AURORA ENERGY RESEARCH

Assessment of Resource Adequacy Needs in ERCOT and Impact of Market Design Changes

November 10th, 2025

Prepared for the Electric Reliability Council of Texas

Context for this report

- **This report, prepared for the Electric Reliability Council of Texas, provides an assessment of resource adequacy needs in the ERCOT power market and the impact of market design changes on key reliability and system costs metrics.**
- The study starts by evaluating resource adequacy risks under the “status quo” market design under different weather scenario, including assessments of increased risks from data center load growth and thermal supply chain constraints. The study also includes modeling and analysis of demand side response, including the recent policy developments from SB6 and NPRR1238.
- The study also assesses the impact on key reliability and system costs metrics of market design changes from different implementations of the Dispatchable Reliability Reserve Service (DRRS) and changes in the Operating Reserve Demand Curve (ORDC).
  - Under the direction of ERCOT and its Staff, Aurora modeled three market design changes to evaluate their impact against the "status quo":
    1. DRRS as an Ancillary Service
    2. DRRS as an Ancillary Service Plus
    3. Extension of the ORDC while maintaining a $5,000/MWh offer cap

Disclaimer

- **This analysis is a deterministic evaluation of resource adequacy under certain weather and system conditions.** Weather conditions and generation outages are modeled based on past observed system behavior to evaluate system reliability under similar conditions in the future, once load growth and expected capacity additions are considered. The forecasted capacity build and impact of market design changes is based on projected economics. Capacity expansion is not constrained, despite potential supply chain risks. We do not assign probabilities to each outcome.
- **This report does not advocate for any specific policy or market design change** but rather aims to evaluate the impact of the proposed changes to system reliability and costs.
- Aurora’s modeling intends to **capture the conceptual approach of the proposed market designs, but the final implementation may differ.**

Executive Summary

1

With its unique energy-only market design in the US, ERCOT has seen faster load growth and renewables capacity additions than any other ISO in the country, but this has also yielded low operational reserves—creating resource adequacy challenges in recent years

- Unlike other markets in the US with a capacity market or other mechanism to ensure adequate supply, ERCOT relies only on wholesale and ancillary service markets price signals for resource adequacy.
- ERCOT's energy only market design has yielded average operational reserves of 8% between 2020-2024, 5p.p. lower than MISO, the second lowest at 13%.
- Over this same period, ERCOT peak load and renewables additions grew faster than any other ISO.

2

By 2030, system reliability depends on data centers providing flexibility under SB6 to avoid load shed in extreme weather conditions. A more conservative Aurora Central case with fewer data centers sees load-shedding events during these conditions.

- Demand growth is forecasted to accelerate, driven by population, industrial and data center demand.
- Under Winter Storm Elliott and Summer 2023 type weather events, load shed in 2030 is forecasted to occur under both Aurora Central and ERCOT Long Term Load Forecast (LTLF) demand forecasts.
- Demand response from data centers, as intended by SB6, eliminates load shed in the ERCOT LTLF case with about half of 22GW data centers curtailing load. In a lower demand growth environment, demand response is insufficient to fully resolve load shed under extreme conditions.

3

DRRS Ancillary Service Plus provides the largest reliability improvement at the lowest system cost. An Extended ORDC provides less reliability benefit at a higher cost, while DRRS Ancillary Service offers comparatively limited improvement.

- In both the Aurora Central and ERCOT LTLF cases, DRRS AS Plus has the highest impact on reducing load shed by bringing 5.2 to 7.9GW of additional dispatchable capacity at a net cost of $0.3 to $1.8 billion.
- While neither load flexibility nor DRRS AS Plus alone fully eliminates load shedding across all cases, their combined implementation reduces the maximum load shed to less than 500 MW.

Sources: Aurora Energy Research, ERCOT

Agenda

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ERCOT has seen faster peak load growth and renewables additions than any other ISO, but historical operational reserves have been considerably lower

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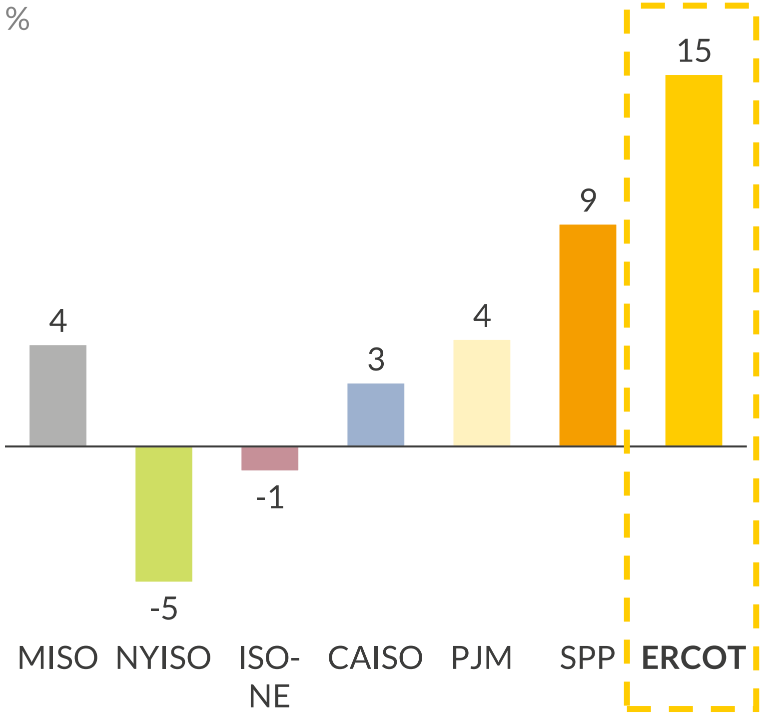
1 ERCOT peak load is growing faster than any other market in the U.S.

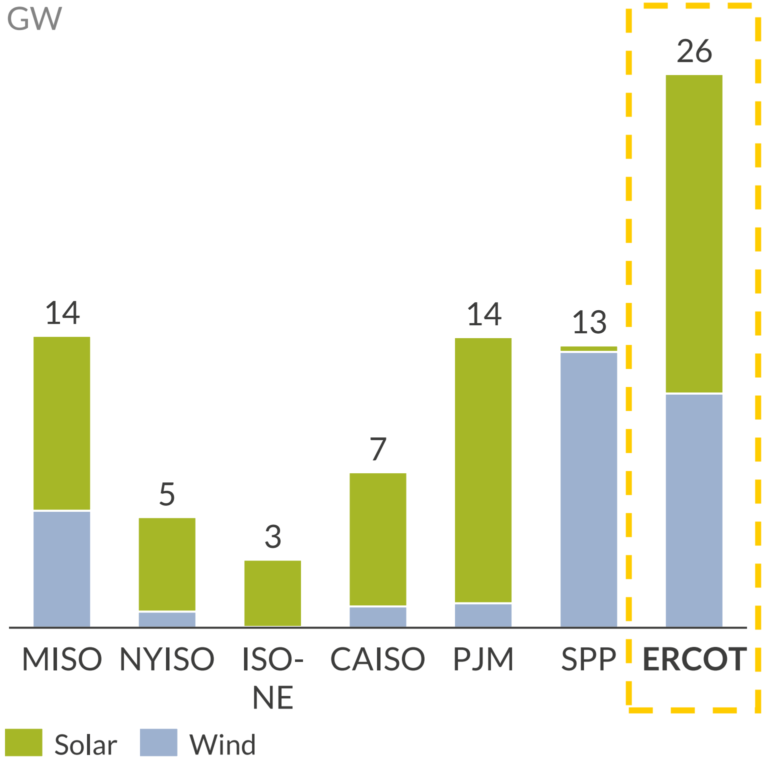
Peak load growth by ISO, 2020-2024[1]



- From 2020 to 2024, ERCOT saw a ~15% growth in peak load, rising from 74.3GW to 85.4GW.
- ERCOT's "connect and manage" approach to interconnection has enabled rapid demand growth.

2 ERCOT is also seeing the fastest rate of renewables penetration.

Renewables capacity additions[2], 2020-2024



- Renewables penetration in ERCOT outpaces all other competitive markets, with 26GW of capacity additions between 2020 and 2024.

3 ERCOT's historical operational reserves have been lower than other ISOs.

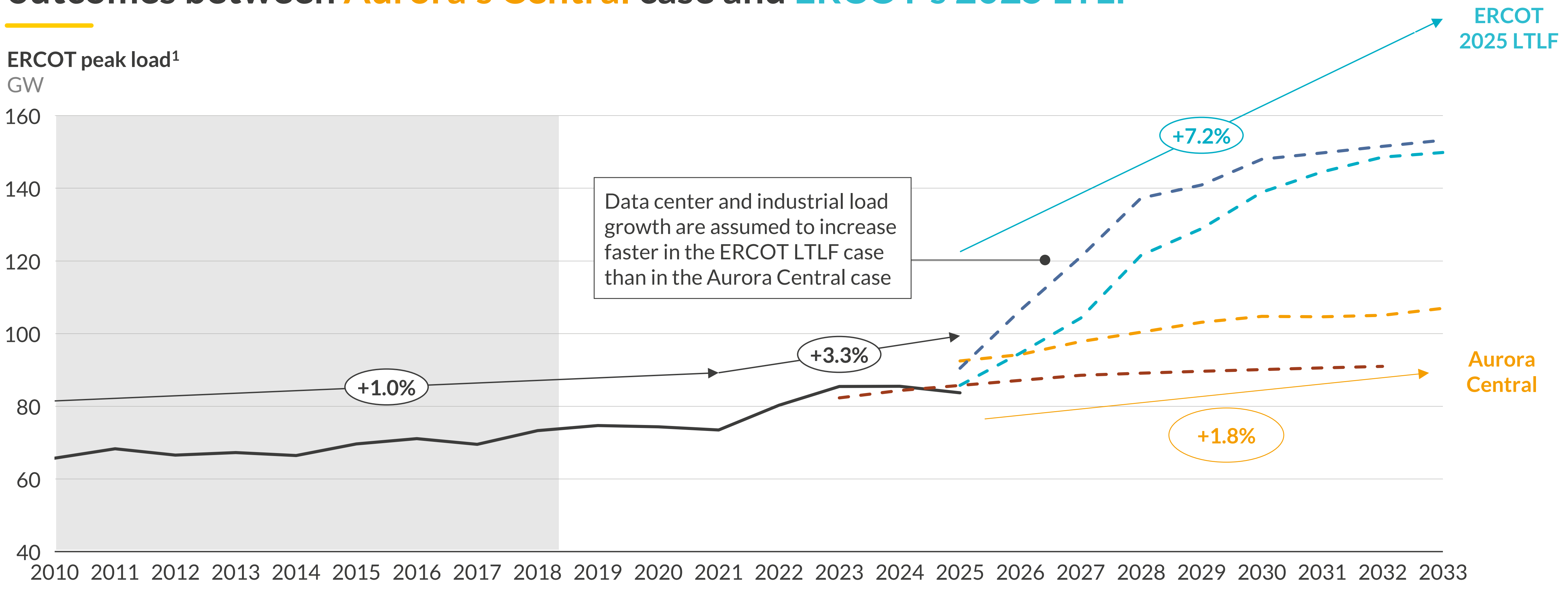
Average historical operational reserves[3], 2020-2024

- ERCOT operates as an energy-only market without a mandated reserve margin. Its historical operational reserves have generally been lower compared to other ISOs with enforced capacity or resource adequacy mechanisms.

1) Data from each respective ISO. 2) Onshore wind, offshore wind, rooftop solar, and ground mount solar. 3) Historical operational reserves are calculated as reserves available during yearly net peak demand divided by net peak demand. Winter Storm Uri in 2021 is excluded from the calculation of historical operational reserves

Sources: Aurora Energy Research, ERCOT, NYISO, ISO-NE, PJM, MISO, CAISO, SPP

Aurora modeled two demand scenarios, testing a wide range of potential outcomes between Aurora's Central case and ERCOT's 2025 LTLF



- Historically, ERCOT has seen limited peak demand growth, averaging a 1% CAGR[2] from 2010-2021. However, in more recent years, hot weather, heavy electrification of industrial activity, and emergent demand from data centers and bitcoin mining have driven a sharp increase in demand from 2021-2024.
- This trend is expected to continue as speculative load growth drivers from data centers combine with firm expectations from economic growth and electrification.
- In the ERCOT 2025 LTLF[3], peak demand increases to 139GW in 2030, based on the volume of actual interconnection requests received.

1) Summer peak demand. 2) Compound Annual Growth Rate. 3) Long-Term Load Forecast.

Sources: Aurora Energy Research, ERCOT

To assess system reliability, Aurora modeled the impact of two historic weather events using forecasted supply and demand assumptions for 2030

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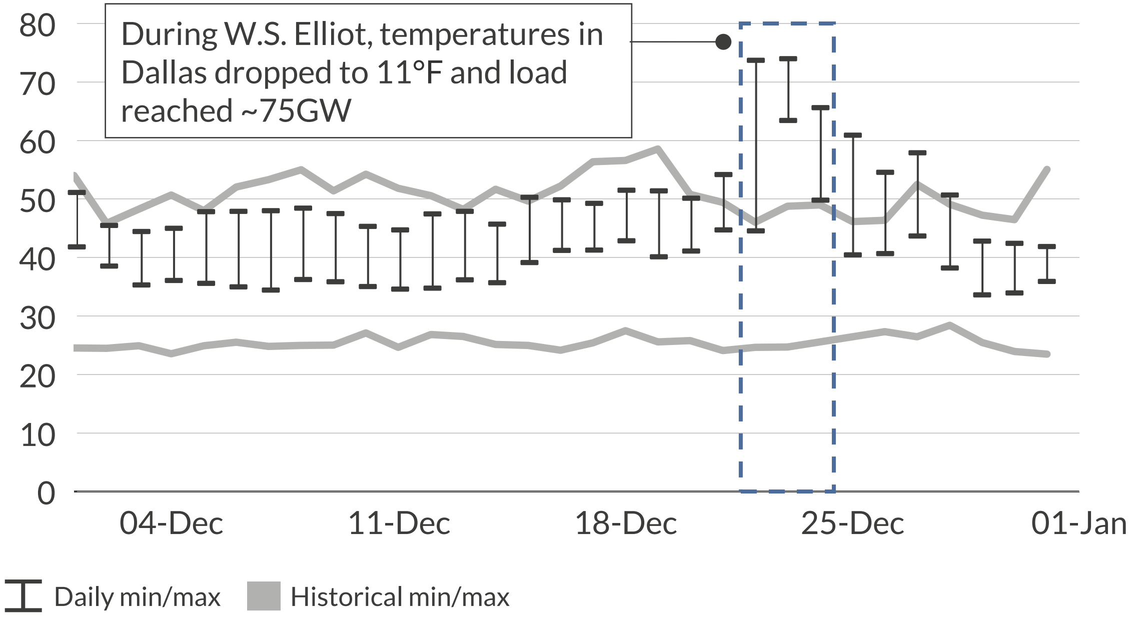
2022 Weather Year (Winter Storm Elliot)

Total ERCOT load, December 2022[1]
GW

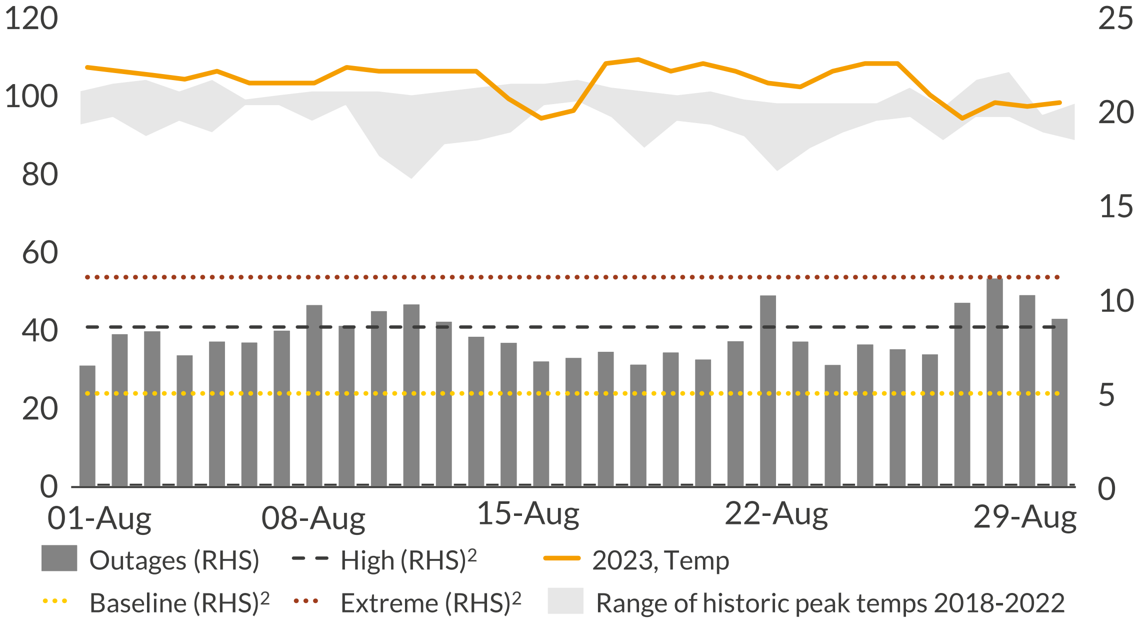


- W.S. Elliot brought **extreme cold weather, which has only been matched once since** (W.S. Heather in January 2024).
- However, temperatures were **not as extreme as during W.S. Uri**, (February 2021) nor were outage levels, largely due to new weatherization standards.
- Aurora used demand, renewables generation and outage profiles to recreate the effect of W.S. Elliot **under 2030 supply and demand assumptions.**

2023 Weather Year (summer heatwave)

Max daily temperature, August 2023
Degrees Fahrenheit

Daily thermal outages
GW



- Extreme summer heat in 2023 put recurring strain on the grid and set a new peak load record.
- Summer **weather in 2023 was far hotter than Texas had seen in recent years**, with 55 days having a heat index of 100°F or greater; 2022 had 47 such days and 2024 had 23 days.
- Aurora modeled **the impact of extreme heat on 2030 supply and demand.**

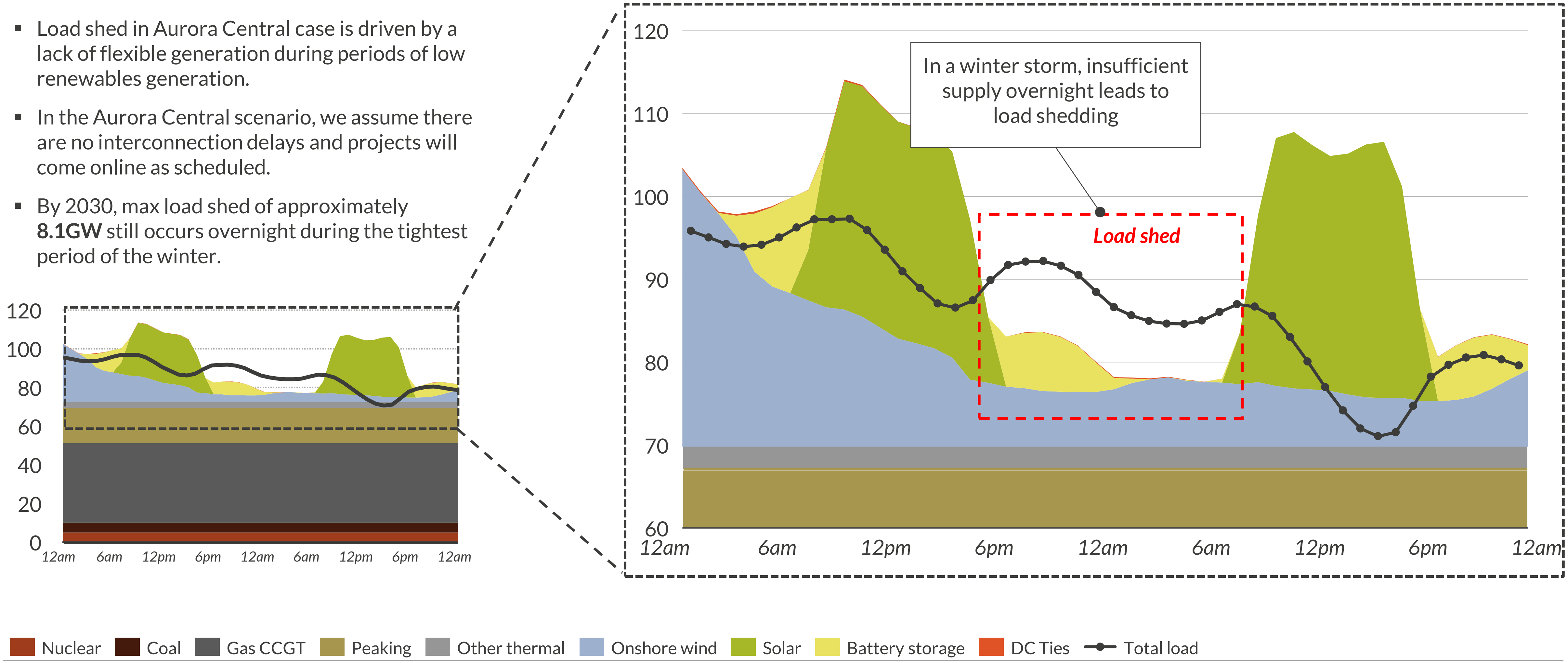
1) Including years since 2010. 2) Baseline, High, and Extreme levels taken from Revised May 2023 ERCOT SARA reports.

Sources: Aurora Energy Research, National Weather Service, ERCOT

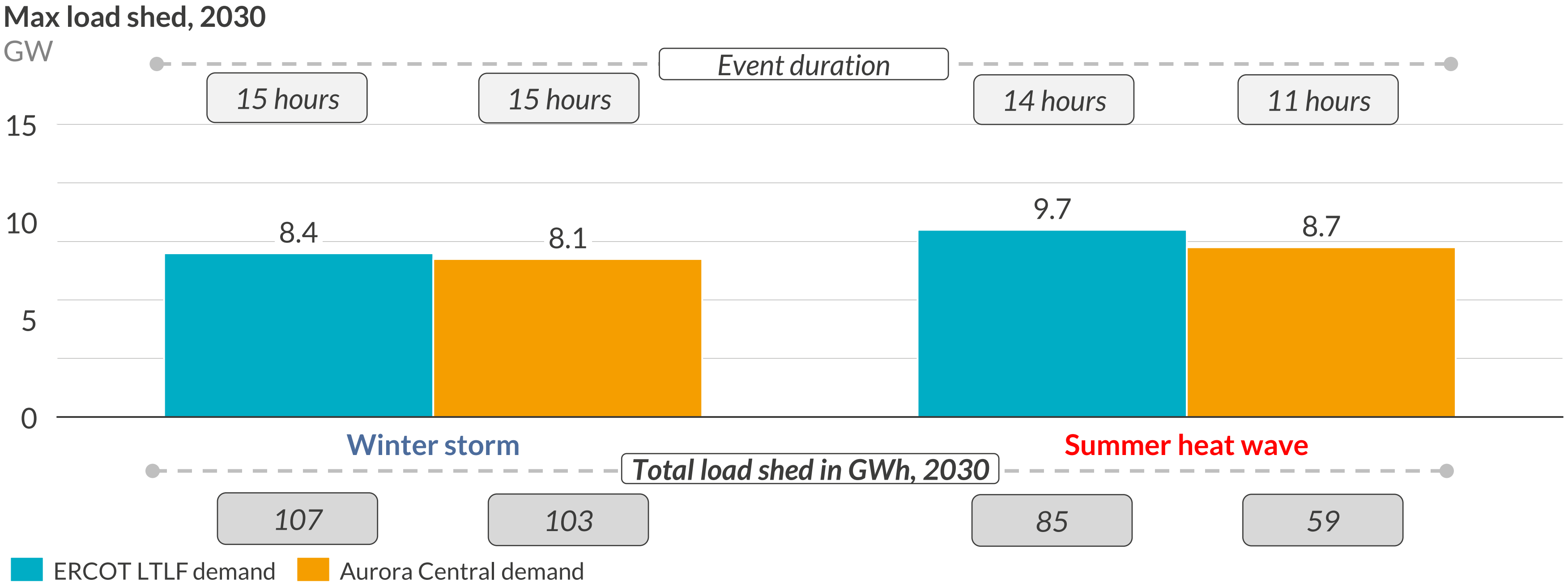
Aurora Central | In 2030, winter storm conditions (Storm Elliot-style event) lead to load shedding as supply is insufficient to satisfy demand requirements

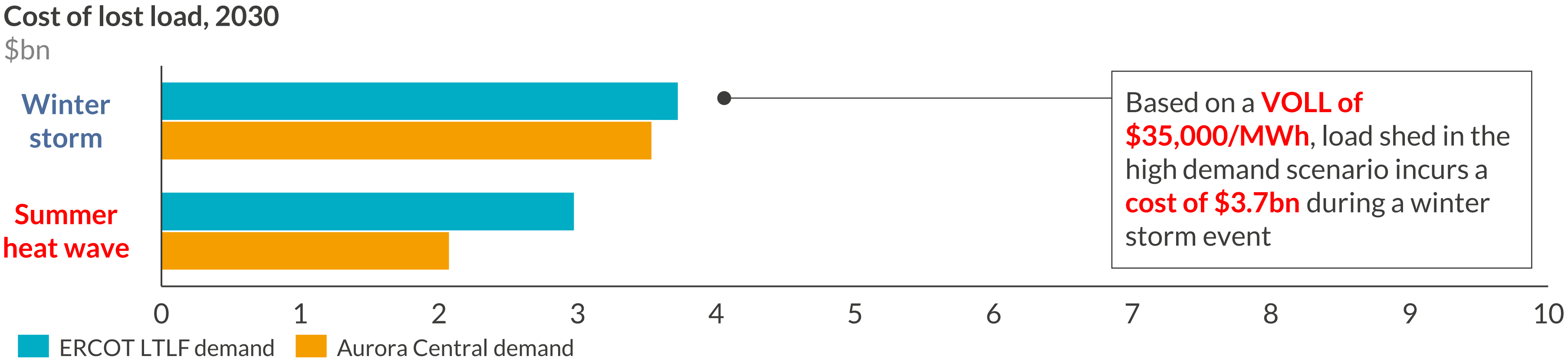
2030 December winter storm (Winter Storm Elliot-style event)
GW

- Load shed in Aurora Central case is driven by a lack of flexible generation during periods of low renewables generation.
- In the Aurora Central scenario, we assume there are no interconnection delays and projects will come online as scheduled.
- By 2030, max load shed of approximately **8.1GW** still occurs overnight during the tightest period of the winter.



Extreme weather drives load shed in both demand cases with up to $3.7bn worth of lost load in the ERCOT LTLF case





- Load-shedding events occur under both extreme summer and winter conditions in the Aurora Central and ERCOT LTLF demand cases.
- Total load shed is most severe in the ERCOT LTLF demand case under summer heatwave conditions.
- Maximum load shed reaches 8.4GW in the winter, and 109.1GWh of energy is unserved over the course of a 15-hour winter event.
- 8GW to 10GW of load shed represents between 2.0 and 2.5 million homes without power.[1]
- Based on a $35,000/MWh value of lost load, in all modeled cases, load-shedding events would cost over $2bn, with the most severe case costing $3.7bn.

1) 1 megawatt (MW) of electricity can power 250 Texas homes during periods of peak demand.

Sources: Aurora Energy Research, ERCOT

Demand Side Response may be an important tool to support system reliability, yet the level of pre-emergency curtailment that can be relied on is unclear

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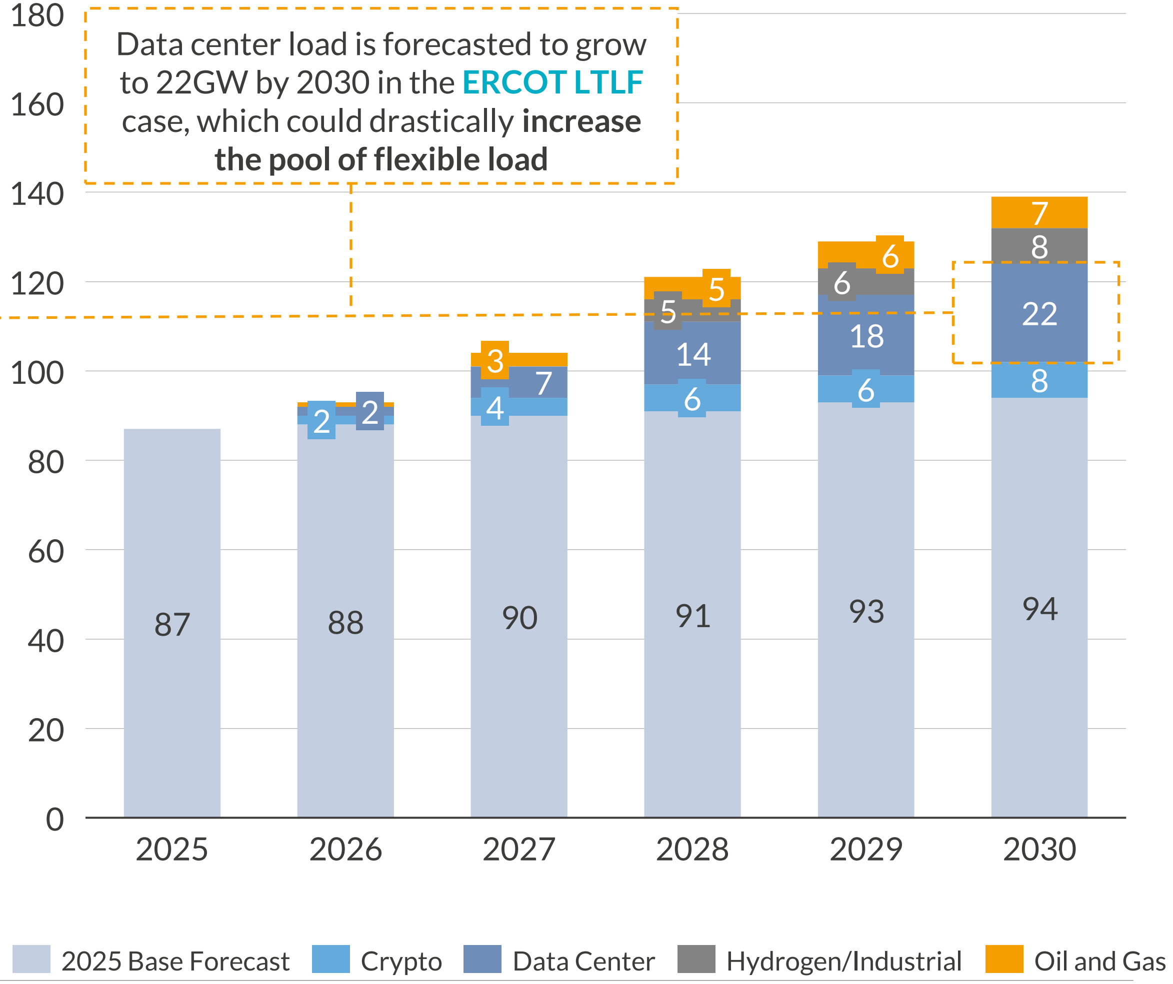
Overview of Demand Side Response

- **Definition and context**
  - Demand response is a mechanism that incentivizes or directs power consumers to **reduce their consumption during periods of system stress.** This can be achieved via a reduction of load, or by shifting consumption to behind the meter backup generators.
  - Demand response improves operational flexibility by providing an additional lever to grid operators as they balance supply and demand.
- **Current forms of demand response**
  - Currently, demand response is typically provided by **large consumers** or load serving entities via one of the following:
    - TDSP[1] management programs
    - 4-Coincindent Peak (4-CP) load reduction
    - Ancillary services such as Responsive Reserve Service (RRS)
    - Emergency Response Service (ERS)
- **The expected impact of demand response**
  - As data center load increases, so does the **pool of load resources** with potential to provide demand response.
  - Grid operators **may be able to utilize load flexibility to mitigate load-shedding events.**

ERCOT LTLF demand by sector
GW



1) Transmission Distribution Service Provider.

Sources: Aurora Energy Research, ERCOT

Aurora modeled the impact of data center load flexibility under SB6, both from emergency directives and economic signals

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Data center operations typically require 24/7 power. However, if necessary, demand response can be provided in the form of behind the meter generation, which can act as a substitute for grid sourced power. Another way could be geographical and/or temporal load shifting, which effectively could reduce demand at the site.

Modeling assumptions and methodology

- Aurora modeled three distinct data center operating behaviors, each with unique market impacts:
  - **Responsive to price** – will run backup generation or shift demand to avoid high prices and transmission charges, influencing peak prices and reducing the need for peaking supply.
  - **Emergency/ancillary service provider** – will turn down only when called upon by the system operator (e.g., under EEA2[4]). This behavior is considered out of market and does not impact prices.
  - **Inflexible** – does not turn down. Only impacted during a load-shedding event (Energy Emergency Alert Level 3).

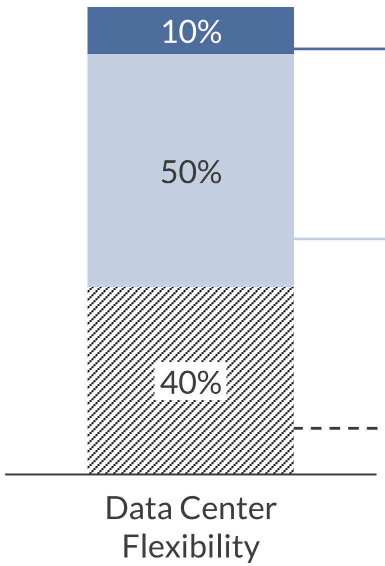
Flexibility modeled	Baseload price	Scarcity prices	Impact on supply[1]
Price responsive			
Emergency service provider			

Modeling assumptions and methodology cont.

- Aurora modeled a scenario - "Data Center Flexibility" – reflecting increased levels of data center participation in demand-side response through voluntary and directed (e.g., SB6) mechanisms.

Assumed demand response from data centers

%



Data center capacity that responds to price signals and is transmission charge avoidant

Data center capacity that provides emergency and ancillary services (held out of SCED[2]) during EEA2 conditions

Data center capacity that does not participate in DSR, would avoid falling under SB6 criteria[3] and is only subject to load shed under EEA3 conditions

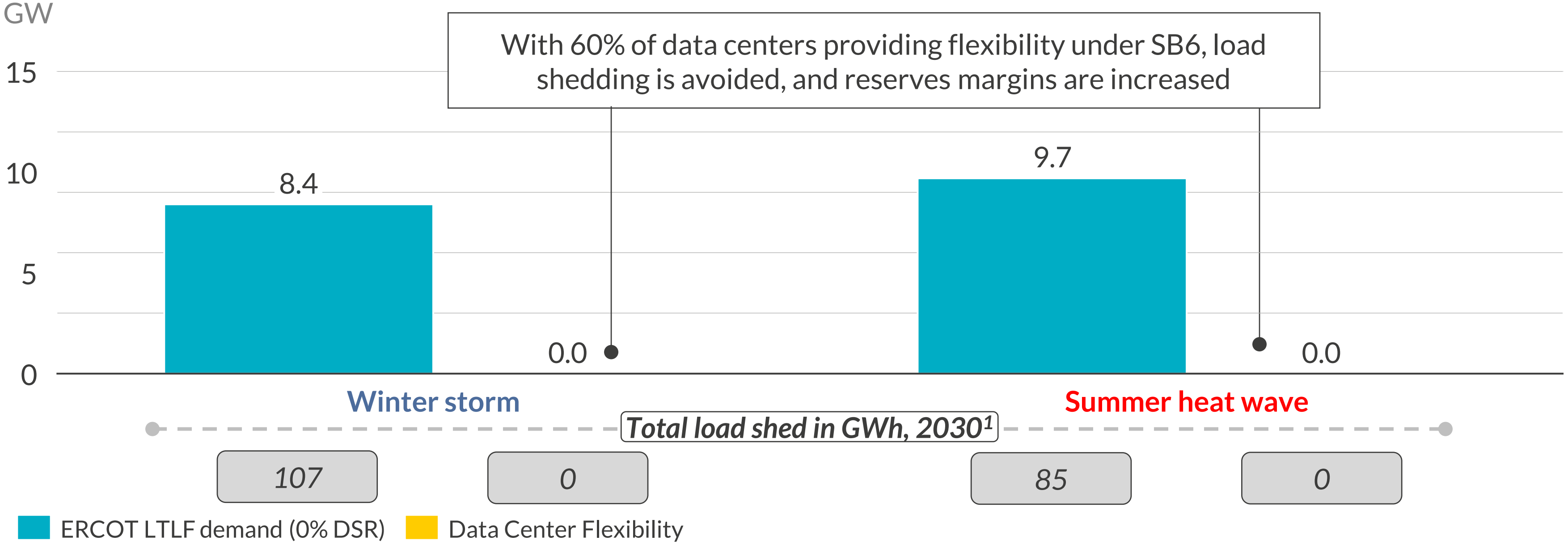
Responsive to price | Emergency/Ancillary services | Rest of DTC Demand

1) Indicates how much demand flexibility will impact supply side build decisions as data center behaviors will affect prices differently, impacting the economic signals to build new supply. A more detailed explanation of Aurora's capacity expansion methodology can be found in the appendix of this

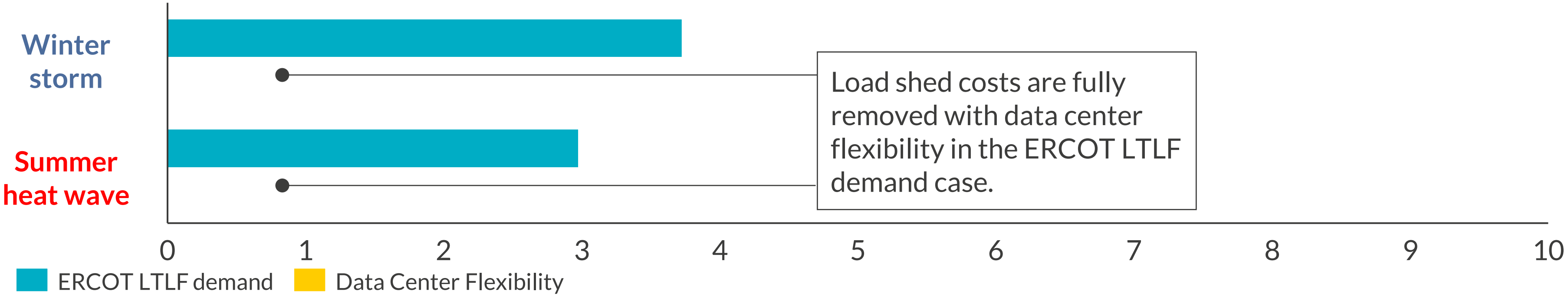
Sources: Aurora Energy Research

ERCOT LTLF | At high levels of data center growth, demand response can eliminate load shed with 60% of data center participating

Max load shed, 2030[1]
GW



Loss of Load Costs, 2030
$bn



- In the Data Center Flexibility scenario, 60% of data center load is considered flexible based on SB6 assumptions, and load shed is eliminated under both winter storm and summer heat wave conditions.
- Considering the maximum load shed under these Winter storm and Summer heat wave conditions, 60% data center flexibility would be sufficient to fully alleviate load shed concerns.
- Data center flexibility saves the system $3.7 billion during an extreme winter storm when considering a $35,000/MWh VOLL.

1) Assumes 22GW of data center load by 2030.

Sources: Aurora Energy Research

Aurora Central | At lower levels of data center penetration, data center flexibility is not sufficient to avoid load shed

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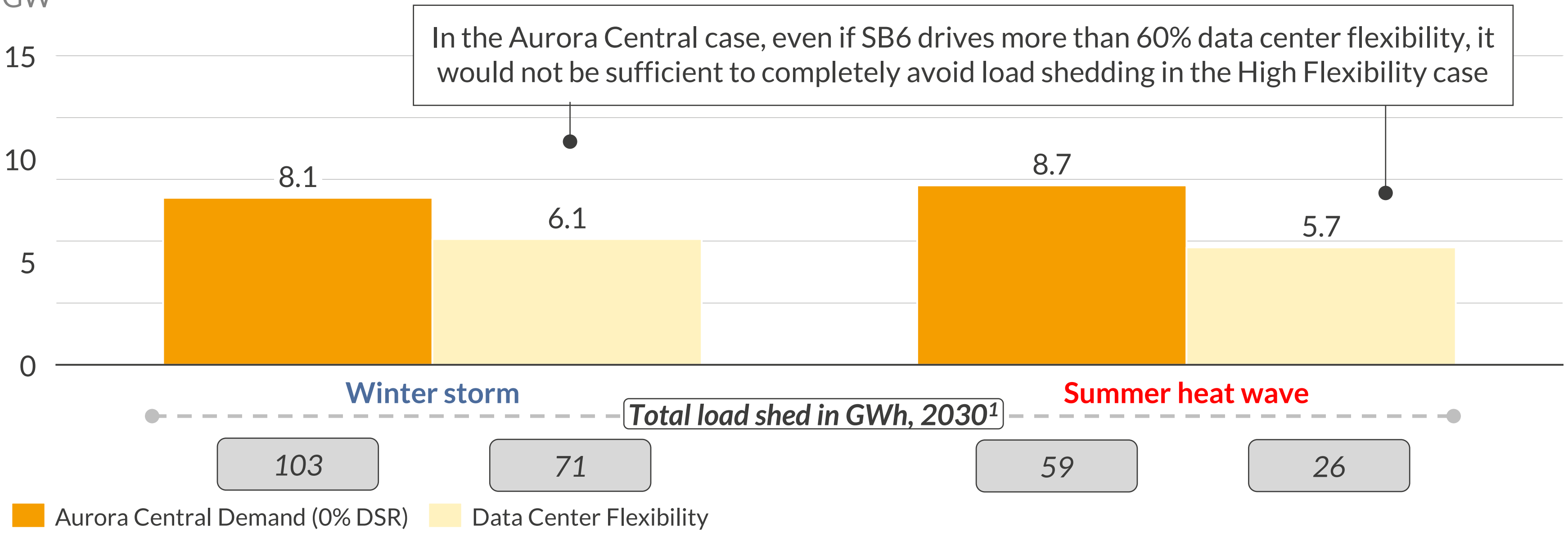
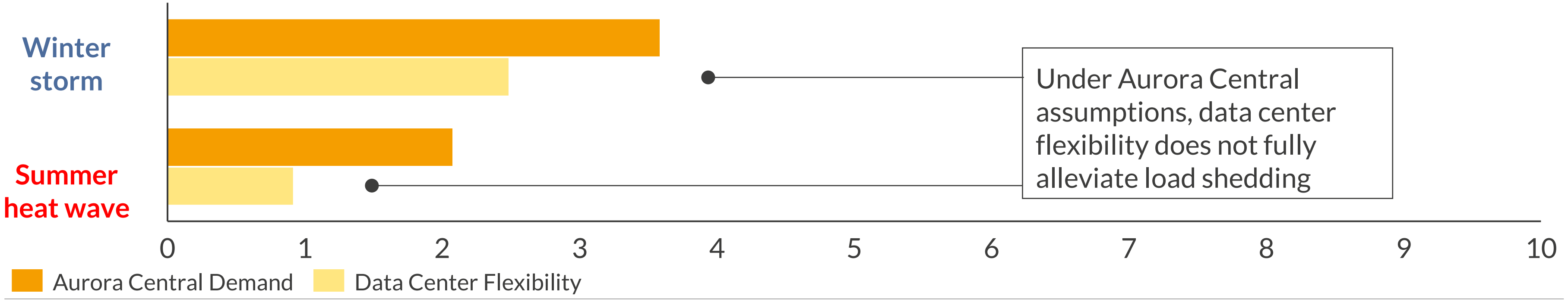
Max load shed, 2030[1]
GW



Loss of Load Costs, 2030
$bn



1) Assumes 7GW of data center load by 2030. Only considers data centers that provide emergency demand response services.

Sources: Aurora Energy Research

- The Aurora Central case takes a more conservative view of data center load growth and assumes 7GW of total data center demand by 2030.
- Due to more limited capacity, DSR from data centers does not have the same level of impact in the Aurora Central case as it does in the ERCOT LTLF case.
- In the Data Center Flexibility scenario, load shed is still necessary under both winter storm and summer heat wave conditions. During these Summer heat wave conditions, even 100% data center flexibility would not be sufficient to avoid load shed.
- Despite not fully alleviating the need to shed load, DSR participation from data centers in the Data Center Flexibility scenario cuts loss of load costs by $1.1bn during an extreme winter storm.

Aurora modeled the impact of three market mechanisms on resource adequacy and system costs

Market Design Properties	DRRS Ancillary Service (AS)	DRRS Ancillary Service Plus	Extended ORDC Curve
Purpose	Increase reserves, improve operational flexibility and reduce the amount of Reliability Unit Commitment.	Improve long-term resource adequacy by **providing a stable and predictable revenue** stream for **dispatchable resources.**	**Increase the value of scarcity** to encourage performance during periods of system stress and incentivize new investment.
Design	**Procured as an ancillary service** in the Day-Ahead market with average procurement volumes similar to Non-Spin.	**An hourly availability payment.** Payment amounts are determined by an annual budget. The total budget is based on the prior year's peaker net CONE[1].	Longer ORDC curve to increase scarcity value in line with a $35,000 VOLL. Total **value from the ORDC increases nearly 2x.** Prices are capped at $5,000/MWh.
Eligibility	Non-dispatchable renewables are not eligible. Resources must be capable of **running for at least four hours.** **Aurora modeled two cases:** 1. Only thermal resources eligible 2. 4+ hour BESS eligible to participate[2]	Non-dispatchable renewables are not eligible. Resources must be capable of **running for at least four hours.** **Aurora modeled two cases:** 1. Only thermal resources eligible 2. 4+ hour BESS eligible to participate[2]	All technologies are eligible.
Procurement size (2030)	1–4GW/hour	80–140GW/hour *(dependent on supply growth)*	*NA*
Primary technologies	Gas peakers; **Modeled with and without long-duration storage eligibility (4hr)**	Gas peakers; **Modeled with and without long-duration storage eligibility (4hr)**	All technologies

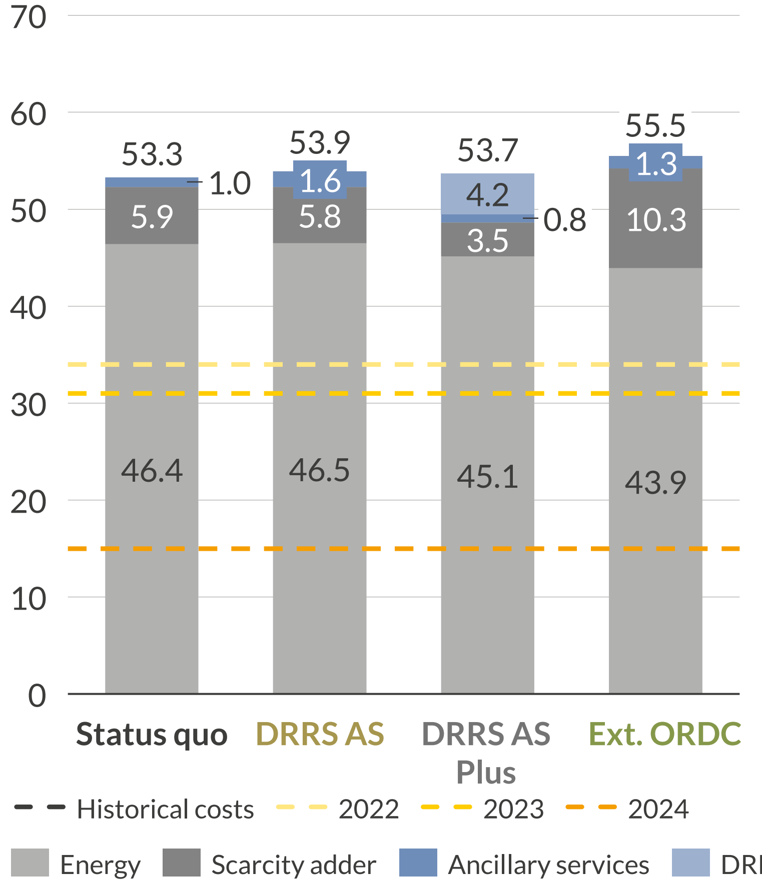
1. Cost of New Entry ($/MW-year). 2) Aurora has modeled a case in which batteries are eligible if their nameplate duration is at least 4-hours.

