# Quarterly Report on the New York ISO Electricity Markets First Quarter of 2024


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# Market Highlights

# Market Highlights:
## Executive Summary

- NYISO energy markets performed competitively in the first quarter of 2024.
- All-in prices ranged from $38/MWh in the North Zone to $81/MWh in New York City, with prices rising west of the Central-East interface (13-30 percent) and NYC (49 percent) while falling in other portions of eastern NY (5-17 percent). (slide 7)
  - ✓ Energy costs rose by 18 to 39 percent west of the Central-East interface and 8 percent in NYC but fell by 5 to 20 percent in the rest of eastern NY.
    - – Lower gas prices contributed to lower energy costs in most eastern NY areas.
    - – The modest increase in NYC was largely due to higher congestion levels resulting from major transmission outages.
    - – The increase west of the Central-East interface resulted from less-frequent congestion across the interface, which was driven by:
      - Net imports from Quebec fell nearly 1.3 GW on average, and
      - The completion of Segment A & B transmission projects.
  - ✓ Capacity costs rose modestly in all areas except NYC. (slide 16) NYC saw a 221 percent increase due largely to the retirement of over 600 MW of peakers and the increase of more than 300 MW in the local ICAP requirement.

# Market Highlights:
## Executive Summary

- Supplemental commitments to satisfy reserve requirements occurred on 74 days in the North Country load pocket and 58 days in NYC load pockets. (slide 10)
  - ✓ The reliability need for 78 percent of DARU commitments in NYC could not be "verified" by the MMU based on information available to the DAM. Most of these commitments were made to (a) avoid cycling older generators not needed on every day or (b) because most DARUs occur 1 to 3 days ahead of the DAM. (slide 15)
  - ✓ We have recommended modeling the underlying N-1-1 and N-1-1-0 requirements as local reserve requirements. (Rec #2017-1)
- An average of 615 MW of net virtual imports were scheduled in the DAM, which reduced Forecast Pass commitments and increased SRE commitments. (slide 14)
  - ✓ We recommend distinguishing between firm and non-firm external transactions for scheduling and pricing under Dynamic Reserves. (Rec #2015-16)
- Regulation scheduling assumes a single movement-to-capacity ratio for all resources, although actual ratios for individual resources vary widely. (slide 12 )
  - ✓ This significantly underestimates the costs of fast-ramping resources in the scheduling process, leading to inefficient market incentives and resource selection. NYISO should consider adjusting the assumed ratio (the "Regulation Movement Multiplier") to a more representative level.



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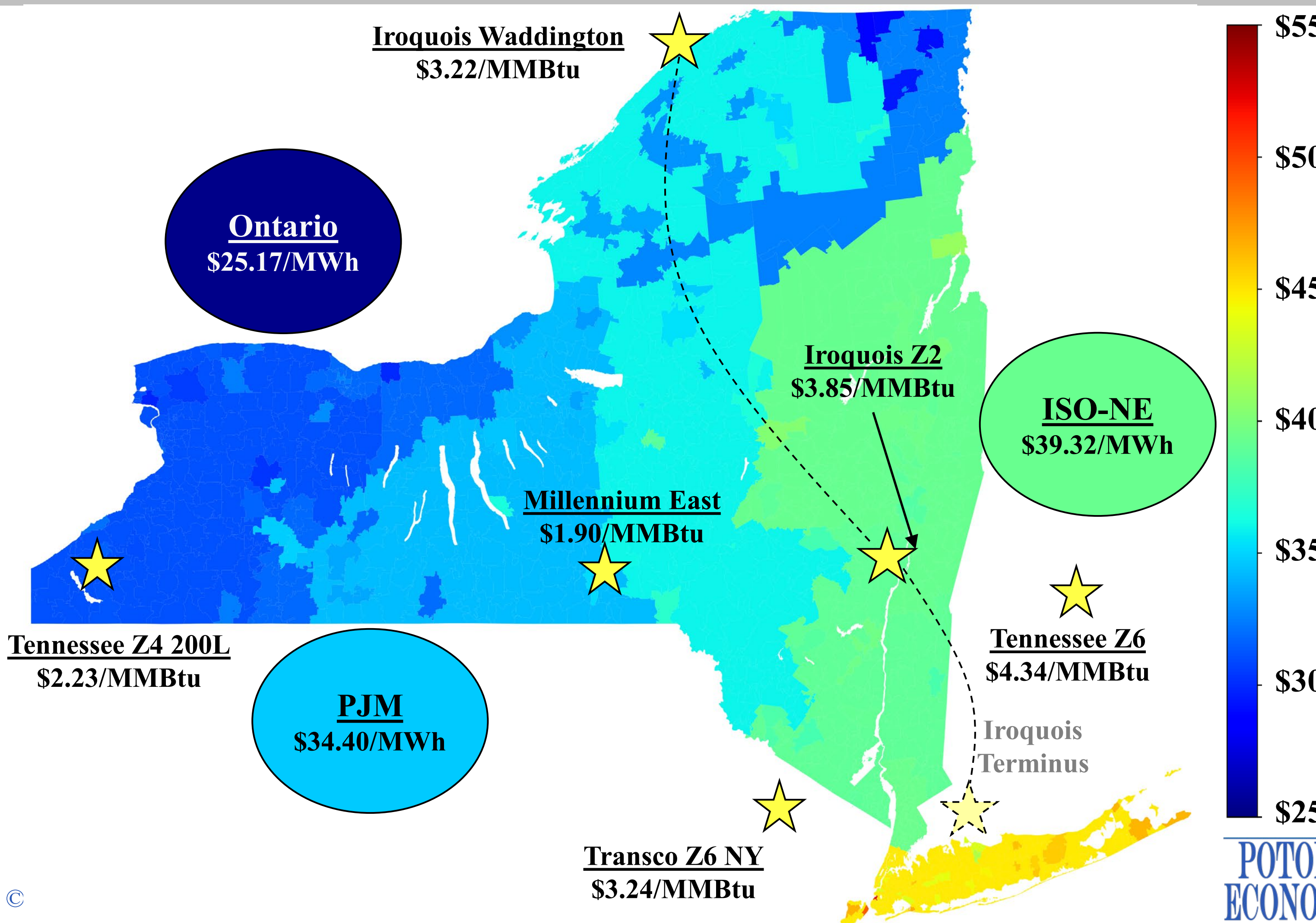
# Market Highlights:

## System Price Diagram

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# Market Highlights:
## Summary of Energy Market Outcomes

- NYISO energy markets performed competitively in the first quarter of 2024.
  - ✓ The amount of output gap (slide 74) and unoffered economic capacity (slide 75) remained reasonably consistent with competitive market expectations.
- All-in prices ranged from \$38/MWh in the North Zone to \$81/MWh in New York City, rising west of Central-East but falling in eastern NY except New York City, which saw the largest increase (49 percent) among all areas. (slide 19)
  - ✓ Lower gas prices drove energy costs down in most of eastern NY. (slides 30-31)
    - – Gas prices fell by 8 to 29 percent from a year ago in most regions because of mild weather, continued growth in gas production, and higher gas storage levels. However, NYC saw a 10 percent increase in gas prices. (slide 21)
    - – In addition, NYC saw higher energy costs due to elevated congestion levels driven by transmission outages.
  - ✓ In contrast, energy costs west of Central-East rose despite lower gas prices.
    - – Substantially lower west-to-east congestion (for the reasons discussed in slide 8) led to eastern NY resources setting prices for west of Central-East more frequently.
  - ✓ Capacity costs rose modestly in all areas except NYC, which saw a 221 percent increase from a year ago for the reasons discussed on slide 17.

# Market Highlights: Congestion Patterns, Revenues and Shortfalls

- Day-ahead congestion revenues fell by 47 percent to $76 million in the first quarter of 2024. (slide 54)  Several factors contributed to the low congestion level:
  - ✓ Low and relatively stable natural gas prices due to mild weather conditions.
  - ✓ Completion of the AC Transmission Segment A and Segment B projects, which:
    - Eliminated the need for lengthy transmission outages to facilitate associated construction work, and
    - Increased transfer capability over the Central-East and UPNY-SENY interfaces.
  - ✓ Lower import levels from Quebec—average net imports fell nearly 1.3 GW compared to a year ago, which reduced overall west-to-east congestion.
- Congestion across the Central-East interface, which typically accounts for the largest share of total congestion, fell 63 percent from a year ago.
  - ✓ The occurrence of this congestion in the day-ahead market dropped to less than 20 percent of hours, compared to over 90 percent of hours a year ago.
  - ✓ Despite the decrease, the Central-East interface still accounted for nearly 50 percent of day-ahead congestion revenue.

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

- New York City facilities accounted for the second largest share (26 percent) of congestion in the day-ahead market.
  - ✓ Unlike other regions that saw reduced congestion levels compared to a year ago, New York City experienced higher congestion this quarter.
  - ✓ Roughly 70 percent of this congestion occurred during the cold spell in mid-January when natural gas prices were elevated.
    - – This coincided with the outage of one Dunwoodie-Motthaven 345 kV Line, which significantly reduced the import capability into New York City.
    - – This outage led to $5 million of congestion shortfalls in the day-ahead market during this cold spell. (slide 56)
- Long Island accounted for another 8 percent of day-ahead congestion.
  - ✓ Despite one of the 345 kV tie lines (the Y50 line) between upstate and Long Island being OOS for nearly the entire quarter, Long Island congestion fell by nearly 50 percent compared to a year ago because of smaller congestion price differentials.



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

- Supplemental commitments to satisfy N-1-1 and N-1-1-0 requirements occurred on 74 days in the North Country load pocket and 58 days in NYC load pockets. (slide 59)
  - ✓ It would be beneficial to incorporate the full reserve requirements into the market model for resource scheduling and pricing in these local areas.
- OOM actions were also frequent on Long Island. (slide 59)
  - ✓ In the Valley Stream load pocket, one or more GTs were needed on 11 days to manage 69 kV transmission constraints involving a contingency not modeled in the market software.
  - ✓ Additionally, OOM commitments occurred on 19 days to address high voltage risks during light load conditions.
    - The frequency of OOM commitment for high voltage has increased since 2023 Q4 because of changing operating practices by the local TO. Previously, high voltage conditions were more frequently addressed by taking lines out of service (to increase reactive power losses).
    - Large steam turbines were supplementally committed for this need, which often resulted in depressed LBMPs and higher BPCG uplift.

# Market Highlights:
## Reliability Commitments, OOM Dispatch, and BPCG

- BPCG payments totaled $7 million, down 30 percent from last year. (slide 70)
  - ✓ The reduction was primarily due to the lower natural gas prices.
  - ✓ However, supplemental commitments on Long Island increased compared to a year ago (slide 67), partially offsetting the decrease.
- New York City accounted for the largest share of BPCG uplift, with $2.9 million or 41 percent of the total, slightly higher than last year.
  - ✓ Nearly $2 million was paid to generators committed for N-1-1 reliability.
  - ✓ We were unable to verify the reliability need for most DARU commitments for local reliability based on information available at the time of the day-ahead market. (slide 69)
- Long Island accrued $1.8 million (or 26 percent) of BPCG uplift this quarter.
  - ✓ Nearly 40 percent of this amount was paid to several steam turbines supplementally committed to address high voltage risks during light load conditions.
- Western New York accounted for another $1.9 million of BPCG uplift.
  - ✓ Roughly 80 percent of this uplift was paid to units supplementally committed to satisfy the N-1-1 requirement in the North Country load pocket.



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# Market Highlights:
## Regulation Market Performance

- A single movement-to-capacity ratio, currently set at 8, is used to formulate composite offer prices for resources when scheduled for providing regulation.
  - ✓ Composite offer price = capacity offer price + 8*movement offer price
- However, resources are deployed according to their actual ramp capability and compensated based on instructed movement and actual performance. We find that:
  - ✓ Resources exhibited a wide range of movement-to-capacity ratios (slide 39); and
  - ✓ The average ratio was above 12 in recent months. (slide 38)
    - – The average ratio has risen due to the entry of new fast-ramping regulation suppliers, primarily battery storage resources. In the near-term, we recommend NYISO adjust the assumed ratio to a more representative level.
  - ✓ Using a single movement-to-capacity ratio for all units significantly underestimates the costs of fast-ramping resources in the scheduling process, which leads to inefficient scheduling and market incentives.
    - – This has led to high uplift (e.g., uplift $/movement MW of up to 150 percent of movement clearing price) for some fast-ramping resources. Such resources have incentives to raise their movement offers above marginal cost.
    - – An enhanced regulation scheduling and pricing model would be needed to address this inefficiency.

# Market Highlights:
## RT Pricing of GTs Bidding Multi-Hour MRT

- The current fast-start pricing rule is currently not applied to fast-start units that submit a minimum run time offer exceeding one hour.
  - ✓ However, the RT scheduling software (RTC and RTD) and market settlement rules ignore their MRT offers and treat them in every other way the same as a unit that submits a one-hour MRT.
  - ✓ This creates an inconsistency between the purpose of fast-start pricing and the eligibility criteria for fast-start pricing, leading to inefficient real-time prices.
- We identified seven groups of GTs in New York City and Long Island that were sometimes not eligible to set price because of this issue. (slide 49)
  - ✓ In more than 50 percent of the hours when these GTs were committed, LBMPs were below the GTs' as-bid costs.
  - ✓ If these GTs were eligible to set prices like other fast start units, the average LBMP during these hours would have increased by up to \$5 to \$19 per MWh at individual locations.
- We have recommended the NYISO revise the eligibility for fast-start pricing to be based on the minimum run time used for scheduling, rather than the value of the offer parameter. (See Recommendation #2023-2 in our 2023 SOM report).

# Market Highlights:
## Virtual Imports and Exports in the DAM

- We define virtual imports and exports as external transactions that are scheduled in the DAM but withdrawn from the RTM (i.e., no RT bids submitted).
  - ✓ These are commonly scheduled between NYISO and neighboring control areas, averaging 615 MW in the net import direction during the quarter. (slide 50)
  - ✓ We identify two issues related to virtual imports and exports in this report.

1) In the DAM, virtual imports and exports are treated as physical energy but fail post-DAM checkout with neighboring control areas. This may lead:
   - ✓ The Forecast Pass of the DAM to not commit sufficient resources, and
   - ✓ The need for SRE commitments to address capacity deficiencies after the DAM.
   - ✓ Furthermore, we have highlighted market inefficiencies that will arise when the Dynamic Reserve design is implemented because it will treat virtual and non-firm transactions as able to satisfy operating reserve requirements.
2) In RTC, despite failing post-DAM checkout, virtual transactions are treated as:
   - ✓ Available in RTC's advisory scheduling time frame, but
   - ✓ Unavailable in RTC's binding scheduling time frame.
   - ✓ This inconsistency can lead to ramp constraints in RTC's advisory scheduling time frame that distort RT prices and schedules in the binding time frame.



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# Market Highlights:
## DARU Commitments in NYC

- The overall amount of capacity committed in the DAM for NYC reliability and not otherwise economic fell slightly compared to a year ago. (slides 67-68)
- Our assessment indicates that of the DARU-requested capacity: (Slide 69)
  - ✓ 0 percent was economic in the DAM, so all DARU-requested capacity was flagged as DARU-commitments;
  - ✓ 22 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.
  - ✓ 78 percent was not verified (by the MMU).
    - – Roughly half of these were made to avoid cycling of older steam turbines. For example, if a unit is needed for reliability on Day 1 and Day 5, the TO may commit the unit on Days 2, 3, and 4 to avoid one shut-down/start-up cycle.
    - – Some of the remaining 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 not included in the information available to the MMU.

# 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 61 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 62 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 63 shows duct-firing capacity that was offered but not physically able to provide a given service.  In on-peak hours (i.e., HB 7-22), on average: (a) 84 MW was offered but unable to follow 5-minute ramp instructions; (b) 162 MW was scheduled but unable to provide 10-minute reserves; and (c) 12 MW was scheduled but unable to provide AGC.
  - ✓ In addition, (a) 34 MW of duct-firing was unavailable because it was not offered; and (b) 40 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.

# Market Highlights: Capacity Market

- Spot capacity prices averaged $12.78/kW-month in NYC, $3.30/kW-month in G-J Locality, and $3.23/kW-month elsewhere. (slides 77-78)
  - ✓ Spot prices rose by 311 percent in NYC, driven by:
    - – Reduced supply due to the retirement of over 600 MW of peaking capacity since last winter; and
    - – Increased ICAP requirement due to an increase of 333 MW in the load forecast and an increase of 0.5 percent in the LCR.
  - ✓ The ROS prices rose by 4 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.
    - – In addition to the 600 MW of peaker retirements, net imports fell by 442 MW on average as the system was a net exporter of capacity to Quebec during January and February.
  - ✓ LI prices cleared on the systemwide demand curve throughout the quarter.



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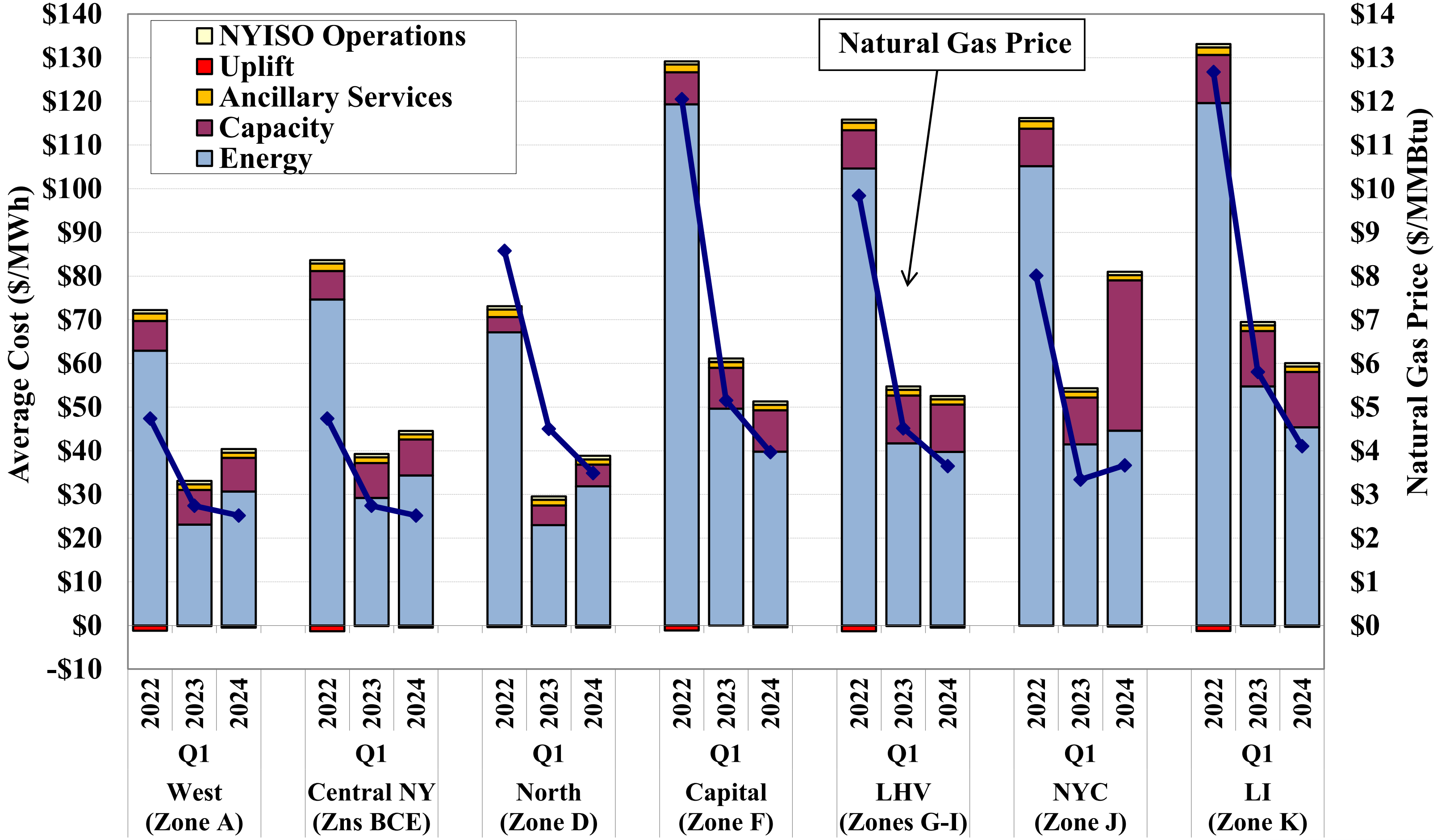
# Charts:

## Market Outcomes

# All-In Prices by Region








Notes: For chart description, see slide 80.

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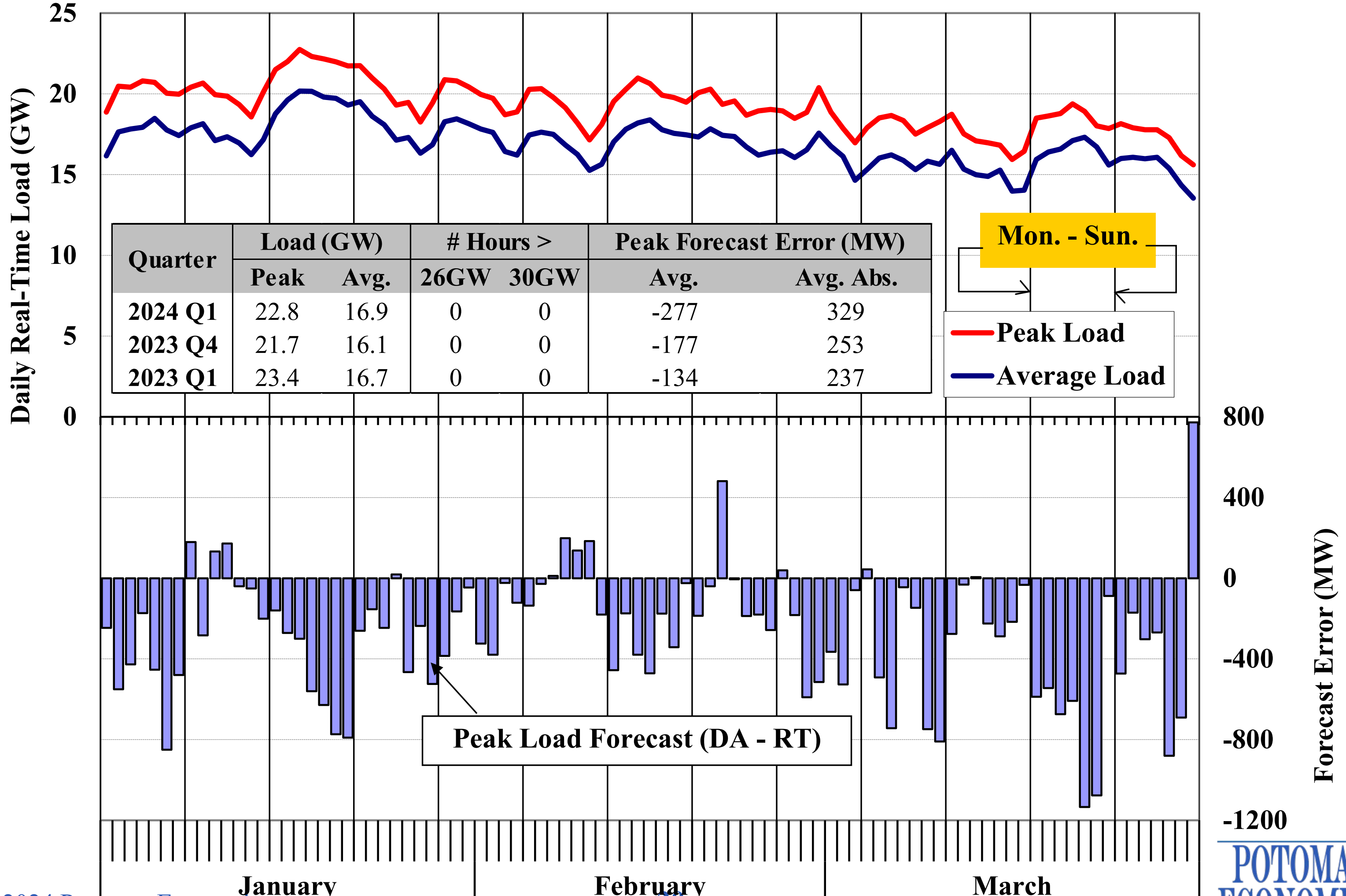
# Load Forecast and Actual Load




| Quarter | Load (GW) Peak | Load (GW) Avg. | # Hours > 26GW | # Hours > 30GW | Peak Forecast Error (MW) Avg. | Peak Forecast Error (MW) Avg. Abs. |
|---|---|---|---|---|---|---|
| 2024 Q1 | 22.8 | 16.9 | 0 | 0 | -277 | 329 |
| 2023 Q4 | 21.7 | 16.1 | 0 | 0 | -177 | 253 |
| 2023 Q1 | 23.4 | 16.7 | 0 | 0 | -134 | 237 |





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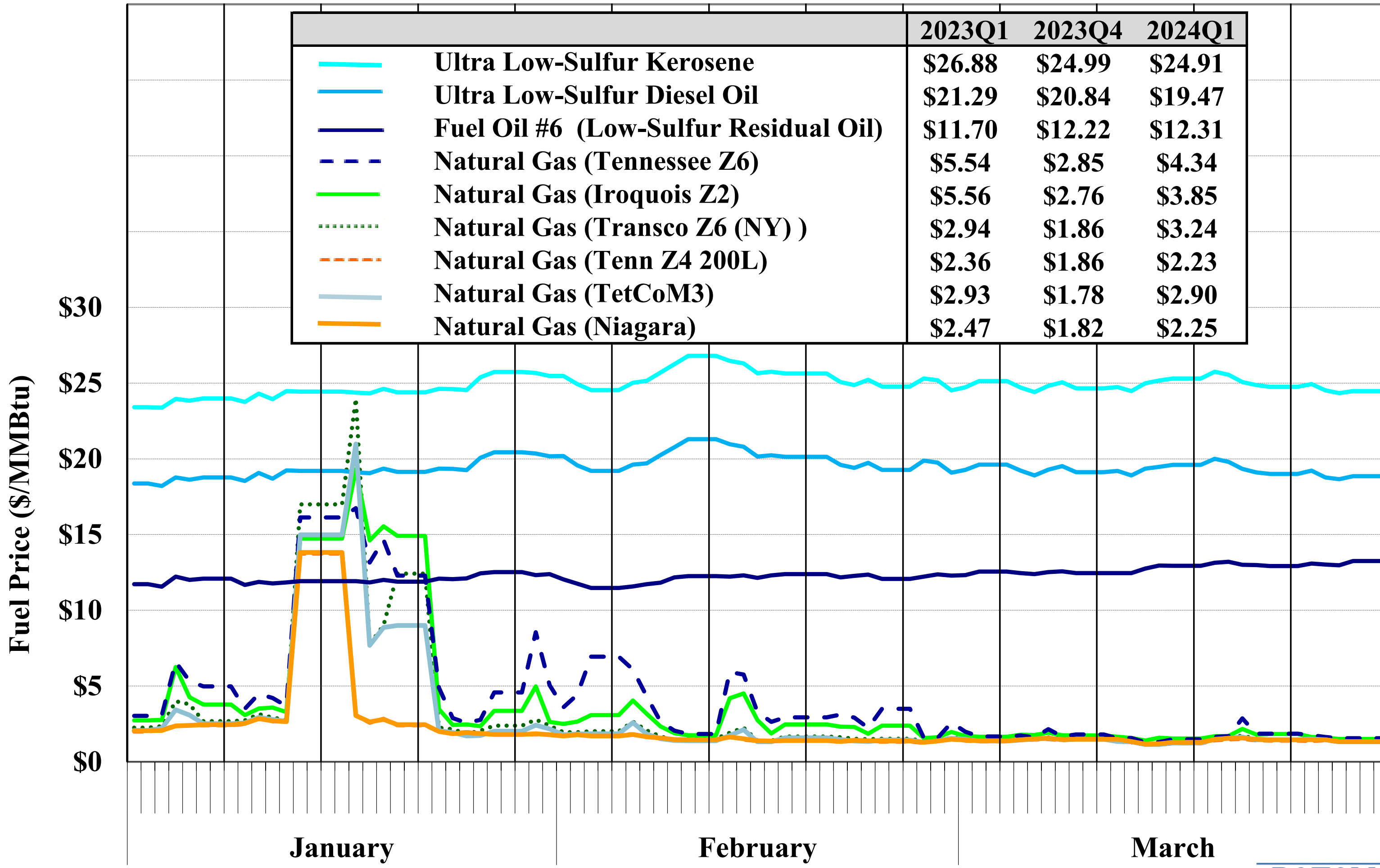
# Natural Gas and Fuel Oil Prices




| | 2023Q1 | 2023Q4 | 2024Q1 |
|---|---|---|---|
| Ultra Low-Sulfur Kerosene | $26.88 | $24.99 | $24.91 |
| Ultra Low-Sulfur Diesel Oil | $21.29 | $20.84 | $19.47 |
| Fuel Oil #6 (Low-Sulfur Residual Oil) | $11.70 | $12.22 | $12.31 |
| Natural Gas (Tennessee Z6) | $5.54 | $2.85 | $4.34 |
| Natural Gas (Iroquois Z2) | $5.56 | $2.76 | $3.85 |
| Natural Gas (Transco Z6 (NY) ) | $2.94 | $1.86 | $3.24 |
| Natural Gas (Tenn Z4 200L) | $2.36 | $1.86 | $2.23 |
| Natural Gas (TetCoM3) | $2.93 | $1.78 | $2.90 |
| Natural Gas (Niagara) | $2.47 | $1.82 | $2.25 |





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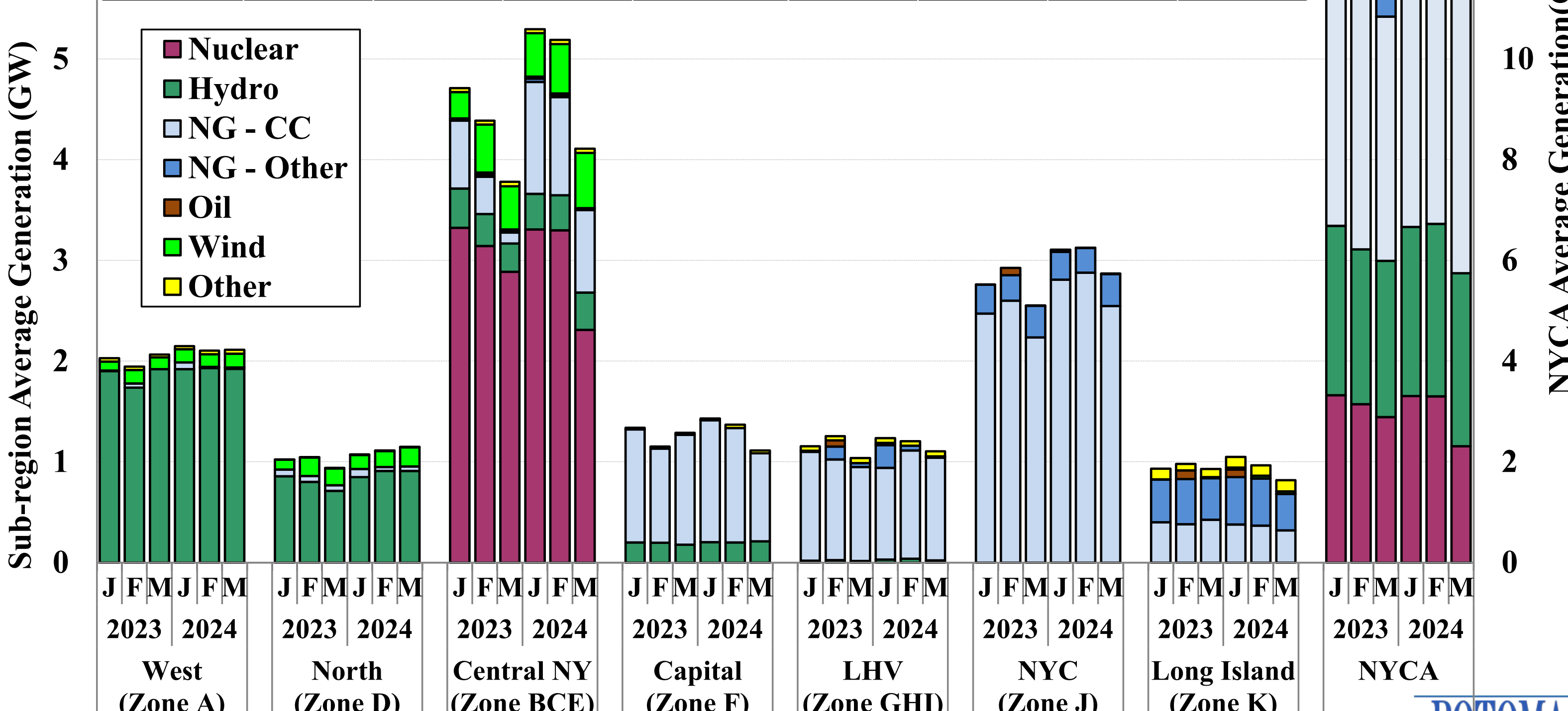
# Real-Time Generation Output by Fuel Type

| Quarter | Average Internal Generation by Fuel Type in NYCA (GW) | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| | Nuclear | Hydro | NG-CC | NG-Other | Oil | Wind | Other | Total |
| 2024 Q1 | 2.96 | 3.40 | 6.22 | 0.84 | 0.06 | 0.81 | 0.26 | 14.55 |
| 2023 Q4 | 3.27 | 3.03 | 5.85 | 0.98 | 0.04 | 0.73 | 0.26 | 14.18 |
| 2023 Q1 | 3.15 | 3.22 | 5.41 | 0.80 | 0.09 | 0.65 | 0.23 | 13.55 |






Notes: For chart description, see slide 81.

