U.S. Winter Storm Fern

February 2026

Executive Summary

Winter Storm Fern drove extreme price spikes across U.S. power and gas markets in late January 2026, exposing gas infrastructure constraints and grid vulnerabilities that vary widely by region. In most markets, day-ahead power prices far exceeded real-time conditions as worst-case demand scenarios failed to materialize, and near-term forward premiums largely faded within days.

Rising liquified natural gas (LNG) export capacity and data center load growth are tightening system margins, amplifying the market's sensitivity to supply disruptions. This report examines how each region's grid and markets responded to Fern, and what forward curves signal about reliability risk pricing.

Key Takeaways

Near-term storm premiums faded, but outer-year forwards retained them.

- Calendar 2026 (Cal 2026) power forward prices spiked 18–21% during the storm across PJM, MISO, ISO New England, NYISO and ERCOT, but largely reverted the 'storm premium' within days.
- ERCOT was the exception, where Cal 2026 forwards have declined after Fern as real-time grid performance confirmed the system's improved winter resilience since Winter Storm Uri in 2021.
- Cal 2027 and Cal 2028 strips in PJM and the Northeast have kept most of their premium, suggesting a structural re-pricing of supply adequacy.

Gas supply couldn't keep up with demand during Fern.

- Production freezes and pipeline constraints drove regional prices as high as $282/MMBtu. Benchmark Henry Hub March 2026 futures swung from $2.6/MMBtu before the storm to $4.4/MMBtu at the peak.
- Prices then dropped 26% in a single day, the largest decline in over 30 years, only to rebound as LNG demand returned. These whipsaws illustrate how difficult it has become to time gas hedging windows.

Regional Power Markets Summary

- **In MISO, load exceeded forecasts by as much as 7.4 GW** while wind underperformed, pushing real-time prices to $1,500–2,500/MWh and exposing the grid's wind-dependent winter supply outlook.
- **PJM operated under sustained emergency conditions,** with day-ahead prices hitting $2,323/MWh in PJM West as markets priced in peak demand of 140 GW that didn't end up materializing.
- **The Northeast's gas supply vulnerabilities resurfaced,** with oil becoming the leading source of power at times and power prices exceeding $4,000/MWh in NYISO.
- **ERCOT stood apart.** Unlike Winter Storm Uri in 2021, the thermal fleet held, wind overperformed, and nearly 7 GW of battery storage kept real-time prices below what day-ahead markets had priced in.

