2015 State of the Market Report for the NYISO Markets: Energy & AS Market Highlights

Pallas LeeVanSchaick
NYISO Market Monitoring Unit
Potomac Economics

Market Issues Working Group
May 20, 2016

POTOMAC ECONOMICS

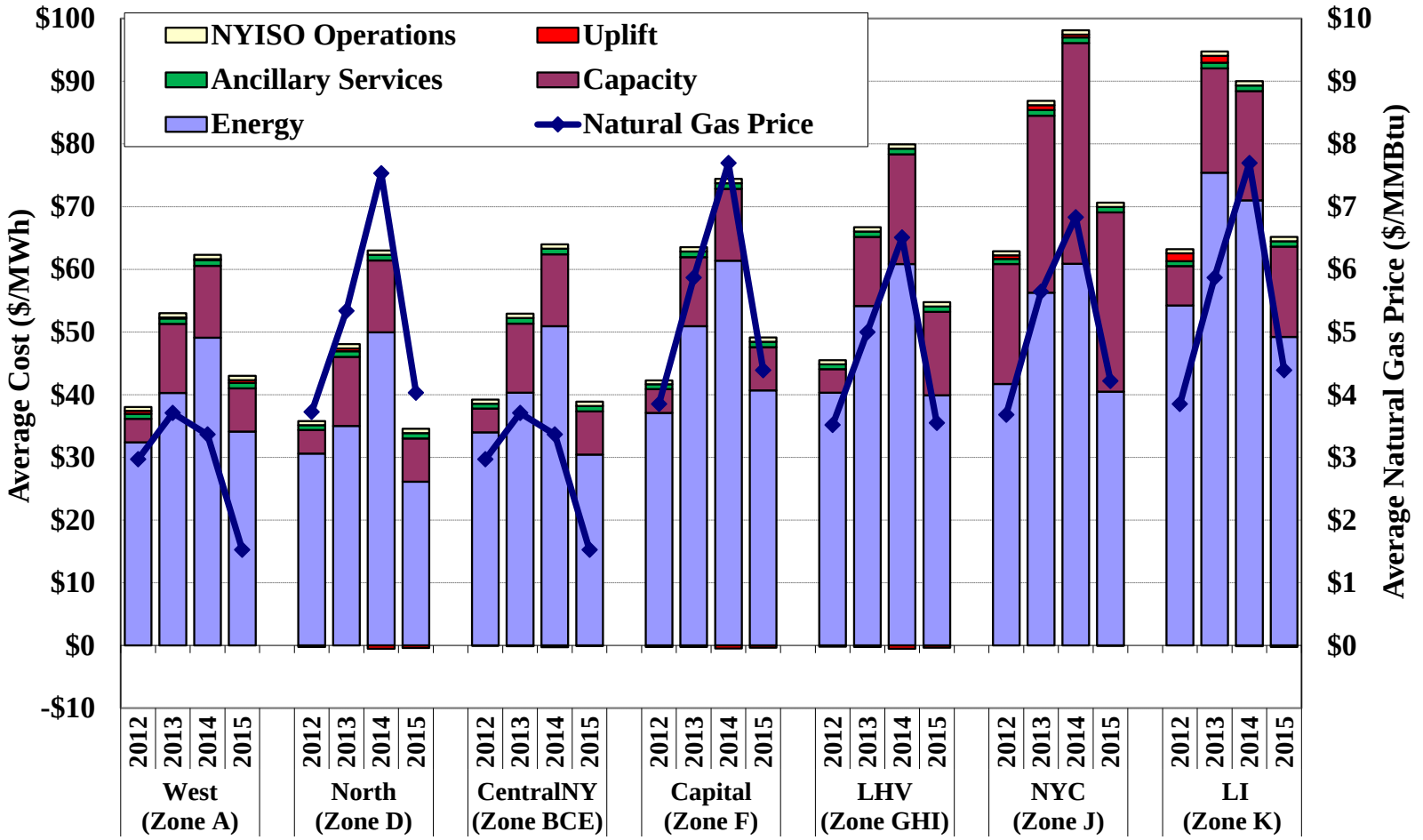
Schedule for Review of 2015 SOM Report

- On 5/5: Report posted on NYISO website
- Presentation schedule:
  - ✓ 5/12 ICAPWG: Capacity Market Results & Recommendations
  - ✓ 5/20 MIWG: Energy Market Results & Recommendations
  - ✓ 5/25 MC: Overview of Report & Recommendations
- Comments/questions submitted by 5/25 will be posted on the NYISO website and addressed on a best-efforts basis at the 5/20 and 5/25 meetings.
  - ✓ To: deckels@nyiso.com & pallas@potomaceconomics.com
- Comments/questions received after 5/25 will be addressed case by case.

