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

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

Potomac Economics
Market Monitoring Unit

August 2021

POTOMAC ECONOMICS



Table of Contents

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)

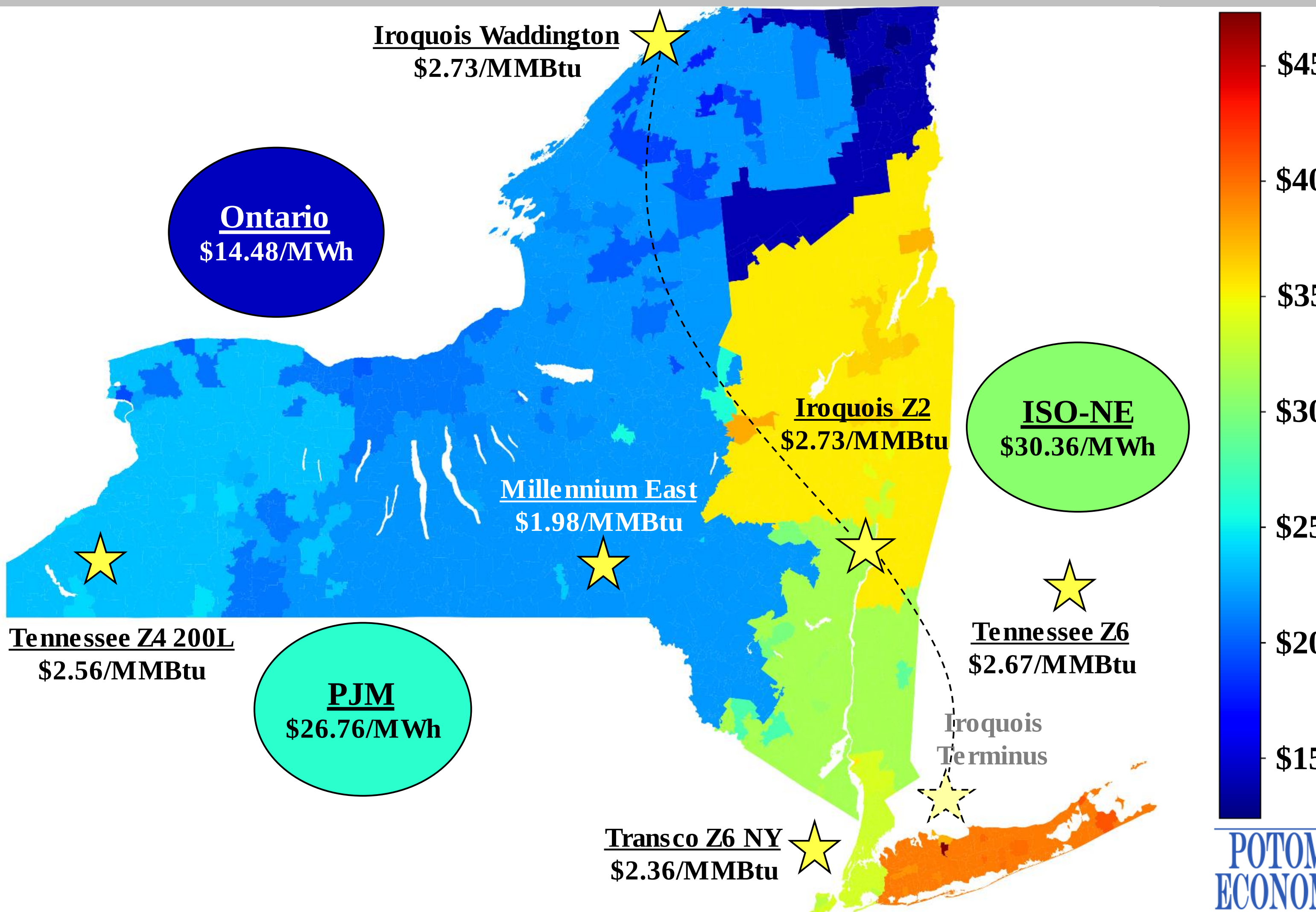
POTOMAC ECONOMICS

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.

POTOMAC ECONOMICS

Market Highlights:
System Price Diagram



POTOMAC ECONOMICS

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.

POTOMAC ECONOMICS

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 NOx emission in New York City in the second quarter of 2021.
  - ✓ Roughly one third of ST NOx emission was from STs that were supplementally committed for local reliability. (slide 28)

POTOMAC ECONOMICS

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.

POTOMAC ECONOMICS

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.

POTOMAC ECONOMICS

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.

POTOMAC ECONOMICS

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.

POTOMAC ECONOMICS

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 NOx-Rule LRR Commitments in NYC

- The NOx 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 NOx emission satisfies the DEC standard.
  - ✓ A steam turbine was LRR-committed solely to satisfy the NOx 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 NOx-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 NOx-only ST commitment.
  - ✓ These avoidable NOx-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)

POTOMAC ECONOMICS

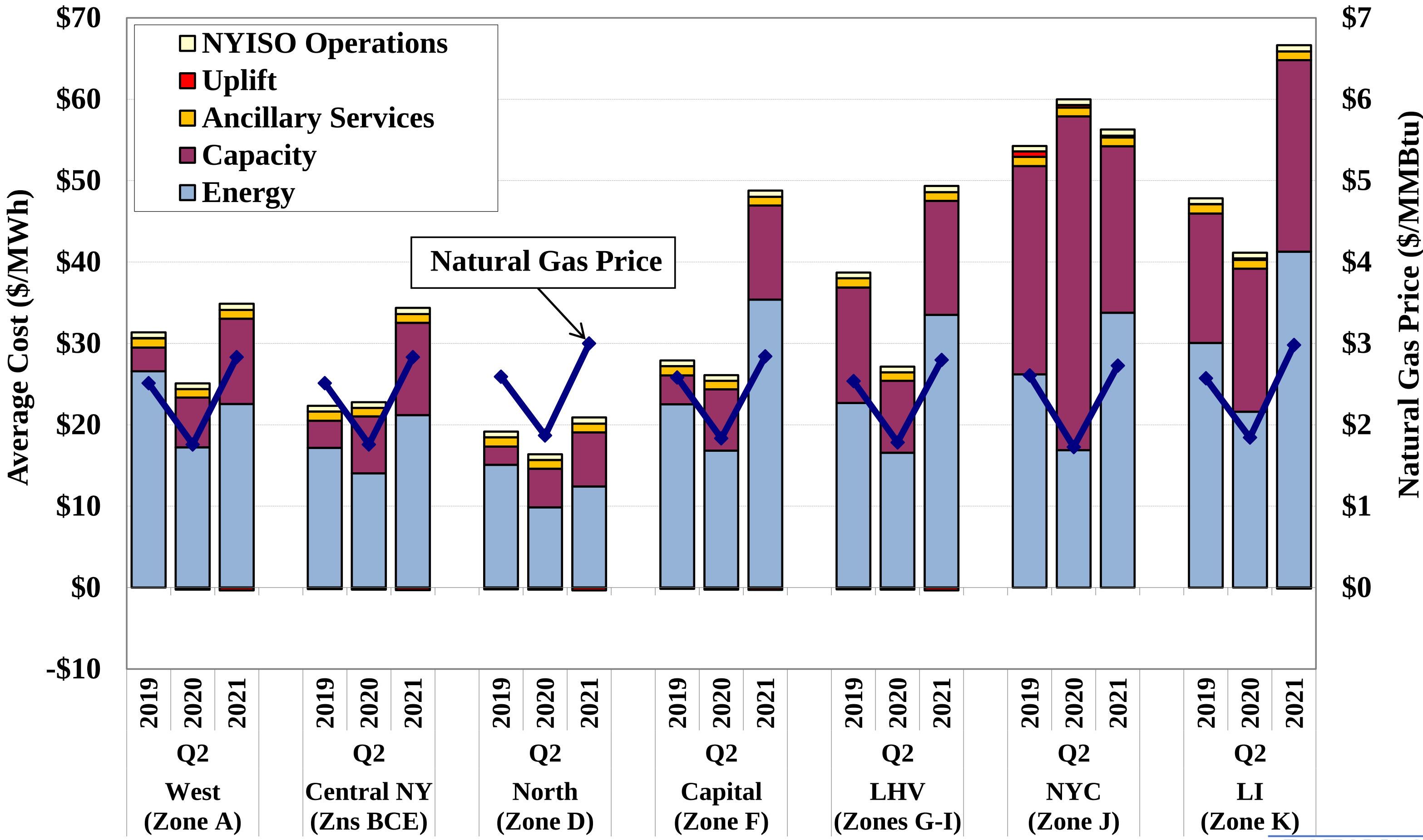
Market Highlights:
Capacity Market

- 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:

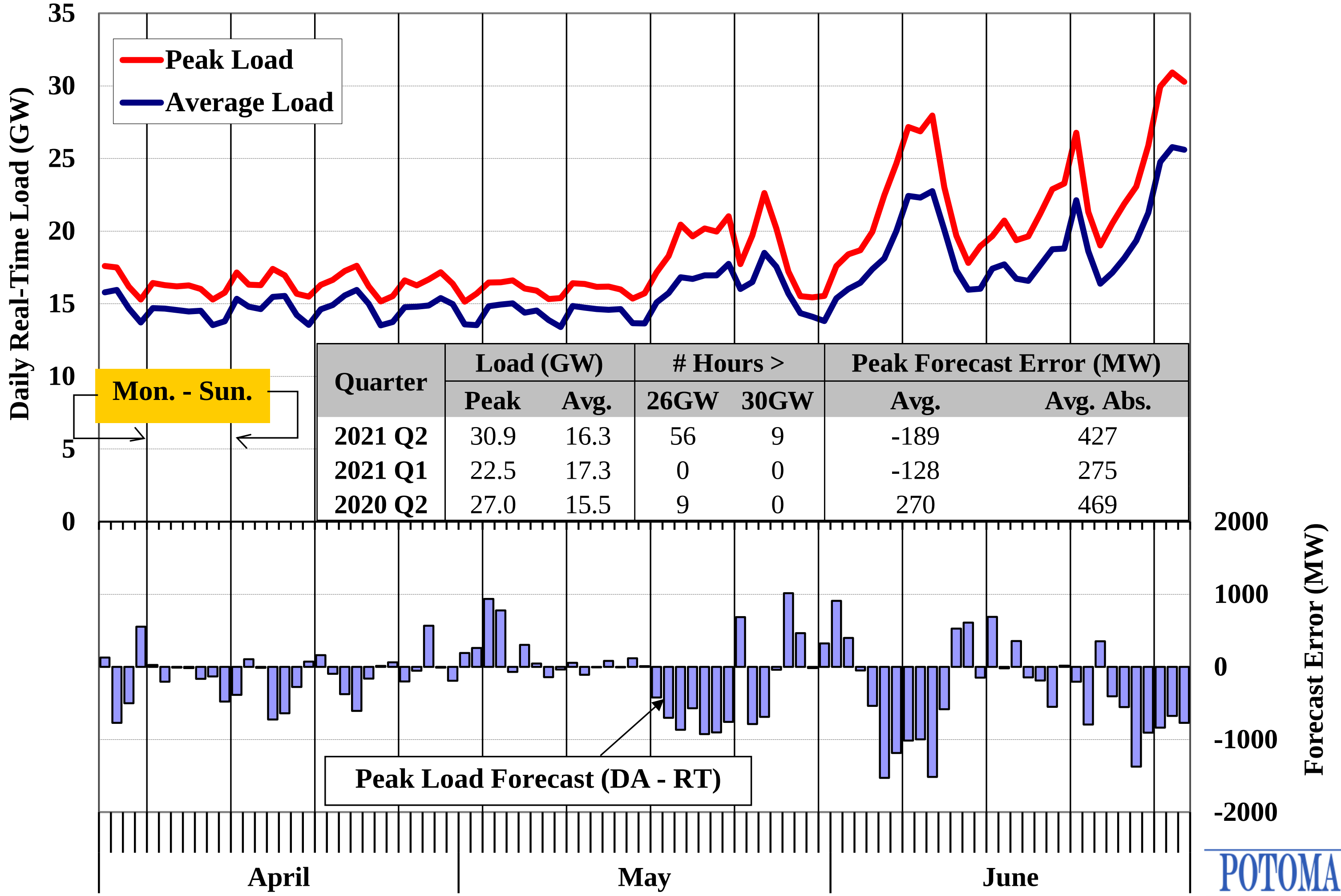
Market Outcomes

All-In Prices by Region



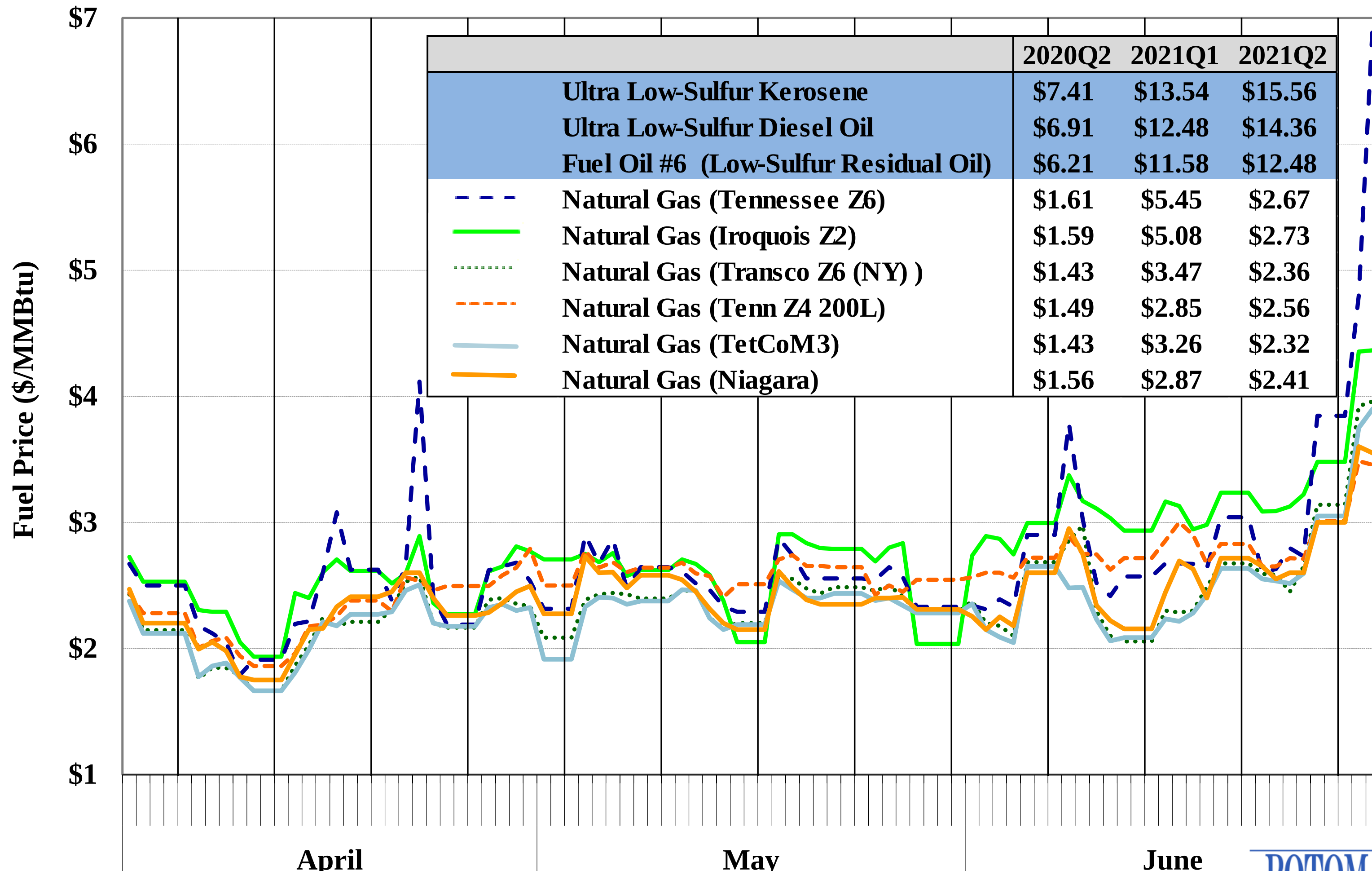
Notes: For chart description, see slide 78.

Load Forecast and Actual Load



Quarter	Load (GW)		# Hours >		Peak Forecast Error (MW)	
	Peak	Avg.	26GW	30GW	Avg.	Avg. Abs.
2021 Q2	30.9	16.3	56	9	-189	427
2021 Q1	22.5	17.3	0	0	-128	275
2020 Q2	27.0	15.5	9	0	270	469

Natural Gas and Fuel Oil Prices

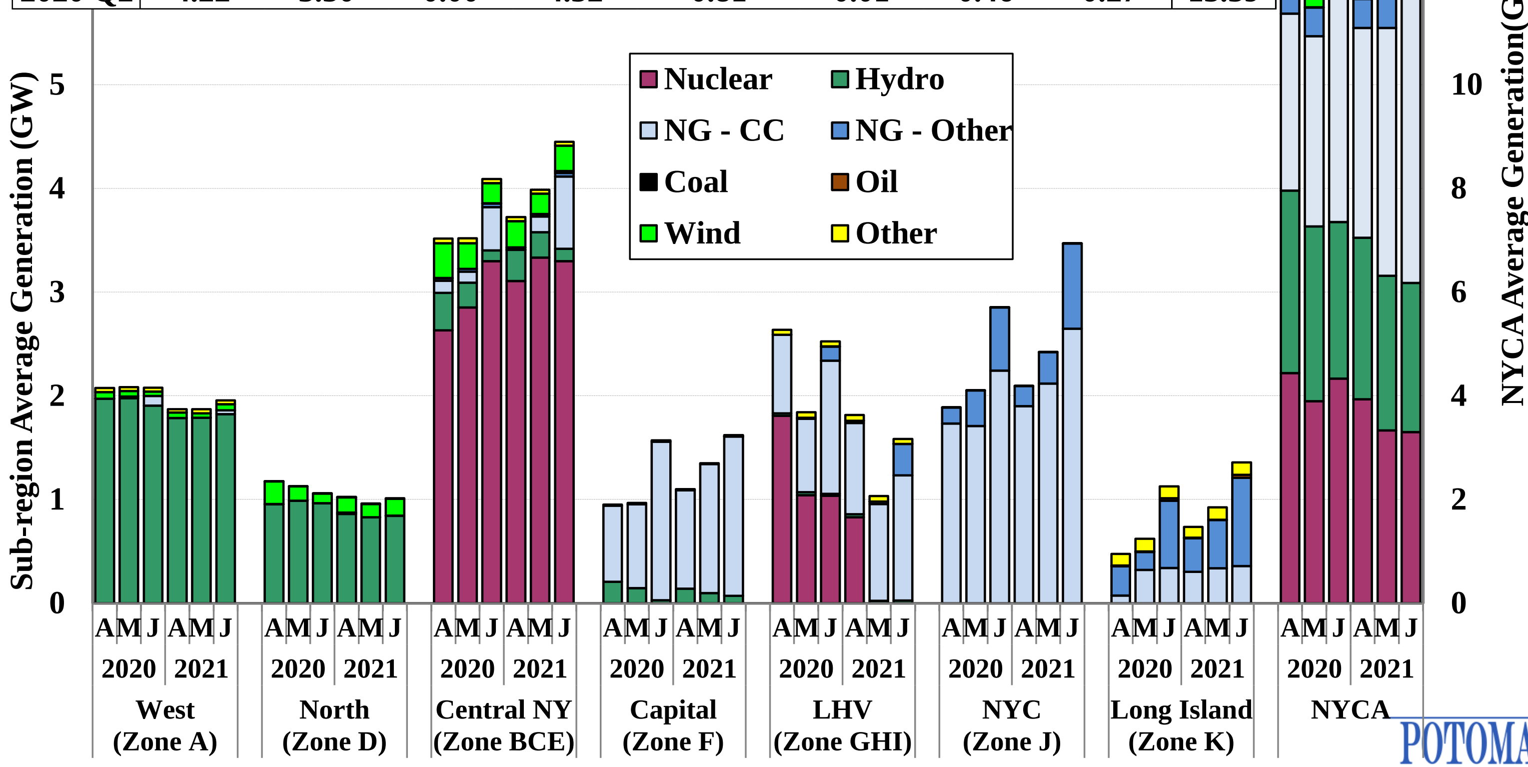


	2020Q2	2021Q1	2021Q2
Ultra Low-Sulfur Kerosene	$7.41	$13.54	$15.56
Ultra Low-Sulfur Diesel Oil	$6.91	$12.48	$14.36
Fuel Oil #6 (Low-Sulfur Residual Oil)	$6.21	$11.58	$12.48
Natural Gas (Tennessee Z6)	$1.61	$5.45	$2.67
Natural Gas (Iroquois Z2)	$1.59	$5.08	$2.73
Natural Gas (Transco Z6 (NY))	$1.43	$3.47	$2.36
Natural Gas (Tenn Z4 200L)	$1.49	$2.85	$2.56
Natural Gas (TetCoM3)	$1.43	$3.26	$2.32
Natural Gas (Niagara)	$1.56	$2.87	$2.41

POTOMAC ECONOMICS

Real-Time Generation Output by Fuel Type

Quarter	Nuclear	Hydro	Coal	NG-CC	NG-Other	Oil	Wind	Other	Total
	Average Internal Generation by Fuel Type in NYCA (GW)								
2021 Q2	3.52	2.99	0.00	5.10	1.12	0.02	0.43	0.25	13.44
2021 Q1	4.30	3.06	0.00	4.76	1.18	0.13	0.55	0.25	14.23
2020 Q2	4.22	3.30	0.00	4.32	0.81	0.01	0.46	0.27	13.39

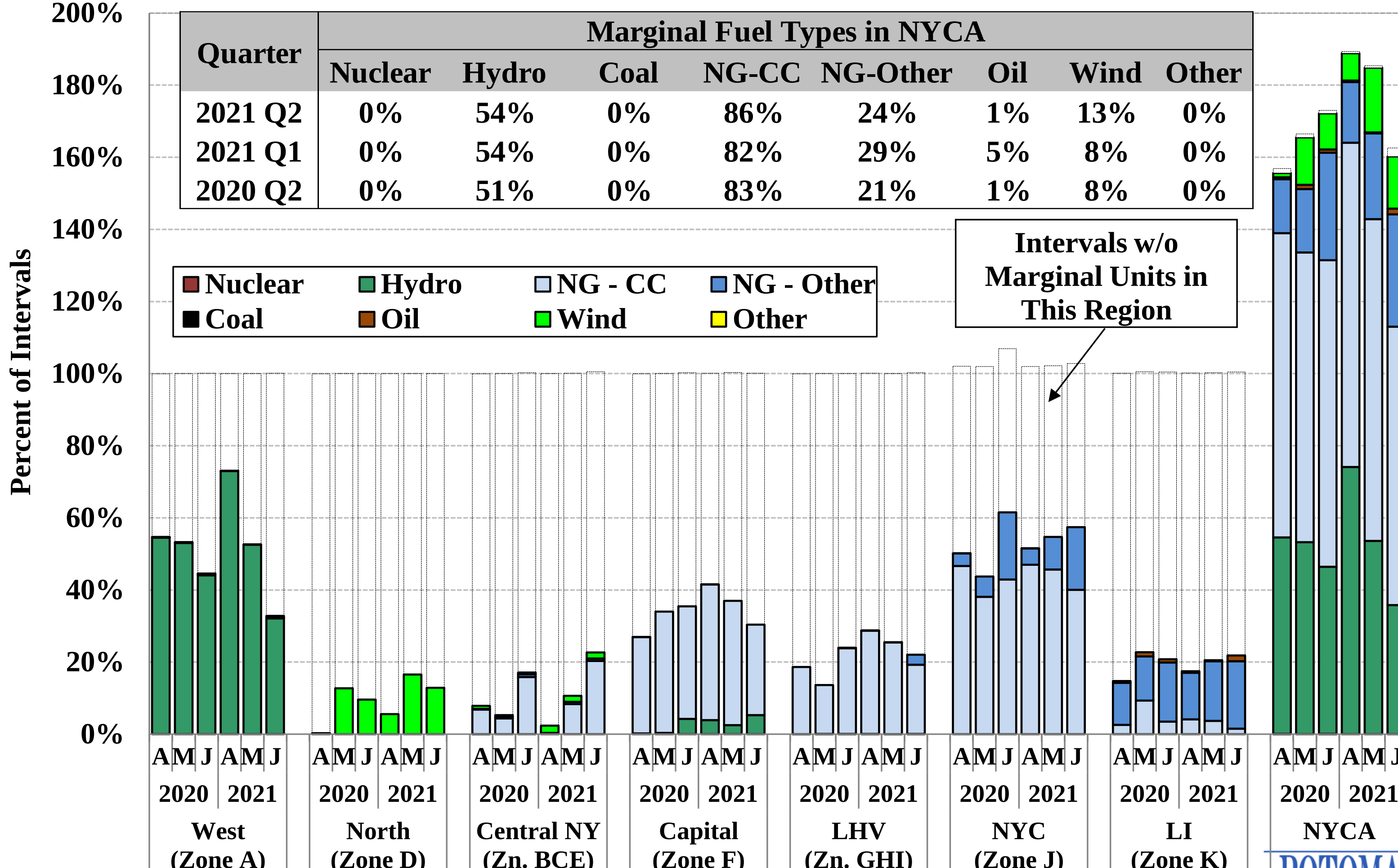


Notes: For chart description, see slide 79.