Power Forwards Overview

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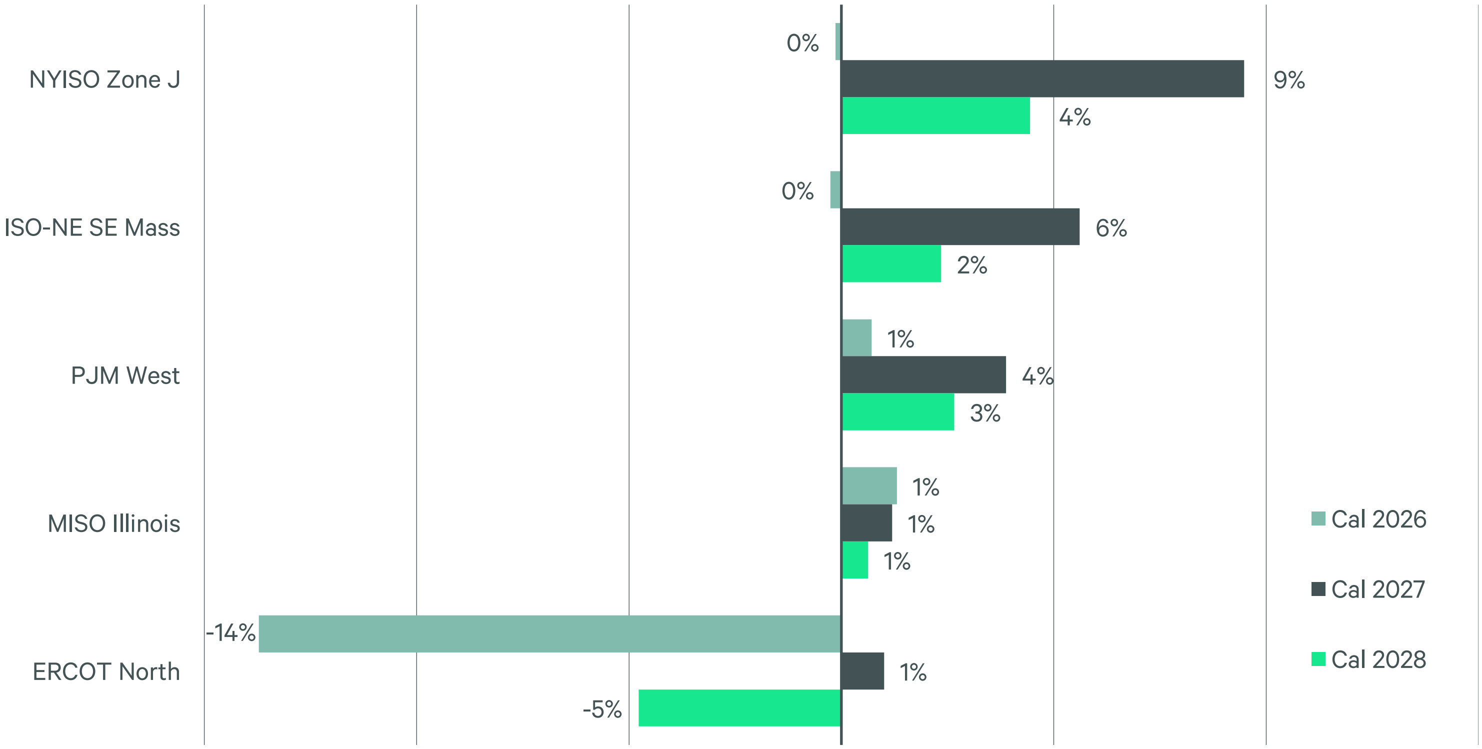
Near-Term Winter Storm Premiums Fade While Long-Term Contracts Price Structural Supply Risk

Power forward curves spiked during Winter Storm Fern, with Cal 2026 strips rising 18–21% across PJM, NYISO, ISO-NE, and MISO. As of February 6, most of those premiums have faded. ERCOT Cal 2026 prices have fallen 14% below pre-storm levels as the grid's performance eased concerns about winter reliability.

Longer-term contracts, however, show persistent risk concerns. PJM, ISO NE, and NYISO Cal 2027 strips remain 4-9% above pre-storm levels, holding nearly all their premium from Fern. Markets are pricing heightened winter vulnerability in these regions after the storm exposed gas infrastructure constraints, particularly as LNG exports and growing load compete for a larger share of available gas supply.

Figure 1) Change in Forward Curves Before the Storm as of February 6, by Major Hub



Source: CBRE, EOX, Enverus. Note: Shows the percentage differences where pre-storm values reflect the average daily forward settlement for January 21–22, before storm-related pricing entered the market. Post-storm reflect the February 6th settlement.

