

Quarterly Report on the New York ISO Electricity Markets Second Quarter of 2026

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September 2026

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Market Highlights

Market Highlights

Executive Summary – Prices and Market Outcomes

- NYISO energy markets performed competitively in the second quarter of 2026.
- All-in prices ranged from \$54/MWh in the North Zone to \$107/MWh in NYC, up modestly in most regions from a year ago. (slide [7](#)) Key drivers include:
 - Capacity prices rose sharply across the system, including 47 percent in NYCA and G-J, 83 percent in NYC, and 106 percent in Long Island. (slide [16](#))
 - Energy prices fell by 9 to 26 percent (in areas outside the North Zone) driven by:
 - Lower natural gas prices (10 to 14 percent); and
 - Lower load levels (2 percent on average and 14 percent at the peak) than 2025 Q2, which experienced unusually hot weather on three days.
 - However, the following factors placed upward pressure on energy prices:
 - Exports to Quebec and New England from upstate increased ~640 MW. (slide [46](#))
 - Rising RGGI prices increased marginal production costs ~\$9/MWh. (slide [23](#))
- Residential retail rates (averaged over 12 months ending May 2026) increased 3.7 cents per kWh (in \$2026) from the same period two years earlier. (slide [20](#))
 - Non-wholesale factors account for 74 percent of the increase, although the supply component increased 10 percent due to higher energy and capacity prices.

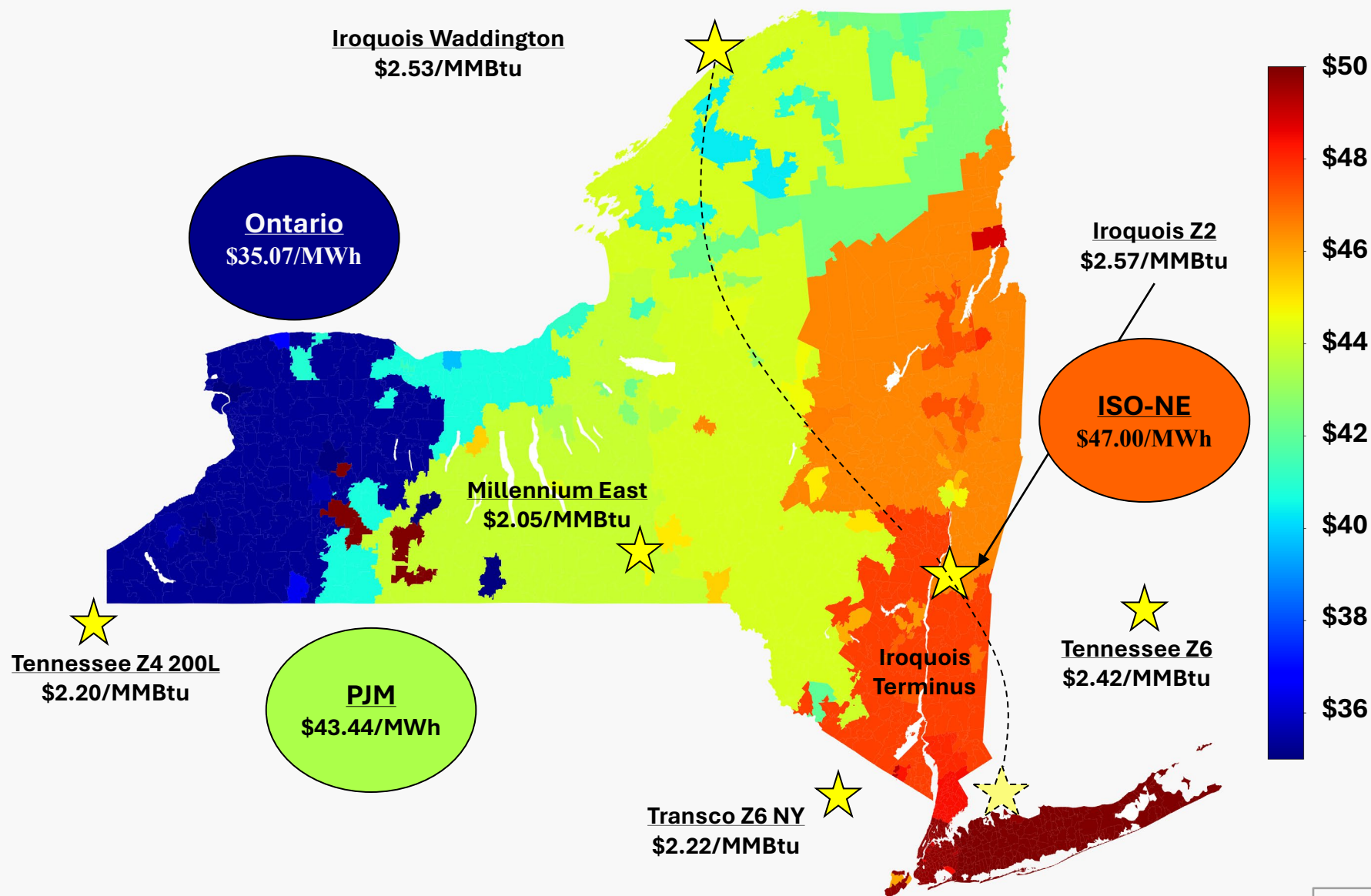
Market Highlights

Executive Summary – High Voltage Issues & Demand Response Uplift

- OOM actions are becoming more frequent to address high voltage issues during low demand periods. We observed OOM actions for voltage (slide [11](#)), including:
 - 35 days with generator commitments and other OOM actions in NYC,
 - 63 days with generator commitments in Long Island,
 - 64 days when transmission lines were taken out on Long Island, and
 - 37 days when a 345kV transmission line into SENY was taken out.
 - This highlights the need to evaluate the cost-effectiveness of options for reactive power support, including:
 - Using inverter-based generation and energy storage, and/or
 - Installing other reactive compensation facilities.
- Uplift from payments to demand response providers totaled \$3 million this quarter and \$45 million YTD. (slide [72](#))
 - These energy payments are required by FERC Order 745.

Market Highlights

System Price Diagram



Market Highlights

Summary of Energy Market Outcomes

- NYISO energy markets performed competitively in the second quarter of 2025.
 - The amount of output gap (slide [74](#)) and unoffered economic capacity (slide [75](#)) were reasonably consistent with competitive market expectations.
- All-in prices ranged from \$54/MWh in the North Zone to \$107/MWh in New York City, up in most regions by 1 percent to 15 percent from a year ago. (slide [19](#))
 - The increases were largely driven by higher capacity costs, which rose by 45 to 101 percent across the system. (slide [16](#)).
 - Energy costs fell in all regions outside of the North Zone by 9 to 26 percent.
 - Natural gas prices fell by 10 to 14 percent across the system. (slide [22](#))
 - Average load fell by 2 percent and peak load fell 14 percent.
 - However, factors tending to increase prices include:
 - Net imports fell during peak hours by 670 MW on average. (slide [46](#))
 - ✓ Net exports to Quebec Upstate and ISO-NE increased by 90 and 550 MW, respectively.
 - RGGI prices increased ~\$20/ton from 2025 Q2. (slide [23](#))

Market Highlights

Congestion Patterns, Revenues, and Shortfalls

- Day-ahead congestion revenues totaled \$73 million in 2026-Q2, up 27 percent from the same quarter last year. (slide [55](#))
 - Congestion declined in most regions because of lower gas prices and load levels.
 - However, congestion increased substantially on exports from the Oswego complex and on transmission paths from West to Central, resulting in higher overall congestion revenues.
- *Oswego generation pocket* – This accounted for the largest share (~30 percent) of day-ahead congestion this quarter. (slide [56](#))
 - Nearly all of this congestion occurred on the Scriba–Volney 345 kV facility in May and June.
 - The increase reflected the combined effects of moderately lower seasonal line ratings and changes in generation and load patterns.
 - Real-time congestion was nearly 50 percent lower than day-ahead congestion, largely because ambient-adjusted ratings increased available transfer capability.
 - This day-ahead congestion should be reduced when NYISO implements the use of ambient adjusted ratings in the day-ahead market.

Market Highlights

Congestion Patterns, Revenues, and Shortfalls (cont.)

- *West-to-Central Congestion* – These transmission paths accounted for the second-largest share (~21 percent) of day-ahead congestion.
 - Most of this congestion occurred for Meyer 230/115 kV constraints and were exacerbated by multiple transmission outages, which contributed nearly \$4 million in congestion shortfalls. (slide [57](#))
- *Long Island* – This accounted for 13 percent of day-ahead congestion revenue.
 - *Imports to Long Island* – About 30 percent of congestion occurred on the 345 kV constraints into Long Island, primarily from late April through early May while the Y49 line was out of service.
 - *Voltage control on Long Island* – Another 40 percent occurred on the Lake Success–Shore Road 138 kV and Northport–Pilgrim 138 kV facilities.
 - These constraints bound when parallel facilities were switched out of service to manage high-voltage risks during light-load conditions.
 - These line-switching actions led to nearly \$2.5 million in day-ahead congestion shortfalls allocated to the responsible TO.

Market Highlights

Allocation of DAM Congestion Residuals

- NYISO allocates DAM congestion residuals to NYTOs using a two-stage process:
 - First, congestion residuals resulted from Qualifying facility changes (e.g., outages, return-to-services, and uprate/derate) are allocated to responsible TOs on a “cost causation” basis. (see OATT 20.2.4 Formula N-5 through N-14)
 - Second, remaining congestion residuals (“Net Congestion Rents”) are socialized to all TOs in proportion to their TCC revenues rather than DAM congestion patterns. (see OATT 20.2.5 Formula N-15)
- In this quarter, \$8M of shortfalls were allocated to responsible TOs on a cost causation basis, while other surpluses and shortfalls were socialized to all TOs.
 - Among socialized residuals, we estimate that: (slides [57](#) - [58](#))
 - \$1.1 million of surpluses accrued on Long Island facilities;
 - \$1.0 million of surpluses accrued on external interfaces;
 - \$1.8 million of shortfalls were associated with West-to-Central facilities.
 - We have recommended the NYISO revise the residual allocation method based on incremental transfer capability scheduled in the DAM. (see Rec. #2023-1)

Market Highlights

OOM Actions to Manage Network Reliability

- OOM commitments to satisfy thermal N-1-1 and N-1-1-0 requirements occurred on 39 days in NYC, on 14 days on Long Island, and on 6 days in the North Country load pocket. (slide [61](#))
 - It would be beneficial to incorporate the full reserve requirements into the market model for resource scheduling and pricing in these local areas. (see Rec. #2024-1)
- Voltage issues have led to more OOM actions over the past year. (slides [61](#) – [62](#))
 - *Long Island* - Large steam turbines (“STs”) were committed on 63 days to manage high voltage risks during light-load conditions. Multiple transmission lines were out of service during most of April and May for high voltages as well.
 - *New York City* - OOM commitments occurred on 30 days and import curtailments occurred on 7 days for voltage support, primarily for high voltage during light loads.
 - *East Update* – The Marcy-FraserAnnex-Coopers 345 kV lines were OOS to control high voltages from March 26 to May 7.
 - *Market impacts* – These OOM actions affected LBMPs and congestion patterns in these regions, leading to roughly \$3.5 million in congestion shortfalls and \$5 million in BPCG uplift.

Market Highlights

Uplift from Reliability Commitment, OOM Dispatch, and Scheduling

- Guarantee payments totaled \$17 million, up 16 percent year-over-year. (slide [69](#))
 - Roughly \$2.9 million of this total came from SRE commitments for system reserves on just two days (June 11-12).
- New York City accounted for the \$4.6 million (27 percent) of BPCG.
 - \$2.9 million was paid to generators committed for N-1-1-0 reliability. (slide [67](#))
- Long Island accrued 8.1 million (or 47 percent) of BPCG uplift this quarter.
 - \$3.4 million was paid to generators committed for managing high voltage during light load conditions.
- Demand Response payments to DERs totaled \$3.2 million this quarter for an average of \$61/MWh. These have reached \$45 million YTD. (slide [72](#))
 - These energy payments are required by FERC Order 745.

Market Highlights

RT Pricing of GTs Bidding Multi-Hour MRT

- The fast-start pricing rule is currently not applied to fast-start units that submit a Minimum Run Time (“MRT”) offer exceeding one hour.
 - However, the RT scheduling software (RTC and RTD) and market settlement rules ignore their MRT offers and treat them in every other way the same as a unit that submits a one-hour MRT.
 - This creates an inconsistency between the purpose of fast-start pricing and the eligibility criteria for fast-start pricing, leading to inefficient real-time prices.
- We identified seven groups of GTs in New York City and Long Island that were sometimes not eligible to set price because of this issue. (slide [51](#))
 - In 2026 Q2, LBMPs were below the GTs’ as-bid costs in approximately 54 percent of the hours when these GTs were committed.
 - If these GTs were eligible to set prices like other fast start units, the average LBMP during these hours would have increased by up to \$8 to \$329 per MWh at individual locations.
- We have recommended the NYISO revise the eligibility for fast-start pricing to be based on the minimum run time used for scheduling, rather than the value of the offer parameter. (See Rec #2023-2).

Market Highlights

Virtual Imports and Exports in the DAM

- We define virtual imports and exports as external transactions that are scheduled in the DAM but withdrawn from the RTM (i.e., no RT bids submitted).
 - These are commonly scheduled between NYISO and neighboring control areas, averaging ~400 MW in the net import direction during the quarter. (slide [45](#))
- We identify two issues related to virtual imports and exports:
 - In the DAM, virtual imports and exports are treated as physical energy but fail post-DAM checkout with neighboring control areas. This may lead:
 - The Forecast Pass of the DAM to not commit sufficient resources, and
 - The need for SRE commitments to address capacity deficiencies after the DAM.
 - Furthermore, we have highlighted market inefficiencies that will arise when the Dynamic Reserve design is implemented because it will treat virtual and non-firm transactions as able to satisfy operating reserve requirements.
 - In RTC, despite failing post-DAM checkout, virtual transactions are treated as:
 - Available in RTC's advisory scheduling time frame, but
 - Unavailable in RTC's binding scheduling time frame.
 - This inconsistency can lead to ramp constraints in RTC's advisory scheduling time frame that distort RT prices and schedules in the binding time frame.

Market Highlights

DARU/LRR/SRE Commitments for N-1-1-0 Requirements in NYC

- Our assessment of supplemental commitments to satisfy N-1-1-0 reliability needs in New York City indicated that: (Slide [67](#))
 - 13 percent was “economic” in the DAM;
 - 21 percent was identified by the MMU as necessary to satisfy a specific reliability requirement represented in the market model, based on information available in the DAM and RTM related to forecasted load, status of generation and transmission equipment, and potential contingencies.
 - Of these MWh, roughly 24 percent was needed to meet the identified requirement, while the remaining 76 percent was surplus headroom on the unit committed (including hours committed to satisfy a Minimum Run Time requirement).
 - Smaller flexible resources like batteries and DERs may be more cost-effective solutions for managing reliability needs. However, the market does not provide incentives for satisfying these local needs. We have recommended modeling these requirements in the market (See Rec #2024-1).
 - 37 percent was committed to address voltage-related reliability requirements
 - 29 percent was associated with reliability needs arising largely from:
 - Load over-forecasting at the time of the DARU; or
 - Local TO requirements that are not represented in the market model.

Market Highlight

Capacity Market Outcomes

- Spot capacity prices averaged \$23.79/kW-month in NYC, 5.87/kW-month in NYCA and in G-J Locality, and \$8.21/kW-month in Long Island. (slides [78-79](#))
 - Spot prices increased 47 to 106 percent in all regions.
- “CHPE-Out” capacity market parameters were used for May and June 2026, including a lower NYC LCR and lower CAFs based on a lower winter reliability risk (which favors technologies with higher availability in the summer).
- New market rules took effect beginning with the 2026/27 Capability Period.
 - *Firm Fuel Capacity Accreditation* – Some units in Zones F-K have a Non-Firm CAF.
 - Non-Firm CAFs ranged from ~85 to 99 percent, but they fell significantly in July when “CHPE-In” parameters became effective.
 - *DMNC Adjustments for Ambient Conditions* – These were enhanced as follows:
 - Temperature adjustments are based on a level more reflective of peak conditions.
 - Humidity adjustments are applied to units with certain auxiliary cooling equipment.
 - For water-cooled generators, the DMNC test window is restricted to certain hours of the day and summer tests must be conducted in July or August.
 - We will evaluate the impact of the new rules in our 2026 Q3 report.

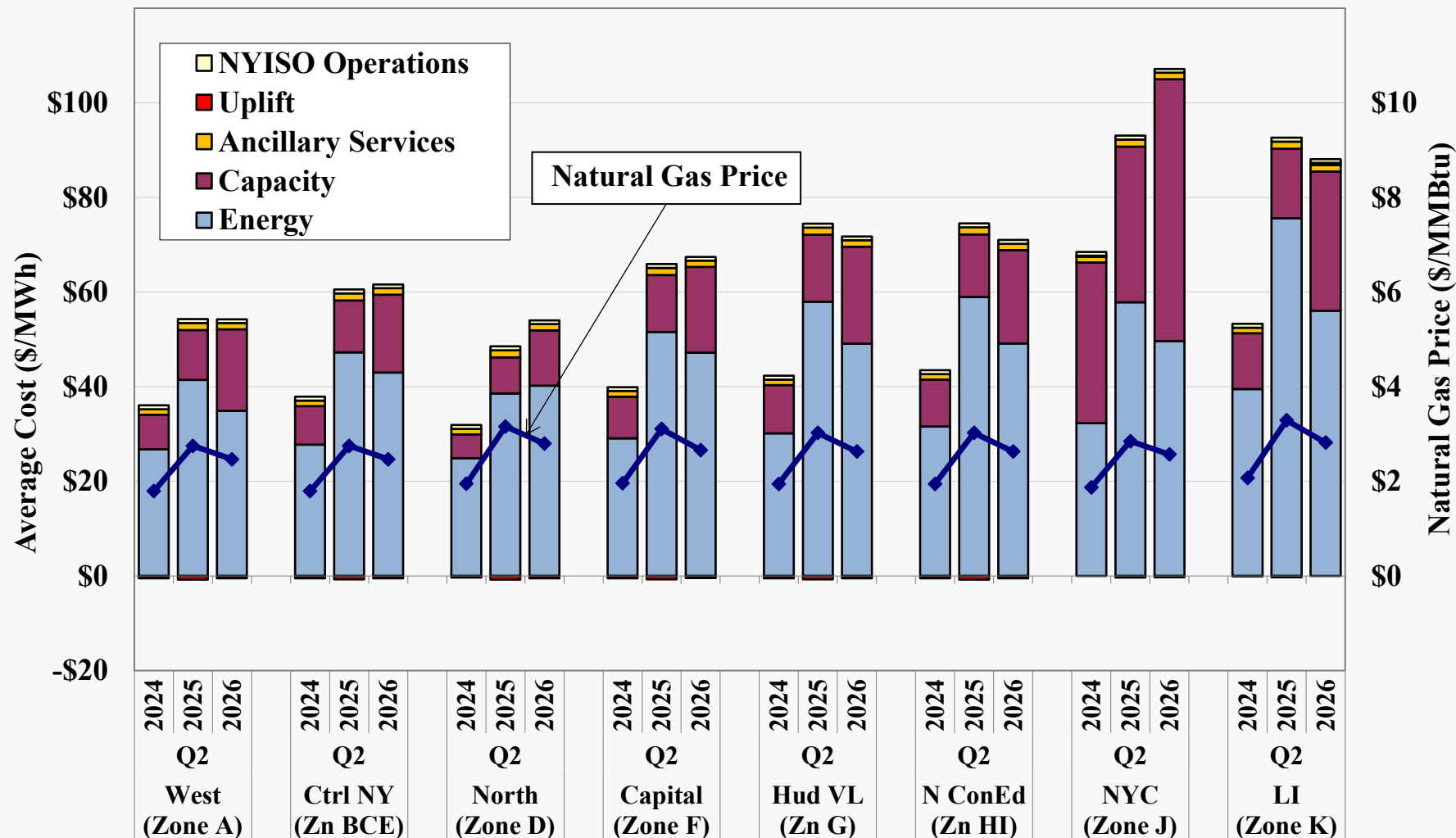
Market Highlights

Capacity Market Outcomes (cont.)

- NYC spot capacity prices averaged \$32.56/kW-month in May and June 2026.
 - ICAP Sales – These fell 191 MW due to ICAP-ineligible forced outages (40 MW) and DMNC reductions (151 MW) largely due to the DMNC enhancements.
 - ICAP Requirement – This increased ~500 MW due to a higher load forecast (57 MW) and LCR which rose 4.1 percent because NYISO began to account for:
 - Non-coincident versus coincident peak load forecast differences; and
 - Transmission outages that reduce generator availability.
- Long Island spot capacity prices rose 106 percent to average \$8.21/kW-month.
 - ICAP Sales – These fell 170 MW due to reduced DMNC ratings of generators.
 - Roughly 150 MW of this reduction was from the new test requirements for water-cooled generators and the sunsetting of the Capacity Limited Resource program.
 - ICAP requirement – This rose 212 MW mostly due to a 3.8 percent LCR increase (after NYISO began to account for non-coincident peak and transmission outages).
- NYCA (and G-J Locality) rose 47 percent and to \$7.90/kW-month in May/June.
 - This increased primarily because of an increase in the capacity demand curve for NYCA, which was caused by a decline in the CAF of the demand curve proxy unit (i.e., 2-hour battery) technology.

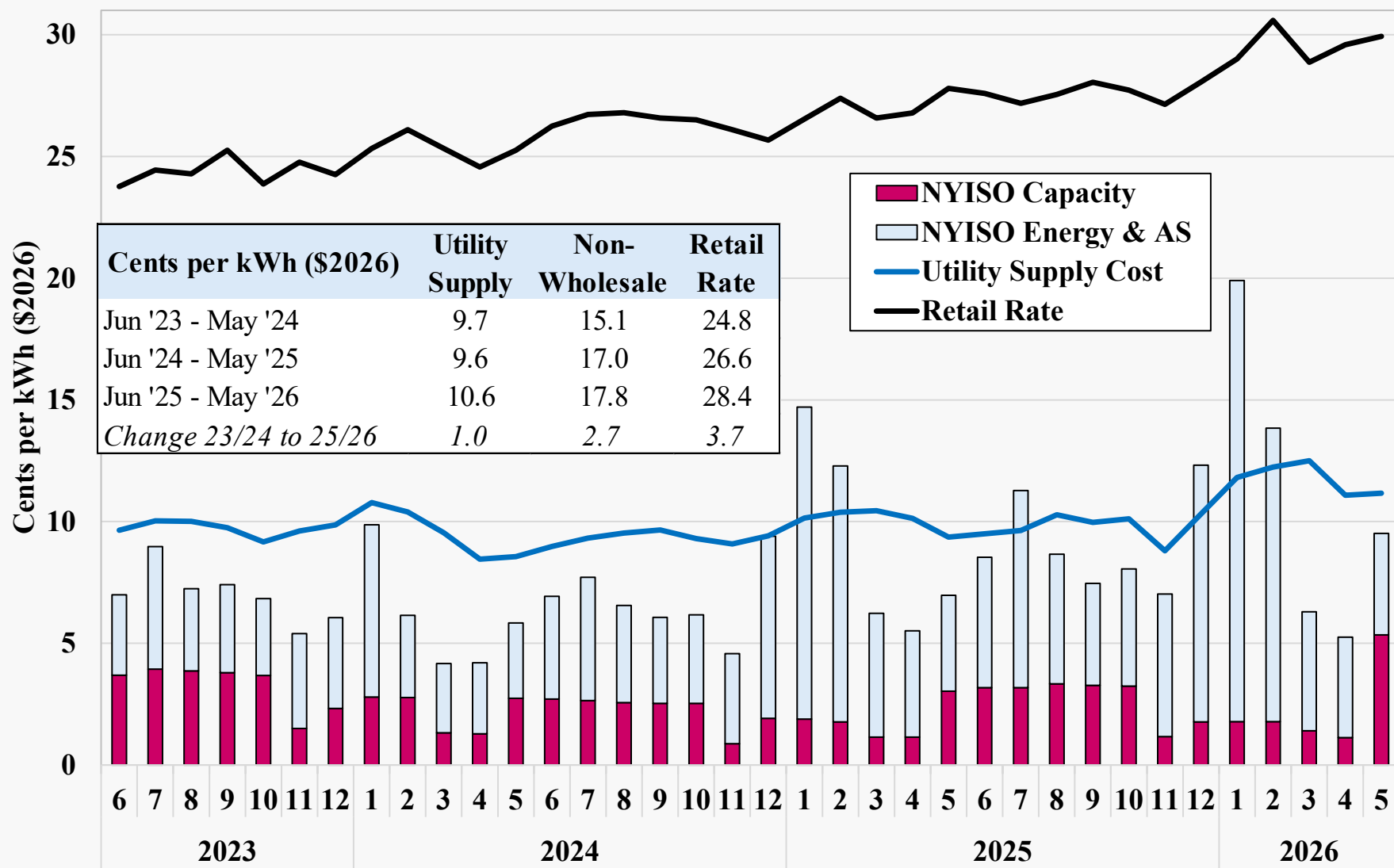
Charts: Market Outcomes

All-In Prices by Region



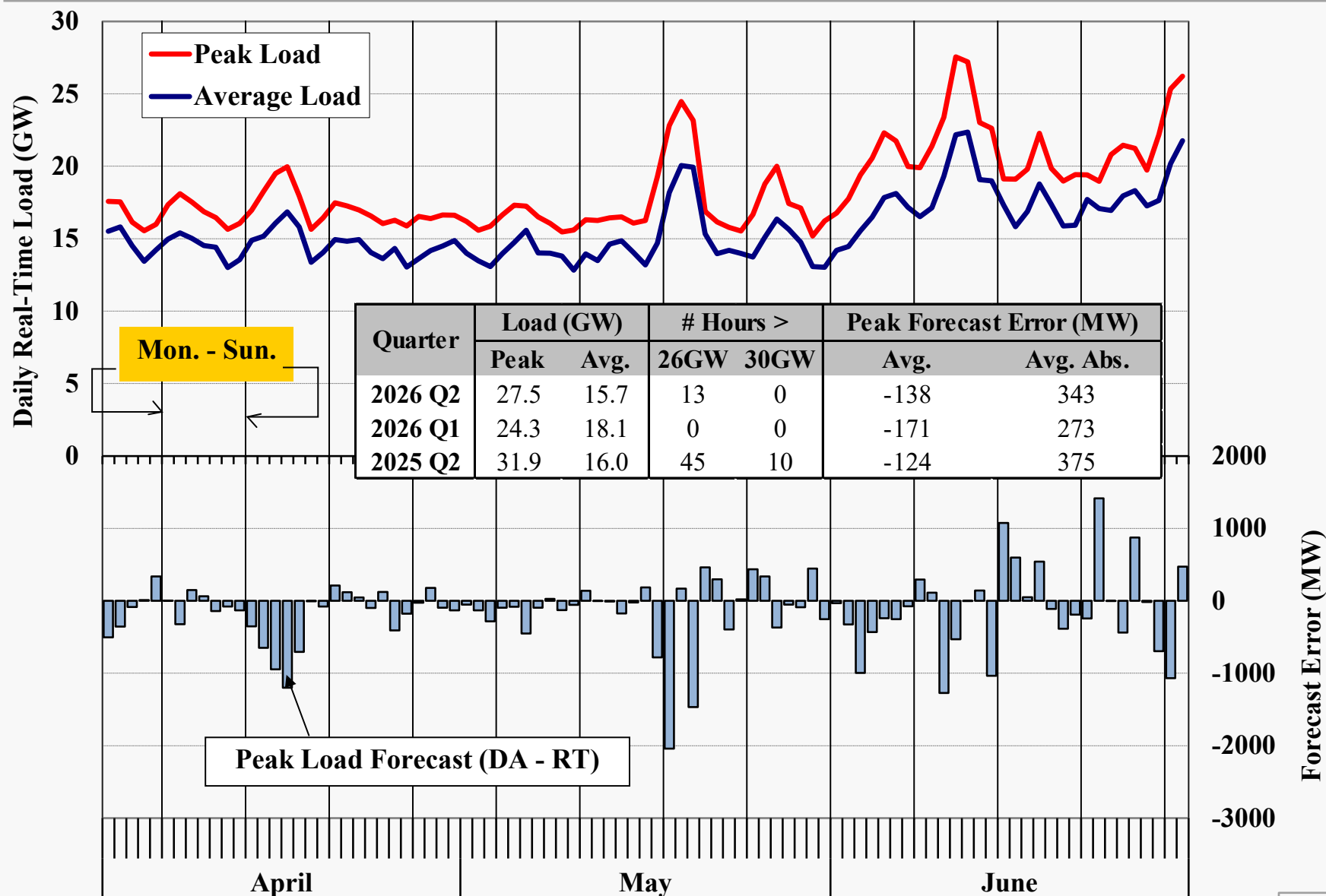
Notes: For chart description, see slide [81](#).

