



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

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Market Highlights



Market Highlights: Executive Summary

- NYISO energy markets performed competitively in the second quarter of 2021.
- All-in prices ranged from \$21 to \$67 per MWh, up 28 to 88 percent from 2020-Q2 in all regions but NYC, which saw a decrease of 6 percent. (slide [7](#))
 - ✓ Energy prices rose 26 to 110 percent primarily because of higher gas prices, which rose 55 to 62 percent across the system. Other contributing factors include:
 - Higher load levels due to partial demand recovery from the COVID-19 pandemic and high temperatures in June.
 - Nuclear and hydro output fell by 1 GW due to unit retirement and drier conditions.
 - Lengthy transmission outages which increased Central-East congestion notably.
 - ✓ Capacity prices: (a) fell sharply in NYC due to a lower LCR; but (b) rose in other areas, reflecting a higher IRM and the Indian Point nuclear retirement. (slide [18](#))
- Reliability commitments fell in NYC because of: (a) procedural changes that improved commitment efficiency for N-1-1-0 load pocket requirements; and (b) improved generation economics because of the reduced Central-East interface capability and the Indian Point nuclear retirement. (slide [12](#))
 - ✓ However, many commitments could have been avoided if the NYISO was allowed to consider whether the GTs in a particular NOx bubble were actually needed to satisfy N-1-1-0 criteria. (slide [16](#))

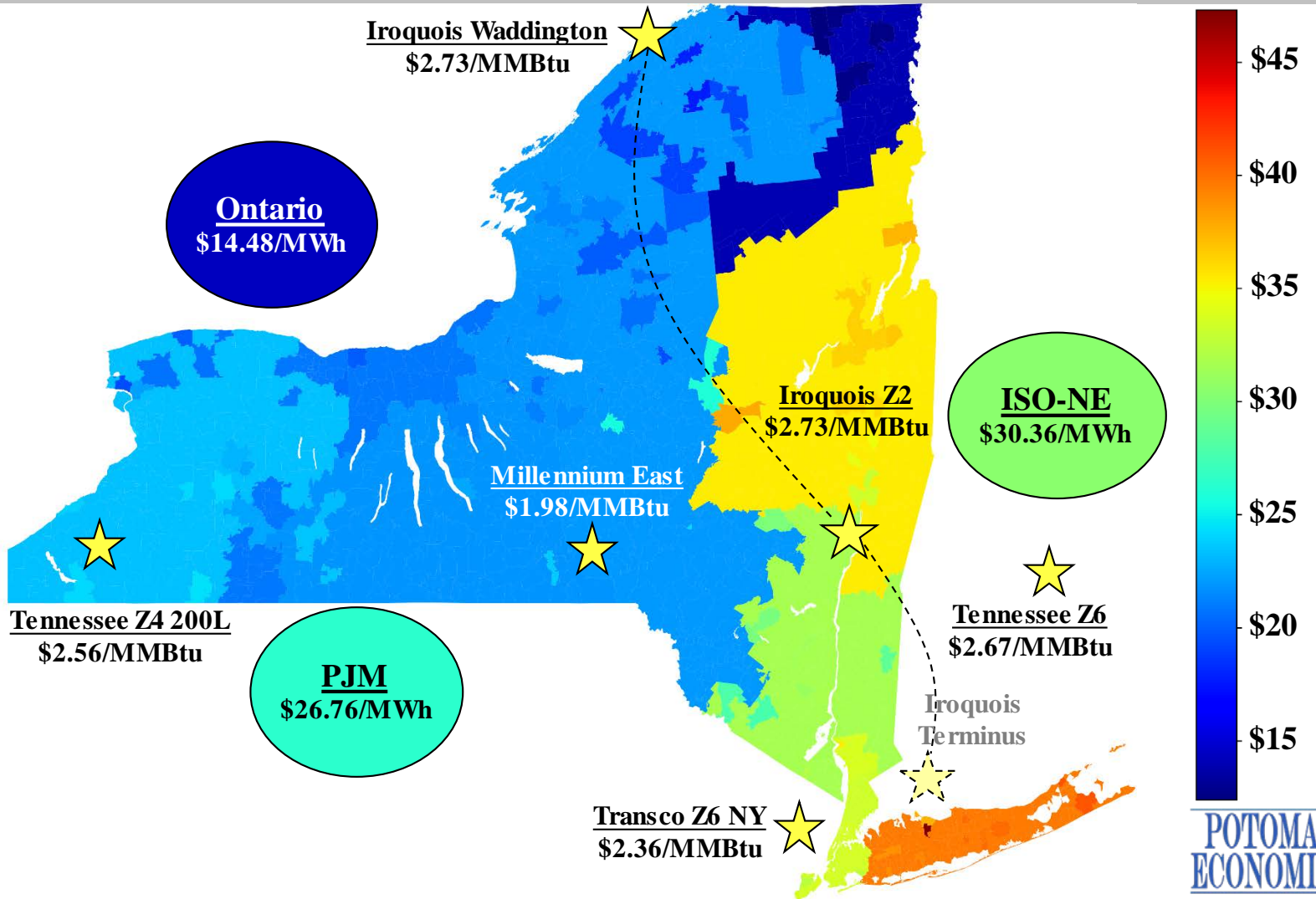


Market Highlights: Executive Summary

- The NYISO began modeling two 69 kV constraints on Long Island in the market software in mid-April. (slide [10](#))
 - ✓ The two constraints accounted for roughly 40 percent of day-ahead congestion and 25 percent real-time congestion on Long Island.
 - ✓ Consequently, OOM actions to manage 69 kV constraints fell notably, resulting in more efficient resource scheduling and pricing and lower BPCG uplift. (slide [12](#))
 - The NYISO has an on-going process to evaluate and incorporate additional 69 kV constraints into the market models.
 - ✓ However, OOM actions to manage the TVR needs on the East End of Long Island were still frequent on high load days, depressing prices and generating uplift in that area.



Market Highlights: System Price Diagram





Market Highlights: Summary of Energy Market Outcomes

- NYISO energy markets performed competitively in the second quarter of 2021.
 - ✓ The amount of output gap (slide [71](#)) and unoffered economic capacity (slide [72](#)) remained modest and reasonably consistent with competitive market expectations.
- All-in prices ranged from \$21/MWh in the North Zone to \$67/MWh in Long Island, rising 28 to 88 percent from last year except for NYC where all-in prices fell by 6 percent. (slide [20](#))
 - ✓ Energy prices rose substantially in all zones, up by 26 to 51 percent in the Upstate regions and 91 to 110 percent in Eastern NY. (slides [25-31](#))
 - This was driven primarily by higher natural gas prices, which rose 55 to 62 percent across the system from a year ago (slide [22](#)). Other contributing factors include:
 - Higher load levels - average load rose 5 percent and peak load rose 15 percent from a year ago, due to the partial demand recovery from the COVID-19 pandemic and higher temperatures in June. (slide [21](#))
 - Lower nuclear and hydro generation – the combined average output fell by roughly 1 GW because of the nuclear retirement and drier conditions. (slide [23](#))
 - Lengthy major transmission outages on the Central-East interface, leading to further elevated prices in Eastern NY. (slide [53](#))
 - ✓ Capacity costs rose in all areas but NYC for the reasons discussed in slide [18](#).



Market Highlights: Generation by Fuel and Emission

- Average nuclear and hydro generation fell by roughly 700 MW and 300 MW, respectively, from a year ago, because of the retirement of the last Indian Point nuclear unit at the end of April and drier weather conditions.
- Consequently, gas-fired generation rose by about 8 percent despite higher natural gas prices. (slides [22-23](#))
 - ✓ Gas-fired combined cycle output increased by 780 MW on average and gas-fired steam turbine generation rose by 320 MW on average.
 - Most of the increase in ST outputs 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.
 - Although these led to increased emissions from 2020-Q2 (slides [26-29](#)), the emission levels have been at historical low levels. (slide [25](#))
- Steam turbines accounted for more than 50 percent of NO_x emission in New York City in the second quarter of 2021.
 - ✓ Roughly one third of ST NO_x emission was from STs that were supplementally committed for local reliability. (slide [28](#))



Market Highlights: Congestion Patterns, Revenues and Shortfalls

- Day-ahead congestion revenues totaled \$98 million, up 57 percent from the second quarter of 2020. (slide [51](#))
- The Central-East interface accounted for the largest share (\$62 million or 64 percent) of day-ahead congestion revenues in the second quarter of 2021. (slide [52](#))
 - ✓ This was noticeably higher than seen in the recent second quarters, either in total congestion values or as a percentage of the total quarterly congestion.
 - ✓ Lengthy transmission outages were a primary driver.
 - Multiple line outages reduced the interface capability by nearly 1500 MW in April and most of May, contributing to \$32 million of day-ahead congestion shortfalls in the quarter. (slide [53](#))
 - ✓ Lower nuclear generation in East NY, as a result of Indian Point 3 retirement, was another key driver. (slide [23](#)).
- North zone accounted for \$12 million (or 12 percent) of day-ahead congestion.
 - ✓ Nearly 90 percent of this congestion occurred on the Moses-Adirondack 230 kV line when the parallel line was OOS throughout the quarter. (slide [53](#))
 - ✓ These outages have been primarily related to the Moses-Adirondack Smart Path Reliability Project.



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

- LI accounted for \$12 million of DA congestion, up from \$6 million in 2020-Q2.
 - ✓ Congestion along 345 kV and 138 kV paths into Long Island totaled a little more than half of the congestion this quarter, driven in part by lengthy transmission outages along these paths. (slide [52](#))
 - The Neptune line was operated at slightly more than half of its full capacity during the quarter, also contributing to higher congestion into Long Island. (slide [46](#))
 - ✓ The NYISO began modeling two 69 kV Long Island constraints in the market software in mid-April.
 - The two constraints accounted for \$5 million of day-ahead congestion revenues.
 - Although this modeling change has led to higher priced congestion, it provides more efficient price signals and has helped reduce OOM actions (slide [57](#)) and associated BPCG uplift (slide [69](#)).
- Congestion in the areas from Capital to Hudson Valley and from Hudson Valley to Dunwoodie rose noticeably on several days in real time.
 - ✓ TSA events were a key driver, which occurred on 7 days and led to elevated congestion levels in SENY, mostly on the Chestror-Shoemaker 138 kV line and the Buchanan 345/138 transformer.
 - ✓ Congestion on the Cricket Valley-Pleasant Valley 345 kV line rose on several days due to combined effects of transmission outages and high Cricket Valley generation and NE imports.



Market Highlights: Regulation Market Costs and Performance

- Regulation capacity prices fell modestly despite higher energy prices in the second quarter of 2021. (slide [41](#))
 - ✓ Monthly 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 using a Regulation Movement Multiplier (“RMM”) of 13. This is based on an assumption of 13 MW of Regulation Movement for every 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 Long Island (18 days) and the Capital Zone (13 days) in this quarter. (slide [56](#))
- The frequency of OOM actions on Long Island fell sharply from the second quarter of 2020 (34 days) despite higher load levels this quarter. (slide [57](#)).
 - ✓ Two 69 kV constraints were secured in the market models beginning in mid-April 2021, allowing resources that were frequently OOMed to manage these constraints to be scheduled economically.
 - The NYISO has an on-going process to evaluate and incorporate additional 69 kV constraints into the market models.
 - ✓ Consequently, the estimated LBMP impact of unmodeled local constraints on Long Island fell to less than \$1 per MWh in most load pockets except the East End load pocket, where OOM actions are frequently used for TVR needs.
- OOM actions rose modestly in the Capital Zone to manage congestion on the Albany-Greenbush 115 kV line on days when the parallel facility was OOS.




Market Highlights: Reliability Commitments, OOM Dispatch, and BPCG

- BPCG payments totaled \$8.7 million, down 10 percent from 2020-Q2 despite higher natural gas prices and higher load levels this quarter, driven largely by:
 - ✓ Fewer reliability commitments in New York City; (slide [64](#)) and
 - ✓ Less frequent OOM actions on Long Island. (slide [66](#))
- \$5.3 million (or 61 percent) of BPCG payments accrued in NYC, 87 percent of which were paid to units that were committed for local reliability. (slide [69](#))
 - ✓ Although NYC reliability commitments still accounted for 83 percent of all reliability commitments this quarter, they fell 33 percent from a year ago.
 - The NYISO and ConEd have implemented several procedural changes to reduce N-1-1-0 reliability commitment in NYC load pockets in recent years. For example,
 - Since January 2021, NYC load pocket requirements assume the use of 300-hour ratings rather than normal transfer limits after the second contingency.
 - Units that were often flagged for local reliability were committed economically more frequently this quarter, attributable to improved economics because of nuclear retirement and higher Central-East congestion.
- RT BPCG uplift rose on high-load days at the end of June when OOM actions were taken to satisfy reliability needs at both system and local levels. (slide [68](#))



Market Highlights: Performance and Availability of Duct Burners

- Most combined cycle generators in the NYISO footprint offer supplemental output from their duct burners, totaling roughly 760 MW of summer capacity.
 - ✓ This capacity often presents difficulties in real-time due to disconnects between market design and the physical limitation of duct burners.
- Slide [59](#) shows an example of a combined-cycle unit that could not follow dispatch instructions during a Reserve Pickup (RPU) event, due largely to its inability to fire the duct burner within the 10-minute timeframe.
 - ✓ However, this duct burner capacity is considered capable of following 5-minute dispatch signals in the market scheduling and pricing software.
 - ✓ This disconnect presents challenges in real-time operations when the duct-firing capacity becomes more valuable under tight system conditions like an RPU event.
- Slide [60](#) shows duct-firing capacity that was offered but not physically capable of providing a given service in the required timeframe. Specifically, during afternoon hours, on average: (a) 145 MW was offered but not capable of following 5-minute ramping instructions; (b) 70 MW was scheduled for but not capable of providing 10-minute reserves; and (c) 25 MW was scheduled for but not capable of providing regulation. In addition, 40 MW of duct-firing capacity was unavailable because of no offer in this range or non-dispatchable due to inflexible self-schedule level.



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 July 2020 to June 2021: (slides [61](#)-[62](#))
 - ✓ 288 audits (of 135 unique GTs) were conducted, much higher than in prior years.
 - ✓ Some GTs performed better when audited than when started economically by RTC, RTD, and RTD-CAM. For example, seven 10-minute GTs and two 30-minute 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.
 - ✓ 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.



Market Highlights: Excess NO_x-Rule LRR Commitments in NYC

- The NO_x rule prevents NYC GTs in two portfolios from generating during the Ozone season unless steam turbines in the same portfolios are also producing such that the portfolio-average NO_x emission satisfies the DEC standard.
 - ✓ A steam turbine was LRR-committed solely to satisfy the NO_x rule on many days during the Ozone season.
 - This occurred on 36 days in the second quarter of 2021, 29 of which were assessed for necessity of the ST commitment. (slide [67](#))
 - ✓ Our evaluation shows that even if the committed steam turbine and the associated GTs were unavailable, all N-1-1-0 criteria in the associated load pockets could have been satisfied by other resources on each of the 29 days.
 - The supply margin (excluding the committed steam turbine and associated GTs) generally exceeded 300 MW each day. (slide [67](#))
 - This suggests that these NO_x-only steam turbine commitments could have been avoided if the market software considered whether the GTs were actually needed for reliability (before committing the associated steam turbine).
 - The GTs would not be available in real time absent a NO_x-only ST commitment.
 - ✓ These avoidable NO_x-only commitments reduce market efficiency by depressing prices and generating uplift and excess production costs.



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-Q2, 60 percent of the RT congestion in NYC occurred on N-1 constraints that would have been loaded above LTE after a single contingency. (slide [58](#))
 - ✓ The additional capability above LTE averaged from about 10 to 65 MW for the 138 kV constraints in the Greenwood load pocket to roughly 230 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

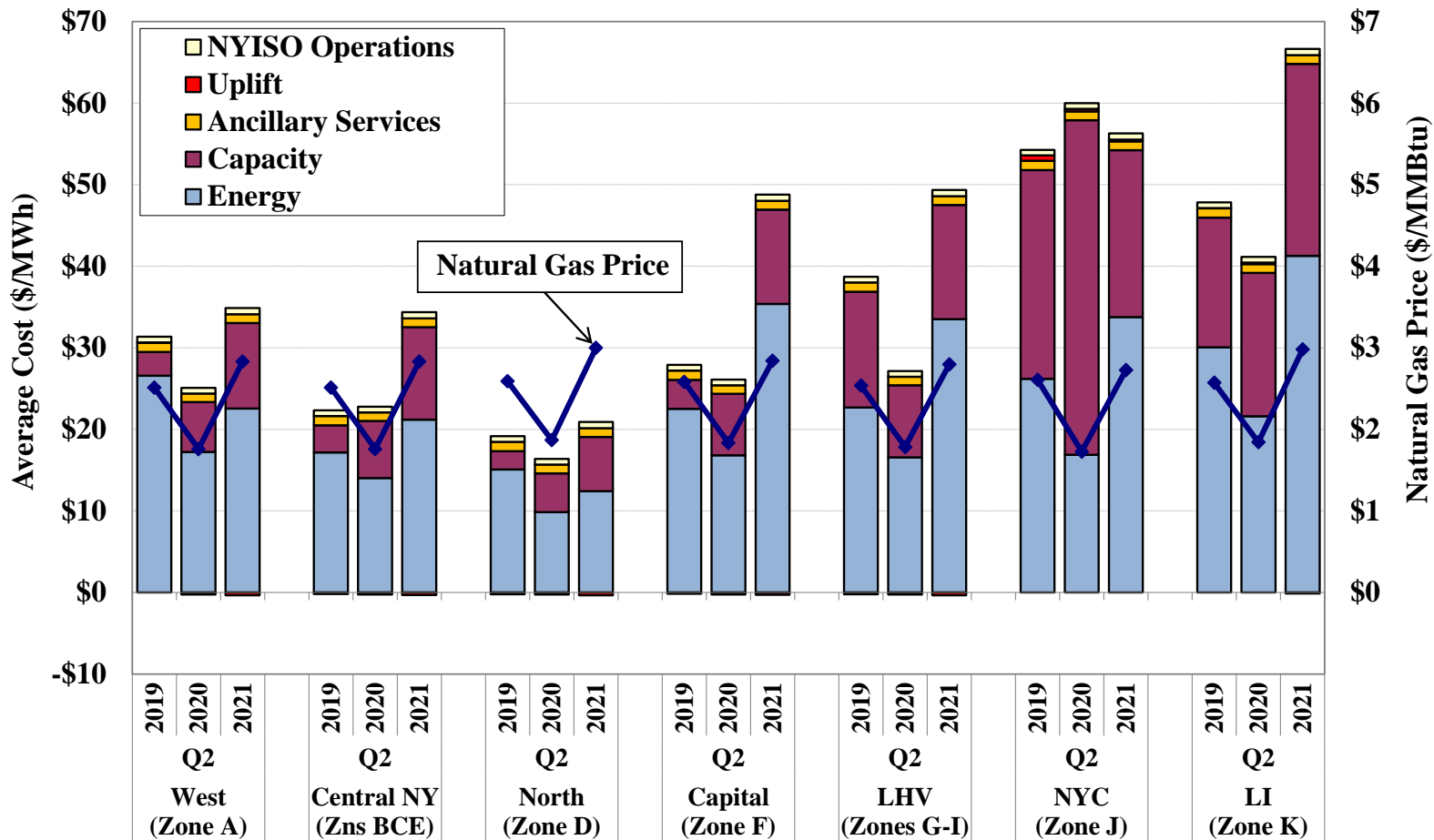
- Spot capacity prices averaged \$6.59/kW-month in LI, \$3.85/kW-month in the G-J Locality and ROS, and \$6.37/kW-month in NYC this quarter. (slides [75-76](#))
 - ✓ Prices increased substantially in all regions from the prior year except in NYC where prices fell by more than half (54 percent).
- The NYC spot price fell 54 percent, driven primarily by a 6.3 percent reduction in the LCR from the prior Capability Year (“CY”).
 - ✓ The steep reduction in the LCR year-over-year despite no significant changes in the supply mix in-city highlights some procedural inefficiencies in the IRM and LCR-setting process discussed in our 2020 SOM Report.
- The UCAP requirements in the G-J Locality and in NYC were not binding in May and June, leading spot prices in both regions to clear at the same level as in ROS in the two months.
- The ROS prices rose by 75 percent from the prior year, due partly to an increase of 1.8 percent in the IRM. In addition,
 - ✓ The spot price in April was influenced by higher spot market offers and resultant unsold capacity.
 - ✓ A few units exited the market, most notably Indian Point 3 in May, which outweighed new entry and increased imports.



