



IMM Quarterly Report: Fall 2024

Presented to:

Market Subcommittee

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Fall Summary

- The MISO markets performed competitively, and market power mitigation was infrequent during the fall.
- Energy prices fell 15 percent compared to last year because gas prices fell around 20 percent and average load was similar to last fall.
 - The fall peak load of 106 GW was almost 10 percent lower than last year.
 - Shortage pricing intervals occurred more frequently, which contributed to average price increases for ancillary services as high as 65 percent.
- MISO declared a Severe Weather Alert and Conservative Operations for the South in September due to Hurricane Francine that made landfall on the 10th.
 - Although 36 transmission lines tripped, there were no major market impacts.
- Lower gas prices contributed to a 33 percent decrease in real-time congestion.
 - FTRs were fully funded, which was an improvement over last fall.
- Average hourly wind production increased 6 percent over last year, while wind curtailments were up 42 percent, averaging 780 MW per hour.
- Day-ahead and real-time RSG fell by 23 and 24 percent, respectively, primarily because of operational improvements and lower natural gas prices.

Quarterly Summary

Fall		Value	Change ¹			Value	Change ¹	
			Prior Qtr.	Prior Year			Prior Qtr.	Prior Year
RT Energy Prices (\$/MWh)	●	\$27.23	-12%	-15%	FTR Funding (%)	●	100%	103% 95%
Fuel Prices (\$/MMBtu)					Wind Output (MW/hr)	●	11,611	51% 6%
Natural Gas - Chicago	●	\$1.92	9%	-18%	Wind Curtailed (MW/hr)	●	780	198% 42%
Natural Gas - Henry Hub	●	\$2.14	-1%	-23%	Guarantee Payments (\$M)⁴			
Western Coal	●	\$0.80	1%	-1%	Real-Time RSG	●	\$3.6	-31% -24%
Eastern Coal	●	\$1.73	1%	-11%	Day-Ahead RSG	●	\$7.1	36% -23%
Load (GW)²					Day-Ahead Margin Assurance	●	\$12.8	-14% 3%
Average Load	●	72.1	-16%	0%	Real-Time Offer Rev. Sufficiency	●	\$0.9	12% -23%
Peak Load	●	105.5	-15%	-9%	Price Convergence⁵			
% Scheduled DA (Peak Hour)	●	101.6%	101.2%	100.5%	Market-wide DA Premium	●	0.4%	0.7% -1.2%
Transmission Congestion (\$M)					Virtual Trading			
Real-Time Congestion Value	●	\$392.1	46%	-33%	Cleared Quantity (MW/hr)	●	22,835	7% -3%
Day-Ahead Congestion Revenue	●	\$327.9	75%	-11%	% Price Insensitive	●	49%	50% 47%
Balancing Congestion Revenue ³	●	\$8.7	\$11.9	\$20.1	% Screened for Review	●	2%	1% 3%
Ancillary Service Prices (\$/MWh)					Profitability (\$/MW)	●	\$0.4	\$0.2 \$0.9
Regulation	●	\$14.51	14%	29%	Dispatch of Peaking Units (MW/hr)	●	1,684	3,007 1,509
Spinning Reserves	●	\$2.69	-10%	-8%	Output Gap- Low Thresh. (MW/hr)	●	33	32 36
Supplemental Reserves	●	\$0.75	-50%	65%				

Key:

- Expected
- Monitor/Discuss
- Concern

Notes:

1. Values not in italics are the values for the past period rather than the change.
2. Comparisons adjusted for any change in membership.
3. Net real-time congestion collection, unadjusted for M2M settlements.
4. Includes effects of market power mitigation.
5. Values include allocation of RSG.



Quarterly Highlights: Fall 2024

Congestion Patterns during the Quarter (Slides 18-20)

Real-time congestion during the fall quarter fell to almost a third of the congestion levels last year because of a number of factors:

- In 2023, drought conditions in Manitoba led to frequent exports to Manitoba and contributed to substantial congestion in the North region.
 - Conditions improved in 2024 and led to imports over the Manitoba interface of 722 MW per hour, which eased congestion in the North Region this fall.
- In 2023, SPP constraints coordinated with MISO (most notably the Charlie Creek-Watford constraint) were severely congested.
 - SPP implemented a “Remedial Action Scheme” for this constraint that, together with lower imports from Manitoba, reduced this congestion by 95 percent.
- Average hourly wind grew by 6 percent and wind curtailments were up 46 percent, yet wind-related congestion fell by 41 percent from last fall.
 - This is partly due to MISO’s continued reliance on manual dispatch actions and dispatch caps that prevent the market from pricing this congestion.
 - Transmission constraint demand curve adjustments allow the market to manage and price the congestion – MISO made fewer adjustments this fall.



Quarterly Highlights: Fall 2024

Winter Assessment (Slide 40)

- We assessed MISO readiness for the upcoming winter, based on its winter peak demand forecast of 103 GW and its available seasonal capacity.
 - MISO forecasts a margin of 32% including assumed scheduled planned outages and a 5% forced outage rate and 11 GW of emergency-only capacity.
 - When typical planned outage rates and winter peak forced outages are included, this margin drops to 20%, which is sufficient under normal conditions.
- Extreme winter events have become more frequent in recent years, which produce unusually high load and high outage rates.
 - We estimate the increases in load and outages/derates based on MISO's experiences during Winter Storms Uri, Elliott, and Heather.
 - Assuming these effects of extreme winter weather events, the margin falls to just 2 percent.
 - This indicates that even under relatively extreme conditions that MISO will have adequate available resources.



Quarterly Highlights: Fall 2024

Operational Challenges of Renewable Resources (Slide 41)

- Solar capacity continues to grow rapidly – solar output set a new peak on October 16 at 8,030 MW and nearly 4 GWs are expected to enter by this winter.
- The growth in solar resources together with the existing wind resources will result in increasing operational challenges this winter.
 - Load peaks in the morning and evenings during the winter months, generally when solar output is low or falling – substantially increasing the need to ramp non-renewable resources.
 - We show that the evening net load ramp on a high load day in 2022 was 6 GW from 3 pm to 7 pm – high solar output on the same day this winter would produce a net load ramp over the same period of 12 GW.
- MISO experienced two shortages during the fall that caused prices to spike to \$3500 per MWh -- one was primarily caused falling renewable output and the other by large top-of-hour decommitments of resources.
 - Operational improvements to commitment and decommitment processes will be key to avoid such shortages in the future – the upcoming shortage pricing changes will raise such price spikes to \$10,000 per MWh.



Submittals to External Entities

During the Fall Quarter, we:

- Responded to several FERC questions related to prior referrals and FERC investigations, and we responded to requests for information on market issues.
- Made two referrals to FERC enforcement this quarter for:
 - Failure to report forced outages to GADS; and
 - Failure to report known transmission outages in advance of the FTR auction.
- Issued a sanction recommendation to MISO for physical withholding.
- Presented the IMM Summer Quarterly report to the MSC and recent market results to the ERSC.



Other Issues

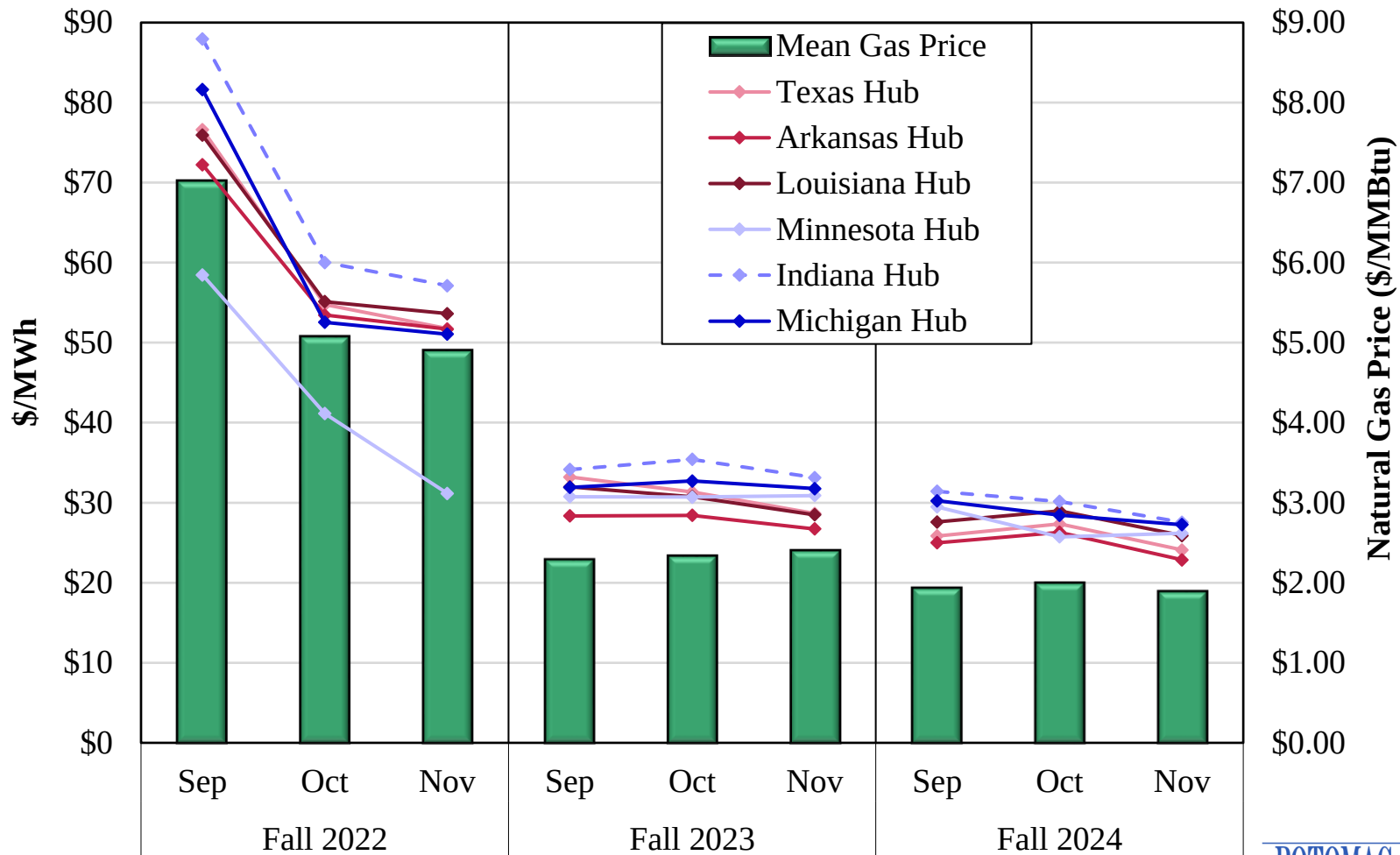
- We worked with MISO on additional recommended operations improvements.
- We developed recommended market design improvements related to demand response participation and LMR accreditation changes, including:
 - Removing Batch Load Demand Response resources in November from its Business Practice Manuals.
 - Eliminating Emergency Demand Response in the near future.
 - Incorporating recommended changes pertaining to registration, testing, and accreditation of demand response resources.
- We continued to investigate potential tariff violations in the market-to-market coordination of congestion between SPP, PJM and MISO.
- We also continued to support upcoming filings to:
 - Reform MISO's shortage pricing to provide more efficient incentives for resources to be available and support the reliability of the system; and
 - Improve provisions governing Demand Response Resources to address market manipulation vulnerabilities.



