FEDERAL ENERGY REGULATORY COMMISSION
Office of Technical Reporting & Economics
Office of Electric Reliability

Winter Energy Market & Electric Reliability Assessment

A Staff Report to the Commission

November 19, 2026

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The views expressed in this report do not necessarily reflect the views of the Commission or any Commissioner.

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Preface

The 2026-2027 Winter Energy Market and Electric Reliability Assessment (2026-2027 Winter Assessment) report provides Commission staff's outlook for December 2026 through February 2027. The report contains five sections: a summary of key findings; anticipated weather and weather-related risks; notable reliability risks for the winter; energy market fundamentals; and regional electric reliability probabilistic assessments.

Key Findings in Winter 2026-2027 Assessment

TAKEAWAYS

- **Temperatures: higher than average; very high likelihood of El Niño and increased likelihood of polar vortex**
- **Extreme weather reliability risk: SERC-East, New England, MISO, and SPP**
- **Drought: significant impact to hydro and other generation in the West**
- **Electricity Demand vs. Supply**
  Resources & Net Transfers Increases > Demand Increases
- **Fuel oil may be critical in Northeast during peak periods.**
- **Natural Gas:**
  Increased demand; lower prices (at most hubs)
  Interstate pipeline additions: 8 Bfcd

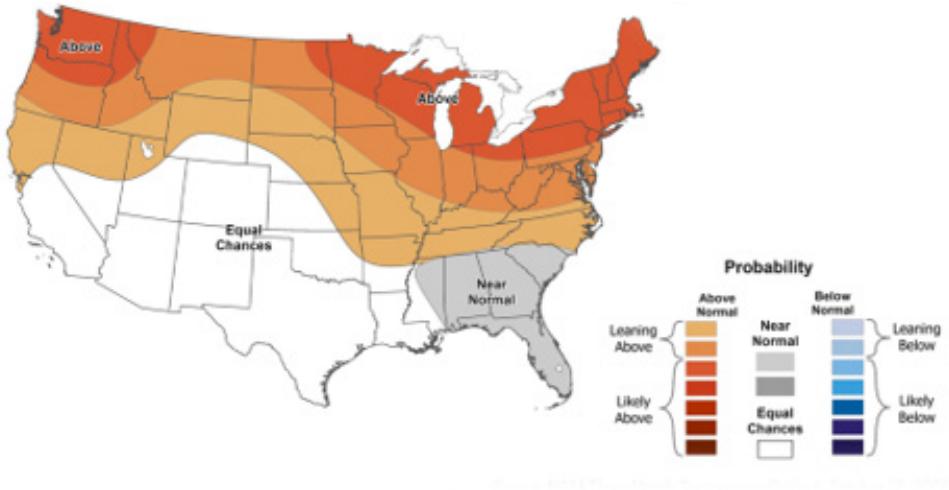
While overall higher-than-average temperatures are forecast for this winter, increased risk of extreme weather events is expected to challenge the grid in affected regions. Several conditions may combine to create challenges for grid operators, including extreme cold events, low snowpack, continued drought, and wildfires. The low water levels resulting from low snowpack and continued drought are expected to restrict hydropower generation in the western United States and imports from Hydro-Quebec to the New York Independent System Operator, Inc. (NYISO) and ISO-New England Inc. (ISO-NE) this winter.

Regarding market fundamentals, recent generator resource additions and transmission line expansions are expected to help address increased electric demand. Fuel-oil generation may be critical in certain regions, particularly ISO-NE, during peak periods. Moreover, natural gas demand is expected to increase this winter compared to the previous five-year winter average, with the residential and commercial sectors continuing to make up the largest share of total natural gas demand. Compared to last winter, natural gas prices are expected to decrease at every major trading hub except for Waha, a point that represents natural gas produced in the Permian Basin. Pipeline projects placed in service after last winter are expected to add 8.1 billion cubic feet per day (Bcfd) of new transportation capacity this winter.

Based on data provided by the assessment areas, the North American Electric Reliability Corporation (NERC) conducted probabilistic assessments that indicate possible challenges this winter for the electric grid. Under normal operating conditions, according to NERC, all assessment areas are expected to have adequate generating resources to meet expected winter electricity demand and operating reserve requirements. However, under extreme weather conditions, several assessment areas face a higher likelihood of tight generation availability in a range of operating scenarios: The SERC Reliability Corporation (SERC)-East area may have elevated risks under extreme conditions, while several other areas are facing transmission or fuel constraints. While electricity supply shortfalls are not expected, Northeast Power Coordinating Council New England (NPCC-NE) remains vulnerable to possible rapid depletion of stored fuel caused by a combination of winter peak demand exceeding projections and high generation outages during prolonged extreme weather. Portions of the Midcontinent Independent System Operator, Inc. (MISO) and Southwest Power Pool, Inc. (SPP) regions that are import-dependent may face local reliability challenges such as potential operational shortfalls during extreme weather. In general, these operating scenarios include higher peak load levels, reduced resources conditions, and wide-area extreme weather conditions. If these scenarios occur, operational mitigation may be needed to avoid facing reliability issues.

Weather Outlook

FIGURE 1
El Niño Expected to Drive Higher than Average Temperatures this Winter



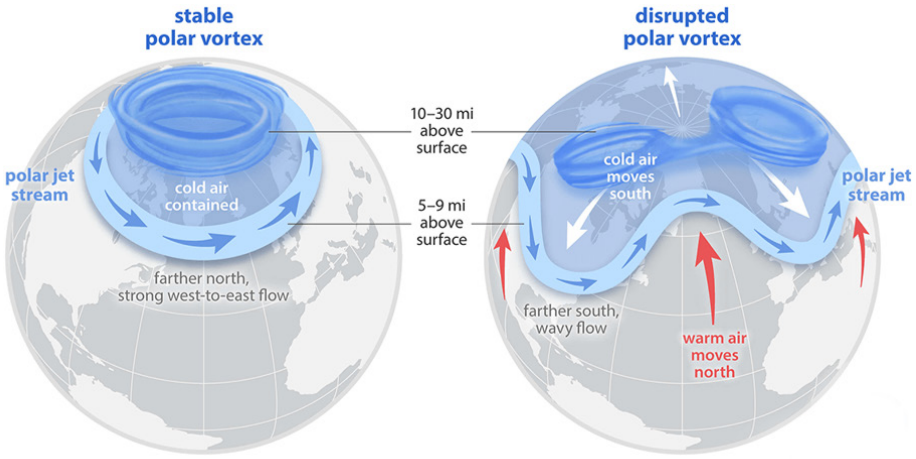
SOURCE: NOAA Three Month Temperature Outlook, Oct. 15, 2026

The National Oceanic and Atmospheric Administration's (NOAA) outlook for December 2026 to February 2027, shown in the map on **Figure 1**, projects above-average temperatures across most of the United States, except portions of the Southwest and Southeast. Additionally, NOAA forecasts a 100% chance of very strong El Niño conditions this winter, with an 83% chance of a historic event exceeding the strength of any El Niño event over the last 75+ years.[1] El Niño conditions typically drive overall higher temperatures across the northern and central United States, as seen in **Figure 1**.

1 NOAA, *El Niño/Southern Oscillation (ENSO) Diagnostic Discussion* (Sept. 10, 2026), www.cpc.ncep.noaa.gov/products/analysis_monitoring/enso_advisory/ensodisc.shtml.

Extreme Cold Risk

FIGURE 2
Extreme Cold Risks Elevated In Central & Eastern United States



SOURCE: NOAA National Environmental Satellite, Data and Information Service

As shown in **Figure 2**, the shifting weather fronts driven by the anticipated very strong El Niño conditions this winter are also expected to increase the risk of polar vortex disruptions, leading to extreme cold events, in the central and eastern United States.[2] Geographically widespread extreme cold temperatures can intensify stress on the electric grid by reducing the ability of neighboring systems to exchange supply while they are simultaneously facing high demand. Very strong El Niño conditions can also increase the probability of storms across the southern and coastal United States including coastal atmospheric river events that enhance flooding risk. When extreme cold coincides with precipitation from storms, it can also increase transmission line outages due to icing.[3] Winter Storm Fern in January 2026 demonstrated the reliability risks that extreme cold can pose in the southern United

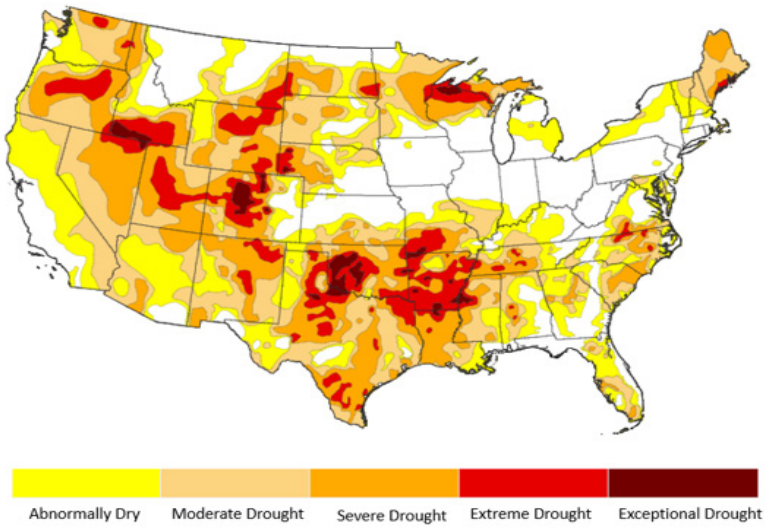
2 NOAA Pacific Marine Environmental Laboratory, *Study: Improving prediction of Arctic outbreaks across the Northern Hemisphere* (Jan. 7, 2026), www.pmel.noaa.gov/elnino/news-story/study-improving-prediction-arctic-outbreaks-across-northern-77hemisphere.

3 Cybersecurity and Infrastructure Security Agency, *Extreme Cold* (accessed Sept. 17, 2026), www.cisa.gov/topics/critical-infrastructure-security-and-resilience/extreme-weather/extreme-cold.

States and underscored the importance of winter preparedness.[4] Extreme cold can also reduce generator availability, leading to outages or derates.[5] Finally, these weather patterns can also lead to warm dry temperatures in the western and northern United States,[6] which can increase the risk of snow drought, decreasing hydro capacity availability and increasing future risk of wildfires in regions already experiencing drought and critically low reservoirs.

