# Quarterly Report on the New York ISO Electricity Markets Second Quarter of 2019


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August 2019

# Table of Contents







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# Market Highlights

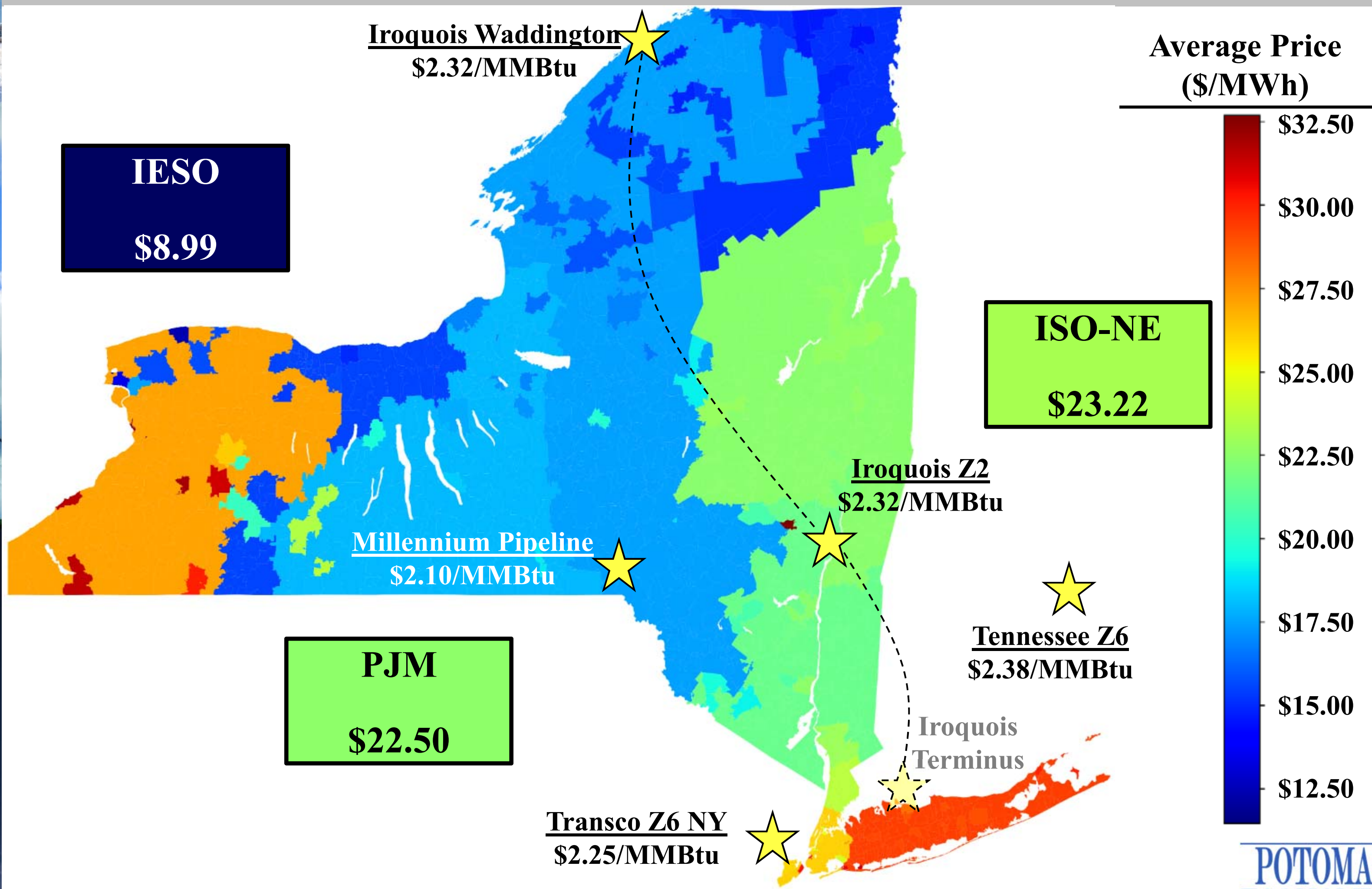
# Market Highlights:
## Executive Summary

- All-in prices fell 9 to 36 percent from the second quarter of 2018 due to lower LBMPs and lower capacity costs outside NYC. (see slide 7)
  - ✓ Energy costs fell by 11 to 34 percent in most regions because of lower natural gas prices and lower load levels.
    - Natural gas prices fell 17 to 29 percent from the previous year in Eastern NY.
    - The average load level was the lowest seen since 2008.
- Day-ahead congestion revenues rose 37 percent from the second quarter of 2018 despite lower gas price spreads and load levels. (see slides 8-9)
  - ✓ The largest increase occurred in the West Zone due to combined effects of: (a) modeling 115 kV constraints in the market software; (b) more costly transmission outages; (c) the return to operation of the South Ripley-Dunkirk 230 kV line on the PJM-NYCA border, which has increased the impact of loop flows; and (d) low Ontario spot prices leading to increased imports from Ontario.
  - ✓ Central East congestion increased primarily because of:
    - Increased exports to New England from eastern NY (up ~400 MW); and
    - More transmission outages leading to reduced transfer capability in April and May.

# Market Highlights:
## Executive Summary

- West Zone constraints were hard to manage despite recent modeling enhancements
  - ✓ These constraints accounted for most of the Alert State Declarations during the quarter.
  - ✓ The NYISO frequently had to reduce "BMS" scheduling limits on 115 and 230 kV facilities in the West Zone to keep "EMS" flows below the physical limits.
  - ✓ Large differences between BMS (i.e., modeled) flows and EMS (i.e., physical) flows were:
    - Primarily driven by the modeling assumptions related to Lake Erie loop flows,
    - Modeling assumptions regarding PAR-controlled lines and Niagara generation also contributed to EMS/BMS differences. (see slides 11-12)
- The NYISO has greatly reduced the use of OOM actions to manage low-voltage transmission constraints by modeling most 115kV constraints in the DA and RT market models. (see slide 10)
- OOM commitments were frequently needed to maintain adequate operating reserves in NYC load pockets. (see slide 13)
  - ✓ Reflecting operating reserve requirements in the day-ahead and real-time markets would provide better incentives to suppliers and investors. (NYISO will discuss with stakeholders as part of the "More Granular…" project.)

# Market Highlights:
# Energy Market Outcomes and Congestion



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# Market Highlights:
## Summary of Energy Market Outcomes

- NYISO energy markets performed competitively in the second quarter of 2019.
  - ✓ Variations in regional wholesale prices were driven primarily by changes in fuel prices, demand, and supply availability.
  - ✓ The amount of output gap (slide 54) and unoffered economic capacity (slide 55) remained modest and reasonably consistent with competitive market expectations.
- Average all-in prices fell in all areas and ranged from $20/MWh in the North Zone to $55/MWh in New York City, down 9 to 36 percent from a year ago. (slide 17)
  - ✓ Energy prices fell in most areas by 11 to 34 percent. (slides 22-23)
    - – Average natural gas prices fell between 17 and 29 percent from a year ago in Eastern NY (slide 19) partly due to higher storage levels.
    - – Load levels fell to the lowest quarterly average since 2008. Average load was down 4.8 percent from a year ago, and peak load fell 3.5 percent (slide 18).
    - – However, energy prices in the North Zone rose slightly because of reduced congestion between the North Zone and central New York.
  - ✓ Capacity costs rose by 4 percent in New York City but fell 14 to 54 percent in other regions for the reasons discussed in slide 15.
- Regulation costs increased due to price spikes in mid-April when large amounts of regulation-capable capacity was on planned outage. (see slides 27 & 30)

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

- Day-ahead congestion revenues totaled $116 million, up 37 percent from the second quarter of 2018. (slide 38)
  - ✓ Most of the increase occurred in the West Zone and on Central-East. (slide 39)
- The West Zone lines accounted for the largest share of congestion (36 percent in DA, 37 percent in RT) in the second quarter of 2019 (slide 39).
  - ✓ High levels of congestion across the West Zone are driven by:
    - – The low marginal cost of renewable generation at Niagara and in Ontario; and
    - – Volatile loop flows around Lake Erie can shift quickly in the clockwise direction.
  - ✓ Priced congestion across the West Zone rose from the previous year because:
    1. 115 kV constraints were previously managed using OOM actions and surrogate transmission constraints, but most of these constraints have been incorporated into the DA and RT markets since December 2018.
       - 115 kV constraints accounted for most of priced congestion in the West Zone (70 percent in DA and 63 percent in RT).
       - Accordingly, OOM actions to manage West Zone congestion fell dramatically (slide 43), which has improved scheduling efficiency and reduced overall costs to manage congestion in this area.




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

2. The South Ripley-to-Dunkirk 230 kV line (which was normally “open” in the past) was “closed” in April 2019, after which it flowed an average of 176 MW from the West Zone to PJM, increasing congestion across the West Zone.
3. Ontario pool prices fell 52 percent, increasing the availability of imports to NY.
4. More costly transmission outages, which contributed to $19 million of day-ahead congestion shortfalls. (slide 40) Much of West Zone congestion occurred in May and June during extended transmission outages on the 115 and 230 kV-system.

- Central-East congestion rose despite lower loads (slide 18) and smaller gas price spreads between West NY and East NY (slide 19). The increase reflected:
  - ✓ More costly transmission outages which led to $6 million of day-ahead congestion shortfalls (slide 40) compared to only $2 million in 2018-Q2.
  - ✓ Higher exports to ISO-NE, which rose more than 400 MW on average (slide 35).
- However, congestion from the North Zone to central NY fell 85 percent (slide 39). This reduction resulted primarily from:
  - ✓ Fewer costly transmission outages, resulting in less than $2 million of day-ahead congestion shortfalls (slide 40), down from $13 million in 2018-Q2.
  - ✓ A lower CRM on modeled 115 kV lines (10 MW vs 20 MW previously). This has reduced the frequency of unnecessarily high congestion in this area.

# Market Highlights:
## OOM Actions to Manage Congestion

- The NYISO has greatly reduced the use of OOM actions over the last year to manage low-voltage transmission constraints by modeling most 115kV constraints in the DA and RT market models.
- OOM actions to manage lower-voltage network congestion were most frequent in Capital Zone (46 days), West Zone (26 days), and Long Island (19 days). (slide 43)
  - ✓ In the Capital Zone, Bethlehem units were frequently dispatched down to manage nearby 115kV constraints prior to the completion of transmission upgrades.
  - ✓ In the West Zone, OOM actions were used to manage Gardenville-to-Dunkirk constraints in April and Erie-to-Gardenville constraints in late-May and early-June.
  - ✓ On Long Island, OOM actions to manage 69 kV constraints were most frequent in the Valley Stream load pocket this quarter. (slide 44)
- Although Ontario imports were limited on only four days to manage unmodeled transmission constraints, the NYISO limited Ontario imports on an additional 12 days to help manage constraints on facilities that are modeled in the DAM & RTM.
  - ✓ An “operating exception” allows the Niagara 230kV exit facilities to be operated to STE (instead of LTE) when there is sufficient generation on at Niagara to clear the overload.
  - ✓ Thus, reducing Ontario imports ensured the operating exception could be utilized, although verbal instructions to Niagara would have been more direct.

# Market Highlights:
## West Zone Congestion Management

- West Zone constraints were hard to manage despite recent modeling enhancements
  - ✓ The closure of the South Ripley-to-Dunkirk line has increased flows significantly across the West Zone, particularly during periods with high clockwise loop flow.
  - ✓ The sum of Niagara generation plus Ontario imports increased by a total of 96 GWh from the second quarter of the previous year.
  - ✓ Thermal rating exceedance on facilities connected to the Niagara 230 kV bus accounted for 62 percent of the NYISO's Alert State Declarations in Q2.
    - NYISO increased the CRM on the Niagara-Packard 230 kV lines and the Niagara-Robinson Rd 230 kV line from 20 MW to 40 MW in June and to 60 MW in late July to assist in managing the constraints.
- When physical (i.e., EMS) flows exceed flows considered by the scheduling models (i.e., BMS flows) by a significant margin, the NYISO reduces scheduling (i.e., BMS) limits to ensure flows remain at acceptable levels. The West Zone accounted for the most significant reductions in BMS limits. (slide 47)
  - ✓ The most significant EMS/BMS differences in the West Zone were driven by the cap on clockwise changes in circulation of 75 MW per RTD interval, which prevented RTD from reducing flows sufficiently after sudden changes in loop flow.
    - This cap was increased to 125 MW in June and 200 MW in July.

# Market Highlights:
## West Zone Congestion Management (cont.)

- ✓ The following factors also contributed to EMS/BMS differences:
  - PAR-modeling assumptions, which reduce the accuracy of estimated flow impacts from external transactions, generation, and PAR tap adjustments in the BMS.
    - The NYISO is considering whether to relocate the proxy bus for Ontario.
      - This could be done to reflect that Ontario imports tend to increase unscheduled power flows in the clockwise direction around Lake Erie.
    - The Saint Lawrence PAR can be used to reduce congestion in the West Zone (by diverting a portion of Ontario imports to northern NY) but the PAR is generally less flexible than assumed by RTD.
      - In August, the NYISO reduced the optimization range used by RTD to be more consistent with the anticipated operation of the PAR.
  - The Niagara generator is not required to follow optimized generation distributions at the sub-plant level.
    - However, Niagara responds to verbal requests (800+ hours in Q2) to redistribute output, thereby limiting EMS/BMS differences.
    - Furthermore, PAR-modeling assumptions may lead the BMS to over-estimate the effectiveness of redistributing output at the sub-plant level.
    - Nonetheless, it may be beneficial to reduce the optimization range used by RTD to be more consistent with anticipated performance of the plant.

# Market Highlights:

## Reliability Commitments, OOM Dispatch, and BPCG

- BPCG payments totaled $11.3 million, up modestly by 7 percent from the second quarter of 2018 (slides 51-52).
- Roughly $7 million (or 63 percent) of BPCG payments accrued in NYC. (slide 52)
  - ✓ About $6 million was paid to units that were committed for local reliability needs.
  - ✓ We have recommended that the NYISO satisfy the reliability needs that drive these out-of-market costs with local reserve requirements in the DA & RT markets.
    - The NYISO began to model reserve requirements for the NYC Zone in the DA and RT markets on June 26, 2019. This is an important step to reduce supplemental reliability commitments and to improve the efficiency of scheduling and pricing.
    - We continue to advocate for modeling more reserve requirements in the sub-pockets of NYC.
- Long Island BPCG payments were about $1.7 million this quarter, up 65 percent from a year ago. (slide 52)
  - ✓ Most of this uplift was incurred to manage reliability and congestion on the 69 kV network. (slides 44, 50)
  - ✓ We have recommended that the NYISO model the 69-kV system on Long Island to provide better price signals for commitment and investment. (slide 44 )

# Market Highlights:
## Use of Operating Reserves to Manage NYC Congestion

- Transmission facilities in New York City can be operated above their Long-Term Emergency ("LTE") rating if post-contingency actions (e.g., deployment of operating reserves) are available to quickly reduce flows to LTE.
  - ✓ The availability of post-contingency actions is important because they allow the NYISO to increase flows into load centers in NYC and reduce congestion costs.
- In 2019-Q2, 58 percent of the RT congestion in NYC occurred on N-1 constraints that would have been loaded above LTE after a single contingency. (slide 45)
  - ✓ The additional capability above LTE averaged from about 10 to 65 MW for the 138 kV constraints in the Greenwood load pocket to roughly 220 to 330 MW for 345 kV facilities in other NYC load pockets.
    - – These increases were largely due to operating reserve providers in NYC.
      - Reserve providers are not compensated for this service, which reduces their incentives to be available in the short term and to invest in flexible resources in the long term.
    - – In addition, when the market dispatches this reserve capacity, it can reduce the transfer capability in NYC.
- We have recommended that the NYISO efficiently schedule and compensate operating reserve units that can help satisfy transmission security criteria. (see Recommendation #2016-1 in our 2018 SOM report)

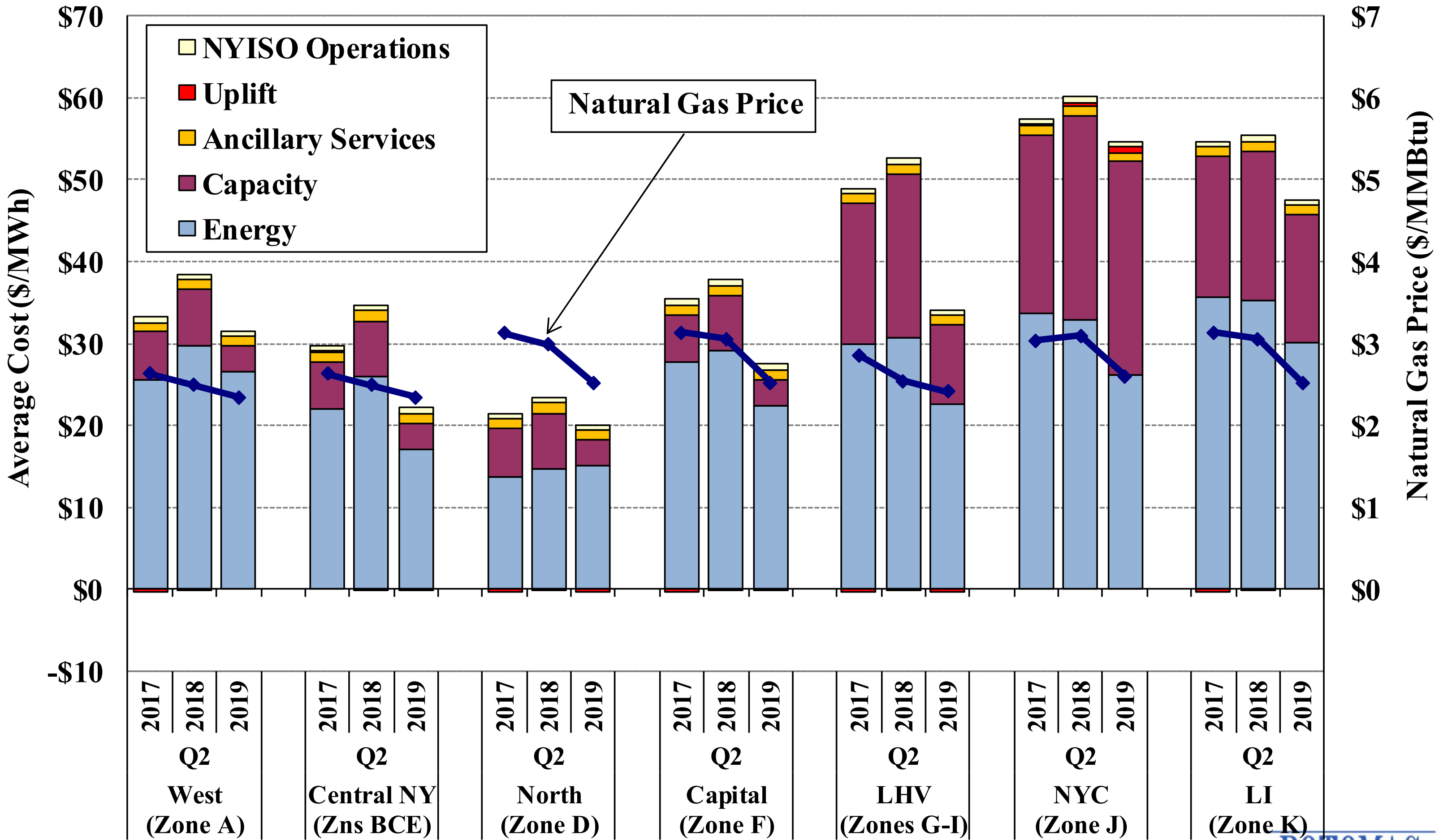
# Market Highlights:
## Capacity Market

- Average spot capacity prices ranged from $1.07/kW-month in ROS to $9.72/kW-month in New York City in the second quarter of 2019. (slides 58-59)
- Compared to a year ago, average spot prices fell 56 percent in ROS, 55 percent in the G-J Locality, and 14 percent in Long Island; however, NYC spot prices rose 9 percent.
  - ✓ Demand-side drivers of capacity prices changes include[1]:
    - Peak load forecasts fell in all regions except for NYC, where an increase in the load forecast increased the overall requirement by 0.6 percent.
    - LCRs increased in NYC (2.3 percent) and Long Island (0.6 percent) but decreased in the G-J Locality (2.2 percent) and NYCA (1.2 percent).
  - ✓ On the supply side:
    - Up-rates and other DMNC changes increased capacity NYCA-wide by 270 MW.
    - Several units were placed in IIFO ("ICAP Ineligible Forced Outage"), including Gilboa 1, Milliken 2, and Hudson Ave GT4, which collectively reduced the internal supply by roughly 450 MW.
    - New generation entered including two Bayonne CTG units (9&10) and Arthur Kill Cogen, adding 142 MW of supply in NYC.

[1]Administrative parameters refer to changes that impact the Summer 2019 months, i.e., May and June.

# Charts:
## Market Outcomes

# All-In Prices by Region








Notes: For chart description, see slide 61.