Highlights and Market Summary: Energy Market Results and Uplift Charges

- The NYISO experienced mild summer weather and winter conditions that improved slightly from 2014 (but were still severe by historic standards).
  - ✓ Natural gas prices fell 38 to 58 percent from 2014 to 2015, helping to reduce electricity prices by 32 to 49 percent over the same period.
- All-in prices ranged from $35/MWh in the North Zone to $71/MWh in NYC.
- Congestion from west-to-east on the natural gas pipeline system led to a similar pattern of congestion in the NYISO energy markets.
  - ✓ Flows across western New York and the Central-East Interface accounted for 61 percent of the $539 million in day-ahead congestion revenue.
- Uplift from guarantee payments fell 52 percent to $71 million because of low gas prices and improved winter market performance.
- Day-ahead congestion shortfalls (revenues less than TCC obligations) totaled $37 million. Most was caused by transmission outages and allocated to TOs.
- Balancing congestion shortfalls (real-time capability less than assumed day ahead) rose to $19 million, primarily when loop flows and transmission outages reduced available transfer capability in western NY.

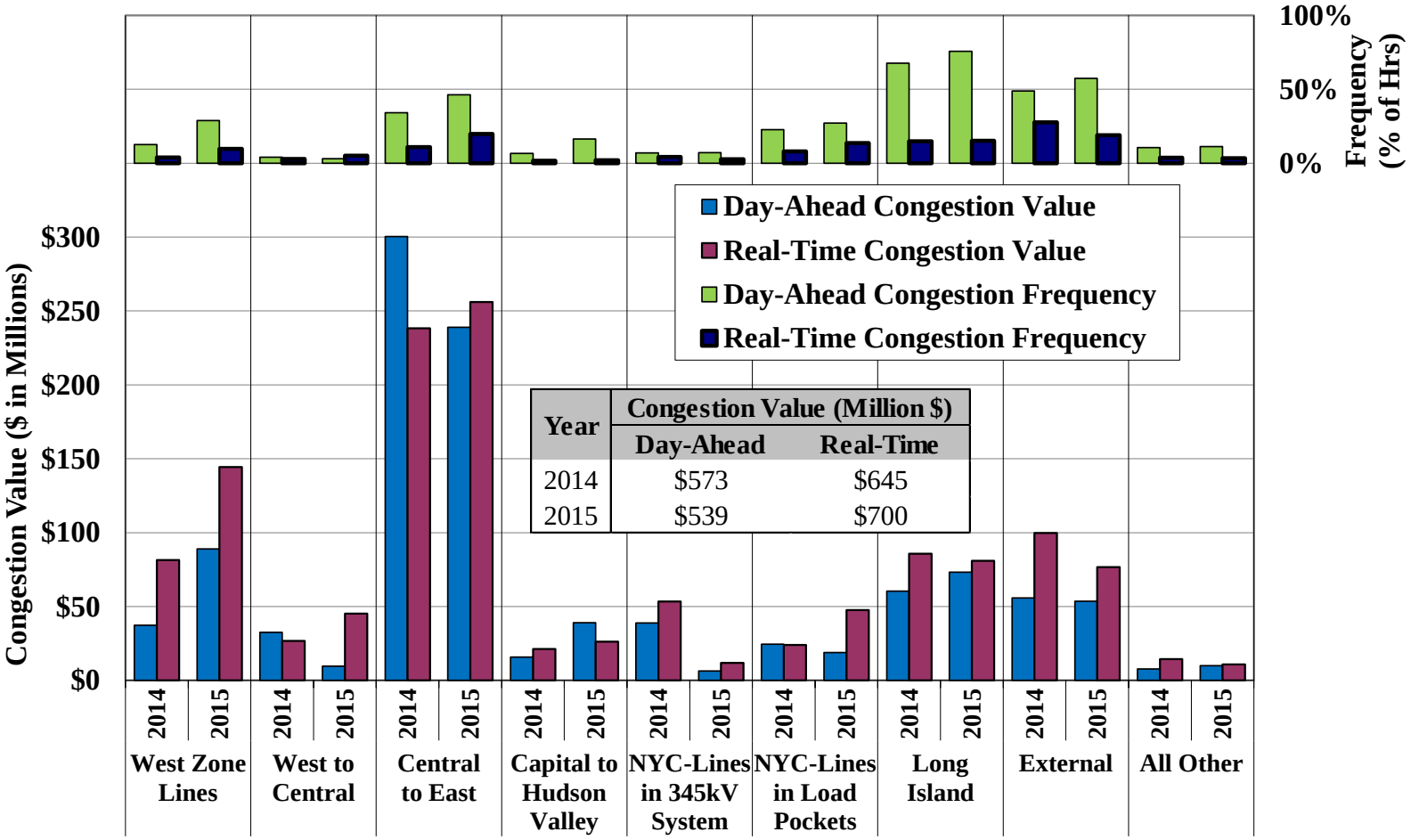
Highlights and Market Summary:
Average All-In Price by Region



