Quarterly Report on the New York ISO Electricity Markets Third Quarter of 2023

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November 2023

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Table of Contents

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Market Highlights

Market Highlights:
Executive Summary

- NYISO energy markets performed competitively in the third quarter of 2023.
- All-in prices ranged from $38 in the North Zone to $83 per MWh in New York City, down 28 to 54 percent from 2022-Q3 in individual regions. (slide 8)
  - ✓ Energy costs fell by 54 to 67 percent across the system primarily because of lower gas prices (down by 64 to 78 percent). Other contributing factors include:
    - Lower load conditions, which fell by 4 percent on average;
    - Fewer planned transmission outages and newly-installed transmission facilities;
    - However, the decrease in energy costs was partly offset by substantially lower imports from Canada (by 1700 MW) because of the impact of wildfires.
  - ✓ Capacity costs increased considerably due largely to the retirement of 800 MW of downstate peakers since the summer of 2022. Capacity costs rose by: (slide 18)
    - 76 to 100 percent in upstate zones,
    - 77 percent in Hudson Valley, and
    - 359 percent in New York City.
- Low gas prices and load levels and transmission upgrades related to several policy-driven transmission projects contributed to a 65 percent reduction in day-ahead congestion revenues, the lowest for Q3 since 2014. (slide 10)

Market Highlights:
Executive Summary

- NYISO's monthly Operations Reports indicate that DARU commitments to satisfy N-1-1 reliability needs in NYC load pockets increased dramatically this quarter.
  - ✓ An average of 900 MW was DARU-committed for NYC load pockets on 74 days.
    - 50 percent was economic in the DAM scheduling software – the SOM reports generally exclude these from summaries of "Supplemental Commitment".
    - 35 percent was verified (by the MMU) as needed to satisfy a specific reliability requirement based on information on system conditions available in the DAM.
    - The remaining 15 percent may result from inaccurate forecasting (since most DARUs are made 2 to 7 days ahead) and local TO operational needs not reflected in information available to the MMU. (slide 72)
  - ✓ The overall amount of capacity committed in the DAM for NYC reliability and not otherwise economic actually *fell* from the previous year due to: (slides 70-71)
    - Increased DARU commitments were partially offset by reduced LRR commitments (which are made in the DAM to address the same underlying needs).
    - Factors such as gas price patterns, lower NOx allowance prices, and the elimination of NOx bubble commitments.
  - ✓ OOM commitments have large impacts on resource scheduling and pricing, hence it would be beneficial to reflect the underlying N-1-1 requirements as local reserve requirements.

Market Highlights:
Executive Summary

- We estimate 1.47 GW of summer installed capacity may receive excessive accreditation under the current rules. (slides 19-20) This includes:
  - ✓ 440 MW of emergency capacity;
  - ✓ 200 MW from ambient humidity and air temperature conditions that exceeded values used in ambient adjustments for DMNC tests applicable to this summer;
  - ✓ 210 MW from high ambient water temperatures and low tide levels;
  - ✓ 150 MW of cogeneration capacity with host-steam obligations; and
  - ✓ 470 MW of unreported derates, which appear driven primarily by:
    - Ambient conditions, and
    - Differences in configuration between test conditions and actual conditions.
  - ✓ Current NYISO proposals will address the ambient humidity and air temperature issues, but they generally do not address the other categories of excessive accreditation.

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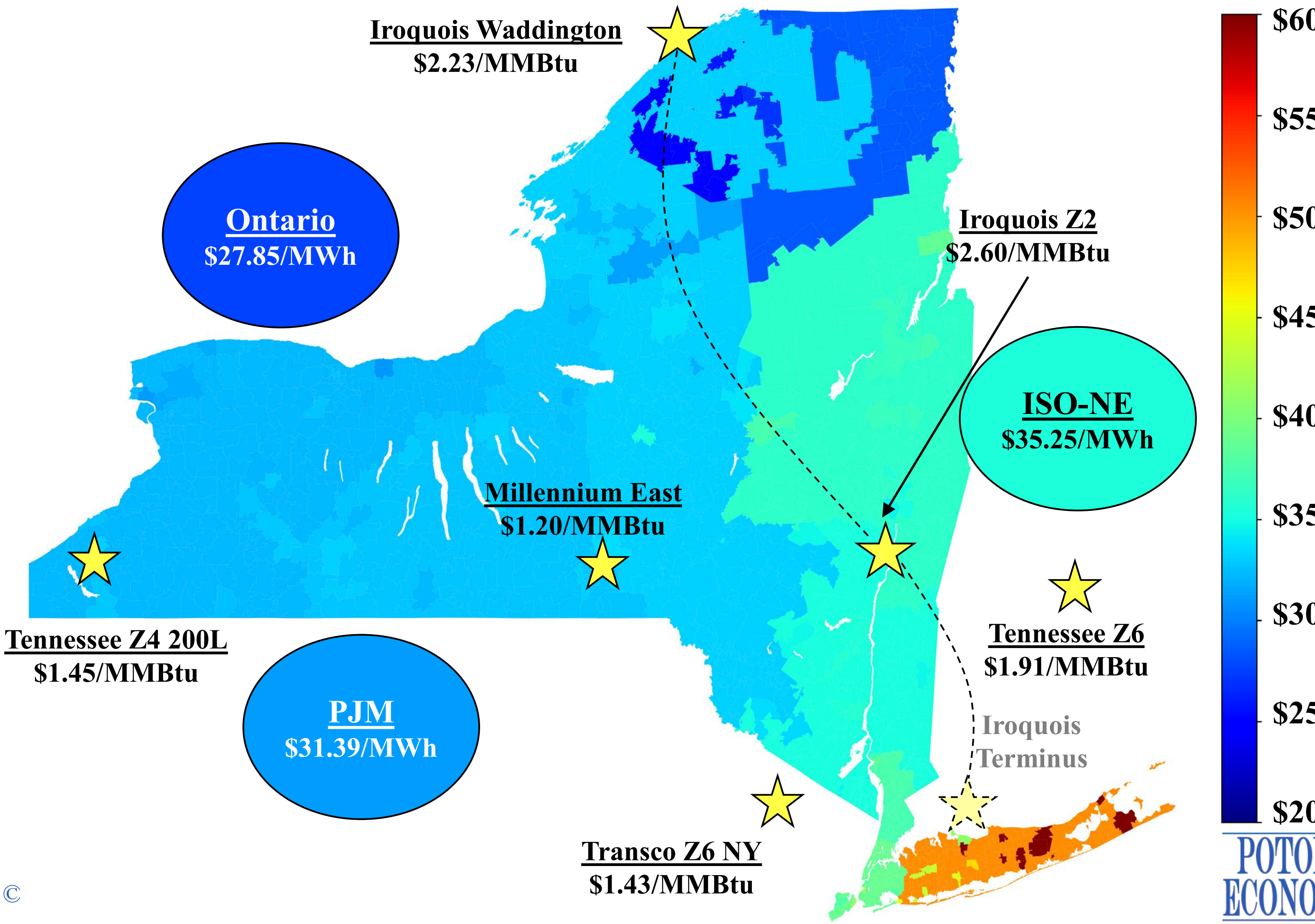
Market Highlights:
System Price Diagram



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Market Highlights:
Summary of Energy Market Outcomes

- NYISO energy markets performed competitively in the third quarter of 2023.
  - ✓ The amount of output gap (slide 80) and unoffered economic capacity (slide 81) remained reasonably consistent with competitive market expectations.
- All-in prices ranged from \$38/MWh in the North Zone to \$83/MWh in New York City, falling by 28 to 54 percent from a year ago across all zones. (slide 22)
  - ✓ Energy costs fell significantly (54 to 67 percent) because of: (slides 27-33)
    - Lower gas prices, which fell 64 to 78 percent from a year ago due to continued growth in gas production and higher storage levels (slide 24).
    - Fewer major planned transmission outages — Last year, Public Policy Transmission Project-related outages led to higher-than-average congestion across the Central-East interface and further elevated prices in East NY. (slide 58)
    - Lower load levels — Load exceeded 30 GW in just one hour and fell by 4 percent on average, which was at the lowest Q3 average level of the last 15 years. (slide 23)
    - However, these factors were partly offset by the dramatic (1.7 GW) reduction in average imports from Ontario and Quebec because wildfires have reduced transmission capability in these areas. (slide 48)
  - ✓ Capacity costs, on the other hand, rose substantially in all areas outside of Long Island for the reasons discussed in slide 18.

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Market Highlights:

Generation by Fuel and Emissions

- Average internal generation rose by 500 MW from last year while average net imports fell by 1400 MW. (slides 25 and 48)
  - ✓ Most of the reduction in imports was associated with Ontario and Quebec, whose internal transmission capability was reduced by wildfires.
  - ✓ Average nuclear generation rose by 230 MW because of fewer refueling outages.
  - ✓ Average hydro generation rose by 210 MW because of higher precipitation levels.
- NOx emissions from steam turbines in NYC rose 12 percent from a year ago.
  - ✓ Roughly 13 percent of steam turbine NOx emissions were from STs that were supplementally committed for local reliability. (slide 30)
  - ✓ The elimination of the NOx Bubble commitment requirements in the DAM before the summer of 2023 resulted in 6 days when one or more steam turbine supplemental commitments were avoided.

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Market Highlights:
Congestion Patterns, Revenues and Shortfalls

- Day-ahead congestion revenues fell by 65 percent from a year ago, totaling $72 million in the third quarter of 2023. (slide 56)
  - ✓ This represents the lowest congestion value for a third quarter since 2014.
- Key contributing factors of low congestion levels include:
  - ✓ Low natural gas prices and load levels.
  - ✓ Completion of the following major transmission upgrades:
    - The Empire State Line project (completed June 2022), which greatly reduced congestion in the West Zone;
    - The Smart Path project (completed June 2023), which reduced the congestion from North to Central New York; and
    - The AC Transmission Segment A and Segment B projects, which reduced congestion across the Central-East interface and from Capital to Hudson Valley.
  - ✓ Planned transmission outages became less frequent after completion of upgrades
    - Consequently, day-ahead congestion shortfalls accrued on these associated transmission paths have fallen dramatically as well. (slide 58)
  - ✓ Changes in import patterns – most notably, average imports from Canada fell by 1700 MW while average imports from PJM rose by 850 MW, helping reduce West-to-East congestion.

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

- In contrast to most other regions, Long Island experienced more frequent congestion compared to a year ago.
  - ✓ Long Island facilities accounted for the largest share of congestion (43% in DA, 30% in RT) this quarter.
  - ✓ Nearly 80 percent of this congestion occurred on 69 kV and 138 kV constraints inside Long Island.
    - West-to-east congestion in Long Island rose in August and September after the Cross Sound Cable was forced out of service in early August.
- Congestion in New York City remained similar to that of the previous year.
  - ✓ Nearly 65 percent of this congestion occurred during three periods of hot weather conditions (i.e., July 5-7, July 26-29, and Sep 5-7) when load levels were highest.
  - ✓ Peaker retirements reduced the transfer limits used in the market software for some N-1 transmission constraints.
- West-to-Central congestion rose from one year ago as Scriba-Volney 345 kV constraints limited production near Oswego in the Central Zone.

Market Highlights:
Load Forecast Errors and RTC/RTD Divergence

- RTC schedules non-dispatchable resources with lead times of 15 minutes to one hour (e.g., external transactions and fast-start units).
  - ✓ Inconsistency between RTC and RTD prices is an indicator that some scheduling decisions of RTC may be inefficient.
- We performed a systematic evaluation of factors that led to inconsistent RTC and RTD prices in the third quarter of 2023. (slide 50)
  - ✓ Load forecasting errors accounted for 23 percent of the overall divergence between RTC and RTD prices this quarter.
    - – On average, RTC load was higher than RTD load by roughly 74 MW, contributing to higher RTC LBMPs (than RTD LBMPs by an average of $1.17/MWh). (slide 51)
      - This improved from the previous year when RTC load was ~90 MW higher.
    - – Upward adjustments to the RTC load forecast are frequently made to offset the risk of over-forecasting BTM solar generation. (slide 52)
    - – Although conservatism in load forecast adjustments may be justified, they contribute to divergences between RTC and RTD prices and inefficient scheduling. Therefore, it would be beneficial to enhance the BTM solar forecast (e.g., the 2023 project “BTM Solar Demand Forecasting Product Enhancements”) and to evaluate the procedure for determining load forecast adjustments in RTC for potential improvements.

Market Highlights:
OOM Actions to Manage Network Reliability

- Supplemental commitments to satisfy N-1-1 requirements occurred on: (a) 14 days in the North Country load pocket; and (b) 84 days in NYC load pockets. (slide 61)
  - ✓ It would be beneficial to incorporate full reserve requirements into the market model for resource scheduling and pricing in applicable local areas, such as North Country, Capital Zone, Long Island, and New York City.
- OOM actions on Long Island were frequent in the Valley Stream load pocket (22 days) and the East End load pocket (68 days). (slide 62)
  - ✓ In the Valley Stream load pocket, one or more GTs were often needed to manage constraints involving a 69 kV contingency not modeled in the market software.
    - This 69 kV contingency is now secured through the market software.
  - ✓ In the East End load pocket, oil-fired peakers were often needed to satisfy local TVR requirements.
    - The estimated LBMP impact of unmodeled TVR needs was significant in this quarter, averaging nearly $64/MWh.
    - We have recommended the NYISO incorporate this TVR need into the market model.
  - ✓ Five 69kV facilities are now modeled in the DAM and RT market, greatly reducing the need for OOM actions.

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Market Highlights:
Reliability Commitments, OOM Dispatch, and BPCG

- BPCG payments totaled $16.5 million, down 50 percent from last year. (slide 77)
  - ✓ This was the lowest third quarter total in at least five years, driven largely by low natural gas prices.
  - ✓ In addition, supplemental commitments in New York City fell significantly (slide 70) from a year ago.
- BPCG uplift was highest on Long Island ($9.5 million or 58 percent) and fell only modestly (by $1.3 million) from a year ago.
  - ✓ Uplift associated with OOM dispatch to satisfy the East End TVR requirement accounted for nearly 40 percent (or $3.7 million).
  - ✓ Uplift associated with OOM dispatch for local 69 kV facilities rose modestly.
    - – Two dual-fuel units had to burn oil because of issues with their gas-firing equipment.
    - – OOM dispatch for 69 kV facilities rose in August and September following an outage affecting the Cross Sound Cable.
- Just $3.2 million (or 20 percent) of BPCG uplift accrued in NYC, 74 percent of which was paid to units that were committed for local reliability.
  - ✓ Low natural gas prices and retirements of 800 MW of peaking capacity led STs that were often needed for local reliability to be more economic.

Market Highlights:
DARU Commitments in NYC

- NYISO's monthly Operations Reports indicate that DARU commitments to satisfy N-1-1 reliability needs in NYC load pockets increased dramatically this quarter. Our assessment indicates that of the DARU-committed capacity: (Slide 72)
  - ✓ 50 percent was economic in the DAM; and
  - ✓ 35 percent was verified (by the MMU) as needed to satisfy a specific reliability requirement based on information available during the DAM related to forecasted load, status of generation and transmission equipment, and potential contingencies.
  - ✓ Although not verified, some of the remaining 15 percent of DARU capacity may have been committed due to the following factors:
    - DARU requests are typically made at least two days ahead of time for multiple consecutive days. Forecasts tend to be less accurate when the DARUs are requested.
    - The local TO may have operational requirements that are not included in the information available to the MMU.
- The overall amount of capacity committed in the DAM for NYC reliability and not otherwise economic actually *fell* from the previous year due to: (slides 70-71)
  - ✓ Increased DARU commitments were partially offset by reduced LRR commitments (which are made in the DAM to address the same underlying needs).
  - ✓ Factors such as gas price patterns, lower NOx allowance prices, and the elimination of NOx bubble commitments.

Market Highlights:
SRE for Capacity on High Load Days

- NYISO experienced three heat waves (July 5-7, July 26-28, and September 5-8) this summer, while load exceeded 30 GW on just one day (i.e., 30.2 GW on Sep 6).
  - ✓ Peak load was below the 50/50 forecast of 32 GW.
    - – Nearly 300 MW of utility DR programs were activated to reduce this peak load.
  - ✓ See presentation "NYISO Summer 2023 Hot Weather Operations" by Aaron Markham at the October 11 OC meeting for more details.
- The NYISO SRE~~e~~d resources for statewide capacity needs on seven days during the three heat waves. (slides 73-75)
  - ✓ SREs were needed to satisfy NYCA reserve requirements on six of the seven days except July 28 (partly because some forced-out capacity unexpectedly returned to service in the morning of the 28th).
  - ✓ The BPCG uplift from these SREs totaled nearly $4 million, and they were incurred to satisfy reserve needs that are not fully anticipated in the DAM.
    - – The NYISO proposes to satisfy these forecasted requirements (currently met in the FCT pass and/or with SREs) through the market with the Dynamic Reserve enhancements and/or other longer-lead-time reserve products.

Market Highlights:
Performance and Availability of Duct Burners

- Most CCs in the NYISO offer supplemental output from duct burners, totaling ~800 MW of summer capacity. This capacity is difficult to utilize due to inconsistencies between the market design and physical limitations of duct burners.
- Slide 64 shows an example CC that cannot follow dispatch instructions in a Reserve Pickup (RPU) event due to its inability to fire the duct burner within 10 minutes.
  - ✓ However, this duct burner capacity is considered capable of following 5-minute dispatch signals in the market scheduling and pricing software.
- Slide 65 illustrates the difficulty of offering duct burner capacity given that response rates are not a biddable parameter. Response rates can only be modified through the registration process, which does not accommodate frequent updates.
  - ✓ The 2024 project "Improve Duct-Firing Modeling" partially addresses inconsistencies between the market design and the physical limitations, however, the project will not enable bid response rates to adjust with the duct burner range of the unit.
- Slide 66 shows duct-firing capacity that was offered but not physically able to provide a given service. In afternoon hours, on average: (a) 105 MW was offered but not able to follow 5-minute ramp instructions; (b) 142 MW was scheduled but not able to provide 10-minute reserves; and (c) 16 MW was scheduled but not able to provide regulation.
  - ✓ In addition, (a) 55 MW of duct-firing was unavailable because it was not offered; and (b) 84 MW of 10- and 30-minute reserves were not offered from baseload capacity (i.e., non-duct ranges) due to their inability to perform in the duct burner range.

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Market Highlights:
Capacity Market

- Spot capacity prices averaged $19.46/kW-month in NYC and $6.00/kW-month elsewhere. (slides 84-85)
  - ✓ Spot prices rose by 423 percent in NYC because of:
    - The retirement of nearly 800 MW of peaking capacity since last summer.
    - The load forecast rose by 333 MW and LCR also rose 0.5 percent from last year.
  - ✓ The ROS prices rose by 85 percent, driven primarily by a higher ICAP requirement for the 2023/24 Capability Year and net reductions in supply.
    - The ICAP requirement rose by roughly 466 MW because:
      - Peak load forecast rose by 282 MW; and
      - The IRM rose from 119.6 to 120 percent.
    - Net supply fell by 800 MW due to the downstate peaker retirements and reduced net imports, especially from PJM.
  - ✓ LI prices fell 9% despite a 5.7% increase of the LCR due to additional UDR sales.
- The Derating Factor was just 1.64 percent for New York City for this Summer Capability Period despite the relative old age of generating capacity there.
  - The Derating Factor (which is derived from data reported to GADS) may under-estimate the impact of forced outages and deratings on unit availability. The MMU is investigating the low Derating Factor and will follow up in subsequent reports.

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Market Highlights:
Functionally Unavailable Capacity

- We examined the availability of capacity procured from conventional resources during peak summer conditions over the past few summers. (slide 86)
- An estimated 1,470 MW from fossil-fuel and nuclear generators was qualified to sell ICAP but not available under peak conditions (for reasons other than a reported forced outage or derate or maintenance outage). Underlying drivers include:
- Ambient water temperature issues: Approximately 560 MW of ICAP from once-through-cooled fossil-fuel and nuclear steam turbine generators are estimated to be unavailable at peak conditions. The main categories for these resource types include:
  - ✓ 210 MW due to ambient water temperature and tidal conditions;
  - ✓ 245 MW of this capacity was also offered in the emergency range;
  - ✓ 100 MW of observed underperformance at high output levels.
  - ✓ In addition, many water temperature-related limitations arise (or are worsened) when multiple generators at the same station are running simultaneously. However, none of these facilities conducted DMNC tests in a multi-unit configuration. (slide 87)
  - ✓ The NYISO proposal to restrict the DMNC testing window (to daytime hours in July and August) on water temperature-affected units fails to address most of the issues identified in our analysis of water temperature-affected units.

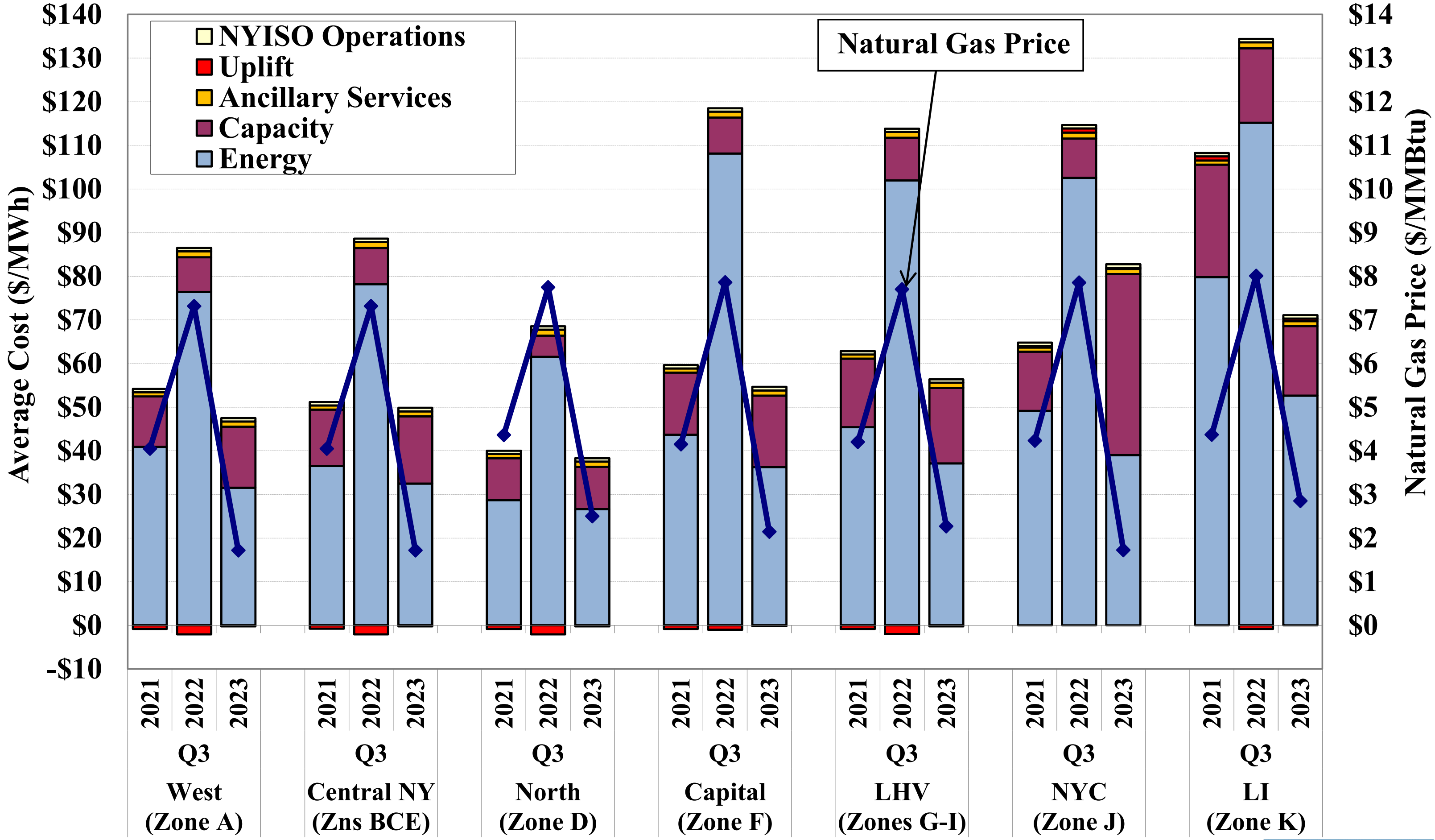
Market Highlights:
Functionally Unavailable Capacity (cont.)

- Host Steam Obligations: Cogeneration units may conduct DMNC tests when host steam demand is lower than the contracted maximum, letting the unit double-sell capacity.
  - ✓ We observed real-time deratings from cogeneration units believed to be related to host steam requirements totaling ~150 MW under high load conditions.
  - ✓ Cogeneration units may not have procedures for curtailing steam load when their capacity is needed for electric system reliability.
- Emergency Capacity: 440 MW of emergency capacity was offered from these resources, most of which are not classified by the NYISO as Capacity Limited Resources (“CLR”).
  - ✓ The NYISO has proposed to “sunset the CLR program” but the ability to offer emergency capacity (i.e., a UOLe above a UOLn) is not limited to CLRs.
  - ✓ Operating in the emergency range may increase the risk of tripping for some units, but this risk is not accounted for in the EFORd calculations. Hence, operators may be reluctant to utilize this capacity during an emergency.
- Unreported Derates: An estimated 470 MW is unavailable with no reported reasons.
  - ✓ This includes 150 MW due to ambient humidity conditions and 40 MW due to warmer temperatures at the peak than were accounted for in the DMNC tests. The NYISO proposal for including relative humidity in the ambient adjustments for combustion units with evaporative cooling systems should sufficiently address that category.

Charts:

Market Outcomes

All-In Prices by Region



Notes: For chart description, see slide 89.

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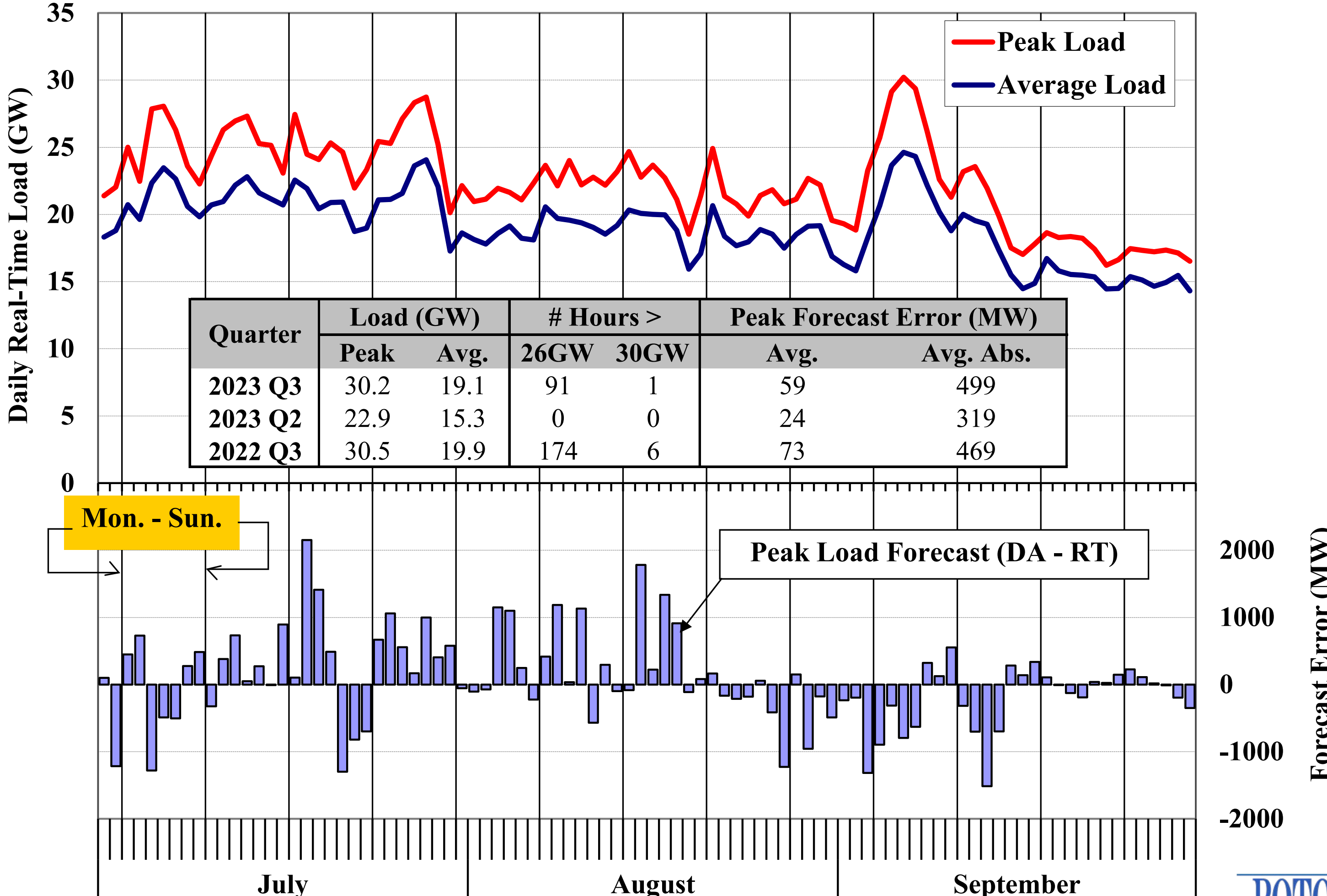
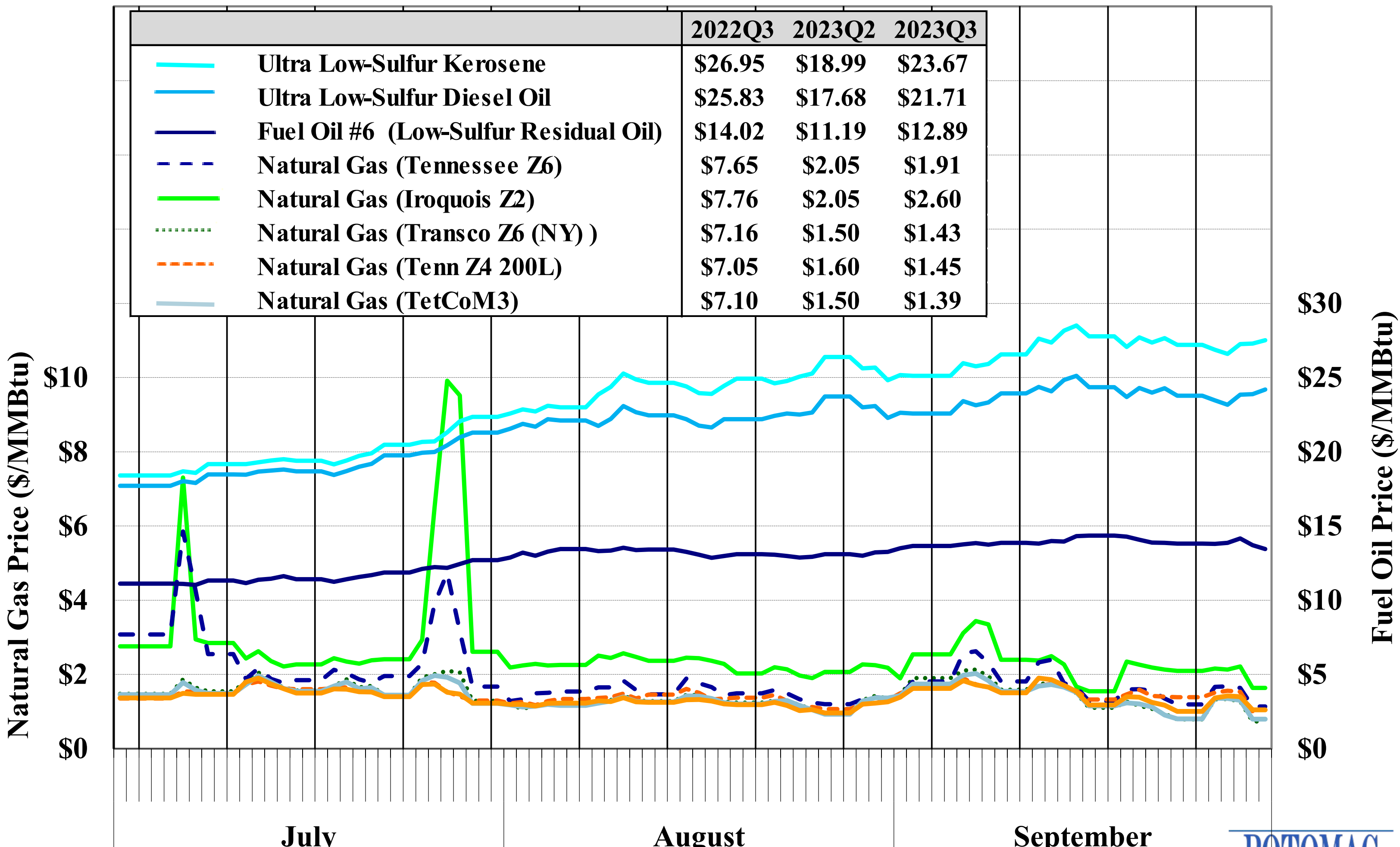
Load Forecast and Actual Load