Quarterly Market Results: Fall 2024

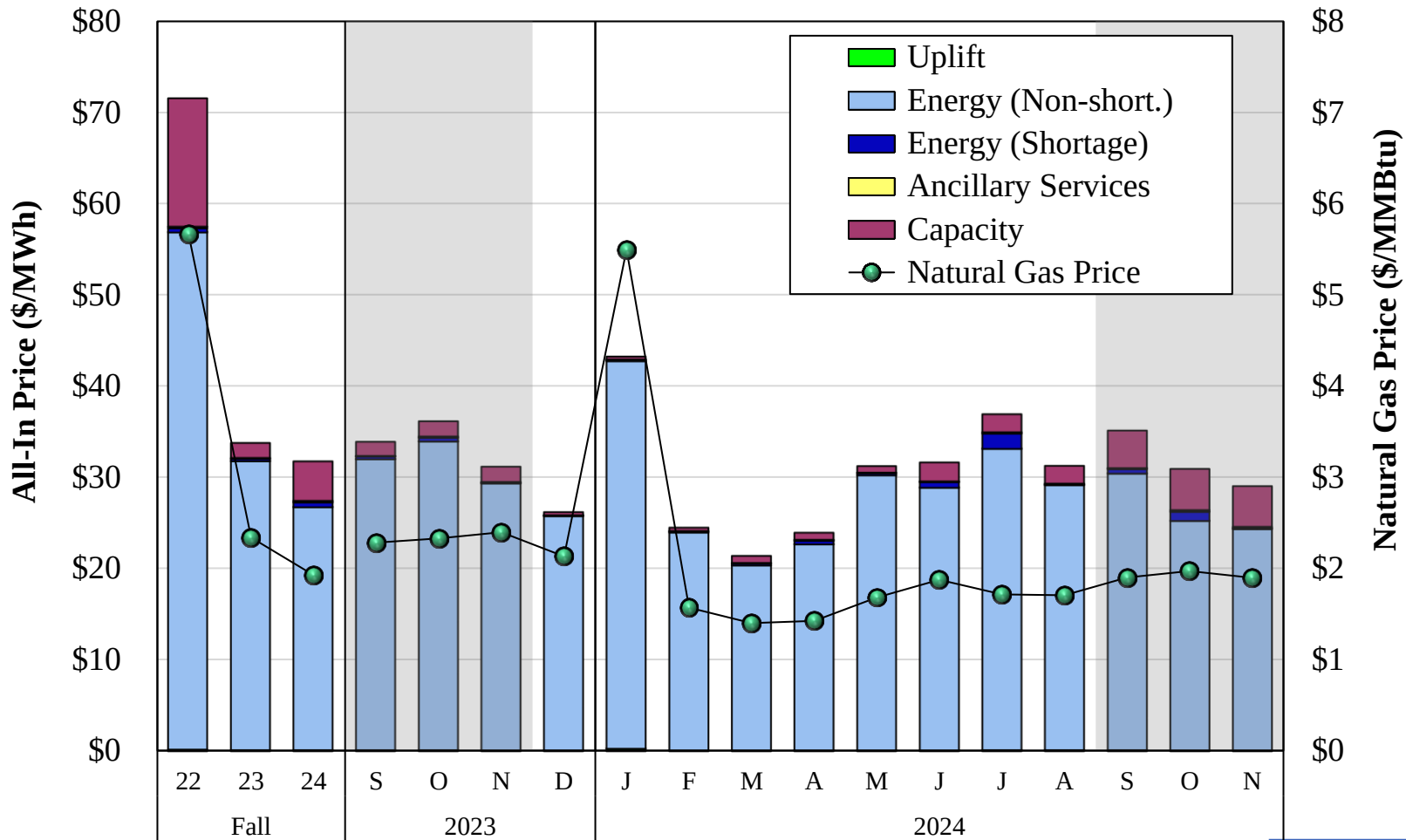


Day-Ahead Average Monthly Hub Prices Fall 2022–2024



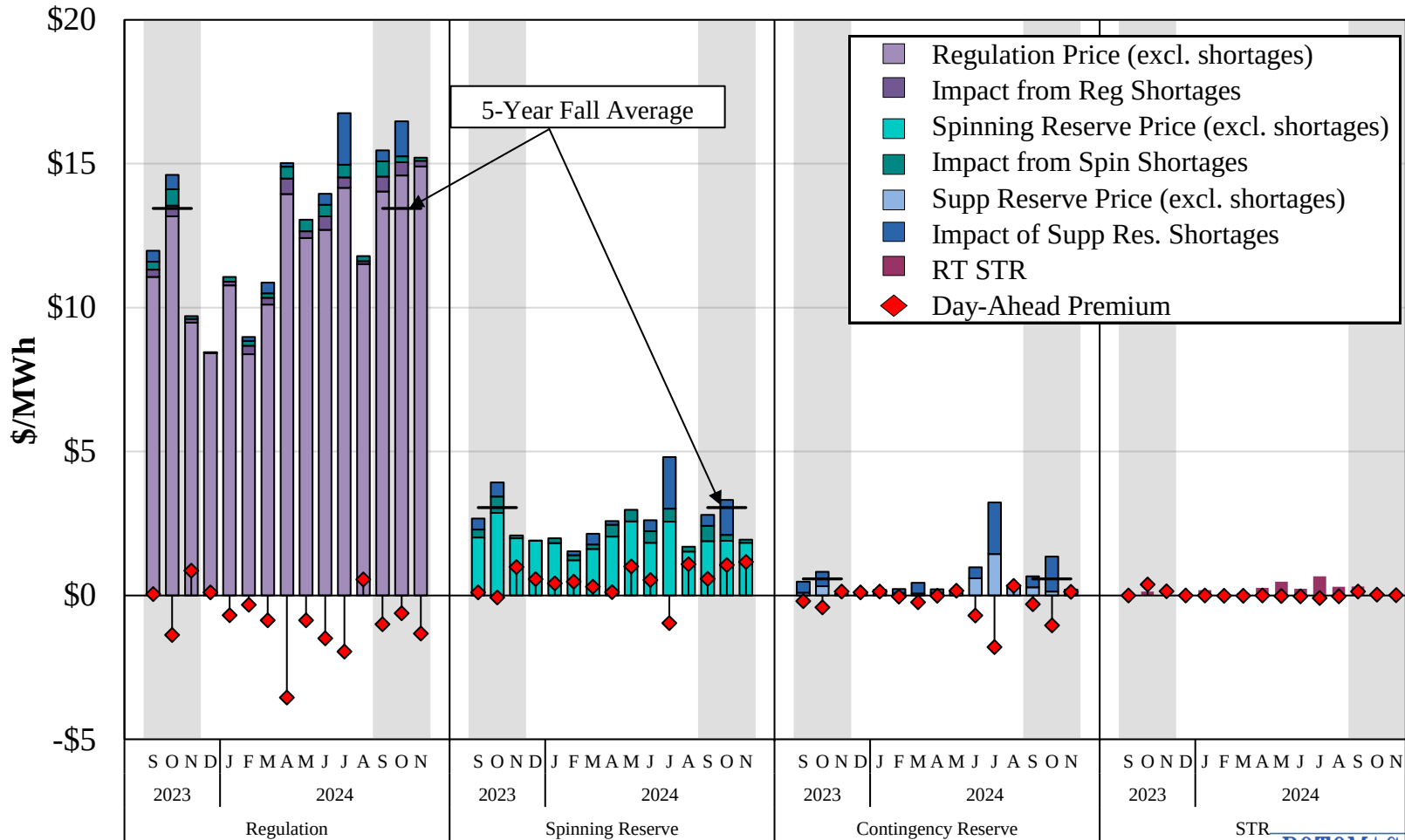


All-In Price Fall 2022 – 2024





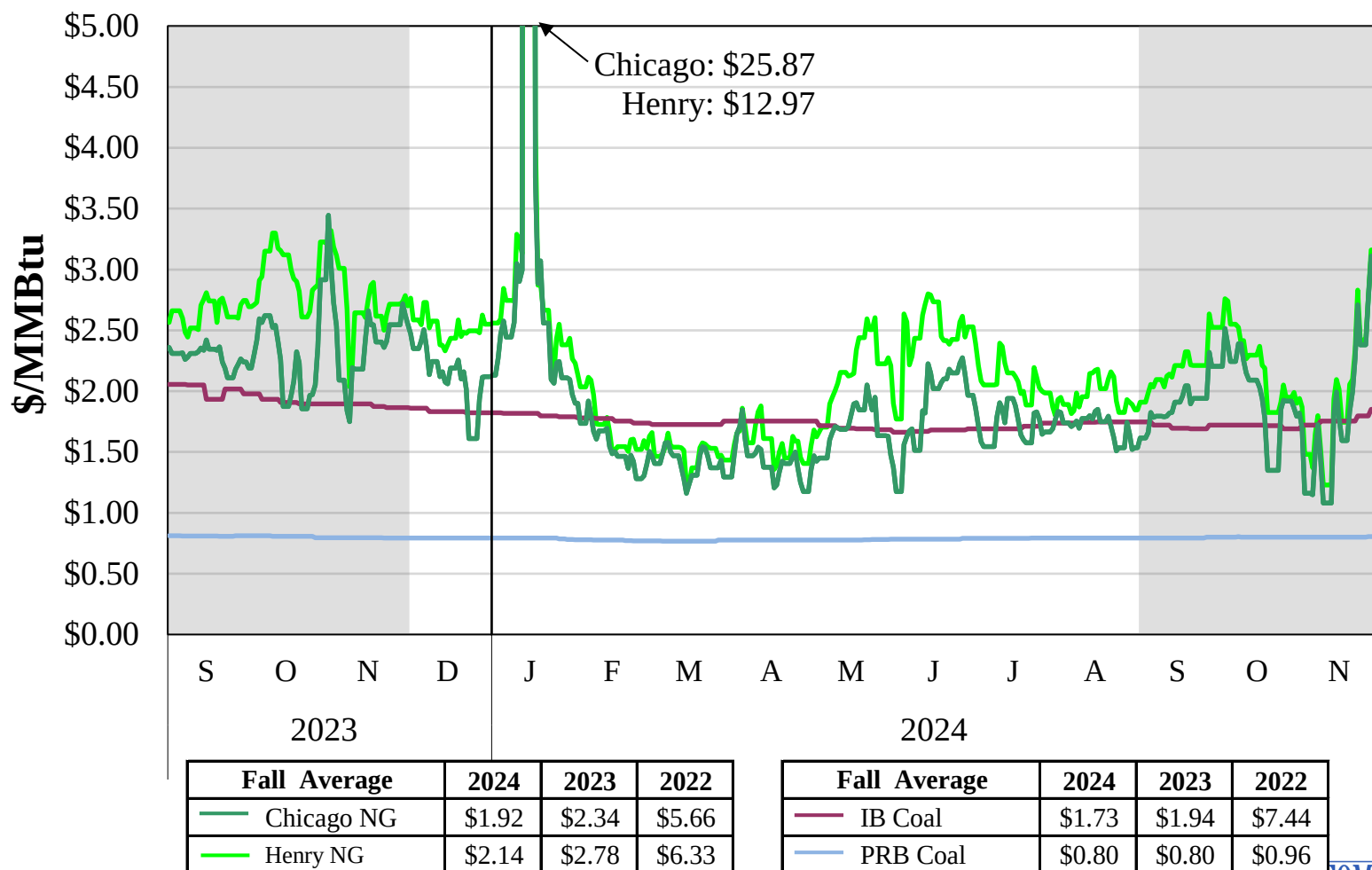
Ancillary Services Prices Fall 2023–2024





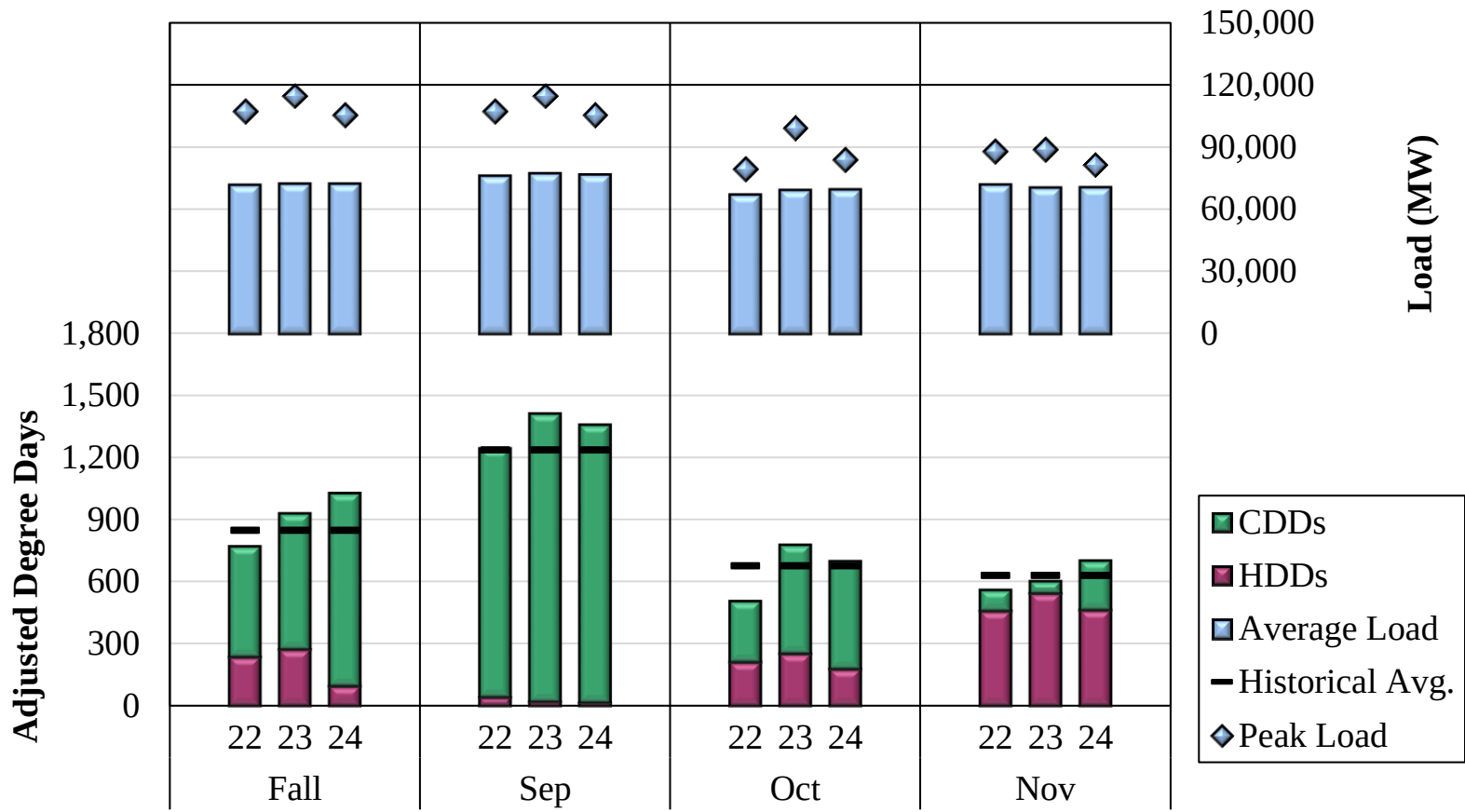
MISO Fuel Prices

2023–2024





Load and Weather Patterns Fall 2022–2024



Notes: Midwest degree day calculations include four representative cities: Indianapolis, Detroit, Milwaukee and Minneapolis. The South region includes Little Rock and New Orleans.

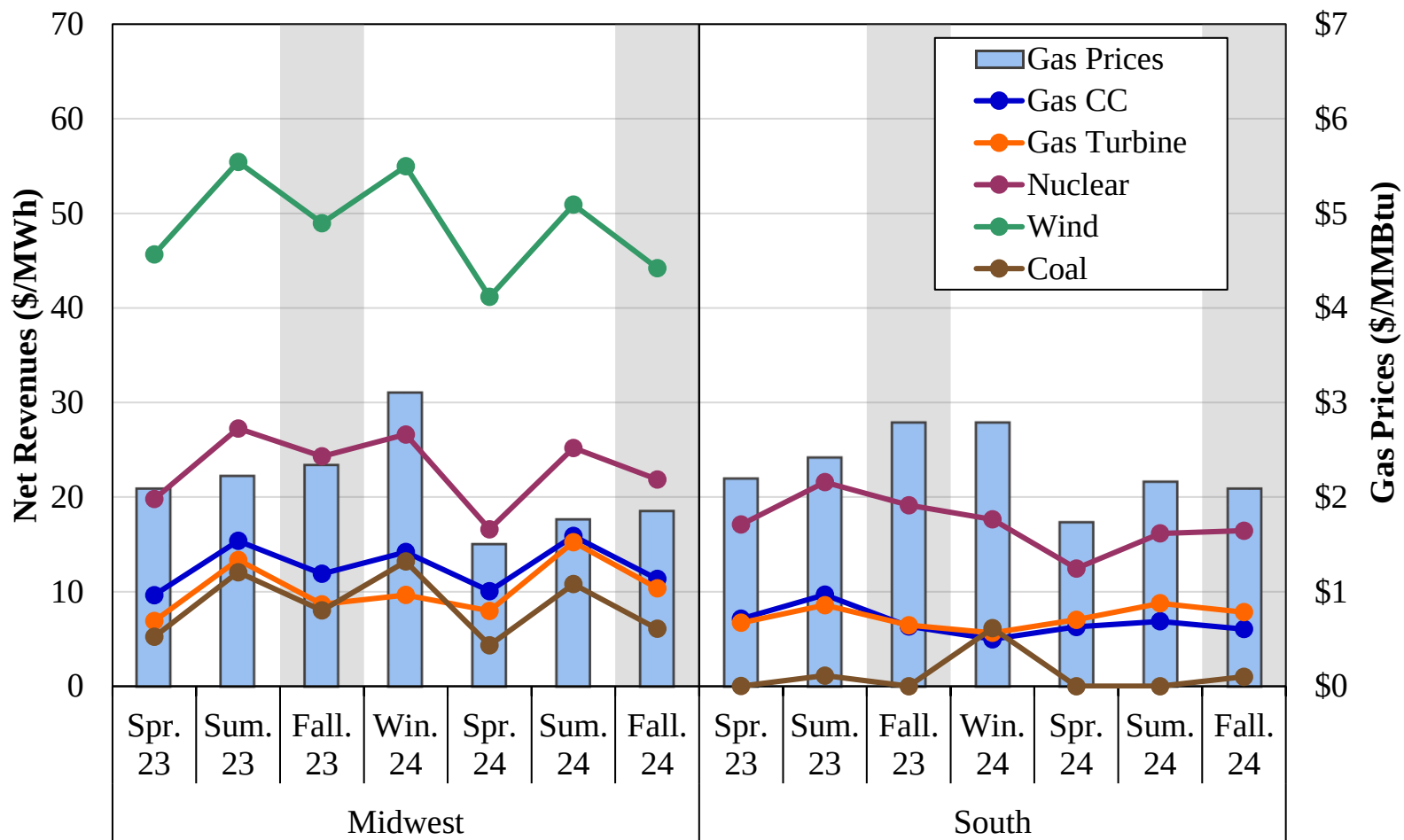
Capacity, Energy and Price Setting Share

