Quarterly Report on the New York ISO Electricity Markets Third Quarter of 2016

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Highlights and Market Summary: Energy Market Outcomes and Congestion

- This report summarizes market outcomes in the third quarter of 2016.
- The energy markets performed competitively and variations in wholesale prices were driven primarily by changes in fuel prices, demand, and supply availability.
- Average all-in prices ranged from roughly $35/MWh in the North Zone to $70/MWh in Long Island. (see slide 9)
  - ✓ LBMPs rose moderately from 2015-Q3 in most areas partly because:
    - Average load levels rose ~600 MW and annual peak load rose by 1 GW primarily because of warmer weather conditions. (see slide 11)
    - Hydro and nuclear output fell ~400 MW. (see slide 15)
    - North Zone was the only region where prices fell because of more frequent congestion in September due to transmission outages. (see slide 20)
    - However, natural gas prices remained very low and actually fell 14 percent in New York City, which helped offset the effect of higher load levels. (see slide 12)
  - ✓ The largest LBMP change (+35%) was in Long Island because the Y49 line outage greatly reduced imports from upstate for most of the quarter (see slide 20).
  - ✓ Capacity costs fell 22 and 23 percent in NYC and Long Island from the previous year. (see slide 9)

Highlights and Market Summary:
Energy Market Outcomes and Congestion

- DAM congestion revenues totaled $131 million, up 42 percent from the third quarter of 2015. (see slide 55)
  - ✓ Over 60 percent of the increase occurred on Long Island primarily because:
    - The Y49 line outage reduced imports from upstate during most of the quarter; and
    - The 677 line derating led to congestion from Northport to other areas of Long Island throughout the quarter.
  - ✓ West Zone accounted for most of the remaining increase as the congestion pattern changed because of factors discussed in the next slide.
  - ✓ Although congestion into Southeast New York was generally reduced following the installation of the new “TOTS” projects, the benefits were largely offset by the derating of the Branchburg-Ramapo line.
- The Graduated Transmission Demand Curve (“GTDC”) project has led to higher congestion prices. (see slides 71-75)
  - ✓ Although most shortages (~70%) are still resolved using the constraint relaxation method (rather than the GTDC), the GTDC project changed key parameters used for constraint relaxation that has increased congestion shadow prices.
  - ✓ Constraint relaxation can lead shadow prices to be unpredictably higher or lower than the GTDC (regardless of severity of shortages).

Highlights and Market Summary: Energy Market Outcomes and Congestion

- West Zone congestion has been affected by significant market changes, including:
  - ✓ (a) the implementation of GTDC in February 2016; (b) the retirements of coal units in December 2015 and in March 2016; (c) the implementation of a composite shift factor at Niagara plant in May 2016; (d) transmission upgrades in May 2016; and (e) the S. Ripley-Dunkirk 230 kV line and Warren-Falconer 115 kV line being taken OOS during most of 2016-Q2.
  - ✓ Also, volatile loop flows continued to exacerbate congestion. (see slides 61-63)
- These challenges increase the need for efficient congestion management in the West Zone.
  - ✓ On 6/28, NYISO implemented enhanced loop flow assumptions in RTC and RTD to deal with uncertainty about loop flows.
  - ✓ However, we continue to observe: (see slides 64-70)
    - Under-utilization of 115kV circuits that are parallel to congested facilities,
    - Inefficiently-high generation from units that exacerbate 230kV congestion,
    - Under-commitment of West Zone units that relieve 115kV & 230kV congestion,
    - Shadow prices are not well correlated with the severity of congestion during transmission shortages, which undermines scheduling incentives for importers and other non-dispatchable resources.

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Highlights and Market Summary: Capacity Market

- UCAP prices fell 20 percent in New York City and 23 percent in Long Island from 2015-Q3, but rose 11 percent in the G-J Locality. (see slides 98-99)
- Average spot prices fell in NYC and Long Island primarily because of lower ICAP requirements (5% in NYC and 2% in Long Island). These fell because of:
  - ✓ Lower LCRs, which resulted partly from the TOTS projects that increased import capability into SENY; and
  - ✓ Lower peak load forecast.
- G-J Locality spot prices rose because the decrease in capacity supply was larger than the decrease in the ICAP requirement.
- In ROS, average spot prices were relatively unchanged from the previous year because of the combined effect of following factors:
  - ✓ Slightly lower ICAP requirement, which reflected the net effect of lower peak load forecast and a higher IRM.
  - ✓ A decrease in internal ICAP supply because of retirements, mothballing, and outages.
  - ✓ Higher sales from external resources (partly offset by lower SCR sales).

Highlights and Market Summary: Uplift and Revenue Shortfalls

- Guarantee payments were \$19M, down 7% from 2015-Q3. (see slides 78-88)
  - ✓ Supplemental commitments and OOM dispatches fell in Western NY because of transmission upgrades and in NYC because of generation being more economic (relative to the rest of Eastern NY due to gas market conditions).
  - ✓ However, these were offset by increased supplemental commitments and OOM dispatches in Long Island because of higher load levels and transmission outages.
- DAM congestion shortfalls were \$20M, up \$13M from 2015-Q3. (see slide 56)
  - ✓ Transmission outages were the main driver – over \$11M of shortfalls were assigned to the responsible transmission owners.
  - ✓ The remaining shortfalls accrued primarily on the West Zone constraints, resulting largely from assumptions related to loop flows.
- Balancing congestion shortfalls were \$9M, up \$3M from 2015-Q3. (see slide 57)
  - ✓ TSA events on several days accounted for the majority of shortfalls.
    - – TSA-related congestion shortfalls were notably higher than in the prior two summers partly because of: a) higher load levels during TSA events; and b) less congestion relief from the Ramapo line because of its derating.
  - ✓ West Zone 230 kV facilities accounted for most of remaining shortfalls.

Energy Market Outcomes

All-In Prices

- The first figure 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 based on spot prices multiplied by capacity obligations.
  - ✓ The NYISO cost of operations and uplift from other Rate Schedule 1 charges.
- Average all-in prices ranged from roughly $35/MWh in the North Zone to $70/MWh in Long Island this quarter.
  - ✓ LBMPs rose in most areas, consistent with higher load levels (see slide 20).
    - – Long Island exhibited the largest increase (35%) primarily because of the lengthy outage of the Y49 line, which greatly reduced imports from upstate.
    - – North Zone was the only region where prices fell. This was driven by more frequent congestion in September because of transmission outages.
  - ✓ Capacity costs (in terms of $/MWh) fell 3.5 percent in the ROS and 22-23 percent in NYC and Long Island, but they rose 4.5 percent in Zones G through I.
    - – These variations were driven by the combined effects of: a) lower ICAP requirements; b) reductions in capacity supply due to retirements, mothballs, and outages; and c) increased sales from external resources. (see slides 97-99)

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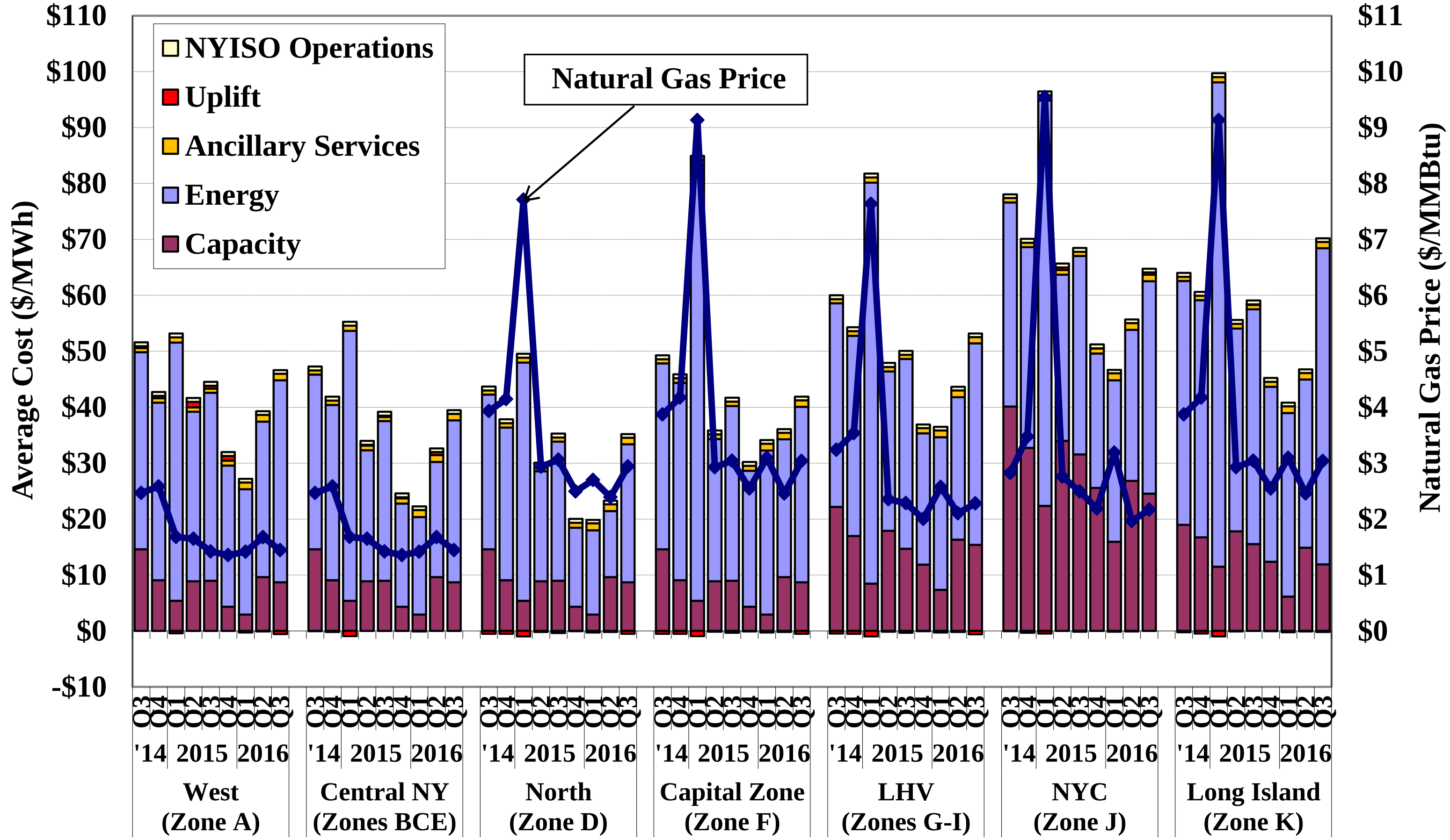
All-In Energy Price by Region



Note: Natural Gas Price is based on the following gas indices (plus a transportation charge of $0.20/MMbtu): the Dominion North index for West Zone and Central NY, the Iroquois Waddington index for North Zone, the Iroquois Zone 2 index for Capital Zone and LI, the average of Texas Eastern M3 and Iroquois Zone 2 for LHV, the Transco Zone 6 (NY) index for NYC. A 6.9 percent tax rate is also included NYC.

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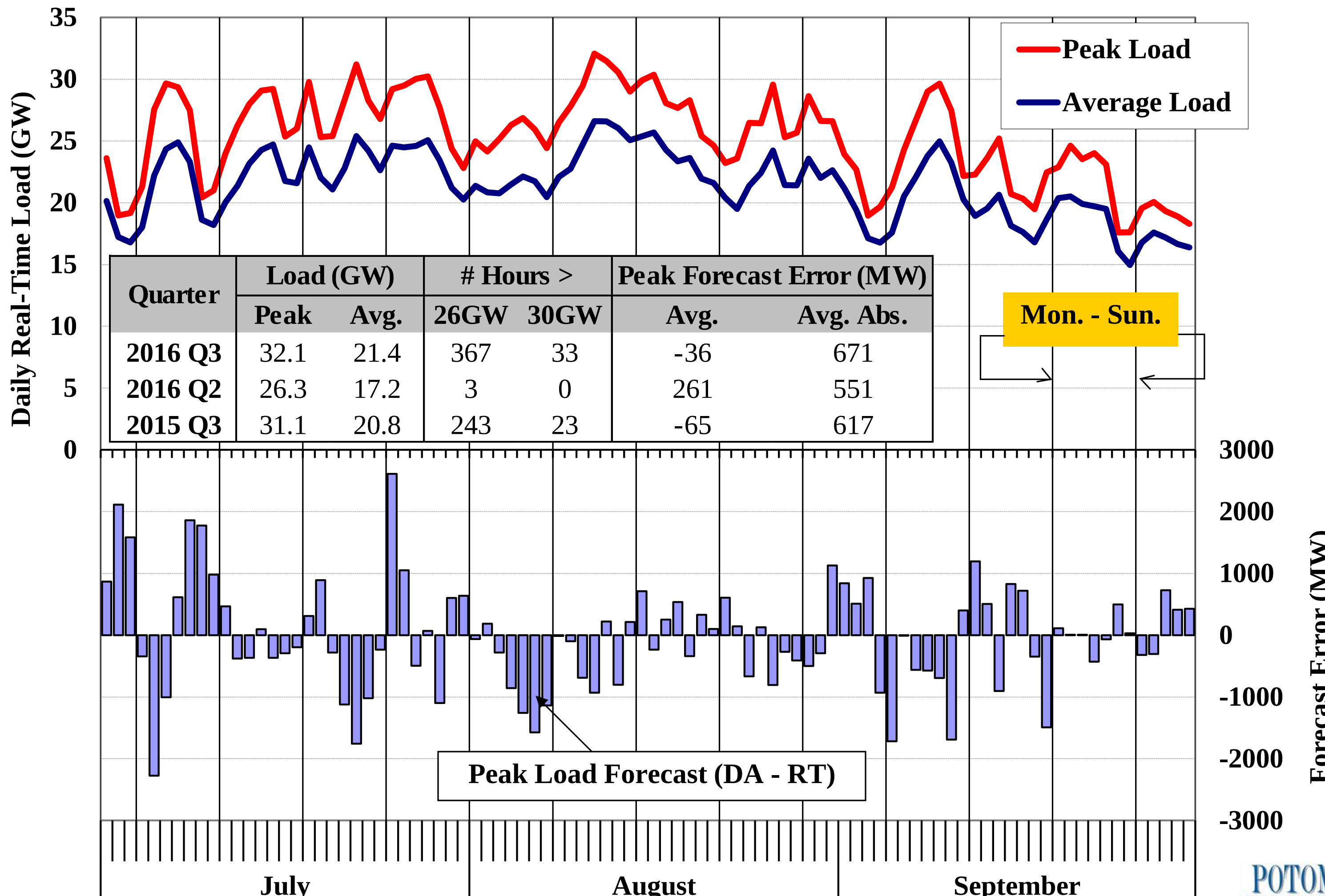
Load Levels and Fuel Prices

- The next two figures show two primary drivers of electricity prices in the quarter.
  - ✓ The first figure shows the average load, the peak load, and the day-ahead peak load forecast error on each day of the quarter.
  - ✓ The second figure shows daily coal, natural gas, and fuel oil prices.
- Load averaged 21.4 GW this quarter and peaked at 32.1 GW on August 12.
  - ✓ Both peak and average load levels rose noticeably (~3% each) from a year ago, due primarily to warmer weather conditions this summer.
    - – Although the peak load level was not the highest, the average load level was the highest in the third quarter since 2009.
  - ✓ Load forecast generally had larger errors on days with larger variations in load levels, contributing to price divergence between DA and RT on these days.
- Natural gas prices were stable throughout the quarter, and were comparable to prices from a year ago in most regions.
  - ✓ However, average gas prices for Transco Z6 NY fell 14 percent from a year ago.
    - – This led NYC generation to be more economic than most areas of Eastern NY.
  - ✓ Gas spreads between New England and Eastern NY increased from a year ago, contributing to higher exports to New England. (see slide 43)

Load Forecast and Actual Load



Quarter	Load (GW)		# Hours >		Peak Forecast Error (MW)	
	Peak	Avg.	26GW	30GW	Avg.	Avg. Abs.
2016 Q3	32.1	21.4	367	33	-36	671
2016 Q2	26.3	17.2	3	0	261	551
2015 Q3	31.1	20.8	243	23	-65	617

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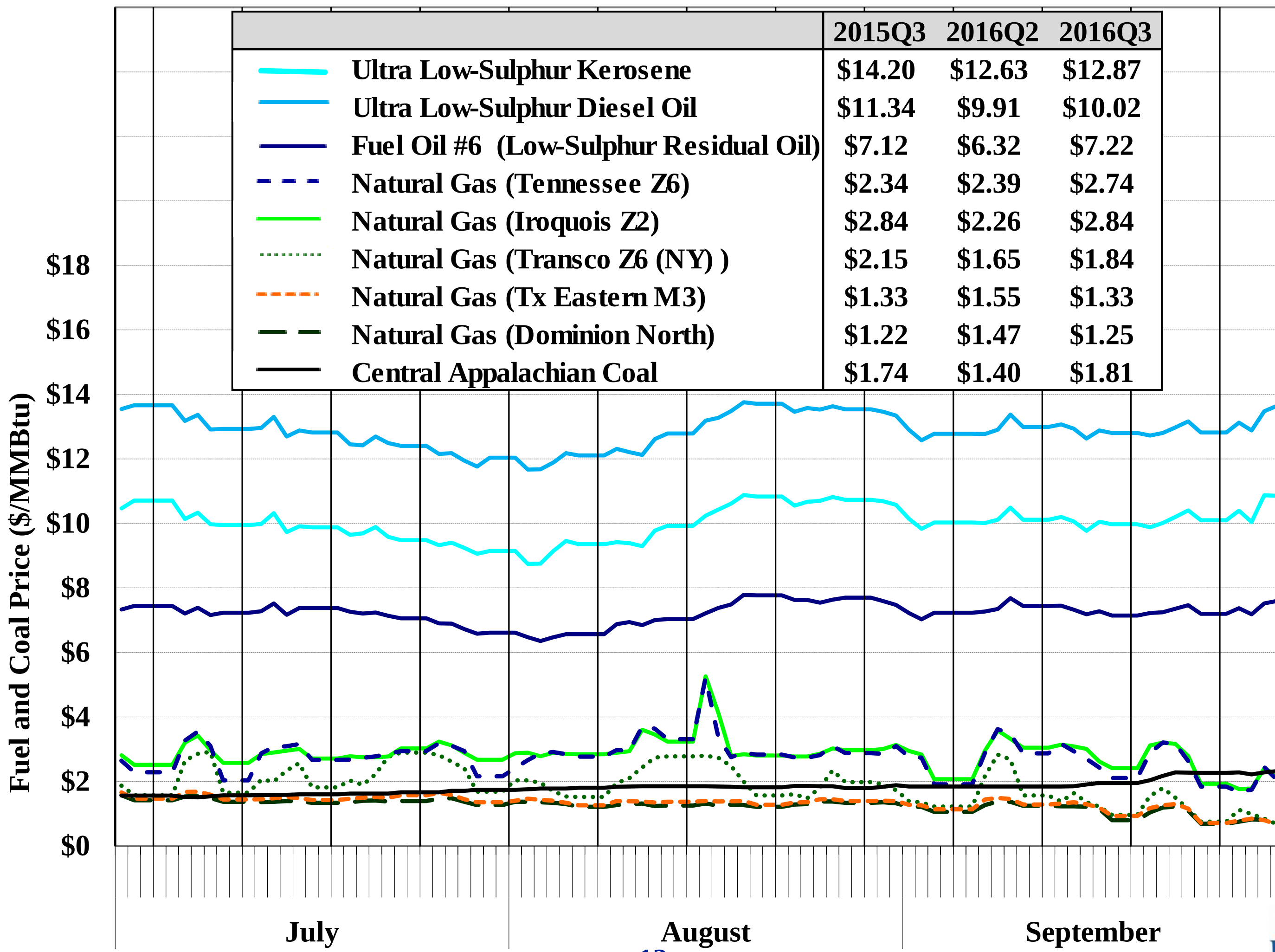
Coal, Natural Gas, and Fuel Oil Prices



Real-Time Generation by Fuel Type

- The following two figures summarize fuel usage by generators in NYCA and its impact on LBMPs in the third quarter of 2016.
- The first figure shows the quantities of real-time generation by fuel type in the NYCA and in each region of New York.
- The second figure summarizes how frequently each fuel type is 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.
- The fuel type for each generator is based on its actual fuel consumption reported to the EPA and the EIA.

Real-Time Generation and Marginal Units by Fuel Type

- Gas-fired (52 percent), nuclear (28 percent), and hydro (15 percent) generation accounted for most of the internal generation in the third quarter of 2016.
  - ✓ Nuclear generation fell modestly from the third quarter of 2015, reflecting more deratings in West NY (offset by fewer deratings in Hudson VL).
  - ✓ Average hydro generation fell 300 MW from a year ago.
  - ✓ Average coal generation rose 90 MW because coal production became more economic in the West Zone due to higher LBMPs during high load periods.
  - ✓ Gas-fired generation rose:
    - – In NYC due partly to lower gas prices than in the rest of East NY (see slide 12).
    - – In Long Island after transmission outages reduced imports from upstate.
- Gas-fired and hydro resources were on the margin the vast majority of time in the third quarter of 2016.
  - ✓ Hydro units in the West Zone were on the margin less frequently because Niagara modeling changes have reduced the frequency of real-time congestion in West Zone. (see slide 55)
  - ✓ Oil-fired GTs on Long Island were on the margin more frequently, reflecting more frequent starts in RT because of higher load, less upstate imports, and changes in offer patterns of several units.

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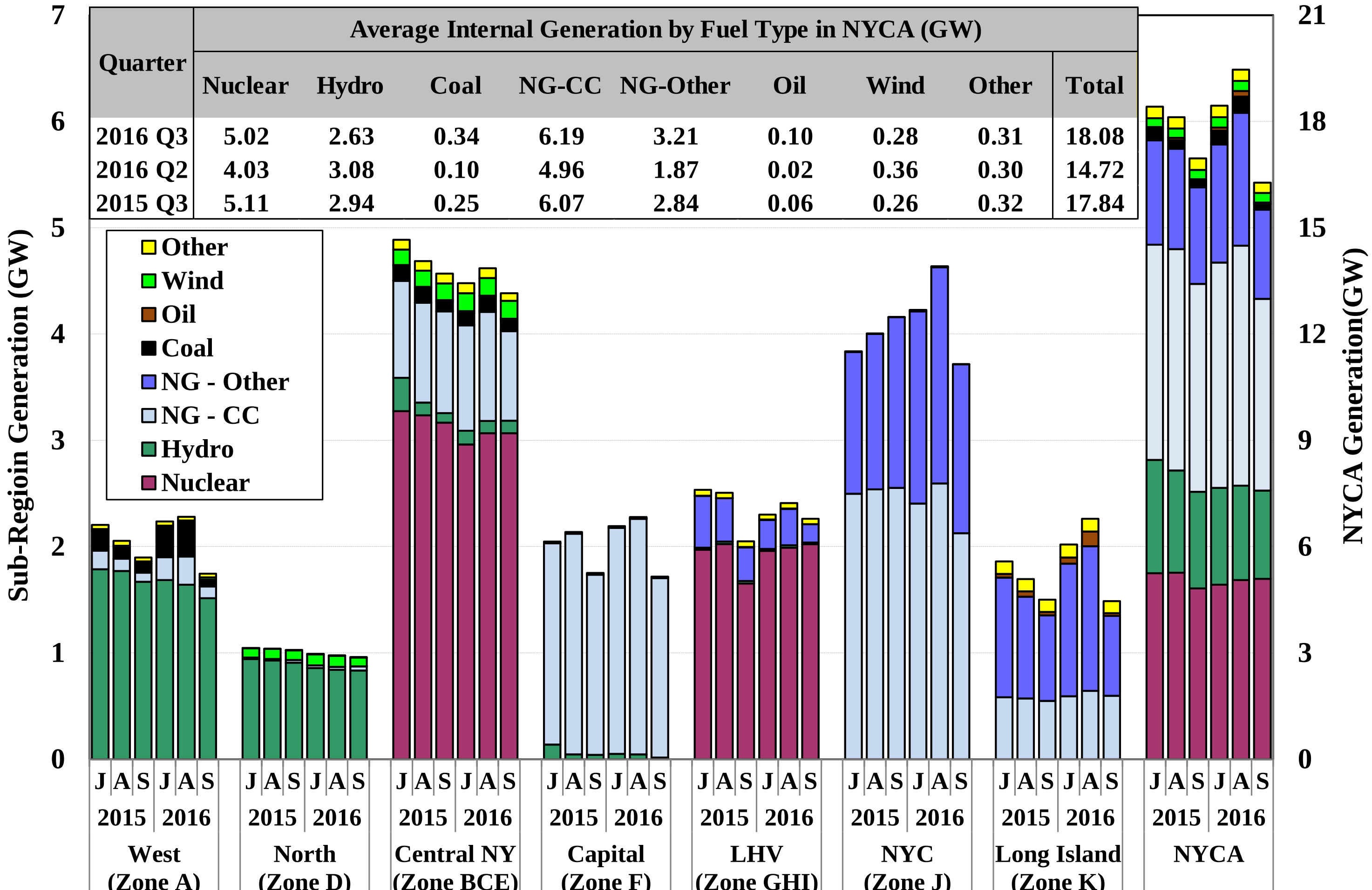
Real-Time Generation Output by Fuel Type

Quarter	Average Internal Generation by Fuel Type in NYCA (GW)								
	Nuclear	Hydro	Coal	NG-CC	NG-Other	Oil	Wind	Other	Total
2016 Q3	5.02	2.63	0.34	6.19	3.21	0.10	0.28	0.31	18.08
2016 Q2	4.03	3.08	0.10	4.96	1.87	0.02	0.36	0.30	14.72
2015 Q3	5.11	2.94	0.25	6.07	2.84	0.06	0.26	0.32	17.84



Notes: Pumped-storage resources in pumping mode are treated as negative generation. "Other" includes Methane, Refuse, Solar & Wood.