Quarter	Load (GW)		# Hours >		Peak Forecast Error (MW)	
	Peak	Avg.	26GW	30GW	Avg.	Avg. Abs.
2023 Q3	30.2	19.1	91	1	59	499
2023 Q2	22.9	15.3	0	0	24	319
2022 Q3	30.5	19.9	174	6	73	469

Natural Gas and Fuel Oil Prices

	2022Q3	2023Q2	2023Q3
Ultra Low-Sulfur Kerosene	$26.95	$18.99	$23.67
Ultra Low-Sulfur Diesel Oil	$25.83	$17.68	$21.71
Fuel Oil #6 (Low-Sulfur Residual Oil)	$14.02	$11.19	$12.89
Natural Gas (Tennessee Z6)	$7.65	$2.05	$1.91
Natural Gas (Iroquois Z2)	$7.76	$2.05	$2.60
Natural Gas (Transco Z6 (NY))	$7.16	$1.50	$1.43
Natural Gas (Tenn Z4 200L)	$7.05	$1.60	$1.45
Natural Gas (TetCoM3)	$7.10	$1.50	$1.39



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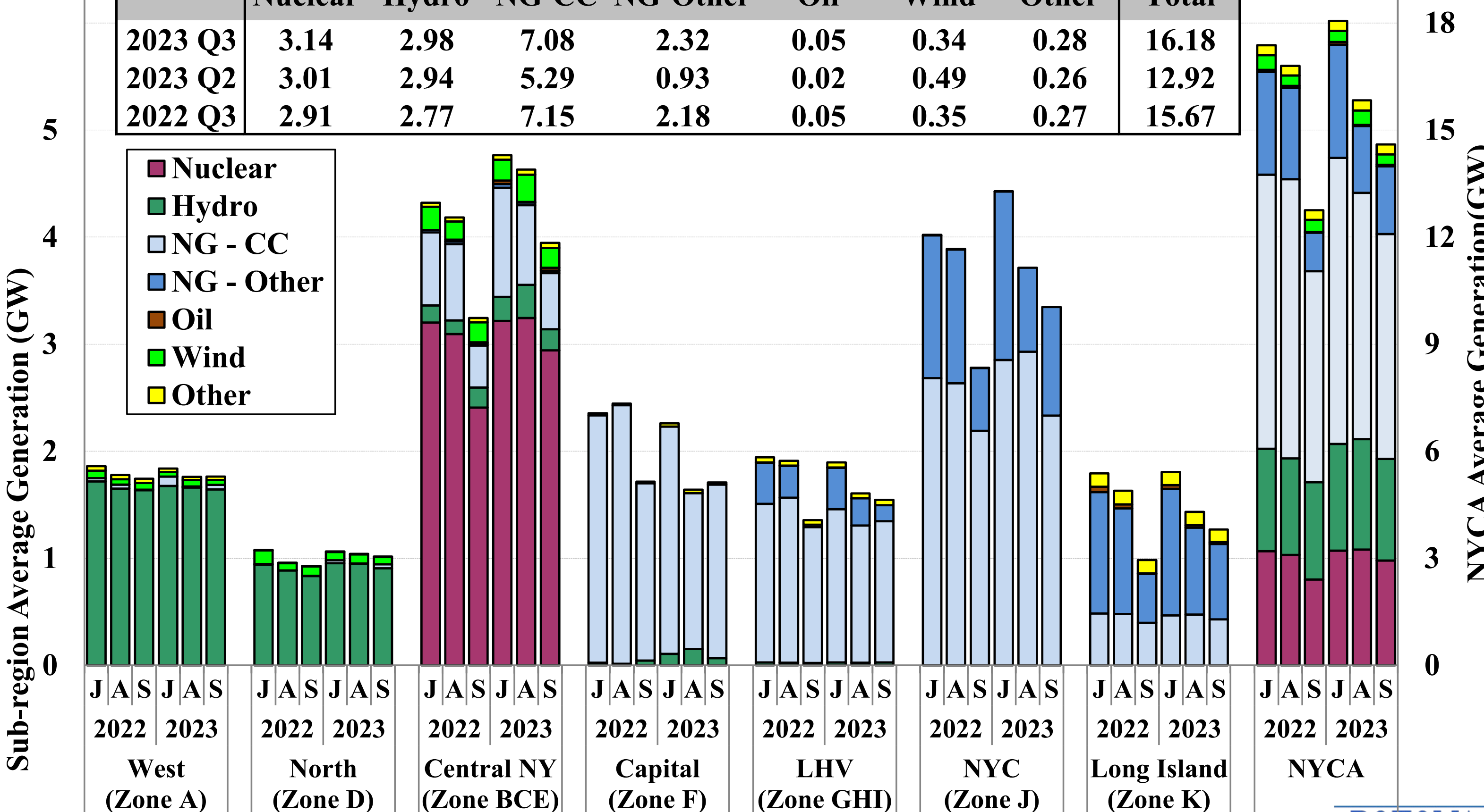
Real-Time Generation Output by Fuel Type

Quarter	Average Internal Generation by Fuel Type in NYCA (GW)							
	Nuclear	Hydro	NG-CC	NG-Other	Oil	Wind	Other	Total
2023 Q3	3.14	2.98	7.08	2.32	0.05	0.34	0.28	16.18
2023 Q2	3.01	2.94	5.29	0.93	0.02	0.49	0.26	12.92
2022 Q3	2.91	2.77	7.15	2.18	0.05	0.35	0.27	15.67



Notes: For chart description, see slide 91.
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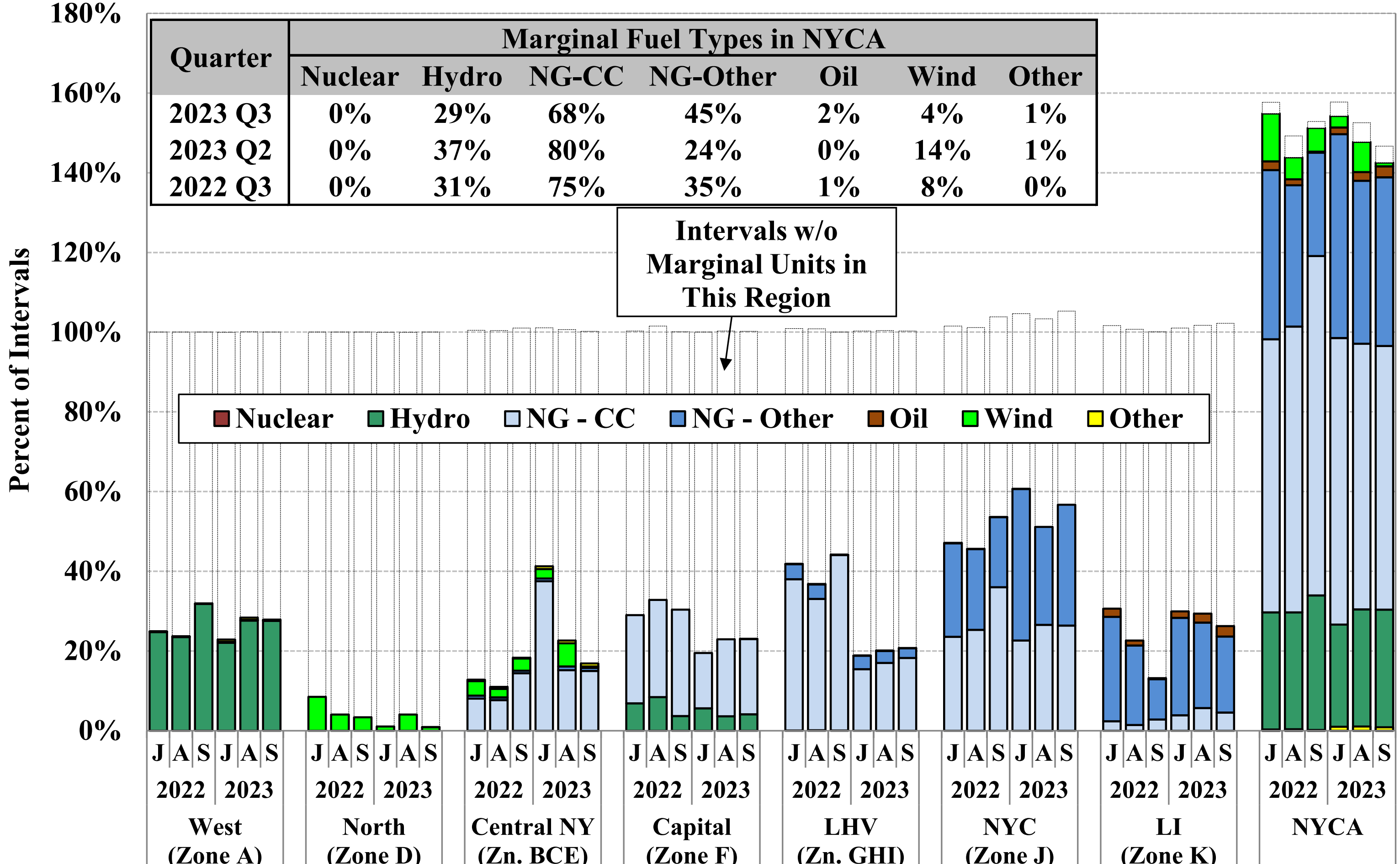
Fuel Type of Marginal Units in the Real-Time Market



Quarter	Marginal Fuel Types in NYCA						
	Nuclear	Hydro	NG-CC	NG-Other	Oil	Wind	Other
2023 Q3	0%	29%	68%	45%	2%	4%	1%
2023 Q2	0%	37%	80%	24%	0%	14%	1%
2022 Q3	0%	31%	75%	35%	1%	8%	0%

Notes: For chart description, see slide 91.

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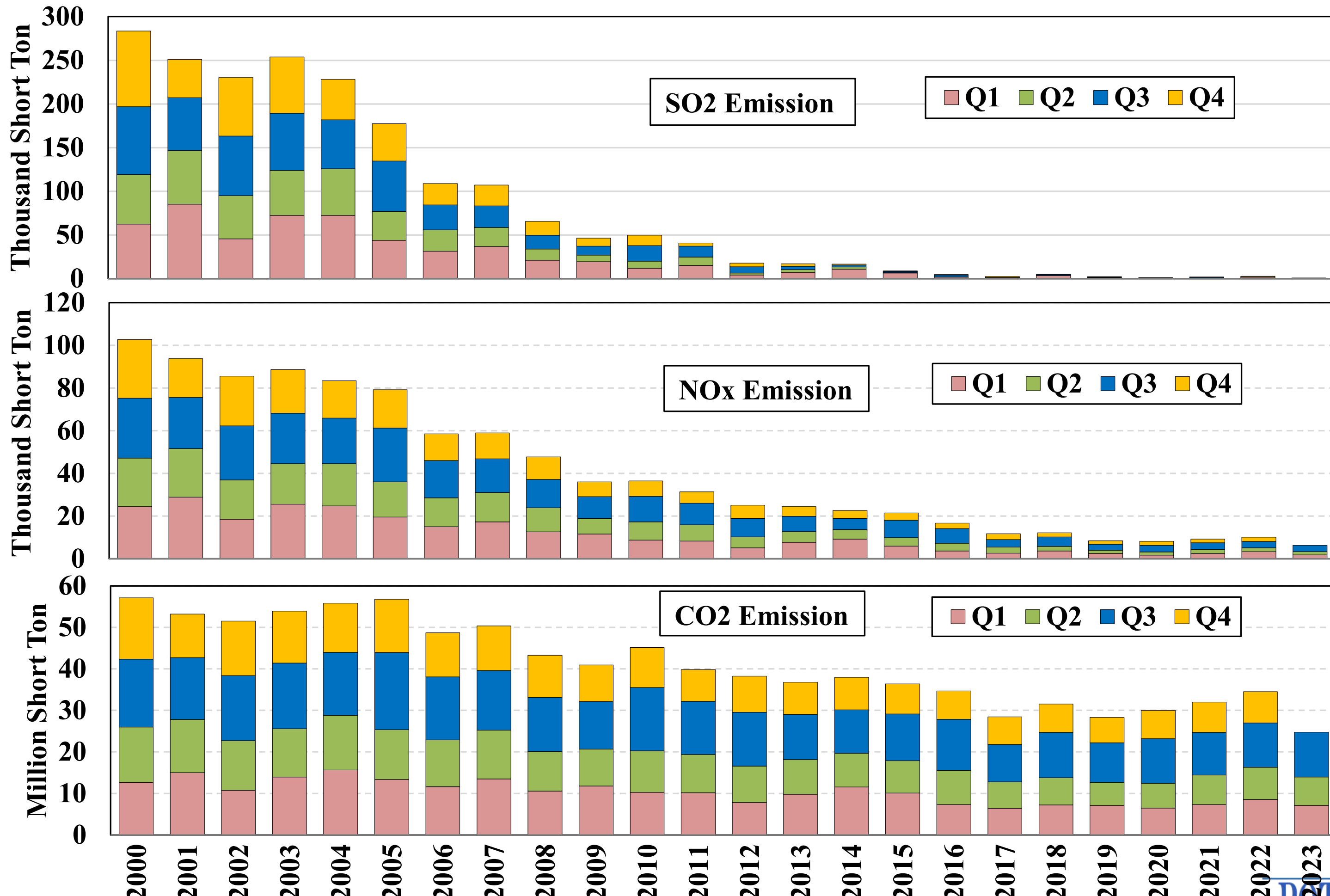
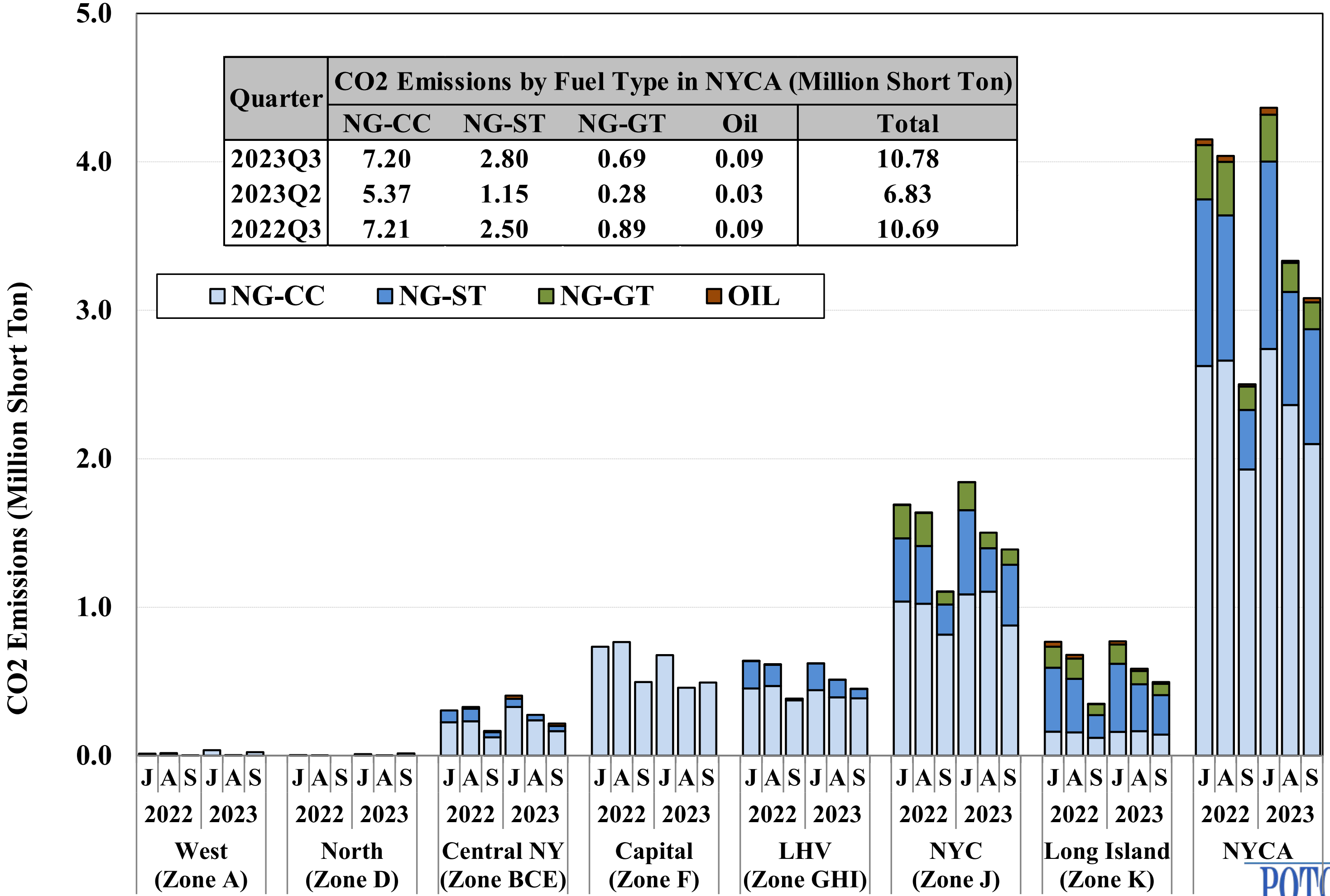
Historical Emissions by Quarter in NYCA
CO_2, SO_2, and NO_X



Notes: For chart description, see slide 92.

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	Total
2023Q3	7.20	2.80	0.69	0.09	10.78
2023Q2	5.37	1.15	0.28	0.03	6.83
2022Q3	7.21	2.50	0.89	0.09	10.69



Notes: For chart description, see slide 92.
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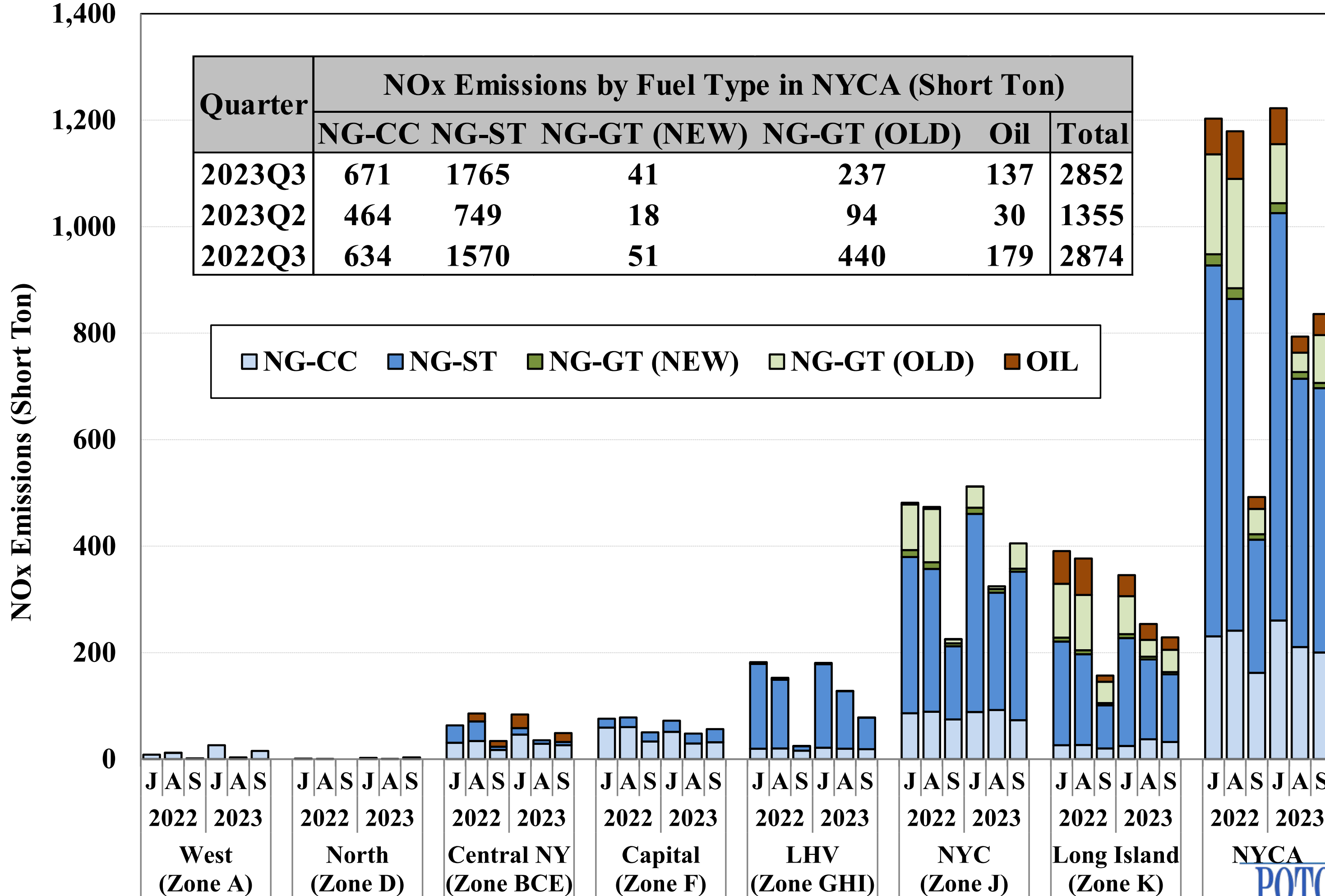
Emissions by Region by Fuel Type
NO_X Emissions



Quarter	NOx Emissions by Fuel Type in NYCA (Short Ton)					
	NG-CC	NG-ST	NG-GT (NEW)	NG-GT (OLD)	Oil	Total
2023Q3	671	1765	41	237	137	2852
2023Q2	464	749	18	94	30	1355
2022Q3	634	1570	51	440	179	2874

Notes: For chart description, see slide 92.

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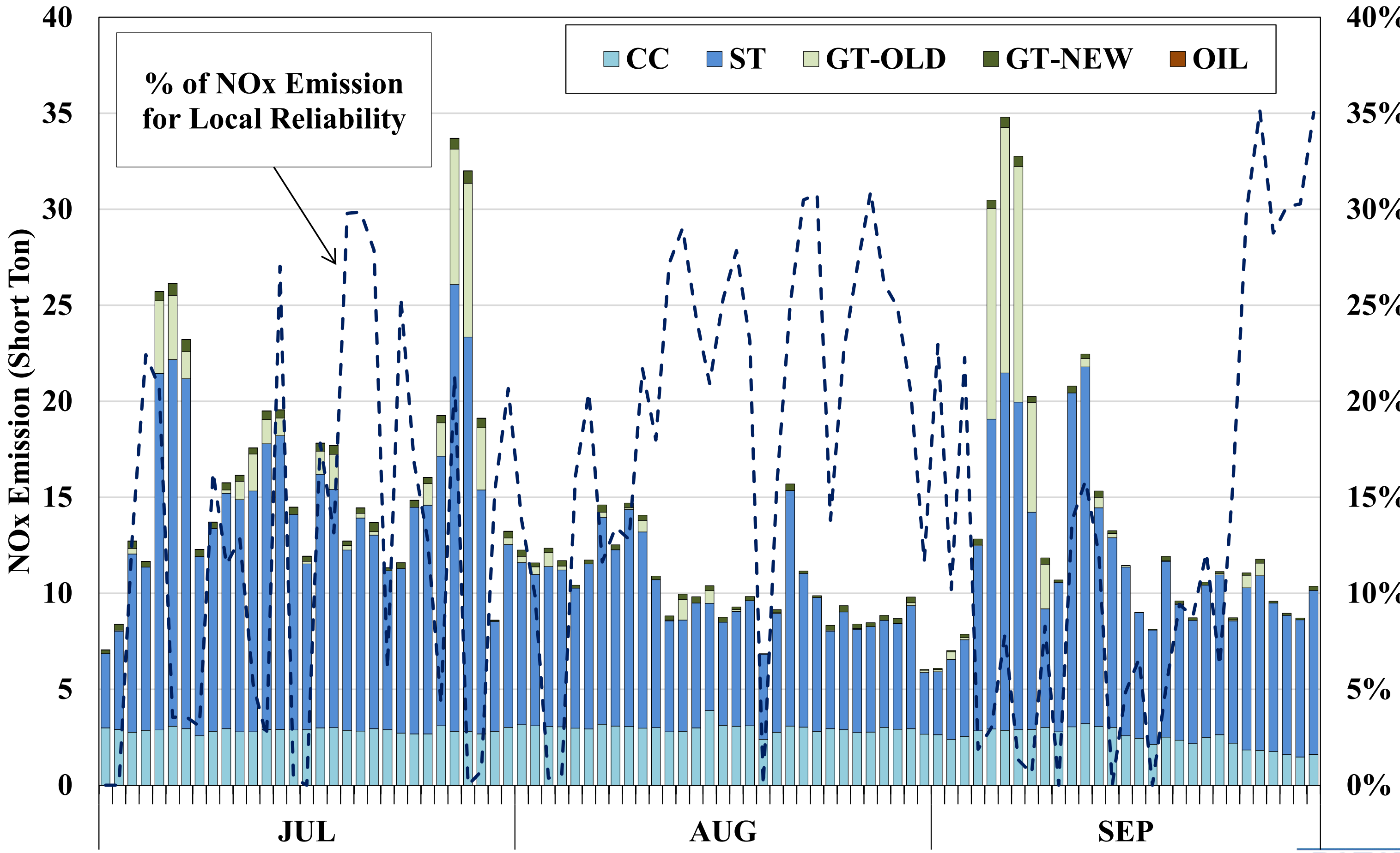
Daily NO_X Emissions in NYC



Notes: For chart description, see slide 92.

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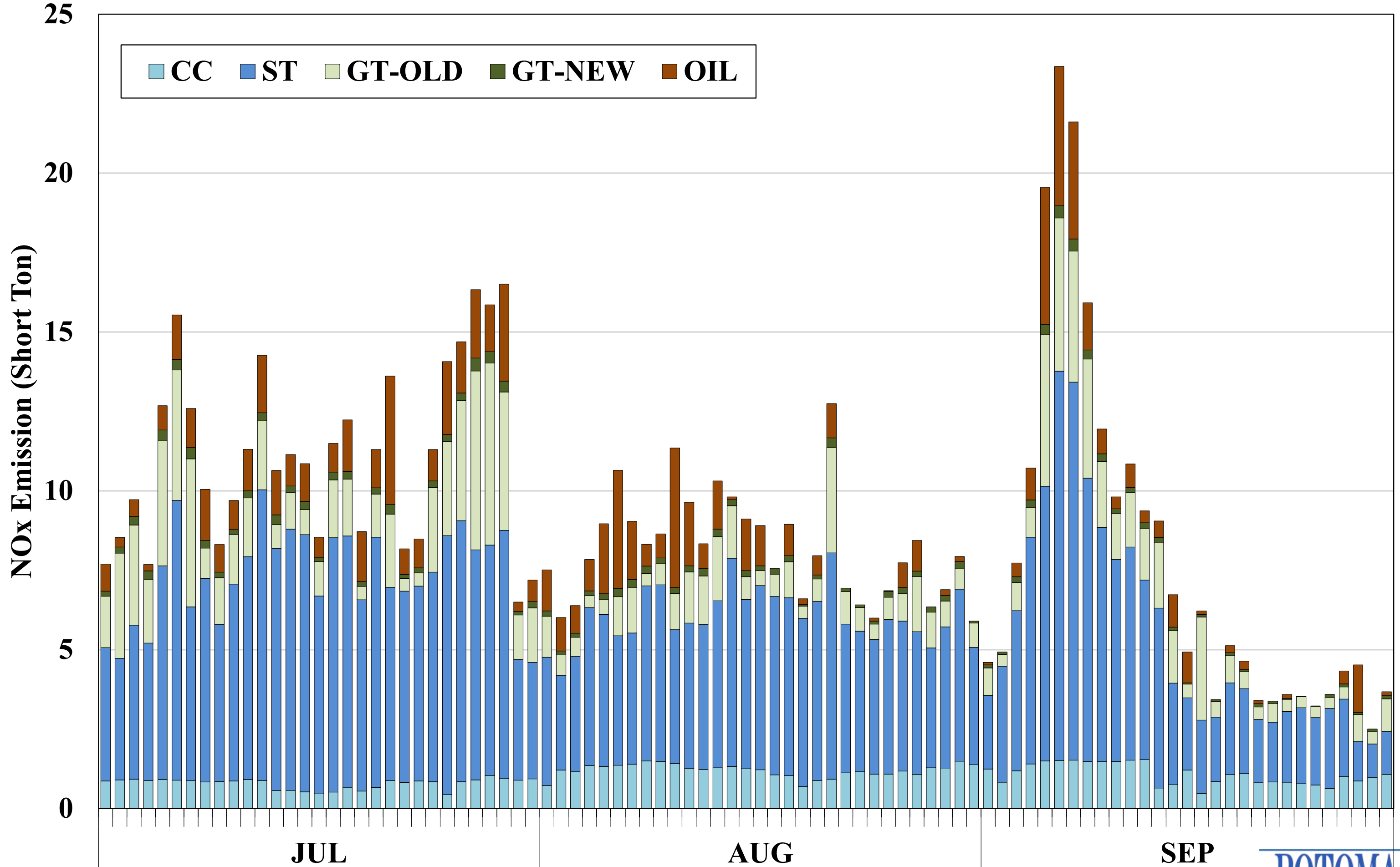
Daily NO_X Emissions in Long Island



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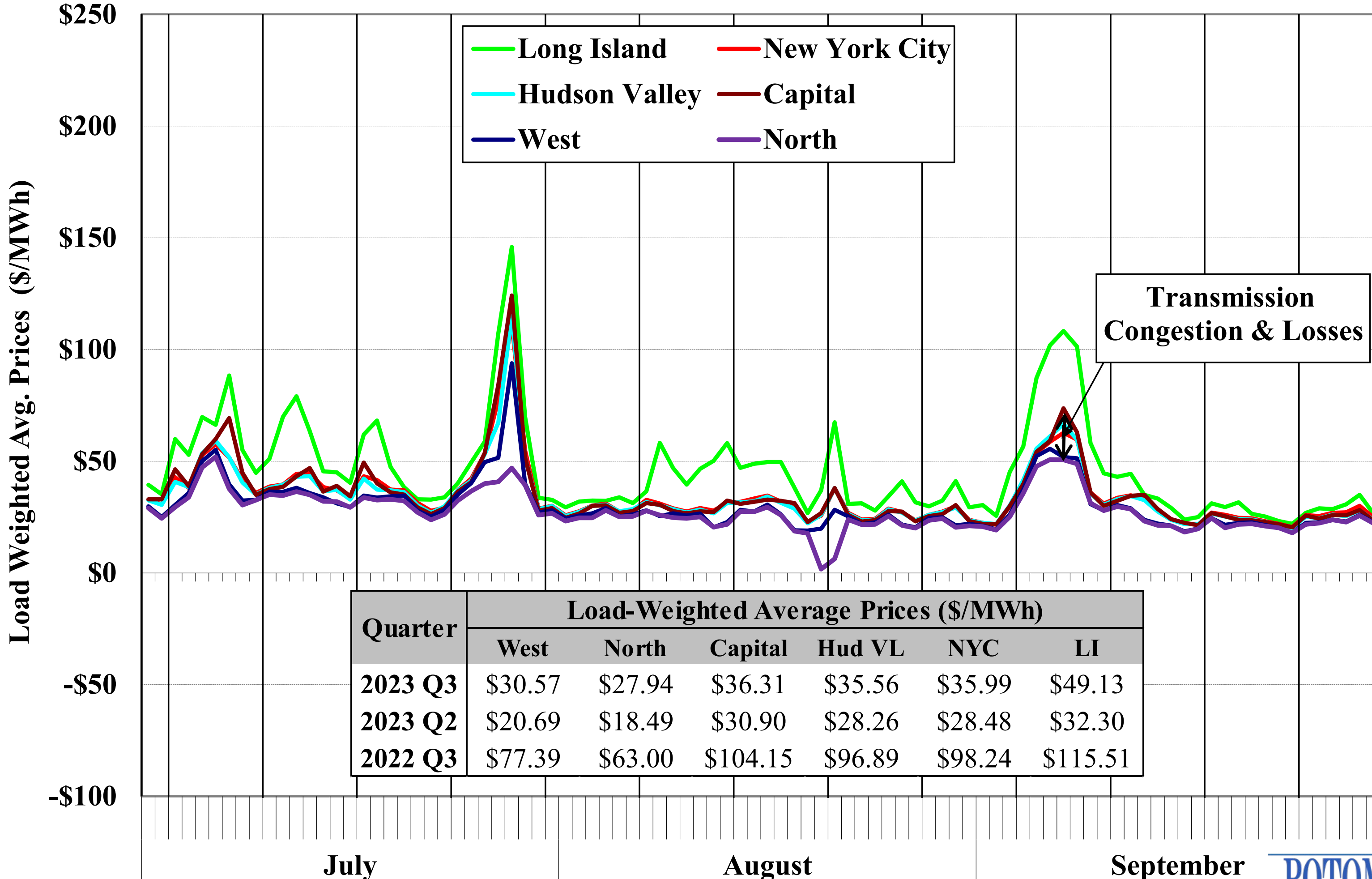
Day-Ahead Electricity Prices by Zone



