2023 State of the Market Report for the NYISO Markets: Energy & Ancillary Services Highlights

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June 4, 2024

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Introduction

- As the Market Monitoring Unit for NYISO, we produce an annual State of the Market (SOM) Report to:
  - ✓ Evaluate the performance of the markets;
  - ✓ Identify market flaws or market power concerns; and
  - ✓ Recommend improvements in the market design.
- Given the breadth of the report, this presentation covers only highlights from our 2023 SOM Report related to energy and ancillary services markets, including:
  - ✓ A summary of E&AS market outcomes;
  - ✓ Recommended market enhancements for the energy and ancillary services markets

Schedule

- The 2023 SOM Report was posted here on May 15.
- The report is being presented at several meetings:
  - ✓ May 29: Management Committee
    - Overview – 60 minutes
  - ✓ May 30: ICAPWG
    - Capacity Market & Policy focus – 90 minutes
  - ✓ June 4: MIWG
    - Energy and Ancillary Services focus – 90 minutes
  - ✓ Additional slots can be scheduled if there is interest.

Energy Market Highlights

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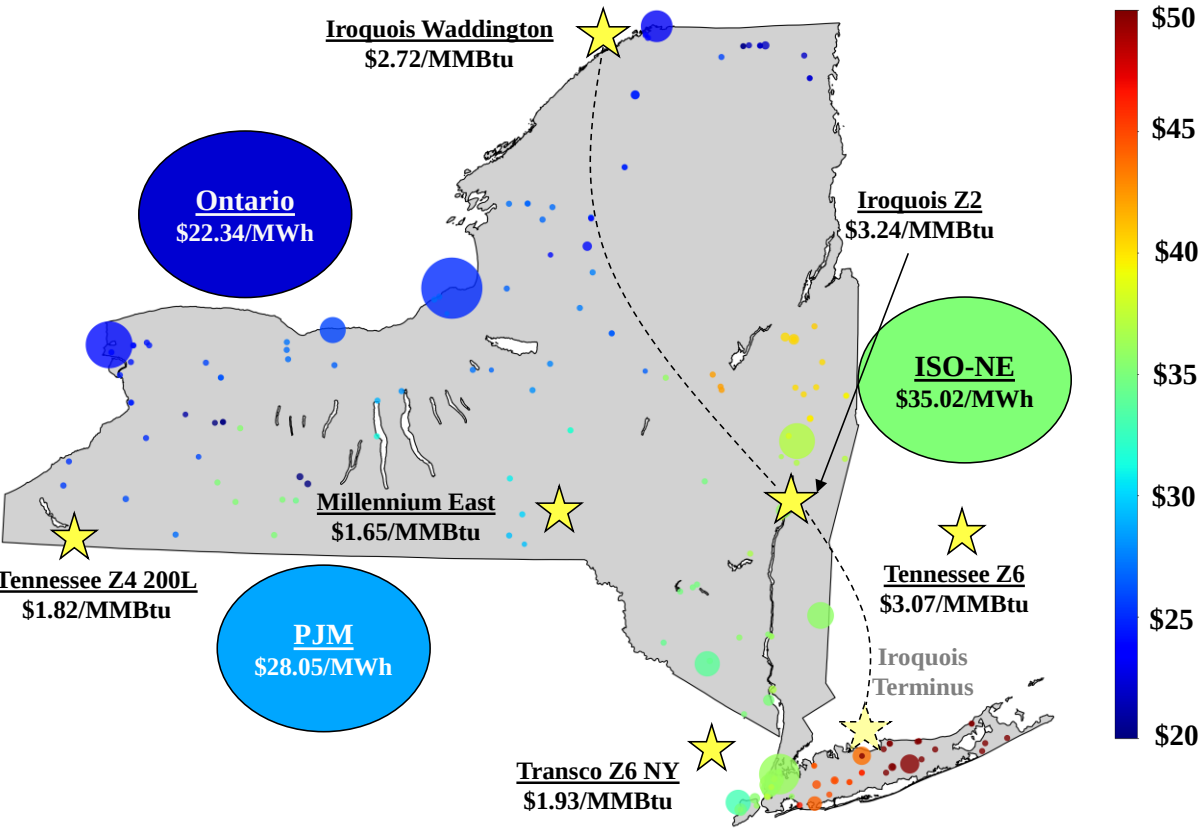
Market Highlights: Congestion Patterns

RT Energy Prices, Natural Gas Prices, and Congestion in 2023



- Congested interfaces:
  - ✓ Central-East
  - ✓ ConEd-LIPA
  - ✓ Long Island West-East
- Gas prices exhibit similar regional patterns
- Imports from Ontario and PJM: avg 2.5 GW
- Exports to ISO-NE from upstate NY: avg 485 GW

