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


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# Market Highlights

# Market Highlights:
## Executive Summary

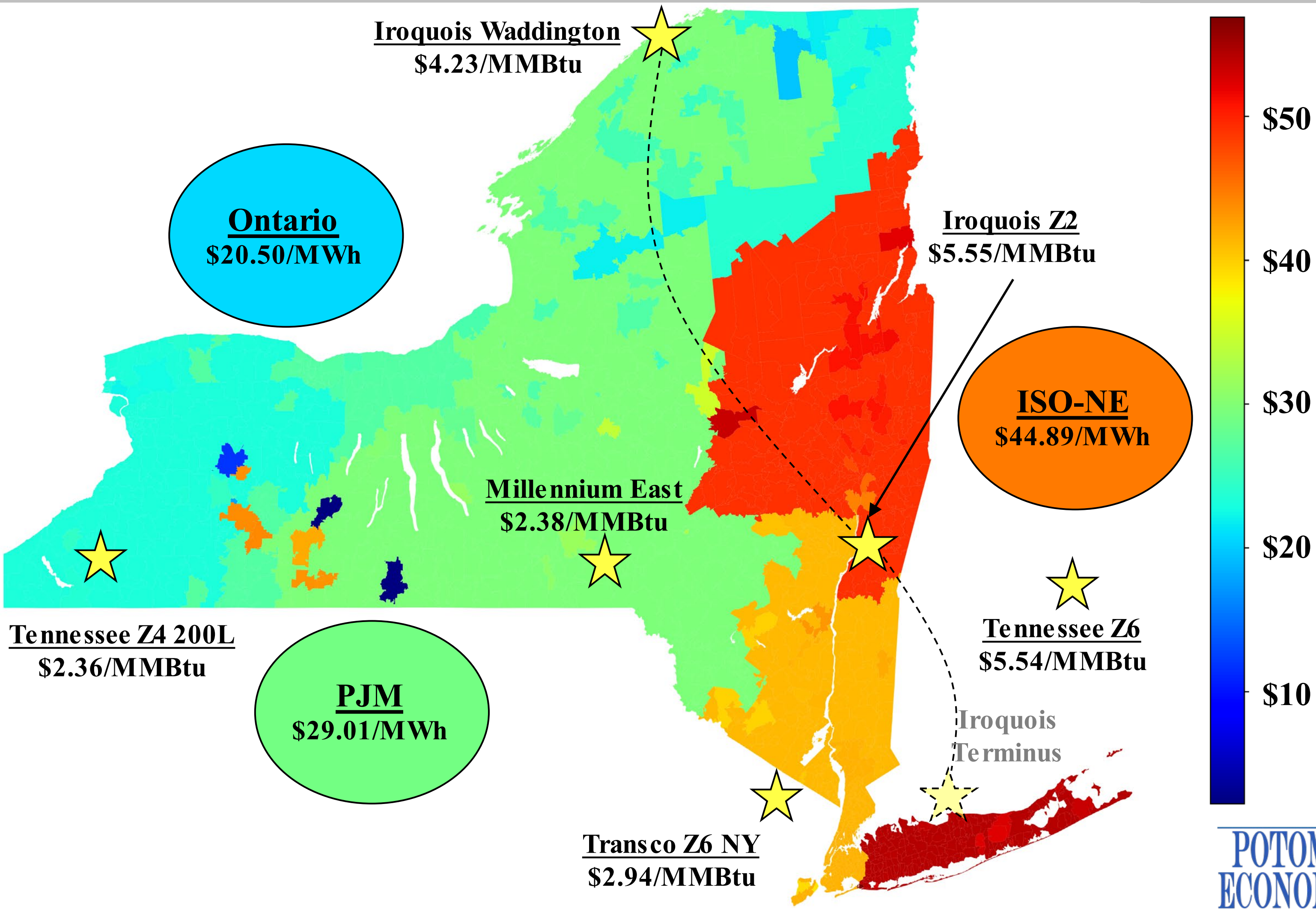
- NYISO energy markets performed competitively in the first quarter of 2023.
  - ✓ However, we identify an issue with local reliability units on the next slide.
- All-in prices ranged from $30/MWh in the North Zone to $65/MWh in Long Island, down 50 to 59 percent from a year ago. (slide 7)
  - ✓ Energy prices fell 54 to 66 percent, primarily because of lower gas prices, which fell 42 to 58 percent because of milder winter conditions.
  - ✓ Average load was down by 5 percent as a result of the mild winter weather.
  - ✓ Congestion revenue fell by 63 percent, reflecting smaller congestion-related price differences because of lower gas prices.
  - ✓ Capacity prices rose with all regions set by the NYCA demand curve. (slide 13)
    - This was driven primarily by supply reductions due to NYC peaker retirements, higher exports to neighboring markets, and lower imports from neighboring areas.
- Wind generation curtailments occurred in 29 percent of intervals, up from 17 percent in 2022-Q1. Curtailment increased after the installation of:
  - ✓ Over 200 MW of additional wind capacity in the Central Zone in late-2022, and
  - ✓ The Western NY PPT Project in May 2022, which shifted some bottlenecks from the Niagara-Buffalo path to 115 kV facilities in the Finger Lakes area.

# Market Highlights:
## Executive Summary

- OOM commitments for local operating reserve needs were frequent in load pockets of: (a) the North Country (82 days); and (b) N.Y.C. (52 days). (slide 11)
  - ✓ Incorporating these reserve requirements in the market software (after the Dynamic Reserves enhancement) would improve price signals and incentives for investment in resources that can satisfy the requirements more efficiently.
- Units committed for local reliability increased their minimum operating MW level in real-time above their reference level without adequate justification.
  - ✓ When units are OOM-committed for local reliability, they typically operate at their minimum stable operating level.
  - ✓ Although appropriately mitigated to their Minimum Generation MW reference level, these units will likely receive roughly $2 million of additional BPCG in a resettlement of 2023-Q1 that categorizes the mitigated output range as a reliability dispatch.

# Market Highlights:
## System Price Diagram

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# Market Highlights:
## Summary of Energy Market Outcomes

- NYISO energy markets performed competitively in the first quarter of 2023.
  - ✓ The amount of output gap (slide 67) and unoffered economic capacity (slide 68) remained modest and reasonably consistent with competitive market expectations.
- All-in prices ranged from $30/MWh in the North Zone to $65/MWh in Long Island, down 50 to 59 percent from a year ago. (slide 15)
  - ✓ Energy prices fell substantially in all zones, including by 61 to 66 percent in West NY and 54 to 61 percent in East NY. Decreases were driven primarily by:
    - Lower natural gas prices, which fell 42 to 58 percent across the system (slide 17);
    - Lower load levels, which fell 5 percent on average (slide 16); and
    - Higher nuclear generation (by ~200 MW) also contributed. (slide 18)
  - ✓ Congestion was still frequent across the Central-East interface partly because of continuing transmission outages to facilitate the Public Policy Transmission work, but congestion value fell substantially due to lower gas prices and load levels. (slide 50)
  - ✓ Capacity costs rose in all areas for reasons discussed in slide 13.

# Market Highlights:
## Generation by Fuel and Emissions

- Internal generation fell by 520 MW from a year ago due to the reduction in average load levels (900 MW).
  - ✓ Average net imports fell by 380 MW.
  - ✓ However, nuclear generation rose by 200 MW because of fewer refueling outages.
- Oil-fired generation averaged 90 MW, down 83 percent from a year ago.
  - ✓ Less severe winter conditions increased the availability of natural gas, making oil-fired production less economic.
  - ✓ Nearly all the oil-fired output occurred on two cold days (Feb. 3 & 4) when natural gas prices significantly exceeded fuel oil prices on several pipelines. (slide 20)
- Gas-fired generation fell by about 220 MW. (slide 18)
  - ✓ Gas-fired CC output rose by 320 MW, while gas-fired generation from STs and GTs fell by 540 MW, with the largest reduction occurring in Lower Hudson VL.
- Wind resources were marginal in 29 percent of intervals as a result of more frequent congestion on the North-to-Central and West-to-Central paths. (slide 19)
  - ✓ Most of the additional congestion was associated with 115 kV limitations in the Finger Lakes area after the installation of new wind generation, the installation of the Western NY public policy project, and re-rating of facilities at the Meyer 230/115 kV substation.

# Market Highlights:
## Congestion Patterns, Revenues and Shortfalls

- Day-ahead congestion revenues totaled $143 million, down 63 percent from the first quarter of 2022. (slide 48)
- Transmission paths from Central to East (primarily the Central-East interface) accounted for the largest share of congestion (DA 69%, RT 56%). (slide 49)
  - ✓ Despite more frequent congestion, congestion value (in $s) fell by nearly 60 percent from a year ago primarily because of lower natural gas prices and regional gas price spreads.
  - ✓ In addition, continuing transmission outages to facilitate Public Policy Segment A & B construction reduced West-to-East transfer capability, especially in March.
- The external interfaces accounted for the second largest share of congestion this quarter (DA 12%, RT 13%).
  - ✓ 90 percent of this congestion occurred on:
    - The primary interface with New England (54%); and
    - The primary interface with PJM (36%)
  - ✓ Congestion across the external interfaces fell by more than 70 percent from a year ago because of lower regional gas price spreads.



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

- West-to-Central congestion has been on the rise in recent quarters partly because of the new entry of wind resources in the Finger Lakes area. In 2023-Q1:
  - ✓ This congestion accounted for 6 percent of DA total congestion and 14 percent of RT total congestion, respectively.
  - ✓ This real-time congestion value more than doubled day-ahead value (in $s) with more than 80 percent occurring at the Meyer 230/115 kV substation.
    - – Central Zone wind resources typically under-schedule energy in the day-ahead market—typically less than 50 percent of real-time generation.
    - – This has contributed to higher frequency and value of congestion in real time.
- Most of the remaining congestion occurred on Long Island. (slide 49)
  - ✓ Nearly 90 percent of this congestion occurred on the Y50 line (one of the two 345 kV inter-ties between upstate regions and Long Island).
  - ✓ This was driven primarily by the planned outage of the parallel Y49 line from October 2022 until May 2023.

# Market Highlights:
## OOM Actions to Manage Network Reliability

- OOM actions to manage network reliability were most frequent in the North Zone (82 days) and New York City (52 days). (slide 53)
  - ✓ The vast majority of these OOM actions was for maintaining reserves to satisfy the N-1-1 requirements in local load pockets within the two areas.
  - ✓ Incorporating these requirements in the market scheduling and pricing process (after the Dynamic Reserves enhancement) would greatly enhance price signals, improving the efficiency of guiding retirement and investment decisions.
- Reliability commitments for the N-1-1 requirements in the North Country Load Pocket ("NCLP") occurred on 82 days. (slide 65)
  - ✓ The NYISO DARUed these units on the vast majority of days instead of using SRE, which helped improve scheduling and pricing efficiency in this area.
  - ✓ Nonetheless, these OOM commitments led to:
    - $5 million of BPCG uplift; and
    - A total of 11.8 GWh of wind curtailments during ~800 intervals across 37 days.
      - Wind generation is currently not counted towards satisfying the N-1-1 requirements in the load pockets, so reliability commitments increase generation in the area, often causing additional wind curtailment.

# Market Highlights:

## Reliability Commitments, OOM Dispatch, and BPCG

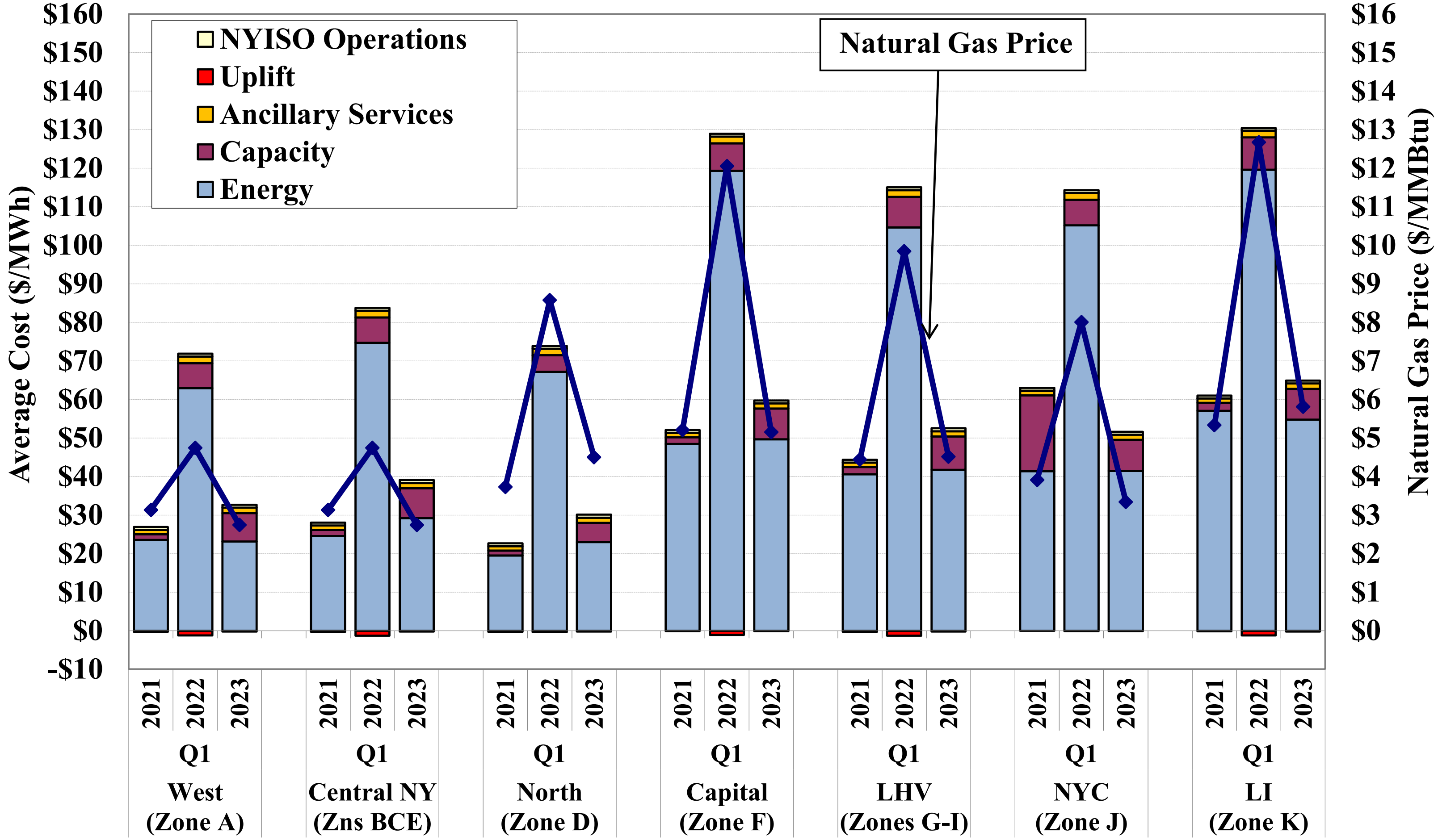
- BPCG payments totaled nearly $10 million, which was down 42 percent from 2022-Q1, primarily because of lower natural gas prices, especially for units in NYC. (slide 17)
- Only $2.7 million (or 27 percent) of BPCG payments accrued in NYC, 64 percent of which were paid to units that were committed for local reliability. (slide 64)
  - ✓ Total BPCG in NYC fell by $4.9 million, or 64 percent, from the prior year.
  - ✓ Nonetheless, the amount of local reliability commitments, which occurred on 52 days, was comparable to a year ago. (slides 61-62)
  - ✓ Reliability commitments were high in March, where the increased needs resulted from transmission maintenance outages in the Freshkills load pocket and maintenance outages of combined-cycle resources in the Astoria West load pocket.
- However, BPCG uplift in West Upstate (i.e., Zones A-E) rose from a year ago, accounting for $5.1 million (or 52 percent) of total BPCG uplift this quarter.
  - ✓ More than 95 percent of this uplift accrued on units that were supplementally committed for the N-1-1 requirement in the North Country load pocket. (slide 64)

# Market Highlights:
## Capacity Market

- Spot capacity prices averaged $3.11/kW-month in all regions this quarter. (slides 71-72)
  - ✓ Prices in all regions cleared on the systemwide curve for each of the three months.
  - ✓ Prices increased in all regions (9 percent in Long Island and 22 percent elsewhere) from the prior year.
- The increase in the systemwide prices was driven largely by supply changes:
  - ✓ 435 MW of supply retired, primarily peaking facilities in NYC.
  - ✓ 350 MW of reduced imports, primarily from PJM and Quebec.
  - ✓ Up to 250 MW of increased capacity exports to Quebec during the peak winter months of January and February.
- Factors that mitigated the increase of prices included:
  - ✓ The systemwide ICAP requirement fell by over 1 GW because:
    - The IRM fell from 120.7 percent to 119.6 percent.
    - The peak load forecast fell by ~570 MW.
  - ✓ Roughly 140 MW of new renewable capacity entered the market.

# Charts:
## Market Outcomes

# All-In Prices by Region








Notes: For chart description, see slide 74.

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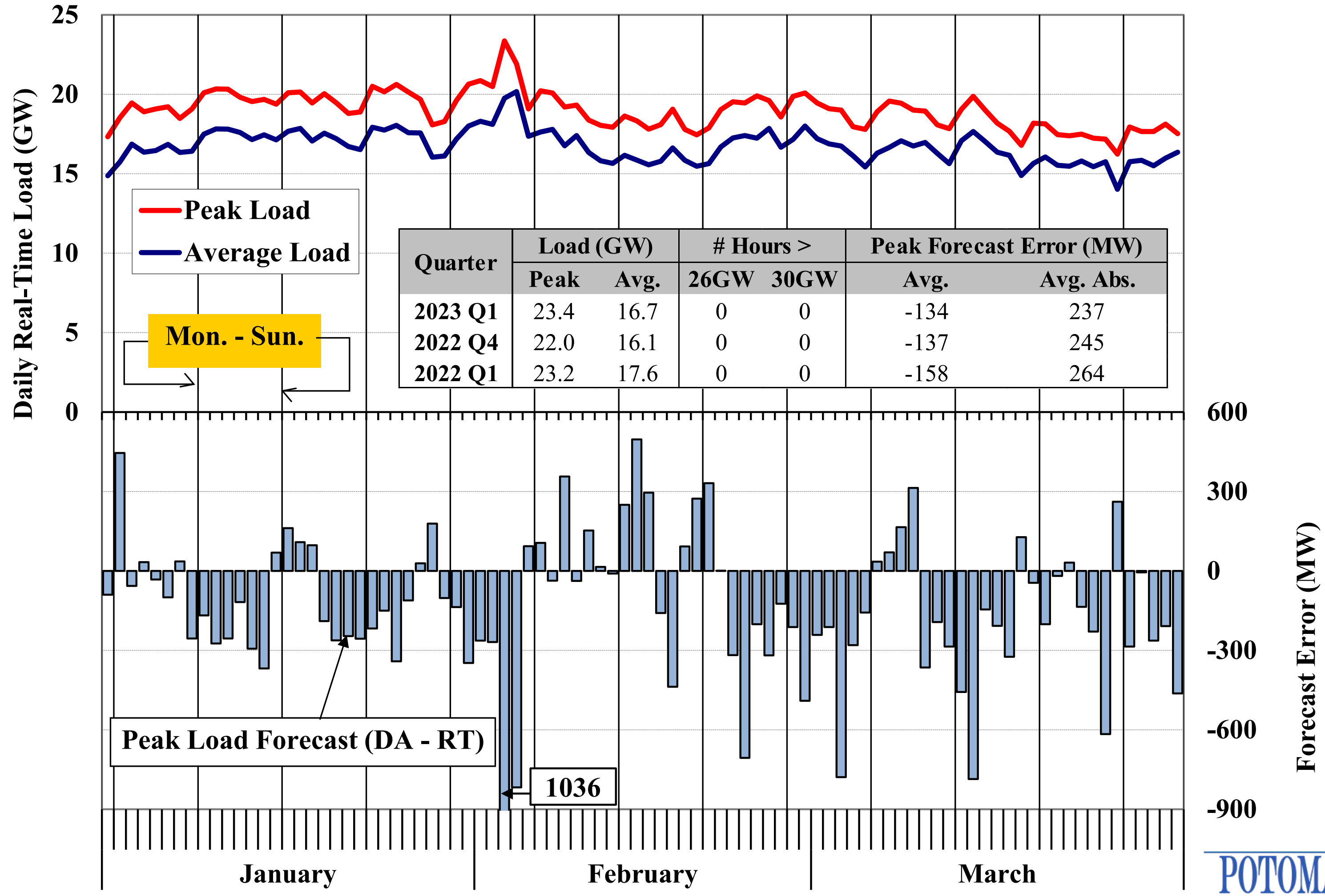
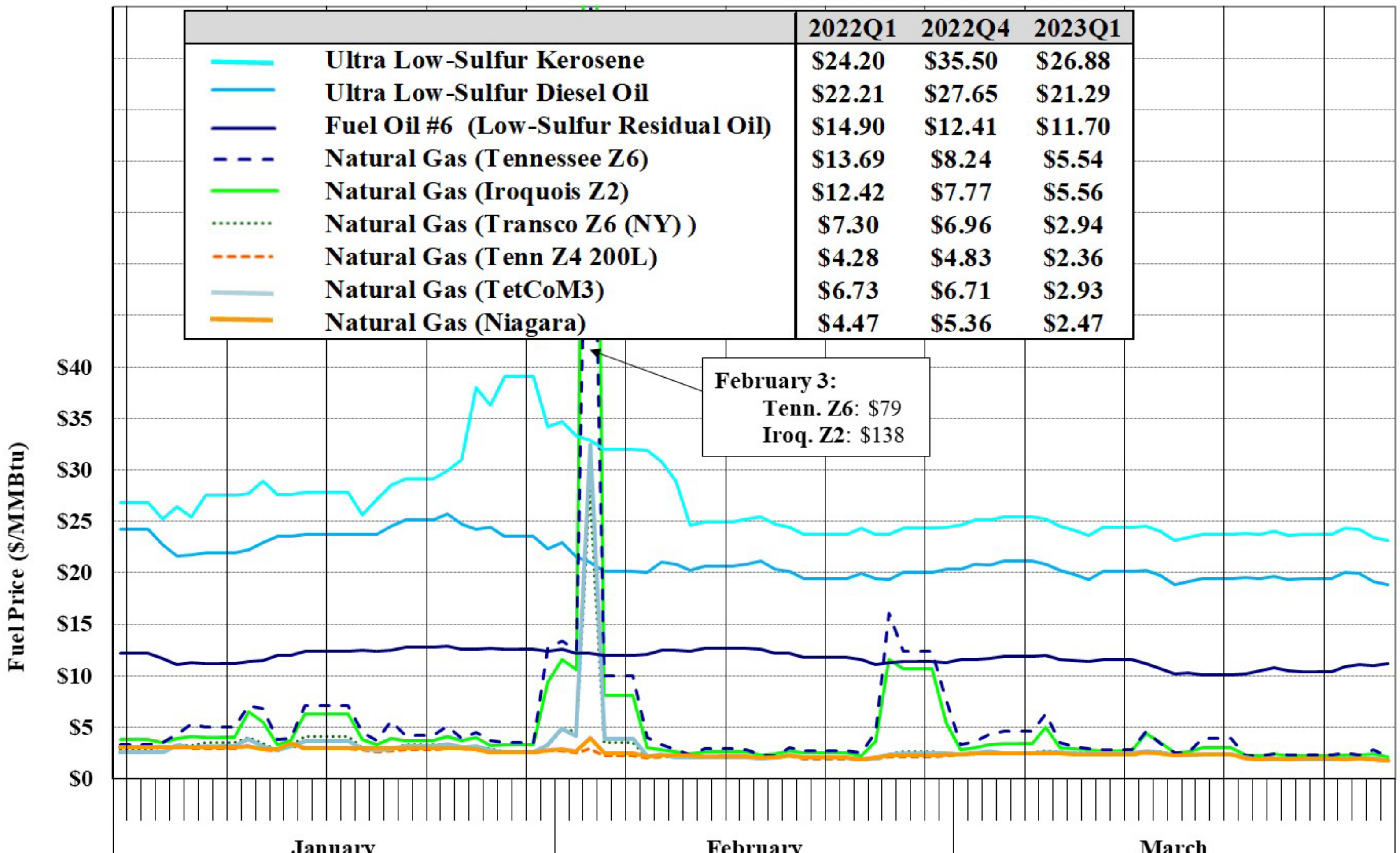
# Load Forecast and Actual Load

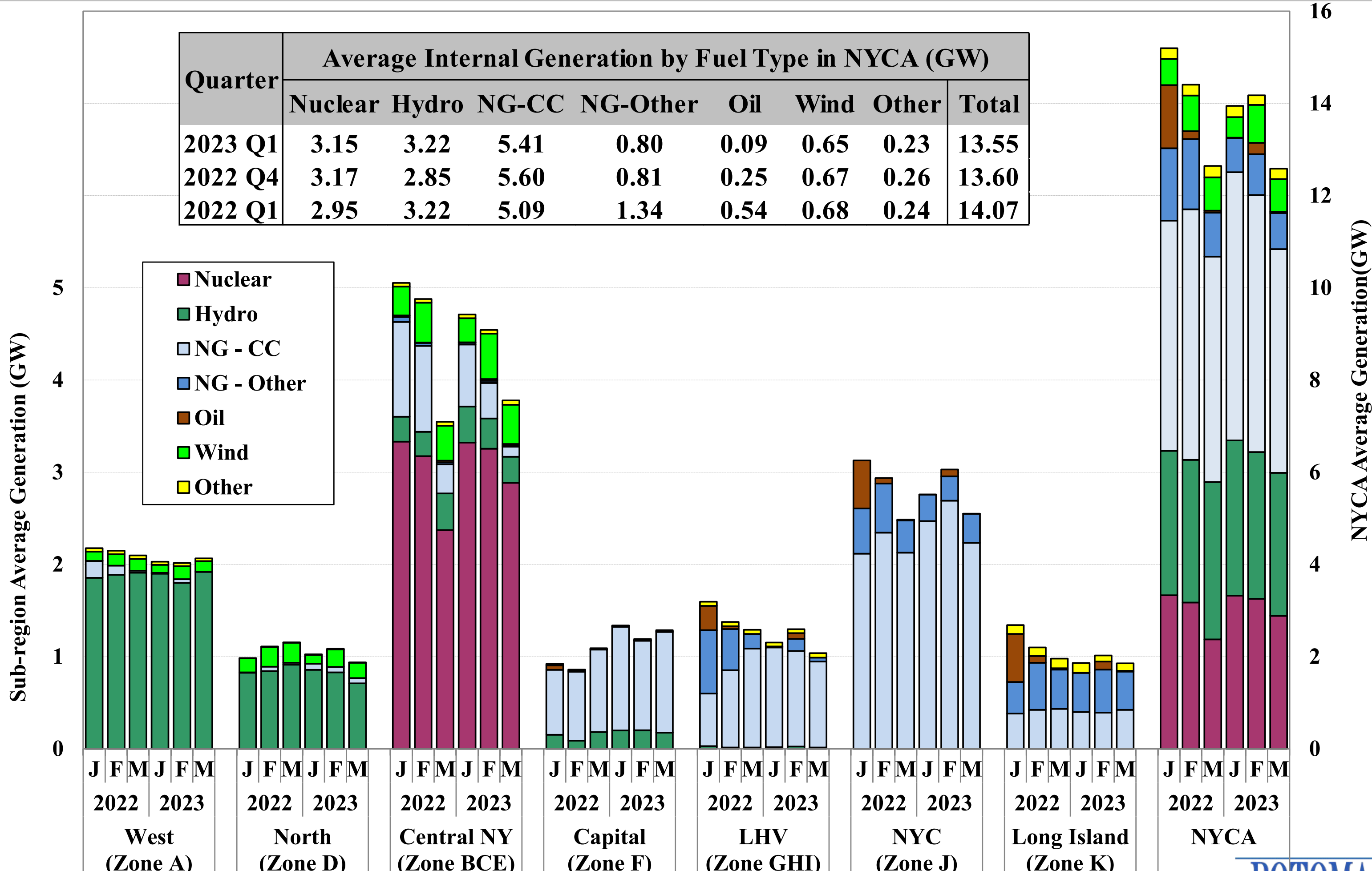



| Quarter | Load (GW) | | # Hours > | | Peak Forecast Error (MW) | |
|---|---|---|---|---|---|---|
| | Peak | Avg. | 26GW | 30GW | Avg. | Avg. Abs. |
| 2023 Q1 | 23.4 | 16.7 | 0 | 0 | -134 | 237 |
| 2022 Q4 | 22.0 | 16.1 | 0 | 0 | -137 | 245 |
| 2022 Q1 | 23.2 | 17.6 | 0 | 0 | -158 | 264 |

# Natural Gas and Fuel Oil Prices



# 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 Q1 | 3.15 | 3.22 | 5.41 | 0.80 | 0.09 | 0.65 | 0.23 | 13.55 |
| 2022 Q4 | 3.17 | 2.85 | 5.60 | 0.81 | 0.25 | 0.67 | 0.26 | 13.60 |
| 2022 Q1 | 2.95 | 3.22 | 5.09 | 1.34 | 0.54 | 0.68 | 0.24 | 14.07 |





Notes: For chart description, see slide 75.

