Quarterly Report on the New York ISO Electricity Markets First Quarter of 2021

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June 2021

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Market Highlights

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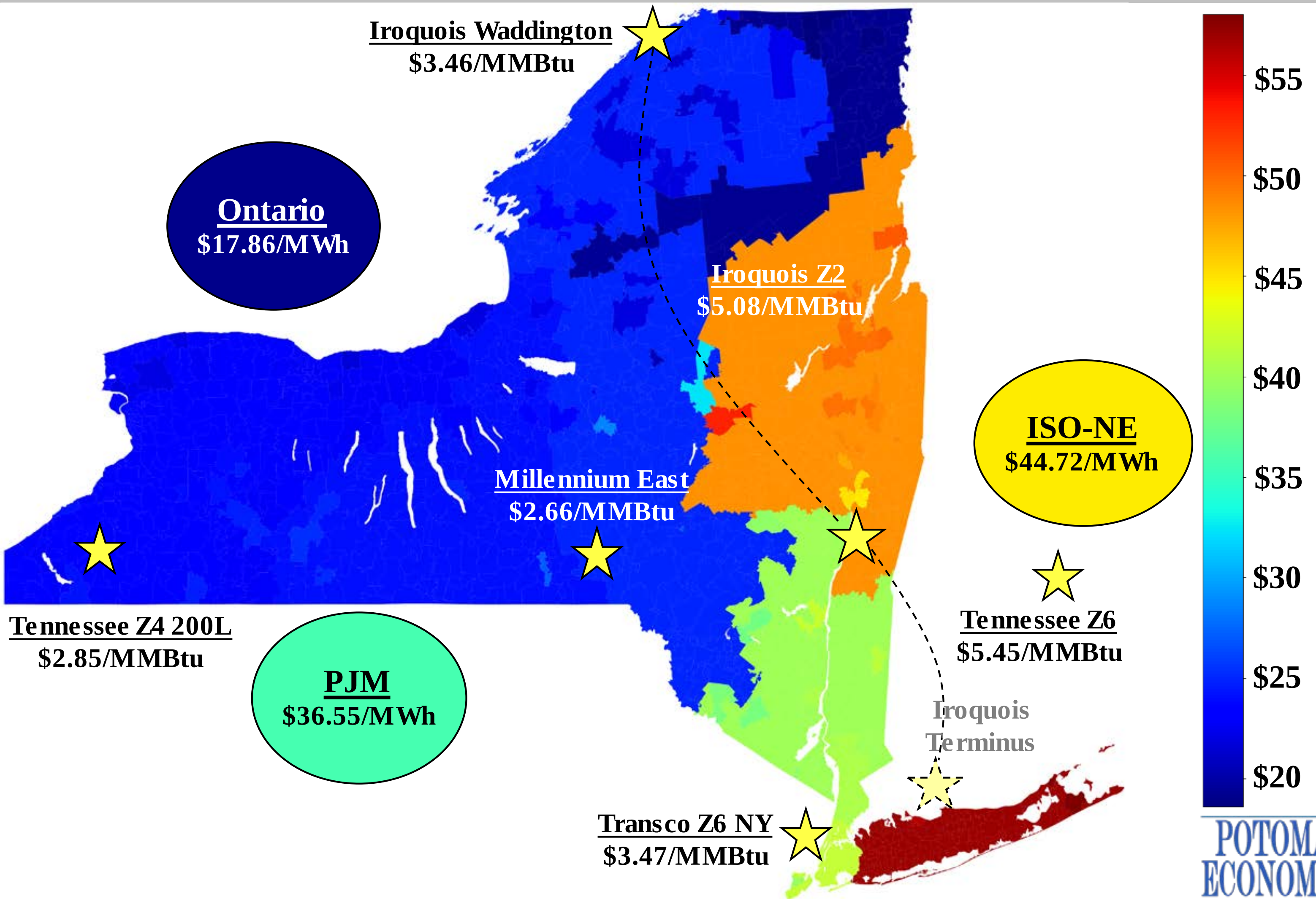
Market Highlights:
Executive Summary

- NYISO energy markets performed competitively in the first quarter of 2021.
- All-in prices ranged from \$22 to \$69 per MWh, up from the very low values observed in 2020-Q1, but more consistent with recent historical levels. (slide 6)
  - ✓ Energy prices rose 40 to 143 percent primarily due to higher gas prices.
  - ✓ Congestion increased because of: (a) larger gas price differences between regions and (b) transmission outages along the Central-East interface and into Long Island.
  - ✓ Capacity prices: (a) rose significantly in NYC as a result of the higher LCR; and (b) increased outside NYC but were still quite low. (slide 15)
- Oil-fired generation rose notably from late January to mid-February as gas prices in East NY rose to the oil price level because of cold weather conditions.
  - ✓ However, the weather was not severe enough to put sufficient strain on the gas supply and oil inventories.
- Reliability commitments rose modestly in NYC as a result of higher load and more transmission outages, leading to higher BPCG uplift. (slide 12)
  - ✓ However, the NYISO and ConEd have made procedural changes for N-1-1-0 in recent years which have improved the efficiency of these commitments and lowered associated uplift.

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 2021.
  - ✓ The amount of output gap (slide 66) and unoffered economic capacity (slide 67) remained modest and reasonably consistent with competitive market expectations.
- All-in prices ranged from $22/MWh in the North Zone to $69/MWh in NYC, rising 44 to 130 percent from last year. (slide 17)
  - ✓ Energy prices accounted for the largest component of the increase, rising by 40 to 143 percent (slides 26-27), driven primarily by higher natural gas prices.
    - – Average natural gas prices rose between 87 and 135 percent from a year ago in Eastern NY (slide 19), reflecting much colder weather compared to last winter.
      - Gas price spreads between West and East NY rose substantially – the East NY premium averaged 78% in 2021-Q1 versus 28% in 2020-Q1.
    - – Other contributing factors include:
      - Higher load levels - average load rose 2% and peak load rose 3%. (slide 18)
      - Lower nuclear output because of the retirement of Indian Point 2 and lower hydro output because of more frequent freezing conditions. (slide 20)
      - Lengthy transmission outages on the Central-East interface and into Long Island. (slide 49)
  - ✓ Capacity costs rose in all regions for the reasons discussed in slide 15.

Market Highlights:
Generation by Fuel and Emission

- Nuclear and hydro generation fell by an average of 1 GW collectively from a year ago, reflecting nuclear retirement and more frequent freezing conditions.
- Consequently, gas-fired generation rose by more than 7 percent despite higher natural gas prices. (slides 19-20)
  - ✓ Gas-fired steam turbine generation rose by 660 MW on average.
    - – Most of the increase occurred in Long Island where STs were used more often during lengthy transmission outages to serve load, satisfy reserve needs, and support contractual requirements to export to New York City.
  - ✓ However, gas-fired CC generation fell by 250 MW in the Hudson Valley.
    - – Increased gas pipeline constraints limited production from gas-fired units in the Hudson Valley during many cold days in the quarter.
- Oil-fired generation in East NY (mostly Long Island) rose significantly on many days in January and February as cold weather drove gas prices to the level of oil prices. (slides 20, 22)
- These changes led to increased CO_2, SO_2, and NO_x emissions from 2020-Q1 despite the retirement of coal generation in 2020. (slides 23-25)
  - ✓ Long Island accounted for most of the increases in emissions.

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Market Highlights:
Congestion Patterns, Revenues and Shortfalls

- Day-ahead congestion revenues totaled $179 million, up 222 percent from the first quarter of 2020. (slide 47) The increase was driven by:
  - ✓ Higher gas prices, especially in February; and
  - ✓ Lengthy transmission outages along the Central-East interface and into Long Island.
- The Central-East interface accounted for the largest share (77 percent) of day-ahead congestion revenues in the first quarter of 2021. (slide 48)
  - ✓ This is typical during the winter season when gas spreads between Western NY and Eastern NY are the largest.
  - ✓ Nonetheless, Central East congestion rose 328 percent from 2020-Q1, and its total quarterly congestion value was the highest seen since 2015. Contributing factors include:
    - – Higher regional gas price spreads (slide 19);
    - – Lower nuclear generation in East NY because of nuclear retirement (slide 20); and
    - – Lengthy transmission outages that lowered the interface capability by as much as 1475 MW, although this was partly offset by putting the Marcy South Series Compensator in service. (slide 49)

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

- Long Island accounted for 7 percent of congestion primarily on 345 kV paths from upstate to Long Island because of lengthy transmission outages.
  - ✓ The Y50 line flows were limited by the outage of one Shore Rd 345/138kV transformer in January, and the Y49 line was OOS across the entire quarter, contributing to more than $20 million of day-ahead congestion shortfalls. (slide 49)
  - ✓ The Neptune line was OOS in January and was operated at slightly more than half of its full capacity for the rest of the quarter. (slide 42)
- External interface constraints accounted for 7 percent of the congestion.
  - ✓ Exports to New England were high because of gas price spreads and the outage of Alps-Berkshire 345 kV line at the interface in March.
- NYC congestion was relatively low, accounting for only 5 percent of total congestion in the first quarter of 2021.
  - ✓ Much of this congestion occurred during the period from late-January to mid-February when one of the Mott Haven-Rainey 345 kV lines was OOS.
  - ✓ NYC congestion has been relatively low in recent years because NYC generation has become more economic as a result of lower Transco Zone 6 NY gas prices (relative to gas prices in other parts of East NY).

Market Highlights:
Regulation Market Costs and Performance

- Although regulation capacity prices rose in line with higher energy prices, regulation movement prices fell from prior periods. (slide 37)
  - ✓ Average regulation movement (relative to scheduled regulation capacity) fell noticeably from more than 12 to roughly 8 since October 2020.
    - – The NYISO enhanced its model for deploying regulation in November 2020, which reduced the frequency of regulation deployment.
- Resources are currently scheduled assuming a Regulation Movement Multiplier ("RMM") of 13 MW per MWh of regulation capacity.
  - ✓ The NYISO has proposed to change the RMM to 8 to reflect the reduction in average regulation movement. We support this change.
  - ✓ Nonetheless, using a common multiplier for all units can significantly underestimate the cost of fast-ramping resources in the scheduling process.
    - – This gives some fast-ramping resources incentives to raise their movement offer prices above marginal cost, which is not efficient.
    - – We will continue to monitor regulation market performance as the number of fast-ramping resources increases.

Market Highlights:
OOM Actions to Manage Low-Voltage Network

- The NYISO has greatly reduced the use of OOM actions in the past 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 the North Zone (13 days) and Long Island (10 days) this quarter. (slide 52)
- In the North Zone, a gas-fired generator was SRE-committed on 13 days for the N-1-1 requirement in the North Country load pocket. (slide 55)
  - ✓ On four days with no transmission outages in the pocket, the need for additional generation averaged just 6 MW, while over 150 MW was committed, resulting in an uplift cost of more than $1,000 per MWh of reserve need satisfied.
  - ✓ On the nine days with a transmission outage, the local need averaged 93 MW, resulting in a more moderate uplift cost of around $40 per MWh of reserve need satisfied.
  - ✓ Modeling local reserve needs in the DA and RT markets would help attract investment to areas like the North Country load pocket.
- Oil-fired peakers were OOMed on eight days for 69 kV constraints in Long Island. (slide 53)
  - ✓ The NYISO began to secure certain 69 kV constraints on Long Island in the market models in mid-April 2021, which should improve the efficiency of congestion management and investment incentives.

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Market Highlights:
Reliability Commitments, OOM Dispatch, and BPCG

- BPCG payments totaled $9 million, up 117 percent from 2020-Q1, reflecting:
  - ✓ Higher gas prices, which increased the production costs of gas-fired resources; and
  - ✓ Increased reliability commitments in New York City.
  - ✓ However, despite the increase from 2020-Q1, total BPCG uplift was still relatively low (e.g., 38% lower than 2019-Q1, 52% lower than 2018-Q1).
- $5.2 million (or 56 percent) of BPCG payments accrued in NYC. (slide 63)
  - ✓ $4.2 million was paid to units that were committed for local reliability needs.
  - ✓ Reliability commitments in NYC accounted for roughly 84 percent of all reliability commitments this quarter and rose 19 percent from a year ago. (slide 59)
    - – The increase reflected higher load levels and more transmission outages in the 345 kV system and around the Freshkills load pocket.
  - ✓ Nonetheless, the NYISO and ConEd have implemented several procedural changes for N-1-1-0 reliability commitment in NYC load pockets in recent years.
    - – For instance, since January 2021, NYC load pocket requirements assume the use of 300-hour ratings rather than normal transfer limits after the second contingency.
    - – These have improved the efficiency of these commitments and lowered the associated uplift.

Market Highlights:
Performance of Non-synchronous Reserve Providers

- The NYISO routinely audits 10- and 30-minute non-synchronous reserve providers to ensure that they are capable of providing the services that they sell.
- We reviewed NYISO audit results and found that in the 12-month period from April 2020 to March 2021: (slides 56-57)
  - ✓ 240 audits (of 137 unique GTs) were conducted, much higher than in prior years.
  - ✓ Many GTs performed better when audited than when started economically by RTC, RTD, and RTD-CAM. For example, eight 10-min GTs and five 30-min GTs had an average response rate below 70 percent but passed the audit.
- Further enhancements to this process could be beneficial such as:
  - ✓ Since units that perform well during audits may still perform poorly during normal market operations, it may be appropriate to suspend or disqualify poor performers.
  - ✓ Using performance during reserve pick-ups or economic starts in lieu of audits would reduce out-of-market actions and uplift costs (~$105K of uplift in 2021-Q1).
  - ✓ Since audits enable a resource to remain qualified to sell operating reserves, they may be considered a cost of participation rather than a cost that should be borne by customers through uplift. This is similar to the practice of requiring individual resource owners to bear the costs of DMNC testing, since it enables them to qualify to sell capacity.

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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 2021-Q1, 48 percent of the RT congestion in NYC occurred on N-1 constraints that would have been loaded above LTE after a single contingency. (slide 54)
  - ✓ The additional capability above LTE averaged from about 30 to 70 MW for the 138 kV constraints in the Greenwood load pocket to roughly 200 to 290 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 2020 SOM report)

Market Highlights:
Capacity Market

- Spot capacity prices averaged $0.61/kW-month in Long Island, the G-J Locality and ROS, and $8.68/kW-month in New York City this quarter. (slides 69-70)
  - ✓ Prices increased substantially in all regions from the prior year.
- The NYC spot price rose 134 percent, driven primarily by higher ICAP requirement, which was up 329 MW from the prior Capability Year ("CY").
  - ✓ Although forecast load fell modestly, the NYC LCR rose from 82.8% in the 2019/20 CY to 86.6% in the 2020/21 CY, resulting in an increase in the ICAP requirement.
- The UCAP requirements in the G-J Locality and Long Island were not binding this quarter, leading spot prices in both regions to clear at the same level as in ROS.
  - ✓ Therefore, price increases in these regions were driven by changes in NYCA.
- The ROS prices rose sharply in percentage terms, but prices were very low in 2020-Q1. The price rose primarily because of supply offer changes.
  - ✓ The spot price rose substantially from $0.06/kW-month in January to $0.89/kW-month in February and March, with unsold capacity rising to ~580 MW.
  - ✓ Some suppliers raised offers to levels consistent with Going Forward Cost estimates rather than offering as price-takers.
    - – We have reviewed their offers and do not have competitive concerns.

Charts:
Market Outcomes

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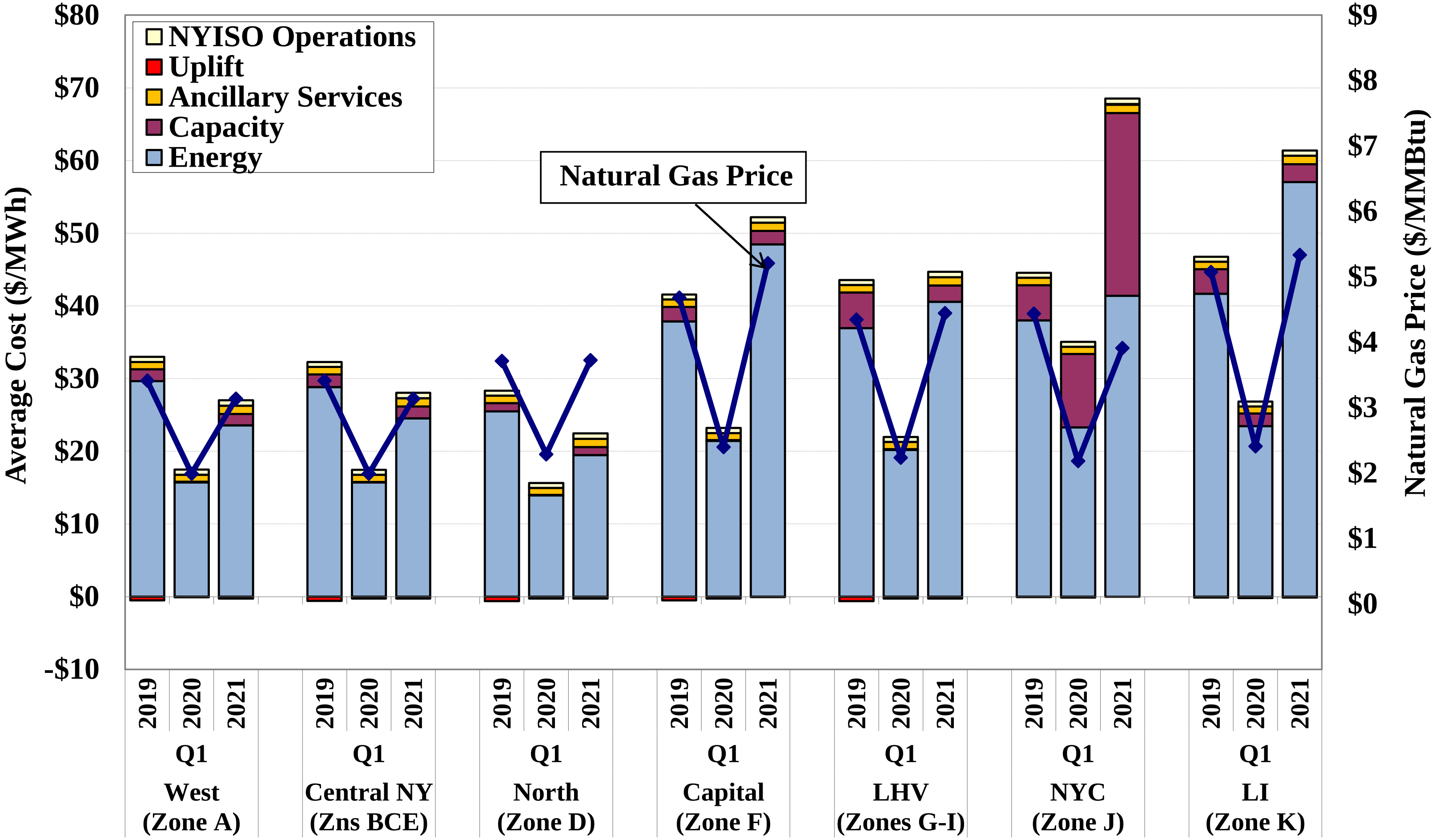
All-In Prices by Region



Notes: For chart description, see slide 72.

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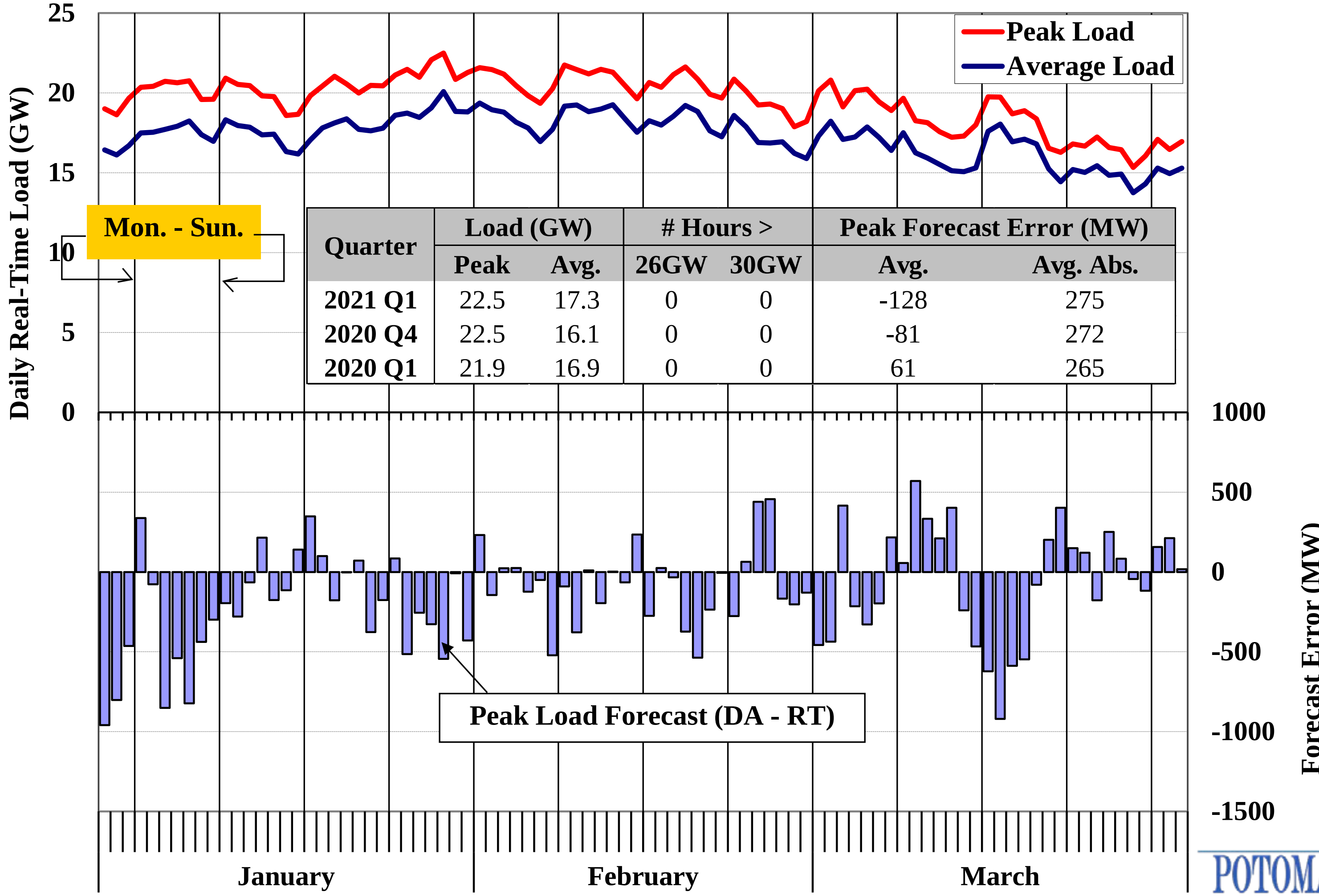
Load Forecast and Actual Load



Quarter	Load (GW)		# Hours >		Peak Forecast Error (MW)	
	Peak	Avg.	26GW	30GW	Avg.	Avg. Abs.
2021 Q1	22.5	17.3	0	0	-128	275
2020 Q4	22.5	16.1	0	0	-81	272
2020 Q1	21.9	16.9	0	0	61	265

