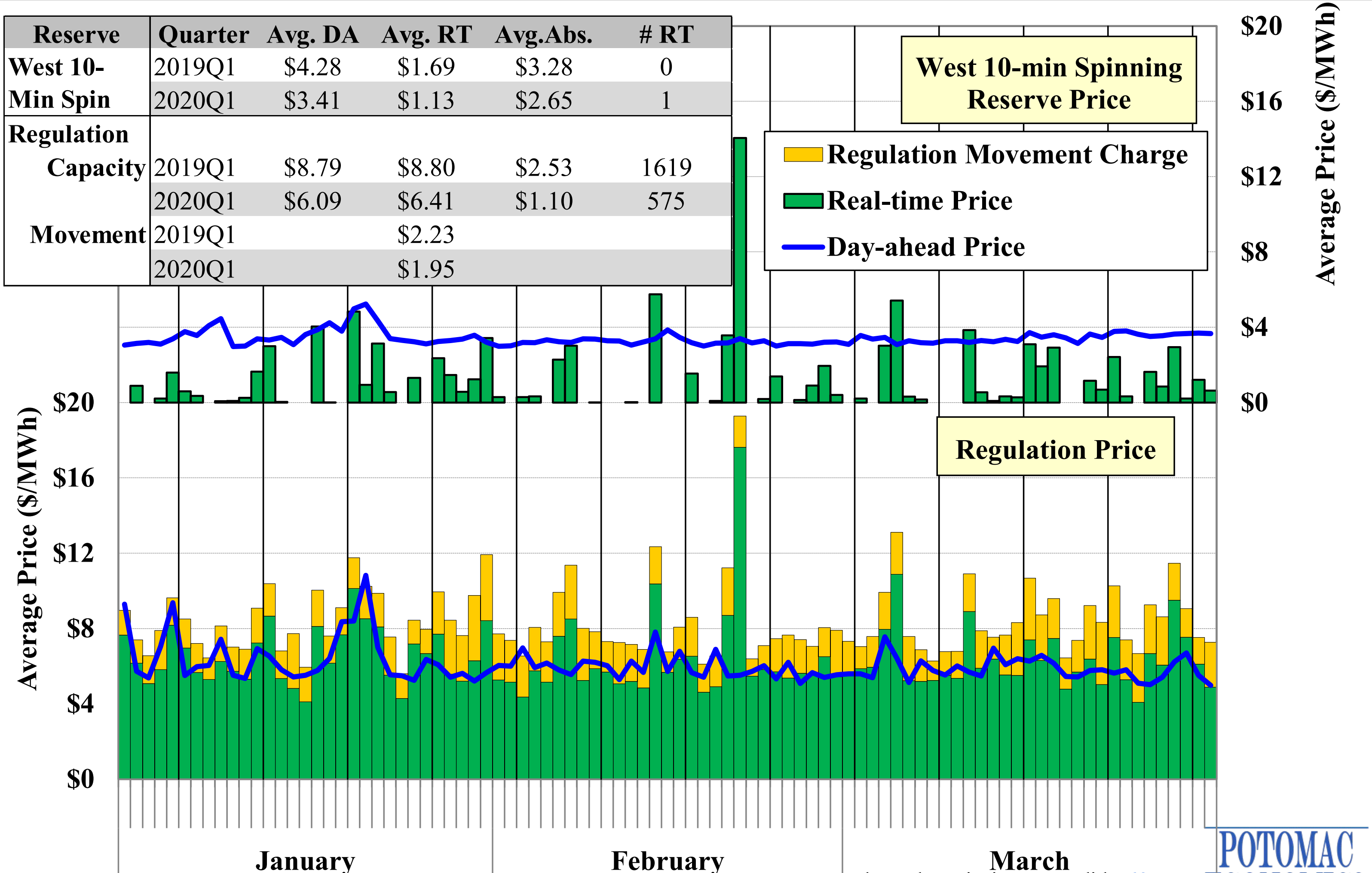
Reserve Type	Quarter	Avg. DA Price	Avg. RT Price	Avg. Abs. Diff	# RT Shortage Intervals
East 10-min Non-Spin	2019Q1	$3.73	$0.23	$3.61	1
	2020Q1	$3.10	$0.28	$3.31	4
East 10-min Spin	2019Q1	$4.77	$2.42	$3.42	285
	2020Q1	$3.47	$1.64	$2.65	161



Notes: For chart description, see slide 63.

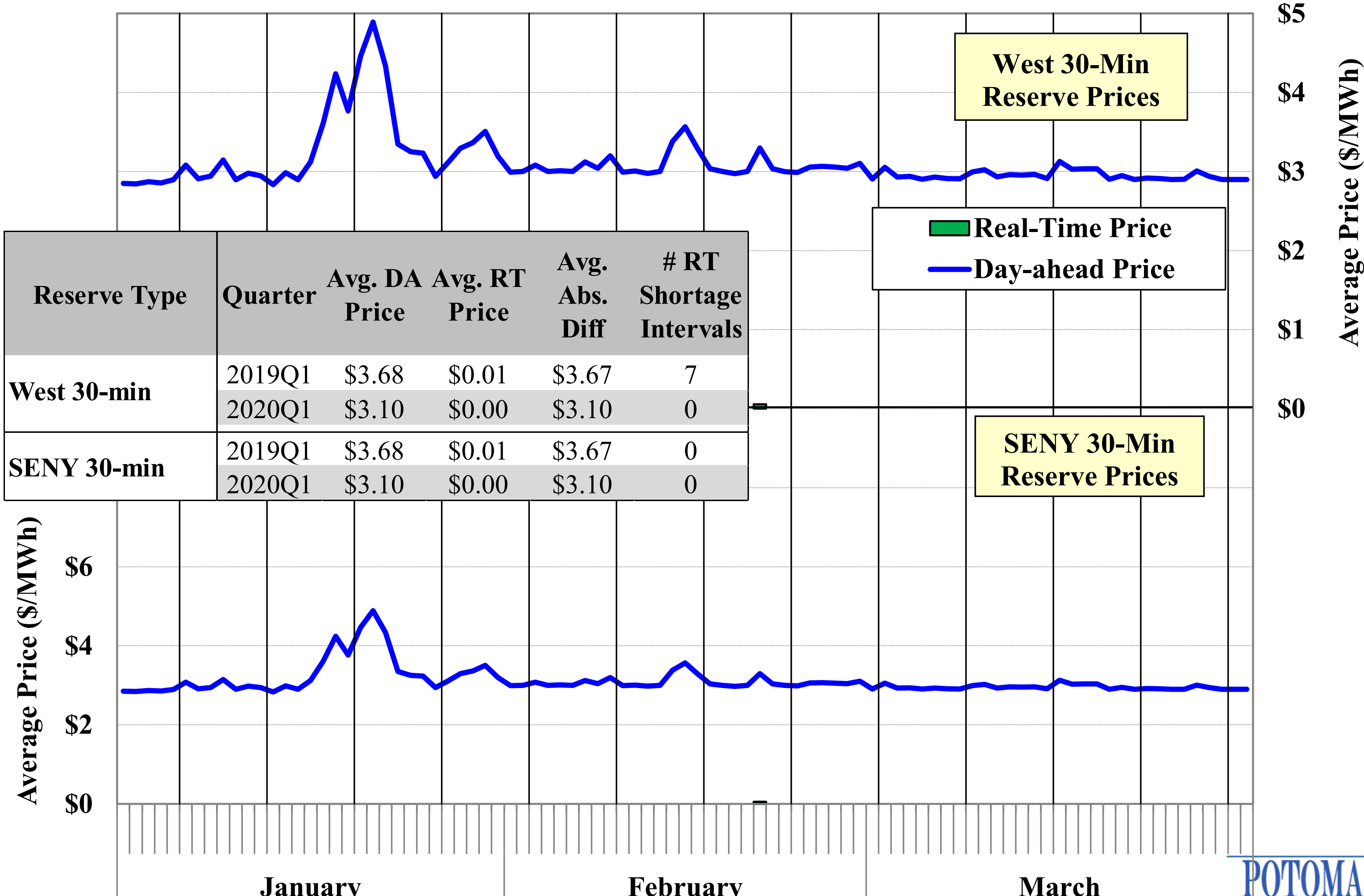
Day-Ahead and Real-Time Ancillary Services Prices
Western 10-Minute Spinning Reserves and Regulation

Reserve	Quarter	Avg. DA	Avg. RT	Avg.Abs.	# RT
West 10-Min Spin	2019Q1	$4.28	$1.69	$3.28	0
	2020Q1	$3.41	$1.13	$2.65	1
Regulation Capacity	2019Q1	$8.79	$8.80	$2.53	1619
	2020Q1	$6.09	$6.41	$1.10	575
Movement	2019Q1		$2.23		
	2020Q1		$1.95		



Notes: For chart description, see slide 63.

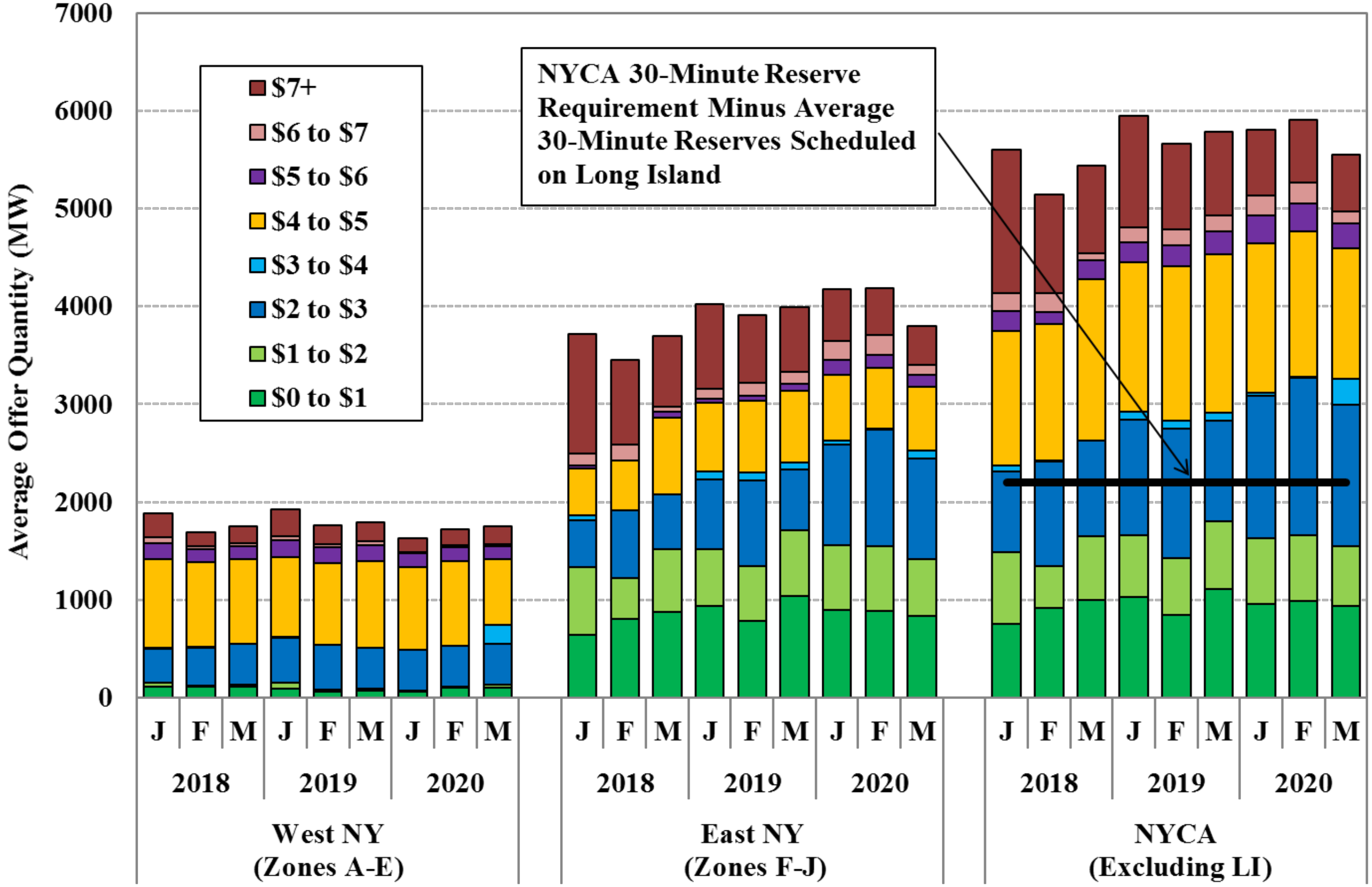
Day-Ahead and Real-Time Ancillary Services Prices
Western and SENY 30-Minute Reserves



Reserve Type	Quarter	Avg. DA Price	Avg. RT Price	Avg. Abs. Diff	# RT Shortage Intervals
West 30-min	2019Q1	$3.68	$0.01	$3.67	7
	2020Q1	$3.10	$0.00	$3.10	0
SENY 30-min	2019Q1	$3.68	$0.01	$3.67	0
	2020Q1	$3.10	$0.00	$3.10	0

Notes: For chart description, see slide 63.

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



Notes: For chart description, see slide 64.