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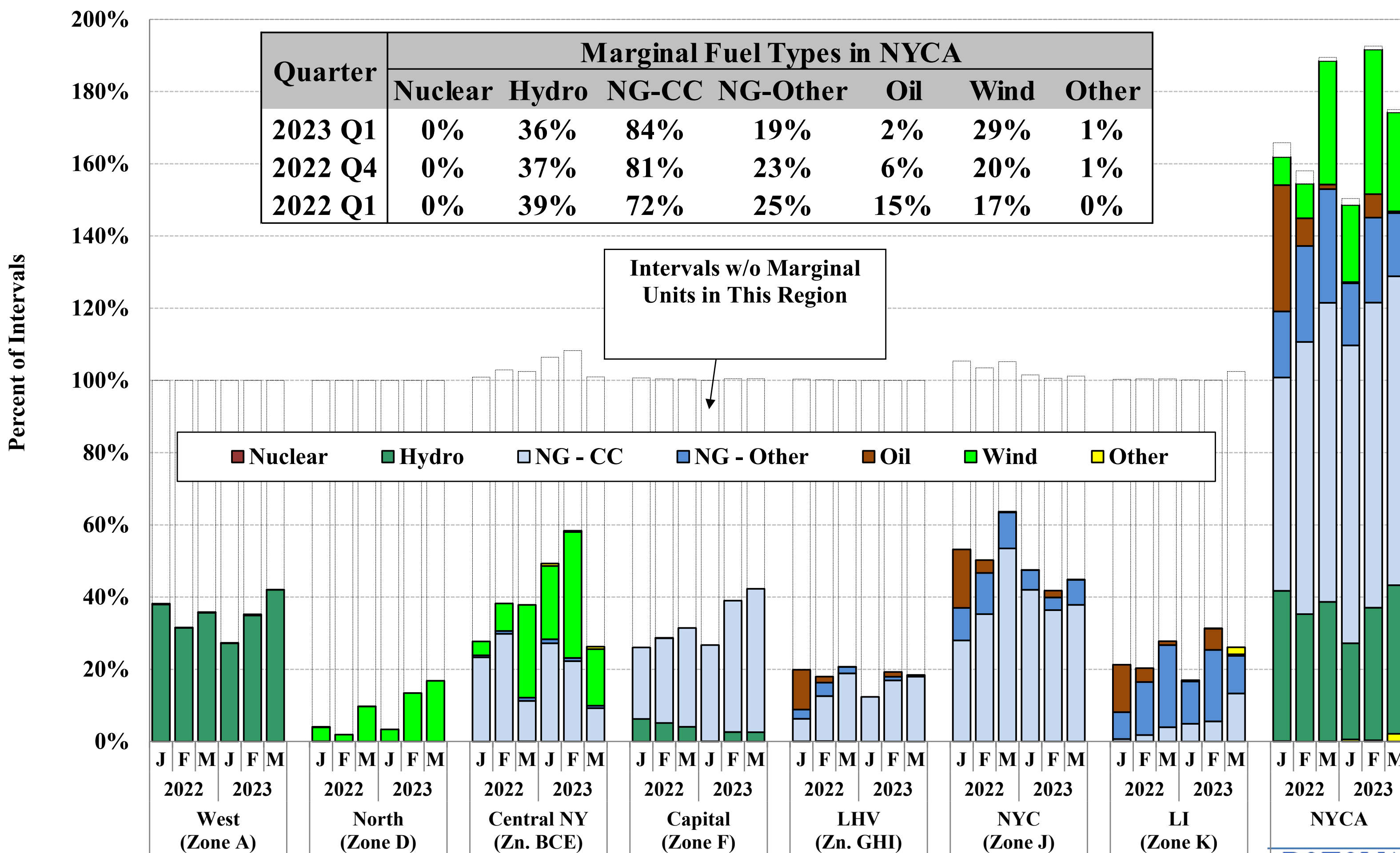
# Fuel Type of Marginal Units in the Real-Time Market




| Quarter | Marginal Fuel Types in NYCA | | | | | | |
|---|---|---|---|---|---|---|---|
| | Nuclear | Hydro | NG-CC | NG-Other | Oil | Wind | Other |
| 2023 Q1 | 0% | 36% | 84% | 19% | 2% | 29% | 1% |
| 2022 Q4 | 0% | 37% | 81% | 23% | 6% | 20% | 1% |
| 2022 Q1 | 0% | 39% | 72% | 25% | 15% | 17% | 0% |



Notes: For chart description, see slide 75.
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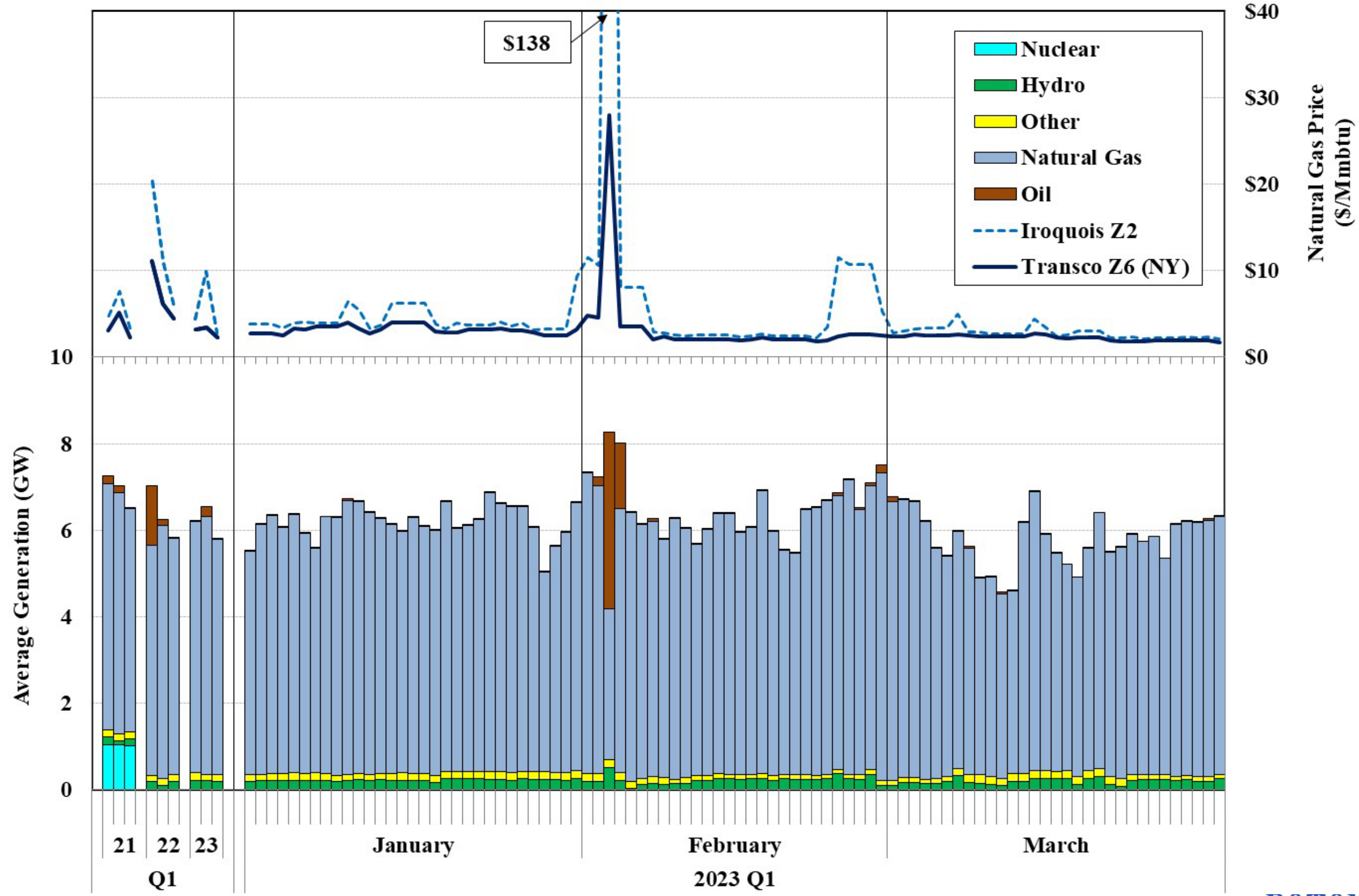
# Winter Fuel Usage
## Eastern New York




  Notes: For chart description, see slide 76.

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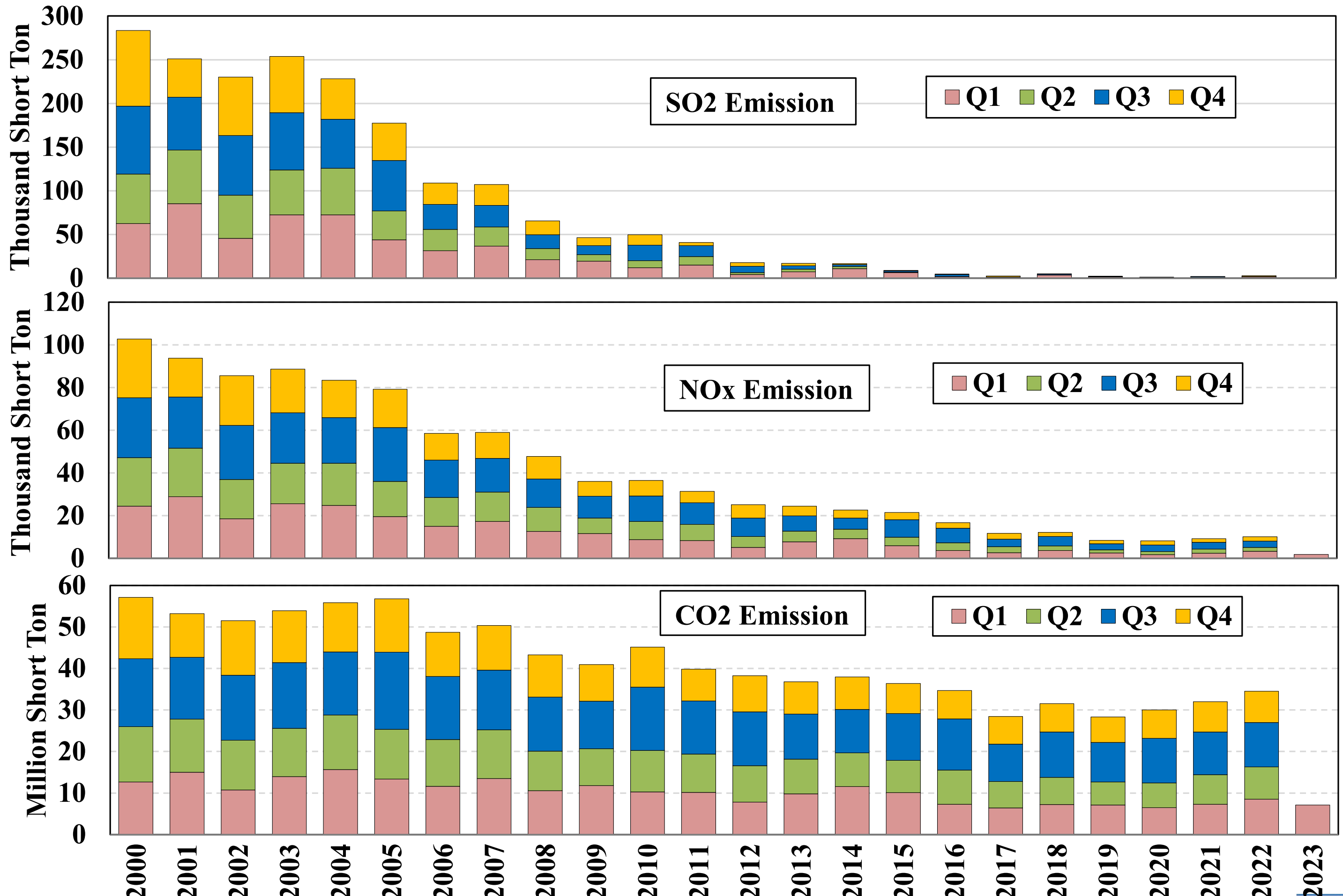
# Historical Emissions by Quarter in NYCA
## $CO_2$, $SO_2$ , and $NO_X$




Notes: For chart description, see slide 79.





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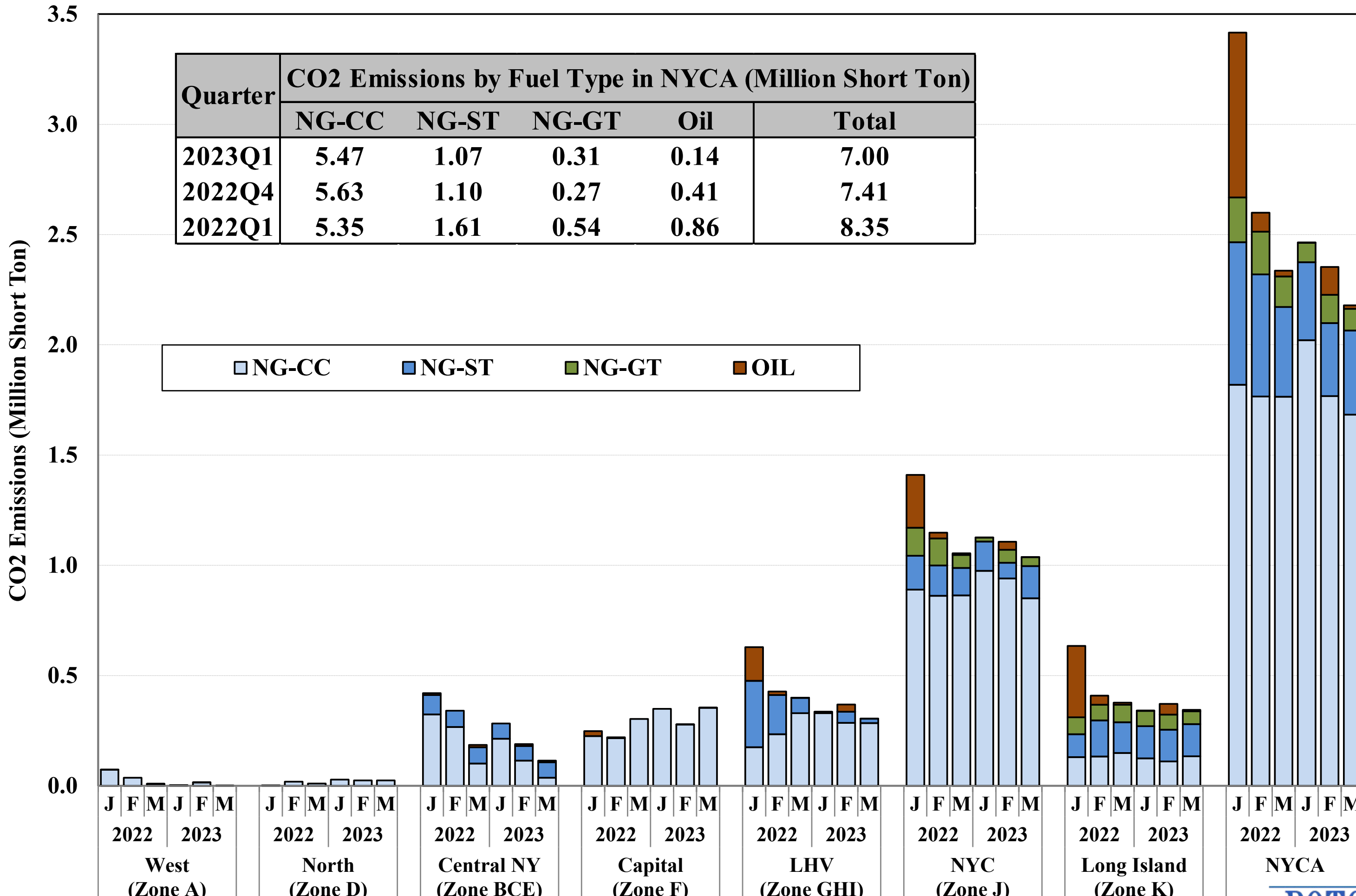
# Emissions by Region by Fuel Type
## $CO_2$ Emissions

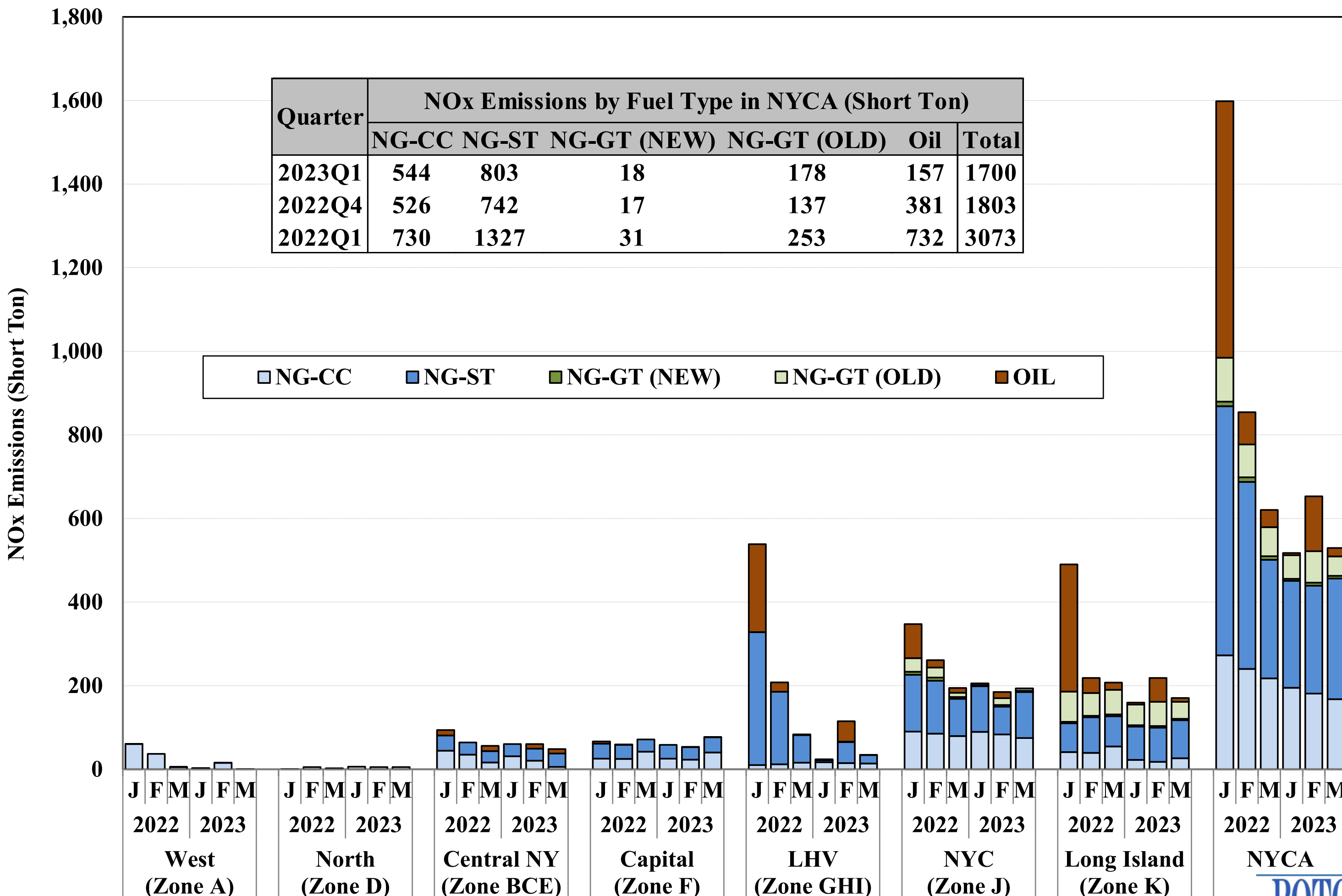
| Quarter | CO2 Emissions by Fuel Type in NYCA (Million Short Ton) | | | | |
|---|---|---|---|---|---|
| | NG-CC | NG-ST | NG-GT | Oil | Total |
| 2023Q1 | 5.47 | 1.07 | 0.31 | 0.14 | 7.00 |
| 2022Q4 | 5.63 | 1.10 | 0.27 | 0.41 | 7.41 |
| 2022Q1 | 5.35 | 1.61 | 0.54 | 0.86 | 8.35 |




Notes: For chart description, see slide 79.

# 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 |
| 2023Q1 | 544 | 803 | 18 | 178 | 157 | 1700 |
| 2022Q4 | 526 | 742 | 17 | 137 | 381 | 1803 |
| 2022Q1 | 730 | 1327 | 31 | 253 | 732 | 3073 |








Notes: For chart description, see slide 79.

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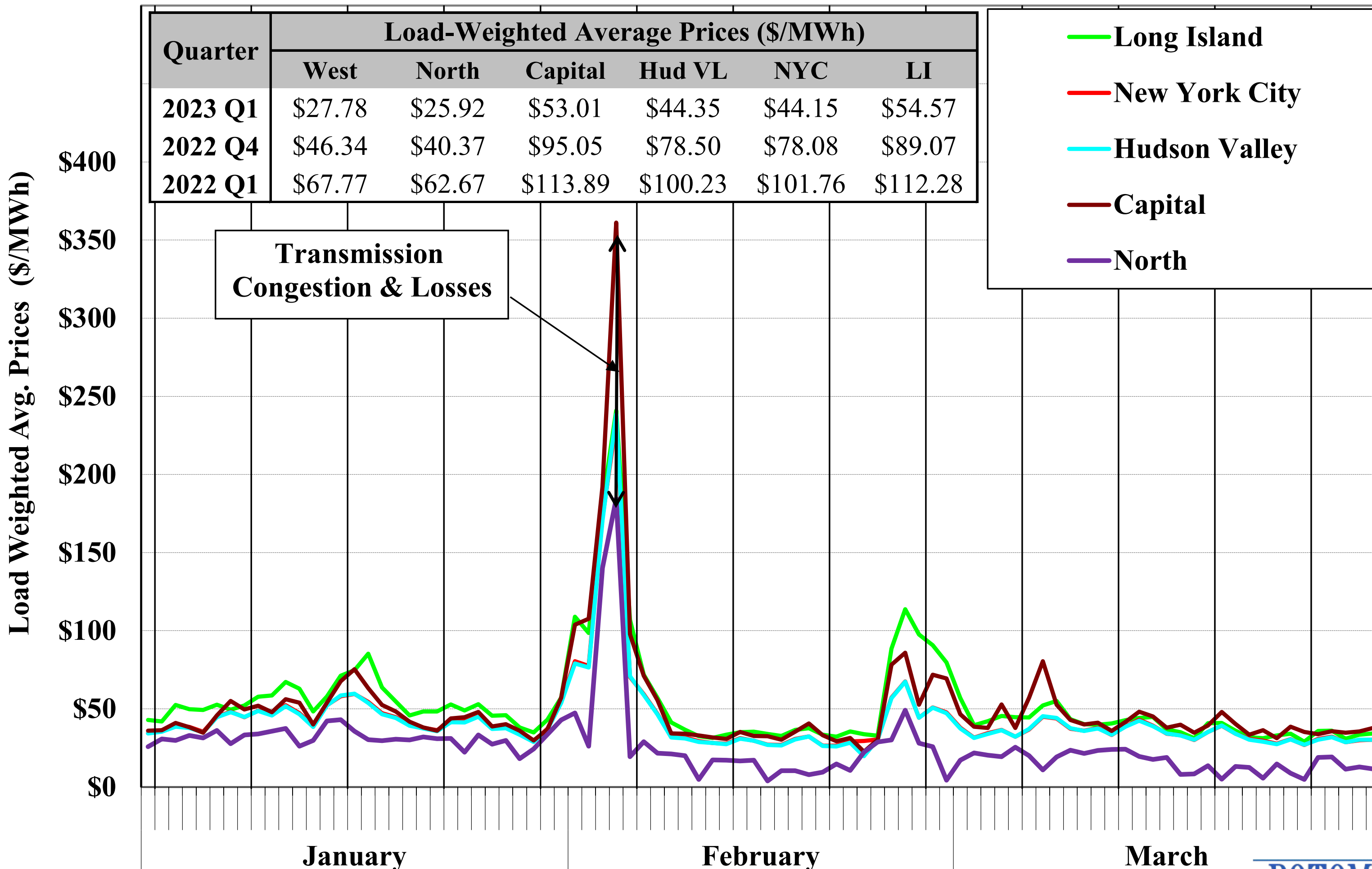
# Day-Ahead Electricity Prices by Zone




| Quarter | Load-Weighted Average Prices ($/MWh) | | | | | |
|---|---|---|---|---|---|---|
| | West | North | Capital | Hud VL | NYC | LI |
| 2023 Q1 | $27.78 | $25.92 | $53.01 | $44.35 | $44.15 | $54.57 |
| 2022 Q4 | $46.34 | $40.37 | $95.05 | $78.50 | $78.08 | $89.07 |
| 2022 Q1 | $67.77 | $62.67 | $113.89 | $100.23 | $101.76 | $112.28 |





