Highlights of the 2017 State of the Market Report for the NYISO Markets

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Market Issues Working Group Meeting
May 31, 2018

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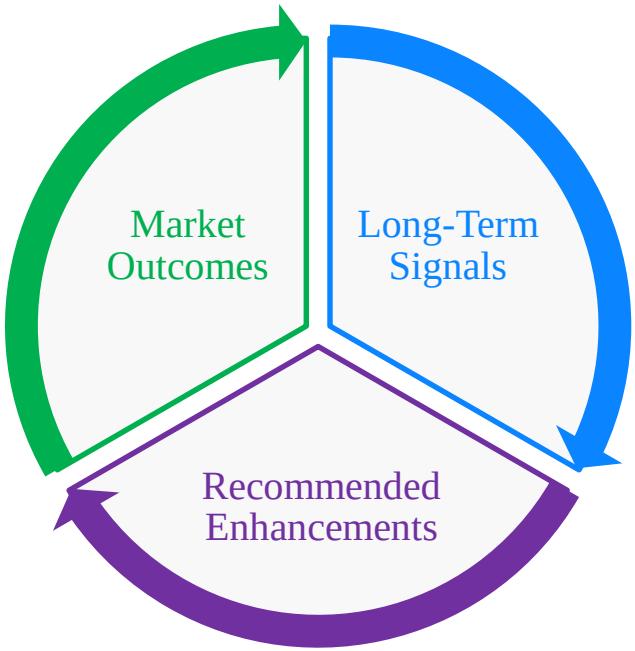
Overview

- Schedule of Presentations
- Market Highlights
  - ✓ Prices, Congestion
  - ✓ Market Operations
- Recommendations
  - ✓ Mapping to BPWG project list and Master Plan
  - ✓ Performance incentives
  - ✓ Market power mitigation
  - ✓ RT scheduling and operations
- Unfinished Business from May 23



Schedule for Review of 2017 SOM Report

- On May 8: Report was posted on NYISO website
- Presentation schedule:
  - ✓ ~~May 16: Overview of Report & Recommendations~~
  - ✓ ~~May 23: Capacity Results & Recommendations~~
  - ✓ May 31: Energy & AS Results & Recommendations
- Submit comments/questions to:
  - ✓ deckels@nyiso.com, pallas@potomaceconomics.com, & jchen@potomaceconomics.com

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Market Highlights

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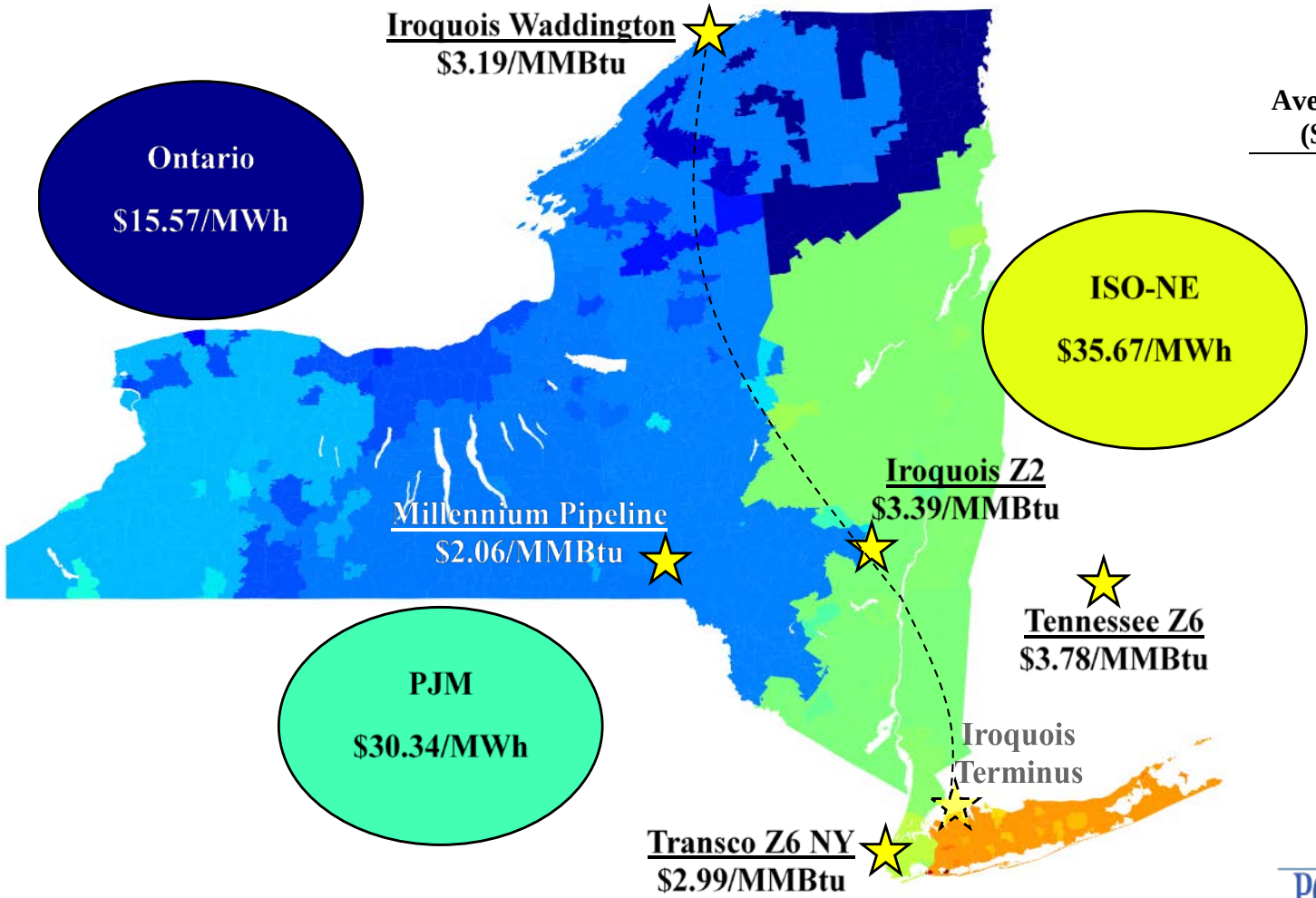
Market Highlights: Energy Prices and Congestion