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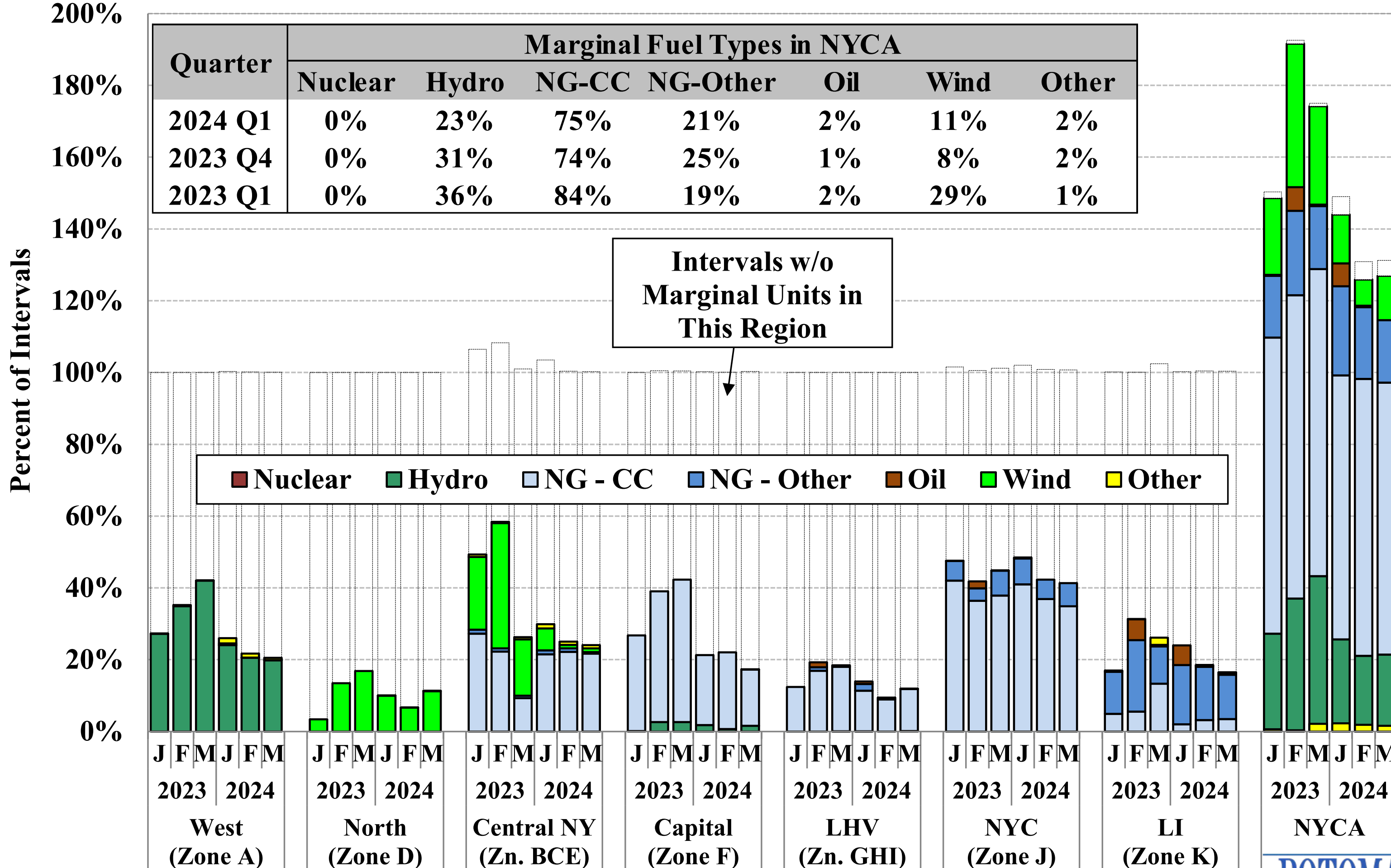
# Fuel Type of Marginal Units in the Real-Time Market



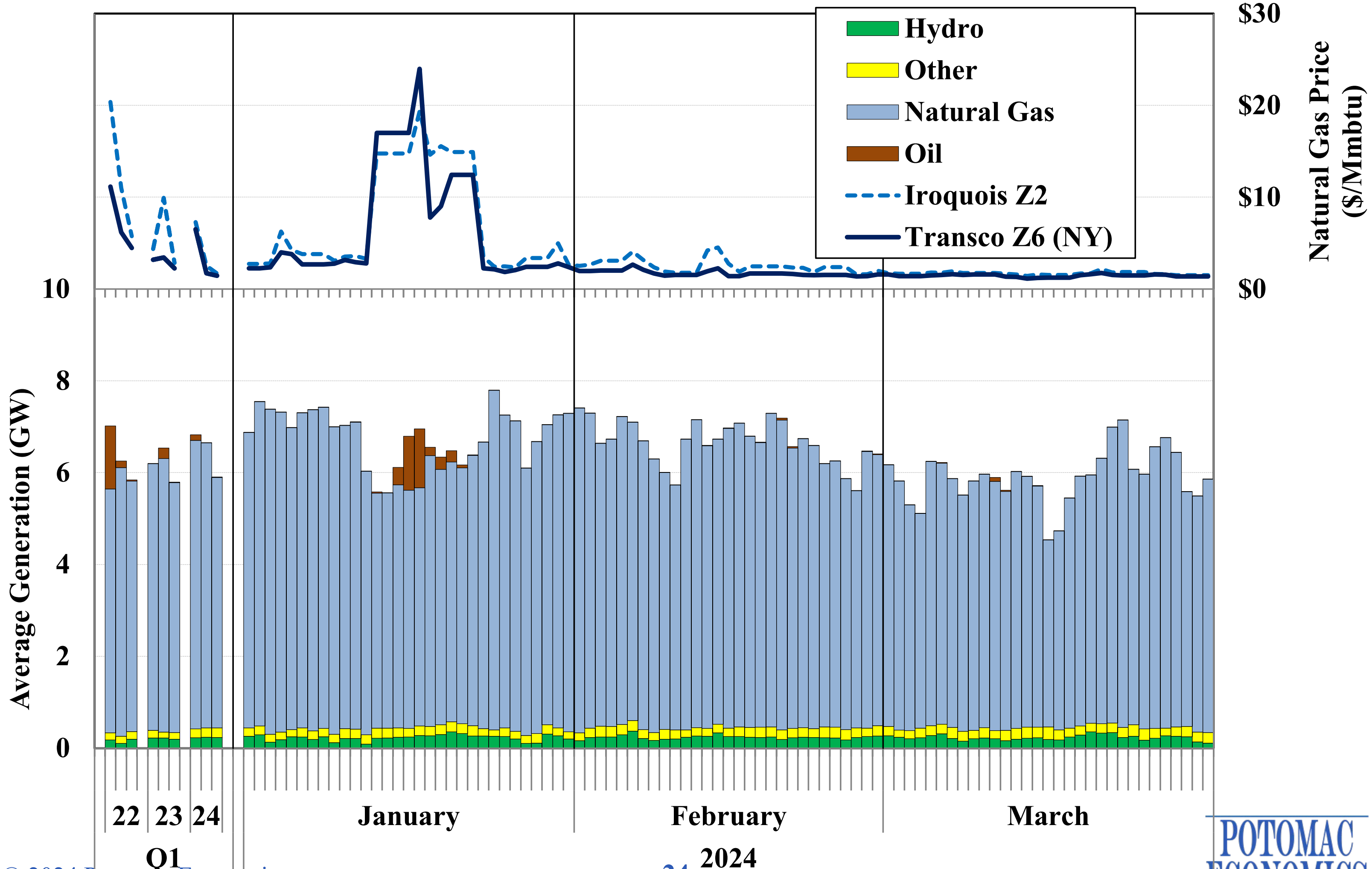

| Quarter | Marginal Fuel Types in NYCA | | | | | | |
|---|---|---|---|---|---|---|---|
| | Nuclear | Hydro | NG-CC | NG-Other | Oil | Wind | Other |
| 2024 Q1 | 0% | 23% | 75% | 21% | 2% | 11% | 2% |
| 2023 Q4 | 0% | 31% | 74% | 25% | 1% | 8% | 2% |
| 2023 Q1 | 0% | 36% | 84% | 19% | 2% | 29% | 1% |



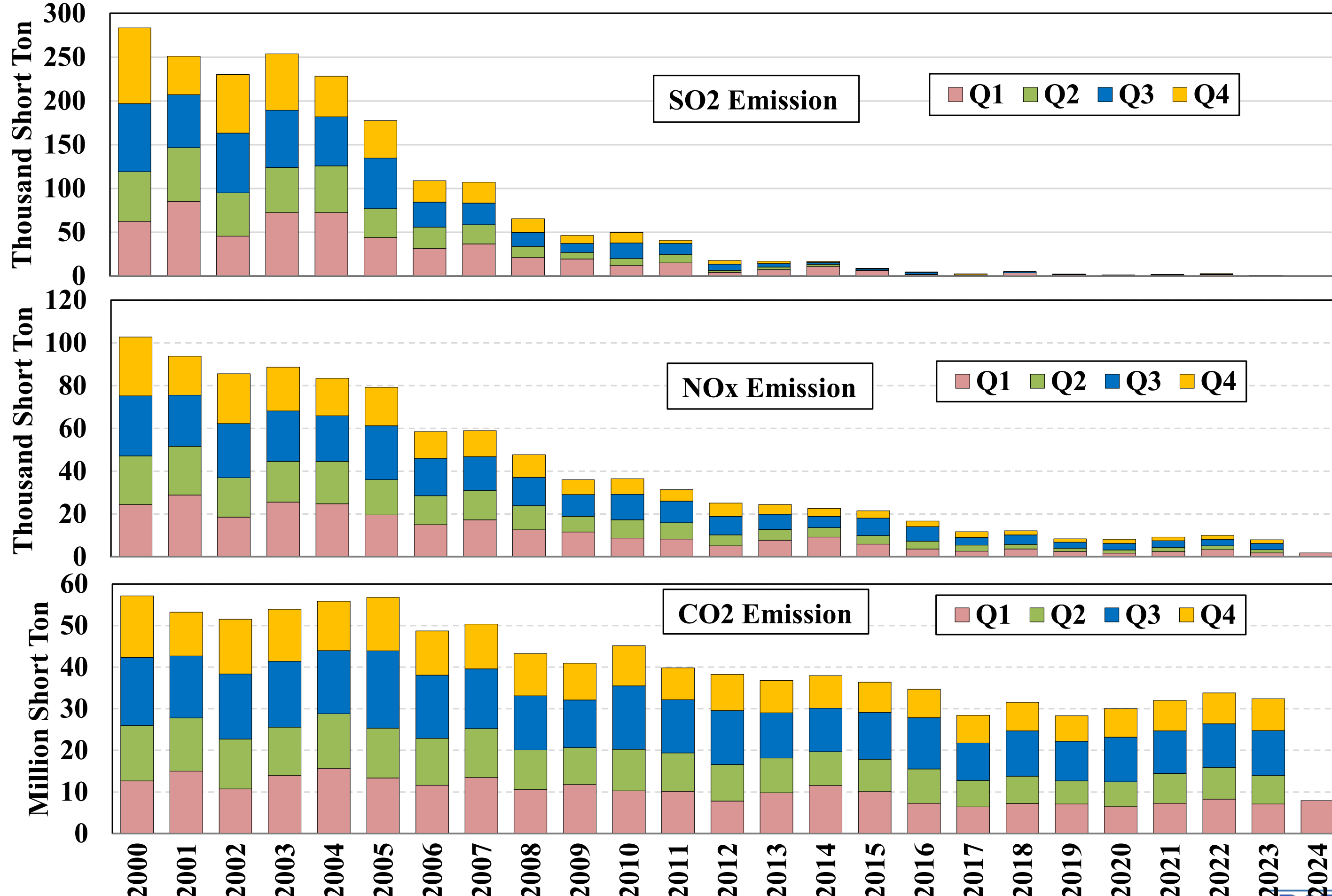


Notes: For chart description, see slide 81.

# Winter Fuel Usage
## Eastern New York




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




Notes: For chart description, see slide 82.





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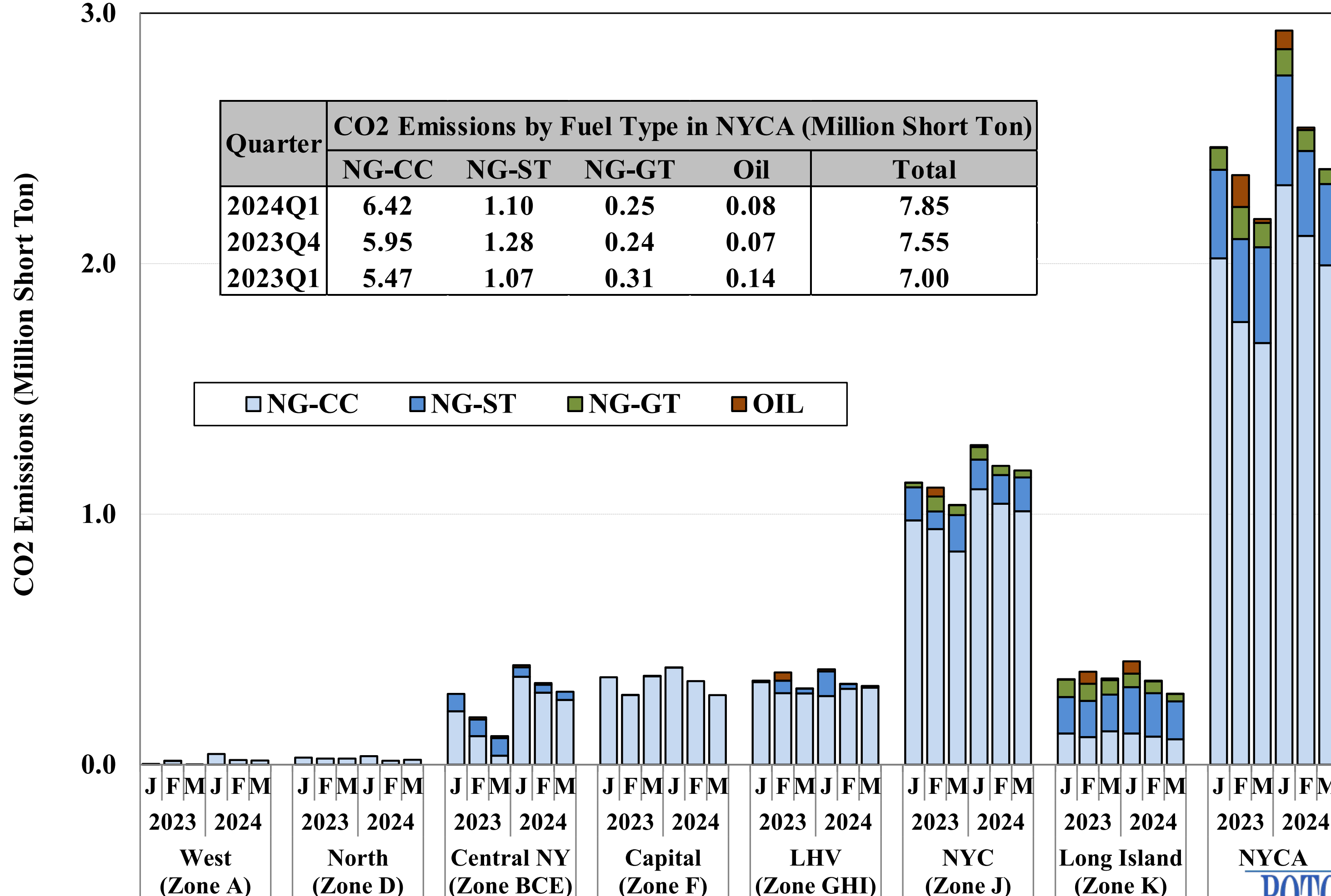
# Emissions by Region by Fuel Type
## $CO_2$ Emissions

| Quarter | CO2 Emissions by Fuel Type in NYCA (Million Short Ton) | | | | |
|---|---|---|---|---|---|
| | NG-CC | NG-ST | NG-GT | Oil | Total |
| 2024Q1 | 6.42 | 1.10 | 0.25 | 0.08 | 7.85 |
| 2023Q4 | 5.95 | 1.28 | 0.24 | 0.07 | 7.55 |
| 2023Q1 | 5.47 | 1.07 | 0.31 | 0.14 | 7.00 |




Notes: For chart description, see slide 82.





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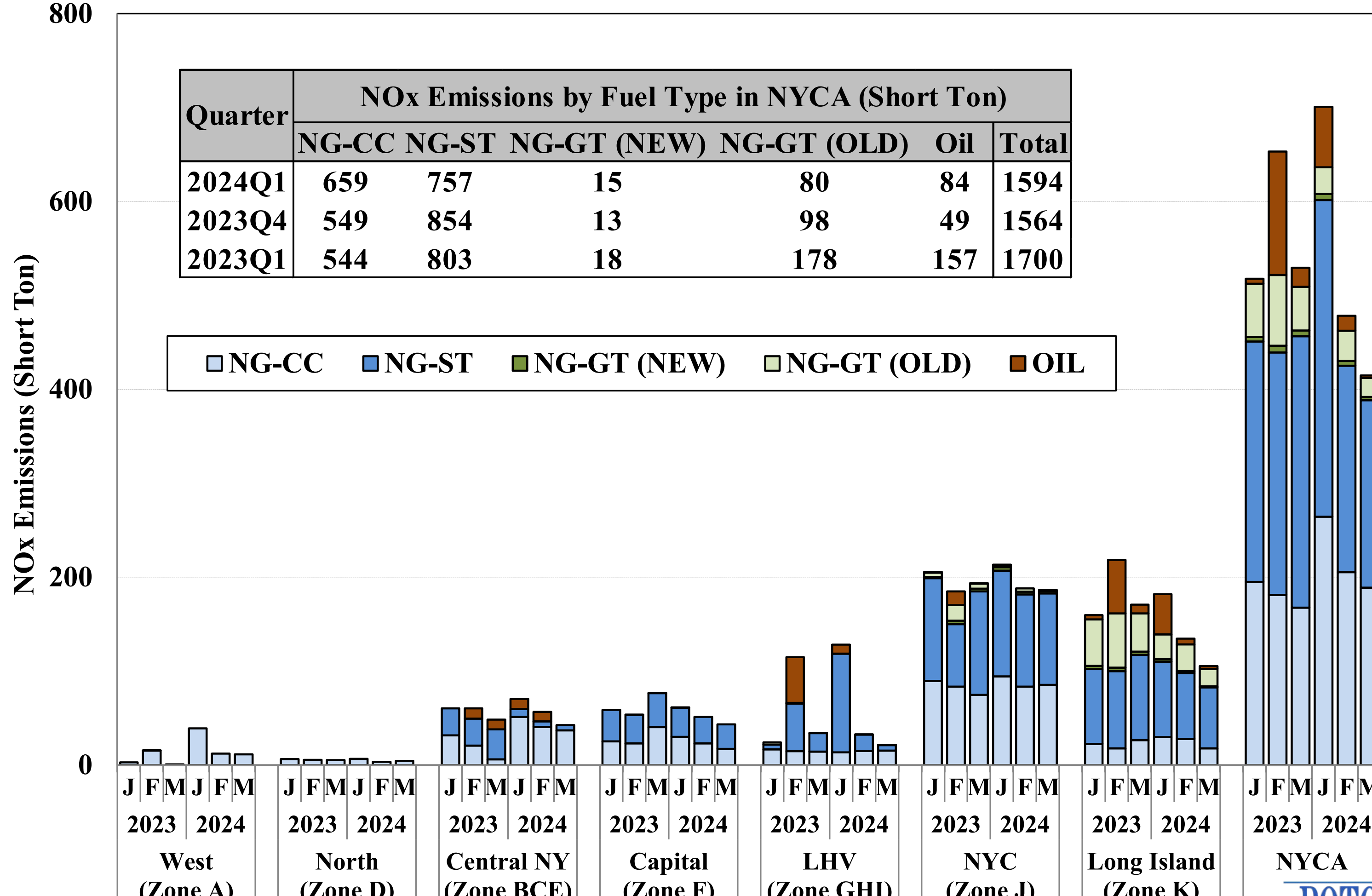
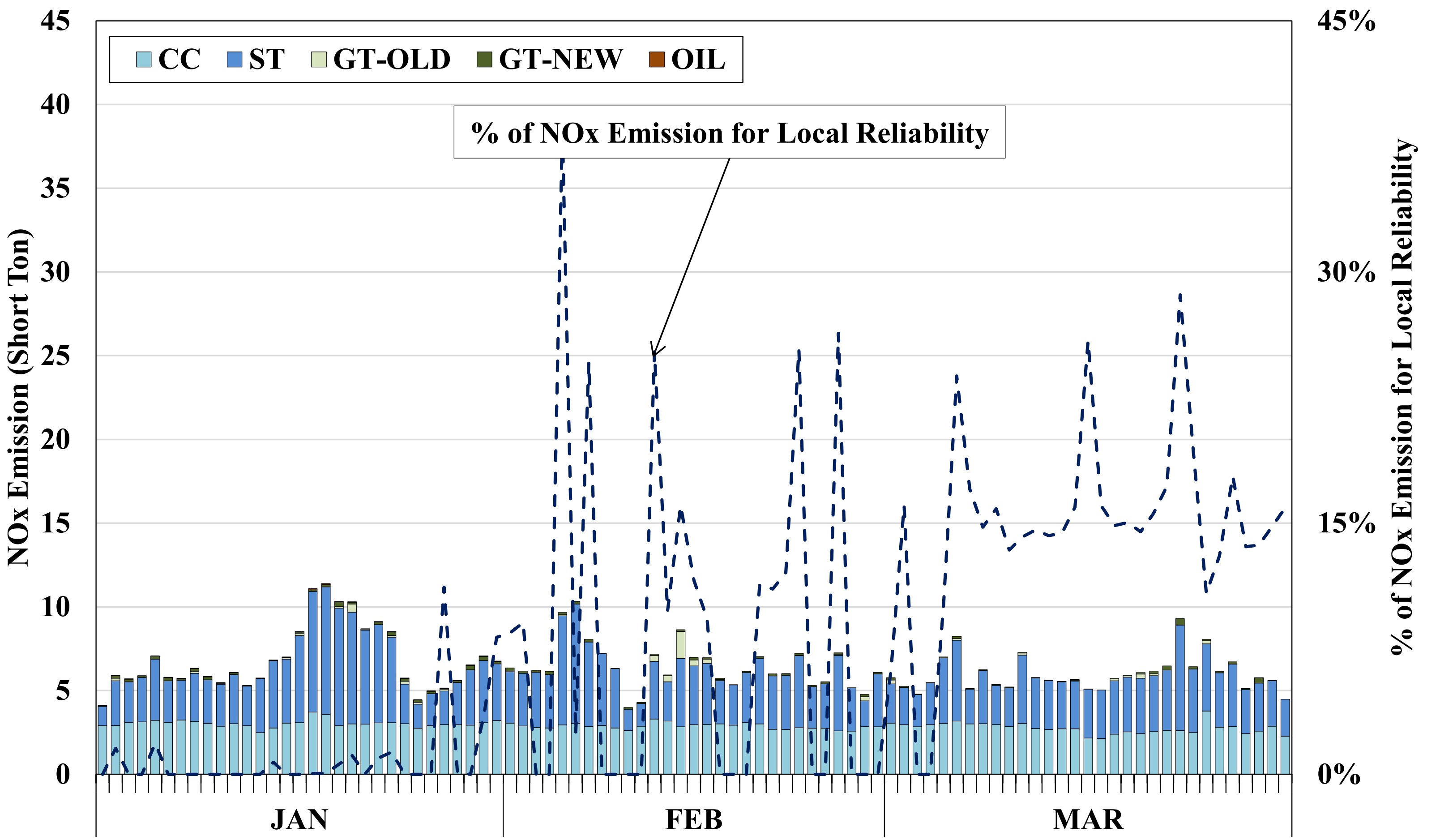
# Emissions by Region by Fuel Type
## $NO_X$ Emissions

| Quarter | NOx Emissions by Fuel Type in NYCA (Short Ton) | | | | | |
|---|---|---|---|---|---|---|
| | NG-CC | NG-ST | NG-GT (NEW) | NG-GT (OLD) | Oil | Total |
| 2024Q1 | 659 | 757 | 15 | 80 | 84 | 1594 |
| 2023Q4 | 549 | 854 | 13 | 98 | 49 | 1564 |
| 2023Q1 | 544 | 803 | 18 | 178 | 157 | 1700 |

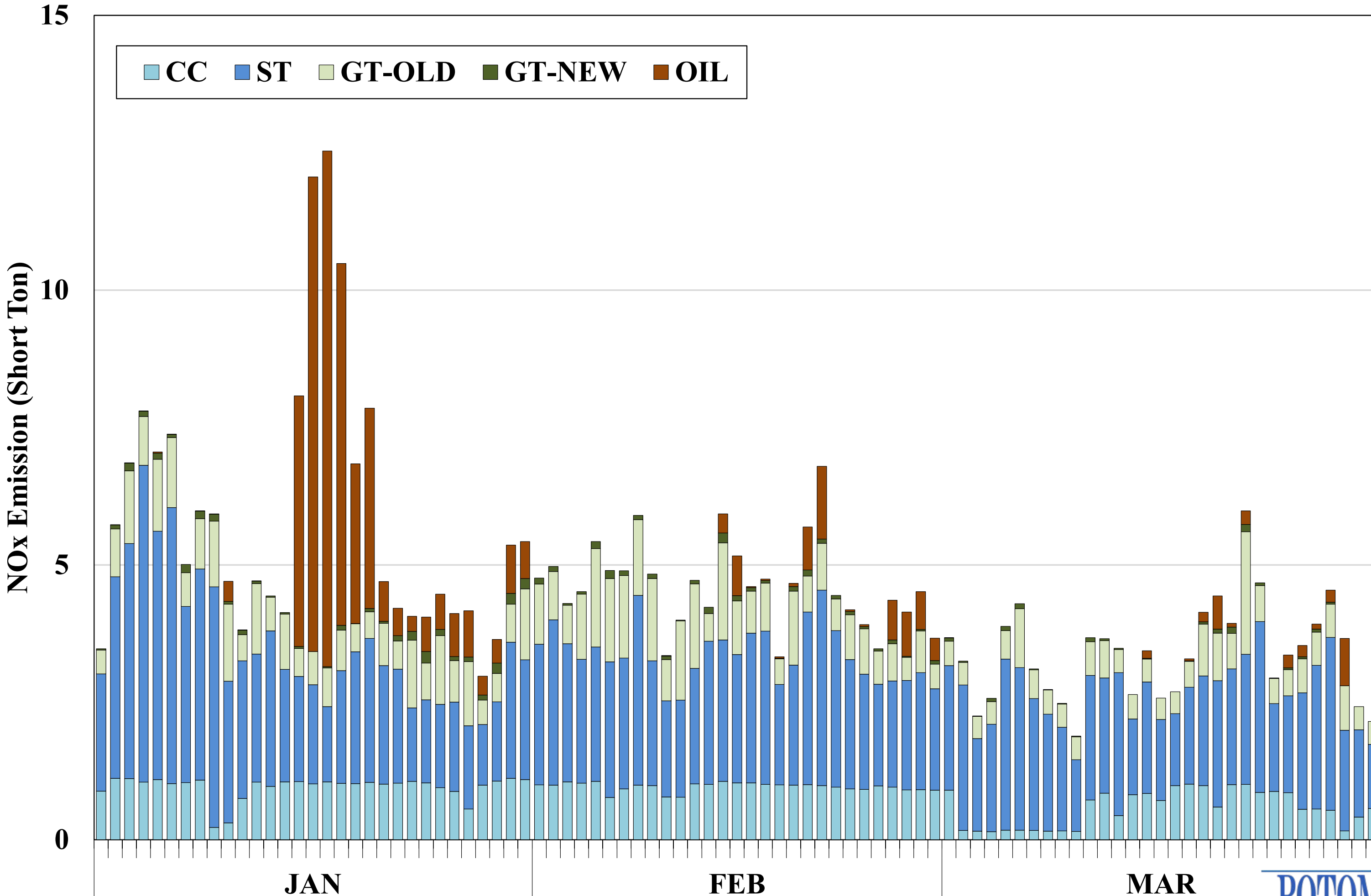



Notes: For chart description, see slide 82.

