2026 Summer Energy Market and Electric Reliability Assessment

FEDERAL ENERGY REGULATORY COMMISSION
Staff Report
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PREFACE

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

KEY FINDINGS IN SUMMER 2026 ASSESSMENT

TAKEAWAYS

- **High temperatures and extreme weather events are expected to challenge the electric grid.**
    - Drought and low snowpack could curb hydropower generation.
    - Wildfires and hurricanes may affect some parts of the country.
- **Projected generation and transmission additions will help address forecasted high electricity demand growth.**
- **Natural gas demand and production are both expected to increase.**
- **Resources and operating reserves are adequate in all NERC assessment areas under normal operating conditions.**
    - Possible reliability challenges in NPCC-NE, western ERCOT, and WECC-NW under extreme operating conditions.

Forecasted higher-than-average summer temperatures and uncertainty from extreme weather events are expected to challenge the electric grid this summer. Addressing those stressors may be difficult because several weather conditions build off each other, namely low snowpack, continued drought, and wildfires. The resulting low water levels are also expected to restrict hydropower generation in key regions.

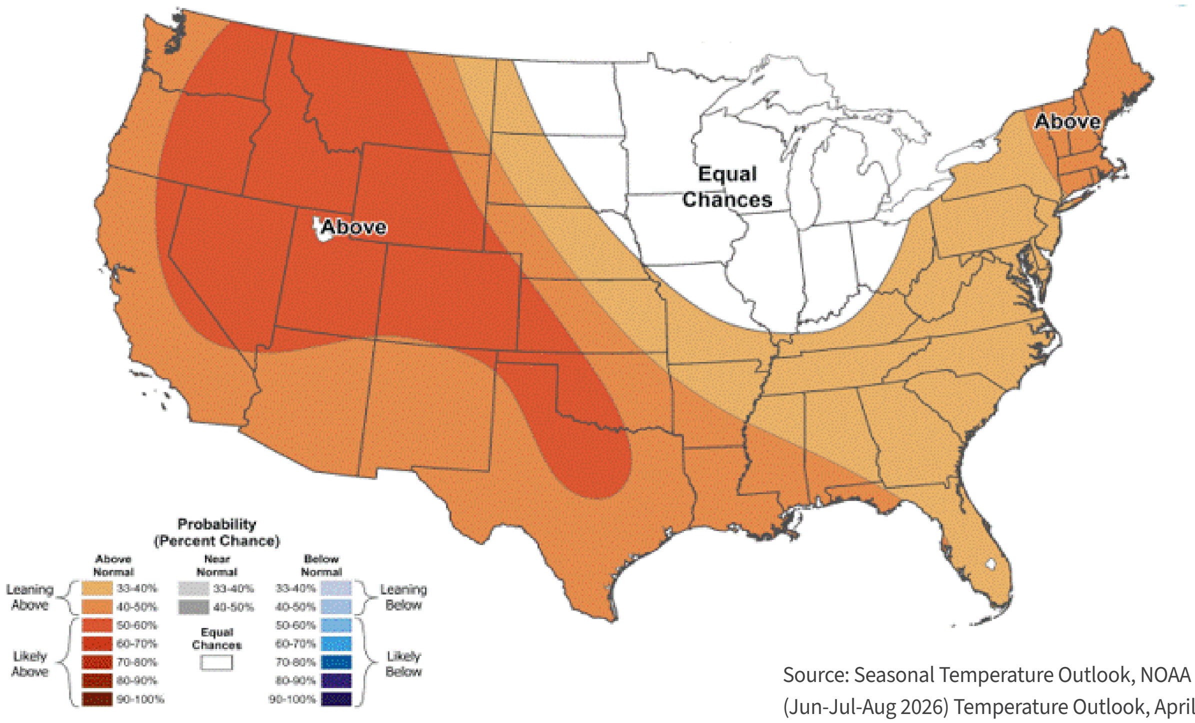
As to market fundamentals, electricity consumption is expected to be higher in summer 2026 than in each of the previous five summers. However, new generator additions and transmission line expansions are expected to help address increased electricity demand. Also, natural gas demand is forecast to increase this summer compared to the previous five summers, while electricity generation is expected to continue to make up the largest share of total natural gas demand.

Wholesale electricity prices are expected to vary by region this summer, with the highest prices expected in the Mid-Atlantic (PJM Interconnection LLC), New York (New York Independent System Operator), and New England (ISO New England). Compared to last summer, natural gas prices are also expected to increase at major eastern trading hubs but decrease at most western and midcontinent trading hubs.

Based on data provided by the assessment areas, the North American Electric Reliability Corporation (NERC) has conducted probabilistic assessments that indicate possible challenges this summer for the electric grid. Under normal operating conditions, according to NERC, all assessment areas are expected to have adequate generating resources to meet expected summer electricity demand and operating reserve requirements. However, under extreme weather conditions, three assessment areas face a higher likelihood of tight generation availability in a range of operating scenarios: the Northeast Power Coordinating Council-New England (NPCC-NE), the western part of the Electric Reliability Council of Texas (ERCOT), and the Western Energy Coordinating Council – Northwest (WECC-NW). These operating scenarios include higher peak load levels, reduced resources conditions, and wide-area extreme weather conditions that may disrupt available transfer and generator availability. If these scenarios occur, operational mitigation may be needed to avoid facing reliability issues.

WEATHER OUTLOOK

Figure 1: Summer Temperatures Likely Higher Than Average with Typical Hurricane Risk Expected



Source: Seasonal Temperature Outlook, NOAA Three Month (Jun-Jul-Aug 2026) Temperature Outlook, April 1, 2026.

Weather risk from extreme heat is elevated this summer with the potential to impact electricity markets and reliability. Forecasts from the National Oceanic and Atmospheric Administration (NOAA) for June to August 2026, shown in the map on **Figure 1**, project above-average temperatures across much of the United States.[1] Additionally, NOAA forecasts a 61% chance of El Niño conditions and a 1-in-4 chance that it will be a ‘strong’ El Niño later this year, raising the risk of extreme heat events this summer.[2] El Niño conditions typically drive higher temperatures across the northern and central United States and stronger storms in the South. As El Niño strengthens, extreme heat could strain the grid beyond expected operating conditions and result in sharp increases in demand as cooling load increases.

Geographically widespread, high 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. High temperatures can also increase transmission line losses and cause conductors to reach operating limits sooner under the combination of high load and high heat conditions, all of which increase the risk of outages and make preparation essential.[3] Extreme heat can also reduce generator capacity, leading to outages or derates.[4]

1 NOAA uses a 30-year climate average in calculating these probabilities along with a range of inputs including the El Niño–Southern Oscillation (ENSO) forecasting data.

2 NOAA, *El Niño/Southern Oscillation (ENSO) Diagnostic Discussion* (Apr. 9, 2026), www.cpc.ncep.noaa.gov/products/analysis_monitoring/enso_advisory/ensodisc.shtml.

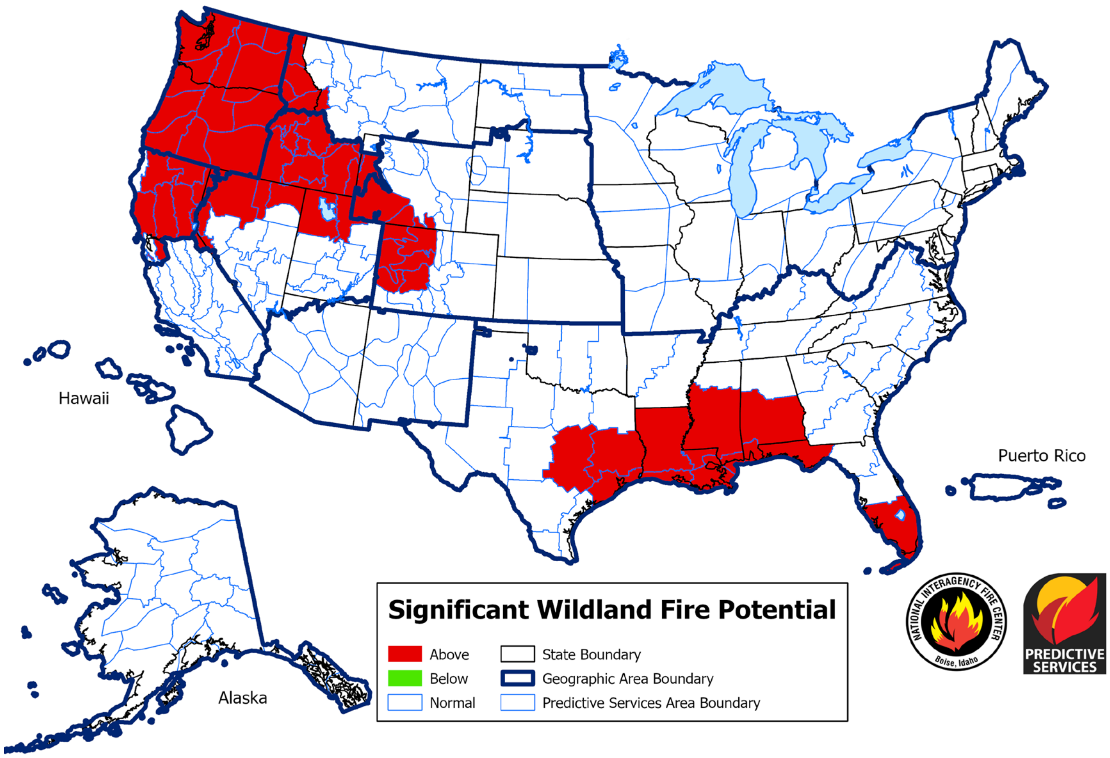
3 Electric Power Research Institute (EPRI), *Extreme Heat Events and Impacts to the Electrical System* at 3 (Sep. 5, 2022), restservice.epri.com/publicdownload/000000003002025522/0/Product.

4 A 2024 Pacific Northwest National Laboratory (PNNL) study concluded that extreme high temperatures can reduce efficiency of some natural gas turbines by 25%. *See PNNL*, *Heatwaves: Less Efficient Power Flow, More Power Demand, press release,* (July 29, 2024), www.pnnl.gov/news-media/extreme-heat-hurricanes-wildfires-how-summers-extremes-disrupt-power-grid.

Finally, higher temperatures forecast for this summer could intensify storm systems and hurricanes.[5] The Atlantic hurricane season runs from June 1 through November 30, typically peaking in late summer or early fall. While the forecasts for this summer anticipate a below-average total of 13 hurricanes, uncertainty remains due to projected weather patterns that produce opposite effects: Projected El Niño conditions typically reduce hurricane formation, but warmer temperatures coupled with warm Atlantic waters can cause hurricanes to form and intensify rapidly.[6]

Wildfire Forecast

Figure 2: Wildfire Risks Elevated across the United States



Above normal significant wildland fire potential indicates a greater than usual likelihood that significant wildland fires will occur. Significant wildland fires should be expected at typical times and intervals during normal significant wildland fire potential conditions. Significant wildland fires are still possible but less likely than usual during forecasted below normal periods.

Source: Significant Wildland Fire Potential Outlook August 2026. National Interagency Coordination Center, Issued: May 1, 2026.

The expansion of wildfire risk from the West to other parts of the country is expected to continue in 2026. The National Interagency Coordination Center's (NICC) map for August 2026, shown in **Figure 2**, shows significant wildfire risk across the West, Southern Plains, and the Southeast regions of the United States, including the risk of fast-moving grass fires. Parts of the Gulf Coast may also experience above-normal fire activity caused by critically dry vegetation, persistent drought, and other conditions.[7]

5 NOAA, *Fuel for the Storm* (Accessed Mar. 9, 2025), oceantoday.noaa.gov/fuelforthestorm/.

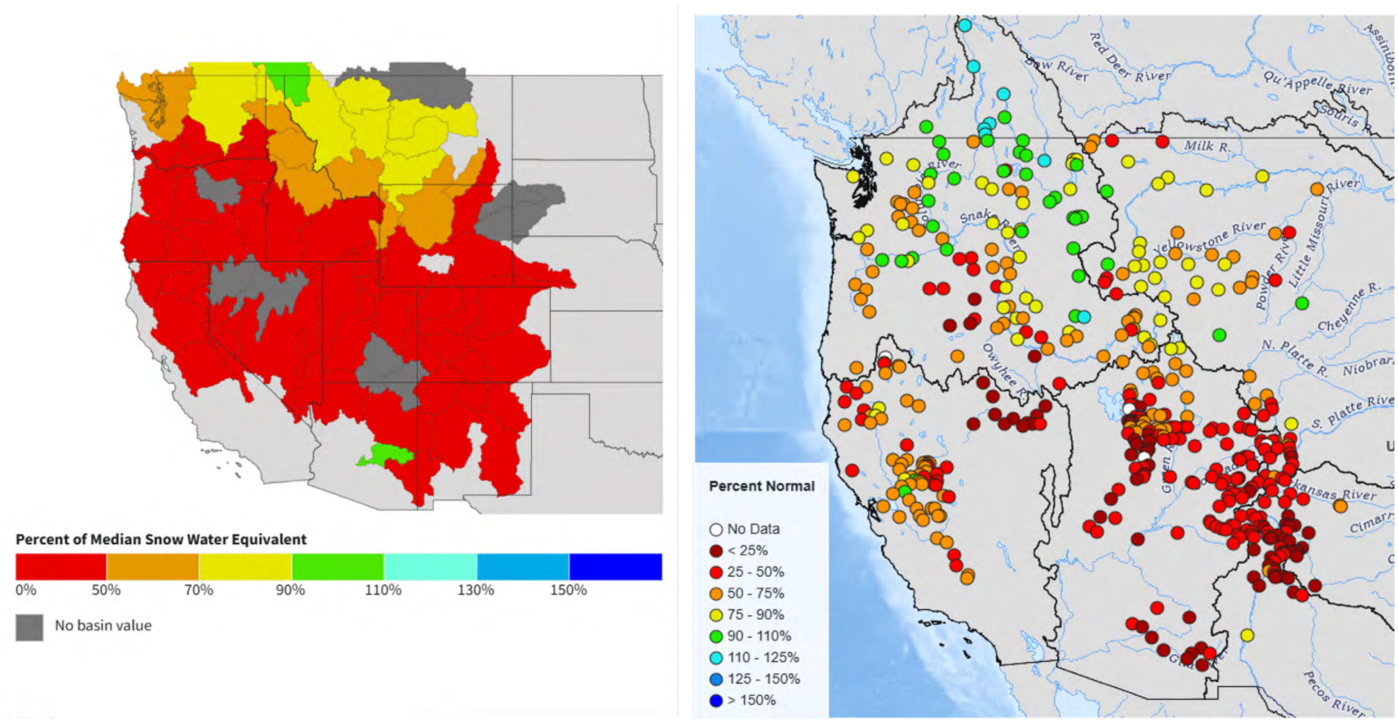
6 Colorado State University, *Forecast for 2026 Hurricane Activity* (Apr. 9, 2026), tropical.colostate.edu/forecasting.html.