Quarter	Load-Weighted Average Prices ($/MWh)					
	West	North	Capital	Hud VL	NYC	LI
2023 Q3	$30.57	$27.94	$36.31	$35.56	$35.99	$49.13
2023 Q2	$20.69	$18.49	$30.90	$28.26	$28.48	$32.30
2022 Q3	$77.39	$63.00	$104.15	$96.89	$98.24	$115.51

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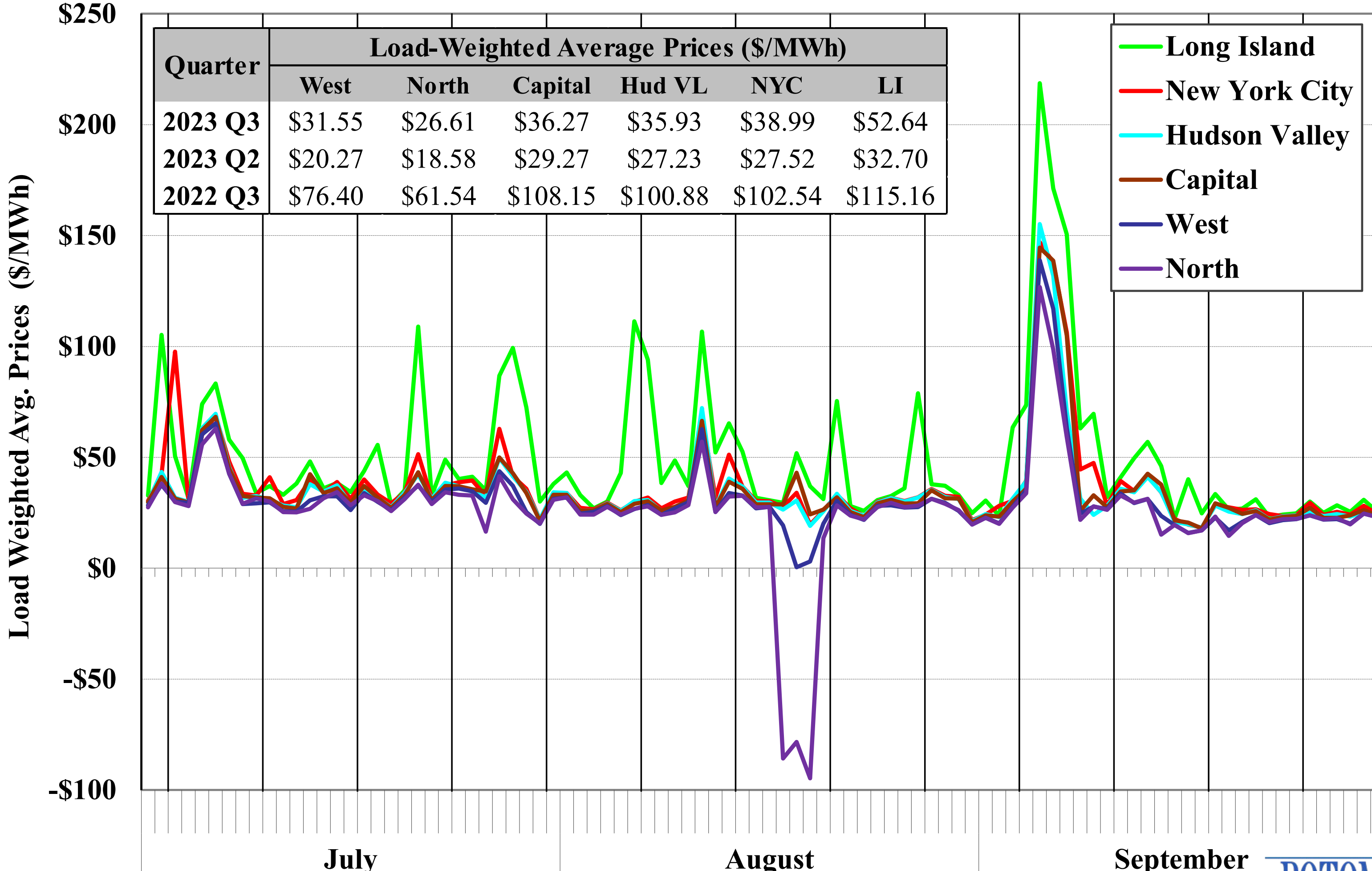
Real-Time Electricity Prices by Zone

Quarter	Load-Weighted Average Prices ($/MWh)					
	West	North	Capital	Hud VL	NYC	LI
2023 Q3	$31.55	$26.61	$36.27	$35.93	$38.99	$52.64
2023 Q2	$20.27	$18.58	$29.27	$27.23	$27.52	$32.70
2022 Q3	$76.40	$61.54	$108.15	$100.88	$102.54	$115.16



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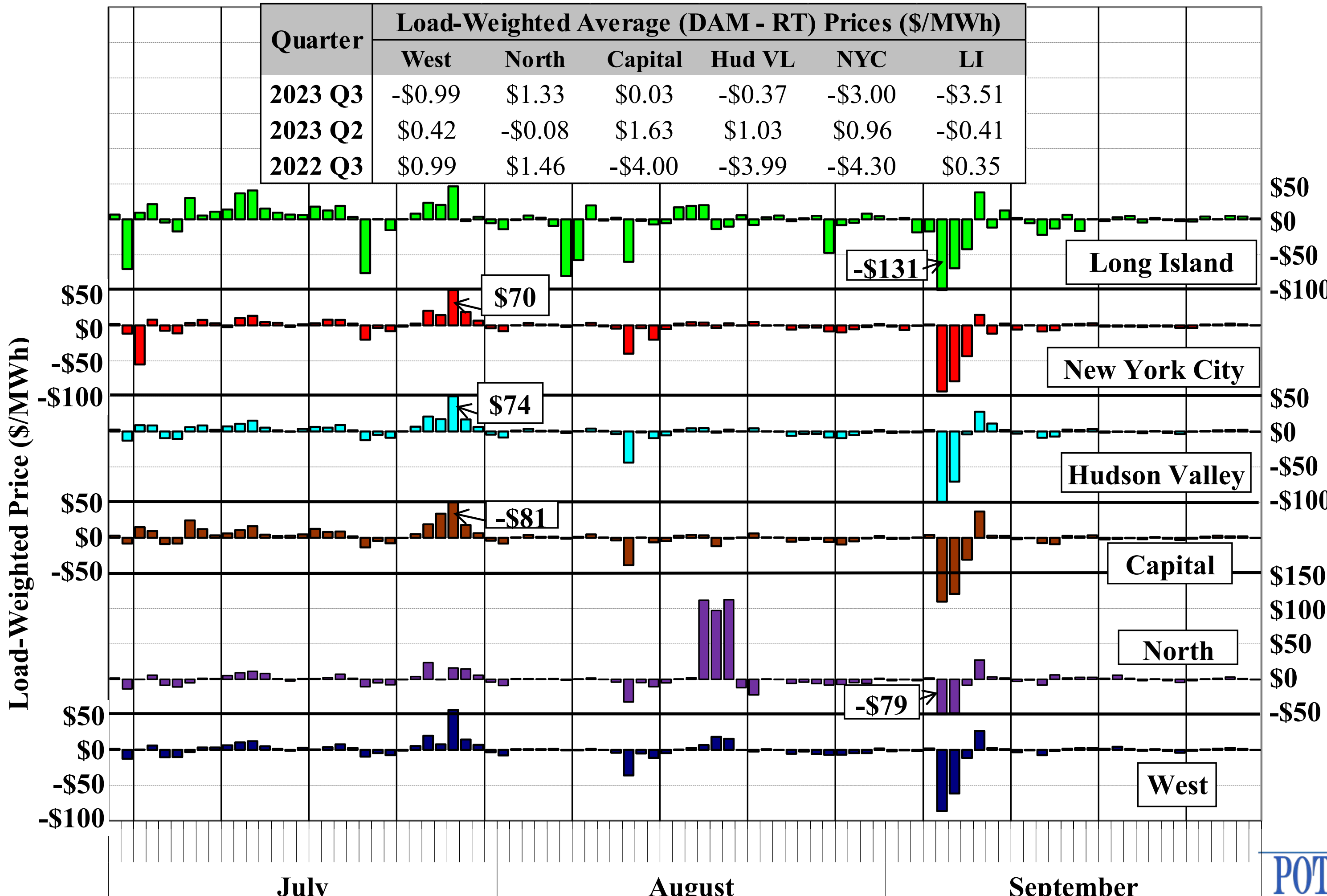
Convergence Between Day-Ahead and Real-Time Prices

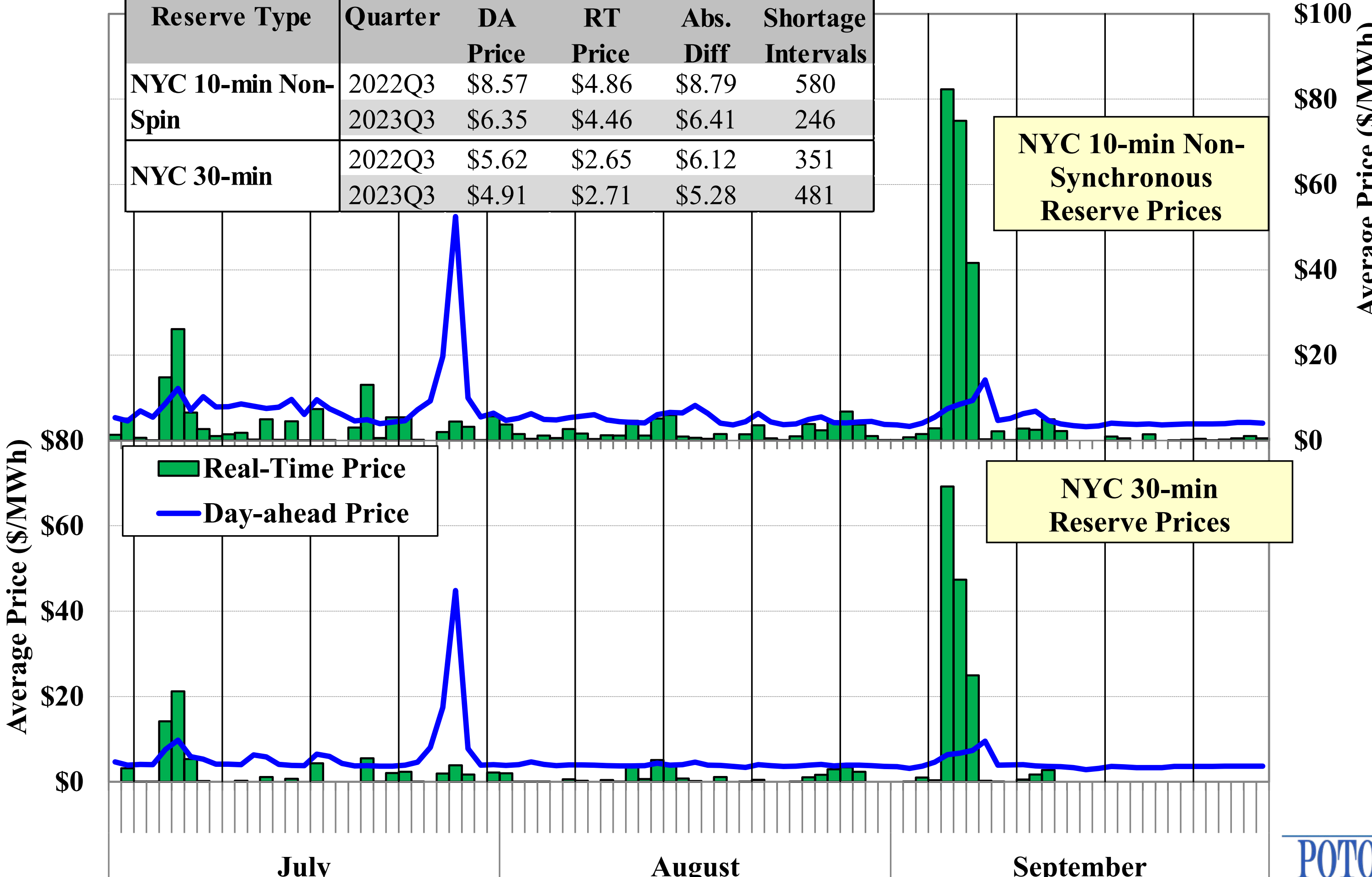
Quarter	Load-Weighted Average (DAM - RT) Prices ($/MWh)					
	West	North	Capital	Hud VL	NYC	LI
2023 Q3	-$0.99	$1.33	$0.03	-$0.37	-$3.00	-$3.51
2023 Q2	$0.42	-$0.08	$1.63	$1.03	$0.96	-$0.41
2022 Q3	$0.99	$1.46	-$4.00	-$3.99	-$4.30	$0.35



Charts:
Ancillary Services Market

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

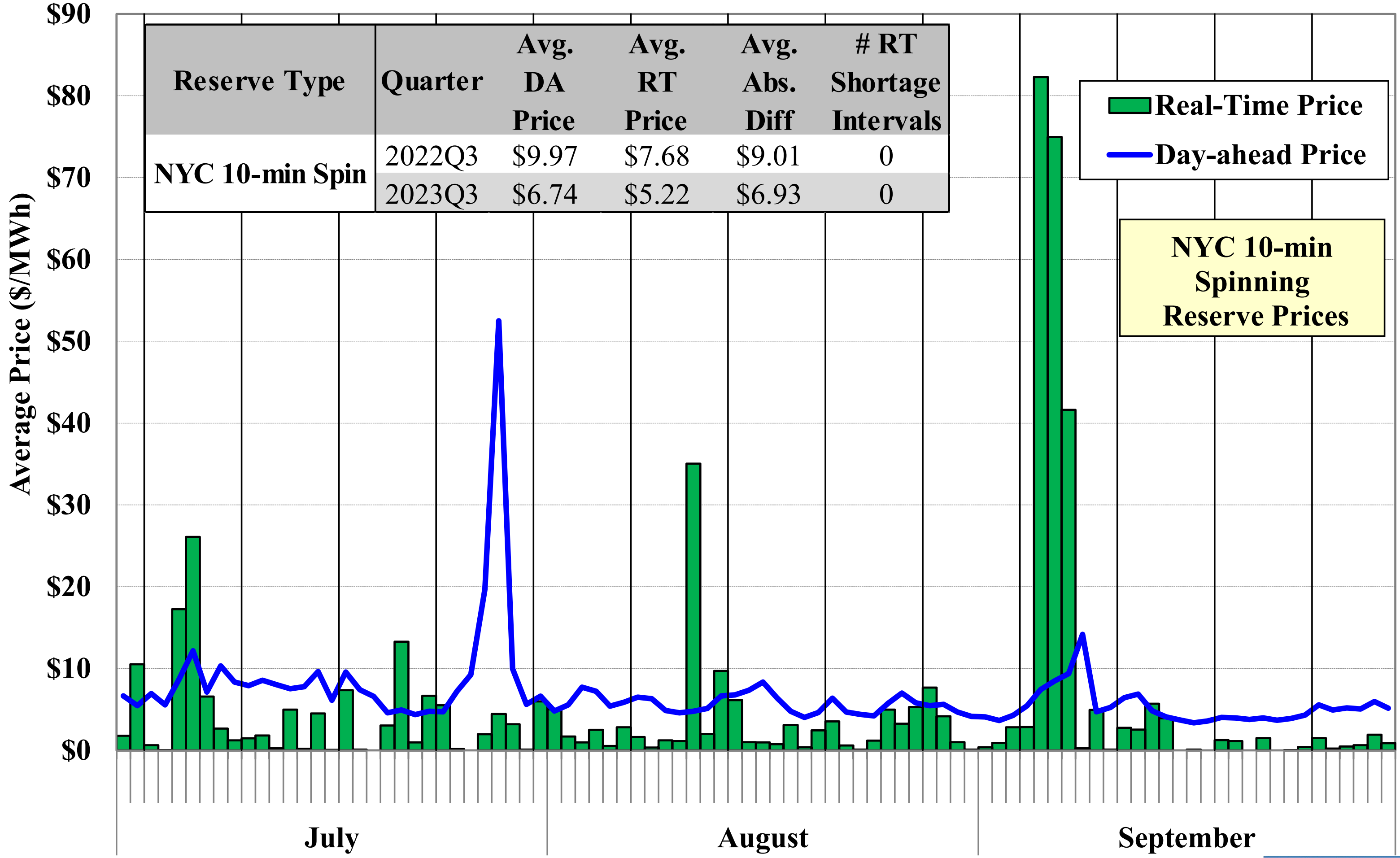
Reserve Type	Quarter	Avg. DA Price	Avg. RT Price	Avg. Abs. Diff	# RT Shortage Intervals
NYC 10-min Non-Spin	2022Q3	$8.57	$4.86	$8.79	580
	2023Q3	$6.35	$4.46	$6.41	246
NYC 30-min	2022Q3	$5.62	$2.65	$6.12	351
	2023Q3	$4.91	$2.71	$5.28	481



Notes: For chart description, see slide 93.

POTOMAC ECONOMICS

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

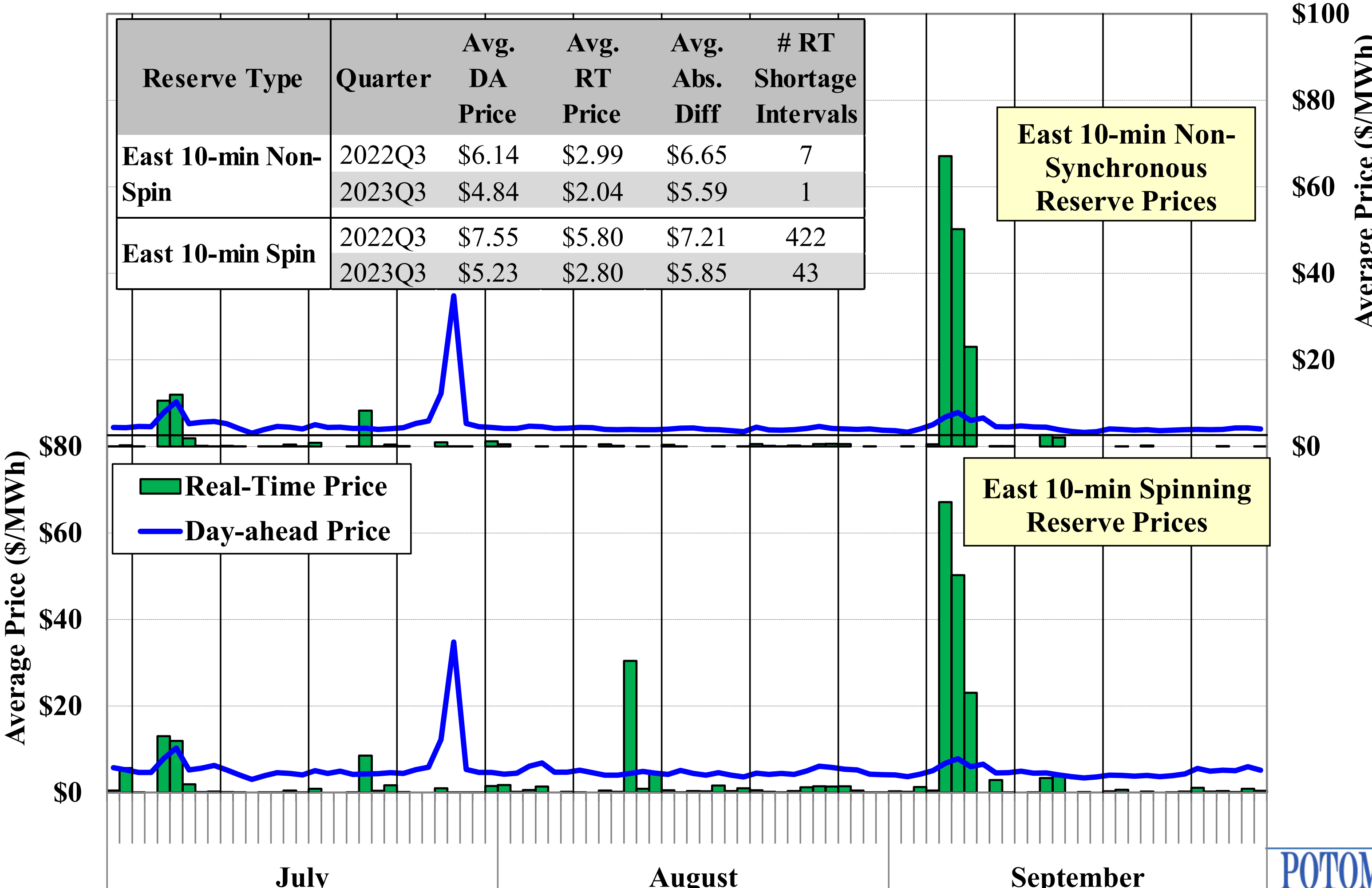


Reserve Type	Quarter	Avg. DA Price	Avg. RT Price	Avg. Abs. Diff	# RT Shortage Intervals
NYC 10-min Spin	2022Q3	$9.97	$7.68	$9.01	0
	2023Q3	$6.74	$5.22	$6.93	0

Notes: For chart description, see slide 93.

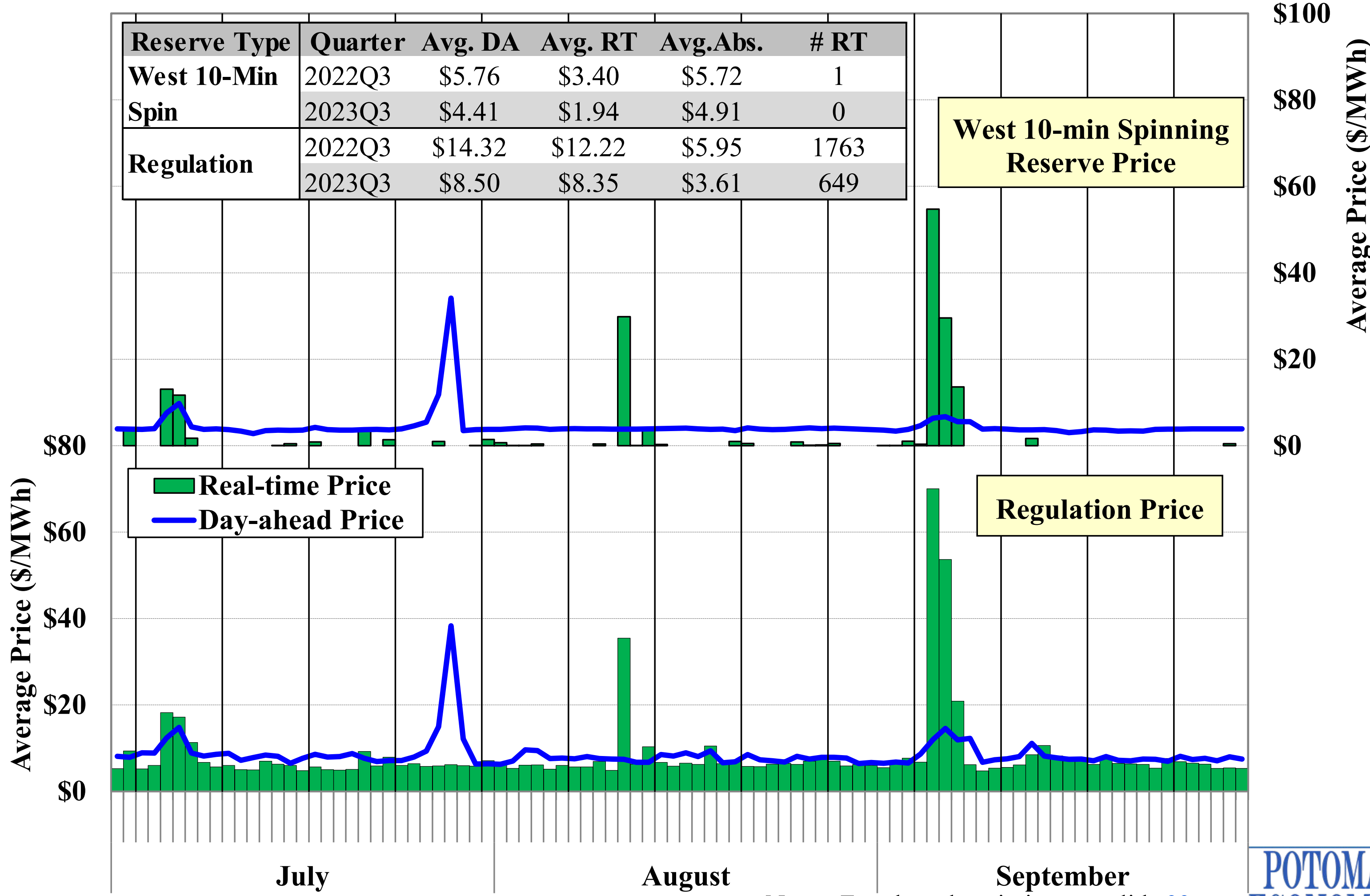
Day-Ahead and Real-Time Ancillary Services Prices
Eastern 10-Minute Spinning and Non-Spinning Reserves

Reserve Type	Quarter	Avg. DA Price	Avg. RT Price	Avg. Abs. Diff	# RT Shortage Intervals
East 10-min Non-Spin	2022Q3	$6.14	$2.99	$6.65	7
	2023Q3	$4.84	$2.04	$5.59	1
East 10-min Spin	2022Q3	$7.55	$5.80	$7.21	422
	2023Q3	$5.23	$2.80	$5.85	43



Notes: For chart description, see slide 93.

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

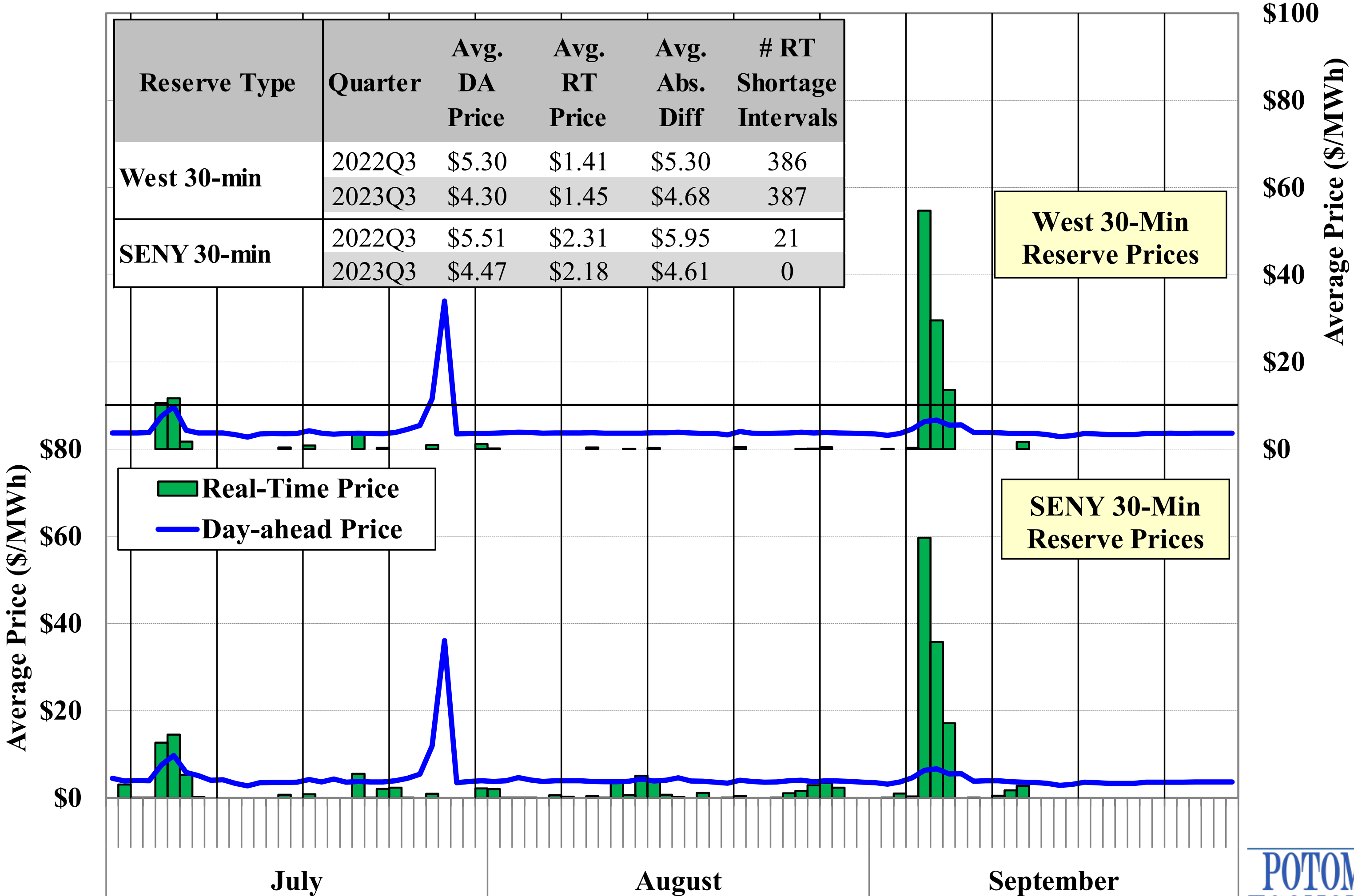


Reserve Type	Quarter	Avg. DA	Avg. RT	Avg.Abs.	# RT
West 10-Min Spin	2022Q3	$5.76	$3.40	$5.72	1
	2023Q3	$4.41	$1.94	$4.91	0
Regulation	2022Q3	$14.32	$12.22	$5.95	1763
	2023Q3	$8.50	$8.35	$3.61	649

Notes: For chart description, see slide 93.

POTOMAC ECONOMICS

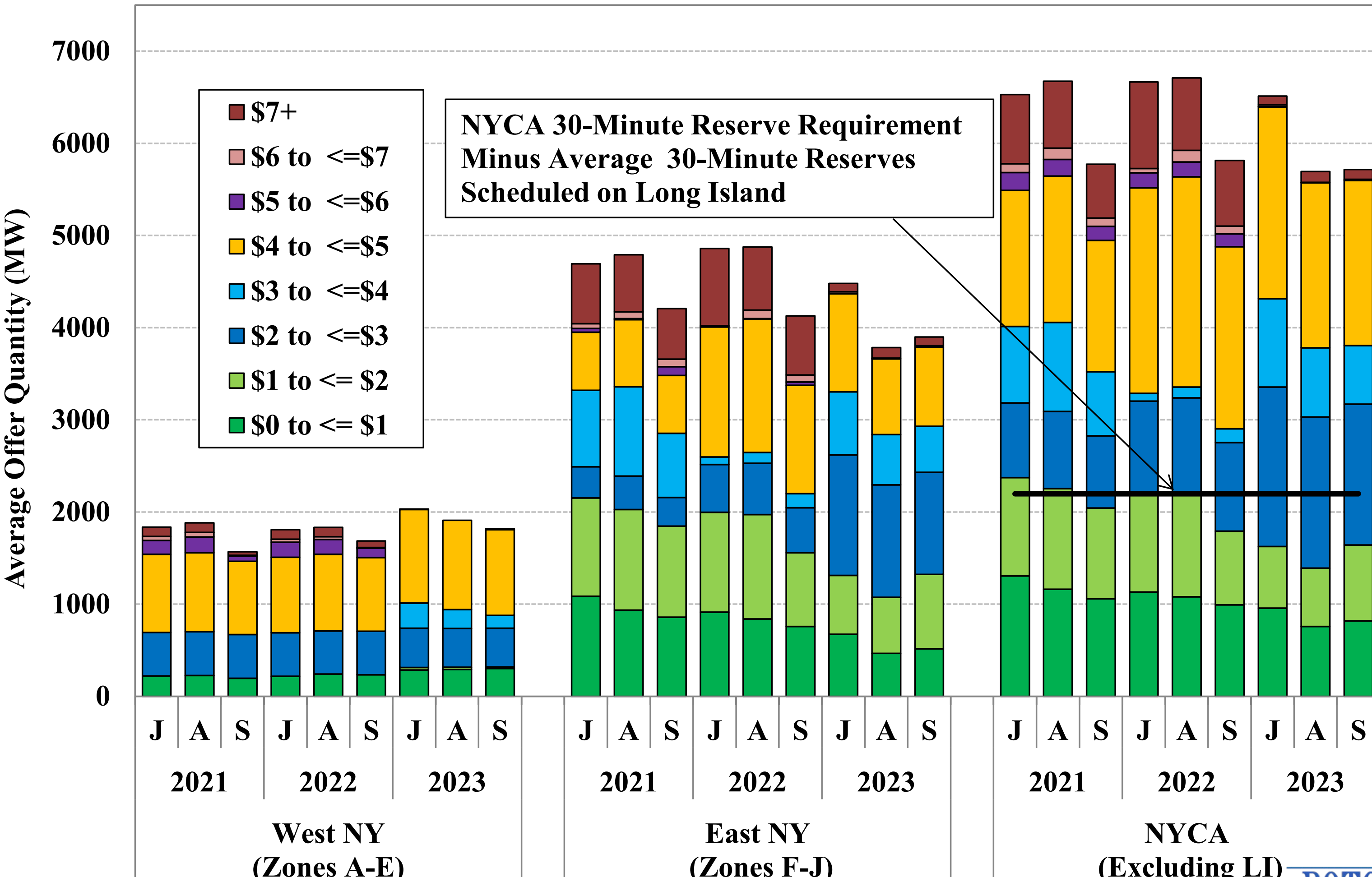
Day-Ahead and Real-Time Ancillary Services Prices
Western and SENY 30-Minute Reserves



Reserve Type	Quarter	Avg. DA Price	Avg. RT Price	Avg. Abs. Diff	# RT Shortage Intervals
West 30-min	2022Q3	$5.30	$1.41	$5.30	386
	2023Q3	$4.30	$1.45	$4.68	387
SENY 30-min	2022Q3	$5.51	$2.31	$5.95	21
	2023Q3	$4.47	$2.18	$4.61	0

Notes: For chart description, see slide 93.