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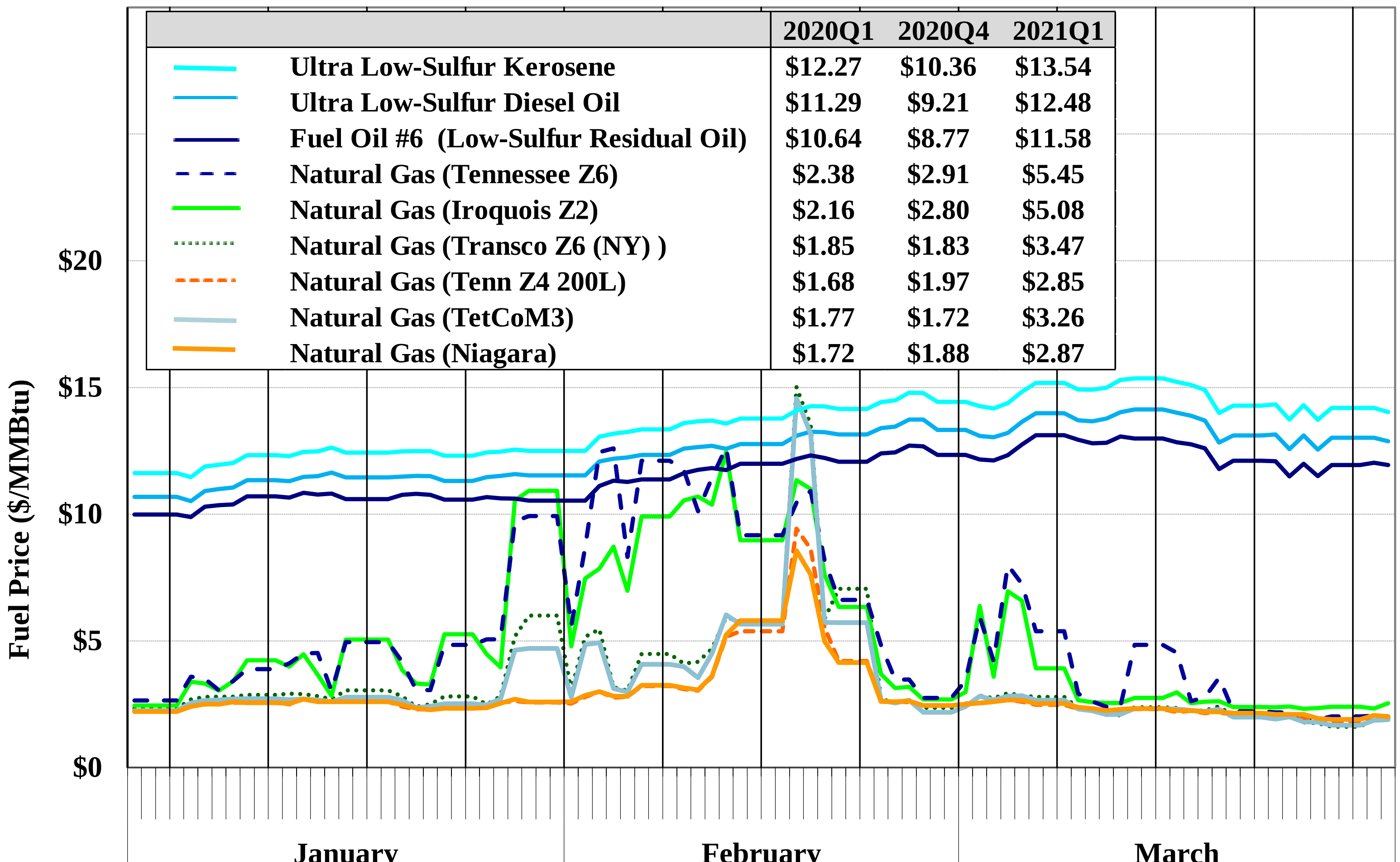
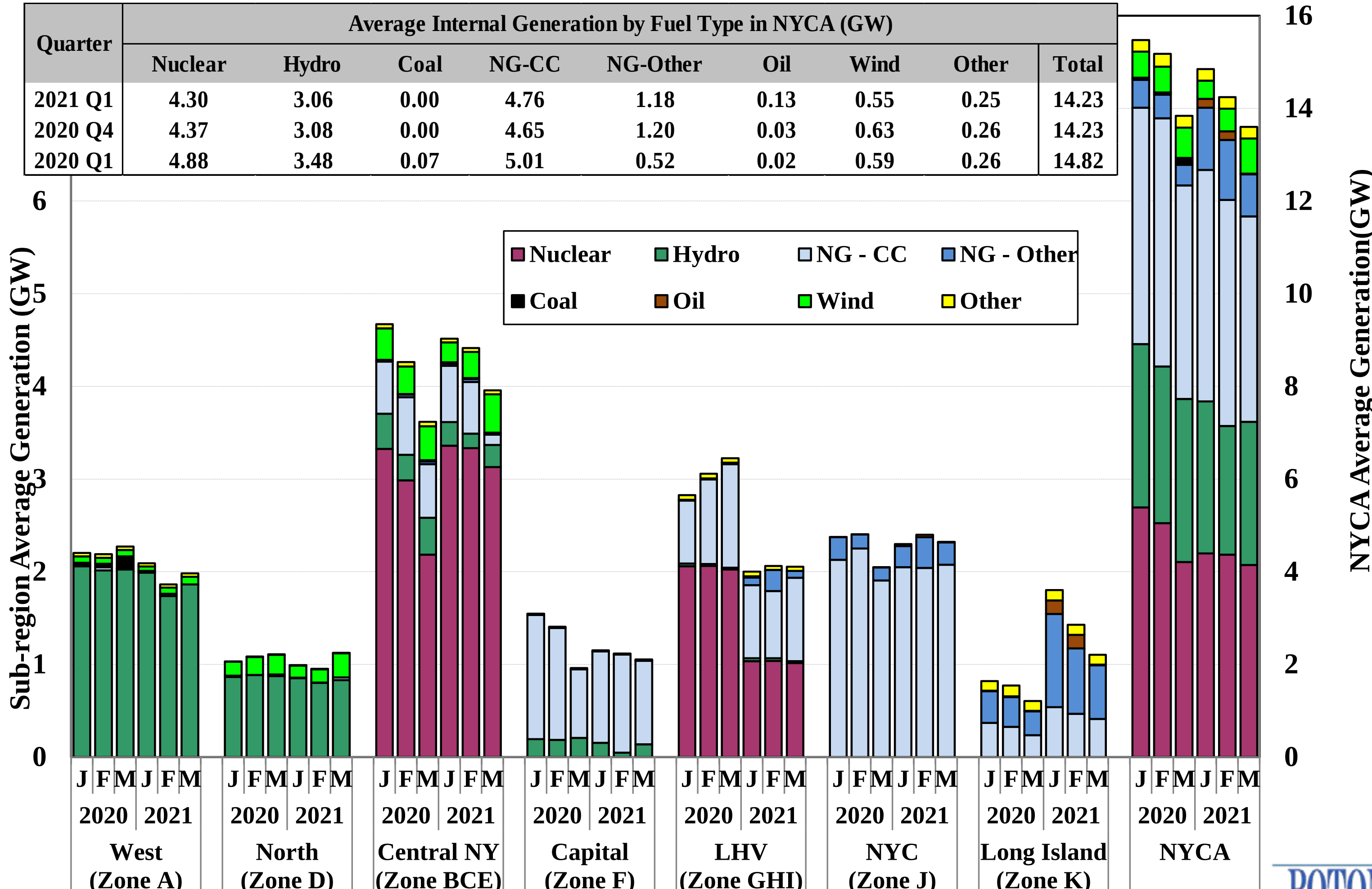
Natural Gas and Fuel Oil Prices



	2020Q1	2020Q4	2021Q1
Ultra Low-Sulfur Kerosene	$12.27	$10.36	$13.54
Ultra Low-Sulfur Diesel Oil	$11.29	$9.21	$12.48
Fuel Oil #6 (Low-Sulfur Residual Oil)	$10.64	$8.77	$11.58
Natural Gas (Tennessee Z6)	$2.38	$2.91	$5.45
Natural Gas (Iroquois Z2)	$2.16	$2.80	$5.08
Natural Gas (Transco Z6 (NY))	$1.85	$1.83	$3.47
Natural Gas (Tenn Z4 200L)	$1.68	$1.97	$2.85
Natural Gas (TetCoM3)	$1.77	$1.72	$3.26
Natural Gas (Niagara)	$1.72	$1.88	$2.87

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
2021 Q1	4.30	3.06	0.00	4.76	1.18	0.13	0.55	0.25	14.23
2020 Q4	4.37	3.08	0.00	4.65	1.20	0.03	0.63	0.26	14.23
2020 Q1	4.88	3.48	0.07	5.01	0.52	0.02	0.59	0.26	14.82



Notes: For chart description, see slide 73.

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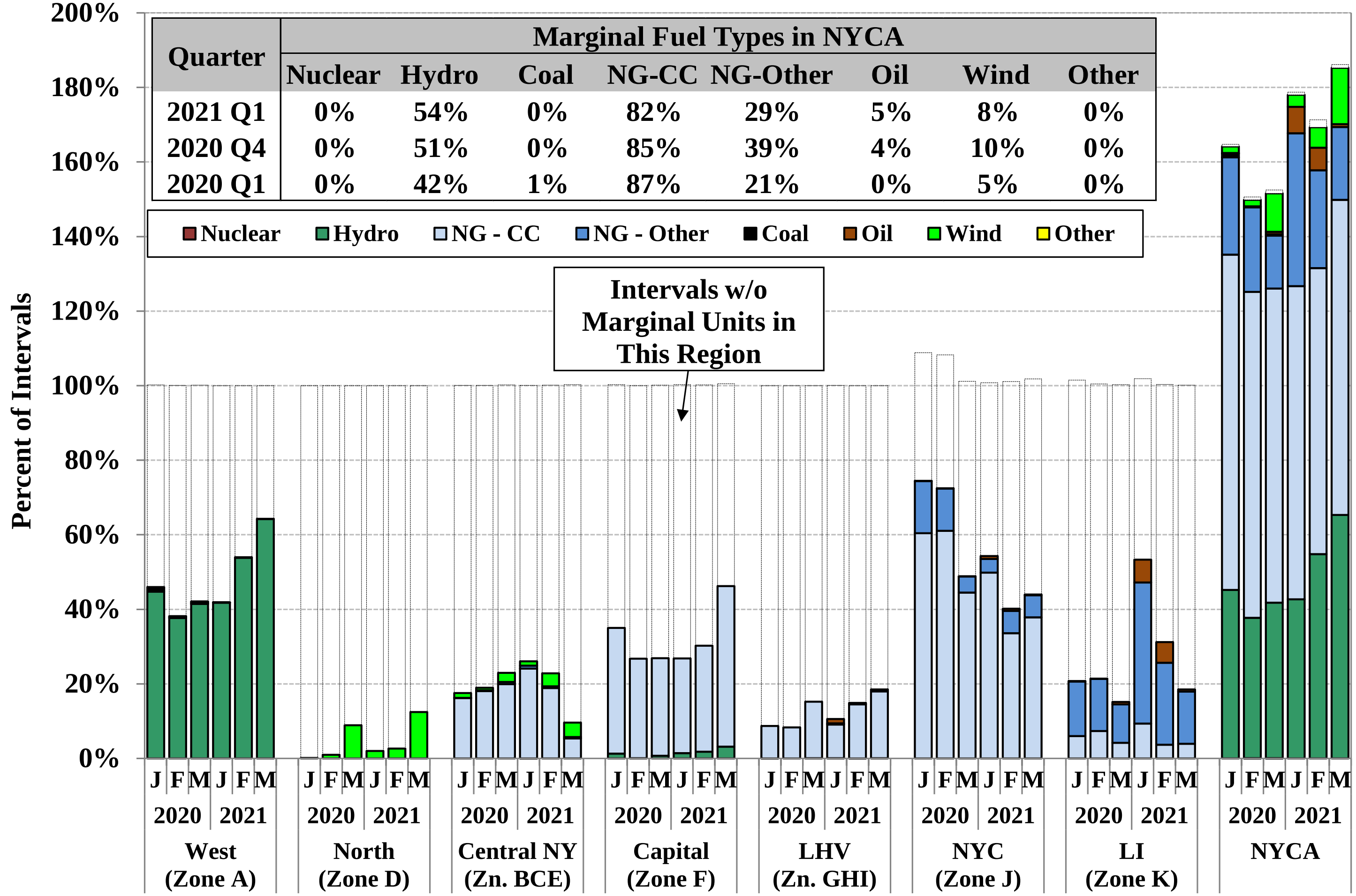
Fuel Type of Marginal Units in the Real-Time Market



Quarter	Marginal Fuel Types in NYCA							
	Nuclear	Hydro	Coal	NG-CC	NG-Other	Oil	Wind	Other
2021 Q1	0%	54%	0%	82%	29%	5%	8%	0%
2020 Q4	0%	51%	0%	85%	39%	4%	10%	0%
2020 Q1	0%	42%	1%	87%	21%	0%	5%	0%

Notes: For chart description, see slide 73.

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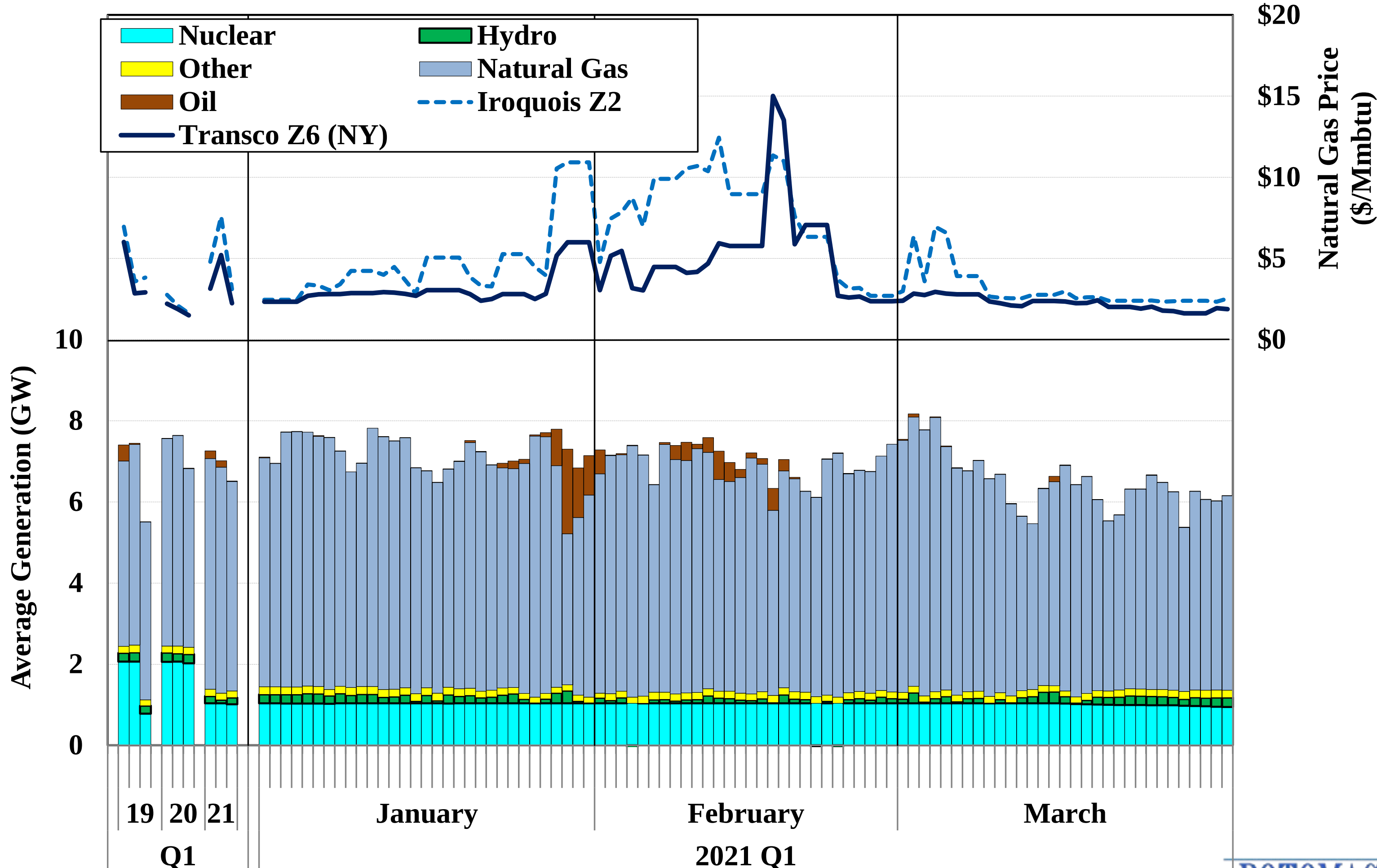
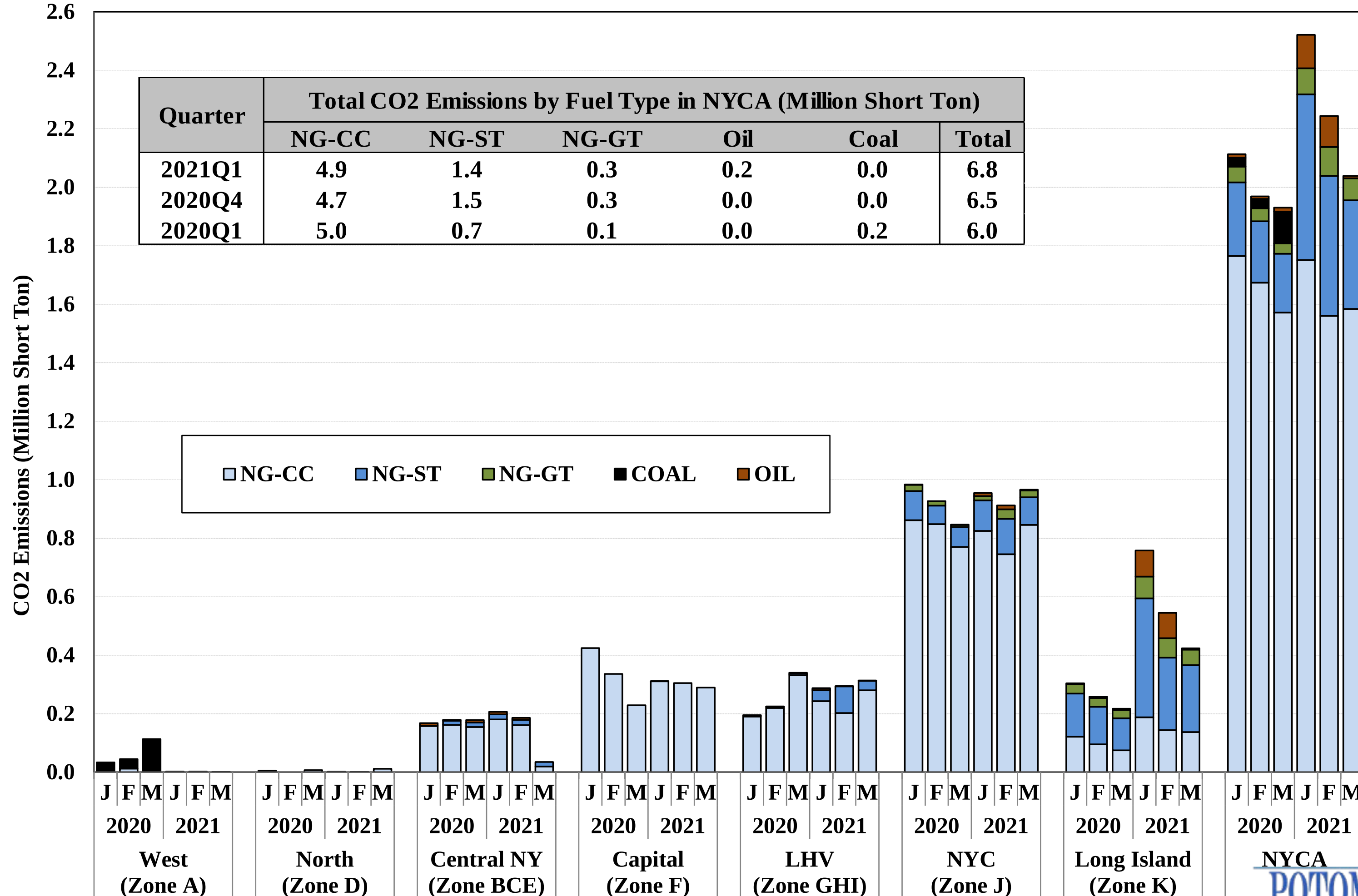
Winter Fuel Usage
Eastern New York



Notes: For chart description, see slide 74.

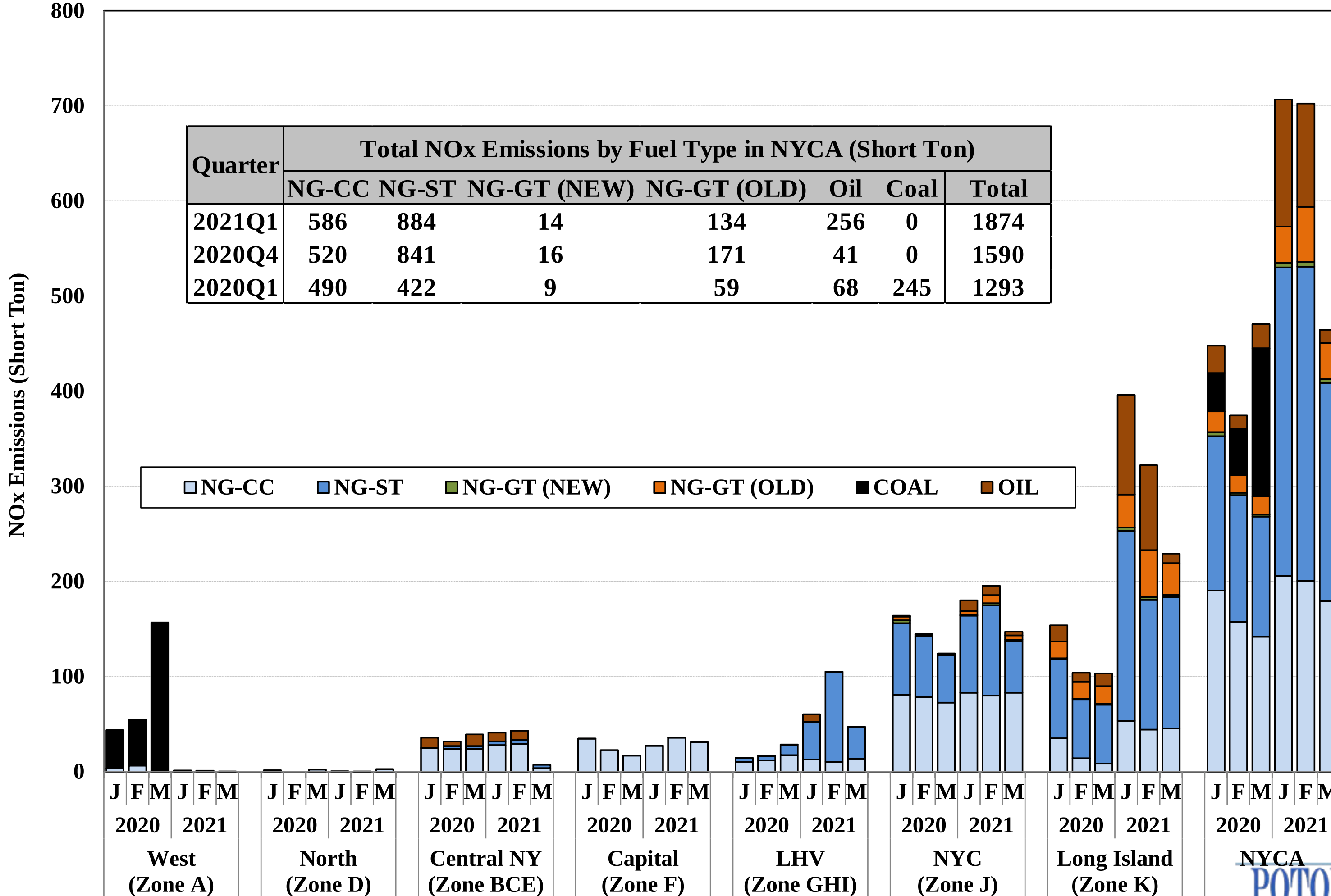
Emissions by Region by Fuel Type
CO_2 Emissions



Quarter	Total CO2 Emissions by Fuel Type in NYCA (Million Short Ton)					
	NG-CC	NG-ST	NG-GT	Oil	Coal	Total
2021Q1	4.9	1.4	0.3	0.2	0.0	6.8
2020Q4	4.7	1.5	0.3	0.0	0.0	6.5
2020Q1	5.0	0.7	0.1	0.0	0.2	6.0

Notes: For chart description, see slide 74.

Emissions by Region by Fuel Type
NO_X Emissions



Quarter	Total NOx Emissions by Fuel Type in NYCA (Short Ton)						
	NG-CC	NG-ST	NG-GT (NEW)	NG-GT (OLD)	Oil	Coal	Total
2021Q1	586	884	14	134	256	0	1874
2020Q4	520	841	16	171	41	0	1590
2020Q1	490	422	9	59	68	245	1293

Notes: For chart description, see slide 74.