7 National Interagency Coordination Center (NICC), *National Significant Wildland Fire Potential Outlook, Outlook Period – March through June 2026* (Mar. 2, 2026), www.nifc.gov/nicc/predictive-services/outlooks.

Since 2019, California utilities have relied on Public Safety Power Shutoffs (PSPSs), or intentional transmission line de-energization, to prevent their equipment from igniting fires. In recent years, PSPSs have been employed as a wildfire mitigation tool more broadly across the West and increasingly in other parts of the United States to counter drought conditions and wildfire risks as they expand eastward.[8]

Western Snowpack and Hydropower Forecast

Figure 3: Record Low Snowpack Impacts Western Hydropower Availability



Source(s): SNOTEL Snow Water Equivalent Percent of Median, USDA Natural Resources Conservation. Service Data Valid End of Day: April 8, 2026; and Western Water Supply Forecast, NWS Colorado Basin River Forecast Center, Valid April 8, 202

Snowpack is important for summer electric system reliability, serving as a natural energy reservoir that gradually releases water during spring and summer and fuels hydropower generation when electricity demand increases with rising temperatures.[9] But across the West this summer, there is record-low snowpack, shown in red, orange and yellow, in **Figure 3**.[10] This could curb production of hydropower throughout the West, where over half of all U.S. utility-scale hydropower generation capacity is concentrated.[11]

8 Pacific Northwest National Laboratory, *Public Safety Power Shutoffs in Wildfire Mitigation Plans* (Feb. 2026), wildfire.pnnl.gov/mitigationPlans/content/analysis/Public%20Safety%20Power%20Shutoffs%20in%20WMPs.pdf.

9 Winter snowpack refers to the depth of water that would theoretically result if the entire snowpack melted instantaneously.

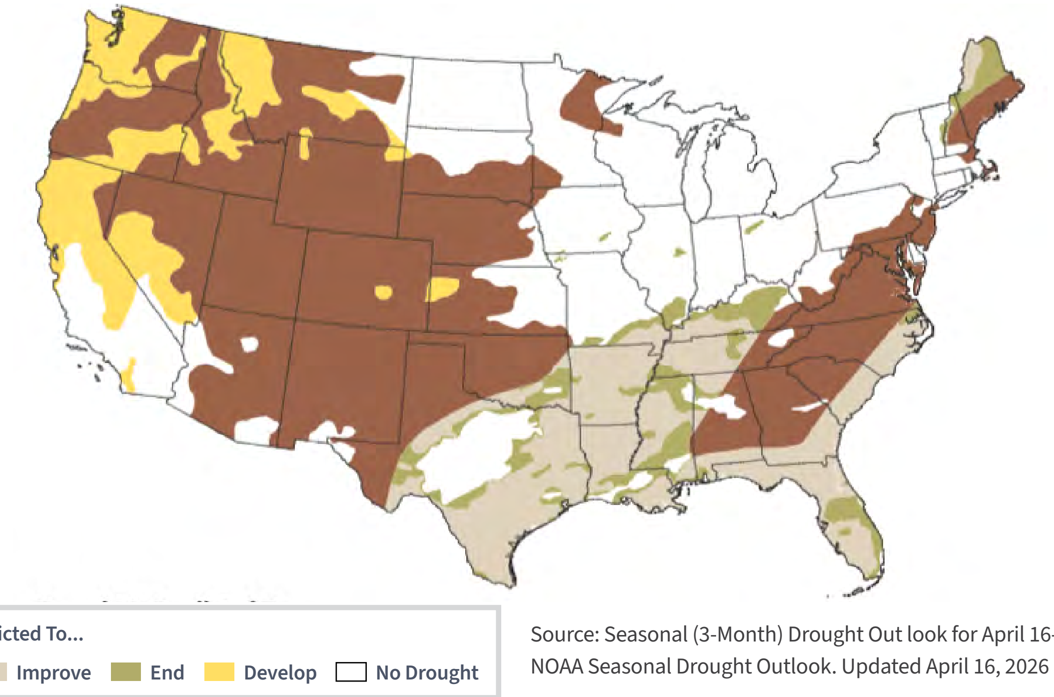
10 National Integrated Drought Information System (NIDIS), *Drought Status Update: Snow Drought Current Conditions and Impacts in the West* (Apr. 9, 2026), www.drought.gov/drought-status-updates/snow-drought-current-conditions-and-impacts-west-2026-04-09.

11 EIA, *Hydropower explained: Where hydropower is generated* (Accessed May 13, 2026), www.eia.gov/energyexplained/hydropower/where-hydropower-is-generated.php.

Meanwhile, low water volumes in summer 2026 in the greater Missouri and Mississippi River basins, following multiple consecutive years of low water flows, increase the risk of disrupted navigation, including for barges carrying coal to power plants. Low water levels, the risk of saltwater intrusion, and increased water temperatures could prompt derating or forced outages of generators with once-through-cooling equipment on the affected rivers.

Drought Conditions

Figure 4: Drought Conditions Impact Western, Central and Eastern Coastal Regions



Source: Seasonal (3-Month) Drought Out look for April 16-July 31, 2026. NOAA Seasonal Drought Outlook. Updated April 16, 2026

Continued drought conditions this summer increase the risks to energy infrastructure, creating challenges for grid reliability. Drought conditions impact 62% of the continental United States and are expected to expand this summer, as shown in **Figure 4**. For example, continued widespread drought conditions could impact energy infrastructure in Texas this summer, as reservoirs along the Gulf Coast are forecast to drop to record lows, putting refineries clustered in Corpus Christi, Texas, and other parts of the region at risk of mandatory water cuts. Refinery capacity in the Corpus Christi region amounts to about 5% of total refinery capacity in the U.S.[12]

To the north, about 53% of Canada was in moderate to extreme drought conditions as of February 2026, and these conditions are projected to persist into summer 2026, particularly in Québec, Manitoba, and British Columbia.[13] That would reduce Canadian hydropower available for export to the United States, potentially affecting thousands

12 Based on a U.S total of refinery capacity of 18,162,000 barrels per day as of January 2026. EIA, *Petroleum and Other Liquids: Refinery Utilization and Capacity* (Accessed Apr. 7, 2026), www.eia.gov/dnav/pet/pet_pnp_unc_dcu_nus_m.htm.

13 Agriculture and Agri-Food Canada, *Canadian Drought Monitor: Current Drought Conditions* (Mar. 6, 2026), agriculture.canada.ca/en/agricultural-production/weather/canadian-drought-monitor/current-drought-conditions.

of megawatts[14] of electricity imports into the New York Independent System Operator, ISO New England, and the Midcontinent Independent System Operator (MISO).[15]

In 2025, 28% less electricity flowed from Canada to the U.S. than in 2024, marking the lowest Canadian export total (35.64 Terawatt hours) since 2004.[16] As of January and February 2026, Canadian electricity exports to the U.S. remained below 2025 levels.

From an operational standpoint, lower Canadian hydropower output will continue to increase U.S.-to-Canada net transfers and potentially strain transmission paths not historically loaded south-to-north.[17] Such strains can lead to further congestion, voltage and loading challenges, or impose limits on power flow management actions during periods of high demand.

14 Canada exported a monthly average 2.6 TWh of electricity to the U.S. in 2025. CER, *Electricity Trade Summary* (Apr. 2, 2026), www.cer-rec.gc.ca/en/data-analysis/energy-commodities/electricity/statistics/electricity-trade-summary/index.html.

15 Canada Energy Regulator (CER), *Electricity Trade Summary* (Apr. 2, 2026), www.cer-rec.gc.ca/en/data-analysis/energy-commodities/electricity/statistics/electricity-trade-summary/index.html.

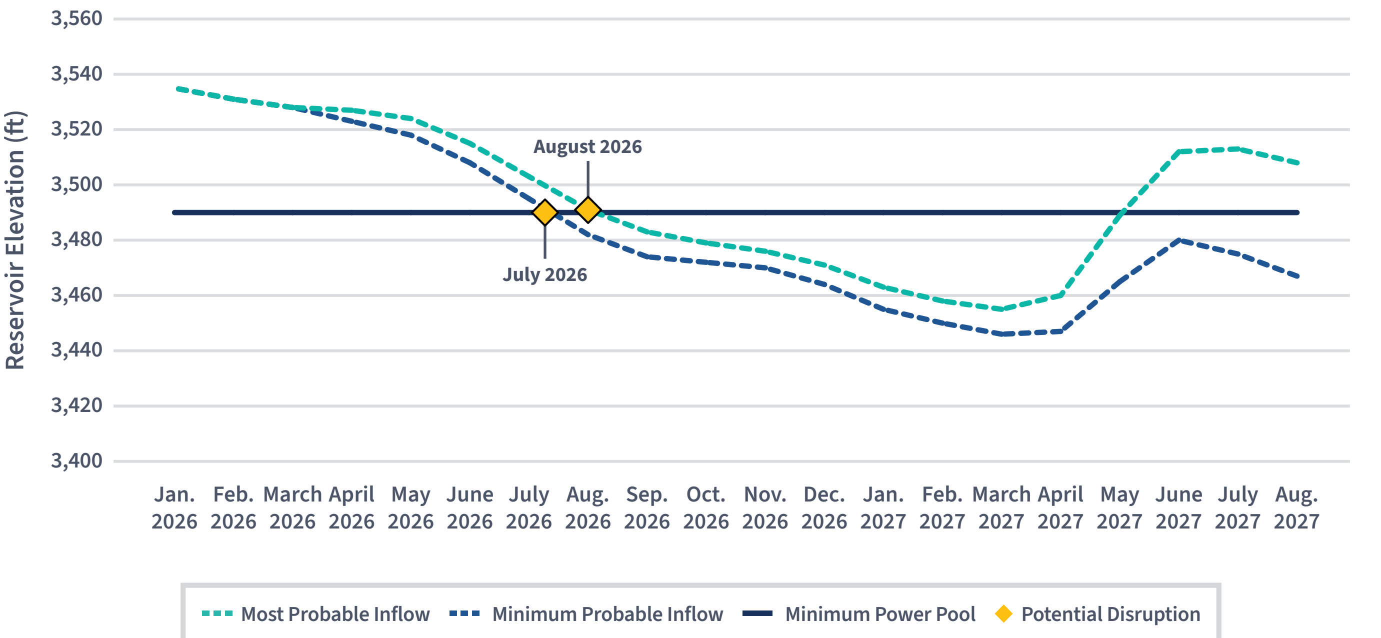
16 CER, *Market Snapshot: Annual Trade Summary – Electricity* (June 25, 2025), www.rec-cer.gc.ca/en/data-analysis/energy-markets/market-snapshots/2025/market-snapshot-annual-trade-summary-electricity.html.

17 EIA, *U.S. Northeast is Relying Less on Electricity Imports from Canada* (Sep. 19, 2025), www.eia.gov/todayinenergy/detail.php?id=66144.

NOTABLE RELIABILITY RISKS AND TRENDS

Colorado River Drought Impacts

Figure 5: Colorado River Expected to Fall to Critical Levels in Summer 2026



Source: Bureau of Reclamation, April 2026 Most Probable 24-Month Study, Bureau of Reclamation Upper and Lower Colorado River Basin Regions, April 16, 2026

Electricity operations in the Colorado River Basin highlight the significant challenges that drought conditions have created across the West. Specifically, Lake Powell at the non-FERC-jurisdictional Glen Canyon Dam is forecast to see the lowest volume of water inflow since the dam began operation in 1964, at only 13% of average inflow volumes.[18]

U.S. Department of Interior's Bureau of Reclamation forecasts indicate that, unless circumstances change, currently under the most probable conditions forecast from April 2026, shown in teal on **Figure 5**, the Glen Canyon dam may reach "minimum power pool," shown as a black line, this summer, below which power generation at the dam is impossible and river flow will be cut off at the dam.[19] However, the Bureau of Reclamation recently announced planned emergency actions it intends to take to preserve operations at Glen Canyon through the summer with emergency releases from upstream reservoirs and significantly reduced water releases from Glen Canyon. Without successful emergency actions or if water releases are reduced significantly, downstream dam operations would be affected, as well as any other municipal, commercial or industrial infrastructure dependent on the river, including the non-FERC jurisdictional Hoover Dam, a 2,000 MW hydropower generator on the Nevada-Arizona border. In total,

18 NOAA Colorado River Basin Forecast Center, *May 2026 Water Supply Briefing* (May 7, 2026) www.cbrfc.noaa.gov/present/2026/cbrfcwsupmay2026.pdf.

