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ENERGY RESEARCH

Battery energy storage impact and benefits assessments in MISO

Commissioned by American Clean Power

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This independent report analyzes the benefits of energy storage buildout on regional grid reliability and electricity costs in MISO

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- Batteries play a multifaceted role within wholesale power markets, including contributions to reliability, system flexibility, ancillary services and a synergistic relationship with both renewable and thermal generation resources.
- This report illustrates the role that batteries play within the Midcontinent Independent System Operator (MISO) region and examines their impact on MISO power markets.
- The analysis in this report is based on Aurora's modeling of two distinct scenarios: the Central scenario, where battery buildout is modelled based on the economic viability of battery projects, and the *No Battery* scenario where battery deployment is severely restricted.

Study limitations and methodology

- All analyses in this report address dynamics within the MISO region only. The Central scenario includes the assumed continuation of various policy reforms and initiatives, including federal clean energy tax credits and DLOL[1] accreditation reform. Further information on assumptions is detailed herein.
- Aurora's model captures the investment decisions of future capacity buildout – technologies build until revenues for the next additional unit would be uneconomic. This allows Aurora to forecast scarcity pricing required to deliver new capacity in wholesale-only market, as well as prevents uneconomic build because it generates 'lowest total system' cost.

About Aurora Energy Research

- Aurora Energy Research is a leading global provider of independent power-market forecasts and analytics for critical investment and financing decisions.
- This independent report has been commissioned by American Clean Power Association. This report is technology-agnostic and does not advocate for any specific policy, regulation, or energy source.

1) Direct Loss of Load.

Executive Summary

1

As demand grows and aging energy generation in MISO is replaced by new, diversified resources, the need for flexible resources like energy storage becomes increasingly important

- MISO is expecting a significant increase in demand for electricity (peak load growing to ~130GW by 2035), putting a strain on generation and transmission networks at a time of increasing renewables penetration.
- As new, diversified resources are added to the grid, battery capacity will be needed for MISO to maintain reliability and manage large ramping requirements in evenings, particularly considering the challenges in bringing new thermal generation online.

2

Batteries provide instantaneous dispatchable generation and are a natural complement to renewable and thermal generation, balancing the grid and enhancing flexibility

- As renewable generation grows (~40% of MISO's installed capacity by 2035), batteries charge when there is excess, low-cost energy generation and discharge during peak demand when costs are higher, effectively shifting generation to times when it is needed most.
- Historical analysis of other markets shows that batteries benefit reliability by dispatching at times of highest system stress in addition to providing key ancillary services and freeing up thermal generation to more efficiently operate as base power.

3

Building a moderate amount of battery capacity over the next decade results in total system costs that are $27 billion lower over the forecast horizon

- By dispatching during peak demand hours, batteries help reduce peak pricing, with daily peak prices that can reach up to ~$159/MWh higher during the evening price peak in the *No Battery* scenario in 2035.

Sources: MISO, Aurora Energy Research

11GW of batteries build economically in Aurora's Central scenario by 2035; the *No Battery* scenario assumes only 250MW are built

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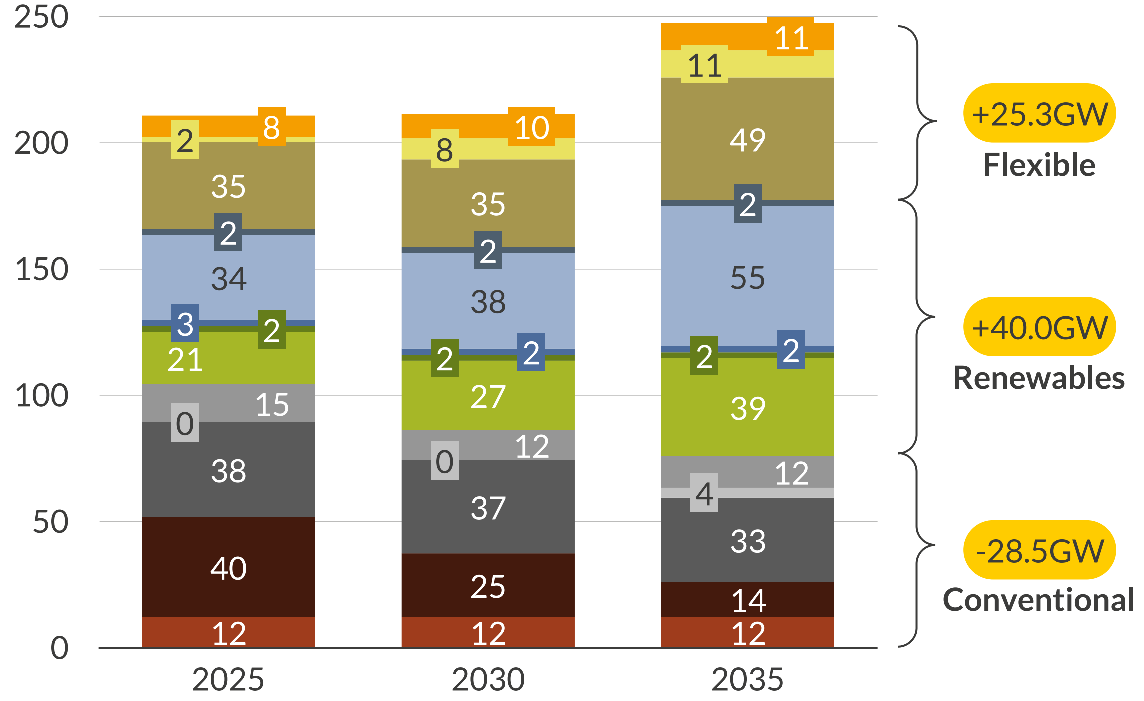
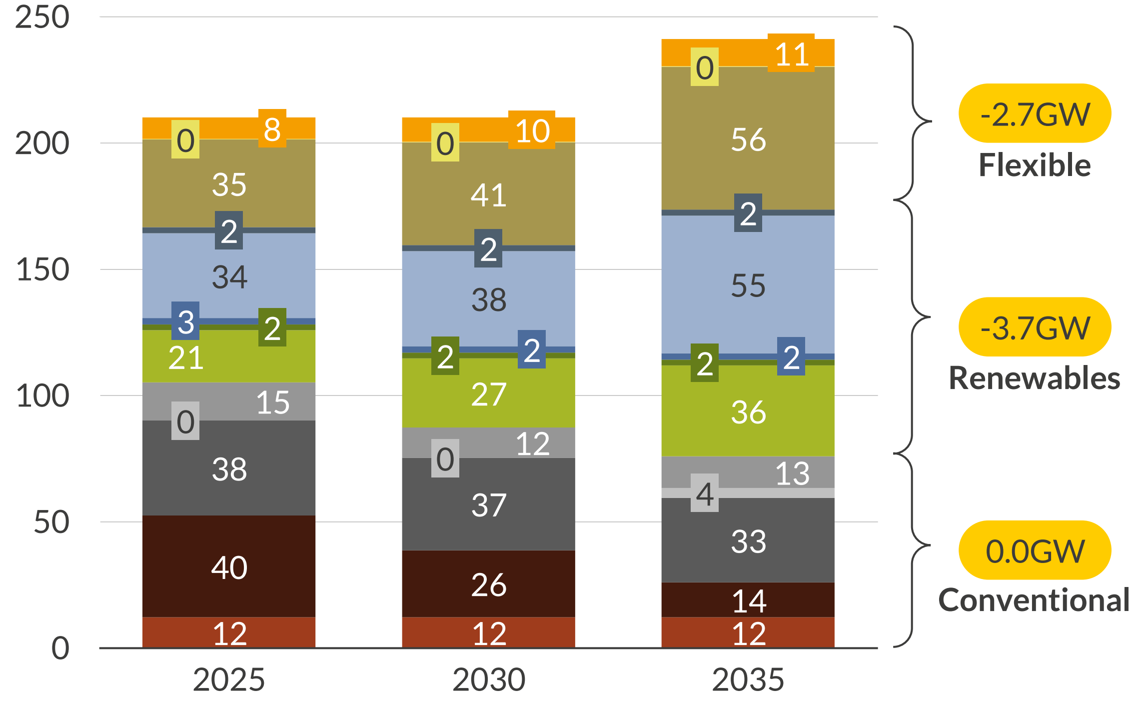
Installed capacity, Central
GW

Total change 2025–2035



Installed capacity, *No Battery*
GW

Delta to Central 2035



- Batteries show the highest growth among all technologies, going from ~2GW in 2025 to ~11GW in 2035 (+554%).

- Renewable buildout is reduced by ~4GW compared to Central scenario.
- Peakers see biggest growth with respect to central scenario, going from ~49GW to ~56GW.

Nuclear | Gas CCGT | Other thermal | Other renewables[1] | Onshore wind | Gas / oil peaker[2] | DSR[3]
Coal | Gas CCS | Solar | Hydro | Pumped storage | Battery storage

1) Other renewables includes biomass, and other waste heat recovery. 2) Peaking includes OCGT and reciprocating engines. 3) DSR includes Demand Response and Load Modifying Resources.

Sources: Aurora Energy Research

Additional battery capacity significantly lowers evening price spikes on peak demand days, resulting in $4.5bn in electricity cost savings from 2025-2035

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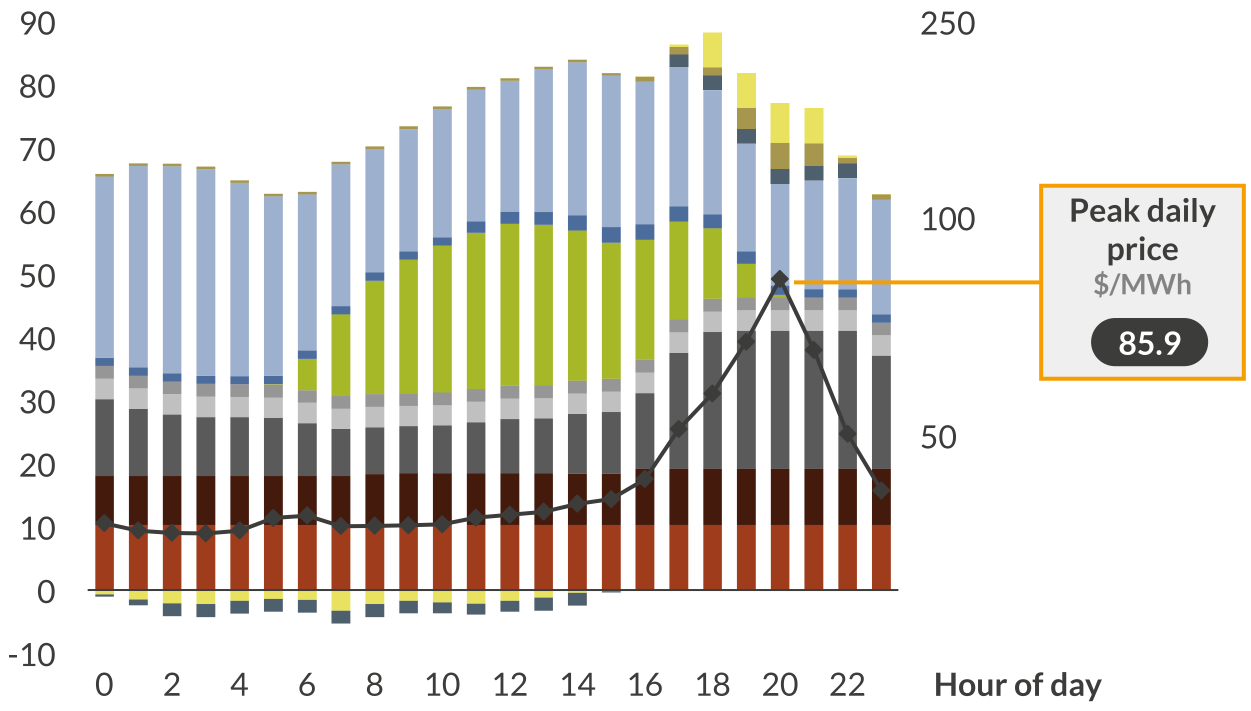
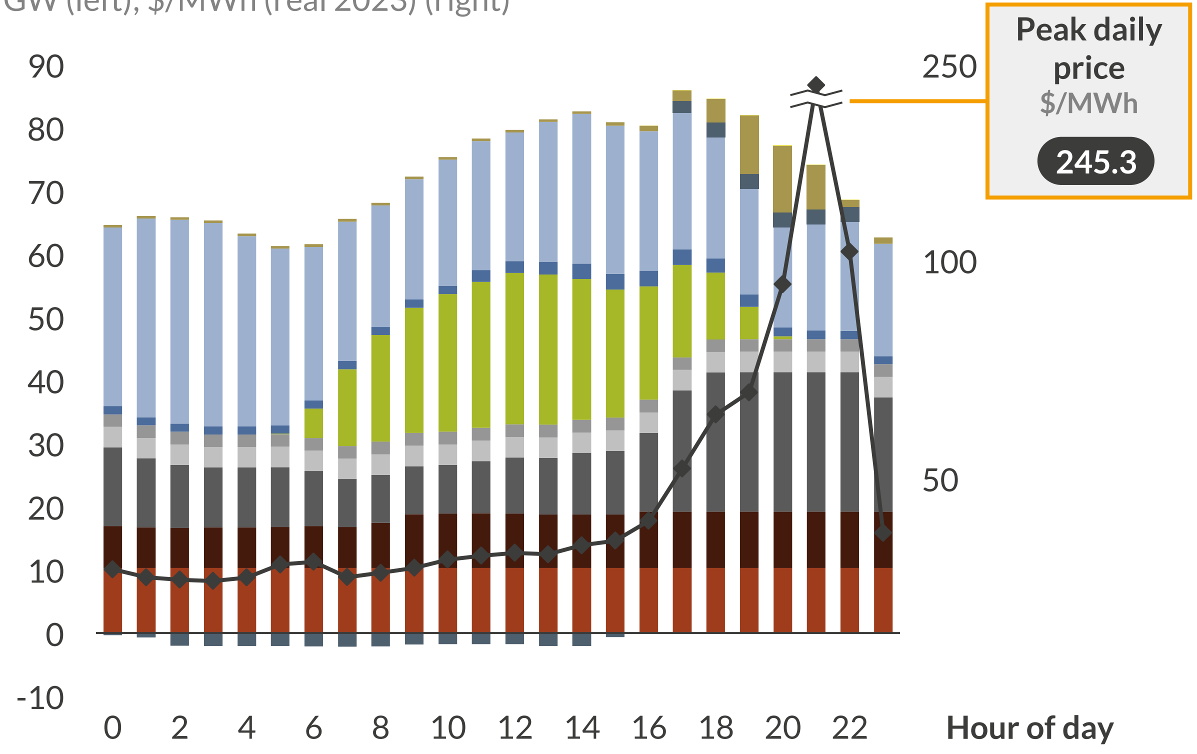
Average hourly net generation[1] and prices, Central scenario, May 25th , 2035
GW (left); $/MWh (real 2023) (right)



Average hourly net generation[1] and prices, *No Battery*, May 25th , 2035
GW (left); $/MWh (real 2023) (right)



- Battery storage supplies energy as demand increases in the afternoon/evening, complementing other sources (e.g., peakers, pumped storage).

- With no batteries to alleviate demand during the afternoon and evening, prices spike to higher levels, reaching **peak prices up to ~$159/MWh higher during the evening price peak.**

Nuclear | Gas CCGT | Other thermal | Hydro | Pumped storage | Battery storage
Coal | Gas CCS | Solar | Onshore wind | Gas / oil peaker | DA Price

1) Net generation is the sum of charge and discharge.

Sources: Aurora Energy Research

Agenda

MISO has the largest geographic footprint and second-highest installed capacity in the country, with relatively low renewables penetration

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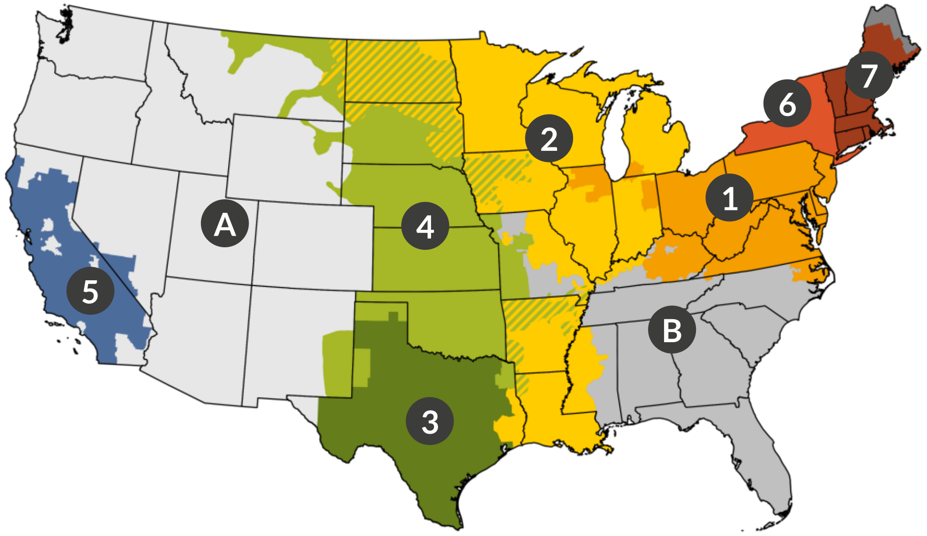
There are seven restructured competitive markets in the lower 48 states which are run by Independent System Operators (ISOs). ISOs use competitive market mechanisms that allow independent power producers and non-utility generators to trade power. WECC and SERC remain vertically integrated by utility or balancing authority (BA).

Map of US wholesale electricity markets



ISO		Installed capacity,[1] GW	Peak demand record, GW	Annual load,[2] TWh	Projected peak load growth[3]	Renewables penetration[4]
PJM	1	223	166 (2006)	813	4.8%	7.6%
MISO	2	203	127 (2011)	643	4.9%	18.9%
ERCOT	3	159	86 (2024)	464	7.1%	33.9%
SPP	4	100	56 (2023)	289	10.7%	40.6%
CAISO	5	88	52 (2022)	224	7.6%	38.9%
NYISO	6	45	34 (2013)	151	-1.0%	21.7%
ISO-NE	7	38	28 (2006)	114	3.2%	10.6%
Regulated markets (Non-ISO)						
WECC	A	188	105 (2022)	535	11.9%	43.4%
SERC[5]	B	276	–	960	–	7.5%

1) Data from January 2024 EIA 860M. Includes capacities of plants not bidding fully into wholesale or capacity market. 2) Data from 2024. 3) Compares Aurora's 2025 and 2030 forecasts. 4) 2024 Data. Renewables includes solar, wind, and hydro. Penetration is measured as post-curtailed generation over total load. 5) Aurora does not maintain a SERC-wide market forecast, and existing utility data do not clearly indicate historical concurrent peak load and expected growth.

Sources: Aurora Energy Research, EIA, FERC, NERC, individual electricity markets

MISO's large footprint and limited transmission lead to significant regional variation in prices, generation mix and investment opportunities

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Region	Price zone	States covered	Avg. load 2021–24, TWh	Avg. DA price 2021–24, $/MWh	Avg. PRA price[1] 2024, $/MW-Day	Installed MISO capacity,[2] GW
North	IA	IA	50	34	70	24
North	MDU[3]	MN, ND, SD	16	28	70	9
North	MN	MN	65	35	70	20
Central	IL	IL	46	40	70	16
Central	IN	IN	91	44	70	21
Central	KY	KY	4	44	70	1
Central	MO	MO	38	39	70	8
Central	SMI[4]	MI	95	42	70	28
Central	WNM[5]	WI, MI	69	40	70	19
South	AR	AR	35	37	11	14
South	LA	LA	88	39	11	27
South	MS	MS	22	37	11	6
South	TX	TX	26	40	11	8

Nuclear · Coal · Gas CCGT · Other thermal · Solar · Other renewables[6] · Hydro · Onshore wind · Pumped storage · Gas / oil peaker[7] · Battery storage

1) Summer PRA price for seasonal auctions. 2) As of January 2025. 3) Montana-Dakota Utilities. 4) South Michigan. 5) Wisconsin & North Michigan. 6) Other renewables includes biomass, and other waste heat recovery. 7) Gas / oil peaker includes open-cycle gas turbines (OCGT) and reciprocating engines. Note: Values in 2023 prices.