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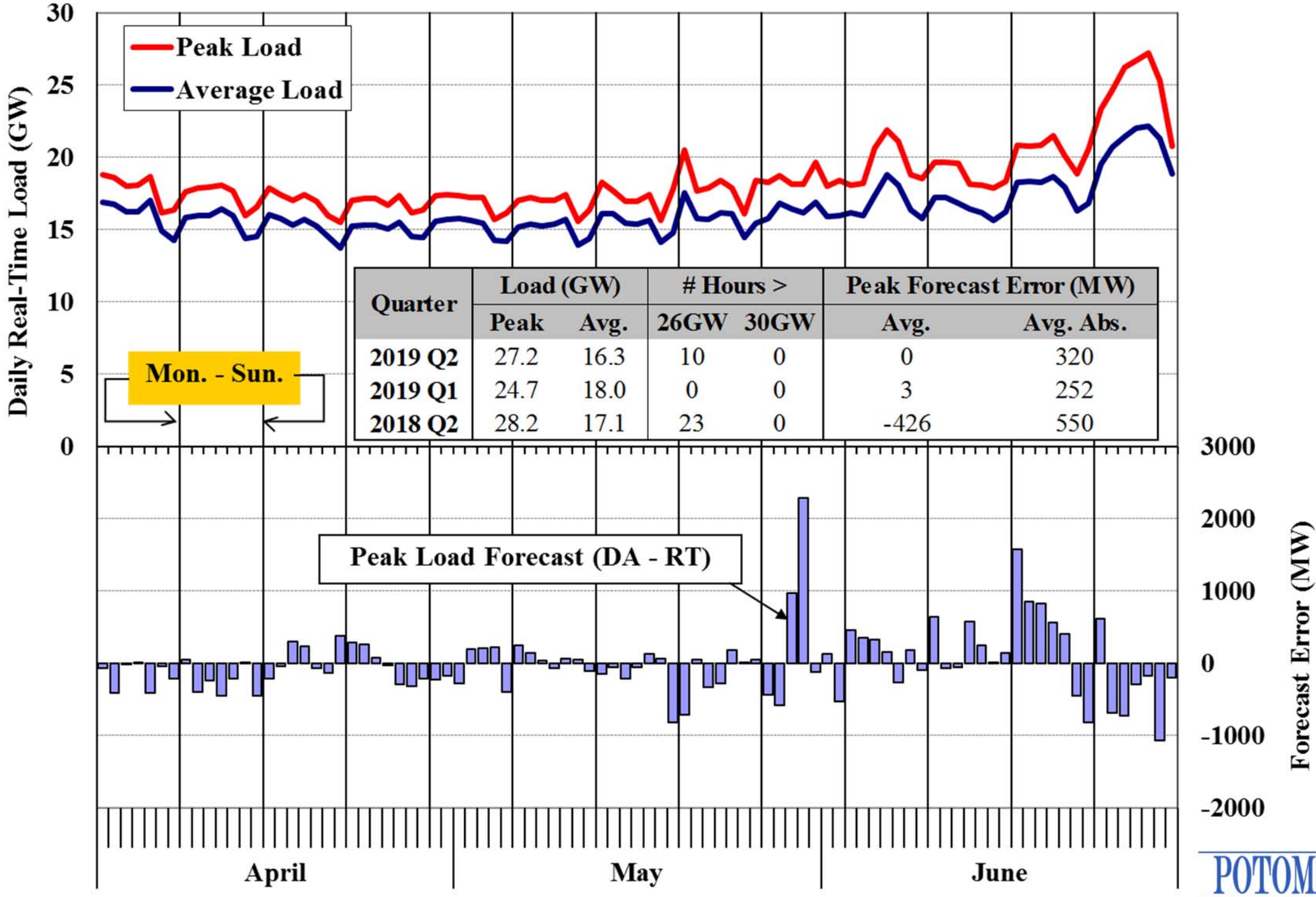
# Load Forecast and Actual Load




| Quarter | Load (GW) Peak | Load (GW) Avg. | # Hours > 26GW | # Hours > 30GW | Peak Forecast Error (MW) Avg. | Peak Forecast Error (MW) Avg. Abs. |
|---|---|---|---|---|---|---|
| 2019 Q2 | 27.2 | 16.3 | 10 | 0 | 0 | 320 |
| 2019 Q1 | 24.7 | 18.0 | 0 | 0 | 3 | 252 |
| 2018 Q2 | 28.2 | 17.1 | 23 | 0 | -426 | 550 |



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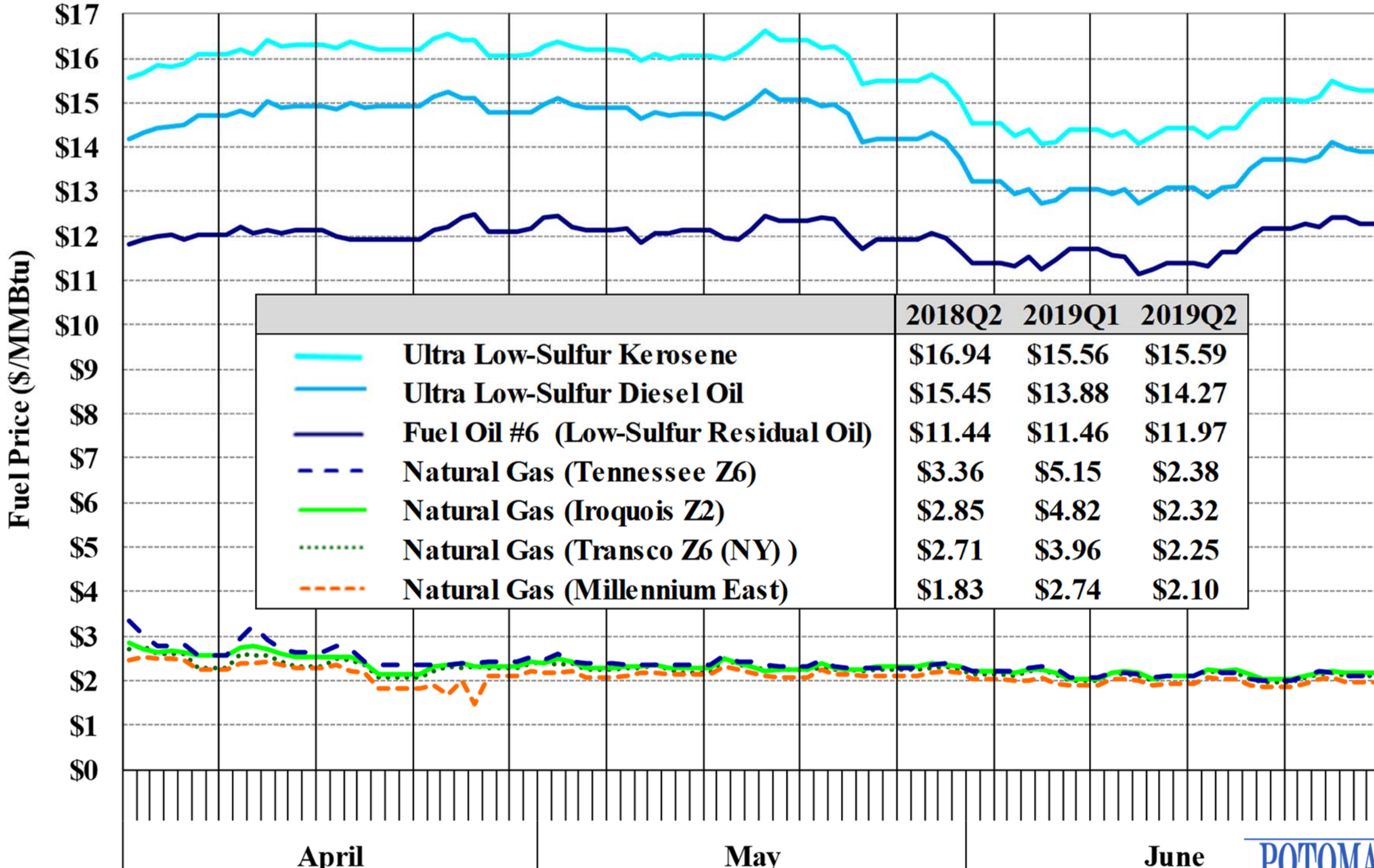
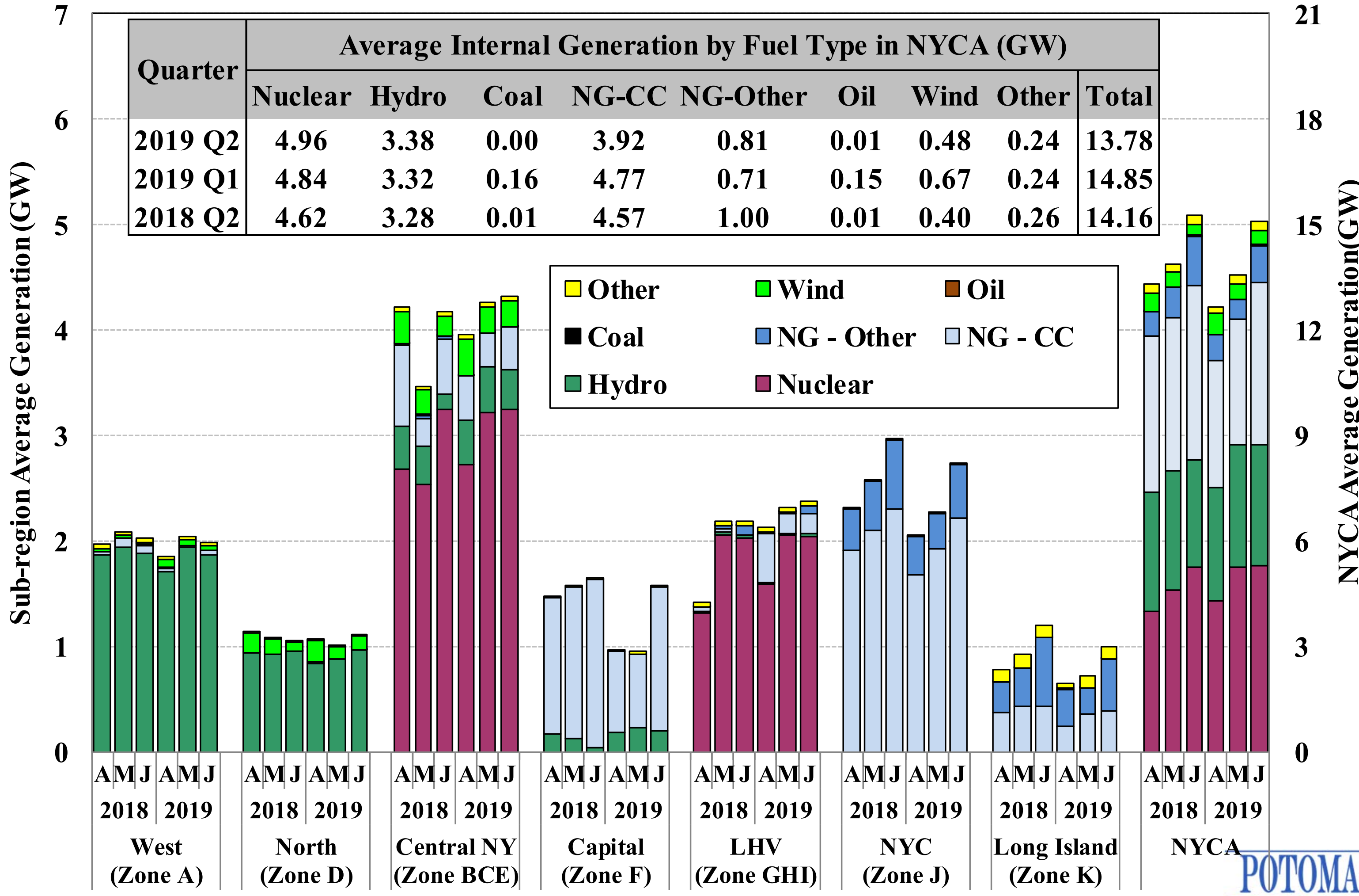
# Natural Gas and Fuel Oil Prices



# Real-Time Generation Output by Fuel Type

| Quarter | Average Internal Generation by Fuel Type in NYCA (GW) | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| | Nuclear | Hydro | Coal | NG-CC | NG-Other | Oil | Wind | Other | Total |
| 2019 Q2 | 4.96 | 3.38 | 0.00 | 3.92 | 0.81 | 0.01 | 0.48 | 0.24 | 13.78 |
| 2019 Q1 | 4.84 | 3.32 | 0.16 | 4.77 | 0.71 | 0.15 | 0.67 | 0.24 | 14.85 |
| 2018 Q2 | 4.62 | 3.28 | 0.01 | 4.57 | 1.00 | 0.01 | 0.40 | 0.26 | 14.16 |








Notes: For chart description, see slide 62.

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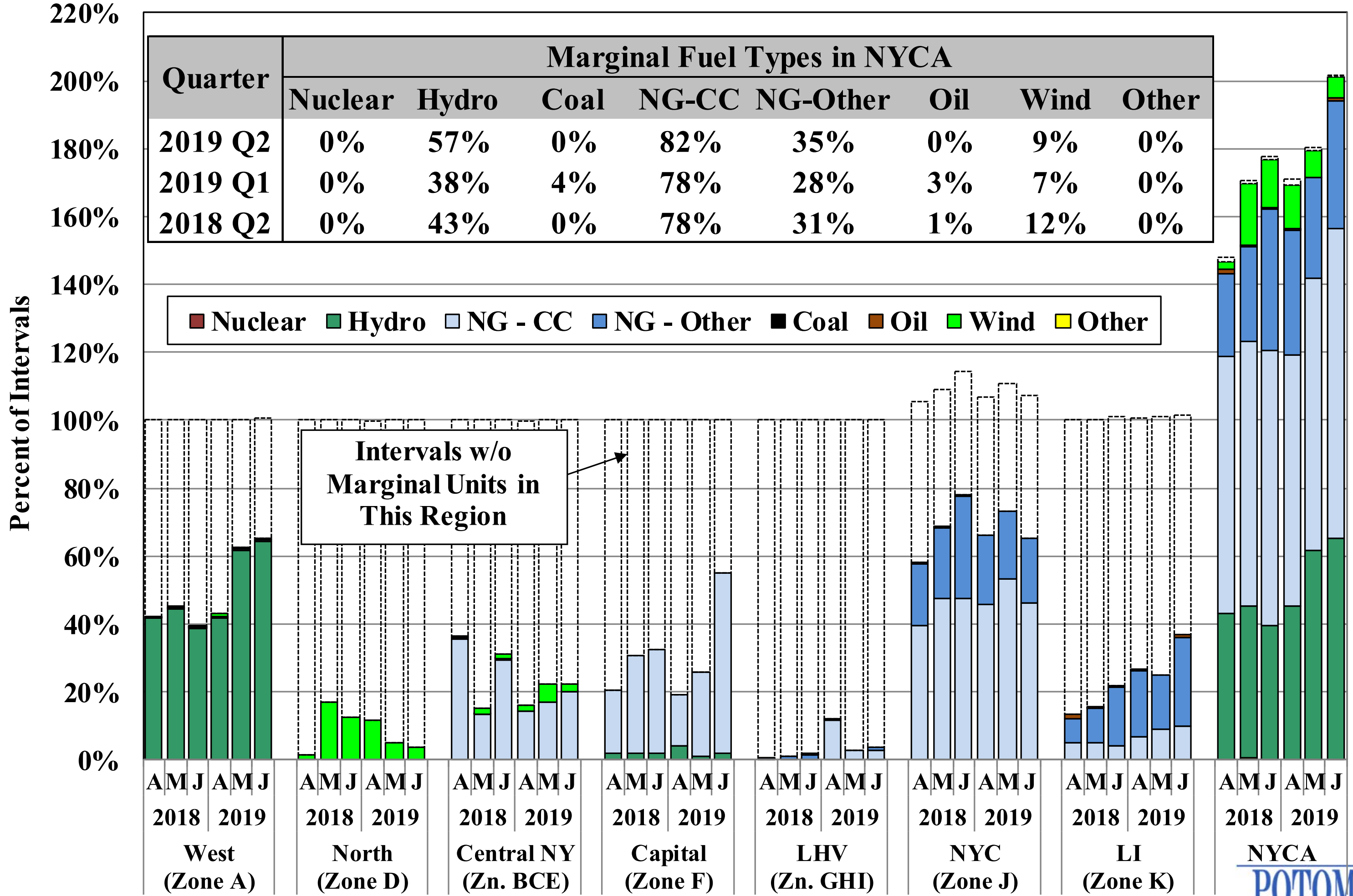
# Fuel Type of Marginal Units in the Real-Time Market




| Quarter | Marginal Fuel Types in NYCA | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| | Nuclear | Hydro | Coal | NG-CC | NG-Other | Oil | Wind | Other |
| 2019 Q2 | 0% | 57% | 0% | 82% | 35% | 0% | 9% | 0% |
| 2019 Q1 | 0% | 38% | 4% | 78% | 28% | 3% | 7% | 0% |
| 2018 Q2 | 0% | 43% | 0% | 78% | 31% | 1% | 12% | 0% |





Notes: For chart description, see slide 62.

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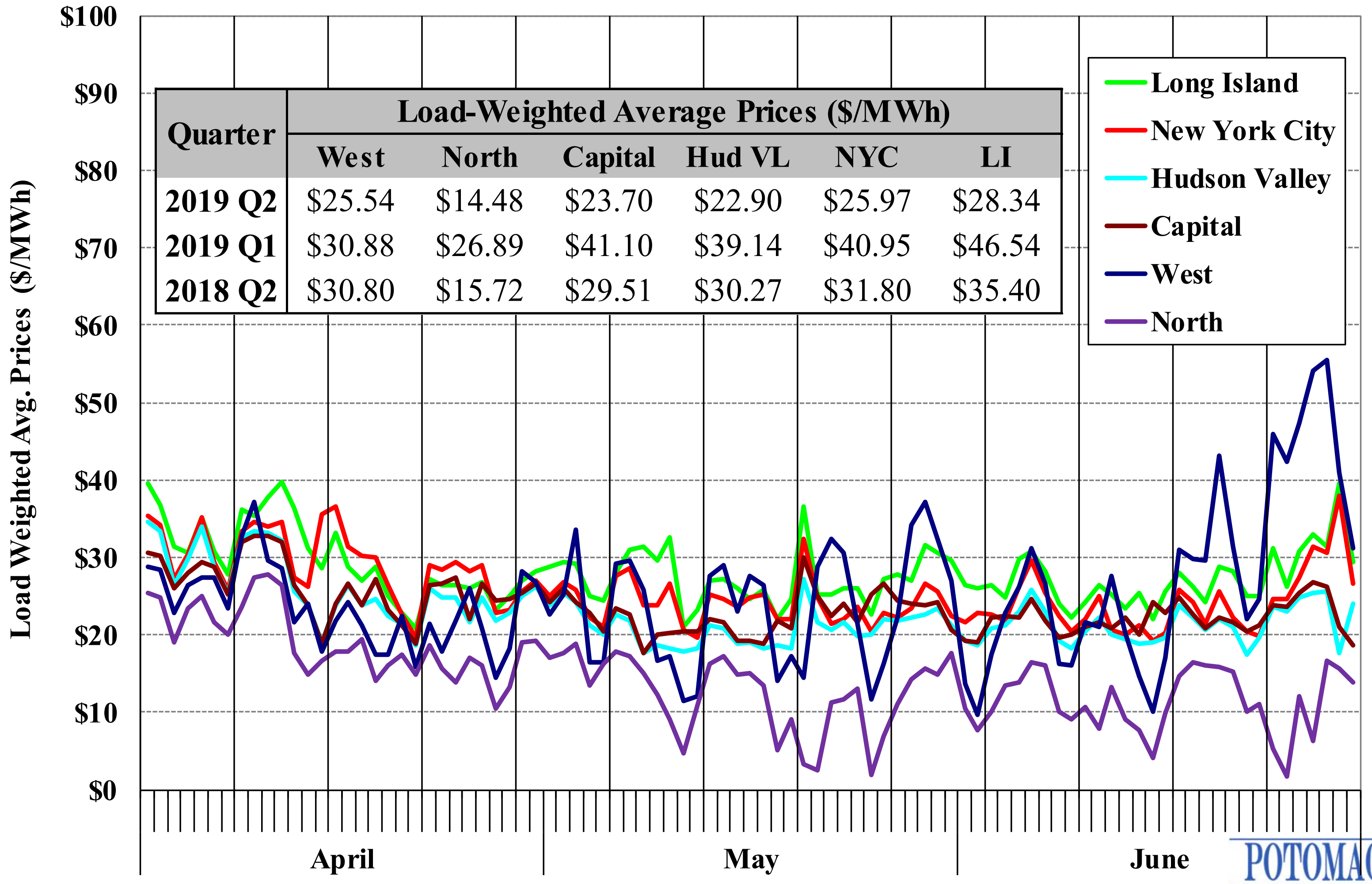
# Day-Ahead Electricity Prices by Zone




| Quarter | Load-Weighted Average Prices ($/MWh) | | | | | |
|---|---|---|---|---|---|---|
| | West | North | Capital | Hud VL | NYC | LI |
| 2019 Q2 | $25.54 | $14.48 | $23.70 | $22.90 | $25.97 | $28.34 |
| 2019 Q1 | $30.88 | $26.89 | $41.10 | $39.14 | $40.95 | $46.54 |
| 2018 Q2 | $30.80 | $15.72 | $29.51 | $30.27 | $31.80 | $35.40 |