Drought and Reservoir Levels

FIGURE 3
Widespread Drought Continues to Impact Grid Resources



SOURCE: U.S. Drought Monitor Updated Oct. 15, 2026

Persistent drought conditions increase the risks to energy infrastructure and generator availability this winter, creating challenges for grid reliability. Drought conditions currently impact 45% of the continental United States, as shown in **Figure 3**. Record-breaking high temperatures in recent months and widespread severe conditions have left most of the western United States, including 95% of the Intermountain West, in drought. Historically low

4 FERC, *System Performance Review of the Winter 2026 Arctic Cold Period* (Sept. 10, 2026), www.ferc.gov/media/report-system-performance-review-winter-2026-arctic-cold-period.
5 Cybersecurity and Infrastructure Security Agency, *Extreme Cold* (accessed Sept. 17, 2026), www.cisa.gov/topics/critical-infrastructure-security-and-resilience/extreme-weather/extreme-cold
6 NOAA, *Prognostic Discussion for Long-Lead Seasonal Outlook* (Sept. 17, 2026), www.cpc.ncep.noaa.gov/products/predictions/90day/fxus05.html.

water levels in the Colorado River and Rio Grande Basins are expected to reduce generator availability at major hydroelectric dams this winter.[7] Fall monsoon rains will neither offset drought and its impacts, nor will they improve the region's long-term water supply challenges in any meaningful way due to the extreme magnitude of the precipitation deficit. According to NOAA, between 250% and 1,200% of normal precipitation is needed in the affected region to end drought before winter. NOAA's models put the chances of drought ending in the affected regions this winter at less than 3%.[8]

Likewise, the precipitation accompanying a very strong El Niño is not likely to alleviate drought in the Intermountain West because of forecasted high risk of early snow melt and high evaporation in this region.[9]

In the Colorado River Basin, even with the current El Niño forecast, under the most probable inflow forecasts predicting water flows into reservoirs, the Glen Canyon dam is expected to remain at critically low elevations through this winter. Under the lowest water inflow forecast, in 2027, the dam remains at risk of reaching minimum power pool, the lowest water level in a reservoir at which a hydroelectric dam can still safely spin its turbines and generate electricity, risking the outage of the generator plant. In addition, under all inflow forecasts, water elevations are expected to continue to decline at Hoover Dam, reducing the generator plant's availability to minimal levels. Regional transmission system planning does not necessarily account for these long-term drought impacts on the grid. On a day-to-day basis, these conditions can create congestion and affect system operators' ability to respond to voltage support challenges, event response mitigation needs, or any additional grid stressors.[10]

7 NOAA National Integrated Drought Information System, *Drought Status Update for the Intermountain West* (Aug. 20, 2026), www.drought.gov/drought-status-updates/drought-status-update-intermountain-west-2026-08-20.

8 NOAA, *Drought Termination and Amelioration* (Oct. 17, 2026), www.ncei.noaa.gov/access/monitoring/drought-recovery/current/wmp/ame-perc/3.

9 NOAA, *Prognostic Discussion for Long-Lead Seasonal Outlook* (Oct. 15, 2026), www.cpc.ncep.noaa.gov/products/predictions/90day/fxus05.html.

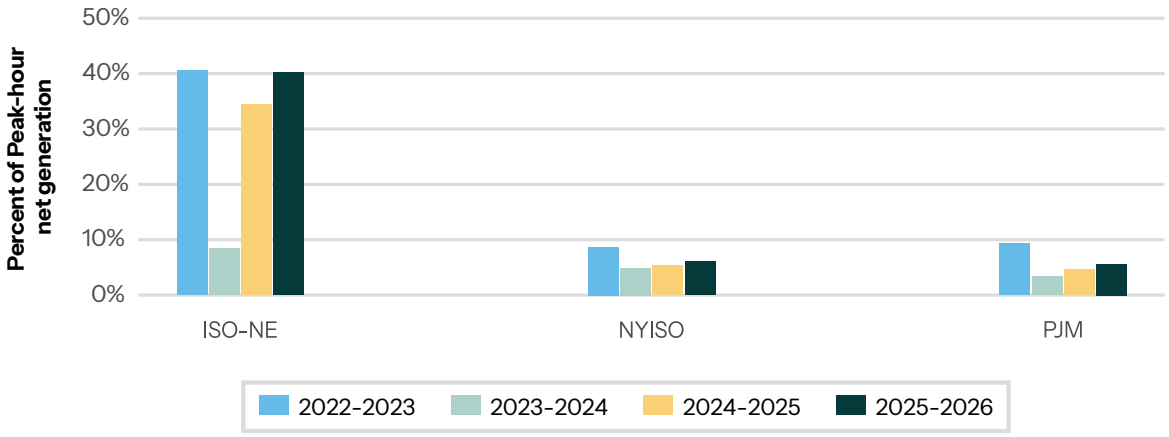
10 Bureau of Reclamation with WAPA, *Technical Appendix – 15 Dams and Electrical Power Resources*, at 15.1.4 (Jan. 2026), www.usbr.gov/ColoradoRiverBasin/post2026/draft-eis/docs/vol-3/P26-DEIS-TA-15.pdf.

Notable Issues

Staff identified two notable issues heading into this winter. The first is fuel oil availability in the Northeast, and is based on fuel oil usage in prior winters in ISO-NE, NYISO, and PJM Interconnection LLC (PJM). The second is recent market reforms in the Western Interconnection, ISO-NE, and NYISO. The next two sections elaborate on these issues as they relate to the upcoming winter.

Fuel Oil Availability in the Northeast

FIGURE 4
Highest Fuel-Oil Share of Net Generation by Winter Season During On-Peak Hours



SOURCE: U.S. Energy Information Administration (EIA) Form 930

During cold weather, Northeast grid operators often rely on fuel oil and dual-fuel generators (together, oil generation) to maintain reliability. As a share of total net generation, ISO-NE relies on oil generation more than any other resources during some periods of high winter demand. This was especially evident on January 25, 2026, when oil generation output reached 7,864 megawatts (MW) in a single hour, supplying roughly 40% of ISO-NE's total net generation during that peak winter hour (**Figure 4**).[11] Moreover, oil generation's hourly share of ISO-NE's total net generation has exceeded 30% in at least one hour in three of the last four winters, demonstrating that, at least in ISO-NE, oil generation consistently proves useful during periods of high winter demand. In NYISO and PJM by comparison, oil generation's maximum share of total net generation is much smaller, and has not reached 10% in either region over the past four winters.

11 EIA-930 Data from 2022-2026. *See also*, EIA, *Petroleum electricity generation surpassed natural gas in New England during winter storm* (Jan. 29, 2026), www.eia.gov/todayinenergy/detail.php?id=67104.

Year-to-year dual-fuel usage varies significantly depending on cold events and distillate inventories.[12] Currently, with global distillate markets tight and U.S. net exports near five year highs, U.S. distillate fuel oil inventories, which include heating oil, are low compared to the five-year nationwide average. For the week ending October 2, 2026, U.S. inventories were 105.1 million barrels, 12% below the prior five-year average and the lowest level for that week on record since 1982.[13]

A similar situation exists for distillate stocks in New England and the Central Atlantic region, where inventories are also at near-record lows. In New England, for example, stocks were at 2.5 million barrels for the week ending October 2, 2026, 46% below the prior five-year average, which came after stocks fell in late August to the lowest levels seen since EIA began reporting regional data in 1990.[14]

Furthermore, beyond fuel on hand to start the winter, the ability to replenish inventories as they are depleted during the season is critical for oil-fired generators. Because the Northeast has little refining capacity, reliable resupply via Gulf Coast pipelines or waterborne deliveries through New York Harbor remain critical.

During winter 2025-2026, ISO-NE replenished nearly 1,800 gigawatt-hours (GWh) of oil inventories and NYISO resupplied 1,430 GWh between January 24 and February 9 alone (an amount equal to 73% of the oil consumed during the same period).[15]

Overall, these trends highlight both near-term fuel availability risks and the need for durable supply-chain planning in preparation for severe winter conditions.[16] Fuel assurance measures, timely inventory replenishment, and closer operator coordination help operators better maintain reliability during extended cold weather events.[17] Operators also gain visibility into expected generator availability through fuel availability reporting, including ISO-NE's 21-Day Energy Assessment, NYISO's Generator Fuel and Emissions Reporting (GFER), and PJM's Enhanced Dispatcher Application and Reporting Tool (eDart) platforms.[18]

12 Distillate fuel oil includes both diesel fuel used in vehicles and home heating oil. During winter heating season, distillate fuel inventories are heavily drawn to meet increased demand for heating oil.

13 EIA, *Weekly Stocks of Distillate Fuel Oil*, (Oct. 2, 2026), www.eia.gov/dnav/pet/pet_stoc_wstk_a_epd0_sae_mbbl_w.htm.

14 EIA, *Short-Term Energy Outlook*, at 7 (Oct. 6 , 2026), Weekly Stocks of Distillate Fuel for PADD 1 New England, www.eia.gov/outlooks/steo/report/index.php.

15 ISO-NE, *IMM Quarterly Markets Performance Report: Winter 2026 Report Highlights* at Slide 8 (July 21, 2026); NYISO, *Quarterly Report on the New York ISO Electricity Markets*, *Q1 2024* at Slide 48 (July 20, 2026).

16 FERC-NERC and Regional Entities Joint Report: *Winter 2026 Arctic Events – A System Performance Review* (Sept. 10, 2026) provides examples of durable supply chain planning to address inventory replenishing challenges on waterways and roads and coordination of non-fuel vulnerabilities.

17 *Id.* at 17-20.

18 ISO-NE's 21-Day Energy Assessment projects potential energy shortfalls and fuel-supply constraints over a multi-week horizon; NYISO's GFER process tracks generator fuel inventories, fuel availability, and replenishment expectations; and PJM's eDART facilitates communication of generator status, outage information, and other operational data.

Market Reforms

Multiple market rule changes are expected to impact the bulk power system this winter, primarily in the West and Northeast. On May 1, 2026, the California Independent System Operator Corporation (CAISO) launched the Extended Day Ahead Market (EDAM), a voluntary day-ahead electricity market intended to expand on the efficiency of CAISO's Western Energy Imbalance Market, which will include parts of 11 states in the West.[19] Similarly, SPP expanded into the Western Interconnection on April 1, 2026, which should allow better pooling of resources and coordination in the West and across interconnections going into winter 2026-2027.[20]

EDAM and SPP's expansion should provide ratepayers in much of the West with production cost savings and improved reliability in winter 2026-2027, particularly during cold weather events. The balancing areas joining EDAM and SPP's expansion had not previously participated in organized day-ahead planning.[21] In particular, improved coordination of generation and reduced need for reserves across western markets will help address the reduction in flexible and affordable power from the Glen Canyon and Hoover dams, which are constrained by low reservoir levels to approximately a third of their maximum output going into this winter.[22] Imbalance reserve requirements since EDAM went live have fallen as much as 66% in some months heading into this winter, freeing dispatchable capacity for other reliability needs.[23]

19 CAISO, *Extended Day-Ahead Market Fact Sheet*, press release (Apr. 2026), www.caiso.com/documents/extended-day-ahead-market-edam-fact-sheet.pdf.

20 SPP's expansion into the Western Interconnection includes 9 load-serving entities in Arizona, Colorado, Montana, Nebraska, New Mexico, Utah, and Wyoming.
The Brattle Group, *Benefits of the SPP RTO Expansion into the WEIS Footprint*, at 8 (Sept. 20, 2022) www.wapa.gov/wp-content/uploads/2023/04/2022-spp-rto-brattle-study.pdf.
SPP, *Powering Progress Together*, at 12-13 and 20, (April 2026) www.spp.org/about-us/value-of-spp. SPP is also establishing Markets+, a day ahead energy market outside of its footprint similar in concept to EDAM; however, as Markets+ will not go live until October 2027 for the first participants, it is not discussed in this assessment.
SPP, *Markets+* (Sept. 2026), www.spp.org/western-services/marketsplus.
Southwest Power Pool, *SPP and member utilities successfully complete historic western expansion*, press release (Apr. 2, 2026) www.spp.org/news-list/spp-and-member-utilities-successfully-complete-historic-western-expansion.

