

Business & Technology Report
September 2026

Electric Industry Outlook Report



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Executive Summary

This report by NRECA's Business & Technology Strategies (BTS) group seeks to provide a high-level summary of trends in the U.S. electric industry using recent projections produced by the U.S. Department of Energy's (DOE) Energy Information Administration (EIA). Below are some high-level findings highlighted in this report:

Electricity demand is rising at an accelerated rate, placing growing pressure on generation and grid infrastructure. Data centers, advanced manufacturing, reshoring of industrial activity, electric vehicles, heat pumps, and other forms of electrification are contributing to rising electricity demand. At the same time, uncertainty around the timing and scale of some large loads makes long-term planning more difficult. The industry is responding with substantial investment in generation, transmission, distribution, and grid modernization, but long interconnection queues and constrained equipment supply chains continue to slow the deployment of new resources.

- **The U.S. generation mix is shifting toward natural gas and renewables, while coal continues to decline.** Projections from EIA show coal's share of utility-scale generation declining from 16% in 2026 to below 3% beginning in 2033. Renewable generation is projected to increase from 26% in 2026 to 48% by 2040, driven primarily by solar and wind, while natural gas remains an important source of generation and is projected to supply roughly 35% of generation through much of the 2030s. EIA also modeled an Alternative Electricity Case that includes the repeal of greenhouse gas emission standards that shows coal generation declining more slowly across the period, falling to 11% in the early 2030s and down to 7% by 2040.
- **The industry is simultaneously retiring existing resources and entering a major capacity-building cycle.** More than 5 gigawatts (GW) of U.S. generation retired in 2025, while approximately 54.9 GW of new capacity was added—the largest annual addition since 2002. Solar accounted for nearly half (27 GW) of 2025 additions, followed by battery storage (15.5 GW), wind (6.2 GW), and natural gas (5 GW). More than 86 GW of capacity is planned for 2026, led by solar and energy storage. Beyond 2026, there is a shift towards a larger amount of natural gas capacity additions as there is a major buildout of natural gas generation of all types.
- **Electric cooperatives are also in a significant generation and storage buildout.** Compared to the 2024 retail fuel mix, co-ops were supplied by a higher share of coal—from 15% the previous year, to 23% in 2025. Renewable sources also made up a higher share of the co-op fuel mix (24% in 2025 vs. 23% in 2024). On the other hand, the share of nuclear (15% in 2025 vs. 18% in 2024) and natural gas (36% in 2025 vs. 43% in 2024) declined.
 - Plant retirements in co-op territory amounted to 12 MW in 2025, mostly from fossil-fuel generators. An additional 3.5 GW will be decommissioned between 2026 and 2031, primarily from coal plants and some natural gas and renewable sources.
 - New generation has been announced, with more than 20.5 GW planned between 2026 and 2031, including substantial investments in natural gas, renewable generation, and battery energy storage.

- **Geopolitical instability is adding another layer of uncertainty to U.S. energy markets.** Ongoing hostilities between the United States and Iran and disruptions surrounding the Strait of Hormuz have contributed to higher oil prices, transportation costs, and global energy market volatility. While U.S. natural gas prices have remained comparatively stable due to strong domestic production, growing demand for natural gas generation and constrained gas turbine manufacturing capacity could create challenges for utilities developing new generation.
 - For co-ops, these conditions reinforce the value of fuel diversity and resource flexibility. Battery storage and renewable generation can reduce exposure to fuel price volatility, while continued investment in natural gas provides dispatchable capacity to support reliability. However, higher transportation costs and disruptions to global battery supply chains could increase the cost of new energy infrastructure and delay battery storage and new generation projects.
- **Regional differences will shape how utilities respond to challenges.** The impacts of load growth, resource retirements, transmission constraints, and market changes vary significantly across the country. Vertically integrated regions such as SERC and WECC are navigating resource adequacy, transmission expansion, and evolving regional coordination. Competitive markets including CAISO, ERCOT, MISO, PJM, and SPP are addressing rapid load growth through changes to market design, interconnection processes, resource procurement, and transmission planning. These differences reinforce the need for solutions that account for regional market and regulatory conditions.

1. Electric Industry Outlook

Introduction

This report by NRECA's Business & Technology Strategies (BTS) group seeks to provide a high-level summary of trends in the U.S. electric industry using recent projections produced by the U.S. Department of Energy's (DOE) Energy Information Administration (EIA). The report supplements these projections with interspersed subsections focused specifically on electric cooperatives, as well as two *Issue in Focus* sections covering topics with industry-wide impact: (1) geopolitical developments influencing global energy supply and demand as well as domestic energy prices; and (2) regional energy market challenges and the different approaches being taken to address them.

Methodology

Each year, the U.S. Department of Energy's Energy Information Administration prepares the *Annual Energy Outlook* (AEO), a report on U.S. energy system projections and analysis. The AEO is broken down into different modeled cases to look at different assumptions and projections on energy production, consumption, technology, and prices to serve as a resource. "AEO2026's projections reflect business-as-usual trends, given known technological and demographic trends and current laws and regulations, and so provides a policy-neutral Reference Case and an accompanying set of core side cases that can be used to analyze policy initiatives."¹

In this report, we will be using the Counterfactual Baseline Case also known as the "Reference Case" which assesses "how [the] U.S. and world energy markets would operate through 2050 under laws and regulations as of December 2025, under evolutionary technological growth assumptions," as well as the Alternative Electricity Case which assumes "the Clean Air Act (CAA) Section 111 rule implemented by the U.S. Environmental Protection Agency (EPA) in April 2024 to regulate carbon dioxide (CO₂) emissions from new natural gas-fired combustion turbines and existing coal-, oil-, and gas-fired steam generating units is not in place, and the affected generators no longer have federal restrictions on greenhouse gas emissions. In this case, existing coal-fired plants continue operating without requiring modifications to reduce emissions, and generation from new natural gas-fired combined cycle units isn't constrained based on whether the plant has installed carbon capture equipment."^{2,3} The AEO projects energy trends out to 2050, but this report will focus on trends from 2026 to 2040.

¹ *Annual Energy Outlook 2026*, (EIA, April 8, 2026), <https://www.eia.gov/outlooks/aeo/>.

² *Annual Energy Outlook 2026*.

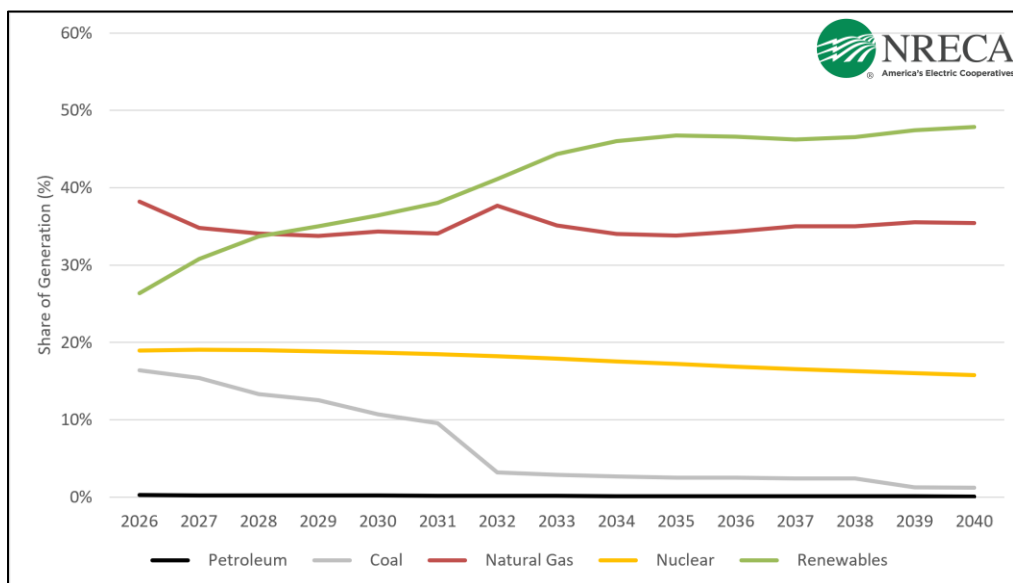
³ On September 17, 2026, EPA issued a final rule repealing most of the April 2024 Section 111 rule, including all requirements on existing coal plants and the most onerous requirements on new combustion turbines, but did not repeal certain standards for new combustion turbines that would limit the output of most new units. *See* 91 Fed. Reg. 58954. At the same time, EPA proposed to repeal all remaining GHG emissions requirements for the power sector. *See* 91 Fed. Reg. 59002.

U.S. Generation Mix

The U.S. generation mix continues to evolve due to changing power supply technologies, shifts in federal and state policies, and the explosion of load growth driven by data center and other large loads. EIA projects U.S. electricity demand to increase by about 25% between 2025 and 2040, with growth closer to 30% under alternative scenarios modeling faster economic and electricity demand growth, though there remains significant uncertainty as the picture around large loads firms up.⁴

In **Figure 1**, EIA's Reference Case⁵ forecasts the change in the U.S. electric generation mix from utility-scale generators (1 megawatt or larger) through 2040. The share of generation produced from coal declines steeply from 16% in 2026 to 10% in 2031 before falling to under 3% in 2033 and beyond, driven by the retirement of legacy generation and other factors. This case assumes that April 2024 greenhouse gas emissions standards for the power sector under Section 111 of the Clean Air Act, most of which were recently repealed, are implemented. Natural gas generation supplies 38% of electricity in 2026 and its share remains mostly flat through the rest of the 2030s. Generation from renewable sources is forecasted to account for 26% of total generation in 2026, growing steadily across the entire period to 48% of generation by 2040, driven primarily by growth in solar and wind. The expansion of renewables is also supported by the widespread adoption of battery energy storage which provides a firming capability to an intermittent class of generation technology. The share of nuclear declines slightly from 19% in 2026 to 16% in 2040 as the installed capacity of the U.S. nuclear fleet remains steady, but the overall generating capacity of the U.S. power sector grows. Generation from petroleum stays consistent throughout the modeled period.