Comparison Residential Retail and Wholesale Prices

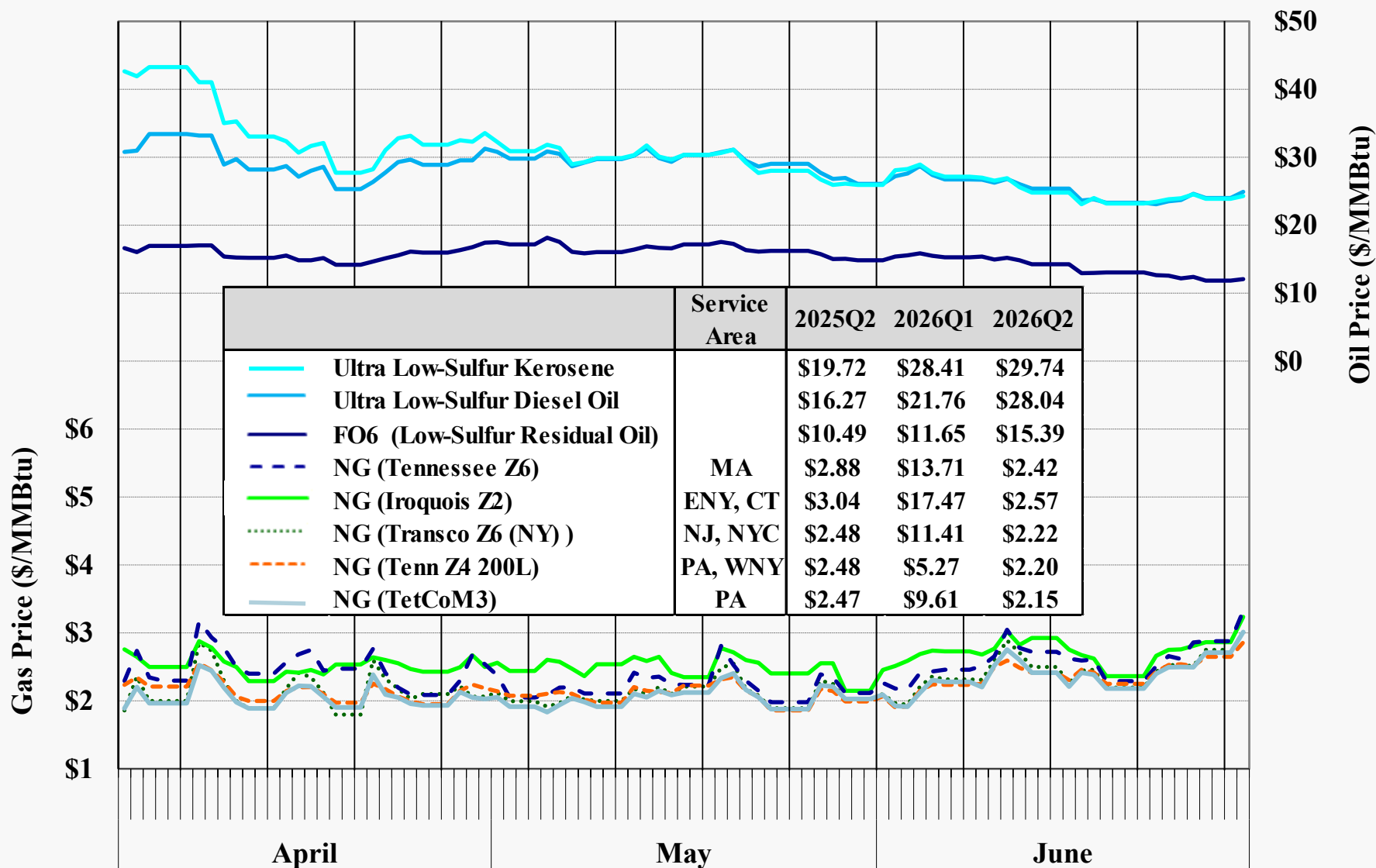


Notes: For chart description, see slide [82](#).

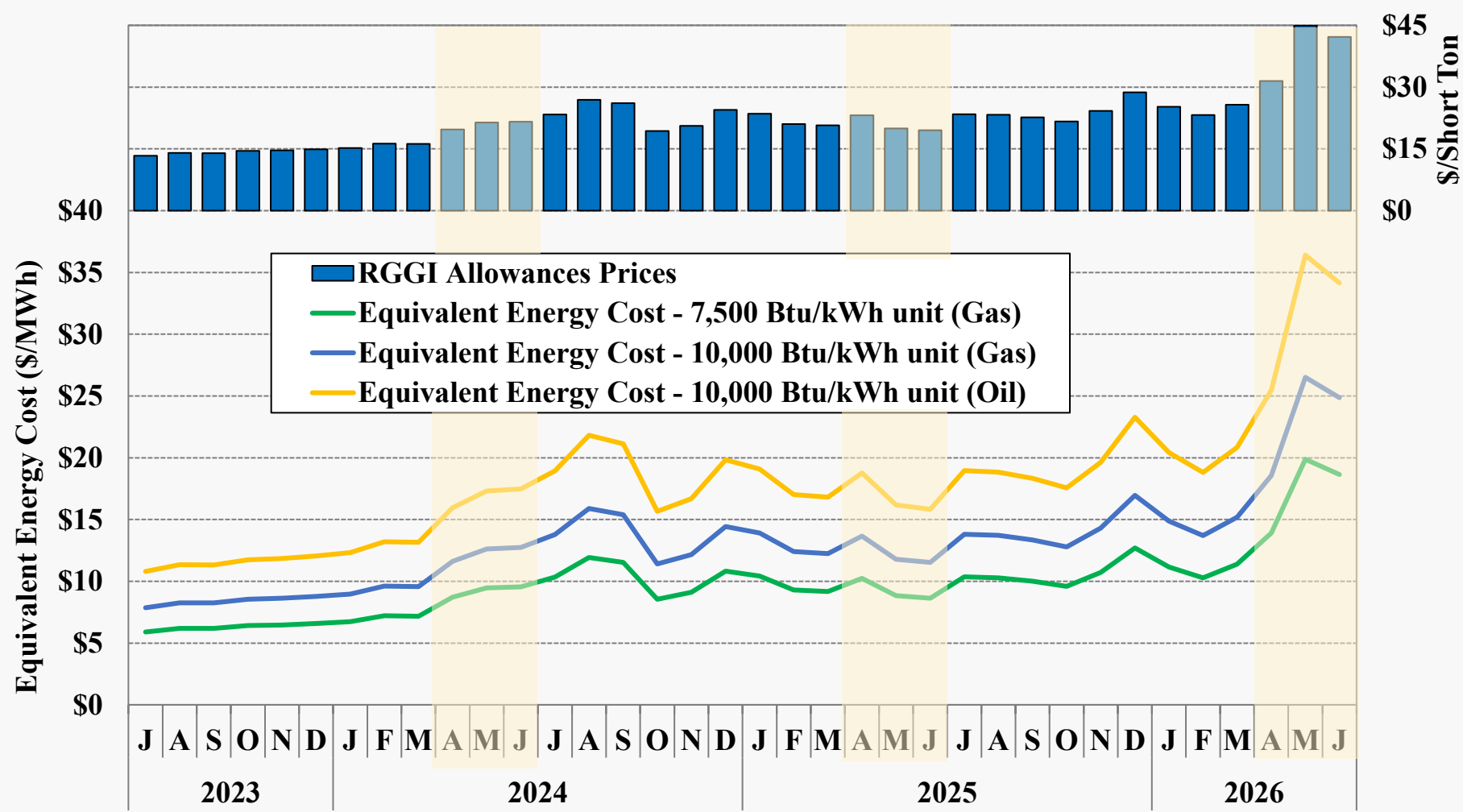
Load Forecast and Actual Load



Natural Gas and Fuel Oil Prices

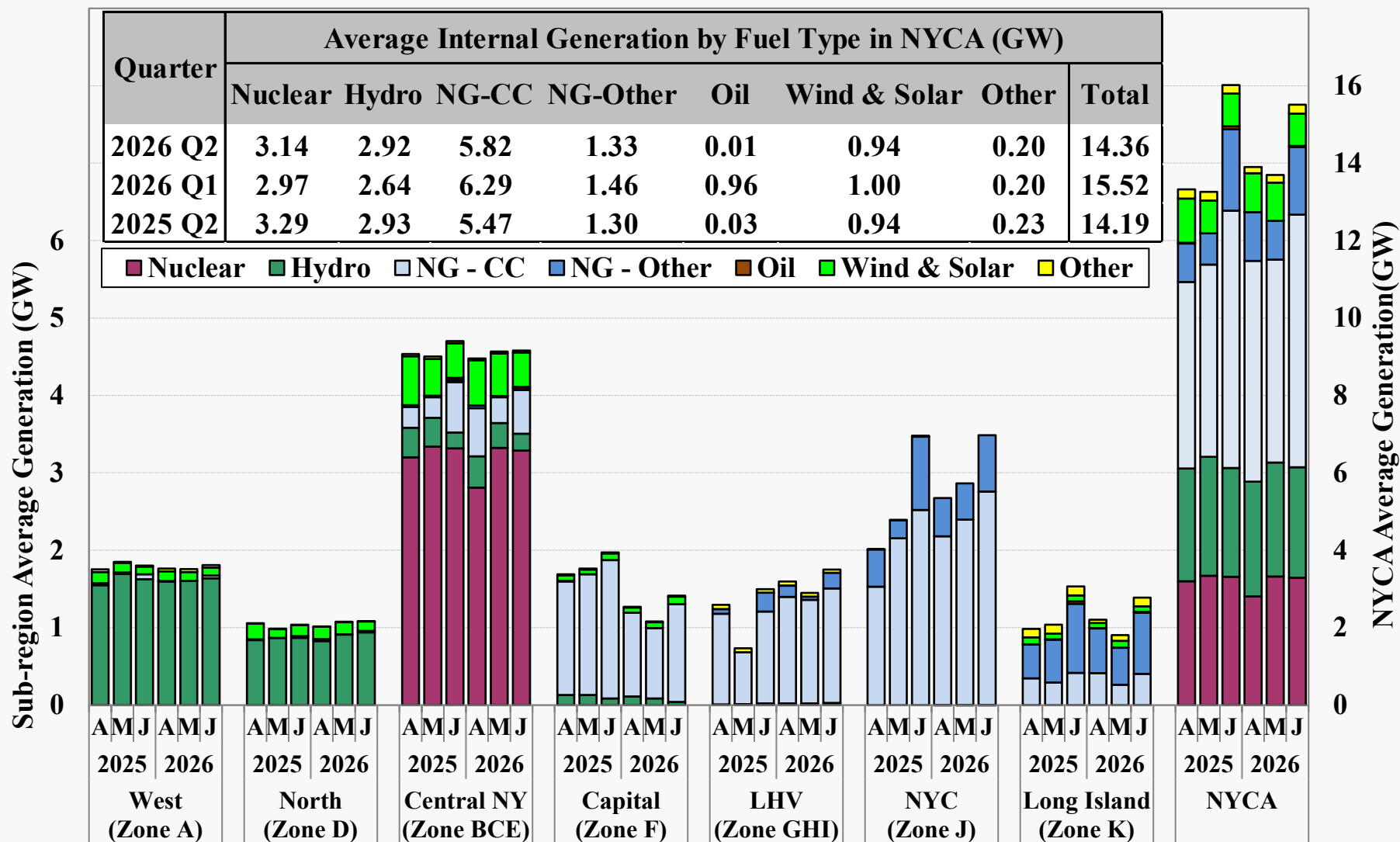


RGGI Prices and Equivalent Energy Costs



Notes: For chart description, see slide 83.

Real-Time Generation Output by Fuel Type

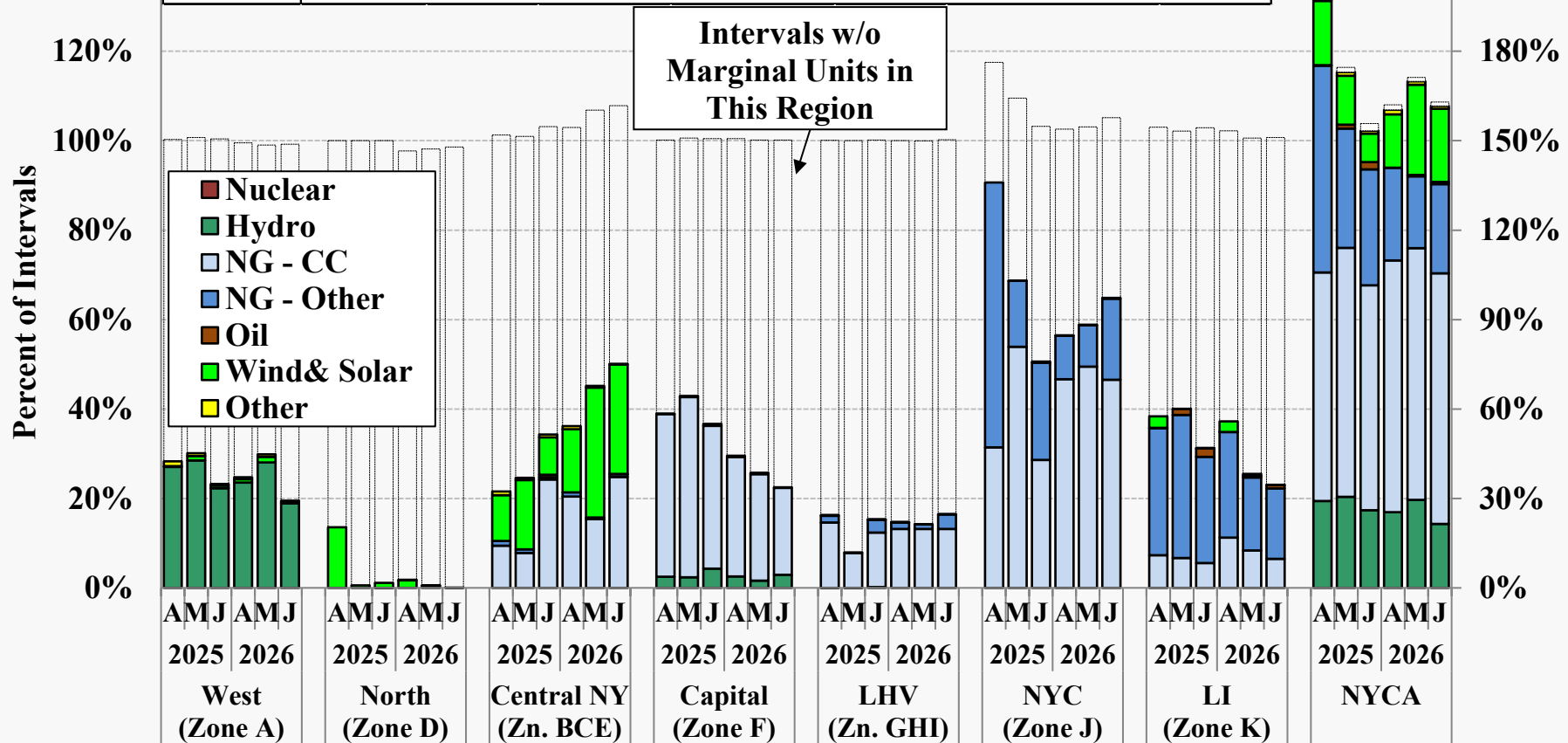


Notes: For chart description, see slide [84](#).

Fuel Type of Marginal Units

In the Real-Time Market

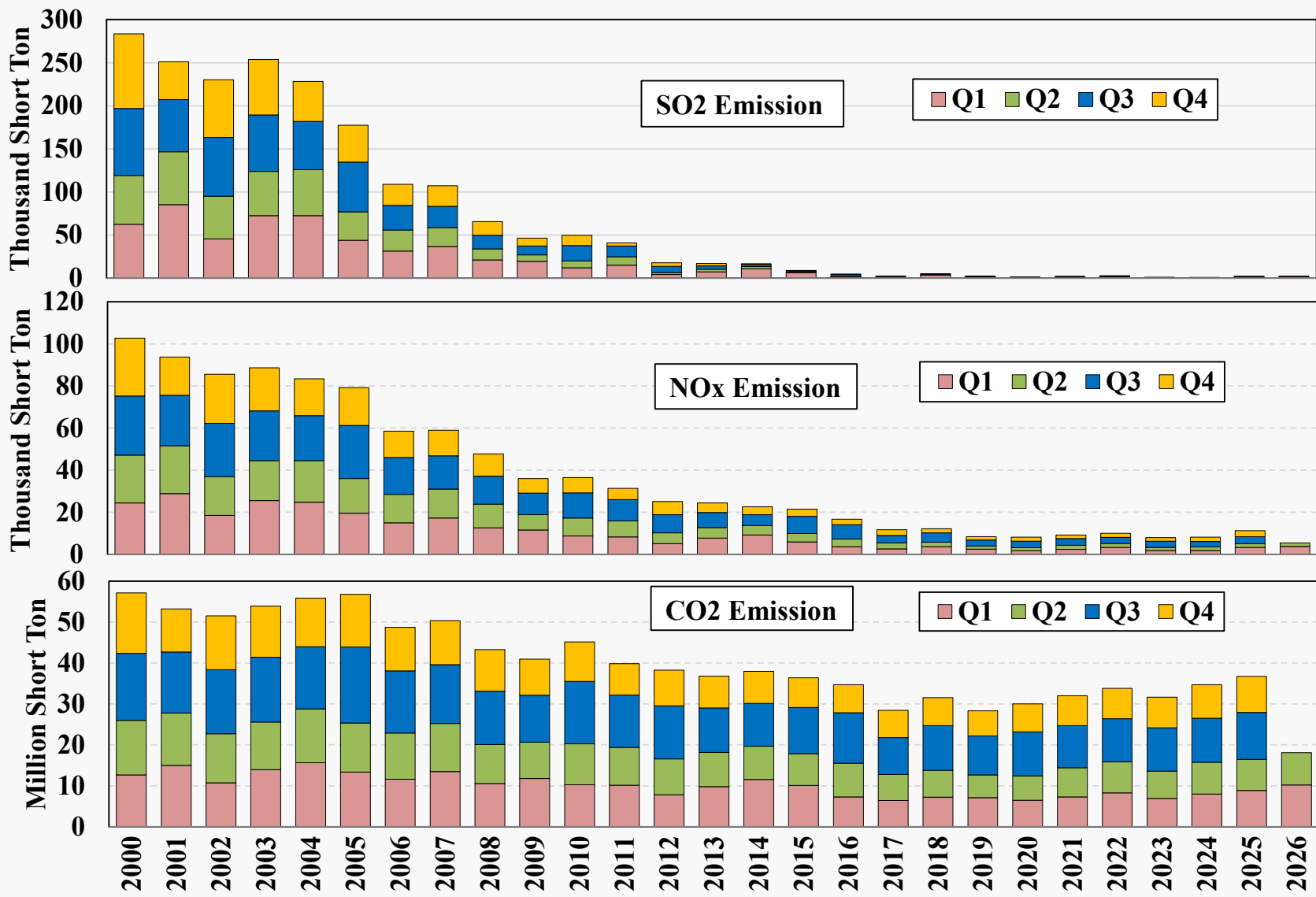
Quarter	Marginal Fuel Types in NYCA						
	Nuclear	Hydro	NG-CC	NG-Other	Oil	Wind & Solar	Other
2026 Q2	0%	25%	84%	28%	0%	24%	1%
2026 Q1	0%	26%	67%	23%	19%	20%	1%
2025 Q2	0%	29%	79%	49%	1%	16%	1%



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

Historical Emissions by Quarter in NYCA

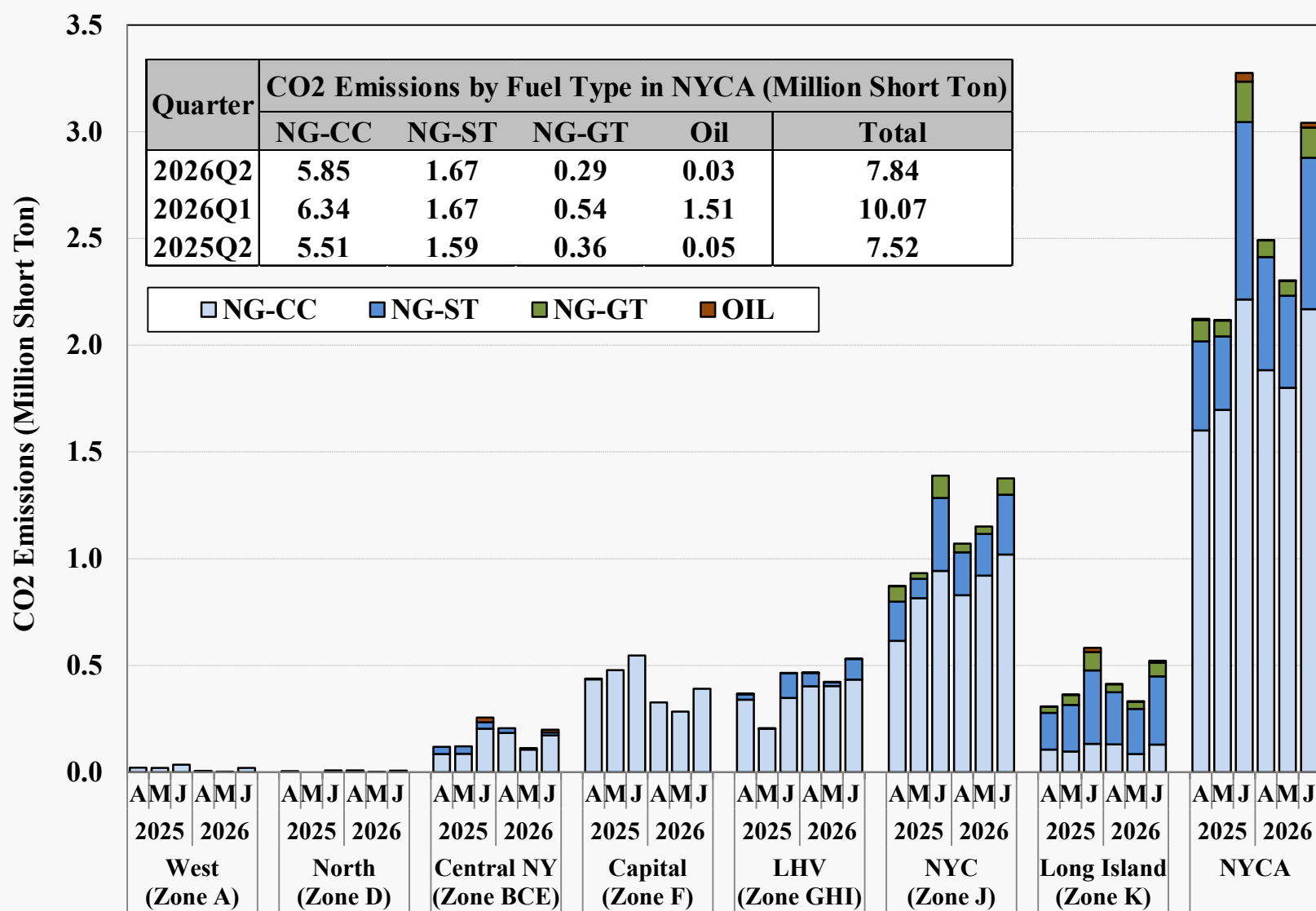
CO₂, SO₂, and NO_x



Notes: For chart description, see slide [85](#).

Emissions by Region by Fuel Type

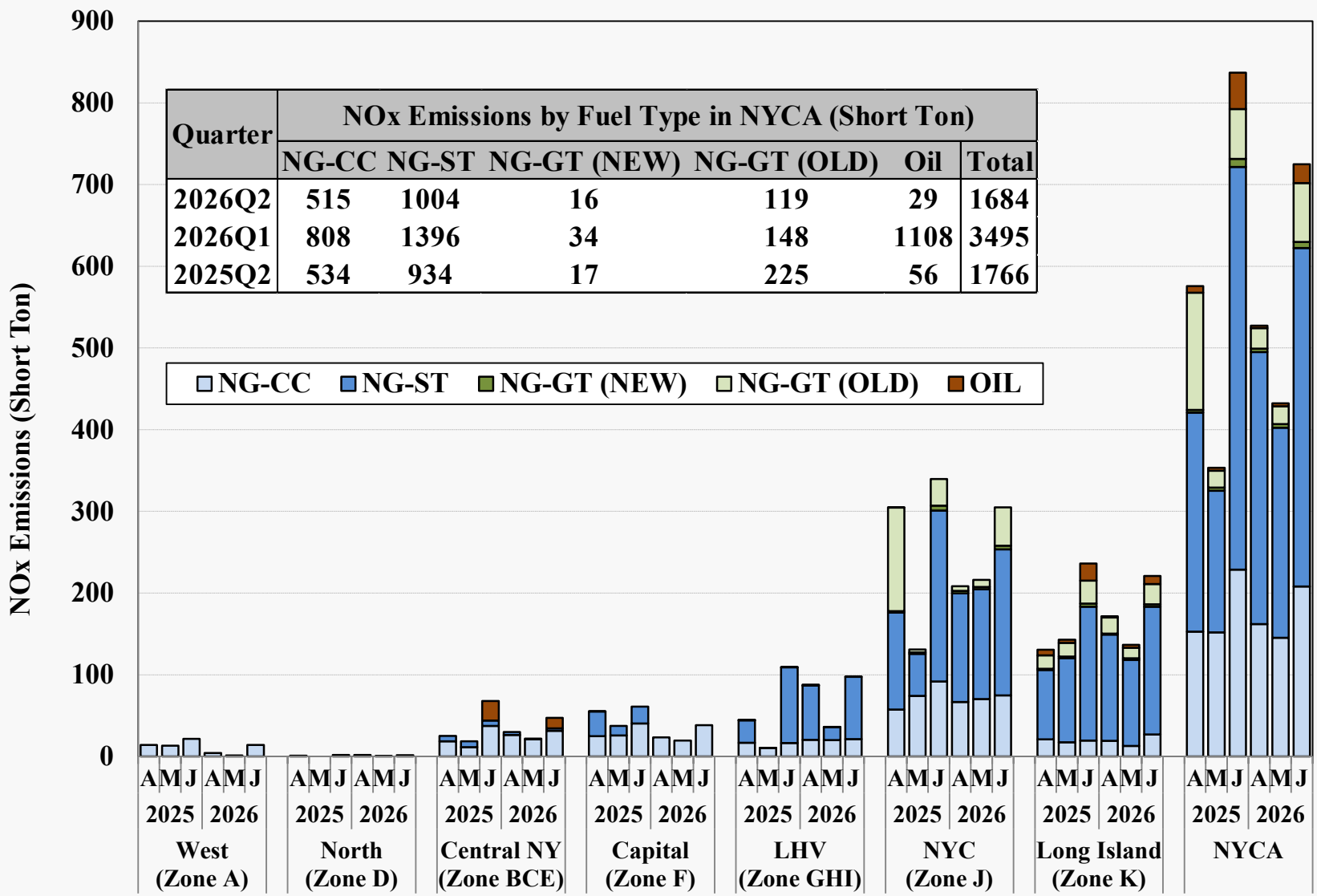
CO₂ Emissions



Notes: For chart description, see slide [85](#).