Gas Markets Overview

February 2026

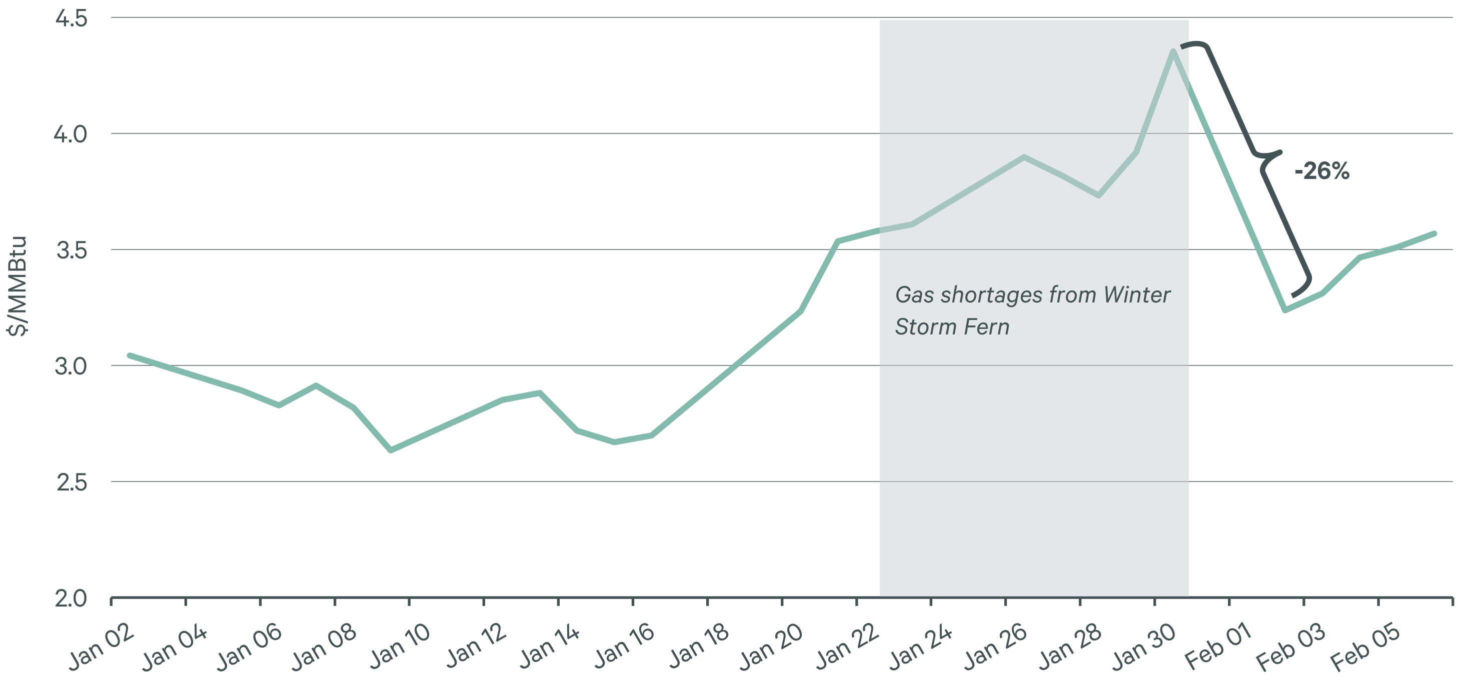
Gas Infrastructure Constraints Amplify Futures Volatility

Gas production freezes and limits on how much gas could be withdrawn from storage or transported through pipelines caused fuel supply shortages for heating and power plants in MISO, PJM, and the Northeast. Severe shortages drove regional prices to $282/MMBtu in the Iroquois Zone 2 hub, with Henry Hub benchmark prices reaching $31/MMBtu on January 26, up from a typical $4/MMBtu.

March 2026 Henry Hub futures were at an all-time low of $2.6/MMBtu just before the storm, then rose 65% to peak at $4.4/MMBtu just a few weeks later. Once forecasts shifted to warmer weather on February 2, prices dropped 26% to $3.2/MMBtu, the single biggest daily decline in over 30 years.

Gas futures markets have remained volatile despite gas production and transport resuming to normal conditions. Prices rebounded when LNG demand came back after export facilities stopped buying during the storm. These whipsaws reflect a structurally more volatile gas market, driven by tighter supply-demand balances from LNG exports grow and power demand from data centers increases gas burns.

Figure 2) Henry Hub March 2026 Future Contracts



Source: CBRE, NYMEX.