19 Bureau of Reclamation, *Reclamation Acts to Protect Colorado River System During Historic Drought*, press release, (Apr. 17, 2026), /www.usbr.gov/newsroom/news-release/5326.

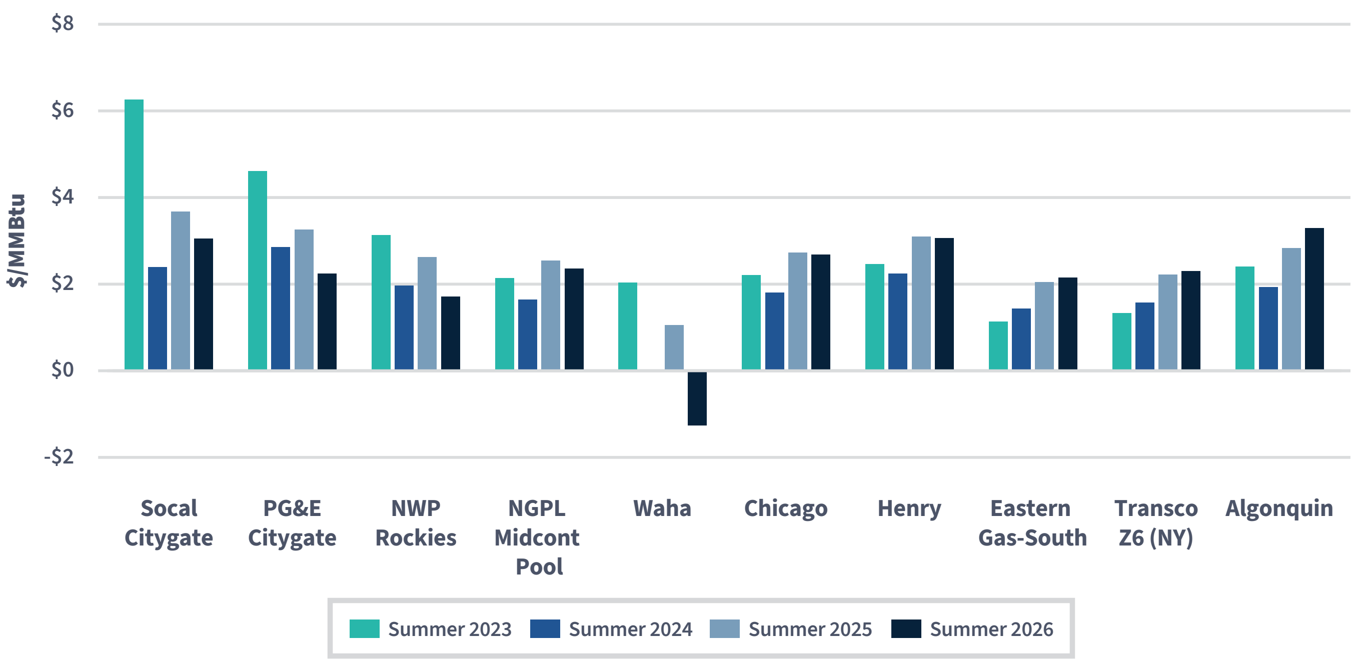
up to 4,500 MW of hydropower capacity on the Colorado River could be impacted by prolonged drought as soon as August 2026, if adverse conditions persist. Such conditions are beyond the region's transmission system design; on a day-to-day basis, they can create congestion and constrain system operators' ability to respond to voltage support challenges, event response mitigation needs, or any additional grid stressors.[20]

20 Bureau of Reclamation, *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.

NATURAL GAS FUNDAMENTALS

Natural Gas Prices

Figure 6: Natural Gas Prices Expected to Decrease at Western Hubs and Increase at Eastern Hubs



Source: InterContinental Exchange

Natural gas prices are signals of the supply-demand balance in natural gas markets and a significant input in the cost of wholesale electricity. Natural gas prices for summer 2026 are expected to be lower at major western and midcontinent trading hubs and higher at major eastern trading hubs across the United States compared to summer 2025. As of April 10, 2026, the futures contract price for the Henry Hub, located in Louisiana, averaged $3.07 per million British thermal units (MMBtu) for this summer, 1% lower than last summer's settled futures price average of $3.10/MMBtu. Relatively high prices at the Henry Hub, compared to other major U.S. natural gas trading hubs, may be driven by expected growth in demand from LNG exports, the anticipated primary driver for total natural gas demand growth this summer.[21] Despite the projected growth in LNG exports, U.S. natural gas prices this summer are relatively insulated from international events and potential global supply shortages. Most U.S. LNG export terminals are already operating at high utilization rates and do not have significant additional export capacity with which they could respond to near-term international market signals.

In the western United States, elevated natural gas storage levels following the 2025-2026 winter are expected to contribute to a decrease in natural gas prices in the Pacific Northwest and California compared to summer 2025 prices. Prices at the Northwest Rockies hub and the Pacific Gas & Electric Citygate, a northern California trading hub,

21 EIA, *Short-Term Energy Outlook* at Table 5a (Apr. 7, 2026), www.eia.gov/outlooks/steo.

are both expected to decrease by more than 30% year-over-year. Prices at the Southern California Gas Citygate hub are also expected to decrease 17% this summer.

At Northeast hubs, futures prices are expected to be higher this summer, as shown in **Figure 6**, reflecting the need to refill Northeast storage following significant regional storage withdrawals this past winter. The Algonquin Citygate, which serves the Boston area, is expected to average $3.29/MMBtu, 16% higher than last summer's settled futures price of $2.83. The Transco Z6 NY hub, a New York City point, is expected to average $2.30/MMBtu an increase of 4% compared to summer 2025.

At the Waha trading hub, a point that represents the oil- and natural gas-rich Permian Basin production area in West Texas and southeastern New Mexico, average summer futures prices are trading at negative $1.26/MMBtu, a significant reduction to last summer's settled price of $1.06/MMBtu. This negative price reflects the limited availability of pipeline takeaway capacity in the Permian Basin relative to the volume of "associated natural gas," or natural gas that is produced as a byproduct of oil production, in the basin. Higher crude oil prices also are expected to incentivize additional crude oil and associated natural gas production in the Permian Basin this summer to help meet the global demand for crude oil, further exacerbating pipeline takeaway constraints in the area.[22]

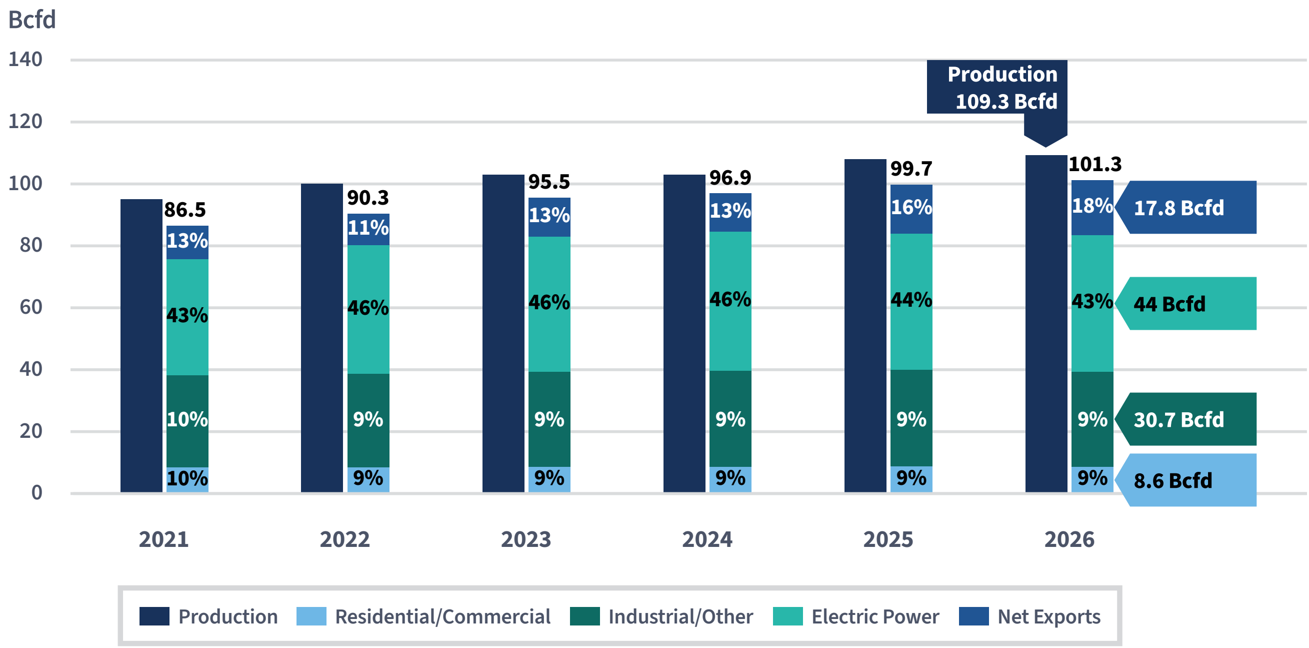
Three natural gas pipeline projects — the Gulf Coast Express Expansion project, the Blackcomb Pipeline project, and Phase 1 of the Hugh Brinson Pipeline project — are expected to add 4.6 Bcfd of pipeline capacity in the second half of 2026. These projects may help to alleviate the constraints in pipeline takeaway capacity for the Permian Basin region and increase natural gas prices at the Waha trading hub towards the end of the year.[23]

22 EIA, *Short-Term Energy Outlook: Global Oil Markets* (Apr. 7, 2026), www.eia.gov/outlooks/steo/report/global_oil.php

23 Chris Newman, *Permian Prompt-Month Natural Gas Forwards Sink to All-Time Lows,* Natural Gas Intelligence, Sep. 25, 2025, naturalgasintel.com/news/permian-prompt-month-natural-gas-forwards-sink-to-all-time-lows/.

Natural Gas Demand

Figure 7: Natural Gas Demand Expected to Continue Growth



Source: U.S. EIA STEO Table 5a

U.S. demand for natural gas continues to grow. As depicted in **Figure 7**, EIA projects total U.S. natural gas demand to average 101.3 Bcfd in summer 2026, 1.6 Bcfd more than summer 2025 levels and 8% more than the previous five-year summer average of 93.8 Bcfd. While electricity generation (also known as power burn) is expected to continue to make up the largest share of natural gas demand, net exports are the largest contributors to the expected growth in overall natural gas demand for summer 2026, consistent with previous summers. Net exports are expected to average 17.8 Bcfd in summer 2026, up 2 Bcfd from summer 2025 and 44% above the previous five-year average.[24] Total domestic natural gas consumption, which includes the residential/commercial, industrial, and power burn sectors but excludes net exports, is expected to average 83.3 Bcfd in summer 2026, a 0.5% decrease from summer 2025 levels but 2.5% above the previous five-year average.

Natural gas demand from the residential/commercial sector is forecast to average 8.6 Bcfd, slightly below summer 2025's level and slightly above the previous five-year average. Natural gas demand in the industrial/other sector is forecast to average 30.7 Bcfd in summer 2026, down slightly from summer 2025's level but 0.7% above the previous five-year average.[25] Industrial demand is mainly concentrated near the Gulf Coast due to the numerous petrochemical and other types of industrial facilities located in that region.

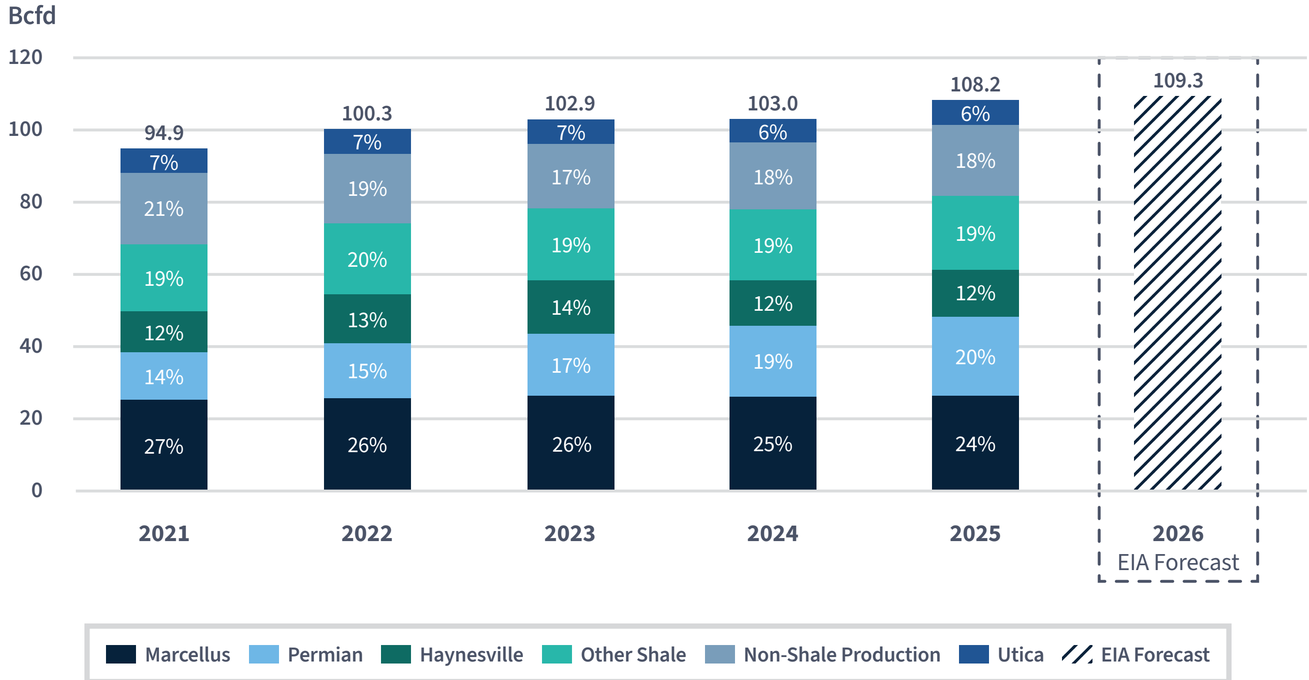
24 EIA, *Short-Term Energy Outlook* at Table 5a (Apr. 7, 2025), www.eia.gov/outlooks/steo.