See Sections I.A & III.A

POTOMAC ECONOMICS

Highlights and Market Summary:
Congestion in the DA & RT Markets

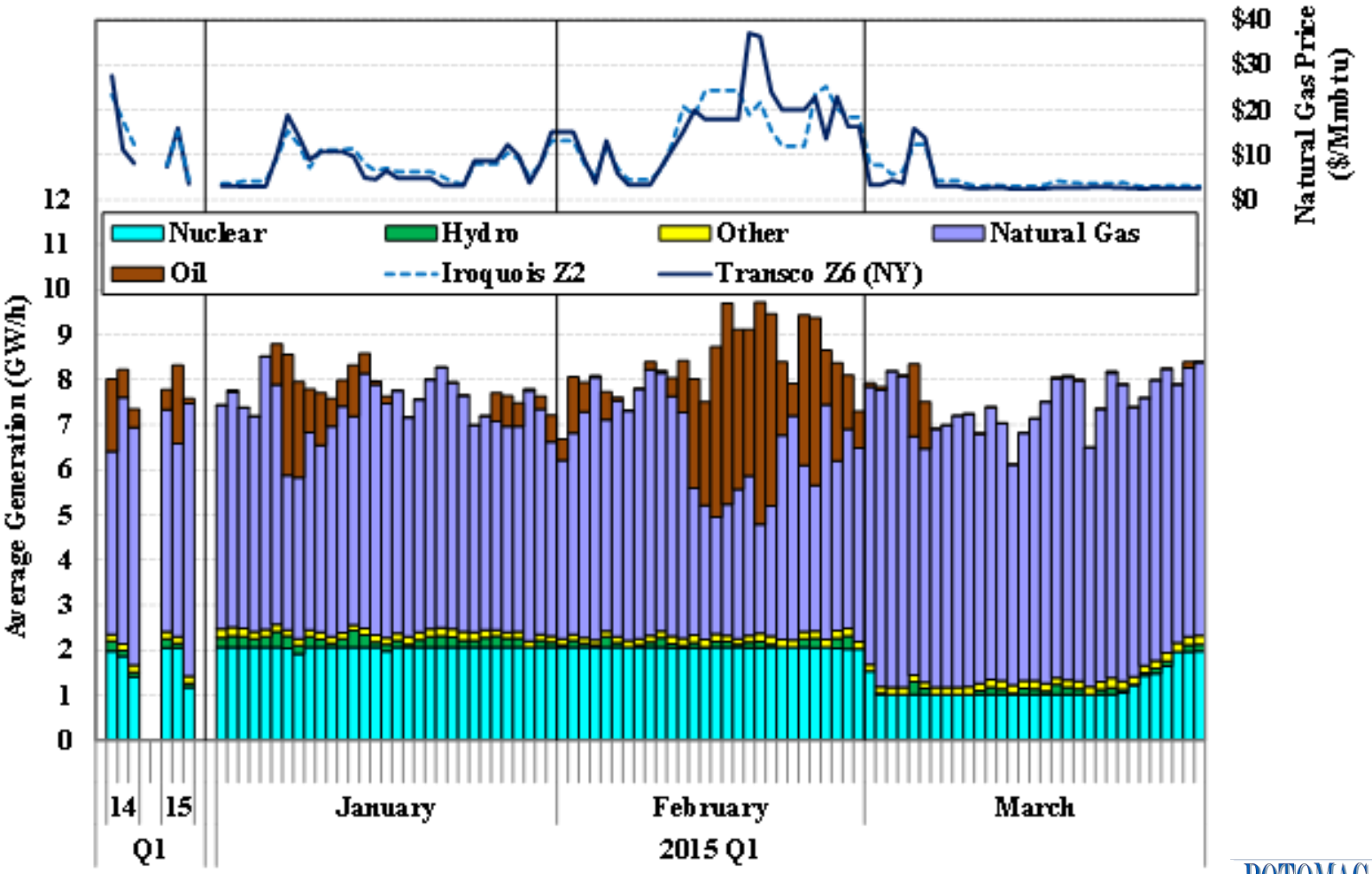


Year	Congestion Value (Million $)	
	Day-Ahead	Real-Time
2014	$573	$645
2015	$539	$700