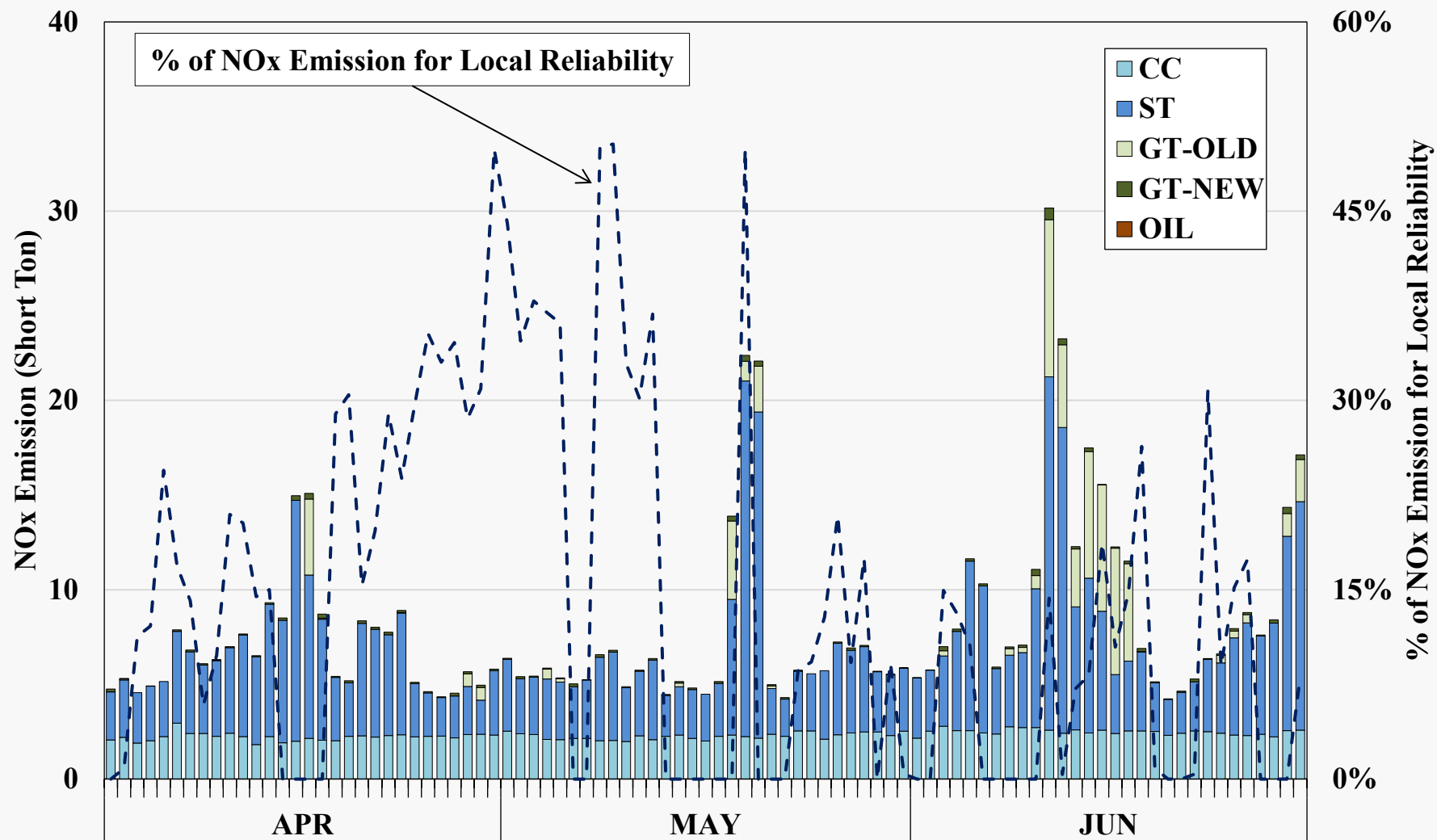
Emissions by Region by Fuel Type

NO_x Emissions



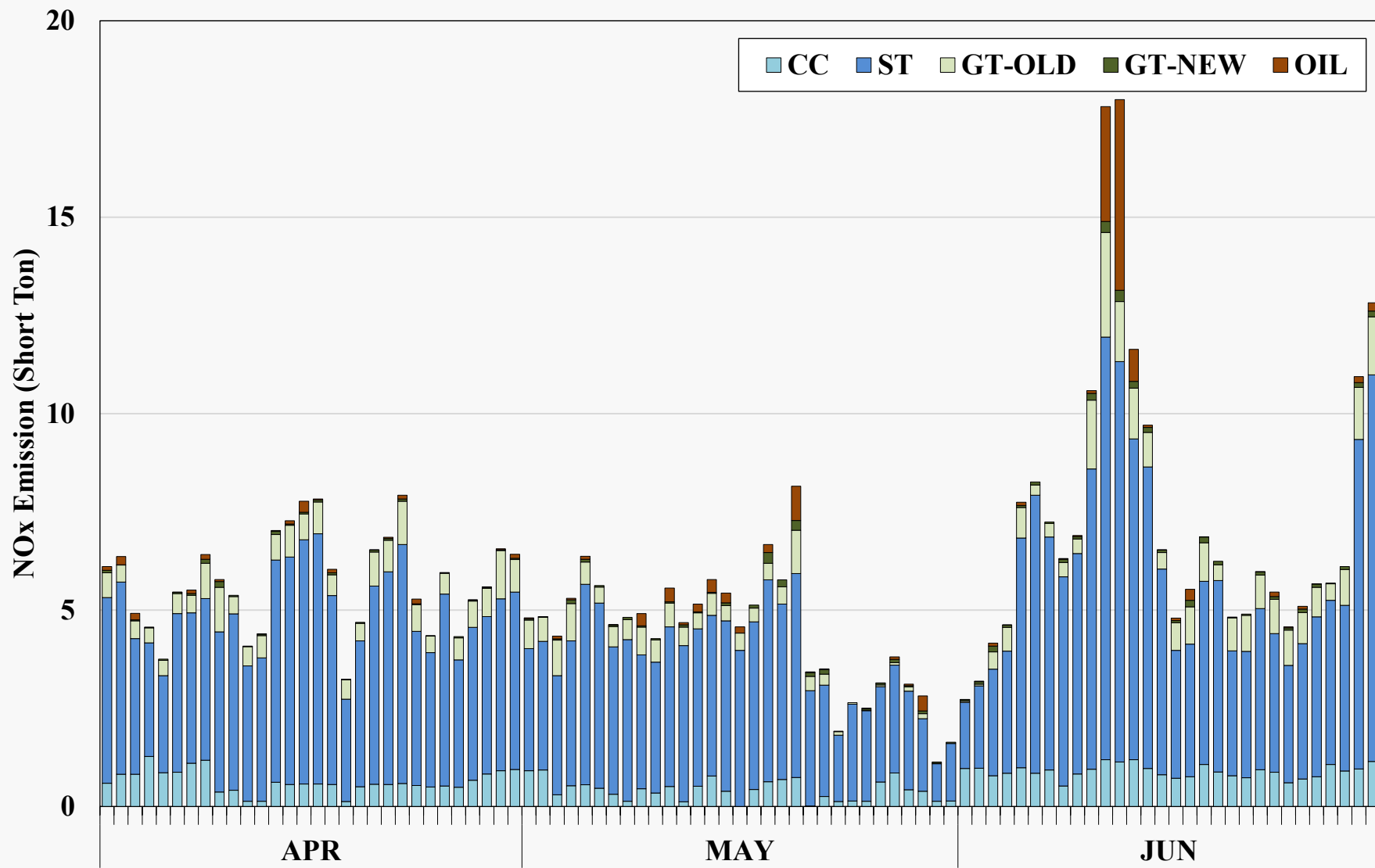
Notes: For chart description, see slide [85](#).

Daily NO_x Emissions in NYC



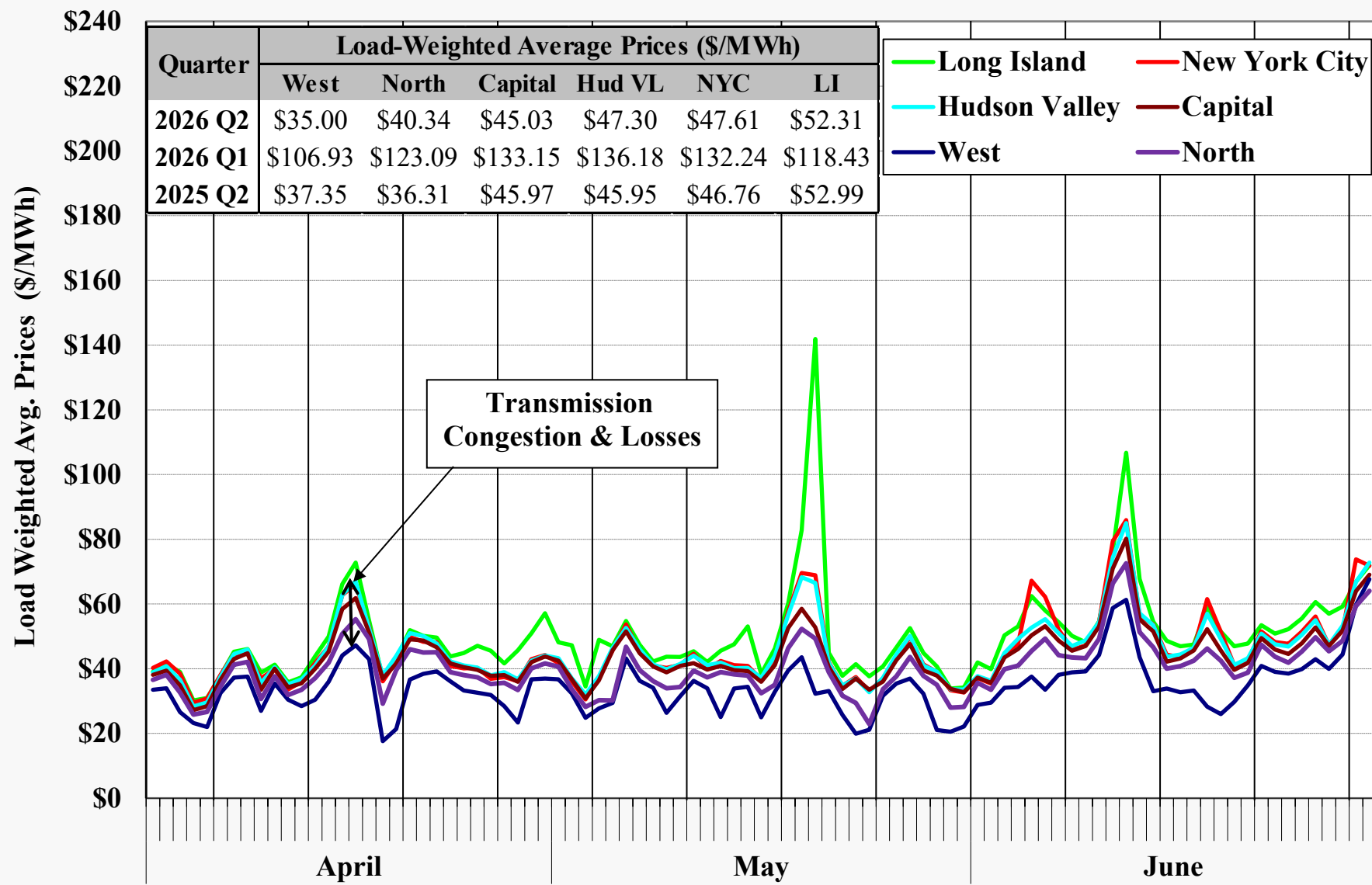
Notes: For chart description, see slide [85](#).

Daily NO_x Emissions in Long Island

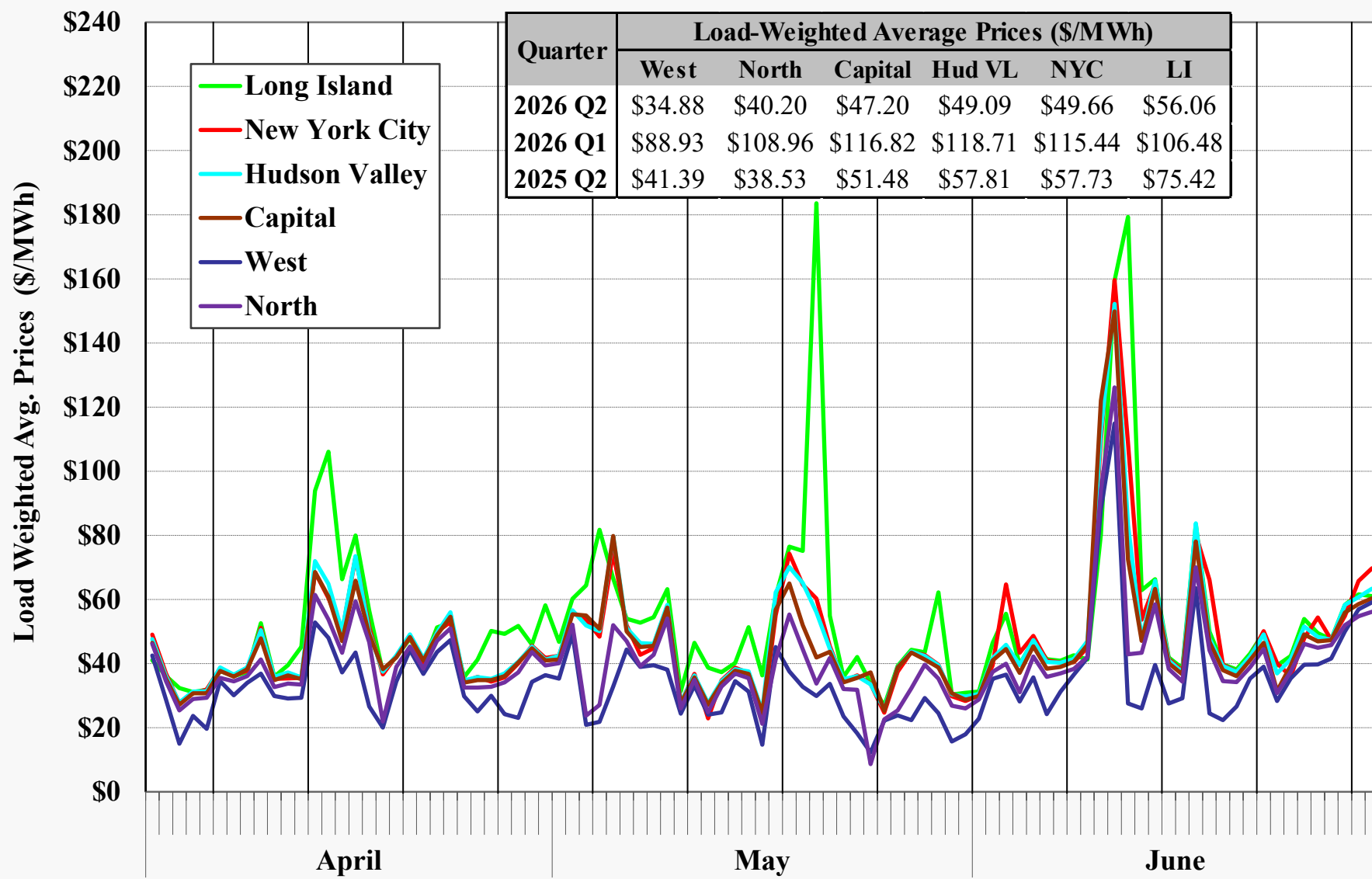


Notes: For chart description, see slide [85](#).

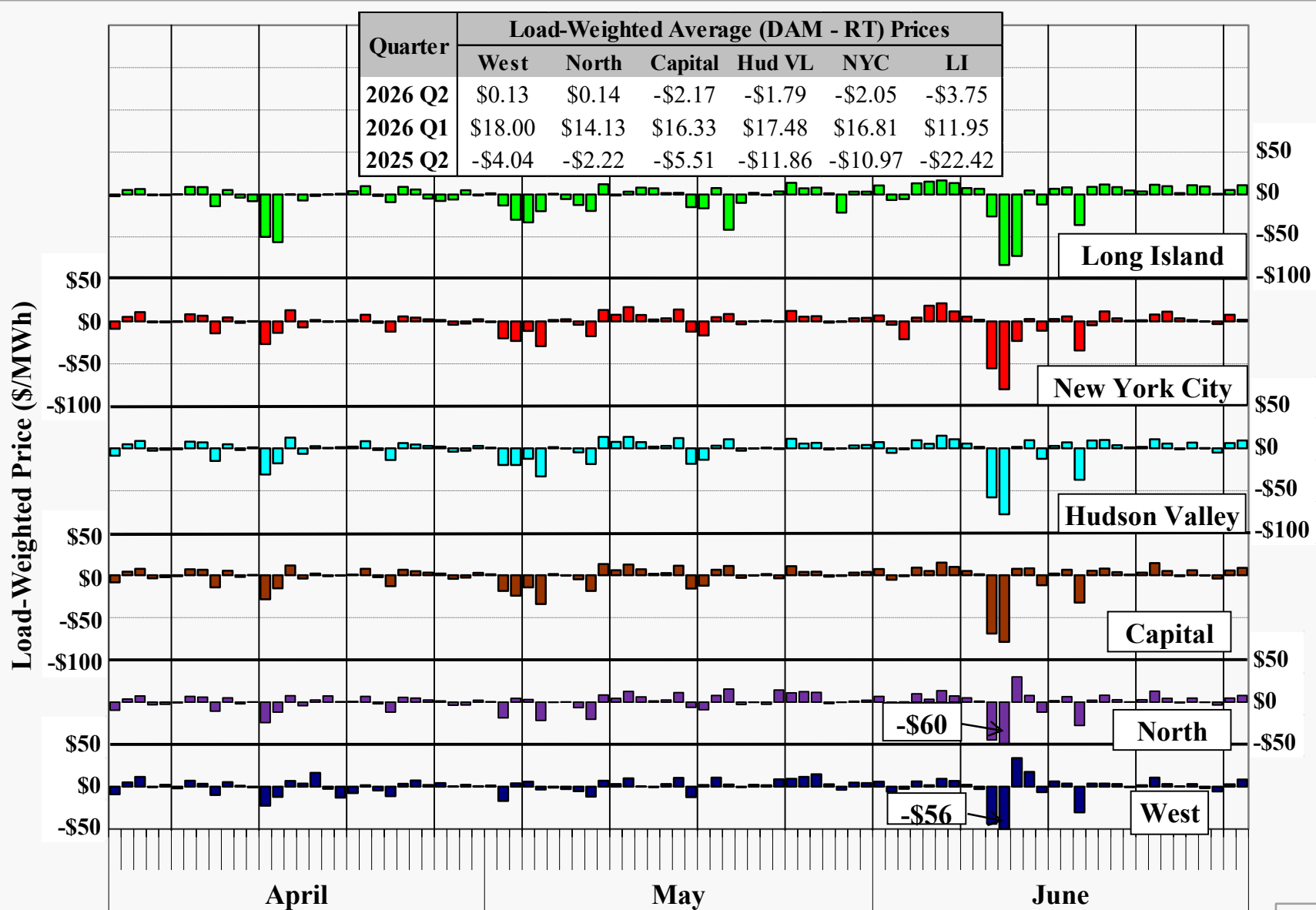
Day-Ahead Electricity Prices by Zone



Real-Time Electricity Prices by Zone



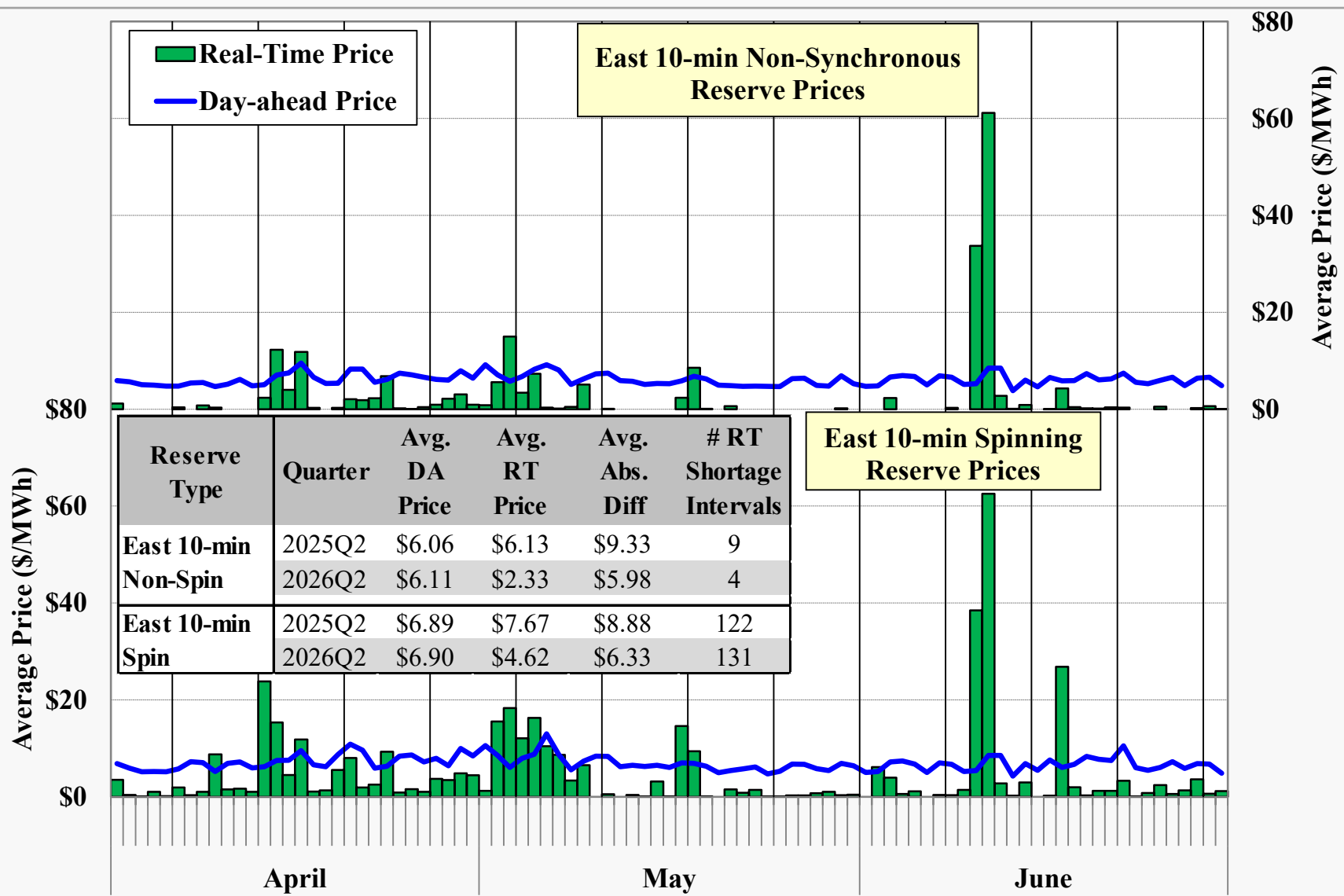
Convergence of Day-Ahead and Real-Time Prices



Charts: Ancillary Services Market

Day-Ahead and Real-Time Ancillary Services Prices

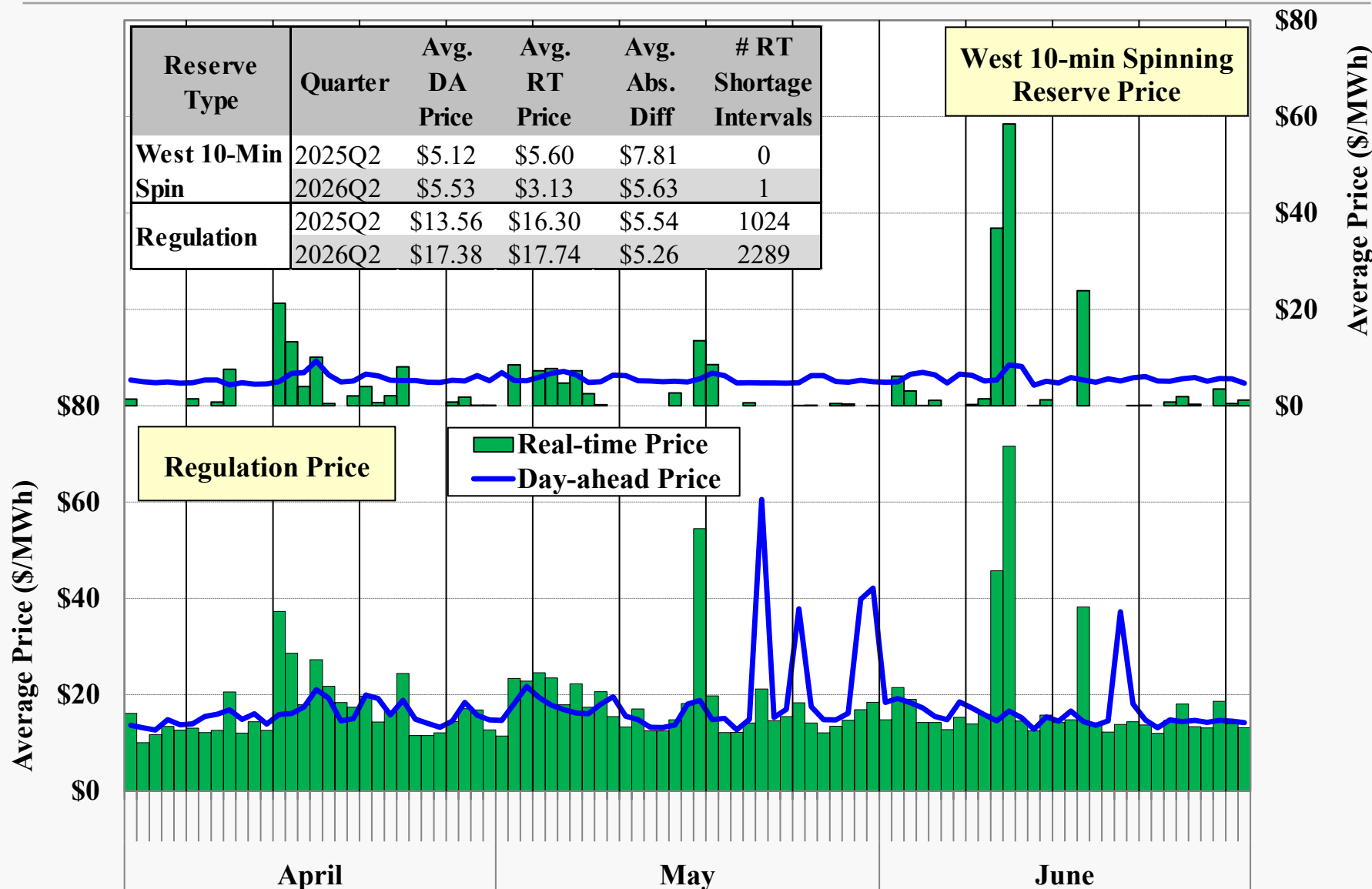
Eastern 10-Minute Spinning and Non-Spinning Reserves



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

Day-Ahead and Real-Time Ancillary Services Prices

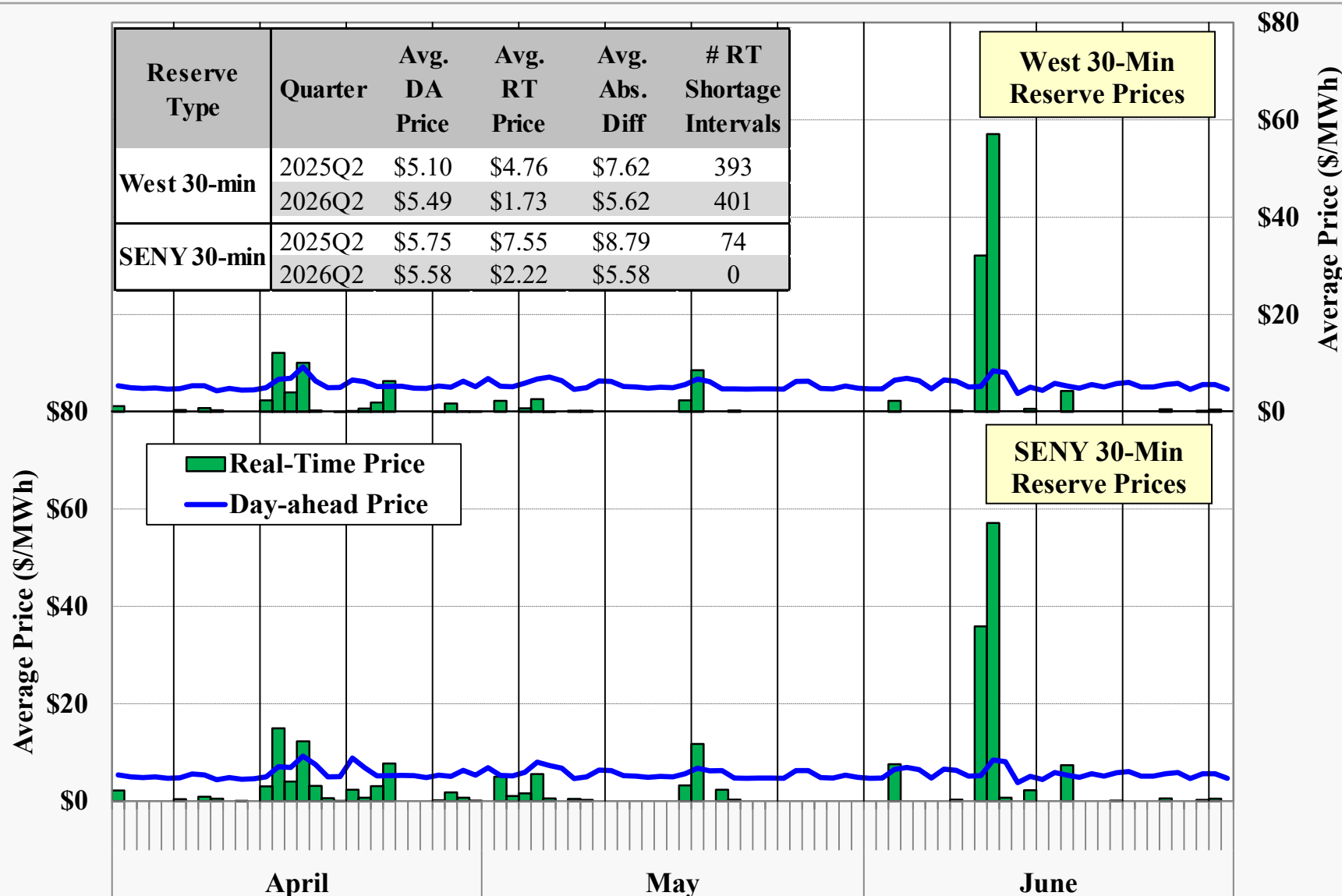
Western 10-Minute Spinning Reserves and Regulation