Sources: Aurora Energy Research, MISO

There are 126.5MW of batteries operational in MISO today; Aurora expects that 980MW will be online by next spring

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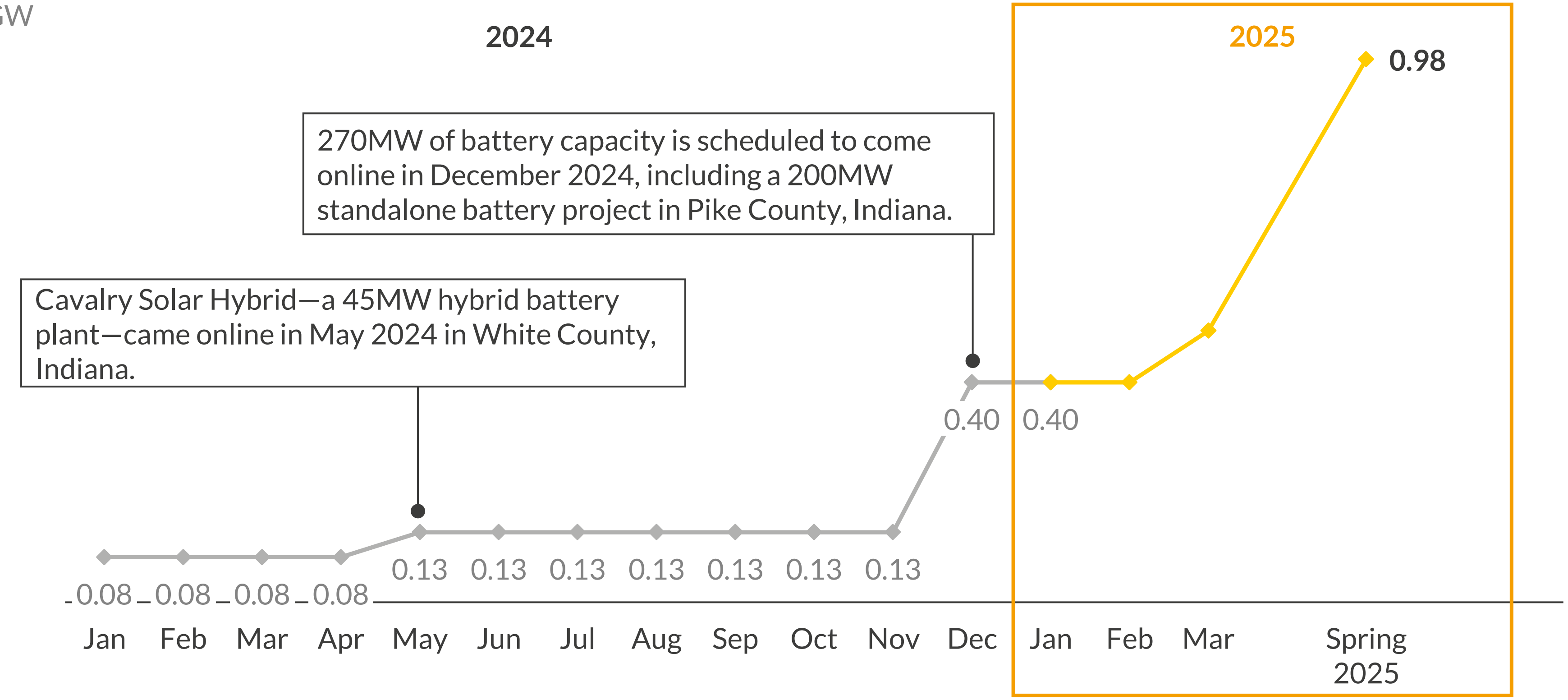
Cumulative operational battery capacity[1]
GW



Total Capacity in Interconnection Pipeline, GW

60GW[2] | 175GW | 42GW

Historical cumulative comercially operable capacity | Aurora Central

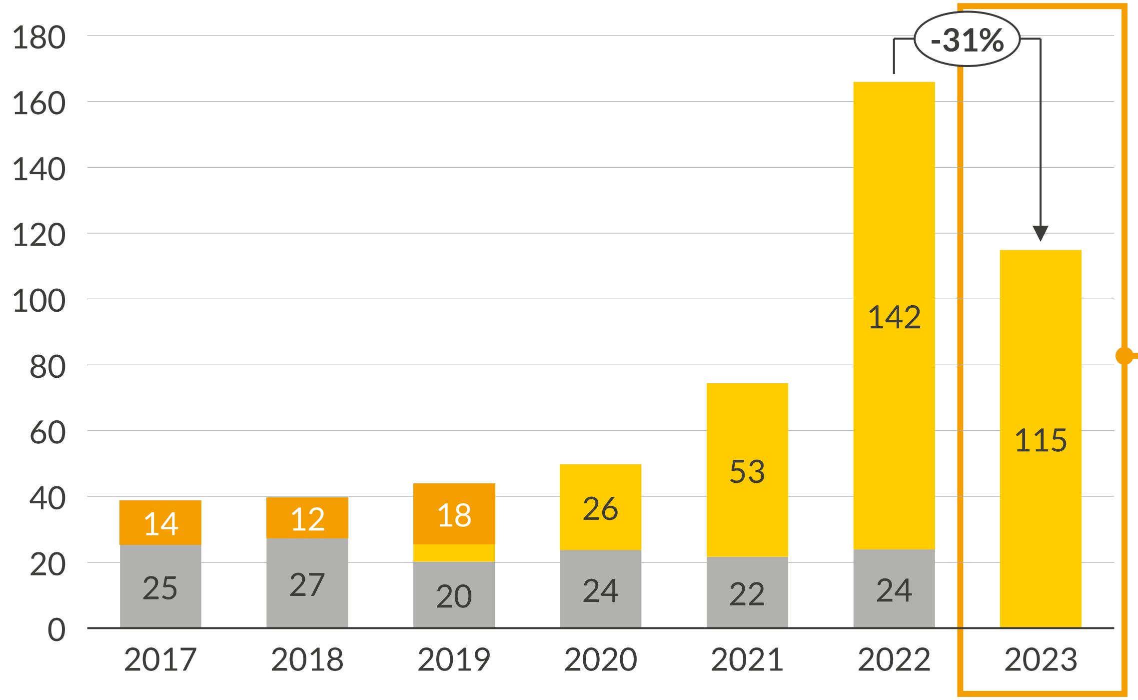
- Battery storage capacity has grown steadily year over year, from 44MW in 2020 to 127MW in 2024.[3]
- The interconnection queue currently contains 351GW of capacity across all technologies, which is around 175% of the current installed capacity in MISO.
- Notably, most projects in the queue are solar, battery storage, or hybrid projects, and there are still a significant number of wind projects in the queue.
- Aurora assumes there to be 980MW of batteries online by next spring.

1) Plant details and status as in MISO's September 2024 EIA860M report. 2) Does not include projects labeled as "Hybrid," "Solar/Wind," "Wind/Battery," or "Solar/Wind/Battery." 3) As of October 31st 2024.

Sources: Aurora Energy Research, MISO

More than 25GW of Battery Storage projects entered the MISO Interconnection Queue in 2024

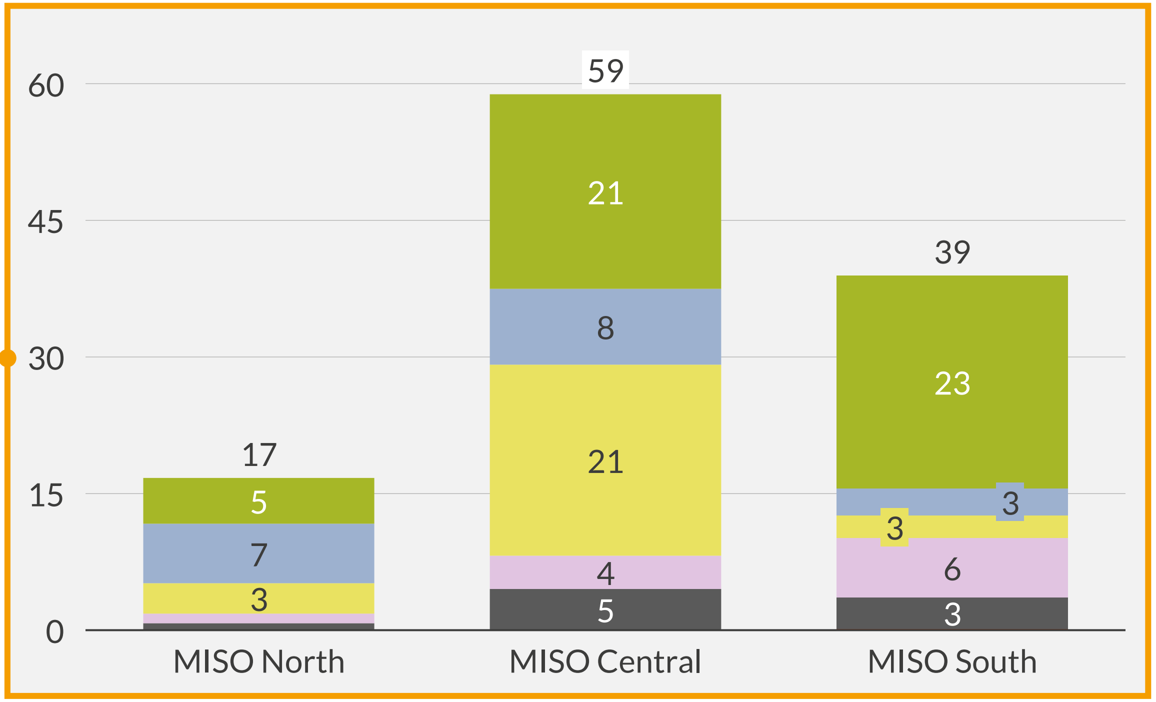
Project status by DPP queue cycle
GW



- The total capacity entering the 2023 interconnection queue is 115GW, 31% lower than the 2022 cycle. This decrease is a result of recent queue reforms raising the barriers to entry by increasing milestone payments and implementing harsher withdrawal penalties to reduce speculative project participation.
- The withdrawal rate is expected to decline due to the more punitive withdrawal penalty structure.

Withdrawn Active Done

Capacity in the MISO interconnection queue by super region
GW



- 43% of the interconnection queue capacity is solar, with the majority located in MISO Central and South.
- More than 50% of the total queue capacity is concentrated in MISO Central, primarily comprising solar and battery storage projects.

Solar Onshore wind Battery storage Hybrid Thermal Nuclear

Sources: Aurora Energy Research, MISO

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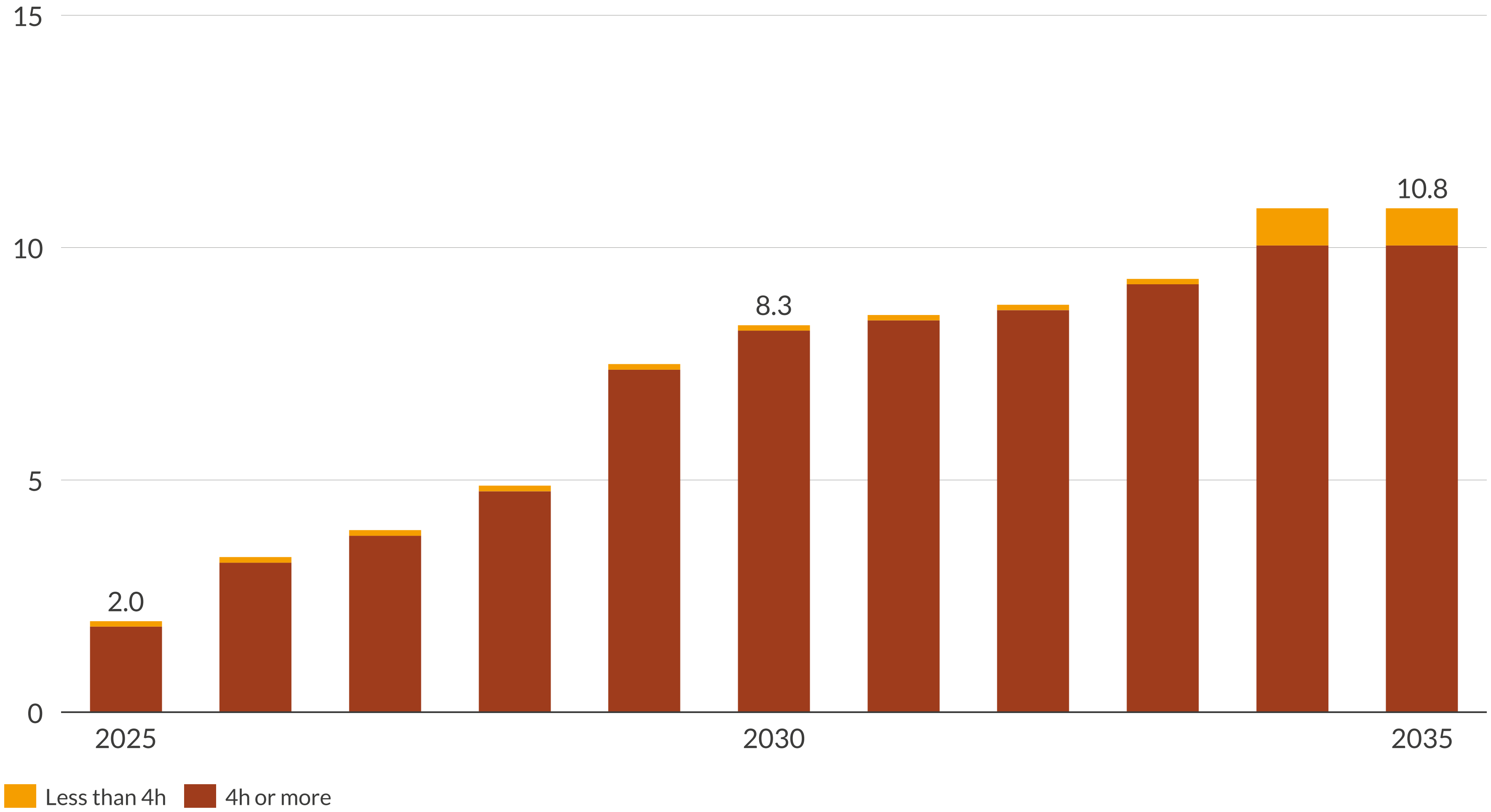
Battery buildout through 2035 driven by needed upgrades to aging infrastructure and rapidly rising demand

Battery capacity timeline under Aurora Central by battery duration
GW



Sources: Aurora Energy Research, EIA

- Market drivers such as retiring thermal assets, rising demand and high renewables deployment create a favorable environment for battery buildout, coupled with declining CAPEX, strong federal clean energy tax credits and the relative ease of deployment of energy storage.
- MISO has seen the operating capacity grow 3-fold since the start of 2020; the introduction of the solar PTC continues this fast-building trend build in the late 2020s until early 2030s period, with battery capacity increasing 85-fold to 11GW by 2035.
- Growth of batteries is mainly driven by 4-hour duration batteries, which achieve full accreditation in capacity market.

Agenda

Overview of key policy changes and regulatory recent events in MISO

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A New accreditation methodology planned for 2028 implementation

- Current approach uses a different methodology for Wind, Solar, BESS and Thermal assets. Under new method a unique method will be used for all.
- DLOL[1] methodology measures availability during loss of load hours and near-miss hours from the MISO LOLE[2] probabilistic model.
- Solar and wind de-rating factors could decline to 36% and 11%, respectively. Thermal sources, batteries and hydro remain largely unchanged.

B New Reliability Based Demand Curve in the PRA[3] starting in 2025-26 Planning Year

- New curve allows for capacity in the supply curve above the PRMR[4] to be cleared and receive capacity payments.
- RBDC[5] will be able to provide consistent price signals around the dangers of a shortfall in each region and season.
- RBDC attributes value to surplus capacity which provides additional reliability to the grid.

C Implementation of Storage as a Transmission-Only Assets (SATOAs)

- SATOA is an electric storage facility designed to connect to the grid system as a transmission asset.
- Functioning as a SATOA allows storage developers to tap into an emerging revenue stream.
- The asset should be able to address any underlying transmission issues, and the issue should be addressed with no reduction in system performance.

D State level policies aimed at driving battery/energy storage development

- Michigan: Law mandate of 2.5GW of energy storage by 2030, to be procured by utilities and enforced by the PSC.
- Illinois: Law mandate of 1.5GW energy storage resources and pending legislative proposals for additional procurement up to as much as 15GW.
- Minnesota: Approval of Xcel's IRP which includes ~3GW of wind and solar and +600MW of energy storage.

Deep dive available

1) Direct Loss of Load. 2) Loss of Load Expectation. 3) Planning Resource Auction. 4) Planning Reserve Margin Requirement. 5) Reliability Based Demand Curve.

Sources: Aurora Energy Research, MISO

To participate in the capacity market, resources must undergo resource accreditation; MISO is planning a new accreditation methodology for 2028

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		Key parameters	Wind	Solar	BESS	Thermal
Current method	Class level	Methodology	Direct output from MISO LOLE probabilistic model[1]	Fixed values: - 50% in summer, fall and spring - 5% in winter	Fixed value - 95% until MISO reaches 30 Battery Energy Storage Systems[2]	Unforced capacity (UCAP): Installed capacity adjusted by forced outage rates[3]
		Hours	N/A		All hours	All hours
		Years			Not available	Last five years
	Unit level	Methodology	Availability during each season's top 8 peak load hours	Historical availability during: - 3:00, 4:00 and 5:00 PM ET hours in summer, fall and spring - 8:00, 9:00 AM, and 7:00, 8:00 PM ET hours in winter	Based on the verified capacity from the Generation Verification Test Capacity (GVTC)[4] test and historical outage rate.	Schedule 53: performance as a weighted average: 70%[5] for the top 3% of hours with the tightest margins and 30%[5] for the remaining 97% of hours.
		Hours	Top 8 peak load hours per day	3–4 hours	1–4 hours	All hours with different weights
		Years	Last three years	Last three years	Most recent year	Last three years
Proposed method	Class level	Methodology	DLOL[6] methodology: Average availability[7] during loss of load hours and near-miss hours (hours in which available capacity exceeds demand by less than 3%) from the MISO LOLE probabilistic model			
		Hours	All relevant hours in which criteria above happens – no more than 65 hours per each season			
		Years	Use 30 different weather years in the MISO LOLE model			
	Unit level	Methodology	Schedule 53: calculates performance as a weighted average: 80% for the top 3% of hours with the tightest margins and 20% for remaining 97% hours. Performance is measured using RT offered availability			
		Hours	65 hours with tightest margin and all other hours of normal operation for each season			
		Years	Last three years with corresponding seasons			

Method temporality: Forward looking | Historic performance | Fixed values

Seasonality component: Seasonal | Not seasonal

1) MISO's Loss-of-Load Expectation model is a probabilistic tool used to calculate wind resource reliability. 2) As of October 2024, MISO has 21 BESS. 3) Measured as Installed capacity x (1 - (average forced outage rate) 4) MISO uses GVTC test to measure the asset's installed capacity. 5) Currently we are in the transition period, the weighting factors will change to 80%/20% for 2025/26 Planning Year and beyond. 6) Direct Loss-of-Load. 7) Calculated for each season.

Sources: Aurora Energy Research, MISO

MISO's new accreditation methodology will lower de-rating factors for renewables, favoring firm resources with higher capacity ratings

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Reform timeline

- **2022:** MISO initiated the DLOL study.
- **Mar 28, 2024:** MISO filed the proposed DLOL methodology with FERC.
- **Oct 25, 2024:** FERC approved the DLOL methodology.
- **2025–2027:** MISO releases 5–10-year resource class accreditation forecast results to prepare for the transition to DLOL.
- **2028:** MISO implements the DLOL methodology for the 2028/29 PY.[1]

Methodology improvement

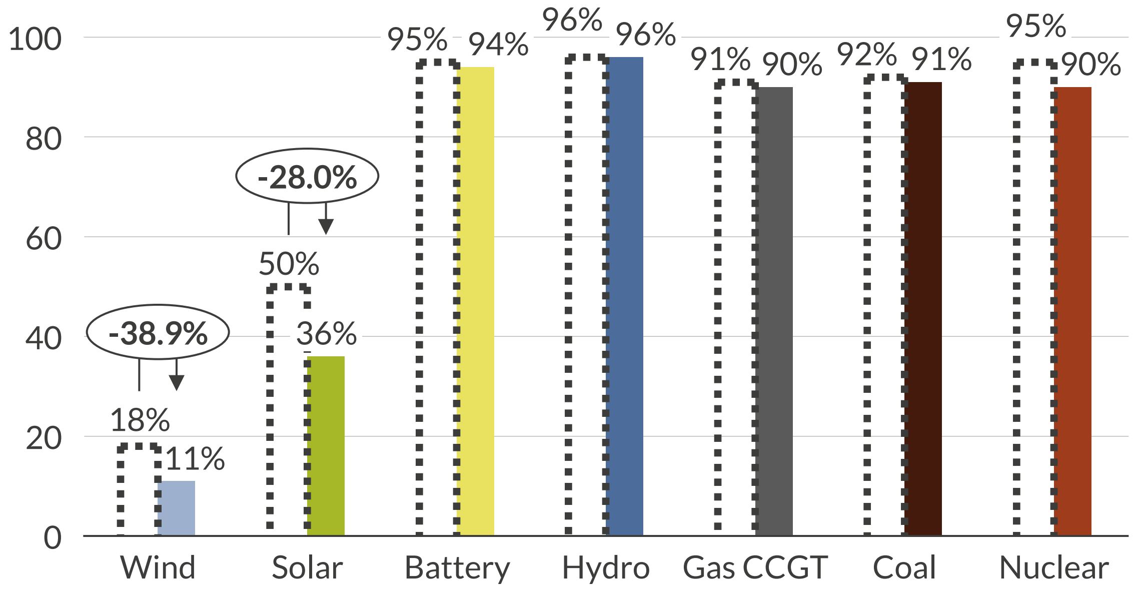
- Accredit resources based on their **availability during high system stress periods** to align with grid reliability needs.
- Implement **a uniform accreditation approach** for all technologies, nondiscriminatory amongst resource classes.
- Create **performance-based incentives** for individual resources to improve long-term reliability and availability when resources are most needed.