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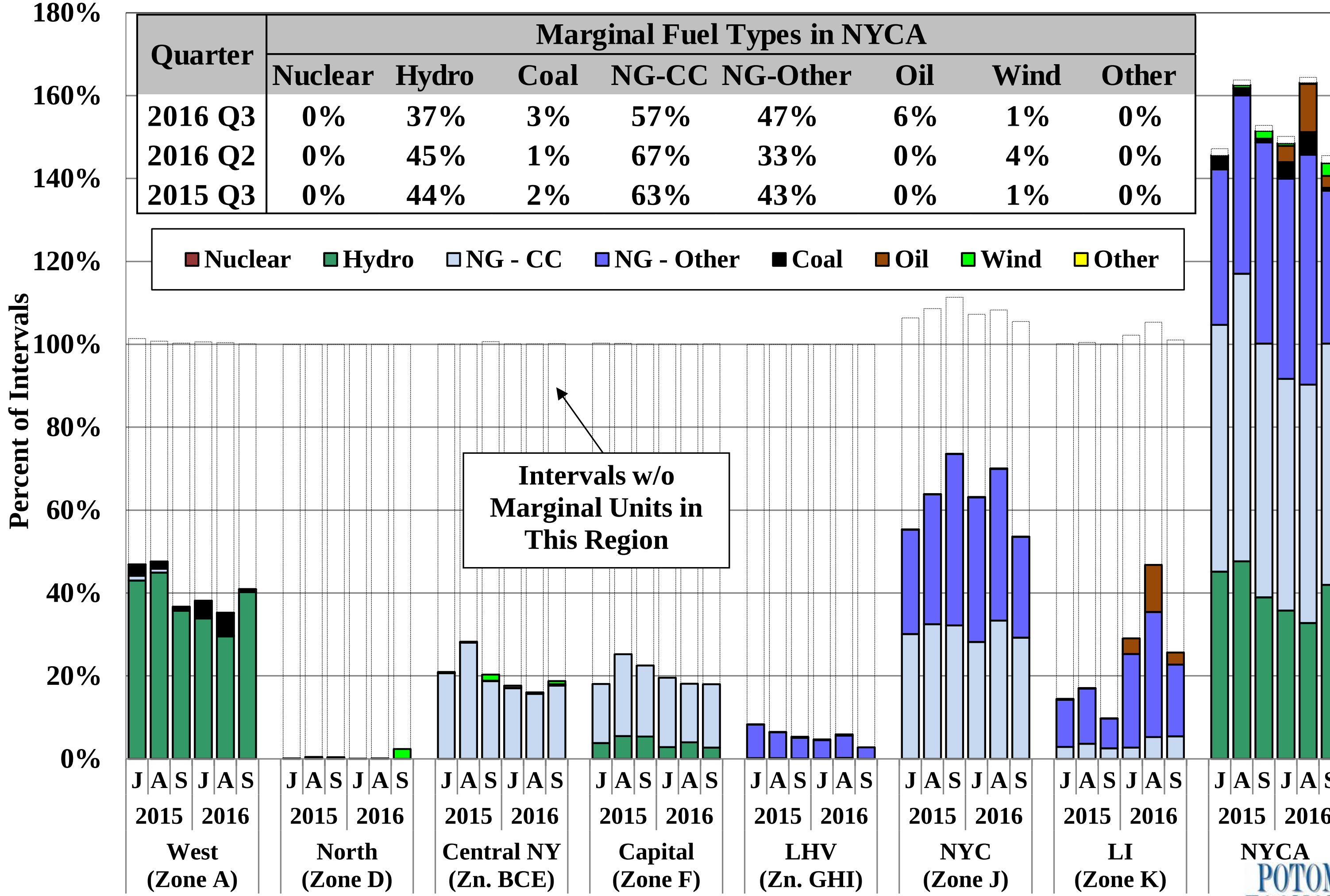
Fuel Types of Marginal Units in the Real-Time Market

Quarter	Marginal Fuel Types in NYCA							
	Nuclear	Hydro	Coal	NG-CC	NG-Other	Oil	Wind	Other
2016 Q3	0%	37%	3%	57%	47%	6%	1%	0%
2016 Q2	0%	45%	1%	67%	33%	0%	4%	0%
2015 Q3	0%	44%	2%	63%	43%	0%	1%	0%



Note: "Other" includes Methane, Refuse, Solar & Wood.

Day-Ahead and Real-Time Electricity Prices

- The following three figures show: 1) load-weighted average DA energy prices; 2) load-weighted average RT energy prices; and 3) convergence between DA and RT prices for six zones on a daily basis in the third quarter of 2016.
- Average day-ahead prices ranged from $25/MWh in the North Zone to over $55/MWh on Long Island, up 5 to 31 percent from the third quarter of 2015.
  - ✓ The statewide increases were driven primarily by higher load levels (see slide 11).
    - – Hydro and nuclear output fell ~400 MW, adding to the increase (see slide 15).
  - ✓ Long Island exhibited the largest increase (31 percent) among all zones.
    - – One of the 345 kV lines into Long Island (i.e., the Y49 line) was OOS in early-July and from early-August to mid-September, greatly reducing import capability from upstate during most of the quarter.
    - – Derating of the 677 line reduced output from Northport throughout the quarter.
  - ✓ The West Zone exhibited the second largest increase (24 percent).
    - – Congestion patterns changed significantly in this area for reasons discussed in later sections (see slides 61-70).
    - – The increase in the DAM was higher than in the RTM partly because of higher DA assumptions in the clockwise Unscheduled Power Flow around Lake Erie.
      - This reduced imports from Ontario scheduled in the DAM.

Day-Ahead and Real-Time Electricity Prices

- Prices are generally more volatile in the real-time market than in the day-ahead market because of unexpected events. For example,
  - ✓ From 8/10 to 8/13, RT LBMPs were often significantly elevated statewide and/or in SENY largely because of unexpected high load levels and TSA events.
  - ✓ On 8/23, RT LBMPs in Long Island spiked as low as -$6,000/MWh in the morning as a result of over-loading on multiple transmission constraints caused by unexpected over-generation from self-scheduled units and OOMs by the local TO.
- Random and otherwise unforeseen factors can cause large differences between DA and RT prices on individual days, while persistent differences may indicate a systematic issue. The table focuses on persistent differences by averaging over the entire quarter.
  - ✓ Average DA prices were generally within 1 to 4 percent of average RT prices in most areas this quarter.
    - – Although a small average DA premium was generally desirable in a competitive market, small RT premiums occurred in some areas because large RT spikes on a few days (due to unexpected RT events) outweighed small DA premiums on other days.
  - ✓ Unlike recent quarters, the West Zone exhibited a DA premium this quarter.

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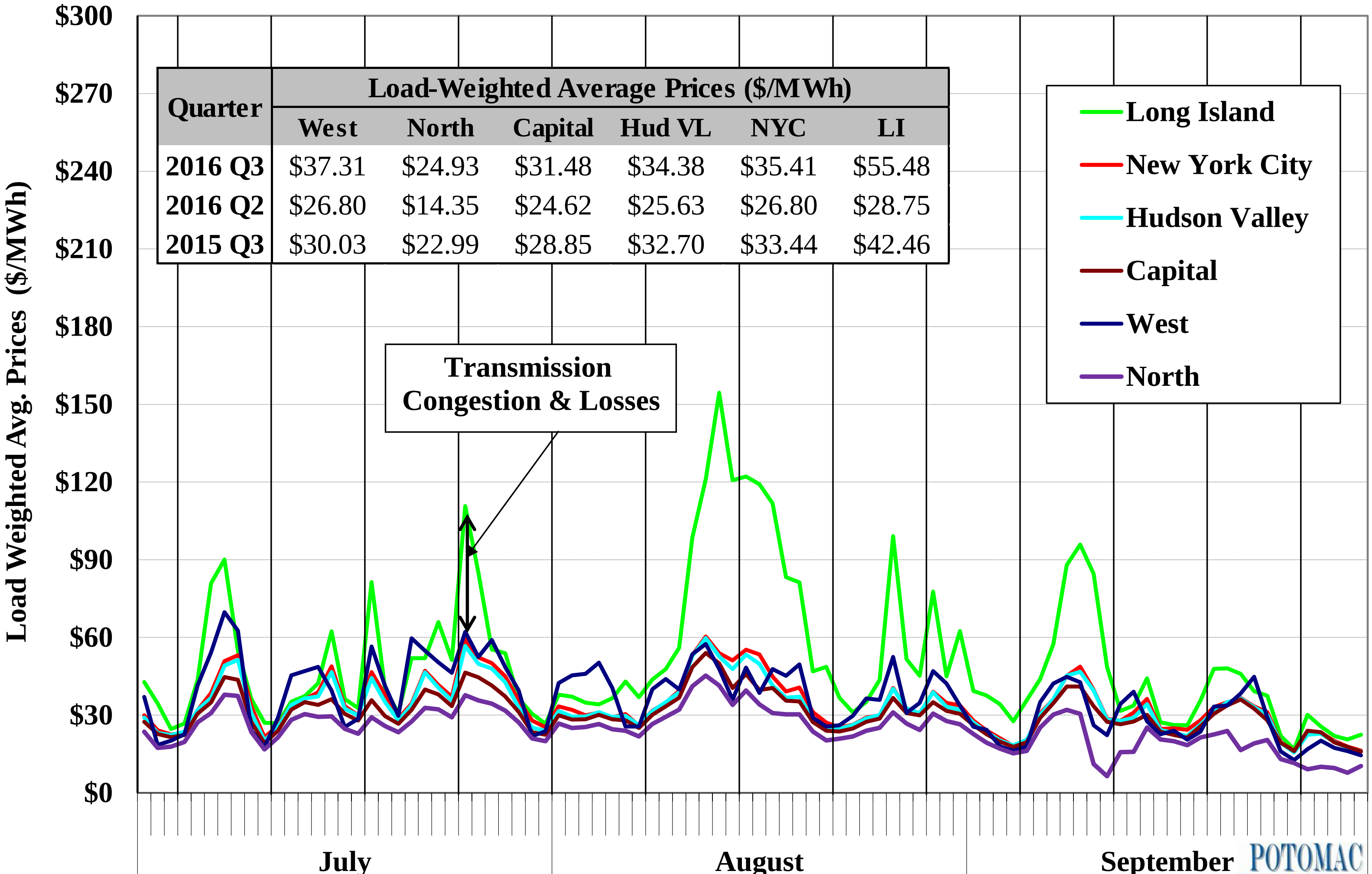
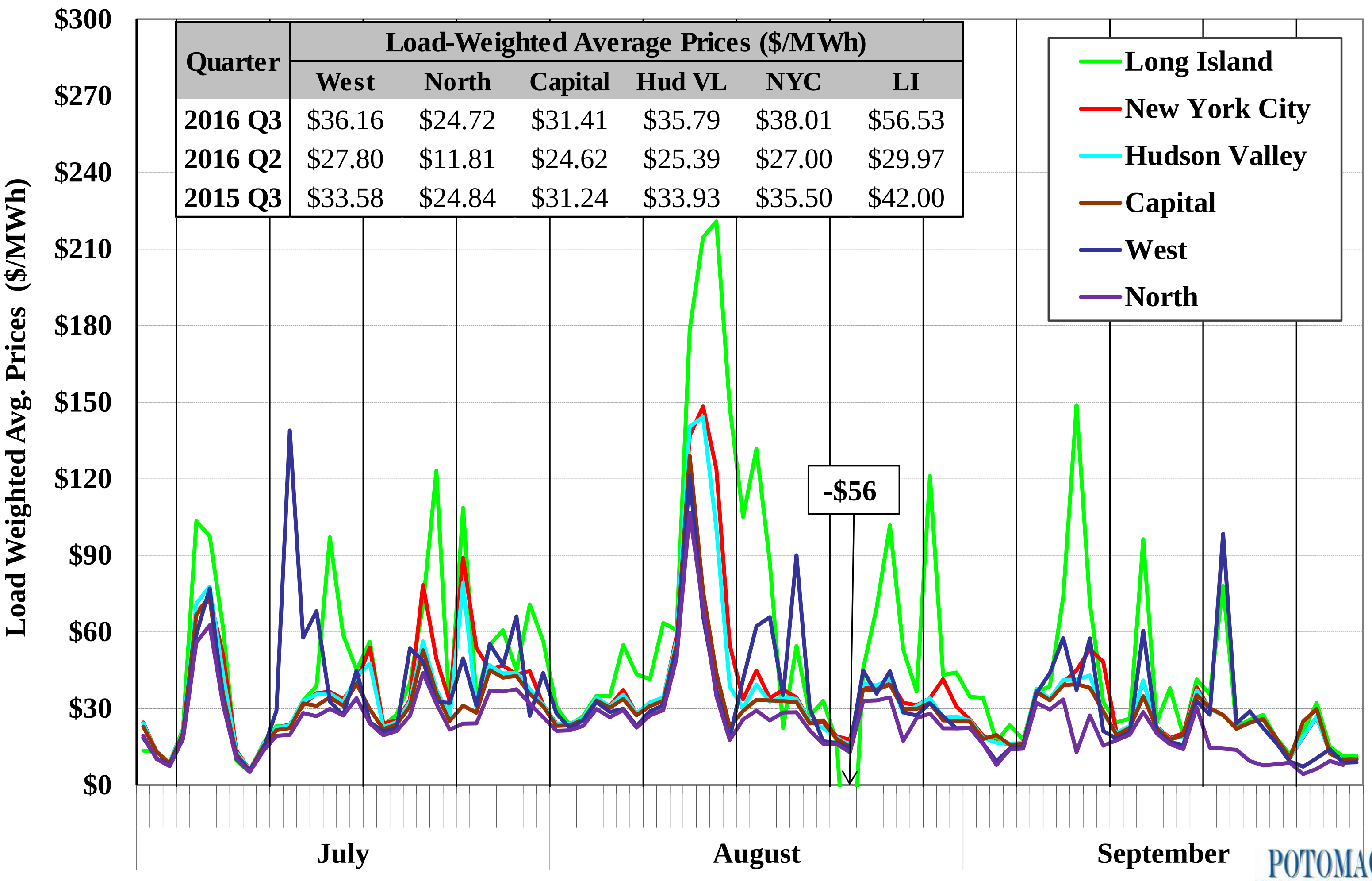
Day-Ahead Electricity Prices by Zone



Quarter	Load-Weighted Average Prices ($/MWh)					
	West	North	Capital	Hud VL	NYC	LI
2016 Q3	$37.31	$24.93	$31.48	$34.38	$35.41	$55.48
2016 Q2	$26.80	$14.35	$24.62	$25.63	$26.80	$28.75
2015 Q3	$30.03	$22.99	$28.85	$32.70	$33.44	$42.46

Real-Time Electricity Prices by Zone



Quarter	Load-Weighted Average Prices ($/MWh)					
	West	North	Capital	Hud VL	NYC	LI
2016 Q3	$36.16	$24.72	$31.41	$35.79	$38.01	$56.53
2016 Q2	$27.80	$11.81	$24.62	$25.39	$27.00	$29.97
2015 Q3	$33.58	$24.84	$31.24	$33.93	$35.50	$42.00

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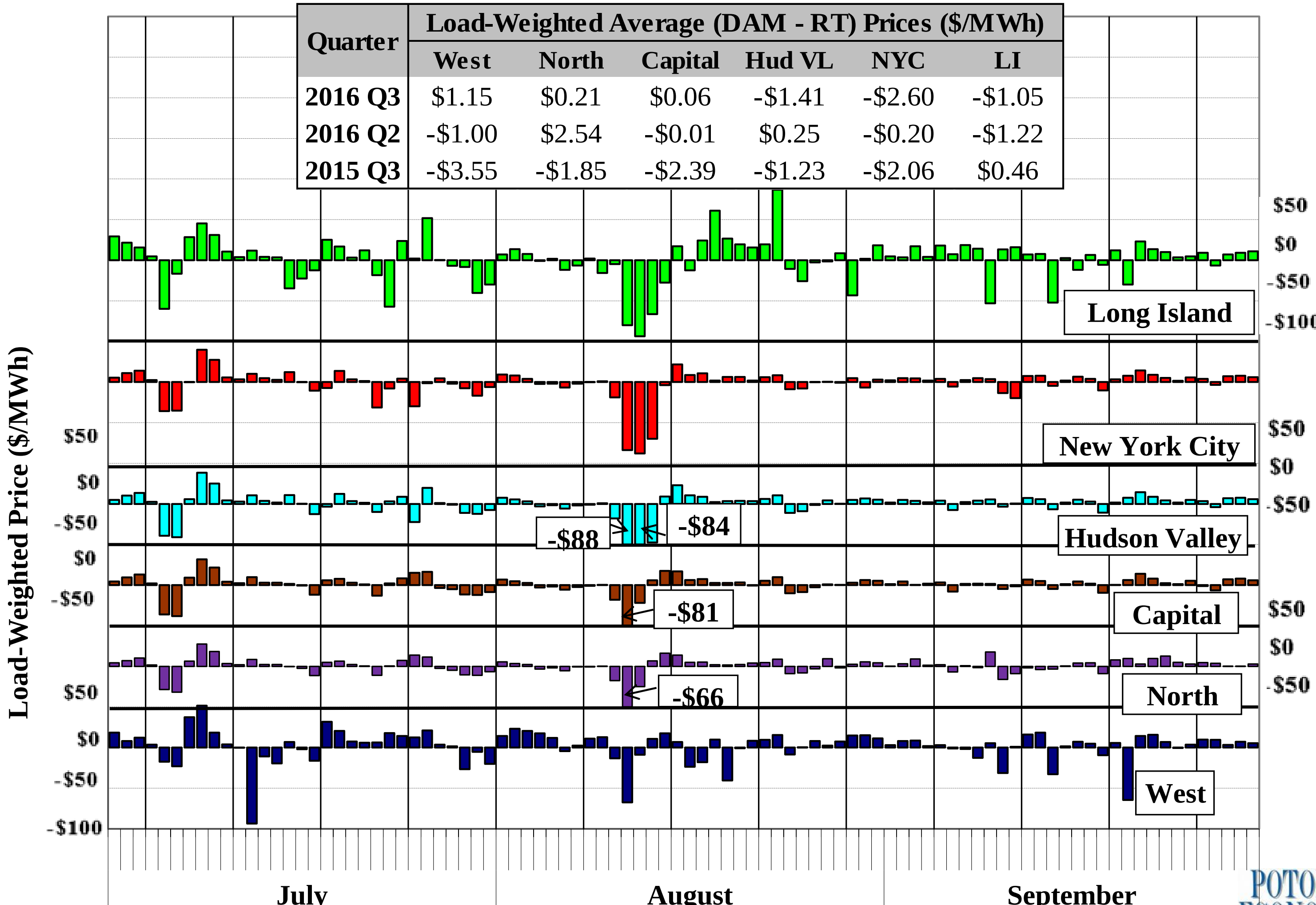
Convergence Between Day-Ahead and Real-Time Prices

Quarter	Load-Weighted Average (DAM - RT) Prices ($/MWh)					
	West	North	Capital	Hud VL	NYC	LI
2016 Q3	$1.15	$0.21	$0.06	-$1.41	-$2.60	-$1.05
2016 Q2	-$1.00	$2.54	-$0.01	$0.25	-$0.20	-$1.22
2015 Q3	-$3.55	-$1.85	-$2.39	-$1.23	-$2.06	$0.46



Demand Response Deployments – Introduction

- NYISO activated DR on August 12 in all zones for five hours (HB 13-17).
  - ✓ Actual peak load was 31.5 GW (estimated peak of 32.4 GW without DR).
    - An estimated ~ 1 GW of DR was activated.
  - ✓ NYISO SREed (the day before) four Danskammer units and one Oswego unit.
  - ✓ See presentation "NYISO Summer 2016 Hot Weather Operations" by Wes Yeomans at 9/28 MC meeting for more details.
- The use of DR resources is complicated by scheduling lead times and other inflexibilities, which have significant implications:
  - ✓ The NYISO must determine how much DR to activate when there is still considerable uncertainty about the needs of the system; and
  - ✓ The DR may not be needed for the entire duration of the DR activation period.
  - ✓ Hence, there may be substantial surplus capacity during portions of the event.
- The new Scarcity Pricing rule (effective on 6/1/16) was designed to ensure that RT prices better reflect actual shortages. The figure (slide 25) evaluates:
  - ✓ Whether RT prices efficiently reflected system conditions in each interval; and
  - ✓ Whether DR deployments were necessary in retrospect to maintain adequate capacity.

Demand Response Deployments – Description of Evaluation

- The figure reports the following in each interval for NYCA:
  - ✓ Available capacity – Includes four categories of unloaded capacity of online units and the capacity of offline peaking units up to the Upper Operating Limit:
    - 30-Minute Reserves – Scheduled;
    - 30-Minute Reserves – Unscheduled;
    - Additional Available Capacity (beyond 30-min rampable) for SRE resources; and
    - Additional Available Capacity for non-SRE resources.
  - ✓ NYISO DR deployed plus requirement for 30-minute reserves (see red line).
  - ✓ Market adjusted requirement (under new pricing rule) for 30-minute reserves (see black line).
  - ✓ LBMP of the least import-constrained zone in NYCA.
- DR was likely necessary to avoid a capacity deficiency when:

  DR deploy + normal 30-min reserve need (2620MW) > all available capacity

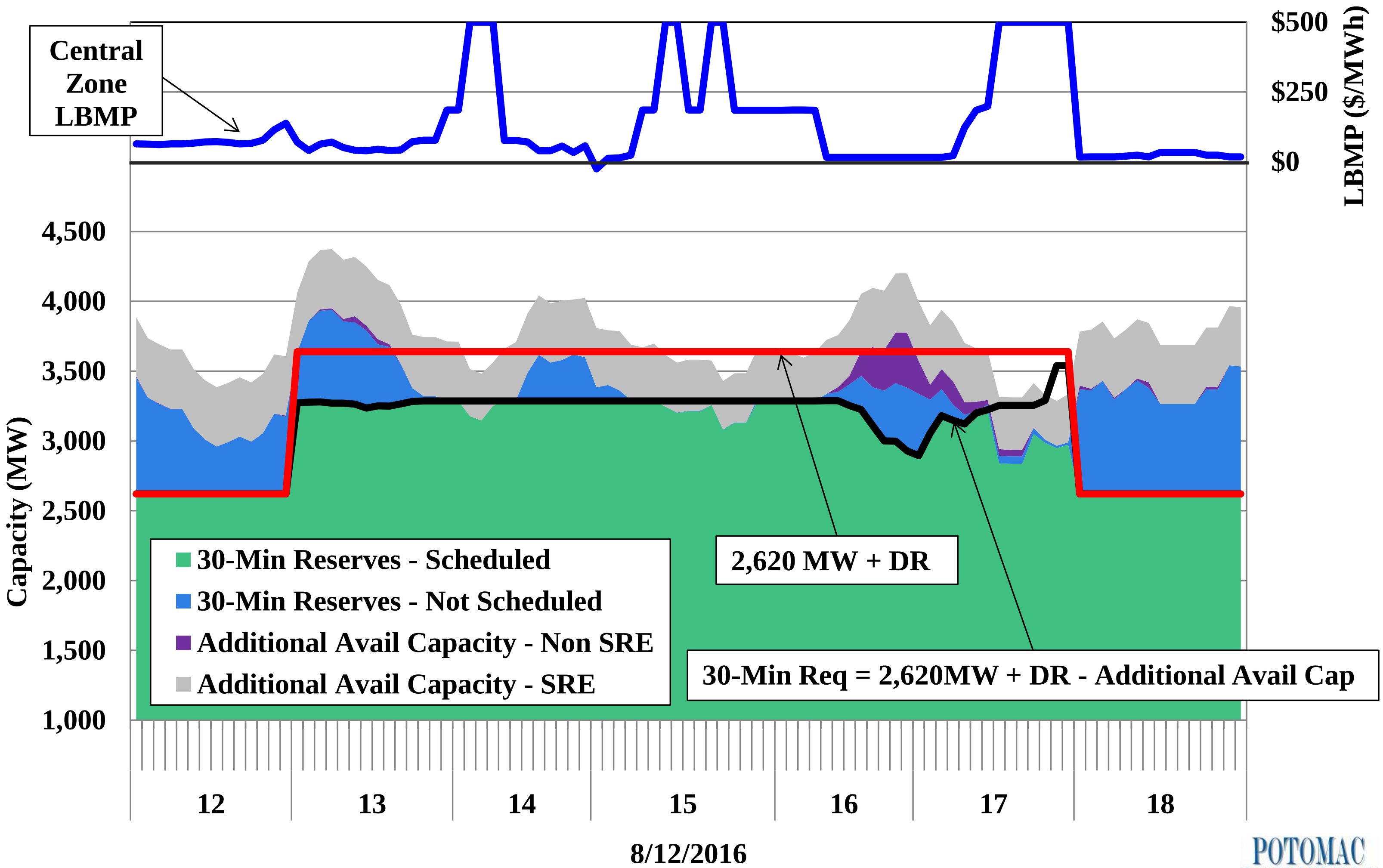
  (shown in the figure when the red line is higher than all areas).