21 PacifiCorp, *EDAM is live: PacifiCorp and CAISO successfully launch new market May 1*, Press Release (May 1, 2026) www.pacificorp.com/about/newsroom/news-releases/extended-day-ahead-market-live.html.
SPP, *SPP and member utilities successfully complete historic western expansion*, press release (Apr. 2, 2026) www.spp.org/news-list/spp-and-member-utilities-successfully-complete-historic-western-expansion.
SPP, *Powering Progress Together*, at 11-13, (Apr 2026) www.spp.org/about-us/value-of-spp.

22 WECC, *2026 Colorado River Hydro Update*, (Oct. 14, 2026), feature.wecc.org/coriverhydro/index.html.

23 Imbalance reserves are procured to cover uncertainty in weather dependent generation and in load forecasting, see *Cal. Indep. Sys. Operator Corp.*, 185 FERC ¶ 61,210, at P 58 (2023).
CAISO, *Western Energy Markets Quarterly Benefits Report*, at 6 (July 2026), www.westernenergymarkets.com/documents/western-energy-markets-quarterly-benefits-report-q2-2026.pdf.

Operators of eastern markets have also enacted reforms ahead of the coming winter. ISO-NE reduced its capacity performance pay rate from $9,337 per MW-hour (MWh) to $3,500 per MWh as of September 1, 2026; other factors remaining the same, this should lower electricity prices in any emergency conditions or capacity performance events in New England this winter.[24] This revised pay rate also provides increased performance incentives during prolonged, multi-hour capacity scarcity conditions for which capacity resources would otherwise reach their monthly or annual stop-loss limit and thus have a reduced incentive to perform during long-duration events.[25] Additionally, NYISO has increased its operating reserve margins in its Day-Ahead and Real-Time Markets for this year going into the upcoming winter with the introduction of an uncertainty reserve product. This higher reserve margin covers 95% of net uncertainty in forecasts and will provide protection against simultaneous forecast error and tight conditions.[26]

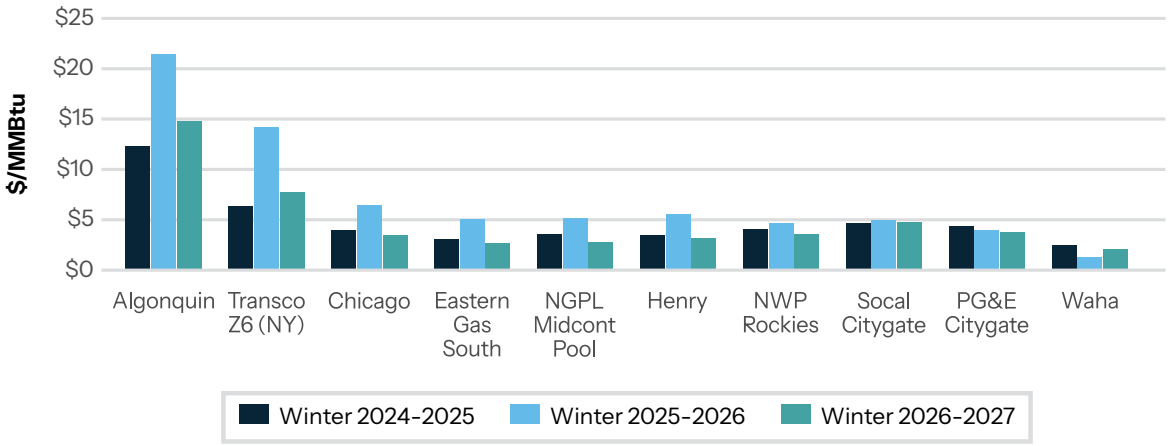
NYISO also modified its Installed Capacity market rules to reflect uncertainty about the amount of power H.Q. Energy Services (U.S.) Inc. (HQUS)[27] will deliver over the 1,250 MW Champlain Hudson Power Express (CHPE) transmission line during the upcoming winter.[28] Since HQUS has an obligation to serve native load in Hydro-Québec, which is a winter-peaking system, this obligation along with ongoing reduced runoff to HQUS's hydroelectric resources has left little or no surplus capacity to export to NYISO in recent years' peak winter months.[29] NYISO changed its market rules to reflect the expectation that HQUS is likely to provide no capacity through the CHPE during December, January, and February, the peak winter months in the 2026-2027 Capability Year.[30] Implementing these rule changes increased the winter capacity reference price from $7.09 per kW-month to $10.18 in New York City for these months.[31]

24 *ISO-New England Inc.*, 196 FERC ¶ 61,172, at P 1 (2026).
25 *Id.* P 39.
26 *N.Y. Indep. Sys. Operator*, Inc., 192 FERC ¶ 61,021, at PP 1-4 (2025); NYISO, *Notice of Delayed Effective Date: Process to Procure Uncertainty Reserves to be effective 9/16/2026 under ER25-1998*, at 2 Docket No. ER25-1998-002 (2026); NYISO, Uncertainty Reserve Requirement (Sep. 24, 2026) www.nyiso.com/power-grid-data.
27 HQUS is an American subsidiary of Hydro-Québec; Hydro-Québec, *Contact Us*, (Oct. 2026), www.hydroquebec.com/clean-energy-provider/contact.html.
28 *N.Y. Indep. Sys. Operator, Inc.*, 196 FERC ¶ 61,154, at 4 (2026).
29 *N.Y. Indep. Sys. Operator, Inc.*, Filing, Docket No. ER26-2959, Attachment III (Zhang Aff.) at 9-10 (filed June 25, 2026). NERC, *2026 Summer Reliability Assessment*, at 24, 52 (May 2026), www.nerc.com/globalassets/our-work/assessments/nerc_sra_2026.pdf.
N.Y. Indep. Sys. Operator, Inc. 196 FERC ¶ 61,154, at PP 1, 6-8 (2026).
30 *Id.* PP 6-8.
31 NYISO, 2026-2027 *Winter Capability Period: Potential ICAP Market Parameter Misalignment*, at 18-23, (April 29, 2026), www.nyiso.com/documents/20142/57787467/2026-2027%20Winter%20Potential%20Misalignment%20-%2004292026%20MC%20Final.pdf/e55f86d9-861c-dd07-76ed-ed2308dda495.

Natural Gas Fundamentals

Natural Gas Prices

FIGURE 5
Natural Gas Prices at All Major Hubs Except Waha Expected to be lower than last winter



NOTE: These prices represent the average last traded futures prices for December, January and February. Previous winters' prices represent average settled futures prices.

SOURCE: InterContinental Exchange

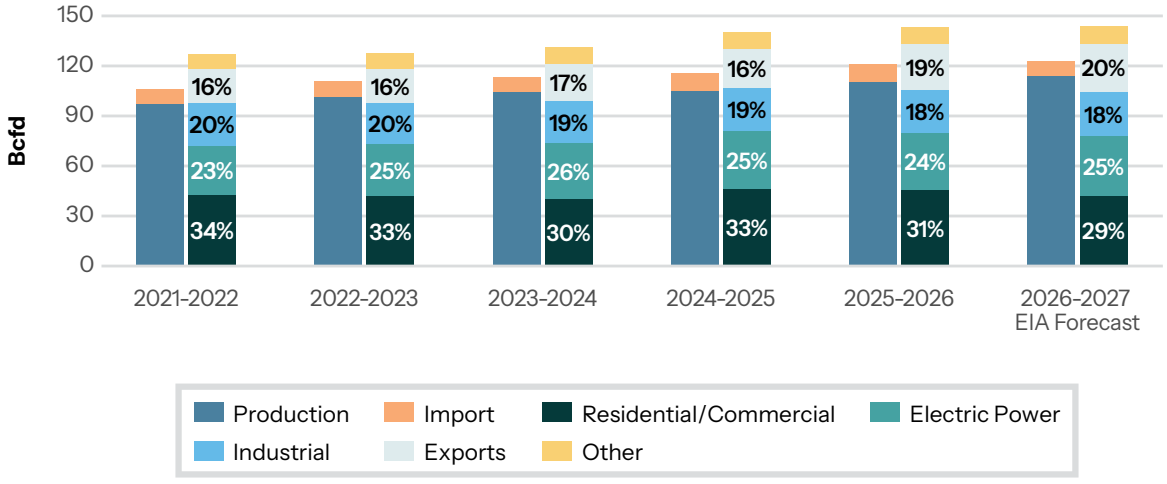
Natural gas futures provide expectations for natural gas prices at key hubs for the upcoming winter. The chart above, **Figure 5**, displays average natural gas futures prices for three consecutive winters. The green bars represent futures prices for the upcoming winter (2026-2027), the gray bars show prices from last winter (2025-2026) and the blue bars show prices from winter 2024-2025. As of November 10, 2026, natural gas futures prices were trading lower than last winter at nearly every major trading hub in the United States. Lower natural gas futures prices in the East and Midwest regions for winter 2026-2027 can likely be attributed, at least in part, to relatively robust regional storage inventory levels heading into the winter and expected warmer than normal temperatures for much of the Midwest and Northeast. Also affecting the comparison, settled prices for winter 2025-2026 reached extremely high levels due to winter storms Fern and Gianna.

For many hubs, lower prices reflect lower expectations for the natural gas commodity price as indicated by trading at the Henry Hub, which has historically served as the North American natural gas pricing benchmark. Natural gas prices at the Henry Hub, located in Louisiana,

are trading at $3.19 per million British thermal units (MMBtu) for the upcoming winter, $2.33/MMBtu (42%) below last winter's settled price of $5.52/MMBtu.[32] Natural gas winter futures prices at Algonquin Citygate, a Boston area pricing hub, remain the highest in the country at $14.81/MMBtu, but are below last winter's settled price of $21.45/MMBtu. Elsewhere in the East, winter futures prices at Transco Zone 6 NY, a hub that represents New York City, are also elevated, trading at $7.73/MMBtu, but remain significantly below last year's settled price of $14.19/MMBtu. Finally, winter futures prices at the SoCal Citygate hub, a point that represents the Southern California market, are trading at $4.75/MMBtu, a slight decrease from last winter's settled price of $4.98/MMBtu. The only hub expected to trade higher than last winter is Waha, a point that represents natural gas produced in the Permian Basin, which is trading at $2.10/MMBtu, $0.72/MMBtu higher than last year's settled price. This higher price may in part reflect the addition of several new pipelines in the Permian Basin, which are helping to alleviate takeaway capacity constraints.

Natural Gas Demand

FIGURE 6
Slight Increase in Natural Gas Demand Forecasted



SOURCE: U.S. EIA, Short-Term Energy Outlook (STEO) Table 5a

32 Natural gas futures prices are price quotations of contracts for the exchange of natural gas, as either a physical or financial settlement, at a specified time in the future. Winter futures prices in this section are the average of the last traded futures contracts as of November 10, 2026, from InterContinental Exchange, Inc. (ICE), for the winter months of December 2026, January 2027, and February 2027. Previous winter averages are final settled futures prices for each month from ICE.