Deep Dive: Regional Power Market Summaries

February 2026

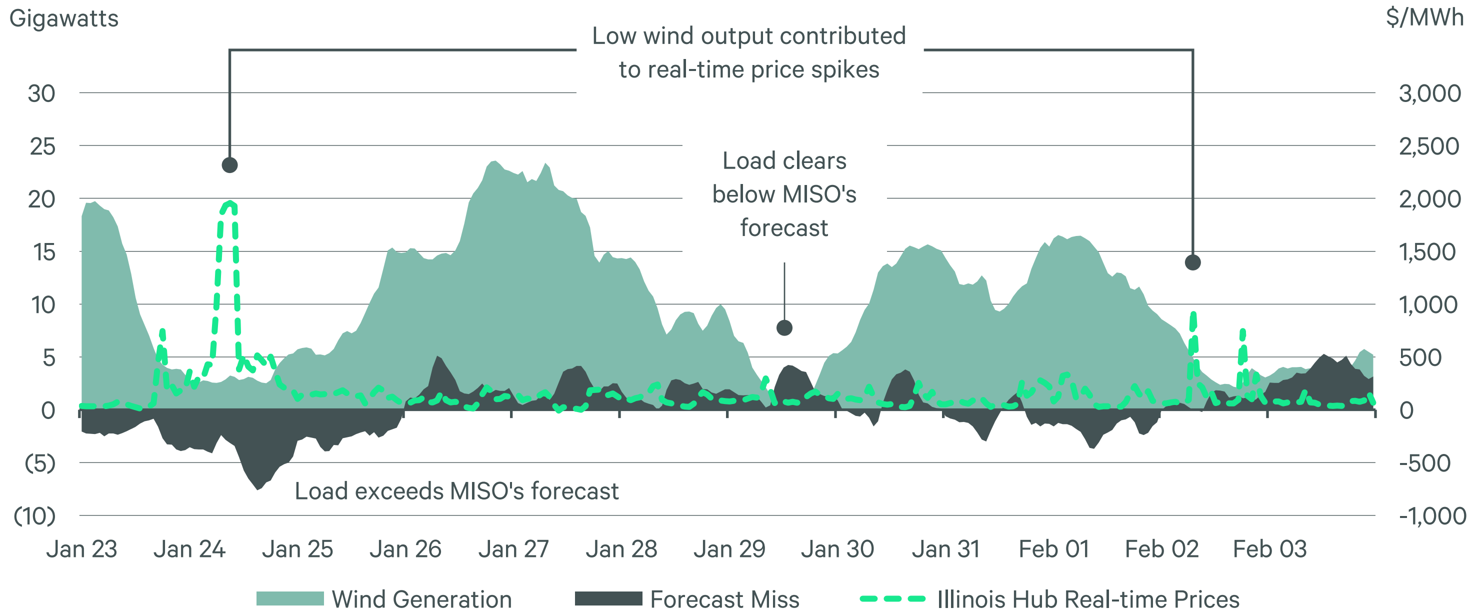
Wind Volatility Compounds MISO's Winter Reliability Challenges

Winter Storm Fern exposed MISO's growing dependence on wind as a critical supply source during high winter demand. Coal units scheduled for retirement but kept online through DOE emergency extensions provided supply during the storm.

- Winter Storm Fern drove MISO into emergency conditions on January 24 when extreme cold pushed load 7.4 GW above forecasts. Wind output underperformed, forcing MISO to import 9 GW from neighboring PJM and SPP.
- Day-ahead markets didn't anticipate the shortfall and real-time prices across MISO hubs spiked to $1,500–2,500/MWh on January 24, well over the roughly $300/MWh in day-ahead prices.
- Day-ahead prices cleared as high as $561/MWh above real-time from January 26-30 as wind output recovered and load came below forecasts. But another wind drop and a small load forecast miss pushed real-time prices back to $1,000/MWh on February 2, underscoring the difficulty for buyers to price in MISO's wind-dependent outlook.

Winter Storm Fern revealed structural winter hedging risks in MISO, pushing January 2027 strips up to 16% higher in the Indiana hub than before the storm as markets price in future winter reliability concerns. Buyers with load in MISO Northern zones may want to assess whether current winter forward premiums justify locking in hedges or waiting for a potential price reversion.

Figure 3) MISO Load Forecasts vs Deviations, Wind Output and Real-Time Power Prices in Illinois Hub



Source: CBRE, GridStatus, MISO. Note: Shows real-time prices for Illinois Hub.