Figure 1: U.S Generation Mix, AEO2026 Reference Case

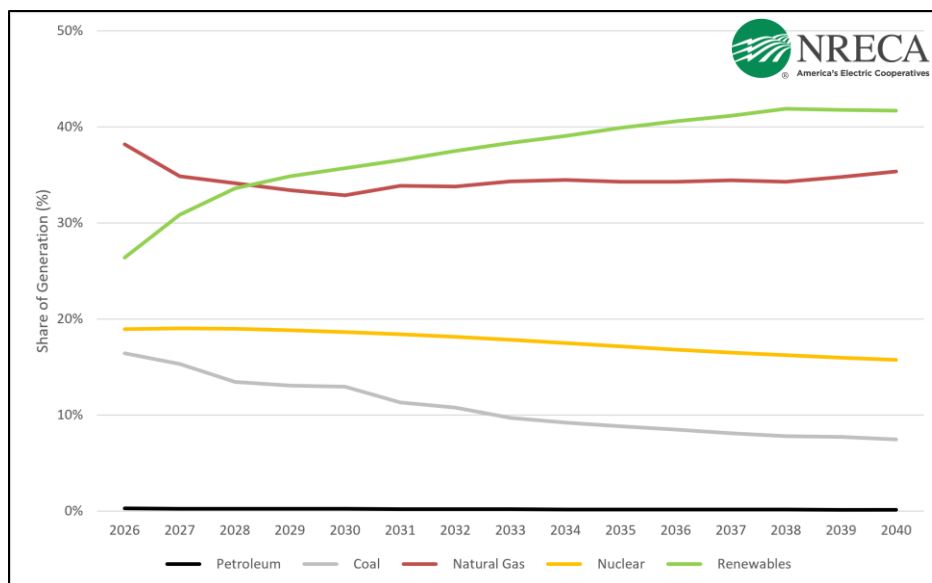


⁴ *Annual Energy Outlook 2026*.

⁵ This report will use Reference Case to refer to EIA's Counterfactual Baseline case from the 2026 Annual Energy Outlook, EIA, "Case Descriptions," Annual Energy Outlook 2026, accessed August 11, 2026, https://www.eia.gov/outlooks/aeo/assumptions/pdf/case_descriptions.pdf.

Figure 2 depicts EIA’s forecast using the Alternative Electricity Case, which assumes that greenhouse gas emissions standards for the power sector under Section 111 of the Clean Air Act are not implemented.⁶ In this case, coal generation stays consistent through the rest of the 2020’s at approximately 13% before dropping to 11% in the early 2030s and then leveling out to 7% of the total U.S. generation mix in 2040. Compared to EIA’s Counterfactual Baseline Case (or Reference Case) above, the share of natural gas generation increases gradually in the early 2030s ending the decade at 36% of U.S. generation in 2040. Generation from renewable sources also increases gradually throughout the 2030s and reaches a peak of 42% of the U.S. generation mix by 2040 compared to 48% in the Reference Case. Nuclear generation does not see significant changes between both cases and still is forecasted to be 16% of U.S. generation mix by 2040. Comparing both cases can demonstrate the impacts of policy changes on the U.S. generation mix over time.

Figure 2: U.S. Generation Mix, AEO 2026 Alternative Electricity Case



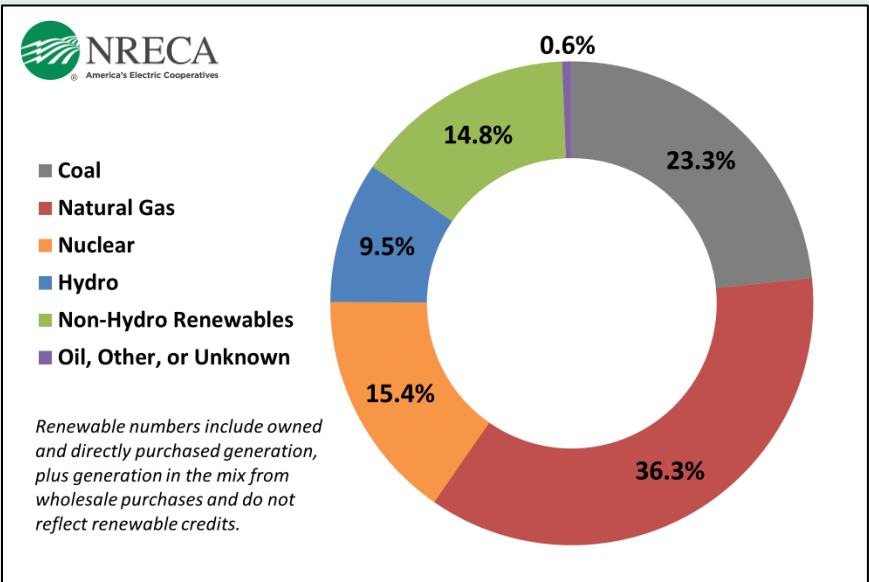
Cooperative Focus: Fuel Mix

The most recent estimate of the national electric cooperative retail fuel mix for 2024 is shown in **Figure 3**. Compared to the 2024 U.S. generation mix, the electric cooperative retail fuel mix – which includes power generated at co-op owned plants and power purchases – had a higher share of coal generation at 23% (vs. 15%), lower generation from natural gas at 36% (vs. 43%), and nuclear at 15% (vs. 18%). The share of power from renewable resources in the co-op mix was slightly higher at 24% (vs. 23%), including a relatively higher share of hydropower, which is mostly purchased from federally owned dams.

⁶ For more information on this Alternative Electric Case, see EIA, “Case Descriptions,” Annual Energy Outlook 2026, accessed August 11, 2026, https://www.eia.gov/outlooks/aeo/assumptions/pdf/case_descriptions.pdf.

“Coal’s share of co-op power supply fell by 2% to 23.3%, a historic low driven in part by the retirement of nearly a gigawatt of G&T-owned coal generation in 2023 and 2024. Natural gas and coal are often directly competing resources, so the decline in natural gas prices in 2024 also put pressure on coal generation overall. Nuclear saw its share increase by more than 1% to 15.4%, including power from the two new units at Plant Vogtle. The share of hydropower in the co-op fuel mix rose slightly in 2024, with increased production in the Southeast offsetting declines elsewhere. Non-hydro renewables continued their steady growth, reaching nearly 15% of supply with notable growth in the co-op solar portfolio in 2023 and 2024.”⁷

Figure 3: 2024 National Electric Cooperative Retail Fuel Mix (~ 523 million MWh)



U.S. Electric Sector Retirements

In 2025, the U.S. electric sector retired approximately 5 GW of generation with coal (2.5 GW), natural gas (1.4 GW), and oil (971 MW) making up most of the retirements that year according to EIA.⁸ This number is roughly 40% less than EIA’s projection at the beginning of the year, and the least amount of generation retired in any year since 2011. These postponements can be partially attributed to the upsurge in demand growth driven by data centers and other large loads as well as the delay of retirements to ensure grid reliability and resource adequacy remains adequate. Additional orders by the U.S. Department of Energy have required some plants to remain operating past their planned retirement dates.⁹

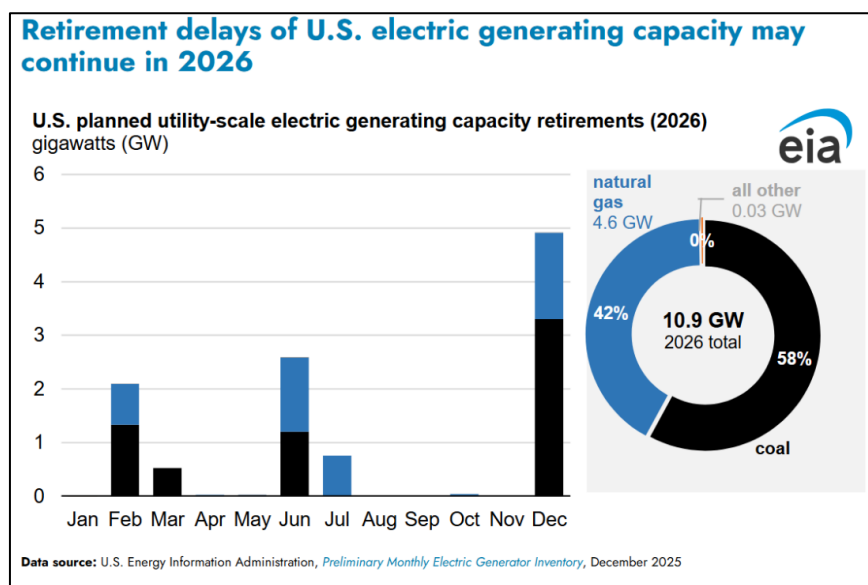
⁷ Michael Leitman and Lauren Khair, “Only Minor Shifts Were Seen in the 2024 Electric Cooperative Fuel Mix as Sales Growth Accelerated” (Arlington, VA: National Rural Electric Cooperative Association, June 2026), <https://www.cooperative.com/programs-services/bts/Documents/Advisories/Advisory-2024-Co-op-Fuel-Mix-Analysis-June-2026.pdf>.

⁸ Analysis based on EIA’s Preliminary Monthly Generator Inventory January 2026 file.

⁹ DOE has used emergency authority under section 202(c) of the Federal Power Act to order some coal units with planned retirements in 2025 and 2026 to continue operating. See <https://www.energy.gov/ceser/does-use-federal-power-act-emergency-authority>.

Figure 4 shows planned 2026 retirements by month and fuel type. Due to the nature of EIA reporting, many of these planned retirements are slated for the end of 2026. In 2026, EIA has reported that about 4% (6.4 GW) of coal generation in the United States is scheduled to retire. Scheduled natural gas generation retirements for 2026 total 1% of gas generation (4.6 GW).¹⁰ As of the end of May 2026, just over 400 MW of plants of all types have been retired.

Figure 4: U.S. Planned Capacity Retirements by Fuel Type, 2026 by Month¹¹



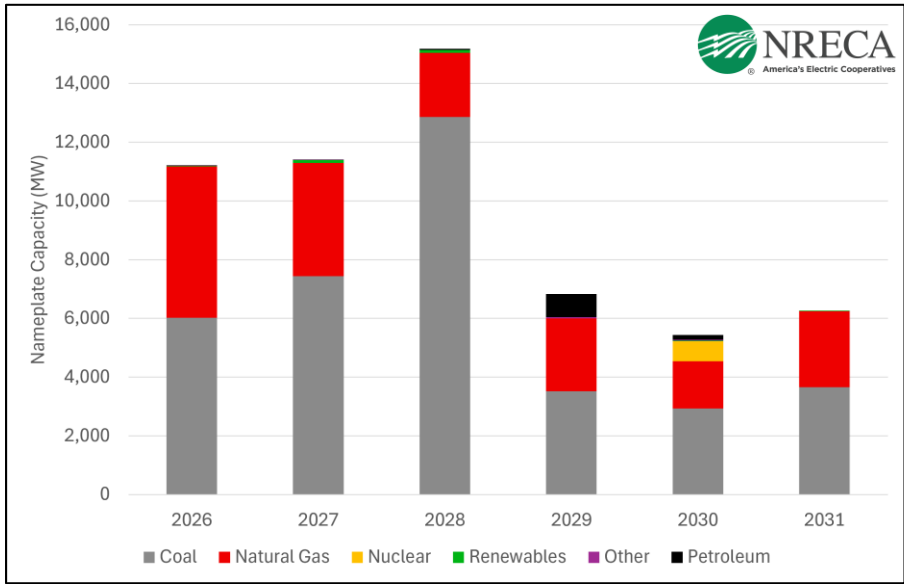
Examining planned retirements beyond 2026 reveals significant retirements for coal and natural gas plants, shown in **Figure 5**. These retirements are reported directly to EIA's 860 Annual and Preliminary Monthly Electric Generator Inventory forms by the plant operator and are subject to change.