Sources: Aurora Energy Research, ERCOT

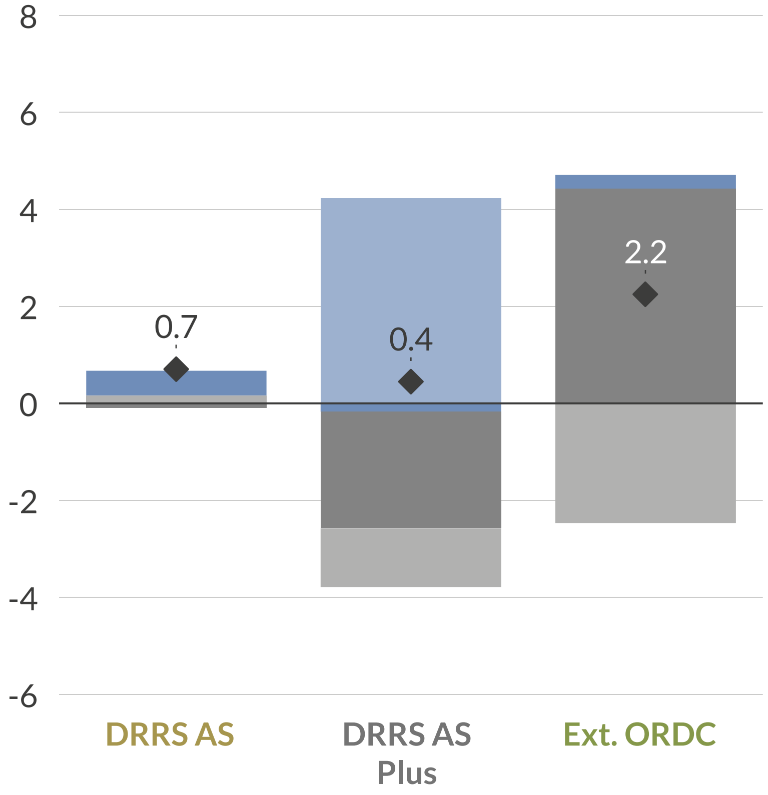
ERCOT LTLF | DRRS AS Plus incentivizes net 5GW of long-duration dispatchable capacity at a net $0.4bn cost, while DRRS AS has limited impact

Batteries ineligible

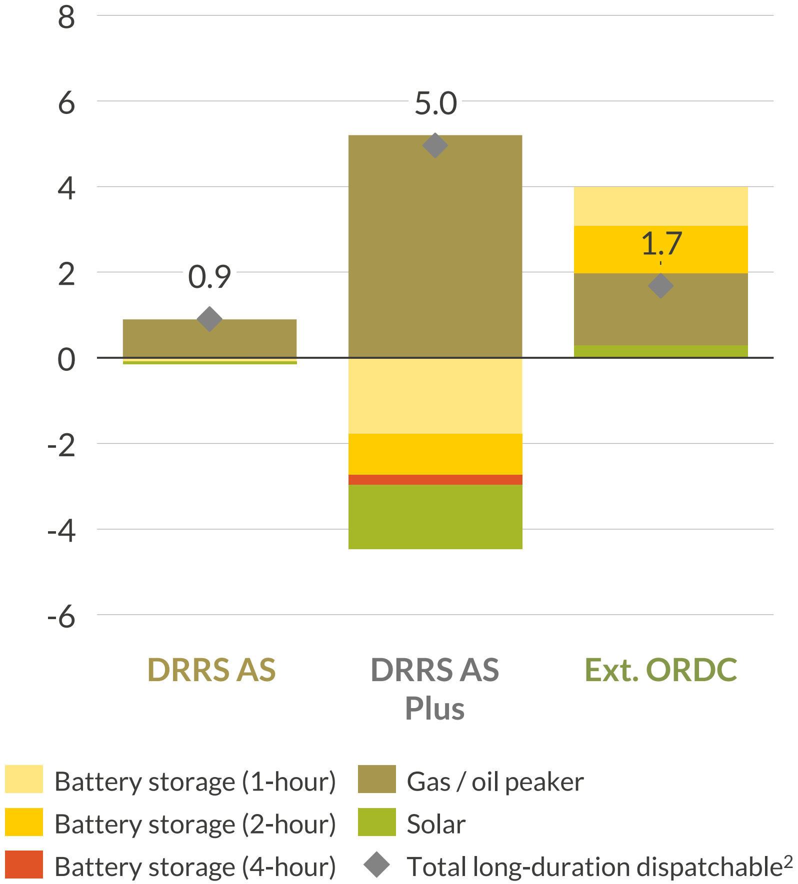
All-in system cost (across entire year 2030)[1]
$ billion



Cost delta to the Status Quo
$ billion



Capacity delta to the Status Quo
GW



1) Under a normal weather year (2013 style weather year). 2) Includes resources capable of running for at least 4 hours.

Sources: Aurora Energy Research

ERCOT LTLF | Battery eligibility in DRRS has limited impact on cost but increases total net additions of long-duration dispatchable capacity to 6.3GW

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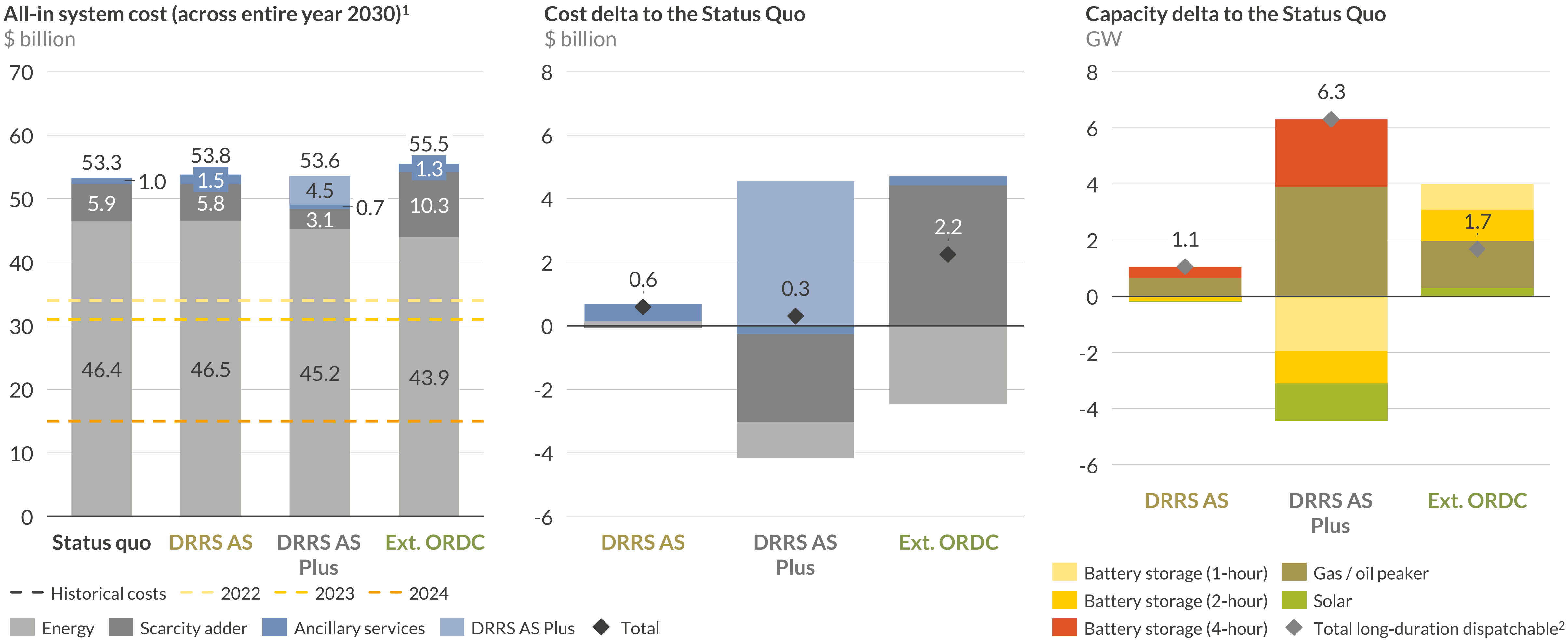
Batteries eligible



1) Under a normal weather year (2013 style weather year). 2) Includes resources capable of running for at least 4 hours.

Sources: Aurora Energy Research

Aurora Central | With batteries eligible, DRRS AS Plus removes a cumulative $2.6bn from the wholesale and ancillary markets, netting a $1.7bn cost

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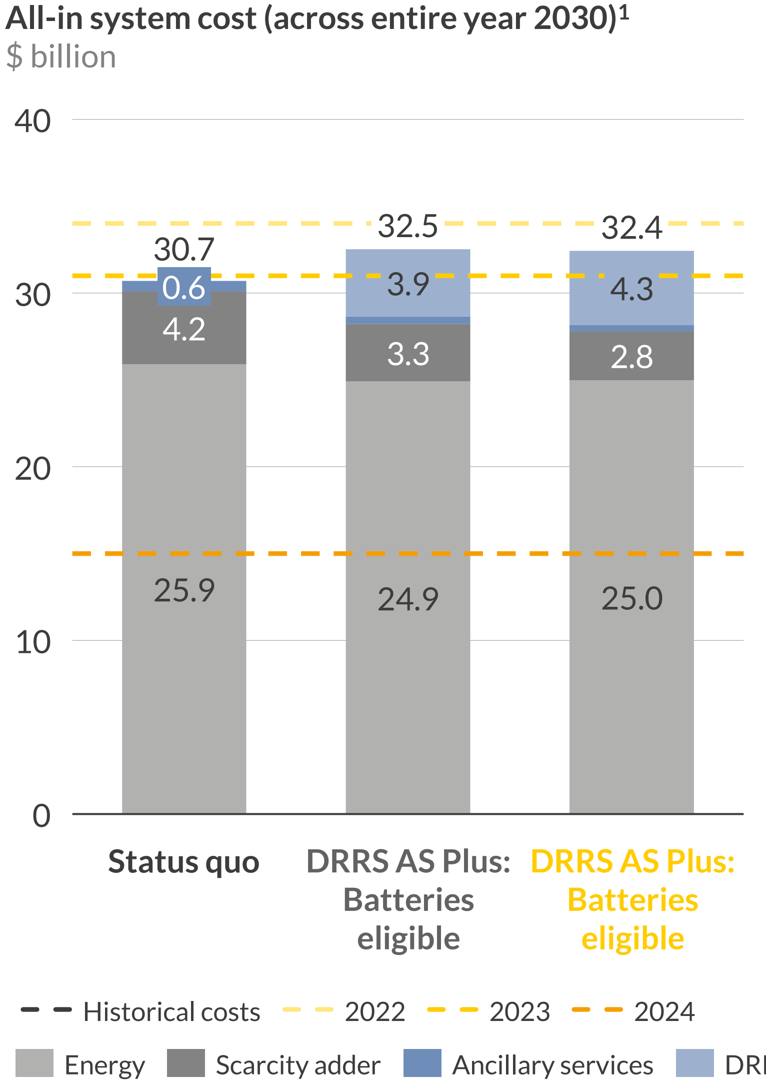
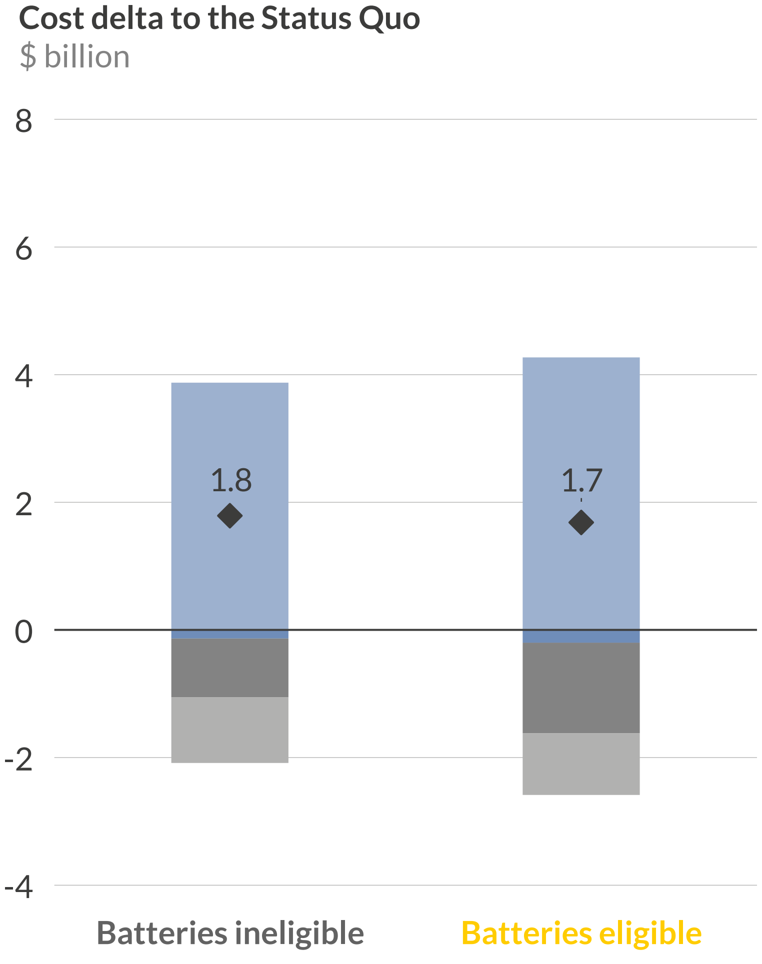
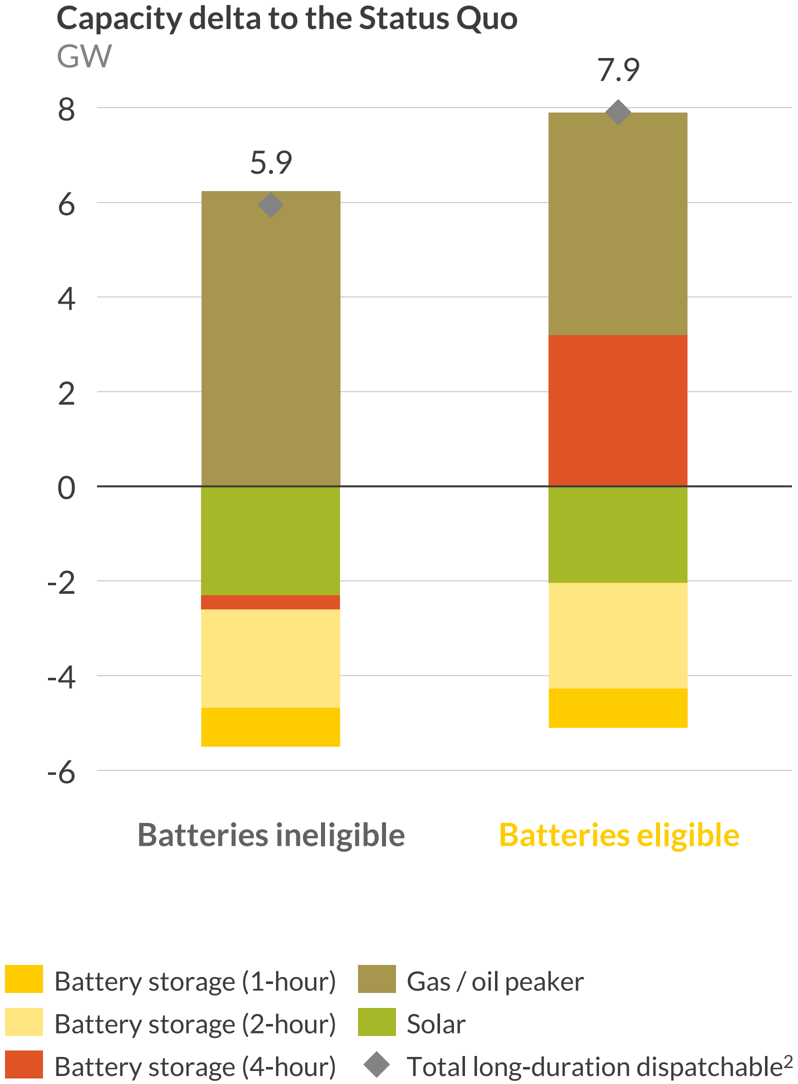


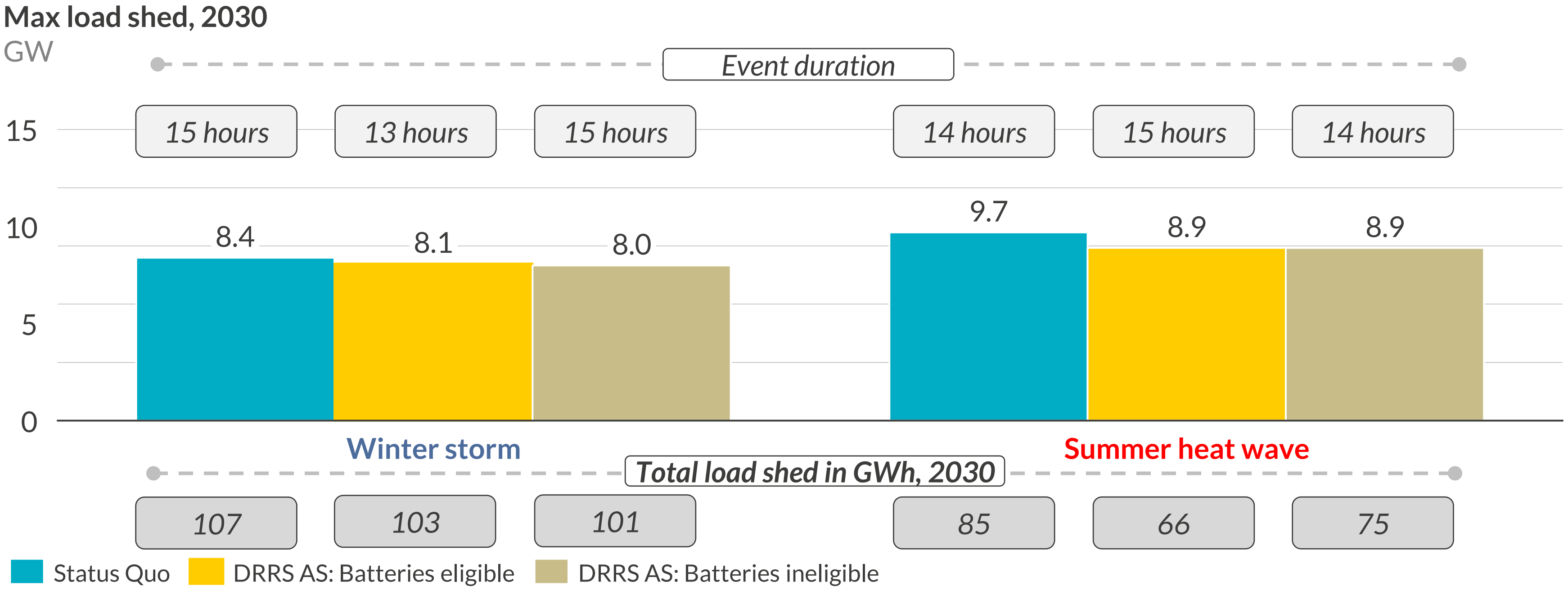


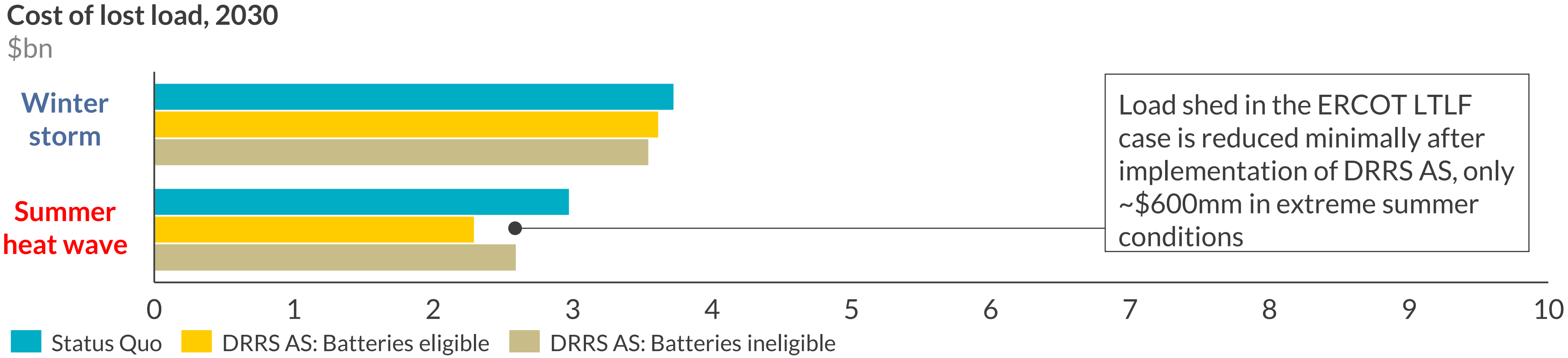


1) Under a normal weather year (2013 style weather year). 2) Includes resources capable of running for at least 4 hours.

Sources: Aurora Energy Research

ERCOT LTLF | DRRS Ancillary Service has limited impact on reliability under extreme weather conditions

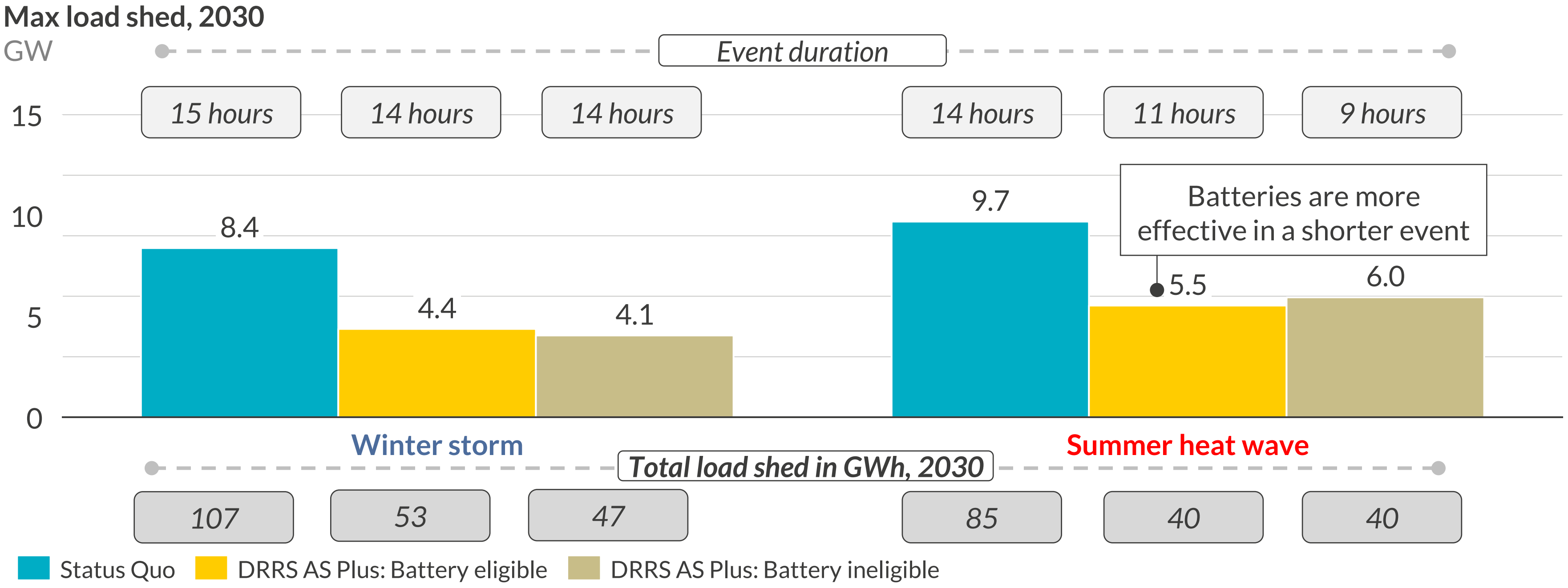


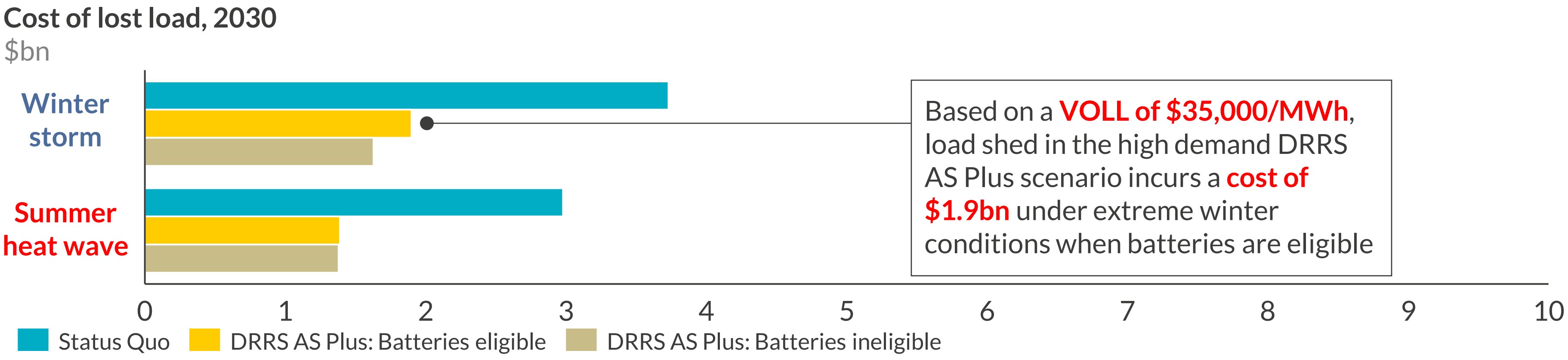


Sources: Aurora Energy Research

- Load-shedding events are slightly impacted by the DRRS AS mechanism, cutting load shed volumes on average by 11% across extreme summer and winter events.
- Both maximum and total load shed remain high, as DRRS AS has a minimal effect on scarcity dynamics over the course of the event, with only a small increase in available capacity compared to the status quo.
- Based on a $35,000/MWh value of lost load, DRRS AS brings costs down by up to $200mm for winter storms and $600mm for summer heat wave events.

ERCOT LTLF | Savings under the DRRS AS Plus mechanism average $2bn across scenarios, cutting load shed volumes by nearly half

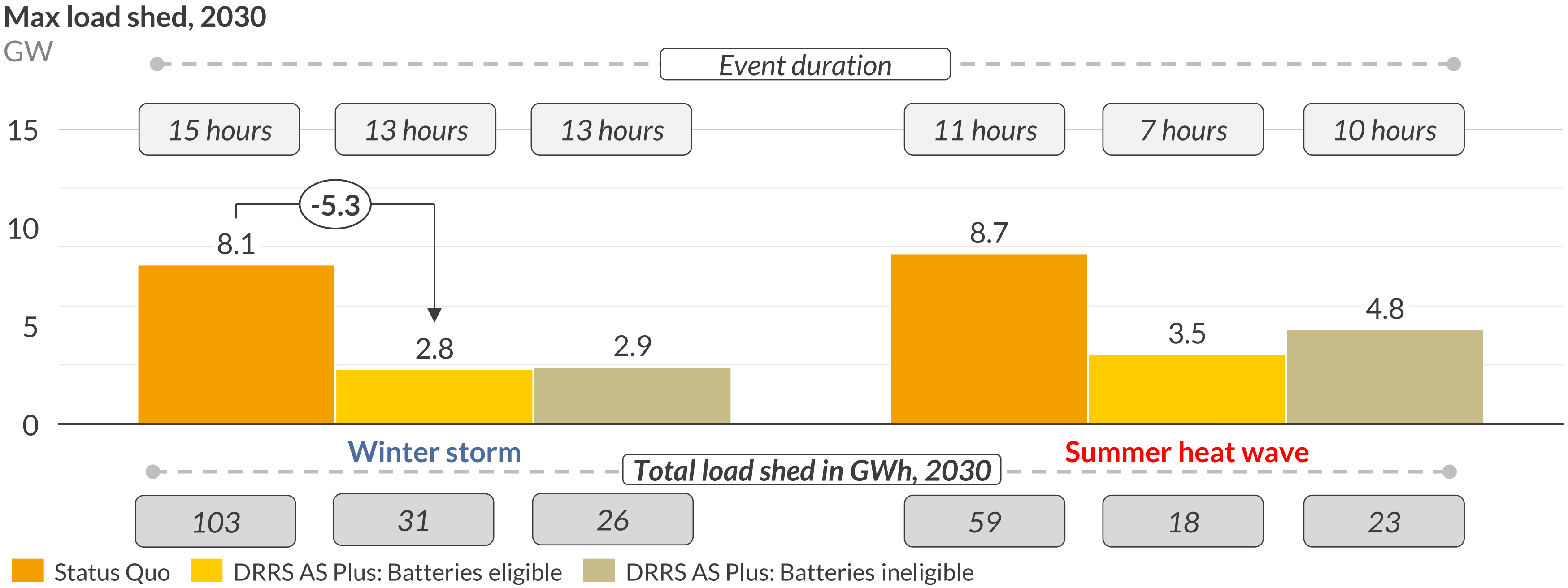


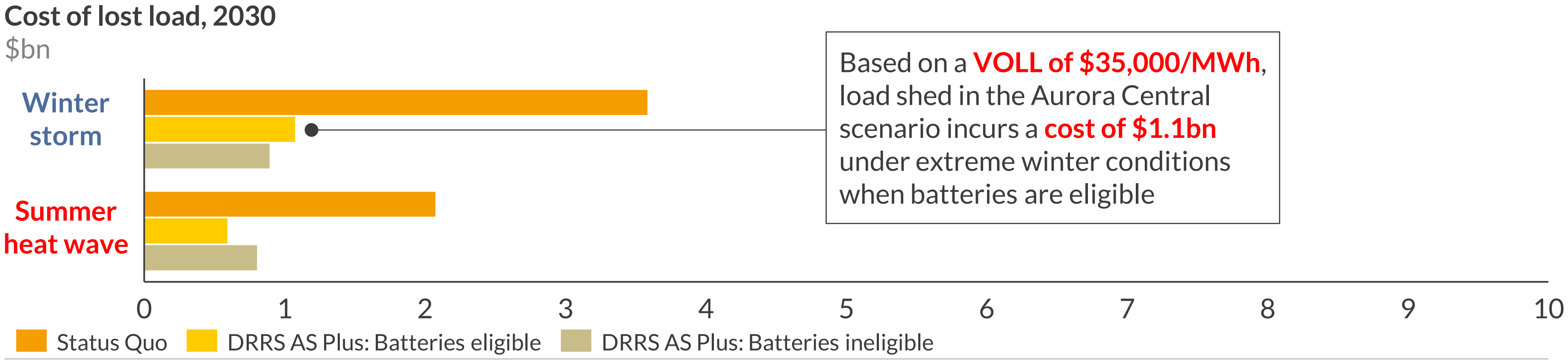


- Load shedding events are reduced by the DRRS AS Plus mechanism, cutting load shed volumes on average by 40% across extreme summer and winter events.
- Total load shed is most severe in the LTLF demand case under winter storm conditions, when maximum load shed reaches 8.4GW and 106.7GWh of energy is unserved over the course of a 15-hour event.
- Based on a $35,000/MWh value of lost load, DRRS Ancillary Service Plus brings costs down by $2.1bn for winter storms and $1.6bn for summer heat wave events.

Sources: Aurora Energy Research

Aurora Central | DRRS AS Plus greatly reduces load shedding, with costs under a winter storm event falling by $2.7bn

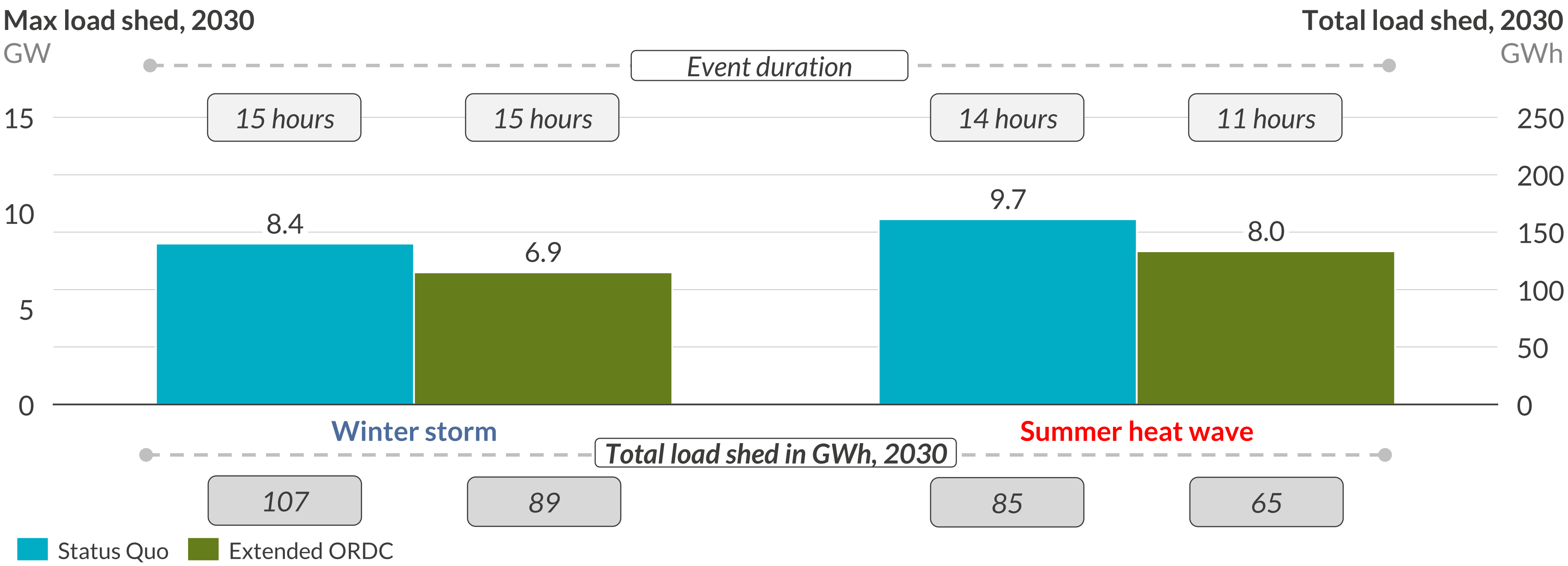


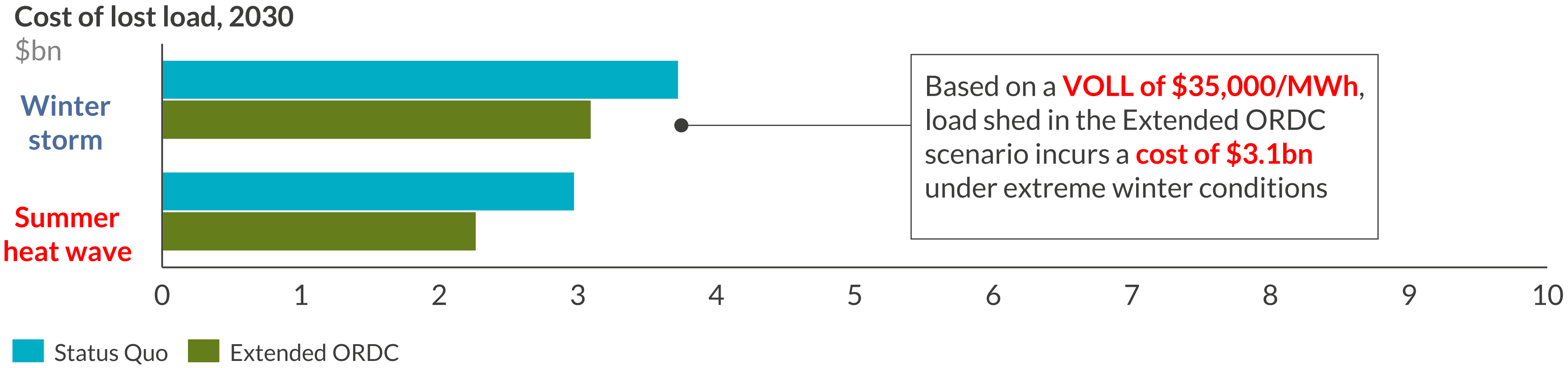


- Load shedding events are significantly reduced by the DRRS Ancillary Service Plus mechanism.
- Maximum load shed is most severe under summer heat wave conditions in Aurora's Central case, reaching 8.7GW of lost load during the tightest hour. With battery ineligible DRRS AS Plus, maximum load shed decreases to 4.8GW.
- Based on a $35,000/MWh value of lost load, battery ineligible DRRS Ancillary Service Plus brings costs down by $2.7bn for winter storms and $1.7bn for summer heat wave events.

Sources: Aurora Energy Research

ERCOT LTLF | Under the Extended ORDC, load shed during extreme weather events is reduced by under 2GW, reducing costs by $0.7bn





- Load-shedding events occur under both extreme summer and winter conditions in the Extended ORDC case.
- Both maximum and total load shed are reduced in winter and summer periods, decreasing max load shed by 1.7GW in summer heat wave conditions.
- Based on a $35,000/MWh value of lost load, in all modeled cases, load shedding events would cost over $2bn, with the most severe case costing $3.7bn. The extended ORDC would reduce cost under these load shed events by approximately $0.7bn.

Sources: Aurora Energy Research

Agenda

ERCOT transitioned to a deregulated, energy-only market in 1999 and has since then periodically adjusted market design to ensure resource adequacy

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1995

ERCOT **opened the wholesale electricity market to competition**, marking the beginning of a competitive power market.

1999

Retail electricity market was deregulated and **ERCOT abandoned the 15% self-mandated reserve margin**, transitioning to an energy-only[1] market.

2006

The Public Utility Commission of Texas (PUCT) introduced a scarcity pricing mechanism[2] with a **$3,000/MWh cap**[3] to enhance resource adequacy.

2012

The **offer cap was increased to $4,500/MWh** to improve incentives for investment during scarcity conditions.

2014

ERCOT introduced the **Operating Reserve Demand Curve**[4] **(ORDC)**, setting the Value of Lost Load (VOLL) at $9,000/MWh to strengthen scarcity pricing signals.

2015

The **offer cap was raised again to $9,000/MWh**, aiming to further enhance resource adequacy signals.

2019

During a heatwave, **wholesale electricity prices reached the $9,000/MWh cap**, highlighting the market's exposure to extreme price events.

2021

After the February Winter Storm Uri, the **cap was lowered to $5,000/MWh**, and a new reliability standard was introduced to address lessons from the crisis.

2022

ERCOT **raised the minimum contingency level**[5] from 2,000MW to 3,000MW, **reduced VOLL**[6] **from $9,000 to $5,000**, and decoupled it from the System-Wide Offer Cap.

2023

ERCOT introduced the **ERCOT Contingency Reserve Service (ECRS)** and a multi-step price floor for the ORDC to improve price signals during scarcity.

2024

ERCOT implemented a **new VOLL of $35,000/MWh** (for planning purposes), alongside a proposal of the Demand Response Reserve Service (DRRS).

1) An energy-only market compensates generators solely for the energy they produce, without capacity payments. 2) A scarcity pricing mechanism raises energy prices during low supply to incentivize generators buildout. 3) An offer cap limits the maximum price energy can reach in the market. 4) The ORDC curve adjusts energy prices based on available reserves to reflect scarcity. 5) The minimum contingency level sets the reserve threshold needed to maintain grid reliability during emergencies. 6) VOLL represents the economic cost of power outages to consumers. Sources: Aurora Energy Research, ERCOT

ERCOT is the sole energy-only market in the US, amplifying price volatility in the wholesale market while maintaining a competitive average all-in price

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	Resource Adequacy Mechanism				Historical Market Conditions	
	Resource adequacy mechanism	Timeline	Price signal for investment	How does the market pay for new capacity?	Avg. all-in price[3], $/MWh	Price Volatility[4], $/MWh
ERCOT	**Energy-only market** using scarcity pricing mechanisms (ORDC curve) without capacity markets	Real-time	Scarcity pricing through the Operating Reserve Demand Curve (ORDC) + Offer Cap	By paying very high scarcity prices occasionally	61	259
CAISO	**Resource Adequacy program** requiring LSEs to secure sufficient capacity through bilateral contracts	1-month to 20-year contracts	High short-term resource adequacy (RA) prices + RT price spikes	By paying for generation capacity support year-round	76	48
NYISO	**Capacity market** with locational capacity requirements	Monthly spot auctions	Seasonal and monthly capacity auctions price + Cost of new entry (CONE)		69	21
ISO-NE	**Forward Capacity Market** (FCM) that procures capacity three years in advance	Monthly auctions	Prices in the FCM auctions + Pay-for-Performance Mechanism		76	28
PJM	**Centralized capacity market**, Reliability Pricing Model (RPM), which procures capacity 3 years in advance	Annual auctions	Clearing prices in PJM's forward capacity auctions + Locational pricing		54	19
MISO	**Hybrid approach** with a voluntary capacity market and resource adequacy requirements for utilities	Seasonal auctions	Prices in the annual resource adequacy auction + Zonal pricing		47	19
SPP	**Resource adequacy requirements** through its Reserve Margin policy, relying on member utilities to meet capacity obligations	1-month to 20-year contracts	Bilateral contract prices + RT price spikes		36	81

Avg Yearly All-In Price
Avg. Yearly Standard Deviation

1) Target planned reserve margin. 2) Average yearly historical reserve margin 2017-2024. 3) Average yearly all-in prices (2022-2024), from Potomac Economics' 2024 State of the Market report on the Midcontinent-ISO. The all-in price is "equal to the load-weighted average real-time energy price plus capacity, ancillary services, and real-time uplift costs per MWh of real-time load." 4) Average yearly standard deviation in hourly wholesale prices 2020-2024.
Sources: Aurora Energy Research, ERCOT, CAISO, ERCOT, MISO, PJM, NYISO, ISO-NE, SPP, EIA

ERCOT has seen faster peak load growth and renewables additions than any other ISO, but historical operational reserves have been considerably lower

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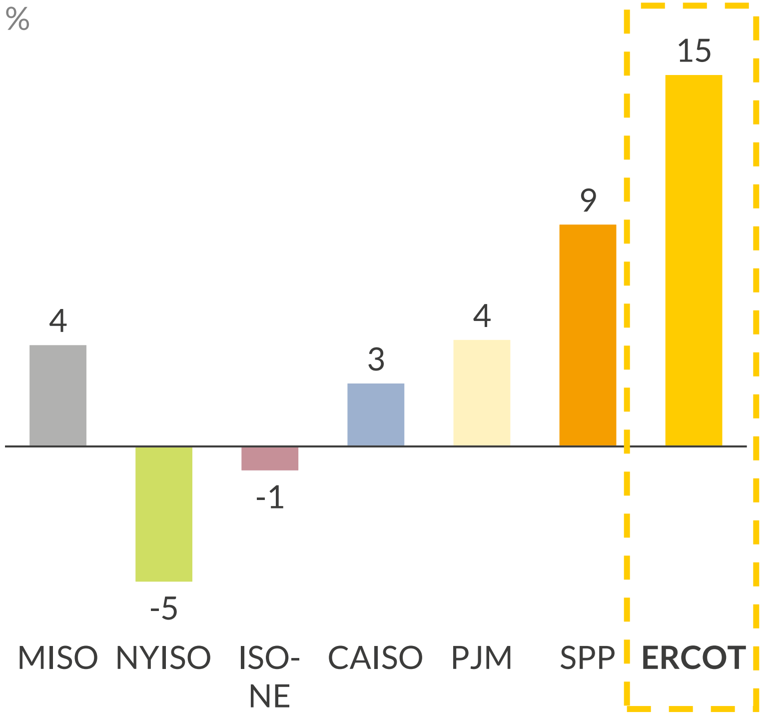
1 ERCOT peak load is growing faster than any other market in the U.S.

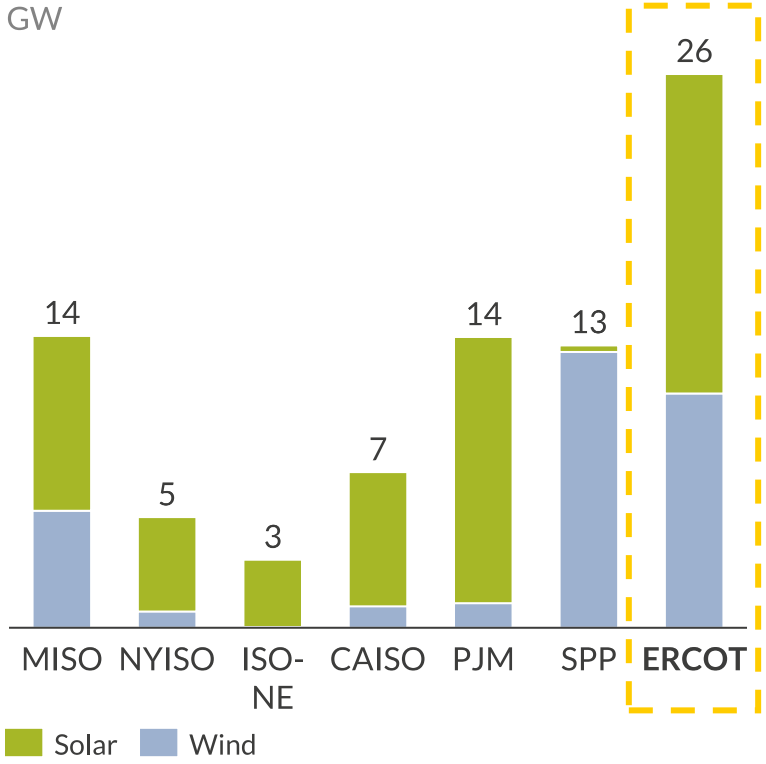
Peak load growth by ISO, 2020-2024[1]



- From 2020 to 2024, ERCOT saw a ~15% growth in peak load, rising from 74.3GW to 85.4GW.
- ERCOT's "connect and manage" approach to interconnection has enabled rapid demand growth.

2 ERCOT is also seeing the fastest rate of renewables penetration.

Renewables capacity additions[2], 2020-2024



- Renewables penetration in ERCOT outpaces all other competitive markets, with 26GW of capacity additions between 2020 and 2024.

3 ERCOT's historical operational reserves have been lower than other ISOs.

Average historical operational reserves[3], 2020-2024

- ERCOT operates as an energy-only market without a mandated reserve margin. Its historical operational reserves have generally been lower compared to other ISOs with enforced capacity or resource adequacy mechanisms.