Impacts on technologies

- Given that DLOL calculates accredited capacity based on the availability during loss-of-load hours, it **will adversely affect intermittent energy sources**, which are unable to increase production as required.

Class level capacity accreditation before and after DLOL implementation[2]

% capacity accreditation, Summer season values



- Under the DLOL framework, de-rating factors for thermal and battery resources remain largely unchanged and all remain in excess of 90%.
- In contrast, the de-rating factors for wind and solar resources decline to 11% and 36%, respectively, as these non-firm resources are unable to ramp up production during periods of low reserve margins.
- MISO expects **DLOL accreditation for solar assets to continue to fall**, as tight margin hours shift away from summer evenings and towards winter mornings.

1) Planning Year (PY). 2) Conducted for the 2023/24 Planning Year.

Sources: Aurora Energy Research, MISO

FERC accepted MISO’s proposal to implement a Reliability Based Demand Curve in the PRA starting in the 2025/26 Planning Year

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After two additional deficiency filings, FERC accepted MISO’s proposed revisions to their Open Access Transmission, Energy and Operating Reserve Markets Tariff to implement a downward sloping, Reliability Based Demand Curve (RBDC) in the Planning Resource Auction effective June 3, 2024.

Potential benefits

MISO’s IMM[1] has long advocated for a RBDC over a vertical demand curve to improve market efficiency and reliability.

A RBDC attributes value to marginal increases in capacity. This creates more efficient market incentives and capacity market prices to inform new investment and retirement decisions.

- **With a vertical demand curve, surplus capacity has no value in the PRA.** Additional capacity improves grid reliability and lowers energy and AS costs.

Participants supplying more than their required capacity share will be properly compensated for improving overall system reliability.

RBDC features

RBDCs will replace all vertical demand curves in the system-wide seasonal PRA clearing process, as well as within each LRZ.

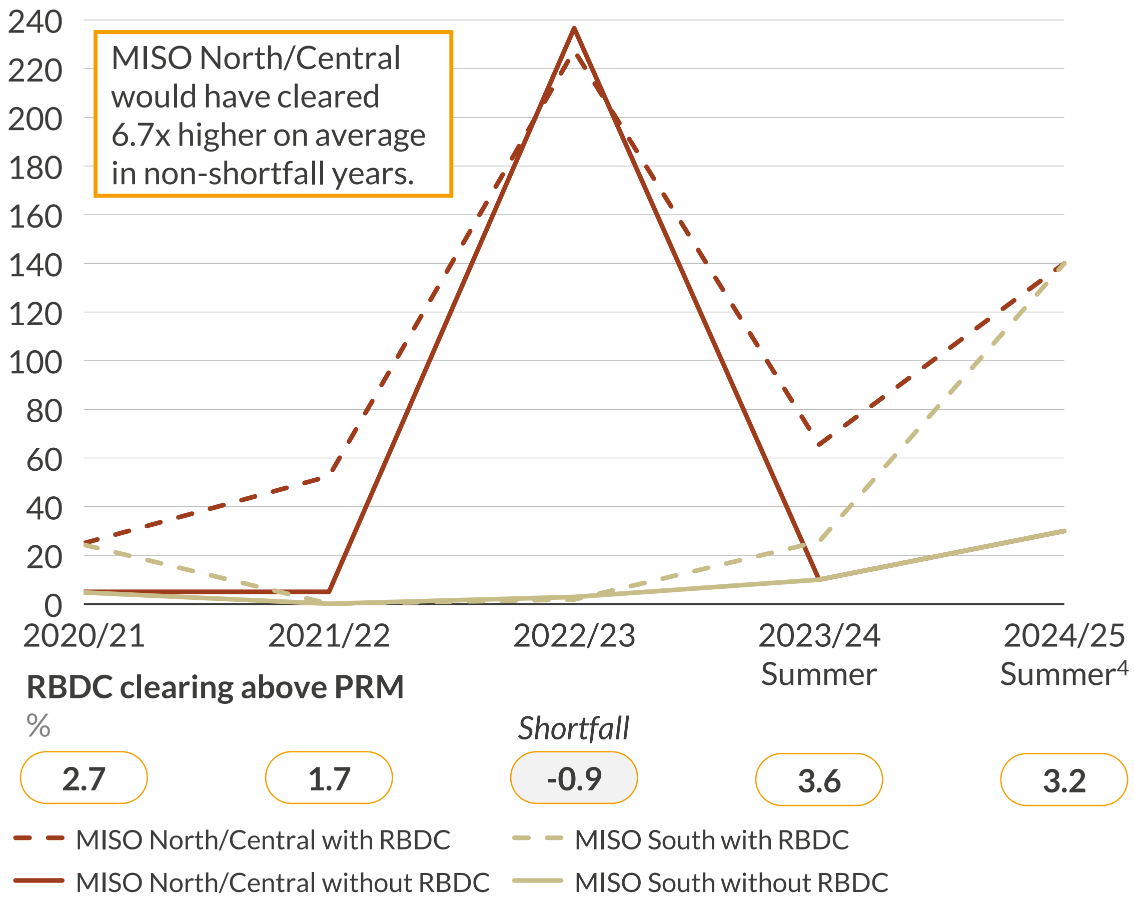
The new design also contains an option for LSEs to opt-out of the PRA entirely to meet their capacity obligations. To maintain system reliability, MISO requires an additional RBDC Opt-Out Adder in addition to the LSE’s PRM for LSEs that choose to do so.[2]

- Historically, **over 60% of MISO’s capacity is cleared outside the Planning Resource Auction** through Self-Scheduling.

LSEs electing to opt-out of the RBDC will be required to lock in their opt-out for three years before being able to opt-in again.[3]

Historical PRA clearing prices with and without RBDC implemented

$/MW-Day



1) Independent Market Monitor. 2) MISO conducted a study calculating the RBDC Opt-Out Adder percentage from the last three PRAs. These values landed between 1.0% and 3.9% depending on the season and capacity margins. 3) Utilities electing the option to Self-Schedule are required to opt-out of the PRA with 100% of their capacity. 4) MISO North/Central and MISO South both cleared at $30/MW-Day for the 2024/25 Summer auction.

Sources: Aurora Energy Research, MISO, Potomac Economics, FERC

Comprehensive requirements for assets to qualify as SATOA[1] in the MISO Transmission System

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The proposed SATOA should have unique [2] features essential for meeting transmission system performance requirements, which are not available at similar costs from other solutions, include faster operation and shorter implementation lead time.

1. The asset should meet the criteria to be classified as a transmission type[3] in MTEP.
2. The asset should be able to address any underlying transmission issues (like loading, voltage, stability, etc.)
   - A. The transmission issue should be addressed in **all hours** it is identified to exist.
   - B. The transmission issue should be addressed with a **life-cycle cost** of the SATOA that is comparable to other proposed solutions including direct capital cost, expected useful life and maintenance costs.
   - C. The transmission issue should be addressed with no reduction in **system performance** as compared to other proposed solutions.
3. The asset must have a required capacity within the minimum and maximum constraints to ensure that excess storage capacity is not classified as a transmission-only asset.
4. The asset should have sufficient energy and/or reactive capability (MWh/MVAr) to charge or discharge for the period identified as necessary in the planning study.
5. The asset would be under MISO's functional control and should follow the MISO operating guide specifying the operating practices applicable to the SATOA.

- SATOA can **only** operate for transmission purposes and cannot participate in the energy, operating reserves market and the planning resource auction.
- Any asset selected as the preferred solution for SATOA with excess capacity than necessary, will be required to go through the Generator Interconnection Process **if** the SATOA seeks to offer that excess capacity into the market.
- The Waupaca Energy Storage project in Wisconsin was developed and went into service in 2022 to improve local reliability and voltage performance by using a 2.5MW/5MWh battery, providing a cost-effective solution at $8.1mn compared to the $11.3mn for a traditional transmission line rebuild.

1) Storage as a Transmission-Only Asset 2) Include degradation of capacity over time, inverter-based impacts on reliability, and impacts on operating and interconnecting market resources
3) Baseline Reliability Project, New Transmission Access Project, Market Efficiency Project, Market Participant Funded Project, Targeted Market Efficiency Project, Multi-Value Project, or other.
Sources: Aurora Energy Research, MISO, FERC

Agenda

The investment case for battery storage in MISO is driven by five main principles

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Batteries are well placed to aid the grid's flexibility moving forward with higher penetration of intermittent assets and retirement of thermal assets

1 Persistent wholesale energy arbitrage opportunities

- High wind and solar generation can produce large swings/steep gradients in residual load; therefore, the system will require more flexible capacity which can quickly ramp production up and down.
- High renewable penetration will also lead to more forecast error due to weather fluctuation.
- This leads to elevated Day-Ahead and Real-Time spreads throughout the forecast horizon.

2 Retained Ancillary Service value due to opportunity costs

- Forecast errors mean there is a need for balancing actions in real time, using flexible generators and loads. Retirement of existing thermal generation further drives the need for new flexible capacity.
- Opportunity costs to participate remain high due to co-optimization of energy and ancillary markets.
- Speed of saturation of these services is a key uncertainty, as is the potential for new services.

3 Increasing Resource Adequacy prices

- PRA[1] prices are expected to increase in the long-run, driven by thermal retirements, growing load, and declining de-rating factors.
- Bi-lateral capacity payments will also grow with the increasing opportunity cost of not bidding into the PRA.
- PRA prices will be broadly set by 4-hour batteries and peakers (or hit net-CONE[2]), with longer duration batteries capturing higher de-rating factors.

4 Declining CAPEX trajectories

- Despite current supply chain issues, long term battery storage CAPEX is expected to reduce significantly from current levels as the supply chain issues resolve and economies of scale becomes more impactful.
- This increases battery economics in the long run with stable annual margins.
- However, uncertainty remains around how tariffs may affect CAPEX in the future with the new presidential administration.

5 Weather/Nodal volatility yielding upsides

- Due to batteries' ability to respond quickly, they can earn upsides from market volatility caused by unexpected events.
- This could be a market-wide impact with extreme weather events or a local-level impact with chronic or severe congestion and transmission or plant outages.

1) Planning Resource Auction. 2) Net-CONE is net Cost of New Entry; MISO currently uses the typical cost for a new gas peaker to form net-CONE.

Sources: Aurora Energy Research

MISO batteries can stack revenues from wholesale energy arbitrage, Ancillary Services, and capacity payments

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Revenue streams available to batteries in MISO

Wholesale energy market

- **Charge and discharge** in response daily spread value
- Can benefit from strategic **siting at nodes experiencing higher volatility** or spreads (e.g., near load centers or increasingly, near renewable hotspots)

Day-Ahead market

Real-Time market

Day-Ahead / Real-Time arbitrage

- Opportunities for **virtual trades** between energy markets when there is sufficient price deviation between DA and RT markets

Ancillary Service markets

- Batteries are optimal to provide Ancillary Services due to their **quasi-instantaneous response times**
- **Regulation** was the only available revenue stream before September 2022
- In both the Day-Ahead and Real-Time markets

Operating Reserves

Regulating

Contingency Reserves

- Spinning and Supplemental

Short-Term Reserves

Ramp capability

Capacity market

- Batteries can act as capacity resources by **participating in the PRA**, subject to derating for reliability
- **Contract bi-lateral agreements with utilities** or bid into the seasonal **PRA auctions** to earn capacity revenues

Planning Resource Auction

- Experiences volatile prices year-to-year
- **Increasing future prices** due to thermal retirements

Bi-lateral contracts

- Utilities establish long-term contracts with capacity assets in **bi-lateral agreements**

Affected by policies and utility targets

Sources: Aurora Energy Research, MISO

Dispatch | Batteries can earn revenues by arbitraging between low and high price energy hours, or between Day Ahead and Real Time markets

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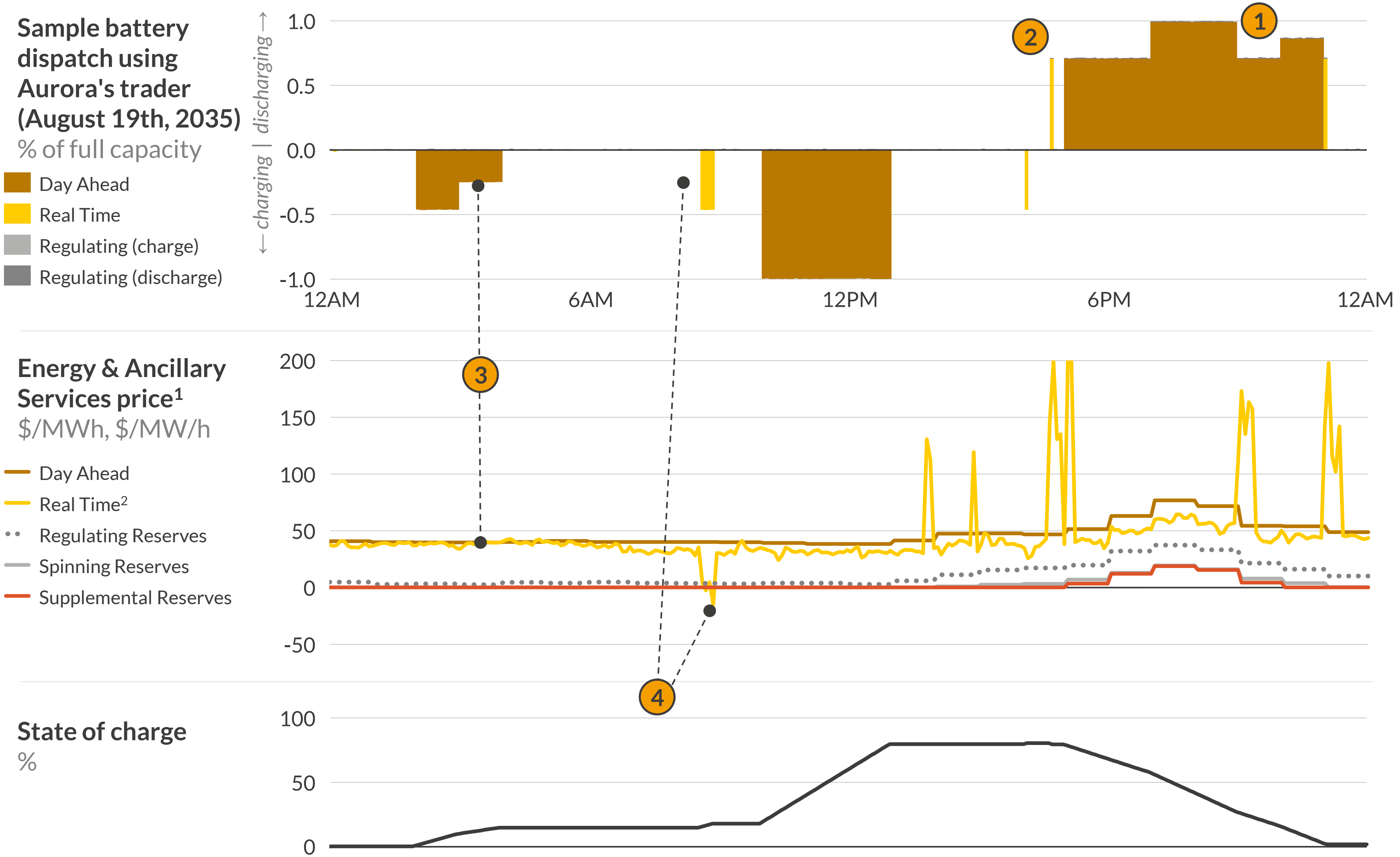
Examples of optimized battery dispatch behavior

1. Batteries almost exclusively discharge on the Day Ahead market, where high prices are generally more predictable and long-lived.
2. Occasionally, a battery will discharge in the Real Time market during a price spike, if it can successfully anticipate it.
3. Charging is generally cheapest in the early hours in the Day Ahead market, where prices tend to be lower…
4. …but a battery may also charge in the Real Time market or later hours of the Day ahead market if it anticipates sufficiently high future prices and is at a low state of charge.



1) Energy price units are in $/MWh. Ancillary Services prices are for capacity commitments, in units of $/MW/h. 2) Real Time price spikes capped at $200/MWh for graph visibility.

Sources: Aurora Energy Research

As load grows and more solar capacity comes online, MISO will face growing hourly net load ramps that must be met by flexible technologies

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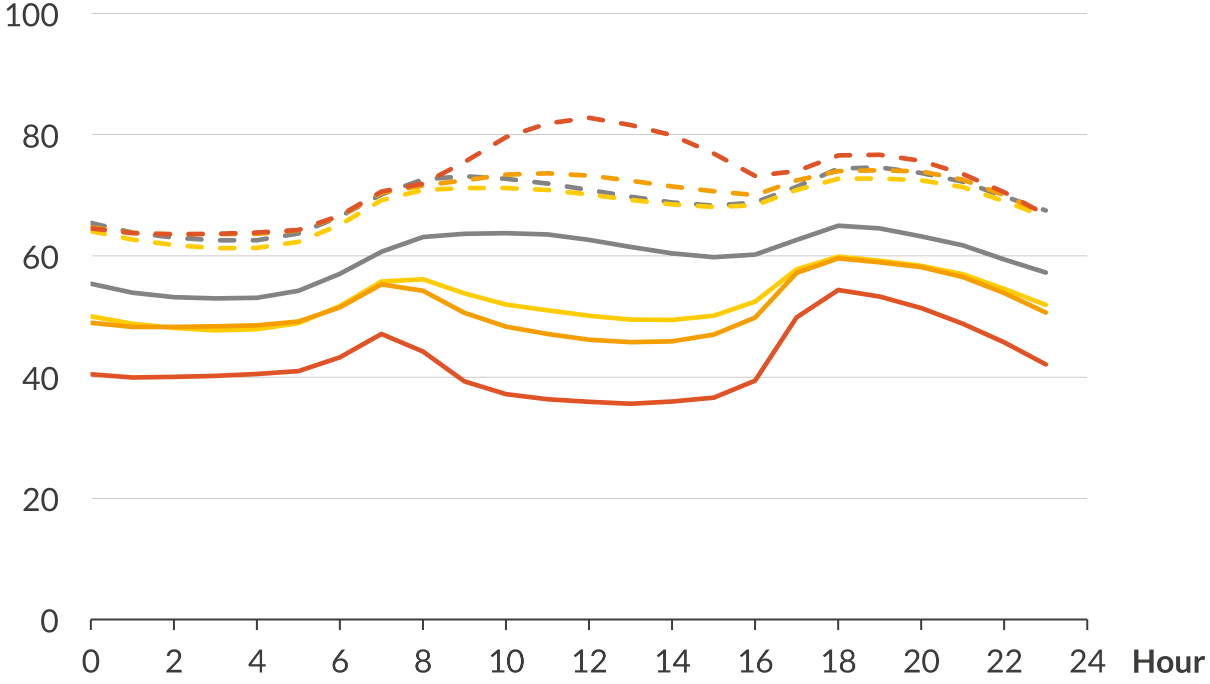
1 As solar buildout accelerates, the "duck curve" will appear and grow more exaggerated

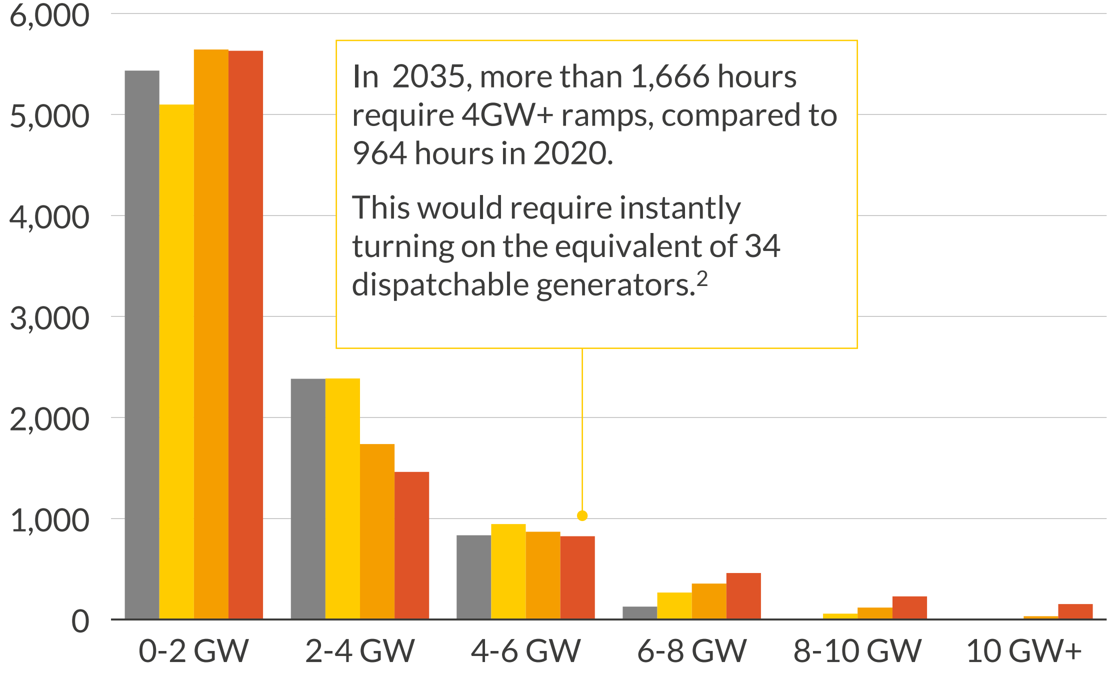
Total and net load average shape in December
GW



- With high population growth and expected solar development in MISO, net load ramps in the evening will grow much steeper in the next 10 years.