See Sections II.A & II.B

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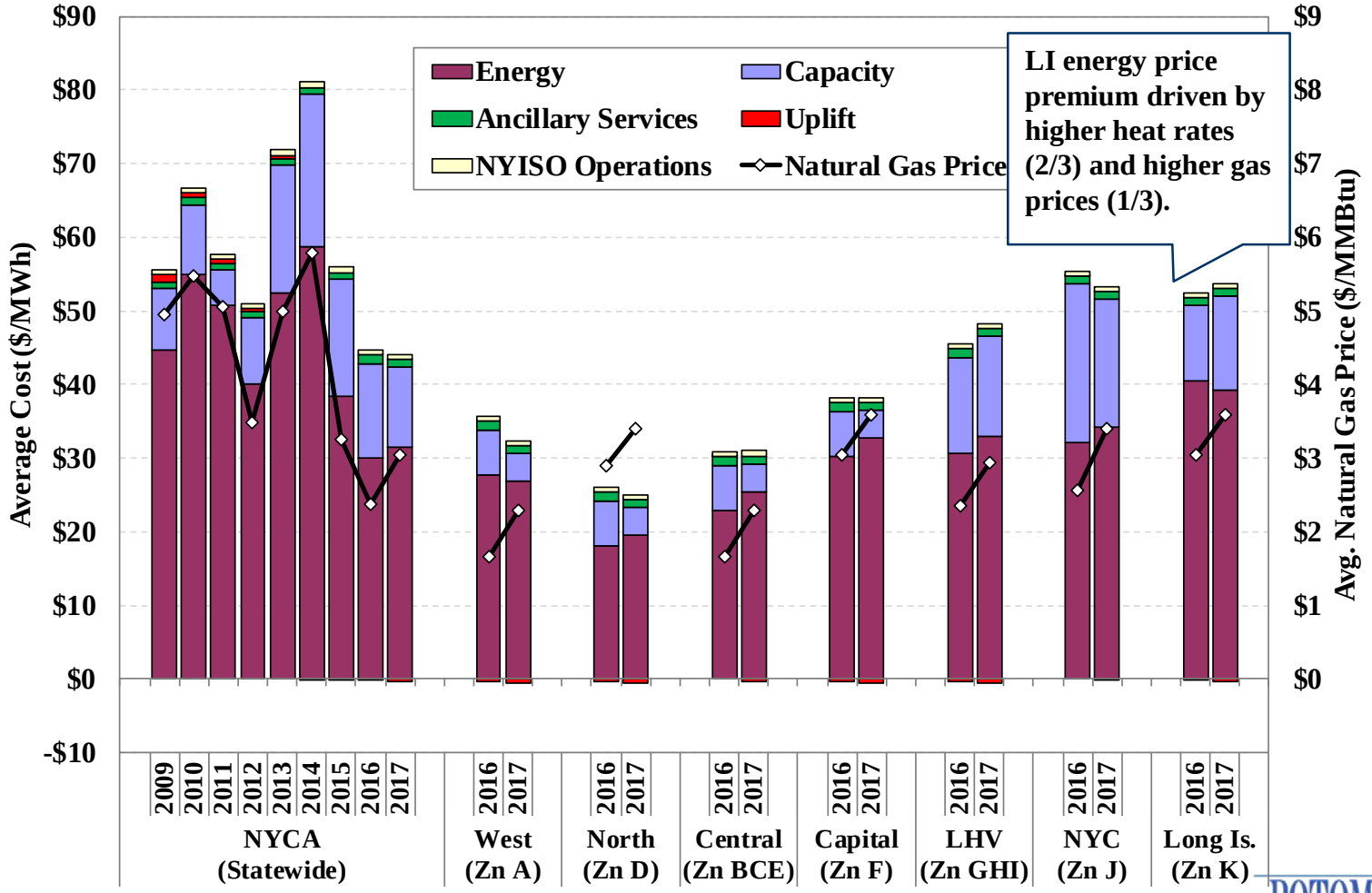
Market Highlights: Average All-In Price by Region



See Sections II.A & App. I.A

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Market Highlights:
Operator Actions to Manage 115 kV Constraints

West Zone	# Days
Ontario Imports	152
PJM Exports	22
Gen Up	40
Gen Down	74
Dysinger East	6
St. Lawr PARs	52
Ramapo PARs	26
ABC PARs	22
Any Resource	226

North Zone	# Days
HQ Imports	41
Gen Up	27
Gen Down	69
Moses South	10
St. Lawr PARs	40
PV-20 PAR	10
Any Resource	120

Capital Zone	# Days
Gen Up	8
Gen Down	76
Any Resource	83

Central Zone	# Days
Gen Up	102

Cent-Hud 69kV	# Days
Gen Up	35
Gen Down	28
Any Resource	59

See Section V.A & Rec 2014-12

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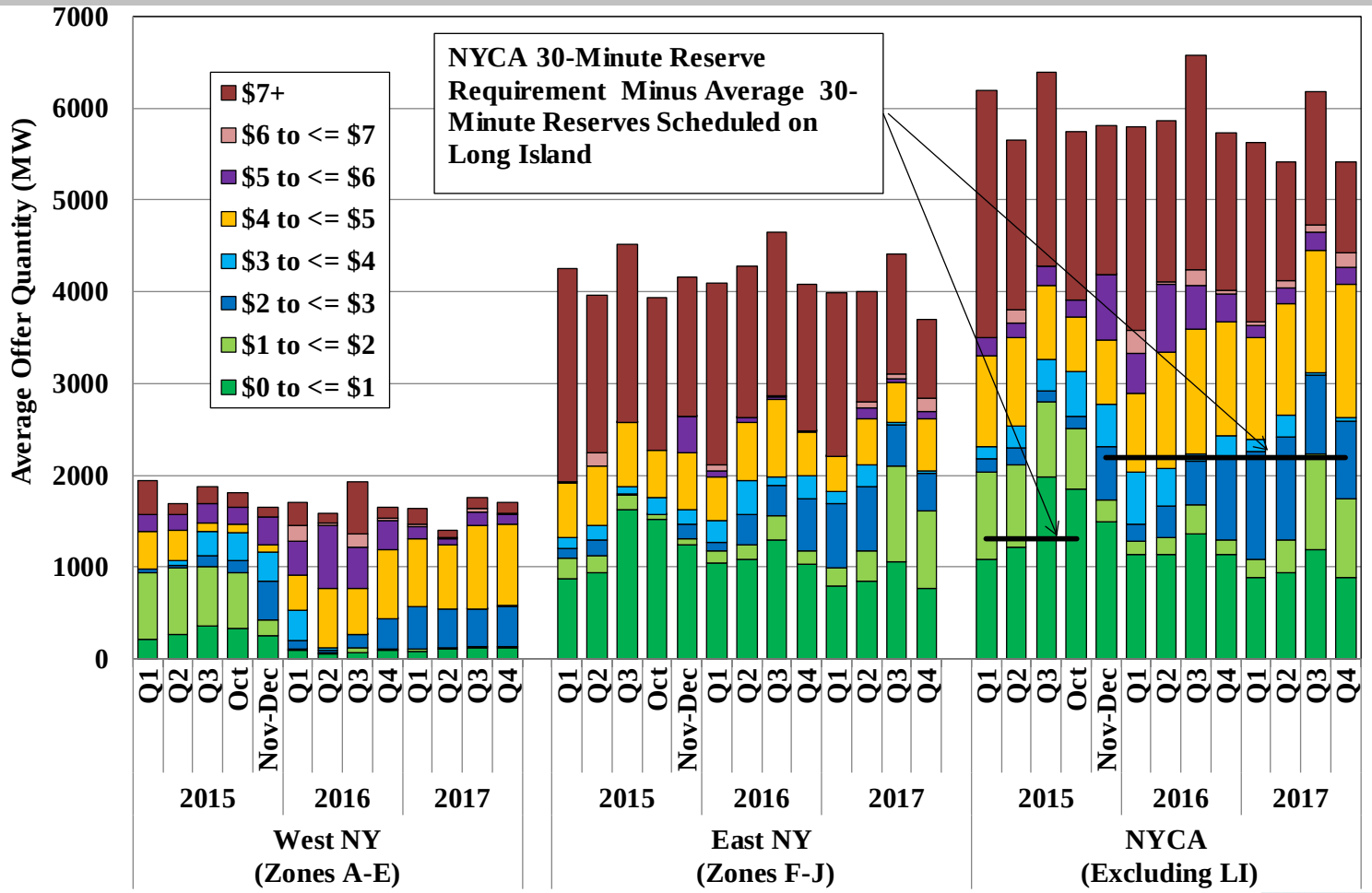
Market Highlights: Day-ahead Reserve Offers