1) Data from each respective ISO. 2) Onshore wind, offshore wind, rooftop solar, and ground mount solar. 3) Historical operational reserves are calculated as reserves available during net peak demand hour divided by peak net demand. Winter Storm Uri in 2021 is excluded from the calculation of historical operational reserves

Sources: Aurora Energy Research, ERCOT, NYISO, ISO-NE, PJM, MISO, CAISO, SPP

ERCOT's historical operational reserves have fluctuated heavily, with periods of system stress followed by significant capacity additions

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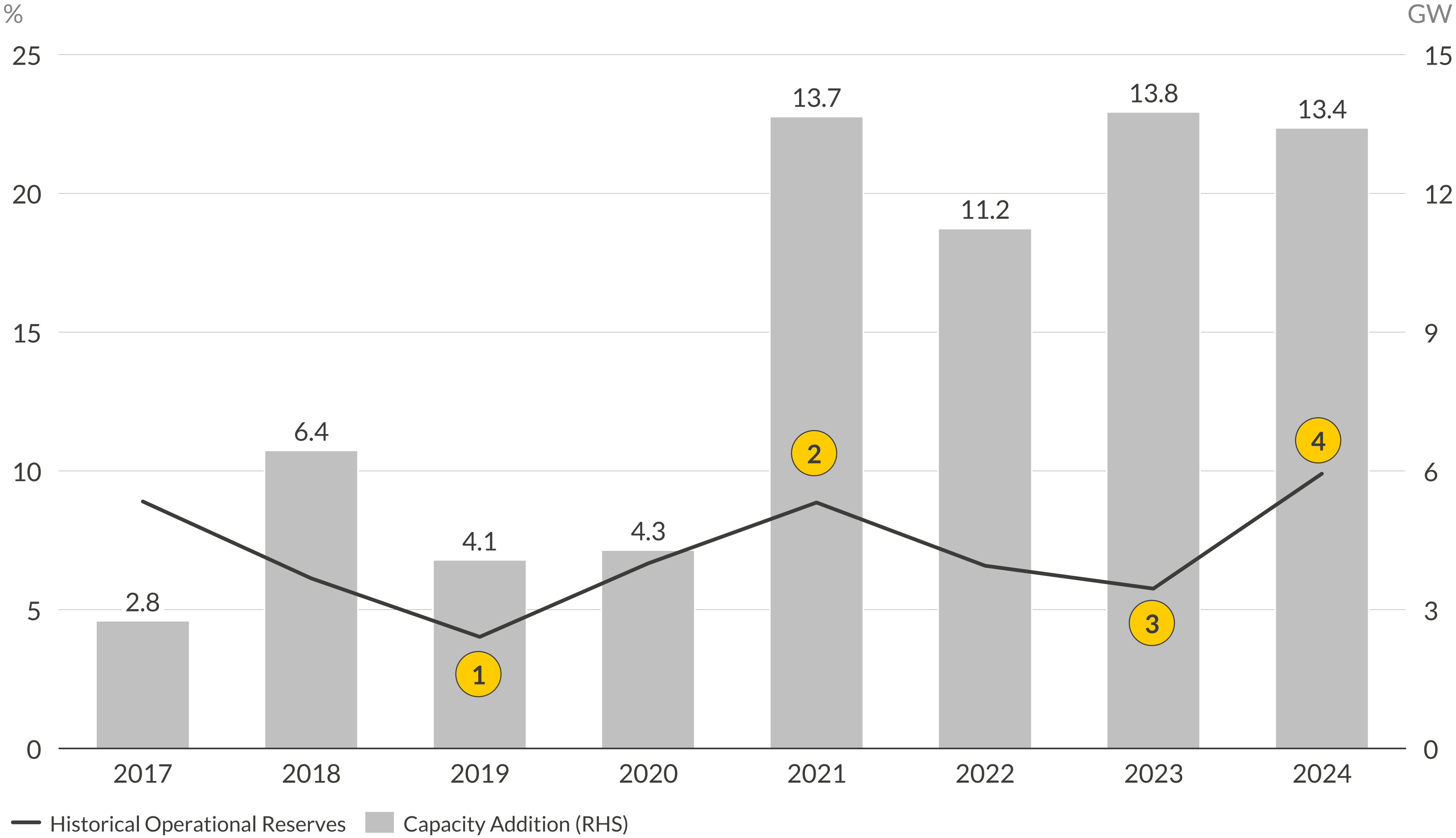
Historical operational reserves[1] in ERCOT

Historic capacity additions in ERCOT



1) Historical operational reserves are calculated as reserves available during net peak demand divided by peak net demand.

Sources: Aurora Energy Research, ERCOT

1. Historical operational reserves drop to 4.1% in 2019 as ERCOT experienced an extremely hot summer, where prices hit the system-wide offer cap of $9,000/MWh several times.
2. Periods of low operational reserves are followed by an increase in investment. 2021 saw a large capacity addition, increasing operational reserves to 8.9%.
3. Reserves in 2022 and 2023 decreased following very hot summers. 2023 saw 46 summer days exceeding 2022 peak demand coupled with high unplanned thermal outages.
4. 2024 saw an increase in operational reserves, following significant solar and BESS capacity additions.

Without a mandated reserve margin, ERCOT has historically seen the lowest operational reserves across all competitive US markets

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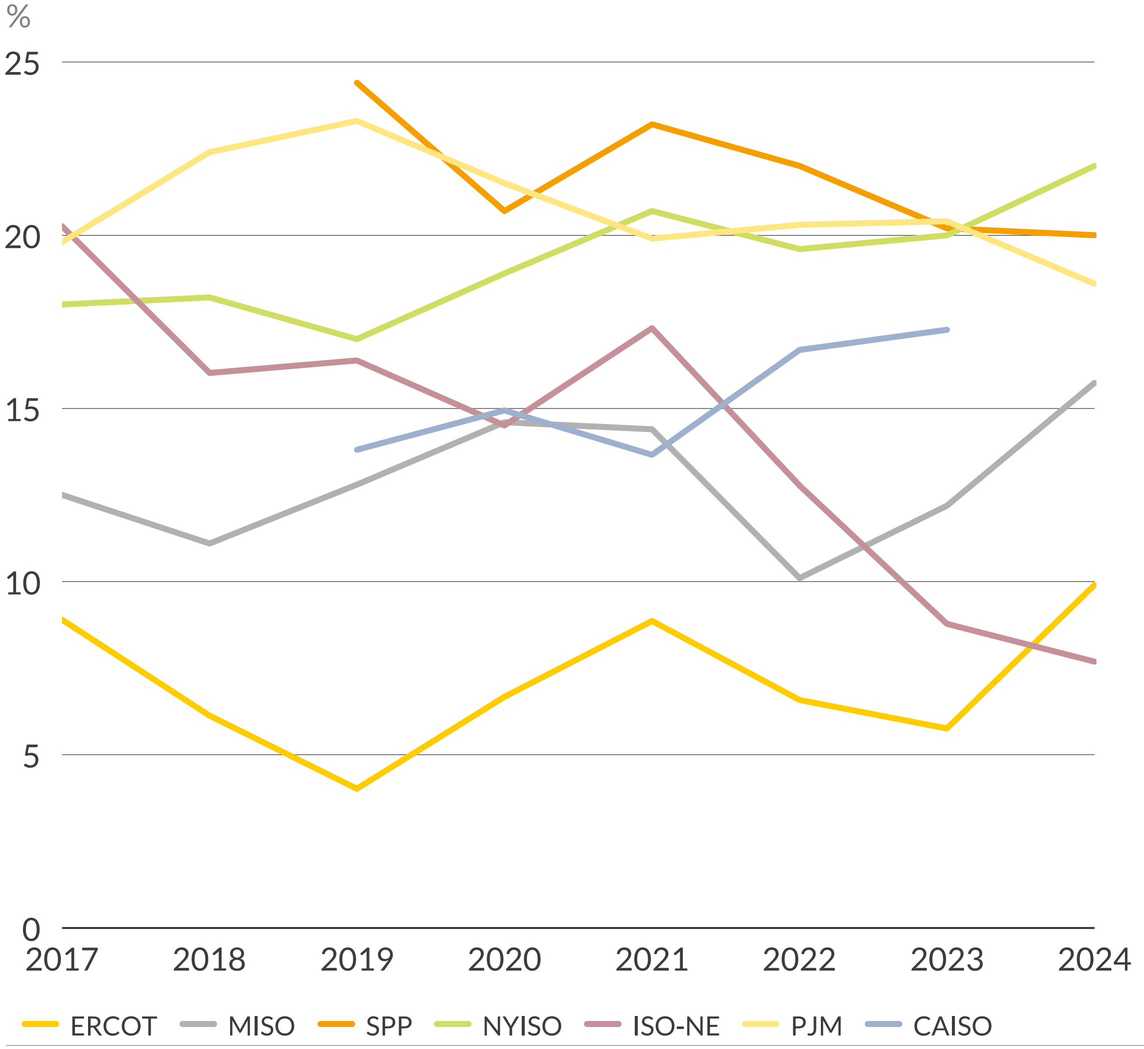
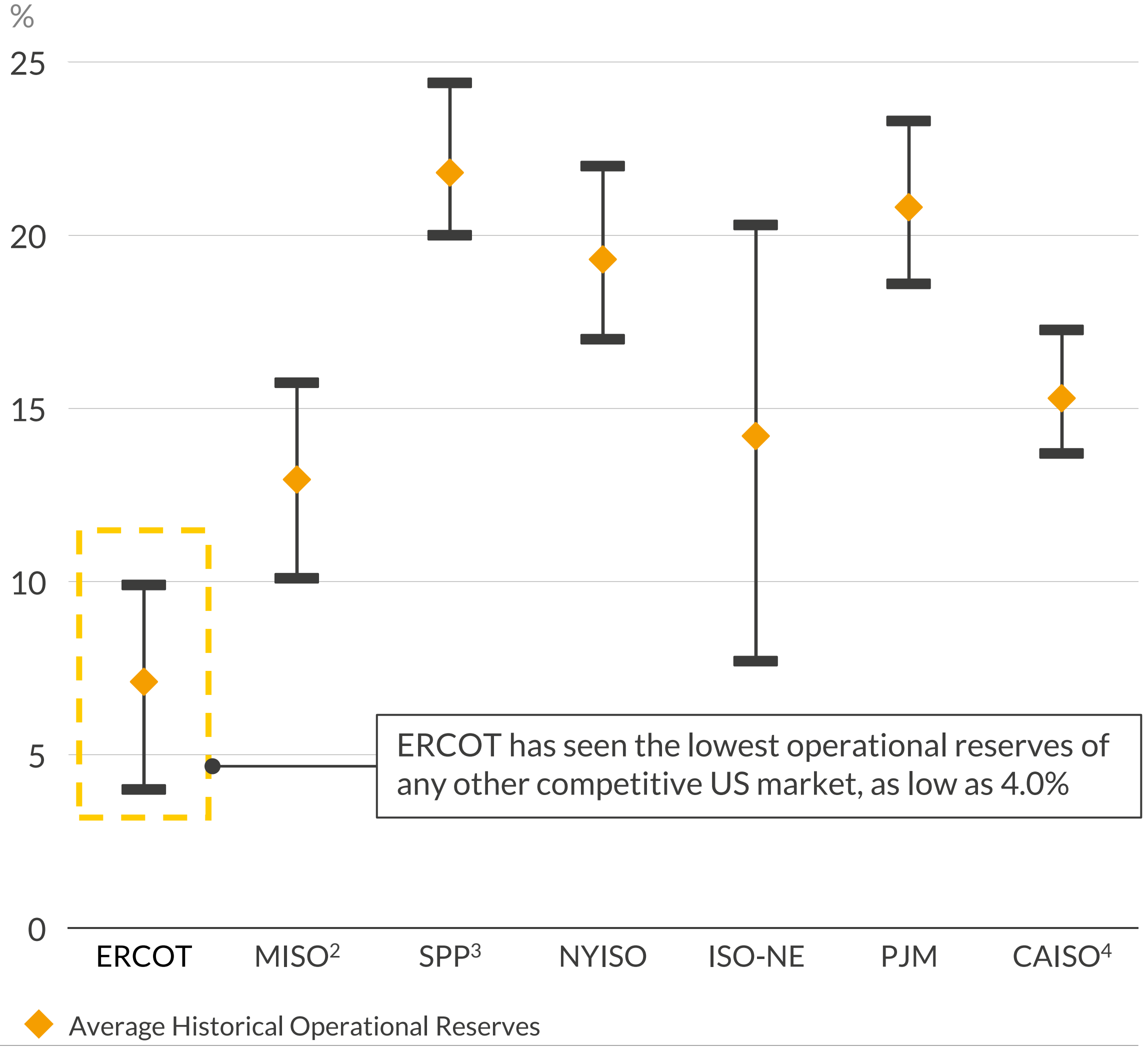
Historical operational reserves by ISO



Min, max, and average historical operational reserves across ISOs[1], 2017-2024



1) Values from the historical operational reserves at the peak net demand hour for each year. 2) 2017-2024. 3) 2019-2024. 4) 2019-2023.

Sources: Aurora Energy Research, ERCOT, MISO, SPP, NYISO, ISO-NE, PJM, CAISO

The recent adoption of a reliability standard and higher VOLL[1] for ERCOT provides a better quantification of reliability risks

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Overview — ERCOT's new reliability standard will evaluate the system for capacity deficiency and encourage reliability upgrades

What inspired this change?
- Winter Storm Uri caused widespread outages where about 69% of Texans lost power. To prevent this from reocurring, Texas' legislature requested the creation of a reliability standard for ERCOT.

How does the standard work?
- There are 3 components the ISO, ERCOT, must ensure:
  - **Frequency:** Outages caused by lacking enough power to meet demand should not happen more than once every 10 years.
  - **Duration:** Outages should last less than 12 hours.
  - **Magnitude:** Maximum amount of Loss of Load during any hour of an outage cannot be more than 19GW.[2]

How will the standard be assessed?
- The standard is assessed by running a model to calculate Loss of Load events for several scenarios.
- To calculate Loss of Load cost, a **VOLL standard of $35,000/MWh** (decoupled from the System-Wide Offer Cap) has been set to weigh the benefits of potential reliability upgrades.
- Assessments will begin in 2026 and be run every 3 years.

What happens if ERCOT fails?
- IMM[3] will conduct a review and PUCT staff will propose market design changes, with the PUCT then finalizing any changes.

What is still uncertain?
- Will the decoupling of VOLL and the system wide offer cap distort market signals for resource adequacy?
- How will ERCOT ensure compliance with this reliability standard as it is currently not related to a market mechanism for capacity adequacy?

Timeline — The new reliability standard assessment will be finalized in 2025

Feb 2021
- Winter Storm Uri hits Texas, resulting in extensive Loss of Load.

June 2021
- Texas Senate Bill 3 passes, directing the PUCT to design a reliability standard and creating the Texas Energy Reliability Council.

Jan 2022
- VOLL[1] is reduced from $9,000 to $5,000 and decoupled from the System-Wide Offer Cap.

Jan 2023
- PUCT orders the creation of a reliability standard and review of the VOLL[1] standard.

June 2023
- ERCOT releases the results of a preliminary study, modeling the year 2026 to evaluate the drafted standard.

Aug 2024
- PUCT votes to approve the new reliability standard and VOLL of $35,000/MWh while the system-wide offer cap remains at $5,000.

Future

Jan 2026
- Deadline for ERCOT to complete reliability standard assessment.

1) Value of Lost Load. 2)Calculated to be the maximum amount of load that can be safely rotated. 3) Independent Market Monitor. For ERCOT, this is Potomac Economics, Ltd..

Sources: Aurora Energy Research, Texas Legislature, ERCOT, PUCT, Texas Comptroller, Utility Dive, RTO Insider

Agenda

All ERCOT regions will experience load growth; data center growth is one of the main drivers that can materially increase demand

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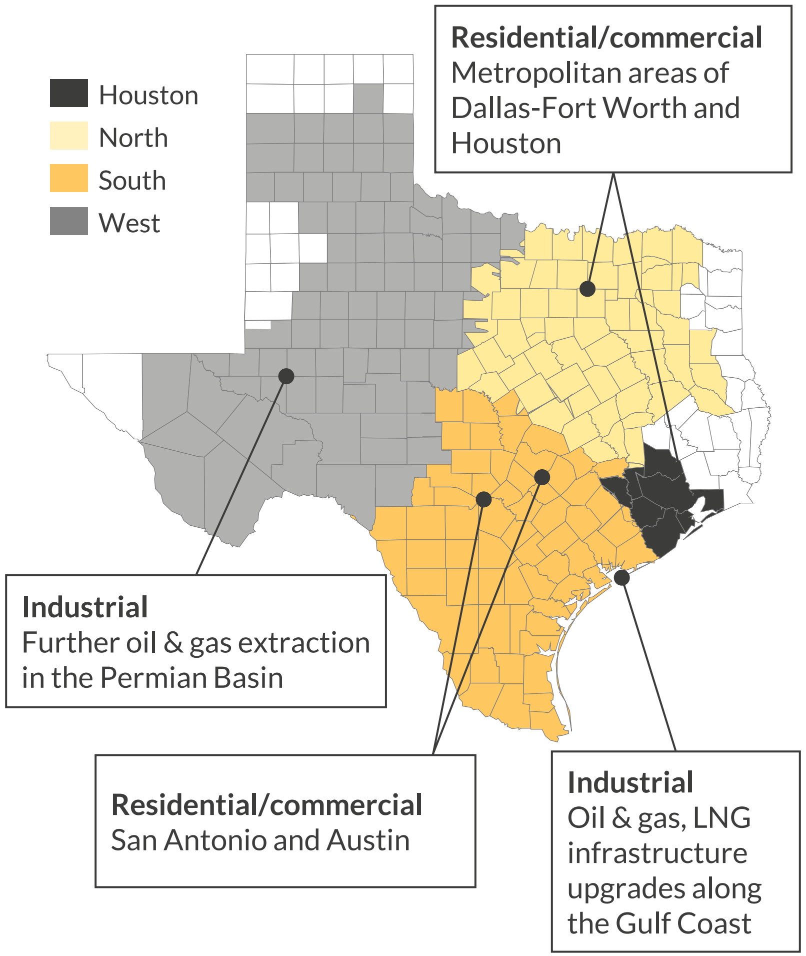
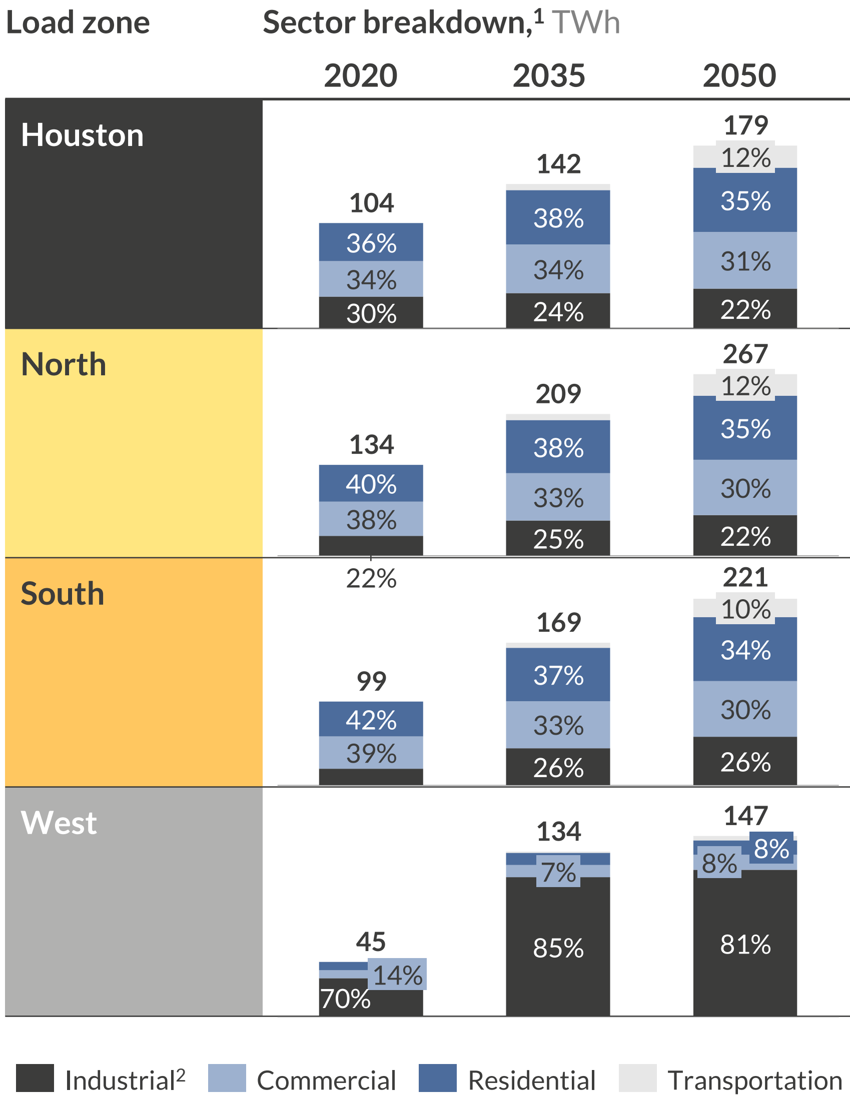
Key load locations in ERCOT



Load zone / Sector breakdown,[1] TWh / Major load drivers



Load zone	Major load drivers
Houston	▪ Data center ▪ Population growth ▪ Rural to urban transition ▪ Office and retail space ▪ Space heating & cooling
North	▪ Data center ▪ Population growth ▪ Urban residential, retail & office growth in DFW[3] ▪ Space heating & cooling
South	▪ Data center ▪ LNG expansion on the Gulf Coast ▪ Urban growth in Austin and San Antonio ▪ Space heating & cooling
West	▪ Data center ▪ West Texas population growth (highest CAGR[4] in Texas) ▪ Oil and gas electrification in the Permian Basin ▪ Crypto mining

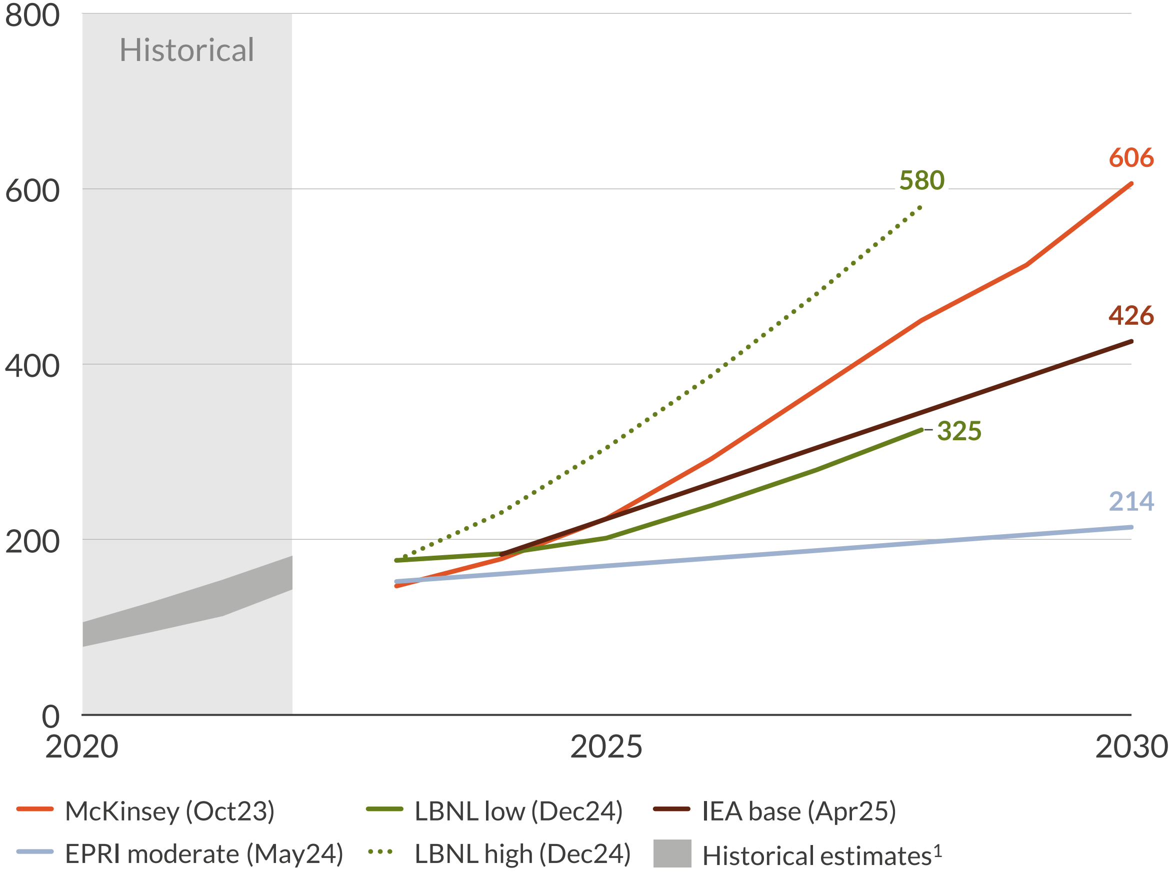
1) Total load breakdown, does not include rooftop solar adjustment or demand side response. 2) Includes Crypto mining and other data center load. 3) Dallas-Fort Worth metroplex; 4) Compound annual growth rate.

Sources: Aurora Energy Research, ERCOT, US EIA, Texas Demographic Center

While data center demand is expected to drive load growth all across the U.S., there is significant uncertainty on how much will materialize

US-wide data center load forecasts

TWh



To reach the upper end of forecasted demand, the following factors could contribute...

- Faster AI adoption and digital integration in the workplace, driving increased demand
- Greater AI workloads, especially for training, enabling greater location flexibility
- Rapid load interconnection across utilities, enabling faster data center energization
- Slower efficiency gains increasing overall energy demand as data center capacity continues to expand

...but might be counterbalanced by factors leading to lower demand

- Continued advances in hardware efficiency, along with software and systems optimization, can reduce overall demand
- Local regulations and grid delays could hinder short-term deployment
- AI monetization uncertainty and a slow shift from traditional pricing could hinder progress
- Supply chain pressure, tariffs, and competing demand for materials (e.g. copper, aluminum) could slow construction and strain energy supplies

Inconsistent definitions, differing methodologies, and divergent beliefs as to how fast load can interconnect into electricity grids lead to a wide range of US-wide data center forecasted load outcomes.

1) Historical estimates of data-center load vary due to differing methodologies, definitions, and scope.

Sources: Aurora Energy Research, McKinsey, EPRI, LBNL, IEA

Data centers are increasingly being used for different applications, each with different energy requirements, load factors and impacts to the grid

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1 Different data center categories have different use cases, different average efficiencies and sizes

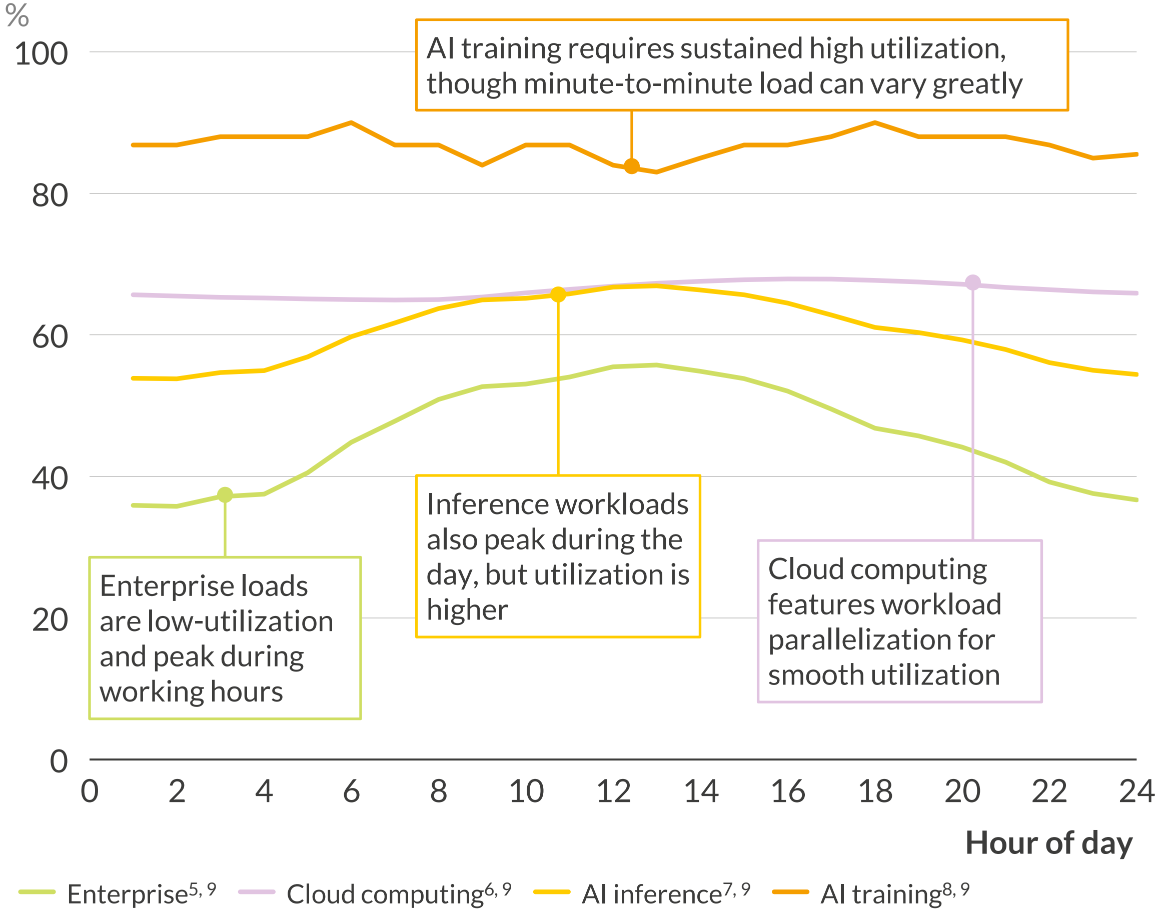
Data center overview and relative parameters

Category and type[1]	Use case	Size[2], MW	Efficiency	VoLL[3]
Enterprise[4]	Individual firm data processing, distributed infrastructure	0.5–10		Medium
Co-location				
Cloud computing	Off-site, scalable data storage	10–100		High
AI inference	Executing queries made to generative AI models	>100		High
Hyperscale				
Cloud computing	Tech firm social-media, video, or data-processing servers	>50		High
AI inference	Executing queries made to generative AI models	>100		High
AI training	Development and training of new generative AI models	>100		Extreme

Artificial intelligence is becoming exponentially more data and energy intensive, driving demand for data centers with larger sizes (>100MW) and high utilization.

2 These parameters and use cases translate to different load factors and will impact the grid in different ways

Illustrative daily load factors by data center category



1) Modular data centers excluded from table. 2) Facility nameplate capacity represents peak load. 3) Value of lost load. 4) Includes edge. 5) Curve shape from NREL ComStock data for VA and TX. 6) Shape taken from PJM 2024 Large Load Adjustments.

Sources: Aurora Energy Research, LBNL, NREL ComStock, PJM, Brattle

Aurora modeled two demand scenarios, testing a wide range of potential outcomes between Aurora's Central case and ERCOT's 2025 LTLF

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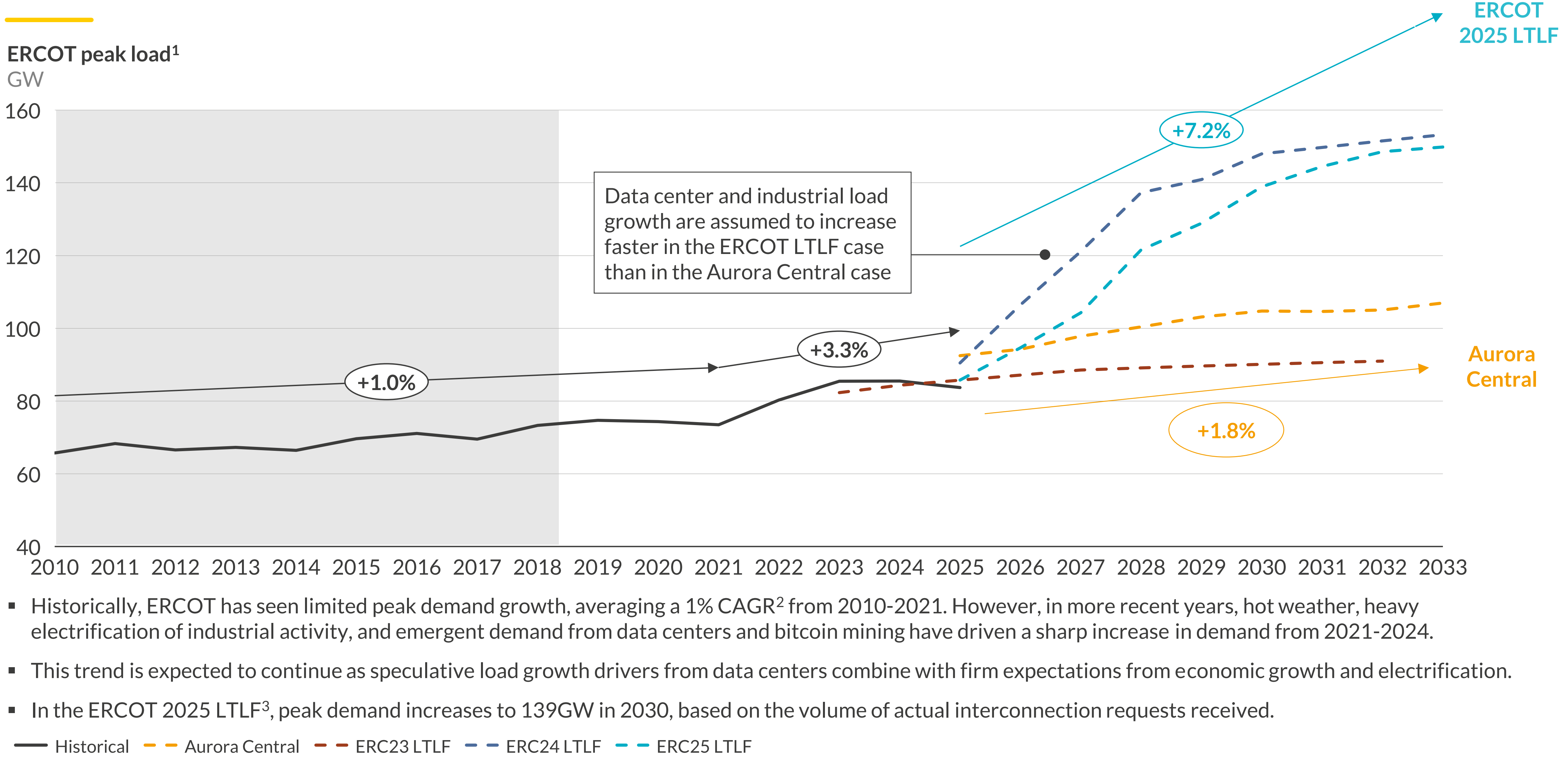

- Historically, ERCOT has seen limited peak demand growth, averaging a 1% CAGR[2] from 2010-2021. However, in more recent years, hot weather, heavy electrification of industrial activity, and emergent demand from data centers and bitcoin mining have driven a sharp increase in demand from 2021-2024.
- This trend is expected to continue as speculative load growth drivers from data centers combine with firm expectations from economic growth and electrification.
- In the ERCOT 2025 LTLF[3], peak demand increases to 139GW in 2030, based on the volume of actual interconnection requests received.

1) Summer peak demand. 2) Compound Annual Growth Rate. 3) Long-Term Load Forecast.

Sources: Aurora Energy Research, ERCOT

In the Aurora modeled ERCOT LTLF scenario, system-wide capacity reaches 253GW by 2030, 48GW more than under Aurora Central load growth

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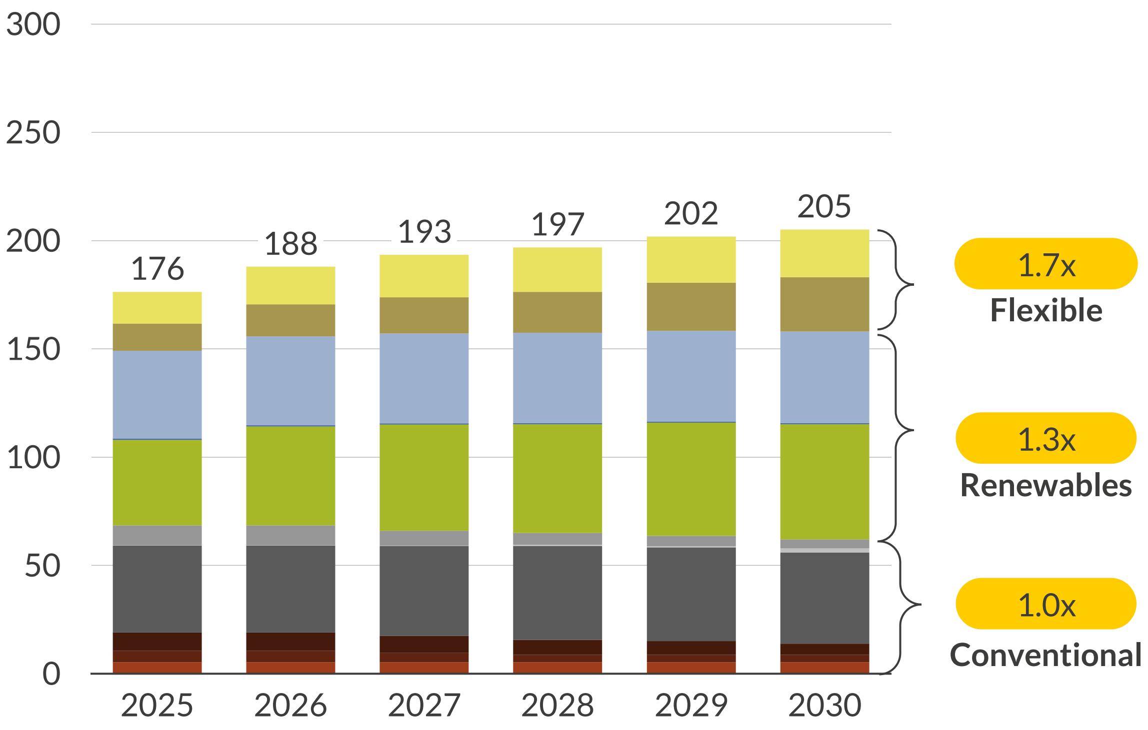
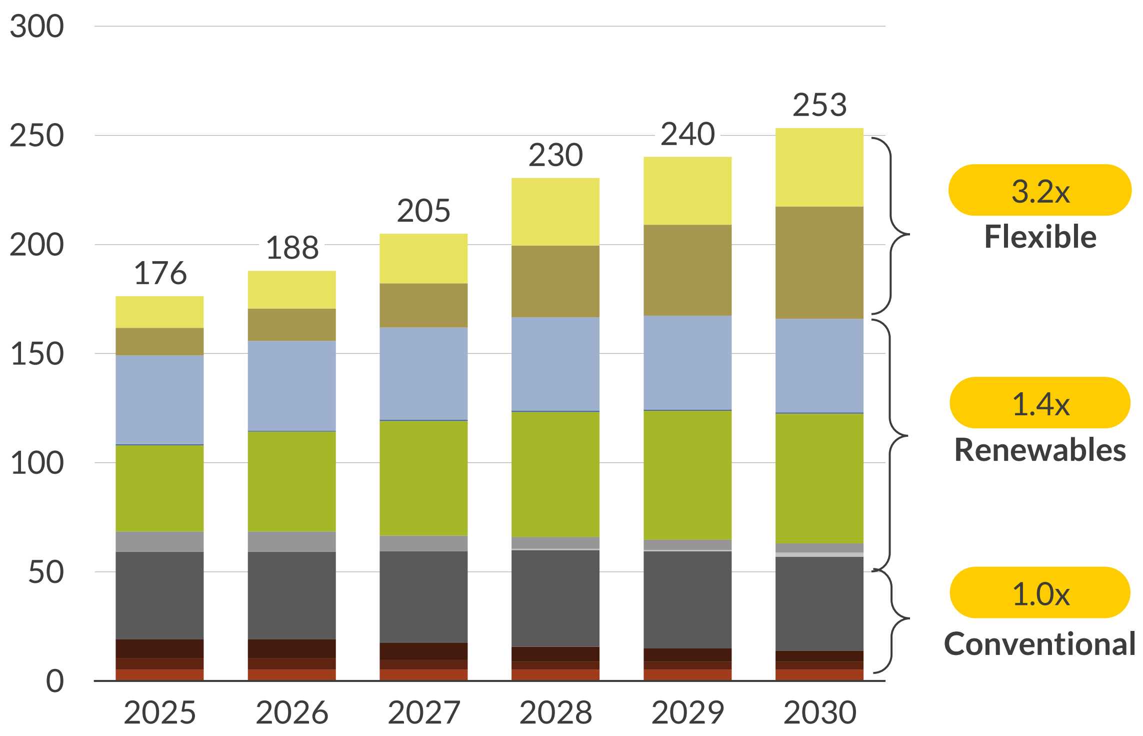
Installed capacity[1] – Aurora Central demand case
GW



- In the Aurora Central demand case, installed capacity increases by ~29GW or 16% by 2030, with increases coming from both renewable and flexible resources.
- Capacity additions result from projects currently in the queue, as well as those deemed economically viable for each year, given market conditions.

Installed capacity[1] – ERCOT LTLF
GW



- With higher demand in ERCOT's LTLF, significantly more supply is needed, resulting in 48GW of additional installed capacity by 2030 versus Aurora Central scenario.
- Additional capacity build responds to an increased demand curve within Aurora's model equilibrium for the LTLF case.

Nuclear | Lignite | Coal | Gas CCGT | Gas CCS | Other thermal | Solar | Other RES[2] | Hydro | Onshore wind | Gas / oil peaker[3] | Battery storage

1) Capacity expansion is based on economics and assumes unconstrained build, despite supply chain risks 2) Includes biomass. 3) Gas / oil peaker includes CT and reciprocating engines.

Sources: Aurora Energy Research, ERCOT

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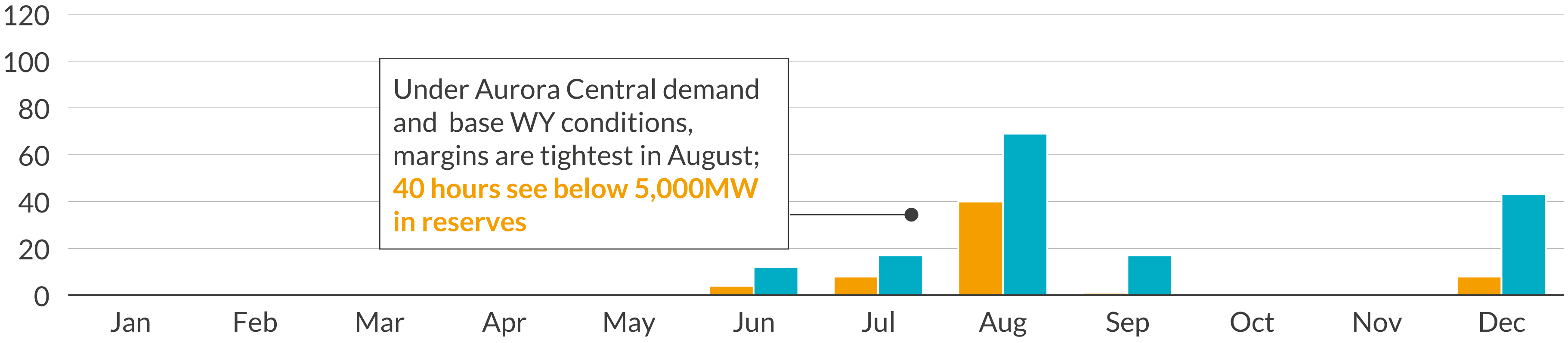
Under average weather conditions and with no market design changes, reserves remain tight although no load shed is observed

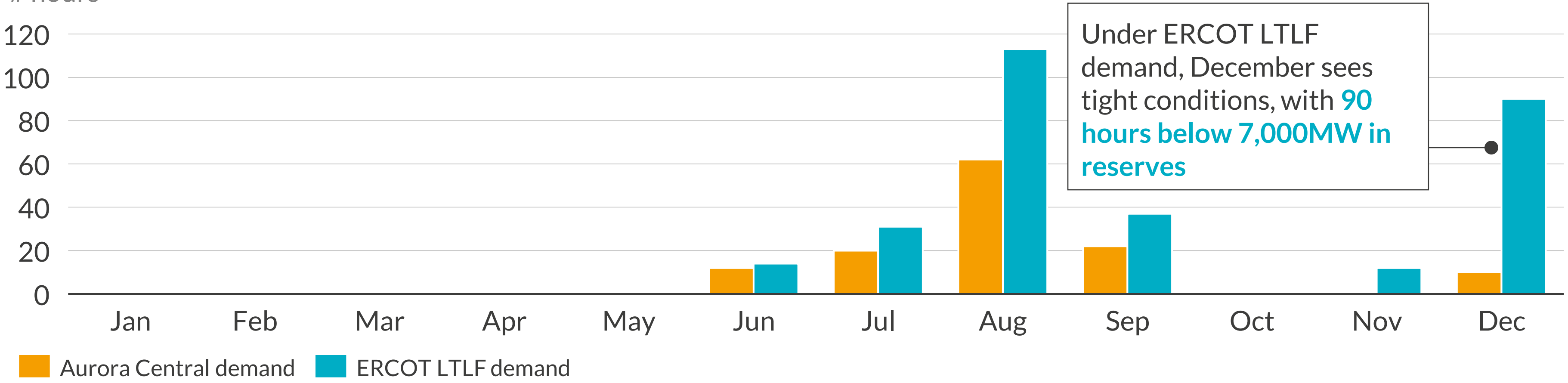
Instances of <5,000MW of reserves – 2030 (under average weather conditions, 2013 Weather Year)

hours



Instances of <7,000MW of reserves – 2030 (under average weather conditions, 2013 Weather Year)

hours



- Although there is no load shed, system conditions tighten in the summer and winter under base weather year assumptions in both the Aurora Central and ERCOT LTLF demand cases.
- The count of hours with reserves below 5,000MW reaches 40 in the Aurora Central case and 69 in the LTLF demand case.
- System tightness between both cases is similar as additional battery and flexible generation in the LTLF demand case help to offset higher peak load, while the system becomes more vulnerable in the LTLF winter.
- During the shoulder months in the spring and fall, system conditions remain stable as load is relatively low and renewables generation is high.