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

Day-Ahead and Real-Time Ancillary Services Prices

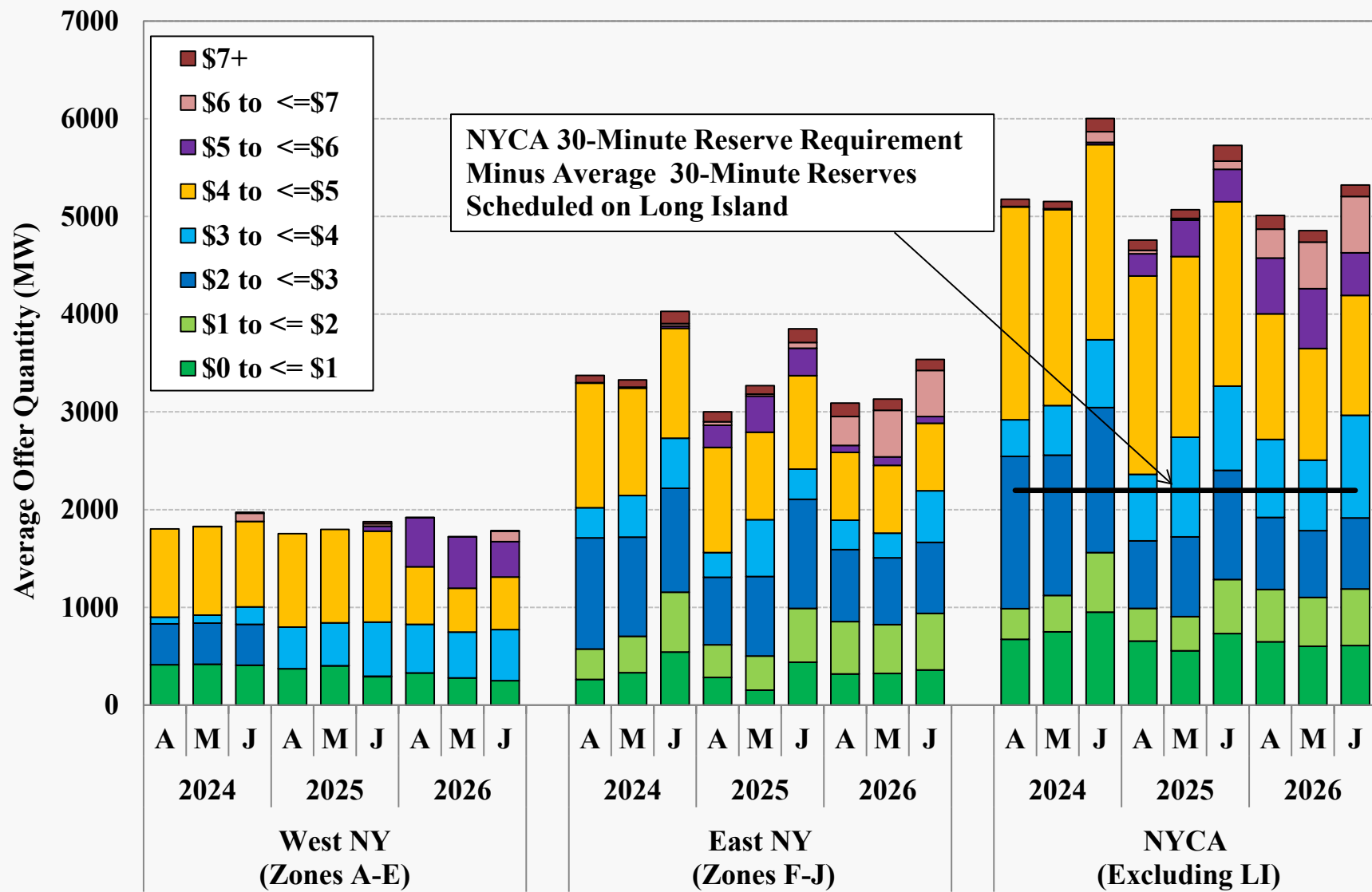
Western and SENY 30-Minute Reserves



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

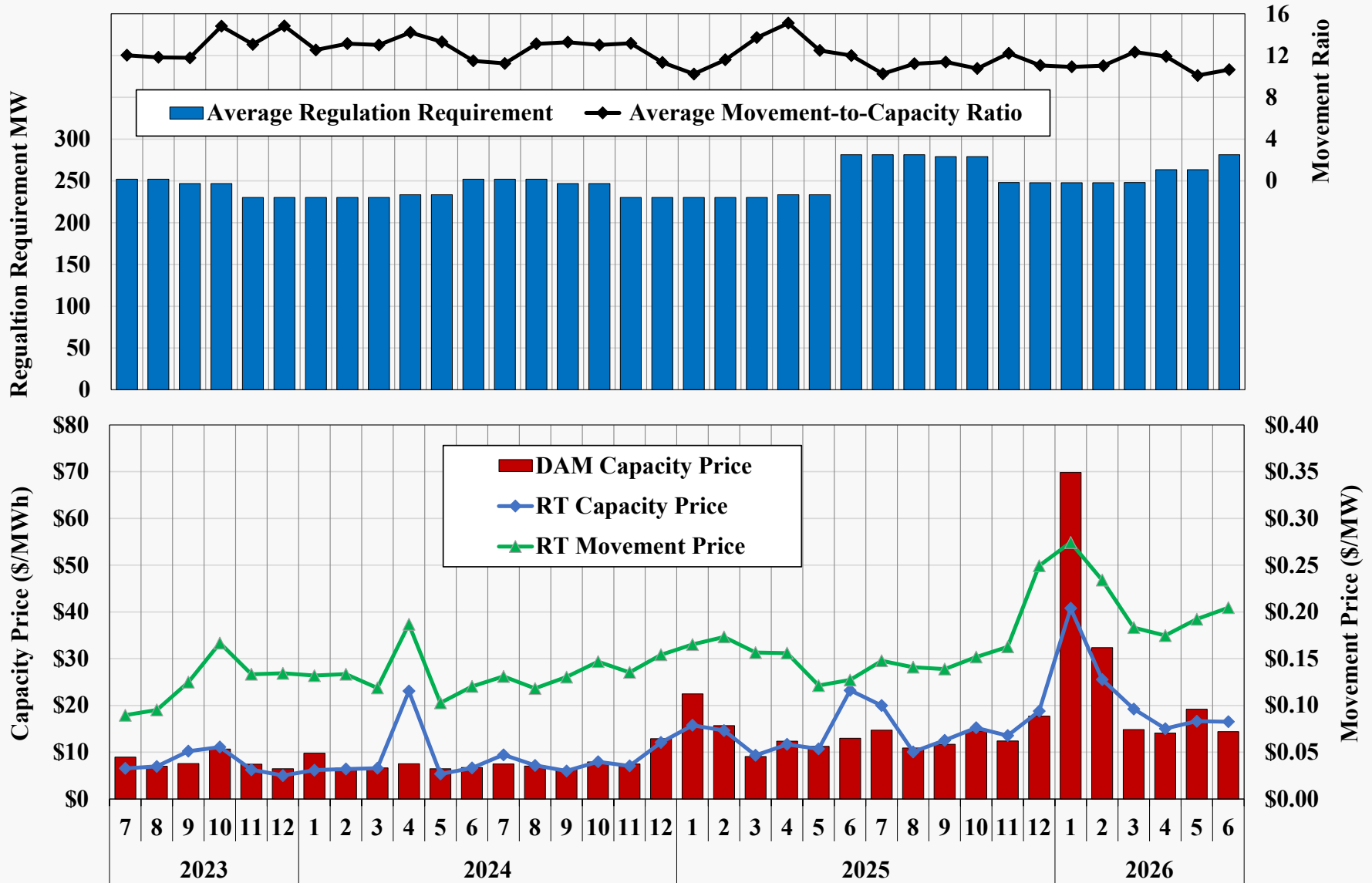
Day-Ahead NYCA 30-Minute Reserve Offers

Committed and Available Offline Quick-Start Resources



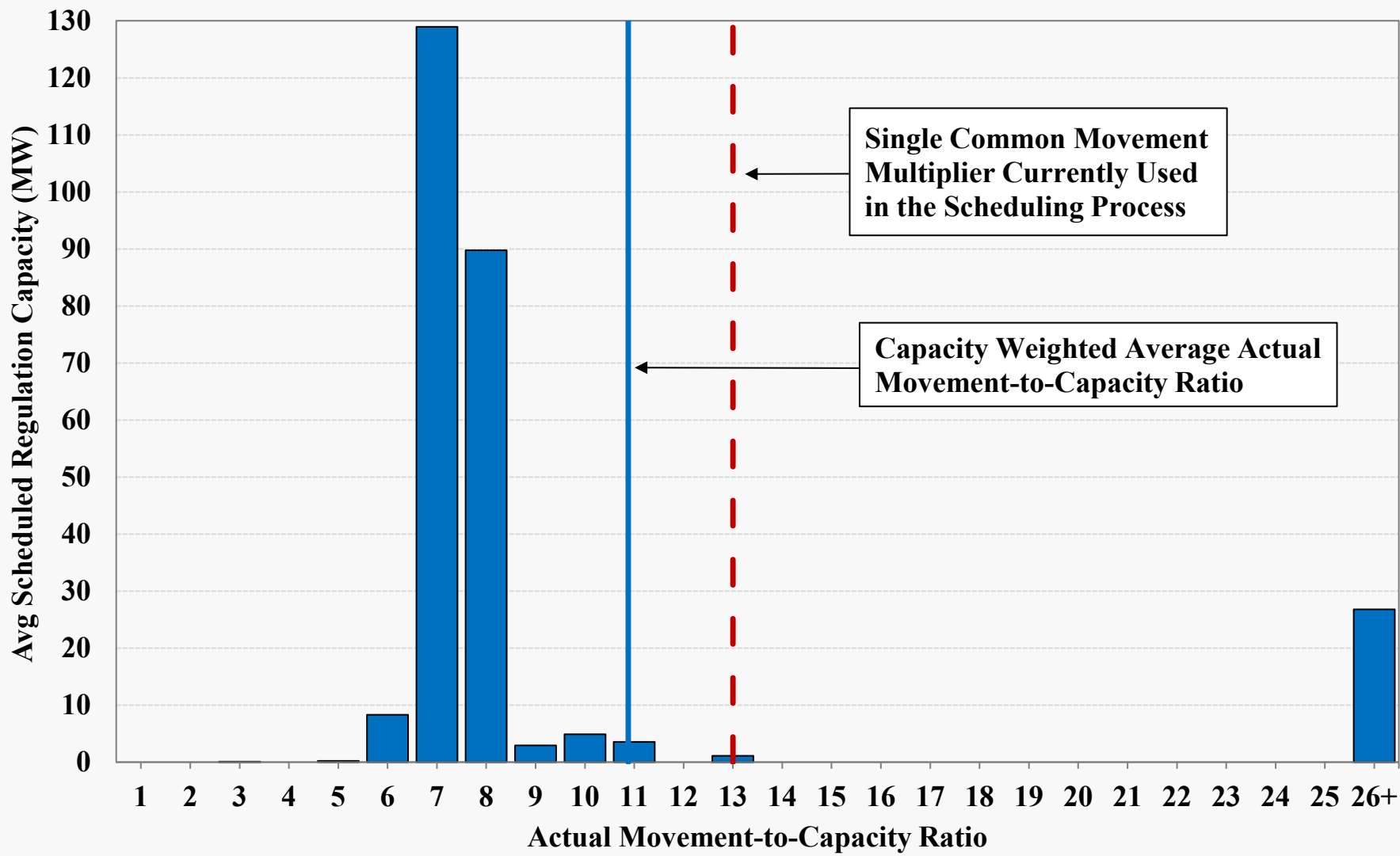
Notes: For chart description, see slide [87](#).

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



Distribution of Actual Regulation Movement

The Second Quarter of 2026

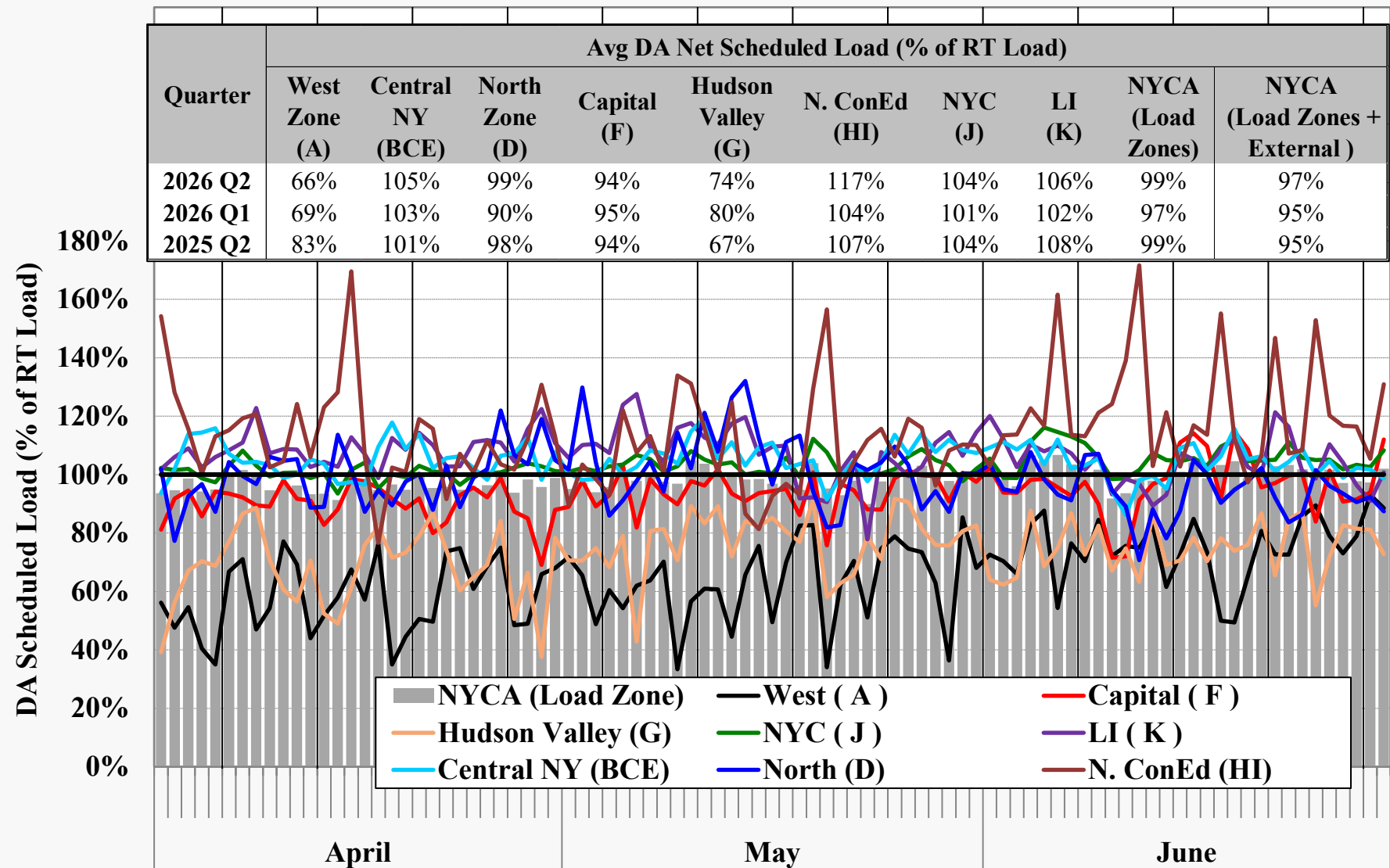


Notes: For chart description, see slide [88](#).

Charts: Energy Market Scheduling

Day-ahead Scheduled Load and Actual Load

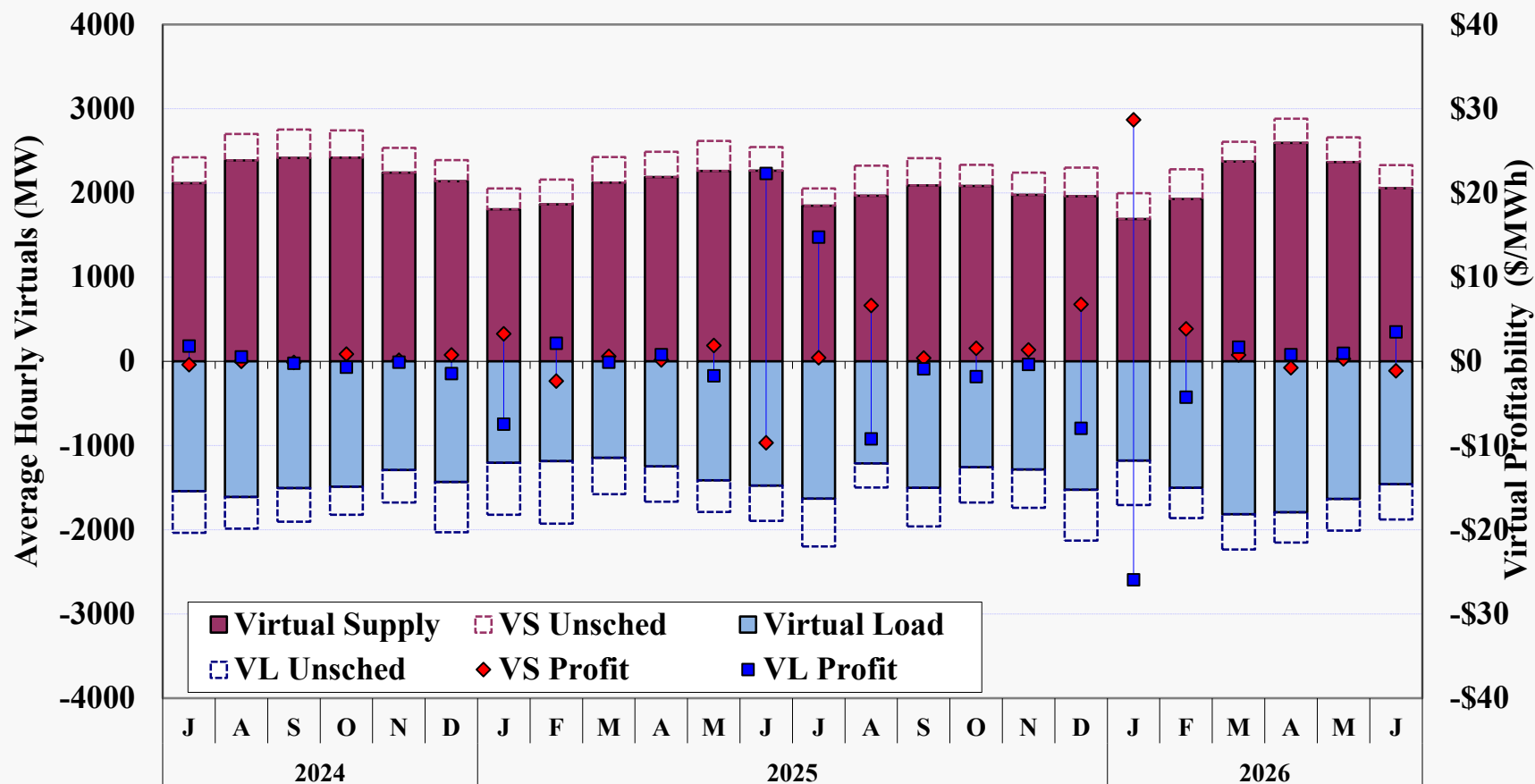
Daily Peak Load Hour



Notes: For chart description, see slide [89](#).

Virtual Trading Activity

by Month

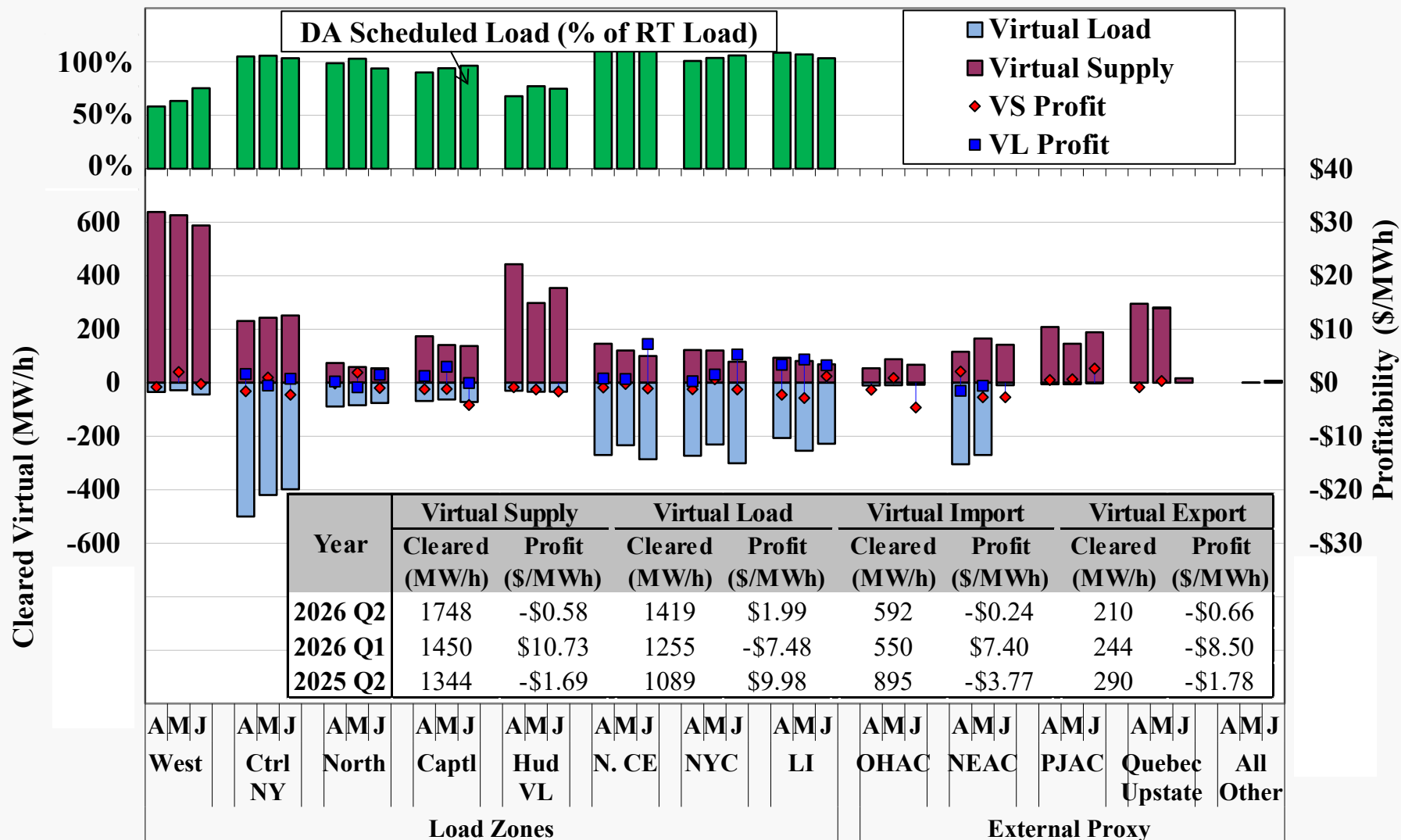


		2024						2025												2026					
Profit > 50% of Avg. Zone Price	MW	249	132	48	104	86	262	251	211	190	141	227	154	281	223	135	121	138	149	263	123	307	177	317	208
	%	7%	3%	1%	3%	2%	7%	8%	7%	6%	4%	6%	4%	8%	7%	4%	4%	4%	4%	9%	4%	7%	4%	8%	6%
Loss > 50% of Avg. Zone Price	MW	252	148	61	110	169	258	255	251	194	133	183	161	301	197	133	125	132	147	210	118	254	166	242	218
	%	7%	4%	2%	3%	5%	7%	8%	8%	6%	4%	5%	4%	9%	6%	4%	4%	4%	4%	7%	3%	6%	4%	6%	6%

Notes: For chart description, see slide [89](#).

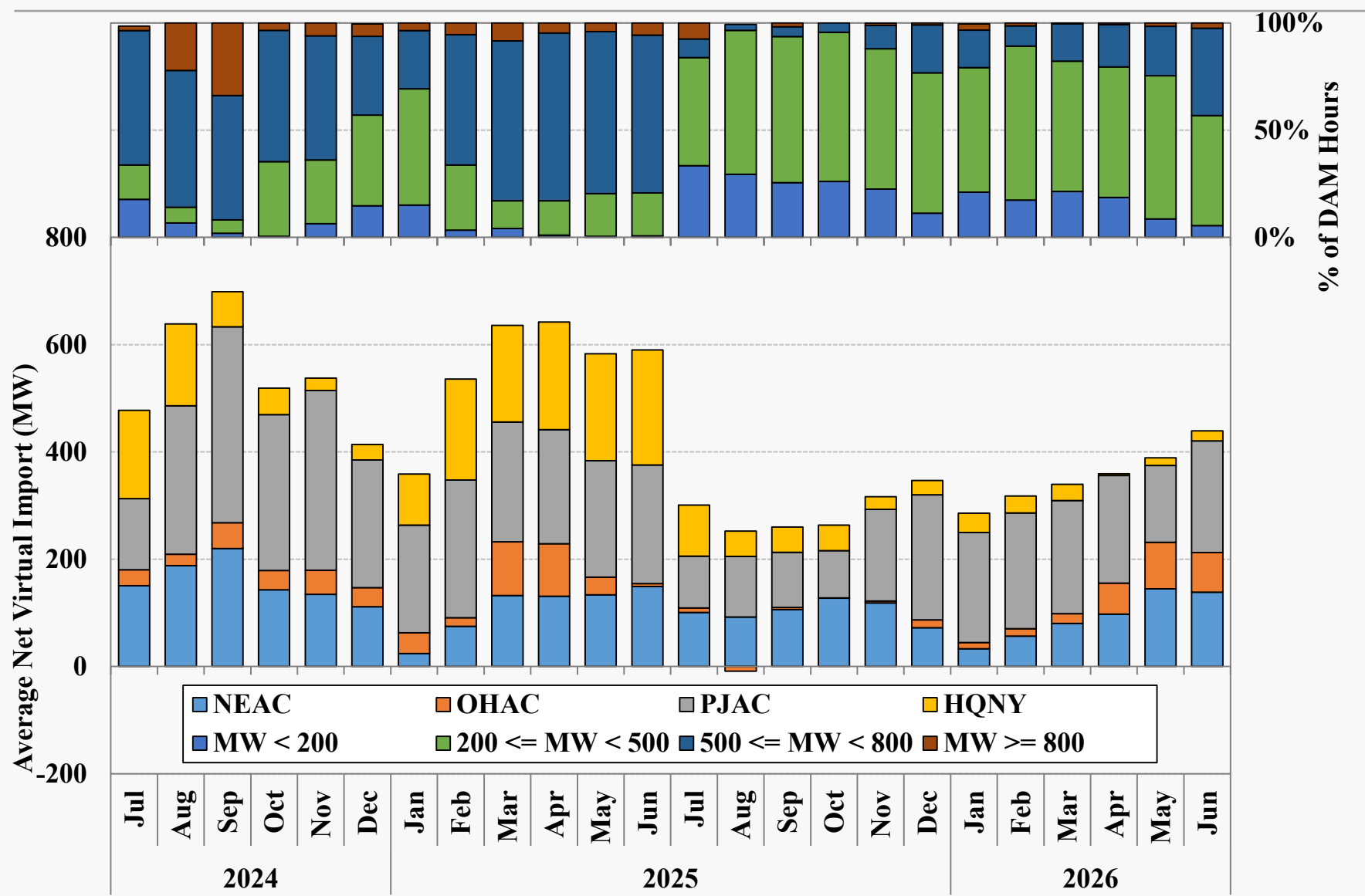
Virtual Trading Activity

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 [89](#).

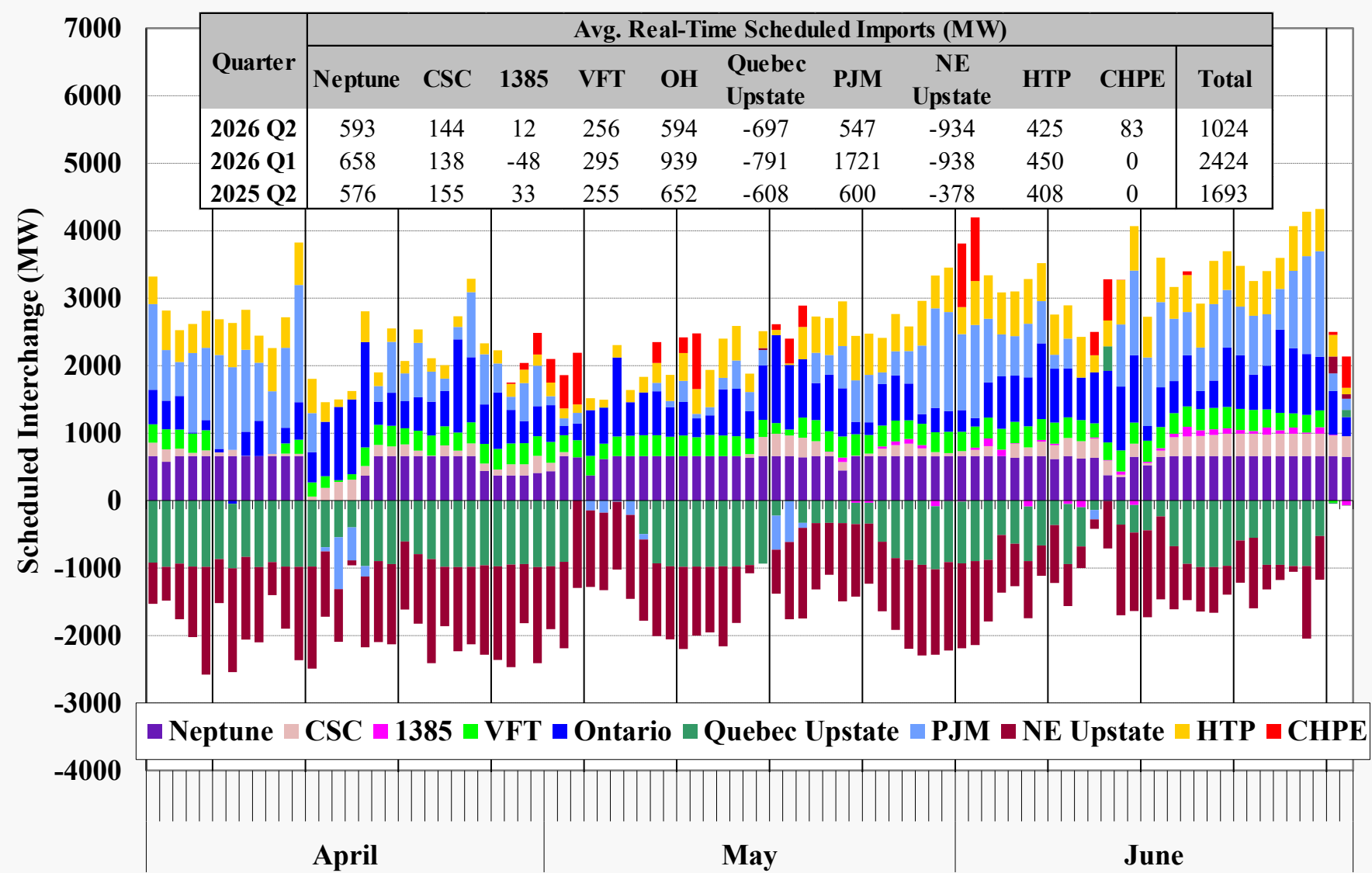
Virtual Imports and Exports in the Day-Ahead Market



Notes: For chart description, see slide [90](#).