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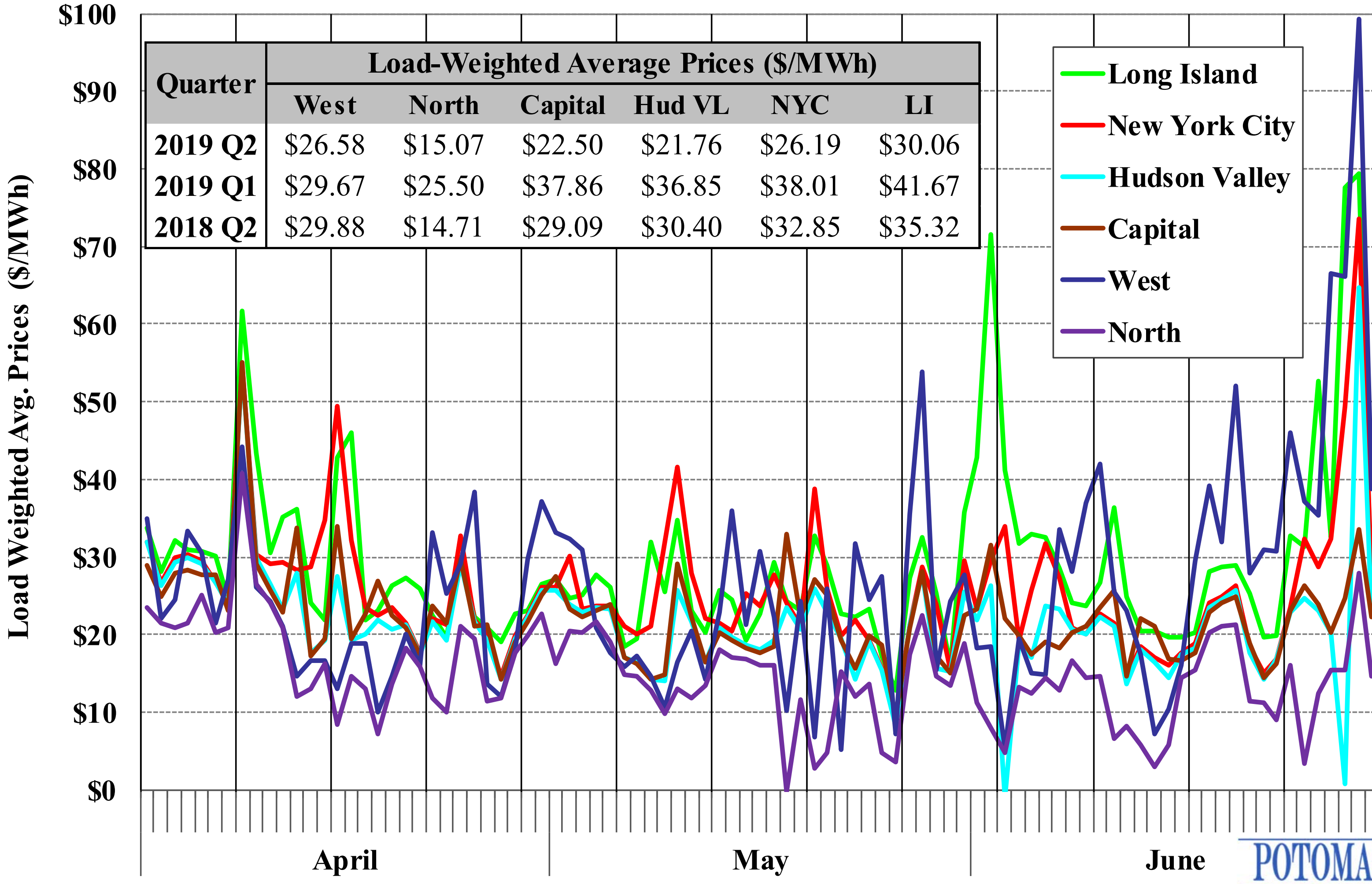
# Real-Time Electricity Prices by Zone




| Quarter | Load-Weighted Average Prices ($/MWh) | | | | | |
|---|---|---|---|---|---|---|
| | West | North | Capital | Hud VL | NYC | LI |
| 2019 Q2 | $26.58 | $15.07 | $22.50 | $21.76 | $26.19 | $30.06 |
| 2019 Q1 | $29.67 | $25.50 | $37.86 | $36.85 | $38.01 | $41.67 |
| 2018 Q2 | $29.88 | $14.71 | $29.09 | $30.40 | $32.85 | $35.32 |



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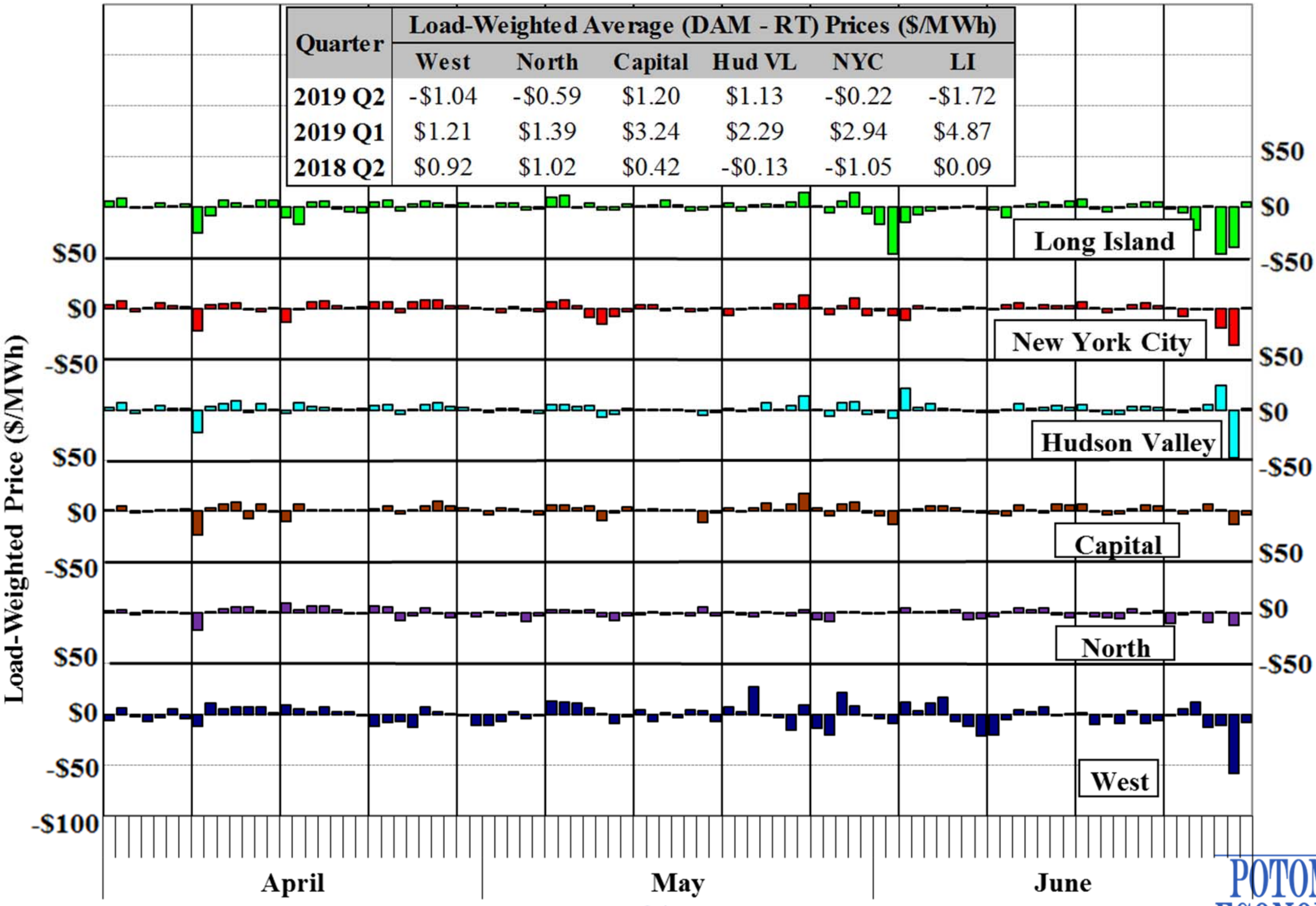
# Convergence Between Day-Ahead and Real-Time Prices




| Quarter | Load-Weighted Average (DAM - RT) Prices ($/MWh) | | | | | |
|---|---|---|---|---|---|---|
| | West | North | Capital | Hud VL | NYC | LI |
| 2019 Q2 | -$1.04 | -$0.59 | $1.20 | $1.13 | -$0.22 | -$1.72 |
| 2019 Q1 | $1.21 | $1.39 | $3.24 | $2.29 | $2.94 | $4.87 |
| 2018 Q2 | $0.92 | $1.02 | $0.42 | -$0.13 | -$1.05 | $0.09 |

# Charts:

## Ancillary Services Market

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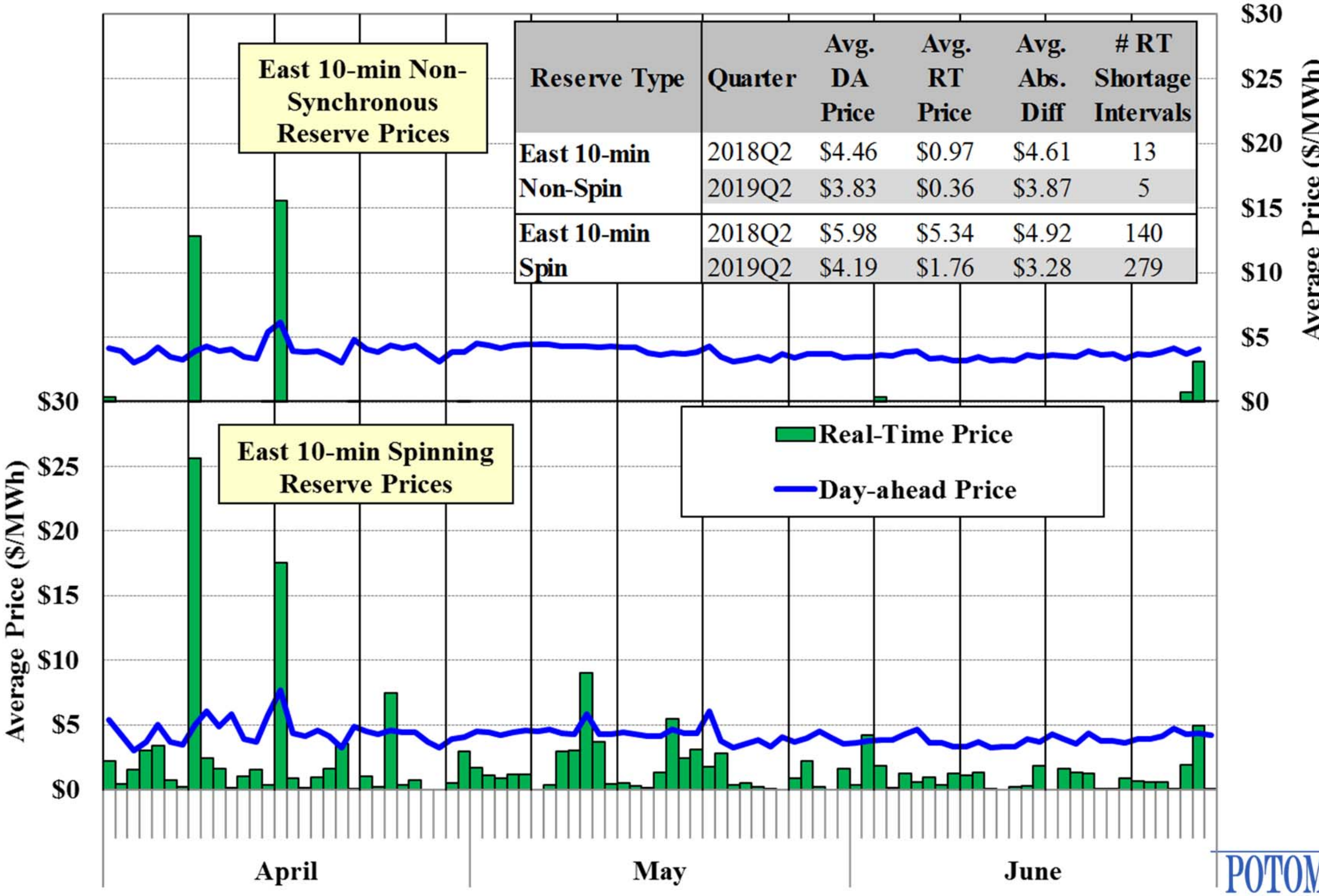
# Day-Ahead and Real-Time Ancillary Services Prices
## Eastern 10-Minute Spinning and Non-Spinning Reserves




| Reserve Type | Quarter | Avg. DA Price | Avg. RT Price | Avg. Abs. Diff | # RT Shortage Intervals |
|---|---|---|---|---|---|
| East 10-min Non-Spin | 2018Q2 | $4.46 | $0.97 | $4.61 | 13 |
| | 2019Q2 | $3.83 | $0.36 | $3.87 | 5 |
| East 10-min Spin | 2018Q2 | $5.98 | $5.34 | $4.92 | 140 |
| | 2019Q2 | $4.19 | $1.76 | $3.28 | 279 |





Notes: For chart description, see slide 63.

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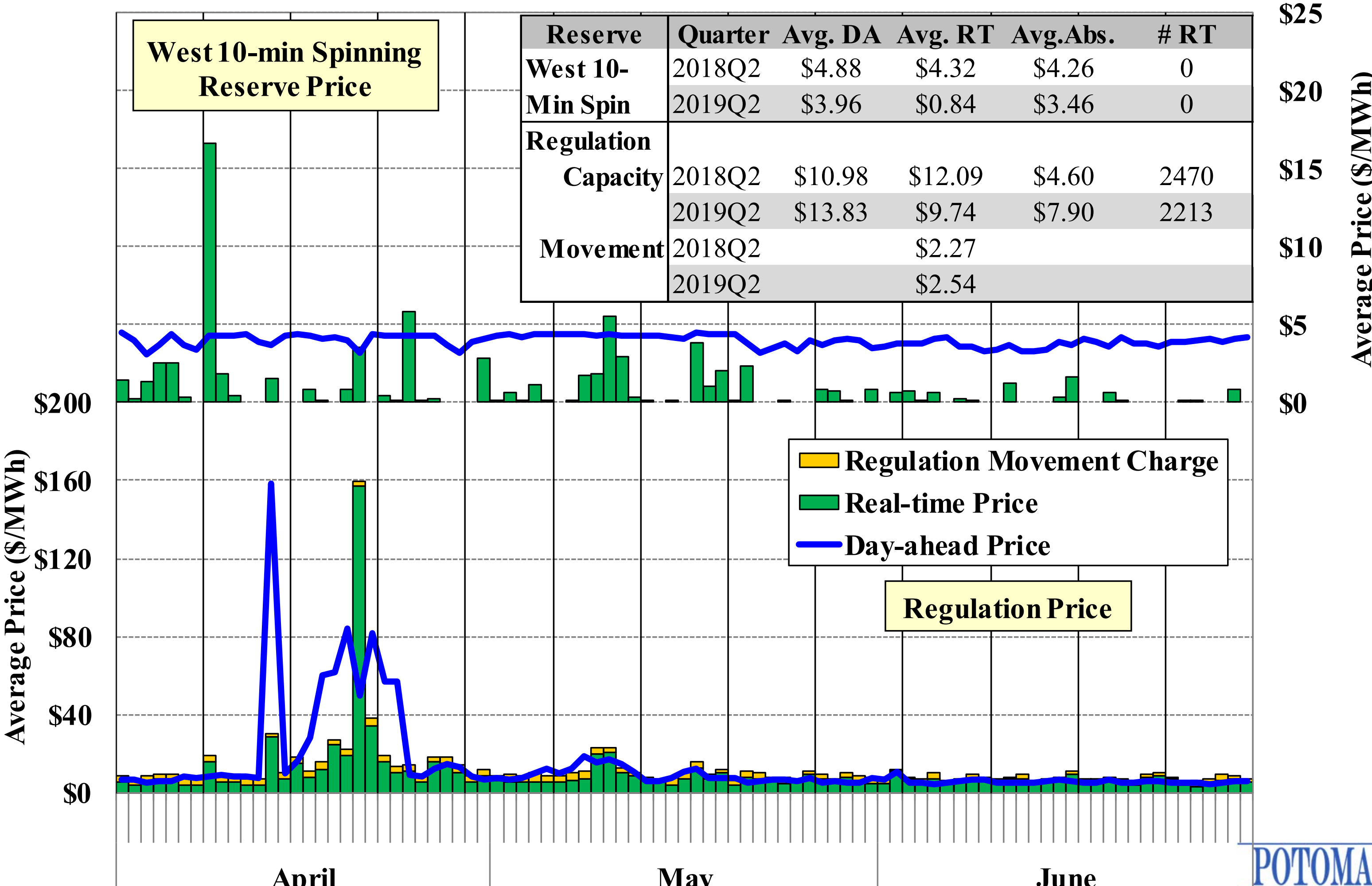
# Day-Ahead and Real-Time Ancillary Services Prices
## Western 10-Minute Spinning Reserves and Regulation

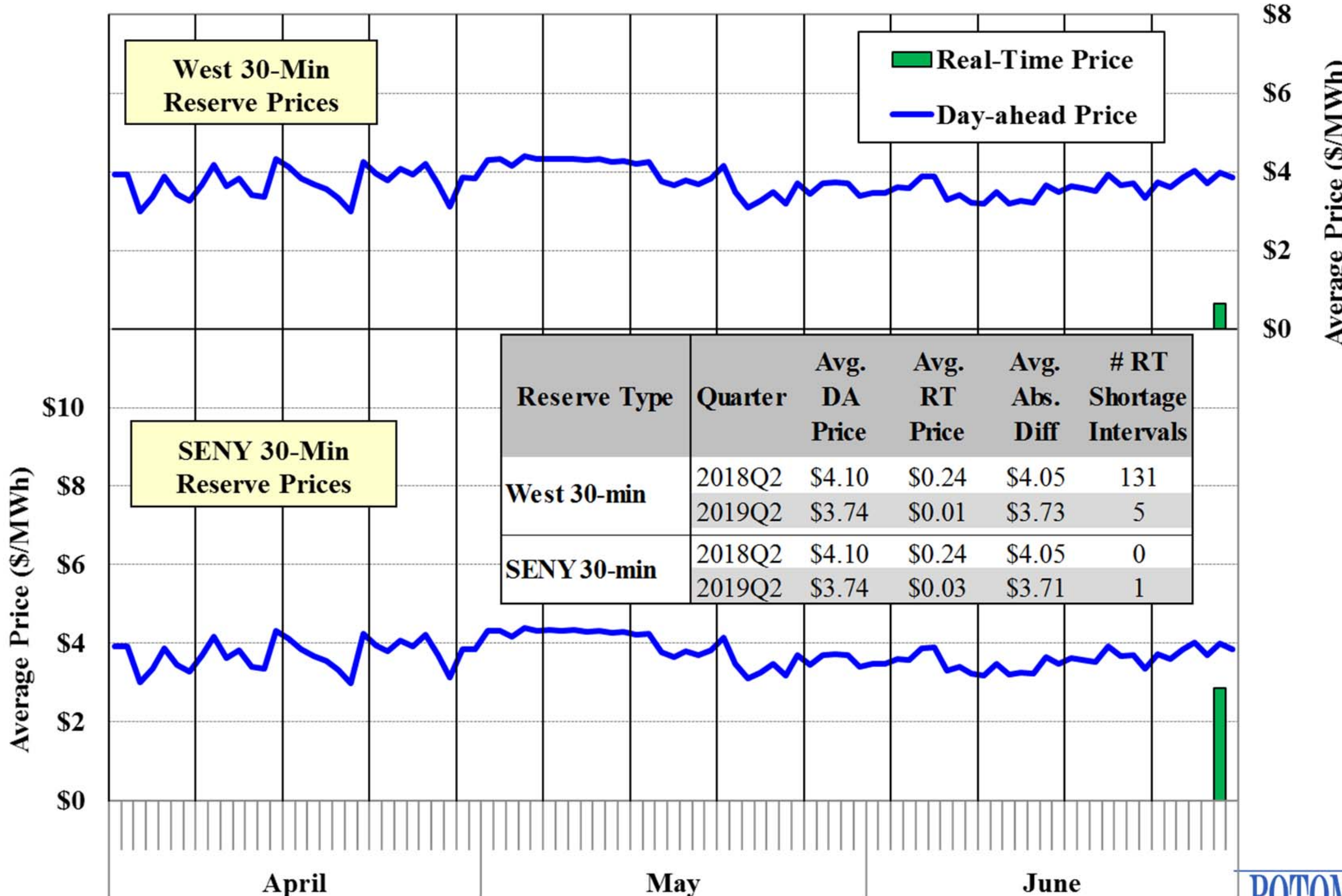



| Reserve | Quarter | Avg. DA | Avg. RT | Avg.Abs. | # RT |
|---|---|---|---|---|---|
| West 10-Min Spin | 2018Q2 | $4.88 | $4.32 | $4.26 | 0 |
| | 2019Q2 | $3.96 | $0.84 | $3.46 | 0 |
| Regulation Capacity | 2018Q2 | $10.98 | $12.09 | $4.60 | 2470 |
| | 2019Q2 | $13.83 | $9.74 | $7.90 | 2213 |
| Movement | 2018Q2 | | $2.27 | | |
| | 2019Q2 | | $2.54 | | |

Notes: For chart description, see slide 63.