Fall 2023–2024

Fall	Accredited Capacity				Energy Output		Price Setting			
	Total (MW)		Share (%)		Share (%)		SMP (%)		LMP (%)	
	2023	2024	2023	2024	2023	2024	2023	2024	2023	2024
Nuclear	10,869	11,797	8%	9%	13%	15%	0%	0%	0%	0%
Coal	38,182	34,546	30%	27%	29%	26%	37%	39%	79%	78%
Natural Gas	62,040	61,150	48%	48%	38%	38%	62%	58%	93%	89%
Oil	1,506	1,618	1%	1%	0%	0%	0%	0%	1%	0%
Hydro	4,184	3,700	3%	3%	1%	1%	0%	1%	1%	2%
Wind	4,867	4,877	4%	4%	16%	17%	0%	1%	61%	72%
Solar	3,679	7,389	3%	6%	1%	3%	0%	0%	7%	6%
Other	2,666	2,612	2%	2%	1%	1%	0%	0%	1%	1%
Total	127,993	127,688								

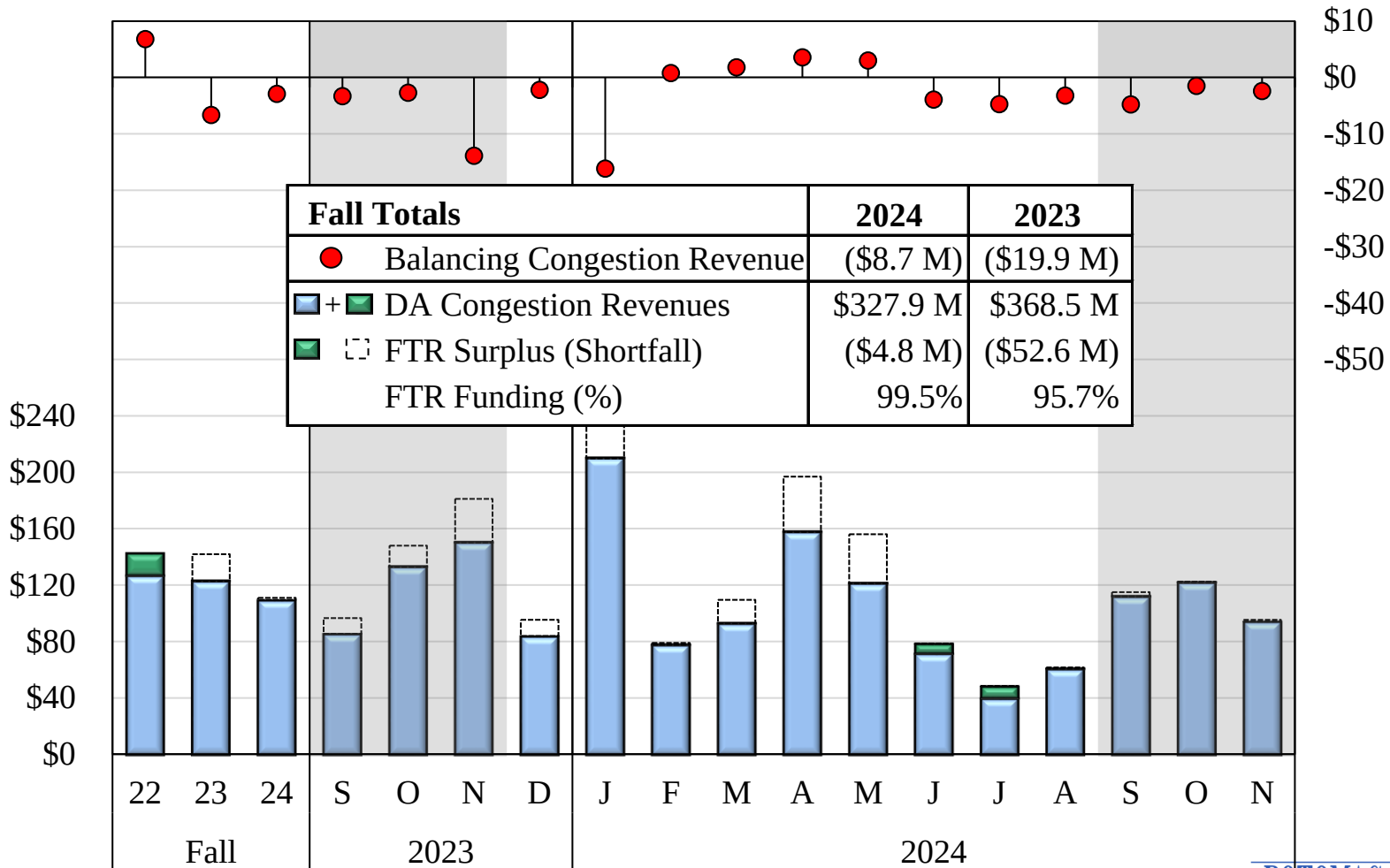


Net Revenues by Technology 2023-2024



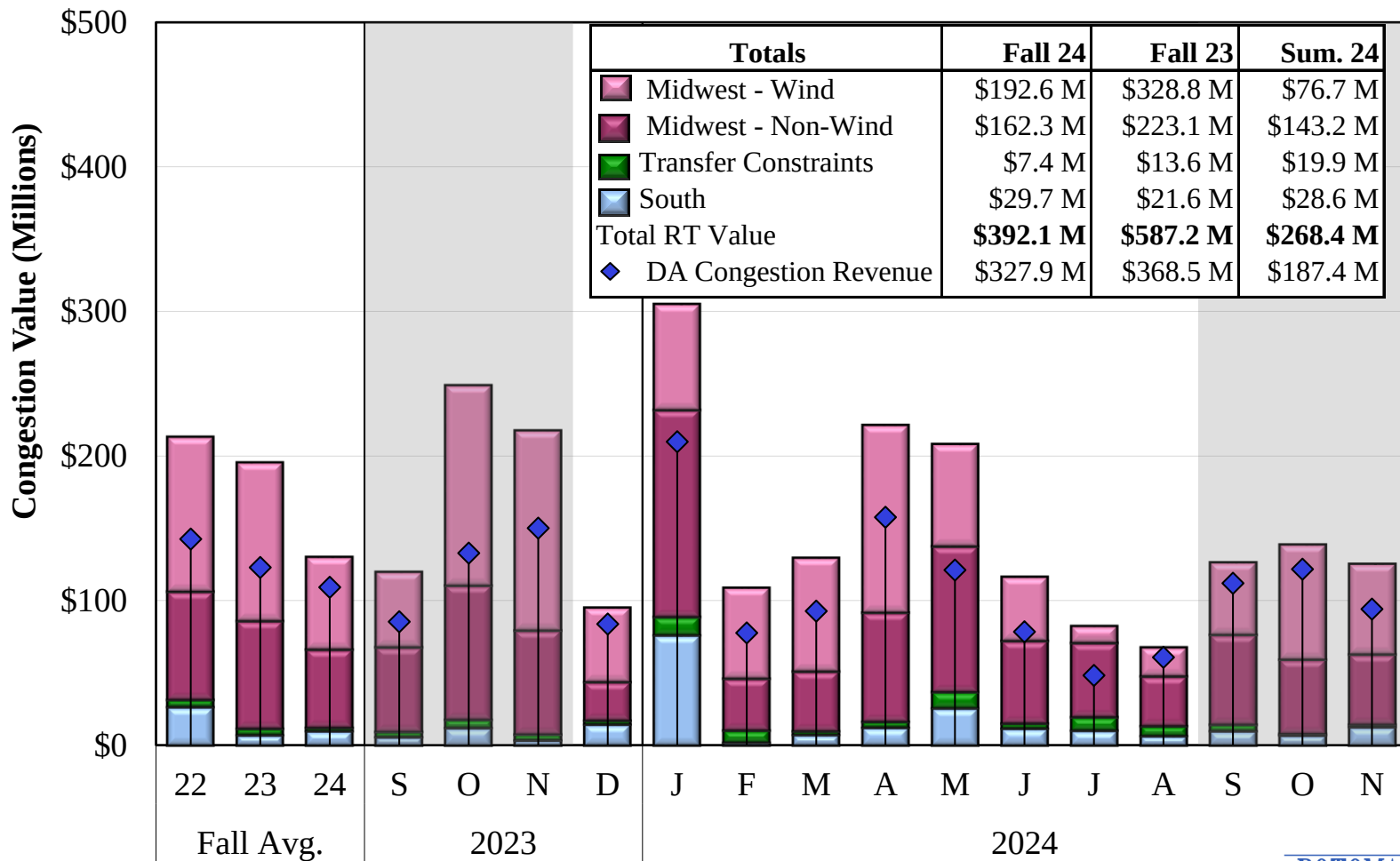


Day-Ahead Congestion, Balancing Congestion, and FTR Underfunding





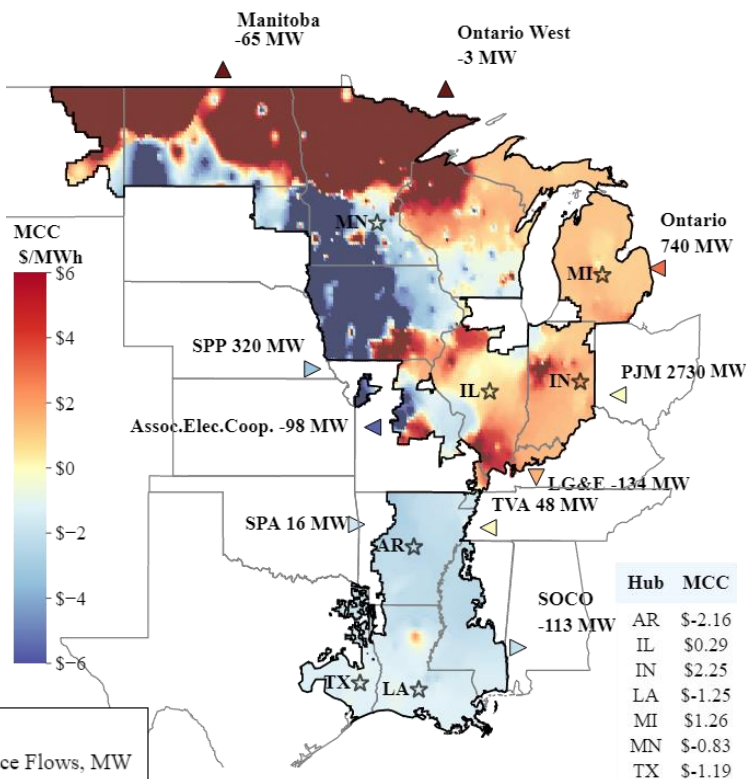
Value of Real-Time congestion Fall 2022-2024



