U.S. WINTER MARKET UPDATE

After the call summary

Compiled: Sept. 29, 2025

Important highlights at a glance

The following is an overview of some important elements of the U.S. Winter Market Update presentation on Sept. 23, 2025.

Weather

Winter '24/25 & Summer '25 review

- Winter '24/'25 was the 27th warmest since 1950 based on gas weighted cooling degree days (GWCDDs), however it was the coolest winter since 2014.
- Summer 2025 was the 10th warmest on record since 1950 based on population-weighted cooling degree days (PWCDDs), with June and July being the 4th and 8th warmest since 1950.
- August was the coolest since 2017, but an anomalously cool August does not equate to a cold winter.

El Niño Southern Oscillation (ENSO)

- **Current state:** ENSO is negative neutral, which reflects negative sea surface temperatures (SSTs), while Pacific Decadal Oscillation (PDO) remains negative and Atlantic Multi-decadal Oscillation (AMO) remains positive.
- **Climate model forecasts:** showing ENSO moving to a weak to moderate La Niña state by Oct/Nov. Previous recent La Niña winters: 2024-25, 2022-23, 2021-22, 2020-21.

What does this mean for fall and winter? Since 2000, winters have been warmer (based on GWCDDs). Recent La Niña winters have fallen near or colder than the 2000s trend. Weak to moderate La Niña will offer increased cold volatility risks, while other factors (-PDO, +AMO) support an overall warm winter. Check out current NOAA winter forecast.

Market update

Across the ISOs: summer power recap

- **Demand:** Power burn levels were down this summer vs. last, while PJM broke a 10-year peak load record of 160 GW on June 23.
- **Prices:** PJM and Northeast markets experienced some market price volatility, while CAISO and ERCOT saw $40/MWh average across the summer months.

Summer natural gas recap

- **Demand:** Overall Y-o-Y demand was higher with lower power burn demand but growing LNG exports due to increased capacity.
- **Production:** Strong production set a record high of 108+ Bcf/day on Aug. 24.
- **Prices:** NYMEX prompt month trends show a year-to-date min/max of $2.696/Dth and $4.49/Dth respectively.

Natural gas fundamentals & pricing

- **Storage:** Current storage is 3,508 Bcf, which is 1% above one year ago and 6% above the 5-year average. We are expected to end injection season just slightly under last year's total volume, but in a comparable overall position. *An early start to winter could cause volatility if large withdrawals occur in Oct/Nov. Conversely, winter weather that doesn't materialize can present buying opportunities.*
- **Demand:** LNG export capacity is forecasted to increase in the next few years as facilities expand and new ones come online. Gas demand is expected to grow with AI/data center growth, which is putting pressure on long-term prices.
- **Pricing:** The 3-year NYMEX trading history shows the 12-month strip has been the most volatile, with highs of over $8/MMBtu in 2022, and lows of $2.50/MMBtu in 2024, and a current floor of around $3.50/MMBtu. Calendars 2027-2029 have remained stable, trading between $3.50-4.00 the last two years and more recently converged around the $3.80/MMBtu level

Electricity fundamentals & pricing

- **Demand:** Load growth forecasts are moderate to dramatic across several regional electricity systems, with ERCOT showing the most growth (peaking at 148 GW by 2030), and PJM showing the highest peak load (184 GW) by 2030. MISO and CAISO are expecting moderate growth.
- **Demand (con't):** PJM grid reliability, cheap electricity rates, and proximity to natural gas supply have made PJM a prime location for investment in data centers: specifically, Ohio, Western and Central PA, and Virginia.
- **Supply:** Pipeline infrastructure is being planned to support the growth in the region, with three notable expansions slated to be completed between 2027 and 2030.
- **PJM pace of supply v. demand:** PJM is estimating a summer peak of 228 GW and a winter peak of 219 GW by 2045, but this growth is outpacing the ability to add new dispatchable generation.

Regional considerations

TEXAS: is seeing forward power price strength due to significant forecasted load growth. ERCOT's August 2025 update shows 189,328 MW of large load interconnection requests, with over 13,000 MW approved for interconnection by 2030. ERCOT's May CDR projects negative reserve margins starting in 2027/2028.

CALIFORNIA: is facing tightening supply and rising demand, with peak demand expected to grow 21% by 2040, in part due to data centers.

- Forward power and gas prices are in contango due to phase-out of clean energy credits.
- Power prices have increased while gas basis has declined, indicating strong demand and limited supply.

MIDCONTINENT:

- Strong gas production and weak demand have pushed storage levels up and regional spot prices down, prompting potential shut-ins of less efficient wells.
- More Southeast pipeline takeaway capacity has been announced.
- PJM expects its summer peak to increase about 70 GW over the next 15 years, driven by data center demand. By 2044, MISO forecasts data center demand to reach 23–37 GW.
- PJM capacity auction construct adjustments and supply/demand tightening resulted in higher capacity rates for both '25/26 and '26/27 capacity delivery years. Similarly, a new pricing methodology for the MISO's capacity auction resulted in a 900% increase in rates for '25/26 over '24/25.
- Forward pricing is flat, with most strips rangebound for 2026-2029.

NORTHEAST:

- Accelerated fossil fuel plant retirements in NY are increasing the risk of scarcity pricing during cold snaps or unplanned outages.
- Electrification of heating and transportation, and data center demand, is pushing winter peak demand higher.
- Natural gas supply constraints during peak winter periods force power generators to switch to more expensive fuels.
- The Administration's policy on wind is impacting ISO-NE's voluntary renewables market and increasing risks to grid reliability, while Maine's new Clean Energy Standard is expected to significantly increase renewable energy prices starting in 2030.

Strategy considerations

- **Choose a flexible strategy:** that allows you to decide when and how much to buy. Current market drivers make it difficult to pick a "best time" to buy, so consider a layering product for more purchasing flexibility in pursuit of great cost control. Also, consider independently managing the cost components that comprise your overall price (instead of locking it all in) for additional cost control opportunities.
- **Focus on what you can control:** consider strategically managing *when* you use power to help lower capacity costs. NRG can help with load management services, like peak load alerts and demand response programs, that help you earn money for your reductions.

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