Net Imports Scheduled Across External Interfaces

Daily Peak Hours (1-9pm)



Notes: The two Quebec interfaces in upstate are combined into one.

Efficiency of Intra-Hour Scheduling Under CTS

Primary PJM and NE Interfaces

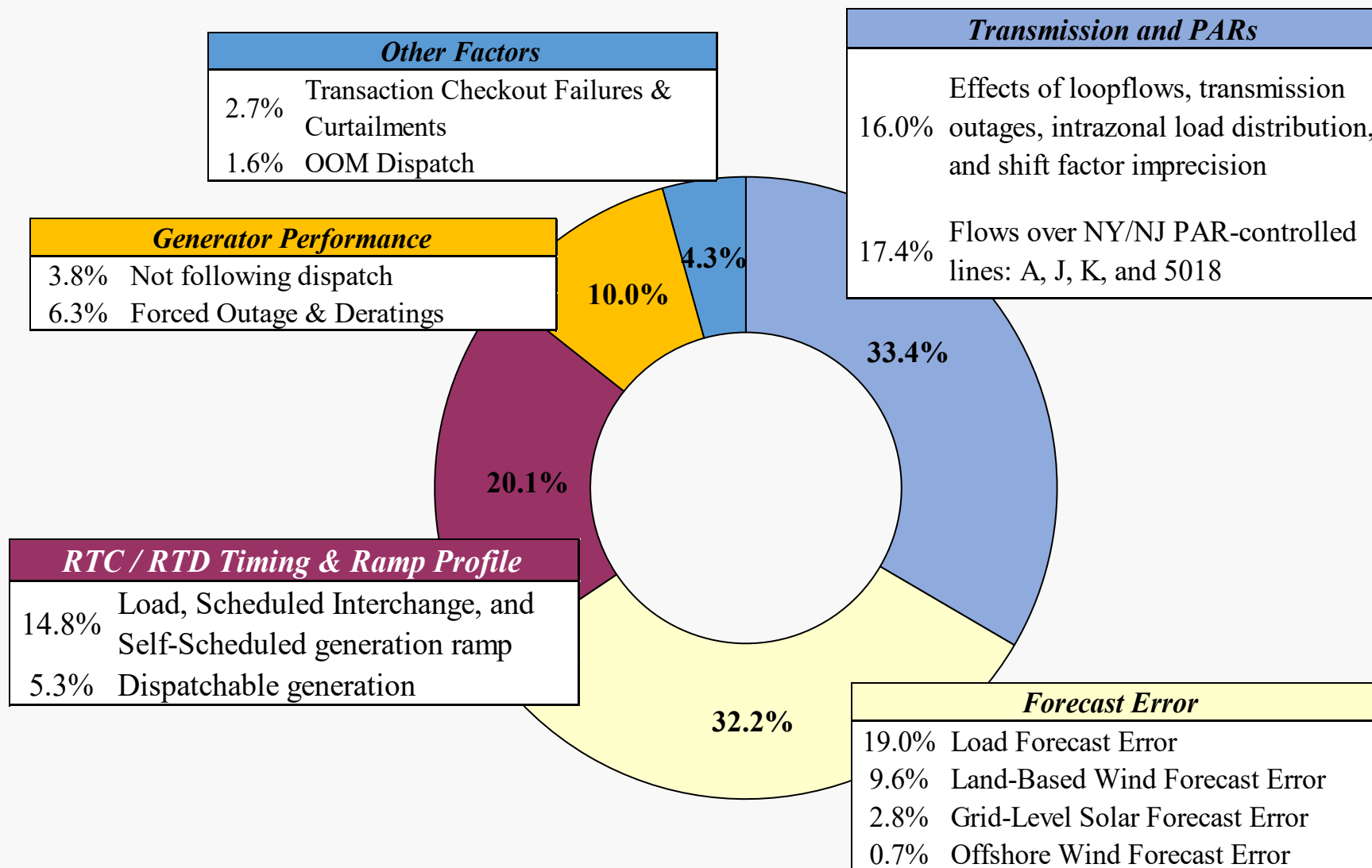
			Average/Total During Intervals w/ Adjustment							
			CTS - NY/NE				CTS - NY/PJM			
			Both Forecast Errors <= \$20	Any Forecast Error > \$20	Total		Both Forecast Errors <= \$20	Any Forecast Error > \$20	Total	
% of All Intervals w/ Adjustment			69%	13%	81%		54%	16%	69%	
Average Flow Adjustment (MW)	Net Imports		42	47	43		-2	-30	-8	
	Gross		127	171	134		74	97	80	
Production Cost Savings (\$ Million)	Projected at Scheduling Time		\$1.9	\$1.5	\$3.4		\$0.6	\$1.4	\$2.0	
	Net Over-Projection by:	NY	-\$0.1	\$0.0	-\$0.1		\$0.0	-\$0.3	-\$0.3	
		NE or PJM	\$0.0	\$0.2	\$0.2		-\$0.1	-\$1.1	-\$1.3	
	Other Unrealized Savings		-\$0.1	-\$0.1	-\$0.2		\$0.0	\$0.0	\$0.0	
	Actual Savings		\$1.7	\$1.5	\$3.2		\$0.3	\$0.0	\$0.4	
Interface Prices (\$/MWh)	NY	Actual	\$37.91	\$75.49	\$43.75	\$43.02	\$33.68	\$60.11	\$39.75	\$38.79
		Forecast	\$39.12	\$63.89	\$42.97	\$42.25	\$34.79	\$55.42	\$39.52	\$38.63
	NE or PJM	Actual	\$39.84	\$72.97	\$44.99	\$46.21	\$28.45	\$80.37	\$40.37	\$38.39
		Forecast	\$40.19	\$69.49	\$44.74	\$46.79	\$30.42	\$78.23	\$41.40	\$38.87
Price Forecast Errors (\$/MWh)	NY	Fcst. - Act.	\$1.21	-\$11.60	-\$0.78	-\$0.76	\$1.11	-\$4.70	-\$0.22	-\$0.16
		Abs. Val.	\$3.12	\$38.59	\$8.64	\$8.24	\$3.10	\$24.28	\$7.97	\$7.04
	NE or PJM	Fcst. - Act.	\$0.35	-\$3.48	-\$0.25	\$0.58	\$1.97	-\$2.14	\$1.03	\$0.47
		Abs. Val.	\$4.35	\$37.60	\$9.52	\$9.61	\$5.71	\$68.78	\$20.20	\$18.36

For Adjustment Intervals Only

For All Intervals

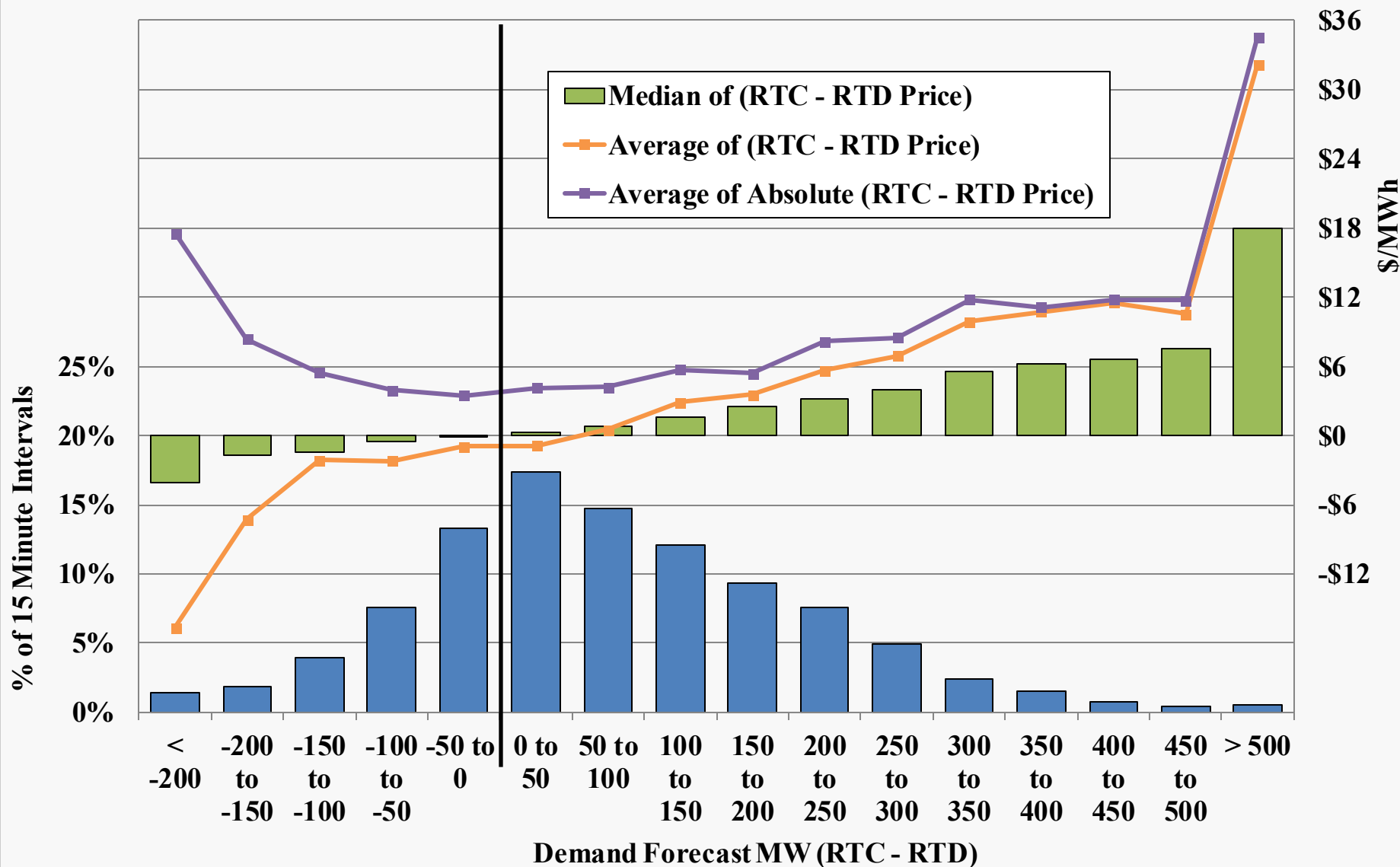
Notes: For chart description, see slide [91](#).

Detrimental Factors to RTC and RTD Price Divergence



Notes: For chart description, see slide [92](#).

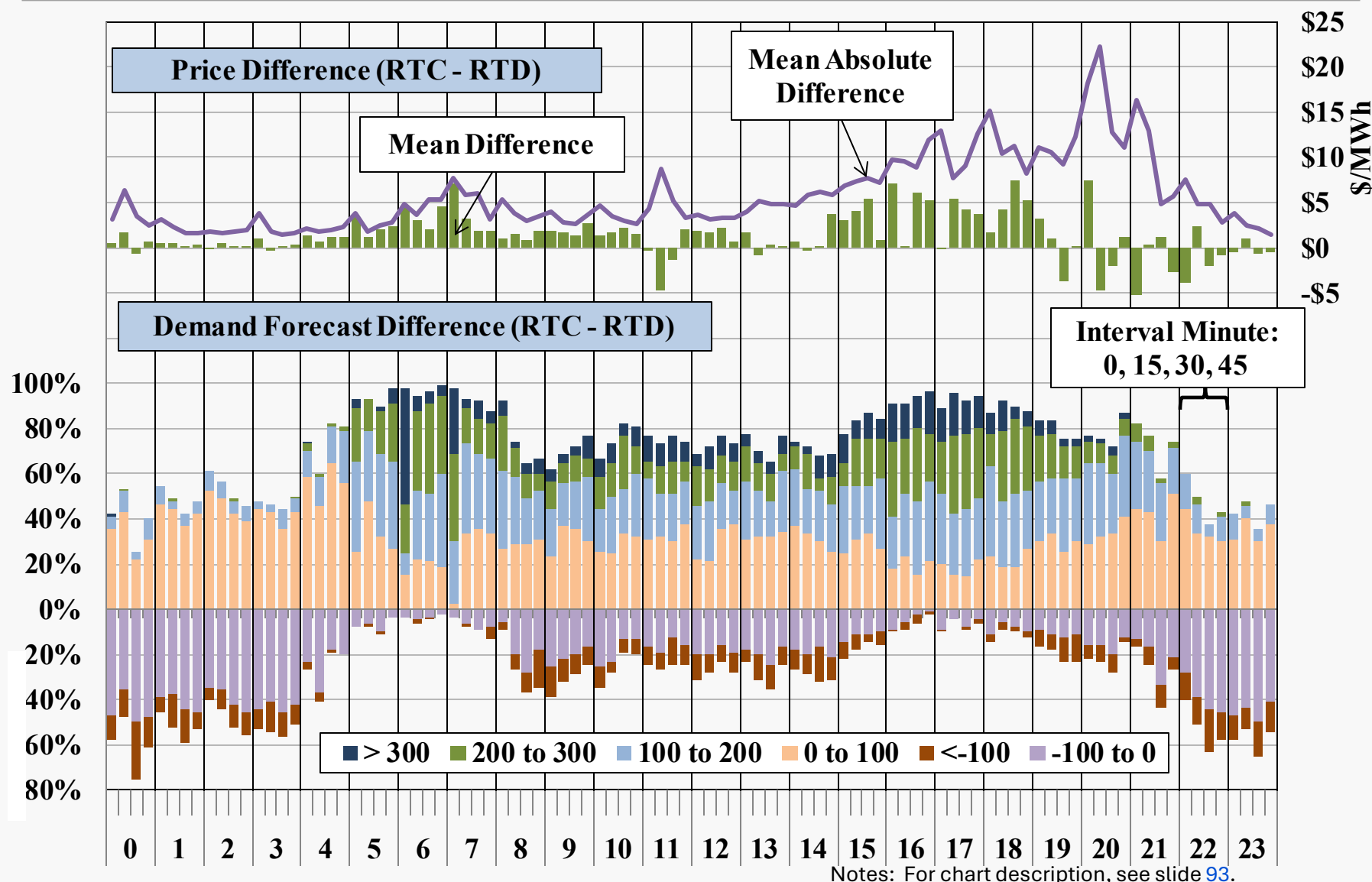
RTC and RTD Price Difference vs Demand Forecast Difference



Notes: For chart description, see slide [92](#).

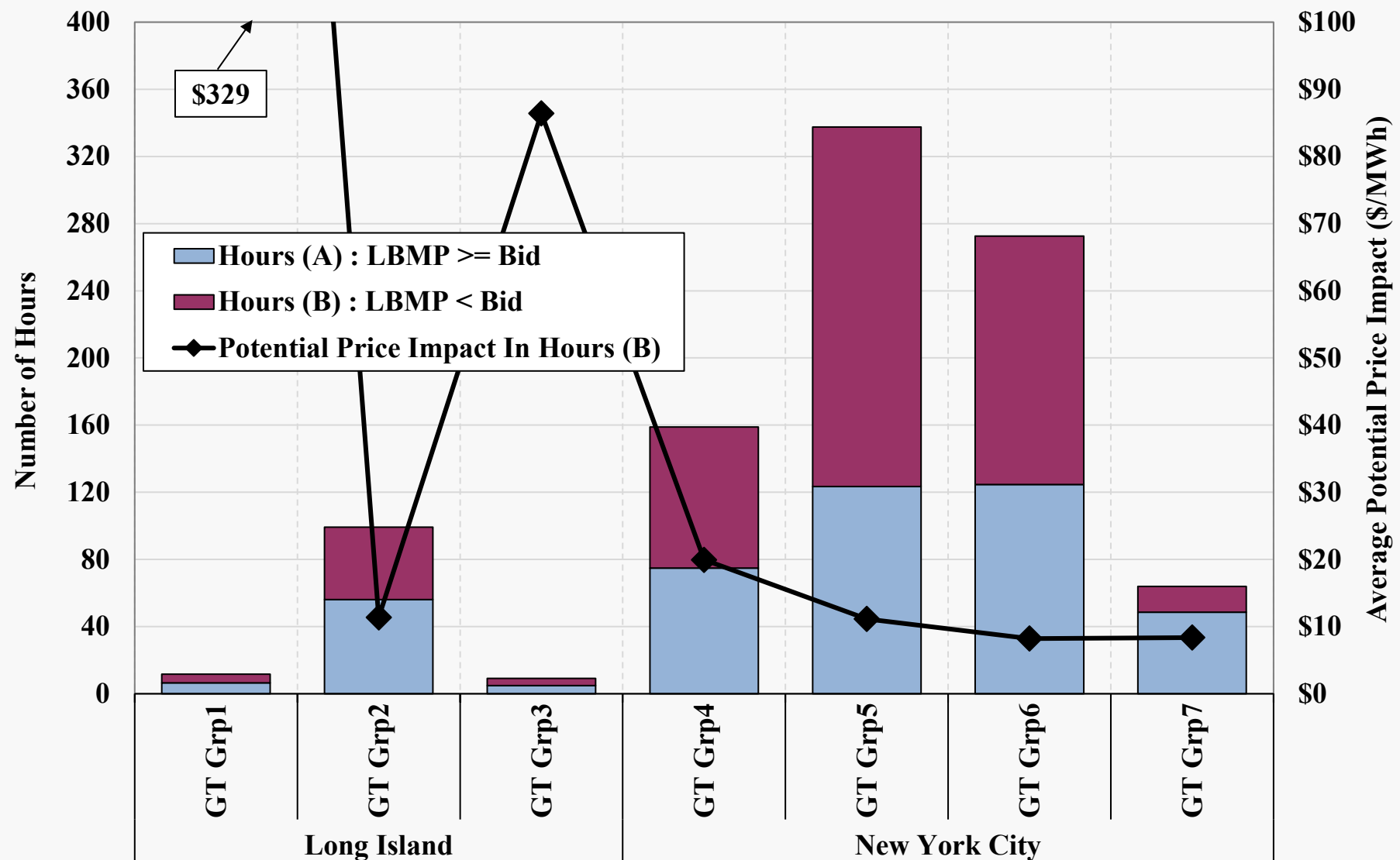
RTC and RTD Price Difference vs Demand Forecast Difference

By Time of Day



Real-Time Prices During Commitments of GTs

Units Offering Multi-Hour Minimum Run Times: 2026 Q2

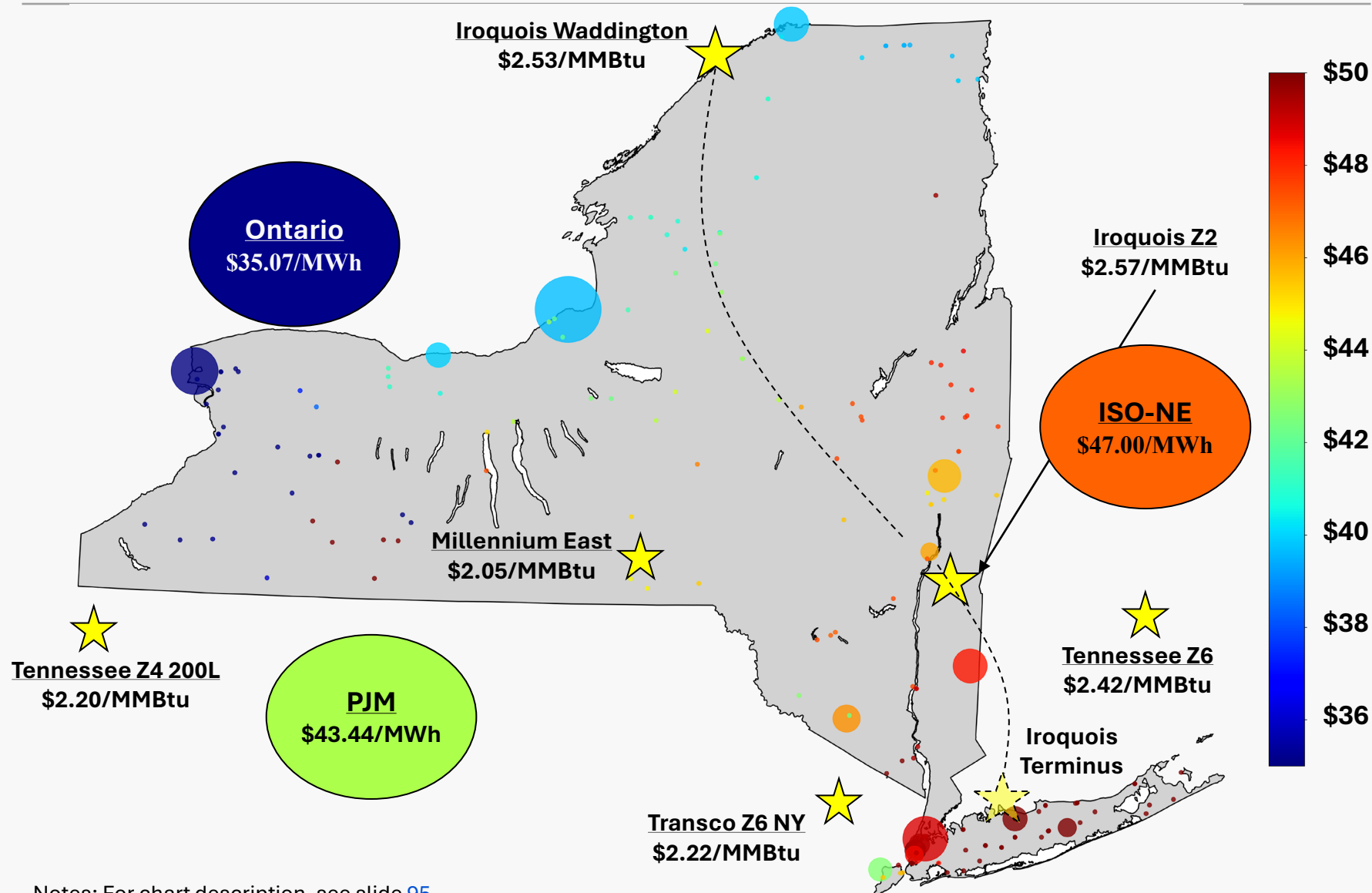


Notes: For chart description, see slide 94.

Charts: Transmission Congestion Revenues and Shortfalls

System Congestion

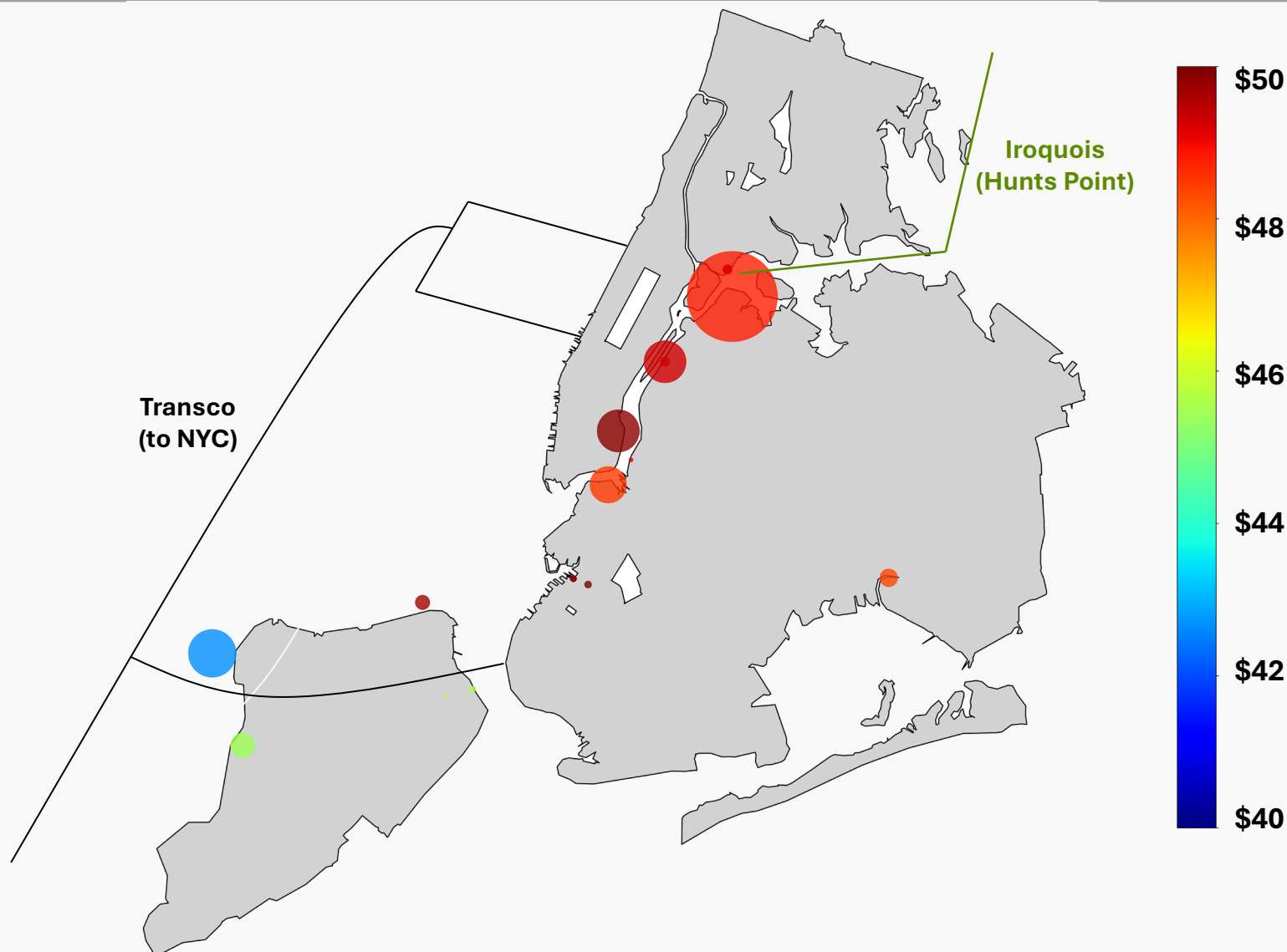
Real-Time Price Map at Generator Nodes



Notes: For chart description, see slide [95](#).

System Congestion

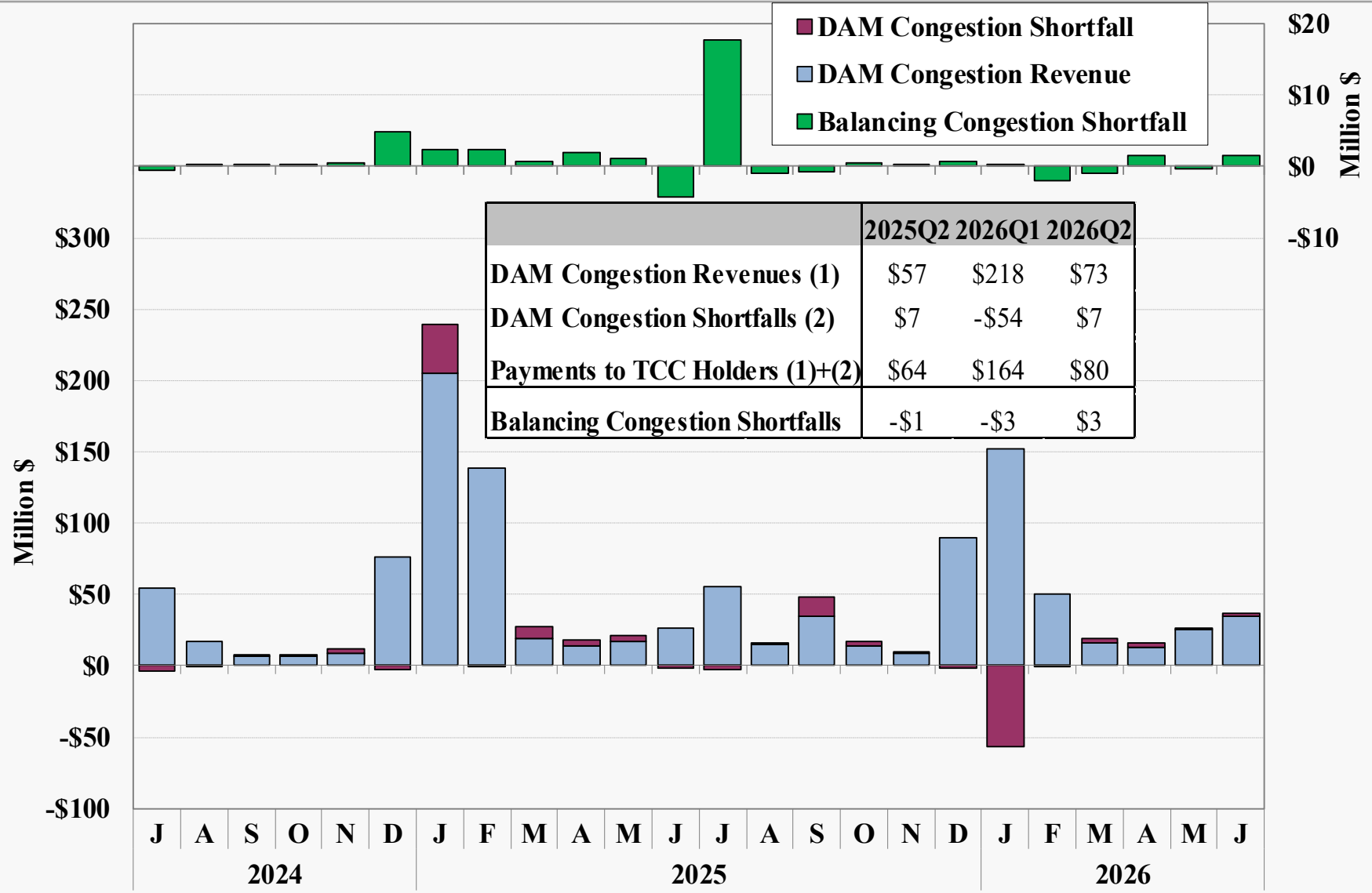
NYC Real-Time Price Map at Generator Nodes



Notes: For chart description, see slide [95](#).