See Section II.F & App. II.D

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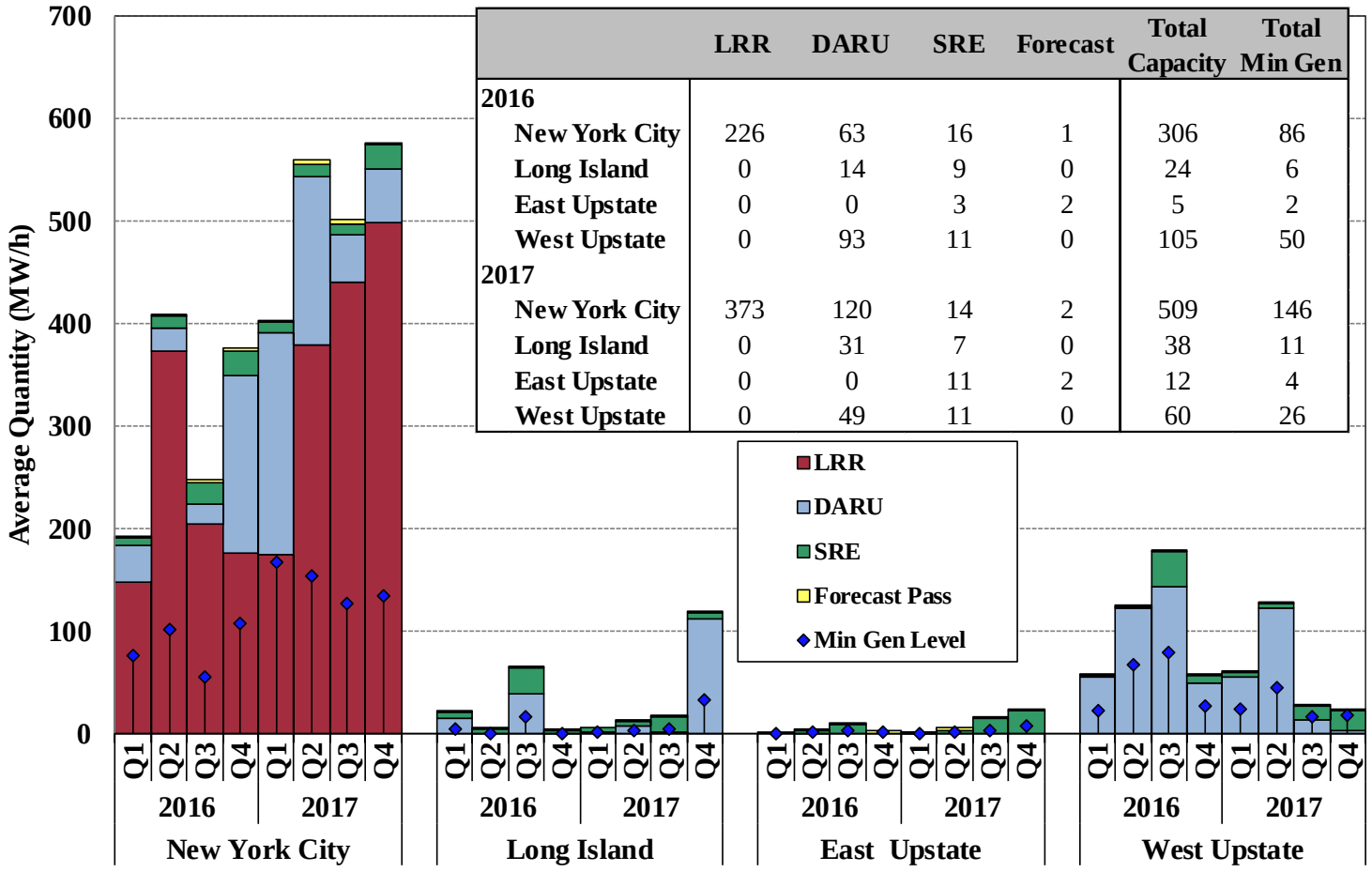
Market Highlights: Supplemental Commitment for Reliability

	LRR	DARU	SRE	Forecast	Total Capacity	Total Min Gen
2016						
New York City	226	63	16	1	306	86
Long Island	0	14	9	0	24	6
East Upstate	0	0	3	2	5	2
West Upstate	0	93	11	0	105	50
2017						
New York City	373	120	14	2	509	146
Long Island	0	31	7	0	38	11
East Upstate	0	0	11	2	12	4
West Upstate	0	49	11	0	60	26



See XI.G, App. V.G, & Rec 2017-1

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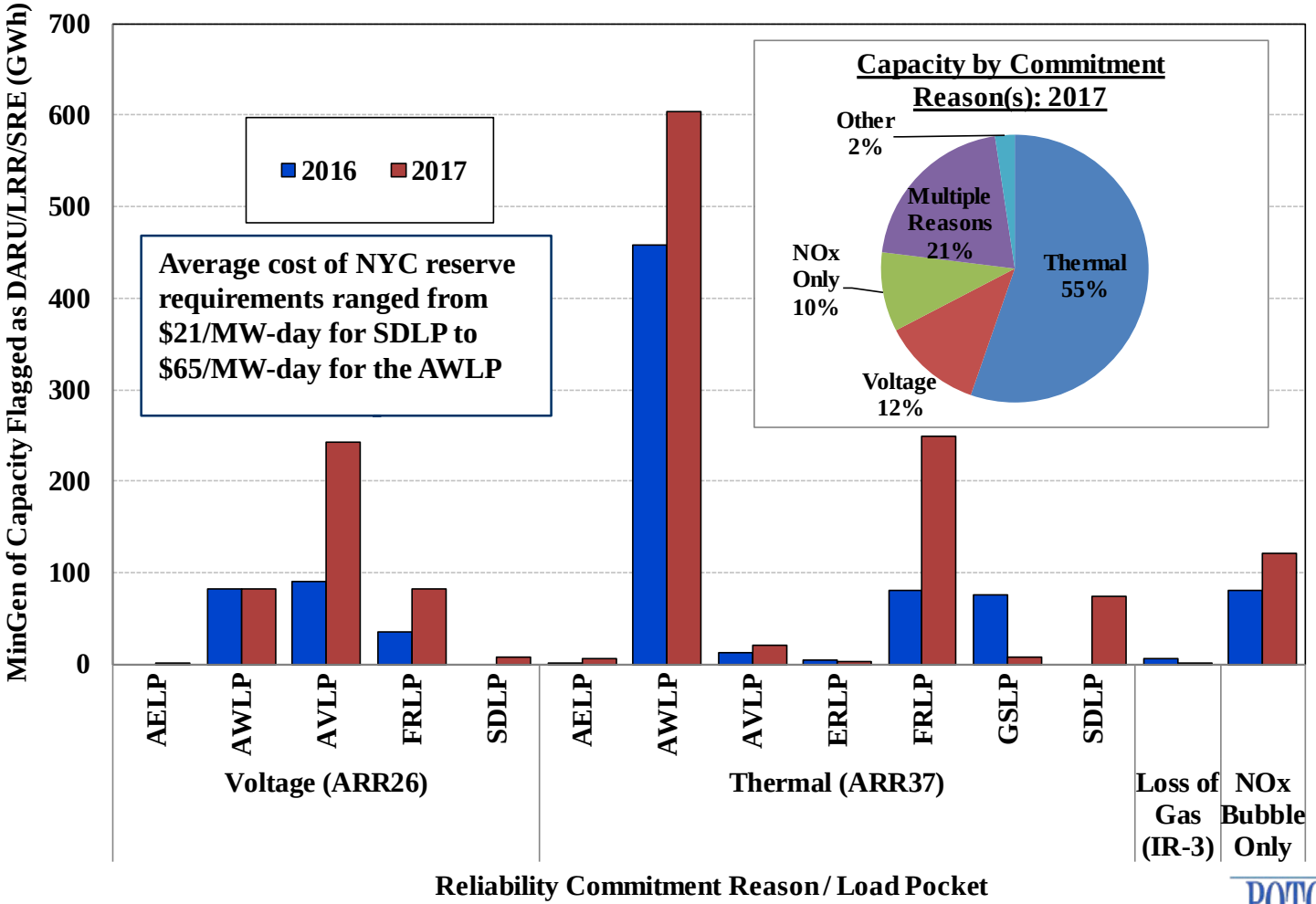
Market Highlights: NYC Reliability Commitments