See Sections I.A & III.E

POTOMAC ECONOMICS

Highlights and Market Summary:
Fuel Use and Gas Prices in Eastern NY



See Sections I.D, III.C, & IX.B.1

POTOMAC ECONOMICS

Highlights and Market Summary:
Day Ahead Market Congestion Uplift

Facility Group	Annual Shortfalls ($ Million)
West Zone Lines	
Niagara Modeling Assumption	**$7**
Other Factors (e.g., Outages, Loopflows)	**$10**
Central to East	**$7**
North Zone Lines	**$14**
Long Island Lines	
901/903 PARs	**-$11**
Excess GFTCC Allocations	**$4**
Other Factors	**$9**
External	**-$10**
All Other Facilities	**$7**

See Sections VI.A

Highlights and Market Summary: Balancing Congestion Uplift

Facility Group	Annual Shortfalls ($ Million)
West Zone Lines	
Niagara Modeling Assumption	**$1**
Ramapo, ABC & JK PARs	**$8**
Other Factors (e.g., Outages, Loopflows)	**$18**
Central to East	
Ramapo, ABC & JK PARs	**-$7**
Other Factors	**-$3**
Capital to HVL (TSAs)	**$4**
Long Island Lines	
901/903 PARs	**$4**
Other Factors	**$1**
All Other Facilities	**-$1**

See Sections VI.A

Enhance Modeling/Coordination with NE & PJM
Recommendations #9, #12, and #13

9. *Eliminate fees for CTS transactions at the PJM-NYISO border.*
12. *Adjust RTC and RTD look ahead evaluations to be consistent with timing of external transaction ramp and GT commitment.*
13. *Enhance modeling of loop flows and PAR-controlled lines.*

- Principle: Reduce unnecessary volatility and barriers to trading
- Approach:
  - ✓ Use cost-causation approach when setting transaction fees.
  - ✓ Eliminate structural differences between forecast & actual outcomes.
- Benefits:
  - ✓ Improve performance of CTS-PJM, CTS-NE, and intraday scheduling processes.
  - ✓ Reduce overall dispatch costs by improving external scheduling.
  - ✓ Reduce unnecessary price volatility.

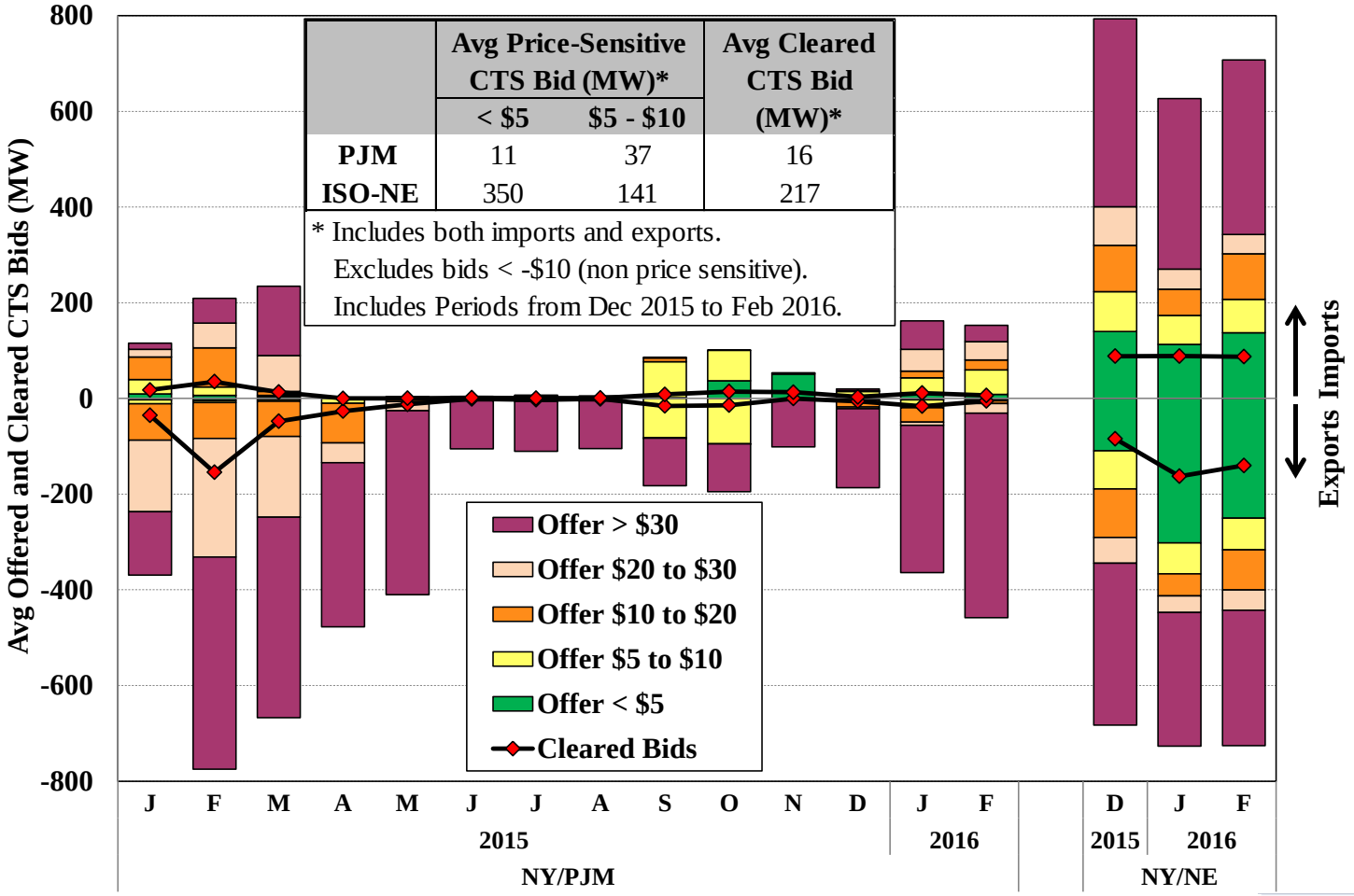
See Sections I.D, VII.D, IX.E, XI, & A-IV.D