Sources: Aurora Energy Research

In 2030, under an average weather year, system conditions become tight in both demand cases, but load is not shed

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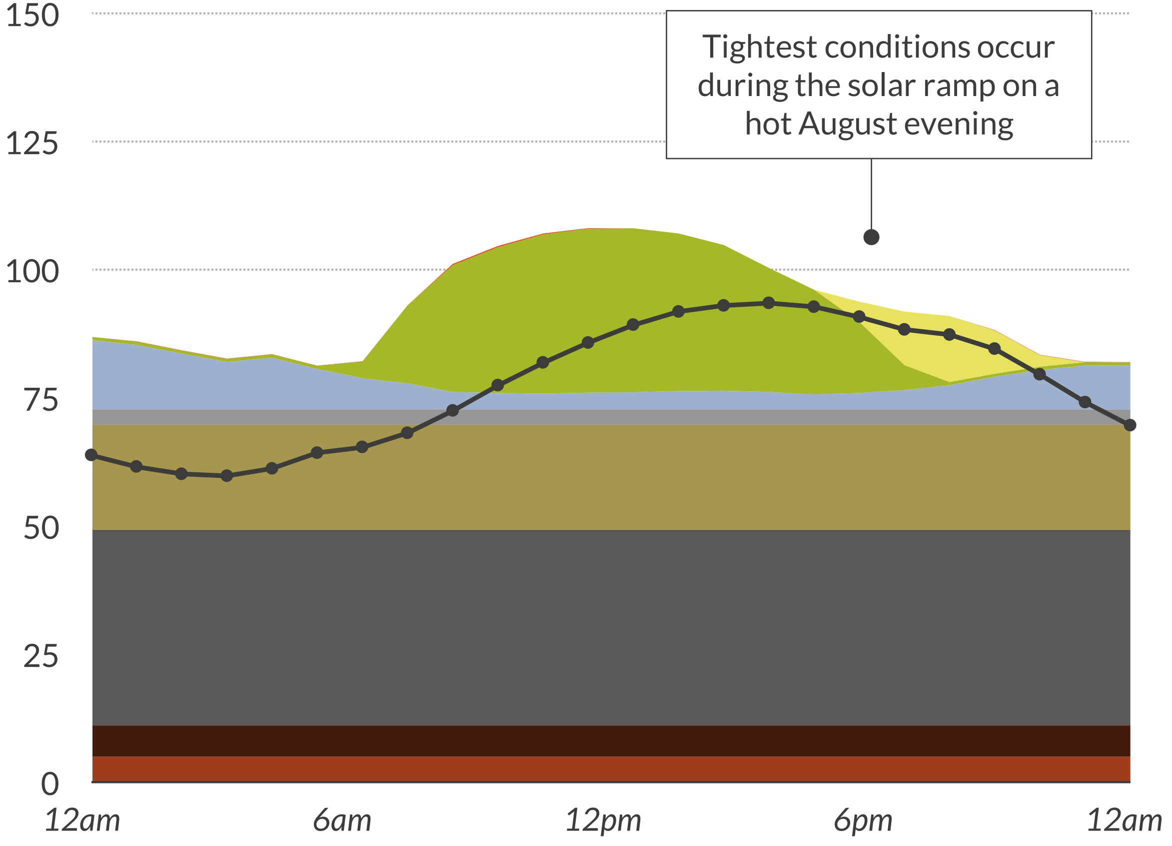
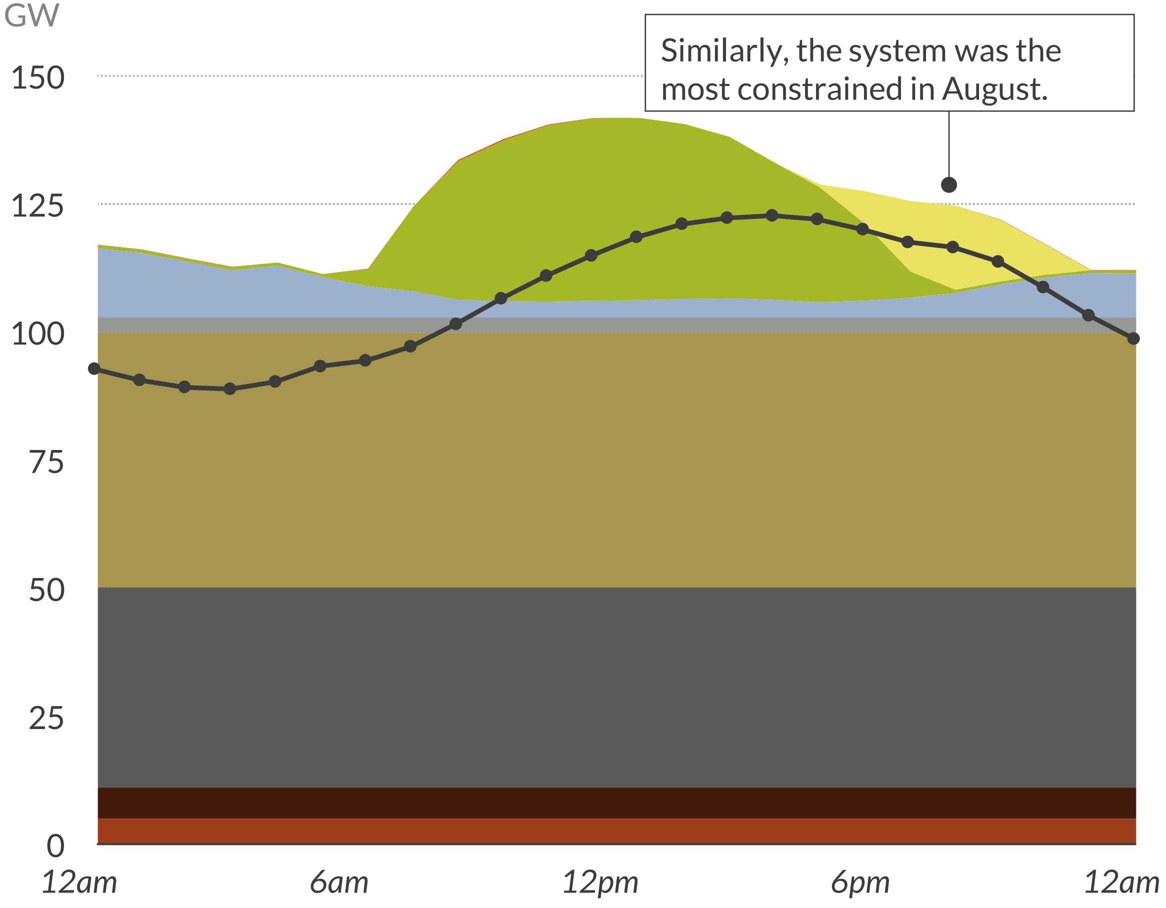
Tightest day in 2030 under average[1] (2013) WY conditions – Aurora Central demand
GW



Tightest day in 2030 under average (2013) WY conditions – ERCOT LTLF demand
GW



DC Ties | Solar | Other thermal | Gas CCGT | Nuclear
Battery storage | Onshore wind | Peaking | Coal | Total load

1) Based on a 2013 WY.

Sources: Aurora Energy Research

Agenda

Supply Risk | Rapid demand growth increases the risk of supply delays; historical data shows 45% of capacity in the queue was delayed by >1 year

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Rapid demand growth creates increased risk of lagged supply

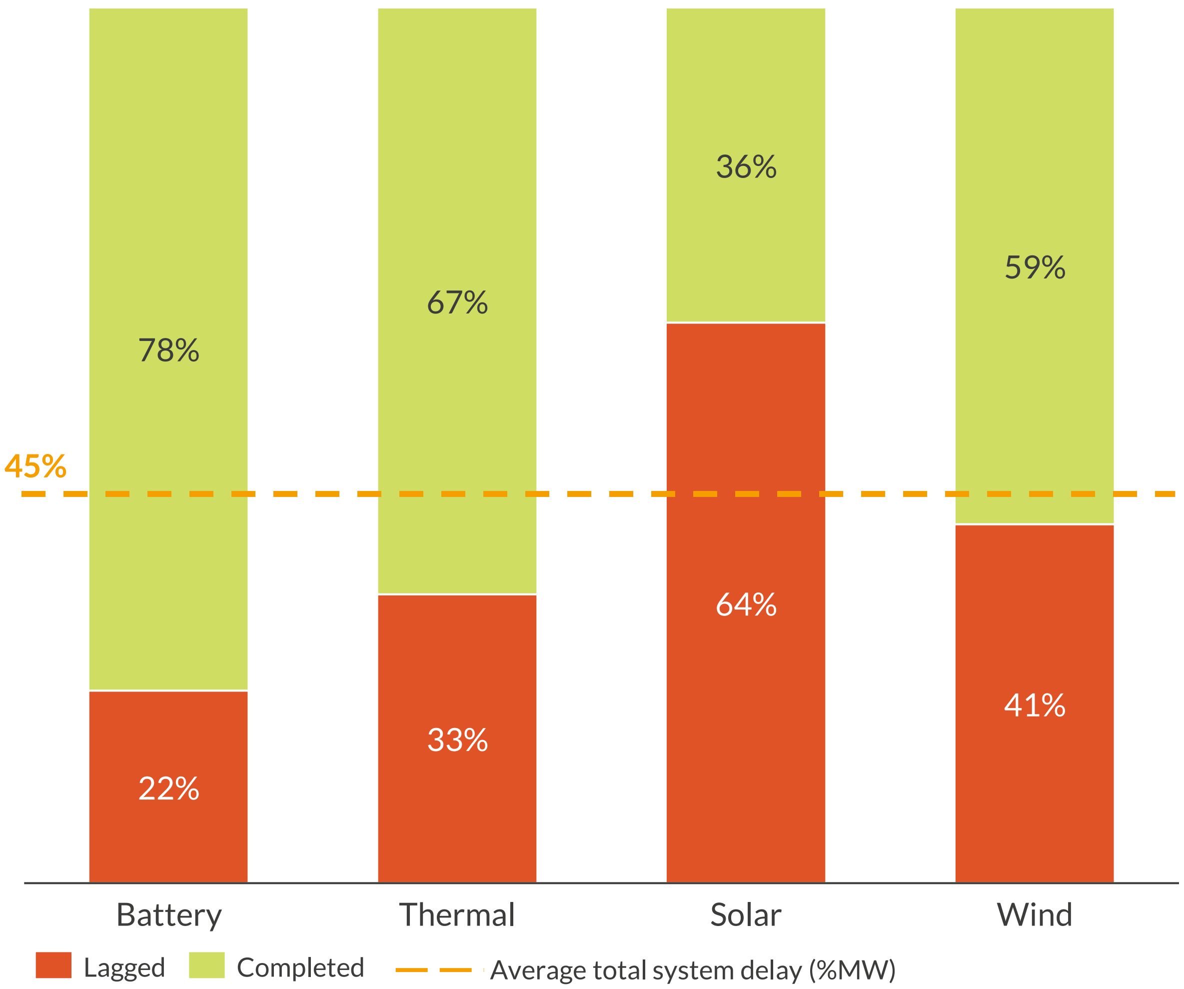
- Rapid demand growth will require **supply to keep pace** to prevent additional reliability risks.
- Even with a strong economic signal to build, the supply side will need to navigate **permitting, supply chain and interconnection constraints.**
- Historically, there exists a **significant lag between planned and realized dates of commercialization.**
- Of all projects with a signed interconnection agreement (IA) in the January 2022 ERCOT GIS[3] report that planned for COD before 2024, **at least 45% (weighted by capacity) experienced a delay >1 year.**

Aurora's modeling methodology

- **To capture the risk of lagged supply, Aurora modeled a scenario based off the ERCOT LTLF demand profile in which:**
  - On average, **45% of new entrants are delayed by a year** beyond their original commercialization date.
    - The average **45%** delay rate **varies by technology** and is calibrated to historical delay rates.

Percent total MW delayed by at least 1 year[1,2]

% of new GIS[3] generation in interconnection queue, by tech



1) Commercial Operations Date (COD) and other data taken from ERCOT GIS Reports (2019-2024). 2)Average delay calculated from remaining projects in GIS report from 2019-2024. 3) Generator Interconnection Status.

Sources: Aurora Energy Research, ERCOT

ERCOT LTLF | Under a normal weather year, the modeled supply delayed case leads to a capacity shortfall and load shedding

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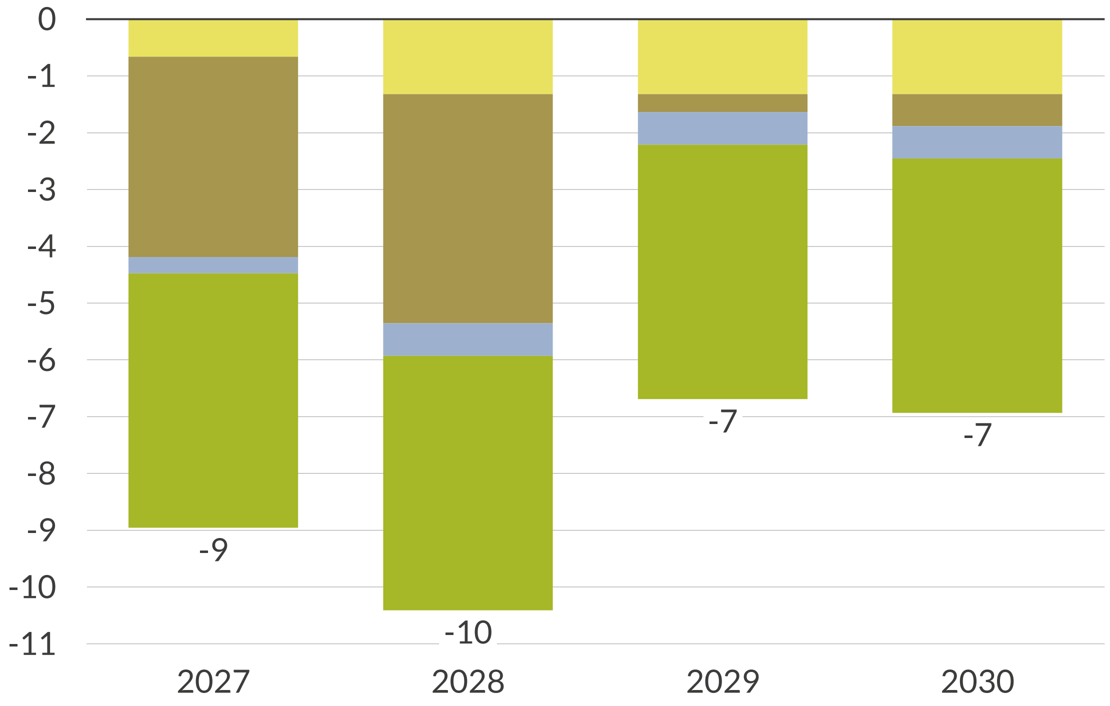
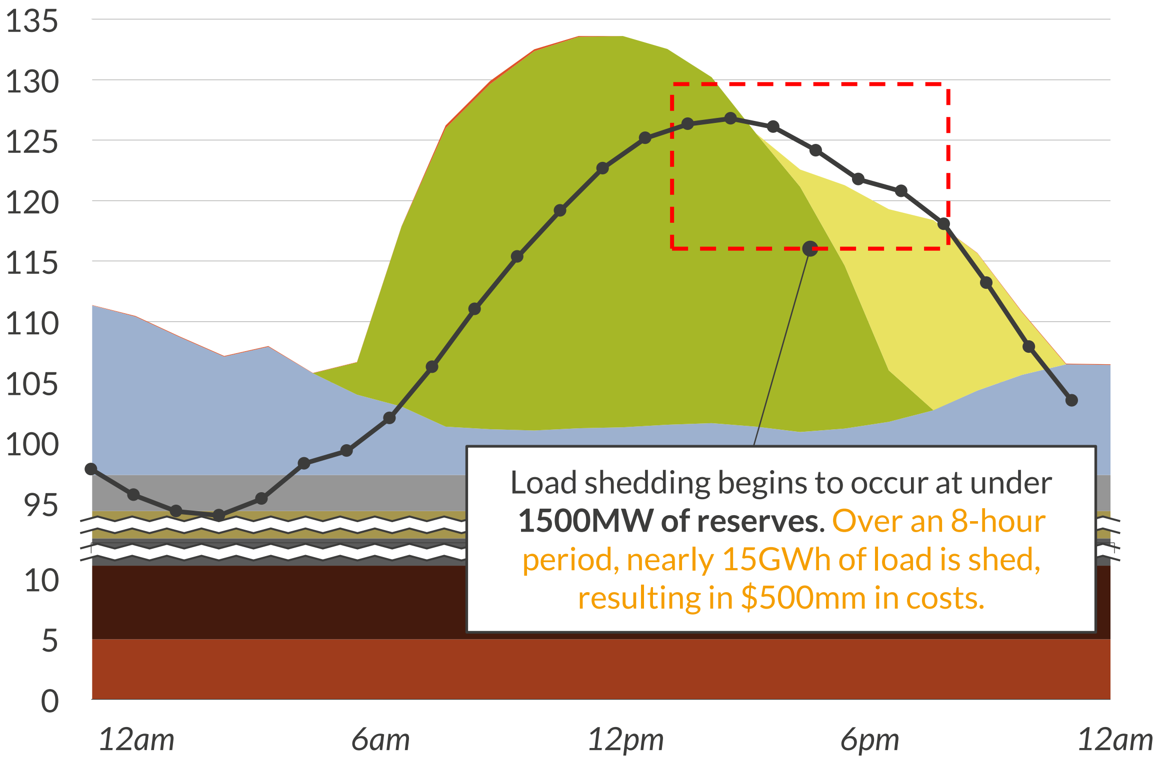
Installed capacity delta – 45% lag assumption
GW



- In the lagged supply case, installed capacity is 7GW lower by 2030, with solar, wind and battery making up the majority of delayed capacity additions.

Tightest day in 2030 under average (2013) WY conditions – 45% lag assumption
GW



Nuclear | Coal | Gas CCGT | Peaking | Other thermal | Onshore wind | Solar | Battery storage | DC Ties | Total load

Agenda

To assess system reliability, Aurora modeled the impact of two historic weather events using forecasted supply and demand assumptions for 2030

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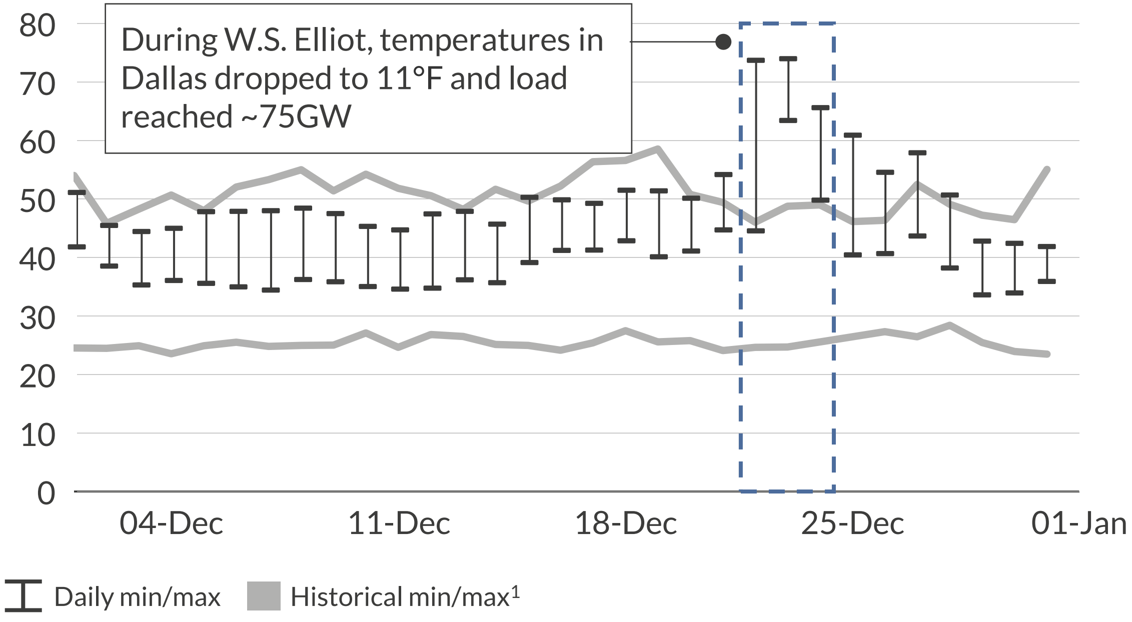
2022 Weather Year (Winter Storm Elliot)

Total ERCOT load, December 2022[1]
GW

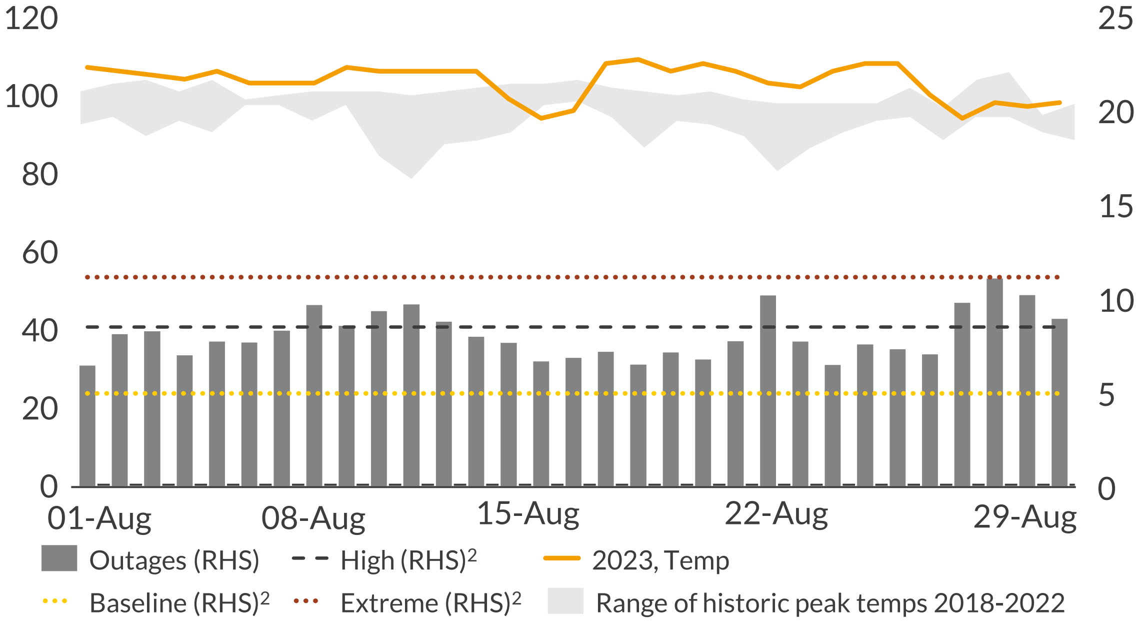


- W.S. Elliot brought **extreme cold weather, which has only been matched once since** (W.S. Heather in January 2024).
- However, temperatures were **not as extreme as during W.S. Uri**, (February 2021) nor were outage levels, largely due to new weatherization standards.
- Aurora used demand, renewables generation and outage profiles to recreate the effect of W.S. Elliot **under 2030 supply and demand assumptions.**

2023 Weather Year (summer heatwave)

Max daily temperature, August 2023
Degrees Fahrenheit

Daily thermal outages
GW



- Extreme summer heat in 2023 put recurring strain on the grid and set a new peak load record.
- Summer **weather in 2023 was far hotter than Texas had seen in recent years**, with 55 days having a heat index of 100°F or greater; 2022 had 47 such days and 2024 had 23 days.
- Aurora modeled **the impact of extreme heat on 2030 supply and demand**.

1) Including years since 2010. 2) Baseline, High, and Extreme levels taken from Revised May 2023 ERCOT SARA reports.

Sources: Aurora Energy Research, National Weather Service, ERCOT

Aurora Central | In 2030, winter storm conditions (Storm Elliot-style event) lead to load shedding as supply is insufficient to satisfy demand requirements

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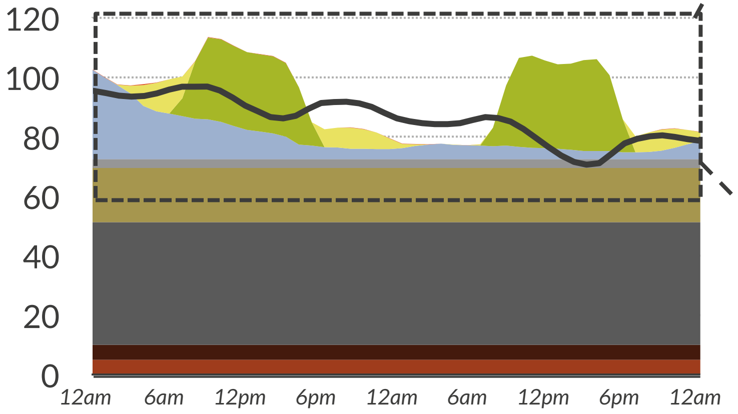
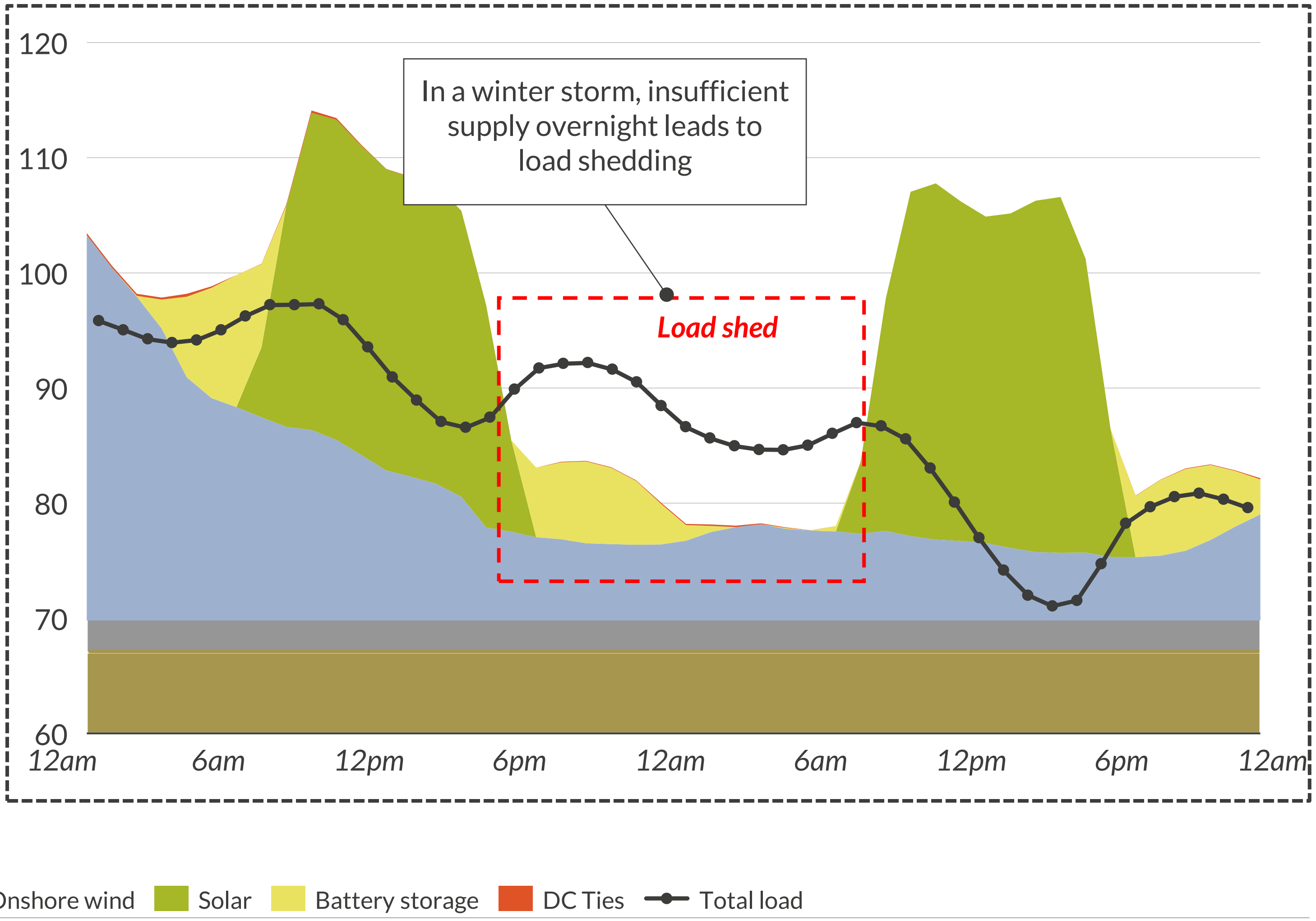
2030 December winter storm (Winter Storm Elliot-style event)
GW

- Load shed in Aurora Central case is driven by a lack of flexible generation during periods of low renewables generation.
- In the Aurora Central scenario, we assume there are no interconnection delays and projects will come online as scheduled.
- By 2030, max load shed of approximately **8.1GW** still occurs overnight during the tightest period of the winter.





Sources: Aurora Energy Research

Aurora Central | In 2030, extreme summer conditions also lead to load shedding as supply is insufficient to satisfy demand requirements

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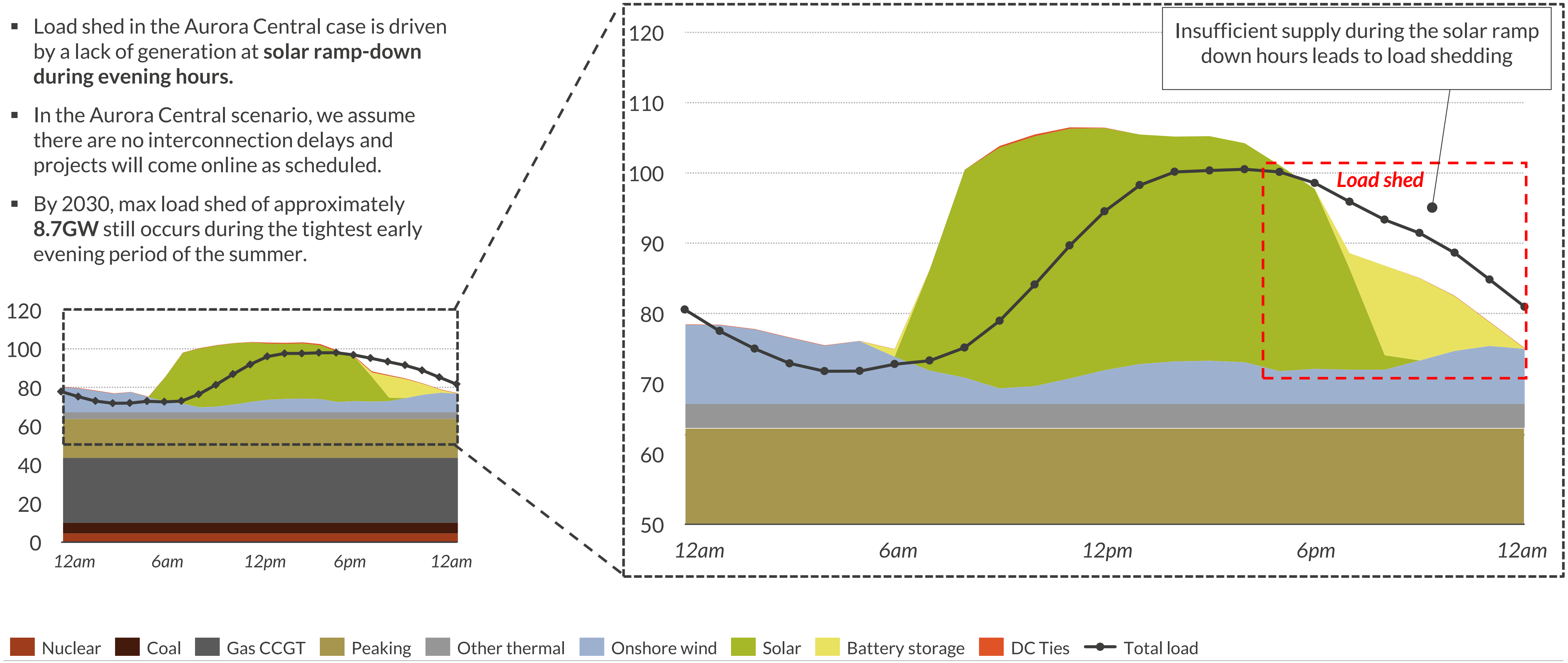
2030 August summer heat wave (2023-style weather year event)
GW

- Load shed in the Aurora Central case is driven by a lack of generation at **solar ramp-down during evening hours.**
- In the Aurora Central scenario, we assume there are no interconnection delays and projects will come online as scheduled.
- By 2030, max load shed of approximately **8.7GW** still occurs during the tightest early evening period of the summer.



Sources: Aurora Energy Research

Extreme weather drives load shed in both demand cases with up to $3.7bn worth of lost load in the ERCOT LTLF case

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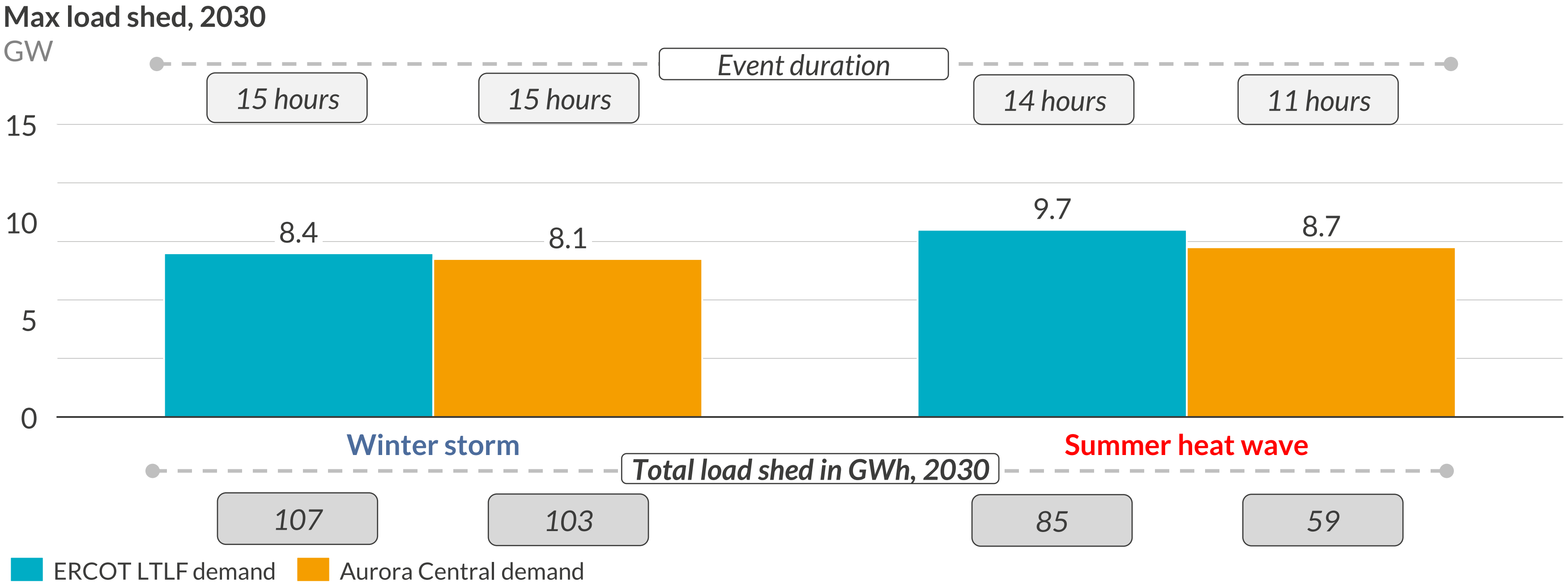

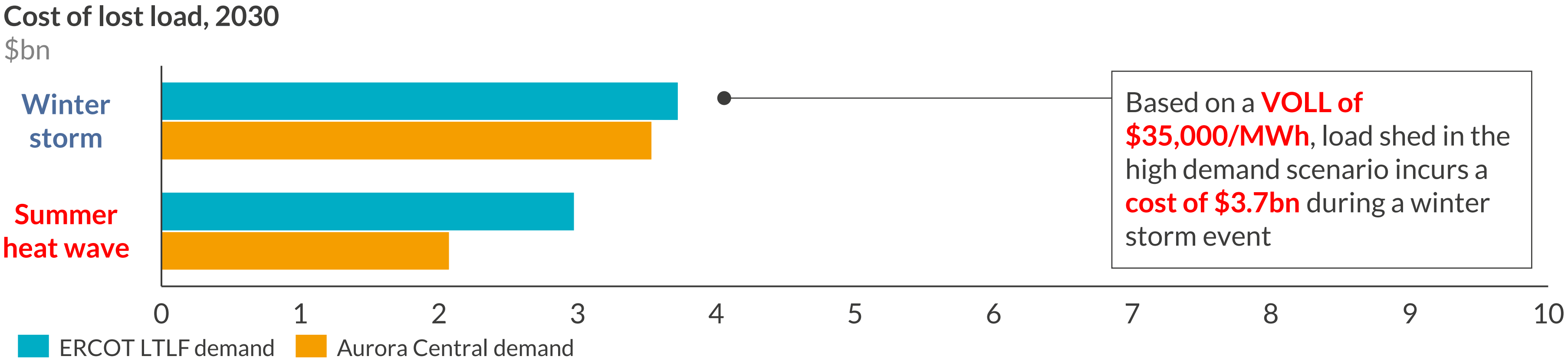

- Load-shedding events occur under both extreme summer and winter conditions in the Aurora Central and ERCOT LTLF demand cases.
- Total load shed is most severe in the ERCOT LTLF demand case under summer heatwave conditions.
- Maximum load shed reaches 8.4GW in the winter, and 106.7GWh of energy is unserved over the course of a 15-hour winter event.
- 8GW to 10GW of load shed represents between 2.0 and 2.5 million homes without power.[1]
- Based on a $35,000/MWh value of lost load, in all modeled cases, load-shedding events would cost over $2bn, with the most severe case costing $3.7bn.

1) 1 megawatt (MW) of electricity can power 250 Texas homes during periods of peak demand.

Sources: Aurora Energy Research, ERCOT

Under current market design, the system has sufficient capacity under average weather conditions but sees reliability issues in all the extreme weather events

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Results for entire year of 2030

Demand Scenario	Weather Year	Total Load Shed (GWh)	Close Call Instances[1]	Max load shed (GW)	Total VOLL ($bn)
Aurora Central	*2013*	0	61	0	0
	2023 (Hot Summer)	312	402	8.7	10.9
	2022 (Winter Storm)	219	391	8.1	7.7
ERCOT LTLF	*2013*	0	158	0	0
	2023 (Hot Summer)	578	471	9.7	20.3
	2022 (Winter Storm)	289	497	8.4	10.1

1) Number of hours in which reserves dip below 5,000MW of reserves ERCOT-wide, inclusive of load-shedding events.

Sources: Aurora Energy Research, ERCOT

Agenda

Demand response may be an important tool to support system reliability, yet the level of expected pre-emergency curtailment flexibility is unclear

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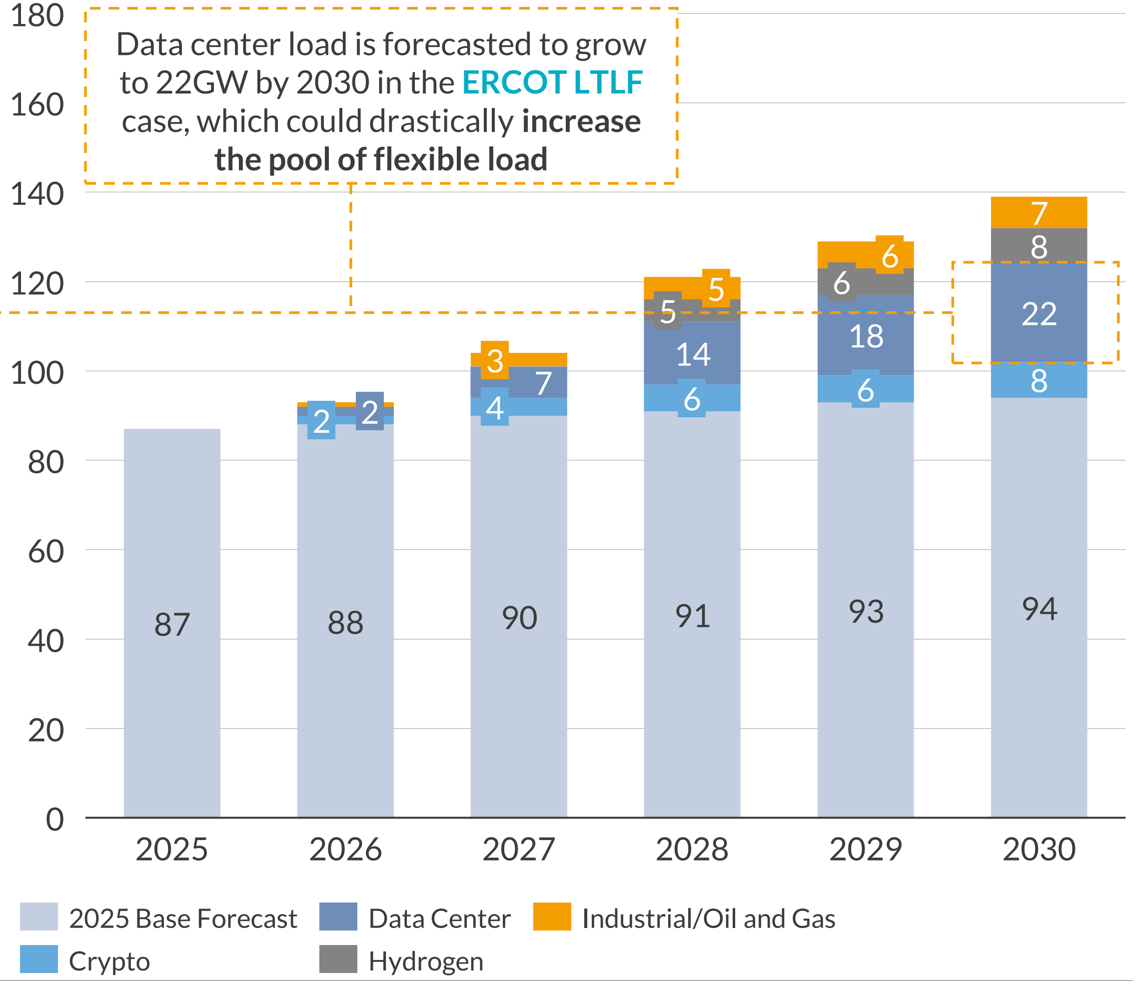
Overview of Demand Side Response

- **Definition and context**
  - Demand response is a mechanism that incentivizes or directs power consumers to **reduce their consumption during periods of system stress**. This can be achieved via a reduction of load, or by shifting consumption to behind the meter backup generators.
  - Demand response improves operational flexibility by providing an additional lever to grid operators as they balance supply and demand.
- **Current forms of demand response**
  - Currently, demand response is typically provided by **large consumers** or load serving entities via one of the following:
    - TDSP[1] management programs
    - 4-Coincindent Peak (4-CP) load reduction
    - Ancillary services such as Responsive Reserve Service (RRS)
    - Emergency Response Service (ERS)
- **The expected impact of demand response**
  - As data center load increases, so does the **pool of load resources** with potential to provide **demand response**.
  - Grid operators **may be able to utilize load flexibility to mitigate load-shedding events.**

ERCOT LTLF demand by sector
GW



1) Transmission & Distribution Service Provider.

Sources: Aurora Energy Research, ERCOT

Data centers may contribute to system flexibility, either through direct load curtailment or backup generation

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Data center operators have different options to maintain reliability while keeping power costs low

Option	Details	Potential to provide system flexibility
Do nothing	Do not curtail load; do not ramp up on-site generation.	**None**
Curtail load	Ramp down operations during high price/grid stress hours.	**Medium**
Redundant backup power for grid emergencies only	Redundant backup power only to prevent load shed during grid stress hours. **This is the status quo for most data center operators today.**	**High**
Redundant backup power for price responsiveness	Redundant backup power for high price hours to enable price arbitrage given fixed price contracts in place; air quality permitting unlikely to be serious issue.	**High –** though if diesel-backup power, it depends on the amount of fuel on-site

Consistent power access (opposed to low costs) is the main priority of data center operators; for most operators today, backup generation is used only as last resort to prevent load-shed, not as a mechanism to avoid high price hours or arbitrage.

In most cases, data centers are unlikely to curtail operations:

- **AI training** — *Shutting off during training runs could disrupt work, VoLL[1] >$2-4k/MWh*
- **AI inference** — *Querying speed unlikely to be compromised by operators*
- **Cloud computing** — *Telecoms work unlikely to be compromised by operators*

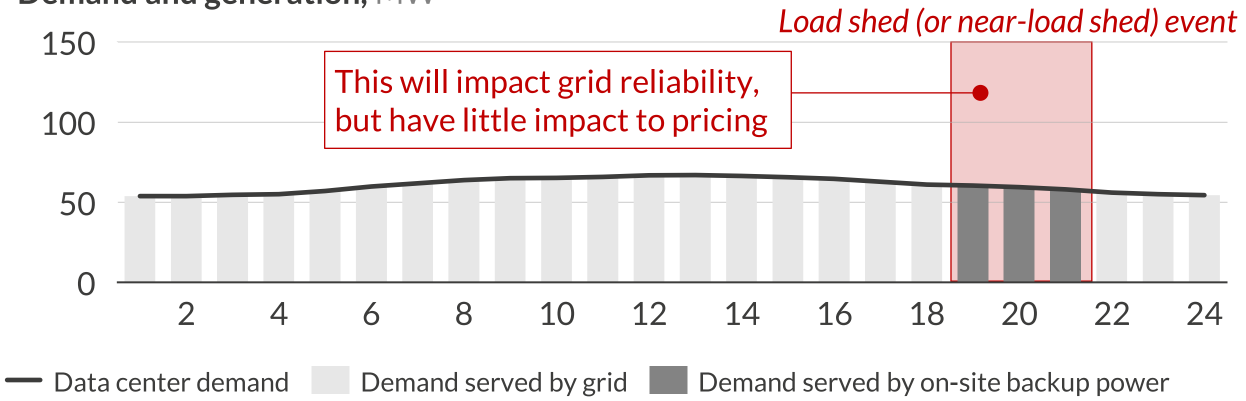
Many projects have full redundancy, utilizing backup power during grid emergencies

Example backup configuration

- 10MW data center
- 10MW UPS,[2] typically short-duration li-ion battery
- 12MW backup diesel peakers

Example daily shape

Demand and generation, MW



1) Value of lost load. 2) Uninterruptable power source. 3) Representing the wholesale price of power.

Sources: Aurora Energy Research

The extent to which data centers will have redundant backup for grid emergencies is uncertain but has important implications for ERCOT

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Many factors will influence if data center projects under development will procure backup generation (e.g., diesel peakers):

	Decision to include backup	Details	Relevance today
✓	Avoid policy uncertainty	Policy with requirement of backup power, likely in the form of state or local action. E.g. Senate Bill 6 (SB 6) in Texas	High
✓	Security	Given high VoLL,[1] desire for full backup	High
✓	Speed to market	Potential for state or ISO policy that could hasten speed to load interconnection given presence of backup power	Low
✗	Equipment cost	Diesel peaker redundancy increases costs especially for large projects (though diesel backup peakers are relatively inexpensive)	Medium
✗	Fuel cost	High diesel prices currently are caused by low domestic production and cuts from OPEC countries, this trend is expected to persist	Medium
✗	Supply constraints	Unlikely issue given ability for ICE manufacturing to ramp	Low
✗	Env. regulation	Avoid issues with air regulations, especially if building in non-attainment zones	Low
✗	Alternative technology	For large facilities with speed to energization as top priority, building a gas peaker onsite may be optimal. After grid connection is obtained, this peaker could act as backup	Medium

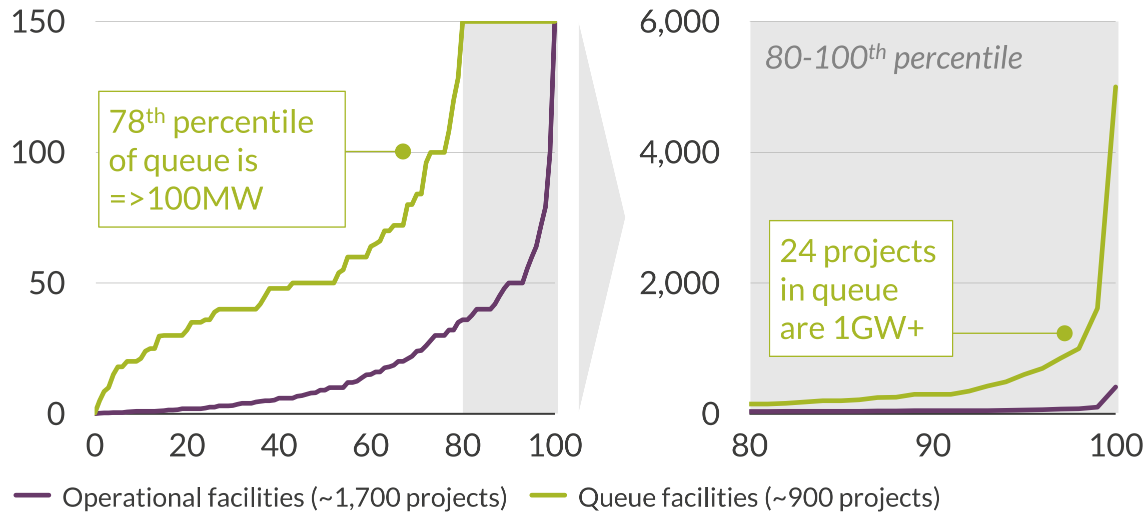
✓ Reasons to include backup diesel peakers on-site ✗ Reasons to not include

Texas' SB 6 (effective June 2025) establishes a threshold and directs use of on-site backup generation during emergencies.

SB 6 mandates financial contributions from large loads for grid upgrades, requires disclosure of backup generation, and empowers ERCOT to enforce emergency curtailment.

Project sizes are growing; cost of backup diesel power scales in line with size.

Operational and queue data center size by percentile,[2] MW power draw



For large projects, procuring fully redundant power could be worth investing in natural gas generation

1) Value of lost load. 2) Includes colocation and hyperscale data centers in the US. MW figure represents total power draw, as opposed to IT load.