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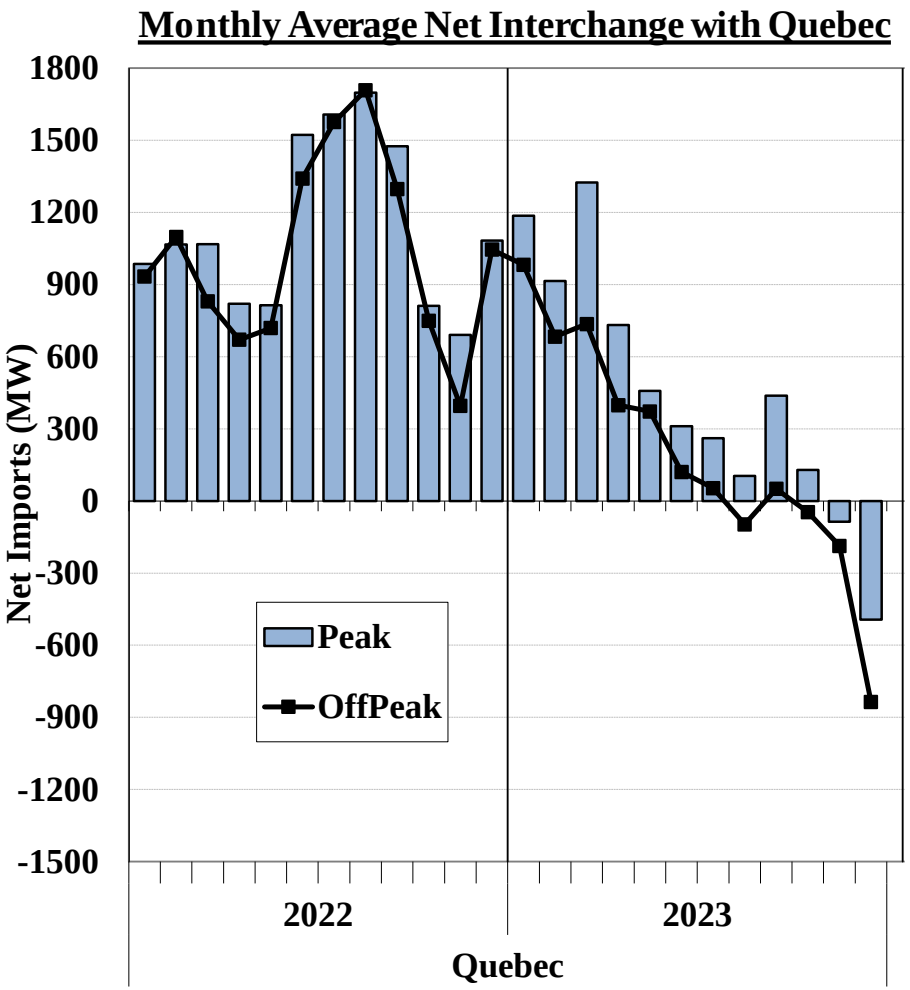
Market Highlights: External Interchange with Quebec



- Net imports fell from:
  - ✓ 1.3 GW in 2021 to
  - ✓ 440 MW in 2023
- Large reservoirs and reduced rainfall lead to hours of high imports and hours of high exports
  - ✓ Complements ISOs with high wind/solar
- High export transaction fees will lead to increased curtailment of renewables