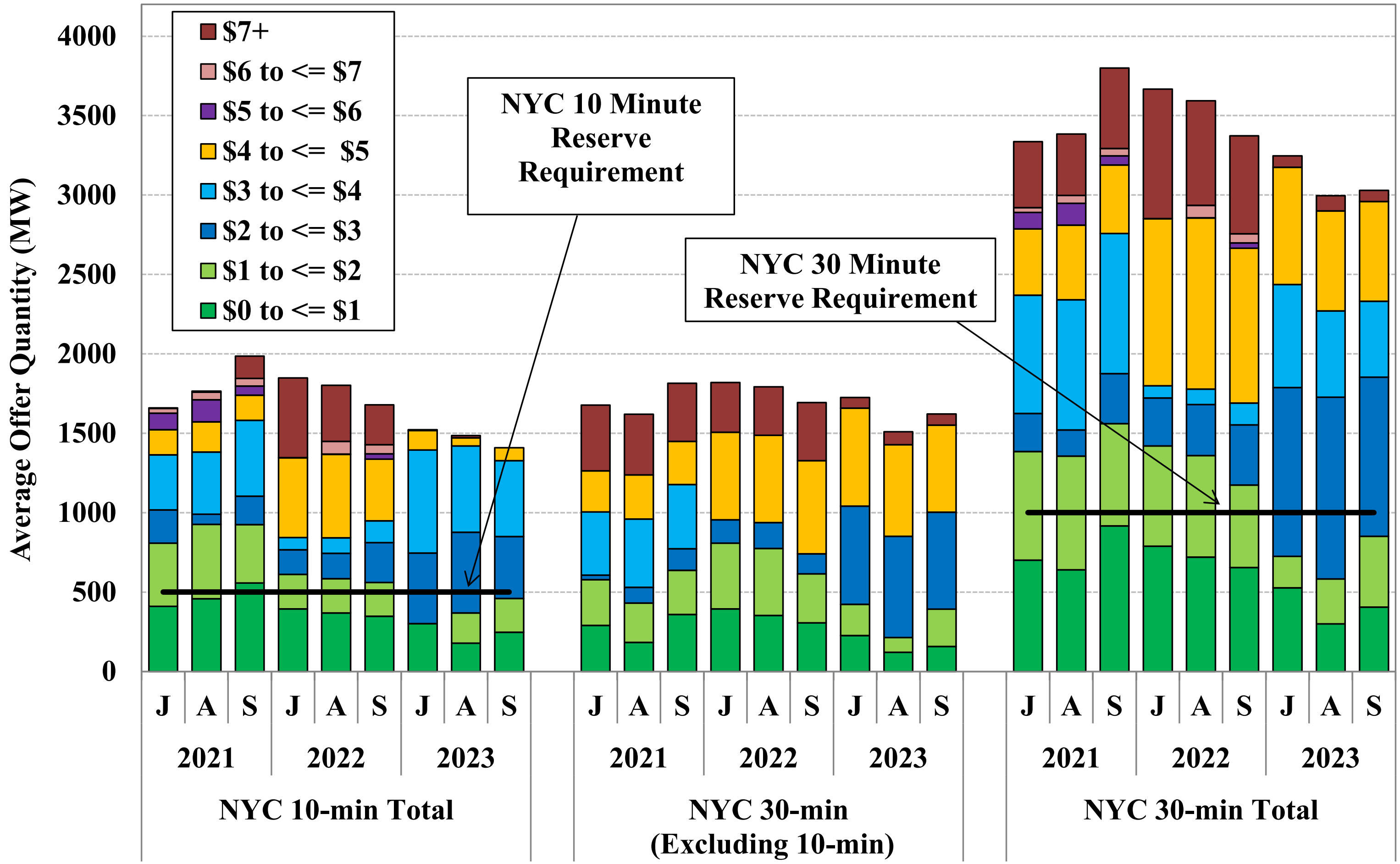
Day-Ahead NYCA 30-Minute Reserve Offers
Committed and Available Offline Quick-Start Resources



  Notes: For chart description, see slide 94.

POTOMAC ECONOMICS

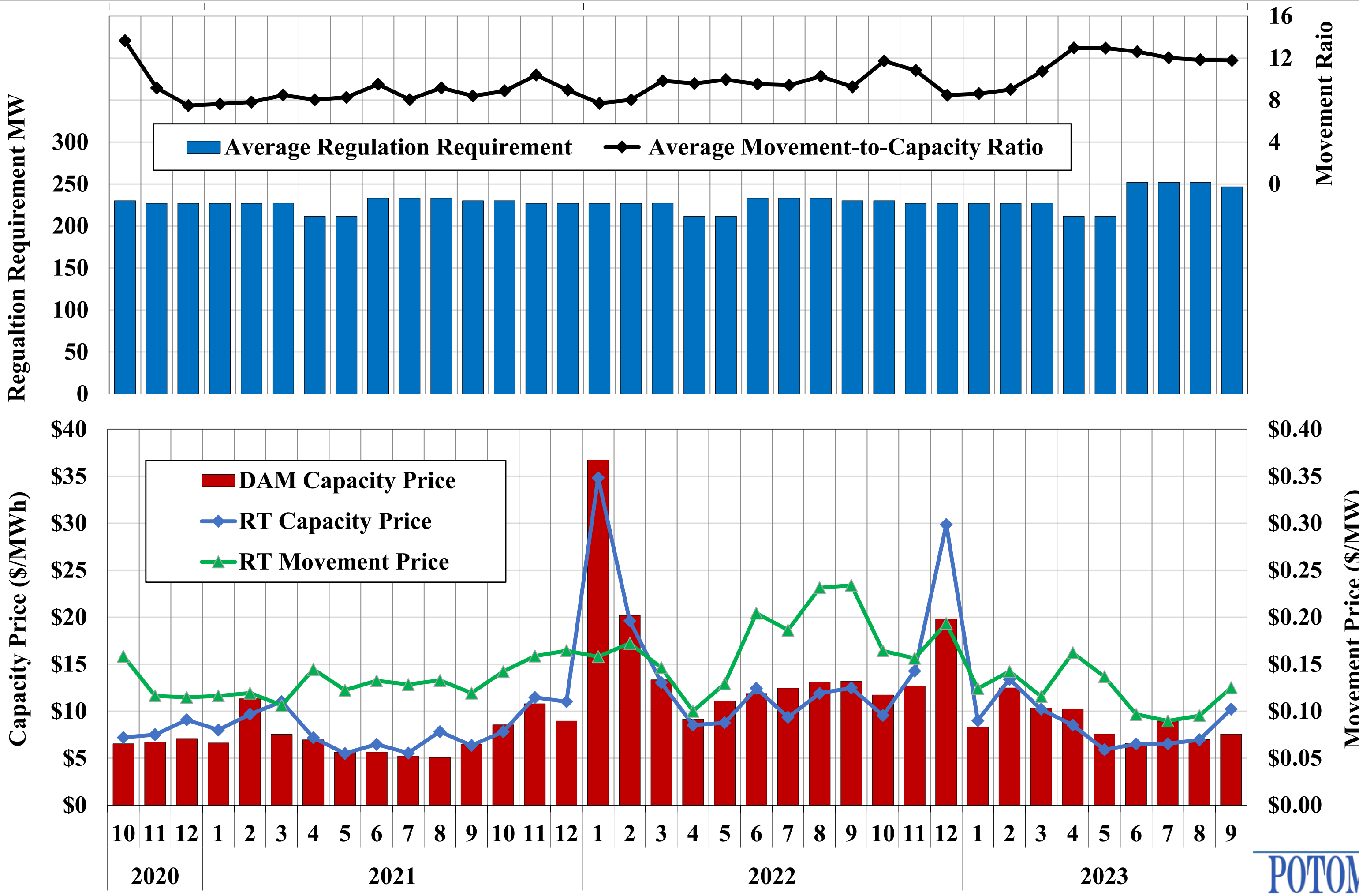
Day-Ahead NYC Reserve Offers
Committed and Available Offline Quick-Start Resources



Notes: For chart description, see slide 94.

POTOMAC ECONOMICS

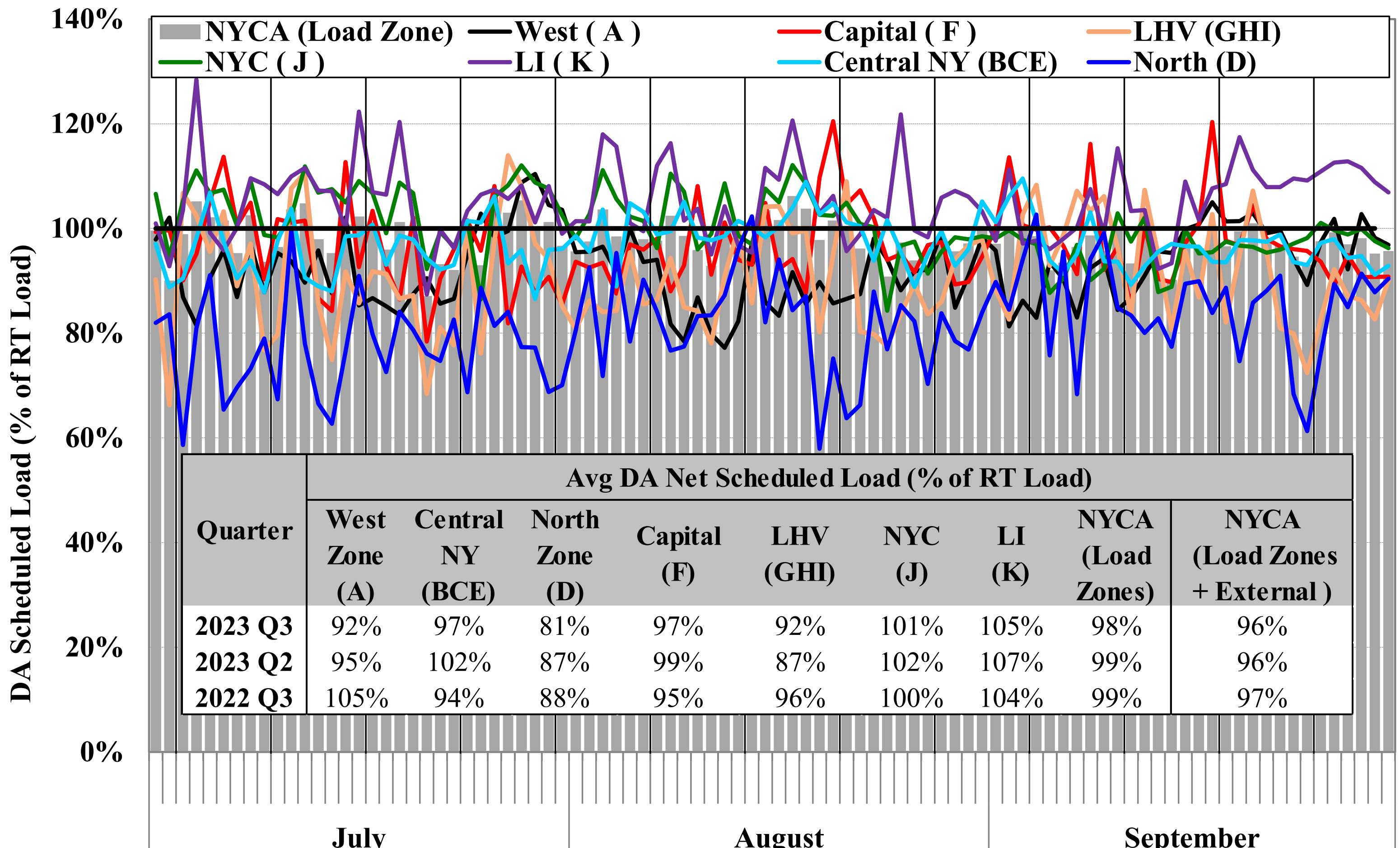
Regulation Requirements, Prices, and Movement-to-Capacity Ratio by Month



Notes: For chart description, see slide 95.

Charts:
Energy Market Scheduling

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

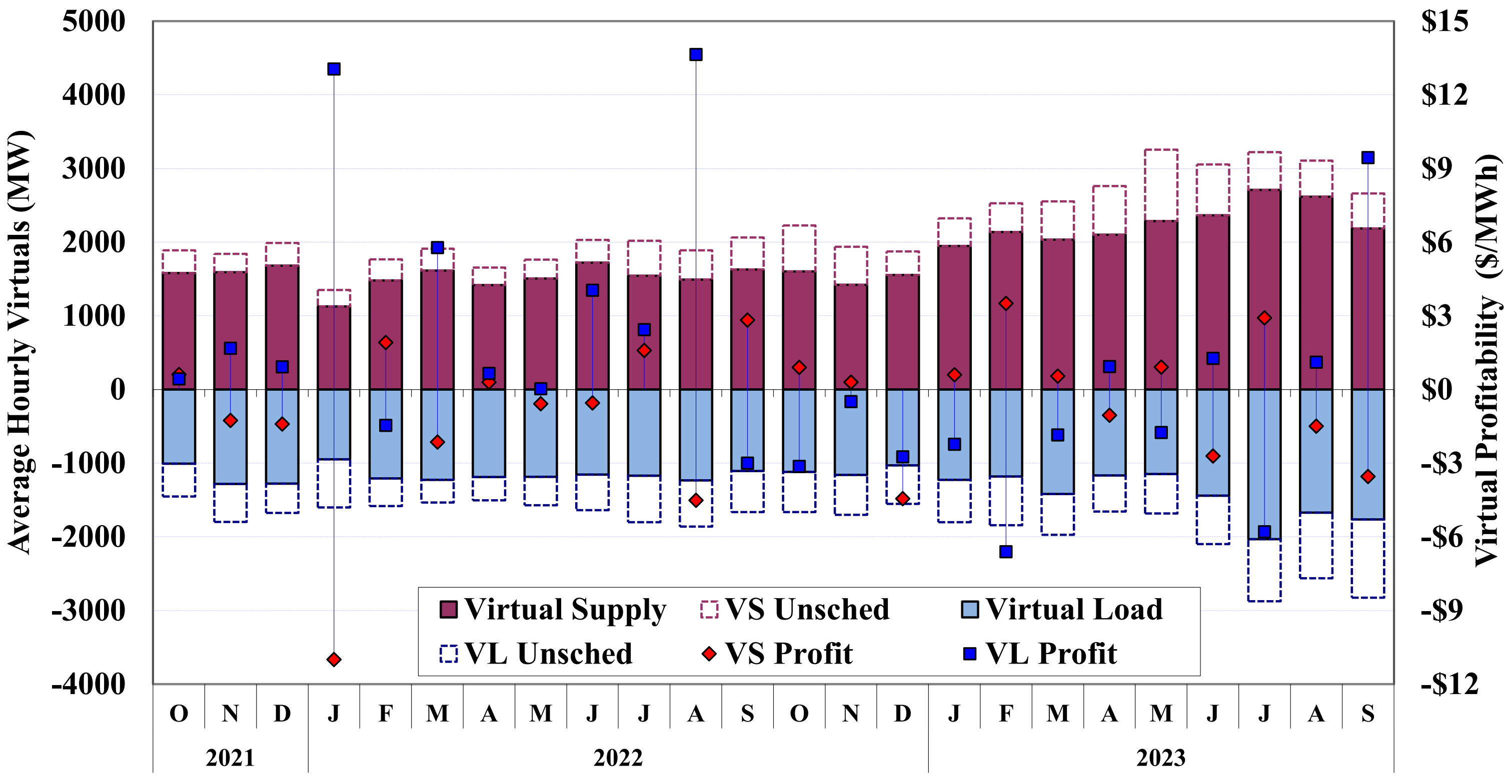


Quarter	Avg DA Net Scheduled Load (% of RT Load)								
	West Zone (A)	Central NY (BCE)	North Zone (D)	Capital (F)	LHV (GHI)	NYC (J)	LI (K)	NYCA (Load Zones)	NYCA (Load Zones + External)
2023 Q3	92%	97%	81%	97%	92%	101%	105%	98%	96%
2023 Q2	95%	102%	87%	99%	87%	102%	107%	99%	96%
2022 Q3	105%	94%	88%	95%	96%	100%	104%	99%	97%

Notes: For chart description, see slide 96.

POTOMAC ECONOMICS

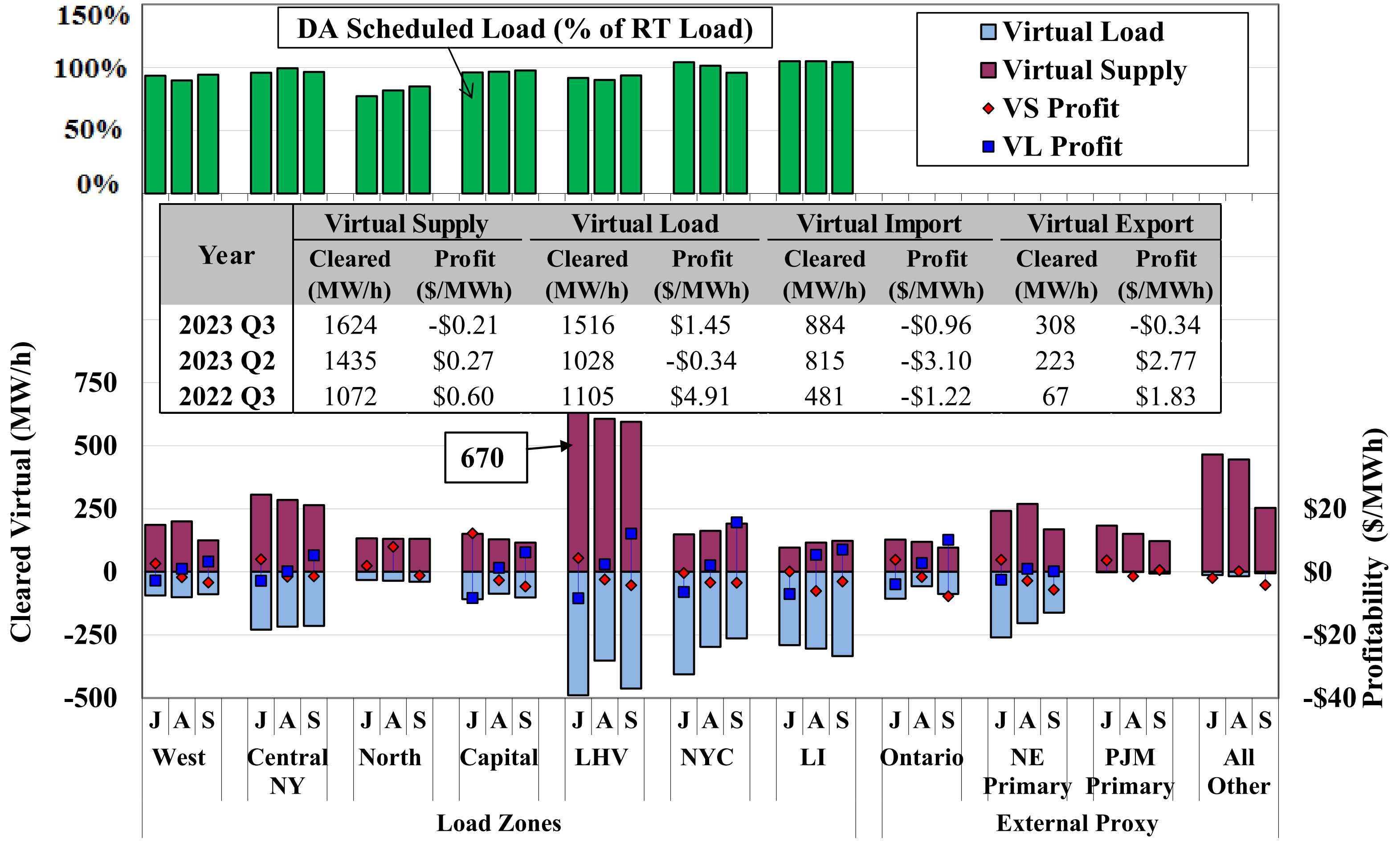
Virtual Trading Activity
by Month



		O	N	D	J	F	M	A	M	J	J	A	S	O	N	D	J	F	M	A	M	J	J	A	S
Profit > 50% of Avg. Zone Price	MW	96	182	195	225	307	217	291	324	183	228	153	96	134	250	302	170	455	343	243	275	130	360	243	244
	%	4%	6%	7%	11%	11%	8%	11%	12%	6%	8%	6%	4%	5%	10%	12%	5%	14%	10%	7%	8%	3%	8%	6%	6%
Loss > 50% of Avg. Zone Price	MW	88	197	215	208	278	226	306	304	180	183	124	109	163	289	287	206	412	377	285	296	164	415	322	156
	%	3%	7%	7%	10%	10%	8%	12%	11%	6%	7%	5%	4%	6%	11%	11%	7%	12%	11%	9%	9%	4%	9%	8%	4%

Notes: For chart description, see slide 96.

Virtual Trading Activity
by Location

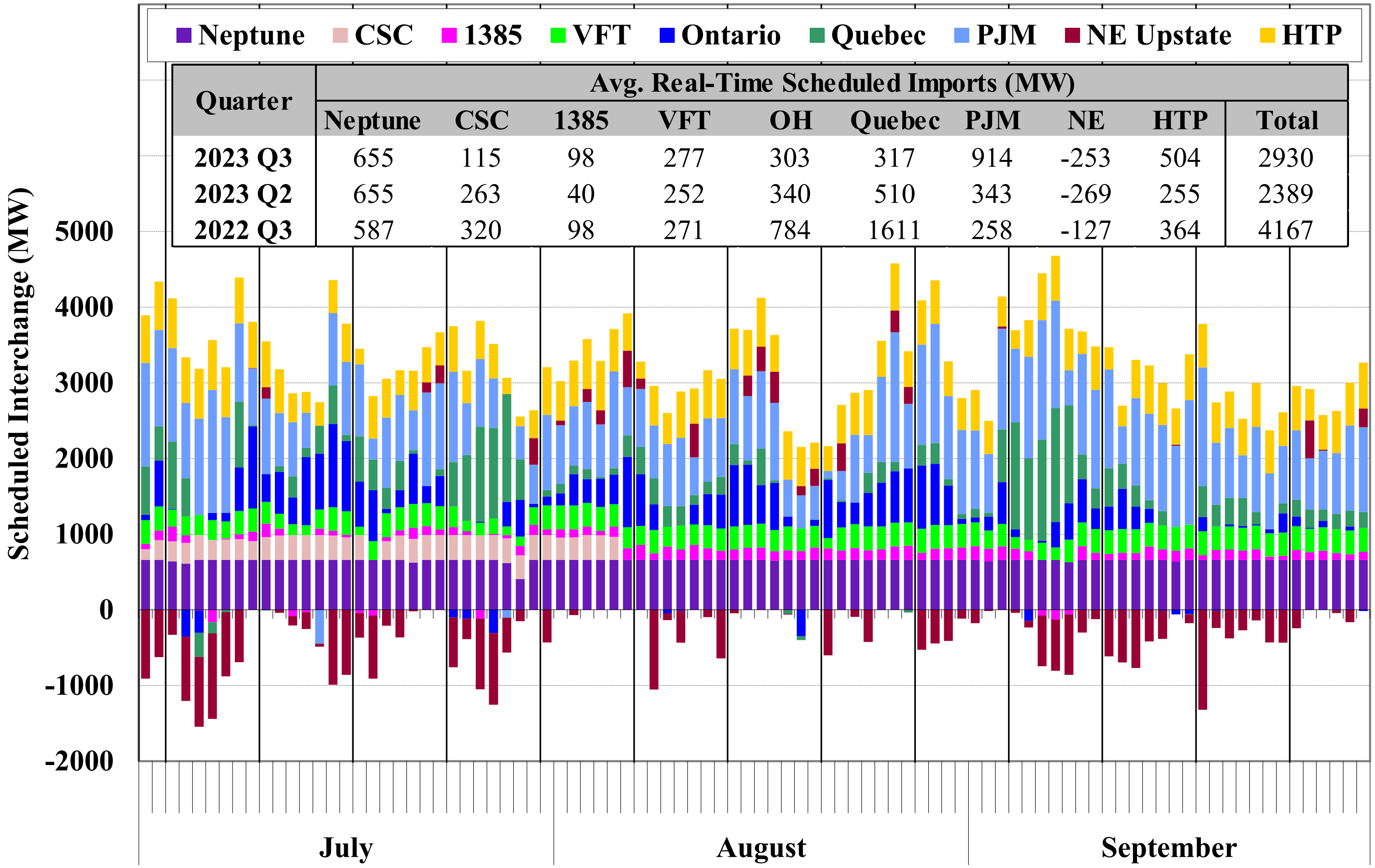


Year	Virtual Supply Cleared (MW/h)	Virtual Supply Profit ($/MWh)	Virtual Load Cleared (MW/h)	Virtual Load Profit ($/MWh)	Virtual Import Cleared (MW/h)	Virtual Import Profit ($/MWh)	Virtual Export Cleared (MW/h)	Virtual Export Profit ($/MWh)
2023 Q3	1624	-$0.21	1516	$1.45	884	-$0.96	308	-$0.34
2023 Q2	1435	$0.27	1028	-$0.34	815	-$3.10	223	$2.77
2022 Q3	1072	$0.60	1105	$4.91	481	-$1.22	67	$1.83

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 96.

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
2023 Q3	655	115	98	277	303	317	914	-253	504	2930
2023 Q2	655	263	40	252	340	510	343	-269	255	2389
2022 Q3	587	320	98	271	784	1611	258	-127	364	4167

Notes: Two Quebec interfaces are combined into one.

POTOMAC ECONOMICS

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

			Average/Total During Intervals w/ Adjustment							
			CTS - NY/NE				CTS - NY/PJM			
			Both Forecast Errors <= $20	Any Forecast Error > $20	Total		Both Forecast Errors <= $20	Any Forecast Error > $20	Total	
% of All Intervals w/ Adjustment			86%	8%	**93%**		46%	12%	**58%**	
Average Flow Adjustment (MW)	Net Imports		-2	9	**-1**		-18	-73	**-30**	
	Gross		129	145	**131**		81	123	**89**	
Production Cost Savings ($ Million)	Projected at Scheduling Time		$1.9	$1.1	**$3.0**		$0.5	$2.0	**$2.5**	
	Net Over-Projection by:	NY	$0.0	-$0.2	**-$0.2**		$0.0	-$0.3	**-$0.4**	
		NE or PJM	$0.0	-$0.1	**-$0.1**		-$0.2	-$1.6	**-$1.8**	
	Other Unrealized Savings		-$0.1	-$0.3	**-$0.4**		$0.0	$0.0	**$0.0**	
	Actual Savings		$1.8	$0.5	**$2.3**		$0.2	$0.1	**$0.3**	
Interface Prices ($/MWh)	NY	Actual	$29.04	$70.33	**$32.54**	**$32.42**	$26.77	$46.12	**$30.79**	**$30.04**
		Forecast	$29.73	$72.75	**$33.37**	**$33.13**	$27.15	$52.08	**$32.32**	**$31.08**
	NE or PJM	Actual	$28.42	$81.02	**$32.88**	**$32.77**	$23.98	$56.41	**$30.71**	**$28.58**
		Forecast	$27.48	$67.40	**$30.86**	**$30.89**	$26.31	$83.36	**$38.16**	**$34.28**
Price Forecast Errors ($/MWh)	NY	Fcst. - Act.	$0.69	$2.42	**$0.84**	**$0.72**	$0.38	$5.95	**$1.53**	**$1.04**
		Abs. Val.	$2.18	$41.37	**$5.50**	**$5.48**	$2.06	$25.63	**$6.95**	**$5.73**
	NE or PJM	Fcst. - Act.	-$0.93	-$13.62	**-$2.01**	**-$1.88**	$2.33	$26.95	**$7.44**	**$5.70**
		Abs. Val.	$3.98	$42.64	**$7.26**	**$7.94**	$5.23	$54.38	**$15.44**	**$12.92**

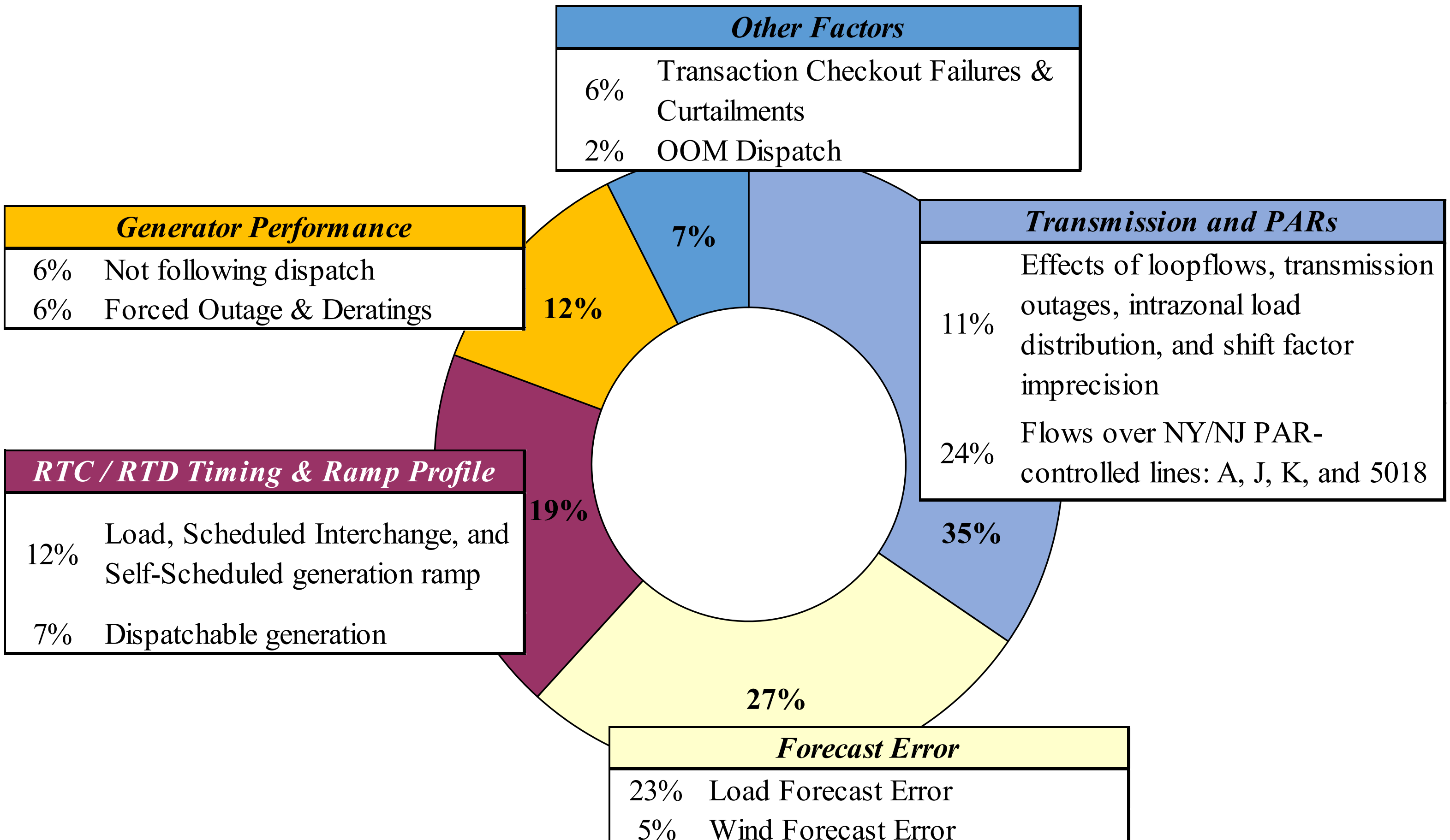
For Adjustment Intervals Only

For All Intervals

Notes: For chart description, see slide 97.

