Battery energy storage impact and benefits assessment for SPP

Commissioned by American Clean Power

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

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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 thermal and renewable generation sources.
- This report illustrates the role that batteries play within the Southwest Power Pool (SPP) region and examines their impact on SPP 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 analysis in this report addresses dynamics within the SPP region only. The Central scenario includes the assumed continuation of various policy reforms and initiatives, including federal clean energy tax credits, CPP[1] reform and ELCCs[3]. 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) Consolidated Planning Process, an SPP initiative to implement interconnection queue reform. 3) Effective Load Carrying Capacity, as proposed by SPP.

Executive Summary

1

As SPP experiences continued demand growth and aging energy generation is replaced, the need for flexible resources like energy storage becomes increasingly important

- SPP is expecting a significant increase in demand for electricity (peak load growing to ~69GW by 2035), putting a strain on generation and transmission networks at a time of increasing renewables penetration.
- Flexible energy resources such as batteries are expected to play an essential role in meeting peak demand growth, considering SPP's need to manage large ramping requirements and 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 (~55% of SPP's installed capacity by 2035), batteries charge when there is excess, low-cost energy production and discharge during peak demand when costs are higher, shifting generation to hours when it is needed most.
- Historical analysis of other markets shows that batteries can help 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

Deploying a moderate amount of battery capacity over the next decade results in total system costs that are $7 billion lower over the forecast horizon

- By dispatching during peak demand hours, batteries help reduce peak pricing, with daily peak prices that are $7/MWh (+10%) higher on average in the *No Battery* scenario in 2035.

Sources: SPP, Aurora Energy Research

5GW of batteries build economically in Aurora's Central scenario by 2035; the *No Battery* scenario assumes only 1.4GW of late-stage projects build

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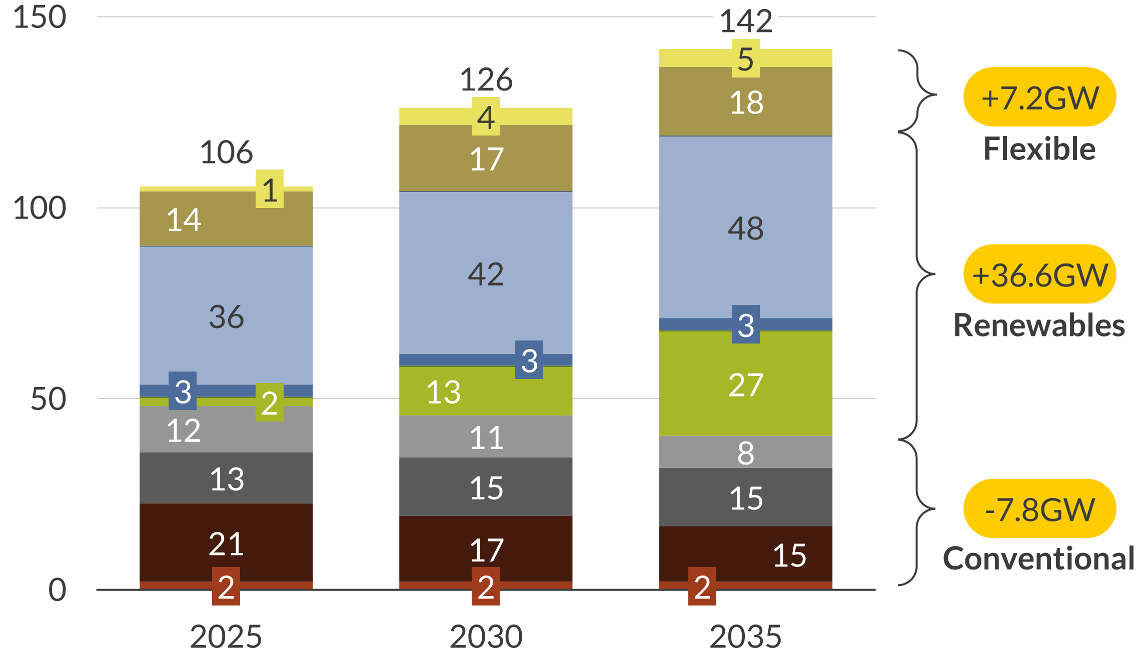
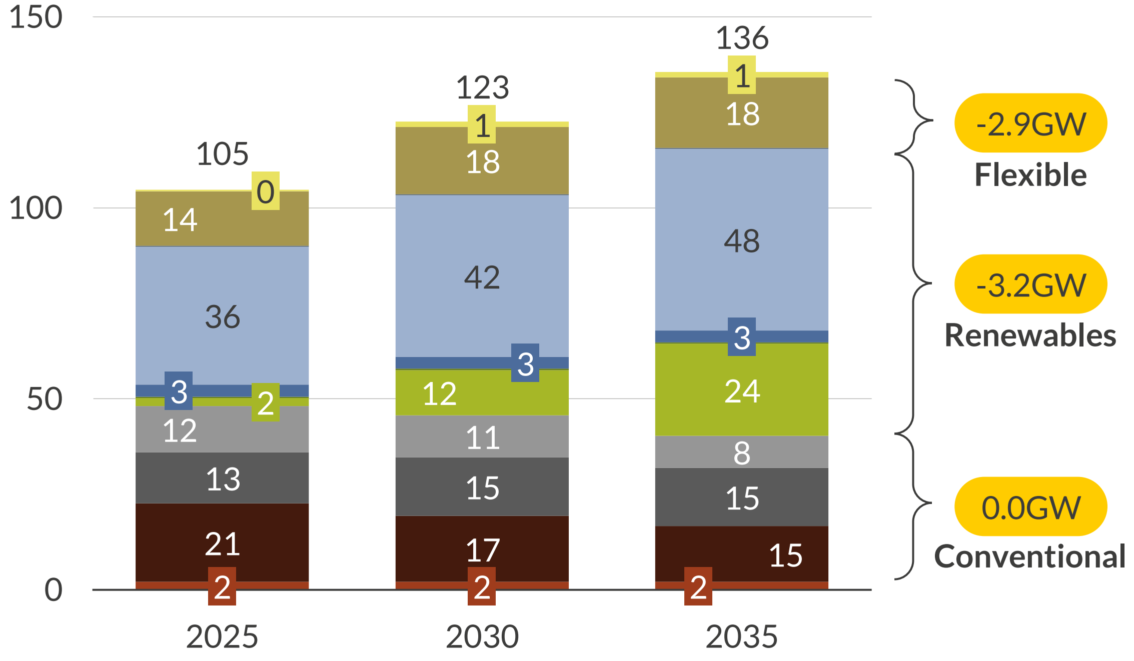
Installed capacity, Central
GW

Total change 2025–2035



Installed capacity, *No Battery*
GW

Delta to Central 2035



- Starting from small levels of currently installed capacity, solar and battery capacity sees the largest growth in the Central scenario.

- Battery buildout supports solar growth, and in the no battery scenario ~3GW less solar capacity is deployed by 2035 relative to the Central scenario.
- Peakers see a slight increase in capacity but largely remain constant.

Nuclear | Gas CCGT | Other thermal | Other renewables[1] | Onshore wind | Gas / oil peaker[2]
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.

Sources: Aurora Energy Research

Additional battery capacity significantly lowers price spikes during peak demand, resulting in $2.2bn in electricity cost savings in SPP from 2025 - 2035

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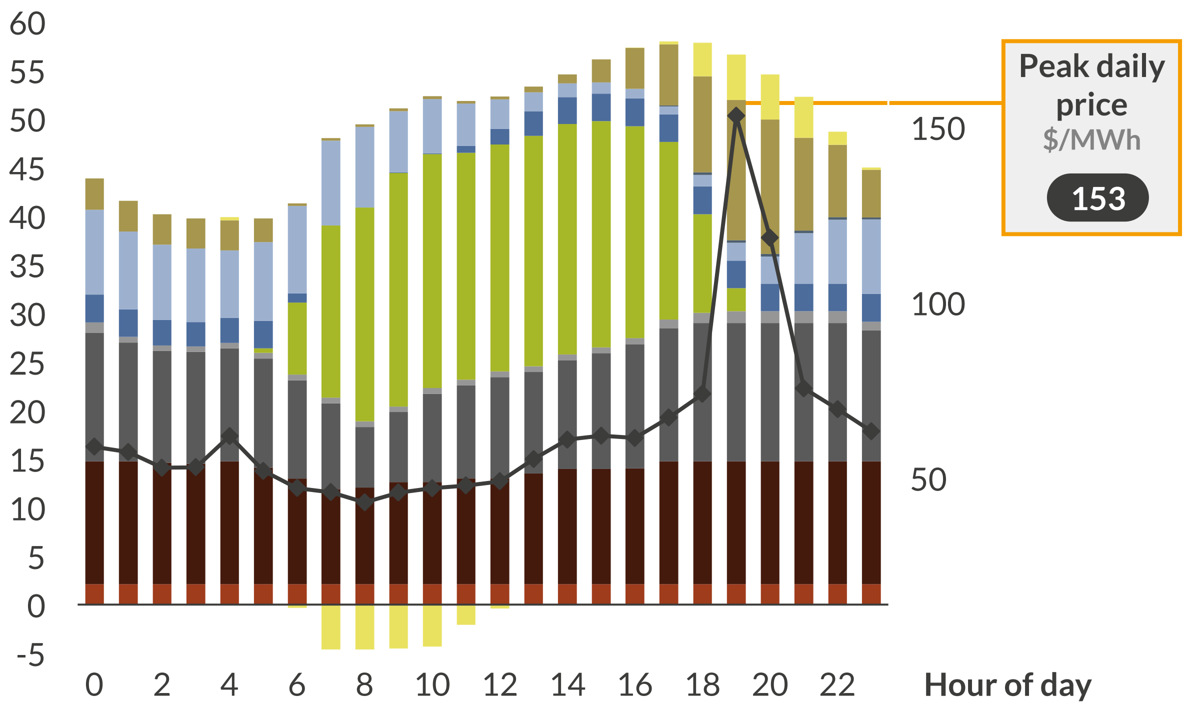
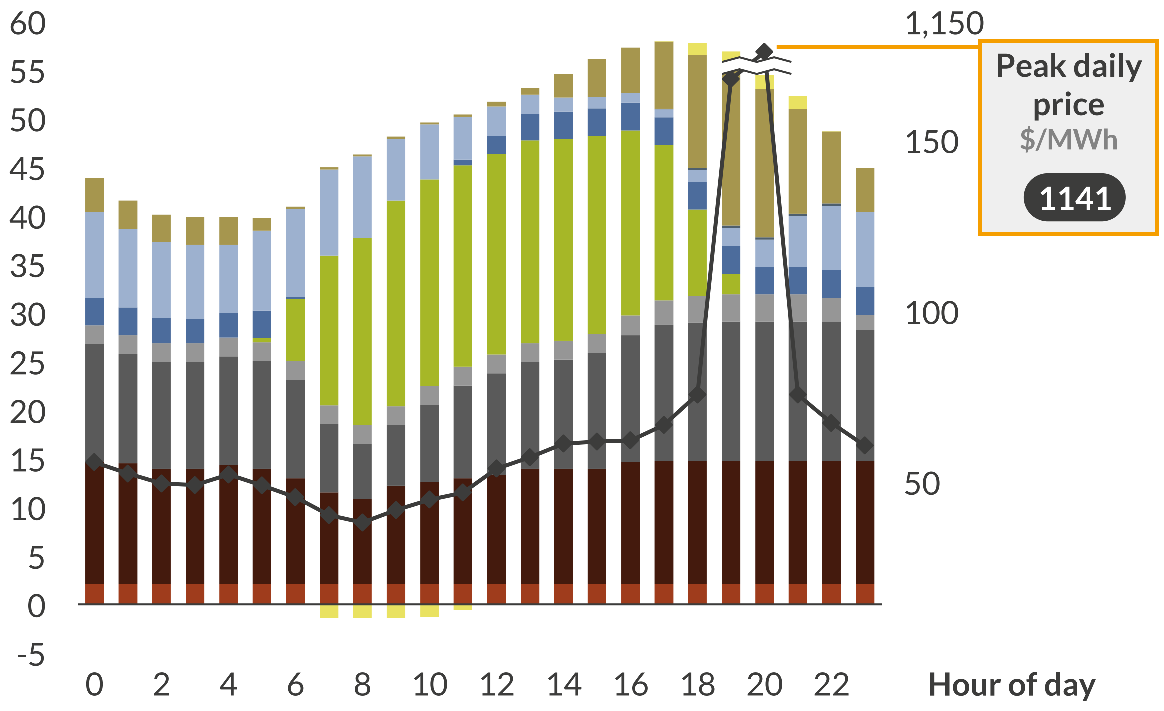
Hourly net generation[1] and prices, Central scenario, August 14th, 2035
GW (left); $/MWh (real 2023) (right)



- Battery storage charges during the day when prices are low and supplies energy as demand increases in the late afternoon, **reducing peak pricing and complementing the capabilities of solar generation.**

Hourly net generation[1] and prices, *No Battery*, August 14th, 2035
GW (left); $/MWh (real 2023) (right)



- With fewer batteries to discharge during the evening, prices spike at higher levels during the tightest hours. On a peak summer day in 2035, increased system scarcity pushes peak prices to **$1141/MWh (+$988/MWh compared to Central scenario) 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

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. System costs comparison

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

SPP has the second-largest geographic footprint and third-highest renewables penetration in the country, driven mainly by wind assets

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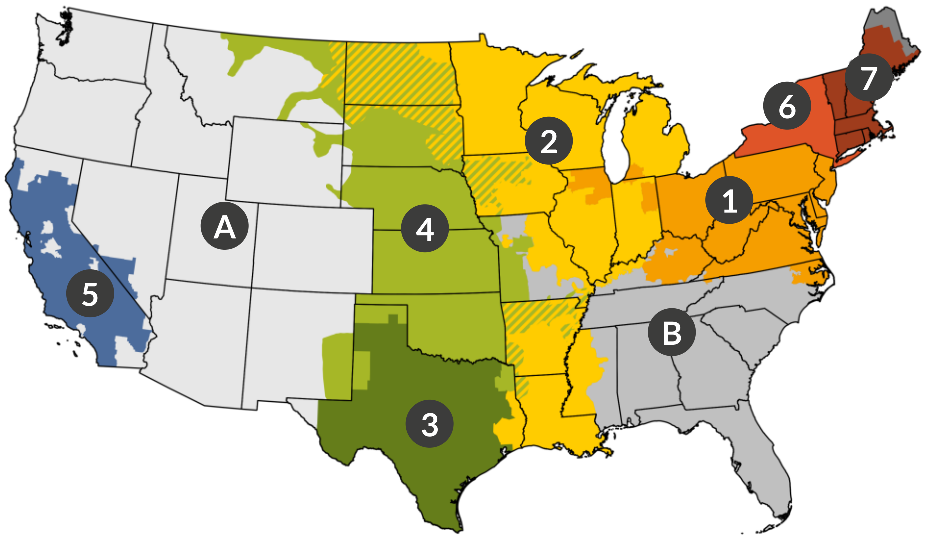
There are seven restructured competitive markets in the lower 48 states which are run by Independent System Operators (ISOs). ISOs use competitive market mechanisms that allow independent power producers and non-utility generators to trade power. WECC and SERC remain vertically integrated by utility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

Aurora models SPP as 7 regions with local load, new build economics, and interregional power flows

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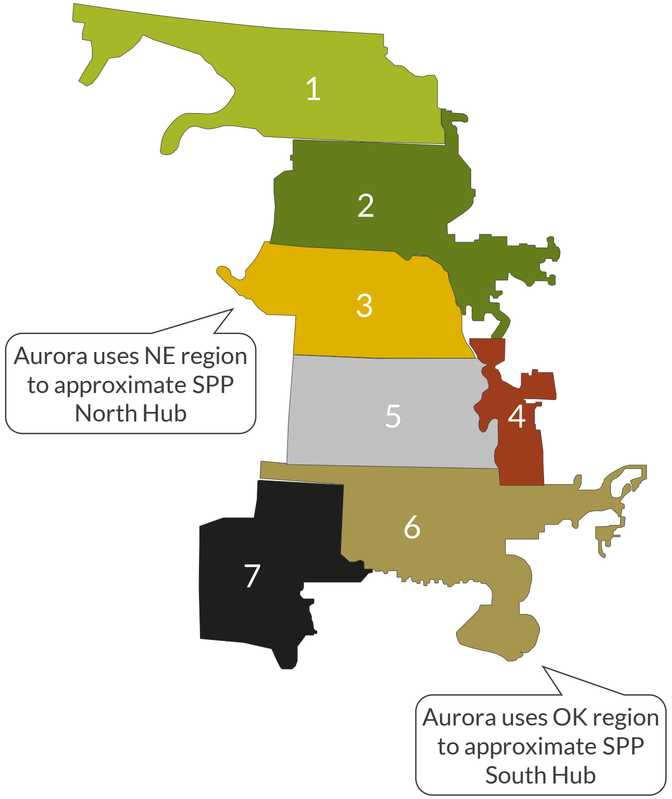
SPP utilizes multiple methodologies to determine how to split into different regions, including different transmission zones by transmission operator, demand areas by load serving entity, and reserve zones for ancillary procurement. The Aurora methodology aggregates demand areas into relevant geographical regions that display materially different behavior historically. Out of all SPP regions, Region 6 has the highest total load for 2024 with large population centers and heavy industrial activity.