# Daily $NO_X$ Emissions in NYC



# Daily $NO_X$ Emissions in Long Island

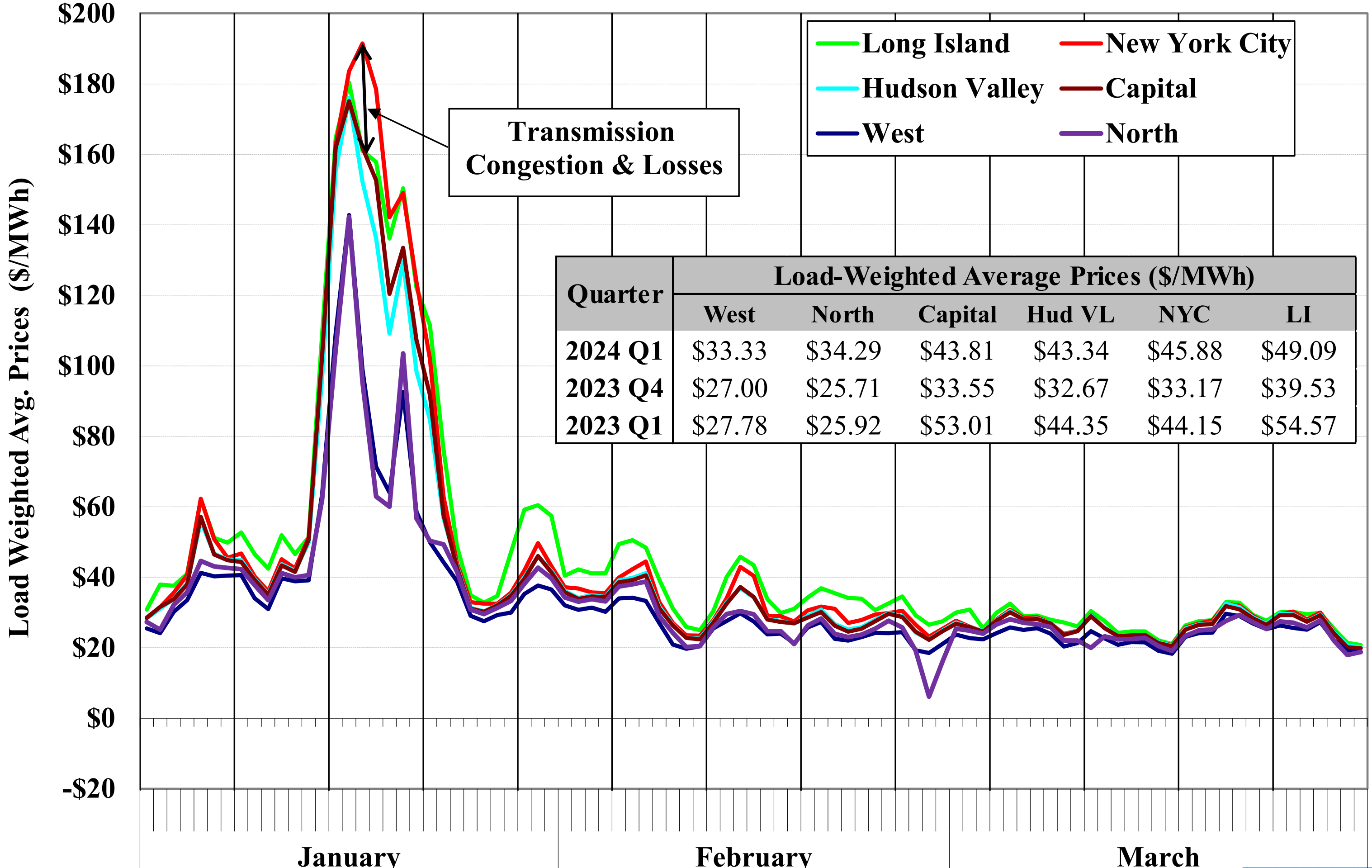







Notes: For chart description, see slide 82.

# Day-Ahead Electricity Prices by Zone




| Quarter | Load-Weighted Average Prices ($/MWh) | | | | | |
|---|---|---|---|---|---|---|
| | West | North | Capital | Hud VL | NYC | LI |
| 2024 Q1 | $33.33 | $34.29 | $43.81 | $43.34 | $45.88 | $49.09 |
| 2023 Q4 | $27.00 | $25.71 | $33.55 | $32.67 | $33.17 | $39.53 |
| 2023 Q1 | $27.78 | $25.92 | $53.01 | $44.35 | $44.15 | $54.57 |



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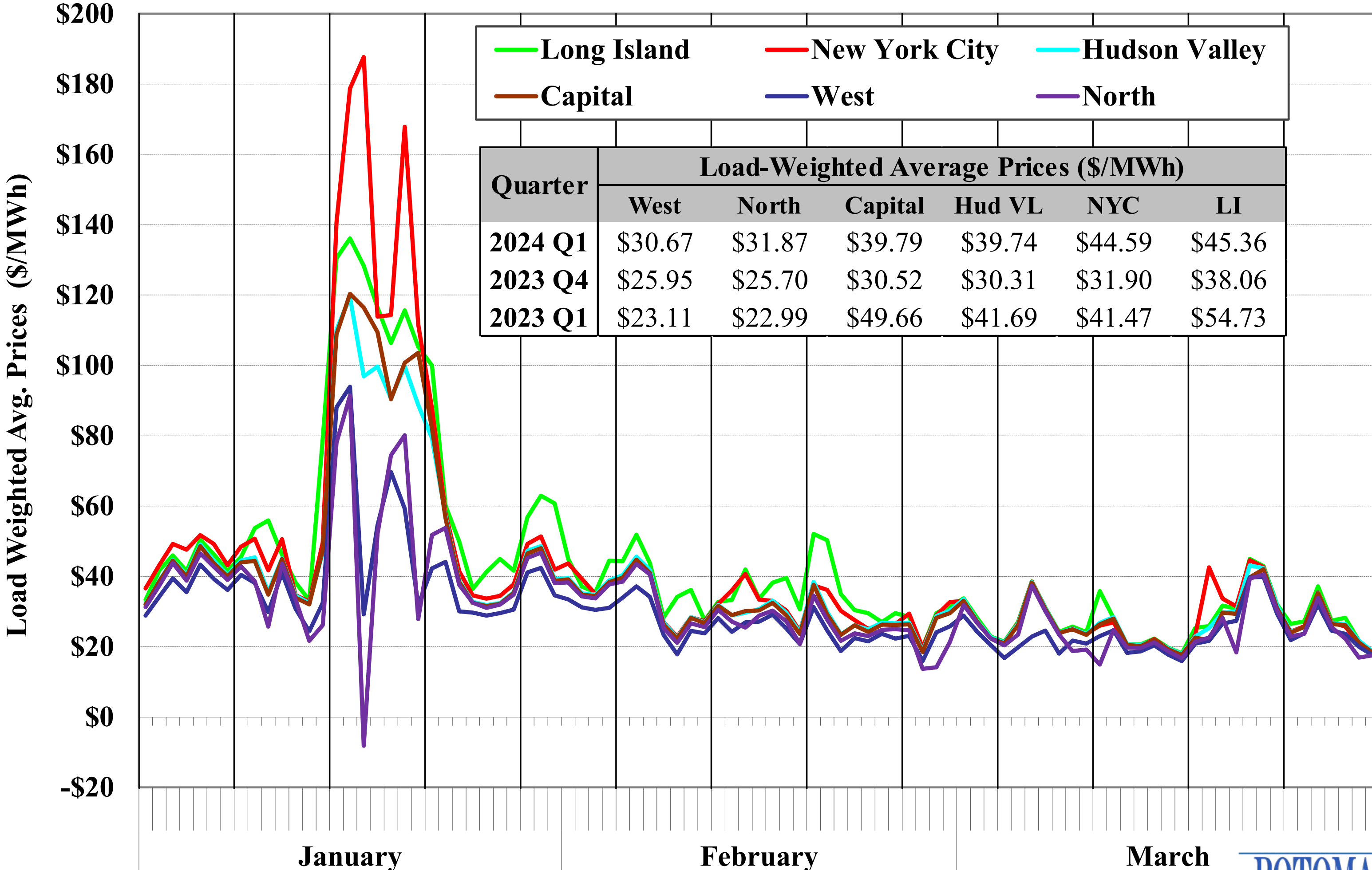
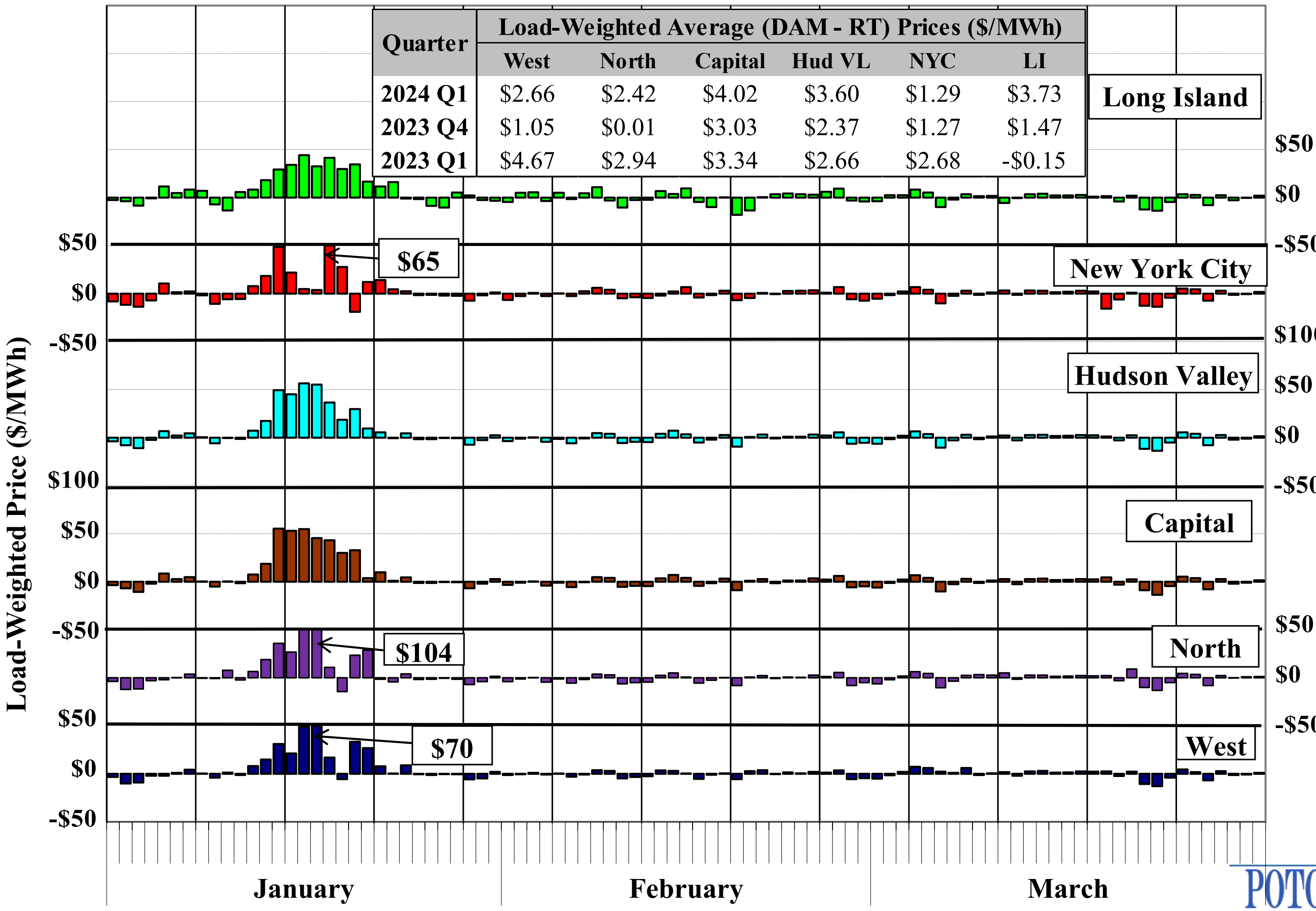
# Real-Time Electricity Prices by Zone




| Quarter | Load-Weighted Average Prices ($/MWh) | | | | | |
|---|---|---|---|---|---|---|
| | West | North | Capital | Hud VL | NYC | LI |
| 2024 Q1 | $30.67 | $31.87 | $39.79 | $39.74 | $44.59 | $45.36 |
| 2023 Q4 | $25.95 | $25.70 | $30.52 | $30.31 | $31.90 | $38.06 |
| 2023 Q1 | $23.11 | $22.99 | $49.66 | $41.69 | $41.47 | $54.73 |

# Convergence Between Day-Ahead and Real-Time Prices




| Quarter | Load-Weighted Average (DAM - RT) Prices ($/MWh) | | | | | |
|---|---|---|---|---|---|---|
| | West | North | Capital | Hud VL | NYC | LI |
| 2024 Q1 | $2.66 | $2.42 | $4.02 | $3.60 | $1.29 | $3.73 |
| 2023 Q4 | $1.05 | $0.01 | $3.03 | $2.37 | $1.27 | $1.47 |
| 2023 Q1 | $4.67 | $2.94 | $3.34 | $2.66 | $2.68 | -$0.15 |



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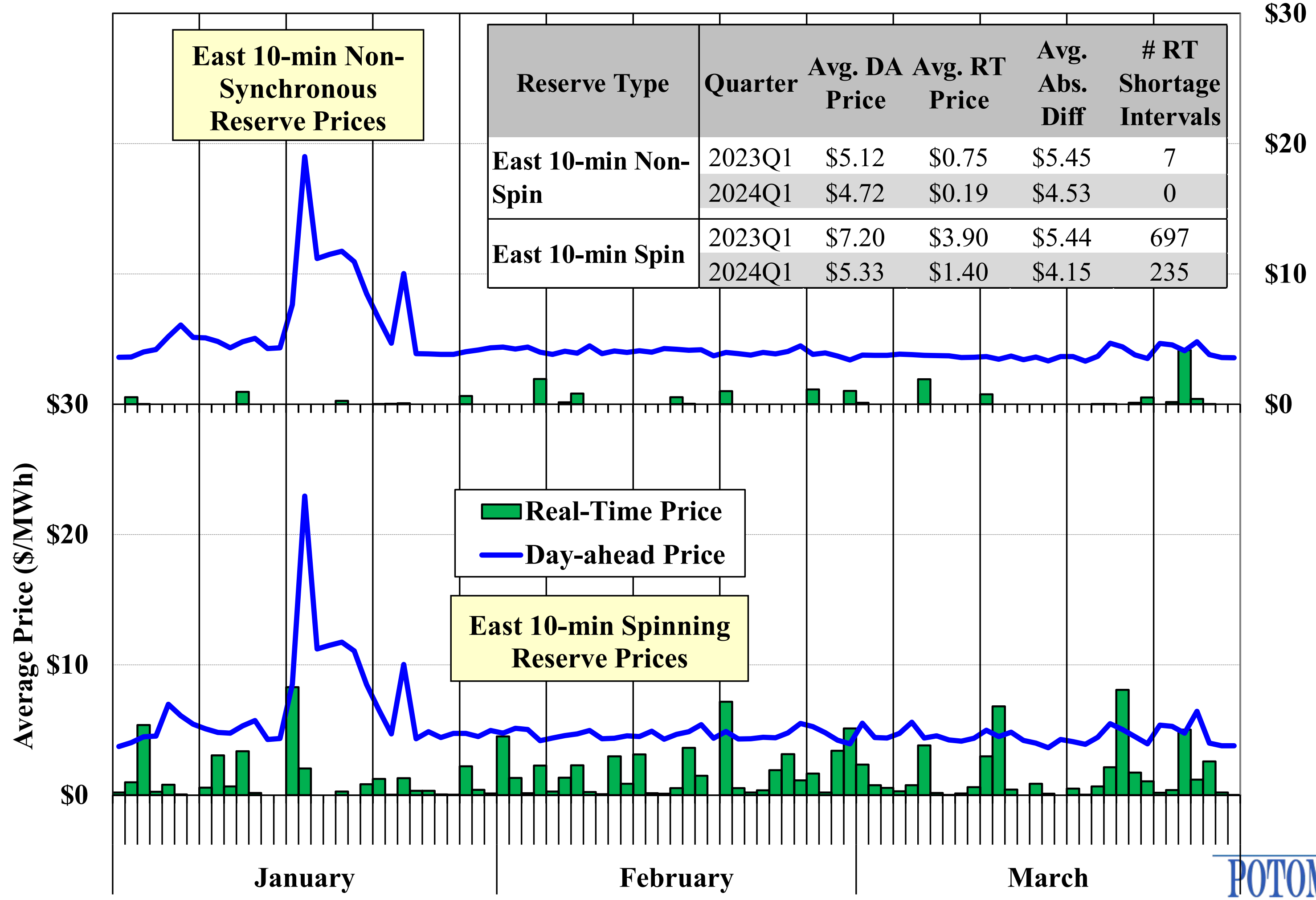
# Charts:

## Ancillary Services Market

# 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 | 2023Q1 | $5.12 | $0.75 | $5.45 | 7 |
| | 2024Q1 | $4.72 | $0.19 | $4.53 | 0 |
| East 10-min Spin | 2023Q1 | $7.20 | $3.90 | $5.44 | 697 |
| | 2024Q1 | $5.33 | $1.40 | $4.15 | 235 |

Notes: For chart description, see slide 83.





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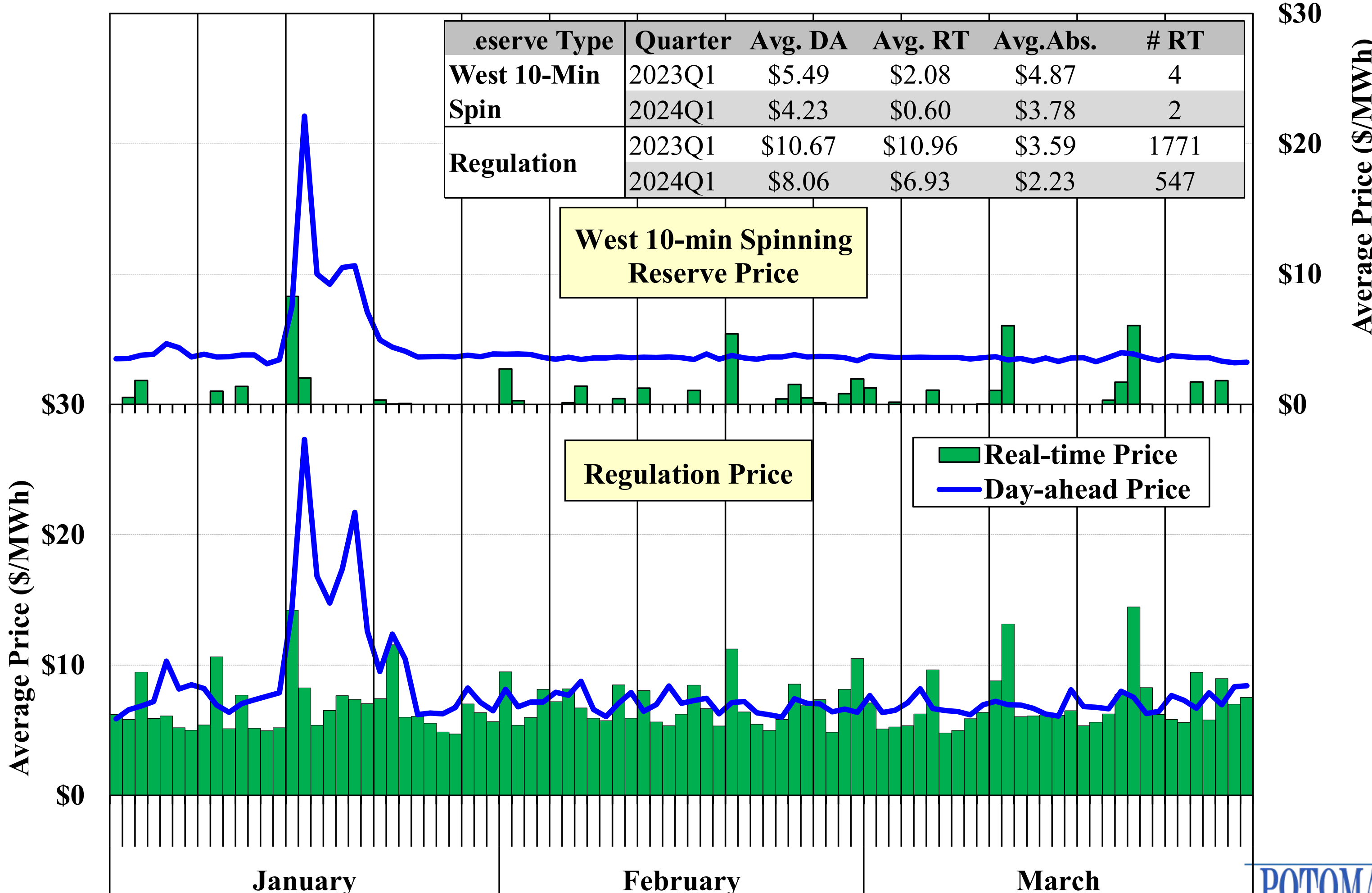
# Day-Ahead and Real-Time Ancillary Services Prices
## Western 10-Minute Spinning Reserves and Regulation

| eserve Type | Quarter | Avg. DA | Avg. RT | Avg.Abs. | # RT |
|---|---|---|---|---|---|
| West 10-Min Spin | 2023Q1 | $5.49 | $2.08 | $4.87 | 4 |
| | 2024Q1 | $4.23 | $0.60 | $3.78 | 2 |
| Regulation | 2023Q1 | $10.67 | $10.96 | $3.59 | 1771 |
| | 2024Q1 | $8.06 | $6.93 | $2.23 | 547 |



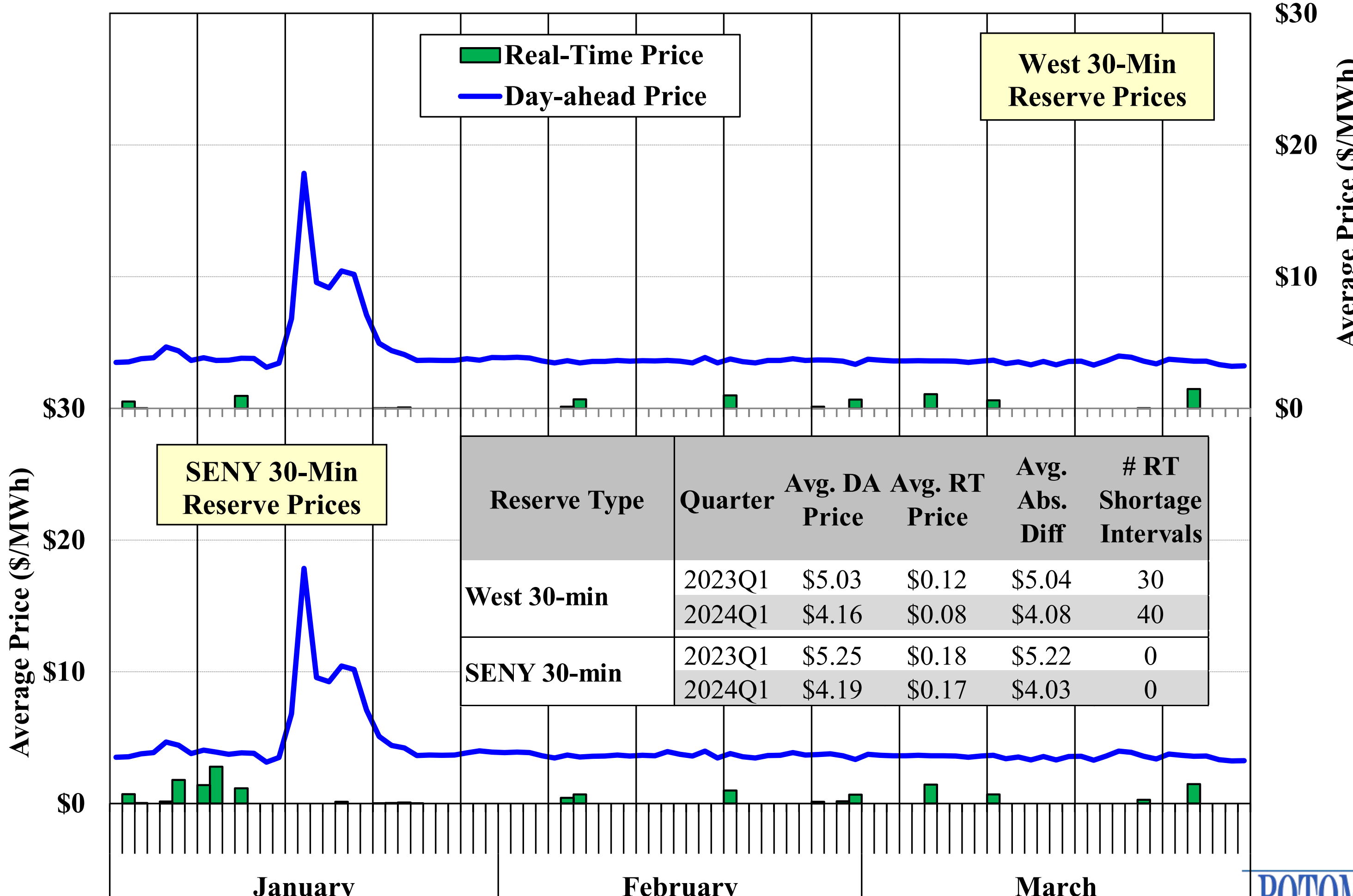





Notes: For chart description, see slide 83.