Sources: Aurora Energy Research, Texas State Legislature, Baxtel, Wall Street Journal

Key regulatory changes are being implemented to provide a framework for pre-load shed curtailment with the integration of large loads on the grid

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	Senate Bill (SB6)	Nodal Protocol Revision Request (NPRR 1238)
Type	• State Legislation (Passed June 20th, 2025)	• ERCOT Nodal Protocol Revision Request: (Approved by PUCT on July 31, 2025)
Summary	• Creates framework for large load planning, including interconnection, co-location, demand management, and transmission cost responsibility. • Requests the PUC to reconsider ERCOT's 4 Coincident Peak (4CP) methodology and could change how transmission costs are allocated.	• NPRR1238 creates a new "Voluntary Early Curtailment Load" (VECL) category, where ERCOT can instruct loads that opt in to curtail their demand when the grid is under stress.
Load Planning	• Large load is defined to be ≥ 75MW. The PUC reserves the right to lower this threshold. A formal curtailment plan is needed for each large load facility. • Mandates large loads to declare of on-site generators. Utilities are to coordinate with large load entities to determine criticality of facility. • Allows ERCOT to establish a threshold and direct use of on-site backup generators only after all market services are exhausted (except frequency response), with reasonable notice during emergency alerts. Applies to large loads with ≥50% on-site backup, connected after December 31st, 2025. • Requires ERCOT to be notified before large load customers enter into net-metering agreements with existing generators.	• The Nodal Protocol Revision Request creates a process for loads to curtail in the event of a Physical Responsive Capacity (PRC) shortfall. • Customers can register as a Voluntary Early Curtailment Load (VECL), subjecting them to ERCOT instructions to shed load as needed. • Establishes a way for large flexible load to opt into the voluntary curtailment program. • Improves ERCOT's visibility into large load operations and enables ERCOT to dispatch, track, and compensate them effectively during emergencies.
Infrastructure costs and cost allocation	• Requires large load customers to provide financial commitment before the buildout of new transmission infrastructure. • Revisit fair transmission cost allocation across everyone in the system.	
Demand management service	• **Mandatory Curtailment:** Grants ERCOT limited, conditional authority to issue instructions to certain large loads with behind-the-meter, on-site backup generation of ≥50%. • **Voluntary Demand Reduction:** Orders the development of a reliability service to competitively procure demand reduction from large load customers 24 hours in advance of an anticipated energy emergency.	• ERCOT will instruct VECLs to begin curtailment when PRC2 falls below 3,100MW and is not expected to recover within 30 minutes. • Final design awaits legislative direction and stakeholder input.

Sources: Aurora, ERCOT, Texas Legislature, PUCT

Large loads can provide a range of demand responses, from price responsiveness to emergency services, with different impacts on the market

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Opportunity	Details	Example	Limitation	Power price Impact: Amount
Large loads provide flexibility by curtailing load or ramping up backup/onsite generation		**Example**	**Limitation**	**Amount**
Price Responsive	Large loads with excess generating capacity, exposure to spot prices, or ability to price arbitrage may sell into wholesale or Ancillary Service markets for a suitable price.	Non-critical or low VoLL load can be turned down temporarily during emergency periods Use on-site gas peakers or batteries during scarcity pricing events to avoid high-priced hours	Limited depth of flexibility, especially under short notice. Consistent power access (opposed to low costs) main priority of data center operators High-upfront CAPEX, access to gas pipeline infrastructure. Reduces redundancy during vulnerable periods.	↑↑
Demand Responsive	Large loads subject to transmission charges based on power draw during highest load hours of the year may avoid charges.	Large tech companies could shift computing load across geographies during periods of system stress	Limited to subset of data centers owned by some advanced tech companies.	↑
Emergency service/ Back-up generators for reliability	System perspective: Large load assets may turn down their operations when called upon by the ISO thereby avoiding the need to shed separate critical loads. Load perspective: Back-up generation is only used in emergencies due to load shedding by the system operator or other system failures. This behavior is considered out of market and does not impact prices	Large load can register as a Voluntary Early Curtailment Load (VECL), subjecting them to ERCOT instructions to shed load as needed BESS for short duration (1, 2 or 4 hours) grid fluctuations Diesel/gas peakers for medium/long duration	Voluntary versus mandatory program **BESS:** Limited duration, high Capex **Diesel:** Challenging logistics, fuel supply **Gas:** turbine supply chain constraints, access to gas pipeline infrastructure	-
No contribution to system flexibility				
No flexibility	Uncritical load will be subject to load shed without compensation, in line with normal load shed procedures during an EEA3-style event; critical load will be preserved as long as possible before forced load shed.	Telecoms (cloud-computing) unlikely to be compromised by operators	NA	-

Responsive to price · Emergency services · Rest of DTC Demand · ↑↑ High impact · No impact

Sources: Aurora Energy Research

Aurora modeled the impact of data center load flexibility under SB6, both from emergency directives and economic signals

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Data center operations typically require 24/7 power. However, if necessary, demand response can be provided in the form of behind the meter generation, which can act as a substitute for grid sourced power. Another way could be geographical and/or temporal load shifting, which effectively could reduce demand at the site.

Modeling assumptions and methodology

- Aurora modeled three distinct data center operating behaviors, each with unique market impacts:
  - **Responsive to price** – will run backup generation or shift demand to avoid high prices and transmission charges, influencing peak prices and reducing the need for peaking supply.
  - **Emergency/ancillary service provider** – will turn down only when called upon by the system operator (e.g., under EEA2[4]). This behavior is considered out of market and does not impact prices.
  - **Inflexible** – does not turn down. Only impacted during a load-shedding event (EEA3).

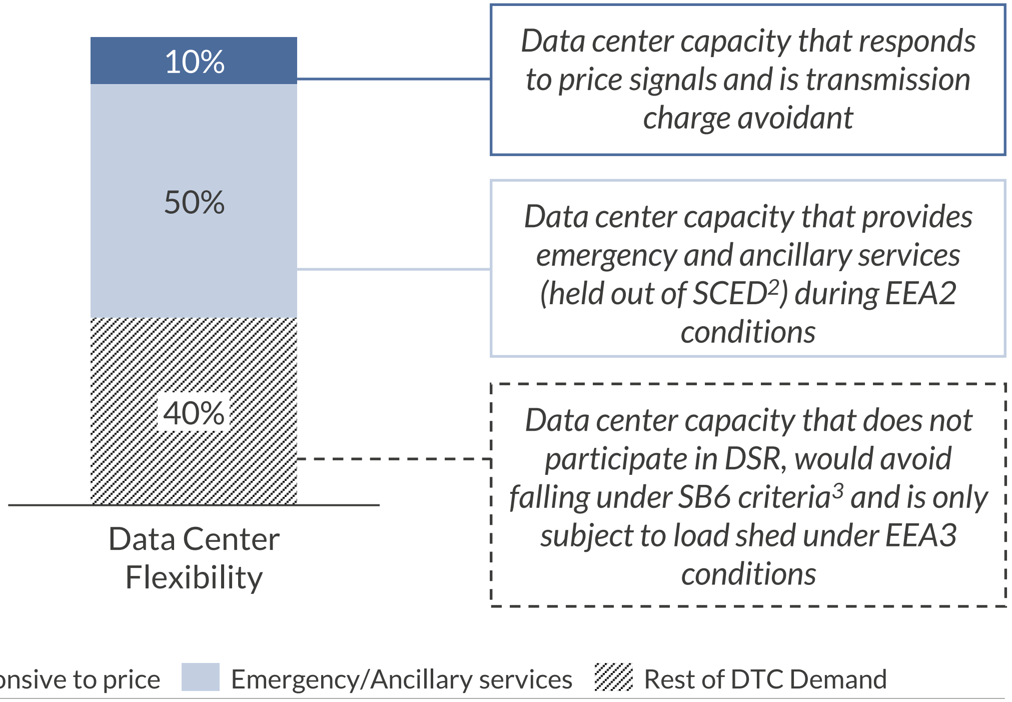
Flexibility modeled	Baseload price	Scarcity prices	Impact on supply[1]
Price responsive	◔	◑	◑
Emergency service provider	○	○	○

Modeling assumptions and methodology cont.

- Aurora modeled a scenario - "Data Center Flexibility" – reflecting increased levels of data center participation in demand-side response through voluntary and directed (e.g., SB6) mechanisms.

Assumed demand response from data centers

%



1) Indicates how much demand flexibility will impact supply side build decisions as data center behaviors will affect prices differently, impacting the economic signals to build new supply. A more detailed explanation of Aurora's capacity expansion methodology can be found in the appendix of this report. 2) This form of flexible capacity will not impact prices from the supply side. 3) By having less than 50% back-up generation for instance. 4) Energy Emergency Alert Level 2.

Sources: Aurora Energy Research

Under the Data Center Flexibility scenario, price responsive data center demand would reduce the need for flexible capacity by 2.7GW in 2030

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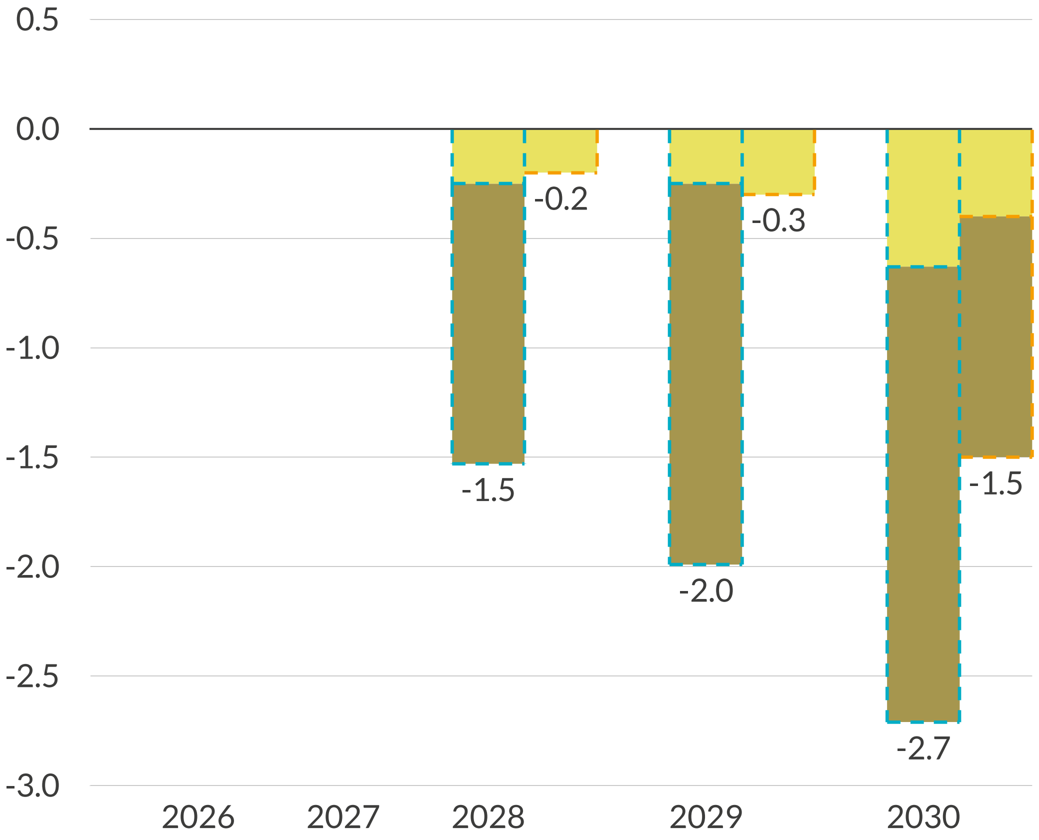
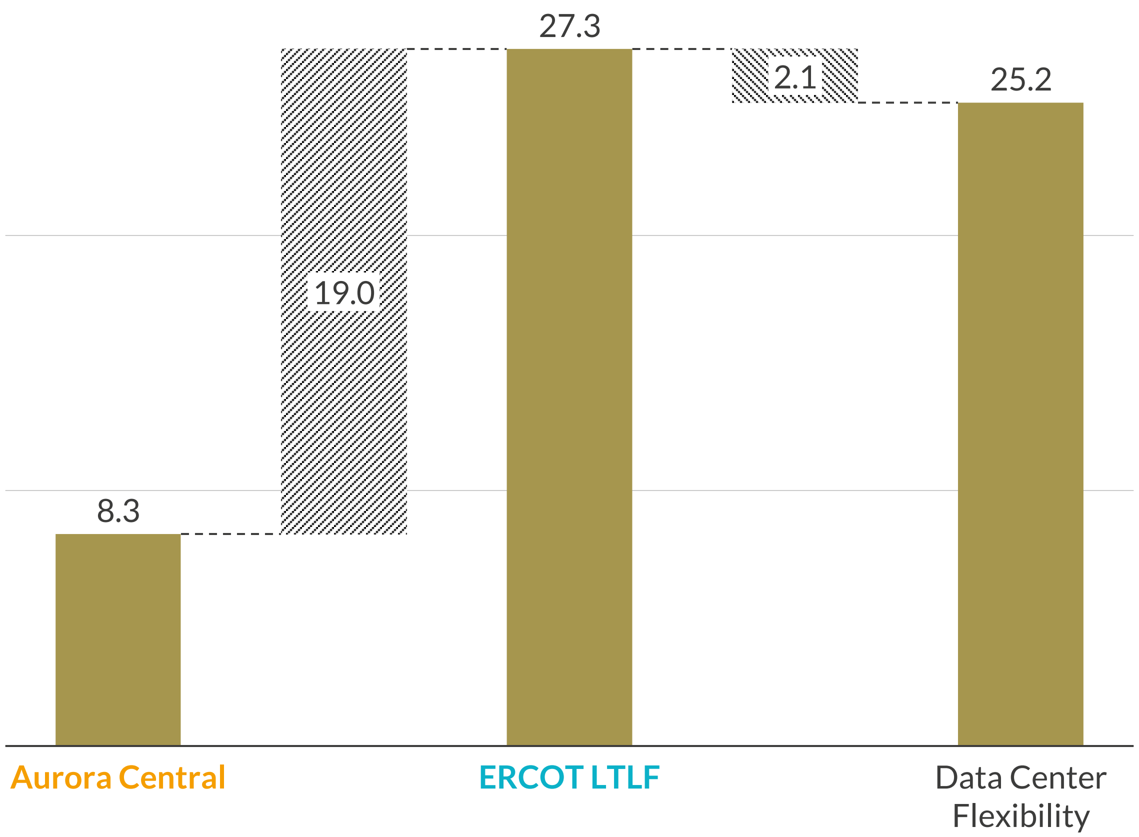
Capacity offset in Data Center Flexibility Scenario (ERCOT-wide)
GW



New build gas peaking capacity 2025 – 2030 (ERCOT-wide)
GW



Solar | Gas / oil peaker | Battery storage | ERCOT LTLF | Aurora Central

Sources: Aurora Energy Research, Heatmap

ERCOT LTLF | Under winter storm conditions, load shed is fully alleviated under the Data Center Flexibility scenario

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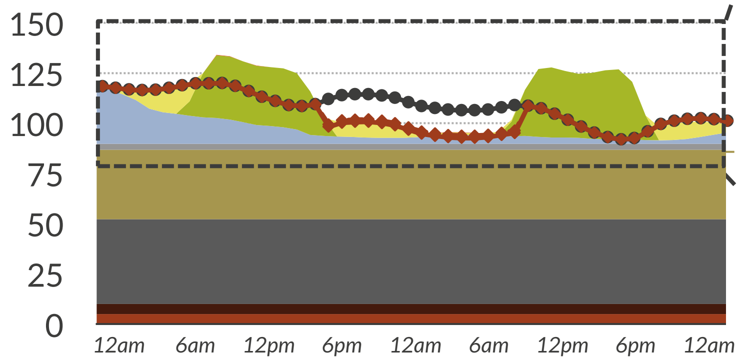
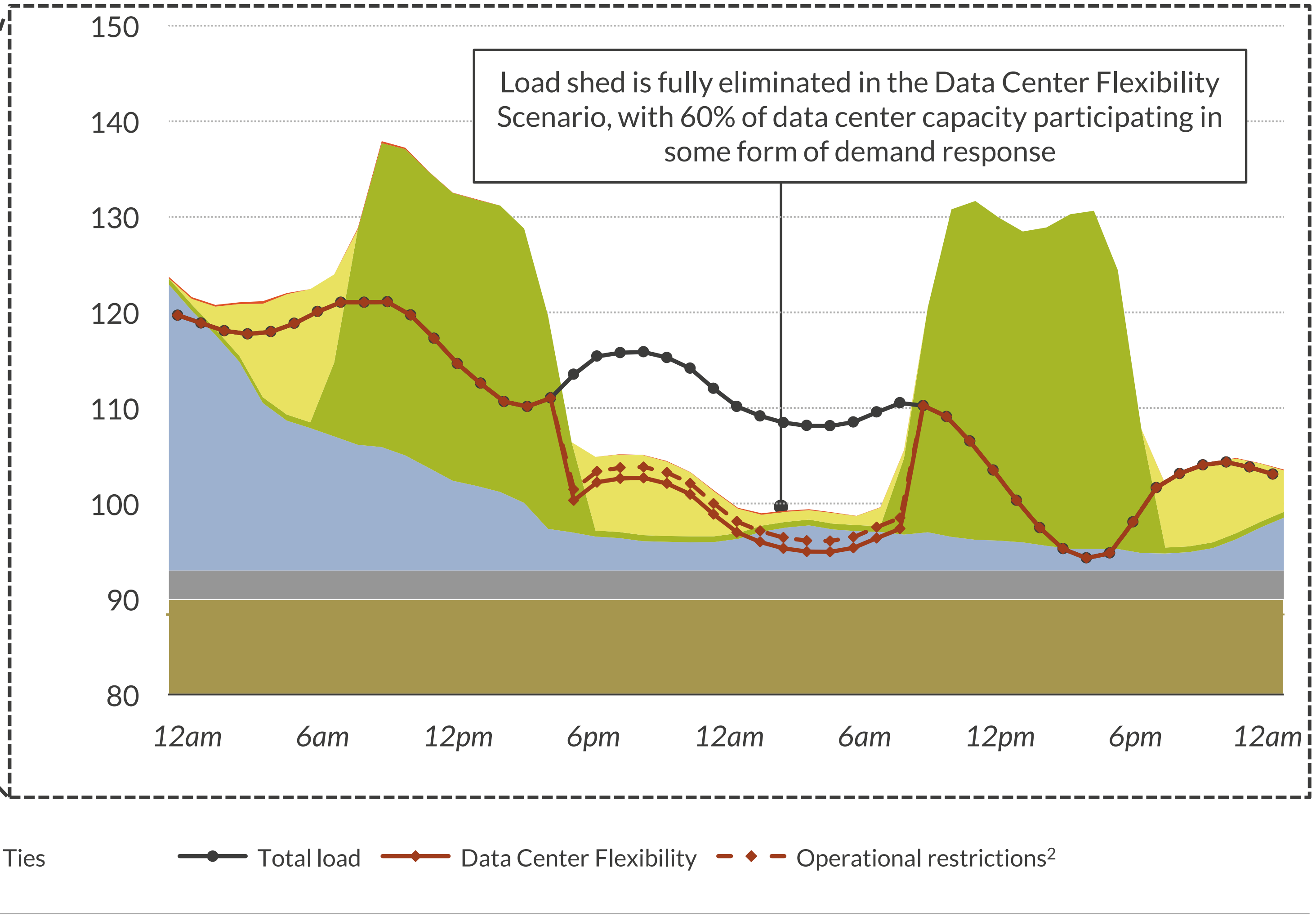
2030 December winter storm (Winter Storm Elliot style event)
GW

- By 2030, max load shed of approximately **8.4GW** occurs during the tightest period of the winter under ERCOT LTLF demand growth conditions.
- In the Data Center Flexibility scenario, Demand Side Response is sufficient to fully alleviate load shed induced in 2030.
- Even if a fraction of the load did not respond as expected when called (only 90% of the backup generation comes online), the load shed can still be fully avoided.





1) Winter storm conditions based on a 2022 style weather year Winter Storm Elliot event. 2) Defined as only 90% of the demand response actually performs as expected

Sources: Aurora Energy Research

Aurora Central | Under winter storm conditions, load shed can still be partially alleviated under the Data Center Flexibility scenario

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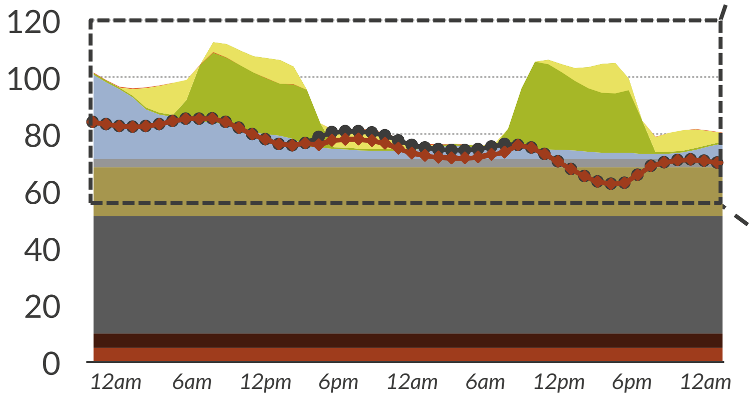
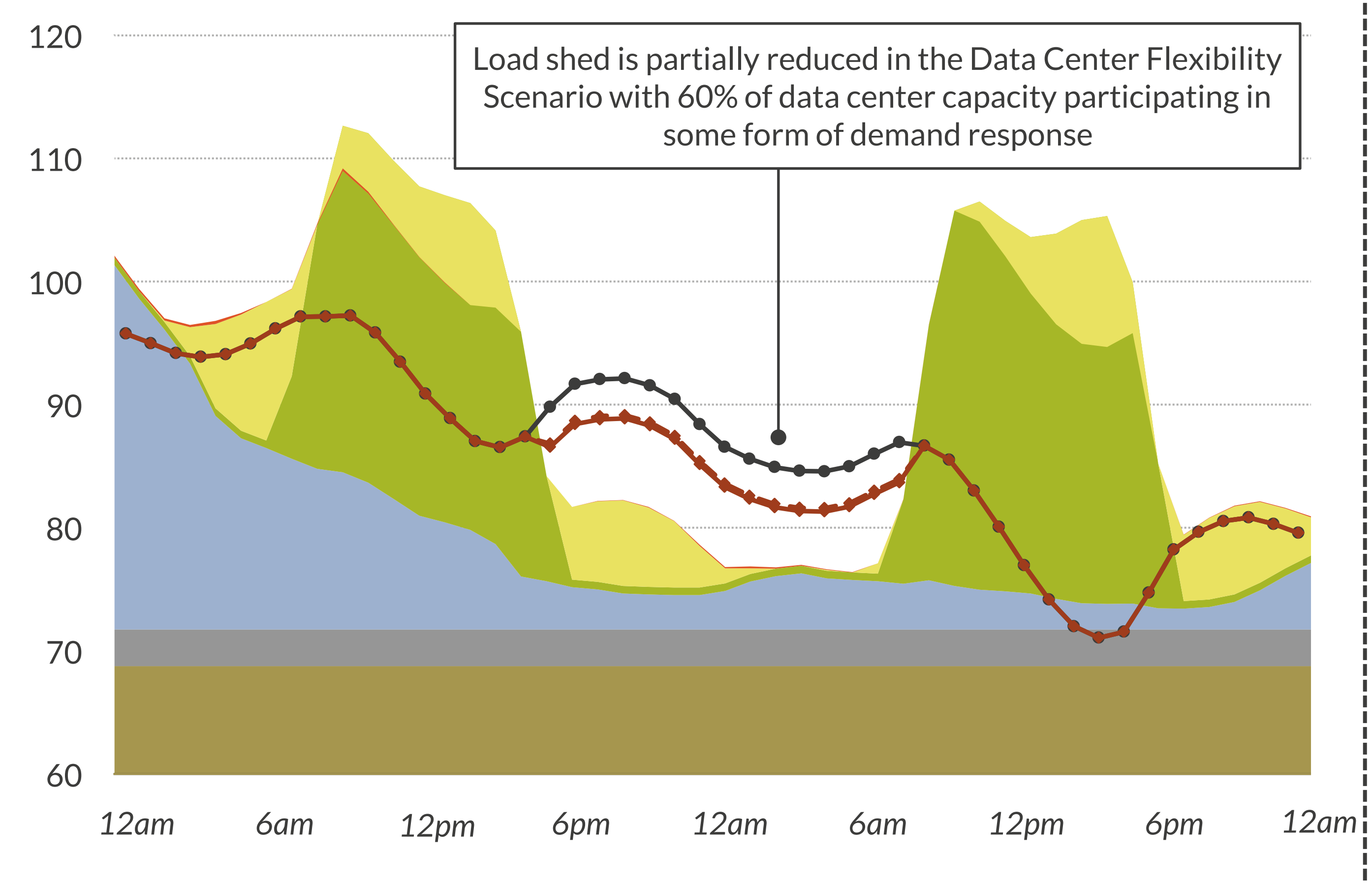
2030 December winter storm (Winter Storm Elliot style event)

GW

- By 2030, max load shed of approximately **8.1GW** occurs during the tightest period of the winter under Aurora Central demand growth conditions.
- In the Data Center Flexibility scenario, Demand Side Response can still partially alleviate load shed induced in 2030 even with operational restrictions.





Nuclear | Gas CCGT | Other thermal | Solar | DC Ties | Total load | Operational restrictions[2]
Coal | Peaking | Onshore wind | Battery storage | Data Center Flexibility

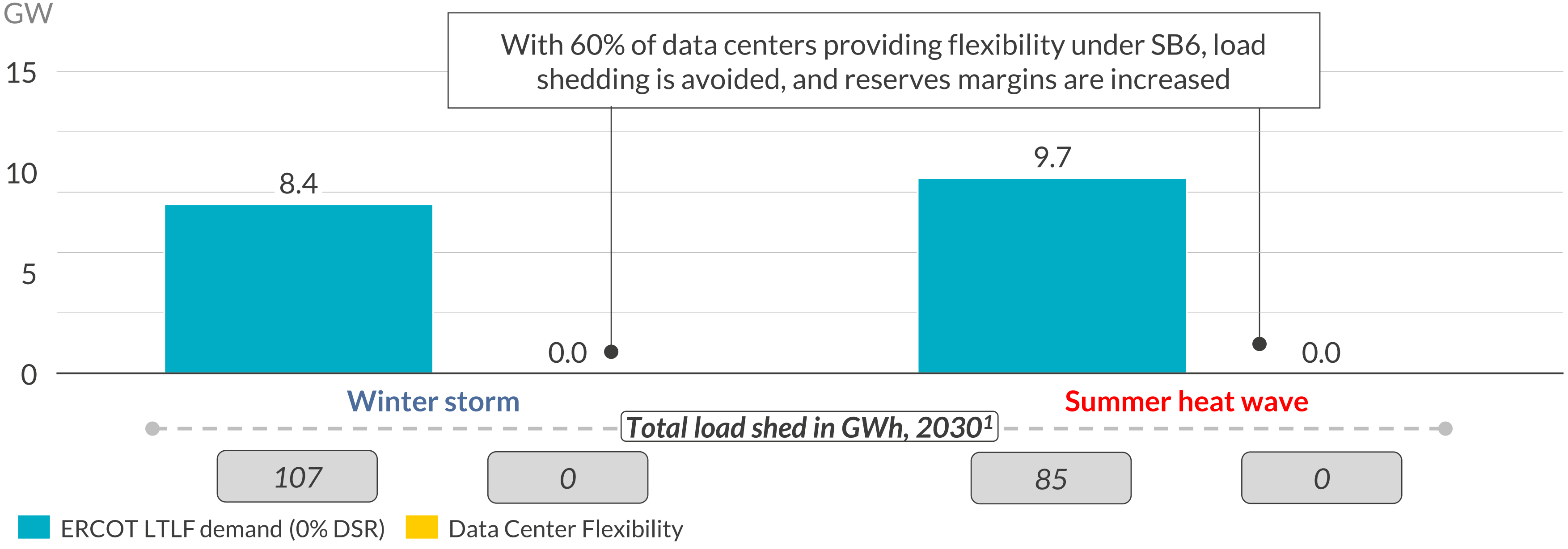
1) Winter storm conditions based on a 2022 style weather year Winter Storm Elliot event. 2) Defined as only 90% of the demand response actually performs as expected

Sources: Aurora Energy Research

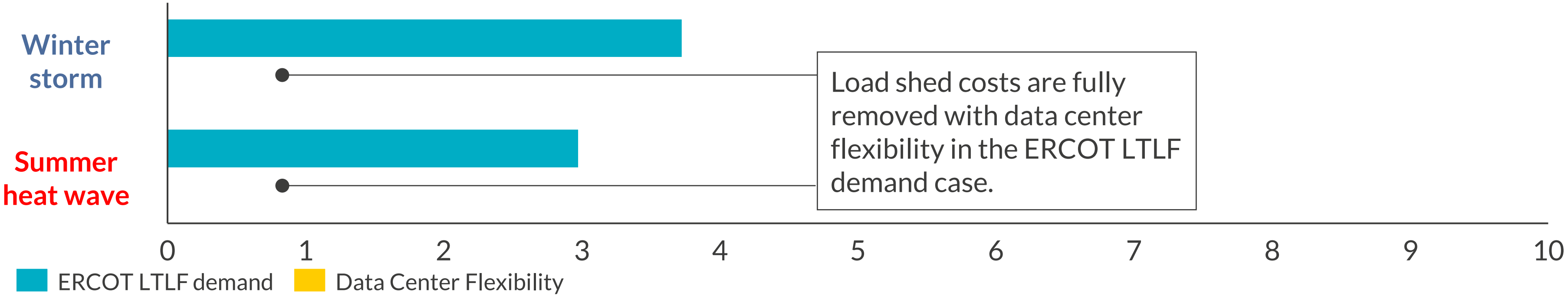
AURORA

ERCOT LTLF | At high levels of data center growth, demand response can eliminate load shed with 60% of data center participating

Max load shed, 2030[1]
GW



Loss of Load Costs, 2030
$bn



1) Assumes 22GW of Data Center load by 2030.

Sources: Aurora Energy Research

- In the Data Center Flexibility scenario, 60% of data center load is considered flexible based on SB6 assumptions, and load shed is eliminated under both winter storm and summer heat wave conditions.
- Considering the maximum load shed under these Winter storm and Summer heat wave conditions, 60% data center flexibility would be sufficient to fully alleviate load shed concerns.
- Data center flexibility saves the system $3.7 billion during an extreme winter storm when considering a $35,000/MWh VOLL.

Aurora Central | At lower levels of data center penetration, data center flexibility is not sufficient to avoid load shed

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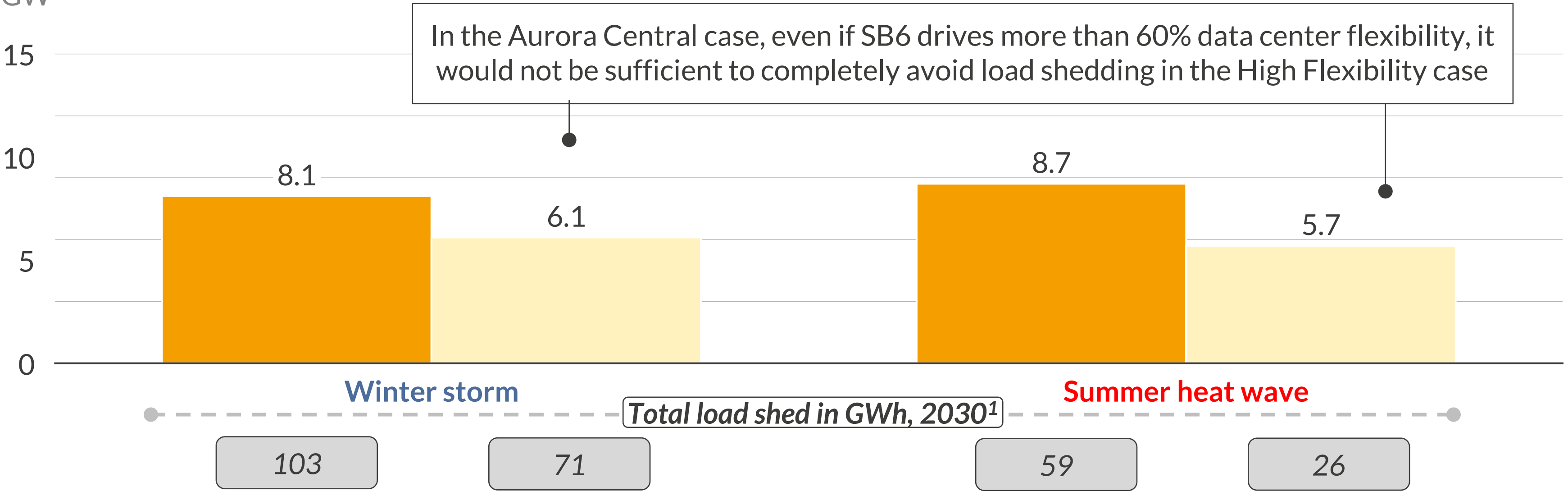
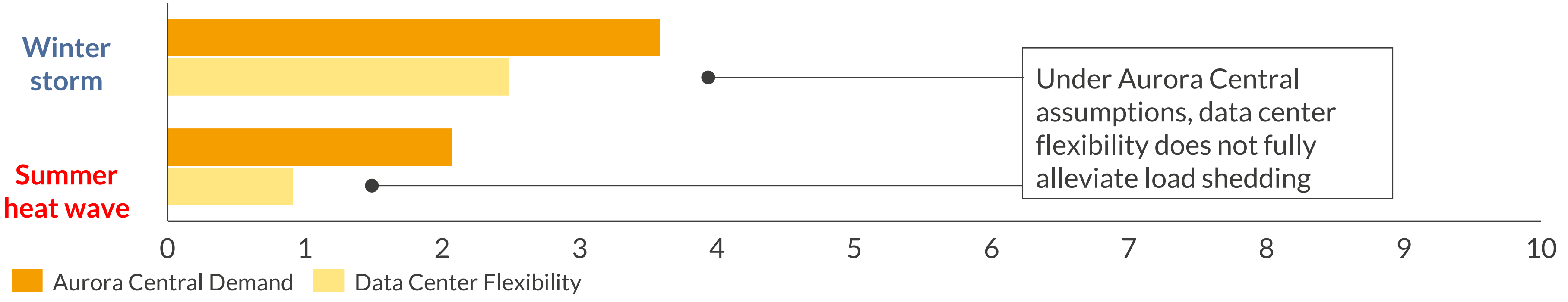
Max load shed, 2030[1]
GW



Loss of Load Costs, 2030
$bn



- The Aurora Central case takes a more conservative view of data center load growth and assumes 7GW of total data center demand by 2030.
- Due to more limited capacity, DSR from data centers does not have the same level of impact in the Aurora Central case as it does in the ERCOT LTLF case.
- In the Data Center Flexibility scenario, load shed is still necessary under both winter storm and summer heat wave conditions. During these Summer heat wave conditions, even 100% data center flexibility would not be sufficient to avoid load shed.
- Despite not fully alleviating the need to shed load, DSR participation from data centers in the Data Center Flexibility scenario cuts loss of load costs by $1.1bn during an extreme winter storm.

1) Assumes 7GW of Data Center load by 2030. Only considers data centers that provide emergency demand response services.

Sources: Aurora Energy Research

For larger data centers, scaling thermal technologies to provide full backup power and flexibility to the grid poses significant challenges

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Data centers can procure backup power primarily through two options – diesel generators or gas peaking turbines. Both technologies have challenges and benefits, and the cost and complexity of implementing full backup power increases as data center sizes grow.

↓ Main challenges to implementation

			Diesel generator		Gas peaker
Procurement and integration	Supply chain		Easier to procure – supply chain constraints may increase if demand for large diesel units grows	↓	Limited number of manufacturers - supply chain constraints could limit availability
Procurement and integration	Number of units	↓	Smaller unit capacity requires large number of individual generators		Fewer number of units required for full backup capacity
Procurement and integration	Technology		Simpler technology to integrate, operate, and maintain	↓	More complex technology – requires specialized staff and engineering knowledge to integrate, operate, and maintain
Logistics	Fuel supply	↓	Significant fuel storage requirements; a 1GW data center would require ~960,000 gallons of diesel fuel for 12 hours of sustained power		Pipeline capacity must be secured, requiring siting near existing pipelines or paying for new service
Logistics	Fuel reliability	↓	Limited shelf life of diesel and difficulty of procurement during extreme weather events threatens reliability		Pipeline delivery allows for extended operations, assuming gas deliveries aren't curtailed in emergency conditions
Cost	CAPEX		CAPEX could range from $250 - $500/kW depending on technology and entry year	↓	CAPEX could range from $700 - $1,600/kW depending on technology and entry year
Cost	Operating costs		Maintenance and operating costs: $5 – $20/kW/year depending on technology and level of use		Maintenance and operating costs: $15 - 25/kW/year depending on technology and level of use
Emissions		↓	Higher emissions		Lower emissions relative to diesel generators

Sources: Aurora Energy Research, NREL, EIA,

The cost and challenges of scaling backup generation with data center buildout show that full backup power may not be feasible for all large loads

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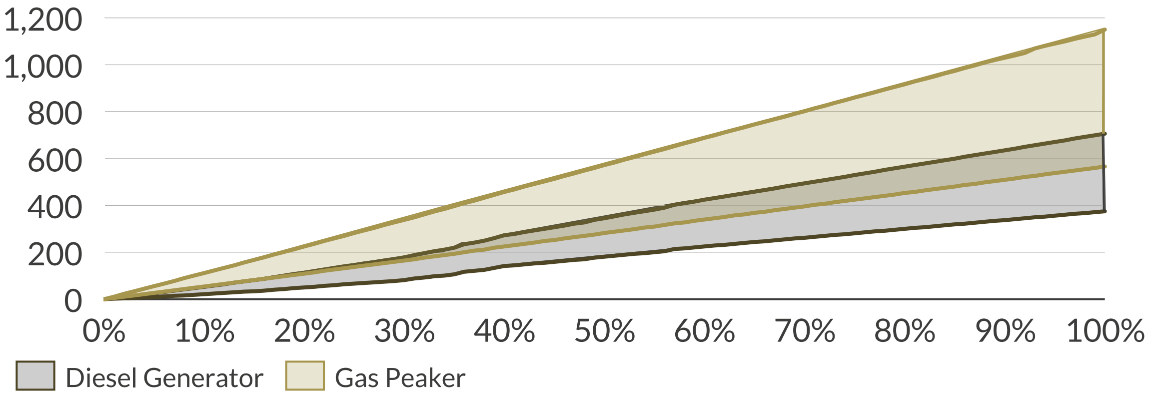
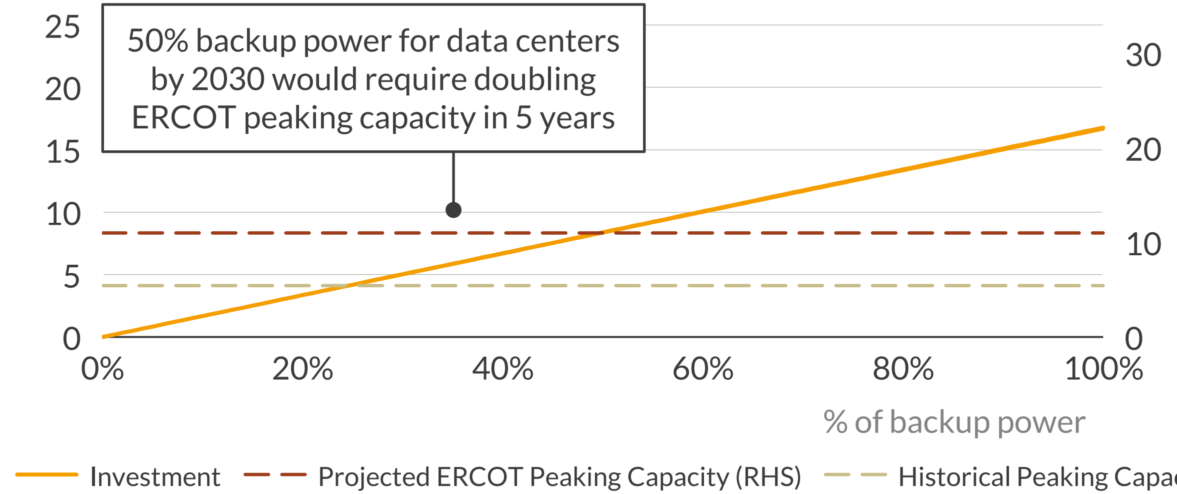
Range of lifetime costs[1] for 500MW backup generation by technology
$ Million



ERCOT-wide investment[2] required by 2030
$Billion

Corresponding capacity
GW



Challenges to backup generation at scale

Individual Data Centers

- As data center sizes grow, the cost and engineering challenges to integrate larger backup generation packages both increase. For a 500MW data center, **the lifetime cost of 100% backup power could range from $360 million to over $1.1 Billion** depending on technology and CAPEX trajectory.
- Additionally, developers may become more cost conscious as the market matures, and the **tradeoff between CAPEX and downtime expectations may favor a smaller portion of backup power** for some data center developers.

ERCOT-wide

- Across ERCOT, a **total of 22GW of capacity and approximately $17 Billion in capital investment** would be required to support full backup power capabilities across the data center fleet by 2030.
- Costs aside, **the manufacturing, EPC support, and specialized staff required to build, develop, and operate this amount of capacity in a short period presents significant headwinds.** Full backup power is unlikely to be feasible, and even procuring 50% backup power for the data center fleet would represent a doubling of installed peaking capacity in ERCOT over a 5-year period.

1) Total of CAPEX, fixed O&M, variable O&M, and fuel costs for a 25-year lifetime. 2) Assumes an even split of gas peakers ($1,150/kW CAPEX) and diesel generators ($375/kW CAPEX).

Sources: Aurora Energy Research, ERCOT

Agenda

Aurora modeled the impact of three market mechanisms on resource adequacy and system costs

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Market Design Properties	DRRS Ancillary Service (AS)	DRRS Ancillary Service Plus	Extended ORDC Curve
Purpose	Increase reserves, improve operational flexibility and reduce the amount of Reliability Unit Commitment.	Improve long-term resource adequacy by **providing a stable and predictable revenue** stream for **dispatchable resources.**	**Increase the value of scarcity** to encourage performance during periods of system stress and incentivize new investment.
Design	**Procured as an ancillary service** in the Day-Ahead market with average procurement volumes similar to Non-Spin.	**An hourly availability payment.** Payment amounts are determined by an annual budget. The total budget is based on the prior year's peaker net CONE[1].	Longer ORDC curve to increase scarcity value in line with a $35,000 VOLL. Total **value from the ORDC increases nearly 2x.** Prices are capped at $5,000/MWh.
Eligibility	Non-dispatchable renewables are not eligible. Resources must be capable of **running for at least four hours.** **Aurora modeled two cases:** 1. Only thermal resources eligible 2. 4+ hour BESS eligible to participate[2]	Non-dispatchable renewables are not eligible. Resources must be capable of **running for at least four hours.** **Aurora modeled two cases:** 1. Only thermal resources eligible 2. 4+ hour BESS eligible to participate[2]	All technologies are eligible.
Procurement size (2030)	1–4GW/hour	80–140GW/hour *(dependent on supply growth)*	*NA*
Primary technologies	Gas peakers; **Modeled with and without long-duration storage eligibility (4hr)**	Gas peakers; **Modeled with and without long-duration storage eligibility (4hr)**	All technologies

1. Cost of New Entry ($/MW-year). 2) Aurora has modeled a case in which batteries are eligible if their nameplate duration is at least 4-hours.

Sources: Aurora Energy Research, ERCOT

Agenda

DRRS Ancillary Service is open to capacity from all dispatchable asset classes, but imposes a 4-hour dispatch requirement

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Overview **Dispatchable Reliability Reserve Service (DRRS) would be a longer-duration reserve product procured in the Day-Ahead Market**

What is DRRS?

- The Dispatchable Reliability Reserve Service as an Ancillary Service would be a service provided using capacity from an Offline Generation Resource that can be online within two hours and can operate at its High Sustained Limit (HSL) for a number of consecutive hours, as determined by ERCOT, but **no less than four hours**.

What is the goal of this Ancillary Service?

- Manage grid uncertainty while mitigating the need for Reliability Unit Commitment (RUC) instructions.
- Ensure appropriate reliability during extreme heat and cold weather conditions and during times of low non-dispatchable power production.

What is the desired impact?

- Incentivizes **new investment in flexible dispatchable resources**.
- Generates additional revenue and provide incremental capacity.
- Mitigates out-of-market actions such as RUC and reduces uplift costs.

What is the requirement to participate in providing this service?

- Capable of running for **at least 4 hours** at the resource's HSL.
- Be online and dispatchable for 2 hours after being called on for deployment.

*Aurora's modeling intends to **capture the conceptual approach of DRRS Ancillary Service Plus, but the final implementation may differ.***

Modeling **Aurora has considered several key parameters when modeling DRRS Ancillary Service**

Eligibility by technology class

- Non dispatchable resources, such as wind and solar, are ineligible.
- Aurora modeled two cases:
  1. Only compliant thermal resources eligible
  2. Same as 1) plus 4+ hour nameplate BESS eligible to participate[1]

Procurement volumes

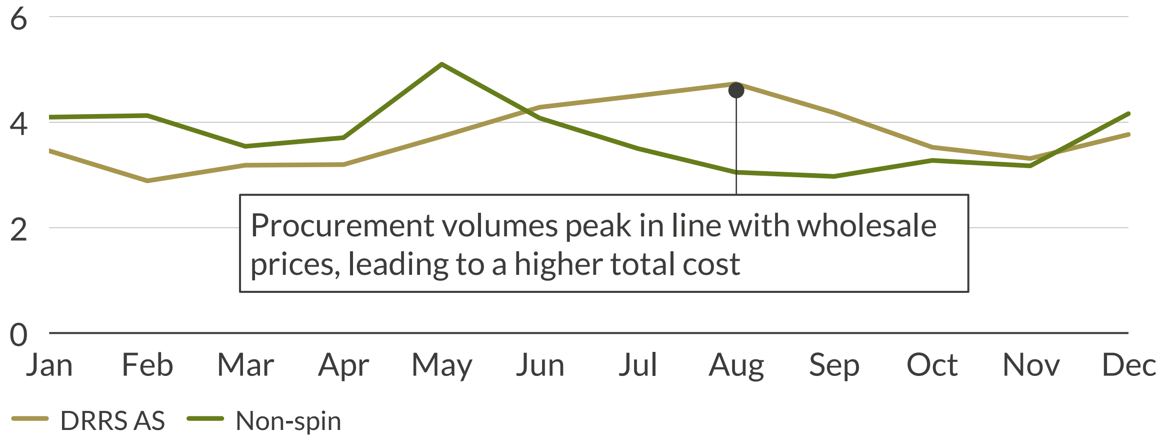
- Average yearly volumes grow with system size
- Hourly volumes vary based on modeled system tightness.

Price formation

- Prices are based on supply offers; Aurora does not assume a demand curve.