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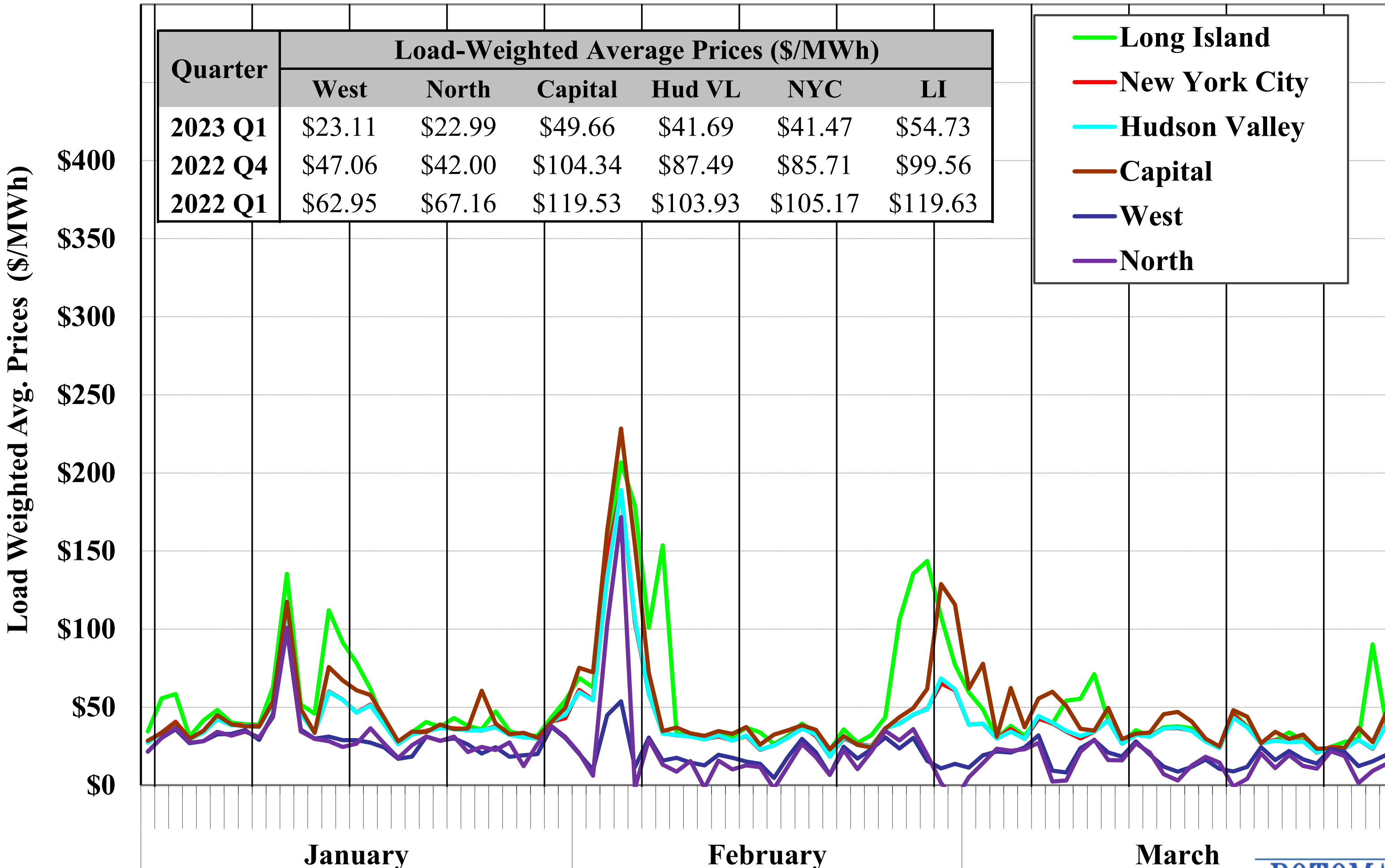
# Real-Time Electricity Prices by Zone




| Quarter | Load-Weighted Average Prices ($/MWh) | | | | | |
|---|---|---|---|---|---|---|
| | West | North | Capital | Hud VL | NYC | LI |
| 2023 Q1 | $23.11 | $22.99 | $49.66 | $41.69 | $41.47 | $54.73 |
| 2022 Q4 | $47.06 | $42.00 | $104.34 | $87.49 | $85.71 | $99.56 |
| 2022 Q1 | $62.95 | $67.16 | $119.53 | $103.93 | $105.17 | $119.63 |





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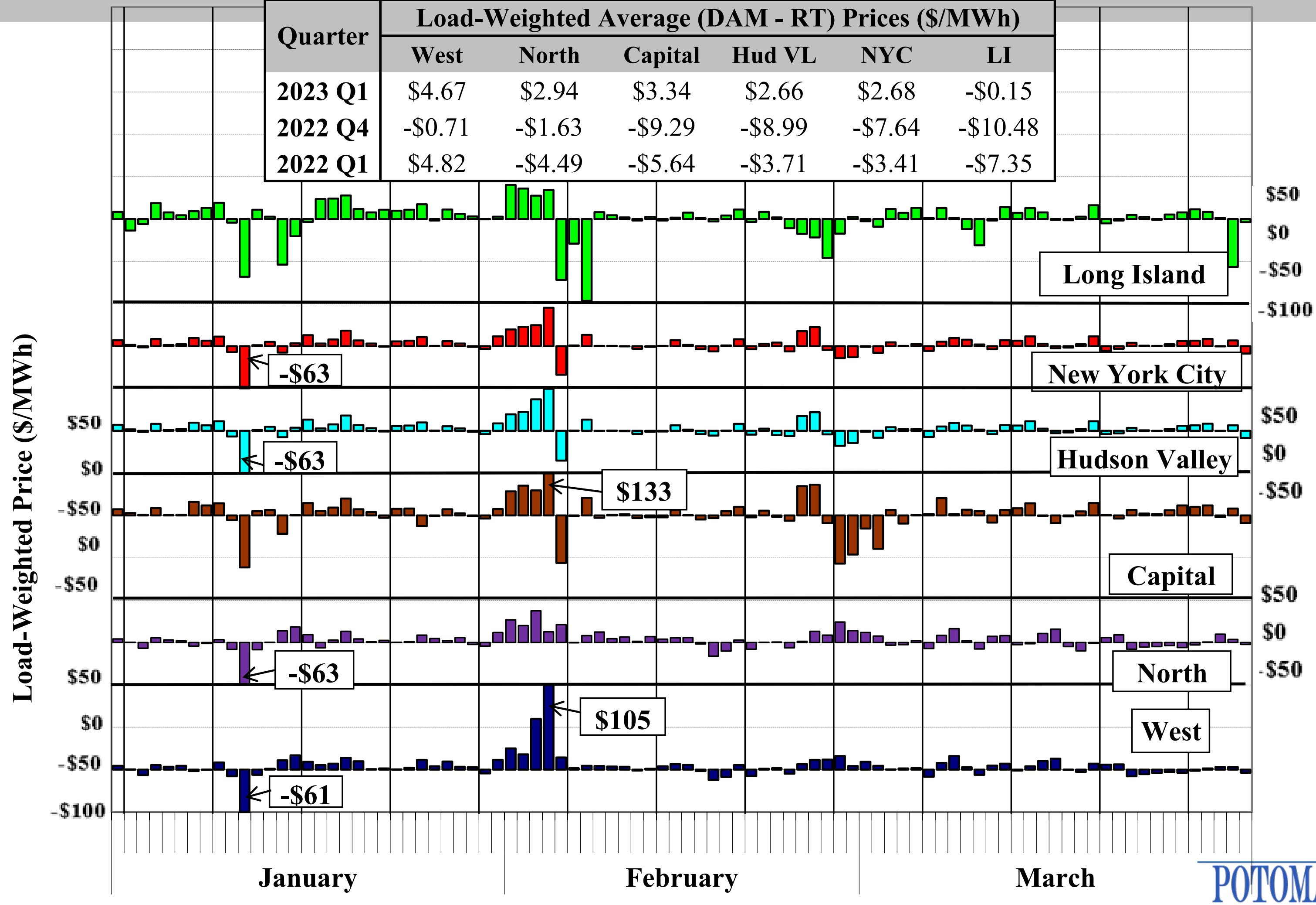
# Convergence Between Day-Ahead and Real-Time Prices

| Quarter | Load-Weighted Average (DAM - RT) Prices ($/MWh) | | | | | |
|---|---|---|---|---|---|---|
| | West | North | Capital | Hud VL | NYC | LI |
| 2023 Q1 | $4.67 | $2.94 | $3.34 | $2.66 | $2.68 | -$0.15 |
| 2022 Q4 | -$0.71 | -$1.63 | -$9.29 | -$8.99 | -$7.64 | -$10.48 |
| 2022 Q1 | $4.82 | -$4.49 | -$5.64 | -$3.71 | -$3.41 | -$7.35 |







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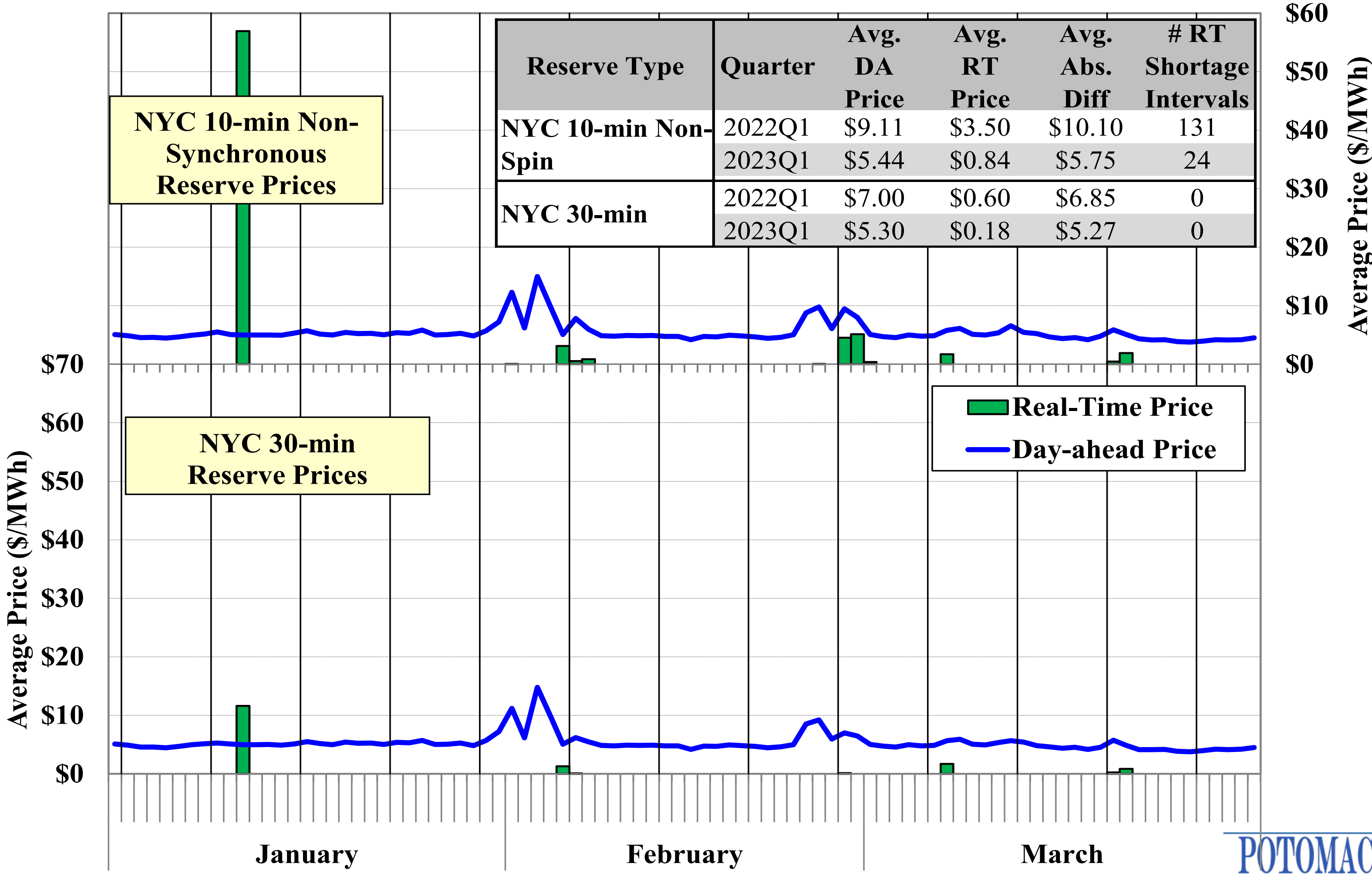
# Charts:

## Ancillary Services Market

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

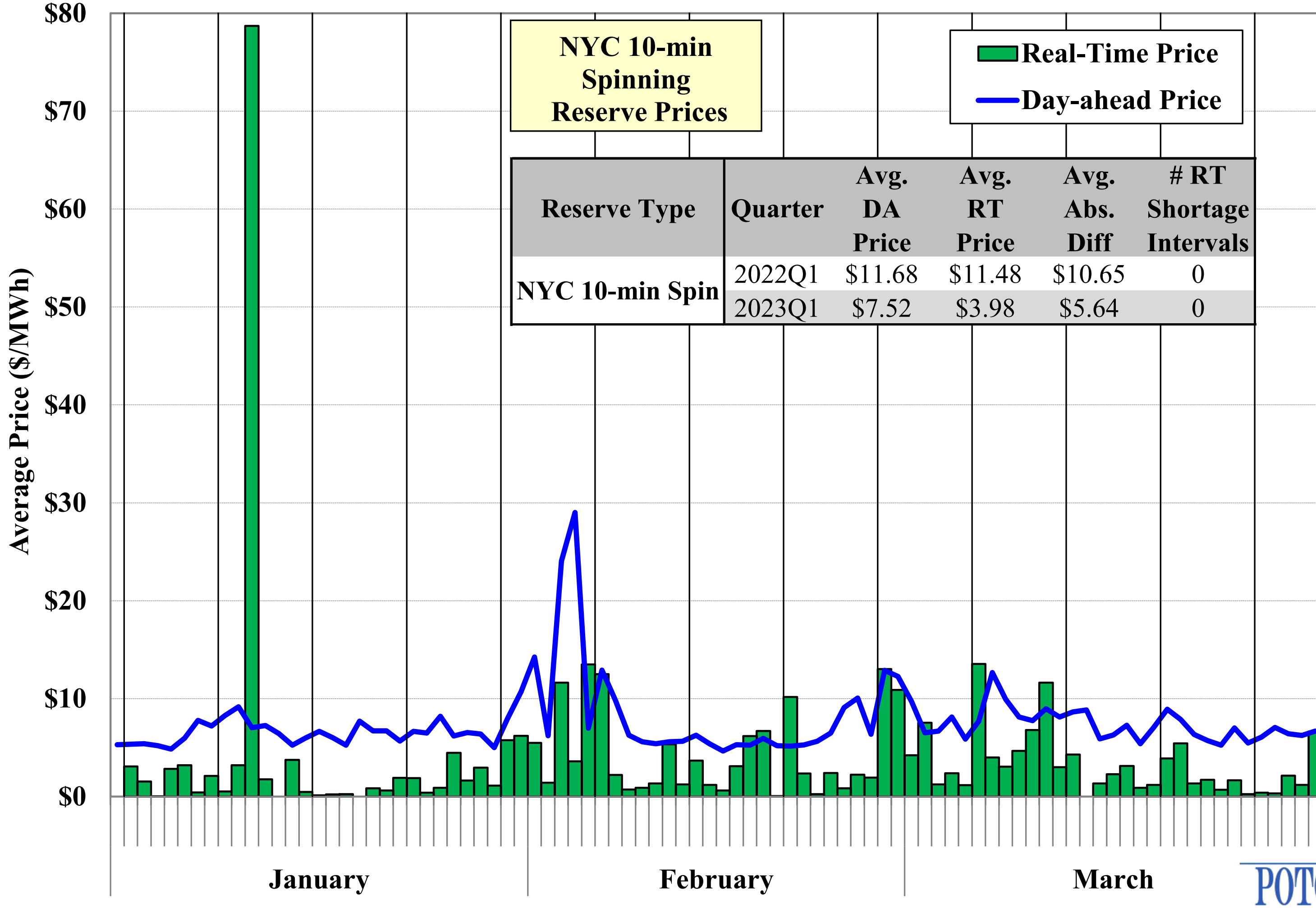



| Reserve Type | Quarter | Avg. DA Price | Avg. RT Price | Avg. Abs. Diff | # RT Shortage Intervals |
|---|---|---|---|---|---|
| NYC 10-min Non-Spin | 2022Q1 | $9.11 | $3.50 | $10.10 | 131 |
| | 2023Q1 | $5.44 | $0.84 | $5.75 | 24 |
| NYC 30-min | 2022Q1 | $7.00 | $0.60 | $6.85 | 0 |
| | 2023Q1 | $5.30 | $0.18 | $5.27 | 0 |



Notes: For chart description, see slide 80.

# 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 | 2022Q1 | $11.68 | $11.48 | $10.65 | 0 |
| | 2023Q1 | $7.52 | $3.98 | $5.64 | 0 |



Notes: For chart description, see slide 80.

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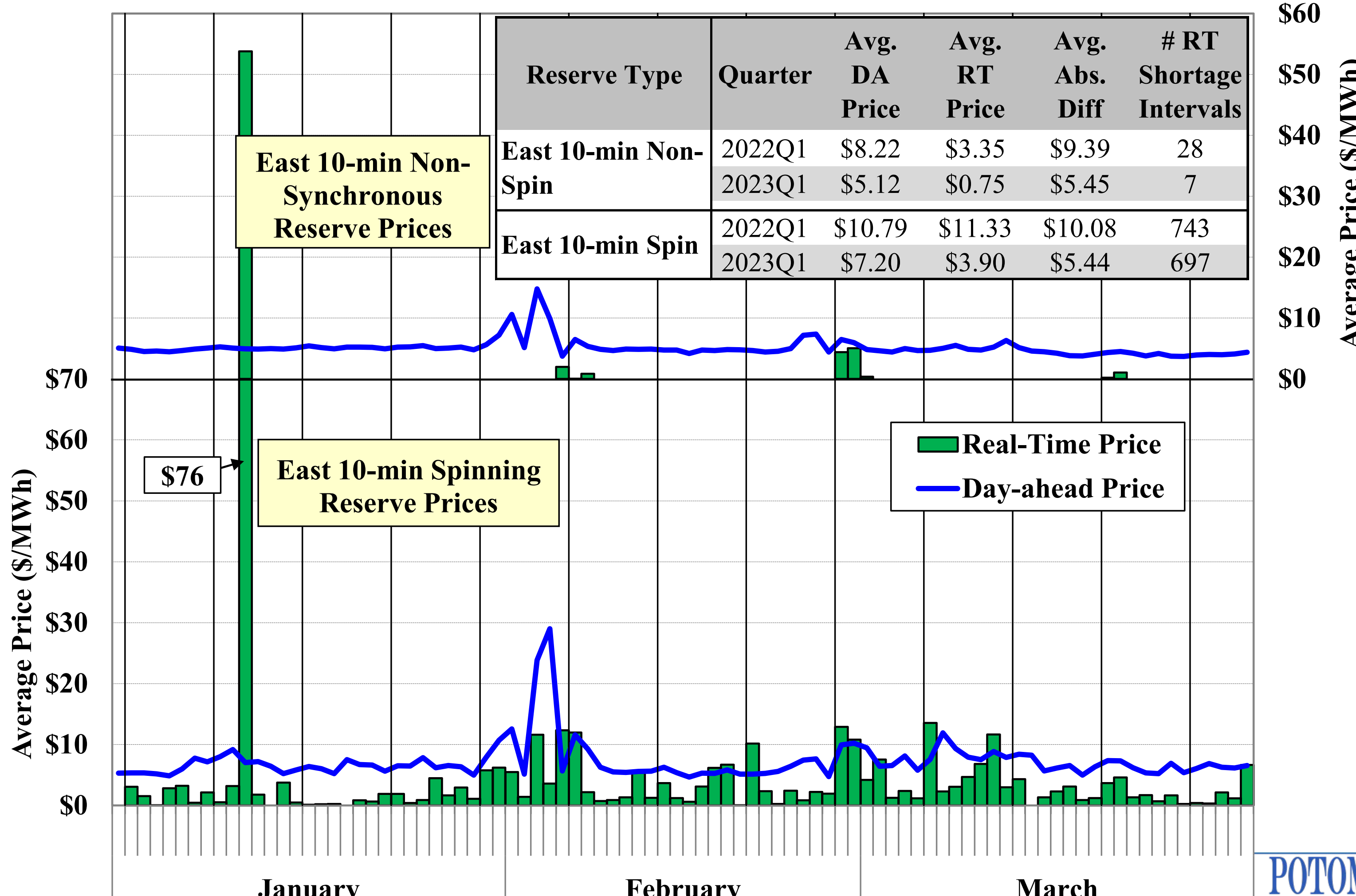
# Day-Ahead and Real-Time Ancillary Services Prices
## Eastern 10-Minute Spinning and Non-Spinning Reserves

| Reserve Type | Quarter | Avg. DA Price | Avg. RT Price | Avg. Abs. Diff | # RT Shortage Intervals |
|---|---|---|---|---|---|
| East 10-min Non-Spin | 2022Q1 | $8.22 | $3.35 | $9.39 | 28 |
| | 2023Q1 | $5.12 | $0.75 | $5.45 | 7 |
| East 10-min Spin | 2022Q1 | $10.79 | $11.33 | $10.08 | 743 |
| | 2023Q1 | $7.20 | $3.90 | $5.44 | 697 |




Notes: For chart description, see slide 80.



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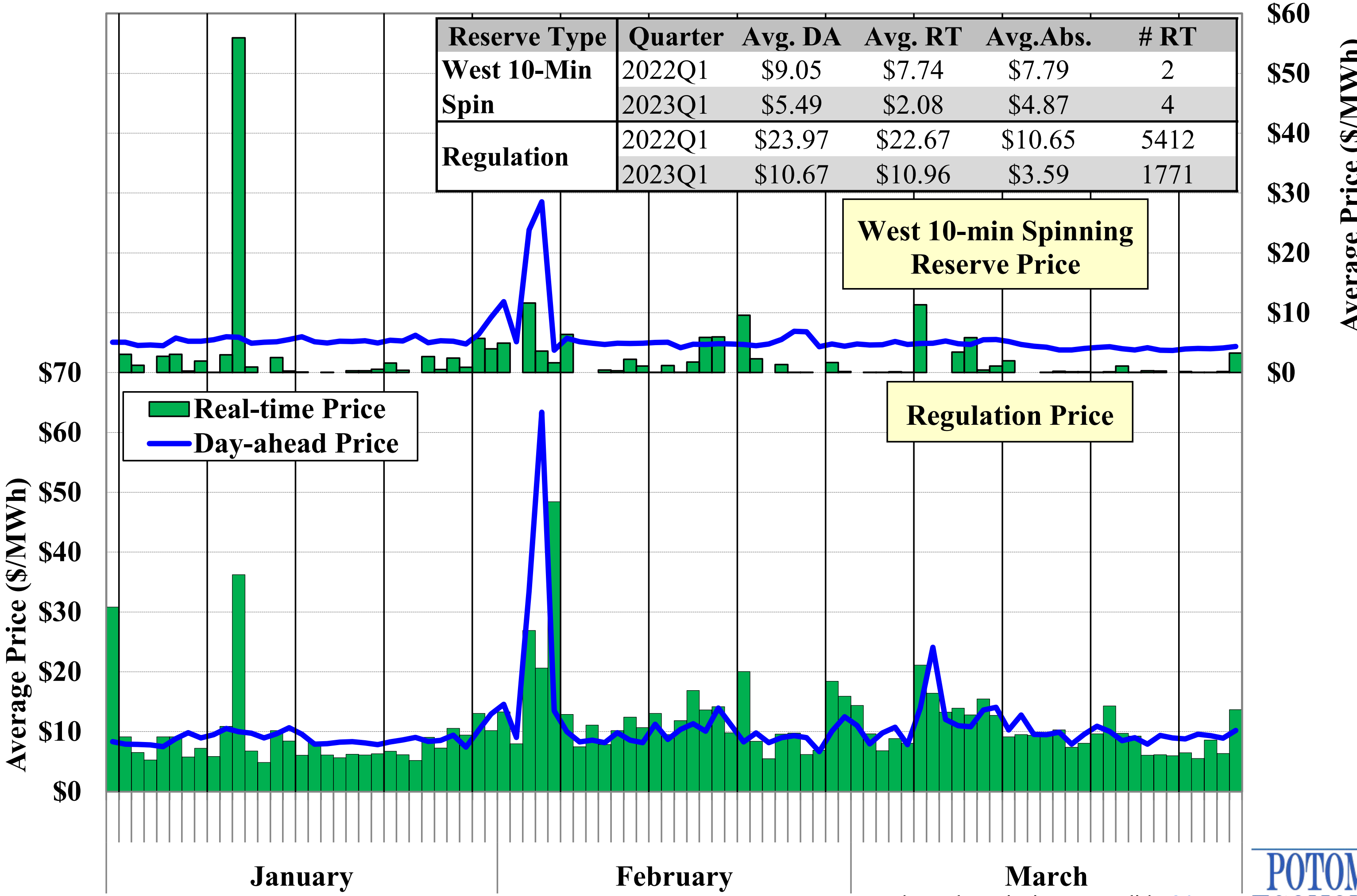
# Day-Ahead and Real-Time Ancillary Services Prices
## Western 10-Minute Spinning Reserves and Regulation




| Reserve Type | Quarter | Avg. DA | Avg. RT | Avg.Abs. | # RT |
|---|---|---|---|---|---|
| West 10-Min Spin | 2022Q1 | $9.05 | $7.74 | $7.79 | 2 |
| | 2023Q1 | $5.49 | $2.08 | $4.87 | 4 |
| Regulation | 2022Q1 | $23.97 | $22.67 | $10.65 | 5412 |
| | 2023Q1 | $10.67 | $10.96 | $3.59 | 1771 |



Notes: For chart description, see slide 80.

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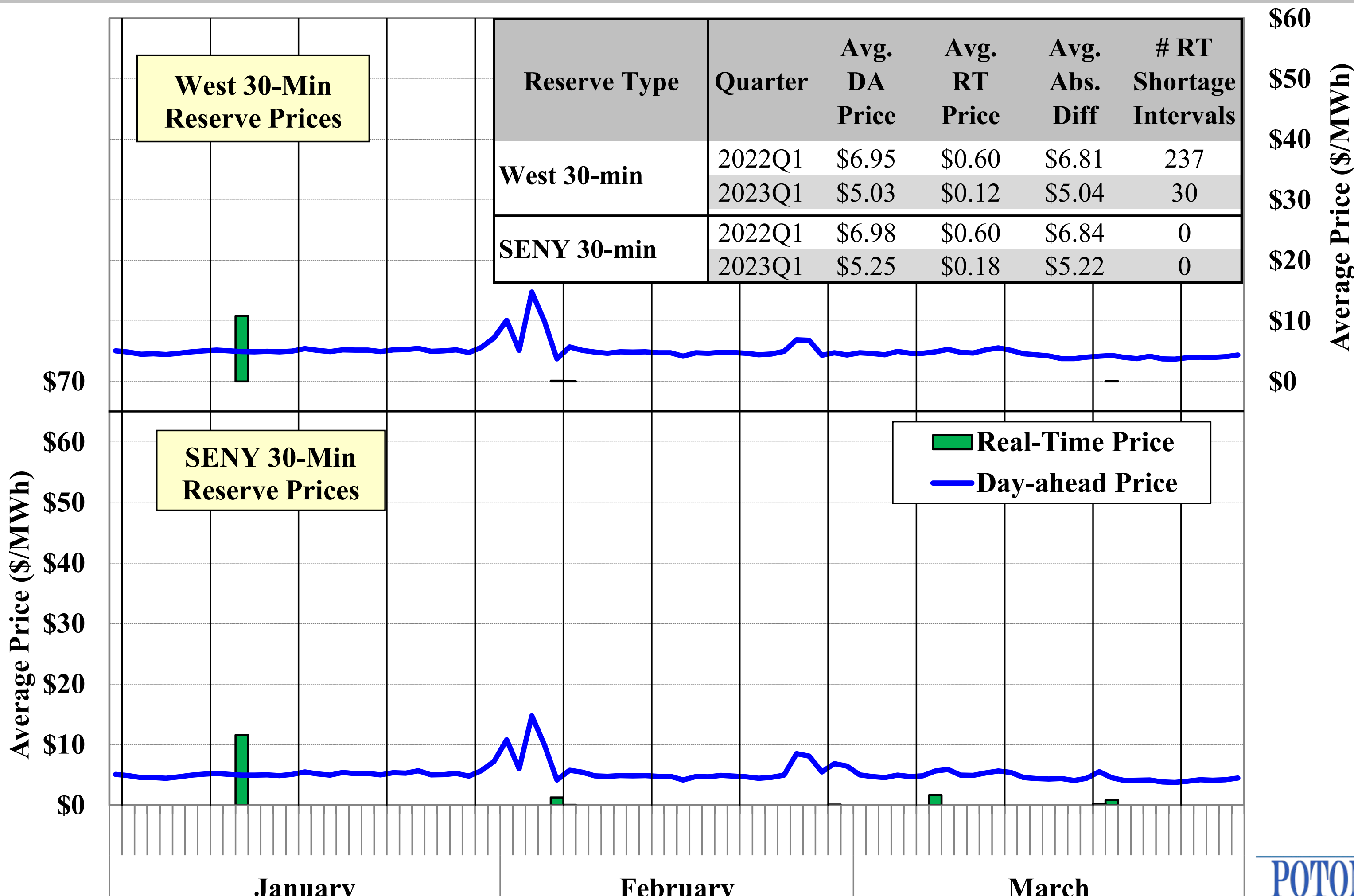
# Day-Ahead and Real-Time Ancillary Services Prices
## Western and SENY 30-Minute Reserves

| Reserve Type | Quarter | Avg. DA Price | Avg. RT Price | Avg. Abs. Diff | # RT Shortage Intervals |
|---|---|---|---|---|---|
| West 30-min | 2022Q1 | $6.95 | $0.60 | $6.81 | 237 |
| | 2023Q1 | $5.03 | $0.12 | $5.04 | 30 |
| SENY 30-min | 2022Q1 | $6.98 | $0.60 | $6.84 | 0 |
| | 2023Q1 | $5.25 | $0.18 | $5.22 | 0 |




Notes: For chart description, see slide 80.



