Winter Storm Markets Review January 18–23, 2025 - Update

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Market Implementation Committee
March 5, 2025

Operational Summary

- Intent is to provide a brief overview of Operational actions taken by PJM
- Full Operational summary during the Cold Weather period will be provide at the February 6 Operating Committee meeting

Key Takeaways for Operations

Instantaneous Peak Load 145,060* MW – January 22 @ 08:13

Successes

- Sufficient reserves to serve All-time Winter peak load and exports.
- Effective PJM Emergency Procedures limited to Advisories and Alerts
- Strong generator & transmission performance
- Good load forecasting

Challenges

- Gas-Electric Market Coordination and the need for multiple-day gas commitments during long holiday weekends
- Inflexible gas nominations & ratable take requirements reducing generator dispatch flexibility
- Operational risk is not reflected in markets
- Future resource adequacy concerns (increasing load / decreasing transfer margins).

Unit Commitment

Risk-based scheduling approach – Unit startup and operating risk, natural gas availability	• Units with extended start times were evaluated and started early to ensure units were online before extreme cold weather settled in. Strategy was to have units warm and ready to ramp up. • Evaluated units that have not operated in the past four weeks and potential need for additional start time • Tested CTs that have not ran to ensure operational capability • Minimized cycling of units
Reliability cases were conducted, and units were committed for reliability based on anticipated congestion and capacity projections.	
Advanced commitment to gas only resources, CTs & Steam units considering multi day extended gas nomination period. Sunday – Thursday commitment	• Considerations were given to min. down time on units to determine if they would be able to come back in time for higher projected loads. • CTs were surveyed for fuel availability – value in having fuel status

Emergency Procedures

Generator Maintenance Outage Recall
Jan. 19, 2025 06:00 through Jan. 23, 2025 10:45 (issued Jan 15, 2025)

Low Voltage Alert
Jan. 19, 2025 15:00 through Jan. 23, 2025 10:45

Cold Weather Advisory – PJM RTO
Jan 20, 2025, 00:01 through Jan. 23, 2025, 10:45 (issued Jan. 15, 2025)

Cold Weather Alert – PJM RTO
Jan 20, 2025, 00:01 through Jan. 23, 2025, 10:45 (issued Jan. 15, 2025)

Conservative Operations
Jan. 20, 2025, 00:01 through Jan. 23, 2025, 23:59 (issued Jan. 17, 2025)

Maximum Generation Alert
Jan. 22, 2025 00:01 through 22:30 (issued Jan. 21, 2025)

NERC Transmission Loading Relief
- **TLR 1**: issued Jan. 22, 2025 04:33 through Jan. 24, 2025 08:29
- **TLR 3**: issued Jan 23, 2025 07:28 through 09:32

Communications Timeline

Jan. 15

- SOS/OC/MRC Pardot message sent summarizing next week's cold weather and generator owner expectations, including a request that generation owners survey their stations for consumables such as fuel oil inventories and demineralized water.

Jan. 16

- SOS-T / Security Conference Call (Inauguration + Cold Weather), SOS-G Cold Weather Conference Call, and DOE Conference Call discussing Cold Weather operations and potential need for 202c order.

Jan. 17

- PJM States Conference Call and RF/SERC Conference Call

Jan. 19

- Generation All-call reminding generation owners to staff CT sites, notify PJM of any fuel procurement issues, and update Market's Gateway with unit limitations.

Jan. 20

- SOS-T System Conditions Conference Call and SOS/OC/MRC Pardot message sent notifying generation owners of PJM gas commitment strategy for the Wednesday gas day (Wednesday 10:00 – Thursday 10:00)

Jan. 21

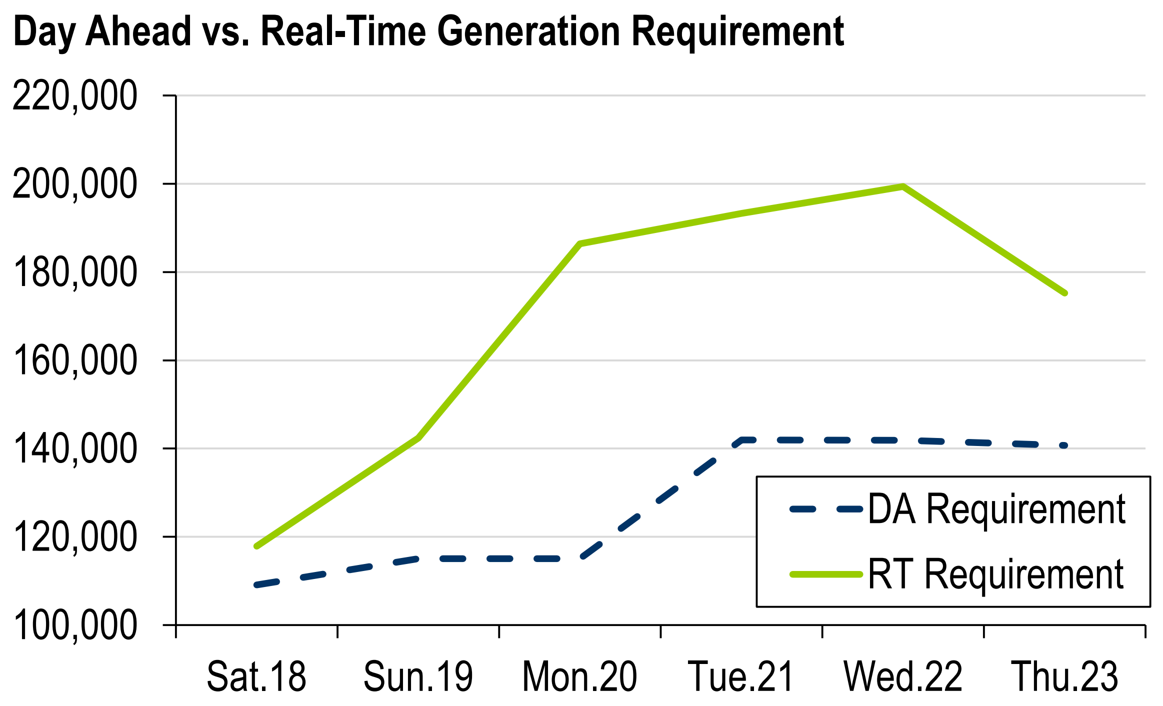
- SOS-G All-Call requesting CTs be staffed Wednesday evening / Thursday morning peaks and SOS-T System Conditions Conference Call

Jan. 22

- SOS-T System Conditions Conference Call.

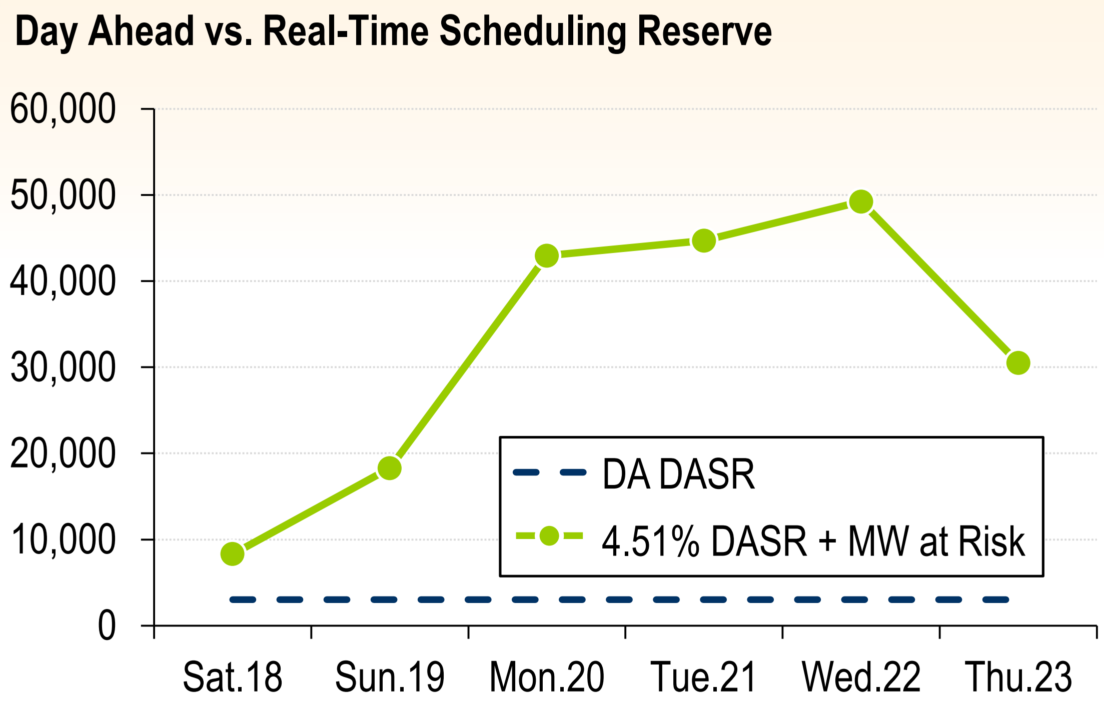
Generation Commitment and Reserves

Generation Requirements



DA = DA Load + DA Exports + 3,000 MW DASR
RT = RT Forecast + DA Exports + 4.51% DASR + MW at Risk *(operating temperature)*

Scheduling Reserve



DA Markets = 3,000 MW DASR
DA Operations = 4.51% DASR + MW at Risk *(operating temperature)*

Key Takeaways on Gas Delivery Performance

Interstate Pipelines	• Overall strong performance under high utilization rates • Hourly and Daily capacity restrictions in place through the cold period • Two brief compressor station outages resulting in localized pressure drops with only minimal impact on generation • Pipeline lateral leak resulted in approximately 300 MW of gas generation taking a forced outage for several days
Local Gas Distribution Companies	• Approximately 1,500 MW of gas-only generation unavailable due to LDC interruptions
Gas Production	• Production remained strong with minimal losses associated with well freeze offs • ~ 2 bcf/day (5%) decline in daily production in Appalachian region • ~11 bcf/day decline during WS Elliott
Gas Availability/Liquidity	• Weekend gas market remains an ongoing challenge with supply uncertainty once past Friday trading • Some generators reported inability to find sellers during the weekend
Gas Prices	• 4 Day Weekend (Saturday 10am through Wednesday 10am) gas strip spot prices much higher in eastern PJM compared to western zones. Eastern trading hubs averaged around \$35/mmbtu to \$10/mmbtu at western PJM hubs. However, individual reported trades peaked between \$50 and \$100/mmbtu with highest price over \$100/mmbtu at Transco Z6NY

Market Impacts

These slides are meant to provide additional detail for how markets reflected system operations and conditions during the recent winter storm.