- In 2027, coal leads retirements with over 7.4 GW scheduled, with natural gas making up most of the other retirements at 3.8 GW.
- In 2028, over 12.8 GW of coal capacity is scheduled to retire, with 2.1 GW of natural gas retirements also planned.
- In 2029, over 3.5 GW of coal capacity is scheduled to retire, along with approximately 2.1 GW of natural gas capacity.
- Similar amounts of generation are currently planned to retire between 2030 and 2031, including 5.4 GW and 6.2 GW of total retirements with the majority of retirements coming from coal and gas generation.

¹⁰ U.S. Energy Information Administration (EIA), "Retirement Delays of U.S. Electric Generating Capacity May Continue in 2026," Today in Energy, February 23, 2026, <https://www.eia.gov/todayinenergy/detail.php?id=67206>.

¹¹ U.S. Energy Information Administration (EIA), "Retirement Delays of U.S. Electric Generating Capacity May Continue in 2026," Today in Energy, February 23, 2026, <https://www.eia.gov/todayinenergy/detail.php?id=67206>.

Figure 15: U.S. Planned Capacity Retirements by Fuel Type, 2026-2031¹²

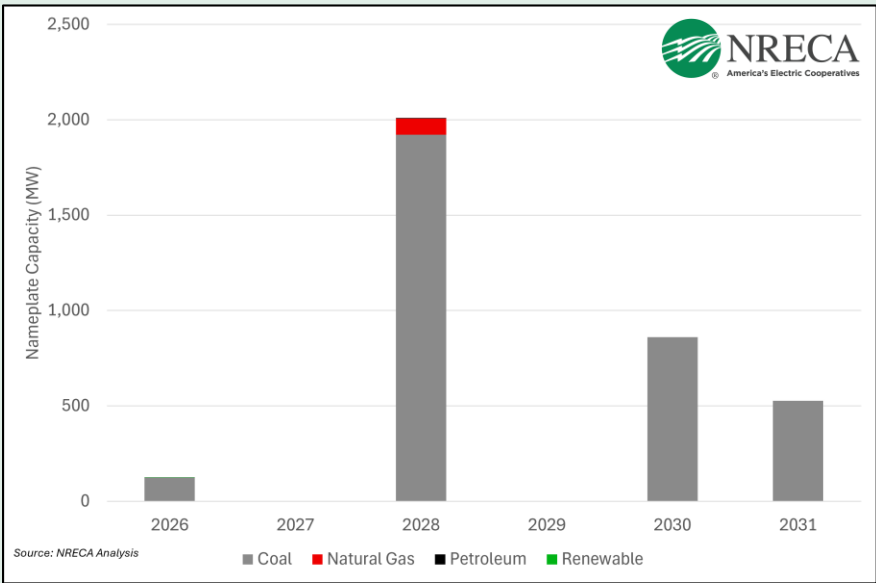


Cooperative Focus: Plant Retirements

Electric cooperatives are retiring generating capacity at a slower pace compared to the rest of the industry, with only about 12 MW of mostly small petroleum-fired generators retired in 2025. **Figure 6** shows announced retirements of co-op owned generating capacity from 2026 through 2031, totaling just over 3.5 GW, including more than 3.4 GW of coal capacity, 85 MW of natural gas, and a small amount of petroleum and renewable generation. In many cases, announced coal retirements are at units where electric cooperatives are minority owners, and the closure decision is being made primarily by the investor-owned utility with majority ownership. Announced coal retirements represent 16.5% of current co-op-owned coal capacity. In many cases, retiring coal generation will be replaced with new natural gas combined cycle plants.

¹² Based on EIA reporting included in the *Preliminary Monthly Inventory (January 2026)*, *EIA-860M (May 2026)*, and the *Annual Energy Outlook 2026*.

Figure 6: Co-op Planned Capacity Retirements, 2026-2031



U.S. Industry Capacity Additions

EIA’s Preliminary Monthly Electric Generator Inventory provides a summary of all confirmed and announced new additions and retirements; for a plant to be added to the EIA’s database, the plant owners or operators report to EIA. Due to the nature of the reporting, many respondents record the end of the year as the commercial operation date, which is why most of the additions show up as planned for December, though some of that capacity may come online earlier in the year. According to EIA, there was approximately 54.9 GW of new additions added to the U.S. electric grid in 2025. Solar generation accounted for nearly half (49%) of all additions, totaling 27 GW of new capacity. This was followed by 15.5 GW of new battery energy storage, 6.2 GW of wind generation, and 5 GW of natural gas-fired generation.¹³ According to the EIA, 2025 was by far the most significant year for capacity additions since 2002.

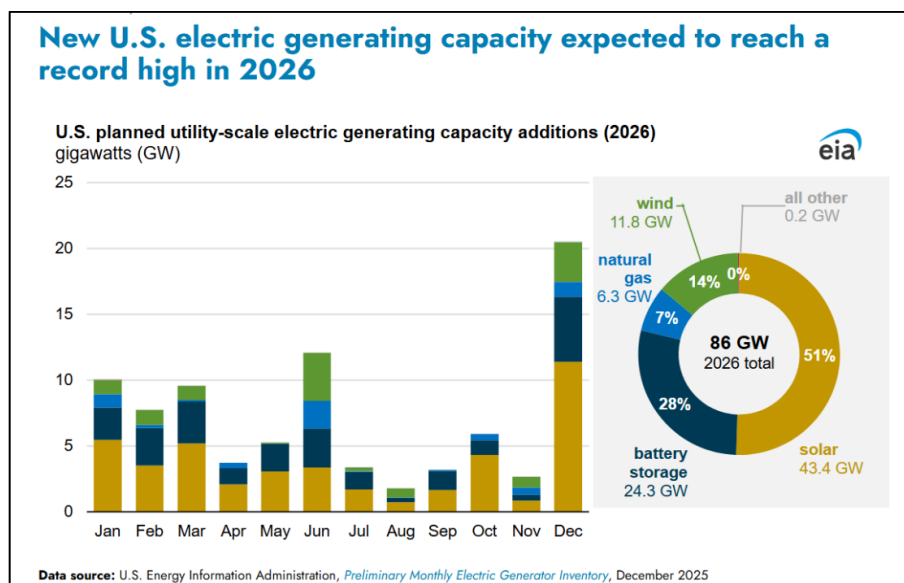
Compared to 2025, the 86 GW of capacity scheduled to come online in 2026 is approximately 56% more than last year. **Figure 7** visualizes this new generation by technology type. Solar represents over half of planned additions (51%) with 43.4 GW scheduled to come online while energy storage adds another 24.3 GW (28%) followed by 11.8 GW of wind (14%) and 6.3 GW of natural gas-fired capacity (7%). Texas leads in both planned solar capacity (40%) and planned battery capacity (53%) and is also the site of the largest natural gas project scheduled to come online in 2026.¹⁴

According to EIA’s Preliminary Monthly Inventory from May 2026, 22 GW of these planned additions have already come online. These additions include approximately 5.5 GW of energy storage, 2.4 GW of

¹³ Analysis based on EIA’s Preliminary Monthly Generator Inventory January 2026 and May 2026 files.
¹⁴ The Orange County Advanced Power Station, a 1,158 MW combined cycle plant.

natural gas generation, 9 GW of solar, and 5.6 GW of wind. Plant owners and operators are on pace to hit the 86 GW of scheduled additions this year.

Figure 7: U.S. Planned Capacity Additions by Fuel Type, 2026 by Month¹⁵



Looking beyond 2026, **Figure 8** illustrates the amount of new capacity announced to be added to the grid through 2031. The pace of additions continues to increase from 2026 to 2027 with EIA reporting over 87 GW of resources will be added in 2027 including more than 11 GW of natural gas additions, up from the 7 GW slated for 2026. Solar energy at 33.9 GW, energy storage at 17.7 GW, and wind at 6 GW of additions make up the lion's share of the remaining resources being added in 2027. From 2028 – 2031, scheduled additions decline to 65 GW in 2028, 34.6 GW in 2029, 25.4 GW in 2030, and 7.1 GW in 2031. The contraction in capacity seen in the year-over-year forecasts are due in part to the sunset of the solar and wind tax credits which have reduced the growth in these resources. Wind and solar additions are expected to contract beginning in 2028 with 2028 figures showing a 56% and 33% reduction in scheduled capacity, respectively. Energy storage also sees a significant decrease in additions starting in 2028 which could be attributed to the fact that many solar installations now install energy storage to help firm the intermittent nature of solar generation.

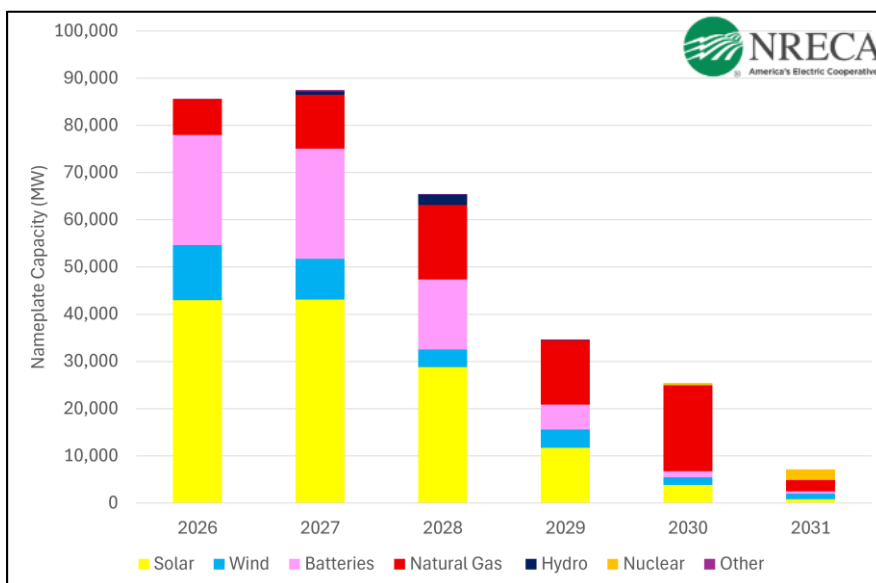
The makeup of the 2029-2031 additions reported to EIA decrease significantly from the highs of 2025 and 2026 additions. Natural gas additions are reported to add 13.5 GW in 2029, 18.1 GW in 2030, and 2.3 GW in 2031, with long lead times for natural gas turbines pushing much of this growth into later years.¹⁶ Solar additions are reported to be at 11.6 GW in 2029, 3.8 GW in 2030, and 800 MW in 2031. Wind additions are reported at 3.9 GW in 2029, 1.5 GW in 2030, and 1.1 GW in 2031. Interestingly,

¹⁵ U.S. Energy Information Administration, "New U.S. Electric Generating Capacity Expected to Reach a Record High in 2026," Today in Energy, February 26, 2026, <https://www.eia.gov/todayinenergy/detail.php?id=67205>.