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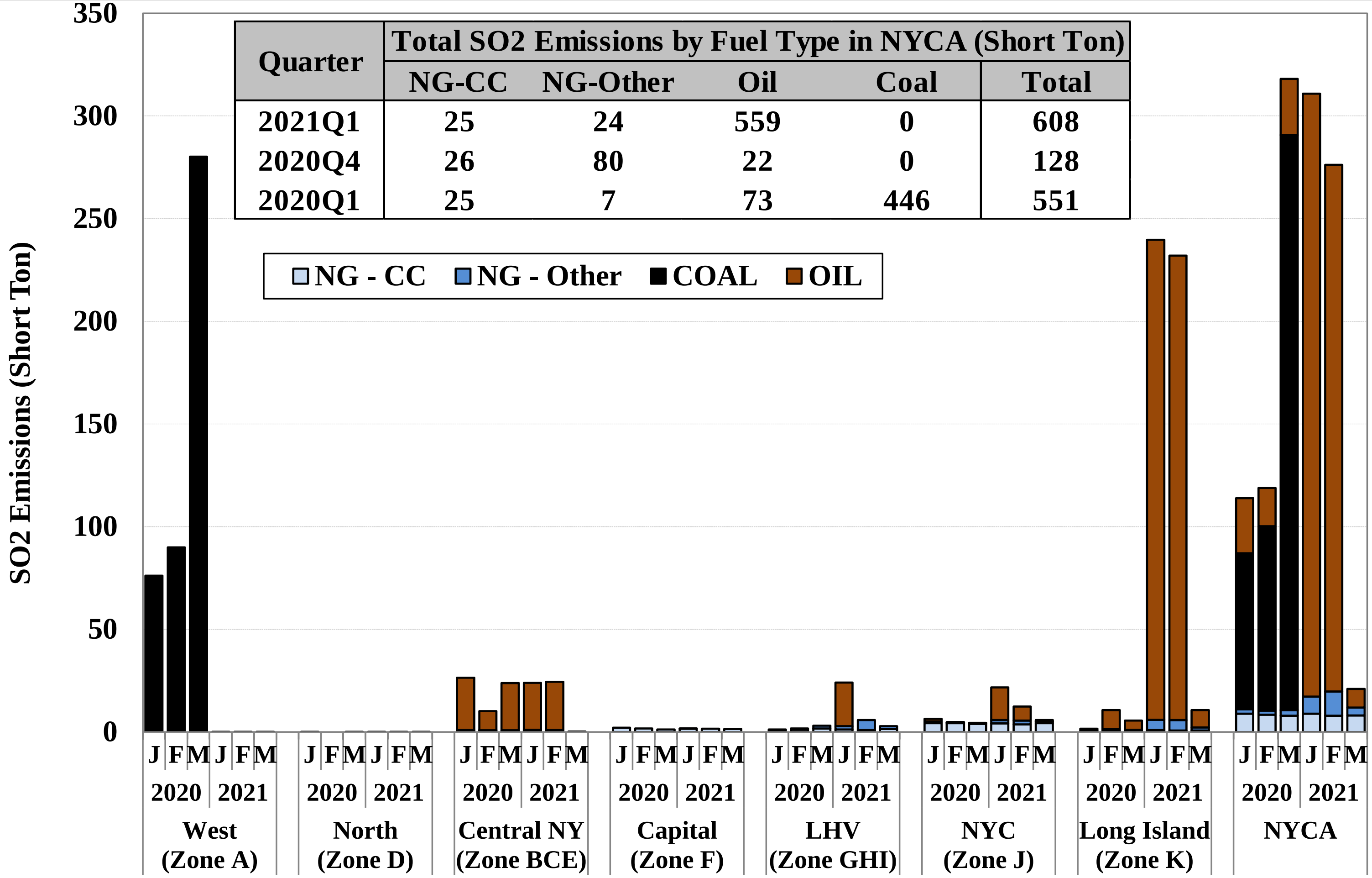
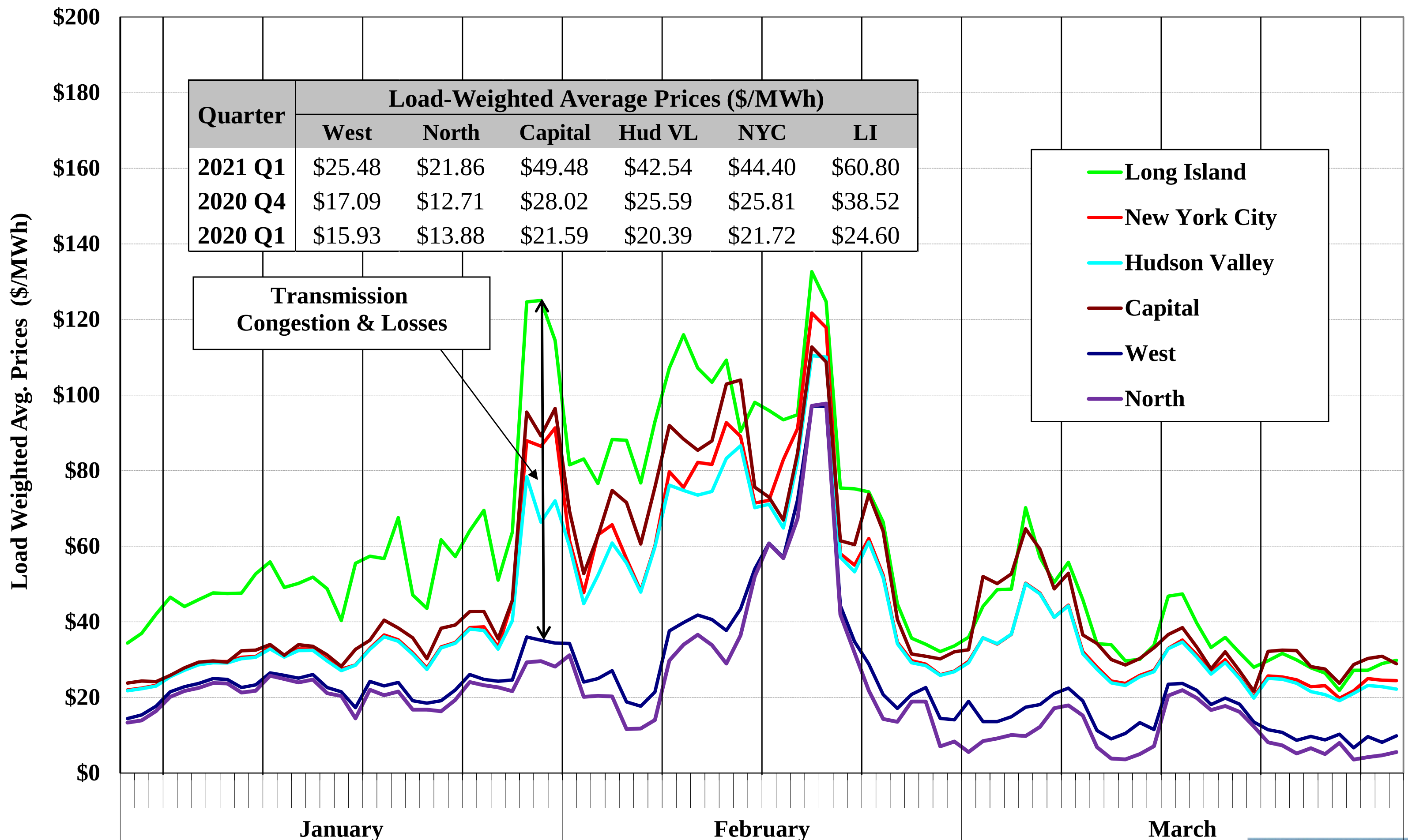
Emissions by Region by Fuel Type
SO_2 Emissions

Quarter	Total SO2 Emissions by Fuel Type in NYCA (Short Ton)				
	NG-CC	NG-Other	Oil	Coal	Total
2021Q1	25	24	559	0	608
2020Q4	26	80	22	0	128
2020Q1	25	7	73	446	551



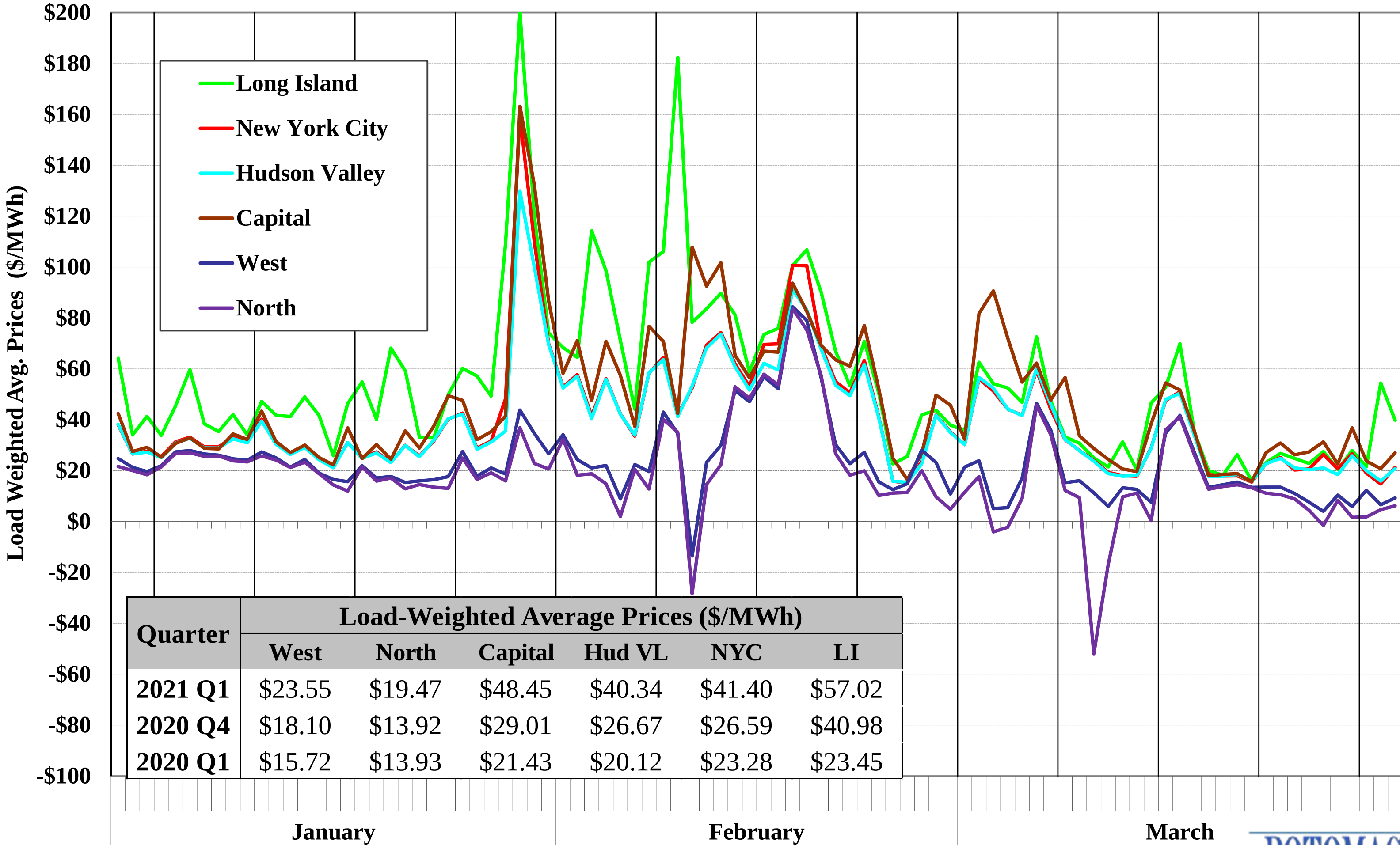
  Notes: For chart description, see slide 74.

Day-Ahead Electricity Prices by Zone



Quarter	Load-Weighted Average Prices ($/MWh)					
	West	North	Capital	Hud VL	NYC	LI
2021 Q1	$25.48	$21.86	$49.48	$42.54	$44.40	$60.80
2020 Q4	$17.09	$12.71	$28.02	$25.59	$25.81	$38.52
2020 Q1	$15.93	$13.88	$21.59	$20.39	$21.72	$24.60

Real-Time Electricity Prices by Zone



Quarter	Load-Weighted Average Prices ($/MWh)					
	West	North	Capital	Hud VL	NYC	LI
2021 Q1	$23.55	$19.47	$48.45	$40.34	$41.40	$57.02
2020 Q4	$18.10	$13.92	$29.01	$26.67	$26.59	$40.98
2020 Q1	$15.72	$13.93	$21.43	$20.12	$23.28	$23.45

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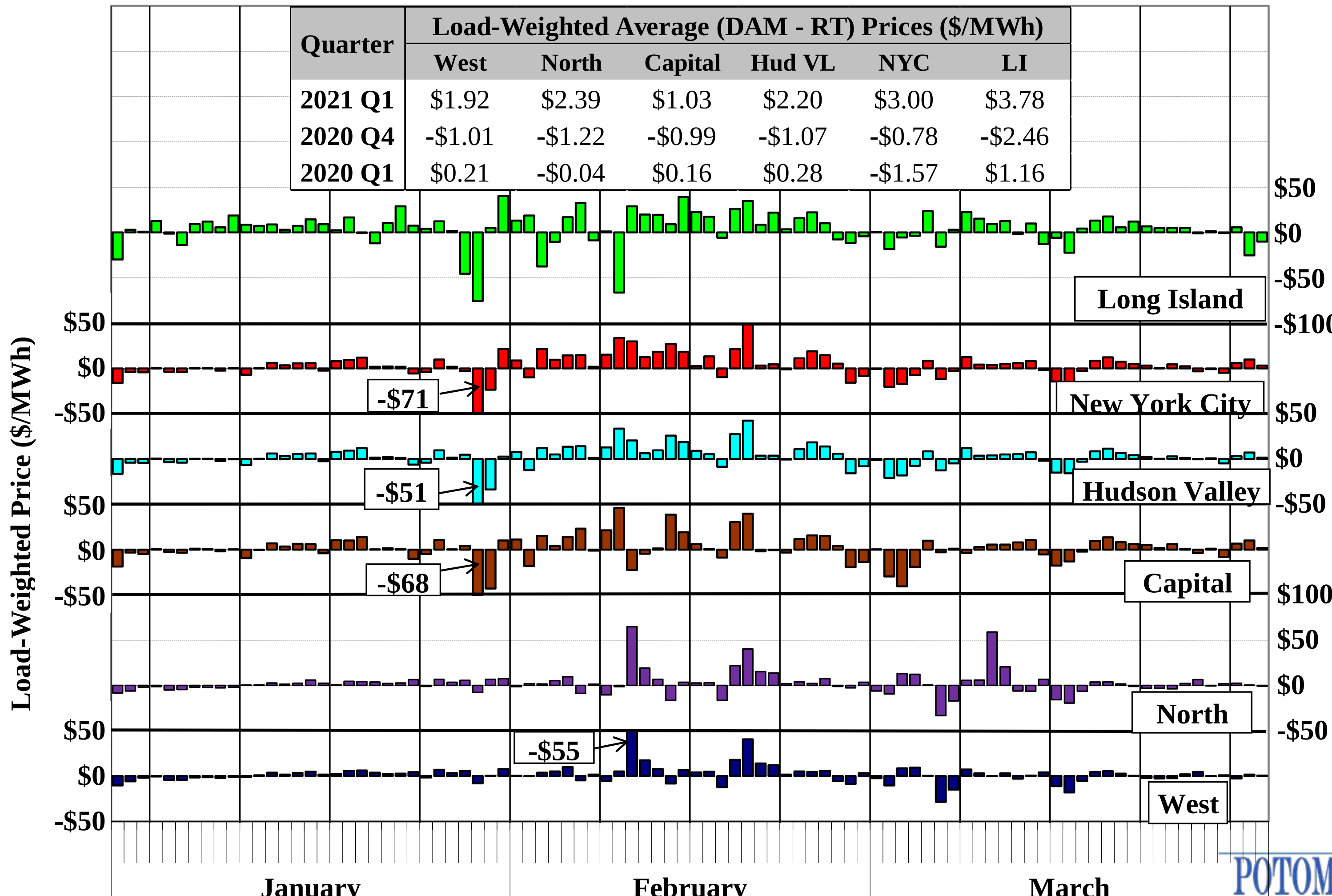
Convergence Between Day-Ahead and Real-Time Prices

Quarter	Load-Weighted Average (DAM - RT) Prices ($/MWh)					
	West	North	Capital	Hud VL	NYC	LI
2021 Q1	$1.92	$2.39	$1.03	$2.20	$3.00	$3.78
2020 Q4	-$1.01	-$1.22	-$0.99	-$1.07	-$0.78	-$2.46
2020 Q1	$0.21	-$0.04	$0.16	$0.28	-$1.57	$1.16



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<u>Charts:</u>

Ancillary Services Market

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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	2020Q1	$3.10	$0.02	$3.09	7
	2021Q1	$4.20	$0.39	$4.40	1
NYC 30-min	2020Q1	$3.10	$0.00	$3.10	0
	2021Q1	$3.98	$0.02	$3.95	0

Notes: For chart description, see slide 75.

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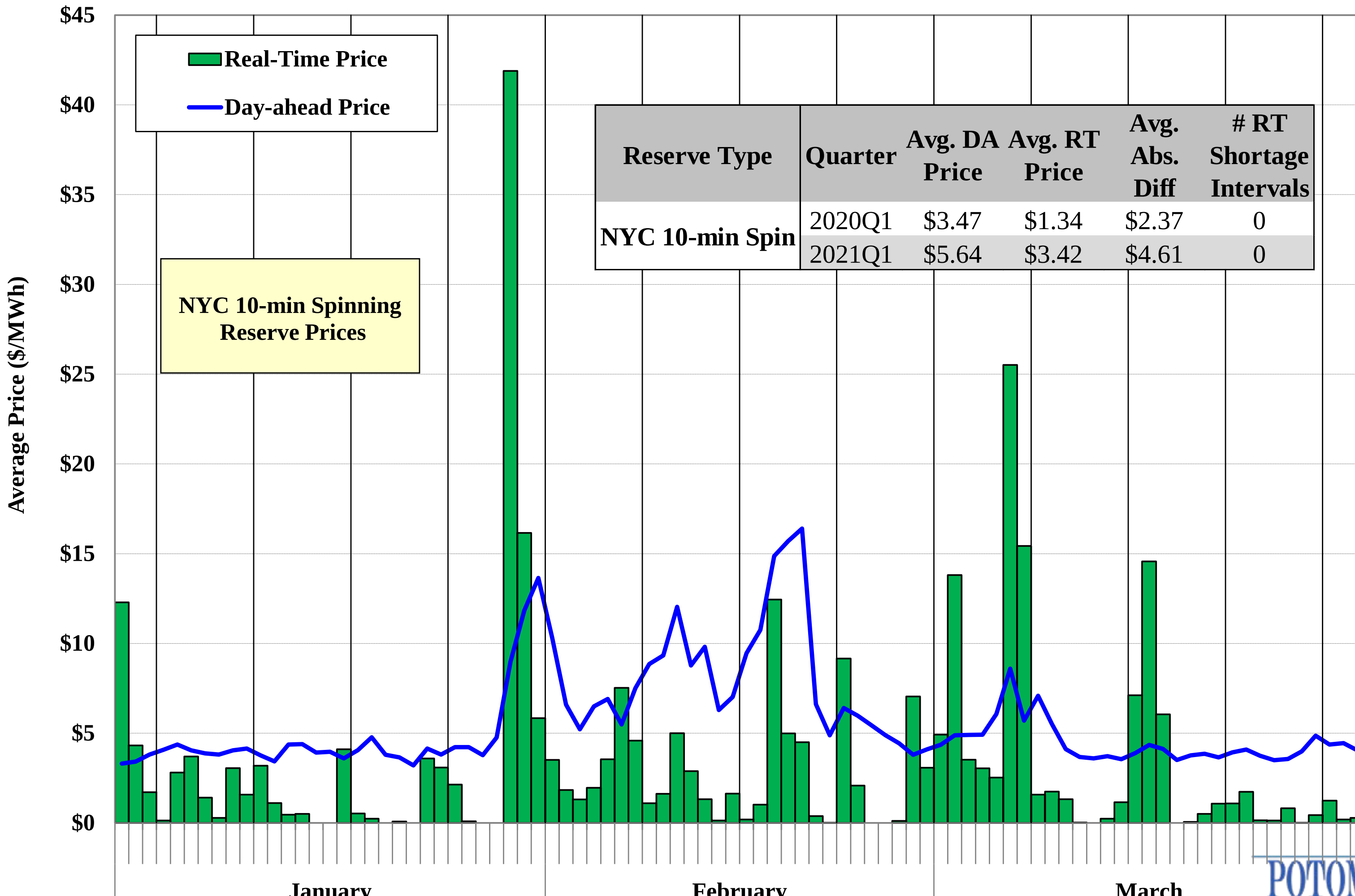
Day-Ahead and Real-Time Ancillary Services Prices
NYC 10-Minute Spinning Reserves



Reserve Type	Quarter	Avg. DA Price	Avg. RT Price	Avg. Abs. Diff	# RT Shortage Intervals
NYC 10-min Spin	2020Q1	$3.47	$1.34	$2.37	0
	2021Q1	$5.64	$3.42	$4.61	0

Notes: For chart description, see slide 75.

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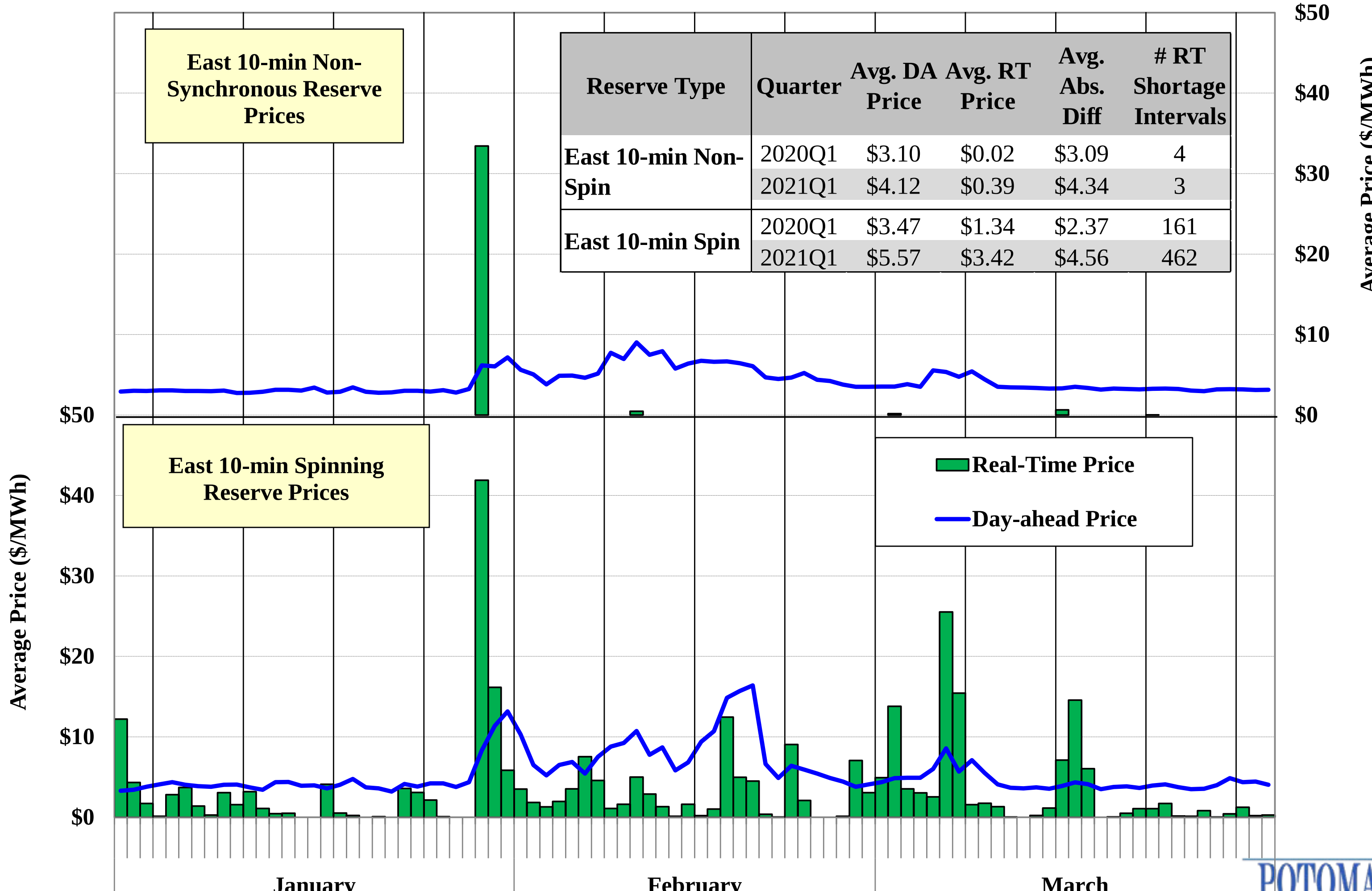
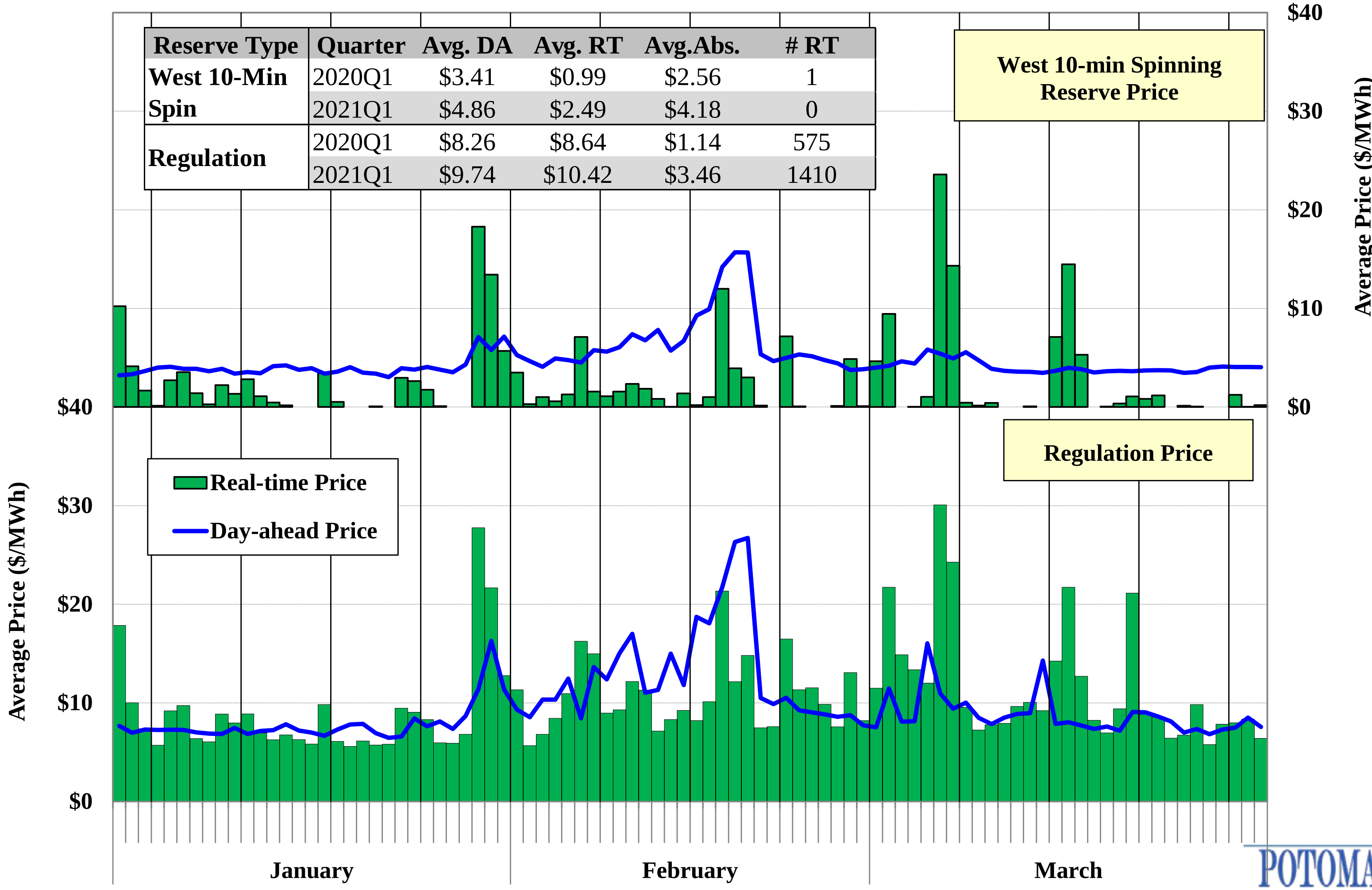
Day-Ahead and Real-Time Ancillary Services Prices
Eastern 10-Minute Spinning and Non-Spinning Reserves



Reserve Type	Quarter	Avg. DA Price	Avg. RT Price	Avg. Abs. Diff	# RT Shortage Intervals
East 10-min Non-Spin	2020Q1	$3.10	$0.02	$3.09	4
	2021Q1	$4.12	$0.39	$4.34	3
East 10-min Spin	2020Q1	$3.47	$1.34	$2.37	161
	2021Q1	$5.57	$3.42	$4.56	462

Notes: For chart description, see slide 75.