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Recommended Enhancements

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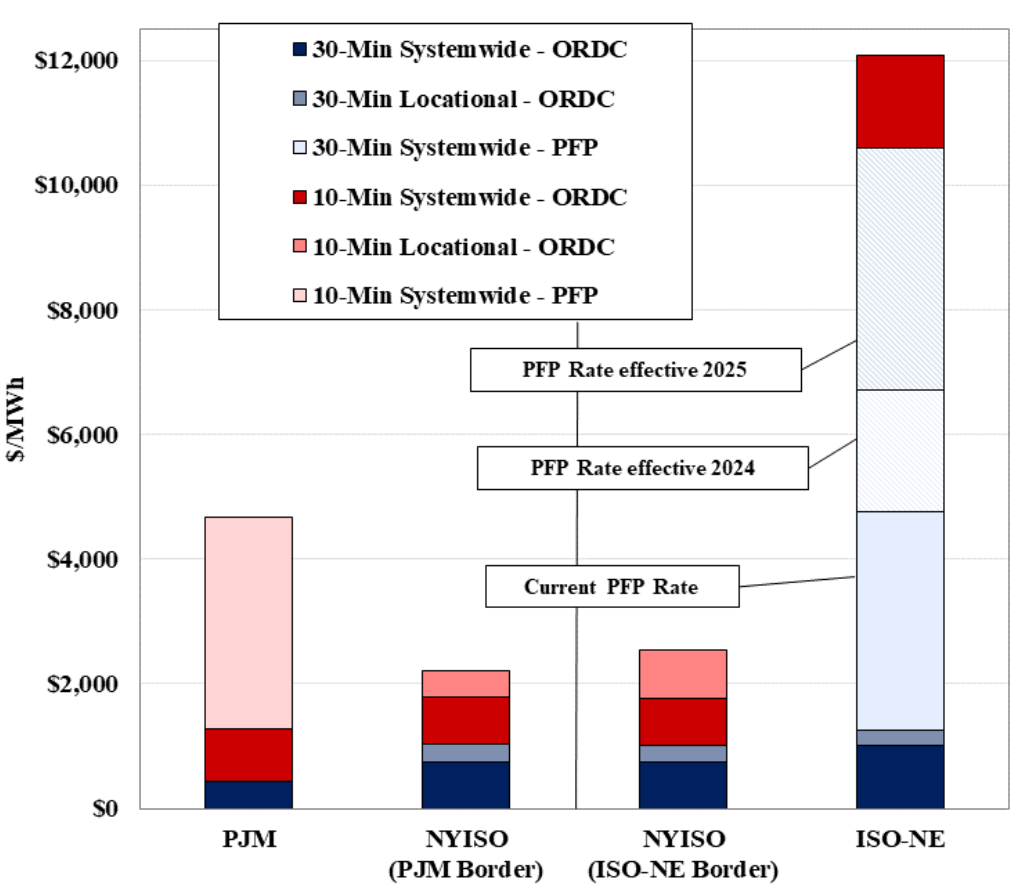
Prioritizing Market Enhancements

- Unprecedented levels of policy-driven investment are expected over the coming decade
- The NYISO should focus on enhancements that:
  - ✓ Guide renewable investment to where it is most deliverable
  - ✓ Provide incentives for investment in resources that facilitate integration of intermittent renewables
  - ✓ Encourage retirement of existing generators that have:
    - Inflexible characteristics, and/or
    - Limited availability during gas supply constraints
- These enhancements will facilitate state policy goals at the lowest cost and minimize market harm

Shortage Pricing Disparities: NYISO vs. PJM & ISO-NE



- Range of 30-min shortage adders:
  - ✓ ~$450 to $10,500
- Range of 10-min shortage adders:
  - ✓ ~$2,450 to $12,000
- Consistent shortage pricing needed to reduce OOM actions to maintain reliability
  - ✓ Rec #2017-2
  - ✓ Recommendations re PFP to PJM/NE/ FERC

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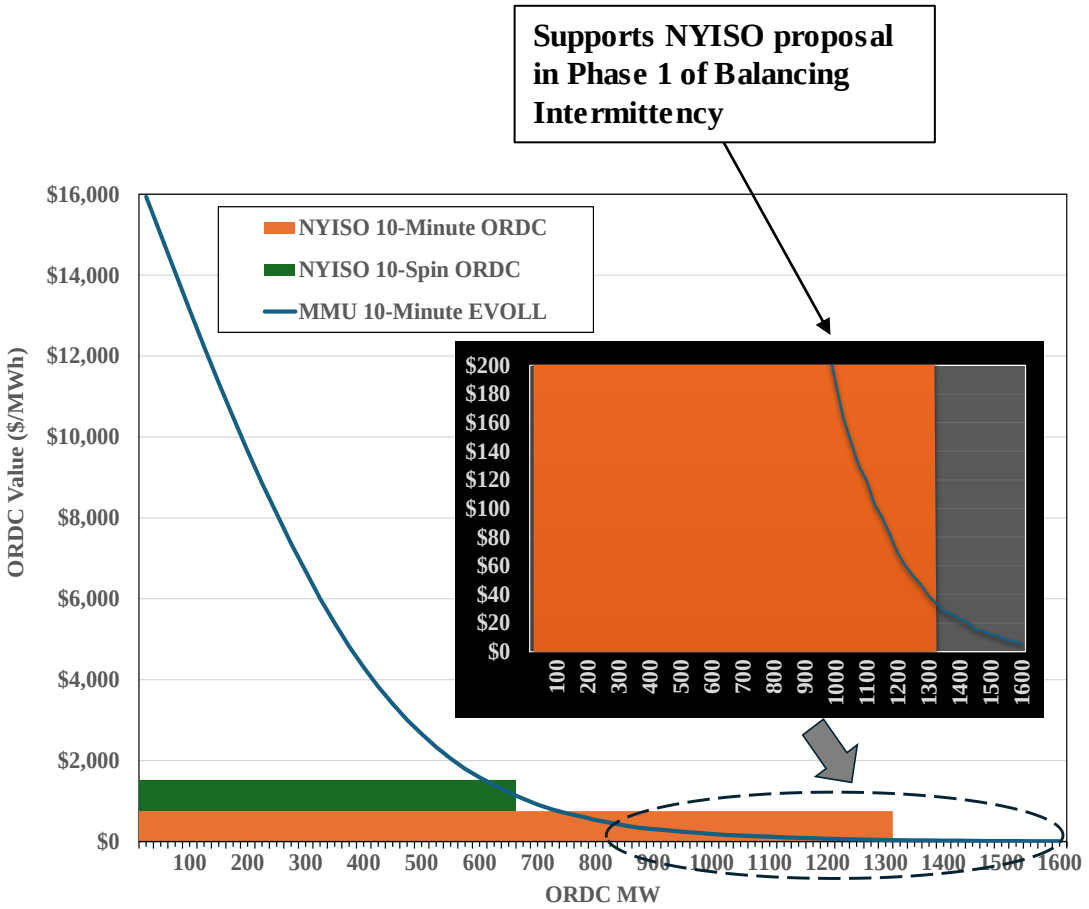
Shortage Pricing Disparities: NYISO 10-Min ORDCs vs. MMU EVOLL Curves