¹⁶ Brian Martucci, "GE Vernova Gas Turbine Backlog Climbs to 116 GW," Utility Dive, July 23, 2026, <https://www.utilitydive.com/news/ge-vernova-gas-turbine-backlog-climbs-to-116-gw/826039/>.

new nuclear generation comes online in later years with 500 MW of additions in 2030 and approximately 2.2 GW in 2031.

Figure 28: U.S. Planned Capacity Additions by Fuel Type, 2026-2031¹⁷



Cooperative Focus: Capacity Additions¹⁸

In response to rising demand for electricity and declining reserve margins across much of the United States, electric cooperatives are in a major building cycle, with announced generation and storage projects totaling more than 20.5 GW of new capacity between 2026 and 2031. These include directly owned projects and projects developed with third-party developers under long-term contracts. Some of these projects are not included in EIA reporting yet but are based on press releases or other public materials.

In 2025, electric cooperatives added more than 2.7 GW of generation capacity, including 2.4 GW of natural gas – including acquisitions of existing plants – and 281 MW of solar. In **Figure 9**, the capacity of announced cooperative-owned generation projects is illustrated. In 2026, cooperatives are expected to add about 2.4 GW of natural gas capacity from new-build plants and plant acquisitions, with 153 MW of solar being added as well. Some of this capacity is already online. G&T cooperatives are in the midst of a historic buildout of natural gas capacity, both to replace retiring coal plants and to meet rising demand for energy and capacity. Cooperatives are expected to bring nearly 1 GW of new natural gas capacity online in 2027, 2.2 GW in 2028, 3.5 GW in 2029, 3 GW in 2030, and 1.3 GW in 2031. Of the more than 12 GW of planned natural gas capacity, nearly two-thirds (63%) are combined cycle plants capable of operating at baseload capacity factors, with

¹⁷ Analysis based on EIA's Preliminary Monthly Generator Inventory January 2026 and May 2026 files.

¹⁸ The numbers and graphs in this section do not include additional renewable and battery projects expected to be funded through the United States Department of Agriculture's (USDA's) Empowering Rural America (New ERA) grant program but for which specific project details have not yet been announced.

the remainder at peaking and load following plants. In total, these projects represent roughly a quarter increase in co-op owned natural gas capacity. Some of these announced projects are still in early stages and details and timelines are subject to change. Additional project announcements are expected.

Most co-op renewable capacity will be added through power purchase agreements (PPA). Significant additional owned renewable capacity is also planned during this period with more than 365 MW of new solar capacity planned to come online between 2027 and 2029, as well as 19 MW of hydro, wind, and biomass.

Figure 9: Planned Co-op Owned Generation Capacity Additions, 2026-2031

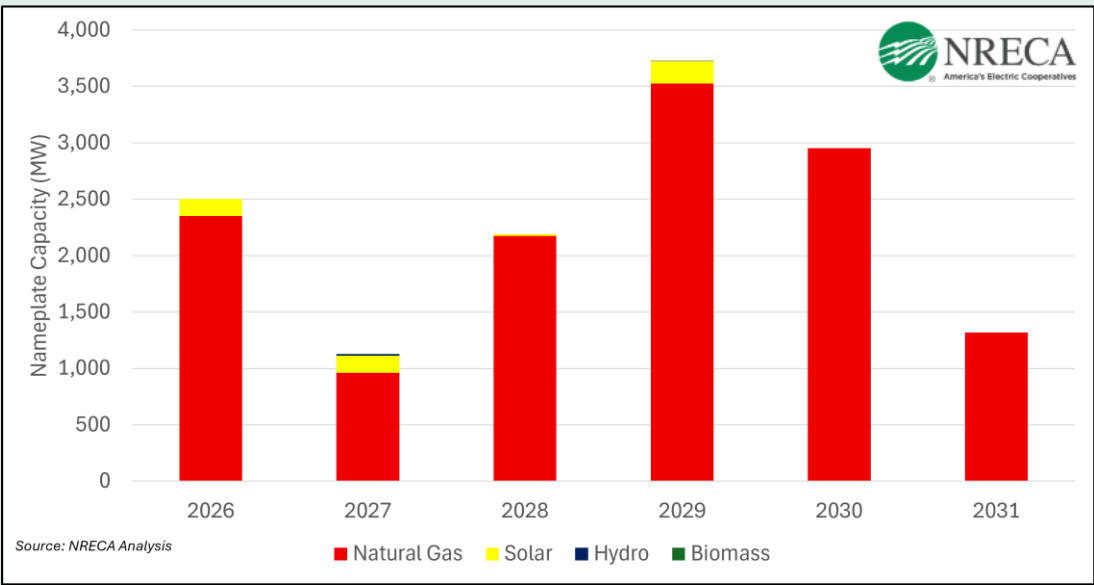
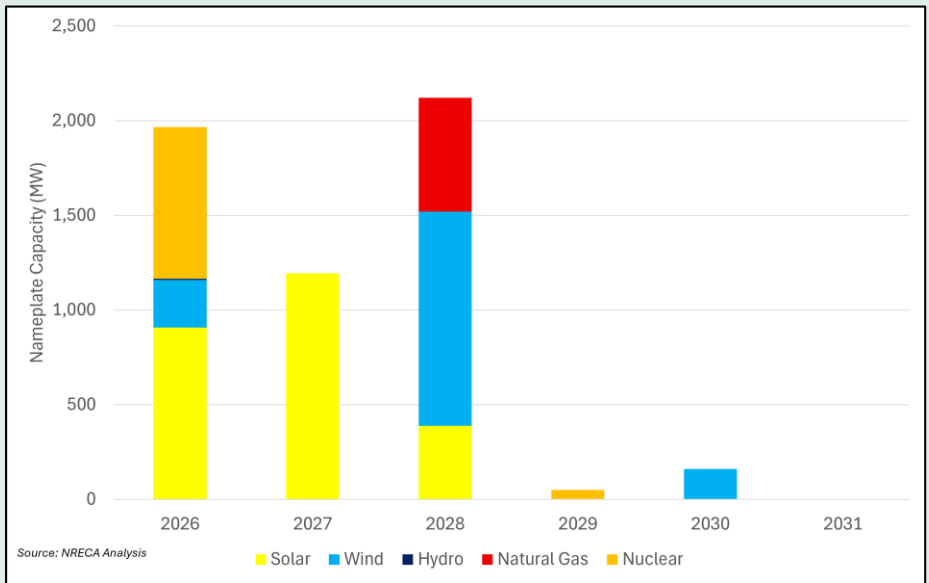


Figure 10 shows the announced capacity co-ops plan to add through PPAs from 2026 through 2030. A PPA is a long-term contract in which a utility buys electricity from a generator it does not own at a specified price, volume, and delivery point over a set term. PPAs are the primary alternative to building and owning generation, and agreements convey various “products,” including energy, capacity, and environmental attributes (e.g., renewable energy credits) to the utility while the counterparty is responsible for operating and maintaining the generator and meeting contractual requirements for performance.

In 2025, co-ops added more than 1.8 GW of renewable capacity, a new record. Most of this capacity (>1.5 GW) was through PPAs for solar and wind facilities. More than 4.4 GW of additional renewable capacity is planned to come online between 2026 and 2030, of which most (>4 GW) is through PPA. While co-ops have most commonly utilized PPAs to add renewable and storage resources, co-ops have recently signed PPAs for other types of resources as well. In 2025, PPAs were signed to add 886 MW of new natural gas capacity with another 1.2 GW of natural gas capacity at two combined cycle plants scheduled to come online in 2028 and 2032 (not shown in graph). G&T’s

have also signed PPAs for nuclear capacity from two previously retired nuclear plants, Palisades in Michigan (for the full 800 MW plant) and Duane Arnold in Iowa (50 MW share of output), scheduled to restart in 2026 and 2029, respectively.

Figure 10: Planned Co-op PPA Generation Capacity Additions, 2026-2031



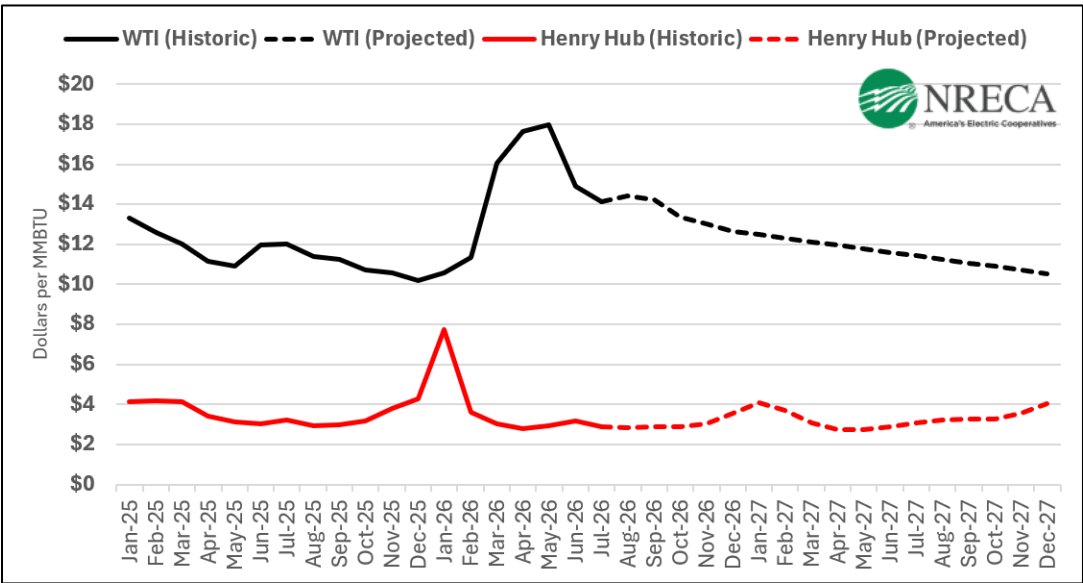
Battery energy storage system (BESS) capacity is not included in these graphs, but NRECA has tracked about 333 MW of new co-op BESS capacity from owned or PPA projects that came online in 2025. NRECA expects total co-op BESS capacity to double from about 1.1 GW today to nearly 2.2 GW by 2031 based on announced projects.