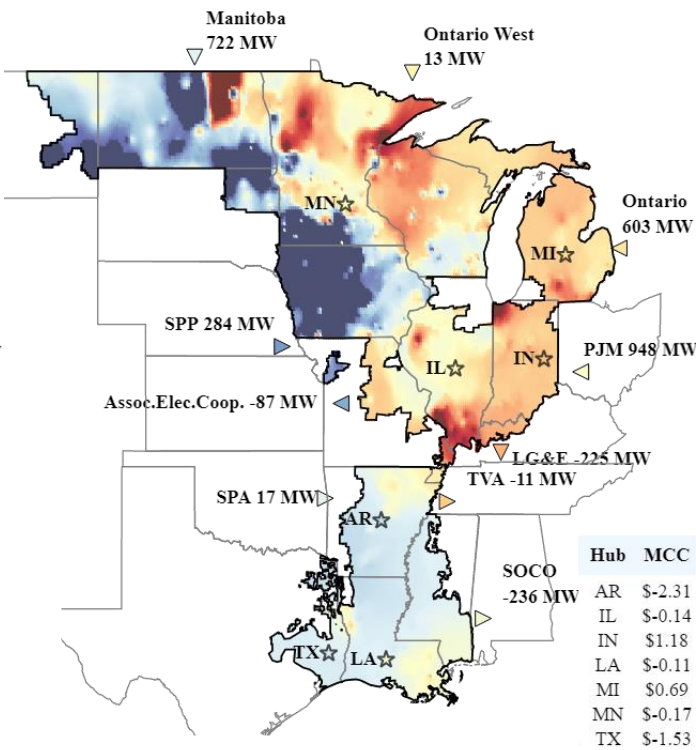


Average Real-Time Congestion Components Fall 2023 – 2024

Fall 2023



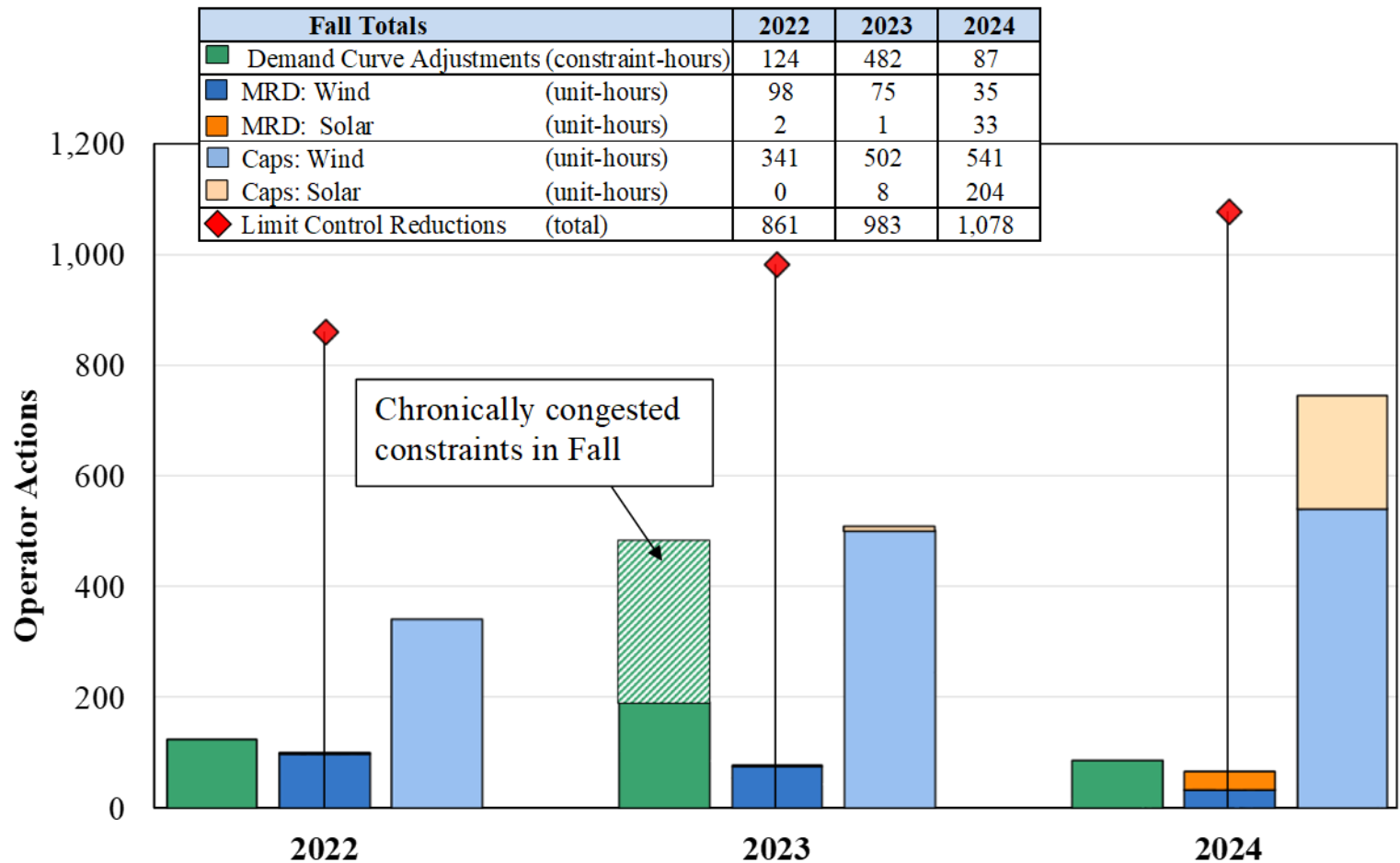
Fall 2024



Legend
Avg Interface Flows, MW
◀ Imports/Exports
★ Hubs



MISO Operator Actions for Congestion Management



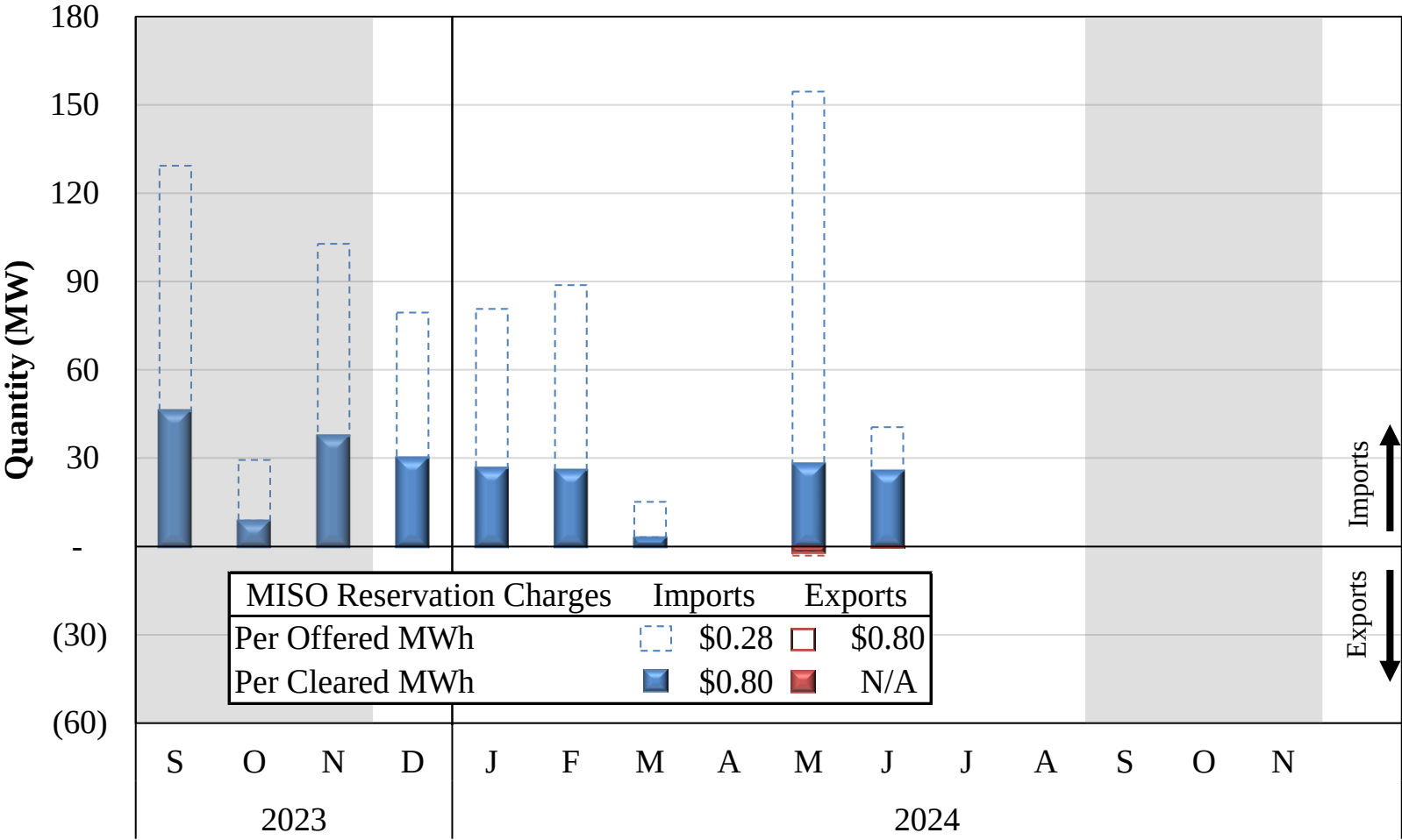


Benefits of Ambient-Adjusted and Emergency Ratings Fall 2023–2024

Fall		Savings (\$ Millions)			# of Facilities for 2/3 of Savings	Share of Congestion
		Ambient Adj. Ratings	Emergency Ratings	Total		
2023	Midwest	\$63.0	\$31.19	\$94.1	11	18.4%
	South	\$0.2	\$0.64	\$0.9	2	6.0%
	Total	\$63.2	\$31.8	\$95.0	13	18.0%
2024	Midwest	\$27.3	\$25.04	\$52.3	18	12.4%
	South	\$0.6	\$0.87	\$1.5	3	4.9%
	Total	\$27.9	\$25.9	\$53.8	21	11.9%