Demand Response Deployments – Scarcity Pricing

- The evaluation suggests that:
  - ✓ In retrospect, DR was needed to prevent a capacity deficiency (i.e., red line > height of all areas) in a total of 18 intervals during the 5-hour deployment period.
  - ✓ 30-minute reserves were priced at $500/MWh during all 18 intervals.
    - The improved consistency between price signals and actual system needs is a significant enhancement under the new Scarcity Pricing Rule.
- Nonetheless, in retrospect, the actual amount of demand response that was needed to avoid a reserve shortage was just ~350 MW (indicated by the largest difference between the red line and the height of all areas).
  - ✓ This implies an over-deployment of DR (by more than 600 MW), which includes ~150 MW that was activated by utilities from their own DR programs.
  - ✓ A total of $1.1 million of guarantee payments were made to DR resources for their deployments (see slides 87-88).

Available Capacity and Real-Time Prices During DR Activations

NYCA, August 12



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Ancillary Services Market

Ancillary Services Prices

- The following three figures summarize DA and RT 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 procuring regulation, and the cost from moving regulation 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.
  - ✓ 30-min operating reserve prices in western NY; and
  - ✓ 30-min operating reserve prices in SENY.
- The figures also show the number of shortage intervals in real-time for each ancillary service product.
  - ✓ 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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Ancillary Services Prices

- The differences in day-ahead prices between different reserve products became much smaller following the rule changes (Comprehensive Shortage Pricing Project) made in November 2015.
  - ✓ The largest average differential was only $0.72/MWh (between eastern 10-min spinning prices and western 30-min total prices), down from $4.89/MWh last year.
  - ✓ This is because the statewide 30-minute requirement accounted for most of the operating reserve scheduling costs in the DAM.
- Day-ahead western 30-minute reserve prices rose markedly from $0.34/MWh in the 2015-Q3 to $5.66/MWh in this quarter for the reasons discussed later (see slides 32-34).
- Average DA and RT prices for all reserve products rose from a year ago, consistent with higher load levels and more frequent peaking conditions in this quarter.
  - ✓ Prices were particularly high on several days with very tight system conditions.
  - ✓ However, regulation prices fell modestly from a year ago.
    - – The rule change in November 2015 reduced the lowest regulation demand curve value from $80 to $25/MWh.
    - – As a result, although the number of RT regulation shortages rose notably, the average prices were lower.

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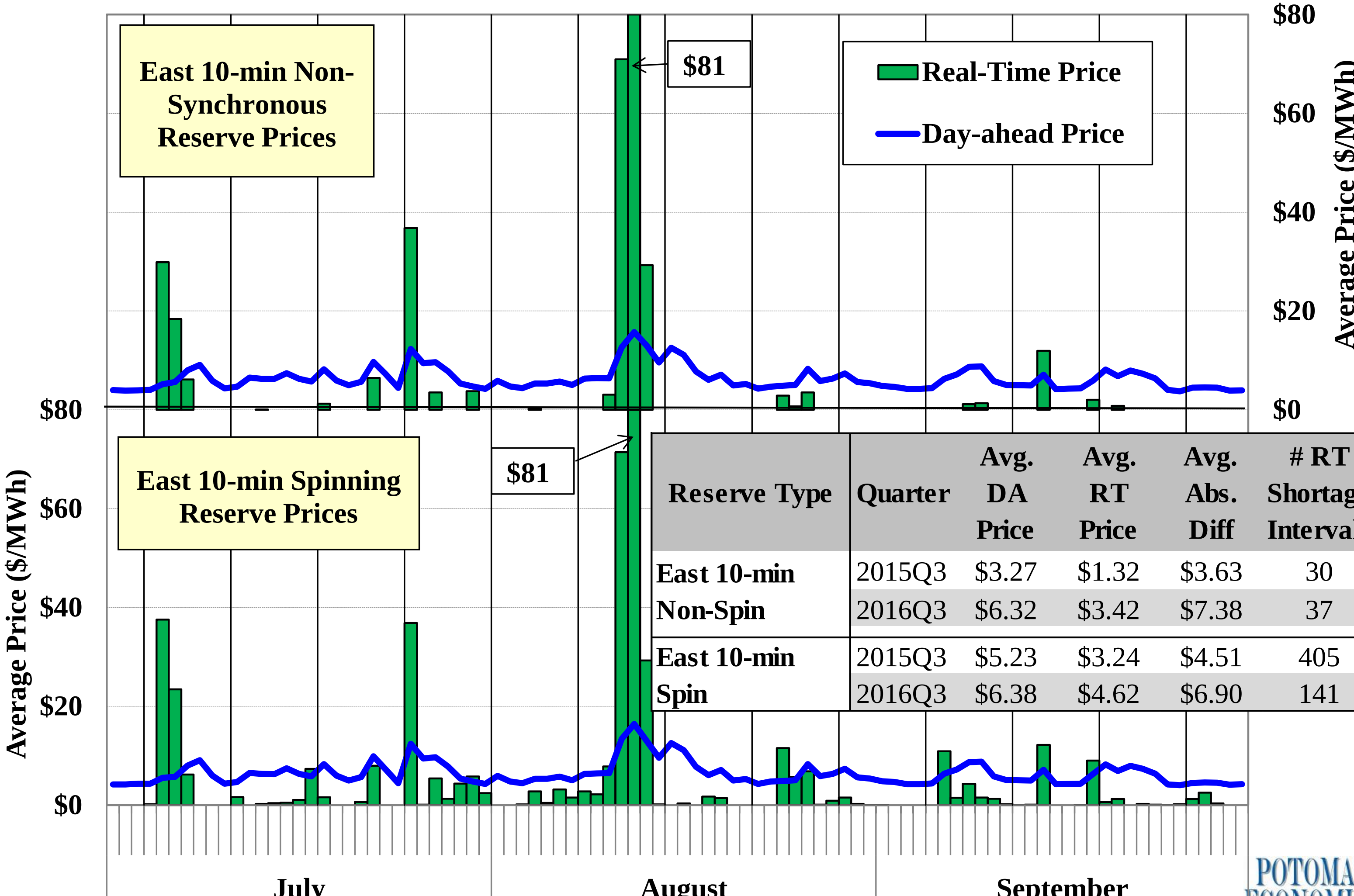
Day-Ahead and Real-Time Ancillary Services Prices
Eastern 10-Minute Spinning and Non-Spinning Reserves



Reserve Type	Quarter	Avg. DA Price	Avg. RT Price	Avg. Abs. Diff	# RT Shortage Intervals
East 10-min Non-Spin	2015Q3	$3.27	$1.32	$3.63	30
	2016Q3	$6.32	$3.42	$7.38	37
East 10-min Spin	2015Q3	$5.23	$3.24	$4.51	405
	2016Q3	$6.38	$4.62	$6.90	141

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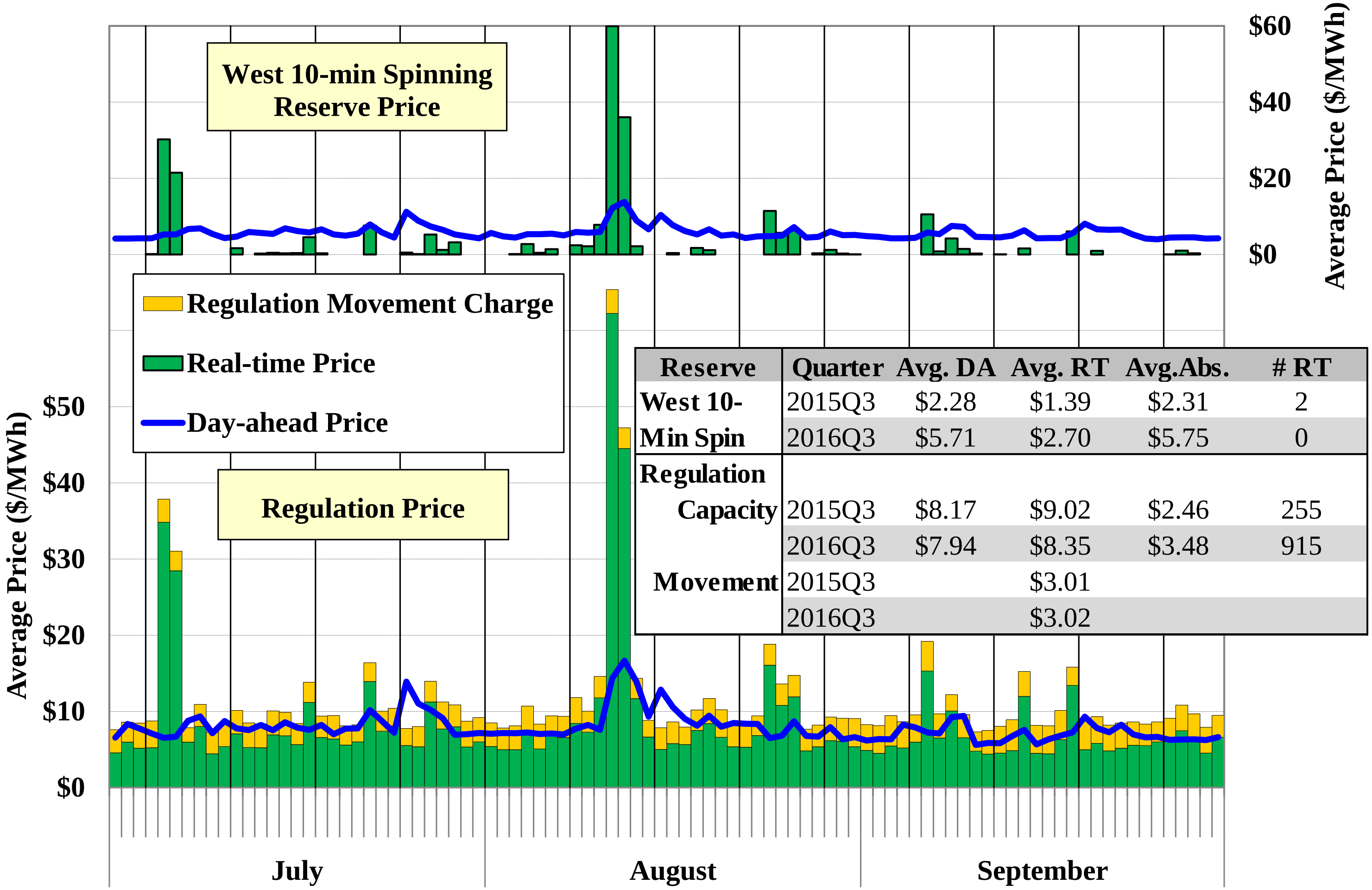
Day-Ahead and Real-Time Ancillary Services Prices
Western 10-Minute Spinning Reserves and Regulation



Reserve	Quarter	Avg. DA	Avg. RT	Avg.Abs.	# RT
West 10-Min Spin	2015Q3	$2.28	$1.39	$2.31	2
	2016Q3	$5.71	$2.70	$5.75	0
Regulation Capacity	2015Q3	$8.17	$9.02	$2.46	255
	2016Q3	$7.94	$8.35	$3.48	915
Movement	2015Q3		$3.01		
	2016Q3		$3.02		

Note: Regulation Movement Charges for regulating in real-time are shown in the figure averaged per MWh of RT Scheduled Regulation Capacity.

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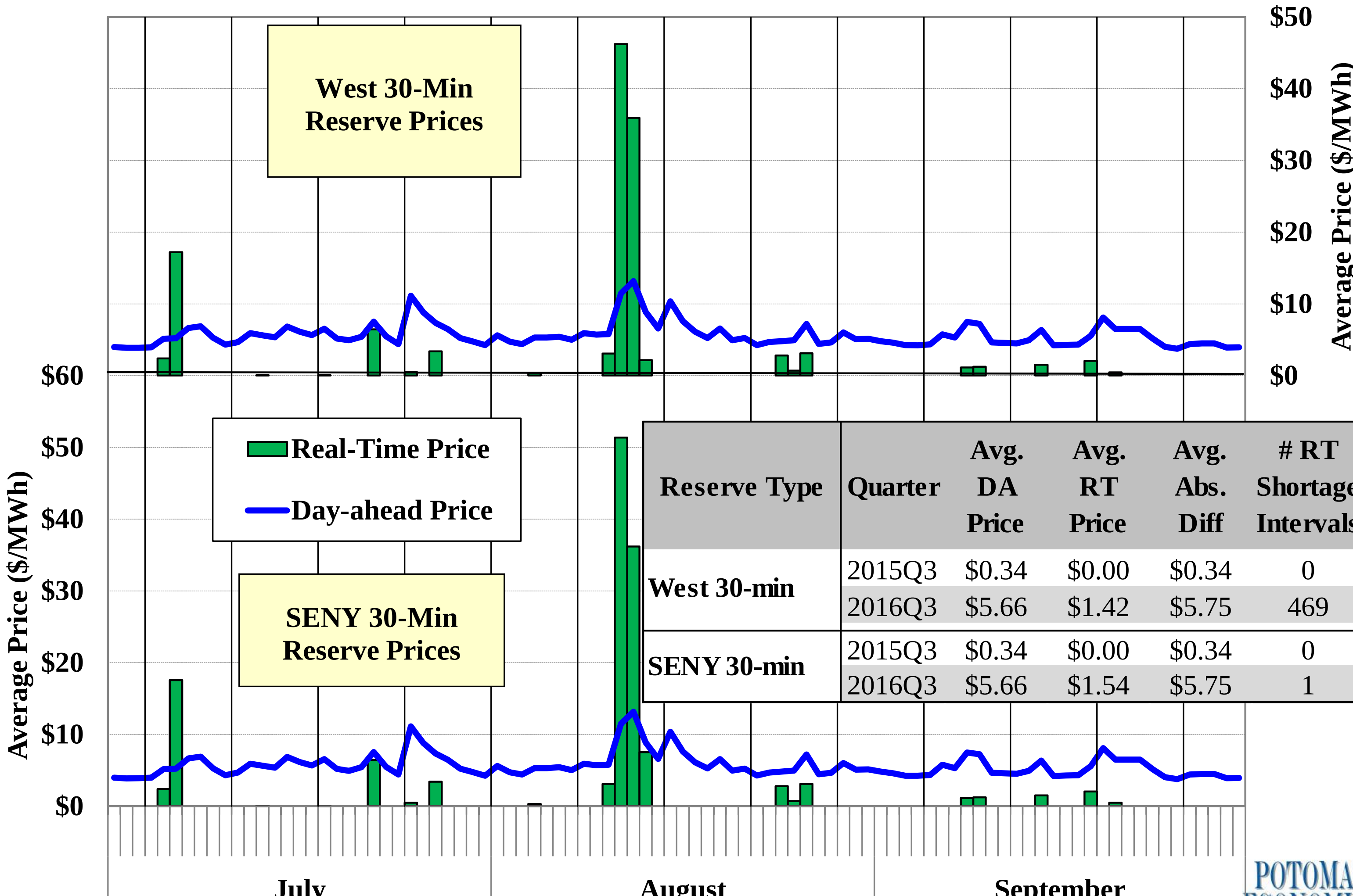
Day-Ahead and Real-Time Ancillary Services Prices
Western and SENY 30-Minute Reserves



Reserve Type	Quarter	Avg. DA Price	Avg. RT Price	Avg. Abs. Diff	# RT Shortage Intervals
West 30-min	2015Q3	$0.34	$0.00	$0.34	0
	2016Q3	$5.66	$1.42	$5.75	469
SENY 30-min	2015Q3	$0.34	$0.00	$0.34	0
	2016Q3	$5.66	$1.54	$5.75	1

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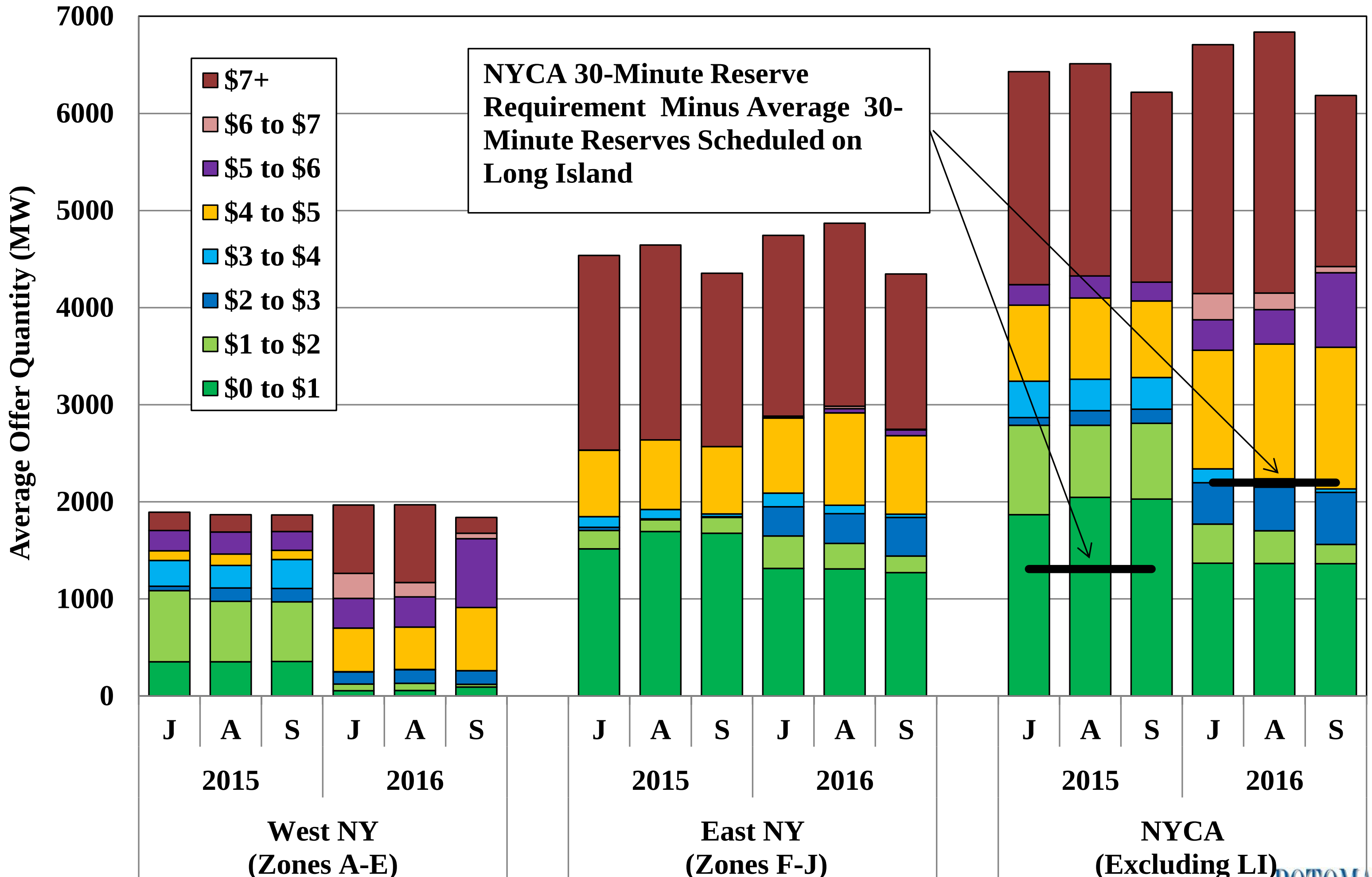
NYCA 30-Minute Reserve Offers in the DAM

- The next figure evaluates the drivers of increased DA 30-minute reserve prices by summarizing DA reserve offers.
  - ✓ 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 in this evaluation, since other resources do not directly affect the reserve prices.
  - ✓ The stacked bars show the amount of reserve offers in selected price ranges 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) to its 30-minute reserve requirement.
    - – As a result, Long Island reserve offers have little impact on NYCA reserve prices.
  - ✓ The two black lines represent the equivalent average 30-minute reserve requirements for areas outside Long Island in the third quarters of 2015 and 2016.
    - – 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 (however, opportunity costs are not reflected here).

NYCA 30-Minute Reserve Offers in the DAM

- The increase in 30-minute reserve prices from a year ago was primarily driven by:
  - ✓ The implementation of the Comprehensive Shortage Pricing project, which:
    - Increased the NYCA 30-min reserve requirement from 1,965 to 2,620 MW; and
    - Limited the amount of reserves scheduled on Long Island resources. An average of 423 MW of 30-minute reserves was scheduled on Long Island in 2016-Q3, down 236 MW from 2015-Q3.
    - Taken together, these two factors increased the need for 30-minute reserves outside Long Island by 891 MW from a year ago.
  - ✓ The increases of reserve offer prices in Western NY.
    - Over 85 percent of the reserve capacity offered in Western NY was offered above $4/MWh in the third quarter of 2016, while roughly 55 percent was offered for less than $2/MWh in the same period of 2015.
    - Nonetheless, we reviewed this offer change and found no significant competitive concerns.
- RT 30-minute reserve prices are much lower than DA prices because units that are dispatchable must have availability bids of $0 in RT.

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



POTOMAC ECONOMICS

Energy Market Scheduling

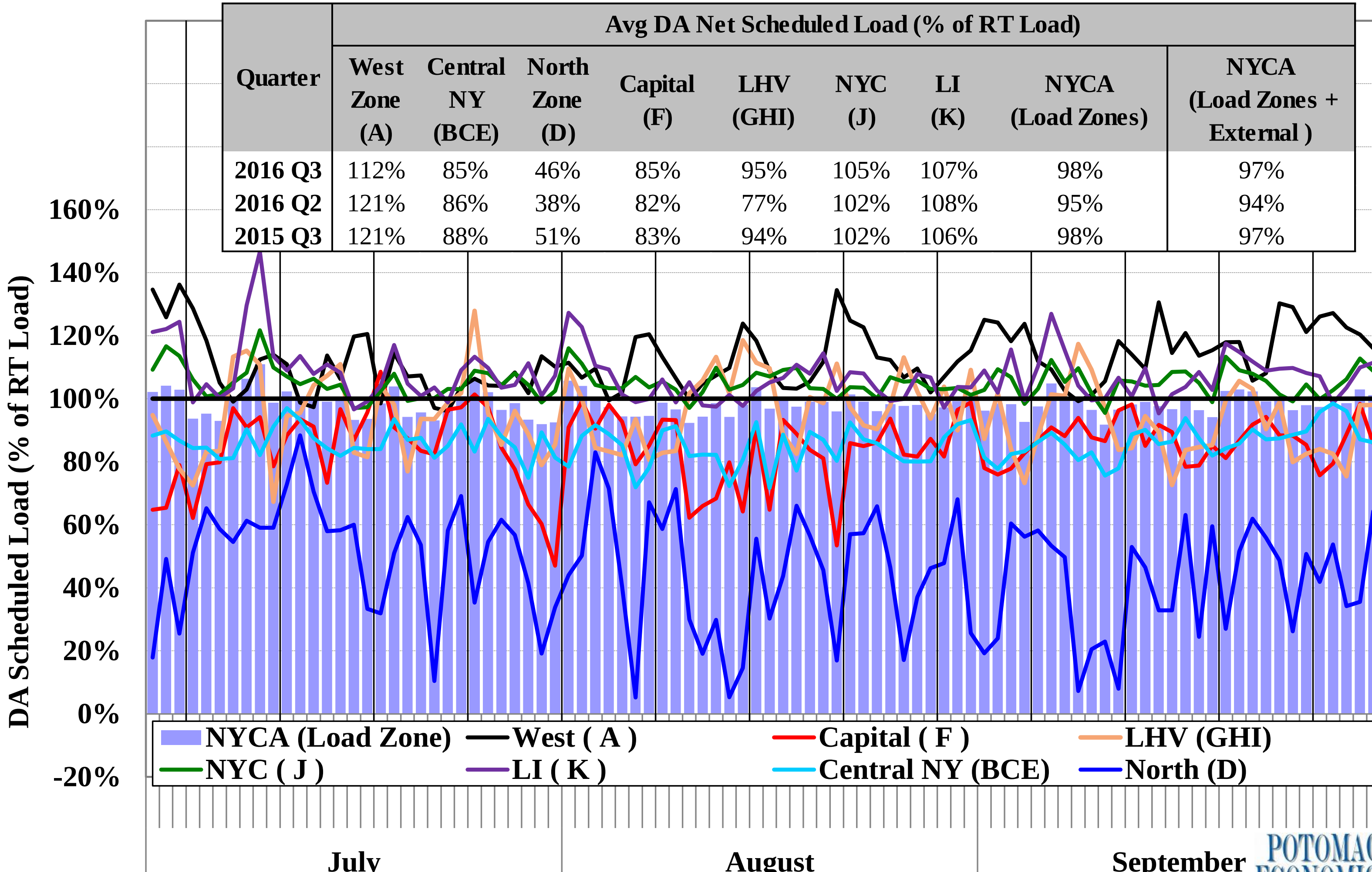
Day-ahead Load Scheduling

- The following figure summarizes the quantity of DA load scheduled as a percentage of RT load in each of seven regions and state-wide.
  - ✓ Net scheduled load = Physical Bilaterals + Fixed Load + Price-Capped Load + Virtual Load – Virtual Supply
  - ✓ The table also summarizes a system-wide net scheduled load that includes virtual imports and virtual exports at the proxy buses.
- For NYCA, 97 percent of actual load was scheduled in the DAM (including virtual imports/exports) during peak load hours in 2016-Q3, similar to 2015-Q3.
  - ✓ DA load scheduling in each sub-region was generally consistent with prior periods.
- Average net load scheduling tends to be higher in locations where volatile real-time congestion is more common.
  - ✓ Net load scheduling was generally higher in NYC and Long Island because they were downstream of most congested interfaces.
  - ✓ Net load scheduling was highest in the West Zone partly because of volatile RT congestion on the West Zone 230kV system.
    - – However, DA scheduling in the West Zone fell from prior quarters. This was likely in response to the average day-ahead premium (persistent real-time premiums were normal in the past).