POTOMAC ECONOMICS

Enhance Coordination with Other Control Areas: Recommendation #9

	Avg Price-Sensitive CTS Bid (MW)*		Avg Cleared CTS Bid (MW)*
	< $5	$5 - $10	
PJM	11	37	16
ISO-NE	350	141	217

* Includes both imports and exports.
Excludes bids < -$10 (non price sensitive).
Includes Periods from Dec 2015 to Feb 2016.



See Sections I.D, VII.D, & XI

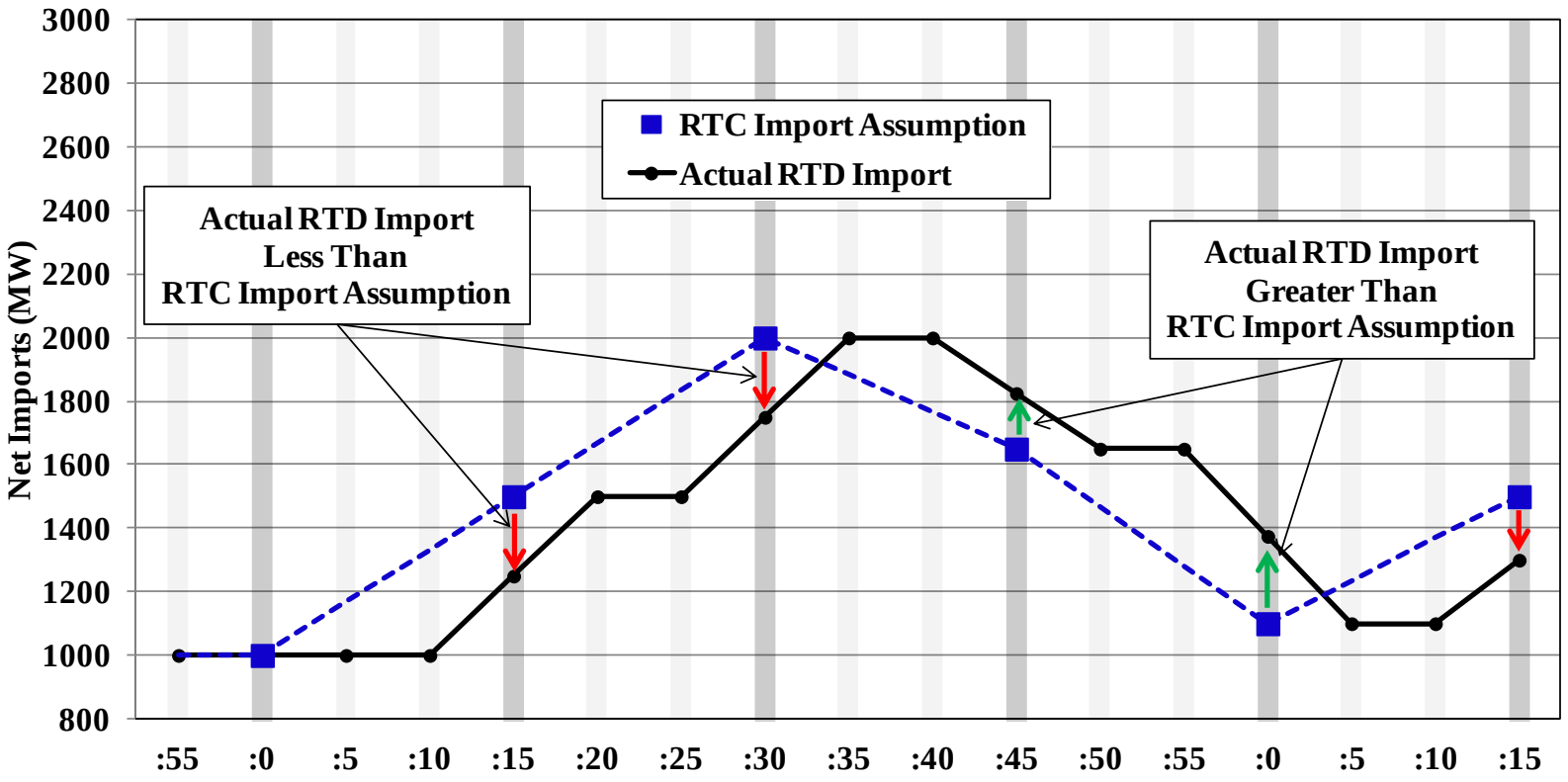
POTOMAC ECONOMICS

Enhanced Modeling & Unnecessary Volatility: Recommendation #13

	Power Balance		West Zone 230kV Lines		Central East		Dunwoodie - Shore Rd 345kV		Intra-Long Island Constraints	
Average Transfer Limit	**n/a**		**637**		**2564**		**719**		**273**	
Number of Price Spikes	**557**		**1279**		**351**		**591**		**1311**	
Average Constraint Shadow Price	**$219**		**$810**		**$319**		**$521**		**$872**	
Source of Increased Constraint Cost:	**(MW)**	**(%)**	**(MW)**	**(%)**	**(MW)**	**(%)**	**(MW)**	**(%)**	**(MW)**	**(%)**
Scheduled By RTC	**174**	**65%**	**2**	**7%**	**66**	**45%**	**43**	**60%**	**5**	**25%**
External Interchange	113	42%	2	7%	36	25%	26	36%	1	7%
RTC Shutdown Resource	37	14%	0	0%	18	13%	13	19%	3	13%
Self Scheduled Shutdown/Dispatch	24	9%	0	0%	12	8%	4	6%	1	5%
Flow Change from Non-Modeled Factors	**9**	**4%**	**18**	**81%**	**59**	**40%**	**20**	**28%**	**14**	**72%**
Loop Flows & Other Non-Market	0	0%	14	63%	11	7%	7	9%	3	14%