 See XI.G, App. V.G, & Rec 2017-1

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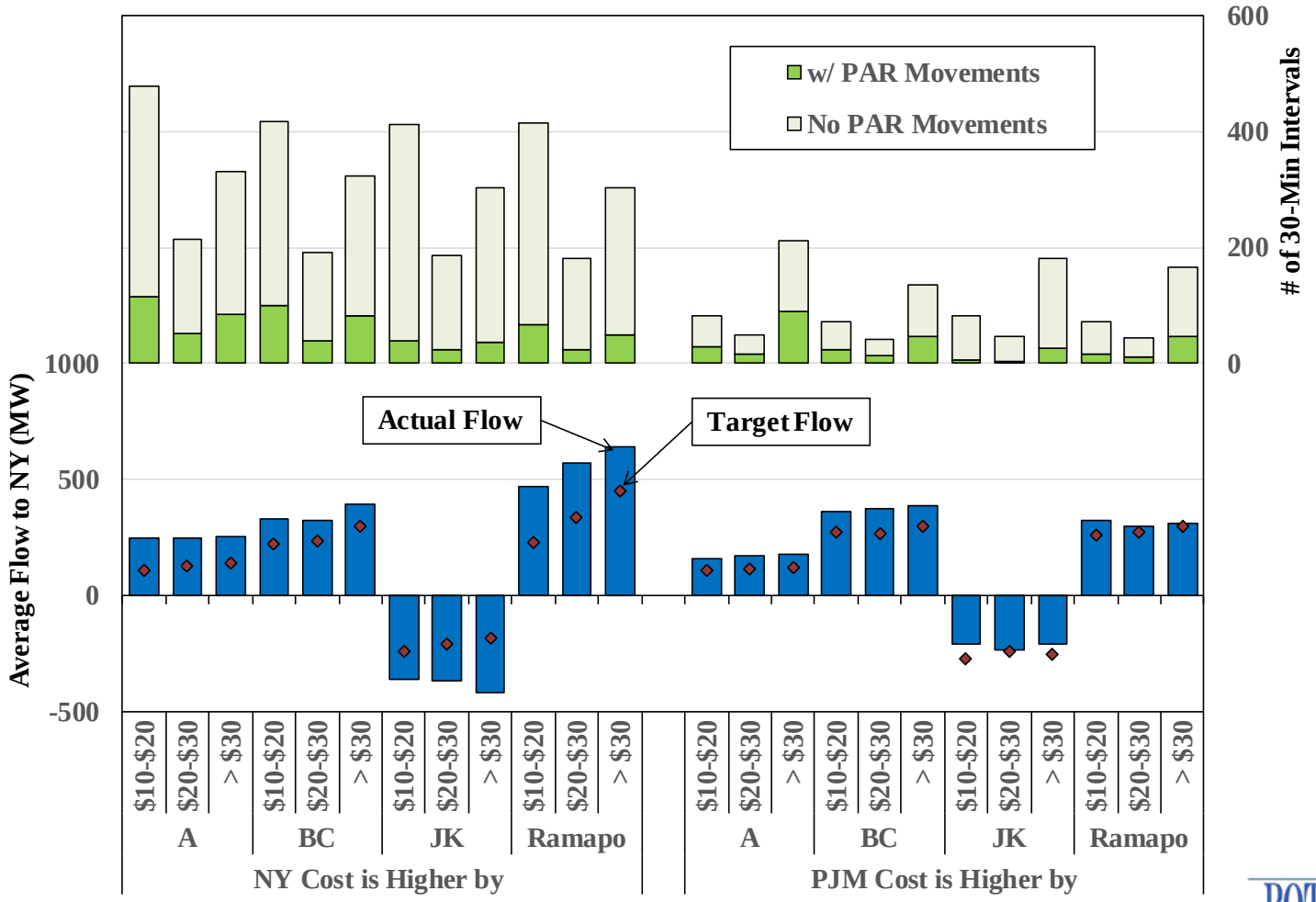
Market Highlights:
PAR Operation Under M2M – May to December



See Section XI.E

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Market Highlights: Coordinated Transaction Scheduling

- Increased cost savings: $1.9M in 2016 to $5.4M in 2017.
  - ✓ Average forecast error by the NYISO fell 12/18 percent and by ISO-NE fell 26 percent.
  - ✓ Price-sensitive bid volume rose from 810 MW to 1.3 GW.
- Impact of transaction fees: The PJM interface accounts for only 28 percent of bid volume and 11 percent of cost savings.
- Drivers of RTC forecast error:
  - ✓ Constraint modeling, PAR Modeling, loop flows – 39 percent
  - ✓ Load and Wind Forecasting – 22 percent
  - ✓ RTC/RTD Timing & Ramp Profiling – 18 percent
  - ✓ These are also the primary drivers of transient price volatility

See Sections VI.D & IX.F and Recs 2014-9, 2012-13, & 2015-9

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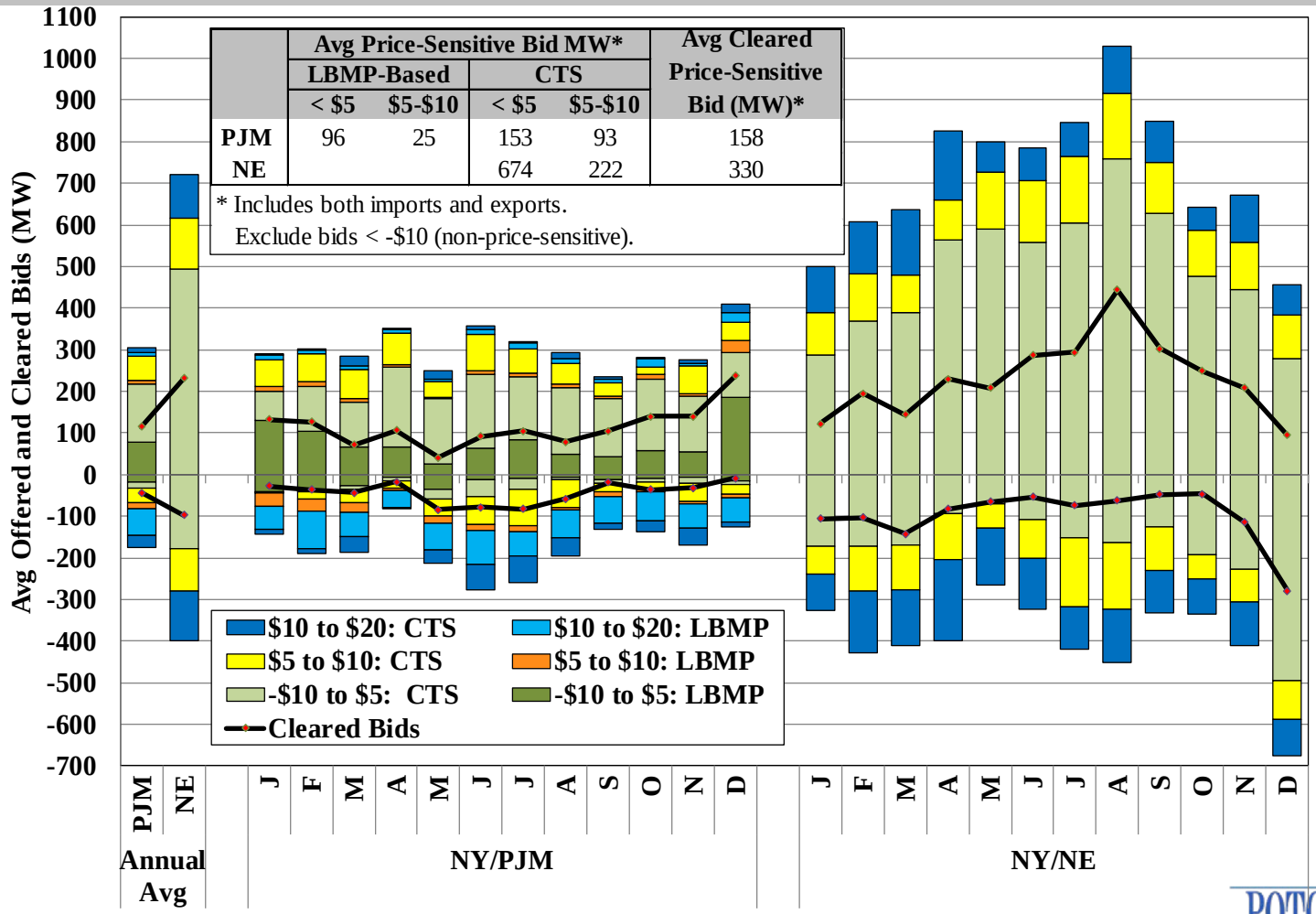
Market Highlights:
CTS – Price Sensitive Bidding