AREAS INCLUDE:

- Day-Ahead Market clearing and scheduling
- Real-Time LMP price verification
- Ancillary service pricing
- Uplift totals

Key Takeaways for Day-Ahead Markets

Day-ahead demand was underbid 5% to 11% as compared to the PJM original forecast (18:00 prior day).

Current market rules do not properly address operational constraints.

- Fuel certainty
- Unit risk
- Forecast error

Day-ahead pricing peaked coincident with system conditions on Jan. 18–23, driven by demand, interchange and virtual bids.

In PJM's existing market constructs, the Day-Ahead Energy Market does not procure sufficient reserves to manage operational risk.

- The Day-Ahead Energy Market clears enough supply to meet bid-in demand, which may be lower than the PJM Load Forecast for the next day.
- PJM's operations 30-minute reserve requirement is routinely higher than the 30-minute reserve requirement reflected in PJM's markets.
- Any shortfall in supply procured through the markets is handled through out-of-market commitments.

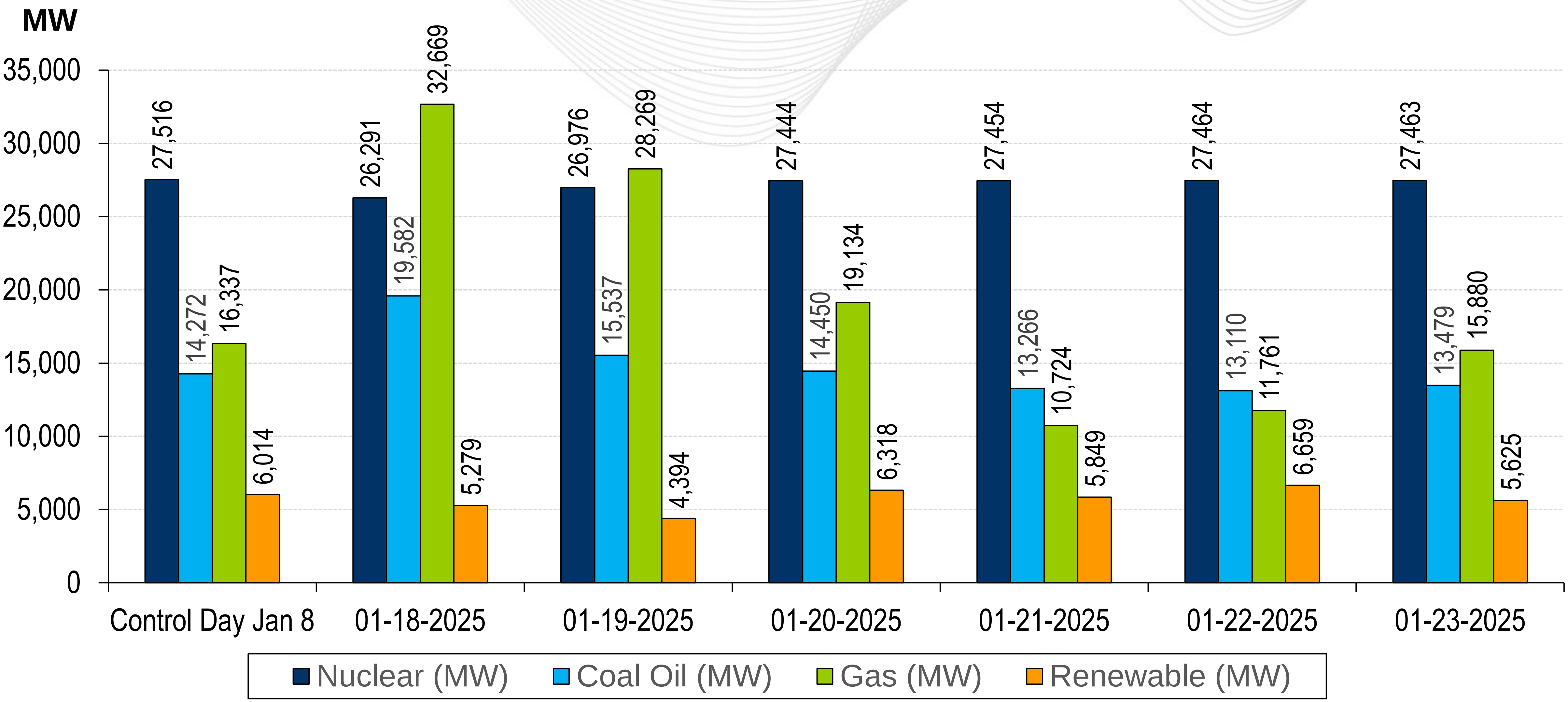
PJM currently uses the Reliability Adequacy Commitment tool to bridge the gaps between Day-Ahead Energy Market procurement, forecasted load and the Day-Ahead Scheduling Reserve (DASR).

Operator Actions That Affect Prices

Unit Scheduling

Date	Day Ahead	Before the Day Ahead
	Self-Scheduled Units	Units Scheduled for Conservative Operations
	Sum of Eco Max	
Sat. 18	83,821	58,131
Sun. 19	75,175	58,131
Mon. 20	67,346	67,678
Tue. 21	57,292	67,728
Wed. 22	58,993	67,688
Thu. 23	62,447	67,554

Day-Ahead Self Scheduling Jan. 18–23



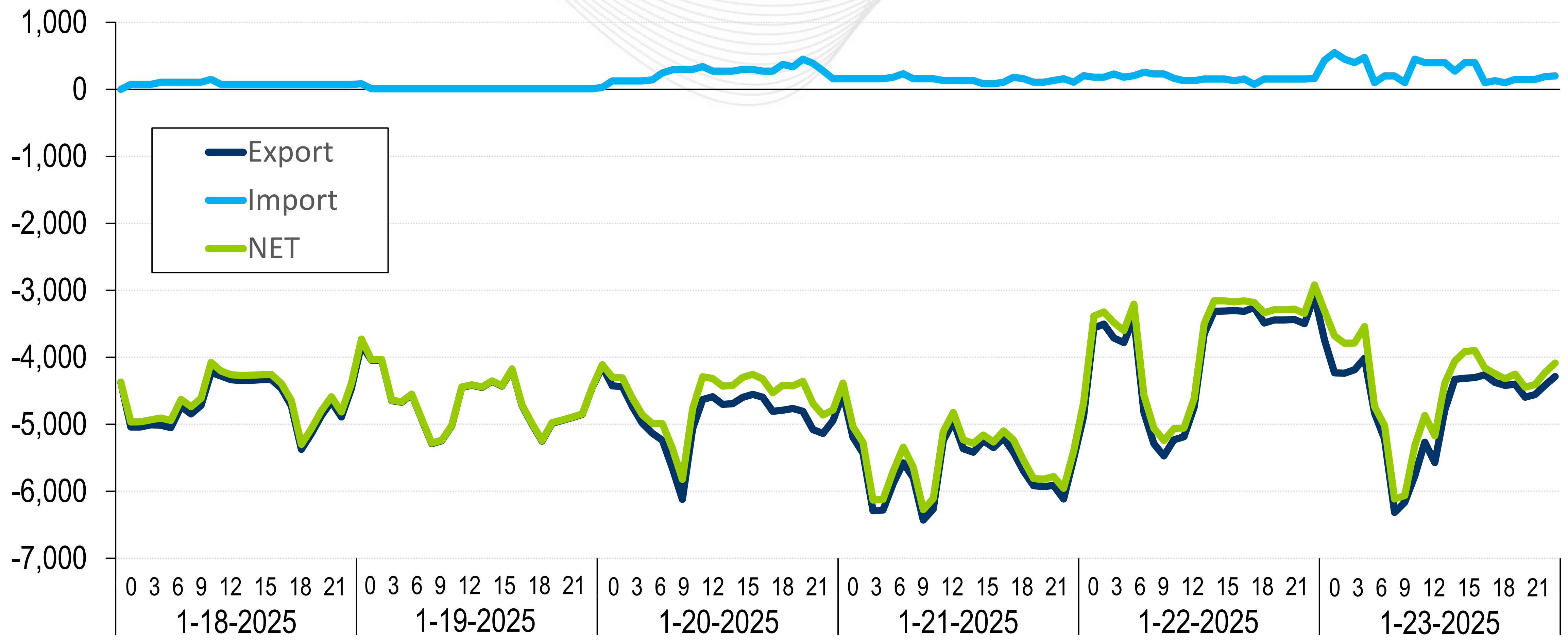
Day-Ahead Self-Scheduled Units

January 2025	Nuclear		Coal Oil		Gas		Renewable		Total (MW)
Jan. 8 Control Day	27,516	43%	14,272	22%	16,337	25%	6,014	9%	**64,138**
Sat. 18	26,291	31%	19,582	23%	32,669	39%	5,279	6%	**83,821**
Sun. 19	26,976	36%	15,537	21%	28,269	38%	4,394	6%	**75,175**
Mon. 20	27,444	41%	14,450	21%	19,134	28%	6,318	9%	**67,346**
Tue. 21	27,454	48%	13,266	23%	10,724	19%	5,849	10%	**57,292**
Wed. 22	27,464	47%	13,110	22%	11,761	20%	6,659	11%	**58,993**
Thu. 23	27,463	44%	13,479	22%	15,880	25%	5,625	9%	**62,447**