POTOMAC ECONOMICS

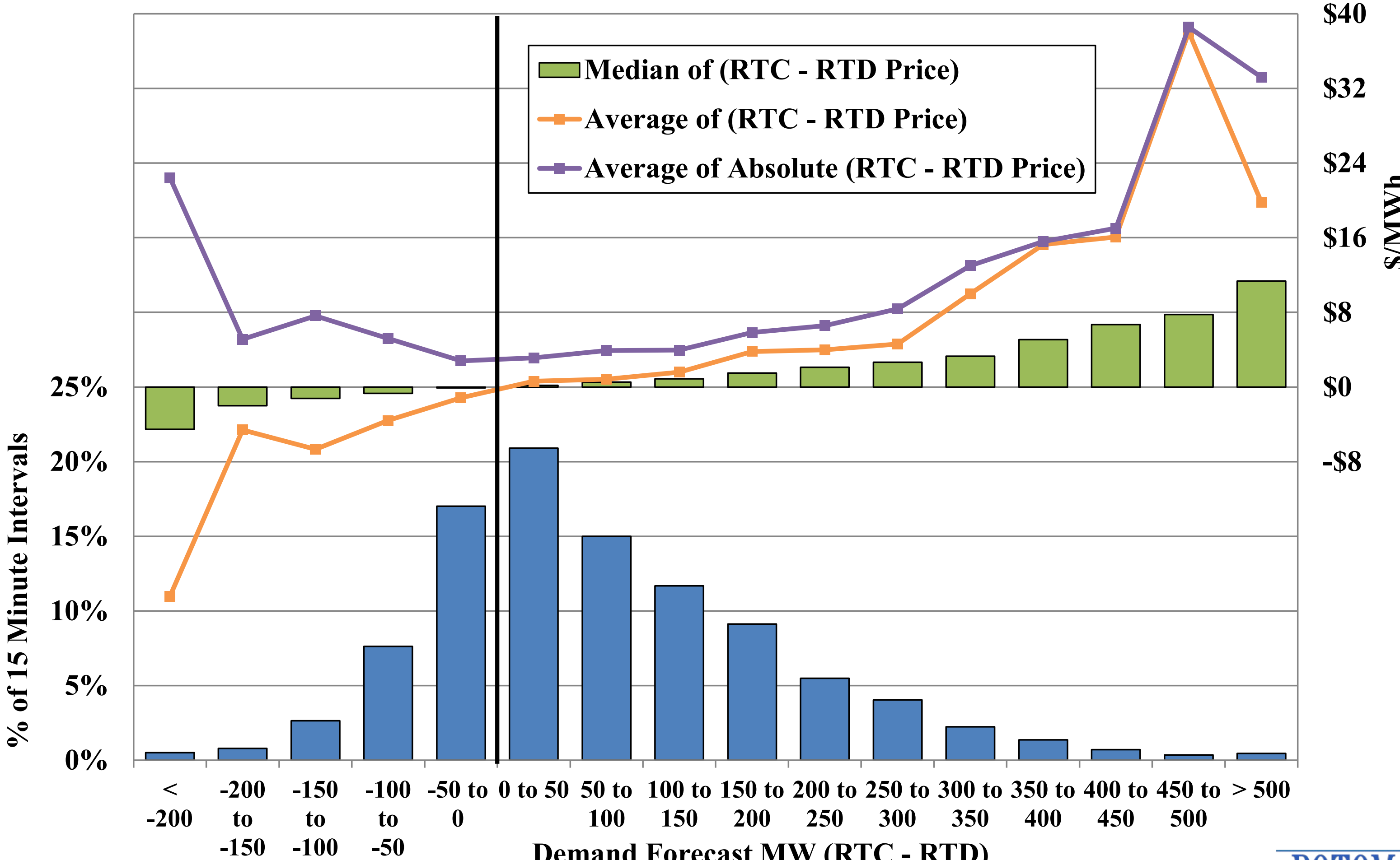
Detrimental Factors to RTC and RTD Price Divergence



Notes: For chart description, see slide 98.

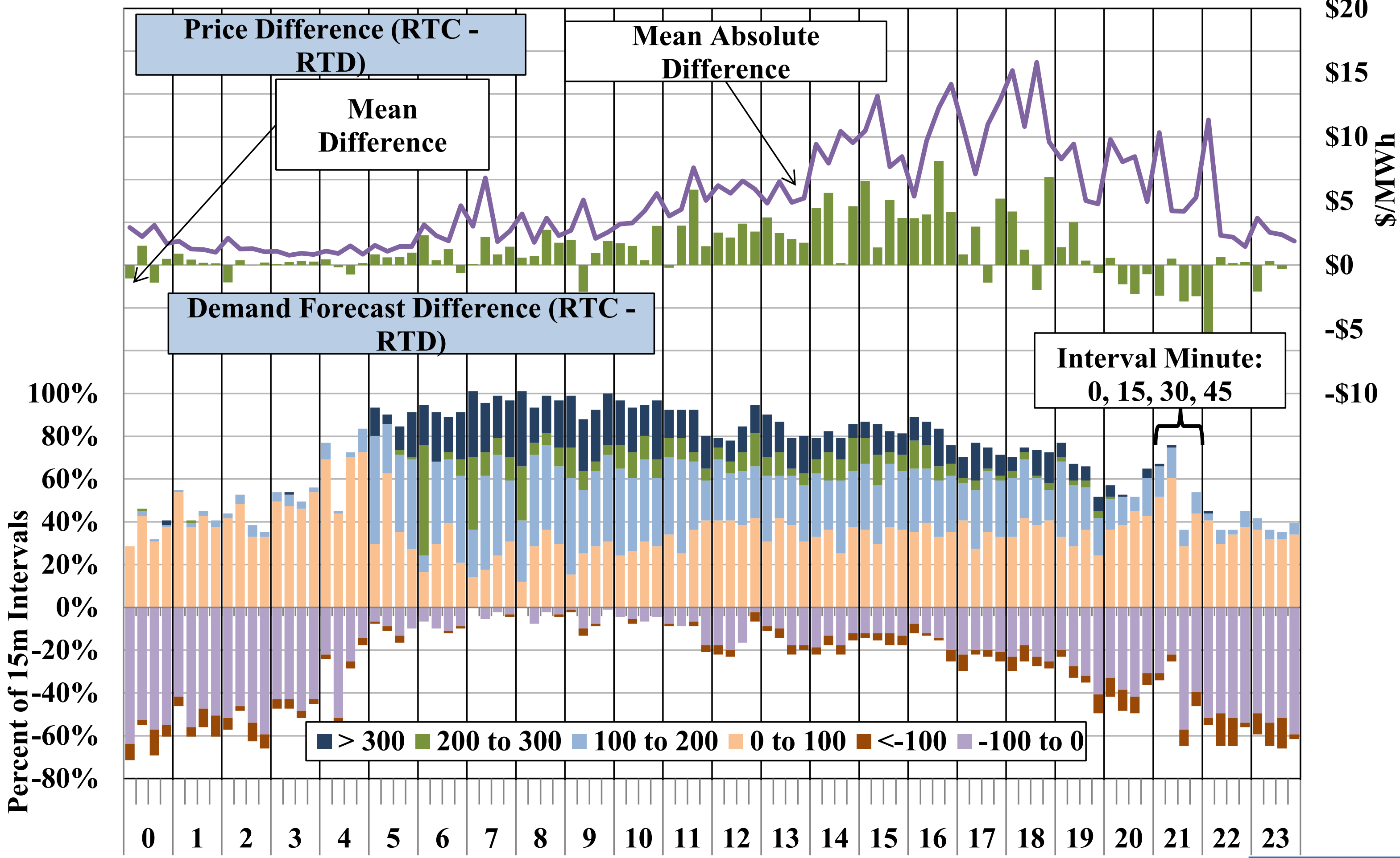
POTOMAC ECONOMICS

RTC and RTD Price Difference vs Demand Forecast Difference



Notes: For chart description, see slide 98.

RTC and RTD Price Difference vs Demand Forecast Difference
by Time of Day

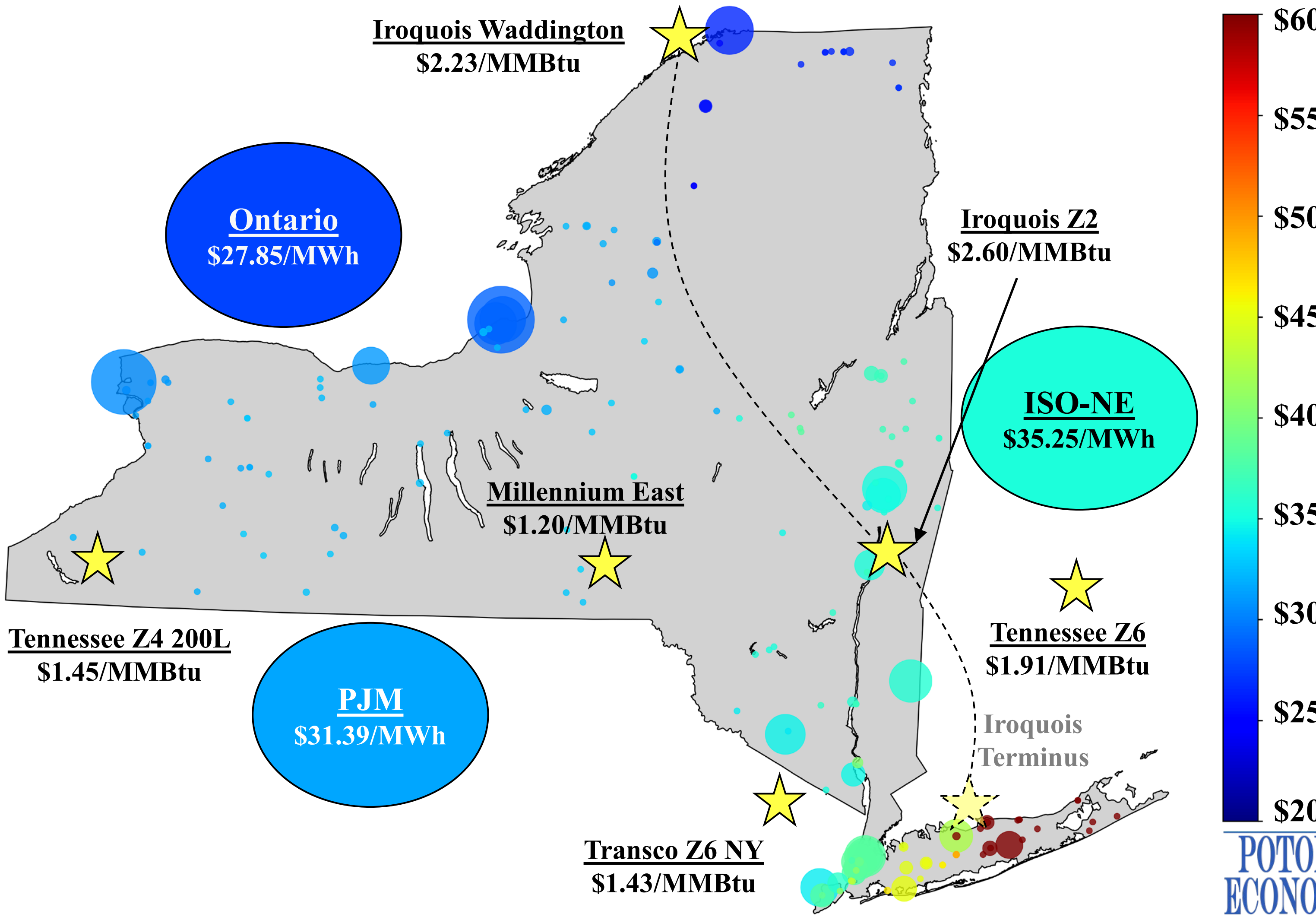


Notes: For chart description, see slide 99.

<u>Charts:</u>
Transmission Congestion Revenues and Shortfalls

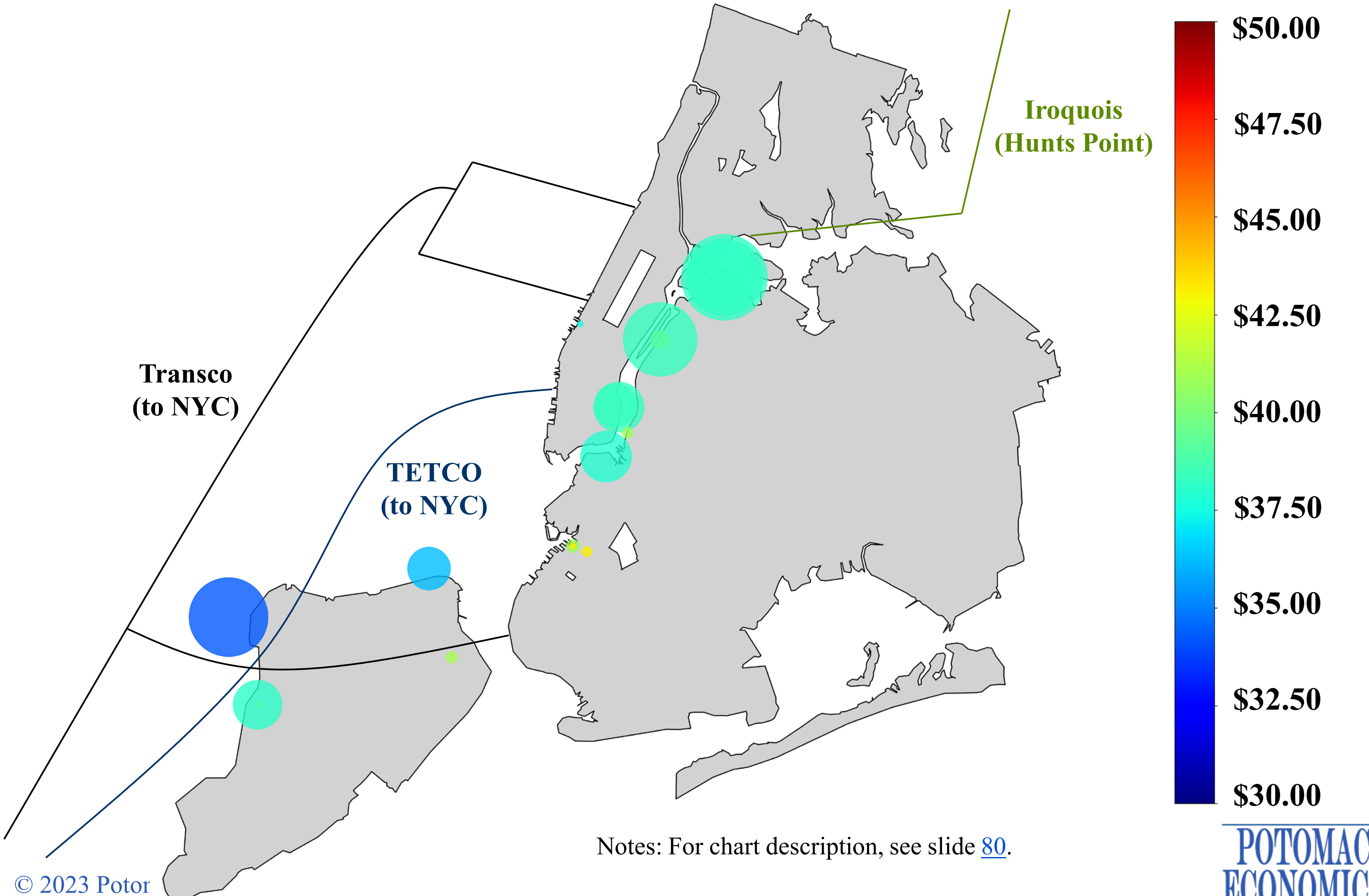
POTOMAC ECONOMICS

System Congestion
Real-Time Price Map at Generator Nodes



POTOMAC ECONOMICS

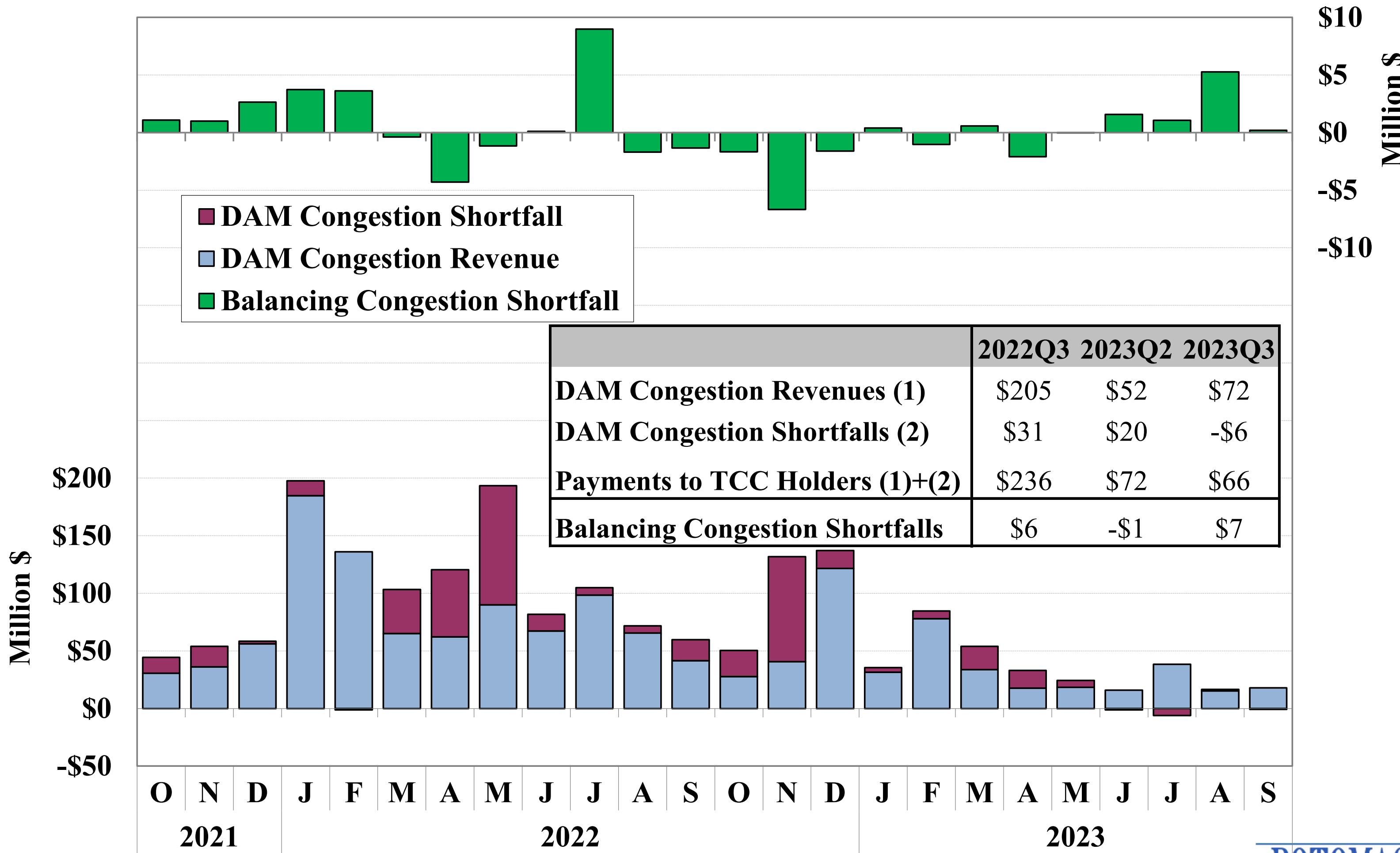
System Congestion
NYC Real-Time Price Map at Generator Nodes



Notes: For chart description, see slide 80.

POTOMAC ECONOMICS

Congestion Revenues and Shortfalls by Month

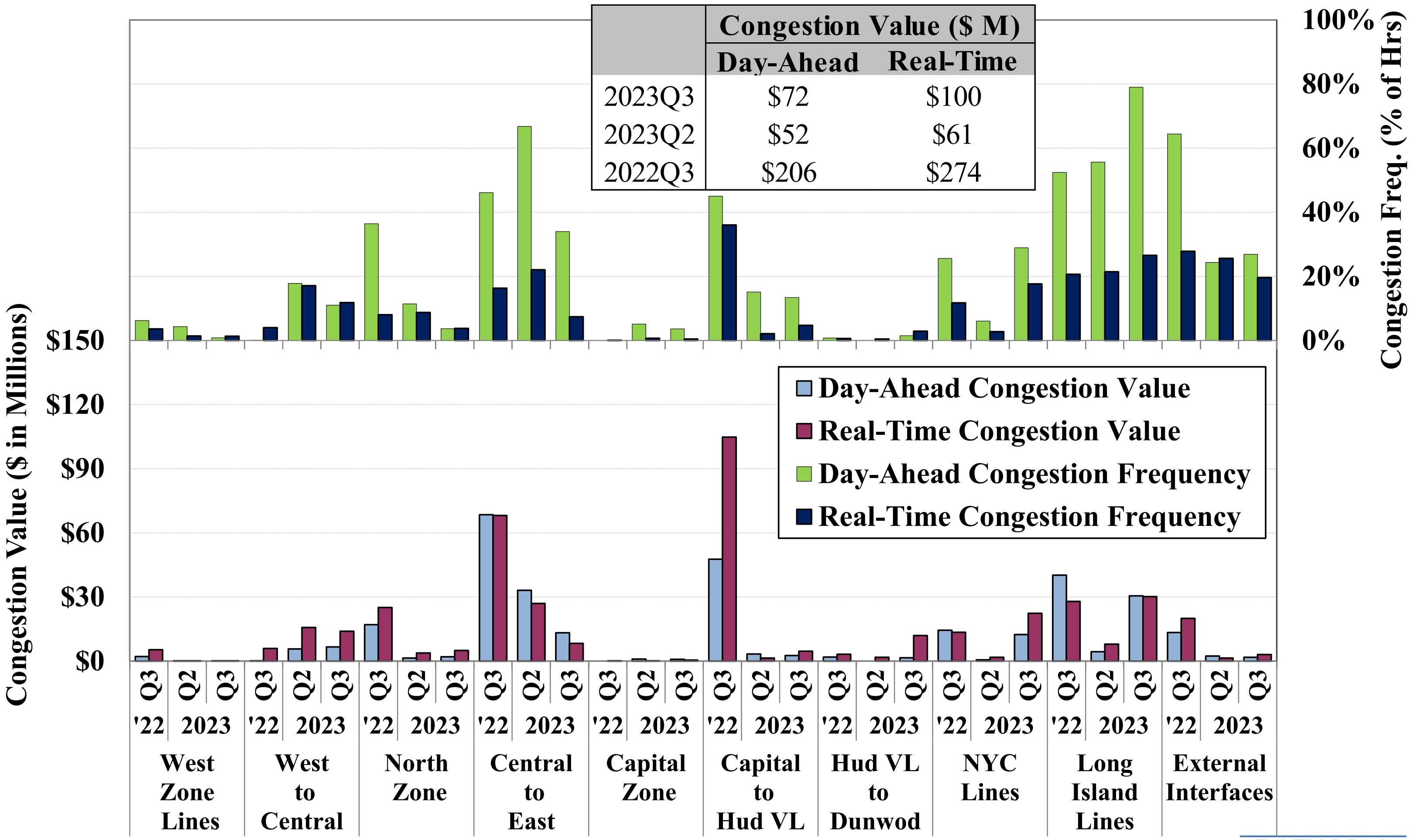


	2022Q3	2023Q2	2023Q3
DAM Congestion Revenues (1)	$205	$52	$72
DAM Congestion Shortfalls (2)	$31	$20	-$6
Payments to TCC Holders (1)+(2)	$236	$72	$66
Balancing Congestion Shortfalls	$6	-$1	$7

Notes: For chart description, see slides 101 and 102.

POTOMAC ECONOMICS

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

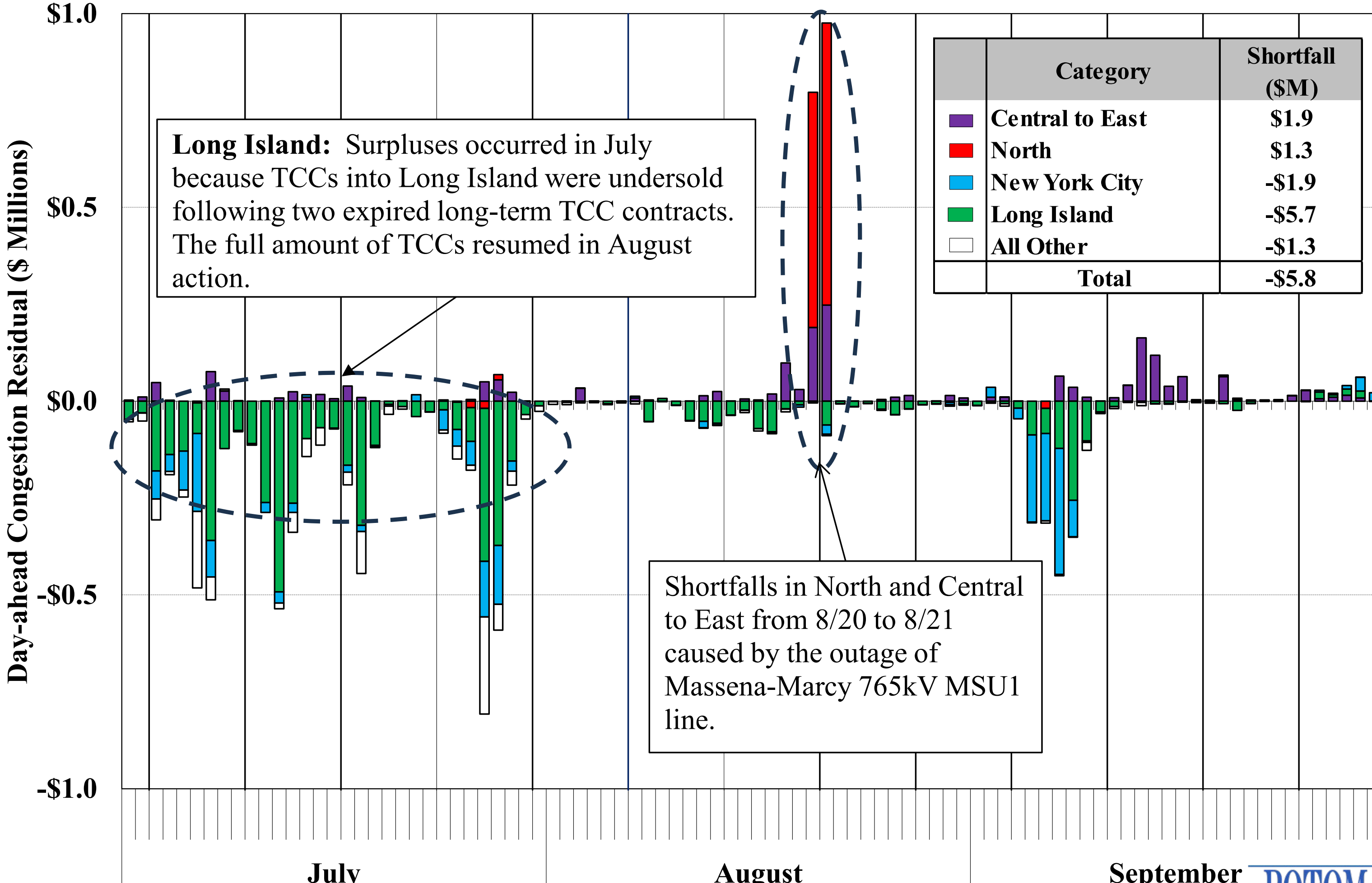


	Congestion Value ($ M)	
	Day-Ahead	Real-Time
2023Q3	$72	$100
2023Q2	$52	$61
2022Q3	$206	$274

Notes: For chart description, see slides 101, 102, and 103.

POTOMAC ECONOMICS

Day-Ahead Congestion Revenue Shortfalls by Transmission Facility

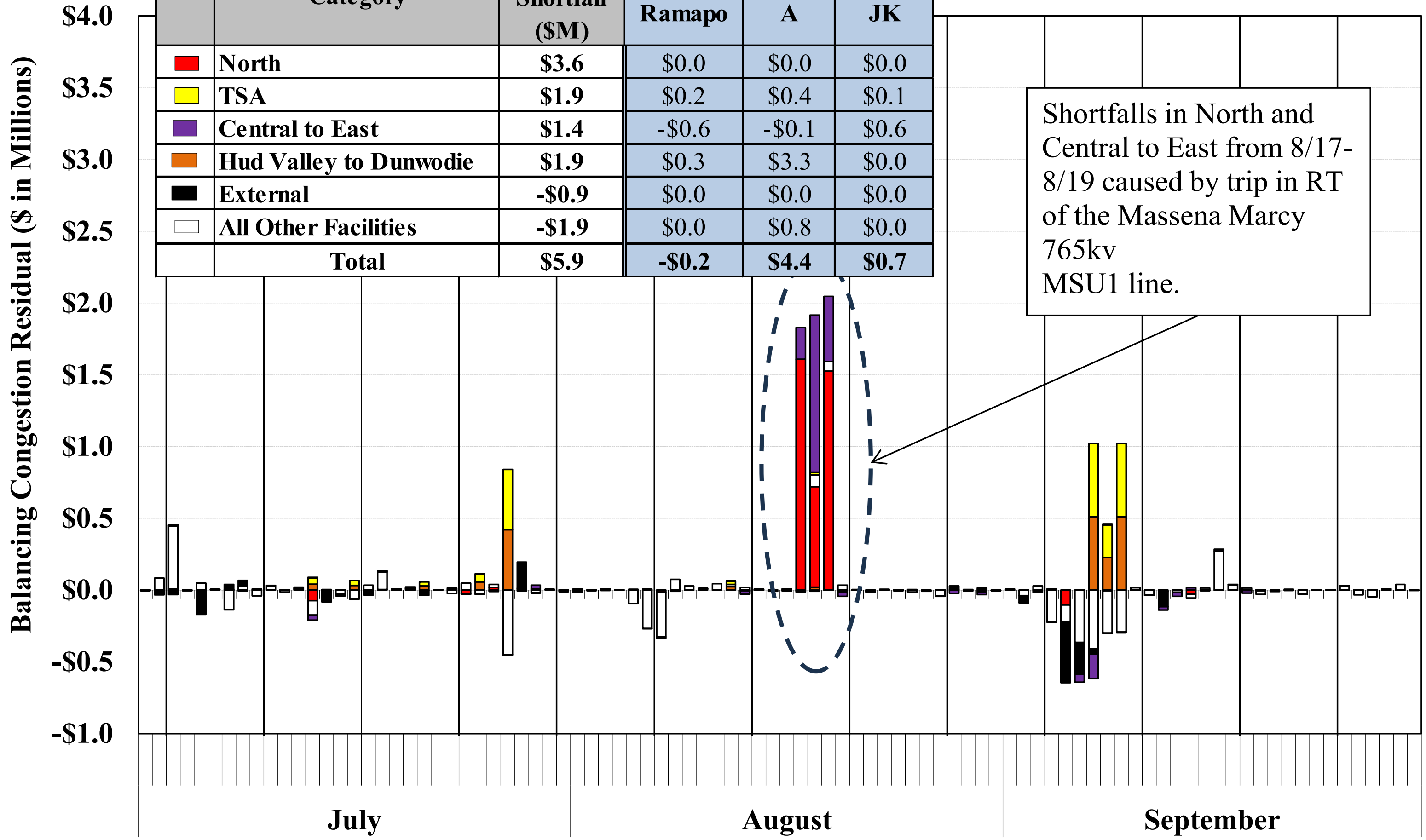


Notes: For chart description, see slides 101, 102, and 103.