Charts: Market Outcomes

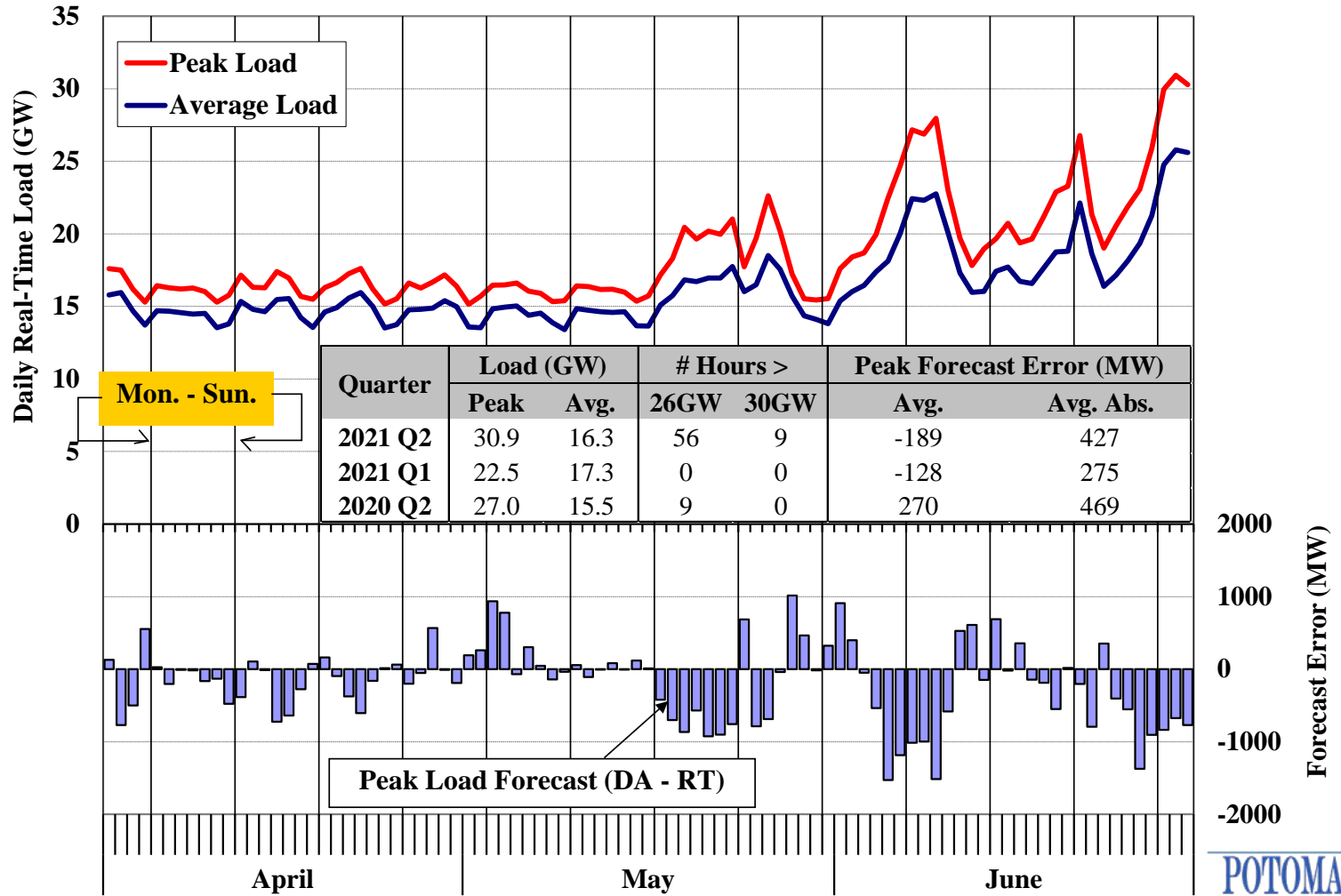


All-In Prices by Region



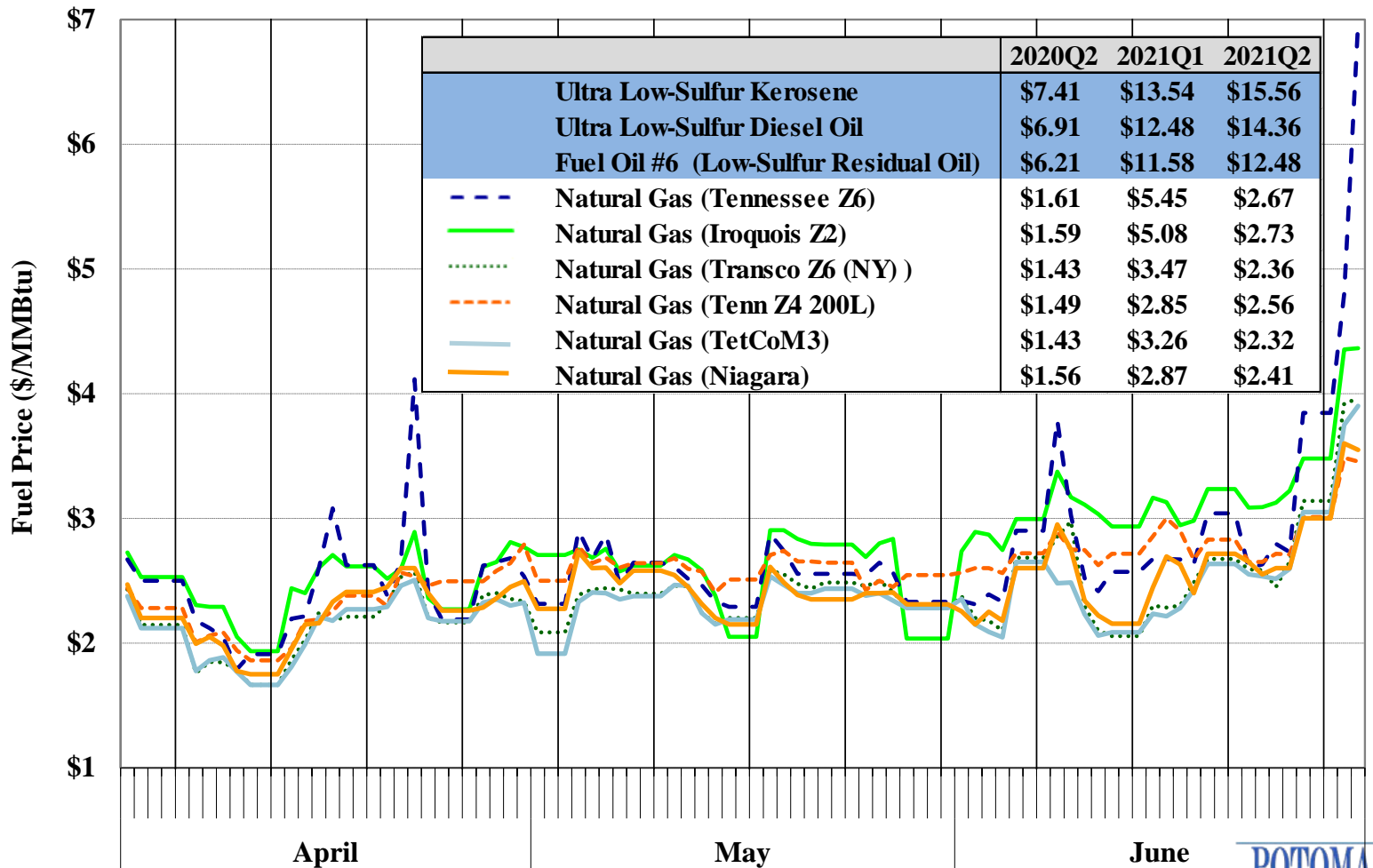


Load Forecast and Actual Load

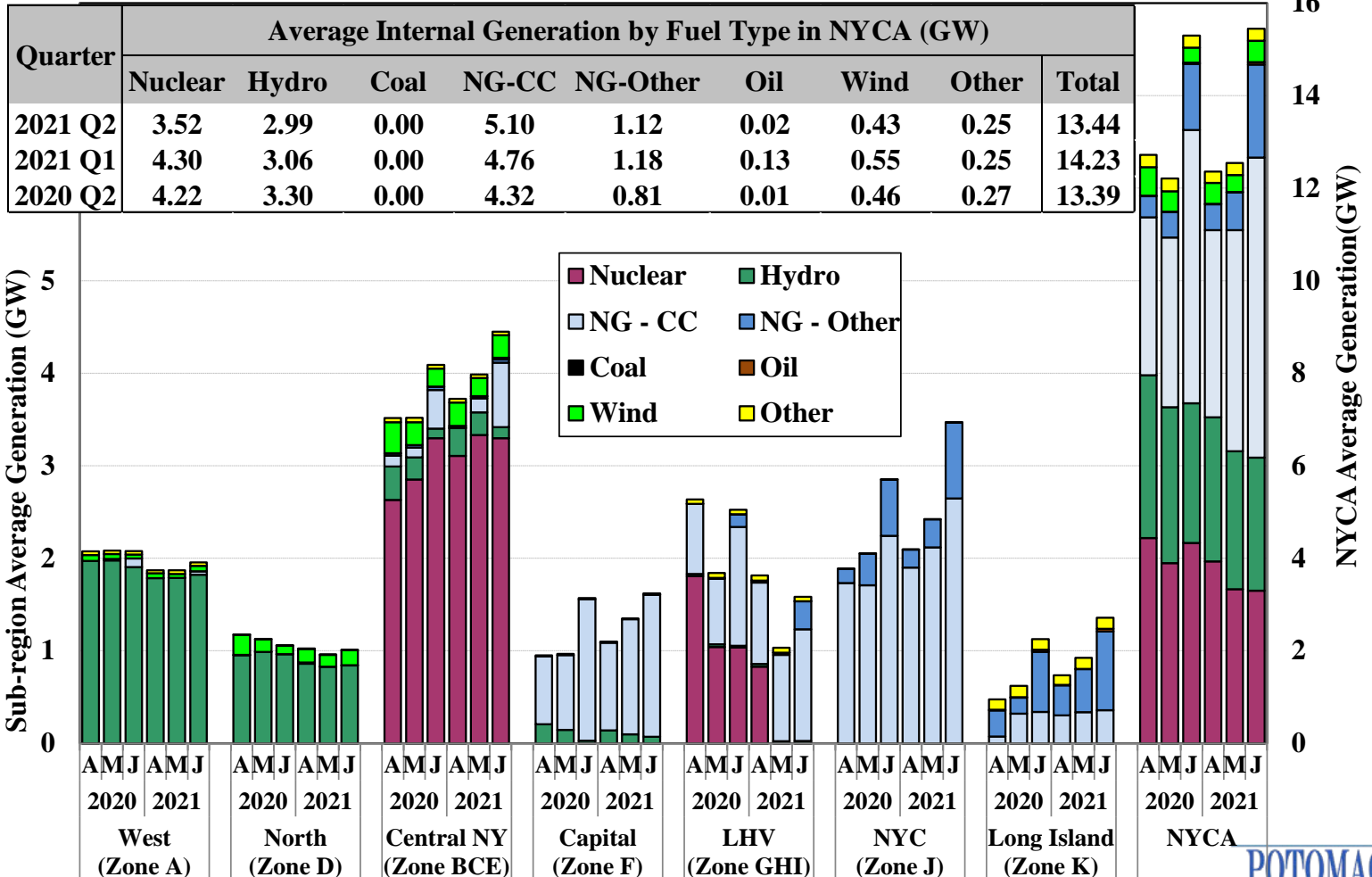




Natural Gas and Fuel Oil Prices

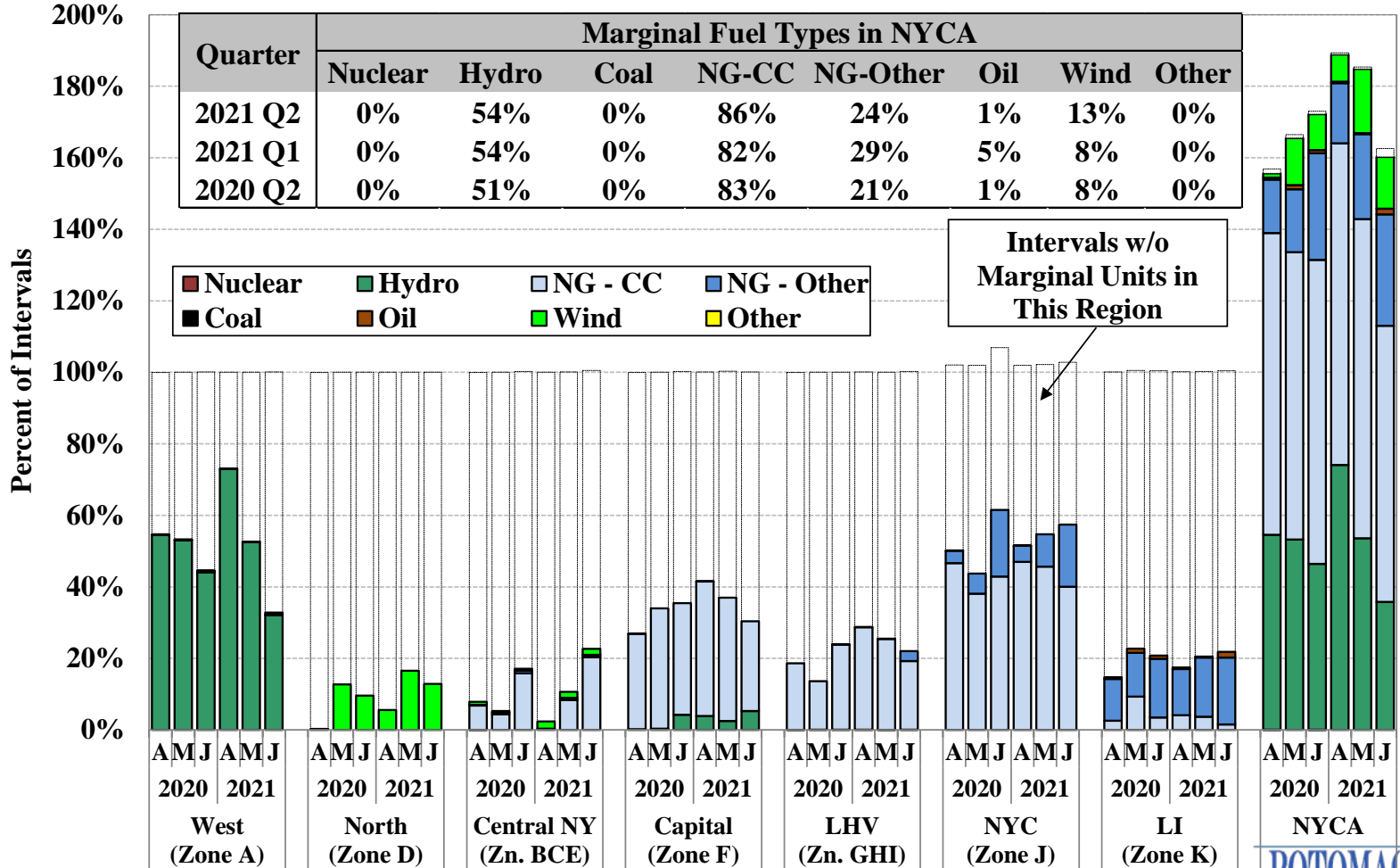


Real-Time Generation Output by Fuel Type





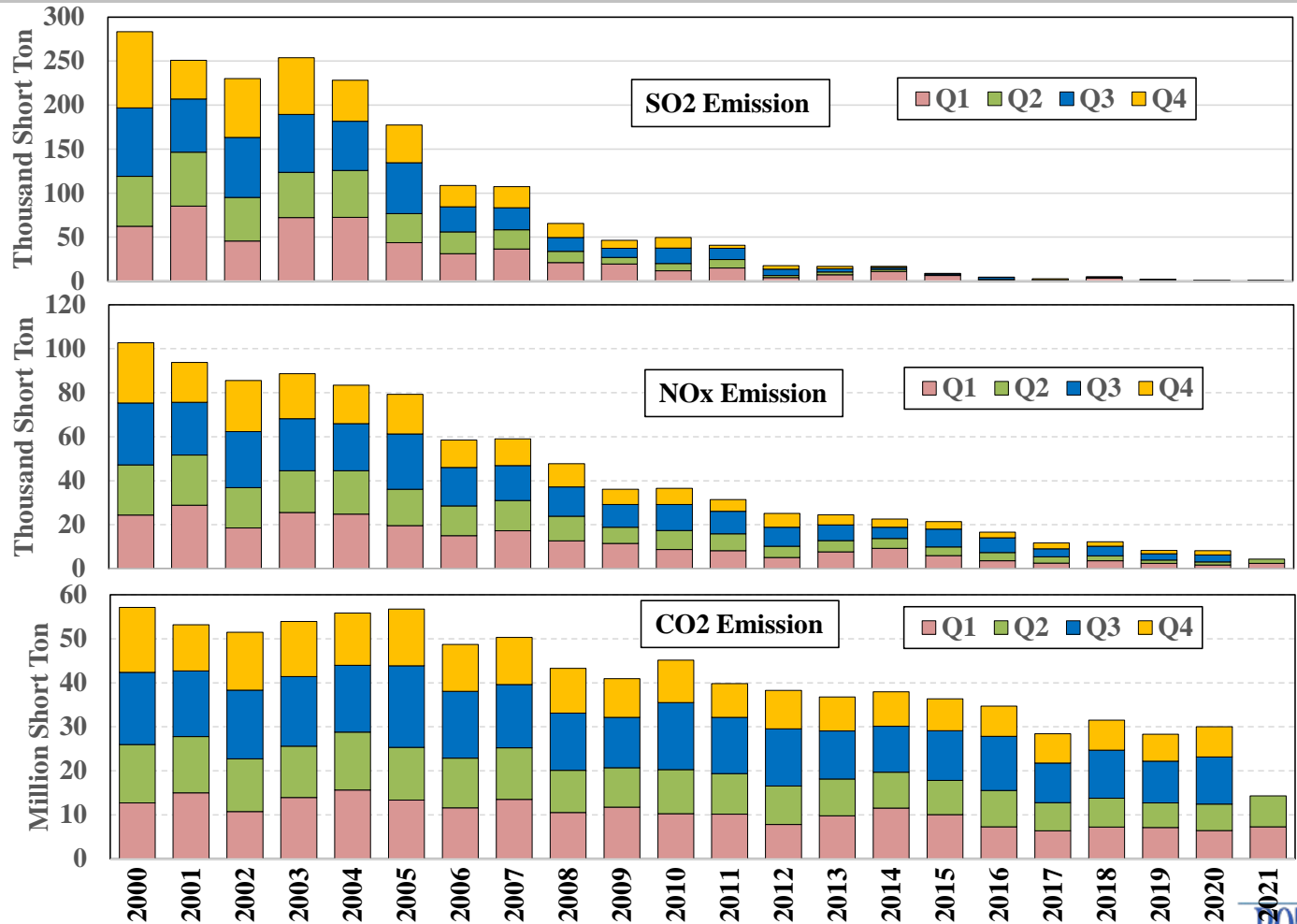
Fuel Type of Marginal Units in the Real-Time Market