25 *Ibid.*

EIA projects power burn to average 44 Bcfd in summer 2026, up 0.7% from summer 2025 and 4.2% above the previous five-year average. The average share of electricity generation from natural gas-fired power plants during summer 2026 is forecast to be 43%, down from 44% in summer 2025 and below the previous five-year average of 44%. Consistent with past summers, power burn in 2026 is forecast to peak during the typically hottest months of July and August, averaging 47.9 Bcfd between the two months, up 2.1% from summer 2025.

Natural Gas Production

Figure 8: Natural Gas Production Expected to Increase to All-Time High



Source: U.S. EIA STEO Tables 5a and 10b

Natural gas production is expected to be slightly higher this summer than last, driven by continued strong production from major shale fields. EIA forecasts U.S. dry natural gas production to average 109.3 Bcfd during summer 2026.[26] This represents a 1% increase from the summer 2025 average of 108.2 Bcfd and is 7% above the previous five-year average of 101.8 Bcfd.[27] The different colored segments within each bar in **Figure 8** 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, Appalachia, the Permian, and the Haynesville accounted for 63% of total U.S. dry gas production for summer 2025.

26 *Ibid;* Dry natural gas is consumer-grade natural gas that is almost entirely composed of methane, with little to no hydrocarbon liquids or impurities.

27 EIA, *Short-Term Energy Outlook* at Table 5a (Apr. 7, 2026), www.eia.gov/outlooks/steo.

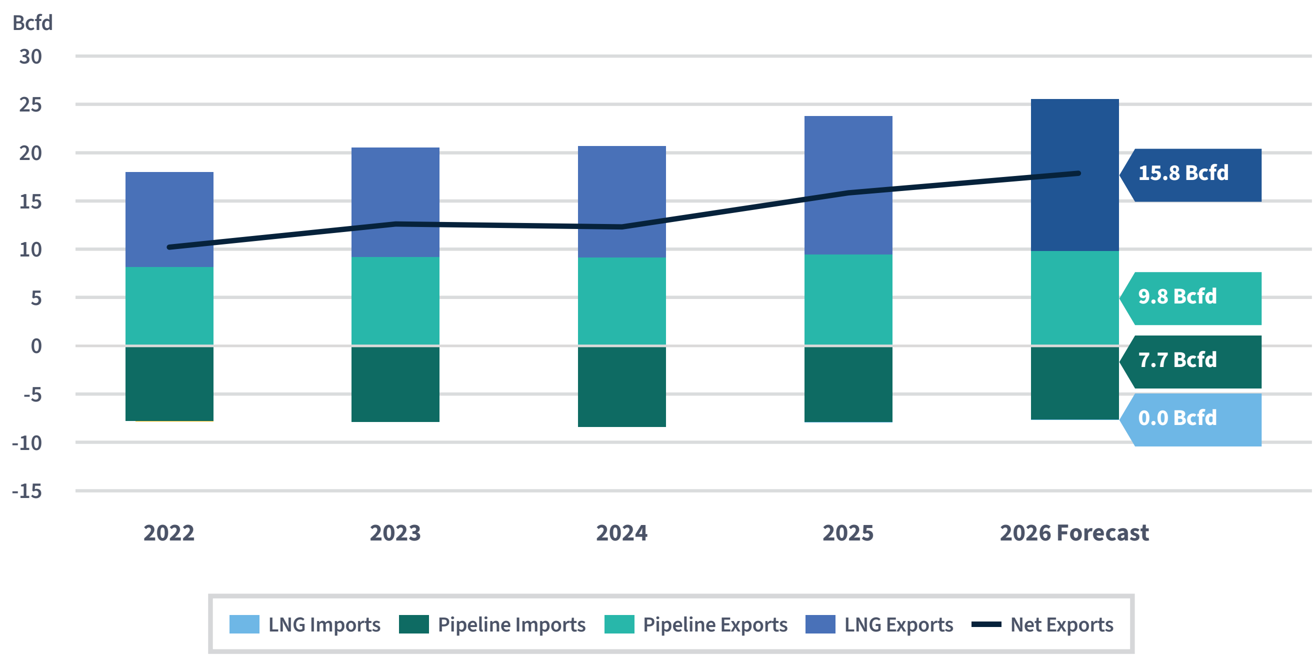
Appalachia remains the largest natural gas-producing region with the Marcellus and Utica shales combining for 33.3 Bcfd, approximately 31% of total U.S. dry natural gas production in 2025. Appalachian natural gas production is primarily located in Pennsylvania, West Virginia, and Ohio. Production growth in Appalachia has slowed in recent years due to pipeline capacity constraints, though recent pipeline capacity additions are expected to support modest growth in 2026.[28]

The Permian Basin, located in West Texas and southeast New Mexico, produced approximately 22 Bcfd of dry natural gas over summer 2025, representing 20% of the total U.S. dry gas production. Growth in Permian natural gas production is driven largely by crude oil market dynamics rather than gas-specific investment. Elevated oil prices are expected to drive more oil-directed drilling for summer 2026, leading to production of more associated natural gas.

The Haynesville formation, located in northwest Louisiana and East Texas, produced 13.3 Bcfd in summer 2025. While production dipped from its all-time peak of 14.7 Bcfd in 2023, the basin is positioned for a rebound in summer 2026. EIA forecasts that Haynesville production will grow 1.2 Bcfd in 2026, partly in response to growing demand from expanding Gulf Coast LNG export capacity.

Natural Gas Exports and Imports

Figure 9: Natural Gas Exports Expected to Increase



Source: U.S. EIA STEO Table 5a

Projected U.S. net natural gas exports show continued growth in summer 2026, as shown in **Figure 9**, increasing by 2 Bcfd as new LNG terminal capacity begins commercial service. According to EIA projections, gross exports via

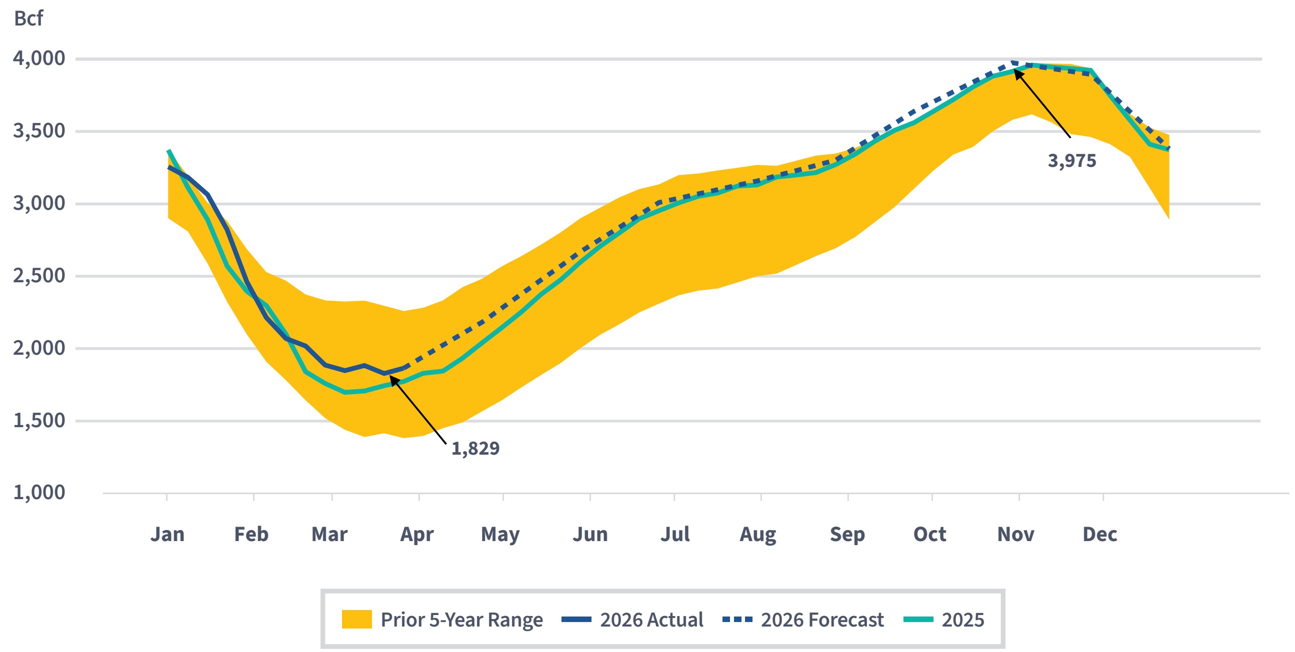
28 EIA, *U.S. Natural Gas Production to Reach Record Highs in 2026 and 2027* (Feb. 13, 2026), www.eia.gov/todayinenergy/detail.php?id=67166.

pipeline and LNG will rise to 25.6 Bcfd in summer 2026, a 7.4% increase from summer 2025. Gross LNG exports for this summer are forecast to average 15.8 Bcfd, up from 14.3 Bcfd in summer 2025 – an increase of 10%.[29] U.S. LNG cargoes continue to face strong demand – particularly from Europe, Japan, and South Korea – which supports additional liquefaction and export capacity growth in the future. The EIA anticipates that U.S. LNG export facilities will operate at high utilization levels this summer, as ongoing geopolitical developments in the Middle East limit global LNG supply.[30]

Gross pipeline exports are forecast to average 9.8 Bcfd this summer, up 0.3 Bcfd from summer 2025. Mexico remains the primary pipeline export destination, driven by growth in demand from Mexico's industrial and electric generation sectors and by expanding pipeline capacity along the U.S.-Mexican border.[31] Gross pipeline imports, primarily from Canada, are forecast to average 7.7 Bcfd in summer 2026, slightly below the 7.9 Bcfd seen in summer 2025.

Natural Gas Storage Inventories

Figure 10: Historical and Forecast U.S. Natural Gas Storage Inventories



Source: U.S. EIA Form 912

29 As of April 2026, FERC-authorized LNG export liquefaction capacity stood at approximately 14.5 Bcfd across eight export facilities. In addition, three facilities are exporting LNG while commissioning. FERC, *North American LNG Export Terminals – Existing, Approved not Yet Built, and Proposed* (Accessed Apr. 7, 2026), www.ferc.gov/media/us-lng-export-terminals-existing-approved-not-yet-built-and-proposed.

30 EIA, *Short-Term Energy Outlook: Natural Gas Market Update*, (Apr. 7, 2026), www.eia.gov/outlooks/steo/report/natgas.php#:~:text=In%20our%20forecast,%20the%20Henry,to%20come%20online%20this%20month.

31 Mexico also began exporting LNG in 2024 from its Fast LNG Altamira LNG production vessel. *See* EIA, *Initial Cargo of Liquefied Natural Gas Ships from Mexico* (Aug. 16, 2024), www.eia.gov/todayinenergy/detail.php?id=62844#:~:text=The%20developer%20of%20the%20first,Tuxpan%20pipeline%20supplies%20the%20project.

Natural gas storage inventories help to balance natural gas demand and supply and are fundamental to price formation in natural gas markets.[32] The 2026 U.S. natural gas storage injection season began in late March with 1,829 Bcf stored in working gas inventories, an inventory level 2.5% above the previous five-year average.[33] The starting inventory level for the 2026 injection season was 131 Bcf (8%) higher than at the start of the 2025 injection season.[34] EIA expects total injections of approximately 2,146 Bcf throughout the 2026 injection season, 5% less than the 2025 injection season but 6% more than the previous five-year average. EIA forecasts a total of 3,975 Bcf of natural gas in storage by the end of October 2026, which would be slightly above the 2021-2025 five-year range.[35]

Regionally, the Mountain and the Pacific regions started the injection season with elevated levels of storage.[36] The Mountain region started with 198 Bcf, 22% higher than the 2025 injection season and 64% more than the 2021-2025 five-year average. The Pacific region started with 257 Bcf, 34% higher than the 2025 storage level and 56% more than the five-year average. Elevated storage levels in these two regions would put downward pressure on prices in the West as the available natural gas supply increases.

Natural Gas Infrastructure

Natural gas infrastructure additions since summer 2025 further increased pipeline transportation capacity available in summer 2026 relative to prior summers, which should ease constraints in some regions. Between September 1, 2025, and April 17, 2026, staff calculates a combined 152 miles of new, enhanced, or expanded interstate natural gas pipelines, adding approximately 1.6 Bcfd in transportation capacity. These capacity additions are distributed across the Northeast, Midwest, and South Central regions. Capacity additions for both interstate and intrastate pipelines continue to support LNG export growth in the South Central region. For example, two large intrastate pipeline projects in Louisiana completed in mid-2025—the 1.7 Bcfd Louisiana Energy Gateway project and the 1.8 Bcfd New Generation Gas Gathering project—will increase access to the Haynesville Shale and expand capacity serving Gulf Coast demand, including LNG facilities, this summer.