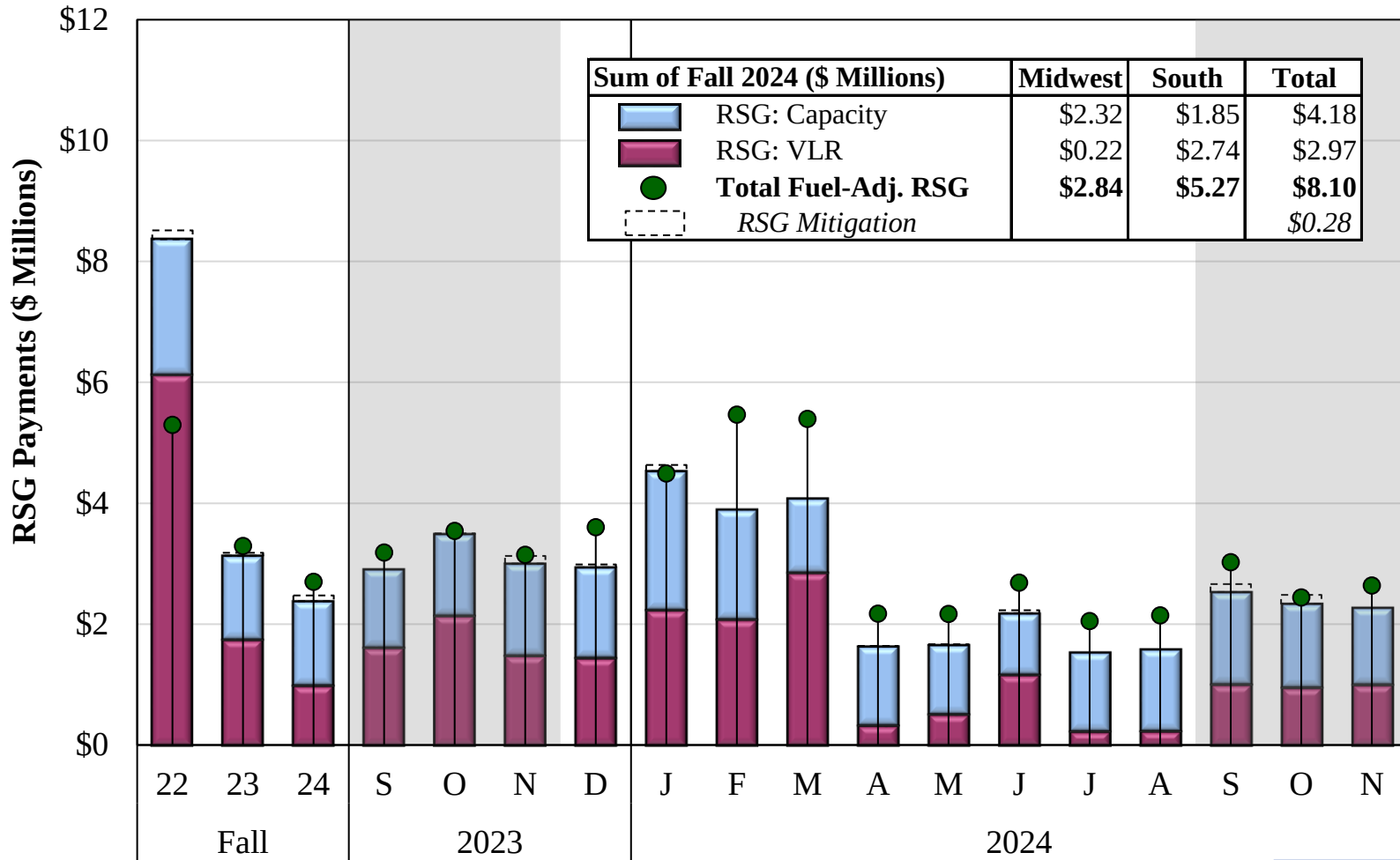


Coordinated Transaction Scheduling (CTS) Fall 2023–2024



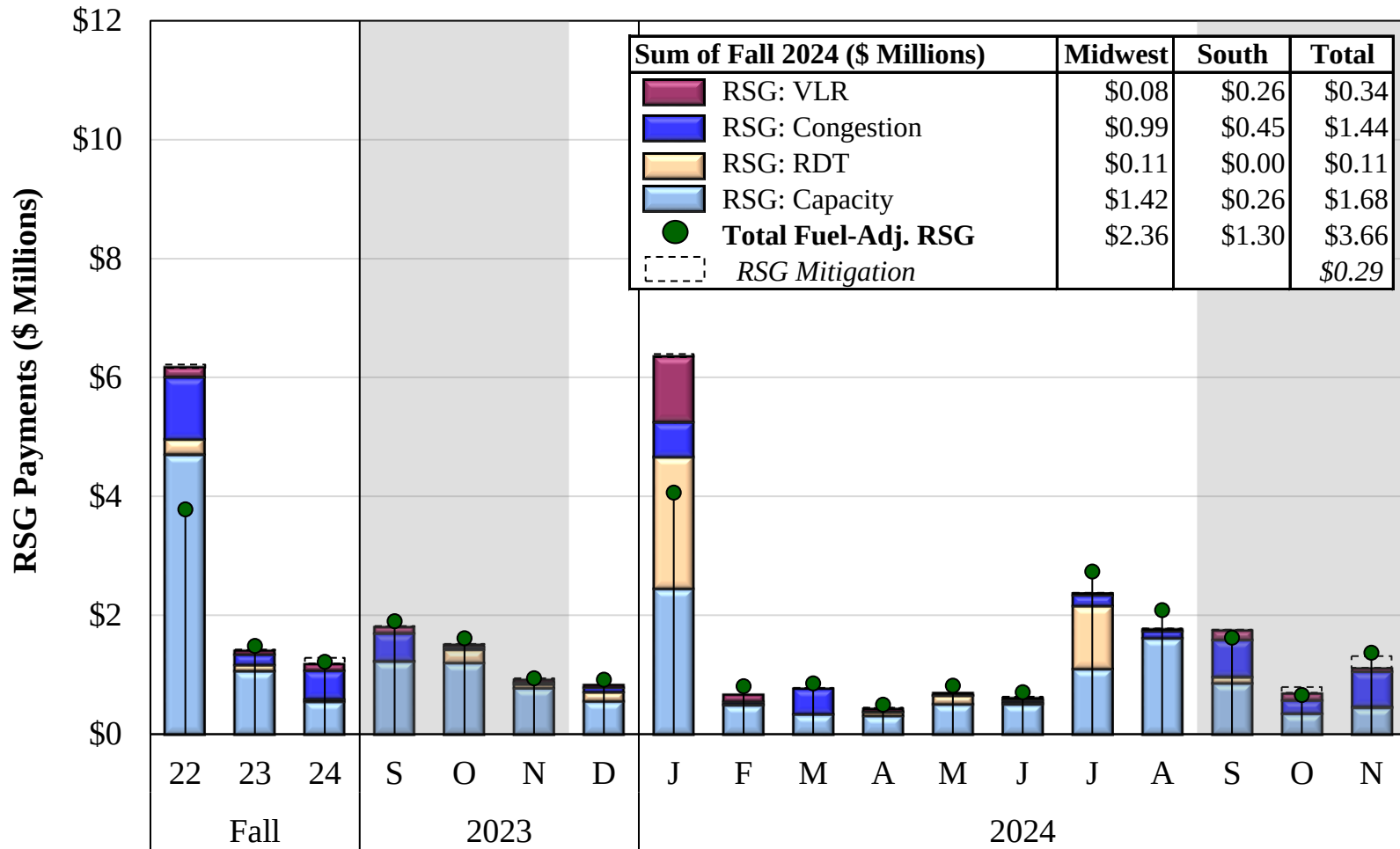


Day-Ahead RSG Payments Fall 2023–2024



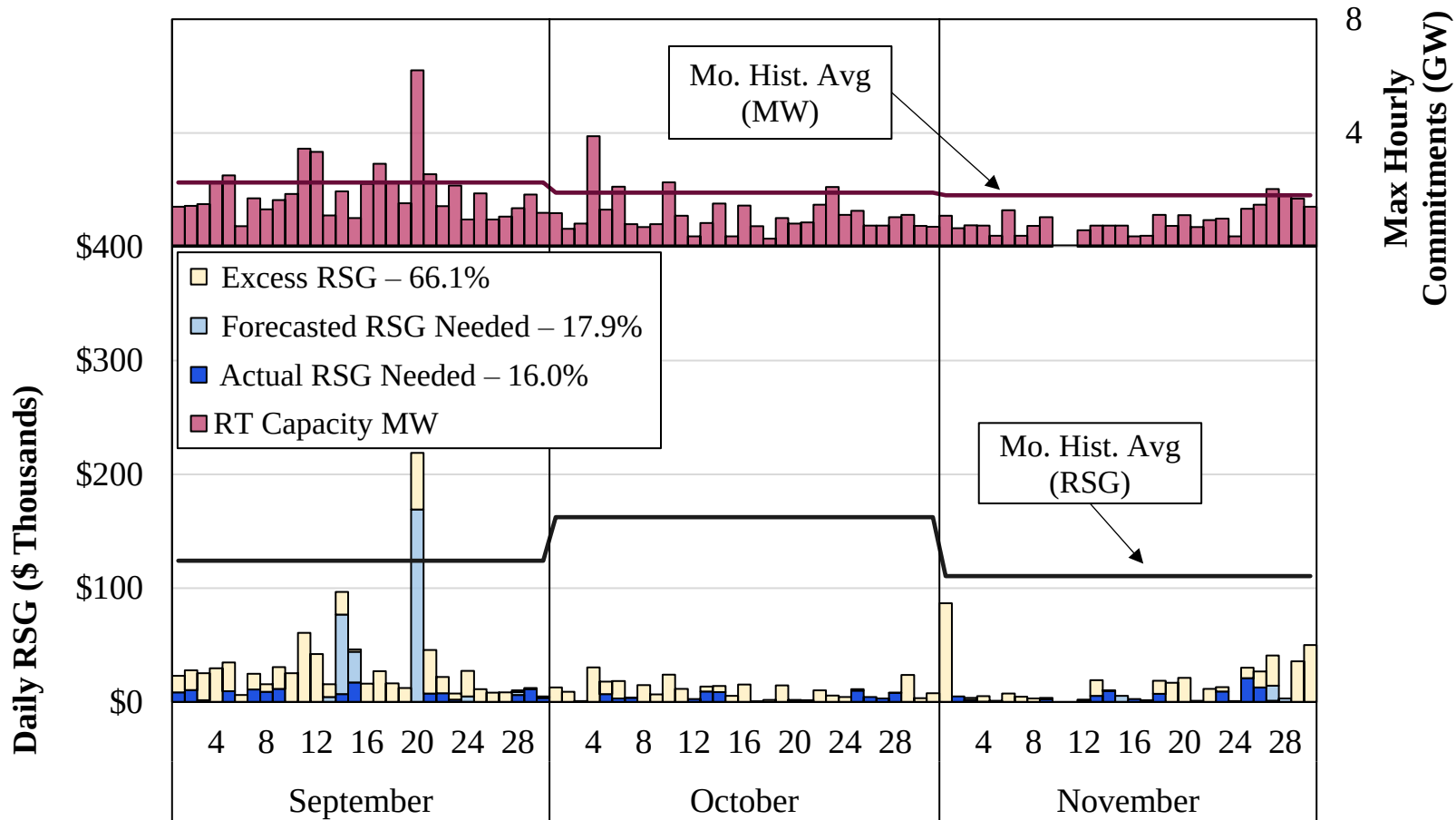


Real-Time RSG Payments Fall 2023–2024



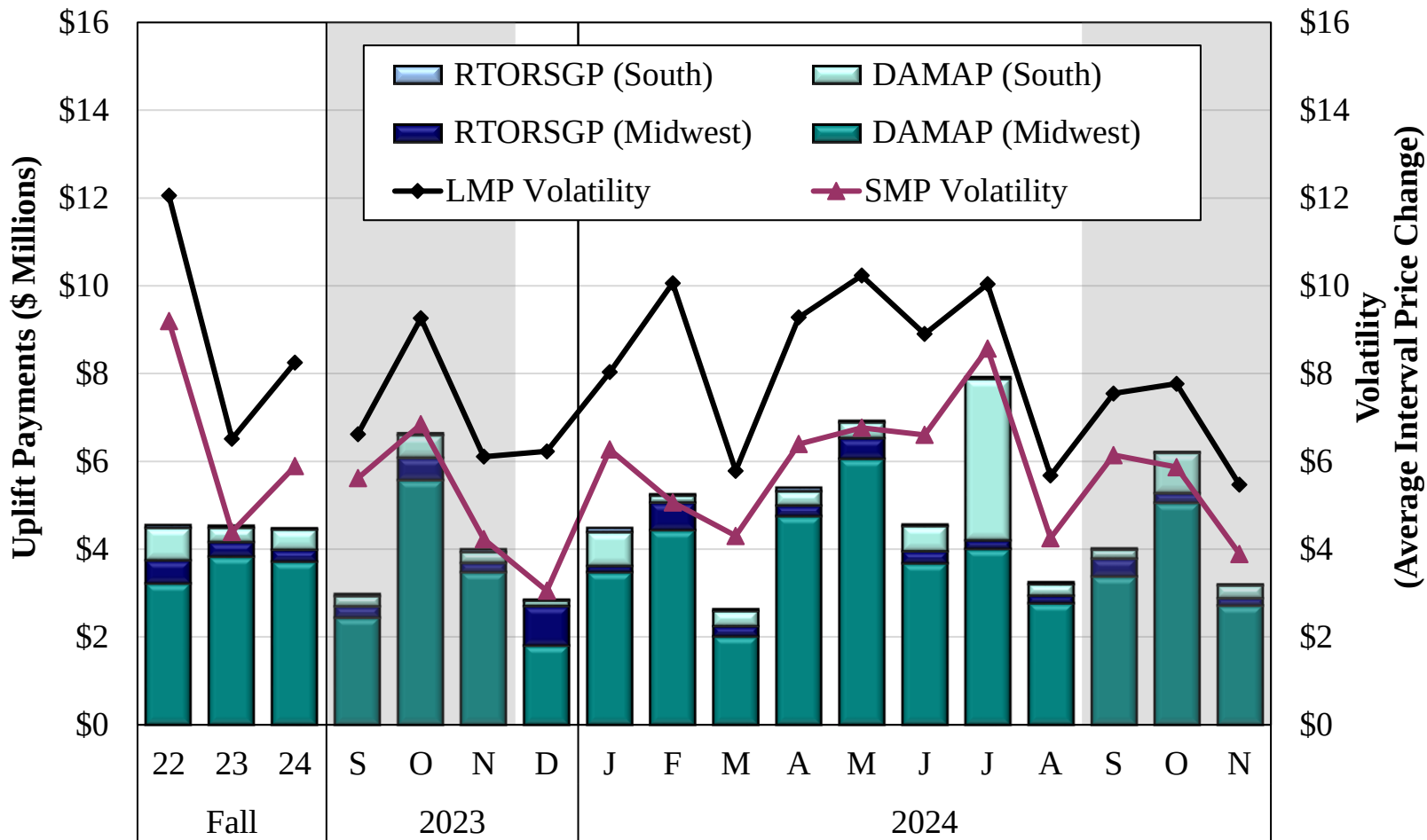


Real-Time Capacity Commitment and RSG Fall 2024





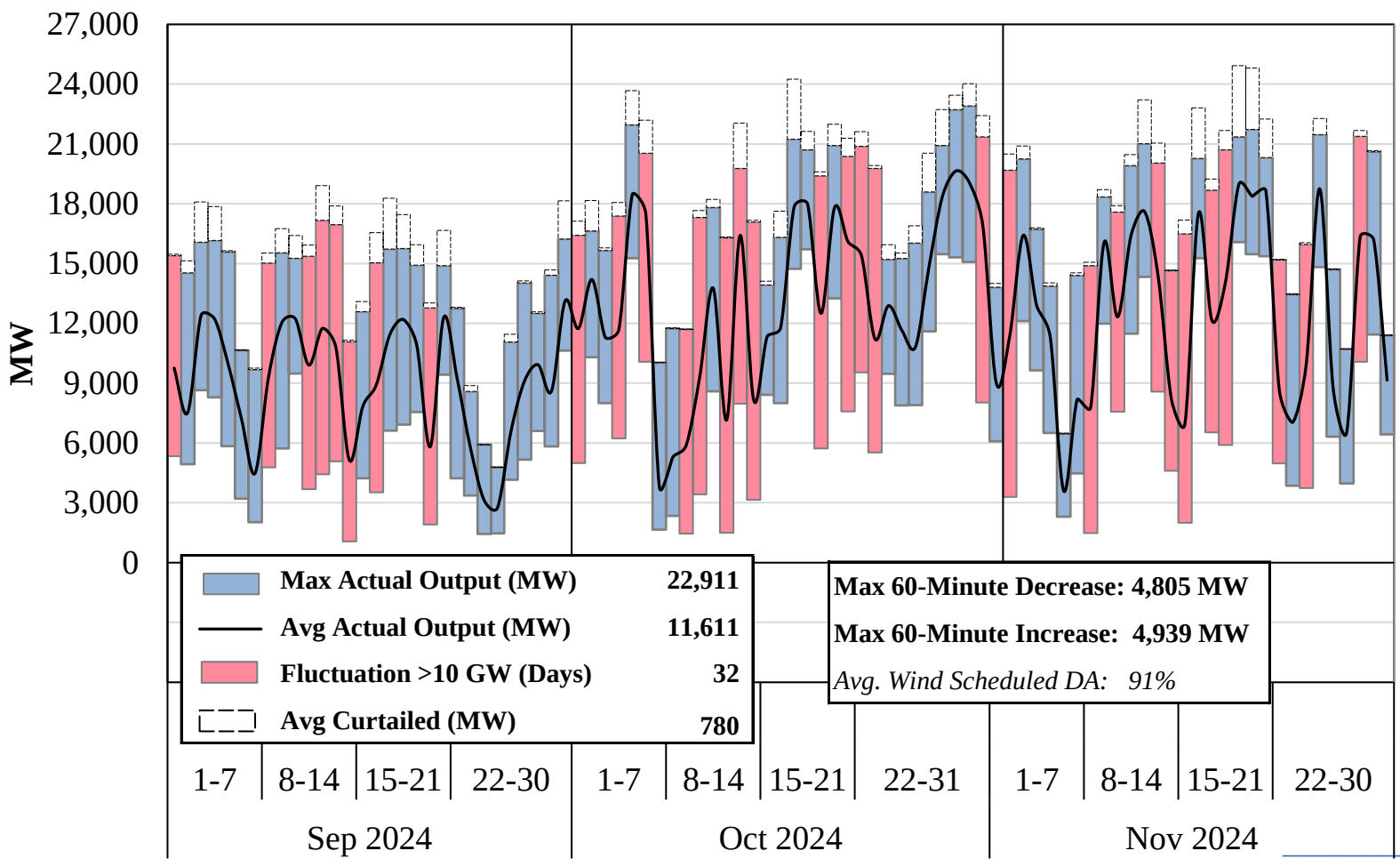
Price Volatility Make Whole Payments Fall 2022–2024