Historical Emissions by Quarter in NYCA

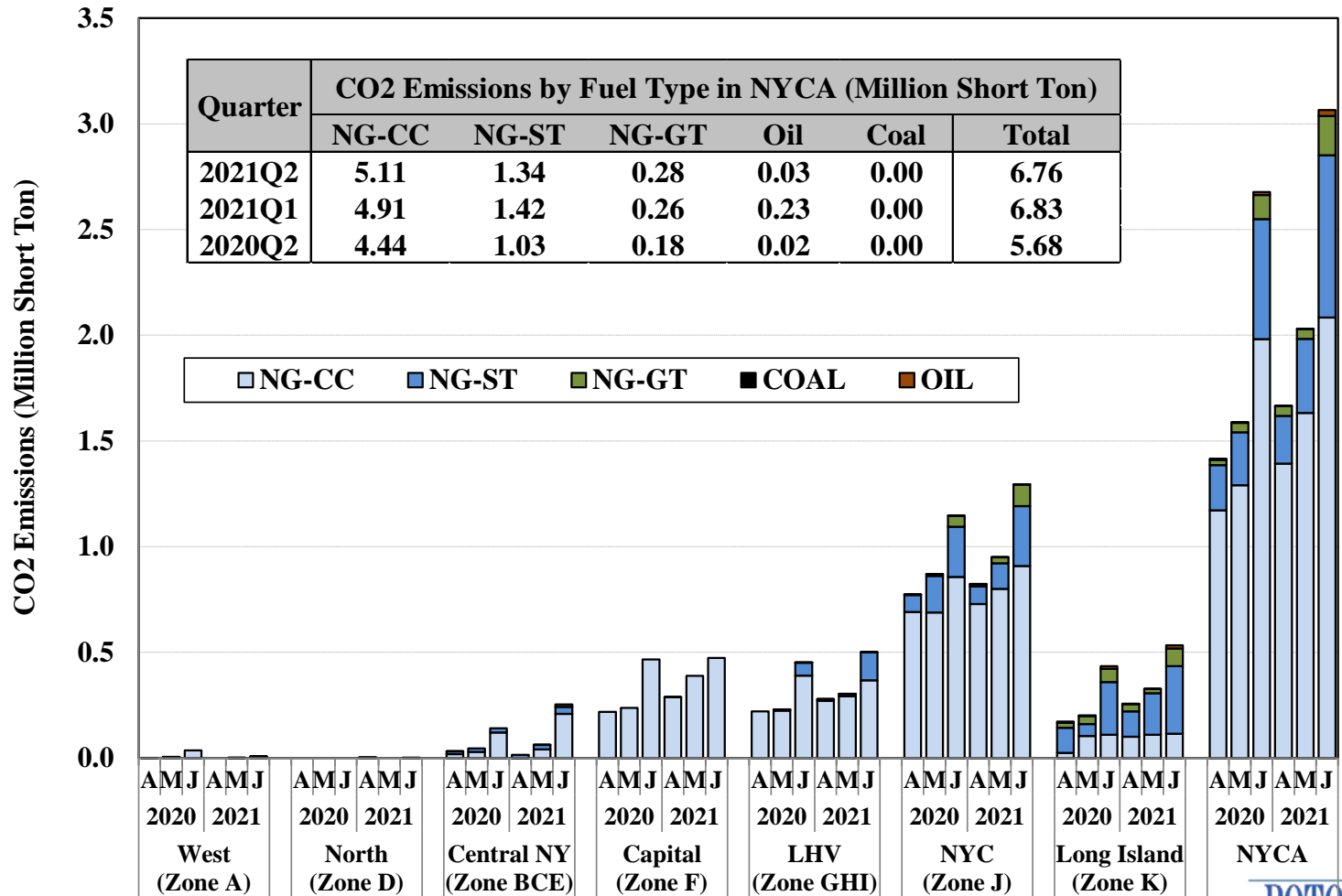
CO₂, SO₂, and NO_x





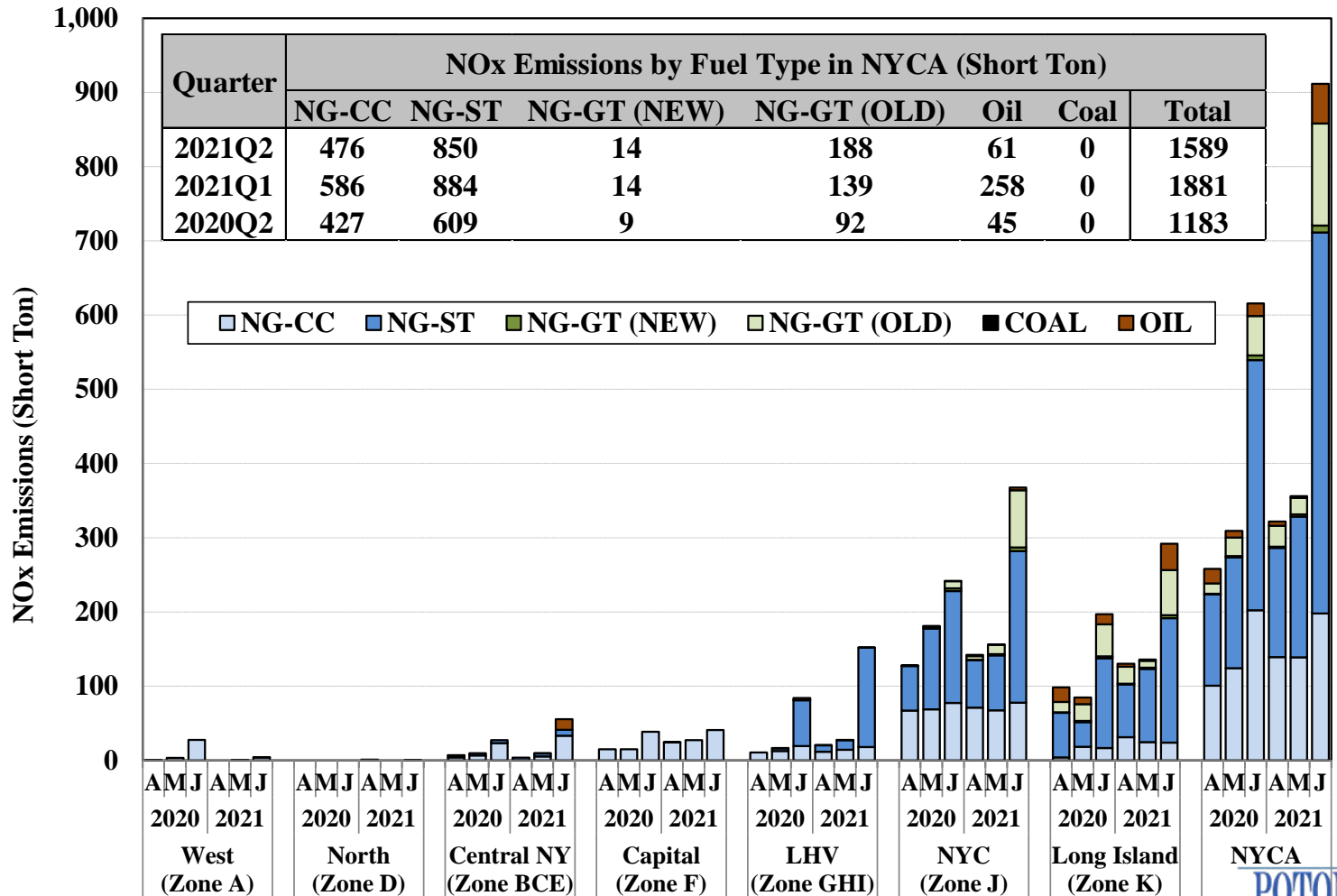
Emissions by Region by Fuel Type

CO₂ Emissions

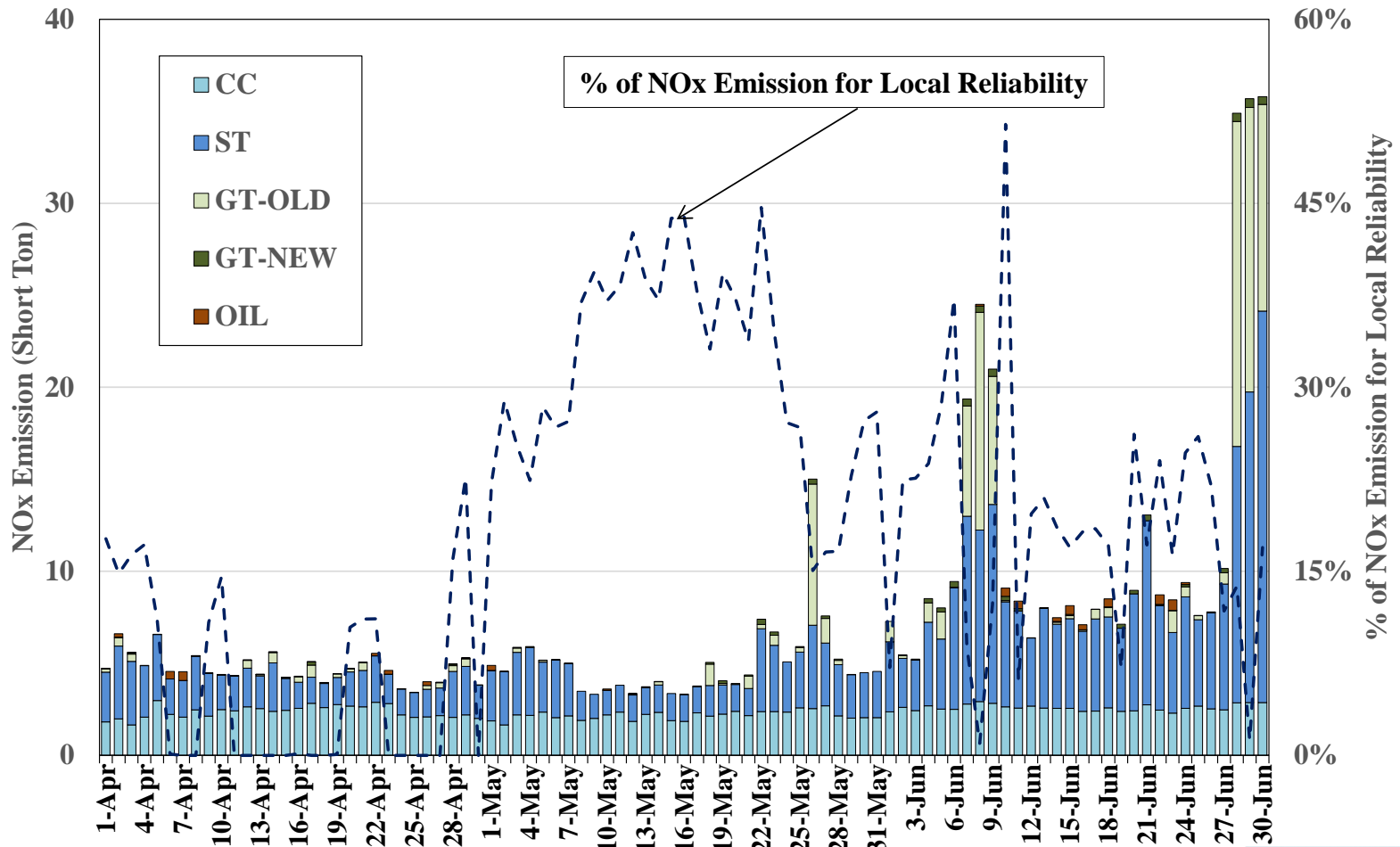


Emissions by Region by Fuel Type

NO_x Emissions

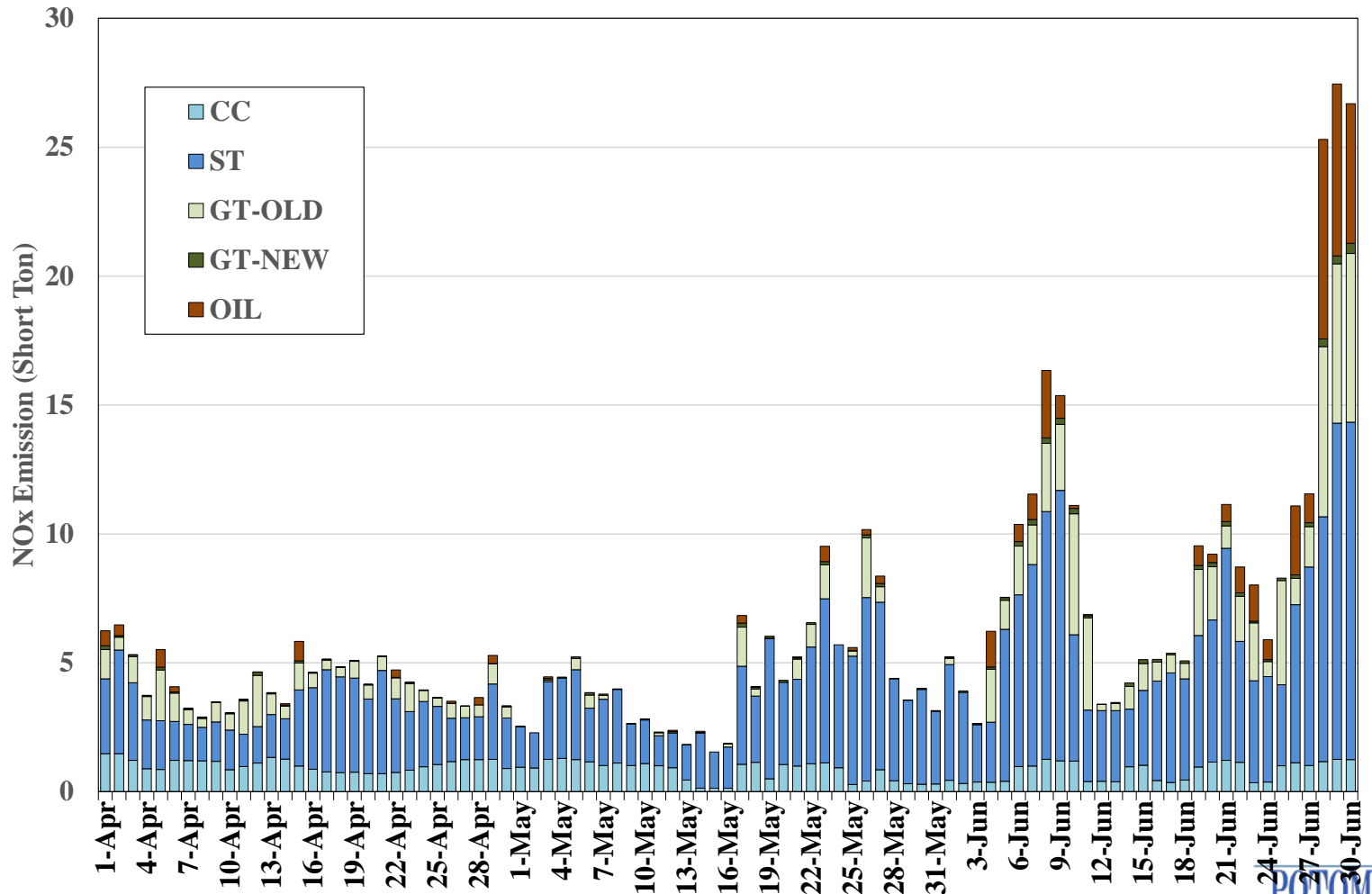


Daily NO_x Emissions in NYC



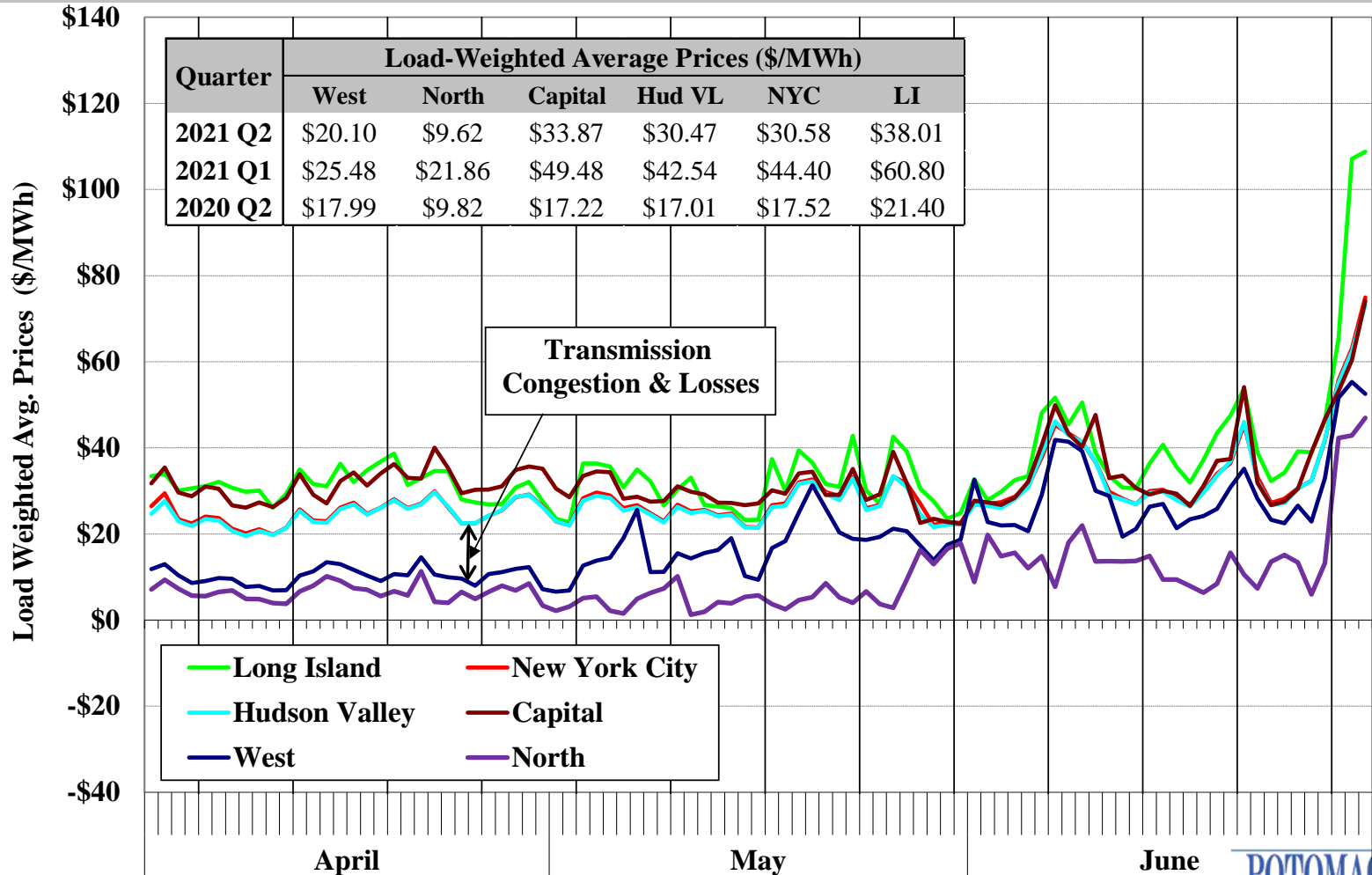


Daily NO_x Emissions in Long Island

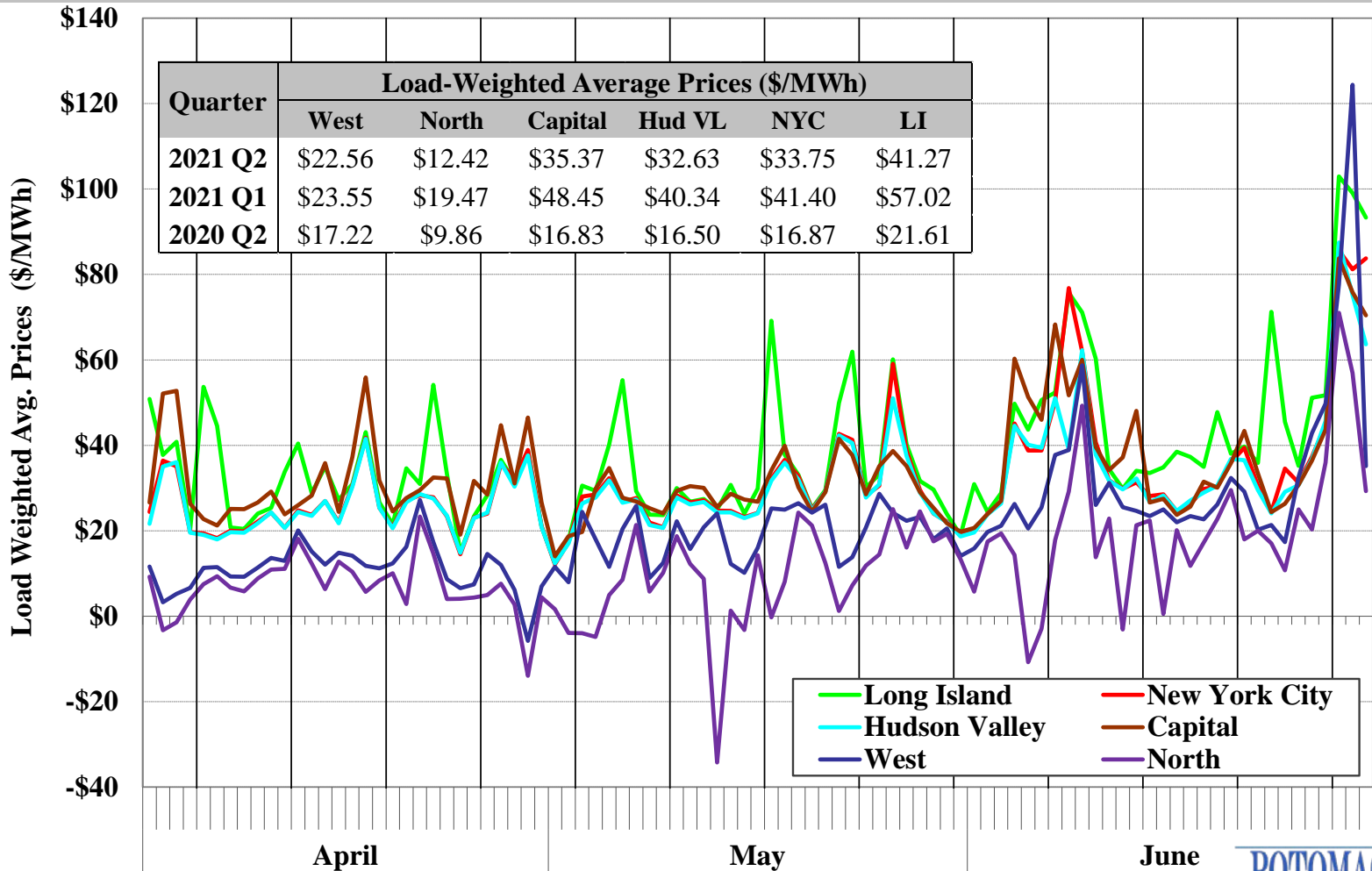




Day-Ahead Electricity Prices by Zone

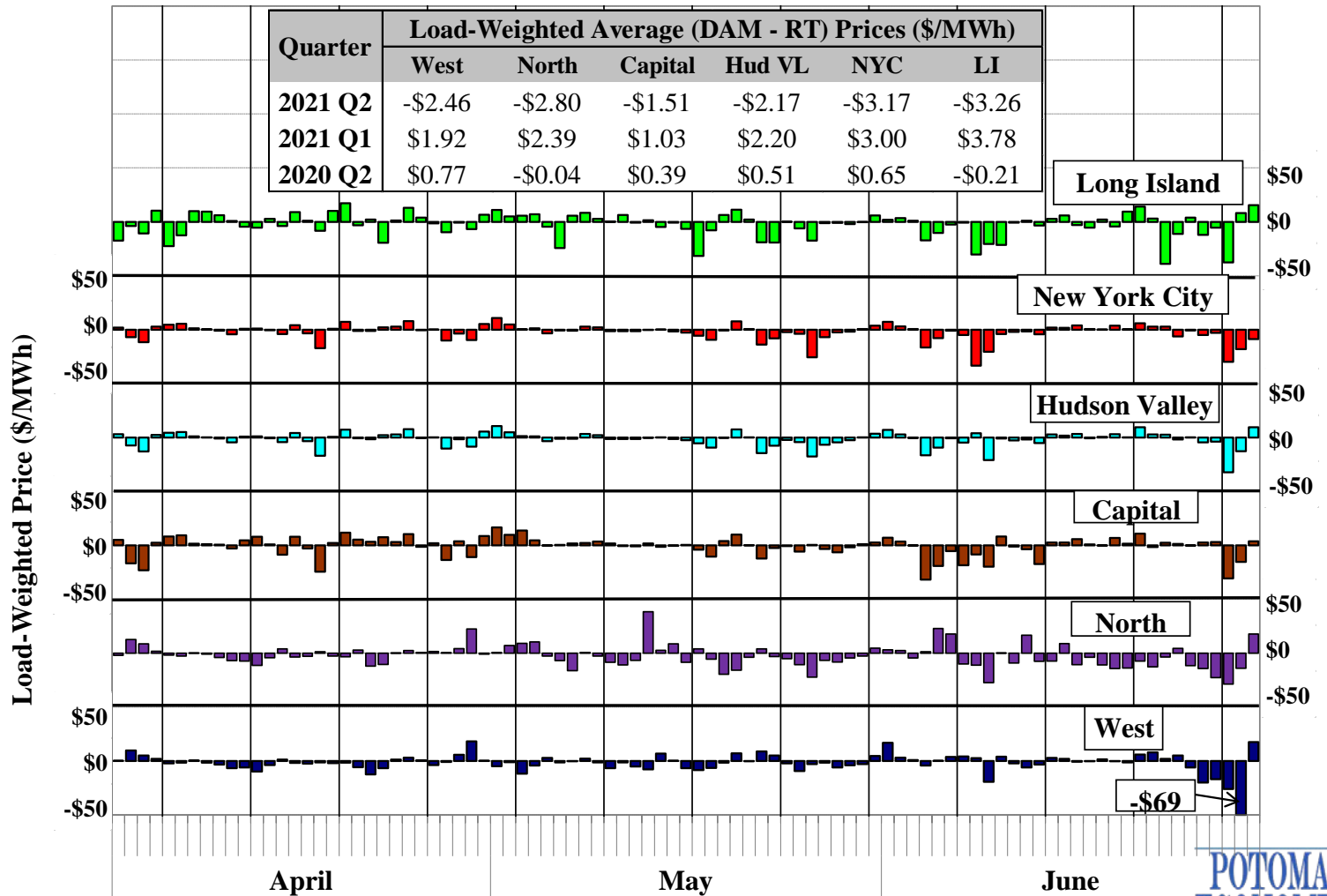


Real-Time Electricity Prices by Zone





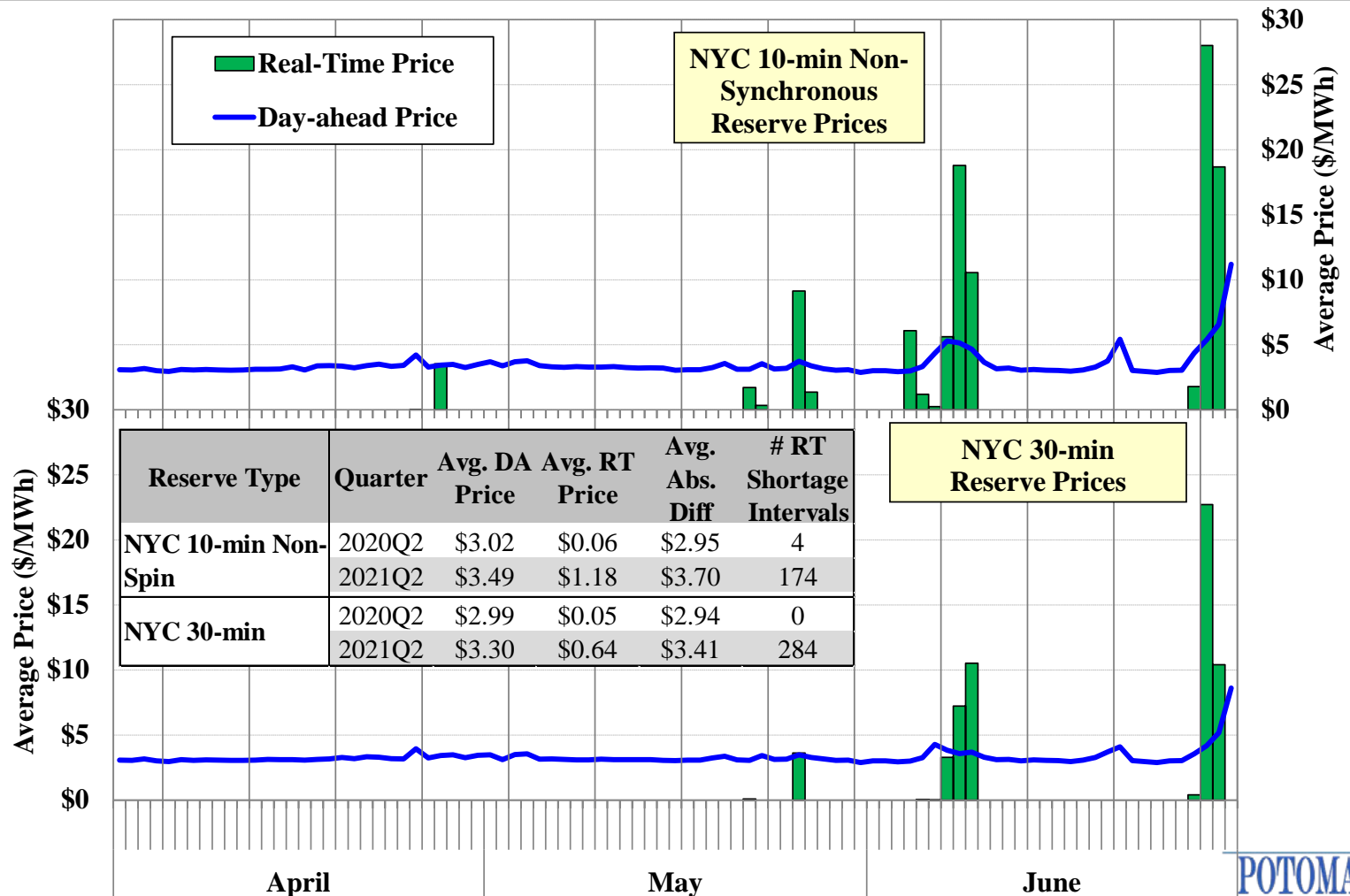
Convergence Between Day-Ahead and Real-Time Prices



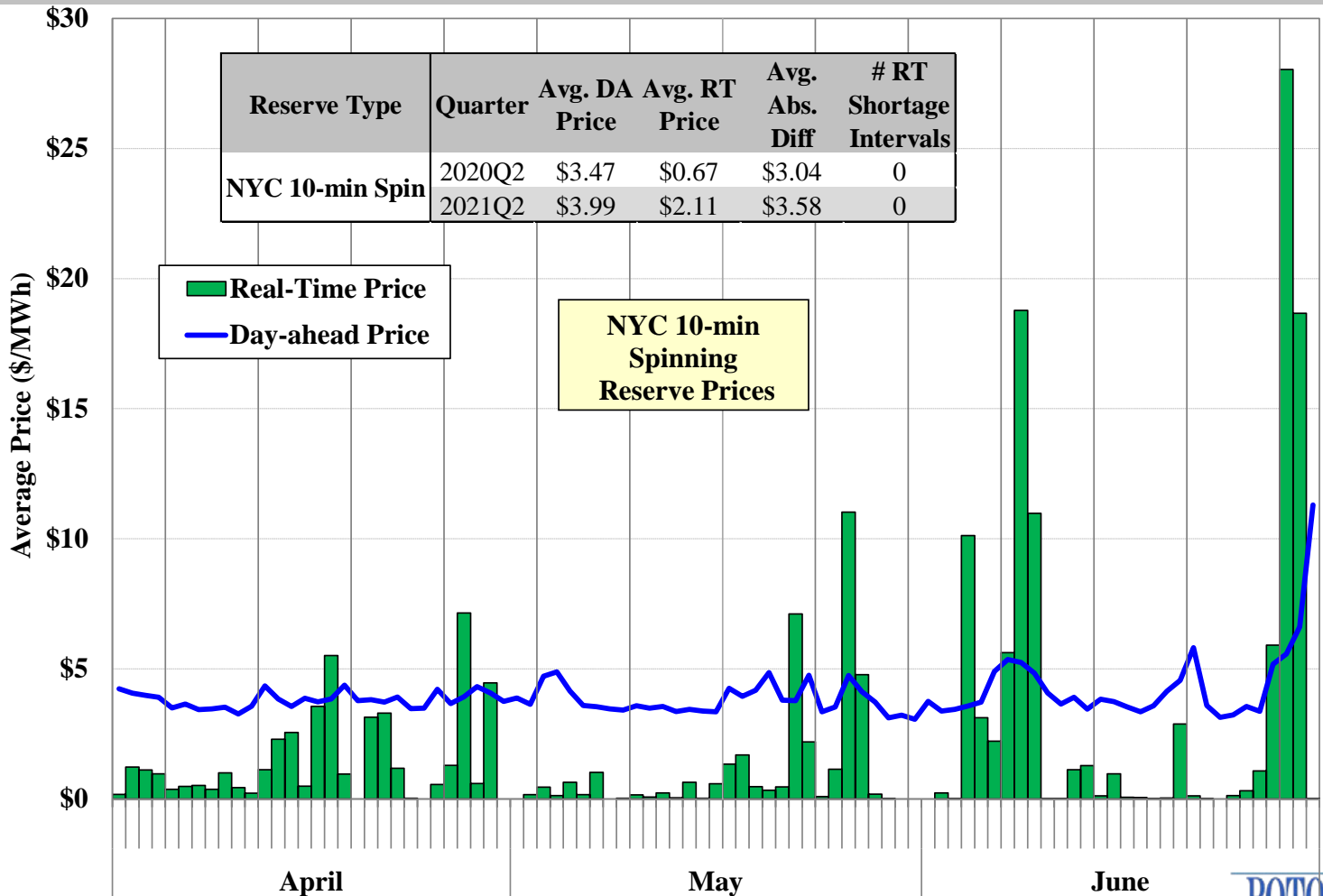


Charts: Ancillary Services Market

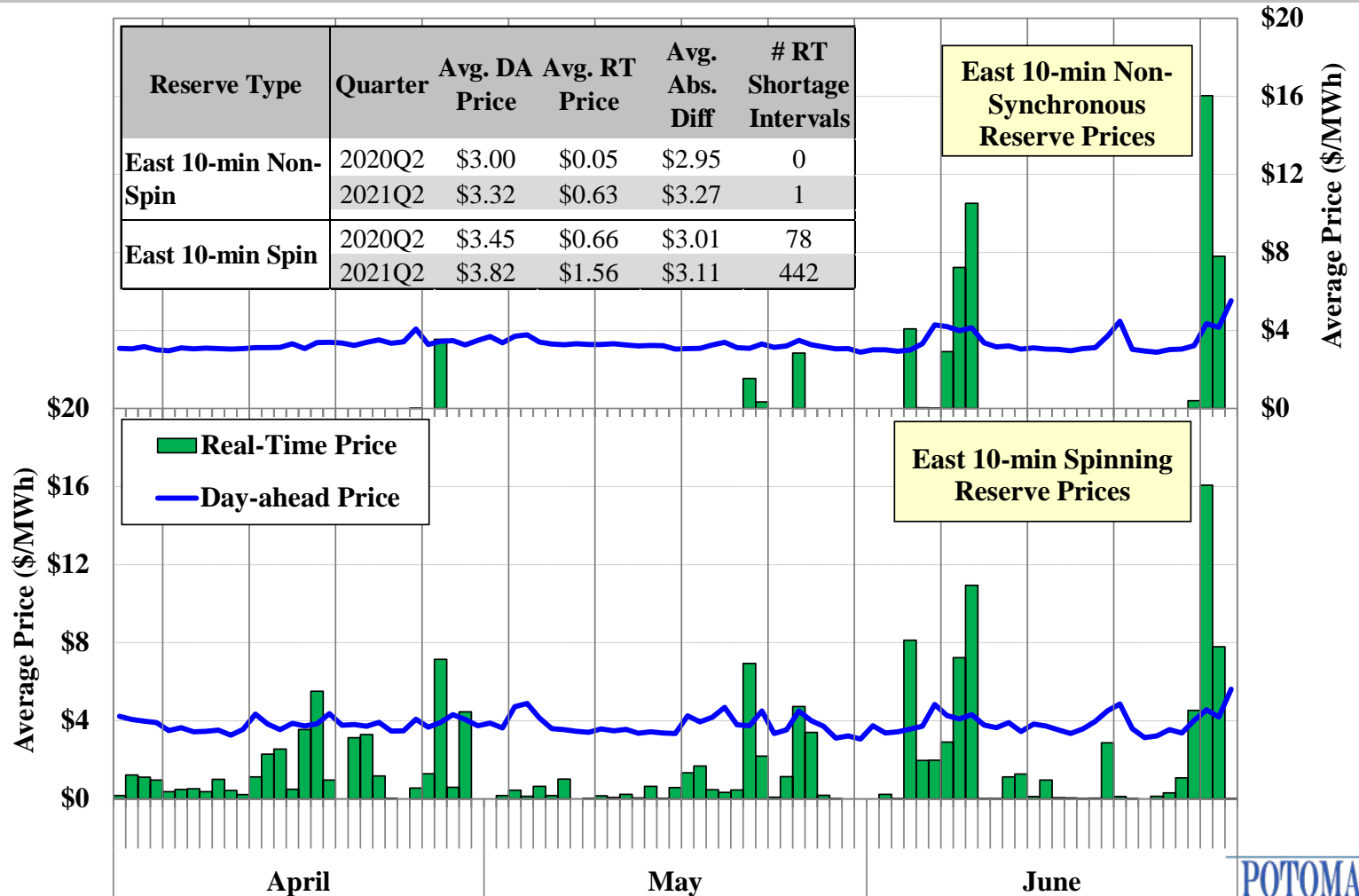
Day-Ahead and Real-Time Ancillary Services Prices NYC 10-Minute Non-Spinning and 30-Minute Reserves