Day-Ahead Demand vs. Forecast at 18:00

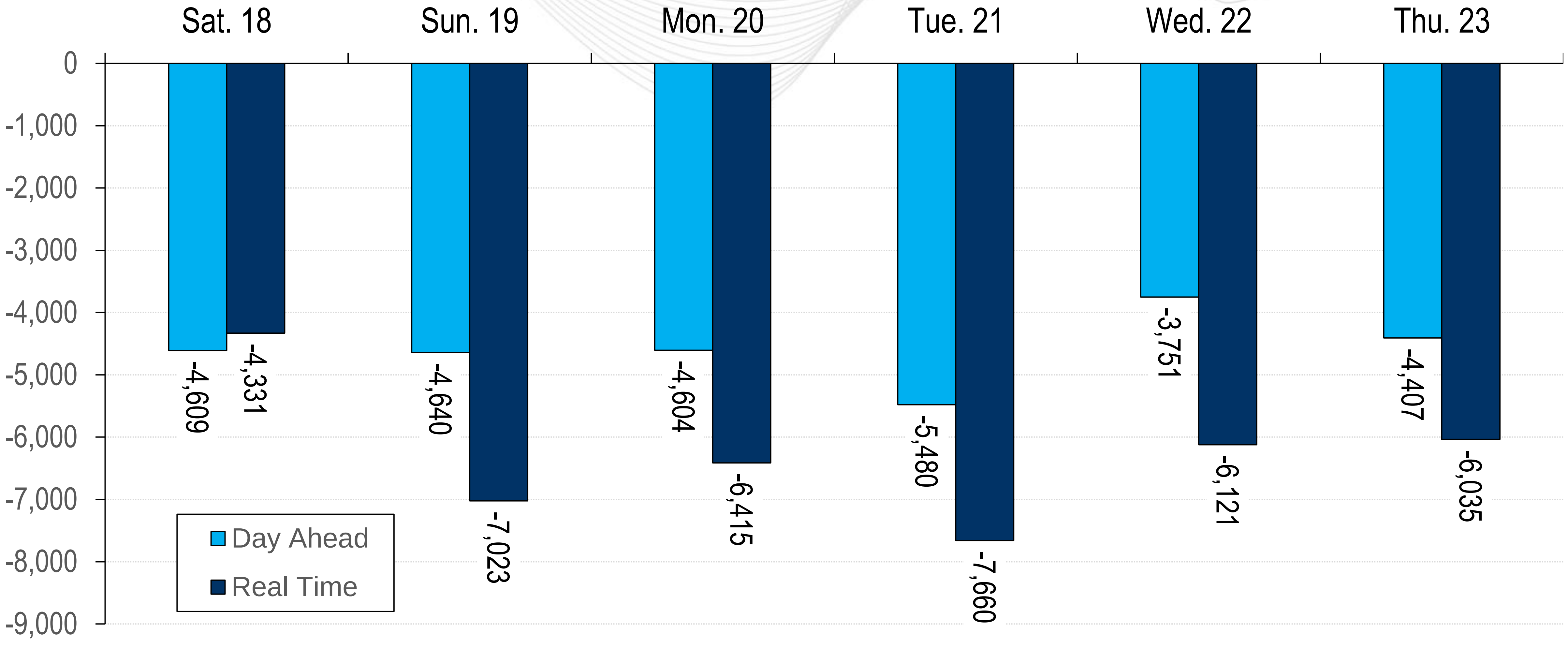
	Valley			Morning Peak			Evening Peak		
January 2025	DA Demand	Org Forecast	DA Over/Under Bid	DA Demand	Org Forecast	DA Over/Under Bid	DA Demand	Org Forecast	DA Over/Under Bid
Sat. 18	85,794	91,395	**-5,601**	97,106	102,019	**-4,913**	100,771	104,269	**-3,498**
Sun. 19	87,028	90,593	**-3,565**	99,515	106,347	**-6,832**	106,899	118,847	**-11,948**
Mon. 20	101,331	106,589	**-5,258**	121,746	130,045	**-8,299**	129,722	139,089	**-9,367**
Tue. 21	115,082	122,245	**-7,163**	133,314	144,024	**-10,710**	131,214	142,740	**-11,526**
Wed. 22	115,521	124,306	**-8,785**	133,802	145,104	**-11,302**	127,562	138,475	**-10,913**
Thu. 23	109,801	117,834	**-8,033**	131,558	138,618	**-7,060**	119,316	131,365	**-12,049**