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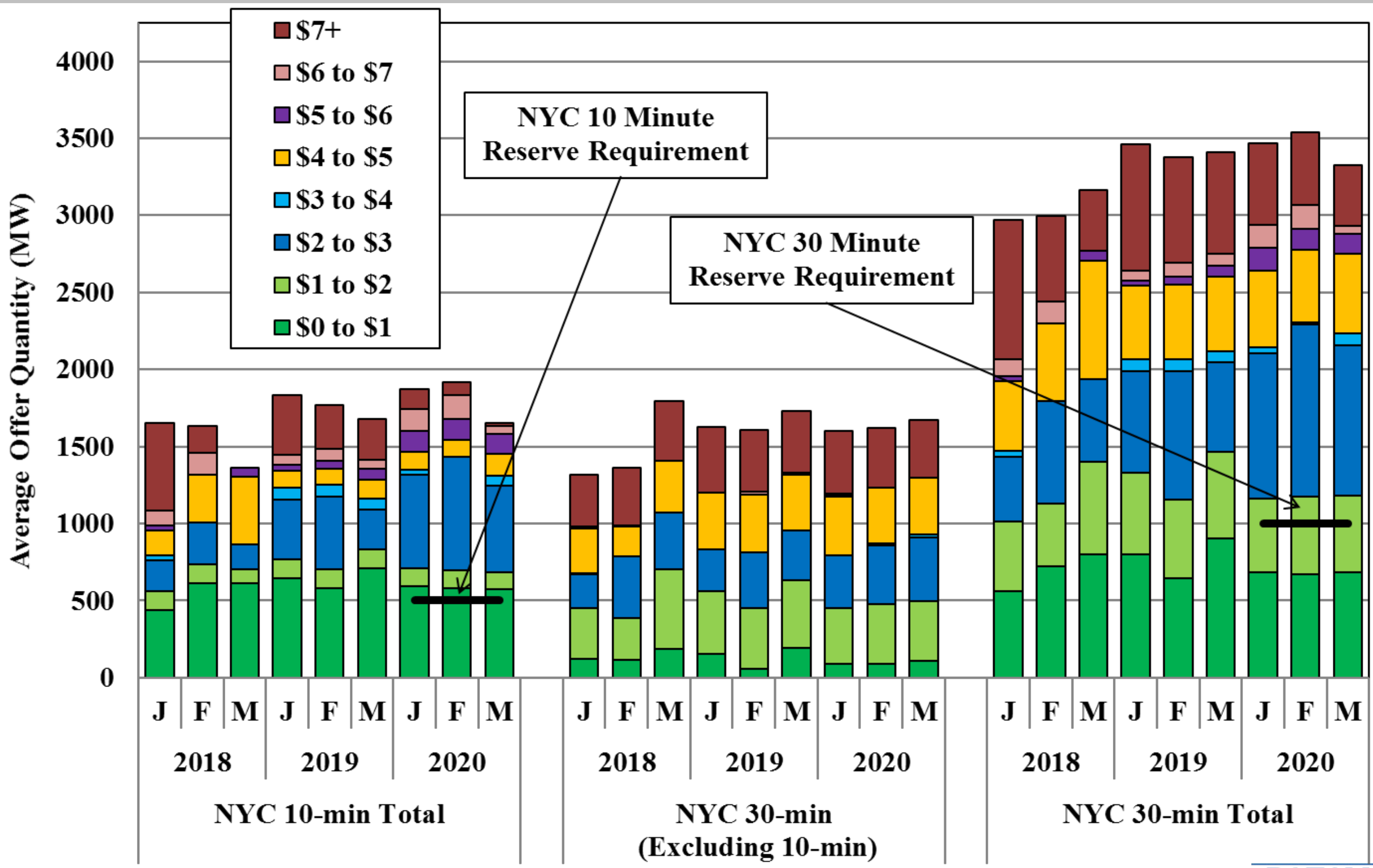
Day-Ahead NYC Reserve Offers
Committed and Available Offline Quick-Start Resources



  Notes: For chart description, see slide 64.

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Charts:
Energy Market Scheduling

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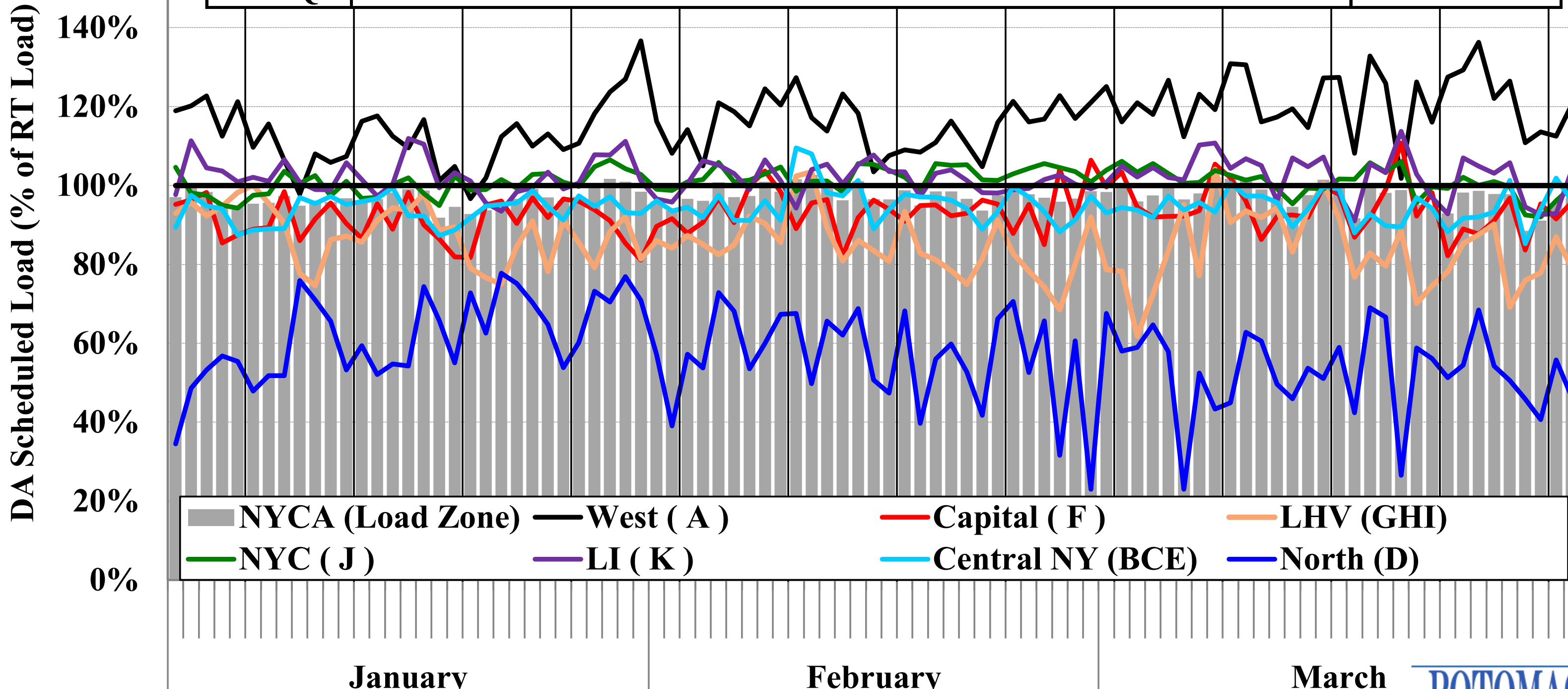
Day-ahead Scheduled Load and Actual Load
Daily Peak Load Hour

Quarter	Avg DA Net Scheduled Load (% of RT Load)								
	West Zone (A)	Central NY (BCE)	North Zone (D)	Capital (F)	LHV (GHI)	NYC (J)	LI (K)	NYCA (Load Zones)	NYCA (Load Zones + External)
2020 Q1	116%	94%	57%	93%	86%	101%	102%	97%	94%
2019 Q4	117%	91%	53%	94%	78%	98%	102%	95%	92%
2019 Q1	116%	91%	53%	98%	86%	98%	104%	96%	94%



Notes: For chart description, see slide 65.

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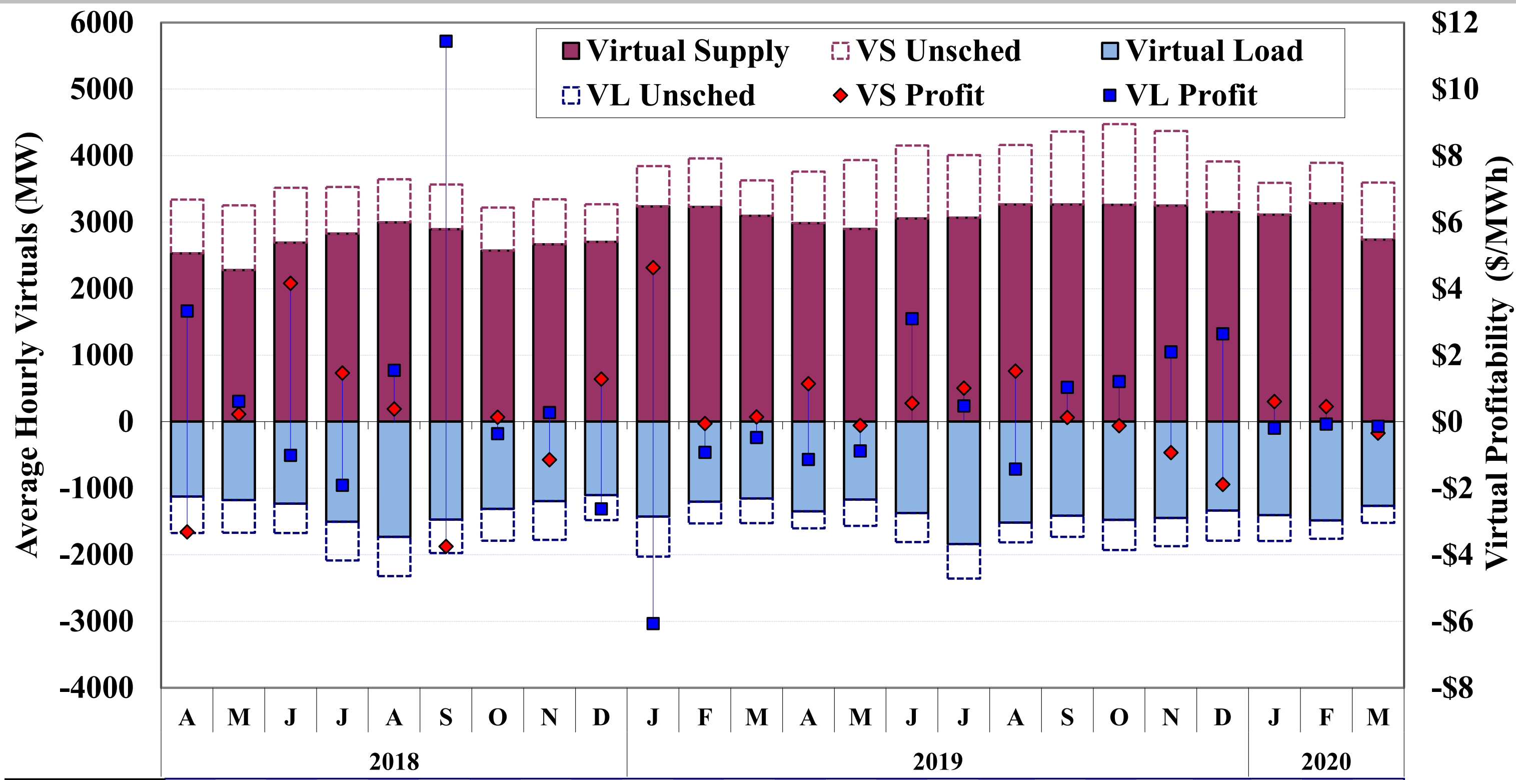
Virtual Trading Activity by Month



		A	M	J	J	A	S	O	N	D	J	F	M	A	M	J	J	A	S	O	N	D	J	F	M
Profit > 50% of Avg. Zone Price	MW	376	475	620	320	299	437	366	312	326	612	279	167	473	477	587	384	396	249	312	290	274	421	322	232
	%	10%	14%	16%	7%	6%	10%	9%	8%	9%	13%	6%	4%	11%	12%	13%	8%	8%	5%	7%	6%	6%	9%	7%	6%
Loss > 50% of Avg. Zone Price	MW	466	537	531	329	328	428	430	345	317	439	331	178	348	591	548	372	321	293	376	344	305	338	253	321
	%	13%	16%	14%	8%	7%	10%	11%	9%	8%	9%	7%	4%	8%	15%	12%	8%	7%	6%	8%	7%	7%	7%	5%	8%

Notes: For chart description, see slide 65.

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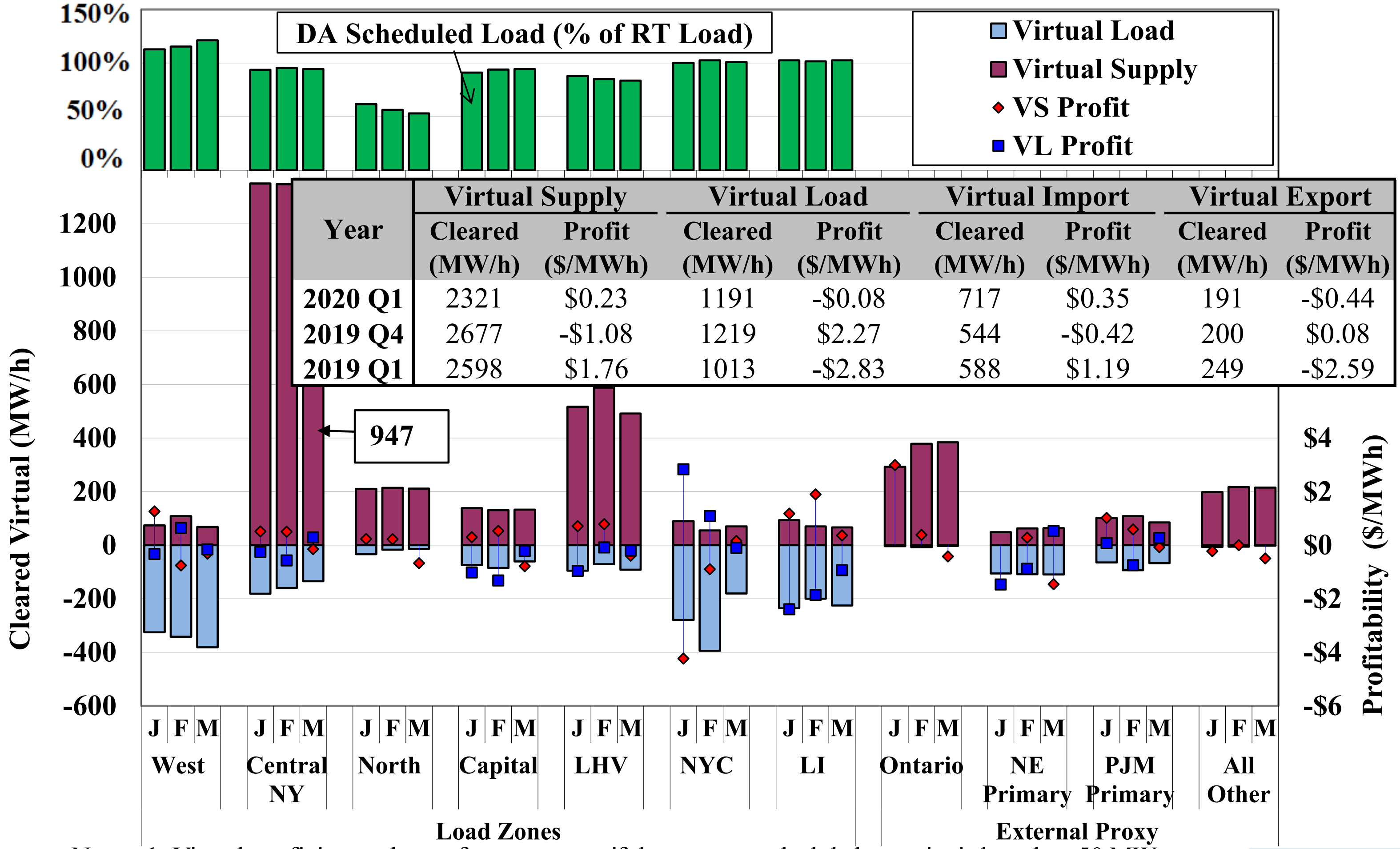
Virtual Trading Activity
by Location