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



Reserve Type	Quarter	Avg. DA	Avg. RT	Avg.Abs.	# RT
West 10-Min Spin	2020Q1	$3.41	$0.99	$2.56	1
	2021Q1	$4.86	$2.49	$4.18	0
Regulation	2020Q1	$8.26	$8.64	$1.14	575
	2021Q1	$9.74	$10.42	$3.46	1410

Notes: For chart description, see slide 75.

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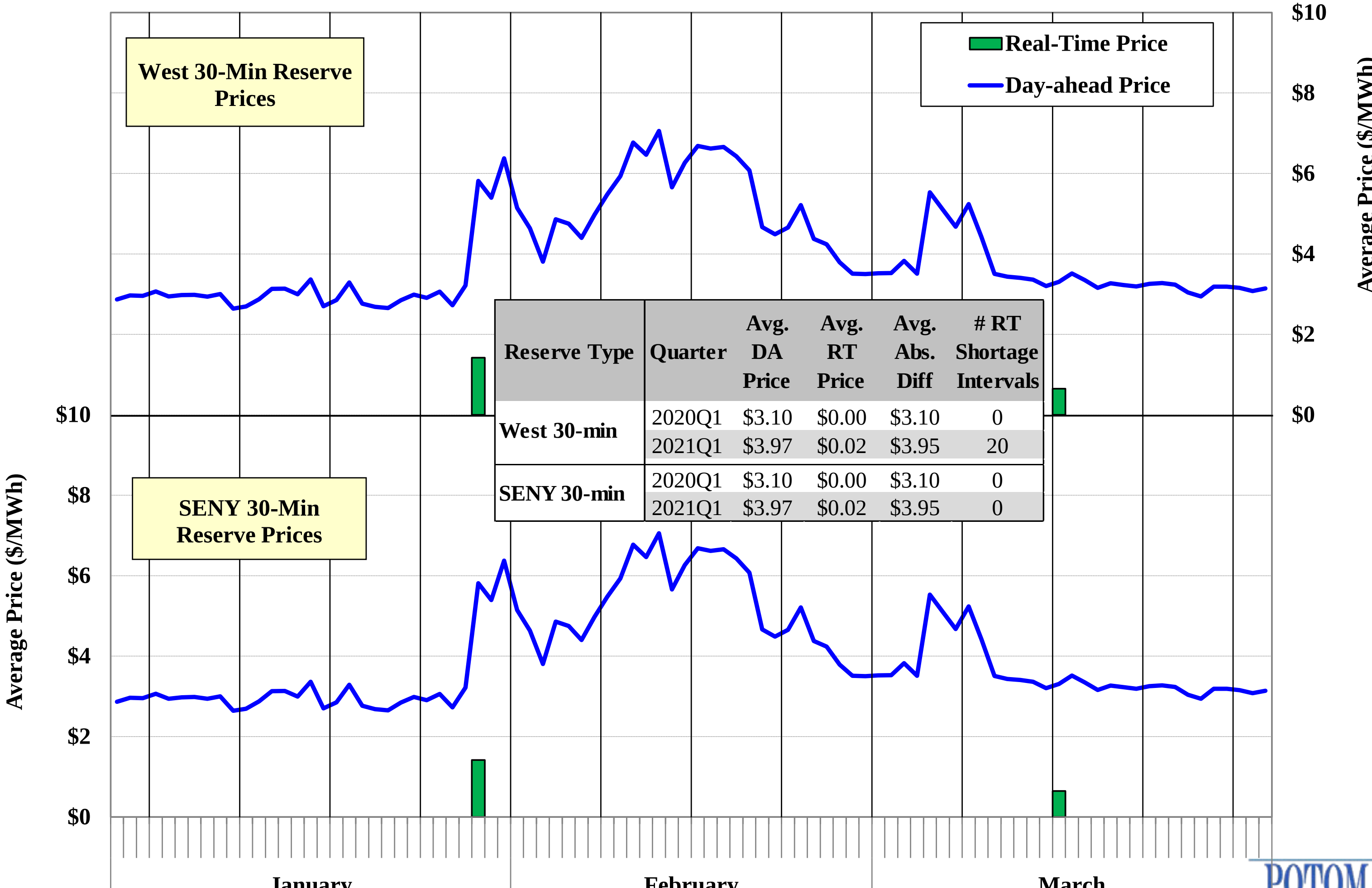
Day-Ahead and Real-Time Ancillary Services Prices
Western and SENY 30-Minute Reserves



Reserve Type	Quarter	Avg. DA Price	Avg. RT Price	Avg. Abs. Diff	# RT Shortage Intervals
West 30-min	2020Q1	$3.10	$0.00	$3.10	0
	2021Q1	$3.97	$0.02	$3.95	20
SENY 30-min	2020Q1	$3.10	$0.00	$3.10	0
	2021Q1	$3.97	$0.02	$3.95	0

Notes: For chart description, see slide 75.

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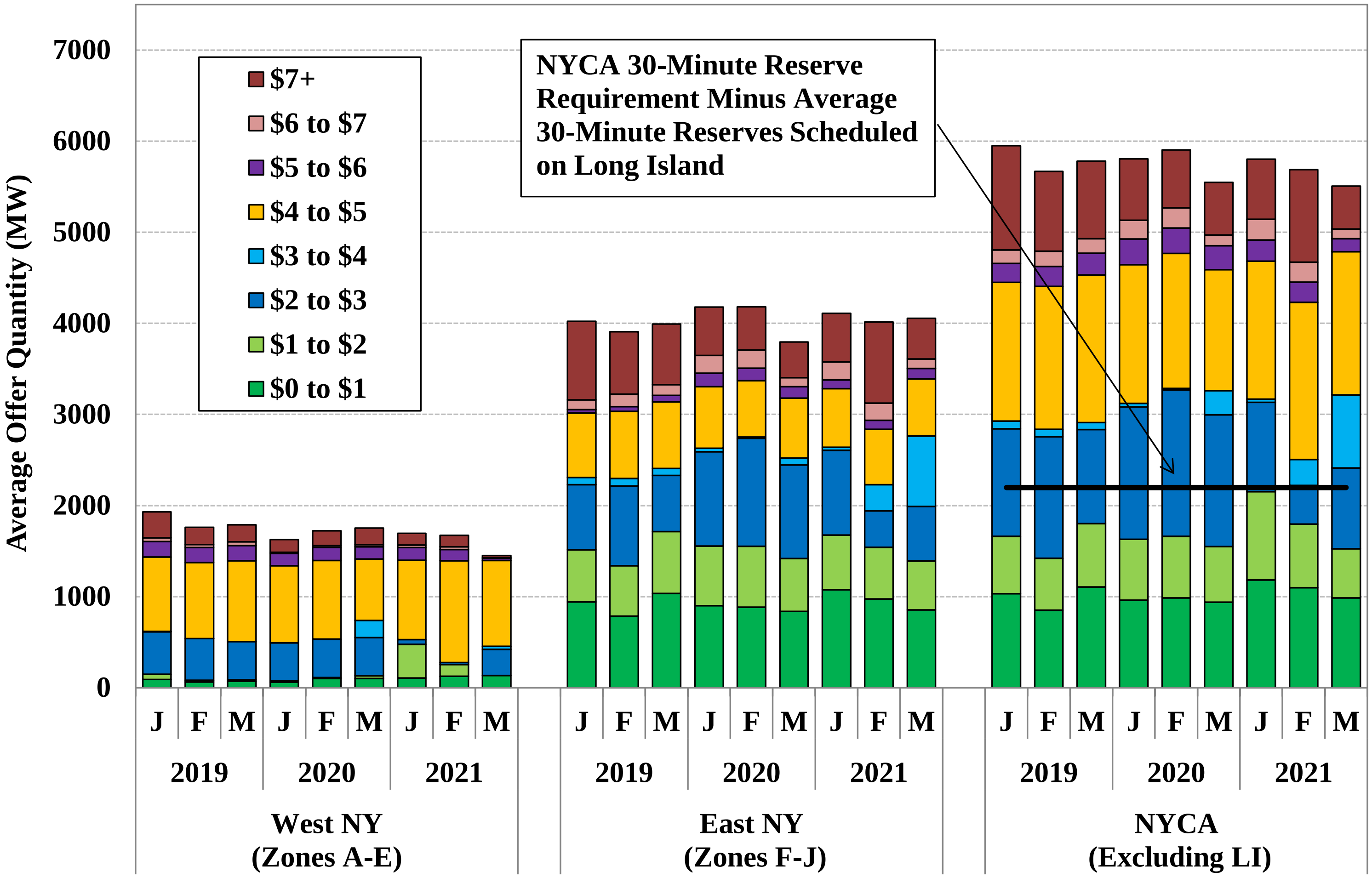
Day-Ahead NYCA 30-Minute Reserve Offers
Committed and Available Offline Quick-Start Resources



Notes: For chart description, see slide 76.

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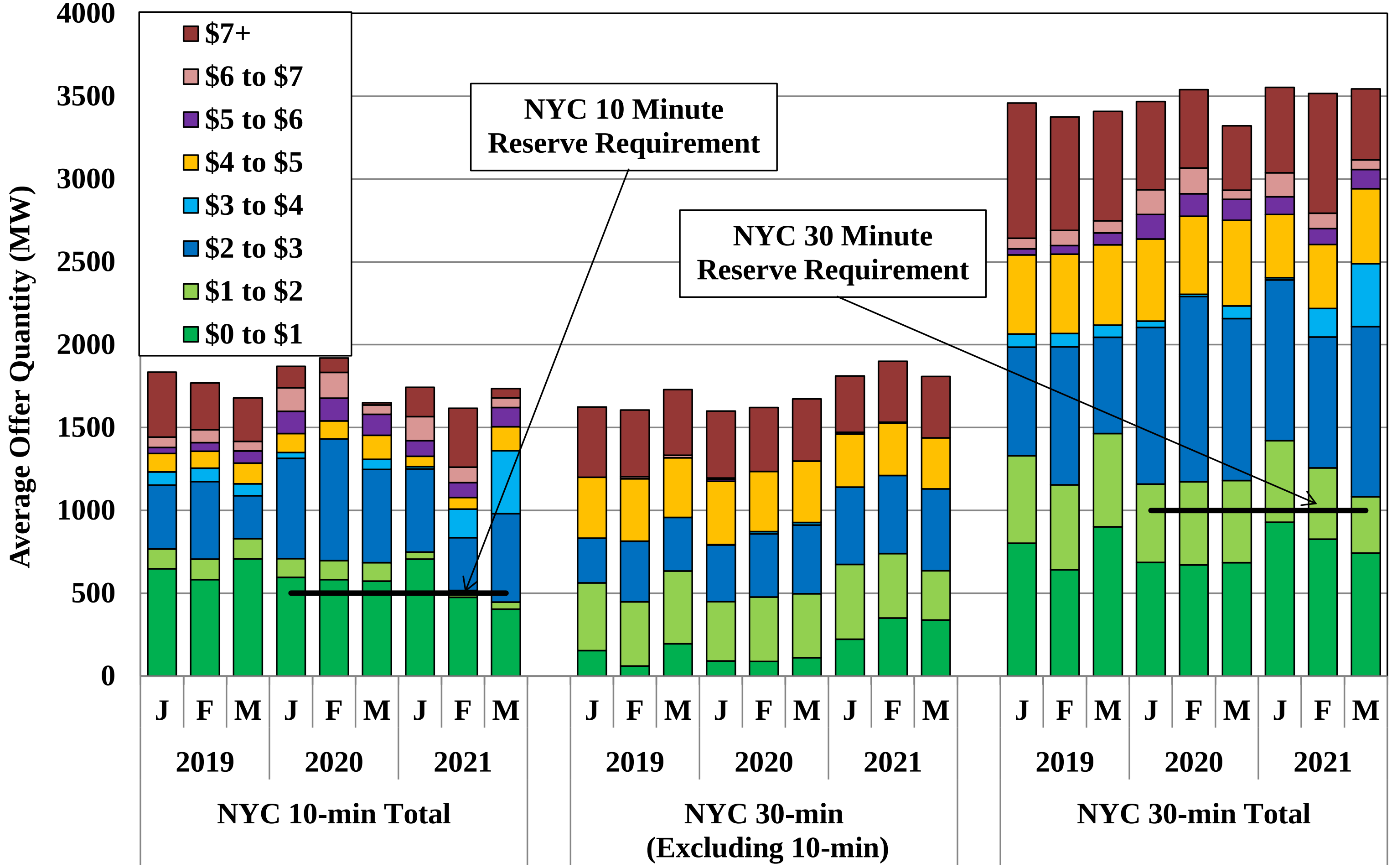
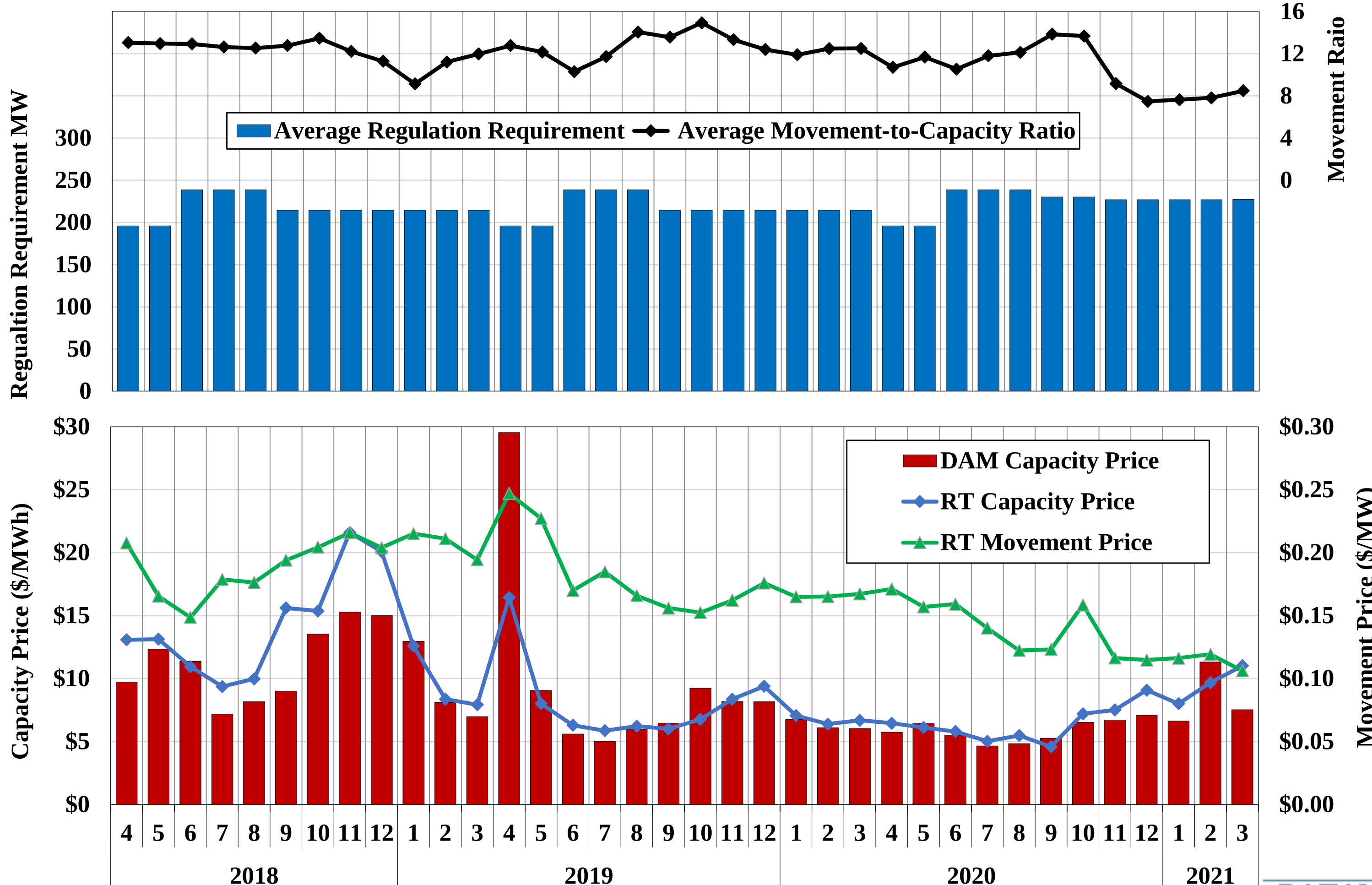
Day-Ahead NYC Reserve Offers
Committed and Available Offline Quick-Start Resources



Notes: For chart description, see slide 76.

POTOMAC ECONOMICS

Regulation Requirements, Prices, and Movement-to-Capacity Ratio by Month



Notes: For chart description, see slide 77.

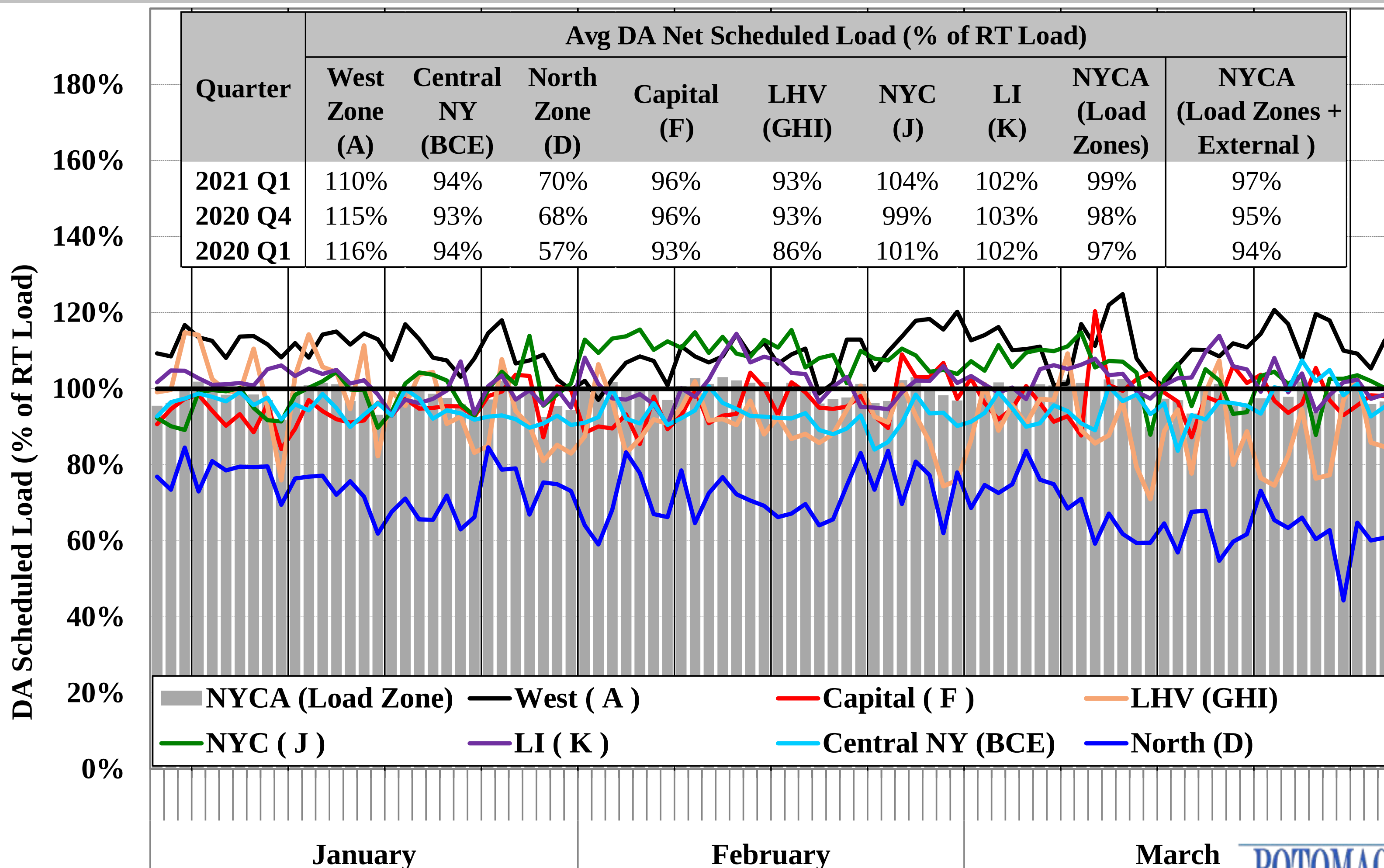
POTOMAC ECONOMICS

Charts:
Energy Market Scheduling

POTOMAC ECONOMICS

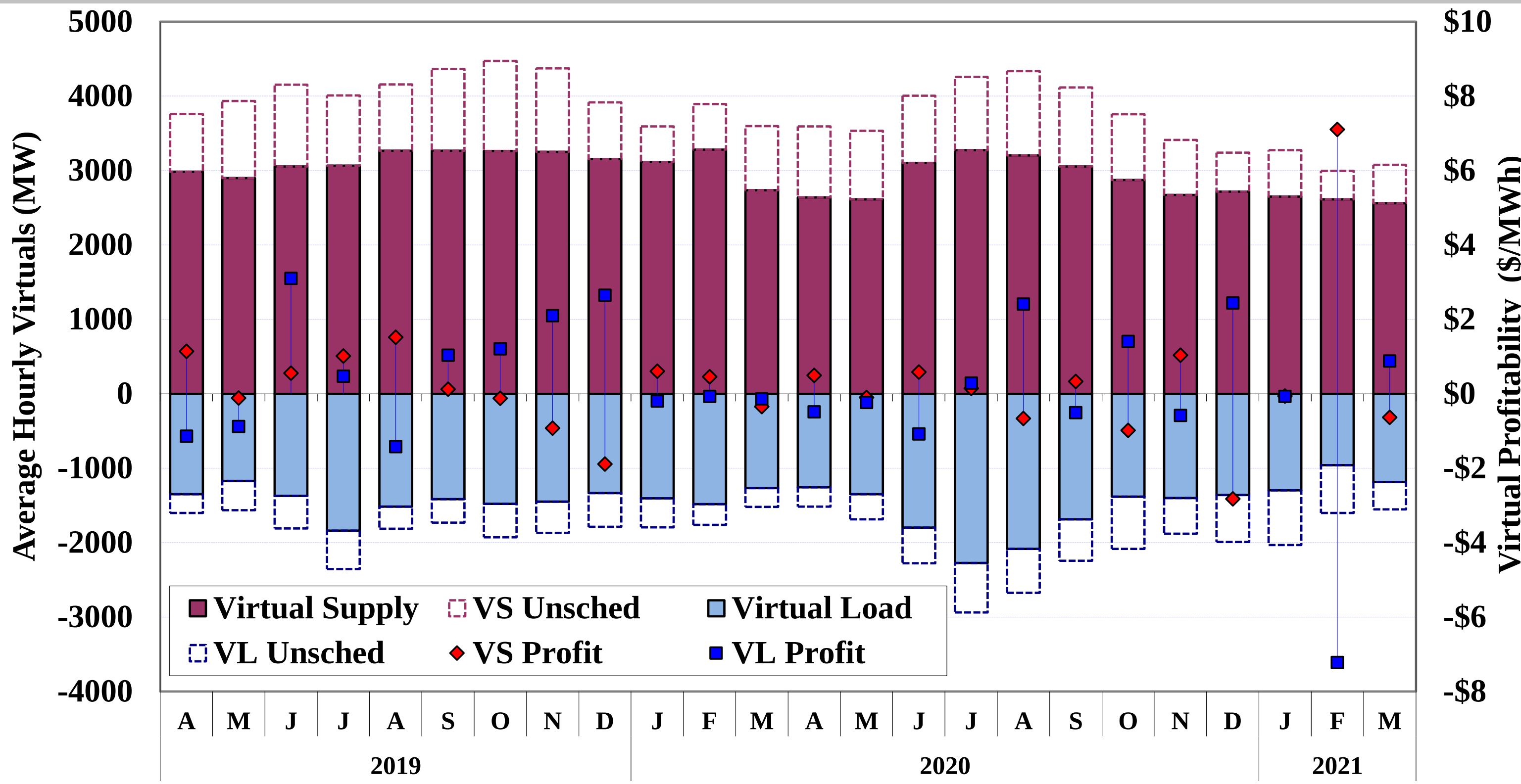
Day-ahead Scheduled Load and Actual Load
Daily Peak Load Hour

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)
2021 Q1	110%	94%	70%	96%	93%	104%	102%	99%	97%
2020 Q4	115%	93%	68%	96%	93%	99%	103%	98%	95%
2020 Q1	116%	94%	57%	93%	86%	101%	102%	97%	94%



Notes: For chart description, see slide 78.