- EVOLL based on assumed $30k VOLL
- Considers 15-minute risk of:
  - ✓ Generation outages
  - ✓ Import curtailment
  - ✓ Net load forecast uncertainty

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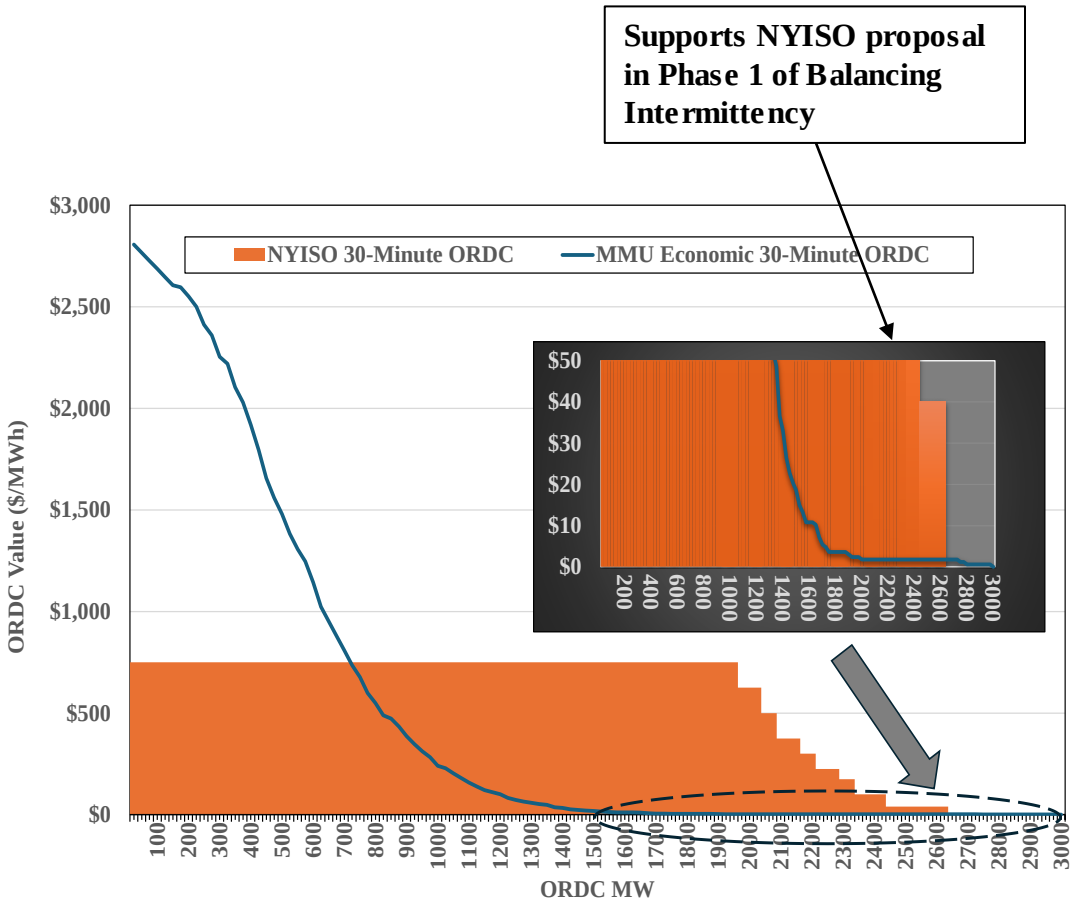
Shortage Pricing Disparities: NYISO 30-Min ORDCs vs. MMU EVOLL Curves



- EVOLL based on assumed $30k VOLL
- Based on additional risk over 30-minute period from:
  - ✓ Generation outages
  - ✓ Import curtailment
  - ✓ Net load forecast uncertainty