POTOMAC ECONOMICS

Fuel Type of Marginal Units in the Real-Time Market

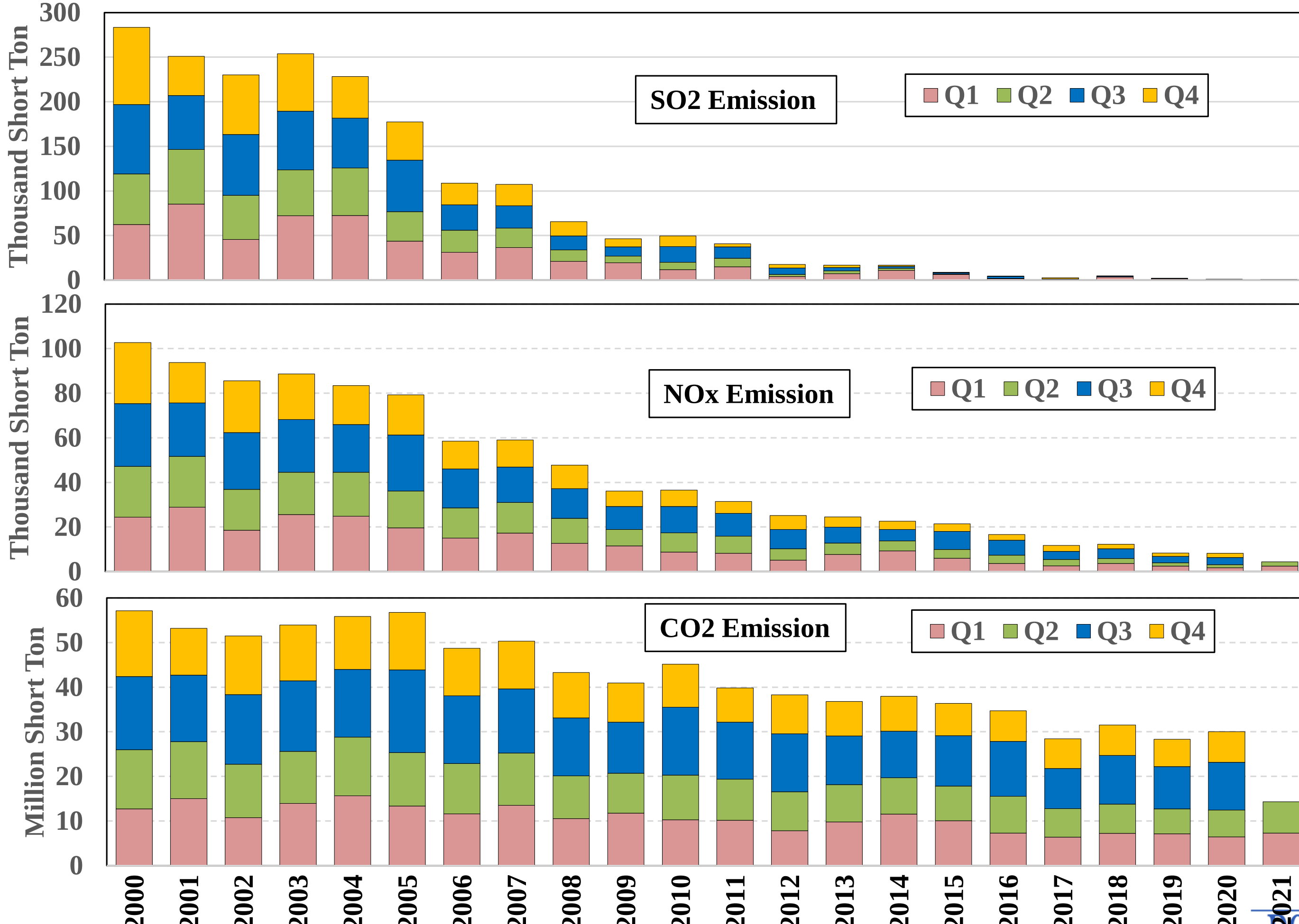
Quarter	Marginal Fuel Types in NYCA							
	Nuclear	Hydro	Coal	NG-CC	NG-Other	Oil	Wind	Other
2021 Q2	0%	54%	0%	86%	24%	1%	13%	0%
2021 Q1	0%	54%	0%	82%	29%	5%	8%	0%
2020 Q2	0%	51%	0%	83%	21%	1%	8%	0%



  Notes: For chart description, see slide 79.

POTOMAC ECONOMICS

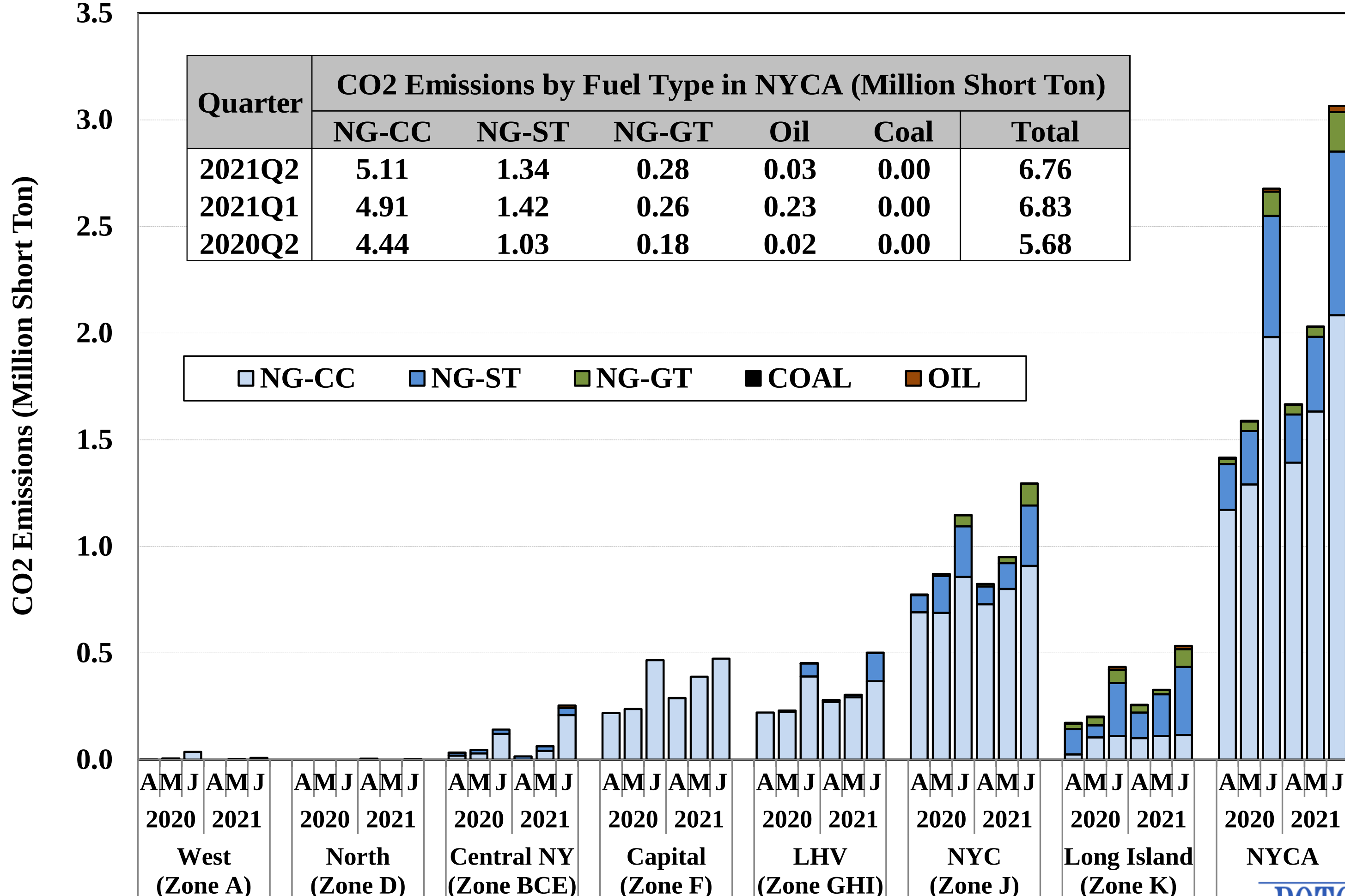
Historical Emissions by Quarter in NYCA
CO_2, SO_2 , and NO_X



Notes: For chart description, see slide 80.

POTOMAC ECONOMICS

Emissions by Region by Fuel Type
CO_2 Emissions



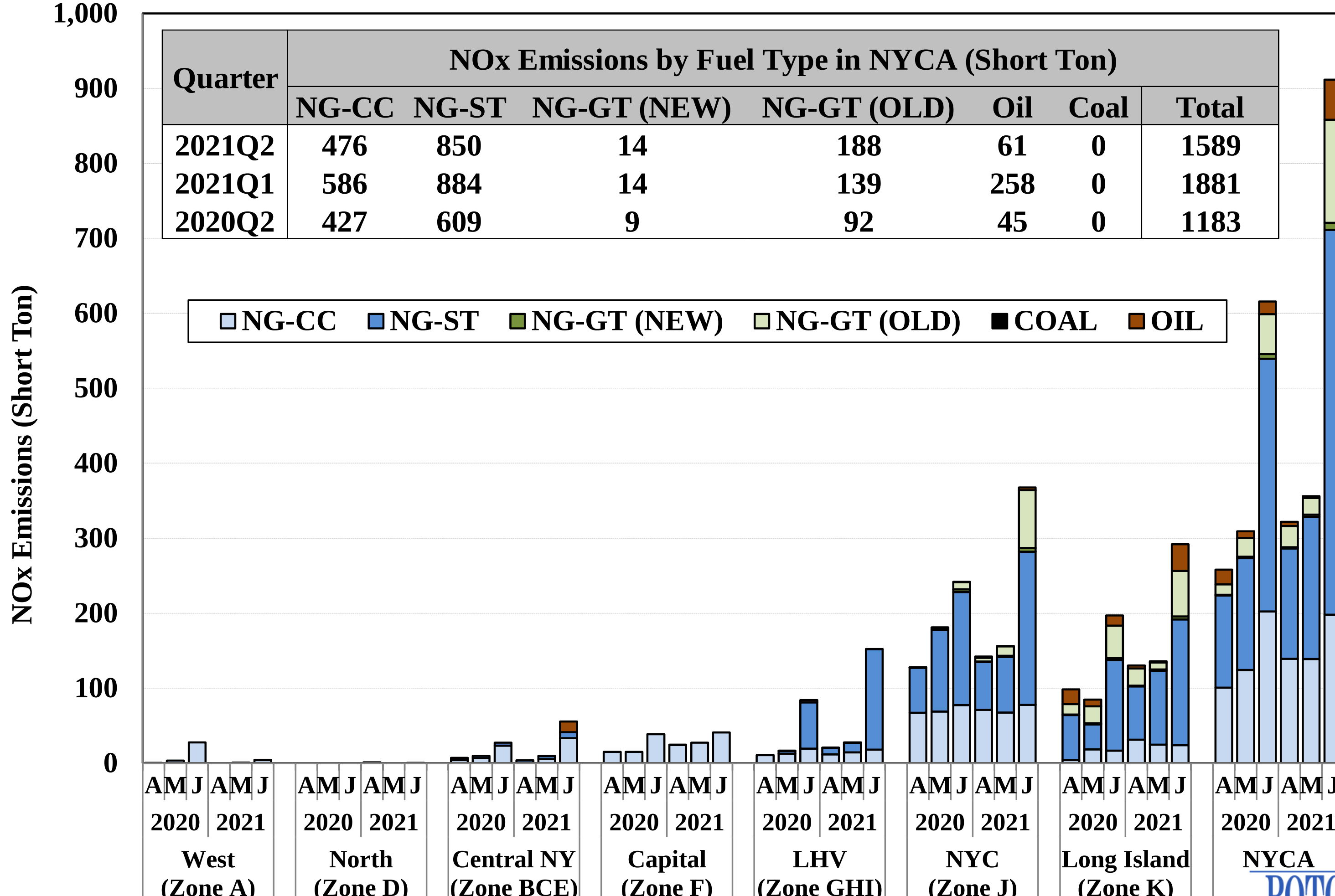
Quarter	CO2 Emissions by Fuel Type in NYCA (Million Short Ton)					
	NG-CC	NG-ST	NG-GT	Oil	Coal	Total
2021Q2	5.11	1.34	0.28	0.03	0.00	6.76
2021Q1	4.91	1.42	0.26	0.23	0.00	6.83
2020Q2	4.44	1.03	0.18	0.02	0.00	5.68

Notes: For chart description, see slide 80.

POTOMAC ECONOMICS

Emissions by Region by Fuel Type
NO_X Emissions

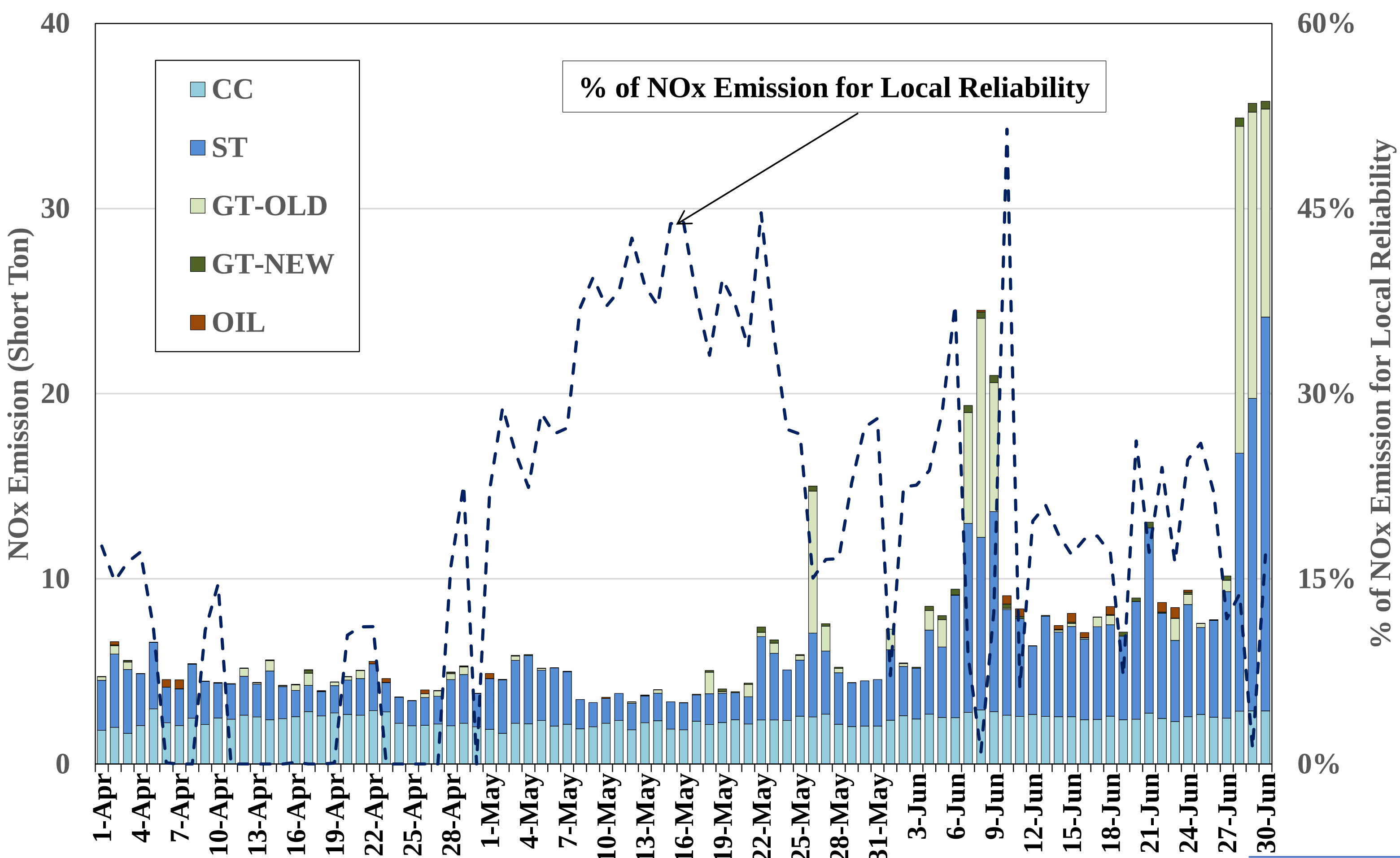
Quarter	NOx Emissions by Fuel Type in NYCA (Short Ton)						
	NG-CC	NG-ST	NG-GT (NEW)	NG-GT (OLD)	Oil	Coal	Total
2021Q2	476	850	14	188	61	0	1589
2021Q1	586	884	14	139	258	0	1881
2020Q2	427	609	9	92	45	0	1183



 Notes: For chart description, see slide 80.

POTOMAC ECONOMICS

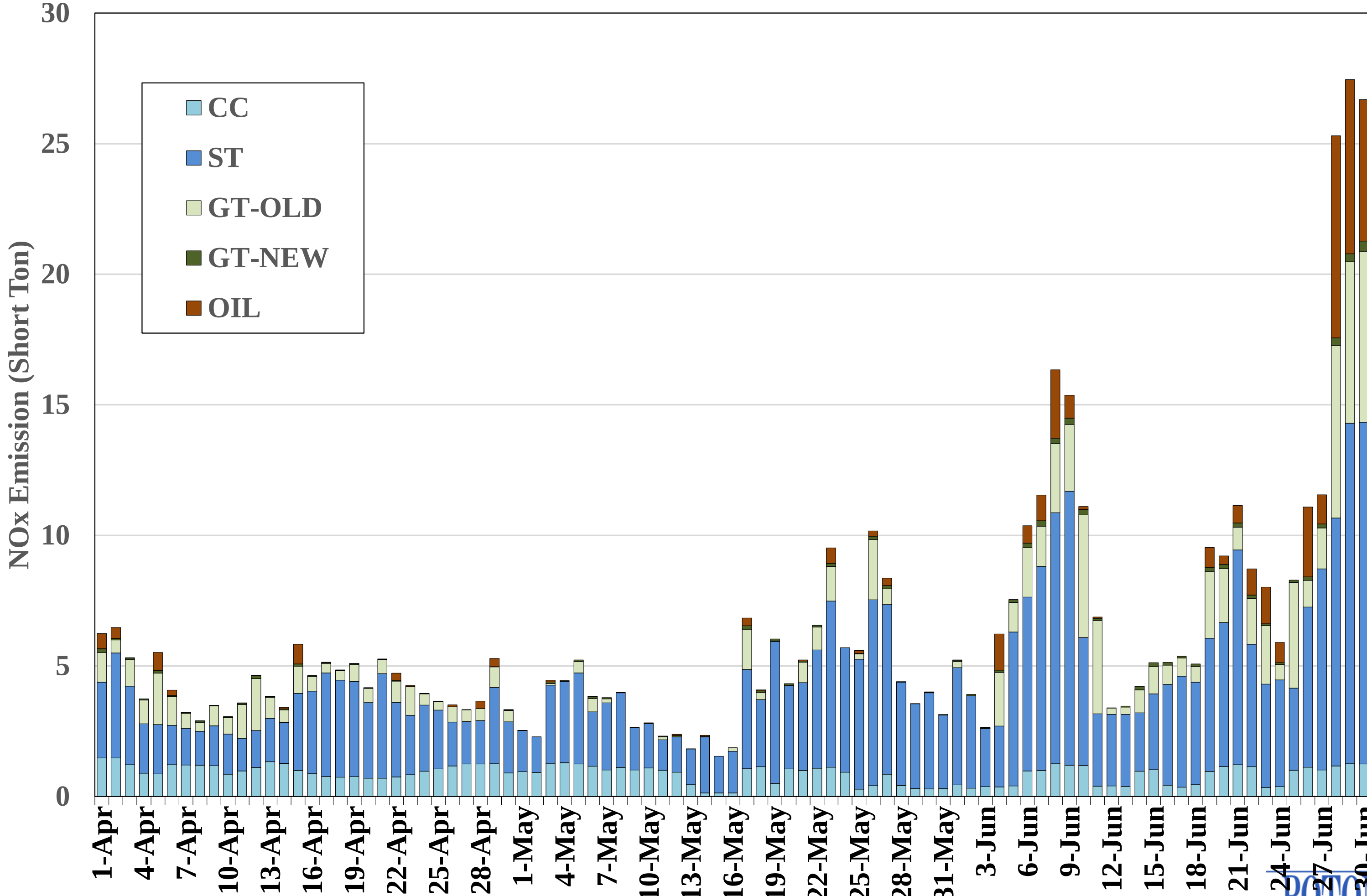
Daily NO_X Emissions in NYC



Notes: For chart description, see slide 80.

POTOMAC ECONOMICS

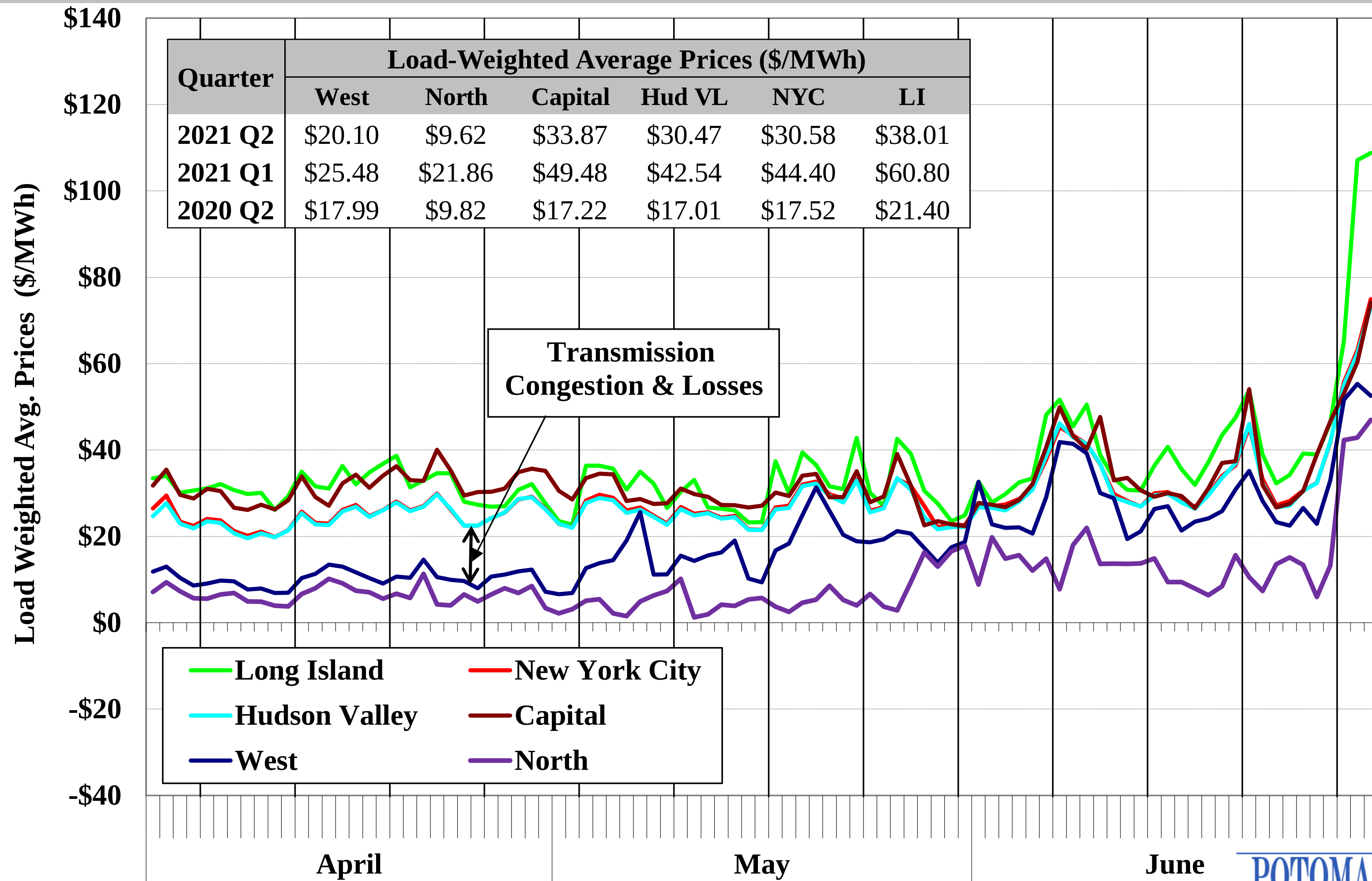
Daily NO_X Emissions in Long Island



Notes: For chart description, see slide 80.