Natural gas demand is forecast to increase slightly this winter, buoyed by increases in demand for electricity generation (also known as power burn) and exports that would offset a forecast decrease in residential and commercial demand. Total natural gas demand is forecast to average 143.7 Bcfd in winter 2026-2027, a 0.2% increase from the 143.4 Bcfd in winter 2025-2026 but 8% higher than the previous 5-year average.

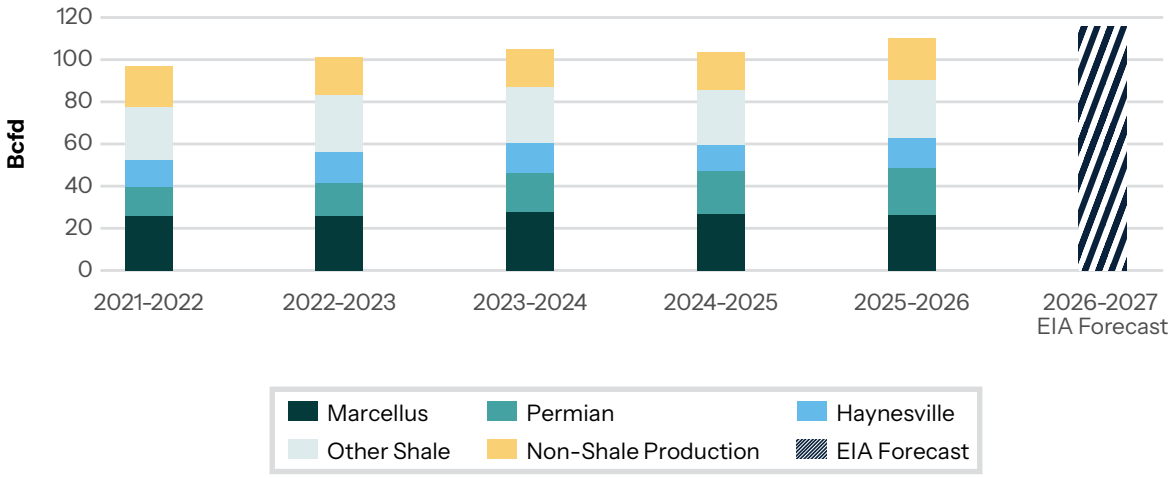
Natural gas demand for electricity generation is expected to increase by 0.8 Bcfd this winter compared to last winter. Natural gas demand for electricity generation is forecast to average 35.7 Bcfd and account for 25% of total demand in winter 2026-2027. Natural gas exports, which include both pipeline and liquefied natural gas (LNG) exports, are expected to increase 1.6 Bcfd from last winter and average 29.2 Bcfd this winter.[33] Natural gas exports are expected to make up 20% of total natural gas demand this winter. Additional LNG liquefaction and export capacity will enable increased LNG exports as discussed below.

The residential and commercial sector is the only sector in which demand is expected to decrease this winter compared to last, from 45.1 to 42.1 Bcfd. This lower expected demand reflects an expected warmer winter, which would result in lower demand for natural gas used for space heating. This winter's forecasted residential and commercial sector demand would equate to a 7% winter-over-winter decrease and a 2% decrease from the previous 5-year average. Residential and commercial demand is projected to account for 29% of expected total natural gas demand this winter, the largest share of total natural gas demand.

33 LNG exports do not include the quantity of natural gas consumed for LNG liquefaction, only the amount of LNG that is exported out of the U.S. Therefore, the quantity of LNG exports, as reported by EIA, is not equal to feedgas. Feedgas is included in "Other" in Figure 6. *See* EIA, *Natural Gas Explained* (June 21, 2024), www.eia.gov/energyexplained/natural-gas/liquefied-natural-gas.php.

Natural Gas Production

FIGURE 7
Natural Gas Production Continues to Increase in the Wintertime



SOURCE: U.S. EIA, STEO Table 5a and 10b

Natural gas production is expected to increase this winter compared to last winter, driven by continued growth in the Permian Basin and Haynesville shale formation. The EIA forecasts U.S. dry natural gas production to average 115.8 Bcfd during winter 2026-2027.[34] This represents a 5% increase from the winter 2025-2026 average of 110.3 Bcfd and is 12% above the previous five-year average of 103.5 Bcfd.[35] The different colored segments within each bar in **Figure 7** break down the total production by region, illustrating how various shale plays contribute to overall production volume. Dry gas production remains concentrated across three regions. Collectively, Appalachian, Permian, and Haynesville production accounted for 64% of total U.S. dry gas production in the first ten months of 2026.[36]

Appalachia remains the largest natural gas-producing region with the Marcellus and Utica shales combining to produce 33.9 Bcfd, approximately 30% of total U.S. dry natural gas

34 EIA, *Short-Term Energy Outlook* at Table 5a (Nov. 10, 2026), https://www.eia.gov/outlooks/steo; Dry natural gas is consumer-grade natural gas that is almost entirely composed of methane with little to no hydrocarbon liquids or impurities.
35 EIA, *Short-Term Energy Outlook* at Table 5a (Nov. 10, 2026), https://www.eia.gov/outlooks/steo.
36 *Id.* at Table 10b (Nov. 10, 2026), www.eia.gov/outlooks/steo.

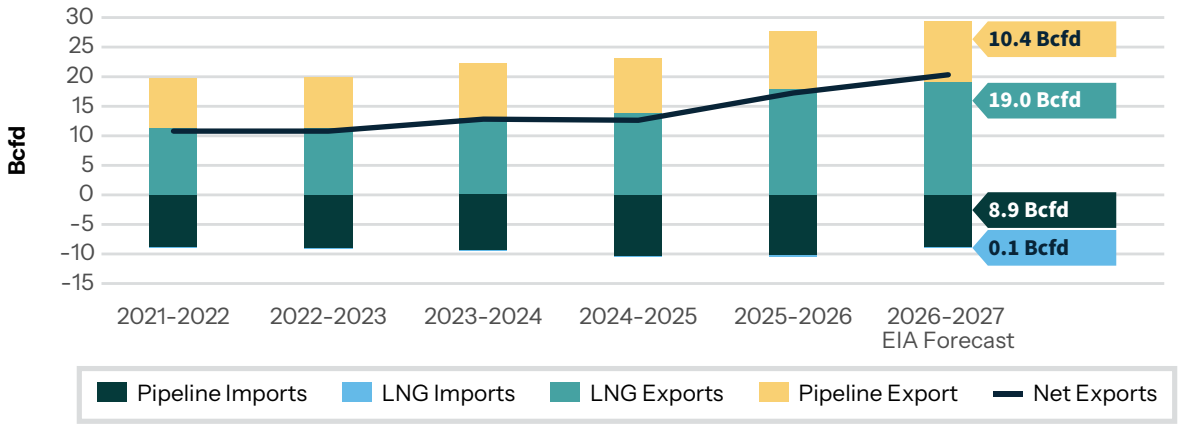
production in the first ten months of 2026.[37] Appalachian natural gas production is primarily located in Pennsylvania, West Virginia, and Ohio.

Production in the Permian Basin, located in West Texas and southeast New Mexico, averaged 23.5 Bcfd for the first ten months of 2026, representing 21% of the total U.S. dry gas production. Growth in Permian production is driven largely by crude oil market dynamics rather than gas-specific investment. Elevated oil prices, along with increased natural gas takeaway capacity, are expected to drive production of more associated natural gas, which is gas obtained as a byproduct of oil production.

The Haynesville formation, located in northwest Louisiana and East Texas, produced 14.5 Bcfd in the ten months of 2026. Haynesville production is advantageously located to serve growing Gulf Coast and Southeast natural gas demand for LNG exports and electric generation.

Natural Gas Exports and Imports

FIGURE 8
U.S. Natural Gas Exports Continue to Outpace Imports



SOURCE: U.S. EIA, STEO

Natural gas exports represent the fastest-growing demand segment in the U.S. market and are expected to significantly outpace natural gas imports this winter. The chart on **Figure 8**

37 EIA, *Short-Term Energy Outlook* at Table 5a (Nov. 10, 2026), www.eia.gov/outlooks/steo; EIA, *Dry Shale Gas Production Estimates by Play* (Nov. 10, 2026), www.eia.gov/outlooks/steo/xls/Fig43.xlsx.

illustrates this trend, breaking down the volumes of U.S. natural gas LNG and pipeline imports and exports. The stacked bars are segmented to show volumes of LNG exports, pipeline exports and pipeline imports. As seen in **Figure 8**, EIA forecasts U.S. gross LNG exports to average 19.0 Bcfd in winter 2026-2027, up 6.6% from winter 2025-2026. Altogether, the United States is expected to be a significant net exporter of natural gas this winter. LNG and pipeline exports are expected to exceed imports by an average of 20 Bcfd, compared to 17.2 Bcfd in winter 2025-2026. This growth in net exports is represented by the black line on the chart in **Figure 8**, and is primarily due to increased LNG export capacity from the Corpus Christi LNG Stage 3 and Golden Pass LNG projects. The United States remains the world's largest LNG exporter, with FERC-authorized liquefaction capacity in the Lower 48 states expected to increase to 21.0 Bcfd by the end of the winter.[38]

Gross pipeline exports, including flows to both Canada and Mexico, are forecast to be 10.4 Bcfd, which is 0.4 Bcfd above average exports in winter 2025-2026.[39] Gross pipeline imports, primarily from Canada, are forecast to average 8.9 Bcfd in winter 2026-2027, declining by 1.4 Bcfd compared to winter 2025-2026.[40] In total, the United States is a net gas importer from Canada and a net exporter to Mexico.

While LNG imports play a minor (and declining) role in the overall U.S. gas balance, LNG imports can play a vital role in ensuring gas supply is adequate to meet demand during cold weather events when pipeline capacity is constrained. During the winter 2025-2026 arctic cold period, which included winter storms Fern and Gianna, some LNG export terminals, such as the Cove Point LNG in Maryland and Elba Island LNG in Georgia, imported LNG to supplement regional supplies.[41] LNG imports reached as high as 1.4 Bcfd during the storm on January 26, 2026, and totaled over 9.3 Bcf during the winter 2025-2026 arctic cold period, helping to offset increased domestic demand during that timeframe.[42]

LNG export terminals also use on-site storage for LNG exports, thereby reducing overall feedgas[43] demand, increasing the amount of U.S. production available for domestic

38 FERC, *North American LNG Export Terminals – Existing, Approved not Yet Built, and Proposed* (Aug. 18, 2026), www.ferc.gov/media/us-lng-export-terminals-existing-approved-not-yet-built-and-proposed; EIA, U.S. *Liquefaction Capacity – Existing & Under Construction, Approved* (Oct. 1, 2026), www.eia.gov/naturalgas/importsexports/liquefactioncapacity/U.S.liquefactioncapacity_2026_Q3.xlsx; Jacob Dick, Golden Pass LNG *Targets 2027 for 2 Trains as Feedgas Hits New High*, Natural Gas Intelligence (Oct. 16, 2026), naturalgasintel.com/news/golden-pass-lng-targets-2027-for-2-trains-as-feedgas-hits-new-high.