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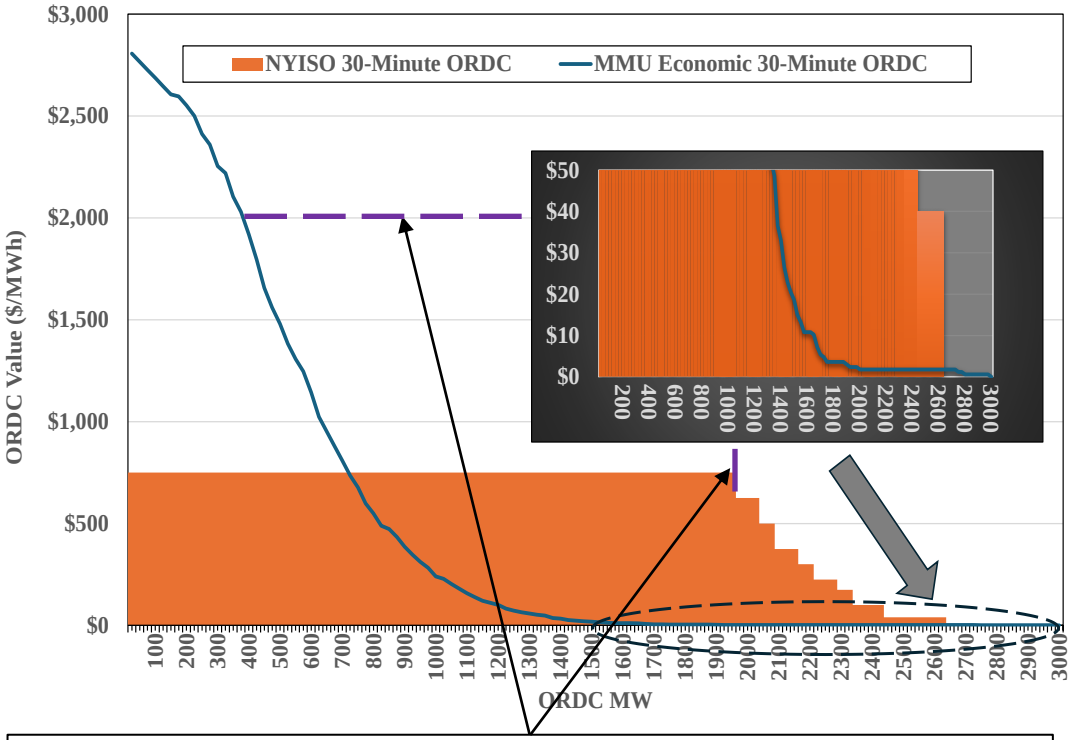
Shortage Pricing Disparities: NYISO 30-Min ORDCs vs. MMU EVOLL Curves



Recommendation #2017-2 would set ORDCs at the higher of:
(a) The reliability value of operating reserves (e.g., blue line), and
(b) A level sufficiently high to ensure exports are not scheduled to ISO-NE and PJM if it will lead to a deficiency of 30-minute reserves required by NPCC unless the neighbor has the same deficiency (e.g., purple line).

- PJM and ISO-NE have unreasonably high shortage pricing incentives.
- To avoid exports to ISO-NE or PJM when NYISO is in a less reliable state:
  - ✓ NYCA 30-min ORDC should be $2000/MWh up to 150% of the largest contingency.

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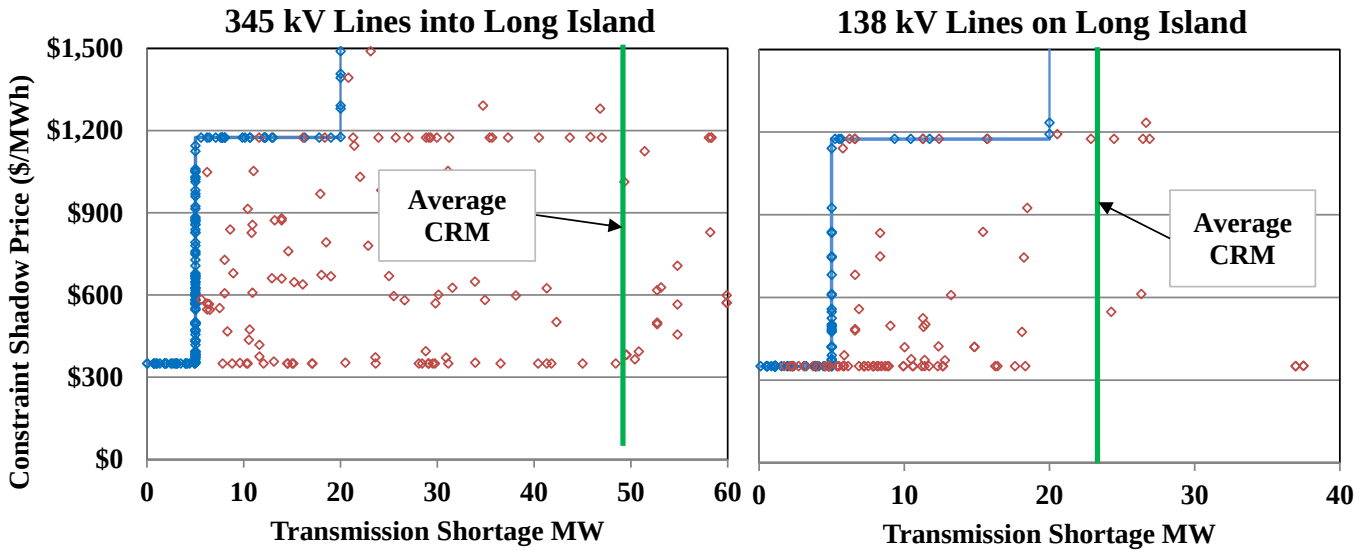
Eliminate "Offline GT Pricing" (Rec #2020-2) to Improve Transmission Shortage Pricing