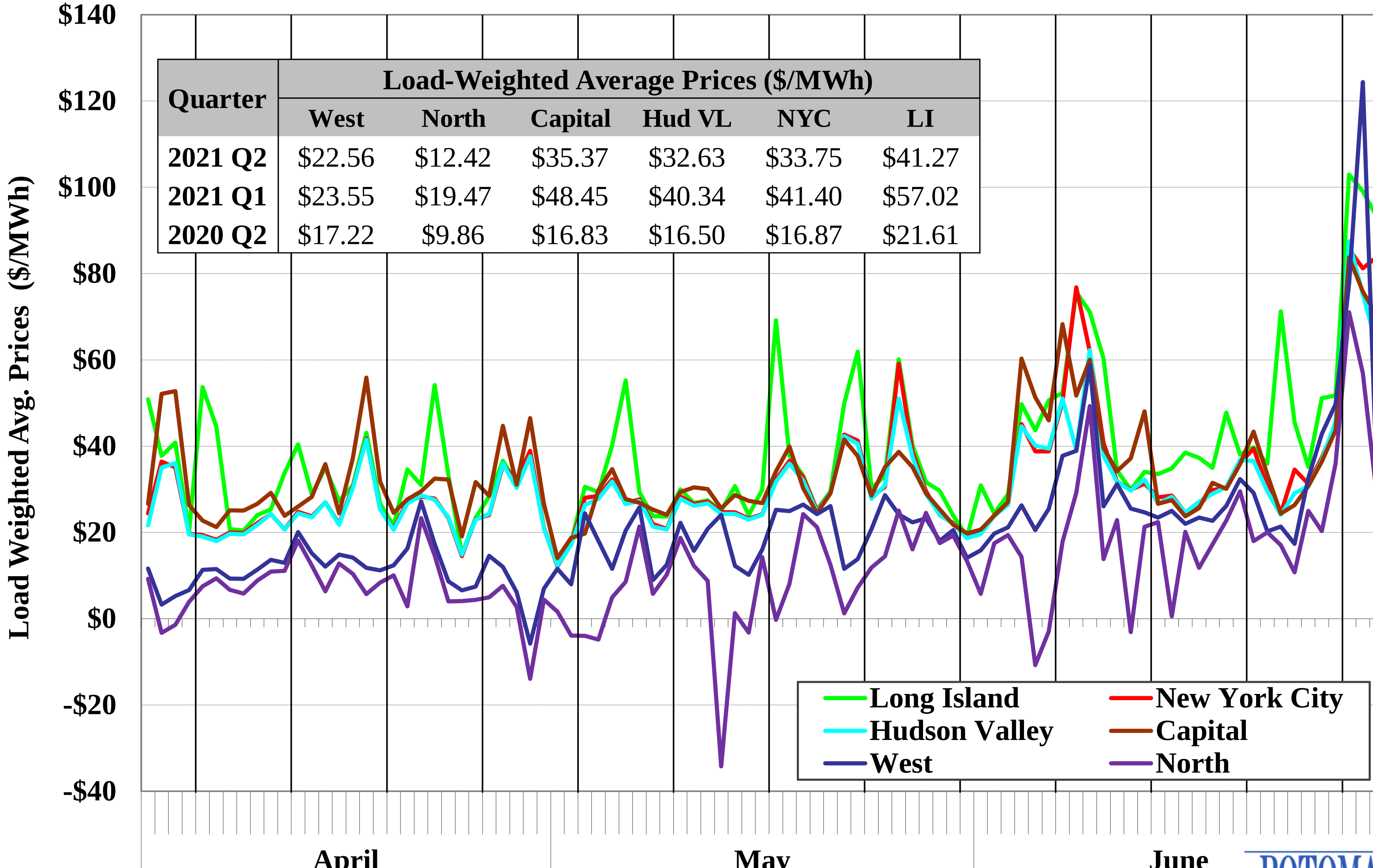
POTOMAC ECONOMICS

Day-Ahead Electricity Prices by Zone



Quarter	Load-Weighted Average Prices ($/MWh)					
	West	North	Capital	Hud VL	NYC	LI
2021 Q2	$20.10	$9.62	$33.87	$30.47	$30.58	$38.01
2021 Q1	$25.48	$21.86	$49.48	$42.54	$44.40	$60.80
2020 Q2	$17.99	$9.82	$17.22	$17.01	$17.52	$21.40

Real-Time Electricity Prices by Zone

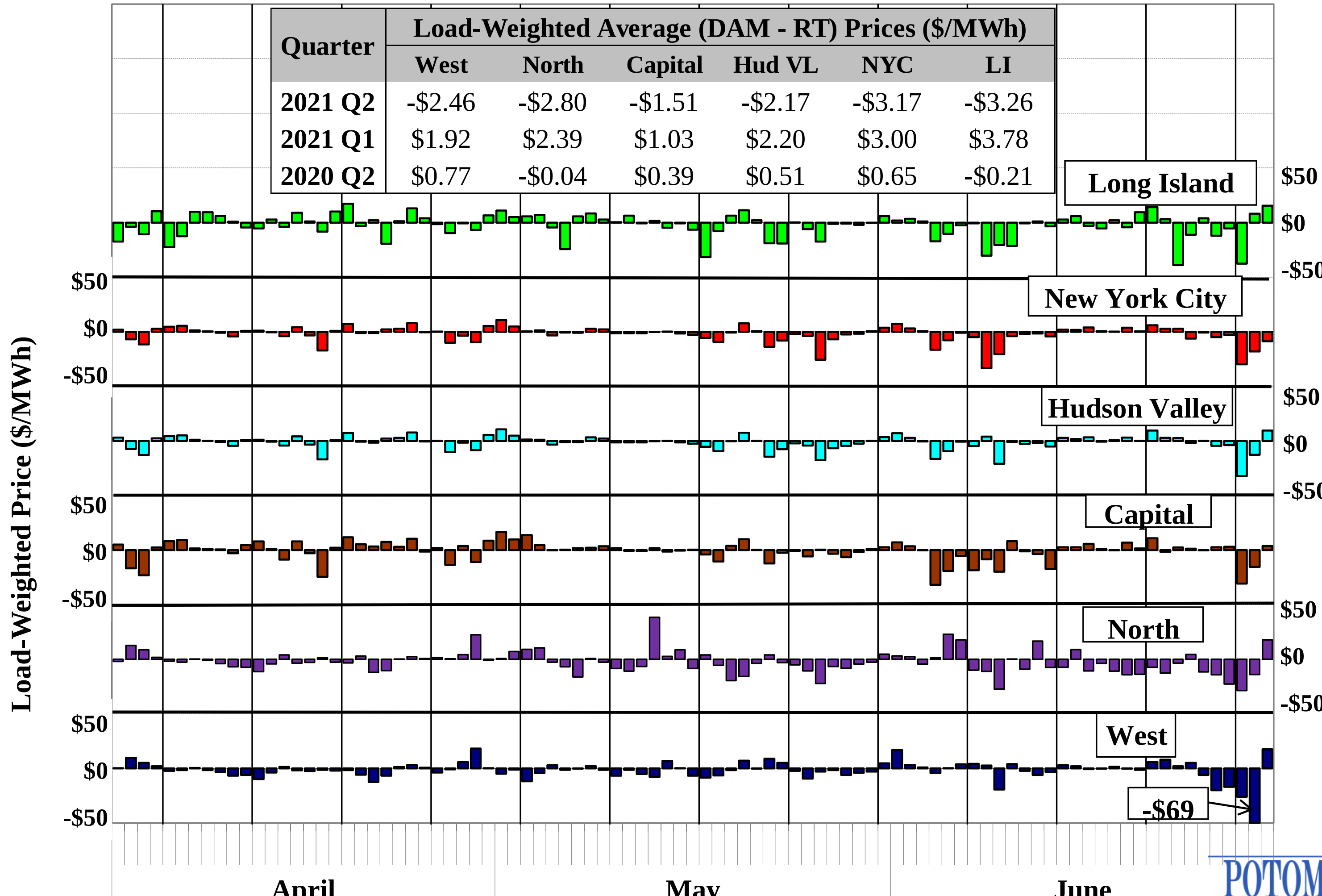


Quarter	Load-Weighted Average Prices ($/MWh)					
	West	North	Capital	Hud VL	NYC	LI
2021 Q2	$22.56	$12.42	$35.37	$32.63	$33.75	$41.27
2021 Q1	$23.55	$19.47	$48.45	$40.34	$41.40	$57.02
2020 Q2	$17.22	$9.86	$16.83	$16.50	$16.87	$21.61

POTOMAC ECONOMICS

Convergence Between Day-Ahead and Real-Time Prices

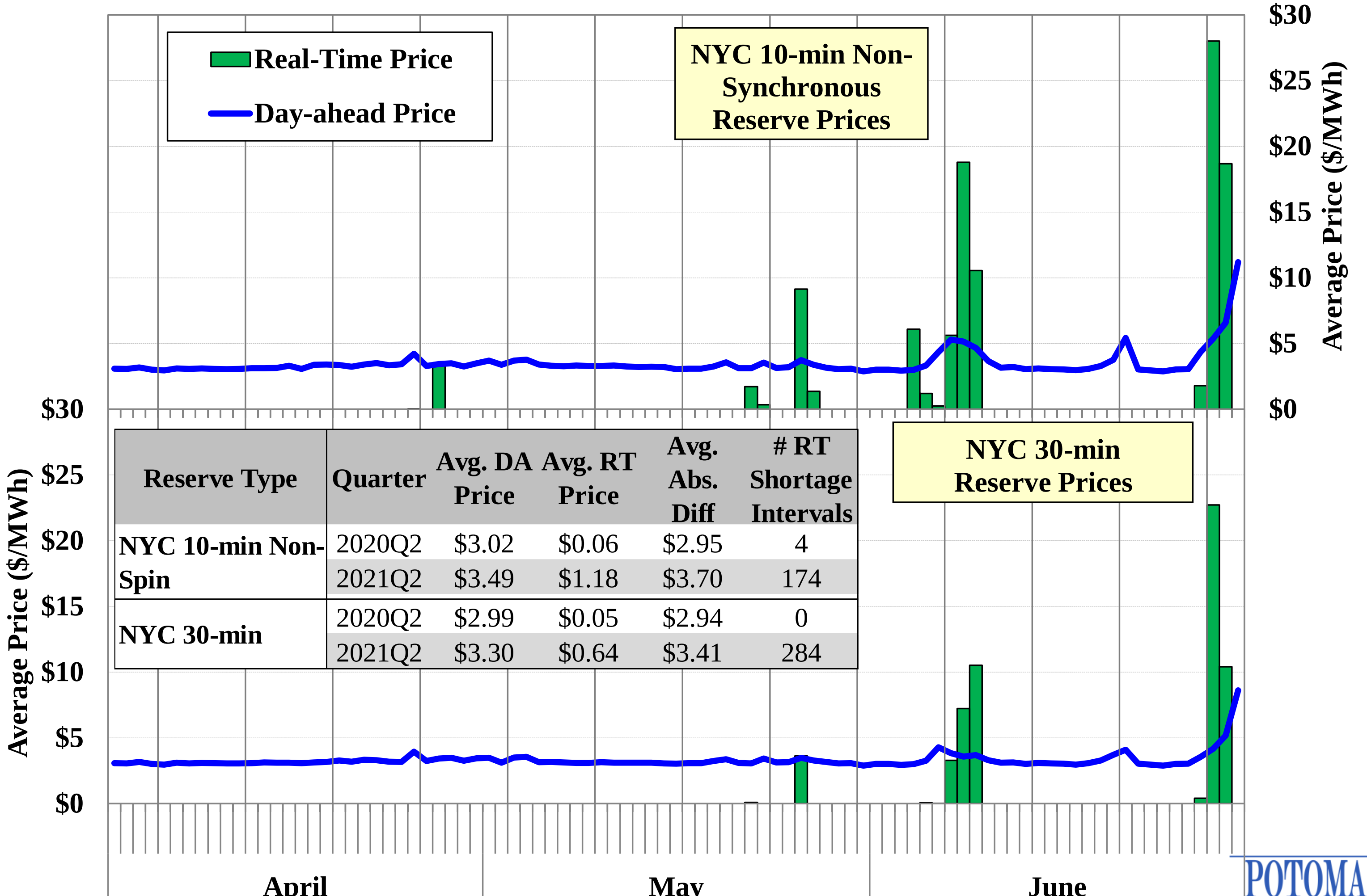
Quarter	Load-Weighted Average (DAM - RT) Prices ($/MWh)					
	West	North	Capital	Hud VL	NYC	LI
2021 Q2	-$2.46	-$2.80	-$1.51	-$2.17	-$3.17	-$3.26
2021 Q1	$1.92	$2.39	$1.03	$2.20	$3.00	$3.78
2020 Q2	$0.77	-$0.04	$0.39	$0.51	$0.65	-$0.21



Charts:

Ancillary Services Market

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

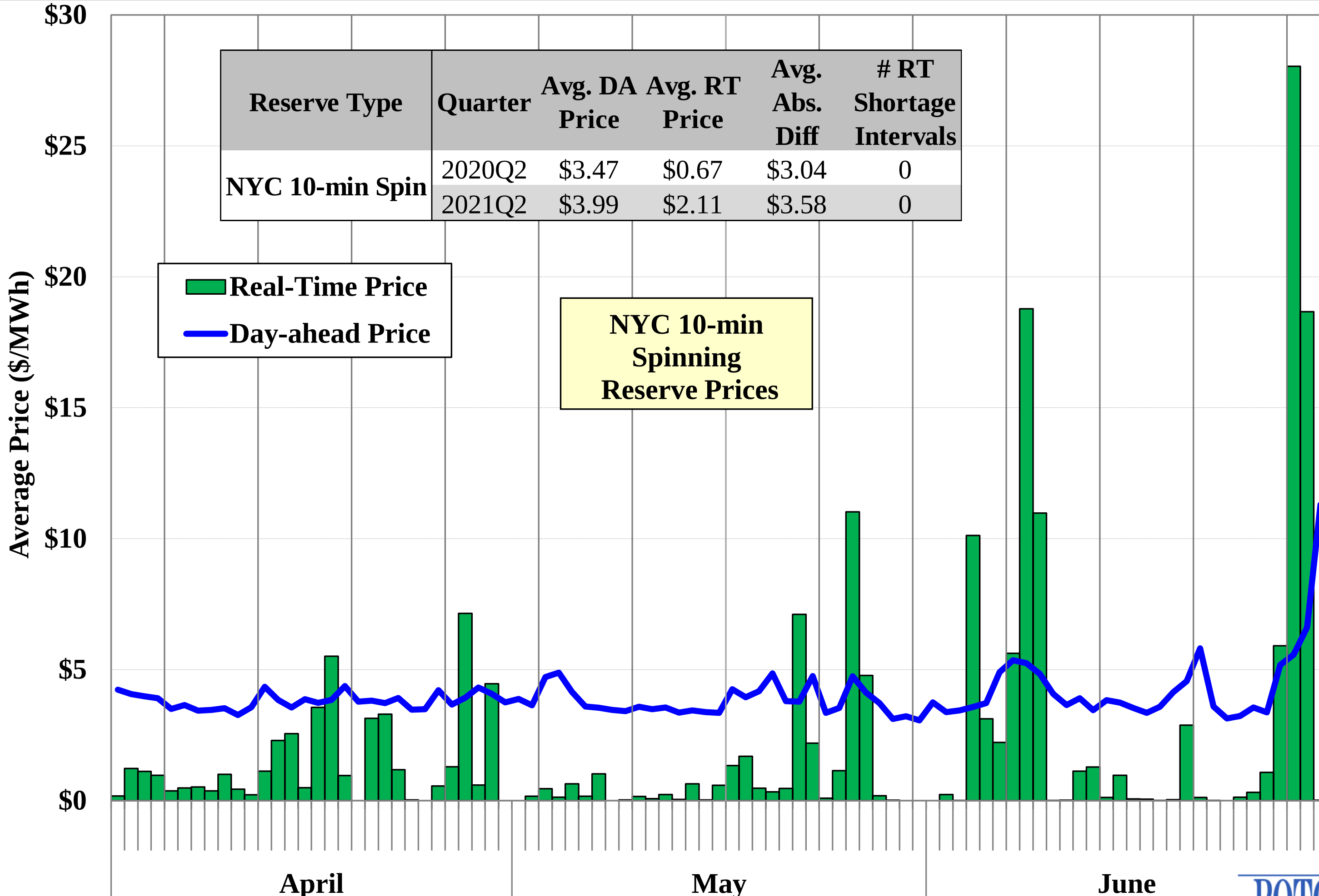


Reserve Type	Quarter	Avg. DA Price	Avg. RT Price	Avg. Abs. Diff	# RT Shortage Intervals
NYC 10-min Non-Spin	2020Q2	$3.02	$0.06	$2.95	4
	2021Q2	$3.49	$1.18	$3.70	174
NYC 30-min	2020Q2	$2.99	$0.05	$2.94	0
	2021Q2	$3.30	$0.64	$3.41	284

Notes: For chart description, see slide 81.

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	2020Q2	\$3.47	\$0.67	\$3.04	0
	2021Q2	\$3.99	\$2.11	\$3.58	0

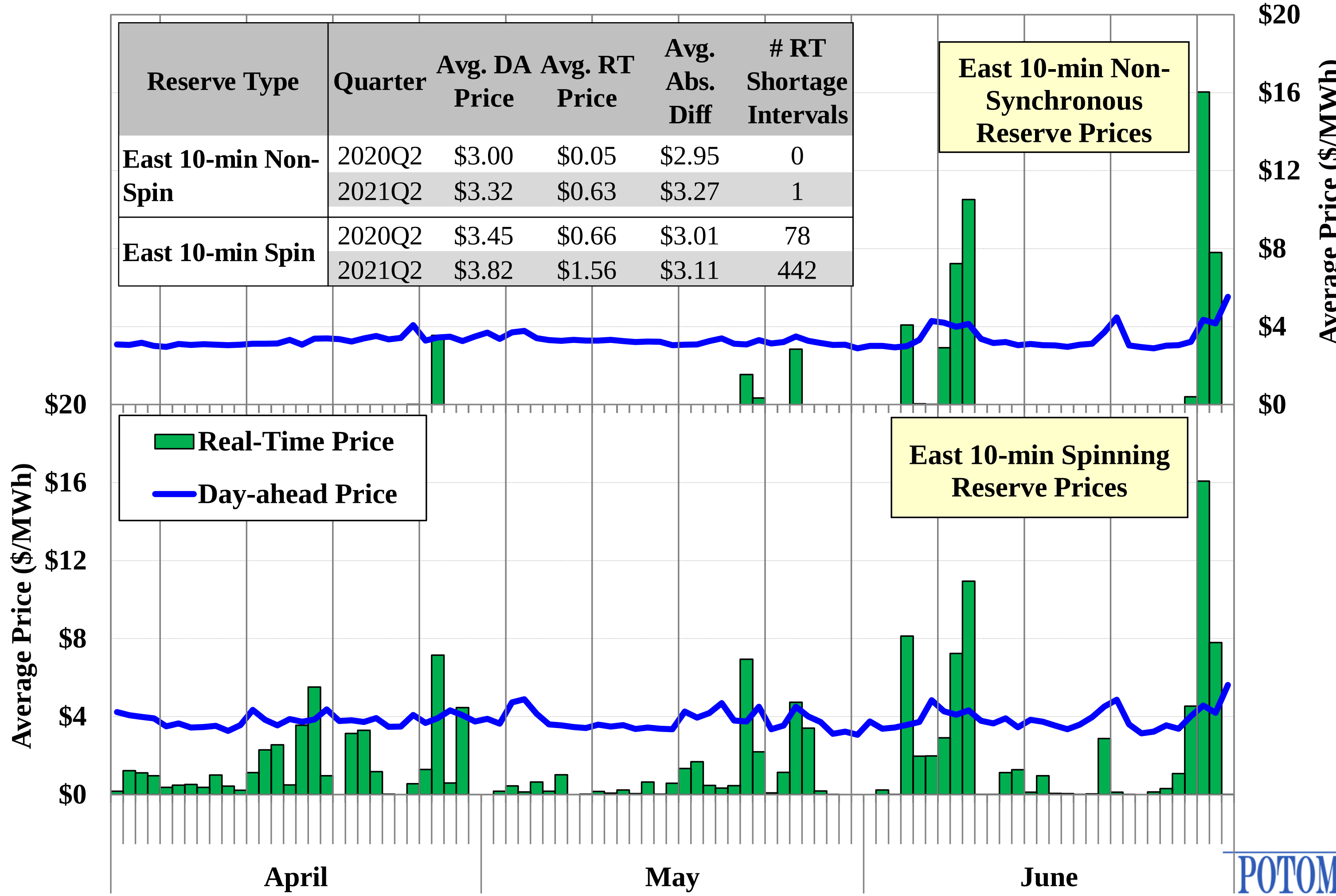


Notes: For chart description, see slide 81.

POTOMAC ECONOMICS

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	2020Q2	$3.00	$0.05	$2.95	0
	2021Q2	$3.32	$0.63	$3.27	1
East 10-min Spin	2020Q2	$3.45	$0.66	$3.01	78
	2021Q2	$3.82	$1.56	$3.11	442

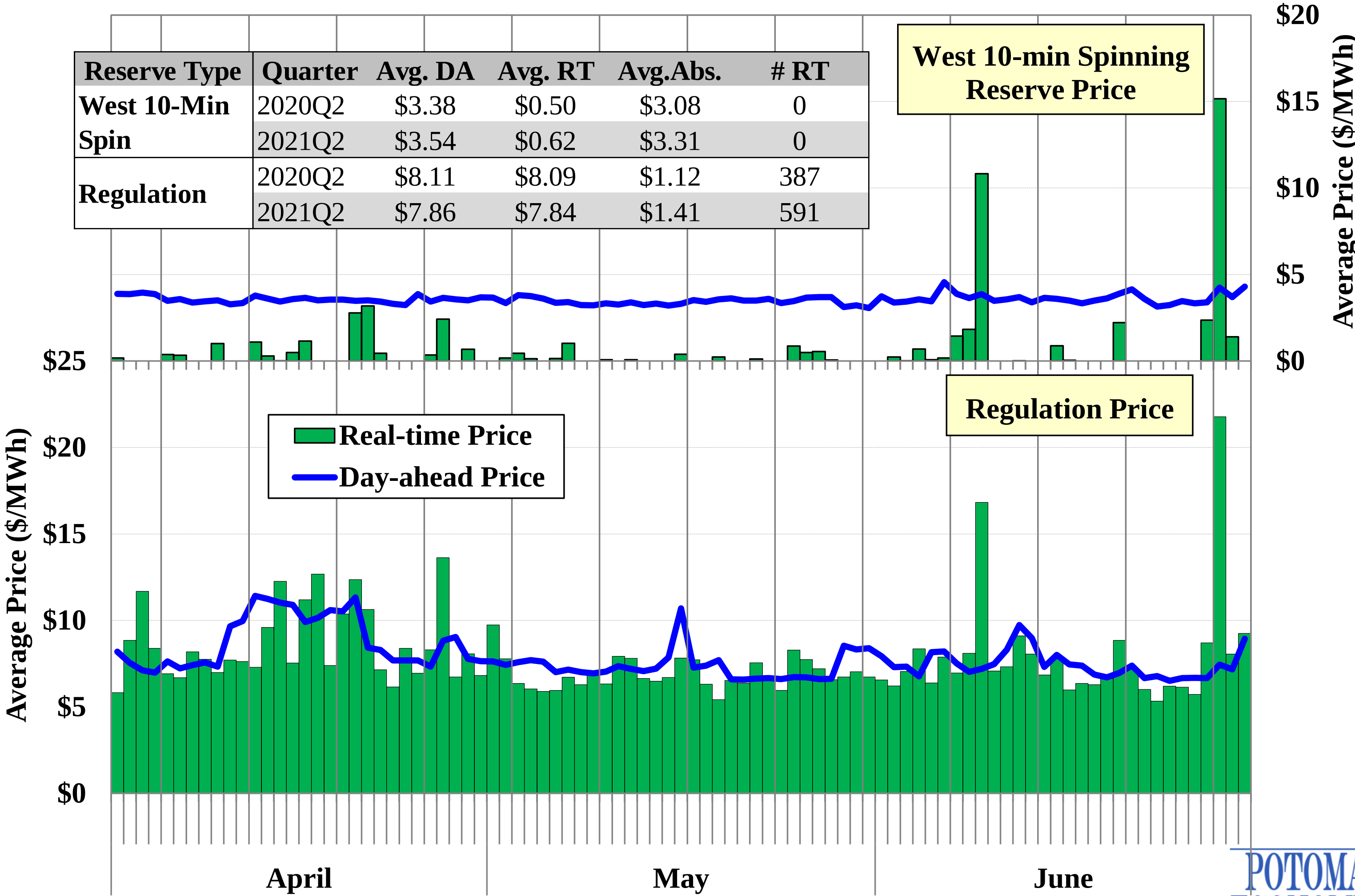


Notes: For chart description, see slide 81.