Aurora's defined SPP regions[1]



Aurora Region	States covered	Demand areas	Total Load 2024[2], TWh	Avg. DA Price 2024, $/MWh	Installed SPP capacity 2024, GW
1	ND, MT	WAUE[2]	24	39	4
2	SD, IA, MN	WAUE[2]	7	22	5
3	NE	LES, NPPD, OPPD	37	18	12
4	KS, MO	EDE, INDN, KACY, KCPL, MPS, SPRM	38	25	14
5	KS	SECI, WR	38	17	16
6	OK, TX, LA, AR	CSWS, GRDA, OKGE, WFEC	105	27	37
7	TX, NM	SPS	37	24	13

Nuclear | Coal | Gas CCGT | Other thermal | Solar | Other RES[3] | Hydro | Onshore wind | Pumped storage | Peaking | Battery storage

1) Regions as defined in Aurora market modelling. 2) WAUE demand distributed across North and South Dakota based on EIA utility data. 3) Other RES refers to other renewables, which includes biomass and biogas.

Sources: Aurora Energy Research, SPP, EIA

BESS deployment in SPP is limited to ~28MW, with a few small batteries deployed in the last 6 years

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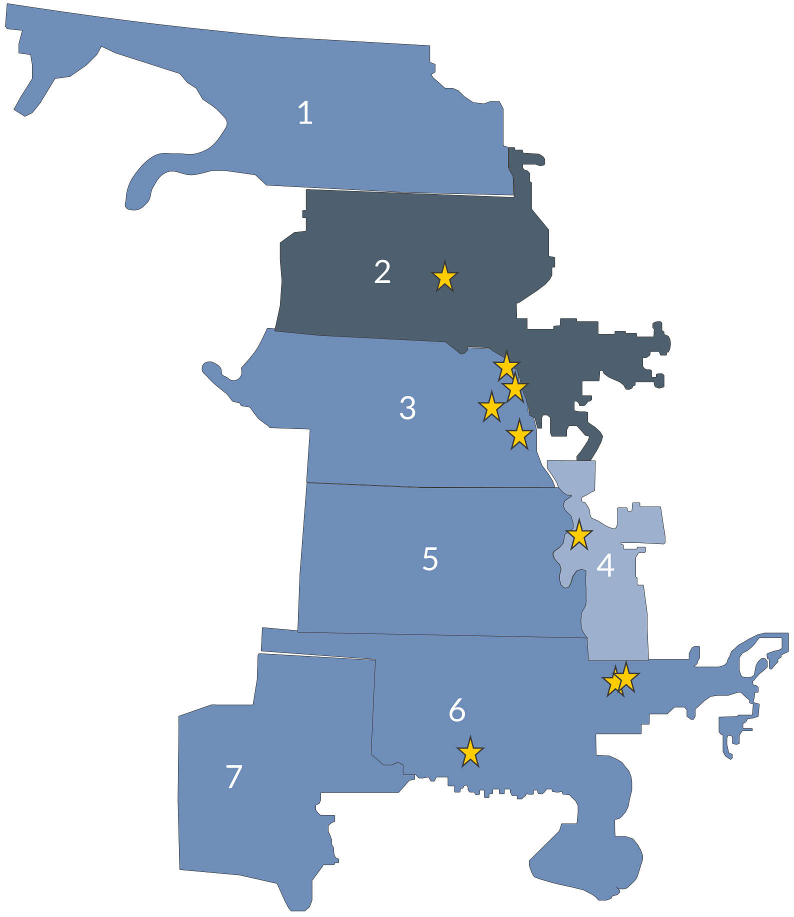
Capacity additions as a percentage increase by region, 2020-24



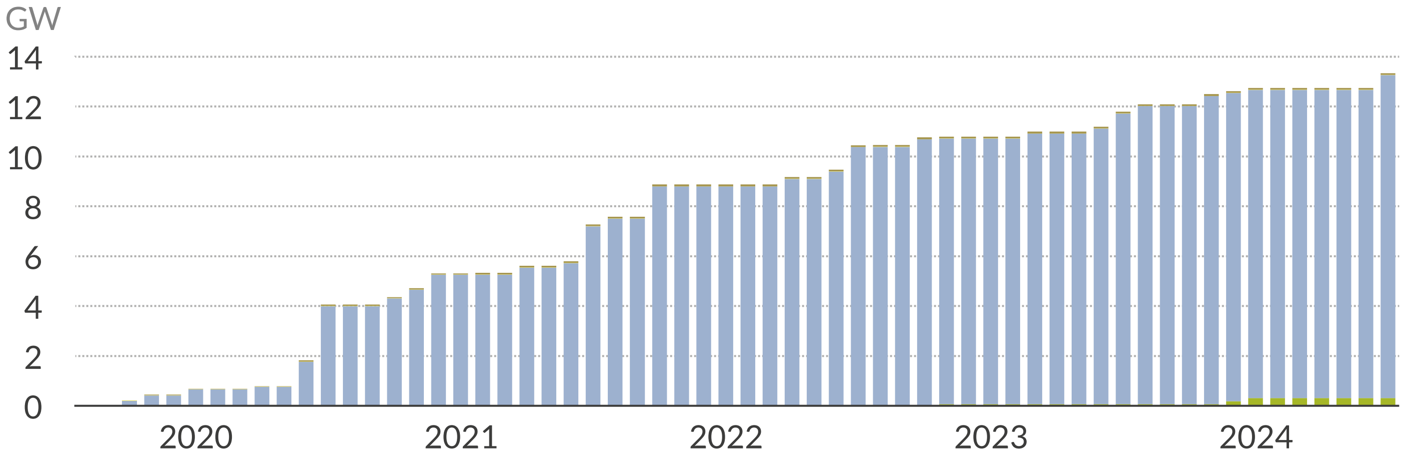
Percentage capacity increase, 2020-24

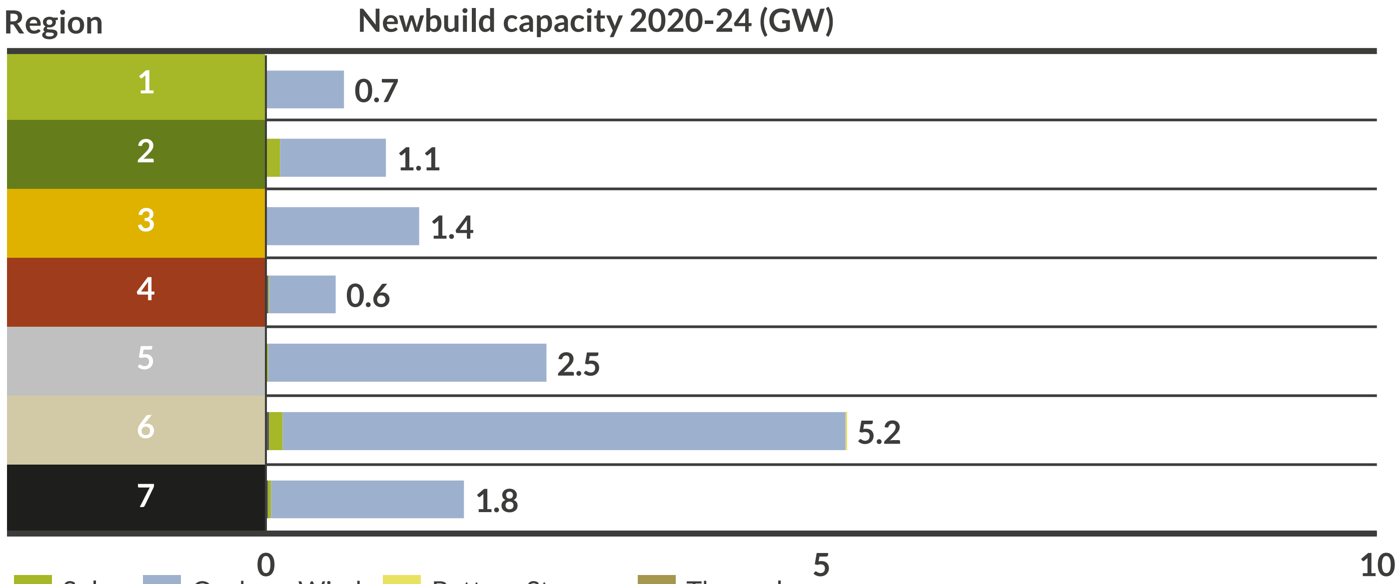
Less than 10% | 10-20% | Greater than 20%

Existing Batteries

★

Cumulative COD[1] capacity additions monthly in SPP 2020-24[2]





Solar | Onshore Wind | Battery Storage | Thermal

1) Commercial operation date, i.e. considering assets that had a commercial operation date in the month listed. 2) As of the March 13, 2025 interconnection queue report. Capacity figures include capacity with commercial operations through December 2024.

Sources: Aurora Energy Research, SPP

~25GW of BESS capacity is requesting to interconnect, although historical backlogs have driven an average of 58% withdrawal rate from the queue[1]

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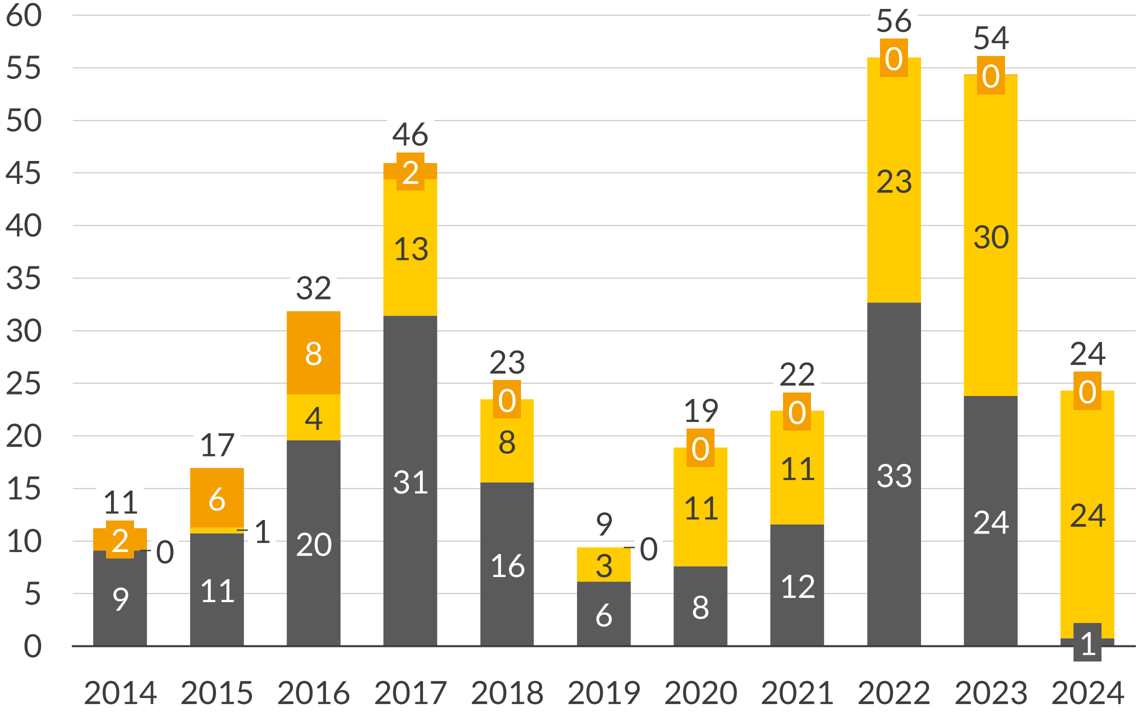
SPP queue capacity for all technologies by request year and project status[2]

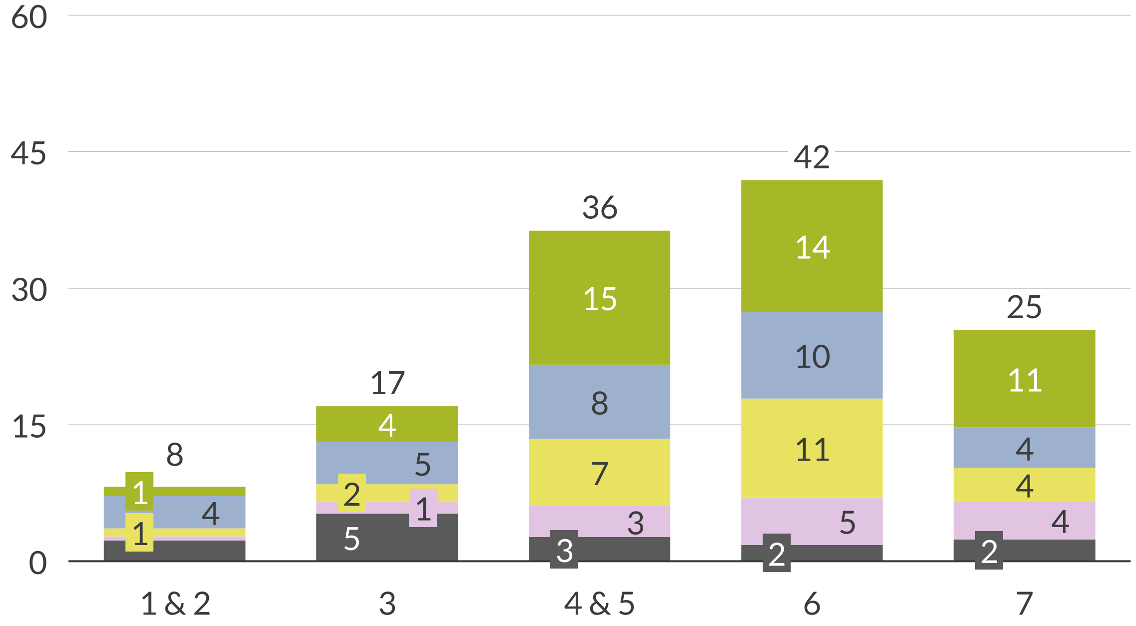
GW



- Queue capacity requests reached the lowest point in 2019 since the Integrated marketplace implementation as increasingly long queue study times depressed investor interest but has since rebounded.
- Despite having just started DISIS Phase 2 studies, the 2022 cluster already has a 58% withdrawal rate, potentially an effect of harsher penalties for projects withdrawing later in the study process.

Active capacity in the SPP interconnection queue by region[3]

GW



- 35% of the interconnection queue capacity is solar, with the majority located in Kansas, Oklahoma, or the Southwest.
- Battery and hybrid projects make up over 30% of the total capacity requesting to interconnect.

1) Average withdrawal rate from 2014 – 2023 request years. 2) Data as of January 25, 2025. 3) States included in each region: 1 & 2 (MN, MT, IA, ND, SD), 3 (NE), 4 & 5 (KS, MO), 6 (OK, AR, LA), 7 (NM, TX).