39 EIA, *U.S. Natural Gas Exports and Re-Exports by Country* (Oct. 30, 2026), www.eia.gov/dnav/ng/ng_move_expc_s1_m.htm.

40 EIA, *U.S. Natural Gas Imports by Country* (Oct. 30, 2026), https://www.eia.gov/dnav/ng/ng_move_impc_s1_m.htm.

41 On January 29, 2026, Elba Island LNG Terminal in Georgia received its first LNG import since 2020. *See* FERC, *System Performance Review of the Winter 2026 Arctic Cold Period*, at 32 (Sept. 10, 2026), www.ferc.gov/media/report-system-performance-review-winter-2026-arctic-cold-period.

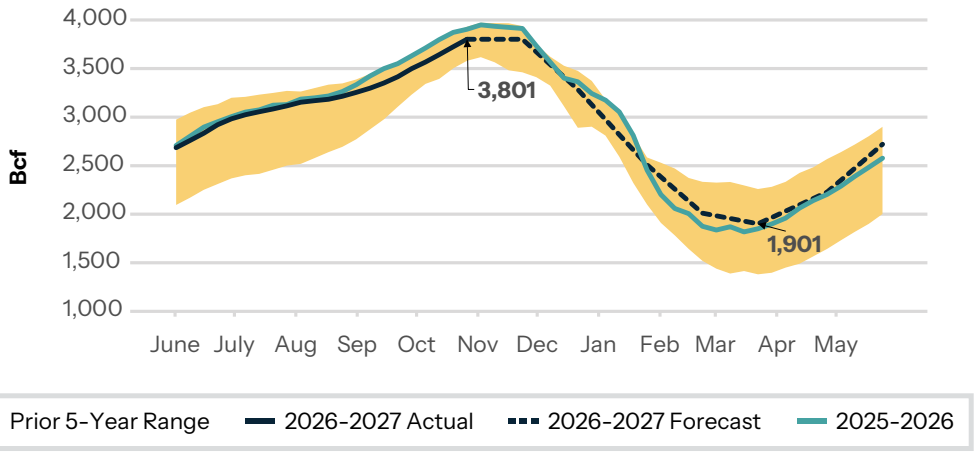
42 IBID..

43 Feedgas is pipeline-quality natural gas that is delivered to an LNG facility for liquefaction.

consumers, and improving overall system resilience. For example, Corpus Christi LNG, Golden Pass LNG, and Plaquemines LNG have in total approximately 43.5 Bcf of natural gas storage capacity that they could use for short periods of time to help serve exports and substitute for feedgas demand.[44] Such substitute use occurred during the winter 2025-2026 arctic cold period, when LNG export feedgas demand fell by over 40% to 11.3 Bcfd on January 26, 2026, likely reflecting the use of on-site storage as well as localized supply impacts, and other commercial responses to market conditions.[45]

Natural Gas Storage Inventories

FIGURE 9
Natural Gas Storage Inventories Forecast to Remain Adequate Through Winter



SOURCE: U.S. EIA, STEO Table 5a and EIA Weekly Natural Gas Storage Report

Natural gas storage helps to balance natural gas supply and demand and is fundamental to winter natural gas price formation. **Figure 9** illustrates the storage forecast for winter 2026-2027.[46] The solid green and dashed blue lines track actual and projected inventory levels

44 Golden Pass LNG, Operations (accessed Sept. 21, 2026), www.goldenpasslng.com/operations/export-project#liquefaction-facilities; Cheniere, Corpus Christi Liquefaction (accessed Sept. 21, 2026), www.cheniere.com/about/where-we-work/ccl; Venture Global, Plaquemines (accessed Sept. 21, 2026), ventureglobal.com/venture-global-plaquemines/plaquemines-facility.

45 FERC, *System Performance Review of the Winter 2026 Arctic Cold Period*, at 2, 31 (Sept. 10, 2026), www.ferc.gov/media/report-system-performance-review-winter-2026-arctic-cold-period. The cause of decline in LNG export feedgas demand from any specific LNG export terminal may differ by facility.

46 U.S. natural gas storage inventory data listed in this section is for the Lower 48 states.

respectively for the current season (2026-2027). Staff projections show natural gas storage inventories remaining within the prior five-year range through the winter, with starting levels near the five-year average but below the past three winters.[47] Lower 48 natural gas storage inventories are forecast to begin the withdrawal season at 3,801 Bcf, 0.2% below the prior five-year average and 3.7% below last season's starting level.[48] Staff projects withdrawals of approximately 1,901 Bcf, 10.8% less than winter 2025-2026 and 5.5% less than the prior five-year average. That would leave 1,901 Bcf in storage at the end of season, 5.8% above the previous five-year average. However, sustained extreme cold could draw inventories down faster than projected, as it did last winter when a single week's withdrawal reached 359 Bcf in January 2026.

Regionally, natural gas storage inventories are forecast to enter the withdrawal season near their five-year averages.[49] The East is expected to begin the season approximately 1.3% above both last year's level and the five-year average, while the Midwest is expected to be about 0.5% below last year's level but 0.3% above the five-year average. The Mountain region shows the largest cushion relative to its five-year average, starting approximately 3.8% above, though 7.8% below last year's starting level. The Pacific region is forecast to start approximately 9.1% above last year's level but 1.2% below its five-year average. The South-Central region, which holds the largest share of national inventories and provides the most flexible deliverability through its salt cavern capacity, is forecast to be approximately 8.3% below last year's levels and 2.8% below its five-year average.

Natural Gas Infrastructure

Natural gas infrastructure additions provide for more capacity used to process, transport, and store natural gas as it moves from initial production (or import) to ultimate delivery (including export). Interstate pipeline projects newly placed in service or expected to be in service by winter 2026–2027 are projected to add approximately 8.1 Bcfd of transportation capacity this winter.[50]

Two of the largest pipeline projects will provide feedgas to LNG export facilities. The Rio Bravo Pipeline project will bring 4.5 Bcfd of natural gas from the Agua Dulce supply area in Kleberg County, Texas to NextDecade's Rio Grande LNG export facility at the Port of

47 Staff's winter storage projections were derived from referral to STEO reported actual monthly storage numbers and extrapolating forecasted storage trends directions and magnitude from its forecasted future monthly storage totals.

48 EIA, *Short-Term Energy Outlook* (Nov. 10, 2026), www.eia.gov/outlooks/steo/pdf/steo_full.pdf.

49 Ibid.

50 This calculation is based on EIA's pipeline project database cross-referenced with FERC certificate filings and in-service announcements. EIA, Natural Gas Pipeline Projects (Aug. 2026), www.eia.gov/naturalgas/pipelines/EIA-NaturalGasPipelineProjects_Aug2026.xlsx.

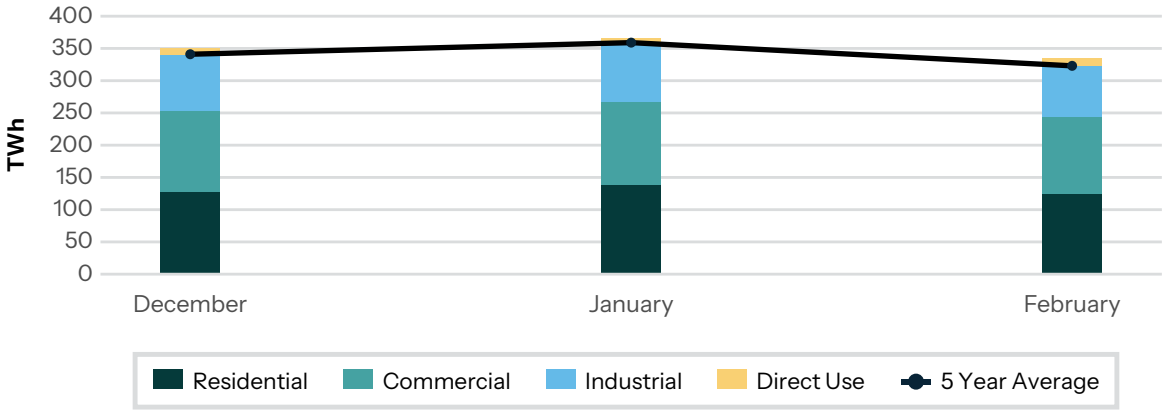
Brownsville in South Texas.[51] The Port Arthur Pipeline Louisiana Connector project will bring 2 Bcfd from southwestern Louisiana to the currently under-construction Port Arthur LNG Phase 1 export facility, located in Jefferson County, Texas. This export facility is expected to be operational in late 2027.[52]

There are also several large intrastate projects designed to bring West Texas Permian natural gas to South and Central Texas. Blackcomb Pipeline is expected to bring 2.5 Bcfd from West Texas to the Agua Dulce hub in Nueces County, Texas.[53] Hugh Brinson Phase I is expected to bring 1.5 Bcfd of natural gas from Waha, Texas to Maypearl, Texas (south of Dallas).[54] Finally, Energy Transfer's North Texas system has completed the first of three laterals, which is expected to supply 900 MMcfd of natural gas to Oracle's flagship Stargate data center campus in Abilene, Texas to serve on-site generation.[55]

51 Rio Bravo Pipeline Co. LLC, Rio Bravo Pipeline: About Us (accessed Oct. 29, 2026), riobravopipeline.com.
52 Sempra Infrastructure, Port Arthur Pipeline Louisiana Connector fact sheet (accessed Oct. 29, 2026), https://semprainfrastructure.com/what-we-do/energy-networks/port-arthur-pipeline-louisiana-connector.
53 Blackcomb Pipeline, About Blackcomb Pipeline: Project Overview (accessed Oct. 29, 2026), https://blackcombpipeline.com.
54 Energy Transfer, Hugh Brinson Pipeline (Phase I & II) fact sheet (accessed Oct. 29, 2026), https://pipelines.energytransfer.com/ipost/capacity/design-capacity-for-intrastates?asset=HBP.
55 Jacob Dick, *Energy Transfer Launches Natural Gas Deliveries to Oracle Data Center*,Natural Gas Intelligence (Feb. 17, 2026), naturalgasintel.com/news/energy-transfer-launches-natural-gas-deliveries-to-oracle-data-center.