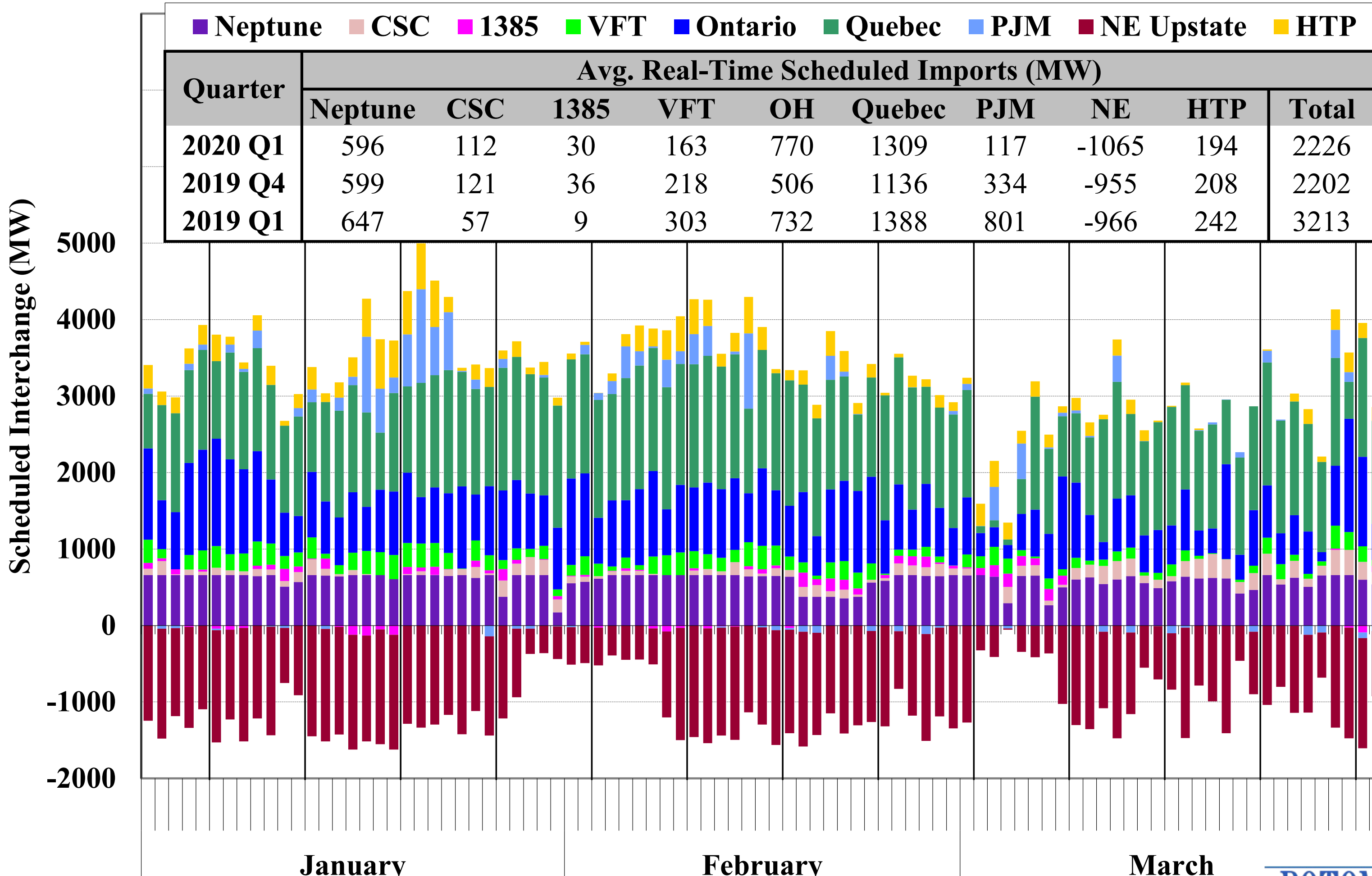
Year	Virtual Supply		Virtual Load		Virtual Import		Virtual Export	
	Cleared (MW/h)	Profit ($/MWh)	Cleared (MW/h)	Profit ($/MWh)	Cleared (MW/h)	Profit ($/MWh)	Cleared (MW/h)	Profit ($/MWh)
2020 Q1	2321	$0.23	1191	-$0.08	717	$0.35	191	-$0.44
2019 Q4	2677	-$1.08	1219	$2.27	544	-$0.42	200	$0.08
2019 Q1	2598	$1.76	1013	-$2.83	588	$1.19	249	-$2.59

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 65.

Net Imports Scheduled Across External Interfaces

Daily Peak Hours (1-9pm)

Quarter	Avg. Real-Time Scheduled Imports (MW)									
	Neptune	CSC	1385	VFT	OH	Quebec	PJM	NE	HTP	Total
2020 Q1	596	112	30	163	770	1309	117	-1065	194	2226
2019 Q4	599	121	36	218	506	1136	334	-955	208	2202
2019 Q1	647	57	9	303	732	1388	801	-966	242	3213



Notes: Two Quebec 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 > $20	Total
% of All Intervals w/ Adjustment			78%	2%	**80%**	26%	2%	**29%**
Average Flow Adjustment (MW)	Net Imports		10	-2	**9**	7	11	**8**
	Gross		99	121	**100**	53	70	**54**
Production Cost Savings ($ Million)	Projected at Scheduling Time		$0.6	$0.1	**$0.7**	$0.1	$0.1	**$0.2**
	Net Over-Projection by:	NY	$0.0	$0.0	**-$0.1**	-$0.1	$0.0	**-$0.1**
		NE or PJM	$0.1	$0.0	**$0.1**	$0.0	-$0.1	**-$0.1**
	Other Unrealized Savings		$0.0	$0.0	**$0.0**	$0.0	$0.0	**$0.0**
	Actual Savings		$0.6	$0.0	**$0.7**	$0.0	$0.0	**$0.0**
Interface Prices ($/MWh)	NY	Actual	$18.63	$64.84	**$20.05**	$18.24	$45.47	**$20.40**
		Forecast	$19.57	$29.58	**$19.88**	$20.58	$29.34	**$21.28**
	NE or PJM	Actual	$18.58	$28.60	**$18.89**	$19.34	$31.87	**$20.34**
		Forecast	$18.39	$26.16	**$18.63**	$19.54	$32.82	**$20.60**
Price Forecast Errors ($/MWh)	NY	Fcst. - Act.	$0.95	-$35.26	**-$0.17**	$2.35	-$16.13	**$0.88**
		Abs. Val.	$2.47	$43.60	**$3.73**	$3.84	$31.10	**$6.00**
	NE or PJM	Fcst. - Act.	-$0.19	-$2.44	**-$0.26**	$0.20	$0.95	**$0.26**
		Abs. Val.	$2.44	$12.53	**$2.75**	$2.10	$33.93	**$4.63**

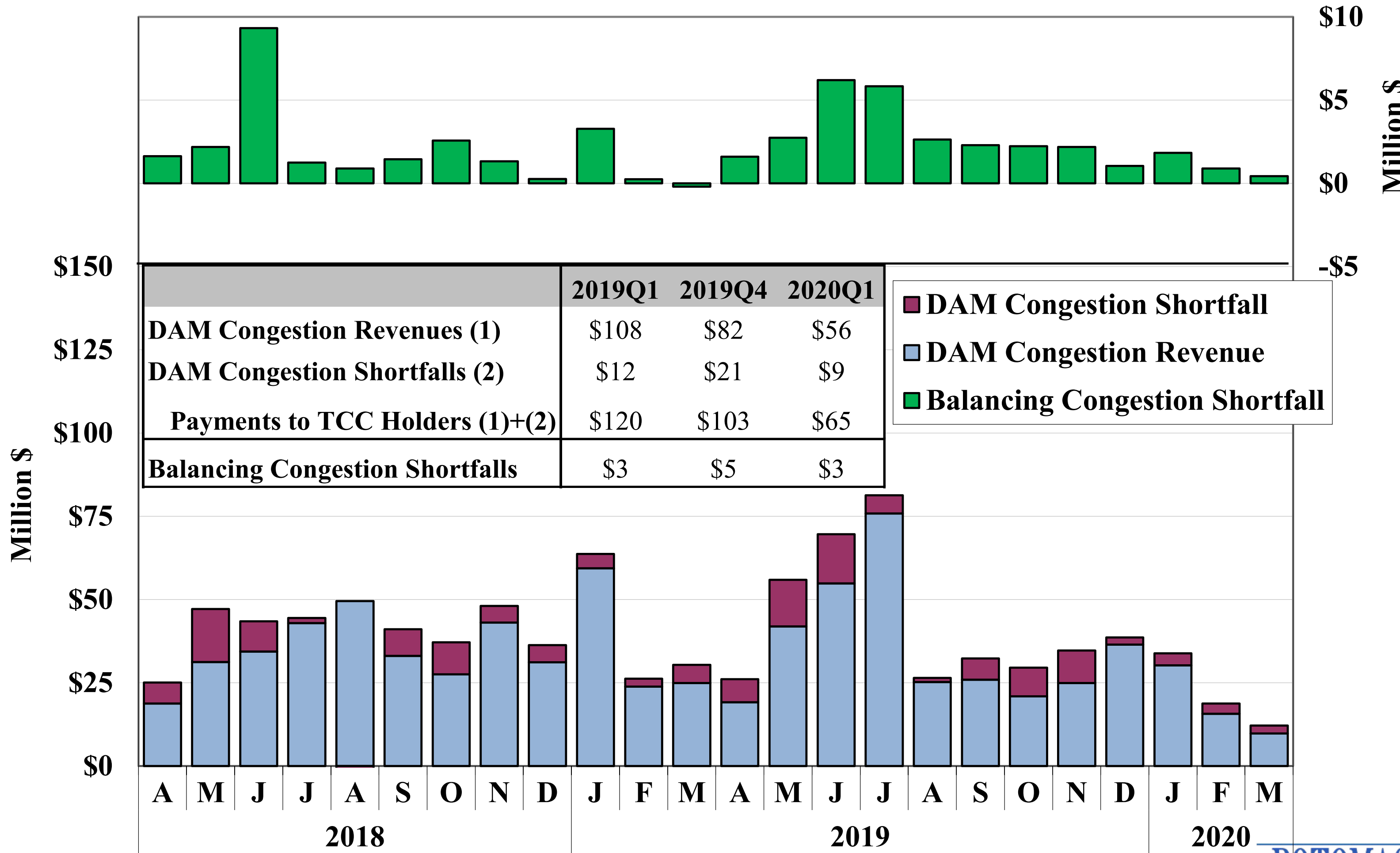
Notes: For chart description, see slide 66.