POTOMAC ECONOMICS

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

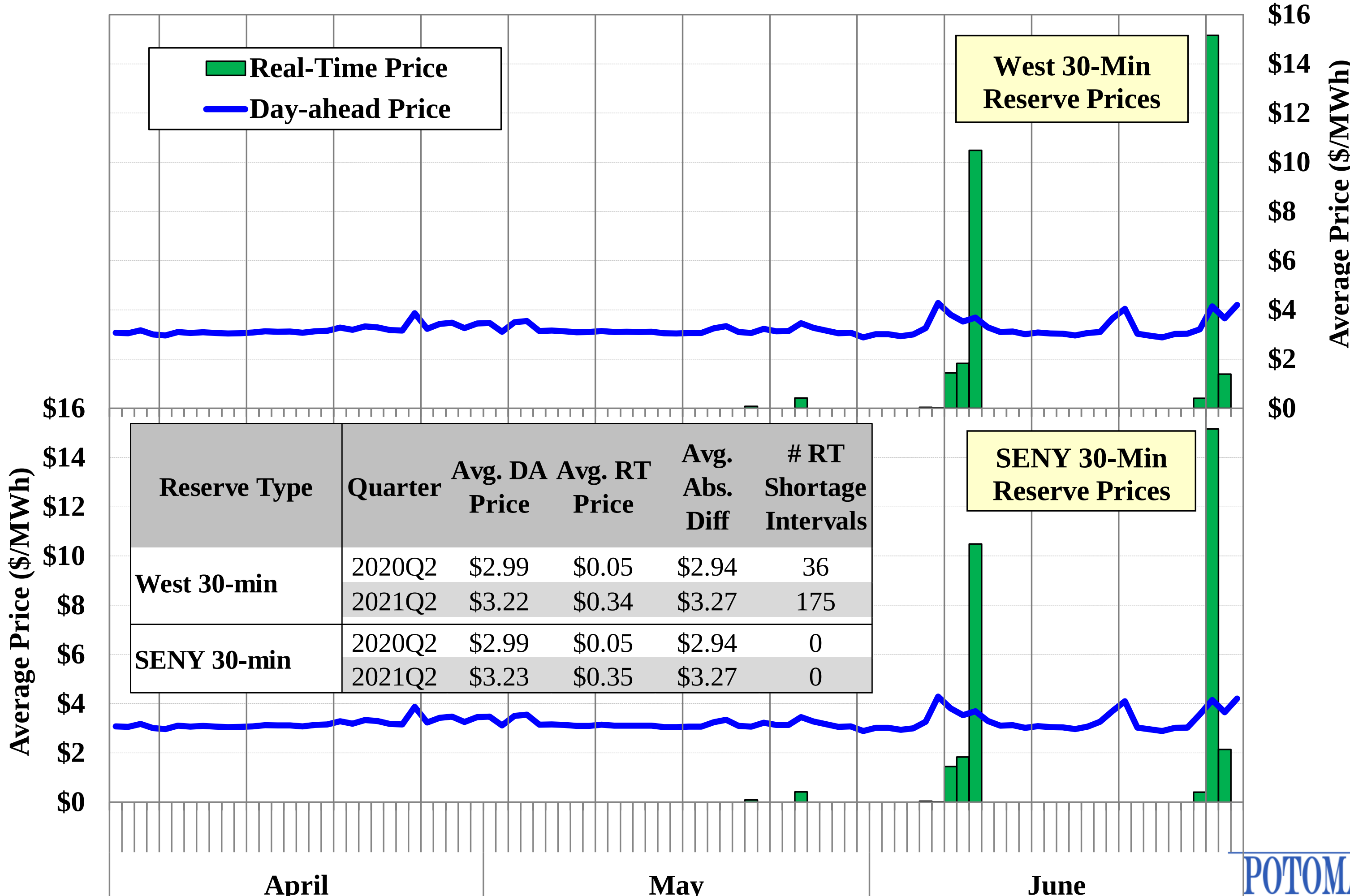
Reserve Type	Quarter	Avg. DA	Avg. RT	Avg.Abs.	# RT
West 10-Min Spin	2020Q2	$3.38	$0.50	$3.08	0
	2021Q2	$3.54	$0.62	$3.31	0
Regulation	2020Q2	$8.11	$8.09	$1.12	387
	2021Q2	$7.86	$7.84	$1.41	591



Notes: For chart description, see slide 81.

POTOMAC ECONOMICS

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

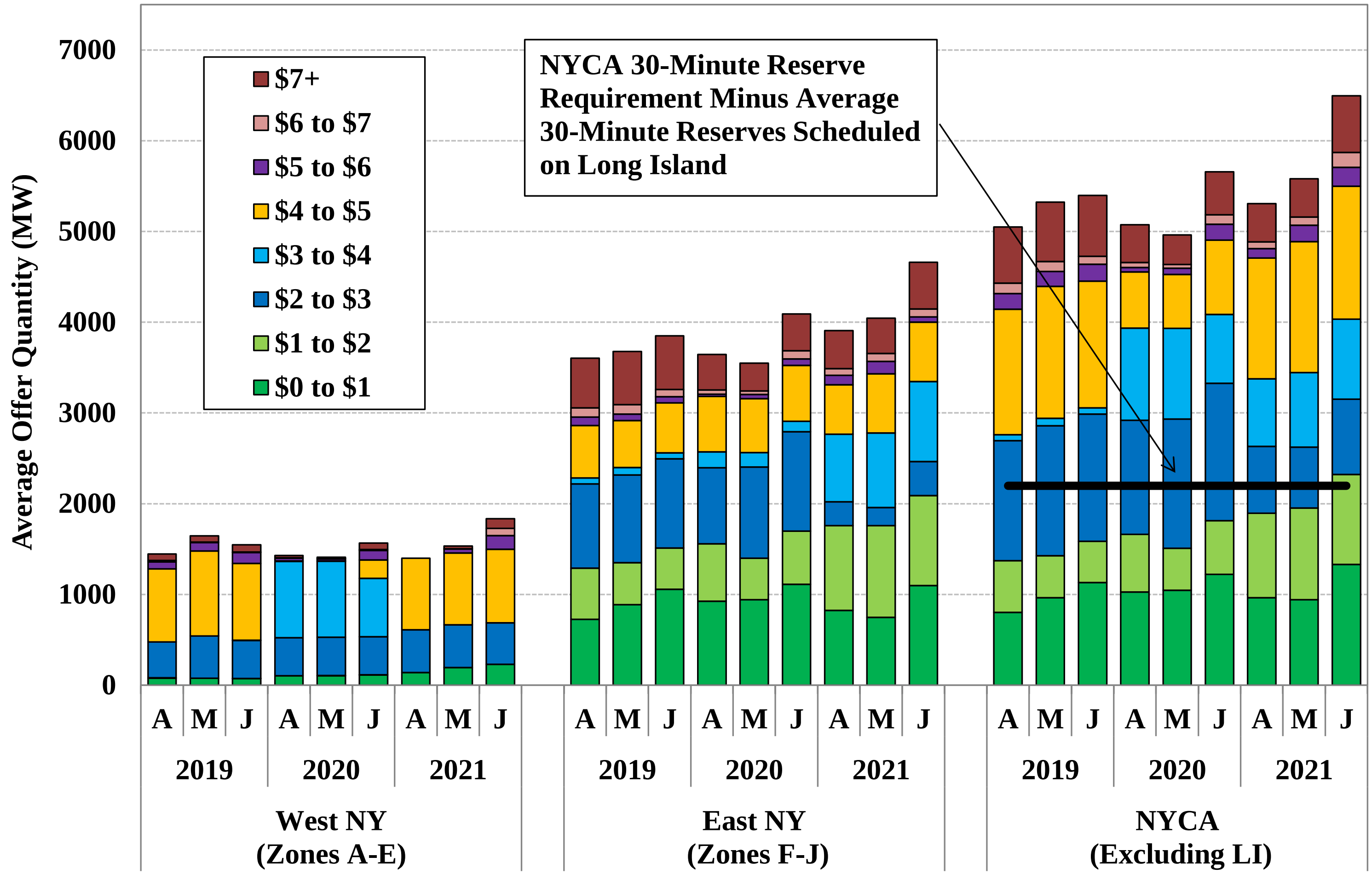


Reserve Type	Quarter	Avg. DA Price	Avg. RT Price	Avg. Abs. Diff	# RT Shortage Intervals
West 30-min	2020Q2	$2.99	$0.05	$2.94	36
	2021Q2	$3.22	$0.34	$3.27	175
SENY 30-min	2020Q2	$2.99	$0.05	$2.94	0
	2021Q2	$3.23	$0.35	$3.27	0

Notes: For chart description, see slide 81.

POTOMAC ECONOMICS

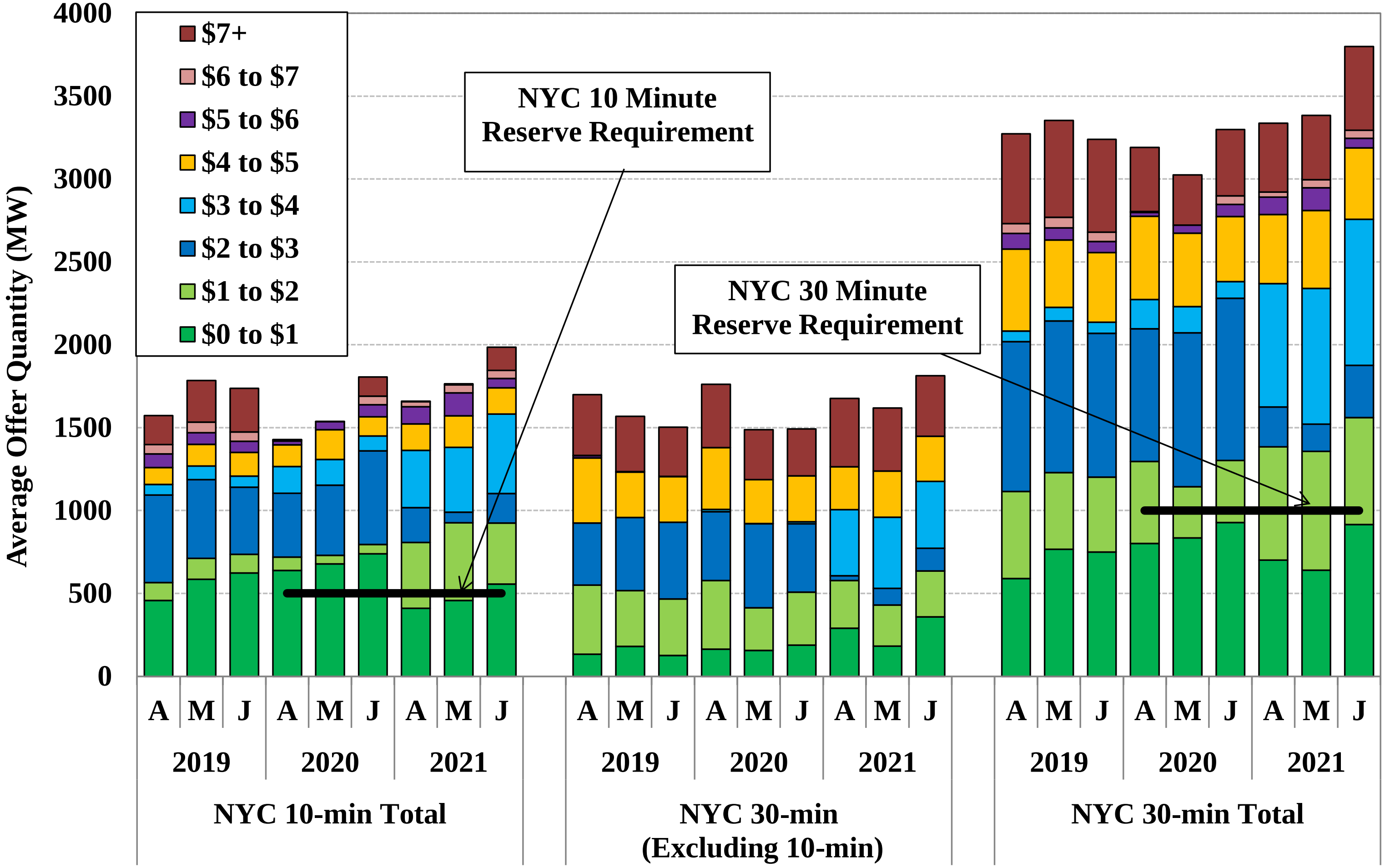
Day-Ahead NYCA 30-Minute Reserve Offers
Committed and Available Offline Quick-Start Resources



Notes: For chart description, see slide 82.

POTOMAC ECONOMICS

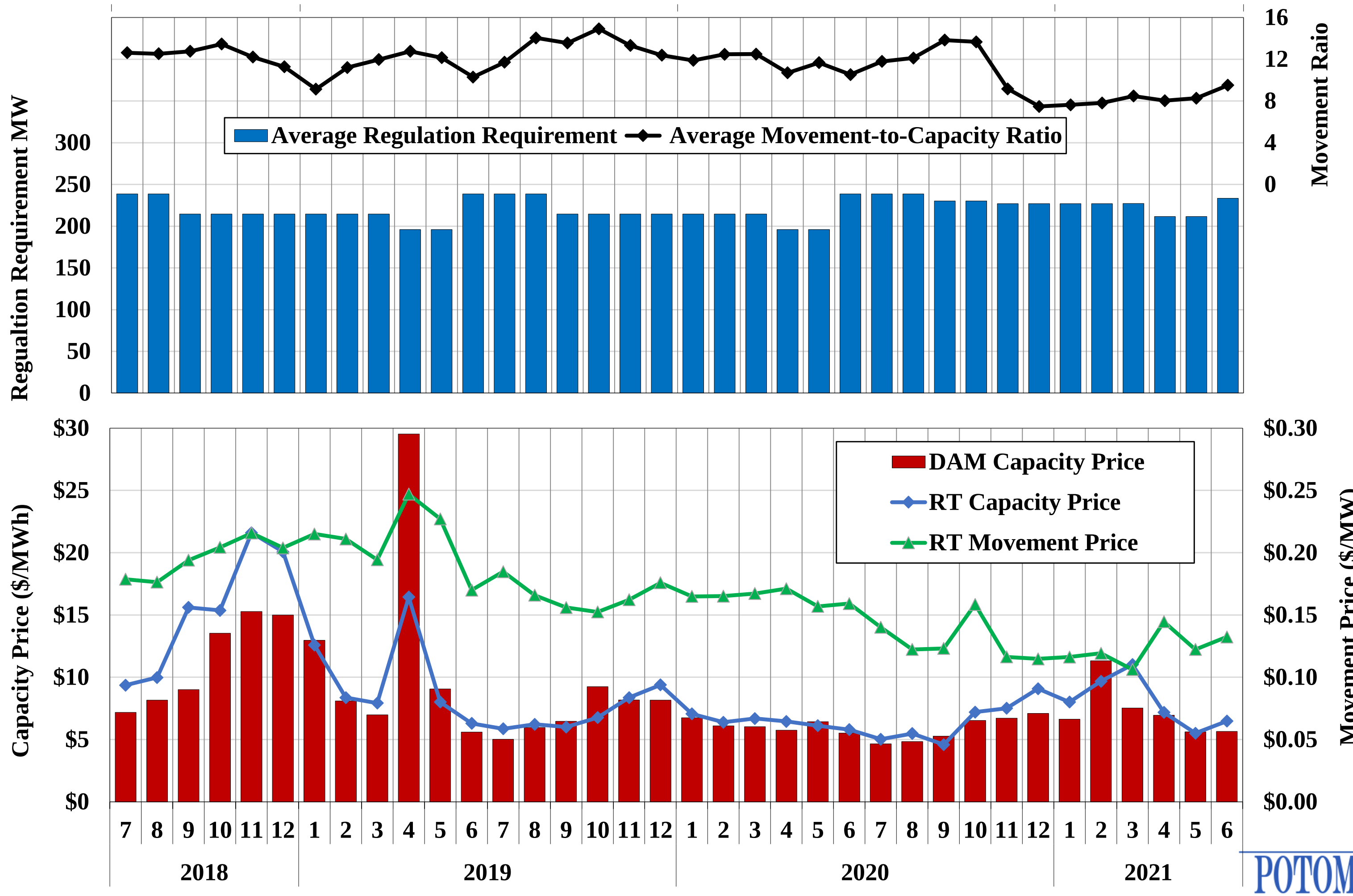
Day-Ahead NYC Reserve Offers
Committed and Available Offline Quick-Start Resources



  Notes: For chart description, see slide 82.

POTOMAC ECONOMICS

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



Notes: For chart description, see slide 83.

POTOMAC ECONOMICS

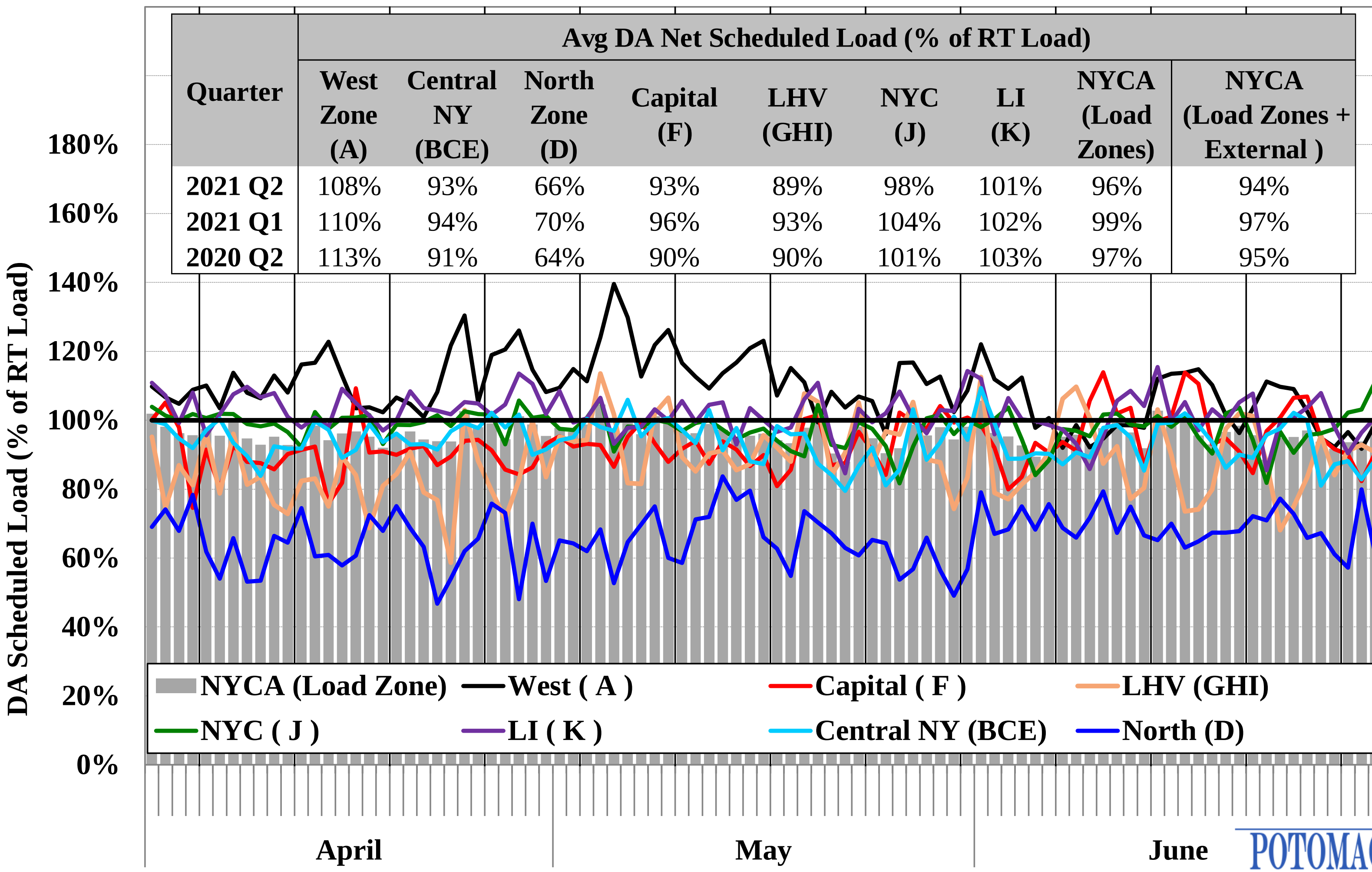
Charts:

Energy Market Scheduling

POTOMAC ECONOMICS

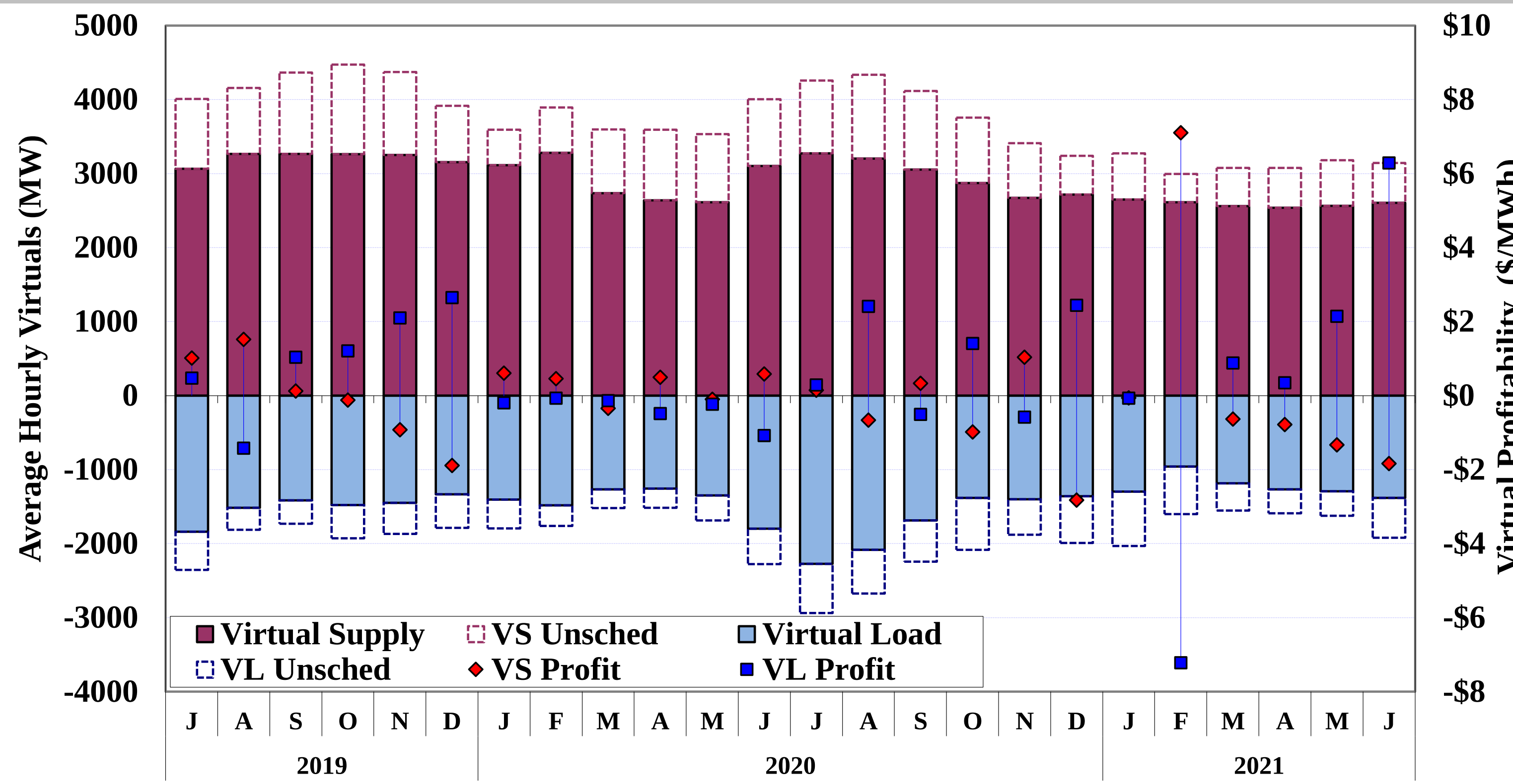
Day-ahead Scheduled Load and Actual Load
Daily Peak Load Hour

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 Q2	108%	93%	66%	93%	89%	98%	101%	96%	94%
2021 Q1	110%	94%	70%	96%	93%	104%	102%	99%	97%
2020 Q2	113%	91%	64%	90%	90%	101%	103%	97%	95%



  Notes: For chart description, see slide 84.