	Avg Price-Sensitive Bid MW*				Avg Cleared Price-Sensitive Bid (MW)*
	LBMP-Based		CTS		
	< $5	$5-$10	< $5	$5-$10	
PJM	96	25	153	93	158
NE			674	222	330

* Includes both imports and exports.
Exclude bids < -$10 (non-price-sensitive).



See Section VI.D and Rec 2015-9

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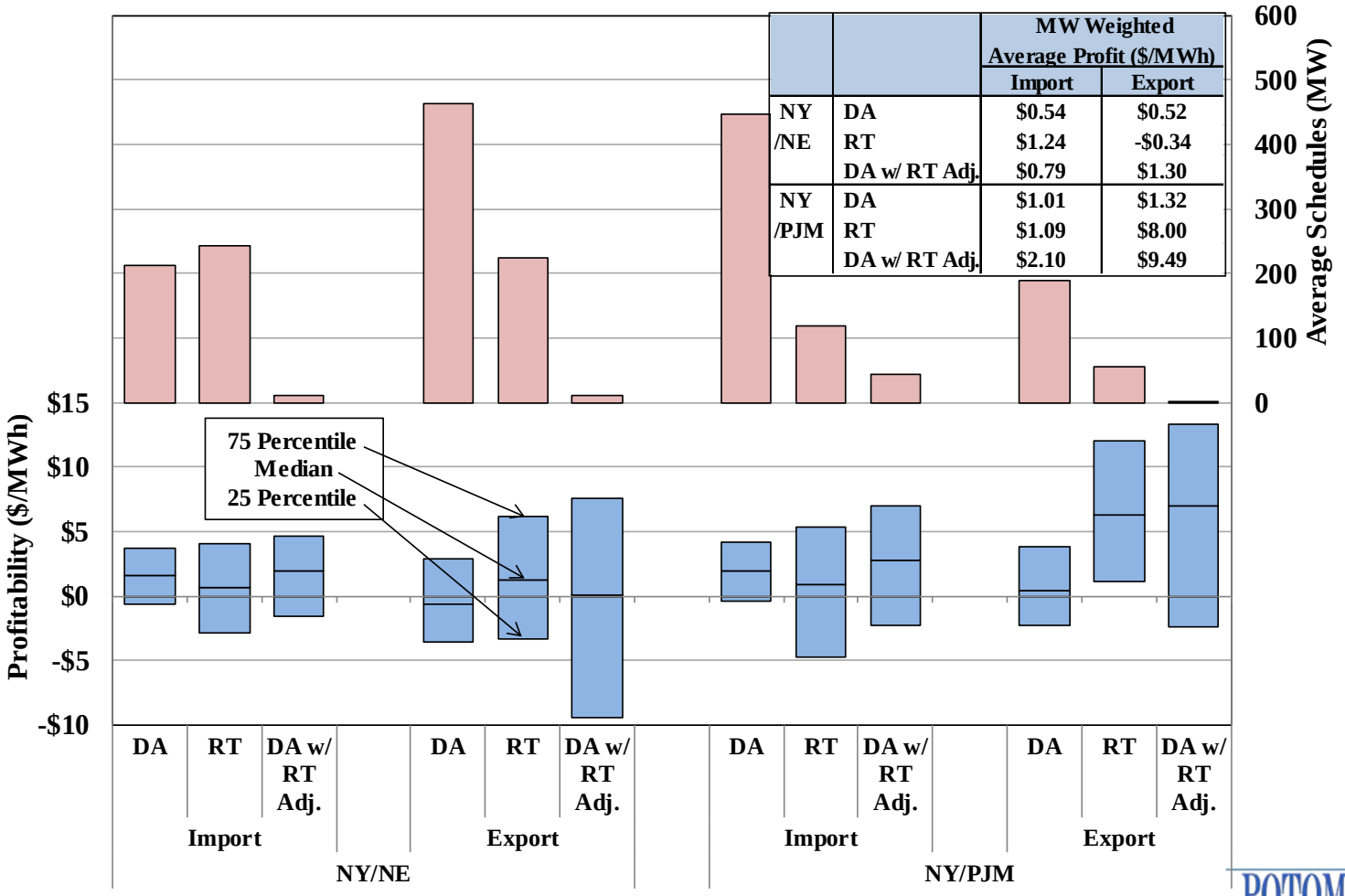
Market Highlights:
CTS – Average Profitability



See Section VI.D and Rec 2015-9

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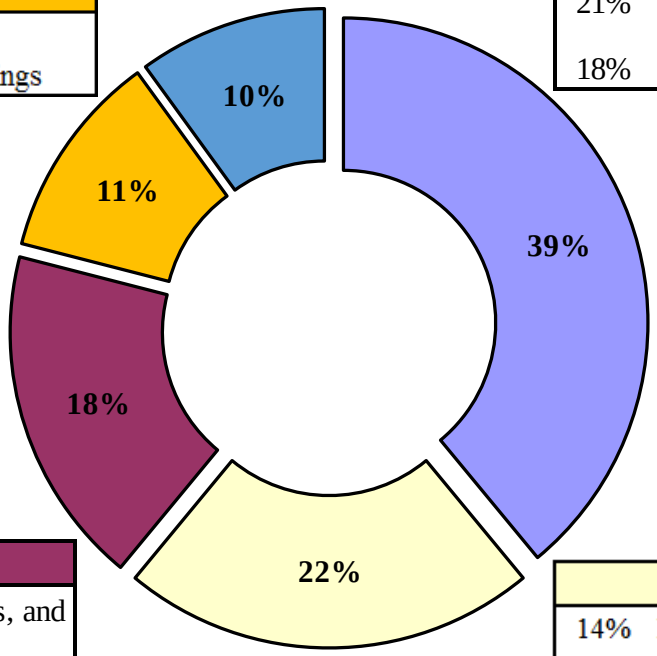
Enhance Real Time Scheduling: Factors Contributing to RTC/RTD Divergence