POTOMAC ECONOMICS

Charts:

Transmission Congestion Revenues and Shortfalls

Congestion Revenues and Shortfalls by Month

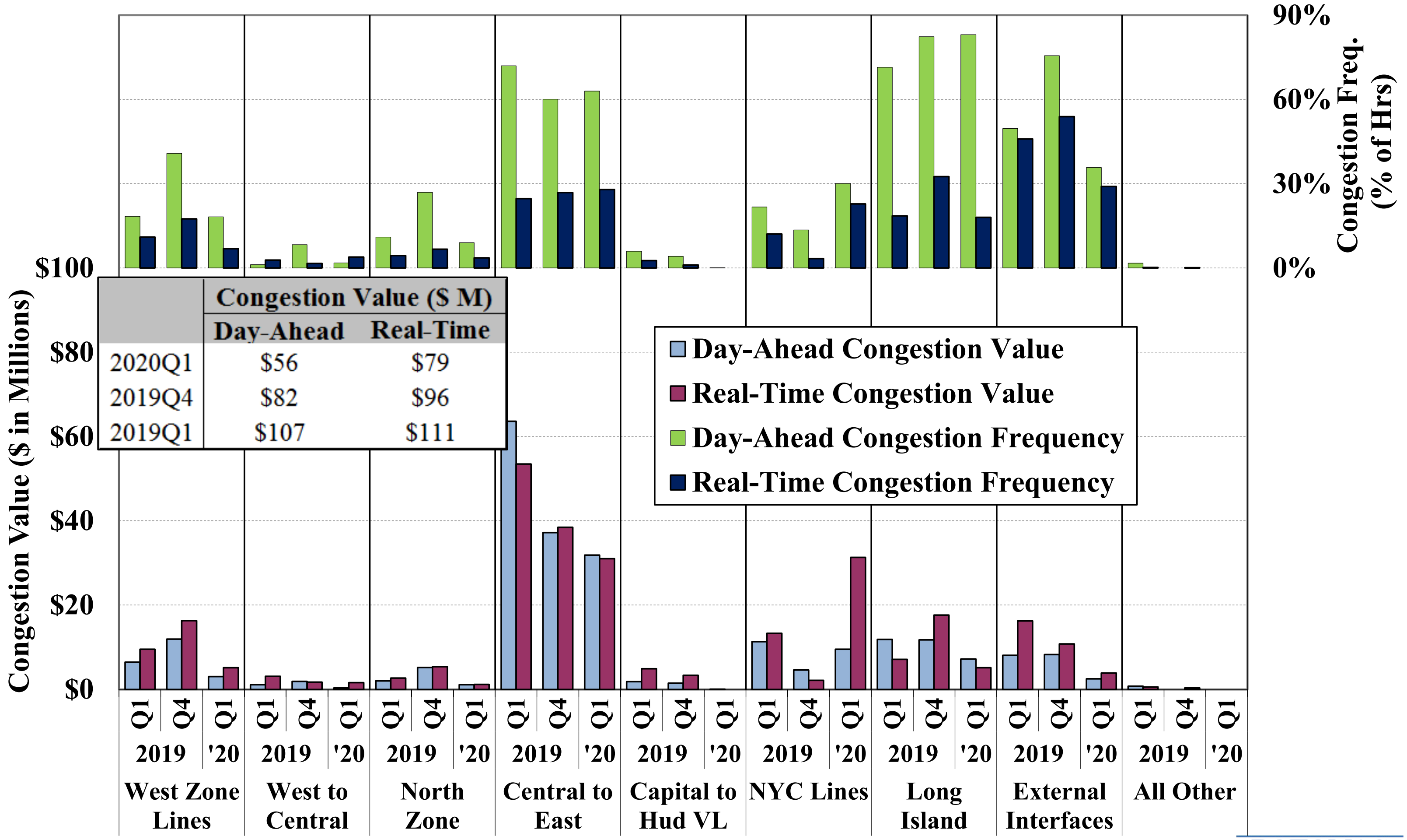


	2019Q1	2019Q4	2020Q1
DAM Congestion Revenues (1)	$108	$82	$56
DAM Congestion Shortfalls (2)	$12	$21	$9
Payments to TCC Holders (1)+(2)	$120	$103	$65
Balancing Congestion Shortfalls	$3	$5	$3

Notes: For chart description, see slides 67 and 68.

POTOMAC ECONOMICS

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

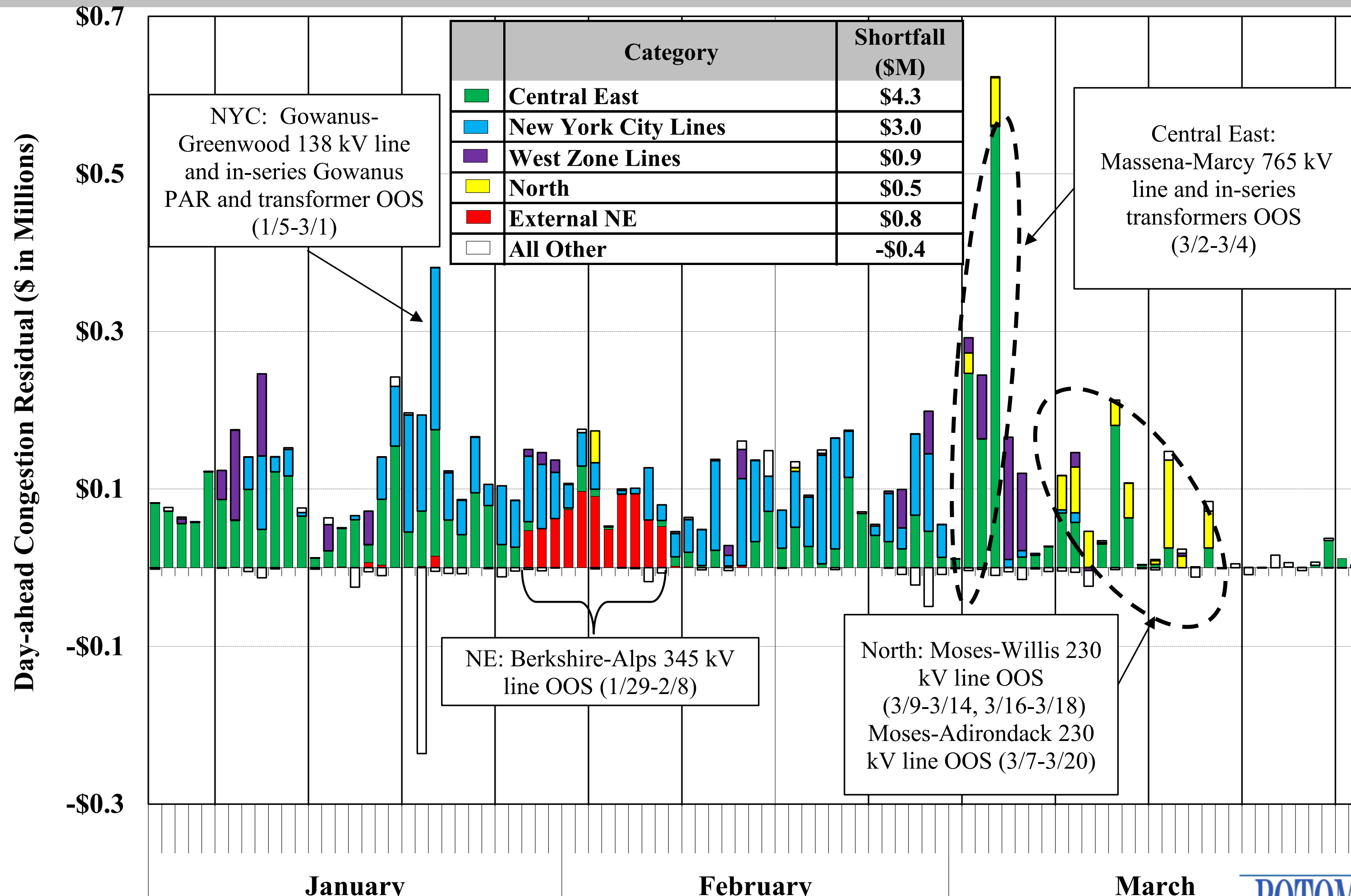


	Congestion Value ($ M)	
	Day-Ahead	Real-Time
2020Q1	$56	$79
2019Q4	$82	$96
2019Q1	$107	$111

Notes: For chart description, see slides 67, 68, and 69.

POTOMAC ECONOMICS

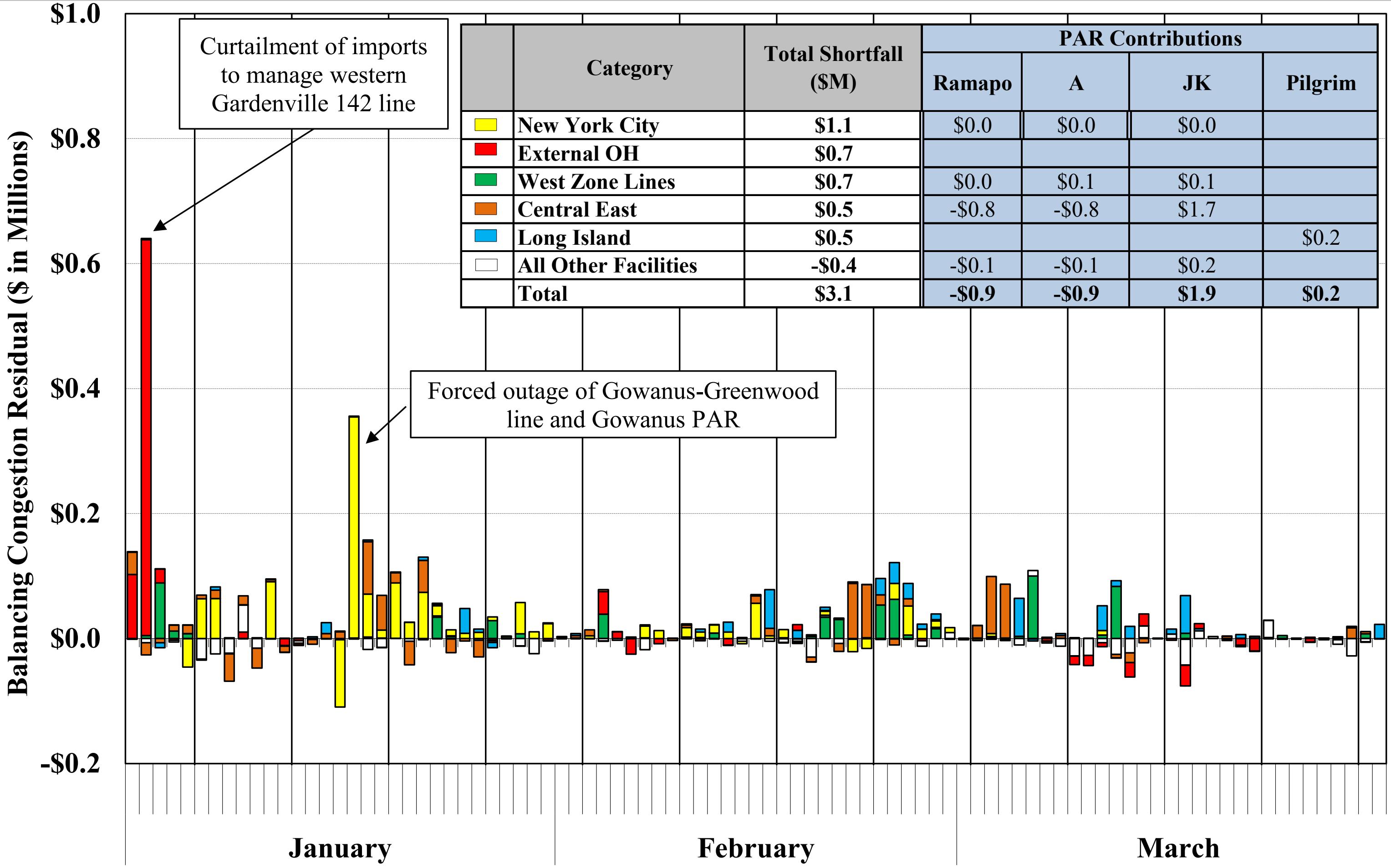
Day-Ahead Congestion Revenue Shortfalls by Transmission Facility



Notes: For chart description, see slides 67, 68, and 69.

POTOMAC ECONOMICS

Balancing Congestion Shortfalls by Transmission Facility

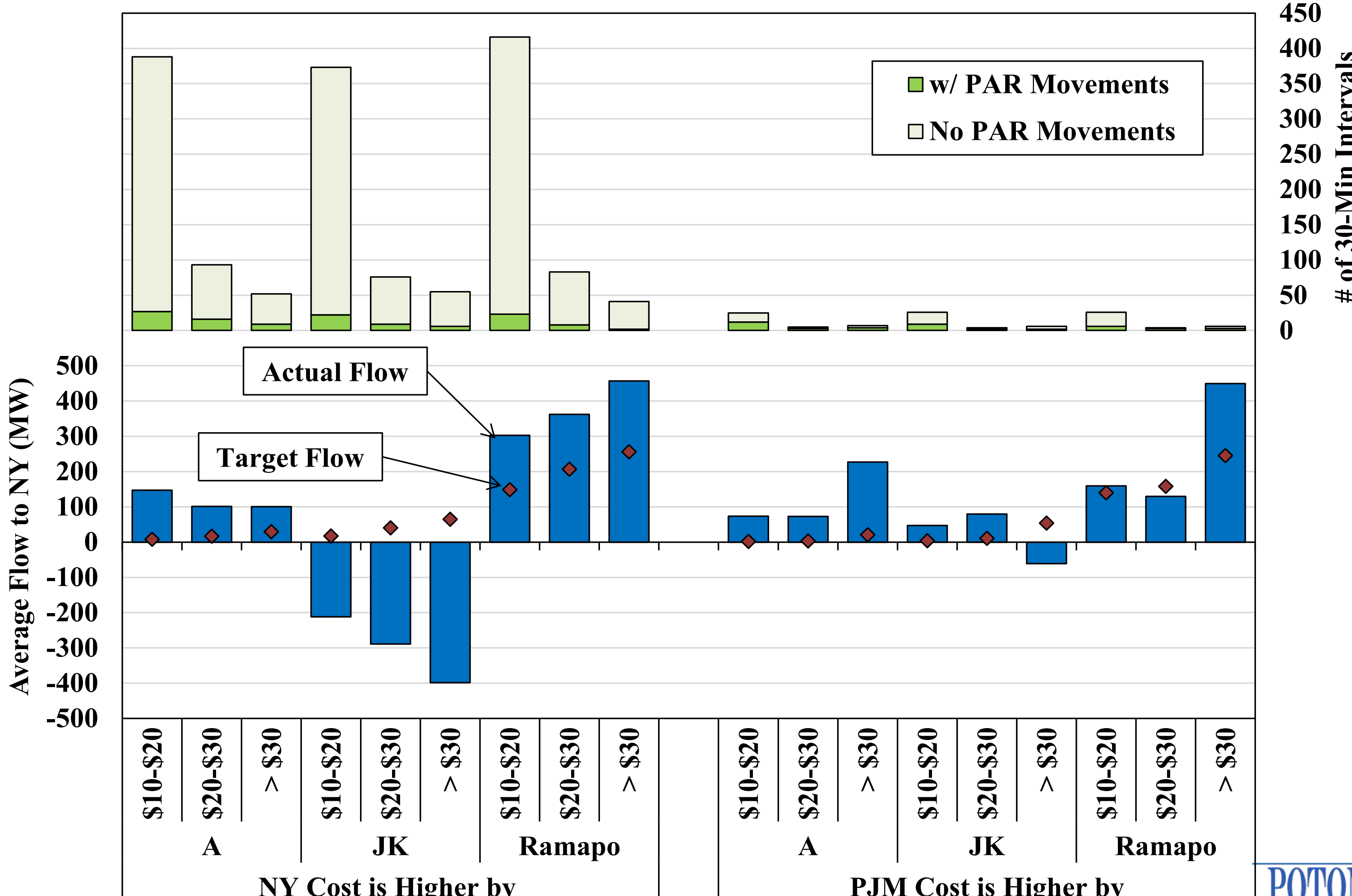


Category	Total Shortfall ($M)	PAR Contributions: Ramapo	A	JK	Pilgrim
New York City	$1.1	$0.0	$0.0	$0.0	
External OH	$0.7				
West Zone Lines	$0.7	$0.0	$0.1	$0.1	
Central East	$0.5	-$0.8	-$0.8	$1.7	
Long Island	$0.5				$0.2
All Other Facilities	-$0.4	-$0.1	-$0.1	$0.2	
Total	$3.1	-$0.9	-$0.9	$1.9	$0.2

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 67, 68, and 69.