CBRE

Deep Dive: Regional Power Market Summaries

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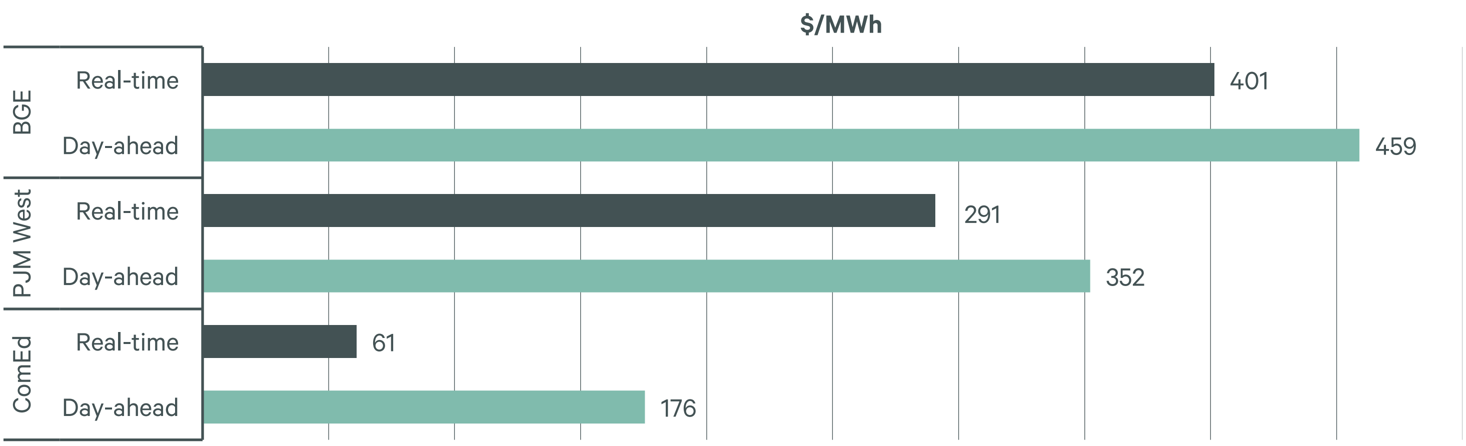
PJM's High Grid Alert Drives Extreme Day-Ahead Pricing

Winter Storm Fern tested PJM's winter reliability as gas supply constraints and West-East transmission limits compounded with forecasts of record peak winter demand. PJM asked for DOE authorization to run backup generators at full output and relied on expensive coal and oil generation. While the grid maintained reliability, these measures confirmed structural vulnerabilities that will likely intensify as load grows.

- Day-ahead prices at PJM Western Hub cleared at $2,323/MWh on January 27 and remained near $1,000/MWh through the next day on supply adequacy fears. Real-time prices consistently cleared below day-ahead as conditions proved less severe than expected. The one exception was January 31, when 20 GW of forced generation outages pushed real-time prices to $2,000/MWh.
- West-to-East transmission constraints created extreme regional spreads. BGE prices in the East hit $4,100/MWh on January 27 while ComEd prices in the West dropped to -$330/MWh. Dominion had to import 3 GW to serve its high data center and electric heating load, reflecting growing winter vulnerability in the East as the data center build-out continues.
- ComEd day-ahead prices were on average $115/MWh higher than real-time during the storm, a higher spread than in most other regions despite having 15 GW of excess capacity throughout the storm. Even with strong fundamentals, day-ahead markets priced aggressive risk premiums.

While near-term day-ahead premiums faded as conditions stabilized, the forward market's response has been more persistent. As of February 6, 2026, winter 2027 forwards for Dominion, PSEG and BGE are trading 10-15% higher than before the storm, suggesting markets are pricing PJM's long-term reliability challenges. Buyers with load in areas with fast-growing demand may want to evaluate whether current seasonal premiums accurately reflect future reliability risks.

Figure 4) Average Real-Time vs Day-Ahead Prices Across Selected PJM Hubs, January 23-February 4



Source: CBRE, GridStatus, PJM. Note: Shows average prices from January 23rd to February 4th.