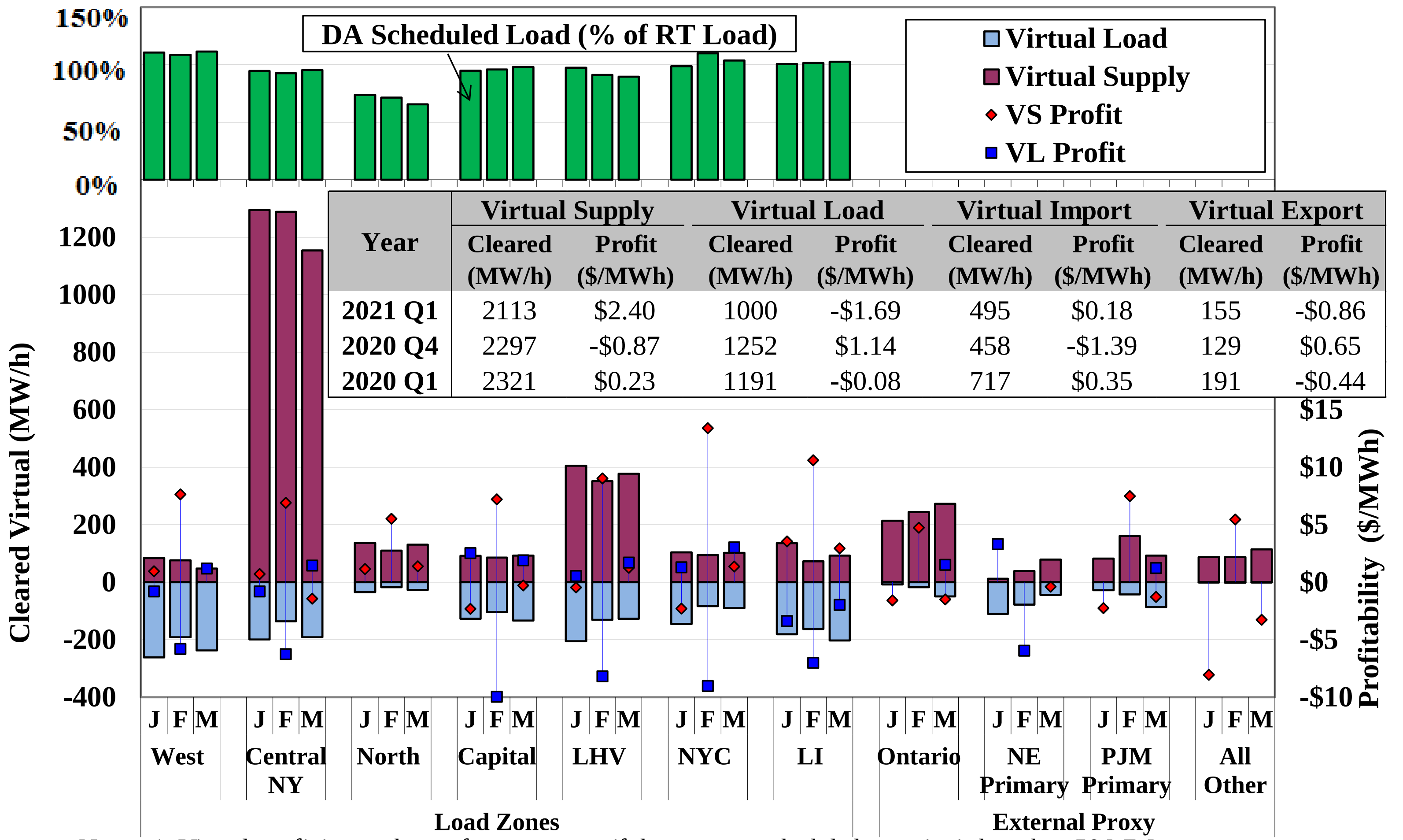
Virtual Trading Activity
by Month



		2019 A	2019 M	2019 J	2019 J	2019 A	2019 S	2019 O	2019 N	2019 D	2020 J	2020 F	2020 M	2020 A	2020 M	2020 J	2020 J	2020 A	2020 S	2020 O	2020 N	2020 D	2021 J	2021 F	2021 M
Profit > 50% of Avg. Zone Price	MW	473	477	587	384	396	249	312	290	274	421	322	232	370	388	464	416	377	196	235	619	375	320	658	514
	%	11%	12%	13%	8%	8%	5%	7%	6%	6%	9%	7%	6%	10%	10%	9%	8%	7%	4%	6%	15%	9%	8%	18%	14%
Loss > 50% of Avg. Zone Price	MW	348	591	548	372	321	293	376	344	305	338	253	321	298	404	460	377	304	198	312	528	440	283	388	491
	%	8%	15%	12%	8%	7%	6%	8%	7%	7%	7%	5%	8%	8%	10%	9%	7%	6%	4%	7%	13%	11%	7%	11%	13%

Notes: For chart description, see slide 78.
POTOMAC ECONOMICS

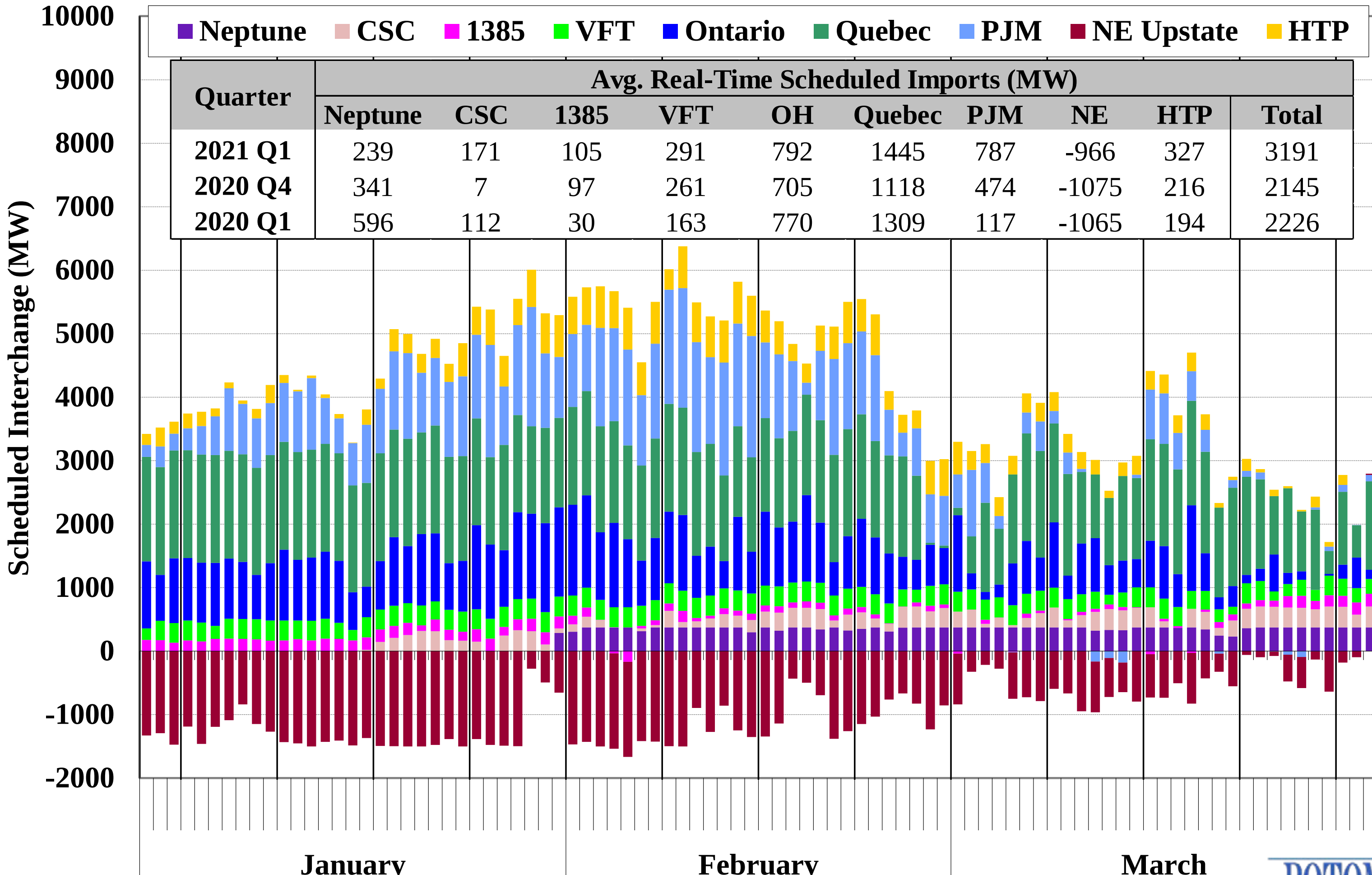
Virtual Trading Activity
by Location



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)
2021 Q1	2113	$2.40	1000	-$1.69	495	$0.18	155	-$0.86
2020 Q4	2297	-$0.87	1252	$1.14	458	-$1.39	129	$0.65
2020 Q1	2321	$0.23	1191	-$0.08	717	$0.35	191	-$0.44

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 78.

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
2021 Q1	239	171	105	291	792	1445	787	-966	327	3191
2020 Q4	341	7	97	261	705	1118	474	-1075	216	2145
2020 Q1	596	112	30	163	770	1309	117	-1065	194	2226

Notes: Two Quebec interfaces are combined into one.

POTOMAC ECONOMICS

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 > $20	Total
% of All Intervals w/ Adjustment			61%	12%	**74%**	41%	11%	**52%**
Average Flow Adjustment (MW)	Net Imports		-19	-66	**-26**	35	15	**31**
	Gross		140	211	**152**	69	83	**72**
Production Cost Savings ($ Million)	Projected at Scheduling Time		$3.0	$1.9	**$4.9**	$0.4	$0.5	**$0.9**
	Net Over-Projection by:	NY	-$0.1	-$0.3	**-$0.4**	-$0.1	$0.1	**$0.0**
		NE or PJM	$0.2	$0.4	**$0.6**	$0.0	-$0.7	**-$0.7**
	Other Unrealized Savings		$0.0	-$0.1	**-$0.1**	$0.0	$0.1	**$0.1**
	Actual Savings		$3.1	$1.9	**$5.0**	$0.3	$0.0	**$0.3**
Interface Prices ($/MWh)	NY	Actual	$36.53	$81.34	**$43.90**	$29.38	$62.76	**$36.23**
		Forecast	$38.17	$68.87	**$43.22**	$30.21	$52.07	**$34.70**
	NE or PJM	Actual	$38.01	$70.35	**$43.33**	$27.75	$93.21	**$41.18**
		Forecast	$36.60	$63.23	**$40.98**	$28.73	$74.84	**$38.19**
Price Forecast Errors ($/MWh)	NY	Fcst. - Act.	$1.64	-$12.47	**-$0.68**	$0.84	-$10.69	**-$1.53**
		Abs. Val.	$4.45	$46.46	**$11.35**	$3.92	$28.37	**$8.94**
	NE or PJM	Fcst. - Act.	-$1.41	-$7.11	**-$2.35**	$0.98	-$18.37	**-$2.99**
		Abs. Val.	$3.56	$15.73	**$5.56**	$3.61	$80.35	**$19.36**

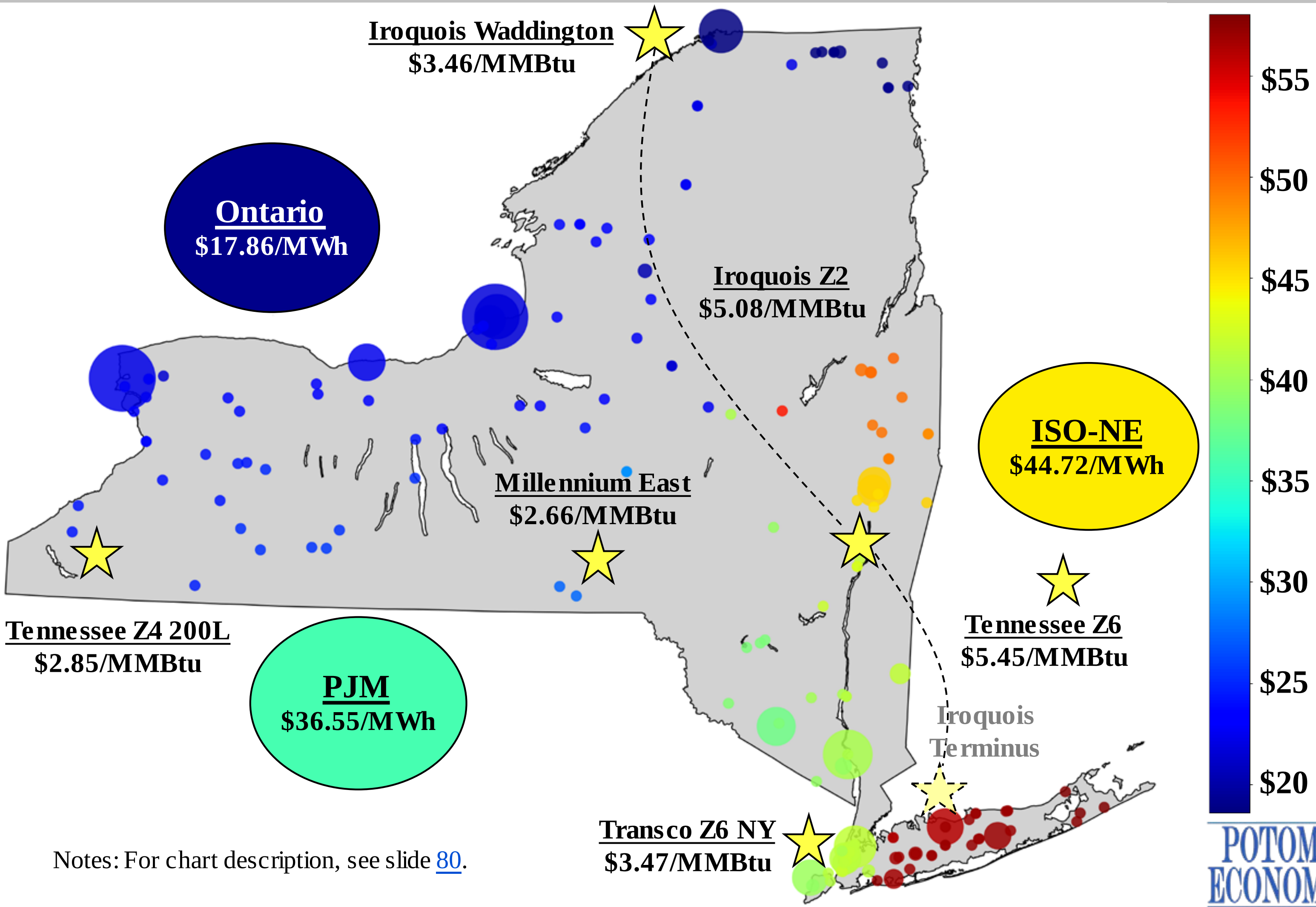
Notes: For chart description, see slide 79.

POTOMAC ECONOMICS

Charts:

Transmission Congestion Revenues and Shortfalls

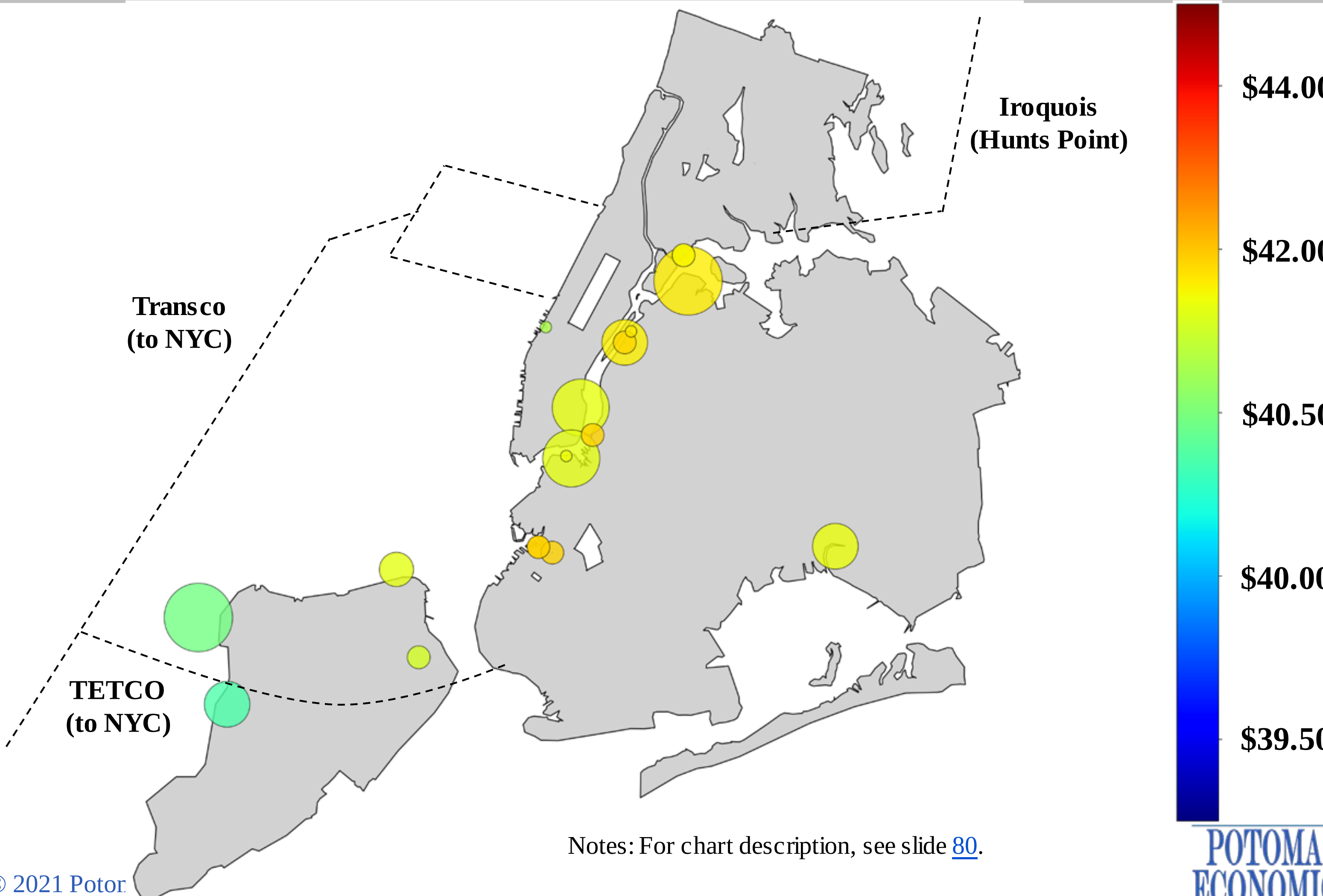
System Congestion
Real-Time Price Map at Generator Nodes



Notes: For chart description, see slide 80.

POTOMAC ECONOMICS

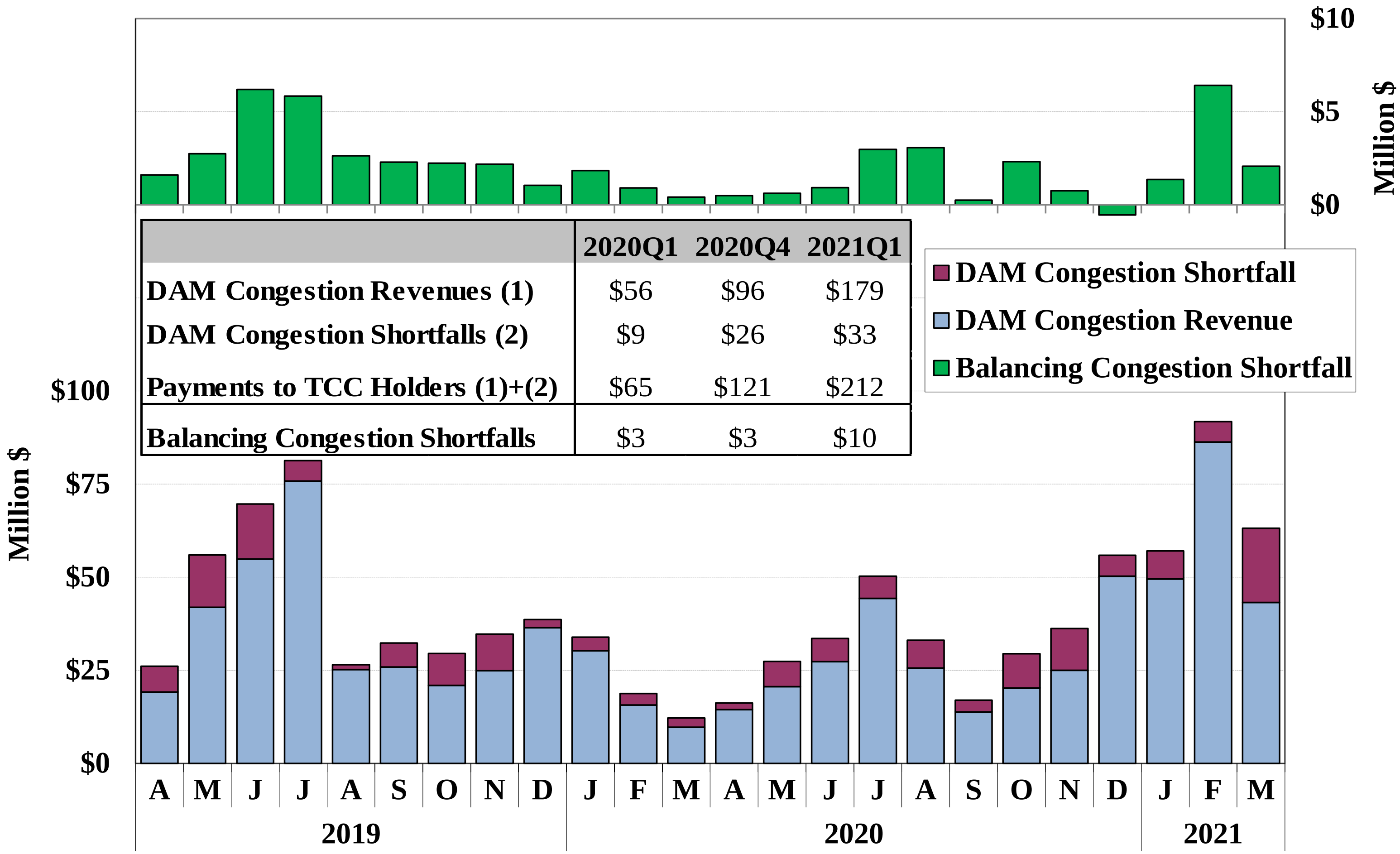
System Congestion
NYC Real-Time Price Map at Generator Nodes



Notes: For chart description, see slide 80.

POTOMAC ECONOMICS

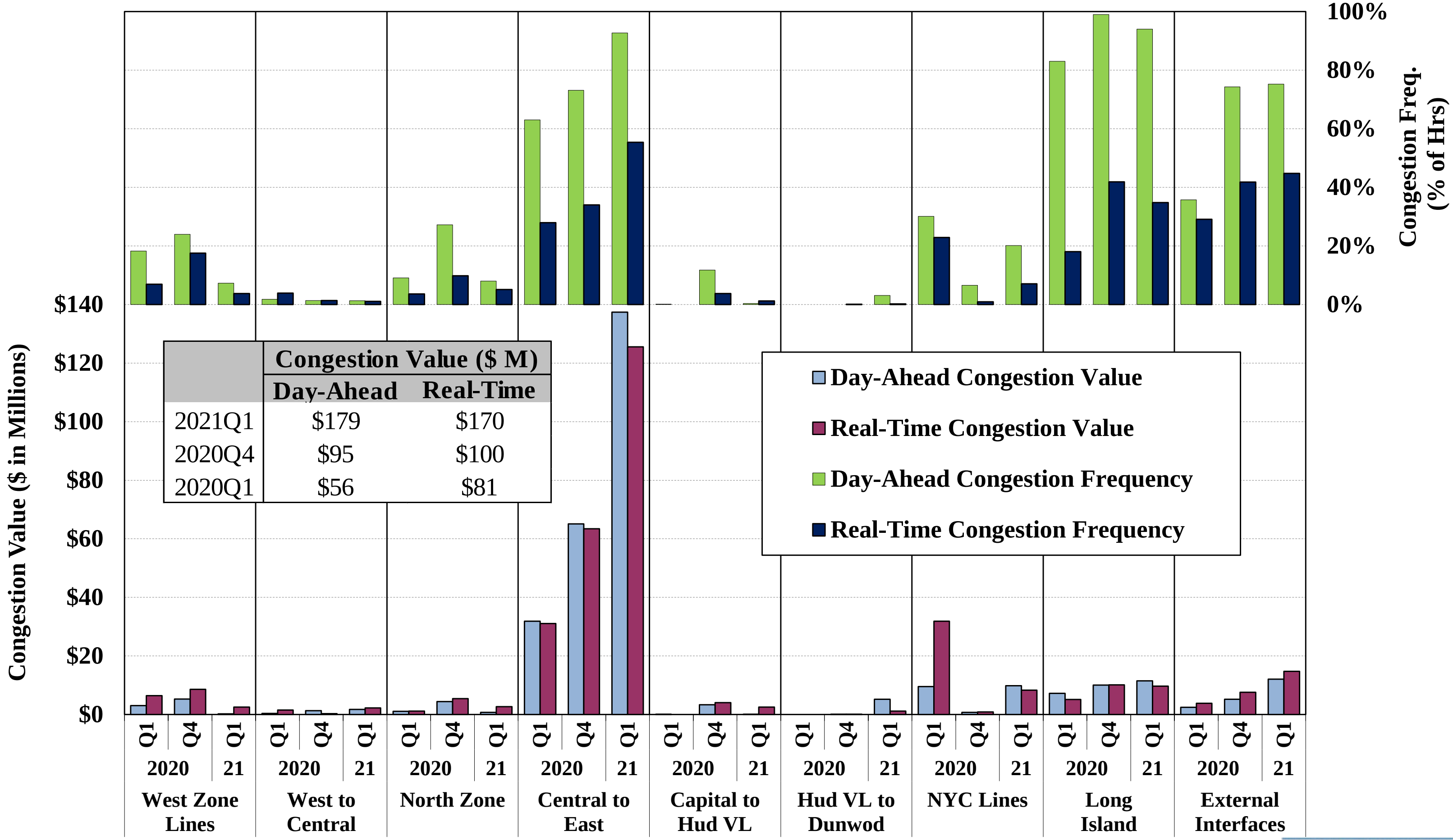
Congestion Revenues and Shortfalls by Month



	2020Q1	2020Q4	2021Q1
DAM Congestion Revenues (1)	$56	$96	$179
DAM Congestion Shortfalls (2)	$9	$26	$33
Payments to TCC Holders (1)+(2)	$65	$121	$212
Balancing Congestion Shortfalls	$3	$3	$10

Notes: For chart description, see slides 81 and 82.