POTOMAC ECONOMICS

Balancing Congestion Shortfalls by Transmission Facility

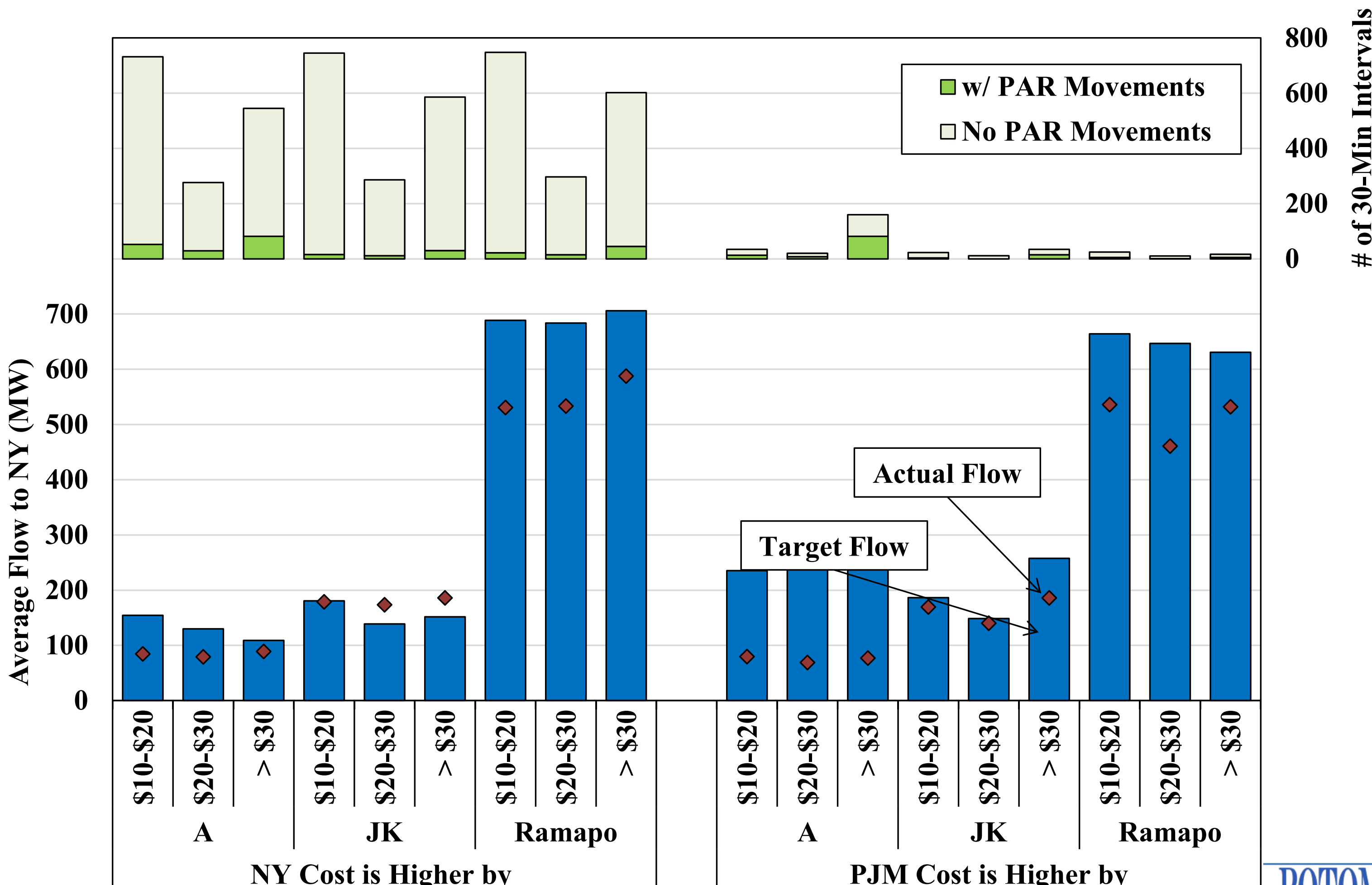
	Category	Total Shortfall ($M)	PAR Contributions		
			Ramapo	A	JK
	North	$3.6	$0.0	$0.0	$0.0
	TSA	$1.9	$0.2	$0.4	$0.1
	Central to East	$1.4	-$0.6	-$0.1	$0.6
	Hud Valley to Dunwodie	$1.9	$0.3	$3.3	$0.0
	External	-$0.9	$0.0	$0.0	$0.0
	All Other Facilities	-$1.9	$0.0	$0.8	$0.0
	Total	$5.9	-$0.2	$4.4	$0.7



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 101, 102, and 103.

POTOMAC ECONOMICS

PAR Operation under M2M with PJM
2023 Q3



Notes: For chart description, see slide 104.

OOM Actions to Manage Network Reliability

North	# Days
N-1-1	14
Voltage	1
Constraint Management	
Import/Export Limitation	1
PAR	10
Any Resource	26

West Zone	# Days
Constraint Management	
Gen Down	1
Import/Export Limitation	1
PAR	3
Any Resource	3

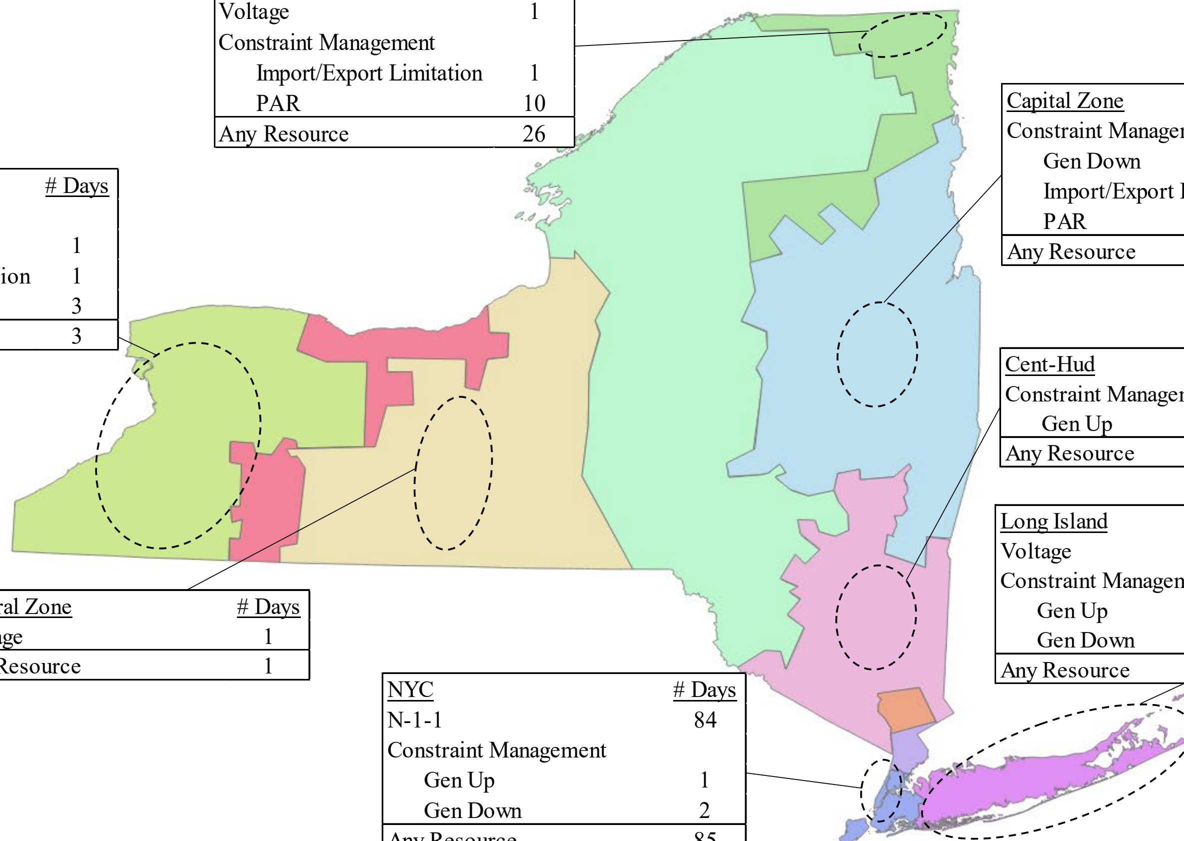
Capital Zone	# Days
Constraint Management	
Gen Down	1
Import/Export Limitation	2
PAR	1
Any Resource	4

Cent-Hud	# Days
Constraint Management	
Gen Up	2
Any Resource	2

Long Island	# Days
Voltage	4
Constraint Management	
Gen Up	70
Gen Down	1
Any Resource	74

Central Zone	# Days
Voltage	1
Any Resource	1

NYC	# Days
N-1-1	84
Constraint Management	
Gen Up	1
Gen Down	2
Any Resource	85

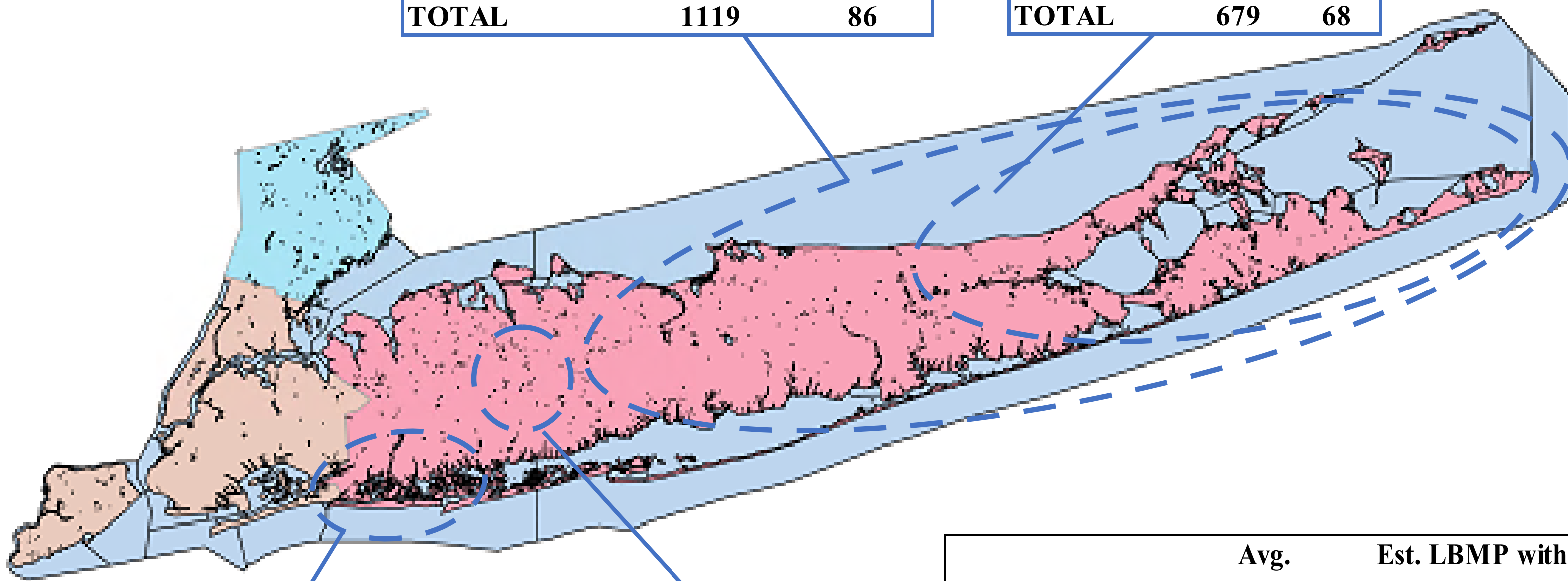


Notes: For chart description, see slides 105-106

Constraints on the Low Voltage Network:
Long Island Load Pockets

East of Northport	#Hours	#Days
69kV OOM	30	7
69kV	1024	84
138kV	915	81
TOTAL	1119	86

East End	#Hours	#Days
69kV OOM	36	4
TVR OOM	663	67
TOTAL	679	68



Valley Stream	#Hours	#Days
69kV OOM	198	22
138kV	113	31
TOTAL	295	40

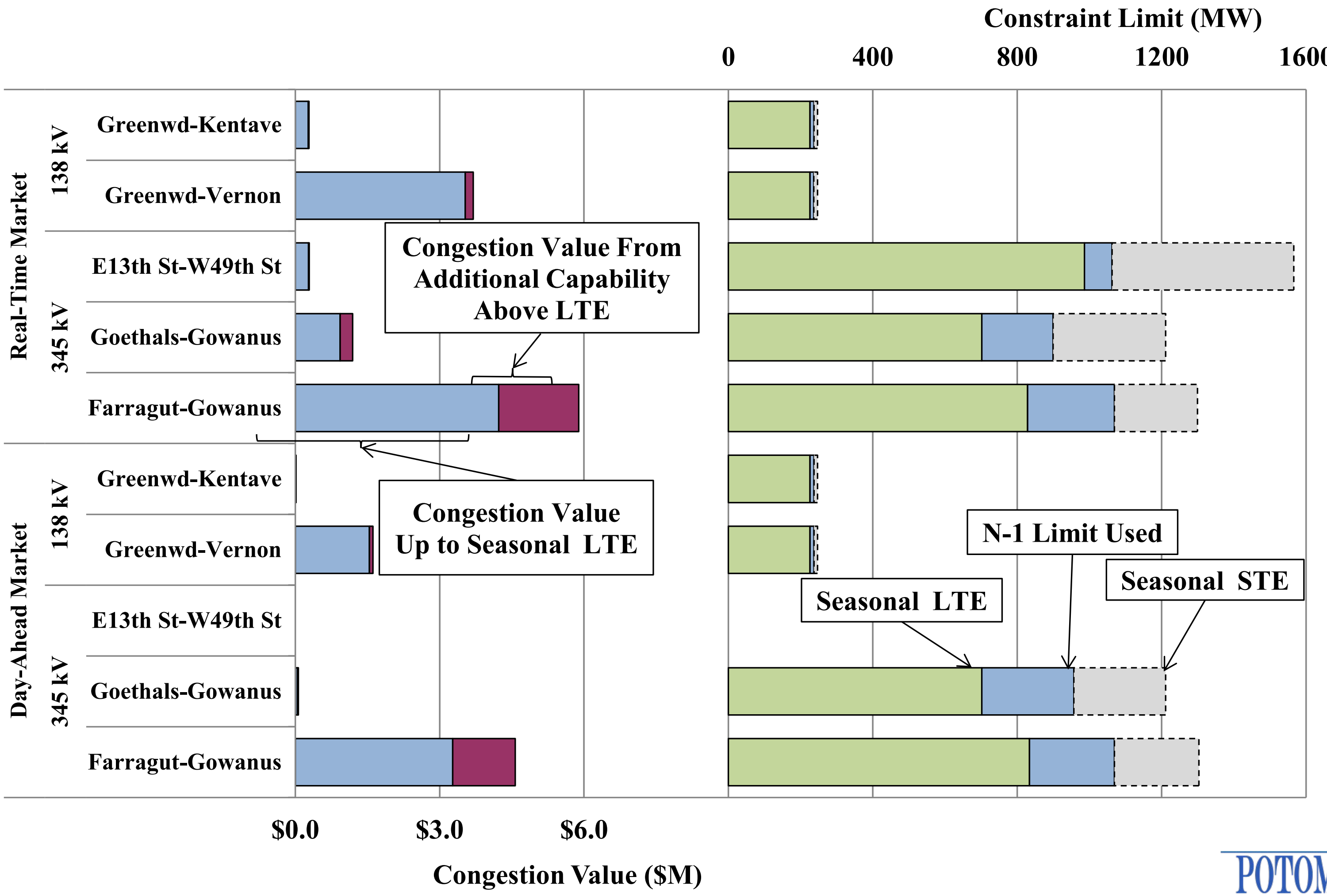
Brentwood	#Hours	#Days
69kV OOM	4	1
69kV	188	53
TOTAL	192	54

Load Pocket	Avg. LBMP	Est. LBMP with Local Constraints
Brentwood	$42.79	$42.80
East End-Revised	$55.27	$119.17
East of Northport	$52.95	$54.74
Valley Stream	$40.12	$56.49

Notes: For chart description, see slides 105-106

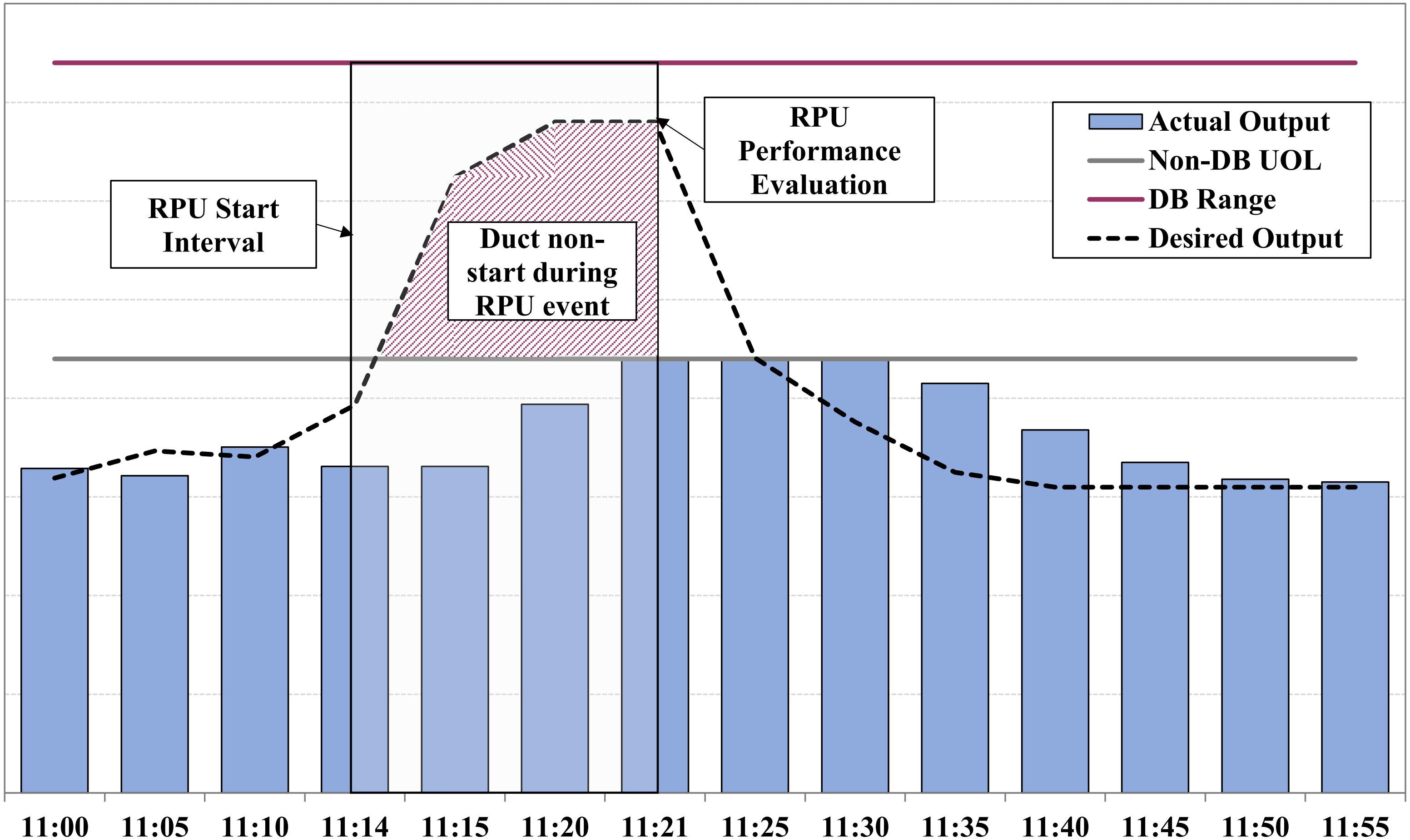
POTOMAC ECONOMICS

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



Notes: For chart description, see slide 107.

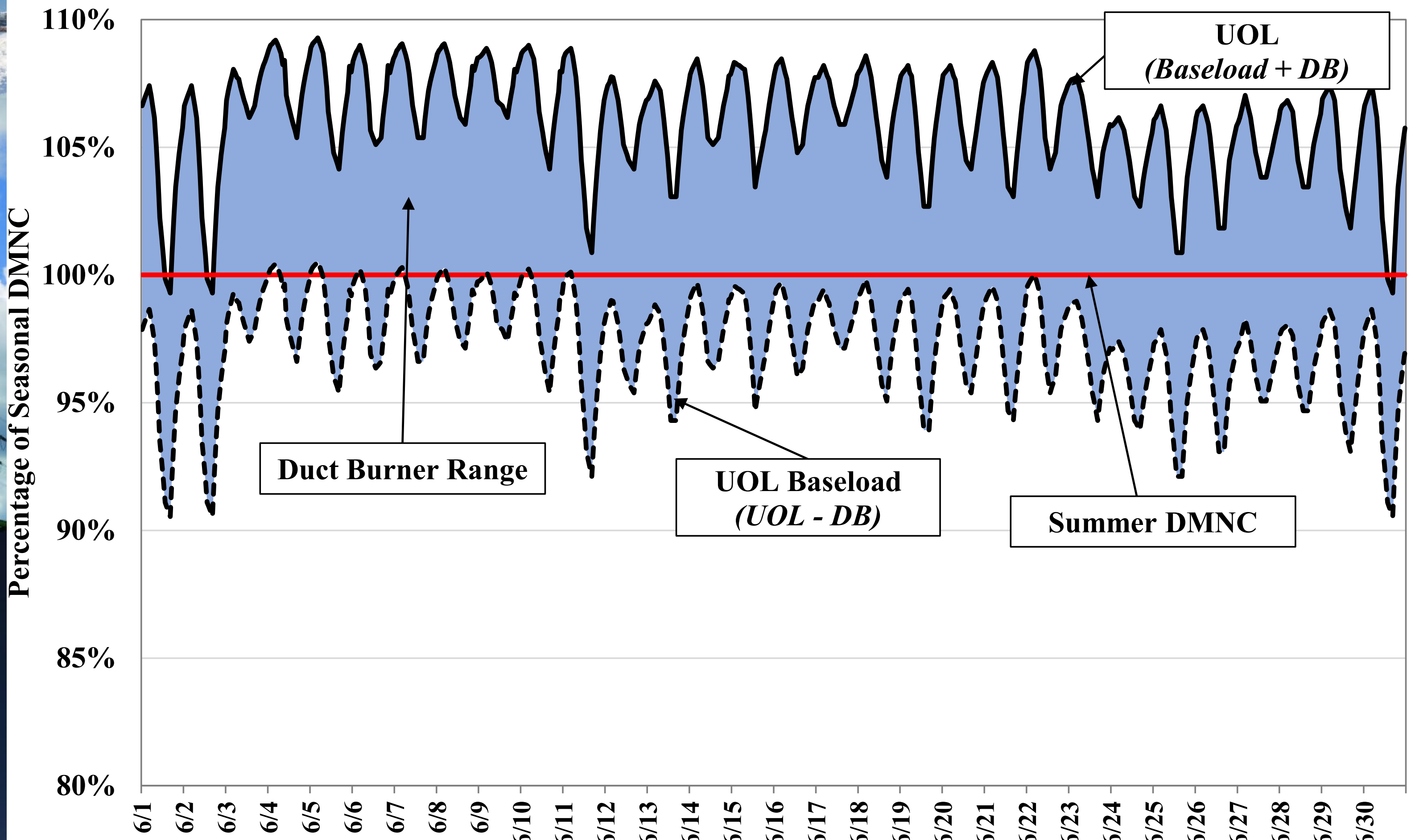
Duct Burner Real-Time Dispatch Issues
Example of a Failed RPU



Notes: For chart description, see slide 108

POTOMAC ECONOMICS

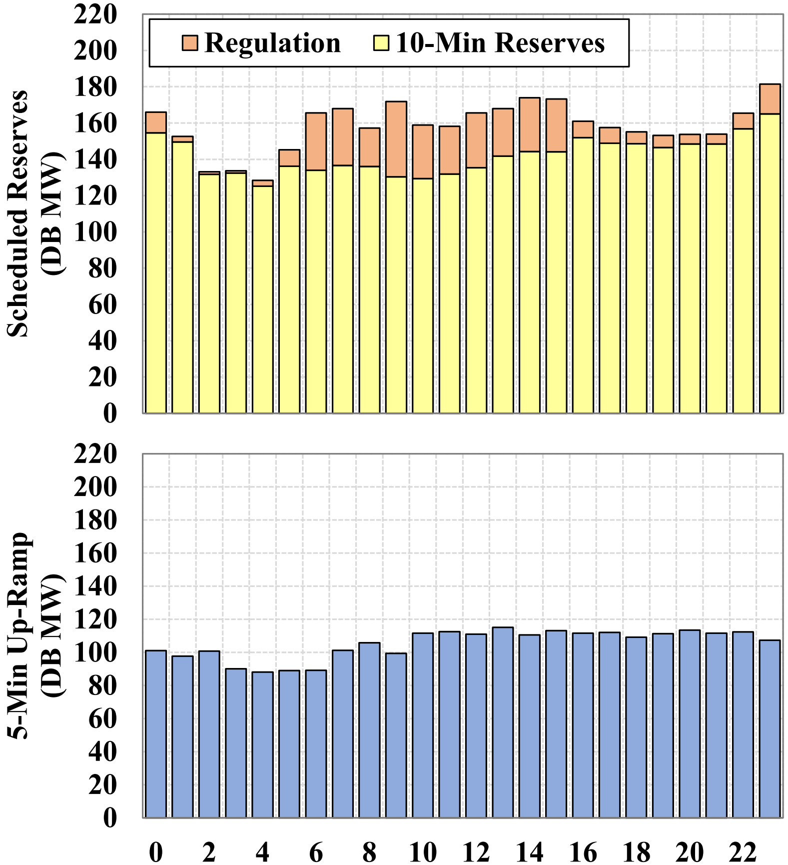
Illustration of Duct Burner Range
Example Generator Hourly Capability



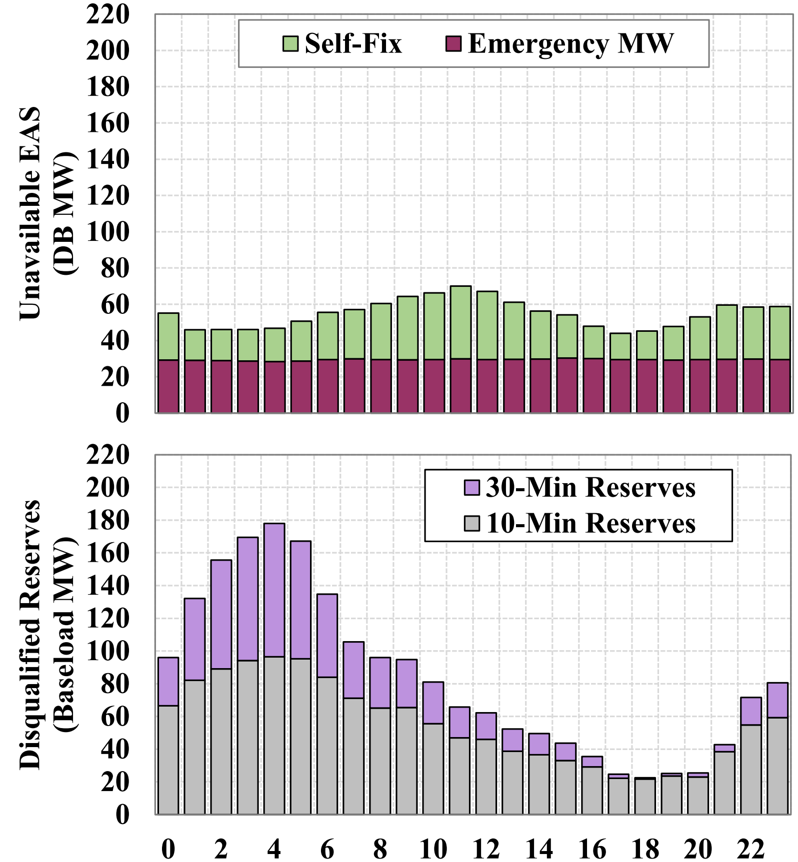
Notes: For chart description, see slide 109

Duct Burner Schedules and Ramp Expectations
Evaluation of Duct Availability in Real-Time

Scheduled or Offered Duct Capacity – but Unable to Follow RT Instructions



Unoffered Energy and/or Reserves (Including Duct and Baseload)



Notes: For chart description, see slide 108

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

10 Minute Economic GT Start Performance vs. Audit Results (October 2022 - September 2023)				
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]	2	3	2	0
0% - 10%	0	0	0	0
10% - 20%	0	0	0	0
20% - 30%	0	0	0	0
30% - 40%	1	6	1	4
40% - 50%	1	6	1	4
50% - 60%	1	9	1	6
60% - 70%	1	8	1	5
70% - 80%	2	5	2	0
80% - 90%	8	32	8	1
90% - 100%	23	101	23	7
TOTAL	**39**	**170**	**39**	**27**

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 110.

POTOMAC ECONOMICS

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

30 Minute Economic GT Start Performance vs. Audit Results (October 2022 - September 2023)				
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]	8	11	6	0
0% - 10%	2	6	2	3
10% - 20%	1	2	1	1
20% - 30%	0	0	0	0
30% - 40%	0	0	0	0
40% - 50%	0	0	0	0
50% - 60%	0	0	0	0
60% - 70%	4	10	4	1
70% - 80%	12	39	12	9
80% - 90%	24	44	24	1
90% - 100%	15	26	15	4
TOTAL	**66**	**138**	**64**	**19**

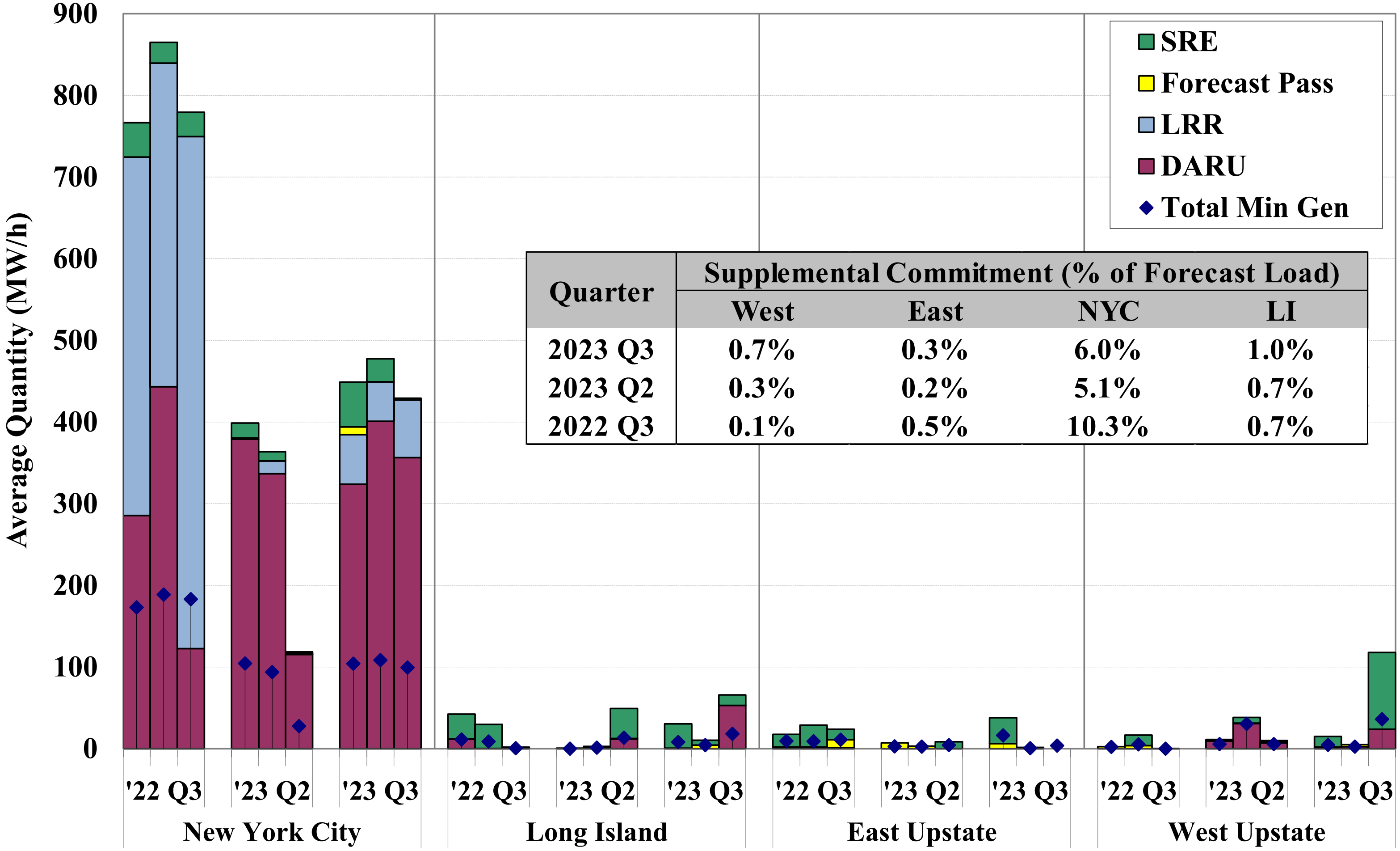
Note: 1. Including units that were OOM- or self-started, units that were never started in the time period, and units that were omitted from the analysis due to certain data issues for reliable performance assessment.

 Notes: For chart description, see slide 110.