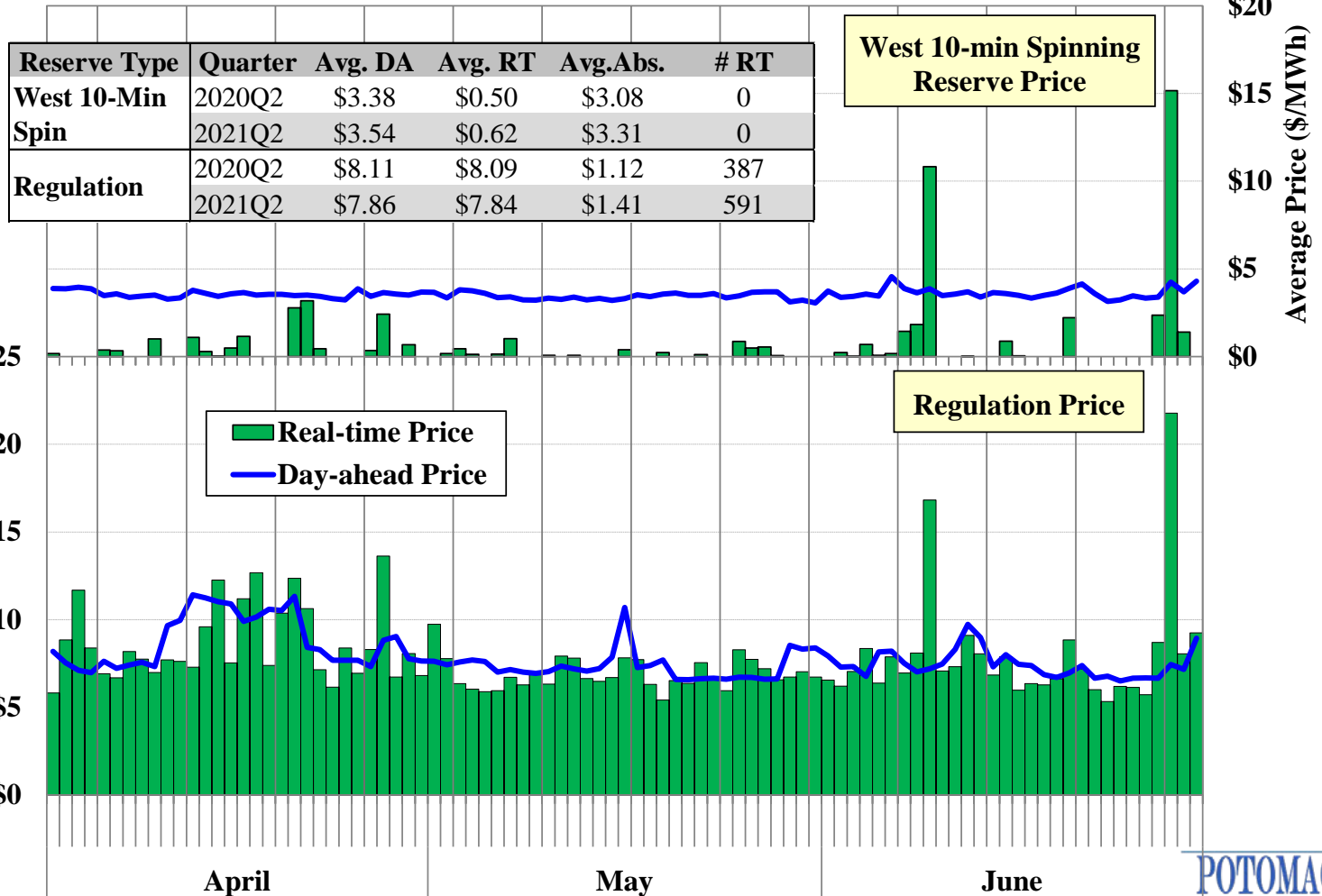
Day-Ahead and Real-Time Ancillary Services Prices NYC 10-Minute Spinning Reserves



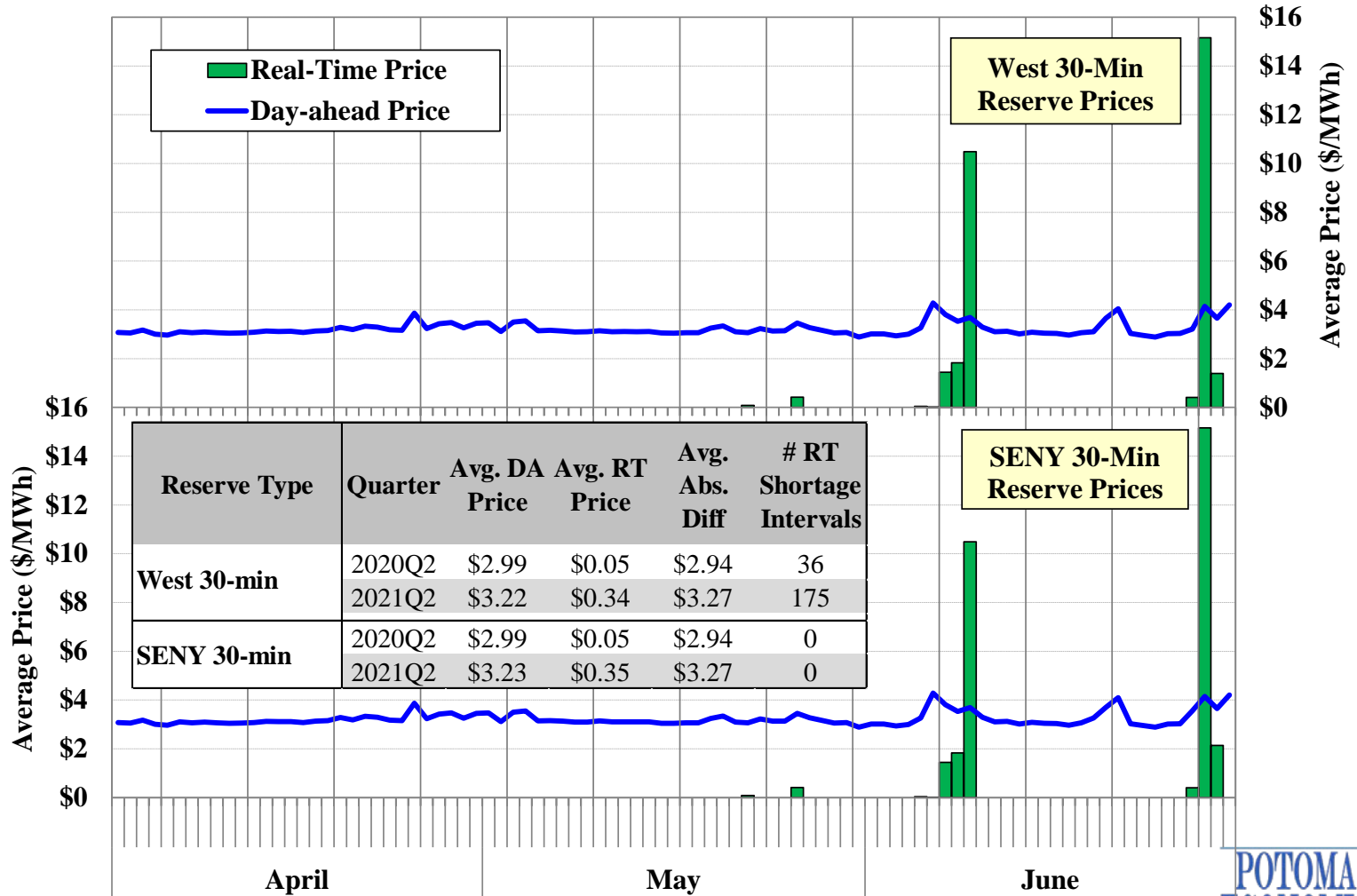
Day-Ahead and Real-Time Ancillary Services Prices Eastern 10-Minute Spinning and Non-Spinning Reserves



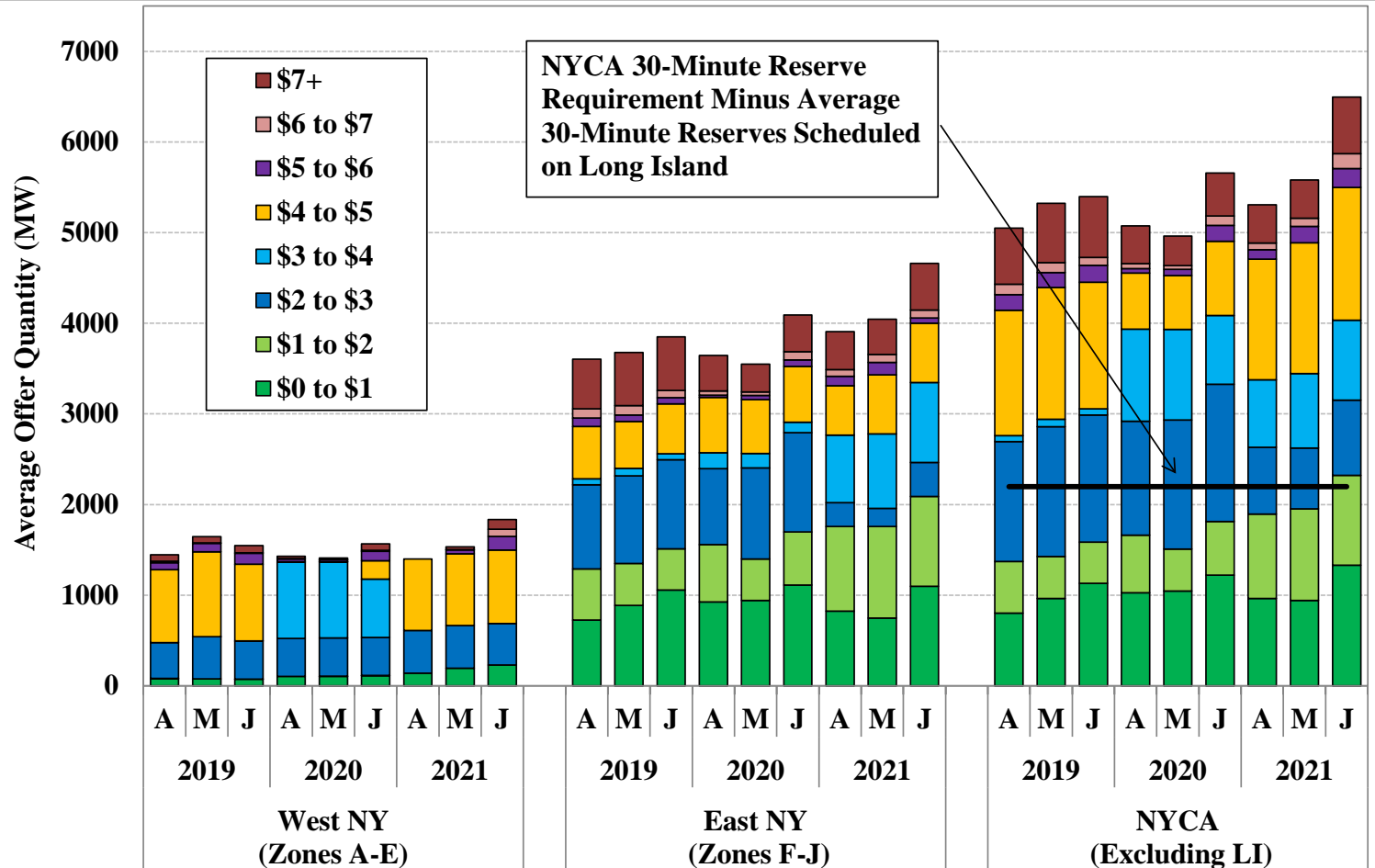
Day-Ahead and Real-Time Ancillary Services Prices Western 10-Minute Spinning Reserves and Regulation



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



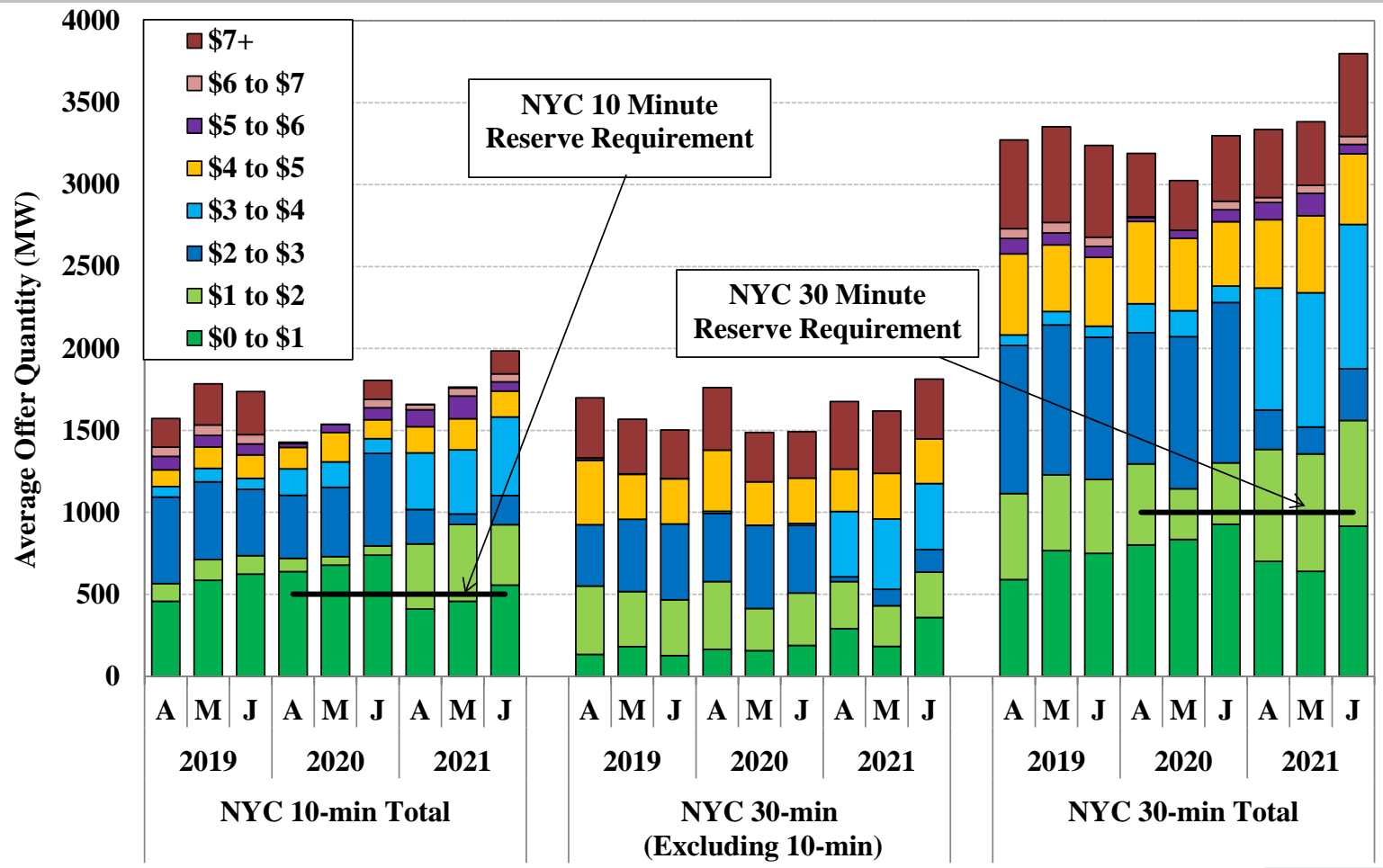
Day-Ahead NYCA 30-Minute Reserve Offers Committed and Available Offline Quick-Start Resources





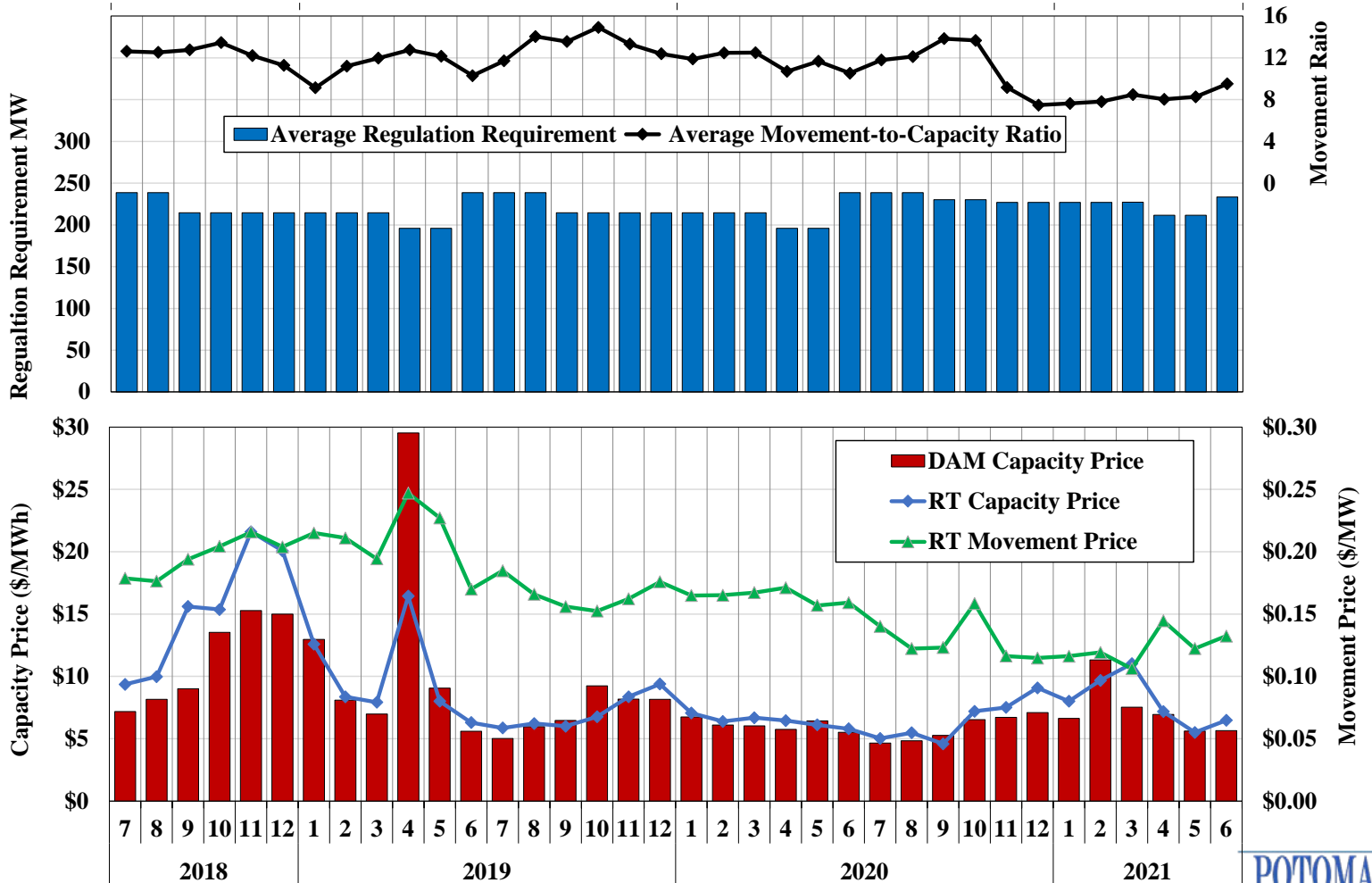
Day-Ahead NYC Reserve Offers

Committed and Available Offline Quick-Start Resources





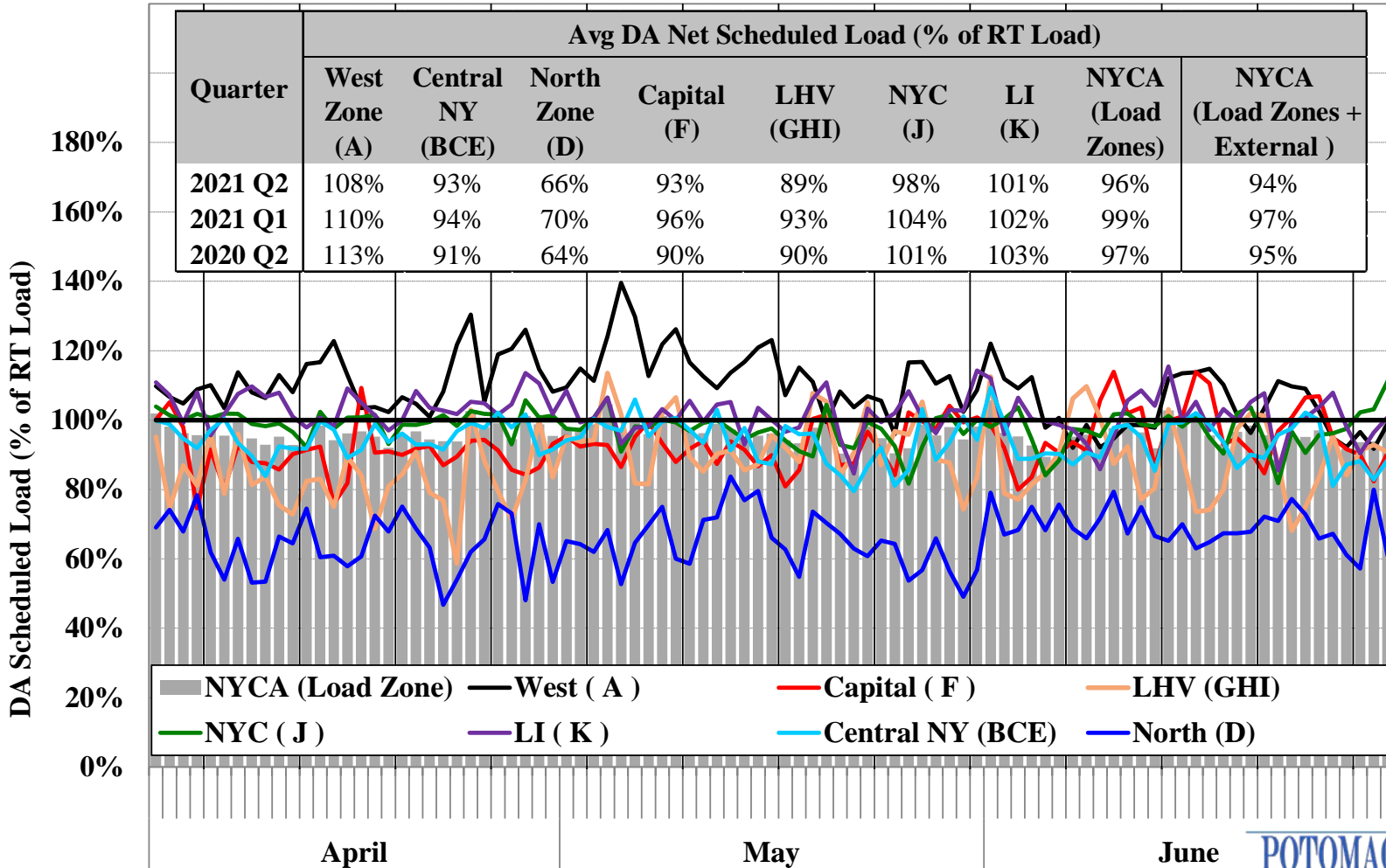
Regulation Requirements, Prices, and Movement-to-Capacity Ratio by Month