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)
2016 Q3	112%	85%	46%	85%	95%	105%	107%	98%	97%
2016 Q2	121%	86%	38%	82%	77%	102%	108%	95%	94%
2015 Q3	121%	88%	51%	83%	94%	102%	106%	98%	97%



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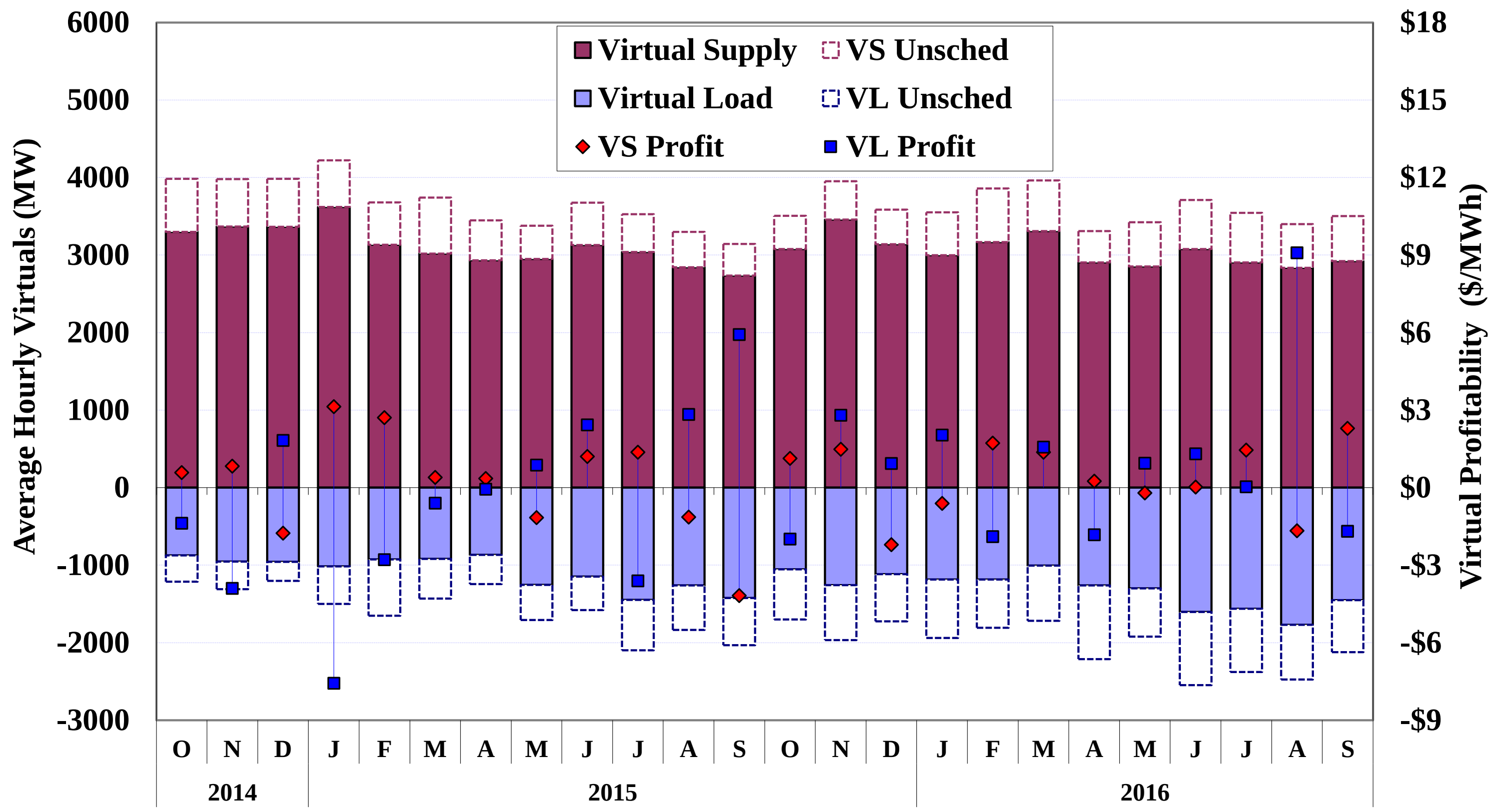
Virtual Trading Activity

- The following two charts summarize recent virtual trading activity in New York.
- The first figure shows monthly average scheduled and unscheduled quantities, and gross profitability for virtual transactions at the load zones in the past 24 months.
  - ✓ The table shows a screen for relatively large profits or losses, which identifies virtual trades with profits or losses larger than 50 percent of the average zone LBMP.
    - Large profits may indicate modeling inconsistencies between DA and RT markets, and large losses may indicate manipulation of the day-ahead market.
- The second figure summarizes virtual trading by geographic region.
  - ✓ The load zones are broken into seven regions based on typical congestion patterns.
  - ✓ Virtual imports and exports are shown as they have similar effects on scheduling.
    - A transaction is deemed virtual if the DA schedule is greater than the RT schedule, so a portion of these transactions result from forced outages or curtailments by NYISO or another control area (rather than the intent of the participant).
  - ✓ The top portion of the chart also shows average day-ahead scheduled load (as a percent of real-time load) at each geographic region.

Virtual Trading Activity

- The volume of virtual trading did not change significantly in the third quarter of 2016, generally consistent with prior periods.
  - ✓ The pattern of virtual scheduling was similar as well.
    - – Virtual traders generally scheduled more virtual load in the West Zone and downstate areas (i.e., NYC and LI) and more virtual supply in other regions.
    - – This was consistent with typical DA load scheduling patterns discussed earlier for similar reasons.
- Overall, virtual traders netted a profit of $14.7 million in the third quarter of 2016.
  - ✓ Virtual transactions were profitable, suggesting that they have generally improved convergence between DA and RT prices. (For example, profitable virtual supply tends to reduce the DA price and bring it closer to the RT price.)
  - ✓ However, the profits and losses from virtual trades varied widely by time and location, reflecting the difficulty of predicting volatile RT prices.
- The quantities of virtual transactions that generated substantial profits or losses were generally consistent with prior periods.
  - ✓ These trades were primarily associated with high price volatility that resulted from unexpected events, which do not raise significant concerns.

Virtual Trading Activity at Load Zones by Month



Profit > 50% of Avg. Zone Price	MW	589	435	380	539	566	316	299	566	782	479	290	241	378	1090	643	692	638	1003	354	431	460	596	398	360
	%	14%	10%	9%	12%	14%	8%	8%	13%	18%	11%	7%	6%	9%	23%	15%	17%	15%	23%	8%	10%	10%	13%	9%	8%
Loss > 50% of Avg. Zone Price	MW	510	456	372	461	453	383	338	671	697	499	300	341	375	715	763	553	547	680	682	550	528	517	413	411
	%	12%	11%	9%	10%	11%	10%	9%	16%	16%	11%	7%	8%	9%	15%	18%	13%	13%	16%	16%	13%	11%	12%	9%	9%

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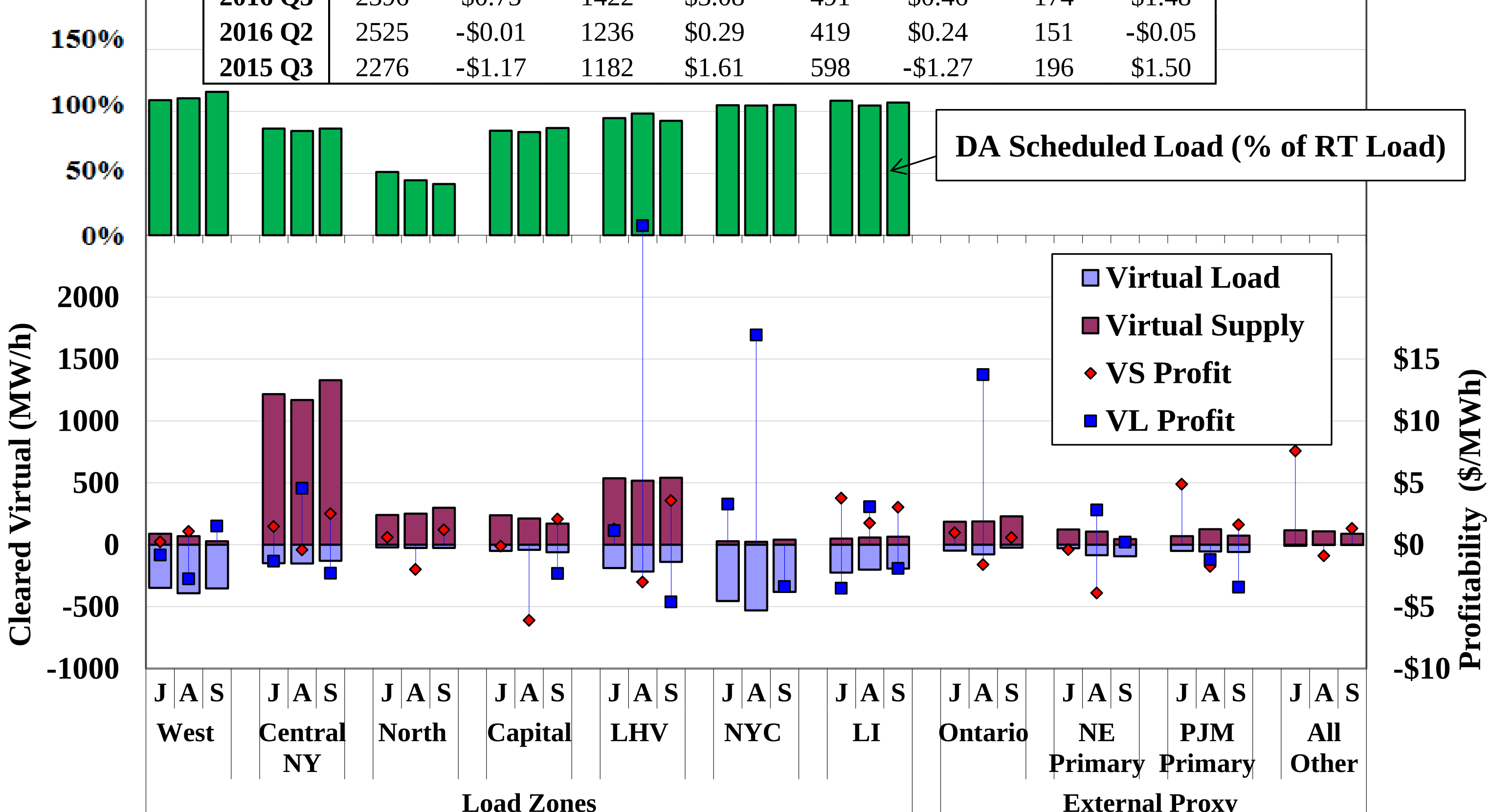
Virtual Trading Activity at Load Zones & Proxy Buses by Location

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)
2016 Q3	2396	$0.75	1422	$3.08	491	$0.46	174	$1.48
2016 Q2	2525	-$0.01	1236	$0.29	419	$0.24	151	-$0.05
2015 Q3	2276	-$1.17	1182	$1.61	598	-$1.27	196	$1.50



Note: Virtual profit is not shown for a category if the average scheduled quantity is less than 50 MW.

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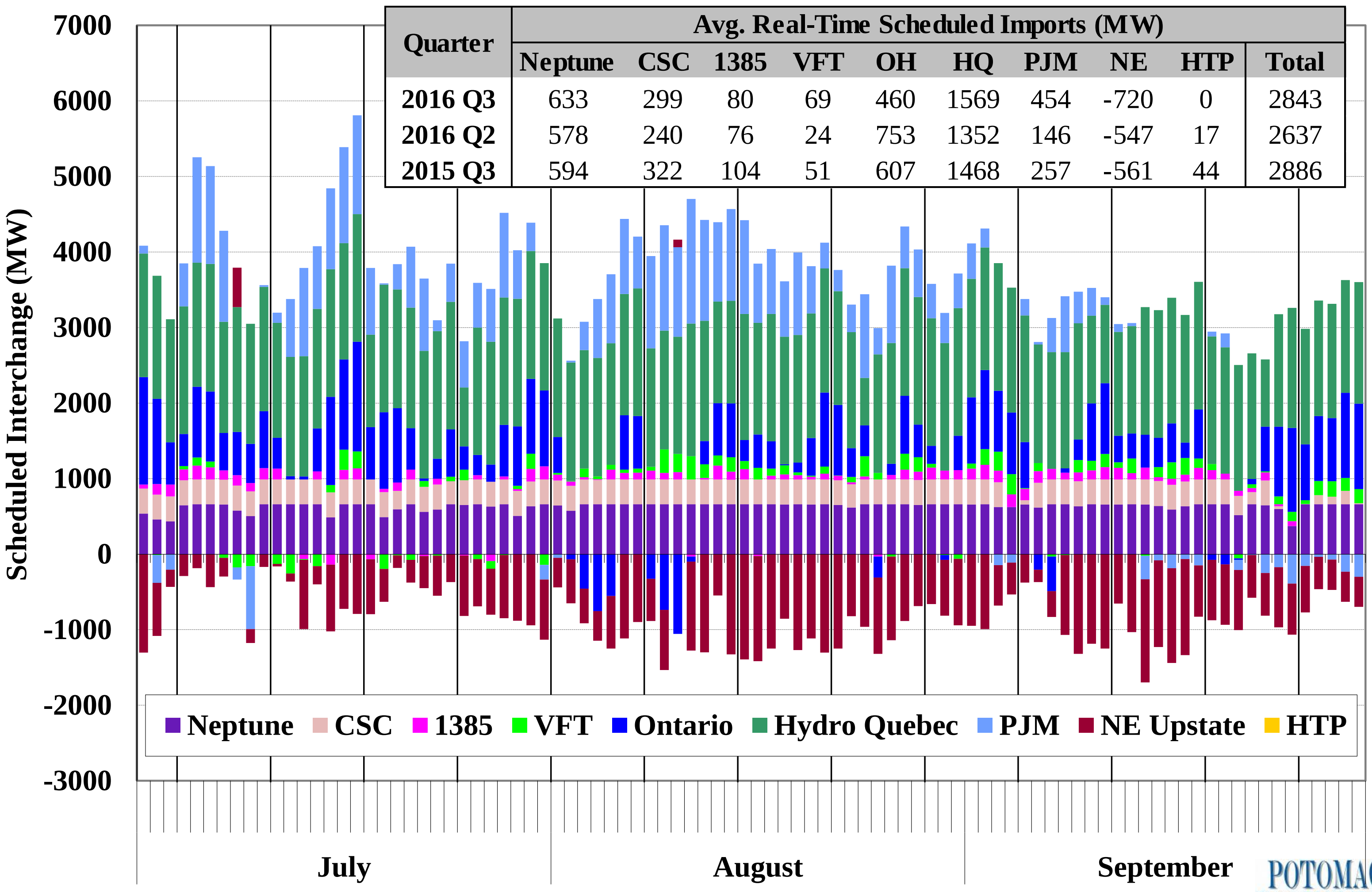
Net Imports Scheduled Across External Interfaces

- The next figure shows average RT net imports to NYCA across ten external interfaces (two HQ interfaces are combined) during peak hours (1-9 pm).
- Overall, net imports averaged roughly 2.8 GW (serving 13 percent of the NY load) during peak hours, comparable to the third quarter of 2015.
- Imports from Hydro Quebec averaged over 1.5 GW during peak hours, accounting for 55 percent of total net imports this quarter.
  - ✓ Variations in HQ imports normally reflect transmission outages on the interface.
- Imports from Ontario fell from previous quarters partly because of higher clockwise loop flows around Lake Erie (see slide 63), other factors that increase West Zone congestion (see slides 64-70), and import transfer limitations on the interface.
- Net imports from PJM and net exports to New England across their primary interfaces rose from a year ago.
  - ✓ These changes were generally consistent with variations in natural gas price spreads between the three markets.
  - ✓ Imports across the HTP interface were zero because the interface was OOS throughout the quarter.

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

Quarter	Avg. Real-Time Scheduled Imports (MW)									
	Neptune	CSC	1385	VFT	OH	HQ	PJM	NE	HTP	Total
2016 Q3	633	299	80	69	460	1569	454	-720	0	2843
2016 Q2	578	240	76	24	753	1352	146	-547	17	2637
2015 Q3	594	322	104	51	607	1468	257	-561	44	2886



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Intra-Hour Scheduling with PJM and NE
Coordinated Transaction Scheduling ("CTS")

- The next table evaluates the performance of CTS with PJM and NE at their primary interfaces during the third quarter of 2016. 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.
    - Unrealized savings, which are not realized due to: a) real-time curtailment ; b) interface ramping; and c) price curve approximation (which applies only to the NY/NE CTS as NYISO transfers the 7-point supply curve forecasted by ISO-NE into a step-function curve for use in the CTS process).
    - Actual savings (= Projected – Over-projected - 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.

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Efficiency of CTS Scheduling with PJM and NE

- The interchange schedules were adjusted during 83 percent of all quarter-hour intervals (from our estimated hourly schedule) at the NE/NY interface, higher than the 57 percent at the PJM/NY interface.
  - ✓ This was partly attributable to the fact that the amount of low-price CTS bids was substantially higher at the NE/NY interface than at the PJM/NY interface.
- Our analyses show that $1.4 million and $1.2 million of production cost savings were projected at the time of scheduling at the NE/NY and PJM/NY interfaces.
  - ✓ However, only an estimated of $0.8 million of savings were realized at the NE/NY interface and nearly no savings were realized at the PJM/NY interface largely because of price forecast errors.
    - – It is important to note that our evaluation may under-estimate both projected and actual savings, because the estimated hourly schedules (by using actual CTS bids) may include some of the efficiencies that result from the CTS process.
    - – Nonetheless, the results of our analysis are still useful for identifying some of the sources of inefficiency in the CTS process.
- Projected savings were relatively consistent with actual savings when the forecast errors were moderate (e.g., less than $20/MWh), while the CTS process produced much more inefficient results when forecast errors were larger.
  - ✓ Therefore, improvements in the CTS process should focus on identifying sources of forecast errors.

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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 > $20	Total
% of All Intervals w/ Adjustment			73%	11%	**83%**	49%	9%	**57%**
Average Flow Adjustment (MW)			3.5 (Net) / 67 (Gross)	14 (Net) / 108(Gross)	**5 (Net) / 72 (Gross)**	6 (Net) / 57 (Gross)	40 (Net) / 122 (Gross)	**11 (Net) / 67 (Gross)**
Production Cost Savings ($ Million)	Projected at Scheduling Time		$0.7	$0.7	**$1.4**	$0.2	$1.0	**$1.2**
	Net Over-Projection by:	NY Market	-$0.01	-$0.03	**-$0.04**	-$0.03	-$1.0	**-$1.0**
		Neighbor Market	-$0.03	-$0.4	**-$0.5**	-$0.04	-$0.1	**-$0.1**
	Unrealized Savings Due to:	Ramping	-$0.04	-$0.1	**-$0.1**	-$0.01	-$0.06	**-$0.06**
		Curtailment	-$0.01	-$0.01	**-$0.02**	$0.003	$0.05	**$0.1**
		Price Curve	-$0.04	$0.004	**-$0.04**	N/A	N/A	**N/A**
	Actual Savings		$0.5	$0.2	**$0.8**	$0.1	-$0.2	**$0.0**
Interface Prices ($/MWh)	NY Market	Actual	$26.17	$66.55	**$31.39**	$23.71	$64.66	**$29.83**
		Forecast	$26.72	$61.49	**$31.22**	$24.17	$69.96	**$30.97**
	Neighbor Market	Actual	$26.95	$66.24	**$32.03**	$23.19	$57.00	**$28.24**
		Forecast	$25.94	$57.38	**$30.00**	$24.55	$50.46	**$28.40**
Price Forecast Errors ($/MWh)	NY Market	Fcst. - Act.	$0.55	-$5.06	**-$0.17**	$0.44	$4.74	**$1.09**
		Abs. Val.	$2.89	$43.72	**$8.16**	$2.82	$62.87	**$11.80**
	Neighbor Market	Fcst. - Act.	-$1.01	-$8.86	**-$2.02**	$1.34	-$6.89	**$0.11**
		Abs. Val.	$3.90	$64.77	**$11.77**	$3.51	$35.39	**$8.28**

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Day-Ahead and Real-Time Transmission Congestion

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Congestion Patterns, Revenues, and Shortfalls

- The next four figures evaluate the congestion patterns in the day-ahead and real-time markets and examine the following categories of resulting congestion costs:
  - ✓ <u>Day-Ahead Congestion Revenues</u> are collected by the NYISO when power is scheduled to flow across congested interfaces in the day-ahead market, which is the primary funding source for TCC payments.
  - ✓ <u>Day-Ahead Congestion Shortfalls</u> occur when the net day-ahead congestion revenues collected by the NYISO are less than the payments to TCC holders.
    - – Shortfalls (or surpluses) arise when the TCCs on a path exceed (or is below) the transfer capability of the path modeled in the DA market in periods of congestion.
    - – These typically result from modeling assumption differences between the TCC auction and the DA market, including assumptions related to PAR schedules, loop flows, and transmission outages.
  - ✓ <u>Balancing Congestion Shortfalls</u> arise when day-ahead scheduled flows over a constraint exceed what can flow over the constraint in the real-time market.
    - – The transfer capability of a constraint falls (or rises) from DA to RT 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).

Congestion Patterns, Revenues, and Shortfalls

- The first figure summarizes day-ahead congestion revenue and shortfalls, and balancing congestion shortfalls over the past two years on a monthly basis.
- The second figure 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.
- The third and fourth figures 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.
- 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.
  - ✓ Central to East: The Central-East interface and other lines transferring power from the Central Zone to Eastern New York.

Day-Ahead and Real-Time Congestion

(cont. from prior slide)

- ✓ North Zone Lines: Lines in the North Zone and leading into Southern NY.
- ✓ 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.

- Day-ahead congestion revenue totaled $131 million this quarter, up 42 percent from the third quarter of 2015.
  - ✓ Over 60 percent of the increase occurred on Long Island because of the Y49 outage and the 677 line derating, which limits flows from Northport.
  - ✓ Higher load levels (see slide 11) and the implementation of the GTDC project (see slides 71-75) were also significant drivers of the increase.
  - ✓ West Zone accounted for most of the remaining increase as the congestion pattern changed for the reasons discussed in the next slide.

Day-Ahead and Real-Time Congestion

- There were notable changes from a year ago in the pattern of West Zone congestion, driven by various factors, including (but not limited to):
  - ✓ The implementation of the GTDC project in February 2016. (see slides 71-75)
  - ✓ The retirements of the last Dunkirk unit in December 2015 and two Huntley units in March 2016, which had helped relieve West Zone congestion.
  - ✓ The implementation of a composite shift factor at the Niagara plant in early May 2016. (see slides 64-70 for more discussion)
  - ✓ The addition of two series reactors on the Packard-Huntley 230 kV #77 and #78 lines in mid-May 2016, which can be used to divert a portion of flows from 230 kV facilities to parallel 345 kV and 115 kV facilities.
  - ✓ The S. Ripley-Dunkirk 230 kV line and Warren-Falconer 115 kV line were taken OOS during most of 2016-Q3 for 115kV transmission security, but these also reduced flows on frequently congested 230 kV lines.
  - ✓ Clockwise loop flows around Lake Erie were higher this quarter.
- NYC exhibited higher RT congestion values than in the DAM partly because:
  - ✓ Congestion into the Greenwood load pocket was under-stated in the DAM because of uneconomic scheduling of GTs by the SCUC model (units were uneconomically scheduled in ~180 hours in 2016-Q3).

Day-Ahead Congestion Shortfalls

- Transmission outages accounted for a large share of shortfalls – over $11 million (out of $20 million) was allocated to the responsible TO in 2016-Q3.
  - ✓ Roughly $12 million of shortfalls accrued on Long Island lines.
    - One 345 kV line into LI (i.e., the Y49 line) was OOS in early July and from early August through mid September, accounting for nearly $8 million of shortfalls.
    - Excess Grandfathered TCCs from Dunwoodie to Long Island accounted for another $3.5 million of shortfalls.
  - ✓ North zone lines accounted for nearly $2 million of shortfalls because:
    - A Marcy 765/345 kV breaker was OOS in early September; and
    - Multiple transmission facilities from Moses to Adirondack were OOS in late September.
- West Zone constraints accounted for over $6 million of shortfalls.
  - ✓ The majority was attributable to different loop flow assumptions between the TCC auction and the DAM.
  - ✓ In addition, transmission outages accounted for roughly $1 million of shortfalls.
  - ✓ These were partly offset by $1 million of surpluses from the inconsistencies between the TCC auction and the DAM in the assumed distribution of Niagara generation (230 kV vs. 115 kV).