POTOMAC ECONOMICS

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

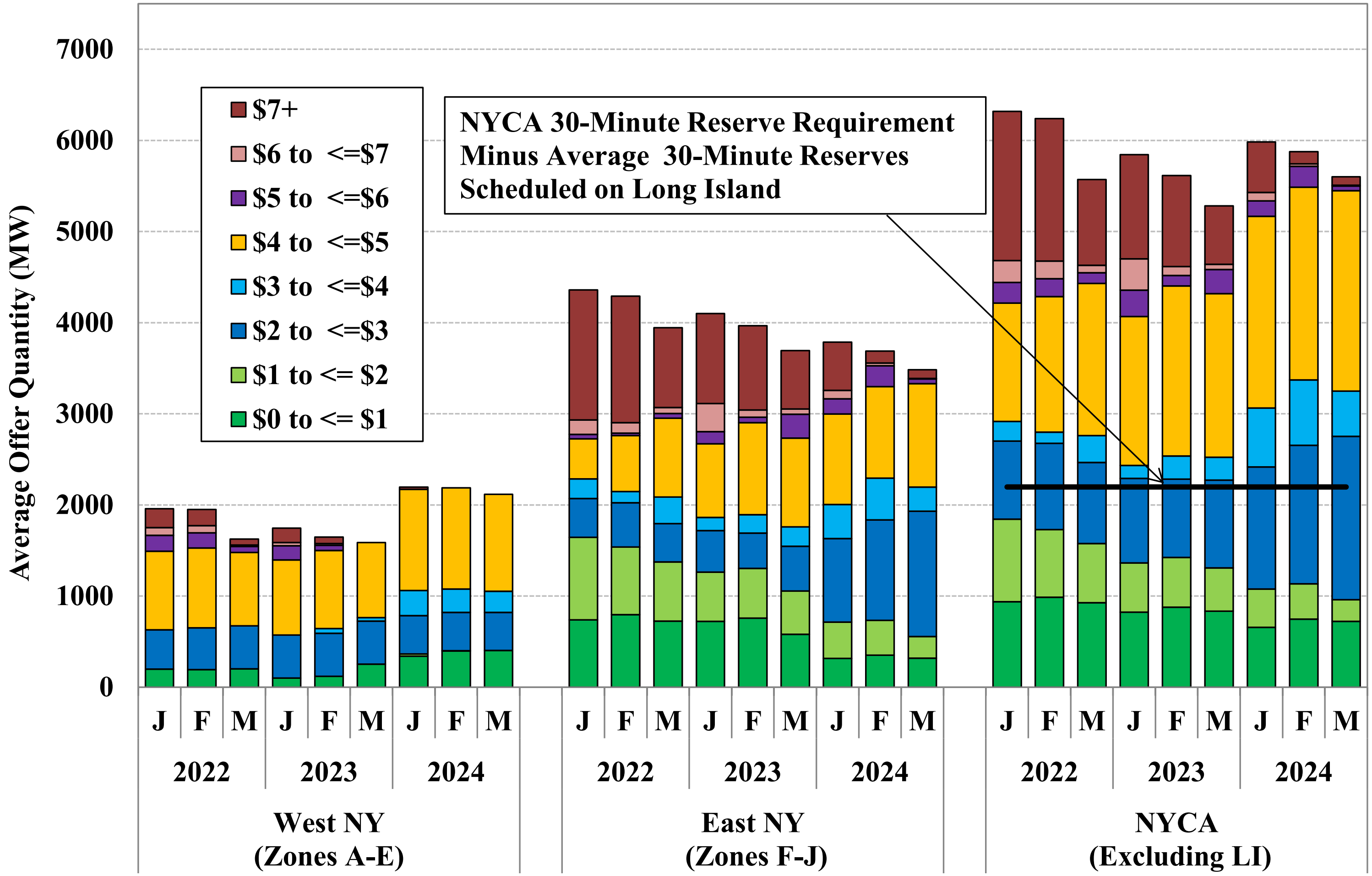



| Reserve Type | Quarter | Avg. DA Price | Avg. RT Price | Avg. Abs. Diff | # RT Shortage Intervals |
|---|---|---|---|---|---|
| West 30-min | 2023Q1 | $5.03 | $0.12 | $5.04 | 30 |
| | 2024Q1 | $4.16 | $0.08 | $4.08 | 40 |
| SENY 30-min | 2023Q1 | $5.25 | $0.18 | $5.22 | 0 |
| | 2024Q1 | $4.19 | $0.17 | $4.03 | 0 |



Notes: For chart description, see slide 83.

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

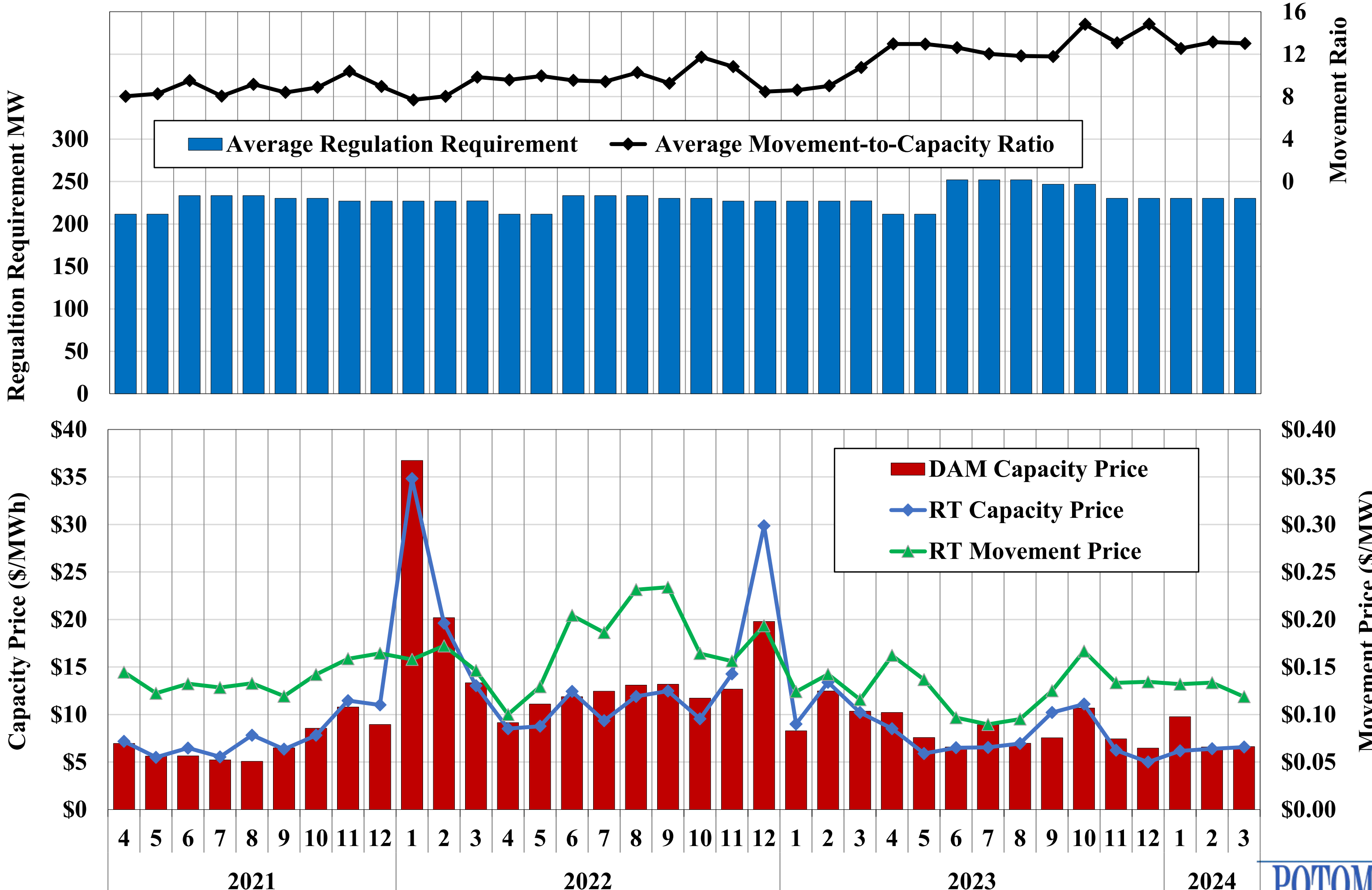







Notes: For chart description, see slide 84.

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

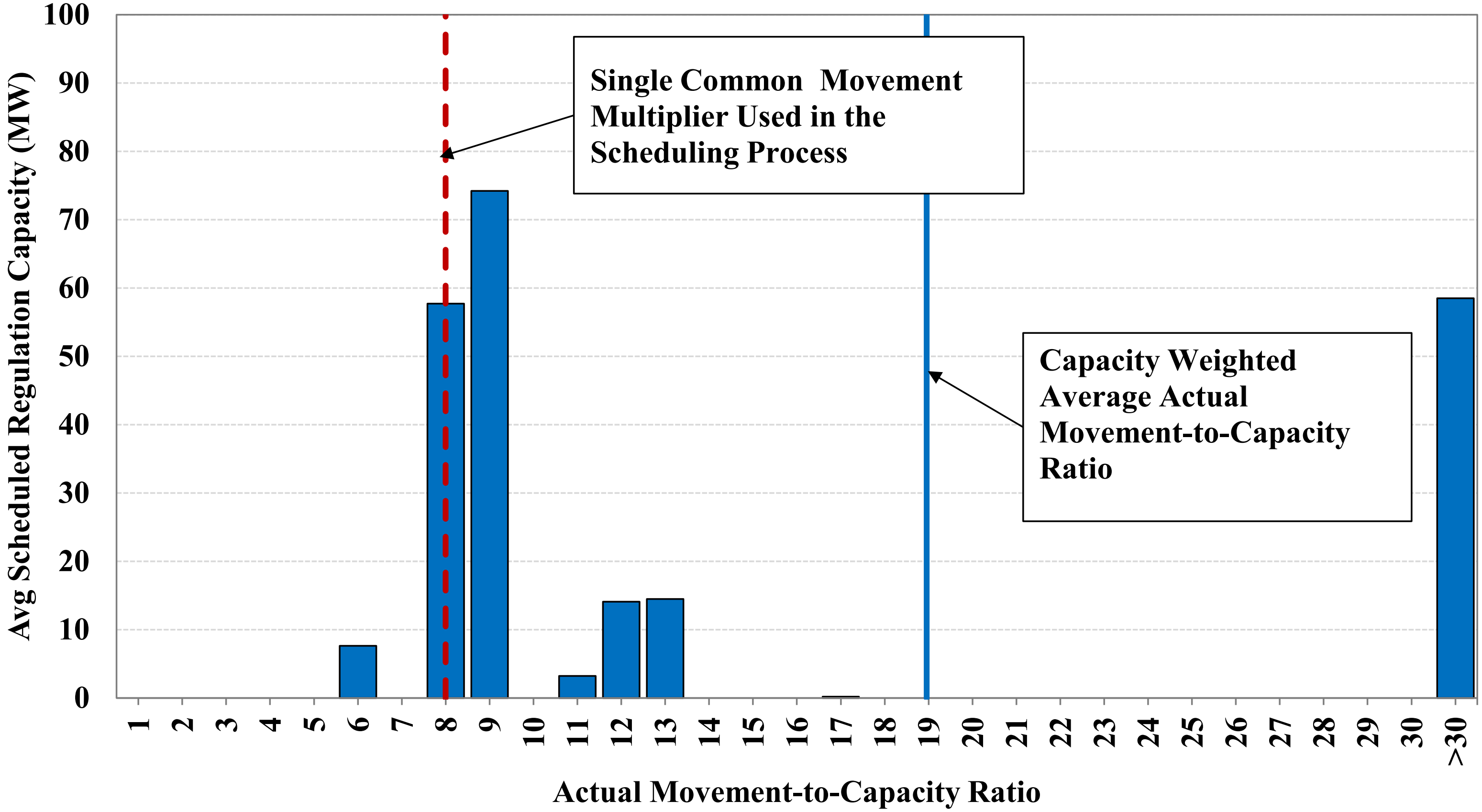





Notes: For chart description, see slide 85.

POTOMAC ECONOMICS

# Distribution of Actual Regulation Movement from One Sample Day





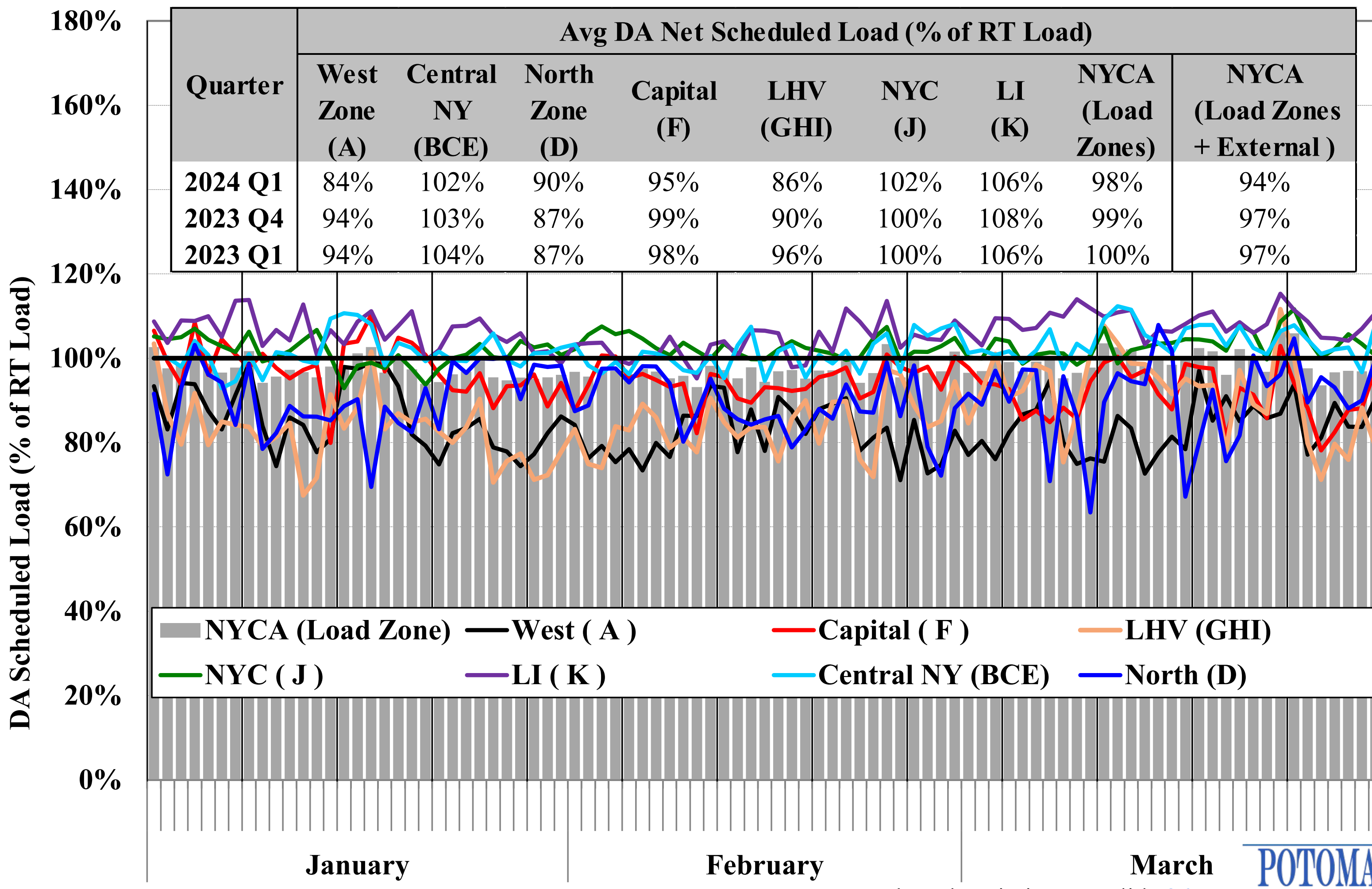


Notes: For chart description, see slide 85.

# Charts:
## Energy Market Scheduling

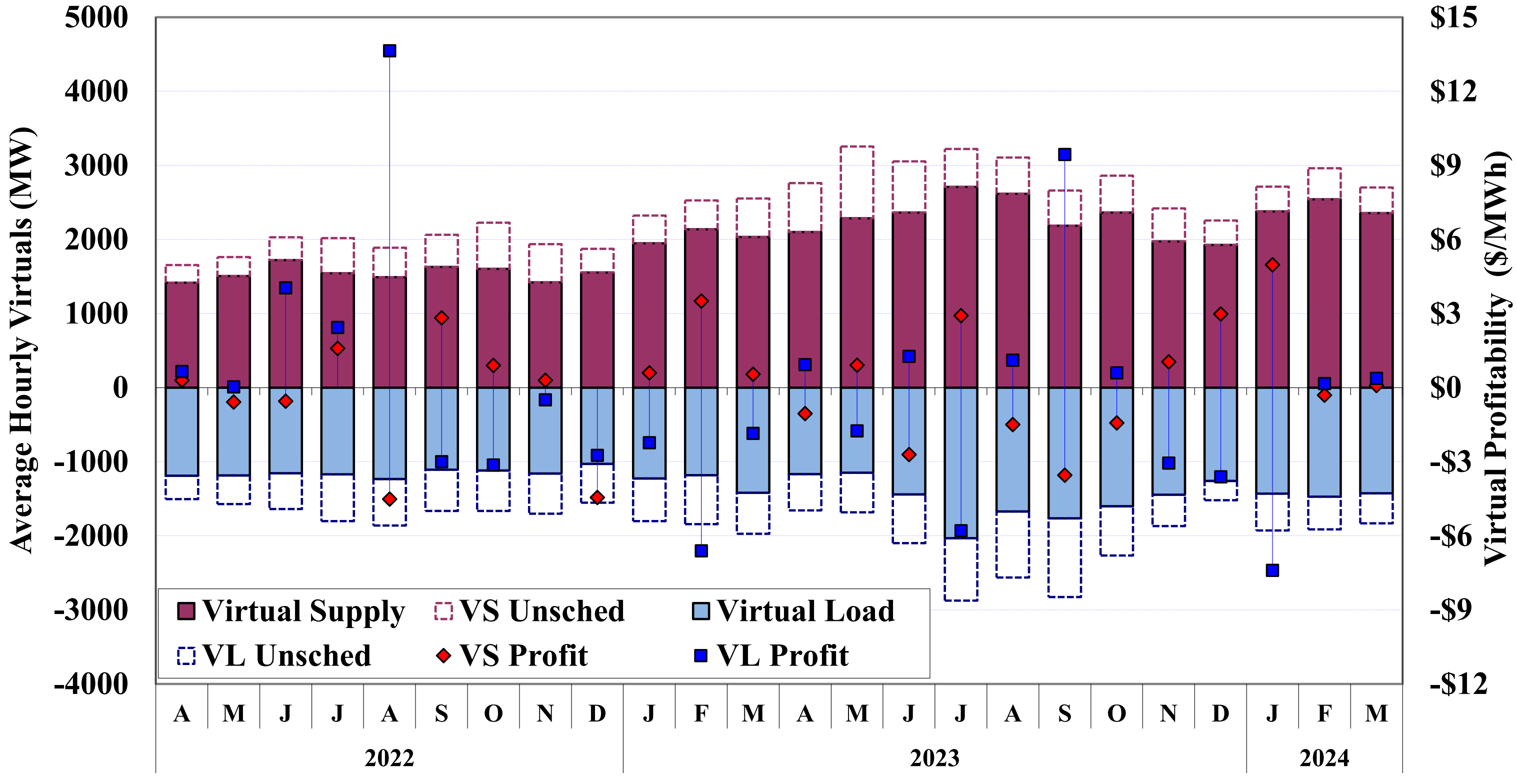
# Day-ahead Scheduled Load and Actual Load
## Daily Peak Load Hour

| 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 ) |
|---|---|---|---|---|---|---|---|---|---|
| 2024 Q1 | 84% | 102% | 90% | 95% | 86% | 102% | 106% | 98% | 94% |
| 2023 Q4 | 94% | 103% | 87% | 99% | 90% | 100% | 108% | 99% | 97% |
| 2023 Q1 | 94% | 104% | 87% | 98% | 96% | 100% | 106% | 100% | 97% |




Notes: For chart description, see slide 86.

# Virtual Trading Activity
## by Month




| | | A | M | J | J | A | S | O | N | D | J | F | M | A | M | J | J | A | S | O | N | D | J | F | M |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Profit > 50% of Avg. Zone Price | MW | 291 | 324 | 183 | 228 | 153 | 96 | 134 | 250 | 302 | 170 | 455 | 343 | 243 | 275 | 130 | 360 | 243 | 244 | 166 | 198 | 136 | 334 | 106 | 138 |
| | % | 11% | 12% | 6% | 8% | 6% | 4% | 5% | 10% | 12% | 5% | 14% | 10% | 7% | 8% | 3% | 8% | 6% | 6% | 4% | 6% | 4% | 9% | 3% | 4% |
| Loss > 50% of Avg. Zone Price | MW | 306 | 304 | 180 | 183 | 124 | 109 | 163 | 289 | 287 | 206 | 412 | 377 | 285 | 296 | 164 | 415 | 322 | 156 | 213 | 255 | 141 | 283 | 148 | 163 |
| | % | 12% | 11% | 6% | 7% | 5% | 4% | 6% | 11% | 11% | 7% | 12% | 11% | 9% | 9% | 4% | 9% | 8% | 4% | 5% | 7% | 4% | 7% | 4% | 4% |

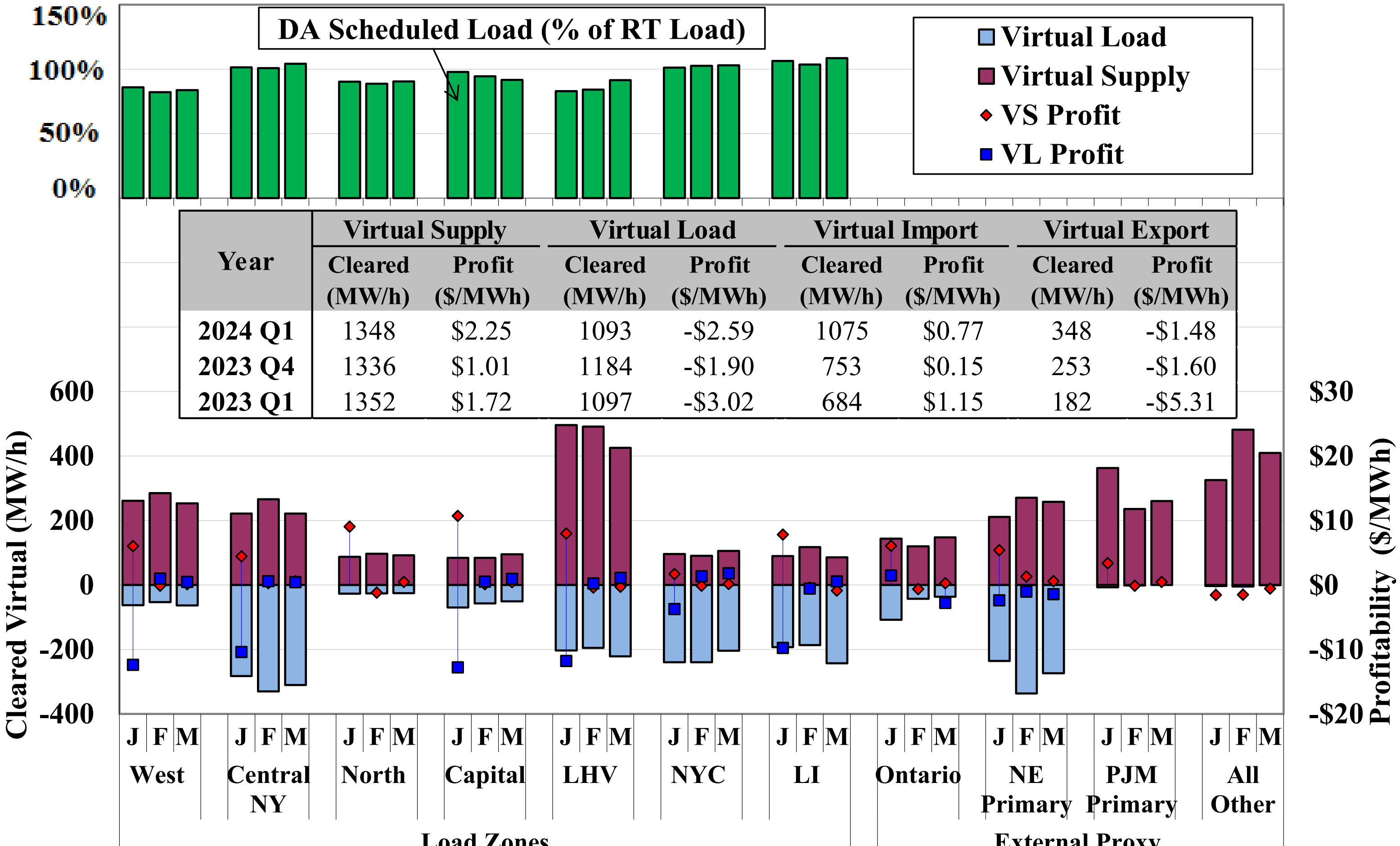




Notes: For chart description, see slide 86.

POTOMAC ECONOMICS

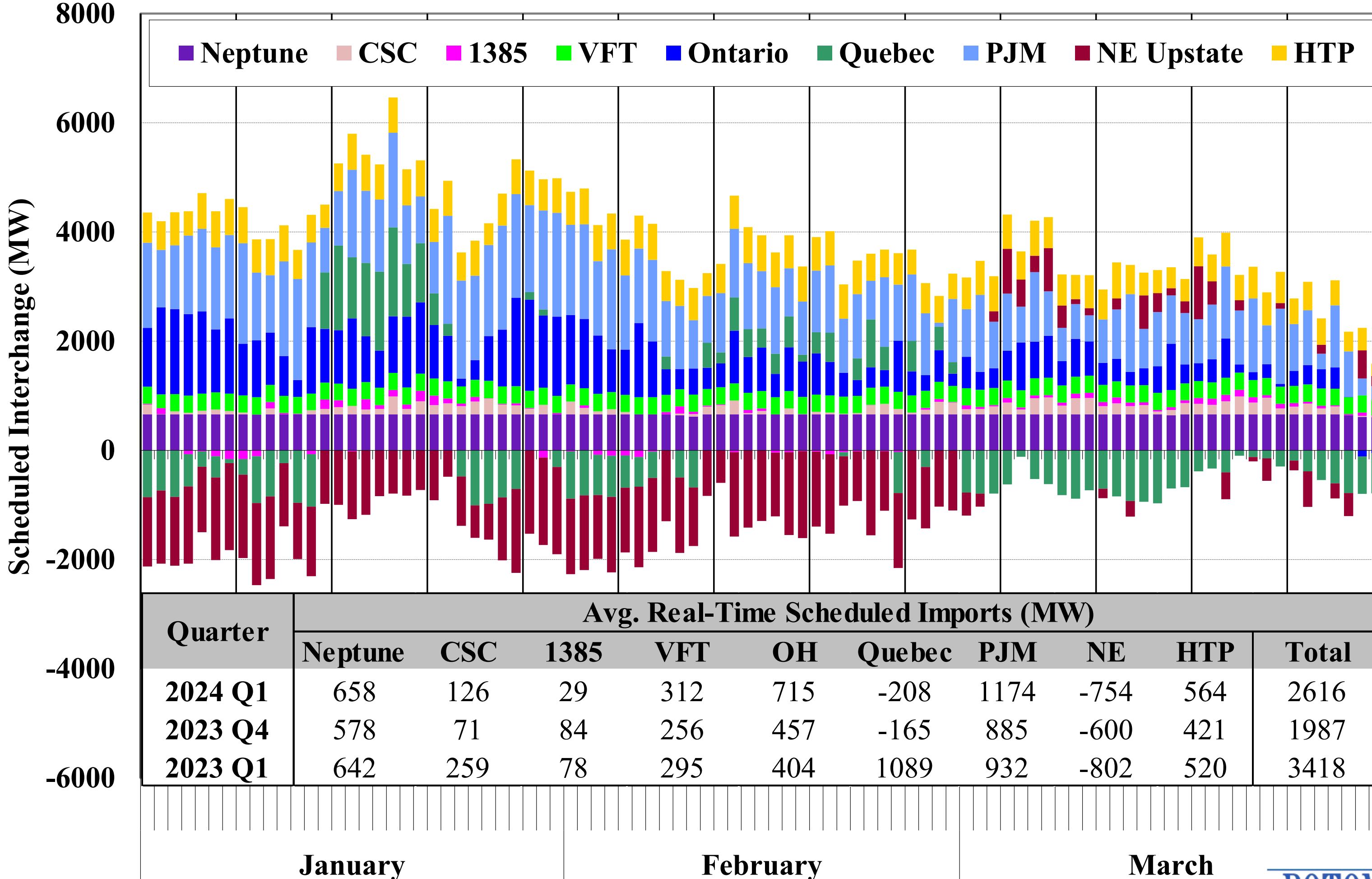
# Virtual Trading Activity by Location




| Year | Virtual Supply Cleared (MW/h) | Virtual Supply Profit ($/MWh) | Virtual Load Cleared (MW/h) | Virtual Load Profit ($/MWh) | Virtual Import Cleared (MW/h) | Virtual Import Profit ($/MWh) | Virtual Export Cleared (MW/h) | Virtual Export Profit ($/MWh) |
|---|---|---|---|---|---|---|---|---|
| **2024 Q1** | 1348 | $2.25 | 1093 | -$2.59 | 1075 | $0.77 | 348 | -$1.48 |
| **2023 Q4** | 1336 | $1.01 | 1184 | -$1.90 | 753 | $0.15 | 253 | -$1.60 |
| **2023 Q1** | 1352 | $1.72 | 1097 | -$3.02 | 684 | $1.15 | 182 | -$5.31 |

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 86.

# 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 |
| 2024 Q1 | 658 | 126 | 29 | 312 | 715 | -208 | 1174 | -754 | 564 | 2616 |
| 2023 Q4 | 578 | 71 | 84 | 256 | 457 | -165 | 885 | -600 | 421 | 1987 |
| 2023 Q1 | 642 | 259 | 78 | 295 | 404 | 1089 | 932 | -802 | 520 | 3418 |

Notes: Two Quebec interfaces are combined into one.