Wind Output in Real Time

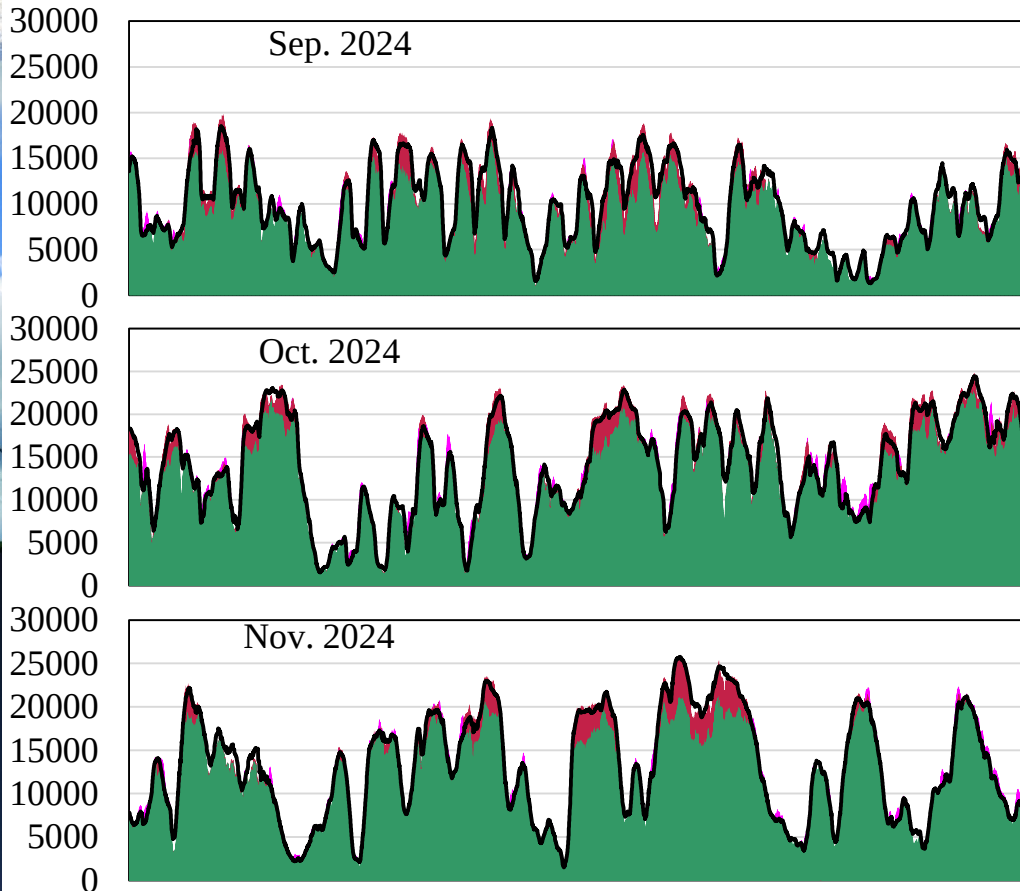
Daily Range and Average





Wind Forecast and Actual Output Fall 2024

■ Wind ■ Curtailed ■ Above Forecast — 2-3 Hour Out Wind Forecast



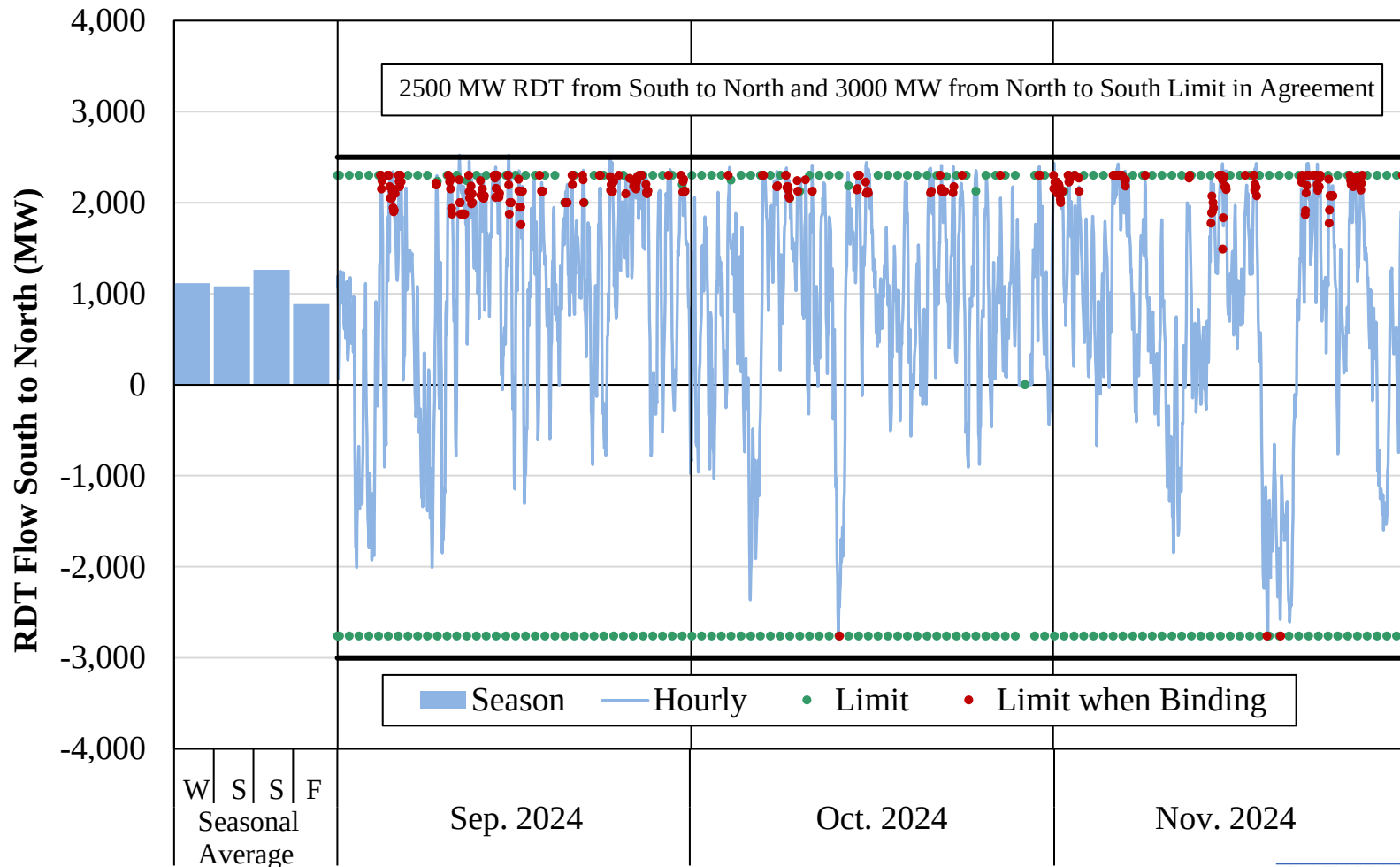
Fall 2024	
Real-Time Wind (MW)	11,611
Day-Ahead Wind (MW)	10,548
Avg Curtailments (MW)	780
Forecast Errors (%)	0.3%
Absolute Errors (%)	7.6%

Fall 2023	
Real-Time Wind (MW)	10,949
Day-Ahead Wind (MW)	9,872
Avg Curtailments (MW)	548
Forecast Errors (%)	-0.3%
Absolute Errors (%)	8.3%

Summer 2024	
Real-Time Wind (MW)	7,710
Day-Ahead Wind (MW)	7,218
Avg Curtailments (MW)	265
Forecast Errors (%)	1.8%
Absolute Errors (%)	16.5%

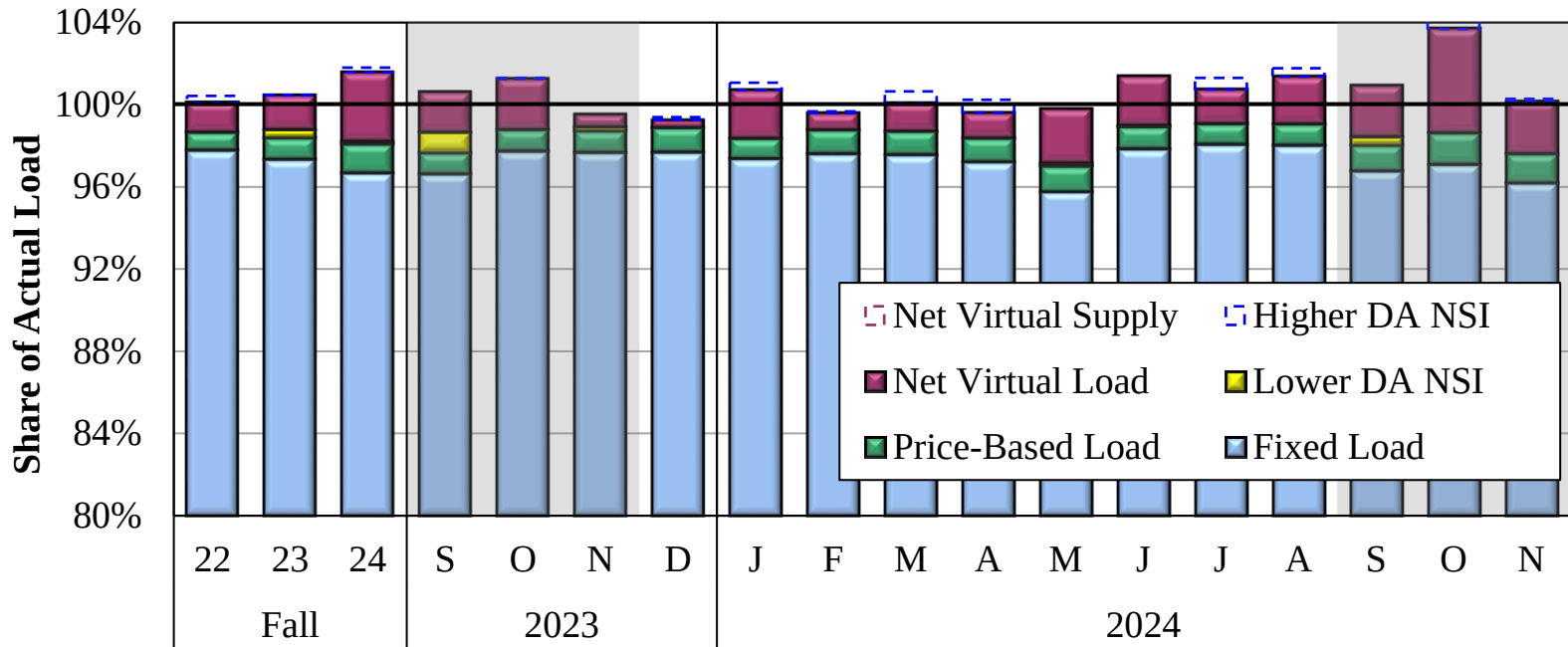


Real-Time Hourly Inter-Regional Flows Fall 2024





Day-Ahead Peak Hour Load Scheduling Fall 2022–2024



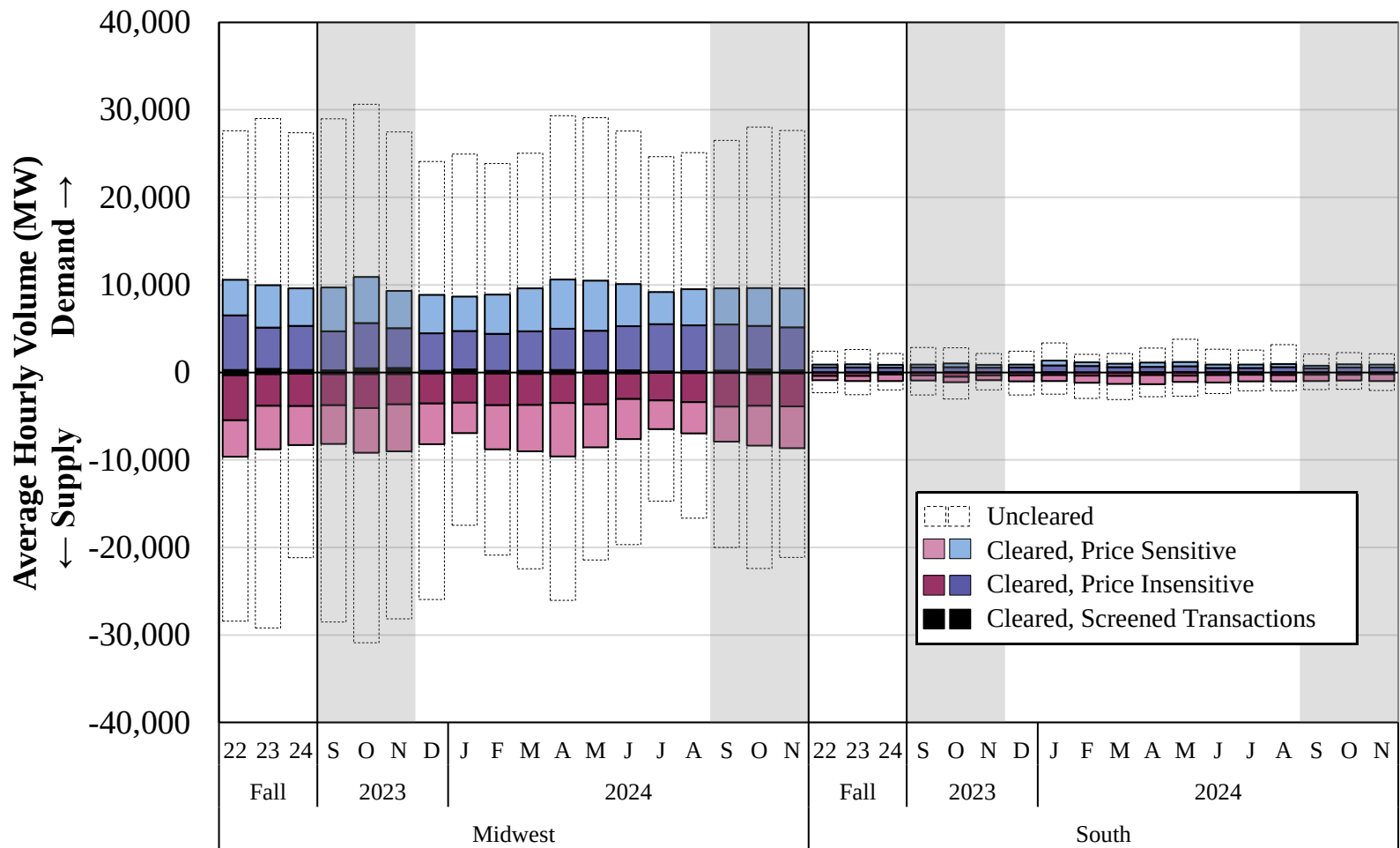
Share of Actual Load (%)

All Hours	99.4	100.0	100.1	100.6	100.3	99.1	98.6	100.5	99.2	99.1	99.3	101.0	101.4	102.0	101.9	100.7	100.4	99.2
Peak Hours Midwest	100.5	100.6	102.4	100.3	101.7	99.7	99.5	100.8	99.9	100.9	99.4	100.3	102.6	101.3	101.9	101.7	105.1	100.5
Peak Hours South	100.0	101.1	101.3	100.7	102.1	100.7	101.3	101.5	99.4	100.8	99.1	100.8	100.7	99.9	100.6	100.2	103.1	100.5