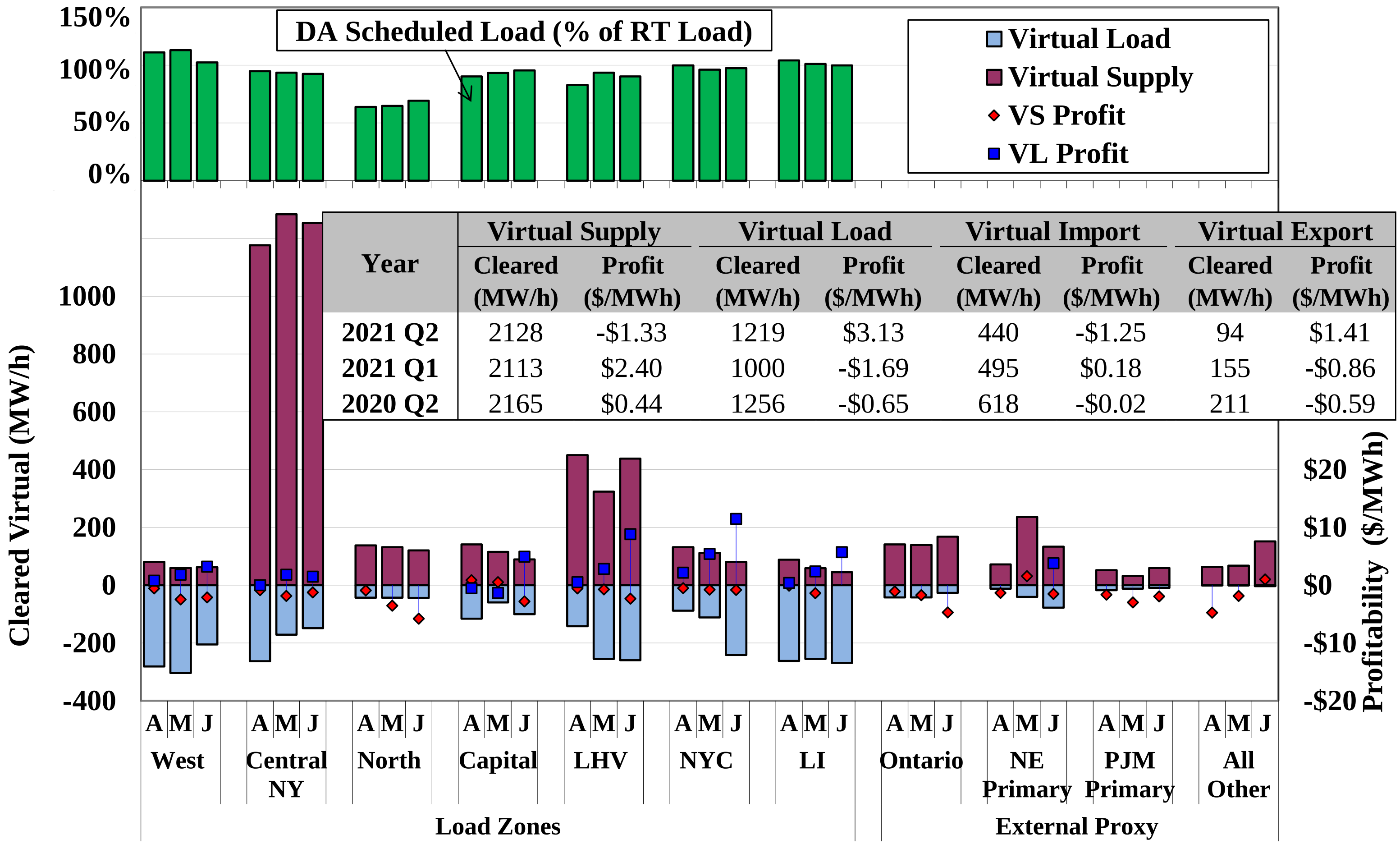
Virtual Trading Activity
by Month



		J	A	S	O	N	D	J	F	M	A	M	J	J	A	S	O	N	D	J	F	M	A	M	J
		2019						2020												2021					
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%

Notes: For chart description, see slide 84.
POTOMAC ECONOMICS

Virtual Trading Activity
by Location

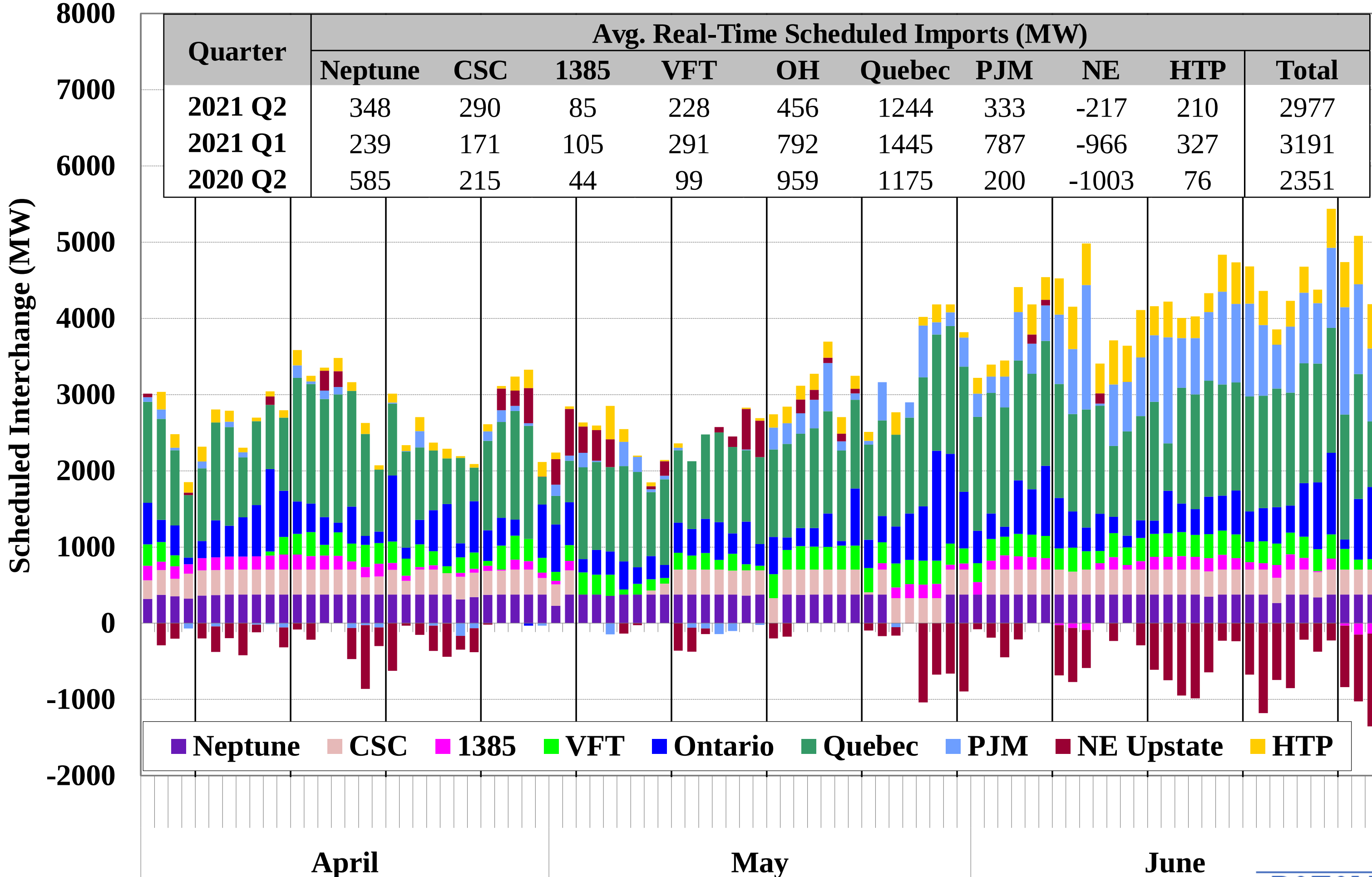


Year	Virtual Supply Cleared (MW/h)	Virtual Supply Profit ($/MWh)	Virtual Load Cleared (MW/h)	Virtual Load Profit ($/MWh)	Virtual Import Cleared (MW/h)	Virtual Import Profit ($/MWh)	Virtual Export Cleared (MW/h)	Virtual Export Profit ($/MWh)
2021 Q2	2128	-$1.33	1219	$3.13	440	-$1.25	94	$1.41
2021 Q1	2113	$2.40	1000	-$1.69	495	$0.18	155	-$0.86
2020 Q2	2165	$0.44	1256	-$0.65	618	-$0.02	211	-$0.59

Notes: 1. Virtual profit is not shown for a category if the average scheduled quantity is less than 50 MW.
2. For chart description, see slide 84.

POTOMAC ECONOMICS

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 Q2	348	290	85	228	456	1244	333	-217	210	2977
2021 Q1	239	171	105	291	792	1445	787	-966	327	3191
2020 Q2	585	215	44	99	959	1175	200	-1003	76	2351

Notes: Two Quebec interfaces are combined into one.

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

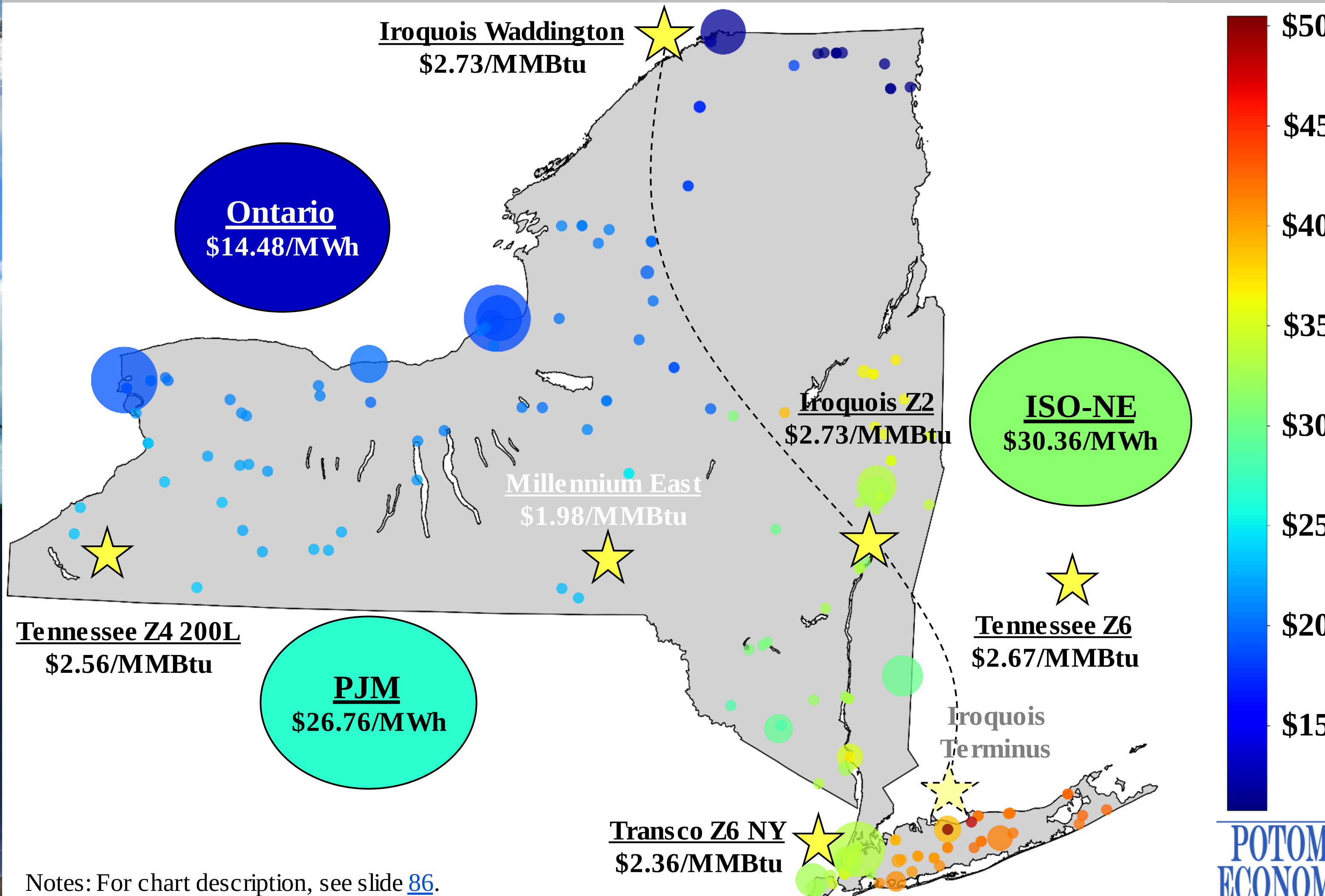
			Average/Total During Intervals w/ Adjustment					
			CTS - NY/NE			CTS - NY/PJM		
			Both Forecast Errors <= $20	Any Forecast Error > $20	Total	Both Forecast Errors <= $20	Any Forecast Error > $20	Total
% of All Intervals w/ Adjustment			89%	6%	**95%**	31%	7%	**38%**
Average Flow Adjustment (MW)	Net Imports		14	13	**14**	2	-34	**-5**
	Gross		98	144	**101**	41	78	**48**
Production Cost Savings ($ 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**

Notes: For chart description, see slide 85.

Charts:

Transmission Congestion Revenues and Shortfalls

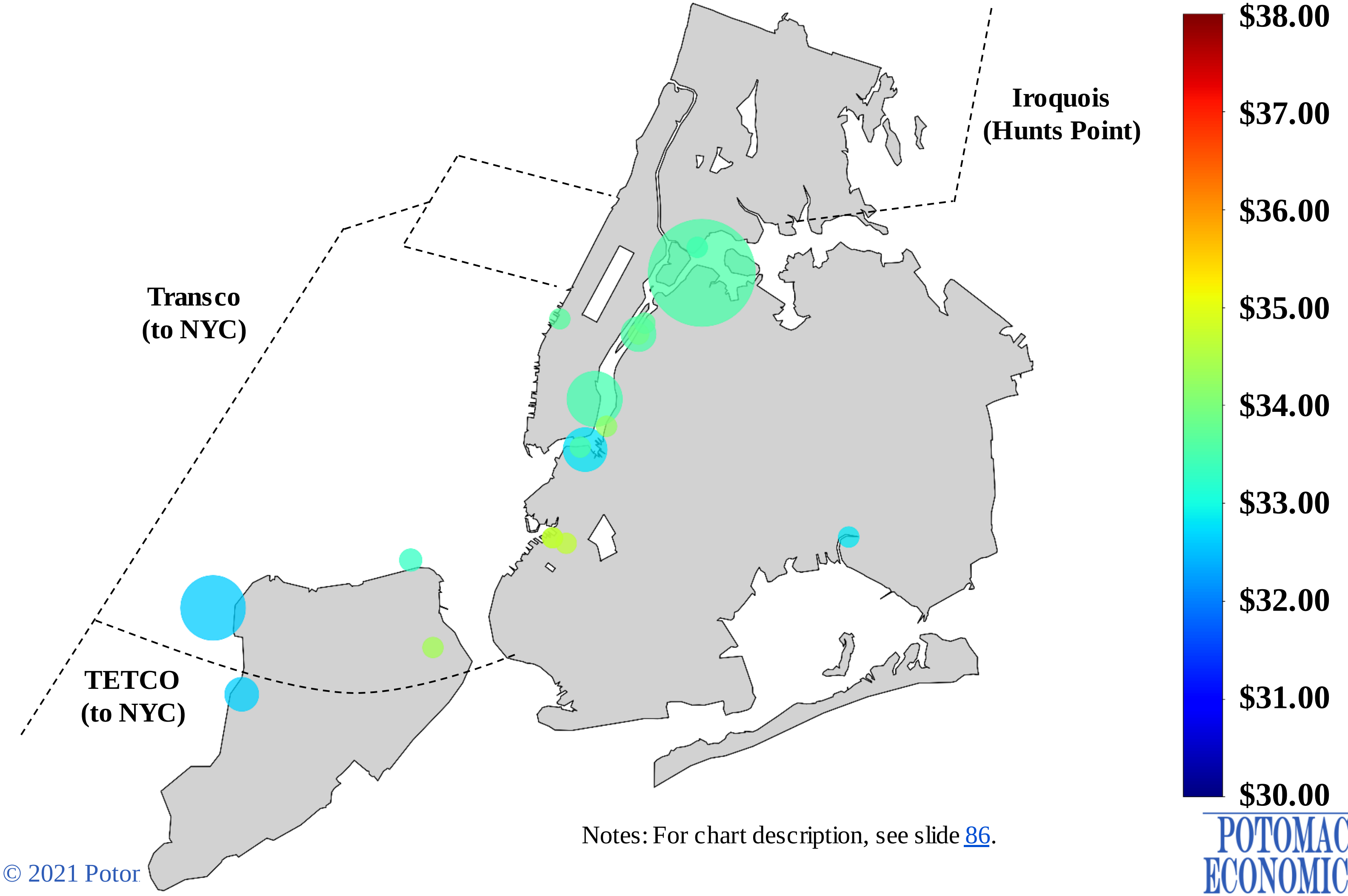
System Congestion
Real-Time Price Map at Generator Nodes



Notes: For chart description, see slide 86.

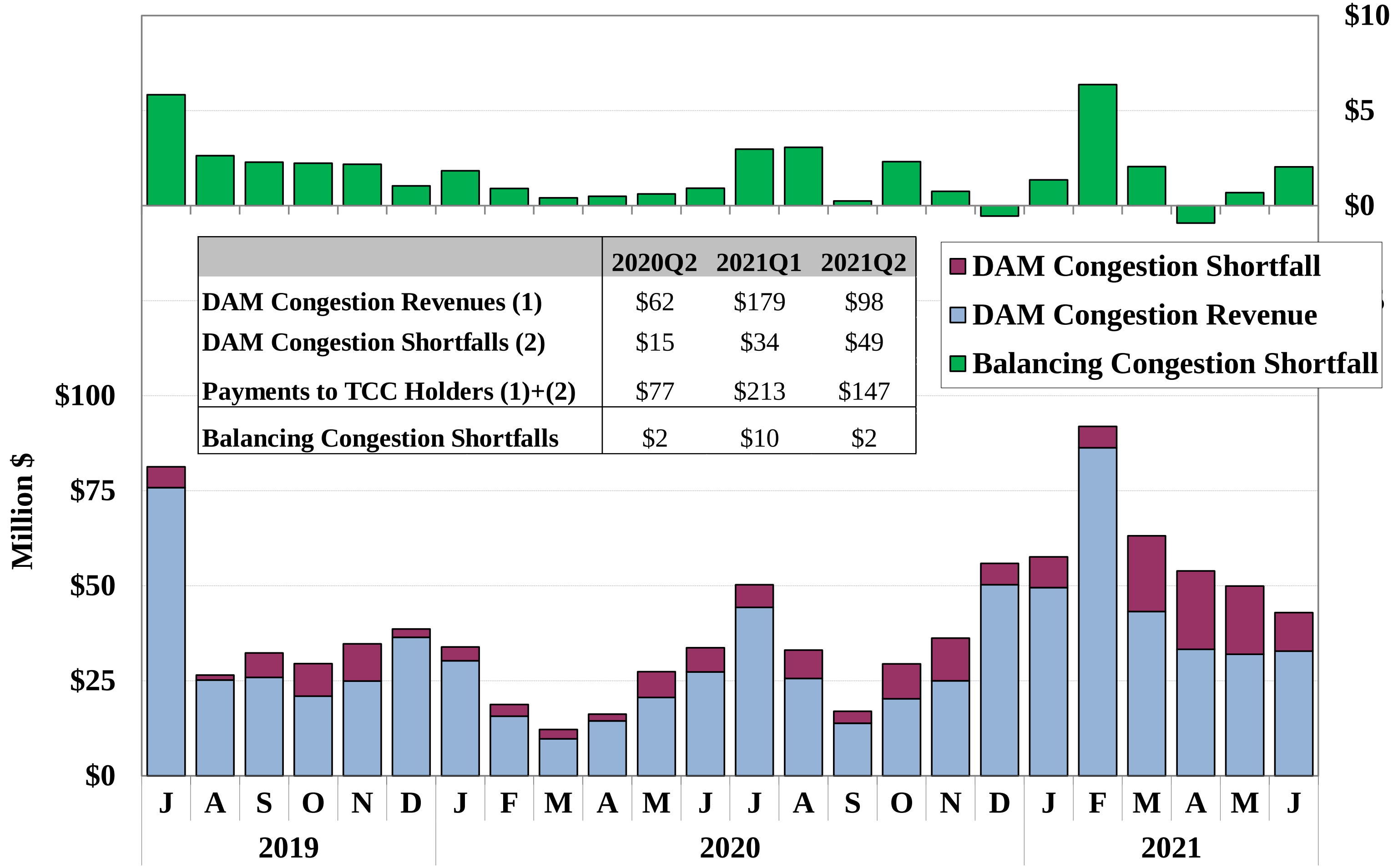
POTOMAC ECONOMICS

System Congestion
NYC Real-Time Price Map at Generator Nodes



Notes: For chart description, see slide 86.

Congestion Revenues and Shortfalls by Month

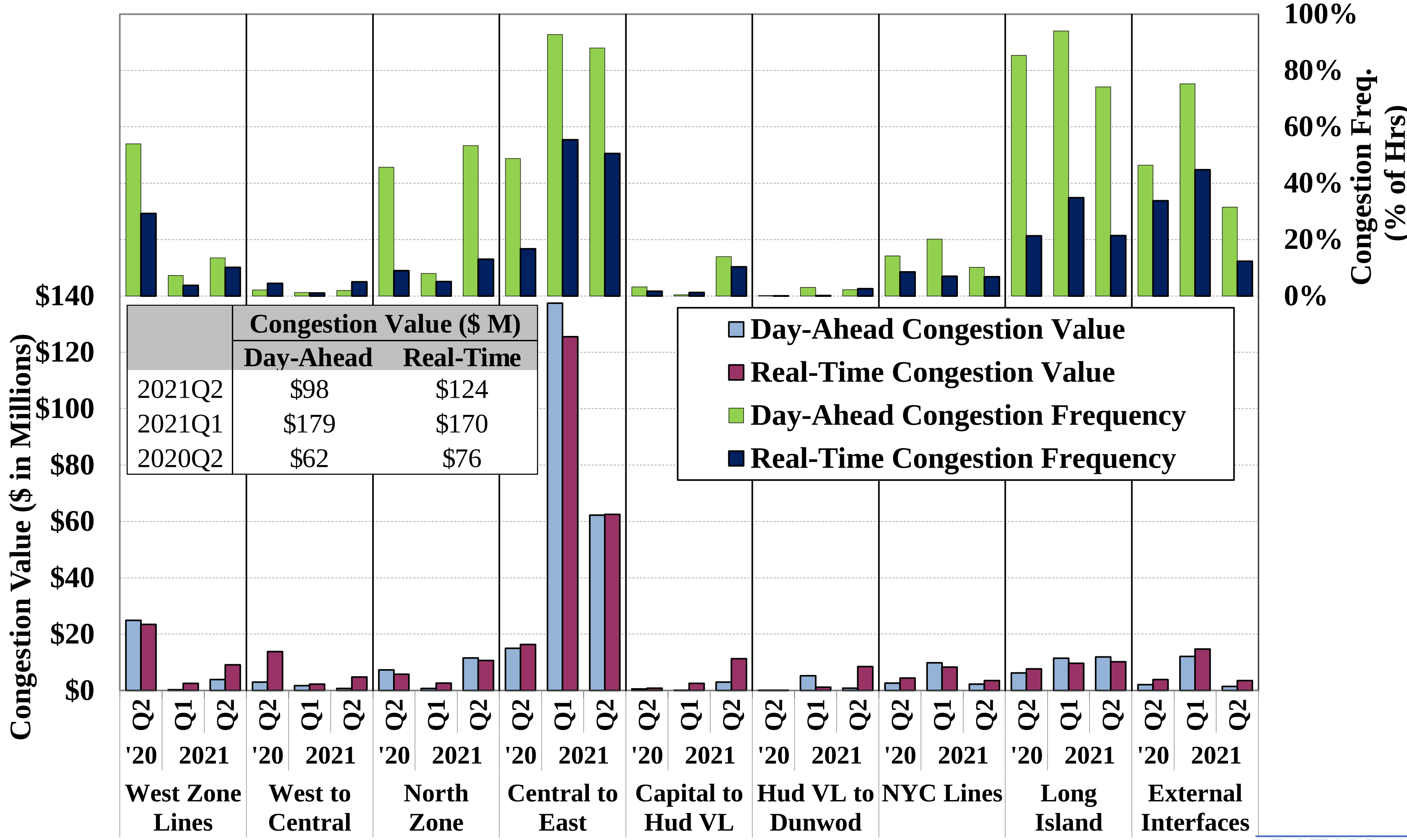


	2020Q2	2021Q1	2021Q2
DAM Congestion Revenues (1)	$62	$179	$98
DAM Congestion Shortfalls (2)	$15	$34	$49
Payments to TCC Holders (1)+(2)	$77	$213	$147
Balancing Congestion Shortfalls	$2	$10	$2

Notes: For chart description, see slides 87 and 88.