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

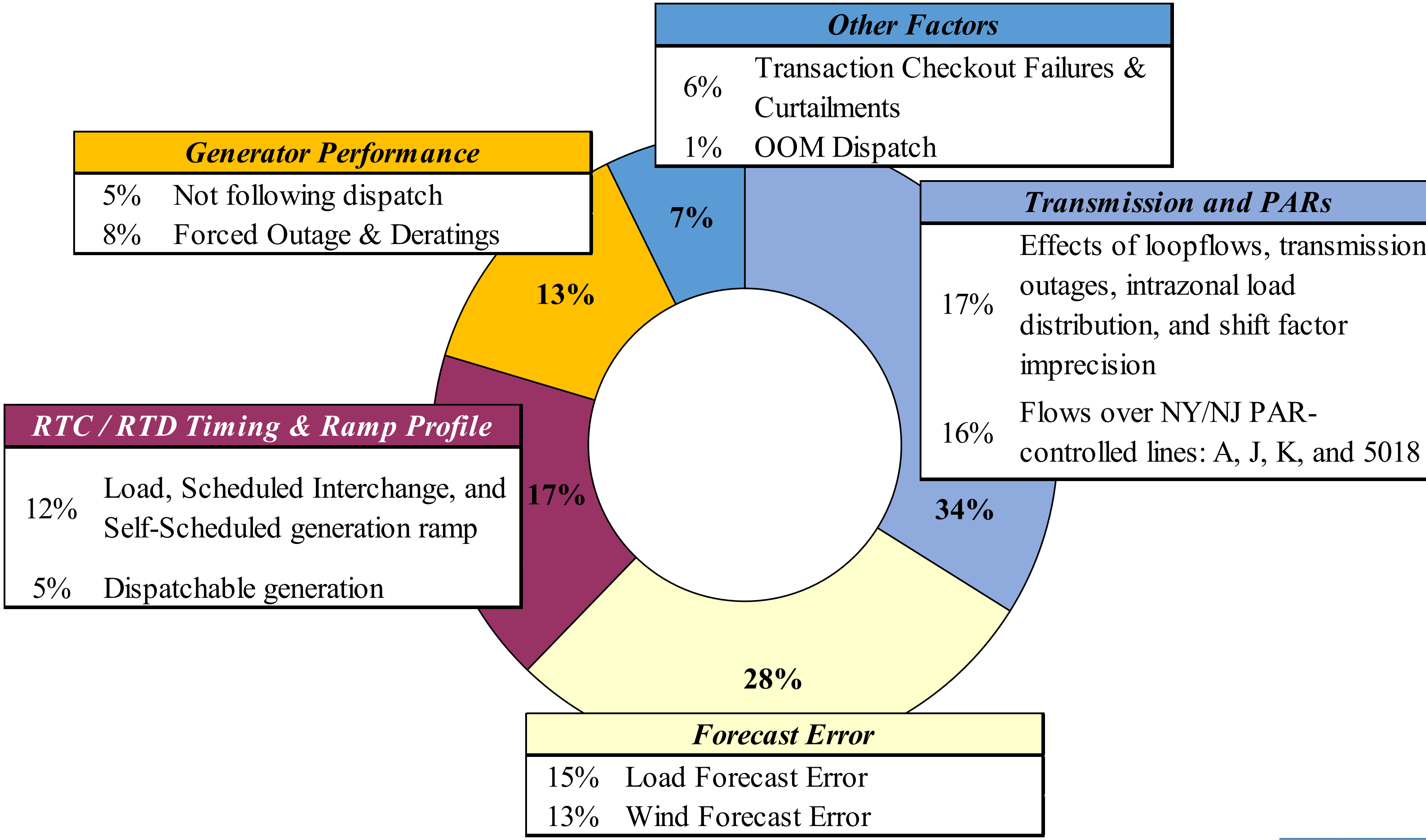
| | | | Average/Total During Intervals w/ Adjustment | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| | | | CTS - NY/NE | | | | CTS - NY/PJM | | | |
| | | | Both Forecast Errors <= $20 | Any Forecast Error > $20 | Total | | Both Forecast Errors <= $20 | Any Forecast Error > $20 | Total | |
| % of All Intervals w/ Adjustment | | | 73% | 10% | **83%** | | 40% | 18% | **58%** | |
| Average Flow Adjustment ( MW ) | Net Imports | | 49 | 62 | **50** | | -6 | -64 | **-24** | |
| | Gross | | 140 | 167 | **143** | | 85 | 117 | **95** | |
| Production Cost Savings ($ Million) | Projected at Scheduling Time | | $2.3 | $0.9 | **$3.1** | | $0.6 | $2.8 | **$3.4** | |
| | Net Over-Projection by: | NY | -$0.1 | $0.0 | **$0.0** | | $0.0 | $0.0 | **$0.0** | |
| | | NE or PJM | $0.0 | -$0.3 | **-$0.3** | | -$0.2 | -$2.7 | **-$2.9** | |
| | Other Unrealized Savings | | -$0.1 | -$0.1 | **-$0.1** | | $0.0 | $0.0 | **$0.0** | |
| | Actual Savings | | $2.1 | $0.6 | **$2.7** | | $0.3 | $0.1 | **$0.4** | |
| Interface Prices ($/MWh) | NY | Actual | $33.32 | $67.35 | **$37.51** | **$36.74** | $30.58 | $47.53 | **$35.75** | **$33.61** |
| | | Forecast | $33.84 | $64.98 | **$37.68** | **$36.91** | $31.03 | $46.52 | **$35.76** | **$33.59** |
| | NE or PJM | Actual | $32.09 | $75.72 | **$37.46** | **$38.31** | $27.69 | $53.74 | **$35.64** | **$32.80** |
| | | Forecast | $31.80 | $64.20 | **$35.79** | **$36.99** | $30.48 | $99.13 | **$51.44** | **$45.75** |
| Price Forecast Errors ($/MWh) | NY | Fcst. - Act. | $0.52 | -$2.37 | **$0.17** | **$0.17** | $0.45 | -$1.01 | **$0.01** | **-$0.03** |
| | | Abs. Val. | $2.62 | $25.81 | **$5.48** | **$5.08** | $2.55 | $10.27 | **$4.91** | **$4.20** |
| | NE or PJM | Fcst. - Act. | -$0.28 | -$11.53 | **-$1.67** | **-$1.32** | $2.79 | $45.40 | **$15.79** | **$12.94** |
| | | Abs. Val. | $3.78 | $27.31 | **$6.68** | **$6.54** | $6.45 | $73.63 | **$26.96** | **$22.78** |

**For Adjustment Intervals Only**

**For All Intervals**

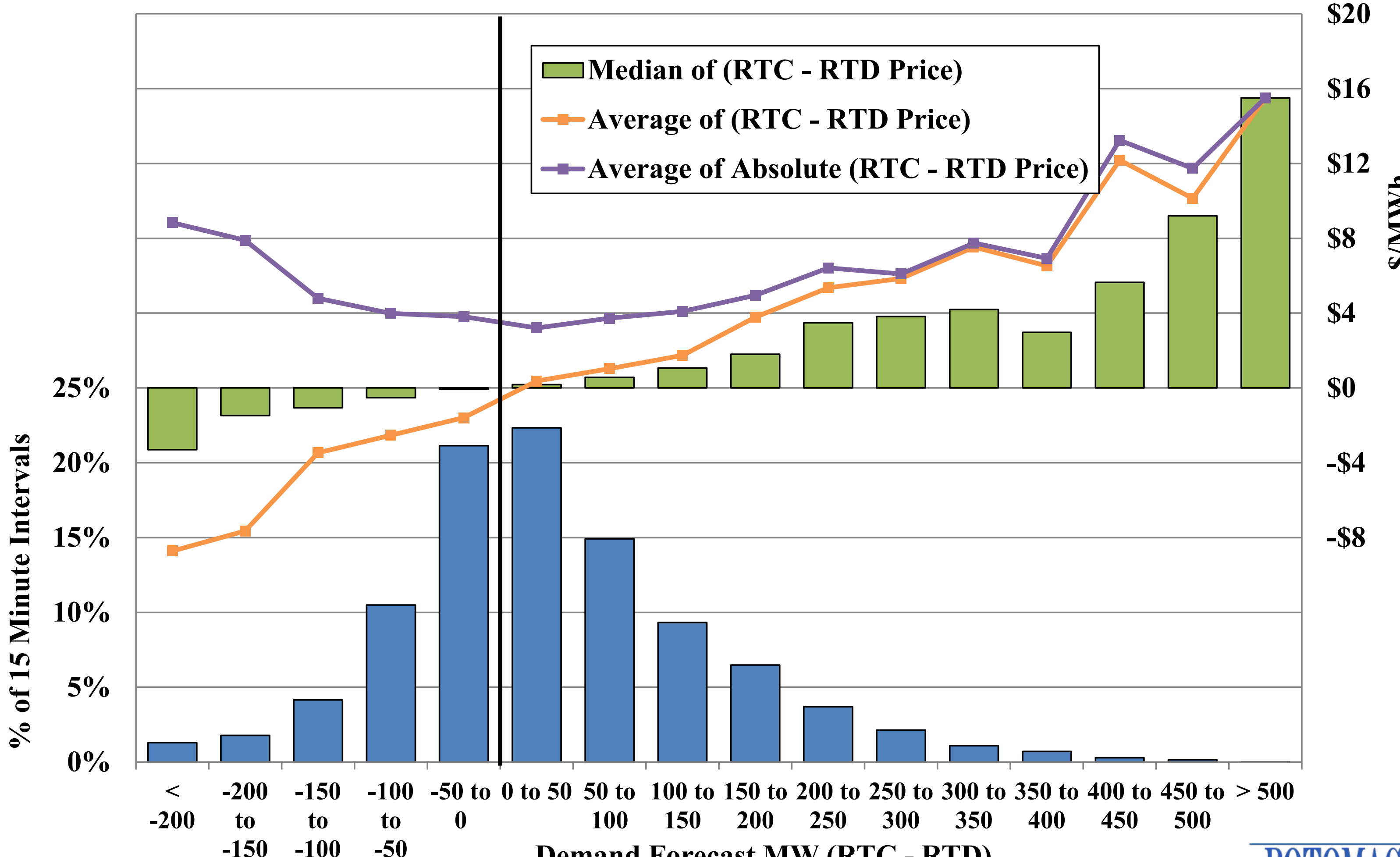
Notes: For chart description, see slide 87.

# Detrimental Factors to RTC and RTD Price Divergence




Notes: For chart description, see slide 88.

# RTC and RTD Price Difference vs Demand Forecast Difference



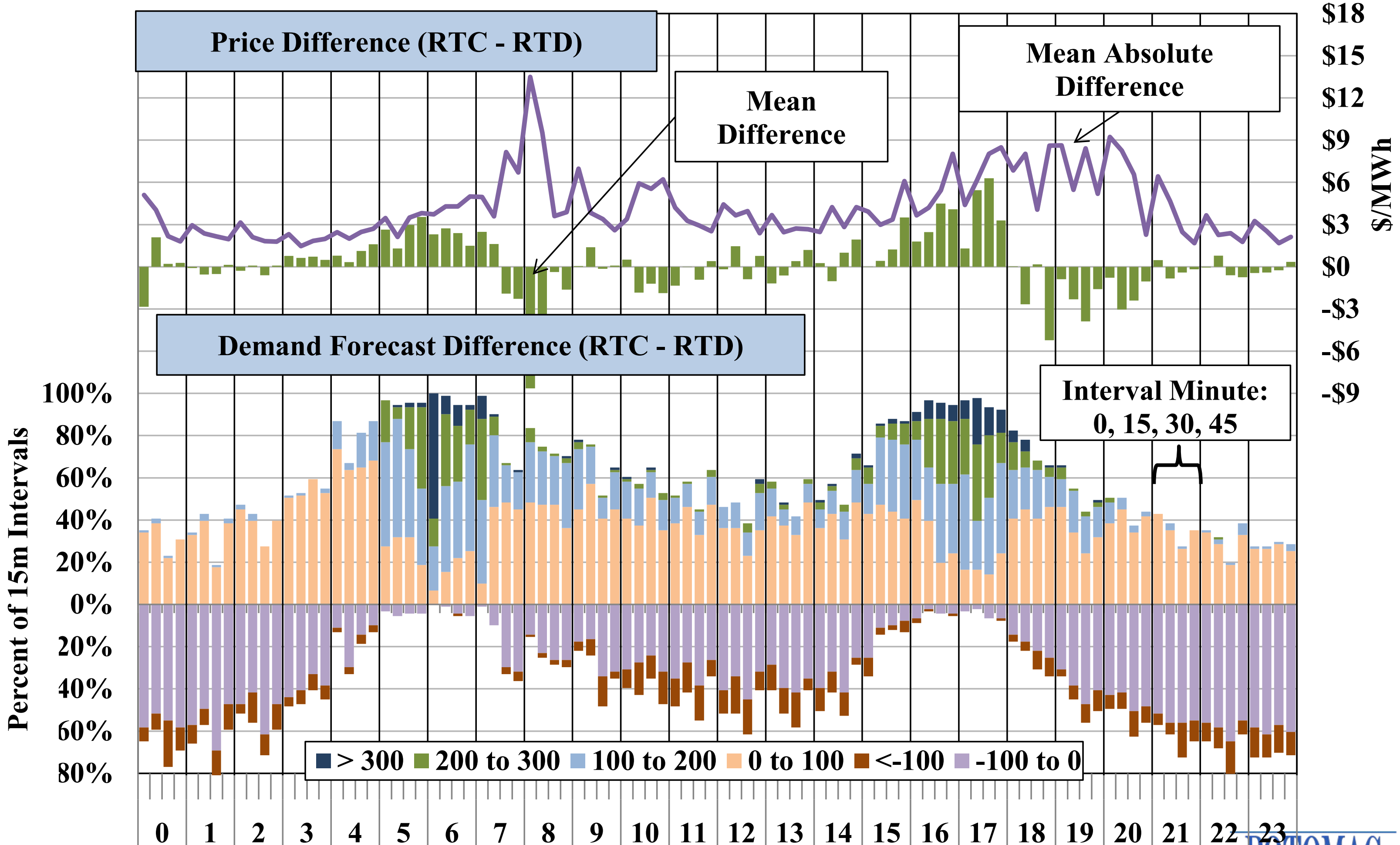





Notes: For chart description, see slide 88.

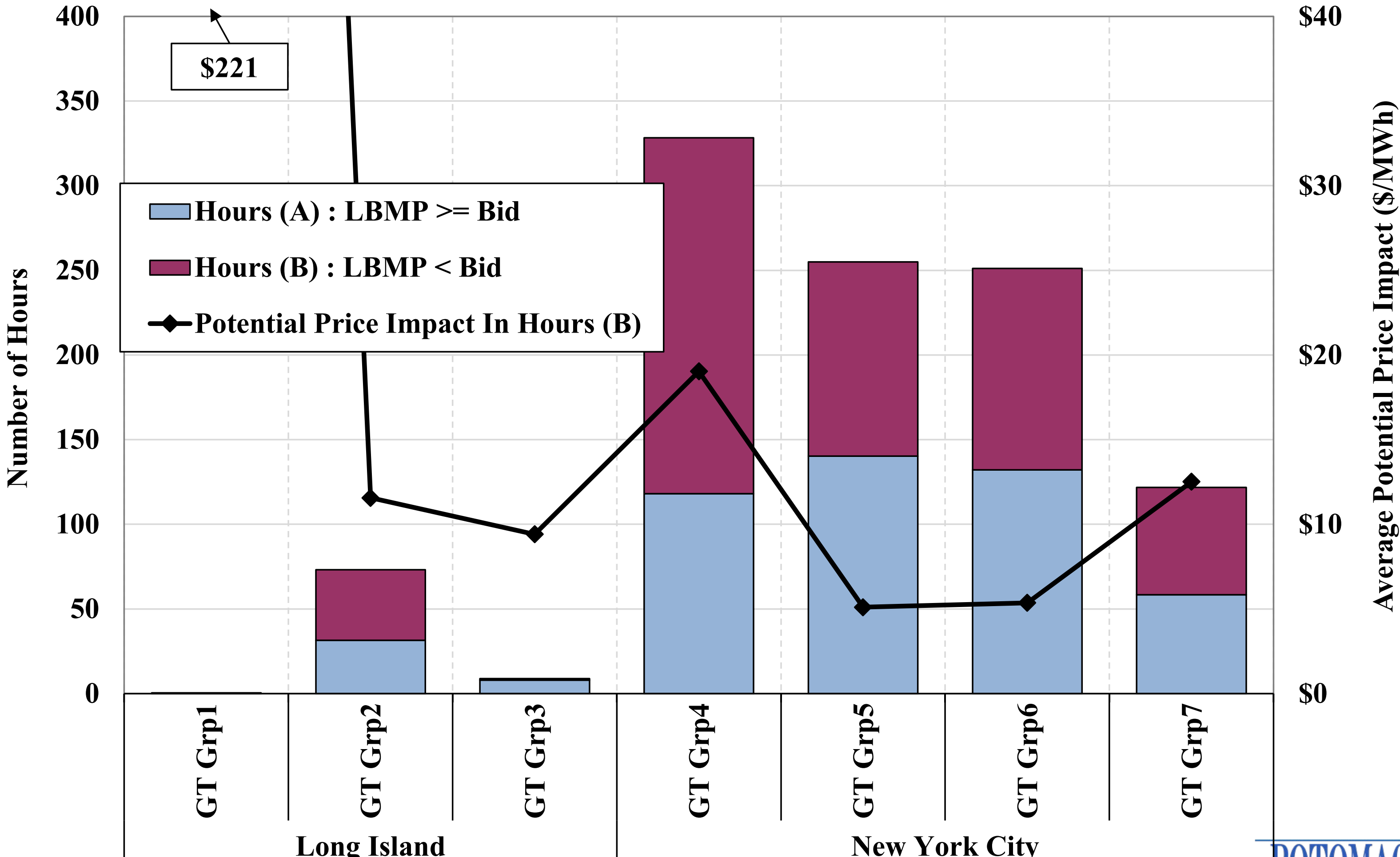
POTOMAC ECONOMICS

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




Notes: For chart description, see slide 89.

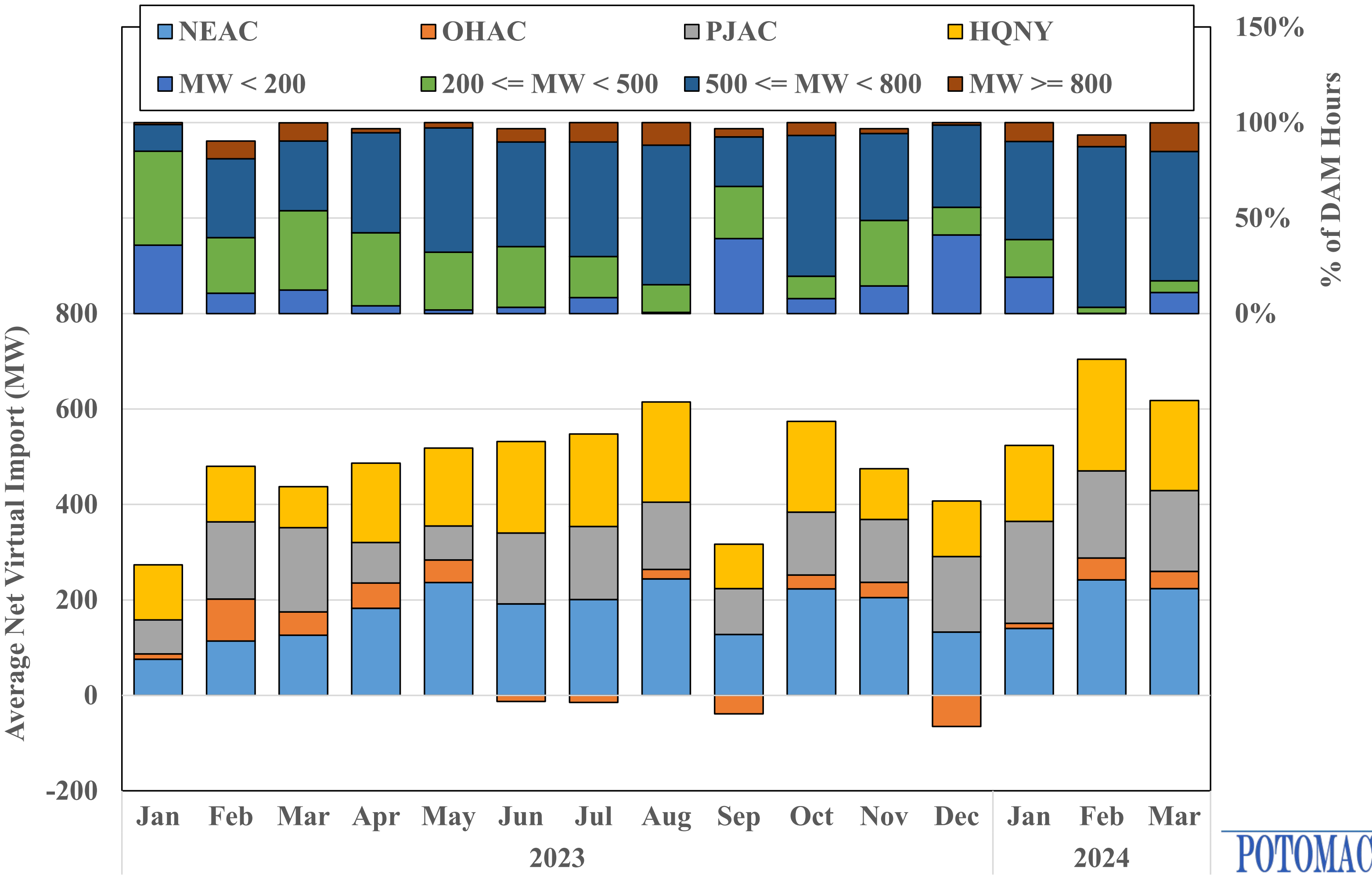
# Real-Time Prices During Commitments of GTs Offering Multi-Hour Min Run Times: 2024 Q1




 Notes: For chart description, see slide 90.

POTOMAC ECONOMICS

# Virtual Imports and Exports in the Day-Ahead Market



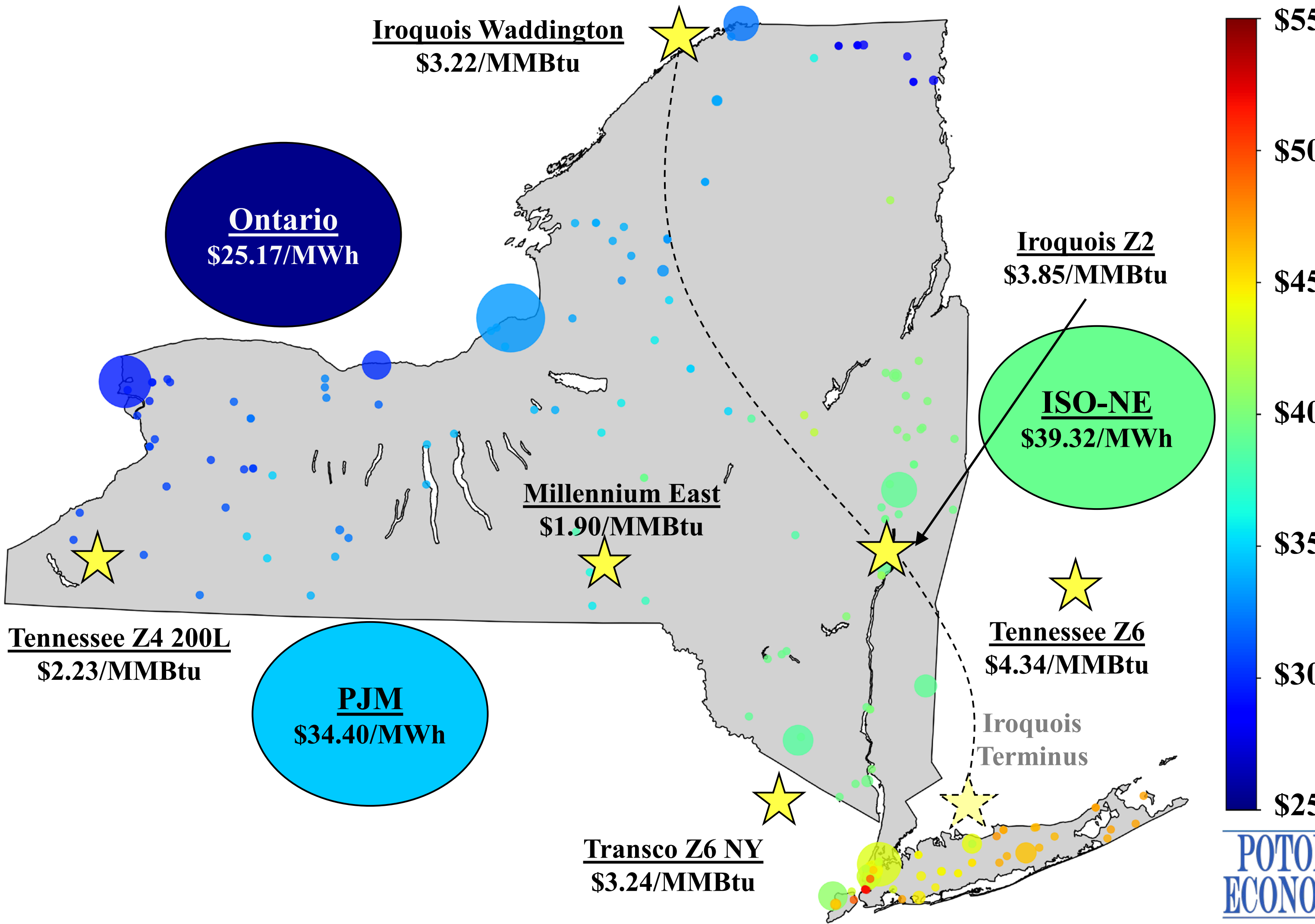

  Notes: For chart description, see slide 91.

POTOMAC ECONOMICS

# Charts:

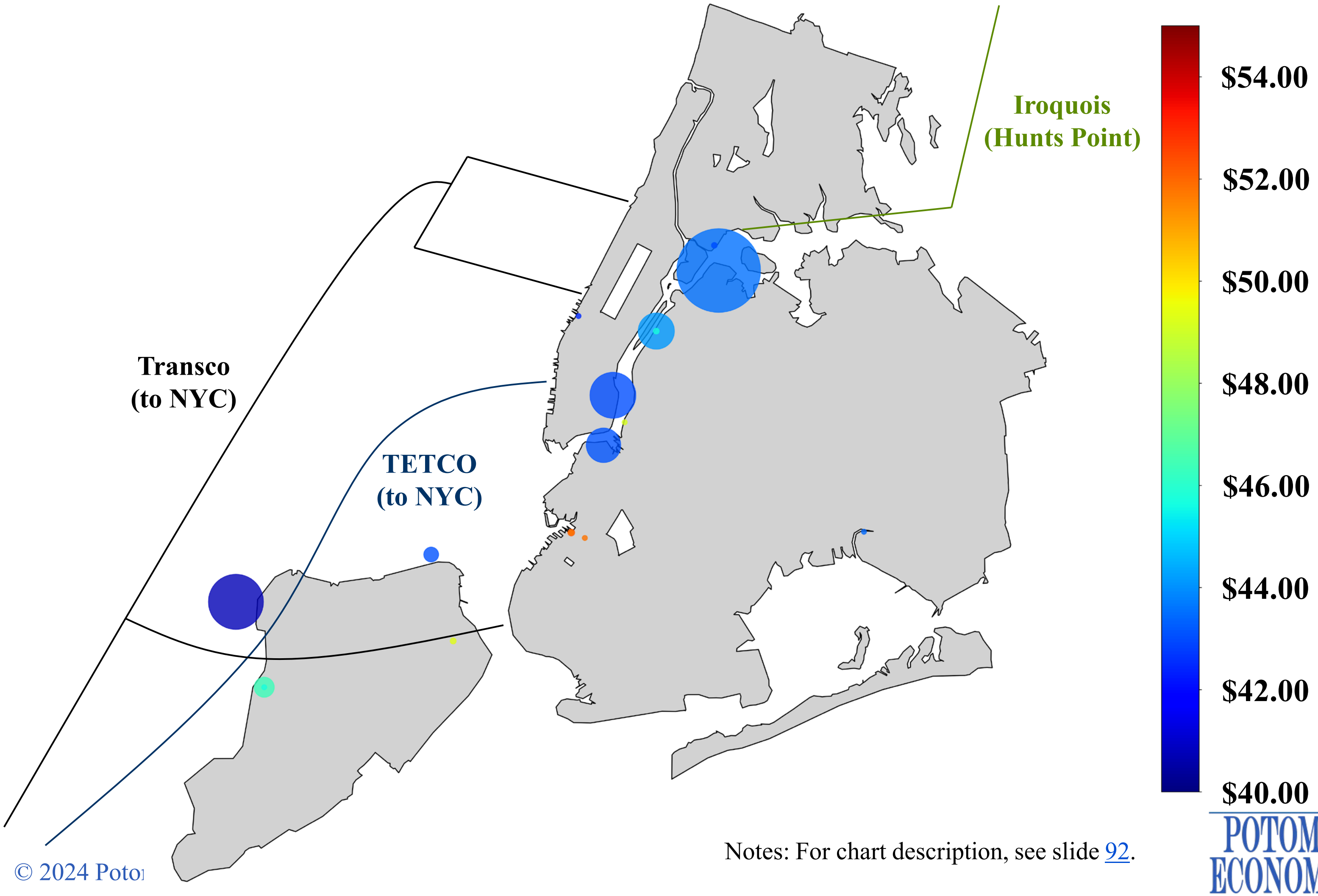
## Transmission Congestion Revenues and Shortfalls

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




POTOMAC ECONOMICS

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

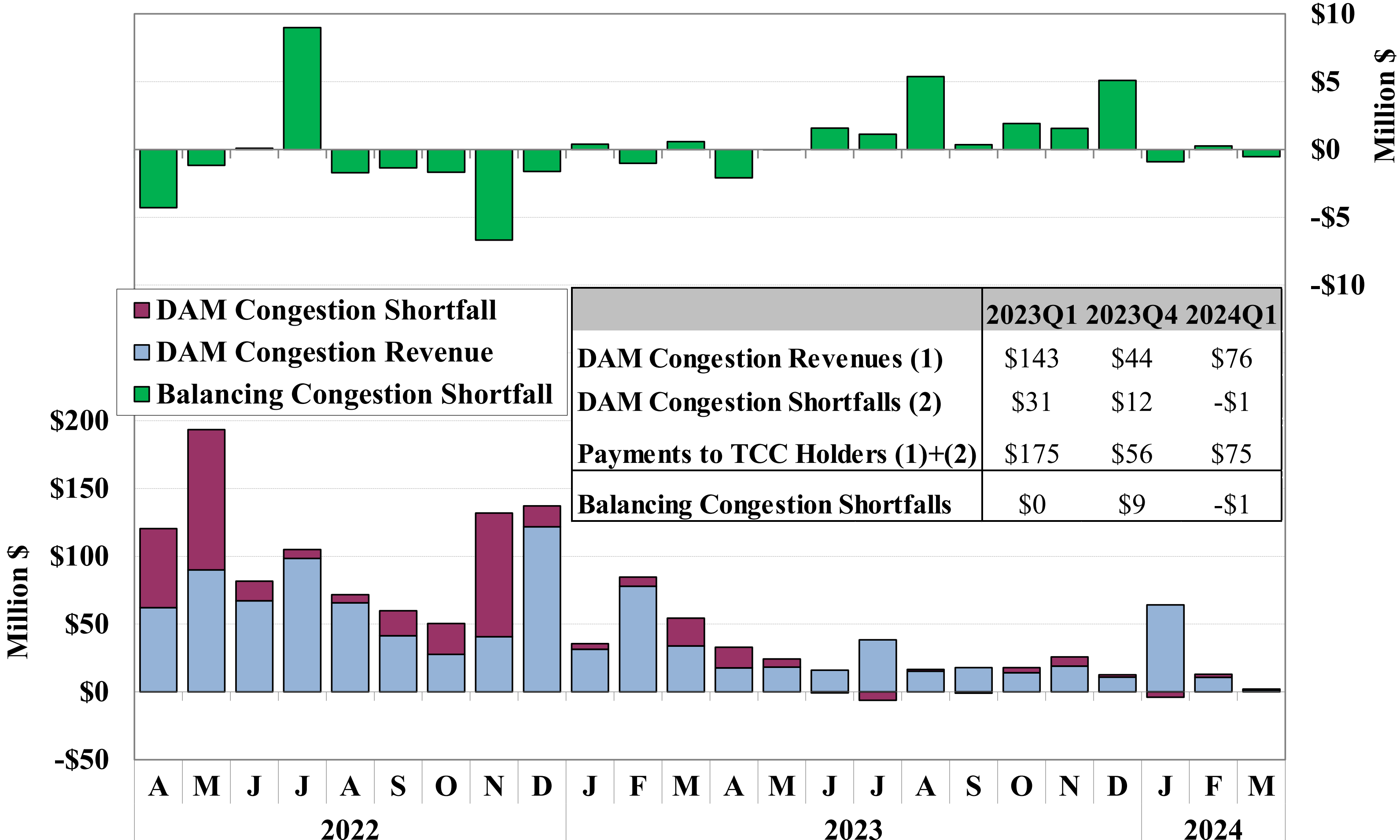



Notes: For chart description, see slide 92.