Day-Ahead Interchange

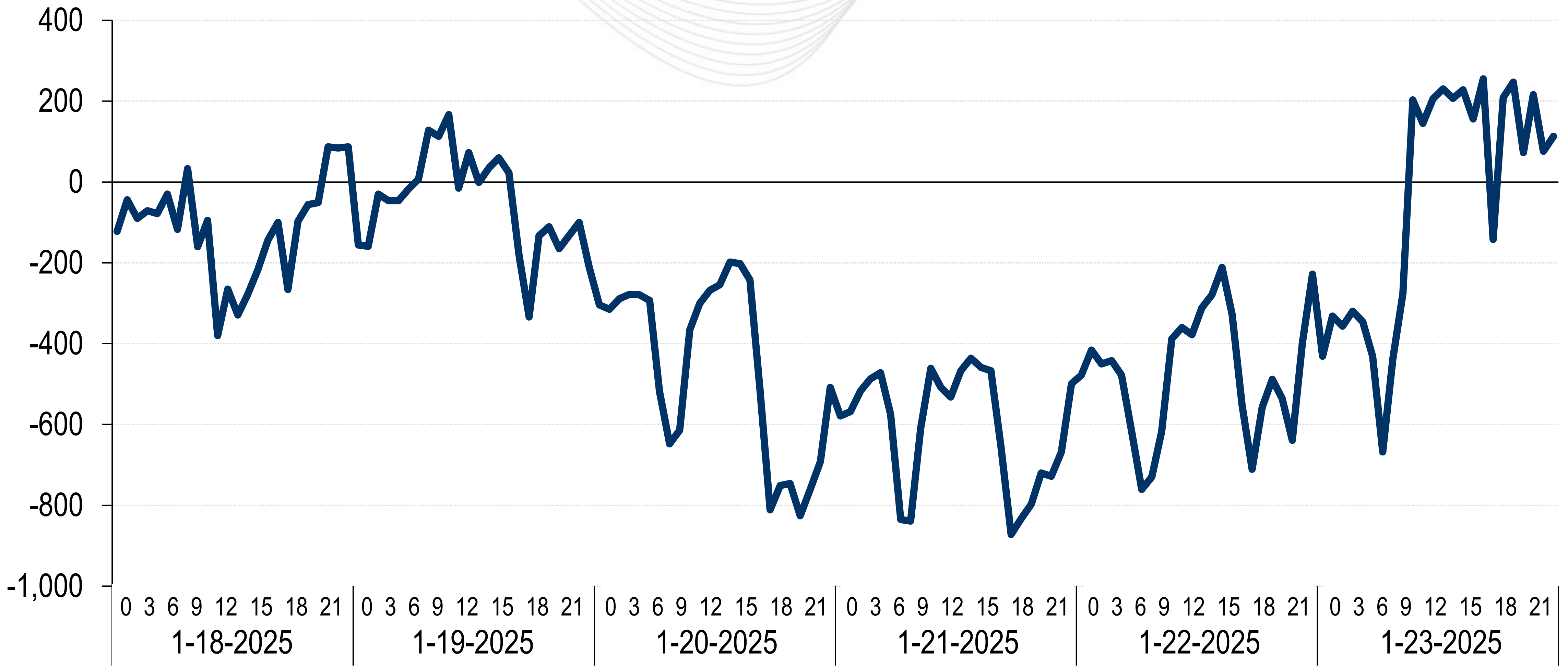


Interchange Day-Ahead vs. Real-Time

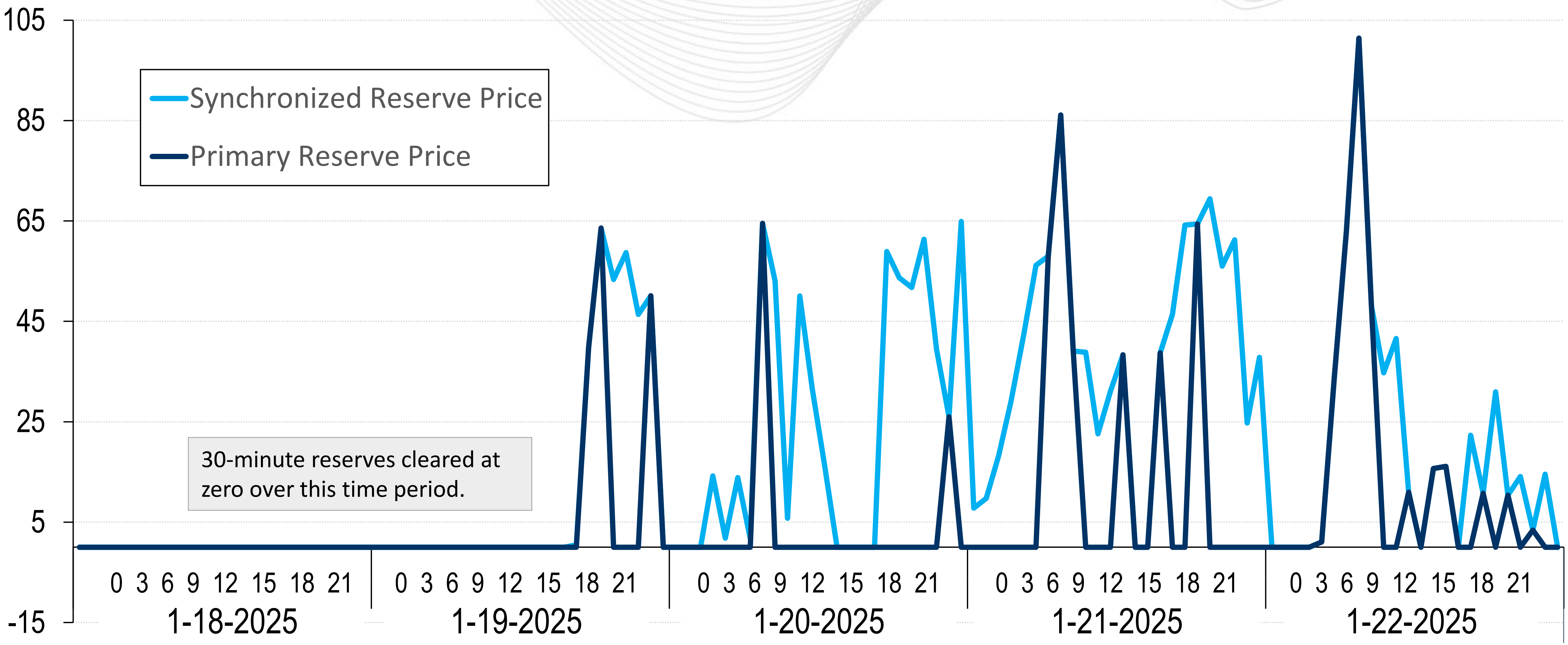
Jan 18–23



Day-Ahead Hourly Net of Virtual Bids Jan 18–23



Day-Ahead Reserve Pricing Jan 18–23



Key Takeaways for RT Markets

Real-time pricing peaked coincident with system conditions on Jan. 21–23, driven by load, interchange and localized congestion.

SMP = $628.97 @ Jan. 22, 08:05; $601.92 @ Jan. 23, 06:55

Localized congestion peaked hour 11, Jan. 23:

- Ten out of 29 active constraints in RT SCED bound at the $2,000/MWh penalty factor.

Ancillary services:

- No reserve shortage cases approved throughout event.
- One Synchronized Reserve event Jan. 21 (<10 minutes)
- 800 MW of Regulation throughout event

RT Market design remains flawed by not appropriately pricing actions for reliability:

- Outdated ORDCs
- No procurement for flexibility to manage forecast uncertainty or ramping needs
- Items in scope of RCSTF

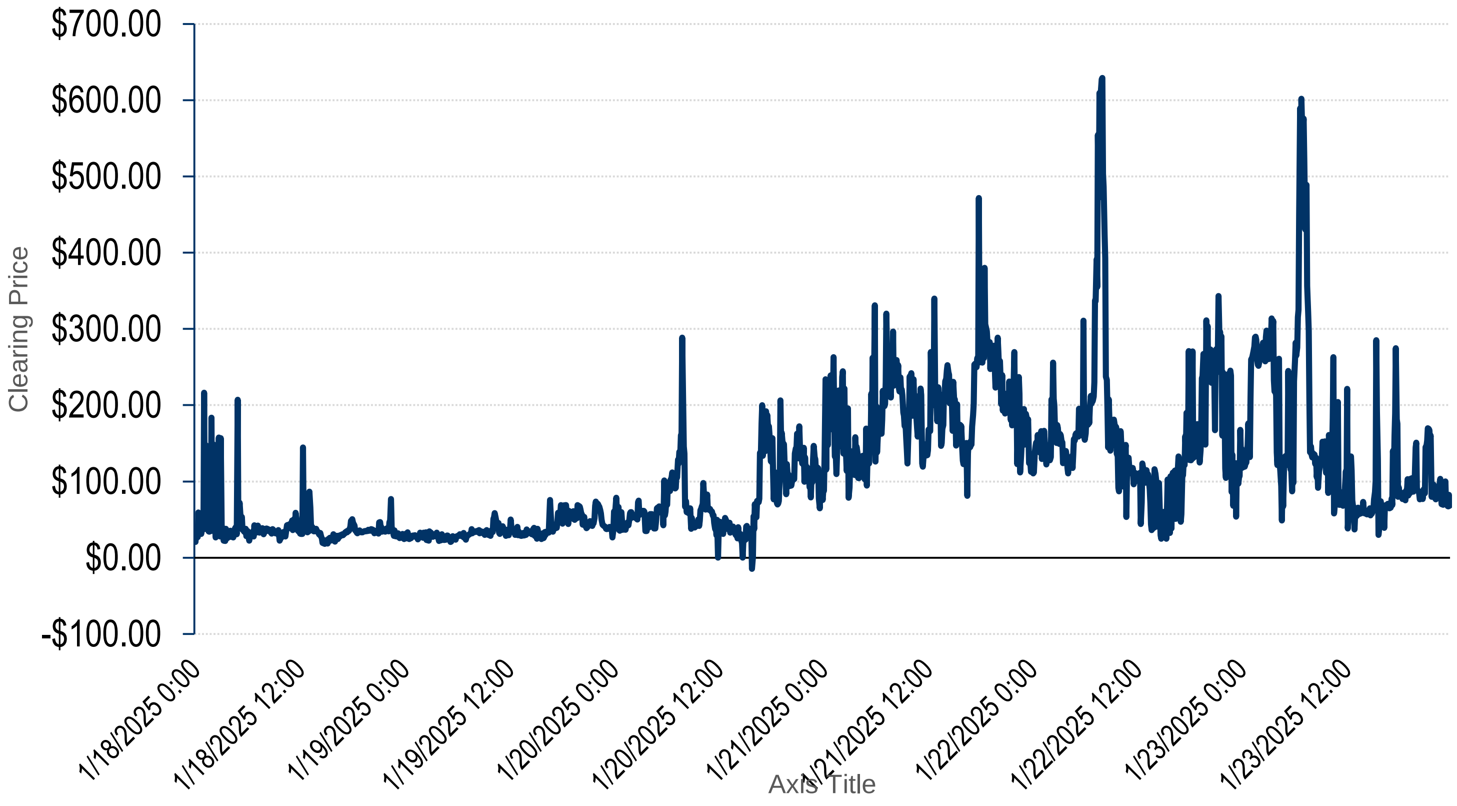
Five-Minute Verified Real-Time System Marginal Price

System Marginal Price (SMP)

Incremental price of energy for the system, given the current dispatch, at the load weighted reference bus

- Same price for every bus in PJM (no locational aspect)
- Calculated both in day ahead and real time

Key takeaway: System Marginal Price spikes morning on Jan. 22, 23, coincident with heavy morning load, congestion and interchange.



Congestion Component of LMP (CLMP)

- **Represents price of congestion for binding constraints**

  Calculated using the Shadow Price

- **Will be zero if no constraints (unconstrained system)**

  Will vary by location if system is constrained

- **Used to price congestion**
  - Load pays Congestion Price.
  - Generation is paid Congestion Price.
- **Calculated both in day ahead and real time**

Locational aspect of load to constraints ultimately impacts pricing.

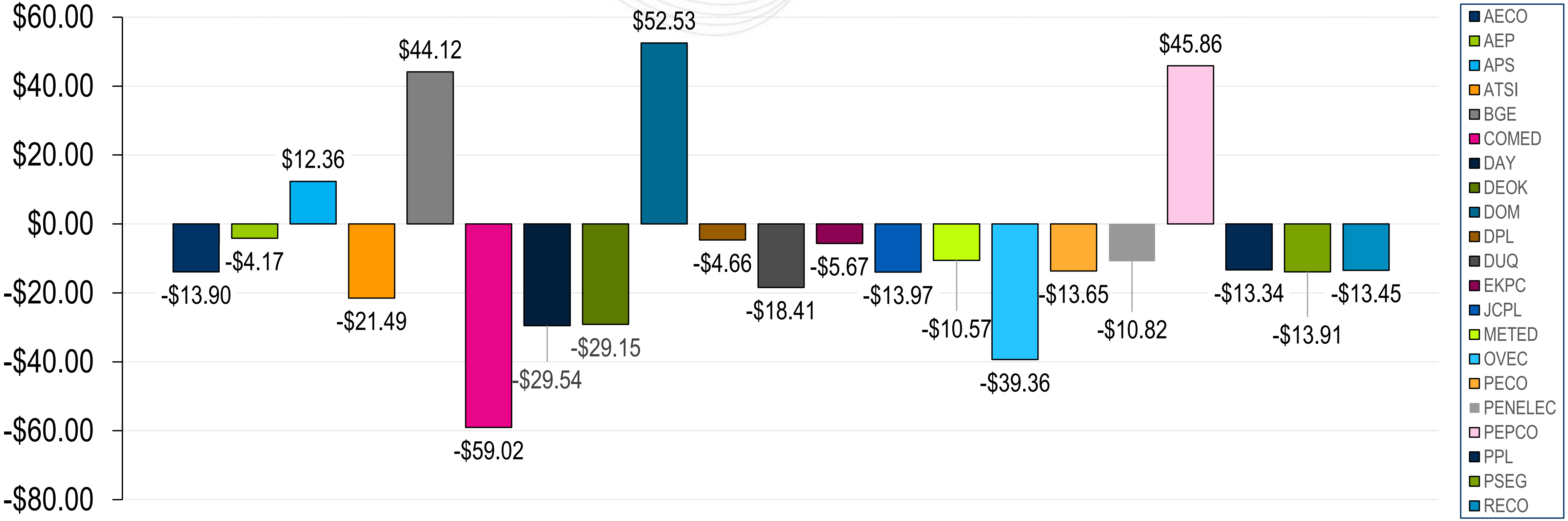
Transmission Constraint Penalty Factors

These are parameters used by the Security Constrained Economic Dispatch (SCED) applications to determine the maximum cost of the re-dispatch incurred to control a transmission constraint. Default is $2,000/MWh.

Average Zonal Congestion Impacts

Represents Jan. 18–23 Average 5-minute CLMP

A **positive** CLMP indicates a total energy price **higher** than the average LMP, due to transmission constraints.