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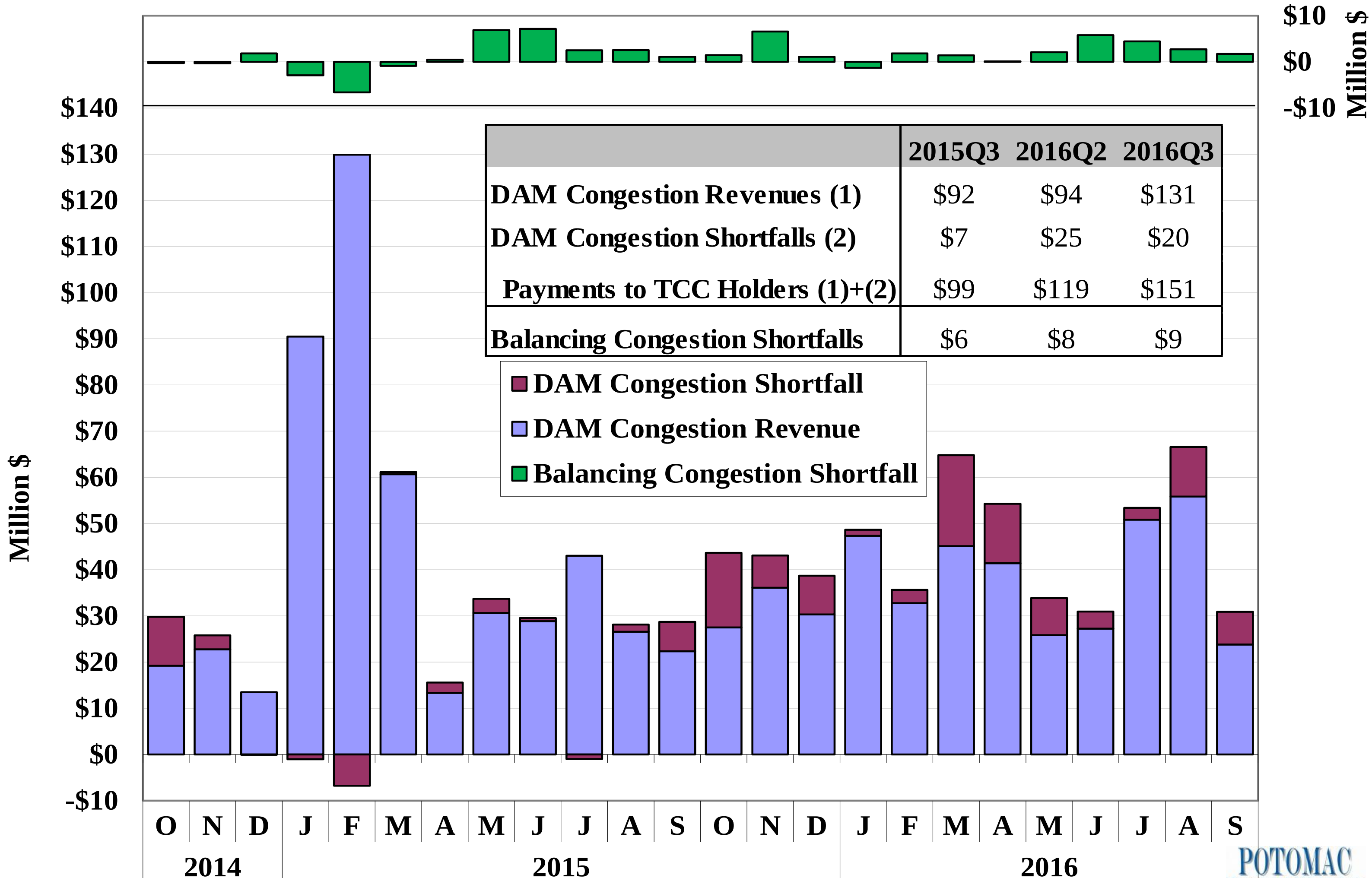
Balancing Congestion Shortfalls

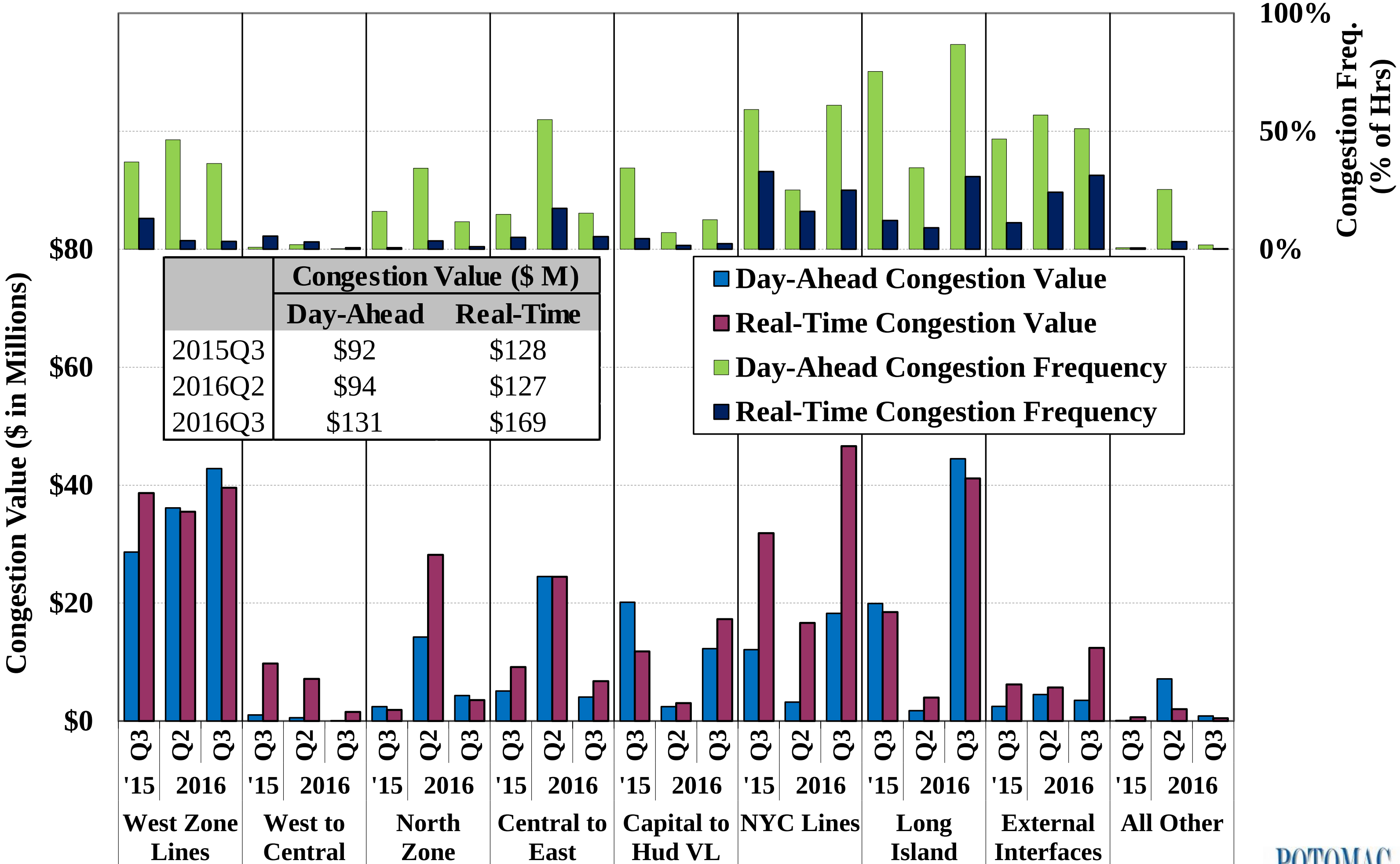
- TSA constraints accounted for the majority of shortfalls, most of which occurred on one day in July and two days in August.
  - ✓ Transfer capability into SENY was greatly reduced during TSA events, contributing to nearly $8 million of shortfalls.
  - ✓ Large schedule deviations on the ABC and JK lines on these days also contributed over $1 million of shortfalls.
  - ✓ TSA-related congestion shortfalls were notably higher than in the prior two summers due in part to:
    - – Higher load levels during TSA events this quarter; and
    - – Less congestion relief from Ramapo PARs because of outages.
- West Zone constraints accounted for the second largest share of shortfalls.
  - ✓ Differences between the assumed distribution of Niagara generation between the 115 kV and 230 kV units in the DAM and the actual distribution contributed $1.4 million of shortfalls.
  - ✓ The operation of the Ramapo, ABC and JK PARs contributed another $0.6 million of shortfalls.
  - ✓ Among the other factors that accounted for an additional $2 million of shortfalls, unexpected changes in loop flows was a key contributor.

Congestion Revenues and Shortfalls by Month



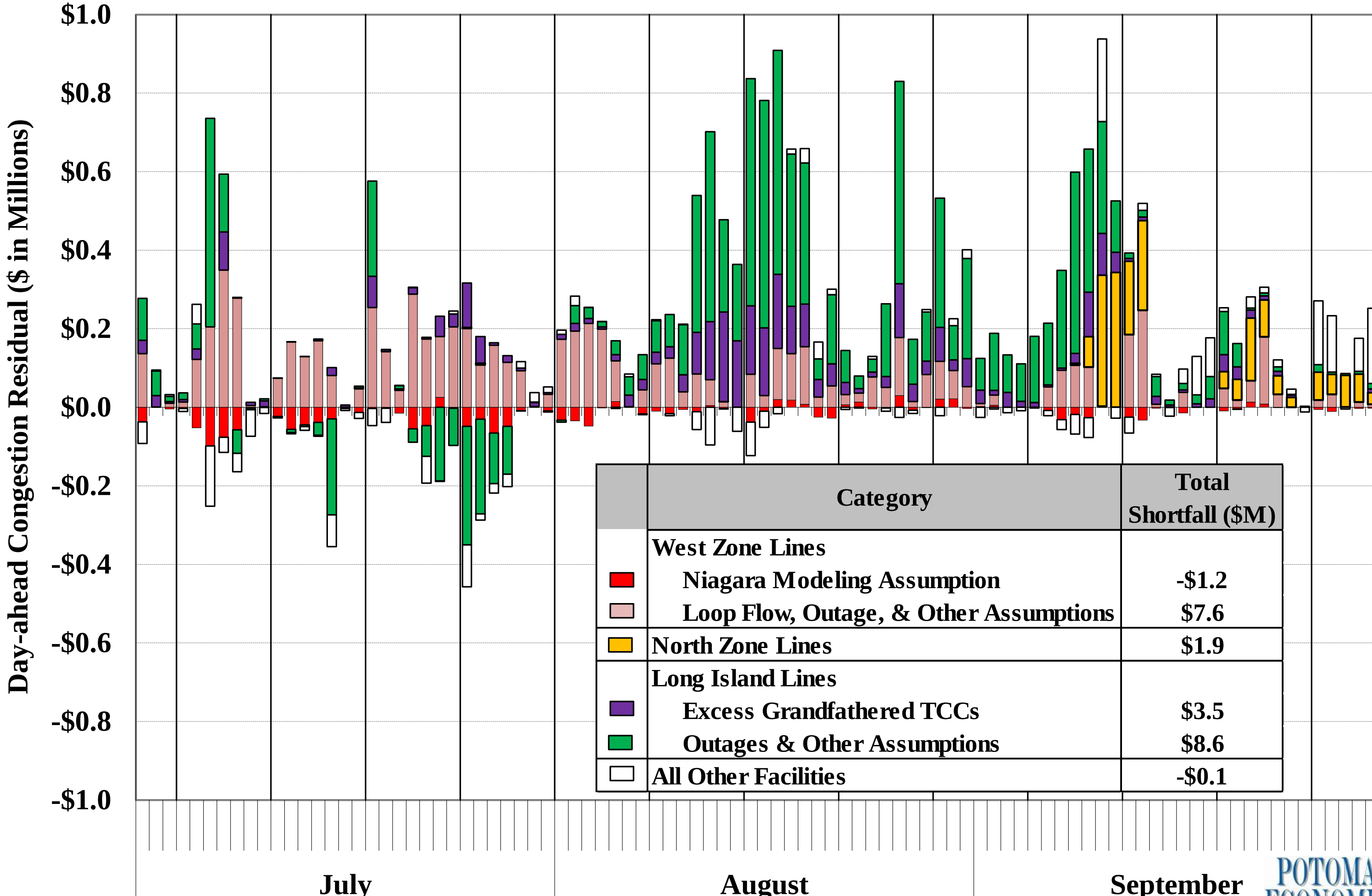
	2015Q3	2016Q2	2016Q3
DAM Congestion Revenues (1)	$92	$94	$131
DAM Congestion Shortfalls (2)	$7	$25	$20
Payments to TCC Holders (1)+(2)	$99	$119	$151
Balancing Congestion Shortfalls	$6	$8	$9

DA and RT Congestion Value and Frequency by Transmission Path

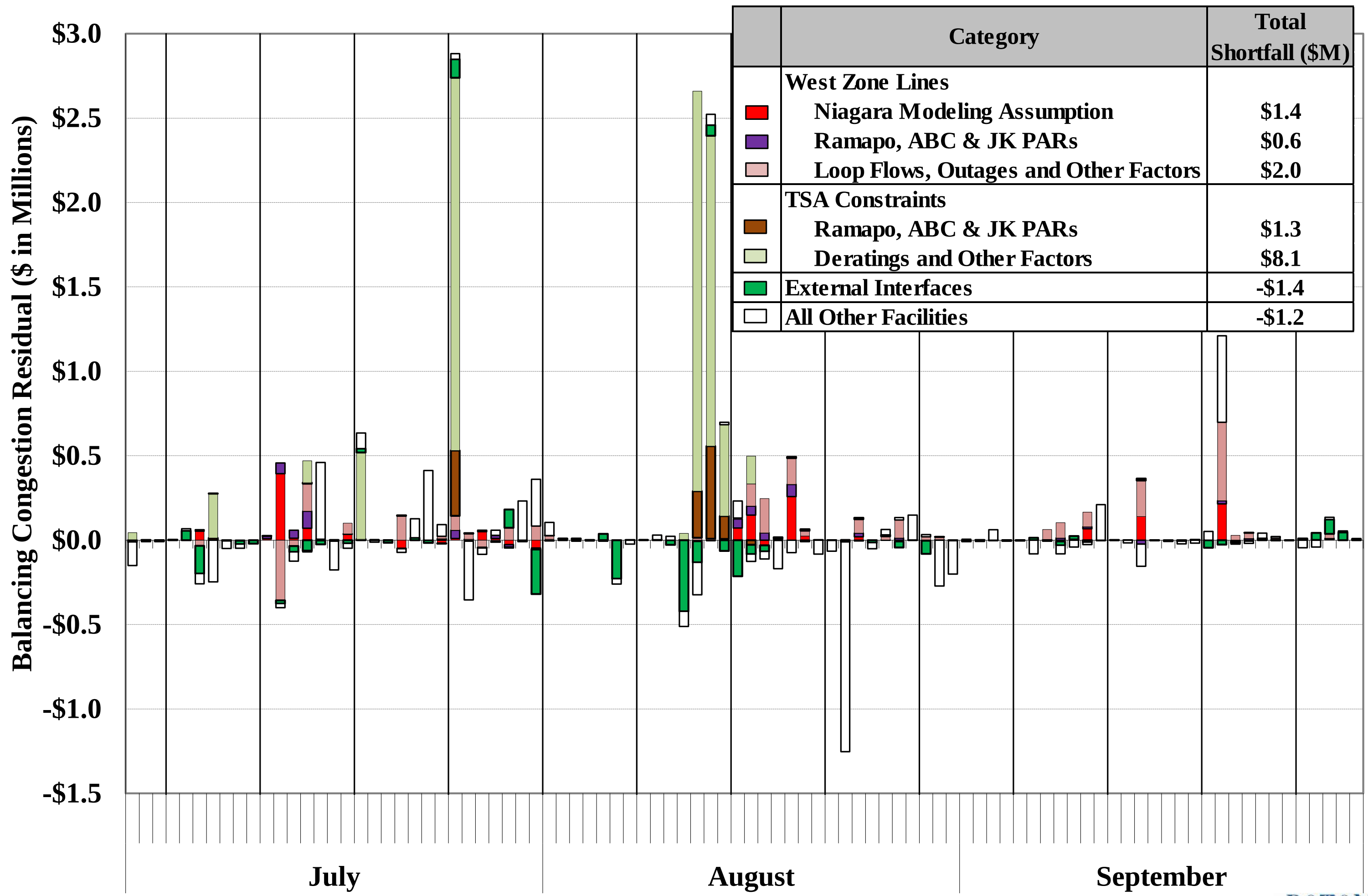


	Congestion Value ($ M)	
	Day-Ahead	Real-Time
2015Q3	$92	$128
2016Q2	$94	$127
2016Q3	$131	$169

Day-Ahead Congestion Revenue Shortfalls by Transmission Facility



Balancing Congestion Shortfalls by Transmission Facility



Note: The BMCR estimated above may differ from actual BMCR because the figure is partly based on real-time schedules rather than metered values.

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Ramapo PAR Operations under M2M with PJM

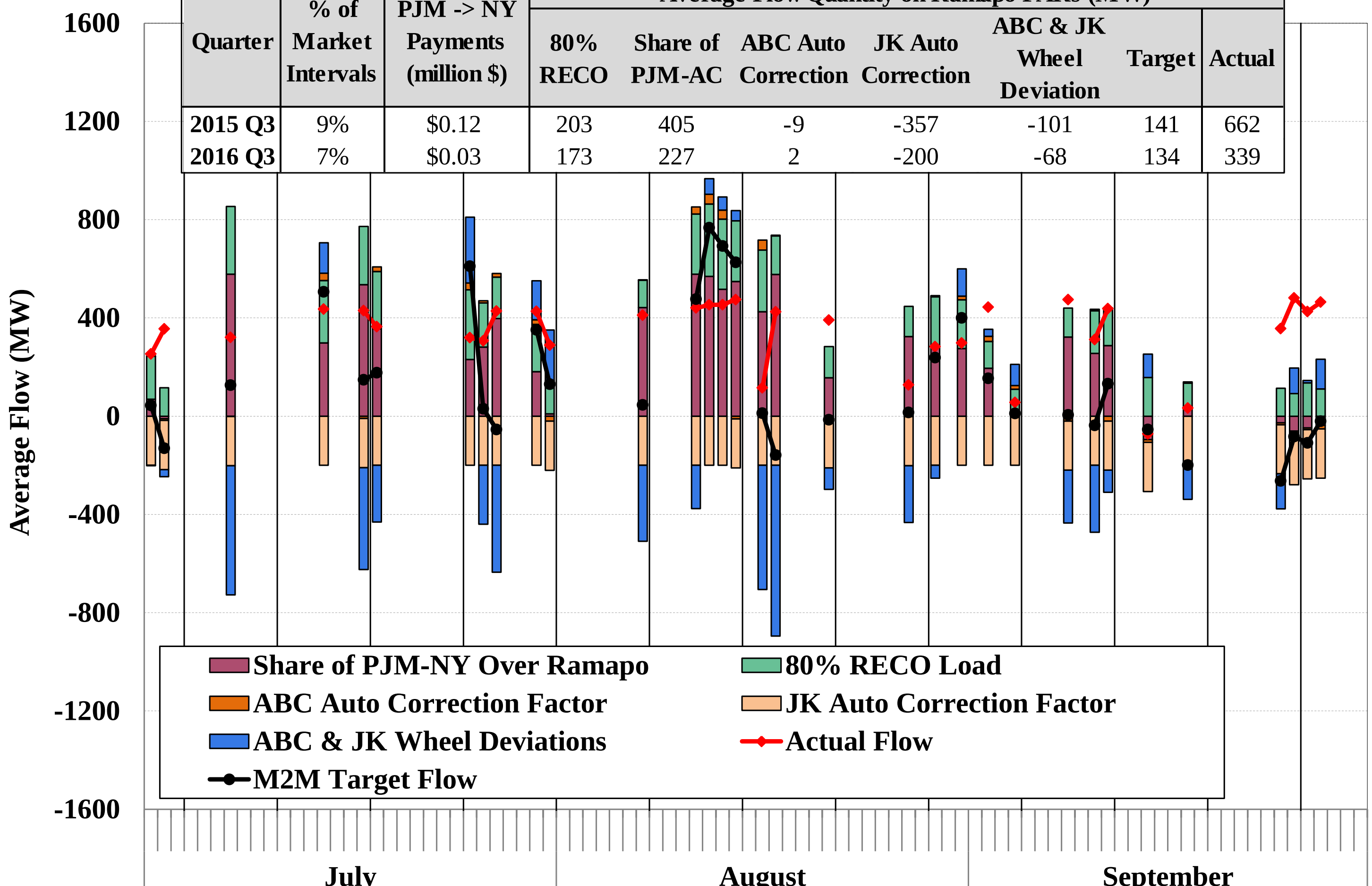
- Ramapo PAR Coordination is frequently used for coordinated congestion management between NYISO and PJM ("M2M").
- The following figure evaluates the operation of Ramapo PARs this quarter, which compares the actual flows on Ramapo PARs with their M2M operational targets.
  - ✓ The M2M target flow has the following components:
    - Share of PJM-NY Over Ramapo – Based on the share of PJM-NY flows that were assumed to flow across the Ramapo Line (46% for this quarter).
    - 80% RECo Load – 80 percent of telemetered Rockland Electric Company load.
    - ABC & JK Flow Deviations – The total flow deviations on ABC and JK PAR-controlled lines from schedules under the normal wheeling agreement.
    - ABC & JK Auto Correction Factors – These represent "pay-back" MW generated from cumulative deviations on the ABC or JK interface from prior days.
  - ✓ The figure shows these average quantities over intervals when M2M constraints for Ramapo Coordination were binding on a daily basis (excluding days with fewer than 12 binding intervals).
- The NYISO is working with PJM to incorporate the A, B, C, J, and K lines into the M2M process after the ConEd-PSEG wheel expires on May 1, 2017.

Ramapo PAR Operations under M2M with PJM

- Active Ramapo Coordination (i.e., when M2M constraints were binding) occurred in 7 percent of intervals, slightly lower than in the third quarter of 2015.
  - ✓ Average actual flows exceeded the Target Flow by 205 MW, resulting in a very small amount of M2M payments (~$30K) from PJM to NY this quarter.
    - The low Target Flow resulted from large cumulative negative deviations on the JK PARs, which were represented by JK auto correction and capped at 200 MW.
- The operation of the Ramapo PARs under M2M with PJM has provided significant benefit to the NYISO in managing congestion on coordinated flow gates.
  - ✓ Balancing congestion surpluses frequently resulted from this operation on the Central-East interface and transmission paths into SENY, indicating that it reduced production costs and congestion.
  - ✓ However, these were partly offset by shortfalls (an indication of PAR operations that increase production costs and congestion) on the West Zone lines, which are currently not under the M2M JOA.
    - The NYISO improved its operating practice in November 2015 to limit the use of Ramapo Coordination process to periods when the NYISO does not expect constraints in Western New York to be active.
    - Nonetheless, it will be difficult to optimize the operation of the Ramapo line without a model to forecast the impacts of PAR tap adjustments in RT.

Actual and Target Flows for the Ramapo Line
During the Intervals with Binding M2M Constraints

Quarter	% of Market Intervals	PJM -> NY Payments (million $)	Average Flow Quantity on Ramapo PARs (MW)						
			80% RECO	Share of PJM-AC	ABC Auto Correction	JK Auto Correction	ABC & JK Wheel Deviation	Target	Actual
2015 Q3	9%	$0.12	203	405	-9	-357	-101	141	662
2016 Q3	7%	$0.03	173	227	2	-200	-68	134	339



Note: This chart does not show the days during which M2M constraints were binding in less than 12 intervals.

West Zone Congestion and Clockwise Loop Flows

- Clockwise loop flows contribute to congestion on transmission paths in Western New York, particularly in the West Zone.
- The following figure illustrates how and to what extent loop flows affected congestion on West Zone 230 kV constraints in the quarter.
  - ✓ The bottom portion of the chart shows the average amount of:
    - Lake Erie clockwise loop flows (the blue bar); and
    - Changes in loop flows from the prior 5-minute interval (the red line) during congested intervals in real-time. The congested intervals are grouped based on different ranges of congestion values.
    - For comparison, these numbers are also shown for the intervals with no West Zone congestion.
  - ✓ In the top portion of the chart,
    - The bar shows the portion of total congestion values that each congestion value group accounted for during the quarter; and
    - The number in each bar indicates how frequently each congestion value group occurred during the quarter.