2. Issue In Focus: Current Geopolitical Influence on Domestic Energy Resources

Geopolitical instability in the Middle East has reemerged as a significant source of uncertainty for U.S. energy markets. Since February 2026, ongoing hostilities between the United States, and Iran has raised concerns about the security of energy supplies moving through the Strait of Hormuz, one of the world’s most important energy trade corridors. Prior to the current conflict, approximately 27% of global seaborne crude oil and petroleum products and 20% of global liquefied natural gas (LNG) exports passed through the Strait, making any disruption a potential catalyst for higher fuel prices and increased market volatility.¹⁹

Unlike crude oil, natural gas is primarily traded within regional markets, making it less susceptible to immediate global price shocks. As shown in **Figure 11**, U.S. crude oil prices, benchmarked by the West Texas Intermediate (WTI), increased following the onset of the Iran conflict. Over the same time period, domestic natural gas prices remained comparatively stable, at the Henry Hub—the U.S. trading hub that benchmarks domestic prices for natural gas. EIA projects U.S. oil prices to gradually decline through 2027, while natural gas prices will remain relatively flat with increases later in the period.

Figure 11: U.S. Average Monthly Natural Gas and Oil Prices²⁰



This difference reflects the greater global integration of oil markets as compared to the more regional natural gas markets. While the influence of global markets in U.S. natural gas prices is increasing as LNG exports rise, they are still driven more by factors including weather patterns, seasonal demand, and

¹⁹ Phillip Brown, Michael Ratner, Liana W. Rosen, and Clayton Thomas, Iran Conflict and the Strait of Hormuz: Impacts on Oil, Gas, and Other Commodities, CRS Report No. R45281 (Washington, D.C: Congressional Research Service, 2026), <https://www.congress.gov/crs-product/R45281>.

²⁰ EIA, “Short Term Energy Outlook,” August 2026, https://www.eia.gov/outlooks/steo/archives/aug26_base.xlsx; WTI converted from barrel price to MMBTU using EIA conversion factor, 1 barrel=5.684 MMBTU, <https://www.eia.gov/energyexplained/units-and-calculators/energy-conversion-calculators.php>.

electricity generation. For example, extreme cold weather in January 2026 caused a significant increase in natural gas prices as demand for space heating and power generation surged (**see Figure 11**), while crude oil prices remained relatively flat. Natural gas also remains the dominant fuel for electricity generation in the United States, and growing electricity demand from emerging loads such as data centers is expected to further increase natural gas consumption. Oil, in comparison, is used predominantly in the transportation sector, with residential heating playing a relatively limited role in overall demand.²¹

The U.S. is on track to record natural gas production in 2026. Production has increased faster than expected, driven in large part by an increase in “associated” gas that is a byproduct of oil production in the Permian Basin (stretching from Texas to New Mexico). Oil production has risen to meet global demand disrupted by the U.S.-Iran conflict. This, combined with other natural gas production increases and some reduction in LNG demand due to maintenance at export facilities have led to a decline in natural gas prices as storage levels have reached their highest levels in a decade heading into the winter season. These factors have led EIA to significantly reduce their short-term forecast of Henry Hub natural gas prices through 2027 from what was projected at the start of the year.²²

Although the duration and ultimate impact of the conflict remain uncertain, the market has already responded to supply concerns. Oil prices climbed sharply during the conflict, with Brent crude surpassing \$100/barrel at one point. Retail fuel prices also increased substantially, with gasoline rising from just under \$3.00/gal before the conflict to more than \$4.50/gal, while diesel prices exceeded \$5.50/gal. Higher diesel prices increase transportation costs throughout the economy, ultimately affecting the delivered cost of equipment, construction materials, and electricity infrastructure.²³

Recent EIA data further indicates that commercial crude oil inventories remain below historical averages despite strong refinery utilization and increased crude imports because of high demand for exports to countries that historically depended on oil supplied from Iran.²⁴ This is on top of ongoing impacts from the Russia-Ukraine War that also continue to disrupt global oil supplies. Lower inventories combined with steady demand have left oil markets vulnerable to additional price increases should supply disruptions continue.²⁵

While U.S. natural gas prices have remained relatively stable because of abundant domestic production, LNG markets in Europe and Asia have experienced significantly larger price increases following disruptions to the shipping of goods and other resources through the Strait of Hormuz.²⁶ A key factor supporting domestic natural gas supplies has been continued production growth in the Permian Basin. Between 2021 and 2025, the Permian Basin’s marketed natural gas production increased from 17.2 billion cubic feet per day (Bcf/d) to 27.6 Bcf/d, a 60% increase, while crude oil production grew from 4.7 million barrels per day (b/d) to 6.6 million b/d, or 39%. According to the EIA, the faster growth in

²¹ Brown et al., Iran Conflict and the Strait of Hormuz.

²² EIA, “Short Term Energy Outlook,” August 2026, <https://www.eia.gov/outlooks/steo/archives/aug26.pdf>.

²³ Brown et al., Iran Conflict and the Strait of Hormuz.

²⁴ Arathy Somasekhar and Liz Hampton, “US Crude Stocks Fall on Strong Export, Refining Demand, EIA Says, as Iran War Continues,” Reuters, June 3, 2026, <https://www.reuters.com/business/energy/us-crude-stocks-fall-gasoline-distillate-inventories-rise-cia-says-2026-06-03/>.

²⁵ EIA, “U.S. Commercial Crude Oil Inventories Have Decreased in June,” Today in Energy, June 24, 2026, <https://www.eia.gov/todayinenergy/detail.php?id=67805>.

²⁶ Brown et al., Iran Conflict and the Strait of Hormuz.

natural gas production reflects increasing gas-oil ratios (GOR), meaning that more associated natural gas is being produced alongside crude oil, helping maintain abundant domestic supplies despite global market disruptions.²⁷ The intensified demand for gas-fired generation, combined with rapidly growing electricity demand from AI-data centers, has also increased global orders for gas turbines and further constrained turbine manufacturing capacity. For electric utilities, including rural electric cooperatives planning new natural gas generation, these market conditions may translate into longer equipment lead times, higher capital costs, and increased competition for available turbine capacity.

Energy Storage and Battery Supply Chains

Heightened fuel price uncertainty is reinforcing the value of resource diversification. Although natural gas remains the dominant fuel for new dispatchable generation, volatile fuel prices increase the attractiveness of resources that are not exposed to changing fuel costs, including renewable generation paired with battery energy storage.²⁸ Battery energy storage remains one of the fastest-growing generation technologies in the United States. Driven largely by rapidly growing electricity demand from data centers, U.S. energy storage deployments are projected to reach approximately 613 gigawatt hours (GWh) by 2030 after recording a record 9.7 GWh of installations during the first quarter of 2026. Utilities are increasingly using battery storage to improve reliability, provide backup power for large loads, and address power quality challenges associated with rapidly growing computing demand.²⁹

Federal policy also continues to shape deployment economics. While recent legislation accelerated the expiration of several renewable energy tax incentives, it preserved the federal Investment Tax Credit (ITC) for qualifying standalone energy storage projects. Retaining the storage ITC helps offset deployment costs and is expected to support continued investment in battery storage, even as the economics of new wind and solar projects become more uncertain.³⁰ While Iran is not a significant producer of battery minerals, the conflict has increased costs throughout the global lithium-ion battery supply chain. Shipping disruptions through the Strait of Hormuz, rising fuel prices, and higher transportation costs have increased the cost of producing battery materials and other inputs used in battery manufacturing.³¹ These pressures are expected to increase manufacturing costs for both electric vehicles (EVs) and BESS, potentially delaying some projects and increasing capital costs. In response, manufacturers continue to diversify battery supply chains by expanding domestic production capacity and reducing reliance on concentrated global manufacturing hubs.³²

²⁷ U.S. Energy Information Administration (EIA), “Permian Natural Gas Production Increased Faster than Crude Oil,” Today in Energy, June 18, 2026, <https://www.eia.gov/todayinenergy/detail.php?id=67785>.

²⁸ Julia Simon, “The Iran War Has Pushed Some Countries Away from Oil and toward Clean Energy,” NPR, July 9, 2026, <https://www.npr.org/2026/07/09/nx-s1-5872786/iran-war-evs-solar-energy-transition>.

²⁹ Brian Martucci, “US Energy Storage Installations Hit Q1 Record, up 32% Year over Year: SEIA,” Utility Dive, March 26, 2026, <https://www.utilitydive.com/news/us-energy-storage-installations-hit-q1-record-up-32-year-over-year-seia/821133/>.

³⁰ Wood Mackenzie and American Clean Power Association (ACP), US Energy Storage Monitor: Q2 2026 (Wood Mackenzie Power & Renewables and ACP, 2026), https://go.woodmac.com/l/131501/2026-06-18/361394i/131501/1782187797Yr73eiaP/US_Energy_Storage_Monitor_Q2_2026.pdf.

³¹ Srikant Jayanthan, “The Iran War Is Exposing the Fragility of the Lithium-Ion Battery Supply Chain,” S&P Automotive Insights, June 2026, <https://www.spglobal.com/automotive-insights/en/blogs/2026/06/iran-war-lithium-ion-battery-supply-chain>.

³² Jayanthan, “The Iran War Is Exposing the Fragility of the Lithium-Ion Battery Supply Chain.”

Electric Vehicles

The market outlook for EVs has become increasingly complex. The expiration of the \$7,500 federal consumer tax credit significantly reduced new EV sales in the United States, with May 2026 sales declining roughly 22% compared with the previous year. Higher battery costs resulting from supply chain disruptions may place additional pressure on manufacturers.³³ At the same time, higher gasoline prices resulting from the conflict have improved the operating cost advantage of EVs. Global EV adoption continues to grow, exceeding one-quarter of worldwide vehicle sales for the first time, although U.S. adoption has slowed considerably following the expiration of federal purchase incentives.³⁴

Outlook for Rural Electric Cooperatives

The interaction between geopolitical events, evolving federal policy, and rapidly growing electricity demand is creating a more complex planning environment. Rising fuel price volatility increases the value of maintaining a diversified generation portfolio, while continued growth in energy storage provides new opportunities to improve system flexibility and reliability. At the same time, changes to federal tax incentives, continued uncertainty surrounding global supply chains, and permitting challenges may affect the timing and economics of future generation investments.³⁵ Rural electric cooperatives have long relied on a diverse mix of generation portfolio that includes natural gas, coal, nuclear, hydropower, renewable energy, and battery energy storage to provide reliable and affordable electricity while adapting to evolving member needs. As of June 2025, cooperatives had announced plans to add nearly 15 GW of new generation capacity by 2030, including more than 8.5 GW of natural gas-fired generation, while continuing investments in battery storage to improve system flexibility and reliability.³⁶ As electricity demand continues to grow, co-ops and other utilities must balance fuel diversity with reliability, affordability, and resiliency at a time when technology options are limited.