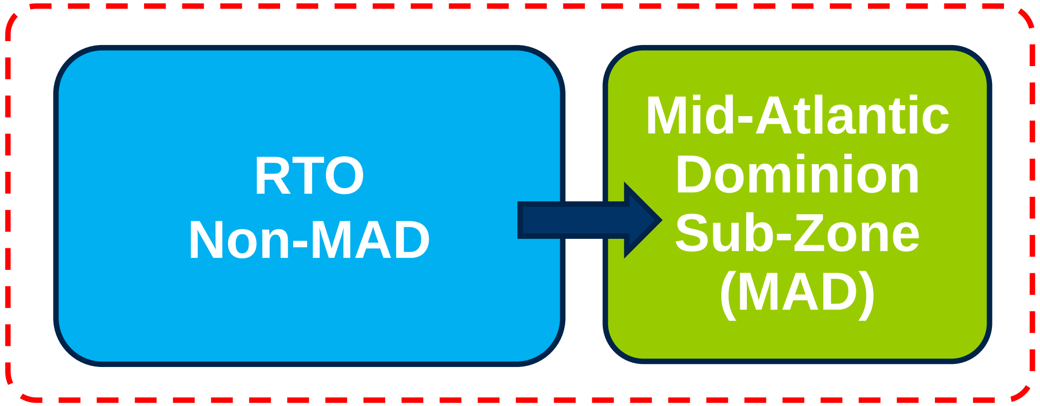
A **negative** CLMP indicates a total energy price **lower** than the average LMP, due to transmission constraints.

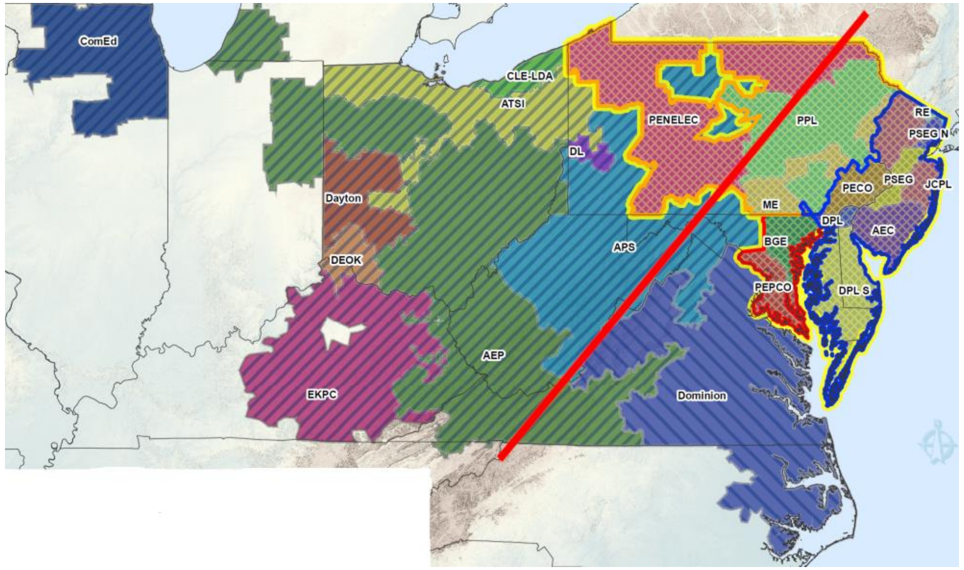
Single reserve zone with a sub-zone: Mid-Atlantic Dominion (MAD)

Exists due to potential reserve deliverability issues

- The sub-zone is defined based on the most-limiting transfer interface.
- Resources with ***3% or greater raise-help distribution factor*** on the interface are included in the MAD sub-zone.
- Sub-zone can be dynamically changed based on system conditions.

RTO Reserve Zone





Reserve Product & Locational Substitution

Sub-Zone Synch Reserves
MW can be used to meet sub-zone PR requirement or RTO SR requirement

Product Substitution

Price: SR ≥ NSR

Sub-Zone Primary Reserves
MW can be used to meet PR requirement or sub-zone 30-min. requirement

Product Substitution

Price: NSR ≥ Secondary Reserve

Sub-Zone 30-Minute Reserves
MW can be used to meet RTO 30-min. requirement
**Sub-zone will be modeled only when needed*

Locational Substitution

Price: Sub-Zone ≥ RTO

Locational Substitution

Price: Sub-Zone ≥ RTO

Locational Substitution

Price: Sub-Zone ≥ RTO

RTO Synch Reserves
MW can be used to meet RTO PR requirement

Product Substitution

Price: SR ≥ NSR

RTO Primary Reserves
MW can be used to meet RTO 30-min. requirement

Product Substitution

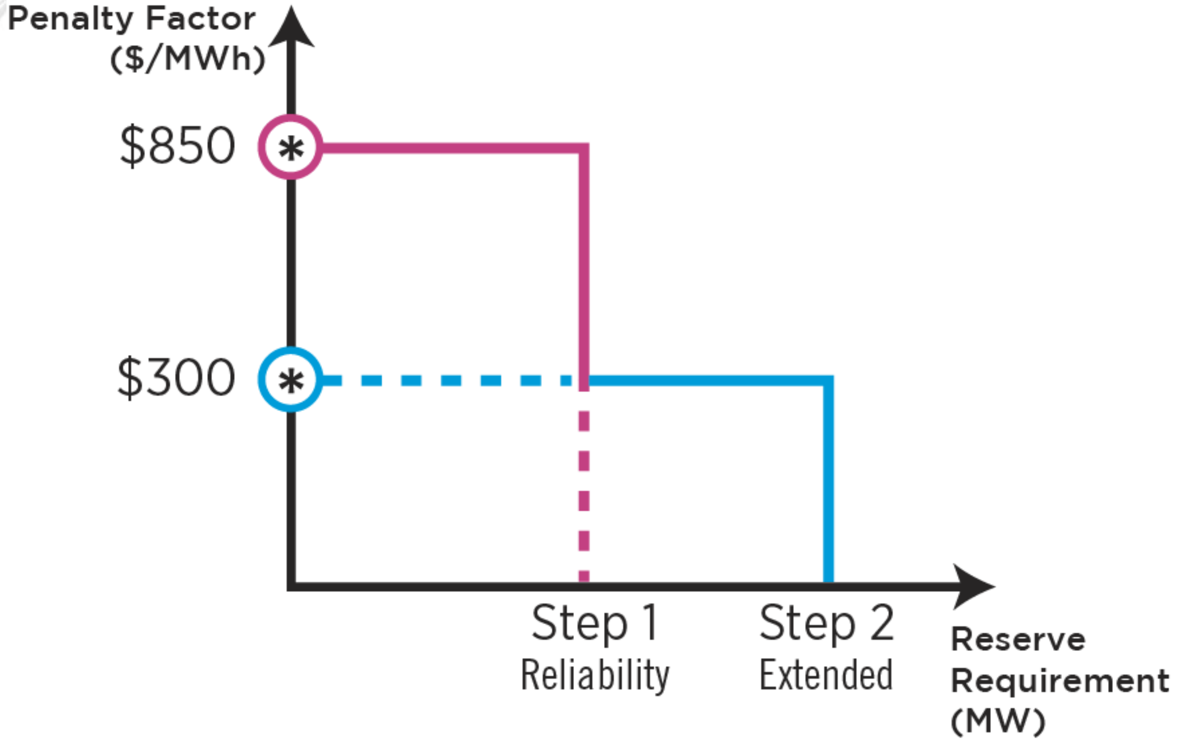
Price: NSR ≥ Secondary Reserve

RTO 30-Minute Reserves

Reserves Requirements and ORDC

	Reserve Service		
	Synchronized Reserve (SR)	Primary Reserve (PR)	30-Minute Reserve (30-Min)
Reliability Requirement	Largest Single Contingency	150% of Synchronized Reserve Reliability Requirement	Greater of (Primary Reserve Reliability Requirement, 3000 MW, or largest active gas contingency)
Reserve Requirement	SR Reliability Requirement + Extended Reserve Requirement	PR Reliability Requirement + Extended Reserve Requirement	30-Min Reliability Requirement + Extended Reserve Requirement