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

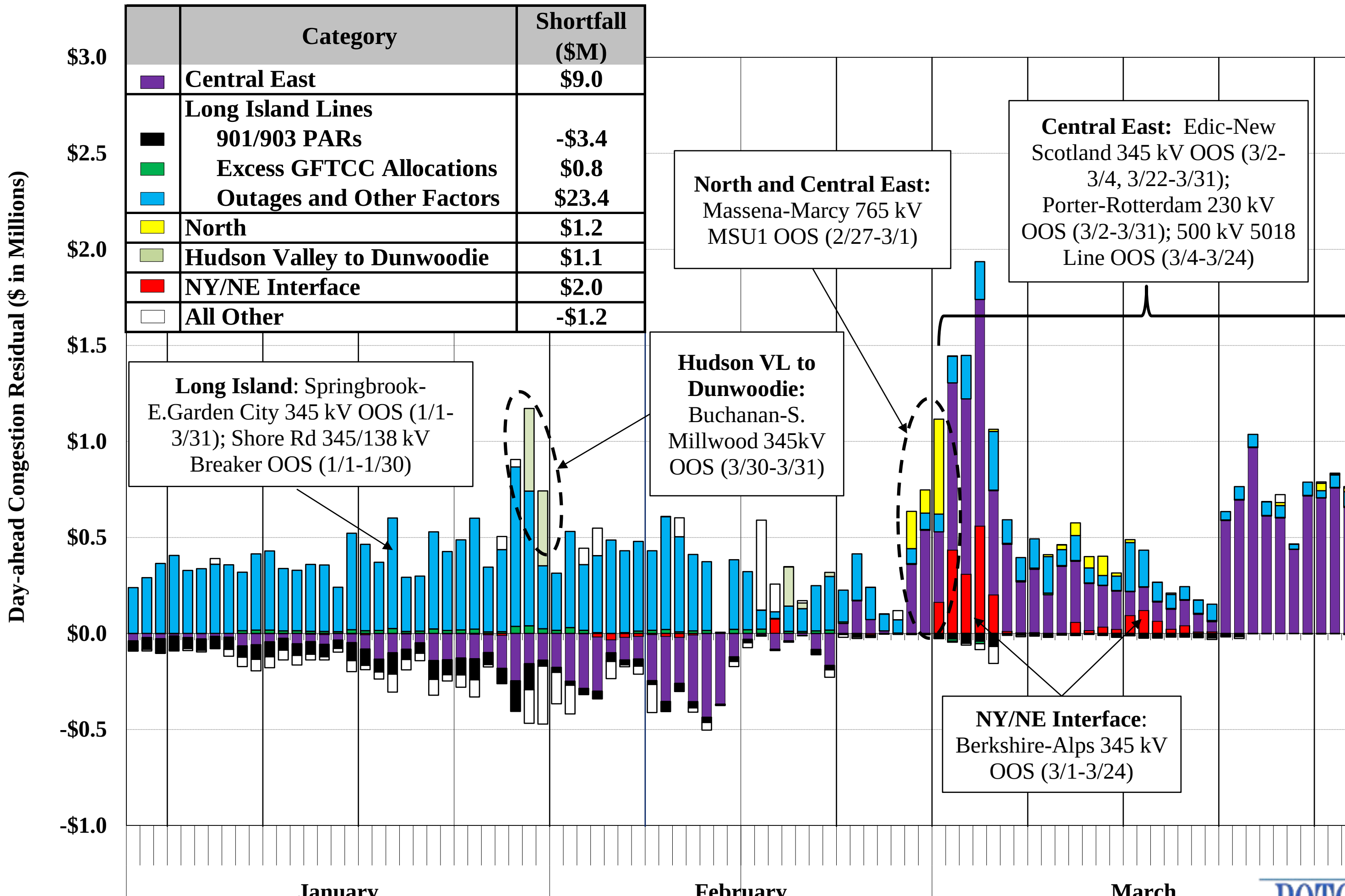


	Congestion Value ($ M)	
	Day-Ahead	Real-Time
2021Q1	$179	$170
2020Q4	$95	$100
2020Q1	$56	$81

Notes: For chart description, see slides 81, 82, and 83.

POTOMAC ECONOMICS

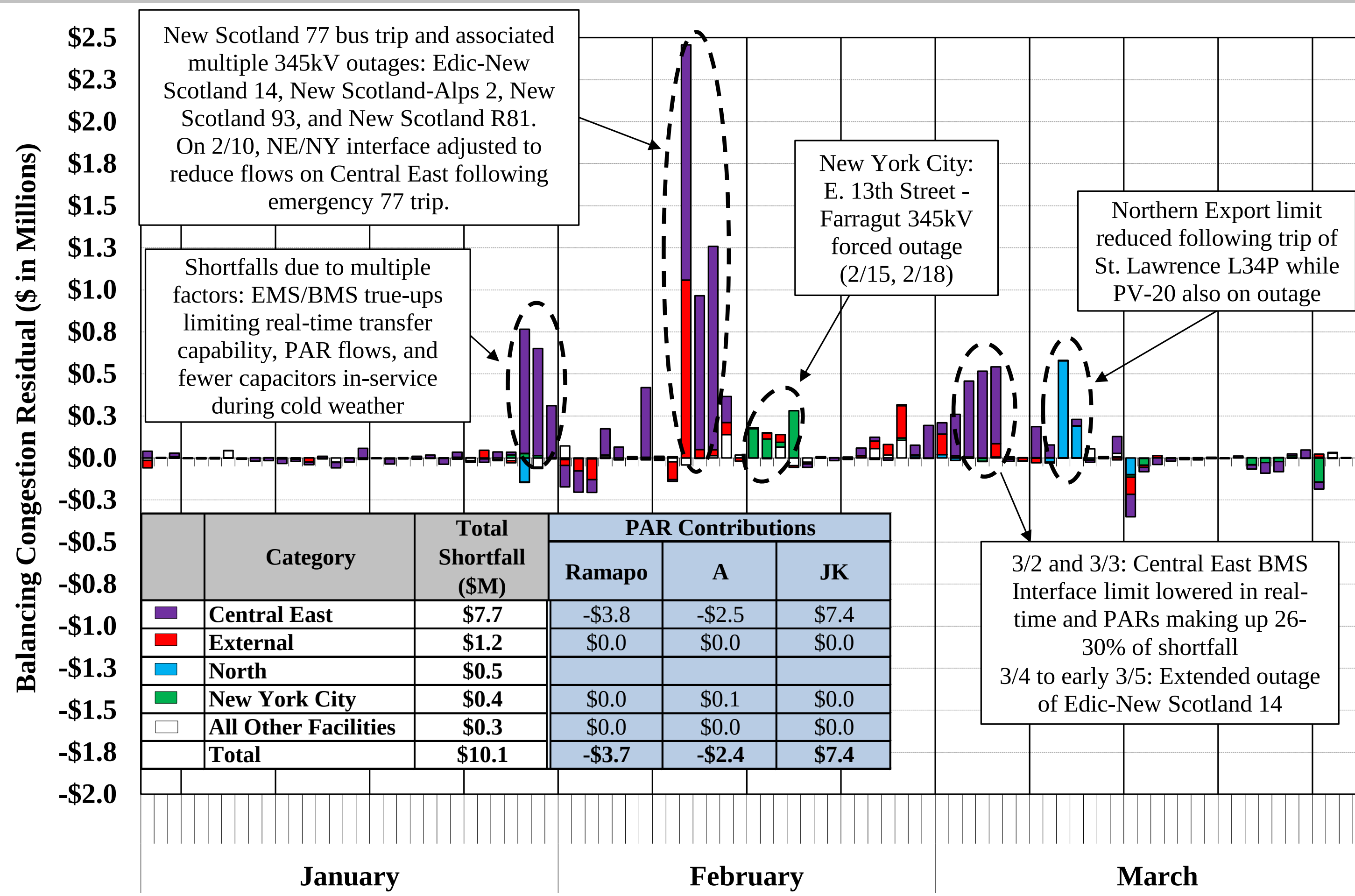
Day-Ahead Congestion Revenue Shortfalls by Transmission Facility



Notes: For chart description, see slides 81, 82, and 83.

POTOMAC ECONOMICS

Balancing Congestion Shortfalls by Transmission Facility

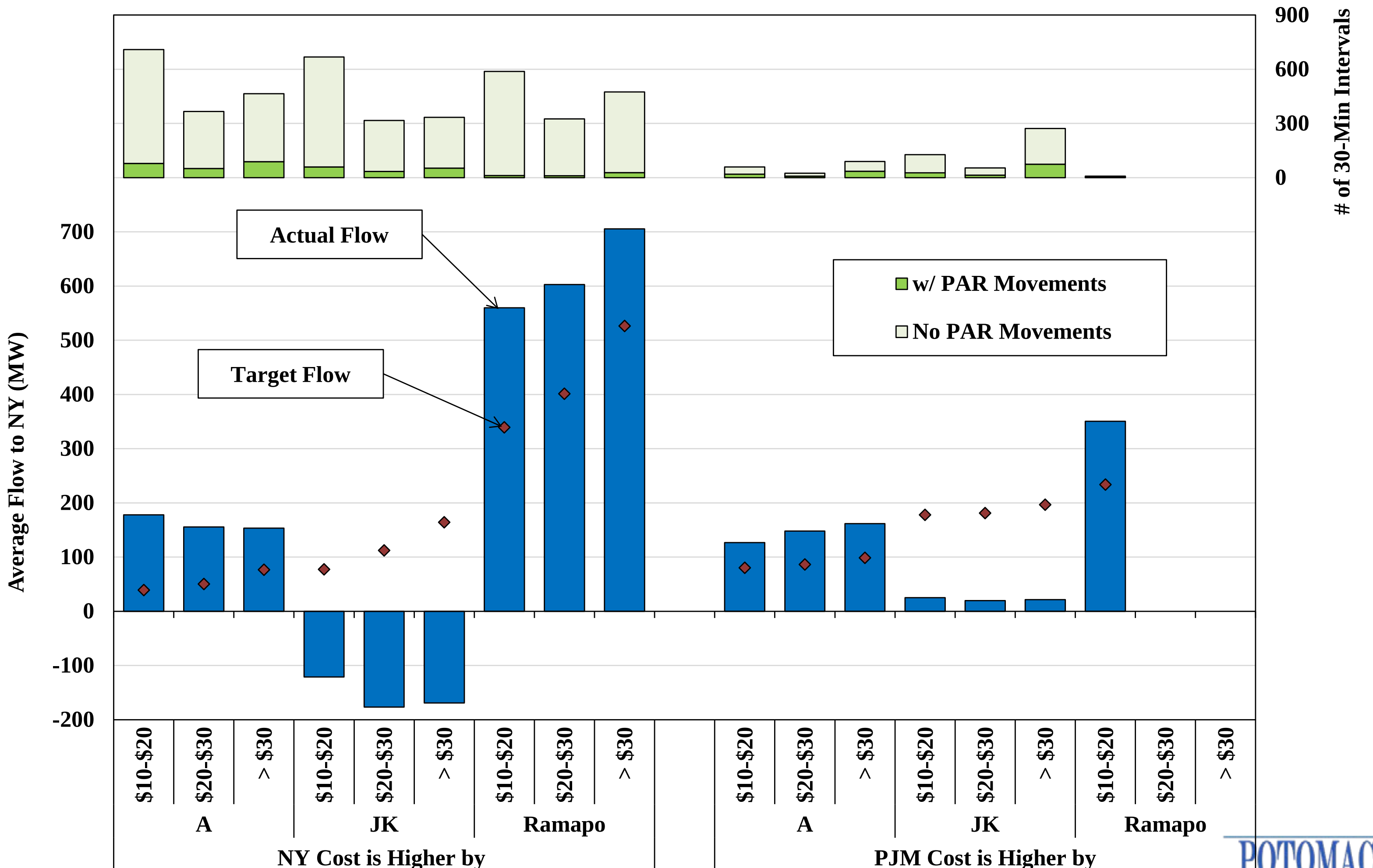


Category	Total Shortfall ($M)	PAR Contributions: Ramapo	A	JK
Central East	$7.7	-$3.8	-$2.5	$7.4
External	$1.2	$0.0	$0.0	$0.0
North	$0.5			
New York City	$0.4	$0.0	$0.1	$0.0
All Other Facilities	$0.3	$0.0	$0.0	$0.0
Total	$10.1	-$3.7	-$2.4	$7.4

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 81, 82, and 83.

POTOMAC ECONOMICS

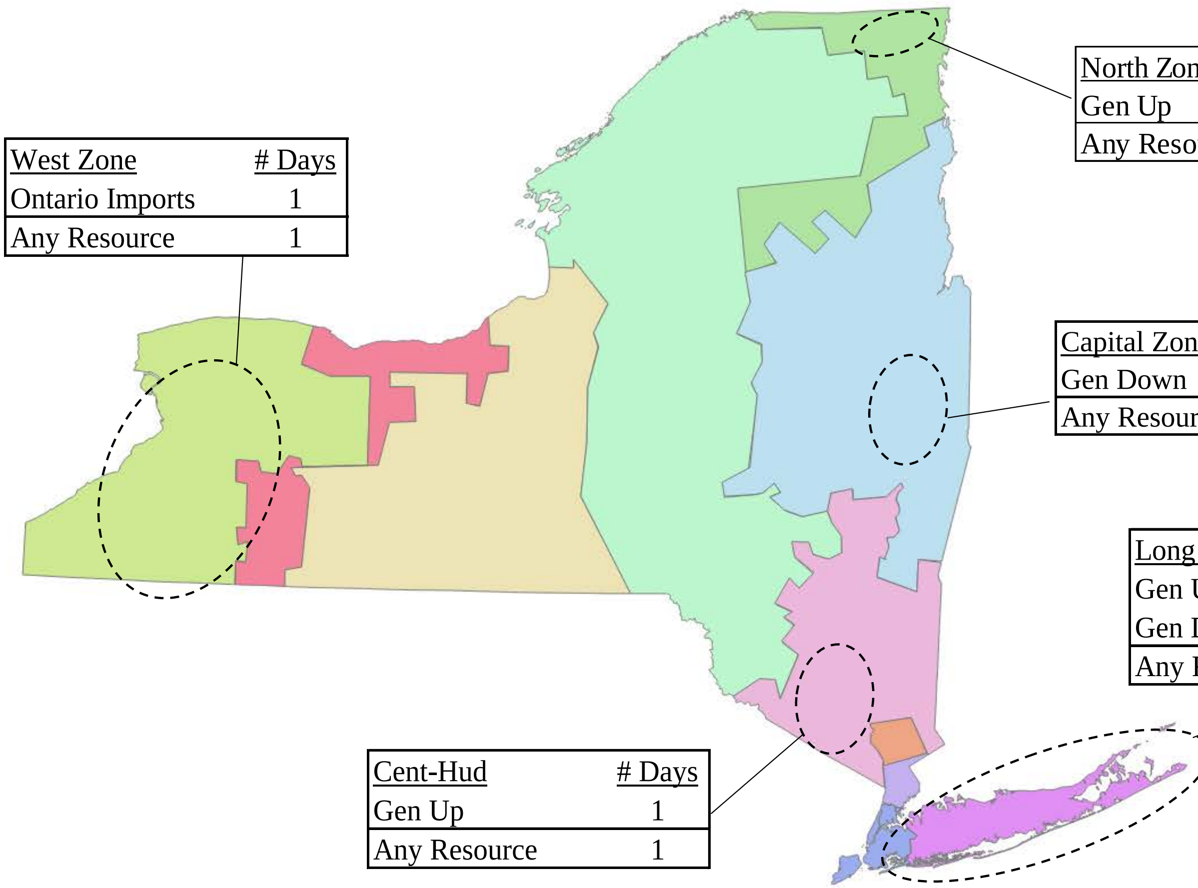
PAR Operation under M2M with PJM
2021 Q1



Notes: For chart description, see slide 84.

POTOMAC ECONOMICS

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



North Zone	# Days
Gen Up	0
Any Resource	13

West Zone	# Days
Ontario Imports	1
Any Resource	1

Capital Zone	# Days
Gen Down	4
Any Resource	4

Long Is 69kV	# Days
Gen Up	8
Gen Down	2
Any Resource	10

Cent-Hud	# Days
Gen Up	1
Any Resource	1

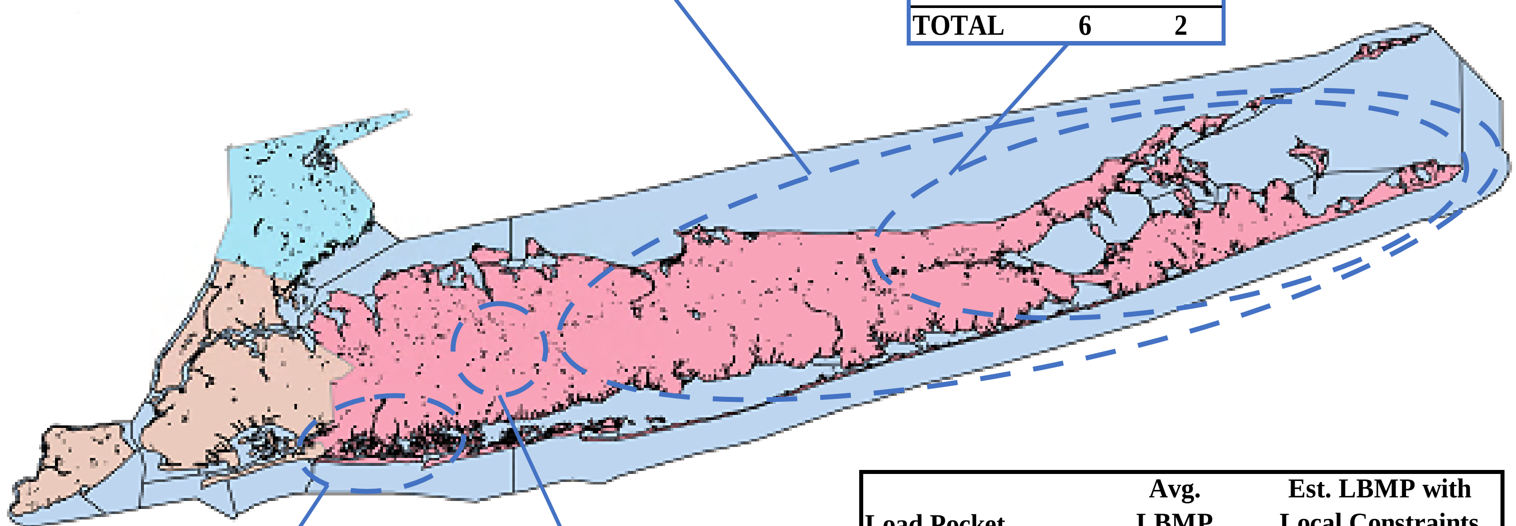
Notes: For chart description, see slides 85-86

POTOMAC ECONOMICS

Constraints on the Low Voltage Network:
Long Island Load Pockets

East of Northport	#Hours	#Days
69kV	21	3
138kV	14	5
TOTAL	35	8

East End	#Hours	#Days
69kV	6	2
138kV	0	0
TOTAL	6	2



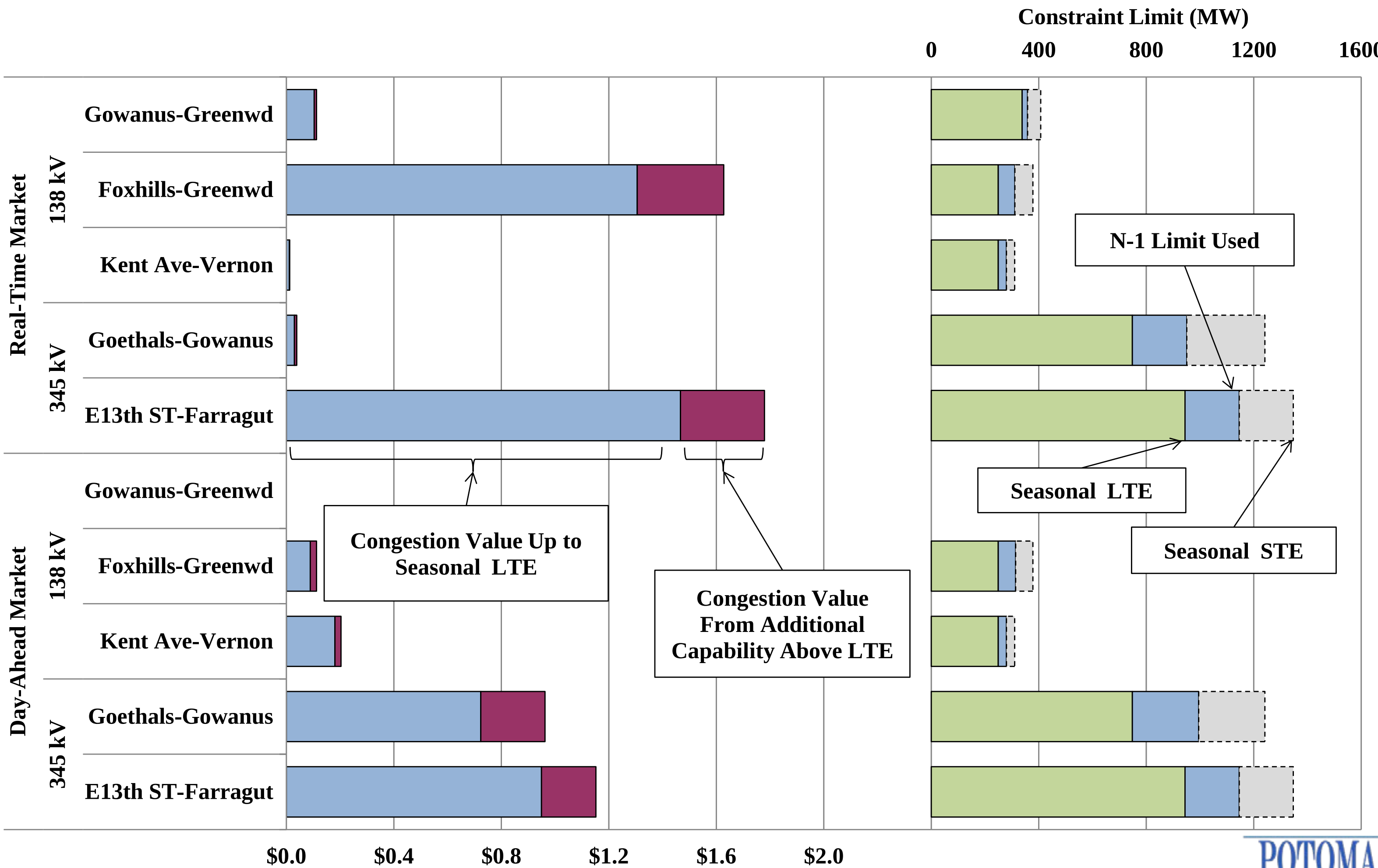
Load Pocket	Avg. LBMP	Est. LBMP with Local Constraints
Brentwood	$53.46	$53.46
East End	$54.34	$55.08
East of Northport	$53.40	$54.13
Valley Stream	$53.29	$53.88

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

Valley Stream	#Hours	#Days
69kV	75	7
138kV	61	15
TOTAL	136	22

Notes: For chart description, see slides 85-86

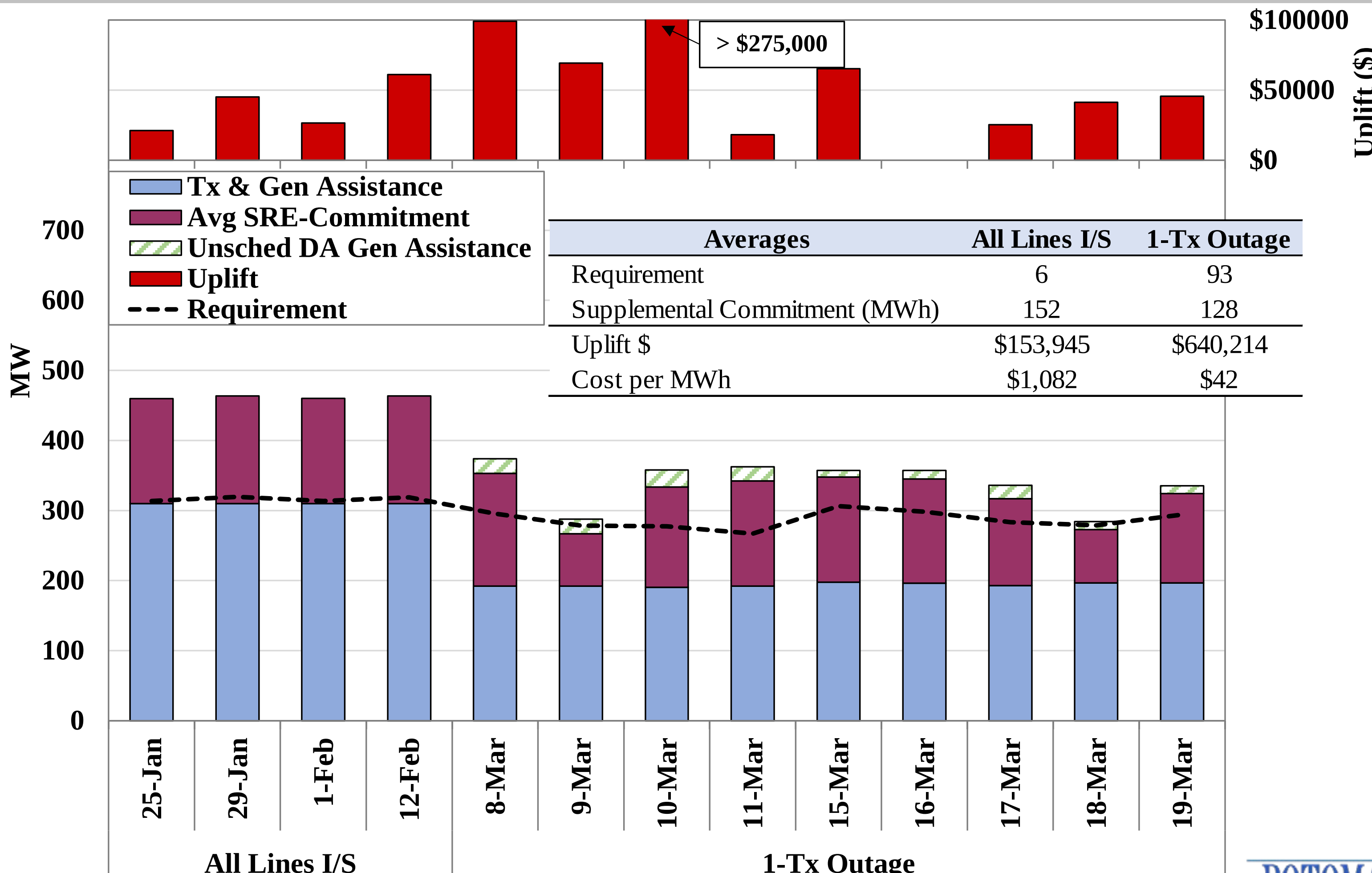
N-1 Constraints in New York City
Limits Used vs Seasonal LTE Ratings



Notes: For chart description, see slide 87.