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

33 EIA, *Weekly Natural Gas Storage Report* (Apr. 9, 2026), www.eia.gov/naturalgas/storage/. The natural gas storage injection season typically spans from the first week of April to the last week of October. The start of the season is determined by the lowest natural gas storage level of the year and the winter withdrawal season by the highest storage level of the year.

34 *Ibid.*

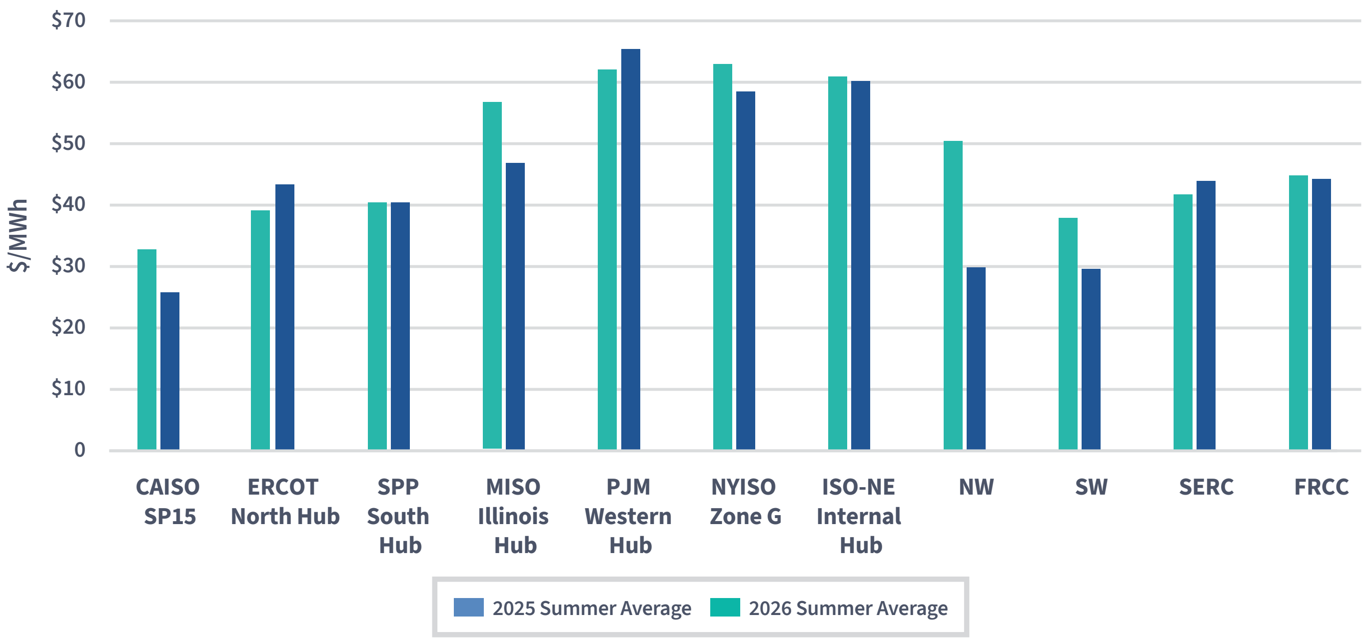
35 EIA, *Short-Term Energy Outlook* (Apr. 7, 2026), www.eia.gov/outlooks/steo.

36 EIA, *Weekly Natural Gas Storage Report* (Apr. 9, 2026), www.eia.gov/naturalgas/storage/.

ELECTRICITY MARKET FUNDAMENTALS & ELECTRIC RELIABILITY

Electricity Prices

Figure 11: Summer Average Wholesale Electricity Price Expected to Decrease



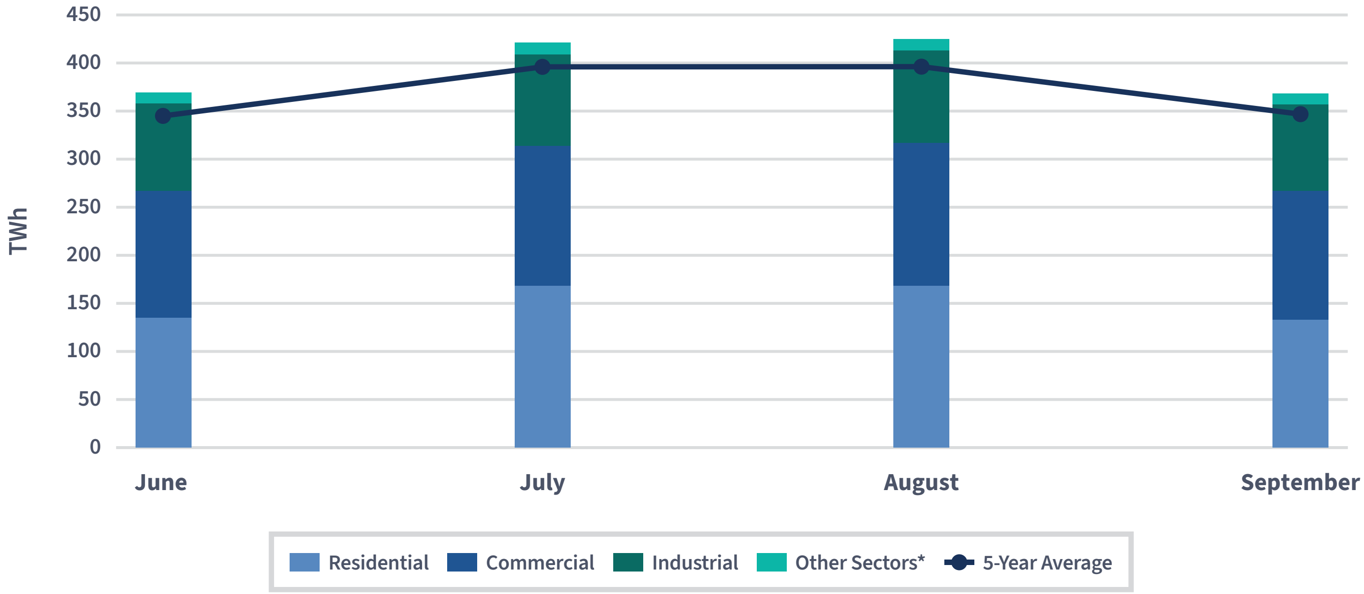
Source: U.S. EIA STEO Table 7a

Overall, the nationwide, wholesale, average electricity price is expected to fall this summer; however, prices will vary by region, reflecting differences in generation additions, shifts in the resource mix, natural gas prices, and regional demand. EIA forecasts that the load-weighted, wholesale electricity prices at benchmark trading hubs for summer 2026 will average $46.81 per megawatt-hour (MWh), a 5% decrease from summer 2025. Most of the regions are expected to see a decline in prices compared to the previous summer, with the greatest price decreases expected in the Northwest (-41%), the Southwest (-22%), and MISO (-17%). ERCOT, PJM, and SERC are the only regions projected to see increases in prices, with ERCOT up by 11%, PJM by 5%, and SERC by 5%.

The price trends align with EIA forecasts for net summer capacity additions in RTOs/ISOs this summer, as described in more detail in the *Electric Generation Additions, Retirements, and Outages* section. Nationwide, EIA projects more generation additions than retirements in 2026, easing supply-demand tension. Regions are also expected to have larger shares of solar capacity that will contribute more energy and help reduce summer electricity prices. Further, as described in the *Natural Gas Prices* section, lower summer natural gas prices in the West may help lower electricity prices in CAISO, the Northwest, and the Southwest.

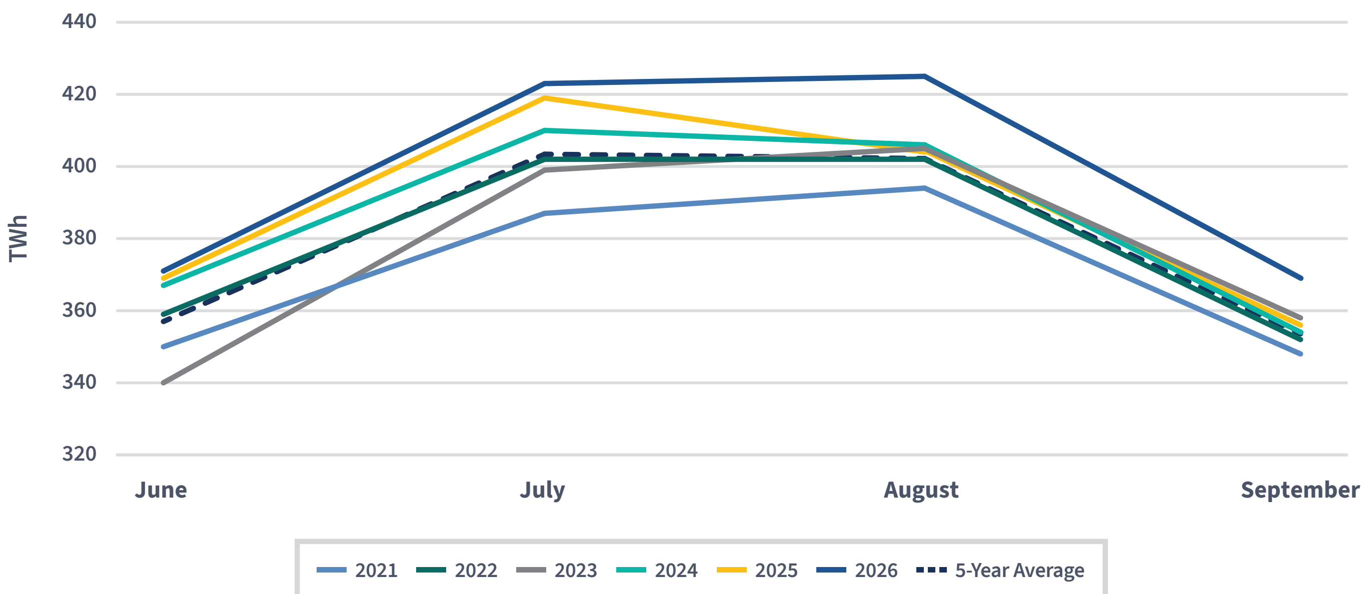
Electricity Consumption

Figure 12: 2026 Summer Electricity Consumption by End User



*Other sectors includes direct use and transportation Source: U.S. EIA Form 912

Figure 13: Summer Electricty Consumption by Year (2021-2026)



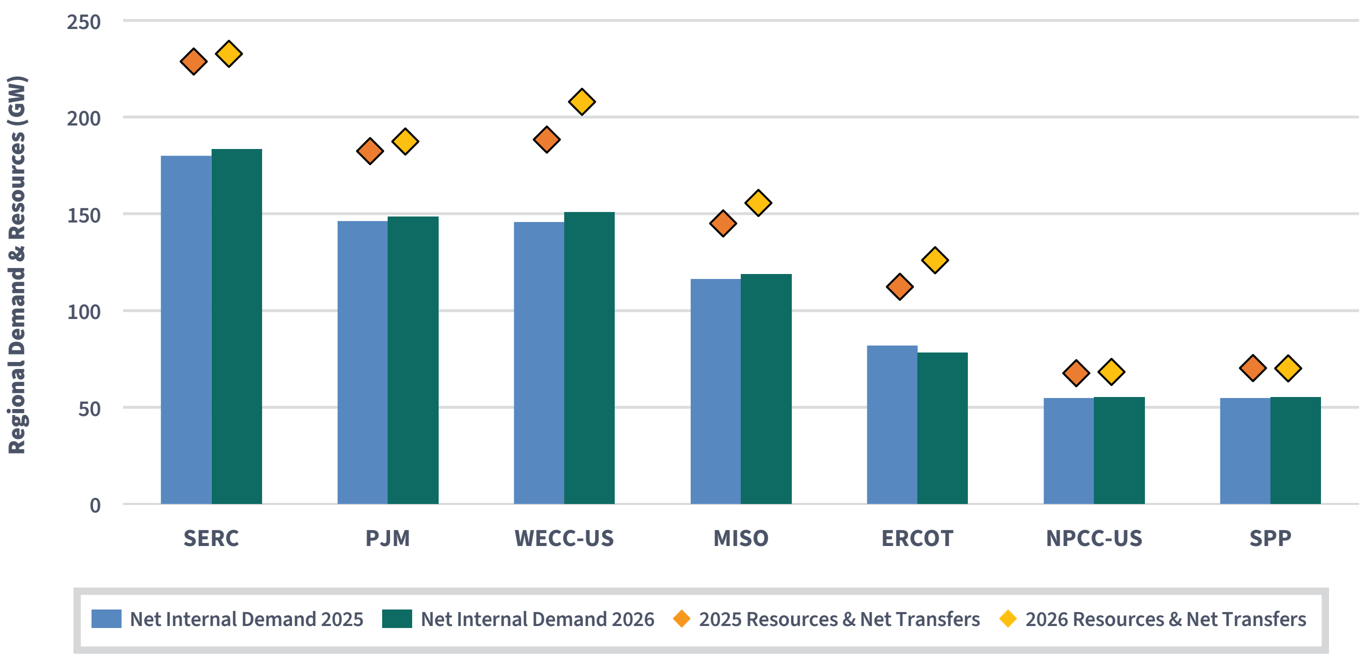
Source: U.S. EIA STEO Table 7a

Electricity consumption is projected to continue to increase in 2026 as it has since 2021. **Figure 12** illustrates electricity consumption across customer classes for summer 2026, with the dark blue line with blue markers showing the previous 5-year average summer consumption. The residential sector's projected 2026 summer consumption of 604 TWh would surpass its 2021-2025 average of 580 TWh by 4.1%, with particularly strong growth in August (6% above the five-year average). The commercial sector shows the most pronounced departure from its historical pattern, with projected 2026 summer consumption of 561 TWh exceeding its 2021-2025 five-year average of 523 TWh, a 7% increase. For the industrial sector, EIA projects 2026 summer consumption of 372 TWh—3% above the previous five-year average of 361 TWh.