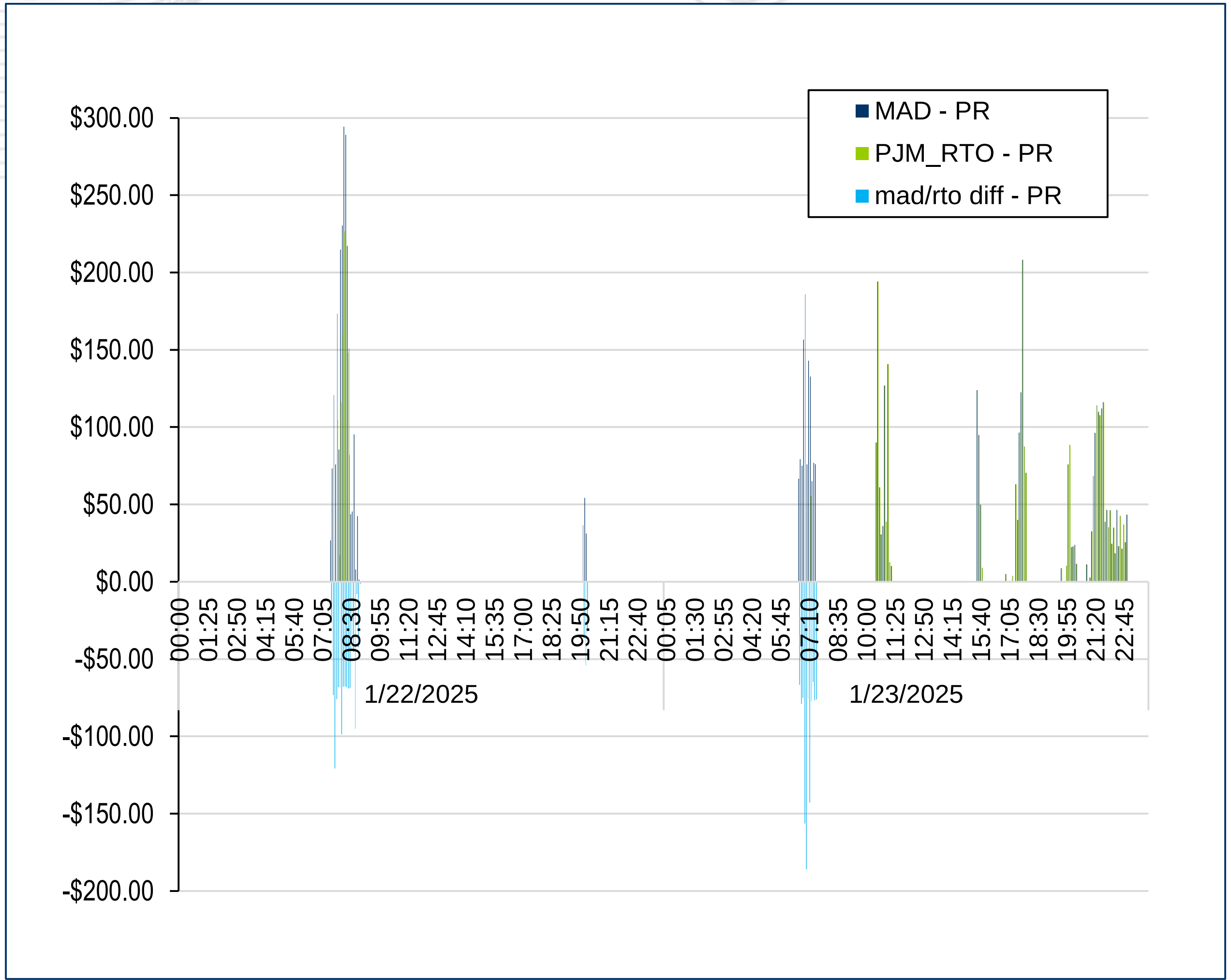
**30% adder to Reliability Requirement (RTO Only) still in effect.*



**Step 2 remained at +190 MW for duration of event.*

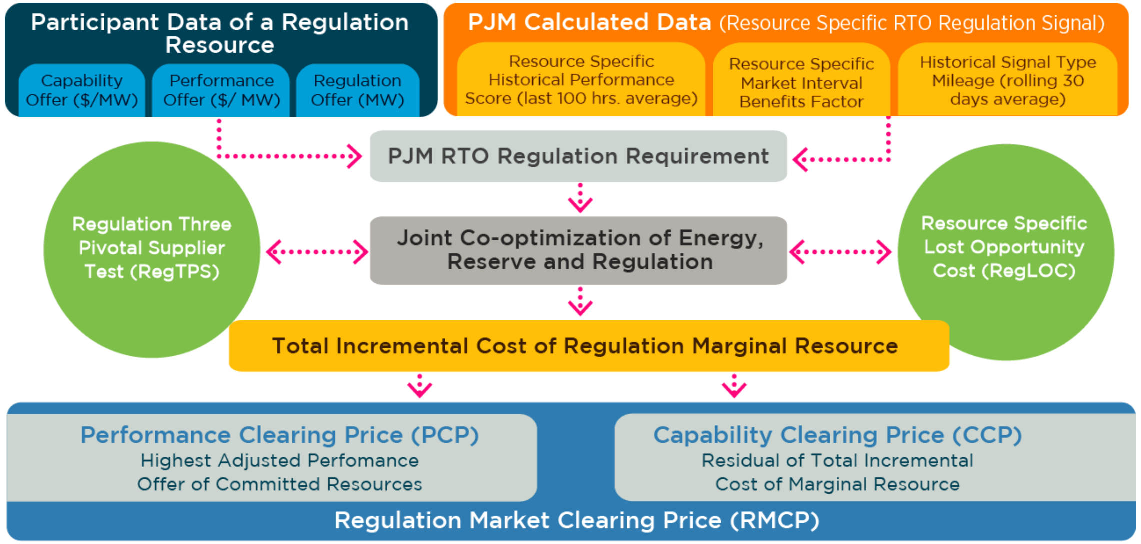
Reserve Market Clearing Prices

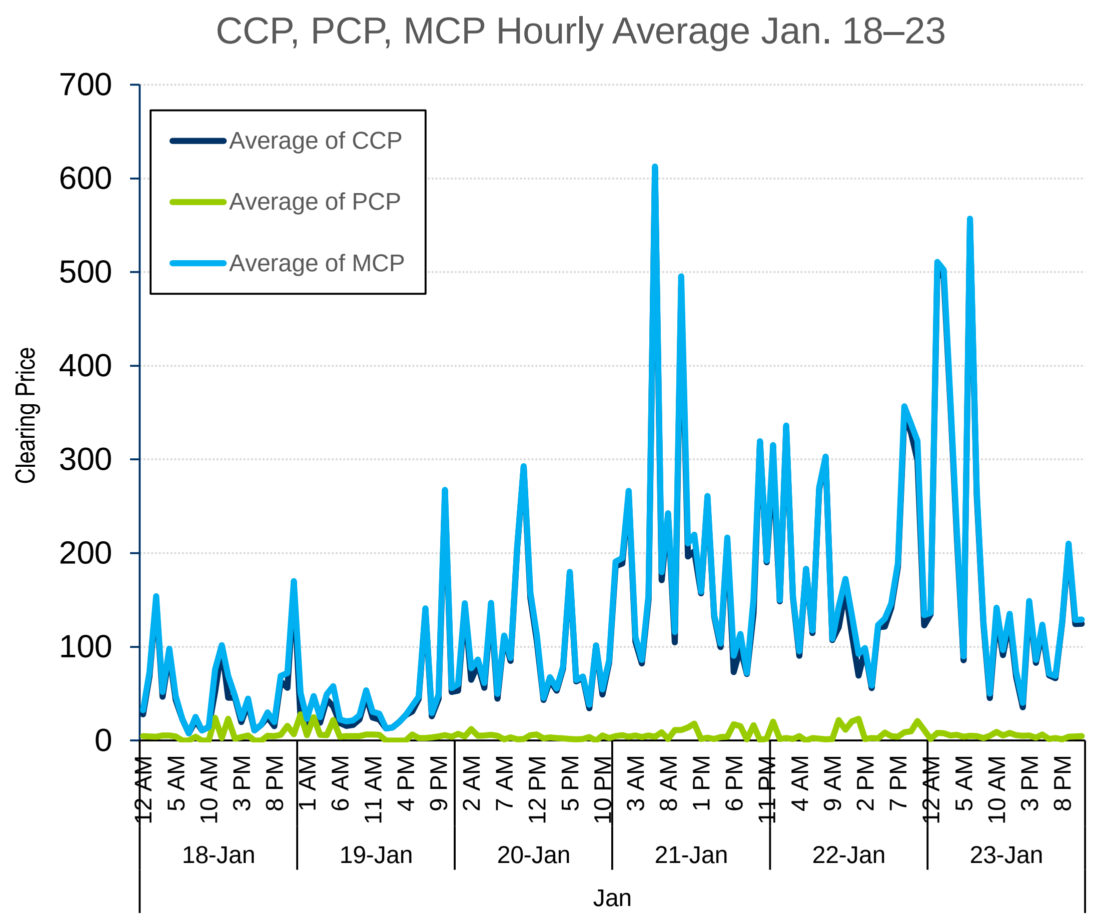
- All clearing prices $0 prior to Jan. 22
  - Indicates sufficient 10-minute ramp capability online to meet SR, PR, 30-minute reserve requirements
- SRMCP = NSRPMCP in all but one interval due to PR-SR product substitution.
  - Additive shadow price concepts
- MAD sub-zone price higher than RTO due to heavy west-to-east flows across system.
  - Dynamic interface binding throughout event.



Regulation Market Clearing Prices

- ASO engine clears Regulation commitment 60-minutes prior to target time.
- LPC prices Regulation based on fixed commitment, system conditions.





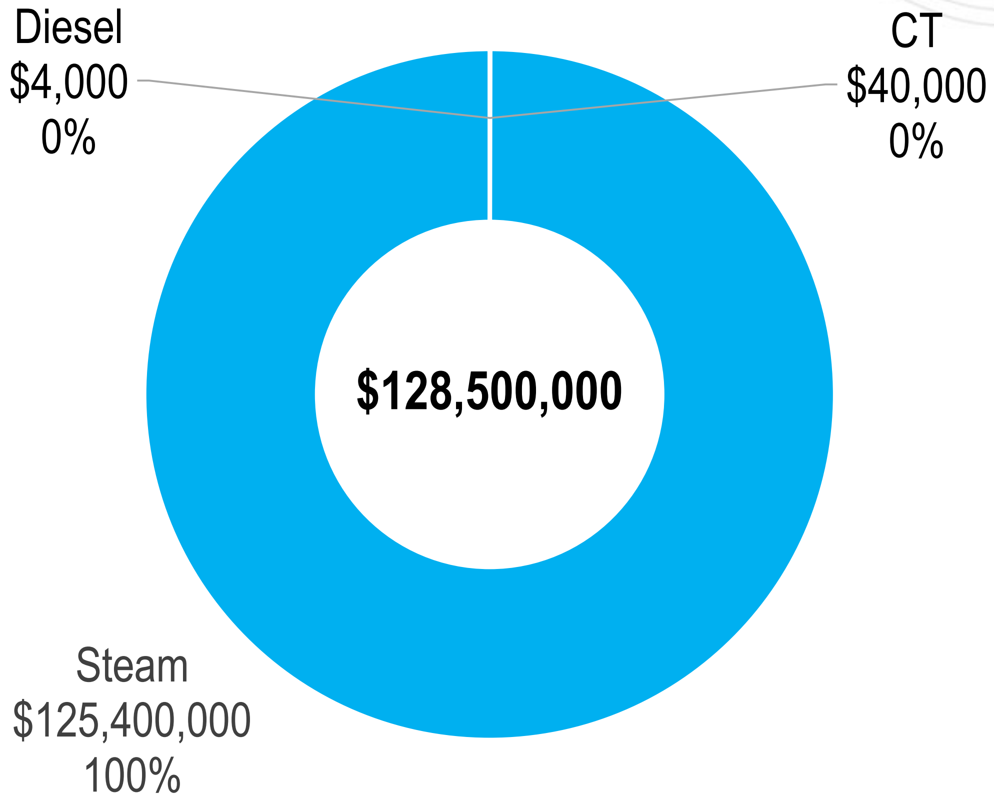
	Operating Reserve Credit		
January 2025	**Day Ahead ($ Millions)**	**Balancing ($ Millions)**	**Total Uplift ($ Millions)**
Sunday: Jan. 19	12.7	34.3	47.0
Monday: Jan. 20	29.1	68.4	97.5
Tuesday: Jan. 21	28.4	60.0	88.4
Wednesday: Jan. 22	28.9	35.3	64.2
Thursday: Jan. 23	26.7	8.1	34.8
Total	125.8	206.1	**331.9**