POTOMAC ECONOMICS

N-1-1 Constraints in North Country Region
Frequency and Magnitude of Capacity Requirements



Averages	All Lines I/S	1-Tx Outage
Requirement	6	93
Supplemental Commitment (MWh)	152	128
Uplift $	$153,945	$640,214
Cost per MWh	$1,082	$42

Notes: For chart description, see slide 88

10-Minute Gas Turbine Start-up Performance
Economic Starts vs. Audits

10 Minute Economic GT Start Performance vs. Audit Results (April 2020 - Mar 2021)				
Economic GT Starts (RTC, RTD, and RTD-CAM)		**GT Audit Results**		
Performance Category	**No. of Units**	**No. of Audits**	**Unique GTs Audited**	**No. of Audit Failures**
Not Evaluated [1]	0	0	0	0
0% - 10%	0	0	0	0
10% - 20%	0	0	0	0
20% - 30%	1	1	1	0
30% - 40%	0	0	0	0
40% - 50%	0	0	0	0
50% - 60%	4	6	4	0
60% - 70%	3	6	3	0
70% - 80%	4	5	3	0
80% - 90%	18	31	18	2
90% - 100%	23	45	23	3
TOTAL	**53**	**94**	**52**	**5**

Note: 1. Including units that were OOM- or self-started, units that were never started in the time period, and units that was omitted from the analysis due to certain data issues for reliable performance assessment.

Notes: For chart description, see slide 89.

POTOMAC ECONOMICS

30-Minute Gas Turbine Start-up Performance
Economic Starts vs. Audits

30 Minute Economic GT Start Performance vs. Audit Results (April 2020 - Mar 2021)

Economic GT Starts (RTC)		GT Audit Results		
Performance Category	**No. of Units**	**No. of Audits**	**Unique GTs Audited**	**No. of Audit Failures**
Not Evaluated [1]	26	39	22	8
0% - 10%	1	1	1	0
10% - 20%	0	0	0	0
20% - 30%	0	0	0	0
30% - 40%	1	0	0	0
40% - 50%	0	0	0	0
50% - 60%	2	1	1	0
60% - 70%	1	1	1	0
70% - 80%	5	12	4	7
80% - 90%	12	18	11	1
90% - 100%	46	74	45	1
TOTAL	**94**	**146**	**85**	**17**

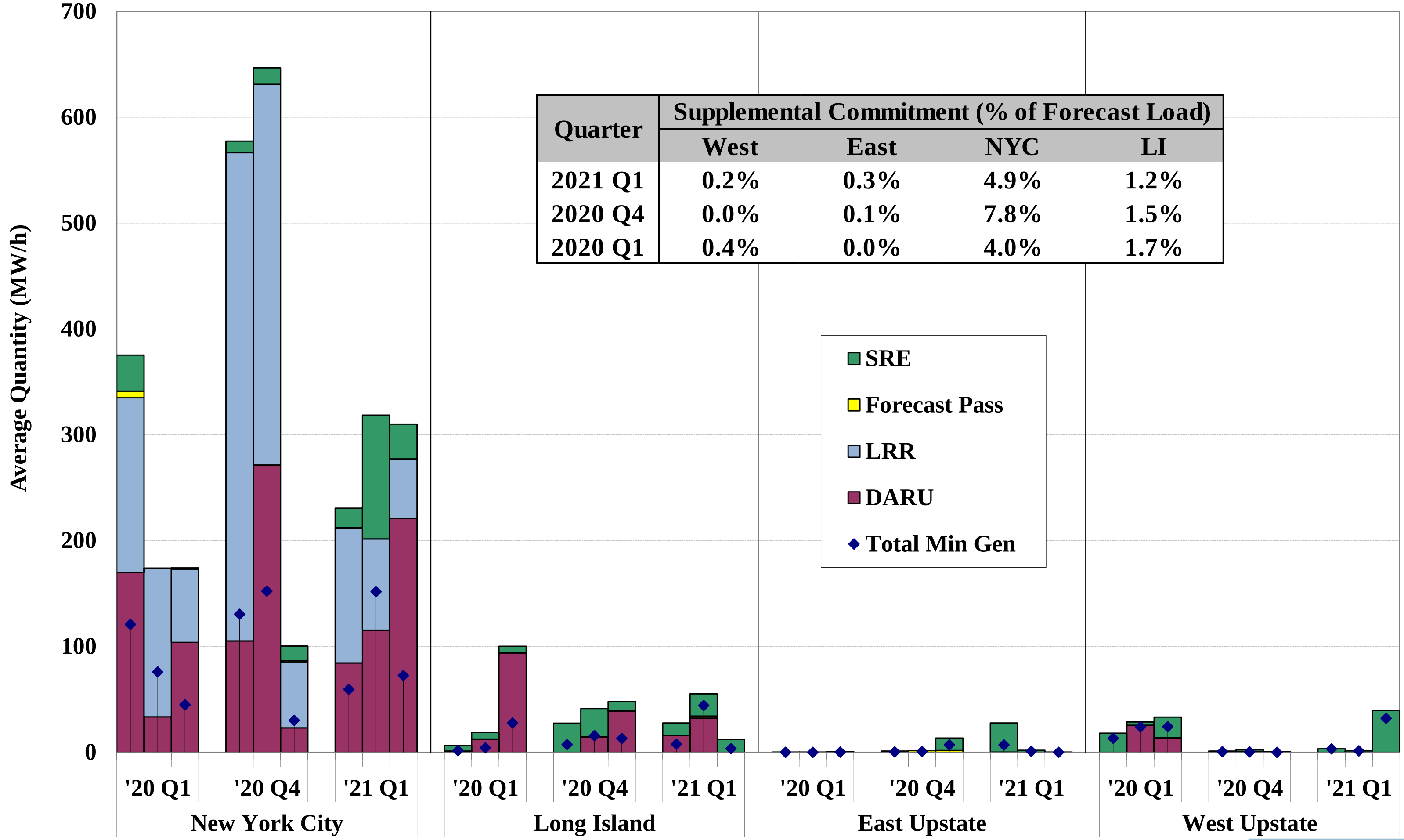
Note: 1. Including units that were OOM- or self-started, units that were never started in in the time period, and units that was omitted from the analysis due to certain data issues for reliable performance assessment.

 Notes: For chart description, see slide 89.

Charts:

Supplemental Commitment, OOM Dispatch, and BPCG Uplift

Supplemental Commitment for Reliability by Category and Region

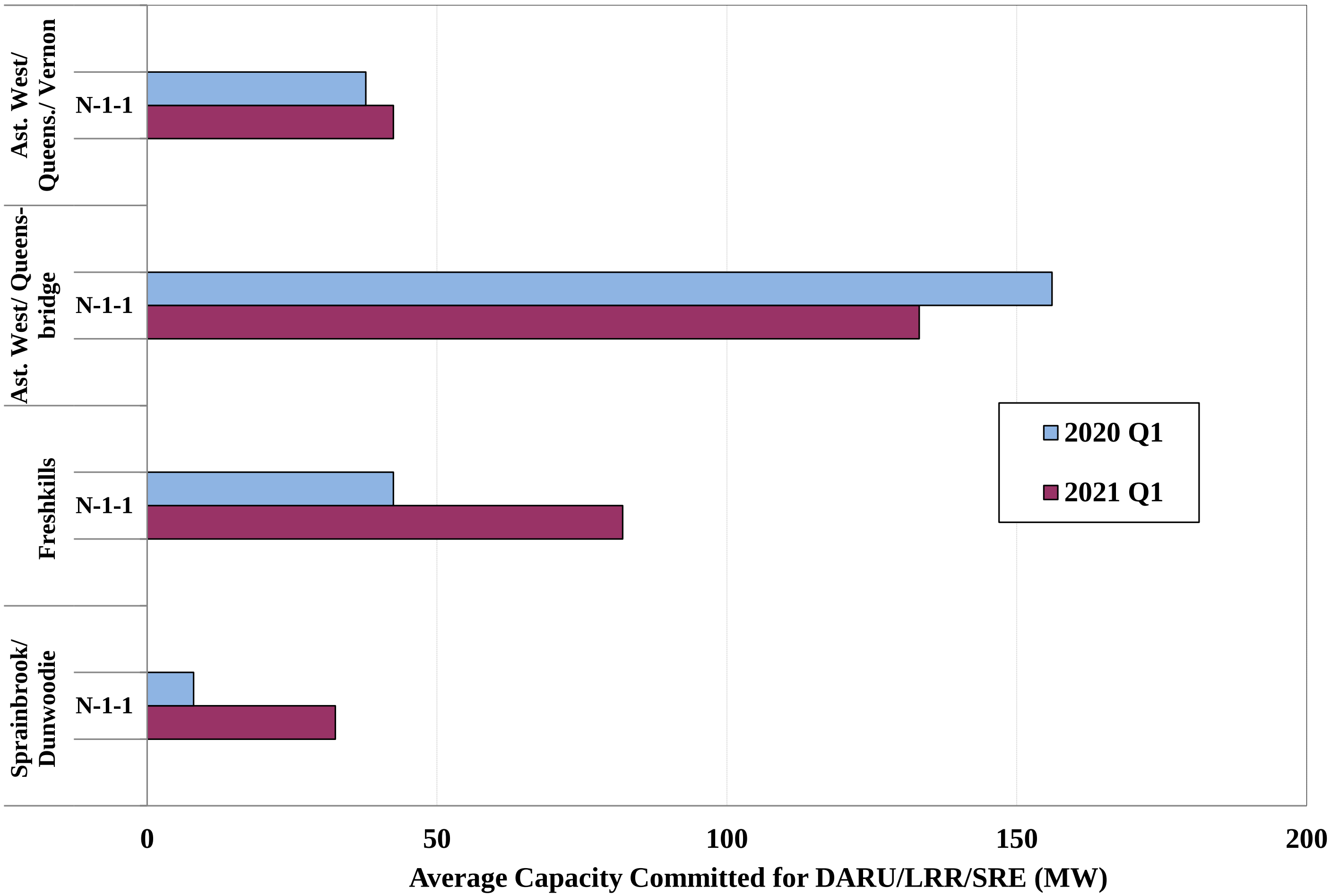


Quarter	Supplemental Commitment (% of Forecast Load)			
	West	East	NYC	LI
2021 Q1	0.2%	0.3%	4.9%	1.2%
2020 Q4	0.0%	0.1%	7.8%	1.5%
2020 Q1	0.4%	0.0%	4.0%	1.7%

Notes: For chart description, see slides 90 and 91.

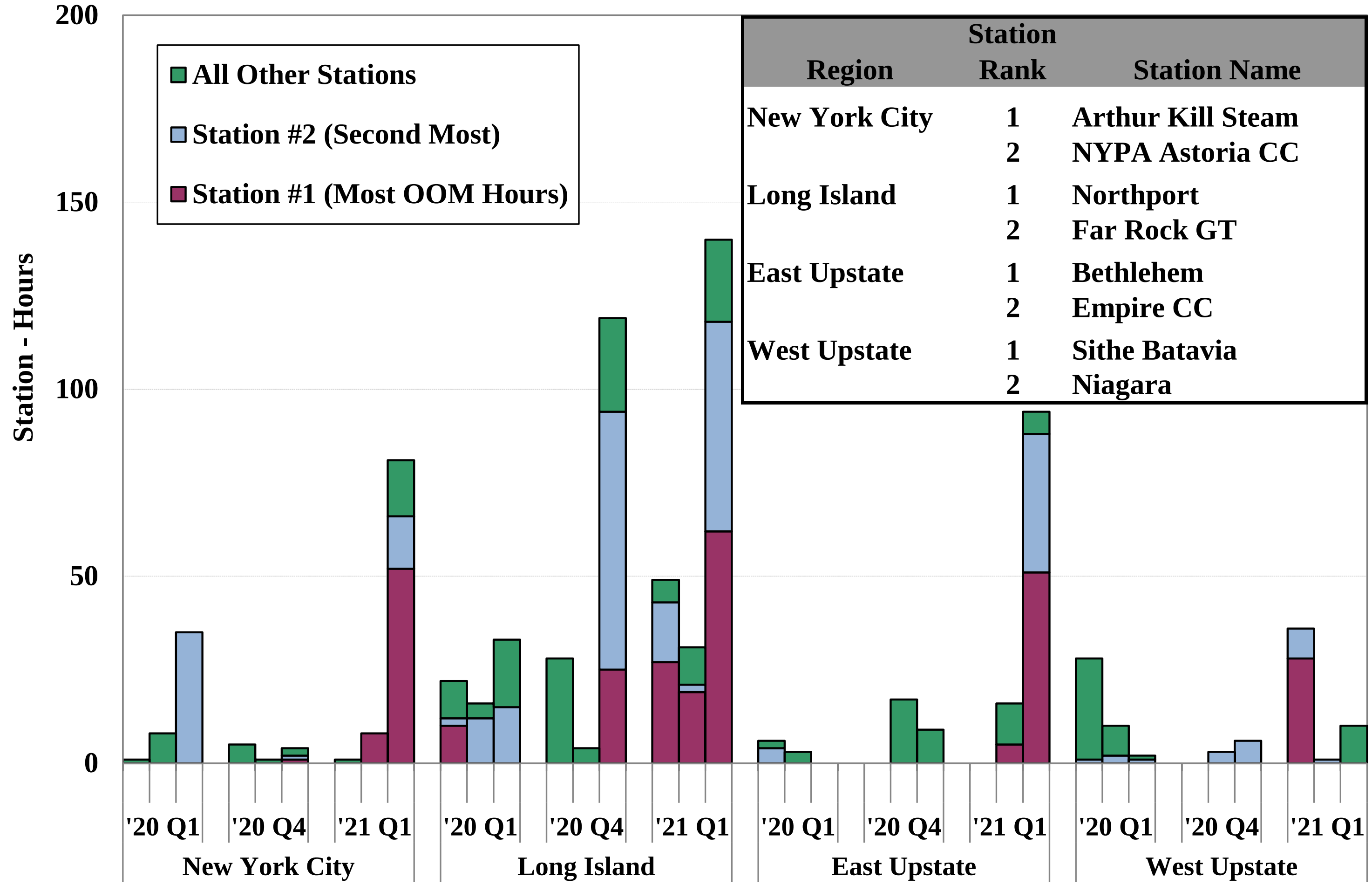
POTOMAC ECONOMICS

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



Notes: For chart description, see slides 90 and 91.

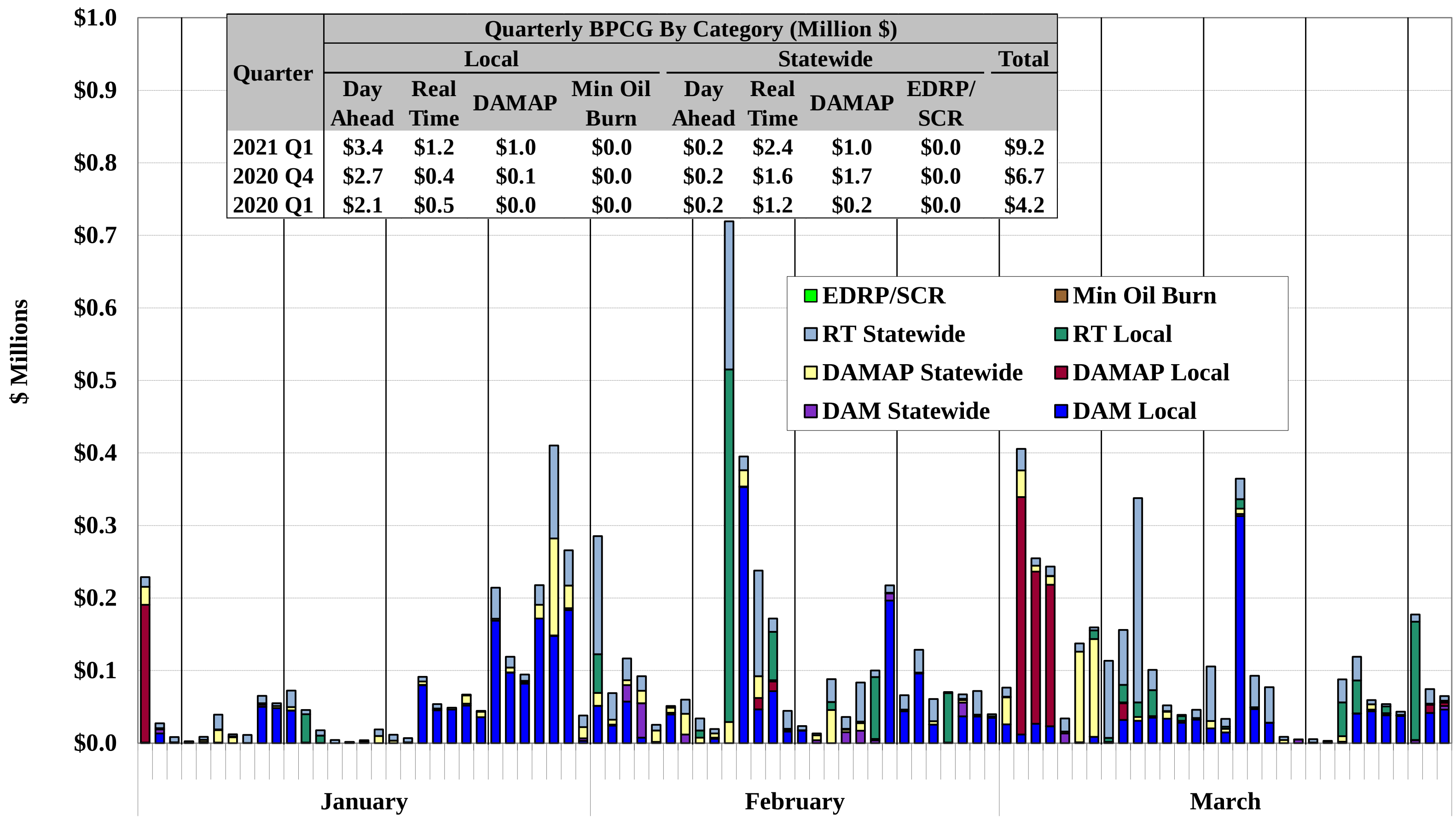
Frequency of Out-of-Merit Dispatch
by Region by Month



Region	Station Rank	Station Name
New York City	1	Arthur Kill Steam
	2	NYPA Astoria CC
Long Island	1	Northport
	2	Far Rock GT
East Upstate	1	Bethlehem
	2	Empire CC
West Upstate	1	Sithe Batavia
	2	Niagara

For chart description, see slides 90 and 91.

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

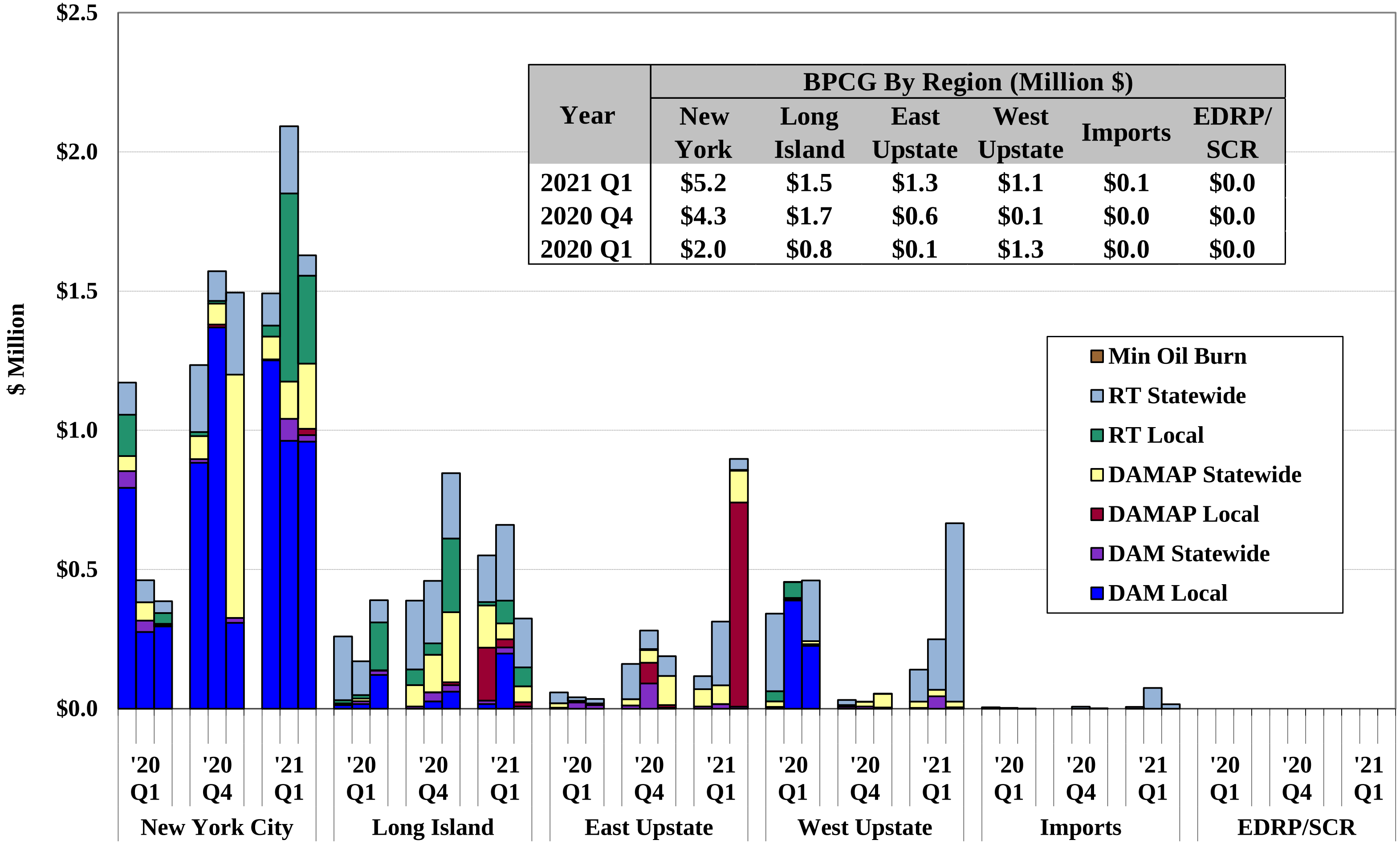


Quarterly BPCG By Category (Million $)

Quarter	Local				Statewide				Total
	Day Ahead	Real Time	DAMAP	Min Oil Burn	Day Ahead	Real Time	DAMAP	EDRP/ SCR	
2021 Q1	$3.4	$1.2	$1.0	$0.0	$0.2	$2.4	$1.0	$0.0	$9.2
2020 Q4	$2.7	$0.4	$0.1	$0.0	$0.2	$1.6	$1.7	$0.0	$6.7
2020 Q1	$2.1	$0.5	$0.0	$0.0	$0.2	$1.2	$0.2	$0.0	$4.2

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 92.