Figure 13 illustrates that electricity consumption in summer 2026, represented by the dark blue line, is expected to exceed total consumption levels over each of the previous five summers. Total electricity consumption is projected to reach 1,587 TWh during summer 2026. EIA forecasts that electricity consumption from June to September 2026 will increase by 106 TWh from summer of 2021. This represents a 7% increase from summer 2021 to summer 2026, with summer 2026 projected to have 3% year -over-year growth compared to summer 2025, which is projected to be the most significant year-over-year growth since summer 2022 and 4.5% above the previous five-year average of 1,518 TWh. EIA's projections for monthly total consumption in summer 2026 suggest that demand will peak in August, when EIA forecasts electricity demand will be 426 TWh, a 5% increase from August 2025.

NERC ELECTRICITY DEMAND & RESOURCES

Figure 14: NERC Forecasted Electricity Demand and Resources Summer 2025 and 2026



Source: NERC, 2026 Summer Reliability Assessment

Each summer, NERC projects electricity demand and resources to gauge resource adequacy for each assessment area and the regions. Nationwide, electricity demand is expected to be higher this summer compared to last summer, except in ERCOT. NERC forecasts net internal demand for electricity to increase by approximately 1.3%, or 10 GW, from 780 GW in summer 2025 to 790 GW in summer 2026. However, electricity demand could vary depending on the number of extreme weather events and the characteristics and duration of those events.

Figure 14 compares the net internal demand shown as solid bars and the resources and net transfer values shown as diamonds.[37] This figure compares summer 2025 and summer 2026 and shows that all 15 NERC assessment areas are expected to have sufficient available generation resources and net transfers to meet their expected loads under normal summer conditions,[38] with all areas' planning reserve margins[39] exceeding the reference margins levels.[40] However, extreme weather conditions can create reliability problems even for a region that has achieved its target

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

38 NERC, 2026 *Summer Reliability Assessment* at 2-3 (May 19, 2026), www.nerc.com/our-work/assessments.

39 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* (Jan. 2026), at 170, www.nerc.com/globalassets/our-work/assessments/nerc_ltra_2025.pdf.

40 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 predominantly thermal systems and 10% for predominantly hydropower systems. NERC, *2025 Long Term Reliability Assessment* at 170 (Jan. 2026), www.nerc.com/globalassets/our-work/assessments/nerc_ltra_2025.pdf.

reserve margin. Those conditions can limit fuel availability for generators, reduce power transfers and cause derates of electric generators, unexpected outages and other problems. A variety of factors affect reliable operation and are managed by system operators to help maintain electric supply and reliability. More comprehensive reliability assessments for three of these assessment areas are in the *Regional Highlights and NERC Probabilistic Assessments* section of this report.

To serve demand in summer 2026, NERC forecasts a national increase of 5%, or approximately 52 GW, in total electric generation capacity compared to summer 2025 and expects net energy transfers to increase from approximately 995 GW to approximately 1,048 GW over the same period, illustrated as diamonds in **Figure 14**.[41] This increase is for all areas except NPCC-US and SPP, where total capacity remains about the same as the prior year.

Three trends could challenge resource adequacy in summer 2026: (1) rapid load growth from data centers, electrification, and industrial expansion; (2) supporting increasing transfers; and (3) possible retirements of coal and natural gas generators.

On the demand side, NERC projects that summer peak demand across North America will grow by about 224 GW over the next decade, a 69% increase over the previous year's ten-year forecast and roughly a 24% increase from 2025 peak demand.[42] NERC attributes most of the expected new load to an increasing number of new data centers.[43] On the supply side, operators are deploying tools and technologies to increase effective transfer capability. For example, the Commission's Order No. 881 requires transmission providers to use ambient-adjusted ratings, potentially increasing available transmission capacity, though implementation is ongoing.[44] For this summer, across the U.S., many transmission providers will have begun using hourly ambient adjusted ratings for their line ratings pursuant to Order No. 881.[45] Among the RTO/ISOs, PJM Interconnection LLC (PJM) has adopted the use of ambient adjusted ratings, and SPP expects to implement them on September 1.[46]

Additionally, in several regions, coal and natural gas-fired plants that were slated to retire are continuing operations pursuant to DOE Orders under section 202 (c) of the Federal Power Act (FPA).[47] These units total more than 4,300 MW

41 NERC, *2026 Summer Reliability Assessment* at 45-50 (May 19, 2026), www.nerc.com/our-work/assessments..

42 NERC, *Long Term Reliability Assessment, January 2026*, T*rends and Reliability Implications* at 9, (Jan. 23, 2026), prod.nerc.com/globalassets/our-work/assessments/nerc_ltra_2025.pdf.

43 *Ibid;* Robert Walton, *NERC Forecasts Peak Demand to Rise 24% on New Data Center Loads*, Utility Dive, Jan. 30, 2026, www.utilitydive.com/news/nerc-10-year-peak-demand-forecast-jumps-24-on-new-data-center-loads/810955/#:~:text=Dive%20Brief%3A&text=Summer%20peak%20demand%20across%20the,most%20of%20the%20projected%20increase.

44 *Managing Transmission Line Ratings,* Order No. 881, 177 FERC ¶ 61,179 (2021). Ambient adjusted ratings are designed to more accurately reflect the transfer capability of the transmission system than seasonal and static transmission line ratings, and in some cases may identify more transfer capacity.

45 Transmission providers using AARs this summer include Tampa Electric Co., Duke Energy Florida, Southern Companies, Dominion Energy South Carolina, Louisville Gas and Electric Co. and Kentucky Utilities, Avista, Idaho Power Co., Public Service Company of New Mexico, and Portland General Electric Co.

46 PJM Inside Lines, *PJM Becomes First RTO to Implement Ambient-Air Ratings for Transmission under FERC Order 881* (Mar. 9, 2026), insidelines.pjm.com/pjm-becomes-first-rto-to-implement-ambient-air-ratings-for-transmission-under-ferc-order-881/. Ethan Howland, *PJM is Now Using Ambient-Adjusted Transmission Ratings. Other Grid Operators Will Soon Follow,* Utility Dive, Mar. 12, 2026, www.utilitydive.com/news/pjm-ambient-adjusted-transmission-ratings-ferc-881/814534/.

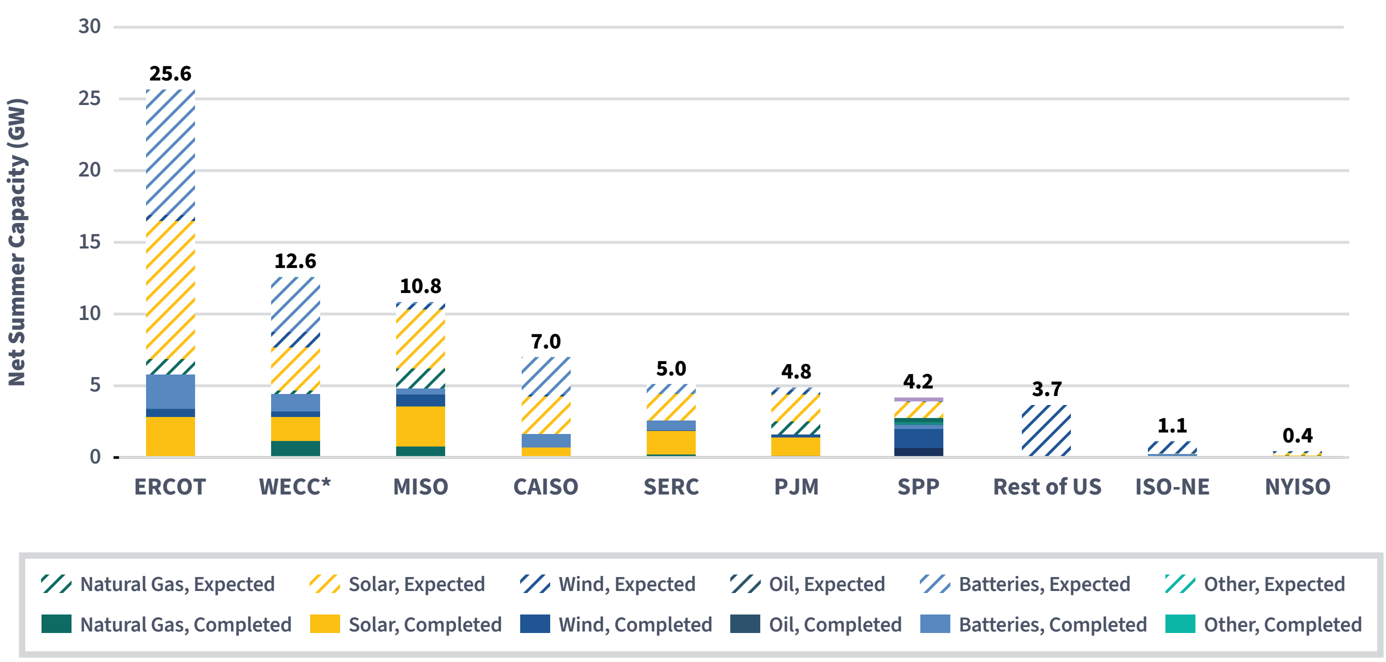
47 Pursuant to FPA section 202(c) and section 301(b) of the Department of Energy Organization Act, the Secretary of Energy may direct a plant to continue running to address an emergency and to serve the public interest. 16 U.S.C. § 824a(c); 42 U.S.C. § 7151(b).

of firm capacity that may be able to support reliability during peak demand.[48] A detailed list of other notable thermal plant retirements that are not subject to the DOE emergency orders can be found in the *Electric Generation Additions, Retirements, and Outages* section of this report.

48 Units directed to continue operations by the Secretary of Energy under FPA 202(c) include: Eddystone Units 3 and 4 (760 MW) in Pennsylvania through May 2026; the Centralia Generating Station Unit 2 (729 MW) in Washington, the R.M. Schahfer Units 17 and 18 (722 MW) in Indiana, the Craig Station Unit 1 (427 MW) in Colorado, and the F.B. Culley Generating Station Unit 2 (360 MW) in Indiana will remain in operation through June 2026. Also, J.H. Campbell (1,331 MW) in Michigan through August 2026. DOE, *2026 DOE 202(c) Orders* (Accessed May 18, 2026), www.energy.gov/ceser/2026-doe-202c-orders; *EIA, Retirement Delays of U.S. Electric Generating Capacity May Continue in 2026* (Feb. 23, 2026), www.eia.gov/todayinenergy/detail.php?id=67206.

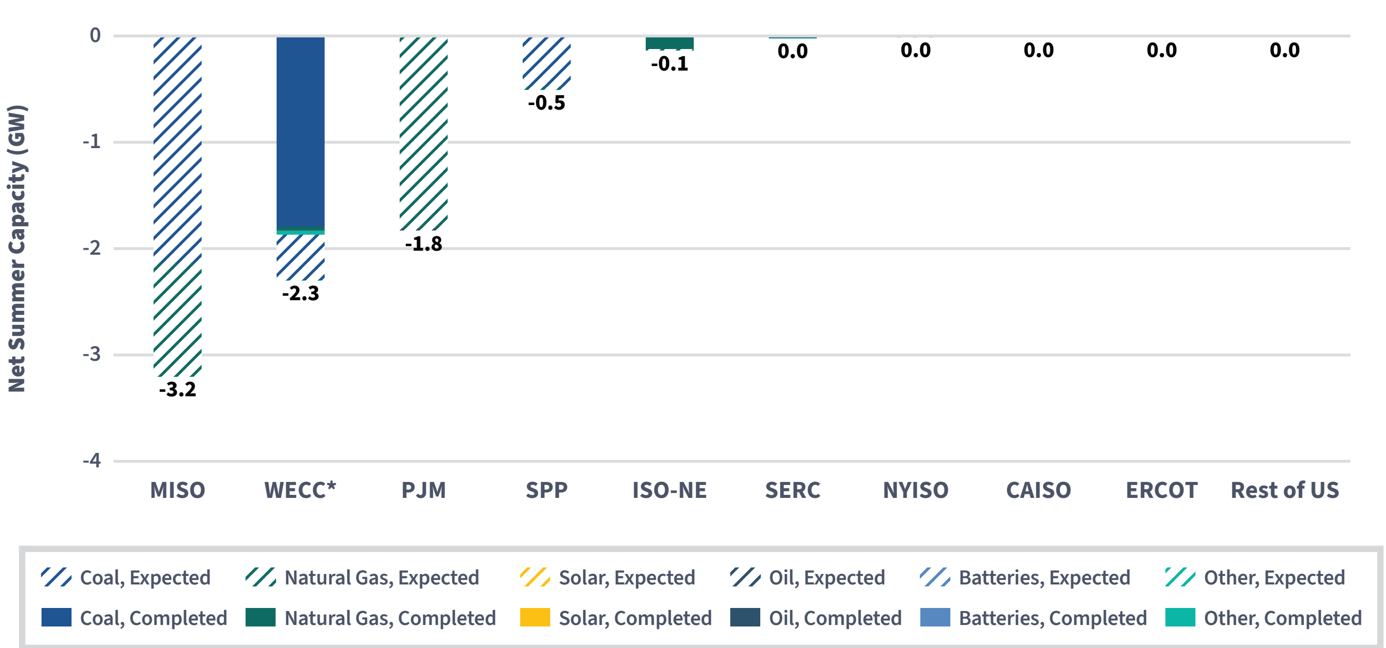
ELECTRIC GENERATION ADDITIONS, RETIREMENTS, & OUTAGES

Figure 15: Electricity Capacity Additions (Oct 2025 - Sep 2026)



NOTE: Completed (from Oct 2025-Jan 2026); Expected (from Feb 2026-Sep 2026) Source: U.S. EIA. Form 860M. *WECC* refers to WECC without CAISO.*

Figure 16: Electricity Capacity Retirements (Oct 2025 - Sep 2026)



NOTE: Completed (from Oct 2025-Jan 2026); Expected (from Feb 2026-Sep 2026) Source: U.S. EIA. Form 860M. *WECC* refers to WECC without CAISO.*

In this section of the assessment, we take a closer look at recent and expected generator additions and retirements heading into summer, including how the resource mix is changing and where plants are being built and retired.