# Day-Ahead and Real-Time Ancillary Services Prices

## Western and SENY 30-Minute Reserves

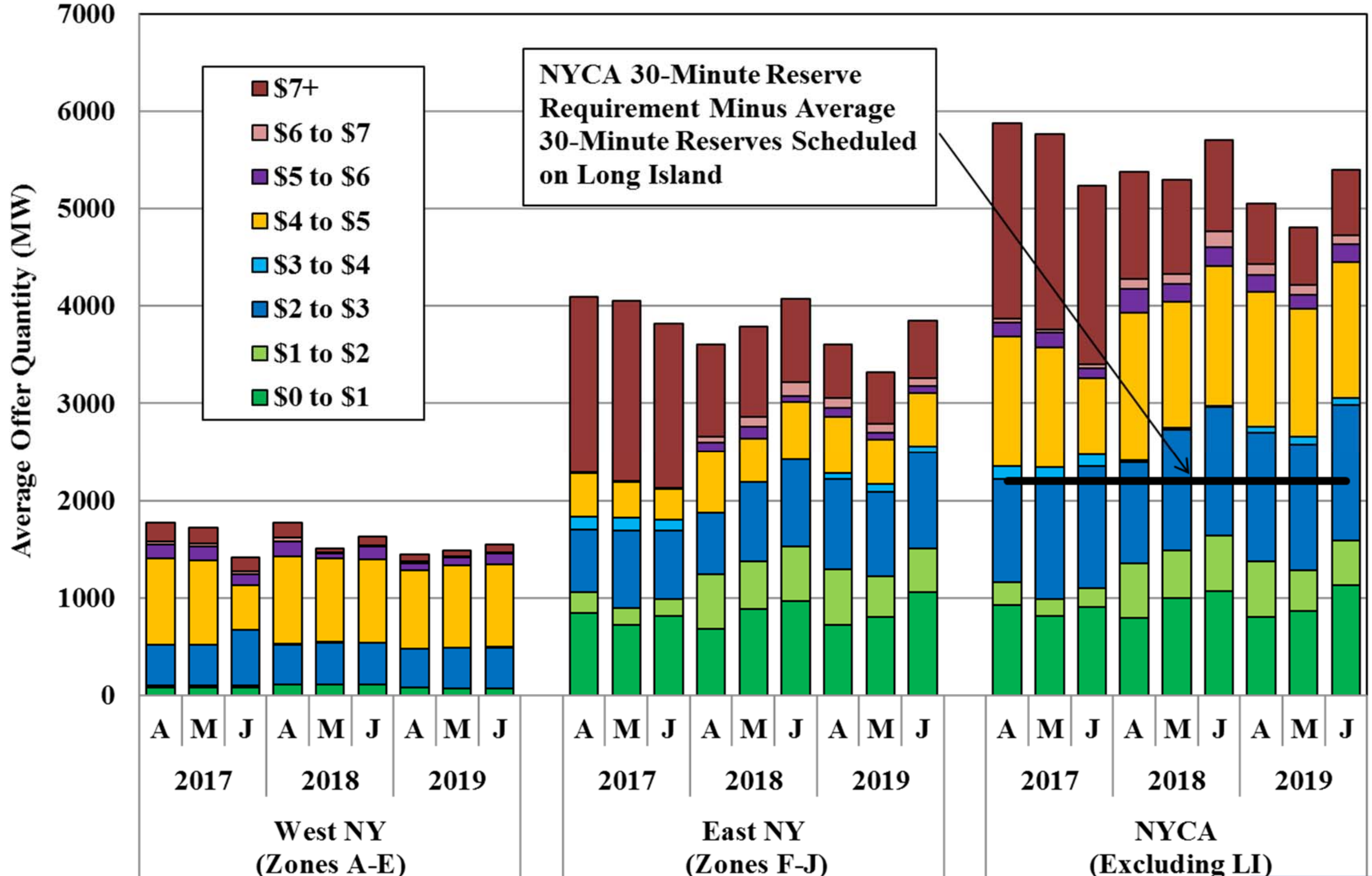



| Reserve Type | Quarter | Avg. DA Price | Avg. RT Price | Avg. Abs. Diff | # RT Shortage Intervals |
|---|---|---|---|---|---|
| West 30-min | 2018Q2 | $4.10 | $0.24 | $4.05 | 131 |
| | 2019Q2 | $3.74 | $0.01 | $3.73 | 5 |
| SENY 30-min | 2018Q2 | $4.10 | $0.24 | $4.05 | 0 |
| | 2019Q2 | $3.74 | $0.03 | $3.71 | 1 |




Notes: For chart description, see slide 63.

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




  Notes: For chart description, see slide 64.

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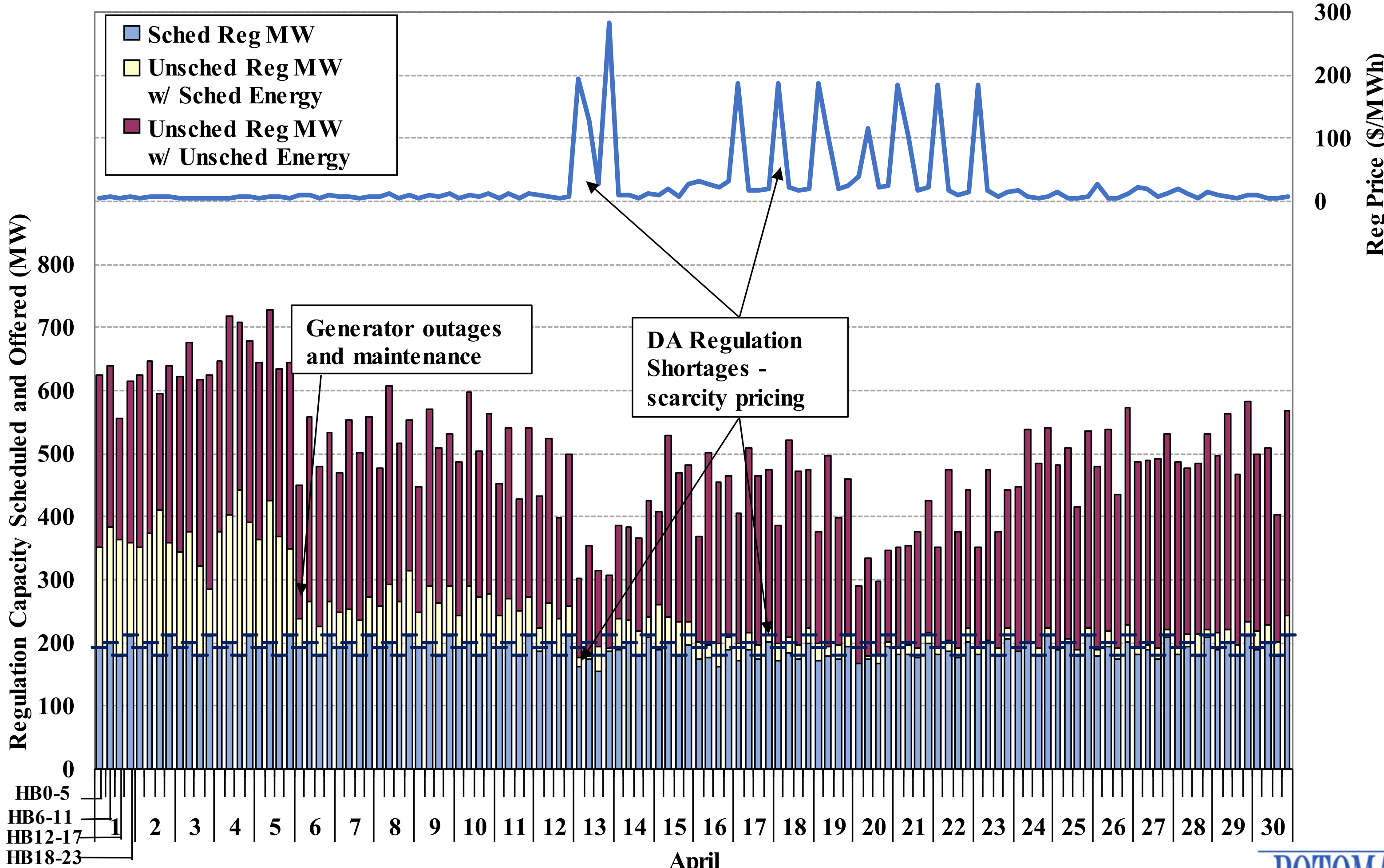
# DA Regulation Capacity Offers & Schedules
# April 2019








Notes: For chart description, see slide 65.

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# Charts:
## Energy Market Scheduling

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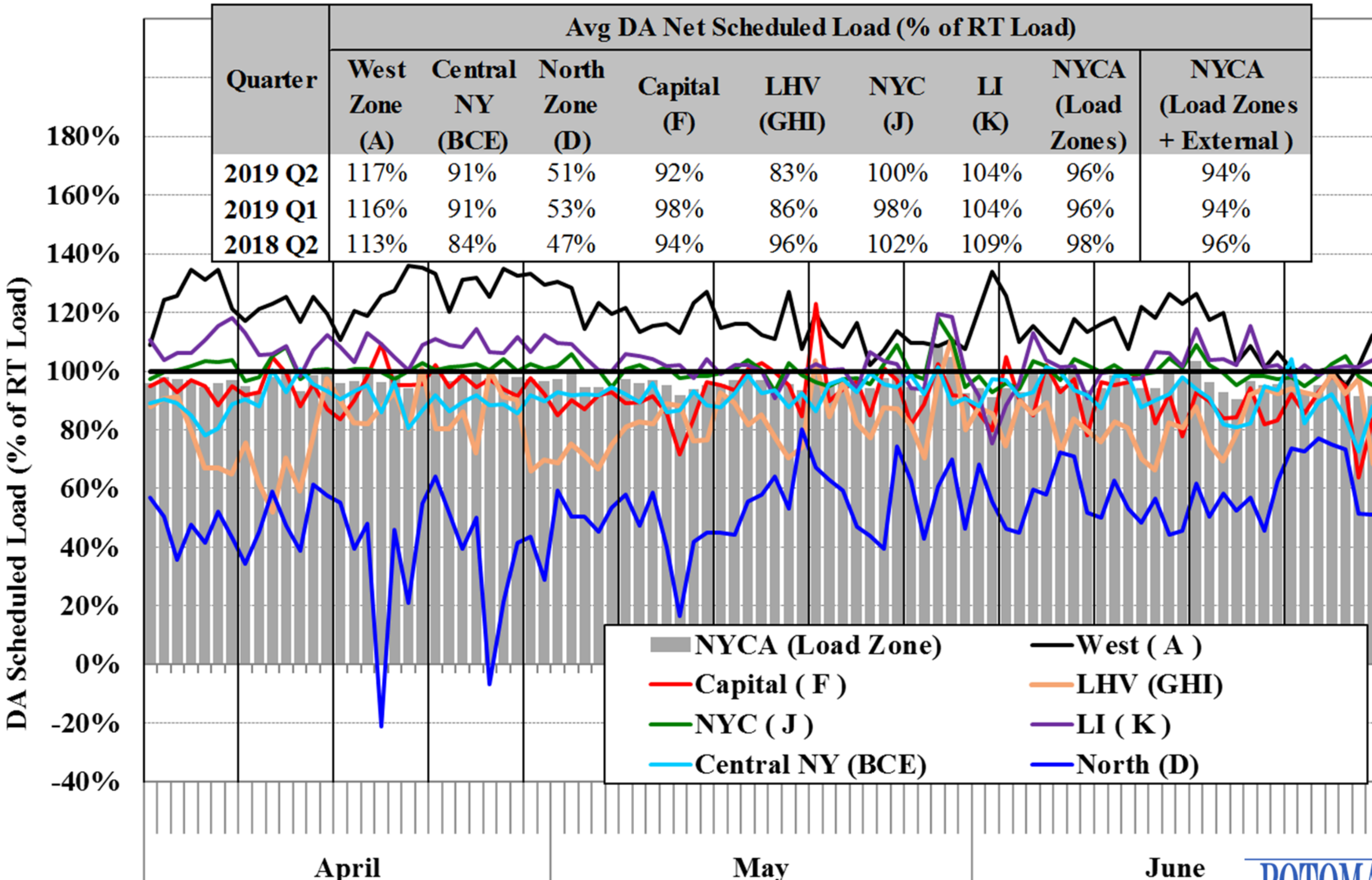
# Day-ahead Scheduled Load and Actual Load
## Daily Peak Load Hour




| 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 ) |
| 2019 Q2 | 117% | 91% | 51% | 92% | 83% | 100% | 104% | 96% | 94% |
| 2019 Q1 | 116% | 91% | 53% | 98% | 86% | 98% | 104% | 96% | 94% |
| 2018 Q2 | 113% | 84% | 47% | 94% | 96% | 102% | 109% | 98% | 96% |





Notes: For chart description, see slide 66.

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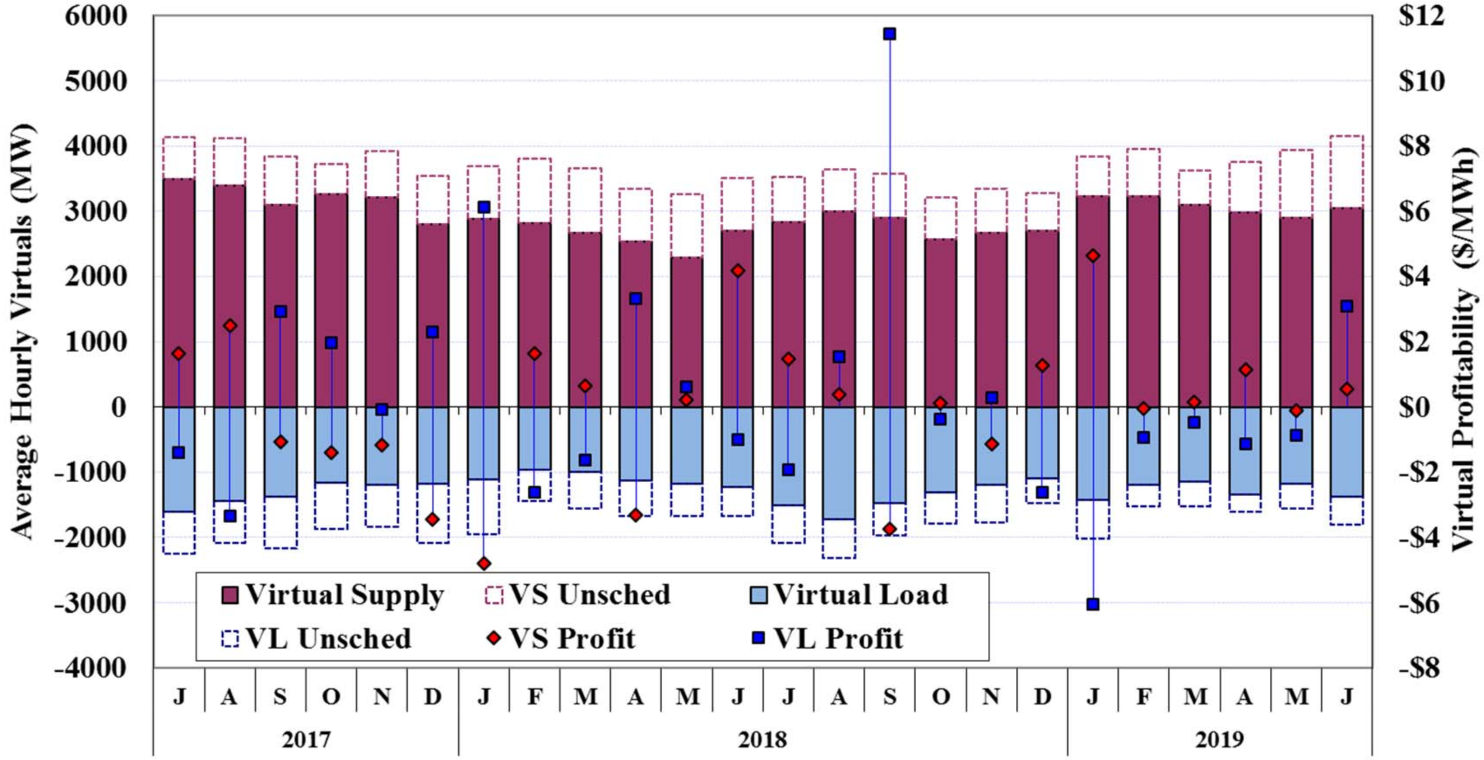
# Virtual Trading Activity
## by Month




| | | 2017 J | 2017 A | 2017 S | 2017 O | 2017 N | 2017 D | 2018 J | 2018 F | 2018 M | 2018 A | 2018 M | 2018 J | 2018 J | 2018 A | 2018 S | 2018 O | 2018 N | 2018 D | 2019 J | 2019 F | 2019 M | 2019 A | 2019 M | 2019 J |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Profit > 50% of Avg. Zone Price | MW | 593 | 439 | 257 | 271 | 320 | 396 | 373 | 450 | 419 | 376 | 475 | 620 | 320 | 299 | 437 | 366 | 312 | 326 | 612 | 279 | 167 | 473 | 477 | 587 |
| | % | 12% | 9% | 6% | 6% | 7% | 10% | 9% | 12% | 11% | 10% | 14% | 16% | 7% | 6% | 10% | 9% | 8% | 9% | 13% | 6% | 4% | 11% | 12% | 13% |
| Loss > 50% of Avg. Zone Price | MW | 568 | 466 | 418 | 399 | 412 | 478 | 442 | 342 | 401 | 466 | 537 | 531 | 329 | 328 | 428 | 430 | 345 | 317 | 439 | 331 | 178 | 348 | 591 | 548 |
| | % | 11% | 10% | 9% | 9% | 9% | 12% | 11% | 9% | 11% | 13% | 16% | 14% | 8% | 7% | 10% | 11% | 9% | 8% | 9% | 7% | 4% | 8% | 15% | 12% |

Notes: For chart description, see slide 66.





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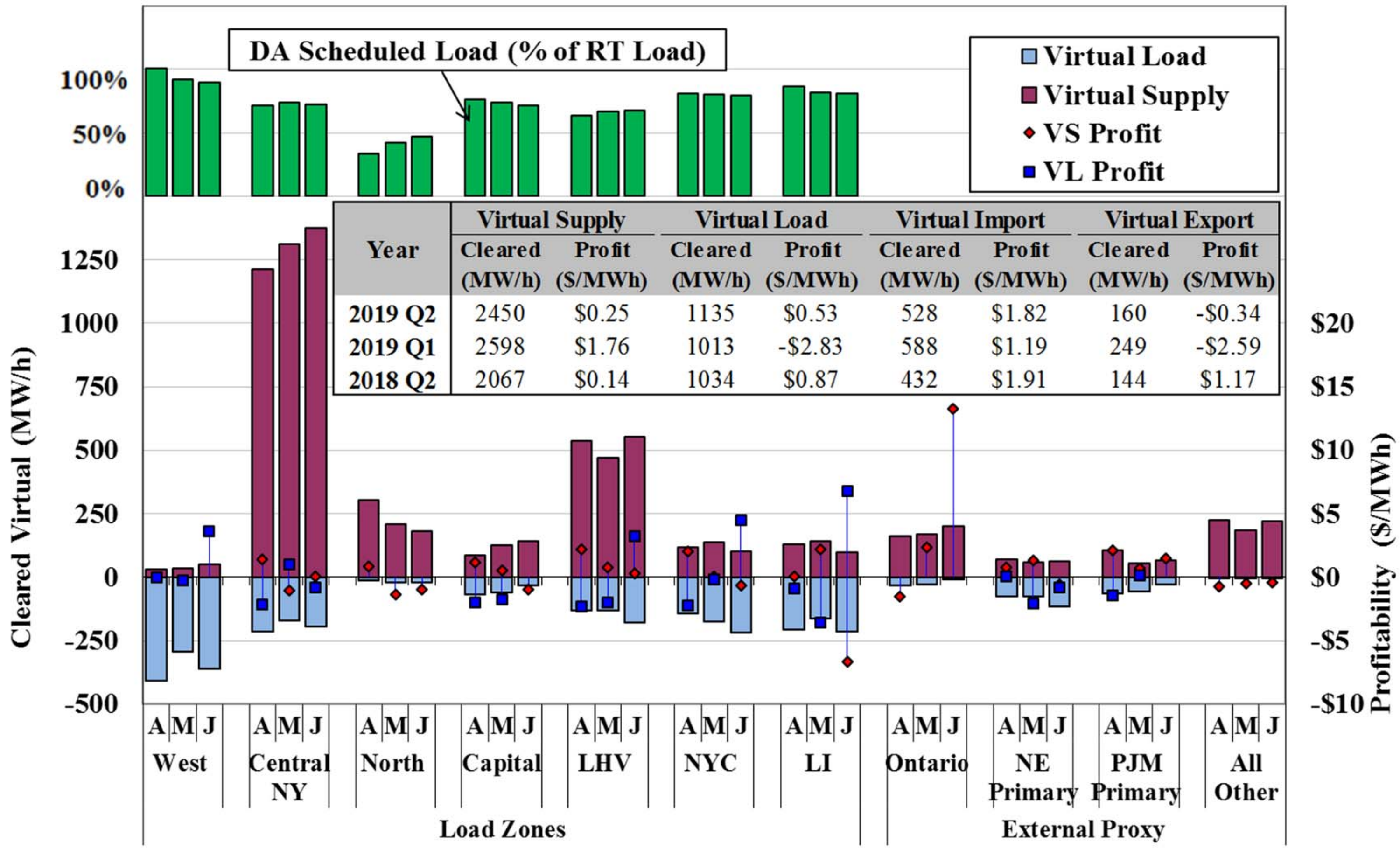
# Virtual Trading Activity
## by Location