West Zone Congestion and Clockwise Loop Flows

- A correlation was apparent between the severity of West Zone congestion (measured by congestion value) and the magnitude of loop flows and the occurrence of sudden changes from the prior interval.
- There was no West Zone congestion in 96.6 percent of intervals in the quarter.
  - ✓ Both the average amount of clockwise loop flows and the average change from the prior interval were low in these intervals (compared to congested intervals).
- However, West Zone congestion was more prevalent when loop flows arose or happened to swing rapidly in the clockwise direction.
  - ✓ The congestion value on the West Zone constraints exceeded $50,000 in just 0.9 percent of all intervals in the third quarter of 2016.
    - – However, these intervals accounted for 87 percent of the total congestion value in the West Zone.
    - – In these intervals, unscheduled clockwise loop flows averaged over 235 MW and clockwise changes in unscheduled loop flows averaged over 25 MW.
  - ✓ In previous quarters, a small number of intervals accounted for relatively large share of the total congestion, this has been accentuated by the implementation of the GTDC project. (see slides 71-75)

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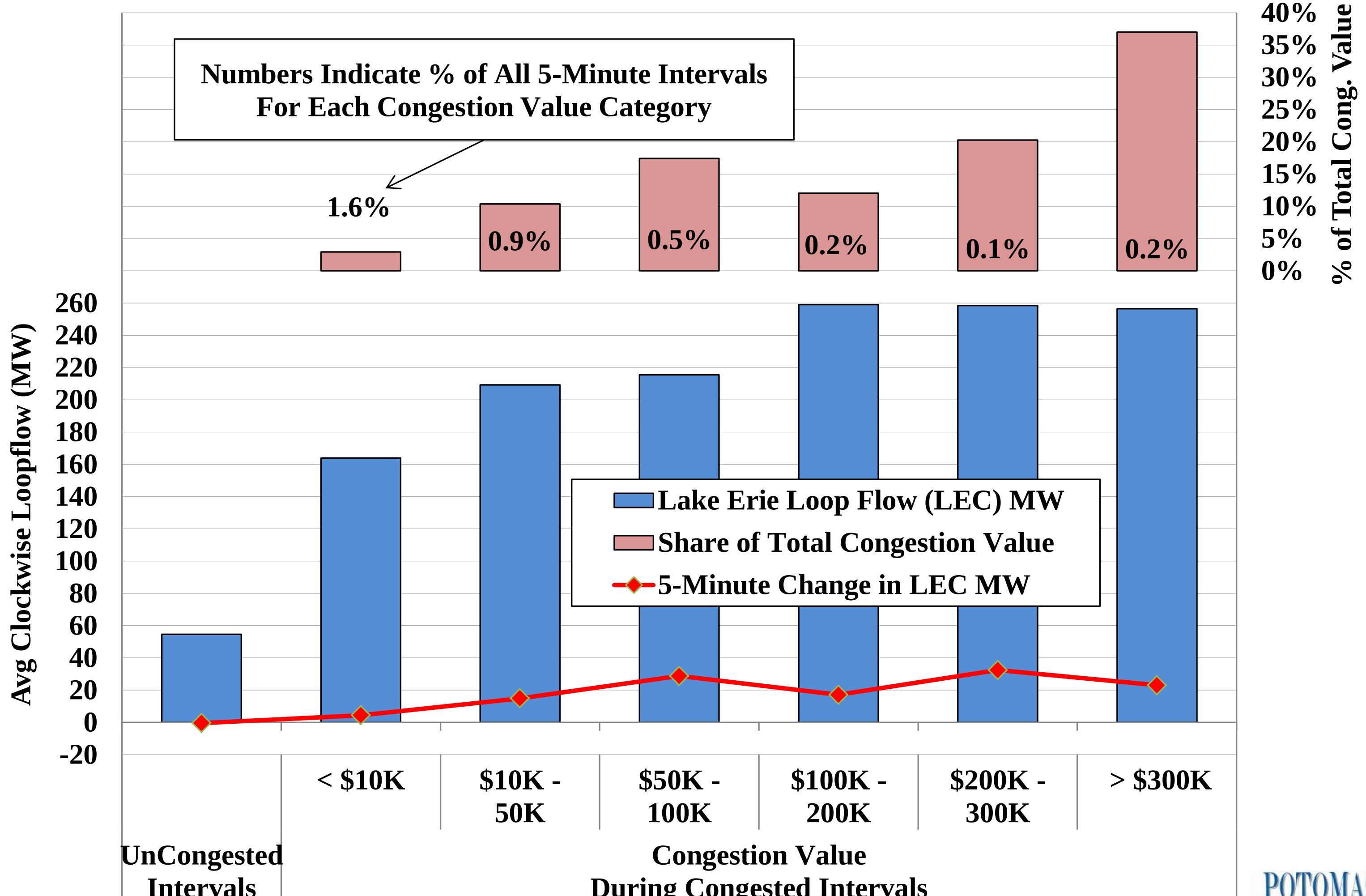
West Zone Congestion and Clockwise Loop Flows During the Third Quarter of 2016



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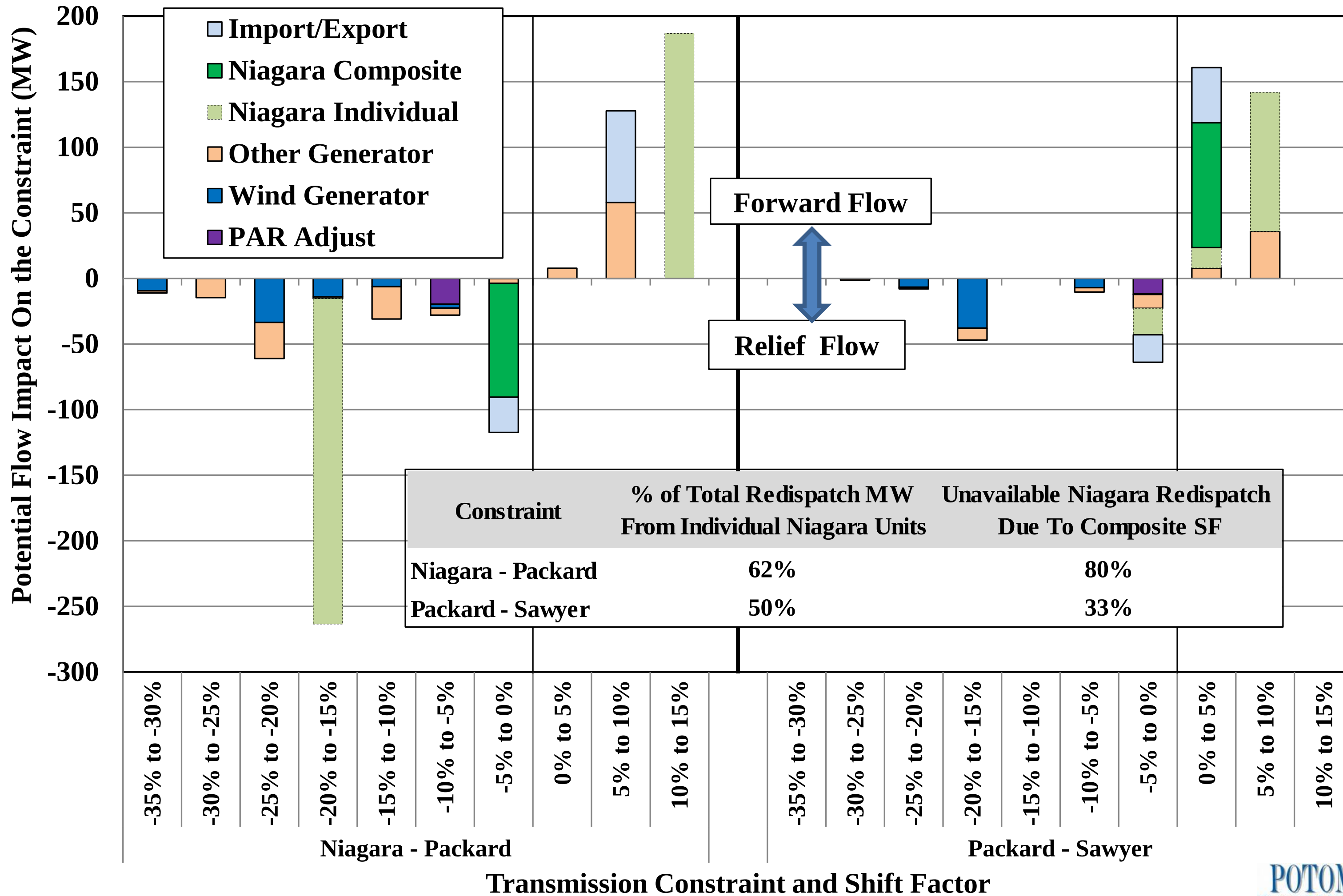
West Zone Congestion and Niagara Generation Modeling

- Transmission constraints on the 230kV network in the West Zone have become more frequent in recent years, limiting the flow of power towards Eastern NY.
  - ✓ Niagara units on the 115kV system tend to relieve these constraints, while ones on the 230kV system exacerbate this congestion.
  - ✓ These impacts are not considered optimally by the optimization engine, which treats Niagara as a single bus for pricing and dispatch.
    - Assumption before May 4, 2016: Output injected at the 230kV bus.
    - Assumption since May 4, 2016: Output distributed among 115kV and 230kV buses consistent with last telemetered distribution.
  - ✓ NYISO procedures still use manual instructions to shift generation among the individual units at the Niagara plant to alleviate congestion when necessary.
    - In 2016-Q3, manual instructions were used in 19 percent of hours to manage congestion (see slide 84).
- The next three figures evaluate how congestion in Western NY is affected by the modeling of the distribution of output from the Niagara plant.

West Zone Congestion and Niagara Generation Modeling

- The first figure (slide 66) shows the potential redispatch options for two transmission constraints in the West Zone on a sample day (September 10, 2016).
  - ✓ The Niagara-Packard and Packard-Sawyer constraints were most frequent.
  - ✓ Wind resources, which are generally not dispatchable in RT, are shown here for the purpose of illustrating their typical impact on the constraints.
  - ✓ Import/Export category reflects the potential relief from 1,000 MW adjustments in PJM and Ontario DNI levels.
- Most potential redispatch is at the Niagara plant, but a large portion are not available to the RT market.
  - ✓ If dispatched individually, Niagara units would account for 62 and 50 percent of potential redispatch options for managing congestion on the two constraints.
  - ✓ However, only 20 and 67 percent of these redispatch options are available as the plant is dispatched as a single unit (base on a composite shift factor).
- It is more difficult to manage congestion on the Niagara-Packard constraint due to much larger inconsistences between modeled and actual Niagara redispatch.
  - ✓ Operators often lower the Packard-Sawyer limit to prevent overloads on Niagara-Packard because the Packard-Sawyer constraint has more predictable effects on congestion.

West Zone Congestion and Niagara Generation Modeling
Potential Redispatch Options



Constraint	% of Total Redispatch MW From Individual Niagara Units	Unavailable Niagara Redispatch Due To Composite SF
Niagara - Packard	62%	80%
Packard - Sawyer	50%	33%

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West Zone Congestion and Niagara Generation Modeling

- The second figure (slide 68) shows average LBMPs for the West Zone and at the individual Niagara buses, as well as additional generation (in MWhs) that would be deliverable if capability of 115kV circuits was fully utilized.
- LBMP differences between the Niagara 115 kV and 230 kV buses were significant during periods of congestion. In 2016-Q3:
  - ✓ West Zone 230 kV congestion occurred in 3.4 percent of all intervals; and
  - ✓ On average, LBMPs were $138 to $172 per MWh higher at the Niagara 115 kV Buses than at the Niagara 230 kV Buses during these intervals.
    - Negative LBMPs suggest over-utilization of 230kV units at the Niagara plant.
- If the 115kV circuits were fully utilized by shifting output to the 115kV buses:
  - ✓ Production costs would have been reduced by $1.3 million in 2016-Q3 (assuming no changes in the constraint shadow costs). However, this does not consider:
    - Production cost savings: (a) from reducing over-utilization of the 230kV units and (b) from improved turbine efficiency during intervals with no congestion, and
    - The capital upgrade costs required to fully optimize.
  - ✓ An additional 12 GWh (or 160 MW on average) of Niagara generation could have been deliverable during these intervals.
    - This would have had significant LBMP effects outside the west zone, since sudden reductions in Niagara output sometimes require expensive generation to be dispatched in East NY.

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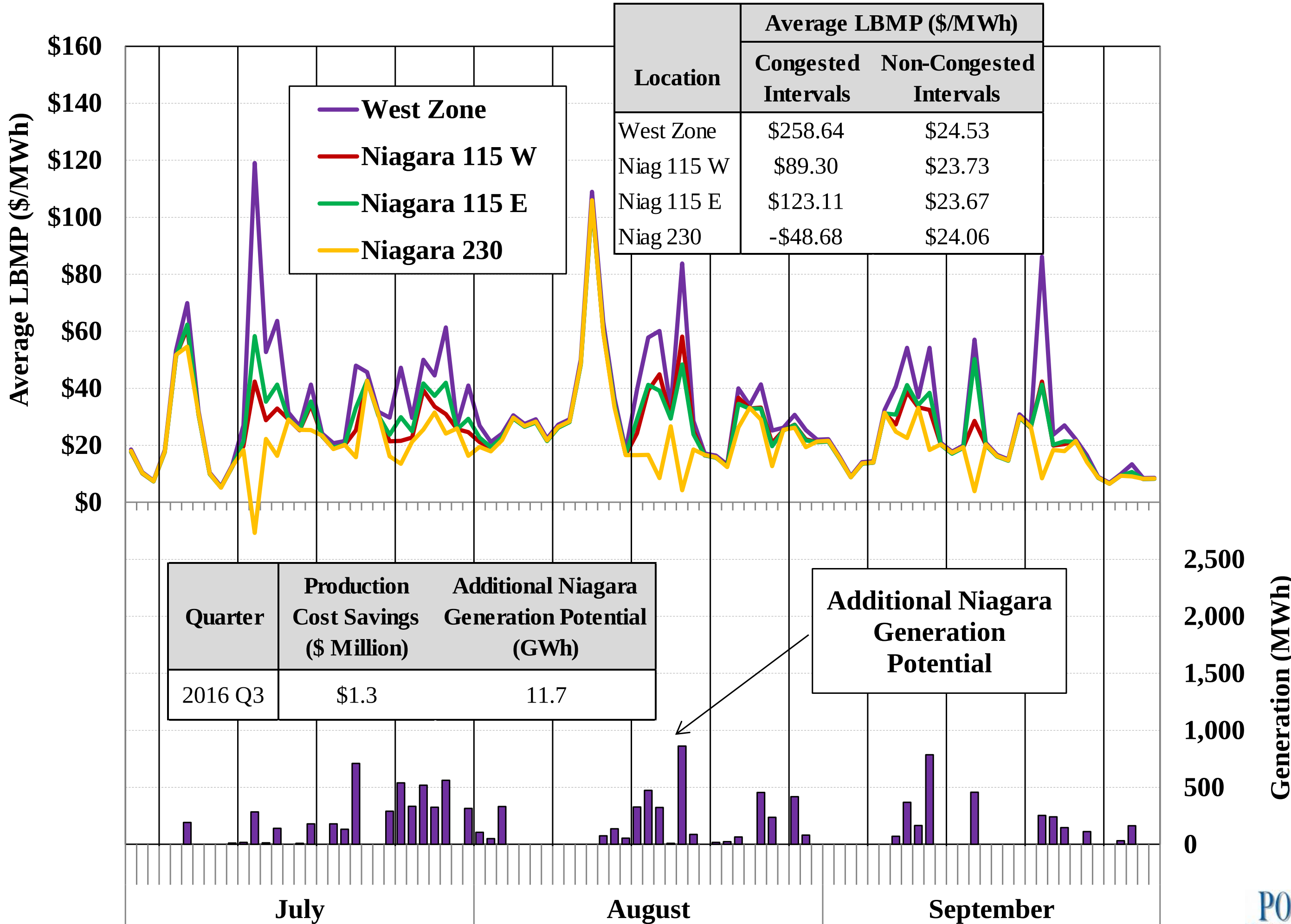
West Zone Congestion and Niagara Generation Modeling
LBMPs by Generator & Under-Utilization of 115kV Circuits



Location	Average LBMP ($/MWh) Congested Intervals	Average LBMP ($/MWh) Non-Congested Intervals
West Zone	$258.64	$24.53
Niag 115 W	$89.30	$23.73
Niag 115 E	$123.11	$23.67
Niag 230	-$48.68	$24.06

Quarter	Production Cost Savings ($ Million)	Additional Niagara Generation Potential (GWh)
2016 Q3	$1.3	11.7

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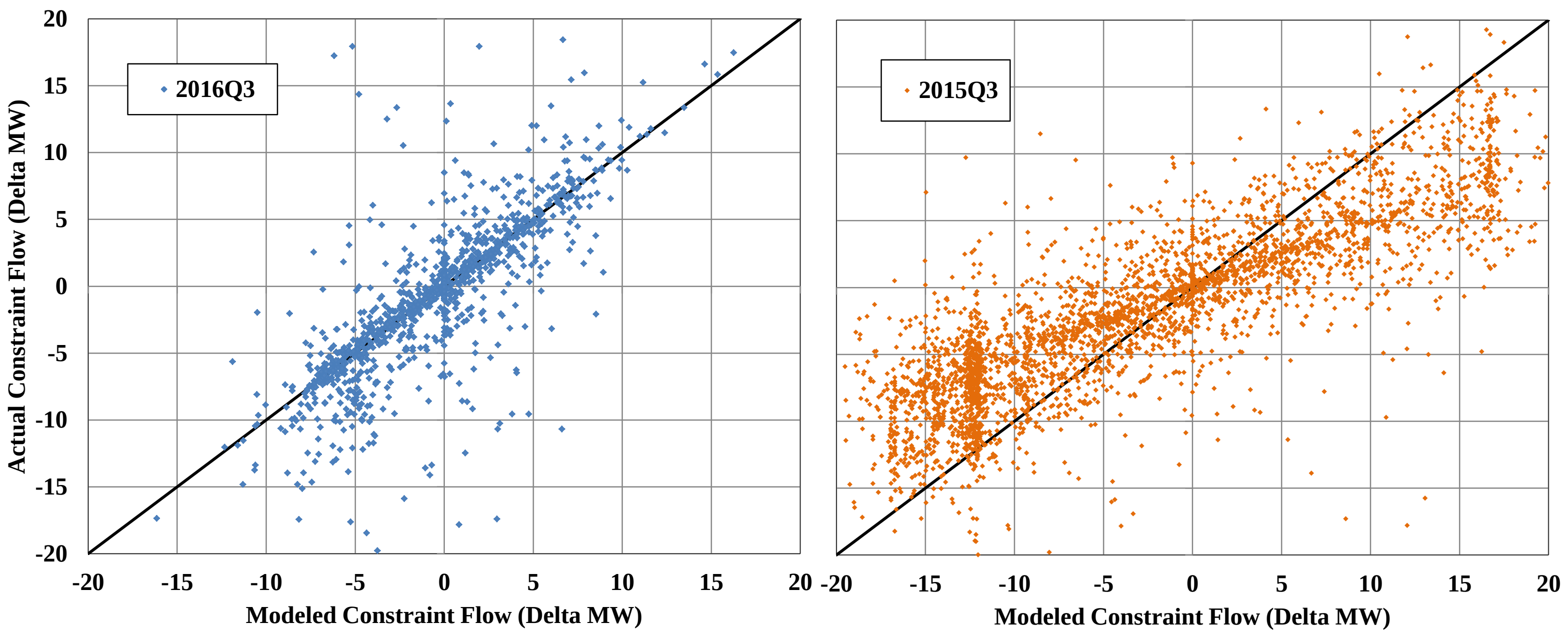
West Zone Congestion and Niagara Generation Modeling

- The third figure (slide 70) illustrates how modeling assumptions related to the system impacts of the Niagara plant differ from the actual impacts of the plant.
  - ✓ The scatter plots show the impact on constrained facilities in the West Zone:
    - The horizontal axis shows the RTD model's assumed impact;
    - The vertical axis reflects where output was actually increased (or decreased) at the plant (assuming perfect dispatch performance relative to the 5-minute signal).
    - Hence, a point on the diagonal line indicates consistency between modeled impact and actual impact.
  - ✓ The table summarizes the average absolute value for both quantities as well as the average differential between the modeled impact and the actual impact.
- Consistency between the modeled and actual impacts was poor in both periods, which has contributed to transient price volatility.
  - ✓ The average differential between modeled and actual impact is large relative to average modeled impact. (2.4 v 3.6 MW in 2016-Q3, 4.9 v 9.6 MW in 2015-Q3.) The average differential has been smaller under the new modeling approach.
  - ✓ Under the old modeling approach, RTD generally over-estimated the impacts from re-dispatching Niagara.
  - ✓ Under the new modeling approach, RTD generally under-estimates the impacts from re-dispatching Niagara.

West Zone Congestion and Niagara Generation Modeling
Modeled Impact vs. Actual Impact



Average Constraint Flow Impact (Delta MW)		
Absolute Value of:	**2016-Q3**	**2015-Q3**
Modeled Impact	3.6	9.6
Actual Impact	5.0	6.0
Modeled v Actual	2.4	4.9

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Congestion Management with the GTDC

- The NYISO implemented the Graduated Transmission Demand Curve (“GTDC”) on February 12 to improve market efficiency during transmission shortages.
  - ✓ Efficient shadow prices facilitate efficient operations by providing incentives for market participants to schedule generation and external transactions efficiently.
  - ✓ Ideally, constraint shadow prices would reflect the importance and severity of a transmission constraint when flows exceed the BMS limit in RTD.
    - – The BMS limit is used by RTD to limit flows in each 5-minute interval.
- The GTDC project changed the scheduling and pricing methodology during shortages. (See *2015 SOM Report*, Appendix Section V.H. for details.)
  - ✓ Key changes include: (a) replacing the $4000 penalty with 3-step GTDC, and (b) reducing the constraint relaxation limit adjustment from +8 MW to +0.2 MW.
  - ✓ This was evaluated as a potential Market Problem (see 11/3 MIWG).
- The next three figures compare market performance before and after the change.
  - ✓ The first figure summarizes shadow prices, shortage quantities relative the BMS limit (adjusted for the CRM), and RT congestion value by constraint group.
  - ✓ The second figure shows this information for individual 5-minute intervals.
  - ✓ The third figure shows shadow prices and shortage quantities relative to the seasonal limit (adjusted for the CRM) for West Zone constraints.

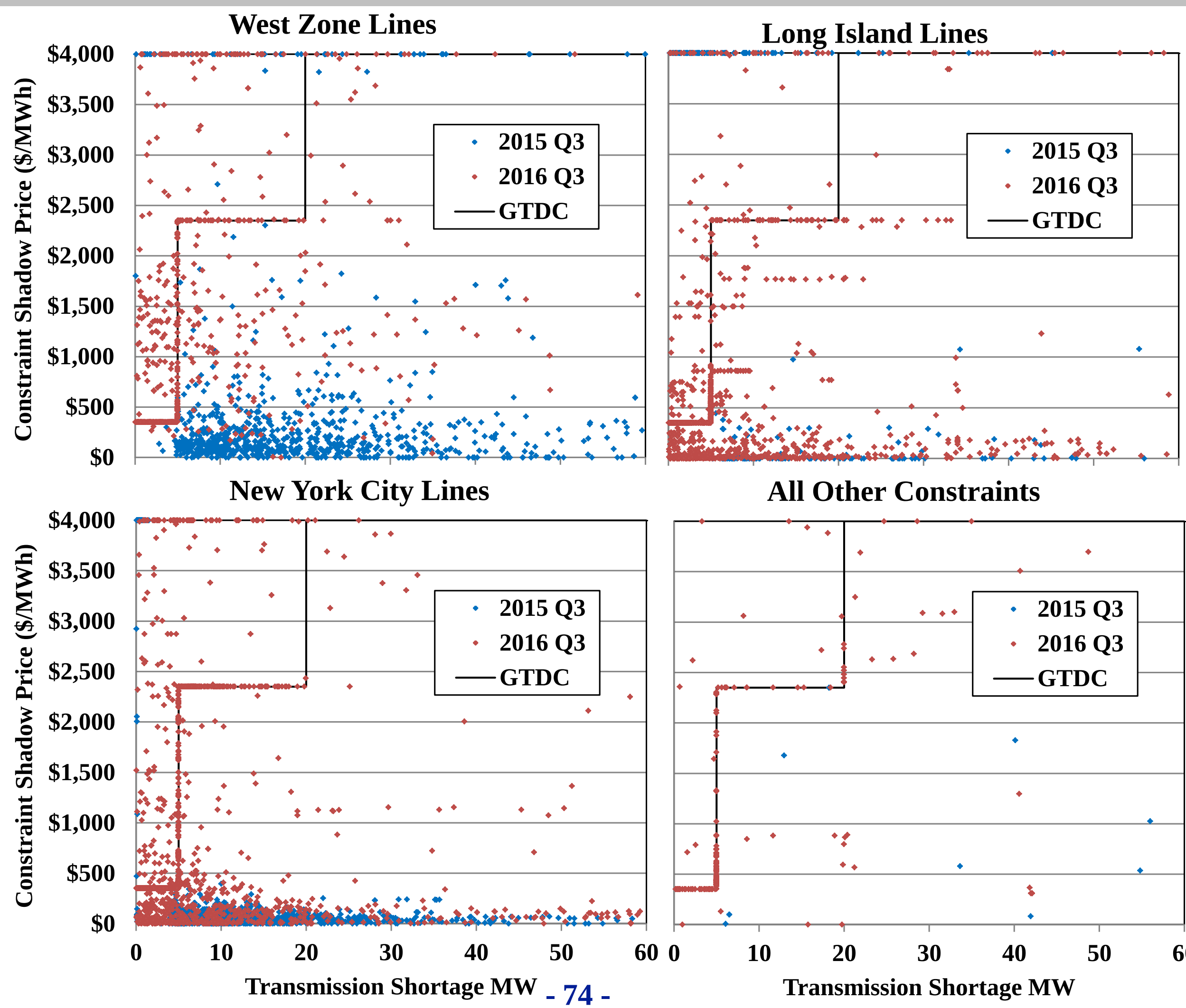
Congestion Management with the GTDC

- Shadow prices during transmission shortages have increased since the GTDC was implemented.
  - ✓ This is from the reduced limit adjustment after relaxation (from 8 to 0.2MW) as most (~70%) shortages are resolved using the relaxation method (rather than the GTDC).
  - ✓ Constraint relaxation can lead shadow prices to be higher or lower than the GTDC. In the third quarter of 2016:
    - For shortages of less than 5 MW, shadow prices were generally higher than the GTDC ($784 in NYC, $414 in LI, $1630 in the West Zone, vs $350 GTDC).
    - However, for shortages of 5 to 20 MW, shadow prices were generally lower than the GTDC ($242 in NYC, $641 in LI, $768 in the West Zone, vs $2350 GTDC).
- Transmission shortage quantities have fallen since the GTDC was implemented.
  - ✓ Higher shadow prices provide stronger incentives for external transactions (and other non-dispatchable resources) to avoid schedules that exacerbate congestion.
    - Efficient prices provide incentives that are neither too strong nor too weak.
  - ✓ However, the shortage frequency rose in some areas due partly to less relaxation.
- In the West Zone, volatile loop flows and difficulty managing congestion can lead operators to reduce the BMS limit below the seasonal limit.
  - ✓ BMS limits and modeled flows have been much closer to the seasonal limits (i.e., higher) this year in the West Zone partly because the GTDC project has improved the ability of RTS to manage flows.