Virtual Load and Supply

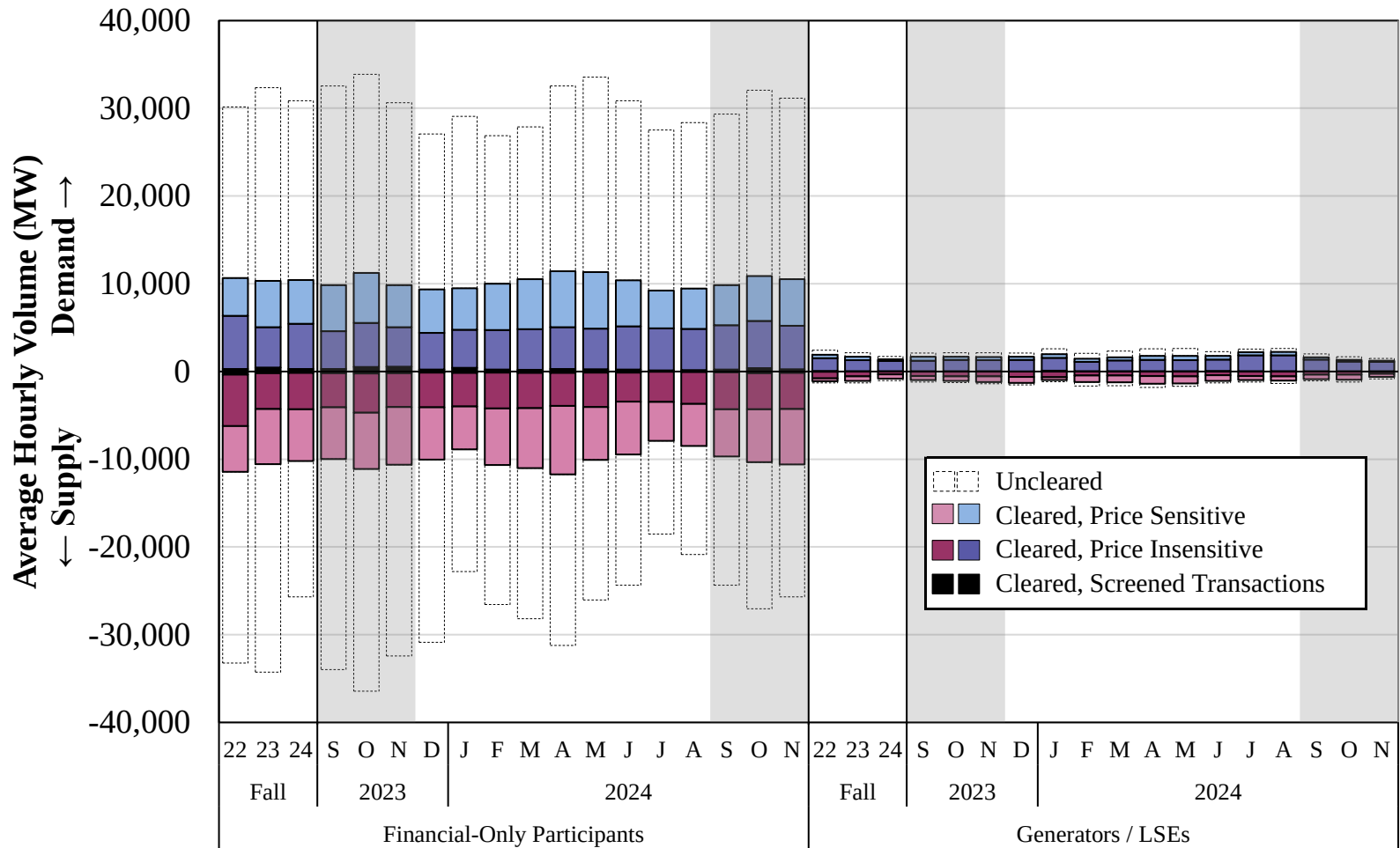
Fall 2022–2024





Virtual Load and Supply by Participant Type

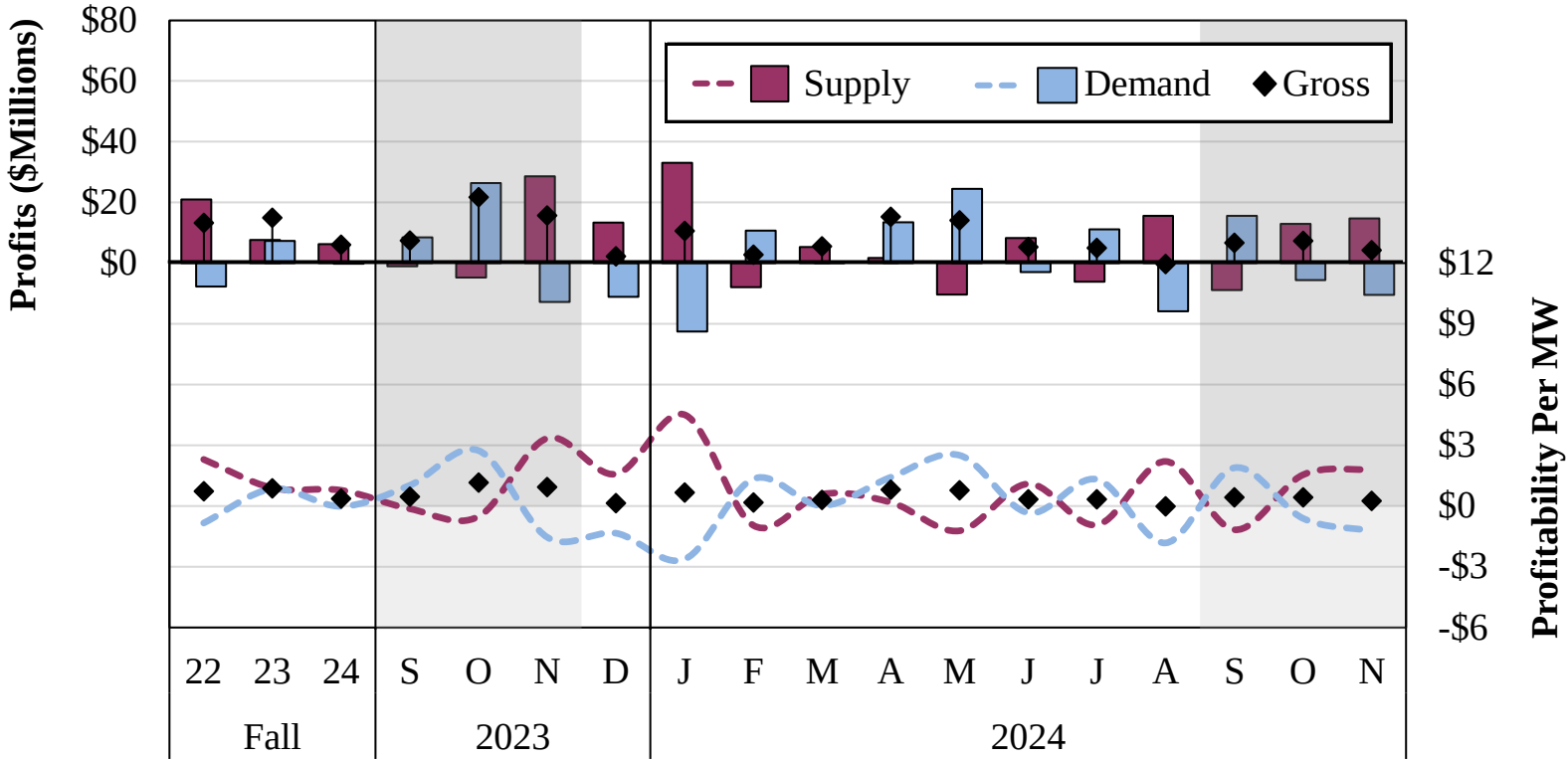
Fall 2022–2024





Virtual Profitability

Fall 2022–2024

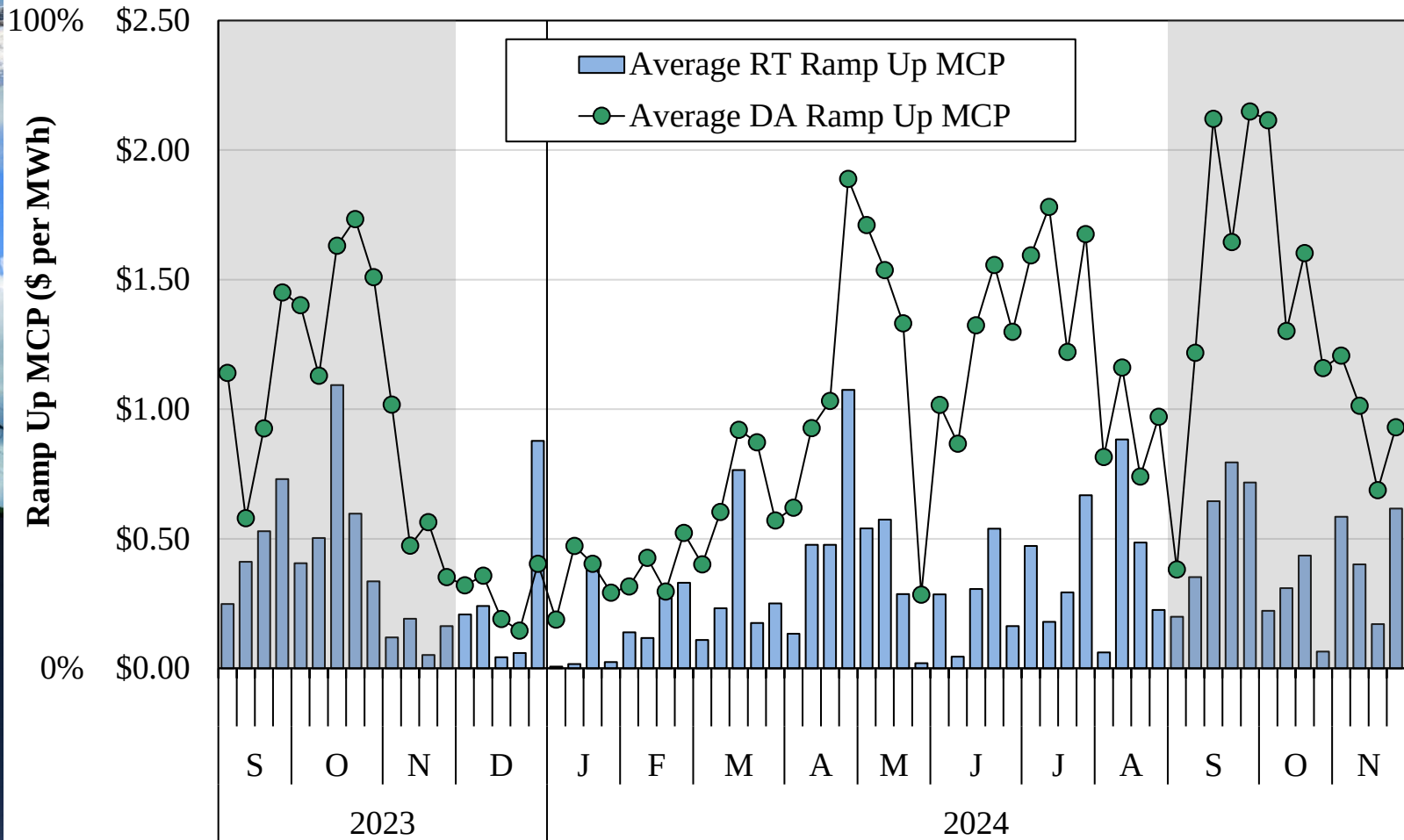


Percent Screened

Supply	3.1	1.9	1.4	2.0	1.9	1.9	1.3	1.7	1.2	1.6	1.3	1.5	1.5	0.7	0.8	0.9	1.9	1.5
Demand	2.5	3.9	2.5	2.6	4.2	4.9	2.0	4.3	2.1	1.6	2.3	2.0	2.2	1.2	1.5	1.9	3.3	2.4
Total	2.8	2.9	2.0	2.3	3.1	3.4	1.7	3.1	1.6	1.6	1.8	1.8	1.9	1.0	1.2	1.4	2.6	2.0



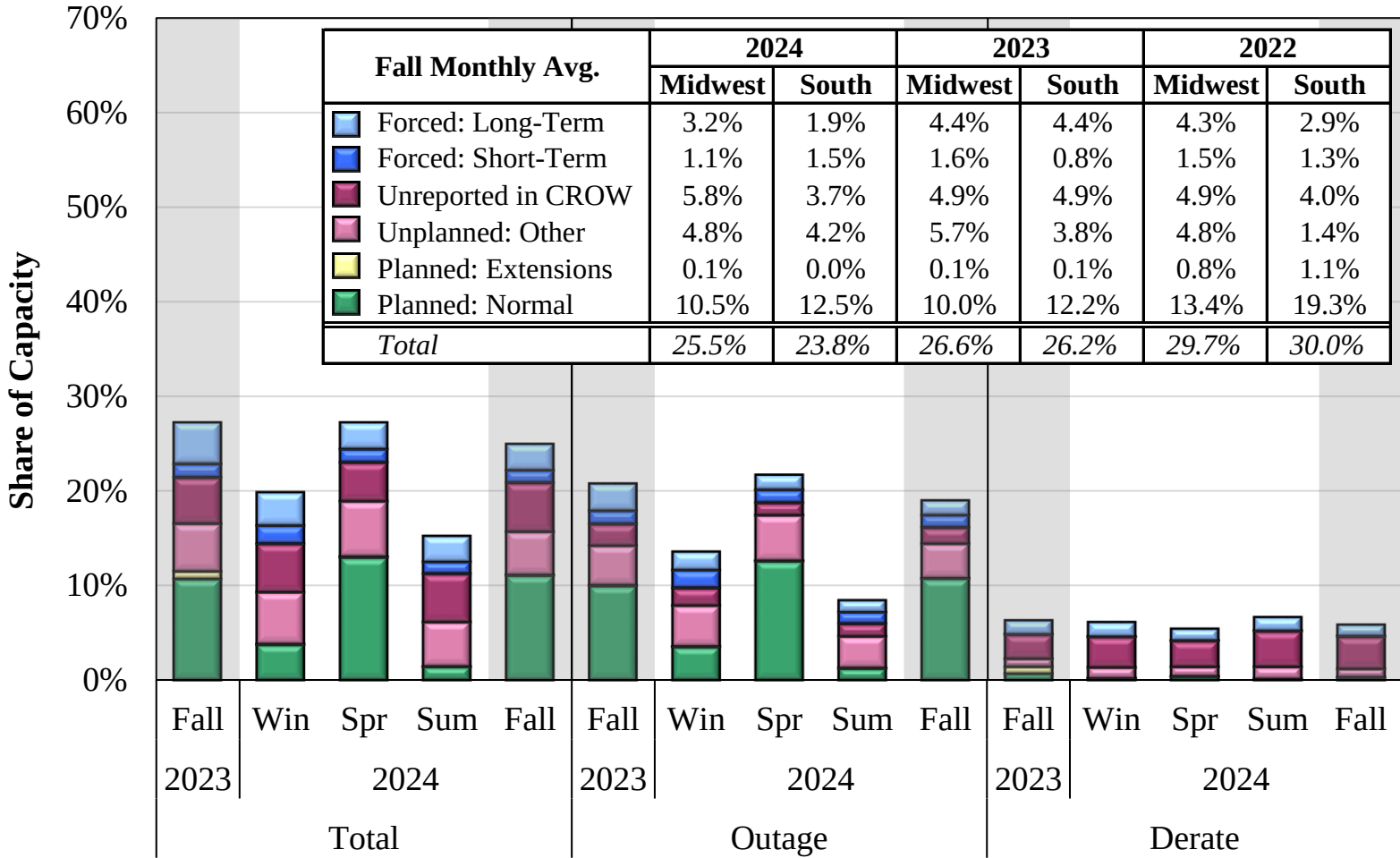
Day-Ahead and Real-Time Ramp Up Price Fall 2022–2024





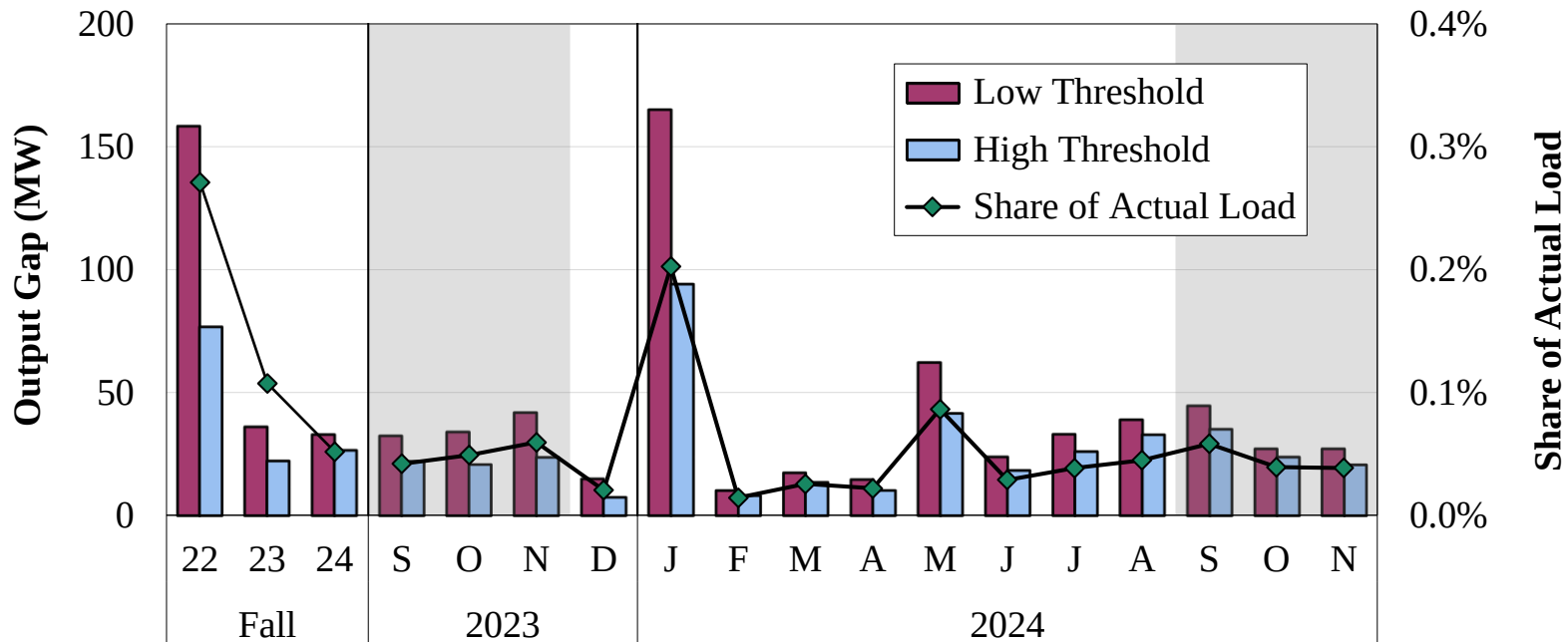
Generation Outages and Deratings

Fall 2022–2024





Monthly Output Gap Fall 2022–2024



Low Threshold Results by Unit Status (MW)