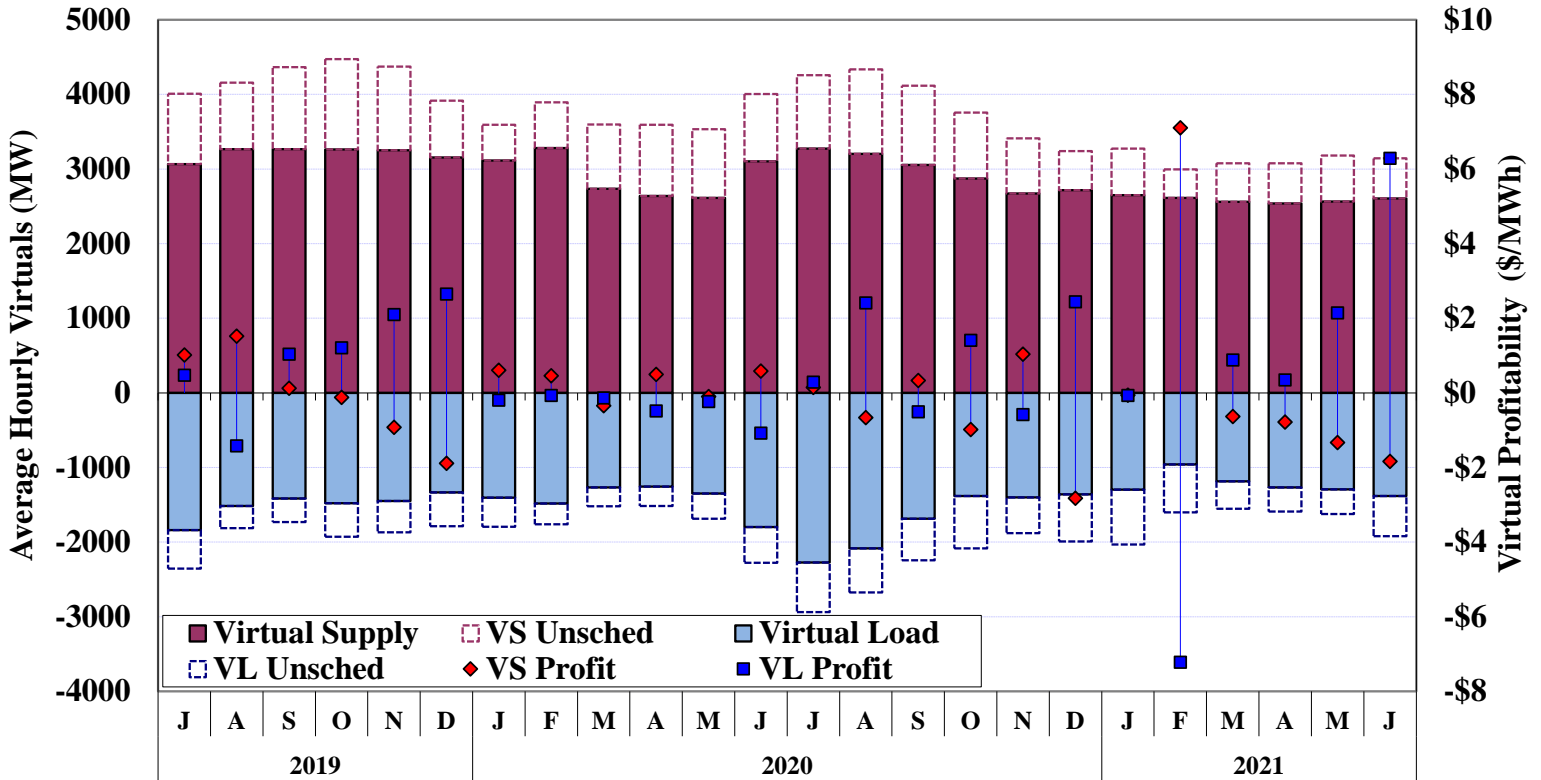


Charts: Energy Market Scheduling

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



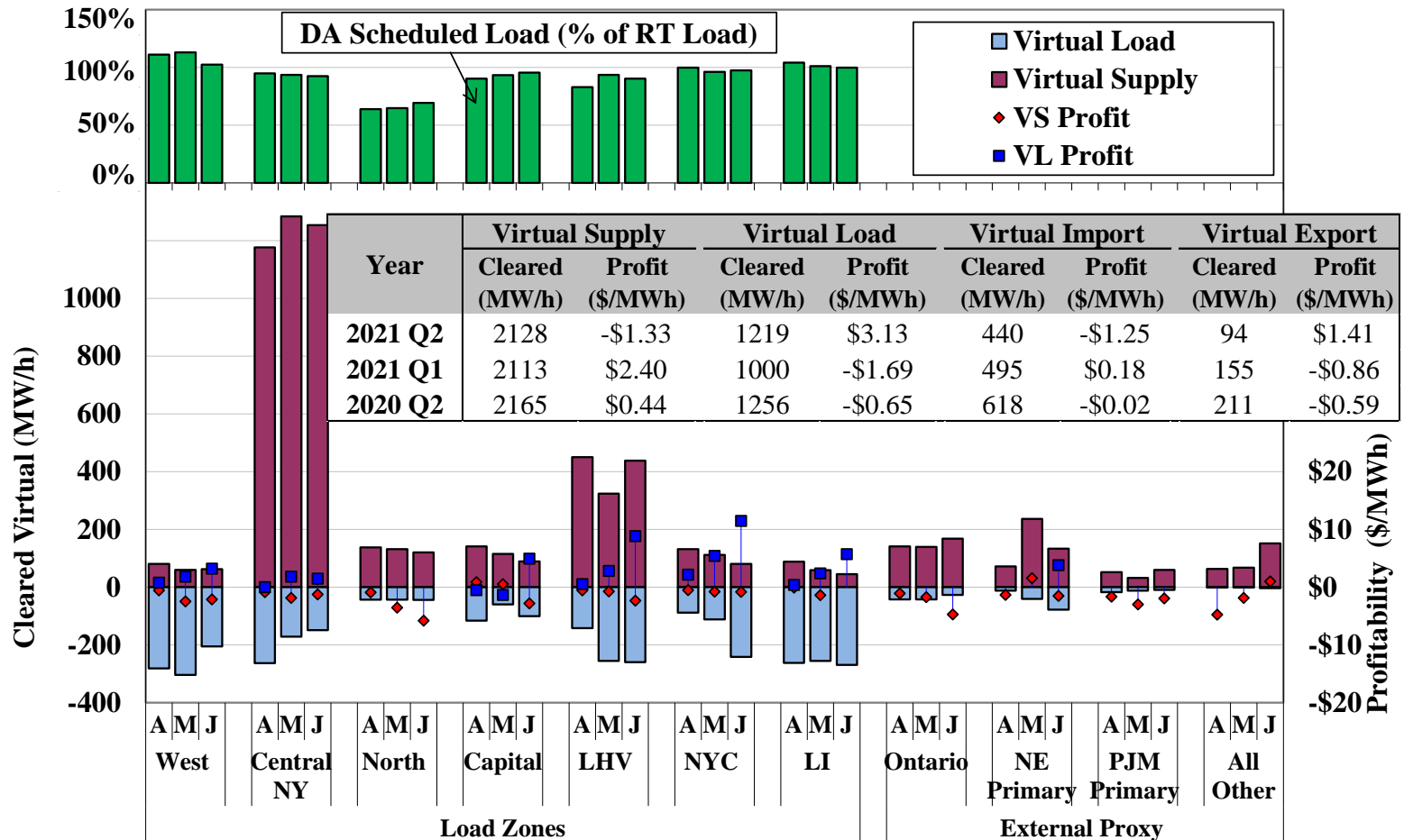
Virtual Trading Activity by Month



		J	A	S	O	N	D	J	F	M	A	M	J	J	A	S	O	N	D	J	F	M	A	M	J
Profit > 50% of Avg. Zone Price	MW	384	396	249	312	290	274	421	322	232	370	388	464	416	377	196	235	619	375	320	658	514	549	378	325
	%	8%	8%	5%	7%	6%	6%	9%	7%	6%	10%	10%	9%	8%	7%	4%	6%	15%	9%	8%	18%	14%	14%	10%	8%
Loss > 50% of Avg. Zone Price	MW	372	321	293	376	344	305	338	253	321	298	404	460	377	304	198	312	528	440	283	388	491	688	498	271
	%	8%	7%	6%	8%	7%	7%	7%	5%	8%	8%	10%	9%	7%	6%	4%	7%	13%	11%	7%	11%	13%	18%	13%	7%



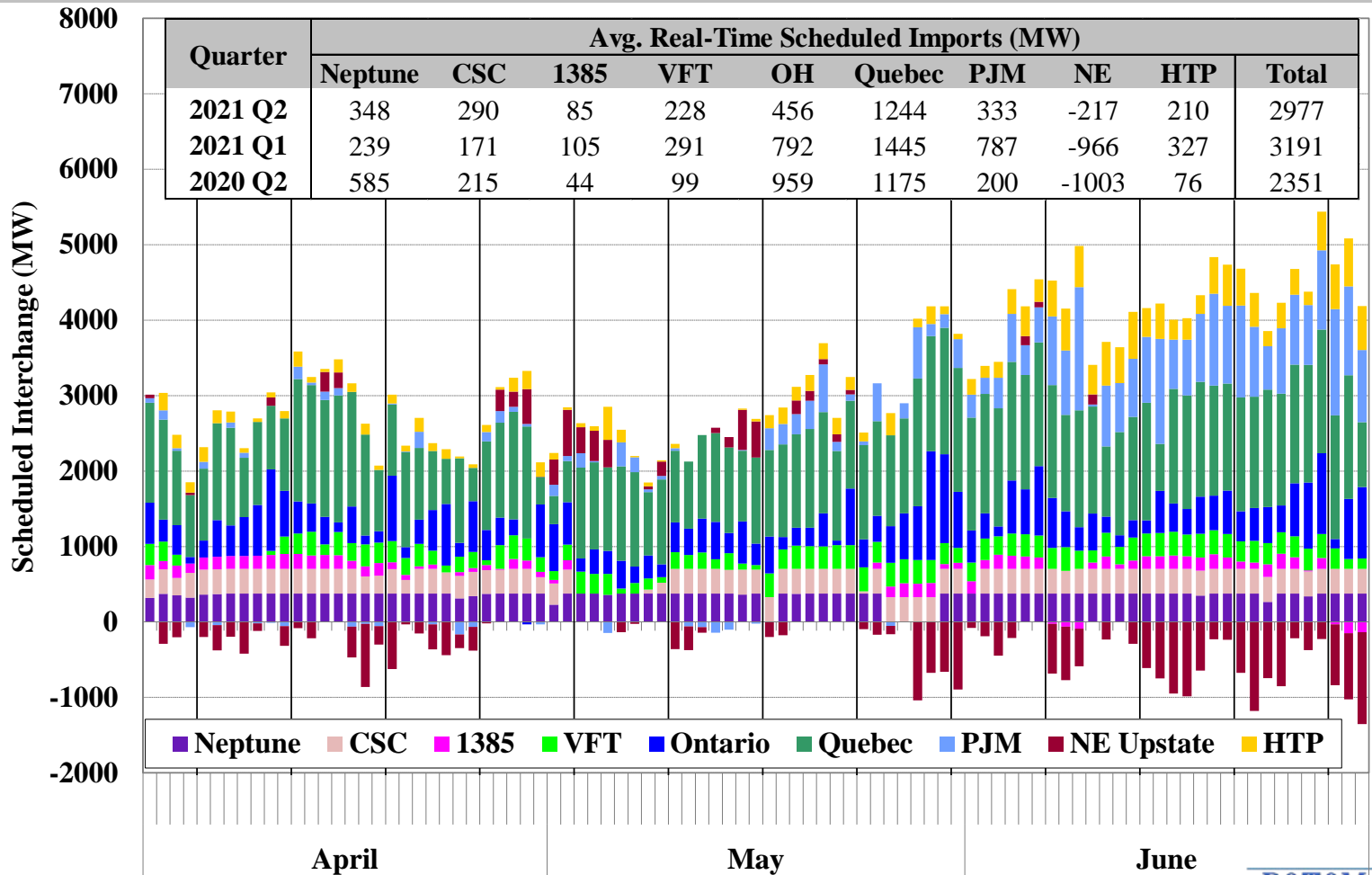
Virtual Trading Activity by Location



Notes: 1. Virtual profit is not shown for a category if the average scheduled quantity is less than 50 MW.

2. For chart description, see slide [84](#).

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



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			89%	6%	95%	31%	7%	38%
Average Flow Adjustment (MW)	Net Imports		14	13	14	2	-34	-5
	Gross		98	144	101	41	78	48
Production Cost Savings (\$ Million)	Projected at Scheduling Time		\$1.0	\$0.4	\$1.4	\$0.1	\$0.9	\$1.0
	Net Over-Projection by:	NY	-\$0.1	-\$0.3	-\$0.4	\$0.0	-\$0.1	-\$0.2
		NE or PJM	\$0.1	-\$0.1	-\$0.1	\$0.0	-\$0.7	-\$0.8
	Other Unrealized Savings		\$0.0	-\$0.1	-\$0.1	\$0.0	\$0.0	\$0.0
Actual Savings		\$0.9	-\$0.1	\$0.8	\$0.1	\$0.0	\$0.1	
Interface Prices (\$/MWh)	NY	Actual	\$27.14	\$46.74	\$28.40	\$24.67	\$47.99	\$28.95
		Forecast	\$28.08	\$66.09	\$30.53	\$25.22	\$51.62	\$30.07
	NE or PJM	Actual	\$25.86	\$61.63	\$28.16	\$23.75	\$50.30	\$28.62
		Forecast	\$24.82	\$56.62	\$26.86	\$26.50	\$92.95	\$38.69
Price Forecast Errors (\$/MWh)	NY	Fcst. - Act.	\$0.94	\$19.35	\$2.13	\$0.55	\$3.63	\$1.12
		Abs. Val.	\$2.79	\$65.18	\$6.80	\$2.71	\$19.85	\$5.85
	NE or PJM	Fcst. - Act.	-\$1.04	-\$5.01	-\$1.30	\$2.75	\$42.65	\$10.07
		Abs. Val.	\$2.73	\$24.32	\$4.12	\$4.26	\$69.39	\$16.21

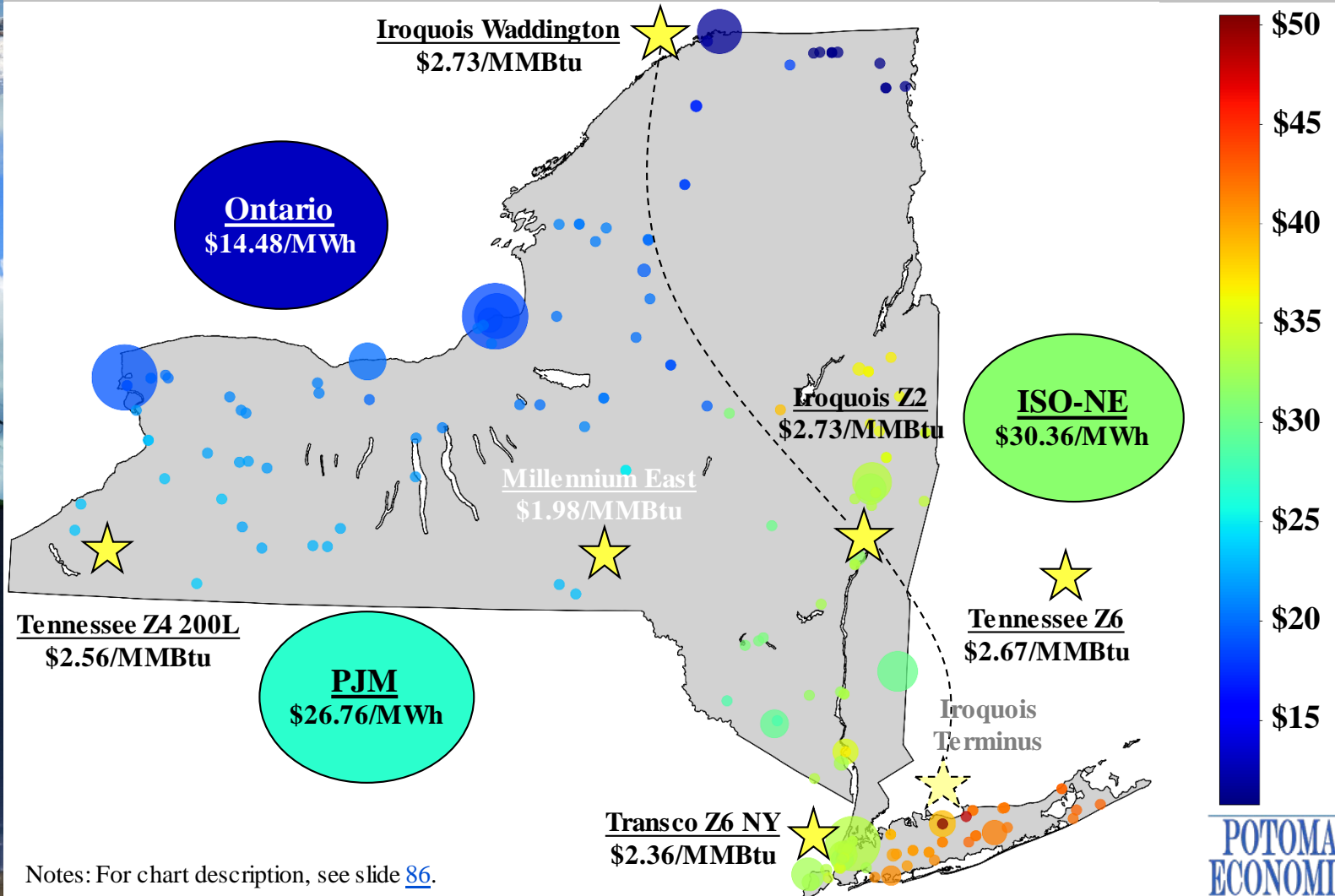


Charts: Transmission Congestion Revenues and Shortfalls



System Congestion

Real-Time Price Map at Generator Nodes

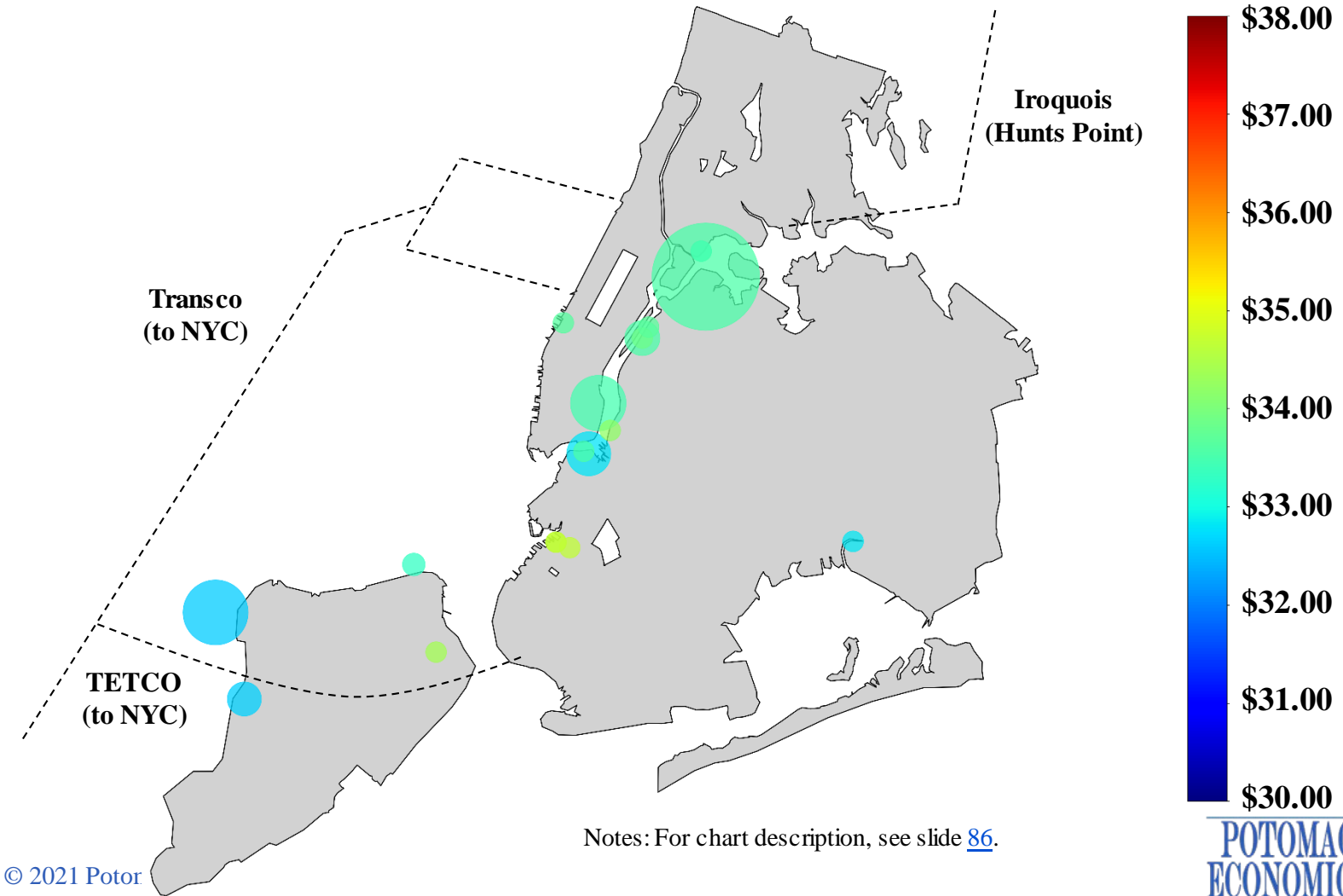


Notes: For chart description, see slide [86](#).

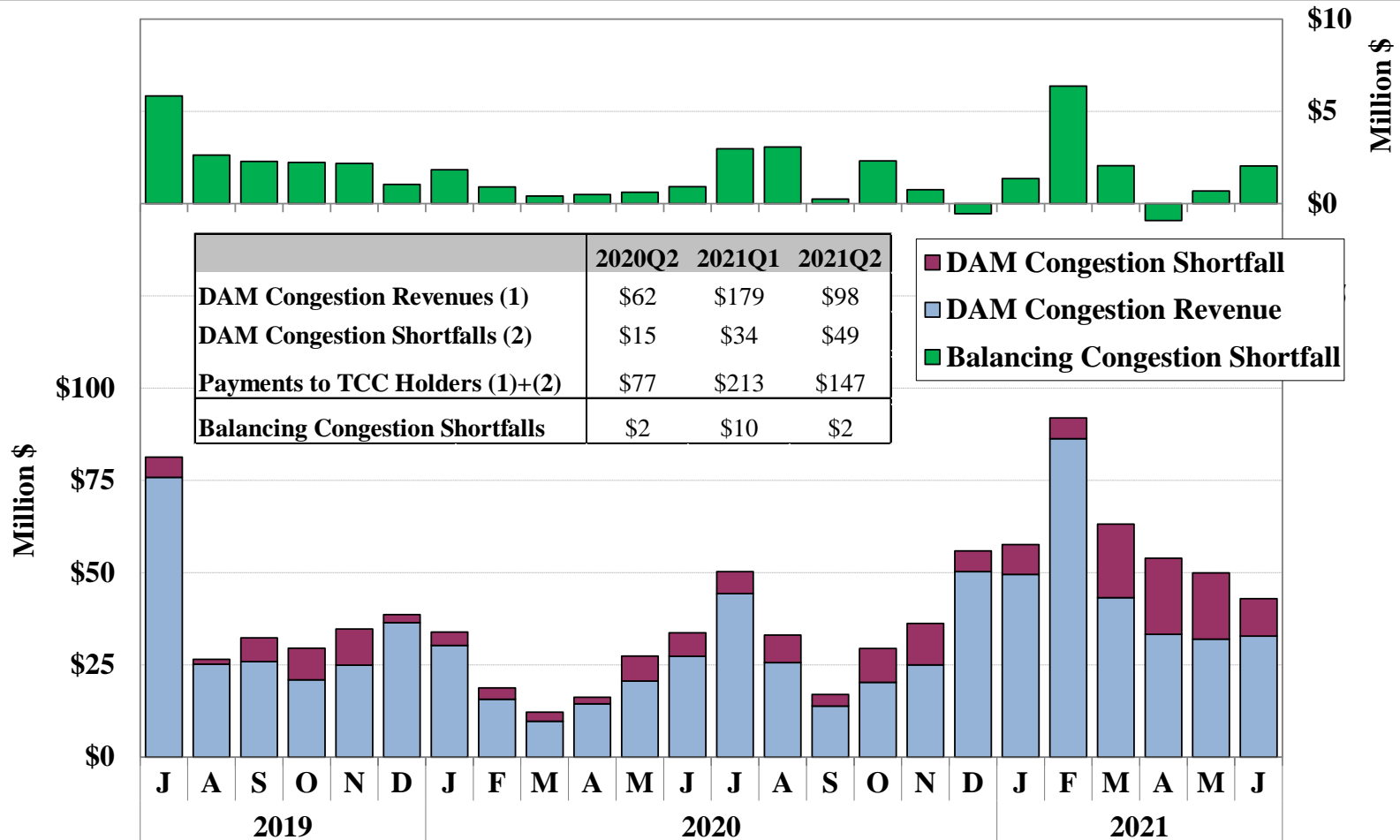


System Congestion

NYC Real-Time Price Map at Generator Nodes

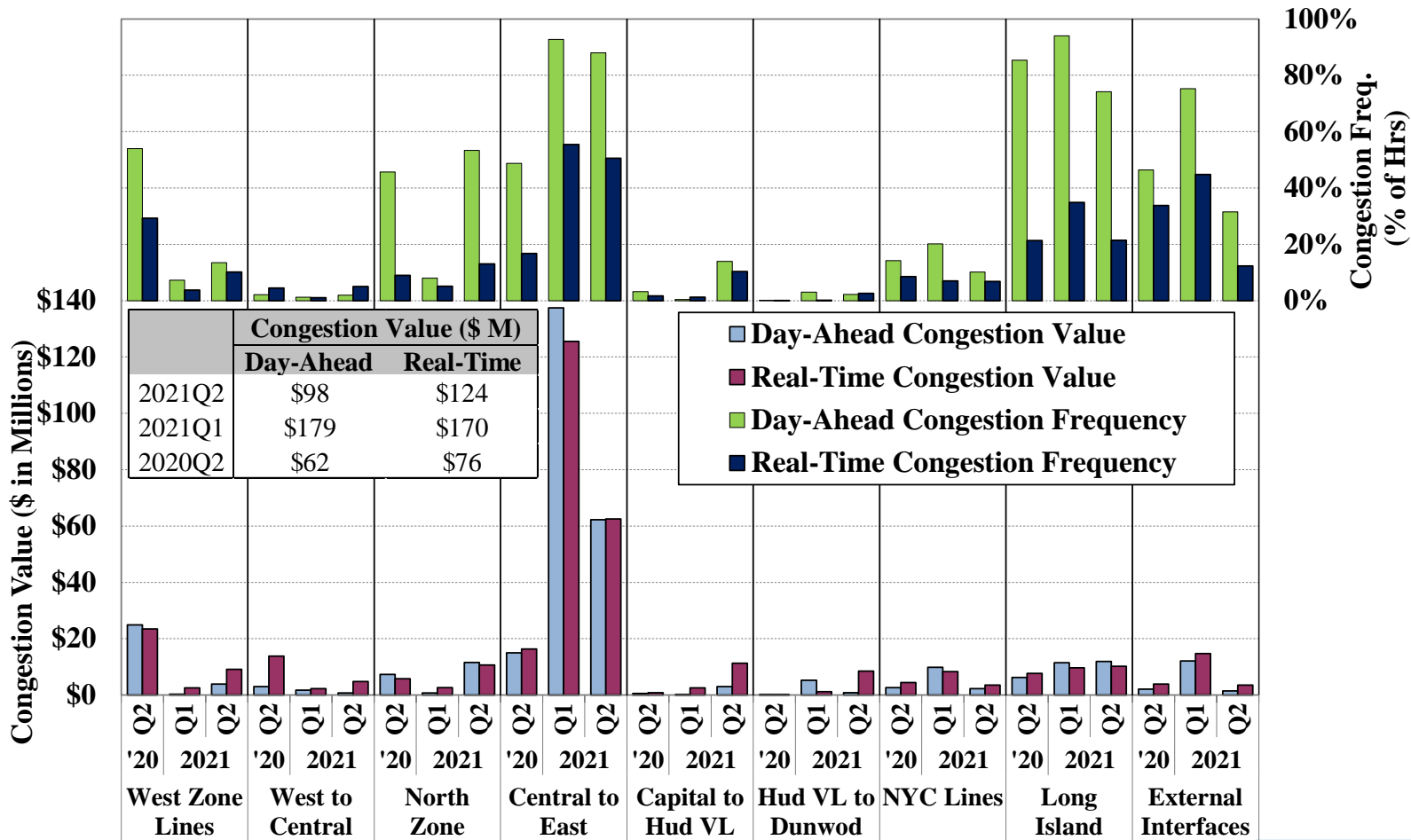


Congestion Revenues and Shortfalls by Month



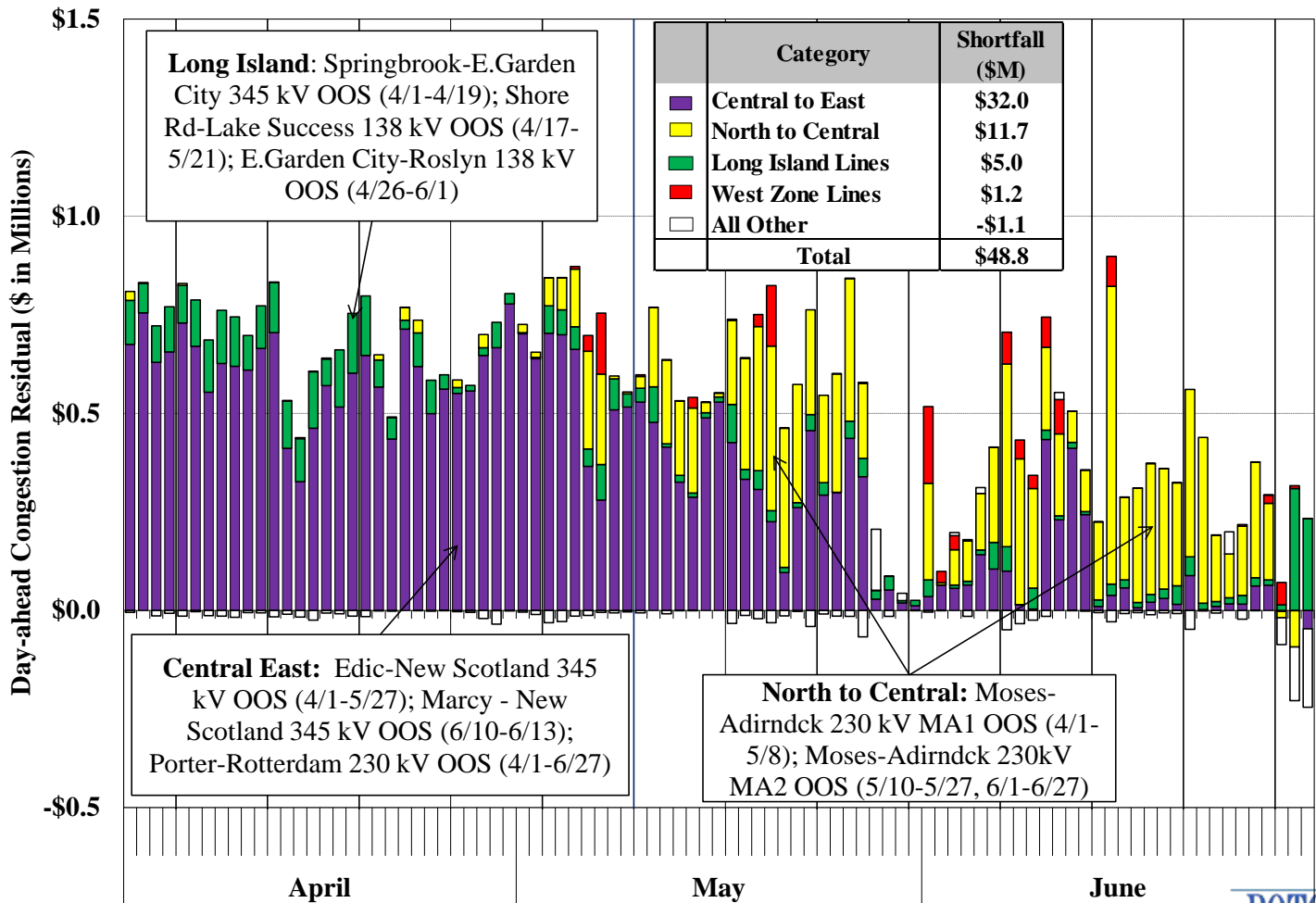
Notes: For chart description, see slides [87](#) and [88](#).