POTOMAC ECONOMICS

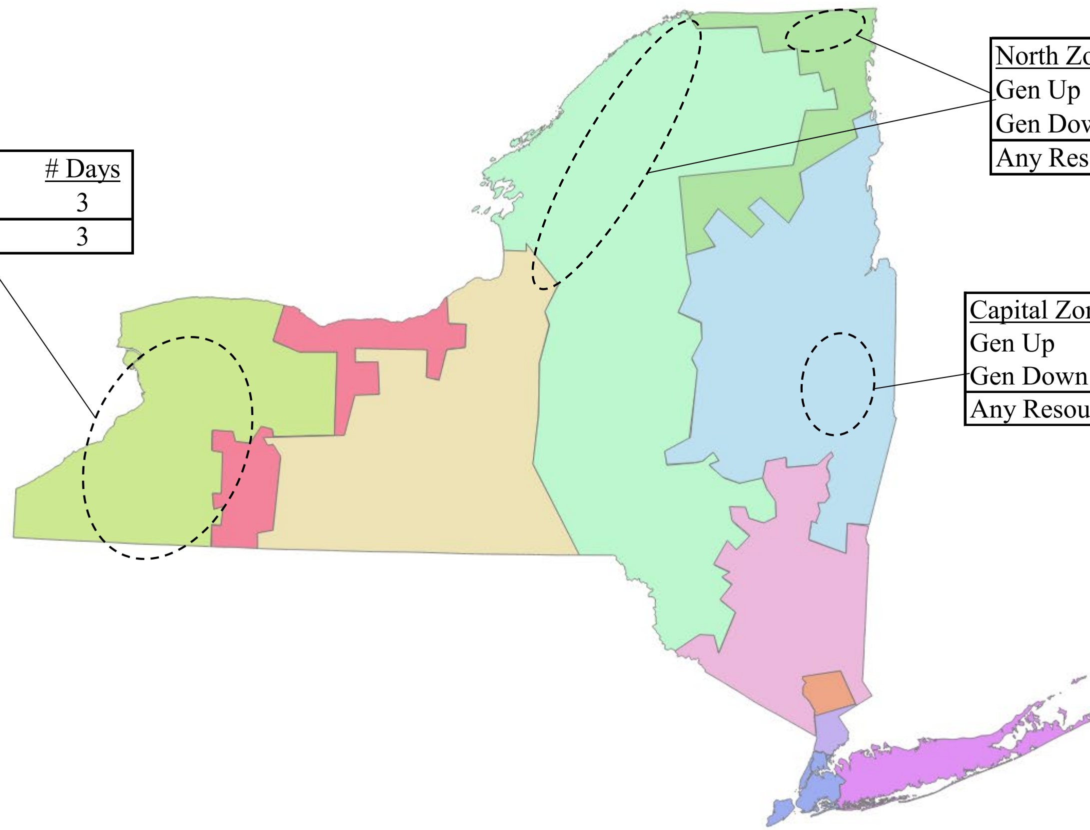
PAR Operation under M2M with PJM
2020 Q1



Notes: For chart description, see slide 70.

POTOMAC ECONOMICS

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



West Zone	# Days
Ontario Imports	3
Any Resource	3

North Zone	# Days
Gen Up	14
Gen Down	2
Any Resource	15

Capital Zone	# Days
Gen Up	0
Gen Down	1
Any Resource	1

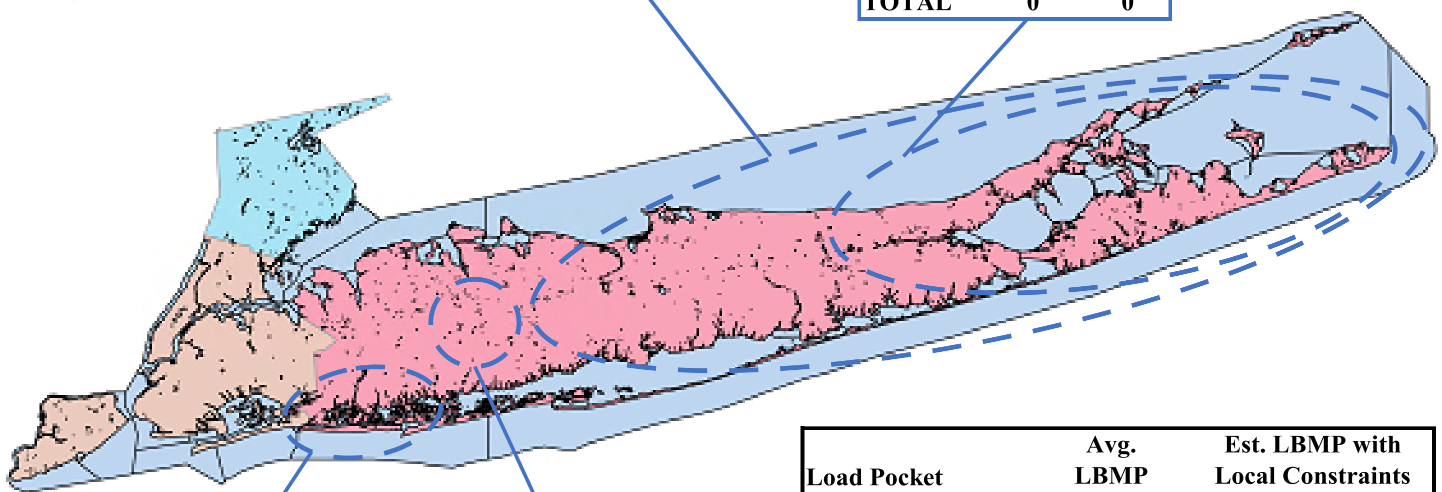
Long Is 69kV	# Days
Gen Up	16
Gen Down	2
Any Resource	18

Notes: For chart description, see slides 71-72

Constraints on the Low Voltage Network:
Long Island Load Pockets

East of Northport	#Hours	#Days
69kV	10	2
138kV	30	8
TOTAL	39	9

East End	#Hours	#Days
69kV	0	0
138kV	0	0
TOTAL	0	0



Load Pocket	Avg. LBMP	Est. LBMP with Local Constraints
Brentwood	$24.47	$24.86
East End	$25.55	$26.09
East of Northport	$24.88	$25.42
Valley Stream	$24.77	$25.49

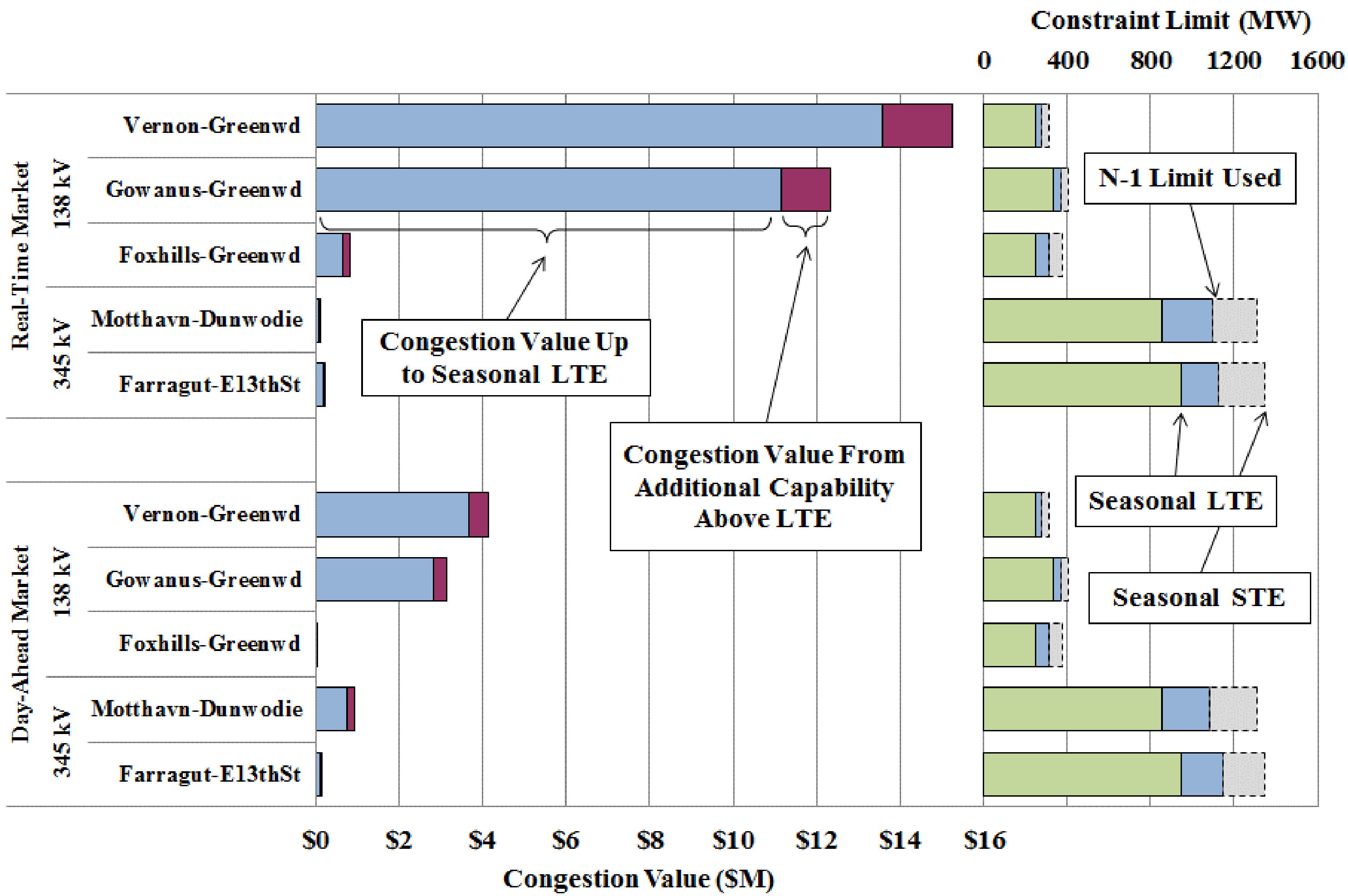
Brentwood	#Hours	#Days
69kV	20	6
138kV	0	0
TOTAL	20	6

Valley Stream	#Hours	#Days
69kV	174	9
138kV	1679	90
TOTAL	1771	91

Notes: For chart description, see slides 71-72

POTOMAC ECONOMICS

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



Notes: For chart description, see slide 73.

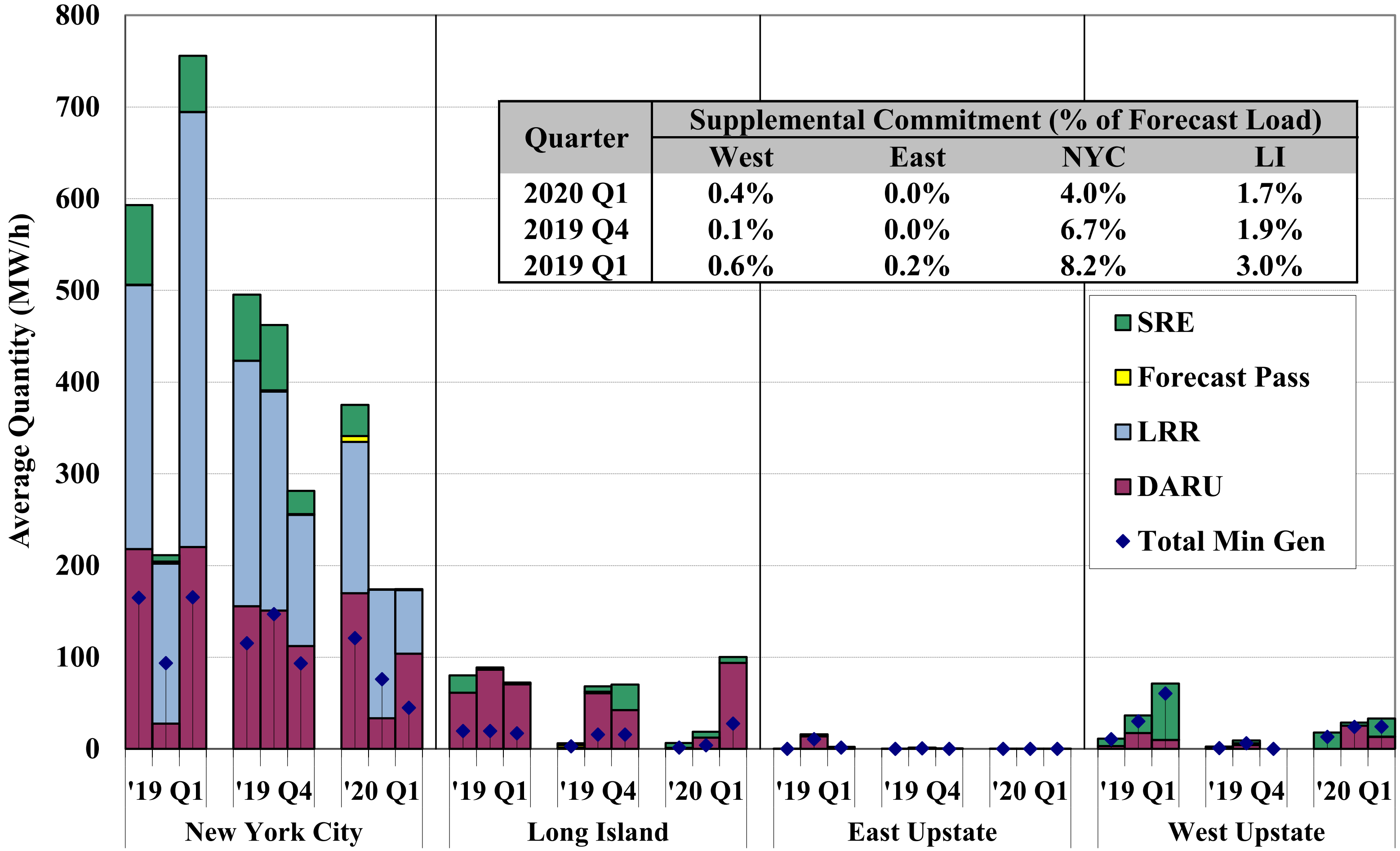
POTOMAC ECONOMICS

Charts:

Supplemental Commitment, OOM Dispatch, and BPCG Uplift

POTOMAC ECONOMICS

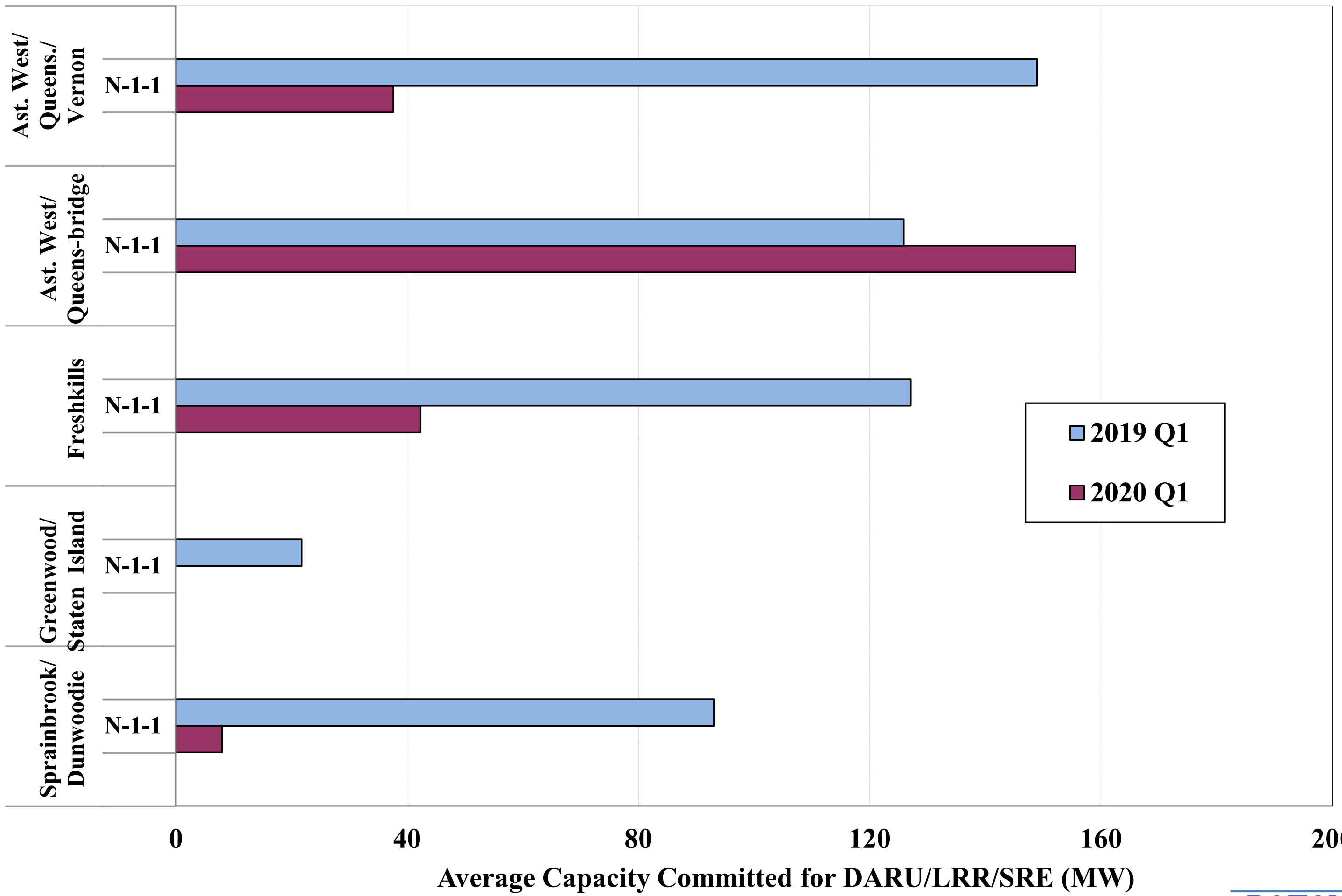
Supplemental Commitment for Reliability by Category and Region



Quarter	Supplemental Commitment (% of Forecast Load)			
	West	East	NYC	LI
2020 Q1	0.4%	0.0%	4.0%	1.7%
2019 Q4	0.1%	0.0%	6.7%	1.9%
2019 Q1	0.6%	0.2%	8.2%	3.0%

Notes: For chart description, see slides 74 and 75.

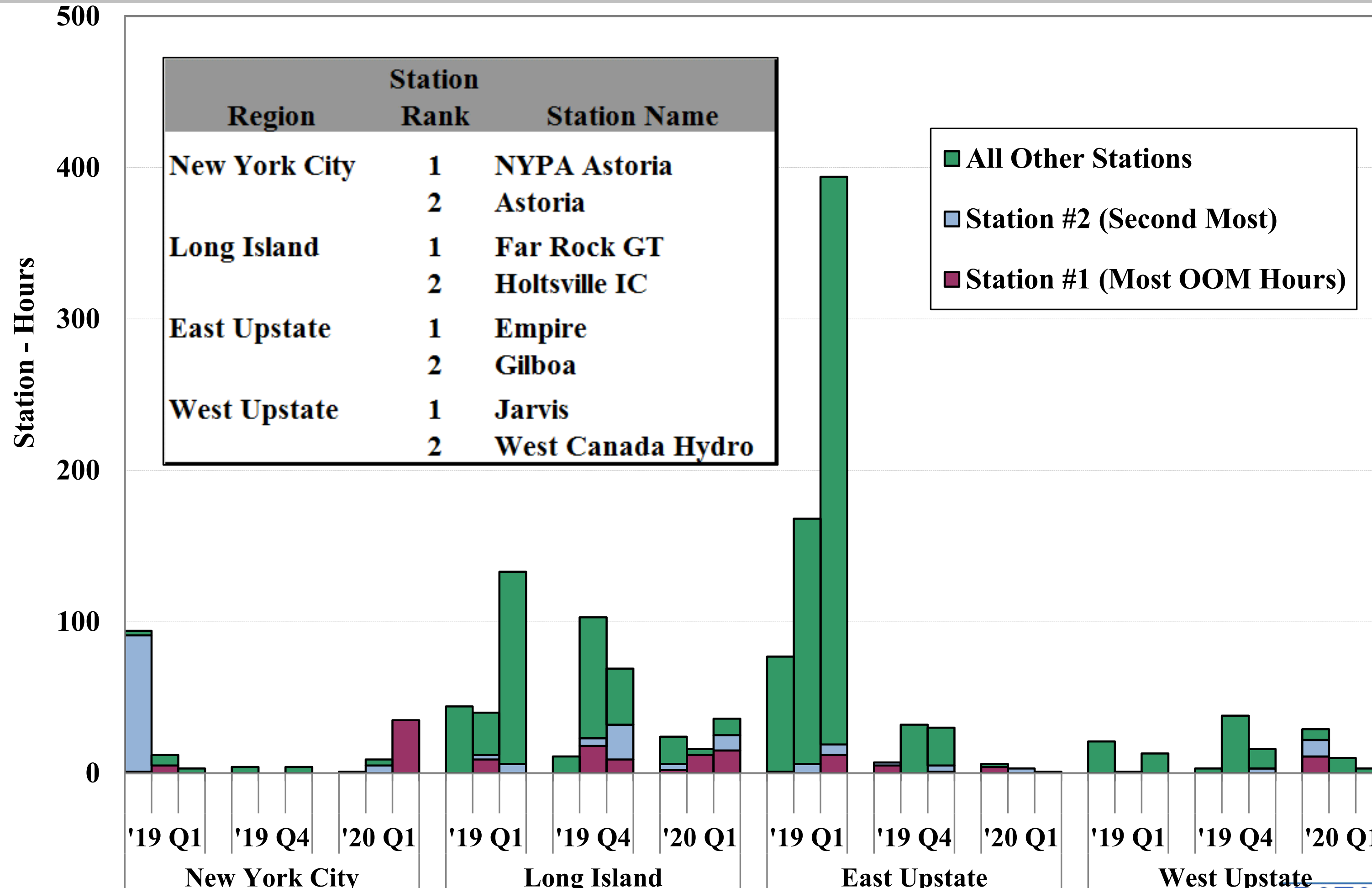
Supplemental Commitment for Reliability in NYC by Reliability Reason and Load Pocket



Notes: For chart description, see slides 74 and 75.

POTOMAC ECONOMICS

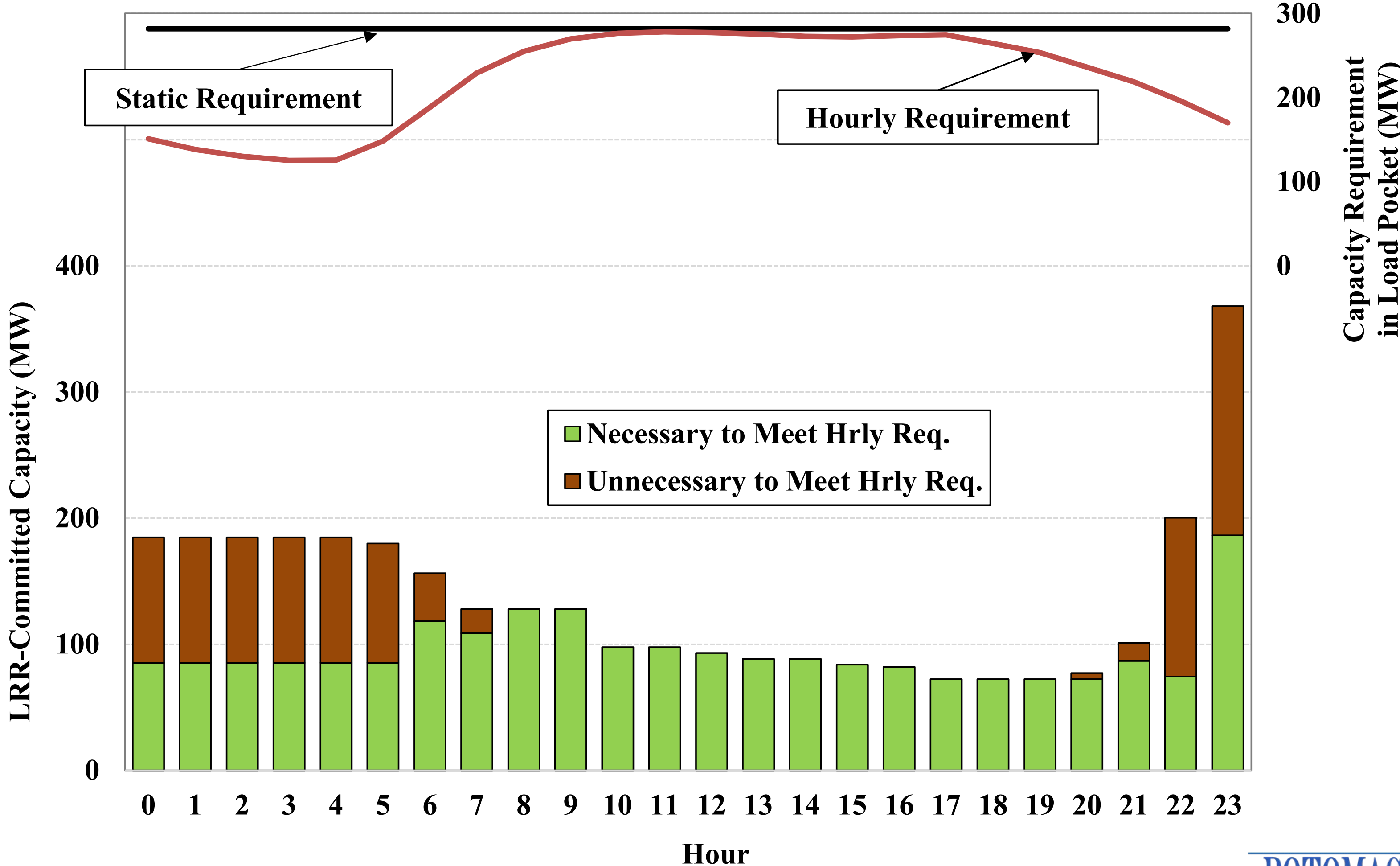
Frequency of Out-of-Merit Dispatch
by Region by Month



Region	Station Rank	Station Name
New York City	1	NYPA Astoria
	2	Astoria
Long Island	1	Far Rock GT
	2	Holtsville IC
East Upstate	1	Empire
	2	Gilboa
West Upstate	1	Jarvis
	2	West Canada Hydro

For chart description, see slides 74 and 75.