Deep Dive: Regional Power Market Summaries

February 2026

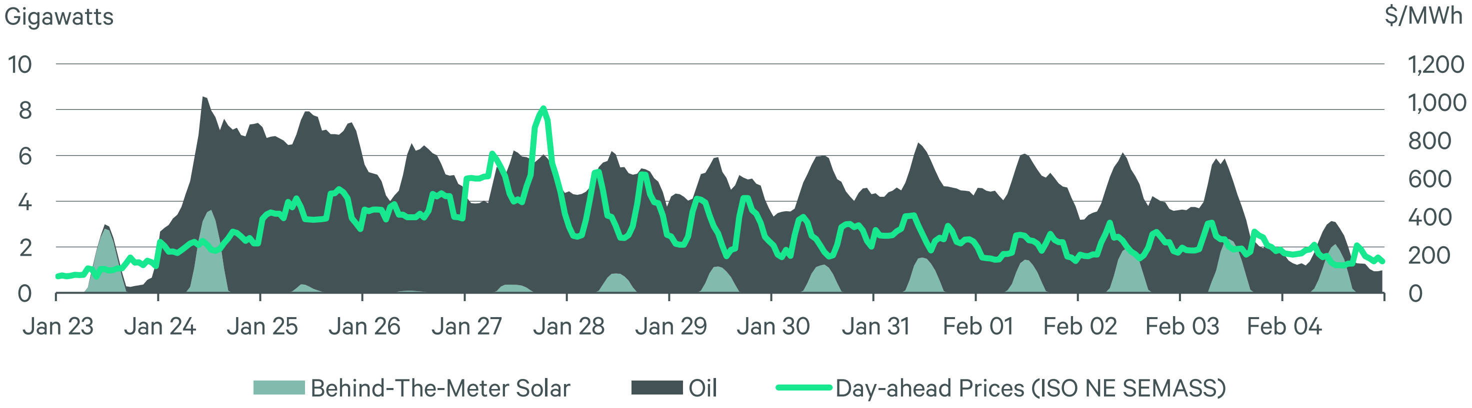
Northeast Winter Supply Vulnerabilities Resurface as Gas Constraints Push Region to Oil

The Northeast's long-standing vulnerability to winter gas supply constraints re-emerged during Fern. With regional gas prices trading at $172-282/MMBtu, oil-fired generation became a cheaper option and was often ISO-NE's leading fuel source.

- Imports from Hydro-Québec, typically a steady source of power for the Northeast, proved highly volatile during the winter storm. Flows from NECEC and other power lines fell to zero during morning and evening peaks as Québec managed its own electric heating demand.
- Day-ahead prices in ISO-NE hit nearly $1,000/MWh on January 27, while NYISO saw real-time prices reach $2,000–4,000/MWh on January 24 when load exceeded the forecasts by 1–2 GW.
- Heavy snow capped ISO-NE's behind-the-meter solar output at less than 0.1 GW on January 26, down from 3.6 GW days earlier, underscoring the limited reliability contribution of behind-the-meter solar during winter storms.
- Gas pipeline expansions, offshore wind, and any new nuclear capacity in the Northeast all face long timelines. Battery storage remains the most viable near-term path to easing the Northeast's winter constraints, and states across the region have set aggressive deployment targets to that end.

Buyers with load in ISO-NE and NYISO should expect winter forward premiums to continue reflecting the region's underlying supply vulnerabilities. Northeast winter hedges warrant more attention than in regions with diversified fuel access, but buying right after a storm also risks paying for premiums that may not hold. As of February 6, NYISO Zone J January 2027 strips are still nearly as high as during the peak of the storm.

Figure 5) ISO New England Behind-the-Meter Solar, Oil-Fired Generation and SEMASS Day-Ahead Prices



Source: CBRE, GridStatus, ISO New England. Note: Shows stacked oil and behind-the-meter solar generation. SEMASS hub located in Southeastern Massachusetts.