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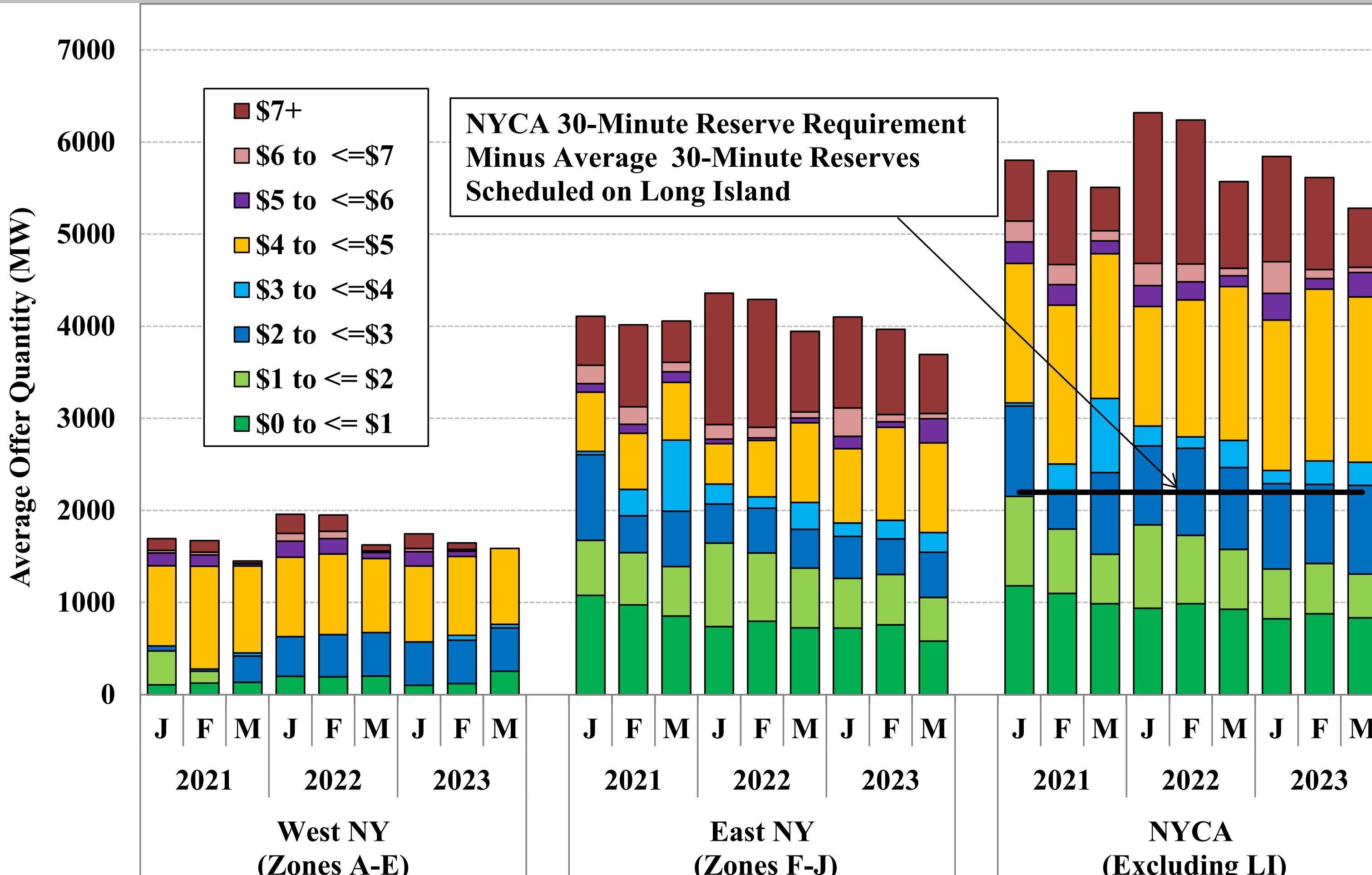
# Day-Ahead NYCA 30-Minute Reserve Offers
## Committed and Available Offline Quick-Start Resources








Notes: For chart description, see slide 81.

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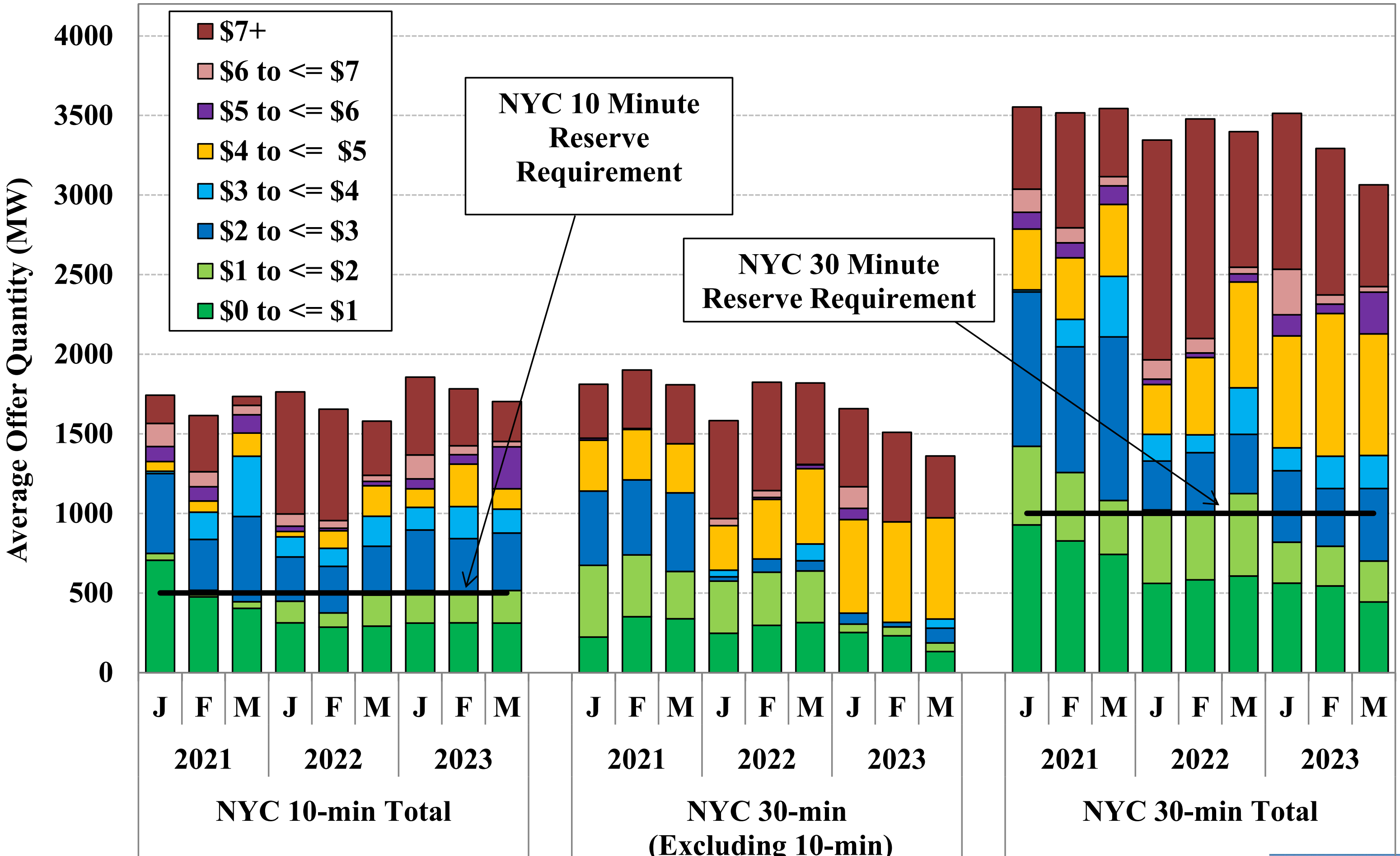
# Day-Ahead NYC Reserve Offers
## Committed and Available Offline Quick-Start Resources






Notes: For chart description, see slide 81.

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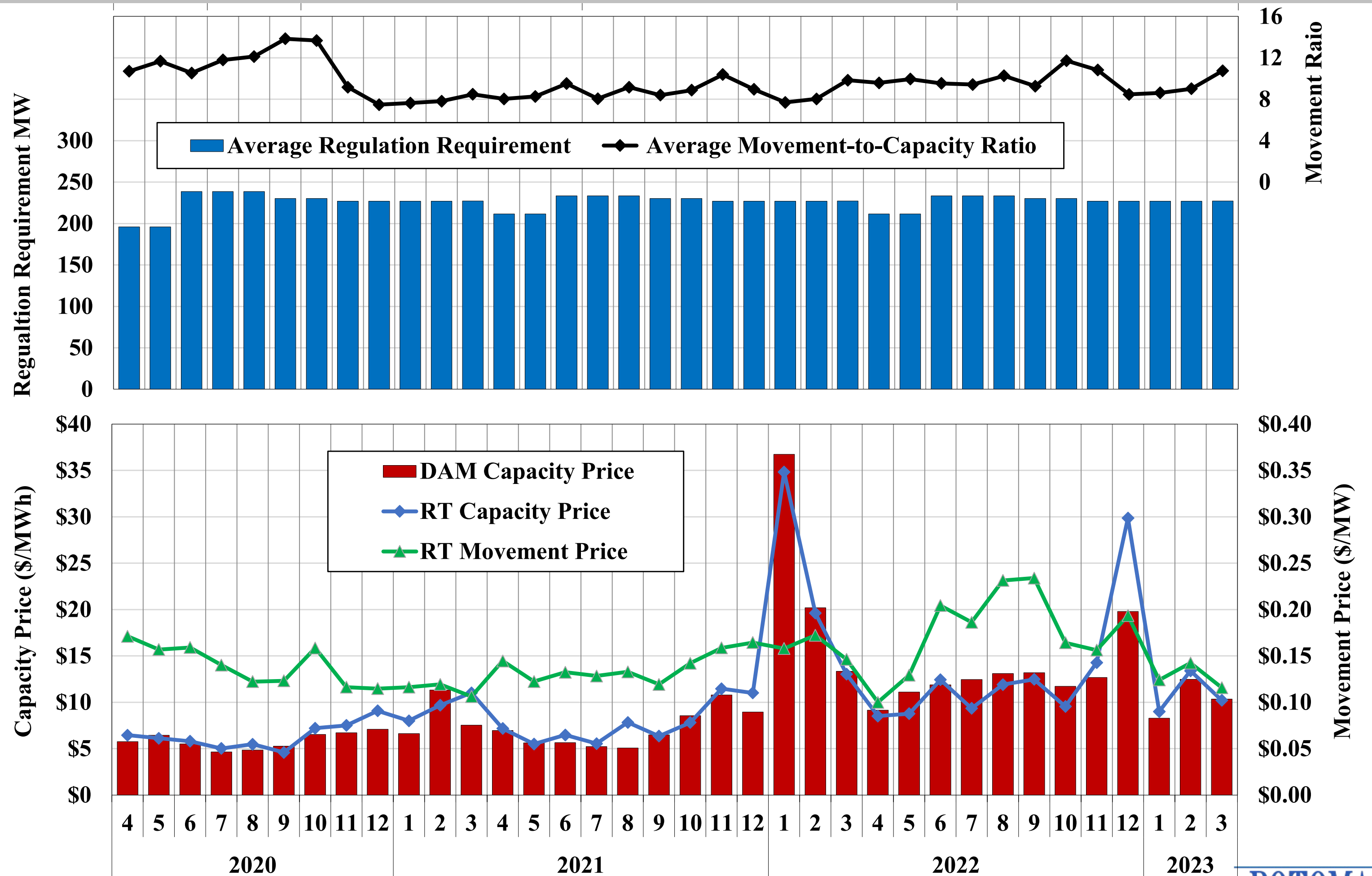
# Regulation Requirements, Prices, and Movement-to-Capacity Ratio by Month






Notes: For chart description, see slide 82.

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# Charts:

## Energy Market Scheduling

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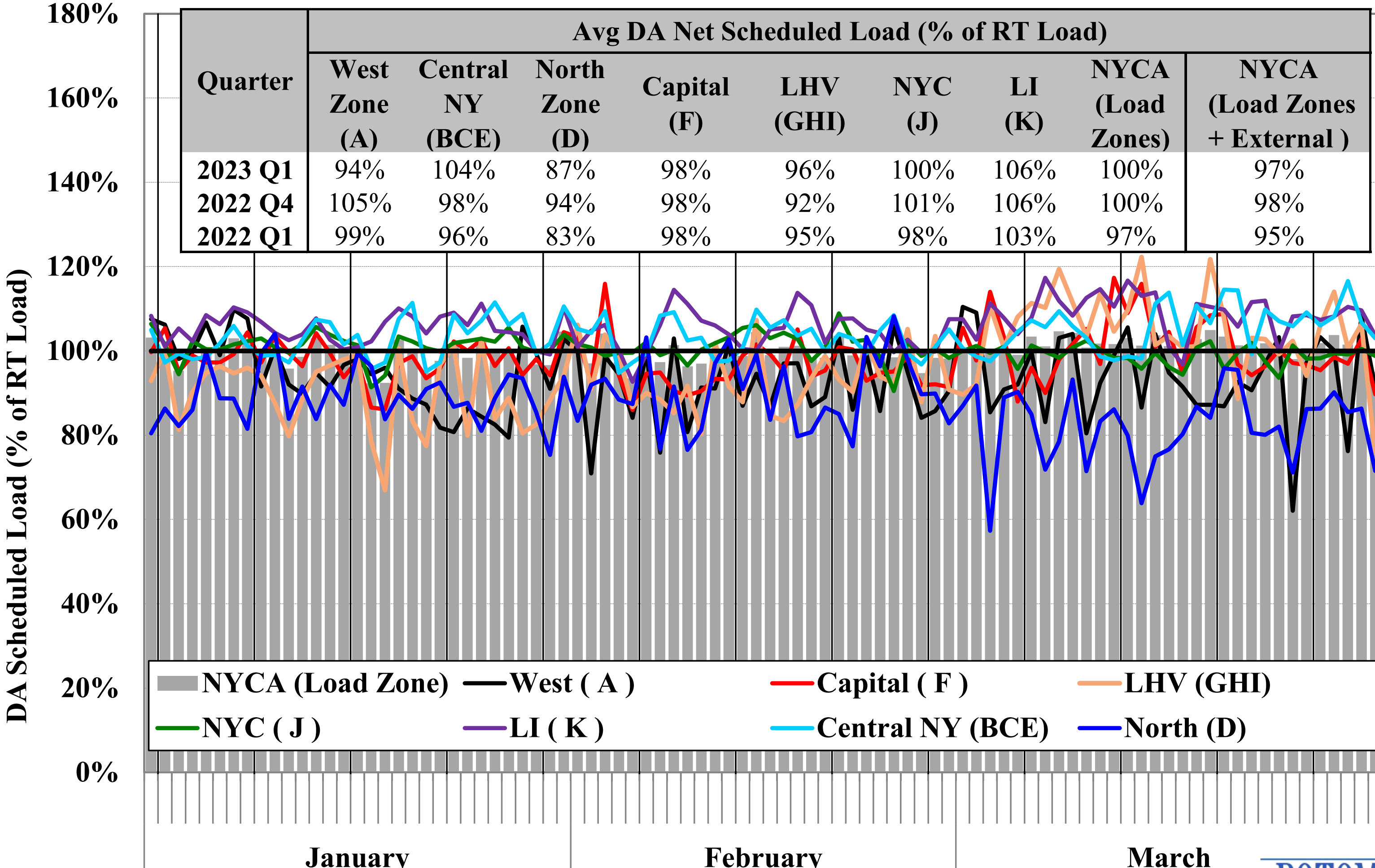
# Day-ahead Scheduled Load and Actual Load
## Daily Peak Load Hour

| 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 Q1 | 94% | 104% | 87% | 98% | 96% | 100% | 106% | 100% | 97% |
| 2022 Q4 | 105% | 98% | 94% | 98% | 92% | 101% | 106% | 100% | 98% |
| 2022 Q1 | 99% | 96% | 83% | 98% | 95% | 98% | 103% | 97% | 95% |








Notes: For chart description, see slide 83.

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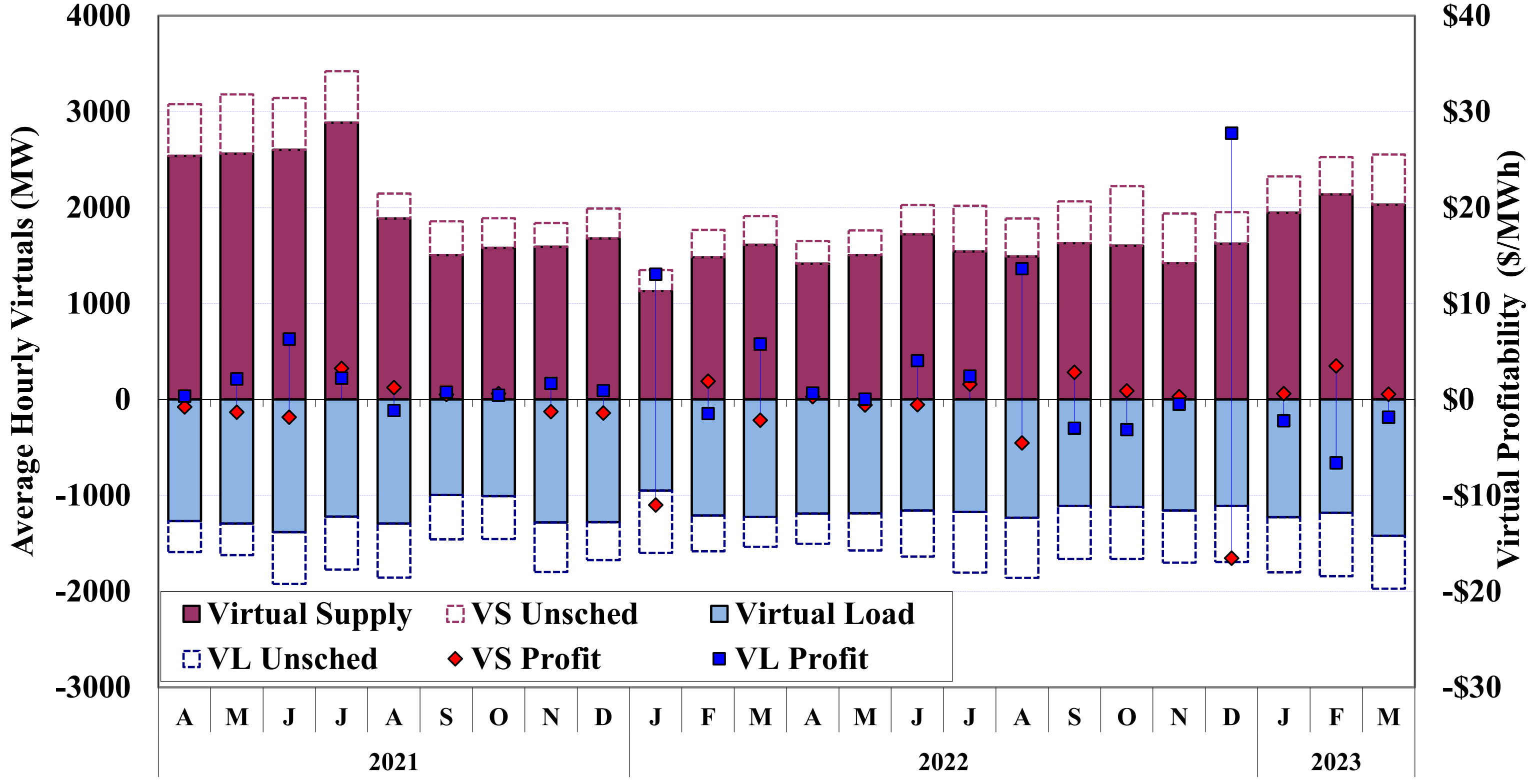
# Virtual Trading Activity
## by Month



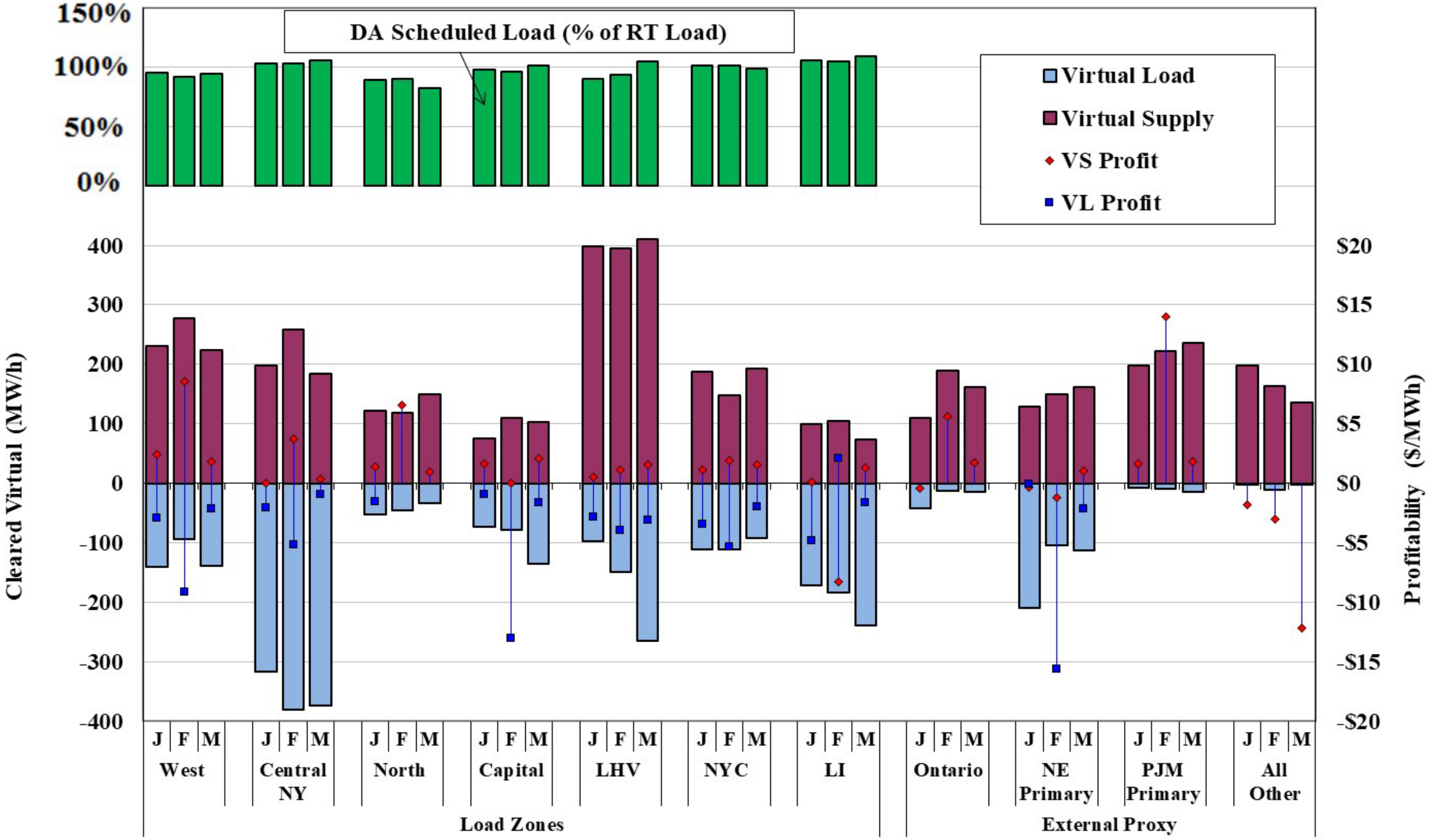

| | | | | | | | | | | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Profit > 50% of Avg. Zone Price | MW | 549 | 378 | 325 | 413 | 158 | 158 | 96 | 182 | 195 | 225 | 307 | 217 | 291 | 324 | 183 | 228 | 153 | 96 | 134 | 250 | 296 | 170 | 455 | 343 |
| | % | 14% | 10% | 8% | 10% | 5% | 6% | 4% | 6% | 7% | 11% | 11% | 8% | 11% | 12% | 6% | 8% | 6% | 4% | 5% | 10% | 11% | 5% | 14% | 10% |
| Loss > 50% of Avg. Zone Price | MW | 688 | 498 | 271 | 234 | 174 | 140 | 88 | 197 | 215 | 208 | 278 | 226 | 306 | 304 | 180 | 183 | 124 | 109 | 163 | 289 | 274 | 206 | 412 | 377 |
| | % | 18% | 13% | 7% | 6% | 5% | 6% | 3% | 7% | 7% | 10% | 10% | 8% | 12% | 11% | 6% | 7% | 5% | 4% | 6% | 11% | 10% | 7% | 12% | 11% |



Notes: For chart description, see slide 83.

POTOMAC ECONOMICS

# Virtual Trading Activity
## by Location

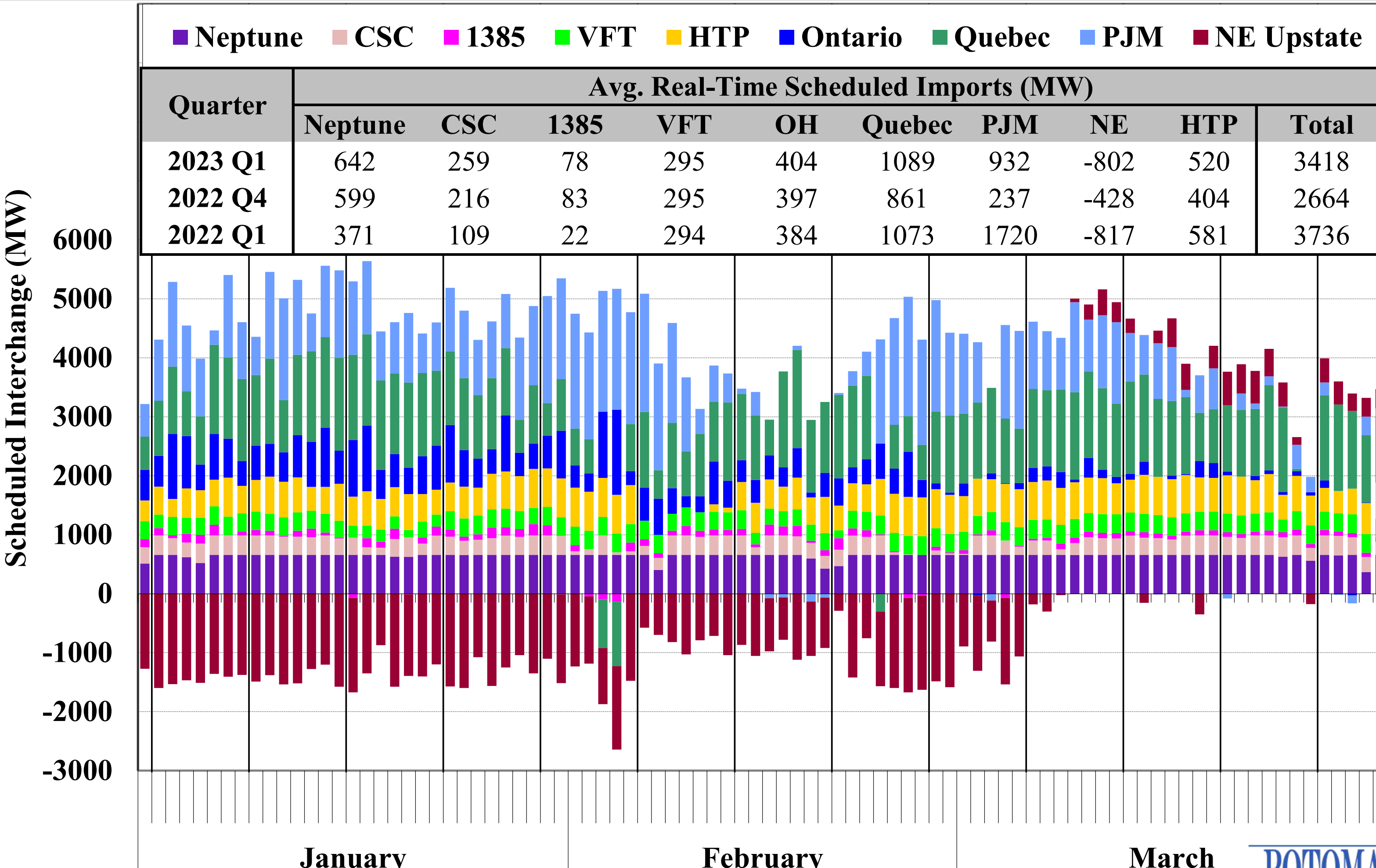



Notes: 1. Virtual profit is not shown for a category if the average scheduled quantity is less than 50 MW.
2. For chart description, see slide 83.