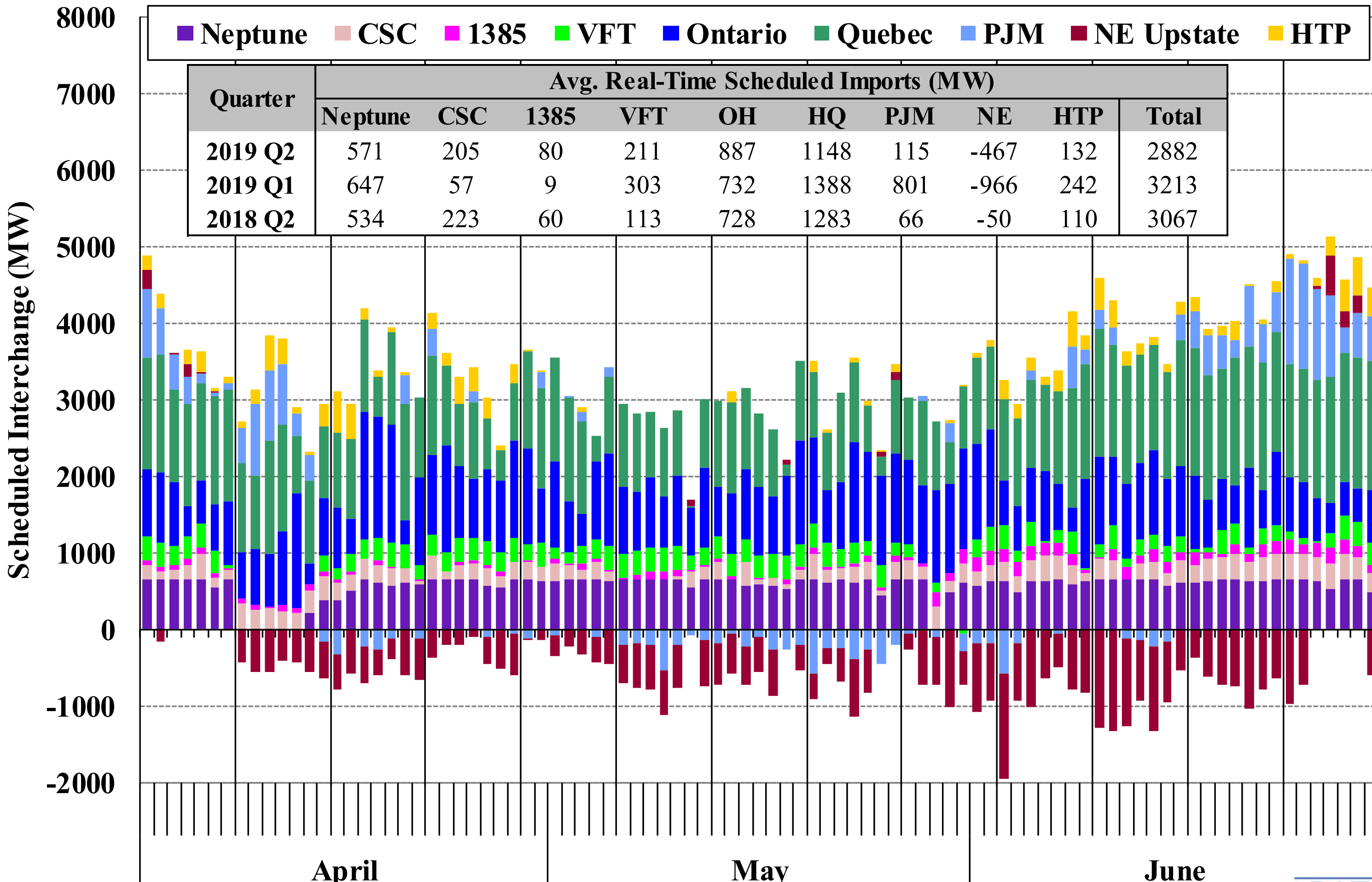

| Year | Virtual Supply | | Virtual Load | | Virtual Import | | Virtual Export | |
|---|---|---|---|---|---|---|---|---|
| | Cleared (MW/h) | Profit ($/MWh) | Cleared (MW/h) | Profit ($/MWh) | Cleared (MW/h) | Profit ($/MWh) | Cleared (MW/h) | Profit ($/MWh) |
| 2019 Q2 | 2450 | $0.25 | 1135 | $0.53 | 528 | $1.82 | 160 | -$0.34 |
| 2019 Q1 | 2598 | $1.76 | 1013 | -$2.83 | 588 | $1.19 | 249 | -$2.59 |
| 2018 Q2 | 2067 | $0.14 | 1034 | $0.87 | 432 | $1.91 | 144 | $1.17 |

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 66.




POTOMAC ECONOMICS

# Net Imports Scheduled Across External Interfaces
## Daily Peak Hours (1-9pm)




| Quarter | Avg. Real-Time Scheduled Imports (MW) | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| | Neptune | CSC | 1385 | VFT | OH | HQ | PJM | NE | HTP | Total |
| 2019 Q2 | 571 | 205 | 80 | 211 | 887 | 1148 | 115 | -467 | 132 | 2882 |
| 2019 Q1 | 647 | 57 | 9 | 303 | 732 | 1388 | 801 | -966 | 242 | 3213 |
| 2018 Q2 | 534 | 223 | 60 | 113 | 728 | 1283 | 66 | -50 | 110 | 3067 |

Notes: Two Quebec interfaces are combined into one.





POTOMAC ECONOMICS

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

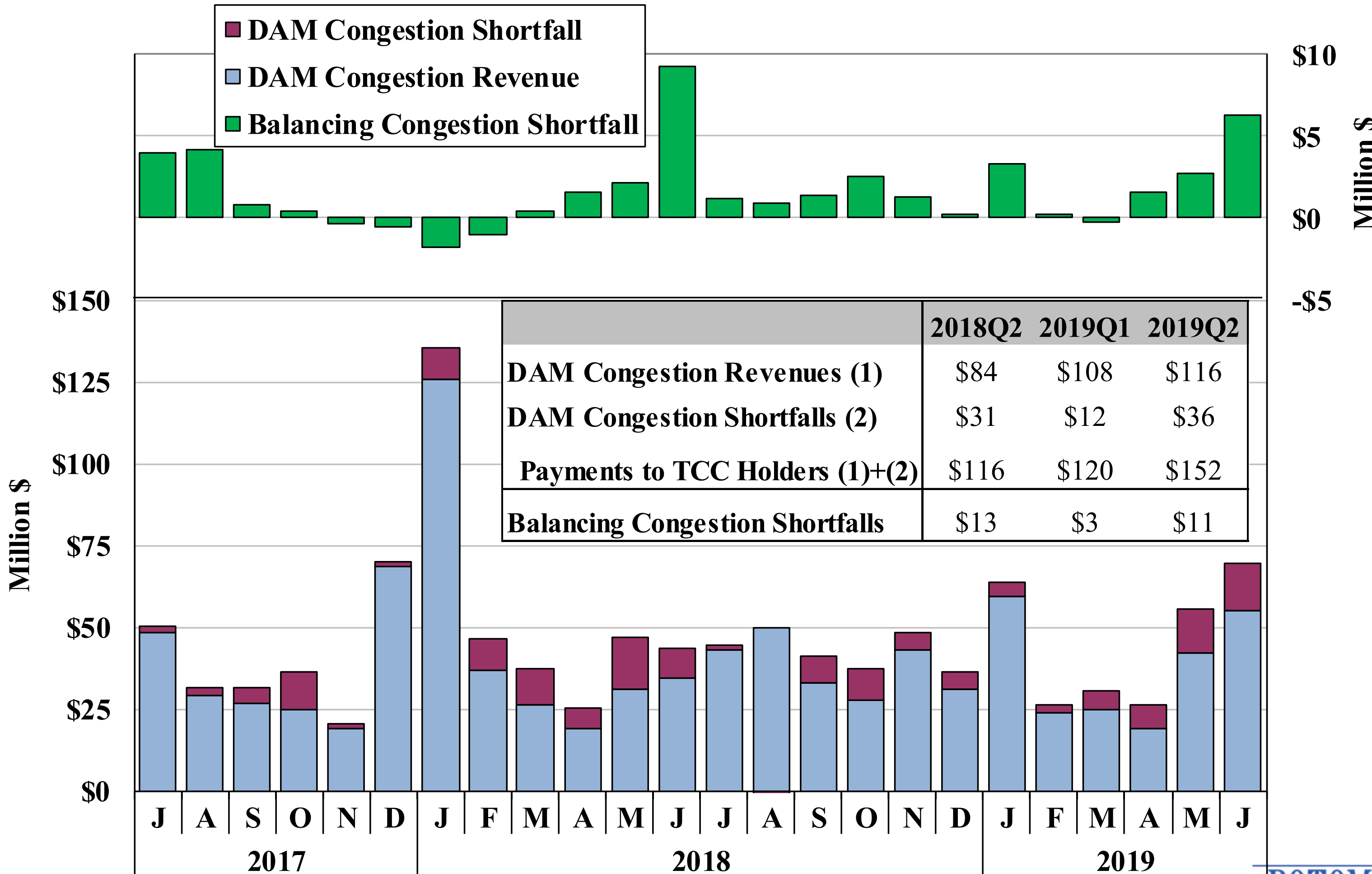
| | | | Average/Total During Intervals w/ Adjustment | | | | | |
|---|---|---|---|---|---|---|---|---|
| | | | CTS - NY/NE | | | CTS - NY/PJM | | |
| | | | Both Forecast Errors <= $20 | Any Forecast Error > $20 | Total | Both Forecast Errors <= $20 | Any Forecast Error > $20 | Total |
| % of All Intervals w/ Adjustment | | | 78% | 5% | **83%** | 50% | 9% | **59%** |
| Average Flow Adjustment (MW) | Net Imports | | -10 | -6 | **-10** | -12 | -51 | **-18** |
| | Gross | | 111 | 136 | **113** | 75 | 112 | **81** |
| Production Cost Savings ($ Million) | Projected at Scheduling Time | | $0.8 | $0.5 | **$1.4** | $0.4 | $0.8 | **$1.1** |
| | Net Over-Projection by: | NY | -$0.04 | -$0.3 | **-$0.3** | -$0.1 | -$0.2 | **-$0.3** |
| | | NE or PJM | $0.04 | -$0.1 | **-$0.04** | -$0.1 | -$0.6 | **-$0.8** |
| | Other Unrealized Savings | | -$0.05 | -$0.04 | **-$0.1** | -$0.01 | $0.00 | **-$0.01** |
| | Actual Savings | | $0.8 | $0.1 | **$0.9** | $0.2 | -$0.1 | **$0.1** |
| Interface Prices ($/MWh) | NY | Actual | $21.26 | $37.47 | **$22.30** | $20.04 | $33.89 | **$22.14** |
| | | Forecast | $22.93 | $31.56 | **$23.48** | $22.25 | $34.80 | **$24.16** |
| | NE or PJM | Actual | $22.36 | $31.80 | **$22.96** | $20.94 | $32.03 | **$22.62** |
| | | Forecast | $21.77 | $28.21 | **$22.19** | $22.82 | $52.70 | **$27.35** |
| Price Forecast Errors ($/MWh) | NY | Fcst. - Act. | $1.67 | -$5.92 | **$1.18** | $2.21 | $0.91 | **$2.01** |
| | | Abs. Val. | $3.96 | $36.08 | **$6.02** | $5.12 | $33.07 | **$9.36** |
| | NE or PJM | Fcst. - Act. | -$0.58 | -$3.59 | **-$0.77** | $1.88 | $20.68 | **$4.73** |
| | | Abs. Val. | $3.16 | $18.48 | **$4.14** | $3.04 | $34.58 | **$7.83** |

Notes: For chart description, see slide 67.

# Charts:

## Transmission Congestion Revenues, Patterns, and Shortfalls

# Congestion Revenues and Shortfalls
## by Month




| | 2018Q2 | 2019Q1 | 2019Q2 |
|---|---|---|---|
| DAM Congestion Revenues (1) | $84 | $108 | $116 |
| DAM Congestion Shortfalls (2) | $31 | $12 | $36 |
| Payments to TCC Holders (1)+(2) | $116 | $120 | $152 |
| Balancing Congestion Shortfalls | $13 | $3 | $11 |

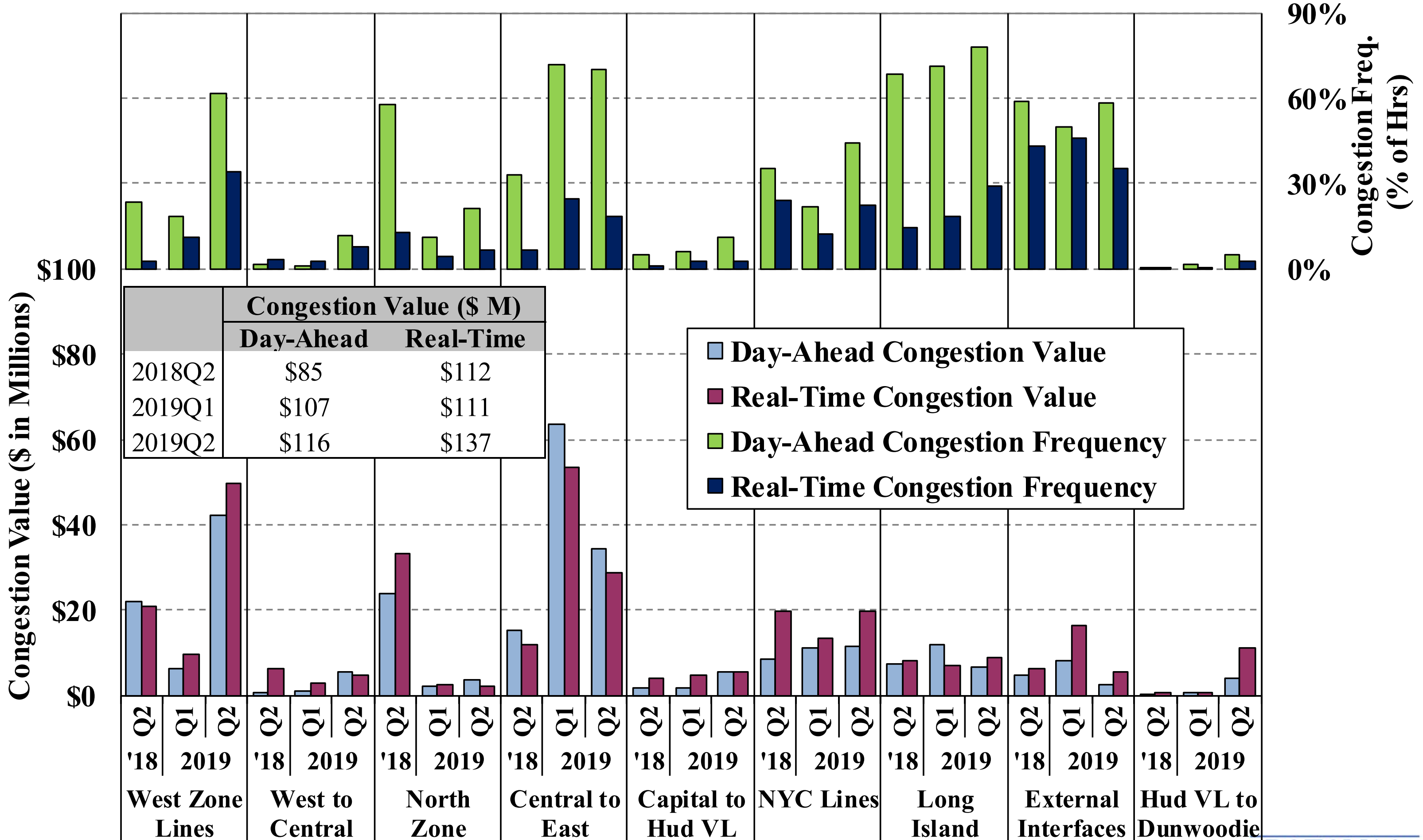
Notes: For chart description, see slides 68 and 69.





POTOMAC ECONOMICS

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




| | Congestion Value ($ M) | |
|---|---|---|
| | Day-Ahead | Real-Time |
| 2018Q2 | $85 | $112 |
| 2019Q1 | $107 | $111 |
| 2019Q2 | $116 | $137 |

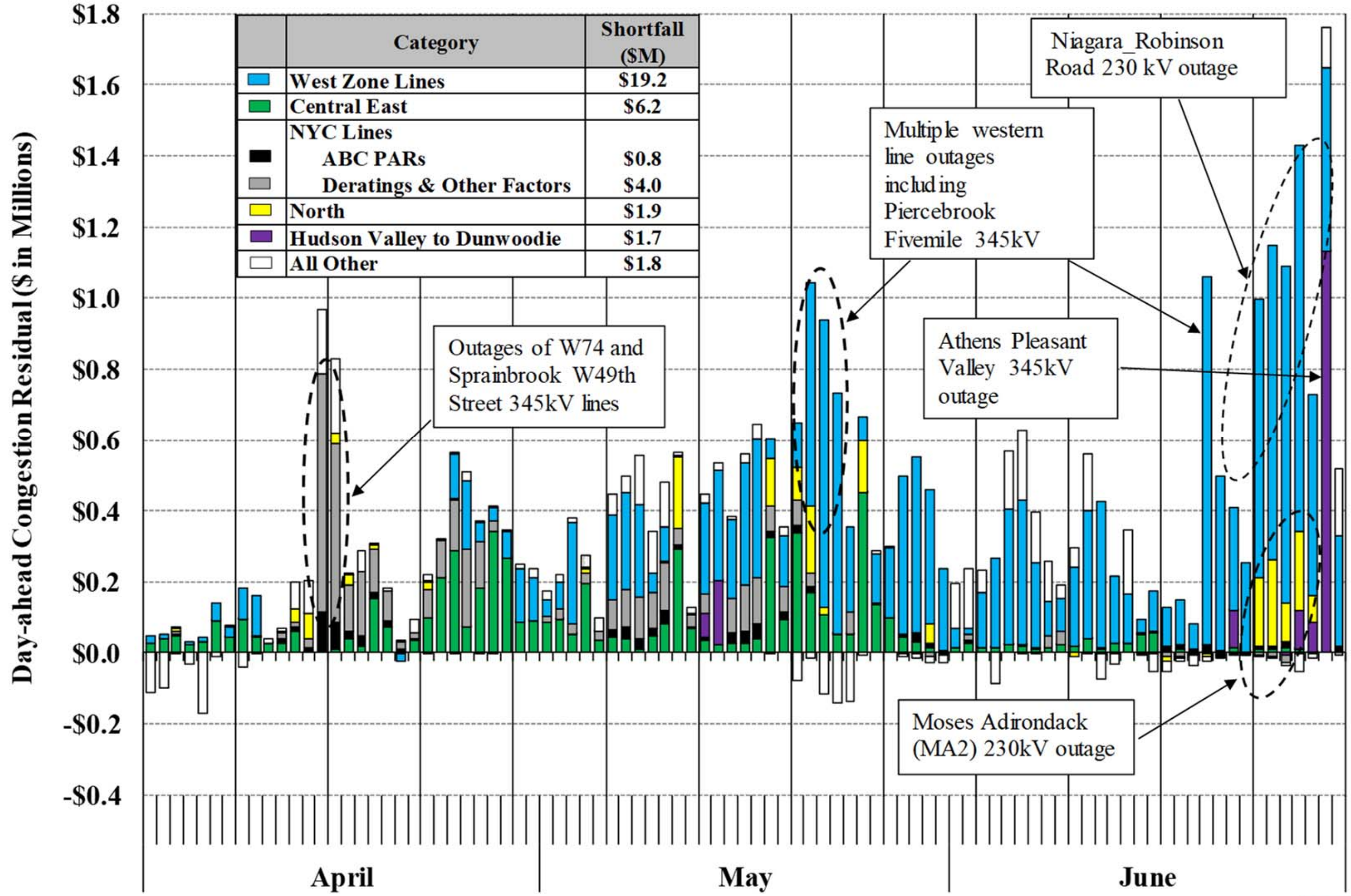
Notes: For chart description, see slides 68, 69, and 70.





POTOMAC ECONOMICS

# Day-Ahead Congestion Revenue Shortfalls
## by Transmission Facility

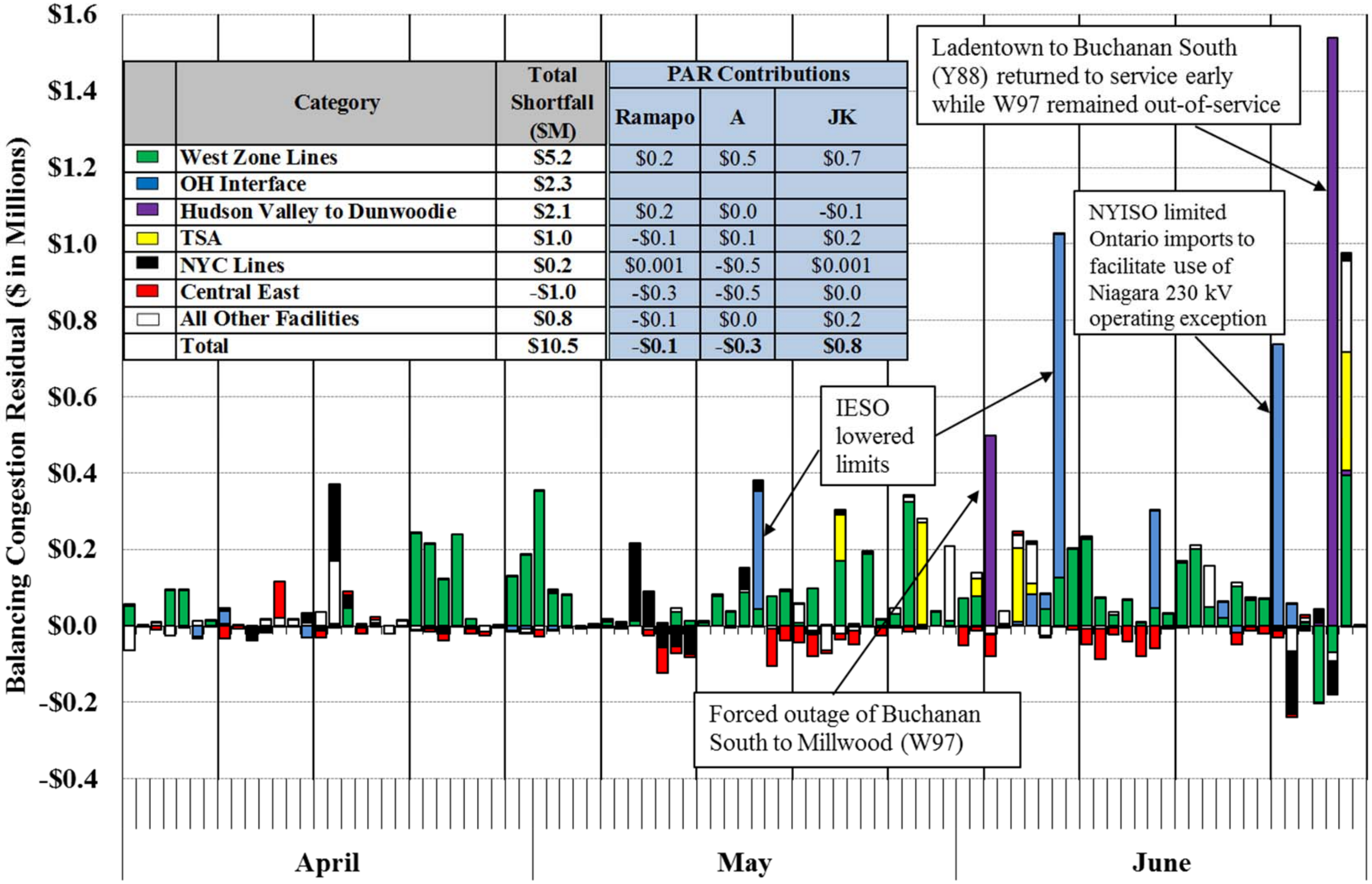



Notes: For chart description, see slides 68, 69, and 70.