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

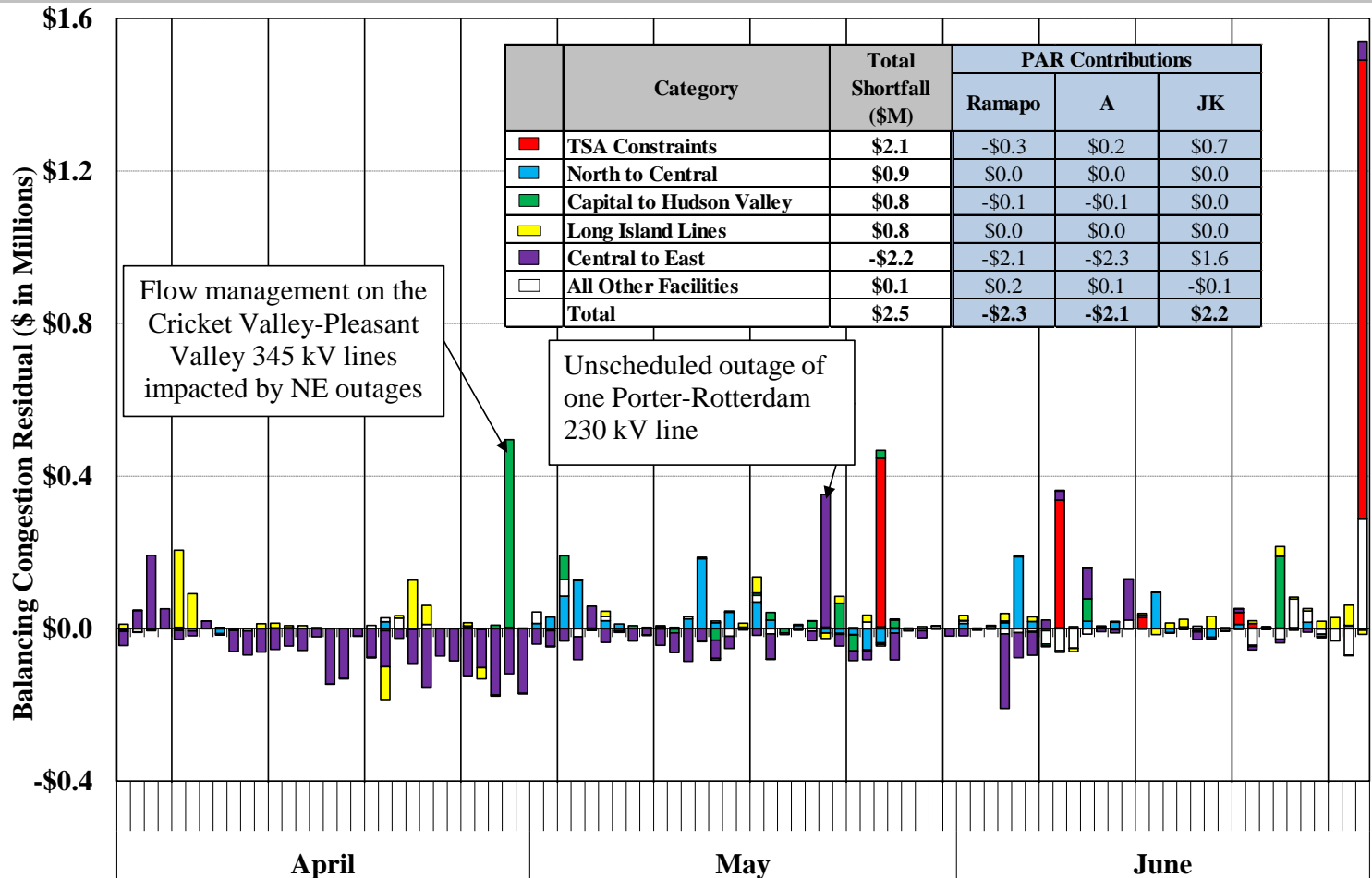


Notes: For chart description, see slides [87](#), [88](#), and [89](#).

Day-Ahead Congestion Revenue Shortfalls by Transmission Facility



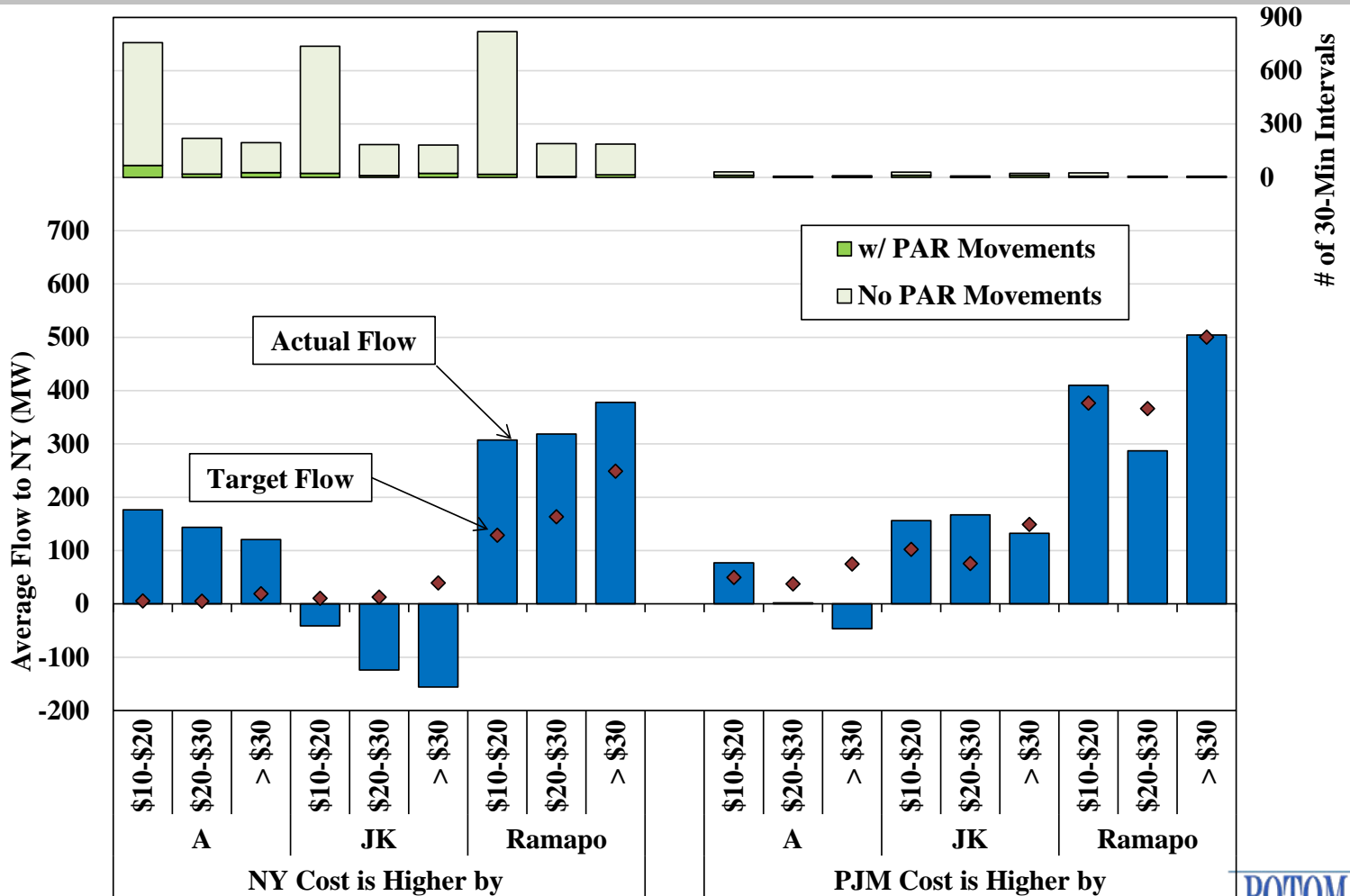
Balancing Congestion Shortfalls by Transmission Facility



Notes: 1. The BMCR estimated above may differ from actual BMCR because the figure is partly based on real-time schedules rather than metered values. 2. For chart description, see slides [87](#), [88](#), and [89](#).
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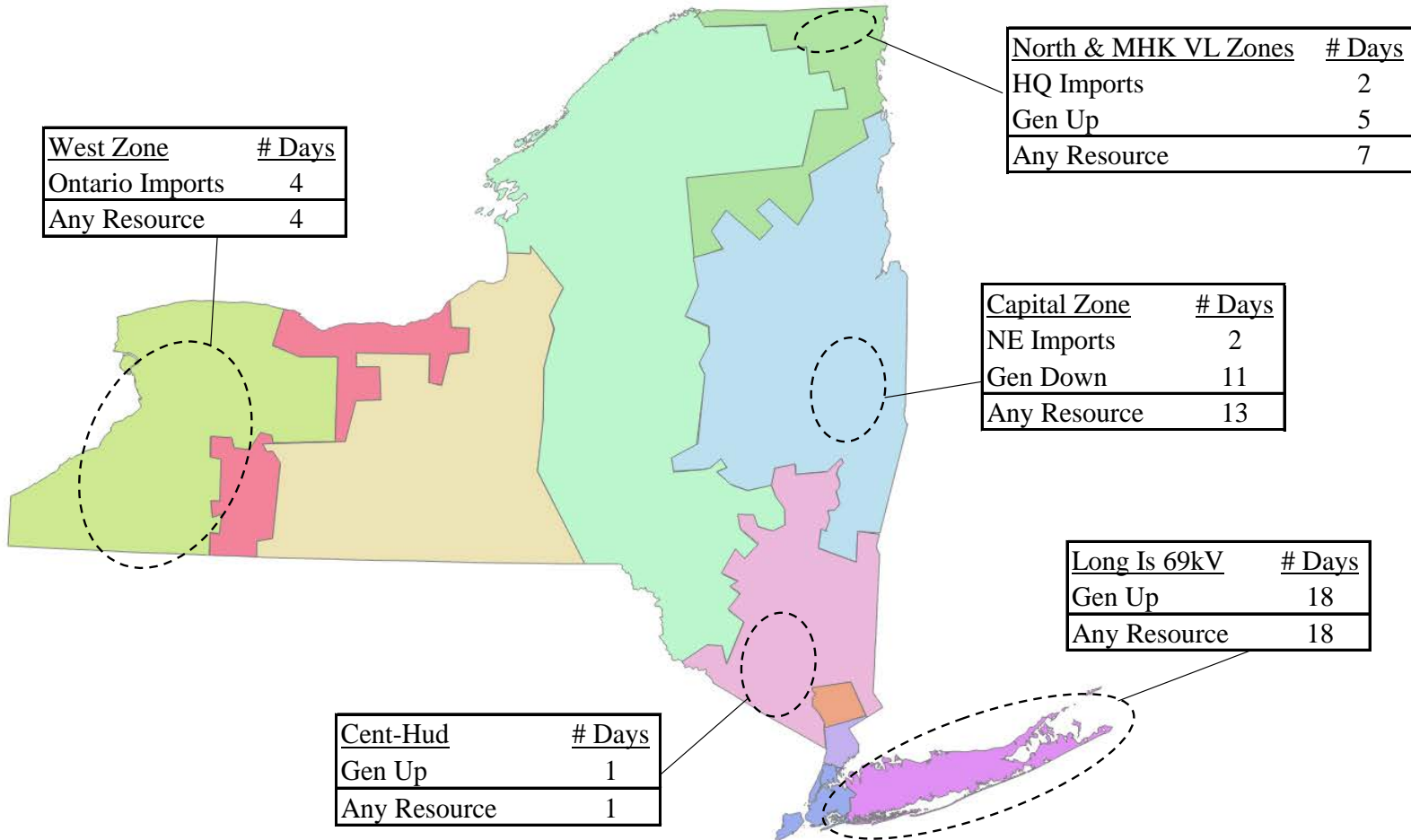


PAR Operation under M2M with PJM 2021 Q2



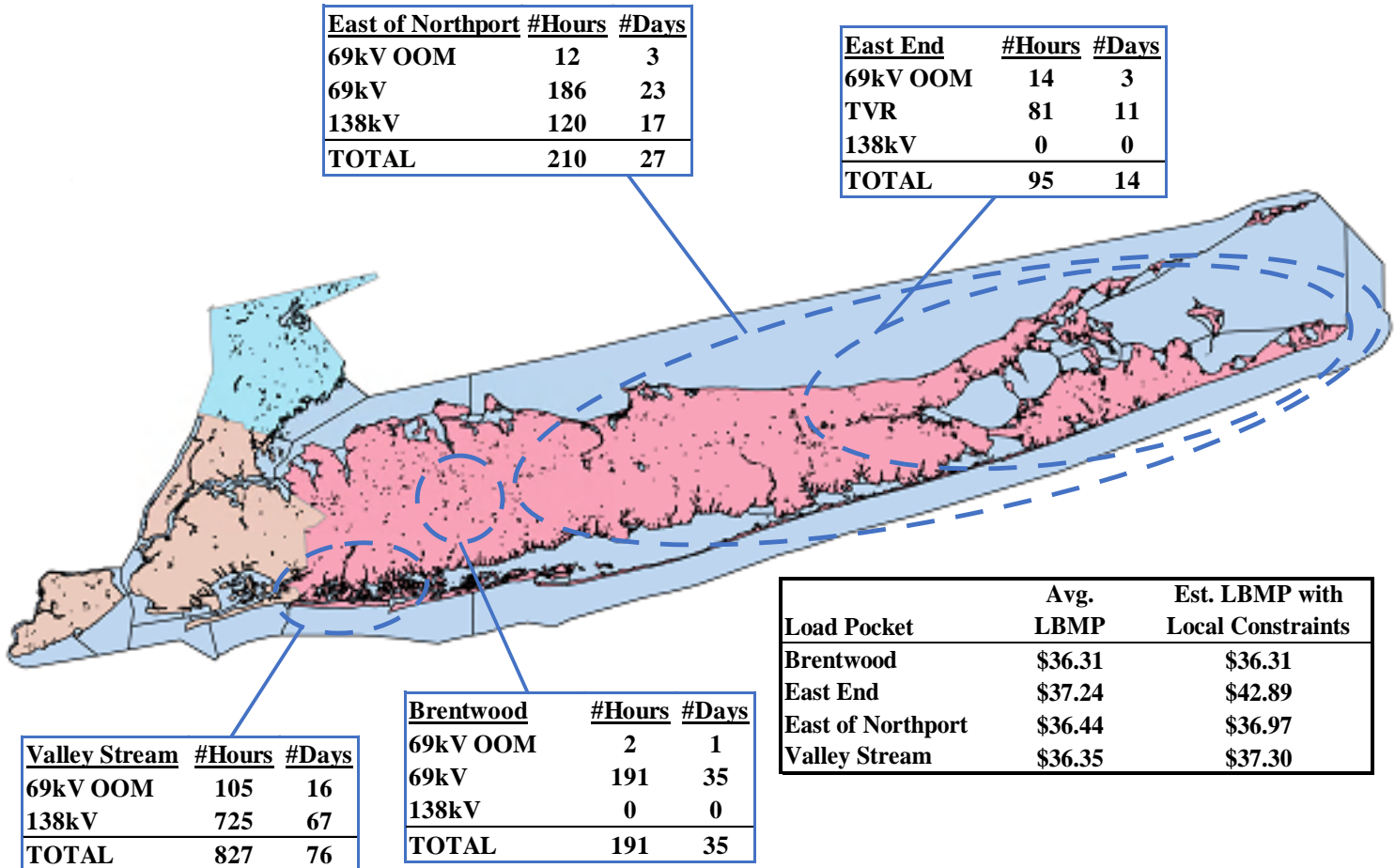


Constraints on the Low Voltage Network: Summary of Resources Used to Manage Congestion



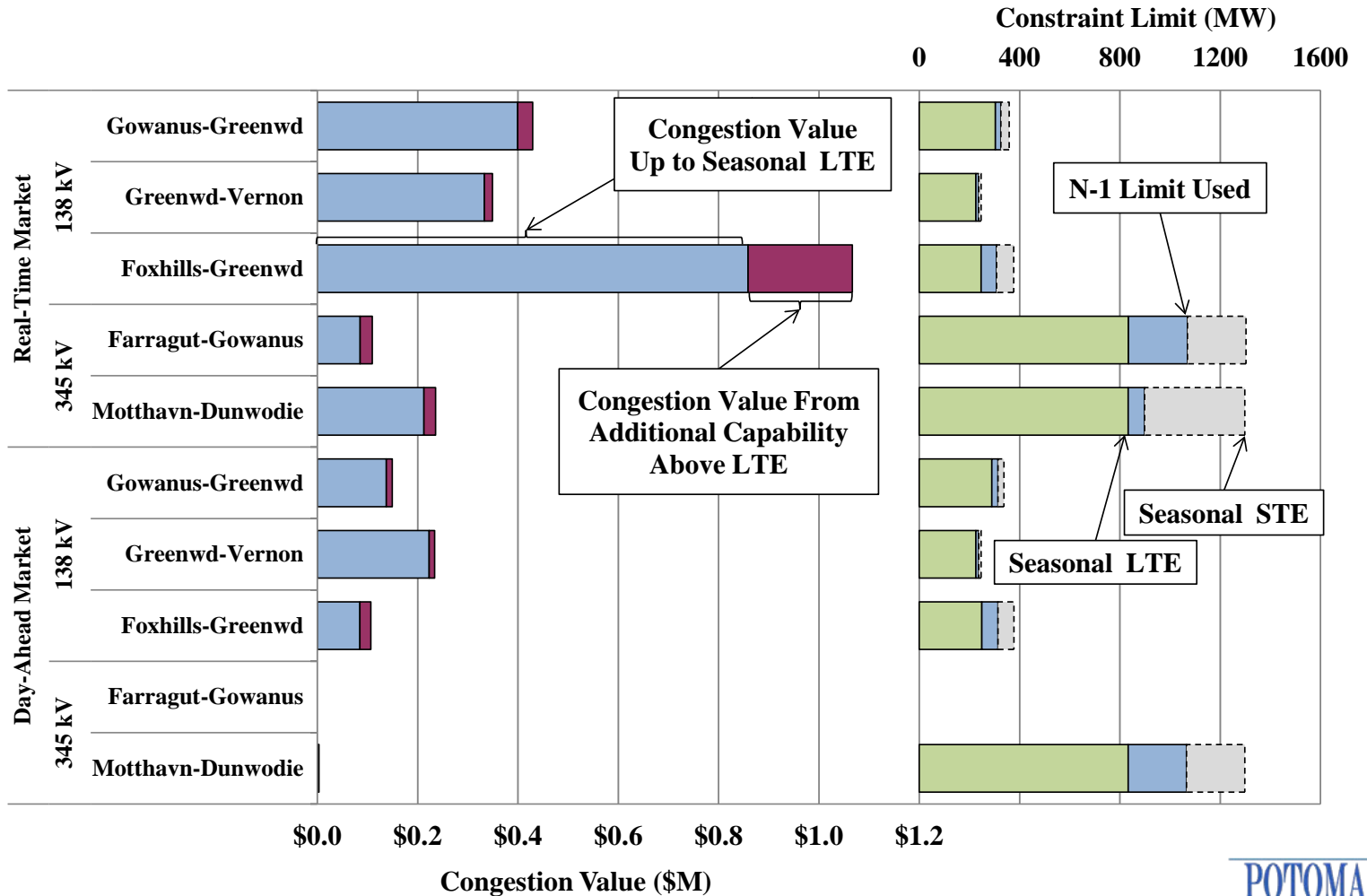
Notes: For chart description, see slides [91-92](#)

Constraints on the Low Voltage Network: Long Island Load Pockets





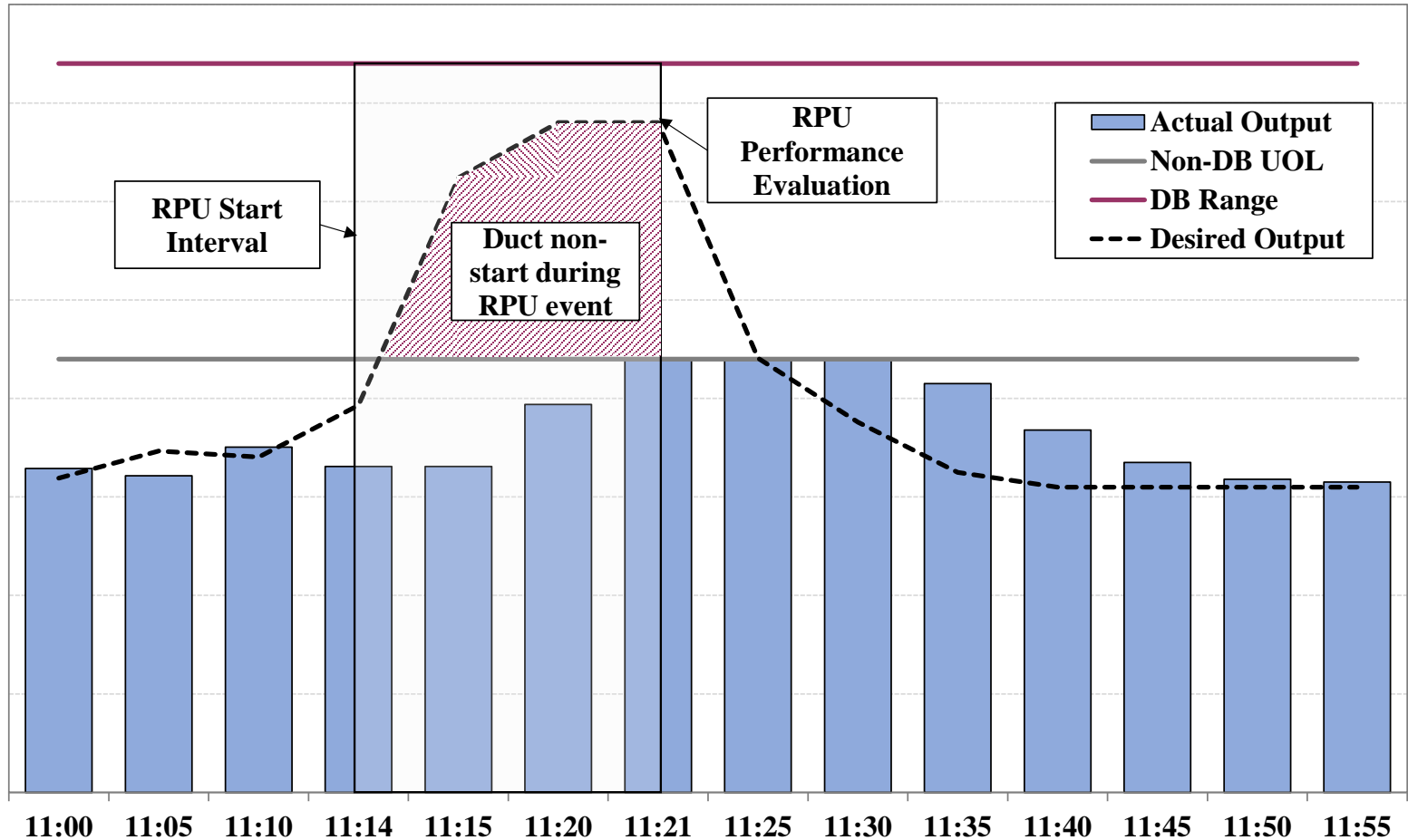
N-1 Constraints in New York City Limits Used vs Seasonal LTE Ratings