POTOMAC ECONOMICS

# Congestion Revenues and Shortfalls by Month




| | 2023Q1 | 2023Q4 | 2024Q1 |
|---|---|---|---|
| DAM Congestion Revenues (1) | $143 | $44 | $76 |
| DAM Congestion Shortfalls (2) | $31 | $12 | -$1 |
| Payments to TCC Holders (1)+(2) | $175 | $56 | $75 |
| Balancing Congestion Shortfalls | $0 | $9 | -$1 |

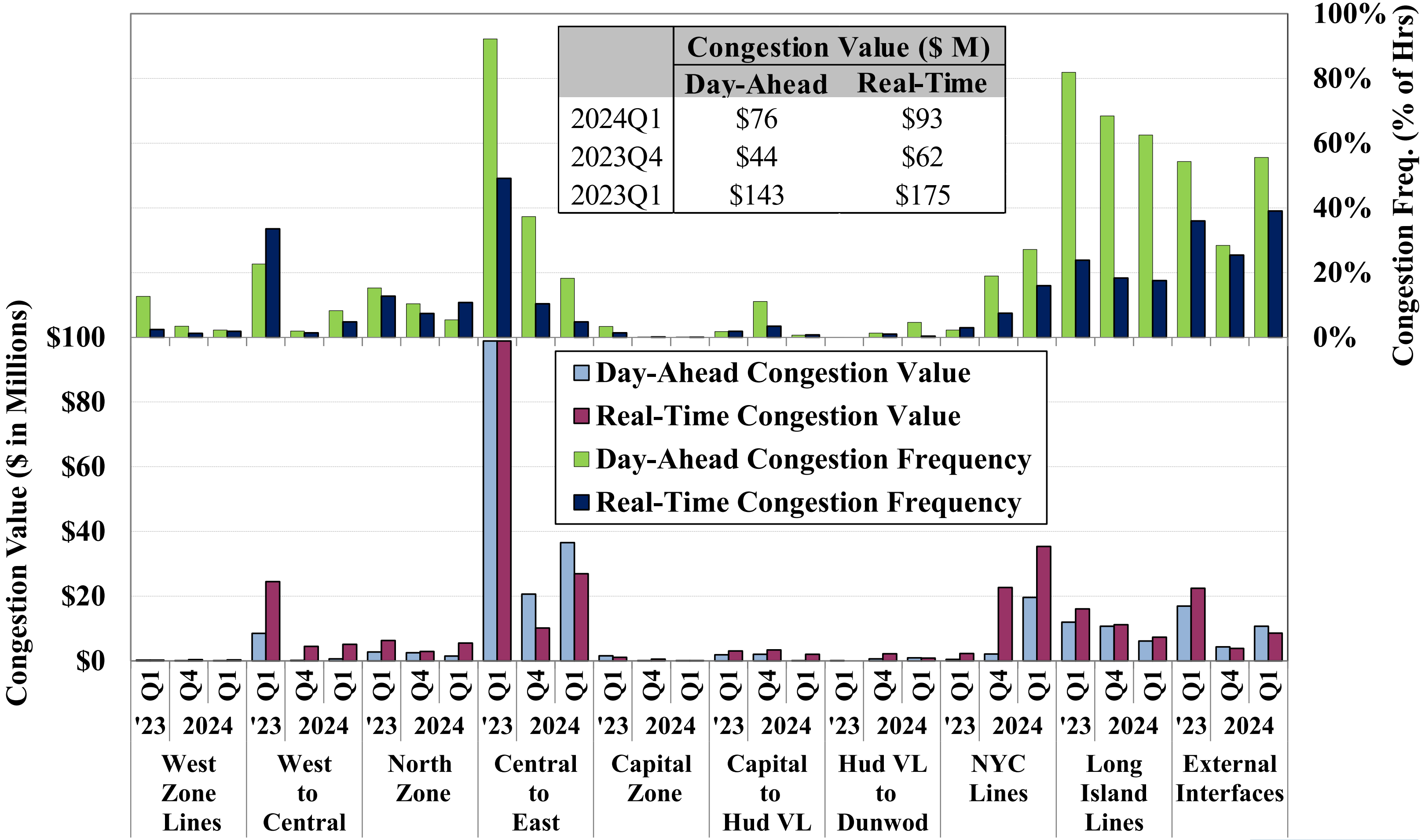
Notes: For chart description, see slides 93 and 94.





POTOMAC ECONOMICS

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



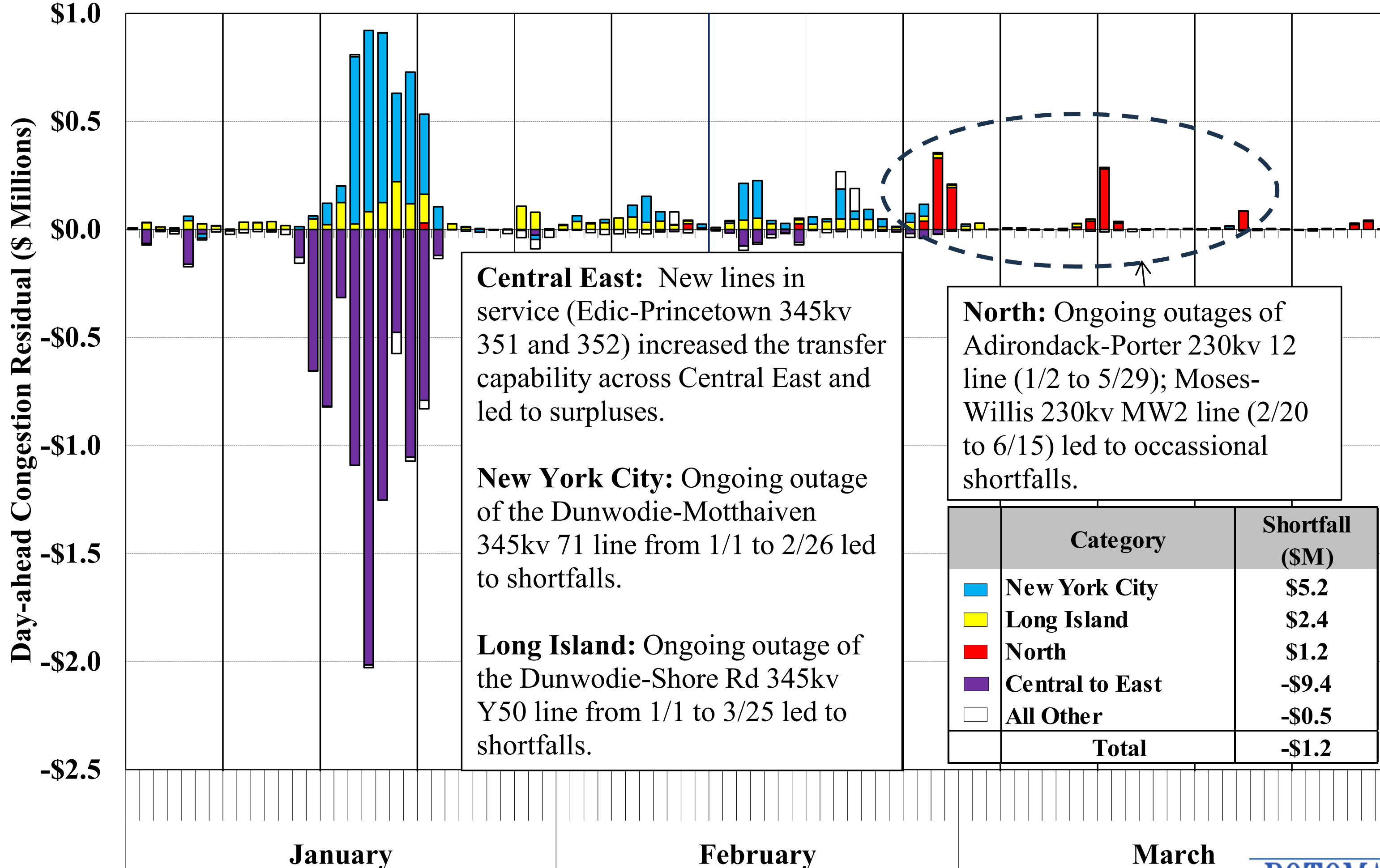

| | Congestion Value ($ M) | |
|---|---|---|
| | Day-Ahead | Real-Time |
| 2024Q1 | $76 | $93 |
| 2023Q4 | $44 | $62 |
| 2023Q1 | $143 | $175 |

Notes: For chart description, see slides 93, 94, and 95.



POTOMAC ECONOMICS

# Day-Ahead Congestion Revenue Shortfalls by Transmission Facility



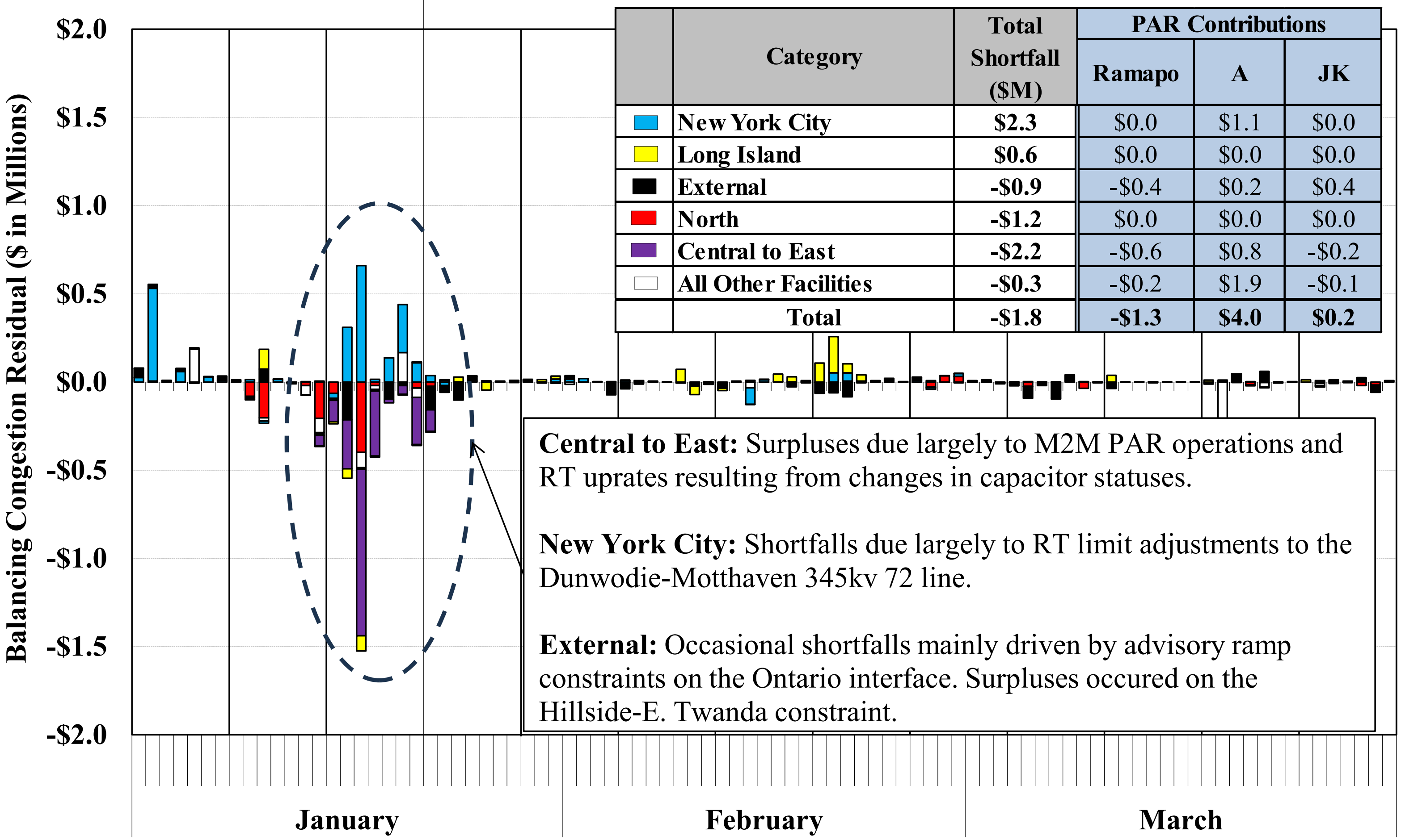

Notes: For chart description, see slides 93, 94, and 95.





POTOMAC ECONOMICS

# Balancing Congestion Shortfalls by Transmission Facility




| | Category | Total Shortfall ($M) | PAR Contributions Ramapo | PAR Contributions A | PAR Contributions JK |
|---|---|---|---|---|---|
| | New York City | $2.3 | $0.0 | $1.1 | $0.0 |
| | Long Island | $0.6 | $0.0 | $0.0 | $0.0 |
| | External | -$0.9 | -$0.4 | $0.2 | $0.4 |
| | North | -$1.2 | $0.0 | $0.0 | $0.0 |
| | Central to East | -$2.2 | -$0.6 | $0.8 | -$0.2 |
| | All Other Facilities | -$0.3 | -$0.2 | $1.9 | -$0.1 |
| | Total | -$1.8 | -$1.3 | $4.0 | $0.2 |

**Central to East:** Surpluses due largely to M2M PAR operations and RT uprates resulting from changes in capacitor statuses.

**New York City:** Shortfalls due largely to RT limit adjustments to the Dunwodie-Motthaven 345kv 72 line.

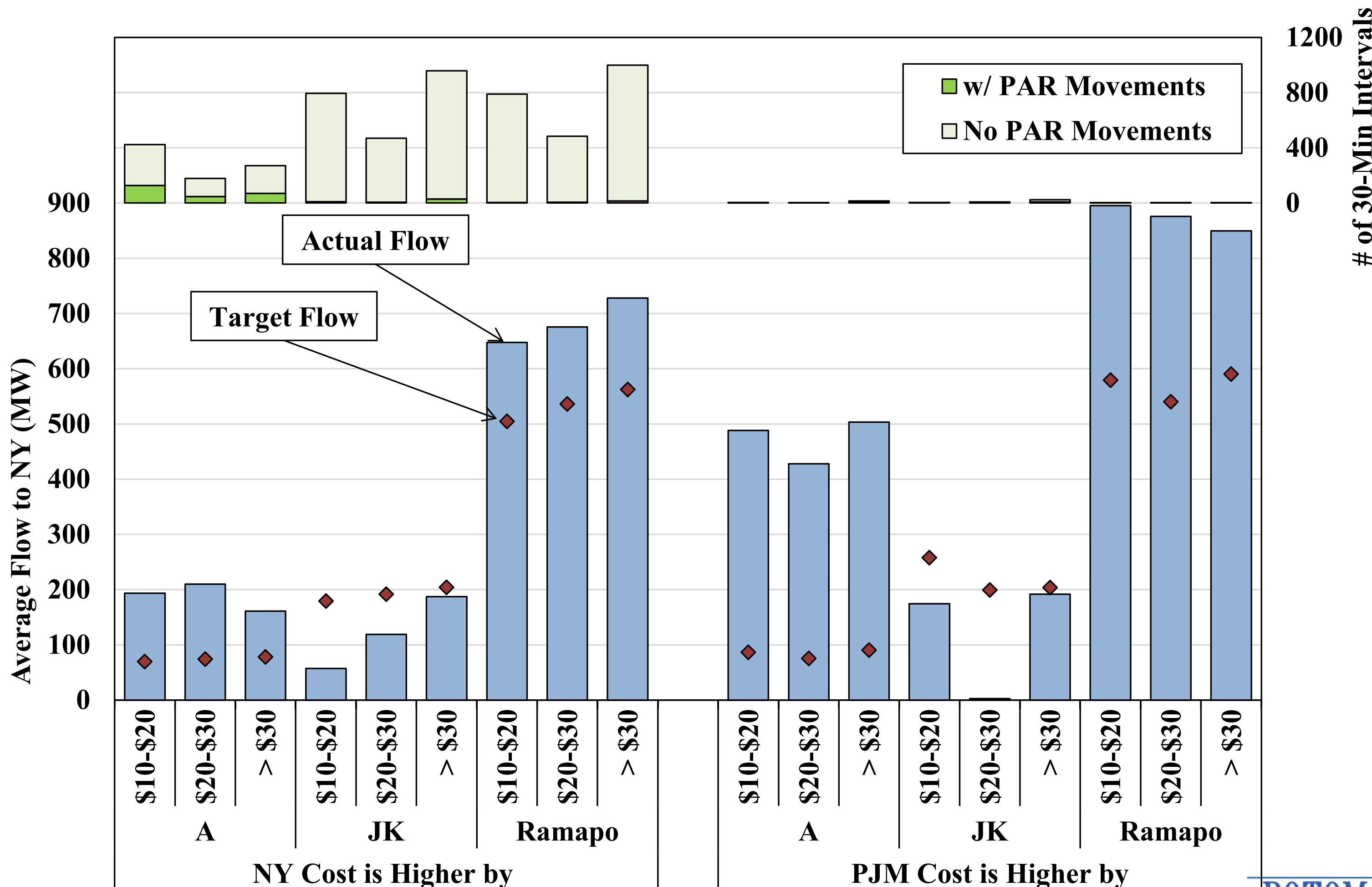
**External:** Occasional shortfalls mainly driven by advisory ramp constraints on the Ontario interface. Surpluses occured on the Hillside-E. Twanda constraint.

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 93, 94, and 95.




POTOMAC ECONOMICS

# PAR Operation under M2M with PJM
# 2024 Q1






Notes: For chart description, see slide 96.

# OOM Actions to Manage Network Reliability

| North | # Days |
|---|---|
| N-1-1 | 74 |
| Voltage | 1 |
| Constraint Management | |
| Gen Up | 4 |
| Gen Down | 4 |
| PAR | 10 |
| Any Resource | 75 |

| West Zone | # Days |
|---|---|
| Constraint Management | |
| PAR | 2 |
| Any Resource | 2 |

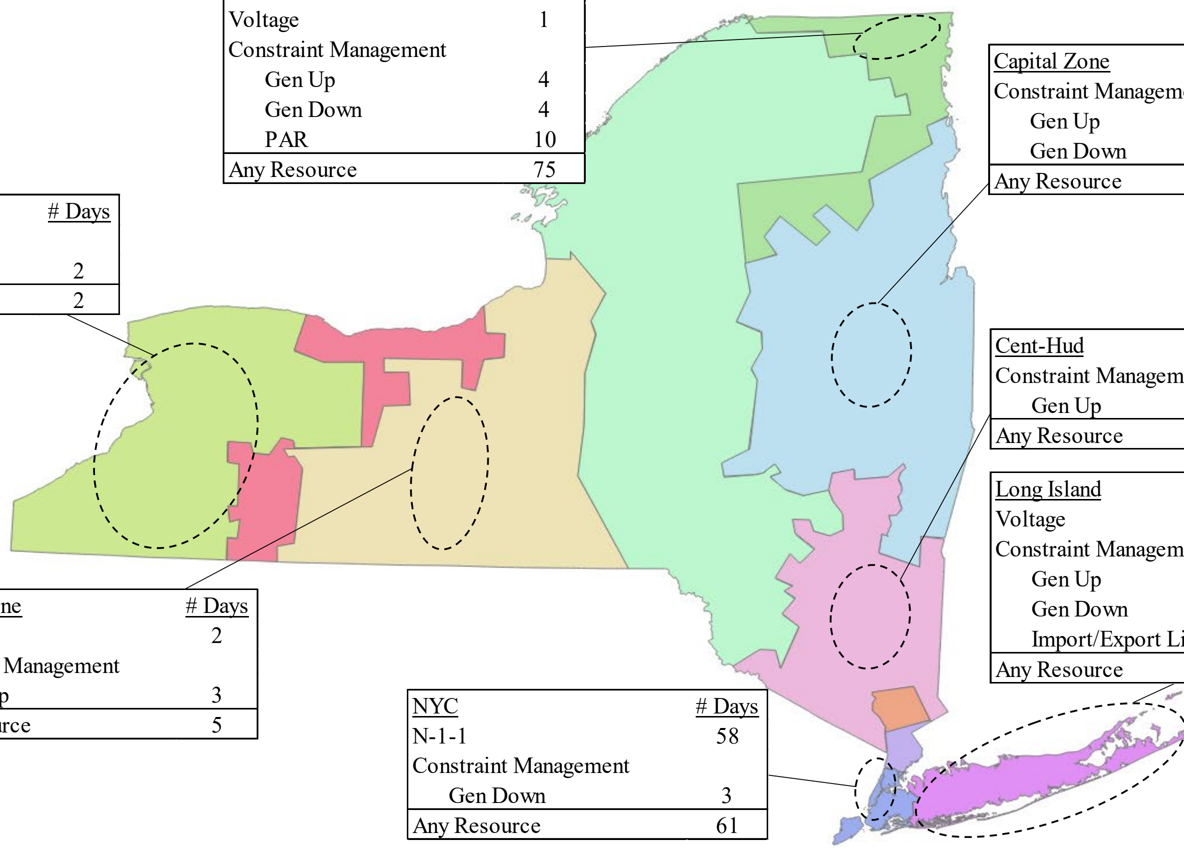
| Capital Zone | # Days |
|---|---|
| Constraint Management | |
| Gen Up | 2 |
| Gen Down | 6 |
| Any Resource | 8 |

| Cent-Hud | # Days |
|---|---|
| Constraint Management | |
| Gen Up | 1 |
| Any Resource | 1 |

| Long Island | # Days |
|---|---|
| Voltage | 19 |
| Constraint Management | |
| Gen Up | 24 |
| Gen Down | 9 |
| Import/Export Limitation | 1 |
| Any Resource | 44 |

| Central Zone | # Days |
|---|---|
| Voltage | 2 |
| Constraint Management | |
| Gen Up | 3 |
| Any Resource | 5 |

| NYC | # Days |
|---|---|
| N-1-1 | 58 |
| Constraint Management | |
| Gen Down | 3 |
| Any Resource | 61 |



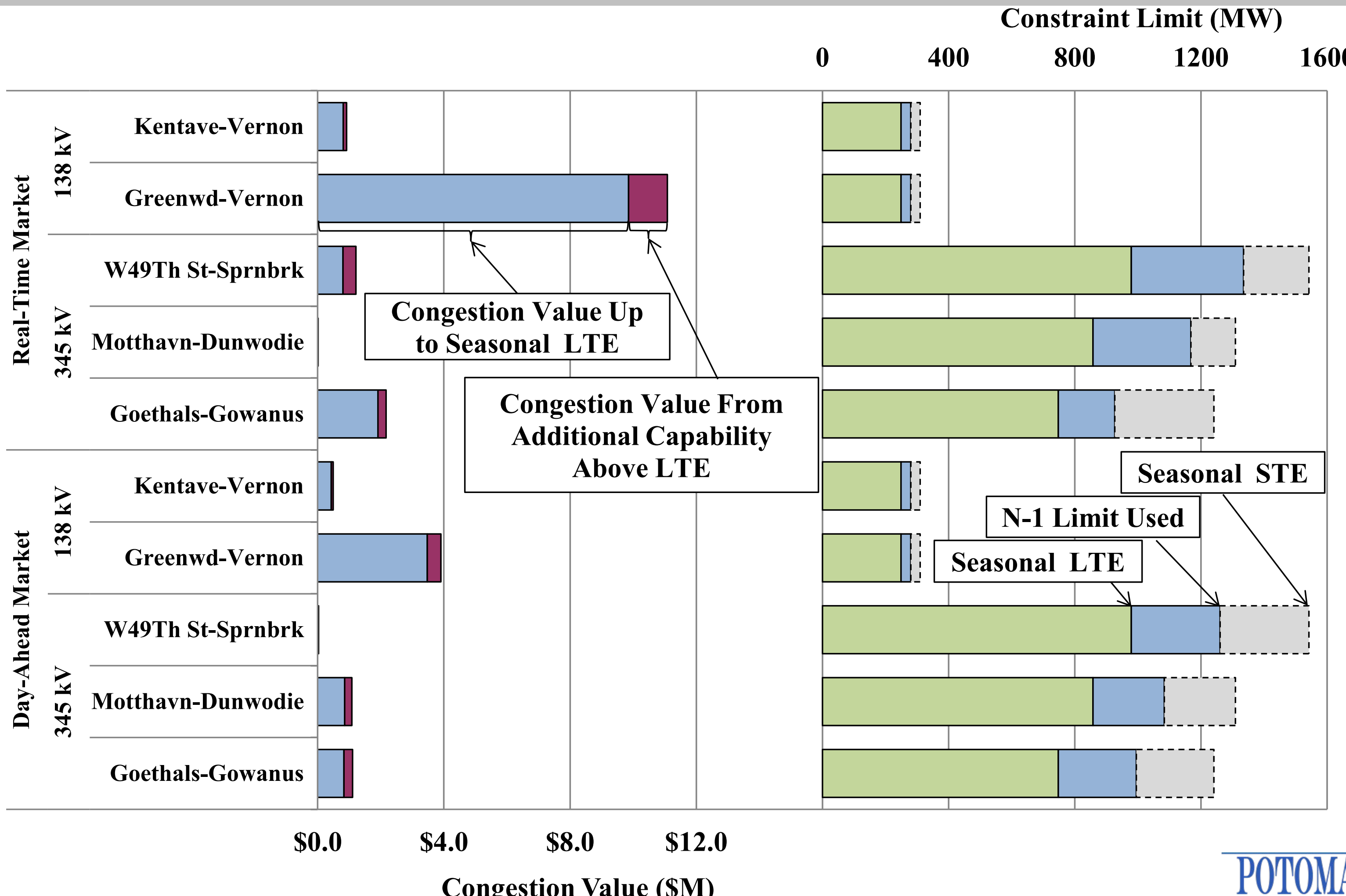
Notes: For chart description, see slide 97





POTOMAC ECONOMICS

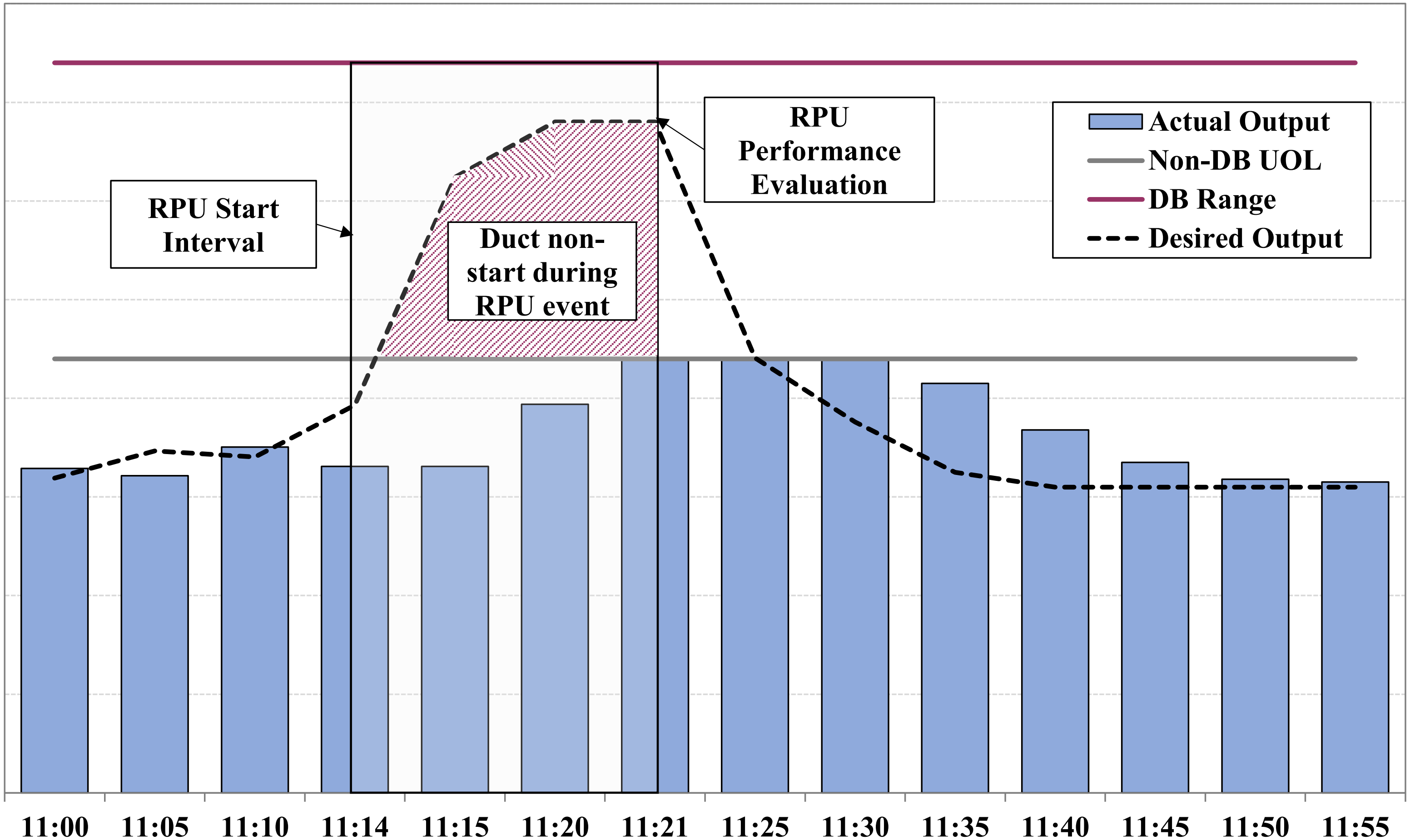
# N-1 Constraints in New York City
## Limits Used vs Seasonal LTE Ratings




  Notes: For chart description, see slide 98.