POTOMAC ECONOMICS

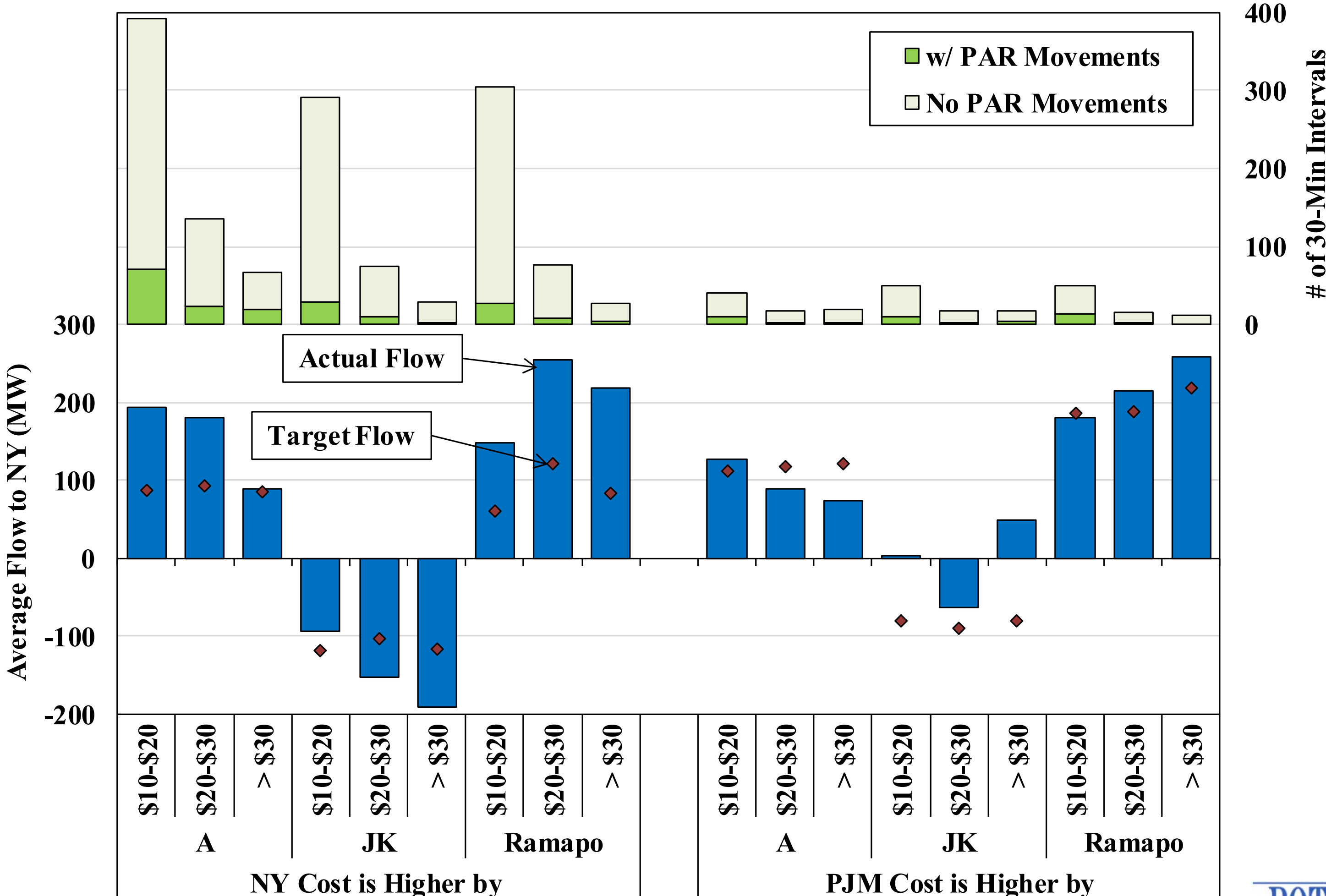
# Balancing Congestion Shortfalls by Transmission Facility




| Category | Total Shortfall ($M) | PAR Contributions: Ramapo | A | JK |
|---|---|---|---|---|
| West Zone Lines | $5.2 | $0.2 | $0.5 | $0.7 |
| OH Interface | $2.3 | | | |
| Hudson Valley to Dunwoodie | $2.1 | $0.2 | $0.0 | -$0.1 |
| TSA | $1.0 | -$0.1 | $0.1 | $0.2 |
| NYC Lines | $0.2 | $0.001 | -$0.5 | $0.001 |
| Central East | -$1.0 | -$0.3 | -$0.5 | $0.0 |
| All Other Facilities | $0.8 | -$0.1 | $0.0 | $0.2 |
| Total | $10.5 | -$0.1 | -$0.3 | $0.8 |

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 68, 69, and 70.

# PAR Operation under M2M with PJM
## 2019 Q2



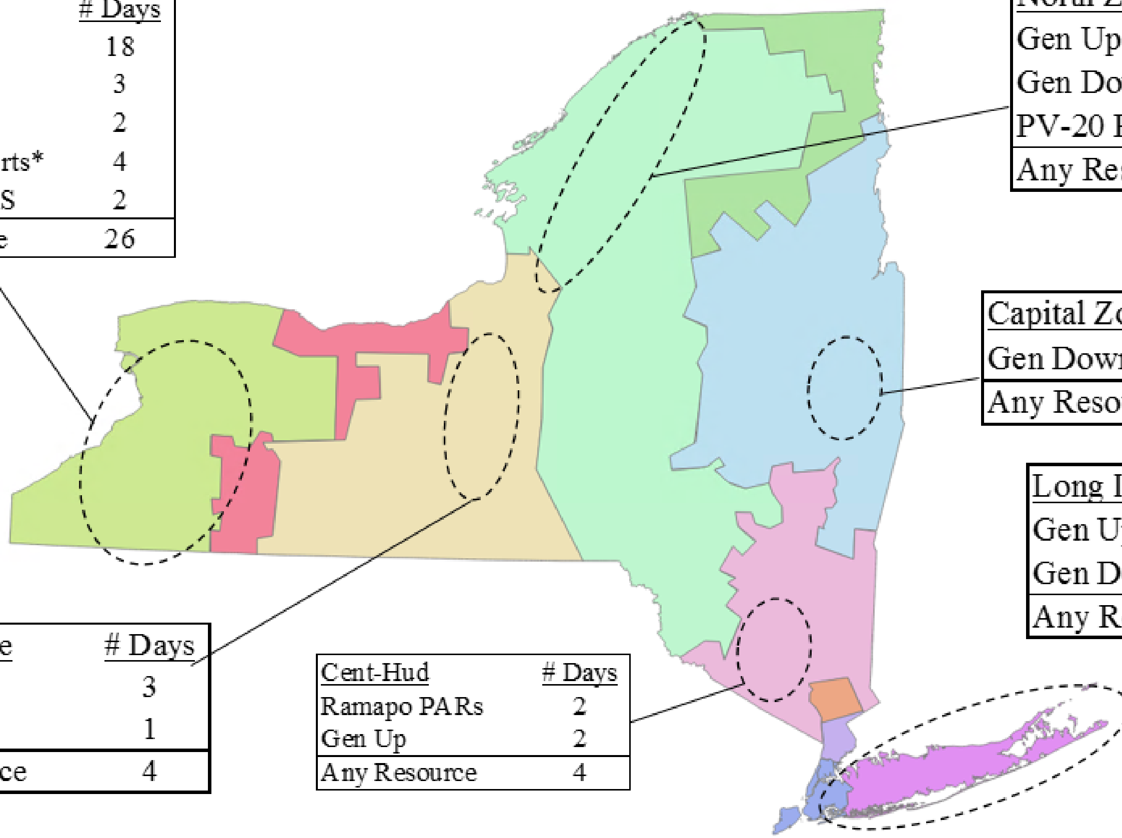





Notes: For chart description, see slide 71.

POTOMAC ECONOMICS

# Unmodeled Constraints on the Low Voltage Network: Resources Used to Manage Constraints



| West Zone | # Days |
|---|---|
| Gen Up | 18 |
| Gen Down | 3 |
| Surrogate | 2 |
| Ontario Imports* | 4 |
| St Lawr PARS | 2 |
| Any Resource | 26 |

| North Zone | # Days |
|---|---|
| Gen Up | 7 |
| Gen Down | 6 |
| PV-20 PAR | 1 |
| Any Resource | 14 |

| Capital Zone | # Days |
|---|---|
| Gen Down | 46 |
| Any Resource | 46 |

| Long Is 69kV | # Days |
|---|---|
| Gen Up | 18 |
| Gen Down | 2 |
| Any Resource | 19 |

| Central Zone | # Days |
|---|---|
| Gen Up | 3 |
| Gen Down | 1 |
| Any Resource | 4 |

| Cent-Hud | # Days |
|---|---|
| Ramapo PARs | 2 |
| Gen Up | 2 |
| Any Resource | 4 |

*Ontario imports were limited or cut on an additional 12 days to manage modeled western constraints.

Notes: For chart description, see slides 72-73

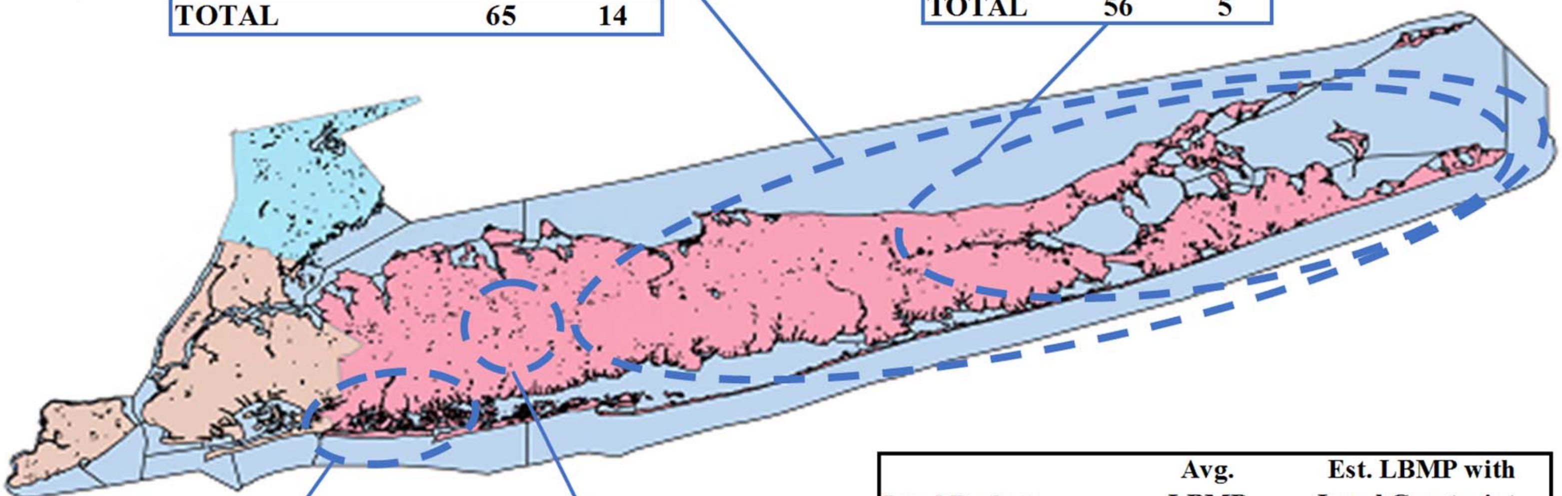


POTOMAC ECONOMICS

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

| East of Northport | #Hours | #Days |
|---|---|---|
| 69kV | 24 | 1 |
| 138kV | 41 | 13 |
| TOTAL | 65 | 14 |

| East End | #Hours | #Days |
|---|---|---|
| 69kV | 3 | 1 |
| TVR | 53 | 4 |
| TOTAL | 56 | 5 |



| Valley Stream | #Hours | #Days |
|---|---|---|
| 69kV | 109 | 11 |
| 138kV | 1244 | 81 |
| TOTAL | 1261 | 81 |

| Brentwood | #Hours | #Days |
|---|---|---|
| 69kV | 14 | 2 |

| Load Pocket | Avg. LBMP | Est. LBMP with Local Constraints |
|---|---|---|
| Brentwood | $27.56 | $27.58 |
| East End | $28.55 | $33.69 |
| East of Northport | $27.57 | $28.07 |
| Valley Stream | $29.90 | $34.63 |

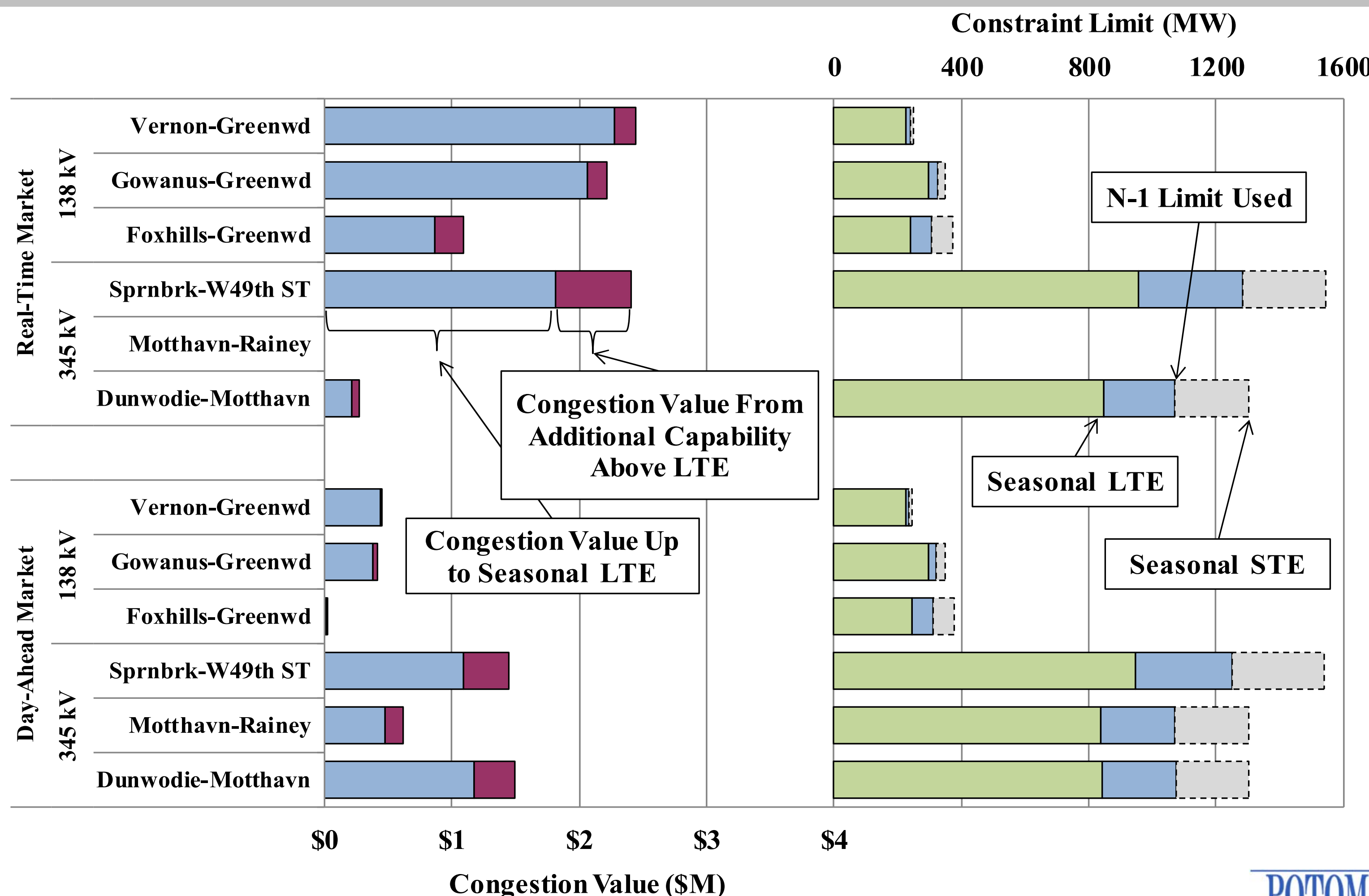
Notes: For chart description, see slides 72-73





POTOMAC ECONOMICS

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






 Notes: For chart description, see slide 74.

POTOMAC ECONOMICS

# Limit Reduction in Congestion Management
## Top Facilities in 2019 Q2

| Location | Facility | Estimated BMCR from Daily Max Limit | # of Intervals w/ Limit Reduction | Avg Daily Max Limit MW | Avg MW Reduced | Reduction as % of Max Limit |
|---|---|---|---|---|---|---|
| West | NIAGARA-PACKARD 230 | $803,933 | 2075 | 844 | 41 | 5% |
| NYC | E179THST-HELLGATE 138 | $378,181 | 1912 | 259 | 19 | 7% |
| West | NIAGB130-PACKARD 115 | $234,432 | 590 | 212 | 9 | 4% |
| NYC | MOTTHAVN-DUNWODIE 345 | $186,712 | 2229 | 763 | 34 | 5% |
| West | NBRDWYNG-ERIE_ST 115 | $148,239 | 134 | 171 | 28 | 16% |
| NYC | RAINEY-VERNON 138 | $144,389 | 1493 | 265 | 33 | 12% |
| West | GARDNVLB-LNGRD209 115 | $125,115 | 345 | 211 | 11 | 5% |
| West | NIAGARA 230/115 | $120,325 | 730 | 288 | 29 | 10% |



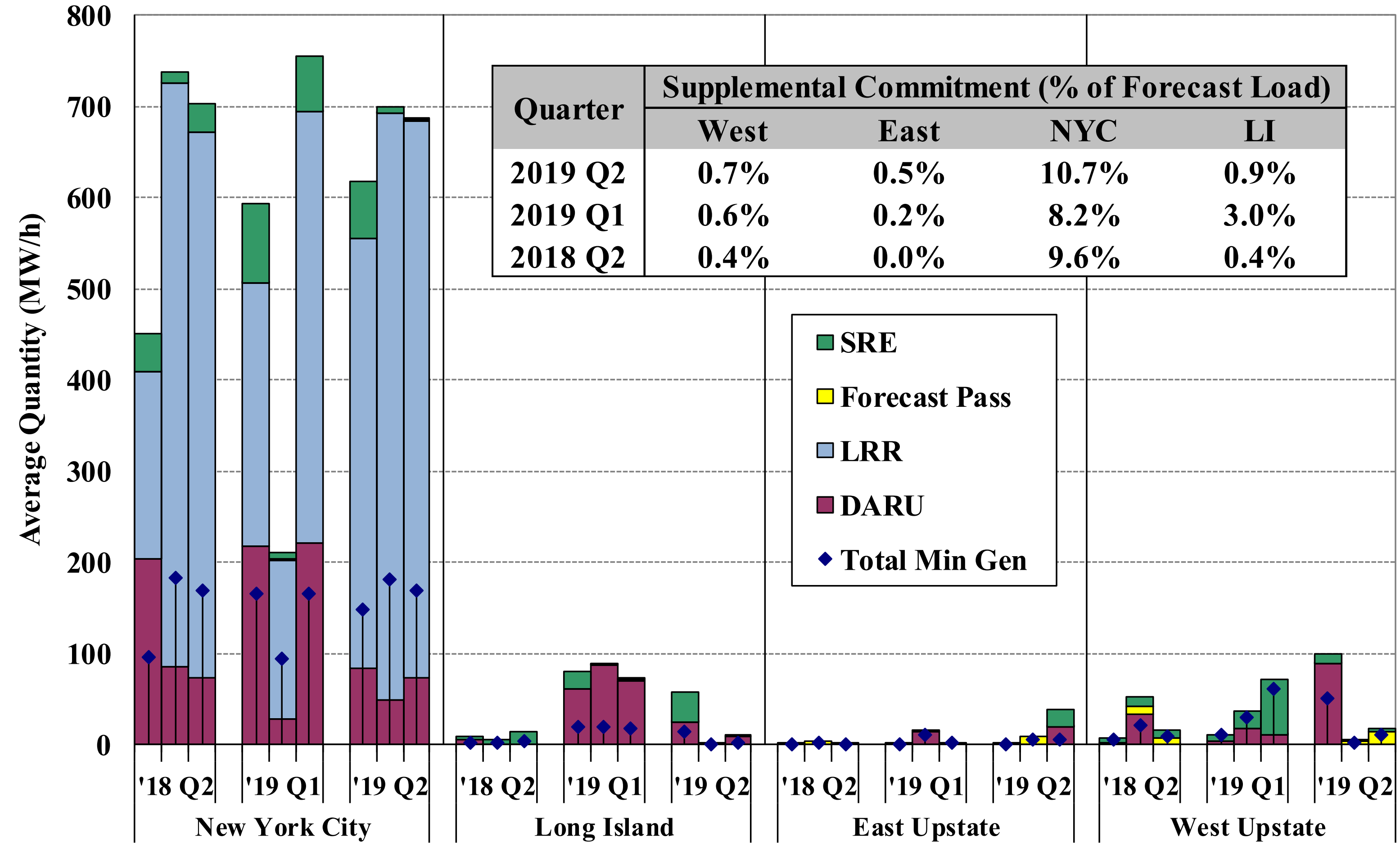
Notes: For chart description, see slide 75.