Electricity Consumption

FIGURE 10
2026-2027 Projected Winter Electricity Consumption by End User



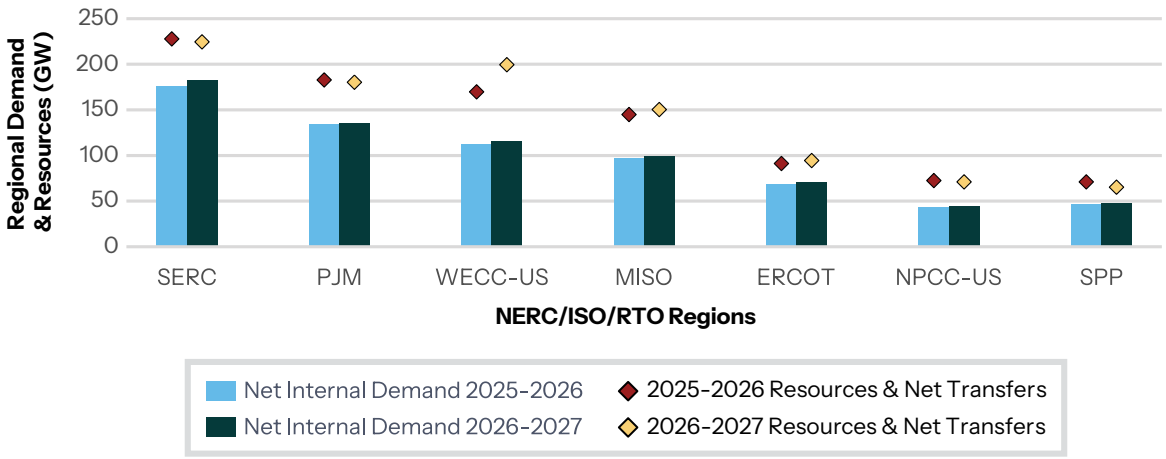
SOURCE: U.S. EIA, STEO Table 7a

Figure 10 highlights continued projected load growth through the winter 2026-27, showing a breakdown of electricity consumption by end-use sector. The residential sector is projected to have the highest total consumption at 391 terrawatt-hours (TWh), followed by the commercial sector at 375 TWh and the industrial sector at 255 TWh. The stacked bars on the chart show that consumption across all sectors is expected to peak in January, reaching a high of 367 TWh. Importantly, the commercial sector is projected to see the most growth at over 6% above its five-year average, representing, in part, continued growth in large load demand. Some commercial and industrial facilities use onsite generation to serve some or all of their own energy needs. This is labeled as 'direct use' on the chart where it represents just over 3% of electricity consumption (35 TWh in winter 2026-2027) and is expected to remain stable.[56]

56 According to EIA, Direct Use represents "commercial and industrial facility use of onsite net electricity generation; and electrical sales or transfers to adjacent or co-located facilities for which revenue information is not available." See EIA, *Short-Term Energy Outlook* at Table 7A (Nov. 10, 2026), www.eia.gov/outlooks/steo/archives/sep26.pdf.

NERC Electricity Demand and Resources

FIGURE 11
NERC Forecasted Electricity Demand & Resources
Winters 2025-2026 and 2026-2027



SOURCE: NERC, 2026-2027 Winter Reliability Assessment

NERC projects electricity demand and generation resources to assess resource adequacy for each assessment area.[57] NERC forecasts net internal demand for electricity to increase by 2.6%, or 17.7 GW, from 676.8 GW in winter 2025-2026 to 694.5 GW in winter 2026-2027. Electricity demand in the winter varies regionally and depends on the number of extreme weather events and the characteristics and duration of those events.

Figure 11 compares the net internal demand shown as solid bars and the resources and net transfer values shown as diamonds.[58] This figure compares winter 2025-2026 and winter 2026-2027 and shows that all seven regions, which cover NERC's 15 assessment areas, are expected to have sufficient available generation resources and net transfers to meet their

57 The NERC ISO/RTO Regions contain 15 U.S. assessment areas, broken down as, the NPCC-US (NPCC-New England and NPCC-New York); PJM Interconnection L.L.C. (PJM); SERC-US (SERC-Central, SERC-East, SERC-Southeast, and SERC Florida Peninsula); MISO; SPP; the Texas Reliability Entity-Electric Reliability Council of Texas (TRE/ERCOT); and WECC-US (WECC-NW (Northwest), WECC-SW, WECC-Rocky Mountain, WECC-Basin and WECC-California). NERC, *2025 Long-Term Reliability Assessment*, (Jan. 29, 2026), www.nerc.com/globalassets/our-work/assessments/nerc_ltra_2025.pdf.

58 Resources and Net Transfers refers to the addition of "Existing-Certain Capacity" and "Net Firm Capacity Transfers." NERC, *2025 Long Term Reliability Assessment*, at 167-168 (Jan. 29, 2026), www.nerc.com/globalassets/our-work/assessments/nerc_ltra_2025.pdf.

expected demand under normal winter conditions.[59] It also shows all assessment areas' planning reserve margins[60] exceeding the reference margins levels.[61] Reserve margins do not necessarily account for extreme winter conditions, which can lead to fuel unavailability, impacting generator availability, derates of electricity generators, unexpected generator outages, transmission outages, or reduced power transfers from adjacent areas. More comprehensive discussions of these assessment areas are in the *Regional Highlights and NERC Probabilistic Assessments* section of this report.

To serve demand in winter 2026-2027, NERC forecasts a national increase of 2.7%, or 25.5 GW, in total electric generation capacity and net energy transfers, i.e., exports/imports, from 960.1 GW in winter 2025-2026 to 985.7 GW in winter 2026-2027, driven largely by increases in the WECC-US, MISO, and ERCOT areas. However, electric generation capacity and net energy transfers have decreased since last year in SPP, SERC, PJM, and NPCC-US. The breakdown of total capacity and transfers by region is illustrated as diamonds in **Figure 11**.[62]

Longer term, NERC projects that winter peak demand across North America will grow by about 245 GW over the next decade, a 65% increase in load growth over the previous year's ten-year load growth forecast.[63] NERC attributes most of the projected load growth to the increasing number of large loads, primarily new data centers.[64] To address such load growth and associated operational risks, in May 2026 NERC escalated its large load response from a level 2 alert to a level 3 alert, focused specifically on computational loads to take actions related to modeling, system studies, instrumentation, commissioning, operations, protection, and control.[65]

Additionally, in several regions, coal and natural gas-fired plants are continuing operations pursuant to orders issued by the Secretary of Energy under section 202(c) of the Federal Power Act (FPA) (DOE section 202(c) orders).[66] These units total more than 5,169 MW of the

59 NERC, *2026-2027 Winter Reliability Assessment*, at 2-3 (Nov. 18, 2026), www.nerc.com/our-work/assessments.

60 The planning reserve margin measures the difference in resources (anticipated or prospective) and net internal demand divided by net internal demand, shown as a percentile. NERC, *2025 Long Term Reliability Assessment*, at 170 (Jan. 29, 2026), www.nerc.com/globalassets/our-work/assessments/nerc_ltra_2025.pdf.

61 The reference margin level (RML) can be determined using both deterministic and probabilistic (based on a 0.1/year loss-of-load study) approaches. If an RML is not provided by an assessment area, NERC applies 15% for predominant thermal systems and 10% for predominant hydropower systems. NERC, *2025 Long Term Reliability Assessment*, at 170 (Jan. 29, 2026), www.nerc.com/globalassets/our-work/assessments/nerc_ltra_2025.pdf.

62 *Id.* at 45-50.

63 *Id.* at 25.

64 *Id.* at 27.

65 NERC, *Essential Action to Industry*, (May 4, 2026), at 1-8, www.nerc.com/globalassets/programs/bpsa/alerts/level-3-computational-load-alert.pdf.

66 Pursuant to FPA section 202(c) and section 301(b) of the Department of Energy Organization Act, the Secretary of Energy may direct a plant to continue running to address an emergency and to serve the public interest. 16 U.S.C. § 824a(c); 42 U.S.C. § 7151(b).

capacity included in the resources shown in **Figure 12** that may be able to support reliability during peak demand.[67] Other notable thermal plant retirements that are not subject to the DOE section 202(c) orders are discussed below.

Electric Generation Additions, Retirements, & Outages

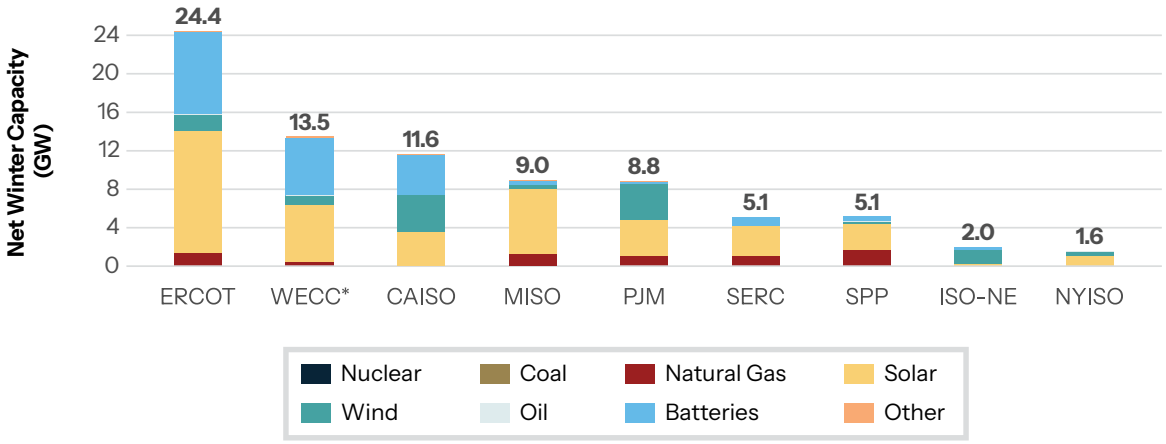
Compared to last winter, the EIA projects the electricity sector will have 75 GW of additional net winter generation capacity in winter 2026-2027.[68] This net increase reflects 80.9 GW of capacity additions offset by 5.9 GW of retirements. Of these capacity changes, 29.9 GW of additions and 820 MW of retirements were completed between March and August 2026, while 51.1 GW of additions and 8.6 GW of retirements are expected to occur between September 2026 and February 2027.[69] Given their operating characteristics and differences in capacity accreditation, new capacity from solar, wind, or storage facilities does not replace the retired thermal capacity from coal, natural gas, or oil units on a one-for-one basis.

67 Units directed to continue operations by the Secretary of Energy under FPA 202(c) include: Stanton Unit 1 (465 MW) in Florida, Eddystone Units 3 and 4 (760 MW) in Pennsylvania through November 2026, the Centralia Generating Station Unit 2 (730 MW) in Washington, the R.M. Schahfer Units 17 and 18 (847 MW) in Indiana, the Craig Station Unit 1 (446 MW) in Colorado, and the F.B. Culley Generating Station Unit 2 (103.7 MW) in Indiana will remain in operation through December 2026. In addition, the Secretary of Energy on Nov. 13 directed that J.H. Campbell (1,420 MW) in Michigan remain in operation through February 12, 2027, and on Nov. 17, directed that H.A. Wagner Unit 4 (397 MW) in Maryland remain in operation through Dec. 31, 2026. DOE, *2026 DOE 202(c) Orders* (accessed November 17, 2026), www.energy.gov/ceser/2026-doe-202c-orders. Additional DOE orders could potentially delay other planned retirements this winter.

68 Net capacity additions and retirements data from EIA Form 860M show new generating capacity that entered service and existing capacity that retired from March 2026 through February 2027. The net increase represents total additions minus total retirements across all fuel types and technologies. EIA, Preliminary Monthly Electric Generator Inventory, Form 860M (Oct. 23, 2026), www.eia.gov/electricity/data/eia860/. EIA provides winter generating capacity data in terms of "net winter capacity," defined as, "The maximum output, commonly expressed in megawatts (MW), that generating equipment can supply to system load, as demonstrated by a multi-hour test, at the time of peak winter demand (period of December 1 through February 28). This output reflects a reduction in capacity due to electricity use for station service or auxiliaries." www.eia.gov/tools/glossary/index.php?id=Net%20winter%20capacity.