Sources: Aurora Energy Research, SPP

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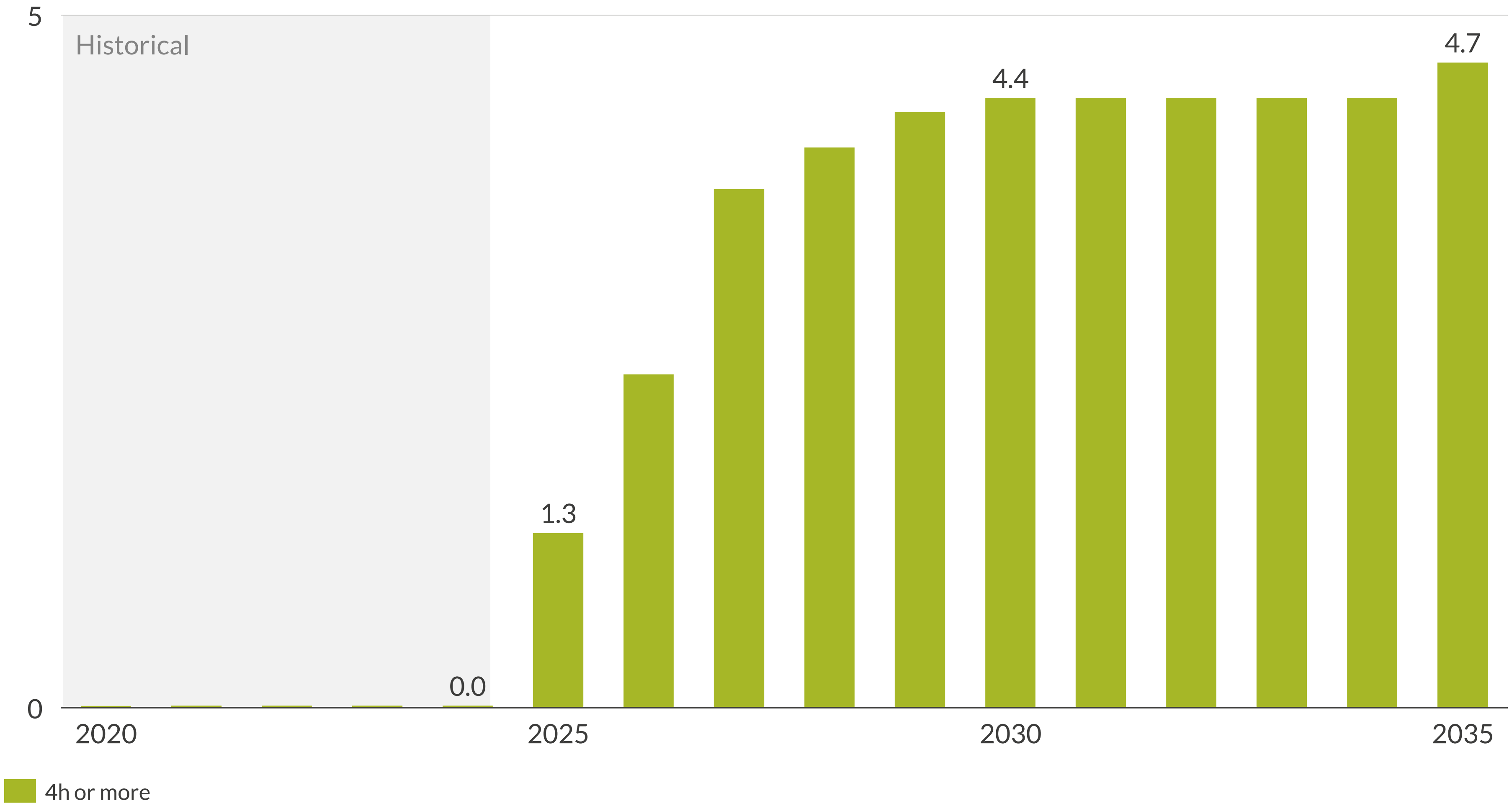
Given declining technology costs and tax credit support, battery build grows to 4.7GW by 2035

SPP Battery capacity by duration timeline under Aurora Central

GW



Sources: Aurora Energy Research, EIA

- There is significant BESS capacity requesting to interconnect in SPP. Based on the volume and stage of interconnection requests, Aurora projects over 4GW of battery buildout by 2030 from the current interconnection queue. The pace of growth slows as market saturation increases, leading to around 5 GW of BESS capacity online by 2035.
- Market drivers such as retiring thermal assets, growing demand, and high renewables deployment create a favorable environment for battery buildout, coupled with declining CAPEX and strong federal clean energy tax credits.
- Aurora sees batteries building primarily in Oklahoma, Texas, and New Mexico, with proximity to demand centers and renewables buildout leading to favorable spreads.

Agenda

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SPP is currently going through two major market changes: ensuring resource adequacy and improving generation interconnection and system planning

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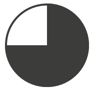
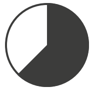
Policy Area	Current Regulation or State of the System	Upcoming changes or reforms	Market Impact
Resource Adequacy (A)	Planning reserve margin (PRM) for capacity is set to 15% additional capacity per demand area over the forecasted summer peak load.	Setting separate Base PRMs for winter and summer seasons based on peak load in demand areas, and also setting Accredited Capacity PRMs that take the accredited capacity of thermal generation into account .	
	Capacity accreditation is based on historical performance for renewable assets, and operational tests for thermal assets.	Capacity accreditation to be performance-based for thermal technologies, and determined using a new “ELCC” methodology for wind, solar and battery storage resources.	
	SPP and some LREs[1] have expressed concerns over the state of the interconnection queue to evaluate projects quickly enough to ensure adequate generation is available to meet PRM[2] requirements in the future.	SPP introduced ERAS[3] to fast-track generation interconnection for LREs that would otherwise project to fall short of their resource adequacy requirement for 2030.	
Interconnection Queue and Transmission planning (B)	Transmission projects individually evaluated by the MISO and SPP ISOs individually, with costs allocated on a case-by-case basis.	The Joint Transmission Interconnection Queue (JTIQ) is a 1.7billion dollar upgrade project for critical 345kV infrastructure along the MISO/SPP seam that also plans to bring interconnection queue reforms to the area.	
	Transmission planning is split into various parallel processes, inviting vague process control and inefficient outcomes.	The Consolidated Planning Process promises to streamline interconnection and transmission planning procedures.	
		The 2024 Integrated Transmission plan totals over $7.7billion of network upgrades and is triple the size of the next-largest transmission plan ever approved.	

X Deep dive to follow

1) Load-Responsible Entities. 2) Planning Reserve Margin. 3) Expedited Resource Adequacy Study.

Sources: Aurora Energy Research, SPP

A Changes to resource adequacy requirement policies highlight the importance of maintaining system reliability in an evolving landscape

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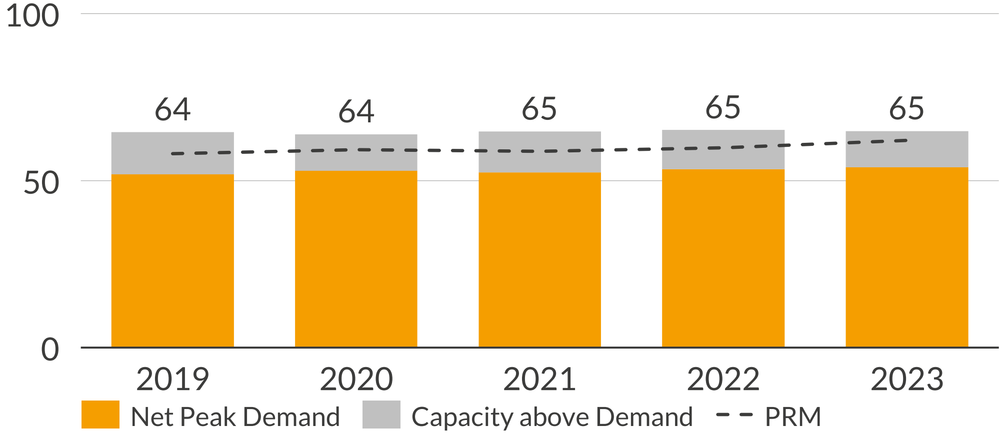
Current — **Winter Resource Adequacy Requirement Flexible and Low PRM for the summer season**

Winter Season Resource Adequacy Validation Requirement:
- SPP currently has a lack of stringent validation requirement for the Winter Season when compared to the Summer Season.

Winter Deficiency Payment:
- SPP does not have a deficiency payment for the Winter Resource Adequacy Requirement, while the Summer Season does.

PRM:
- The current Planning Reserve Margin is set to 15% for the Summer Season. There is no current PRM for the Winter Season.

Capacity targeted and cleared



Future — **Planning Reserve Margin to increase and Winter Season to have deficiency payment and greater validation requirements.**

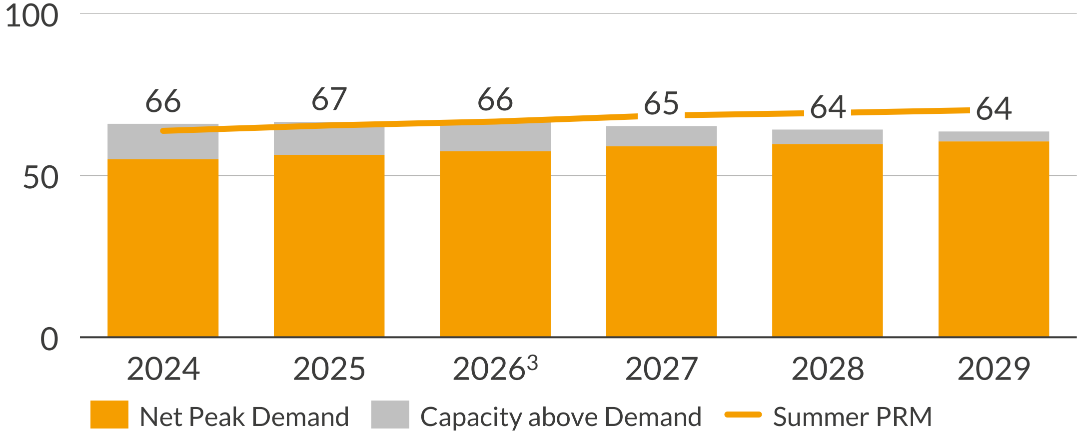
Changes:
- **Increase PRM for Summer to 16% and set Winter to 36%.**
- **Create a stricter validation requirement and deficiency payment for Winter.**

What inspired these revisions?
- SPP seeks to ensure that LREs are planning for both summer and winter season capacities adequately.
- The lack of Winter Resource Adequacy deficiency payment shies from motivating LREs to ensure Winter Peak Demand is met.

FERC has approved PRM calculation methodology as of October 17, 2024.

SPP's MOPC[1] has approved further revising PRM for 2029 to 17% for the Summer PRM and 38% for the Winter PRM.

Capacity targeted and cleared[2]



1) Markets and Operations Policy Committee. 2) SPP has not yet published a winter peak demand forecast , therefore we are unable to calculate SPP winter PRM. 3) Base PRM changes to 16% and 36% is set to occur in 2026/2027.

Sources: Aurora Energy Research, FERC, SPP, RTO, UTILITY DIVE

B Initiatives such as SPP's Consolidated Planning Process (CPP) promise a cohesive approach for streamlining generator interconnection…

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Timeline of changes

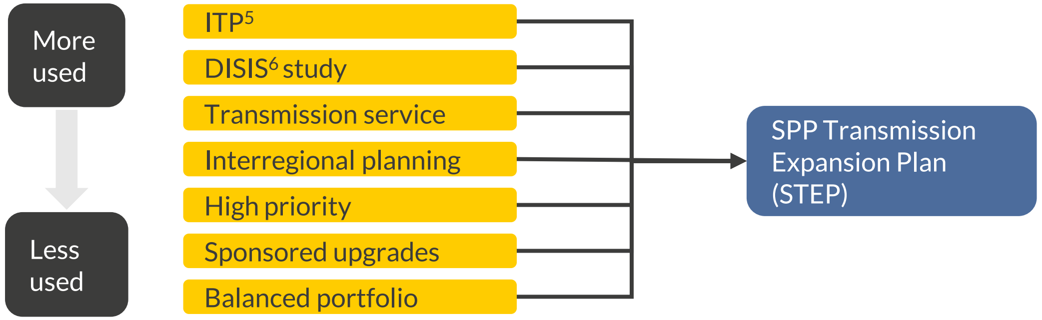
2021

- *Nov 2021:* The CPP Task Force (CPPTF) is created, charged with implementing the changes necessary to create the CPP.
- *Jan 2022:* Interconnection queue process reforms go into effect, increasing incentives to drop out early and streamlining the IC process.
- *Jan 2024:* CPPTF publishes final outline for elements included in Phase 1 of the CPP, detailing a planned incorporation for each existing process.
- *Feb 2024:* CRIS[1] method is finalized, which promises a faster alternative to the current IC queue that also will immediately give designated resource status.
- *Apr 2024:* Entry fee[2] reform policy direction approved by SPP MOPC[3], detailing cost allocations of transmission upgrades to each entity in SPP including LREs and generators.
- *2024-26:* 2026 ITP assessment, CPP transition and preparation of first long-term 20-year assessment for 2027 in addition to annual 10-year horizon assessment.
- *May 2026:* CPP effective date: projects that are not yet at Decision Point 2 required to transition to CPP process. Projects past Decision Point 2 continue under previous GIP[4].

2027

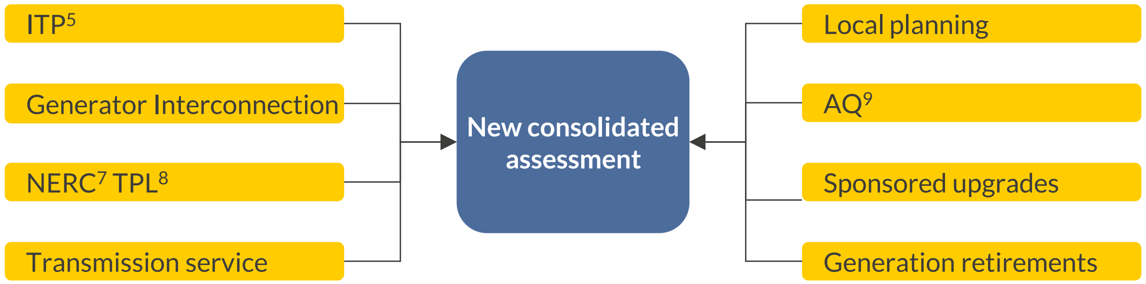
Current approach

- Multiple transmission planning operations are considered in parallel processes, with multi-year queue delays leading to re-studies.
- Transmission solution assignment is based on a first-to-the-finish-line approach, with an increasing number of interconnection requests leading to further delays, re-studies and uncertainty.



Proposed CPP approach

- Generation interconnection and all transmission planning will be reorganized in a clear, hierarchical structure with consolidated assessments.
- A new consolidated assessment process will integrate the generator interconnection process with the various other transmission planning processes, eventually including generator retirement, sponsored upgrades and overall SPP system load.



1) Capacity Resource Interconnection Service. 2) Entry fee later renamed Network Upgrade Contribution. 3) Markets and Operations Planning Committee . 4) Generator Interconnection Procedure. 5) Integrated Transmission Plan. 6) Definitive Interconnection System Impact Study. 7) North American Electric Reliability Corporation. 8) TPL-001: Transmission System Planning Performance Requirements. 9) Aggregate queue.

Sources: Aurora Energy Research, SPP

B … and over $7bn allocated to the 2024 Integrated Transmission Plan (ITP) will enable SPP to more effectively utilize this future capacity

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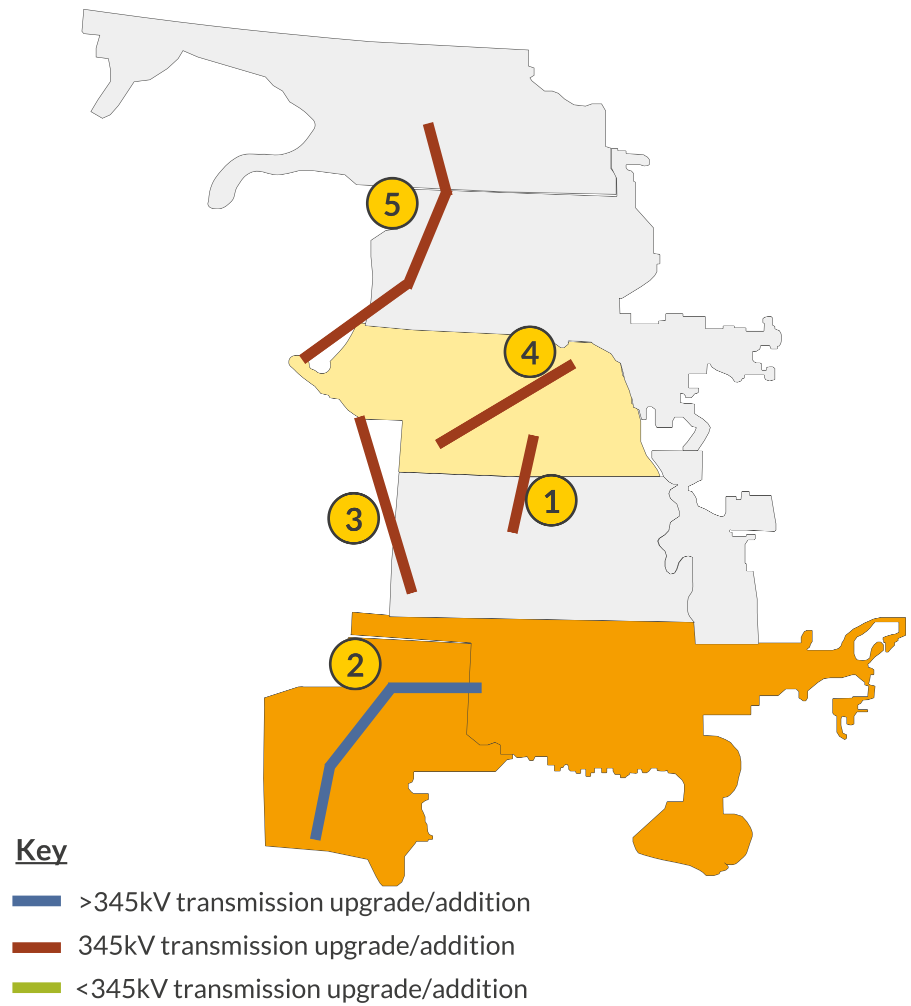
Map of 2024 ITP key upgrades



Project	Operational Year	Miles	Cost (2024$M)	Capacity (GW)	kV	Status
1) Tobias-Elm Creek	2028	85.2	148	3.88	345	Approved
2) Phantom-Crossroads-Potter	2029	293	1,690	-	765	Approved
3) Sidney-Holcomb	2029	300	887	3.63	345	Approved
4) R Project	2027	226	417	2.5	345	Approved
5) Belfield-Maurine-New Underwood-Laramie River	2029	438.6	1,114	-	345	Approved

Source: Aurora Energy Research, SPP, NPPD, Flatwater Free Press, E&E News, R Project

Agenda

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

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Revenue streams available to batteries in SPP

Wholesale energy market

- **Charge and discharge** in response to 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**
- Optimized across both the Day-Ahead and Real-Time markets