Other Factors	
5%	Transaction Checkout Failures & Curtailments
4%	OOM Dispatch

Transmission and PARs	
21%	Outages, loopflows, shift factor calc, and load distribution
18%	NY/NJ PAR-controlled lines

Generator Performance	
6%	Not following dispatch
5%	Forced Outage & Deratings



RTC / RTD Timing Issues	
18%	Load, external transactions, and generation

Forecast Error	
14%	Load Forecast Error
8%	Wind Forecast Error

See Sections VI.D & IX.F and Recs 2014-9 & 2012-13

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Recommendations for Market Enhancements

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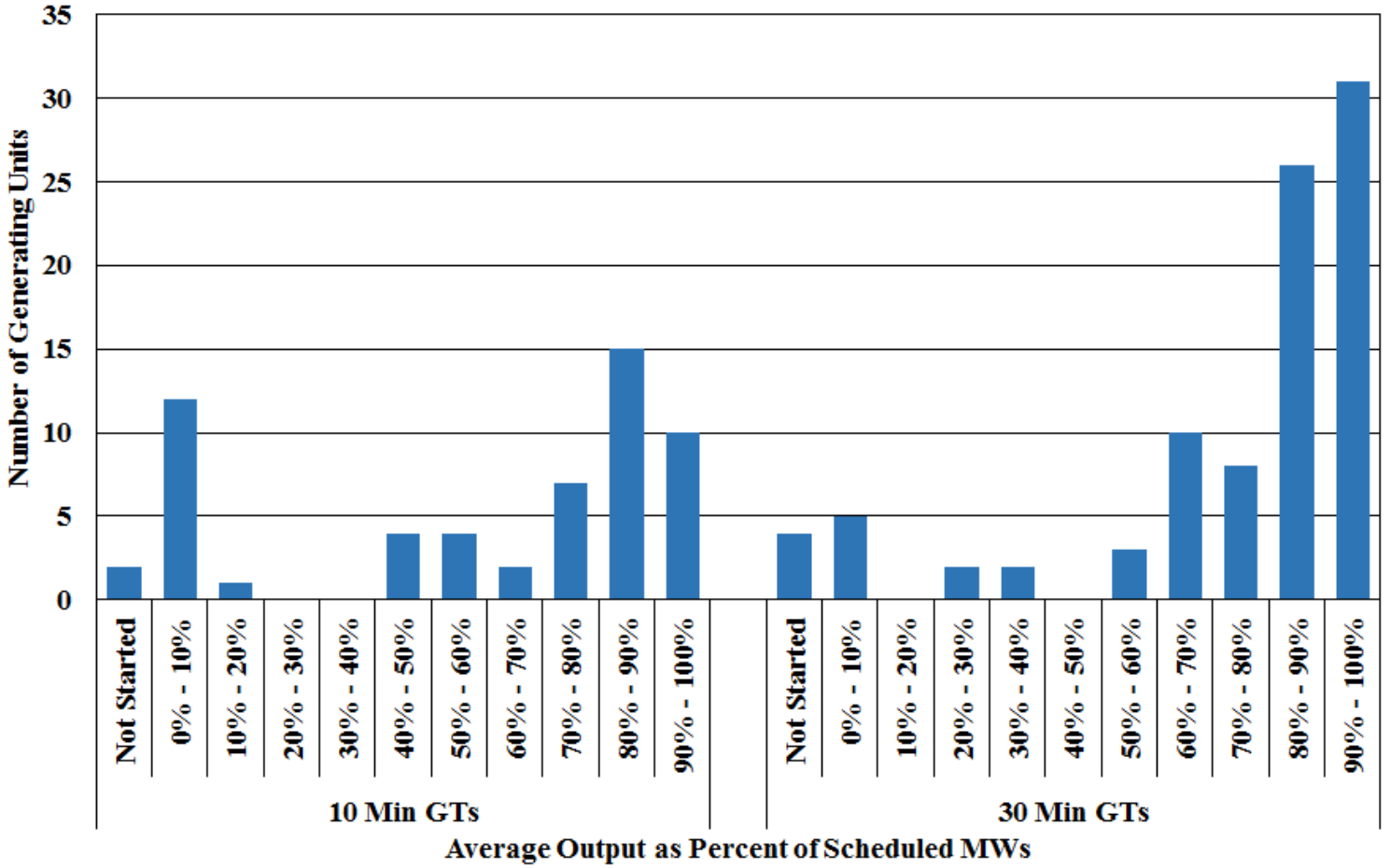
Performance Incentive Recommendations

- 2017-1: Model local reserve requirements in NYC
  - ✓ Satisfy requirements through market rather than OOM actions
- 2017-2: Raise reserve demand curves to adapt to PJM and ISO-NE "Pay For Performance" capacity market rules
  - ✓ Current ORDCs not sufficient to maintain reliability during peak summer conditions without OOM actions beginning in June 2018
- 2016-1: Pay reserve units for congestion relief
  - ✓ Operating reserves allow increased imports to NYC
- 2016-2: Discount reserve payments to poor-performers
  - ✓ Provide incentives for reserve providers to respond quickly and reliably to start instructions

See Sections VIII.C & IX.A,C,G

Performance Incentive Recommendation: GT Start Up Performance 2016-2



See Section IX.C

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Performance Incentive Recommendations

- 2015-16: Dynamic Reserve Requirements
  - ✓ Would recognize that need to hold reserves on internal generators depends on available import capability and size of largest supply contingency.
- 2015-17: Constraint-specific GTDCs
  - ✓ NYISO implemented a big improvement in June 2017.
  - ✓ However, GTDCs should be set based on importance, severity, and/or duration of a constraint violation and CRM of facility.
- 2014-12: Model 100kV transmission constraints in the market
  - ✓ Would improve incentives to schedule resources more efficiently, maintain 115kV resources, and build transmission and generation relieves congestion.

See Sections V.A & IX.A

Recommendations related to Pricing and Performance Incentives

Number	Section	Recommendation	2019 BPWG Project	Master Plan (thru 2023)
Energy Market Enhancements - Pricing and Performance Incentives				
2017-1	IX.G	Model local reserve requirements in New York City load pockets.	More Granular Operating Reserves	2019 to 2022
2017-2	IX.A	Modify reserve demand curves to ensure NYISO reliability after PJM and ISO-NE implement PFP.	Ancillary Services Shortage Pricing	2020 to 2023
2016-1	VIII.C	Pay operating reserve providers for congestion relief.	Pricing Reserves for Congestion Management (Future)	Study only
2016-2	IX.C	Reserve compensation based on actual and/or expected performance.	Performance-Based Reserve Payments (Future)	--
2015-9	VI.D	Eliminate transaction fees for CTS transactions at the PJM-NYISO border.	Eliminate Fees for CTS Transactions with PJM (Future)	--
2015-16	IX.A	Dynamically adjust operating reserve requirements.	Dynamic Reserve Requirements (Future)	2020 to ??
2015-17	IX.A	Use constraint-specific graduated transmission demand curves.	Constraint Specific Transmission Shortage Pricing	2019, 2021, 2022
2014-12	V.A	Model 100+ kV transmission constraints and develop associated mitigation measures.	Model 100+kV Transmission Constraints	2018 / Mitigation 2019 to 2021

Mitigation Measures: Recommendations 2017-3 and 2017-4

- Evolving market conditions have revealed gaps in the existing mitigation rules. These have not been exploited significantly, but we recommend rule changes to address the gaps.
- 2017-3: Deter generators from over-producing to benefit from negative real-time prices. To illustrate, suppose a generator:
  - ✓ DAM: 200 MW schedule at $20/MWh
  - ✓ In RTM: Transmission outage or loop flows require generator to back down
    - Self-schedule 160 MW and LBMP = -$300/MWh.
    - RT buy-back MWs at cost of -$12,000/hour.