2 Ramping requirements will increase accordingly, seeing ~19% of hours with ramping greater than 4GW in 2035

Frequency distribution of hourly ramping requirement[1]
Number of hours



- Growing net load ramps underscore the need for greater system flexibility, which dispatchable technologies like batteries and gas provide efficiently.

2020 2025 2030 2035 Total load (dashed) Net load (solid)

1) Ramping requirement is the absolute difference in net load between consecutive hours. Net load is calculated as the difference between total load and generation from renewables (wind and solar). 2) Assuming an average dispatchable plant size of 118MW running at full capacity

Sources: Aurora Energy Research, MISO

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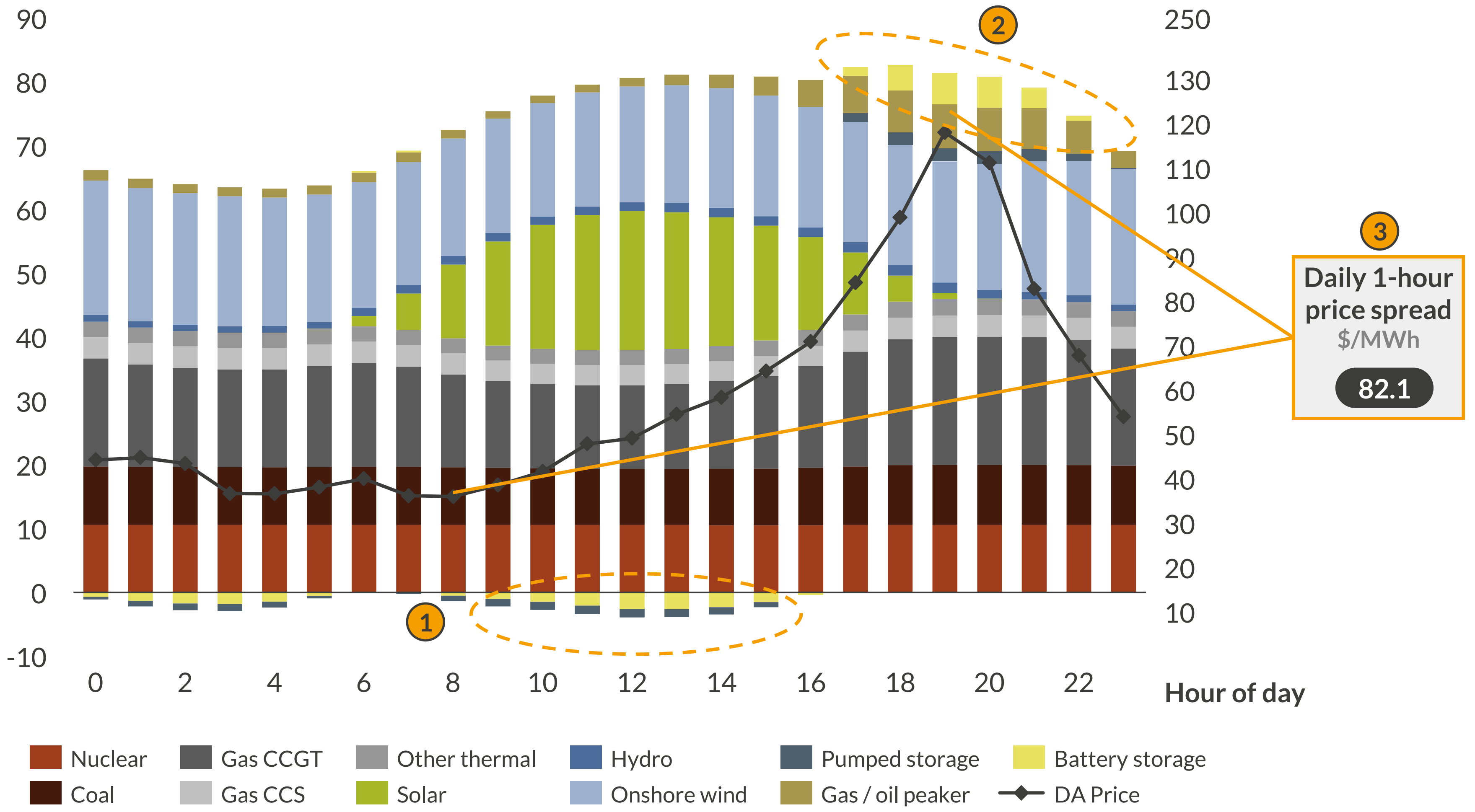
Batteries can efficiently balance generation with peak demand, shifting capacity to meet times of highest need

Average hourly net generation[1] and prices, Aurora Central scenario, August 2035
GW (left); $/MWh (real 2023) (right)



1. Batteries charge when prices are lowest and there is a surplus of lower-priced generation.
2. Batteries release energy when prices are high and demand is peaking, relieving pressure from the grid.
3. Batteries take advantage of the price spreads and can arbitrage between price peaks and troughs.

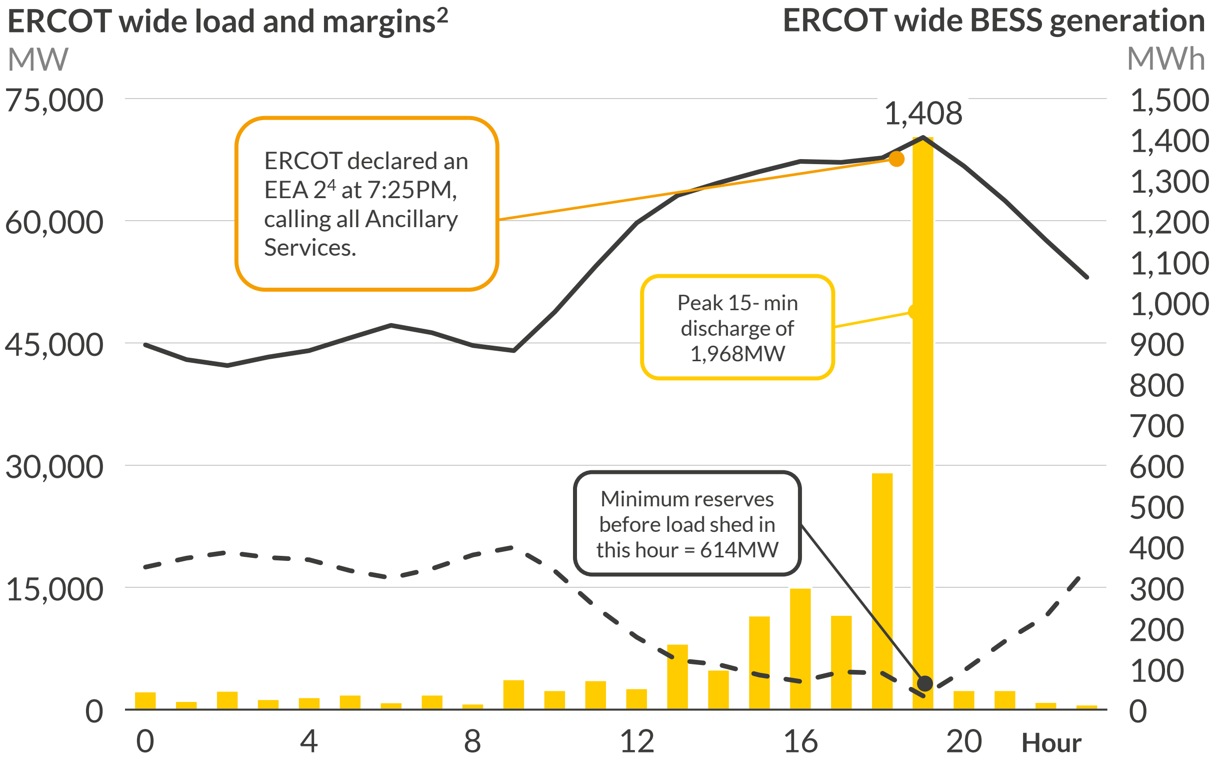
1) Net generation is the sum of charge and discharge.

Sources: Aurora Energy Research

Case study | In ERCOT, BESS provided critical energy in 2023 during the hours of highest system stress, preventing the ISO from having to shed any load

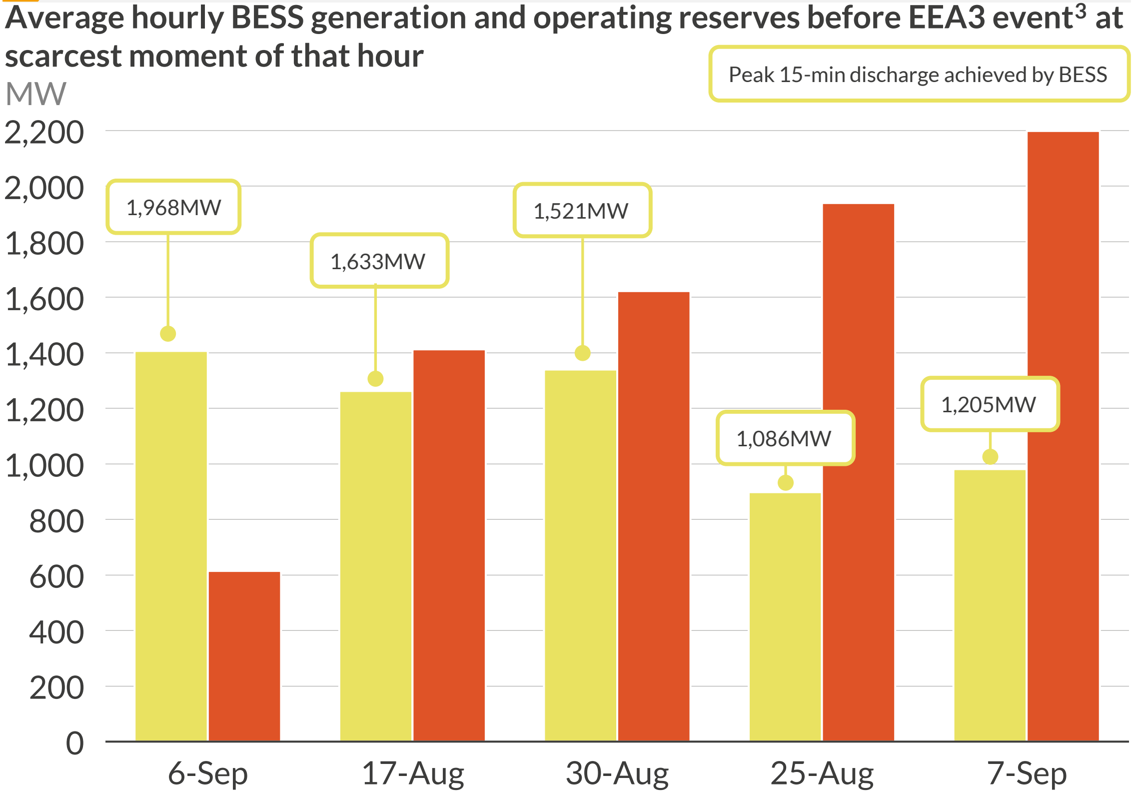
AURORA

1 **September 6th, 2023:** ERCOT BESS discharged their energy between 6-8pm, right as system reserve margins were tightest



- BESS dispatched nearly 1.5GWh of power between 7 and 8 PM in response to ERCOT calling all Ancillary Services amid low operating margins, helping to restore normal grid frequency and preventing load shed.

2 Across the five scarcest days[1] of 2023, BESS discharged most of their power at the hour when reserves were at their lowest point



- On September 6th, 2023, without BESS dispatch, ERCOT's operational reserves would have fallen below the 1,500 MW threshold, forcing the ISO to start shedding load to protect the integrity of the grid.

1) Individual days with the lowest hourly operating reserves (multiple hours in the same day are not shown). 2) Margins, also called operating reserves, are the difference between online operating capacity and available offline capacity. 3) An Energy Emergency Alert 3 is issued when operating reserves drop below 1,500MW, triggering a load shed event.4) Calculated as the minimum operating reserves from each hour minus 1,500MW. 5) Calculated as average operating reserves from each hour minus 1,500MW.

Sources: Aurora Energy Research, ERCOT

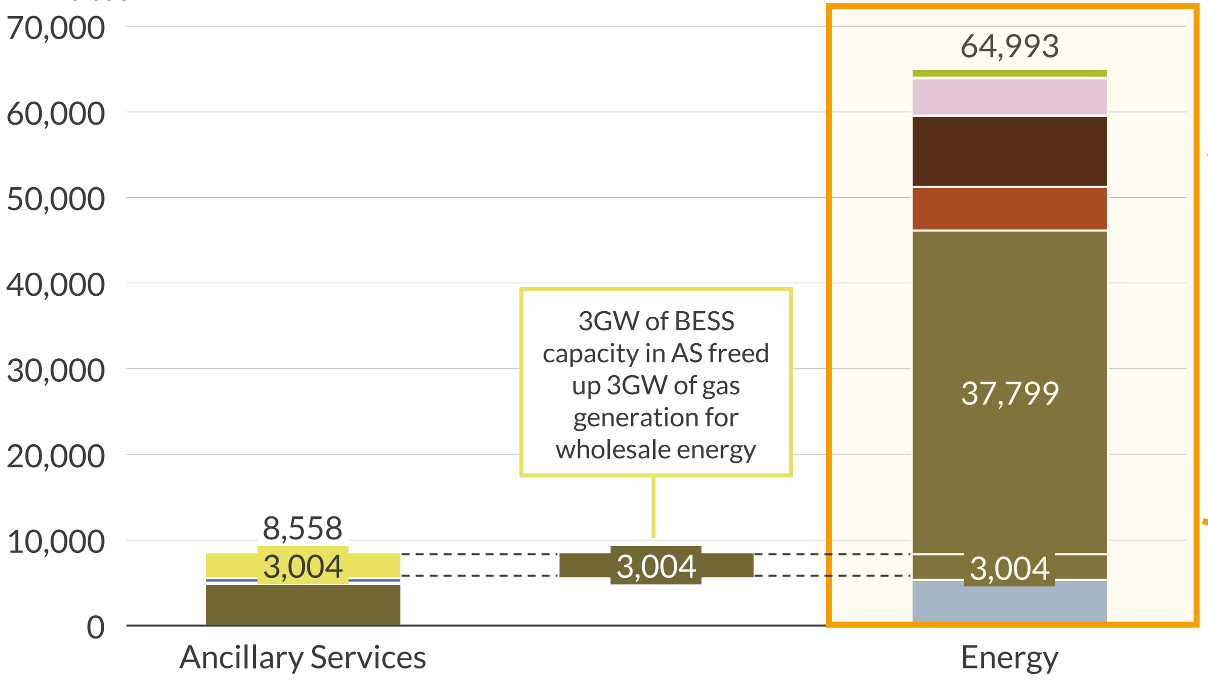
Case study | In January 2024 in ERCOT, 3GW of BESS capacity in Ancillary Services freed up an equivalent 3GW of natural gas to provide base power

AURORA

1 In tight morning hours[1] on January 14th and 15th, BESS overwhelmingly participated in AS while gas provided energy to the grid

Total power generation in AS and energy markets[2], by technology

MW

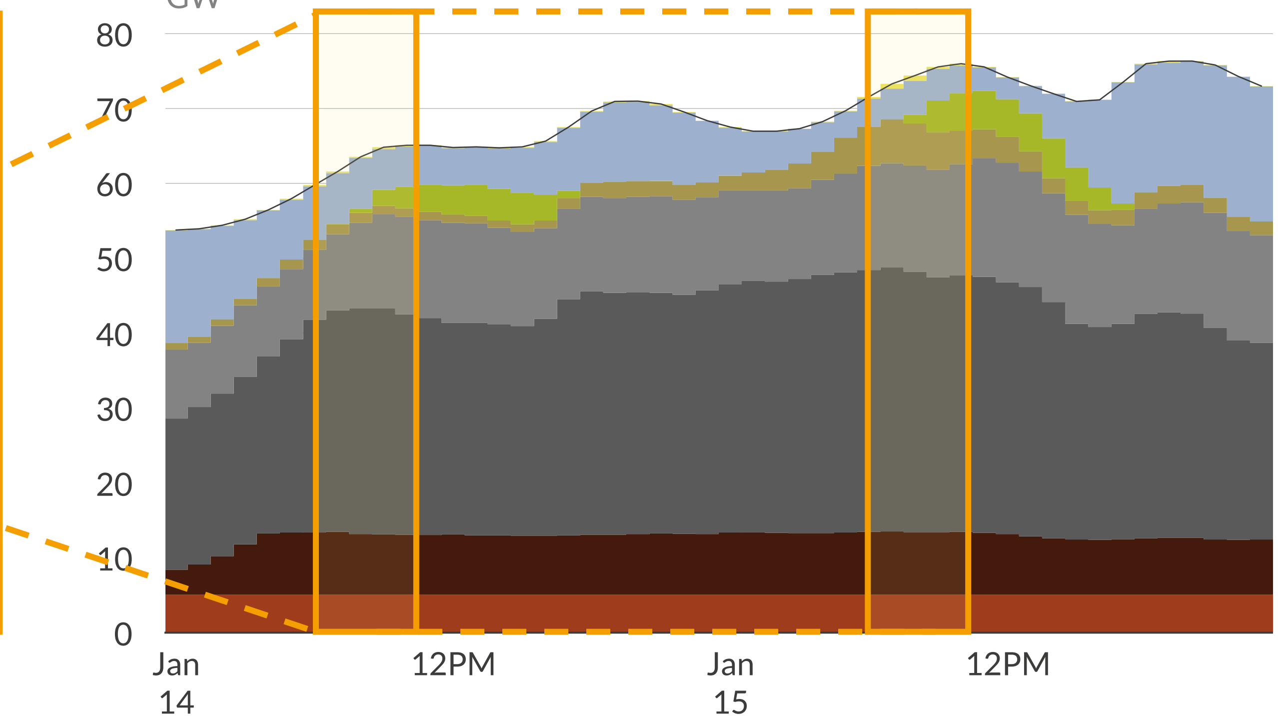


- Across these two days in January with very low wind generation and high load stemming from freezing temperatures, BESS committed an hourly average of 2.8 GW of capacity every hour to Ancillary Services, allowing least-cost CCGT generators to primarily generate power for wholesale markets.

2 On these freezing and low-wind days in January, thermal resources generated most of the energy needed to meet demand

Load and generation on Jan 14th and Jan 15th, 2024

GW



- With BESS providing most Ancillary Services on days of system tightness, thermal generators sell greater shares of energy to the grid, helping to push down system-wide real-time prices.

Onshore wind | Gas-fired[3] | Nuclear | Coal | Hydro Storage | Lignite | BESS | Solar PV | CCGT | Other Gas | Peaking | Load

1) Analysis includes hours between 6:00AM and 10:00AM when wind generation was low and system conditions were tightest. 2) Ancillary Services awards and energy generation for January 14 and 15, 2024 3) Gas-fired (for the lefthand graph) is a combination of Gas-CCGT, OCGT, and Peakers.

Sources: Aurora Energy Research, ERCOT

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Summary of MISO Central scenario input assumptions

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Inputs		Aurora Central
Demand	Underlying demand	+56TWh between 2025 and 2035 driven by population and industrial growth
	EVs	3.9mn EVs by 2030 and 7.7mn by 2035
Commodities	Gas price	Henry Hub increases to $4.6/MMBtu in 2030 and $5.1/MMBtu in 2035
	Coal price	Stable coal price across forecast horizon
Technology	Renewables	Between 2024 and 2040 wind CAPEX falls by 13% and solar by 41%
	Battery storage (Aurora Central scenario)	New build determined economically within the model
	Battery storage (*No Battery* scenario)	~250 MW of battery capacity online by 2027, followed by a freeze in further battery development
	Interconnection process	Short term impact of new build projects coming online in 2024 to 2030
	Build and retirement decisions	New build and retirements determined economically within the model
Policy	Pollution standards	Plants face increasing environmental costs but are not mandated to close early. NOx allocations included in plant run limits and costs
	Renewables incentives	Extension of PTC and ITC for wind and solar and introduction of ITC for batteries. REC prices ensure RPS targets are met
	Carbon price	No carbon price for any states
	Transmission upgrades	Strengthening of network increases transmission capacity between most regions by ~25% by 2035
	Accreditation	Application of DLOL (Direct Loss of Load) methodology beginning with the 2028/29 Planning Year

1) Which are at least in Phase 3 of the Interconnection Queue process and COD of 2026 or earlier.