# 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 Q1 | 642 | 259 | 78 | 295 | 404 | 1089 | 932 | -802 | 520 | 3418 |
| 2022 Q4 | 599 | 216 | 83 | 295 | 397 | 861 | 237 | -428 | 404 | 2664 |
| 2022 Q1 | 371 | 109 | 22 | 294 | 384 | 1073 | 1720 | -817 | 581 | 3736 |




Notes: Two Quebec interfaces are combined into one.

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

| | | | Average/Total During Intervals w/ Adjustment | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| | | | CTS - NY/NE | | | | CTS - NY/PJM | | | |
| | | | Both Forecast Errors <= $20 | Any Forecast Error > $20 | Total | | Both Forecast Errors <= $20 | Any Forecast Error > $20 | Total | |
| % of All Intervals w/ Adjustment | | | 69% | 13% | **82%** | | 43% | 6% | **48%** | |
| Average Flow Adjustment (MW) | Net Imports | | -2 | 4 | **-1** | | -2 | -60 | **-9** | |
| | Gross | | 105 | 141 | **111** | | 75 | 119 | **80** | |
| Production Cost Savings ($ Million) | Projected at Scheduling Time | | $1.2 | $1.8 | **$2.9** | | $0.3 | $0.3 | **$0.6** | |
| | Net Over-Projection by: | NY | -$0.1 | -$0.8 | **-$0.9** | | $0.0 | $0.0 | **$0.0** | |
| | | NE or PJM | $0.0 | $0.0 | **$0.0** | | -$0.1 | -$0.6 | **-$0.7** | |
| | Other Unrealized Savings | | $0.0 | -$0.1 | **-$0.2** | | $0.0 | -$0.5 | **-$0.5** | |
| | Actual Savings | | $1.1 | $0.9 | **$1.9** | | $0.2 | -$0.8 | **-$0.6** | |
| Interface Prices ($/MWh) | NY | Actual | $32.95 | $95.43 | **$43.06** | **$43.08** | $28.77 | $61.29 | **$32.68** | **$31.88** |
| | | Forecast | $34.08 | $77.69 | **$41.14** | **$41.43** | $29.28 | $49.23 | **$31.68** | **$30.93** |
| | NE or PJM | Actual | $32.76 | $80.88 | **$40.55** | **$46.50** | $26.78 | $53.70 | **$30.02** | **$28.29** |
| | | Forecast | $31.26 | $66.13 | **$36.90** | **$42.46** | $28.15 | $63.48 | **$32.39** | **$30.05** |
| Price Forecast Errors ($/MWh) | NY | Fcst. - Act. | $1.13 | -$17.74 | **-$1.93** | **-$1.65** | $0.51 | -$12.06 | **-$1.00** | **-$0.95** |
| | | Abs. Val. | $3.29 | $48.35 | **$10.58** | **$10.01** | $2.66 | $30.61 | **$6.02** | **$5.28** |
| | NE or PJM | Fcst. - Act. | -$1.50 | -$14.75 | **-$3.64** | **-$4.04** | $1.37 | $9.78 | **$2.38** | **$1.76** |
| | | Abs. Val. | $3.38 | $29.31 | **$7.58** | **$8.47** | $3.65 | $49.69 | **$9.18** | **$7.86** |

For Adjustment Intervals Only

For All Intervals

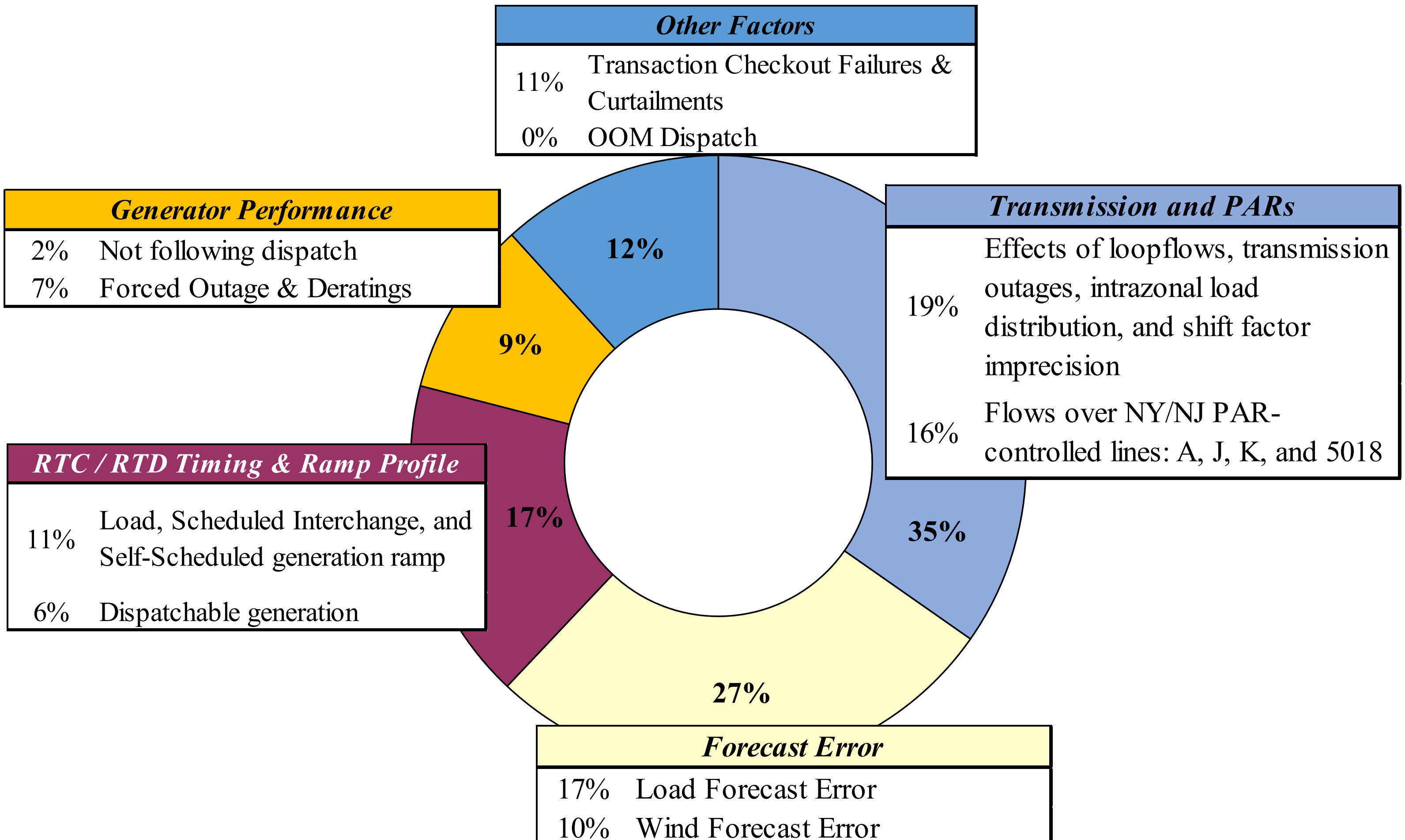




Notes: For chart description, see slide 84.

POTOMAC ECONOMICS

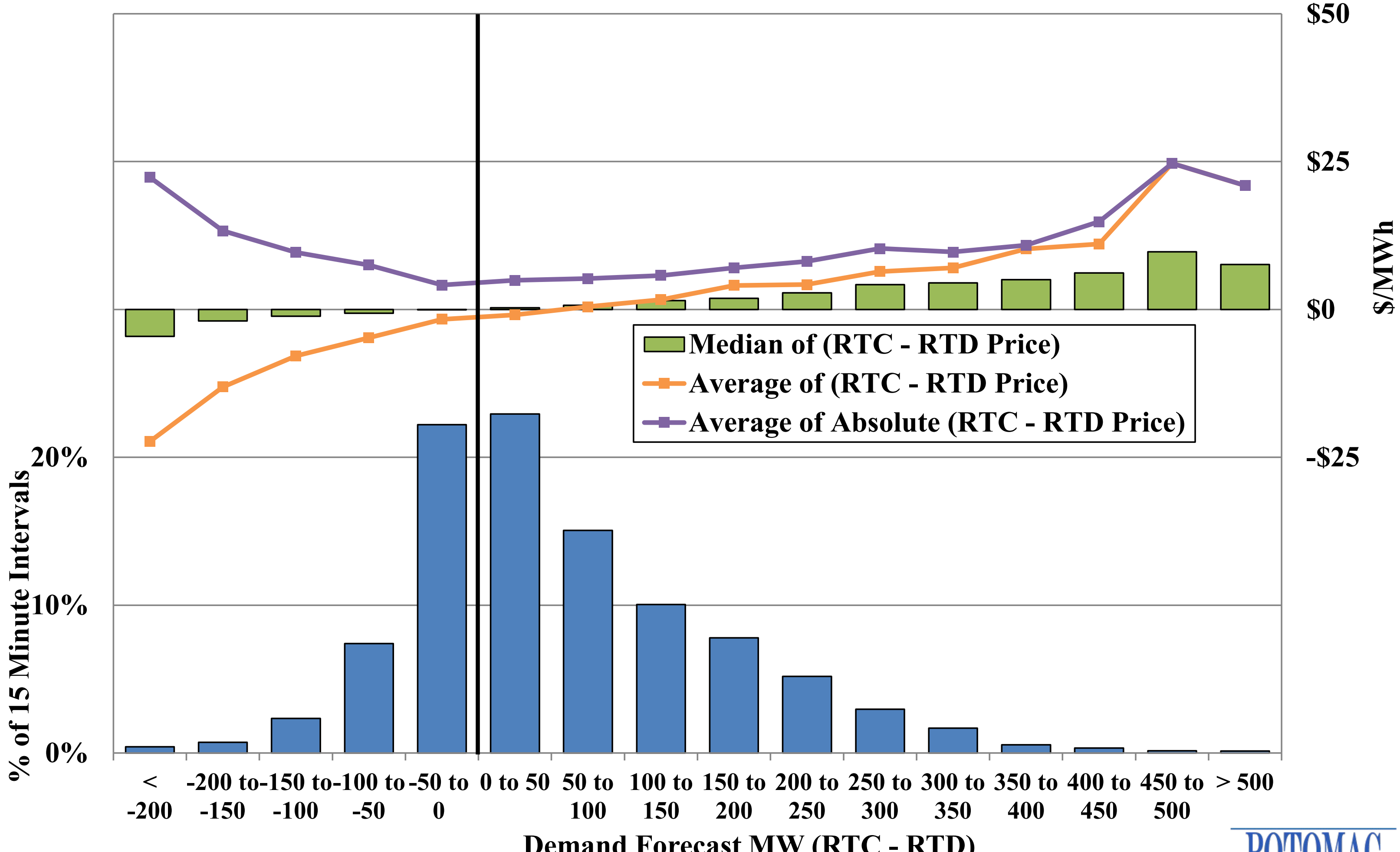
# Detrimental Factors to RTC and RTD Price Divergence






Notes: For chart description, see slide 78.

# RTC and RTD Price Difference vs Demand Forecast Difference



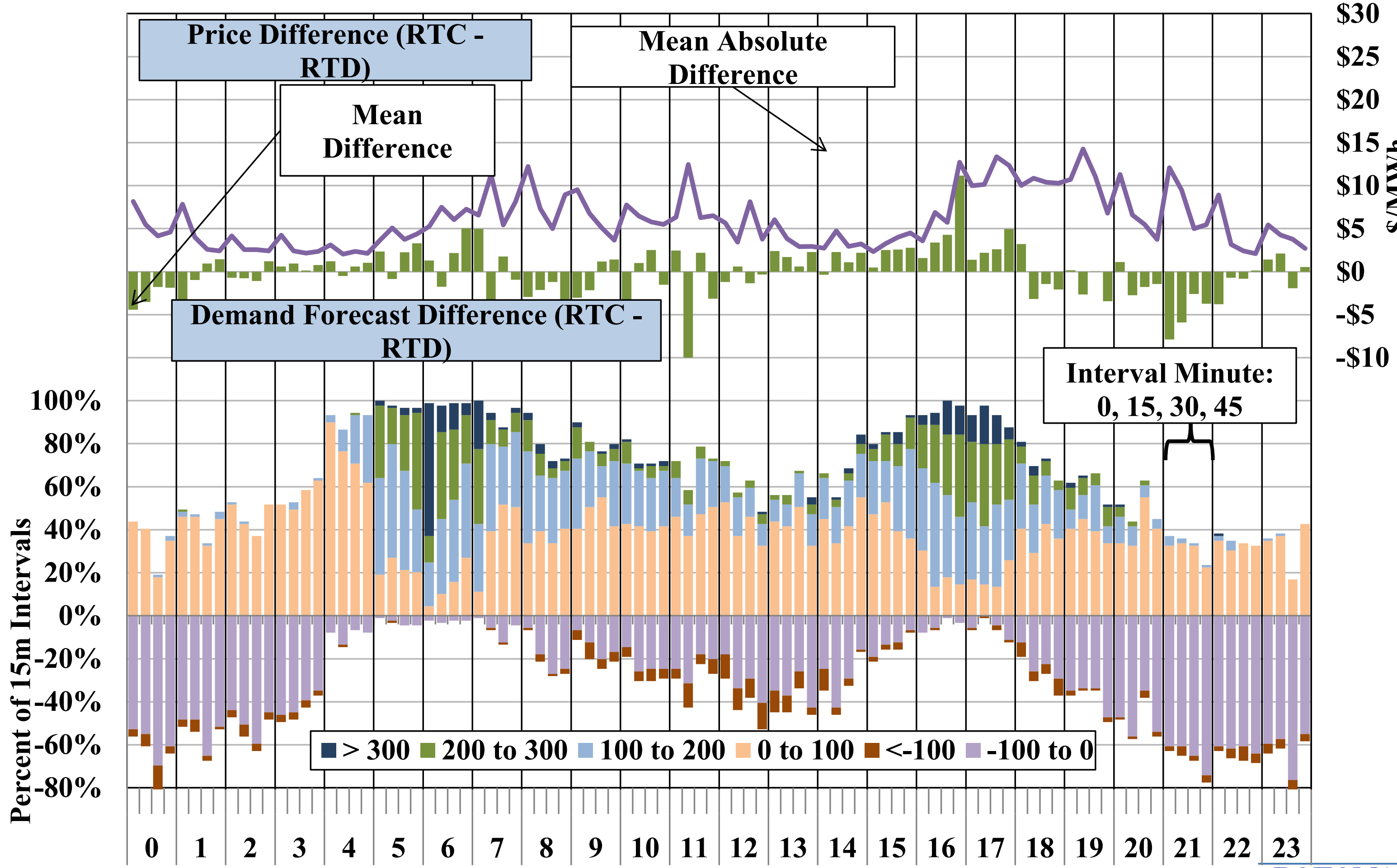





Notes: For chart description, see slide 78.

POTOMAC ECONOMICS

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





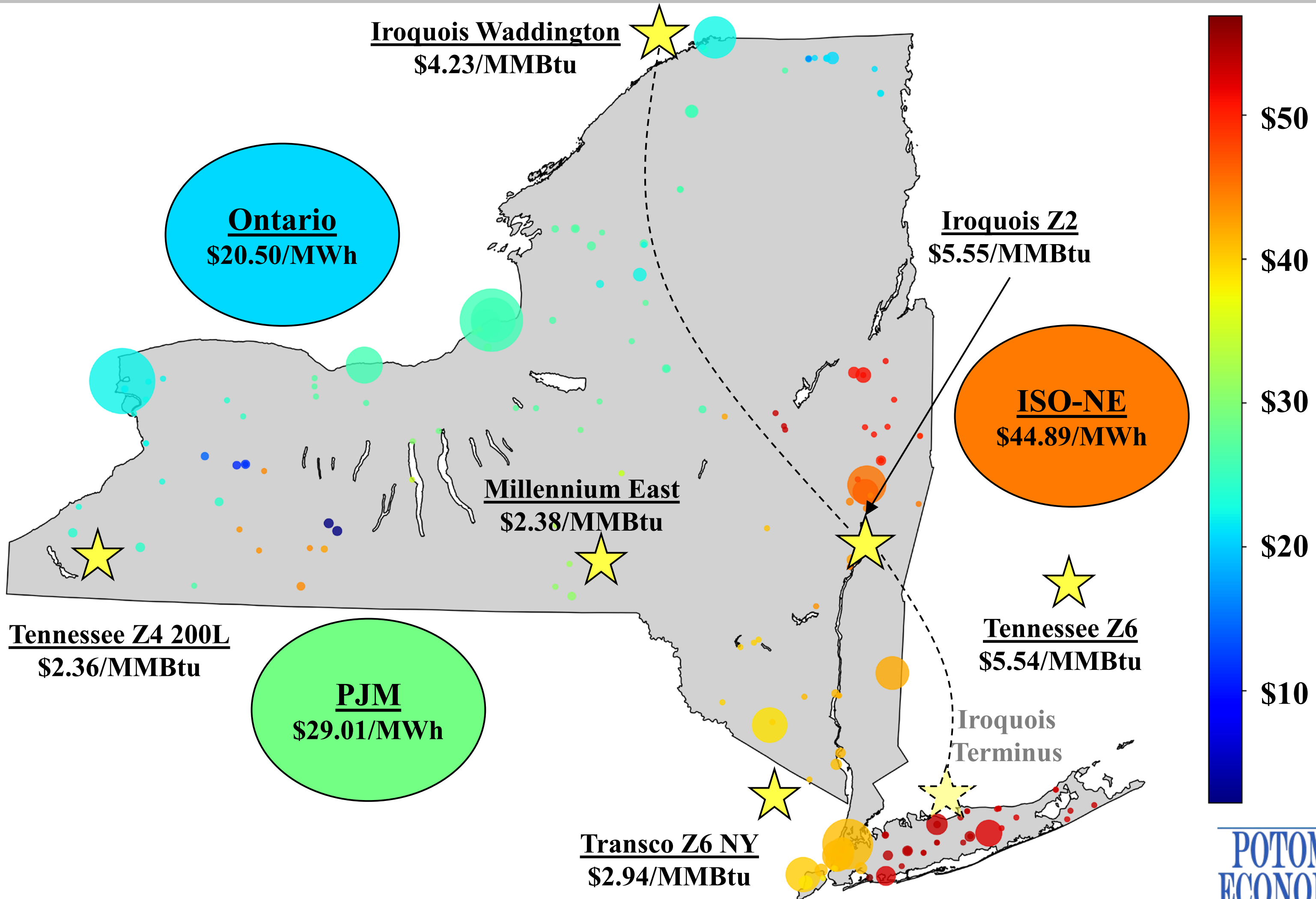

Notes: For chart description, see slide 86.

POTOMAC ECONOMICS

# Charts:

## Transmission Congestion Revenues and Shortfalls

# System Congestion
## Real-Time Price Map at Generator Nodes

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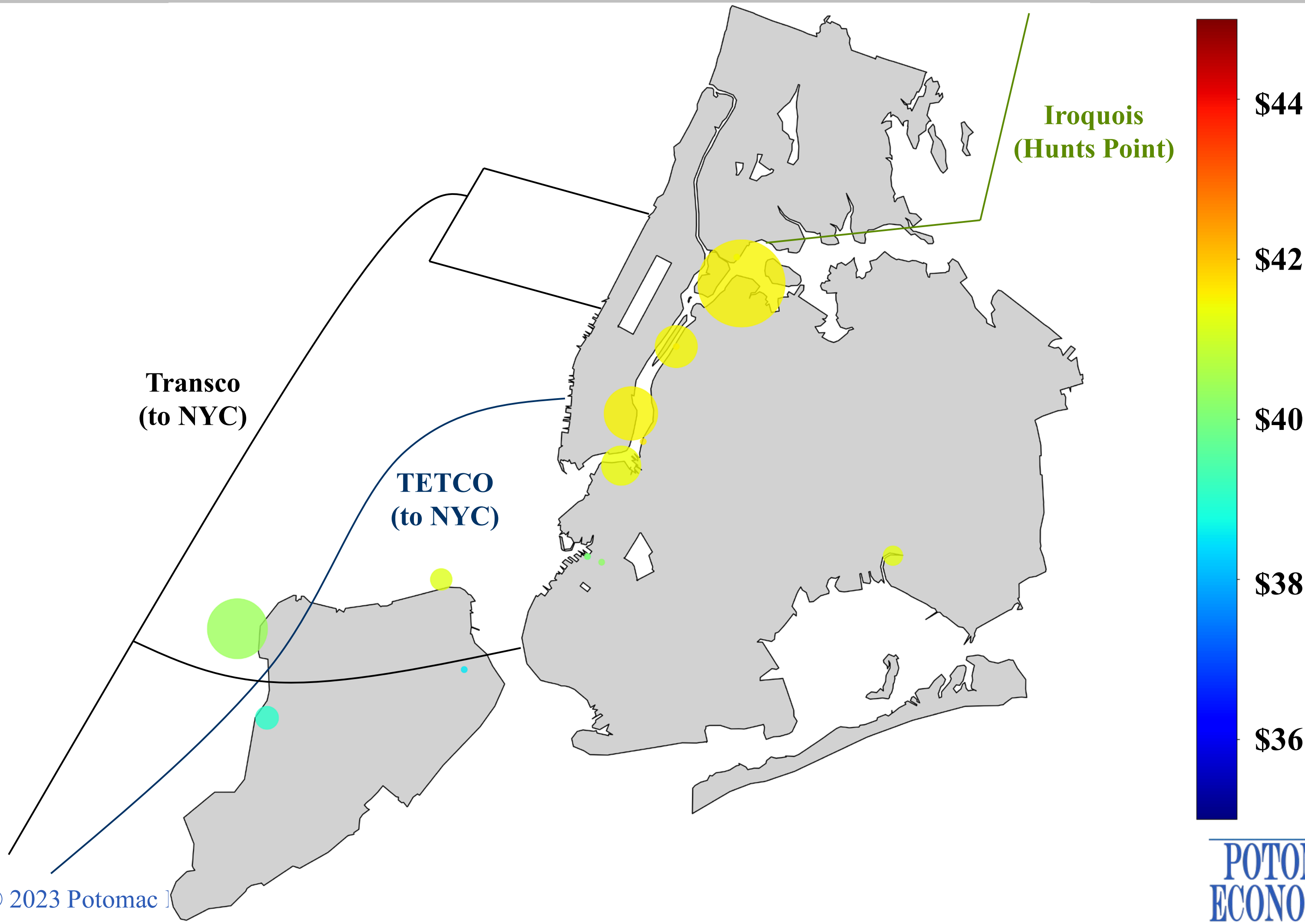
ECONOMICS

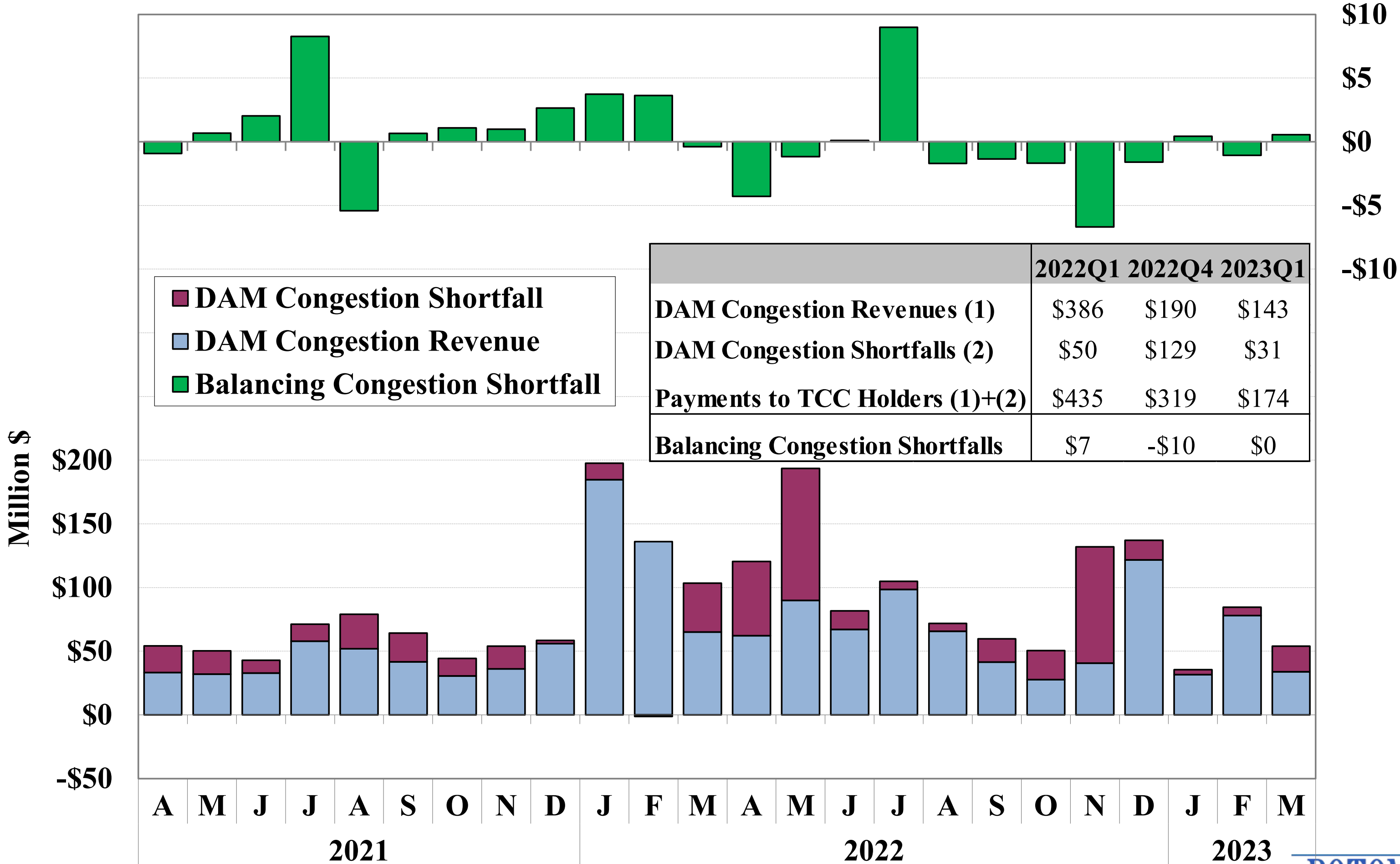
# System Congestion
## NYC Real-Time Price Map at Generator Nodes