³³ Dan McCarthy, “The Tax Credit Cliff Has Hit EV Sales Hard,” Canary Media, May 29, 2026, ; Catherina Gioino, “The Iran War Is Accelerating the EV Transition Faster than Any Climate Policy Ever Did—but Not Much,” Fortune, June 25, 2026.

³⁴ Gioino, “The Iran War Is Accelerating the EV Transition Faster than Any Climate Policy Ever Did—but Not Much.”

³⁵ National Rural Electric Cooperative Association (NRECA), “Reliability and Affordability,” accessed July 13, 2026, <https://www.electric.coop/issues-and-policy/reliability-and-affordability>.

³⁶ National Rural Electric Cooperative Association (NRECA), “Electric Co-op Facts & Figures,” June 25, 2025, <https://www.electric.coop/electric-cooperative-fact-sheet>.

3. Issue in Focus: Regional Obstacles

This *Issue in Focus* section outlines the central issues facing the electric industry within vertically integrated markets, competitive markets, and at the national level. Many issues are shared regardless of geography or market structure like load growth and resource adequacy. Others, like coal retirements in MISO or market expansion in both CAISO and SPP, are region-specific. For cooperatives seeking to understand what may affect their operations and long-term planning, it's important to consider regional challenges as well as the influence that national issues may have on potential solutions. The following sections offer a discussion of both national and more localized solutions to widespread issues.

National

The electric industry is facing a series of deeply interconnected challenges at the national level. Since 2020, demand for electricity has been rising, buoyed by data center expansion, reshored manufacturing, and economy-wide electrification.³⁷ Utilities have sharply accelerated capital investments into grid modernization, resilience, and expansion as well as new generation with investor-owned utilities (IOU) alone planning to spend a record \$1.4 trillion dollars in capital expenditures through 2030.³⁸ After nearly two decades of slow load growth, a surge in demand driven by data centers and other large loads over the last five years, as well as continued electrification in the broader economy, has led demand to grow faster than new generation and supporting transmission infrastructure can be brought online to serve it, creating concerns about resource adequacy in many regions of the country. This growth is projected to continue in the coming years. However, while growth, both realized and forecasted, has been dramatic, considerable uncertainty remains around which load sources, particularly data centers, will make it to commercial operation.³⁹ At the same time, supply chains for vital equipment are being stressed by the need for new generation and grid infrastructure. For example, as of August 2026, the three largest manufacturers of gas turbines, GE Vernova⁴⁰, Siemens Energy⁴¹, and Mitsubishi Heavy Industries⁴², have a combined order backlog of 220 GW and are taking order reservations four to five years in advance due to the skyrocketing demand for turbines.

In an effort to support the industry, the Federal Energy Regulatory Commission (FERC) released a series of show cause orders on June 18, 2026, directing each of the six regional grid operators under its jurisdiction to demonstrate why “their current tariffs remain just and reasonable despite clear and consistent provisions for large load customers.”⁴³ Importantly, despite requiring justification from grid

³⁷ U.S. Department of Energy, Office of Policy, “Electricity Demand Growth Resource Hub,” accessed August 11, 2026, <https://www.energy.gov/policy/electricity-demand-growth-resource-hub>.

³⁸ Jordan Blum, “U.S. Utilities Are Planning a \$1.4 Trillion Spending Spree, up 30%, over the Next Five Years amid the AI Construction Boom,” *Fortune*, April 14, 2026, <https://fortune.com/2026/04/14/us-utility-spending-jumps-to-1-4-trillion-amid-ai-construction-boom/>.

³⁹ North American Electric Reliability Corporation (NERC), Long-Term Reliability Assessment (Atlanta, GA: NERC, January 2026), https://www.nerc.com/globalassets/our-work/assessments/nerc_ltra_2025.pdf.

⁴⁰ Brian Martucci, “GE Vernova Gas Turbine Backlog Climbs to 116 GW,” *Utility Dive*, July 23, 2026, <https://www.utilitydive.com/news/ge-vernova-gas-turbine-backlog-climbs-to-116-gw/826039/>.

⁴¹ Emma Penrod, “Siemens Energy’s Gas Turbine Backlog Nears 70 GW as Company Expands Manufacturing,” *Utility Dive*, August 10, 2025, <https://www.utilitydive.com/news/siemens-gas-turbine-backlog-nears-70-gw-as-company-expands-manufacturing/827390/>.

⁴² Emma Penrod, “Mitsubishi’s Large-Frame Gas Turbine Backlog Reaches 35 GW,” *Utility Dive*, August 13, 2025, <https://www.utilitydive.com/news/mitsubishi-gas-turbine-backlog-earnings/827761/>.

⁴³ Federal Energy Regulatory Commission (FERC), “Fact Sheet: FERC Takes Action to Supercharge America’s Grid for Efficiency, Reliability, and a Bold Energy Future,” June 18, 2026, <https://www.ferc.gov/news-events/news/fact-sheet-ferc-takes-action-supercharge-america-s-grid-efficiency-reliability-and>.

operators, the orders do not supplant state control over the selection, siting, and permitting of generating resources nor the authority of public utility commissions to set rates and regulate the retail sale of electricity. FERC, rather, endeavored to provide a series of common reforms to standardize the integration of large loads and generators while respecting regional market differences. The suite of reforms aims to increase the efficiency of interconnection study processes, limit large load cost shifting, and accommodate load flexibility and generation co-location. Regional grid operators have 60 days from the date of the show cause orders to submit justification to FERC.

Traditional Vertically Integrated Markets

SERC

SERC is forecasted to be one of the few regions in the United States not broadly facing elevated power supply risk through 2030.⁴⁴ SERC-East covers most of the Carolinas, where Duke Energy Carolinas and Duke Energy Progress forecast annual growth rates of 1.1% and 1.0%, respectively, through 2038.⁴⁵ In NERC's 2025 LTRA, SERC-East was the only SERC subregion facing elevated risk, beginning in 2027. Nevertheless, current resource addition projections are insufficient to simultaneously replace generator retirements and meet growing demand. NERC's analysis found that with SERC-East's projected resource portfolio and composition, supply shortfalls would occur in below-normal winter temperatures.

Outside of major infrastructure expansion, efficient and cost-effective generation procurement is another key challenge facing SERC. Although the Southeast is not an ISO/RTO area, it does currently have a voluntary, intra-hour bilateral trading platform called the Southeast Energy Exchange Market (SEEM). Launched in 2022, SEEM seeks to make the process of bilateral agreements between utility footprints more efficient, transparent, and less expensive.⁴⁶ To do so, the platform aggregates bids and offers and seeks to connect the lowest-priced offers with the highest-priced bids to maximize savings and revenues for buyers and sellers respectively. This process introduced a competitive mechanism to the SERC region and increased regional coordination with the long-term goal of reducing costs for customers.

However, to this point SEEM has failed to deliver its projected cost savings. A 2020 study by Guidehouse and Charles River Associates predicted \$40 million in savings annually,⁴⁷ yet SEEM has fallen well short of projections in both trading volume and monetary benefits.⁴⁸ The platform only delivered approximately \$3.3 million in regional benefits and 51,000 MWh in trades, a fraction of the expected 1,000,000 MWh.⁴⁹ Various groups and stakeholders have suggested policy solutions to improve SEEM's performance, so the direction that the new market takes and its success at delivering value will determine the future course of market development in the region.

⁴⁴ NERC, 2025 Long-Term Reliability Assessment.

⁴⁵ Duke Energy Carolinas, LLC, and Duke Energy Progress, LLC, "Appendix D: Electric Load Forecast," in Carolinas Resource Plan, filed with the Public Service Commission of South Carolina, accessed August 11, 2026, <https://dms.psc.sc.gov/Attachments/Matter/7b016a65-5ab4-47ec-8c9f-138c63646636>.

⁴⁶ Jenn Tribble, Alex Smith, and Kelly Lefler, "How the US Southeast's Energy Market Leaves Cost Savings on the Table," World Resources Institute, April 24, 2026, <https://www.wri.org/technical-perspectives/southeast-energy-market-missed-cost-savings>.

⁴⁷ Guidehouse Inc. and Charles River Associates, Benefits Analysis of the Southeast Energy Exchange Market (SEEM) (prepared for the Southeast Energy Exchange Market, February 2021), https://southeastenergymarket.com/wp-content/uploads/20210212-5033_8_Att.-E-1_Benefits-Analysis.pdf.

⁴⁸ Tribble et al., "How the US Southeast's Energy Market Leaves Cost Savings on the Table."

⁴⁹ Tribble et al., "How the US Southeast's Energy Market Leaves Cost Savings on the Table."

WECC

As the primary reliability standard development and enforcement entity in the non-CAISO West, the Western Electricity Coordinating Council (WECC) oversees long-term regional planning and interconnection processes. Unlike PJM or MISO, WECC does not operate a centralized interconnection queue. Instead, it coordinates generation and transmission changes across multiple balancing authorities in the Western Interconnection. In this way, WECC is a unique electric market among the various vertically integrated and competitive markets in the U.S. Historically, WECC has operated almost exclusively on bilateral trading to maintain resource adequacy and reliability,⁵⁰ competing day-ahead offerings, the Extended Day-Ahead Market (EDAM) and Markets+, respectively. WECC balancing authorities and virtually all utilities in the region have either declared which one they will be joining or indicated which one they are leaning towards.

Beyond day-ahead market participation, WECC, like other parts of the country, is facing a future shortage of generation and transmission capacity.⁵¹ In WECC's 2025 Western Assessment of Resource Adequacy report, they find that the "West's planned resource buildout will not keep up with anticipated load growth over the next decade."⁵² Entities in WECC plan to add 177 GW of resources over the next decade, but 90% of new additions are inverter-based resources whose weather dependency creates reliability concerns for the additional 31 GW of new load.⁵³ Generator retirements will also potentially sunset 22 GW of mostly dispatchable generation like coal, natural gas, and nuclear over the next ten years which, if all retirements and additions are made as planned, will transform WECC's fuel mix into one composed of more than 50% inverter-based resources.⁵⁴

WECC is in the midst of an expansive transmission buildout to effectively accommodate both growing load and increasing intermittent renewable generation. Two projects totaling 810 miles came online in 2025-2026, with more than 4,500 miles of additional transmission projects in progress and targeted for completion between 2026 and 2034.⁵⁵ Most of these projects are high voltage lines rated at 500- or 525-kV designed to meet the need for enhanced intra- and interregional transfer capacity and resource adequacy during extreme weather events. In a region less densely connected than the East with significant growth in intermittent renewable resources, WECC's transmission projects will facilitate the distribution of low-cost energy to load centers and enhance reliability if the projects continue on schedule.

⁵⁰ Western Electricity Coordinating Council (WECC), "Markets," State of the Interconnection, 2024, <https://feature.wecc.org/soti/topic-sections/markets/index.html>.