Uncertainty Reserve

Regulating

Contingency Reserves

- Spinning and Supplemental

Ramp capability

Resource adequacy market

- Batteries can **contract bi-lateral agreements with utilities** to earn capacity revenues

Bi-lateral contracts

- Utilities establish long-term contracts with capacity assets in **bi-lateral agreements**
- Increasing short term future prices due to **growing demand and higher reserve margin requirements**

Affected by policies and utility targets

Sources: Aurora Energy Research, SPP

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

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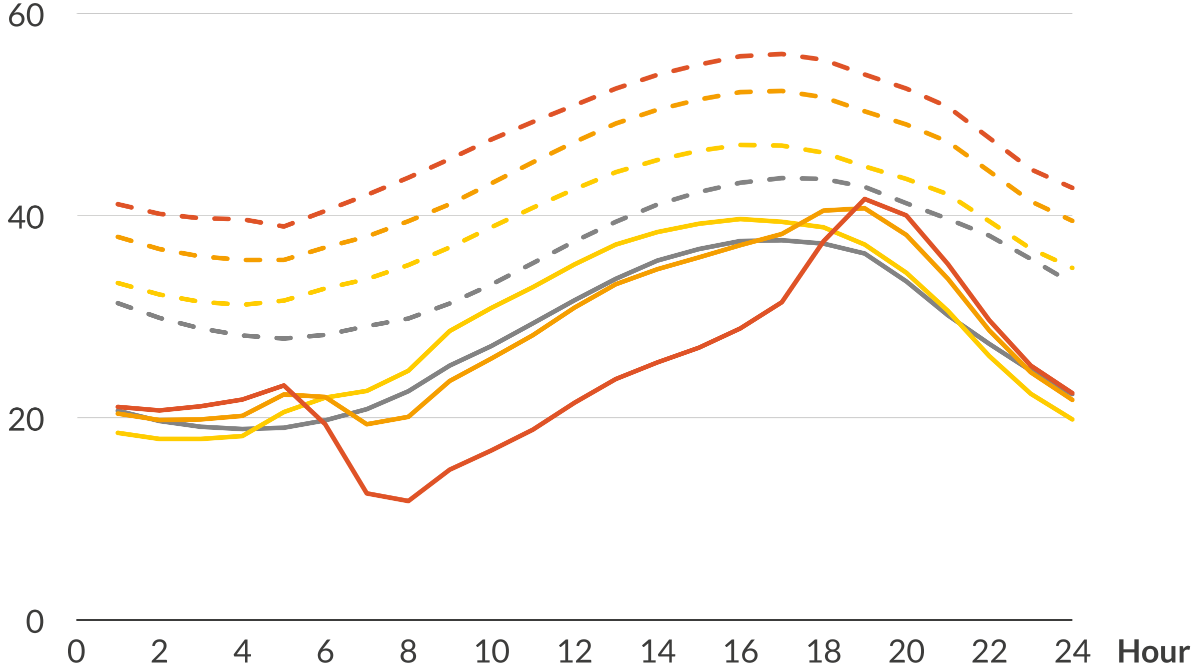
1 **As solar buildout accelerates, the "duck curve" will appear and grow more exaggerated**

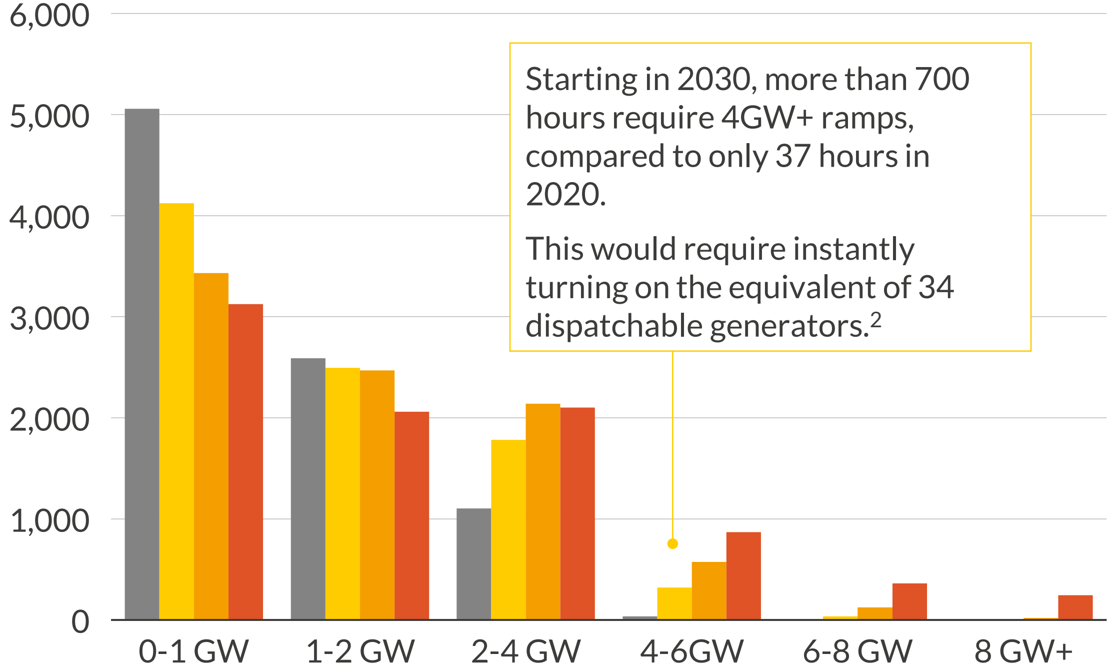
2 **Ramping requirements will increase accordingly, seeing ~17% of hours with ramping greater than 4GW starting in 2035**

Total and net load average shape in August
GW



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

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.

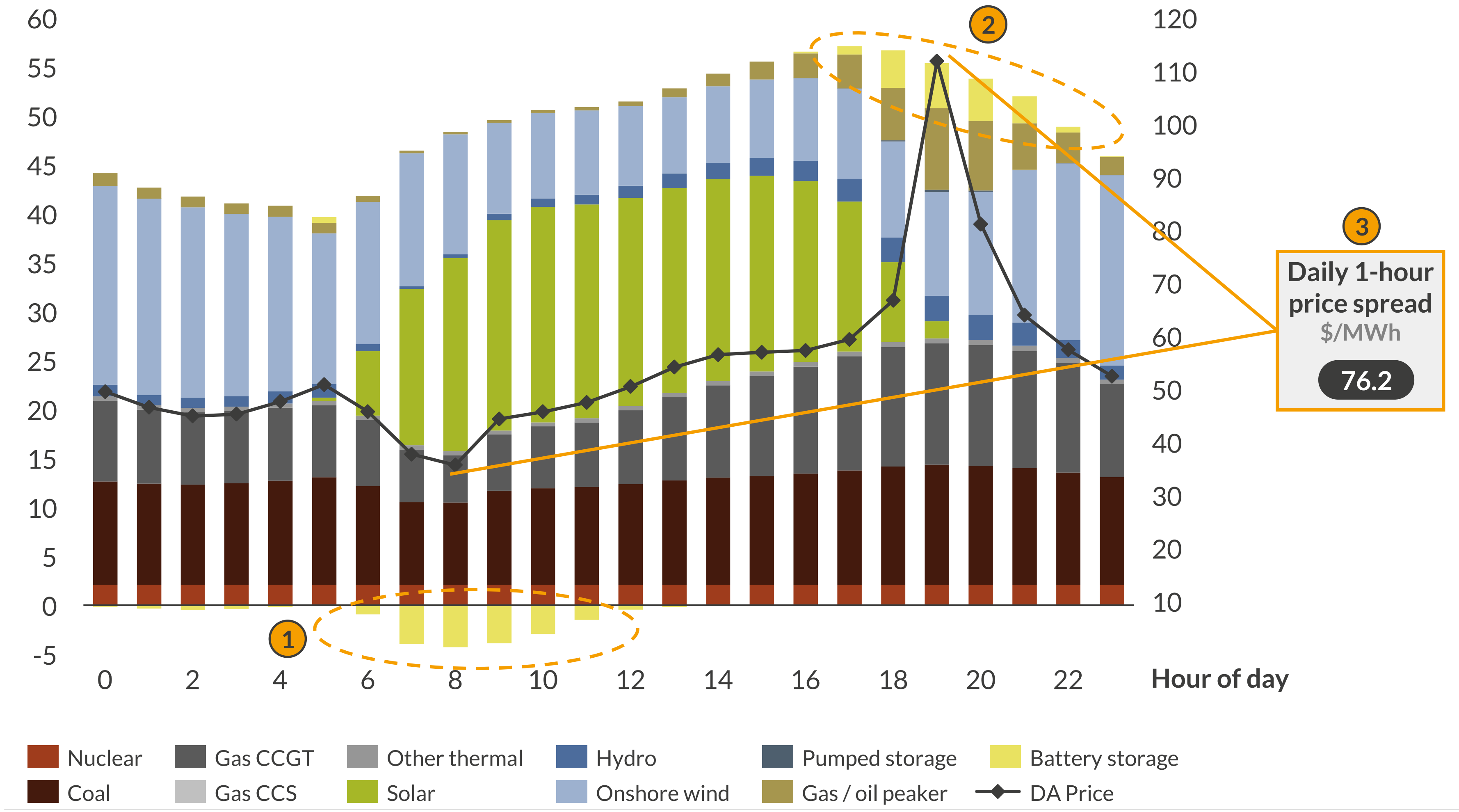
2020 2025 2030 2035 Total load Net load

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, SPP

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 SPP, outages and high heating demand during Winter Storm Uri underscored the benefits of a diverse resource mix during system stress

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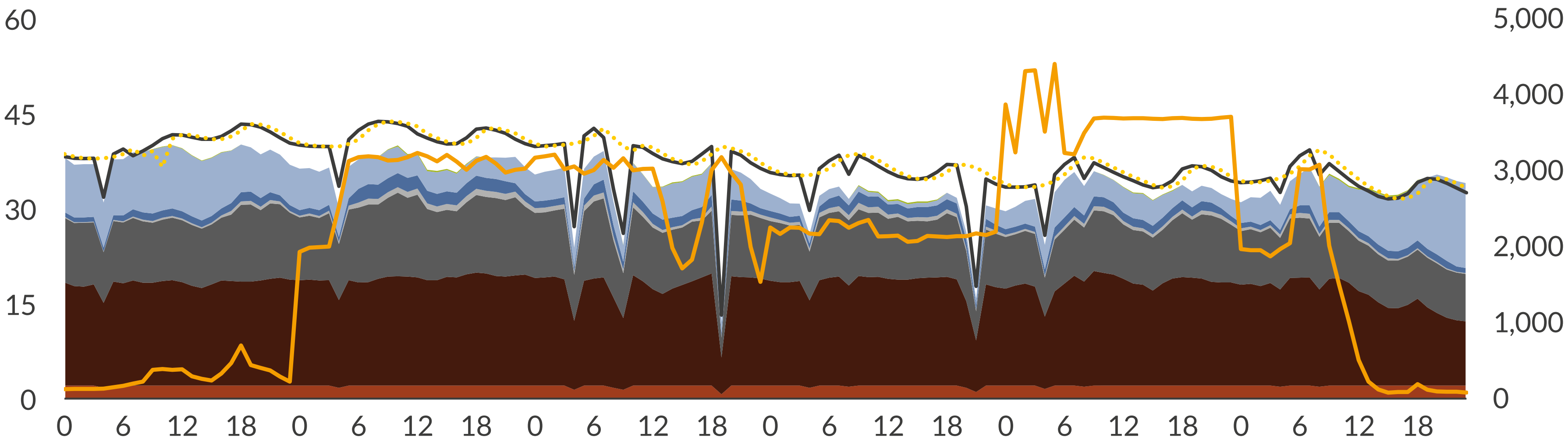
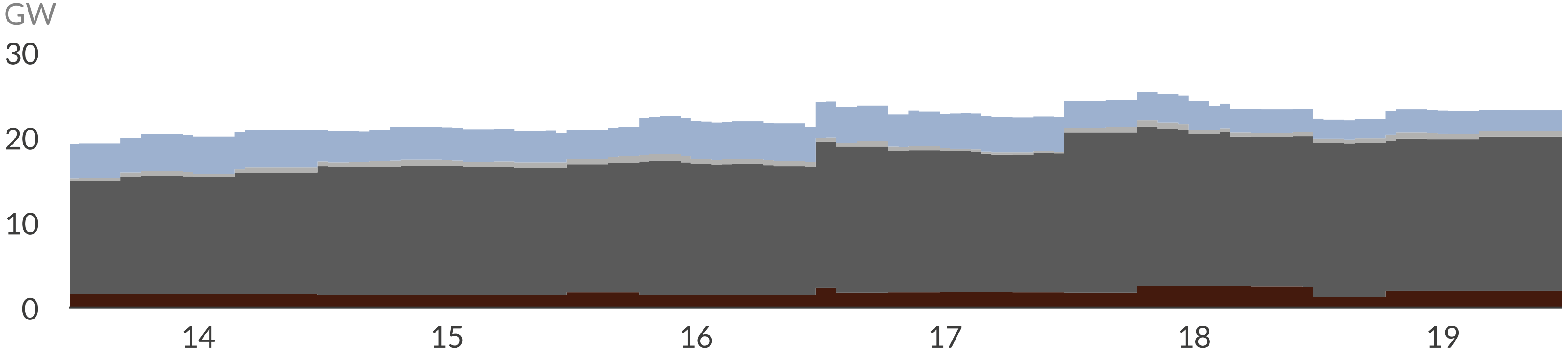
- Between February 14-20, 2021, SPP weathered the worst effects of Winter Storm Uri. A then winter peak load record of 43.7GW was set on Feb.15 at 9am, and from Feb 15-16th SPP was forced to shed a combined 3.3GW of load.
- Combining with high heating demands was large scale gas capacity outages, as plants were unable to acquire fuel supplies. Between Feb 14-19, an average of 16.2GW of gas-fired plants were on outage.
- Wind capacity was also forced offline due to the arctic temperatures, with an average of 3.4GW of wind unavailable in the same time period.
- During the critical time between Feb 14-18, Day-Ahead prices averaged over $1850/MWh despite SPP scheduling plants for dispatch multiple days into the forecast.

Average hourly Real-Time generation and demand, February 14-19, 2021[1]

Average hourly RT[1] and DA prices



Forecasted capacity on outage, February 14-19, 2021



Actual demand · Day-Ahead demand forecast · Real-Time prices · Day-Ahead prices · Nuclear · Coal · Gas · Other thermal · Hydro · Onshore Wind · Solar PV

1) Real-Time values averaged into hourly increments.

Sources: Aurora Energy Research, SPP

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

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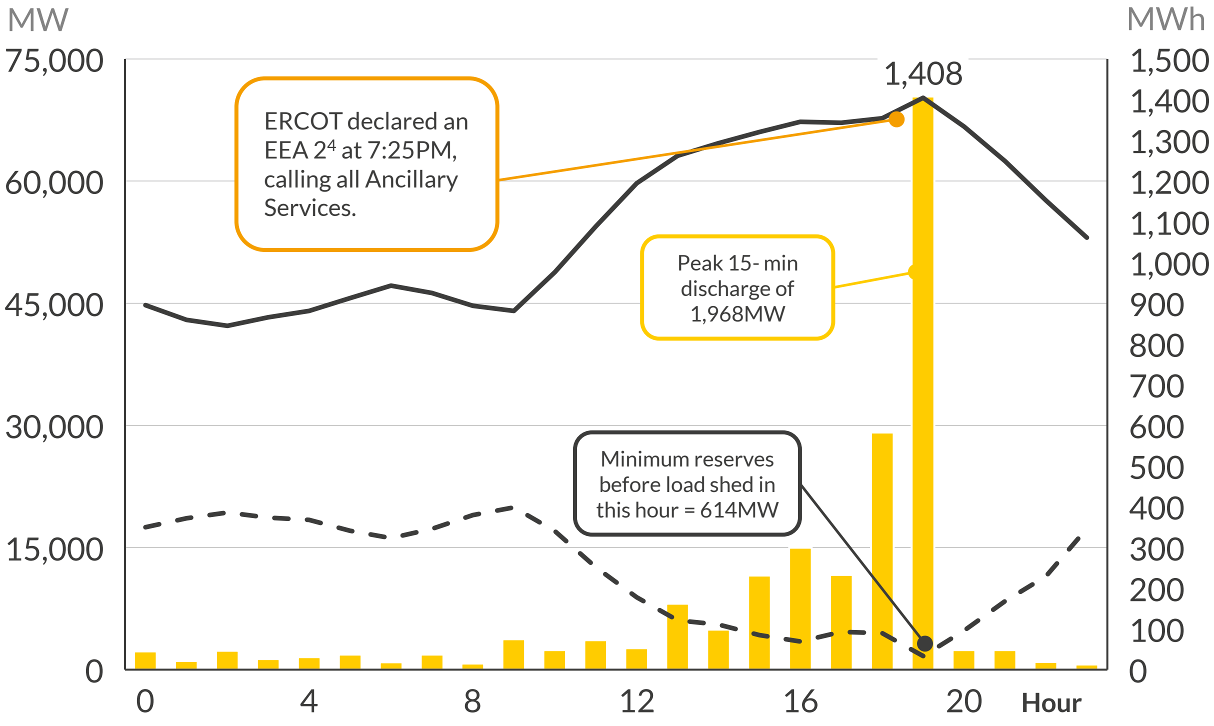
1 **September 6th, 2023:** ERCOT BESS discharged their energy between 6-8pm, right as system reserve margins were tightest