Duct Burner Real-Time Dispatch Issues

Example of a Failed RPU

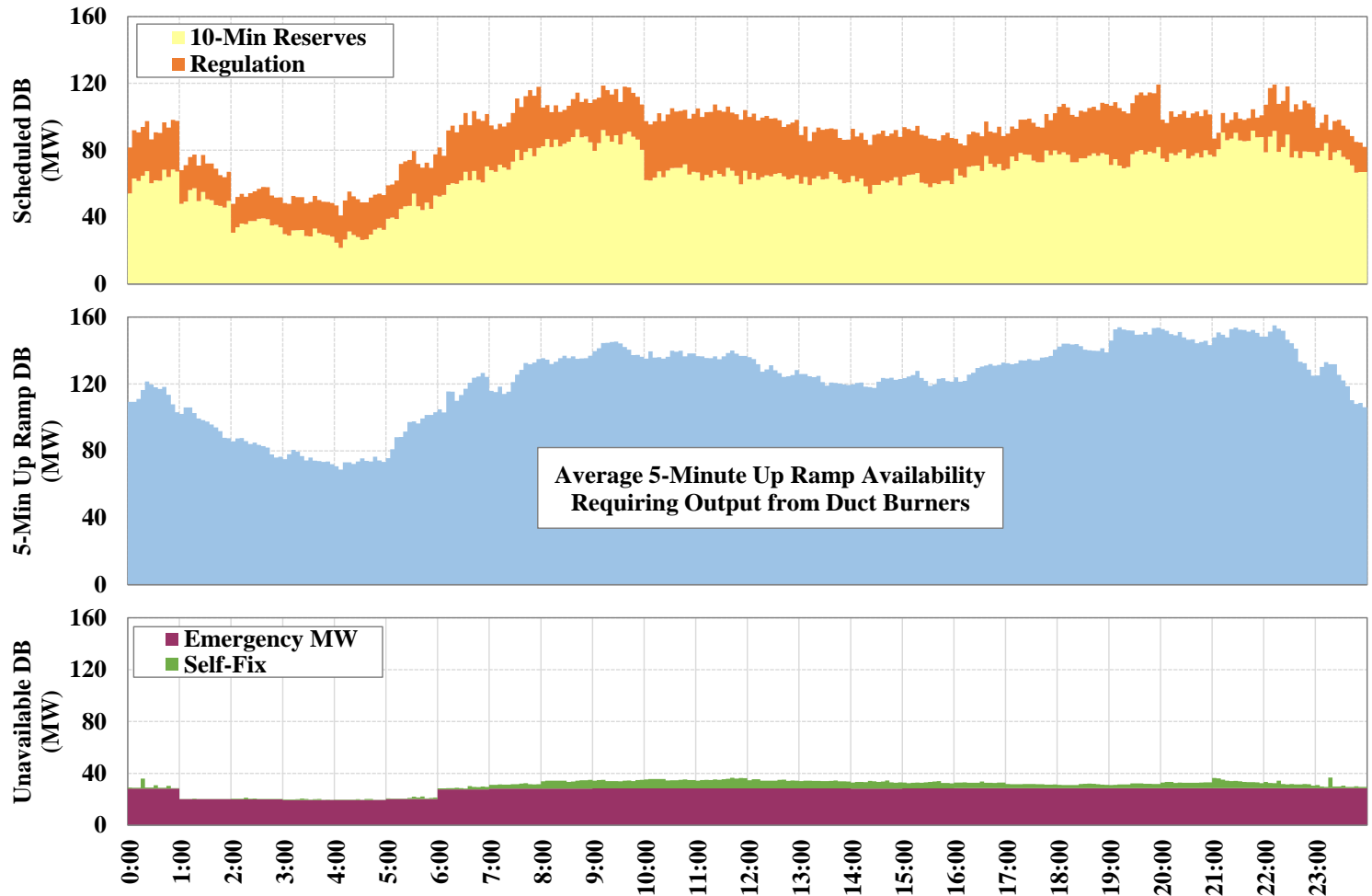


Notes: For chart description, see slide [94](#)



Duct Burner Schedules and Ramp Expectations

Evaluation of Duct Availability in Real-Time



10-Minute Gas Turbine Start-up Performance

Economic Starts vs. Audits

10 Minute Economic GT Start Performance vs. Audit Results (July 2020 - June 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%	0	0	0	0
30% - 40%	0	0	0	0
40% - 50%	3	8	3	2
50% - 60%	2	4	2	0
60% - 70%	2	3	2	0
70% - 80%	4	8	4	0
80% - 90%	16	33	16	3
90% - 100%	26	56	26	2
TOTAL	53	112	53	7

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

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

30 Minute Economic GT Start Performance vs. Audit Results (July 2020 - June 2021)

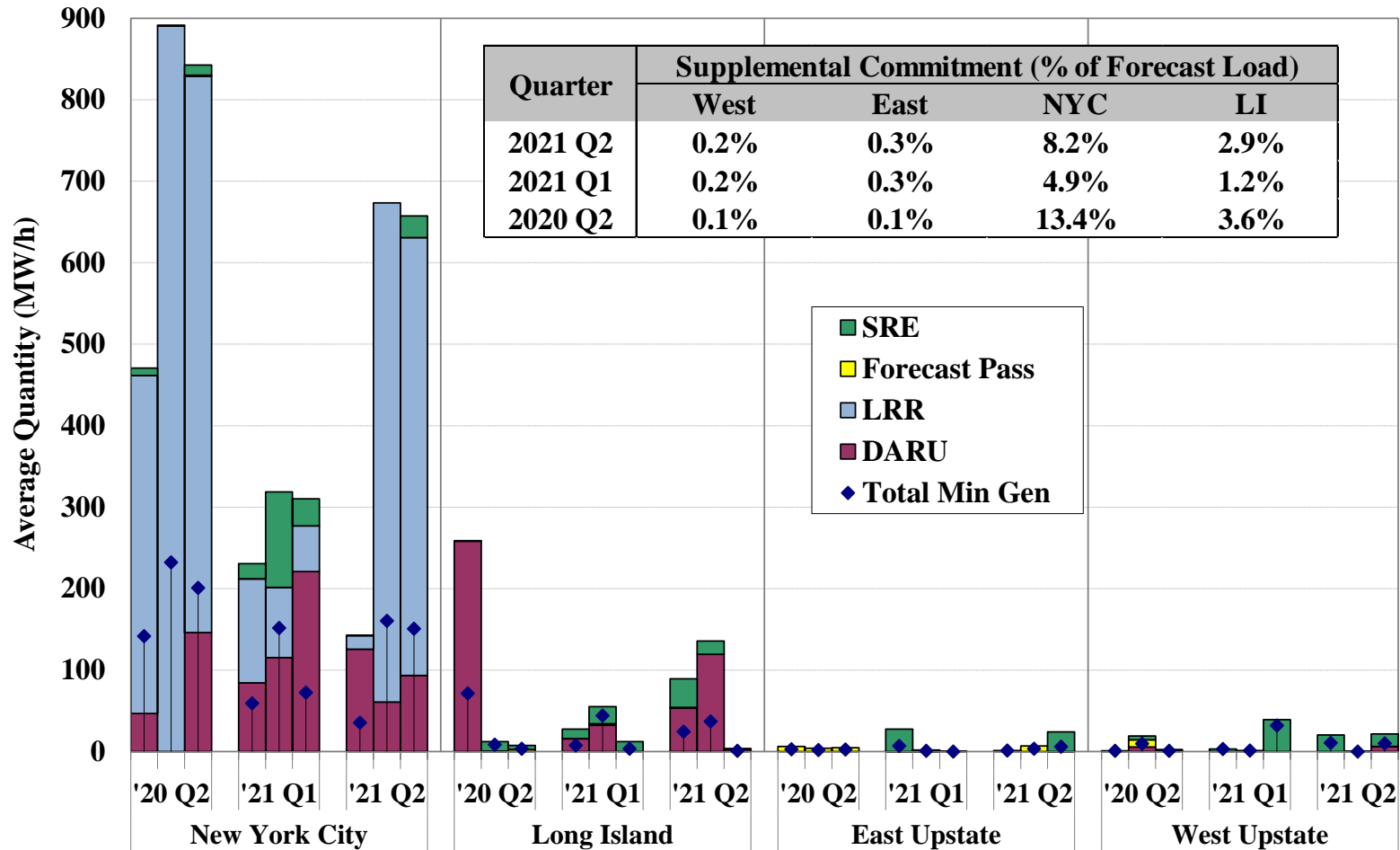
Economic GT Starts (RTC)		GT Audit Results		
Performance Category	No. of Units	No. of Audits	Unique GTs Audited	No. of Audit Failures
Not Evaluated ¹	20	30	15	5
0% - 10%	1	2	1	1
10% - 20%	0	0	0	0
20% - 30%	0	0	0	0
30% - 40%	2	0	0	0
40% - 50%	0	0	0	0
50% - 60%	1	1	1	0
60% - 70%	0	0	0	0
70% - 80%	6	14	6	7
80% - 90%	10	19	10	2
90% - 100%	52	110	49	3
TOTAL	92	176	82	18

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



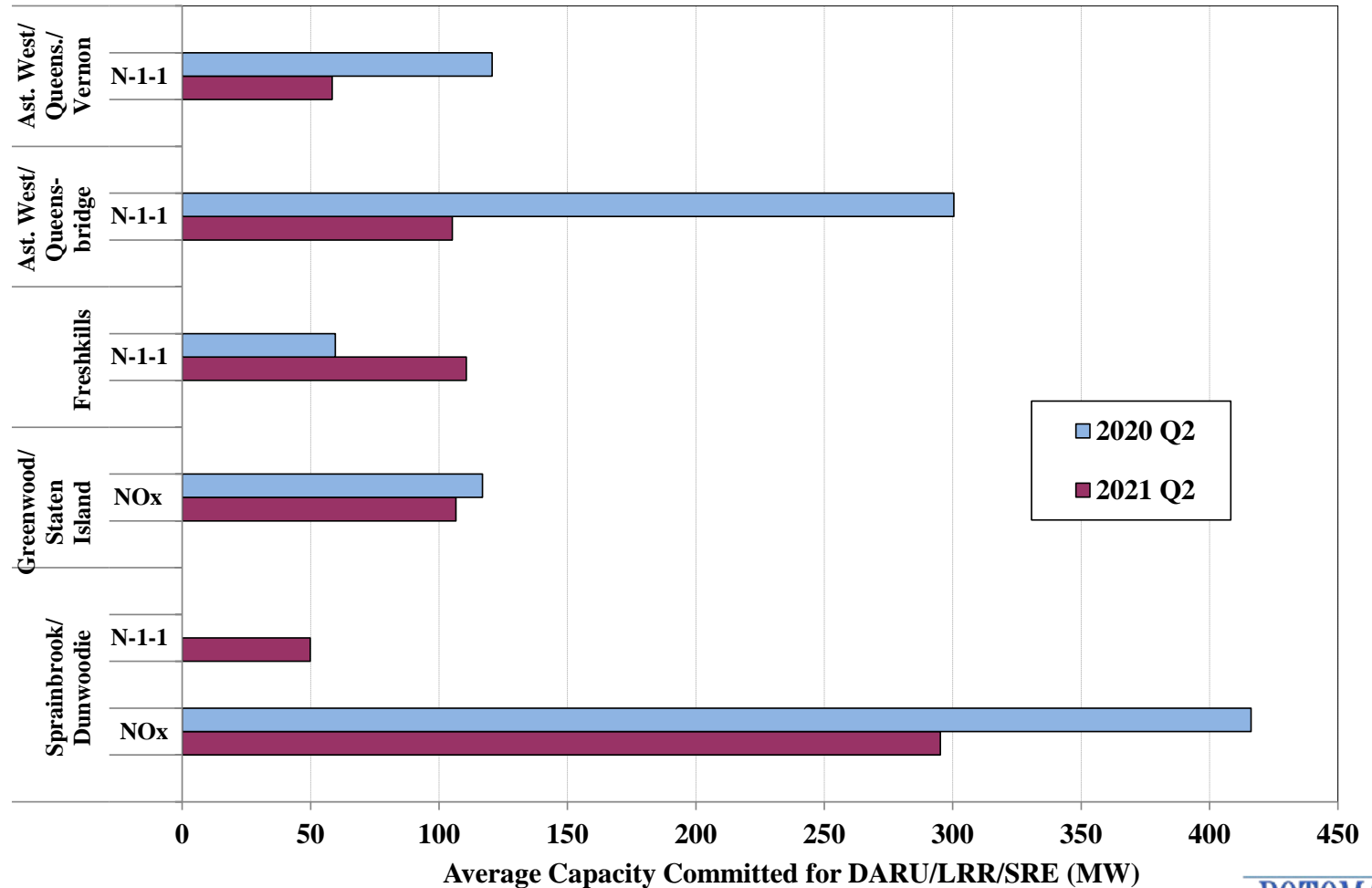
Charts:
**Supplemental Commitment, OOM Dispatch,
and BPCG Uplift**

Supplemental Commitment for Reliability by Category and Region



Notes: For chart description, see slides [96](#) and [97](#).

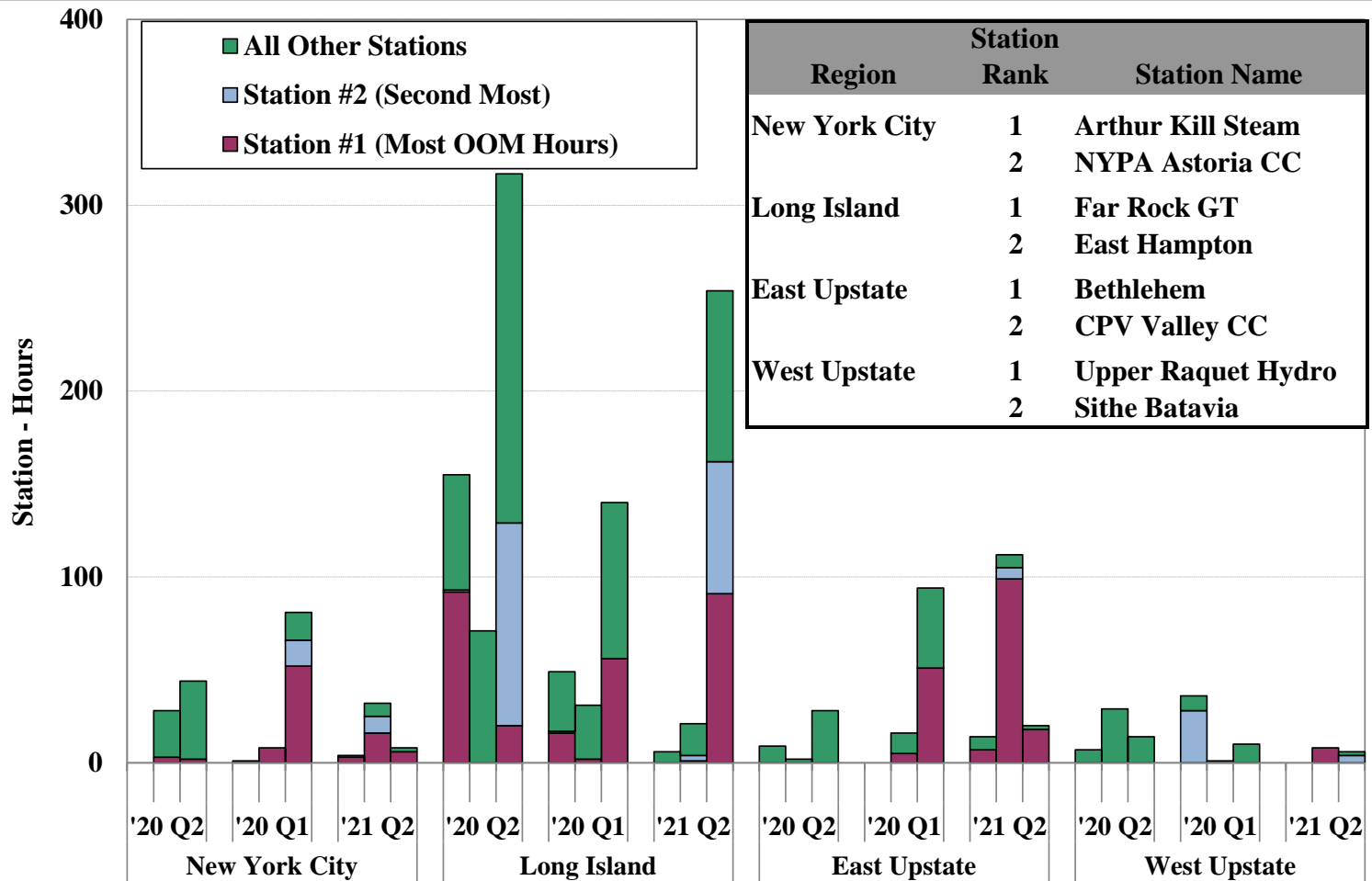
Supplemental Commitment for Reliability in NYC by Reliability Reason and Load Pocket



Notes: For chart description, see slides [96](#) and [97](#).



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

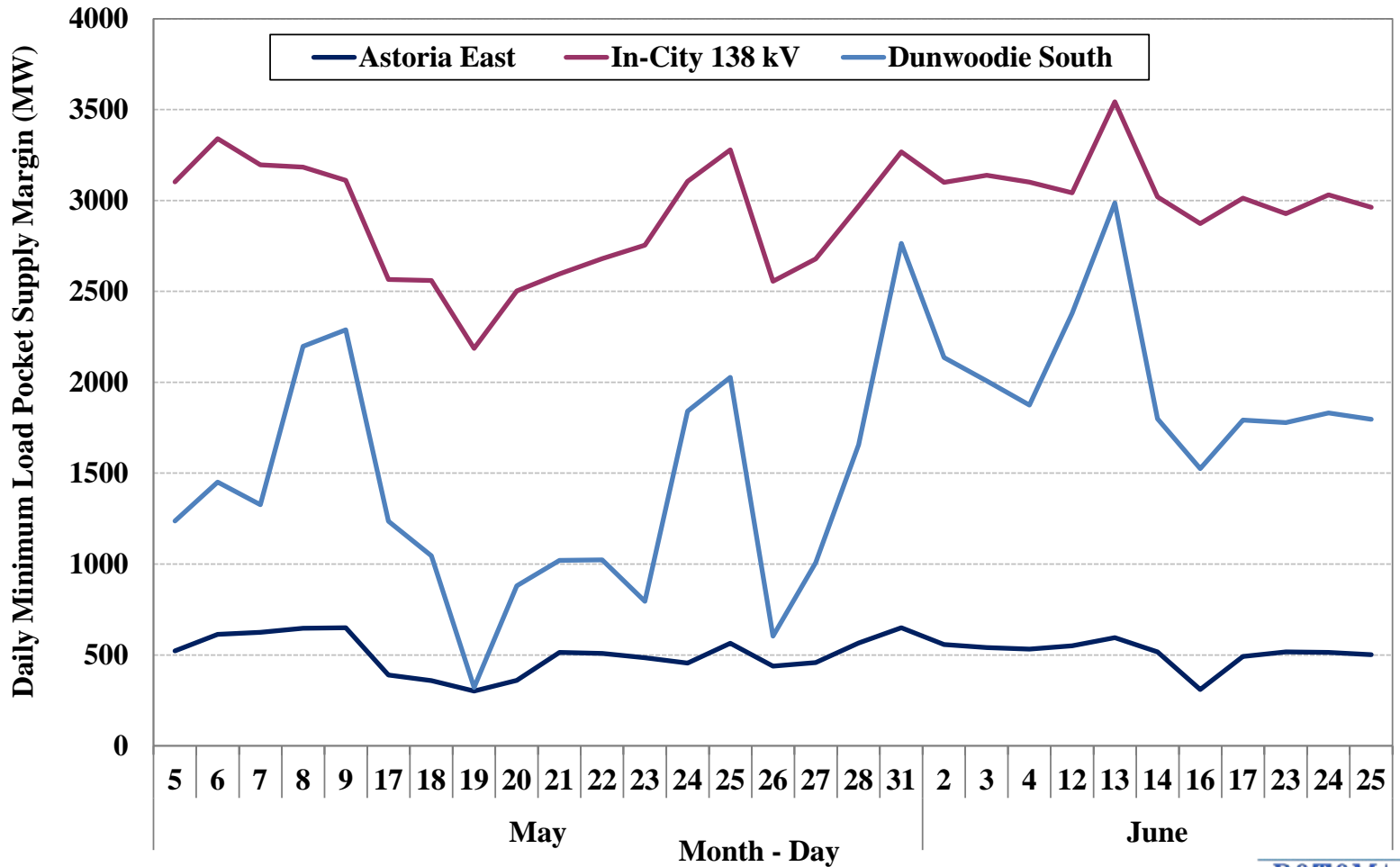


For chart description, see slides [96](#) and [97](#).



Supply Margin in NYC Load Pockets

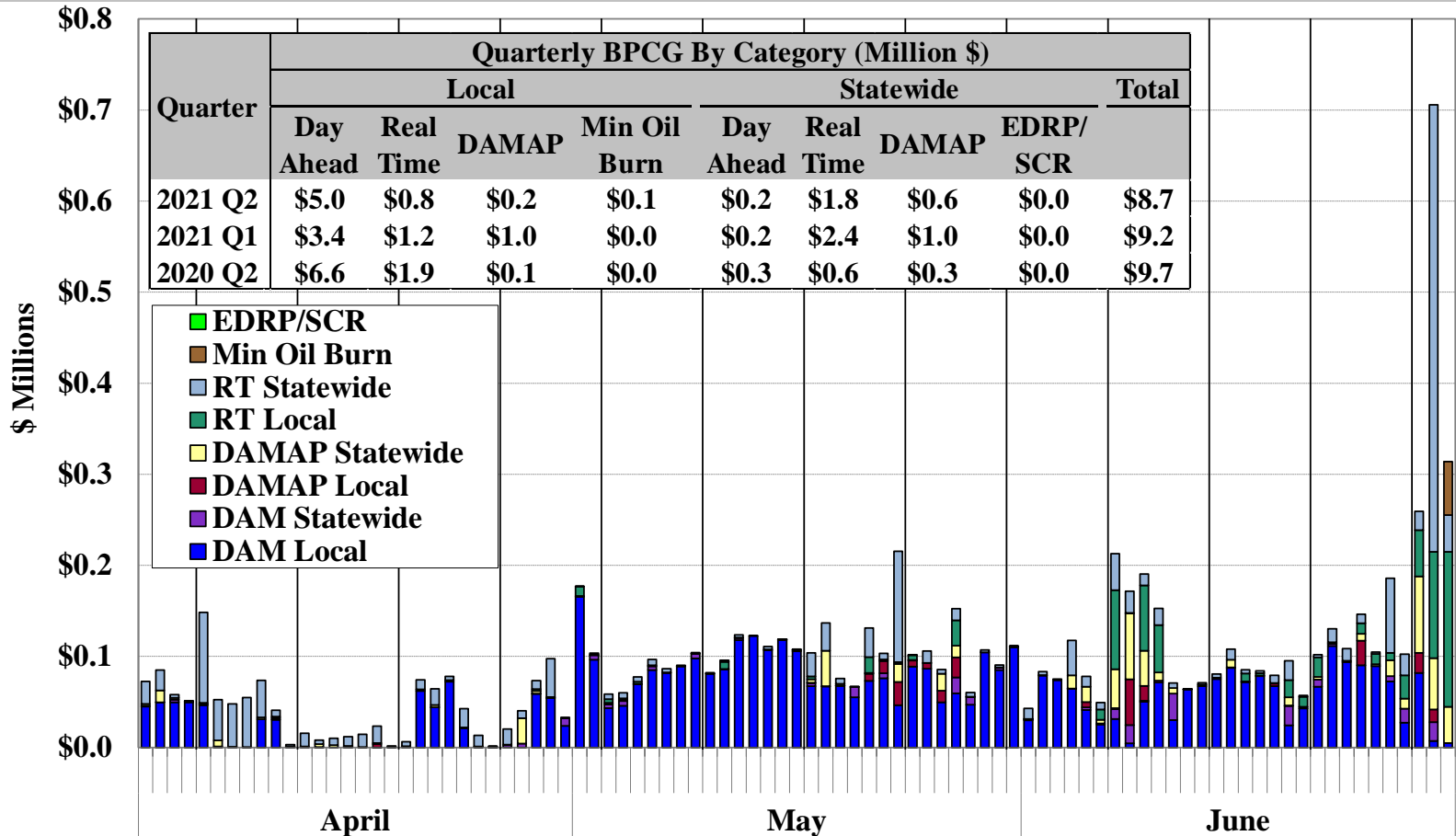
After Removing NOx-only Committed ST and GT in the NOx Bubble





Uplift Costs from Guarantee Payments

Local and Non-Local by Category

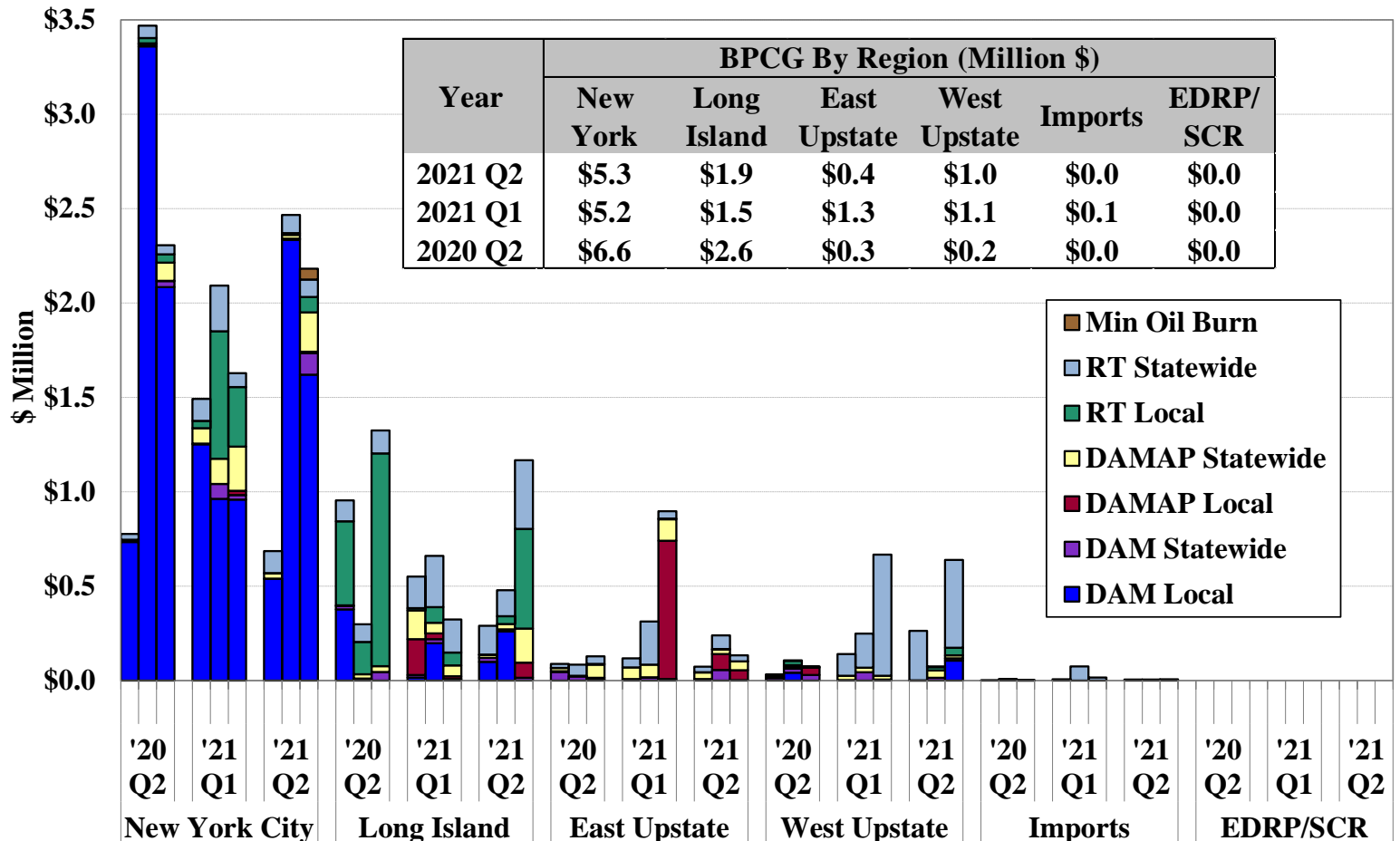


Notes: 1. This data is based on information available at the reporting time and does not include some manual adjustments to mitigation, so it can be different from final settlements.