Congestion Revenues and Shortfalls

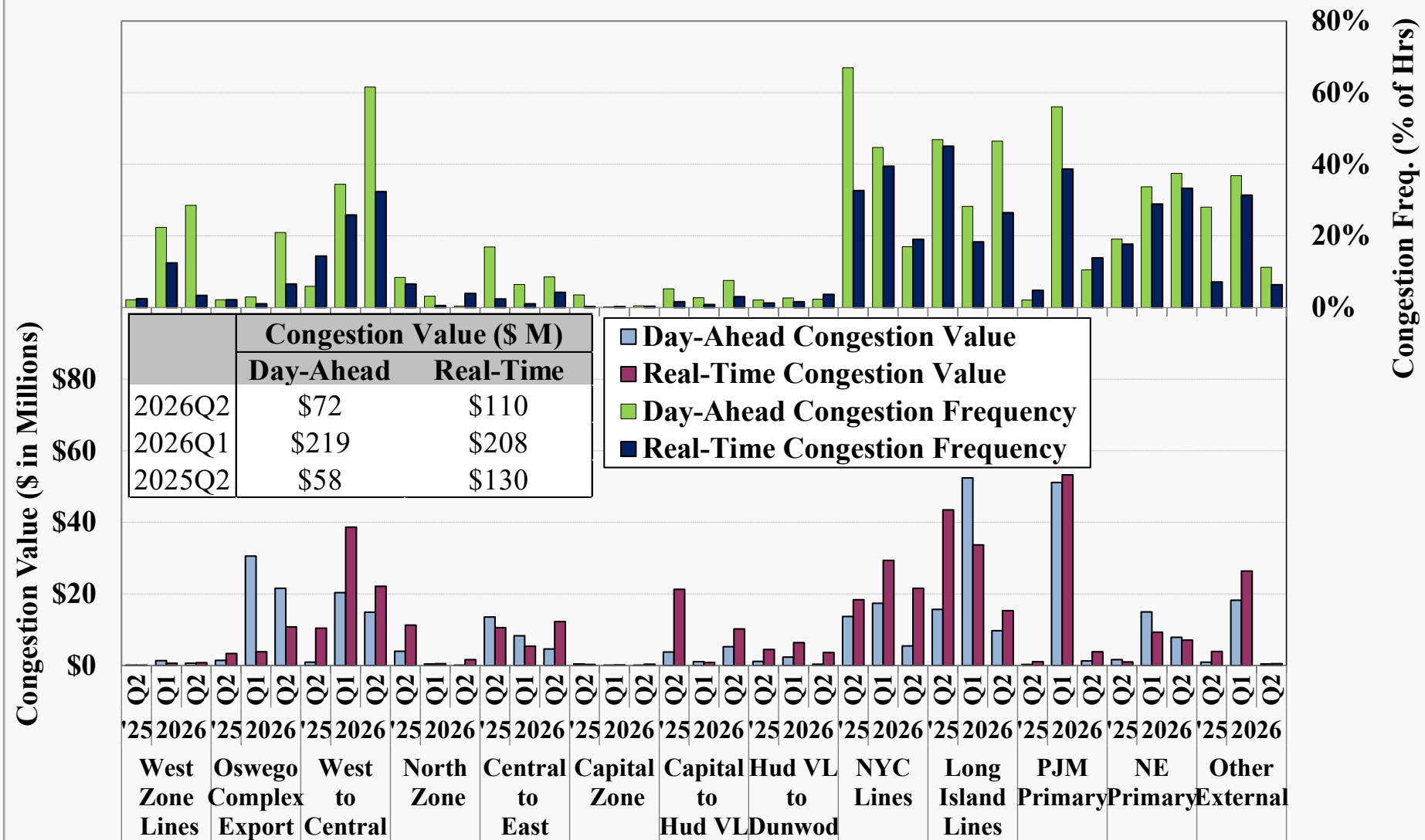
By Month



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

Day-Ahead and Real-Time Congestion Value

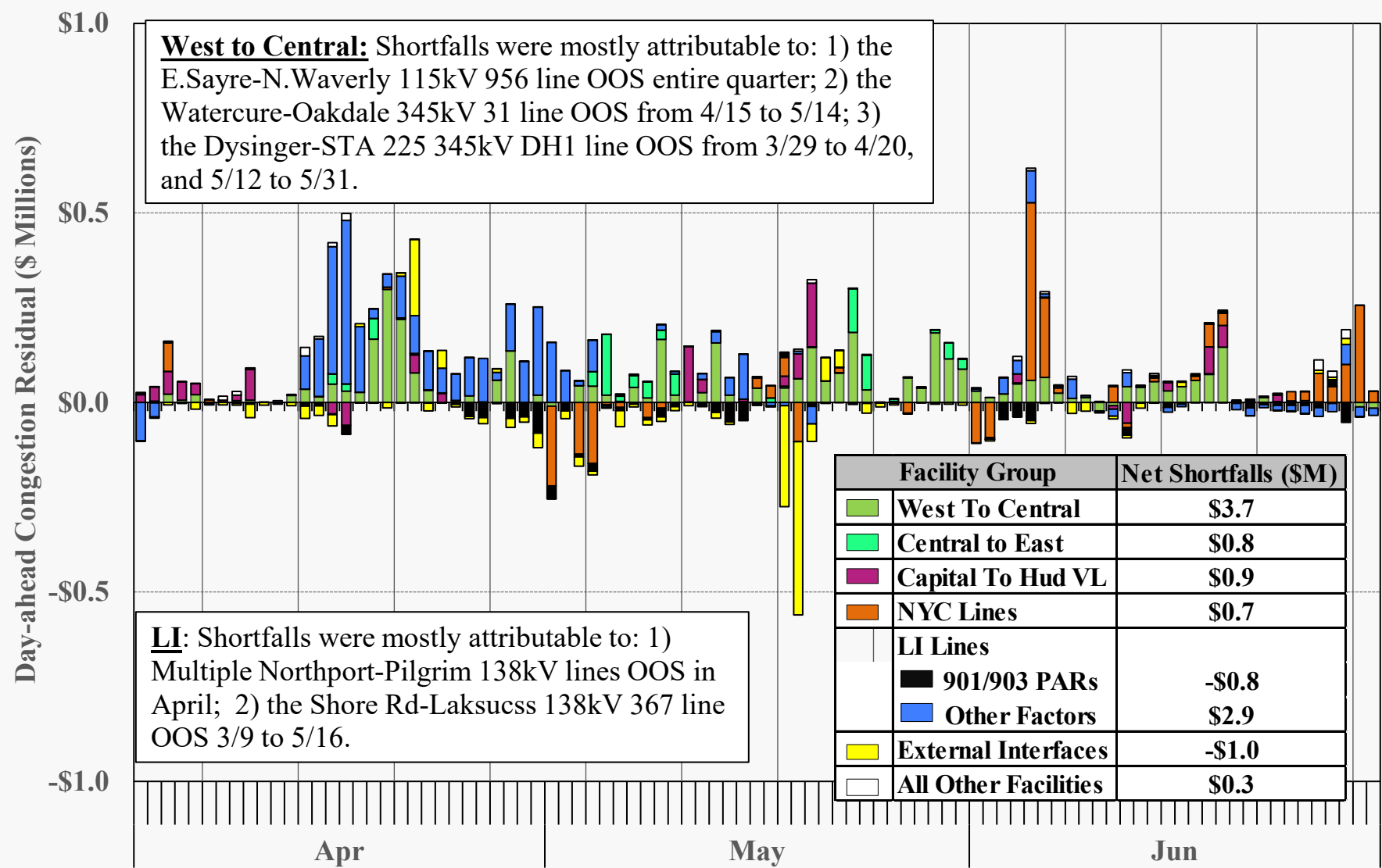
By Transmission Path



Notes: For chart description, see slides [96](#), [97](#), and [98](#).

Day-Ahead Congestion Revenue Shortfalls

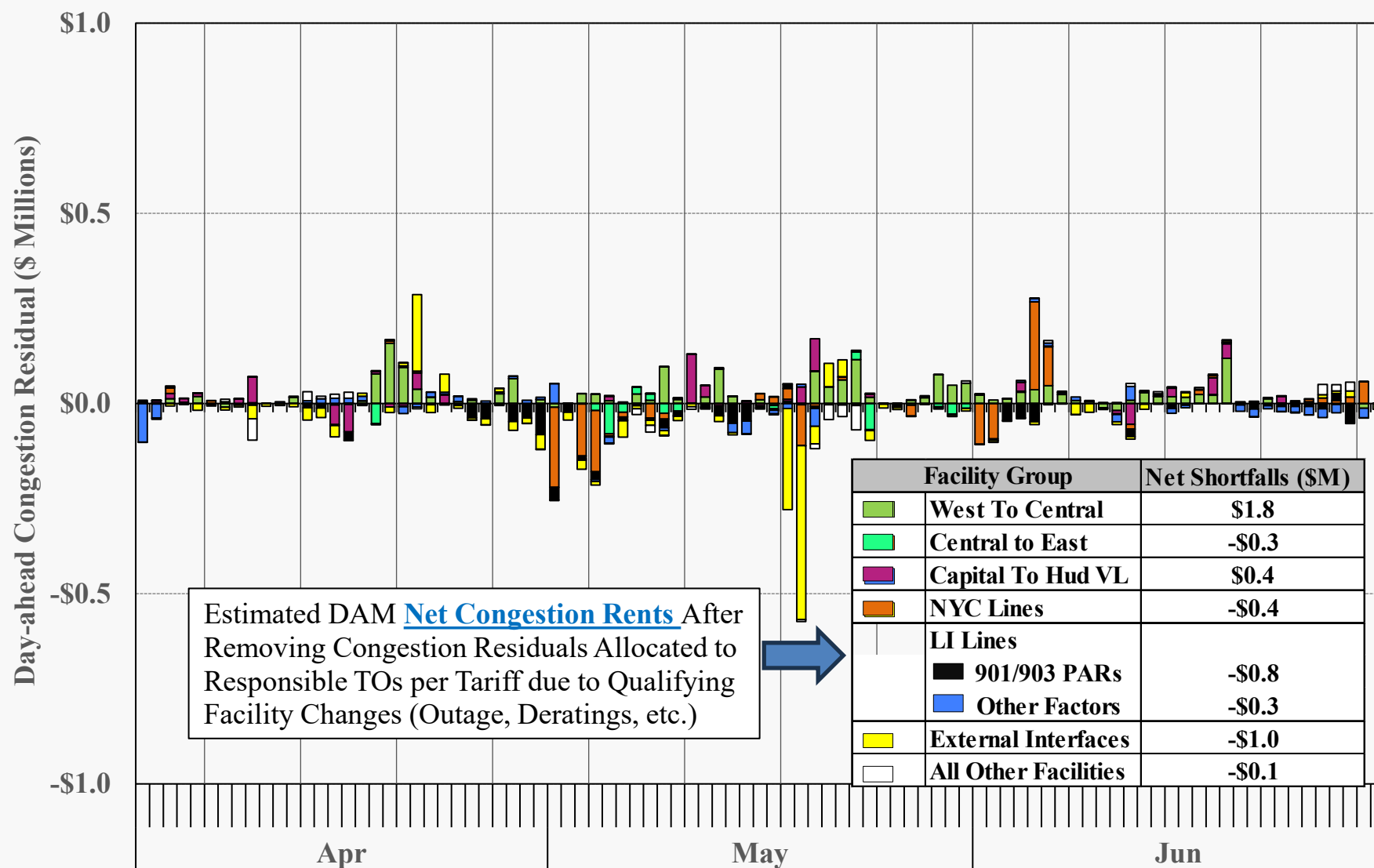
By Transmission Facility



Notes: For chart description, see slides 96, 97, and 98.

Estimated DAM Net Congestion Rents

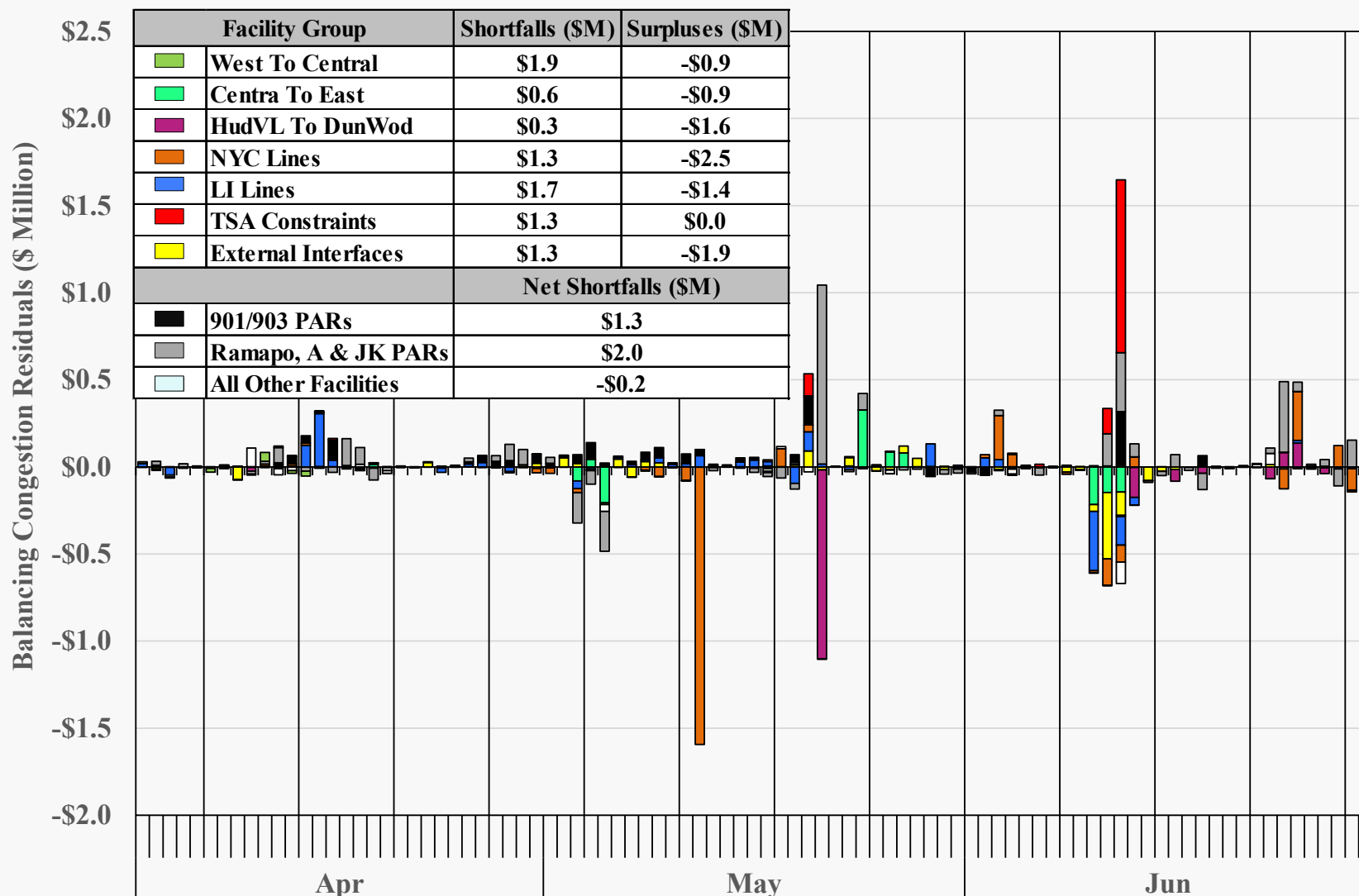
By Transmission Facility



Notes: For chart description, see slides [96](#), [97](#), and [98](#).

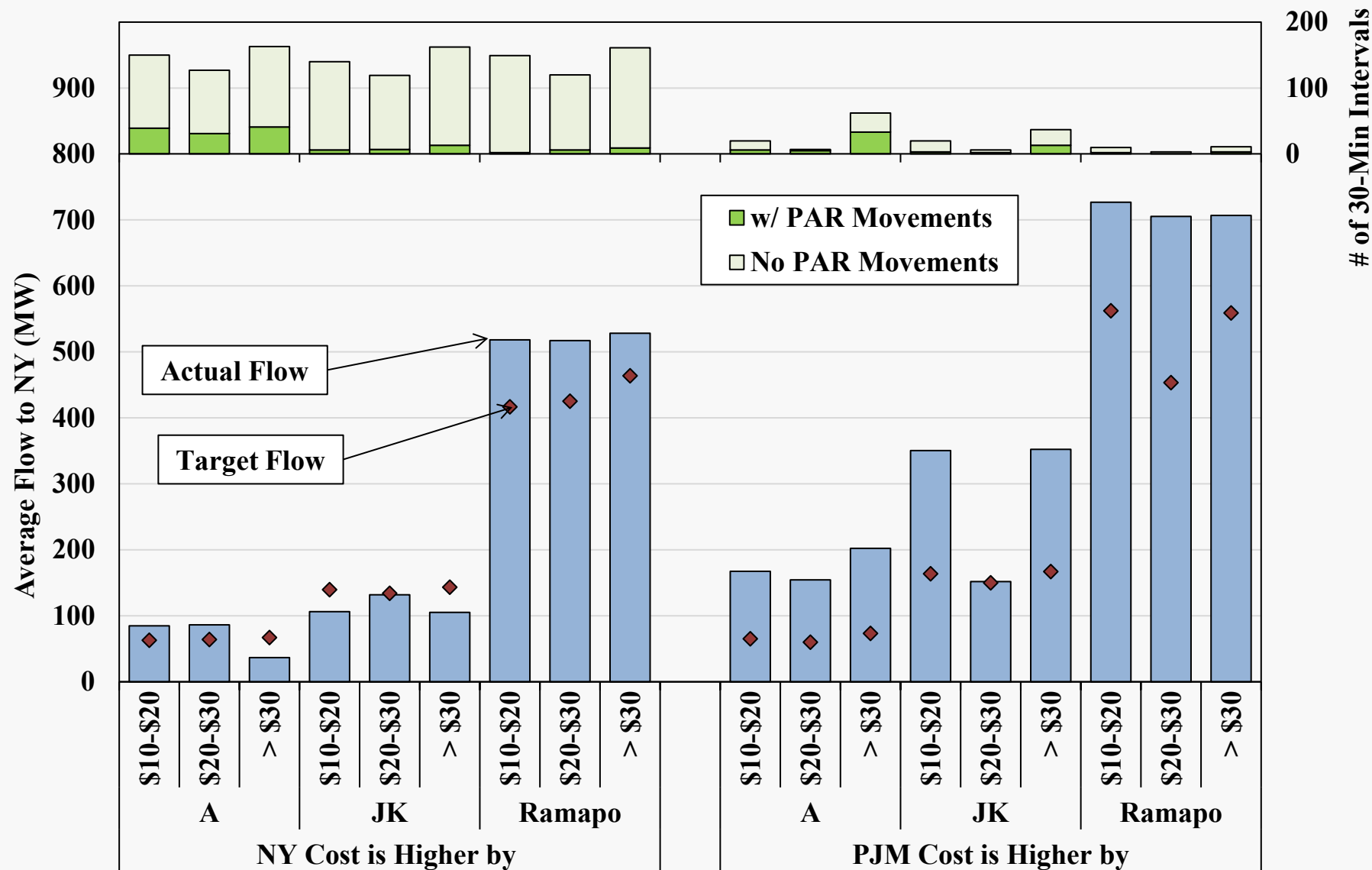
Balancing Congestion Shortfalls

By Transmission Facility



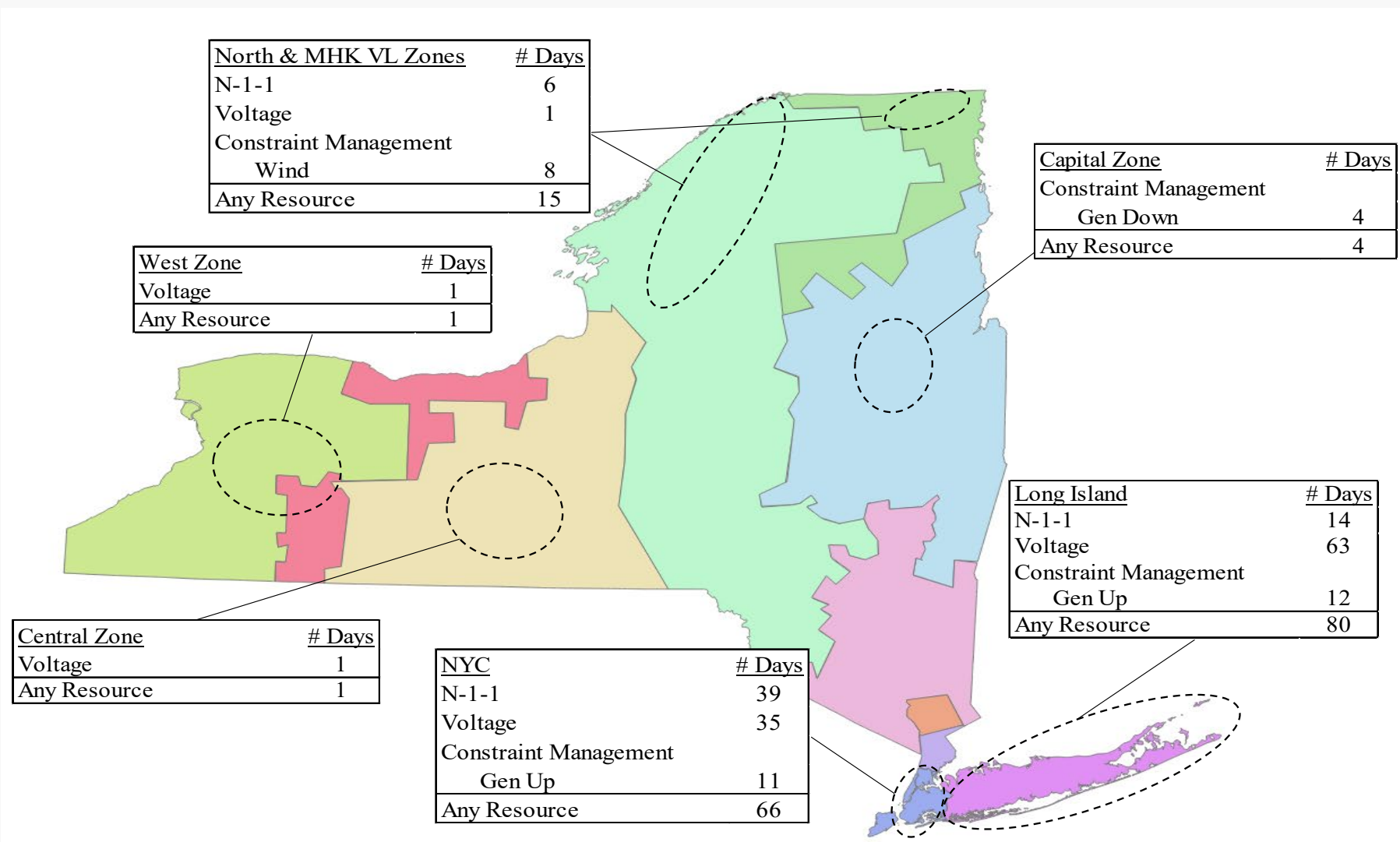
Notes: 1. The BMCR estimated above may differ from actual BMCR because the figure is partly based on real-time schedules rather than metered values. 2. For chart description, see slides [96](#), [97](#), and [98](#).

PAR Operation under M2M with PJM: 2026 Q2



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

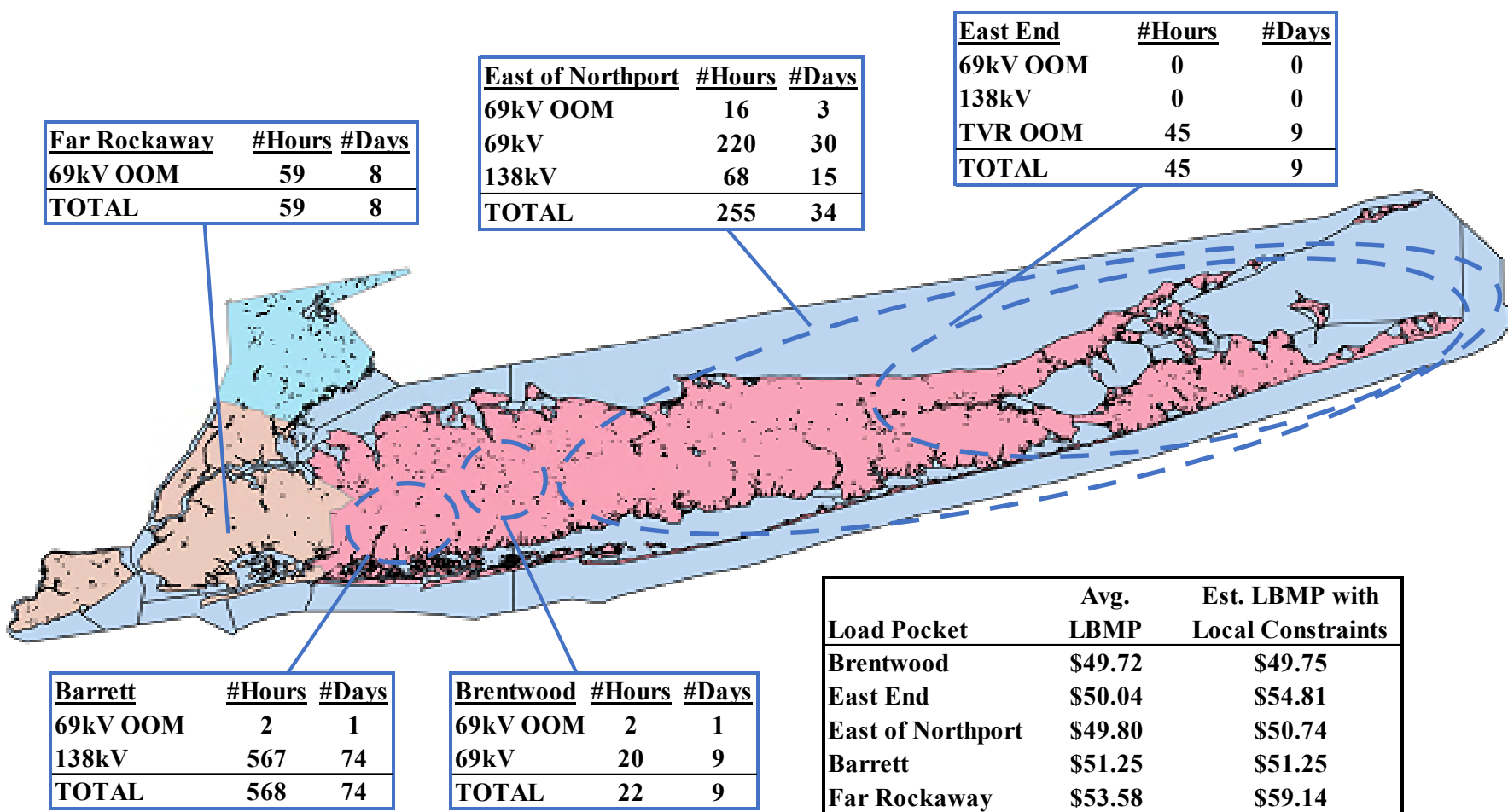
OOM Actions to Manage Network Reliability



Notes: For chart description, see slide [100](#)

Constraints on the Low Voltage Network

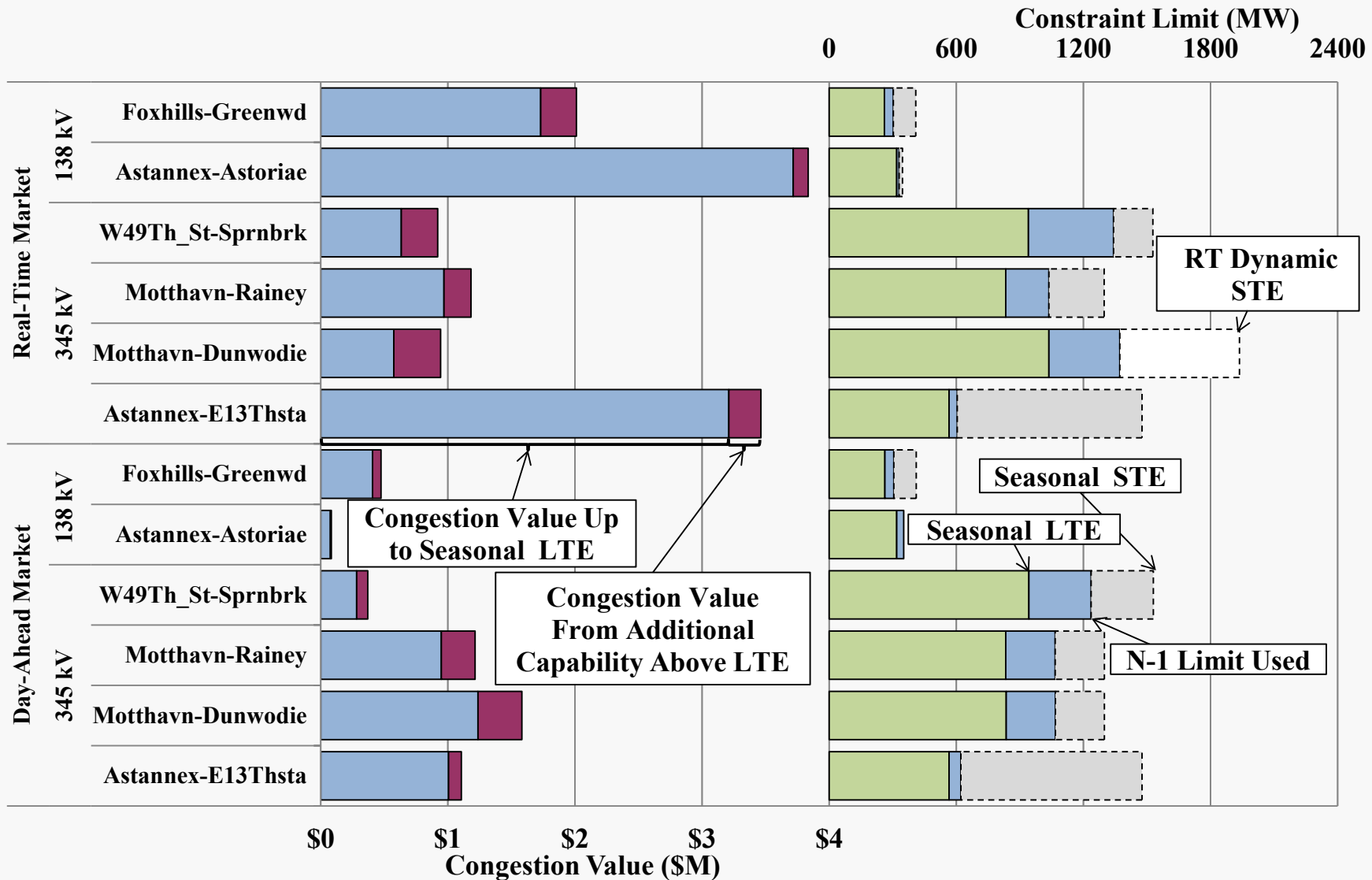
Long Island Load Pockets



Notes: For chart description, see slides [100-101](#)

N-1 Constraints in New York City

Limits Used vs Seasonal LTE Ratings



Notes: For chart description, see slide [102](#).