Sources: Aurora Energy Research

Peak load is forecasted to rise to 125 GW in 2030 and 130 GW by 2035 driven by population and economic growth

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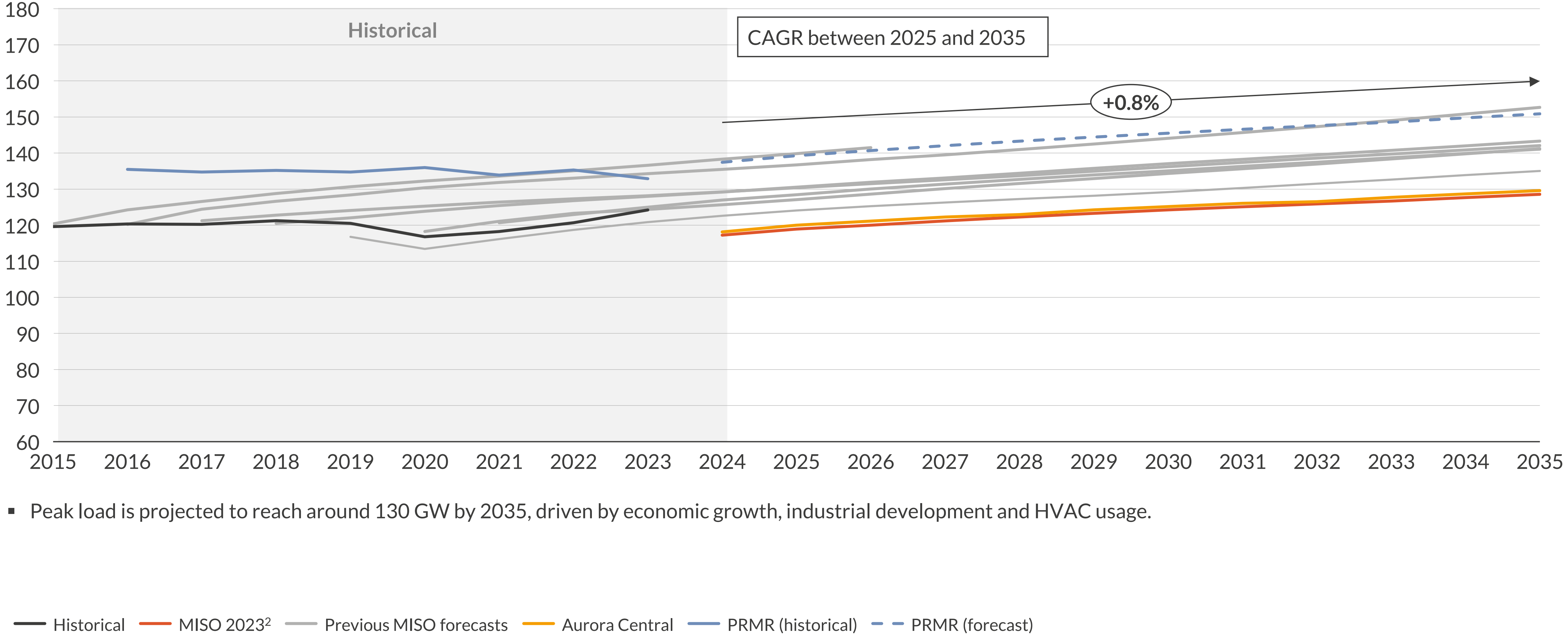
MISO peak load[1]
GW



- Peak load is projected to reach around 130 GW by 2035, driven by economic growth, industrial development and HVAC usage.

1) Summer peak demand. 2) Forecast for MISO 2023 and previous MISO forecasts are from SUFG's 2023 MISO Independent Energy and Peak Demand Forecast.

Sources: Aurora Energy Research, MISO, Purdue University

The "*No Battery*" scenario assumes projects in the later stages of the queue come online, followed by a freeze in BESS deployment

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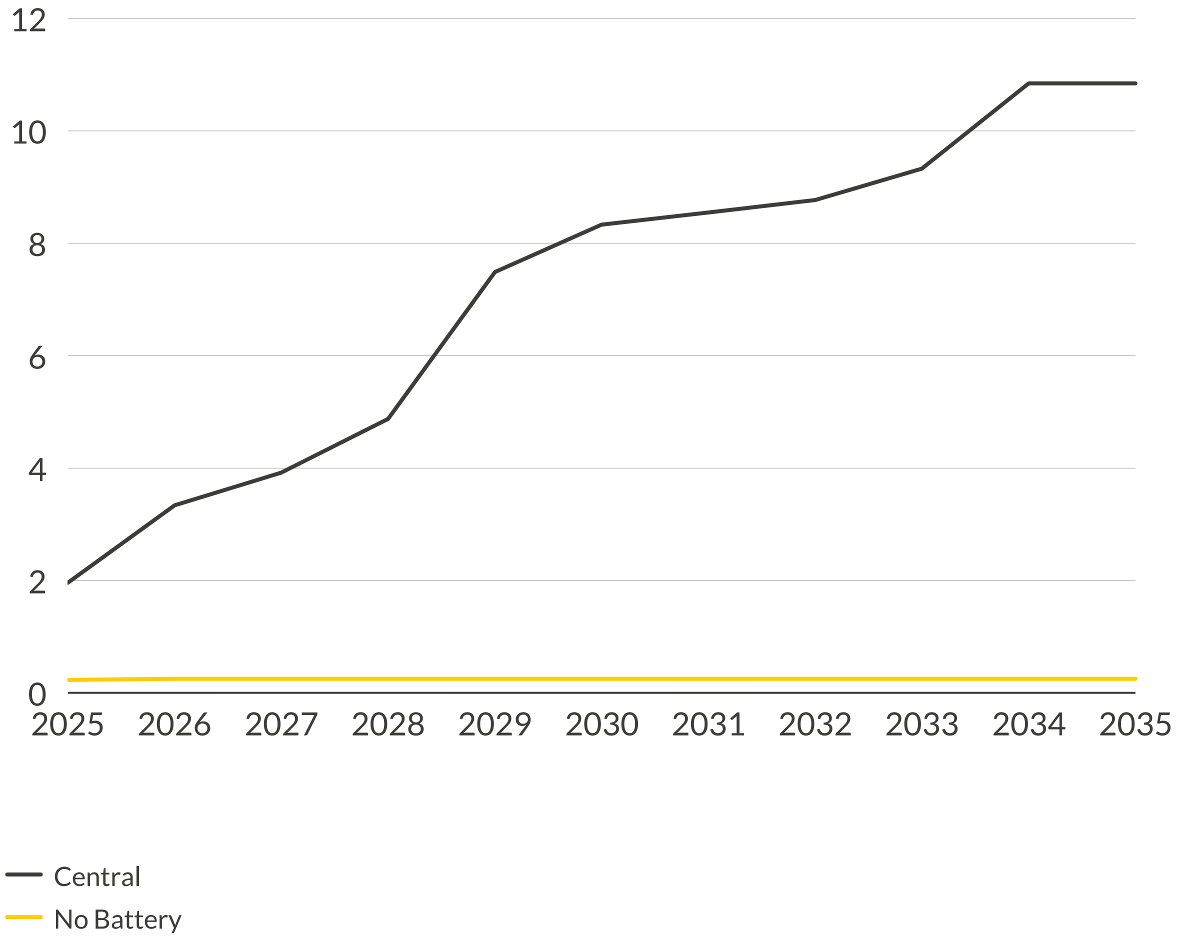
BESS IQ assumptions for the *No Battery* scenario

Project ID	Study Phase	Construction stage	Technology	Start year	Capacity MW
J1269	GIA[1]	Under Construction	Solar/Battery	2025	100.0[2]
J1272	GIA	Under Construction	Battery	2025	50.0
J1329	Phase 3	Under Construction	Battery	2026	20.0
Existing capacity (as of 2025)		Installed	Battery	-	146

Cumulative MISO BESS capacity by scenario
GW



1) Generator Interconnection Agreement, 2) Assumed 2:1 split of solar to battery capacity (i.e. 33.3MW battery capacity).

Sources: Aurora Energy Research, MISO

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In the no batteries scenario, renewables' buildout is slowed down and peakers increase capacity in response to battery reduction

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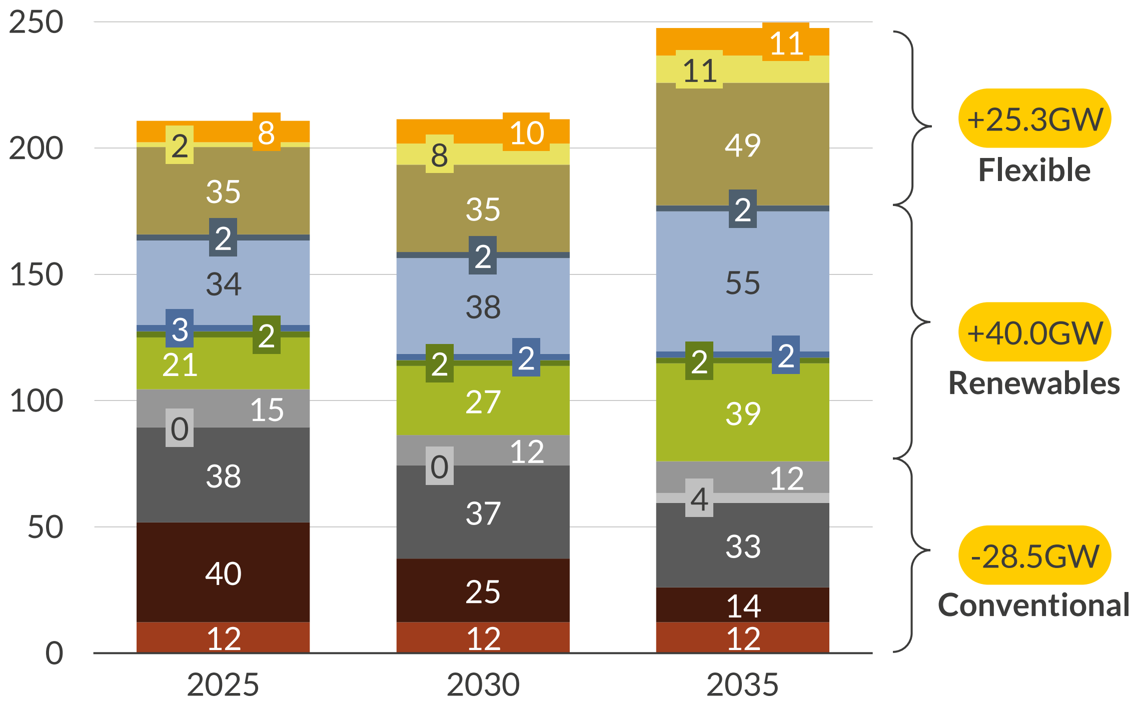
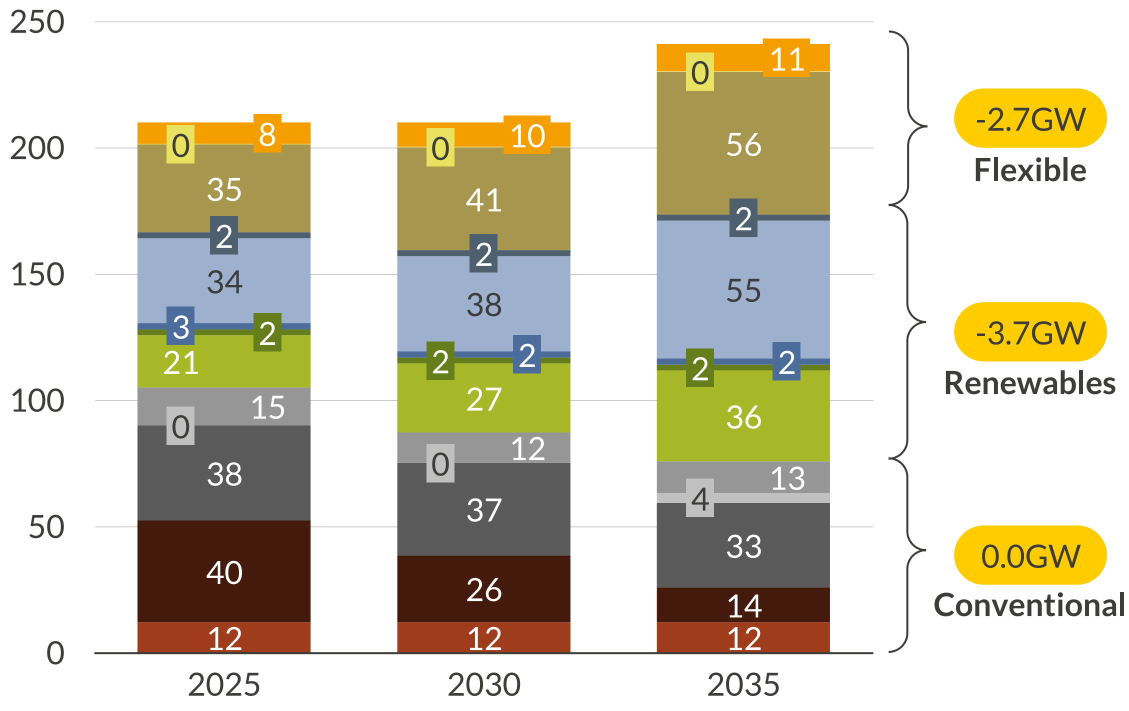
Installed capacity, Central
GW

Total change 2025–2035



Installed capacity, *No Battery*
GW

Delta to Central 2035



- Batteries show the highest growth among all technologies, going from ~2GW in 2025 to ~11GW in 2035 (+554%).
- Renewable buildout is reduced by ~4GW compared to Central scenario.
- Peakers see biggest growth with respect to central scenario, going from ~49GW to ~56GW.

Nuclear | Gas CCGT | Other thermal | Other renewables[1] | Onshore wind | Gas / oil peaker[2] | DSR[3] | Coal | Gas CCS | Solar | Hydro | Pumped storage | Battery storage

1) Other renewables includes biomass, and other waste heat recovery. 2) Peaking includes OCGT and reciprocating engines. 3) DSR includes Demand Response and Load Modifying Resources.

Sources: Aurora Energy Research

Region with most battery buildout in Central scenario (MISO Central) also displays the most growth of peakers in *No Battery* scenario

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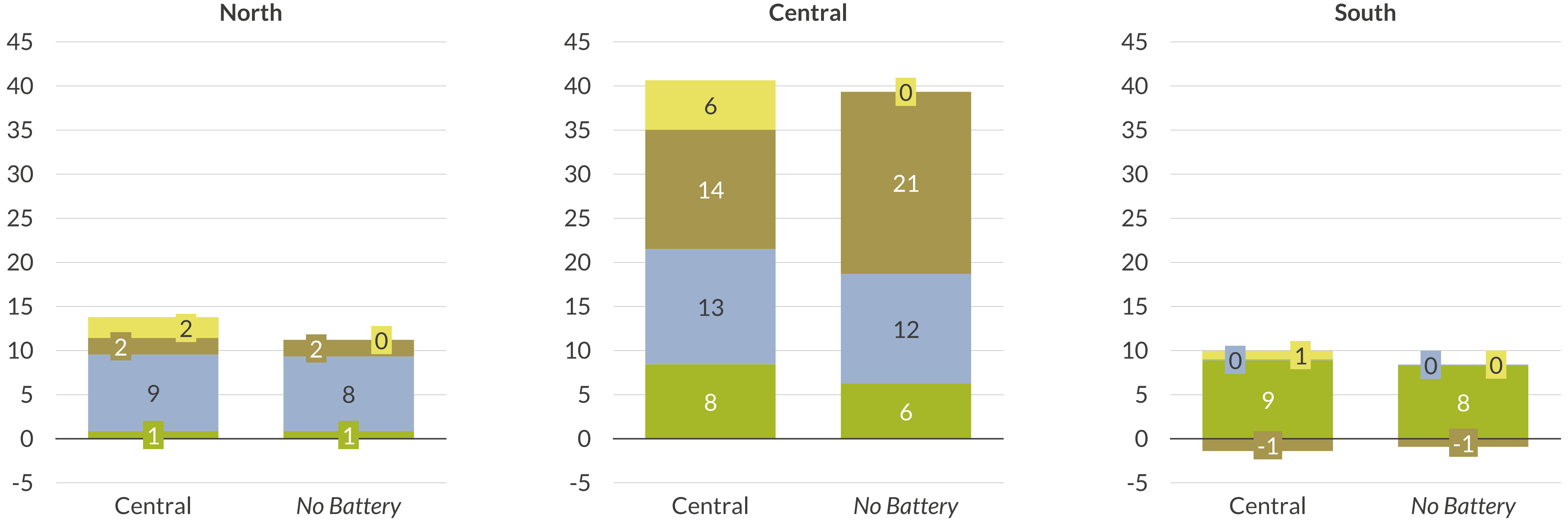
Delta of installed capacity (2025-2035), by MISO super region
GW



- Central region shows the highest growth in renewables in both scenarios, accompanied by a significant increase in flexible resources to ensure reliability.
- In North and South regions, as battery capacity growth is reduced, so does the growth of renewable energy sources.
- Significant increases in peaker capacity envisioned in the *No Battery* scenario could be hindered by supply chain constraints, tariffs, and other challenges.

Sources: Aurora Energy Research

Lack of energy storage in the *No Battery* scenario results in increased peaking resources generation

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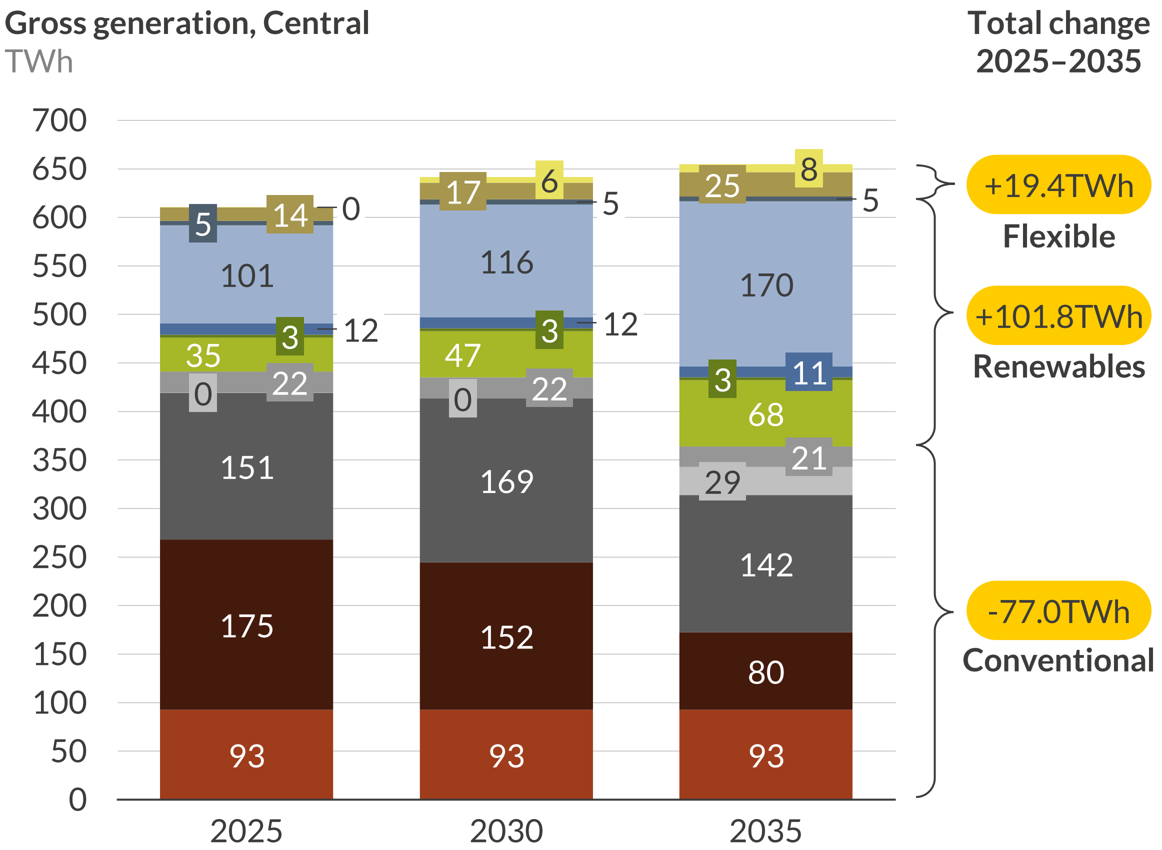
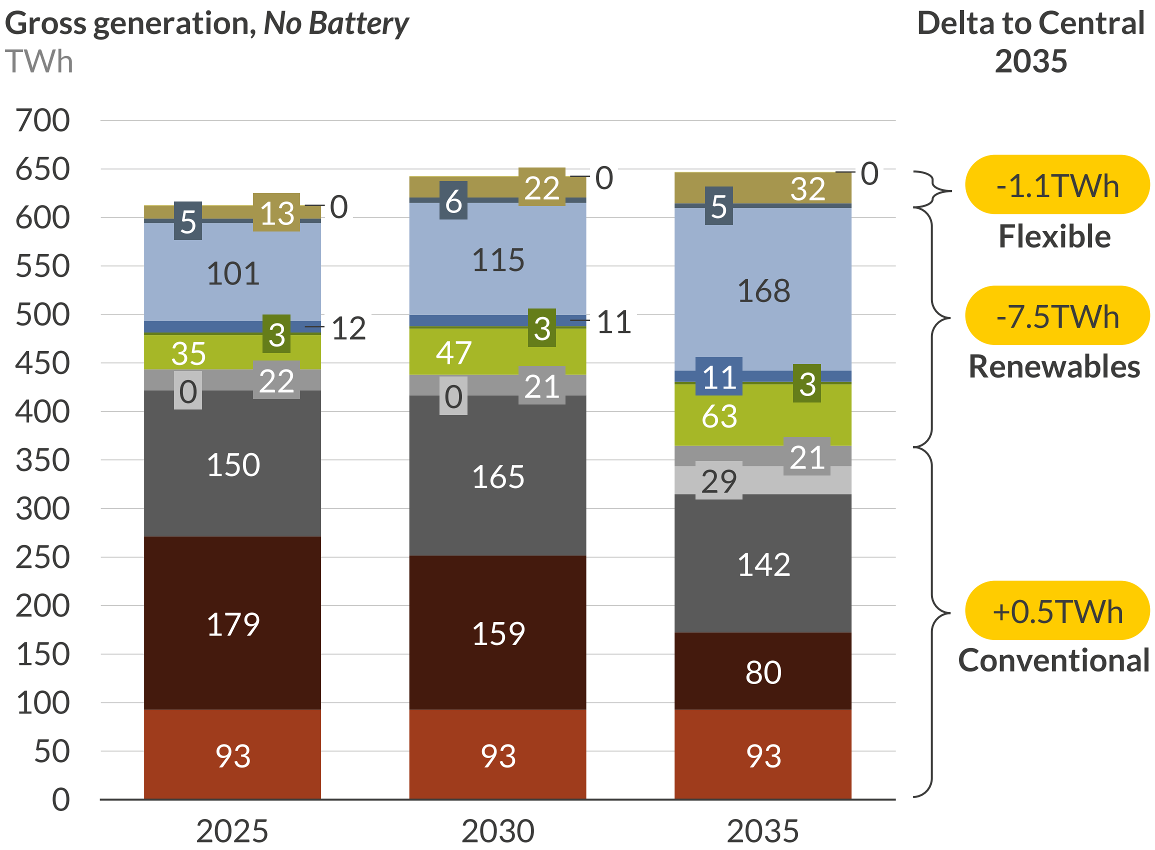




- In Central scenario, conventional fuel sources are phased out in favor of renewables and flexible sources, driven by both batteries and peakers increased production.
- In the *No Battery* scenario the pattern repeats (conventional fuel sources phased out), however flexible generation is driven mainly by peakers and renewable generation is also slightly reduced.