- "Offline GT Pricing" is where an offline 10-minute GT is treated by RTD as capable of starting-up in five minutes.
  - ✓ Most 10-minute non-spin MWs are *not* eligible for this treatment.
  - ✓ However, this treatment suppresses RT prices and prevents *actual* 5-minute dispatchable units from being scheduled. (See below)



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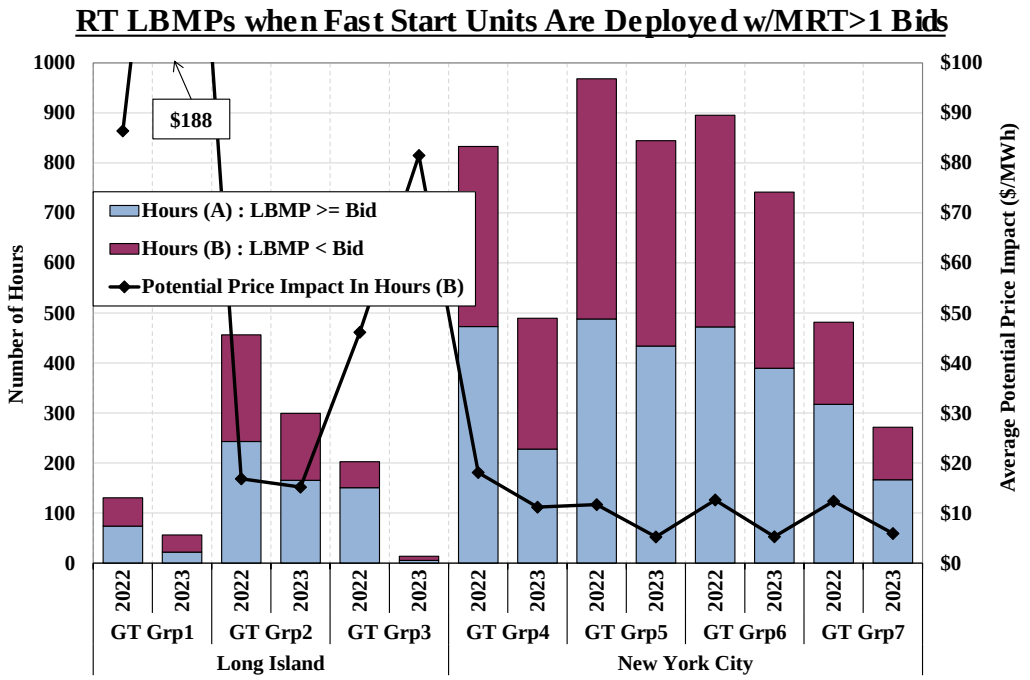
Minimum Run Time Offers and Eligibility for Online Fast Start Units to Set Price



- Making these units eligible to set price would raise net revenues $1 to $6 per kW-year at these locations.

- MST requires FS units be eligible if:
  - ✓ 30-minute start up
  - ✓ 1-hour MRT
- If FS units offer MRT>1 hour, but:
  - ✓ RTC treats the unit as MRT=1 hour.
- Recommendation #2023-2 would make FS eligibility consistent with scheduling treatment.