Gas Turbine Start-up Performance

Economic Starts & Audits

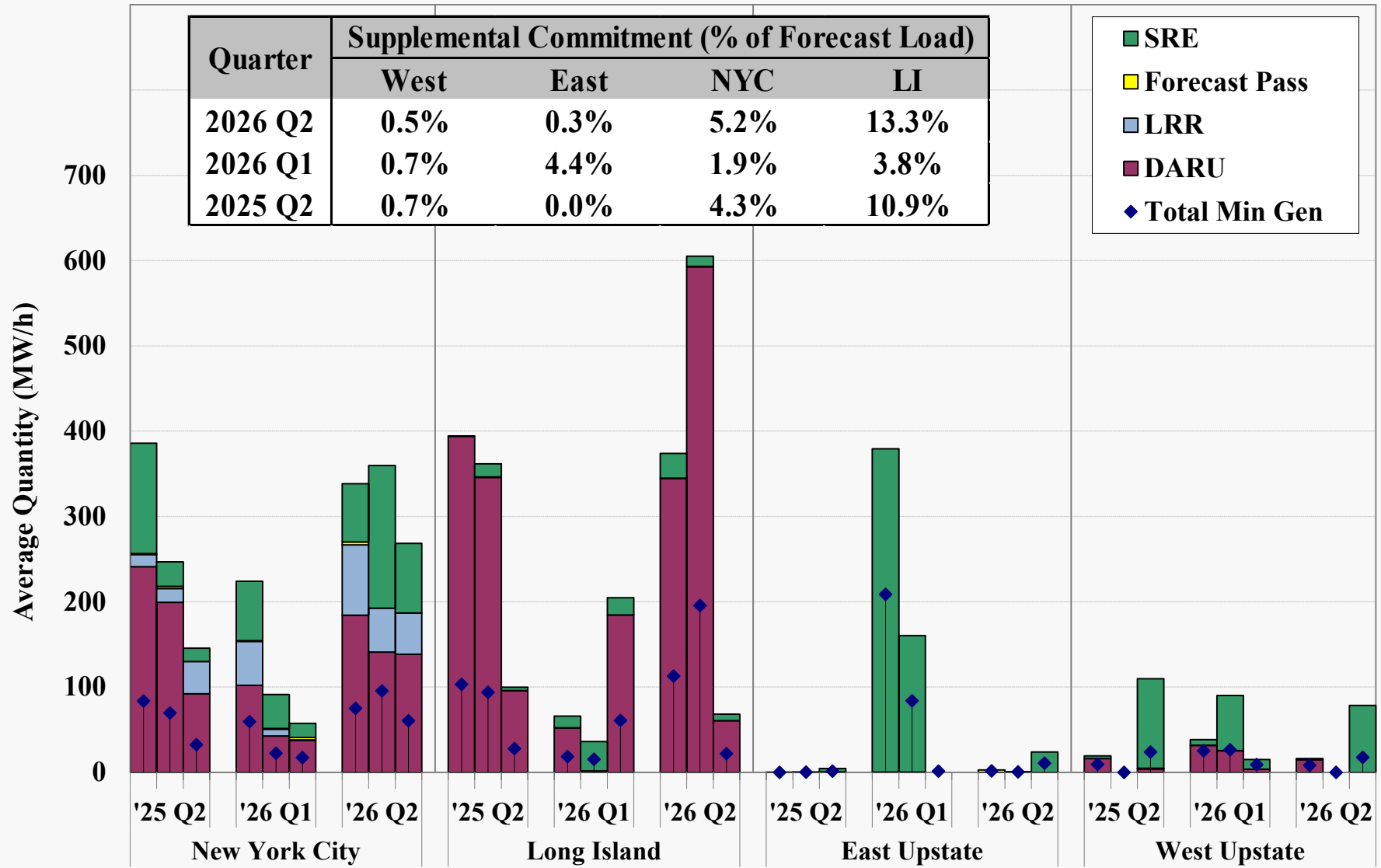
10/30-Minute GT Start Performance - Jul 2025 - Jun 2026						
Performance Category	No. of Units	Total No. of Starts Evaluated	Other Economic Starts and Audits		RPUs + Unforeseen Economic Starts and Audits	
			Avg Performance On Time	Avg Performance 10 Minutes Later	Avg Performance On Time	Avg Performance 10 Minutes Later
Data Unavailable	0	0				
0% - 10%	1	2	0.0%	0.0%		
10% - 20%	0	0				
20% - 30%	0	0				
30% - 40%	0	0				
40% - 50%	2	31	29.9%	54.0%	55.7%	63.0%
50% - 60%	5	110	59.2%	75.3%	54.6%	78.7%
60% - 70%	2	25	68.1%	72.3%	55.6%	66.7%
70% - 80%	4	183	75.3%	82.8%	74.7%	83.2%
80% - 90%	35	4312	85.7%	93.5%	87.0%	94.8%
90% - 100%	49	5488	93.7%	95.9%	92.4%	95.7%
TOTAL	98	10151				

Notes: For chart description, see slide [103](#)

Charts: Supplemental Commitment, OOM Dispatch, and BPCG Uplift

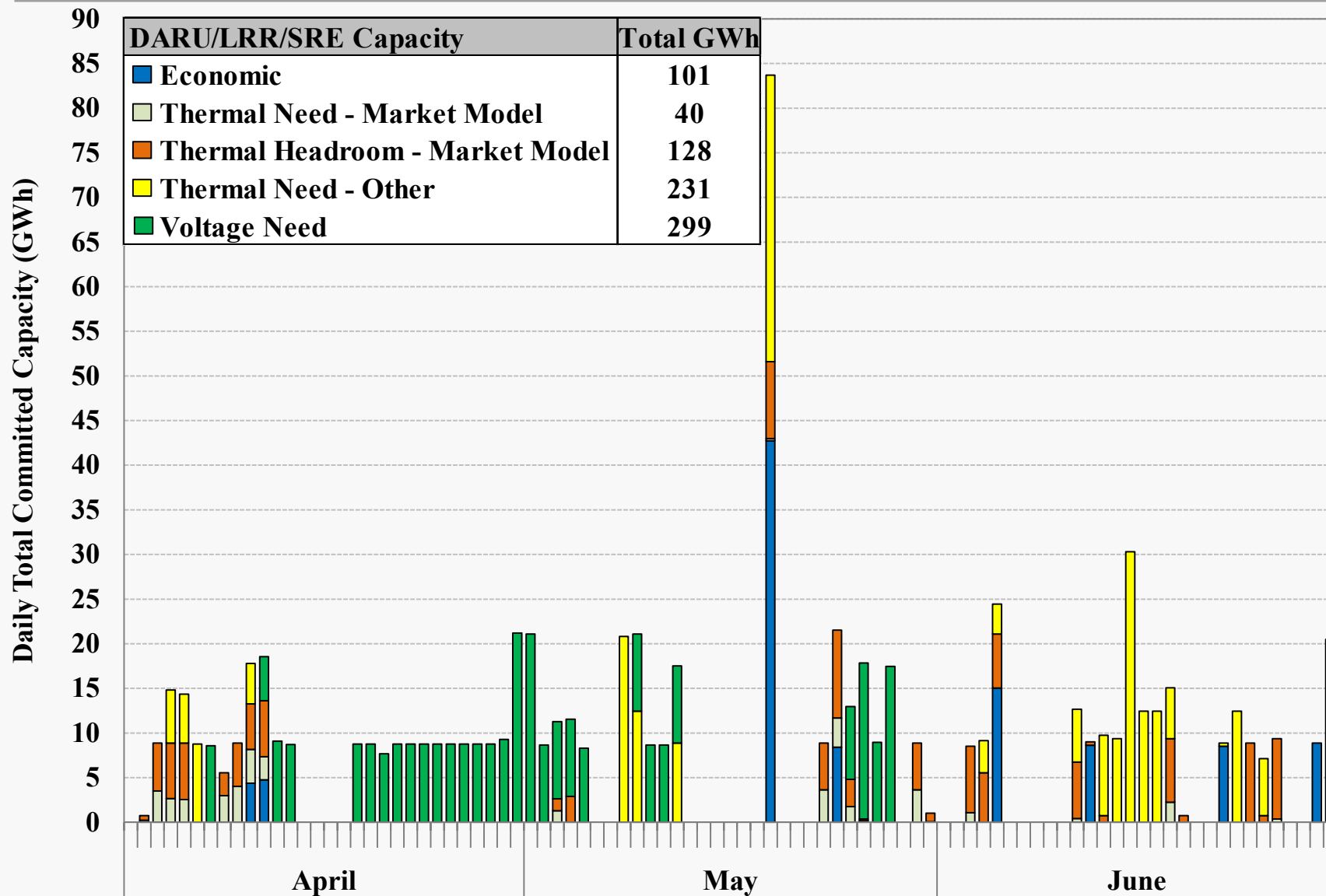
Supplemental Commitment for Reliability

By Category and Region



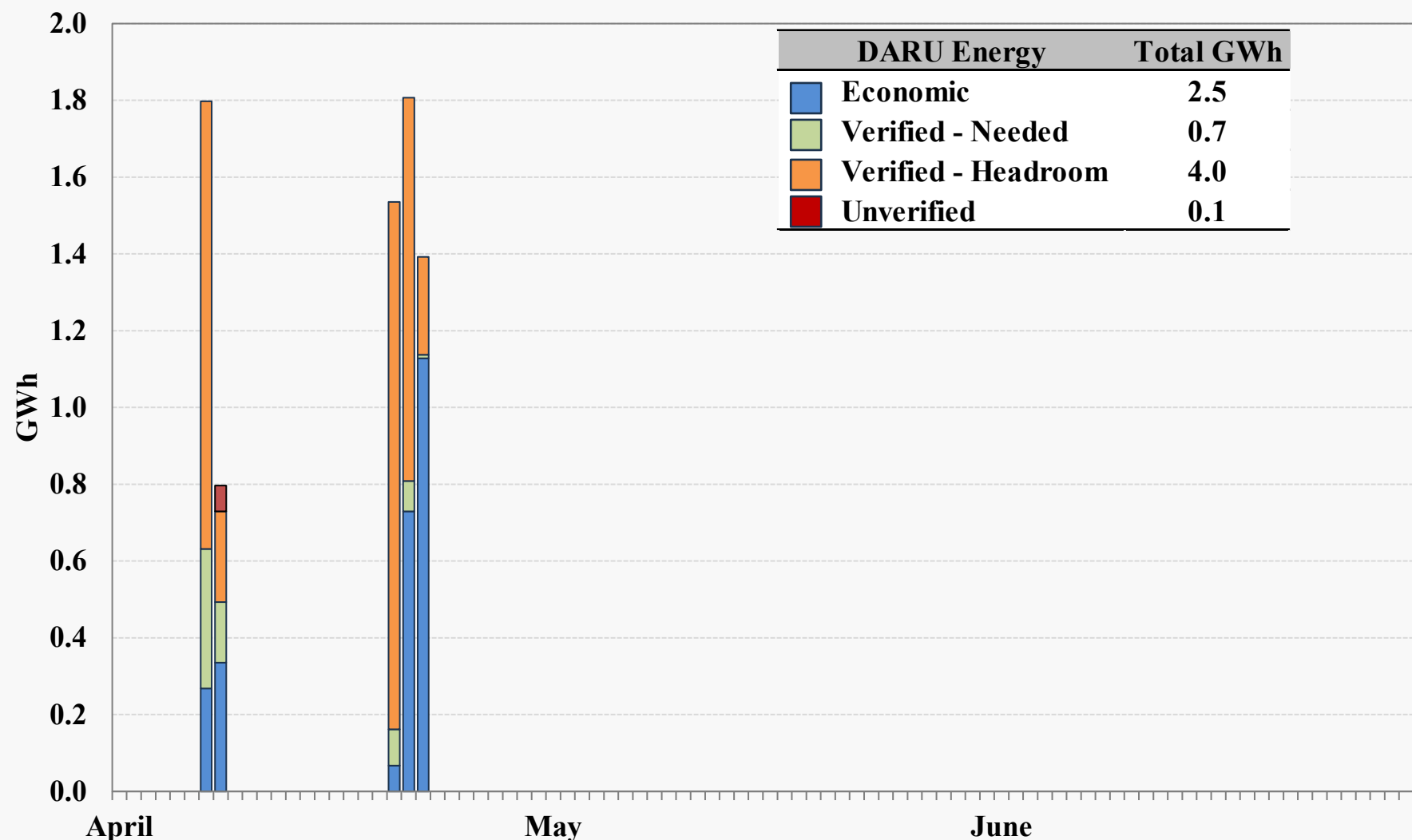
Notes: For chart description, see slides [104](#).

DARU/LRR/SRE Commitments in NYC: 2026 Q2



Notes: For chart description, see slide [105](#).

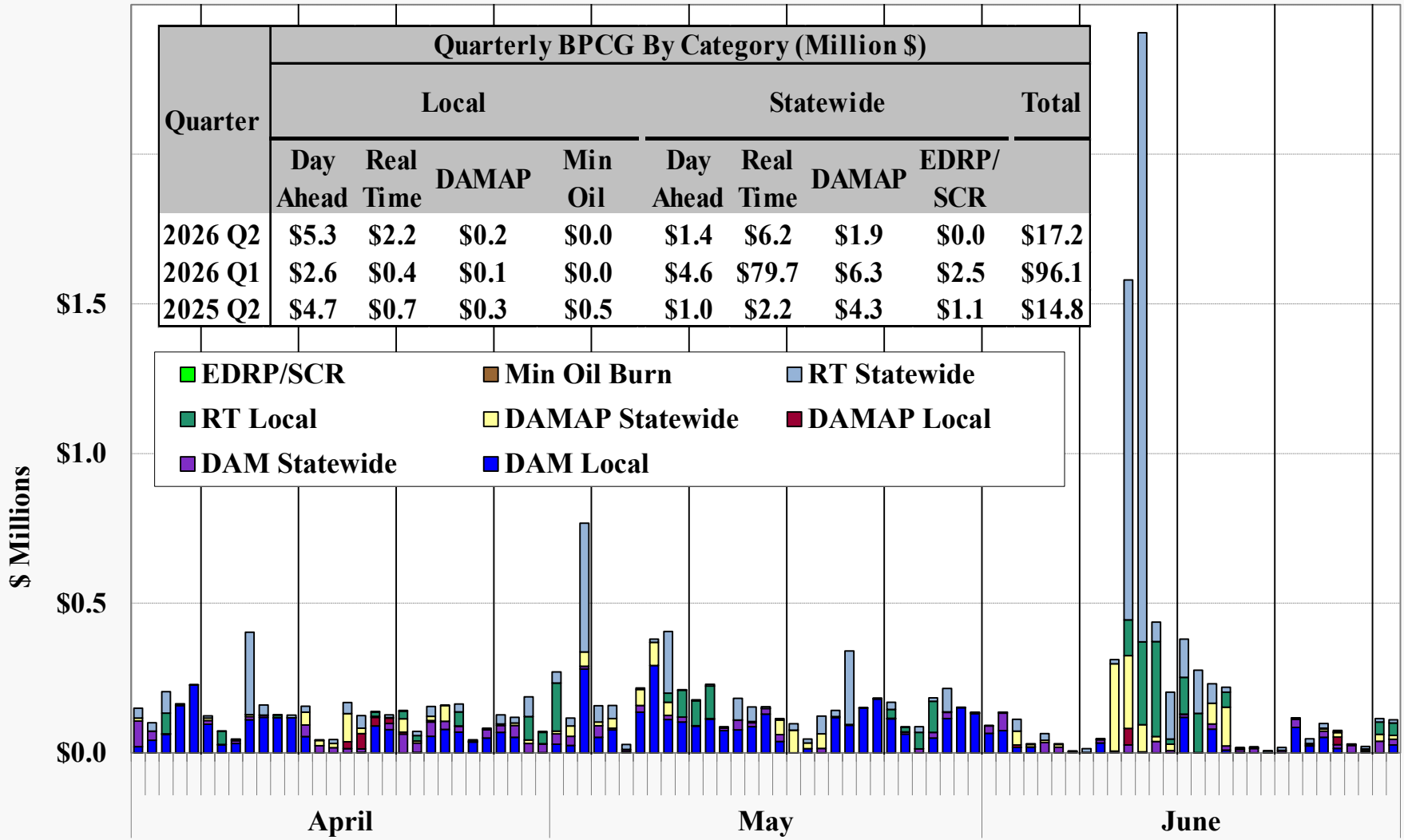
DARU Commitments in North Country: 2026 Q2



Notes: For chart description, see slide [106](#).

Uplift Costs from Guarantee Payments

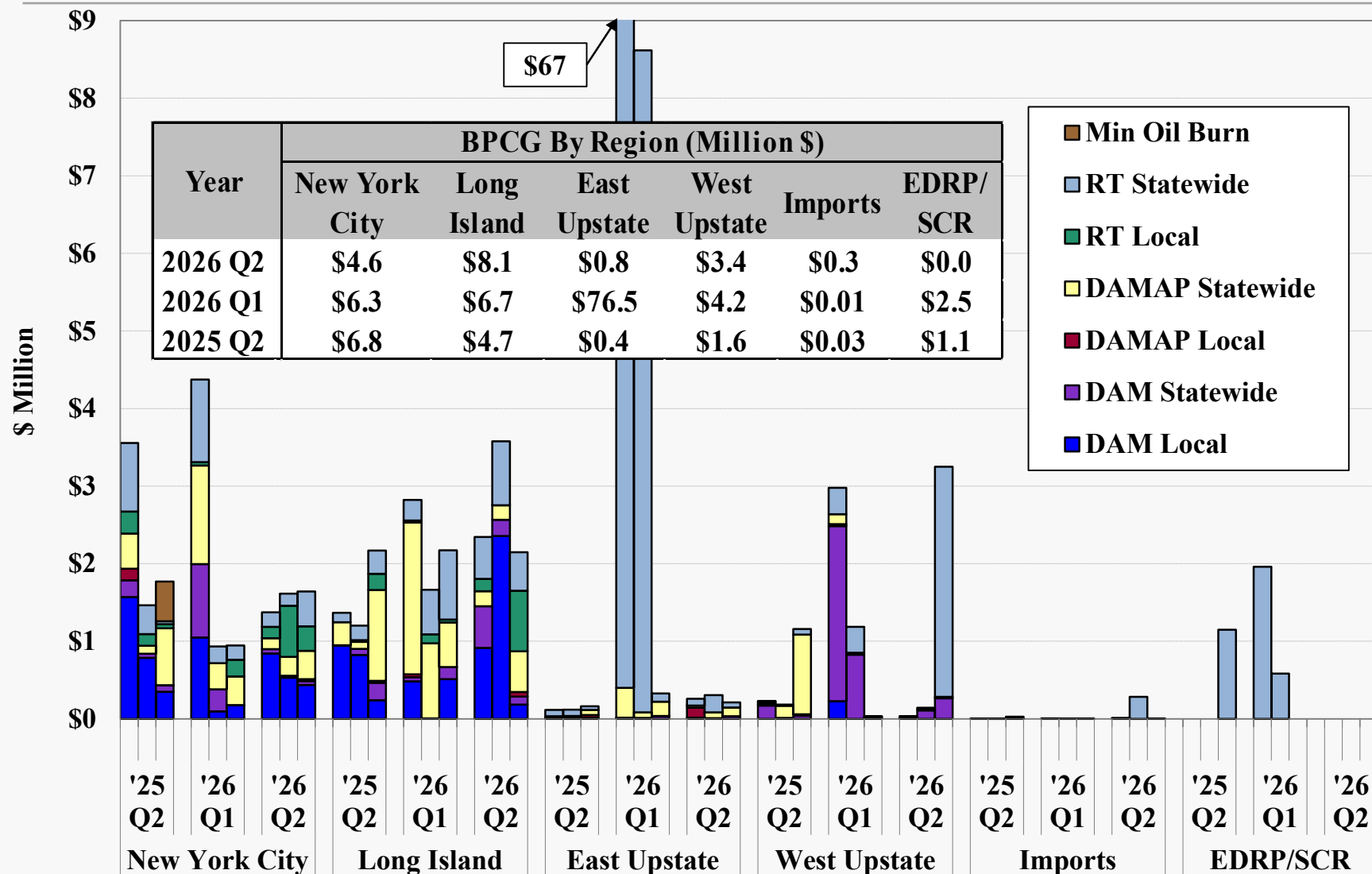
Local and Non-Local by Category



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 [107](#).

Uplift Costs from Guarantee Payments

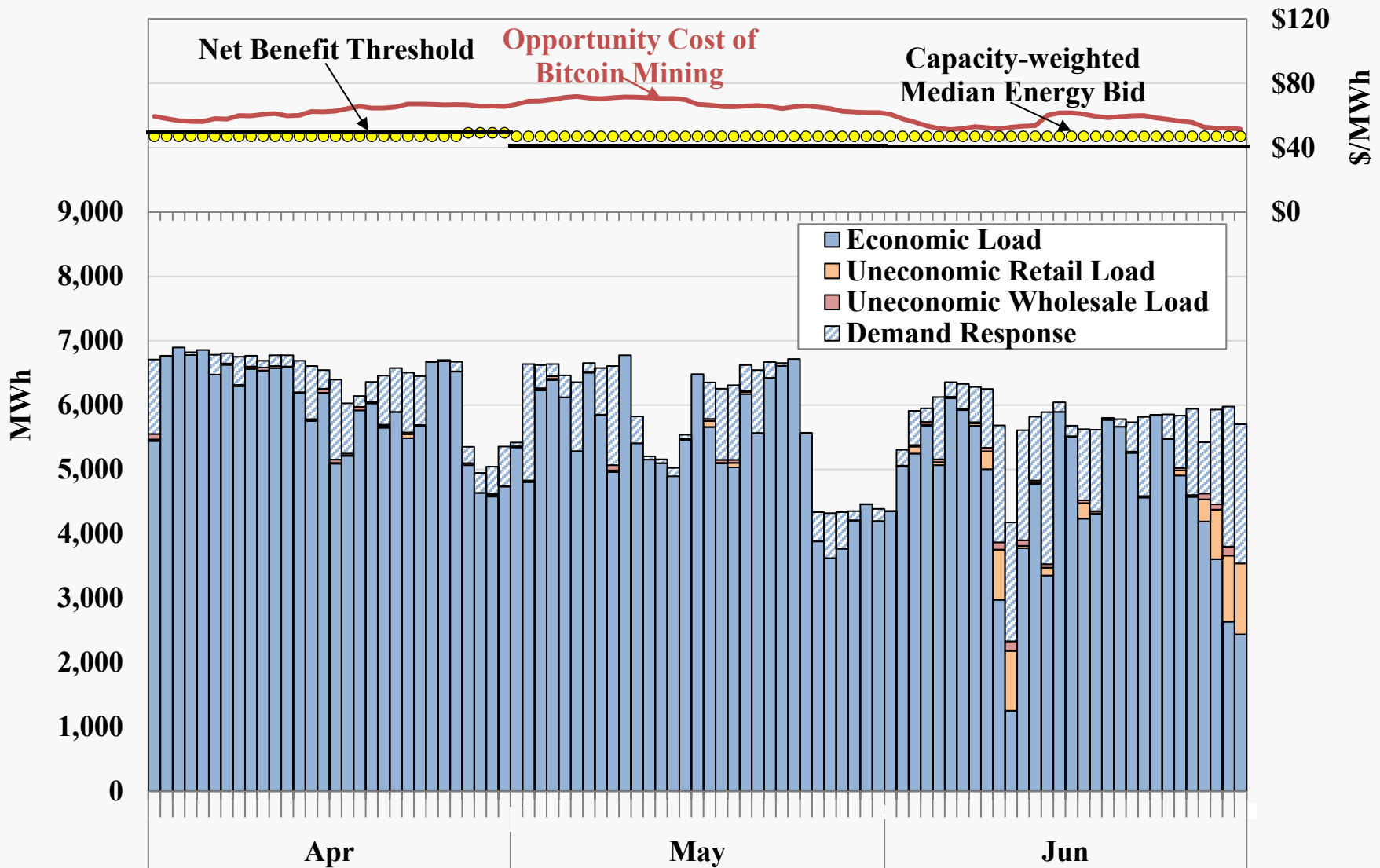
By Category and Region



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 [107](#).

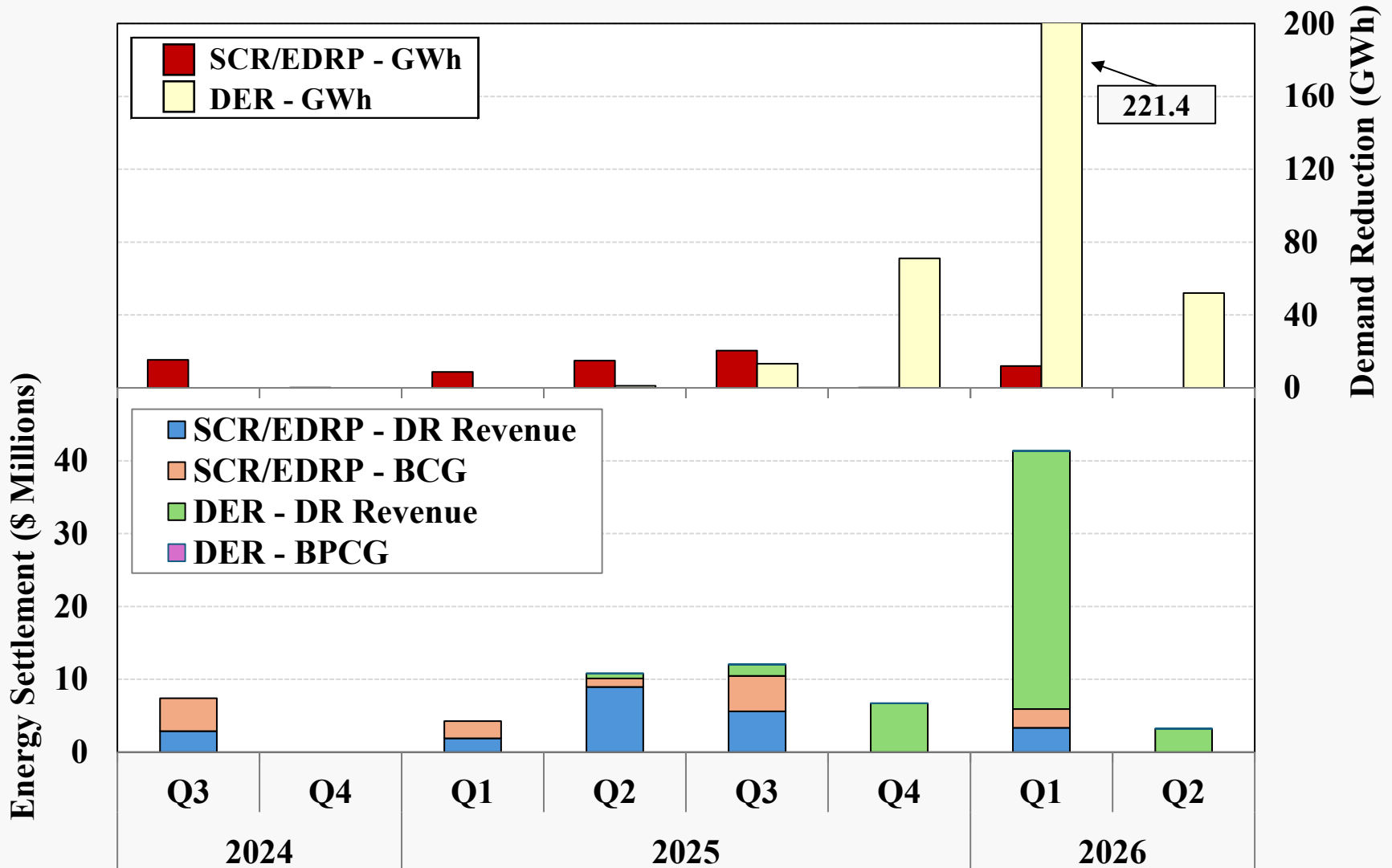
Demand Response from DER

Evaluation of Cryptocurrency Mining Loads



Notes: For chart description, see slide [108](#).