⁵¹ Western Electricity Coordinating Council (WECC), 2025 Western Assessment of Resource Adequacy (Salt Lake City, UT: WECC, 2026), <https://feature.wecc.org/2025wara/index.html>.

⁵² WECC, 2025 Western Assessment of Resource Adequacy.

⁵³ WECC, 2025 Western Assessment of Resource Adequacy.

⁵⁴ WECC, 2025 Western Assessment of Resource Adequacy.

⁵⁵ Western Electricity Coordinating Council (WECC), "Transmission," in State of the Interconnection 2026 (Salt Lake City, UT: WECC, 2026), <https://feature.wecc.org/soti2026/state-of-the-interconnection-2026/transmission/index.html>.

Competitive/Deregulated Markets

CAISO

Over the next four years, CAISO will add nine new balancing authority (BA) service territories⁵⁶ as utilities operating in the Western Interconnection begin choosing whether to join CAISO's newly debuted Extended Day-Ahead Market (EDAM) or SPP's Markets+ construct. The addition of new utility loads will flatten CAISO prices during the day by reducing the severity of CAISO's net load curve against the rest of the EDAM's less intermittent renewable-heavy portfolios.⁵⁷ Despite the expanded footprint and price flattening effect, new BA generator capacities are only a fraction of CAISO's existing generation portfolio, so any changes in price dynamics will happen on the margin.

CAISO's EDAM went live on May 1, 2026, adding a new level of operational certainty to the Western Interconnection. The EDAM adds a day-ahead bidding system to the existing real-time Western Energy Imbalance Market (WEIM) to increase operational savings, reliability, and environmental benefits. On June 1, 2026, CAISO reported that, one month in, the EDAM had been running smoothly. Prices looked typical for spring, remaining moderate and "consistent with normal daily load patterns and typical spring shoulder-season conditions."⁵⁸ Price signals for ancillary services were also clearer as supply that previously provided voltage and frequency regulation was dispatched to fill gaps between day-ahead and real-time forecasts. In other words, the market is more explicitly procuring for pricing uncertainty needs using fewer resources, thus enabling more targeted and cost-effective flexibility for grid operators.

ERCOT

ERCOT is facing tremendous growth in all operational facets. Solar and storage capacity additions dominate the interconnection queue through 2030, with forecasts projecting the addition of 95.5 GW and 101 GW, respectively.⁵⁹ Future generation growth is being spurred by recent success in generation interconnection in the ERCOT footprint as 22.5 GW of new capacity has come online since January 2024.⁶⁰ Solar and storage continue to dominate ERCOT's interconnection queue as of 2025, but new natural gas resources are also beginning to appear as the need for dispatchable generation for large loads grows.⁶¹

At the same time, reformed interconnection queue processes are debuting just as ERCOT's new load pipeline continues to expand. As of February 2026, ERCOT had 367.8 GW of requests under review

⁵⁶ Western Energy Markets, "Extended Day-Ahead Market (EDAM)," accessed August 20, 2026, <https://www.westernenergymarkets.com/extended-day-ahead-market-edam>.

⁵⁷ Modo Energy, "WECC: What the Launch of EDAM Means for Renewable Investments," Modo Energy Research, 2026, <https://modoenergy.com/research/en/caiso-spp-extended-day-ahead-market-launch-edam-western-interconnection-markets-plus>.

⁵⁸ California Independent System Operator (CAISO), Western Energy Markets Observations, June 1, 2026, <https://www.westernenergymarkets.com/documents/energy-market-observations-report-jun-01-2026.pdf>.

⁵⁹ Enverus Intelligence Research, "The Future of ERCOT: 765 kV Transmission Expansion and Fast-Track Interconnection Set Stage for Unprecedented Power Growth," Enverus, October 7, 2025, <https://www.enverus.com/newsroom/the-future-of-ercot-765-kv-transmission-expansion-and-fast-track-interconnection-set-stage-for-unprecedented-power-growth/>.

⁶⁰ Enverus Intelligence Research, "The Future of ERCOT."

⁶¹ Joseph Rand, Ryan Wisner, Galen Barbose, and Ben Hoen, Queued Up: Characteristics of Power Plants Seeking Transmission Interconnection as of the End of 2025 (Berkeley, CA: Lawrence Berkeley National Laboratory, June 2026), <https://emp.lbl.gov/sites/default/files/2026-06/Queued%20Up%202026%20Edition.pdf>.

with online dates between 2026 and 2030.⁶² On the high end, projections show ERCOT essentially doubling electric demand by 2030, but there is significant uncertainty around how much of this load will materialize. In an effort to eliminate phantom and immature projects, ERCOT has raised the qualification bar for new large loads which increases the likelihood of successful interconnection but also pushes anticipated data center growth further out in the timeline.⁶³

Despite record-breaking solar and storage proposals in 2025⁶⁴ and improved large load integration processes, ERCOT's load growth rate of 5.6%⁶⁵ threatens grid reliability and resource adequacy. In addition, limited intraregional transmission connectivity and growing intermittent and variable renewable energy penetration continue to exacerbate economic dispatch difficulties for ERCOT transmission service providers and grid operators. However, the rapidly expanding battery storage fleet in ERCOT has been a key reliability asset in recent years and is poised to continue playing a critical role in further improving reliability in the near-term.

In a plan sent to Texas regulators in January 2025, ERCOT presented two major high voltage transmission line portfolios that would expand and reconductor existing 345 kV lines and integrate 765 kV lines for the first time ever.⁶⁶ These new facilities will expand transfer capabilities within ERCOT's footprint, connect significant renewable resources in the Permian Basin to eastern load centers, and reduce curtailment and congestion costs for customers in Texas. As reserve margins continue to tighten in the coming years, maximizing wire and non-wire solutions will be key to minimizing service interruptions.

ERCOT also debuted a long-anticipated market change, called Real-Time Co-Optimization plus Batteries (RTC+B), in December 2025 to increase the efficiency of ancillary service procurement processes and reshape how battery storage projects compete in the real-time market. For the first time, ancillary services will be procured in the real-time market alongside energy to increase efficient economic dispatch in near-real time.⁶⁷ ERCOT's real-time dispatch engine reassesses grid conditions, ancillary service demand curves, and state-of-charge requirements for batteries in 5-minute intervals, determines the optimal mix of energy and ancillary services at that moment, and permits operators to update their energy deployment plan in real-time.⁶⁸ Previously, all ancillary services were procured in the day-ahead market (DAM) and operators were locked into their commitments regardless of gaps between the DAM prediction and real-time market conditions. ERCOT intends for this market reform to improve congestion management, improve dispatch efficiency, and reduce system costs.⁶⁹

⁶² Electric Reliability Council of Texas (ERCOT), "ERCOT Releases Preliminary Long-Term Load Forecast for Years 2026–2032 for PUCT Discussion," news release, April 15, 2026, <https://www.ercot.com/news/release/04152026-ercot-releases-preliminary>.

⁶³ Modo Energy, "ERCOT Market Outlook Report – Q1 2026," Modo Energy Research, 2026, <https://modoenergy.com/research/en/ercot-market-outlook-q1-2026-bess-revenue-demand-generation-capacity-prices>.

⁶⁴ NERC, 2025 Long-Term Reliability Assessment.

⁶⁵ NERC, 2025 Long-Term Reliability Assessment.

⁶⁶ R.A. Dyer, "ERCOT Gears Up For New Transmission Construction Projects—See the Maps," Cities Served by Oncor, September 8, 2025, <https://citiesservedbyoncor.org/ercot-gears-up-for-new-transmission-construction-projects-see-the-maps/>.

⁶⁷ Modo Energy, "RTC+B: How Real-Time Co-Optimization Will Affect Ancillary Services for Batteries in ERCOT," Modo Energy Research, 2026, <https://modoenergy.com/research/en/rtcb-real-time-cooptimization-rtc-ercot-ancillary-service-duration-soc-management>.

⁶⁸ Tyba Energy, "Guide to ERCOT RTC+B," accessed June 10, 2026, <https://www.tyba.ai/resources/guides/guide-to-ercot-rtcb/>.

⁶⁹ Tyba Energy, "Guide to ERCOT RTC+B."

ISO-NE & NYISO

Of the seven major ISO/RTO markets in the United States, New England and New York are projected to experience the least amount of load growth through 2030, with both regions anticipating annual growth rates of around 1%.⁷⁰ While demand growth may be less of an issue compared to other parts of the country, the northeast will still have to contend with several challenges in the coming years. Through 2030, tightening reserve margins, price volatility from uncertain capacity market forward curve forecasts in ISO-NE, and fuel security and reliability across both markets will need to be mitigated.

While both markets are predicted to have enough reserve capacity to meet NERC reliability standards through 2030⁷¹, higher renewable penetration and future thermal plant retirements are forecasted to put pressure on the grid during peak events. This is especially true as increasing electrification from heat pumps and EV charging, as well as increased adoption of behind-the-meter solar, take off in the northeast and push peak load hours further into the evening when solar generation begins to taper off and fossil fuel generation ramps up. The dispatchable characteristics of renewable hybrid plants (e.g., solar paired with battery storage) and fossil generation will be valuable to operators moving forward.

Although the need for dispatchable and firm generation resources is going to increase, constructing new generation of any type (but especially fossil generation) is difficult in ISO-NE and NYISO due to strong clean energy mandates^{72,73} and interconnection queue timelines averaging between 35 and 40 months.⁷⁴ As a result, generation retirements and deactivations are outpacing new supply, tightening reserves all over the region. In an effort to address this, ISO-NE has moved away from a Forward Capacity Auction every three years to an Annual Capacity Auction to be held one month before the applicable period for which capacity is being procured.⁷⁵ ISO-NE intends for the new structure to send clearer signals to market participants about when and where investment in new generation is needed. While the structure is rolled out, however, utilities in the area should expect price volatility as limited new entries and retirements pair with uncertainty around future grid conditions.^{76, 77, 78}

MISO

According to NERC's 2025 LTRA, MISO will confront major reliability issues beginning in 2028, earlier than any other assessed market region. According to the May 2026 EIA 860-M report, MISO is

⁷⁰ Federal Energy Regulatory Commission (FERC), "State of the Market," presentation, March 24, 2026, https://www.ferc.gov/sites/default/files/2026-03/26_State-of-the-Market_0324_1430.pdf.

⁷¹ NERC, 2025 Long-Term Reliability Assessment.

⁷² New York State Energy Research and Development Authority (NYSERDA), "Clean Energy Standard," accessed June 15, 2026, <https://www.nyserdera.ny.gov/All-Programs/Clean-Energy-Standard>.

⁷³ Gordon van Welie, "NEPPA Keynote," presentation to the Northeast Public Power Association (NEPPA), August 21, 2023 (Holyoke, MA: ISO New England, 2023), <https://www.iso-ne.com/static-assets/documents/2023/08/8-21-neppa-keynote-gvw-isone.pdf>.