ERCOT wide load and margins[2]

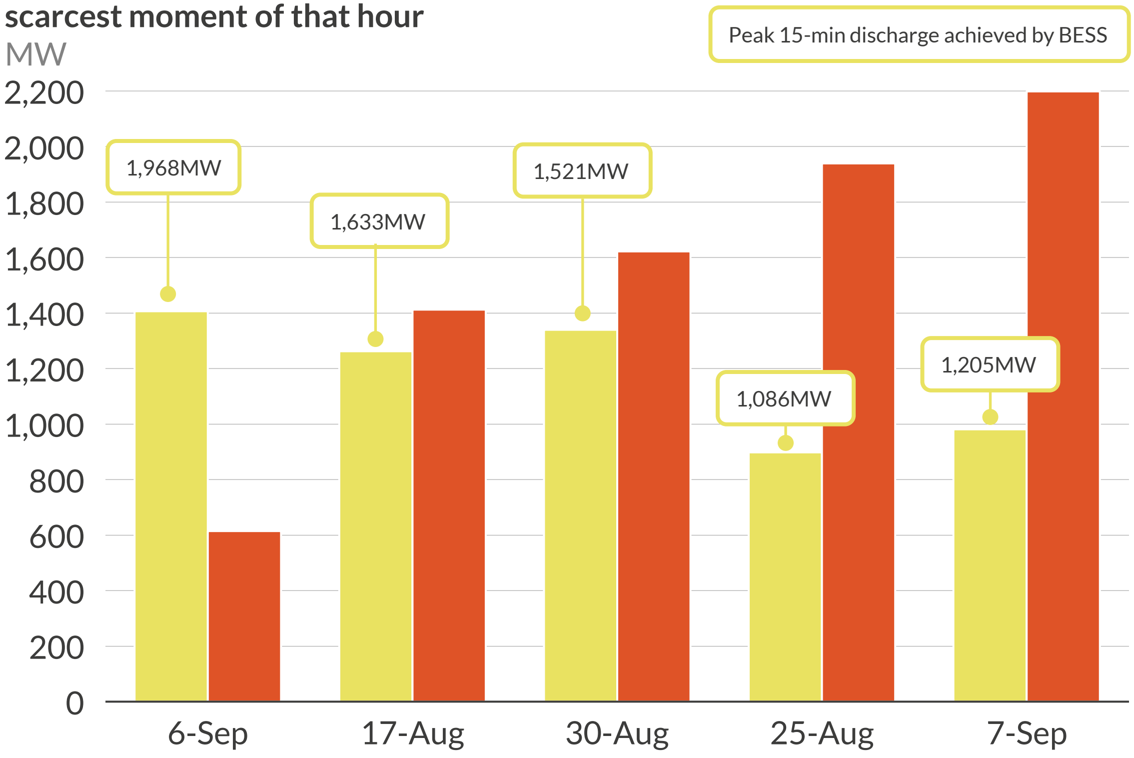
ERCOT wide BESS generation



- 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

Average hourly BESS generation and operating reserves before EEA3 event[3] at scarcest moment of that hour



- 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.

Net Load — Average Remaining Physical Reserves (PRC) before EEA3[5] — BESS Generation

BESS Generation — Minimum Remaining Physical Reserves (PRC) before EEA3[4]

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

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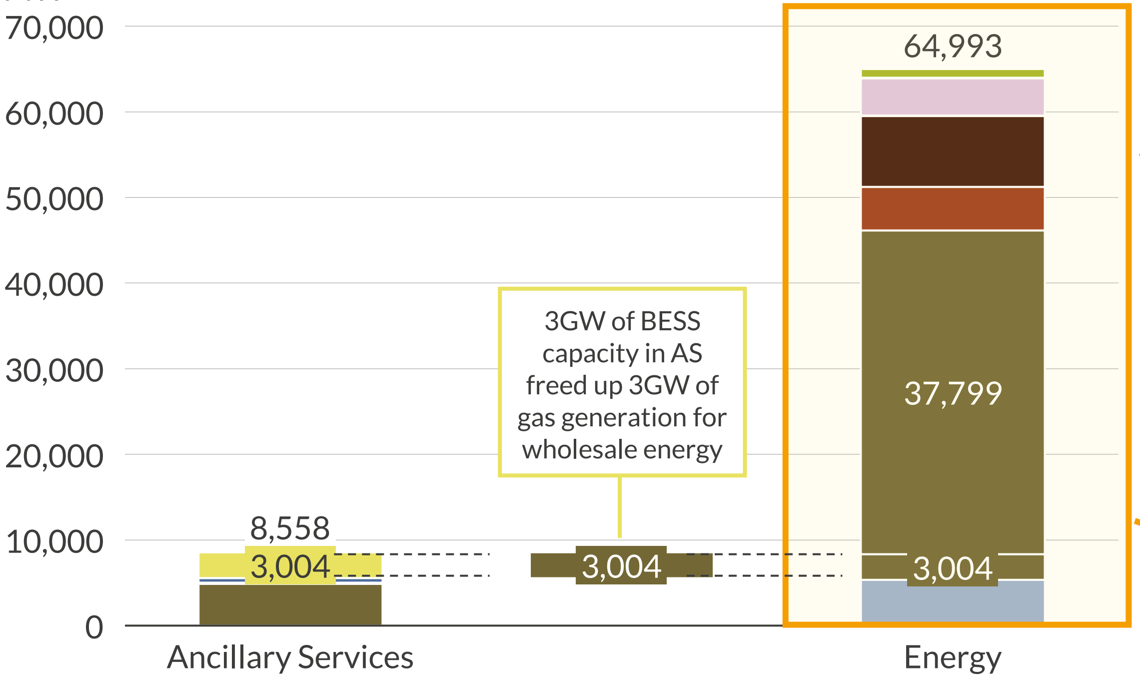
1 In tight morning hours[1] on January 14th and 15th, BESS overwhelmingly participated in AS while gas provided energy to the grid

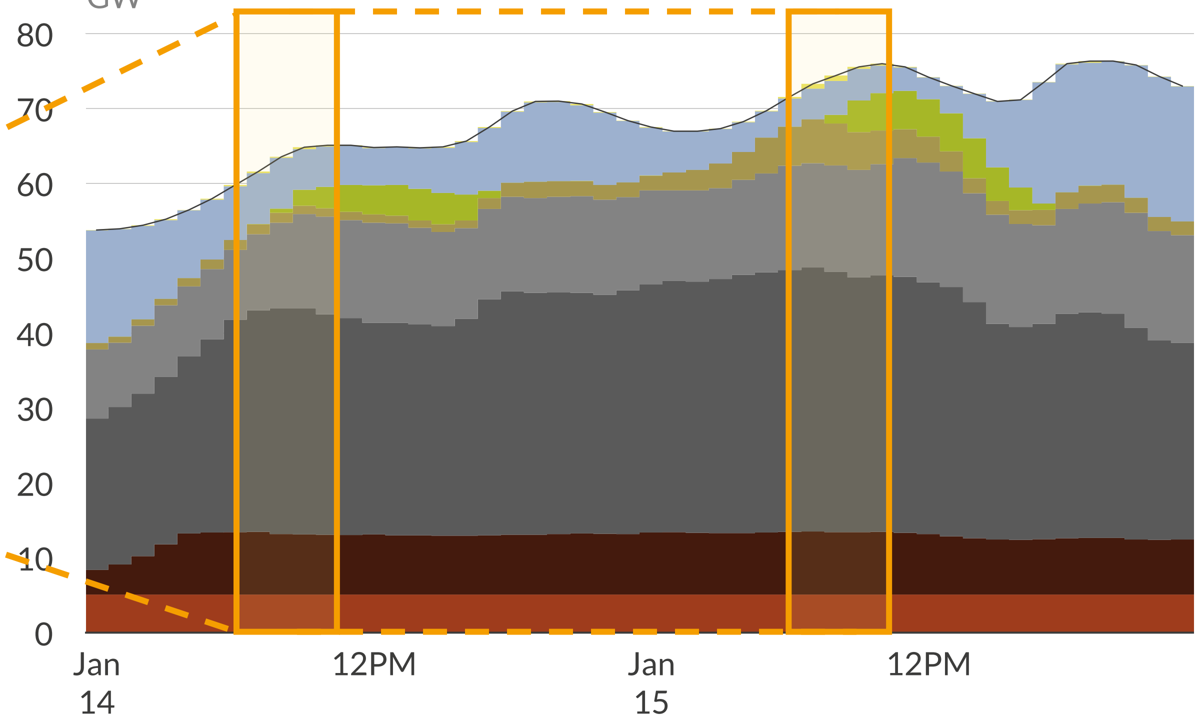
Total power generation in AS and energy markets[2], by technology
MW



- 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 SPP scenario input assumptions

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Inputs		Aurora Central
Demand	Underlying demand	+64TWh to 2035 driven by population, general industrial, and general commercial sector growth
	Oil/gas electrification	+14TWh by 2030 driven mainly by Permian and Bakken shale basin electrification and expansion
	Data centers	+12TWh by 2030, concentrated mostly in Kansas City, Nebraska, and Oklahoma
Commodities	Gas price	Price goes to $4.6 in 2030 and $5.1/MMBtu in 2035[1]
Technology	Renewables	Between 2024 and 2030, onshore wind CAPEX falls by 10%, solar by 30% leading to +11GW of wind and +25GW of solar by 2035
	Battery storage (Aurora Central scenario)	+4.7GW of battery capacity online by 2035
	Battery storage (*No Battery* scenario)	+1.4GW of battery capacity online by 2027, followed by a freeze in further battery development
	Gas Peakers	+4GW of gas peaking capacity by 2035 for reliability concerns
	Gas Combined Cycle	+2GW of gas CCGT by 2035 mainly driven by resource adequacy/reliability concerns
	Future of aging thermal fleet	Coal capacity decreases by 29% and gas-fired steam turbine capacity by 31% by 2035
Policy	Interconnection queue reform	SPP implements queue reform as currently planned by the CPP Task Force, eliminating backlog and increasing queue efficiency
	Reliability	Determined by Resource Adequacy Planning Reserve Margin requirements, announced changes expected to take effect in 2026.
	Renewables incentives	Inclusion of ITC and PTC as in Inflation Reduction Act
	Transmission upgrades	Strengthening of network increases transmission capacity between regions by ~53% by 2035

1) Henry Hub

Sources: Aurora Energy Research

Total load in SPP is forecasted to be over 63GW by 2030, driven by oil/gas electrification and data center buildout

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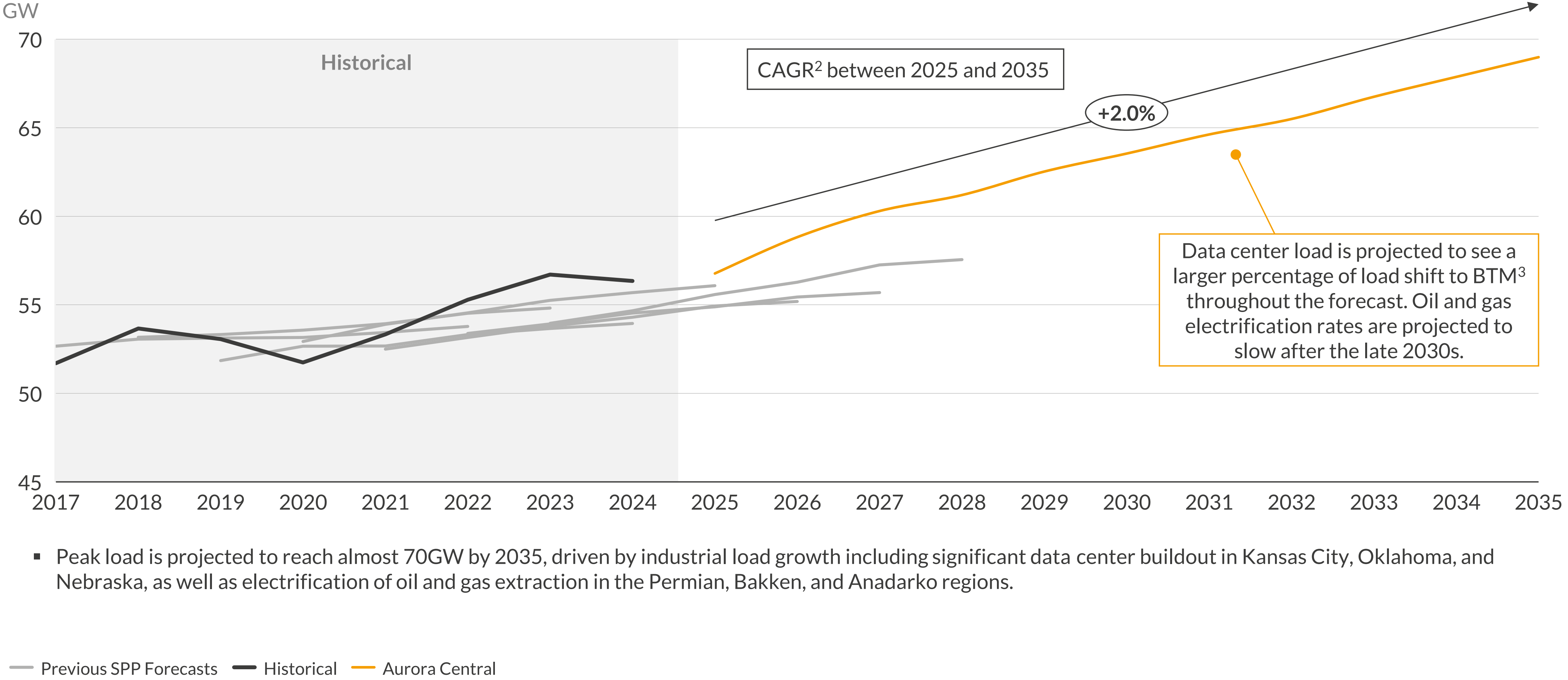
SPP peak load[1]

GW



- Peak load is projected to reach almost 70GW by 2035, driven by industrial load growth including significant data center buildout in Kansas City, Oklahoma, and Nebraska, as well as electrification of oil and gas extraction in the Permian, Bakken, and Anadarko regions.

1) North Dakota and South Dakota are winter-peaking systems, all other regions use a summer peak demand. 2) Compound Annual Growth Rate. 3) Behind-the-meter.

Sources: Aurora Energy Research, EIA, SPP

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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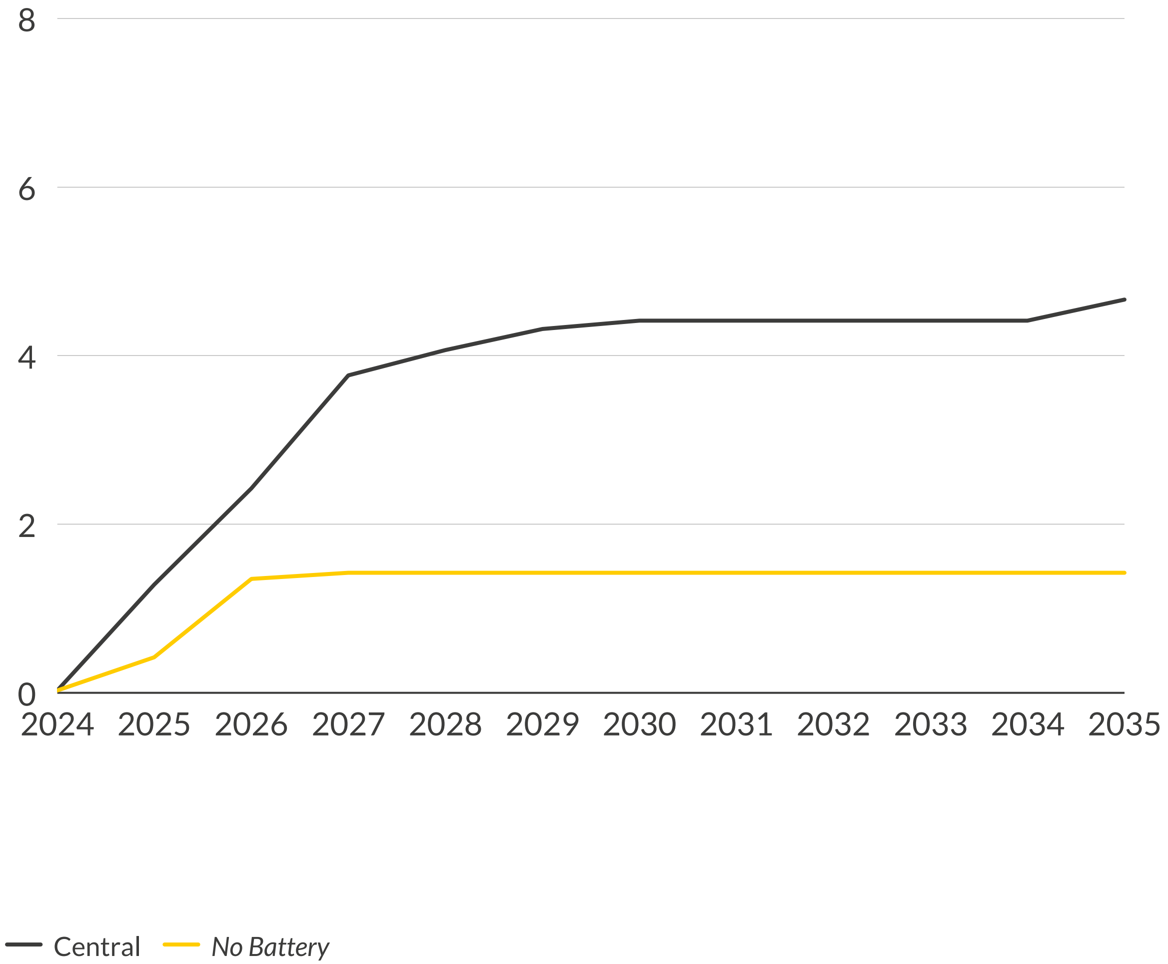
BESS projects included in *No Battery* scenario