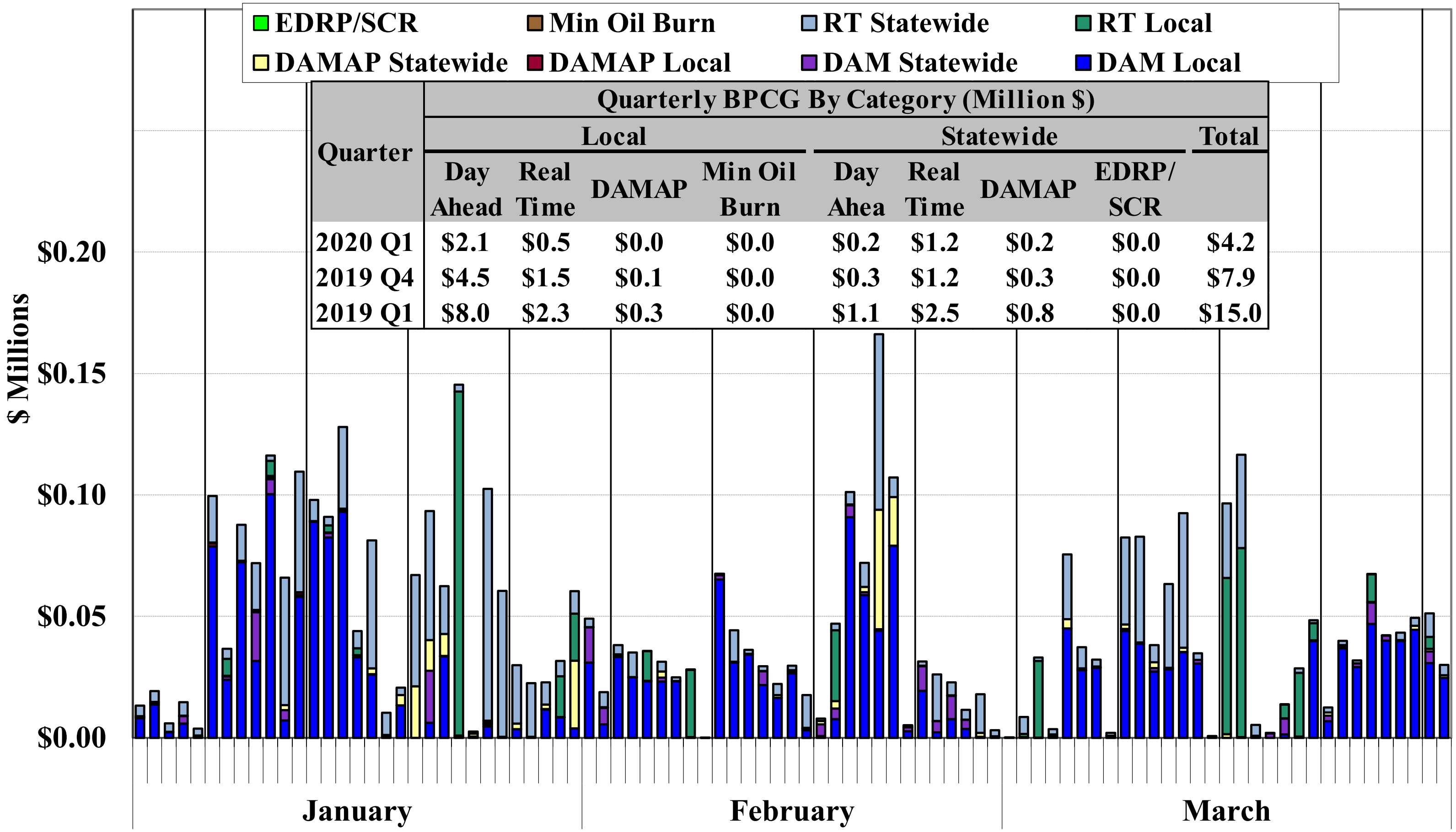
LRR Commitments in New York City
Hourly Requirement vs. Static Daily Requirement



For chart description, see slide 76.

POTOMAC ECONOMICS

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



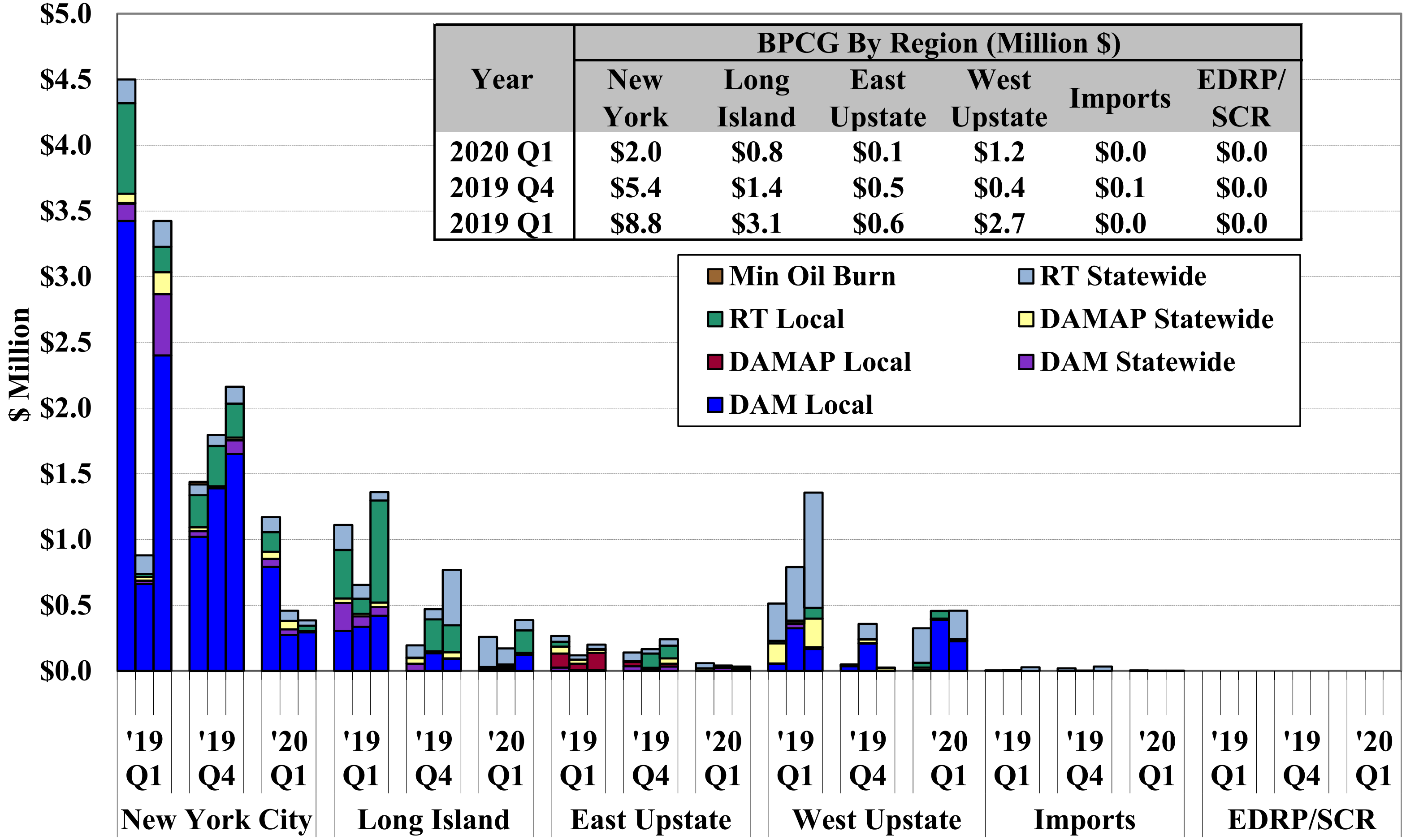
Quarter	Local Day Ahead	Local Real Time	Local DAMAP	Local Min Oil Burn	Statewide Day Ahea	Statewide Real Time	Statewide DAMAP	Statewide EDRP/ SCR	Total
2020 Q1	$2.1	$0.5	$0.0	$0.0	$0.2	$1.2	$0.2	$0.0	$4.2
2019 Q4	$4.5	$1.5	$0.1	$0.0	$0.3	$1.2	$0.3	$0.0	$7.9
2019 Q1	$8.0	$2.3	$0.3	$0.0	$1.1	$2.5	$0.8	$0.0	$15.0

Quarterly BPCG By Category (Million $)

Notes:1. This data is based on information available at the reporting time and does not include some manual adjustments to mitigation, so it can be different from final settlements.
2. For chart description, see slide 77.

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
2020 Q1	$2.0	$0.8	$0.1	$1.2	$0.0	$0.0
2019 Q4	$5.4	$1.4	$0.5	$0.4	$0.1	$0.0
2019 Q1	$8.8	$3.1	$0.6	$2.7	$0.0	$0.0



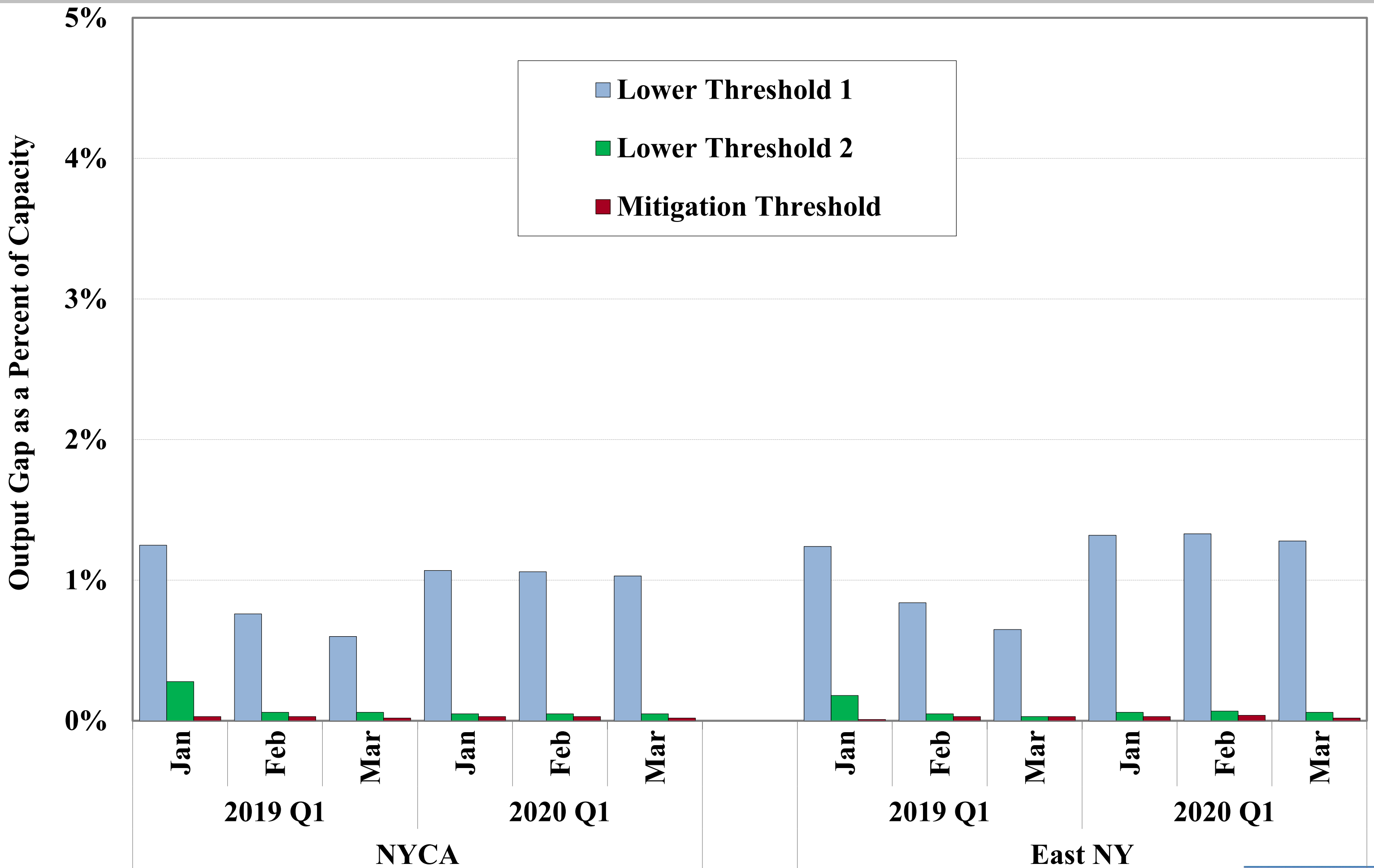
Notes: 1. BPCG data are based on information available at the reporting time that can be different from final settlements.
2. For chart description, see slide 77.