Congestion Management with the GTDC
Constraint Summary, 2015-Q3 vs. 2016-Q3

Location of Constrained Facility	Transmission Shortage	# of Constraint-Intervals		Average Shortage (MW)		Average Shadow Price ($/MWh)		RT Congestion Value ($M): Original		RT Congestion Value ($M): Adjusted Using GTDC Directly	
		2015	2016	2015	2016	2015	2016	2015	2016	2015	2016
West Zone	**N**	2779	592	0	0	$135	$161	$17	$3	$17	$3
	Y	846	637	21	10	$522	$1,462	$22	$36	$117	$38
New York City	**N**	26802	27184	0	0	$42	$46	$25	$24	$25	$24
	Y	1133	1662	13	10	$337	$745	$7	$23	$83	$48
Long Island	**N**	6394	14042	0	0	$50	$60	$11	$25	$11	$25
	Y	245	1303	22	16	$1,503	$619	$8	$16	$14	$48
All Other	**N**	4517	2875	0	0	$64	$44	$31	$11	$31	$11
	Y	18	185	62	11	$1,074	$1,215	$2	$18	$7	$21

Congestion Management with the GTDC
Transmission Shortage Pricing



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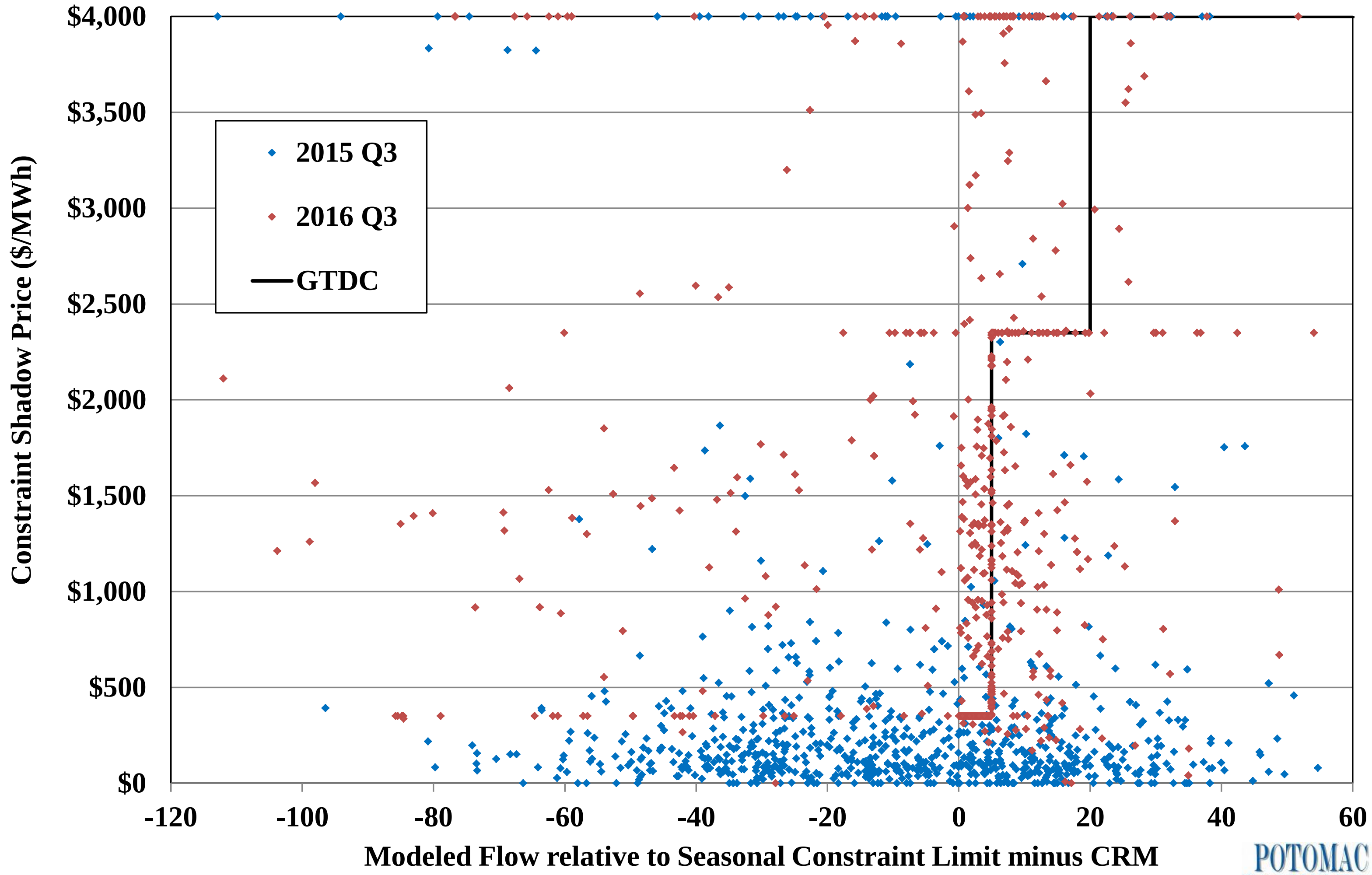
Congestion Management with the GTDC
Limit Adjustments & Shortage Pricing, West Zone Constraints



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Conclusions Regarding West Zone Congestion

- Transmission constraints in West Zone have become more frequent in recent years, increasing wholesale prices, price volatility, and congestion residual uplift.
  - ✓ These have been driven by many factors including gas market conditions, coal plant retirements, and increased renewables in NY and neighboring regions.
  - ✓ Volatile loop flows continue to exacerbate congestion.
  - ✓ However, recent transmission investments have ameliorated congestion.
  - ✓ (See the NYISO's 8/4 MIWG presentation for a detailed discussion of factors.)
- These challenges increase the importance of efficient congestion management.
  - ✓ Ultimately, efficient congestion management can reduce the need for transmission infrastructure investments.
  - ✓ However, we continue to observe:
    - – Under-utilization of 115kV circuits that are parallel to congested facilities,
    - – Inefficiently-high generation from units that exacerbate 230kV congestion,
    - – Under-commitment of West Zone units that relieve 115kV & 230kV congestion,
    - – Shadow prices are not well correlated with the severity of congestion during transmission shortages, which undermines scheduling incentives for importers and other non-dispatchable resources.

Supplemental Commitments, OOM Dispatch, and Uplift Charges

Supplemental Commitment and OOM Dispatch: Chart Descriptions

- The next three figures (slides 82-84) summarize out-of-market commitment and dispatch, which are the primary sources of guarantee payment uplift.
  - ✓ The first figure 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; and
    - Supplemental Resource Evaluation ("SRE") Commitment – occurs after the DAM.
    - Forecast Pass Commitment – occurs after the economic commitment in the DAM.
  - ✓ The second figure examines the reasons for reliability commitments in NYC where most reliability commitments occur. (This is described on the following slide.)
  - ✓ The third figure 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, the two stations with the highest number of OOM dispatch hours in the current quarter are shown separately.

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Supplemental Commitment and OOM Dispatch: Chart Descriptions

- Based on a review of operator logs and LRR constraint information, each New York City commitment (flagged as DARU, LRR, or SRE) was categorized for one of the following reasons:
  - ✓ NOx Only – If needed for NOx bubble requirement and no other reason.
  - ✓ Voltage – If needed for ARR 26 and no other reason except NOx.
  - ✓ Thermal – If needed for ARR 37 and no other reason except NOx.
  - ✓ Loss of Gas – If needed for IR-3 and no other reason except NOx.
  - ✓ Multiple Reasons – If needed for two or three out of ARR 26, ARR 37, IR-3. The capacity is shown for each separate reason in the bar chart.
- A unit is considered to be committed for a LRR constraint if the constraint would be violated without the unit's capacity.
- For voltage and thermal constraints, the capacity is shown by the following load pocket that was secured:
  - ✓ (a) AELP = Astoria East; (b) AWLP = Astoria West/Queensbridge; (c) AVLP = Astoria West/Queensbridge/ Vernon; (d) ERLP = East River; (e) FRLP = Freshkills; (f) GSLP = Greenwood/ Staten Island; and (g) SDLP = Sprainbrook/Dunwoodie.

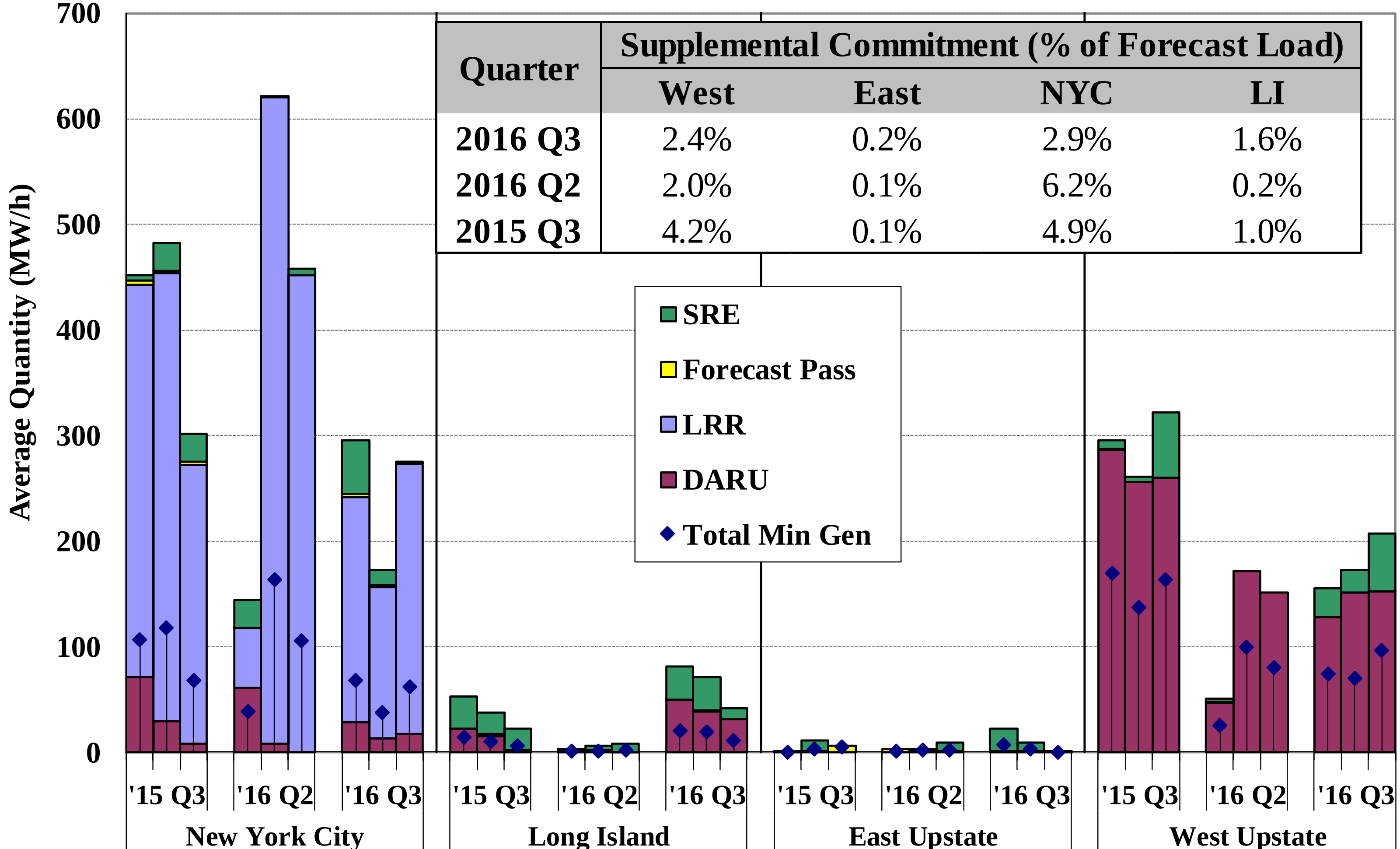
Supplemental Commitment and OOM Dispatch: Supplemental Commitment Results

- An average of 500 MW of capacity was committed for reliability in the third quarter of 2016, down 33 percent from the third quarter of 2015.
  - ✓ NYC (49 percent) and Western NY (36 percent) accounted for most of the capacity committed for reliability in this quarter.
- Reliability commitments in Western NY averaged 178 MW, down 39 percent from a year ago, which was driven partly by reduced local needs because of recent transmission upgrades that facilitated several unit retirements in Western NY.
  - ✓ With several coal retirements, the vast majority of DARU commitments has recently occurred in the Central Zone at the Cayuga (Milliken) plant.
  - ✓ SRE commitments rose because of more transmission outages in the North Zone.
- Reliability commitments in NYC averaged 248 MW, down 40% from a year ago.
  - ✓ The units often needed for local reliability were economically committed more frequently this quarter because of lower gas prices in NYC (see slide 12).
  - ✓ Most reliability commitments were made to satisfy the N-1-1 thermal and voltage requirements in the Astoria West/Queensbridge load pocket in the 2016-Q3.
- Reliability commitments in LI rose from a year ago because higher load levels and transmission outages led to increased needs to prevent voltage collapse from inadequate transient voltage recovery (see Reliability Rule ARR-28C).

Supplemental Commitment and OOM Dispatch: OOM Dispatch Results

- The NYISO and local TOs sometimes dispatch generators out-of-merit in order to:
  - ✓ Maintain reliability of the lower-voltage transmission and distribution networks; or
  - ✓ Manage constraints of high voltage transmission facilities that are not fully represented in the market model.
- Generators were dispatched Out-of-Merit ("OOM") for 3176 station-hours (primarily in Western NY and LI) this quarter, down slightly from the 2015-Q3.
  - ✓ OOM levels fell 26 percent in Western NY, due partly to the retirement of the last Dunkirk unit (which was frequently OOMed in the past for local reliability needs).
    - – The Milliken units were still frequently OOMed to manage congestion on the Elbridge-State Street 115kV line.
  - ✓ However, this decrease was offset by a 46 percent increase in Long Island.
    - – Higher load levels and transmission outages led to increased needs for voltage support on the East End of LI, which accounted for over 60% of all OOM needs.
- The Niagara facility was often manually instructed to shift output among its units to secure certain 115kV and/or 230 kV transmission constraints.
  - ✓ In the third quarter of 2016, this was required in 281 hours to manage 115 kV constraints and in 149 hours to manage 230 or 345 kV constraints.

Supplemental Commitment for Reliability
by Category and Region



Quarter	Supplemental Commitment (% of Forecast Load)			
	West	East	NYC	LI
2016 Q3	2.4%	0.2%	2.9%	1.6%
2016 Q2	2.0%	0.1%	6.2%	0.2%
2015 Q3	4.2%	0.1%	4.9%	1.0%

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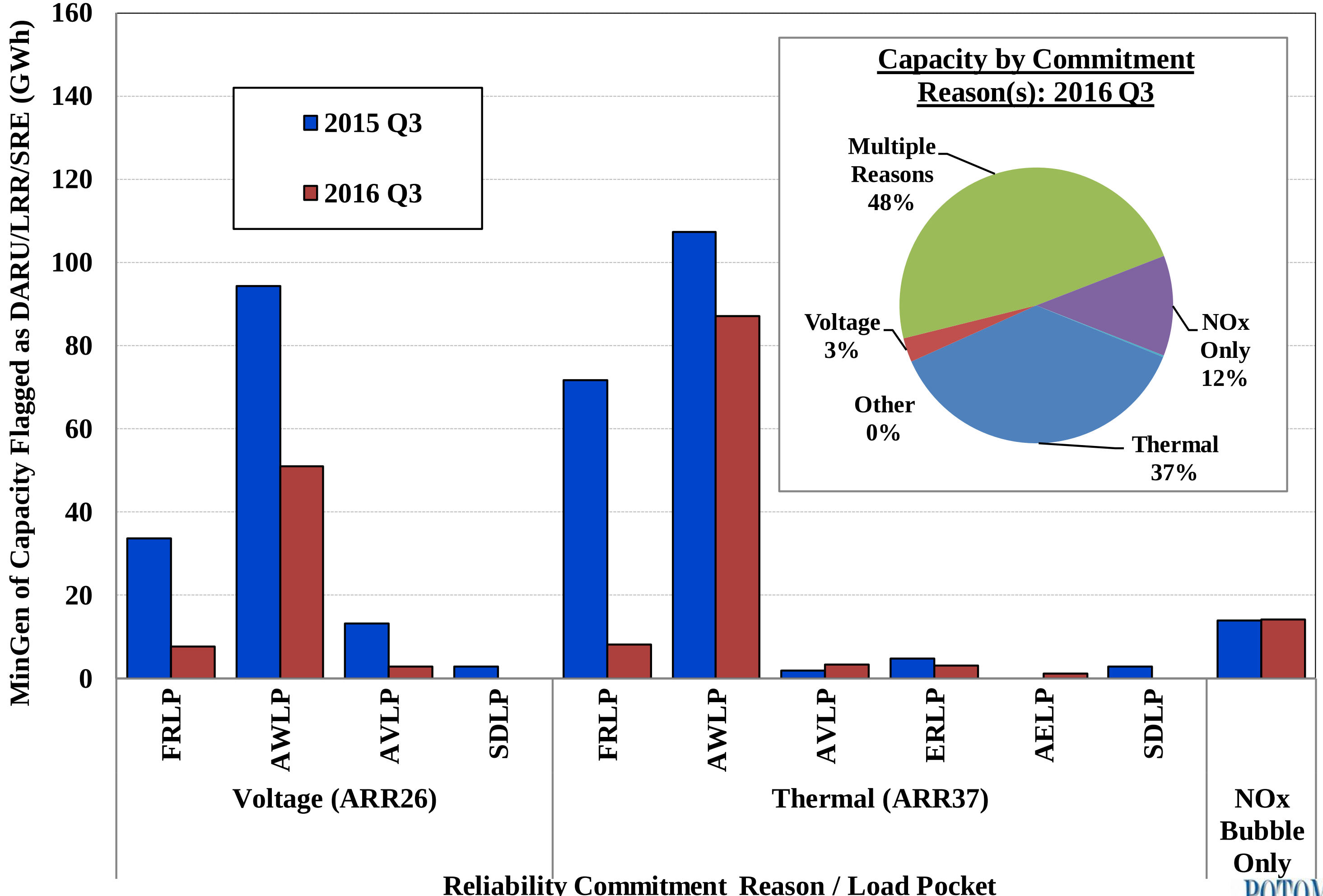
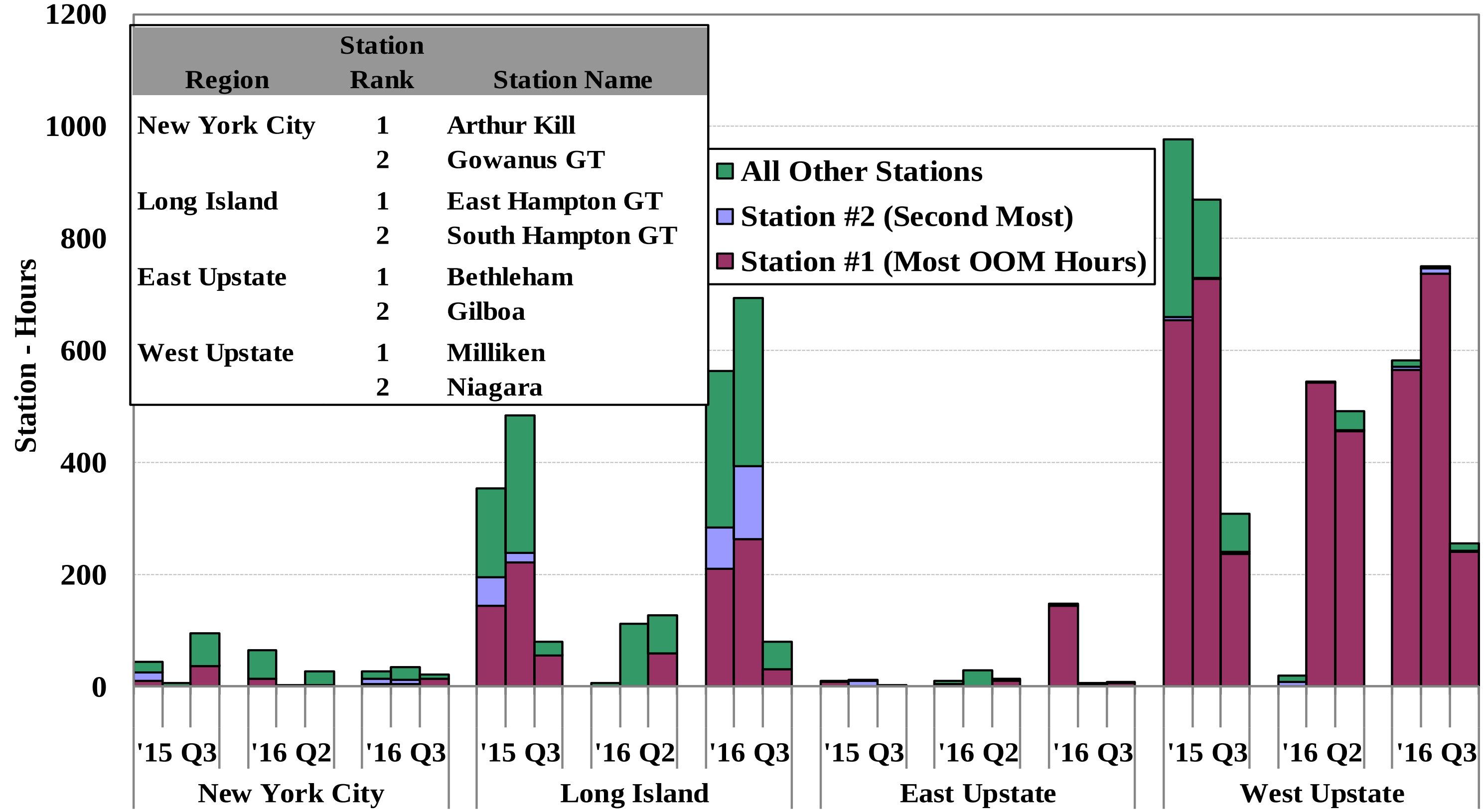
Supplemental Commitment for Reliability in NYC by Reliability Reason and Load Pocket



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



Region	Station Rank	Station Name
New York City	1	Arthur Kill
	2	Gowanus GT
Long Island	1	East Hampton GT
	2	South Hampton GT
East Upstate	1	Bethleham
	2	Gilboa
West Upstate	1	Milliken
	2	Niagara

Note: "Station #1" is the station with the highest number of out-of-merit ("OOM") hours in that region in the current quarter; "Station #2" is that station with the second-highest number of OOM hours in that region in the current quarter.

Note: 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, 790 hours in 2015-Q3, and 600 hours in 2016-Q2, and 430 hours in 2016-Q3. However, these were not classified as Out-of-Merit in hours when the NYISO did not adjust the UOL or LOL of the Resource.

Uplift Costs from Guarantee Payments: Chart Descriptions

- The next two figures 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 day-ahead market (usually economically) whose day-ahead market revenues do not cover their as-offered costs.
    - Real Time: For gas turbines 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.
    - 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.
  - ✓ The first figure shows these seven categories on a daily basis during the quarter.
  - ✓ The second figure summarizes uplift costs by region on a monthly basis.