IQ Number	Cluster	State	COD	Capacity MW
GEN-2023-SR18	Surplus	OK	5/15/2025	80
GEN-2023-SR16	Surplus	OK	6/1/2025	70
GEN-2023-SR13	Surplus	OK	6/1/2025	70
GEN-2023-SR12	Surplus	TX	9/30/2025	120
GEN-2017-178	DISIS-2017-002	OK	12/1/2025	52
GEN-2020-SR2	Surplus	OK	3/31/2026	100
GEN-2018-026	DISIS-2018-001	OK	5/31/2026	100
GEN-2017-198	DISIS-2017-002	NE	5/31/2026	11.64
GEN-2023-SR9	Surplus	TX	6/1/2026	50
GEN-2023-SR8	Surplus	TX	6/1/2026	200
GEN-2023-SR5	Surplus	OK	6/1/2026	85
GEN-2023-SR4	Surplus	ND	6/1/2026	170
GEN-2023-SR15	Surplus	OK	6/1/2026	50
GEN-2018-052	DISIS-2018-001	NM	12/31/2026	70
GEN-2018-010	DISIS-2018-001	ND	12/31/2026	74.1
GEN-2016-160	DISIS-2016-002-1	KS	12/31/2026	20
GEN-2018-011	DISIS-2018-001	OK	12/31/2027	74.1

Annual BESS growth	2025	2026	2027
MW	392	931	74

Cumulative SPP BESS capacity by scenario

GW



Sources: Aurora Energy Research, SPP

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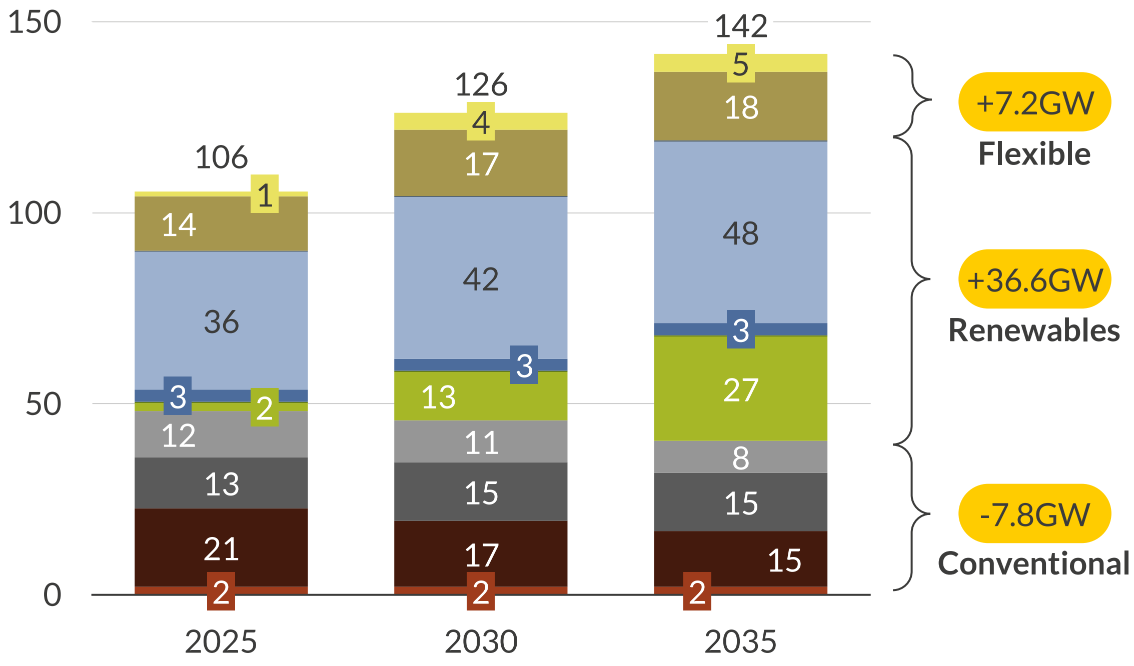
The *No Battery* scenario results in reduced solar capacity growth, leading to 6GW less of total installed capacity by 2035

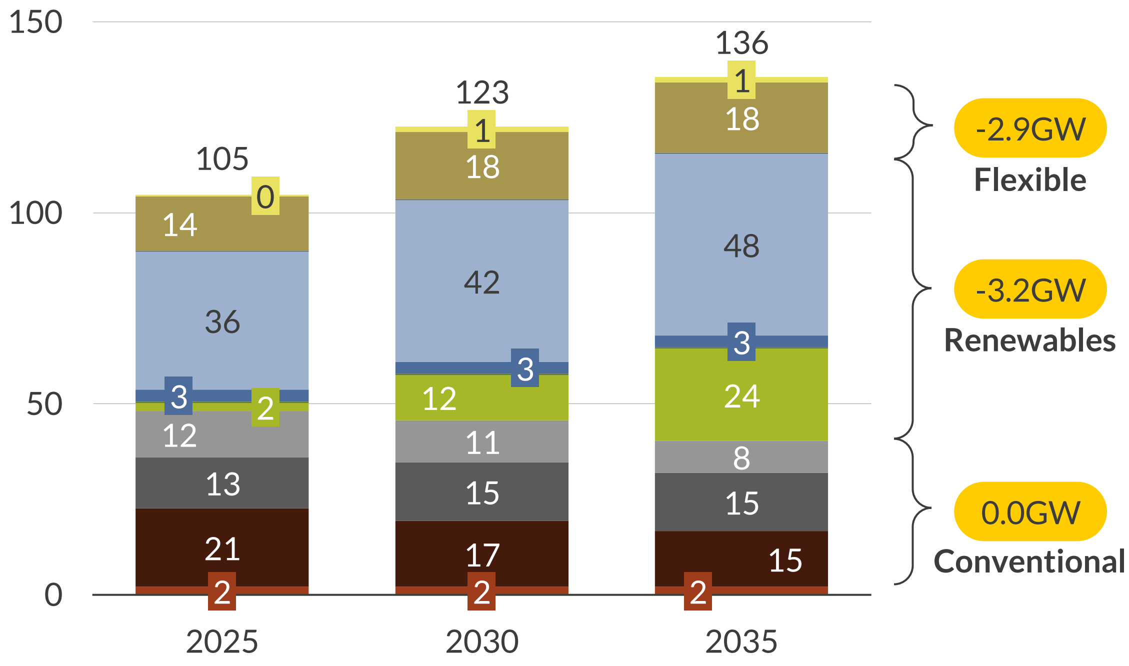
Installed capacity, Central
GW

Total change 2025–2035



Installed capacity, *No Battery*
GW

Delta to Central 2035



- Starting from small levels of currently installed capacity, solar and battery capacity sees the largest growth in the Central scenario.

- Battery buildout supports solar growth, and in the no battery scenario ~3GW less solar capacity is deployed by 2035 relative to the Central scenario.
- Peakers see a slight increase in capacity but largely remain constant.

Nuclear | Gas CCGT | Other thermal | Other renewables[1] | Onshore wind | Gas / oil peaker[2]
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.

Sources: Aurora Energy Research

Additionally, higher generation from conventional resources is required to meet demand in the *No Battery* scenario

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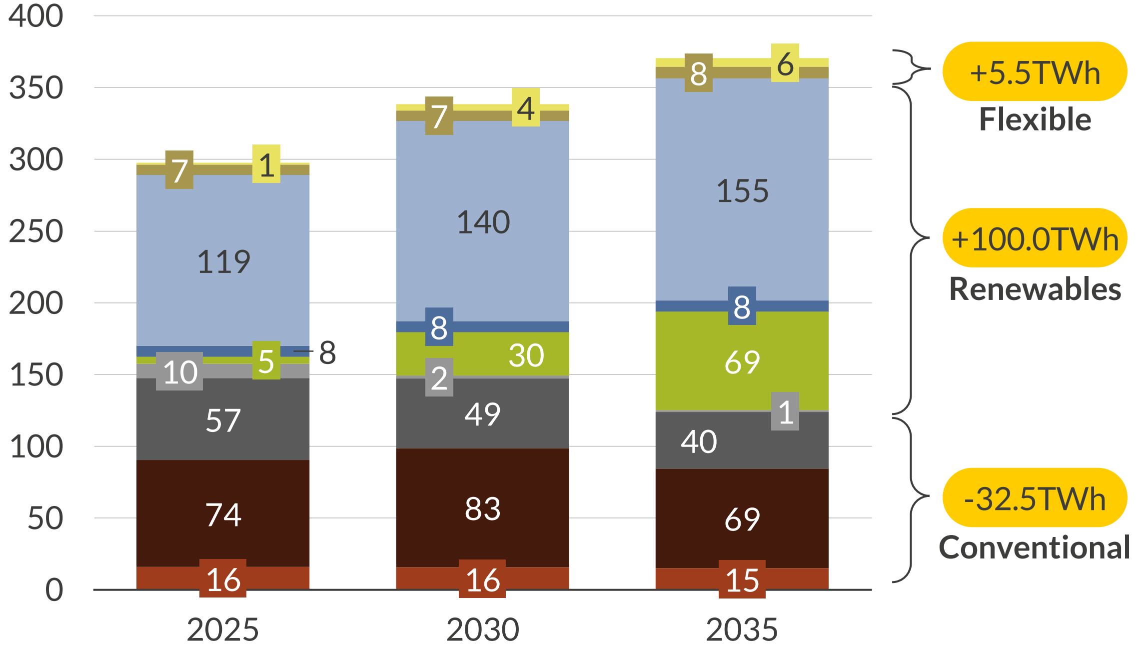
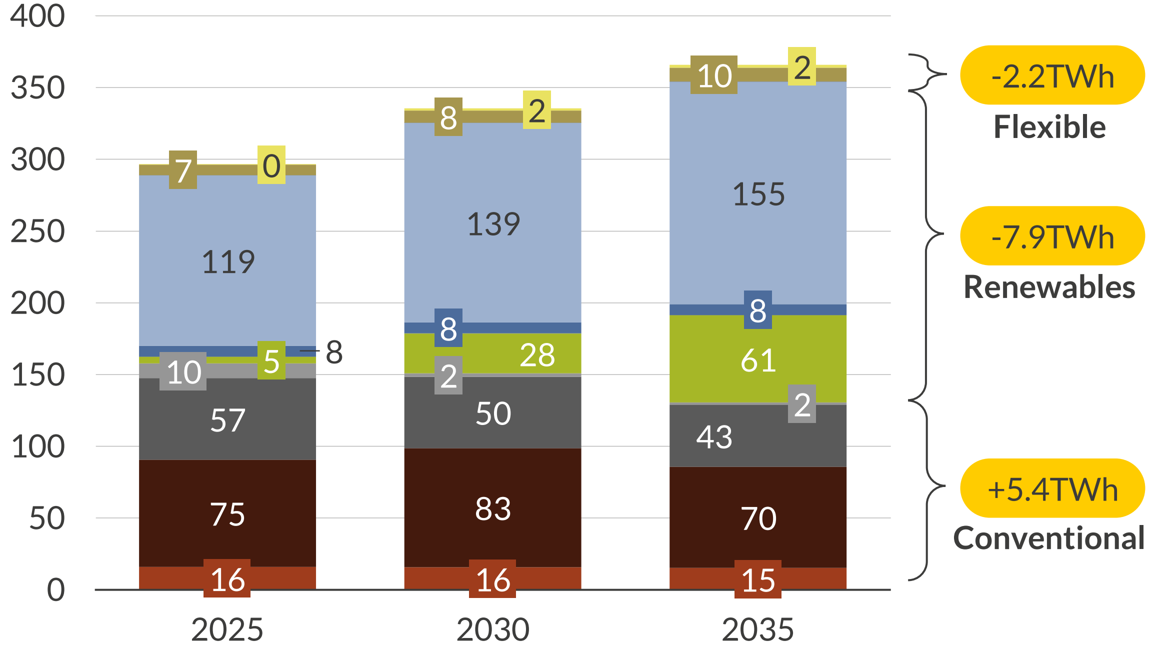
Gross generation, Central
TWh

Total change 2025–2035



Gross generation, *No Battery*
TWh

Delta to Central 2035



- In the Central scenario, generation from conventional fuel sources is increasing replaced by renewable generation.

- In the *No Battery* scenario, generation from conventional thermal sources also declines, but at a slower pace than in the Central scenario.
- Generation from peaking assets is ~2TWh than in the Central scenario.

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

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Lower battery capacity in *No Battery* scenario leads to higher peak prices in evenings when demand is highest and flexible energy is needed the most

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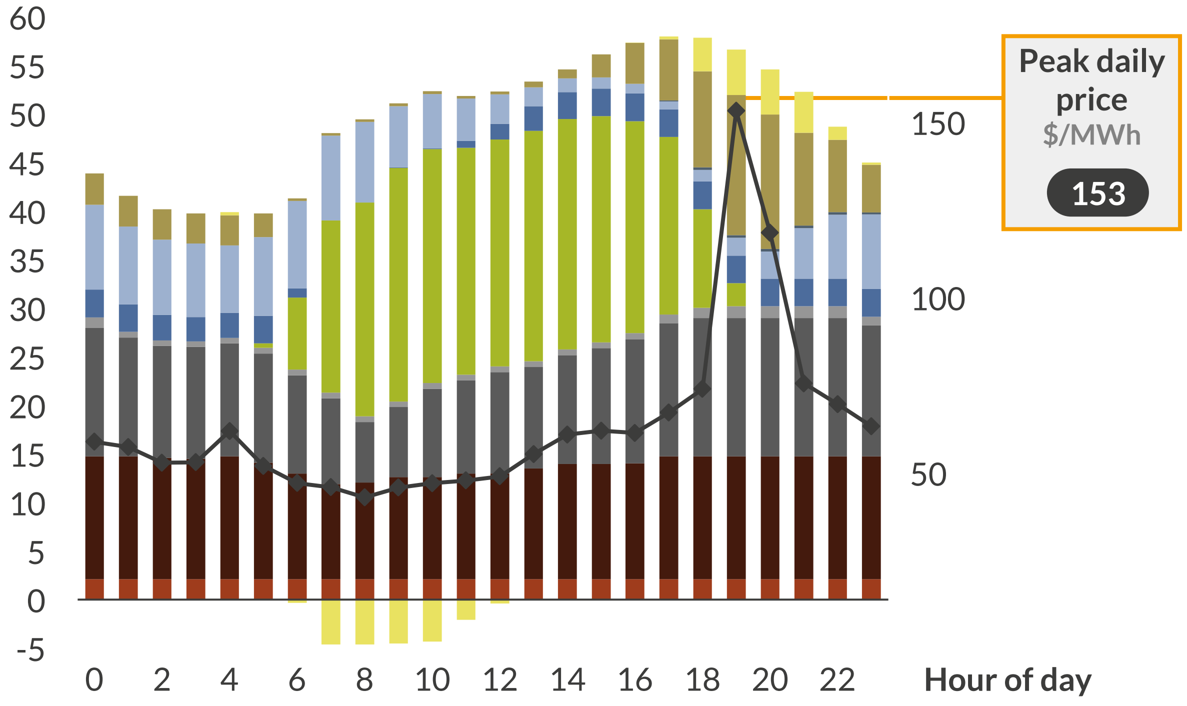
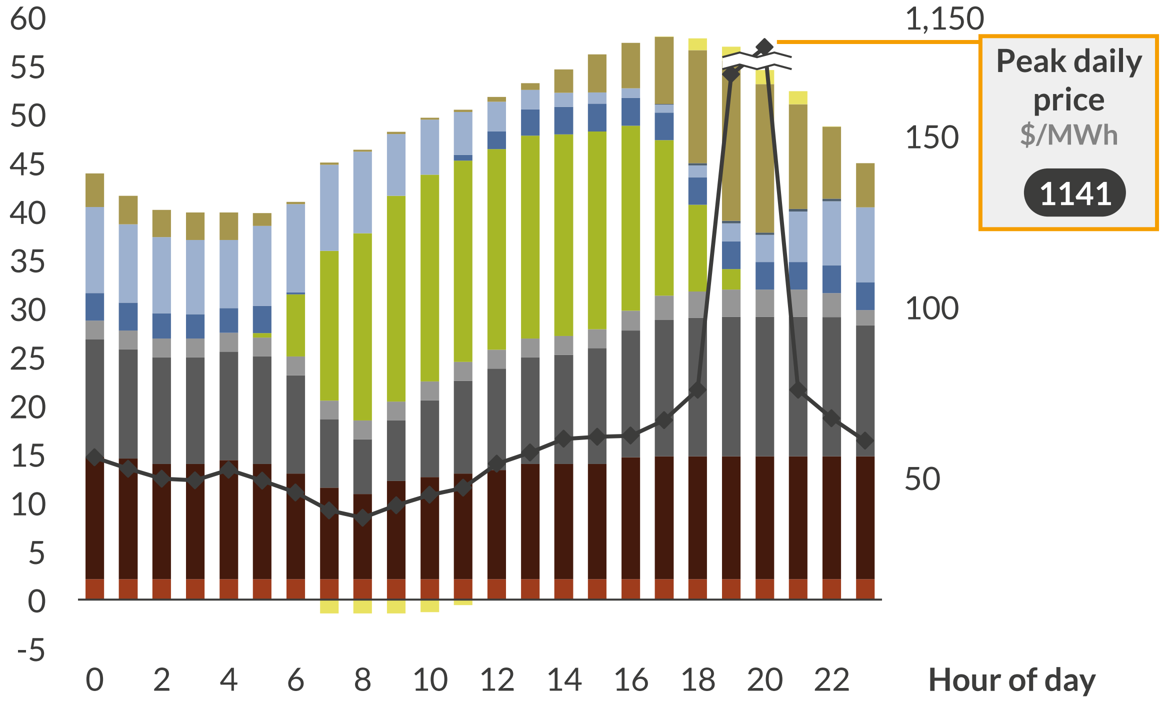
Hourly net generation[1] and prices, Central, August 14th, 2035
GW (left); $/MWh (real 2023) (right)