Fixed Schedule PARs (excl. Ramapo)	0	0%	3	12%	29	20%	13	18%	11	56%
Ramapo PARs	0	0%	1	7%	16	11%	0	0%	0	0%
Redispatch for Other Constraint (OOM)	9	4%	0	0%	3	2%	1	1%	0	1%
Other Factors	**86**	**32%**	**3**	**11%**	**21**	**14%**	**9**	**12%**	**1**	**3%**
Total	**270**	**100%**	**22**	**100%**	**146**	**100%**	**72**	**100%**	**20**	**100%**
Redispatch for Other Constraint (RTD)	**106**		**1**		**34**		**9**		**1**	

See Sections I.D, IX.E, & XI

Enhance Modeling/Coordination: Recommendation #12 – High Priority



See Sections I.D, IX.E, XI, & A-IV.D

POTOMAC ECONOMICS

Modernize Grandfathered Wheeling Agreements: Recommendations #10 & #11 – High Priority

10. *Incorporate the ABC and JK interfaces (between SE New York and PJM) into M2M process.*
11. *Operate PAR-controlled lines to minimize production costs and create financial rights that compensate affected TOs.*

- Principles/Approach:
  - ✓ Use transmission to reduce production costs
  - ✓ Convert physical transmission rights and transactions into financial rights
- Benefits:
  - ✓ Reduce production costs (up to $44M/year combined)
  - ✓ Reduce unnecessary price spikes for Long Island customers
  - ✓ Create financial rights that benefit NYC customers

See Sections I.B, I.D, V.A.2, IX.D, & XI

Modernize Grandfathered Wheeling Agreements: Recommendations #10 & #11 – High Priority