Deep Dive: Regional Power Market Summaries

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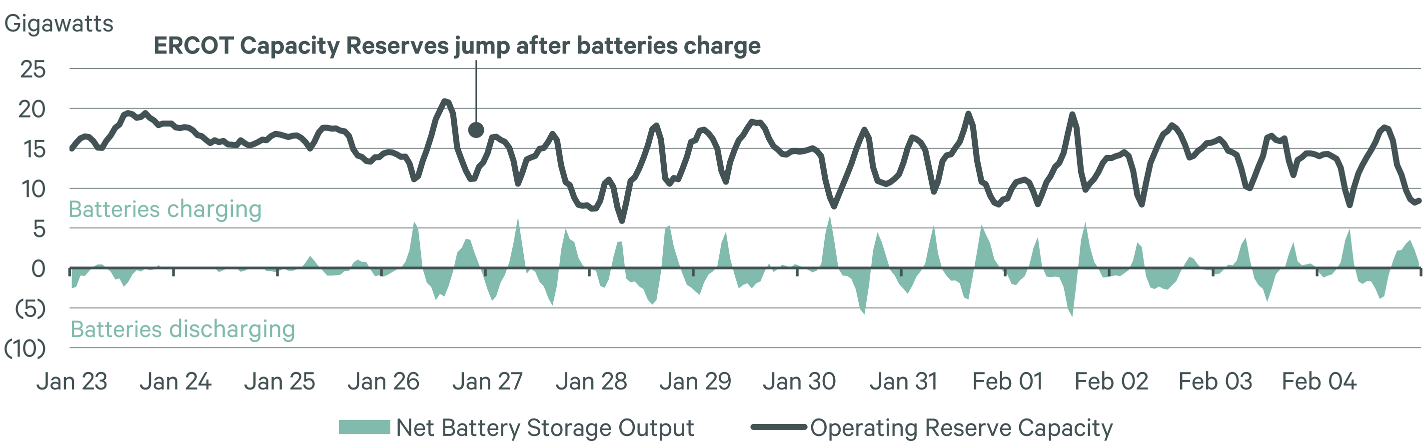
ERCOT's Grid Performance Sends Winter Forwards Lower

ERCOT's grid held during Winter Storm Fern in a stark contrast to Winter Storm Uri in 2021, when the system lost 32 GW of thermal capacity and 22 GW of renewables, sending prices to $9,000/MWh. At the time, ERCOT had virtually no battery storage online. This time, the thermal fleet held up without major outages, wind overperformed forecasts, and nearly 7 GW of battery storage was available to dispatch throughout the storm.

- Day-ahead markets priced in significant supply risks at the start of the storm, with hub-wide prices averaging $1,800/MWh in the morning of January 26. But load came in nearly 5 GW below forecast and 6 GW of batteries discharged, keeping real-time prices below $300/MWh.
- Conditions tightened briefly on January 28 when low wind and thermal outages pushed real-time prices to $1,200/MWh, well above the $140/MWh day-ahead price. Solar generation and battery discharges during morning and evening peaks contained further price spikes.
- Strong South-to-North congestion also emerged during the storm, driven by a 20-degree temperature difference between Southern and Northern Texas. This resulted in day-ahead price separation and localized grid constraints causing real-time price spikes.

ERCOT is the one region where Winter Storm Fern lowered forward prices, reflecting market confidence in the system's battery storage depth, thermal fleet resilience, and grid investments since Uri. January 2027 on-peak forwards are now 9% below pre-storm levels. Falling winter risk premiums raise the question of whether current levels warrant locking hedges before data center load tightens the supply-demand balance. Buyers with procurement flexibility may be comfortable keeping partial unhedged winter exposure given of the region's improved grid performance.

Figure 6) ERCOT Battery Storage Net Output and Total Capacity Reserves



Source: CBRE, GridStatus, ERCOT. Note: Total capacity reserves represent the physical responsive capability (PRC) of the grid, including generation and flexible load resources.

Thank you.

FOR MORE INFORMATION

Brendan Biddlecom

Global Managing Director, Energy Procurement
CBRE Energy
Brendan.Biddlecom@cbre.com

Pol Lezcano

Director, Market Intelligence
CBRE Energy
Pol.Lezcano@cbre.com

Brian May

Director, Energy Procurement
CBRE Energy
Brian.May@cbre.com

Kevin Arritt

Vice President
CBRE Energy
Kevin.Arritt@cbre.com