POTOMAC ECONOMICS

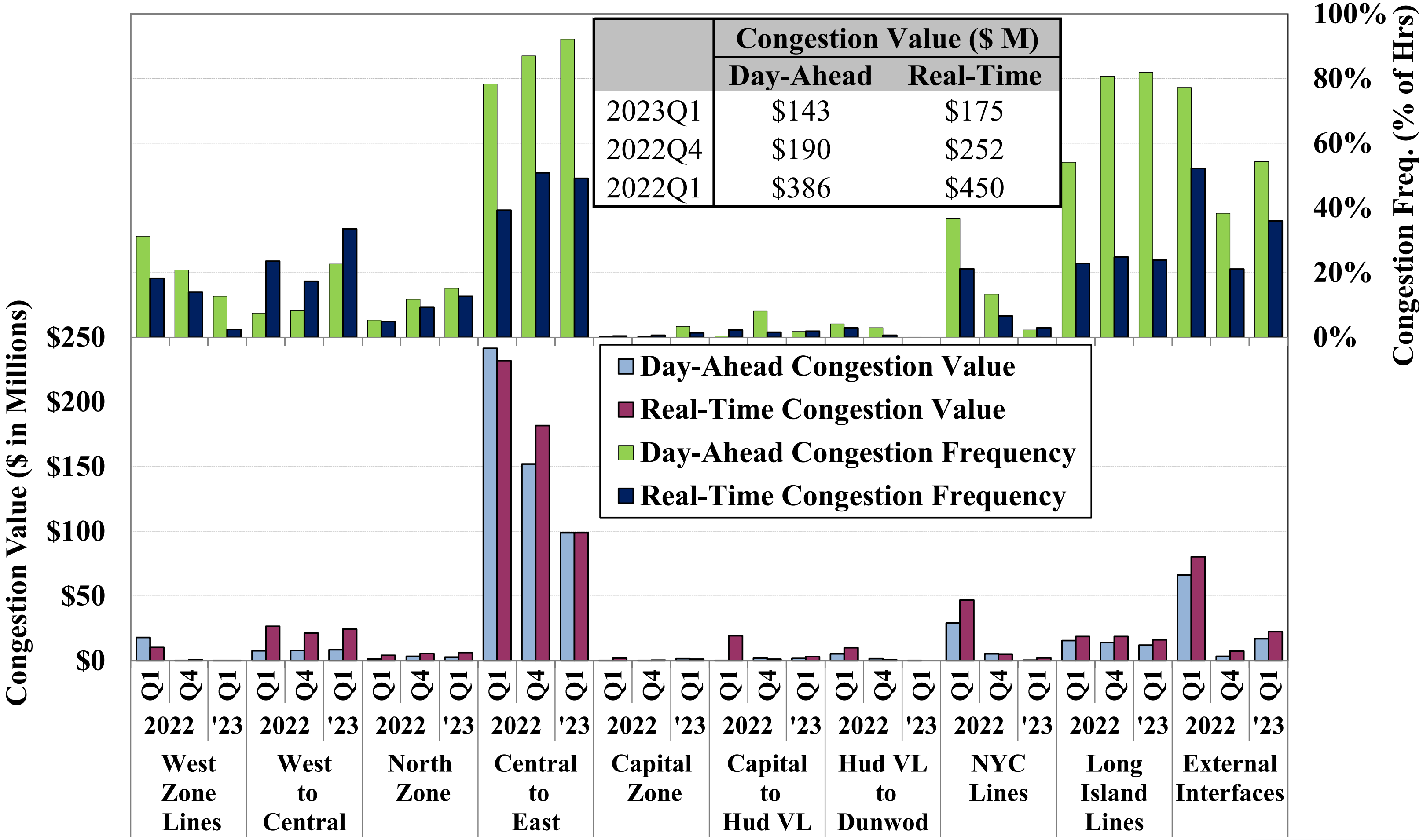
# Congestion Revenues and Shortfalls by Month




| | 2022Q1 | 2022Q4 | 2023Q1 |
|---|---|---|---|
| DAM Congestion Revenues (1) | $386 | $190 | $143 |
| DAM Congestion Shortfalls (2) | $50 | $129 | $31 |
| Payments to TCC Holders (1)+(2) | $435 | $319 | $174 |
| Balancing Congestion Shortfalls | $7 | -$10 | $0 |

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

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



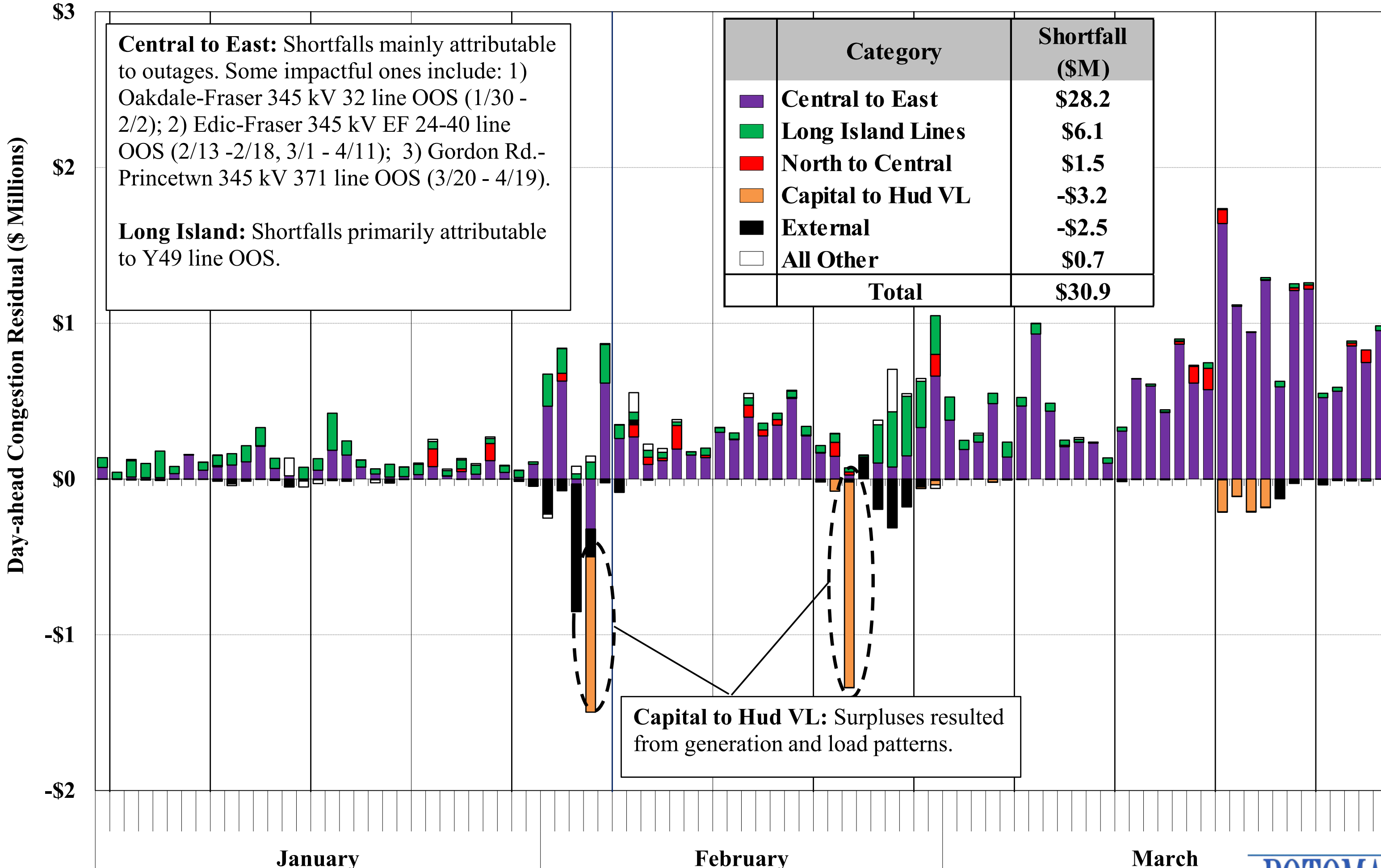

Notes: For chart description, see slides 88, 89, and 90.





POTOMAC ECONOMICS

# Day-Ahead Congestion Revenue Shortfalls by Transmission Facility




| Category | Shortfall ($M) |
|---|---|
| Central to East | $28.2 |
| Long Island Lines | $6.1 |
| North to Central | $1.5 |
| Capital to Hud VL | -$3.2 |
| External | -$2.5 |
| All Other | $0.7 |
| Total | $30.9 |

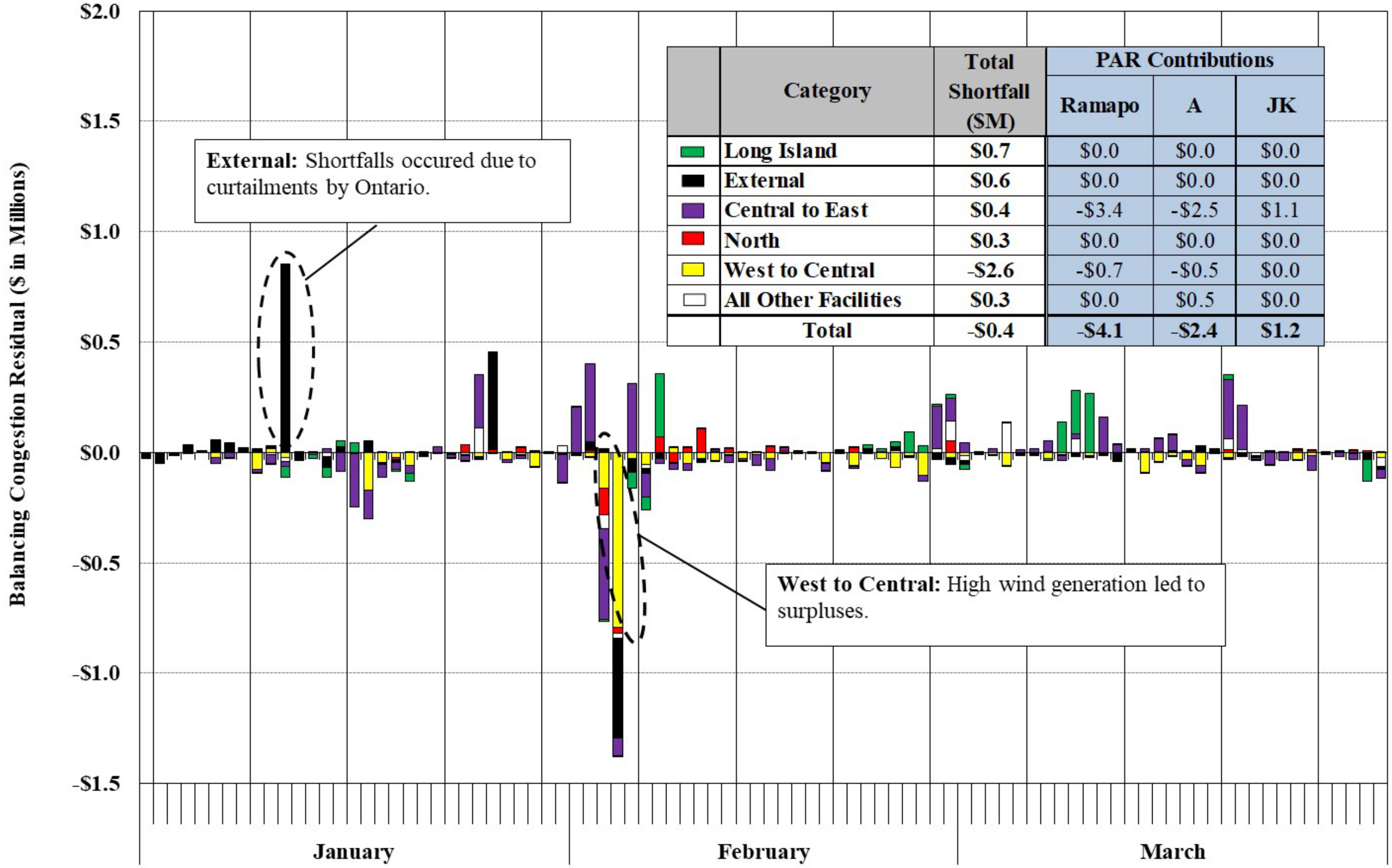
Notes: For chart description, see slides 88, 89, and 90.





POTOMAC ECONOMICS

# Balancing Congestion Shortfalls
## by Transmission Facility



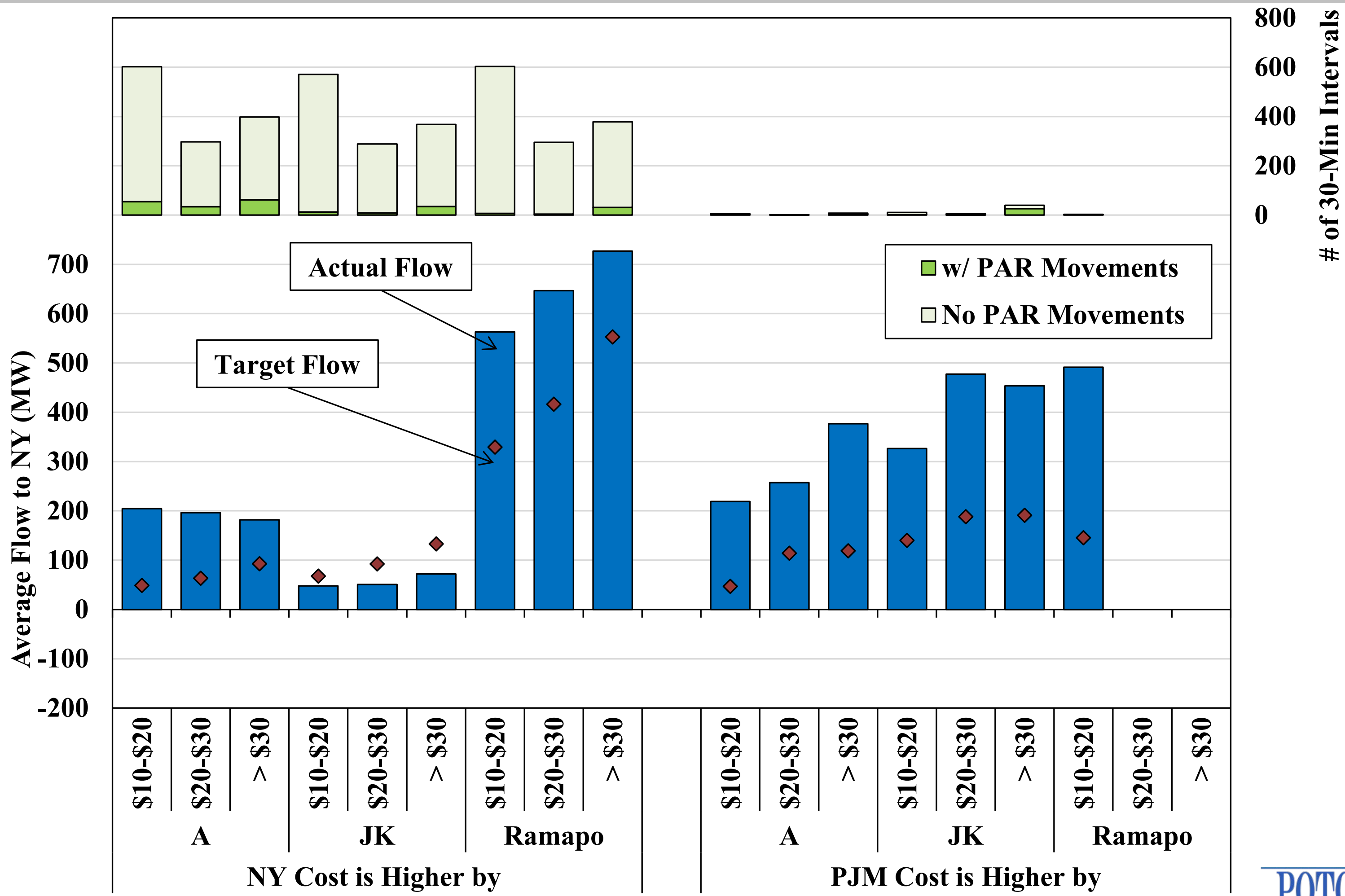

| | Category | Total Shortfall ($M) | PAR Contributions | | |
|---|---|---|---|---|---|
| | | | Ramapo | A | JK |
| Long Island | Long Island | $0.7 | $0.0 | $0.0 | $0.0 |
| External | External | $0.6 | $0.0 | $0.0 | $0.0 |
| Central to East | Central to East | $0.4 | -$3.4 | -$2.5 | $1.1 |
| North | North | $0.3 | $0.0 | $0.0 | $0.0 |
| West to Central | West to Central | -$2.6 | -$0.7 | -$0.5 | $0.0 |
| All Other Facilities | All Other Facilities | $0.3 | $0.0 | $0.5 | $0.0 |
| | Total | -$0.4 | -$4.1 | -$2.4 | $1.2 |

Notes: 1. The BMCR estimated above may differ from actual BMCR because the figure is partly based on real-time schedules rather than metered values. 2. For chart description, see slides 88, 89, and 90.




POTOMAC ECONOMICS

# PAR Operation under M2M with PJM
# 2023 Q1

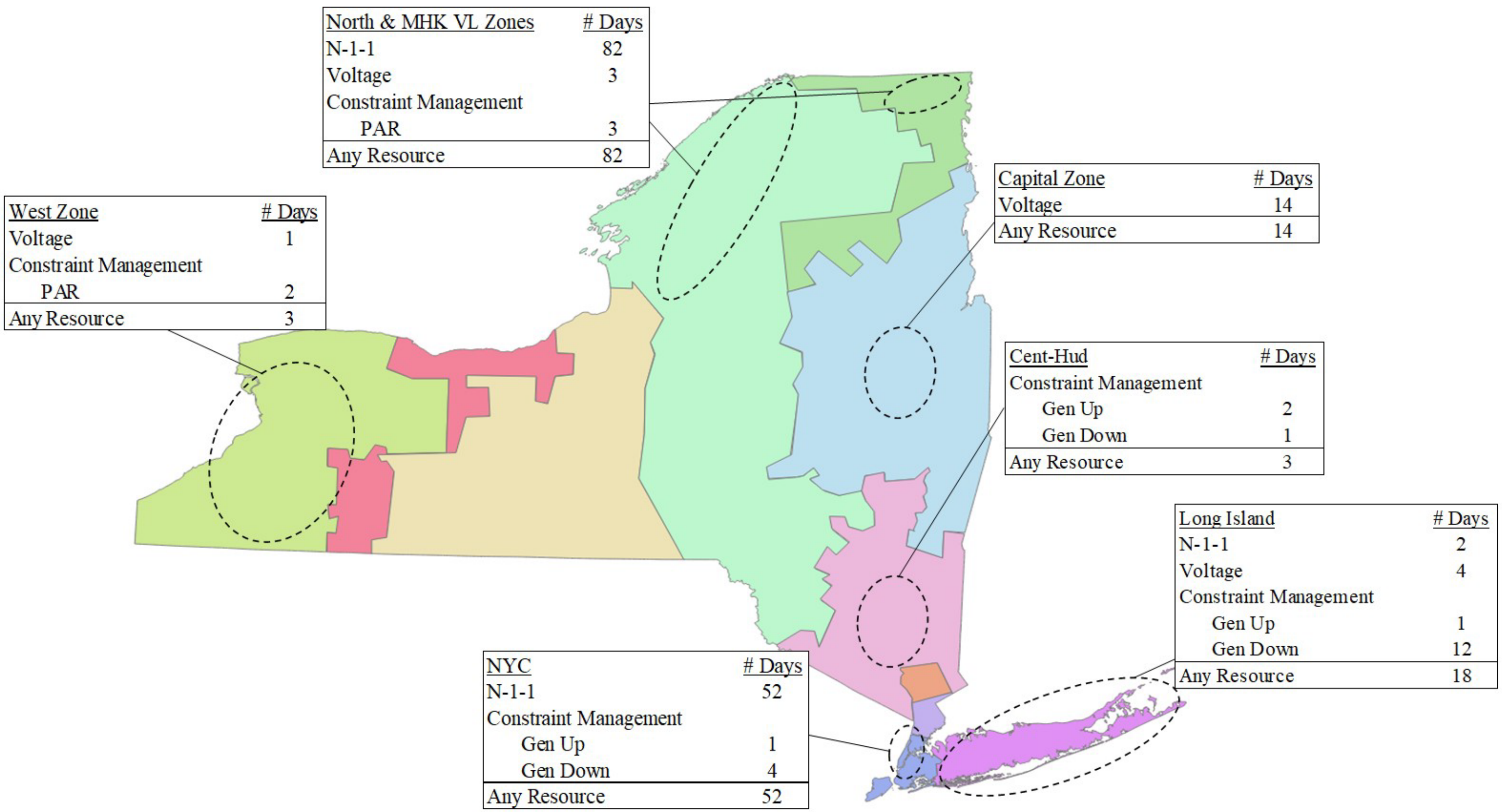







Notes: For chart description, see slide 91.

# OOM Actions to Manage Network Reliability




Notes: For chart description, see slides 92-93

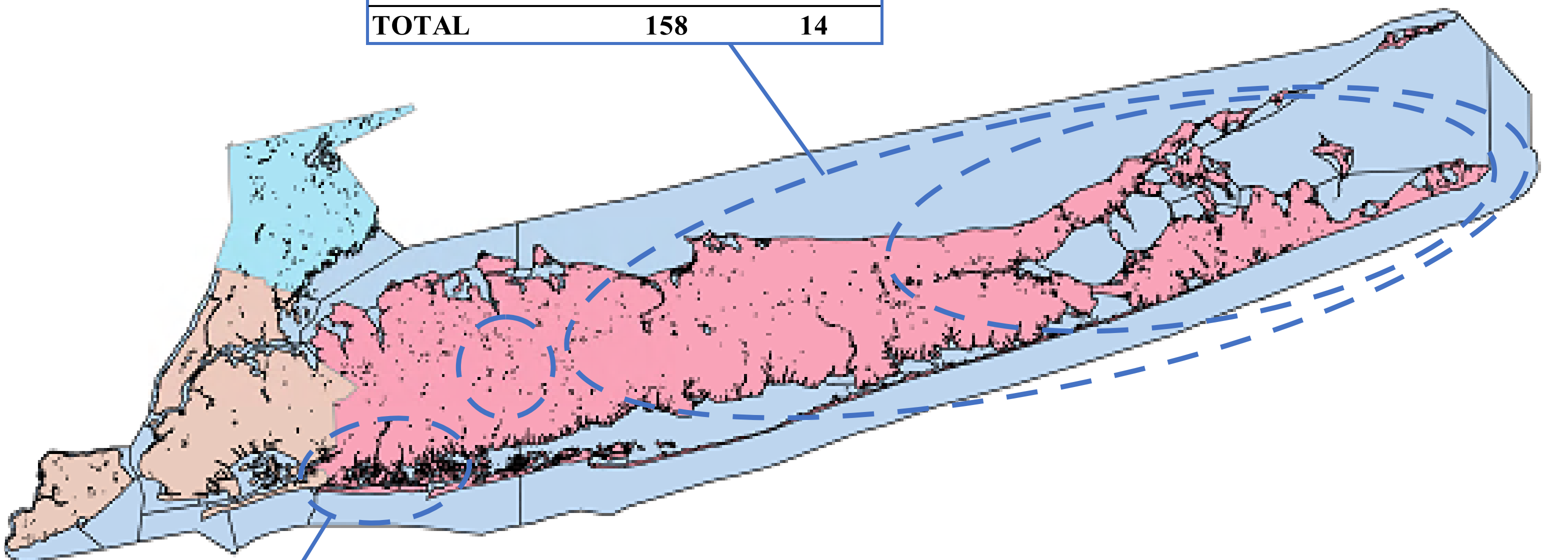




POTOMAC ECONOMICS

# Constraints on the Low Voltage Network:
## Long Island Load Pockets

| East of Northport | #Hours | #Days |
|---|---|---|
| 69kV | 150 | 13 |
| 138kV | 8 | 1 |
| TOTAL | 158 | 14 |

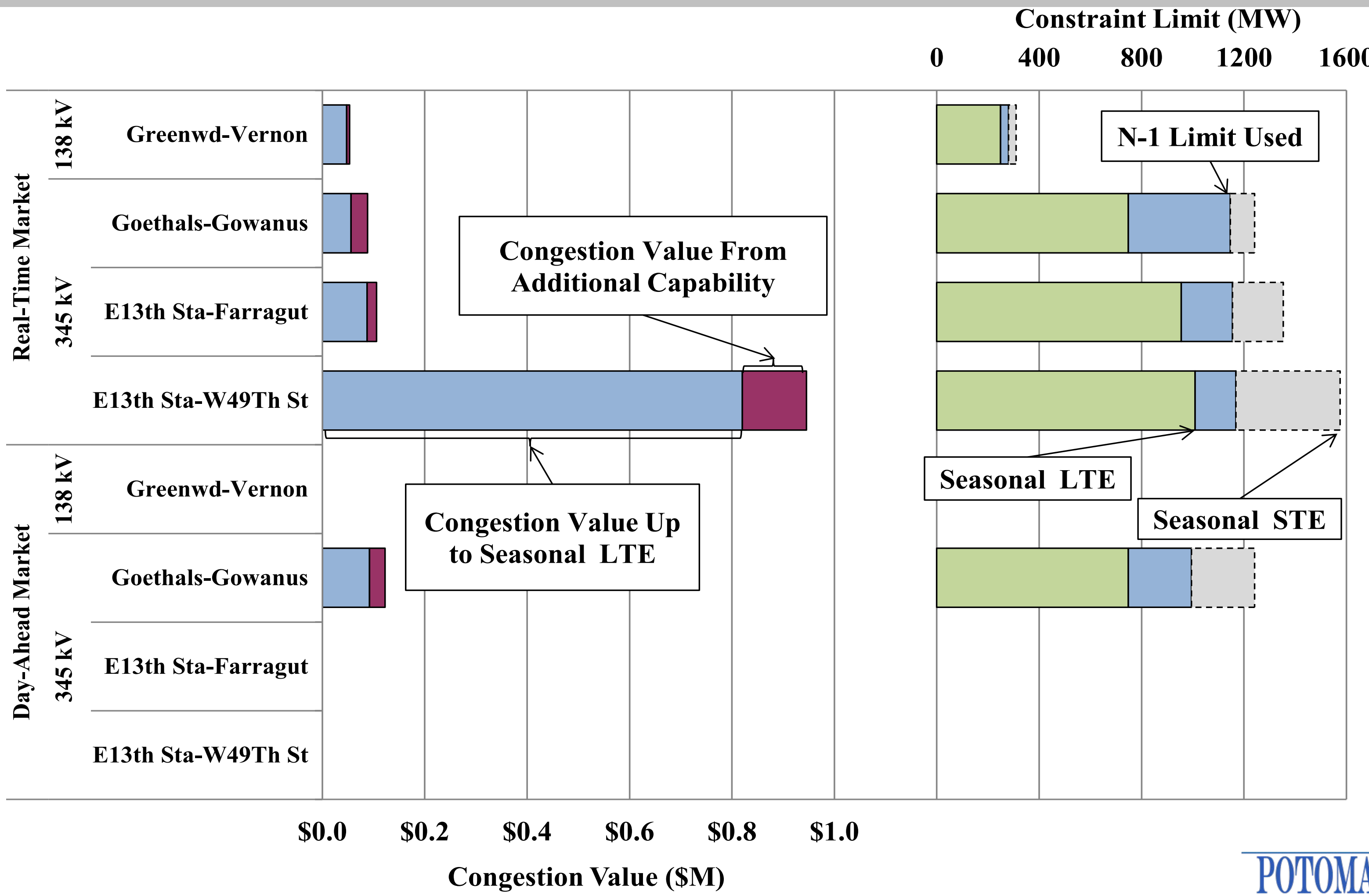


| Valley Stream | #Hours | #Days |
|---|---|---|
| 69kV OOM | 229 | 11 |
| 138kV | 480 | 57 |
| TOTAL | 674 | 62 |

| Load Pocket | Avg. LBMP | Est. LBMP with Local Constraints |
|---|---|---|
| Brentwood | $51.91 | $51.91 |
| East End | $50.99 | $50.99 |
| East of Northport | $51.72 | $51.72 |
| Valley Stream | $50.38 | $54.85 |

Notes: For chart description, see slides 92-93

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

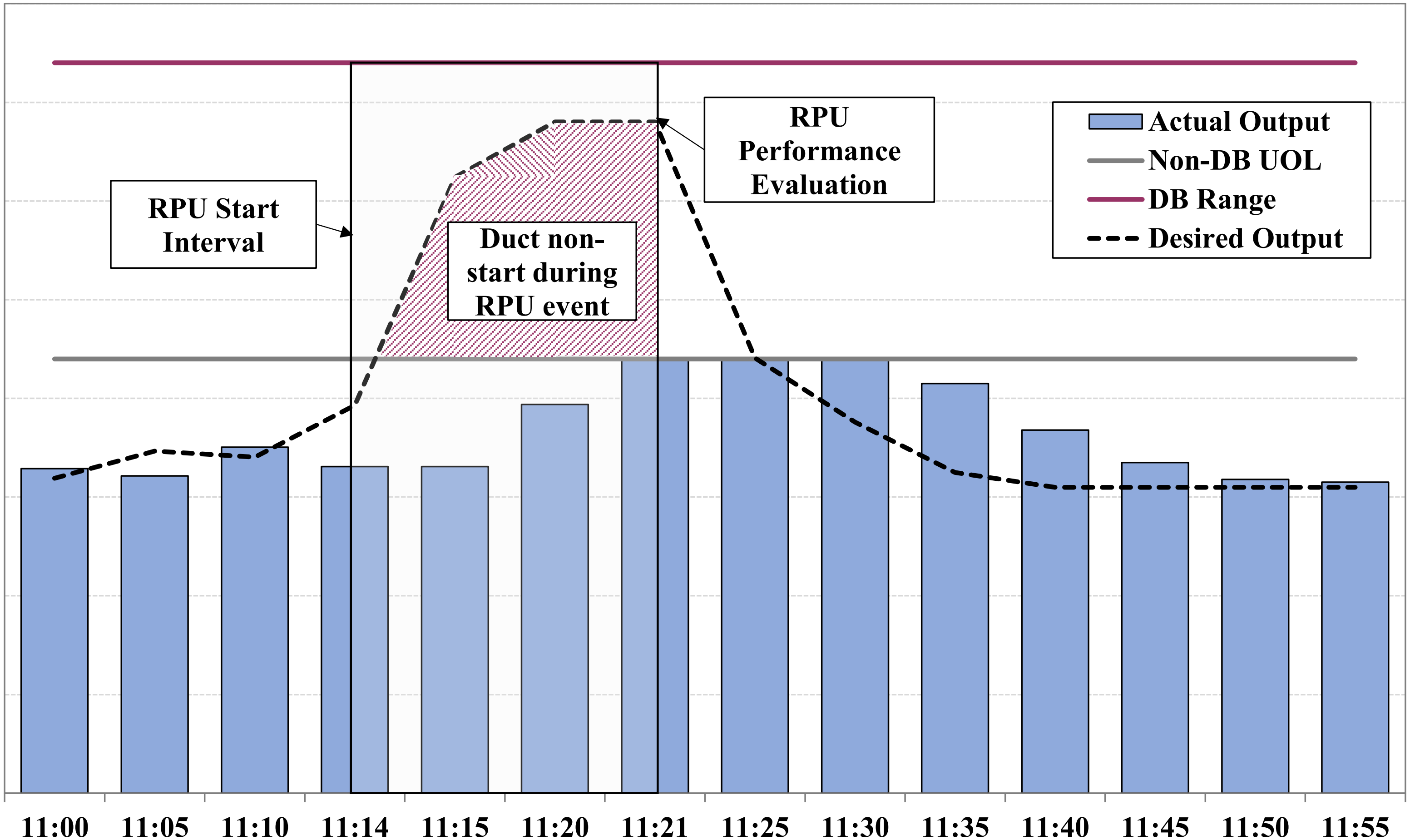





Notes: For chart description, see slide 94.