Charts:

Supplemental Commitment, OOM Dispatch, and BPCG Uplift

Supplemental Commitment for Reliability
by Category and Region

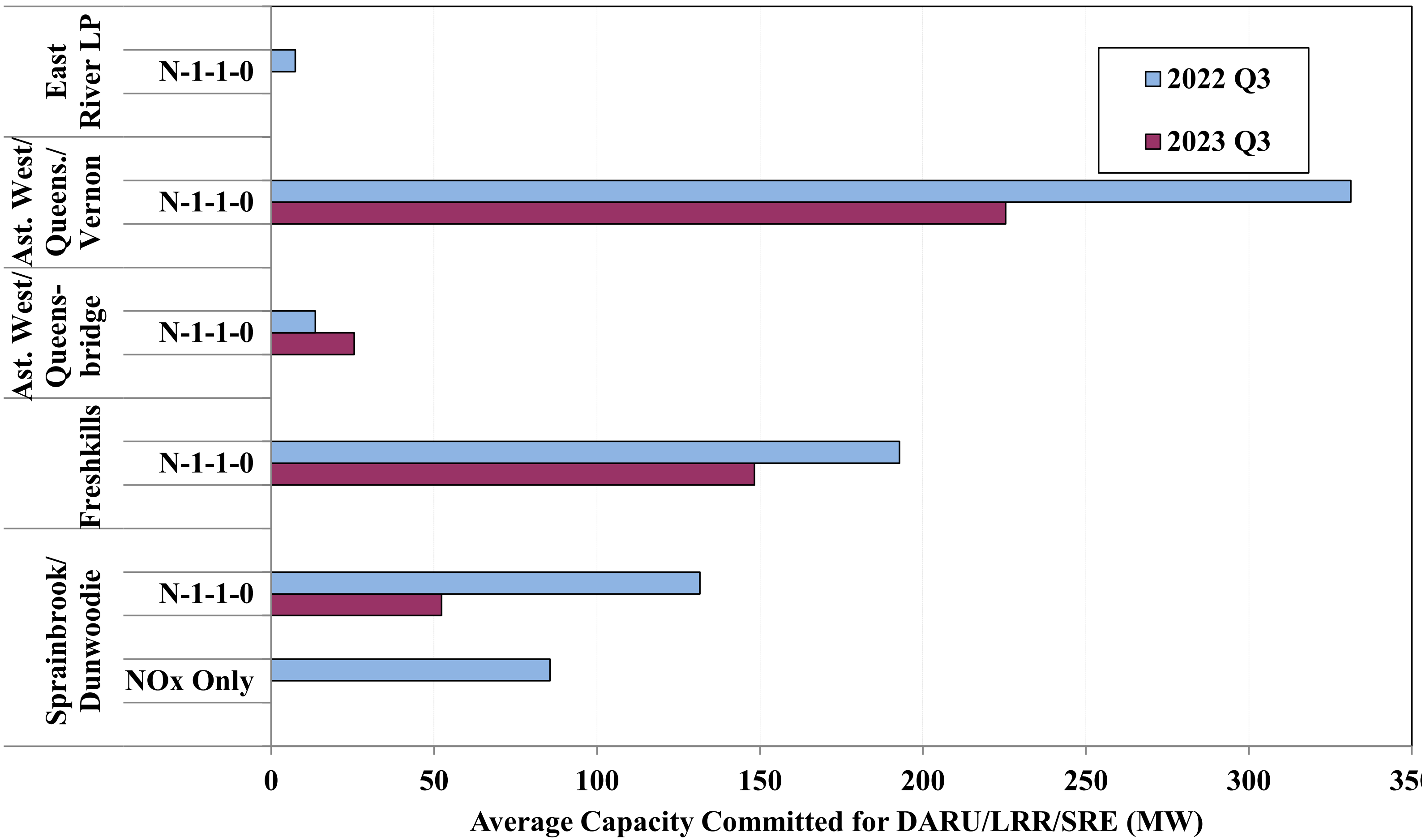


Quarter	Supplemental Commitment (% of Forecast Load)			
	West	East	NYC	LI
2023 Q3	0.7%	0.3%	6.0%	1.0%
2023 Q2	0.3%	0.2%	5.1%	0.7%
2022 Q3	0.1%	0.5%	10.3%	0.7%

Notes: For chart description, see slides 111 and 112.

POTOMAC ECONOMICS

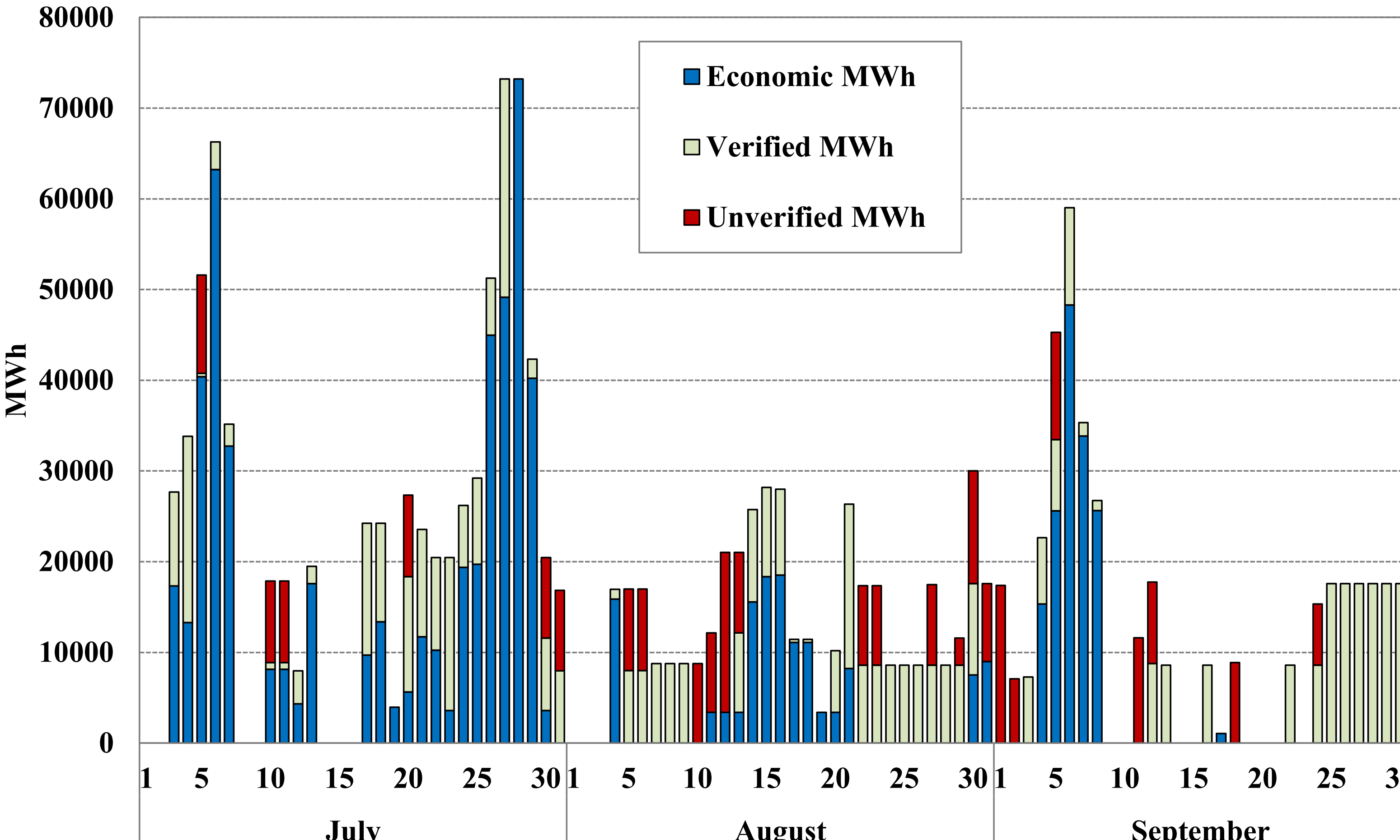
Supplemental Commitment for Reliability in NYC
by Reliability Reason and Load Pocket



Notes: For chart description, see slides 111 and 112.

POTOMAC ECONOMICS

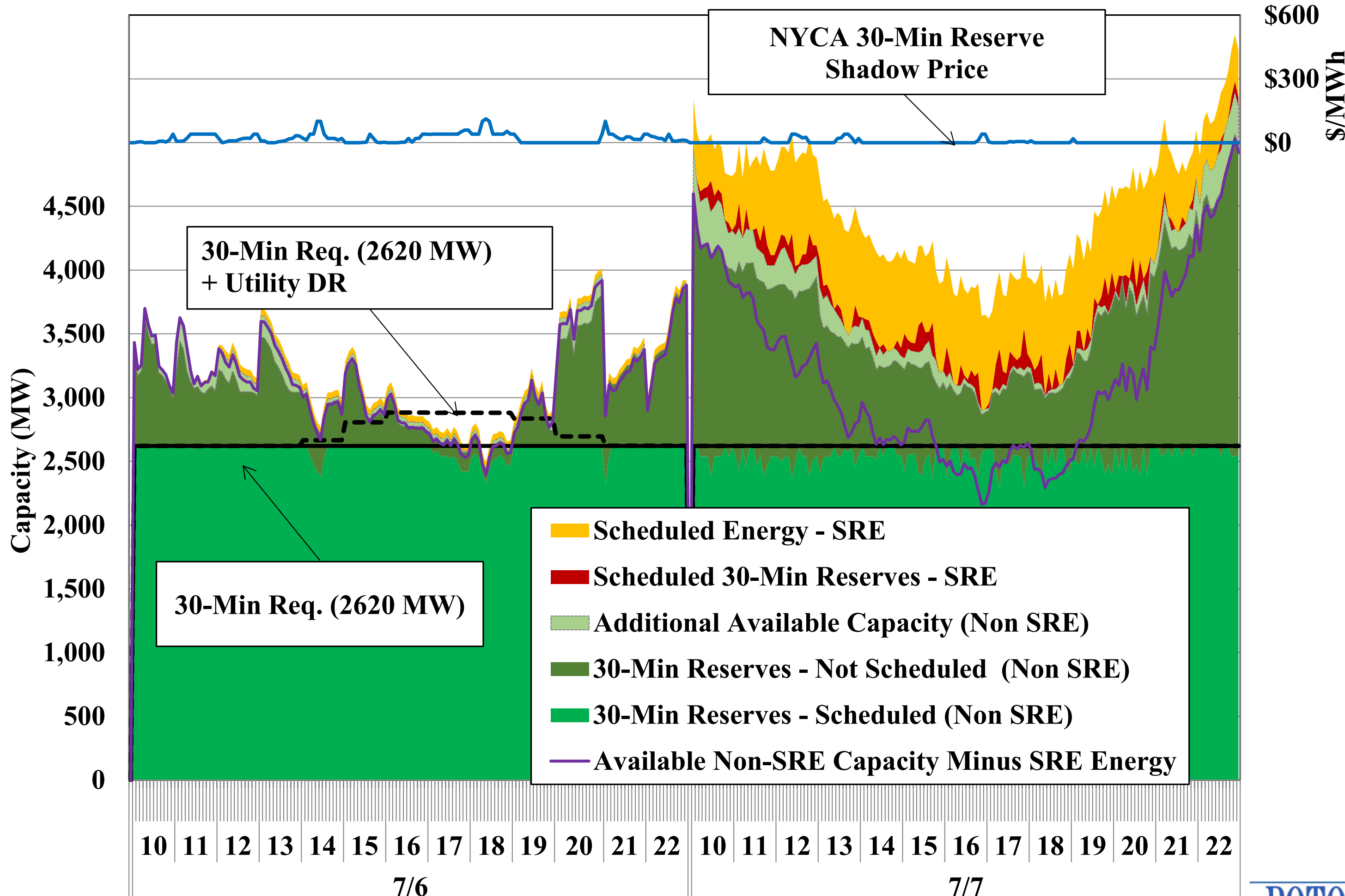
DARU Commitments in NYC
2023 Q3



Notes: For chart description, see slide 112.

POTOMAC ECONOMICS

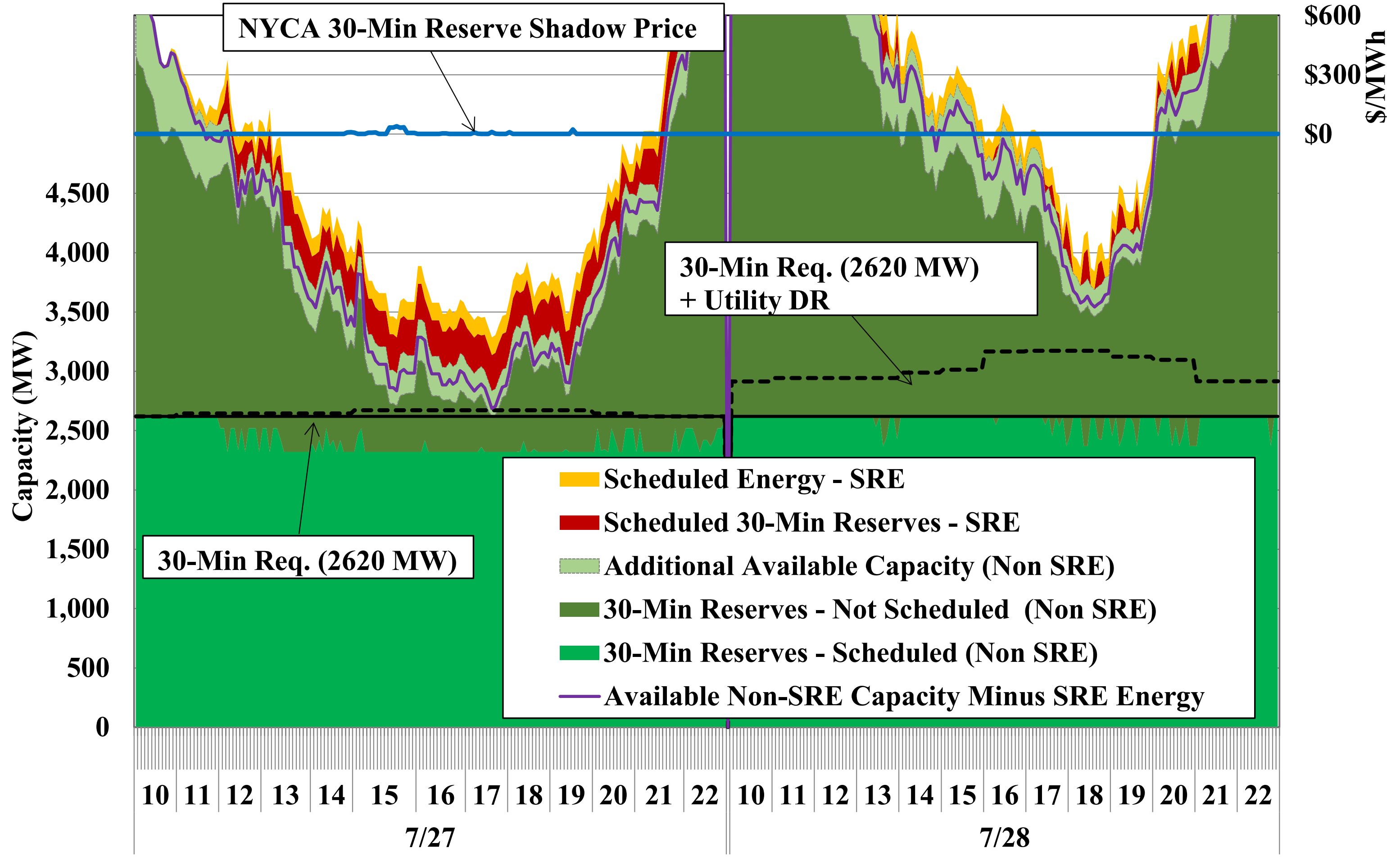
SRE Commitments for Capacity and DR Deployments on High Load Days
July 6 - 7



Notes: For chart description, see slide 113.

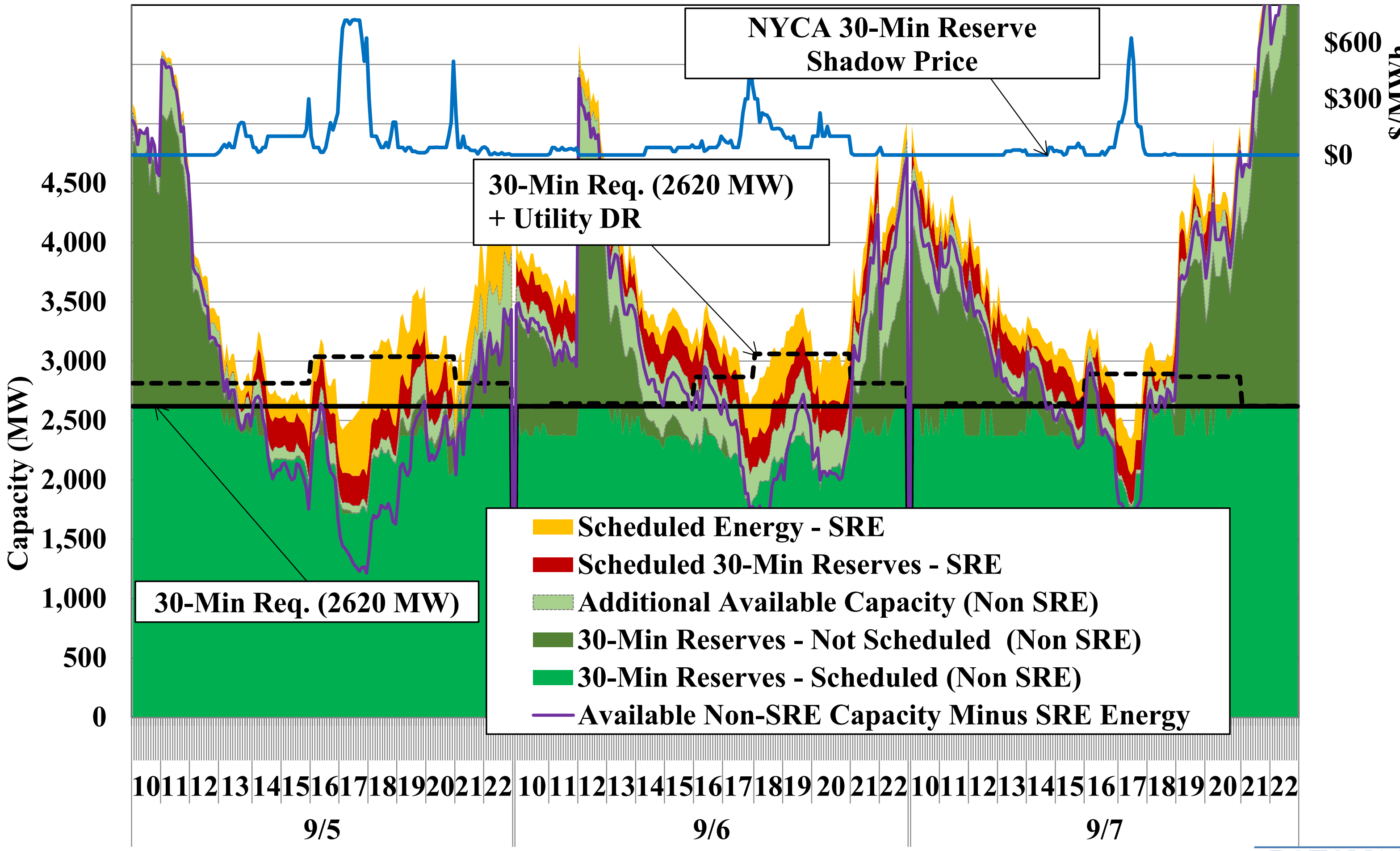
POTOMAC ECONOMICS

SRE Commitments for Capacity and DR Deployments on High Load Days
July 27 - 28



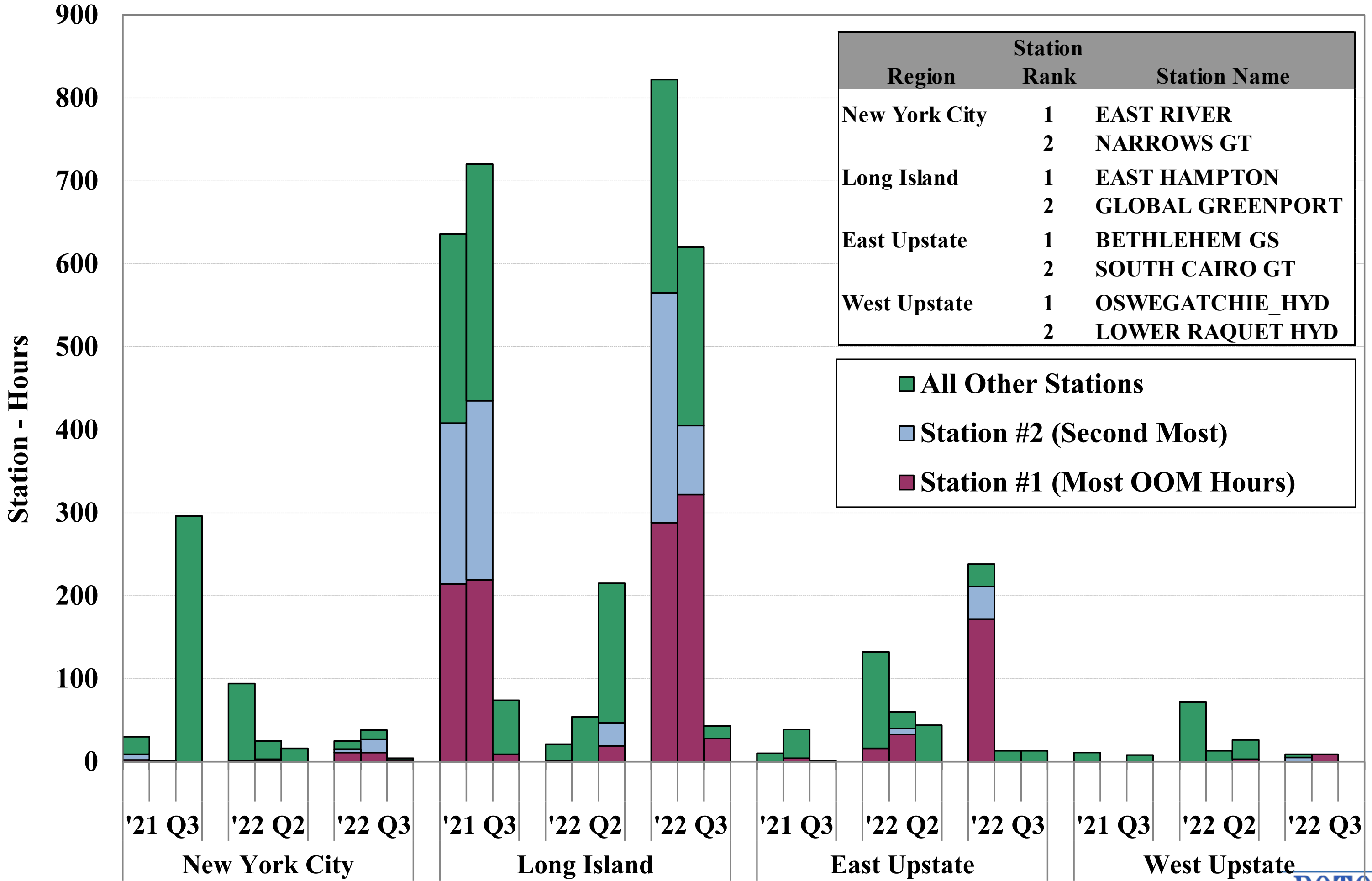
Notes: For chart description, see slide 113.

SRE Commitments for Capacity and DR Deployments on High Load Days
September 5 - 7



Notes: For chart description, see slide 113.

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

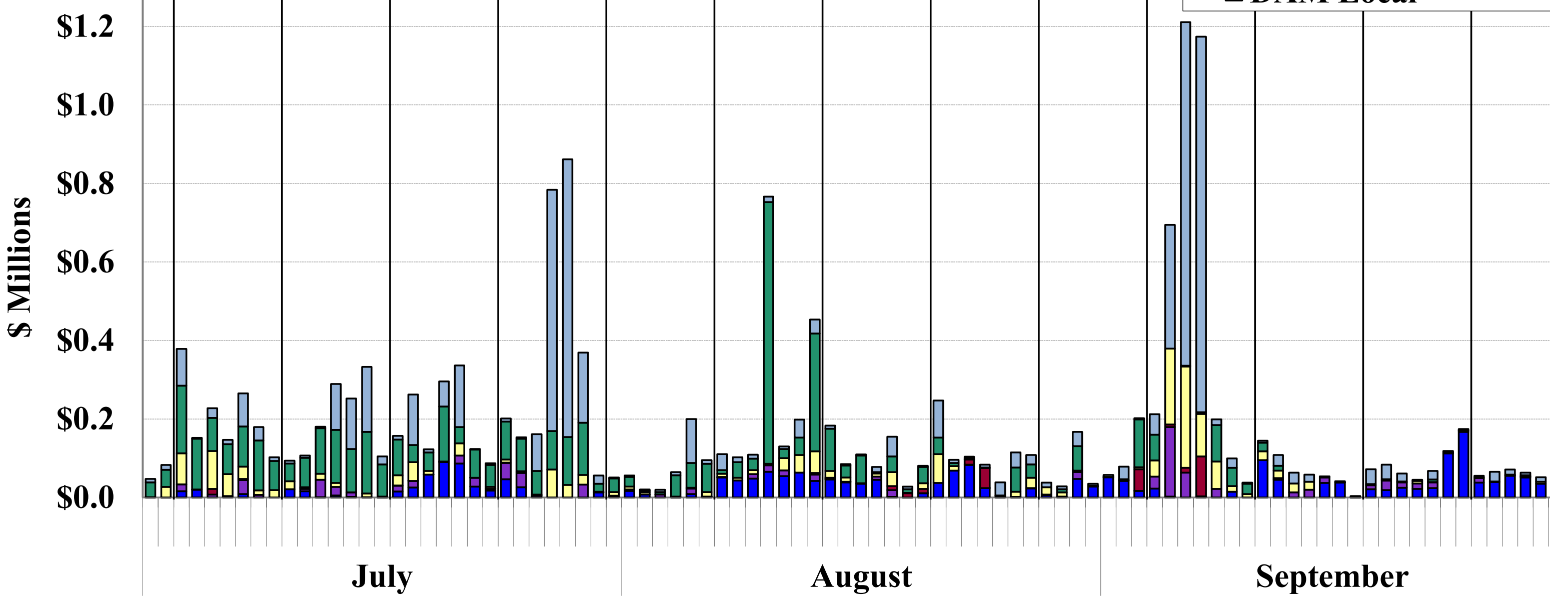


For chart description, see slides 111 and 112.

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

Quarter	Local				Statewide				Total
	Day Ahead	Real Time	DAMAP	Min Oil Burn	Day Ahead	Real Time	DAMAP	EDRP/ SCR	
2023 Q3	$2.4	$5.0	$0.3	$0.0	$0.9	$6.0	$1.9	$0.0	$16.5
2023 Q2	$2.9	$3.0	$0.1	$0.0	$1.0	$1.2	$0.8	$0.0	$9.1
2022 Q3	$12.8	$8.8	$3.8	$0.3	$1.1	$2.8	$3.5	$0.1	$33.2

Quarterly BPCG By Category (Million $)



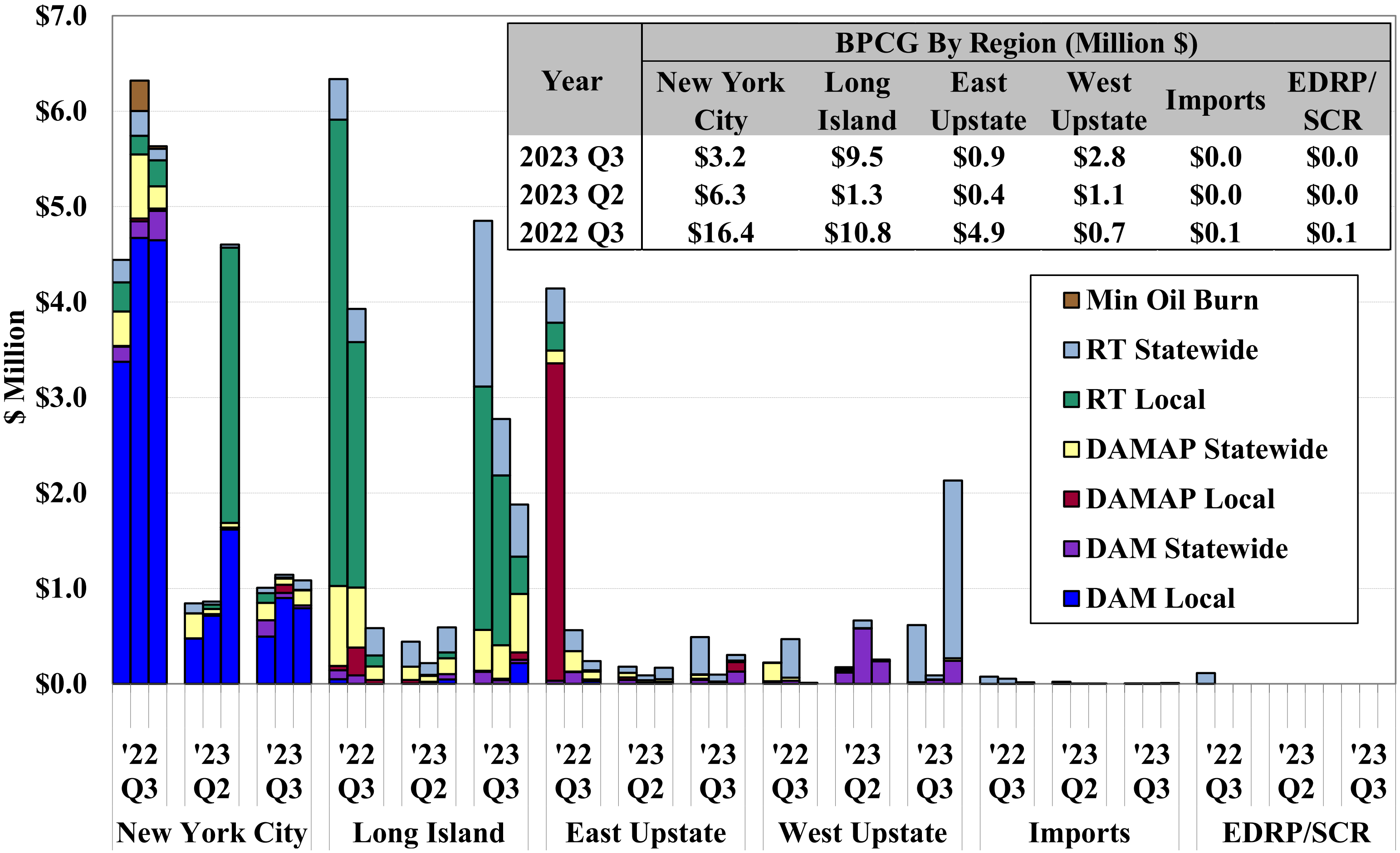
Notes: 1. This data is based on information available at the reporting time and does not include some manual adjustments to mitigation, so it can be different from final settlements.

2. For chart description, see slide 115.

POTOMAC ECONOMICS

Uplift Costs from Guarantee Payments
By Category and Region

Year	BPCG By Region (Million $)					
	New York City	Long Island	East Upstate	West Upstate	Imports	EDRP/ SCR
2023 Q3	$3.2	$9.5	$0.9	$2.8	$0.0	$0.0
2023 Q2	$6.3	$1.3	$0.4	$1.1	$0.0	$0.0
2022 Q3	$16.4	$10.8	$4.9	$0.7	$0.1	$0.1



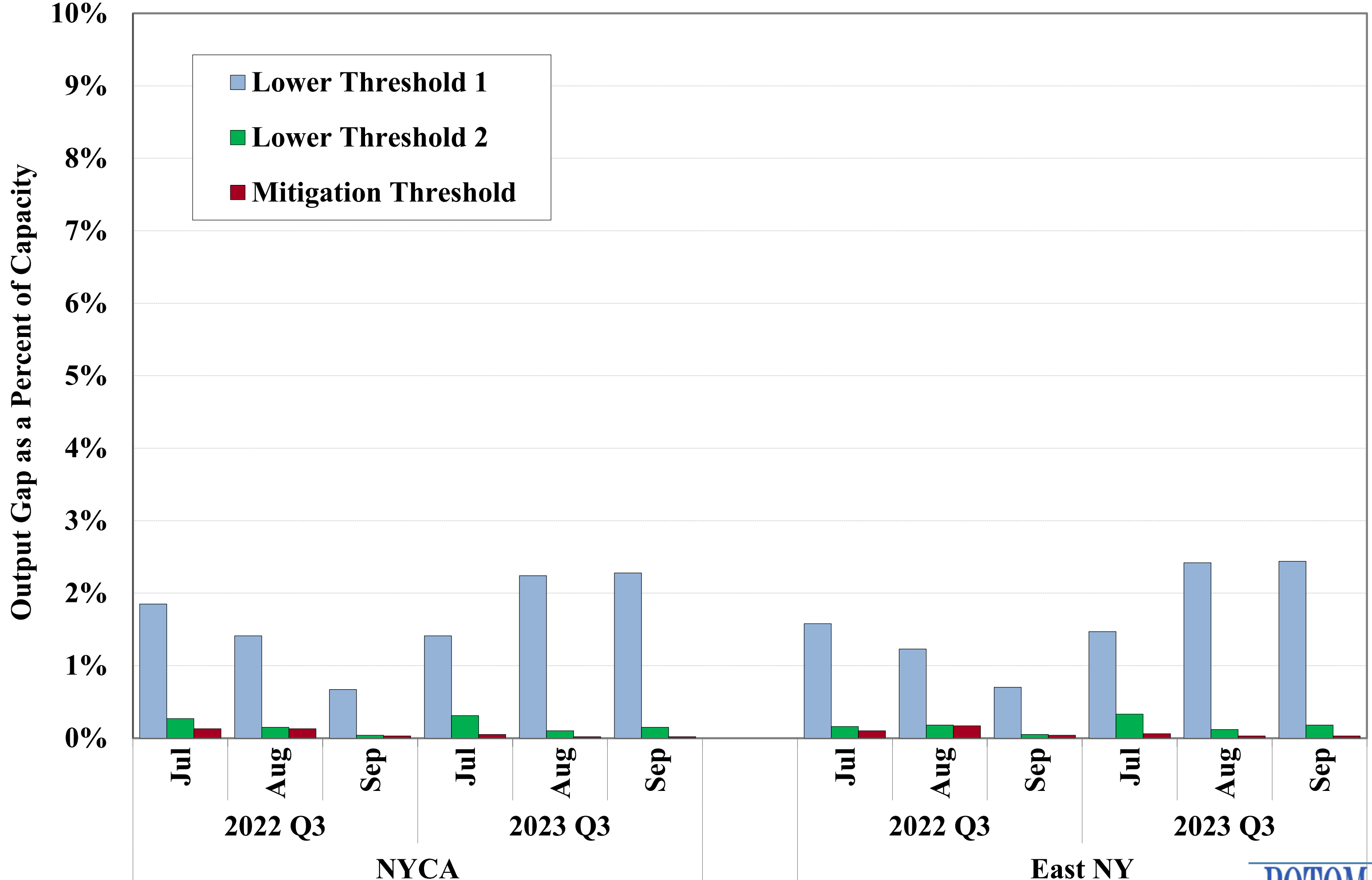
Notes: 1. BPCG data are based on information available at the reporting time that can be different from final settlements.
2. For chart description, see slide 115.