Average hourly procurement volume by month (2030)

GW/hour

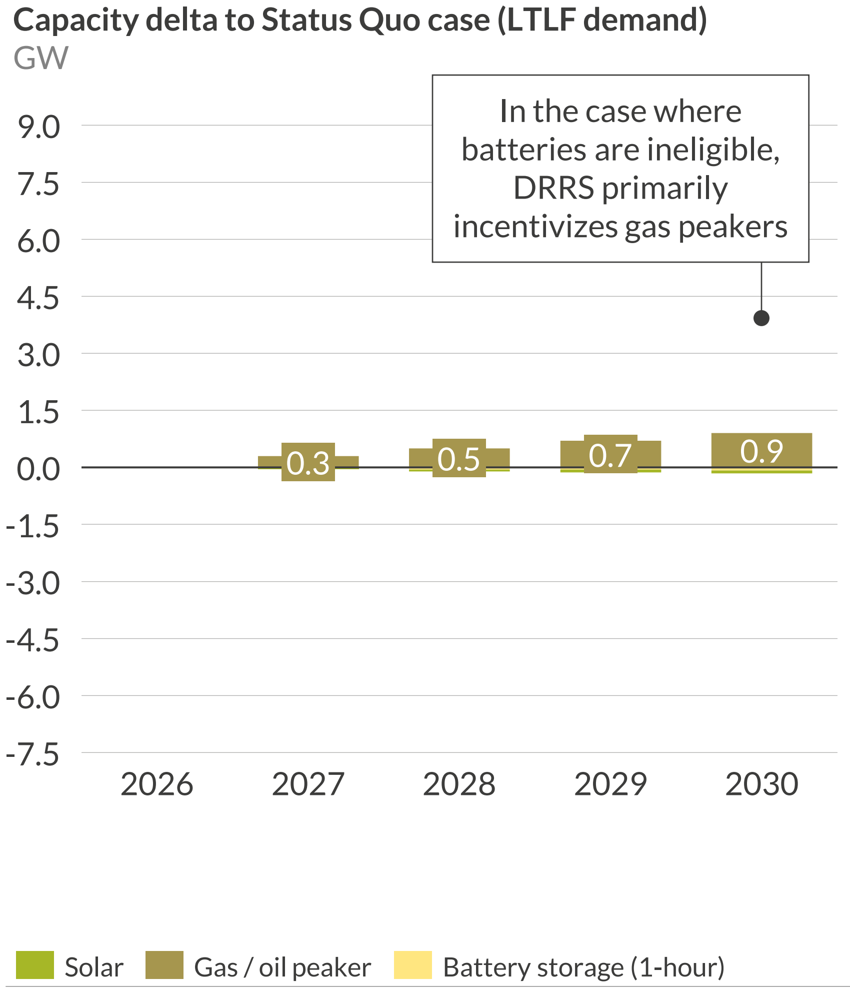


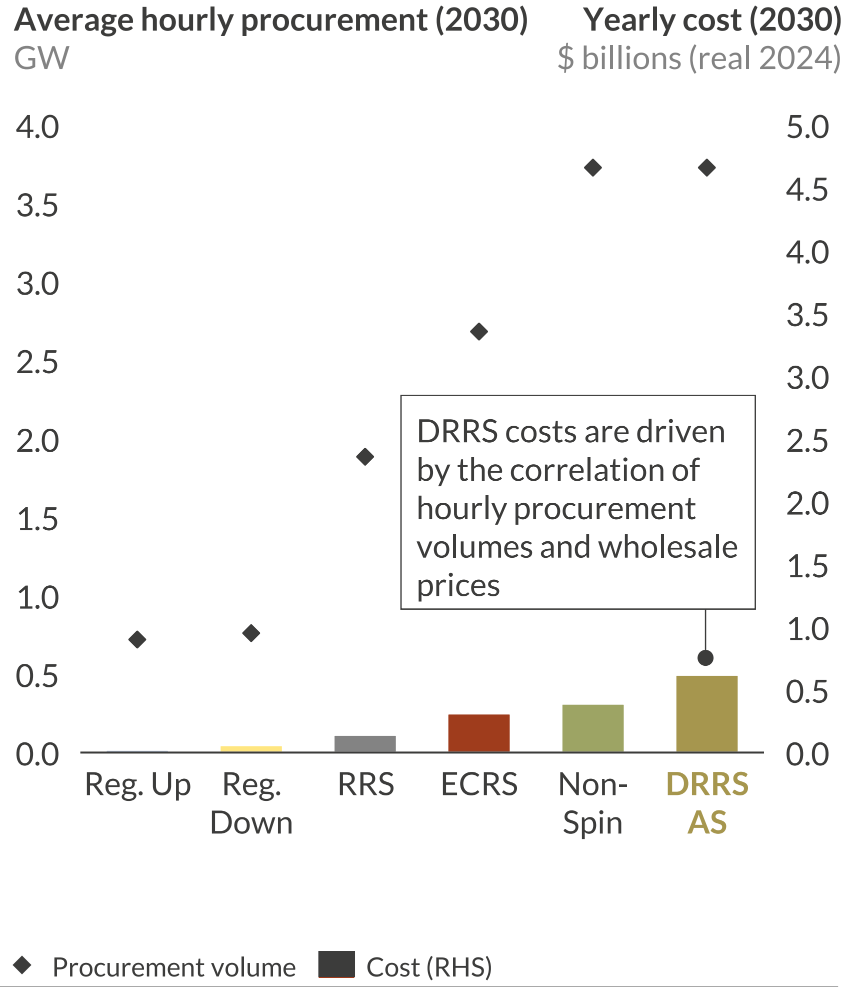
1) Aurora has modeled a case in which batteries are eligible if their nameplate duration is at least 4-hours. 2) Aurora's modeling intends to capture the conceptual approach of DRRS, but the final implementation may differ.

Sources: Aurora Energy Research

DRRS AS – Batteries ineligible | Incentivizes 0.9GW of additional peaking capacity by 2030

Batteries ineligible





- DRRS Ancillary Service incentivizes 0.9GW of additional peaking capacity by 2030 in the case where batteries are ineligible.
- Average hourly procurement volumes are similar to Non-Spin but are more coincident with peak net load, which drives higher prices.
- The yearly gross cost of DRRS in 2030 is $620mn. Hourly clearing prices are similar to those in ECRS, but higher procurement volumes lead to higher overall costs.

Sources: Aurora Energy Research

DRRS AS – Batteries eligible | Incentivizes 1.1GW of additional long-duration dispatchable capacity by 2030

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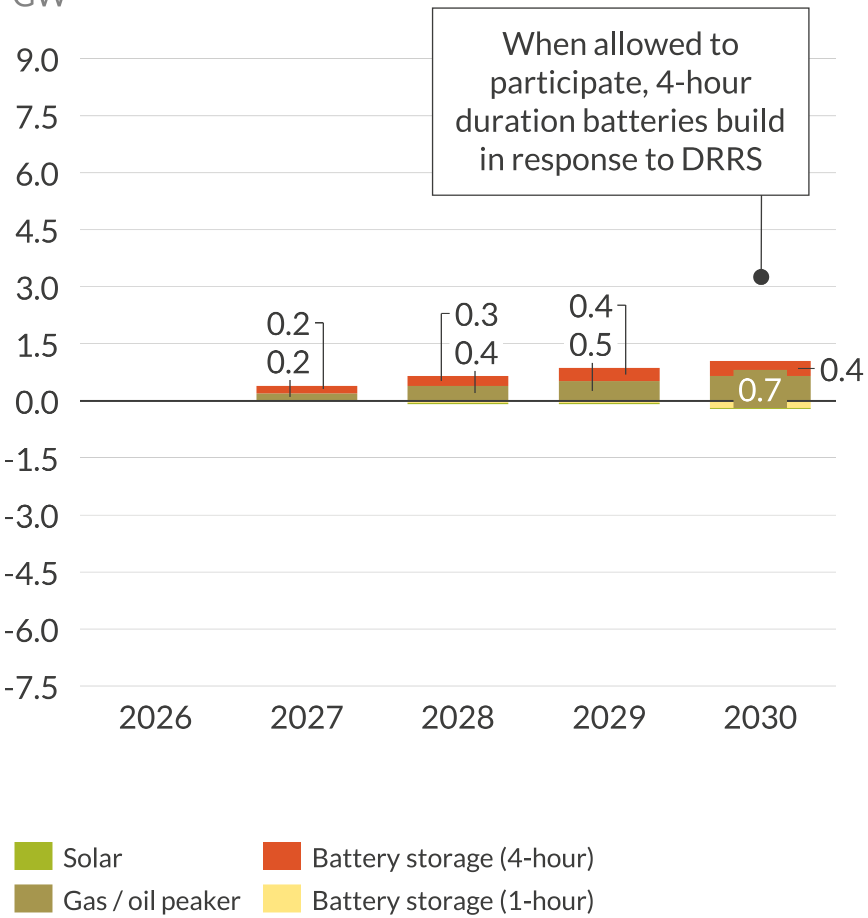
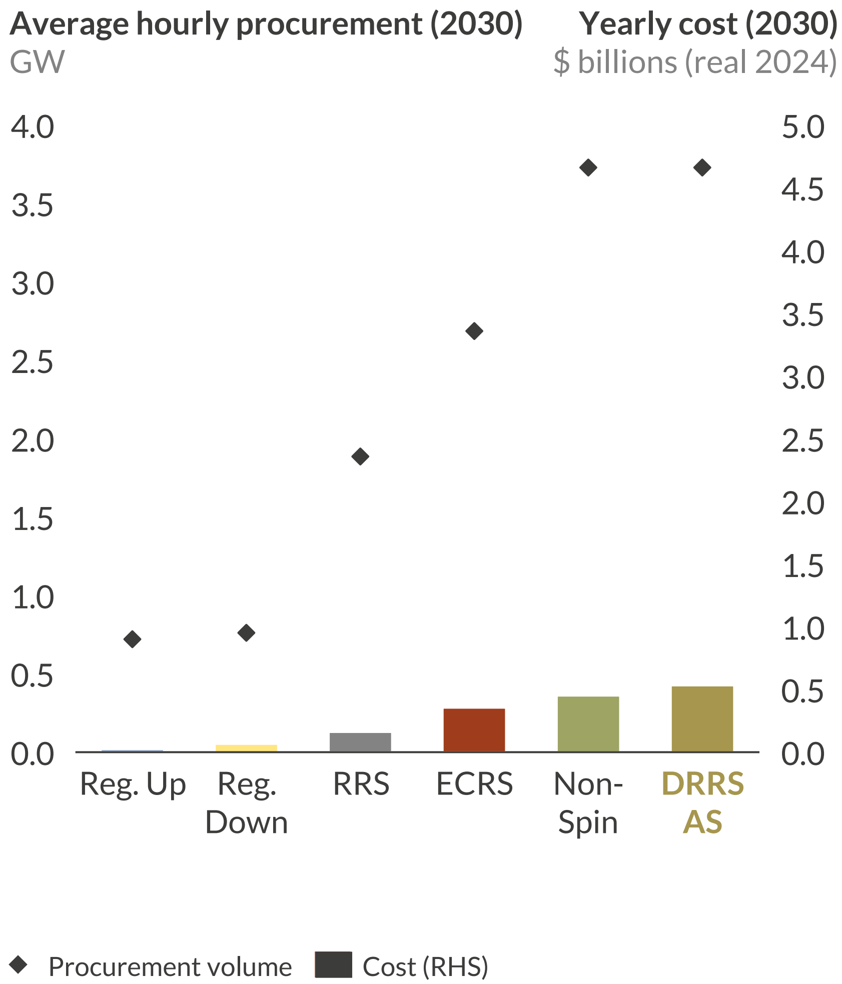
Batteries eligible[1]





- DRRS Ancillary Service incentives 1.1GW of additional dispatchable capacity by 2030.
- In the case where batteries are eligible (assuming a nameplate duration of at least 4-hours) 400MW of 4-hour duration batteries build in response to DRRS AS.
- The yearly gross cost of DRRS in 2030 is $532mn. Allowing battery participation increases competition and reduces prices in DRRS relative to the case where batteries are ineligible.

1) To qualify, systems must have a 4-hour nameplate duration. Energy storage systems with shorter durations are ineligible, regardless of any derating applied to align with the 4-hour threshold.

Sources: Aurora Energy Research

ERCOT LTLF | DRRS Ancillary Service has limited impact on reliability under extreme weather conditions

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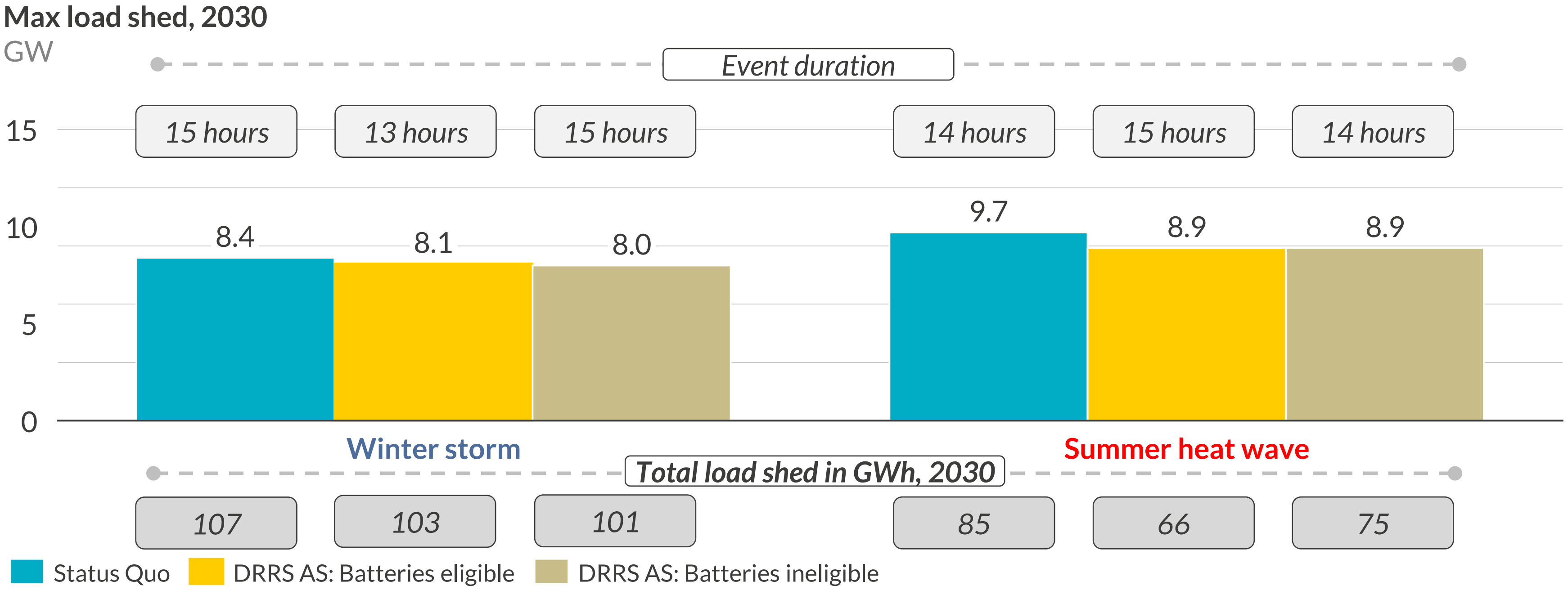

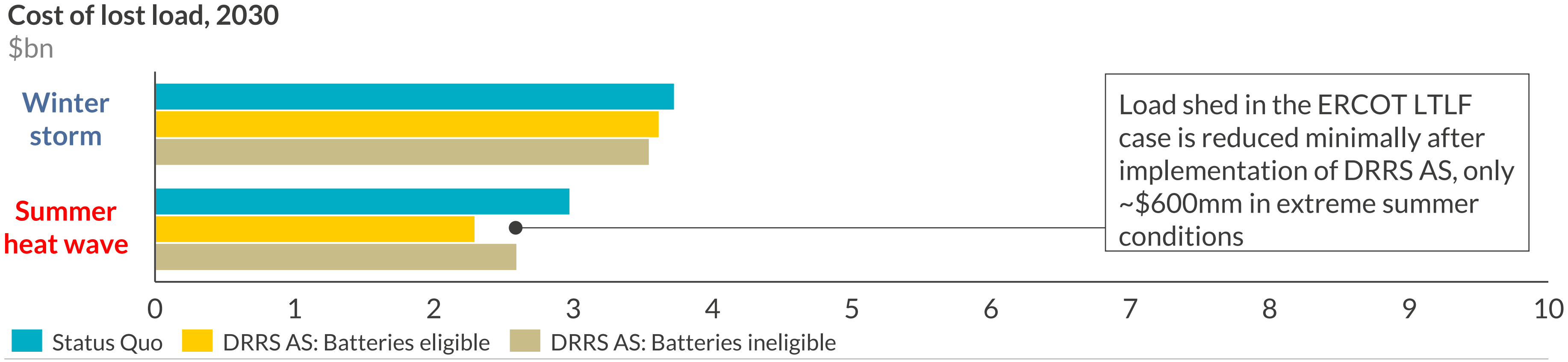

- Load-shedding events are slightly impacted by the DRRS AS mechanism, cutting load shed volumes on average by 11% across extreme summer and winter events.
- Both maximum and total load shed remain high, as DRRS AS has a minimal effect on scarcity dynamics over the course of the event, with only a small increase in available capacity compared to the status quo.
- Based on a $35,000/MWh value of lost load, DRRS AS brings costs down by up to $200mm for winter storms and $600mm for summer heat wave events.

Sources: Aurora Energy Research

DRRS Ancillary Service Plus would be designed to incentivize long-duration dispatchable resources

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Overview DRRS Ancillary Service Plus provides an hourly payment for all available and eligible dispatchable resources

What is DRRS Ancillary Service Plus?

- Unlike DRRS strictly as an ancillary service, DRRS Ancillary Service Plus is an **hourly availability payment** designed to satisfy long-term resource adequacy needs, as opposed to short-term operational requirements.
- DRRS Ancillary Service Plus would remunerate eligible dispatchable generators for being available to the system for dispatch, rather than for providing an ancillary service.

What is the desired impact?

- Compensate dispatchable assets, when revenues generated from the energy and ancillary services markets are below peaker gross CONE[1].
- Incentivize **greater investment in flexible dispatchable resources,** with a focus on long-duration asset classes.
- Improve the retention of aging dispatchable resources.
- Provide additional resource availability during periods of system stress.

What is the requirement to receive an availability payment?

- Participating plants must be dispatchable and available to the market.

*Aurora's modeling intends to **capture the conceptual approach of DRRS Ancillary Service Plus, but the final implementation may differ.***

Modeling Aurora has considered several key parameters when modeling DRRS Ancillary Service Plus

Eligibility by technology class

- Non dispatchable resources, such as wind and solar, are ineligible.
- Aurora modeled two cases:
  1. Only compliant thermal resources eligible
  2. Same as 1) plus 4+ hour nameplate BESS eligible to participate[2]

Availability by technology class

- Technology level availabilities are based on historical availability by month for thermal assets.

DRRS Ancillary Service Plus annual budget

- The annual budget is **based on peaker net CONE[1]** and total eligible capacity from the prior year.
- Any peaker that is fully available throughout the current operating year can recoup its missing money from the prior year.
- The annual **gross budget is capped at $5 billion** and can be reduced if average reserve margins are sufficiently high.

DRRS Ancillary Service Plus hourly payment

- Hourly procurement targets are set similarly to ancillary services and are based on projected needs for dispatchable resources by hour and month.
- Procurement volumes are passed through a demand curve that translates each hourly target into a corresponding budget allocation.
- Higher payments are concentrated during hours of high system stress.

1) Cost of New Entry. 2) Aurora has modeled a case in which batteries are eligible if their nameplate duration is at least 4-hours.

Sources: Aurora Energy Research

The total annual budget for DRRS is based on the prior year's peaker net CONE, with reserve margin adjustments to reflect the state of resource adequacy

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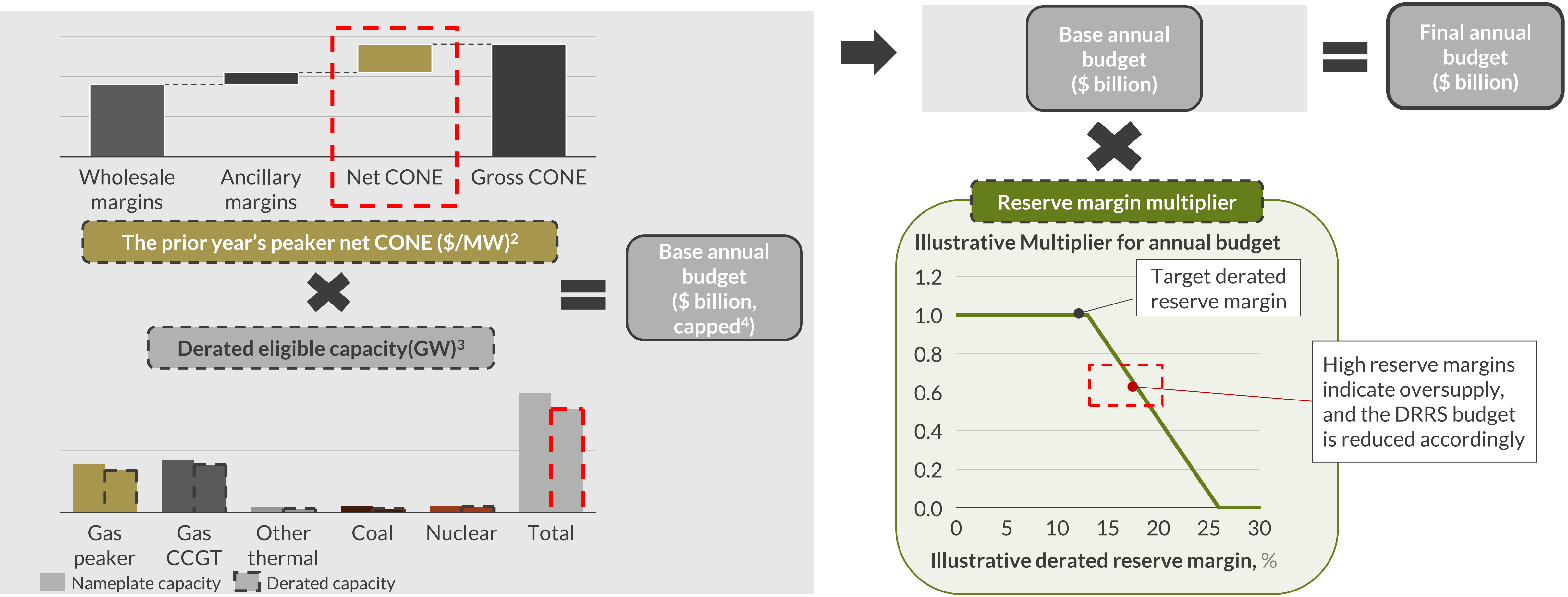
Illustrative

The base annual budget is first calculated as the prior year's peaker net CONE[1] multiplied by total derated eligible capacity, capped at $5 billion per year. Then, a multiplier based on the prior year's reserve margins will be applied to the base annual budget to reach the final annual budget.

Illustrative Annual Budget Allocation Mechanism[1]



1) This shows Aurora's view of ERCOT DRRS AS Plus's conceptual design, but actual mechanism may differ from the final ERCOT proposed design. 2) Cost of New Entry ($/MW). 3) De-ratings are based on forecasted availabilities. 4) Gross budget is capped at $5 billion.

Sources: Aurora Energy Research

DRRS AS Plus's hourly budget is determined by the procurement target and demand curve, concentrating payments during periods of highest stress

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Illustrative

Once determined, the annual budget will be allocated throughout the year according to procurement targets. The demand curve will concentrate hourly payments during periods of greatest anticipated system stress.

Hourly Budget Allocation Mechanism[1]

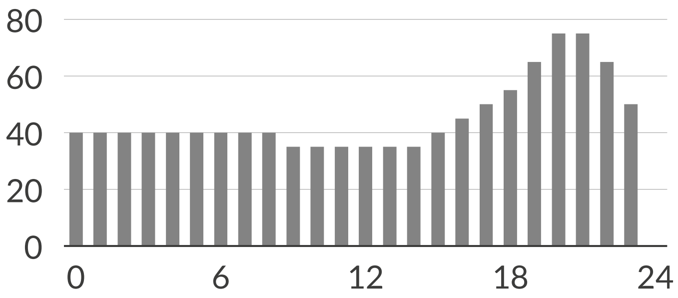
Based on the hourly procurement target, seasons and hours with higher demand will receive a larger share of the budget.

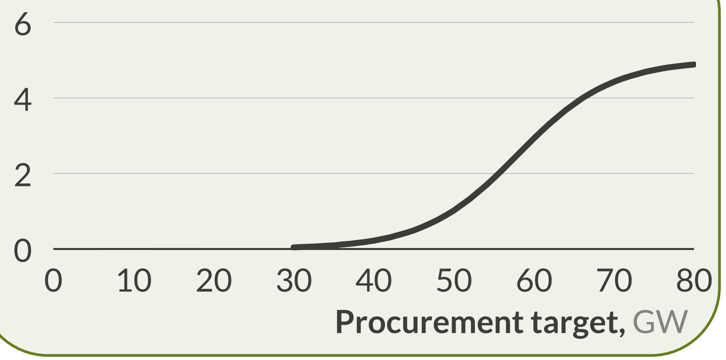
Final annual budget ($ billion) → Base hourly budget by season($ million)

×

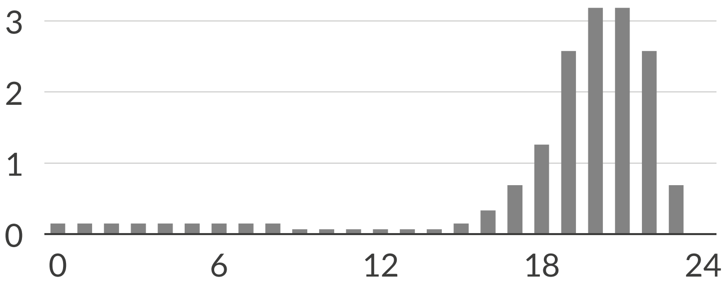
Hourly procurement target(GW) → Demand curve

= Hourly budget ($ million) → Hourly payment ($/MW)





Hourly budget
$ million



Procurement targets will be set for each month and hour of day, reflecting the anticipated need for dispatchable capacity.

The budget allocation curve rises during periods with higher demand and reliability risks and decreases during hours of lower needs.

The final hourly budget for a given month set at the beginning of the year will then be allocated hourly across all eligible and available capacity.

1) This shows Aurora's view of ERCOT DRRS AS Plus's conceptual design, but actual mechanism may differ from the final ERCOT proposed design.

Sources: Aurora Energy Research

DRRS AS Plus | ~5 to 6GW of gas peaking is added by 2030 and ~3GW of batteries capacity is reduced in the case without battery eligibility

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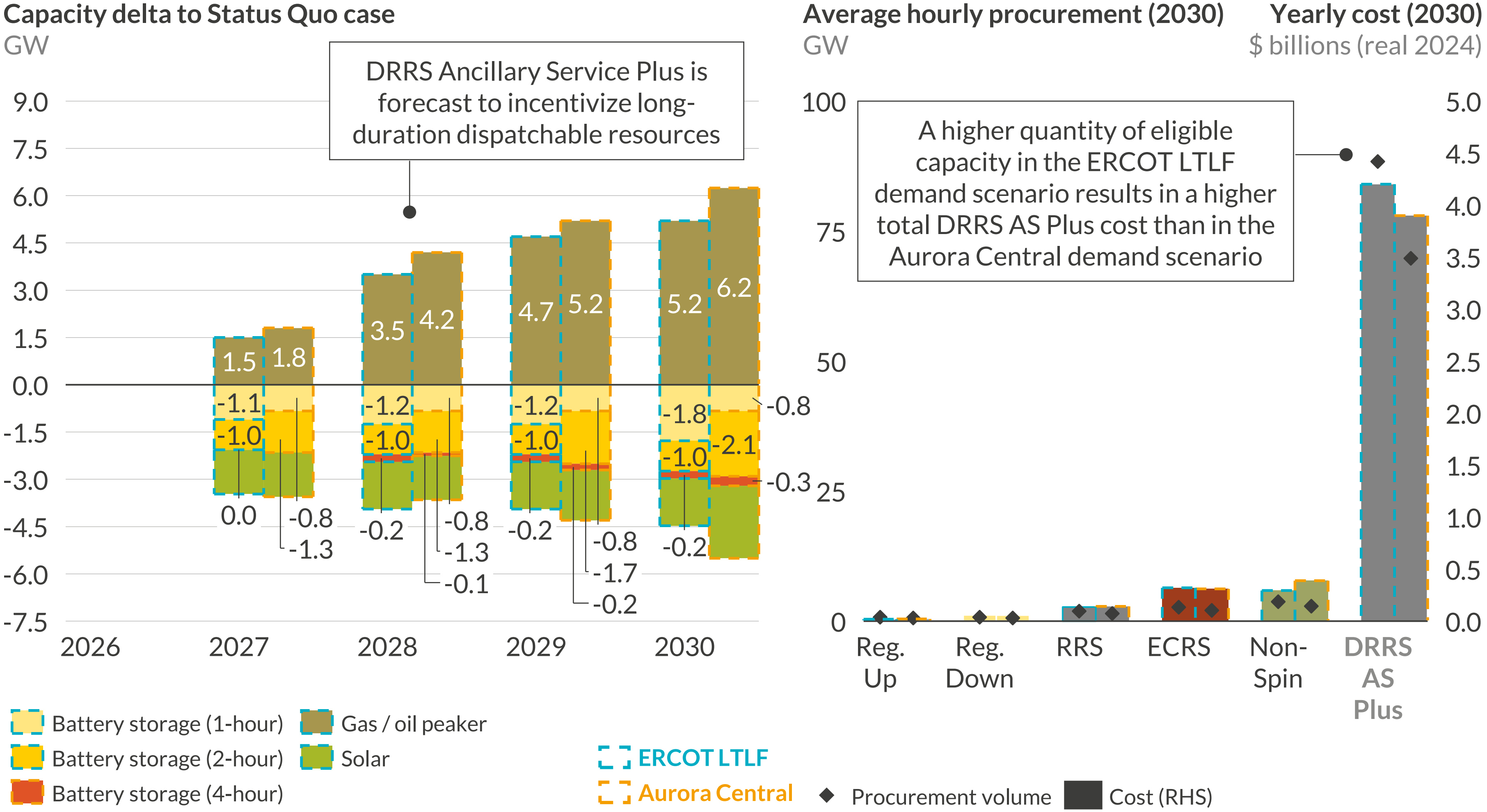
Batteries ineligible



- DRRS Ancillary Service Plus is forecast to incentivize 5.2 to 6.2GW of additional dispatchable capacity by 2030 from gas fired peaking plants.
- DRRS Ancillary Service Plus remunerates all available resources that meet eligibility requirements. Between 2027 and 2030, DRRS AS Plus compensates an average of 77.8GW of capacity per hour in the ERCOT LTLF case.
- The gross cost of DRRS AS Plus in 2030 is $4.2bn in the ERCOT LTLF case and $3.9bn in the Aurora Central load case. The total cost injection from DRRS is determined based on peaker net CONE from the prior year but is capped at $5bn.

Sources: Aurora Energy Research

DRRS AS Plus | With BESS eligibility, 4-5GW of gas peaking and 2-3GW of 4h+ BESS is added, while ~3GW of shorter duration BESS is reduced

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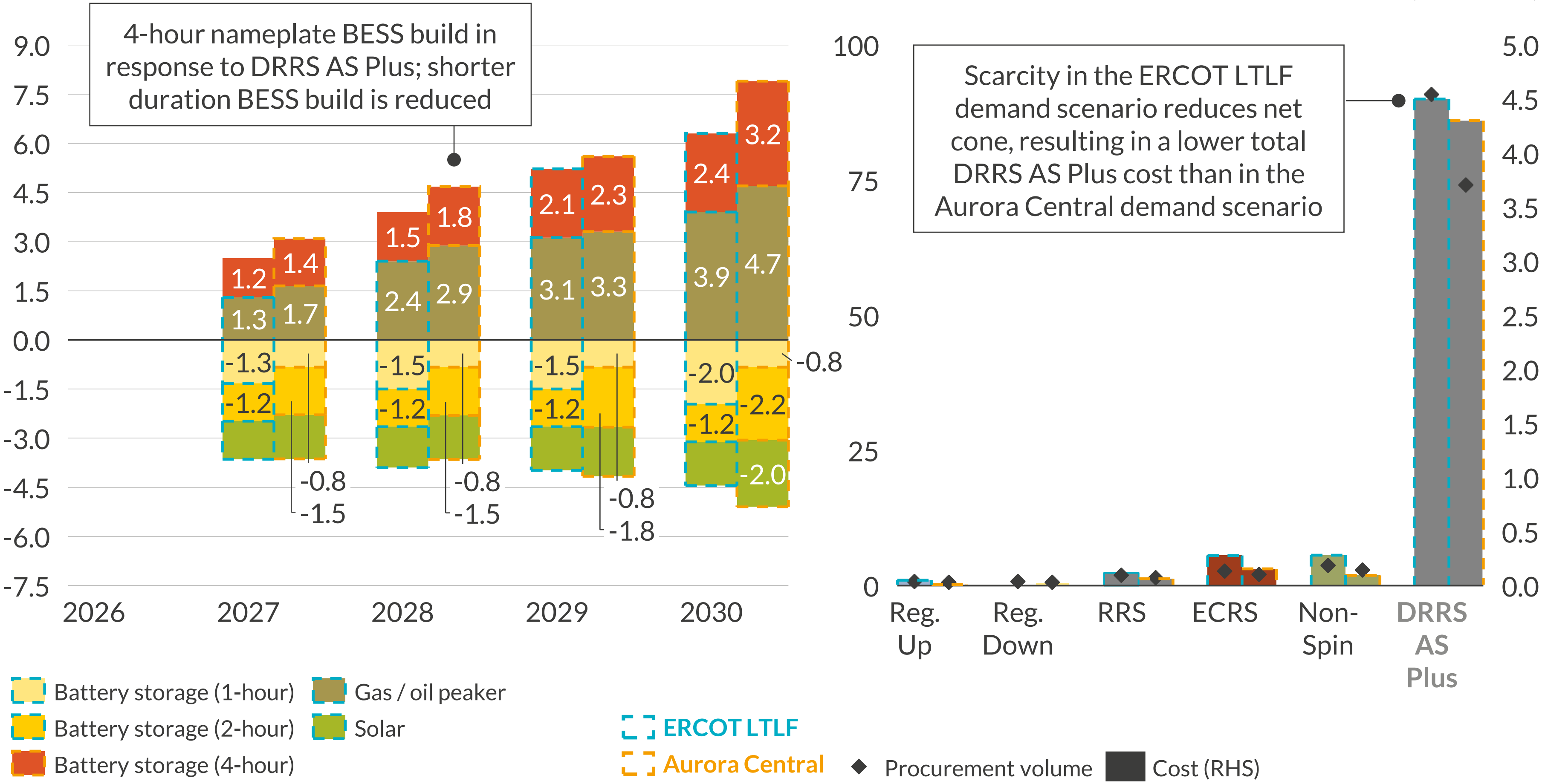
Batteries eligible[1]

Capacity delta to Status Quo case
GW

Average hourly procurement (2030)
GW

Yearly cost (2030)
$ billions (real 2024)



1) To qualify, systems must have a 4-hour nameplate duration. Energy storage systems with shorter durations are ineligible, regardless of any derating applied to align with the 4-hour threshold.

- DRRS Ancillary Service Plus incentivizes 6.3 to 7.9GW of additional long-duration dispatchable capacity by 2030. The capacity is primarily gas fired peaking with some 4-hour duration batteries.
- While DRRS incentivizes long-duration assets, it disincentivizes short-duration storage and renewables, resulting in 3.0GW and 2.0GW less 1- and 2-hour BESS and solar PV capacity, respectively, by 2030.
- The gross cost of DRRS AS Plus in 2030 is $4.5bn in the ERCOT LTLF case and $4.3bn in the Aurora Central load case. The total cost injection from DRRS is determined based on peaker net CONE from the prior year but is capped at $5bn.

Sources: Aurora Energy Research

Aurora Central | DRRS AS Plus greatly reduces load shedding, with costs under a winter storm event falling by $2.7bn

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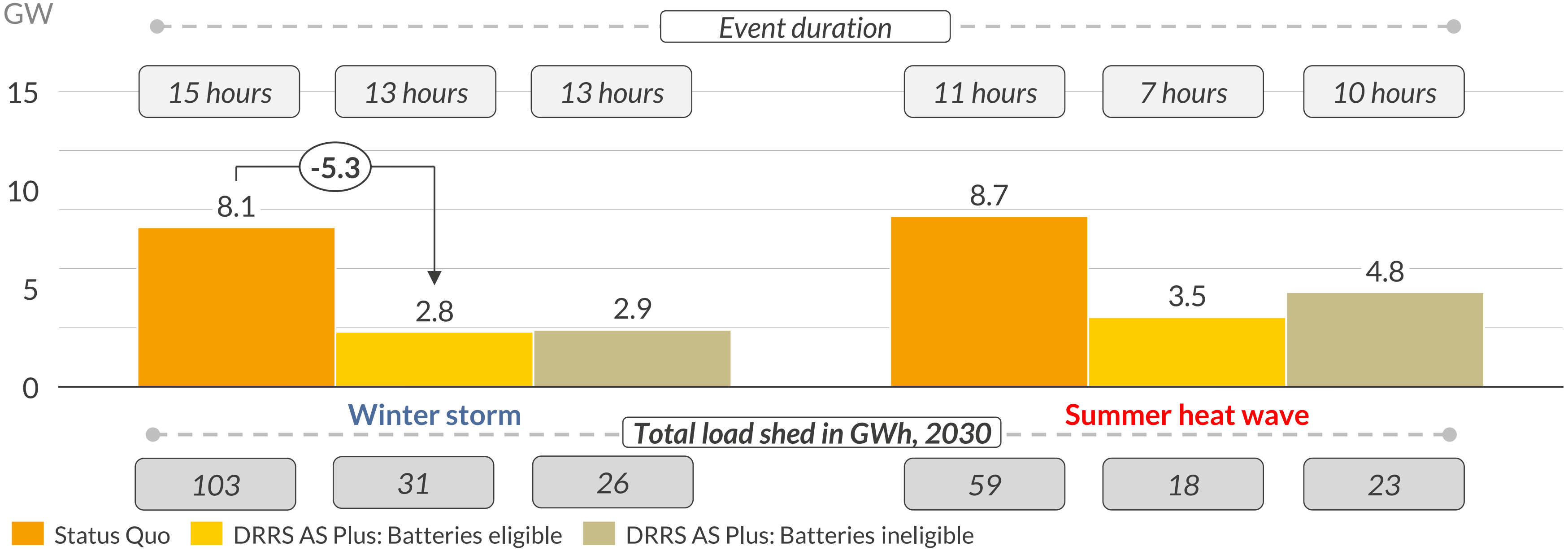
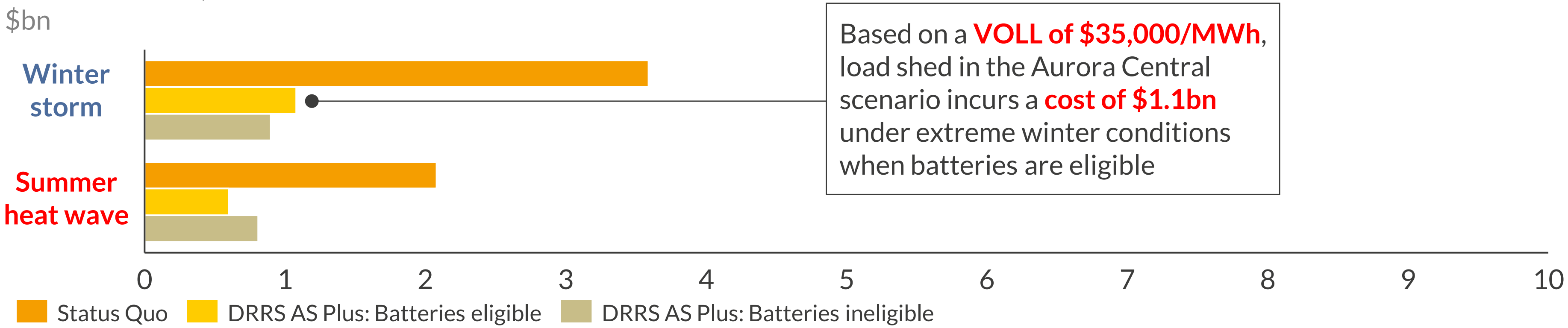
Max load shed, 2030
GW



Cost of lost load, 2030
$bn



- Load shedding events are significantly reduced by the DRRS Ancillary Service Plus mechanism.
- Maximum load shed is most severe under summer heat wave conditions in Aurora's Central case, reaching 8.7GW of lost load during the tightest hour. With battery ineligible DRRS AS Plus, maximum load shed decreases to 4.8GW.
- Based on a $35,000/MWh value of lost load, battery ineligible DRRS Ancillary Service Plus brings costs down by $2.7bn for winter storms and $1.7bn for summer heat wave events.

Sources: Aurora Energy Research

ERCOT LTLF | Savings under the DRRS AS Plus mechanism average $2bn across scenarios, cutting load shed volumes by nearly half

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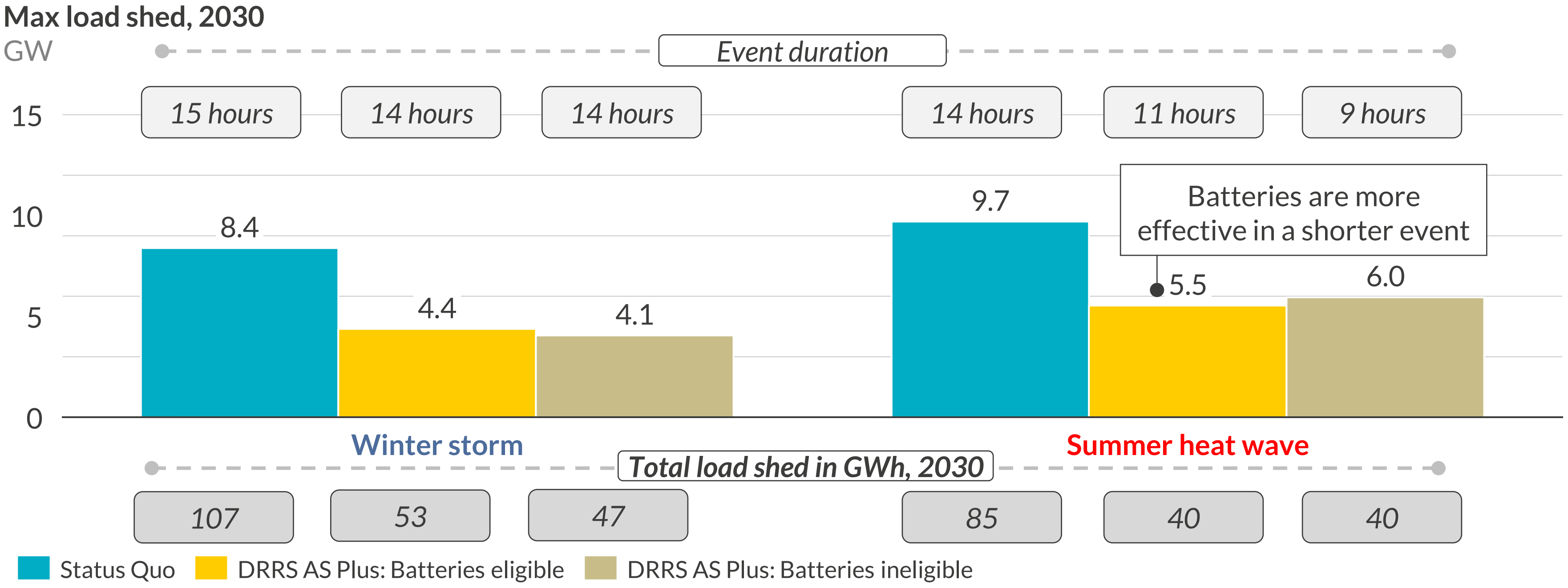

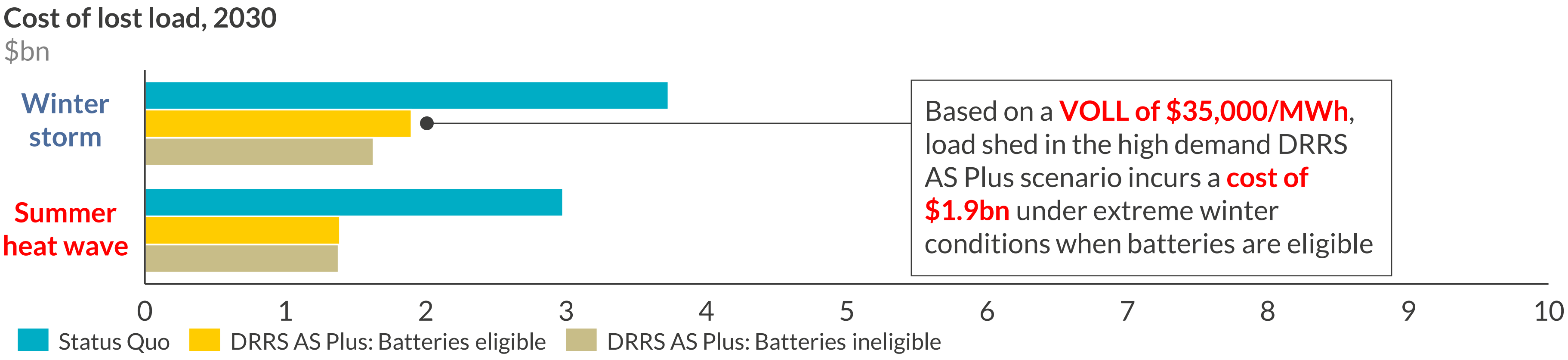

- Load shedding events are reduced by the DRRS AS Plus mechanism, cutting load shed volumes on average by 40% across extreme summer and winter events.
- Total load shed is most severe in the LTLF demand case under winter storm conditions, when maximum load shed reaches 8.4GW and 106.7GWh of energy is unserved over the course of a 15-hour event.
- Based on a $35,000/MWh value of lost load, DRRS Ancillary Service Plus brings costs down by $2.1bn for winter storms and $1.6bn for summer heat wave events.

Sources: Aurora Energy Research

Agenda

The Extended ORDC scenario curve remains capped at $5,000/MW, but provides additional value at PRC levels above 3,000MW

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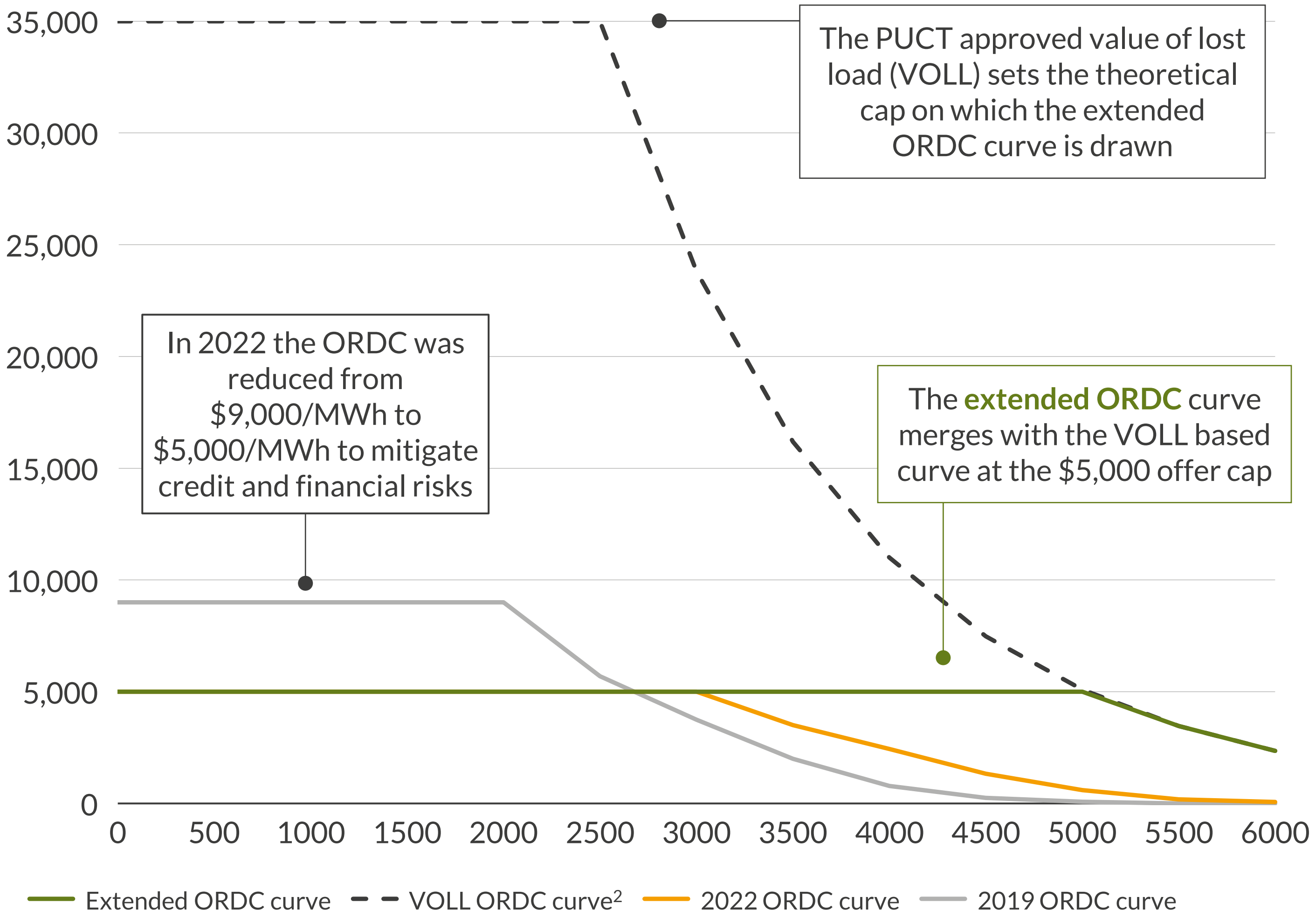
ORDC overview and background

- The Operating Reserves Demand Curve (ORDC) was introduced in 2014 to incentivize investment in new capacity. The curve is adjusted seasonally.
- When reserve margins are tight, the adder is applied according to a set formula that accounts for the value of lost load and probability of losing load for a given level of operating reserves.
- After the events of Feb 2021, the PUCT reduced the market cap to $5,000/MWh effective January 2022.