POTOMAC ECONOMICS

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

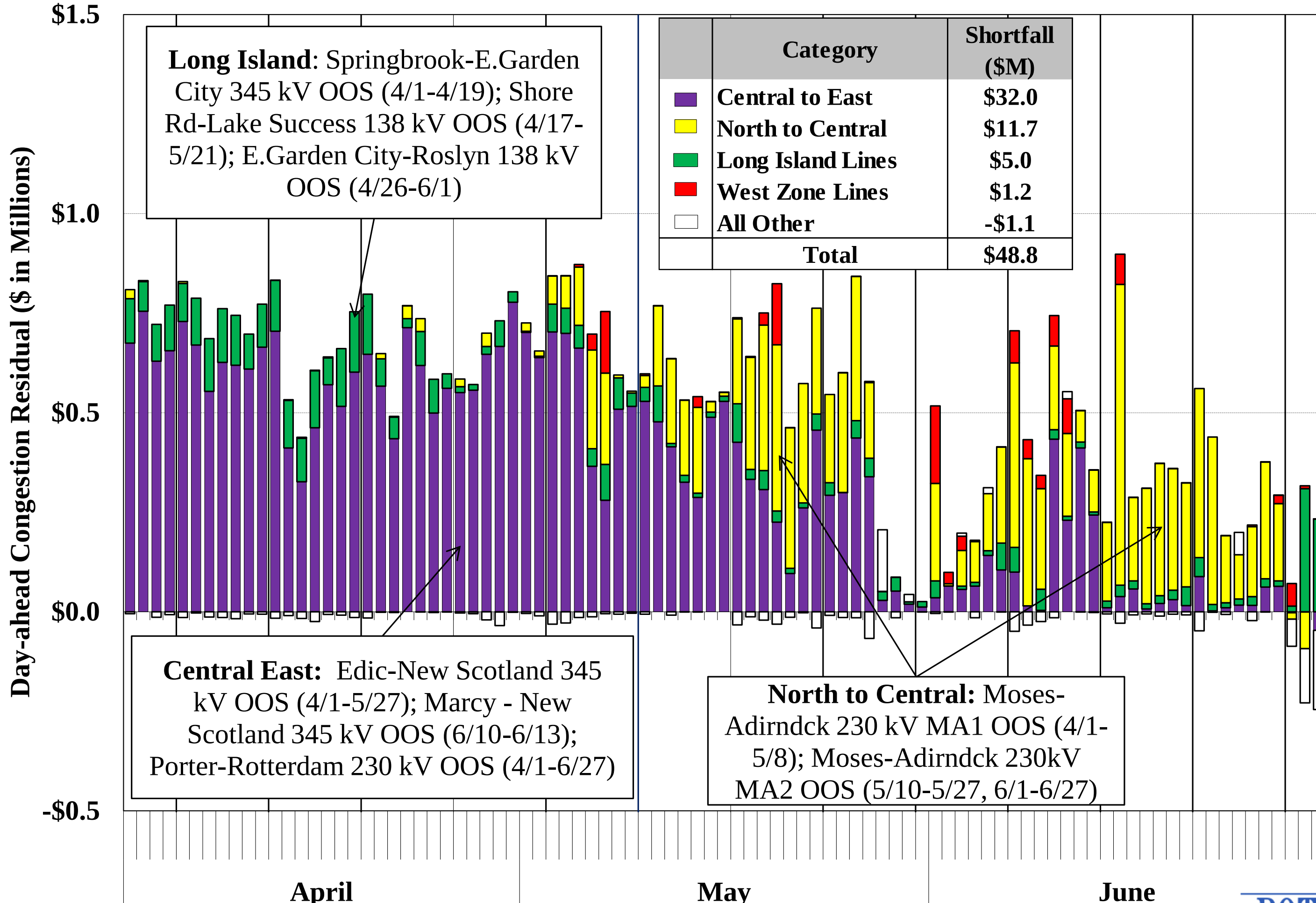


	Congestion Value ($ M)	
	Day-Ahead	Real-Time
2021Q2	$98	$124
2021Q1	$179	$170
2020Q2	$62	$76

Notes: For chart description, see slides 87, 88, and 89.

POTOMAC ECONOMICS

Day-Ahead Congestion Revenue Shortfalls by Transmission Facility

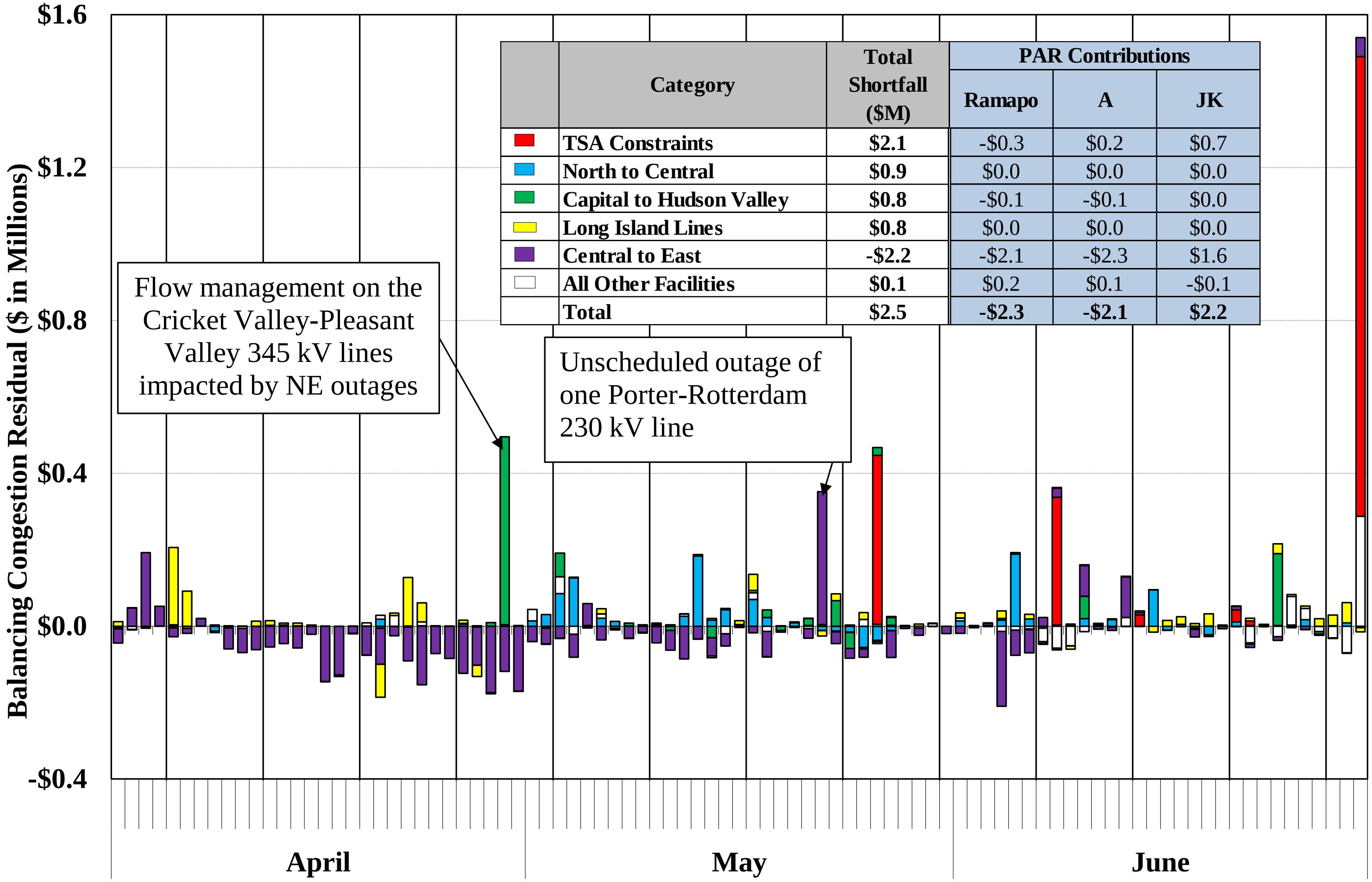


Category	Shortfall ($M)
Central to East	$32.0
North to Central	$11.7
Long Island Lines	$5.0
West Zone Lines	$1.2
All Other	-$1.1
Total	**$48.8**

Notes: For chart description, see slides 87, 88, and 89.

POTOMAC ECONOMICS

Balancing Congestion Shortfalls by Transmission Facility

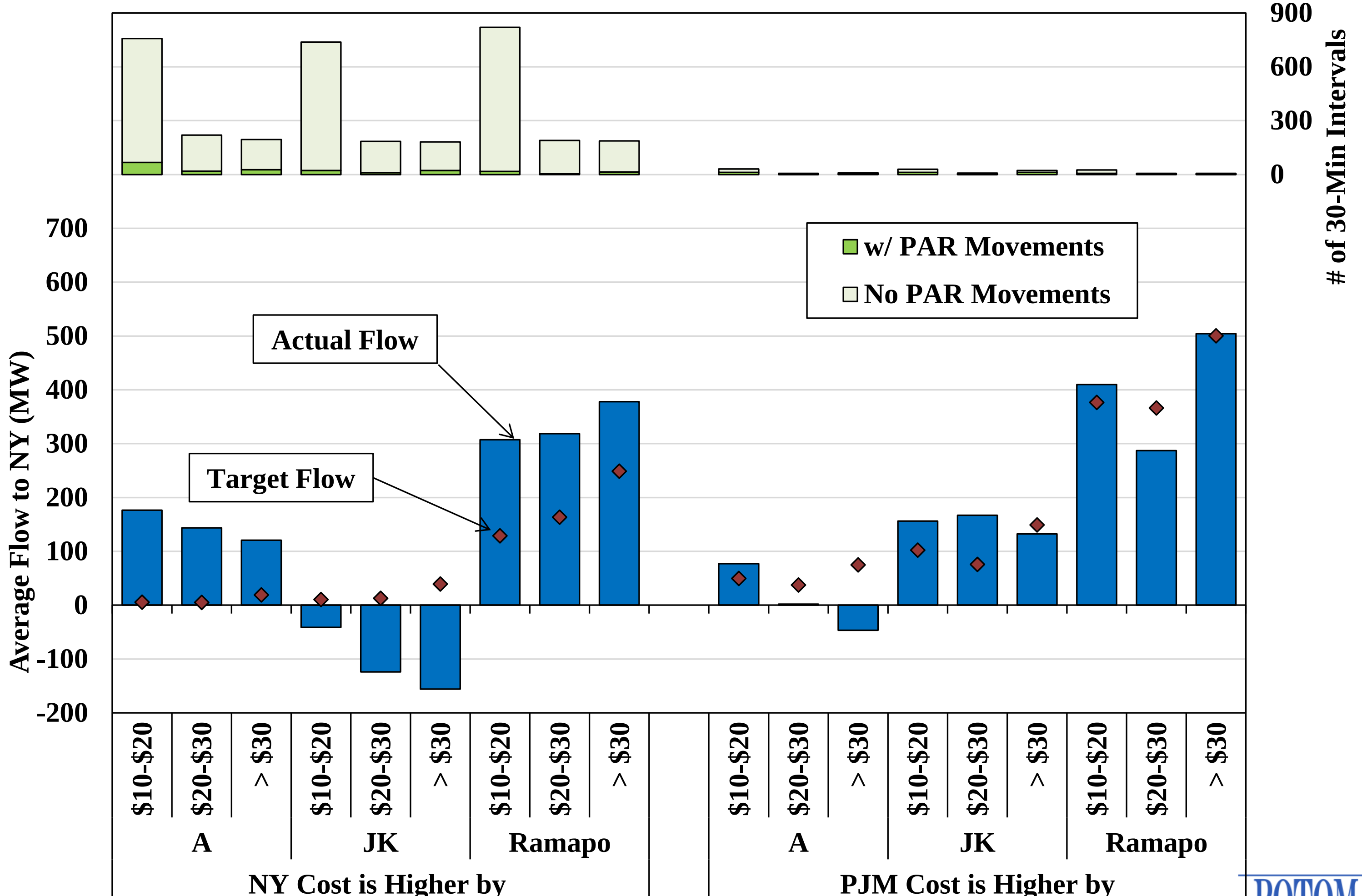


	Category	Total Shortfall ($M)	PAR Contributions Ramapo	PAR Contributions A	PAR Contributions JK
	TSA Constraints	$2.1	-$0.3	$0.2	$0.7
	North to Central	$0.9	$0.0	$0.0	$0.0
	Capital to Hudson Valley	$0.8	-$0.1	-$0.1	$0.0
	Long Island Lines	$0.8	$0.0	$0.0	$0.0
	Central to East	-$2.2	-$2.1	-$2.3	$1.6
	All Other Facilities	$0.1	$0.2	$0.1	-$0.1
	Total	$2.5	-$2.3	-$2.1	$2.2

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

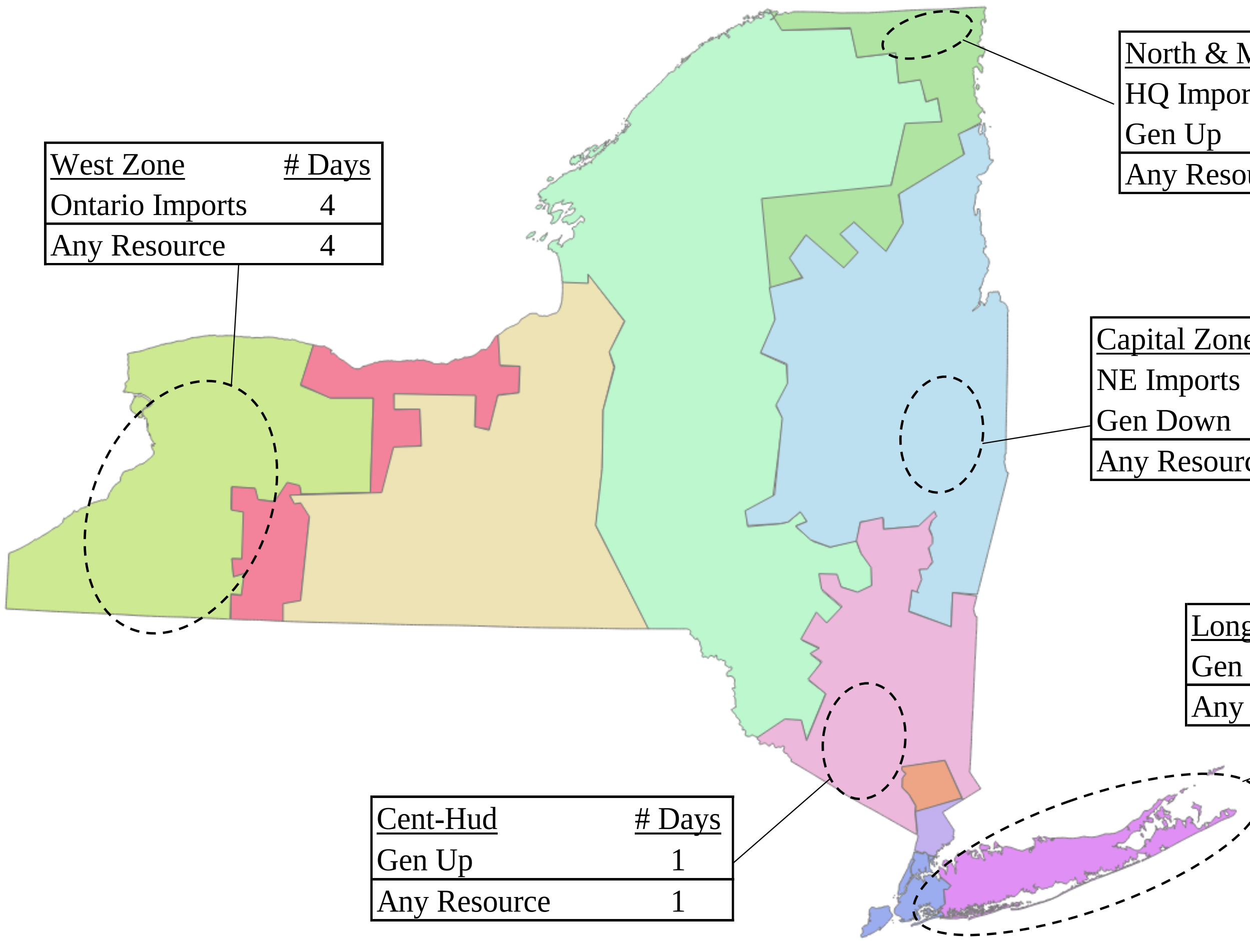
POTOMAC ECONOMICS

PAR Operation under M2M with PJM
2021 Q2



Notes: For chart description, see slide 90.

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



West Zone	# Days
Ontario Imports	4
Any Resource	4

North & MHK VL Zones	# Days
HQ Imports	2
Gen Up	5
Any Resource	7

Capital Zone	# Days
NE Imports	2
Gen Down	11
Any Resource	13

Long Is 69kV	# Days
Gen Up	18
Any Resource	18

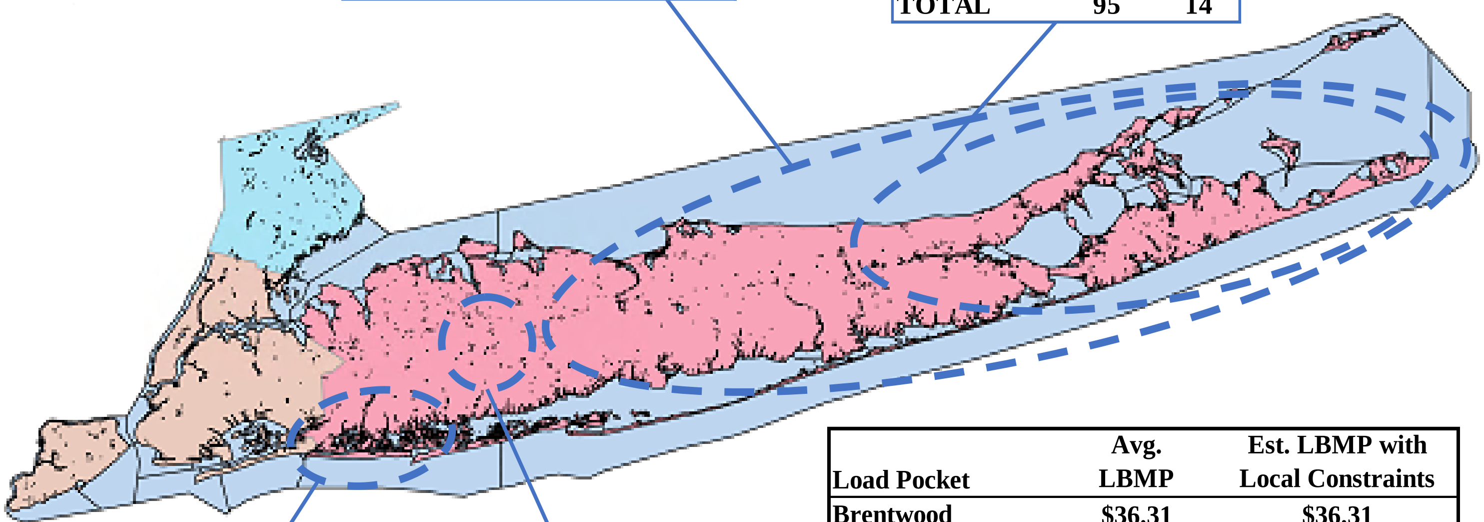
Cent-Hud	# Days
Gen Up	1
Any Resource	1

Notes: For chart description, see slides 91-92

Constraints on the Low Voltage Network:
Long Island Load Pockets

East of Northport	#Hours	#Days
69kV OOM	12	3
69kV	186	23
138kV	120	17
TOTAL	210	27

East End	#Hours	#Days
69kV OOM	14	3
TVR	81	11
138kV	0	0
TOTAL	95	14



Load Pocket	Avg. LBMP	Est. LBMP with Local Constraints
Brentwood	$36.31	$36.31
East End	$37.24	$42.89
East of Northport	$36.44	$36.97
Valley Stream	$36.35	$37.30

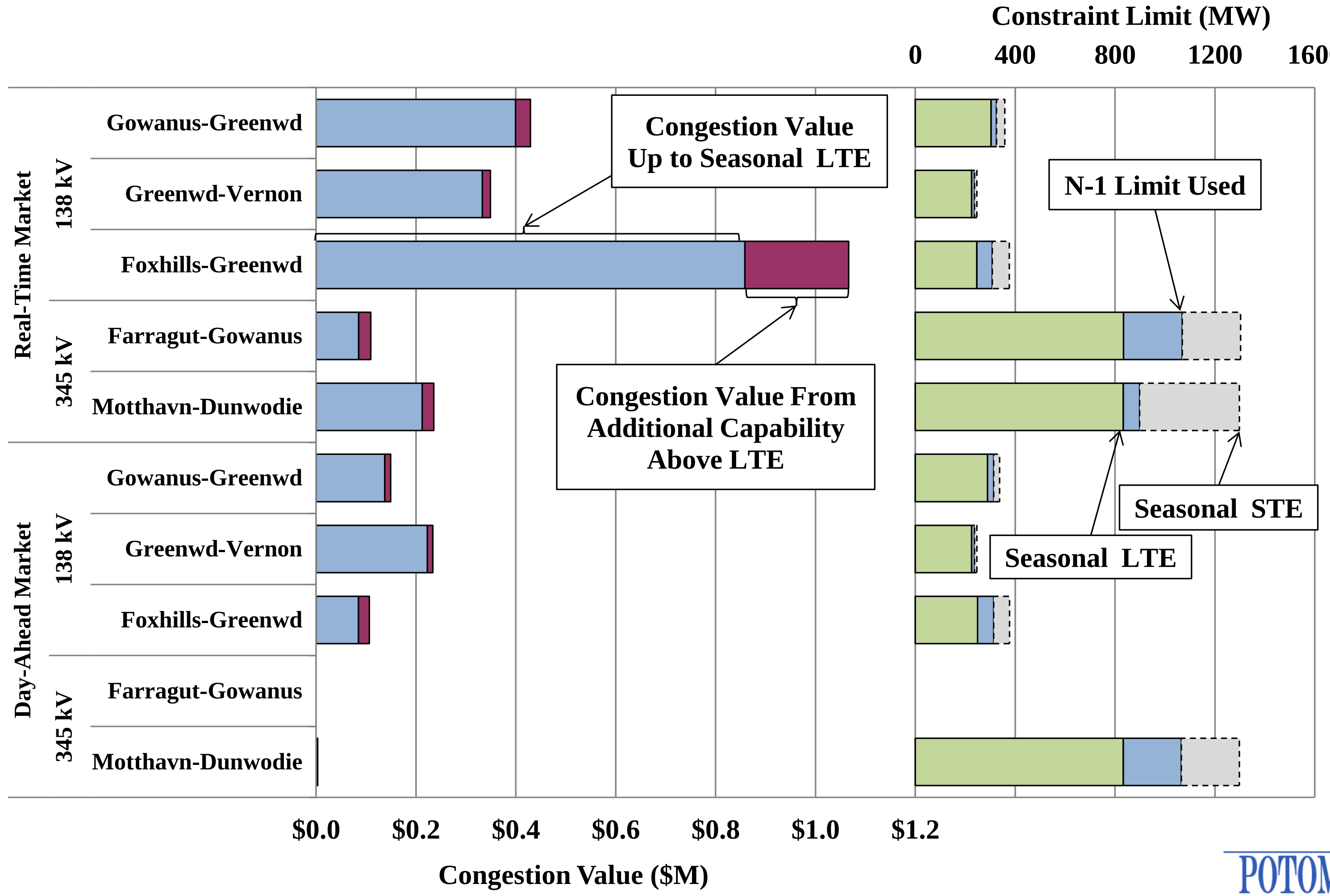
Valley Stream	#Hours	#Days
69kV OOM	105	16
138kV	725	67
TOTAL	827	76