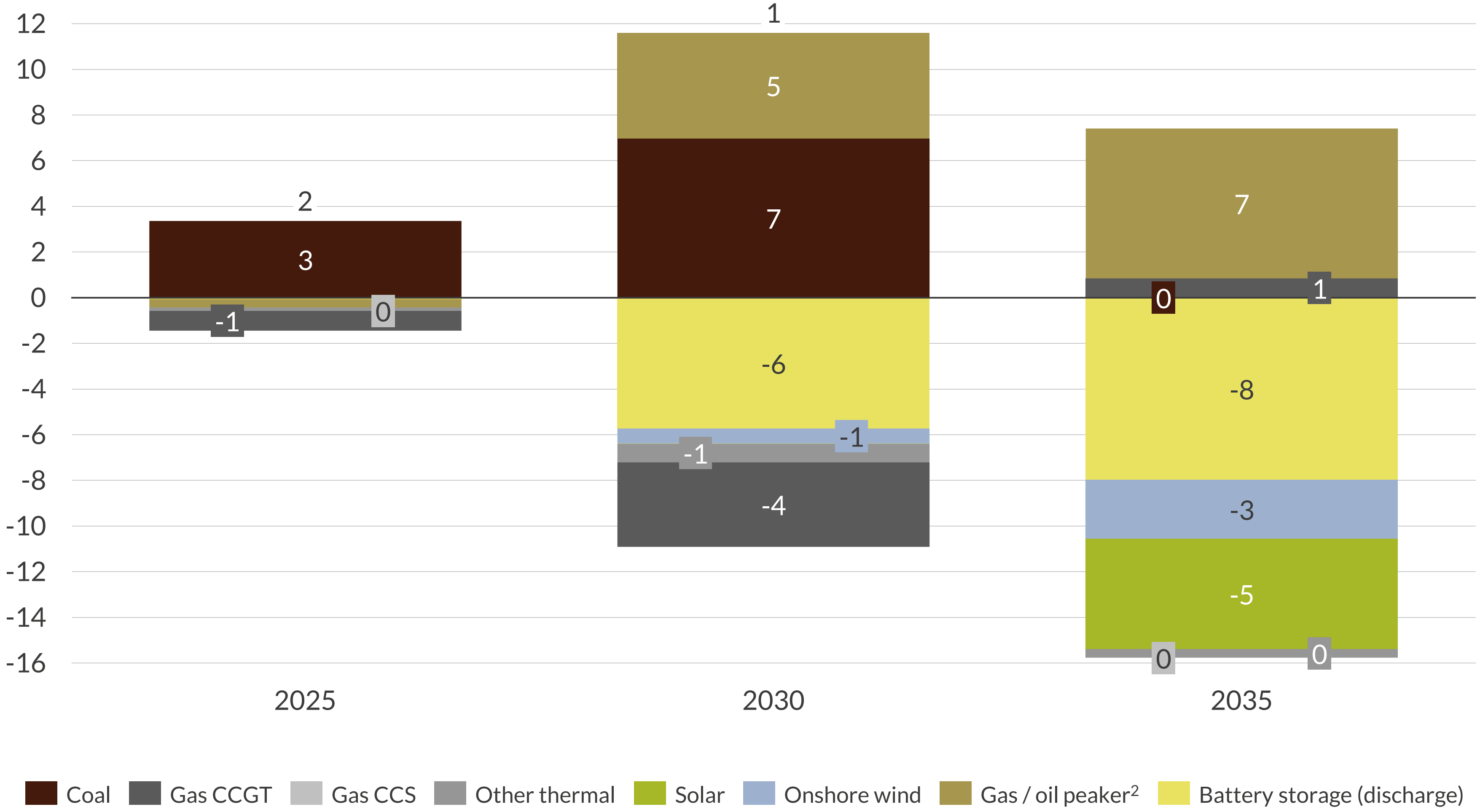
Nuclear | Coal | Gas CCGT | Gas CCS | Other thermal | Solar | Other renewables[1] | Hydro | Onshore wind | Pumped storage | Gas / oil peaker[2] | Battery storage (discharge)

1) Other renewables includes biomass, and other waste heat recovery. 2) Peaking includes OCGT and reciprocating engines.

Sources: Aurora Energy Research

In a world without batteries, solar and wind generation is ~8TWh less by 2035, replaced by (generally more expensive) peaker resources

Gross generation delta, *No Battery* vs. Central scenario
TWh



1) Peaking includes OCGT and reciprocating engines. Showing only technologies which delta is more than 0 in at least one year

Sources: Aurora Energy Research

- The Central scenario includes a broader diversity of resources providing generation, with renewable generation enabled by the presence of battery storage.
- Renewable generation sees the largest drop in production in the *No Battery* scenario. In 2035, onshore wind and solar generate ~3TWh and ~5TWh less than in Aurora's Central scenario.
- In the *No Battery* scenario, coal sees a significant increase in demand, generating up to ~7TWh in 2030 more than in Aurora's Central scenario.
- To make up for the generation lost due to the absence of batteries (~8TWh in 2035) peakers increase output, generating ~7TWh more than in Aurora's Central Scenario.

Agenda

If battery energy storage deployment is restricted, MISO experiences higher prices with an elevated dependence on peakers for moments of high demand

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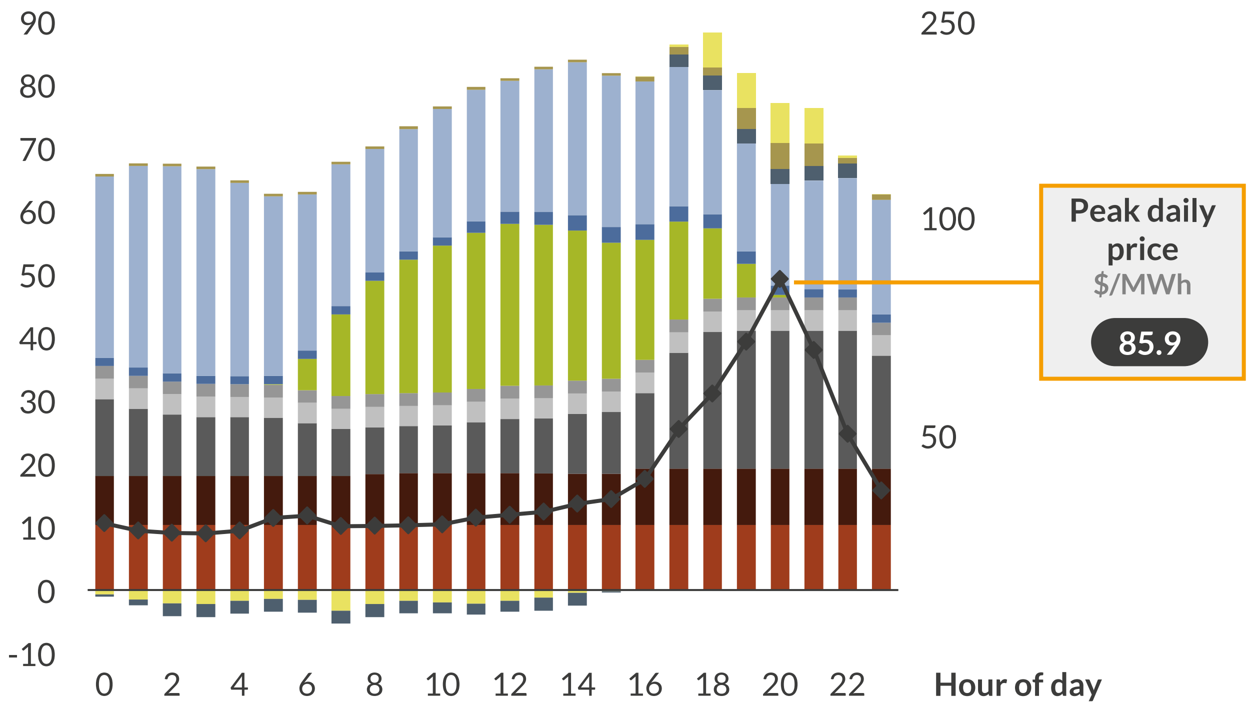
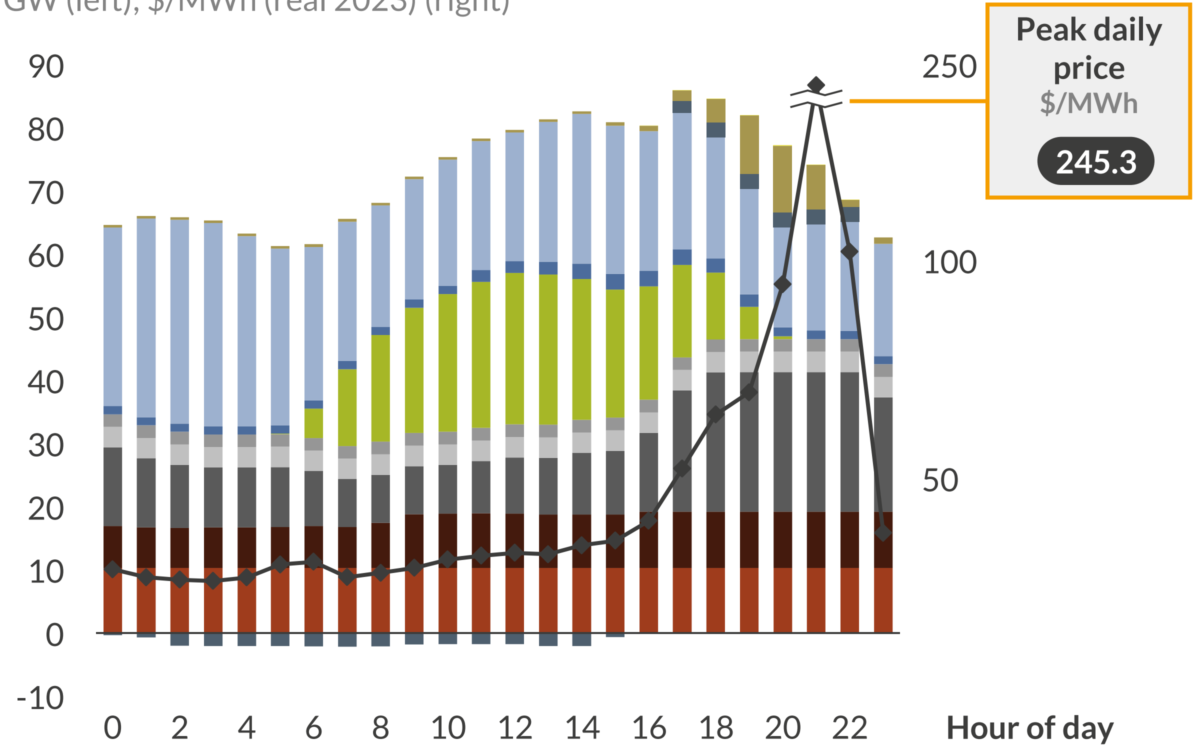
Average hourly net generation[1] and prices, Central, May 25th, 2035
GW (left); $/MWh (real 2023) (right)



Average hourly net generation[1] and prices, *No Battery*, May 25th, 2035
GW (left); $/MWh (real 2023) (right)



- Battery storage supplies energy as demand increases in the afternoon/evening, complementing other sources (e.g., peakers, pumped storage).

- With no batteries to alleviate demand during the afternoon and evening, prices spike to higher levels, reaching **peak prices up to ~$159/MWh higher during the evening price peak.**

Nuclear | Gas CCGT | Other thermal | Hydro | Pumped storage | Battery storage
Coal | Gas CCS | Solar | Onshore wind | Gas / oil peaker | DA Price

1) Net generation is the sum of charge and discharge.

Sources: Aurora Energy Research

Battery energy storage provides needed diversification of peaking capacity and complimentary value to thermal capacity

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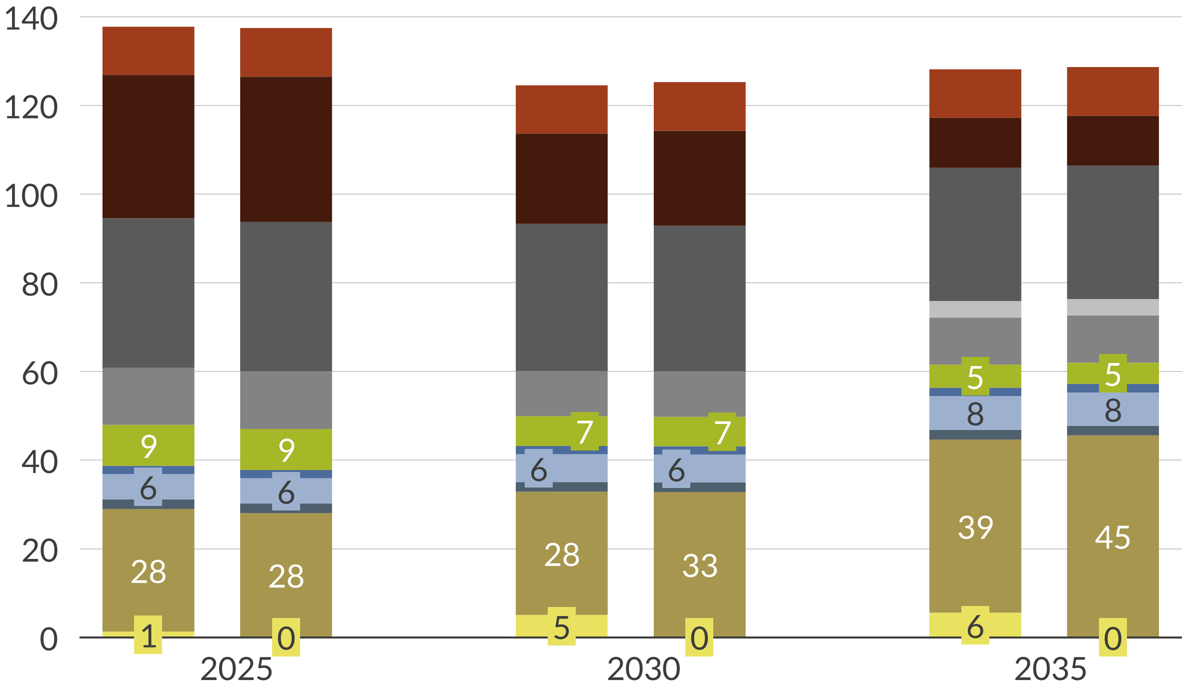
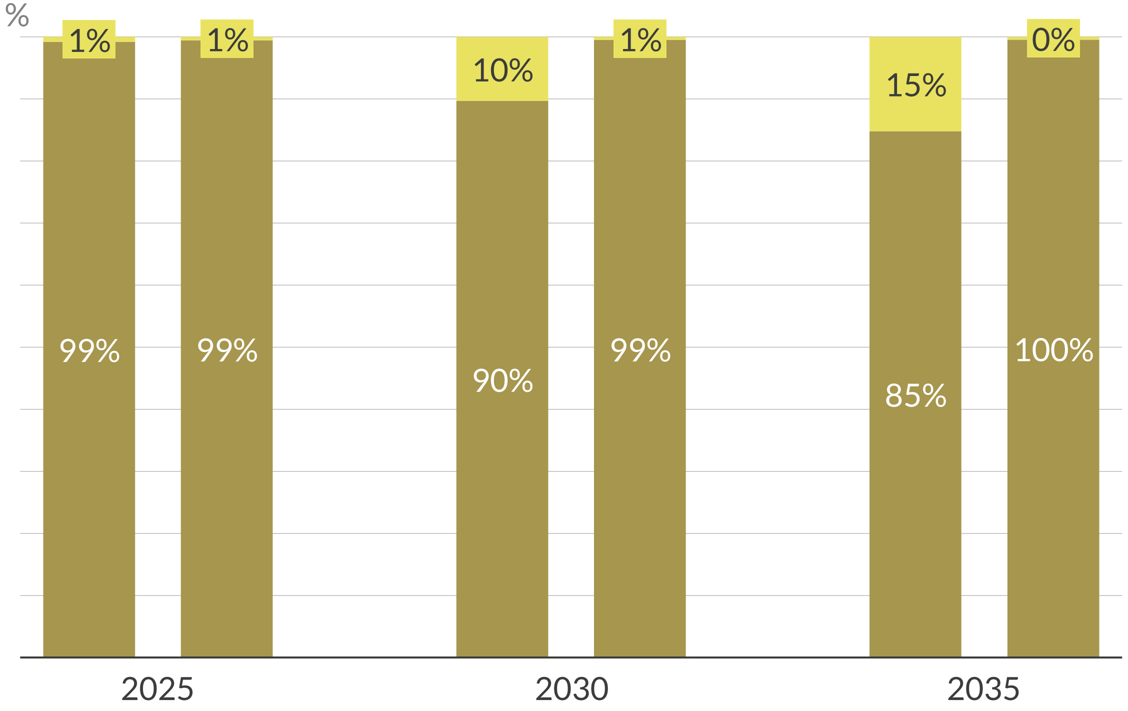
De-rated capacity — Central (left) vs. *No Battery* scenario (right)
GW



- In *No Battery* scenario BESS contribution is replaced by Gas / oil peaker, underscoring the importance of batteries during peak load moments.

Ratio of net production[1] in events of high prices[2] — Central (left) vs. *No Battery* scenario (right)
%



- In the *No Battery* scenario, MISO is reliant on peakers to generate during high-price events. In the Central scenario, battery systems work in conjunction with peakers to deliver flexible energy needs more cost-effectively.

Nuclear | Gas CCGT | Other thermal | Hydro | Pumped storage | Battery storage | Coal | Gas CCS | Solar | Onshore wind | Gas / oil peaker

1) Net generation is the sum of charge and discharge; 2) High prices defined as hours with wholesale prices upwards of $100USD, considers only generation from Gas / oil peakers and Battery Storage

Sources: Aurora Energy Research

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I. **Battery Market Outlook**
    1. BESS capacity forecast
    2. Policy and regulatory recent events
    3. Overview of BESS business case

II. **Comparative analysis of scenarios with and without BESS development**
    1. Scenario input assumptions
    2. Capacity stack in Central scenario and *No Battery* scenario
    3. System reliability and flexibility in *No Battery* scenario
    4. Deflationary impact on ancillary prices
    5. System costs comparison

III. **Appendix**
    1. Further detail on assumptions

MISO procures five ancillary services to support operations and ensure system reliability

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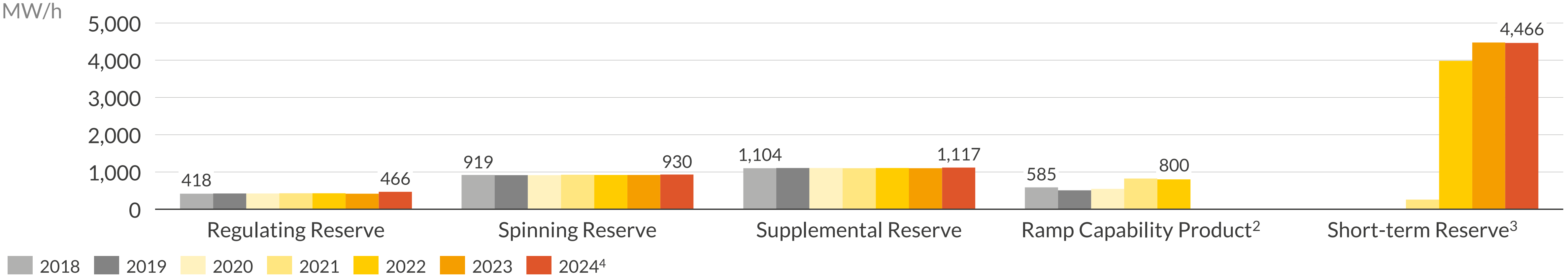
Ancillary Service properties	Regulating Reserve	Spinning Reserve	Supplemental Reserve (Non-spinning)	Ramp Capability Product (RCP)	Short-Term Reserve (STR)
Purpose	Capacity held by frequency responsive resource for the purpose of providing Regulating Reserve deployment[1] in both up/down direction.	A specified percentage of Contingency Reserve that must be synchronized to the system and converted to energy within the deployment period.	Contingency Reserve not considered spinning.	Capacity held to provide quick ramping generation to respond to fluctuations in net load.	Capacity held to meet system, regional, and local needs.
Response time	1–5 seconds	10-minute	10-minute	10-minute	30-minute
Market size (MW)	~500	~900	~1,100	~700	~4,400
Battery compatibility	●	●	●	◕	◕

Annual average procurement by ancillary services



1) Regulation deployment is accomplished by using automatic control equipment to raise or lower the output of on-line Resources as necessary to follow the moment-by-moment changes in demand and frequency. 2) Data not available for 2023 and 2024. 3) MISO implemented Short-term Reserve in December 2021. 4) As of July 2024.