2. For chart description, see slide [99](#).



Uplift Costs from Guarantee Payments By Category and Region



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

2. For chart description, see slide [99](#).

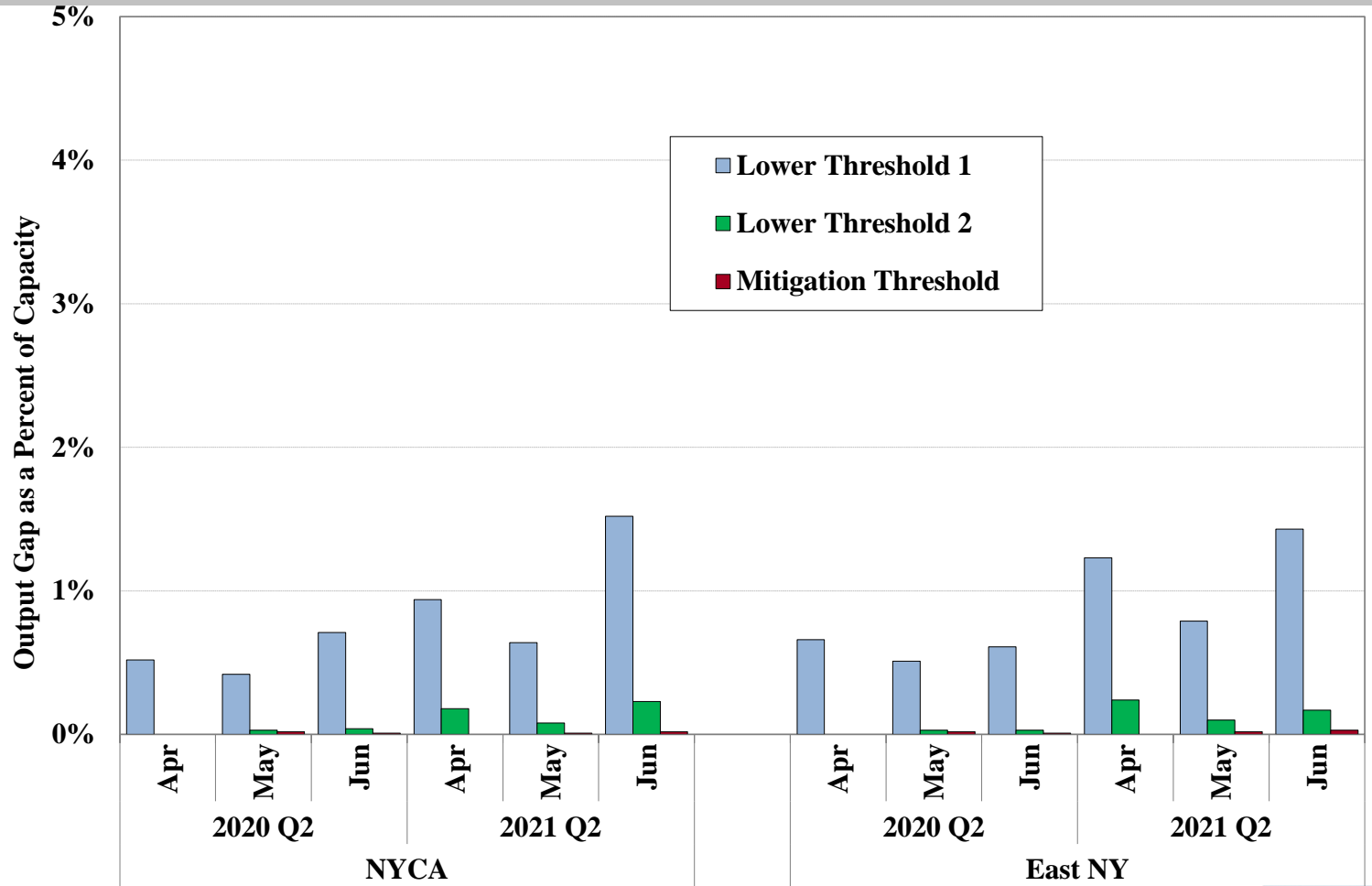


Charts: Market Power and Mitigation



Output Gap by Month

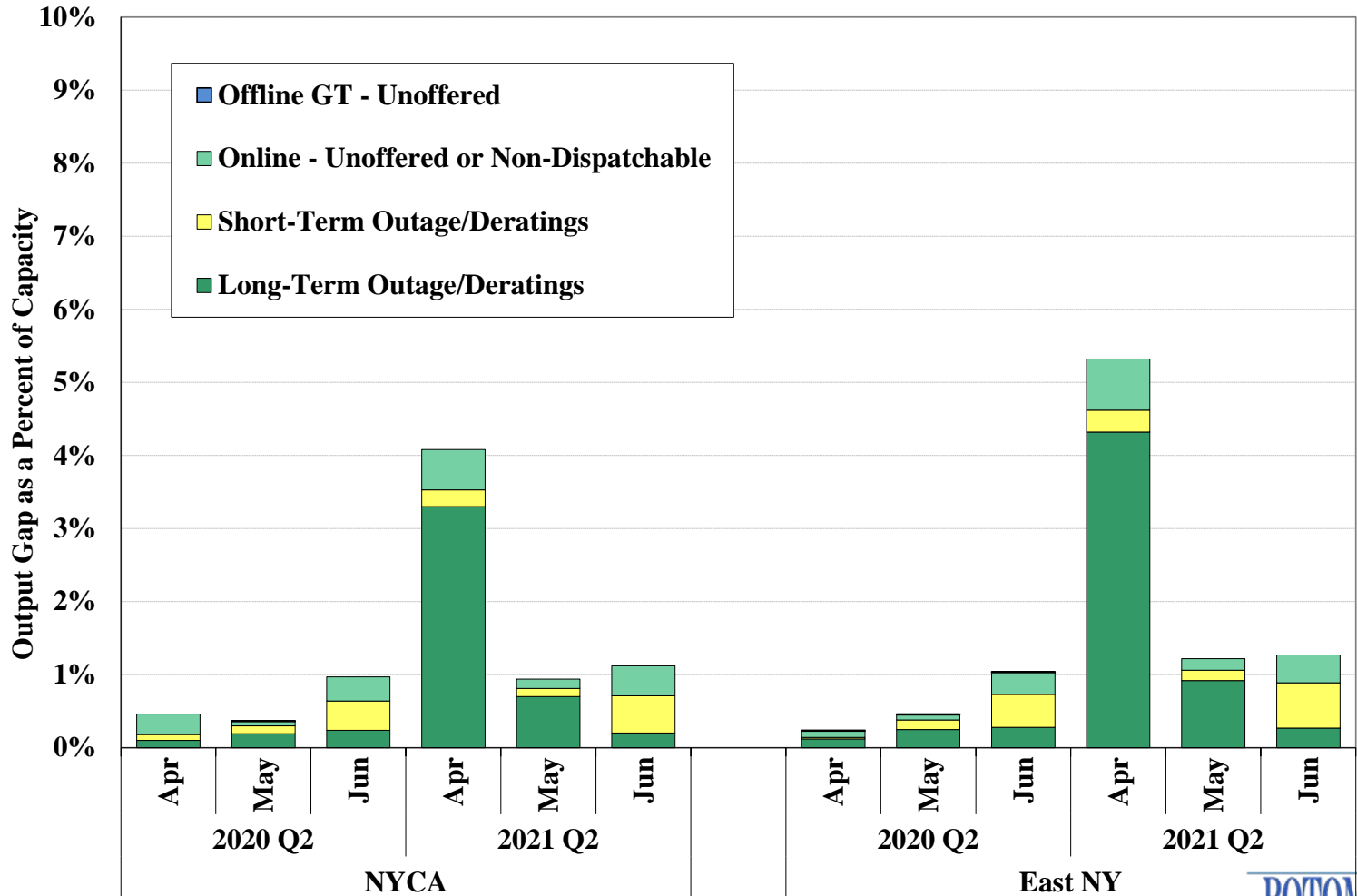
NYCA and East NY



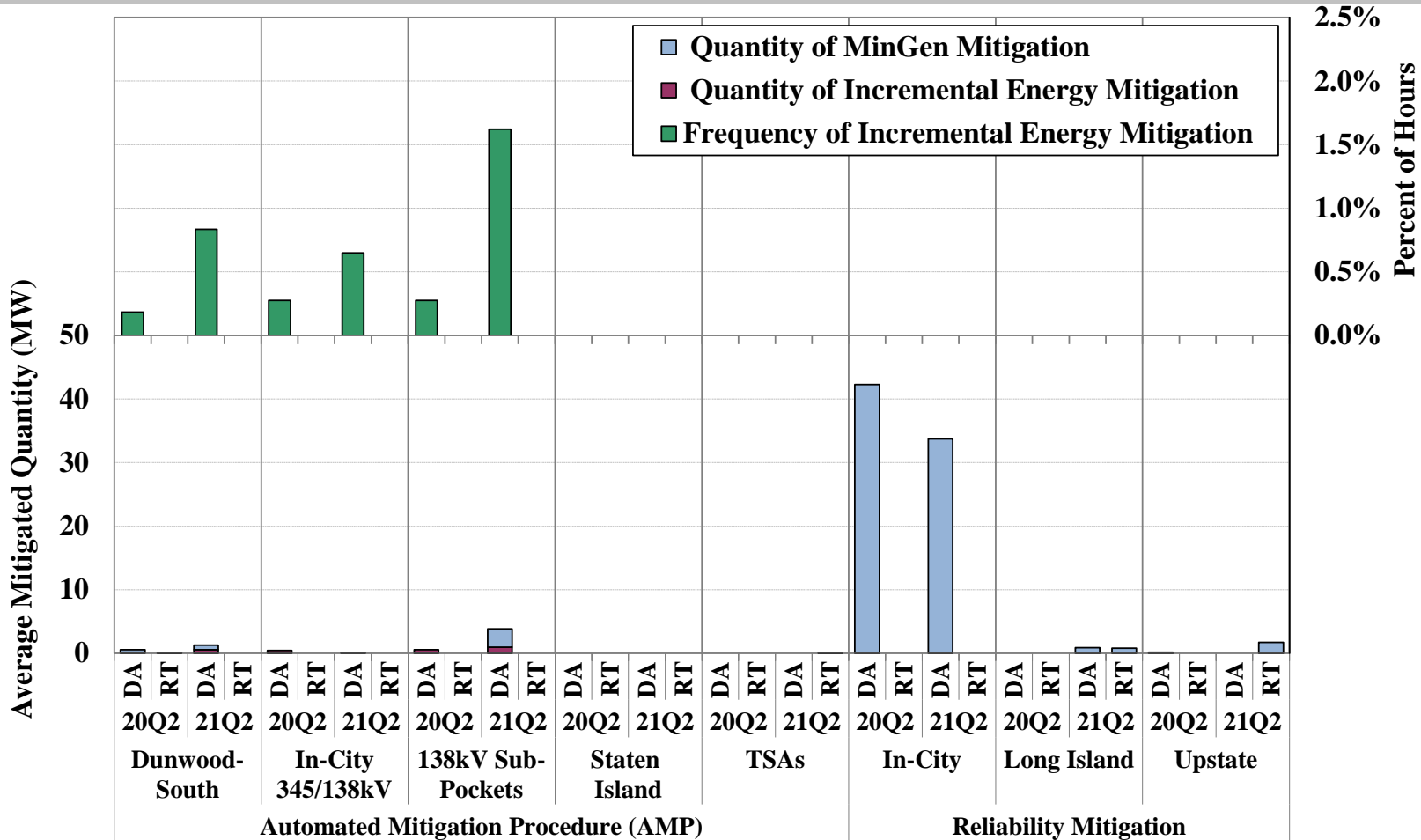


Unoffered Economic Capacity by Month

NYCA and East NY



Automated Market Power Mitigation

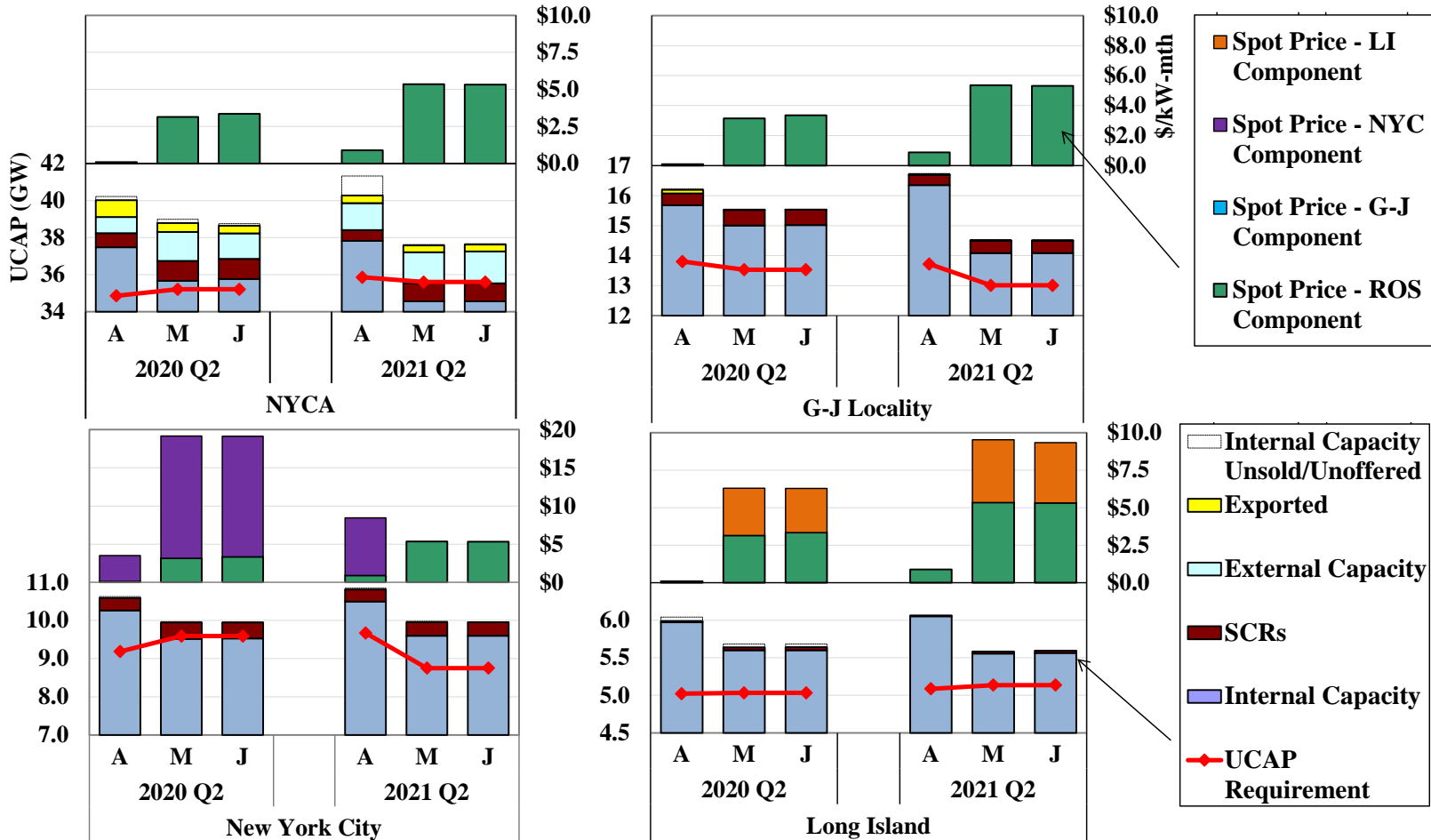




Charts: Capacity Market

Spot Capacity Market Results

Monthly Results by Locality



Key Drivers of Capacity Market Results

	NYCA	NYC	LI	G-J Locality
Avg. Spot Price				
2021 Q2 (\$/kW-Month)	\$3.85	\$6.37	\$6.59	\$3.85
% Change from 2020 Q2	75%	-54%	56%	75%
Change in Demand				
Load Forecast (MW)	37	-278	21	-284
IRM/LCR	1.8%	-6.3%	-0.5%	-2.4%
2021/22 Capability Year	120.7%	80.3%	102.9%	87.6%
2020/21 Capability Year	118.9%	86.6%	103.4%	90.0%
ICAP Requirement (MW)	626	-946	-4	-626
Key Changes in ICAP Supply (MW)				
<i>Generation</i>	-692	12	-53	-607
Entry	375	8	0	384
Exit	-1117	-17	-66	-1050
Other Capacity Changes ⁽¹⁾	50	21	14	59
<i>Cleared Import</i> ⁽²⁾	348			

(1) Other changes include DMNC ratings, former exports, unsold capacity, etc.

(2) Based on average of quarterly cleared quantity.



Appendix: Chart Descriptions



All-in Price

- Slide [20](#) 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 [23](#) 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 [24](#) 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.



Emission by Region

- Slides [25-29](#) evaluate emissions from generators in the NYISO market.
 - ✓ Slide [25](#) shows the historical trend of annual total emissions since 2000 in the NYISO footprint for CO₂, NO_x, and SO₂.
 - ✓ Slides [26-27](#) show quarterly emissions across the system by generation fuel type for CO₂ and NO_x.
 - Emission values are given for 7 regions 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.
 - ✓ Slides [28-29](#) evaluate NO_x emission during the quarter in the non-attainment areas in New York City and Long Island, respectively, on a daily basis.
 - The emission tonnage is shown separately for oil-fired units and gas-fired units in stacked bars, where gas-fired units are also grouped based on technology: (a) combined-cycle; (b) steam turbine; (c) gas turbines that were in service before 2000; and (d) gas turbines that were in service since 2000.
 - The line in slide [28](#) shows the emission from STs in NYC that were supplementally committed for local reliability as a percent of total emission in NYC.



Ancillary Services Prices

- Slides [34-38](#) 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 [37](#) 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 [39](#) 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 [41](#) 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 [43](#) 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 [44](#) 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 [45](#) 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 [47](#) 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 [49](#) and [50](#) 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 [51](#), [52](#), [53](#), and [54](#) 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 [51](#) 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 [52](#) 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 [53](#) and [54](#) 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 [47](#) evaluates operations of NY-NJ PARs under M2M with PJM during the following periods of noticeable congestion differential between NY and PJM:
 - ✓ When NY costs on relevant M2M constraints exceed PJM costs by: a) \$10/MWh to \$20/MWh; b) \$20/MWh to \$30/MWh; or c) more than \$30/MWh.
 - ✓ When PJM costs on relevant M2M constraints exceed NY costs by: a) \$10/MWh to \$20/MWh; b) \$20/MWh to \$30/MWh; or c) more than \$30/MWh;
 - ✓ The market cost is measured as the constraint shadow price multiplied by the PAR shift factor, summed over relevant M2M constraints in each 5-minute market interval and then averaged over each half-hour period.
 - ✓ The top portion of the figure shows two stacked bars for each evaluation group, representing the total number of 30-minute intervals with and without any PAR tap movements.
 - ✓ The bottom portion of the figure shows average actual PAR flows (blue bar), compared with their average M2M targets (red diamond).



Constraints on the Low Voltage Network

- Transmission constraints on the 115 kV and lower voltage networks in New York are often resolved in ways that include:
 - ✓ Out of merit dispatch and supplemental commitment of generation;
 - ✓ Curtailment of external transactions and limitations on external interface limits;
 - ✓ Use of an internal interface transfer limit that functions as a proxy for the limiting transmission facility; and
 - ✓ Adjusting PAR-controlled lines on the high voltage network.
- Slide [56](#) 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 [57](#) shows the number of hours and days in the quarter when various resources were used to manage 69 kV (“69 kV OOM”) 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 69 kV and 138 kV constraints via the market model.
- Slide [57](#) also shows our estimated LBMP impacts in each LI load pocket that result from explicitly modeling 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 [58](#) 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.



Duct Burner RPU Performance and Real-Time Availability

- Slide [59](#) shows a case study of real-time performance of a combined-cycle unit that failed to follow 5-minute instructions during an RPU event due to its inability to fire the duct burner within 10-minutes.
 - ✓ The two lines show the levels where resource capacity shifts from baseload without duct burners (gray line) to the duct burner range (red line). Capacity values are not given for confidentiality purposes.
 - ✓ The blue columns show the actual output produced by the resource in each RTD and RTD-CAM interval. The black dotted line shows the 5-minute instructions by the market model.
 - ✓ A faded box highlights the RPU timeframe and the red-patterned area between the columns and the instructed output line outlines the duct burner output that was not delivered by the station.
- Slide [60](#) shows quarterly average real-time duct burner data across all applicable units during this quarter on a 5-minute interval level basis.
 - ✓ The topmost chart shows the average amount of MWs from duct burners scheduled in real-time to provide 10-minute spinning reserves and regulation services.
 - ✓ The middle chart shows the amount of 5-minute up-ramping capability assumed to be available by duct burners (but likely not actually available due to physical operating restrictions) based on real-time output levels and generator offers.
 - ✓ The bottom chart reveals the average amount of duct burner capacity unavailable in real-time because of no offer in this range or non-dispatchable due to inflexible self-schedule level.



GT Start-up Performance

- Slides [61](#)-[62](#) 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 [61](#)): “26 10-minute GTs exhibited a response rate of 90 to 100 percent during economic starts in the examined period, 26 of them were audited 56 times in total with 2 failures”.




Supplemental Commitments and OOM Dispatch

- Slides [64](#), [65](#), and [66](#) summarize out-of-market commitment and dispatch, which are the primary sources of guarantee payment uplift.
- Slide [64](#) 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 [65](#) examines the reasons for reliability commitments in NYC where most reliability commitments occur.
 - ✓ Based on a review of operator logs and LRR constraint information (where a unit is considered to be committed for a LRR constraint if the constraint would be violated without the unit’s capacity), each NYC commitment (flagged as DARU, LRR, or SRE) was categorized for one of the following reasons:



Supplemental Commitments and OOM Dispatch (cont.)

- NO_x Only – If needed for NO_x bubble requirement and no other reason.
 - Voltage – If needed for ARR 26 and no other reason.
 - Thermal – If needed for ARR 37 and no other reason.
 - Loss of Gas – If needed for IR-3, a sudden loss of gas supply in NY, and no other reason except NO_x.
 - Multiple Reasons – If needed for two or three of the following reasons: voltage support, thermal support, NO_x, or loss of gas. The capacity is shown multiple times for each separate reason in the bar chart.
- ✓ For voltage and thermal constraints, the capacity is shown by the load pocket that was secured.
 - Slide [66](#) 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.



Supply Margin in NYC Load Pockets After Removing NO_x-only Committed ST and GT in the NO_x Bubble

- Steam units in New York City are often LRR-committed solely to satisfy the NO_x Bubble requirement in the Ozone season.
 - ✓ On many of these days, even if both the committed ST and its supported GTs were unavailable, all N-1-1 criteria could be satisfied by other resources.
 - This questions the necessity of such commitments in each day of the Ozone season.
- Slide [67](#) shows our evaluation of the necessity in the quarter.
 - ✓ The figure shows the daily minimum supply margin in the relevant load pockets after the removal of the NO_x-committed STs and their supported GTs in the NO_x Bubble.
 - ✓ The evaluation is done on days when the ST is NO_x-only committed in the day-ahead market.
 - ✓ A positive minimum supply margin indicates that both the ST and associated GTs were not needed to satisfy any N-1-1 criteria in the load pocket.



Uplift Costs from Guarantee Payments

- Slides [68](#) and [69](#) 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 [68](#) shows these seven categories on a daily basis during the quarter.
 - ✓ Slide [69](#) summarizes uplift costs by region on a monthly basis.



Potential Economic and Physical Withholding

- Slides [71](#) and [72](#) 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 [73](#) 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 [75](#) and [76](#) summarize market results and key drivers in the monthly spot capacity auctions.
 - ✓ Slide [75](#) 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 [76](#) 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.