	Day-Ahead Market Schedule			Adjustment in Real-Time		
	Avg Flow (MW)	Avg NYCA Price minus Avg Outside Price ($/MWh)	Estimated Production Cost Savings (Million $)	Avg Flow (MW)	Avg NYCA Price minus Avg Outside Price ($/MWh)	Estimated Production Cost Savings (Million $)
PJM to NYCA						
Waldwick (JK)	-862	$2.47	-$19	152	$1.98	$1
Ramapo	196	$3.78	$30	157	$4.35	$6
Farragut (BC)	645	-$2.60	-$15	-66	-$6.47	$0
Goethals (A)	224	$2.60	$5	67	$3.08	$1
Long Island to NYC						
Lake Success	145	-$8.20	-$9	-9	-$8.47	$1
Valley Stream	48	-$13.19	-$6	4	-$16.71	-$2

See Sections I.B, I.D, V.A.2, IX.D, & XI

POTOMAC ECONOMICS

Enhance RT Performance Incentives: Recommendations #14, #15, #17, and #20

14. *Enhance criteria for gas turbines to set energy prices.*
15. *Model 100+kV transmission constraints in the day-ahead and real-time markets.*
17. *Enhance real-time pricing during transmission shortages.*
20. *Recognize gas system limits for reserve providers.*

- Principles:
  - ✓ Price = marginal cost of maintaining reliability
  - ✓ Reward resources based on flexibility and performance in satisfying NYISO's reliability needs
- Benefits:
  - ✓ Efficient scheduling of generation and imports
  - ✓ Increased investment in resources with flexible characteristics
  - ✓ Improve resource performance
  - ✓ Reduce reliance on capacity market

See Sections I.B, I.D., I.E, IX, & XI

Enhance RT Performance Incentives: Out-of-Merit Dispatch & Recommendation #15

Region	OOM Station-Hours		
	2014	2015	% Change
West Upstate	2031	5050	149%
East Upstate	189	222	17%
New York City	241	613	154%
Long Island	701	1621	131%
Total	**3162**	**7506**	**137%**

In addition, 115kV congestion was also managed by:

(A) Instructing the Niagara plant out-of-market to shift generation among its units in 950 hours.

(B) Taking out-of-service two transmission lines on the NYISO-PJM interface for a combined 2,470 hours.

See Sections I.D, IX.F.3, & XI

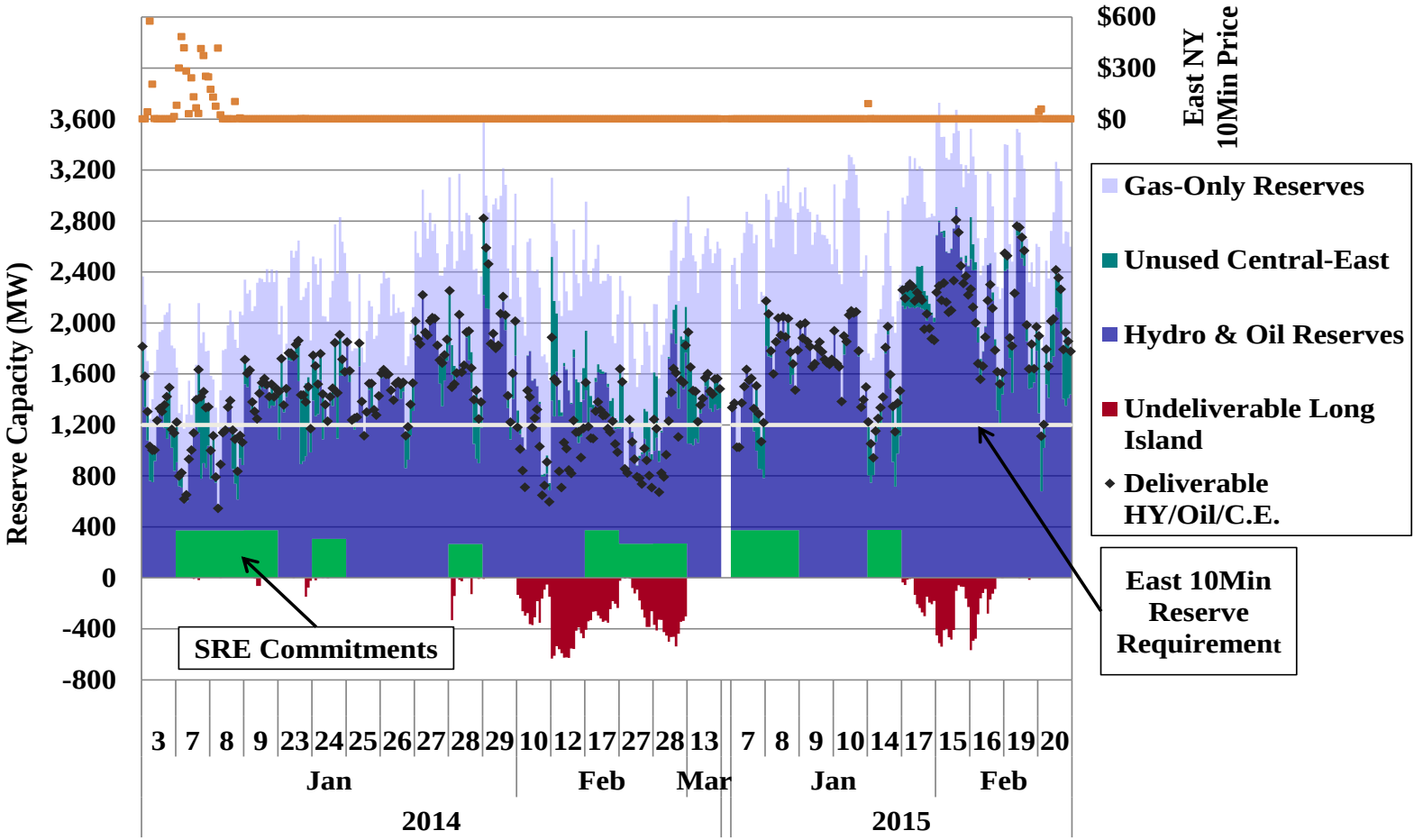
Enhance RT Performance Incentives: Transmission Shortages & Recommendation #17