Brentwood	#Hours	#Days
69kV OOM	2	1
69kV	191	35
138kV	0	0
TOTAL	191	35

Notes: For chart description, see slides 91-92

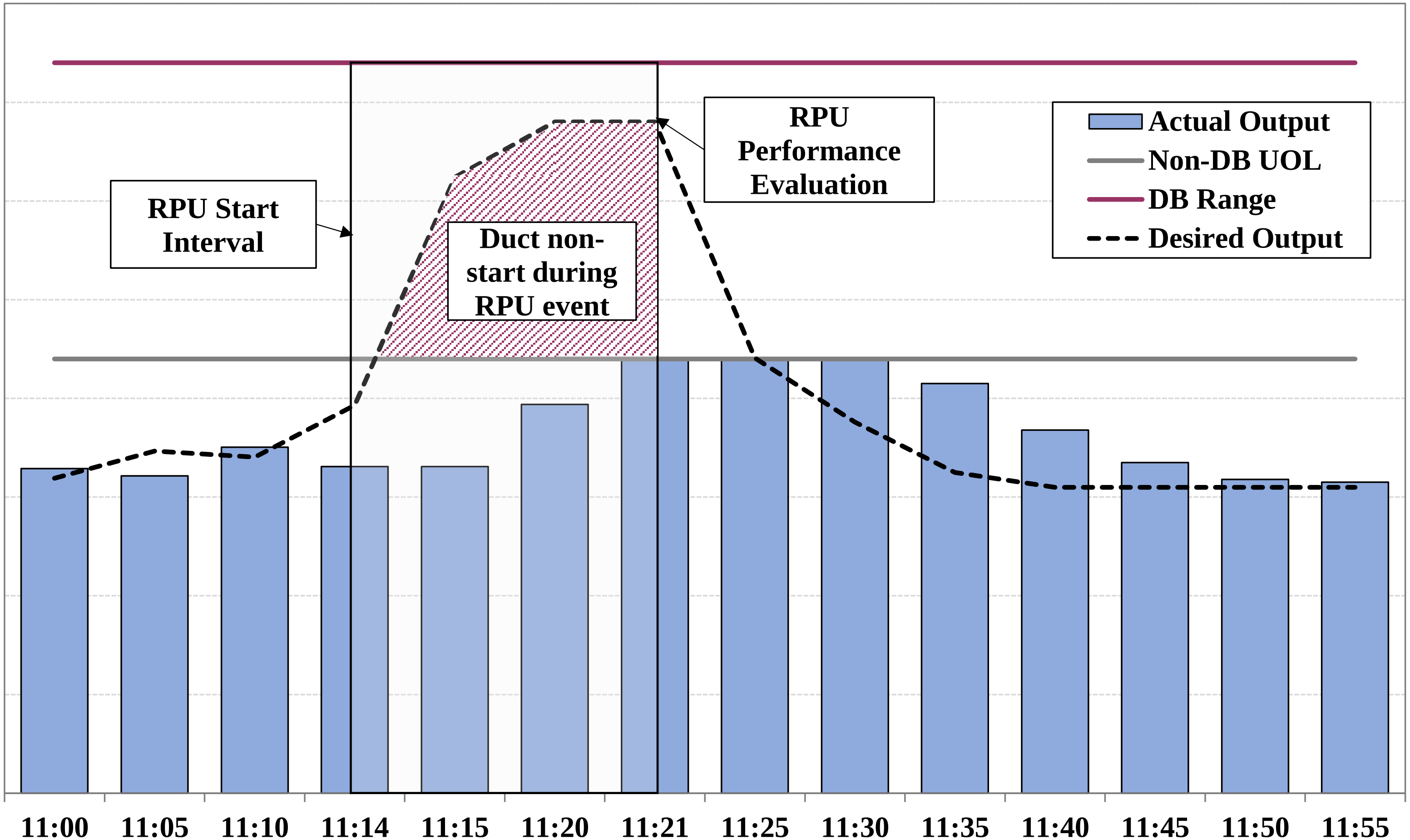
POTOMAC ECONOMICS

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



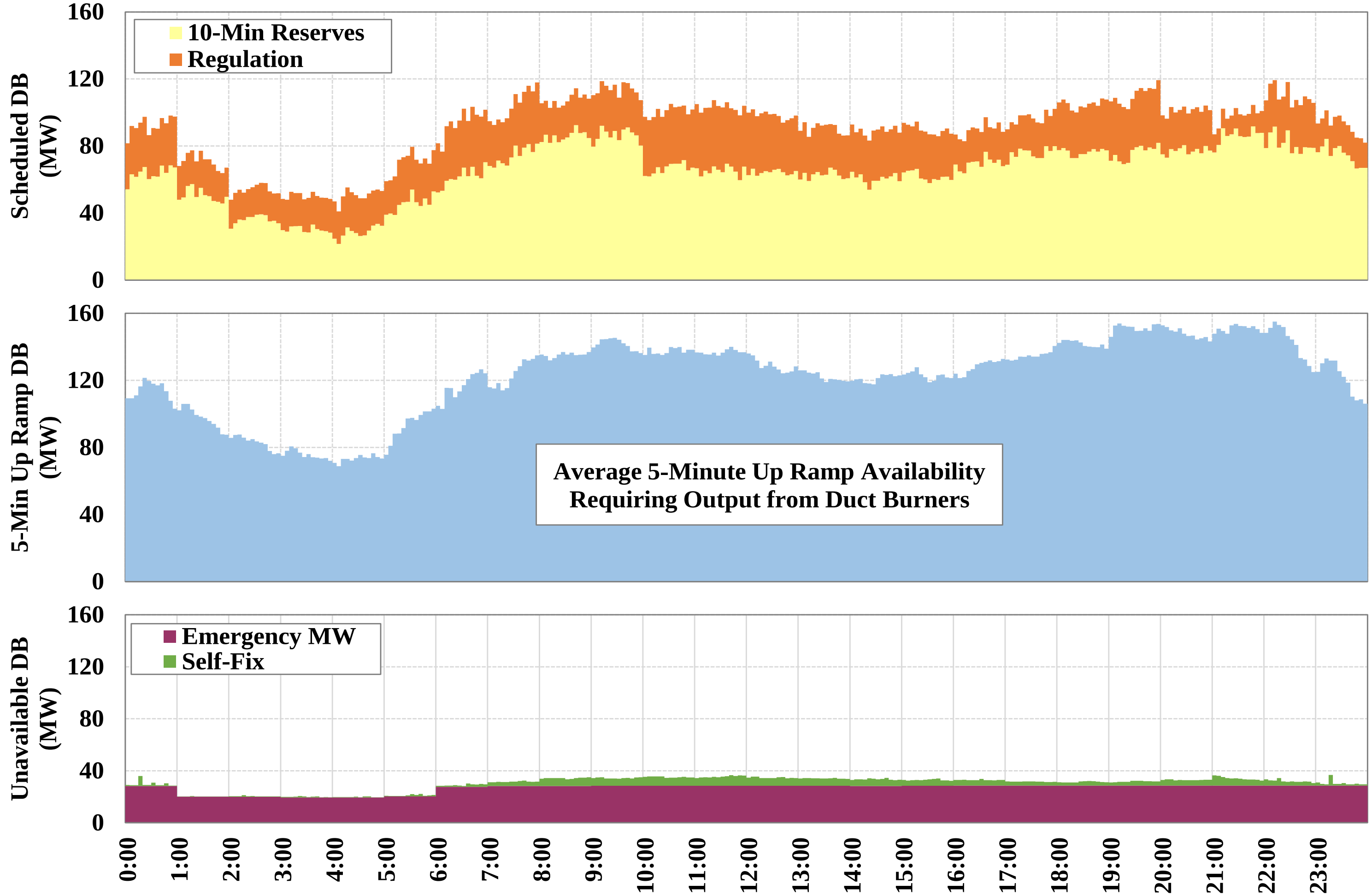
 Notes: For chart description, see slide 93.

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



Notes: For chart description, see slide 94

POTOMAC ECONOMICS

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.

Notes: For chart description, see slide 95.

POTOMAC ECONOMICS

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.

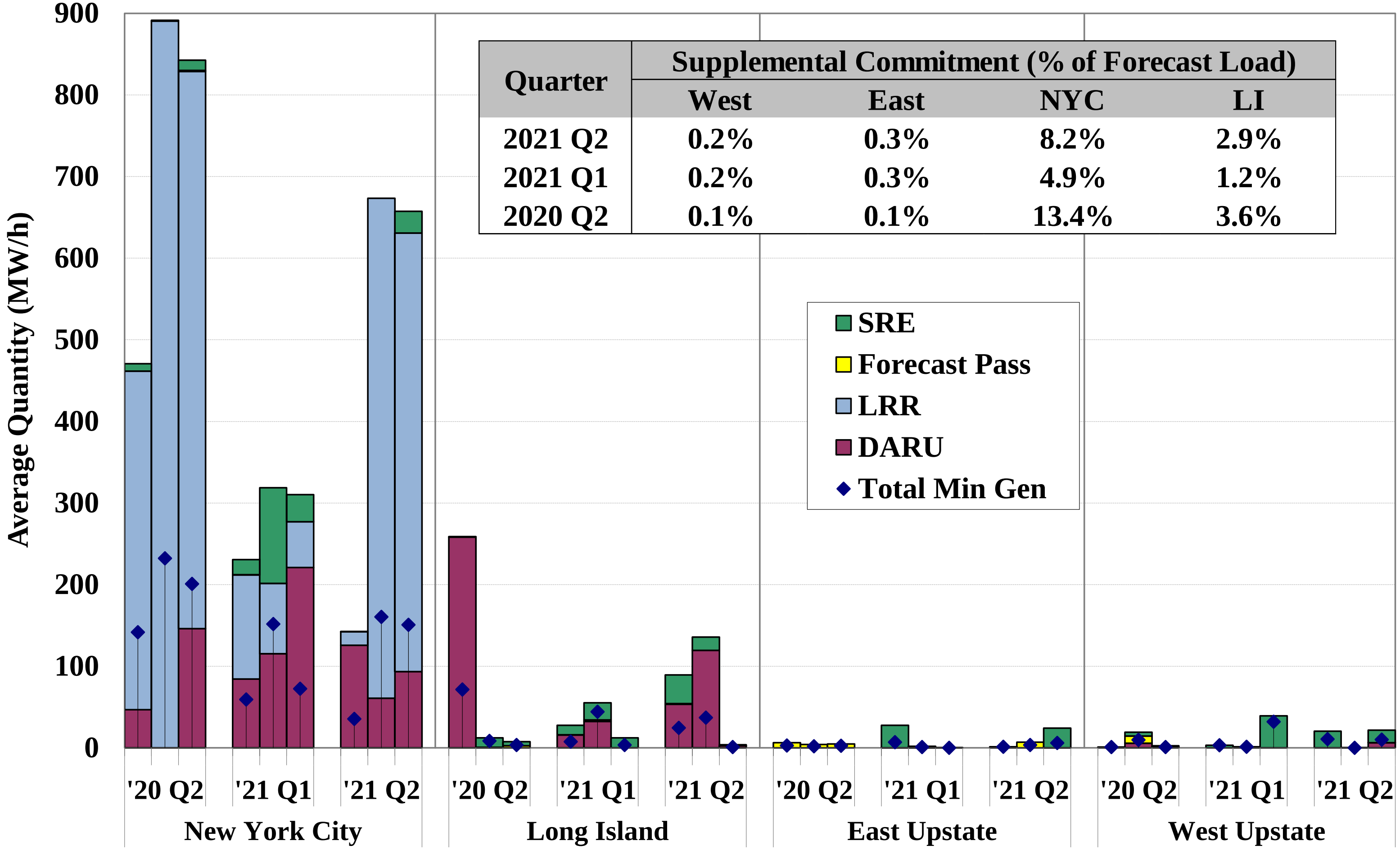
Notes: For chart description, see slide 95.
POTOMAC ECONOMICS

Charts:

Supplemental Commitment, OOM Dispatch, and BPCG Uplift

POTOMAC ECONOMICS

Supplemental Commitment for Reliability by Category and Region

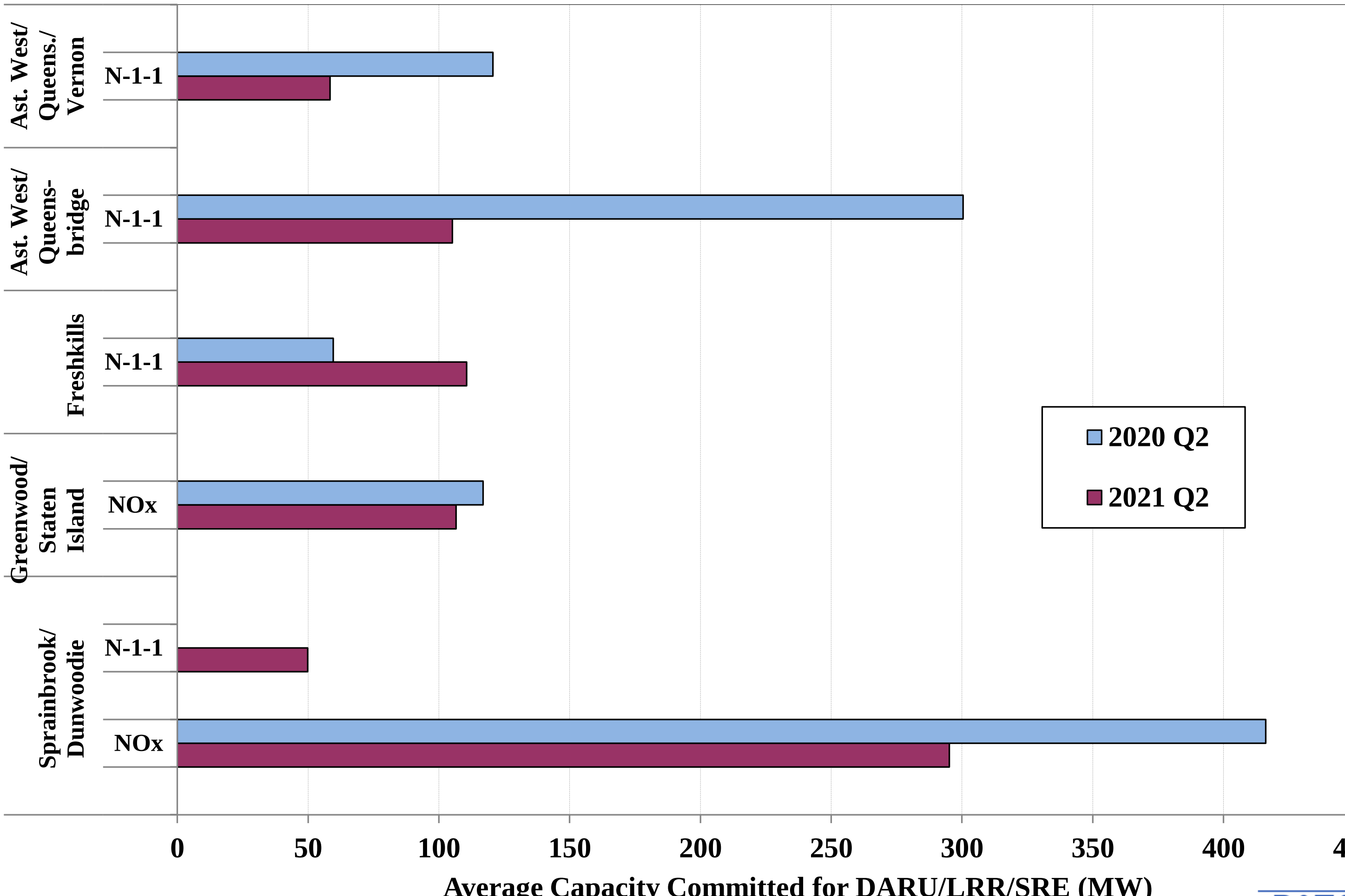


Quarter	Supplemental Commitment (% of Forecast Load)			
	West	East	NYC	LI
2021 Q2	0.2%	0.3%	8.2%	2.9%
2021 Q1	0.2%	0.3%	4.9%	1.2%
2020 Q2	0.1%	0.1%	13.4%	3.6%

Notes: For chart description, see slides 96 and 97.

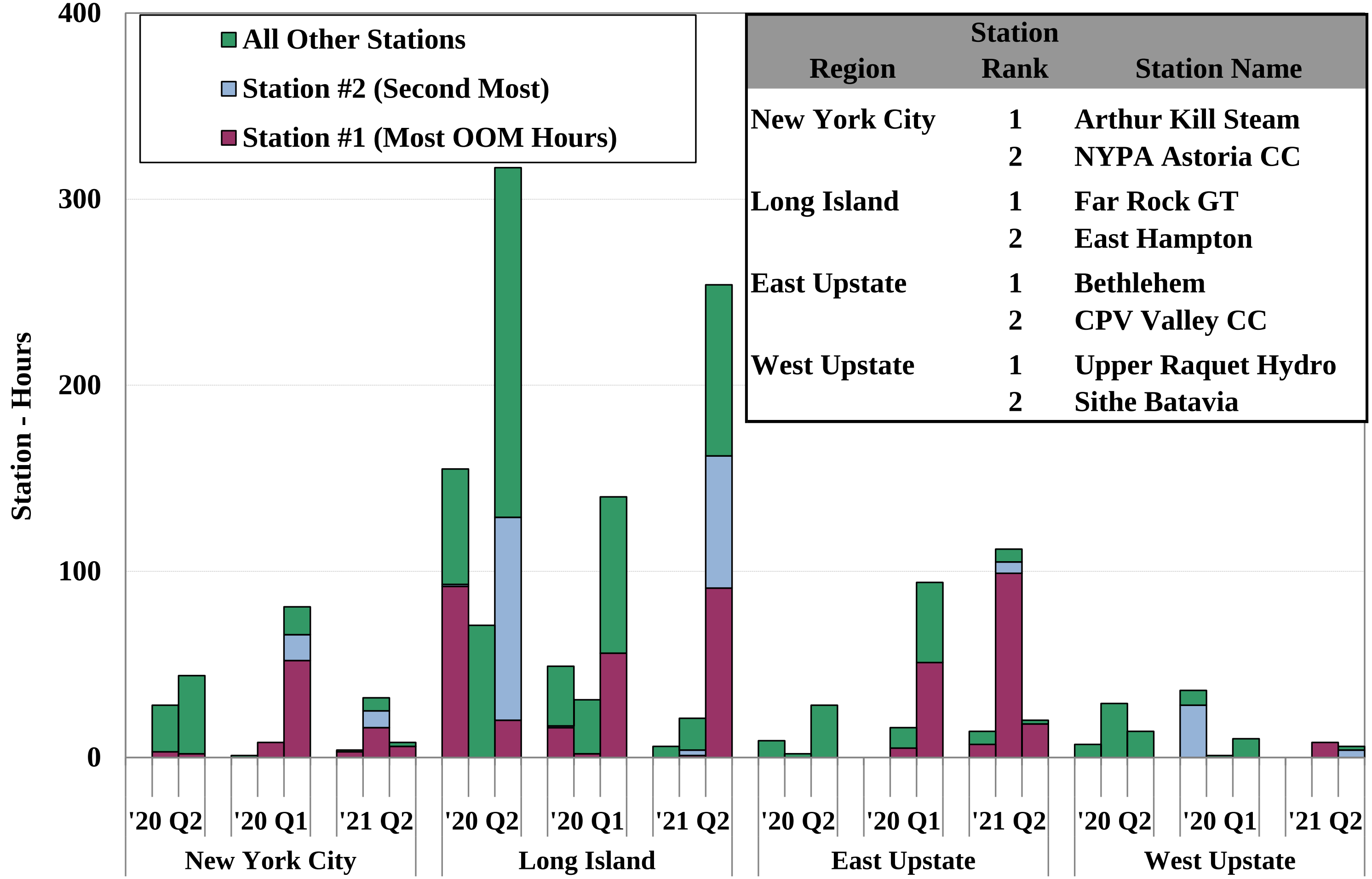
POTOMAC ECONOMICS

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



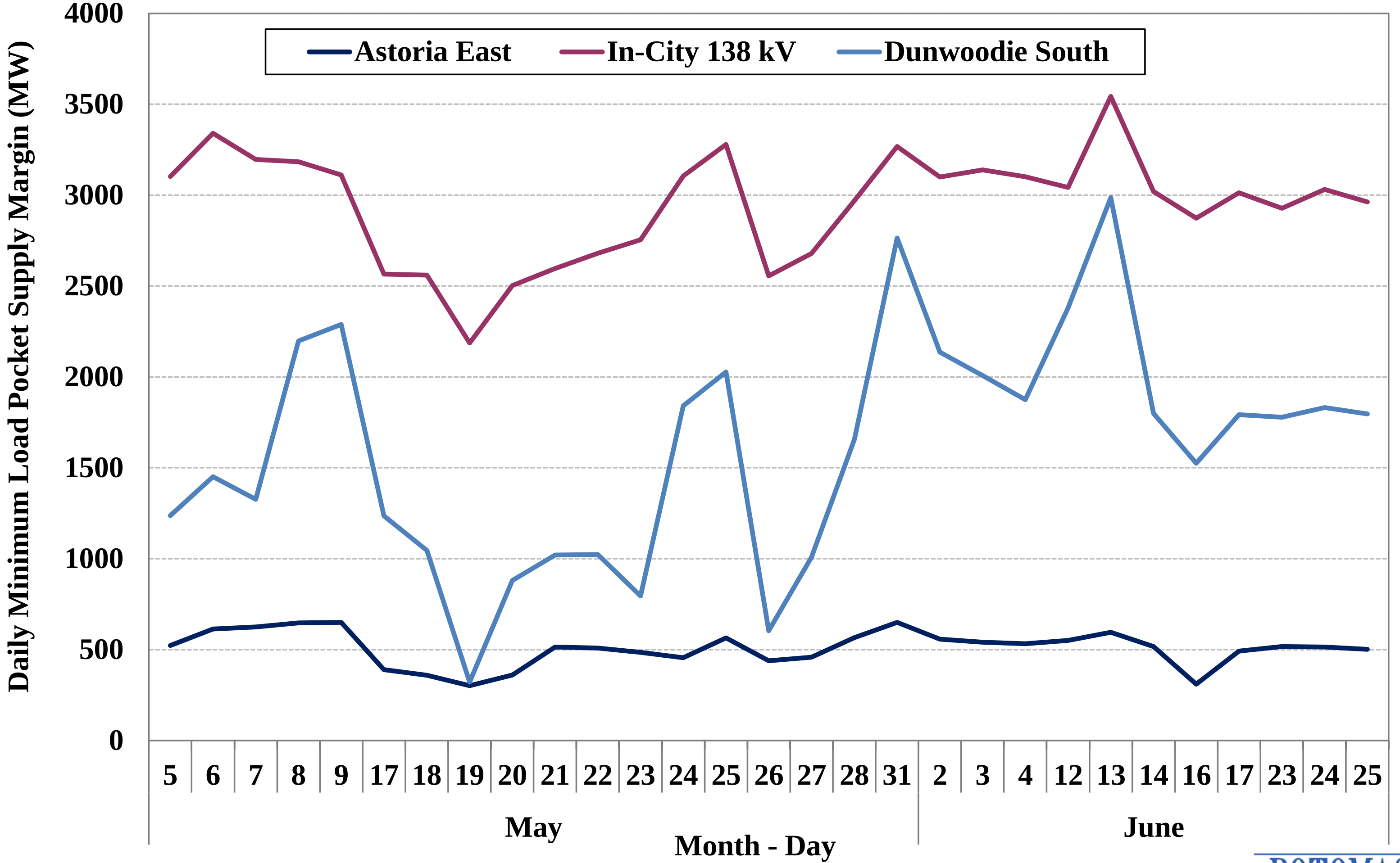
Notes: For chart description, see slides 96 and 97.

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



For chart description, see slides 96 and 97.