Sources: Aurora Energy Research, MISO, Potomac Economics

Increased participation from batteries in ancillary services in Central scenario leverages unique capabilities and complements base power resources

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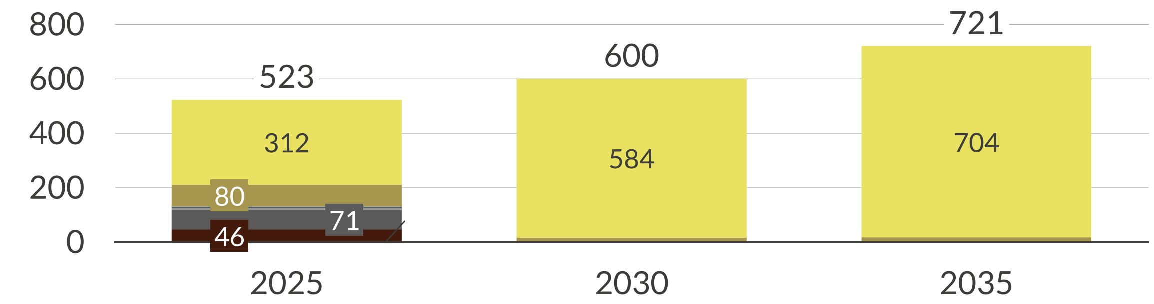
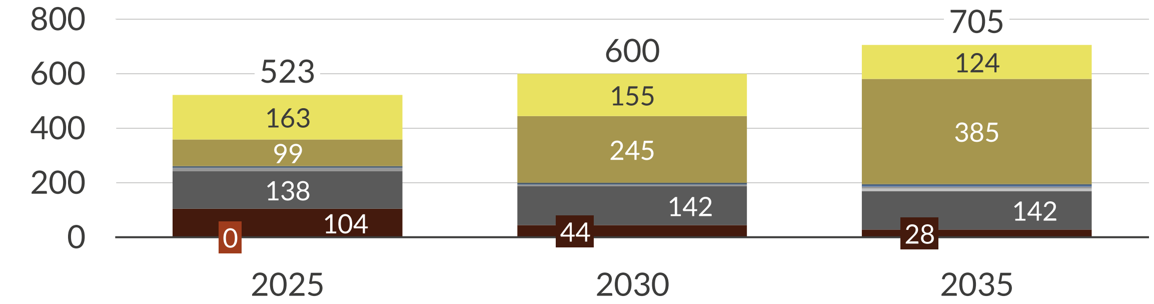
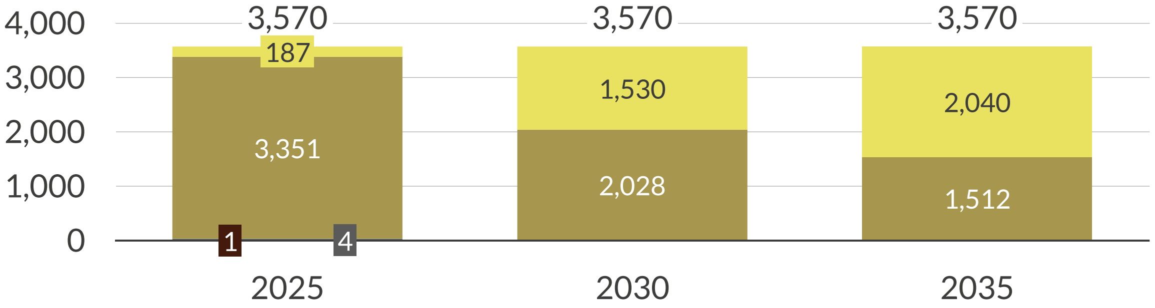
Technology mix of Regulating Reserve, Central
MW



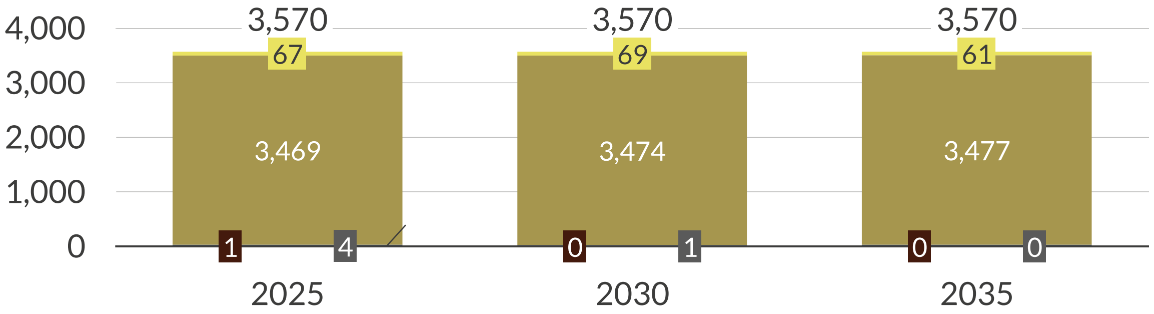
Technology mix of Regulating Reserve, *No Battery*[1]
MW



Technology mix of Short-term Reserve, Central
MW



Technology mix of Short-term Reserve, *No Battery*
MW



- Central scenario shows batteries taking a central role in Ancillary services, such as Regulating Reserve and Short-term Reserve.

- Capacity from batteries is supplied from batteries already installed and working in the grid.
- With no new batteries, peakers take on a more prominent role for the deployment of ancillary services.

Nuclear | Coal | Gas CCGT | Gas CCS | Other thermal | Hydro | Pumped storage | Gas / oil peaker | Battery storage

1) Battery capacity in *No Battery* scenarios derives from batteries already installed and working on the grid.

Sources: Aurora Energy Research, MISO

AS[1] prices increase if battery energy storage deployment is restricted as more expensive energy sources are shifted to fill the gaps

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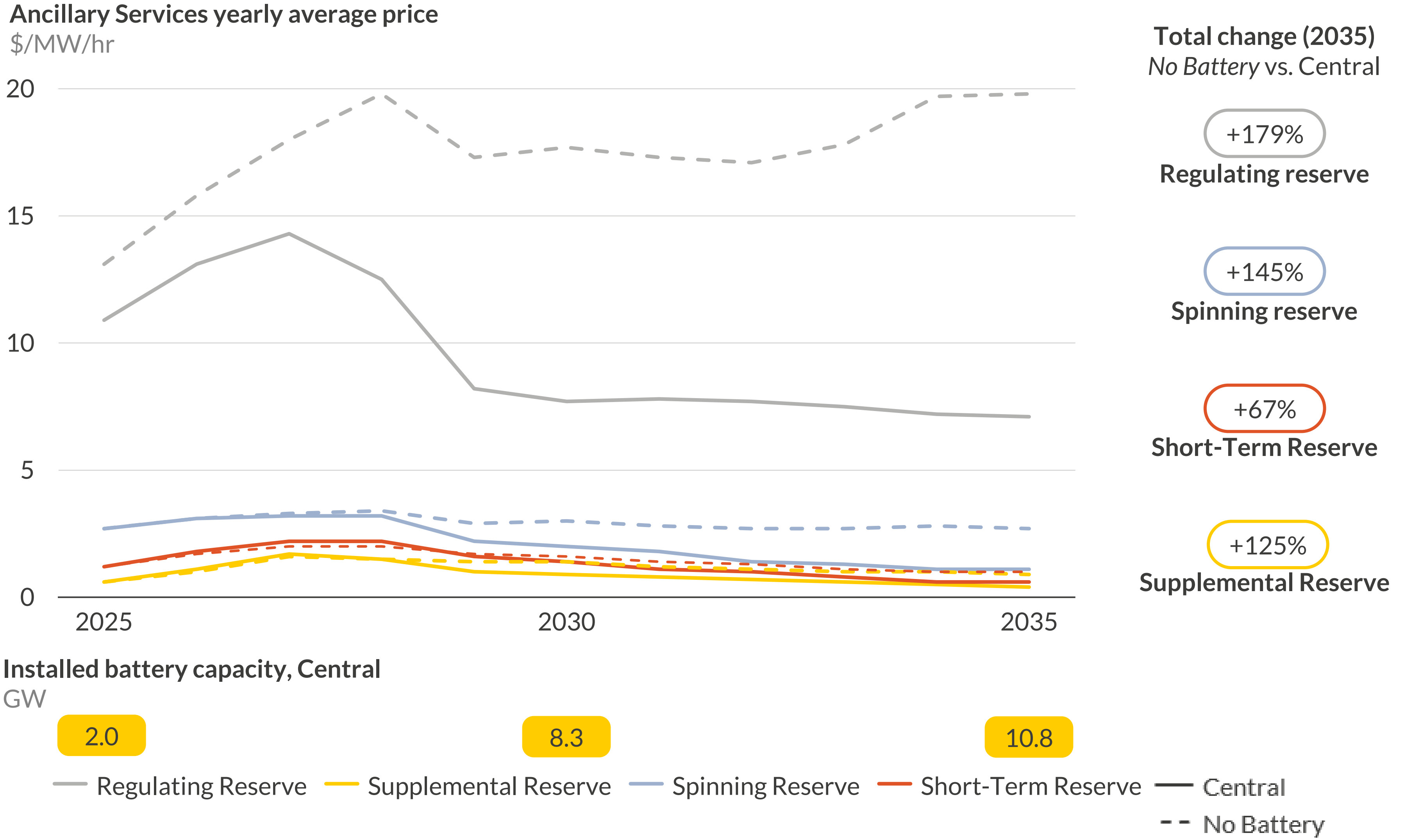

- Prices are increased by an average of 129% with peakers gaining more relevance in the ancillary services market.
- Highest increase is for Regulating reserve with an increase of ~179%.
- As ancillary services prices increase, maintaining grid reliability would become more and more expensive.

1) Ancillary Services

Sources: Aurora Energy Research,

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Long-term equilibrium modelling seeks out the lowest system cost solution; the *No Battery* scenario results in total system costs that are $27 billion higher

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Scenario outcomes

- In the *No Battery* scenario, **total system costs[1] are $27 billion higher in total** across the model horizon[2], driven primarily by the evolution of CAPEX and wholesale costs:
  - In the *No Battery* scenario, CAPEX costs are initially lower as fewer batteries are built across MISO.
  - As the forecast progress, **wholesale electricity costs rise in the *No Battery* scenario and outweigh the initial reduction in CAPEX** from building fewer batteries.
- From 2025–2035, the cumulative total annual cost of electricity generated in MISO is **$4.5 billion higher** in the *No Battery* scenario than in the Central scenario.
- Scenario outcomes reflect the **efficiency gained from adding batteries** to the system by **reducing peak wholesale electricity prices** and lowering overall system costs through improved flexibility and resource optimization.

Modelling overview

- Aurora's power market model iteratively solves for a solution that minimizes system cost based on economic build decisions.
- The economic equilibrium outcome considers the impacts of CAPEX, operational and maintenance costs, fuel costs, and resulting electricity prices.

INPUTS

- Technology
- Policy
- Demand
- Commodity prices
- Weather patterns

Dispatch model

- ½ hourly or hourly
- Iterative modeling
- Dynamic dispatch of plant
- Endogenous interconnector flows

Continuous iteration until an equilibrium is reached

Investment decisions module

- Capacity market modeling
- Capacity build / exit / mothballing
- IRR / NPV driven
- Detailed technology assessments

OUTPUTS

- Capacity mix
- Generation mix
- Wholesale & imbalance prices
- Capacity market prices
- Profit / Loss and NPV
- Electric vehicle charging

1) Total of CAPEX, fixed and variable O&M costs, fuel costs, and electricity costs. 2) The model horizon is from 2025 – 2050.

Source: Aurora Energy Research

Electricity prices rise in MISO in *No Battery* scenario, resulting in a cumulative increase of $4.5bn in electricity costs across the ISO by 2035

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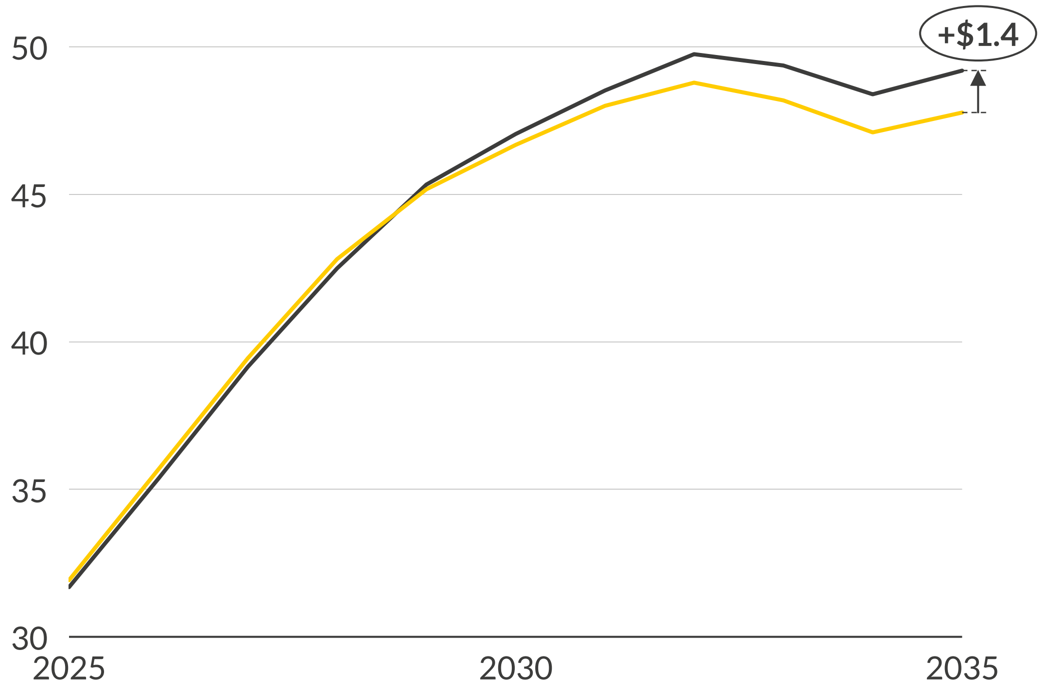
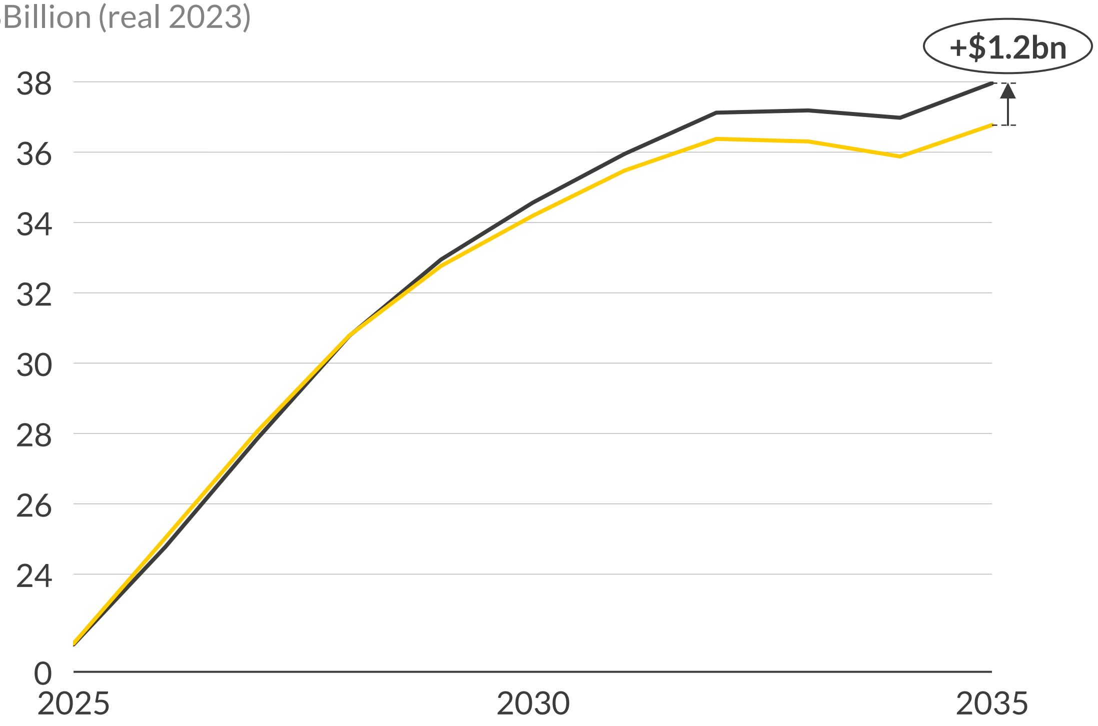
Yearly average ATC[1] electricity price
$/MWh (real 2023)



- With fewer batteries deployed, higher evening peak prices result in wholesale electricity prices that are $1.4/MWh higher annually on average compared to the Central case by 2035.
- Electricity prices begin to be materially impacted starting in the late 2020s as the delayed effects of the lower battery buildout kick in, particularly the increased reliance on gas peakers and more limited solar buildout.

Total annual cost of generated electricity in MISO
$Billion (real 2023)



- Higher average electricity prices result in additional costs for electricity across MISO. By 2035, an additional $1.2 billion is required in terms of incremental electricity costs in the *No Battery* scenario.
- From 2025 to 2035 total cost of wholesale electricity is increased by **$4.5bn** when battery deployment is restricted.

No battery Central

1) Around the clock.