POTOMAC ECONOMICS

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



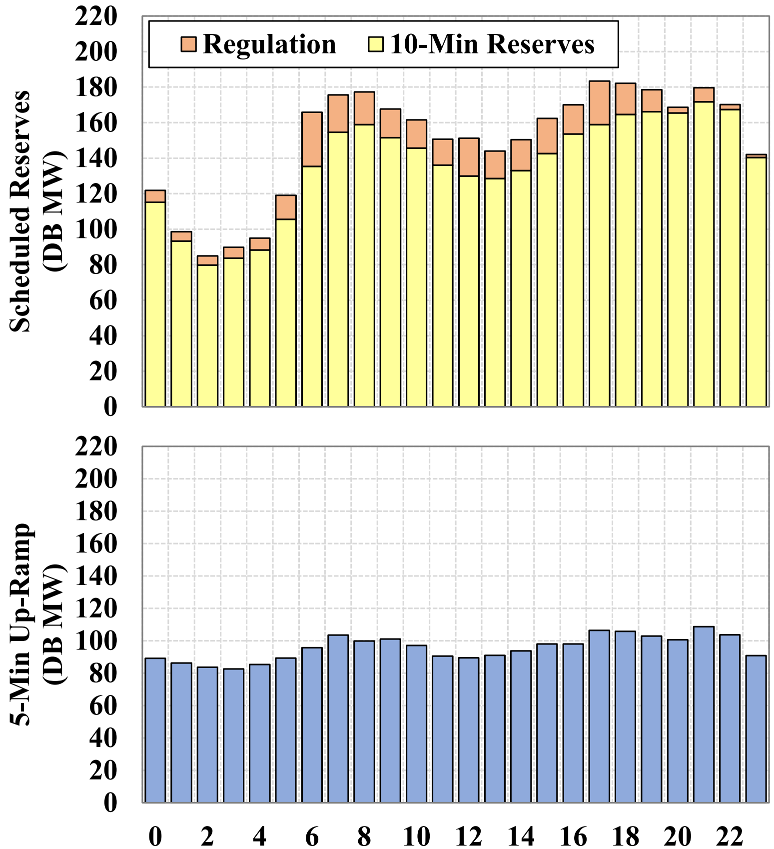

Notes: For chart description, see slide 95



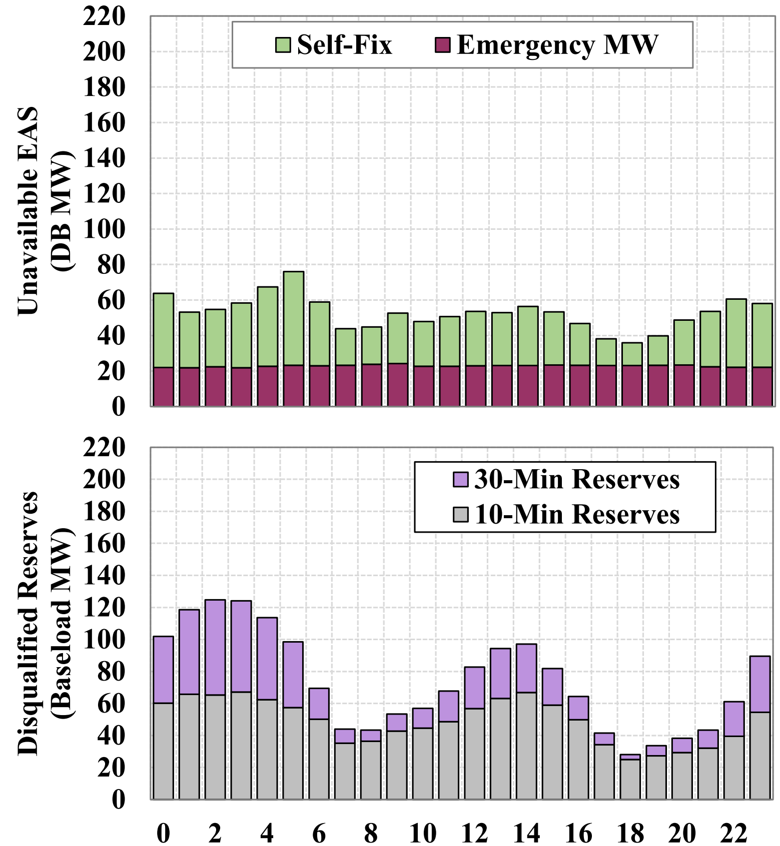


# Duct Burner Schedules and Ramp Expectations Evaluation of Duct Availability in Real-Time

**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 95



POTOMAC ECONOMICS

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

| 10 Minute Economic GT Start Performance vs. Audit Results (April 2022 - March 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] | 0 | 0 | 0 | 0 |
| 0% - 10% | 0 | 0 | 0 | 0 |
| 10% - 20% | 0 | 0 | 0 | 0 |
| 20% - 30% | 0 | 0 | 0 | 0 |
| 30% - 40% | 1 | 2 | 1 | 1 |
| 40% - 50% | 2 | 9 | 2 | 4 |
| 50% - 60% | 2 | 11 | 2 | 6 |
| 60% - 70% | 1 | 6 | 1 | 4 |
| 70% - 80% | 3 | 11 | 3 | 5 |
| 80% - 90% | 17 | 85 | 17 | 13 |
| 90% - 100% | 26 | 117 | 26 | 13 |
| **TOTAL** | **52** | **241** | **52** | **46** |

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 96.

POTOMAC ECONOMICS

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

**30 Minute Economic GT Start Performance vs. Audit Results (April 2022 - March 2023)**

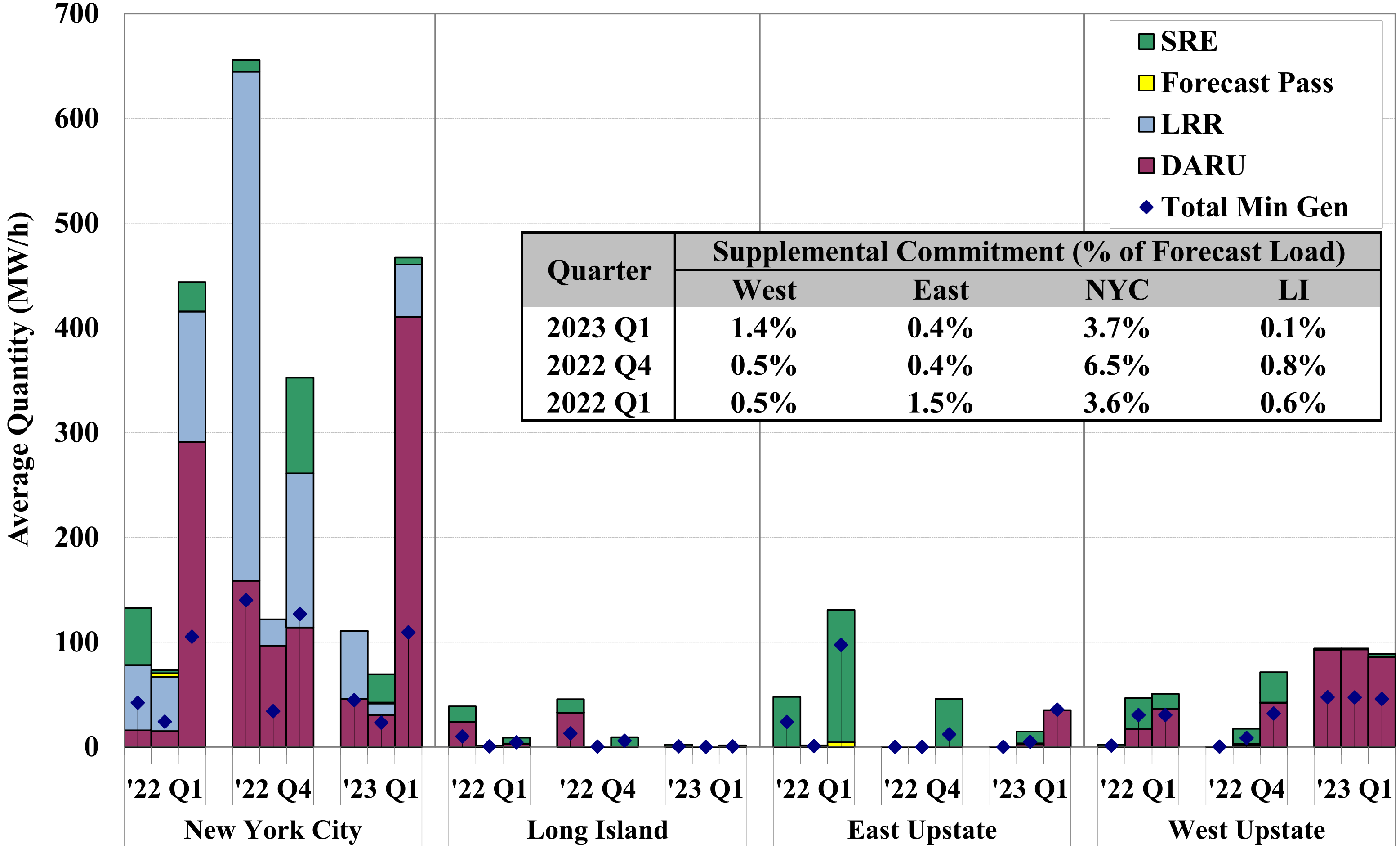
| Economic GT Starts (RTC) | | GT Audit Results | | |
|---|---|---|---|---|
| **Performance Category** | **No. of Units** | **No. of Audits** | **Unique GTs Audited** | **No. of Audit Failures** |
| Not Evaluated [1] | 26 | 30 | 22 | 1 |
| 0% - 10% | 1 | 2 | 1 | 1 |
| 10% - 20% | 0 | 0 | 0 | 0 |
| 20% - 30% | 1 | 1 | 1 | 0 |
| 30% - 40% | 0 | 0 | 0 | 0 |
| 40% - 50% | 0 | 0 | 0 | 0 |
| 50% - 60% | 2 | 2 | 2 | 0 |
| 60% - 70% | 1 | 1 | 1 | 0 |
| 70% - 80% | 4 | 7 | 4 | 0 |
| 80% - 90% | 29 | 64 | 29 | 4 |
| 90% - 100% | 23 | 39 | 23 | 1 |
| **TOTAL** | **87** | **146** | **83** | **7** |

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

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

POTOMAC ECONOMICS

# Supplemental Commitment for Reliability by Category and Region




| Quarter | Supplemental Commitment (% of Forecast Load) | | | |
|---|---|---|---|---|
| | West | East | NYC | LI |
| 2023 Q1 | 1.4% | 0.4% | 3.7% | 0.1% |
| 2022 Q4 | 0.5% | 0.4% | 6.5% | 0.8% |
| 2022 Q1 | 0.5% | 1.5% | 3.6% | 0.6% |

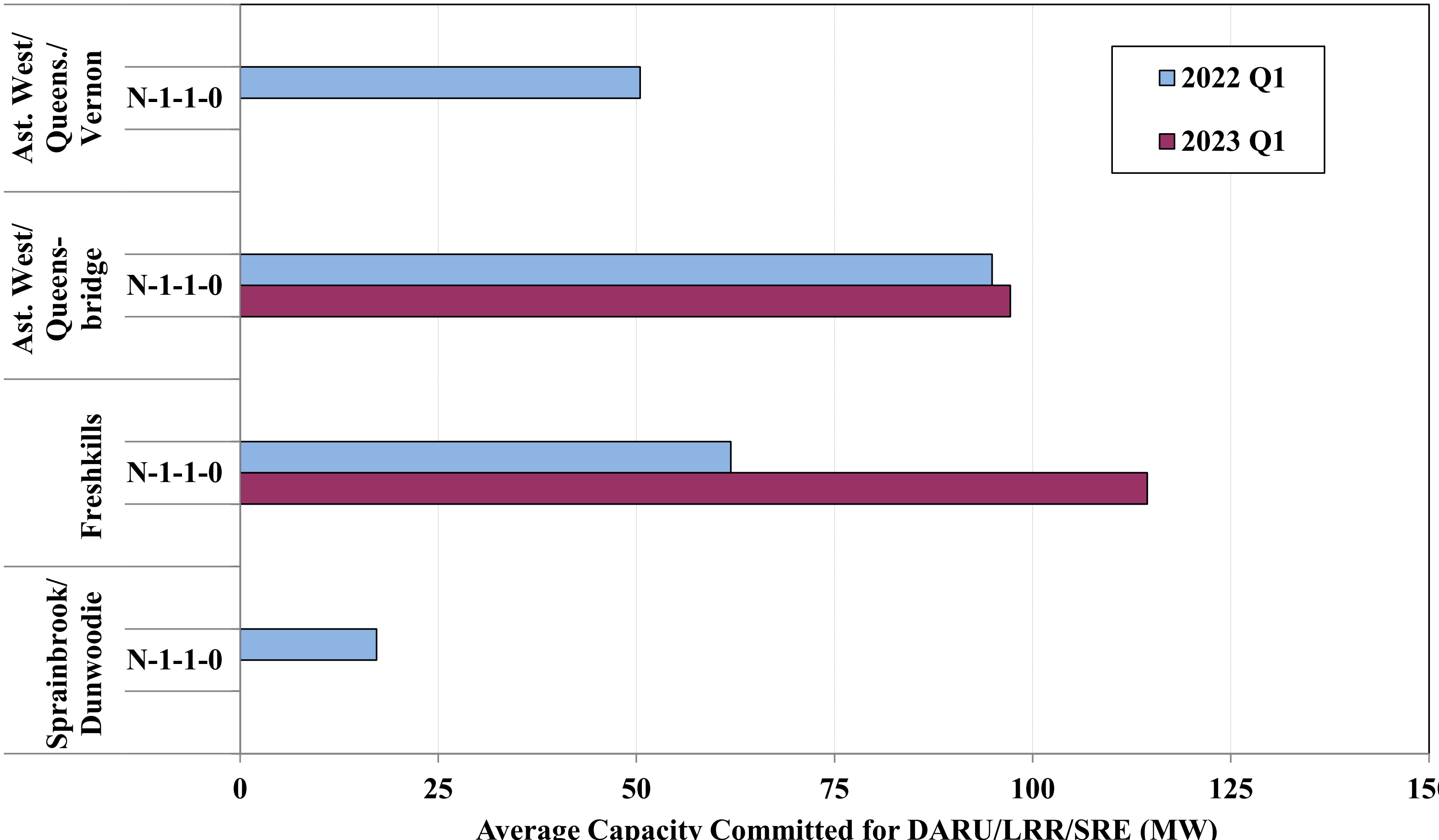
Notes: For chart description, see slides 97 and 98.





POTOMAC ECONOMICS

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



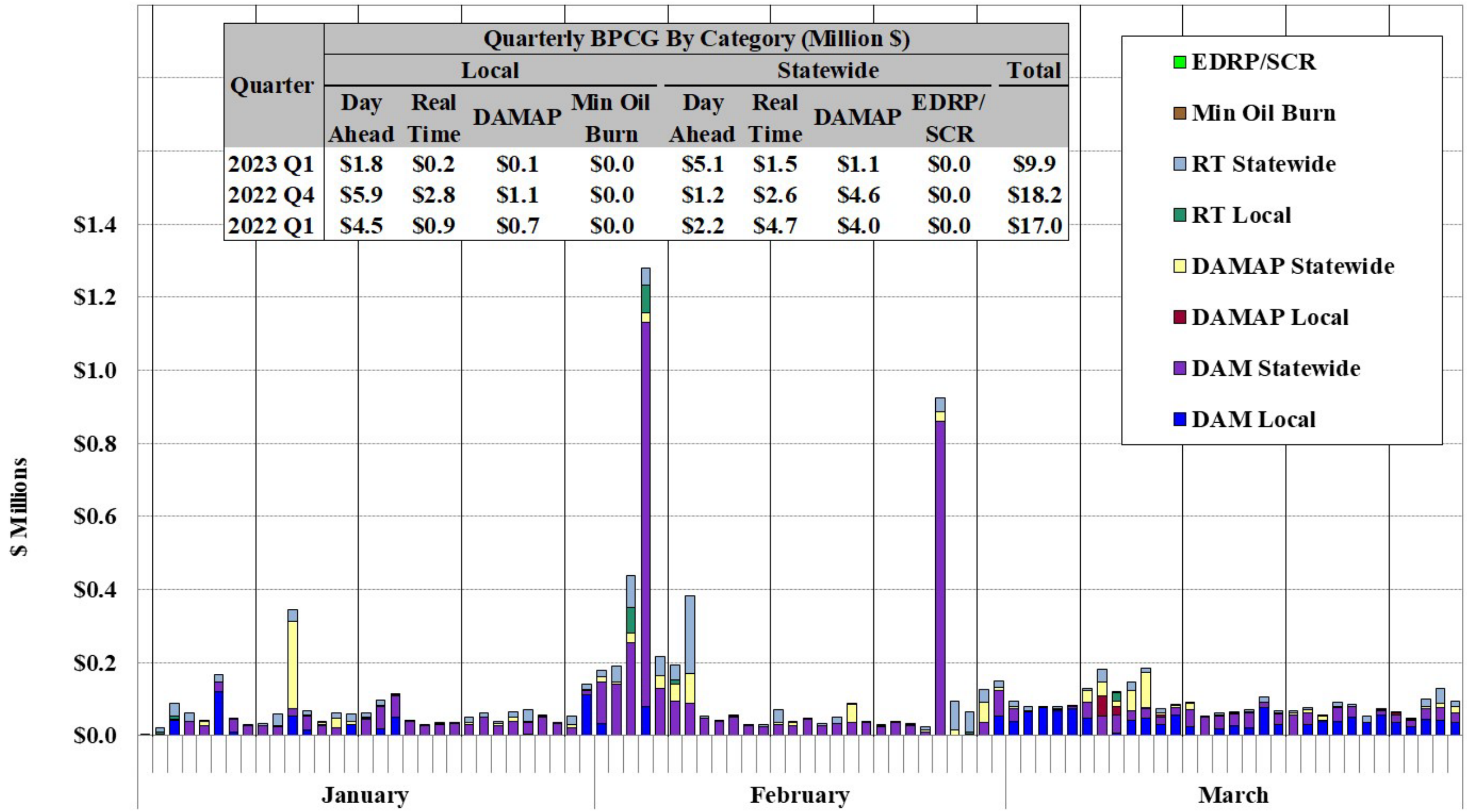

Notes: For chart description, see slides 97 and 98.





POTOMAC ECONOMICS

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




| Quarter | Quarterly BPCG By Category (Million $) | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| | Local | | | | Statewide | | | | Total |
| | Day Ahead | Real Time | DAMAP | Min Oil Burn | Day Ahead | Real Time | DAMAP | EDRP/ SCR | |
| 2023 Q1 | $1.8 | $0.2 | $0.1 | $0.0 | $5.1 | $1.5 | $1.1 | $0.0 | $9.9 |
| 2022 Q4 | $5.9 | $2.8 | $1.1 | $0.0 | $1.2 | $2.6 | $4.6 | $0.0 | $18.2 |
| 2022 Q1 | $4.5 | $0.9 | $0.7 | $0.0 | $2.2 | $4.7 | $4.0 | $0.0 | $17.0 |

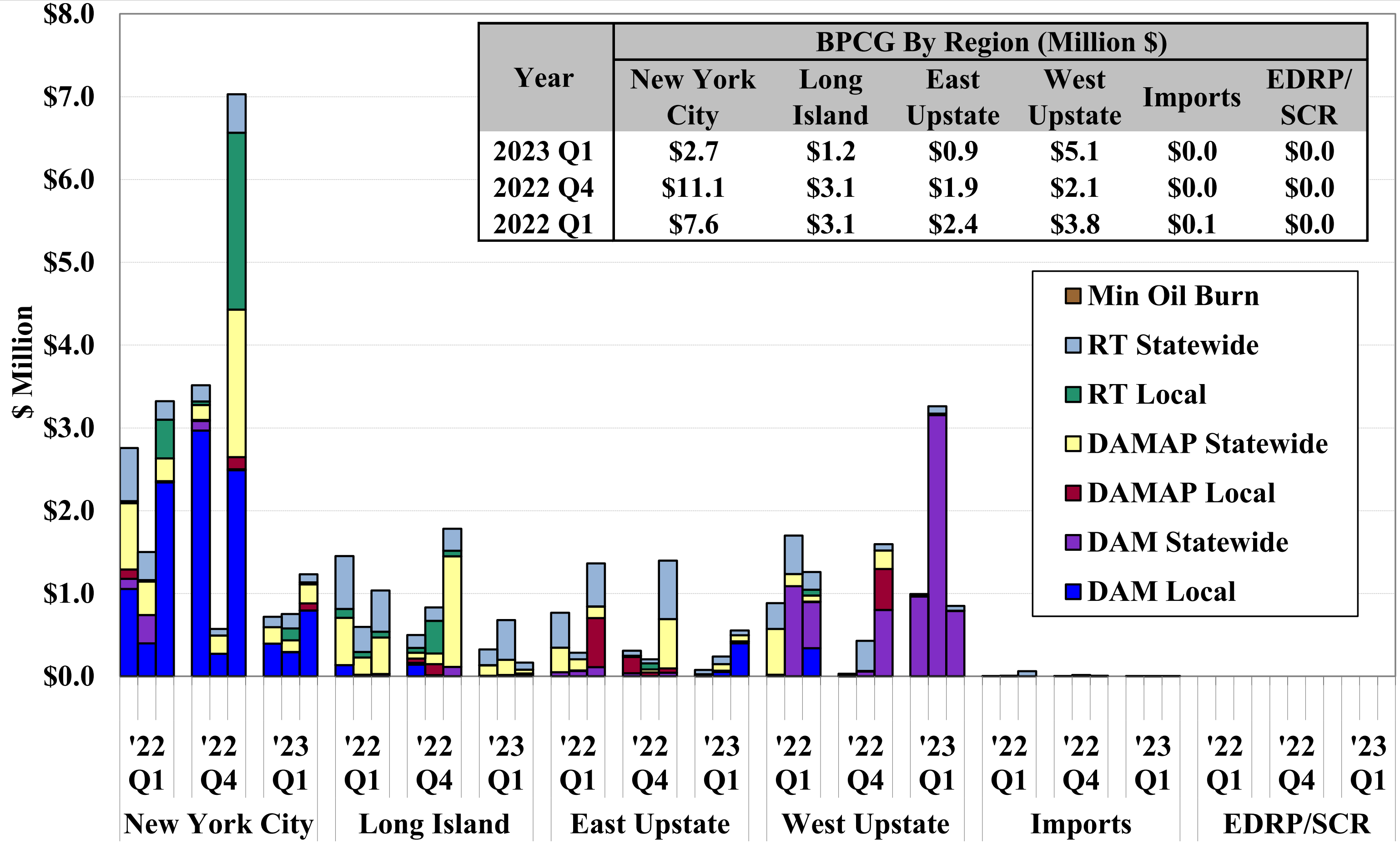
Notes:1. This data is based on information available at the reporting time and does not include some manual adjustments to mitigation, so it can be different from final settlements.
2. For chart description, see slide 99.



POTOMAC ECONOMICS

# Uplift Costs from Guarantee Payments
## By Category and Region

| Year | BPCG By Region (Million $) | | | | | |
|---|---|---|---|---|---|---|
| | New York City | Long Island | East Upstate | West Upstate | Imports | EDRP/ SCR |
| 2023 Q1 | $2.7 | $1.2 | $0.9 | $5.1 | $0.0 | $0.0 |
| 2022 Q4 | $11.1 | $3.1 | $1.9 | $2.1 | $0.0 | $0.0 |
| 2022 Q1 | $7.6 | $3.1 | $2.4 | $3.8 | $0.1 | $0.0 |



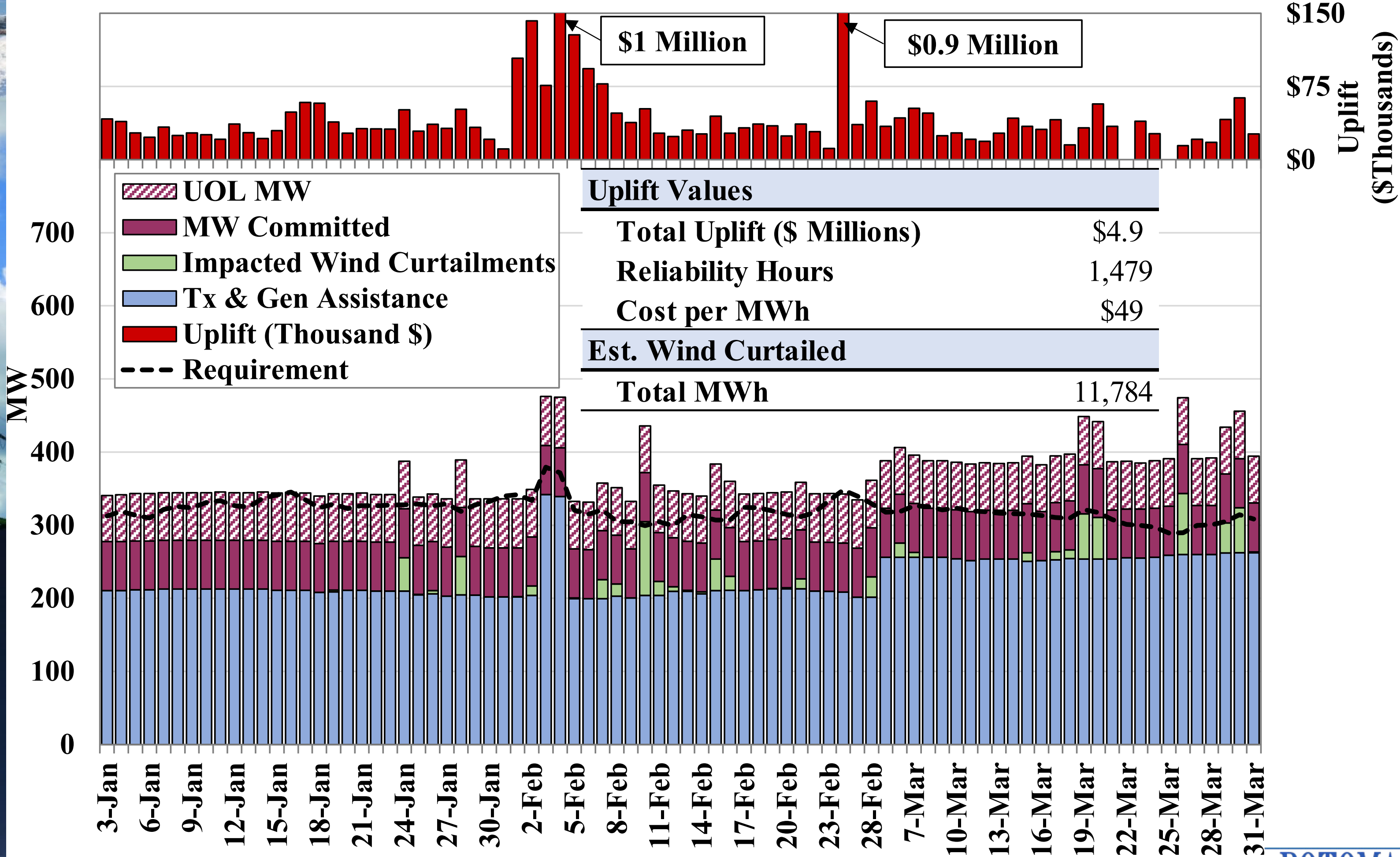

Notes: 1. BPCG data are based on information available at the reporting time that can be different from final settlements.
2. For chart description, see slide 99.