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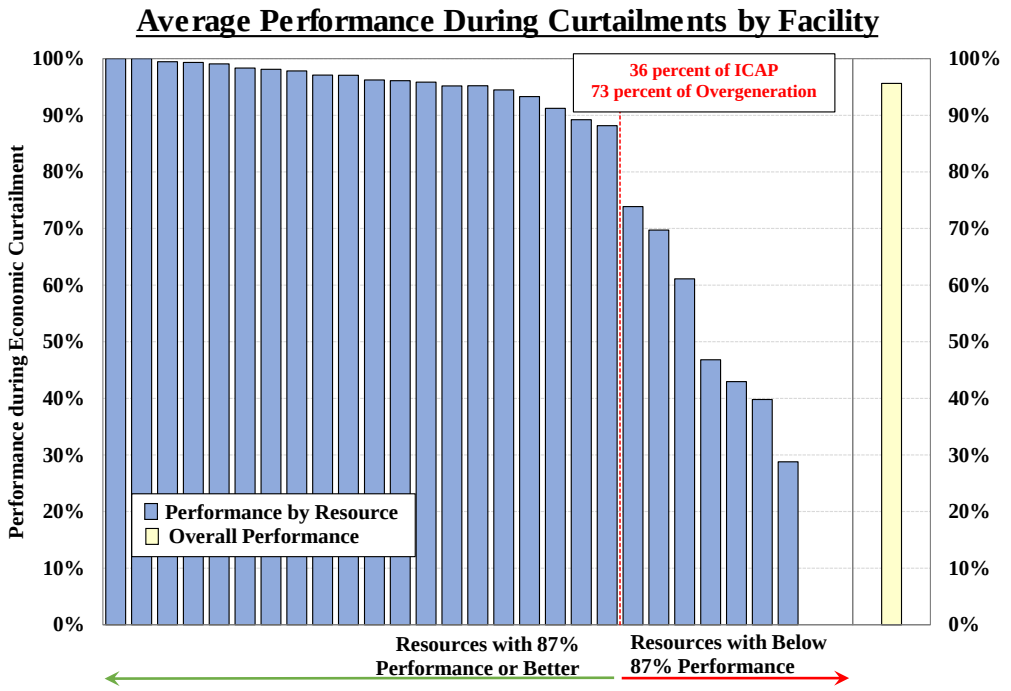
Compliance with Curtailment Instructions by Individual Resources



- Recommendation #2023-3 would strengthen penalties for not following dispatch instructions, which are weak for units with negative marginal costs.

- The majority of IPRs generally comply with curtailment instructions.
- A minority of IPRs exhibit poor performance.
  - ✓ This undermines transmission and system security.
  - ✓ Leads operators to manually dispatch *other* IPRs to maintain security.

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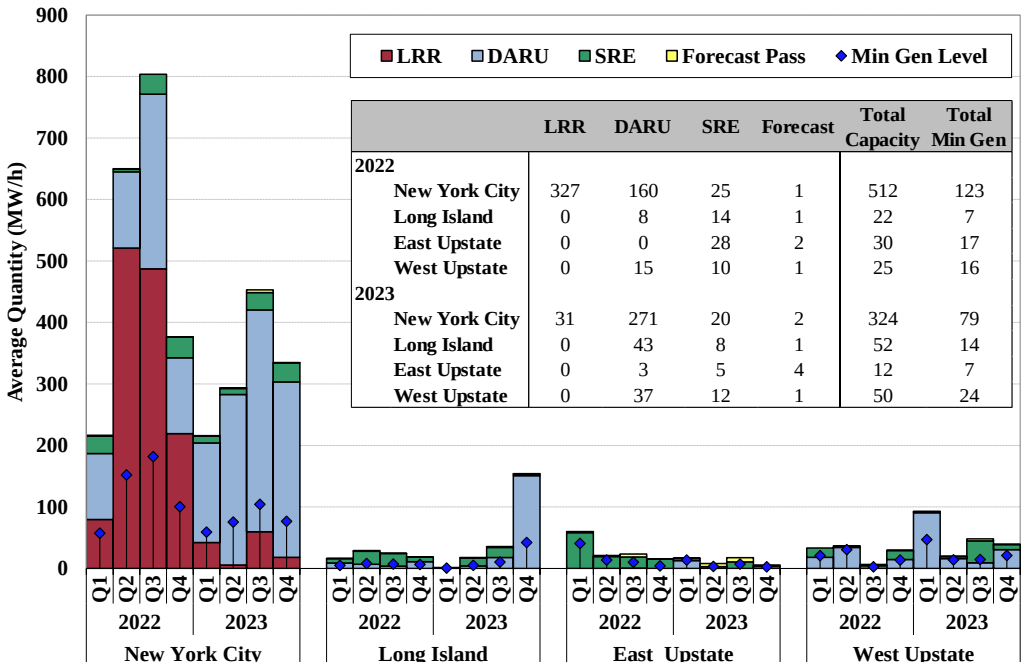
Efficient DAM Congestion Surplus and Shortfall Allocation

- Most congestion revenue is allocated efficiently to NYTOs:
  - ✓ TCC revenues based on value in auctions
  - ✓ Responsible TO bears cost of transmission outages
- However, surpluses and shortfalls are socialized from:
  - ✓ Changing generation patterns – These are becoming more prevalent as renewables are added to the system.
  - ✓ Non-Responsible TO equipment status changes – NYTOs receive more TCC revenue because on non-NYTO equipment, so it is reasonable if they bear the cost of changes in the status of such equipment.
  - ✓ Recommendation #2023-1 would assign surpluses and shortfalls based on changes in utilization in the DAM (similar to TCC revenues).