Hourly net generation[1] and prices, *No Battery*, August 14th, 2035
GW (left); $/MWh (real 2023) (right)



- Battery storage charges during the day when prices are low and supplies energy as demand increases in the late afternoon, **reducing peak pricing and complementing the capabilities of solar generation.**

- With fewer batteries to discharge during the evening, prices spike at higher levels during the tightest hours. On a peak summer day in 2035, increased system scarcity pushes peak prices to **$1141/MWh (+$988/MWh compared to Central) during the evening price peak.**

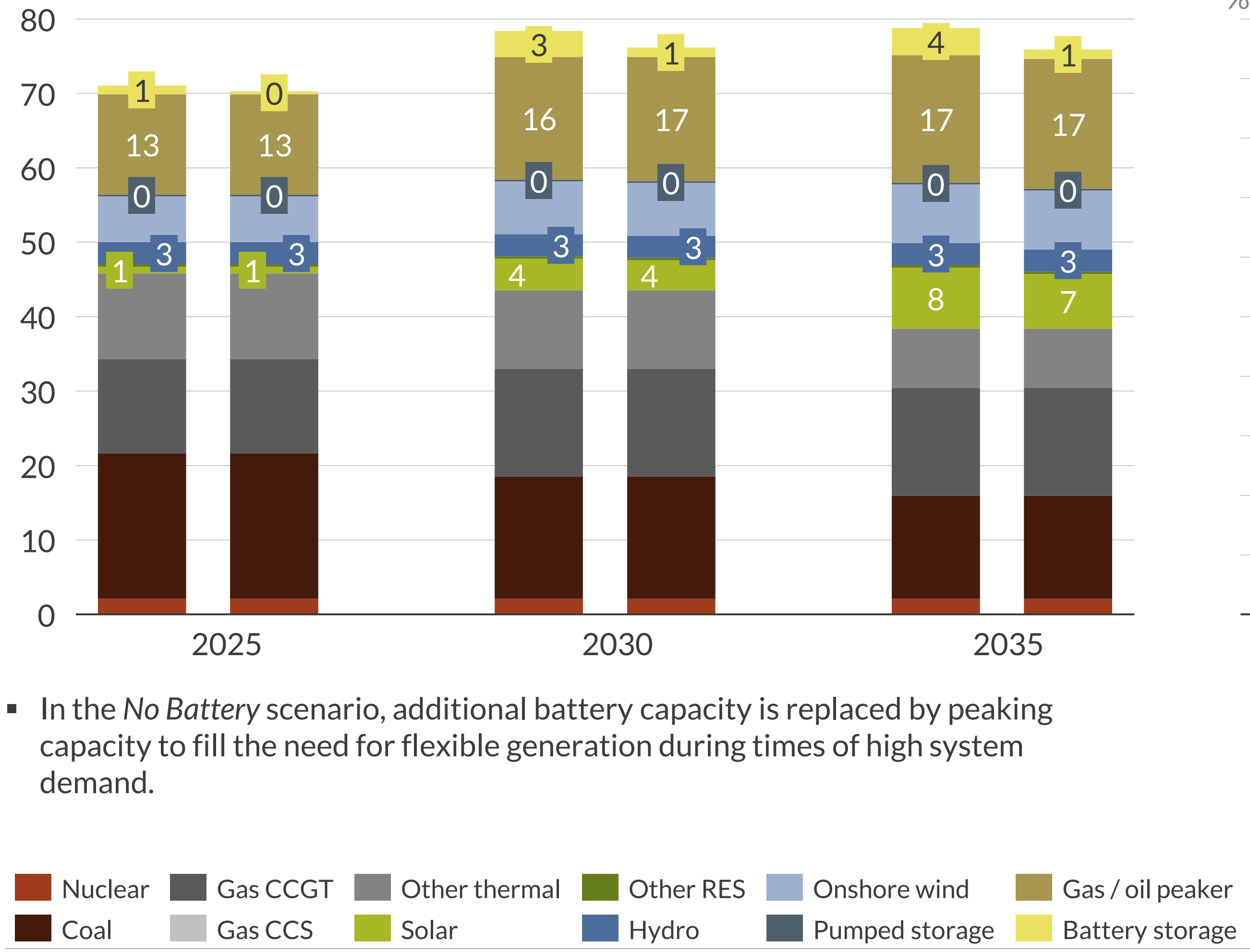
Nuclear | Gas CCGT | Other thermal | Hydro | Pumped storage | Battery storage
Coal | Gas CCS | Solar | Onshore wind | Gas / oil peaker | DA Price

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

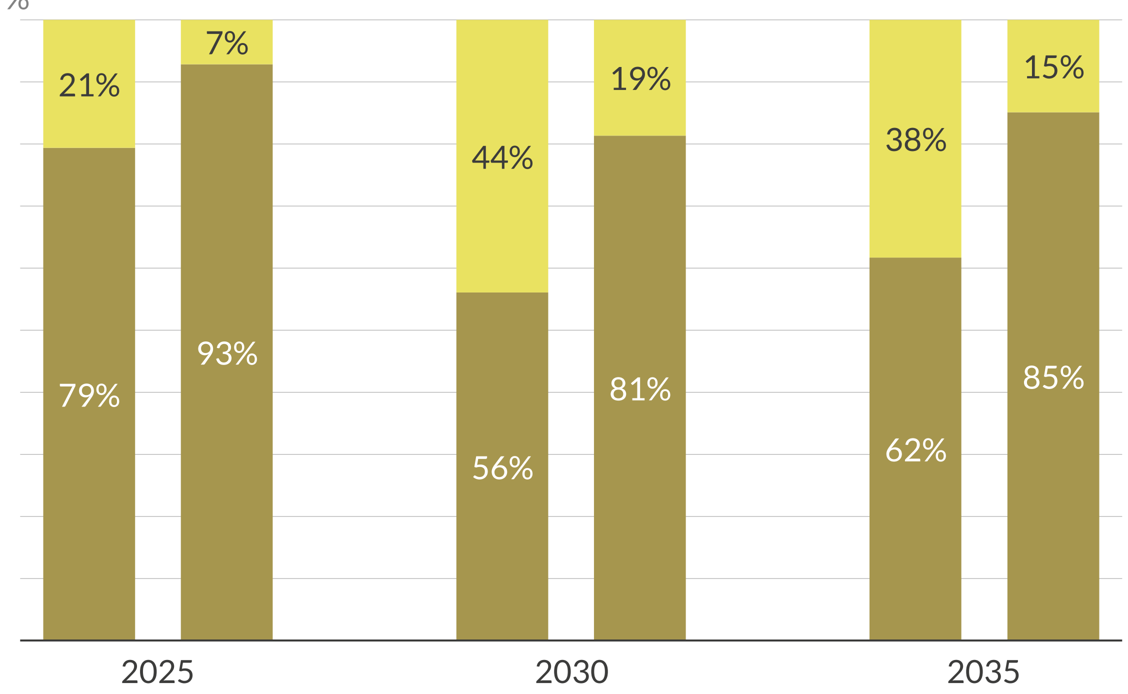
Sources: Aurora Energy Research

With fewer batteries, peaking generation provides a larger share of generation in high-priced hours in the *No Battery* scenario

Accredited capacity — Central (left) vs. *No Battery* scenario (right)
GW



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



- In the *No Battery* scenario, additional battery capacity is replaced by peaking capacity to fill the need for flexible generation during times of high system demand.

- Evaluating high price events, the Central scenario shows the Battery Storage provides an important contribution to meeting demand and **improves the diversity of resources capable of providing flexible generation**.
- The *No Battery* scenario results in an over-reliance on peakers during high-priced events due to the lack of Battery Storage capacity.

1) Net generation is the sum of charge and discharge; 2) High prices defined as hours with wholesale prices upwards of $90USD, considers only generation from Gas / oil peakers and Battery Storage

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 $7 billion higher

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Scenario outcomes

- In the *No Battery* scenario, **total system costs[1] are $7 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 SPP.
  - 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 SPP is **$2.2 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 SPP in the *No Battery* scenario, resulting in an additional $2.2 billion in electricity costs from 2025 - 2035

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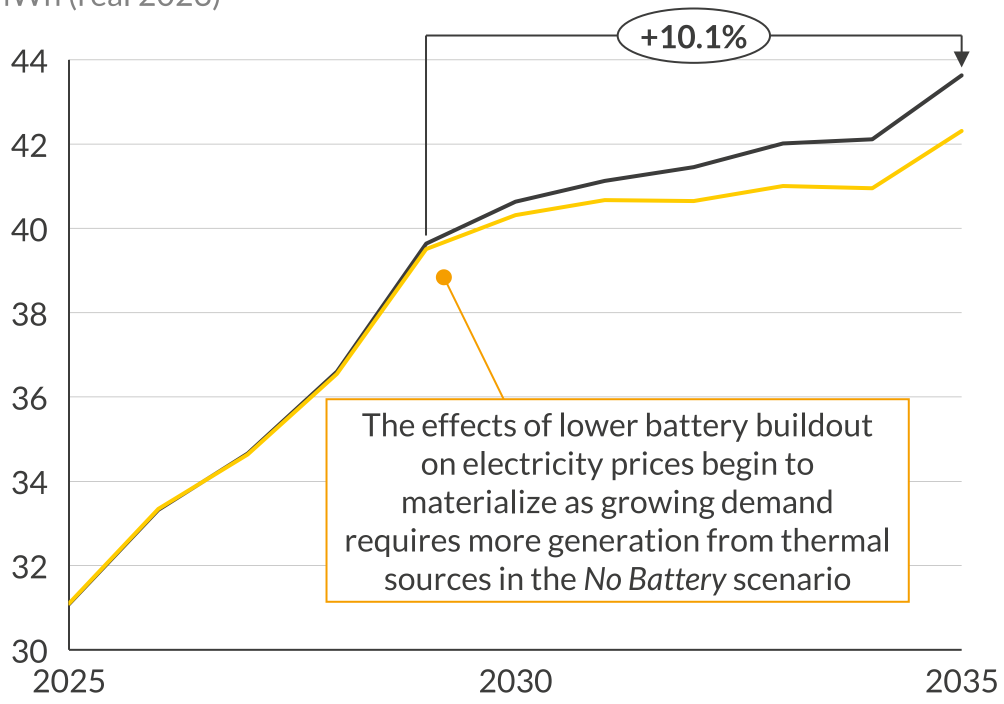
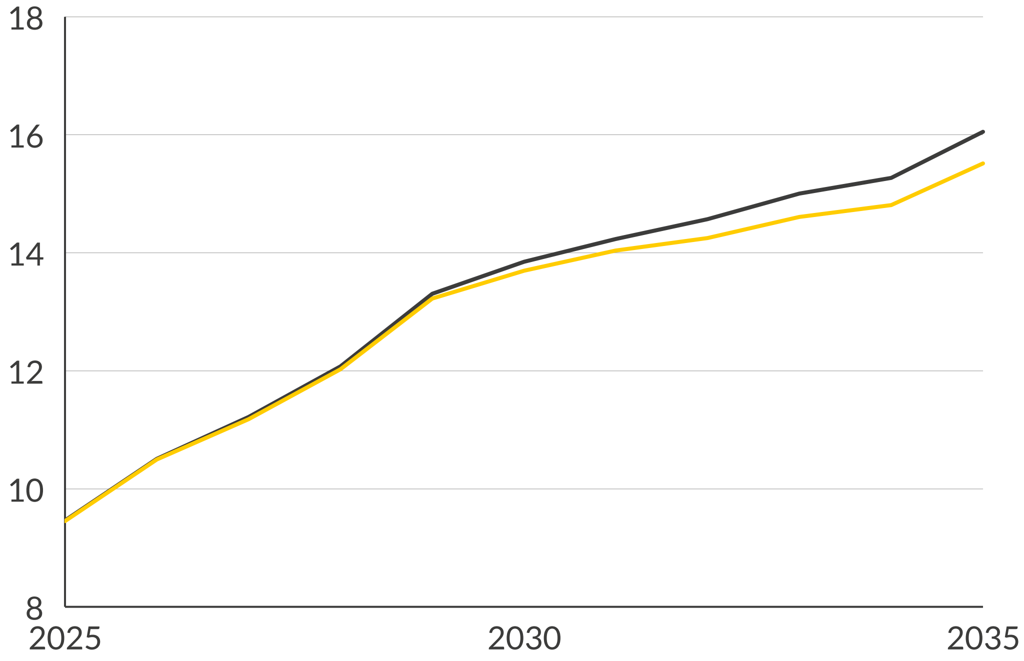
Yearly average ATC[1] electricity price
$/MWh (real 2023)



- With fewer batteries deployed, higher evening peak prices result in wholesale electricity prices that are $1.3/MWh higher annually on average compared to the Central case by 2035.
- From 2029 – 2035, **electricity prices grow by 10.1% in the *No Battery* scenario**, 3 p.p. higher than in the Central scenario.

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



- Higher average prices drive up electricity costs across SPP, with an additional $536 million required in the *No Battery* scenario by 2035. From 2025 – 2035, the cumulative costs total $2.2 billion higher with restricted battery buildout.
- 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.

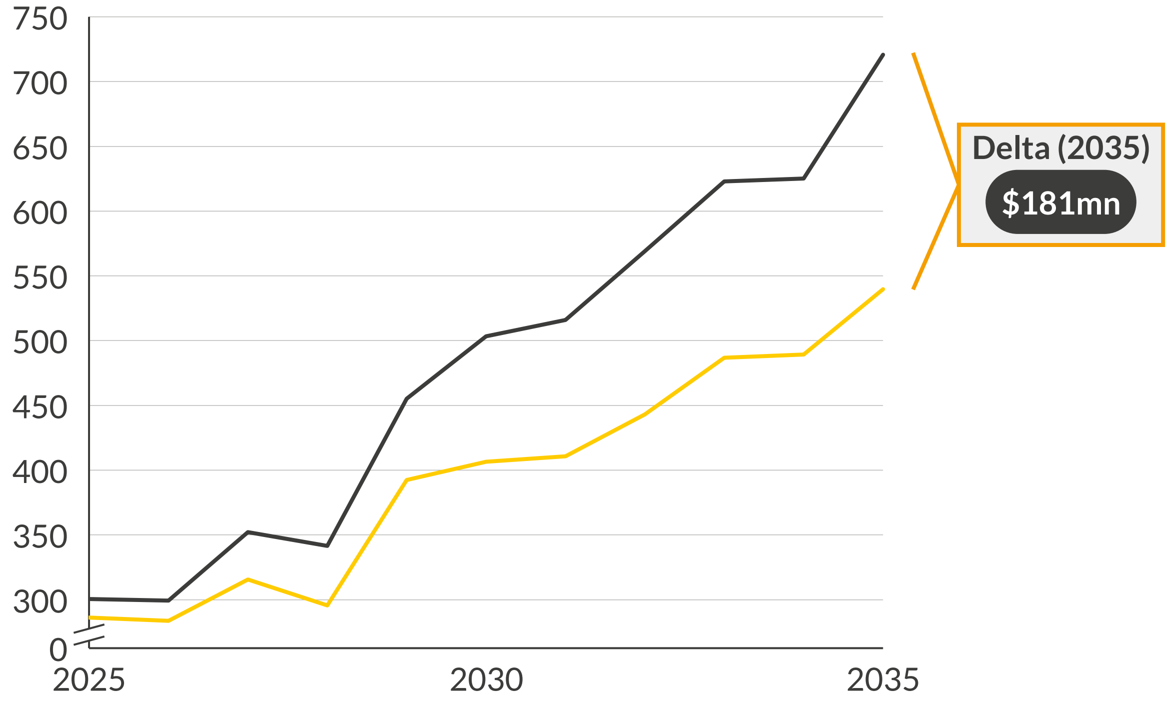
No battery — Central

1) Around the clock.