Includes Make-Whole Credits and Lost Opportunity Cost Credits

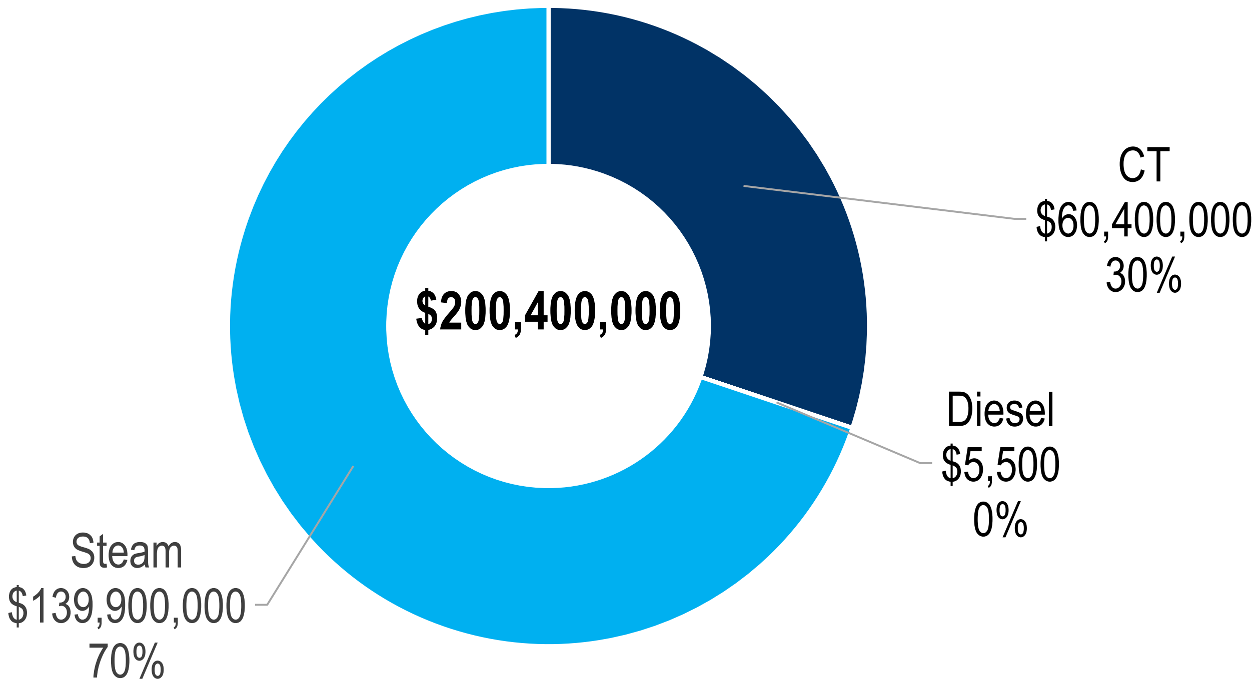
Operating Reserve Credits by Unit Type

Sunday, Jan. 19, to Thursday, Jan. 23

Day Ahead Operating Reserve Credits



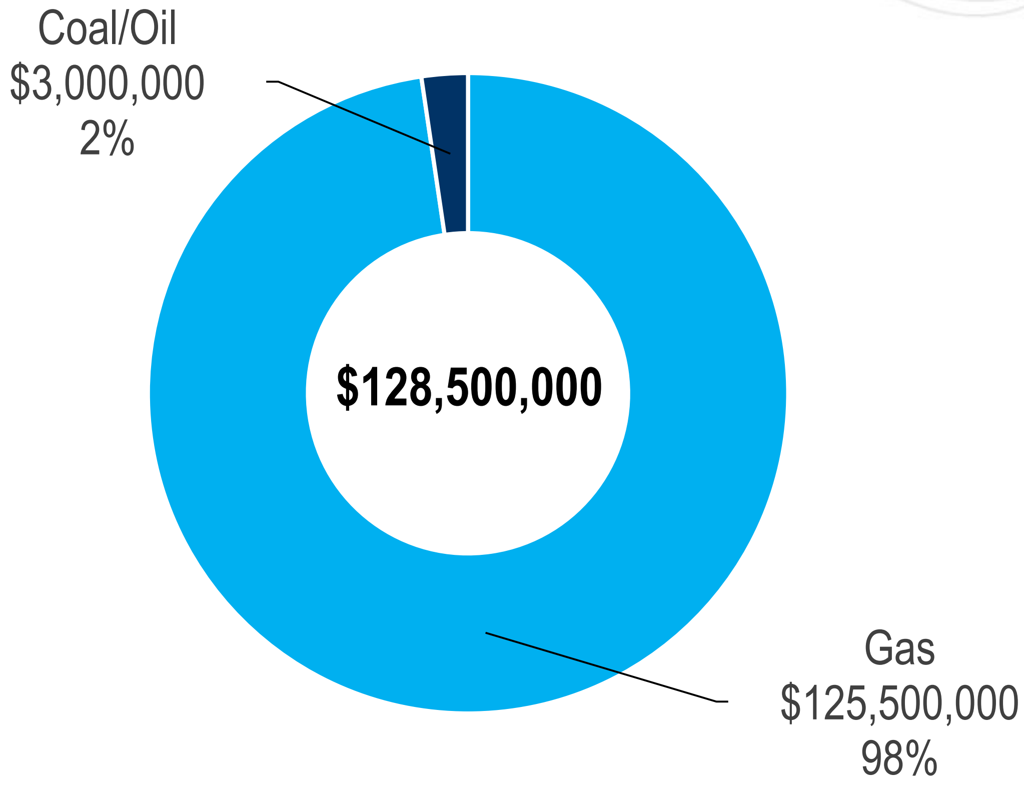
Balancing Operating Reserve Credits (Make-Whole Only)



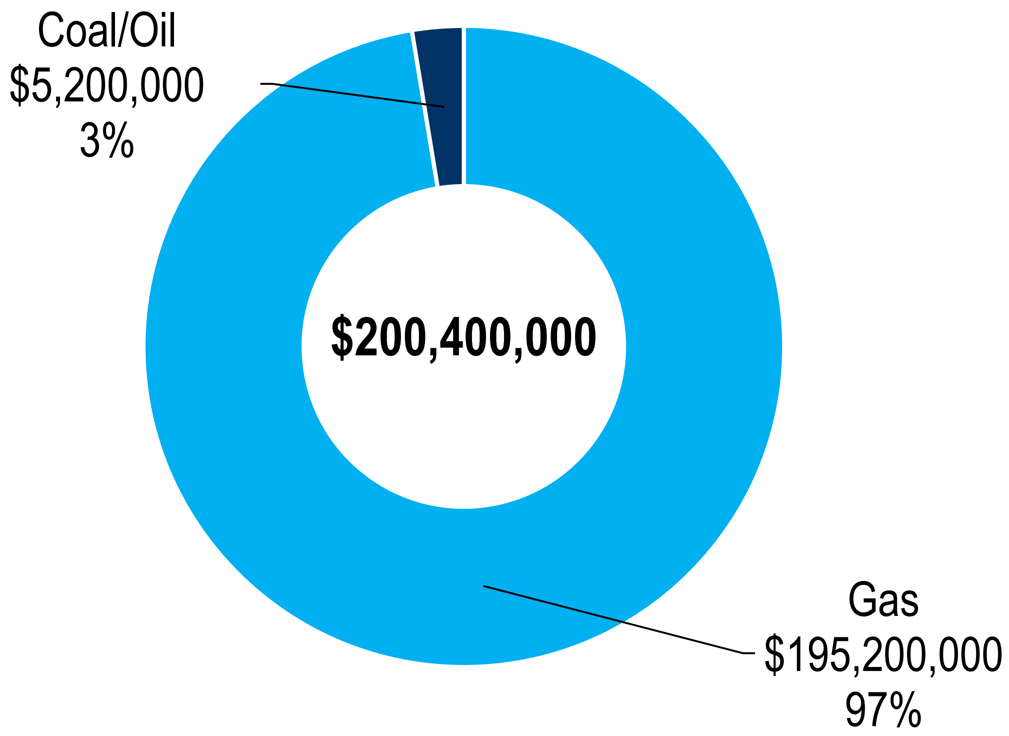
Operating Reserve Credits by Fuel Type

Sunday, Jan. 19, to Thursday, Jan. 23

Day-Ahead Operating Reserve Credits



Balancing Operating Reserve Credits (Make-Whole Only)