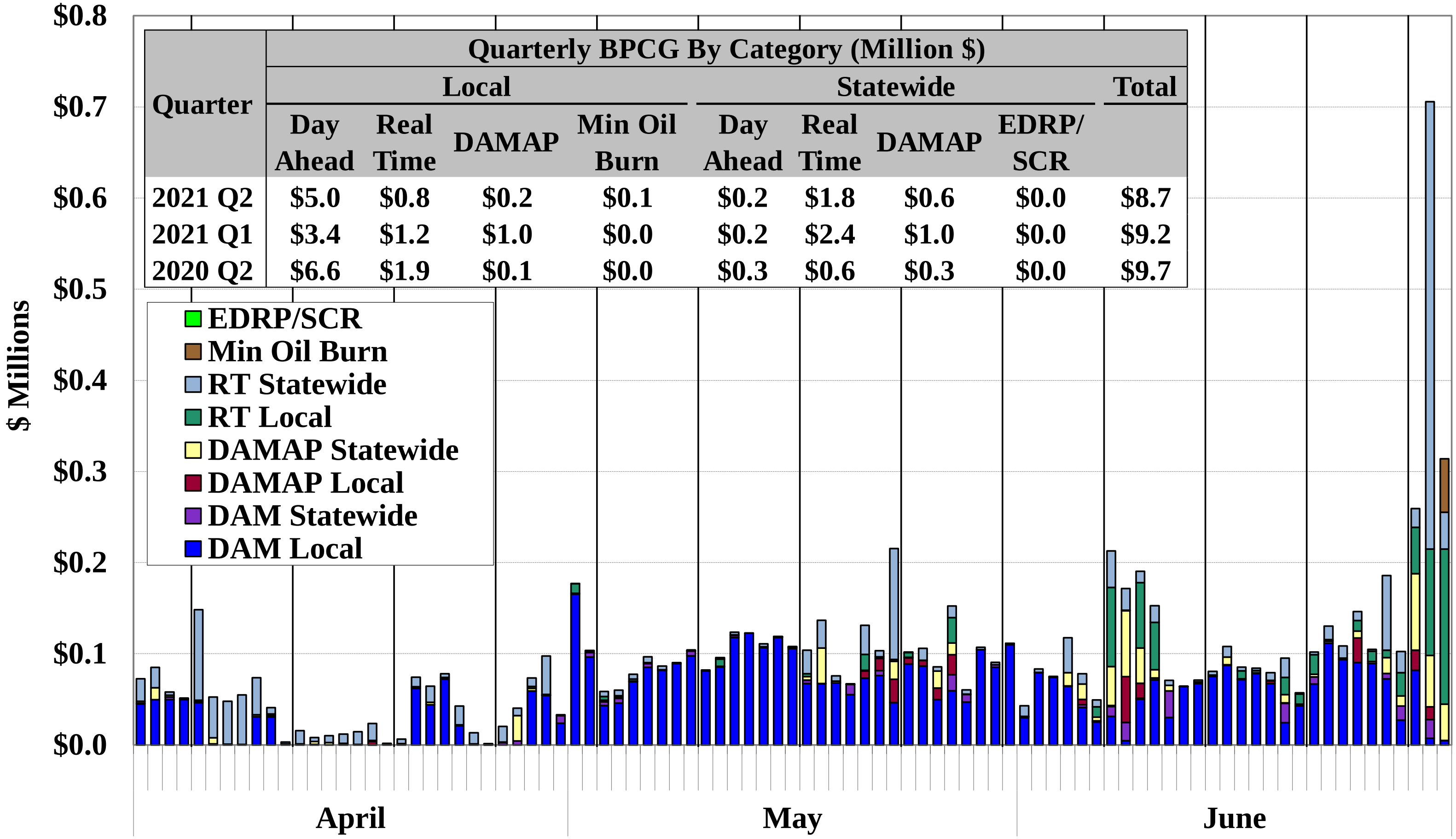
Supply Margin in NYC Load Pockets
After Removing NOx-only Committed ST and GT in the NOx Bubble



For chart description, see slide 98.

POTOMAC ECONOMICS

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



Quarterly BPCG By Category (Million $)

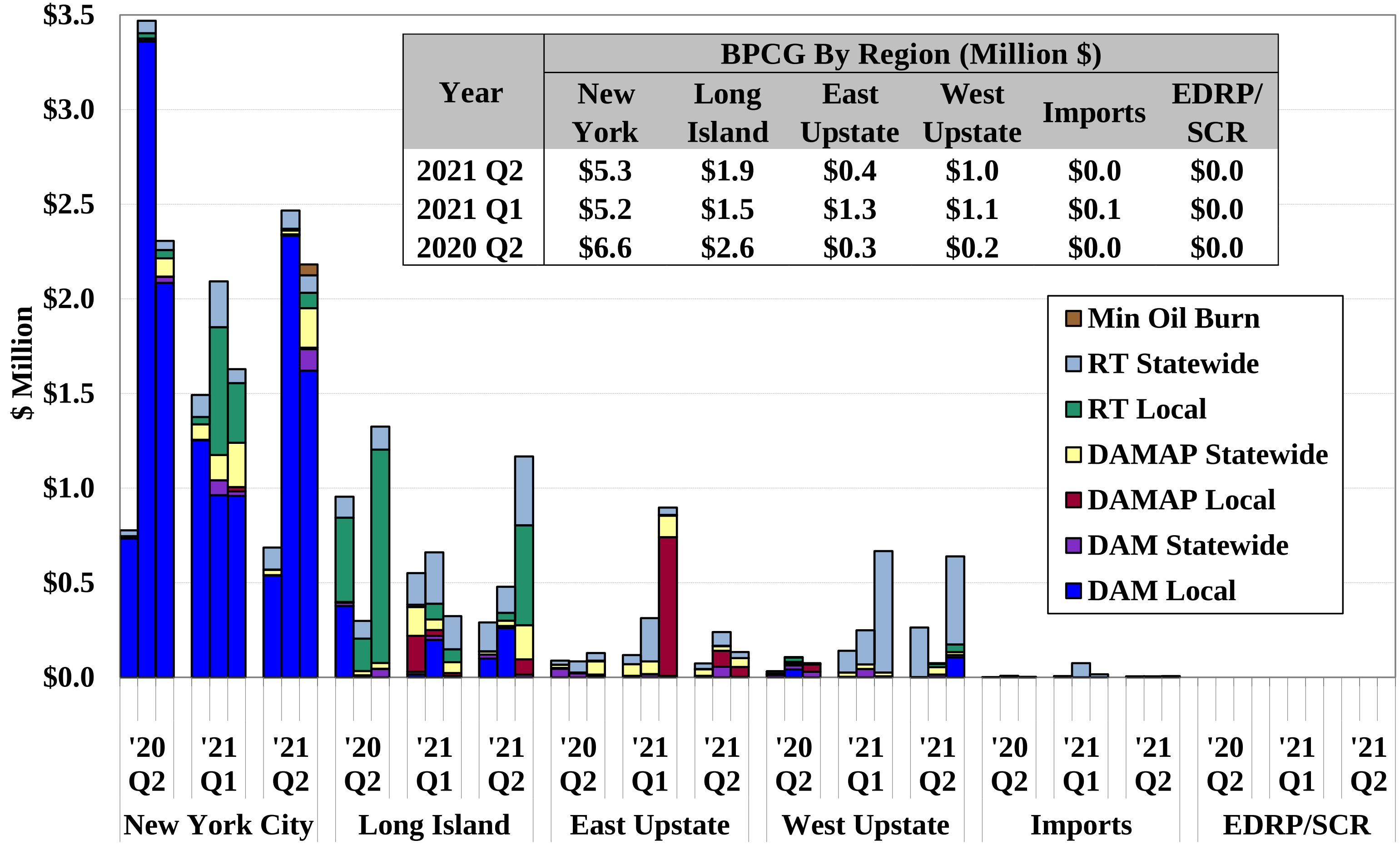
Quarter	Local				Statewide				Total
	Day Ahead	Real Time	DAMAP	Min Oil Burn	Day Ahead	Real Time	DAMAP	EDRP/ SCR	
2021 Q2	$5.0	$0.8	$0.2	$0.1	$0.2	$1.8	$0.6	$0.0	$8.7
2021 Q1	$3.4	$1.2	$1.0	$0.0	$0.2	$2.4	$1.0	$0.0	$9.2
2020 Q2	$6.6	$1.9	$0.1	$0.0	$0.3	$0.6	$0.3	$0.0	$9.7

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.

POTOMAC ECONOMICS

Uplift Costs from Guarantee Payments
By Category and Region



Year	BPCG By Region (Million $)					
	New York	Long Island	East Upstate	West Upstate	Imports	EDRP/ SCR
2021 Q2	$5.3	$1.9	$0.4	$1.0	$0.0	$0.0
2021 Q1	$5.2	$1.5	$1.3	$1.1	$0.1	$0.0
2020 Q2	$6.6	$2.6	$0.3	$0.2	$0.0	$0.0

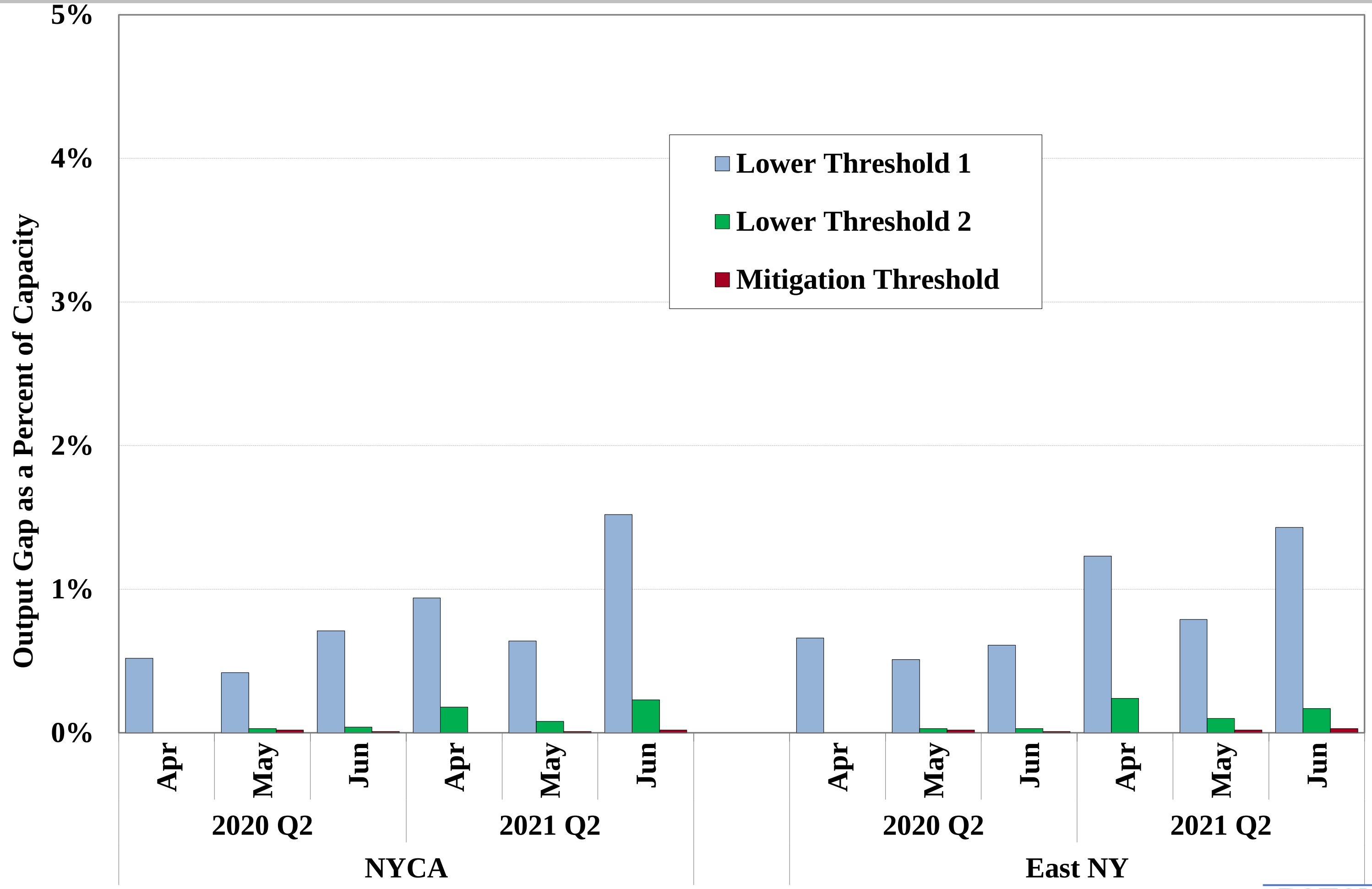
Notes: 1. BPCG data are based on information available at the reporting time that can be different from final settlements.
2. For chart description, see slide 99.

POTOMAC ECONOMICS

Charts:

Market Power and Mitigation

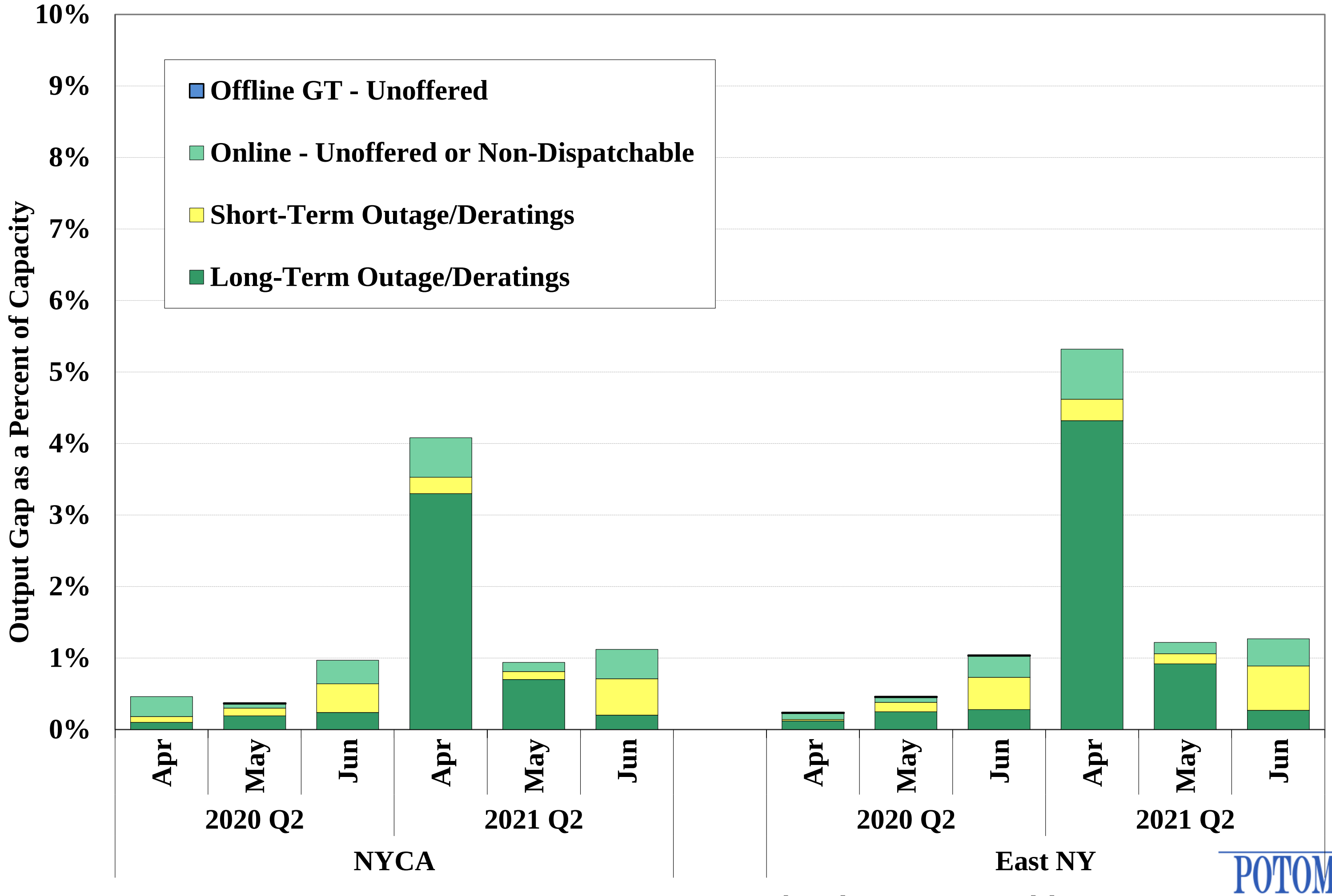
Output Gap by Month
NYCA and East NY



For chart description, see slide 100.

POTOMAC ECONOMICS

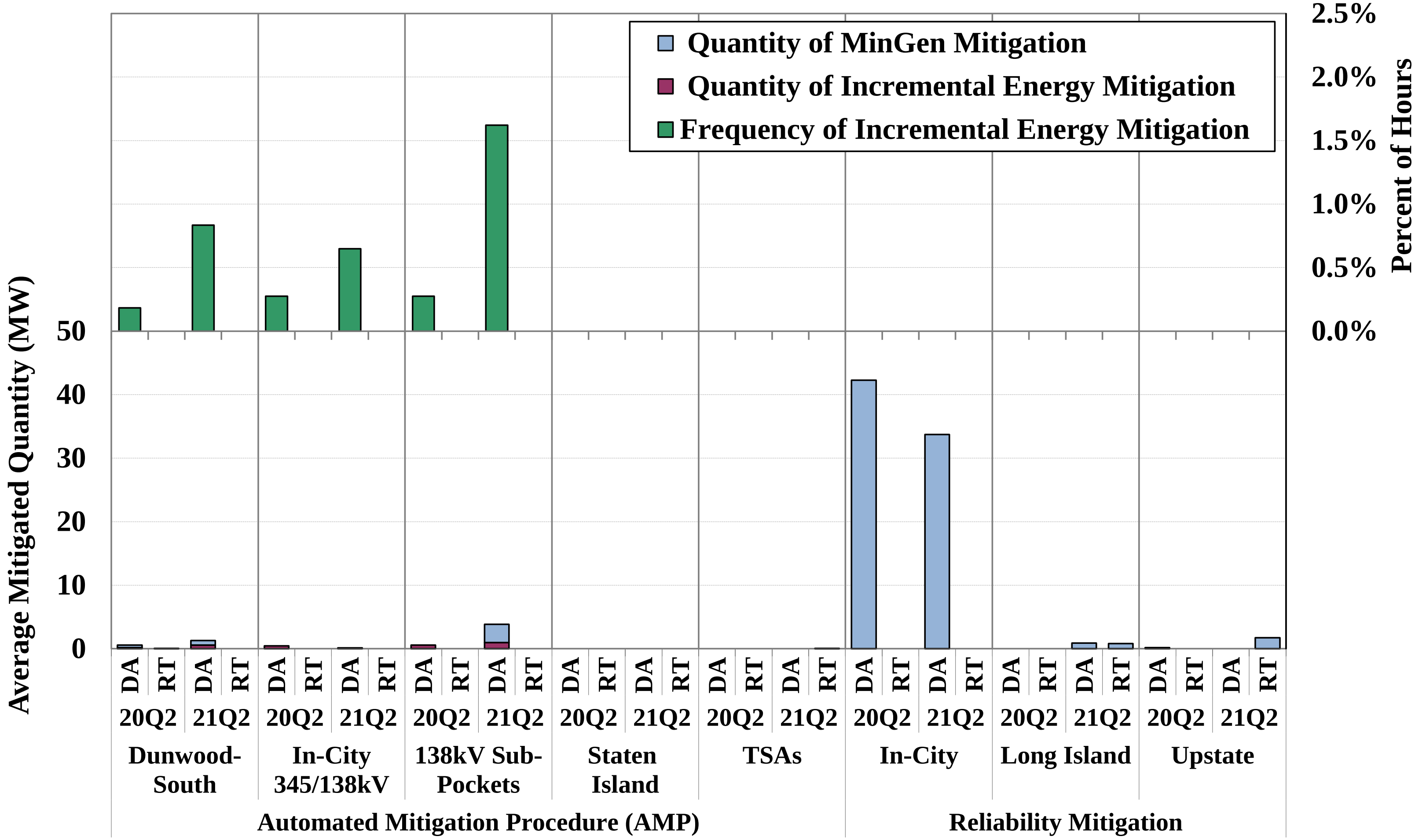
Unoffered Economic Capacity by Month
NYCA and East NY



 For chart description, see slide 100.

POTOMAC ECONOMICS

Automated Market Power Mitigation



Notes: For chart description, see slide 101.

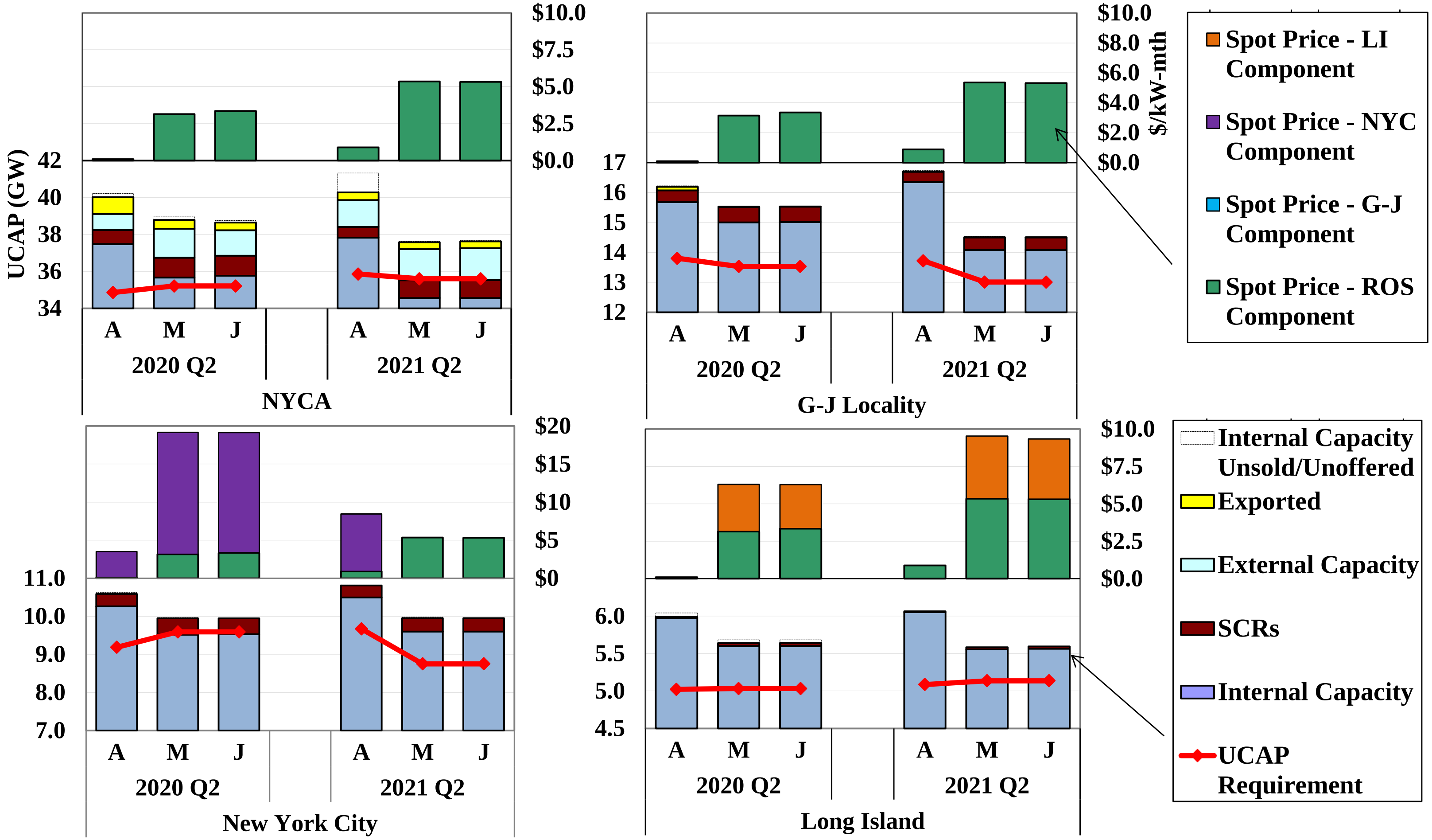
POTOMAC ECONOMICS

Charts:

Capacity Market

POTOMAC ECONOMICS

Spot Capacity Market Results
Monthly Results by Locality



Notes: For chart description, see slide 102.

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)				
Generation	**-692**	**12**	**-53**	**-607**
Entry	375	8	0	384
Exit	-1117	-17	-66	-1050
Other Capacity Changes (1)	50	21	14	59
Cleared Import (2)	**348**			

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

(2) Based on average of quarterly cleared quantity.

Notes: For chart description, see slide 102.

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.

POTOMAC ECONOMICS

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 CO_2, NO_X, and SO_2 .
  - ✓ Slides 26-27 show quarterly emissions across the system by generation fuel type for CO_2 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.

POTOMAC ECONOMICS

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.

POTOMAC ECONOMICS

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).

POTOMAC ECONOMICS

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).

POTOMAC ECONOMICS

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.

POTOMAC ECONOMICS

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".

POTOMAC ECONOMICS

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.)

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

- Steam units in New York City are often LRR-committed solely to satisfy the NOx 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 NOx-committed STs and their supported GTs in the NOx Bubble.
  - ✓ The evaluation is done on days when the ST is NOx-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.

POTOMAC ECONOMICS

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.

POTOMAC ECONOMICS

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.

POTOMAC ECONOMICS

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.