69 EIA, Preliminary Monthly Electric Generator Inventory, Form 860M (Oct. 23, 2026), www.eia.gov/electricity/data/EIA860.

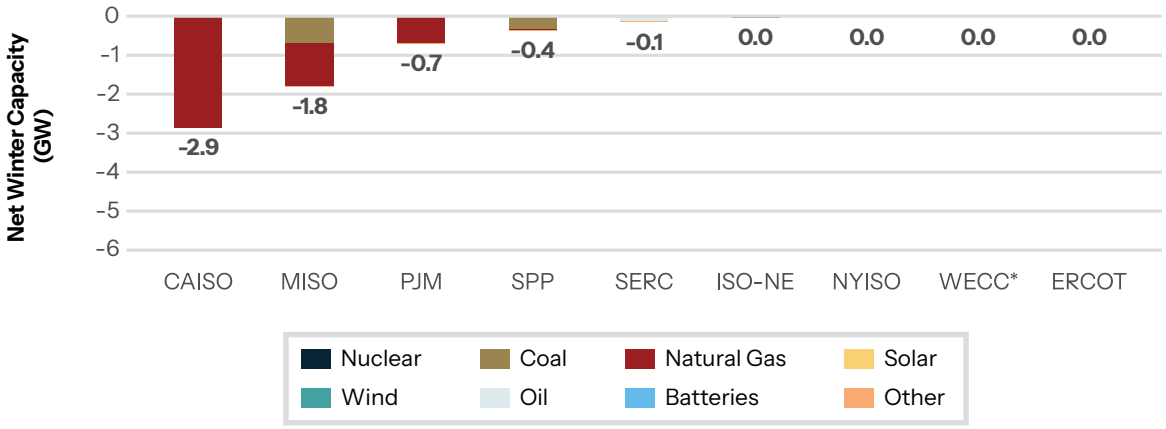
FIGURE 12
Net Winter Capacity Additions Since Last Winter



NOTE: WECC* refers to the Western Electricity Coordinating Council (WECC) without CAISO. SOURCE: U.S. EIA 860M

Figure 12 breaks down the 81 GW of EIA's new net winter capacity additions by region and resource type. Each vertical bar represents the total new capacity for a specific region, while the segments within each bar show the mix of different resources being added. In total, solar accounts for 49% (39.8 GW) of new capacity additions and batteries represent 27% (21.6 GW), with wind accounting for 16% (12.9 GW) and natural gas (6.5 GW, or 8%) comprising the remainder. Solar and wind represent the largest shares (as percentages) of new capacity additions in PJM (solar at 42.5% and wind at 42.4%), and solar represents the largest share of new capacity additions in MISO (76.1%). New battery capacity additions have continued to grow steadily from 698 MW in 2021 to a projected 17.3 GW in 2026. As the chart shows, western and central regions drive 72.3% of overall capacity additions: these projects are in ERCOT (24.4 GW); WECC (13.5 GW); CAISO (11.6 GW); and MISO (8.8 GW).

FIGURE 13
Net Winter Capacity Retirements Since Last Winter



NOTE: WECC* refers to WECC without CAISO. This figure excludes resources covered under DOE section 202(c) orders..

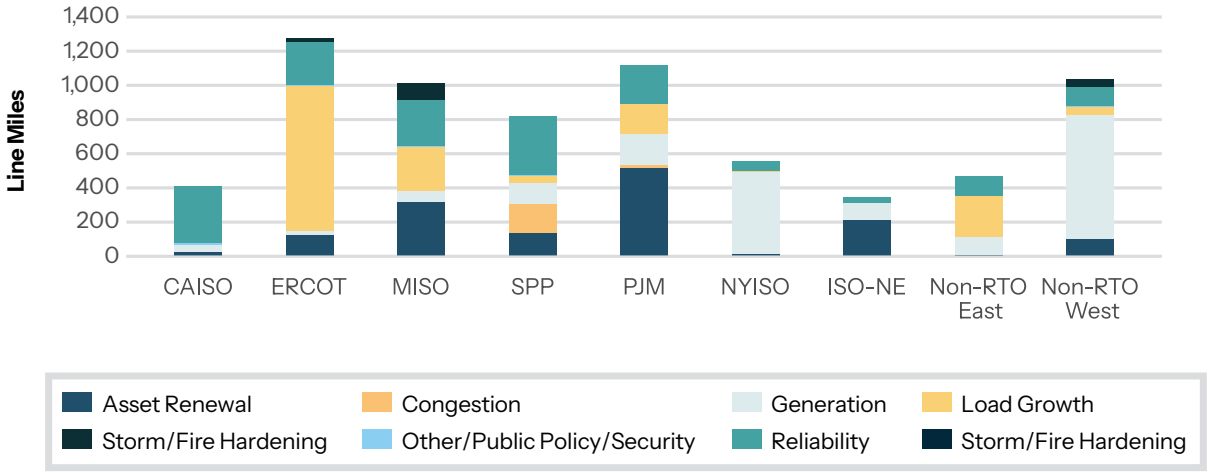
SOURCE: U.S. EIA 860M

Capacity retirements are projected by EIA to total 5.9 GW, with natural gas units representing 4.7 GW (80%) and coal-fired units 1.0 GW (17%). The chart on **Figure 13** breaks down these figures by region and shows the specific fuel types being retired in each area. The majority of planned coal retirements are in SPP (335 MW) and MISO (680 MW), while the majority of planned natural gas retirements are in CAISO (2.9 GW). The largest planned coal retirements besides those covered under DOE section 202(c) orders are Sherburne unit 1 (680 MW) in Sherburne, Minnesota and Comanche unit 2 (335 MW) in Pueblo, Colorado. The largest planned gas retirements besides those covered under DOE section 202(c) orders are located in Southern California, including Ormond Beach (1,491 MW) and Alamitos (1,142 MW), and MISO (Sabine 1,074 MW).[70]

70 EIA, *Preliminary Monthly Electric Generator Inventory* Form 860M (Oct. 23, 2026), www.eia.gov/electricity/data/eia860.

Electricity Transmission

FIGURE 14
Transmission Additions Since Last Winter



SOURCE: North American Electric Transmission and Distribution Project Database, The C Three Group L.L.C.

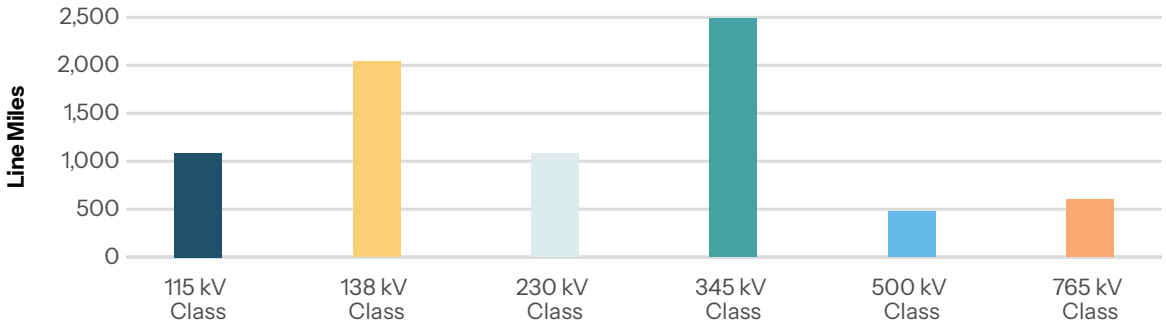
There are 744 transmission projects that have either come online since March 2026 or will enter service by February 2027, totaling 7,770 line-miles.[71] **Figure 14** shows the primary drivers of these projects. Collectively, projects designed to address four of these primary drivers in particular account for 94% of all projected new mileage.[72] Those primary drivers are: asset renewal or aging infrastructure (1,442 miles), system reliability (1,740 miles), load growth (1,615 miles), and interconnecting generation (1,836 miles).

Since last winter, the most active regions by project count are ERCOT (1,277 miles), MISO (1,014 miles), and PJM (1,113 miles). The needs behind these projects vary significantly: ERCOT is focused on load growth (67% of its mileage) and PJM's and MISO's new transmission lines are driven by a mix of aging infrastructure needs, load growth, generation, and system reliability.

71 Transmission line-mile data is from Yes Energy's Electric Transmission and Distribution database (accessed Sept. 22, 2026). For these purposes, WECC refers to non-RTO regions of WECC (i.e., CAISO is excluded).

72 These exclude projects defined as "conceptual" or "early development" by Yes Energy, as in-service dates of these projects are uncertain.

FIGURE 15
Transmission Projects by Voltage Level



SOURCE: North American Electric Transmission and Distribution Project Database, The C Three Group L.L.C.

Figure 15 indicates that most development involves lines below the 345 kilovolts (kV) class, with 720 of the 744 projects planned for this voltage range.[73] Among the 24 projects in the 500 kV and 765 kV classes, CAISO, MISO, and PJM account for 16 of them. Of these, three projects are in the higher voltage 765 kV class.[74]

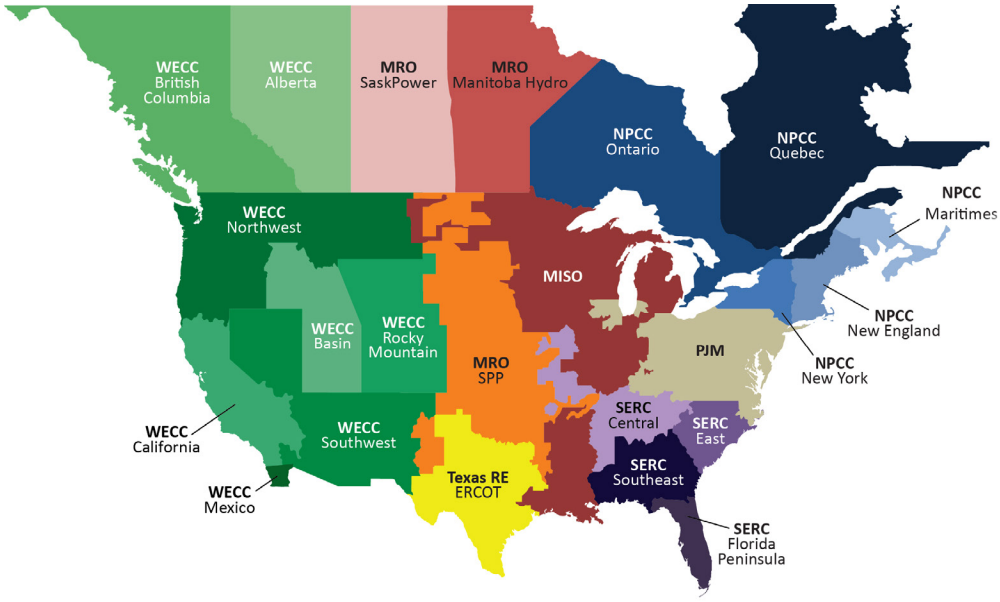
73 These voltage classes follow measurements as designed by the U.S. Department of Energy. See U.S. Department of Energy, Office of Cybersecurity, Energy Security, and Emergency Response, *How It Works: Electric Transmission and Distribution and Protective Measures* (accessed Oct. 8, 2026), www.energy.gov/sites/default/files/2023-11/FINAL_CESER%20Electricity%20Grid%20Backgrounder_508.pdf.