POTOMAC ECONOMICS

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

POTOMAC ECONOMICS

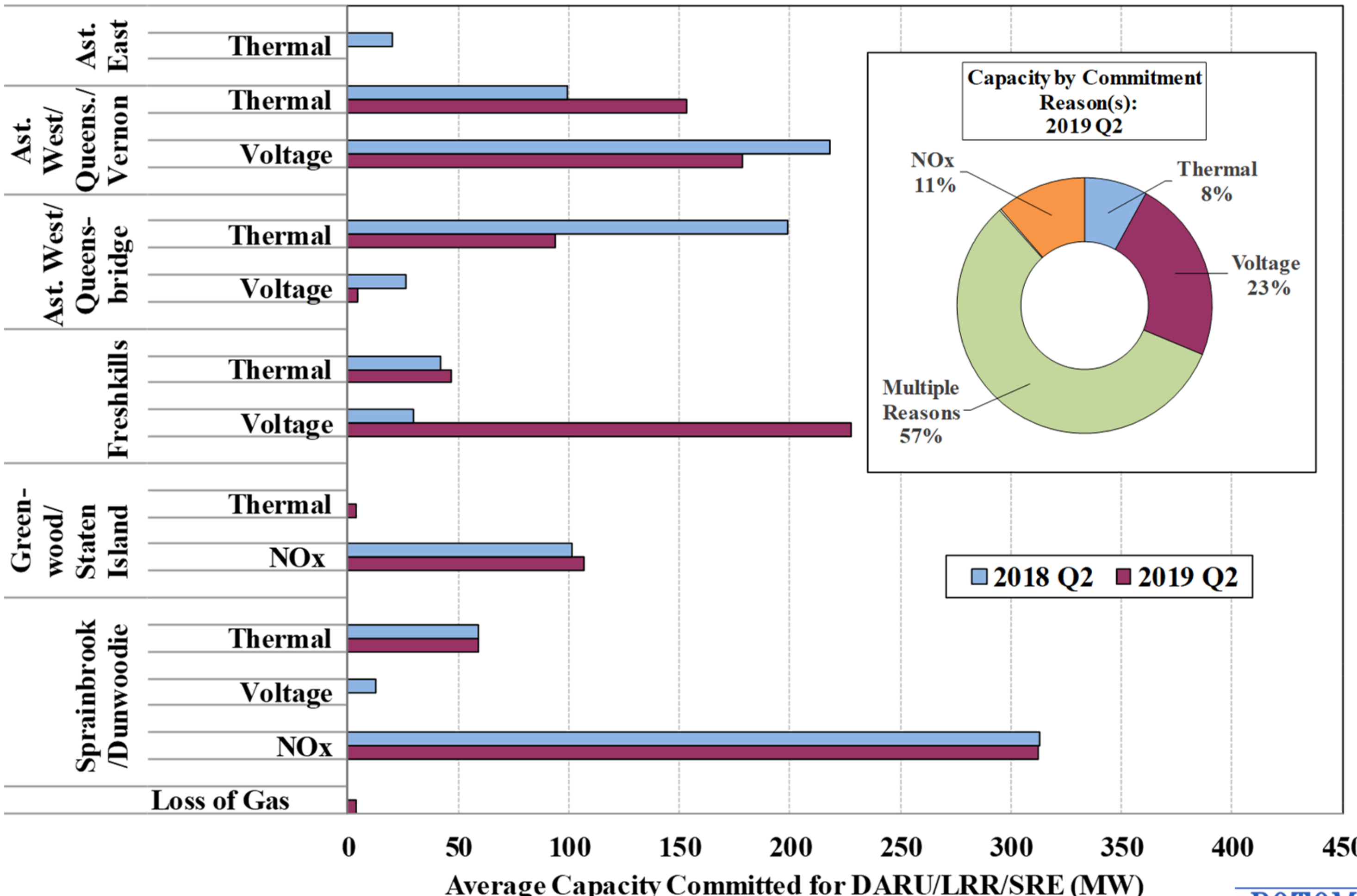
# Supplemental Commitment for Reliability
## by Category and Region




| Quarter | Supplemental Commitment (% of Forecast Load) | | | |
|---|---|---|---|---|
| | West | East | NYC | LI |
| 2019 Q2 | 0.7% | 0.5% | 10.7% | 0.9% |
| 2019 Q1 | 0.6% | 0.2% | 8.2% | 3.0% |
| 2018 Q2 | 0.4% | 0.0% | 9.6% | 0.4% |

Notes: For chart description, see slides 76 and 77.

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



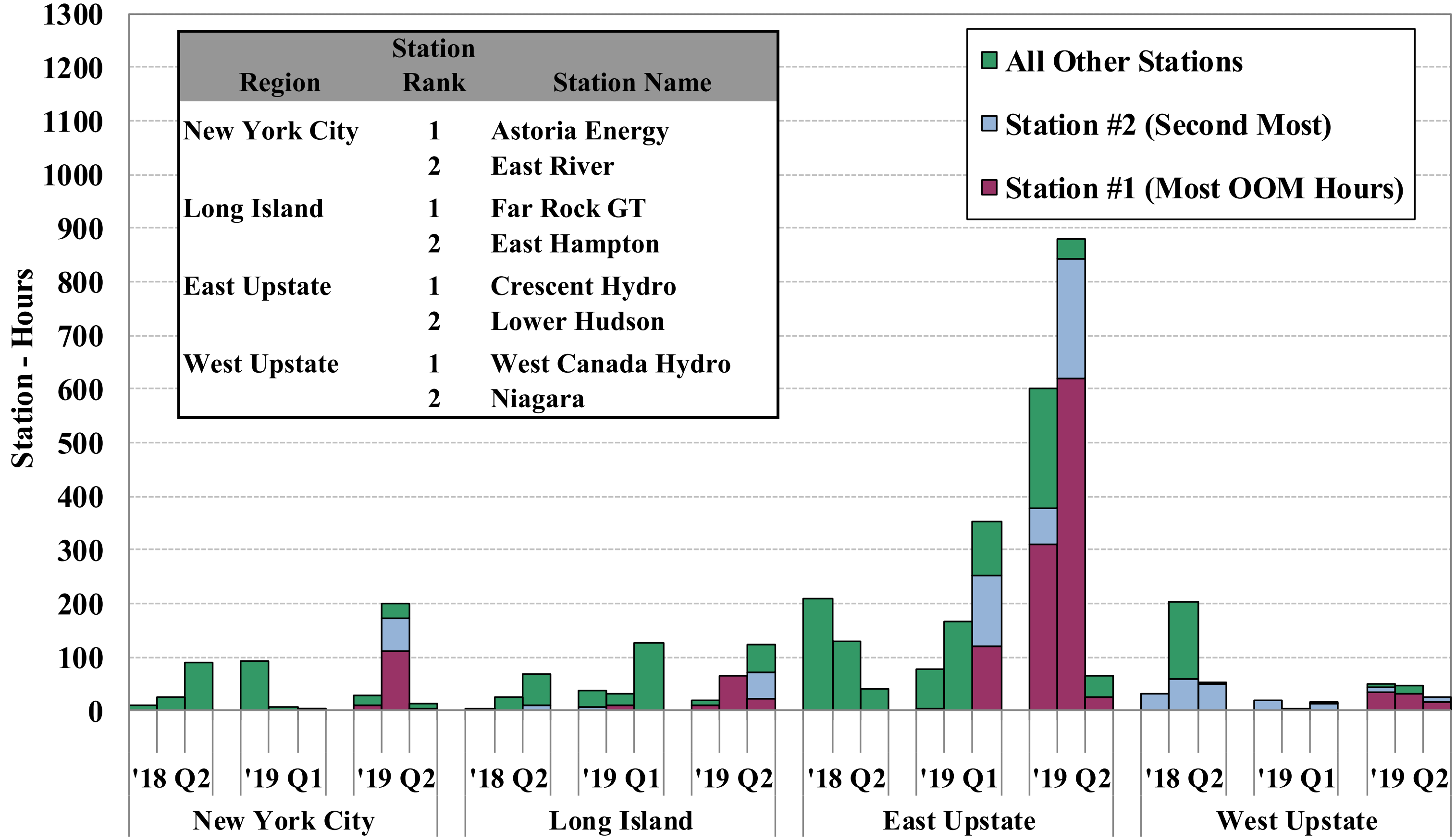

Notes: For chart description, see slides 76 and 77.





POTOMAC ECONOMICS

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




Notes: 1. The NYISO also instructed Niagara to shift output among the generators at the station in order to secure certain 115kV and/or 230kV transmission facilities in 382 hours in 2018-Q2, 517 hours in 2019-Q1, and 806 hours in 2019-Q2. However, these were not classified as Out-of-Merit in hours when the NYISO did not adjust the UOL or LOL of the Resource.

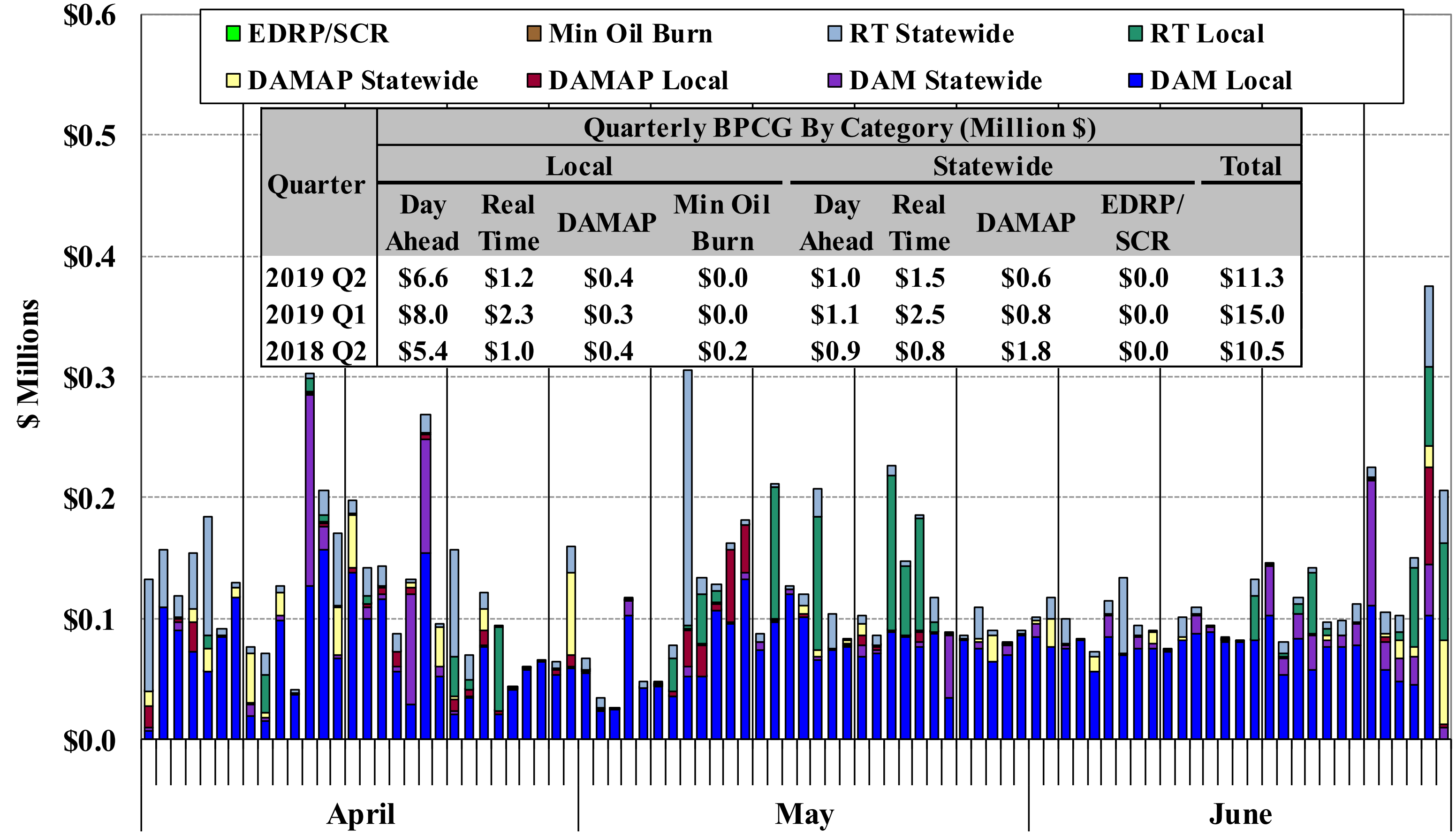
2. For chart description, see slides 76 and 77.





POTOMAC ECONOMICS

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

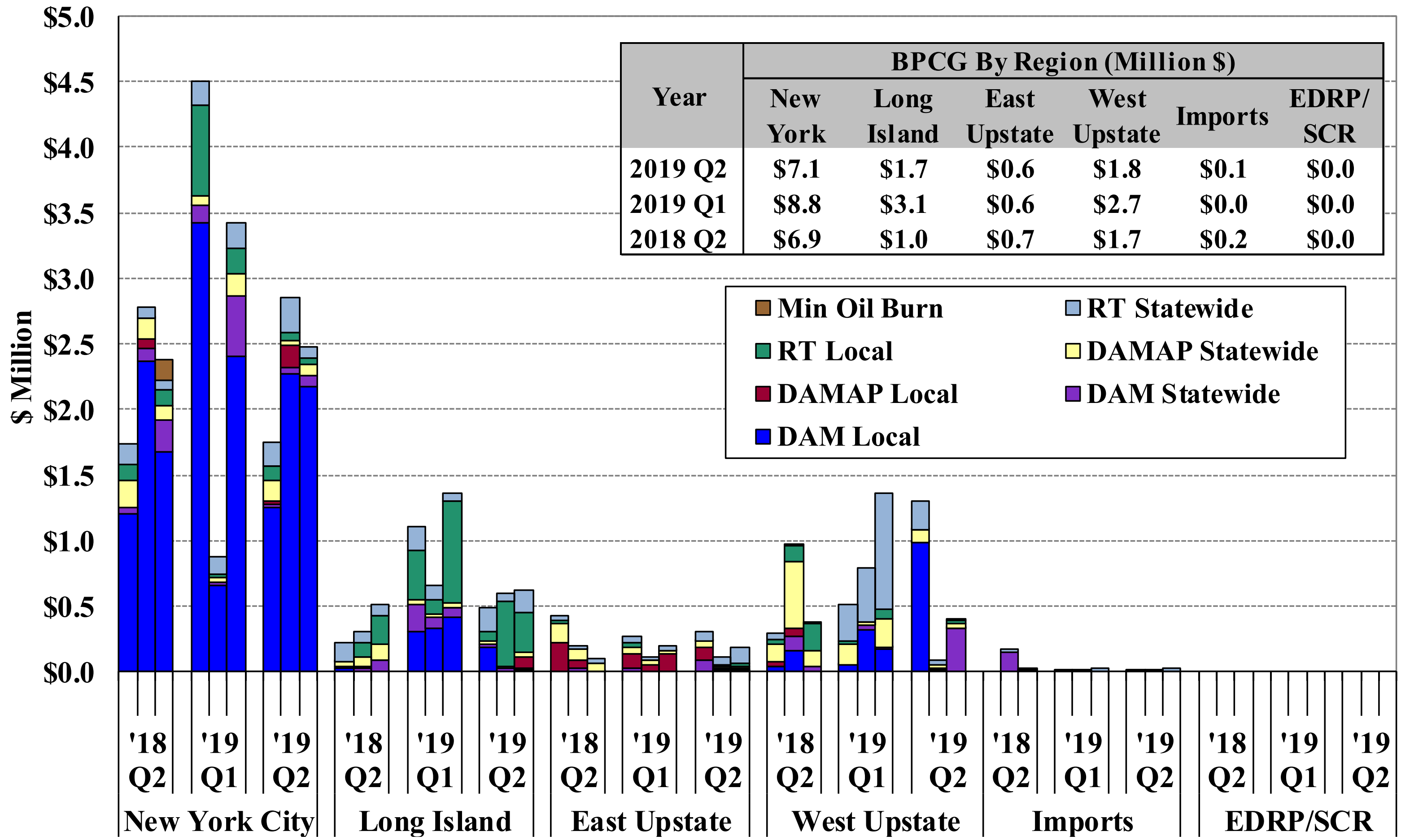



| Quarter | Local | | | | Statewide | | | | Total |
|---|---|---|---|---|---|---|---|---|---|
| | Day Ahead | Real Time | DAMAP | Min Oil Burn | Day Ahead | Real Time | DAMAP | EDRP/ SCR | |
| 2019 Q2 | $6.6 | $1.2 | $0.4 | $0.0 | $1.0 | $1.5 | $0.6 | $0.0 | $11.3 |
| 2019 Q1 | $8.0 | $2.3 | $0.3 | $0.0 | $1.1 | $2.5 | $0.8 | $0.0 | $15.0 |
| 2018 Q2 | $5.4 | $1.0 | $0.4 | $0.2 | $0.9 | $0.8 | $1.8 | $0.0 | $10.5 |

Quarterly BPCG By Category (Million $)

Notes: 1. These data are based on information available at the reporting time and do not include some manual adjustments to mitigation, so they can be different from final settlements.
2. For chart description, see slide 78.

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



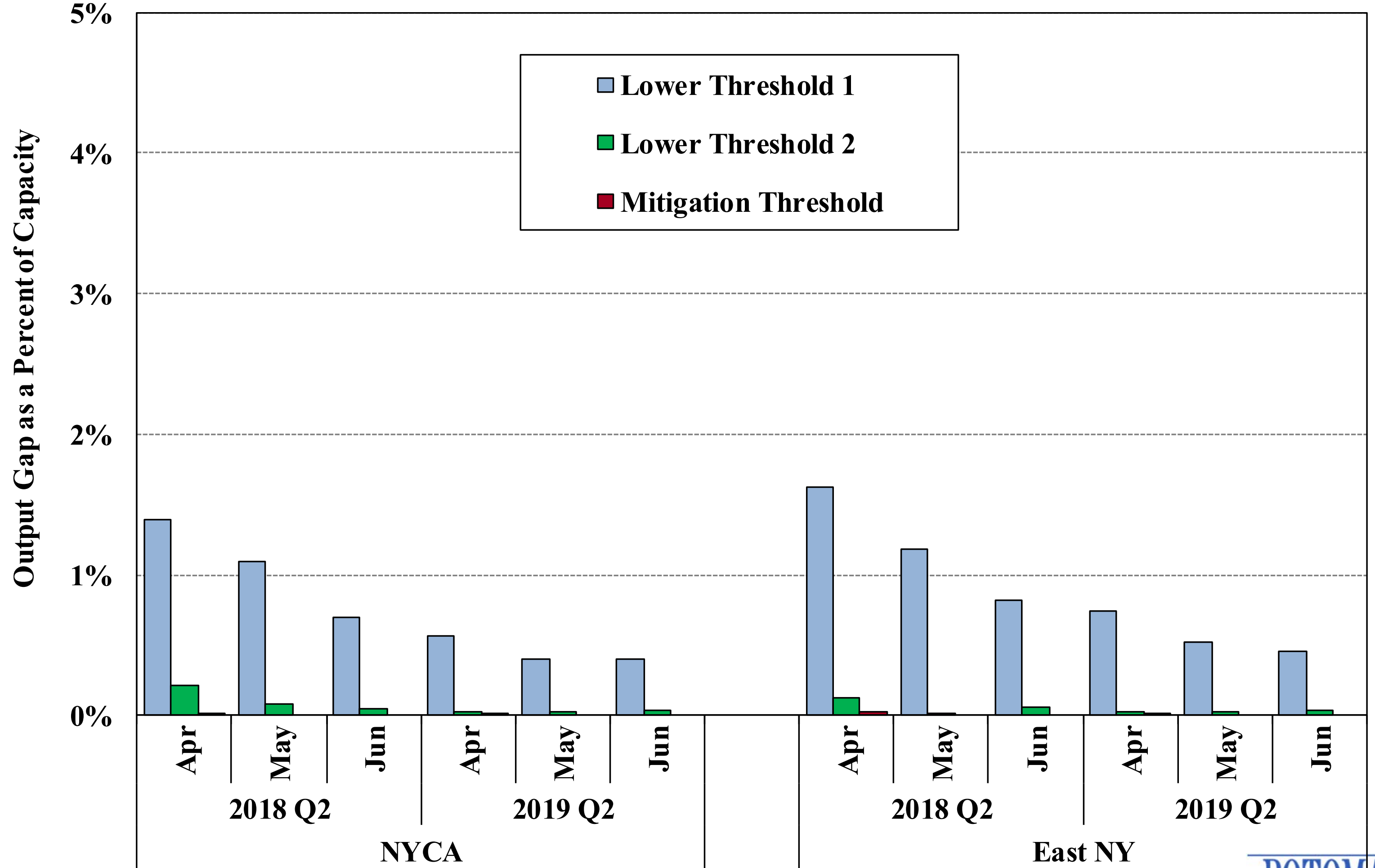

| Year | BPCG By Region (Million $) | | | | | |
|---|---|---|---|---|---|---|
| | New York | Long Island | East Upstate | West Upstate | Imports | EDRP/ SCR |
| 2019 Q2 | $7.1 | $1.7 | $0.6 | $1.8 | $0.1 | $0.0 |
| 2019 Q1 | $8.8 | $3.1 | $0.6 | $2.7 | $0.0 | $0.0 |
| 2018 Q2 | $6.9 | $1.0 | $0.7 | $1.7 | $0.2 | $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 78.