-

Transmission Facilities	Transmission Shortage MW					
	< 5 MW		5 - 20 MW		> 20 MW	
	# Intervals	Avg Shadow Price ($/MWh)	# Intervals	Avg Shadow Price ($/MWh)	# Intervals	Avg Shadow Price ($/MWh)
West Zone 230 kV Lines	125	$1,376	1264	$528	1048	$870
Upstate - LIPA 345 kV Lines	365	$233	752	$247	545	$309
E. Garden City - Valley Stream	556	$884	848	$738	232	$872
Greenwood Load Pocket	214	$2,117	872	$119	246	$62
All NYCA Facilities	1783	$875	5072	$364	2806	$542

See Sections I.D, IX.A.2, & XI

Enhance RT Performance Incentives: Reserves During OFOs & Recommendation #20



See Sections I.D, IX.B, & XI

POTOMAC ECONOMICS



List of Recommendations:
Broader Regional Markets & RT Market Operations

RECOMMENDATION	Discussed in	Current Effort	High Priority	Scoping/Future
Broader Regional Markets				
(8) Modify the capacity market and planning process to better account for capacity that is exported to neighboring control areas from import-constrained capacity zones.	VIII.B		X	
(9) Eliminate transaction fees for CTS transactions at the PJM-NYISO border.	VII.D			
(10) After the ConEd-PSEG wheeling agreement expires, work with PJM to coordinate scheduling of the associated controllable lines (i.e., the A, B, C, J, and K lines) to minimize production costs across the two regions.	IX.D			
Energy Market Enhancements - RT Market Operations				
(11) Operate certain PAR-controlled lines to minimize production costs and create financial rights that compensate affected transmission owners.	IX.D		X	
(12) Adjust look ahead evaluations of RTD and RTC to be more consistent with the timing of external transaction ramp and gas turbine commitment.	VII.D IX.E	X	X	X
(13) Consider enhancing modeling of loop flows and PAR-controlled lines to reflect the effects of expected generation, load, and PAR-controls on line flows more accurately.	IX.E	X		X

See Section XI

List of Recommendations:
Energy Market Enhancements

RECOMMENDATION	Discussed in	Current Effort	High Priority	Scoping/Future
Energy Market Enhancements - RT Pricing				
(14) Modify criteria for GTs to set prices in the real-time market by allowing GTs to be eligible to set price in the final pricing pass and incorporating start-up costs.	IX.C	X		
(15) Model 100+ kV transmission constraints in the DA and RT markets using economic commitment and dispatch software.	IX.F.3			
(16) Dynamically adjust operating reserve requirements to account for factors that increase or decrease the amount of reserves that must be held on internal resources.	IX.A.1			X
(17) When a transmission constraint cannot be satisfied, utilize graduated transmission demand curves to set constraint shadow prices.	IX.A.2			X
Energy Market Enhancements - BPCG Eligibility Criteria				
(18) Work with generators in NOx bubbles to ensure their RACT compliance plans use the most economic compliance option available.	IX.F.2			
Energy Market Enhancements - Fuel Assurance				
(19) Consider allowing generators to submit offers that reflect certain energy storage and fuel supply constraints in the day-ahead market.	IX.B.2	X		X
(20) Enhance recognition of gas system limitations when scheduling resources to provide operating reserves.	IX.B.2			X
Energy Market Enhancements - DAM Scheduling				
(21) Improve assumptions in the commitment logic of the DAM to avoid scheduling uneconomic gas turbines.	V.A			

See Section XI