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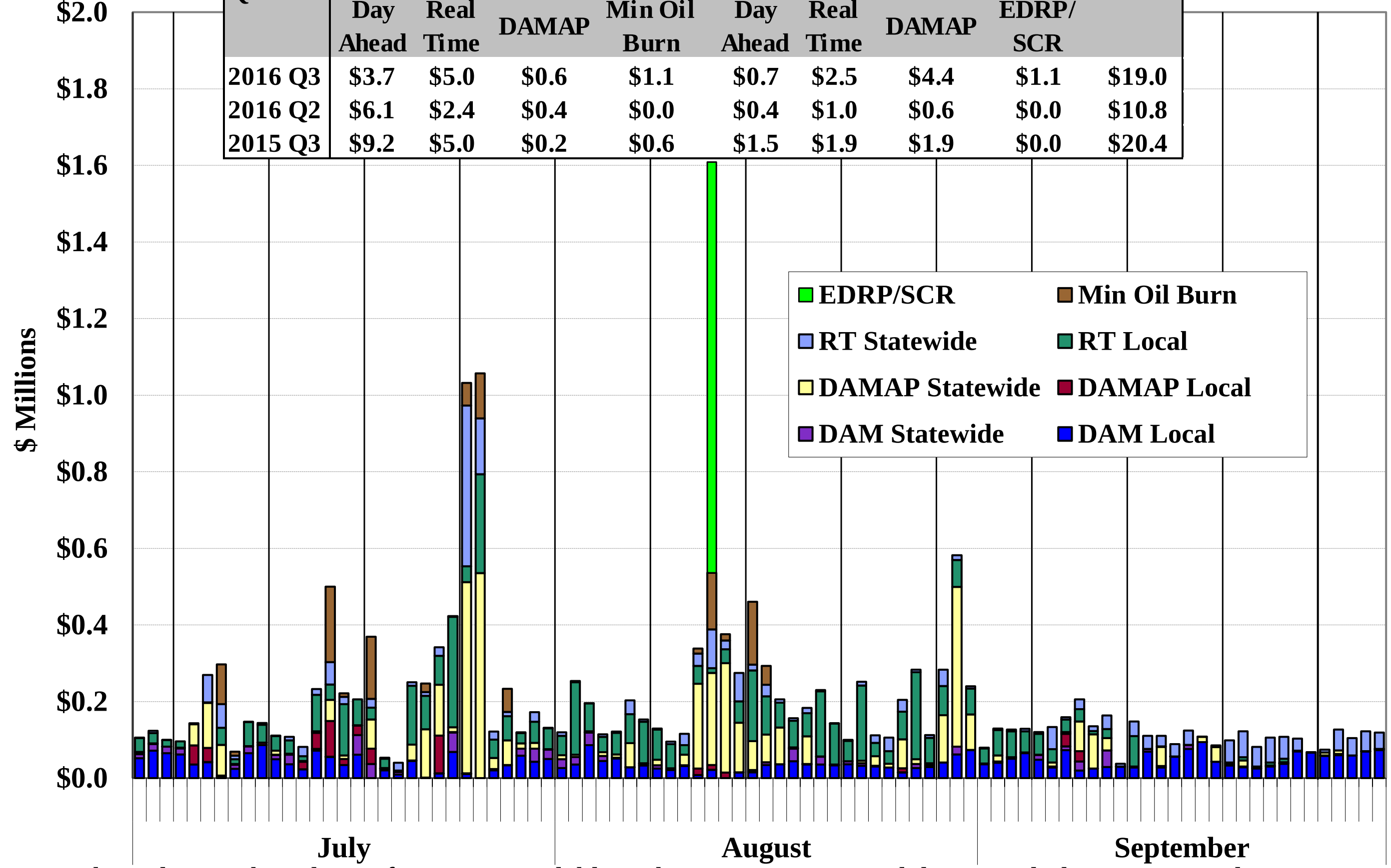
Uplift Costs from Guarantee Payments: Results

- Guarantee payments totaled nearly $19 million this quarter, down 7 percent from the third quarter of 2015.
  - ✓ The reduction was due primarily to decreased supplemental commitments and OOM dispatches in New York City and West NY (see slides 82-83).
  - ✓ However, this was partly offset by:
    - – Higher BPCG payments in Long Island from increased supplemental commitments and OOM dispatches for the reasons discussed earlier (see slides 80-81);
    - – High DAMAP payments to NYC and Long Island GTs on several high-load days.
      - DAMAP payments typically accrued during intervals with RT price spikes when the units were scheduled for energy in the DAM but not in the RTM.
    - – Higher guarantee payments to NYC units for the Minimum Oil Burn requirement because of higher load levels; and
    - – Additional guarantee payments to DR resources because of DR activation.
- Local uplift in Western NY totaled $5.5 million, accounting for 29 percent of total guarantee uplift this quarter.
  - ✓ Nearly all of this local uplift was paid to units that were committed and/or OOMed to manage congestion on the 115 kV system (see slide 84).

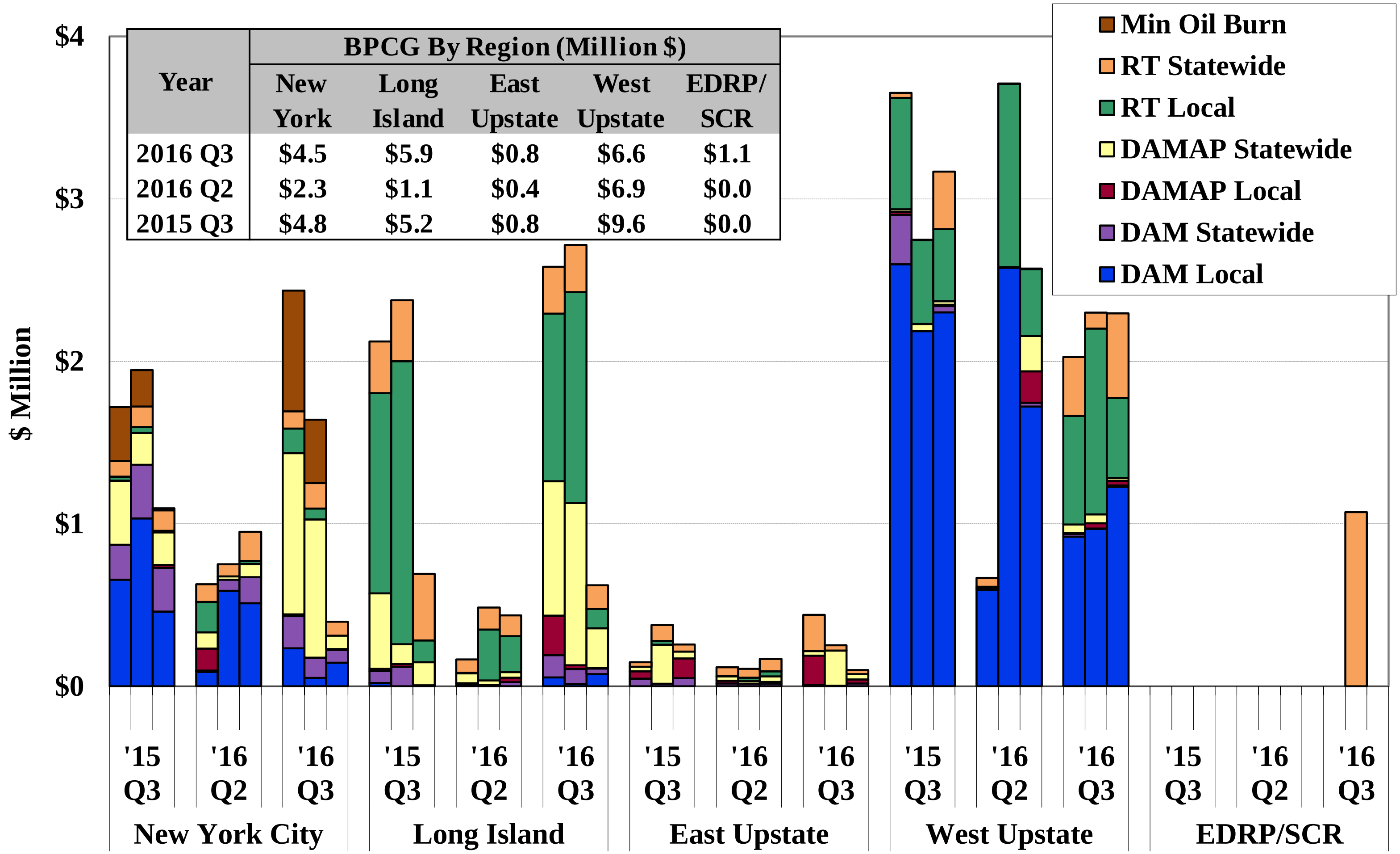
Uplift Costs from Guarantee Payments
Local and Non-Local by Category

Quarter	Quarterly BPCG By Category (Million $)								
	Local				Statewide				Total
	Day Ahead	Real Time	DAMAP	Min Oil Burn	Day Ahead	Real Time	DAMAP	EDRP/ SCR	
2016 Q3	$3.7	$5.0	$0.6	$1.1	$0.7	$2.5	$4.4	$1.1	$19.0
2016 Q2	$6.1	$2.4	$0.4	$0.0	$0.4	$1.0	$0.6	$0.0	$10.8
2015 Q3	$9.2	$5.0	$0.2	$0.6	$1.5	$1.9	$1.9	$0.0	$20.4



Note: 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.

Uplift Costs from Guarantee Payments
By Category and Region



Year	BPCG By Region (Million $)				
	New York	Long Island	East Upstate	West Upstate	EDRP/ SCR
2016 Q3	$4.5	$5.9	$0.8	$6.6	$1.1
2016 Q2	$2.3	$1.1	$0.4	$6.9	$0.0
2015 Q3	$4.8	$5.2	$0.8	$9.6	$0.0

Note: BPCG data are based on information available at the reporting time that can be different from final settlements.

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Market Power and Mitigation

Market Power Screens: Potential Economic and Physical Withholding

- The next two figures 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 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.

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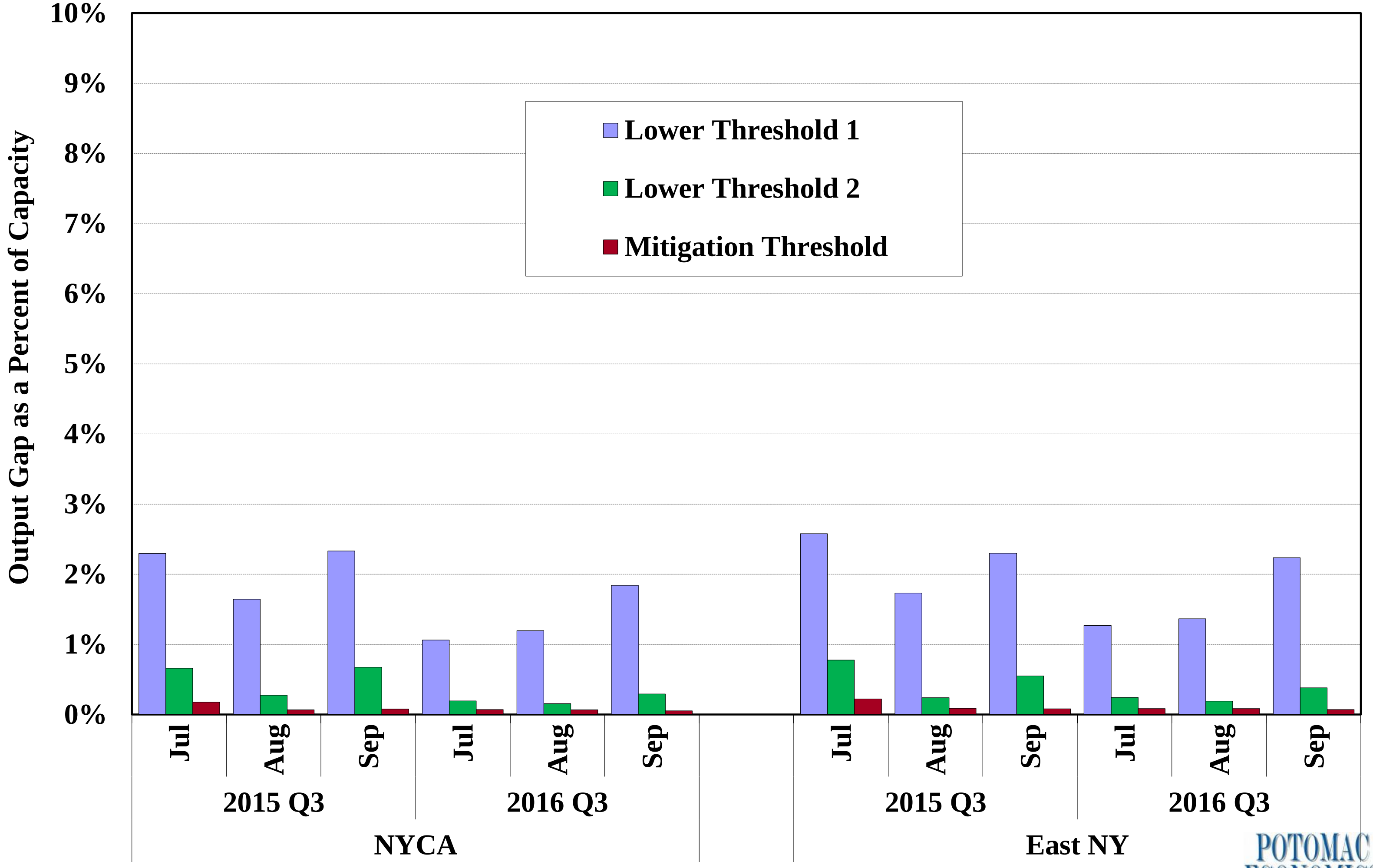
Market Power Screens:
Potential Economic and Physical Withholding

- The amount of output gap was relatively low, averaging:
  - ✓ Less than 0.1 percent of total capacity at the mitigation threshold; and
  - ✓ Roughly 1 to 2 percent at the lowest threshold evaluated (i.e., 25 percent).
  - ✓ Overall, the output gap raised no significant market power concerns this quarter.
- Economic capacity on long-term outages/deratings was higher in September than in July and August as some suppliers began to perform seasonal maintenance.
  - ✓ In some cases, it might have been efficient to postpone an outage because the unit would have been economic to operate given high load conditions.
  - ✓ However, some generators would have been economic whenever they took an outage because they have very low marginal costs (e.g., nuclear units).
- Economic capacity on outages/deratings (both long and short-term) were higher than in the previous year primarily because:
  - ✓ One steam unit in Southeast New York was forced OOS from early-June to mid-September; and
  - ✓ One nuclear unit had forced deratings for refueling during the quarter.
- The amounts of unoffered (including outages/deratings) economic capacity were modest and consistent with expectations for a competitive market.

Output Gap in NYCA and East NY



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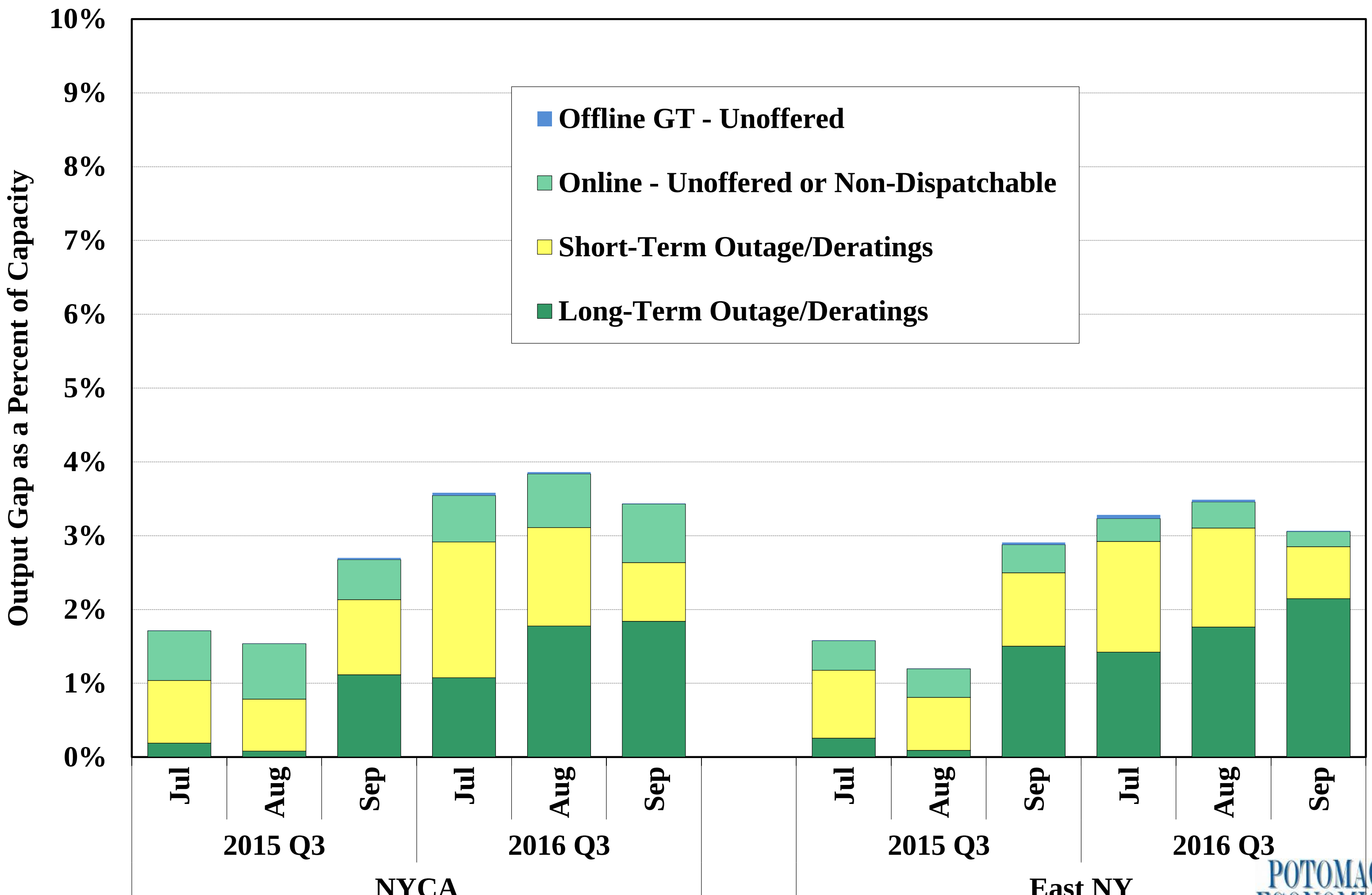
Unoffered Economic Capacity in NYCA and East NY



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Automated Market Power Mitigation

- The next table summarizes the automated mitigation that was imposed during the quarter (not including BPCG mitigation).
- Energy, minimum generation, and start-up offer mitigation is performed by automated mitigation procedure (“AMP”) software in the day-ahead and real-time markets in New York City. The following figure reports:
  - ✓ The frequency of incremental energy offer mitigation; and
  - ✓ The average quantity of mitigated capacity, including capacity below the minimum generation level when the minimum generation offer is mitigated.
- Most mitigation occurs in the day-ahead market, since that is where most supply is scheduled. In the third quarter of 2016,
  - ✓ Nearly all of mitigation occurred in the day-ahead market, of which:
    - – Local reliability (i.e., DARU & LRR) units accounted for 47 percent. These mitigations generally affect guarantee payment uplift but not LBMPs.
    - – Units in the Greenwood/Staten Island load pocket accounted for 39 percent.
- The quantity of mitigation declined from the third quarter of 2015 primarily because of reduced DARU and LRR commitments in NYC (see slides 82-83).

Automated Market Mitigation

Quarterly Mitigation Summary		2014 Q3	2015 Q3	2016 Q2	2016 Q3
Day-Ahead Market	**Average Mitigated MW**	116	141	103	99
	Energy Mitigation Frequency	15%	40%	8%	31%
Real-Time Market	**Average Mitigated MW**	2	4	0.6	4
	Energy Mitigation Frequency	1%	4%	0%	0%

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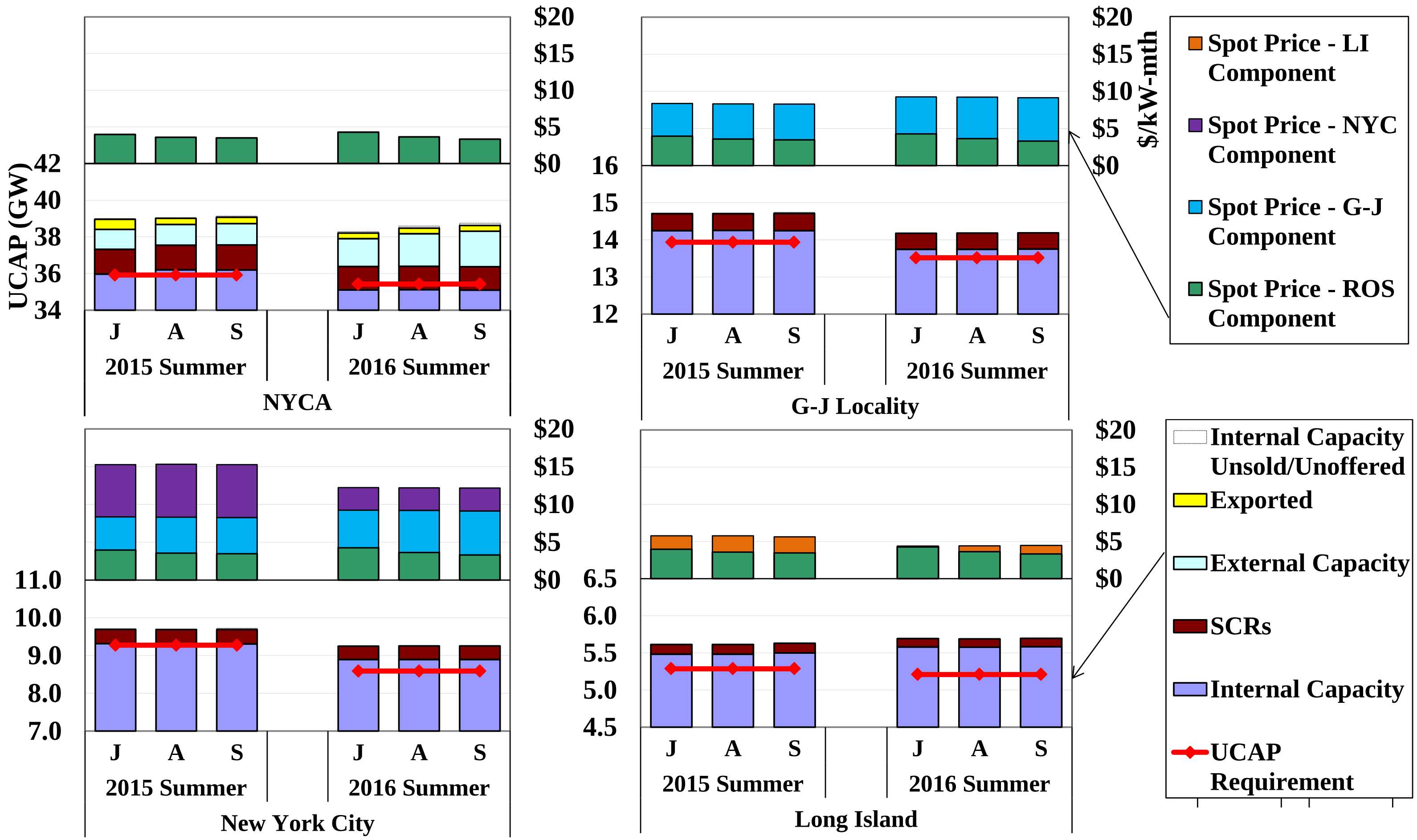
Capacity Market

Capacity Market Results

- The following two figures summarize capacity market results and key market drivers in the third quarter of 2016.
  - ✓ The first figure summarizes available and scheduled Unforced Capacity ("UCAP"), UCAP requirements, and spot prices that occurred in each capacity zone by month (compared to those from a year ago).
  - ✓ The next table shows: (a) the year-over-year changes in spot prices by locality; and (b) variations in key factors that drove these changes.
- In the ROS, average spot prices rose slightly from a year ago because of the:
  - ✓ Lower ICAP requirement, reflecting the net effect of lower peak load forecast and higher IRM;
  - ✓ Decrease in internal ICAP supply because of retirements, mothballing, and outages.
  - ✓ Higher sales from external resources (partly offset by lower SCR sales).
- Average spot prices fell in NYC and Long Island but rose in the G-J Locality.
  - ✓ The reductions in NYC and Long Island were due primarily to lower ICAP requirements, which reflected: a) lower peak load forecast; and b) reduced LCRs (due partly to the TOTS projects, which increased import capability into SENY).
  - ✓ Prices rose in the G-J Locality because the decrease in the amount of capacity supply was larger than the decrease in capacity requirement.
    - – A large ICAP supplier had a substantially worse EFORd this quarter.

Capacity Market Results:
2015 & 2016 Q3



Note: Sales associated with Unforced Deliverability Rights ("UDRs") are included in "Internal Capacity," but unsold capacity from resources with UDRs is not shown.

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Key Drivers of Capacity Market Results

	NYCA	NYC	LI	G-J Locality
Avg. Spot Price				
2016 Q3 ($/kW-Month)	3.74	12.21	4.42	9.21
% Change from 2015 Q3	2%	-20%	-23%	11%
Change in Demand				
Load Forecast (MW)	-209	-136	-61	-31
IRM/LCR	0.5%	-3.0%	-1.0%	-0.5%
2016 Summer	*117.5%*	*80.5%*	*102.5%*	*90.0%*
2015 Summer	*117.0%*	*83.5%*	*103.5%*	*90.5%*
ICAP Requirement (MW)	**-77**	**-467**	**-117**	**-109**
Change in ICAP Supply (MW)				
Reductions Due to: Retirement (R), ICAP Inegilible FO (FO), Mothball (M)				
R - Huntley 67 & 68 (Mar-16)	-375			
FO - Astoria GT 05,07,12,13 (Jan-16)	-58	-58		-58
M - Astoria GT 08,10,11 (Jul-16)	-47	-47		-47
R - Dunkirk 2 (Jan-16)	-75			
M - Ravenswood 04,05,06 (May-16)	-49	-49		-49
Changes Due to: DMNC Test	63	89	19	56
Changes in External & SCR Sales	537	-22	-18	-23
Net Changes (MW)	**-5**	**-87**	**0**	**-121**

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