Proposed design change

- An extended ORDC curve increases prices during system stress when the PRC is below 6,000MW.
- Aurora models an extended ORDC curve that increases scarcity **value by nearly 2x, by having more frequent price spikes.**
- Higher scarcity value provides an investment signal and **encourages performance during system stress.**
- An extended curve provides similar value with less credit and financial risk than raising the cap.

ORDC adder price across PRC[1] levels
$/MWh



1) Physical Responsive Capability. 2) The Public Utility Commission of Texas approved a VOLL of $35,000 in August 2024. 2) Aurora's modeling intends to capture the conceptual approach of an extended ORDC, but the final implementation may differ.

Sources: Aurora Energy Research

ERCOT LTLF | The Extended ORDC case incentivizes 3.7GW of additional dispatchable capacity and 0.3GW of renewables by 2030

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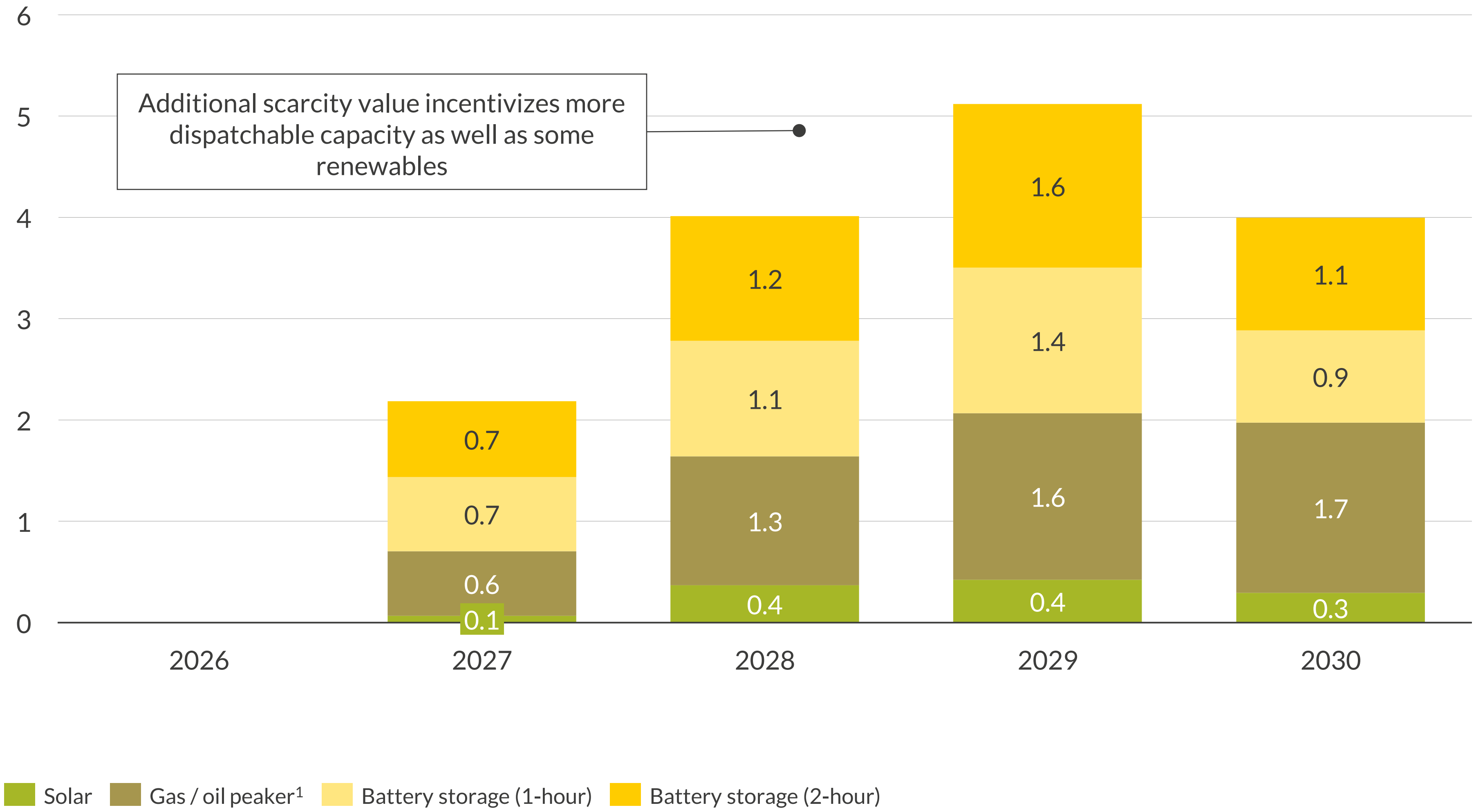
Capacity delta to Status Quo case (LTLF demand)
GW



1) Peaking includes OCGT, and reciprocating engines.

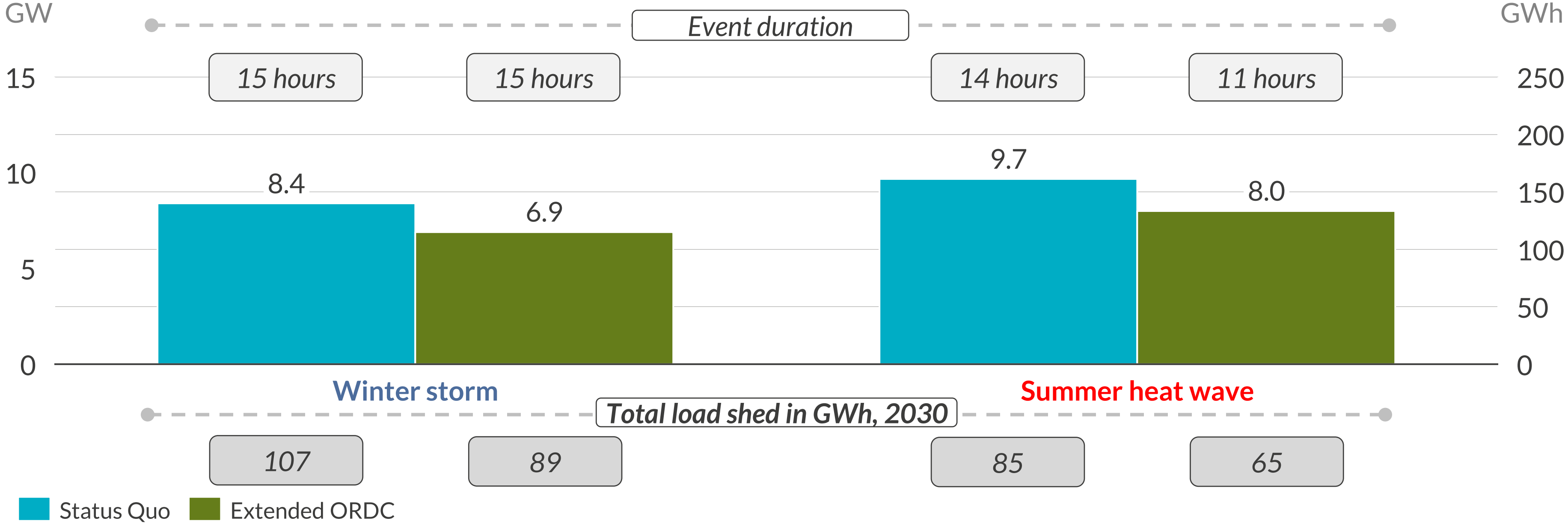
- Elongating the ORDC curve provides additional scarcity value to the system, encouraging more flexible assets and some renewables to build.
- The flexibility of assets such as peakers and batteries enables them to capitalize on higher scarcity value, which often occurs during periods of low renewables generation and high load.
- Although solar economics improve with an elongated ORDC curve, improvements are minimal. Additional ORDC value is primarily concentrated in the evening, when net load is highest and solar is no longer producing.
- The extended ORDC magnifies existing investment signals, incentivizing more short-duration battery storage.

Sources: Aurora Energy Research

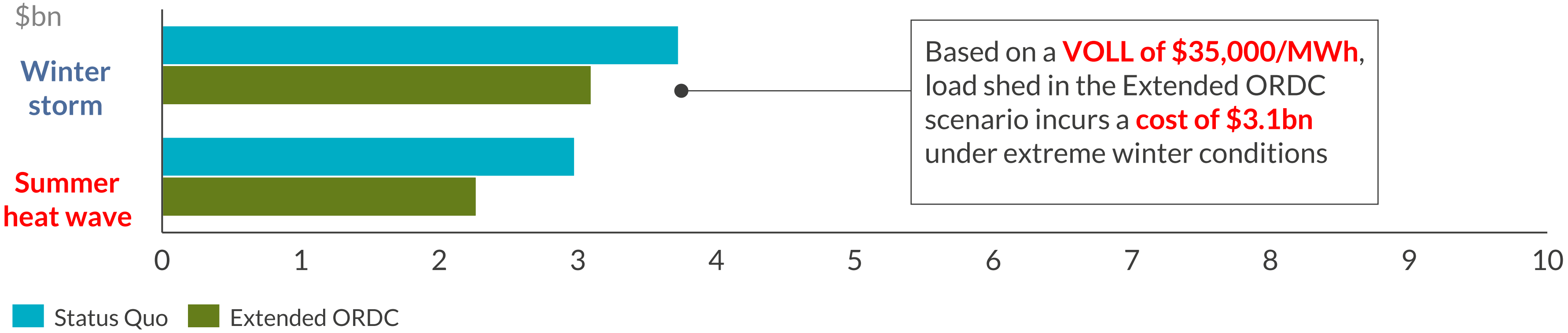
ERCOT LTLF | Under the Extended ORDC, load shed during extreme weather events is reduced by under 2GW, reducing costs by $0.7bn

Max load shed, 2030
GW

Total load shed, 2030
GWh



Cost of lost load, 2030
$bn



- Load-shedding events occur under both extreme summer and winter conditions in the Extended ORDC case.
- Both maximum and total load shed are reduced in winter and summer periods, decreasing max load shed by 1.7GW in summer heat wave conditions.
- Based on a $35,000/MWh value of lost load, in all modeled cases, load shedding events would cost over $2bn, with the most severe case costing $3.7bn. The extended ORDC would reduce cost under these load shed events by approximately $0.7bn.

Sources: Aurora Energy Research

Agenda

AURORA

I. **Executive summary**

II. **ERCOT's historical resource adequacy in context**

III. **Future resource adequacy challenges in ERCOT**

1. Demand growth
2. Supply risk
3. The impact of extreme weather
4. Demand Side Response (DSR)

IV. **Impact of market design changes**

1. Dispatchable Reliability Reserve Service (DRRS)
2. Operating Reserve Demand Curve (ORDC)
3. Reliability and cost outcomes

V. **Appendix**

ERCOT LTLF | DRRS AS yields a net cost of ~$0.6bn in 2030 and incentivizes just over 1GW of capacity in the battery eligible case

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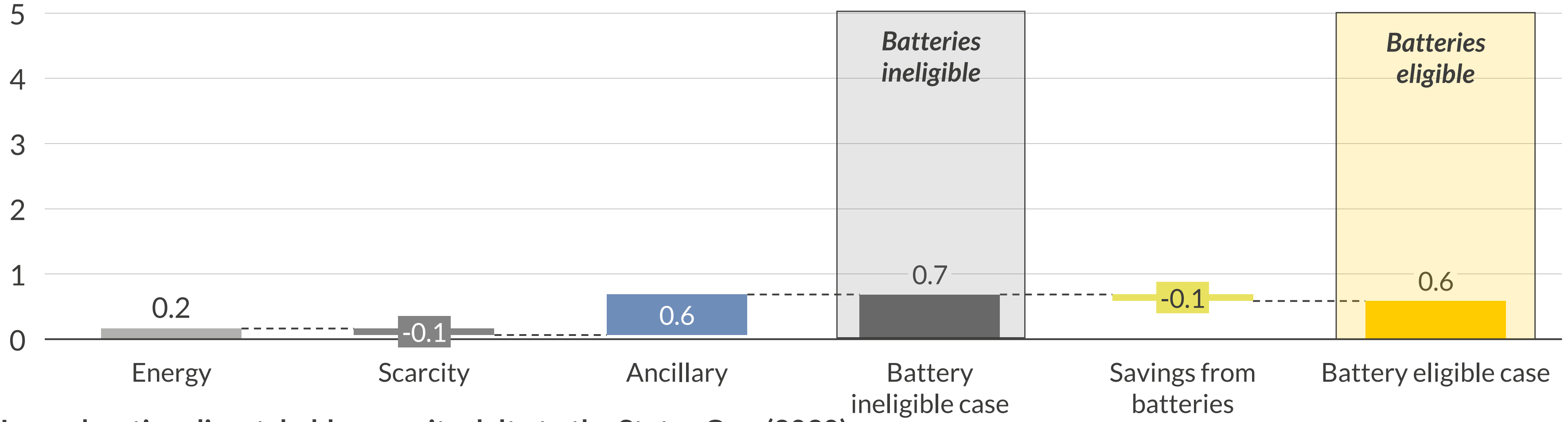
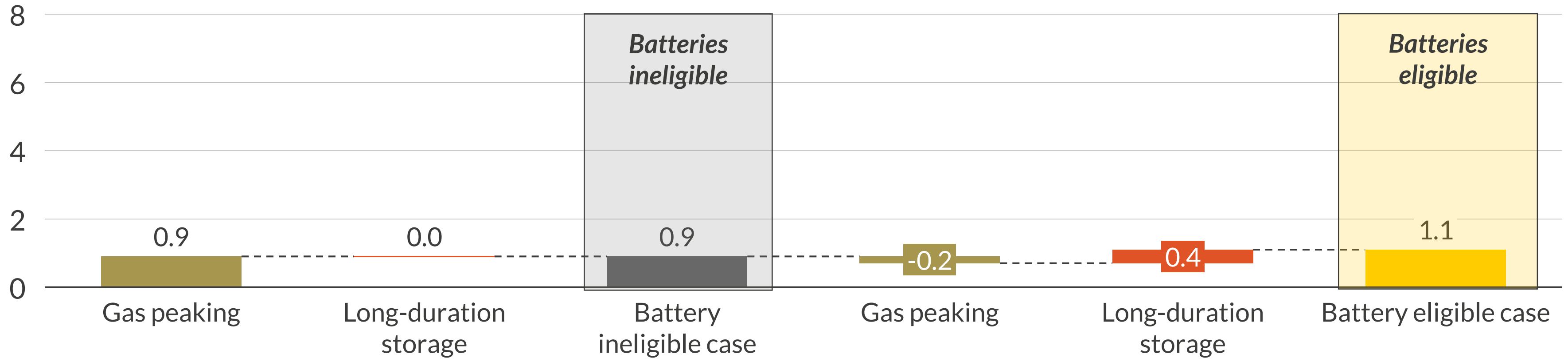
Yearly cost delta to the Status Quo by category (2030)
$ billion



Long-duration dispatchable capacity delta to the Status Quo (2030)
GW



- When implemented as an ancillary service, DRRS has significantly less impact on costs and capacity. This is driven by lower procurement volumes than in the DRRS AS Plus implementation.
- Cost offsets in the wholesale market are limited in the AS case, since unlike in the AS Plus case, procured capacity is unavailable to the wholesale market.
- Capacity increase is limited, with an additional 1.1GW being incentivized by 2030 in the case where batteries are eligible, as the price signal from DRRS AS is not strong enough to incentivize significant supply.

Sources: Aurora Energy Research

ERCOT LTLF | DRRS AS Plus yields a net cost of ~$0.4bn in 2030, with slightly lower costs in the case where batteries are eligible

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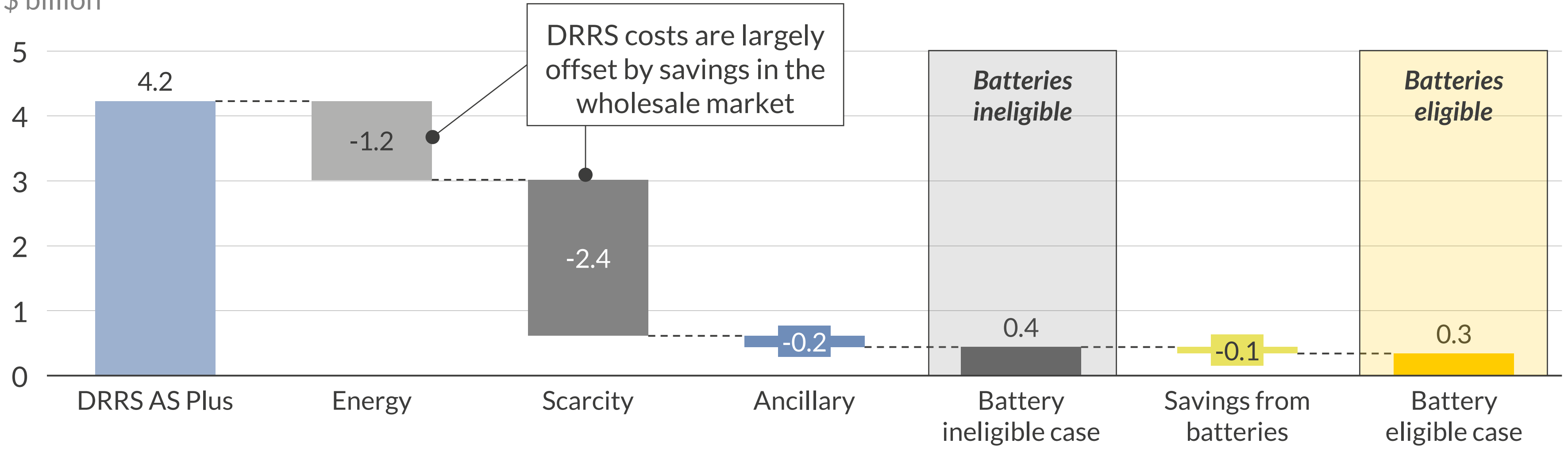
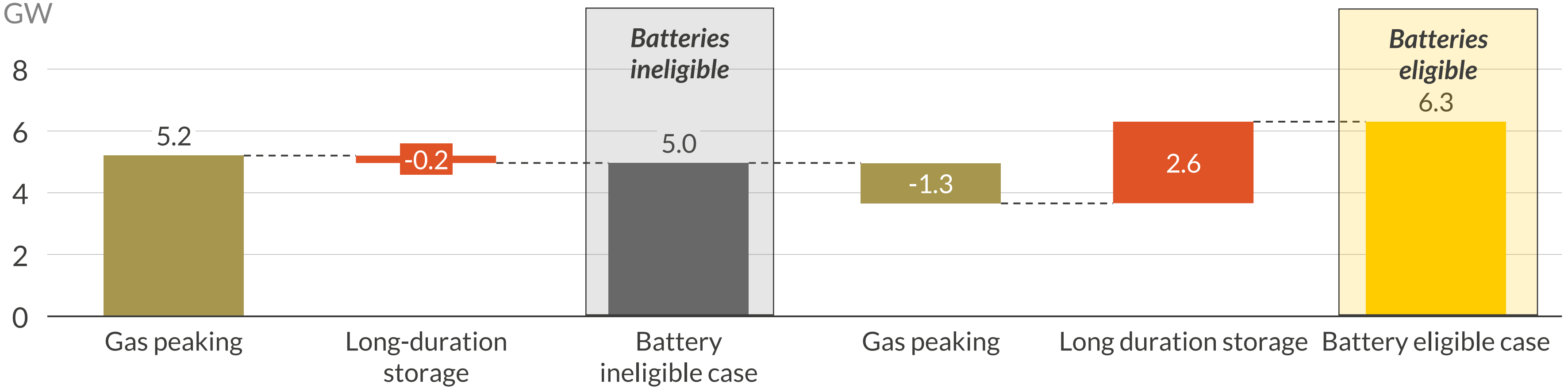
Yearly cost delta to the Status Quo by category (2030)
$ billion



Long-duration dispatchable capacity delta to the Status Quo (2030)
GW



- Under the ERCOT LTLF demand scenario, and in the case where batteries are not eligible to participate, DRRS has a gross cost of $4.2bn in 2030.
- Costs from DRRS are mostly offset by savings in the wholesale market. Savings are created by increased supply, which reduces the cost of energy and scarcity. This effect is most pronounced in the ERCOT LTLF case, which assumes high demand growth by 2030.
- Gas peaking capacity increases by 5.2GW in the case where batteries are ineligible. In the battery eligible case, total long-duration dispatchable capacity rises to 6.3GW.

Sources: Aurora Energy Research

ERCOT LTLF | Extended ORDC yields a net cost of ~$2.2bn in 2030, higher than both variations of DRRS

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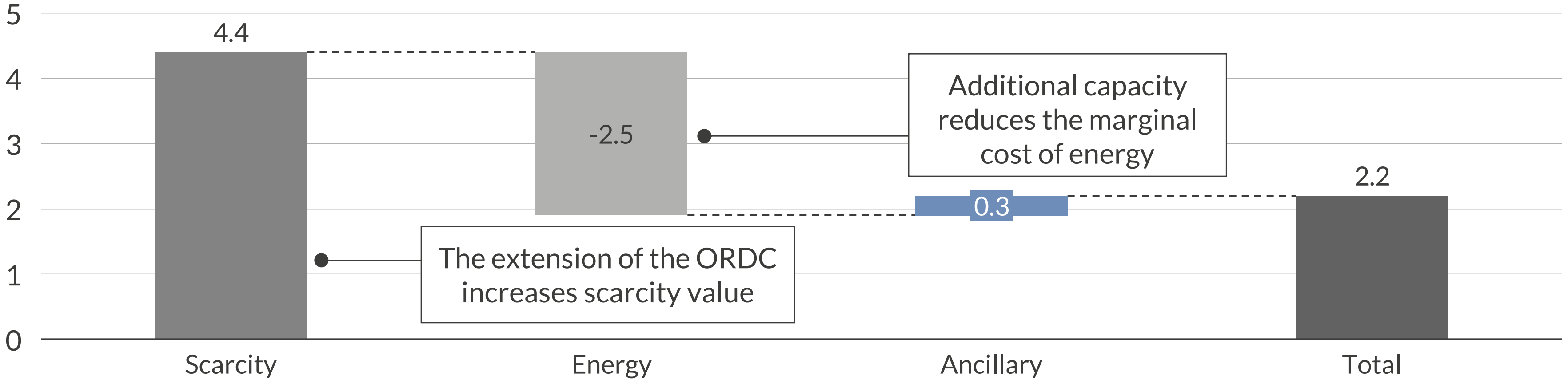
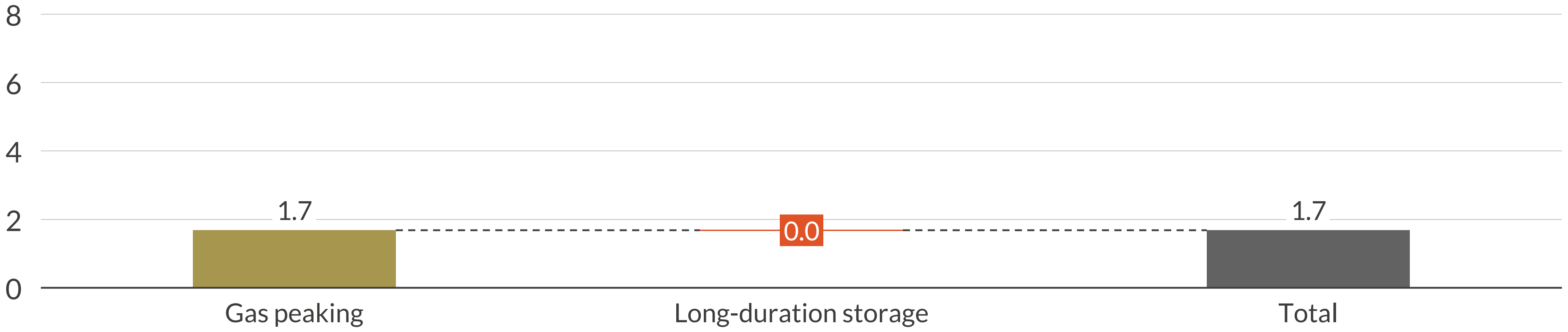
Yearly cost delta to the Status Quo by category (2030)
$ billion



Long-duration dispatchable capacity delta to the Status Quo (2030)
GW



- The Extended ORDC scenario adds significant scarcity value to the system, increasing total net costs by $2.2bn. Scarcity costs are partially offset by decreases in the marginal cost of energy, which are caused by additional capacity.
- Unlike DRRS, an extended ORDC incentivizes short-duration dispatchable resources as well as renewables, since there is not a duration requirement for receiving ORDC payments.

Sources: Aurora Energy Research

ERCOT LTLF | DRRS AS Plus incentivizes net 5GW of long-duration dispatchable capacity at a net $0.4bn cost, while DRRS AS has limited impact

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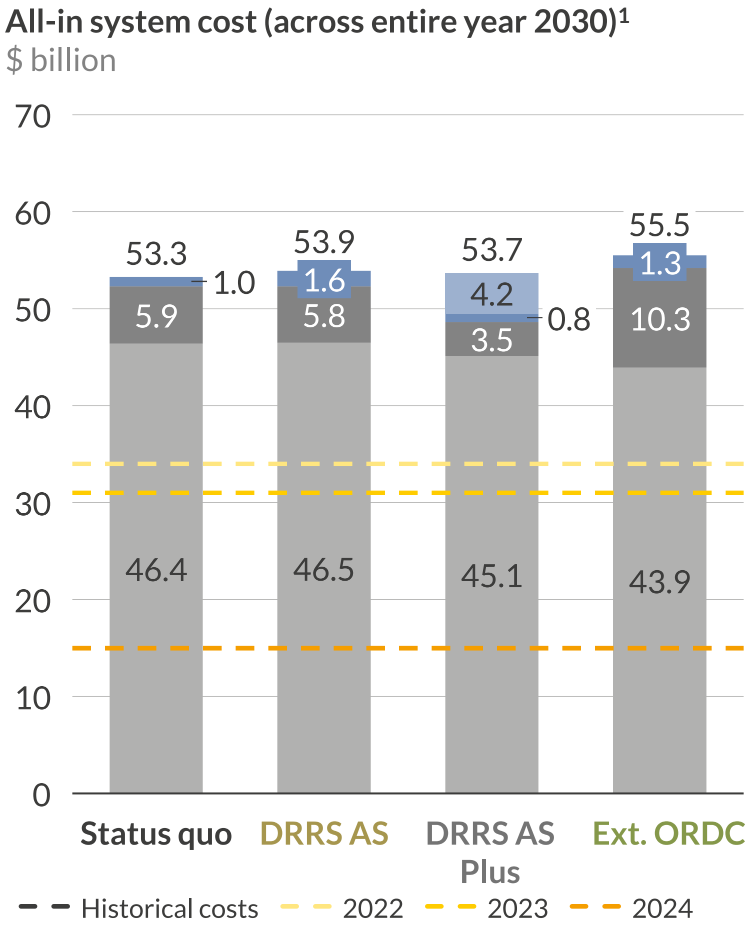
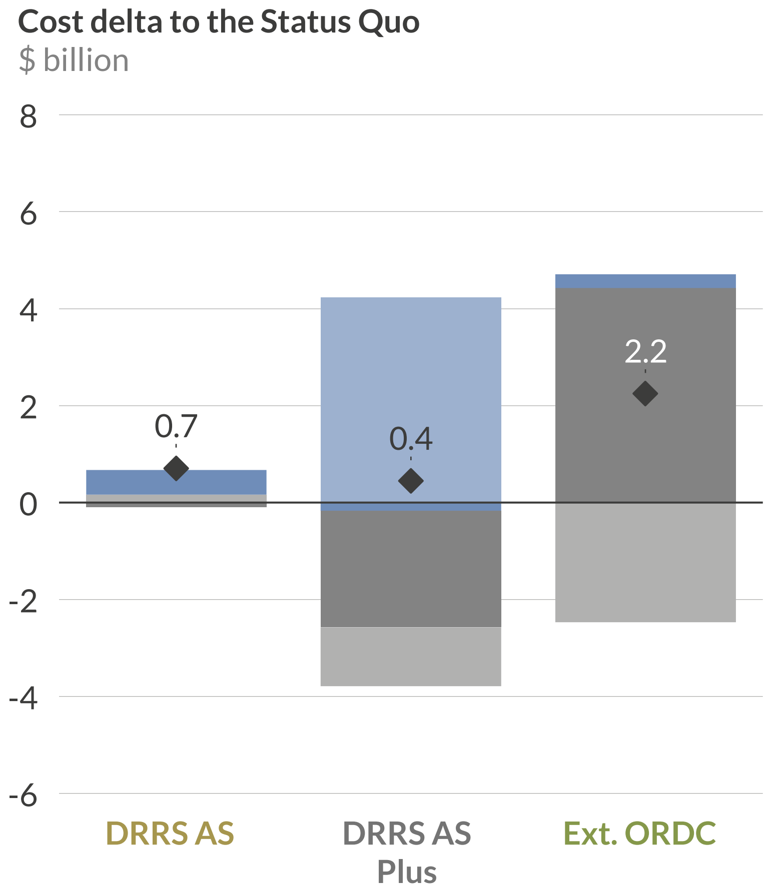
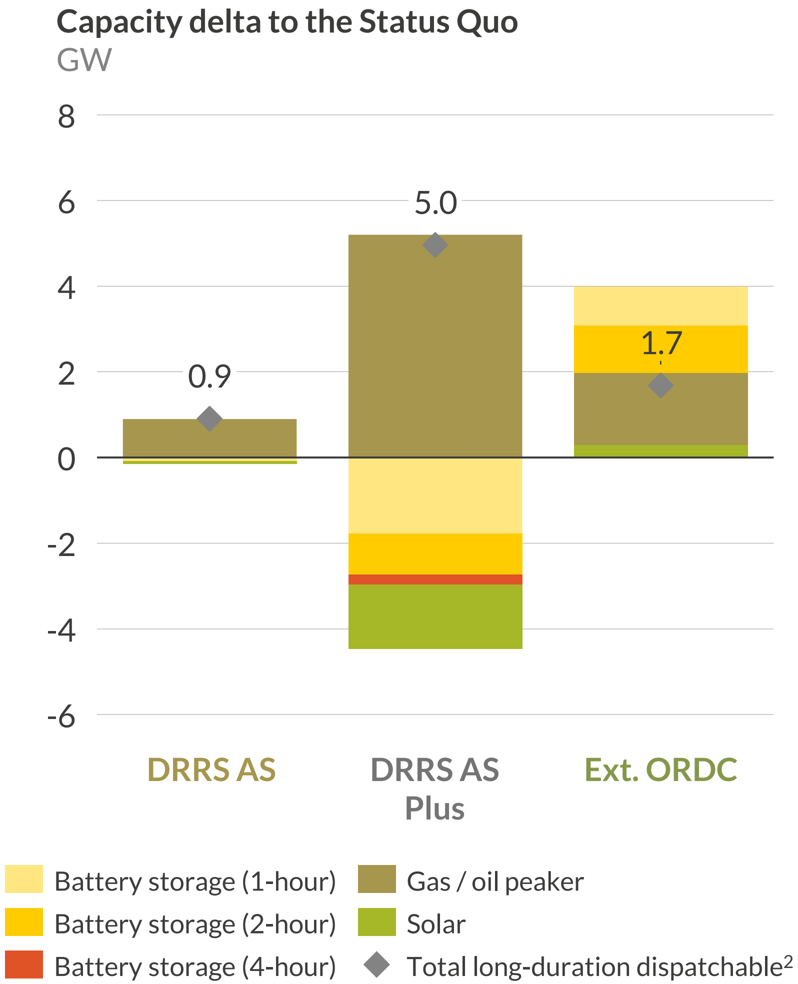
Batteries ineligible







Energy | Scarcity adder | Ancillary services | DRRS AS Plus | Total

1) Under a normal weather year (2013 style weather year). 2) Includes resources capable of running for at least 4 hours.

Sources: Aurora Energy Research

ERCOT LTLF | Battery eligibility in DRRS has limited impact on cost but increases total net additions of long-duration dispatchable capacity to 6.3GW

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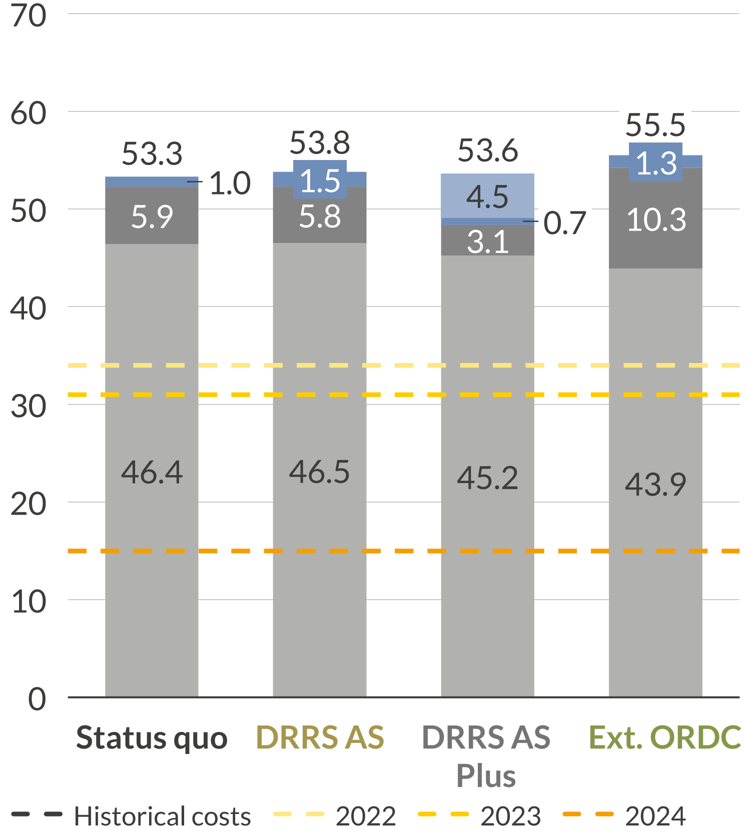
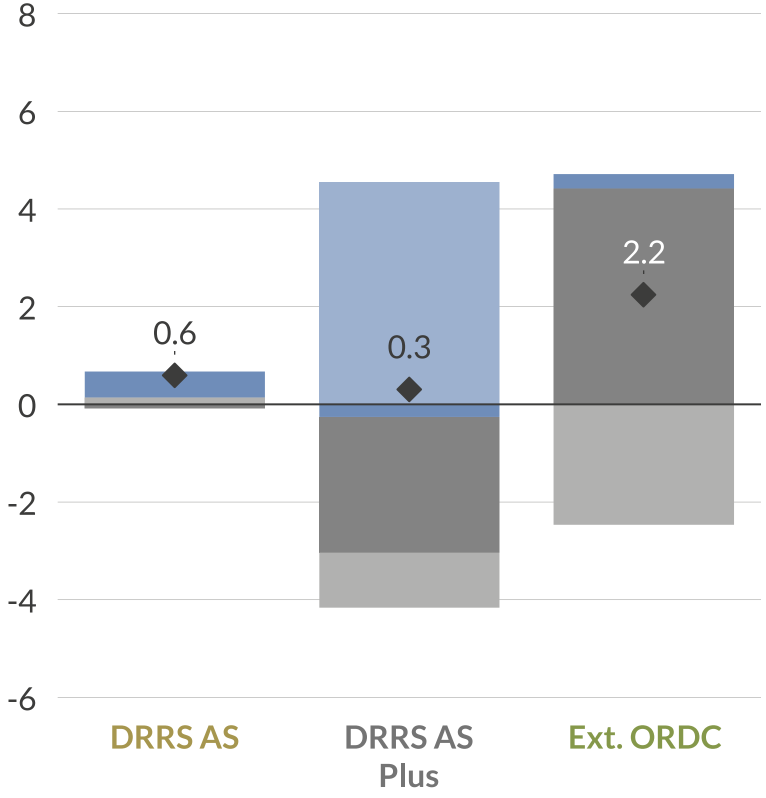
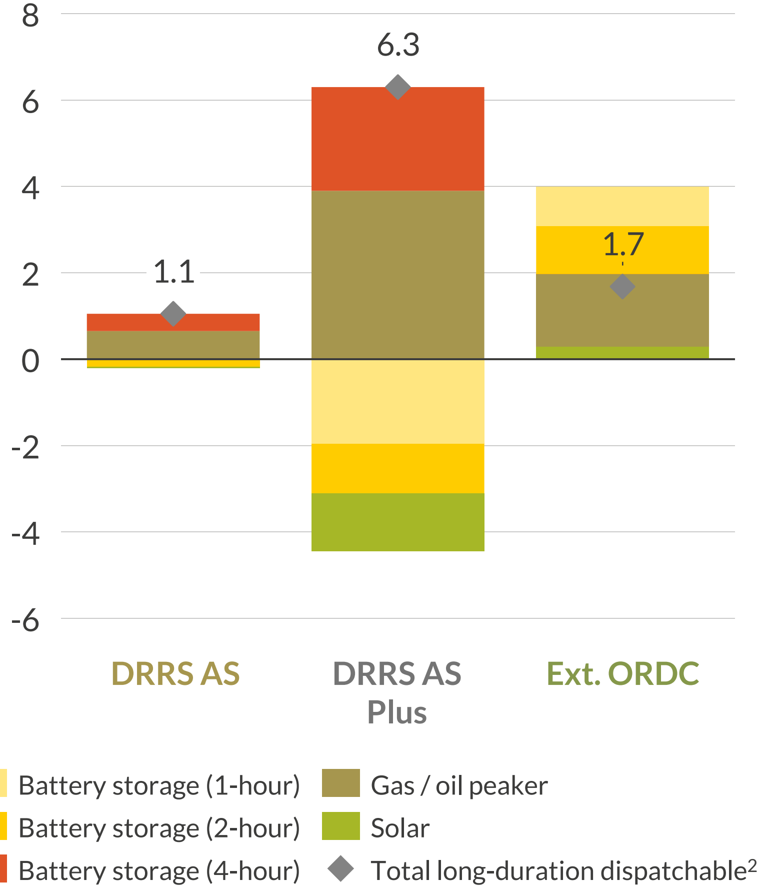
Batteries eligible





Energy | Scarcity adder | Ancillary services | DRRS AS Plus | Total

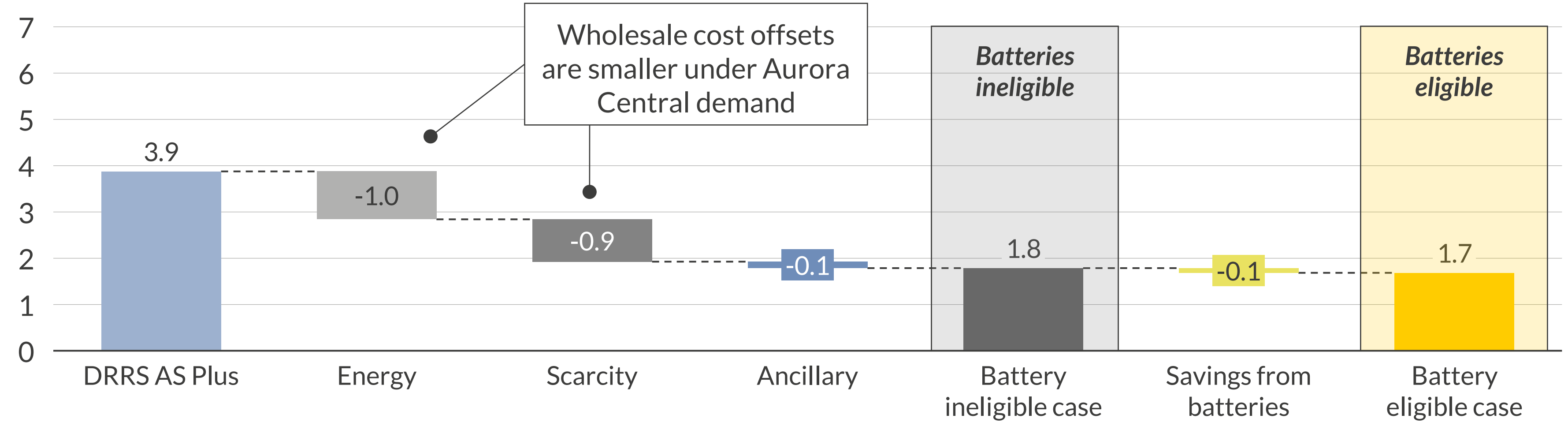


1) Under a normal weather year (2013 style weather year). 2) Includes resources capable of running for at least 4 hours.

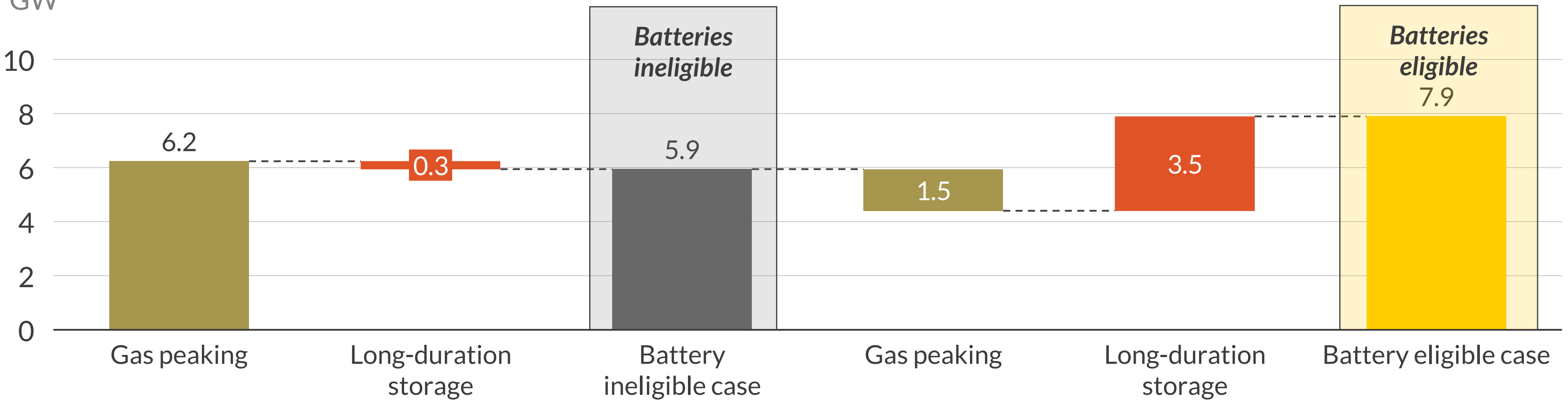
Sources: Aurora Energy Research

Aurora Central | DRRS AS Plus yields a higher net cost under Aurora Central demand, but incentivizes more capacity

Yearly cost delta to the Status Quo by category (2030)
$ billion



Long-duration dispatchable capacity delta to the Status Quo (2030)
GW



- Under the Aurora Central demand scenario, lower demand and prices result in a lower wholesale cost offset, leading to higher net total costs than under LTLF demand conditions.
- Due to a smaller system under the Aurora Central demand scenario, a similar DRRS budget in 2030 relative to the LTLF scenario incentivizes a slightly larger amount of new capacity.
- As in the LTLF case, under Aurora Central demand assumptions, allowing batteries to participate in DRRS increases total capacity.

Sources: Aurora Energy Research

Aurora Central | With batteries eligible, DRRS AS Plus removes a cumulative $2.6bn from the wholesale and ancillary markets, netting a $1.7bn cost

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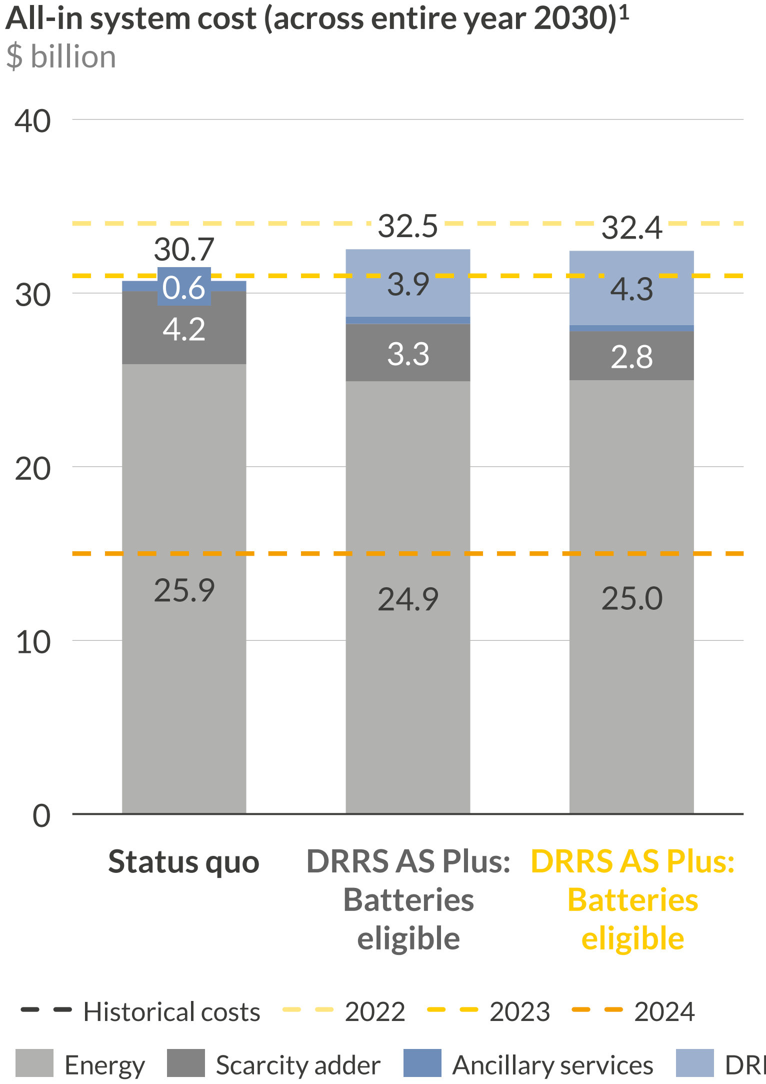
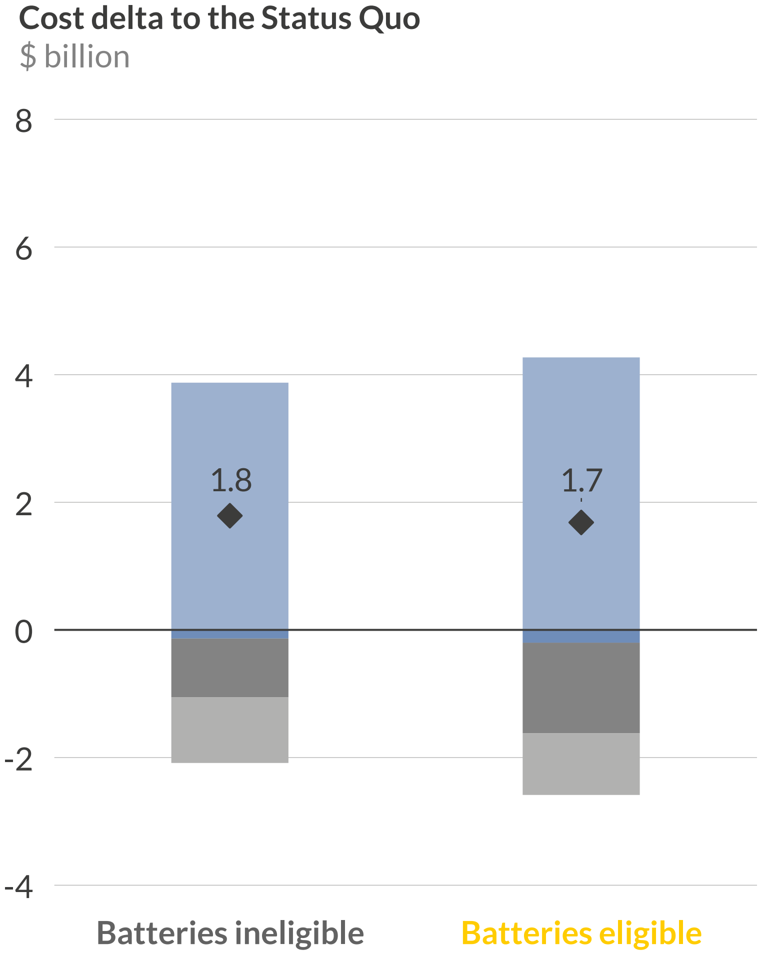
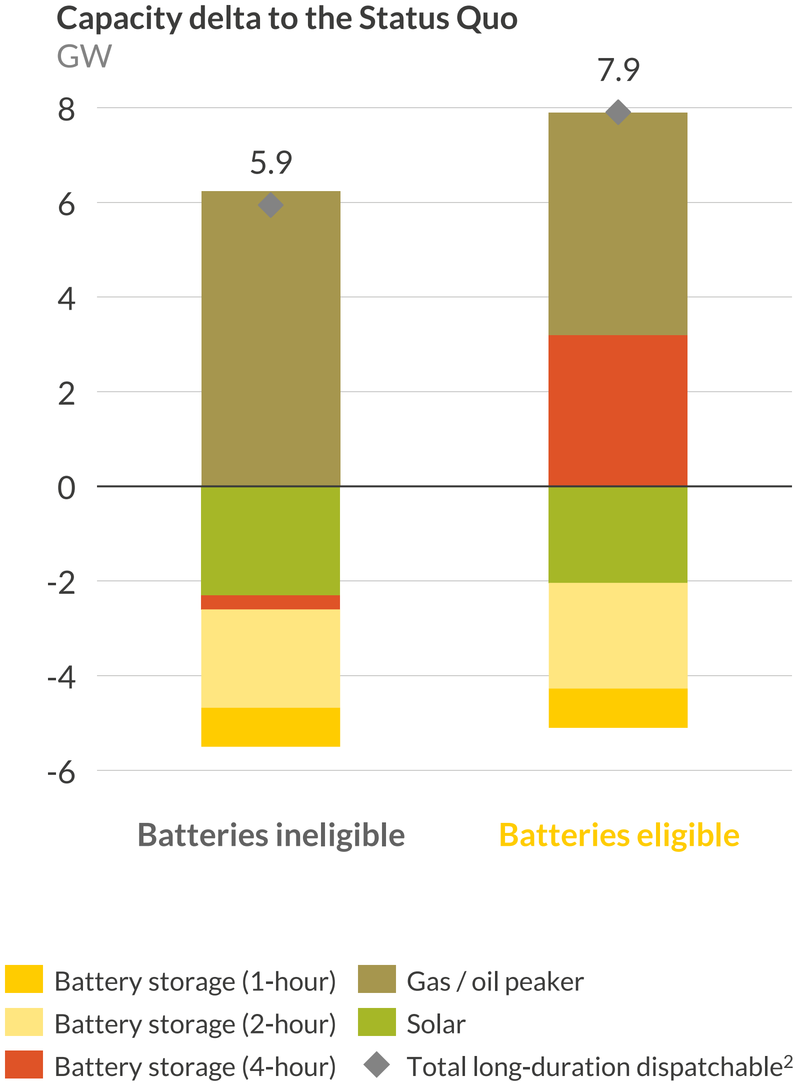






1) Under a normal weather year (2013 style weather year). 2) Includes resources capable of running for at least 4 hours.