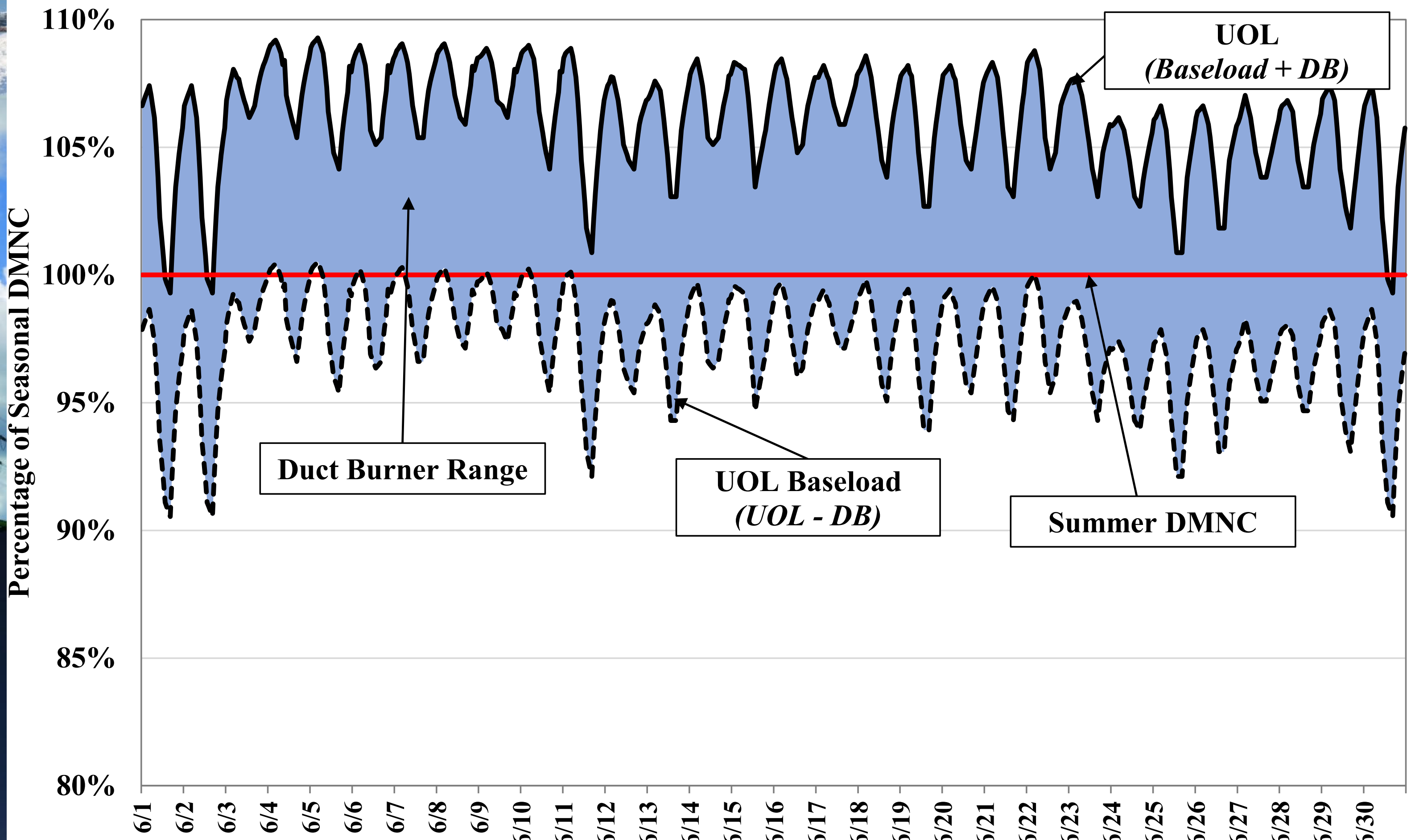
POTOMAC ECONOMICS

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




Notes: For chart description, see slide 99

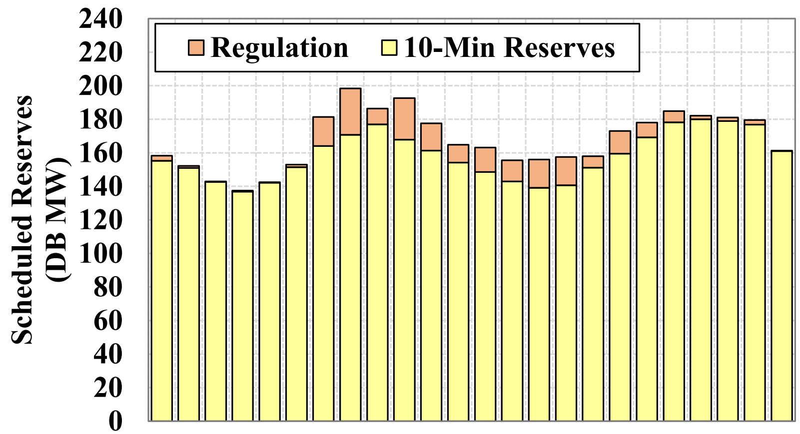
# Illustration of Duct Burner Range
## Example Generator Hourly Capability

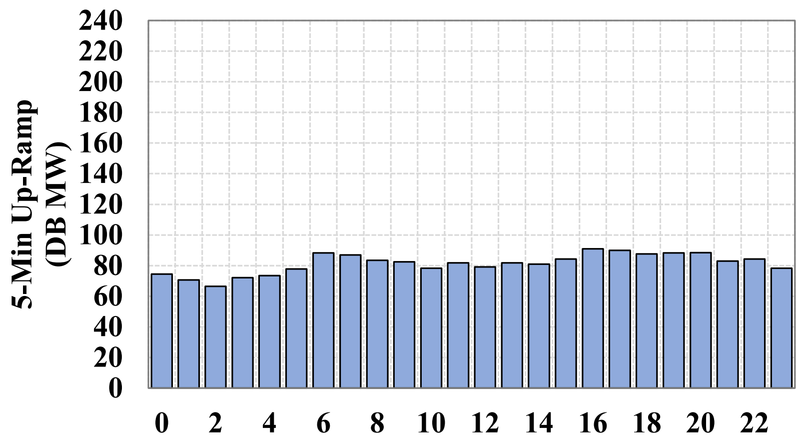



Notes: For chart description, see slide 100

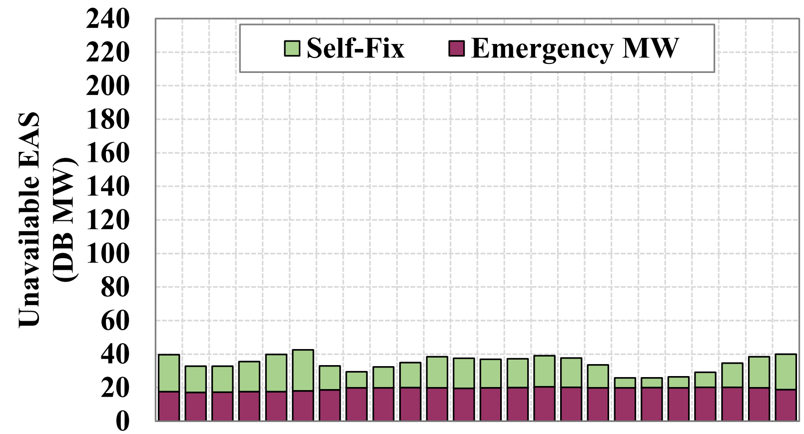
# Duct Burner Schedules and Ramp Expectations Evaluation of Duct Availability in Real-Time

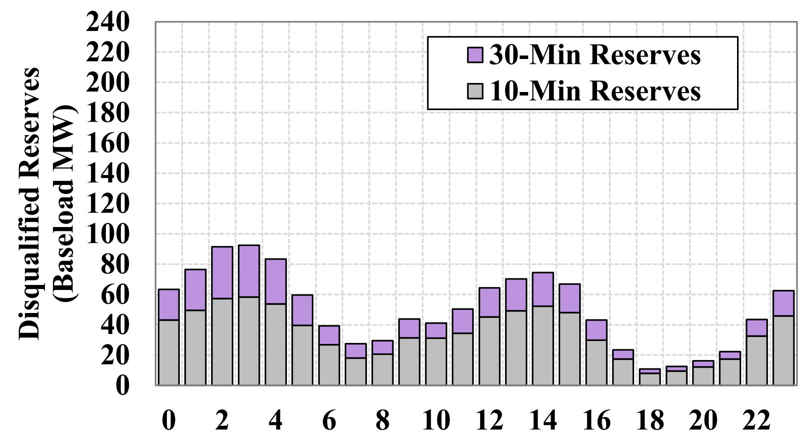
### Scheduled or Offered Duct Capacity – but Unable to Follow RT Instructions




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




Notes: For chart description, see slide 99



POTOMAC ECONOMICS

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

**10 Minute Economic GT Start Performance vs. Audit Results (April 2023 - March 2024)**

| 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] | 1 | 1 | 1 | 0 |
| 0% - 10% | 0 | 0 | 0 | 0 |
| 10% - 20% | 0 | 0 | 0 | 0 |
| 20% - 30% | 0 | 0 | 0 | 0 |
| 30% - 40% | 0 | 0 | 0 | 0 |
| 40% - 50% | 0 | 0 | 0 | 0 |
| 50% - 60% | 5 | 20 | 5 | 13 |
| 60% - 70% | 0 | 0 | 0 | 0 |
| 70% - 80% | 2 | 5 | 2 | 0 |
| 80% - 90% | 6 | 13 | 6 | 1 |
| 90% - 100% | 26 | 112 | 26 | 3 |
| **TOTAL** | **40** | **151** | **40** | **17** |

Note: 1. Including units that were OOM- or self-started, units that were never started in the time period, and units where data was unavailable.



Notes: For chart description, see slide 101.

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

**30 Minute Economic GT Start Performance vs. Audit Results (April 2023 - March 2024)**

| 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] | 3 | 6 | 3 | 1 |
| 0% - 10% | 1 | 2 | 1 | 1 |
| 10% - 20% | 0 | 0 | 0 | 0 |
| 20% - 30% | 0 | 0 | 0 | 0 |
| 30% - 40% | 0 | 0 | 0 | 0 |
| 40% - 50% | 0 | 0 | 0 | 0 |
| 50% - 60% | 1 | 3 | 1 | 1 |
| 60% - 70% | 2 | 3 | 2 | 0 |
| 70% - 80% | 9 | 20 | 9 | 3 |
| 80% - 90% | 16 | 38 | 16 | 8 |
| 90% - 100% | 32 | 64 | 32 | 3 |
| **TOTAL** | **64** | **136** | **64** | **17** |

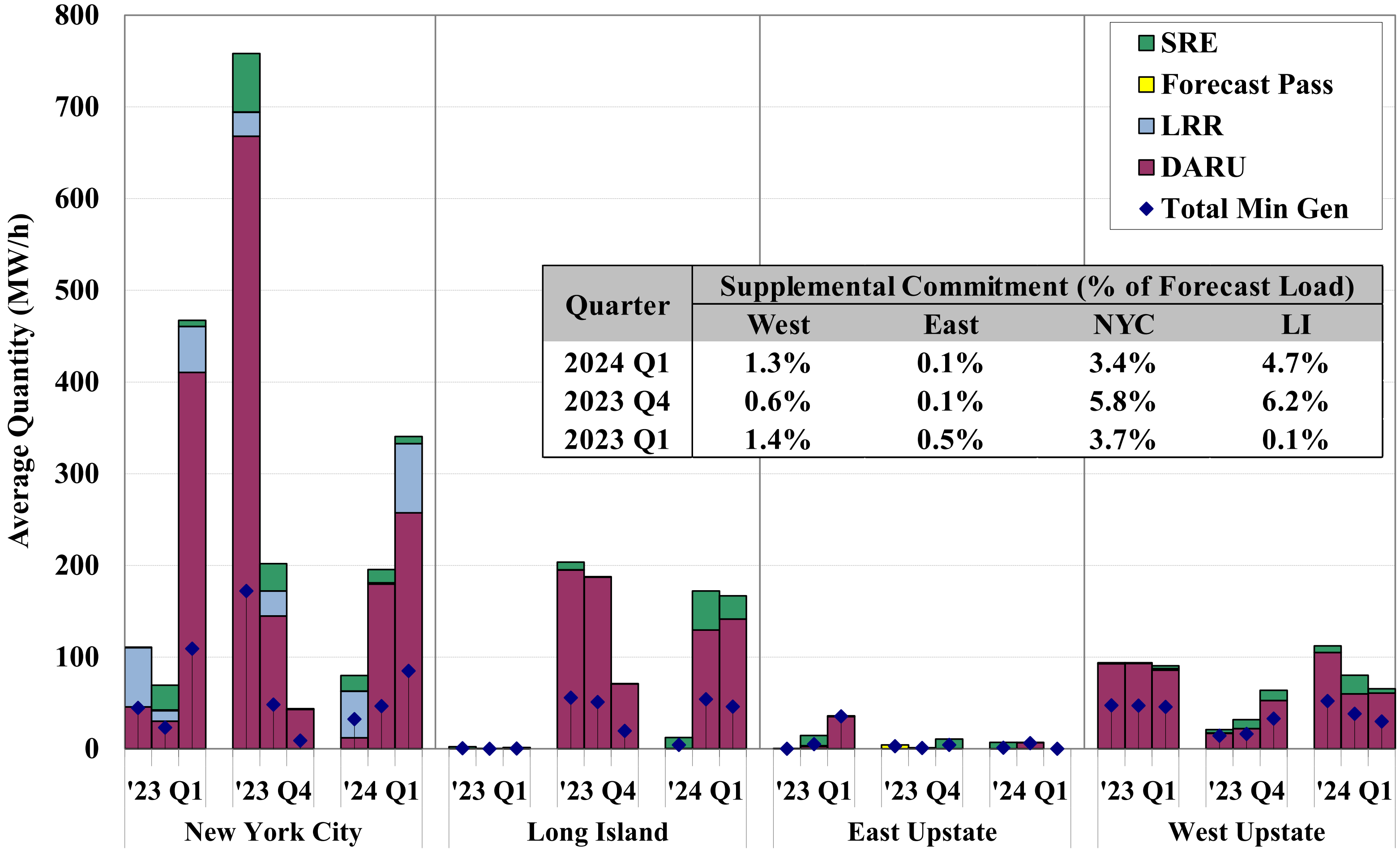
Note: 1. Includes units there had no economic starts in this period or were missing from the dataset in this evaluation.

# Charts:

## Supplemental Commitment, OOM Dispatch, and BPCG Uplift

POTOMAC ECONOMICS

# Supplemental Commitment for Reliability
## by Category and Region



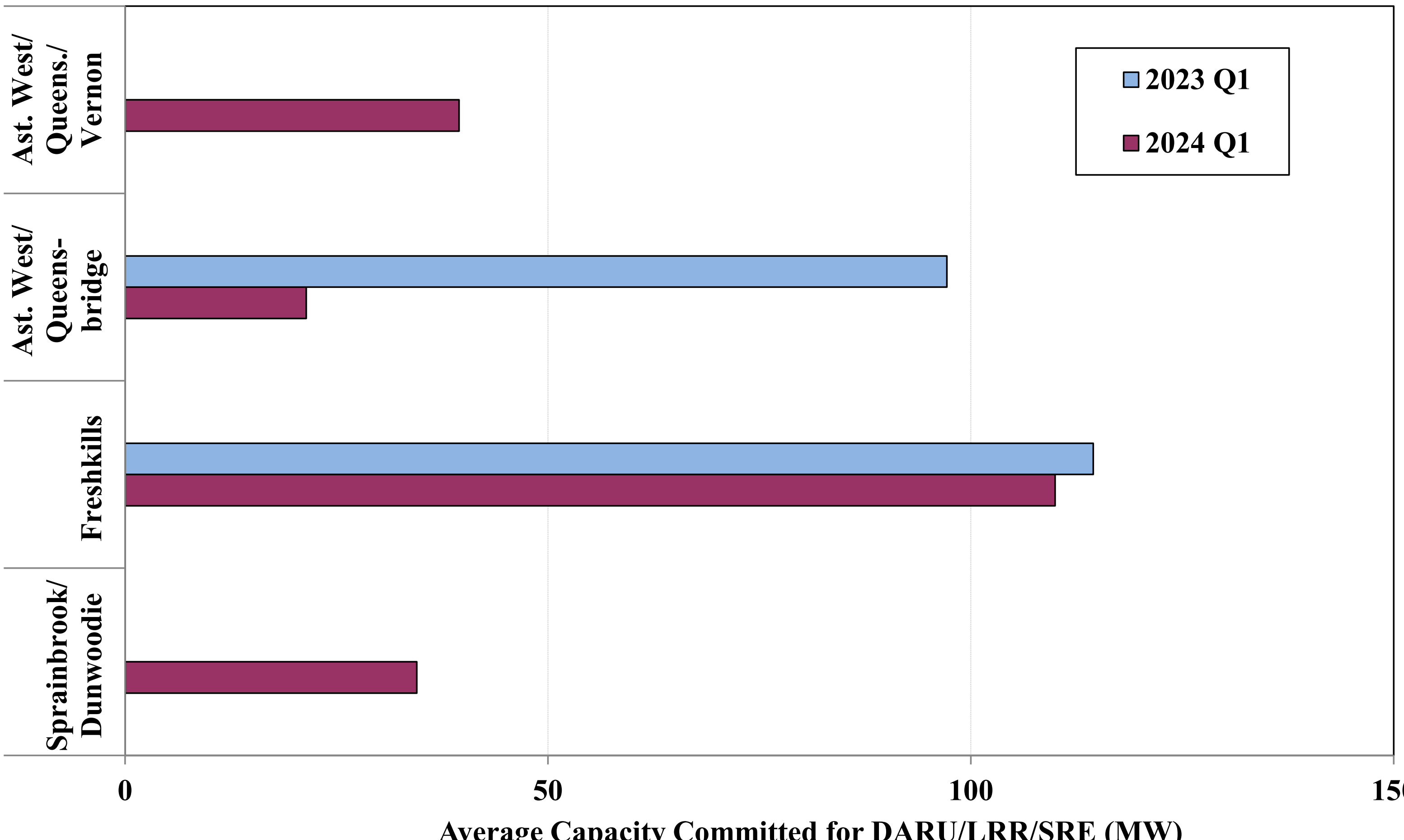

| Quarter | Supplemental Commitment (% of Forecast Load) | | | |
|---|---|---|---|---|
| | West | East | NYC | LI |
| 2024 Q1 | 1.3% | 0.1% | 3.4% | 4.7% |
| 2023 Q4 | 0.6% | 0.1% | 5.8% | 6.2% |
| 2023 Q1 | 1.4% | 0.5% | 3.7% | 0.1% |

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



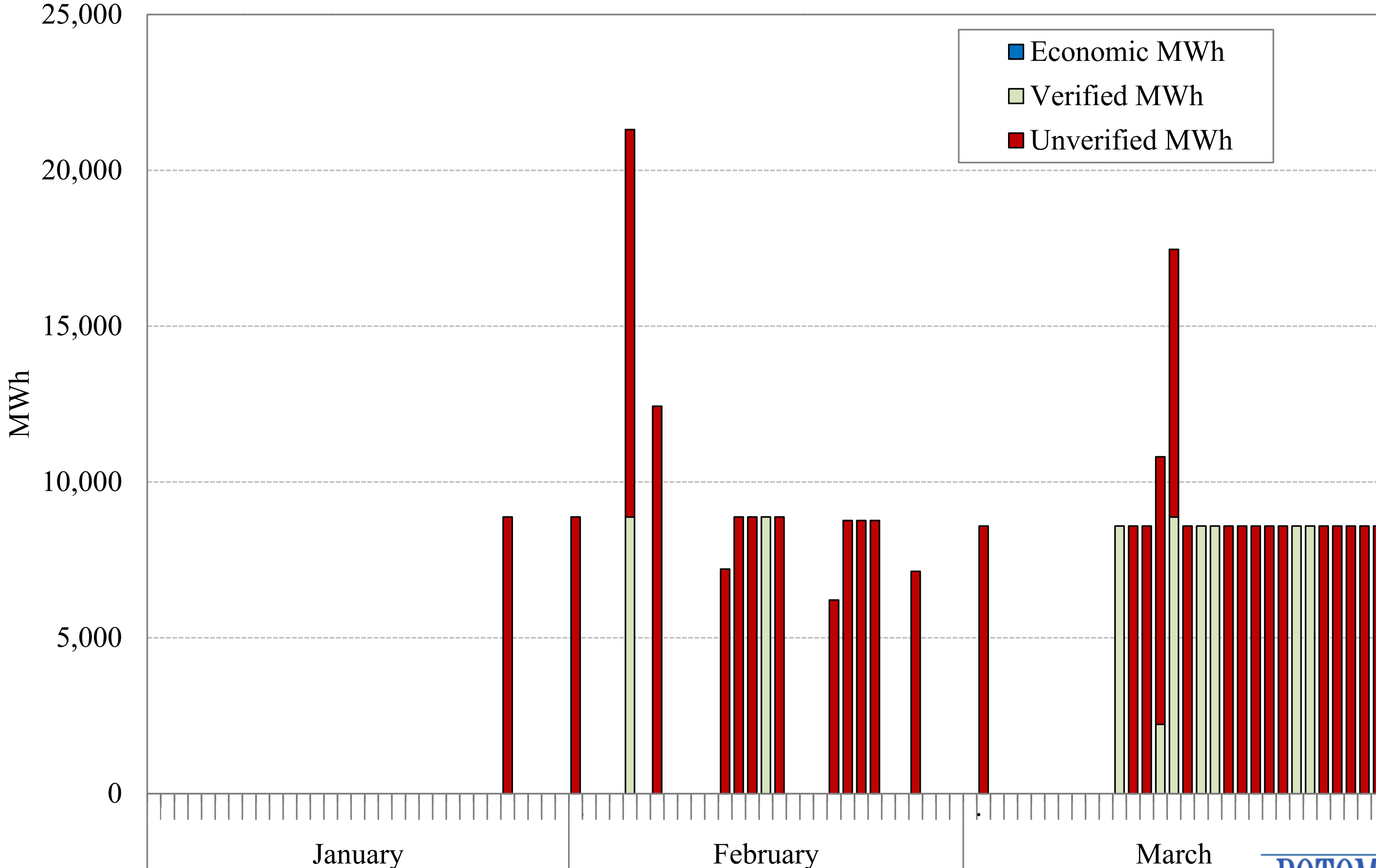
POTOMAC ECONOMICS

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




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

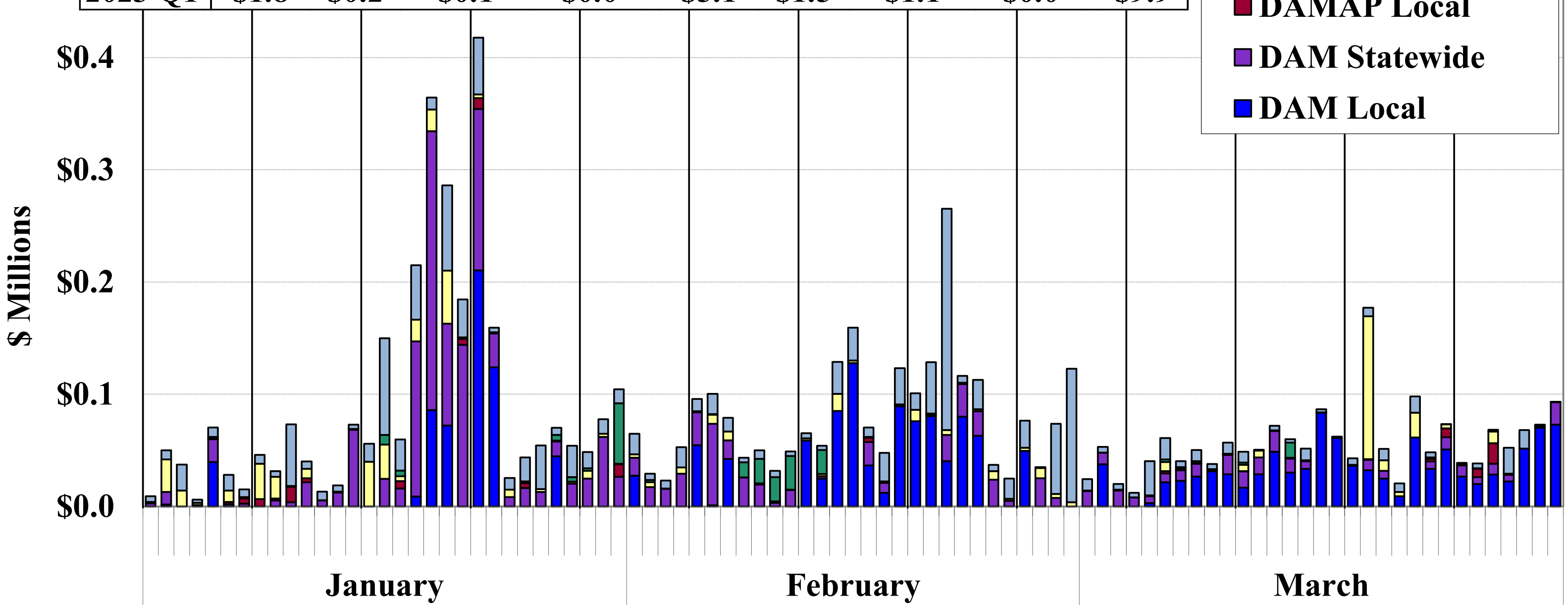
# DARU Commitments in NYC
## 2024 Q1




Notes: For chart description, see slide 103.