74 *Id.* 765 kV lines are classified as extra-high-voltage (EHV) or "power highways." EHV lines play critical roles in grid reliability, such as providing long-distance bulk power transfers, reducing transmission losses, minimizing the land footprint needed for towers, and improving grid stability.

Regional Highlights & NERC Probabilistic Assessments

NERC Regional Probabilistic Assessments

FIGURE 16
Regional Highlights & Probabilistic Assessment



SOURCE: NERC

NERC, working with Regional Entities[75] and RTOs/ISOs, conducts a probabilistic risk analysis to assess resource adequacy as part of its winter 2026-2027 seasonal assessment and supporting reports. NERC's analysis shows that all 15 U.S. assessment areas (see **Figure 16**) anticipate adequate supplies and reserve margins under normal conditions, but that the SERC-East region, along with NPCC-NE, and portions of MISO and SPP assessment areas, may face a higher likelihood of tight supply and reliability issues during extreme conditions.[76] In the section below, we focus on the assessments for these areas.

75 Regional Entities are delegated regional organizations that work with NERC to monitor and enforce mandatory reliability standards across the North American bulk power system.

76 All Regional Entities and assessment areas provide a probability-based resource adequacy risk assessment for the summer season. *See* NERC, *2026-2027 Winter Reliability Assessment*, (Nov. 18, 2026), www.nerc.com/our-work/assessments.

Regions may face energy shortfalls even if planning reserve margins exceed the reference margin levels.[77] The probabilistic risk assessments for each of the 15 NERC assessment areas study expected system performance and uncertainty under region-specific scenarios to evaluate the risk of resource adequacy shortfalls for this coming winter. Should an assessment area experience above-normal winter peak load and resource outages, system operators have several operational mitigation measures available. For example, system operators may call on demand response resources, cancel or postpone non-critical maintenance outages of generation and transmission, and request voluntary conservation measures. If system conditions deteriorate substantially, Reliability Coordinators would declare an Energy Emergency Alert, allowing system operators to activate emergency demand response measures and increase generation imports from neighboring regions during scarcity conditions. Some areas also may request DOE section 202(c) orders.

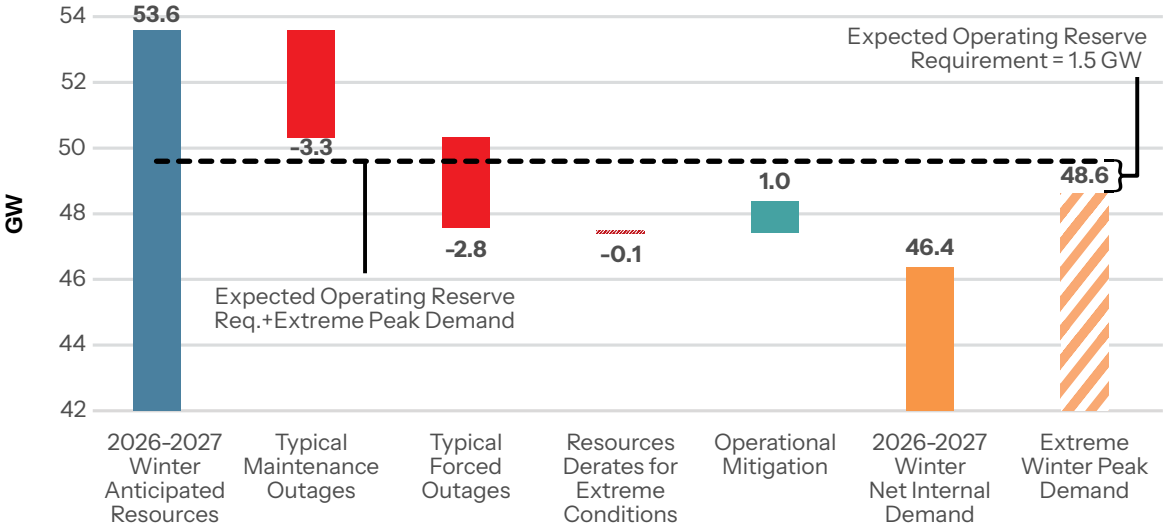
Regional Highlights

NERC's probabilistic risk analysis produces likely seasonal risk scenarios to provide insight into unexpected events in normal or extreme conditions, but not all unique risks are captured. The scenarios generally assess the greatest risk hours for Expected Unserved Energy,[78] along with the varying demand and available resource profiles. The methods, scenarios considered, and assumptions differ across assessment areas and may not be comparable. While all areas are expected to have adequate anticipated resources under normal winter conditions, several assessment areas may experience challenges during extreme winter conditions.

77 *Id*.

78 Expected Unserved Energy is the sum of the expected number of MWhs that will not be served in a given time period when demand exceeds available capacity. *NERC, Long Term Reliability Assessment, January 2026* at 172-173 (Jan. 29, 2026), https://prod.nerc.com/globalassets/our-work/assessments/nerc_ltra_2025.pdf.

Figure 17
Probabilistic Assessments



SOURCE: NERC

SERC-East. NERC's *2026 Winter Reliability Assessment* uses "waterfall" charts to illustrate probabilistic assessments for each region. **Figure 17** shows the seasonal risk assessment for SERC-East as an example. The blue column on the left shows anticipated resources of 53.6 GW, and the two orange columns on the right show the demand scenarios with the normal winter peak of 46.4 GW (50/50) and the extreme winter peak of 48.6 GW (90/10).[79] The red bars in the middle show the factors that can reduce resource availability, including maintenance outages (3.3 GW less available), forced outages (2.8 GW), and derates for extreme conditions (0.1 GW), which are not already accounted for in anticipated resources. The middle green bar depicts potential additions of 1 GW in resource availability from operational mitigation actions that are available during scarcity conditions but have not been accounted for in the reserve margins. The dotted, horizontal line (50.1 GW) represents the expected operating reserve requirement of 1.5 GW above the extreme peak demand (48.6 GW), or the amount of power that SERC-East would need to produce to avoid a shortfall.

79 A 50/50 peak load forecast is based on a 50% chance that the actual system peak load will exceed the forecasted value. A 90/10 peak load forecast is based on a 10% chance that the actual system peak load will exceed the forecasted value.

SERC-East expects low risk under normal conditions but severe winter conditions could create periods of resource adequacy stress due to elevated demand and reduced resource availability. The SERC-East risk assessment identifies January as the highest risk period, especially during the morning peaks and extreme cold events, when high demand, reduced solar output, potential transmission loading from loop flows, and weather related generator derates could combine to challenge resource adequacy. Existing preparedness activities, fuel assurance measures, operating procedures, and regional coordination form the backbone of mitigation for these identified risks.[80]

SERC-East faces a low to medium likelihood of challenges from regional loop flows, which, under certain dispatch and interchange conditions, could elevate loading on portions of the transmission system. Existing operating procedures and coordination with neighboring entities are expected to provide mitigation. Regarding fuel supply, some entities are securing additional gas transportation capacity as a precaution, with no significant fuel constraints anticipated.[81]

The SERC-East assessment area continues to transition toward a winter peaking profile due to increased electrification and residential, commercial, industrial, and large load growth, where the demand peaks during the morning hours have become more sensitive to generation availability and weather conditions. While no broad resource adequacy deficiencies are identified, these early morning hours are the primary period of heightened risk this winter.[82]

NPCC-NE. NPCC-NE expects to meet its regional transmission and resource adequacy requirements for the upcoming winter operating period. NPCC-NE forecasts sufficient capacity to meet 20.1 GW (50/50) and 21.5 GW (90/10) winter demand, consistent with ISO-NE's *2026 Capacity Energy Loads and Transmission* load forecast and ISO-NE's updated hourly methodology for long-term demand.[83]

However, NPCC-NE identifies fuel security and energy adequacy during extreme cold as its primary winter reliability risks. NPCC-NE notes that constrained natural gas pipelines during low-probability cold snaps can lead to rapid depletion of stored fuel supplies. In all, NPCC-NE expects about 8,450 MW of gas-only resources and 9,338 MW of dual-fuel units to be available at winter peak. NPCC-NE says it will continue weekly fuel surveys, gas-electric coordination, and 21-day energy assessments to identify emerging shortfalls and prompt replenishment plans.[84]

80 NERC, *2026-2027 Winter Reliability Assessment* (Nov. 18, 2026), www.nerc.com/our-work/assessments.
81 *Id.*
82 *Id.*
83 ISO-NE, *2026 Forecast Report of Capacity, Energy, Loads, and Transmission* (May 1, 2026) www.iso-ne.com/system-planning/system-plans-studies/celt.
84 NERC, *2026-2027 Winter Reliability Assessment* (Nov. 18, 2026), www.nerc.com/our-work/assessments.

Furthermore, NPCC-NE anticipates transmission risk with external impact for a five-day outage of the New York to New England AC tie line in late February 2027, with a 10-hour emergency restoration time, which could temporarily reduce import flexibility between NPCC-NE and NPCC-NY. However, NPCC-NE also has increased transfer capability from Québec via the New England Clean Energy Connect (NECEC), a 320 kV HVDC import-only tie line capable of up to 1,200 MW of transfers from Hydro-Québec.[85] Imports via this line should partially offset a 67% decrease in net firm transfers from capacity-supply-obligation imports compared to last winter.[86]

However, Québec is experiencing a record drought that has reduced water reserves and forced Hydro-Québec to recalibrate how much electricity it can export. Even when NECEC is technically operational, the power flowing through it may be less than originally envisioned. Hydropower plans across Canada have had to be scaled back as conditions persist.[87]

MISO and SPP. In both MISO and SPP, several load pockets rely on imported power during peak winter conditions. These pockets could face imports that are insufficient to maintain reliability. During a high generation outage and high winter load scenario, reliability may be challenged in the import-dependent load pocket areas. For MISO, abnormal system flows, specific generator outages, or restricted transfer capability could contribute to insufficient imports to maintain reliability in these load pockets. In SPP, operating challenges are driven by increasing winter peak loads and the timing of transmission system upgrades to support continued integration of variable energy resources and inverter-based resources.

85 EIA, *New Transmission line connecting Hydro-Quebec to ISO-NE begins commercial operation* (Jan. 30, 2026), www.eia.gov/todayinenergy/detail.php?id=67105.

86 NERC, *2026-2027 Winter Reliability Assessment* (Nov. 18, 2026), www.nerc.com/our-work/assessments.

87 Carlos Albero Rojas, *Massachusetts spent a decade building a hydropower lifeline from Canada until it went dark for two weeks and left the region burning natural gas through its hottest summer days*, Energias Media (Sept. 2, 2026), www.energiesmedia.com/massachusetts-hydropower-dam-challenges.



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