See Sections III.B & IX.A

Mitigation Measures: Recommendations 2017-3 and 2017-4

- 2017-4: Deter generators from submitting inflated fuel cost estimates to drive up LBMPs.
  - ✓ Attachment H of the Market Services Tariff documents the mitigation measures applicable to these recommendations.
  - ✓ §23.3.1.4.6.9: NYISO may revoke use of the automated Fuel Cost Adjustment tool if submissions are found to be biased.
  - ✓ §23.4.3.3.3 sets financial penalties when a generator is found to have biased FCAs that impact either:
    - Guarantee payments
    - Market price paid to the generator
    - *Does not address the price impact of biased FCAs that result in a generator not being scheduled.*

See Sections III.B & IX.A

Enhance Real Time Scheduling: Recommendations 2014-9, 2012-13, & 2015-9

- To improve RTC forecasting, reduce unnecessary RT price volatility, and better utilize external interfaces:
  - ✓ 2014-9: Consider effect of generator dispatch on PAR-controlled line flows and enhance loop flow modeling
  - ✓ 2012-13: Adjust look ahead of RTD and RTC to be consistent
  - ✓ 2015-9: Eliminate transaction fees at the PJM-NYISO border
- Benefits:
  - ✓ Improve performance of CTS with PJM and ISO-NE
  - ✓ Increase potential ramp of PJM and ISO-NE interfaces
  - ✓ Improve fast-start commitment and shut-down decisions

See Sections VI.D, IX.F

Recommendations related to Mitigation Measures, Market Operations, Uplift, and Fuel Issues

Energy Market Enhancements – Market Power Mitigation Measures				
2017-3	IX.A	Address deficiencies in current uneconomic over-production rule.	?	--
2017-4	III.B	Deter the use of fuel cost adjustments by a supplier to economically withhold.	?	--
Energy Market Enhancements - Real-Time Market Operations				
2014-9	VI.D, IX.F	Enhance modeling of loop flows and flows over PAR-controlled lines.	Enhanced PAR Modeling (Future)	--
2012-8	VI.D, IX.F	Operate certain PAR-controlled lines to minimize production costs and create financial rights that compensate affected transmission owners.	Long Island PAR Optimization & Financial Rights (Future)	--
2012-13	VI.D, IX.F	Adjust look ahead evaluations of RTD and RTC to be more consistent with the timing of external transaction ramp and gas turbine	RTC-RTD Convergence Improvements	2020 to 2023
Energy Market Enhancements - BPCG Eligibility and Fuel Limitations/Storage				
2014-13	IX.G	Work with generators in NOx bubbles to ensure their RACT compliance plans use the most economic compliance option available.	Review of RACT Compliance Plans	--
2013-11	IX.B.2 (2015 SOM)	Allow generators to reflect energy storage and fuel supply constraints in the day-ahead market.	(May include in) ESR Participation Model	--

Capacity Market Pricing: Recommendations 2012-1a & 2013-1c

- We have two key recommendations to improve capacity pricing incentives by location based on planning requirements.
  - ✓ 2012-1a: Establish a more disaggregated set of locations or interfaces to allow the market more flexibility in procuring and pricing capacity.
  - ✓ 2013-1c: Lower costs and improve pricing by the market to optimize its locational procurements.
- Benefits:
  - ✓ Reduce the costs of satisfying resource adequacy needs.
  - ✓ Facilitate efficient investment and retirement.
  - ✓ More adaptable to changes in resource portfolio.
  - ✓ Simplify market administration.

See Sections VII.B, VII.F

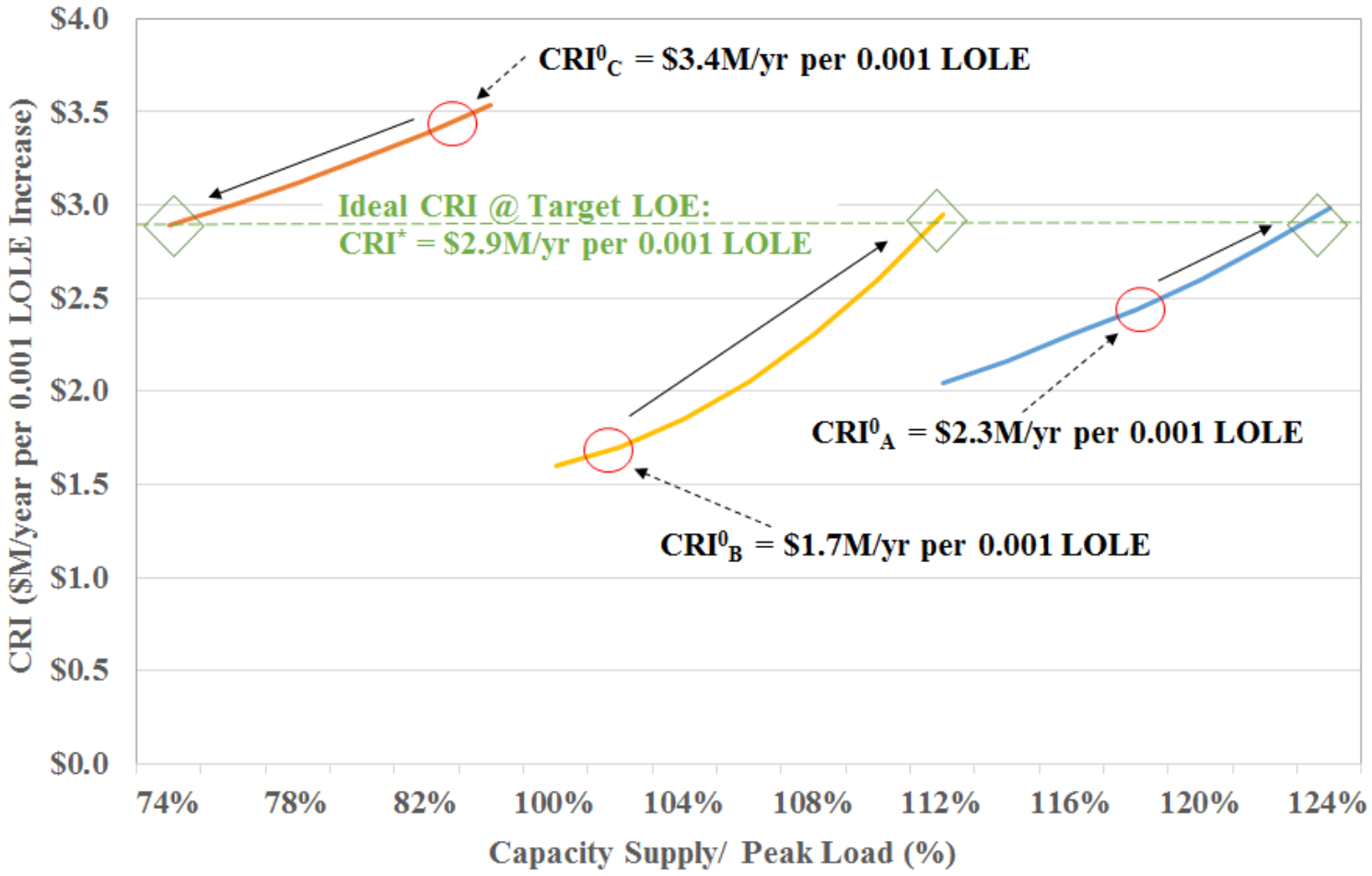
Capacity Market Pricing: Recommendations 2012-1a & 2013-1c