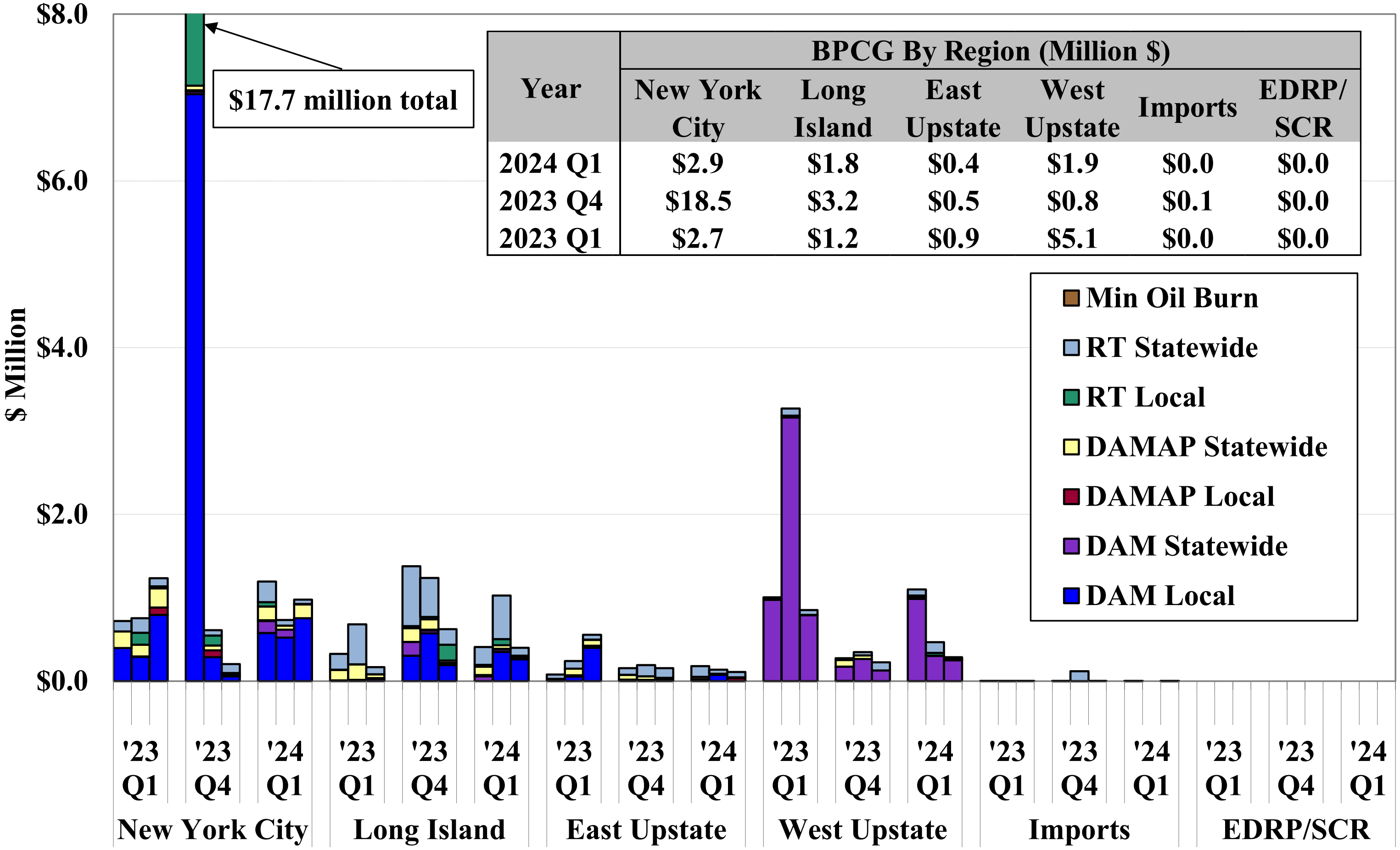
# Uplift Costs from Guarantee Payments
## Local and Non-Local by Category

| Quarter | Quarterly BPCG By Category (Million $) | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| | Local | | | | Statewide | | | | Total |
| | Day Ahead | Real Time | DAMAP | Min Oil Burn | Day Ahead | Real Time | DAMAP | EDRP/ SCR | |
| 2024 Q1 | $2.5 | $0.2 | $0.1 | $0.0 | $1.9 | $1.7 | $0.6 | $0.0 | $7.0 |
| 2023 Q4 | $8.5 | $10.8 | $0.1 | $0.0 | $0.9 | $2.3 | $0.7 | $0.0 | $23.2 |
| 2023 Q1 | $1.8 | $0.2 | $0.1 | $0.0 | $5.1 | $1.5 | $1.1 | $0.0 | $9.9 |




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 104.

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

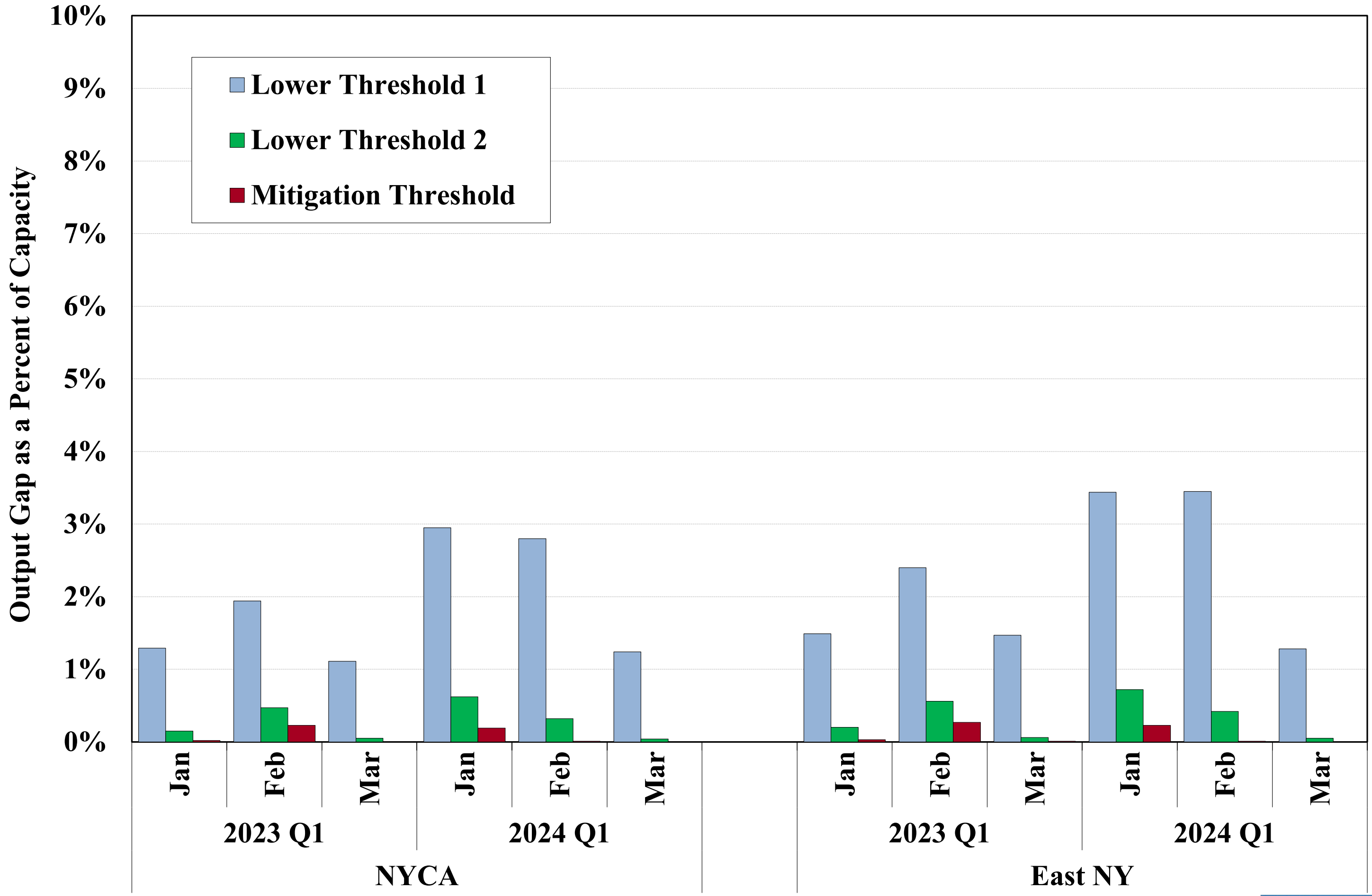



| Year | BPCG By Region (Million $) | | | | | |
|---|---|---|---|---|---|---|
| | New York City | Long Island | East Upstate | West Upstate | Imports | EDRP/ SCR |
| 2024 Q1 | $2.9 | $1.8 | $0.4 | $1.9 | $0.0 | $0.0 |
| 2023 Q4 | $18.5 | $3.2 | $0.5 | $0.8 | $0.1 | $0.0 |
| 2023 Q1 | $2.7 | $1.2 | $0.9 | $5.1 | $0.0 | $0.0 |

Notes: 1. BPCG data are based on information available at the reporting time that can be different from final settlements.
2. For chart description, see slide 104.

# Charts:
## Market Power and Mitigation

# Output Gap by Month
## NYCA and East NY








For chart description, see slide 105.

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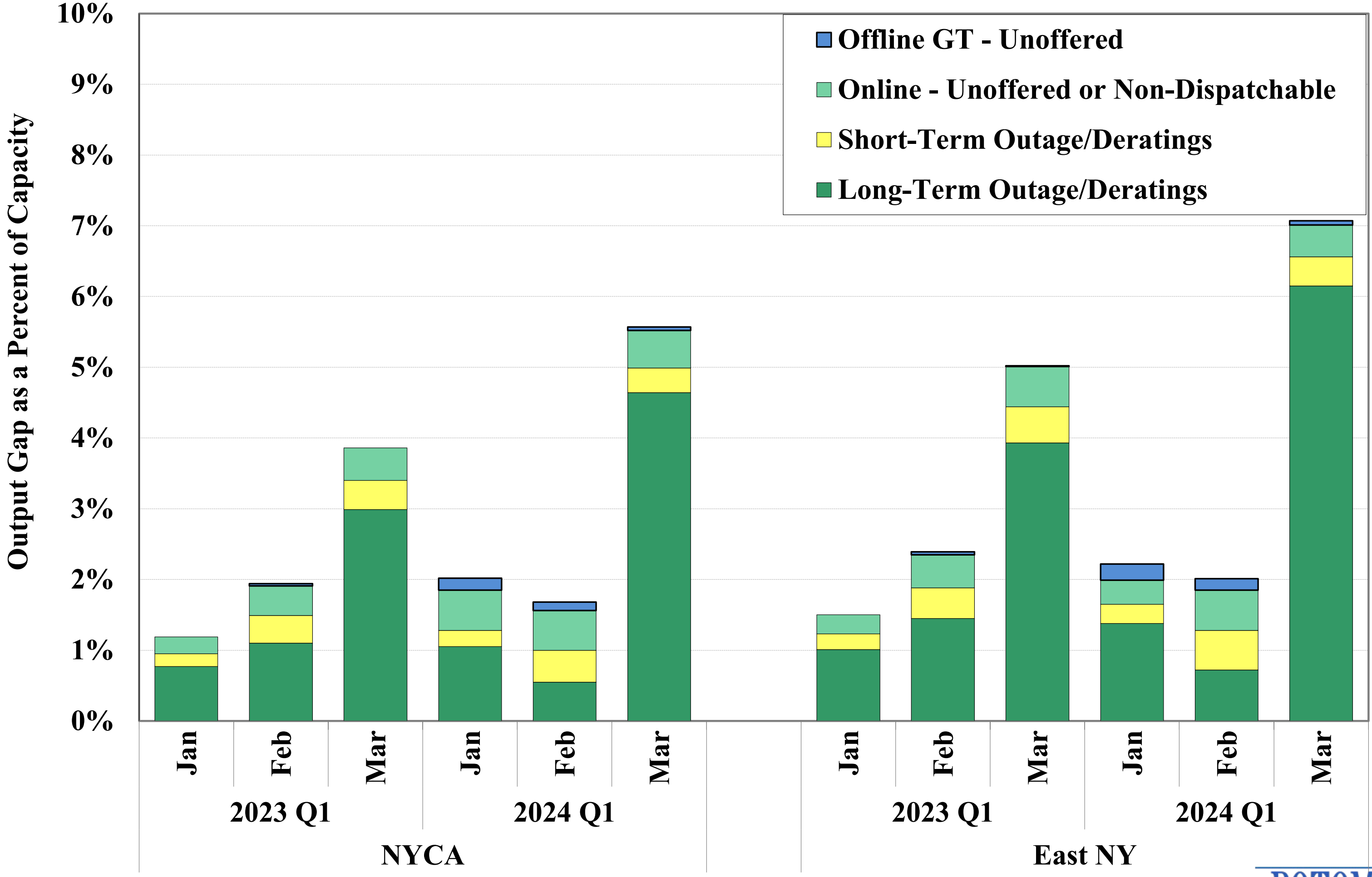
# Unoffered Economic Capacity by Month
## NYCA and East NY




 For chart description, see slide 105.
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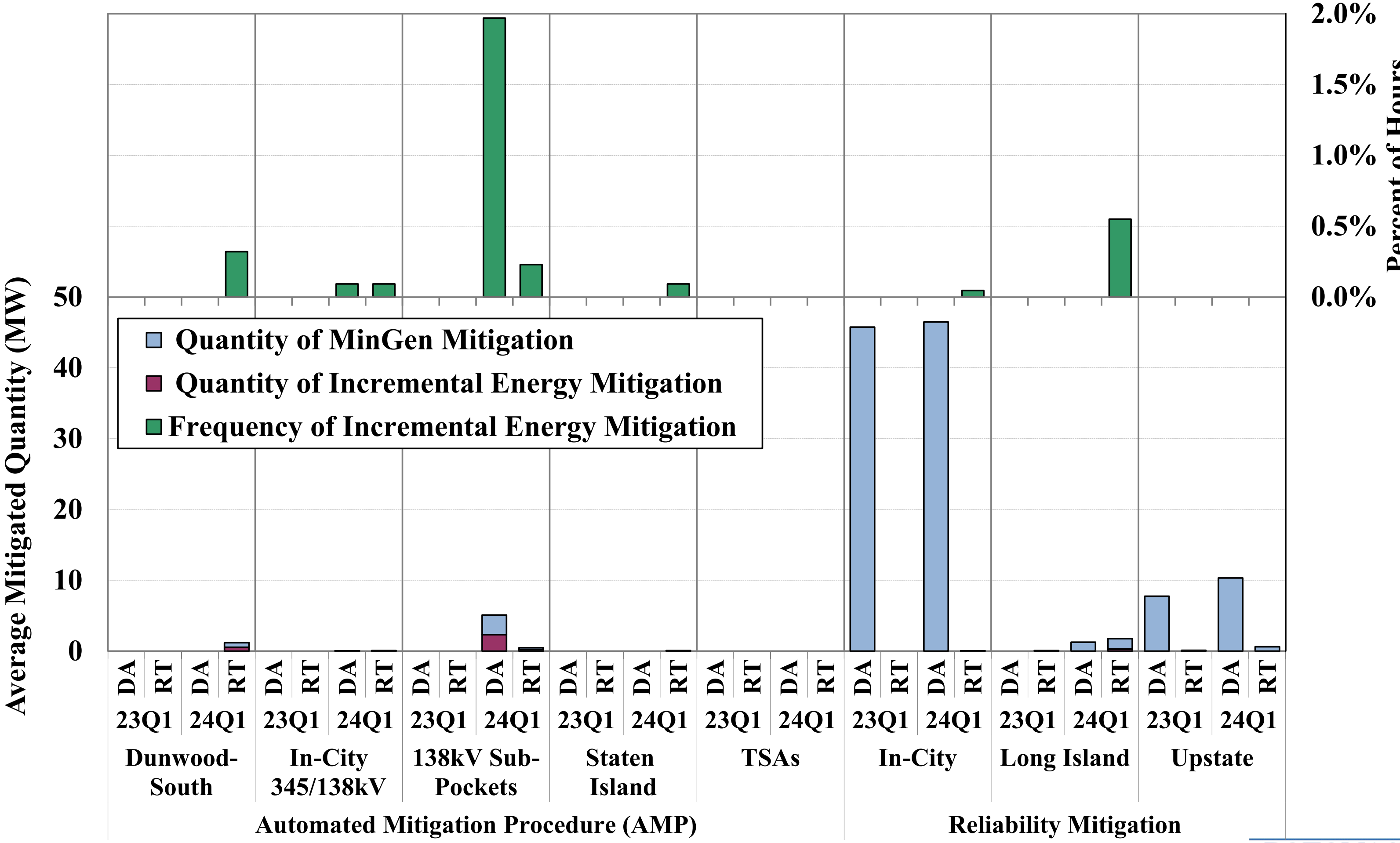
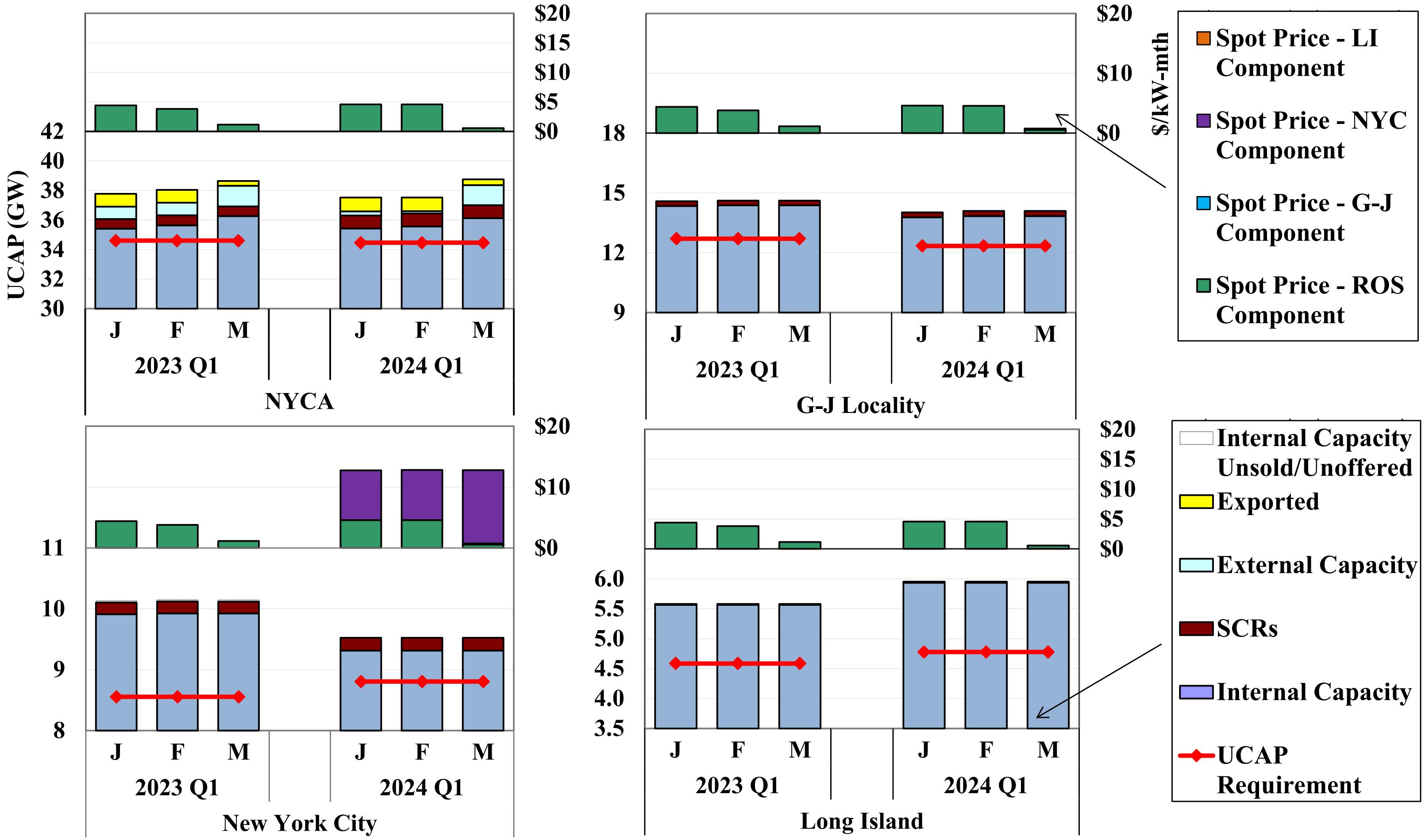
# Automated Market Power Mitigation




Notes: For chart description, see slide 106.

# Charts:
## Capacity Market

# Spot Capacity Market Results
## Monthly Results by Locality




Notes: For chart description, see slide 107.





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# Key Drivers of Capacity Market Results

| | NYCA | NYC | LI | G-J Locality |
|---|---|---|---|---|
| **Avg. Spot Price** | | | | |
| 2024 Q1 ($/kW-Month) | $3.23 | $12.78 | $3.23 | $3.30 |
| % Change from 2023 Q1 | **4%** | **311%** | **4%** | **6%** |
| **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* | **113** | **-555** | **306** | **-547** |
| *Entry* (3) | 447 | 17 | 330 | 17 |
| *Exit* (3) | -647 | -617 | -28 | -617 |
| *Other Capacity Changes* (1) | 313 | 45 | 3 | 53 |
| *Cleared Import* (2) | **-442** | | | |

*(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 107.

# Appendix:  Chart Descriptions

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# All-in Price

- Slide 19 summarizes the total cost per MWh of load served in the New York markets by showing the "all-in" price that includes:
  - ✓ An energy component that is a load-weighted average real-time energy price.
  - ✓ A capacity component that is calculated based on clearing prices in the monthly spot capacity auctions and capacity obligations in each zone, allocated over the energy consumption in that zone.
  - ✓ An uplift component that is based on local and statewide uplift from Schedule 1 charges, allocated over the energy consumed in the area.
  - ✓ An ancillary services component that is based on costs associated with operating reserves, regulation, voltage support, and black start.
    - For the purpose of this metric, these costs are distributed evenly across all locations.
  - ✓ The figure also shows representative natural gas prices for each location that is based on the following indices (plus transportation charges equal to $0.27 per MMBtu for Zones A through I, $0.20 per MMBtu for New York City, and $0.25 per MMBtu for Long Island):
    - (a) Tennessee Z4 200L index for the West Zone, (b) the minimum of TN Z6 and Iroquois Zone 2 indices during the months Dec through Feb, and TN Z4 200L index otherwise for Central New York; (c) Iroquois Waddington index for North Zone; (d) the minimum of TN Z6 and Iroquois Z2 indices for the Capital Zone; (e) the average of Iroquois Z2 index and the Tetco M3 index for Lower Hudson Valley; (f) Transco Zone 6 (NY) index for New York City, and (g) the Iroquois Z2 index for Long Island. A 6.9 percent tax rate is also included NYC.

# Real-Time Output and Marginal Units by Fuel

- Slide 22 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 23 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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# Emission by Region

- Slides 25-29 evaluate emissions from generators in the NYISO market.
  - ✓ Slide 25 shows the historical trend of annual total emissions since 2000 in the NYISO footprint for $CO_2$, $NO_X$, and $SO_2$ .
  - ✓ Slides 26-27 show quarterly emissions across the system by generation fuel type for $CO_2$ and $NO_X$ .
    - Emission values are given for 7 regions as well as the system as a whole.
    - The emission tonnage is given by aggregating the total pollution from operations on the various fossil fuel types for each month of the quarter.
    - The inset tables in each chart provides summary data on the total tonnage of emissions by fuel type for three recent quarters.
  - ✓ Slides 28-29 evaluate $NO_X$ emission during the quarter in the non-attainment areas in New York City and Long Island, respectively, on a daily basis.
    - The emission tonnage is shown separately for oil-fired units and gas-fired units in stacked bars, where gas-fired units are also grouped based on technology: (a) combined-cycle; (b) steam turbine; (c) gas turbines that were in service before 2000; and (d) gas turbines that were in service since 2000.
    - The line in slide 28 shows the emission from STs in NYC that were supplementally committed for local reliability as a percent of total emission in NYC.

# Ancillary Services Prices

- Slides 34-36 summarize day-ahead and real-time prices for six ancillary services products during the quarter:
  - ✓ 10-min spinning reserve prices eastern NY and Western NY;
  - ✓ 10-min non-spinning reserve prices in eastern NY;
  - ✓ Regulation prices, which reflect the cost of procurement, and the cost of moving generation of regulating units up and down.
    - – Resources were scheduled assuming a Regulation Movement Multiplier of 8 per MW of capability, but they are compensated according to actual movement.
    - – Real-time Regulation Movement Charges shown on Slide 35 are estimated by dividing total movement charges by real-time scheduled regulation capacity.
  - ✓ 30-min operating reserve prices in western NY and SENY.
- The number of shortage intervals in real-time for each ancillary service product are also shown.
  - ✓ A shortage occurs when a requirement cannot be satisfied at a marginal cost less than its "demand curve".
  - ✓ The highest demand curve values are currently set at $775/MW.



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# Day-Ahead NYCA 30-Minute Reserve Offers

- Slide 37 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).



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# Regulation Market Requirements and Prices

- Slide 38 displays several aspects pertaining to the regulation requirements, prices, and relationship between scheduled regulation capacity and actual regulation movement in the past 36-month period.
  - ✓ The top chart displays information relevant to the regulation requirement and the regulation movement-to-capacity ratio.
    - – The blue column bars show the average monthly regulation requirement.
    - – The secondary y-axis shows the average movement-to-capacity ratio.
  - ✓ The bottom chart shows the average monthly prices.
    - – The columns show the average monthly regulation capacity prices in the DAM.
    - – The two lines show the real-time capacity prices and movement prices.
- Regulation resources are scheduled assuming a common regulation movement multiplier of 8 per MW of capability, however, slide 39 shows a wide variation in actual movement-to-capacity ratio from one sample day.
  - ✓ The blue bars show the average scheduled regulation capacity in each movement-to-capacity ratio tranche.
  - ✓ The solid blue line represents the capacity weighted average actual movement-to-capacity ratio for the day, compared to the common multiplier of 8, indicated by the red dash line.

# Day-Ahead Load Scheduling and Virtual Trading

- Slide 41 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 42 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 43 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.





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# Efficiency of CTS Scheduling with PJM and NE

- Slide 45 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 46 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 47 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 48 shows these pricing and load forecasting differences by time of day.
  - ✓ The stacked bars in the lower portion of the figure show the frequency, direction, and magnitude of differences between RTC and RTD load forecast levels in tranches.
  - ✓ The upper portion of the figure summarizes the accuracy of the RTC price forecast by showing:
    - the average RTC LBMP minus the average RTD LBMP;  and
    - the mean absolute difference between the RTD and RTC LBMPs.

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

- Slide 49 evaluates real-time prices during commitments of gas turbines offering minimum run times greater than one hour in the quarter, focusing on economic commitments made by RTC, RTD, or RTD-CAM.
  - ✓ Self-schedule and out-of-market commitments are excluded from the analysis.
- The bars in the figure show the total number of equivalent hours (i.e., the total number of 5-minute RT intervals divided by 12) when GTs are economically committed in the quarter.
  - ✓ The blue bars indicate the number of hours when LBMPs exceeded GT costs (i.e., incremental cost + amortized startup cost).
  - ✓ The red bars represent the number of hours when LBMPs were below GT costs.
  - ✓ The black line shows our estimate of potential price impact if these GTs were allowed to set prices.
- GTs are combined into seven groups in New York City and Long Island based on their electric connection to the grid.



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# Virtual Imports and Exports in the Day-Ahead Market

- Slide 50 evaluates scheduled virtual imports and exports in the day-ahead market.
  - ✓ Virtual imports and exports are defined as external transactions that are scheduled in the day-ahead market but withdrawn from the real-market market (i.e., no RT bids submitted).
- The bottom portion of the chart shows the hourly average quantity of net virtual imports for each month.
  - ✓ The bars represent the average net virtual imports scheduled across the four primary interfaces between NYISO and neighboring control areas.
    - – Virtual imports and exports are rare across the Scheduled-Line interfaces, which are excluded from this analysis.
- The top portion of the chart shows the percentage of hours in each month when total net virtual imports across the four primary interfaces fall into the following ranges:
  - ✓ Less than 200 MW;
  - ✓ Between 200 and 500 MW;
  - ✓ Between 500 and 800 MW; and
  - ✓ More than 800 MW.



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# Real-Time System Price Maps at Generator Nodes

- Slides 52 and 53 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 54, 55, 56, and 57 evaluate the congestion patterns in the DAM and RTM and examine the following categories of resulting congestion costs:
  - ✓ Day-Ahead Congestion Revenues are collected by the NYISO when power is scheduled to flow across congested interfaces in the DAM, which is the primary funding source for TCC payments.
  - ✓ Day-Ahead Congestion Shortfalls occur when the net day-ahead congestion revenues are less than the payments to TCC holders.
    - – Shortfalls (or surpluses) arise when the TCCs on a path exceed (or is below) its DAM transfer capability in periods of congestion.
    - – These typically result from modeling differences between the TCC auction and the DAM, including assumptions related to PAR schedules, loop flows, and transmission outages.
  - ✓ Balancing Congestion Shortfalls arise when DAM scheduled flows over a constraint exceed what can flow over the constraint in the RTM.
    - – The transfer capability of a constraint falls (or rises) from day-ahead to real-time for the similar reasons (e.g., deratings and outages of transmission facilities, inconsistent assumptions regarding PAR schedules and loop flows, etc.).
    - – In addition, payments between the NYISO and PJM related to the M2M process also contribute to shortfalls (or surpluses).

# Transmission Congestion and Shortfalls (cont.)

- Slide 54 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 55 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 56 and 57 show the day-ahead and balancing congestion revenue shortfalls by transmission facility on a daily basis.
  - ✓ Negative values indicate day-ahead and balancing congestion surpluses.

# Transmission Congestion and Shortfalls (cont.)

- Congestion is evaluated along major transmission paths that include:
  - ✓ West Zone Lines: Primarily 230 kV transmission constraints in the West Zone.
  - ✓ West to Central: Including transmission constraints in the Central Zone and interfaces from West to Central.
  - ✓ North Zone: The Moses-South interface and other lines in the North Zone and leading into Southern New York.
  - ✓ Central to East: The Central-East interface and other lines transferring power from the Central Zone to Eastern New York.
  - ✓ Capital to Hudson Valley: Primarily lines leading into SENY (e.g., the New Scotland-Leeds line, the Leeds-Pleasant Valley line, etc.)
  - ✓ NYC Lines: Including lines into and within the NYC 345 kV system, lines leading into and within NYC load pockets, and groups of lines into NYC load pockets that are modeled as interface constraints.
  - ✓ Long Island: Lines leading into and within Long Island.
  - ✓ External Interfaces – Congestion related to the total transmission limits or ramp limits of the external interfaces.
  - ✓ All Other – All of other line constraints and interfaces.



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# NY-NJ PAR Operation Under M2M with PJM

- Slide 58 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 59 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.

# 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 60 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 61 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 63 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.

# Illustration of Duct Burner Range Example Generator Hourly Capability

- Slide 62 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 64-65 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 64): "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 67 and 68 summarize out-of-market commitment and dispatch, which are the primary sources of guarantee payment uplift.
- Slide 67 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 68 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 69 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.

# Uplift Costs from Guarantee Payments

- Slides 70 and 71 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 70 shows these seven categories on a daily basis during the quarter.
  - ✓ Slide 71 summarizes uplift costs by region on a monthly basis.

# Potential Economic and Physical Withholding

- Slides 73 and 74 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 75 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 77 and 78 summarize market results and key drivers in the monthly spot capacity auctions.
  - ✓ Slide 77 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 78 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.