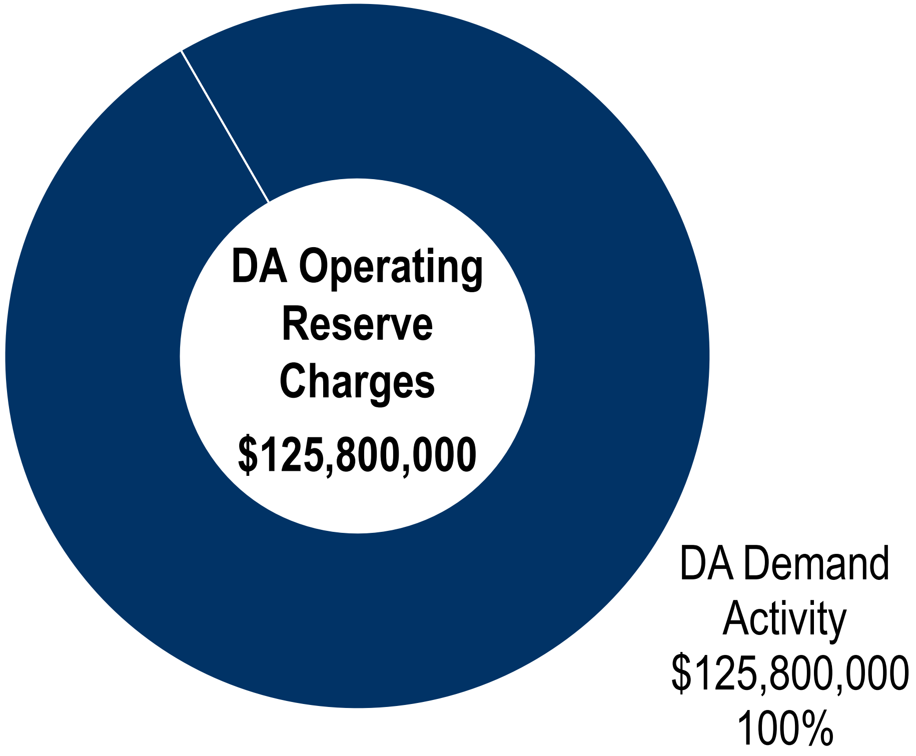


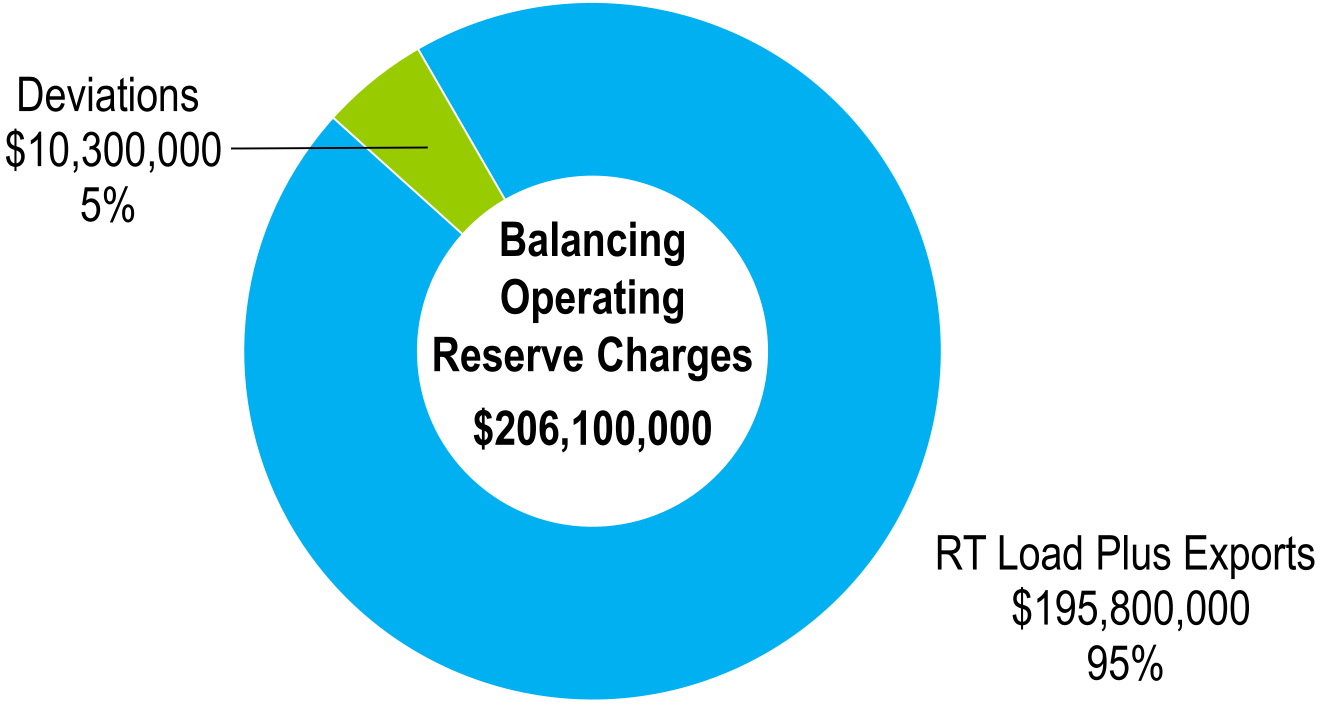
Operating Reserve Charge Allocations
Sunday, Jan. 19, to Thursday, Jan. 23

Day-Ahead Operating Reserves are charged to DA Demand Activity

(DA Demand + Dec bids + UTCs + Exports)

Balancing Operating Reserves are charged to either RT Load plus Exports or Deviations based on the Balancing Operating Reserve Cost Analysis





Appendix

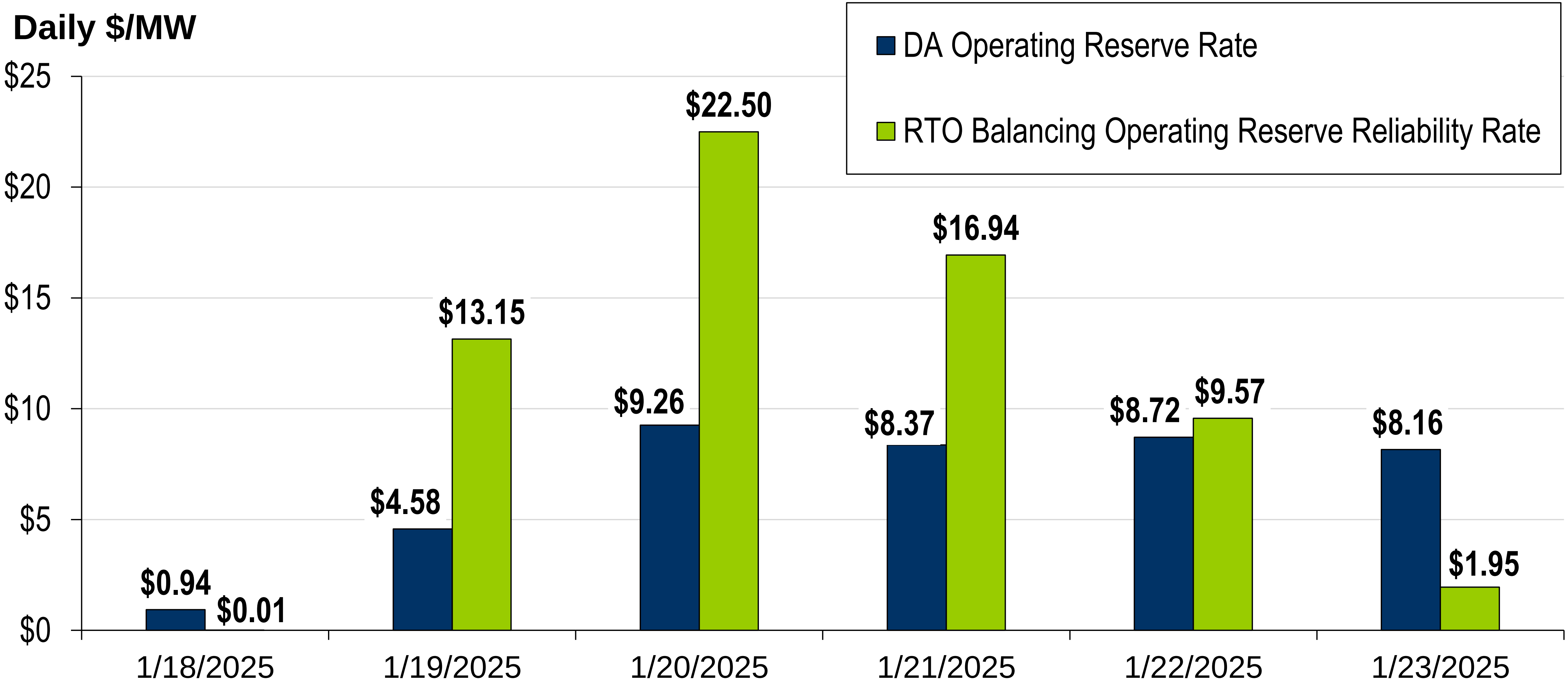
2024 Winter Storm Gerri vs. 2025 MLK Weekend

DATE (JANUARY)		SELF SCHEDULED		CONSERVATIVE OPERATIONS	
2024	2025	2024	2025	2024	2025
Sat. 13	Sat. 18	72,693	83,821	< 1,000	58,131
Sun. 14	Sun. 19	67,200	75,175	< 9,000	58,131
Mon. 15	Mon. 20	67,088	67,346	10,140	67,678
Tues. 16	Tue. 21	68,977	57,292	15,189	67,728
Wed. 17	Wed. 22	68,823	58,993	14,009	67,688
Thur. 18	Thur. 23	63,056	62,447	< 2,000	67,554

Self-Scheduled Units January 2025
Combined Cycle & Combustion Turbine Break Down

DATE	Combined Cycle	Combustion Turbine
Sat. 18	30,011	<1,200
Sun. 19	26,348	<1,200
Mon. 20	16,746	2,309
Tue. 21	8,275	2,901
Wed. 22	9,248	2,921
Thur. 23	14,163	1,925

Daily $/MW Uplift Impact



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