⁷⁴ Rand et al., Queued Up.

⁷⁵ Alex Spratley and Jackie Triggs, "FERC Approves Tariff Revisions for ISO-NE Prompt Capacity Market," Washington Energy Report, April 8, 2026, <https://www.troutmanenergyreport.com/2026/04/ferc-approves-tariff-revisions-for-iso-ne-prompt-capacity-market/>.

⁷⁶ New York Independent System Operator (NYISO), Power Trends 2026: Annual Grid & Markets Report (Rensselaer, NY: NYISO, 2026), <https://www.nyiso.com/documents/d/guest/2026-power-trends>.

⁷⁷ ISO New England, "Spring 2026 Update on Regional Transmission Investment Now Available; 2 Projects under Construction in New England," ISO Newswire, April 14, 2026, <https://isonewswire.com/2026/04/14/spring-2026-update-on-regional-transmission-investment-now-available-2-projects-under-construction-in-new-england/>.

⁷⁸ Miriam Wasser, "Energy Company Proposes Big Natural Gas Pipeline Expansion in New England," WBUR News, May 19, 2026, <https://www.wbur.org/news/2026/05/19/energy-company-proposes-big-natural-gas-pipeline-expansion-in-new-england>.

expecting just over 25.1 GW of generator retirements by 2040. Of that, 14.8 GW is coal-fired generation, of which 12.1 GW is scheduled to be retired between 2026 and 2029. Coal makes up slightly more than a quarter of MISO's fuel mix,⁷⁹ making the loss of such a significant amount of baseload generation during a period of rapid load growth a major issue. It is possible that some generator retirements may be delayed due to Department of Energy 202(c) orders. For example, three MISO coal plants totaling 2.8 GW of capacity were scheduled to retire in part or in full in 2026 but received 202(c) orders to continue operating through the early fall.⁸⁰ By 2030, NERC forecasts MISO will add 5.5 GW of new generation, mostly solar which is accredited at a lower rating than fossil generation. In other words, coal will be replaced with intermittent solar, potentially necessitating energy storage buildout and operational adjustments.

Accompanying major operational and fuel mix changes is significant load growth driven by data centers. MISO is forecasting coincident total internal peak demand to rise from 127.1 GW during the 2026 Summer season to 143.7 GW by 2035 with 6 GW of data center demand expected to come online by 2027.⁸¹

PJM

PJM has been under increasing scrutiny from regulators, utilities, and customers for many years but concerns about its ability to efficiently procure supply peaked in July 2024 when its 2025/2026 Base Residual Auction (BRA) cleared record high prices.⁸² Prices were more than ten times higher than the previous BRA which PJM attributed to decreased long-term supply due to plant retirements, increased demand, and other market design changes like adjustments to the marginal effective load carrying capacity accreditation structure.⁸³ In response, PJM released a white paper in May 2026 proposing three paths forward.⁸⁴ Each path seeks to solve the growing reliability and inefficient supply investment problems in PJM.

The first path introduces a “come hedged” model under which load serving entities (LSE) would be mandated to enter the BRA with a minimum level of their expected forward capacity requirements hedged. In this structure, the BRA would no longer be relied upon as the sole or majority provider of power and would instead transition to a truly “residual” procurement system. Regional power needs would be met by their LSE with the market acting as a reliability backstop in the event of unexpected capacity degradation like forced outages.

The second path involves an expansion and centralization of the current reliability pricing model and BRA as well as the introduction of a “differential reliability” concept. Instead of conducting auctions for three-year time horizons, PJM would extend that window to seven years in one example and, regardless

⁷⁹ NERC, 2025 Long-Term Reliability Assessment.

⁸⁰ U.S. Department of Energy, Office of Cybersecurity, Energy Security, and Emergency Response (CESER), “2026 DOE 202(c) Orders,” accessed August 11, 2026, <https://www.energy.gov/ceser/2026-doe-202c-orders>.

⁸¹ NERC, 2025 Long-Term Reliability Assessment.

⁸² Laurie C., “PJM 2026/2027 Capacity Auction Clears at \$329.17 | Record-High Rates,” Energy News, July 2025, <https://energy-news.aes-energ.com/pjm-2026-2027-capacity-auction-results>.

⁸³ Ashley J. Lawson, PJM's Electric Capacity Market: Background and Current Issues, CRS Report No. R48553 (Washington, DC: Congressional Research Service, June 2, 2025), https://www.congress.gov/crs_external_products/R/PDF/R48553/R48553.1.pdf.

⁸⁴ PJM Interconnection, Powering Reliability Through Market Design: Addressing Rising Demand and Constrained Supply, and Stimulating Investment To Support Durable Reliability (Valley Forge, PA: PJM Interconnection, May 6, 2026), <https://www.pjm.com/-/media/DotCom/library/reports-notice/special-reports/2026/20260506-powering-reliability-through-market-design.pdf>.

of time horizon, seek to provide roughly 70% of all capacity obligations. The remainder would be procured annually by LSE. This second approach provides long-term and much-needed price certainty to make large-scale generator investments economical. It also reduces price volatility from contract laddering. Unlike the first path, the shared reliability compact is modified in path two. Reliability is differentiated geographically or by customer class during periods of supply scarcity to incentivize LSE investment in generation.

In the third and final path, PJM would shift revenue recovery away from the capacity market to the energy and ancillary services (E&AS) markets and pair the structural change with long-term forward energy contracting requirements. This is not a wholesale abandonment of a capacity market nor a swap to an energy-only market like ERCOT, but instead an emphasis on a new financial instrument to preserve reliability. The capacity market will remain to backstop revenues for future investments. The third path also increases the E&AS market price limit to reflect scarcity conditions and attempts to provide a solution to the “missing money” problem.

As these major market reform discussions are occurring, PJM continues to forecast rapid load growth through the 2030s. Revised forecasts released in early 2026 predict PJM’s summer peak load will increase from 156 GW in 2026 to 222 GW in 2036.⁸⁵ However, development constraints (e.g., interconnection queue timelines, equipment and material procurement, etc.) may limit the amount of new load that can be successfully brought online.

SPP

SPP’s upcoming challenges can be divided into two categories: expansion and adequacy. Like the conditions faced by other electric markets in the U.S., SPP is dealing with significant load growth from data centers, industrial loads, and cryptocurrency mining operations.⁸⁶ Unlike most other markets in the U.S., however, SPP is staging and implementing a significant expansion, SPP Markets+, into WECC territory.⁸⁷

Like other markets, SPP is dealing with significant uncertainty in determining which loads will manifest in the coming years. Load growth is arriving and SPP has identified two probable futures for 2034: Future 1 with a projected 69 GW peak, and Future 2 with an 80 GW peak.⁸⁸ Demand growth is driving investment in significant generation resources as well as transmission grid expansion. SPP has been forced to redesign their generator interconnection process to ensure planning reserve margins remain adequate. There is also renewed concern that winter storms will create fuel insecurity and instigate rolling blackouts when paired with the “always on” demand profiles of some large loads. Thus, SPP’s Expedited Resource Adequacy Study (ERAS) has been introduced to simultaneously accelerate the integration of a diverse portfolio of generators that can provide both dispatchable energy and hedge against fuel risks.⁸⁹ 70% of the ERAS queue is natural gas due to its high accreditation value.⁹⁰

⁸⁵ Ethan Howland, “PJM Trims Near-Term Load Forecast on Stricter Data Center Vetting, Economic Outlook,” Utility Dive, January 15, 2026, <https://www.utilitydive.com/news/pjm-interconnection-load-forecast-data-centers/809717/>.

⁸⁶ NERC, 2025 Long-Term Reliability Assessment.

⁸⁷ Southwest Power Pool (SPP), “Markets+,” accessed June 23, 2026, <https://www.spp.org/western-services/marketsplus/>.

⁸⁸ NERC, 2025 Long-Term Reliability Assessment.

⁸⁹ Southwest Power Pool, Market Monitoring Unit, 2025 Annual State of the Market Report (Little Rock, AR: Southwest Power Pool, 2026), https://www.spp.org/documents/76798/2025_annual_state_of_the_market_report.pdf.

⁹⁰ SPP Market Monitoring Unit, 2025 Annual State of the Market Report.

The revised, if temporary, ERAS structure is designed to ensure reliability in the near term but is just one step that SPP has taken towards increasing resource adequacy in the West. Following first-mover market development from CAISO's EDAM, SPP's Markets+ structure was unveiled in 2022 as a voluntary, centralized day-ahead and real-time unit commitment and dispatch platform intended to increase efficient access to low-cost resources and integrate renewables.⁹¹ It is currently in the implementation phase and set to go live in October 2027, with several major utilities committed for the 2027 debut including Arizona Public Service, Salt River Project, and the Public Service Company of Colorado.⁹² Tri-State and Basin are also slated to join in 2027 as Phase 1 participants. Compared to CAISO's EDAM, which is an extension of its internal day-ahead market, Markets+ is a standalone SPP market service offering.⁹³ Utilities that join Markets+ retain balancing authority control and hegemony while gaining access to the efficiency, transparency, and price stability of a day-ahead market.

⁹¹ Hartigen, "Markets+ vs CAISO EDAM: Key Differences for Western Market Participants," PowerOptix Blog, accessed August 11, 2026, <https://www.hartigen.com/blog/markets-vs-caiso-edam-key-differences>.

⁹² Southwest Power Pool (SPP), "Markets+ Participants," Markets+, accessed June 24, 2026, <https://www.marketsplus.org/current-participants/current-participants-2>.

⁹³ Hartigen, "Markets+ vs CAISO EDAM."

Conclusion

The significant changes underway in the U.S. energy industry are reflected in accelerating electricity demand, an evolving generation mix, and increased investment in new generation, energy storage, and grid infrastructure. Utilities are under growing pressure to adapt to these changes while also managing generation retirements, lengthy interconnection queues, equipment supply constraints, and rising infrastructure costs.

These challenges are further complicated by geopolitical developments and regional differences in energy markets. Global events can affect domestic fuel, equipment, and transportation costs, while the impacts of load growth, resource adequacy, market design, transmission needs, and generation retirements vary considerably across regions. As a result, there is no single approach to addressing the industry's evolving needs.

For electric cooperatives, these trends reinforce the importance of maintaining a diverse and flexible resource portfolio while balancing reliability, resilience, and affordability. Co-ops are already adapting through investments in natural gas, renewable generation, battery storage, and other resources, but will continue to face decisions around generation retirements, new capacity, transmission, market participation, and infrastructure costs. The path forward will vary by electric co-op and region, but the central objective remains the same: ensuring that co-ops can meet growing electricity needs while continuing to provide safe, affordable, and reliable power to their members and the rural communities they serve.