POTOMAC ECONOMICS

# North Country Reliability Commitments
## Unmodeled Costs & Excess Wind Curtailments






Notes: For chart description, see slide 100
POTOMAC ECONOMICS

# Charts:

## Market Power and Mitigation

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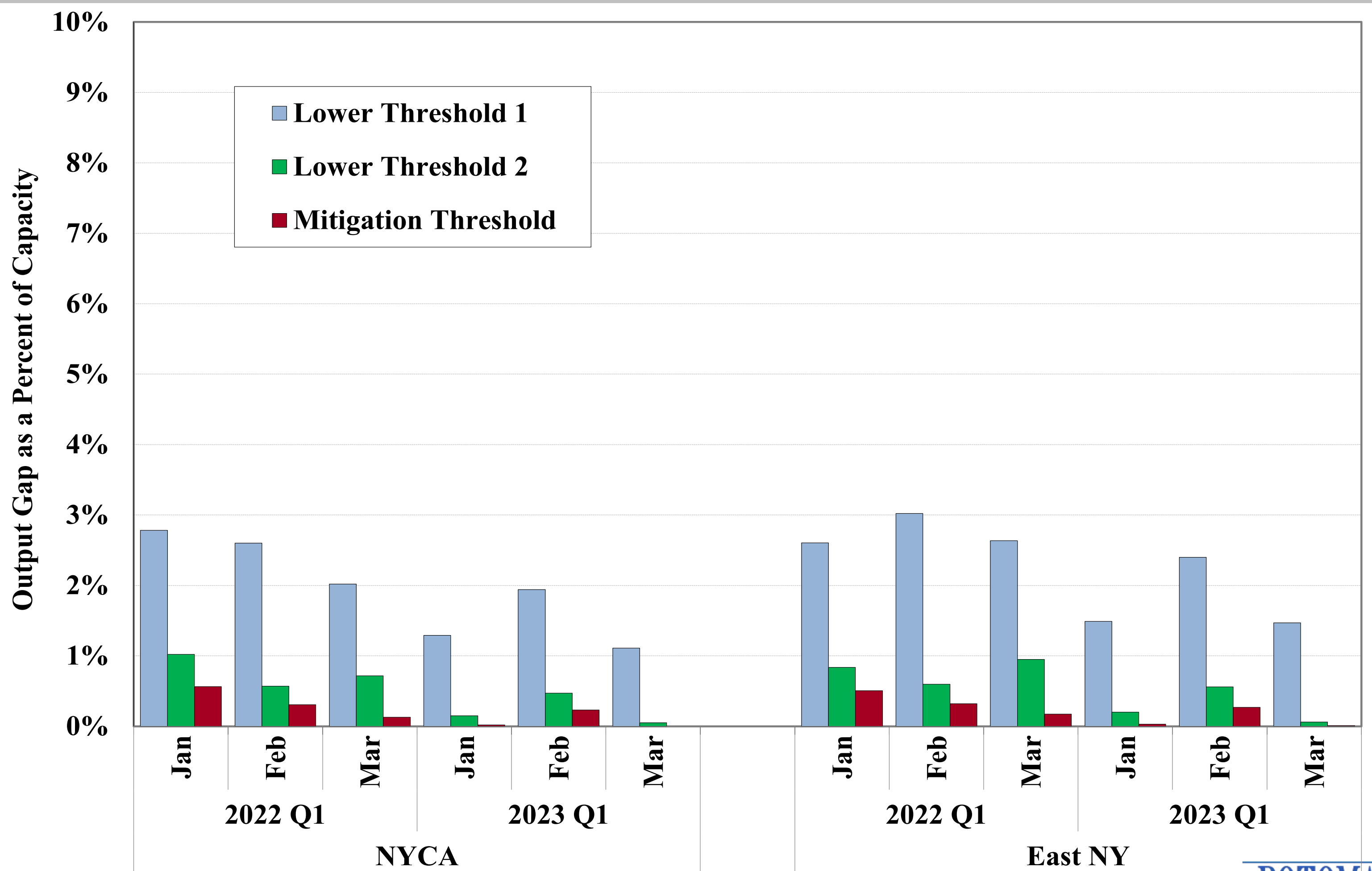
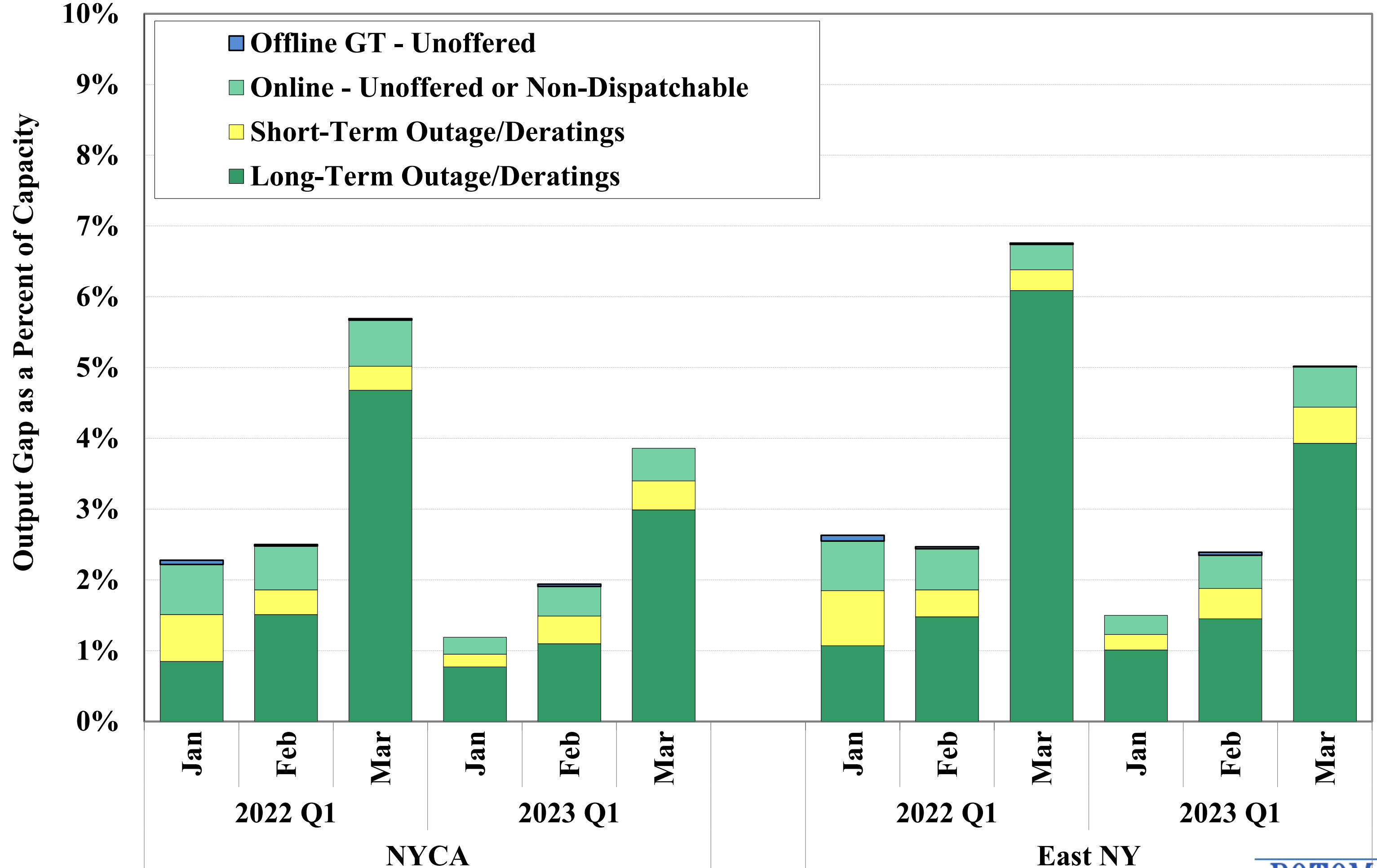
# Output Gap by Month
## NYCA and East NY






For chart description, see slide 101.
POTOMAC ECONOMICS

# Unoffered Economic Capacity by Month
## NYCA and East NY



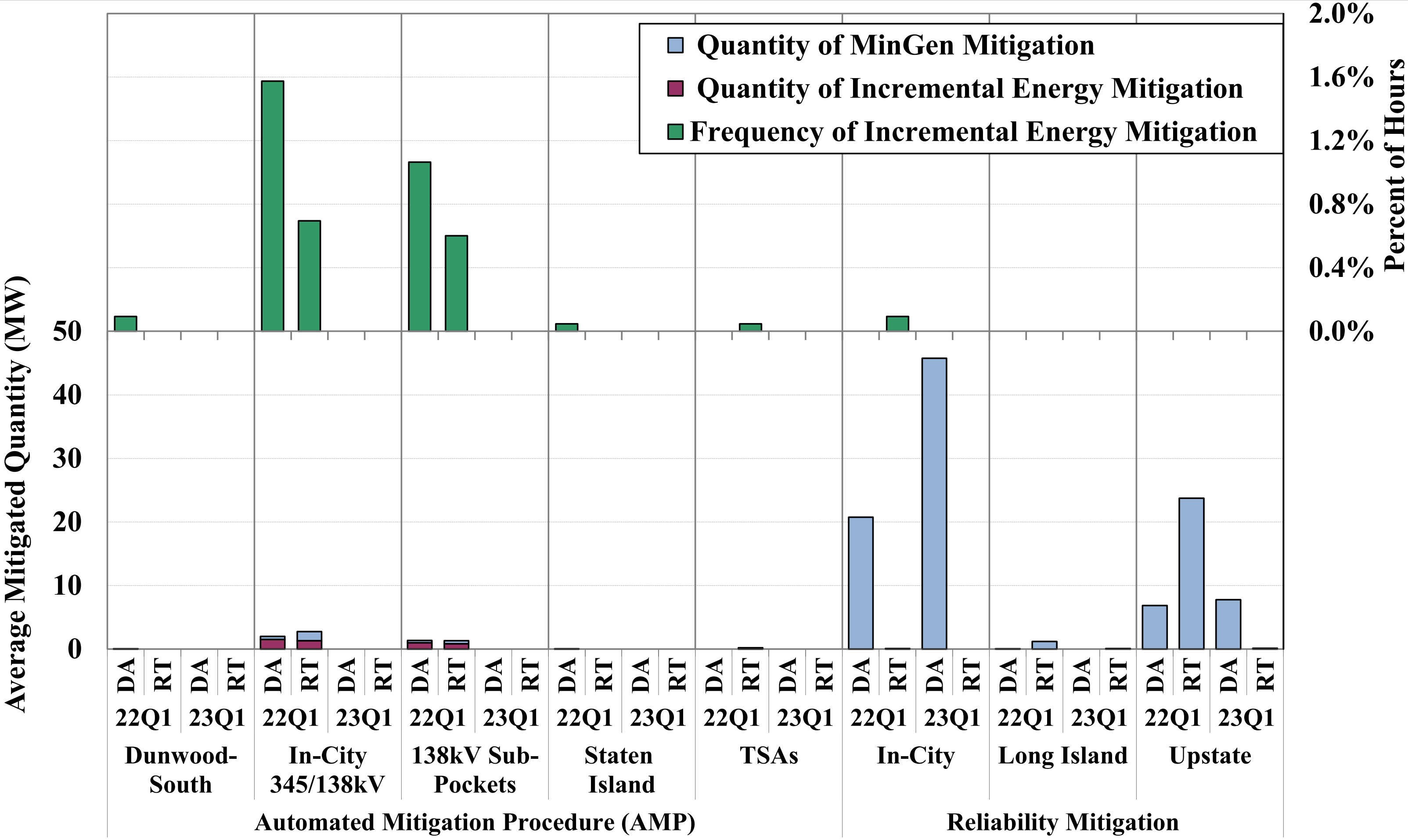





For chart description, see slide 101.

POTOMAC ECONOMICS

# Automated Market Power Mitigation








Notes: For chart description, see slide 102.

POTOMAC ECONOMICS

# Charts:
## Capacity Market

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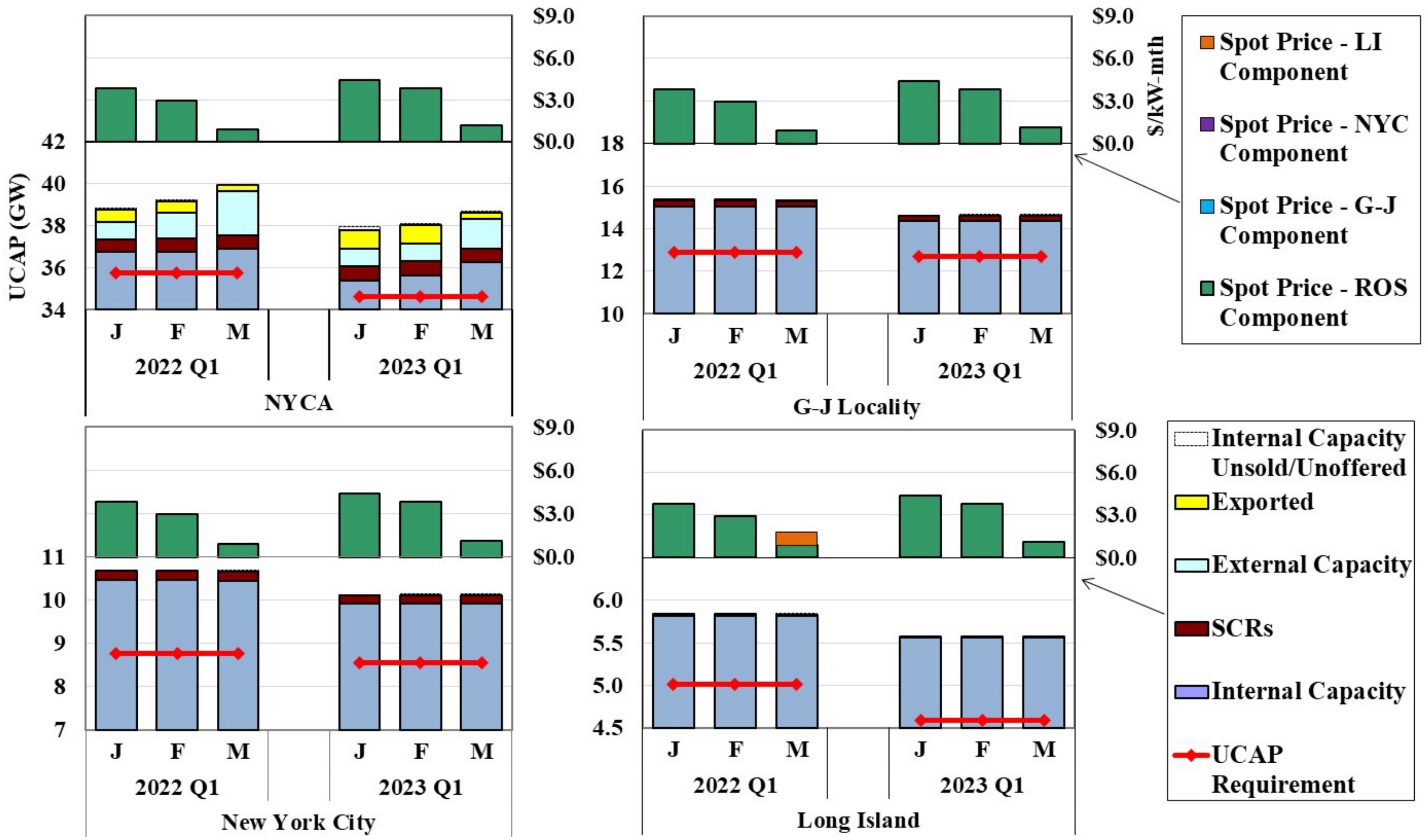
# Spot Capacity Market Results
## Monthly Results by Locality







Notes: For chart description, see slide 103.

POTOMAC ECONOMICS

# Key Drivers of Capacity Market Results

| | NYCA | NYC | LI | G-J Locality |
|---|---|---|---|---|
| **Avg. Spot Price** | | | | |
| 2023 Q1 ($/kW-Month) | $3.11 | $3.11 | $3.11 | $3.11 |
| % Change from 2022 Q1 | **22%** | **22%** | **9%** | **22%** |
| **Change in Demand** | | | | |
| Load Forecast (MW) | -566 | -293 | -111 | -286 |
| IRM/LCR | -1.1% | 0.9% | -3.4% | 1.6% |
| *2022/23 Capability Year* | *119.6%* | *81.2%* | *99.5%* | *89.2%* |
| *2021/22 Capability Year* | *120.7%* | *80.3%* | *102.9%* | *87.6%* |
| **ICAP Requirement (MW)** | **-1,033** | **-137** | **-289** | **-7** |
| **Key Changes in ICAP Supply (MW)** | | | | |
| *Generation* | **-735** | **-441** | **-81** | **-488** |
| *Entry* (3) | 137 | 0 | 23 | 0 |
| *Exit* (3) | -435 | -388 | -47 | -388 |
| *Other Capacity Changes* (1) | -437 | -53 | -56 | -100 |
| *Cleared Import* (2) | **-349** | | | |

*(1) Other changes include DMNC ratings, former 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 103.

# Appendix:  Chart Descriptions

# All-in Price

- Slide 15 summarizes the total cost per MWh of load served in the New York markets by showing the "all-in" price that includes:
  - ✓ An energy component that is a load-weighted average real-time energy price.
  - ✓ A capacity component that is calculated based on clearing prices in the monthly spot capacity auctions and capacity obligations in each zone, allocated over the energy consumption in that zone.
  - ✓ An uplift component that is based on local and statewide uplift from Schedule 1 charges, allocated over the energy consumed in the area.
  - ✓ An ancillary services component that is based on costs associated with operating reserves, regulation, voltage support, and black start.
    - For the purpose of this metric, these costs are distributed evenly across all locations.
  - ✓ The figure also shows representative natural gas prices for each location that is based on the following indices (plus transportation charges equal to $0.27 per MMBtu for Zones A through I, $0.20 per MMBtu for New York City, and $0.25 per MMBtu for Long Island):
    - (a) Tennessee Z4 200L index for the West Zone, (b) the minimum of TN Z6 and Iroquois Zone 2 indices during the months Dec through Feb, and TN Z4 200L index otherwise for Central New York; (c) Iroquois Waddington index for North Zone; (d) the minimum of TN Z6 and Iroquois Z2 indices for the Capital Zone; (e) the average of Iroquois Z2 index and the Tetco M3 index for Lower Hudson Valley; (f) Transco Zone 6 (NY) index for New York City, and (g) the Iroquois Z2 index for Long Island. A 6.9 percent tax rate is also included NYC.

# Real-Time Output and Marginal Units by Fuel

- Slide 18 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 19 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.





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# Winter Fuel Usage and Emissions by Region

- Slide 20 evaluates the efficiency of fuel usage in Eastern New York in the quarter.
  - ✓ The figure shows the daily averages for:
    - – Internal generation by actual fuel consumed in the lower portion; and
    - – Day-ahead natural gas price index for Iroquois Zone 2 and Transco Zone 6 (NY) in the upper portion.
  - ✓ For a year-over-year comparison, these quantities are also shown by month for the same quarter in the recent three years.

# Utilization of Oil-Fired and Dual-Fuel Capacity
## Eastern New York During Tight Gas Conditions

- Slide 21 evaluates use of capacity listed as oil-fired or dual-fuel in the Gold Book in Eastern New York during cold weather and tight gas conditions in January 2022.
  - ✓ The figure shows the estimated generation that would have been economic to burn oil based on day-ahead and real-time clearing prices during this period.
- The figure shows the capacity in the following categories:
  - ✓ Actual output, from oil-fired and gas-fired generation separately.
  - ✓ The amount of economic oil-fired generation that was unavailable because of:
    - – Long-term OOS – oil capable but with mothballed or decommissioned oil equipment;
    - – Oil equipment failure – short-term outages/deratings due to oil equipment failures;
    - – Outages and deratings – other outages and deratings;
    - – Oil permit issues – oil capable and had inventory but prohibited from burning oil by state regulations;
    - – Emission – output that would violate emission requirements, mostly NOx;
    - – Gas-only range – the portion of the dispatchable range of dual-fuel combined cycle generators that cannot fire on oil; and
    - – Oil inventory limitations.

# Evaluation of Implied Gas Demand at Hunts Point
## NYC Gas-Only Generators on ConEd System

- Slide 22 analyzes day-ahead implied natural gas demand for gas-only generators in NYC on the ConEd system that fuel-cost-adjusted their bids to source gas from Iroquois Zone 2 (Hunts Point) during gas days from January 7 to 31.
- The stacked columns show:
  - ✓ Scheduled deliveries to Hunts Point from all demand sources (source: Iroquois Pipeline data)
  - ✓ Offered & unscheduled demand from gas-only generators on the ConEd LDC for Hunts Point deliveries.
    - – The portion of gas output scheduled from these generators would not be included in the yellow columns since it is likely that this demand is already counted in the blue columns.
- The dashed and solid black lines show:
  - ✓ Dashed: Contracted maximum daily transportation (Dth) for deliveries to Hunts Point
  - ✓ Solid: Operational capacity for deliveries to Hunts Point, representing the maximum achievable daily deliveries to this point.
- Days impacted by ConEd hourly OFOs are shaded gray.

# Emission by Region

- Slides 21-27 evaluate emissions from generators in the NYISO market.
  - ✓ Slide 21 shows the historical trend of annual total emissions since 2000 in the NYISO footprint for $CO_2$, $NO_X$, and $SO_2$ .
  - ✓ Slides 22-23 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 26-27 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 26 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 28-32 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 31 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 33 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 35 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 37 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 38 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 39 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 41 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 42 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 77 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 44 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 46 and 47 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.



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# Transmission Congestion and Shortfalls

- Slides 48, 49, 50, and 51 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 48 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 49 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 50 and 51 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 41 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

- Unmodeled transmission constraints (mostly on the 115kV and lower voltage network) 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 surrogate for the limiting transmission facility; and
  - ✓ Adjusting PAR-controlled lines on the high voltage network.
- Slide 53 shows the number of days in the quarter when various resources were used to manage transmission constraints in six areas of upstate New York:
  - ✓ West Zone;
  - ✓ North & Mohawk Valley Zones;
  - ✓ Capital Zone;
  - ✓ Central Hudson;
  - ✓ New York City; 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 on Long Island

- Slide 54 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 54 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 55 shows such select N-1 constraints in New York City. In the figure,
  - ✓ The left panel summarizes their DA and RT congestion values in the quarter.
    - – The blue bars represent the congestion values measured up to the seasonal LTE ratings of the facilities (i.e., constraint shadow cost*seasonal LTE summed over all intervals); and
    - – The red bars represent the congestion values measured for the additional transfer capability above LTE (i.e., constraint shadow cost*(modeled constraint limit – seasonal LTE) summed over all intervals).
  - ✓ The bars in the right panel show the seasonal LTE and STE ratings for these facilities, compared to the average N-1 constraint limits used in the market software.



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# Duct Burner RPU Performance and Real-Time Availability

- Slide 56 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 57 shows quarterly average real-time duct burner data across all applicable units during this quarter on a 5-minute interval level basis.
  - ✓ The topmost chart shows the average amount of MWs from duct burners scheduled in real-time to provide 10-minute spinning reserves and regulation services.
  - ✓ The middle chart shows the amount of 5-minute up-ramping capability assumed to be available by duct burners (but likely not actually available due to physical operating restrictions) based on real-time output levels and generator offers.
  - ✓ The bottom chart reveals the average amount of duct burner capacity unavailable in real-time because of no offer in this range or non-dispatchable due to inflexible self-schedule level.

# GT Start-up Performance

- Slides 58-59 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 58): "26 10-minute GTs exhibited a response rate of 90 to 100 percent during economic starts in the examined period, 26 of them were audited 56 times in total with 2 failures".

# Supplemental Commitments and OOM Dispatch

- Slides 61 and 62 summarize out-of-market commitment and dispatch, which are the primary sources of guarantee payment uplift.
- Slide 61 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 62 examines the reasons for reliability commitments in NYC where most reliability commitments occur.
  - ✓ Based on a review of operator logs and LRR constraint information (where a unit is considered to be committed for a LRR constraint if the constraint would be violated without the unit's capacity), each NYC commitment (flagged as DARU, LRR, or SRE) was categorized for one of the following reasons:

# Supplemental Commitments and OOM Dispatch (cont.)

- NOx Only – If needed only for NOx bubble requirement.
- N-1-1-0 – If needed for one or two of the following reasons: voltage support (ARR 26), and thermal support (ARR 37).
- Loss of Gas – If needed for IR-3, a sudden loss of gas supply in NY, and no other reason.

✓ For N-1-1-0 constraints, the capacity is shown by the load pocket that was secured.

# Uplift Costs from Guarantee Payments

- Slides 63 and 64 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 63 shows these seven categories on a daily basis during the quarter.
  - ✓ Slide 64 summarizes uplift costs by region on a monthly basis.

# Reliability Commitments in the North Country

- Slide 65 shows the size of the N-1-1 requirement in the North Country Load Pocket ("NCLP") on applicable days in the quarter that required supplemental commitments of uneconomic gas units.
  - ✓ The bottom portion of the chart shows details relevant to the calculation of the requirement including:
    - *Tx & Gen Assistance*: Assistance from available transmission lines and day-ahead scheduled energy from non-wind resources in the pocket;
    - *MW Committed & UOL MW*: The generation scheduled (typically the minimum generation level) and the remaining headroom up to its UOL from those unit(s);
    - *Requirement*: The daily maximum capacity requirement in the pocket that drives the supplemental commitments; and
    - *Impacted Wind Curtailments*: The average amount of wind curtailments in the North Zone that would have been avoided had the thermal unit(s) supplemental commitments not been needed.
  - ✓ The top portion of the chart provides the uplift associated with the reliability commitments.
- The inset table provides statistics detailing the uplift costs paid to the thermal unit(s) and the total curtailed wind generation that could have been avoided absent these reliability commitments.



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# Potential Economic and Physical Withholding

- Slides 67 and 68 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.



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# Automated Market Power Mitigation

- Slide 69 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 71 and 72 summarize market results and key drivers in the monthly spot capacity auctions.
  - ✓ Slide 71 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 72 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 2022 to 2024.