Payments to Demand Response Providers

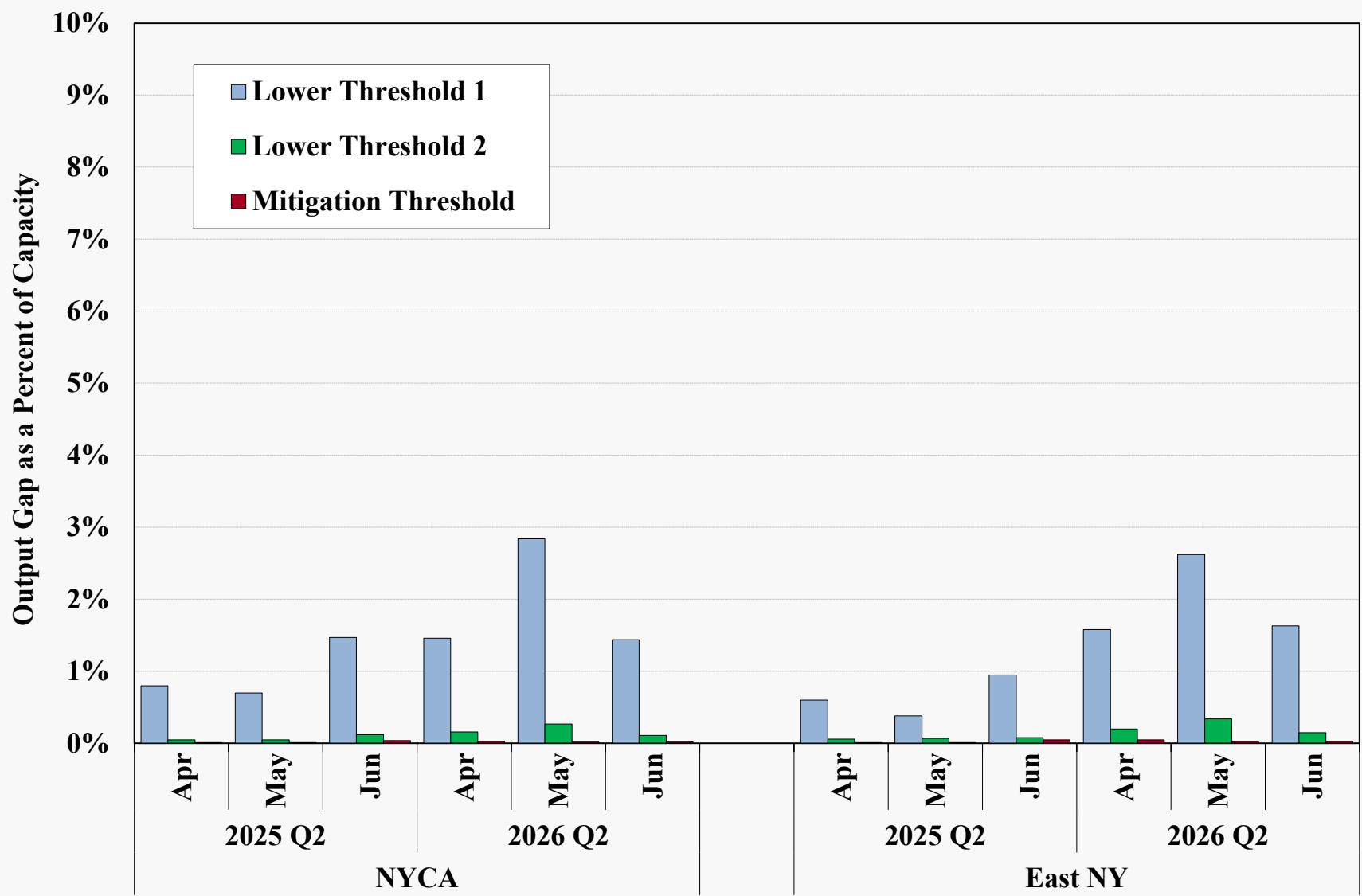


Notes: For chart description, see slide [108](#).

Charts: Market Power and Mitigation

Output Gap by Month

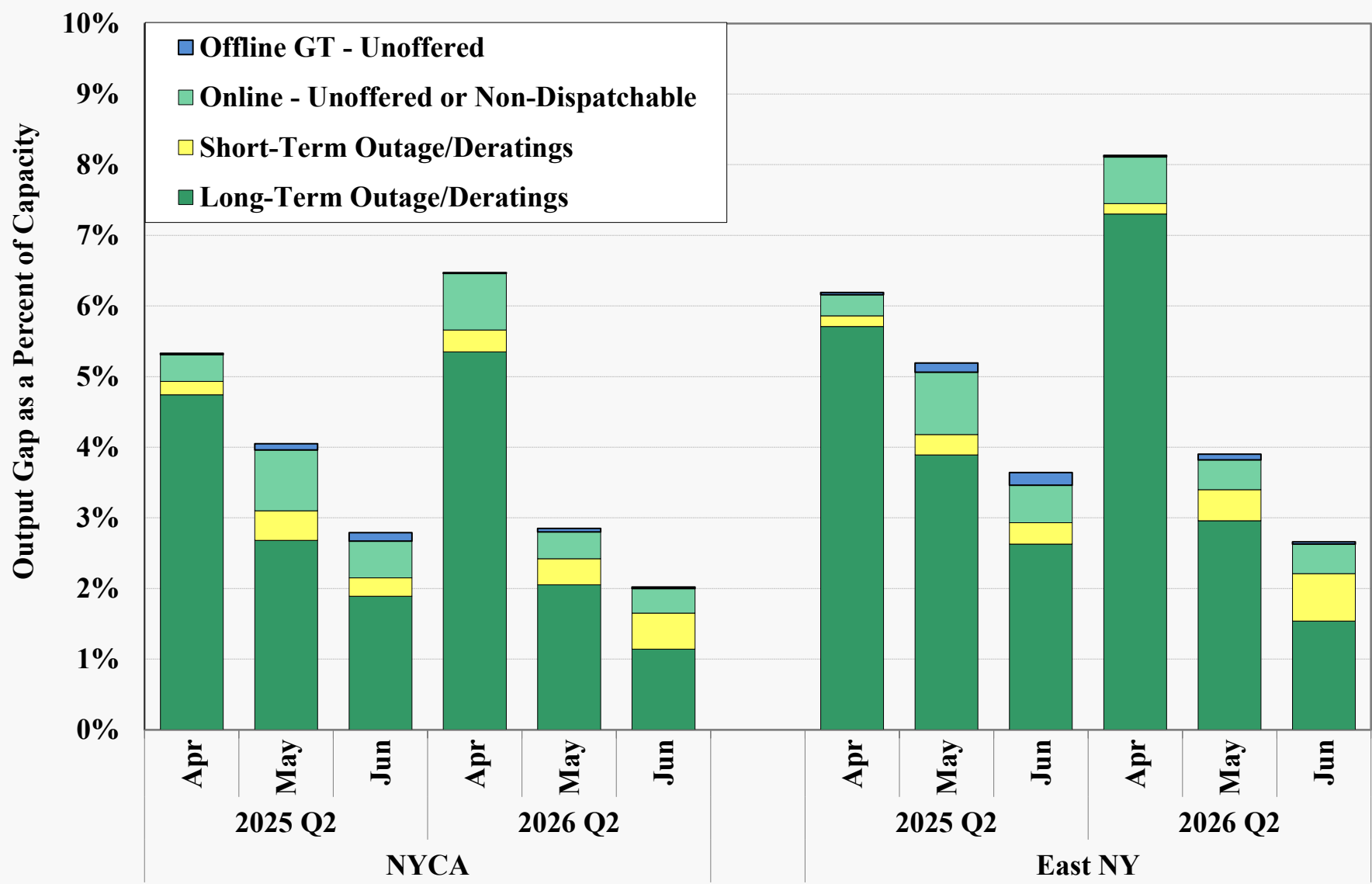
NYCA and East NY



For chart description, see slide [109](#).

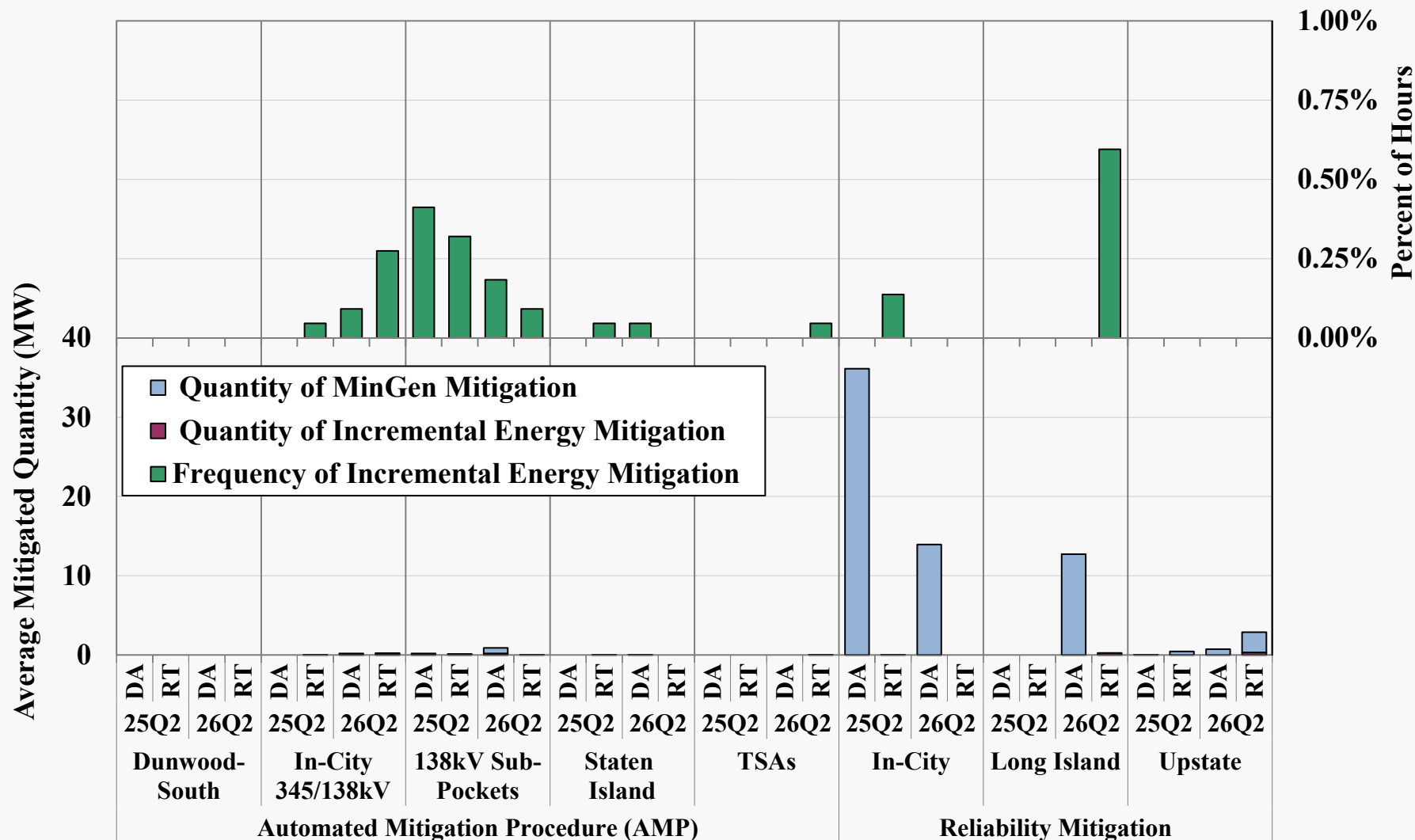
Unoffered Economic Capacity by Month

NYCA and East NY



For chart description, see slide [109](#).

Automated Market Power Mitigation

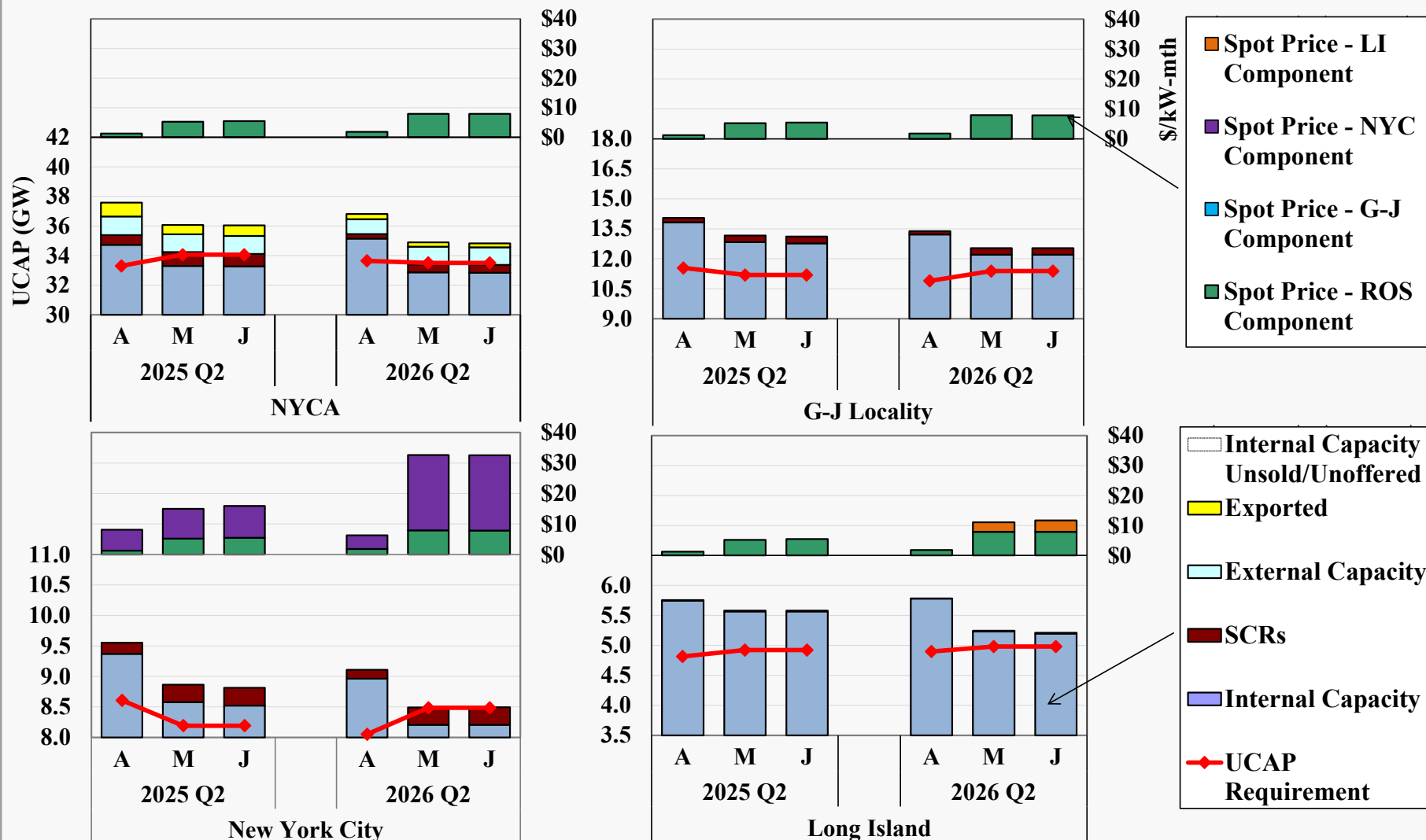


Notes: For chart description, see slide [110](#).

Charts: Capacity Market

Spot Capacity Market Results

Monthly Results by Locality



Notes: For chart description, see slide [111](#).

Key Drivers of Capacity Market Results

	NYCA	NYC	LI	G-J Locality
Avg. Spot Price				
2026 Q2 (\$/kW-Month)	\$5.87	\$23.79	\$8.21	\$5.87
% Change from 2025 Q2	47%	83%	106%	47%
Change in Demand				
Load Forecast (MW)	109	57	18	106
IRM/LCR	0.1%	4.1%	3.8%	3.7%
2026/27 Capability Year	124.5%	82.6%	110.3%	82.5%
2025/26 Capability Year	124.4%	78.5%	106.5%	78.8%
ICAP Requirement (MW)	168	499	212	650
Key Changes in ICAP Supply (MW)				
<i>Generation & UDR</i>	204	-191	-170	-205
<i>Entry</i> ⁽³⁾	43	0	0	43
<i>Exit</i> ⁽³⁾	-88	-40	-48	-40
<i>Other Capacity Changes</i> ⁽¹⁾	249	-151	-122	-208
<i>Cleared Import</i> ⁽²⁾	-99			
<i>(1) Other changes include DMNC ratings, change in exports, unsold capacity, etc.</i>				
<i>(2) Based on average of quarterly cleared quantity.</i>				
<i>(3) Includes entry into or return from IIFO, Mothball, & other unavailable states</i>				

Notes: For chart description, see slide [111](#).

Appendix: Chart Descriptions

All-in Price

- Slide [19](#) 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.

Comparison of Residential Retail and Wholesale Prices

- Slide [20](#) compares residential retail rates in New York to NYISO market prices and utility supply costs
 - Average retail rates are from EIA Form 861
 - Residential-weighted NYISO market prices are estimated using average zonal residential load distributions and residential hourly load shapes and load factors derived from utility data
 - Utility supply costs are reflect reported monthly residential volumetric supply rates from Con Edison, National Grid, NYSEG, RGE, LIPA, Central Hudson, and Orange & Rockland. We exclude REC/ZEC compliance costs, NTAC costs and transmission costs collected through NYISO OATT schedules (e.g. related to PPTN and reliability projects)
- Utility supply rates differ from monthly NYISO market prices primarily due to (1) distribution losses, (2) utilities' hedges and supply agreements, and (3) prior-month supply cost reconciliation mechanisms

RGGI Prices and Equivalent Energy Costs

- Reginal Greenhouse Gas Initiative (RGGI) allowance prices have increased substantially over the past few years, contributing significantly to the costs of electricity production.
- Slide [23](#) shows monthly RGGI allowance prices in the past 36 months.
 - The lower portion of the chart illustrates the equivalent energy costs, expressed in \$ per MWh, for hypothetical generating units with heat rates of:
 - 7,500 Btu/kWh (once for gas emission rates and again for oil emission rates); and
 - 10,000 Btu/kWh, respectively.
 - The equivalent energy cost equals $\text{RGGI price} * 0.059 \text{ short ton/MMBtu} * \text{unit heat rate}$ for a generator burning natural gas. The oil emission rate is assumed to be 0.081 short ton/MMBtu.

Real-Time Output and Marginal Units by Fuel

- Slide [24](#) 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 [25](#) 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 [26-30](#) evaluate emissions from generators in the NYISO market.
 - Slide [26](#) shows the historical trend of annual total emissions since 2000 in the NYISO footprint for CO₂, NO_x, and SO₂.
 - Slides [27-28](#) 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 [29-30](#) 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 [29](#) 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 [35-37](#) summarize day-ahead and real-time prices for six ancillary services products during the quarter:
 - 10-min spinning reserve prices eastern NY and Western NY;
 - 10-min non-spinning reserve prices in eastern 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 8 per MW of capability, but they are compensated according to actual movement.
 - Real-time Regulation Movement Charges shown on Slide [36](#) are estimated by dividing total movement charges by real-time scheduled regulation capacity.
 - 30-min operating reserve prices in western NY and 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 [38](#) 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 [39](#) 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 top 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.
 - The bottom chart shows the average monthly prices.
 - The columns show the average monthly regulation capacity prices in the DAM.
 - The two lines show the real-time capacity prices and movement prices.
- Regulation resources are scheduled assuming a common regulation movement multiplier of 13 per MW of capability, however, slide [40](#) shows a wide variation in actual movement-to-capacity ratio from one sample day.
 - The blue bars show the average scheduled regulation capacity in each movement-to-capacity ratio tranche.
 - The solid blue line represents the capacity weighted average actual movement-to-capacity ratio for the day, compared to the common multiplier of 8, indicated by the red dash line.

Day-Ahead Load Scheduling and Virtual Trading

- Slide [42](#) shows the quantity of day-ahead load scheduled as a percentage of real-time load in each of eight regions and statewide by day.
 - Net scheduled load = Physical Bilaterals + Fixed Load + Price-Capped Load + Virtual Load – Virtual Supply
- Slide [43](#) 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 [44](#) summarizes virtual trading by region including average quantities of scheduled virtual supply and load and gross profitability for eight 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.

Virtual Imports and Exports in the Day-Ahead Market

- Slide [45](#) evaluates scheduled virtual imports and exports in the day-ahead market.
 - Virtual imports and exports are defined as external transactions that are scheduled in the day-ahead market but withdrawn from the real-market market (i.e., no RT bids submitted). Wheel transactions are excluded from this analysis.
- The bottom portion of the chart shows the hourly average quantity of net virtual imports for each month.
 - The bars represent the average net virtual imports scheduled across the four primary interfaces between NYISO and neighboring control areas.
 - Virtual imports and exports are rare across the Scheduled-Line interfaces, which are excluded from this analysis.
- The top portion of the chart shows the percentage of hours in each month when total net virtual imports across the four primary interfaces fall into the following ranges:
 - Less than 200 MW;
 - Between 200 and 500 MW;
 - Between 500 and 800 MW; and
 - More than 800 MW.

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.

RTC and RTD Price Difference vs Load Forecast Difference

- Slide [48](#) summarizes the RTC/RTD divergence metric results for detrimental factors in the quarter.
 - See Section IV.D and Figure A-79 in the Appendix of our SOM 2021 report for detailed descriptions of the metric and chart.
- Slide [49](#) shows a histogram of the differences in systemwide load forecasts (including load biases by operators) between RTC and RTD at the quarter-hour intervals (i.e., at :00, :15, :30, :45) in the quarter.
 - For each tranche of the histogram, the figure summarizes the accuracy of the RTC price by showing:
 - The average of the RTC LBMP minus the RTD LBMP;
 - The median of the RTC LBMP minus the RTD LBMP; and
 - The mean absolute difference between the RTD and RTC LBMPs.
 - LBMPs are shown as zonal-load-weighted prices at the quarter-hour intervals for both RTC and RTD.

RTC and RTD Price Difference vs Load Forecast Difference

- Slide [50](#) shows these pricing and load forecasting differences by time of day.
 - The stacked bars in the lower portion of the figure show the frequency, direction, and magnitude of differences between RTC and RTD load forecast levels in tranches.
 - The upper portion of the figure summarizes the accuracy of the RTC price forecast by showing:
 - the average RTC LBMP minus the average RTD LBMP; and
 - the mean absolute difference between the RTD and RTC LBMPs.

Real-Time Prices During Commitments of GTs Offering Multi-Hour Min Run Times

- Slide [51](#) evaluates real-time prices during commitments of gas turbines offering minimum run times greater than one hour in the quarter, focusing on economic commitments made by RTC, RTD, or RTD-CAM.
 - Self-schedule and out-of-market commitments are excluded from the analysis.
- The bars in the figure show the total number of equivalent hours (i.e., the total number of 5-minute RT intervals divided by 12) when GTs are economically committed in the quarter.
 - The blue bars indicate the number of hours when LBMPs exceeded GT costs (i.e., incremental cost + amortized startup cost).
 - The red bars represent the number of hours when LBMPs were below GT costs.
 - The black line shows our estimate of potential price impact if these GTs were allowed to set prices.
- GTs are combined into seven groups in New York City and Long Island based on their electric connection to the grid.

Real-Time System Price Maps at Generator Nodes

- Slides [53](#) and [54](#) 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 [55](#), [56](#), [57](#), and [59](#) 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 [55](#) 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 [56](#) 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 [57](#) and [59](#) 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 [60](#) 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).

OOM Actions to Manage Network Reliability

- 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 [61](#) 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).
- In addition, the figure also reports the number of days when OOM commitments were made to satisfy N-1-1 reserve needs in several local load pockets.

Constraints on the Low Voltage Network

- Slide [62](#) 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 [62](#) 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 [63](#) 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.

GT Start-up Performance

- Slide [64](#) summarizes the average performance of offline GTs in responding to start-up instructions from NYISO audits and economic commitments (including commitments by RTC, RTD, and RTD-CAM) in the past 12-month period.
 - The table's rows categorize performance into 10-percent increments from 0 to 100 percent. A unit's performance for a given start is measured based on its output level at its expected full output time (i.e., at 10 or 30 minutes after receiving a start-up instruction), expressed as a percentage of its Upper Operating Limit ("UOL").
 - For each average performance category, the table shows:
 - Number of Units;
 - Total Number of Associated Unit-Starts;
 - Average Performance On Time: measured at the unit's expected full output time;
 - Average Performance 10 Minute Later.
- Performance metrics are also broken down for two different operating conditions:
 - RPU + Unforeseen Economic Starts & Audits: These include Reserve Pickup ("RPU") events, random NYISO audits, and economic starts that are NOT anticipated in the look-ahead advisory evaluations.
 - Remaining Economic Starts and Audits: These include re-tests conducted within days after an initial audit failure and economic starts that are anticipated in the look-ahead advisory evaluations.

Supplemental Commitments

- Slide [66](#) summarizes out-of-market commitment, which is one of the primary sources of guarantee payment uplift.
- Slide [66](#) 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.

Reliability Commitment in New York City

- Slide [67](#) show the amount of reliability commitments in New York City for each day of the quarter.
- The chart shows these quantities in stacked bars in five distinct categories:
 - **Economic MWh:** This category represents the total MWh of the initial DARU commitments that eventually qualify as economic capacity within the scheduling software.
 - **Thermal Need MWh – Market Model:** This category represents the total MWh of the initial DARU and applicable LRR and SRE commitments that do not qualify as **Economic** but are deemed necessary by the MMU's assessment for maintaining reliability in the applicable load pockets.
 - This assessment is based on the reliability requirements reflected in the market model for the relevant load pockets and information available in the DAM and RTM, including factors such as load forecast, resource availability, and transmission network conditions.
 - **Thermal Headroom MWh - Market Model:** This category represents the total MWh associated with commitments categorized as **Thermal Need MWh – Market Model** but exceed the amount of **Need MWh**.
 - For example, if a 100 MW unit is identified for a reliability need of 50 MWh over two hours but has a minimum run time commitment of five hours, the headroom MWh would be 450 MWh ($= 5 \times 100 - 50$).
 - **Voltage Need MWh:** This category represents the total MWh associated with commitments made to address voltage-related reliability risks, including high voltage risks during light load conditions and post-contingency voltage collapse risks.
 - **Thermal Need MWh – Other:** This category represents the remaining OOM commitments that do not fit into the other four categories. These include, but are not limited to, reliability criteria not represented in the market model and reliability needs due to load over-forecasting.

Reliability Commitment in North Country

- Slide [68](#) shows the amount of reliability commitments in North Country for each day of the quarter.
- The chart shows these quantities in stacked bars in four distinct categories:
 - **Economic MWh:** This category represents the total MWh of the initial DARU commitments that eventually qualify as economic capacity within the scheduling software.
 - **Verified – Needed MWh:** This category represents the total MWh of the initial DARU commitments that do not qualify as **Economic** but are verified by the MMU's assessment as necessary for maintaining reliability in the applicable load pockets.
 - Our assessment relies on information available in the DAM, including factors such as load forecast, resource availability, and transmission network conditions.
 - **Verified – Headroom MWh:** This category represents the total MWh that are associated with **Verified** commitments but exceed the amount of **Needed** MWh.
 - For example, if a 100 MW unit is verified for a reliability need of 50 MWh over two hours but has a minimum run time commitment of five hours, the headroom MWh would be 450 MWh ($= 5 \times 100 - 50$).
 - **Unverified MWh:** This category represents the remaining DARU commitments that do not fit into the other three categories.

Uplift Costs from Guarantee Payments

- Slides [69](#) and [70](#) 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 [69](#) shows these seven categories on a daily basis during the quarter.
 - Slide [70](#) summarizes uplift costs by region on a monthly basis.

Demand Response from DER

- Slide [71](#) shows information pertaining to DER performance this quarter, focusing on cryptocurrency mining loads in the program.
- The bottom portion of the chart provides information about the loads and demand reductions from these resources.
 - Economic Load: the metered load when LBMP was less than or equal to the Opportunity Cost of Bitcoin Mining (OCBM)
 - Uneconomic Retail Load: the metered load when LBMP was greater than the OCBM for resources exposed to retail rates
 - Uneconomic Wholesale Load: the metered load when LBMP was greater than the OCBM for resources exposed to wholesale rates
 - Demand Response: the reported demand reductions
- The upper portion of the chart provides bid and price information.
 - The solid black lines show the monthly Net Benefits Threshold (NBT) value.
 - The red line shows the estimated Opportunity Cost of Bitcoin Mining.
 - The yellow points show the capacity-weighted median energy bid value from applicable DERs.

Potential Economic and Physical Withholding

- Slides [74](#) and [75](#) 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 [76](#) 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 [78](#) and [79](#) summarize market results and key drivers in the monthly spot capacity auctions.
 - Slide [78](#) 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 [79](#) 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.