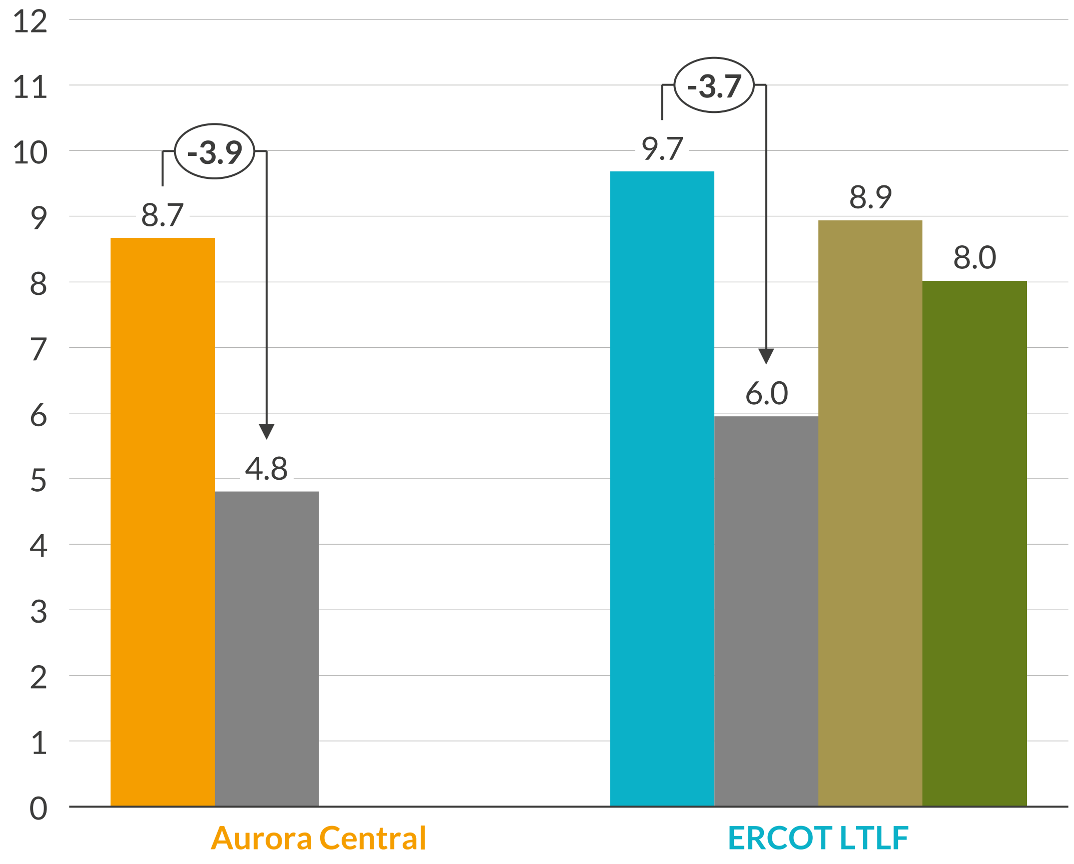
Sources: Aurora Energy Research

In a 2023 WY, DRRS AS Plus provides the most reliability among alternative market designs, reducing total load shed across the year by 432GWh

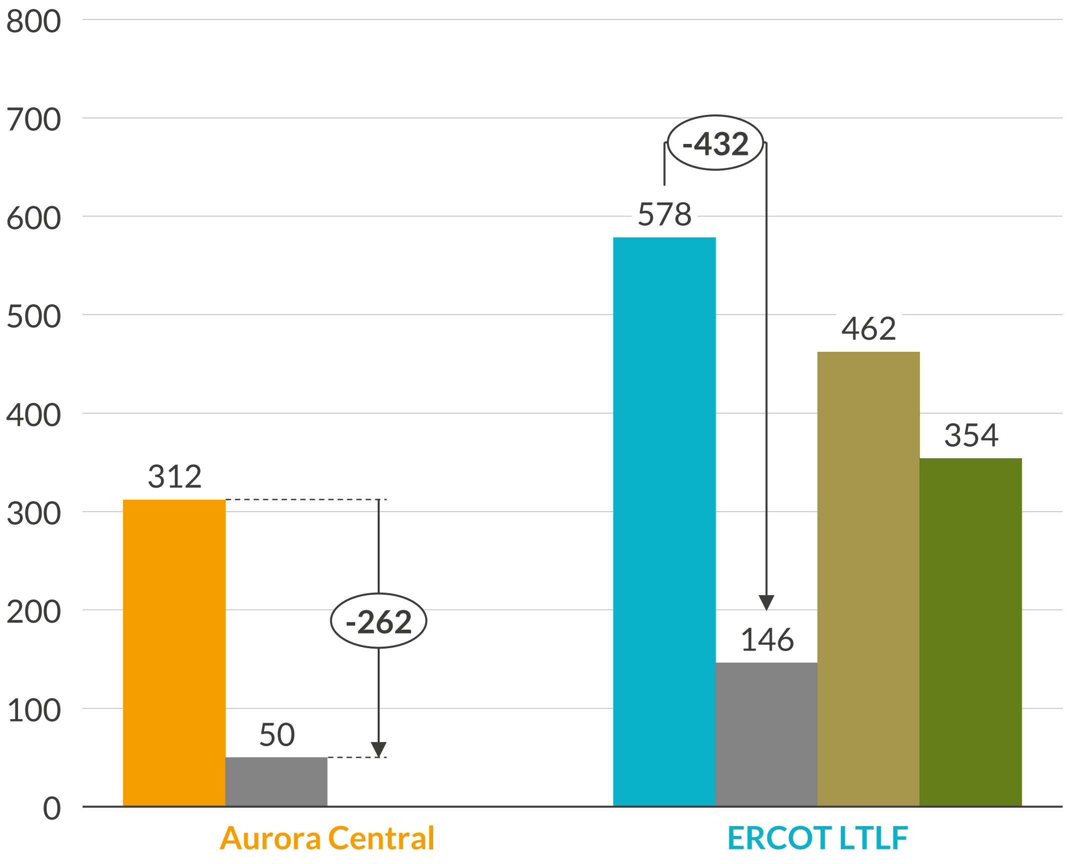
AURORA

Batteries ineligible

Max load shed – across entire year 2030 under 2023 WY conditions
GW



Total load shed – across entire year 2030 under 2023 WY conditions
GWh



Status quo · Status quo · DRRS AS Plus · DRRS AS · Ext. ORDC

Sources: Aurora Energy Research

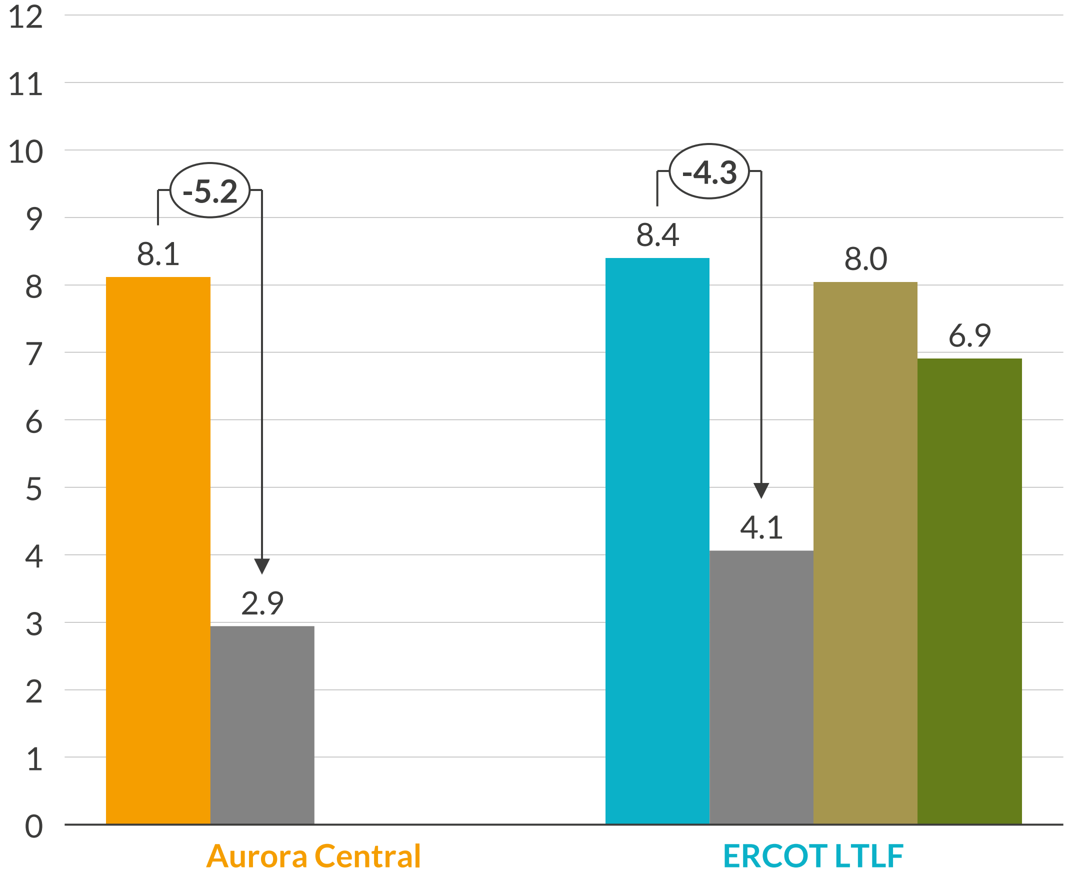
Under 2022 WY conditions, reductions in load shed range from 0.4GW to 5.2GW, with DRRS AS Plus providing the greatest reliability benefit

AURORA

Batteries ineligible

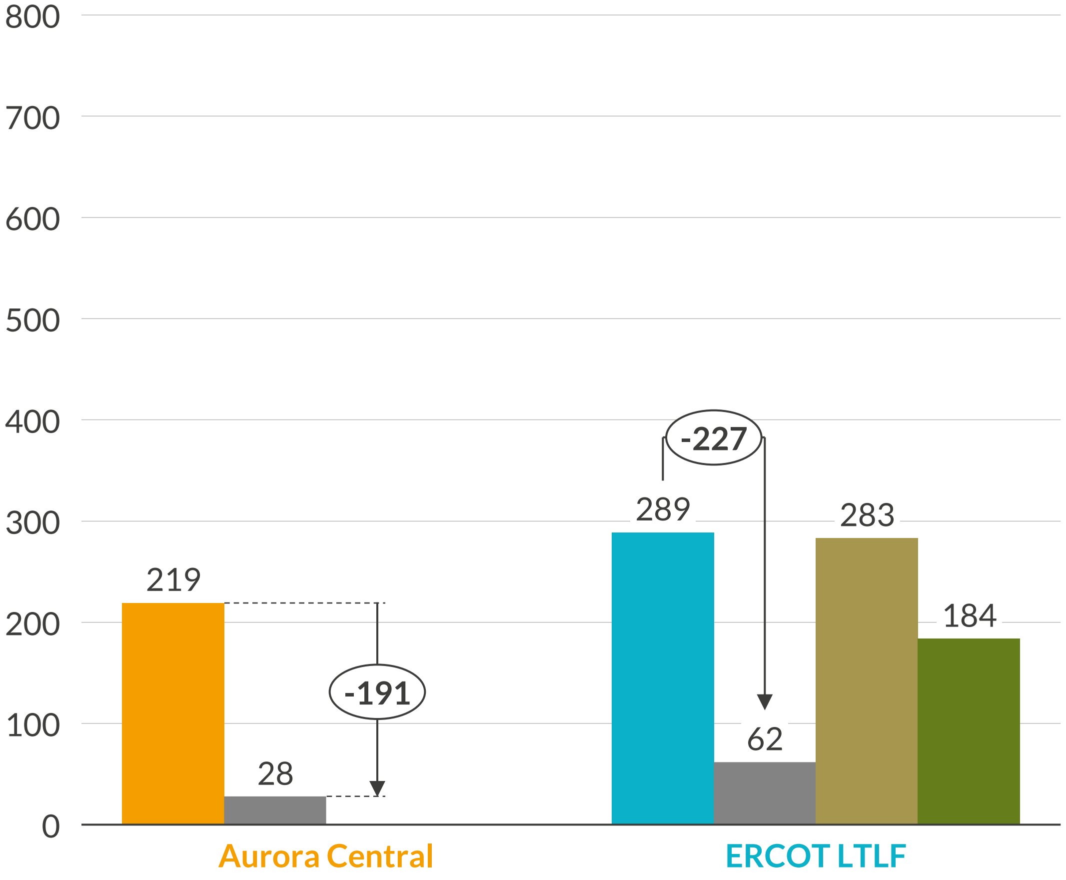
Max load shed – across entire year 2030 under 2022 WY conditions

GW



Total load shed – across entire year 2030 under 2022 WY conditions

GWh



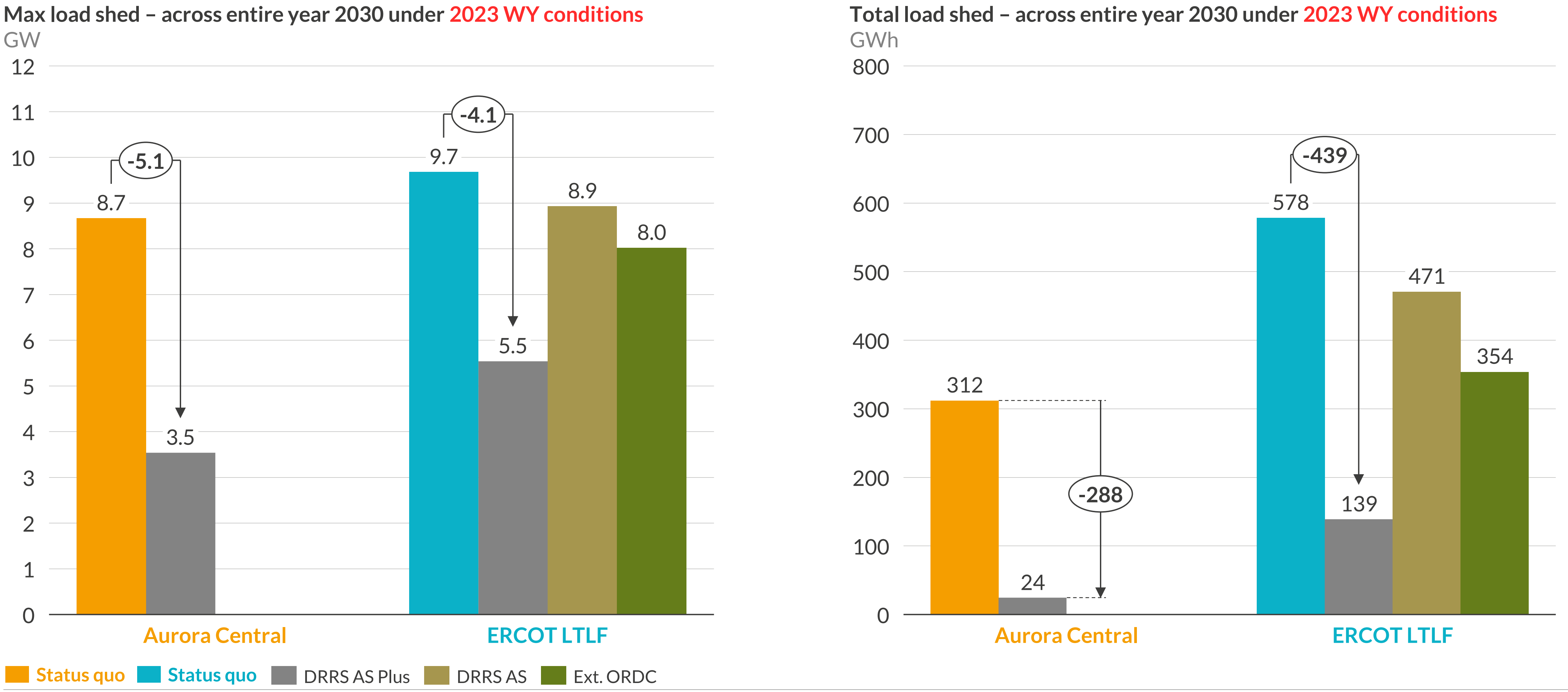
Status quo | Status quo | DRRS AS Plus | DRRS AS | Ext. ORDC

Sources: Aurora Energy Research

Under 2023 WY conditions, allowing battery participation in DRRS improves reliability outcomes slightly versus the Ineligible case

AURORA

Batteries eligible

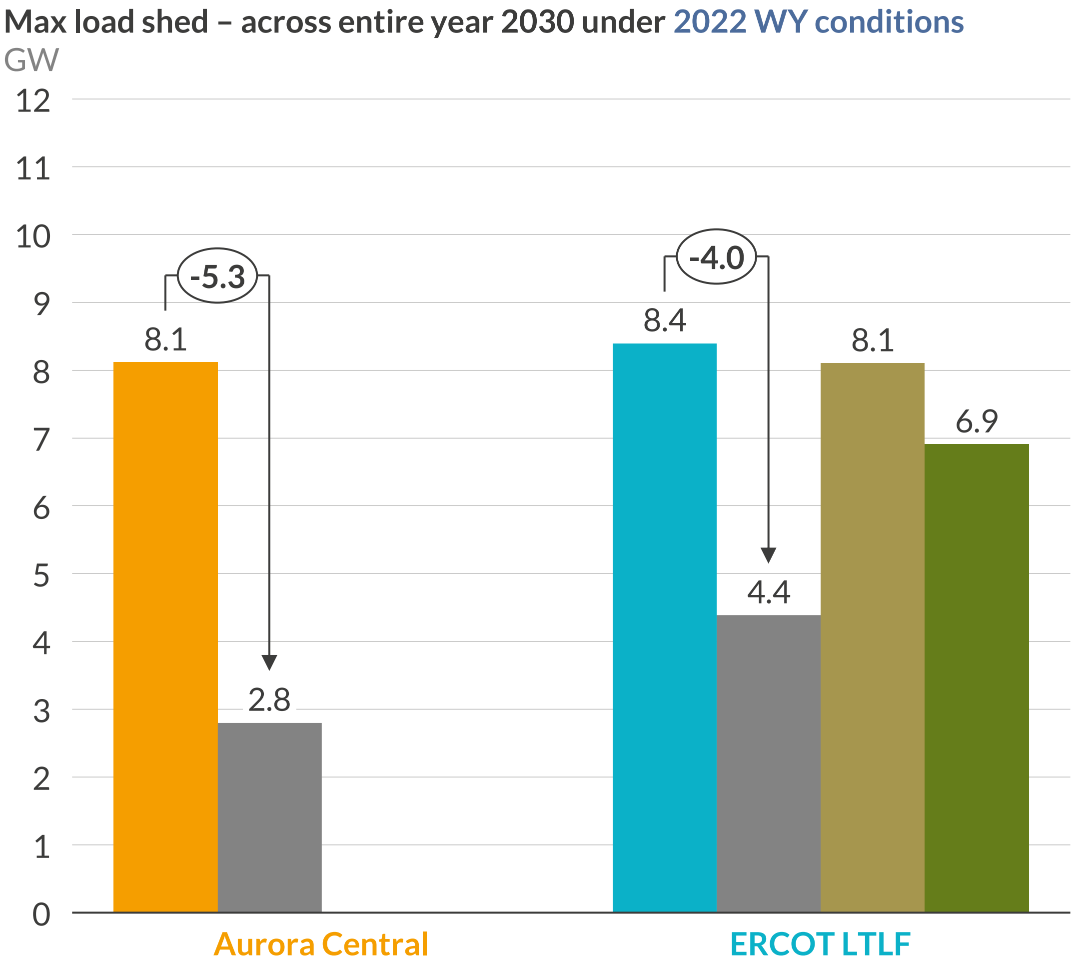


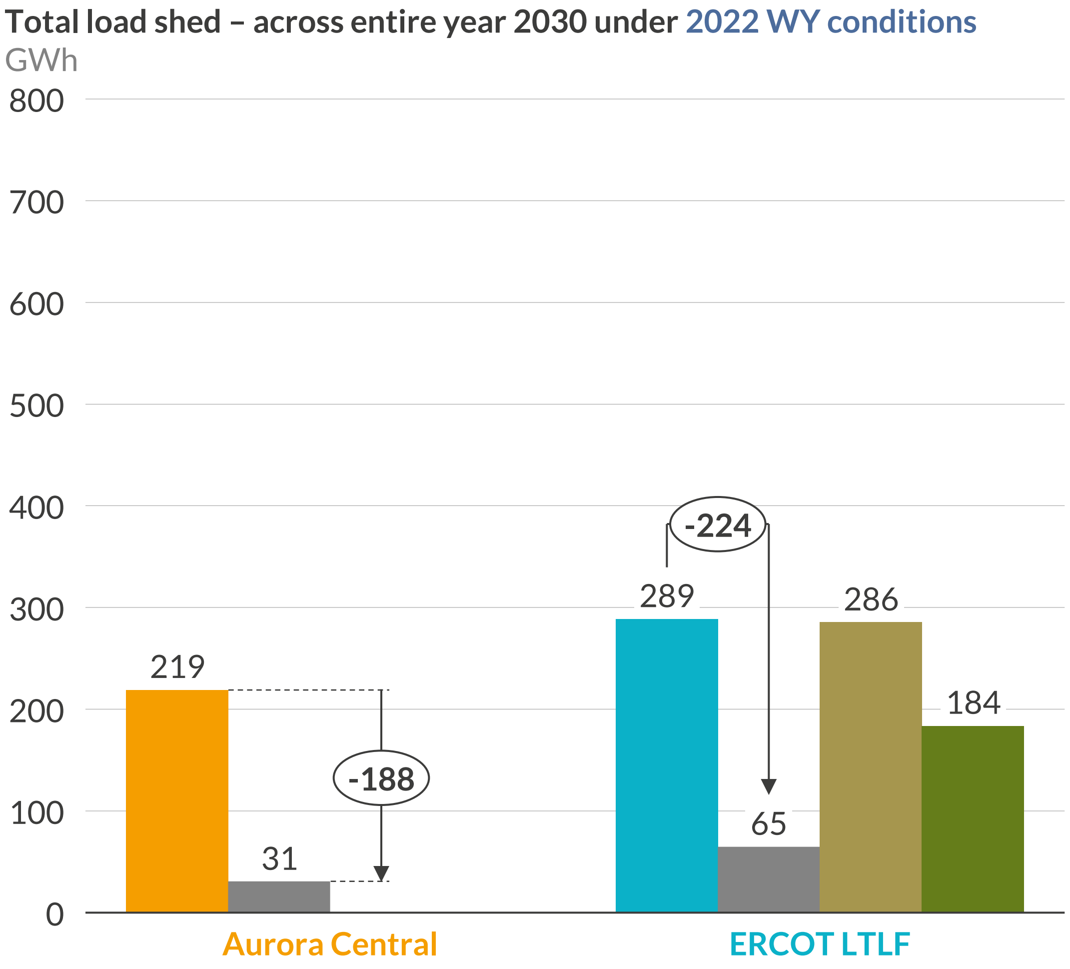
Sources: Aurora Energy Research

Under 2022 WY conditions, allowing battery participation in DRRS has little impact on reliability outcomes compared to the Ineligible case

AURORA

Batteries eligible





Status quo | Status quo | DRRS AS Plus | DRRS AS | Ext. ORDC

Sources: Aurora Energy Research

Agenda

I. **Executive summary**

II. **ERCOT's historical resource adequacy in context**

III. **Future resource adequacy challenges in ERCOT**

1. Demand growth
2. Supply risk
3. The impact of extreme weather

IV. **Impact of market design changes**

1. Dispatchable Reliability Reserve Service (DRRS)
2. Operating Reserve Demand Curve (ORDC)
3. Reliability and cost outcomes

V. **Appendix**

Each demand scenario was tested across multiple weather conditions to assess resource adequacy and system reliability

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As per *Aurora Central* scenario unless otherwise indicated

		Aurora Central	ERCOT Long Term Load Forecast (LTLF)	2023 Weather Year (WY)	2022 Weather Year (WY)
Demand	**Peak demand**	105GW by 2030	139GW by 2030[1]	Base demand identical to the Aurora Central and the ERCOT LTLF respectively and adjusted for weather impact	Base demand identical to the Aurora Central and the ERCOT LTLF respectively and adjusted for weather impact
	Bitcoin mining	4GW of mining load held constant through the horizon, price of bitcoin at $60,000 through horizon	8GW by 2030		
	Data centers	3.5GW in 2025, increases to 7.0GW by 2030	22GW by 2030		
Weather Year Methodology	**Reference year**	2013 (Moderate Weather)	2013 (Moderate Weather)	Hot Summer Reduced thermal plant availability High	Winter storm Elliot Hot Summer
Technology	**Renewables**	Between now and 2060 wind CAPEX falls by 24% and solar by 54%			Reduced availability during December winter storm
	Thermal	Gas CCGT increase by 6.7% by 2030. Coal decreases by 39% by 2030.		Reduced availability in summer months	Reduced availability in summer months
	Flexible	Gas/oil peakers increase to 51GW by 2030. Battery capacity increases to 36GW	+21GW of battery storage, +34GW of gas/oil peakers by 2030		

1) Peak demand in line with the revised ERCOT February 2025 Capacity, Demand and Reserves (CDR) report.

Sources: Aurora Energy Research, ERCOT

Aurora's demand forecast is built bottom up; demand is classified by its sector and flexibility

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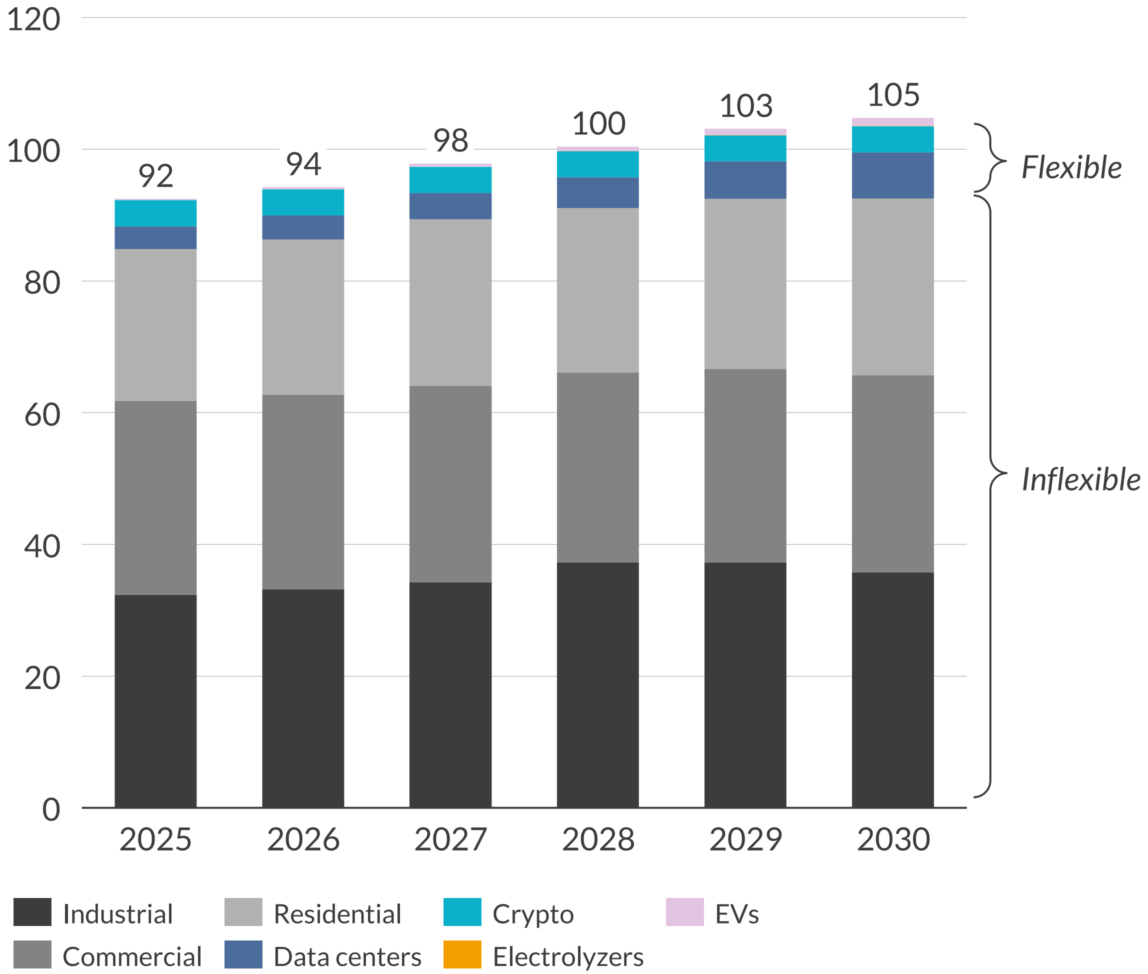
Aurora's demand methodology

- Aurora builds its demand forecast from the **bottom up**, taking a view on key demand drivers such as population growth, industrial growth and electric vehicle uptake.
- Demand fed into the Aurora model can be classified as either **flexible or inflexible,** each of which have **different impacts on grid reliability and power prices.**
  - Flexible demand puts downwards pressure on power prices, turning off when prices render power consumption uneconomic.
  - Due to its price responsiveness flexible demand indirectly supports grid reliability, as high prices coincide with periods of system stress.

Inflexible "base" demand	Flexible demand (price responsive)
▪ Residential	▪ Electric vehicles[1]
▪ Commercial	▪ Data centers
▪ Inflexible industrial	▪ Crypto mines
	▪ Hydrogen electrolyzers

Central case peak load forecast by demand sector
GW



1) Not all electric vehicles are considered flexible. Aurora classifies EVs as "Smart", "Time-of-use-tariff", and "Dumb", with "Dumb" EVs being fully inflexible. As the forecast progresses, the ratio of flexible EVs increases with the expectation of higher rates of smart charging.
Sources: Aurora Energy Research

Aurora incorporates both announced retirements as well as modeled economic retirements into its capacity expansion methodology

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Thermal retirement assumptions between 2025 and 2030[1]

Year	Plant	Size (MW)	Technology/ fuel	Hub
2026	Coleto Creek[3]	655	Coal	South
2027	Stryker Creek	679	STG	North
2027	Mountain Creek	808	STG[3]	North
2027	Sim Gideon[3]	601	STG	South
2028	V H Brauning	420	STG	South
2028	Martin Lake[3]	1786	Lignite	North
2028	Graham	629	STG	West
2029	J K Spruce	1482	Coal	South
2029	W A Parish (STG)	863	STG	Houston
2030	W A Parish (coal unit)[3]	1715	Coal	Houston
2030	O W Sommers	434	STG	South

Aurora's plant retirement methodology

- **Announced retirements**
  - Announced retirements are incorporated into Aurora's capacity expansion model based on the ERCOT Capacity Demand and Reserves report.
  - This includes full and partial retirements across all technology types.
- **Model based economic retirements**
  - Aurora's capacity expansion model can choose to retire a plant's capacity if its future revenues are insufficient to cover its costs, yielding it present value negative.
  - Additionally, plants built within the model will be retired when they reach the end of their technical lifetime, even if they are present value positive.
  - Aurora's model allows thermal plants to mothball at a yearly granularity, if favorable, as a means to avoid economic retirement.
  - Costs factored into retirement decisions are based on Aurora's in-house research and include values for fuel, as well as fixed and variable operations.

1) Includes full and partial, announced and model based retirements. 2) Partial retirement. 3) Steam turbine generator.

Sources: Aurora Energy Research

Aurora's analysis is based on proprietary, in-house modeling with integrated energy, ancillary, and capacity expansion modeling

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5 Integrated Models

- **Global Commodities (AER-GLO)**
- **Hydrogen (AER-HY)**
- **Gas (AER-GAS)**
- **Power markets (AER-ES)**

INPUTS

- Technology
- Policy
- Demand
- Commodity prices[1]
- Weather patterns

Dispatch model

- Hourly or sub-hourly
- Iterative modeling
- Dynamic dispatch of plant
- Ancillary services modeled endogenously

Continuous iteration until an equilibrium is reached

Investment decisions module

- Capacity market modeling (where applicable)
- 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

Up to 70 specifications modeled for each plant

c. 85k investment hours on modeling capabilities

~15k model runs per week

50+ strength of modeling team globally

Quarterly updates through subscription research

1) Gas, coal, oil and carbon prices fundamentally modeled in-house with fully integrated commodities and gas market model.

Source: Aurora Energy Research

Aurora utilizes both the interconnection queue and an economics-based model solve to forecast future capacity

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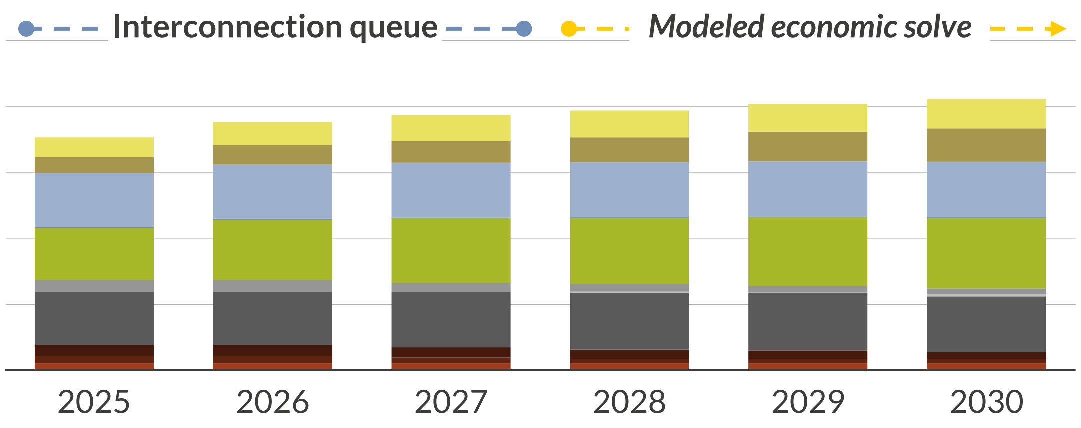
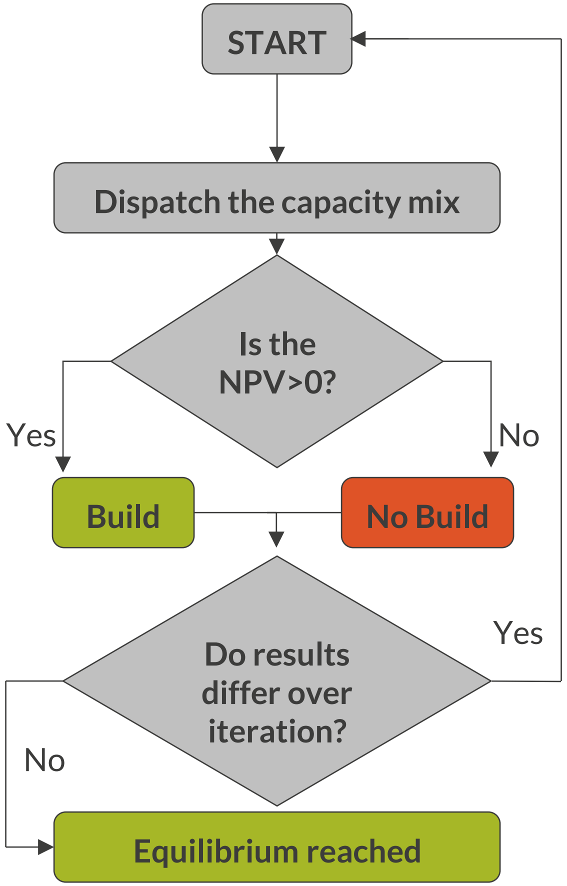
Inclusion of capacity from the ERCOT Interconnection Queue

- Aurora's near-term capacity additions are based off the ERCOT interconnection queue.
- Aurora evaluates completion rates of projects in the existing interconnection queue with historical success rates in determining the timeline of their market entry.
- Plants included in the forecast must have already signed an interconnection agreement.
- **Capacity additions are updated by Aurora on a quarterly basis.**

Forecasted capacity stack



Aurora AER-ES Model Internal Capacity Expansion



- In the mid to long-term, Aurora forecasts capacity additions based on an economic model solve.
- Plants in Aurora's model choose to either build or retire based off a NPV calculation.
- Existing plants have the ability to close or continue operating based on unit economics for the plant.
- The Aurora methodology **minimizes total system cost over the model lifetime** through a process of algorithmic iteration until lowest system cost is achieved.

1) Refers to evaluation of December 2024 ERCOT GIS report.

Aurora assessed ERCOT's reliability outlook in three phases, utilizing multiple permutations of demand, weather and market design

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1 Assess system reliability under the status quo market design across two demand forecasts during a normal weather year

Two load growth scenarios:

- Aurora Central demand, ERCOT LTLF

Market design:

- Status quo – Current configuration of the ERCOT market – energy only with price adders.

Weather year:

- Normal weather year – 2013 style weather year conditions – no extreme events but several periods of moderate scarcity.

Additional analysis – Impact of supply delays

Demand scenario – ERCOT LTLF

Supply risk – Re-assess system reliability with historical interconnection delays applied to the forecast.

2 Introduce extreme weather conditions and re-assess reliability

Two load growth scenarios:

- Aurora Central demand, ERCOT LTLF

Market design:

- Status quo – Current configuration of the ERCOT market – energy only with price adders.

Weather year:

- Winter storm – 2022 style weather year conditions – hot summer and extreme winter conditions (emulating Winter Storm Elliot).
- Summer heatwave – 2023 style weather year conditions – extreme temperatures drive high demand over summer. Increased risk of outages.

Additional analysis – Impact of data center Demand Side Response (DSR)

Demand scenario – ERCOT LTLF

Assess system reliability across different levels of demand responsiveness.

3 Introduce alternative market designs and assess their impact on reliability and cost

Two load growth scenarios:

- Aurora Central demand, ERCOT LTLF

Market design:

- DRRS Ancillary Service (AS) – A new ancillary service that procures dispatchable resources.
- DRRS Ancillary Service Plus – An hourly availability payment for dispatchable resources.
- Extended ORDC – An extension of the ORDC curve that keeps the offer cap at $5,000/MWh.
  Weather year:
- 2013, 2022 and 2023

Final outcomes

- Compare reliability and system costs across demand, market design and weather year combinations.

Sources: Aurora Energy Research

Aurora modeled the previous demand scenarios under 2022 & 2023 weather conditions, capturing extreme conditions from a hot summer and winter storm

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Weather year	"# of Heating Degree Days" (Cold Day)[1,2]	"# of Cooling Degree Days" (Hot Day)[1,2]	Wind production[2], %	Solar production[2], %	Potential for market impact
2009	30	26			Low –High RES production
2010	38	42			High – Hot summer and low wind
2011	27	74			High – Very hot summer and low wind
2012	12	36			High – Warm summer and low wind
2013 *Central case*	30	29			Moderate – Cool winter and low wind
2014	34	16			Low – Cold winter but average RES
2015	30	30			Moderate - Cool winter and low wind
2016	12	29			Moderate – Mild seasons but low RES
2017	11	17			Low – Mild seasons but low solar
2018	24	30			High – Warm summer and low wind
2019	29	18			Moderate – Cool winter and average RES
2020	12	15			Low – Mild seasons and high RES
2021	19	13			Moderate – Mild seasons and high solar
2022	27	50			High – Hot summer and cold winter
2023	6	61			High – Hot summer and low wind

Cold Days Hot Days
Weather Year Sensitivities Weather Year Aurora Central
Wind CF Wind CF at high load hours
Solar CF Solar CF at high load hours
Average production at high load times

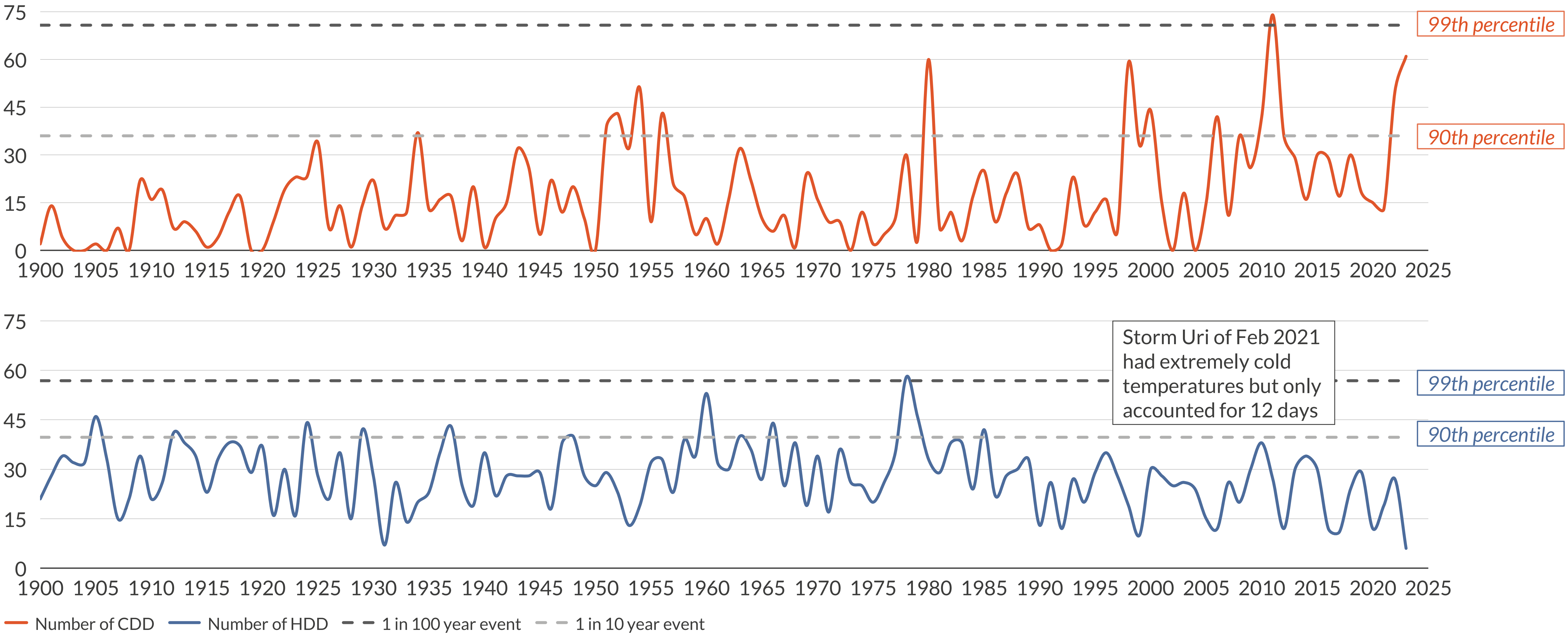
1) Temperature data taken for Dallas/Ft.Worth. 2) Heating degree days and cooling degree days are filtered to only reflect the number of days per year which were above 88 degreesF or below 42 degreesF. 3) Wind and solar capacity factors (CF) shown as an annual average and as an average over the top 20 total load hours of that weather year.

Sources: Aurora Energy Research, National Weather Service: NOAA

Volatility of extreme cooling degree days has increased over the last century, with hotter, longer summers

Evolution of Extreme Cooling and Heating Degree Days over the last century[1,2,3]

days per year



1) Dallas- Fort Worth temperatures. 2) A day is counted towards Extreme HDD or CDD if its value is greater than 23F, i.e. the day's average temperature was greater than 88F or less than 42F. 3) Cooling Degree Day and Heating Degree Day abbreviated to CDD and HDD respectively.

Sources: NOAA, Aurora Energy Research

Methodological differences between this report and the ERCOT Capacity, Demand and Reserves (CDR) Report

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Differences in capacity build

- Aurora uses a specific approach to modeling capacity build, including plants from the GIS interconnection que with a signed **Interconnection Agreement**, as well as **connecting new plants that are currently not in the queue** to meet economic signals to balance ERCOT market load with supply.
- The CDR report includes all plants that **have received Financial Securitization, along with a notice to proceed with construction from the respective Transmission Service Provider.**

Differences in market design forecasting

- For this report, Aurora modeled capacity build under varying market conditions to gauge a capacity build response to several variables including different long-term demand assumptions, extreme weather, varying levels of plant interconnection lag, and resource adequacy mechanisms.
- Aurora's forecasts are focused on **long-term build equilibrium**, simulating economic scenarios in which clearing prices accurately reflect market conditions.
- The ERCOT CDR report does not include economic build and is solely based off of an Aurora Central case 2013 Weather year scenario, with load stressed under winter and summer conditions but with no accompanying effects on capacity.

Sources: Aurora Energy Research

Details and disclaimer

Date: November 10th, 2025

This report was commissioned by the Electric Reliability Council of Texas (ERCOT).

All analysis and findings are the independent work and opinion of Aurora Energy Research.

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