Figure 15 and **Figure 16** show solid bars for completed electric capacity additions and retirements from October 2025 to January 2026, and stripe patterned bars show expected electric capacity additions and retirements from February 2026 to September 2026.[49] These figures reflect net summer capacity[50] across different regions and resource types. Based on EIA data, during this time period net summer capacity additions are expected to total about 75 GW, which is 78% higher than the average net summer capacity additions seen in the last five years.[51] ERCOT is expected to add the most net summer electric capacity, 25.6 GW, which is a 16% increase from its 2025 net summer electric capacity of 158 GW. Other regions expected to add significant net summer electric capacity are the non-CAISO WECC (12.6 GW, a 7% increase to its 2025 capacity) and MISO (10.8 GW, a 6% increase to its 2025 capacity).

Most of these new capacity additions are from solar, battery, and wind facilities, while the expected 8.1 GW of retirements are almost all (98%) coal and natural gas facilities.[52] Given their operating characteristics, new capacity from solar, battery, and wind facilities does not replace the thermal capacity from coal and natural gas facilities on a one-for-one basis.[53]

Meanwhile, across all regions, natural gas generators will continue to provide the largest share (39%) of net summer generation capacity, followed by solar at 14%, coal at 13%, wind at 12%, and nuclear and hydropower both at 7%.[54]

Natural gas resources will remain the dominant source of net summer capacity even while that capacity will decrease more than that of any other fuel type this summer compared to last. Meanwhile, the share of solar net summer capacity will increase the most.

Specifically, generators are expected to retire 3.1 GW of natural gas net summer capacity and to add 35.9 GW of solar capacity, which would decrease the share of natural gas net summer capacity from 41% to 39% and increase the share of solar net summer capacity from 11% to 14%. Generators are also expected to add 22.3 GW of battery net summer capacity, which would increase the share of battery net summer capacity from 3% to 4.5%. All other resource types are expected to see installed capacity share changes of one percent or less.

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49 Of the units directed to continue operations by the Secretary of Energy under FPA 202(c), J.H. Campbell, Eddystone Units 3 and 4, R.M. Schahfer Units 17 and 18, and the Craig Station Unit 1 are included in the expected electric capacity retirements in Figure 16. FPA 202(c) order status changes statuses change every three months, and EIA updates their data accordingly.

50 In this report, net summer capacity refers to the maximum output that generating equipment can supply to system load at the time of peak summer demand. EIA, *Glossary* (Accessed Mar. 18, 2026), www.eia.gov/tools/glossary/index.php/.

51 EIA, *Preliminary Monthly Electric Generator Inventory* (Mar. 24, 2026), www.eia.gov/electricity/data/eia860m/.

52 The WECC amounts include two coal-fired units at the Intermountain Power Plant that are not operating but have not been decommissioned. *See Alixel Cabrera, IPP Coal-fired Units are no Longer Operating as State Government Searches for Buyers,* Utah News Dispatch, Dec. 5, 2025, utahnewsdispatch.com/2025/12/05/intermountain-power-plant-coal-fired-units-no-longer-operating/.

53 For example, Bolson et al. estimate replacing 1 MW of thermal electricity generation requires 2 MW of wind generation or 4 MW of solar generation. *See* N. Bolson, P. Prieto, & T. Patzek, *Capacity Factors for Electrical Power Generation from Renewable and Nonrenewable Sources, Proc. Natl. Acad. Sci. U.S.A. 119 (52) e2205429119*, doi.org/10.1073/pnas.2205429119 (2022).

54 Note that these installed summer capacity estimates capture expected capacity retirements and planned capacity through September 2026 and do not imply that generation output will match the summer capacity of a resource type. *See* EIA, *Preliminary Monthly Electric Generator Inventory* (Mar. 2026), www.eia.gov/electricity/data/eia860m/.

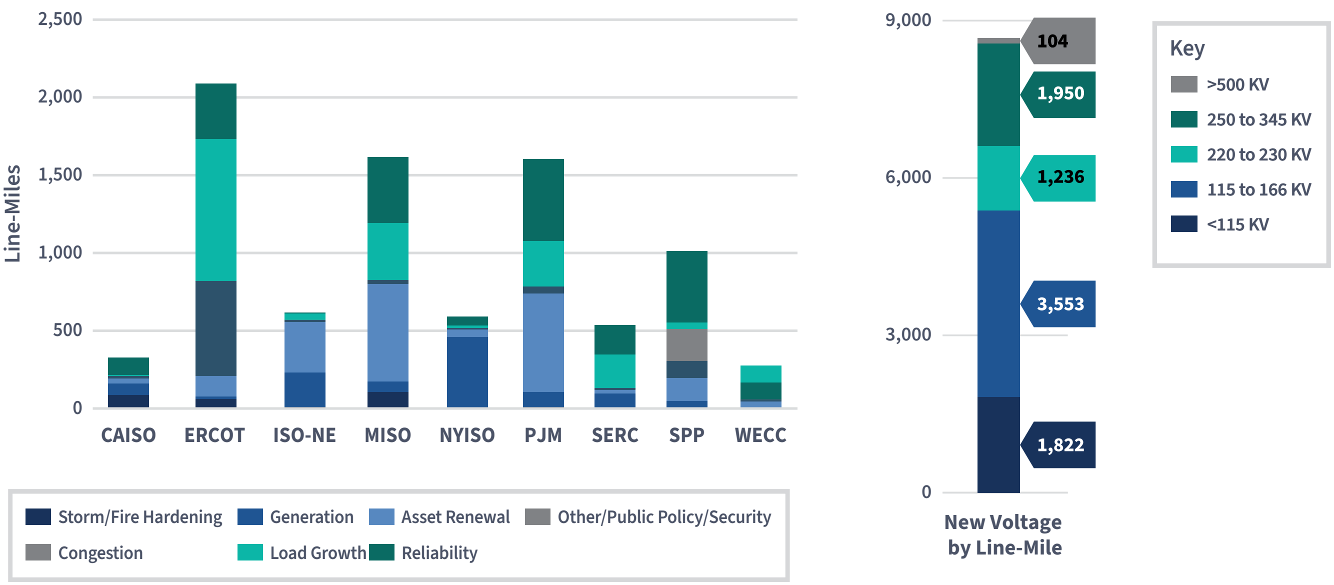
Electricity generators plan to retire 8.1 GW of nameplate capacity between summer 2025 and summer 2026, accelerating by 55% the previous-year pace of retirement. Between summer 2024 and summer 2025, 5.2 GW were retired from the U.S. power grid, the smallest amount of generation capacity retired since 2008. Coal generating capacity accounts for the largest share of planned capacity retirements (60%), followed by natural gas (38%).

Some notable large thermal plants slated for retirement include: the Elwood Energy Power Station (1,344 MW) in Illinois; Grand River Energy Center (594 MW) in Oklahoma; Sabine Power Plant (1,304 MW) in Texas; Oak Creek Units 7 and 8 (616 MW) in Wisconsin; and the AES Alamitos (1,142 MW) and Huntington Beach (226 MW) plants in California.[55]

Generally, planned outages for conventional units tend to decline into the summer from a peak in April and rise again in September to a peak in October or November. As a result, total coincident capacity on outage generally declines in the summer. During July and August, forced outages and derates make up the majority or plurality of unavailable capacity.[56] Proactive grid management strategies are important to maintain grid reliability during extended planned outages as well as when unexpected, forced outages occur.

Electricity Transmission

Figure 17: New Line and Line Upgrades in Summer 2026 by Project Driver (Left) and Voltage (Right)



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

New and upgraded transmission infrastructure supports summer reliability by alleviating constraints, connecting new generation resources, and reinforcing the grid to meet growing electricity demand. Across the country, there are 2,202 new transmission projects in service supporting grid reliability this summer, including 1,136 substation-only projects,

55 EIA, *Preliminary Monthly Electric Generator Inventory* (Mar. 2026), www.eia.gov/electricity/data/eia860m/.

56 Staff analysis of NERC's Generating Availability Data System data from 2021 to 2025.

662 transmission line projects, and 404 combined projects. These projects total 8,665 line-miles, including both projects in regional transmission plans developed by RTOs and ISOs and local projects planned by individual transmission owners within those regions. Of these, 6,476 miles were completed and placed in service between October 2025 and May 2026, and 2,189 miles are expected to enter service between June and September 2026.[57] **Figure 17** breaks down new and upgraded line-miles by region and project driver. Nationwide, the primary drivers for these projects are system reliability (2,244 line-miles), asset renewal (2,019 line-miles), and load growth (1,997 line-miles).

By transmission project count, ERCOT (684), PJM (481), and MISO (450) are the most active regions for transmission development. **Figure 17** illustrates that the top drivers vary by region: ERCOT is primarily focused on load growth (44% of its line-miles) and other/policy/grid security drivers (29%); MISO is driven by a combination of asset renewal (39%) and system reliability (26%); PJM's transmission expansion is concentrated on asset renewal (39%) and system reliability (33%); and CAISO's new mileage is led by system reliability (35%) and storm and fire hardening (27%). SERC is driven by load growth (40%) and system reliability (36%). SPP and MISO are the only regions with new transmission projects developed during this period to relieve congestion, totaling 209 line-miles.

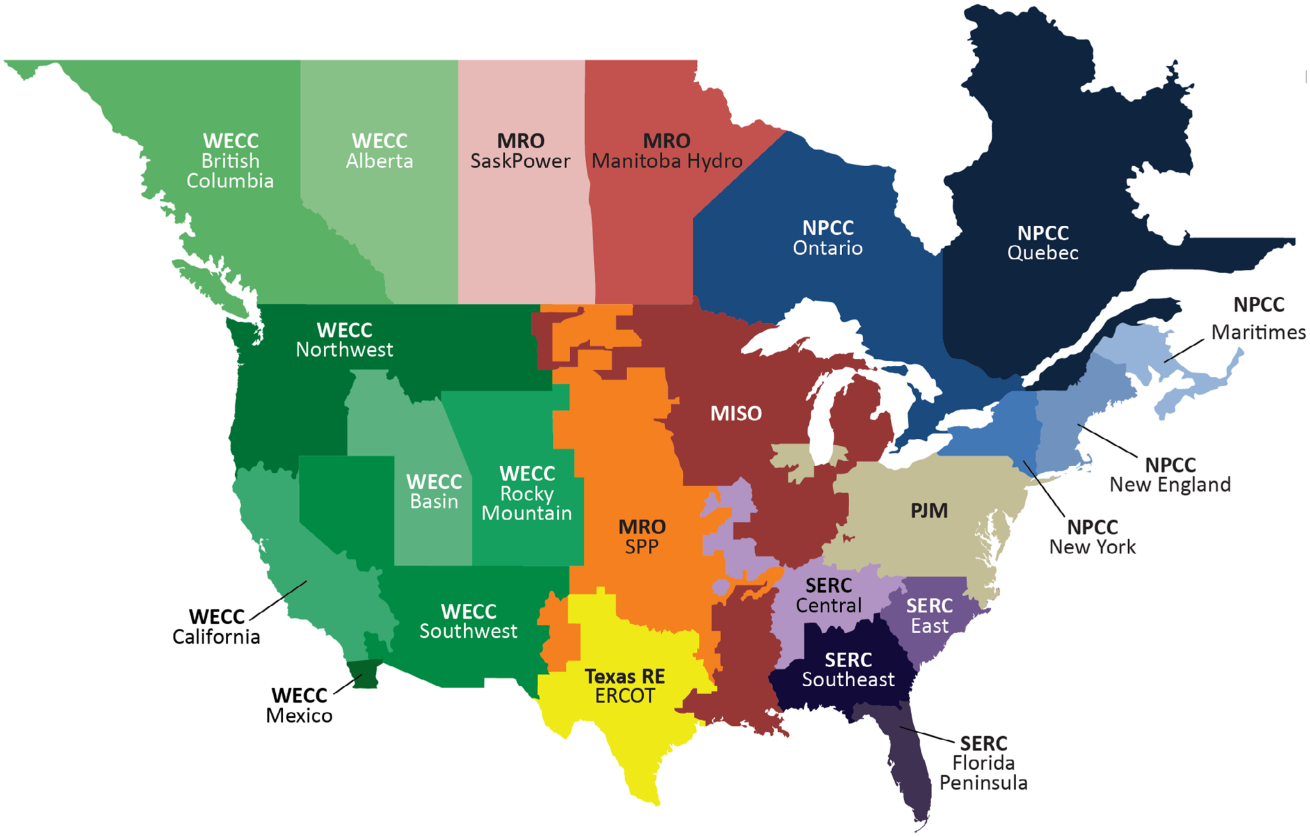
Most projects involve lines below 230 kV, accounting for 62% (or 5,375 line-miles) of new line-miles. The highest voltage lines of 500 kV or more account for 104 line-miles.