Charts:

Market Power and Mitigation

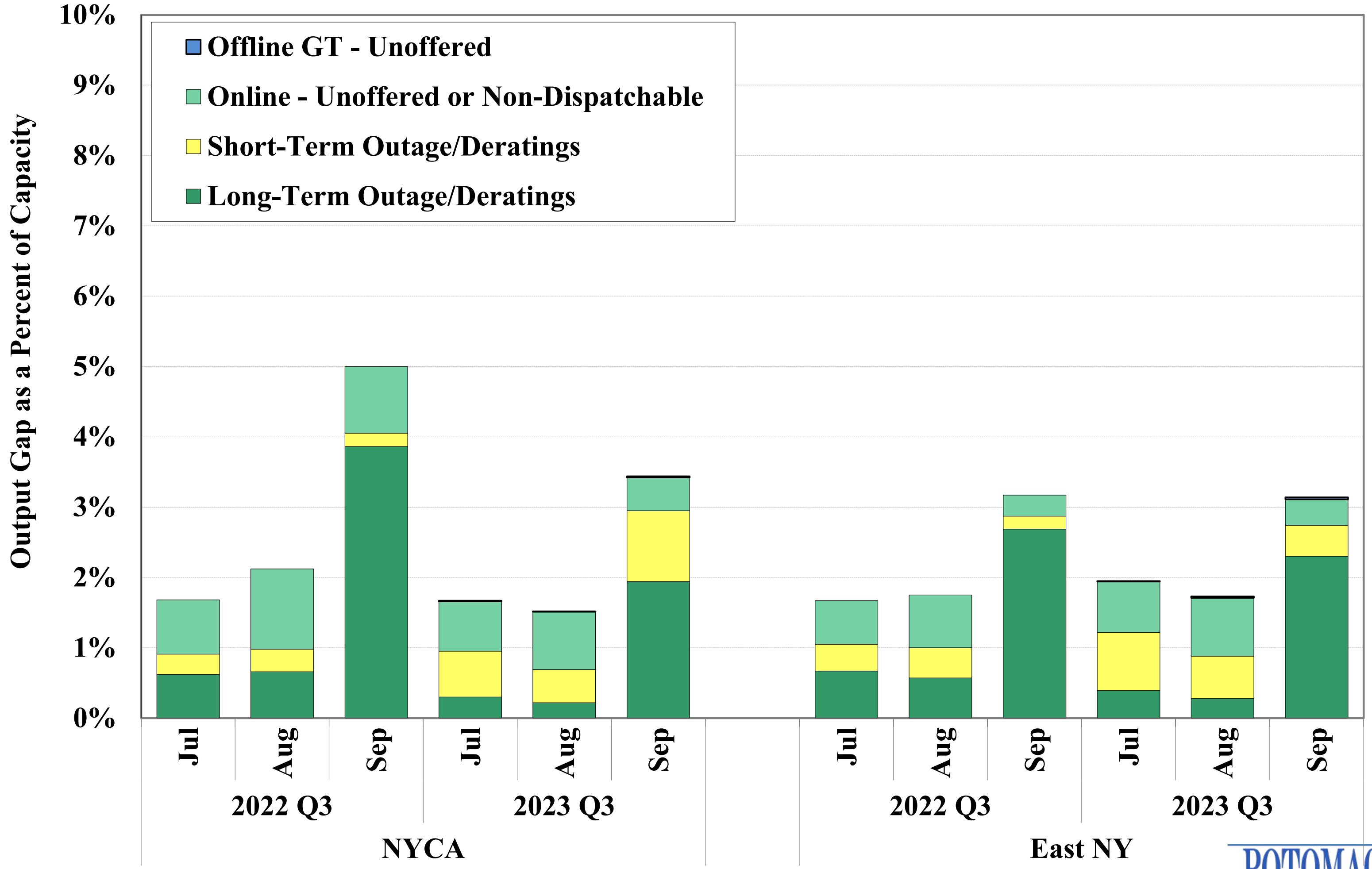
POTOMAC ECONOMICS

Output Gap by Month
NYCA and East NY



For chart description, see slide 116.

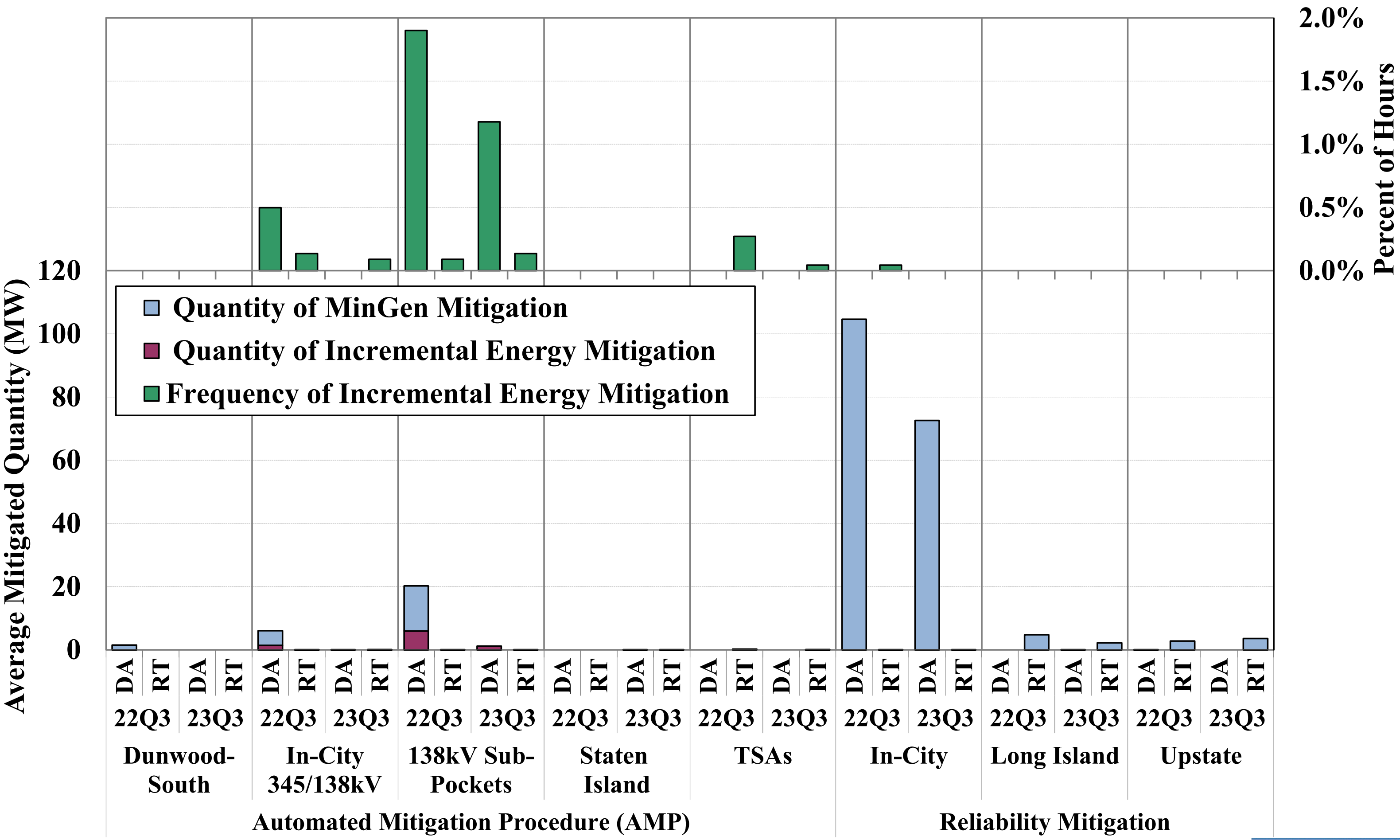
Unoffered Economic Capacity by Month
NYCA and East NY



For chart description, see slide 116.

POTOMAC ECONOMICS

Automated Market Power Mitigation



Notes: For chart description, see slide 117.

POTOMAC ECONOMICS

Charts:

Capacity Market

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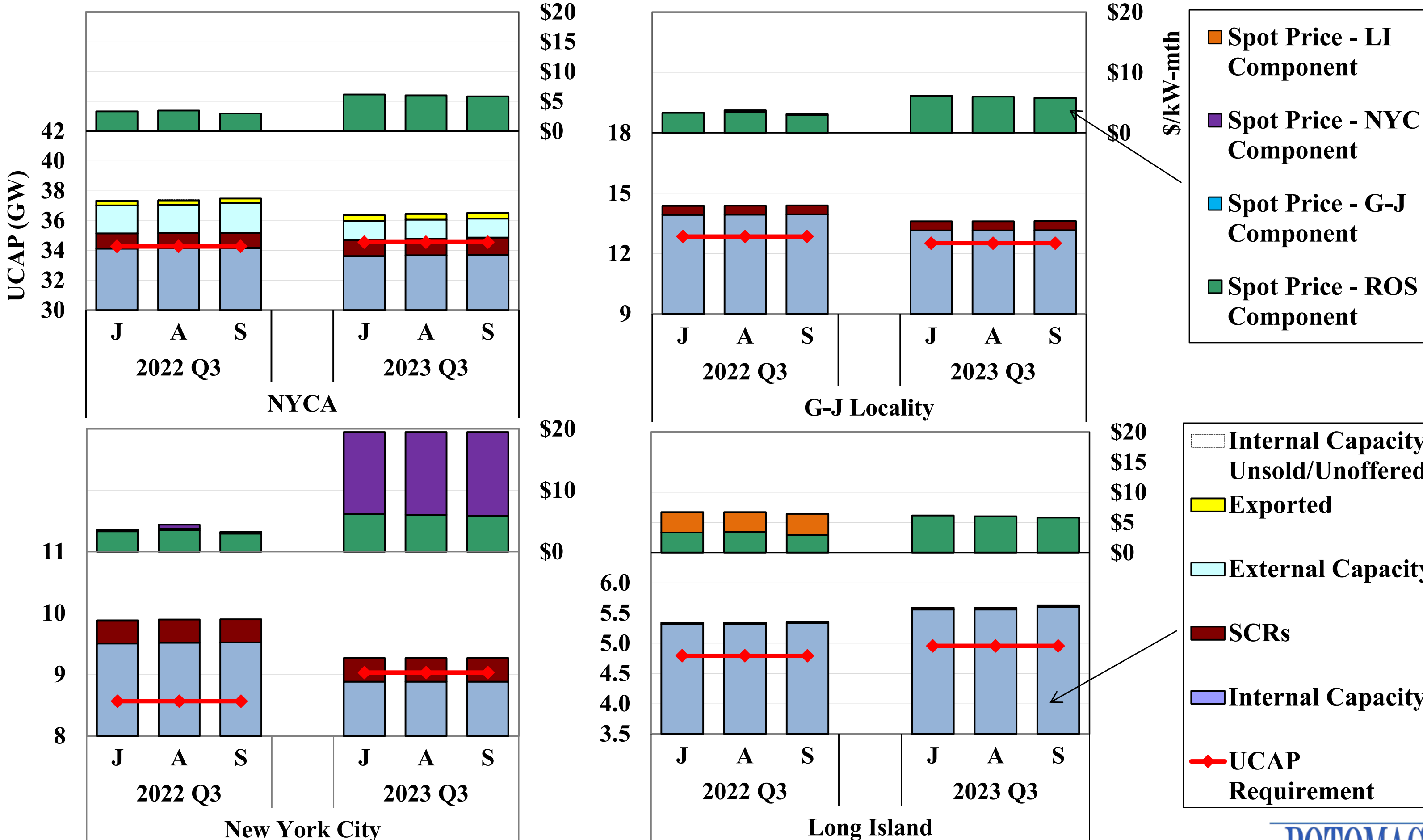
Spot Capacity Market Results
Monthly Results by Locality



Notes: For chart description, see slide 118.

POTOMAC ECONOMICS

Key Drivers of Capacity Market Results

	NYCA	NYC	LI	G-J Locality
Avg. Spot Price				
2023 Q3 ($/kW-Month)	$6.00	$19.46	$6.00	$6.00
% Change from 2022 Q3	**85%**	**423%**	**-9%**	**77%**
Change in Demand				
Load Forecast (MW)	282	333	-56	268
IRM/LCR	0.4%	0.5%	5.7%	-3.8%
2023/24 Capability Year	*120.0%*	*81.7%*	*105.2%*	*85.4%*
2022/23 Capability Year	*119.6%*	*81.2%*	*99.5%*	*89.2%*
ICAP Requirement (MW)	**466**	**327**	**234**	**-346**
Key Changes in ICAP Supply (MW)				
Generation	**-152**	**-793**	**269**	**-802**
Entry (3)	433	0	330	16
Exit (3)	-795	-770	-25	-770
Other Capacity Changes (1)	210	-23	-36	-48
Cleared Import (2)	**-649**			

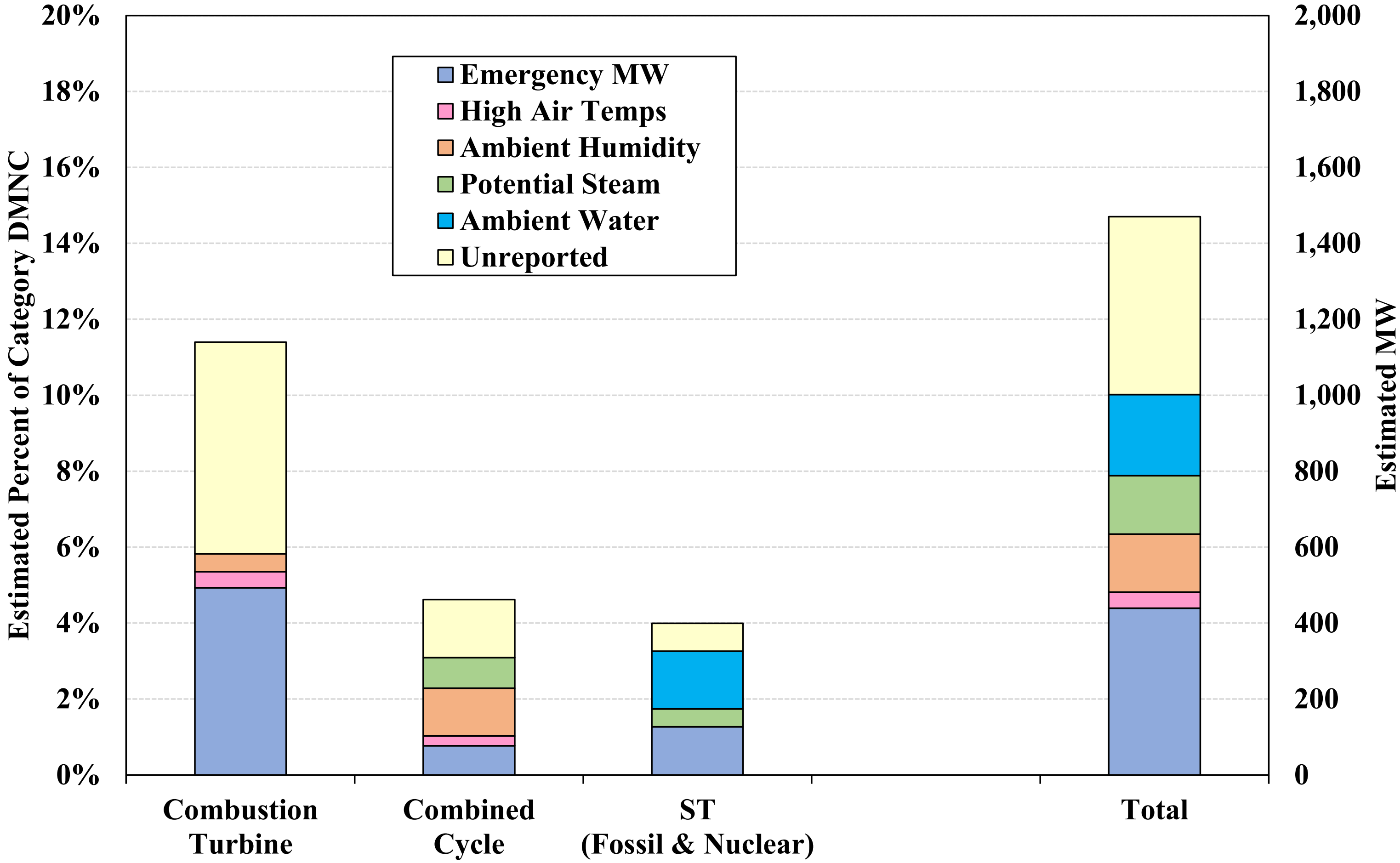
(1) Other changes include DMNC ratings, change in exports, unsold capacity, etc.

(2) Based on average of quarterly cleared quantity.

(3) Includes change in sales from UDR line(s)

Notes: For chart description, see slide 118.

Functionally Unavailable Capacity from Fossil-Fuel and Nuclear Generators

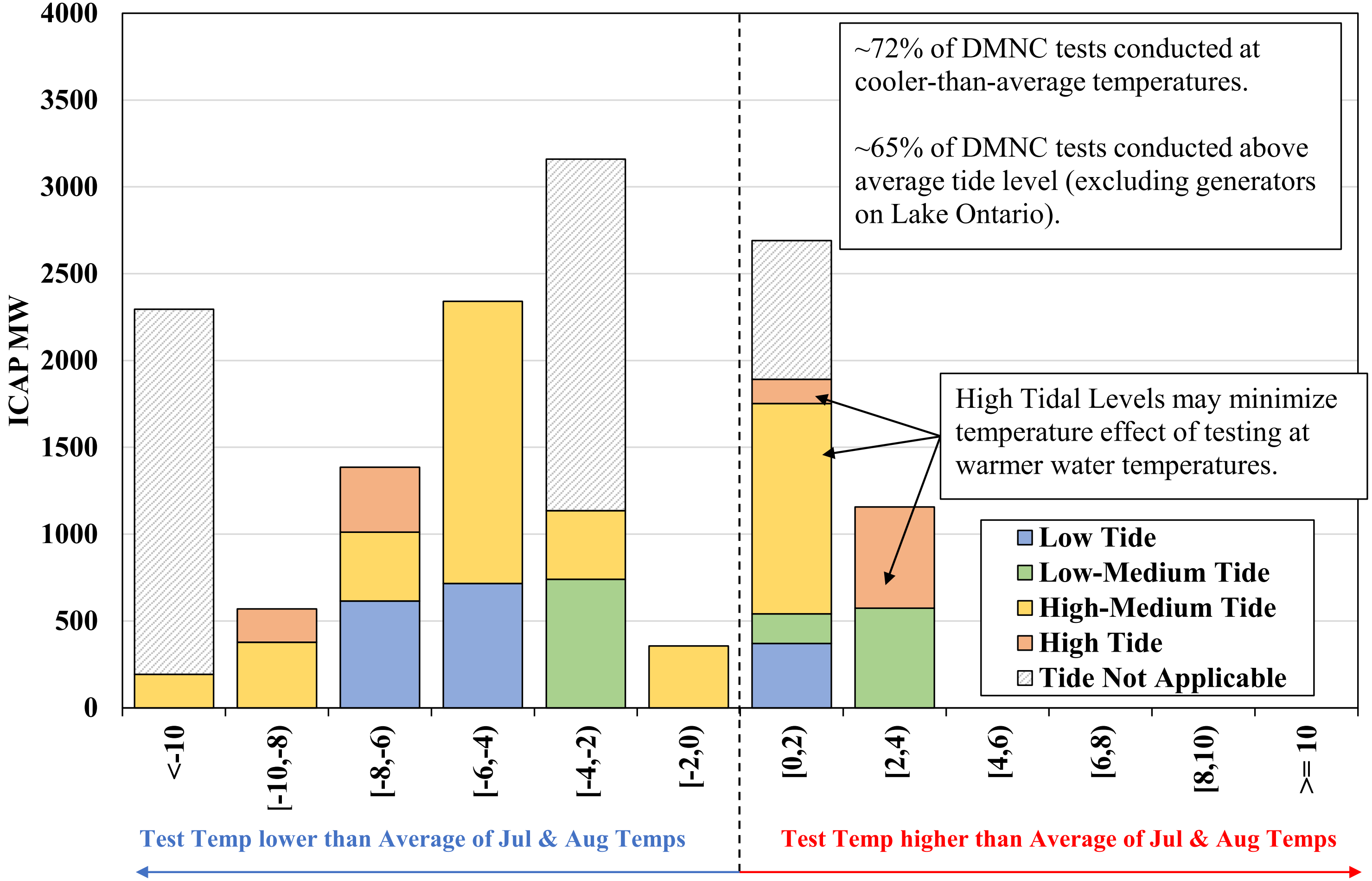


Notes: For chart description, see slide 119.

POTOMAC ECONOMICS

Ambient Conditions during DMNC Tests of Once Through Cooled Units

Summer 2023 DMNC Submissions



Notes: For chart description, see slide 120.

POTOMAC ECONOMICS

Appendix: Chart Descriptions

All-in Price

- Slide 22 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.

Emission Costs by Unit Type
Natural Gas Fired Resources

- Slide 27 shows estimates for the generation-weighted average hourly marginal costs of the two main emissions, CO_2 and NOx, by month for each of the following unit types firing on natural gas:
  - ✓ Combined cycles, Steam Turbines, and Peaking units.
- Emission cost estimates are calculated based on:
  - ✓ Daily price indexes for RGGI (CO_2) and CSAPR Group 3 (NOx) emissions allowances.
  - ✓ CO_2 emission coefficient of 118 Lb/MMBtu for natural gas.
  - ✓ Generation-weighted average hourly NOx emission rates for each unit type based on actual operations during June 2022 from EPA CEMS data.
  - ✓ Heat rate assumptions of 7.5 MMBtu/MWh for combined cycles, 11 MMBtu/MWh for steam turbines, 9.4 MMBtu/MWh for Peakers (post-2000), and 13.25 MMBtu/MWh for Peakers (pre-2000).
- Actual unit-specific emission rates and associated costs may vary substantially for each individual unit based on factors like (a) heat rate efficiency, (b) level of emission control technology at the plant, and (c) typical output factor during operations, etc.

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Real-Time Output and Marginal Units by Fuel

- Slide 25 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 26 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 27-31 evaluate emissions from generators in the NYISO market.
  - ✓ Slide 27 shows the historical trend of annual total emissions since 2000 in the NYISO footprint for CO_2, NO_X, and SO_2 .
  - ✓ Slides 28-29 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 30-31 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 30 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 36-40 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 8 per MW of capability, but they are compensated according to actual movement.
    - Real-time Regulation Movement Charges shown on Slide 39 are estimated by dividing total movement charges by real-time scheduled regulation capacity.
  - ✓ 30-min operating reserve prices in western NY and NYC; and
  - ✓ 30-min operating reserve prices in SENY.
- The number of shortage intervals in real-time for each ancillary service product are also shown.
  - ✓ A shortage occurs when a requirement cannot be satisfied at a marginal cost less than its "demand curve".
  - ✓ The highest demand curve values are currently set at $775/MW.

Day-Ahead NYCA 30-Minute Reserve Offers

- Slide 41 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 43 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 45 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 46 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 47 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 49 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 50 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 51 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 52 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 System Price Maps at Generator Nodes

- Slides 54 and 55 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 56, 57, 58, 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).

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Transmission Congestion and Shortfalls (cont.)

- Slide 56 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 57 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 58 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.

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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.

Duct Burner RPU Performance and Real-Time Availability

- Slide 64 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 66 shows quarterly average real-time duct burner data across all applicable units during this quarter on an hourly basis.
  - ✓ The two charts on the left side show the amount of duct burner capacity scheduled or made available for scheduling within the timeframes that are unlikely deliverable for energy and reserves. These values show: (a) the average amount of MWs scheduled to provide 10-minute spinning reserves and regulation services; and (b) the amount of 5-minute up-ramping capability assumed to be available by duct burners.
  - ✓ The two charts on the right side show capacity that was not made available in offers for either energy and/or reserves from units with duct burners, including: (a) 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; and (b) the average amount of baseload capacity that was available but not offered for reserves in real-time because the units were disqualified from offering reserves.

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Illustration of Duct Burner Range
Example Generator Hourly Capability

- Slide 65 provides an illustration of how the beginning and end of a typical combined cycle generator's duct-firing ranging varies on an hourly basis across the month of June 2023.
  - ✓ The solid black line shows the hourly Upper Operating Limit ("UOL") of the example generator taken from the day-ahead ("DA") bids across each day of June 2023.
  - ✓ The dashed black line shows the hourly UOL of the generator excluding the duct range, i.e., the UOL of the unit minus its reported duct firing capability.
  - ✓ The shaded blue region shows the capacity associated with the duct burner range. It is assumed that the duct range will be utilized last due to higher costs of firing in that range.
- All capacity values are shown as ratios to the Summer DMNC for the example unit.
  - ✓ For example, it is often the case that a combined cycle will offer a higher UOL than its DMNC due to ambient conditions, especially in the early parts of summer or in the off-peak hours. Thus, the total UOL may be 110% of DMNC and the non-duct burner range ending at 100% of DMNC level.

GT Start-up Performance

- Slides 67-68 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 67): "23 10-minute GTs exhibited a response rate of 90 to 100 percent during economic starts in the examined period, 23 of them were audited 101 times in total with 7 failures".

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Supplemental Commitments and OOM Dispatch

- Slides 70, 71, and 76 summarize out-of-market commitment and dispatch, which are the primary sources of guarantee payment uplift.
- Slide 70 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 71 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:

DARU Commitment in New York City

- Slide 72 shows the amount of DARU capacity in New York City for each day of the quarter.
- The chart shows the DARU quantity in stacked bars in three 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 MWh***: This category represents the total MWh of the initial DARU commitments that do not qualify as ***Economic*** but are verified through our assessment as necessary for maintaining reliability (including both thermal and voltage requirements) in the applicable load pockets.
    - – Our assessment relies on information available in the day-ahead market, including factors such as load forecast, resource availability, and transmission network conditions.
    - – For a particular DARU unit, if it is verified to meet reliability need for at least one hour of the day, all other hours of the day not designated as ***Economic*** will fall into this category.
  - ✓ ***Unverified MWh:*** This category represents the remaining DARU commitments that do not fit into the other two categories.

SRE Commitments for Capacity and DR Deployments On High Load Days

- Slides 73, 74, and 75 summarize market outcomes on select high load days when SRE commitments were made for capacity and/or DR were deployed by NYISO and/or TO. The figures report the following quantities in each interval of hours 10-22 for NYCA:
  - ✓ Available capacity from non-SRE resources – including three categories of unloaded capacity of online units and the capacity of offline peaking units up to the Upper Operating Limit:
    - 30-Minute Reserves – Scheduled;
    - 30-Minute Reserves – Unscheduled; and
    - Additional Available Capacity (beyond 30-min rampable).
  - ✓ Schedules from SRE resources – including energy and total 30-minute reserves.
  - ✓ Constraint shadow prices on the NYCA 30-minute reserve requirement.
  - ✓ 30-min reserves requirement, adjusted for SCR/EDRP calls (solid black line).
  - ✓ Utility DR deployed plus 30-minute reserves requirement (dashed black line).
  - ✓ Available capacity from non-SRE resources minus SRE energy schedules (solid purple line).
    - Shortage w/o SRE = solid black line – solid purple line
    - Shortage w/o (Utility DR & SRE) = dashed black line – solid purple line

SRE Commitments for Capacity and DR Deployments On High Load Days

- Slides 73, 74, and 75 summarize market outcomes on select high load days when SRE commitments were made for capacity and/or DR were deployed by NYISO and/or TO. The figures report the following quantities in each interval of hours 7-22 for NYCA:
  - ✓ Available capacity from non-SRE resources – including three categories of unloaded capacity of online units and the capacity of offline peaking units up to the Upper Operating Limit:
    - 30-Minute Reserves – Scheduled;
    - 30-Minute Reserves – Unscheduled; and
    - Additional Available Capacity (beyond 30-min rampable).
  - ✓ Schedules from SRE resources – including energy and total 30-minute reserves.
  - ✓ Constraint shadow prices on the NYCA 30-minute reserve requirement.
  - ✓ 30-min reserves requirement, adjusted for SCR/EDRP calls (solid black line).
  - ✓ Utility DR deployed plus 30-minute reserves requirement (dashed black line).
  - ✓ Available capacity from non-SRE resources minus SRE energy schedules (solid purple line).
    - Shortage w/o SRE = solid black line – solid purple line
    - Shortage w/o (Utility DR & SRE) = dashed black line – solid purple line

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Uplift Costs from Guarantee Payments

- Slides 77 and 78 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 77 shows these seven categories on a daily basis during the quarter.
  - ✓ Slide 78 summarizes uplift costs by region on a monthly basis.

Potential Economic and Physical Withholding

- Slides 80 and 81 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 82 summarizes the automated mitigation that was imposed in the day-ahead and real-time markets (not including BPCG mitigation) in the quarter.
  - ✓ The bars in the upper panel shows the percent of hours when incremental energy offer mitigation was imposed on one or more units in each category.
  - ✓ The bars in the lower panel shows the average mitigated capacity.
    - – Mitigated quantities are shown separately for flexible output range of units (i.e., Incremental Energy) and the non-flexible portion (i.e., MinGen).
  - ✓ The left portion shows the amount of mitigation by the Automated Mitigation Procedure (“AMP”) on economically committed units in NYC load pockets.
  - ✓ The right portion shows the amount of mitigation on the units committed for reliability in New York City, Long Island, and the upstate area.
  - ✓ Mitigation of gas turbine capacity is shown in the Incremental Energy category whenever the incremental energy offer or the startup offer is mitigated.

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Spot Capacity Market Results

- Slides 84 and 85 summarize market results and key drivers in the monthly spot capacity auctions.
  - ✓ Slide 84 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 85 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.

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Unavailable Capacity Ambient Conditions Dependent Generators

- Slide 86 shows the estimated ICAP that was functionally unavailable to the market during peak conditions this summer from fossil generators and nuclear units by category:
  - ✓ Emergency Capacity
    - – The amount of capacity offered by units in their UOLe ranges. This is unavailable for normal operations and only dispatchable under emergency circumstances.
  - ✓ High Air Temps
    - – The amount of capacity unavailable due to actual peak summer temperatures exceeding the temperature adjustment values used by various generators in DMNC tests.
  - ✓ Ambient Humidity
    - – The amount of capacity explicitly derated from CCs and Peakers not explained by air temperature conditions.
  - ✓ Potential Steam
    - – The amount of capacity unavailable from cogeneration resources with active host steam load obligations.
  - ✓ Ambient Water
    - – The amount of capacity explicitly derated from fossil and nuclear STs due to ambient water temperatures.
  - ✓ Unreported
    - – The amount of capacity observed to be unavailable from generator dragging when dispatched to maximum under peak conditions but without an explicit derate reason reported.
- Values by category are given as percentages of total by unit type on the primary axis with the total ICAP across all resources summed in the secondary axis.

DMNC Test Ambient Conditions of Fossil and Nuclear ST Units

- Slide 87 shows the ambient water temperature and tidal conditions during the DMNC tests applicable to Summer 2023 of once-through-cooled steam turbine units.
  - ✓ The x-axis provides temperature ranges in 2°F increments based on the difference between the resource's DMNC test water temperatures and the average water temperature for each resource across July and August 2022.
    - DMNC tests for the current Summer Capability Period were conducted per usual procedures during the Summer Capability Period one year prior.
    - Columns that stack to the left of the dashed black line show the amount of DMNC from these resources that tests at cooler-than-average temperatures.
  - ✓ The stacked columns are differentiated based on how the DMNC test conditions for each resource compared against its average tide conditions.
    - Low Tide denotes cases where the average tidal level during the DMNC test was in the bottom 25th percentile of the tidal range.
    - Low-Medium Tide shows cases where the average tidal level during the DMNC test was below the average tidal level but above the 25th percentile.
    - High-Medium Tide shows cases where the average tidal level during the DMNC test was above the average tidal level but below the 75th percentile.
    - High Tide denotes cases where the average tidal level during the DMNC test was above the 75th percentile of the tidal range.