POTOMAC ECONOMICS

Charts:
Market Power and Mitigation

POTOMAC ECONOMICS

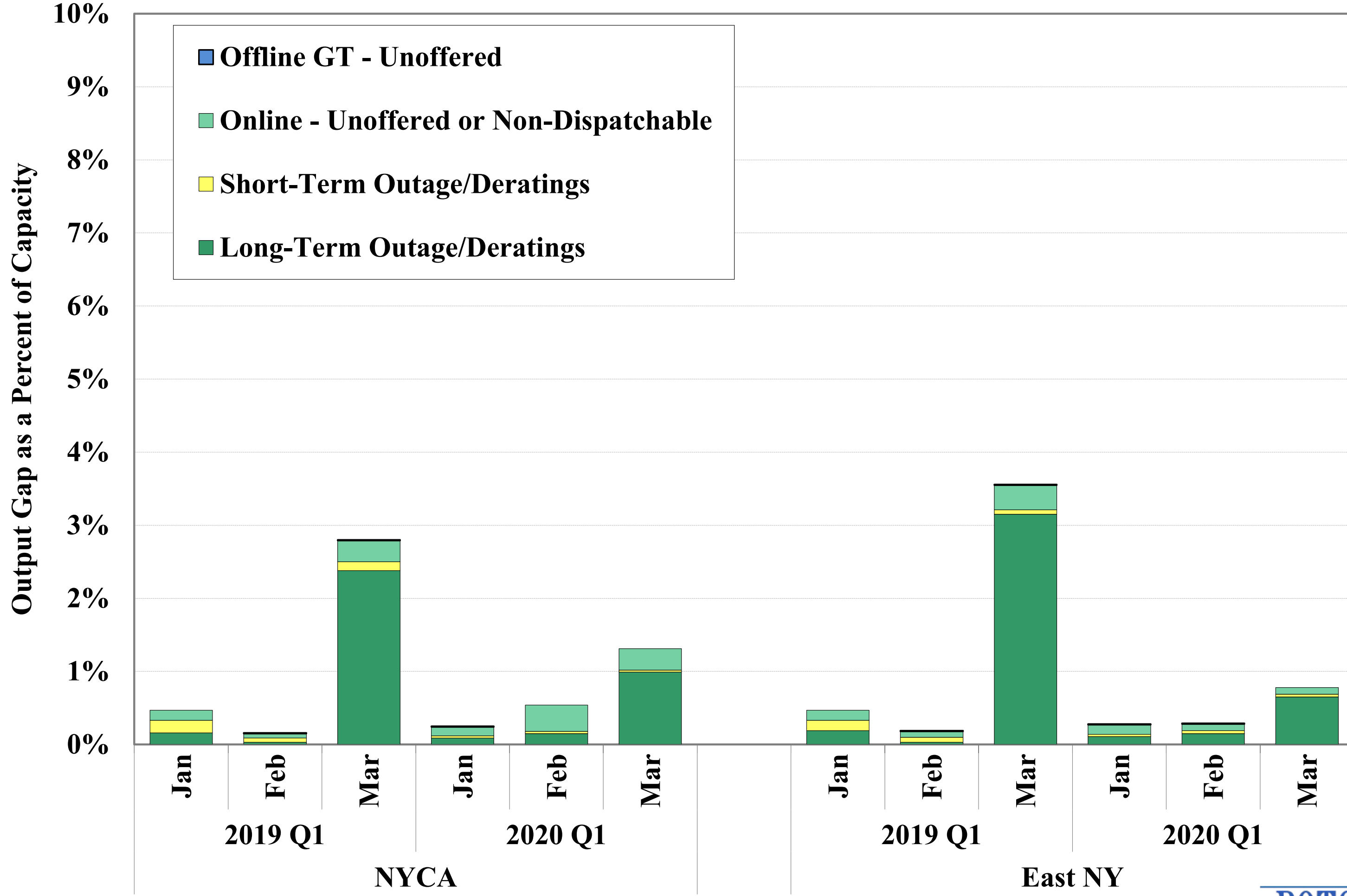
Output Gap by Month
NYCA and East NY



For chart description, see slide 78.

POTOMAC ECONOMICS

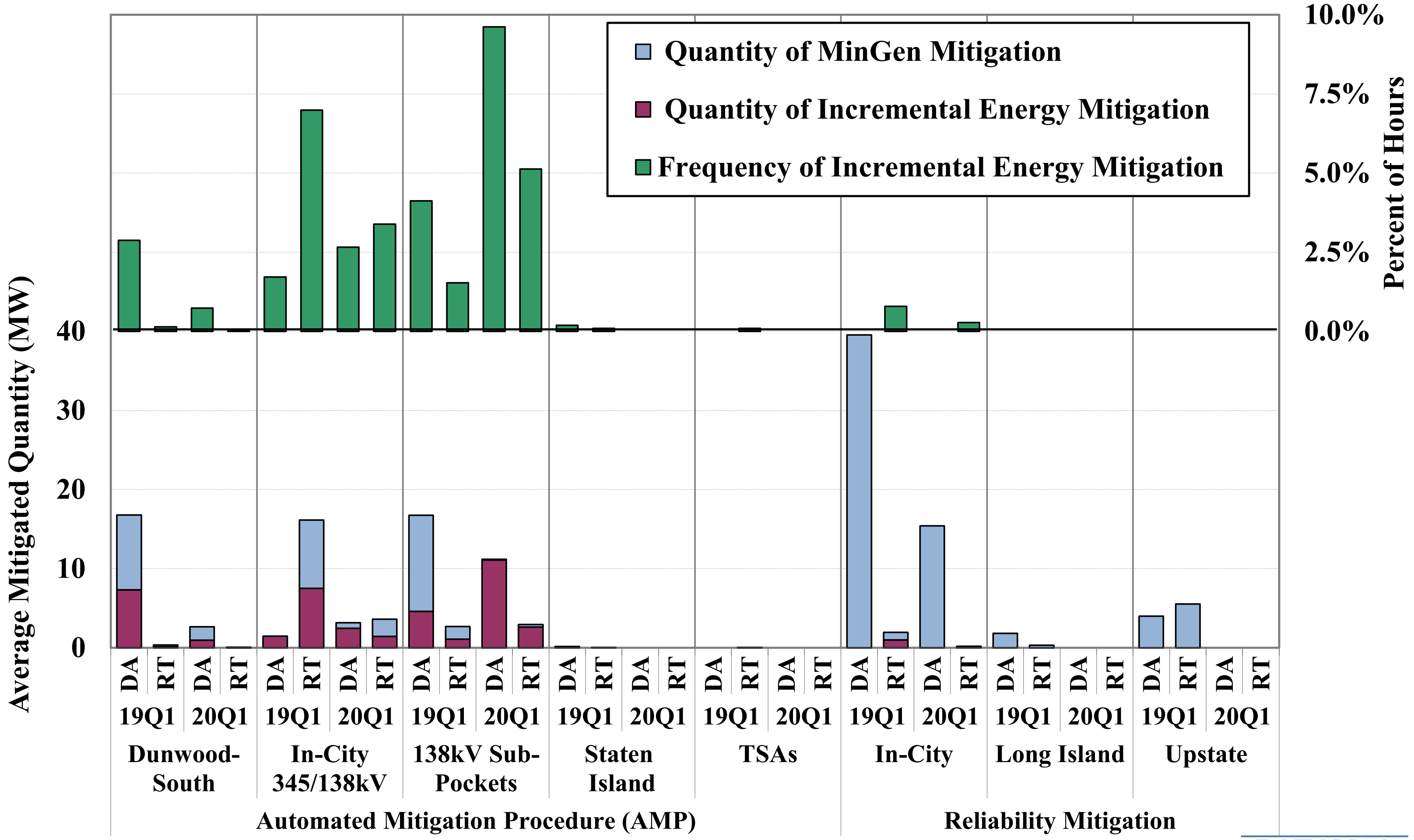
Unoffered Economic Capacity by Month
NYCA and East NY



For chart description, see slide 78.

POTOMAC ECONOMICS

Automated Market Power Mitigation

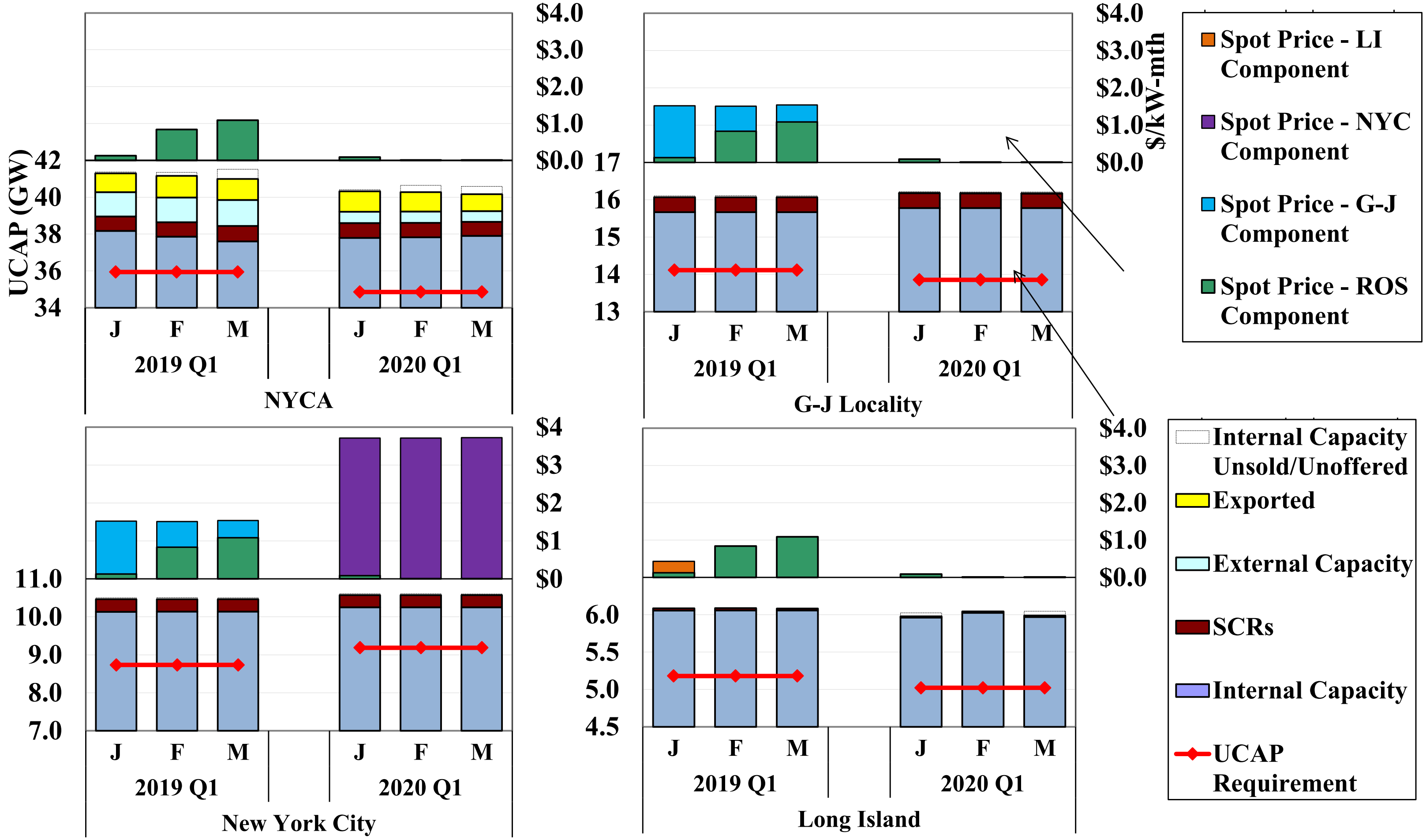


Notes: For chart description, see slide 79.

Charts:

Capacity Market

Spot Capacity Market Results
2019-Q1 & 2020-Q1



Notes: For chart description, see slide 80.

POTOMAC ECONOMICS

Key Drivers of Capacity Market Results

	NYCA	NYC	LI	G-J Locality
Avg. Spot Price				
2020 Q1 ($/kW-Month)	$0.04	$3.71	$0.04	$0.04
% Change from 2019 Q1	**-95%**	**144%**	**-95%**	**-98%**
Change in Demand				
Load Forecast (MW)	-519	68	-136	-72
IRM/LCR	-1.2%	2.3%	0.6%	-2.2%
2019/20 Capability Year	*117.0%*	*82.8%*	*104.1%*	*92.3%*
2018/19 Capability Year	*118.2%*	*80.5%*	*103.5%*	*94.5%*
ICAP Requirement (MW)	**-1,003**	**322**	**-109**	**-417**
Key Changes in ICAP Supply (MW)				
Generation	**-33**	**-39**	**-11**	**-34**
Entry (1)	312	11		11
Exit (2)	-364	-36		-36
DMNC	19	-14	-11	-9
Cleared Import (3)	**-751**			

(1) Includes capacity returning to service from IIFO designation.

(2) Includes Generator ICAP transitioned to BTM:NG designation.

(3) Based on average of quarterly cleared quantity.

Notes: For chart description, see slide 80.

POTOMAC ECONOMICS

Appendix: Chart Descriptions

All-in Price

- Slide 15 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 zone, allocated over the energy consumption in that zone.
  - ✓ 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 transportation charges equal to $0.27 per MMBtu for Zones A through I, $0.20 per MMBtu for New York City, and $0.25 per MMBtu for Long Island):
    - (a) Tennessee Z4 200L index for the West Zone, (b) the minimum of TN Z6 and Iroquois Zone 2 indices during the months Dec through Feb, and TN Z4 200L index otherwise for Central New York; (c) Iroquois Waddington index for North Zone; (d) the minimum of TN Z6 and Iroquois Z2 indices for the Capital Zone; (e) the average of Iroquois Z2 index and the Tetco M3 index for Lower Hudson Valley; (f) Transco Zone 6 (NY) index for New York City, and (g) the Iroquois Z2 index for Long Island. A 6.9 percent tax rate is also included NYC.

POTOMAC ECONOMICS

Real-Time Output and Marginal Units by Fuel

- Slide 18 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 19 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 24-28 summarize day-ahead and real-time prices for eight ancillary services products during the quarter:
  - ✓ 10-min spinning reserve prices in NYC, eastern NY, and Western NY;
  - ✓ 10-min non-spinning reserve prices in NYC, eastern NY, and 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 per MW of capability, but they are compensated according to actual movement.
    - – Real-time Regulation Movement Charges shown on Slide 27 are estimated by dividing total movement charges by real-time scheduled regulation capacity.
  - ✓ 30-min operating reserve prices in western NY and NYC; 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 29 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.

POTOMAC ECONOMICS

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.

NY-NJ PAR Operation Under M2M with PJM

- Slide 42 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).

POTOMAC ECONOMICS

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 43 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;
  - ✓ Central Zone;
  - ✓ Capital Zone:
  - ✓ North & Mohawk Valley Zones; and
  - ✓ Long Island (mostly constraints on the 69kV system).

Constraints on the Low Voltage Network

- Slide 44 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 44 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 45 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 47, 48, and 49 summarize out-of-market commitment and dispatch, which are the primary sources of guarantee payment uplift.
- Slide 47 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 48 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.)

  - 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 49 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.

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LRR Commitments in NYC

- Slide 50 evaluates how much of the capacity committed to satisfy an N-1-1 LRR constraint may have been unnecessary had the daily requirements been calculated hourly instead.
- The slide shows the following quantities as the averages for each hour on days when one or more units were committed to satisfy an LRR constraint:
  - ✓ The static daily requirement vs. the varying hourly requirement (in the top portion of the chart);
  - ✓ LRR-committed capacity (based on the daily requirement) that was:
    - Necessary to satisfy the hourly requirement;
    - Unnecessary to satisfy the hourly requirement.
- This evaluation is done for load pockets that account for most of the LRR-commitments in NYC this quarter.

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.

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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.

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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.