Sources: Aurora Energy Research

Reliance on less efficient use of generation assets and reduced resource diversification leads to higher costs when demand peaks

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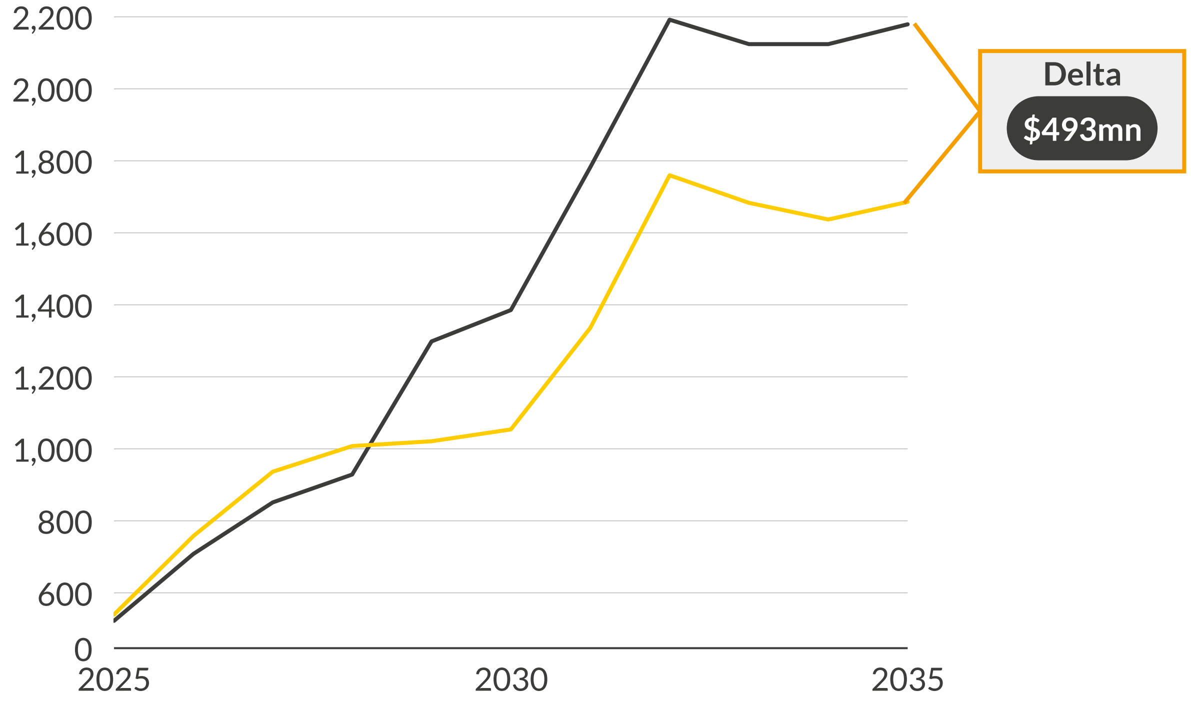
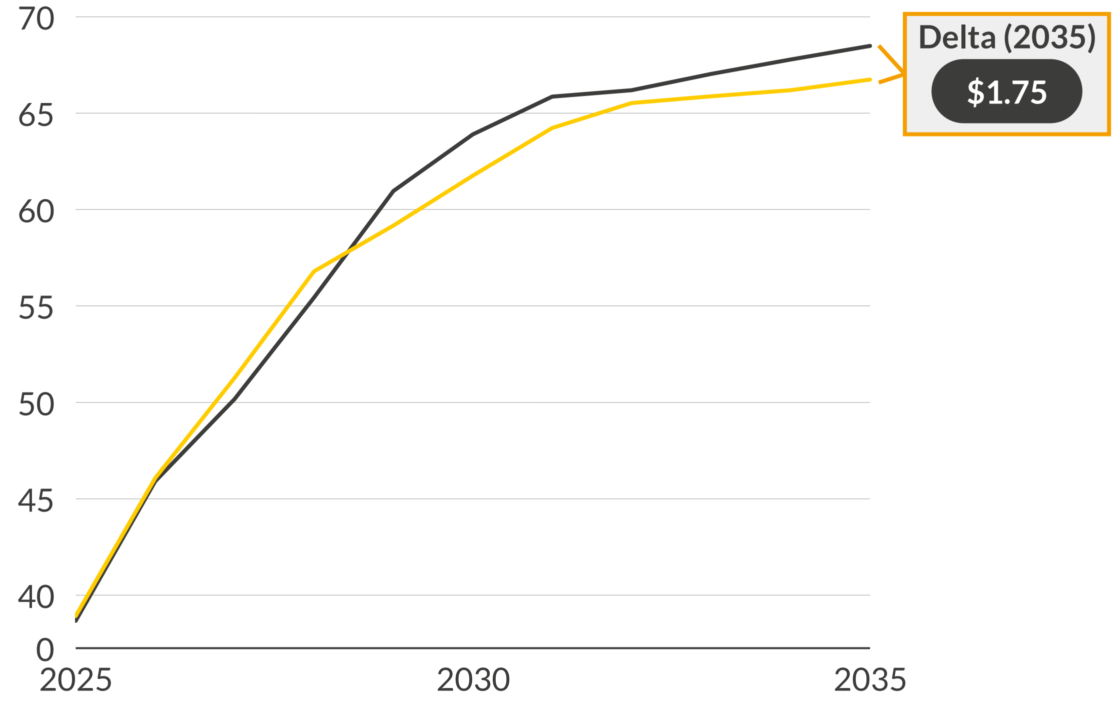
Total cost of peakers' generated electricity, 2025-2035
$mn



Peaker GWA[1], 2025-2035
$/MWh (real 2023)



- Without batteries, peakers see their demand increase which translates into higher total costs for peaker generated electricity.
- Furthermore, each MWh provided by peakers will be more expensive compared to prices in a world with batteries, starting around 2029.

No battery Central

1) Generation weighted average

Sources: Aurora Energy Research

In *No Battery* scenario PRA clearing prices rise by ~$35 per MW-day in both North and Central, and South regions by 2030

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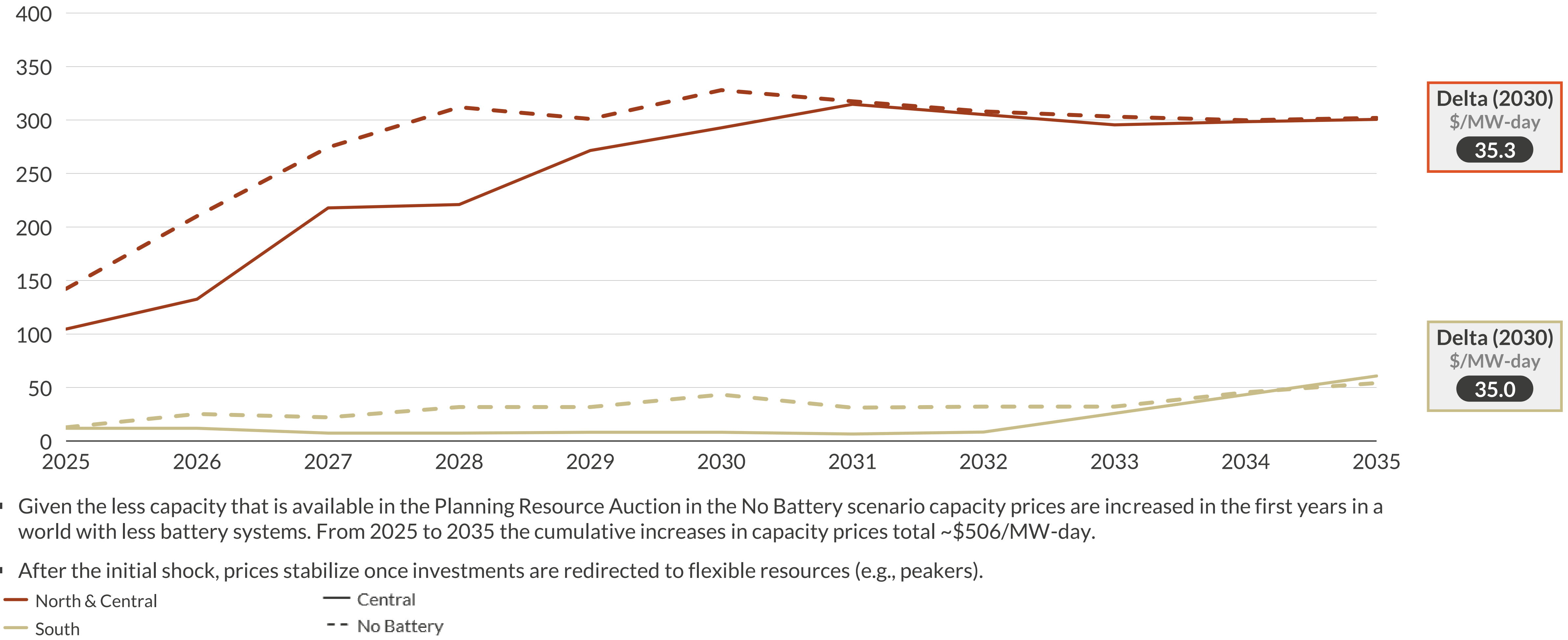
Clearing prices[1] for MISO Planning Resource Auction (PRA)
$/MW-day, real 2023



- Given the less capacity that is available in the Planning Resource Auction in the No Battery scenario capacity prices are increased in the first years in a world with less battery systems. From 2025 to 2035 the cumulative increases in capacity prices total ~$506/MW-day.
- After the initial shock, prices stabilize once investments are redirected to flexible resources (e.g., peakers).

1) 5-year rolling average prices, vertical demand curve structure.

Sources: Aurora Energy Research

Agenda

Henry Hub and Chicago Citygate yearly prices range between $3-5/MMBtu between 2025 and 2035

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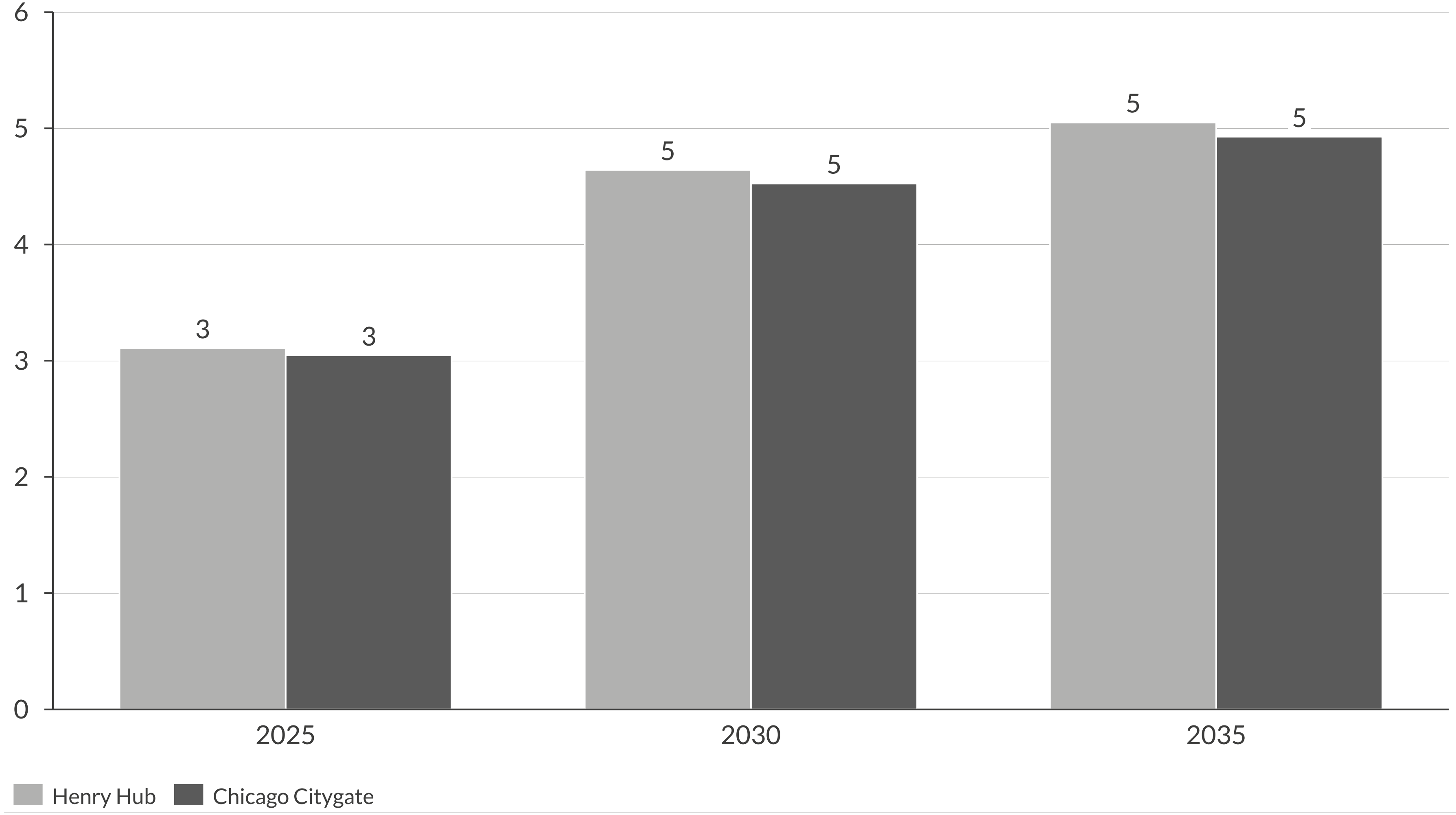
Central natural gas price forecast[1]
$/MMBtu (real 2023)



1) For years 2025–2028, the prices shown reflect current futures prices for the years in question, with declining weights. In 2024, forecast prices include historical prices up to Nov-24.

Sources: Aurora Energy Research, Natural Gas Intelligence

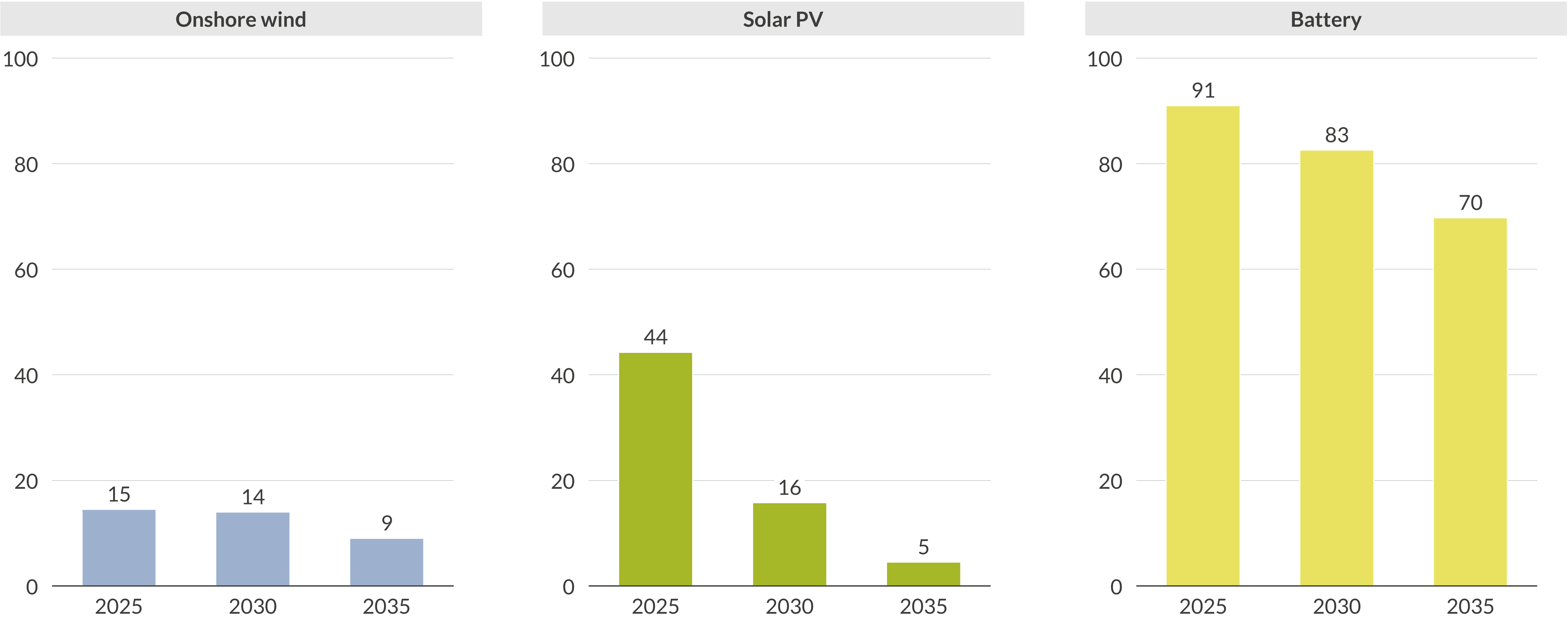
Aurora's Henry Hub forecast has several key upwards drivers:

- **Fast growing Asian demand:** Between 2025 and 2040, Asian natural gas demand rises by 36%, more than offsetting the 31% decline in European gas demand due to decarbonization.
- **Increased reliance on LNG:** US LNG exports to Europe increase by 15% through 2027, at which point they account for 25% of European gas supply, before gradually declining.
  - US LNG exports to Asia rise by 50% through 2030.
  - Investments in pipeline takeaway capacity from the Permian Basin partially offset rising prices this decade.
- **Increased US gas production costs:** Depletion of lowest-cost fields increase production costs through the 2040s.

De-rating factors in MISO vary significantly by technology, with those of newer technologies expected to change as more data is collected

Aurora assumed renewable de-rating factors[1] by technology

%



1) With Direct Loss of Load methodology.

Sources: Aurora Energy Research, MISO

Total load is forecasted to rise to 700TWh in 2030 driven by population and economic growth

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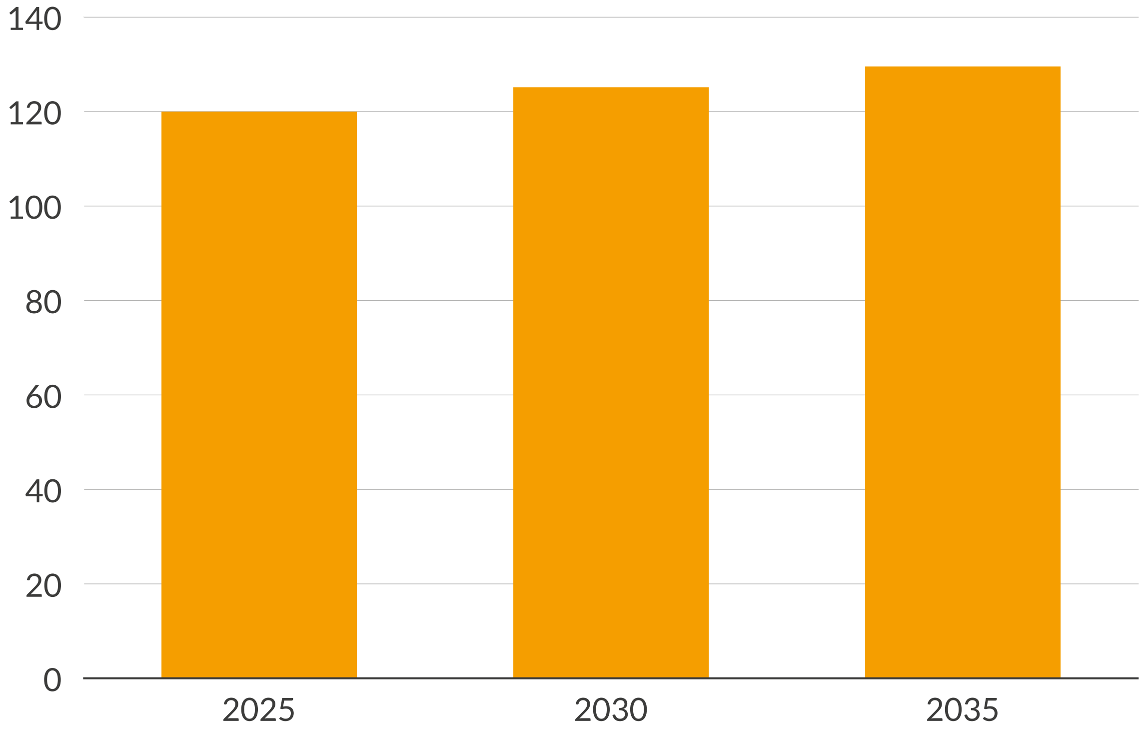
MISO peak load[1]

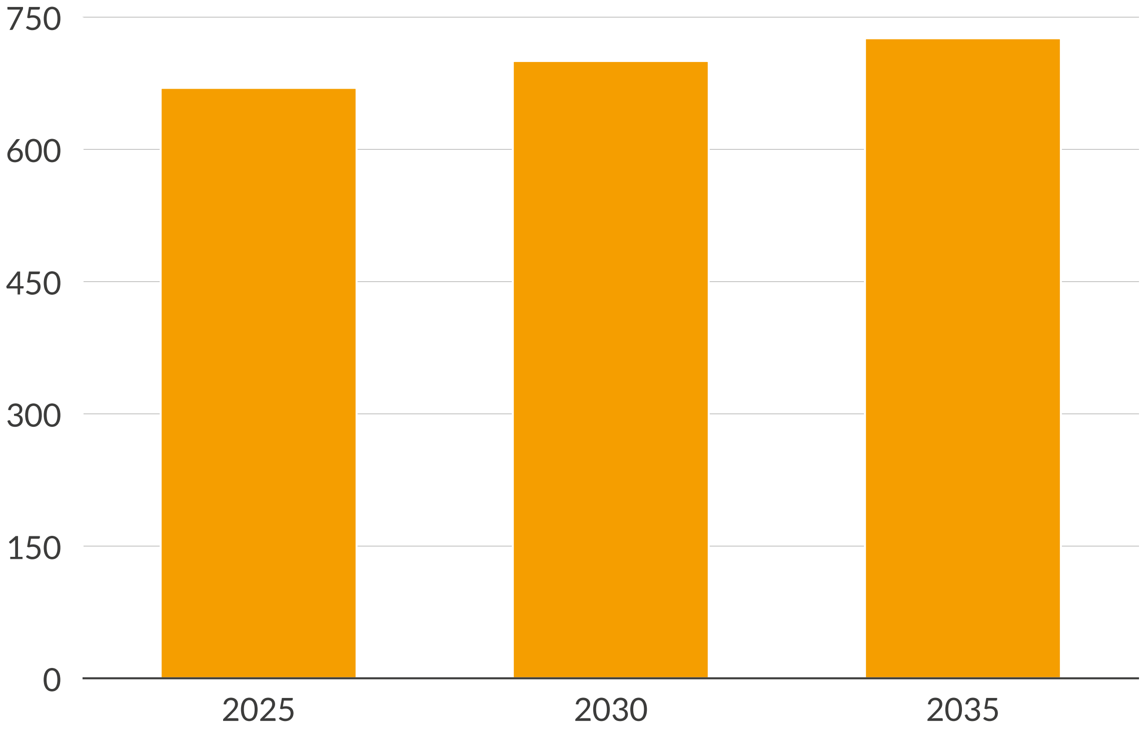
GW



- Future peak demand growth and annual demand are driven by strong economic growth, industrial development and HVAC usage.

MISO total annual load

TWh



- Annual energy demand is set to increase in line with peak demand and reach 700TWh by 2030.

Aurora Central

1) Summer peak demand.

Sources: Aurora Energy Research, MISO, Purdue University

Details and disclaimer

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