OOM Commitments are Made to Maintain Local Reserves in NYC, Long Island, and Northern NY

Average OOM Commitment for Reliability by Region



	LRR	DARU	SRE	Forecast	Total Capacity	Total Min Gen
2022						
New York City	327	160	25	1	512	123
Long Island	0	8	14	1	22	7
East Upstate	0	0	28	2	30	17
West Upstate	0	15	10	1	25	16
2023						
New York City	31	271	20	2	324	79
Long Island	0	43	8	1	52	14
East Upstate	0	3	5	4	12	7
West Upstate	0	37	12	1	50	24

- Forecast Pass commitments are rare largely because virtual imports are counted as physical supply, requiring some SREs after DAM checkout.

- DARU requests increased in 2023, but OOM commitment fell in NYC because:
  - ✓ More units were economic at DAM prices.
- LRR requirements were reduced by changes in air permits that no longer require steam turbine commitments.

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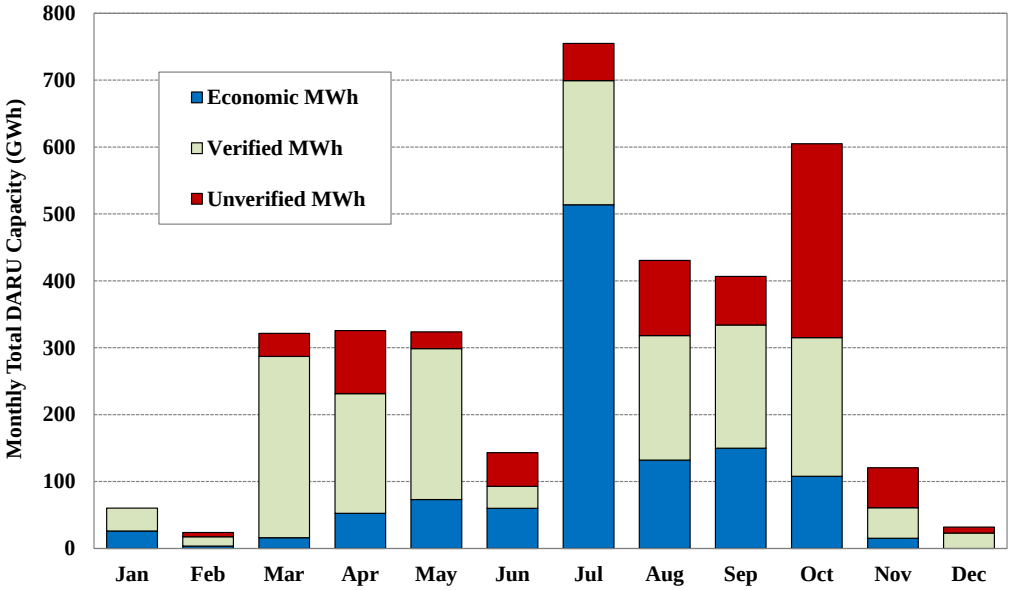
Evaluation of DARU Commitments in NYC



- Recommendation #2017-1 would model these local reserve requirements in the DA and RT markets.
- (Recommendation #2021-2 would model the full reserve requirements for Long Island.)

- 32% Economic at DAM prices
- 45% Verified as needed for N-1-1-0 based on DAM forecast
- 23% Not Verified – Likely reasons:
  - ✓ DARUs requested 2+ days ahead,
  - ✓ Treatment of imports,
  - ✓ Unknown local TO requirements

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Model TVR ("Transient Voltage Recovery") Constraints that Require OOM Dispatch

Average OOM Dispatch for Long Island Constraints

Year	Long Island Load Pockets	69kV OOM		TVR OOM		Avg. LBMP	Est. LBMP w/ Modeling Local Constraints
		#Hours	#Days	#Hours	#Days		
2022	Valley Stream	604	65			$98.08	$99.50
	Brentwood	38	8			$98.31	$98.34
	East of Northport	148	25			$97.30	$98.37
	East End	84	7	814	68	$99.40	$127.95
2023	Valley Stream	473	41			$38.97	$44.46
	Brentwood	33	5			$40.19	$40.25
	East of Northport	114	16			$43.52	$44.37
	East End	44	8	676	69	$44.31	$61.20

- Recommendation #2021-3 is for NYISO to model these with surrogate constraints in the DA and RT markets.

- East End TVR constraints have become the most-costly constraints requiring OOM dispatch.
- Modeling these would improve:
  - ✓ RT commitment and dispatch
  - ✓ DA scheduling
  - ✓ Investment incentives on Long Island

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