Zone	Unified Methodology		Optimized LCRs Method	
	Marginal Reliability Impact	Cost of Reliability Improvement	Marginal Reliability Impact	Cost of Reliability Improvement
	ΔLOLE per 100MW	*MM$ per 0.001 ΔLOLE*	*ΔLOLE per 100MW*	*MM$ per 0.001 ΔLOLE*
A - F	0.003	$3.0	0.003	$3.2
G - I	0.004	$3.9	0.004	$3.5
J	0.006	$3.2	0.007	$2.7
K	0.006	$2.2	0.005	$2.9

- Marginal Reliability Impact ("MRI") is the estimated reliability benefit from 100 MW UCAP addition to an area.
- Cost of Reliability Improvement ("CRI") is the estimated capital investment cost of adding sufficient capacity to reduce LOLE by 0.001.
- Efficient capacity market design: CRI is the same at each location.
  - ✓ Optimized LCR Method is an improvement over Unified Methodology.

See Sections VII.B, VII.F

Capacity Market Pricing: Recommendations 2012-1a & 2013-1c – Illustration



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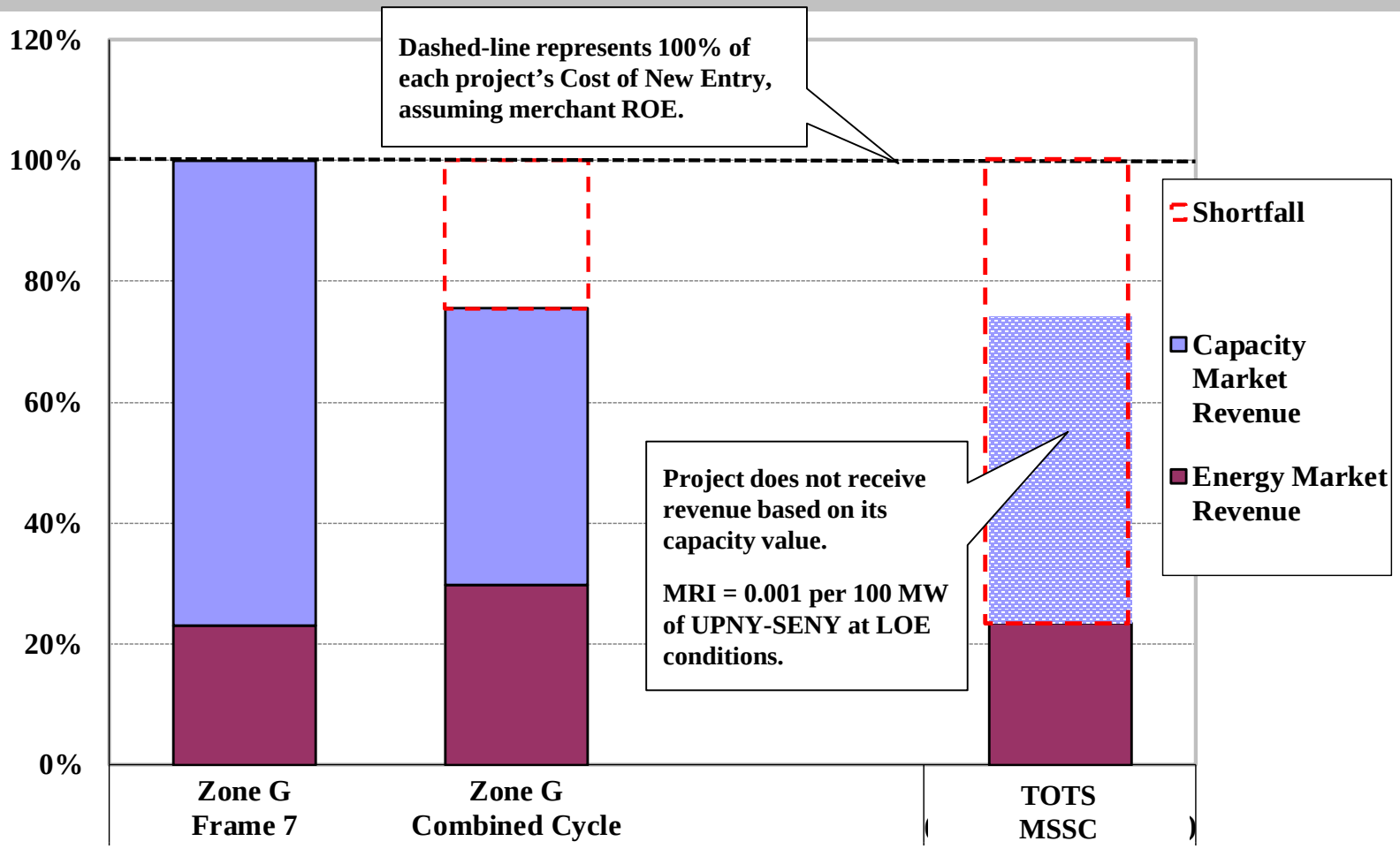
Transmission Incentives & Planning Enhancements Recommendations 2012-1c & 2015-7

- The NYISO markets do not provide incentives for efficient transmission investment. To address this, we recommend:
  - ✓ 2012-1c: Compensate merchant investors for capacity value of transmission upgrades (expanded capability between zones).
  - ✓ 2015-7: Reform CARIS to better identify potential economic transmission.
- Benefits:
  - ✓ Achieve cost savings by lowering barriers to entry (that favor generation and demand response over transmission).
  - ✓ Substantially reduce the need for out-of-market public policy investment.

See Sections VII.D, VII.E

Transmission Incentives & Planning Enhancements: Recommendations 2012-1c & 2015-7



See Sections VII.D, VII.E

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Transmission Incentives & Planning Enhancement: Recommendations 2012-1c & 2015-7

- There are additional improvements beyond including capacity benefits that are worth consideration for improving the CARIS planning processes.
- Administrative enhancements:
  - ✓ Reduce 80% voting requirement in CARIS
  - ✓ Eliminate $25 Million project threshold in CARIS
- Forecasting enhancements:
  - ✓ Gas system modeling
  - ✓ Electric system modeling
  - ✓ Retirement and New-Entry assumptions in the CRP

See Section VII.E

Recommendations related to Capacity Market Enhancements and Planning Process

Capacity Market Enhancements				
2015-8	VII.C	Modify the capacity market to better account for imports from neighboring control areas to import-constrained capacity zones.	Treatment of Locality Exports and Imports	--
2013-2d	III.C	Enhance BSM Forecast Assumptions.	Enhanced BSM Mitigation Study Period	--
2013-1c	VII.B	Location-based marginal cost pricing of capacity that minimizes the cost of satisfying planning requirements.	Explore Locational Reliability Pricing	--
2012-1a	VII.F	Dynamic locational framework so prices reflect locational value of capacity.	Dynamic Creation of Zones	--
2012-1c	VII.D	Grant financial capacity transfer rights between zones when investors upgrade the transmission system and help satisfy planning reliability needs without receiving a cost-of-service rate.	Capacity Transfer Rights for Internal Transmission Upgrades (Future)	--
Planning Process Enhancements				
2015-7	VII.E	Reform CARIS to better identify and fund economically efficient transmission investments.	?	--

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