57 Transmission line-mile data is from Yes Energy's Electric Transmission and Distribution database. Projects listed include those completed between October 2025 and May 2026 and those expected to enter service between June and Sept. 2026.

REGIONAL HIGHLIGHTS & NERC PROBABILISTIC ASSESSMENTS

NERC Regional Probabilistic Assessments

Figure 18: Regional Highlights and Probabilistic Assessments



Source: NERC

Regions may face energy shortfalls even if planning reserve margins exceed the reference margin levels.[58] To better understand this possibility, NERC assessment areas undertake probabilistic risk analysis[59] to study expected system performance and uncertainty under region-specific scenarios. In doing so, they evaluate the risk of resource adequacy shortfalls for each assessment area this summer. This section relies on the probabilistic risk analyses from NERC's summer 2026 seasonal assessment and supporting reports to assess resource adequacy. NERC's analysis shows that all assessment areas, shown in **Figure 18**, anticipate adequate supplies and reserve margins under normal conditions, but the NPCC-NE, the western part of ERCOT, and the WECC-NW may face a higher likelihood of tight supply and reliability issues during extreme conditions.[60] Below, we focus on the assessments for these three areas.

58 NERC, *2026 Summer Reliability Assessment* at 10-11 (May 19, 2026), www.nerc.com/our-work/assessments.

59 A probabilistic risk analysis assesses a range of scenarios, including potential variations in resources and load that can affect grid operations and can include model parameters to mimic operator actions that could help to mitigate shortfalls in operating reserves.

60 All Regional Entities and assessment areas provide a probability-based resource adequacy risk assessment for the summer season. *See* NERC, *2026 Summer Reliability Assessment* (May 19, 2026), www.nerc.com/our-work/assessments.

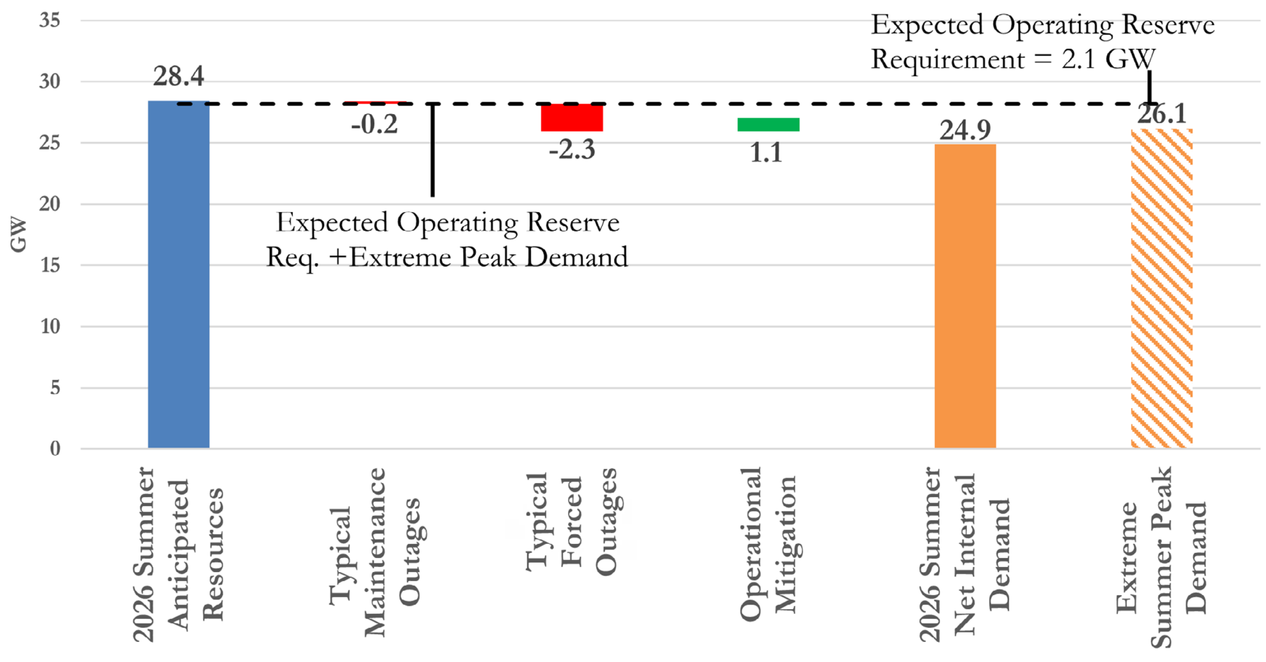
Across all assessment areas, above-normal summer peak load and resource outages could require operational mitigation measures. System operators may call on demand response resources, cancel or postpone non-critical maintenance outages of generation and transmission, and request voluntary conservation measures. If system conditions deteriorate substantially, Reliability Coordinators would declare an Energy Emergency Alert (EEA), allowing system operators to activate emergency demand response measures and increase generation imports from neighboring regions during scarcity conditions.

Regional Highlights

As noted above, NERC's probabilistic assessments evaluate the risk of resource adequacy shortfalls for each assessment area this summer.

Assessment areas set 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 hour(s) for Expected Unserved Energy,[61] along with the varying demand and available resource profiles. The methods, scenarios considered, and assumptions differ by assessment area and may not be comparable. While all areas are expected to have adequate anticipated resources under normal summer conditions, NPCC-NE, western ERCOT, and WECC-NW assessment areas may experience challenges during extreme summer conditions.

Figure 19: NPCC-NE'S Seasonal Risk Assessment



Source: NERC, 2026 Summer Reliability Assessment

61 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, Metrics for Probabilistic Evaluation Used in this Assessment* at 172-173, prod.nerc.com/globalassets/our-work/assessments/nerc_ltra_2025.pdf.

NPCC-NE. NERC's *2026 Summer Reliability Assessment* uses "waterfall" charts to illustrate probabilistic assessments for each region. **Figure 19** shows the seasonal risk assessment for NPCC-NE. The left blue column shows anticipated resources of 28.4 GW and the two orange columns on the right show the demand scenarios with normal summer peak of 24.9 GW (50/50) and the extreme summer peak of 26.1 GW (90/10).[62] The middle red bars show the factors that can reduce resource availability, including maintenance outages (0.2 GW less available) and forced outages (2.3 GW), which are not already accounted for in anticipated resources. The middle green bar depicts potential additions of 1.1 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 represents the expected operating reserve requirement of 2.1 GW plus the extreme peak demand, or the amount of power that a region would need to produce to avoid a shortfall.

NPCC-NE's probabilistic assessment shows that established operating procedures should be adequate to maintain supply-demand balance under expected normal conditions during summer 2026. However, under the highest peak load and reduced resources scenario, the area faces elevated risk.[63] The extreme scenario produces an anticipated reserve margin of 11%, below the reference margin level of 13%, and short by approximately 559 MW, with numerous modeled loss-of-load events in June, July, and August.

NPCC-NE's forecasted normal net internal demand peak of 24,882 MW is up 0.3% from last summer.[64] The forecast incorporates expected demand reductions from energy efficiency, load management, behind-the-meter solar, and other distributed generation resources. While the assessment area assumes a net interchange of about 409 MW as firm transmission, actual summer imports often approach 3,000 MW during summer peak conditions, including non-firm resources.[65] In January 2026, NPCC-NE added the New England Clean Energy Connect,[66] a 1,200 MW, 320 kV HVDC, import-only tie line, connecting Hydro-Québec to ISO-New England at an interconnection in Maine.[67] However, the higher-than-normal temperatures and drier conditions in the Québec assessment area may limit transfers into NPCC-NE, a problem exacerbated by the relatively small amount of firm transmission capacity (409 MW) projected as available for net interchange into NPCC-NE this summer.

ERCOT. ERCOT's preliminary summer 2026 outlook indicates a strong chance of warmer and drier-than-normal conditions, with drought potentially driving high statewide electricity demand. While ERCOT expects sufficient operating reserves for the August peak load hour under normal summer conditions, rapid load growth and intermittent renewable resources increase the risk of emergency conditions during evening hours when solar generation ramps down and demand remains elevated.[68]

62 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.

63 The study evaluated a base case reflecting 50/50 normal demand and a highest peak load scenario with a 7% probability.

64 NERC, *2026 Summer Reliability Assessment* at 46, (May 19, 2026), www.nerc.com/our-work/assessments.

65 *Id* at 21.

66 Iberdrola, *NECEC: Connecting Canada and the United States to supply renewable energy to New England*, (Accessed Apr. 23, 2026), www.iberdrola.com/about-us/what-we-do/smart-grids/necec-project-canada-united-states-and-new-england.

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

68 NERC, *2026 Summer Reliability Assessment* at 30, (May 19, 2026), www.nerc.com/our-work/assessments.

Rapid load growth in far West Texas has created new reliability challenges.[69] High demand combined with low solar and wind output may overload transmission lines, risking thermal cascading. Additionally, significant and concentrated growth of large, energy-intensive loads such as data centers and industrial facilities pose risks[70] of sudden load loss, which can trigger frequency disturbances, voltage instability, and cascading outages.[71] ERCOT has implemented new Interconnection Reliability Operating Limits in the far west as mitigation efforts. Until longer-term upgrades are in place, ERCOT relies on price-responsive demand to maintain reliability during tight supply periods.[72]

ERCOT is implementing its operational preparedness activities, including its Real-Time Co-optimization Plus Batteries (RTC+B) program to enable improved decision making for energy dispatch, unit commitment, and reserves procurements during periods of tight supply. Also, ERCOT has improved real-time visibility into energy storage resource state of charge, enabling earlier actions when reserves appear insufficient for summer.[73] ERCOT anticipates no major impacts on summer grid reliability from neighboring assessment areas. However, some Switchable Generation Resources[74] totaling about 1,941 MW will be operated to serve SPP's load during the summer to meet contractual obligations. While this reduces capacity available to ERCOT under normal conditions, some of these resources could be temporarily returned to ERCOT if an EEA condition is declared.[75]

WECC-NW. The WECC-NW assessment area faces reliability risks from weather, resource variability, and infrastructure constraints, with wildfire remaining a major concern.[76] As described earlier, below-average snowpack and shifting precipitation patterns reduce hydropower output, increasing reliance on flexible thermal resources and real-time monitoring to manage variability.

To address extreme weather, variable renewable output, and growing load additions, WECC-NW is expanding weather forecasting, wildfire monitoring, conservative hydropower management, battery storage transmission upgrades, and new gas generation. WECC-NW has enhanced its resource planning to manage these impacts.[77]

Reduced local generation, especially hydropower, increases dependence on imports, adding operational exposure during peak periods.[78] Finally, persistent supply chain constraints, including long equipment lead times, rising costs, and limited manufacturing capacity,[79] continue to delay infrastructure projects and reduce operational flexibility,

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69 ERCOT, Notice Operations: M-A022326-01 Large Load Interconnection Studies update for Far West Texas region, (Feb. 23, 2026), www.ercot.com/services/comm/mkt_notices/M-A022326-01

70 NERC, *2026 Summer Reliability Assessment* at 30, (May 19, 2026), www.nerc.com/our-work/assessments.

71 ERCOT proposed an operating guide revision (NOGRR 282) establishing frequency and voltage ride-through requirements for certain Large Electronic Loads. This will not be in place for Summer 2026. ERCOT, NOGRR 282 - Large Electronic Load Ride-Through Requirements, www.ercot.com/mktrules/issues/NOGRR282#summaryERCOT, NOGRR 282 - Large Electronic Load Ride-Through Requirements (Accessed May 14, 2025), www.ercot.com/mktrules/issues/NOGRR282#keydocs .

72 NERC, *2026 Summer Reliability Assessment* at 30, (May 19, 2026), www.nerc.com/our-work/assessments.

73 ERCOT, *ERCOT Goes Live with Real-Time Co-optimization Plus Batteries,* press release, (Dec. 5, 2025), https://www.ercot.com/news/release/12052025-ercot-goes-live.

74 Switchable Generation Resources are generating units that are capable of nonsimultaneous synchronization with both the Texas Interconnection and the Eastern Interconnection.

75 NERC, *2026 Summer Reliability Assessment* at 30, (May 19, 2026), https://www.nerc.com/our-work/assessments.

76 *Id* at 36.

77 *Ibid.*

78 *Ibid*.

79 Sonal Patel, *Transformers in 2026: Shortage, Scramble, or Self-Inflicted Crisis?,* POWER, Jan. 2, 2026, www.powermag.com/transformers-in-2026-shortage-scramble-or-self-inflicted-crisis/.

making those constraints a sustained and structural risk to reliability. According to WECC, the Northwest area supply chain constraints and economic uncertainty may impact Tier 1 resources (i.e., future capacity that is typically considered more certain because it is either under construction or has received approved planning requirements) that total 477 MW.[80] When large loads go offline, the WECC-NW assessment area may experience energy imbalance and over-frequency, increasing the need for regulation reserves requiring operator intervention.[81]

80 NERC, *2026 Summer Reliability Assessment* at 36 (May 19, 2026), https://www.nerc.com/our-work/assessments.

81 *Ibid.*

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