# Charts:

## Market Power and Mitigation

# Output Gap by Month
## NYCA and East NY

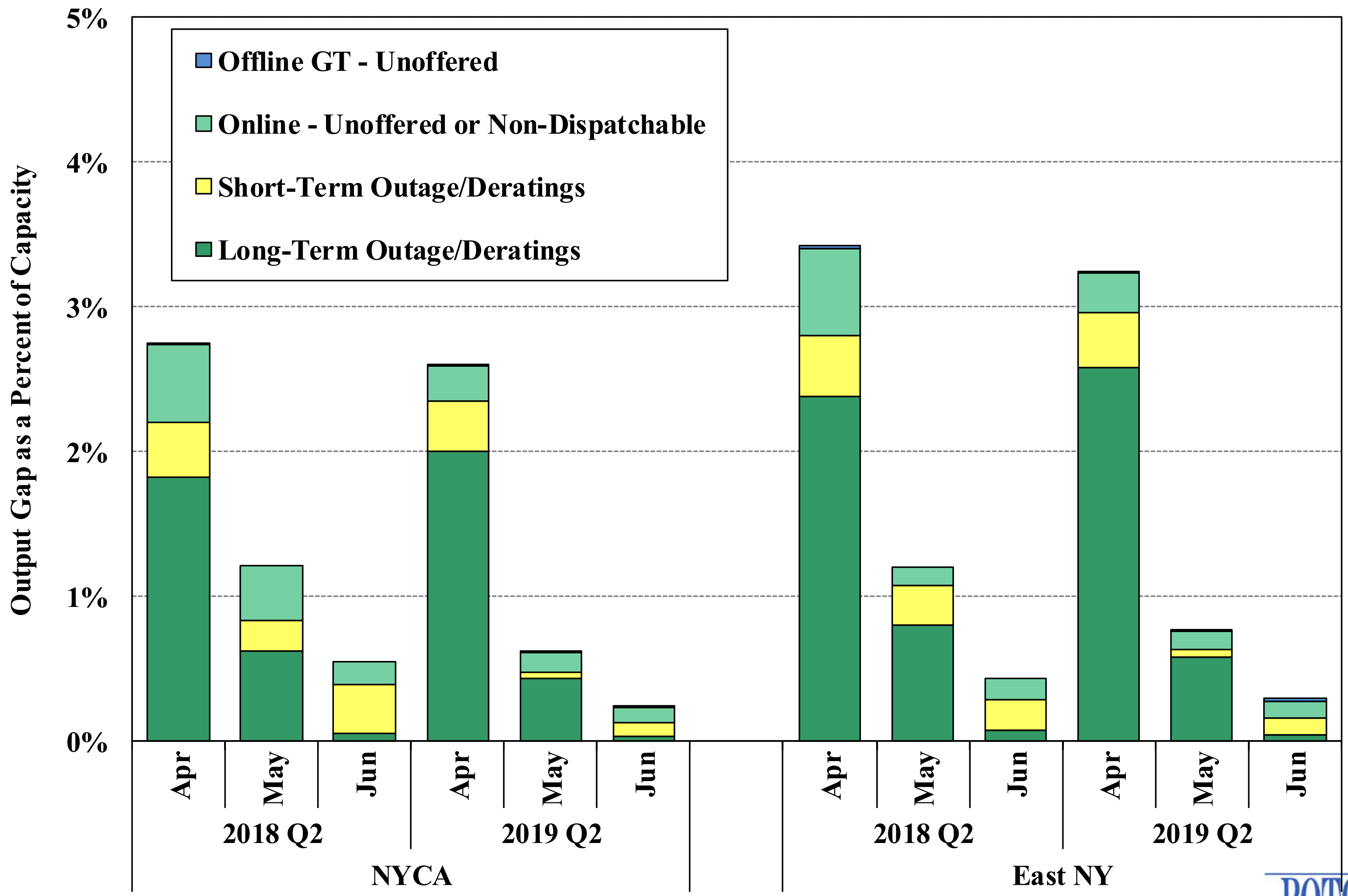





For chart description, see slide 79.

POTOMAC ECONOMICS

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

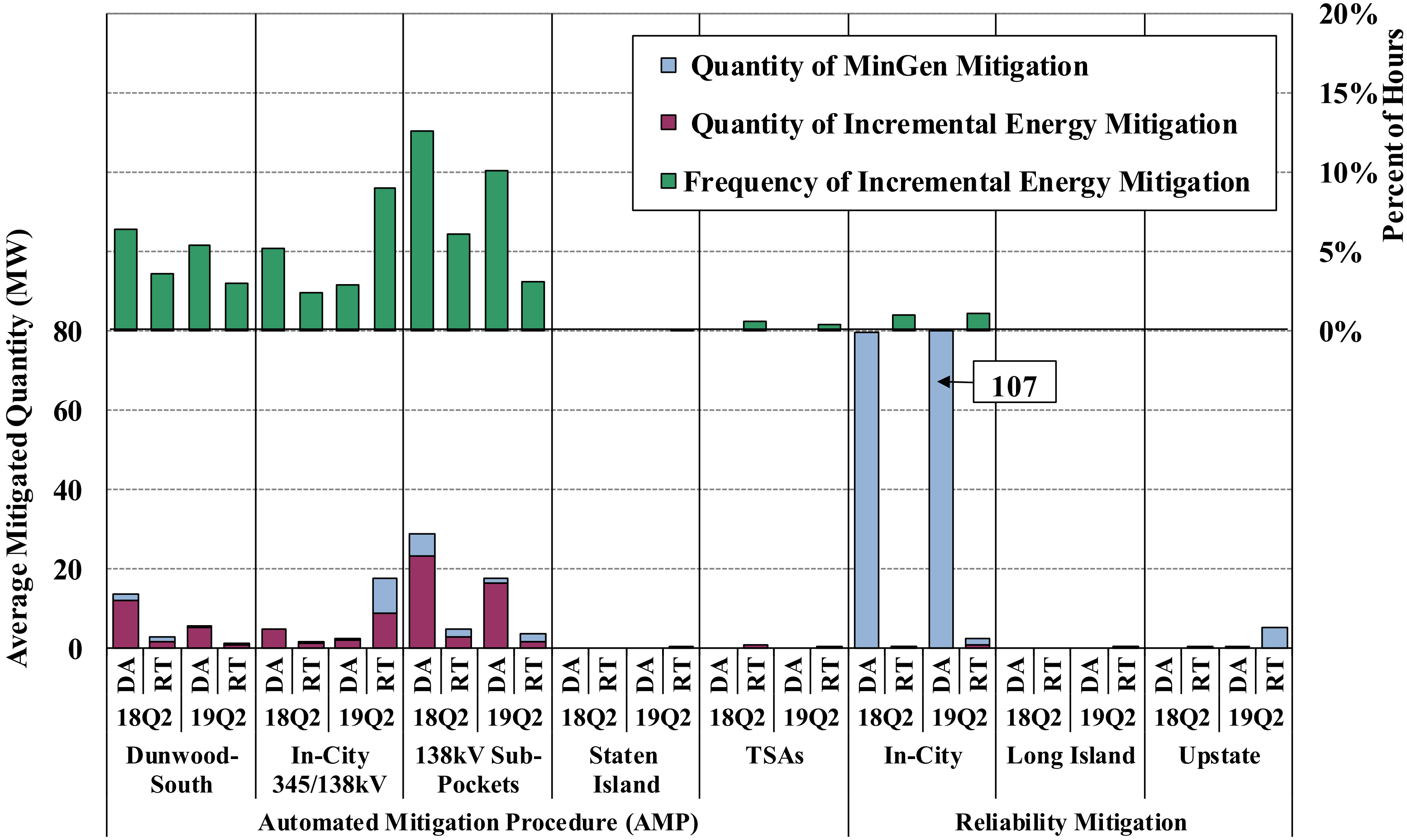






For chart description, see slide 79.

# Automated Market Power Mitigation




Notes: For chart description, see slide 80.





POTOMAC ECONOMICS

# Charts:
## Capacity Market

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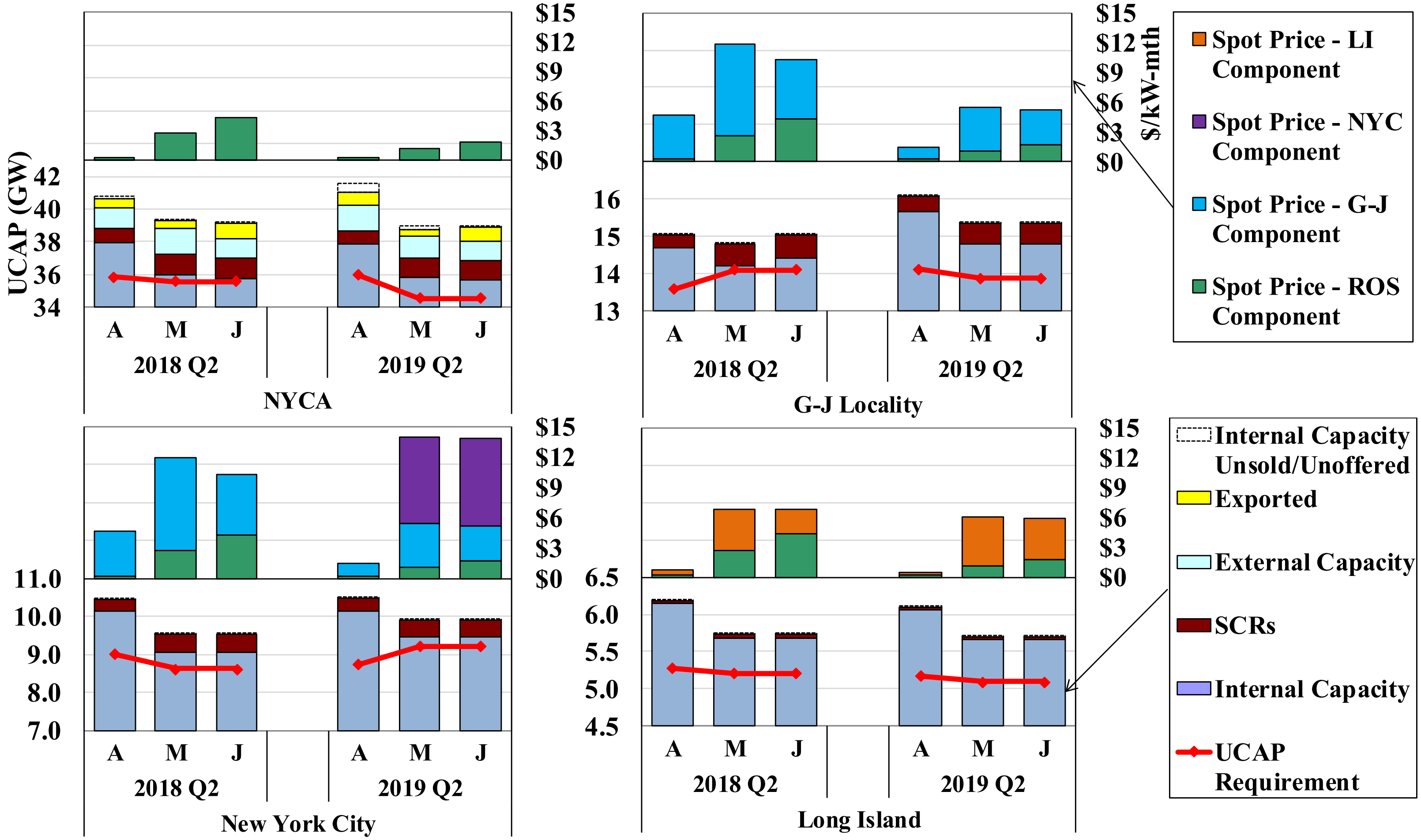
# Spot Capacity Market Results
## 2018-Q2 & 2019-Q2








Notes: For chart description, see slide 81.

POTOMAC ECONOMICS

# Key Drivers of Capacity Market Results

| | NYCA | NYC | LI | G-J Locality |
|---|---|---|---|---|
| **Avg. Spot Price** | | | | |
| 2019 Q2 ($/kW-Month) | $1.07 | $9.72 | $4.11 | $4.03 |
| Summer 2019 Price Component ($/kW-Month) | $1.47 | $13.86 | $5.96 | $5.32 |
| % Change from 2018 Q2 | **-56%** | **9%** | **-14%** | **-55%** |
| **Change in Demand**[(1)] | | | | |
| Load Forecast (MW) | -519 | 68 | -136 | -72 |
| IRM/LCR | -1.2% | 2.3% | 0.6% | -2.2% |
| *2019 Summer* | *117.0%* | *82.8%* | *104.1%* | *92.3%* |
| *2018 Summer* | *118.2%* | *80.5%* | *103.5%* | *94.5%* |
| **ICAP Requirement (MW)** | **-1,003** | **322** | **-109** | **-417** |
| **Key Changes in ICAP Supply (MW)** | | | | |
| *Generation* | **-40** | **135** | **-35** | **382** |
| *Entry* | 142 | 142 | | 142 |
| *Exit* | -452 | -15 | | -15 |
| *DMNC* | 270 | 8 | -35 | 255 |
| *Cleared Import*[(2)] | **16** | | | |

*(1) Demnand Curve Parameters based on Summer Capability Periods*

*(2) Based on quarterly average cleared quantity.*





Notes: For chart description, see slide 81.

POTOMAC ECONOMICS

# Appendix:  Chart Descriptions

# All-in Price

- Slide 17 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 area, allocated over the energy consumption in that area.
  - ✓ 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 a transportation charge of $0.20/MMBtu):
    - a) the Millennium East index for West Zone and Central NY; b) the Iroquois Waddington index for North Zone; c) the Iroquois Zone 2 index for Capital Zone and LI; d) the average of Millennium East and Iroquois Zone 2 for LHV; and e) the Transco Zone 6 (NY) index for NYC. A 6.9 percent tax rate is also included NYC.

# Real-Time Output and Marginal Units by Fuel

- Slide 20 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 21 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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# Ancillary Services Prices

- Slides 26, 27, and 28 summarize day-ahead and real-time prices for six ancillary services products during the quarter:
  - ✓ 10-min spinning reserve prices in eastern NY;
  - ✓ 10-min non-spinning reserve prices in eastern NY;
  - ✓ 10-min spinning reserve prices in western NY;
  - ✓ Regulation prices, which reflect the cost of procurement, and the cost of moving generation of regulating units up and down.
    - Resources were scheduled assuming a Regulation Movement Multiplier of 13 MW per MW of capability, but they are compensated according to actual movement.
    - Real-time Regulation Movement Charges shown on Slide 27 are estimated by dividing total movement charges by real-time scheduled regulation capacity.
  - ✓ 30-min operating reserve prices in western NY; 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 29 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).

# DA Regulation Capacity Schedules, Offers, and Prices – April 2019

- Slide 30 summarizes the outcomes of Regulation Capacity schedules and prices for each day of April 2019 when prices displayed the greatest volatility.
  - ✓ The daily values are broken down further into the averages across six-hour time blocks (i.e., averages during Hour-beginning 0-5, 6-11, 12-17, and 18-23).
- The bottom portion of the chart displays the Regulation Capacity in the Day-Ahead Market by:
  - ✓ Scheduled MWs
  - ✓ Unscheduled MWs associated with generators that received an energy schedule
  - ✓ Unscheduled MWs associated with generators that were not scheduled for energy
  - ✓ The black markers denote the Regulation Capacity requirement for each hour block.
    - – The hourly regulation requirement for April 2019 of the NYCA is published via the NYISO website.
- The top portion of the chart gives the actual Day-Ahead Regulation Capacity price
- Each of these values are shown by day as averages across 6-hour time blocks.

# Day-Ahead Load Scheduling and Virtual Trading

- Slide 32 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 33 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 34 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 36 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.

# Transmission Congestion and Shortfalls

- Slides 38, 39, 40, and 41 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 38 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 39 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 40 and 41 show the day-ahead and balancing congestion revenue shortfalls by transmission facility on a daily basis.
  - ✓ Negative values indicate day-ahead and balancing congestion surpluses.

# Transmission Congestion and Shortfalls (cont.)

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

# NY-NJ PAR Operation Under M2M with PJM

- Slide 42 evaluates operations of NY-NJ PARs under M2M with PJM during the following periods of noticeable congestion differential between NY and PJM:
  - ✓ When NY costs on relevant M2M constraints exceed PJM costs by: a) \$10/MWh to \$20/MWh; b) \$20/MWh to \$30/MWh; or c) more than \$30/MWh.
  - ✓ When PJM costs on relevant M2M constraints exceed NY costs by: a) \$10/MWh to \$20/MWh; b) \$20/MWh to \$30/MWh; or c) more than \$30/MWh;
  - ✓ The market cost is measured as the constraint shadow price multiplied by the PAR shift factor, summed over relevant M2M constraints in each 5-minute market interval and then averaged over each half-hour period.
  - ✓ The top portion of the figure shows two stacked bars for each evaluation group, representing the total number of 30-minute intervals with and without any PAR tap movements.
  - ✓ The bottom portion of the figure shows average actual PAR flows (blue bar), compared with their average M2M targets (red diamond).

 

# Constraints on the Low Voltage Network

- Transmission constraints on the 115 kV and lower voltage networks in New York are often resolved in ways that include:
  - ✓ Out of merit dispatch and supplemental commitment of generation;
  - ✓ Curtailment of external transactions and limitations on external interface limits;
  - ✓ Use of an internal interface transfer limit that functions as a proxy for the limiting transmission facility; and
  - ✓ Adjusting PAR-controlled lines on the high voltage network.
- Slide 43 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:  Mostly Gardenville-to-Dunkirk and Erie-to-Gardenville 115kV circuits;
  - ✓ Central Zone:  Mostly constraints around the State Street 115kV bus;
  - ✓ Capital Zone:  Mostly Albany-to-Greenbush 115kV constraints;
  - ✓ North Zones:  115kV constraints on facilities that flow power south from the North Zone and circuits into the North Zone; and
  - ✓ Long Island:  Mostly constraints on the 69kV system on Long Island.

# Constraints on the Low Voltage Network

- Slide 44 shows the number of hours and days in the quarter when various resources were used to manage 69 kV 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 Pilgrim-Hauppaug and Hauppaug-Central Islip circuits;
  - ✓ East End: Mostly to satisfy the TVR requirement.
  - ✓ For a comparison, the tables also show the frequency of congestion management on the 138 kV constraint via the market model.
- Slide 44 also shows our estimated price impacts in each LI load pocket that result from explicitly modeling these 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 45 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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# Limit Reduction in Congestion Management
## Top Facilities in 2019-Q2

- Slide 46 lists top transmission facilities that experienced frequent constraint limit reduction by operators during the quarter to manage congestion in real-time.
- The table shows the following quantities:
  - ✓ # of Intervals w/ Limit Reduction – the total number of 5-minute intervals in the quarter during which the constraint limit for a particular facility is reduced from its daily maximum.
  - ✓ Avg Daily Max Limit MW – the average of daily maximum constraint limits during all reported intervals.
  - ✓ Avg MW Reduced – the average of reduced MW during all reported intervals.
  - ✓ Reduction as % of Max Limit – the average limit reduction as a percent of average daily maximum limit.
  - ✓ Estimated BMCR from Daily Max Limit – the resulting balancing congestion residuals from limit reduction, estimated by (Daily Max Limit – Limit Used in the Interval)*Constraint Shadow Cost summed over all reported intervals.

# Supplemental Commitments and OOM Dispatch

- Slides 48, 49, and 50 summarize out-of-market commitment and dispatch, which are the primary sources of guarantee payment uplift.
- Slide 48 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 49 examines the reasons for reliability commitments in NYC where most reliability commitments occur.
  - ✓ Based on a review of operator logs and LRR constraint information (where a unit is considered to be committed for a LRR constraint if the constraint would be violated without the unit’s capacity), each NYC commitment (flagged as DARU, LRR, or SRE) was categorized for one of the following reasons:

# Supplemental Commitments and OOM Dispatch (cont.)

  - NOx Only – If needed for NOx bubble requirement and no other reason.
  - Voltage – If needed for ARR 26 and no other reason.
  - Thermal – If needed for ARR 37 and no other reason.
  - Loss of Gas – If needed for IR-3, a sudden loss of gas supply in NY, and no other reason except NOx.
  - Multiple Reasons – If needed for two or three of the following reasons: voltage support, thermal support, NOx, or loss of gas. The capacity is shown multiple times for each separate reason in the bar chart.
- ✓ For voltage and thermal constraints, the capacity is shown by the load pocket that was secured.

- Slide 50 summarizes the frequency (measured by the total station-hours) of Out-of-Merit dispatches by region on a monthly basis.
  - ✓ The figure excludes OOMs that prevent a generator from being started, since these usually indicate transmission outages that make the generator unavailable.
  - ✓ In each region, “Station #1” is the station with the highest number of OOM hours in its region in the current quarter; “Station #2” is the station with the second-highest number of OOM hours; all other stations are grouped together.

# Uplift Costs from Guarantee Payments

- Slides 51 and 52 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 51 shows these seven categories on a daily basis during the quarter.
  - ✓ Slide 52 summarizes uplift costs by region on a monthly basis.

# Potential Economic and Physical Withholding

- Slides 54 and 55 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 56 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 58 and 59 summarize market results and key drivers in the monthly spot capacity auctions.
  - ✓ Slide 58 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 59 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.