Uplift Costs from Guarantee Payments
By Category and Region



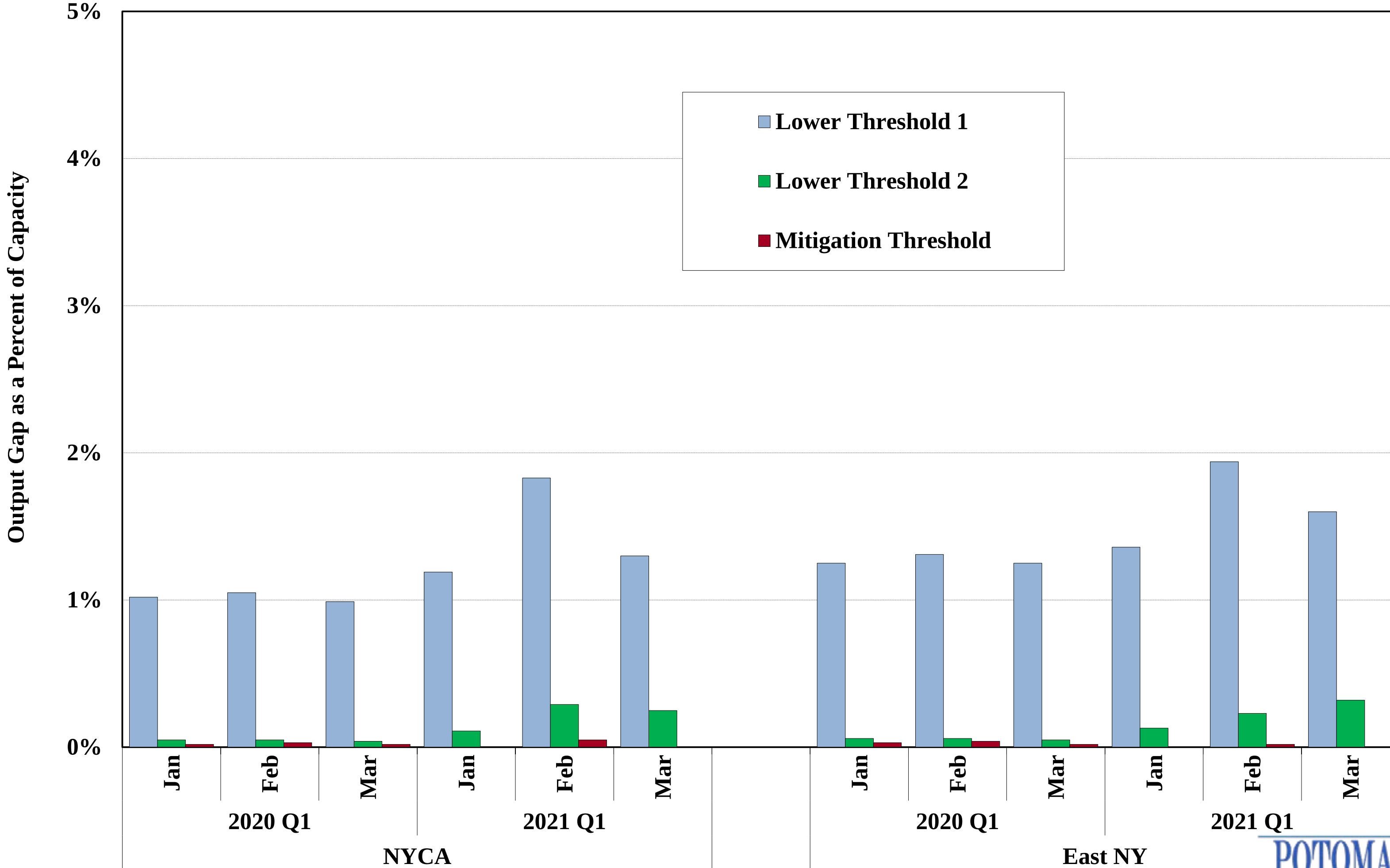
Year	BPCG By Region (Million $)					
	New York	Long Island	East Upstate	West Upstate	Imports	EDRP/ SCR
2021 Q1	$5.2	$1.5	$1.3	$1.1	$0.1	$0.0
2020 Q4	$4.3	$1.7	$0.6	$0.1	$0.0	$0.0
2020 Q1	$2.0	$0.8	$0.1	$1.3	$0.0	$0.0

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 92.

POTOMAC ECONOMICS

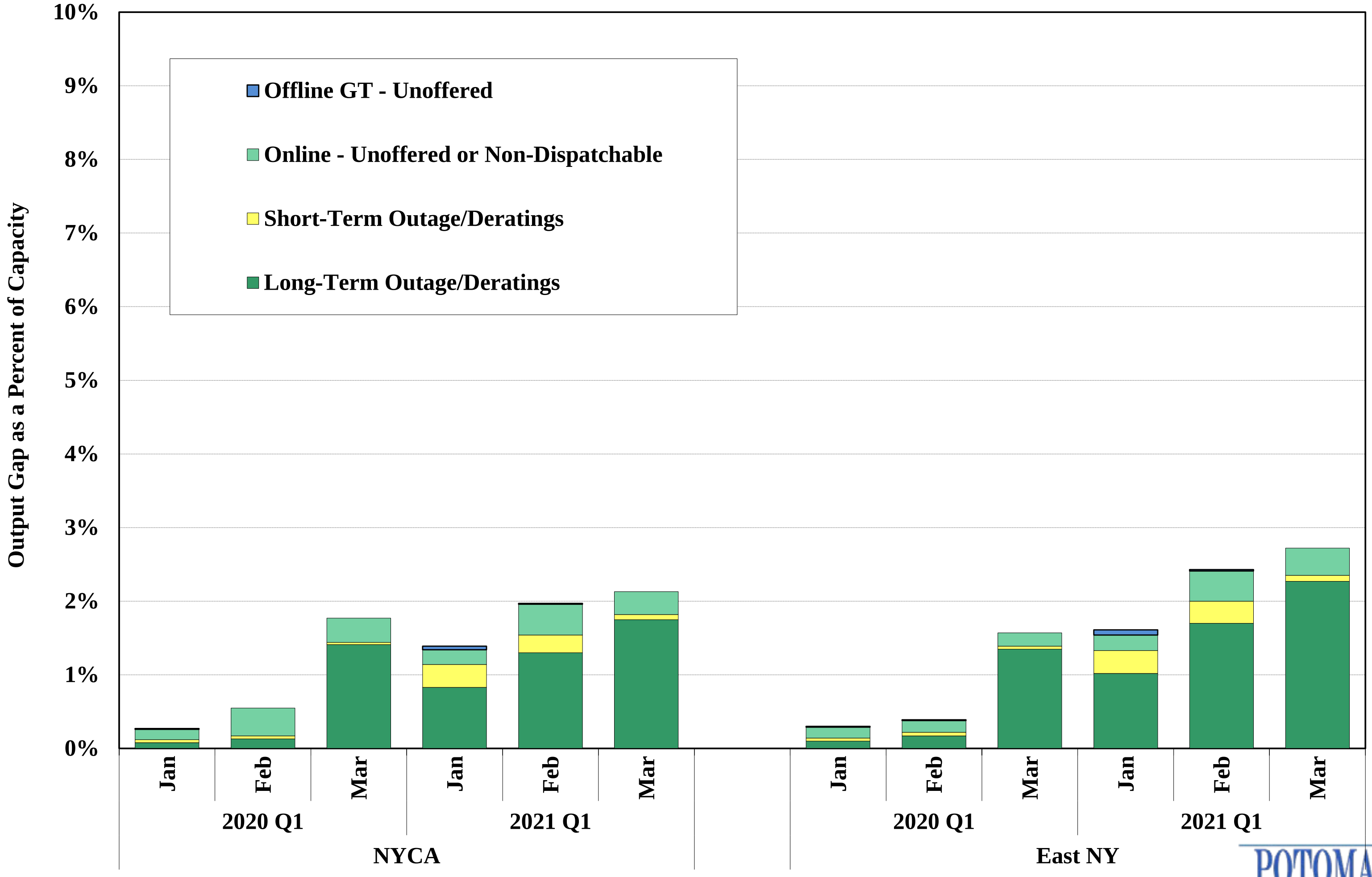
Charts:
Market Power and Mitigation

Output Gap by Month
NYCA and East NY



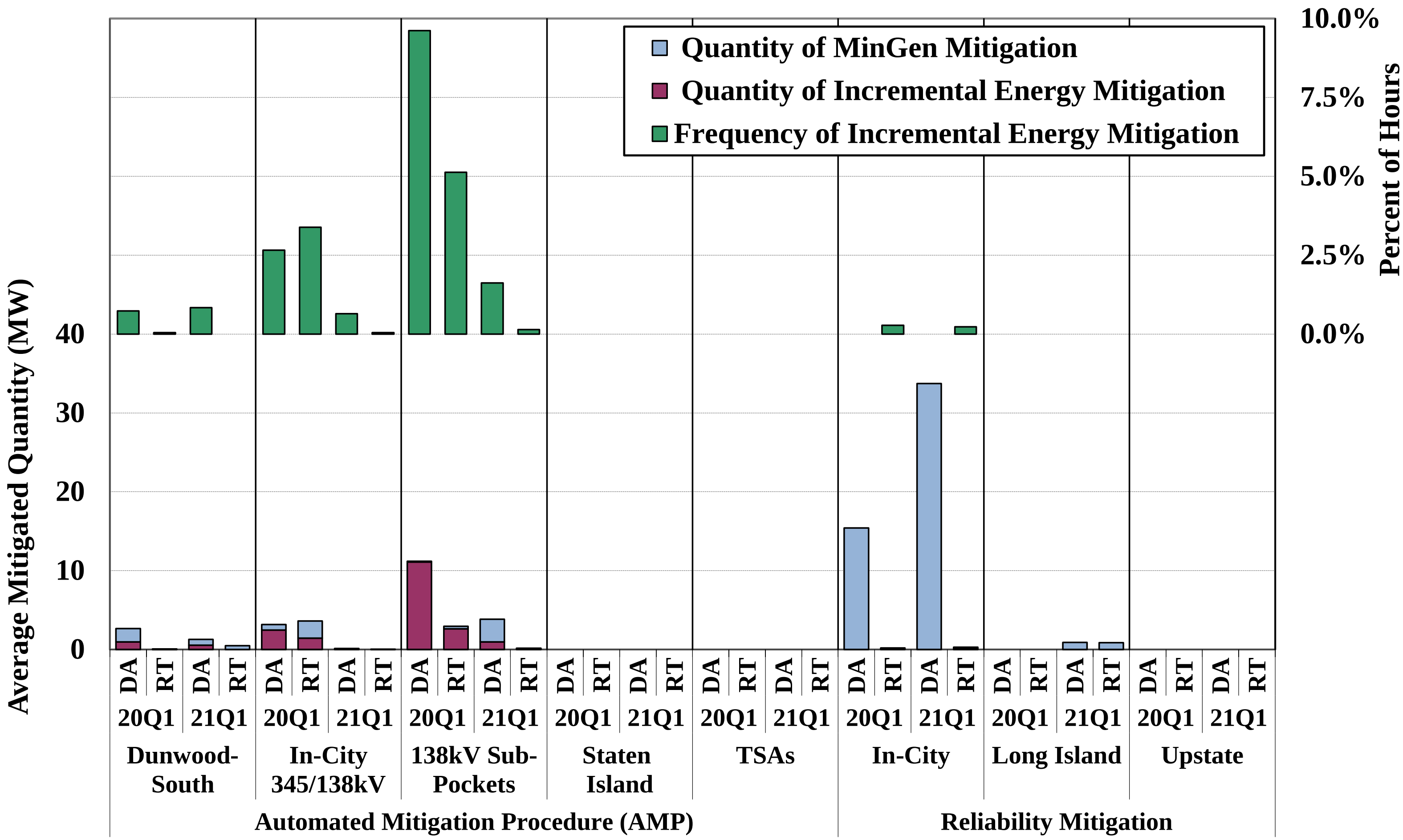
For chart description, see slide 93.

Unoffered Economic Capacity by Month
NYCA and East NY



For chart description, see slide 93.

Automated Market Power Mitigation



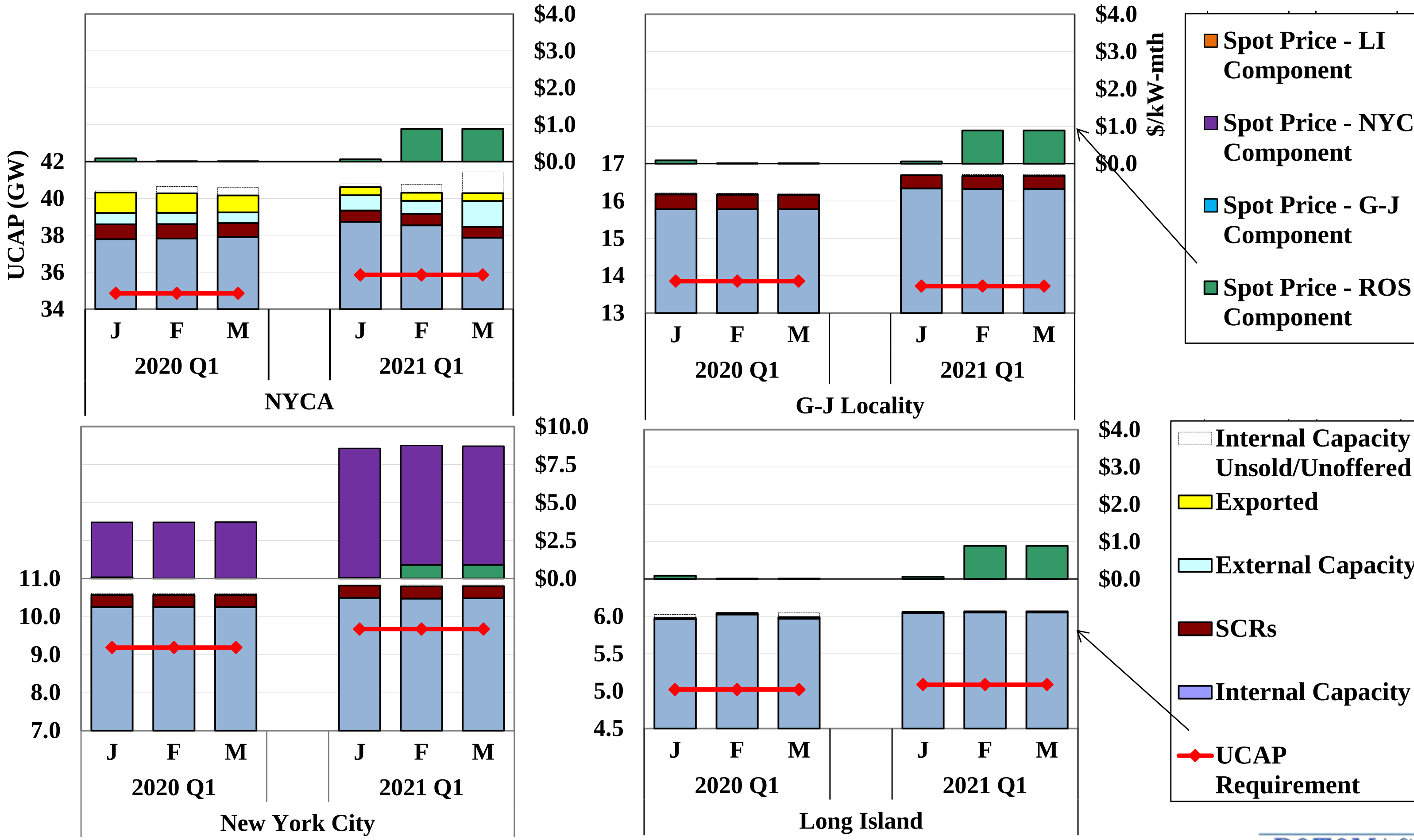
Notes: For chart description, see slide 94.

POTOMAC ECONOMICS

Charts:

Capacity Market

Spot Capacity Market Results
2020-Q1 & 2021-Q1



Notes: For chart description, see slide 95.

POTOMAC ECONOMICS

Key Drivers of Capacity Market Results

	NYCA	NYC	LI	G-J Locality
Avg. Spot Price				
2021 Q1 ($/kW-Month)	$0.61	$8.68	$0.61	$0.61
% Change from 2020 Q1	**1573%**	**134%**	**1573%**	**1573%**
Change in Demand				
Load Forecast (MW)	-87	-130	-13	-150
IRM/LCR	1.9%	3.8%	-0.7%	-2.3%
2020/21 Capability Year	*118.9%*	*86.6%*	*103.4%*	*90.0%*
2019/20 Capability Year	*117.0%*	*82.8%*	*104.1%*	*92.3%*
ICAP Requirement (MW)	**512**	**329**	**-50**	**-501**
Key Changes in ICAP Supply (MW)				
Generation	**176**	**0**	**-67**	**103**
Entry	1132	0	0	1124
Exit	-1810	-21	-79	-1048
DMNC & Return from Export (1)	854	21	11	26
Unsold (Feb & Mar) (2)	-579			
Cleared Import (3)	**377**			

(1) Many units exported to ISO-NE during 2020. Increased internal sales influence NYCA totals.

(2) Prices rose in Feb & Mar due to offer patterns. The unsold tied to those offers is given here.

(3) Based on average of quarterly cleared quantity.

Notes: For chart description, see slide 95.

POTOMAC ECONOMICS

Appendix: Chart Descriptions

POTOMAC ECONOMICS

All-in Price

- Slide 17 summarizes the total cost per MWh of load served in the New York markets by showing the "all-in" price that includes:
  - ✓ An energy component that is a load-weighted average real-time energy price.
  - ✓ A capacity component that is calculated based on clearing prices in the monthly spot capacity auctions and capacity obligations in each 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.

Real-Time Output and Marginal Units by Fuel

- Slide 20 shows the quantities of real-time generation by fuel type.
  - ✓ Real time generation by fuel type is derived from data reported to the U.S. Environmental Protection Agency ("EPA") and the U.S. Energy Information Administration ("EIA").
  - ✓ Pumped-storage resources in pumping mode are treated as negative generation. "Other" includes Methane, Refuse, Solar & Wood.
- Slide 21 summarizes how frequently each fuel type was on the margin and setting real-time LBMPs in these regions.
  - ✓ More than one type of generator may be on the margin in an interval, particularly when a transmission constraint is binding. Accordingly, the total for all fuel types may be greater than 100 percent.
    - For example, if hydro units and gas units were both on the margin in every interval, the total frequency shown in the figure would be 200 percent.
  - ✓ When no generator is on the margin in a particular region, the LBMPs in that region are set by:
    - Generators in other regions in the vast majority of intervals; or
    - Shortage pricing of ancillary services, transmission constraints, and/or energy in a small share of intervals.

Winter Fuel Usage and Emissions by Region

- Slide 22 evaluates the efficiency of fuel usage in Eastern New York in the quarter.
  - ✓ The figure shows the daily averages for:
    - – Internal generation by actual fuel consumed in the lower portion; and
    - – Day-ahead natural gas price index for Iroquois Zone 2 and Transco Zone 6 (NY) in the upper portion.
  - ✓ For a year-over-year comparison, these quantities are also shown by month for the same quarter in the recent three years.
- Slides 23 – 25 evaluate the quarterly emissions across the system by generation fuel type for each of the three major emissions, i.e., CO_2, NO_X, and SO_2.
  - ✓ Emission values are given for 7 regional designations as well as the system as a whole.
  - ✓ The emission tonnage is given by aggregating the total pollution from operations on the various fossil fuel types for each month of the quarter.
  - ✓ The inset tables in each chart provides summary data on the total tonnage of emissions by fuel type for three recent quarters.

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Ancillary Services Prices

- Slides 30-34 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 33 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 35 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).

Regulation Market Requirements and Prices

- Slide 37 displays several aspects pertaining to the regulation requirements, prices, and relationship between scheduled regulation capacity and actual regulation movement in the past 36-month period.
- The topmost chart displays information relevant to the regulation requirement and the regulation movement-to-capacity ratio.
  - ✓ The blue column bars show the average monthly regulation requirement.
  - ✓ The secondary y-axis shows the average movement-to-capacity ratio for each month.
- The bottom chart shows the average monthly prices.
  - ✓ The columns show the average monthly regulation capacity prices in the day-ahead market.
  - ✓ The two lines show the real-time capacity prices and movement prices.

Day-Ahead Load Scheduling and Virtual Trading

- Slide 39 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 40 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 41 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 43 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.

Real-Time System Price Maps at Generator Nodes

- Slides 45 and 46 show maps of real-time LBMPs at generator nodes across the entire NYISO system and in New York City specifically to illustrate congestion patterns in both areas.
  - ✓ Prices are load-weighted real-time hourly LBMPs.
  - ✓ Generators are marked as circles of various sizes and colors which are determined based on market outcomes:
    - – Circle size is developed based on real-time generation from each generator across the quarter.
    - – Colors are scaled based on the load-weighted real-time prices at each node.
    - – However, both circle sizes and color scales are not necessarily the same at the same generator location in the system map and the NYC map. Because these are independently determined based on the set of generators analyzed in each map.
  - ✓ Natural gas prices for major indices and load-weighted external energy prices are also provided.
    - – External LBMPs are not scaled to size in like manner as the generators.
    - – Natural gas pipeline connections are given for the NYC price map to illustrate approximate gas delivery points to the city from three major pipelines.

Transmission Congestion and Shortfalls

- Slides 47, 48, 49, and 50 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 47 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 48 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 49 and 50 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.

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NY-NJ PAR Operation Under M2M with PJM

- Slide 51 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).

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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 52 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).

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Constraints on the Low Voltage Network

- Slide 53 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 53 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 54 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.

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N-1-1 Constraints in North Country

- Slide 55 shows the size of the N-1-1 requirement in the North Country load pocket ("NC") on applicable days during the quarter that required supplemental commitments of uneconomic gas units.
  - ✓ The bottom portion of the chart shows details relevant to the calculation of the requirement including:
    - – NC portion of day-ahead load forecast of the North Zone;
    - – Assistance from available transmission lines and day-ahead scheduled energy from non-wind resources in the NC;
    - – The amount of energy scheduled from the unit(s) supplementally committed; and
    - – The unscheduled, potentially-available capacity from the non-wind resources scheduled in the day-ahead.
  - ✓ The x-axis is delineated between days where capacity was SRE-committed despite all transmission lines being in-service (i.e., due to high loads) and when at least one major transmission line in the pocket was on outage.
  - ✓ The top portion of the chart provides the uplift associated with the reliability commitments for this capacity requirement.
- The inset table provides statistics relevant to the two scenarios that may warrant a supplemental commitment of a generator for pocket reliability.

GT Start-up Performance

- Slides 56-57 show the results of the NYISO's auditing process for 10- and 30-minute GTs in the past 12-month period, compared to performance measured for economic GT starts by the market model (including starts by RTC, RTD, and RTD-CAM) in the same period. In each table,
  - ✓ The performance is measured as the GT output at 10 or 30 minutes after receiving a start-up instruction as a percent of its UOL.
  - ✓ The rows show the number of units with an average performance in the quarter that falls in each performance range from 0 to 100% with a 10% increment.
    - – The left hand side of the table shows these numbers based on performance measured during economic starts;
    - – While the right hand side of the table shows numbers based on audit results.
    - – The units that are in service but were never started by RTC, RTD, or RTD-CAM in the examined period are placed in a separate category of "Not Evaluated", which also includes units that we could not assess their performance reliably because of data issues.
  - ✓ An example read of the table (slide 56): "23 10-minute GTs exhibited a response rate of 90 to 100 percent during economic starts in the examined period, 23 of them were audited 45 times in total with 3 failures".

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Supplemental Commitments and OOM Dispatch

- Slides 59, 60, and 61 summarize out-of-market commitment and dispatch, which are the primary sources of guarantee payment uplift.
- Slide 59 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 60 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 61 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 62 and 63 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 62 shows these seven categories on a daily basis during the quarter.
  - ✓ Slide 63 summarizes uplift costs by region on a monthly basis.

Potential Economic and Physical Withholding

- Slides 65 and 66 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 67 summarizes the automated mitigation that was imposed in the day-ahead and real-time markets (not including BPCG mitigation) in the quarter.
  - ✓ The bars in the upper panel shows the percent of hours when incremental energy offer mitigation was imposed on one or more units in each category.
  - ✓ The bars in the lower panel shows the average mitigated capacity.
    - – Mitigated quantities are shown separately for flexible output range of units (i.e., Incremental Energy) and the non-flexible portion (i.e., MinGen).
  - ✓ The left portion shows the amount of mitigation by the Automated Mitigation Procedure ("AMP") on economically committed units in NYC load pockets.
  - ✓ The right portion shows the amount of mitigation on the units committed for reliability in New York City, Long Island, and the upstate area.
  - ✓ Mitigation of gas turbine capacity is shown in the Incremental Energy category whenever the incremental energy offer or the startup offer is mitigated.

Spot Capacity Market Results

- Slides 69 and 70 summarize market results and key drivers in the monthly spot capacity auctions.
  - ✓ Slide 69 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 70 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.