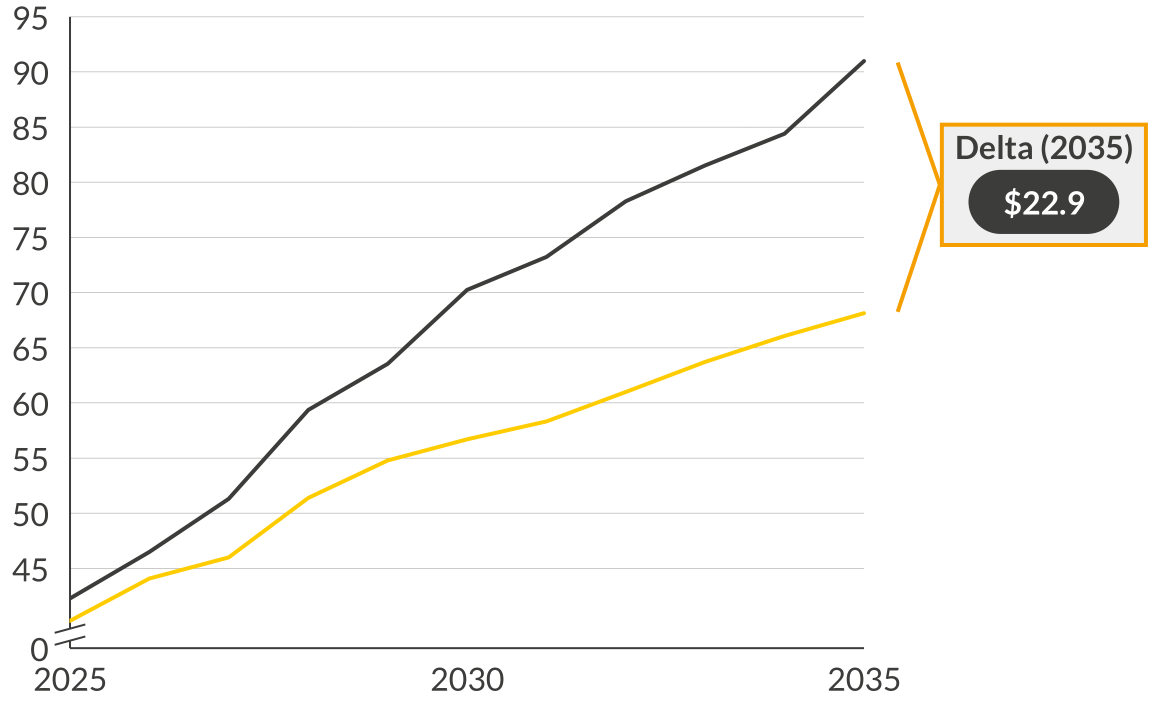
Sources: Aurora Energy Research

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

Total cost[1] of peakers' generated electricity, 2025-2035
$million



Peaker GWA[2] price, 2025-2035
$/MWh (real 2023)



- In the *No Battery* scenario, peakers are relied upon for generation more often, translating into higher total costs for peaker generated electricity.

- Furthermore, **without the dampening effect of batteries on peak pricing, each MWh of electricity provided by peakers will cost more on average.** By 2039, the average price of peaker electricity weighted by generation costs $22.9/MWh more than in the *No Battery* scenario.

No battery — Central

1) Based on wholesale electricity prices only; not including ancillary services or resource adequacy payments. 2) Generation weighted average.

Sources: Aurora Energy Research

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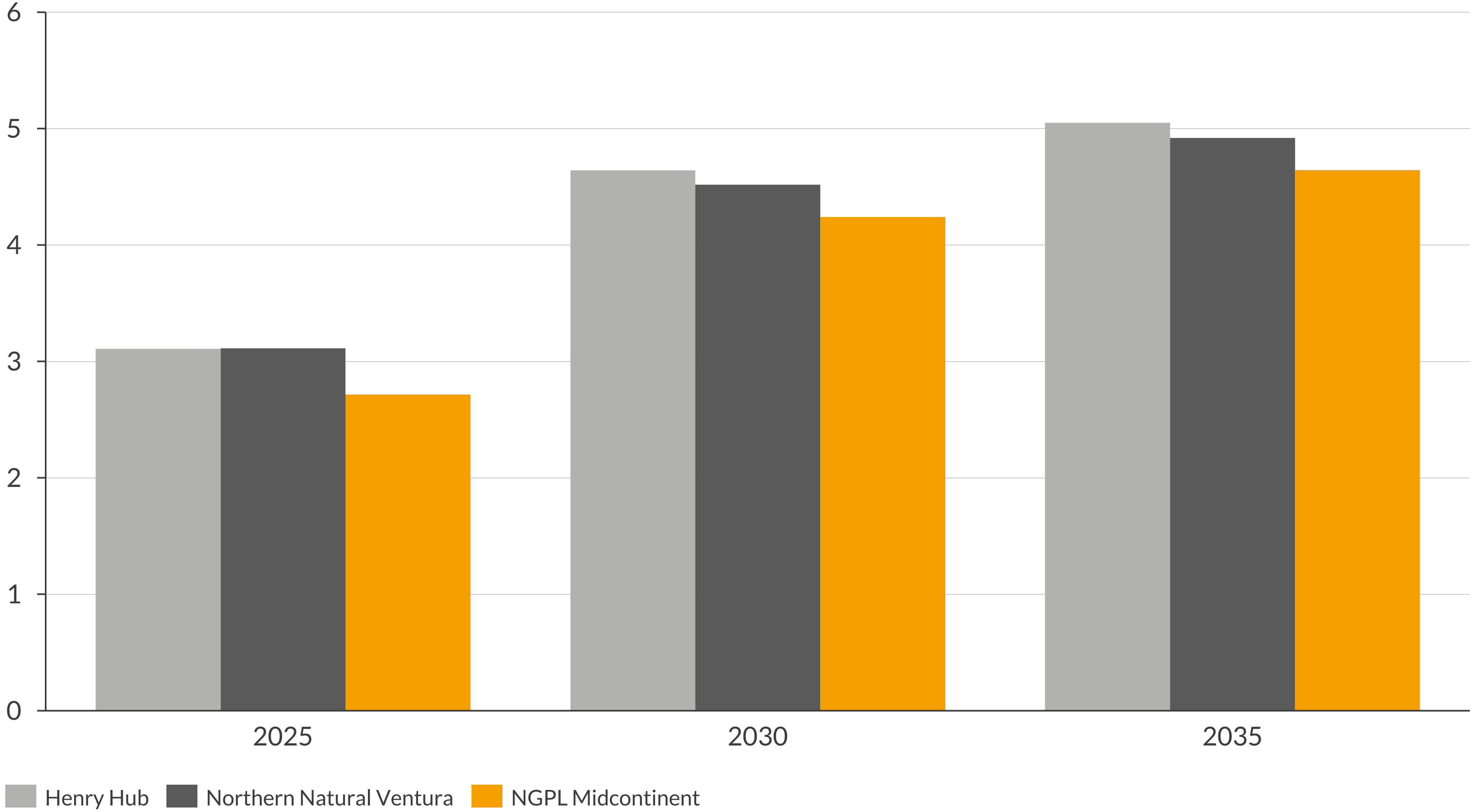
Henry Hub and regional gas prices range between $2.7-4.9/MMBtu between 2025 and 2035

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 SPP vary by technology, with wind assets' higher initial installed capacity leading to higher derating factors

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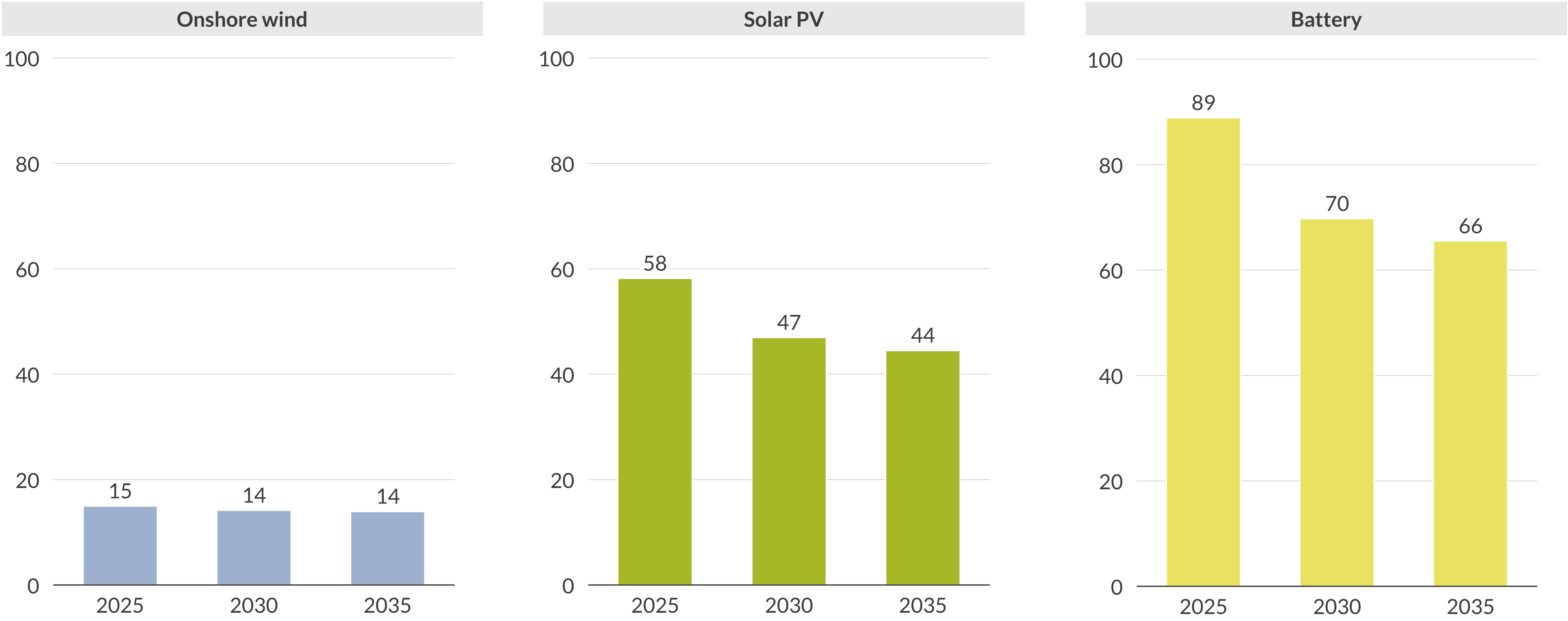
Aurora assumed renewable ELCC de-rating factors by technology[1]
%



1) Summer values shown.

Sources: Aurora Energy Research

Total load in SPP is forecasted to hit 332TWh by 2030 with peak load over 63GW, driven by oil/gas electrification and data center buildout

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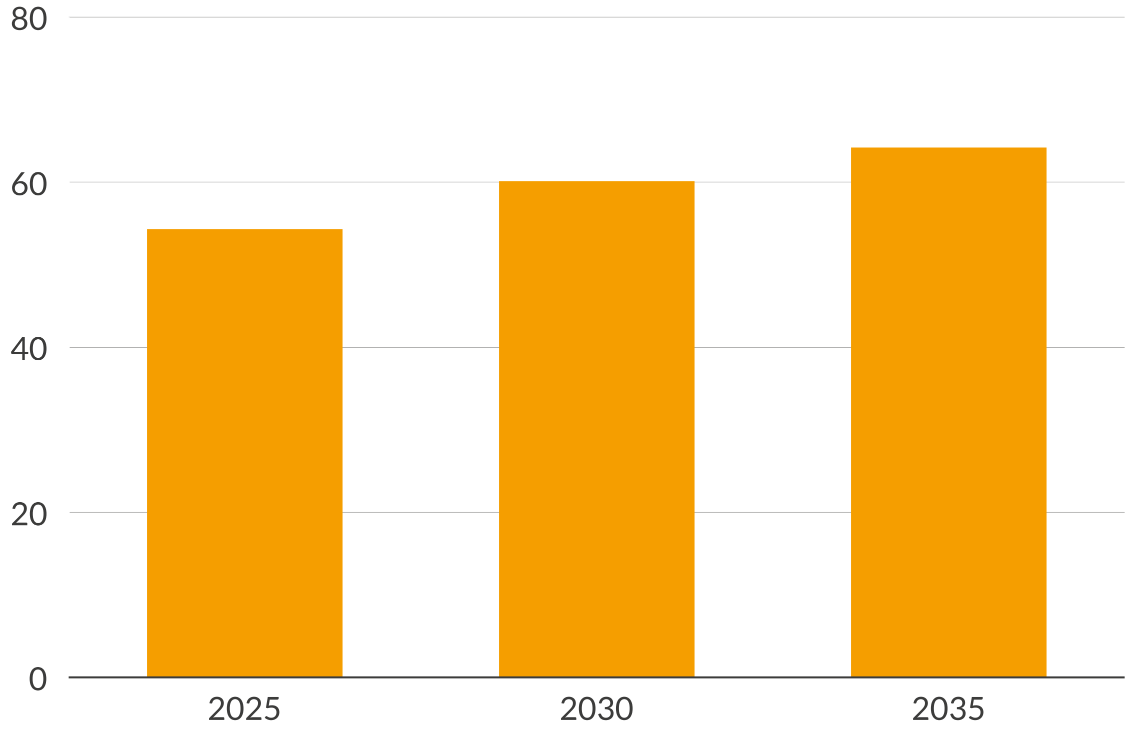
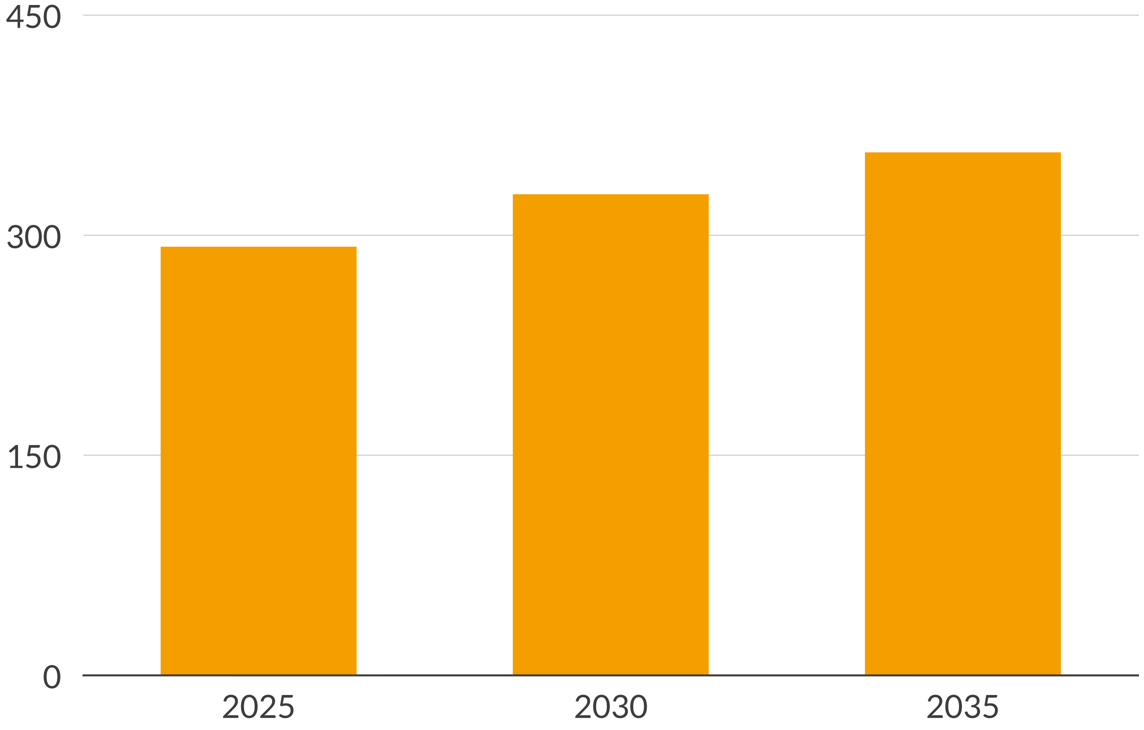
SPP peak load[1]
GW



- Peak load is projected to reach almost 65GW by 2035, with early growth driven by rapid data center expansion in Kansas City and Nebraska.

SPP total annual load
TWh



- Total annual load is projected to reach 356TWh by 2035 with a large portion coming from Oklahoma and the Southwest region.

1) North Dakota and South Dakota are winter-peaking systems, all other regions use a summer peak demand.

Sources: Aurora Energy Research

Details and disclaimer

Publication
Battery energy storage impact and benefits assessment for SPP

Date
July 2025

This report was commissioned by the American Clean Power Association. All analysis and findings are the independent work and opinion of Aurora Energy Research.

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