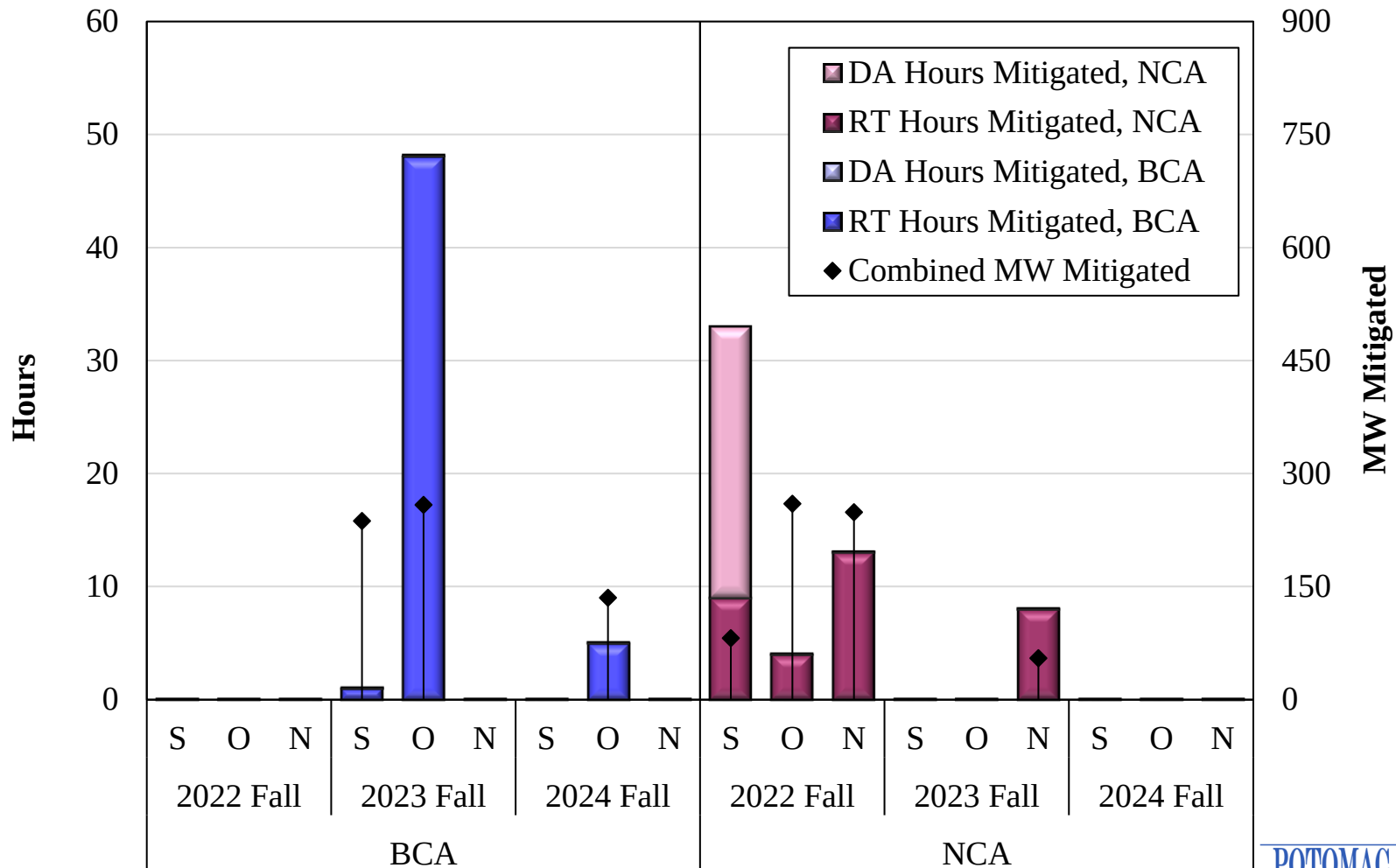
Offline	110	23	27	25	17	27	4	98	3	8	6	56	18	25	31	37	22	23
Online	48	13	6	7	17	15	11	66	7	10	9	6	6	8	7	8	6	4

High Threshold Results by Unit Status (MW)

Offline	66	19	23	19	16	21	4	84	3	6	4	38	14	22	29	31	20	18
Online	10	4	4	3	5	3	3	9	6	7	6	4	5	4	4	4	4	3

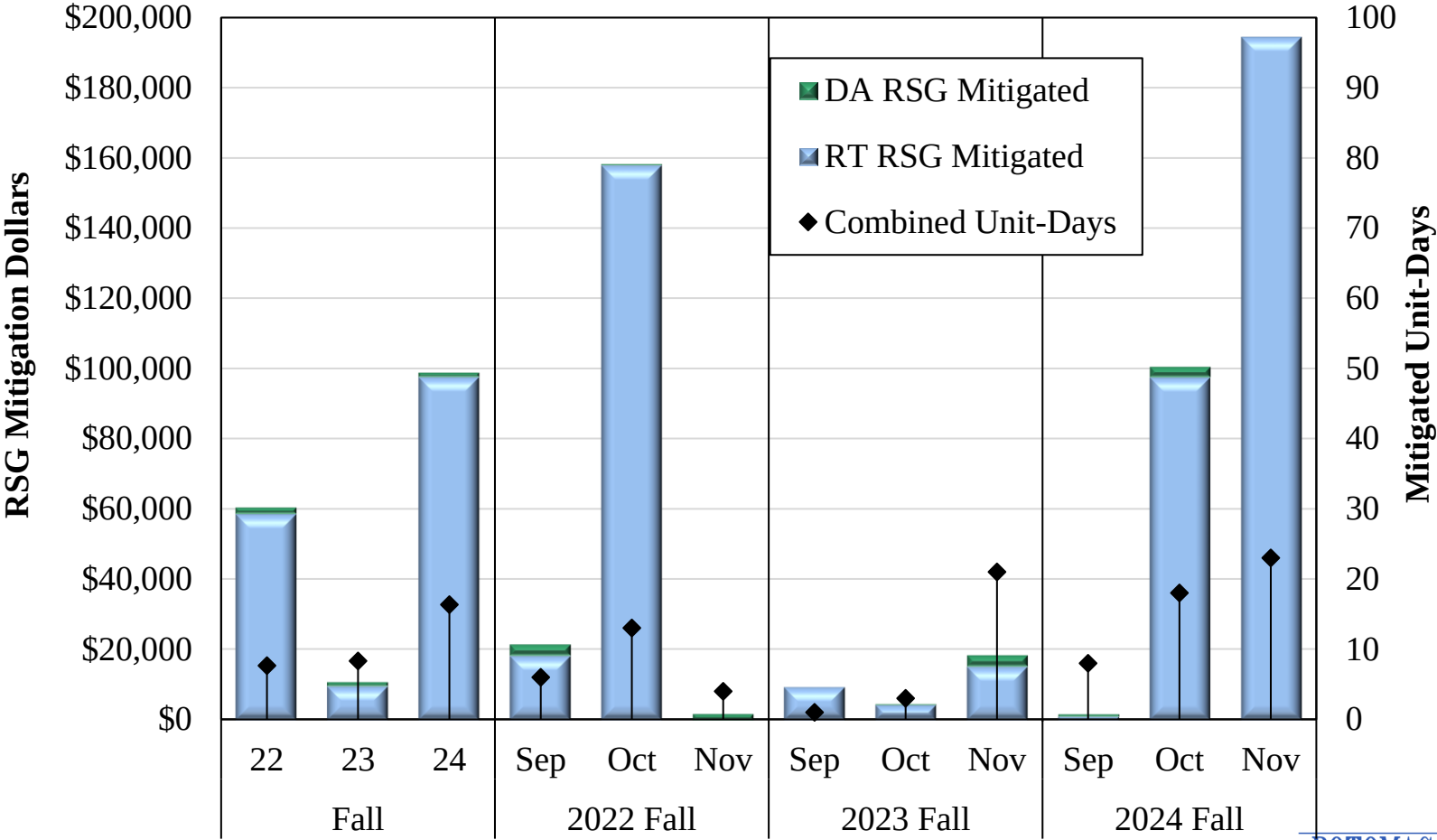


Day-Ahead And Real-Time Energy Mitigation Fall 2022 - 2024





Day-Ahead and Real-Time RSG Mitigation Fall 2022 - 2024





Other Key Market Issues

2024–2025 Winter Assessment

	Base Scenario	Alternative IMM Scenarios*		
		Realistic Scenario	Extreme Event	
			High Load	High Load, High Outage
Load				
Base Case	103,122	103,122	103,122	103,122
High Load Increase	-	-	3,849	3,849
Total Load (MW)	103,092	103,092	106,970	106,970
Generation				
Internal Generation Excluding Exports	142,102	142,102	142,102	142,102
BTM Generation	3,406	2,453	2,453	1,839
Unforced Outages and Derates**	(12,243)	(17,114)	(13,114)	(13,114)
Adjustment due to Transfer Limit	-	-	(874)	-
Total Generation (MW)	133,265	127,441	130,568	130,828
Imports and Demand Response***				
Demand Response (ICAP)	6,823	3,591	3,591	3,591
Firm Capacity Imports	3,314	3,314	3,314	3,314
Margin (MW)	40,310	31,255	30,503	30,763
Margin (%)	39.1%	30.3%	28.5%	28.8%
Expected Capacity Uses and Additions				
Expected Forced Outages****	(7,105)	(13,006)	(13,006)	(28,306)
Non-Firm Net Imports in Emergencies	-	2,400	-	-
Expected Margin (MW)	33,205	20,649	17,497	2,458
Expected Margin (%)	32.2%	20.0%	16.4%	2.3%

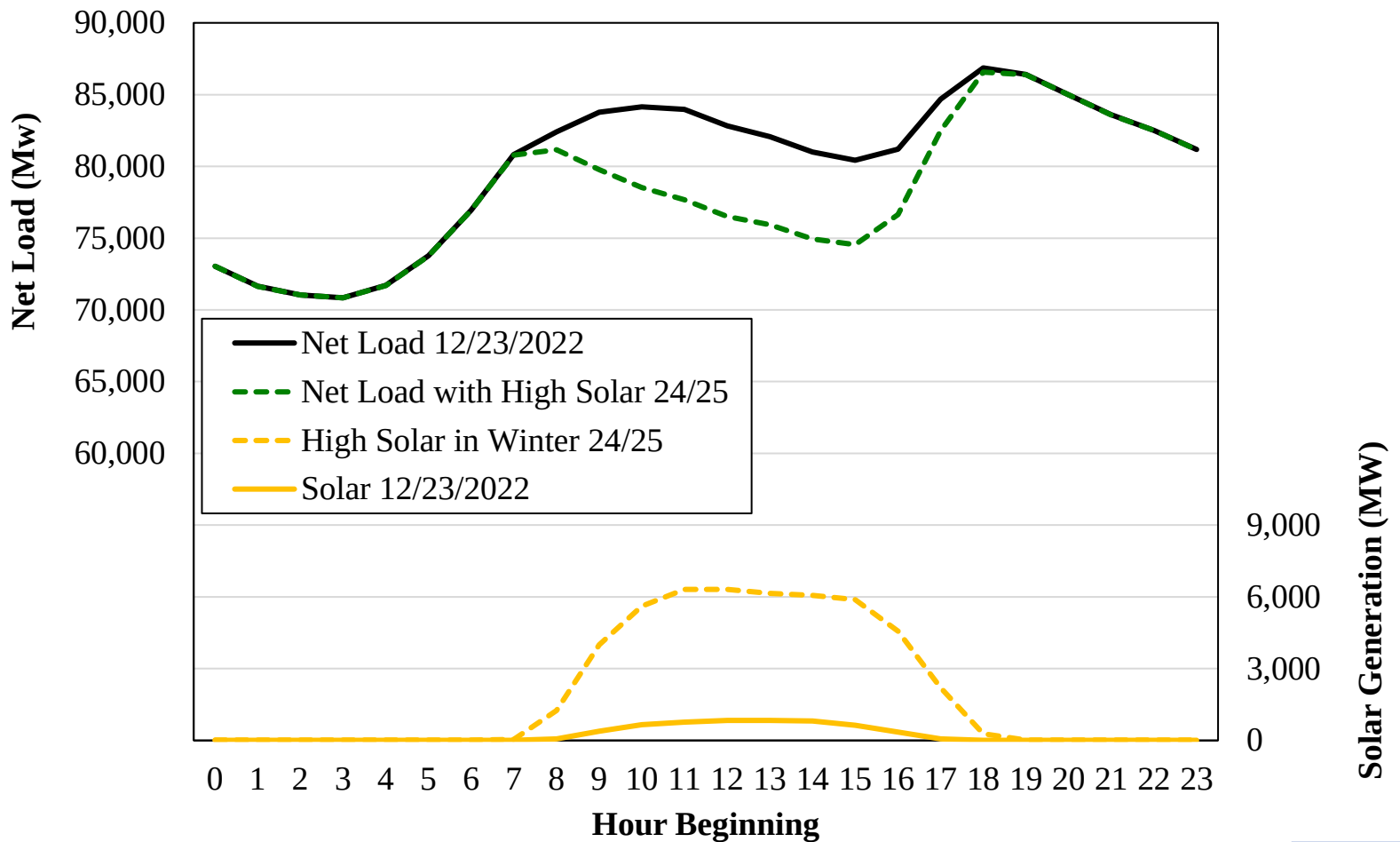
* Assumes 75% response from short-lead DR and 33% response from longer-lead DR.

** Base scenario shows approved planned outages for winter 2024. Realistic cases use historical average unforced outages/derates during peak winter hours. Low temp. cases are based upon MISO's 2024-25 Winter Assessment.

*** Cleared amounts for the Winter Season of the 2024/2025 planning year.

**** Base scenario assumes 5% forced outage rate for internal generation. Alternative cases use historical average forced outages/derates during peak winter hours.

Winter Challenges from Rapidly Growing Solar Capacity





List of Acronyms

• AAR	Ambient-Adjusted Ratings	• ORDC	Operating Reserve Demand Curve
• AMP	Automated Mitigation Procedures	• PITT	Pseudo-Tie Issues Task Team
• BCA	Broad Constrained Area	• PRA	Planning Resource Auction
• CDD	Cooling Degree Days	• PVMWP	Price Volatility Make Whole Payment
• CMC	Constraint Management Charge	• RAC	Resource Adequacy Construct
• CTS	Coordinated Transaction Scheduling	• RDT	Regional Directional Transfer
• DAMAP	Day-Ahead Margin Assurance Payment	• RSG	Revenue Sufficiency Guarantee
• DDC	Day-Ahead Deviation & Headroom Charge	• RTORSGP	Real-Time Offer Revenue Sufficiency Guarantee Payment
• DIR	Dispatchable Intermittent Resource	• SMP	System Marginal Price
• HDD	Heating Degree Days	• SOM	State of the Market
• ELMP	Extended Locational Marginal Price	• STE	Short-Term Emergency
• JCM	Joint and Common Market Initiative	• STR	Short-Term Reserves
• JOA	Joint Operating Agreement	• TLR	Transmission Loading Relief
• LAC	Look-Ahead Commitment	• TCDC	Transmission Constraint Demand Curve
• LSE	Load-Serving Entities		
• M2M	Market-to-Market	• UD	Uninstructed Deviation
• MSC	MISO Market Subcommittee	• VLR	Voltage and Local Reliability
• NCA	Narrow Constrained Area	• WUMS	Wisconsin Upper Michigan System